Fuel Life Cycle Assessment Model Methodology

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Preface

The Government of Canada's Fuel Life Cycle Assessment (LCA) Model (the Model) is a tool that allows users to calculate the life cycle carbon intensity (CI) of fuels and energy sources produced and used in Canada. The Model uses a life cycle approach, which considers the greenhouse gas (GHG) emissions involved in multiple stages of the fuel's production process, from feedstock production to fuel combustion.

This document describes the general assumptions, data sources, and calculation procedures associated with the development of the Model.

Throughout the development of the Model, Environment and Climate Change Canada (ECCC) conducted extensive quality assurance and quality control (QA/QC) activities. The QA/QC activities consisted of a review of the methodologies, calculation procedures, data inputs, and literature sources used to generate CIs for various fossil and low carbon-intensity fuels (LCIF).

Since the first formal publication of the Model in 2022, ECCC established a process to update the Model on a two-year cycle. ECCC pre-publishes proposed updates to the Model to increase transparency and to allow stakeholders to submit comments prior to the publication of the formal versions of the Model. The comments submitted in response to the pre-publications are considered during the development of the formal versions.

Ongoing development and maintenance activities for the Model are prioritized based on engagement with the Stakeholder Technical Advisory Committee (STAC), comments received from individual stakeholder and other governmental departments and issues identified by ECCC.

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Definitions

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).

Biofuel: any liquid, gaseous or solid fuel produced from biomass.

Biogas: gaseous mixture that is recovered from the anaerobic decomposition of biomass, consists primarily of methane and carbon dioxide and contains other constituents that prevent it from meeting the standard for injection into the closest natural gas pipeline.

Biomass: comprises the biodegradable portion of products from agriculture, forestry, animal, waste and related industries. Examples include residues and waste from trees, plants and crops, food co-products, and the biodegradable portions of municipal waste.

Carbon dioxide equivalent (CO_2e): quantity of carbon dioxide that would be required to produce an equivalent warming effect over a given time period.

Carbon Intensity: in relation to a pool of a given type of fuel, this means the quantity of CO_2e in grams that is released during the activities conducted over the fuel's life cycle — including all emissions associated with the extraction or the cultivation of feedstock used to produce the fuel, with the processing, refining or upgrading of that feedstock to produce the fuel, with the transportation or distribution of that feedstock, of intermediary products or of the fuel and with the combustion of the fuel — per megajoule of energy produced during that combustion.

Characterization factor: factor derived from a characterization model which is applied to convert assigned life cycle inventory analysis result to the common unit of the category indicator (ISO 14040). Also called impact factor.

Ecosphere: consists of the entire natural environment. Examples include air, water, and natural resources.

Elementary flow: flow that is exchanged with the environment, for example, greenhouse gas.

Feedstock: resource that is extracted, cultivated, collected, harvested, and/or processed and delivered at the gate of the conversion plant from which fuel is produced.

Flow: material or energy that enters or leaves a process.

Fuel pathway: a collection of unit processes, modelling parameters, and background data in the Model that allows the determination of the carbon intensity of a fuel from a particular feedstock type.

Functional unit: quantified performance of a product system for use as a reference unit (ISO 14040).

Intermediate flow: flow that is exchanged within the technosphere (that is, within human control). In the context of the Fuel LCA Model, any flow that is not an elementary flow.

Life cycle assessment (LCA): compilation and evaluation of the inputs, outputs, and the potential environmental impacts of a product system throughout its life cycle (ISO 14040).

Life cycle impact assessment (LCIA): phase of LCA aimed at understanding and evaluating the magnitude and significance of the potential environmental impacts for a product system throughout the life cycle of the product (ISO 14040).

Life cycle inventory (LCI): phase of LCA involving the compilation and quantification of inputs and outputs for a product through its life cycle (ISO 14040).

Life cycle: consecutive and interlinked stages of a product system, for example, from feedstock acquisition to combustion of the produced low carbon-intensity fuel.

Life cycle stage: collection of unit processes connected by a network of flows that models a main stage of the life cycle of a fuel. In the Model, there are five life cycle stages: feedstock production, feedstock transportation, fuel production, fuel distribution, and fuel combustion.

Low-carbon intensity fuel (LCIF): fuels, other than the fossil fuels, with a lower carbon intensity than fossil fuels. This definition includes hydrogen.

Monte Carlo analysis: technique used in computer simulation that serves to generate probabilistic outcomes of a model repeatedly and that, for all the simulations, provides a randomly chosen value for each variable on the basis of each distribution of the input parameters.

System process: process that contains the LCI of a group of unit processes.

Technosphere: consists of all anthropogenic developments. Once materials from the ecosphere are extracted and in human-control, they are part of the technosphere.

Unit process: smallest element for which input and output data are quantified (ISO 14040).

Acronyms

AR5	IPCC's 5th Assessment Report
AR6	IPCC's 6th Assessment Report
CAFE3	*Canadian Analytical Framework for the Environmental Evaluation of Electricity*
CCS	Carbon capture and storage
CI	Carbon intensity
CIRAIG	International Reference Centre for the Life Cycle of Products, Processes and Services
CNG	Compressed natural gas
CRSC	Canadian Roundtable for Sustainable Crops
DDG	Distiller's dried grains
DDGS	Distiller's dried grains with solubles
DQI	Data quality indicators
ECCC	Environment and Climate Change Canada
GWP	Global warming potential
GHG	Greenhouse gas
GREET	Greenhouse gases, Regulated Emissions, and Energy use in Technologies
HHV	Higher Heating Value
IEA	International Energy Agency
IPCC	Intergovernmental Panel on Climate Change
LCA	Life cycle assessment
LCIA	Life cycle impact assessment
LCI	Life cycle inventory
LCIF	Low-carbon intensity fuel
LNG	Liquefied natural gas
NEB	National Energy Board
NETL	National Energy Technology Laboratory
NIR	National Inventory Report
MEIT	National Marine Emissions Inventory Tool
NGL	Natural gas liquids
OPGEE	Oil Production Greenhouse gas Emissions Estimator
PRELIM	Petroleum Refinery Life-Cycle Inventory Model
RNG	Renewable natural gas
R&D GREET	Research & Development Greenhouse gases, Regulated Emissions, and Energy use in Technologies
RoW	Rest of World
RU	Reconciliation unit
SMR	Steam methane reforming
SOC	Soil organic carbon

UCO	Used cooking oil
UNEP	United Nations Environment Programme
WDG	Wet distiller’s grain
WDGS	Wet distiller’s grain with solubles

Chapter 1: Introduction and general principles

1.1 Presentation of the Fuel LCA Model

The Government of Canada developed a Fuel Life Cycle Assessment (LCA) Model (the Model) to calculate the life cycle carbon intensity (CI) of fuels and energy sources produced or used in Canada. The Model helps to support the delivery of regulations and programs as part of Canada's actions on climate change.

For example, the *Clean Fuel Regulations* use the Model to determine the CI of fuels, material inputs and energy sources when creating credits. The Model is robust, transparent, bilingual, and based on the Canadian context. Users of the Model include industry, academia, LCA practitioners, governmental and non-governmental organizations, indigenous organizations, and other organisations with interest in the energy sector.

The Model consists of the following 3 components:

- Fuel LCA Model Database: Contains a library of CI datasets and fuel pathways developed to model a CI specific to a fuel or an energy source
- Fuel LCA Model Methodology (this document): Describes the methodology, data sources and assumptions used in the development of the Model. The document provides the rationale supporting the methodological approach
- Fuel LCA Model User Manual: Provides information on general definitions and concepts related to LCA as it relates to the Model. It also provides technical guidance on how to perform basic operations in the openLCA software that are required for CI calculations

1.2 Purpose of the Fuel LCA Model Methodology

The purpose of this document is to explain the methodology used in the development of the Model. It describes the general assumptions, data sources and calculation procedures used in the development of the Model. It also describes some general LCA concepts used in developing the database.

The document is divided into the following chapters:

- Chapter 1: Introduction and general principles: Presents the Model and provides some general concepts used in the rest of the document
- Chapter 2: Goal and scope of the Fuel LCA Model: Provides the goal and scope of the Model, as well as assumptions and modelling choices used for the development of the Model Database
- Chapter 3: Fuel LCA Model Data Library: Describes the modelling approach, modelling assumptions, and data sources for each category of system processes in the Model Data Library
- Chapter 4: Fuel Pathways: Describes the structure of the fuel pathways and the modelling approach of configurable processes included in the Model Database

This document is updated with each formal publication of the Model planned every 2 years.

For instructions on how to set up and use the Model Database, please refer to the Fuel LCA Model User Manual.

1.3 Related standards

The Model was designed to align with the following standards:

- ISO 14040 - Environmental management - Life cycle assessment - Principles and Framework: This standard provides terminology related to LCA and the structure to follow when performing an LCA
- ISO 14044 - Environmental management - Life cycle assessment - Requirements and guidelines: This standard provides requirements and guidelines when conducting an LCA and is used in parallel with ISO 14040

1.4 General principles and fundamentals of greenhouse gas assessments for LCIF pathways

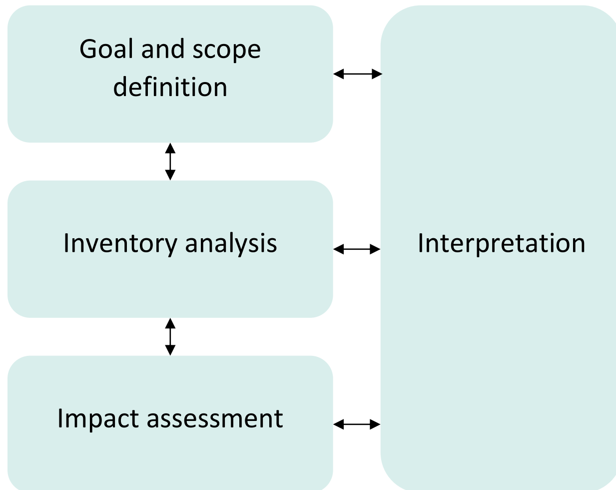
1.4.1 Description of the general LCA concept

LCA studies are performed in a structured manner, with certain principles guiding their development. ISO 14040 describes four phases for an LCA study as follows:

- Goal and scope definition: defines the depth and breadth of the LCA study depending on the goal of the particular LCA
- Inventory analysis: lists and quantifies all emissions and extractions to and from the environment involved in the life cycle of the system being studied (for example, the total mass of methane emitted during the life cycle, expressed in kilograms of methane)
- Impact assessment: converts the inventory into indicator results (for example, the carbon footprint in kilograms of CO_2 equivalent)
- Interpretation: summarizes and discusses results to draw conclusions, make recommendations, and for decision-making, in accordance with the goal and scope definition

Figure 1 shows the four phases of an LCA study. The relationship between these phases is presented by arrows to depict that LCA is an iterative process where the results of one phase can affect the outcome of both preceding and subsequent phases. The combination of the four phases of the LCA process results in a more complete picture when assessing the environmental impacts of a given process.

Figure 1: The four phases of an LCA study adapted from ISO 14040



1.4.2 Principles and appropriateness

Since the Model was designed to align with ISO 14040, it was based on many of the same principles. Some of the principles relevant to the Model are described below.

Life cycle perspective

The Model and the calculation of LCIF CIs are based on a life cycle approach. This approach accounts for activities from raw material extraction and acquisition to end use and combustion. This allows users to consider the environmental impacts of a full product system and to identify where environmental burdens exist so they can be addressed or avoided.

Greenhouse gas focus

The Model currently focuses on greenhouse gas (GHG) emissions. The Model does not consider economic and social factors when determining LCIF CIs.

Transparency

Transparency is an important requirement of LCA due to its complex nature. To ensure transparency, the Model includes a description of the methodology, a list of the documentation used, and calculation procedures at the unit process level (refer to section 0 for the definition of a unit process). Dataset (collections of data) documentation is in line with the Global Guidance Principles for Life Cycle Assessment Databases (UNEP, 2011).

1.4.3 LCA modelling concepts and definitions

The Model relies on a series of concepts used in LCA to keep information organized. The following concepts are referred to throughout the Model documentation:

- Unit process: Smallest divisible activity of a life cycle
    - Transforms quantities of inputs into quantities of outputs
    - Can use modeling 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 (for example, extractions and emissions)
    - While “intermediate flows” refer to exchanges between unit processes (for example, electricity)
- Life cycle stage: Specific part of a life cycle (for example, 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
- Global parameter: An openLCA term for a variable input/output amount
    - Can be a calculation rule, formula, or a fixed value
    - User can modify the global parameter in a unit process under certain circumstances
- System process: Process that contains the LCI of a group of unit processes

Chapter 6 of the Fuel LCA Model User Manual provides detailed information about LCA concepts and definitions. The document also defines concepts that are part of 0of the Fuel LCA Model Methodology such as functional unit, allocation procedures and life cycle impact assessment (LCIA) method.

Chapter 2: Goal and scope of the Fuel LCA Model

This chapter outlines the goal and scope of the Model, as well as the methodology that is consistent with all processes in the database. This includes the data collection methods, data quality indicators, LCI assessment methods, and limitations of the LCA methodology.

2.1 Goal

The goal of the Model is to allow the life cycle CI calculation of fuels and energy sources produced and used in Canada. The Model provides users with three components to calculate CIs: the Fuel LCA Model Database, Fuel LCA Model Methodology, and Fuel LCA Model User Manual.

The Fuel LCA Model Database consists of a Data Library of system processes of foundational CIs for fuel pathways, and configurable unit processes (configurable processes). While processes in the Data Library have been developed to model the life cycles of fuels produced in Canada, the Model also includes processes that model activities that occur outside Canada and that are relevant to the Canadian context. Fuel pathways are empty unit processes that allow users to model the life cycle of specific systems in the Canadian context, and configurable processes are partially completed unit processes that support fuel pathways.

The Model has been developed in conformity with ISO 14040 and 14044 requirements. As stated in ISO 14040, the CI results calculated by the Model are based on a relative approach, which means that they represent potential GHG emissions as opposed to actual GHG emissions. Therefore, the Model results should not be used to make direct comparative assertions for CIs or environmental impacts either outside of the scope of a specific program or without meeting the requirements of ISO 14040 and ISO 14044 standards. Programs that allow or require the use of the Model may have specific documentation on how to use the Model under the program.

2.2 Scope

2.2.1 Functional unit

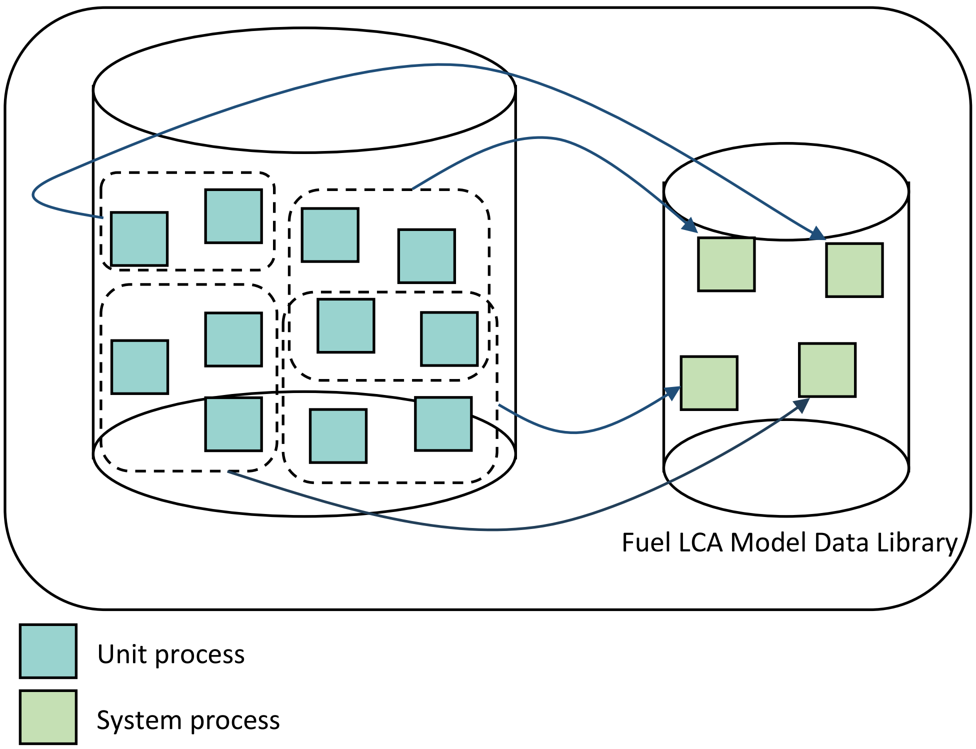
A functional unit is defined as the quantified performance of a product system for use as a reference unit. This facilitates determination of reference flows for the systems being studied. There are two functional units for the fuel pathways in the Model. The first is 1 MJ of energy content based on the Higher Heating Value (HHV) delivered to the end user and used for its energy content. The energy content excludes fossil-based denaturant added to the fuel. The second is 1 kg of pure fuel at the fuel production gate and is used only by the hydrogen pathway – mass basis.

CIs are expressed in grams of carbon dioxide (CO_2) equivalents (g CO_2e) per functional unit produced. For the energy-based functional unit, the Data Library includes LCIF combustion emission factors for use in the Fuel Pathways that do not consider the efficiency of the combustion device; a single combustion emission factor per fuel is applied to calculate the CI. However, the Data Library includes some fossil fuel emission factors without upstream emissions (not life cycle basis).

2.2.2 Data library of system processes

The Model Database includes a data library of several hundred system processes which can be used when modelling CIs. These system processes were produced from the life cycle inventory (LCI) of multiple unit processes that were created as part of the development of the Model. System processes allow for the aggregation and simplification of multiple unit processes and increase accessibility of the Model. A visualization of the development of the Data Library is shown in Figure 2.

Figure 2: Visualization of the development of the Model Data Library



2.2.3 Fuel pathways and configurable processes

The Model contains unit processes that are structured to model various LCIF pathways. These pathways allow users to enter data and, using the system processes in the Data Library, generate a CI tailored to their modelling needs.

The Model also contains configurable processes that model certain activities. These unit processes are partially modelled and allow the user to replace certain flows with other flows representing their situation.

2.2.4 Geographical scope

The Model was developed to model the Canadian context. As such, most processes included in the Model use Canadian data, when available, and were developed such that they can be applied as proxy for any location in Canada, unless otherwise specified. For example, natural gas production was modelled using Canadian data and sorghum was modelled using United States (U.S.) data, but both processes can be used regardless of their geographical location.

System processes that are applicable beyond the Canadian context are identified as such in the Data Library and are listed below, along with the section containing their documentation:

- Chemical inputs: Section 3.1
- Combustion emission factors: Section 3.2
- Electricity generation technologies: Section 3.3.4
- Other energy sources: Section 3.4
- Cultivation of agricultural crops: Section 3.5.2
- Agricultural crop residues: Section 3.5.3
- Other waste materials: Section 3.5.4
- Fossil fuels: Section 3.6
- Renewable fuels: Section 3.7
- Transport: Section 3.8

The Model also contains some international feedstock and electricity processes to better reflect the complex fuel production system in Canada. The modelling choices and data documentation for each type of international process are indicated in the specified sections of this document. The international processes included in the Data Library are listed below:

Feedstock

- Sugar cane for Brazil: Section 3.5.2

Grid electricity

- United States: Section 3.3.2
- Countries other than Canada and the United States: Section 3.3.2

2.2.5 Temporal scope

System and configurable processes are developed or updated with the most recent data available at the time of their development. Process modelling systems that evolve rapidly over time are updated more frequently to ensure they accurately reflect current conditions. Examples of such processes include electricity and natural gas production. Generally, data is collected for a period of one year, but there are a few exceptions such as crops modelling, which is based on a 5-year average to minimize the impact of the inherent annual variability of agricultural systems. Chapter 3: provides more information on the scope of data collection for each process.

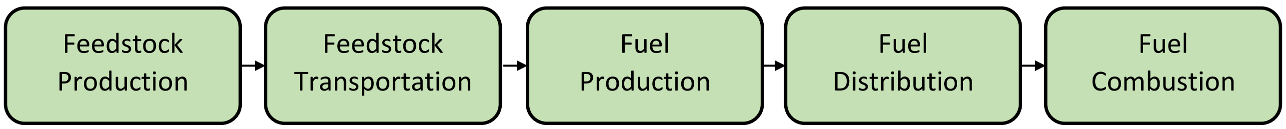
In order to remain consistent with the time horizon of global warming potentials (GWP) included in the Model (refer to section 2.8), only emissions or uptake occurring within a 100-year timeframe are considered. For this reason, long-term emissions or uptake beyond this timeframe of 100-year such as emissions from hydro reservoirs are excluded.

2.3 System boundaries

System boundaries are established in LCA to include the significant life cycle stages and unit processes, as well as the associated elementary flows in the analysis. The general system boundaries for fuel pathways in the Model are defined by the five main life cycle stages, which are outlined in Figure 3.

The system boundary of each life cycle stage includes the life cycle GHG emissions associated with the use of feedstock, electricity inputs (both grid and onsite generation), fuel inputs, material inputs (for example, chemicals), transportation processes, process emissions (for example, venting and flaring), and other direct emissions. Excluded processes and cut-off criteria are presented in the following sections.

Figure 3: The five life cycle stages of LCIF in the Model



Feedstock Production: resource acquisition (such as natural gas extraction and soybean cultivation) and transformation (such as natural gas upgrading and soybean oil extraction) into substances ready for transport to the fuel production plant.

Feedstock Transportation: transportation of feedstock from its last transformation activity to the fuel producer.

Fuel Production: conversion of feedstock into fuel, including potential pre-processing of feedstock, and post-processing and upgrading of fuel to final fuel product.

Fuel Distribution: storage and handling of fuel, transport of finished fuel product to storage and to final user.

Fuel Combustion: combustion of the final fuel product by the end user.

2.3.1 Excluded processes

The LCI in the Model prioritizes 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 are excluded from the Model Database due to their negligible contribution or limitations such as lack of data, methods or high uncertainty:

- Construction and decommissioning of equipment and facilities
- Manufacturing of fuel transportation infrastructure (such as pipelines, trucks, ships, roads)
- Manufacturing of fuel combustion infrastructure (such as vehicles, boilers)
- Direct land use change of equipment, facilities, and infrastructure
- Solid waste management processes and wastewater treatment processes
- Research and development activities

- Indirect activities associated with fuel production (such as marketing, accounting, commuting, and legal activities)
- Indirect land use change

These exclusions have been applied consistently across the Model, which limit the risk of bias and inconsistency between the different pathways.

2.3.2 Cut-off criteria

While the excluded processes represent explicit activities that are out of the scope of the Model, cut-off criteria are applied in LCA to the selection of processes or flows that are included in the study. The processes or flows below these cut-offs or thresholds may be excluded from the Model. Different types of criteria are used in LCA to decide which inputs and outputs are to be considered in the LCA, including mass, energy, and environmental significance. Definitions of cut-off criteria specified in ISO 14044 include:

- Mass: inclusion of all inputs that cumulatively contribute more than a defined percentage of the product system's material inputs
- Energy: inclusion of all inputs that cumulatively contribute more than a defined percentage of the product system's energy inputs
- Environmental significance: inclusion of inputs that are specially selected because of environmental relevance although they may fall below other cut-off criteria (for example, mass)

As noted in ISO 14044, making the initial identification of inputs and outputs based on mass contribution alone may result in important inputs or outputs being omitted from the analysis. As such, energy and environmental significance have also been used as cut-off criteria.

In the Model, effort was made to include all the relevant flows associated with each process with the exception of the excluded processes listed in Section 2.3.1. During the completeness and sensitivity check, a 1% cut-off criteria has been applied on the environmental significance, as calculated by the impact assessment method. Cut-off criteria were applied at the individual unit process level.

Based on the cut-off criteria, the following additional processes are excluded from the Model Database:

- Ancillary materials (such as lubricants, cleaning agents, and packaging)
- Water from municipal water supply systems or directly extracted from surface and underground sources

2.4 Data collection and data quality

This section outlines a set of data quality preferences established for the Model and which were applied during the modelling of the Data Library.

Data collection to develop the LCI was based on review and compilation of data from a wide range of sources including government publications and statistics, industry publications and statistics, other fuel LCA modelling tools, and data for low carbon fuel systems with little or no current production in Canada.

The LCI data used in the fuel modelling is a mixture of data that is specific to Canadian systems and data from other jurisdictions that is considered adequately representative of Canada. When relevant, datasets from other jurisdictions were adapted to the Canadian context (for example, by replacing an electricity input with the Canadian grid mix process).

Due to the regional variability in a number of aspects in Canadian fuel production, the Model considers regional variation by providing some system processes defined at the regional (Eastern or Western Canada) or provincial level. The following regional factors, which could influence CI for LCIFs, were used in the Model, within the confines of the available data:

- Differences in fuel consumption in forest harvesting, sawmilling and other processing activities
- Background energy systems such as variations in electricity grids providing energy to fuel conversion processes

The following sections present the data collection practices used in the development of the Model.

2.4.1 Data collection for system processes in the Data Library

The Model contains several different data sources for modelling the hundreds of system processes. The data quality levels and definitions considered for Model development are listed below:

- High quality data
    - Regionally specific and recent (less than 5 years)
    - Based on measurements and published by official and verified sources (for example, government statistics)
    - Collected from more than 50% of sites in the region under study
- Acceptable quality data
    - Average from a larger region including the region under study and less than 10 years
    - Based on measurements and published in scientific publications or by an industry organization
    - Collected from a sample of sites
- Lowest acceptable quality data
    - Data or LCI extracted from recognized tools and initiatives (such as R&D GREET)
    - From a different region but representative of the region under study and less than 15 years
    - Measurement from a single site or expert estimate from a qualified individual

Time and effort were invested to collect data that corresponds to the “high quality data” level. When these types were not available, data corresponding to the “acceptable data quality” and “lowest acceptable data quality” levels were considered. Data sources that could not achieve the lowest acceptable data quality level were not included in the Model.

2.5 Data uncertainty

Data uncertainty was applied in the development of the Model to evaluate the quality of the data used for modelling the system processes of the Data Library. While data uncertainty was applied during model development, its results are not available in the Data Library.

To quantify data uncertainty, data quality indicators (DQI) were used to assess each flow using a data quality matrix approach. These scores were then used to assess uncertainties of the data and subsequently assess the uncertainty of the Model and the results with a Monte Carlo analysis.

When quantitative information about uncertainty was available (for example, sample of data or standard deviation), the uncertainty was applied by specifying the dispersion parameters of the distribution type (for instance, uniform, lognormal or triangular distribution).

In instances where quantitative information about uncertainty was not directly available, the pedigree matrix provided by Weidema et al. (2013) was used. It contains five types of DQI, each of which is assigned a score from 1 to 5 for the following parameters:

- Reliability
- Completeness
- Temporal correlation
- Geographical correlation
- Further technological correlation

Based on these criteria, scores are assigned to the data and the linked pathways. These scores are then combined with basic uncertainty factors to develop squared geometric standard deviations for use in Monte Carlo analysis to determine the influence of data quality on the reliability of the results.

Raw data and intermediate calculations used in the Model use all available significant figures provided in the data source. While these significant figures are available in openLCA, the number of significant figures presented in the CI calculation tables in this document is set to 4.

2.6 Co-product allocations

In cases where the studied system is a multifunctional process which generates more than one marketable product, the environmental burden related to that process may be distributed amongst the different outputs of the system (main product and co-products) using an allocation method. According to ISO 14044, the allocation approach should be avoided by further sub-dividing the system to isolate co-products, or by using the system boundary expansion approach. If allocation cannot be avoided, an allocation method based on physical causality (such as mass or energy content) or other relationships (such as economic value) should be used.

The need to allocate environmental burdens between products and co-products arises at several points in the life cycle of several fuels, including:

- Canola and soybean meal co-products produced from vegetable oil extraction
- Animal feed and combined heat and power production co-products from ethanol production
- Agricultural and forest residues derived from primary cultivation and harvesting that are used to produce biofuels
- Extraction and processing of liquid and gaseous fossil fuels

The Model applies different allocation approaches, which are defined in the following sections.

2.6.1 Energy-based allocation

In the Model, energy content is the default allocation approach. In fuel production systems, energy content, also known and referred to as the HHV, is generally recognized as the most appropriate metric.

2.6.2 Mass-based allocation

The Model uses mass allocation for wood fibre and animal fat feedstock processes, as well as for the configurable process for oil from oilseeds.

2.6.3 System expansion

The system expansion approach involves accounting for the environmental burdens associated with the substituted product of a co-product produced at the fuel production facility. The environmental burdens associated with this substituted product are subtracted from the CI of the product system under study. For example, a fuel production plant can generate excess electricity as a co-product which can then be used on site or exported to the grid. With a system expansion approach, it is assumed that the excess electricity will "displace" the environmental burdens associated with grid electricity (which represents the substituted product).

System expansion is used in the Model for excess electricity and steam produced at the fuel production facility. In the case of excess electricity, for provinces, territories, and United States, the Model includes a list of processes for excess electricity representing each regional grid mix. There is a single process for excess steam.

