FUEL LCA MODEL
METHODOLOGY

Environment and
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Canada

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Preface

The objective of the following document entitled *The Fuel Lifecycle Assessment (LCA) Model Methodology* is to explain the methodology used in the development of the Fuel Lifecycle Assessment (LCA) Model and to indicate how the output carbon intensity (CI) applies to the proposed *Clean Fuel Regulations* (proposed Regulations). The document identifies two separates components:

- Part 1: Describes the general assumptions, data sources, and calculation procedures associated with the Fuel LCA Model.
- Part 2: Explains the credit creation under Compliance Categories 1, 2 and 3 in the proposed Regulations. Default carbon intensity values of electricity by province, and of fossil fuels and energy sources (natural gas, compressed natural gas, liquefied natural gas, propane, liquefied petroleum gas and hydrogen), are presented.
- Appendices: Appendix A contains global warming potential for various Greenhouse gases (GHGs). Appendix B contains two reports related to previous work to support the development of the Fuel LCA Model.

QA/QC and ISO Critical Review

Upon reception of the technical reports and all associated datasheets from the contractor in Appendix B, ECCC carried out and extensive review for quality assurance and quality control (QA/QC). The QA/QC included a review of the methodologies, calculation procedures, included data, and literature sources used to generate a CI for various fossil and low carbon-intensity fuels (LCIF).

The Milestone 2 report was subject to a critical review performed by experts in the field of LCA to abide by the ISO guidelines for LCA studies. The critical review was finalized in summer 2020 and resulted in a positive verdict. The final fossil fuel critical review report is available upon request. The Milestone 2 report and the subsequent resulting carbon intensities include all changes identified throughout the critical review process. The fossil fuel baseline CI values identified in the Milestone 2 report are the same values that are presented in *Canada Gazette I* (CGI) for the proposed Regulations.

The Milestone 3 report is also the subject of a critical review performed by experts in the field of LCA to abide by the ISO guidelines for LCA studies (currently in progress). The results of the critical review as well as the ECCC conducted QA/QC, road testing, and the 75-day consultation period following the release of the Fuel LCA Model Methodology will translate to implemented changes in the Fuel LCA Model prior to the its launch. Therefore, as ECCC is still conducting project activities pertaining to the development of the Fuel LCA Model, **the carbon intensities highlighted in the Milestone 3 report in Appendix B are to be considered "under review" and are not representative of final values.** The Milestone 3 report is being shared in the interest of transparency and obtaining feedback.

Appendix B

1. *Milestone 2: Methodology for Fossil Fuel Pathways and Baseline Carbon Intensities*
2. *Milestone 3: Methodology for Low Carbon Fuel Pathways and Default Carbon Intensities*

The technical reports (Milestone 2 and 3) listed in Appendix B were products developed by EarthShift Global, LLC under contract by ECCC. The milestone reports were submitted to ECCC to fulfill the development of fossil fuel baseline CI values and LCIF pre-defined CI values for the proposed Regulations as part of the Fuel LCA Modelling contract.

The reports present the methodology and data sources used to develop various fuel pathways and resulting baseline CI values for fossil fuels and LCIFs produced in Canada. All technical calculations and modelling used to develop the various fuel pathways and associated carbon intensities was carried out by the contractor EarthShift Global, LLC.

Disclaimer

This document does not in any way supersede or modify the *Canadian Environmental Protection Act*, 1999 or the proposed *Clean Fuel Regulations*, or offer any legal interpretation of those proposed Regulations. Where there are any inconsistencies between this document and the Act or the Regulations, the Act and the Regulations take precedence.

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Part I

Context

The Government of Canada is developing a proposed *Clean Fuel Regulations* (proposed Regulations) to reduce the life cycle carbon intensity of fuels and energy used in Canada. The proposed Regulations are one of the complementary policies under Canada's climate plan, which will work in concert with carbon pollution pricing to reduce emissions across the economy.

As part of the proposed Regulations, the Government of Canada is developing a Fuel Life Cycle Assessment (LCA) Model to determine the carbon intensity (CI) of low-carbon-intensity fuels (LCIF) used in Canada. In order to create credits, a LCIF fuel producer or foreign supplier would be required to obtain an approved CI value for each LCIF that they produce or import. The proposed Regulations would require the use of either the Fuel LCA Model to calculate facility-specific CI values using facility specific data, or the use of disaggregated default values available in the proposed Regulations.

The Fuel LCA 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 extraction to fuel combustion. The Fuel LCA Model contains multiple building blocks that form pre-defined pathways representing LCIF production processes in Canada. Using their primary data, users of the Fuel LCA Model can use the pre-defined pathways, modify the building blocks, or create new pathways to calculate facility-specific CI values.

The Fuel LCA Model Methodology describes the methods used in creating the pre-defined pathways available in the Fuel LCA Model. It covers key definitions related to LCA, as well as the concepts used in developing the Fuel LCA Model.

Definitions

CO_2e: Quantity of carbon dioxide that would be required to produce an equivalent warming effect over a given time period as determined by Chapter 2.8 of this document.

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: the biodegradable fraction of products, waste and residues of biological origin , including vegetal and animal substances from agriculture, forestry and other industries, including fisheries and aquaculture, as well as the fraction of waste, including industrial and municipal waste, of biological origin.

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: A scalar quantity, or weighting factor, indicating the greenhouse gas potential (or Global Warming Potential, GWP) of an emission. A general term that may also refer to scale factors associated with other potential impacts.

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

Feedstock: Resource that is extracted, cultivated, collected, or harvested from which fuel is produced.

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, from feedstock acquisition to combustion of the produced low carbon intensity fuel.

Low carbon intensity fuel: fuel, other than a fossil fuel that is in the liquid class, gaseous class or solid class, as defined in the proposed Regulations, that has a carbon intensity that is, for the compliance period during which the fuel was produced or imported, not more than 90 % of the applicable reference carbon intensity set out in Schedule 1 of the proposed Regulations or, in the case of a fuel or hydrogen referred to in subsections 85(1), 86(1) or 88(1), that is not more than the applicable reference carbon intensity set out in Schedule 1 of the proposed Regulations.

Monte Carlo Analysis: An assessment of uncertainty created by running a calculation multiple times (typically more than 1000 times) while varying the underlying uncertainty differently each time.

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

Acronyms

AER	Alberta Energy Regulator
CA-GREET	California GREET
CRSC	Canadian Roundtable for Sustainable Crops
CCS	Carbon capture and storage
CI	Carbon intensity
CEPEI	Centro de Pensamiento Estratégico Internacional
CEPR	Complementary Environmental Performance Reports
CNG	Compressed natural gas
CAFE3	Conceptual and Analytical Frameworks for Environmental Evaluation of Electricity Generation in Canada
CORRIM	Consortium for Research on Renewable Industrial Materials
C&D	Construction and demolition
DQI	Data Quality Indicators
DDGS	DDG with solubles
DDG	Distiller's dried grains
ECCC	Environment and Climate Change Canada
FFA	Free fatty acid
GWP	Global warming potential
GHG	Greenhouse gas
GREET	Greenhouse gases, Regulated Emissions, and Energy use in Transportation
HHV	Higher Heating Value
HDRD	Hydrogen derived renewable diesel
HEFA	Hydroprocessed esters and fatty acids
IPCC	Intergovernmental Panel on Climate Change
AR5	IPCC's Fifth Assessment Report
LCA	Life cycle assessment
LCIA	Life cycle impact assessment
LCI	Life cycle inventory
LNG	Liquefied natural gas
LEAP	Livestock Environmental Assessment and Performance
LCIF	Low carbon-intensity fuel
MSW	Municipal solid waste
NBB	National Biodiesel Board
NEB	National Energy Board
NETL	National Energy Technology Laboratory
NIR	National Inventory Report

MEIT	National Marine Emissions Inventory Tool
NPRI	National Pollutant Release Inventory
NREL	National Renewable Energy Laboratory
NGL	Natural gas liquids
NRCan	Natural Resources Canada
NCG	Non-condensable gases
NACFE	North American Council for Freight Efficiency
OPGEE	Oil Production Greenhouse Gas Emissions Estimator
PPC	Pea protein concentrate
PRELIM	Petroleum Refinery Life-Cycle Inventory Model
PCEM	Prairie Crop Energy Model
RU	Reconciliation unit
RNG	Renewable natural gas
RESD	Report on Energy Supply and Demand in Canada
SOC	soil organic carbon
SMR	Steam methane reforming
SAGD	Steam-assisted gravity drainage
SPK	Synthetic paraffinic kerosene
CIRAIG	The International Reference Centre for the Life Cycle of Products
UNEP	United Nations Environment Programme
UCO	Used cooking oil
VRE	Variable renewable energy
WWT	Wastewater treatment
WDGS	WDG with solubles
WDG	Wet distiller’s grains

Chapter 1: Introduction and General Principles

1.1 Proposed Clean Fuel Regulations

The Government of Canada has developed a proposed *Clean Fuel Regulations* (proposed Regulations) to reduce the life cycle carbon intensity of fuels and energy used in Canada. The proposed Regulations are one of the complementary policies under Canada's climate plan, which will work in concert with carbon pollution pricing to reduce emissions across the economy.

Under the proposed Regulations, primary suppliers and registered creators will be able to create credits through three compliance categories (**Figure 1**).

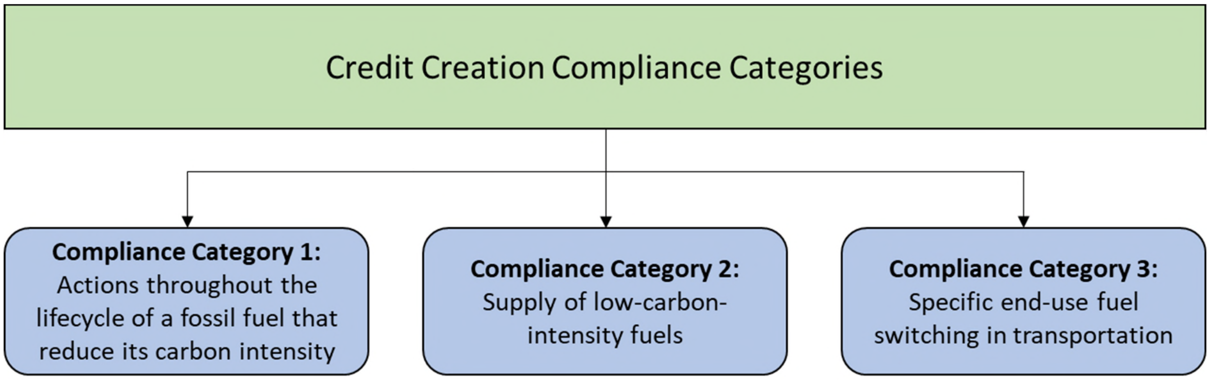


Figure 1: Credit creation compliance categories under the proposed Regulations.

The Government of Canada has developed a model that is designed to calculate the carbon intensity (CI) of low-carbon-intensity fuels (LCIF) to be used in the three compliance categories. This model uses a life cycle assessment (LCA) approach, which is explained in further sections.

1.2 Role of the Fuel LCA Model

The Fuel Life Cycle Assessment Model (Fuel LCA Model) allows the calculation of specific CI values from LCIF producers, including the ability to use and modify several pre-defined LCIF pathways alongside primary data. These CI values are then used in Compliance Category 2 and Compliance Category 3 during credit creation. Additionally, some quantification methodologies developed for Compliance Category 1 also refer to this document or the Fuel LCA Model for the calculation of emissions reductions from CO_2e emissions reduction projects. Additional details related to the three compliance categories are available in Part II of this document.

1.3 Purpose of the Fuel LCA Model Methodology

The purpose of Part I of this document is to explain the methodology used in the development of the Fuel LCA Model. Part I describes the general assumptions, data sources and calculation procedures used in the Fuel LCA Model's development. This document is expected to be updated when new versions of the Model are released to reflect modifications, improvements and expansion of the Fuel LCA Model. This document also contains two reports detailing previous work done in the Fuel LCA Model's development (**Appendix B**).

1.4 Related Standards

The Fuel LCA Model is being designed in conformity with *ISO 14040: Environmental management – Life cycle assessment – Principles and Framework* and *ISO 14044: Environmental management — Life cycle assessment — Requirements and guidelines*. ISO 14040 provides the structure of LCA, including the goal and scope of the LCA and important terminology. ISO 14044 provides important requirements and guidelines when conducting an LCA and is used in parallel with ISO 14040.

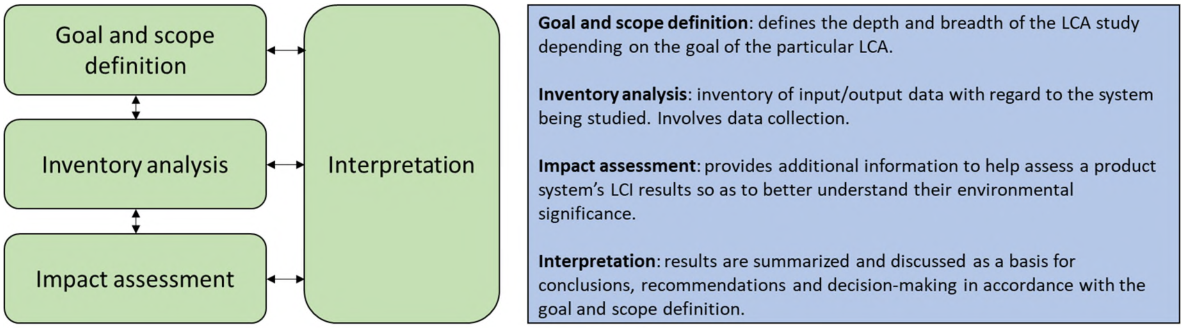
ISO 14040: Environmental management – Lifecycle assessment – Principles and Framework

ISO 14044: Environmental management — Life cycle assessment — Requirements and guidelines

1.5 General Principles and Fundamentals of GHG Assessments for LCIF Pathways

1.5.1 Description of the General LCA Concept

LCA studies are performed in a structured manner, with certain principles guiding the development process. As described in ISO14040, LCA studies consist of four phases: the goal and scope definition phase, the inventory analysis phase, the impact assessment phase, and the interpretation phase. **Figure 2** describes the relationships and descriptions of the four phases. Notably, 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 with the life cycle approach results in a more complete picture when assessing the environmental impacts of a given process.



Goal and scope definition: defines the depth and breadth of the LCA study depending on the goal of the particular LCA.

Inventory analysis: inventory of input/output data with regard to the system being studied. Involves data collection.

Impact assessment: provides additional information to help assess a product system's LCI results so as to better understand their environmental significance.