System expansion can also be applied when a waste material is used as feedstock for LCIF production and results in real methane reductions. In this case, the system boundary around the waste material for fuel production should be expanded to include the emission differential between using the waste material for fuel production and a baseline scenario that would have occurred if the waste material was not used for fuel production.

2.6.4 Cut-off allocation approach

Some of the feedstock processes in the Data Library represent wastes from other industries such as used cooking oil from restaurants and animal by-products from slaughterhouses. This is a case of waste recycling. The Model applies the "cut-off" allocation approach to waste recycling. Under this approach, if a waste material is used for another purpose instead of disposal, the producer of the waste material is not attributed any burdens for disposal, and the user of the waste material is not attributed any environmental burdens for the upstream production of the material.

2.7 Greenhouse gases, biogenic carbon and land use change

In accordance with the scope of the National Inventory Report (NIR), the Model LCI includes CO_2, methane (CH_4), nitrous oxide (N_2O), halocarbons and related components, but excludes near-term climate forcers (for example, CO, NOx, VOC, black carbon) and other forcing factors (for example, albedo effects) (Environment and Climate Change Canada [ECCC], 2026). Biogenic CO_2 emissions associated with LCIF combustion are set to zero in the LCI of the Model. In line with the Intergovernmental Panel on

Climate Change (IPCC, 2006), it is assumed that the biogenic CO_2 emissions are balanced by carbon uptake prior to harvest.

Biogenic CO_2 emissions from changes in land management practices are considered in the modelling of crops: changes in crop productivity and crop residue carbon inputs, changes in tillage practices and changes in summerfallow area[1]. Carbon emissions from changes in the proportion of annual and perennial crops are not considered; indirect land use changes are excluded from the Model.

Emissions and uptake from land transformation related to all relevant activities (including electricity production infrastructure and activities) are excluded when assumed that the land will return to its natural or original state within 100 years, as described in Section 2.2.5. Otherwise, they are included (for example, hydro reservoirs, which are assumed to permanently change the land). As explained in Section 2.2.5, long-term emissions or uptake occurring after 100 years are neglected.

Finally, it is generally assumed that provision of agricultural and wood biomass feedstocks is within the capacity of existing commercial production and harvesting regions and does not require conversion of land from other uses (other than the ones mentioned above).

2.8 Life cycle impact assessment methods

Life cycle impact assessment (LCIA) methods are used in LCA to convert LCI data (environmental emissions and feedstock extractions) into a set of environmental impacts using impact factors.

In the Model, there are two LCIA methods available for calculation. These methods employ impact factors that use global warming potentials (GWP) for a 100-year time horizon. The 100-year time horizon is the impact factor most-widely applied in CI studies, which facilitates ease of comparison to other study results. The two LCIA methods available in the Model use the GWP-100 values sourced from the IPCC's Fifth Assessment Report (AR5) (IPCC, 2013) and Sixth Assessment Report (AR6) (IPCC, 2021) respectively. For both LCIA methods, the near-term climate forcers and climate-carbon cycle feedbacks are not considered for consistency with the NIR and other GHG accounting initiatives in Canada. The CIs resulting from the LCIA method are expressed in grams of CO_2e per MJ of HHV energy.

Table 1 provides a summary of the GWP for the main GHGs for both LCIA methods. A complete list of GHGs with their associated GWP in the two LCIA methods are available in the Model Database in their respective Impact categories under the Indicators and parameters section in openLCA.

In remaining consistent with the Government of Canada's policy on biogenic carbon, as described in Canada's NIR (ECCC, 2026), the GWP for uptake of carbon during the biomass growth and emissions of biogenic carbon from combustion of low carbon fuels are not reported. The assumption is that biogenic CO_2 emissions associated with LCIF combustion are balanced by carbon uptake prior to their harvest. The Model considers that CO_2 emissions or atmospheric CO_2 uptake from changes in soil organic carbon (SOC) due to land management practices have the same GWP as fossil CO_2. It is considered that these emissions or uptake have a lasting effect on the concentration of GHG in the atmosphere.

[1] Biogenic emission from changes in summerfallow area are included for sorghum only.

Furthermore, the Model does not take in consideration the temporal profile of uptake and emissions of biogenic carbon (also called the carbon debt). In other words, the capture of carbon during forest biomass growth will fully compensate carbon emissions from biomass combustion independently of the time delay between these two events. The temporal aspect is not included to be consistent with the GHG accounting rules in other governmental programs and initiatives.

Table 1: Select characterization factors for calculating carbon intensities using IPCC AR5 and AR6 GWP-100

Greenhouse gas	**FuelLCAModelLCIA_AR5 GWP-100 (gCO2e/g)**	**FuelLCAModelLCIA_AR6 GWP-100 (gCO2e/g)**
CO_2	1	1
CO_2 (biogenic)	0	0
CO_2 (land use change)	1	1
CH_4 (fossil)	30	29.8
CH_4 (biogenic)	28	27.9
N_2O	265	273
Sulfur hexafluoride (SF_6)	23,500	24,300

2.9 Limitations of the Fuel LCA Model

The Model is based on current data and information regarding Canadian production systems, and some foreign systems. As such, the Model does not include information regarding future technologies or policy implications on the Canadian energy sector.

Given that the scope of the Model is limited to the calculation of CI, other environmental indicators are not covered.

Since the Model is based primarily on publicly available data, the processes included represent generic or average practices. This limitation is partly mitigated through the inclusion of the fuel pathways, which allow users to input facility-specific data.

Chapter 3: Fuel LCA Model Data Library

As mentioned, the Model Database is composed of multiple "building blocks" that can be used to model fuel life cycles and calculate CIs. This chapter presents the modelling approach, functional unit, modelling assumptions and data sources used to model system processes in the data library.

3.1 Chemical inputs

Chemicals used throughout the production processes of LCIF pathways include enzymes, acids, fertilizers, and catalysts, and others. The functional unit for each chemical is 1 kg of product at a Canadian end user, unless otherwise specified. The methodology for determining the CI for each of these chemicals included in the Model is described in the following sections, and the methodology used depends on Canadian data availability.

3.1.1 Chemicals

Geographical scope

Chemicals with the location tag "[RoW]" (Rest of World) are representative of chemicals produced abroad and imported into Canada. The national average electricity grid mix of the United States is used as a proxy for electricity used for chemical production abroad.

Certain chemicals have Canada-specific versions with the location tag "[CA]," when the difference in CI with the "RoW" process is notable or for fertilizer-related chemicals with significant production volumes in Canada. They are modelled using Canada's national average electricity grid mix and require shorter transportation distances (more details in the following section).

Table 2: List of chemical processes available in the Model

Chemical	Canada	Rest of World
Acetic acid (CH3COOH)	No	Yes
Alpha amylase	Yes	Yes
Ammonia from SMR (NH3)	Yes	Yes
Ammonium nitrate, as N (NH4NO3)	Yes	Yes
Ammonium sulfate (NH4)2SO4)	Yes	Yes
Calcium carbonate (CaCO3)	Yes	Yes
Cellulase	Yes	Yes
Cellulase protein	Yes	Yes
Chlorine (Cl2)	Yes	Yes
Citric acid (C6H8O7)	Yes	Yes
Corn steep liquor	No	Yes
Diammonium phosphate ((NH4)2HPO4)	No	Yes
Diammonium phosphate, as N ((NH4)2HPO4)	No	Yes
Diammonium phosphate, as P2O5 ((NH4)2HPO4)	No	Yes
Gluco amylase	Yes	Yes

Glucose	No	Yes
Hexane (n-hexane)	No	Yes
Hydrochloric acid (HCl)	Yes	Yes
Lime (CaO)	No	Yes
Methanol (CH3OH), from natural gas	Yes	Yes
Monoammonium phosphate (NH4H2PO4)	No	Yes
Monoammonium phosphate, as N (NH4H2PO4)	No	Yes
Monoammonium phosphate, as P2O5 (NH4H2PO4)	No	Yes
Nitric acid (HNO3)	Yes	Yes
Nitrogen (N2), gaseous	Yes	Yes
Phosphate rock	Yes	Yes
Phosphoric acid (H3PO4)	Yes	Yes
Potassium hydroxide (KOH)	Yes	Yes
Sodium chloride (NaCl)	Yes	Yes
Sodium hydroxide (NaOH)	Yes	Yes
Sodium methoxide (CH3ONa), dry	Yes	Yes
Sodium methoxide (CH3ONa), in solution	Yes	Yes
Starch	No	Yes
Sulfuric acid (H2SO4)	Yes	Yes
Urea (CH4N2O)	Yes	Yes
Urea ammonium nitrate, as N (UAN)	Yes	Yes
Yeast	No	Yes
Yeast extract	No	Yes

Transport of chemicals to the end user

The following transportation scenarios were considered for the modelling of the transport of chemicals to an end user:

- Chemicals produced in Canada
- Chemicals produced elsewhere in North America
- Chemicals produced outside North America

Chemicals produced in Canada

The primary modes of transport for products produced in Canada are truck transport and rail transport. It is assumed that chemicals transported in Canada by truck would travel 427 km (Statistics Canada, 2020a)[2], and those transported by rail would travel 2200 km (Statistics Canada, 2020b)[3]. All truck transport within Canada is assumed to be by 45-tonne truck.

For short distance transport of chemicals (less than 100 km in total) from the production facility to the end-user, distance data from the 2025 R&D version of the Greenhouse gases, Regulated Emissions, and Energy use in Technologies (GREET) Model (Argonne National Laboratory, 2025) were used instead of the Statistics Canada distances. This includes the following chemicals:

- Alpha amylase
- Calcium carbonate
- Cellulase
- Cellulase protein
- Citric acid
- Corn steep liquor
- Glucoamylase
- Glucose
- Lime
- Sodium methoxide (dry)
- Sodium methoxide (in solution)
- Starch
- Yeast
- Yeast extract

For transportation processes from a bulk centre to a farm or other such location comprising a minor portion of overall transport, R&D GREET 2025 data was used to represent the distance. Chemicals with transport components related to a bulk centre include:

- Ammonia
- Ammonium nitrate
- Ammonium sulphate
- Diammonium phosphate (DAP)
- Methanol
- Monoammonium phosphate (MAP)
- Phosphoric acid
- Urea
- Urea ammonium nitrate (UAN)

It is assumed that for chemicals produced in Canada, by default, half are transported to the end user by rail, while the other half is transported by truck. If one of the transport modes for a particular chemical is excluded in R&D GREET 2025, that mode was excluded, and the remaining share was allocated to the other mode.

[2] Average distance traveled for domestic shipments in 2018.

[3] Average distance per shipment for plastics/chemicals transport originating and delivered to Canada in 2017.

Chemicals produced elsewhere in North America

Data from Statistics Canada indicates that transport of chemicals from the U.S. and Mexico to Canada by truck and by rail is approximately 1,504 km (Statistics Canada, 2020a)[4] and 2,200 km (Statistics Canada, 2020b)[5] respectively. Data on barge transport, a lesser used means of transport, came from R&D GREET 2025 for both countries.

The share of transport from rail, truck and barge transport came from R&D GREET 2025. The share of transport from ocean tanker transport was removed, and the shares of the other transportation modes was increased to compensate. If no transport data was provided in R&D GREET 2025 for a particular chemical, it was assumed that transport of chemicals is split 50/50 between rail and truck transport, with no transport by barge.

Chemicals produced outside North America

The modelling of the transportation for chemicals produced outside of North America is broken into two parts:

- Transport from the country of origin to a Canadian port with the following assumptions:
  - All transport within the country of origin is negligible compared to the transport of the finished product to Canada
  - Ocean tanker transport is a representative proxy for the modes of transport used to import products into Canada
  - The transport distances for a particular country can be represented by a single region-specific proxy distance as follow:
    - Asia
    - Central and South America
    - Europe
    - Middle East
    - North Africa
    - Sub-Saharan Africa
    - Oceania
- Transport from the Canadian port to the end-user
  - This transport portion is modelled using the Canadian methodology described in the section Chemicals produced in Canada

The proxy distances for each region were determined by identifying the major countries Canada trades with within each region based on data from Table 12-10-0114-01 (Statistics Canada, 2024), excluding those with very small trade volumes. For each selected country, its largest port is used as a national proxy. Distances are then measured from these ports to the closest major Canadian port. Finally, a total trade value-weighted average is calculated to represent the entire region.

[4] Average distance traveled for transborder shipments in 2018.

[5] Average distance per shipment for plastics/chemicals transport originating from the U.S./Mexico and delivered to Canada in 2017.

Transport distances for each chemical are then developed based on the specific countries from which each chemical is imported. The distance used for each country of origin is based on the regional proxy distance assigned to the region that country belongs to. For each chemical, a weighted-average transport distance is calculated using the total trade volume imported from each country (or total trade value if the former is not available), based on 2024 Canadian import data from the World Integrated Trade Solution (WITS, 2024).

Chemicals related to fertilizers

The following processes are modelled using the R&D GREET 2025 model's process energy, material inputs and process emissions. The functional units available in the Model for each fertilizer process are on a mass of product basis (for example, one kg of fertilizer product) or on a mass of nutrient basis (for example, one kg of nitrogen in fertilizer product), as specified below:

- Ammonium nitrate (NH4NO3), as N
- Ammonium sulfate ((NH4)2SO4)
- Diammonium phosphate ((NH4)2HPO4))
- Diammonium phosphate ((NH4)2HPO4)), as N
- Diammonium phosphate ((NH4)2HPO4)), as P2O5
- Monoammonium phosphate (NH4H2PO4)
- Monoammonium phosphate (NH4H2PO4), as N
- Monoammonium phosphate (NH4H2PO4), as P2O5
- Nitric acid (HNO3)
- Phosphate rock
- Phosphoric acid (H3PO4)
- Sulfuric acid (H2SO4)[6]
- Urea-Ammonium nitrate (UAN), as N

In the case of monoammonium phosphate (MAP) and diammonium phosphate (DAP), both allocated nutrient categories (N and P_2O_5) must be accounted for. The user must ensure that the quantities of both components of the multinutrient fertilizers are correctly reported.

The modelling of the following chemical processes uses the Canadian production data (feedstock and energy requirements) collected from the Greenhouse Gases Reporting Program (GHGRP) from 2019 to 2022 (ECCC):

- Ammonia from SMR (NH3)
- Urea (CH4N2O)

The modelling of ammonia and urea considers that ammonia from SMR and urea are co-products. Urea production combines two molecules of ammonia with one molecule of CO_2 to form urea and water in solution. With this process, a portion of the CO_2 that would otherwise be emitted to the atmosphere is recovered by the urea process. A feedstock ratio of 0.567 kg NH3/kg urea is used to calculate the mass balance of the net ammonia production (stoichiometric mass ratio for $2NH_3 + CO_2 \rightarrow CH_4N_2O + H_2O$).

[6] Elemental sulfur used in the sulfuric acid production carries no emissions since it is considered a waste product from another industry.

A four-year combined average, from 2019 to 2022, for production, natural gas feedstock and energy requirements data was used. Plant activities considered included flaring, on-site transportation, steam generation, and other stationary combustion. Only data from plants that produce ammonia from SMR were used.

Allocation for chemicals related to fertilizers

For ammonia from SMR and urea, an allocation procedure based on nitrogen content was used for the ammonia and urea co-products in the background modelling. The nitrogen contents used were 82.2% and 46.6% for ammonia and urea, respectively.

For MAP and DAP, all inputs of ammonia are allocated to the per-mass of N process and all inputs of phosphoric acid are allocated to the per-mass of P2O5 process. For energy and transport inputs, the allocation factor is calculated using the share of the specific process energy input associated either with N or P2O5 per tonne of MAP or DAP taken from a life cycle inventory report (Nemecek & Kägi, 2007).

No allocation procedures were performed for other chemicals.

Enzymes

The following enzymes are in the Model and are based on the energy inputs, material inputs, process emissions, and transportation data from R&D GREET 2025:

- Alpha amylase
- Cellulase
- Cellulase protein
- Gluco amylase
- Yeast extract[7]

The following process is modelled using R&D GREET 2025 life cycle emission factors:

- Yeast

Allocation for enzymes

No allocation procedures were performed for enzymes.

Sodium hydroxide and chlorine

The following chemicals are modelled based on the membrane cell and diaphragm cell techniques for the chlor-alkali process, found in two reports on the chlor-alkali process (Brinkmann et al., 2014; D.-Y. Lee et al., 2017):

- Chlorine (Cl2)
- Sodium hydroxide (NaOH)

Energy inputs (electricity and natural gas) from Lee et al. (2017) were used to model the process. The sodium chloride input was pulled from Brinkmann et al. (2014). The process is modelled as a production-weighted average of both techniques (0.45 for the membrane cell technique and 0.55 for the diaphragm

[7] Yeast used for yeast extract carries no emissions since it is a considered a waste from another industry.

cell technique). This is based off Lee et al. (2017), which analyzed the prevalence of each technique for the chlor-alkali process in the U.S. 2015 was used as the reference year.

Allocation for sodium hydroxide and chlorine

Each process input is attributed to a specific product (chlorine or sodium hydroxide) if it is only used for its post-treatment. Otherwise, a mass allocation was used.

Methanol

The modelling of methanol production from natural gas uses data from the Methanex 2025 Sustainability Report (Methanex, 2025) for the 2024 reference year. The data used includes material and energy inputs for the production of methanol, including the total combined volume of natural gas used as a material input and as an energy input, as well as grid electricity consumption. Since methanol produced in Canada is currently produced in Alberta, its provincial grid was used in the modelling of the Canada-specific process.

The total natural gas consumption was divided into a material input and an energy input to account for combustion emissions from natural gas. The split between the two inputs was calculated using a carbon balance and yielded a 72% split as a material input.

Allocation for methanol

No allocation procedures were performed for methanol.

Citric acid

The modelling of citric acid uses data from the ion exchange recovery method (the method used for the only citric acid producer in Canada) as modelled in a 2020 report on citric acid production (Wang et al., 2020). The data used includes the quantities of corn, amylase, urea, concentration of urea in solution, hydrochloric acid, grid electricity, and steam.

Assumptions were made with respect to the transportation of the corn feedstock to the citric acid plant. Typical market concentrations were used for the concentration of hydrochloric acid in solution.

Allocation for citric acid

No allocation procedures were performed for citric acid.

Sodium methoxide

Dry sodium methoxide and sodium methoxide in solution are both modelled using data from Process III in a 2015 report on sodium methoxide production (Granjo & Oliveira, 2016), which models production with sodium hydroxide as the feedstock. This process was chosen due to its prevalence in industry and its higher stability compared to production with a sodium metal feedstock. In the modeling, sodium hydroxide in the output was assumed to be a minor impurity and was omitted.

Sodium methoxide is generally produced in a 30 weight % solution with methanol. This excess methanol is modelled differently in the two processes; sodium methoxide in solution includes it in its CI, whereas dry sodium methoxide omits the excess methanol entirely. If users wish to include methanol in their subsequent modelling themselves, dry sodium methoxide should be used, and methanol must be added in their process to properly account for its CI. For every kilogram of dry sodium methoxide, users should add 2.344 kg of methanol to their modelled process.

Allocation for sodium methoxide

No allocation procedures were performed for the modelling of sodium methoxide.

Other chemicals

All other chemical processes found in the folder Data Library/Chemical inputs/Chemicals (with the exception of 'Hydrogen production, at producer' described in Section 3.1.3) were modelled using energy inputs, material inputs and process emissions from R&D GREET 2025.

The following chemicals fall under this category:

- Acetic acid (CH3COOH)
- Calcium carbonate (CaCO3)
- Corn steep liquor[8]
- Glucose
- Hydrochloric acid (HCl)
- Lime (CaO)
- Nitrogen (N2), gaseous[9]
- Potassium hydroxide (KOH)
- Sodium chloride (NaCl)
- Starch[10]

The following process was modelled using R&D GREET 2025 life cycle emission factors:

- Hexane (n-hexane)

Allocation for other chemicals

No allocation procedures were performed for these chemicals

3.1.2 Agrochemicals

Modelling approach for agrochemicals

The CIs for agrochemicals were determined using two different methods depending on the fertilizer nutrient types (nitrogen (N), phosphorus (P), potassium (K) and sulphur (S)).

The CIs for N, P and K fertilizer were calculated using chemical input data from Cheminfo Services Inc. (2016) pertaining to the types and amounts of chemicals used in their production. The processes for N and P fertilizers are modeled using the 'Rest-of-World' Model processes for each fertilizer chemical (as described in Section 3.1.1). Since most K fertilizer used in North America is produced in Saskatchewan,

[8] Assumption: The transportation of corn to the corn steep liquor production plant is done by a 25-tonne truck and the distance transported is 100 km.[9] Assumption: Nitrogen gas is produced onsite, and transportation to the end user is omitted.

[9] Assumption: Nitrogen gas is produced onsite, and transportation to the end user is omitted.

[10] Assumption: The transportation of corn to the starch production plant is done by a 25-tonne truck and the distance transported is 100 km.

this process is modelled using the Saskatchewan grid process, and transport to the end-user is modelled using the transport methodology for chemicals produced in Canada in Section 3.1.1.

The most common S fertilizer used in Canada (ammonium sulfate) is produced from waste sulfur feeds in mining and smelting operations. As a result, the only CI contribution comes from the transport of S fertilizer to the end-user as modelled using the transport methodology for chemicals produced in Canada in Section 3.1.1.

In the absence of detailed Canadian data on the shares of each type of pesticide used in Canada for a given crop, the average CI for pesticides was calculates using the R&D GREET 2025 emission factors for five primary pesticides in widespread use in Canada (atrazine, metolachlor, acetolachlor, cyanazine, and insecticides).

Geographical scope for agrochemicals

The following agrochemical processes are represented with a global geographic scope:

- Nitrogen fertilizer
- Phosphorus fertilizer
- Pesticides, active ingredients

The following agrochemical processes are represented with a Canadian geographic scope:

- Potassium fertilizer
- Sulfur fertilizer

Allocation for agrochemicals

No allocation was performed for the modelling of agrochemicals.

Data sources for agrochemicals

All data on the types and amounts of chemicals used to model the CI of N, P and K fertilizers come from Cheminfo Services Inc.(2016). The emission factors for calculating the CI of pesticides come from R&D GREET 2025.

3.1.3 Hydrogen

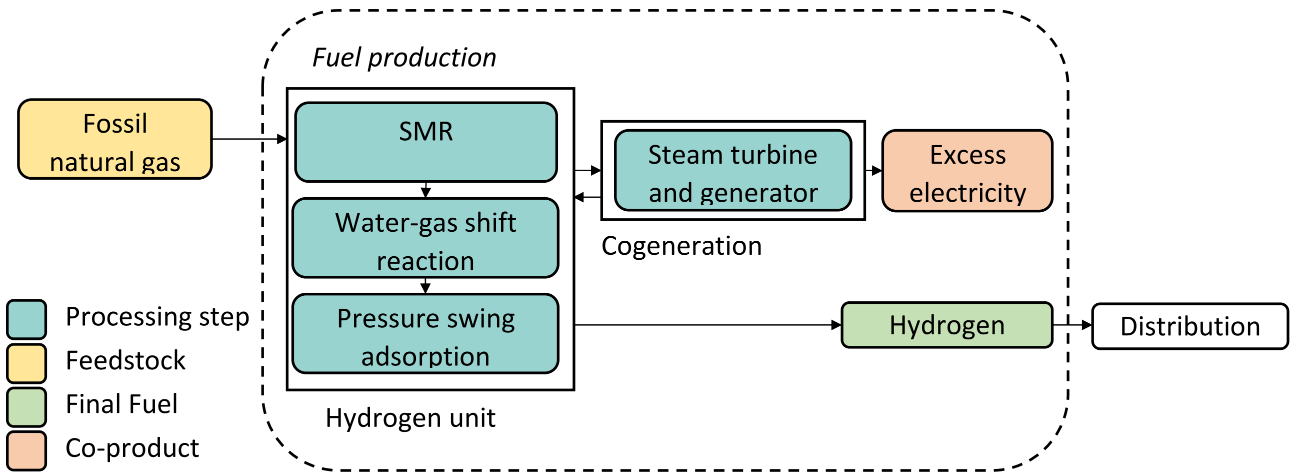
The Model includes a system process that models the production of hydrogen from SMR when hydrogen is used as material or fuel input. While the Data Library only includes hydrogen from SMR, users can use existing system processes in the Data Library to model hydrogen production from other sources and production methods with a fuel pathway (Chapter 4:). The modelling of SMR hydrogen production in the Model is based on a techno-economic analysis completed by the International Energy Agency Greenhouse Gas R&D Programme (IEAGHG, 2017). Inputs and outputs needed to model SMR hydrogen production are based on this analysis (for example, amounts of natural gas needed as feedstock and fuel, as well as amounts of hydrogen and excess electricity produced). Energy requirements for the geological storage of the produced hydrogen are modelled based on a study by Ramsden et al. (2013).

Modelling approach for hydrogen

In the SMR process, CH_4 from fossil natural gas reacts with steam in the presence of a catalyst to produce hydrogen, carbon monoxide (CO), and CO_2. In the next step, CO and steam are reacted using a catalyst to produce CO_2 and more hydrogen, followed by pressure-swing adsorption during which CO_2 and other impurities are removed to produce pure hydrogen.

The process begins with the production and transmission of natural gas to the hydrogen production plant via gas pipeline. The process ends with the production of 1 MJ of hydrogen at the plant gate, including geological storage. The process includes process emissions (for example, CO_2), while CH_4 and N_2O emissions from the hydrogen SMR process are considered negligible. Hydrogen leaks during production are assumed to be negligible as well and are therefore excluded from the process. The hydrogen production includes electricity export to the grid produced from excess steam at an onsite cogeneration plant. Figure 4 displays the processing overview for the production of hydrogen from SMR. Modelling for the extraction of natural gas is described in Section 3.6.2. The production process produces a functional unit of 1 MJ HHV of hydrogen.

Figure 4: Processing overview for the production of hydrogen from SMR



Geographical scope for hydrogen

The SMR conversion process was modelled based on a theoretical state-of-the-art SMR plant producing 100,000 Nm^3 /h of hydrogen using natural gas as feedstock and fuel, as assessed in the IEAGHG (2017) study. The plant is assumed to operate as a standalone facility without integration to other industrial complexes. This theoretical hydrogen production plant is used as a proxy to model Canadian hydrogen conversion from SMR. This assumes that processes do not vary between regions. The process can be used regardless of geographical location.

Allocation for hydrogen

Excess electricity is treated with a system expansion approach. The excess electricity is assumed to be exported to the grid and a credit corresponding to the CI of the Canadian average grid mix is attributed to the hydrogen production system. Section 3.3.3 provides additional information about the modelling approach for excess electricity exported to the grid.

Data sources for hydrogen

The conversion of fossil natural gas to hydrogen using SMR was modelled using data compiled by the IEAGHG R&D Programme (2017), specifically amounts of natural gas consumption and excess electricity export expected from a 100,000 Nm^3/ h hydrogen plant. Because there are few large-scale operating facilities that produce hydrogen, the IEAGHG data is based on a theoretical base case production scenario. The main data sources used in modelling the conversion of hydrogen from natural gas are IEAGHG (2017), Ramsden et al. (2013), and Sun et al. (2019) (see References).

3.1.4 Predefined chemical mixes

The Model contains three types of predefined chemical mixes to represent the chemicals used in the production of three types of fuels: conventional bioethanol, cellulosic ethanol, and biodiesel. The functional unit for each chemical mix is the quantity of chemicals needed to produce 1 MJ (based on HHV) of the specified LCIF.

All Model processes for chemicals used as inputs to the predefined chemical processes are split evenly between production in Canada and production in the RoW, where appropriate. For chemicals without a Canadian specific production process in the Model, as outlined in Section 3.1.1, the modelling only uses the “RoW” processes.

Modelling approach for predefined chemical mix for conventional bioethanol production

The predefined chemical mix for conventional bioethanol production was modelled using Canadian production data from the Complementary Environmental Performance Reports (CEPR). These reports were compiled by Natural Resources Canada (NRCan) as part of NRCan's ecoENERGY for Biofuels Program (Natural Resources Canada, 2017). The predefined chemical mix CI for bioethanol is a weighted average of the CI of the chemicals used for bioethanol from corn and from wheat. The process scope includes starch extraction, liquefaction and saccarification, fermentation, and distillation and drying. The chemicals considered are glucoamylase, ammonia, urea, sodium hydroxide, alpha amylase, sulfuric acid, and yeast. The modelling for these chemical inputs is described in Section 3.1.1.