Interpretation: results are summarized and discussed as a basis for conclusions, recommendations and decision-making in accordance with the goal and scope definition.

Figure 2: The four phases of an LCA study. Adapted from ISO 14040.

1.5.2 Principles and Appropriateness

Since the Fuel LCA Model is designed in conformity with ISO 14040, it is based on many of the same principles. Some of the particularly important principles to the Fuel LCA Model are described below.

Life cycle perspective

The Fuel LCA Model and the calculation of LCIF carbon intensities are based on a life cycle approach. The life cycle approach, from raw material extraction/acquisition to end use/disposal, allows for consideration of the environmental impacts of a full process as well as identification of where environmental burdens exist and can be addressed or avoided.

GHG Focus

As in ISO 14040, the LCA's design assesses only the environmental impacts of a process. Therefore, the Fuel LCA Model does not consider economic and social factors when determining LCIF carbon intensities. It also only considers greenhouse gases.

Transparency

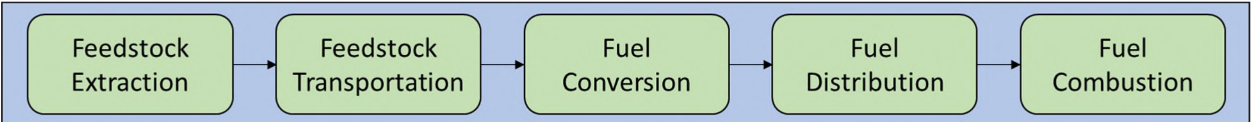
Transparency is an important requirement of the LCA due to its complex nature. It includes clear explanation of the methodology, complete documentation, and calculation procedures at the unit process level. Dataset documentation is in line with the Global Guidance Principles for Life Cycle Assessment Databases (UNEP, 2011).[1]

1.5.3 Pathway Concept and Definitions

The Fuel LCA Model contains several pre-defined LCIF pathways that can be used in CI calculations. Each pathway represents the life cycle of an LCIF, starting at the feedstock collection and ending at fuel combustion. Several concepts are used to break down each pathway in order to accurately model the CI of each LCIF. This section presents each component of an LCIF pathway in the Fuel LCA Model.

Life cycle Stage

The first breakdown of a pathway is the **life cycle stage**. Life cycle stages are characterized by their function but not defined solely by their final product. The Fuel LCA Model uses five life cycle stages, which are outlined in **Figure 3**. Each of the pre-defined fuel pathways in the Fuel LCA Model follow these life cycle stages.



- **Feedstock Extraction**: extraction of raw feedstock materials (e.g. corn cultivation, wood harvesting).
- **Feedstock Transportation**: transportation of raw or upgraded feedstock to the fuel producer, including any upgrading or processing required prior to transport.
- **Fuel Conversion**: processes for converting the feedstock into fuels, including any post-processing and upgrading 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.

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

Unit Process

Life cycle stages are further divided into **unit processes**. Unit processes are subdivisions that each have their own input flows, output flows, and intermediate flows. They can be imagined as activities that transform an input into an output. In a similar manner, the output of one unit process can be the input of another, and based on defined boundaries, will be encompassed by the overall life cycle stage. The subdivisions that unit processes provide allow for the use of a **building blocks approach**, where unit

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[1] Sonnemann, G., & Vigon, B. (2011). *Global guidance principles for life cycle assessment LCA databases*. Paris: United Nations Environment Programme (UNEP).

processes act as building blocks that can come together to represent a larger life cycle stage. An example is shown in **Figure 4**.

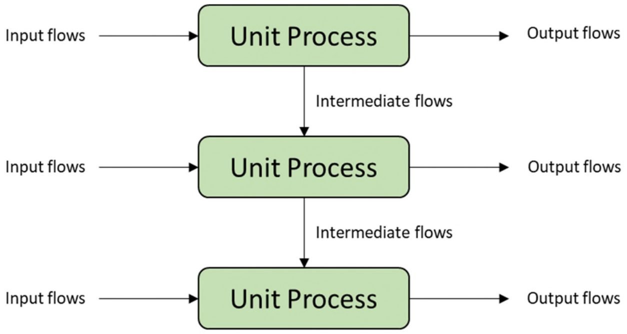

Figure 4: Schematic of unit process design. Output flows represent environmental flows, such as GHG emissions. This is explained in the following section. The three unit processes here could combine to define a life cycle stage.

Reference Product

Each unit process has its own **reference product**. The reference product defines the function of the unit process. It normalizes the inflows and outflows by having defined units. This allows for a consistent measurement of different kinds of inputs and outputs to a unit process. For example, since the function of a fuel is to provide energy, the reference product for most fuel production processes are expressed on an energy basis rather than a volumetric basis. Therefore, one can easily compare the amount of fuel produced in a bioethanol production process with the amount of fuel produced in a hydrogen production process.

Environmental Flows and Intermediate Flows

There are two types of flows with respect to unit processes. **Environmental flows** (also called elementary flows) involve the exchange of the reference product between the technosphere and the ecosphere. In the Fuel LCA Model, they are limited to greenhouse gas emissions. **Intermediate flows** involve the exchange of the reference product within the technosphere. They are the reference products of the unit processes that are assembled together to create a life cycle stage of a pathway.

Foreground and Background Unit process

This document uses the concept of foreground and background unit processes when breaking down pathway stages. **Foreground unit processes** represent activities that are directly included in the main life cycle stage, while **background unit processes** are indirectly linked to these activities.

For example, in a bioethanol pathway, activities taking place in the biorefinery are modelled within a foreground unit process. The production of raw material and energy sources used at the biorefinery, but produced elsewhere, is modelled with background processes. The only exception is the production of the feedstock that will be modelled by a foreground process associated with the extraction life cycle stage. The concept of foreground and background unit processes is useful to distinguish data quality requirements for data collection; data quality for foreground unit process should be higher. Also, it is generally expected that primary data can be collected on foreground unit processes, while this is rarely possible for background processes.

1.6 Modelling Options for New, Modified and Existing pathways

According to the proposed Regulations, LCIF suppliers can calculate their CI by using, or modifying, a pre-defined pathway or creating a new pathway. The Fuel LCA Model contains pre-defined pathways that are described in **Chapter 3:** of this document. In addition, a new pathway can be built with the building blocks available in the model. This section describes these three modelling options.

Using a pre-defined pathway: this option is available when the pathway is already described by one of the pre-defined pathways. In this case, the values of the environmental and intermediate flows in the unit processes are modified, but new flows, unit process or life cycle stage are not created or added. The new values must be based on primary data collected along the supply chain. For example, modifying the amount of natural gas consumed at the conversion plant.

Modifying a pre-defined pathway: this option is used when the pathway is similar to one of the pre-defined pathways, but the pre-defined pathway must be modified to enable the calculation of a representative CI. Existing environmental and intermediate flows can be modified, new flows can be added to existing unit process, and new unit processes can be created. The new flows and unit processes must be based on primary data collected along the supply chain. For example, modelling the extraction life cycle stage of a new feedstock that is used in a conversion process already available in the default pathways.

Creating a new pathway: this option is required when the pathway is different from the pre-defined pathways and the two previous modelling options above cannot be applied. In this case, new life cycle stages are created using new and background unit processes. All elements of the life cycle model (flow, unit process and stage) must be based on primary data collected along the supply chain. For example, modelling the production of biofuel made from algae, which is not included in the pre-defined pathways.

In the Fuel LCA Model, the three modelling options can be carried out using the building blocks approach provided by the unit processes. The Fuel LCA Model contains a data library that houses all unit processes used in the multiple LCIF pathways. The building blocks approach allows for the modelling of unique processes by combining blocks specific to a certain process. When performing the life cycle inventory analysis phase, users can select unit processes from the database to model their own processes, using their own data. If a certain unit process does not exist in the library, an existing unit process can be modified or a new unit process can be created. A schematic of this process is shown in **Figure 5**.

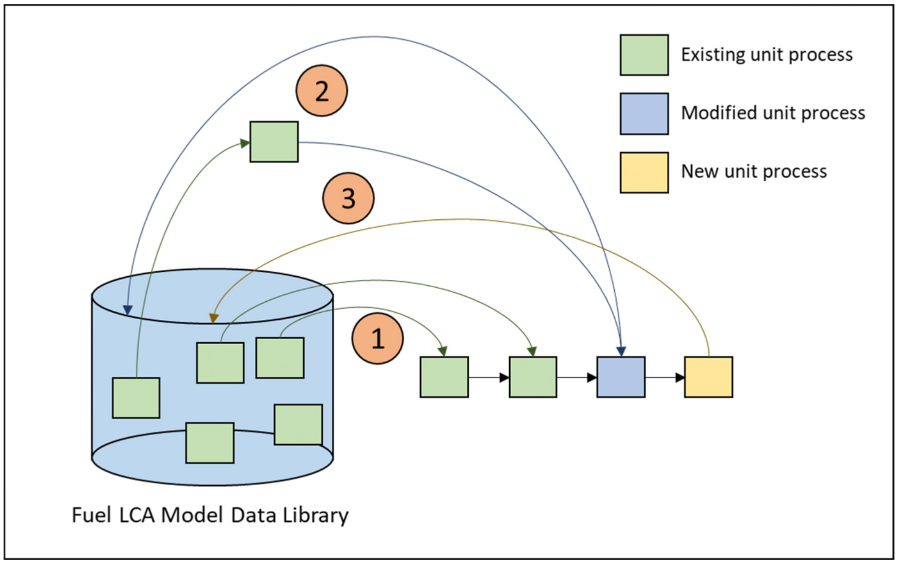

Figure 5: Schematic visualizing the use of the Fuel LCA Modelling Tool Data Library. (1) Existing unit processes (foreground and background) in the library database can be used to model known processes. (2) Existing unit processes are modified as necessary and are applied to the LCIF pathway. (3) New unit processes are created and applied to the LCIF pathway.

For example, in the case of fuel pathways that rely on agricultural feedstock, the building blocks approach allows re-using the agricultural information for another pathway. So, even in an instance where a LCIF producer has developed a novel fuel conversion technology for biomass already considered in other default pathways, the modelling data for cultivation, harvesting, pre-processing, and transport will be available to create the life cycle model of the new conversion technology. In this case, the building blocks approach also allows users of the Fuel LCA Model to easily quantify the GHG emissions associated with alternative feedstock that are available to them and make decision aiming to improve the environmental performance of their fuel.

Chapter 2: Goal and Scope of the Fuel LCA Model

This chapter outlines the goal and scope of the Fuel LCA Model, as well as the methodology that is consistent with all life cycle stages. This includes data collection, data quality, life cycle inventory assessment methods, and limitations of the LCA methodology.

2.1 Goal

The primary goal of the Fuel LCA Model is to be a publicly available compliance tool for the proposed Regulations that allows the CI calculation of LCIFs currently being used in Canada. The Fuel LCA Model provides users with pre-defined unit process building blocks of foundational carbon intensity values for LCIF pathways. These pre-defined building blocks and pathways are based on fuels produced in Canada. LCIF producers will be able to determine specific CI values for fuels they produce in, or import to, Canada by modifying, or rearranging, these building blocks and using their primary data.

As stated in ISO 14040, the CI results calculated by the Fuel LCA Model are based on a relative approach. Therefore, the intent of the Fuel LCA Model includes that its results should not be used to make comparative assertions for carbon intensity values or environmental impact.

In addition, the Fuel LCA Model will be publicly available in the efforts to inform and reduce the carbon intensity of Canadian fuels. As such, the modelling used for the fuel pathways will be open and transparent. The Fuel LCA Model is currently being developed in conformity with ISO 14040 and 14044 requirements.

2.2 Scope

2.2.1 Function and Functional Unit

In the Fuel LCA Model, the **function** to be studied is the provision of energy to be combusted in all sectors in Canada. This includes liquid, solid, and gaseous fuels produced and used onsite by fuel producers. Non-combustion uses (e.g. feedstock, solvents or diluents) are outside of the scope of this model as they are outside the scope of the proposed Regulations.

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. The functional unit is 1 MJ of energy content based on the Higher Heating Value (HHV) at the regional distribution centre.

The carbon intensity values are expressed in grams of carbon dioxide equivalents (g CO_2e) per unit of energy produced from combustion of the fuel in megajoules (MJ) on a HHV basis. The model does not take into consideration the efficiency of the combustion device. As such, a single combustion emission factor per fuel is applied to calculate the CI.

2.2.2 Imported Fuels and Foreign Feedstock in the Fuel LCA Model

The Fuel LCA Model will be used to calculate specific CI's of LCIF produced or imported to Canada. The background LCI and pre-defined pathways in the model should be suitable for all geographical contexts.

In addition to the foreground and background unit processes reflecting Canadian values, a CI for some of the most common imported feedstocks will be available in the model. Electricity grid mixes, representing other countries, will also be available in the model to ensure that users have access to the building blocks required to calculate a CI of their LCIF that are representative of their geographical context.

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 environmental flows in the analysis. The general system boundaries for the Fuel LCA Model are defined by the five main life cycle stages presented and described in **Chapter 1.5.3**.

The system boundary of each life cycle stage includes the life cycle GHG emissions associated with the use of electricity inputs (both grid and onsite generation), fuel inputs, material inputs (e.g. chemicals), process emissions (e.g. venting and flaring), transportation processes, and direct land use change. The inclusion of processes and emissions for each life cycle stage is also determined by the rules for excluded processes and cut-off criteria, presented in the following subsections.

2.3.1 Excluded processes

In an LCA, some aspects within the system boundaries can be excluded when considered irrelevant to the goal of the study. Under the proposed Regulations, credit creation for LCIF is based on the difference between the CI of the LCIF and the reference carbon intensity for the fuel. As such, the calculation of the

CI value for LCIF does not take into account the emissions reductions associated with the displacement of fossil fuels.

The specific processes excluded from LCIF CI calculations include:

- Construction and decommissioning of equipment and facilities;
- The manufacturing of fuel transportation infrastructure (i.e., pipelines, trucks, ships, roads);
- The manufacturing of fuel combustion infrastructure (i.e., vehicles, boilers);
- Ancillary materials (e.g. lubricants, cleaning agents, packaging, etc.)
- 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; and
- Indirect land use change.

With the exception of the data related to electricity generation (see **Chapter 4.3**), 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

Cut-off criteria are used in LCA for the selection of processes or flows that are not part of the excluded processes, but can be omitted in the system boundary if data are not readily available. 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, 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 (e.g. 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 Fuel LCA Model, every effort was made to include all the relevant flows associated with the included fuel pathways with the exception of the excluded processes listed in **Chapter 2.3.1**. A 1% of environmental significance criterion, as calculated by the impact assessment method, was used to test the sensitivity of the results to assumptions and data substitutions made. Cut-off criteria were applied at the individual unit process level. Although these cut-offs are diffused throughout the system, a cumulative threshold for these cut-off criteria was not calculated.