Three types of data exclusions were applied to the conventional bioethanol production facilities:

- General plant-year exclusions
  - Facilities-years with a mass balance out of the range [0.75, 1.25]
  - Facilities-years for which the blending feedstock types is high (that is percentage of input feedstock inside the range [40%, 50%])
  - Facilities-years for which the production rate (L biodiesel/tonne feedstock) is out of the range [arithmetic average over all facilities and all years - 2*standard deviation, arithmetic average over all facilities and all years + 2*standard deviation]
- Specific parameters exclusions
  - Flow amounts were individually excluded when out of range [arithmetic average over all facilities and all years - 2*standard deviation, arithmetic average over all facilities and all years + 2*standard deviation]
- Manual exclusions of plant
  - All flow amounts were excluded for a facility-year considered non-representative (the facility was starting its production at a very low capacity)

As there is no wet mill facility in Canada, the process is representative of dry mills. There is no flow for denaturant input and sodium hypochlorite in the Model Database. The reported flows are negligible and therefore are not considered in the modeling.

Geographical scope for predefined chemical mix for conventional bioethanol production

The CEPR data was compiled to model a single process for chemical use for bioethanol production. This assumes that the production process is the same across provinces. The process can be used regardless of geographical location.

Allocation for predefined chemical mix for conventional bioethanol production

No allocation was performed.

Modelling approach for predefined chemical mix for cellulosic bioethanol production

The predefined chemical mix for cellulosic bioethanol production was determined based on data on cellulosic bioethanol production from wheat straw and corn stover. The production processes modelled included enzymatic pre-treatment, C5 / C6 sugar fermentation, and distillation. The chemical inputs that were considered in the bioethanol production process were corn steep liquor, cellulase, lime, sodium hydroxide, diammonium phosphate, yeast, ammonia, and sulfuric acid. The modelling for these chemical inputs is available in Section 3.1.1. The results were then used to create the predefined chemical mix for cellulosic bioethanol.

Geographical scope for predefined chemical mix for cellulosic bioethanol production

The cellulosic bioethanol conversion process was modelled based on a U.S. literature review. The data was compiled to model a single national average approach for cellulosic ethanol conversion from corn stover. This assumes that the conversion process is the same across provinces. The process can be used regardless of geographical location.

Allocation for predefined chemical mix for cellulosic bioethanol production

The allocation of burdens of the chemicals and other inputs in the cellulosic bioethanol production process is based on energy content.

Data sources for predefined chemical mix for cellulosic bioethanol production

The data used to model the production of cellulosic bioethanol for the CI determination of the predefined chemical mix was gathered from a 2011 study by the National Renewable Energy Laboratory (Humbird et al., 2011). Excluding feedstock, data for inputs to each step in the production process were obtained from the R&D GREET model (U. Lee et al., 2016) and the Environmental Resource Letters (Wang et al., 2012). The conversion of sugars to bioethanol for corn was considered with the same efficiency as that from wheat, however corn stover was modelled to have a higher sugar yield than wheat straw.

Modelling approach for predefined chemical mix for biodiesel production

The predefined chemical mix CI for biodiesel is a weighted average of the CI of the chemicals used for biodiesel production from vegetable oils (soybean, canola and camelina) and from high free fatty acid (FFA) feedstocks (animal fats, used cooking oil (UCO) and corn oil). The predefined chemical mix CI for biodiesel production was modeled using Canadian production data from the Complementary Environmental Performance Reports (CEPR). These reports were compiled as part of NRCan's ecoENERGY for Biofuels Program (Natural Resources Canada, 2017).

The processes used for the chemical use modelling include starch extraction, liquefaction and saccarification, fermentation, and distillation and drying. The chemicals used in the modelling are potassium hydroxide, sulfuric acid, sodium methoxide, acetic acid, and sodium hydroxide. The modelling for these chemical inputs is described in Section 3.1.1.

The modelling for oil extraction is available in Section 4.2.5. The modelling for animal fats production is available in Section3.5.1. The modelling for UCO and yellow grease is available in Section 3.5.6. For biodiesel produced from canola oil, the conversion process and chemical inputs modelling relied on Canadian production data collected and averaged from 2009 to 2017, provided by the CEPR. Methanol was not included in the predefined chemical mix so that it can be modelled by the user (Natural Resources Canada, 2017).

The same data exclusions as conventional bioethanol was used for biodiesel. There is also no flow for trysil input in the Model Database. The reported flow is negligible and therefore are not considered in the modeling.

Geographical scope for predefined chemical mix for biodiesel production

The CEPR data was compiled to model a single process for chemical use for biodiesel production. This assumes that the production process is the same across provinces. The process can be used regardless of geographical location.

Allocation for predefined chemical mix for biodiesel production

No allocation was performed.

3.2 Combustion emission factors

The Model Data Library includes several processes that model solely fuel combustion; these processes do not include the life cycle emissions related to the production of each fuel. The Data Library contains 3 folders: combustion from biomass feedstock, combustion from non-biomass feedstock and combustion from fossil fuels.

Modelling approach for combustion by fuel type

This section includes the modelling approach and data sources used for the processes representing the combustion of fuels.

Note that the same emission factors were used for LCIF made from biomass and non-biomass feedstock. However, the carbon emission factors (such as CO_2 and CH_4) from the combustion of fuel made from biomass-based feedstock are considered as biogenic emissions. In accordance with the Government of Canada’s approach on biogenic carbon, the biogenic CO_2 emissions are not included in the CI calculations in the Model and biogenic CH_4 emissions have a different impact factor than fossil CH_4 emissions. If a fuel is made from non-biomass feedstock, the carbon content is then considered non-biogenic and the CO_2 and CH_4 emissions from the combustion are accounted as fossil emissions. Please refer to Sections 2.7 and 2.8 for further explanations about biogenic and fossil emissions accounting in the Model.

Aviation Fuel: Modelling has been carried out using the fossil-based aviation turbo fuel combustion emission factors from the 2026 NIR (ECCC, 2026), reference year 2024, and the annual weighted average combustion in Canada from Statistics Canada (Statistics Canada, 2025b).

Bioethanol: Modelling has been carried out using the fossil-based gasoline combustion emission factors from the 2026 NIR (ECCC, 2026), reference year 2024, as a proxy. Only the neat (unblended) portion of the fuel is considered. Carbon dioxide and methane emissions are considered biogenic.

Biodiesel: Modelling has been carried out using the fossil-based diesel combustion emission factors from the 2026 NIR (ECCC, 2026), reference year 2024, as a proxy. Carbon dioxide and methane emissions attributed to the feedstock are considered biogenic. To note that the carbon content of the fuel linked to the use of methanol in biodiesel production is considered as fossil and estimated based on stoichiometric calculations of emission factors (however, emissions of fossil CH_4 associated with methanol are neglected).

Biogas: Modelling has been carried out using the fossil-based natural gas combustion emission factors from the 2026 NIR (ECCC, 2026), reference year 2024, as a proxy, assuming that they will be similar on a MJ basis. Carbon dioxide and methane emissions are considered biogenic.

Coal (bituminous, sub-bituminous, lignite): Modelling has been carried out using the coal combustion emission factors from the 2026 NIR (ECCC, 2026), reference year 2024.

Diesel: Modelling has been carried out using the diesel combustion emission factors from the 2026 NIR (ECCC, 2026), reference year 2024, and the annual weighted average combustion in Canada from Statistics Canada (Statistics Canada, 2025b)

Gasoline: Modelling has been carried out using the gasoline combustion emission factors from the 2026 NIR (ECCC, 2026), reference year 2024, and the annual weighted average combustion in Canada from Statistics Canada (Statistics Canada, 2025b).

Heavy Fuel Oil: Modelling has been carried out using the heavy fuel oil combustion emission factors from the 2026 NIR (ECCC, 2026), reference year 2024, and the annual weighted average combustion in Canada from Statistics Canada (Statistics Canada, 2025b).

Hydrogen: As hydrogen combustion does not release GHGs, there are no emissions from combustion based on the scope of the Model.

Kerosene: Modelling has been carried out using the kerosene combustion emission factors from the 2026 NIR (ECCC, 2026), reference year 2024, and the annual weighted average combustion in Canada from Statistics Canada (Statistics Canada, 2025b).

Light Fuel Oil: Modelling has been carried out using the light fuel oil combustion emission factors from the 2026 NIR (ECCC, 2026), reference year 2024, and the annual weighted average combustion in Canada from Statistics Canada (Statistics Canada, 2025b).

Liquefied Petroleum Gas: Modelling has been carried out using the propane and butane combustion emission factors from the 2026 NIR (ECCC, 2026), reference year 2024, and the annual weighted average combustion in Canada from Statistics Canada (Statistics Canada, 2025b).

Natural gas: Modelling has been carried out using the marketable fossil-based natural gas combustion emission factors from the 2026 NIR (ECCC, 2026), reference year 2024, and the annual weighted average combustion in Canada from Statistics Canada (Statistics Canada, 2025b).

Compressed Natural Gas and Liquefied Natural Gas: Modelling has been carried out using the fossil-based natural gas combustion in vehicle emission factors from the 2026 NIR (ECCC, 2026), reference year 2024.

Compressed Renewable Natural Gas (CRNG) and Liquefied Renewable Natural Gas (LRNG): Modelling has been carried out using the fossil-based natural gas combustion in vehicle emission factors from the 2026 NIR (ECCC, 2026), reference year 2024, and the annual weighted average combustion in Canada from Statistics Canada (Statistics Canada, 2025b), as a proxy. Carbon dioxide and methane emissions are considered biogenic.

Petcoke: Modelling has been carried out using the petcoke combustion emission factors from the 2026 NIR (ECCC, 2026), reference year 2024.

Propane: Modelling has been carried out using the propane combustion emission factor from the 2026 NIR (ECCC, 2026), reference year 2024, and the annual weighted average combustion in Canada from Statistics Canada (Statistics Canada, 2025b).

Renewable Diesel: Modelling has been carried out using the fossil-based diesel combustion emission factors from the 2026 NIR (ECCC, 2026), reference year 2024, as a proxy.

Renewable Gasoline: Modelling has been carried out using the fossil-based gasoline combustion emission factors from the 2026 NIR (ECCC, 2026), reference year 2024, as a proxy.

Renewable Naphtha: Modelling has been carried out using the fossil-based kerosene combustion emission factors from the 2026 NIR (ECCC, 2026), reference year 2024, as a proxy.

Renewable Natural Gas (RNG): Modelling has been carried out using the fossil-based natural gas combustion emission factors from the 2026 NIR (ECCC, 2026), reference year 2024, and the annual weighted average combustion in Canada from Statistics Canada (Statistics Canada, 2025b), as a proxy. However, per MJ emission factors have been calculated using the RNG HHV.

Renewable Propane: Modelling has been carried out using the fossil-based propane combustion emission factors from the 2026 NIR (ECCC, 2026), reference year 2024, and the annual weighted average combustion in Canada from Statistics Canada (Statistics Canada, 2025b), as a proxy.

Stove Oil: Modelling has been carried out using the light fuel oil combustion emission factors from the 2026 NIR (ECCC, 2026), reference year 2024, and the annual weighted average combustion in Canada from Statistics Canada (Statistics Canada, 2025b), as a proxy.

Sustainable Aviation Fuel: Modelling has been carried out using the fossil-based aviation turbo fuel combustion emission factors from the 2026 NIR (ECCC, 2026), reference year 2024, as a proxy.

3.3 Electricity

3.3.1 Scope of electricity modelling

The Model contains several system processes that model electricity generation and transmission processes. These processes are divided into three categories:

- Grid mix processes representing Canada, the U.S., and other countries
- Processes for displaced electricity production associated with excess electricity exported to the grid
- Technology-specific processes for electricity generation (for example, “hydropower, reservoir”)

The modelling and boundaries for each category is described in the following sections.

3.3.2 Modelling approach for grid electricity

The available grid mix processes for Canada, the U.S., and other countries are shown below.

Canada:

- Canadian provinces and territories
- Canadian national average

United States:

- U.S. states
- U.S. national average

Other Countries:

- National average for the following countries:
  - Argentina
  - Australia
  - Austria
  - Belgium
  - Brazil
  - Bulgaria
  - Chile
  - China
  - Colombia
  - Costa Rica
  - Croatia
  - Czechia
  - Denmark
  - Estonia
  - Finland
  - France
  - Germany
  - Greece
  - Hungary
  - Iceland
  - India
  - Indonesia
  - Ireland
  - Israel
  - Italy
  - Japan
  - Latvia
  - Lithuania
  - Luxembourg

- Mexico
- The Netherlands
- New Zealand
- Norway
- Peru
- Poland
- Portugal
- Romania
- Singapore
- Slovakia
- Slovenia
- South Africa
- South Korea
- Spain
- Sweden
- Switzerland
- Thailand
- Türkiye
- United Kingdom

The scope for these processes includes the following:

- Combustion emissions from fuel used for electricity generation
- Cradle-to-gate GHG emissions for fossil fuels and uranium used for electricity generation
- Reservoir emissions related to hydroelectricity
- Electricity losses from electricity transmission and distribution
- SF_6 emissions produced from equipment used in electricity transmission and distribution

In addition to the exclusions mentioned in Section 2.3.1, inter-provincial (or inter-state) and international trade are not considered in the modelling of these processes.

The functional unit for electricity grid mix processes is 1 kWh of electricity produced and distributed from the grid. No allocation is required for the modelling of electricity production.

Canada

The Canadian grid electricity processes are modelled using data from Annex 7, Tables A7 1-14 of the 2026 NIR (ECCC, 2026) for the 2024 reference year. Provincial and national direct emissions for the grid from the NIR were used to model the provincial and national grid processes. The NIR presents annual data on electricity generation by fuel type and direct combustion emissions for each province and territory, including data on electricity losses and SF_6 emissions associated with electricity transmission and distribution. The electricity CIs are calculated by dividing the GHG emissions by the net production of electricity.

Hydroelectric reservoir emissions for all provinces except British Columbia are based on net emissions over 100 years as estimated from the G-Res model and published in table 5 of Levasseur et al., (2021). Reservoir emissions for British Columbia are modelled using emission factors provided by BC Hydro. The emission factors were developed using the G-Res model for reservoirs representing approximately 90% of annual average energy generated by BC Hydro hydroelectric facilities.

The fraction of hydroelectricity in grid mixes is directly provided by the NIR. The fraction of hydroelectricity that is from reservoirs versus run-of-water are taken from the Canadian Analytical Framework for the Environmental Evaluation of Electricity (CAFE3), an internal ECCC LCA model for electricity generation (ECCC, 2020).

The national and provincial fractions of hydroelectricity that is from reservoirs, as provided by CAFE3, are shown in Table 3. Note that these values were not vetted by provinces or utilities.

Table 3: Fractions of hydroelectricity generation that are from reservoirs, by region

Region	Fraction
Canada	0.780
Alberta	0.660
British Columbia	0.950
Manitoba	0.998
New Brunswick	0.910
Newfoundland and Labrador	0.970
Nova Scotia	0.560
Northwest Territories	0.000
Nunavut	0.000
Ontario	0.867
Prince Edward Island	0.000
Quebec	0.629
Saskatchewan	0.970
Yukon	0.000

As previously mentioned, the main source of information for the grid mix composition is the NIR 2026. However, provided that some of the fuels used for electricity generation listed in the NIR are aggregated, additional data from Statistics Canada[11,12] were used to identify the amount of bituminous coal, lignite coal, sub-bituminous coal, diesel, heavy fuel oil, and light fuel oil used to generate electricity (Statistics Canada, 2025c, 2025d).

Heat rates for power plants consuming fossil fuels are determined using Statistics Canada Fuel supply and demand[11] and Statistics Canada Electric power generation[12] data. To minimize the variability in calculated heat rates at the provincial level due to statistical limitations, the Canadian average heat rate (expressed in MJ/kWh) was used for all provinces and territories. For LFO only, the Canadian average

[11] Statistics Canada. Table 25-10-0029-01 Supply and demand of primary and secondary energy in terajoules, annual.

[12] Statistics Canada. Table 25-10-0084-01 Electric power generation, fuel consumed and cost of fuel by electricity generating thermal plants.

heat rate did not include data from Nova Scotia, New Brunswick, or Saskatchewan because the table did not include amounts of electricity generated from LFO in those provinces.

The heat rate used for nuclear facilities was taken from CAFE3. Unit process inputs are modelled to represent the amount of fuel feedstock in MJ per kWh electricity consumed.

Fuel amounts used per kWh on the grid are calculated using the grid mix composition and heat rates for fuel consumption (in MJ of fuel per kWh of electricity output). The calculated fuel amounts take into consideration electricity losses based on NIR.

United States

The United States grid electricity processes were primarily modelled using the second revision of eGRID 2023 data (US EPA, 2025). Each process is modelled with the following information:

- The amount of fuel consumed to produce electricity (in MJ, represented as heat rate values per kWh of electricity output)
- The total amount of electricity output (in kWh) per fuel and per state
- Direct GHG emissions released from electricity production per state

Direct emissions from electricity generation are either taken directly from eGRID or estimated using eGRID data and data from other external sources, as explained later in the section. Upstream emissions are estimated using the fuel consumption data from eGRID and the Model's processes for fuels supplied to the end-user as a proxy. For each state, the inputs and outputs are normalized by the total amount of electricity generated by all plants in the state, according to eGRID plant data.

These calculations account electricity generated from both primary and secondary fuels.

Heat rate values (in MJ/kWh) for each fuel subtype were calculated at the national level using the total fuel input from plants that only used that one fuel subtype and dividing it by the total electricity output of those plants. Further information for each non-renewable fuel category is given below.

Coal:

- This category includes the following fuel subtypes: bituminous coal, lignite coal, refined coal, subbituminous coal and waste coal
- There are two coal types covered in eGRID for which there are no processes in the Model: coke-oven gas and coal-derived synthetic gas. To account for these coal types, the quantity of electricity generated by other coal types was scaled up to maintain total coal consumption
- Refined coal and waste coal are represented with the Model process for lignite coal as a proxy. Lignite is the coal type with the closest CO_2 emission value to the coal processes in eGRID

Oil:

- This category includes the following fuel subtypes: aviation fuel, diesel fuel oil, heavy fuel oil, kerosene, petcoke, and waste oil

- Waste oil used for electricity generation is significant in Hawaii and Alaska, but it is assumed that the cradle-to-gate impacts of the waste oil at power plants are negligible. Therefore, combustion emissions from burning waste oil are included based on the direct emission data from eGrid, but upstream emissions are not included

Gas:

- This category includes the following fuel subtypes: natural gas, process gas, other gas and blast furnace gas
- Process gas is represented in the Model with the process for natural gas at the fuel production gate. In eGRID, this fuel uses the same emission factors as natural gas. Process gas is assumed to be produced and used onsite
- Other gas is represented in the Model with the process for natural gas at the end-user. In eGRID, this fuel uses the same emission factors as natural gas
- Blast furnace gas, a gas covered in eGRID, is not included in the Model. The amount of blast furnace gas from eGRID was reallocated to the other gas fuel type

Nuclear:

- This category consists of only the uranium fuel subtype
- Upstream emissions are calculated using the CAFE3 model, which represents imported and local uranium enrichment

Municipal solid waste (MSW):

- This category consists of only the municipal solid waste fuel subtype
- MSW was modelled using truck transport of MSW to an end-user as the only source of upstream emissions

The total amount of electricity generated was calculated from the total net generation from each power plant in the 2023 reference year from the “PLNT23” tab of the eGRID workbook.

Total process emissions of fossil-based CO_2, fossil-based methane and nitrous oxide from all fuel subtypes (including renewables) were calculated from the total output emission rate of the corresponding emission from the “ST23” tab of the eGRID workbook.

Reservoir emissions for both CO_2 from land transformation and biogenic methane emission were calculated using the world average factors of 85g CO_2/kWh and 3g CH_4/kWh provided in Hertwich (2013). The share of hydroelectricity from reservoir in the U.S. was estimated as 20% of total hydropower, based on Itten et al. (2012).

SF_6 emissions are taken from the Table 2-11 from the 2024 U.S. National Inventory Report and scaled per kWh using eGRID data (US EPA, 2024, 2025).

All emissions and fuel inputs for grid electricity processes at the end-user were scaled to account for losses in transmission and distribution using 2024 eGRID data on losses. A national U.S. process for grid electricity was developed using the state-level electricity grid processes and the corresponding shares of national grid electricity generation.

Electricity grids of other countries

The national grid electricity processes for countries other than Canada and the United States use data from the International Energy Agency (International Energy Agency [IEA], 2026)[13]. Each individual country has its own webpage from which data is taken. IEA is the primary source of data for the quantity of electricity generated per electricity generation source for the latest available reference year[14]. National grid processes are included in the Model for the following countries:

- Argentina
- Australia
- Austria
- Belgium
- Brazil
- Bulgaria
- Chile
- China
- Colombia
- Costa Rica
- Croatia
- Czechia
- Denmark
- Estonia
- Finland
- France
- Germany
- Greece
- Hungary
- Iceland
- India
- Indonesia
- Ireland
- Israel
- Italy
- Japan
- Latvia
- Lithuania
- Luxembourg

[13] This is a work derived by ECCC from IEA material and ECCC is solely liable and responsible for this derived work. The derived work is not endorsed by the IEA in any manner.

[14] Due to differences in data availability, Bulgaria, China, Croatia, India, Indonesia, Peru, Romania, Singapore, South Africa and Thailand use the latest available IEA data from the 2023 reference year. All other countries use IEA data from the 2024 reference year.

- Mexico
- The Netherlands
- New Zealand
- Norway
- Peru
- Poland
- Portugal
- Romania
- Singapore
- Slovakia
- Slovenia
- South Africa
- South Korea
- Spain
- Sweden
- Switzerland
- Thailand
- Türkiye
- United Kingdom

The grid electricity processes were modeled using the fraction of electricity produced by different electricity generation sources for each country. Then, the technology-specific processes of the Model were used to represent the direct and upstream emissions for each generation source.

The shares of electricity generated by each generation source are modelled using the following methodology and are presented in Table 4:

- Emissions from electricity generated from biofuels, coal, hydro, oil and wind are modelled with the most conservative electricity generation technology processes
- Emissions from electricity generated from geothermal, nuclear, solar (solar photovoltaic [PV] and solar thermal) and tidal sources are modelled with the electricity generation technology processes
- Emissions from electricity generated from natural gas are modelled with two electricity generation technology processes, each comprising a share of total electricity generation (90% combined cycle, 10% simple cycle)

Table 4: Process used in the modeling by electricity generation source

IEA electricity generation source	Model Data Library process used in the modeling
Biofuels	Electricity, from wood biomass, simple cycle, offsite generation
Coal	Electricity, from coal, lignite, offsite generation
Geothermal	Electricity, from geothermal, offsite generation
Hydro	Electricity, from hydro, reservoir, offsite generation

Natural gas	Electricity, from natural gas, combined cycle, offsite generation (90% assumed share of total electricity generation from natural gas)[15]
	Electricity, from natural gas, simple cycle, offsite generation (10% assumed share of total electricity generation from natural gas)[15]
Nuclear	Electricity, from nuclear, CANDU, offsite generation
Oil	Electricity, from heavy fuel oil, offsite generation
Solar PV	Electricity, from solar, photovoltaic, offsite generation
Solar thermal	Electricity, from solar, concentrated solar power, offsite generation
Tidal	Electricity, from tidal, offsite generation
Wind	Electricity, from wind, offshore, offsite generation

Other electricity generation sources that satisfy the following criteria are modelled with the process 'Electricity, from coal, lignite, offsite generation':

- The generation source does not have a technology-specific Model process
- The generation source comprises more than 5% of a country's overall electricity generation
- The generation source emits direct GHG emissions from fuel combustion

Generation sources not available in the Model that contribute 5% or less to the electricity generated or that do not emit direct GHG emissions are excluded, and the contributions of the other sources are proportionally scaled up.

3.3.3 Modelling approach for excess electricity

Excess electricity to the grid is modelled in a conservative simplified static allocation method. In this method, the boundary of the LCIF production system was expanded and the emissions associated with the yearly average CI of the provincial/state grid electricity displaced by the excess electricity are all credited to the LCIF fuel production system, up to a maximum CI. The functional unit for excess electricity processes is 1 kWh electricity produced and exported.

Canada and the United States

The processes for displaced electricity production associated with excess electricity exported to the grid have been developed for the Canadian provinces and territories, Canadian national average, and American states. The excess electricity processes were modeled using the same data and approach as for the grid mixes (please consult the previous sections). However, because the amount of electricity sold is based on the quantity produced, the processes for excess electricity do not consider transportation and distribution to end users and therefore do not include electricity losses and SF_6 emissions in transmission and distribution.

[15] Shares were validated by internal analysis of Model processes (August 2024 version).

Maximum excess electricity

The maximum excess electricity was modelled using the approach described for electricity generation from cogeneration, available in Section 3.3.4**.** The maximum displaced electricity CI was determined to prevent an overestimation of the emission reductions that are occurring from the generation of excess electricity.

The goal of the method was to allocate emissions that occur at the fuel production facility to the electricity produced on site and transferred or sold to the grid or to an adjacent facility in order to not allocate these emissions to the fuel system. The goal was not to allocate emission reductions that may occur in the electricity sector to the fuel system.

The following elements were considered in the selection of this method:

- For fuel production facilities producing electricity in excess, the most common technology used to produce electricity on-site was a cogeneration system using natural gas
- Historically, industrial cogeneration systems are sized and operated to meet the required thermal load of the facility with the electricity output being complementary to the grid electricity supply for additional redundancy and resilience. There are a few examples of industrial cogeneration systems designed to supply electricity to the grid, but these are not typical

3.3.4 Modelling approach for electricity generation technologies

The Data library includes processes for the following electricity generation technologies:

- Biomass, wood, cogeneration
- Biomass, wood, simple cycle
- Coal, bituminous
- Coal, lignite
- Coal, sub-bituminous
- Diesel
- Geothermal
- Heavy fuel oil
- Hydro, reservoir
- Hydro, run-of-river
- Natural gas, cogeneration
- Natural gas, combined cycle
- Natural gas, converted boiler
- Natural gas, simple cycle
- Nuclear, CANDU
- Solar, concentrated solar power
- Solar, photovoltaic
- Tidal
- Wind, offshore
- Wind, onshore

Two sets of processes are available for each technology:

- Onsite generation: includes life cycle GHG emissions up to the point where the electricity is ready to be used or transferred to the grid
- Offsite generation: includes life cycle GHG emissions associated with onsite generation as well as direct GHG emissions associated with the transmission and distribution of the electricity to the end-user

Onsite generation

For onsite electricity generation processes, the functional unit is 1 kWh electricity produced onsite from the specified technology. All processes were modelled for the Canadian context but can be used regardless of geographical location. Allocation was only applied to natural gas cogeneration. Further details for each technology, including data sources used, are explained below.

Where applicable, the processes were modelled by determining the amount of fuel consumption needed to produce 1 kWh of electricity and linking it to combustion Model processes to determine combustion and upstream life cycle emissions. Intermediary inputs to operation or pollution control were also included in the modelling when their contributions accounted for more than 1% of the total CI.

As stated in Section 2.8, the Model uses a 100-year time horizon for its impact assessment methods. For most electricity technologies it is assumed that the land used for electricity generation is returned to its natural state within 100 years, thus resulting in a net-zero change in land use emissions. However, hydro reservoirs permanently change the land after their construction, making this assumption invalid. Furthermore, the flooding of land during reservoir creation results in biogenic carbon dioxide and methane emissions from decaying biomass during the life cycle of the hydro plant. For these reasons, land use change emissions are included for electricity generation from hydro reservoirs.

Electricity from coal, diesel, and heavy fuel oil

The processes were modelled by determining the amount of fuel needed to produce 1 kWh of electricity and linking it to Model combustion processes of specific fuels to determine combustion and upstream life cycle emissions.

For coal, diesel, and heavy fuel oil, fuel consumption amounts were calculated using Statistics Canada electric power generation data (Statistics Canada, 2025c).

Electricity from natural gas

The Model contains processes representing electricity generation from three production methods using natural gas: cogeneration, combined cycle, converted boiler, and simple cycle.

Unlike most electricity generation methods, cogeneration is multifunctional; it consists of the production of both heat and electricity. Therefore, cogeneration requires allocation. Different allocation methods can result in different emission profiles for each function of the cogeneration system.

For example, energy allocation can be used as a simple way to allocate emissions based on the ratio of the energy content of the final products. However, it does not account for the quality of the energy produced and its ability to do useful work. Another method is through fuel chargeable to power, where emissions that would have been produced by a boiler to produce the thermal energy required are calculated and subtracted from the cogeneration system’s total emissions, leaving only the electricity emissions.

These allocation methods require specific data that is unavailable or inconsistent due to the high variability occurring in cogeneration systems:

- Electricity energy output of the cogeneration system
- Thermal energy output of the cogeneration system
- Fuel consumption of the cogeneration system, including fuel gas or other intermediary products that are burned in the cogeneration system, which would require the CI for the fuel gas and intermediary products to be determined
- A reference base case for the thermal energy emission intensity would also need to be chosen for the fuel chargeable to power method

Because of these reasons, a simplified static allocation method was used to model electricity produced from cogeneration. With this method, average emissions for the electricity producing portion of the system were assumed to be 250 g CO2/kWh. This value represents emissions for a typical cogeneration system using the fuel chargeable to power method with an 80% efficient reference boiler. The corresponding amount of fuel needed (assumed natural gas) was then calculated based on the set emissions and the average combustion emissions reported for natural gas in the NIR (reference year 2024).

For natural gas combined cycle, converted boiler, and simple cycle, the processes were modelled by determining the amount of fuel needed to produce 1 kWh of electricity. The fuel consumption was determined using low heating value (LHV) efficiencies sourced from the Canada Energy Regulator (2016) for combined cycle and simple cycle, and from the U.S. Energy Information Administration (2024) for the converted boiler. The efficiencies were converted to a higher heating value (HHV) basis using a factor of 1.11 (FortisBC).

Then, the amount of natural gas calculated was linked to the Model combustion process of natural gas to model the direct and upstream emissions.

Electricity from nuclear

The process was modelled by using the amount of uranium needed to produce 1 kWh of electricity and an internal Model process that represents the life cycle emissions for the production of uranium. Uranium amounts for nuclear electricity generation were calculated using Statistics Canada electric power generation data (Statistics Canada, 2025c).

The heat value used to convert mass of uranium to energy is sourced from the table of Heat Values of Various Fuels published by the World Nuclear Association (2025).

Emissions representing intermediary inputs to operation and pollution control as well as upstream uranium processing were included and modelled using the CAFE3 model (ECCC, 2020).

Electricity from hydro run-of-river, onshore wind, and solar

As these technologies do not rely on fuels to produce electricity, there are no upstream emissions attributed to their energy sources. The processes only include emissions related to intermediary inputs to operation or pollution control taken from CAFE3.

Electricity from hydro reservoir

As a renewable technology, electricity produced from hydro reservoirs does not result in any direct combustion emissions. However, hydro reservoirs contain biomass that decays during the occupation phase of the reservoir, resulting in biogenic carbon and methane emissions.

The process is modelled using the CO2 and CH4 emission factors (g/kWh) for the net emissions over 100 years, as estimated from the G-Res model, published in table 5 of Levasseur et al. (2021).

Electricity from wood biomass

The wood biomass electricity processes are modelled by determining the amount of wood biomass needed to produce 1 kWh electricity. To determine the amount of wood biomass needed, the following shares, on a mass basis, were used:

- Wood chips: 55%
- Wood pellets: 40%
- Other fuels: 5%

The shares come from the 2023 NRCan's Bioheat database (Natural Resources Canada, 2023). The "other fuels" category consists of a mix of biofuels such as firewood, hog fuel/bark, agricultural residues, and occasional specialty biomass fuels (i.e. mill fines). In the Model, other fuels are modelled using agricultural residues combustion as a proxy. The share of wood biomass was used alongside the following HHV efficiencies for combustion, for each process, to determine the amount of wood biomass needed:

- Cogeneration: 79%
- Simple cycle: 24%

Energy based allocation is performed for wood biomass cogeneration.

The HHV of "Other fuels" was approximated using the average of HHVs for corn stover and wheat straw from the R&D GREET Model (Argonne National Laboratory, 2024) and Manitoba Agriculture (2017), respectively. The efficiencies were calculated using averages from several sources (Abbas et al., 2020; Canadian Model Forest Network, 2013; Hydro-Quebec, 2021; National Institute of Building Sciences, 2024; University of California – Agriculture and Natural Resources, 2025).

The amount of wood biomass for each feedstock was linked to each respective Model combustion process to model the direct and upstream emissions.

Electricity from geothermal

A binary-cycle power plant fed by low-temperature enhanced geothermal systems (EGS) was selected to represent the geothermal technology in the Model for the Canadian context. Several sources were consulted in the determination of the representative technology (Canada Energy Regulator, 2023a; Goldstein et al., 2011; Natural Resources Canada, 2012)

As there are no direct combustion emissions in the use of this technology, the process was modelled by determining the emissions associated to intermediary inputs to operation or pollution control. These activities were modelled using Frick et al. (2010) and LIRIDE (2025).

Electricity from tidal

Electricity produced from tidal currents, driven by the filling and emptying of coastal regions due to tidal cycles, is represented in the Model by a horizontal-axis tidal current energy converter technology used in the Canadian context. Several sources were consulted in the determination of the representative technology (Acadia Tidal Energy Institute, 2014; Canada Energy Regulator, 2023b; Nova Scotia Department of Energy, 2016; Energy BC, 2016; Lewis, A., 2011).

As there are no direct combustion emissions in the use of this technology, the process was modelled by determining the emissions associated to intermediary inputs to operation or pollution control. These activities were modelled using Table S3 of Douziech et al. (2016) and LIRIDE (2025).

Electricity from offshore wind

A grounded gravity-base offshore wind turbine system was selected to represent the offshore wind technology in the Model for the Canadian context. Several sources were consulted in the determination of the representative technology (Dolan & Heath, 2012; Tang & Kilpatrick, 2021; TGS 4C Offshore, 2025; Wiser et al, 2011).

As there are no direct combustion emissions in the use of this technology, the process was modelled by determining the emissions associated to intermediary inputs to operation or pollution control. These activities were modelled using table S17 of Arvesen & Hertwich (2012) and LIRIDE (2025).

Offsite generation

For offsite electricity generation processes, the functional unit is 1 kWh electricity produced and delivered to the user. All processes were modelled for the Canadian context but can be used regardless of geographical location. Allocation was only applied to natural gas cogeneration.

The modelling is done using the onsite processes and adding the emissions associated to distribution and transmission. SF_6 emissions produced by the equipment used in electricity transmission and distribution as well as electricity losses were based on 2026 NIR data for the 2024 reference year (Table A7-1) (ECCC, 2026).

3.4 Other energy sources

The Data Library has three additional energy source processes representing purchased steam, non-biogenic waste combustion, and fuel gas combustion.

3.4.1 Purchased steam

The purchased steam process was developed with a functional unit of 1 MJ of steam generated from a natural gas boiler. The scope of the process includes the direct emissions from the combustion of natural gas in addition to the upstream emissions related to the production and distribution of the natural gas. Direct emissions of the natural gas boiler were set to 223 g CO_2e per kWh of steam generated, assuming a boiler efficiency of 80%. The natural gas processes in the Model were used to determine the amount of natural gas needed to produce 1 MJ of steam. Natural gas modelling is described in Section 3.6.

3.4.2 Non-biogenic waste combustion

The "Non-biogenic waste combustion" process was developed to model the combustion of non-biogenic waste materials used as a fuel. The process was developed with a functional unit of 1 kg of non-biogenic waste combusted. The scope of the process only includes the combustion emissions of non-biogenic waste used as fuel input. In accordance with the cut-off allocation rule (refer to section 2.6), the production of the non-biogenic waste is excluded from the dataset. In addition, transportation to the end-user is excluded because it is expected that in most cases the waste is produced onsite or nearby.

The combustion is modelled using the emission factor and HHV (36.2 MJ/kg) for petcoke combustion as a proxy. Petcoke combustion modelling is described in section 3.2.

3.4.3 Fuel gas combustion

Fuel gas is a gas commonly composed primarily of CH_4 that is used as a fuel input. Fuel gas also contains other gases such as water or other hydrocarbons. The Model includes fuel gas as an energy input. The process is modelled using natural gas combustion as a proxy. Natural gas combustion modelling is described in Section 3.6.2.

3.5 Feedstocks

The Data Library contains six main categories of feedstock that can be used in LCIF pathways: animal fats, crops (field peas, grains, and sugar cane), residues, waste, wood fibre, and yellow grease.

The following sections present the modelling approach and assumptions used to model the CI associated with the production and/or the collection of the six feedstock categories found in the "Feedstocks" folder of the Data Library.

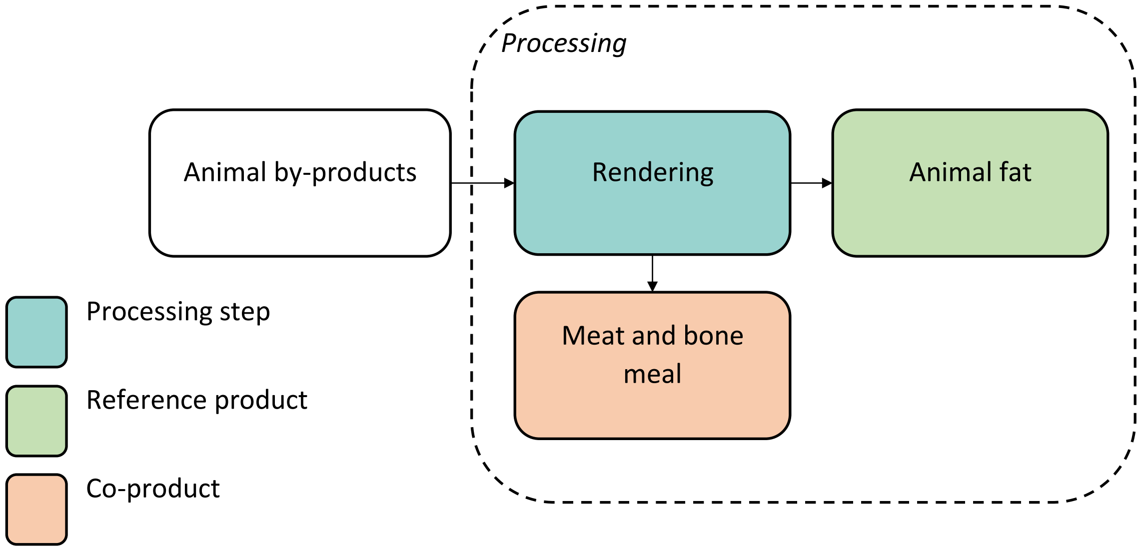
It should be noted that there are other processes that can be considered as feedstock. For example, natural gas can be used as feedstock for hydrogen production; natural gas processes can be found in the "Fossil fuels" folder. Details for fossil fuel extraction and production are available in Section 3.6. In addition, the Model includes some configurable processes that can be used to model feedstock processes that are not included the Data Library. These processes are documented in Section 4.2.

3.5.1 Animal fats production

Modelling approach for the production of animal fats from animal by-products

The boundary of the production of animal fats begins with the transport of the animal by-products from the slaughterhouse to the rendering plant and ends with the production of animal fat. The upstream GHG emissions related to animal by-product are not included in the modeling since it is considered a waste. A trucking distance of 100 km is assumed. Animal by-products from the slaughterhouse are processed in a rendering plant to produce animal fat, with meat and bone meal as co-products. Natural gas and heavy fuel oil are used for the thermal energy requirements of the rendering process, and the values used for the modeling are based on average values from table 1 of Chen et al. (2017). The cooking vapours are a waste stream and are excluded from calculations. An overview of the processing steps involved in the production of animal fat is presented in Figure 5.

Figure 5: Processing overview for rendering of animal by-products into animal fat



Geographical scope for rendering animal by-products into animal fat

The Model includes processes defined at the provincial and national levels for animal fat production in Canada. All Canadian processes were based on U.S. data on rendering of animal by-product. Processes only differ in the provincial electricity grid mix used in the rendering process. This assumes that the production process does not differ across Canada, and only the emissions related to electricity differ.

Allocation approach for rendering animal by-products into animal fat

The allocation of burdens to the meat and bone meal and animal fat at the rendering plant is performed according to the dry mass content of the products.

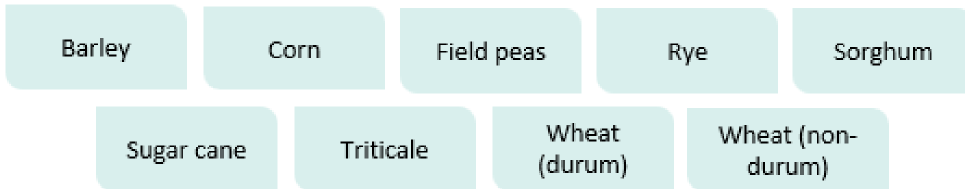
Data sources for rendering animal by-products into animal fat

The main data source used to model animal fat rendering is Chen et al. (2017). Beef tallow was used as a proxy for animal fats.

3.5.2 Cultivation of agricultural crops

Figure 6 shows the crops that are included in the Model Data Library.

Figure 6: Agricultural Crop Feedstocks included in the Fuel LCA Model



The following sections present the modelling approach for the agricultural crops. The crops are grouped by the main data sources used for modelling. The first section presents the modelling for barley, corn, field peas, rye, triticale, and wheat (durum and non-durum), the second section presents the modelling for sorghum, and the third section presents the modelling for Brazilian sugar cane. The modelling approach is similar for the crops presented in first and second sections, while the modeling approach for sugar cane is different. For each of these feedstocks, the functional unit is 1 kg of dry mass crop at the farm gate.

Modelling approach for barley, corn, field peas, rye, triticale and wheat (durum and non-durum)

The boundaries of each crop dataset include all field activities related to crop production (from soil preparation to harvest and storage). It excludes the subsequent transportation, distribution, processing and use stages of the harvested crops. The life cycle inventory (LCI) for barley, corn, field peas, durum wheat and wheat was modelled based on the 2022 CRSC carbon footprint reports ((S&T)2 Consultants Inc., 2022a, 2022c, 2022d, 2022e, 2022g). The LCI for rye and triticale were modelled based on the 2023 CO-OP carbon footprint reports ((S&T)2 Consultants Inc., 2023a, 2023b), which rely on the same methodology as used in the CRSC reports.

The main inputs and emissions considered in the carbon intensity (CI) of crops are listed below:

Energy inputs: cover the quantities of diesel, gasoline, natural gas and electricity for direct on-farm operations (for example, machinery operation, soil preparation, chemical application, harvesting, seeding, tillage, irrigation[16], on-farm transportation of crops from the field to storage units and drying of harvested crops). Tillage techniques (i.e. conventional tillage or intensive tillage, reduced tillage and direct seeding or no-tillage) were considered for the calculation of energy use in the form of diesel fuel consumption. Included in the LCI are the combustion emissions from fossil fuel consumption and upstream emissions related to the production and distribution of fossil fuels and electricity.

Chemical inputs: cover synthetic fertilizers (nitrogen, phosphorous, potassium and sulfur-based) and pesticides applied on cropland. Included in the LCI are the emissions related to the manufacturing of fertilizers and pesticides. The Model covers several nitrogen-based fertilizers as explained in Section 3.1.2.

Seeds: cover the mass of seed required to produce one kilogram of crop. Included in the LCI are the emissions associated with the production, treatment and transport of seeds following the approach

[16] Only energy use for irrigation was considered; irrigation water is excluded from the scope of the Model.

described in the CRSC reports and CO-OP reports. This CI of the seed is determined based on the CI of the crop to which an impact factor is applied to account for the treatment and transport of seeds to the farms.

N_2O emissions: include direct and indirect N2O emissions from nitrogen inputs, including nitrogen-fertilizers, crop residues and mineralized nitrogen from soil. Indirect N2O emissions cover both volatilization of nitrogen from synthetic fertilizers and leaching/runoff of nitrogen from synthetic fertilizers and crop residues.

The N2O emission factors were reported in the 2022 CRSC carbon footprint reports ((S&T)2 Consultants Inc., 2022a, 2022c, 2022d, 2022e, 2022g) and the 2023 CO-OP carbon footprint reports for rye and triticale ((S&T)2 Consultants Inc., 2023a, 2023b). Emissions were calculated using the Tier 2 Canadian methodology described in the 2022 National Inventory Report (ECCC, 2022) and consider region-specific emission factors for direct N2O emissions, as described in the CRSC and CO-OP reports.

Crop residue nitrogen was estimated using Canadian crop data based on Janzen et al. (2003), as explained in the 2022 CRSC methodology report ((S&T)2 Consultants Inc., 2022h).

CO_2 emissions from soil organic carbon (SOC): include emissions and sequestered carbon associated with soil organic carbon due to two changes in land management practices:

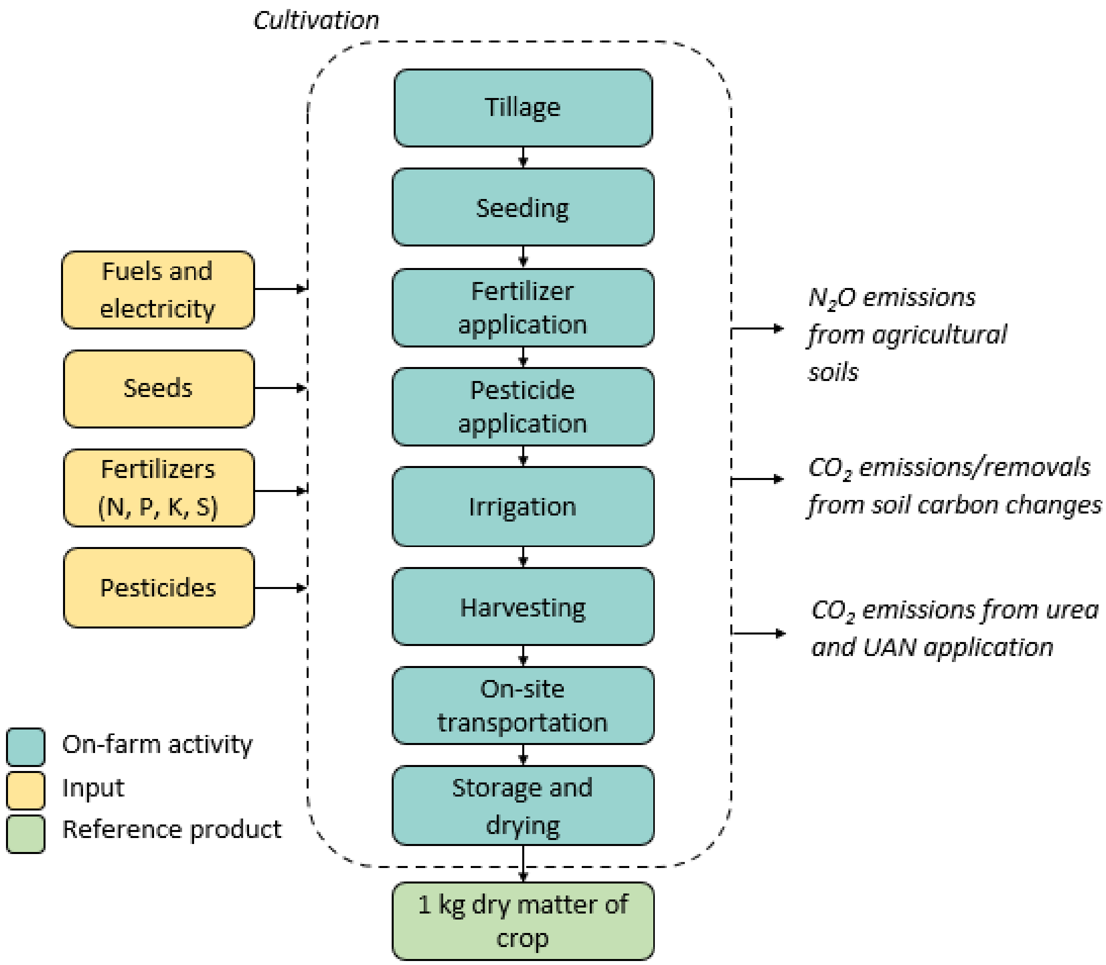
- Changes in crop productivity and crop residue carbon inputs
- Changes in tillage practices (i.e. no till, reduced till and conventional till)

The SOC emission factors were reported in the 2022 CRSC carbon footprint reports ((S&T)2 Consultants Inc., 2022a, 2022c, 2022d, 2022e, 2022g) and the 2023 CO-OP carbon footprint reports for rye and triticale ((S&T)2 Consultants Inc., 2023a, 2023b). The CRSC data on SOC included in the Model covered changes in soil carbon up to the year 2019.

CO_2 emissions from urea and UAN application: include CO_2 emissions released from nitrogen fertilizers. When applied as fertilizers on croplands, both urea and UAN release captured process CO_2.

Figure 7 illustrates the process flows for agricultural crops, including the inputs, emissions and the functional unit.

Figure 7: Process overview for agricultural crop cultivation



As explained in the 2022 CRSC methodology report ((S&T)2 Consultants Inc., 2022h), the following elements were either excluded from the scope of the LCI due to lack of data or because the contribution of some of these inputs to the CI was negligible:

- On-farm production of renewable energy, such as solar, wind, and biomass combustion
- On-farm ancillary operations, such as work area lighting and heating
- Manufacture, maintenance and decommissioning of capital equipment (for example, machinery, trucks, infrastructure)
- Transport of pesticides and fertilizers between the manufacturing plant and the farm
- Waste or co-products, such as:
    - Disposal of process wastes
    - Straw and stover co-products
    - Emissions related to manure application

In addition, carbon emissions from changes in the proportion of annual and perennial crops were excluded because of methodological limitations and high uncertainty.

Regarding the exclusion of organic fertilizers such as manure, the Model uses the default approach from the CRSC and CO-OP carbon footprint reports which is to allocate emissions and resource use related to manure storage and application to the livestock production system. This approach is aligned with the guidelines of the Food and Agriculture Organization of the United Nations (Food and Agriculture Organization (FAO) of the United Nations, 2016).

Geographical scope for Canadian grown agricultural crop cultivation

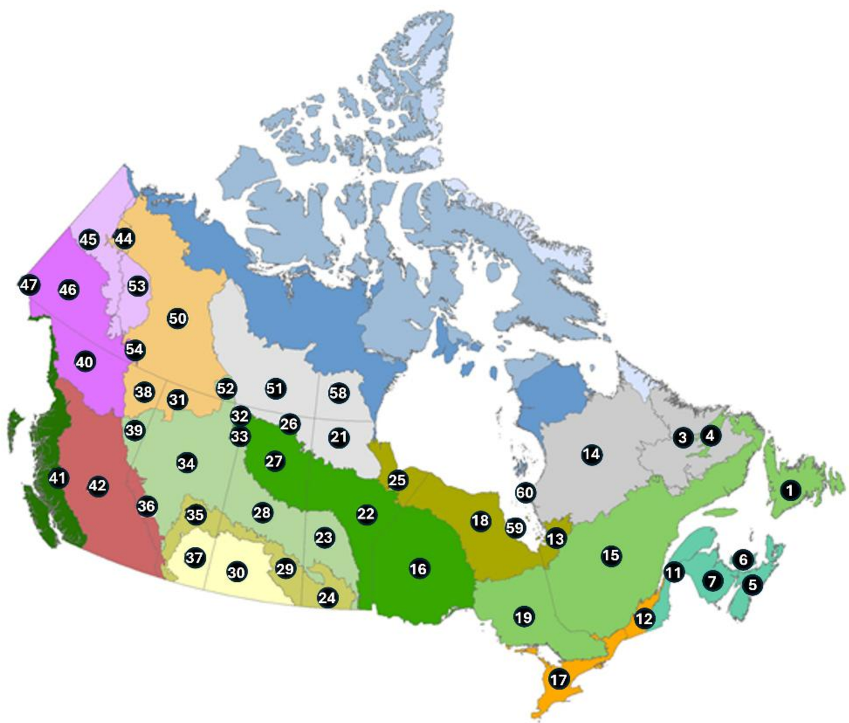
There is one system process available for each crop, with each crop having a unique CI. Each process can be used regardless of geographical location. Agricultural feedstock LCI data was collected and compiled for each province where crops are produced, except for Newfoundland and Labrador. Table 5 indicates which regions were included in the CI calculations for each crop. A weighted average of the provincial datasets was then calculated for each crop using 2018 to 2020 average production data from Statistics Canada.

Table 5: Geographical scope of barley, corn, field peas, rye, triticale, and wheat (durum and non-durum) included in the Model

Crop	AB	BC	MB	NB	NL	NS	ON	PE	QC	SK
Barley	Yes	Yes	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes
Corn	Yes	No	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes
Field Peas	Yes	Yes	Yes	Yes	No	No	No	Yes	No	Yes
Rye	Yes	No	Yes	No	No	No	No	No	No	Yes
Triticale	Yes	No	No	No	No	No	No	No	No	Yes
Wheat (Durum)	Yes	No	Yes	No	No	No	No	No	No	Yes
Wheat (non-Durum)	Yes	Yes	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes

The provincial data was also calculated using weighted averages of regional data at the reconciliation unit (RU) level when available. RUs are the geographic entities formed by the intersection of terrestrial ecozones of Canada with the provincial and territorial boundaries. They are used to reconcile data from multiple agencies of the Government of Canada. Figure 8 shows the RU breakdown in Canada.

Figure 8: RUs in Canada (Natural Resources Canada, 2025).



Allocation for Canadian grown agricultural crop cultivation

Crop cultivation results in agricultural residues that are left on the field. The Model considers these residues as a waste (i.e. not co-product) from the crop cultivation and the “cut-off” allocation approach is applied (refer to section 3.5.3). No other allocation procedure was applied to the LCI dataset of agricultural crops.

Data sources for Canadian grown agricultural crop cultivation

The 2022 CRSC methodology report ((S&T)2 Consultants Inc., 2022g), the 2022 CRSC carbon footprint reports for barley, corn, field peas, wheat ((S&T)2 Consultants Inc., 2022a, 2022c, 2022d, 2022e, 2022g), along with the 2023 CO-OP carbon footprint reports for rye and triticale ((S&T)2 Consultants Inc., 2023a, 2023b) are the main sources of data for compiling the LCI. Those LCA reports represent the current best available sources of Canadian field crop LCI data.

The 2022 CRSC and 2023 CO-OP carbon footprint reports detail carbon footprints of barley, corn, field peas, wheat, rye and triticale in Canada using a variety of data sources: national statistics, provincial field crop budgets and agricultural surveys, data from provincial agricultural associations and literature data. The reports contain detailed information regarding fertilizer, pesticide and seeding rates as well as energy consumption values for crop production. Although data sources sometimes vary between crops depending on data availability, the modelling approach is consistent for all crops. The methodology and data sources are also consistent with those used in the 2022 NIR with respect to N_2O emissions from managed soils and land management practices (ECCC, 2022b).

Modelling approach for sorghum

The dataset for sorghum was generated based on a report developed for ECCC by consultancy firm, Quantis. As with the modelling of other crops, the boundaries of the sorghum dataset considered of all field activities related to crop production (from soil preparation to harvest and storage) and excluded the subsequent transportation, distribution, processing and use phase of the harvested grains and oilseeds. The LCI was modelled based on data generated by the geoFootprint tool. The geoFootprint tool was developed by Quantis and models the footprints of agricultural commodities around the world by accounting for local environmental conditions (soil and climate) in conjunction with best estimates of regional farm management practices. The tool relies entirely on publicly available data which have been consolidated and harmonized (Reinhard et al., 2021).

Sorghum was modelled using the same eight production processes as other crops included in the Data Library: tillage, seeding, irrigation[17], fertilizer and pesticide application, harvesting, transportation of the product from the field to the on-farm storage bin, and storage (including aeration/drying). Fuel and energy consumption as well as agricultural inputs such as fertilizers, pesticides and seeds were considered for all processes.

Similarly, tillage techniques (i.e. conventional tillage or intensive tillage, reduced tillage and direct seeding or no-tillage) were considered for the calculation of energy use in the form of diesel fuel consumption, direct N_2O emissions and soil carbon changes.

N_2O emissions for sorghum are calculated using a modified IPCC Tier 1 equation. Data was collected for the geoFootprint N_2O modelling approach using the Bouwman model (Bouwman et al., 2002) as implemented by the Cool Farm Tool (Kayatz et al., 2020).

Carbon emissions associated with SOC changes from the two following land management practices are included:

- Changes in area of summerfallow
- Change in tillage practices (i.e. no till, reduced till and conventional till)

Canadian national harvest-area weighted average values for SOC changes were applied to crops grown internationally.

Carbon emissions associated with urea and UAN application are included.

The modelling scope for the development of the LCI of sorghum followed the same scope as other crops and excludes the following:

- Carbon emissions associated with SOC changes from changes in the proportion of annual and perennial crops
- On-farm production of renewable energy, such as solar, wind, and biomass combustion
- On-farm ancillary operations, such as work area lighting and heating

[17] Only energy use for irrigation was considered; irrigation water was not included in the model because it is outside the scope of the Fuel LCA Model.

- Manufacture, maintenance and decommissioning of capital equipment (for example, machinery, trucks, infrastructure)
- Transport of pesticides and fertilizers between the manufacturing plant and the farm
- Waste or co-products, such as:
  - Disposal of process wastes
  - Straw and stover co-products
  - Emissions related to manure application

Organic fertilizers such as manure were excluded from the scope.

Geographical scope for sorghum

LCI data for sorghum was generated by the geoFootprint tool based on data from the U.S. The energy and material inputs (for example, fertilizers, pesticide, and diesel) were modelled using the datasets from the Model. A weighted average of regional data from Kansas, Missouri, Nebraska, and Texas was used to create a single process in the Data library.

The geoFootprint geographical unit of analysis (the most fundamental level at which data is held and processed) is at the grid cell level. GeoFootprint operates on a grid cell resolution 5 x 5 arcminutes (i.e., 10 x 10 km at the equator). GeoFootprint aggregates grid cells to the State level. For each state, a specific number of grid cells is considered in the aggregation. Grid cells included in the aggregation must have a scaled production volume higher than a given threshold. For sorghum, the threshold, is 20.00 metric tons per grid cell.