2.4 Data Collection and Data Quality

This section outlines a set of data quality preferences established for the Fuel LCA Model and which were applied during the modelling of low carbon fuel pathways.

Data collection to develop the life cycle inventory (LCI) of low carbon fuels was based on review and compilation of data from a range of primary and secondary sources on Canadian fuel pathways. Data sources used include government publications and statistics, industry publications and statistics, other fuel LCA modelling tools, and literature data for low carbon fuel systems with little or no current production in Canada. For ethanol and biodiesel production, several years of primary operating data were available for a large segment of Canadian ethanol and biodiesel producers and were aggregated to protect the confidentiality of these data.

The pre-defined pathways included in the Fuel LCA Model focus on LCIFs produced in Canada (but also include hydrogen-derived renewable diesel (HDRD) from palm oil which is not currently produced in Canada). For this reason, the LCI data used in the low carbon fuel modelling is a mixture of data that is either specific to Canadian systems, data from other jurisdictions that is considered adequately representative and modified to include Canadian energy and emissions, or data from other jurisdictions that is considered adequately representative without revision.

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

- Differences in fuel consumption in forest harvesting, sawmilling and other processing activities;
- Inputs and crop management practices for Canadian crops across different provinces and regions;
- Background energy systems such as variations in electricity grids providing energy to fuel conversion processes; and
- The sourcing of regional/provincial feedstock could also influence transport distances and modes for feedstock transportation and finished fuel distribution.

Data collection procedures and requirements for data quality depend on whether the unit process pertains to foreground or background systems. The following subsections present the rules for each type of unit process.

2.4.1 Data Collection for Foreground Unit Processes

The foreground unit processes for this project include the primary activities involved directly in the extraction, feedstock transport, conversion, fuel distribution and combustion life cycle stages. Given the importance of these activities in quantifying the carbon intensity of fuel and determining the representativeness of the Fuel LCA Model, the highest data quality possible was used to characterize the inputs and outputs of foreground unit processes. **Table 1** presents the different data quality levels considered during data collection. For foreground unit processes, time and effort were invested to collect data that corresponds to the level of "*high data quality*". When these types of data were not available, data corresponding to the *acceptable data quality* and *lowest acceptable data quality* levels were considered. Data collection of the foreground unit processes for fuel pathways that could not achieve the lowest acceptable data quality level were not included in the Fuel LCA Model.

Table 1: Definition of the data quality level considered during the data collection process

Data quality level	Definition
High data quality	• Regionally specific and recent data (less than 5 years). • Based on measurements and published by official and verified sources (e.g. government statistics) • Collected from more than 50% of sites in the region under study.
Acceptable data quality	• Average data from a larger region that include the region other study and no more old than 10 years. • Based on measurements and published in scientific publications or by industry organization. • Collected from a sample of sites
Lowest acceptable data quality	• Data or LCI extracted from recognized tools and initiatives (e.g. GREET) • From a region different but representative of the region under study and no older than 15 years. • Measurement from a single site or expert estimate from qualified individual.

2.4.2 Data Collection for Background Unit Processes

The background unit processes in the Fuel LCA Model include upstream activities that support foreground process activities. For example, the amount of electricity (kWh) used to produce 1 MJ of biofuel at a bioethanol plant is information that pertains to the foreground unit process. However, the CI of producing 1 kWh is provided by a background process. Most of the background processes, excluding fossil fuels, are based on previous LCA studies with their own data quality requirements. For background processes that were created specifically for an LCIF pathway (e.g. agrochemical and chemical inputs), the data quality requirements are lower. By definition, background processes are not specific to a given product system. Consequently, achieving high or even acceptable data quality level would require a massive investment of time and effort without significantly improving the overall quality of the LCIF pathway's LCI. For this reason, most of the background processes (with the exception of fossil fuels) are sourced from other recognized tools and initiatives. **Chapter 4:** provides more details on background unit processes.

2.5 Data Uncertainty

All data used in an LCA study is a mix of measured, estimated and calculated data. To evaluate the quality of the data used for modelling the fuel pathways, Data Quality Indicators (DQI) were used to assess each flow and linked pathway 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 (e.g. sample of data or standard deviation), the uncertainty was entered into the model 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)[2] was used. It contains five types of DQI, each of which is assigned a score from 1 to 5 for the following parameters:

1. Reliability (related to the reliability of the collected primary data);
2. Completeness (related to the completeness of the primary data);
3. Temporal correlation (related to the temporal correlation of the primary data);
4. Geographical correlation (related to the geographical correlation of the secondary data used);
5. Further technological correlation (related to the technological correlation of the secondary data used)

Scores are assigned to the data and the linked pathways based on these criteria. 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 study results.

Users of the Fuel LCA Model have both options described above to enter information about uncertainty for each parameter. For example, an LCIF producer that builds a pathway model for pyrolysis of wood residues may be able to provide a minimum and maximum bio oil yield from the process, or a minimum and maximum electricity input value. In instances where data cannot be provided on known distributions users can define distributions based on DQI scoring using the pedigree matrix described above.

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 (e.g. mass or energy content) or other relationships (e.g. 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 low carbon fuel pathways, including:

- Renewable natural gas: digestate co-product generated from biogas upgrading;
- Biodiesel: Canola and soybean meal co-products produced from vegetable oil extraction;
- Bioethanol: Animal feed and combined heat and power production are co-products from ethanol production;
- Cellulosic ethanol: Electricity generation from combustion of lignin;
- Agricultural and forest residues derived from primary cultivation and harvesting that are used to produce biofuels.

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[2] Weidema B P, Bauer C, Hischier R, Mutel C, Nemecek T, Reinhard J, Vadenbo C O, Wernet G., 2013. *Swiss Centre for Life Cycle Inventories Overview and methodology* (final)(v3) 3, 1(v3).

Energy content is the default allocation approach. Indeed, in fuel production systems, energy content, also known and referred to as the heating value, is generally recognized as the most appropriate metric. In situations where energy content allocation is not applicable, either the mass allocation or the system expansion (also called displacement) approaches were applied.

System boundary expansion is used in cases where an alternative co-product is a direct substitution for a fossil-based fuel or electricity. Also, forestry products are allocated based on mass because the majority of forestry products are used for non-fuel purposes.

For several pre-defined pathways of the Fuel LCA Model, waste from other industries are also used as feedstock for low carbon fuel production. Examples of waste materials used as feedstock in the Fuel LCA Model include municipal solid waste (MSW), wastewater treatment (WWT) sludge, livestock manure, used cooking oil, and beef tallow. This is a case of waste recycling. The Fuel LCA Model applies the "cut-off" allocation approach to waste recycling, except if the use of the waste material for low carbon fuel production results in significant and real methane reductions. In this latter case, the system expansion approach is applied.

Under the "cut-off" allocation approach, if a waste material (first life) is used for another purpose (second life) 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 and handling of the material. Consequently, waste products used as feedstock are represented in the Fuel LCA Model by empty unit processes (zero carbon intensity).

When the use of the waste material for low carbon fuel production results in significant and real methane reductions, the system boundary around the waste material for fuel production is 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 were not used for fuel production.

2.7 Greenhouse gases, Biogenic carbon and Land use change

In accordance with the scope of the National Inventory Report (NIR), the Fuel LCA Model LCI includes carbon dioxide, methane, nitrous oxide, halocarbons and related components, but excludes near-term climate forcers (e.g. CO, NOx, VOC, black carbon, albedo effect, etc.). Biogenic carbon emissions and capture associated with LCIF combustion are not included in the LCI of the Fuel LCA Model. In line with the Intergovernmental Panel on Climate Change (IPCC), it is assumed that the biogenic CO_2 emissions are balanced by carbon uptake prior to harvest.[3]

Carbon dioxide emissions and capture associated with direct land use change were included in instances where feedstock production requires the conversion of land from existing use to bioenergy production. Direct land use change is only modelled for Canadian crops and includes carbon emissions from change in tillage and summer fallow practices as well as increase or reduction of annual and perennial crop areas. Indirect land use change is excluded from the Fuel LCA Model. **Chapter 4** defines how land use change is modelled for the background unit processes.

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[3] Intergovernmental Panel on Climate Change. 2006. *2006 IPCC Guidelines for National Greenhouse Gas Inventories.* Prepared by the National Greenhouse Gas Inventories Programme. Eggleston HS, Buendia L, Miwa K, Ngara T, Tanabe K, editors. Kanagawa (JP): Institute for Global Environmental Studies. Available online at www.ipcc-nggip.iges.or.jp/public/2006gl/index.html.

Finally, it is generally assumed that provision of agricultural and wood biomass feedstock 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 Method

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.

In order to calculate CI values for LCIF pathways, the Fuel LCA Model includes a LCIA method based on the IPCC's Fifth Assessment Report (AR5) global warming potential (GWP) factors for a 100-year time horizon.[4] The 100-year time horizon is the characterization factor most-widely applied in CI studies, which facilitates ease of comparison to other study results. The results are expressed in grams of CO_2 equivalents per MJ of HHV energy. **Table 2** provides a summary of the GWP for the main GHGs. A complete list of GHGs with their associated GWP and uncertainty can be found in **Appendix A**.

In remaining consistent with the Government of Canada's policy on biogenic carbon, as shown in Canada's NIR (2018), the GWP for uptake of carbon during the biomass growth and emissions of biogenic carbon from combustion of low carbon fuels are assumed to be zero. However, biogenic CO_2 emissions or capture from direct land use change (that include emissions or capture from soil organic carbon and biomass losses or gains due to land transformation) have the same GWP as fossil CO_2. It is considered that these emissions or capture have a lasting effect on the concentration of GHG in the atmosphere.

Furthermore, the Fuel LCA Model does not take in consideration the temporal profile of uptake and emissions of biogenic carbon. 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 in the Fuel LCA Model due to the complexity of its modelling and the lack of scientific consensus on a method.[5]

Table 2. Select characterization factors for calculating carbon intensities using IPCC AR5 GWP 100.

Greenhouse Gas	GWP 100-year
CO_2	1
CO_2 (biogenic)	0
CO_2 (land use change)	1
CH_4 (fossil)	30
CH_4 (biogenic)	28
N_2O	265
Sulfur hexafluoride	23,500

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[4] Myhre, G., D. Shindell, F.-M. Bréon, W. Collins, J. Fuglestvedt, J. Huang, D. Koch, J.-F. Lamarque, D. Lee, B. Mendoza, T. Nakajima, A. Robock, G. Stephens, T. Takemura and H. Zhang, 2013: Anthropogenic and Natural Radiative Forcing. In: *Climate Change 2013: The Physical Science Basis. Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change* [Stocker, T.F., D. Qin, G.-K. Plattner, M. Tignor, S.K. Allen, J. Boschung, A. Nauels, Y. Xia, V. Bex and P.M. Midgley (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA.

[5] Brandão, M.; Levasseur, A. *Assessing Temporary Carbon Storage in Life Cycle Assessment and Carbon Footprinting: Outcomes of an Expert Workshop*; Publications Office of the European Union: Luxembourg, 2011.

2.9 Limitations of the Fuel LCA Model

Many of the low carbon fuels modelled in the Fuel LCA Model are not currently being produced at commercial scale in Canada, and therefore, data and information regarding Canadian production systems are limited or not yet readily available. As such, the modelling of these fuel pathways are based heavily on data from literature sources and assumptions put forward to extrapolate literature values for Canadian applications which could produce higher variability of results. This is mitigated by the fact that users of the Fuel LCA Model will be replacing some of the pre-defined values with primary data, resulting in more accurate CI values.

The Fuel LCA Model provides CI results intended for use with the proposed Regulations. Given the objective of the proposed Regulations is to reduce Canada's greenhouse gas emissions (GHG) through the increased use of lower carbon fuels, energy sources and technologies, other environmental indicators are not covered.

Chapter 3: Low Carbon Fuels: Foreground Unit Processes

The following chapter presents information collected and the approach taken for the foreground unit processes (**see Chapter 1.5.3**) of the Fuel LCA Model. As mentioned, the Fuel LCA Model is composed of multiple building blocks that come together to form several LCIF pathways. The pre-defined pathways included within the Fuel LCA Model are presented in **Table 3**. The pathways are distinguished by their feedstock, conversion process, and final fuel produced. The pathway-level system boundaries are also described. This chapter expands on the modelling performed for each pathway through a breakdown of the five life cycle stages included in the Fuel LCA Model, including feedstock extraction (**Chapter 3**), feedstock transportation (**Chapter 3.2**), fuel conversion (**Chapter 0**), fuel distribution (**Chapter 3.4**), and fuel combustion (**Chapter 3.5**).

Table 3: Pre-defined pathways that are included in the Fuel LCA Model. The pathways are composed of several building blocks and are based on the five life cycle stages previously defined. True to the building blocks approach, some building blocks are used for multiple pathways.

Fuel	Feedstock	Conversion Process	Pathway-level system boundaries
Bioethanol	Grains	Wet and dry milling	From feedstock cultivation to fuel combustion
	Crop residues	Acid pretreatment, enzymatic hydrolysis, fermentation, distillation	From collection of crop residues to fuel combustion
	Yard trimmings	Acid pretreatment, enzymatic hydrolysis, fermentation, distillation	From collection of waste yard trimmings to fuel combustion
Biodiesel	Oilseeds	Oil extraction, transesterification, refining	From feedstock cultivation to fuel combustion
	Beef tallow	Rendering/purification, high free fatty acid conversion, transesterification/refining	From waste collection to fuel combustion
	Used cooking oil	Purification, free fatty acid conversion, transesterification/refining	From waste collection to fuel combustion

Solid LCIFs	Wood fibres	Pelletization, and/or steam treatment, and/or torrefaction	From wood harvesting to fuel combustion
	Crop residues	Densification	From collection of crop residues collection to fuel combustion
Pyrolysis oil	Wood fibres	Mobile fast pyrolysis/stationary fast pyrolysis	From collection of wood fibers to combustion
Renewable natural gas (RNG)	Waste	Anaerobic digestion, biogas upgrading	From waste collection to fuel combustion
	Landfill gas	Biogas upgrading	From biogas collection to fuel combustion
Hydrogen derived renewable diesel (HDRD)	Canola oil/ palm oil	Oil extraction, hydroprocessing	From feedstock collection to fuel combustion
Biojet fuel	Canola oil/ used cooking oil	Oil extraction, hydroprocessing	Canola: From feedstock cultivation to fuel combustion Used cooking oil: From waste collection to fuel combustion
Hydrogen	Natural gas and renewable natural gas	Steam methane reforming (SMR)	From feedstock collection to fuel combustion
	Water	Electrolysis	
	Wood fibres	Gasification/reforming of syngas	

3.1 Feedstock Extraction

The extraction life cycle stage consists of the cultivation, harvesting, and the collection of feedstock used in the production of low carbon intensity fuels. The Fuel LCA Model considers three main categories of feedstock that can be used in LCIF production: agricultural feedstock, wood fibre feedstock, and waste feedstock. Hydrogen uses natural gas as a feedstock, which is included in the Fuel LCA Model as a background unit process. Details for natural gas extraction are available in **Chapter 4.1.3**. The following sections present the general approach and assumptions used to model the carbon intensity associated with the production or the collection of the three feedstock categories.