Allocation for sorghum

Agricultural residues that are left on the field are considered a waste (i.e. not a co-product) from the crop production and the “cut-off” allocation approach is applied (refer to section 3.5.3). No other allocation procedure was applied to the LCI dataset of agricultural crops.

Data sources for sorghum

The geoFootprint tool was the main source of data for compiling the internationally grown crop inventories.

The tool uses two clusters of raw data as its foundation. The first cluster of data consists of consolidated LCI datasets representing country-level cultivation practices. These data are derived from the World Food LCA Database (WFLDB) (Nemecek et al., 2019) and from the Ecoinvent database (Weidema et al., 2013). These datasets are all rasterized and harmonized with regards to their resolution and projection system and then overlaid to create grid cell specific LCIs. Where more granular spatial data is available for a given parameter, it overwrites the value extracted from the default inventory at country-level. The second, a repository of publicly available geospatial data for key parameters reflecting certain farm management practices (for example, harvested areas, yields, fertilizer application rates, manure application rates) and environmental conditions (for example, soil pH, soil clay content, SOC stock, temperature, rainfall).

Some data points of key relevance (i.e. harvested area, production volume, yield) are retrieved from the EarthStat consortium (Monfreda et al., 2008), which modelled the expected cultivation properties for 172 crops at a resolution of 10x10 km worldwide, for the year 2000. In geoFootprint, these data are therefore scaled to provide the best possible representation of these properties in 2016. A full list of parameters and data sources are found in Table 6.

Table 6: Parameters and data sources in geoFootprint

Parameter	Data source	Native resolution	Scaling method	Aggregation method
Harvested crop area	EarthStat (Monfreda et al., 2008)	10 x 10 km	Based on FAOSTAT[18] data evolution from (1999-2001) to (2015-2017)	Sum
Yield	EarthStat (Monfreda et al., 2008)	10 x 10 km	Based on FAOSTAT[18] data evolution from (1999-2001) to (2015-2017)	Production Volume Weighted Average
Production volume	EarthStat (Monfreda et al., 2008)	10 x 10 km	Based on FAOSTAT[18] data evolution from (1999-2001) to (2015-2017)	Sum
Irrigation water withdrawal	WFN (Mekonnen & Hoekstra, 2011)	10 x 10 km	n/a	Production Volume Weighted Average
Surface irrigation	WFLDB (Nemecek et al., 2019)	Country	n/a	Constant at country-level
Sprinkler irrigation	WFLDB (Nemecek et al., 2019)	Country	n/a	Constant at country-level
Drip irrigation	WFLDB (Nemecek et al., 2019)	Country	n/a	Constant at country-level
Nitrogen fertilizer	EarthStat (Monfreda et al., 2008)	10x10 km	n/a	Production Volume Weighted Average
Phosphorus fertilizer	EarthStat (Monfreda et al., 2008)	10x10 km	n/a	Production Volume Weighted Average
Potassium fertilizer	EarthStat (Mueller et al., 2012)	10x10 km	n/a	Production Volume Weighted Average
Fuel consumption	WFLDB (Nemecek et al., 2019) Ecoinvent	Country	n/a	Constant at country-level

18 FAO (2020). FAOSTAT Database (FAO, 2020).

Parameter	Data source	Native resolution	Scaling method	Aggregation method
	(Weidema et al., 2013)			
Crop protection	WFLDB (Nemecek et al., 2019) Ecoinvent (Weidema et al., 2013)	Country	n/a	Constant at country-level
SOC stock	ISRIC Soil Grids (Hengl et al., 2014)	10x10 km	n/a	Simple Average
Clay content	ISRIC Soil Grids (Hengl et al., 2014)	10x10 km	n/a	Simple Average
Silt content	ISRIC Soil Grids (Hengl et al., 2014)	10x10 km	n/a	Simple Average
Sand content	ISRIC Soil Grids (Hengl et al., 2014)	10x10 km	n/a	Simple Average
Precipitation	GAEZ (FAO et al., 2009)	10x10 km	n/a	Simple Average
Temperature	GAEZ (FAO et al., 2009)	10x10 km	n/a	Simple Average

Modelling approach for sugar cane

Data used for the modeling of the sugar cane process comes from the RenovaCalc tool of the RenovaBio certification program implemented by the Brazilian government though 2019 and 2020 (RenovaBio, 2021). As part of the program, producers had to submit CI data for the ethanol derived from sugar cane that they produced, including for the cultivation of sugar cane (Liu et al., 2023). RenovaBio is also a source of input data for other publications dealing with Brazilian sugarcane cultivation (International Energy Agency, 2022).

The modelling considers the following material inputs, energy inputs and outputs emissions for the CI calculation:

- Synthetic fertilizers
- Pesticide application
- Direct on-site energy requirements
    - Fuel consumption (biodiesel, gasoline, diesel, hydrous ethanol)
    - Electricity (modeled with the Brazilian electricity grid mix in the Model)

- Direct and indirect N_2O emissions (both volatilization and leached)
- Emissions from burning practices
- Upstream emissions associated with soil amendments
- Direct emissions associated limestone and urea

For data on the application rate for pesticides, assumptions from GREET 2023 Feedstock CI Calculator (FD-CIC) were used (Argonne National Laboratory, 2023a). The IPCC disaggregated N_2O emission factors for wet climate were used for the direct and indirect volatilized emission factor (EF1 and EF4), while the aggregated values from the IPCC were used for the indirect leached emission factor (EF5) and the fractions leached and volatilized from synthetic and organic fertilizers (IPCC, 2019) (Tables 11.1 and 11.3).

Geographical scope for sugar cane

The process in the Model corresponds to the cultivation of sugar cane in Brazil. The process takes aggregated data from a total of 67 ethanol production mills in Brazil that have published their performance data for public review, including data on the cultivation of sugar cane.

Allocation for sugar cane

No allocation is required for the cultivation process of sugar cane.

3.5.3 Agricultural crop residues

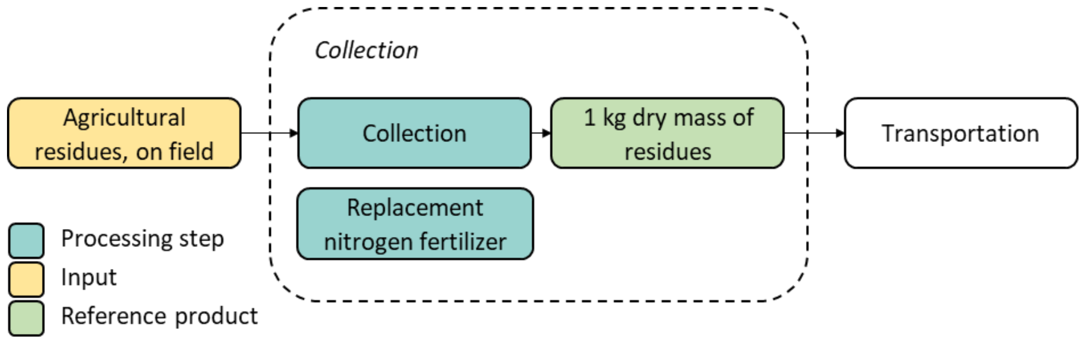
Modelling approach for agricultural crop residues

The Model includes a system process that models the collection of agricultural crop residues. These residues comprise the above-ground parts of the corn and wheat plants that are left on the fields after harvest. The crop residue feedstock process included in the Model is an average of corn stover, non-durum wheat straw, and durum wheat straw. Consequently, the dataset is applicable for residues from corn and wheat production only.

Given that most crop residues are currently left on agricultural fields, agricultural residues are treated as waste products in the Model. As such, no upstream impacts from cultivation are allocated to the residues. However, the modelling of crop residues includes the use of diesel to account for the collection of these residues, as well as an N-fertilizer input to account for the removal of these crop residues. Furthermore, because the residues contain nitrogen, which is removed from the field, the field will require an additional nitrogen (N) input from N-fertilizers the following year. The quantity of nitrogen removed from the fields in residues is calculated using data from Thiagarajan et al. (2018) on the nitrogen content of corn stover and wheat straw.

The energy use input for the collection of residues is modelled based on fuel consumption for farm machinery compiled by Whitman et al. (2011). The fuel consumption is estimated by hectare for a multiple passes collection process with conventional farm machinery and considers the quantity of residues by hectare. Residues quantities by hectare estimated using a relative yield of crop residues per kg of crops from Janzen et al. (2003). The agricultural residues process has a functional unit of 1 kg dry mass of crop residues at the farm gate (before transportation to the LCIF production facility).

Figure 9: Crop residue process overview



Geographical scope for agricultural crop residues collection

The process was modelled using Canadian data but can be used regardless of geographical location.

Allocation for agricultural crop residues collection

Agricultural residues are considered as a waste from crop cultivation, and the “cut-off” allocation approach is applied. System expansion is applied to account for the production of replacement nitrogen fertilizer.

Data Sources for agricultural crop residues collection

The nitrogen content and yield of crop residues was modelled based on Thiagarajan et al. (2018). Diesel consumption for harvesting per kg of residues were estimated based off yield data from the CRSC reports ((S&T)2 Consultants Inc., 2017a, 2017b) and Janzen et al. (2003) and average fuel consumption by hectare from Whitman et al. (2011).

3.5.4 Other waste materials

Modelling approach for other waste materials

Wastes from various agricultural, commercial and industrial activities can be used as feedstock for many LCIFs, including ethanol, biodiesel, biogas/RNG and hydrogen.

The Model includes three generic processes for waste (two for biogenic waste and one for non-biogenic waste) which can be used to model a number of waste materials other than the feedstocks already included in the Data library. In accordance with the “cut-off” allocation approach, there is no burden associated with these processes, but they are differentiated between waste with biogenic and non-biogenic carbon content. This distinction is important for the combustion life cycle stage of the fuel (refer to section 3.7.1).

However, when a waste material is used as a feedstock for fuel production, the transportation and processing of these waste feedstocks should be included in the fuel life cycle using the relevant processes from the Data library of the Model.

The use of some waste feedstocks for fuel production can prevent emissions that would have occurred if the waste materials were not used as feedstocks. For example, livestock manure used to produce biogas or RNG can prevent CH_4 emissions from manure management practices. Although the processes for waste feedstocks in the Model do not include any predefined quantities of avoided emissions, the

Model allows users to enter the quantity of avoided emissions in the waste processes. The methodology for calculating these avoided emissions may vary according to the program for which the Model is used.

3.5.5 Production of wood fibre feedstock in Canada

Modelling approach for wood fibre production

The Canadian forest sector produces several types of wood fibre which can be used as feedstock for LCIF production; the sector is a highly integrated system of products and processes all originating from the harvest of standing timber in Canadian forests and culminating in a wide variety of midstream uses and end products and uses. Figure 10 illustrates the wood fibre feedstocks included in the Model.

Figure 10: Wood fibre feedstocks included in the Fuel LCA Model

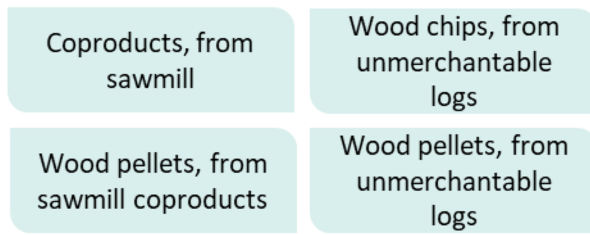
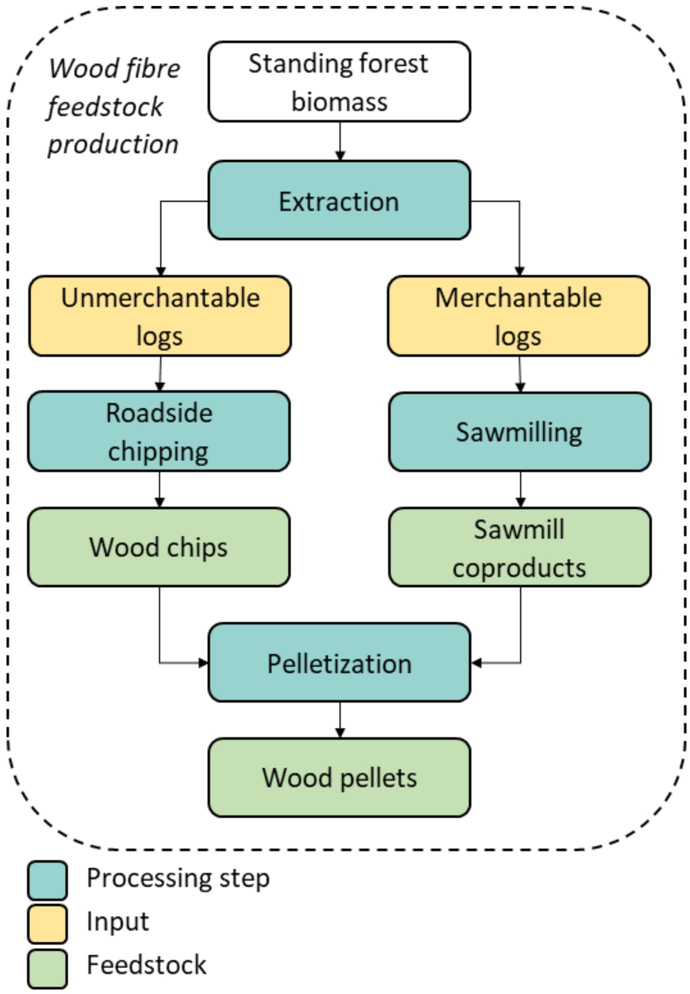


Figure 11 presents the process flow and interaction between the different wood fibre feedstocks included in the Fuel LCA Model. The feedstock production life cycle stage includes harvesting and processing of the feedstock sources mentioned previously and concludes with the production of the main wood fibre feedstocks.

Figure 11: Harvesting and feedstock production process overview for wood fibre feedstocks



Merchantable logs and unmerchantable logs from standing forest biomass are modelled as sources of wood fibre in the preparation of wood chips or sawmill co-products as feedstocks. These feedstocks can subsequently be compressed into pellets, also available as feedstock.

The LCI for merchantable logs includes fossil fuel use (diesel, propane and gasoline) related to collection and harvesting operations and excludes any other material or chemical inputs (related to wood production, for example) which were not accounted for in the LCA data sources. For example, the best publicly available LCI data for Canadian forest harvesting operations for merchantable logs is from the Athena Sustainable Materials Institute, which was used as a data source for the LCI of merchantable logs (Athena Sustainable Materials Institute, 2018a). Seeding and planting activities are excluded from the scope of the LCI because emission factors for these inputs were not available and they did not account for GHG emissions associated with these activities. Similarly, unmerchantable logs are modelled based on the amount diesel consumed related to forestry operations. The modelling approach for unmerchantable logs only considers the collection activities, which is consistent with the approach to crop residues. Logs are transported at the roadside and converted into wood chips.

Once transported to the sawmill, merchantable logs are converted into lumber, a process which generates sawdust and wood chips, as well as other co-products (bark, shavings, trim ends and chipper fines). The woodchips and sawmill co-products can be converted in wood pellets. A trucking distance of 100 km is assumed for log transport to the sawmill from the forest. The modelling therefore allocates the energy consumption (i.e. electricity and fossil fuel use) of sawmill operations based on the mass content of the different sawmill co-products. Drying energy used in the sawmill is attributed to the sawlogs.

The chipping of unmerchantable logs at the forest roadside can be done using a wide range of technologies with varying capabilities and fuel consumption. Roadside chipping of wood biomass was based on an average diesel consumption value per amount of wood chipped based on the literature.

The pelletization process converts wood chips (and other sawmill co-products) into wood pellets. It is modelled based on the amount of energy and materials consumed at the pelletization plant; this includes energy use for hammer mill, drying, compression, cooling and sieving steps of the pelletization process as well as diesel for on site machinery and vegetable oil for lubrication. It is assumed that thermal energy for drying is partially derived from biomass. A trucking distance of 100 km is assumed from the sawmill to the pellet plant.

Excluded processes and their justification are described in Section 2.3.1. The wood fibre feedstock processes use a functional unit of 1 kg of wood fibre feedstock on a dry-mass basis.

Land use change emissions are not included for wood fibre feedstocks, since it is assumed that the existing Canadian forest sources require no conversion for bioenergy production in the LCI of wood feedstocks.

Geographical scope for wood fibre feedstock

Forest harvesting data is unavailable at the provincial level. Instead, the LCI for wood fibre feedstocks (merchantable logs, sawmill co-products and sawmill coproduct pellets) is grouped into two regional averages: Eastern Canada and Western Canada, because the Athena Sustainable Materials Institute aggregated data for Eastern Canada and for Canada as a whole (Athena Sustainable Materials Institute, 2018a, 2018b). Survey data from these studies included more than 20 sawmills located in Alberta, British Columbia, New Brunswick, Ontario, and Quebec. As such, “Western Canada” represents mills in Manitoba, Saskatchewan, Alberta and British Columbia, while “Eastern Canada” include mills in Newfoundland and Labrador, Nova Scotia, Prince Edward Island, New Brunswick, Quebec and Ontario.

Unmerchantable logs harvest, unmerchantable log chips and unmerchantable log pellets are modelled as Canadian averages.

Allocation for wood fibre production

For the harvesting and production of wood fibre, allocation occurs at the sawmill where sawmilling operations generate several co-products (sawdust, wood chips, bark, shavings, chipper fines and trim ends) aside from lumber. The modelling of sawmill co-products involves allocating the energy consumption (i.e. electricity and fossil fuel use) of sawmill operations based on the mass content of the different sawmill co-products.

Data Sources for wood fibre production

The best publicly available LCI data for primary Canadian forest harvesting operations for merchantable logs is from the Athena Sustainable Materials Institute, who have completed a number of LCAs of Canadian forest products (Athena Sustainable Materials Institute, 2018a). In their most recent publications on Canadian softwood lumber manufacturing, they provide fuel consumption for production-weighted Canadian average softwood harvesting based on surveys of 11 forest harvesting operators for 2015, and production-weighted Eastern Canadian average softwood harvesting based on five forest harvesting operators for 2015.

The Athena Sustainable Materials Institute studies contain information regarding Eastern and national data. Although no LCA study was available for Western Canada specifically, it was possible to use weighted averages of the Canadian and Eastern Canada datasets to estimate values for Western Canada (Athena Sustainable Materials Institute, 2018b).

Canadian-specific data was not available for the harvesting of unmerchantable trees which may be harvested as part of a clear cut or during more selective cutting operations such as thinning. The modelling relies on U.S. data from the Consortium for Research on Renewable Industrial Materials in a 2012 LCA study on wood biomass collection and processing in the Southeast United States (Johnson et al., 2012).

For sawmill co-products, the most recent publicly available LCI data for Canadian sawmilling operations is also from the LCA studies conducted by the Athena Sustainable Materials Institute.

The default fuel consumption value for roadside chipping of forest harvest residues and unmerchantable logs is based on a 2012 study of wood biomass energy in Ontario (McKechnie, 2012). The default fuel consumption value for roadside chipping of whole trees is assumed to be the same as chipping of harvest residues.

The pelletization process is based on a study of two Quebec's plants that pelletize sawmill coproducts (Padilla-Rivera et al., 2017). The data from this study are used as a proxy for the pelletization process of chips from unmerchantable logs. The study includes fuel (fossil and biomass) consumption as well as materials used at the pelletization plant.

3.5.6 Raw used cooking oil (UCO) and yellow grease

Modelling approach for yellow grease production from raw UCO

The boundary of the raw UCO process begins with the production of the raw UCO at the restaurants and ends with the restaurant gate. The upstream GHG emissions related to the raw UCO are not included in the dataset since the oil is considered a waste. This process allows Model users to choose raw UCO as feedstock for biodiesel plants that use raw UCO at their facility instead of receiving yellow grease from a rendering plant.

For yellow grease, the boundary of the process begins with the raw UCO at the restaurants and ends with the UCO processing at the rendering facility.

The transport of the raw UCO to the rendering facility considers a trucking distance of 313.6 km calculated using the shares of transportation (R&D GREET 2023 Revision 1) (Argonne National Laboratory, 2023b):

- To rendering plants directly
- Via a bulk transfer tank before being transported to the rendering plant

The Model assumes an average truck payload of 45 tonnes.

The Model includes processes for two rendering methods for UCO processing at the rendering facility (traditional and settling method), both of which include removing water from the UCO with mechanical and thermal processes. The modeling takes into account that UCO has a water content of 26% based on the amount of raw UCO (1.35kg) needed to produce 1 kg of yellow grease at the rendering plant (Xu et al., 2022). The traditional UCO rendering method, which involves high-temperature cooking and tricanting, requires 2.11 MJ of natural gas and 0.25 MJ of electricity per kg of yellow grease (Xu et al., 2022). The settling rendering method, which involves heating raw UCO and then letting it settle, uses 0.76 MJ of natural gas and 0.09 MJ of electricity per kg of yellow grease (Xu et al., 2022).

Geographical scope for yellow grease production from raw UCO

The Model includes processes defined at the provincial and national levels for yellow grease production in Canada. Processes only differ in the provincial electricity grid mix used in the purification process. This assumes that the purification process does not differ across Canada, and only the emissions related to electricity differ.

Allocation for yellow grease production from raw UCO

No allocation is required for the production of yellow grease from raw UCO.

3.6 Fossil fuels

3.6.1 Scope of fossil fuels modelling

The fossil fuel modelling consists of the same life cycle stages presented in Section 2.3: feedstock production (extraction), feedstock transportation (transmission), fuel production (processing, refining), fuel distribution (transmission, distribution), and fuel combustion. The main processing steps, system boundaries, and final products included in each life cycle stage for gaseous, liquid, and solid fossil fuels in the Model are detailed in the following sections.

The following processes are excluded from calculations of the LCI of fossil fuels:

- Construction and decommissioning of mines, drilling sites, production facilities (for example, refineries and upgraders
- The manufacturing of fuel transportation infrastructures (i.e., pipelines, trucks, ships, roads) and fuel combustion infrastructure (that is vehicles, boilers)
- Oil and gas exploration
- GHG emissions associated with exported fuels
- Research and development activities
- Indirect activities associated with fuel production, such as marketing, accounting, and legal activities
- Land use change related to the extraction stage

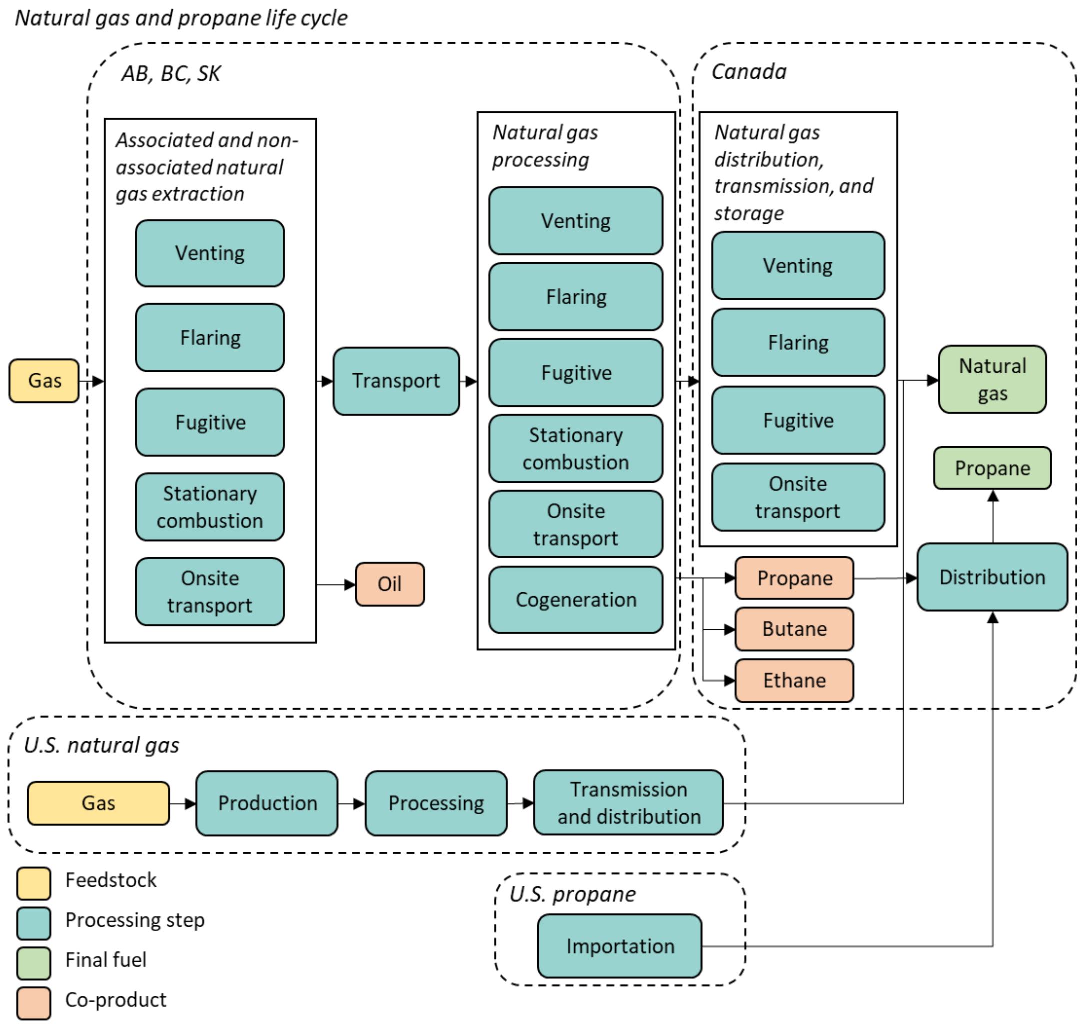
The functional unit for fossil fuels is 1 MJ of energy content based on the HHV of each fuel. The LCI for all fuels were calculated from cradle-to-consumer-gate (WTCG) and from cradle-to-combustion.

Given the interconnectivity of the different fossil fuel chain values, allocation methods based on the energy content of fuels was used to allocate impacts between co-products of multifunctional processes (for which there is more than one product).

3.6.2 Modelling approach for natural gas and propane

The main processing steps, system boundaries, and final products included in each life cycle stage for natural gas and propane are presented in Figure 12.

Figure 12: Life cycle stages for natural gas and propane in the Model



The methodology for the calculation of the CI of natural gas and propane consists of integrating two sets of data. The first set of data is the direct emissions data using the reference year 2024 of the 2026 NIR (ECCC, 2026), applying to the oil and gas sector in Canada, and the indirect emissions data that are from other processes in the Model. The second set of data is related to production, processing, and marketable volumes of natural gas and propane for 2024 and is collected from Petrinex (2026) and Statistics Canada databases (Statistics Canada, 2025a).

The CI of natural gas and propane is representative of consumption in Canada in 2024. The Model assumes that 84% of the natural gas consumed in the country is produced in Canada and the balance is imported from the United States (U.S.) (Natural Resources Canada, 2026). For propane, the imported share from the U.S. is about 4% (Statistics Canada, 2025a).

The life cycle stages considered for natural gas CI calculations are extraction, processing, storage, transmission and distribution, and combustion. Since propane is a co-product from natural gas processing, the life cycle stages before transmission are identical with natural gas. When electricity and diesel are consumed during the different life cycle stages, the upstream emissions of these inputs are included by using existing datasets from the Model. Emissions from electricity production are modelled at the provincial level for extraction and processing and at the national level for transmission and distribution. The CIs are expressed in grams of CO_2 equivalents on the basis of one MJ of energy content based on the HHV of natural gas (38.59 MJ/m^3) or propane (25310 MJ/m^3). It is important to note that the HHV of natural gas varied through the life cycle stages, provinces and types of natural gas (associated and non-associated). The different HHV values are listed below:

- Marketable natural gas CA: 38.59 (MJ/m^3)*
- Marketable natural gas US: 38.99 (MJ/m^3)*
- Marketable natural gas AB: 38.82 (MJ/m^3)*
- Marketable natural gas SK: 38.13 (MJ/m^3)*
- Marketable natural gas BC: 38.87 (MJ/m^3)*
- Natural gas at extraction from associated resources AB: 42.41 (MJ/m^3)*
- Natural gas at extraction from associated resources SK: 48.64 (MJ/m^3)*
- Natural gas at extraction from associated resources BC: 43.74(MJ/m^3)*
- Natural gas at extraction from non-associated resources AB: 41.74 (MJ/m^3)*
- Natural gas at extraction from non-associated resources SK: 40.30 (MJ/m^3)*
- Natural gas at extraction from non-associated resources BC: 42.17 (MJ/m^3)*
- Conventional light oil: 38800 (MJ/m^3)*
- Propane liquid: 25310 (MJ/m^3)**
- Ethane liquid: 17220 (MJ/m^3)**
- Butane liquid: 28440 (MJ/m^3)**

*ECCC, 2026; **Statistics Canada, 2025a

The following sections describe the domestic natural gas and propane modelling for Canada and the U.S.