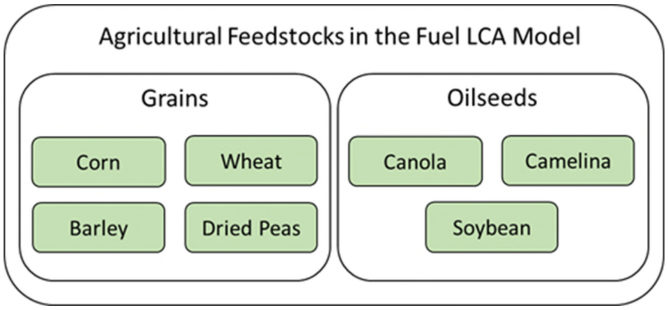
As stated in **Chapter 2.2.2**, in instances where a foreign feedstock is imported into Canada, or used in the production of an imported fuel, users of the Fuel LCA Model must use the pre-defined feedstock CI that is representative of their feedstock. For both domestic and foreign feedstock, the users will not be allowed to modify the pre-defined feedstock CI or calculate a custom CI for their specific feedstock.

3.1.1 Cultivation of Agricultural Feedstock in Canada

There are two main sources of agricultural feedstock: crops and crop residues. This section describes the modelling approach for both crops and crop residues in Canada.

General Approach for Agricultural Crops Cultivation in Canada

There are many low carbon fuels included within the Fuel LCA Model that rely on crops as their primary feedstock. The Fuel LCA Model includes the following primary feedstock:



The reference product of the dataset for each of these feedstocks is one kg of crop produced in Canada with a moisture content equivalent to market level content. The moisture contents used for the different crops in the Fuel LCA Model are based on the Canadian Roundtable for Sustainable Crops (CRSC) reports and are presented in **Table 4**.

Table 4: Moisture content of studied crops.

Crop	Moisture content (%)
Corn	14.5
Wheat	13.5
Durum wheat	14.5
Barley	13.5
Canola	8.5
Soybean	12.0
Camelina	8.0

The life cycle assessment of each crop considered 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 lifecycle inventory for each crop was modelled based on the 2017 LCA studies for major crops from the Canadian Roundtable for Sustainable Crops (CRSC).

Each crop was modelled using eight production processes: tillage, seeding, irrigation[6], 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. **Figure 6** illustrates the process flow, which includes the inputs considered as well as the functional unit.

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[6] Only energy use for irrigation was considered; irrigation water was not included in the model given its minor role in Canadian agriculture.

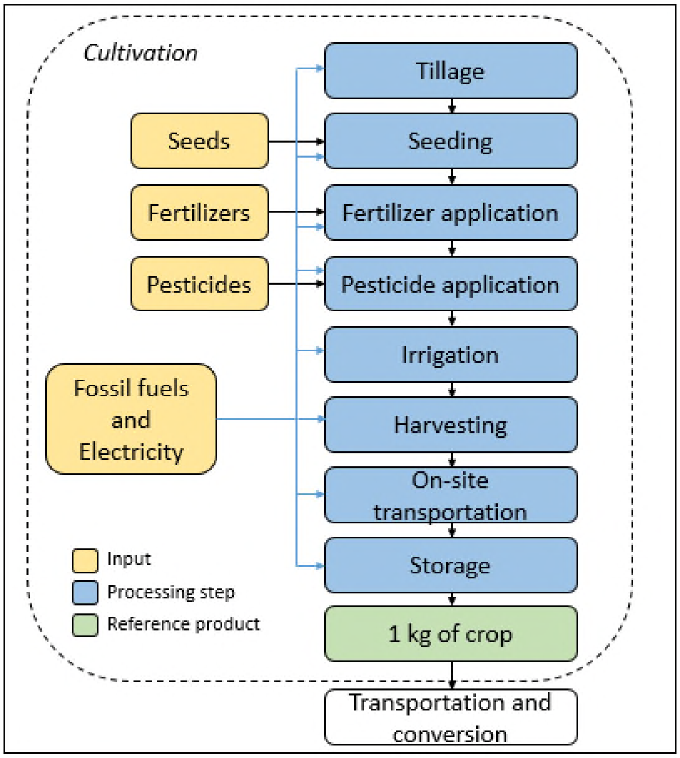

Figure 6: Cultivation overview for agricultural feedstocks, which represents the extraction life cycle stage.

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.

The scope of the model also includes direct and indirect N_2O emissions from nitrogen inputs (nitrogen-fertilizers, crop residues and mineralized nitrogen from soil) as well as CO_2 sequestration and emissions from land use change. N_2O emissions are calculated using Tier 2 emission factors from the CRSC reports which take into account tillage type, irrigation practices, and topography.

In accordance with the approach in Canada's NIR (2018), carbon emissions associated with soil organic carbon (SOC) changes in Canada are included for the three following mechanisms:

- Reduction of summer fallow practices
- Change in tillage practices (no till, reduced till and conventional till)
- Land use change from perennials to annual crops

The CRSC data on SOC that was included in the model covered changes in soil carbon up to the year 2014. The following elements were excluded from the scope of the crops LCI:

- 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 (e.g. machinery, trucks, infrastructure)
- transport of pesticides and fertilizers between the manufacturing plant and the farm
- waste or coproducts, such as:

- disposal of process wastes
- straw and stover co-products
- emissions related to manure application

The provincial datasets were modelled based on a Canadian average fertilizer mix as opposed to distinct provincial fertilizer mixes.

Regarding the exclusion of organic fertilizers such as manure, the Fuel LCA Model uses the default approach from the LEAP guidelines[7] which is to consider manure as a residue co-product of livestock systems. Emissions and resource use related to manure storage and application are therefore allocated to the livestock farm. In this approach the N_2O emissions associated with the application of the manure are also attributed to the livestock production. It essentially assumes that the manure (and emissions from manure) would have been produced whether or not it is used for fertilizer.

Geographical Scope for Agricultural Crops Cultivation

Agricultural feedstock LCI data was collected and compiled for each province, with the exception of Newfoundland and Labrador. Canadian averages were calculated and can be used in the absence of regional data.

In cases where no data was available at the provincial or national level (e.g. energy use for soybean production, seeding rates for corn and wheat in Atlantic provinces and Western provinces), data from the USDA for non-irrigated states was used as a proxy. **Table 5** indicates which regions were included for each crop.

Table 5: Geographical scope of Canadian grains and oilseed crops included in the Fuel LCA Model. Canadian averages were calculated for all crops and can be used in the absence of regional data.