Canadian Natural Gas and Propane

Extraction of natural gas

For the domestic production, the Model considers production of raw gas from associated (conventional oil sector) and non-associated gas resources in Alberta (AB), British Columbia (BC), and Saskatchewan (SK). This represents more than 95% of the total Canadian gaseous fuel production. Therefore, Canadian CI cradle-to-gate is a weighted average of extraction and processing CI based on produced and processed volumes in each province.

For extraction, natural gas is extracted from two types of wells: the non-associated well, which mainly produces natural gas and the conventional light oil well, which produces oil and gas simultaneously.

Extraction volumes of raw gas and oil (for energy allocation) at the provincial level are from Petrinex (2026). The volumes are then converted to energy with the HHV specific to the province and type of resource.

Two other types of wells or natural gas sources in Canada, heavy oil extraction sites and thermal oil extraction sites, are not considered because it is assumed that they do not contribute significantly to the production of marketable gas in Canada.

Extraction emissions include emissions that may occur before well exploitation, during well drilling, and after wells are closed. For each type of well, the main categories of direct emissions are fugitive, venting, flaring, stationary combustion and onsite transport (i.e., diesel use). Emissions from the production of electricity used by the natural gas production sector are also considered.

Processing of natural gas and propane

Processing modelling is based on gas plants located in Alberta, British Columbia and Saskatchewan. Processing volumes of natural gas and natural gas liquids at the provincial level are identified with marketable volumes at the provincial level. The data comes from Table 25-10-0055-01, Statistics Canada (2025e). They are then converted to energy with the HHV specific to the province. The national processing volume is the sum of the three provinces and represents more than 98% of the Canadian marketable natural gas output.

The processing scope covers sulfur recovery, sweet gas and acid flaring. The main categories of emissions that are included are fugitive, venting, flaring, stationary combustion and industrial cogeneration. Emissions from the production of electricity used by the natural gas processing sector are also considered.

U.S. Natural Gas and Propane

The US CI of natural gas and propane in the Model is based on the R&D GREET model values for the hybrid pathway (Argonne National Laboratory, 2025). It includes production, processing, transmission and distribution. In the R&D GREET model, emissions are provided by British Thermal Unit (BTU) low heating value (LHV) and the quantities of energy have been converted to HHV based on the conversion factors available in the U.S. model.

U.S. natural gas

Total U.S. production is divided between onshore conventional (19%), onshore unconventional (78%) and offshore (3%). The production stage includes emissions from flaring, venting, leakage and stationary combustion. The processing stage includes these same sources of emissions in addition to non-combustion emissions. Transmission and distribution include emissions from venting, leakage and stationary combustion only. Losses are considered between upstream stages and transmission and distribution (approximately 8% over the entire lifecycle).

U.S. propane

In the U.S., propane is a coproduct of both the oil and natural gas supply chain. Emissions linked with extraction and gathering of these feedstocks to produce propane are included in the U.S. CI, as well as propane production and transmission emissions.

Transmission, storage and distribution of natural gas and propane

In the NIR, transmission and storage emissions for natural gas are taken at the national level and gathered under the same sector of emissions. This report covers emissions for the natural gas transported from the processing plants in Canada or from the border with the U.S. to the gate of the local distribution systems by high-pressure pipelines. The NIR includes emissions from normal operation, but also accidental releases. It includes emissions from delivering and withdrawing from storage. The main categories of emissions that are included are fugitive, venting, flaring and onsite transport. Emissions from the production of electricity used by the natural gas transmission and storage sector are also considered.

The volume of natural gas is taken from Statistics Canada (2025e)[19]. The imported volume from the U.S. is added to the Canadian marketable natural gas. The resulting volume is then converted to energy with Canadian and U.S. average HHV.

Distribution refers to the activity of delivering natural gas to the final consumer. Pressure of pipeline is cut down from the transmission grid and the meshing is denser. It includes emissions due to normal operation, but also accidental releases. The same categories of emissions for transmission and storage are considered.

The volume of natural gas is taken from Statistics Canada (2025e). The volume exported to the U.S. is subtracted from the sum of Canadian marketable natural gas and U.S. imports. The resulting volume is then converted to energy with Canadian and U.S. average HHV.

Statistics Canada (2018a)[20] and other ECCC internal reports were used as the main sources for propane transmission and distribution. Please refer to Section 3.8.4 for more information on propane distribution.

Allocation of natural gas

Energy allocation is performed to allocate emissions to the natural gas system where co-production occurs: associated extraction (oil and natural gas) and natural gas processing (ethane, propane, butane and natural gas).

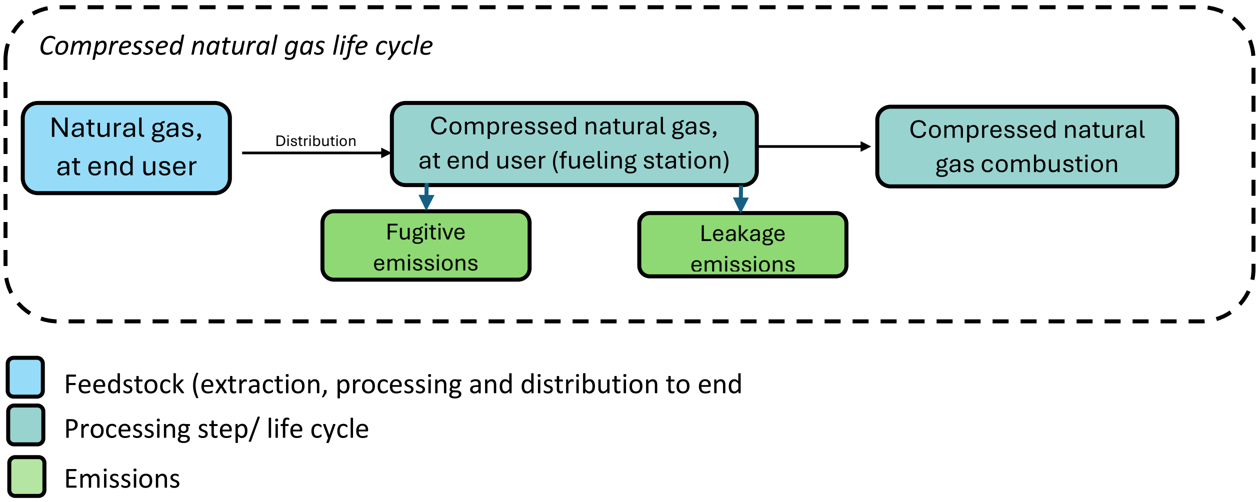
Compressed Natural Gas

Compressed natural gas (CNG) in Canada is currently produced and used at fueling stations in Alberta, British Columbia, Ontario and Quebec. The modelling of CNG in the Data Library includes two processes for CNG: ‘Compressed natural gas, at end user’ and ‘Compressed natural gas combustion.’

[19] Statistique Canada. Tableau 25-10-0055-01 Approvisionnements et utilisations du gaz naturel, mensuel (données en milliers) (x 1 000).

[20] Statistics Canada. Table 23-10-0057-01 Railway industry summary statistics on freight and passenger transportation.

Figure 13: Life cycle stages of compressed natural gas



The 'Compressed natural gas, at end user' process models the lifecycle emissions associated with natural gas extraction through its distribution, and compression at the end user (fueling station in Canada). The system boundary for this unit process follows a cradle-to gate approach which includes natural gas extraction, processing, distribution to the end user as well as onsite compression. Figure 13 outlines the life cycle stages of compressed natural gas.

The 'Compressed natural gas, at end user' process assumes that the natural gas is compressed onsite at the end user (fueling station). The end user uses an electric driven compressor to compress the natural gas from 4-60 bar to approximately 250 bar, using the GREET CNG Compressor efficiency values in Table 1-50 (Coordinating Research Council, 2018). The GHG emissions related to the production of CNG includes impacts related to the electricity used to compress the natural gas as well as fugitive emissions (compressor packing vents, compressor blowdowns and dryers) (Clark et al., 2016), and methane losses from leakage and venting (dispensing fueling nozzle and other sources) at the fueling station.

The distribution and transmission of CNG is already included in the scope of the 'Natural gas, at end user' process because the CNG is produced directly at the end user (fueling station in Canada). Thus, transport modes and distances are not accounted for in the 'Compressed natural gas, at end user' process. Though, fueling station methane losses from leakage and venting (dispensing fueling nozzle and other sources) are still considered (Clark et al., 2016).

The 'Compressed natural gas combustion' process represents the full life cycle of the fuel, encompassing both the upstream emissions associated with the 'Compressed natural gas, at end user' and the combustion of CNG, which is assumed to be combusted in a natural gas vehicle (ECCC, 2026).

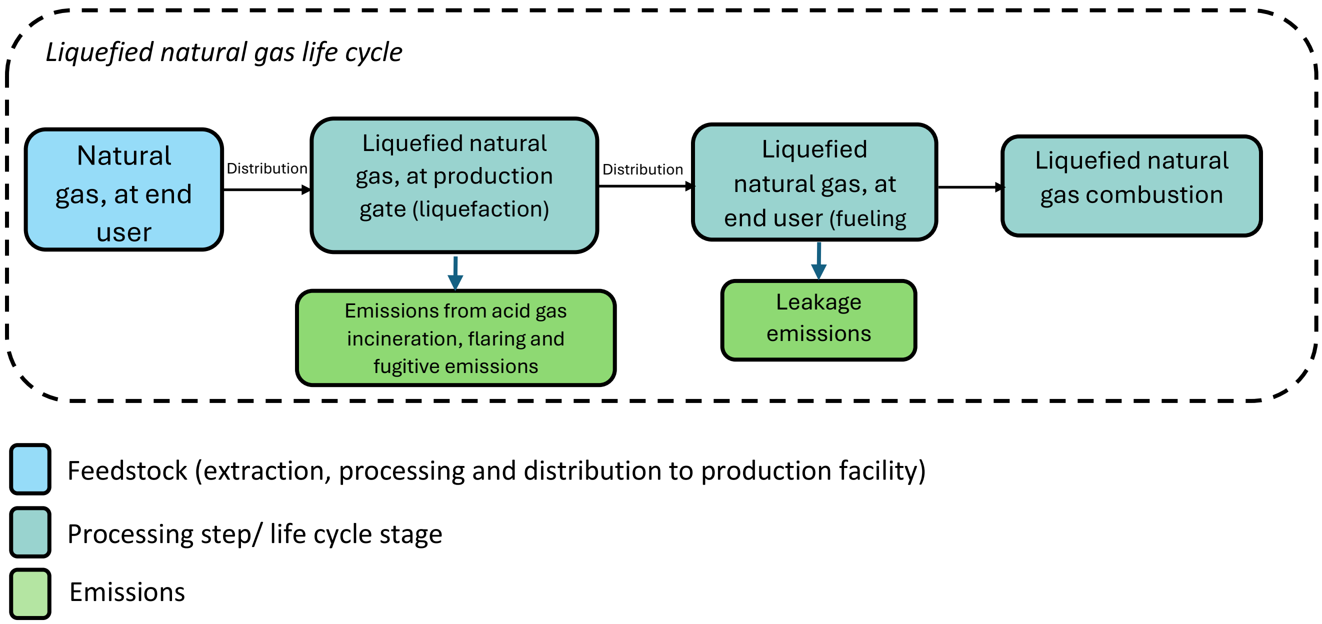
No allocation treatment was performed for any processes related to CNG.

Liquefied Natural Gas

Liquefied natural gas (LNG) in Canada is currently produced in Quebec and British Columbia. The modelling of LNG in the Data Library includes three life cycle stages: 'Liquefied natural gas, at fuel production gate, 'Liquefied natural gas, at end user' and 'Liquefied natural gas combustion.'

The 'Liquefied natural gas, at fuel production gate' process models the lifecycle emissions from the extraction of natural gas, natural gas processing, natural gas distribution up to the liquefaction facility of natural gas (that is, from cradle-to-gate). Figure 14 outlines the life cycle stages of liquefied natural gas.

Figure 14: Life cycle stages of liquefied natural gas



LNG production is modelled based on LNG Canada's 26MTPA capacity project with four liquefaction trains (eight natural gas-fueled turbines). Natural gas is used as a feedstock and as a fuel input for the gas turbines. Boil off gas from LNG storage tanks is recovered and used as the main fuel input for the gas turbines for power generation purposes (modelled with 'Natural gas, no upstream emissions' as a proxy). There is also a small amount of electricity (purchased from the grid) due to auxiliary electricity demand. Process emissions include emissions from acid gas incineration, flaring, and fugitive emissions (Banholzer et al., 2014).

The 'Liquefied natural gas, at end user' process models the distribution of the LNG by truck from the fuel production gate to the end user (fueling station) (ECCC, 2025a). This process includes the total amount of electricity purchased from the grid that is used for dispensing the LNG fuel at the fueling station (Prussi et al., 2020). It also includes fugitive emissions from the delivery of LNG, storage tank boil-off gas, fueling nozzle and other sources that release methane at the fueling station (Clark et al., 2016). Please note that this does not consider the impacts of re-gasification of the LNG at the end user.

The 'Liquefied natural gas combustion' process represents the full life cycle of the fuel, encompassing the upstream emissions associated with the 'Liquefied natural gas, at fuel production gate,' 'Liquefied natural gas, at end user' and the combustion of LNG, which is assumed to be combusted in a natural gas vehicle (ECCC, 2026).

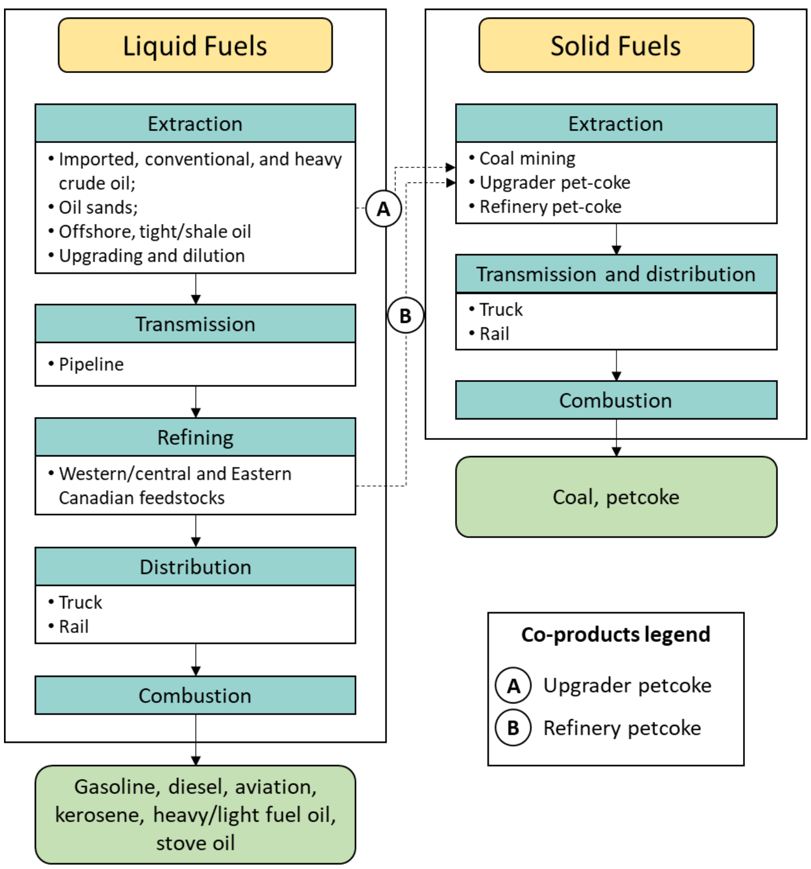
No allocation treatment was performed for any processes related to LNG.

3.6.3 Modelling approach for liquid and solid fossil fuels

Efforts to model in a consistent way across all fuels were made despite the differences in tools and data available. Wherever possible, Canadian-specific data that reflects 2016 fossil fuel production operations were used. In addition, once modelling and data uncertainties are considered, the cradle-to-combustion CIs for Canadian, American (Cooney et al., 2017) and European (Life Cycle Associates) fossil fuels do not show significant differences. Hence, the approach for the internationally produced fossil fuels is to treat their CI as equivalent to Canadian produced fossil fuels.

The main processing steps, system boundaries, and final products included in each life cycle stage for liquid, and solid fossil fuels in the Model are presented in Figure 15, dashed lines represent co-products transferred between liquid and solid fossil fuel life cycle stages. Note that special process routes and other co-products are not represented.

Figure 15: Life cycle stages for liquid and solid fossil fuels in the Model



The following sections summarize the modelling approach taken for liquid and solid fossil fuels.

Liquid fuels

Crude oil for refining in Canada originates from several sources: conventional crude, oil sands mining and upgrading, oil sands in-situ (and heavy crude via steam-assisted gravity drainage), offshore extraction, and imports from countries outside of Canada. Each of these feedstock sources was considered in developing the dataset for fossil fuels in the Model. While crude oil extraction occurs in many provinces within Canada, 95% of domestic production primarily takes place in Alberta and Saskatchewan. The Model also considered crude oil imports from the U.S. and other international sources, which represent of 33% of domestic consumption.

Extracted crudes are transported via pipeline to refineries distributed in Eastern and Western Canada. Canadian oil and gas market reports, and facility production data, were used to identify the extraction and pre-processing methods relevant to the Canadian industry. CI results were aggregated based on the source locations of crude products (for example, Eastern and Western Canada, and imports) and the refinery types. In this sense, each refinery product (for example, aviation fuel, diesel, gasoline, and kerosene) was modelled for Eastern and Western/Central Canada; Canadian pathways were derived based on the production-weighted average of both regions.

Extraction of liquid fuels

Distinct extraction models were developed for each Canadian oil source: conventional crude, oil sands mining and upgrading, oil sands in-situ, and offshore extraction. The modelling was conducted using the Oil Production Greenhouse Gas Emissions Estimator (OPGEE) (Environmental Assessment and Optimization Group), an engineering-based model that estimates GHG emissions from the production, processing, and transport of crude oil, based on data from Canadian facilities. Government information on technology pathways and operating parameters were sourced from Alberta Energy Regulator, the NEB and Statistics Canada. The CIs of crude oil imports from other countries were based on data from the NEB and the Oil Climate Index (Oil Climate Index plus Gas, 2018). An average CI was calculated for imported crudes based on import shares (%) between the different countries. Venting and flaring emissions from oil extraction were modelled using actual reported facility level data when available. Emissions were allocated to other fuels produced during oil extraction, including natural gas liquids (NGL) (associated gas) and upgrader petcoke, by using an energy-based allocation procedure and are not considered in the fossil fuel CI values.

Refining of crude to liquid fuels

Thirteen of the sixteen Canadian refineries were modelled in detail based on 2016 data from Woods Mackenzie as well as the Petroleum Refinery Life Cycle Inventory Model (PRELIM) (University of Calgary). The refinery products from Wood Mackenzie were matched with PRELIM's product slate. PRELIM was used to model a mass- and energy-based representation of the refining process and calculate GHG emissions for refined products (for example, blended gasoline, jet fuel, ultra-low sulfur diesel, fuel oil, coke, liquid heavy ends, and liquefied petroleum gas). Both the OPGEE and PRELIM models are unique in that they offer the ability to model the respective processes in detail for a specific facility or refinery. The refining processes for each of these products were defined for Eastern and Western Canada. In addition, results from the PRELIM model were compared to data available in the Canadian Greenhouse Gas Reporting Program (GHGRP) (ECCC, 2019b). Once the results from each tool were adjusted to ensure a comparable scope, results were generally consistent.

Transmission and distribution of liquid fuels

Crude transport in pipelines across Canada was modelled by estimating distances between oil reservoirs, production facility and refineries using a combination of Canadian data and published literature. Transport of imported crudes was modelled using Canada's National Marine Emissions Inventory Tool (MEIT) (ECCC, 2019a).

In the Model, it is assumed that there is no difference in energy requirements for the transport of crude oil, bitumen and diluent. The LCI for liquid pipeline transport was calculated based on the amount of electricity used to power the pipelines pumps based on energy intensity data from Choquette-Levy et al. (2018).

Solid fuels

The LCI of petcoke was modelled based on results from both OPGEE and PRELIM to reflect the amount of petcoke that is produced and used from both upgrading and refining. Imported petcoke was assigned the same CI value as Canadian domestic petcoke.

For coal, the extraction stage, which was assumed to occur entirely in Western Canada, was based on 2012 data from a study by Cheminfo Services Inc. on coal mining (Cheminfo Services Inc. & Clearstone Engineering Ltd., 2014). The scope of the analysis for coal was limited to thermal coal, including bituminous, sub-bituminous, and lignite coal. The dataset for imported coal from the U.S. was obtained from the R&D GREET model (Argonne National Laboratory, 2018).

3.6.4 Combustion emission factors for fossil fuels

Emission factors related to combustion were based on the 2024 reference year of the 2026 NIR (ECCC, 2026). For cases where multiple emissions values were reported for fuels based on their origin of production, a single combustion value was calculated based on the production-weighted average of each of these fuels. Since useful energy generated from fuel combustion varies depending on the efficiency of the combustion device, the modelling of CI values for specific combustion types and devices (heating, transportation, and electricity) was also included in the scope of this project. As such, a technology-specific combustion emission factor per fuel based on HHV can be used to calculate the CI. While the technology-specific combustion emission factors are now available in the Data Library, the average combustion emission factor per fuel based on HHV is still used to calculate the final CI.

3.7 Renewable fuels

The Data Library includes five renewable fuels that can be used as a fuel input in the modelling of a fuel pathway. These datasets cover the cradle-to-combustion life cycle stages of these fuels.

3.7.1 Combusted renewable fuels

Combusted renewable fuels are modelled using two feedstock sources: wood fibres (sawmill co-products) and agricultural residues. The modelling for each feedstock production is detailed in Sections 3.5.4 and 3.5.3, respectively**.** Table 7 summarizes the renewable fuel combustion processes included based on feedstock and fuel production type.

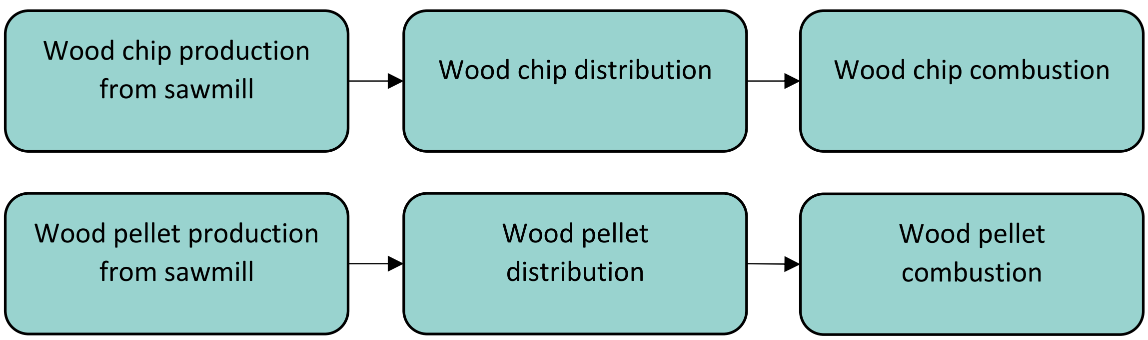
Table 7: List of feedstocks and conversion processes included in the Model for combusted renewable fuels

Feedstock	Fuel production process	Fuel
Sawmill co-products	None	Wood chips
Sawmill co-products	Pelletization	Wood pellets
Agricultural residues	Densification	Agricultural residue pellets
Agricultural residues	None	Corn stover and wheat straw
Agricultural residues	None	Bagasse

Modelling approach for wood chip and wood pellet combustion

The Model includes the conversion of wood fibre feedstocks into solid renewable fuels. This group of fuels includes wood chips and wood pellets from sawmill co-products. These processes model the LCI for renewable fuel combustion, which is visualized in Figure 16.

Figure 16: Life cycle stages for renewable fuels based on wood fibre included in the Model



The cradle-to combustion datasets are based on a functional unit of 1 MJ of energy content based on the HHV delivered to the end user and used for its energy content.

The modelling of distribution to end users is a function of the moisture content equivalent to market level content. Table 8 summarizes the moisture content of solid renewable fuels included in the Model, as well as the corresponding HHV based on data from *Solid Biofuels Bulletin No. 2 Primer for Solid Biofuels* (Natural Resources Canada, 2016). For both types of fuels, it is assumed that the HHV on dry mass basis is 21.5 MJ/kg. A distance of 100 km by truck is assumed for transportation between the sawmill and the end user.

Table 8: Moisture content of solid renewable fuels and corresponding high heating values (MJ/kg)

Renewable fuels	Moisture content (%)	HHV (MJ/kg)
Wood chips from sawmill	45%	10.5
Wood pellets from sawmill co-products	10%	19

CH_4 and N_2O emissions from the combustion process is modelled with emission factors from the NIR for two general applications: combustion of wood chips in industrial furnaces and combustion of wood pellets in residential pellet stoves. Biogenic CO_2 emissions are not included in the modelling.

Geographical scope for wood chip and wood pellet combustion

Fuel production processes were modelled to be representative of a Canadian national average process, using a 50/50 mix of sawmill co-products from Western and Eastern Canada. More information on the geographical scope of the wood pellets and chips from sawmills is available in Section 3.5.5. These processes can be used regardless of geographical location.

Allocation for wood chip and wood pellet combustion

Allocation procedure for the cradle-to-sawmill gate life cycle stages are explained in Section 3.5.5. No other allocation procedure was performed for solid renewable fuel produced from wood fibres.

Data sources for wood chip and wood pellet combustion

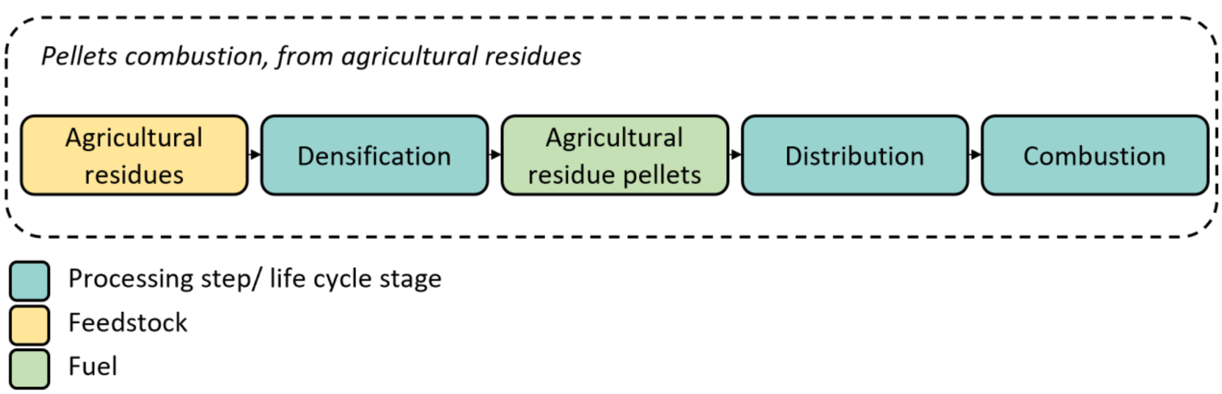
Data sources for the cradle-to-sawmill gate life cycle stages are presented in Section 3.5.5.The combustion process is based on the NIR (ECCC, 2018). The data sources for distribution and combustion life cycle stages are listed below.

Modelling approach for agricultural residue pellet combustion

The Model includes a system process that models the combustion of pellets produced from agricultural residues. The process covers the collection of harvest residues and transportation to a densification unit where residues are converted into pellets before being transported to the final user and combusted.

The agricultural residues collection process is explained in Section 3.5.3. The production process involves the densification of agricultural residues to produce agricultural residue pellets, which are used much like wood pellets from wood fibre conversion. The densification process generally includes a series of steps including receiving bales of residues, grinding, pelletizing, cooling, and screening. The process was modelled by including electricity and fossil fuel inputs for the pelletization process, as well as for the other steps. Figure 17 outlines the scope of the agricultural residue pellets combustion dataset. The dataset is based on a functional unit of 1 MJ of agricultural residue pellets HHV delivered to the end user.

Figure 17: Processing overview for the combustion of agricultural residue pellets.



The modelling of the densification process relies on Canadian data for the densification of wheat straw. As such, it is assumed that agricultural residue feedstocks, would undergo the same densification process.

The modelling of transportation to the densification plant and subsequent distribution to end user is a function of the moisture contents of the residues and the pellets and they are assumed to be respectively at 11.9% and 9%. The distances between the farm and the densification plant, and between the densification and the end user are both 100 km by truck. CH_4 and N_2O emissions are included based on the emission factors for wood fuel combustion in an industrial furnace from Canada's NIR. Biogenic CO_2 emissions are not included in the modelling.

Geographical scope for agricultural residue pellets combustion

The production process was modelled at the Canadian national level using data from a 2012 LCA study focusing on the densification of wheat straw pellets in the Canadian Prairies (Li et al., 2012). The geographical scope for the cradle-to-farm gate life cycle stages is presented in Section 3.5.3. This system process can be used regardless of geographical location.

Allocation for agricultural residue pellets combustion

The allocation procedure for the cradle-to-farm gate life cycle stages is explained in Section 3.5.3. No other allocation procedure was performed for solid renewable fuel produced from crop residues.

Data Sources for agricultural residue pellets combustion

Data sources for the cradle-to-farm gate life cycle stages are presented in Section 3.5.3. The production process and moisture content relied on data from a 2012 LCA study focusing on the densification of wheat straw pellets in the Canadian Prairies (Li et al., 2012). As mentioned, it is assumed that the densification process stays the same regardless of the type of agricultural residue feedstock. The combustion process is based on the NIR (ECCC, 2018) and the HHV for agricultural residues are taken from the R&D GREET Model (Argonne National Laboratory, 2018). The main data sources used in the densification process are listed below.

Modelling approach for agricultural residues combustion, from corn stover and wheat straw

The Data Library includes a system process that models the combustion of agricultural residues. The process includes the emissions associated to the transport from the farm to the end user and the combustion emissions from the residues. The process also includes the upstream emissions associated with the collection of agricultural residues. These include the emissions associated with fuel production and consumption by farm machinery, and production of replacement of nitrogen (N) fertilizer. For more information on this, see section 3.5.3 of the Methodology.

Agricultural residues are considered a waste from agriculture. Therefore, the scope of the process doesn’t include emissions associated with the growth, harvesting, and processing of the main crop. Pre-treating agricultural residues prior to use as an energy input is excluded from the process scope. Agricultural residues are assumed to be left to air-dry in heaps or bales at the production facility.

Transportation modelling from the farm to the end user considers that agricultural residues have a moisture content of 11.5%. This is an average of the moisture of corn stover and wheat straw which are 12% (Argonne National Laboratory, 2024) and 11% (Manitoba Agriculture, 2017) respectively. A distance of 100 km by 25-tonnes truck is used for the modeling of the transport between the farm and end user.

CH_4 and N_2O combustion emissions are calculated with the emission factors for wood fuel/wood waste combustion in an industrial furnace from Table A6.6-1 Emission Factors for Biomass. These can be found in the *National Inventory Report 1990-2023: greenhouse gas sources and sinks in Canada* (ECCC, 2025b). The model sets biogenic CO_2 emissions from LCIF combustion to zero in the LCI.

The process uses a functional unit of 1 MJ of agricultural residues using an HHV of 18.13 MJ/kg on a dry basis. This is an average of the HHV for corn stover, 18.34 MJ/kg (Argonne National Laboratory, 2024) and the HHV of wheat straw, 17.92 MJ/kg (Manitoba Agriculture, 2017). The transport begins from a farm to an end user where agricultural residues are used to generate heat or electricity.

Geographical scope for agricultural residues combustion

The system process is modeled using data from Canada's National Inventory Report. It can be used regardless of geographical location.

Allocation for agricultural residues combustion

The combustion of agricultural residues does not require allocation.

Modelling approach for bagasse combustion from sugar cane

The Data Library includes a system process that models the combustion of bagasse. This process includes the emissions associated to the combustion of bagasse used for heat or electricity generation at a biofuel production plant.

Bagasse is considered a waste from the industrial process of milling sugar cane. Therefore, the scope of the process doesn't include emissions associated with the growth, harvesting, and processing of sugar cane. Pre-treating bagasse prior to use as an energy input is excluded from the process scope because bagasse is assumed to be left to air-dry in heaps or bales at the production facility. The cut-off criteria of the Model are applied to exclude transportation of third-party bagasse which represents a small percentage (< 1%) of overall emissions from bagasse combustion[21] (International Energy Agency [IEA], 2022).

CH_4 and N_2O combustion emissions are calculated with stationary combustion emission factors for other primary solid biomass in energy industries taken from Table 2.2 of 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC, 2006). The Model sets biogenic CO_2 emissions associated to LCIF combustion to zero in the LCI.

The process uses a functional unit of 1 MJ of bagasse using an HHV of 17.97 MJ/kg on a dry basis (M. De O. Camargo et al., 2021).

Geographical scope for bagasse combustion

The system process is modeled using data from the 2006 IPCC Guidelines for National Greenhouse Gas Inventories, which are applicable to agricultural biomass fuels internationally. It can be used regardless of geographical location (IPCC, 2006).

Allocation for bagasse combustion

The combustion of bagasse does not require allocation.

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[21] Less than 10% of bagasse that is used for the generation of heat or energy is imported and transported an average of 55km to a biofuel production facility (IEA, 2022).

3.8 Transport

3.8.1 Generic transport

There are four generic modes of transportation and distribution included in the Model presented in Figure 18.

Figure 18: Modes of transportation and distribution in the Model

The fuel used for each process is as follows:

- Truck: Diesel
- Train: Diesel
- Tanker ship: Marine diesel oil and heavy fuel oil
- Gas pipeline: Natural gas and electricity

As the fossil fuel consumption of each transport process is directly linked to the mass transported and the distance travelled, the functional unit of transport system processes in the Model is 1 tonne-kilometre (tkm - that is transport of 1 metric tonne of feedstock or fuel over a distance of 1 kilometre). The transport processes considered the amount of fossil fuel consumed per tkm of transport. As stated in section 2.3.1, the manufacturing of fuel transport infrastructure (that is pipelines, trucks, ships, and roads) was excluded from the Model.

Modelling approach for generic transportation

Fuel consumption data was gathered for each mode of transportation using Canadian and U.S. statistics as well as literature data. The following sections describe the modelling approach taken for that mode of transportation.

Train transport

The amount of diesel consumed per tkm of train transport was based on 2021 data from the Rail Association of Canada on the freight mass, the distance travelled and the annual quantity of diesel consumed (Rail Association of Canada, 2021).

Truck transport

The truck's diesel consumption is directly related to the mass transported and the distance traveled.

The Model assumes B Train trucks are used for generic truck transport. The fuel consumption factor modeled for B Train trucks is 60.98 L/100km. This factor considers the fuel efficiency for full trucks of 50 L/100km, averaged from multiple sources (Natural Resources Canada, 2000; Kabir & Kumar, 2012), an empty fuel consumption ratio of 0.6097 (Kabir & Kumar, 2012), the distance travelled empty between loads of 26% from the American Transportation Research Institute (Leslie & Murray, 2021), and the payload.

There are two generic truck transport processes. The truck transport payload of 45 tonnes is determined by using the maximum weight of a truck (Council of Ministers Responsible for Transportation and Highway Safety, 2019) and the average weight of an empty truck (Onsite, Truck and Equipment Repair, 2022). The truck transport payload of 25 tonnes is determined by using data from the 2023 GREET model (Argonne National Laboratory, 2023b)[22].

This process is considered representative of transport by truck in North America. Some data was sourced from U.S. references. The processes can be used regardless of geographical location.

Ship transport

The process modelling is based on the 2018 fuel consumption data and Efficiency Operational Indicator (EEOI) data taken from the International Marine Organization's (IMO) Fourth Greenhouse Gas Study (table 35 and 60 respectively) (International Maritime Organization, 2020).

The modeling considers EEOI and fuel consumption for the following ship types: bulk carrier, container ship, general cargo ship, chemical tanker, and oil tanker. The EEOI is used to model direct emissions while fuel consumption is used to model the amount of energy required for the transport (for upstream emissions). The amount of fuel consumed (assumed to consist entirely of marine diesel oil (MDO) and heavy fuel oil (HFO) oil) per tonne of cargo * km traveled is calculated using the vessel-based approach. The shares of fuel consumption attributed to HFO and MDO were distributed based on 2017 fuel consumption by fuel type and light fuel oil (LFO) is used in the Model as a proxy for MDO.

Direct emissions and energy requirement for the process are calculated by taking a weighted average of EEOI and fuel consumption respectively of ship types, where the weighted average for each ship type is calculated by taking a weighted average of the EEOI and fuel consumption by size category.

Gas Pipeline transport

The amount of energy consumed per tkm of gas pipeline transport was based on 2022 GREET model (Argonne National Laboratory, 2022). Weighted average energy to transport 1 MJ over a distance of 1 km by pipeline was used to model the energy use. Natural gas is responsible for the 98% of the energy needed for pump operations. The remainder is assumed to be coming from electricity. Canadian grid electricity is used to reflect the emissions due to the average electricity usage across Canada.

Flaring, fugitive, venting and emergency response emissions were included to calculate the CI of natural gas transport. The 2021 reference year data collected for 2023 Canada's National Inventory Report (ECCC, 2023) is used to quantify fugitive, venting and flaring emissions from natural gas pipelines.

This process is considered representative of transport by pipeline in Canada. However, some data was sourced from U.S. references. The processes can be used regardless of geographical location.

[22] Argonne National Laboratory. (2023). The Greenhouse gases, Regulated Emissions, and Energy use in Technologies Model. Tab 'T&D'. 1) Cargo Payload By Transportation Mode and by Product Fuel Type: Tons. Row 7.

3.8.2 Hydrogen transport

Transportation of hydrogen covers the transport of 1 tkm of hydrogen. The hydrogen transportation processes available in the Model provided are the following:

- Truck transport, of liquid hydrogen
- Truck transport, of gaseous hydrogen
- Pipeline transport, of hydrogen, injected in natural gas pipeline
- Pipeline transport, of hydrogen, dedicated pipeline

Modelling approach for hydrogen transportation

The following sections describe the modelling for hydrogen transportation based on mode of transportation. No allocation procedures were performed while modelling the transportation of hydrogen.

Truck transport

The truck's diesel consumption is directly related to the mass transported and the distance travelled.

The Model assumes heavy-duty trucks other than B Train trucks are used for hydrogen truck transport. The fuel consumption factor modeled for heavy-duty trucks is 69.09 L/100km. This factor considers the fuel efficiency for full trucks of 40 L/100km, averaged from multiple sources (Natural Resources Canada, 2000; Kabir & Kumar, 2012), an empty fuel consumption ratio of 0.7273 (Kabir & Kumar, 2012), and the payload.

It also assumes that transporting compressed and cooled fuels requires specialized equipment, limiting the type of material the truck can transport and requires the trucks to travel further while empty. A worst-case scenario is assumed, with 50% of the distance being travelled empty between loads, as emptied trucks will return directly to their origin for another load.

Truck transport average payloads are based on GREET 2022 and are 3.6 tonnes for liquid hydrogen and 1.0 tonne for gaseous hydrogen (Argonne National Laboratory, 2022)[23].

These processes are intended to be representative of truck transport of hydrogen in North America. Some data was sourced from US references. The processes can be used regardless of geographical location.

Dedicated pipeline and transport in natural gas pipeline

For hydrogen transport using natural gas pipelines, the 2022 GREET model for natural gas pipeline modelling has been used as a proxy (Argonne National Laboratory, 2022)[24]. Weighted average energy to transport 1 MJ over a distance of 1 km by pipeline was used to model the energy use. Natural gas is responsible for the 98% of the energy needed for combustion. The remainder is assumed to be coming

[23] Argonne National Laboratory (2022). [The Greenhouse gases, Regulated Emissions, and Energy use in Technologies Model](). Tab T&D. 1) Cargo Payload by Transportation Mode and by Product Fuel Type: Tons Cell Q7 Gaseous Hydrogen and R7 Liquid Hydrogen.

[24] Argonne National Laboratory. (2022). [The Greenhouse gases, Regulated Emissions, and Energy use in Technologies Model](). Tab 'T&D'. 7) Energy Intensity of Pipeline Transportation: Btu/ton-mile. Cell B89.

from electricity. The Canadian average grid is applied to reflect the emissions due to the average electricity usage across Canada (Ramsden et al., 2013).

For hydrogen transported in a dedicated pipeline, it has been assumed that 100% of the energy requirements are met by electricity from grid. Energy input data is based on the 2022 GREET model.

3.8.3 Natural gas transport

Modelling approach for natural gas transportation

Transport of 1 tkm of CNG, LNG, RNG and LRNG in Canada was modelled using pipelines and diesel trucks.

The following sections describe the modelling approach taken for each of these modes of transportation.

Truck transport, liquefied natural gas and RNG

The truck's diesel consumption is directly related to the mass transported and the distance traveled.

The Model assumes heavy-duty trucks other than B Train trucks are used for both LNG and RNG truck transport. The fuel consumption factor modeled for heavy-duty trucks is 69.09 L/100km. This factor considers the fuel efficiency for full trucks of 40 L/100km, averaged from multiple sources (Natural Resources Canada, 2000; Kabir & Kumar, 2012), an empty fuel consumption ratio of 0.7273 (Kabir & Kumar, 2012), and the payload.

It also assumes that transporting compressed and cooled fuels requires specialized equipment, limiting the type of material the truck can transport and requires the trucks to travel further while empty. A worst-case scenario is assumed, with 50% of the distance is being travelled empty between loads, as emptied trucks will return directly to their origin for another load.

The average LNG payload from GREET 2022 are used for both LNG transport and as a proxy for liquefied RNG at 13.6 tonnes (Argonne National Laboratory, 2022)[25].

Boil-off emissions during truck transport of LNG from GREET 2022 are used as a proxy for the transport of liquefied RNG[26].

This process is intended to be representative of both LNG and liquefied RNG in North America. Most data were sourced from U.S. references. The processes can be used regardless of geographical location.

Truck transport, compressed natural gas and RNG

The truck's diesel consumption is directly related to the mass transported and the distance traveled.

The Model assumes heavy-duty trucks other than B Train trucks are used for CNG and compressed RNG truck transport. The fuel consumption factor modeled for heavy-duty trucks is 69.09 L/100km. This

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[25] Argonne National Laboratory. (2022). The Greenhouse gases, Regulated Emissions, and Energy use in Technologies Model. Tab 'T&D'. 7) Energy Intensity of Pipeline Transportation: Btu/ton-mile. Cell B89.

[26] Argonne National Laboratory. (2022). The Greenhouse gases, Regulated Emissions, and Energy use in Technologies Model. Tab 'NG'. 3) Calculations of Energy Consumption, Water Consumption, and Emissions for Each Stage: Total emissions: grams/mmBtu of fuel throughput. Cell AM67.

factor considers the fuel efficiency for full trucks of 40 L/100km, averaged from multiple sources (Kabir & Kumar, 2012; Natural Resources Canada, 2000), an empty fuel consumption ratio of 0.7273 (Kabir & Kumar, 2012), and the payload.

It also assumes that transporting compressed and cooled fuels requires specialized equipment, limiting the type of material the truck can transport. A worst-case scenario is assumed, with 50% of the distance being travelled empty between loads, as emptied trucks will return directly to their origin for another load.

The average payload for CNG is 6 tonnes and is used as a proxy for compressed RNG[27].

Boil-off emissions during truck transport are based on 2022 GREET model and used as a proxy for CNG and compressed RNG (Argonne National Laboratory, 2022).

These processes are considered to be representative of truck transport of CNG and compressed RNG in North America. Most data were sourced from U.S. references. The processes can be used regardless of geographical location.

Pipeline transport, RNG

The amount of energy consumed per tkm of renewable natural gas (RNG) pipeline transport is based on 2022 GREET model, using natural gas pipelines as a proxy (Argonne National Laboratory, 2022).

Weighted average energy to transport 1 MJ over a distance of 1 km by pipeline was used to model the energy use. RNG is responsible for the 98% of the energy needed for pump operations. The remainder is assumed to be coming from electricity. Canadian average grid is applied to reflect the emissions due to the average electricity usage across Canada.

Flaring, fugitive, venting and emergency response emissions were included to calculate the CI of RNG transport. The 2021 reference year data collected for 2023 Canada's National Inventory Report is used to quantify fugitive, venting and flaring emissions from RNG pipelines, using natural gas as a proxy (ECCC, 2023).

This process is representative of pipeline transport of RNG in Canada. However, some data was sourced from U.S. references. The processes can be used regardless of geographical location.

3.8.4 Propane transport

Modelling approach for propane transportation

Transport of 1 tkm of propane and renewable propane in Canada was modelled for pipelines and diesel trucks.

The following sections describes the modelling approach for each of these transportation modes.

Truck transport, liquid propane

The truck's diesel consumption is directly related to the mass transported and the distance traveled.

The Model assumes B train trucks are used for liquid propane transport. The fuel consumption factor modeled for B Train trucks is 60.98 L/100km. This factor considers the fuel efficiency for full trucks of 50

[27] Based on internal communication with Transport Canada (May 2023).

L/100km, averaged from multiple sources (Natural Resources Canada, 2000; Kabir & Kumar, 2012), an empty fuel consumption ratio of 0.6097 (Kabir & Kumar, 2012), the distance travelled empty between loads of 26% from the American Transportation Research Institute (Leslie & Murray, 2021), and the payload. The average payload for propane is 25 tonnes[28]. Fugitive propane emissions are not considered.

This process is considered to be representative of liquid propane by truck in North America. Most data were sourced from U.S. references. The processes can be used regardless of geographical location.

Pipeline transport of liquid renewable propane

The amount of energy consumed per tkm of renewable propane pipeline transport is based on GREET 2022 model (Argonne National Laboratory, 2022), using crude oil pipelines as a proxy. Weighted average energy to transport 1 MJ over a distance of 1 km by pipeline was used to model the energy use. Electricity is responsible for 100% of the energy needed for pump operations. The average Canadian average grid was used to reflect the emissions due to the average electricity usage across Canada.

Fugitive emissions, emergency response emissions and venting emissions were excluded for renewable propane transport and only flaring emissions were included. The 2021 reference year data collected for 2023 Canada's National Inventory Report is used to quantify flaring emissions from propane pipelines, using natural gas as a proxy (ECCC, 2023).

This process is considered representative of pipeline transport of liquid renewable propane in Canada. However, some data was sourced from U.S. references. The processes can be used regardless of geographical location.

3.8.5 Predefined transport scenarios

When a user of the Model does not have information about the transportation distances and modes for the feedstock or the finished fuel, pre-defined transport scenarios are available to estimate the contribution of these life cycle stages. In some instances, the pre-defined scenarios are available for two options: "low-impact" and "high-impact" transport scenarios. Decision criteria for each option can be provided in the instructions of a specific program. Otherwise, it is at the discretion of the user to decide if a low- or high-impact scenario should be applied, based on information available in this chapter.

The Model contains three types of predefined transport scenarios: feedstock transport, fossil fuel distribution (i.e. natural gas and propane) and LCIF distribution (i.e. gaseous and liquid LCIFs).

In a predefined transport scenario, the distances and transport modes of the transported feedstock, fossil fuel or LCIF, are predetermined. The functional units of the three predefined transport scenario types are:

- Feedstock transport: 1 kg (dry-basis, where applicable) of feedstock transported to the fuel production plant (for example, 1kg (dry-basis) of agricultural residue to a hydrogen plant)
- Fossil fuel transport: 1 MJ of gaseous fossil fuel (natural gas or propane) transported from the production plant to the end-user
- LCIF distribution:

[28] Based on internal communication with Transport Canada (May 2023).

- 1 MJ of LCIF (gaseous) transported from the production plant to the end-user (via injection in a natural gas pipeline)
- 1 MJ of LCIF (liquid) transported from the production plant to the delivery point (no specific transport mode assumed) (Leg 1)
- 1 MJ of LCIF (liquid) transported from the delivery point to the end-user (via truck (diesel) transport) (Leg 2)

As mentioned in the generic transport section and as stated in Section 2.3.1, the manufacturing of fuel transport infrastructure (i.e., trucks, ships, and rail) was excluded from the Model. Also excluded are any on-site transport within the processing or conversion facility boundaries.

Modelling approach for predefined transportation scenarios

The following sections describe the modelling approach taken for that type of predefined transport.

Feedstock transport

Feedstock transport includes the transport of the feedstock from the source (that is, where the feedstock is produced) to the production facility (including all intermediate steps).

The generic modes of transportation for the feedstock transport include truck, rail and ship. The various transportation modes included in the predefined feedstock transport scenarios are all based on conventional fossil fuels (for example, truck transport is based on a diesel-powered truck and not a biofuel powered truck). In the case of imported feedstocks, the Model also includes transport analysis to account for transport related emissions that occur outside of the Canadian boundaries (for example, transoceanic shipping).

Predefined transport scenarios are presented on a “low-impact” and a “high-impact” base for each feedstock transport. Similar to the LCIF distribution, a “low-impact” scenario has been modelled to add 1 g CO_2e/MJ of fuel, whereas a “high-impact” scenario has been modelled to add 3 g CO_2e/MJ of fuel. The “low-impact” scenario only assumes truck transport, whereas the “high-impact” scenario assumes a combination of truck, rail and ship transport. The predefined distances for each feedstock transport scenario are based on the distance an amount of feedstock needed to produce 1 MJ of fuel has to be transported to increase the CI of the fuel by 1 or 3 g CO_2e. This distance is calculated using the CI of the generic transport processes in the Model for a generic diesel truck with a capacity of 45 tonnes, a generic diesel train, and a generic heavy fuel oil ship. These CIs are multiplied by a generic yield of fuel from each transported feedstock (Humbird et al., 2011; Natural Resources Canada, 2019; Chen et al., 2018; Ramsden et al., 2013; Han et al., 2013; Chu, 2014; (S&T)2 Consultants Inc., 2011; CIRAIG, 2019). Resulting transport distances (kg-km) are then rounded for simplicity.

Transport distances needed to determine emissions for each feedstock scenario are hence based on the following parameters:

- Feedstock amount at the production facility and co-product allocation at the production facility to produce 1 MJ of fuel
- Moisture content to adjust weight of feedstock amount (where applicable)
- Transport CIs (Section 3.8.1)

Fossil fuel distribution

The predefined scenarios for fossil fuel distribution include the transport of the gaseous fossil fuel (i.e. natural gas and propane) from the production facility to the end-user.

For natural gas distribution, the predefined transport scenario has been modelled using the aggregated transmission, distribution and storage emissions for natural gas in the NIR (ECCC, 2026). The total emissions reflect the average transmission, distribution and storage of natural gas in Canada via pipeline and include venting, fugitive, flaring and stationary combustion emissions. Upstream natural gas stages such as extraction and processing are excluded from the scope of this process.

For propane distribution, the predefined transport scenario has been developed based on the assumption that the propane is transported by train over a distance of 175 km to a regional hub and then the downstream distribution to end-users is assumed to be by truck over a distance of 275 km.

The predefined train distance for propane was based on the Railway industry summary statistics on freight and passenger transportation (Statistics Canada, 2018a). The truck transport distance represents an average of fossil fuel transportation distances in Western and Eastern Canada which was weighted based on the domestic propane demand in Canada. The transport distances in Western and Eastern Canada were estimated based on ECCC expert judgment.

LCIF distribution

LCIF distribution includes the life cycle stages that bridges fuel conversion and use by the end-users. This includes the transport from the production facility to a distribution facility or a delivery point and then to the end-users. The predefined scenarios for LCIF distribution include transport scenarios for gaseous and liquid LCIFs. All the predefined transport scenarios for the gaseous LCIFs (i.e. hydrogen, RNG and renewable propane) assume that the produced LCIF is injected into an existing natural gas pipeline. The predetermined distance for these scenarios is hence identical to the predefined process of natural gas distribution (please refer to the previous section Fossil fuel distribution). The energy usage for the natural gas pipeline is based on the R&D GREET model (Argonne National Laboratory, 2022) (please refer to section Gas Pipeline). The predefined transport scenario for RNG also includes non-combustion emissions to represent fugitive, venting, flaring and emergency response emissions from the LCIF transmission and distribution stages. These emissions are based on data from CEPEI (ORTECH Environmental, 2018). The predefined transport scenario for renewable propane only includes flaring emissions.

Predefined transport scenarios of liquid LCIFs are further broken down into two legs; leg 1 represents the transport from the production plant to the delivery point and leg 2 represents the transport from the delivery point to the end-user.

The predefined transport scenarios of the liquid LCIFs for leg 1 are presented on a “low-impact” and a “high-impact” base for each fuel type. Similar to scenarios for feedstock transport, the “low impact” scenario has been modelled to add 1 g CO_2e/MJ of fuel, whereas the “high impact” scenario has been modelled to add 3 g CO_2e/MJ of fuel.

For leg 2, the predefined transport scenarios do not include high-impact and low-impact scenarios for each liquid LCIF. Instead, a predefined scenario is included for each liquid LCIF based on the assumption that these are transported by truck over a set distance of 290 km. This weighted average distance to deliver refined fuel to the end-users was estimated based on ECCC expert judgement.

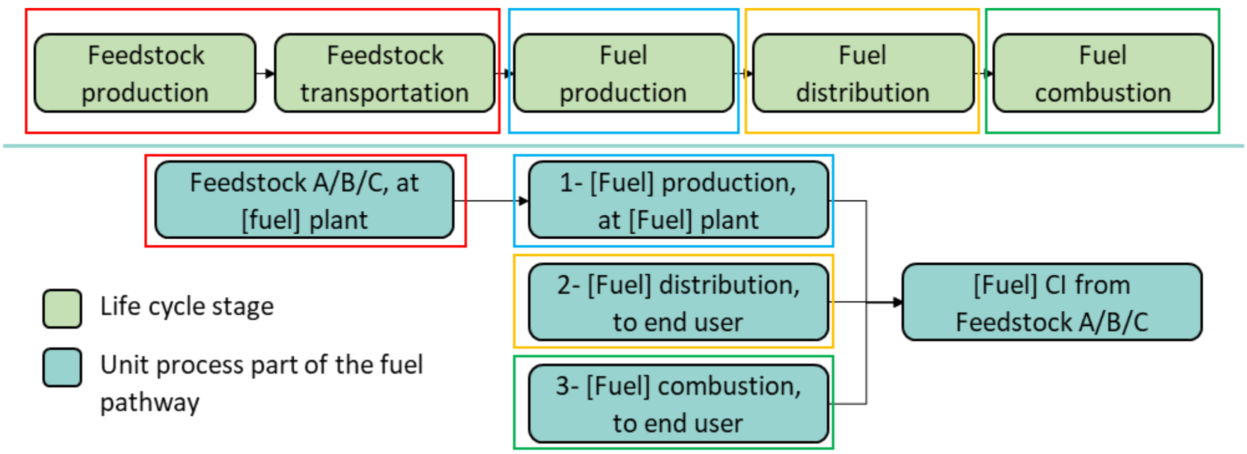
Chapter 4: Fuel Pathways

This chapter presents the approach taken for the modelling structure of the unit processes in the fuel pathways of the Model. Refer to the Model User Manual for how to use the fuel pathways alongside the Data library. This includes fuel pathways, which are templates to model the entire life cycle of fuels, and configurable processes, which are templates to model individual activities related to a life cycle.

4.1 Fuel pathway structure

As mentioned in Section 2.3, the Model contains five main life cycle stages, starting with feedstock production and ending with fuel combustion. The fuel pathways have been designed to allow the modelling of all five life cycle stages but are structured differently than what would practically occur for a fuel life cycle. The general structure is shown in Figure 19.

Figure 19: Top: five main life cycle stages. Bottom: general structure of fuel pathways in the Model Database

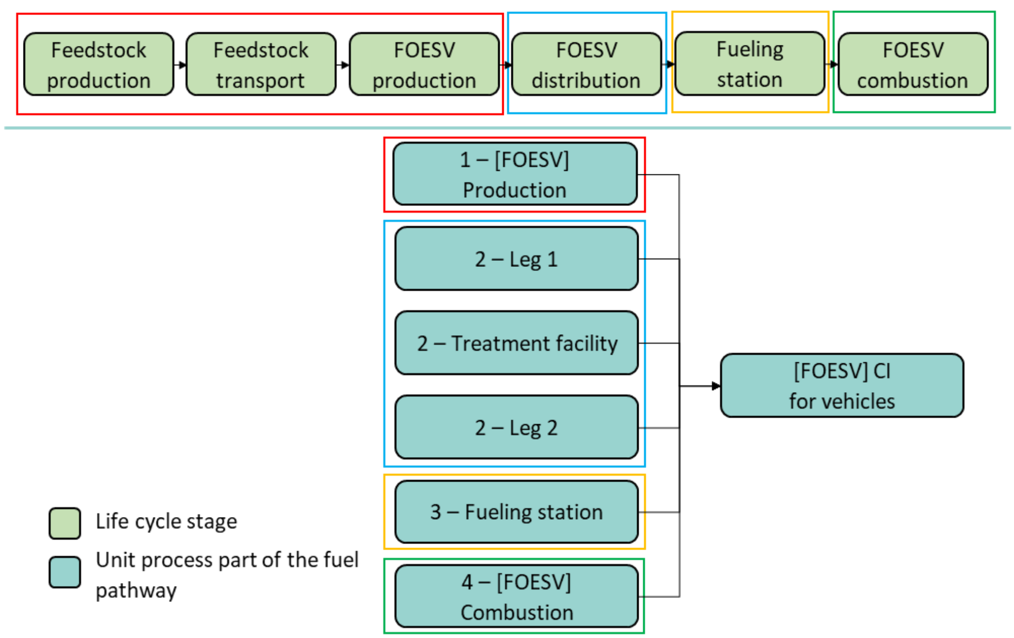


The structure of the fuel pathways was designed to represent different fuels and to account for different situations. The design allows for a high degree of customization to adapt itself to the need of different programs. For example, the fuel pathways include three feedstock production unit processes for the modelling of different feedstocks for a single fuel. Furthermore, each feedstock may have its own transportation needs, so the transportation step is grouped with feedstock production. The fuel production and fuel distribution life cycle stages are separate to allow for proper allocation at the fuel production stage, given that co-products may not all undergo the same distribution. The fuel combustion process allows for the input of the Data Library system processes that contain combustion emission factors. Finally, the “[Fuel] CI from Feedstock A/B/C” unit process combines the three previous processes to easily allow a user to calculate a CI without having to create complex links between other processes.

A hydrogen pathway is included in the Fuel pathways folder. This pathway has distinct characteristics compared to other fuel pathways, such as a cradle-to-gate (feedstock production to fuel production life cycle stages) scope and a functional unit expressed in terms of mass (kg of hydrogen) instead of MJ HHV. In addition, the pathway includes two modelling options: simplified and advanced. The simplified modelling approach is largely similar to the current approach used by other pathways (but excludes distribution and combustion). The advanced modelling approach allows users to break the production life cycle stage into more than one unit process. This option offers the possibility to apply energy or mass-based allocation to co-products generated by unit processes that are part of the production life cycle stage, allowing for a more representative modelling of the product system. Users can refer to instructions of programs for more information related to the use of this pathway.

The design of the fuel pathway dedicated to Fuel and Other Energy Sources for Vehicles (FOESV) is slightly different from the other fuel pathways. There is an additional life cycle stage between fuel distribution and fuel combustion: Fuelling station. Also, the first 3 life cycle stages are grouped under Fuel production. Finally, the distribution life cycle stage is broken into three unit processes. The fuel pathway structure for FOESV is shown in Figure 20.

Figure 20: Top: six life cycle stages for FOESV. Bottom: structure of a Fuel pathway dedicated to FOESV in the Model Database



4.2 Configurable processes

The Model contains multiple configurable unit processes to provide templates that represent feedstock, electricity, and other scenarios. The processes are partially modelled but allow the use of specific inputs from the Data Library. The animal fats, corn oil, and oil from oilseeds configurable processes use global parameters to calculate the transport flow quantities based on co-product allocation procedures. Global parameters can be used to define a common value or assumption allowing consistent updates throughout the life cycle assessment. The modelling approaches for each type of configurable process included in the database are described in the following sections.

4.2.1 Modelling approach for animal fats configurable processes

The animal fats configurable processes were modelled from the Canadian animal fat process available in the Data Library (Section 3.5.1). The LCI was calculated excluding electricity as well as animal by-product transport inputs.

The LCI results were then added to the output of the configurable processes, while an electricity dummy flow, an international ship transport, a train transport and domestic and international truck transport (25 tonnes and 45 tonnes payloads) flows were added as inputs.

For electricity, a default consumption of 0.1786 kWh is assigned to the dummy flow. The user can replace the dummy flow with an electricity flow to represent the grid mix of their geographical location using the same energy consumption as in the dummy flow.

For all the transport modes, the user should multiply the transported distance with the global parameter for the mass of animal by-products allocated to animal fats[29], provided in the Parameters tab, to account for the allocation. If a mode is not used, the user leaves the transported distance at zero. A default trucking distance of 100 km multiplied by the mass of animal by-products allocated to animal fats being transported is set for the domestic 25 tonne truck payload. This represents the load-distance over the default trucking distance of 100 km.

All data sources for this configurable process are listed in Section 3.5.1.

4.2.2 Modelling approach for CCS configurable processes

The CCS configurable processes do not contain modelling. They are used to enter the net emission reductions from captured CO_2 at a fuel production plant and sent to permanent storage or used for an enhanced oil recovery project with permanent storage. This amount is set by the user or in accordance with the instructions of a program. The net reduction is calculated as the sum of emissions associated with CO_2 capture, transportation, injection and recycle stream minus the quantity of CO_2 permanently stored[30]. However, it is important to avoid double counting emissions reductions: a negative fossil CO_2 value for the quantity permanently stored should only be considered in the calculation of net emissions reductions if the quantity of CO_2 captured has not been subtracted from the emissions of the fuel production process that would have occurred without CCS or if the captured CO_2 emissions from the fuel production process are biogenic.

The captured CO_2 is modelled as a waste flow, which can then be added as an output in a fuel production process.

4.2.3 Modelling approach for corn oil configurable processes

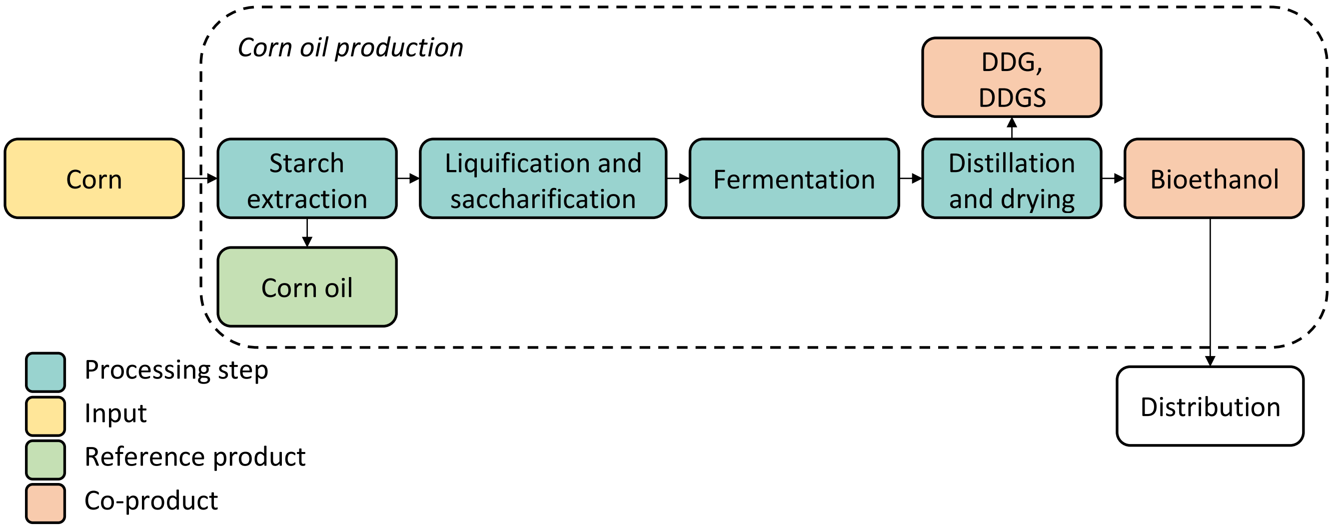
The corn oil configurable processes were modelled as a co-product of dry mill ethanol production from the fermentation of corn feedstock. The boundary of the corn oil production process begins with the

[29] The mass of animal by-products allocated to animal fats of 1.962 kg is calculated by multiplying 3.548 kg (the unallocated amount of animal by-products (wet basis) needed to produce 1 kg of animal fat) by a mass-based allocation factor for animal fat of 0.553.

[30] The user can also add existing processes from the Data Library directly in these processes to model capture, transport and injection activities of captured CO_2.

corn production and ends with the production of corn oil at the bioethanol plant. Figure 21 shows the processing steps modelled in the development of the corn oil configurable process. The functional unit is 1 kg of oil extracted at the bioethanol plant, prior to distribution.

Figure 21: Processing overview for the production of corn oil in Canada and America



During the ethanol separation process, three main co-products are generated: corn ethanol, corn oil, and dried distiller's grains with solubles. The allocation of burdens to the co-products is performed according to the energy content of the co-products.

The configurable processes were modelled by calculating the LCI of the corn oil production process, excluding the electricity and corn transport inputs. The LCI results were then added to the output of the configurable processes, while an electricity dummy flow, an international ship transport, a train transport and domestic and international truck transport (25 tonnes and 45 tonnes payloads) flows were added as inputs.

For electricity, a default consumption of 0.1855 kWh is assigned to the dummy flow. The user can replace the dummy flow with an electricity flow to represent the grid mix of their geographical location using the same energy consumption as in the dummy flow.

For all transport modes, the user should multiply the transported distance with the parameter for the mass of corn grain allocated to corn oil[31], provided in the Parameter tab, to account for the allocation. If a mode is not used, the user leaves the transported distance at zero. A default trucking distance of 100 km multiplied by the mass of corn grain allocated to corn oil being transported is set for the domestic 25 tonne truck payload. This represents the load-distance over the default trucking distance of 100 km. Data from an internal report prepared by the firm Quantis was used to model the corn oil production (Quantis, 2021).

[31] The mass of corn grain allocated to corn oil of 2.244 kg is calculated by multiplying the unallocated wet mass of corn (102.94 kg corn per kg of corn oil) by an energy-based allocation factor for corn oil of 0.0218.

4.2.4 Modelling approach for grid electricity configurable processes

The grid electricity configurable processes do not contain additional modelling. They are used to create electricity grid mixes for regions that are not already covered in the Data Library. Any of the electricity production technologies in the inputs section of the unit process can be set by the user, with the total amount of electricity equalling 1 kWh.

4.2.5 Modelling approach for oil from oilseed configurable processes

The oil from oilseed configurable processes were modelled based on an average of vegetable oil production processes from canola oil, soybean oil, and camelina oil. Model users can use one of the configurable processes to model the oil production from oilseeds in a given region. Oilseed cultivation, and oil extraction were modelled in the development of the configurable processes.

Oilseed cultivation was modelled as described in Section 3.5.2, using the same methodology as barley, corn, field peas, rye, triticale, and wheat. Canola and soybeans are modelled from the CRSC reports ((S&T)2 Consultants Inc., 2022b, 2022f).

Most of the LCI for camelina was developed using the same data sources from the CRSC reports and the modelling approach remained the same ((S&T)2 Consultants Inc., 2022h; Statistics Canada, 2018b). Data gaps were filled in using data from the Government of Saskatchewan's Crop Planning Guide and Specialty Crop Reports (Saskatchewan Ministry of Agriculture, 2018a, 2018b, 2019a, 2019b, 2020a, 2020b).

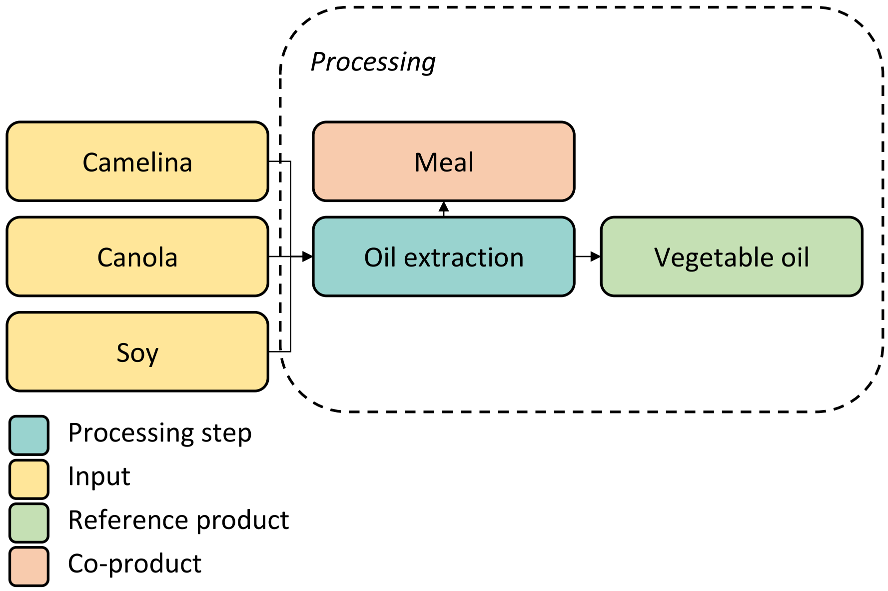
The provincial data used for the three oilseed crops from the CRSC reports is shown in Table 9.

Table 9: Geographical scope of camelina, canola, and soybean oilseeds used to model the oil from oilseed configurable processes

Crop	AB	BC	MB	NB	NL	NS	ON	PE	QC	SK
Camelina	No	No	No	No	No	No	No	No	No	Yes
Canola	Yes	Yes	Yes	No	No	No	No	No	No	Yes
Soybean	No	No	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes

During the oil extraction process, a protein-rich meal is co-produced. An overview of the processing steps for oil extraction from oilseeds is presented in Figure 22.

Figure 22: Processing overview for the extraction of vegetable oil feedstock from oilseeds



Oil extraction data was compiled from U.S and Canadian literature review for camelina oil, canola oil and soybean oil production (Shonnard et al., 2010; (S&T)2 Consultants Inc, 2010; Chen et al., 2018; Miller & Kumar, 2013; Argonne National Laboratory, 2022).

The allocation of burdens to the meal protein and oil in the oil extraction is performed according to the dry-mass content of the products.

For coherence among all types of oil extraction processes, the total thermal energy requirement for all oil extraction processes is assumed to be always supplied through the combustion of natural gas.

The configurable processes were modelled by calculating the LCI of the oilseed extraction process excluding the electricity as well as oilseed transport inputs. The LCI results were then added to the output of the configurable processes, while an electricity dummy flow, an international ship transport, a train transport and domestic and international truck transport (25 tonnes and 45 tonnes payloads) flows were added as inputs.

For electricity, a default consumption of 0.03334 kWh is assigned to the dummy flow. The user can replace the dummy flow with an electricity flow to represent the grid mix of their geographical location using the same energy consumption as in the dummy flow.

For the transport, the user should multiply the transported distance with the parameter for the mass of oilseed allocated to oil[32], provided in the Parameter tab, to account for the allocation. If a mode is not used, the user leaves the transported distance at zero. A default trucking distance of 100 km multiplied

[32] The mass of oilseed allocated to oil of 1.111 kg is the average (for canola, camelina, and soybean) of the multiplication of the unallocated amount of oilseed (wet basis) needed to produce 1 kg of oil from oilseed (Camelina: 2.670 kg; Canola: 2.611 kg; and Soybean: 5.230 kg) by the respective mass-based allocation factor (Camelina oil: 0.407; Canola oil: 0.426; and Soybean oil: 0.217).

by the mass of oilseed allocated to oil from oilseeds being transported is set for the domestic 25 tonne truck payload. This represents the load-distance over the default trucking distance of 100 km.

4.2.6 Modelling approach for oxygen configurable process

Processes have been modelled for a two-column cryogenic air separation plant where three compressors and one pump are used to isolate nitrogen and oxygen liquid flows (at 5 bar pressure). The electricity input for the three compressors and pump is based on an article from Ebrahimi et al. (2015).

After separation, the liquid oxygen flow is pressurized to a gaseous phase at 29.2 bar. The electricity input for the pressurization is based on an internal study from the National Research Council (2023). This pressure is suitable for pipeline injection. Possible recompression and loss along pipeline are excluded.

As a conservative assumption, it is assumed that only oxygen is used, the nitrogen is considered as vented. Hence all impacts are allocated to oxygen output.

The user can replace the dummy flow for electricity with an electricity flow to represent the grid mix of their geographical location.

4.2.7 Modelling approach for yellow grease configurable processes

The yellow grease configurable processes for both the traditional and settling rendering methods were modelled from the Canadian yellow grease process available in the Data Library (Section 3.5.6). The yellow grease CI was calculated excluding electricity and raw UCO transport inputs. The CI results were then added to the outputs of the configurable processes, while an electricity dummy flow, a ship transport, a train transport and domestic and international truck transports (45 tonnes and 25 tonnes payloads) flows were added as inputs.

A default electricity consumption of 0.069 kWh (traditional rendering) and 0.025 kWh (settling rendering) are assigned to the dummy flow. A default trucking distance of 423.36 kg*km (representing the load-distance over the default trucking distance of 313.6 km) is assigned to the domestic 25 tonnes truck payload (both traditional and settling rendering). The other transport flows are set at zero.

The user can replace the dummy flow with an electricity flow to represent the grid mix of their geographical location and add the calculated load-distance to all transport modes that are applicable. If a mode is not used, the user leaves it at zero.

Appendix A: Supplemental parameters for unit conversions

The Model uses several different unit types that are sometimes atypical from conventional units for data collection to allow for consistent LCA modelling. This section includes some common conversions that can be used with the Model.

Table 10: Supplemental feedstock conversion values

Feedstock category	Feedstock type	Density	Unit	Data source
Grains	Barley	48.00	wet lbs/bushel	US Grain Council. Converting Grain Units.
Grains	Corn Sorghum	56.00	wet lbs/bushel	US Grain Council. Converting Grain Units.
Grains	Wheat	60.00	wet lbs/bushel	US Grain Council. Converting Grain Units.
Oilseeds	Soybeans	60.00	wet lbs/bushel	US Grain Council. Converting Grain Units.
Field peas	Field peas	60.00	wet lbs/bushel	US Grain Council. Converting Grain Units.
Vegetable Oils and animal fat	Animal fat	0.884	kg/L	GHGenius 5.01e (tab "Fuel Char"), based on density for tallow
Vegetable Oils and animal fat	Corn oil	0.915	kg/L	GHGenius 5.01e (tab "Fuel Char"), based on density for canola oil
Vegetable Oils and animal fat	Oil from oilseeds	0.915	kg/L	GHGenius 5.01e (tab "Fuel Char"), based on density for canola oil
Vegetable Oils and animal fat	Used cooking oil (UCO)	0.910	kg/L	GHGenius 5.01e (tab "Fuel Char"), based on density for used oil
Vegetable Oils and animal fat	Yellow grease	0.884	kg/L	GHGenius 5.01e (tab "Fuel Char")
Wood fibres	Wood chips, from unmerchantable logs	12.10	dry lbs/ft3	NRCan's Solid Biofuels Bulletin No. 2 (Table 2).
Wood fibres	Wood pellets, from sawmill co-products	34.04	dry lbs/ft3	NRCan's Solid Biofuels Bulletin No. 2 (Table 2).
Wood fibres	Wood pellets, from unmerchantable logs	34.04	dry lbs/ft3	NRCan's Solid Biofuels Bulletin No. 2 (Table 2).

Table 11: Supplemental parameters for low carbon intensity fuels (LCIFs). For gaseous LCIFs, HHV and density are provided at a volume at standard conditions

LCIF	Parameter	Value	Data source
Bioethanol	HHV (MJ/kg)	29.67	Developed by ECCC based on references used for the NIR
Bioethanol	HHV (MJ/L)	23.42	Calculated
Bioethanol	Density (kg/m^3)	789.3	Developed by ECCC based on references used for the NIR
Biodiesel	HHV (MJ/kg)	39.89	Developed by ECCC based on references used for the NIR
Biodiesel	HHV (MJ/L)	35.18	calculated
Biodiesel	Density (kg/m^3)	882.0	Developed by ECCC based on references used for the NIR
Biogas	HHV (MJ/L)	0.0186	Developed by ECCC
Hydrogenation derived renewable diesel (HDRD)	HHV (MJ/kg)	46.63	CA-GREET3.0 model ("Fuel_Specs" tab)
Hydrogenation derived renewable diesel (HDRD)	HHV (MJ/L)	34.92	calculated
Hydrogenation derived renewable diesel (HDRD)	Density (kg/m^3)	748.93	Calculated based on GREET 2018. Refer to "HHV GREET Calcs.xlsx"
Sustainable aviation fuel (SAF)	HHV (MJ/kg)	47.17	CA-GREET3.0 model ("JetFuel_WTP" tab)
Sustainable aviation fuel (SAF)	HHV (MJ/L)	36.40	calculated
Sustainable aviation fuel (SAF)	Density (kg/m^3)	771.6	Neste MY Sustainable Aviation Fuel Product Data Sheet
Renewable propane (gaseous)	HHV (MJ/kg)	51.34	Assumed to be the same as fossil propane
Renewable propane (gaseous)	HHV (MJ/L)	0.097	calculated
Renewable propane (gaseous)	Density (kg/m^3)	1.88	Assumed to be the same as fossil propane (gaseous)
Renewable propane (liquid)	HHV (MJ/kg)	51.34	Assumed to be the same as fossil propane
Renewable propane (liquid)	HHV (MJ/L)	25.31	calculated
Renewable propane (liquid)	Density (kg/m^3)	493.0	Assumed to be the same as fossil propane
Renewable natural gas (gaseous)	HHV (MJ/kg)	54.03	Assumed to be the same as gaseous natural gas
Renewable natural gas (gaseous)	HHV (MJ/L)	0.038	Assumed to be the same as gaseous natural gas
Renewable natural gas (gaseous)	Density (kg/m^3)	0.7105	Assumed to be the same as gaseous natural gas
Renewable natural gas (liquid)	HHV (MJ/kg)	55.21	Assumed to be the same as liquid natural gas
Renewable natural gas (liquid)	HHV (MJ/L)	23.64	Assumed to be the same as liquid natural gas

LCIF	Parameter	Value	Data source
Renewable natural gas (liquid)	Density (kg/m^3)	428.2	Assumed to be the same as liquid natural gas
Hydrogen (gaseous)	HHV (MJ/kg)	141.92	CA-GREET3.0 model ("Fuel_Specs" tab)
Hydrogen (gaseous)	HHV (MJ/L)	0.013	calculated
Hydrogen (gaseous)	Density (kg/m^3)	0.0899	Hydrogen Tools. Equation state calculator. Properties at 0 degrees C and 1 atm
Hydrogen (liquid)	HHV (MJ/kg)	141.8	CA-GREET3.0 model ("Fuel_Specs" tab)
Hydrogen (liquid)	HHV (MJ/L)	10.04	calculated
Hydrogen (liquid)	Density (kg/m^3)	70.80	CA-GREET3.0 model ("Fuel_Specs" tab)

Table 12: Supplemental parameters for LCIF co-products.

LCIF	Coproduct	Parameter	Value	Data source
Bioethanol	Animal feed (including DDG, WDG, DDGS, WDGS, gluten feed, gluten meal, germ)	HHV (MJ/kg dry basis)	21.75	Morey et al. (2009).
Bioethanol	Corn oil	HHV (MJ/kg dry basis)	36.55	EPA (2018). Emission Factors for Greenhouse Gas Inventories.
Bioethanol	Syrup, thin stillage	HHV (MJ/kg dry basis)	19.73	Morey et al. (2009).
Bioethanol	Lignin	HHV (MJ/kg dry basis)	25.60	GHGenius 5.01e (tab "Fuel Char")
Biodiesel	Distillation bottoms	HHV (MJ/kg dry basis)	42.21	GREET1_2022 ("Fuel_Specs" tab, cell D29)
Biodiesel	Free fatty acids	HHV (MJ/kg dry basis)	42.21	GREET1_2022 ("Fuel_Specs" tab, cell D29)
Biodiesel	Glycerin	HHV (MJ/kg dry basis)	18.10	GHGenius 5.01e (tab "Fuel Char")
Renewable hydrocarbon biofuels	Biochar	HHV (MJ/kg dry basis)	22.00	CA-GREET3.0 model ("Fuel_Specs" tab)

Table 13: Supplemental material input parameters

Chemical	Density (kg/m3)	Data Source
Hydrogen (gaseous)	0.0899	Hydrogen Tools. Equation state calculator. Properties at 0 degrees C and 1 atm
Hydrogen (liquid)	70.8	CA-GREET3.0 model ("Fuel_Specs" tab)

Table 14: Supplemental parameters for other fuels

Type of fuel	Fuel	Parameter	Value	Data source
Fossil fuels	Aviation fuel	HHV (MJ/kg)	46.32	Calculated
Fossil fuels	Aviation fuel	HHV (MJ/L)	37.40	Based on value from the NIR
Fossil fuels	Aviation fuel	Density (kg/m^3)	807.4	Based on value from the NIR
Fossil fuels	Coal (bituminous)	HHV (MJ/kg)	28.37	Based on value from the NIR
Fossil fuels	Coal (lignite)	HHV (MJ/kg)	16.29	Based on value from the NIR
Fossil fuels	Coal (sub-bituminous)	HHV (MJ/kg)	18.44	Based on value from the NIR
Fossil fuels	Diesel	HHV (MJ/kg)	45.50	Developed by ECCC based on references used for the NIR
Fossil fuels	Diesel	HHV (MJ/L)	38.35	Calculated
Fossil fuels	Diesel	Density (kg/m^3)	842.9	Based on value from the NIR
Fossil fuels	Gasoline	HHV (MJ/kg)	45.80	Developed by ECCC based on references used for the NIR
Fossil fuels	Gasoline	HHV (MJ/L)	33.45	Calculated
Fossil fuels	Gasoline	Density (kg/m^3)	730.4	Based on value from the NIR
Fossil fuels	Heavy fuel oil	HHV (MJ/kg)	42.81	Calculated
Fossil fuels	Heavy fuel oil	HHV (MJ/L)	42.50	Based on value from the NIR
Fossil fuels	Heavy fuel oil	Density (kg/m^3)	992.8	Based on value from the NIR
Fossil fuels	Kerosene	HHV (MJ/kg)	46.67	Calculated
Fossil fuels	Kerosene	HHV (MJ/L)	37.68	Based on value from the NIR
Fossil fuels	Kerosene	Density (kg/m^3)	807.4	Based on value from the NIR
Fossil fuels	Light fuel oil	HHV (MJ/kg)	46.22	Calculated
Fossil fuels	Light fuel oil	HHV (MJ/L)	38.80	Based on value from the NIR
Fossil fuels	Light fuel oil	Density (kg/m^3)	839.5	Based on value from the NIR
Fossil fuels	Liquefied petroleum gas (LPG)	HHV (MJ/kg)	52.04	Calculated
Fossil fuels	Liquefied petroleum gas (LPG)	HHV (MJ/L)	26.41	Based on value from the NIR
Fossil fuels	Liquefied petroleum gas (LPG)	Density (kg/m^3)	507.5	Based on value from the NIR
Fossil fuels	Natural gas, gaseous	HHV (MJ/kg)	54.03	Calculated
Fossil fuels	Natural gas, gaseous	HHV (MJ/L)	0.038	CA-GREET3.0 model ("Fuel_Specs" tab)

Type of fuel	Fuel	Parameter	Value	Data source
Fossil fuels	Natural gas, gaseous	Density (kg/m^3)	0.7105	Enbridge. Learn about natural gas-Chemical composition of natural gas. Properties at standard conditions.
Fossil fuels	Natural gas, liquid	HHV (MJ/kg)	55.21	Calculated
Fossil fuels	Natural gas, liquid	HHV (MJ/L)	23.64	CA-GREET3.0 model ("Fuel_Specs" tab)
Fossil fuels	Natural gas, liquid	Density (kg/m^3)	428.2	CA-GREET3.0 model ("Fuel_Specs" tab)
Fossil fuels	Petcoke	HHV (MJ/kg)	36.24	Calculated
Fossil fuels	Petcoke	HHV (MJ/L)	43.46	Based on value from the NIR
Fossil fuels	Petcoke	Density (kg/m^3)	1199.3	Based on value from the NIR
Fossil fuels	Propane (gaseous)	HHV (MJ/kg)	51.34	Calculated
Fossil fuels	Propane (gaseous)	HHV (MJ/L)	0.097	Calculated
Fossil fuels	Propane (gaseous)	Density (kg/m^3)	1.8839	CA-GREET3.0 model ("Fuel_Specs" tab)
Fossil fuels	Propane (liquid)	HHV (MJ/kg)	51.34	Calculated
Fossil fuels	Propane (liquid)	HHV (MJ/L)	25.31	Based on value from the NIR
Fossil fuels	Propane (liquid)	Density (kg/m^3)	493.0	Based on value from the NIR
Fossil fuels	Stove oil	HHV (MJ/kg)	46.22	Assumed to be the same as light fuel oil
Fossil fuels	Stove oil	HHV (MJ/L)	38.80	Assumed to be the same as light fuel oil
Fossil fuels	Stove oil	Density (kg/m^3)	839.5	Assumed to be the same as light fuel oil
Other energy sources	Purchased steam	HHV (MJ/kg)	2.790	GHGenius 5.01e
Renewable fuels	Agricultural residues	HHV (MJ/dry kg)	18.13	Calculated using R&D GREET 2024 and Manitoba Agriculture (2017)
Renewable fuels	Bagasse	HHV (MJ/dry kg)	17.97	M. de O. Camargo, Julia et al. 2021.
Renewable fuels	Pellets, from agricultural residues	HHV (MJ/dry kg)	18.30	GREET 2018
Renewable fuels	Wood chips from sawmill co-products	HHV (MJ/wet kg)	10.50	Density values for wood fibres are based on parameters from NRCan's "Solid Biofuels Bulletin No. 2" (see Table 2).
Renewable fuels	Wood pellets from sawmill co-products	HHV (MJ/wet kg)	19.00	Density values for wood fibres are based on parameters from NRCan's "Solid Biofuels Bulletin No. 2" (see Table 2).

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