Crop	AB	BC	MB	NB	NL	NS	ON	PE	QC	SK	CA
Barley	✓	✓	✓	✓		✓	✓	✓	✓	✓	✓
Corn			✓	✓		✓	✓	✓	✓		✓
Wheat (Durum)	✓									✓	✓
Wheat (non Durum)	✓	✓	✓	✓		✓	✓	✓	✓	✓	✓
Camelina			✓							✓	✓
Canola	✓	✓	✓	✓						✓	✓
Soybean			✓	✓		✓	✓	✓	✓		✓
Dried Peas	✓		✓							✓	✓

The Canadian averages for the LCI were calculated using weighted averages of provincial data when available. The provincial data, in turn, was also calculated using weighted averages of regional data at the **reconciliation unit** (RU) level when available. Reconciliation units 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. Defining the LCI of

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[7] FAO. 2016. Livestock Environmental Assessment and Performance (LEAP) Partnership. http://www.fao.org/partnerships/leap/overview/goals-and-objectives/en/

crops and oilseeds at a regional level is important given the variations in production practices, soil conditions, and climate which have a direct influence on the carbon intensities of crops. **Figure 7** shows the RU breakdown in Canada.

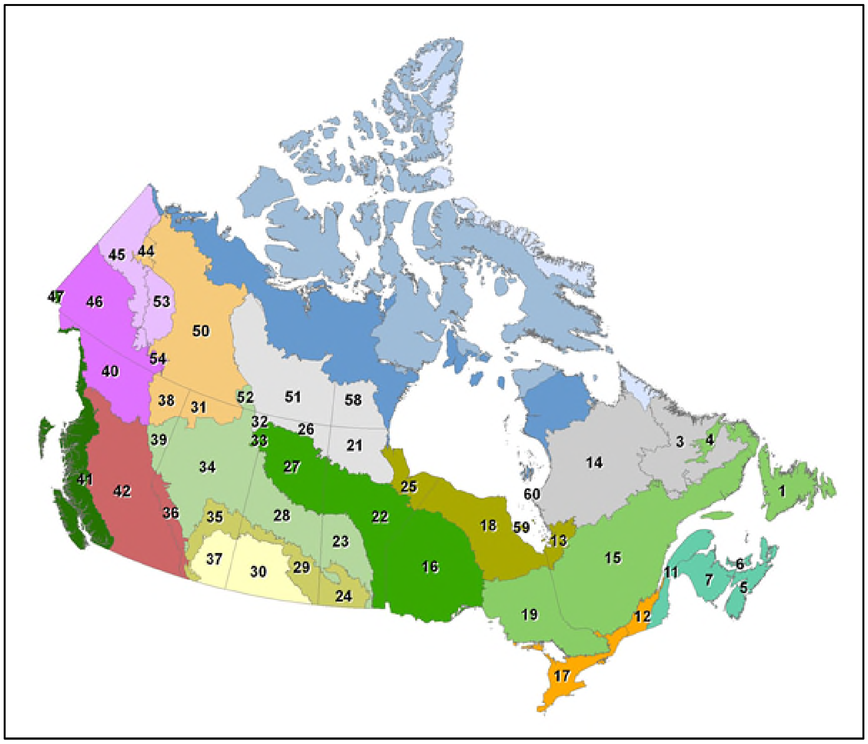

Figure 7: Reconciliation units in Canada.[8]

Allocation for Agricultural Crops Cultivation

While crop production can generate co-products such as straw, these were not included in the Fuel LCA Model. As such, no allocation procedure was performed on any of the crops covered by the Fuel LCA Model.

Data Sources for Agricultural Crops Cultivation

The Carbon Footprint Methodology report from the Canadian Roundtable for Sustainable Crops (CRSC) carbon footprint studies, along with the crop-specific CRSC reports for corn, wheat, barley, and canola, were the main sources of data for compiling these inventory tables. The CRSC studies represent the current best available source of Canadian field crop life cycle inventory data. In addition, data on crop residues was obtained from Thiagarajan et al. (2018).

The CRSC reports detail carbon footprints of barley, corn, wheat, and canola 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

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[8] Natural Resources Canada. *Spatial Framework*. See https://www.nrcan.gc.ca/climate-change/impacts-adaptations/climate-change-impacts-forests/carbon-accounting/spatial-framework/13117

modelling approach is consistent for all grains and oilseeds. The methodology and data sources are also consistent with those used in the NIR with respect to N_2O emissions from managed soils and land use change.

The pre-defined CIs related to the production of fertilizer and pesticide inputs for the field activities were modelled as background processes and are explained in more details in **Chapter 4.4**. The *Greenhouse gases, Regulated Emissions, and Energy use in Transportation* (GREET) 2018 Model was used in determining their values. Production of fuels and electricity used on farm are included as background processes. **Chapter 4:** contains more information regarding the modelling of these background processes. **Table 6** details the main data sources to model agricultural feedstock.

Table 6: Main data sources for agricultural feedstock.

Parameters	Data source
Yield Seeding rates Fertilizer/pesticide rates Energy use N_2O emissions CO_2 emissions from SOC	Crop-specific CRSC reports on corn, wheat, canola and barley: (S&T)2 Consultants. (2017). *Carbon Footprint for Canadian Grain Corn.* Winnipeg, MB: Canadian Roundtable on Sustainable Crops. (S&T)2 Consultants. (2017). *Carbon Footprint For Canadian Wheat.* Winnipeg, MB: Canadian Roundtable on Sustainable Crops. (S&T)2 Consultants. (2017). *Carbon Footprint For Canadian Barley.* Winnipeg, MB: Canadian Roundtable on Sustainable Crops. (S&T)2 Consultants. (2017). *Carbon Footprint For Canadian Canola.* Winnipeg, MB: Canadian Roundtable on Sustainable Crops. (S&T)2 Consultants Inc. (2017c). *Carbon Footprints for Major Canadian Grains Methodology Report.* Winnipeg, MB: Canadian Roundtable on Sustainable Crops.
Quantification of crop residues and nitrogen content of crops	Thiagarajan, A., Fan, J., McConkey, B.G., Janzen, H., Campbell, C.A. (2018). *Dry matter partitioning and residue N content for 11 major field crops in Canada adjusted for rooting depth and yield*. Can. J. Soil Sci. 98: 574-579

The CRSC reports did not contain information for soybean, camelina, durum wheat, and dried peas. Nevertheless, most of the LCI for these crops were built using the same data sources from the CRSC reports and the modelling approach remained the same. Data gaps were filled in using literature data to supplement missing information. **Table 7** details the main data sources for camelina, soybean and durum wheat.

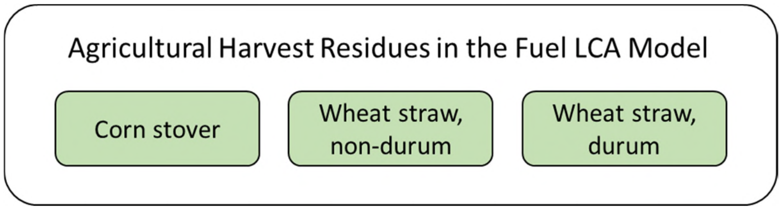
Table 7: Main data sources for camelina, soybean and durum wheat.

Parameters	Camelina	Soybean	Durum wheat
Yields	2019 data from Smart Earth Seeds	CANSIM Table 001-0071 from Statistics Canada	CANSIM Table 001-0071 from Statistics Canada
Fertilizer rates	2019 Crop Planning Guide from Saskatchewan	Manitoba: 2012-2014 averages from Manitoba Management Plus Program Ontario and Quebec: 2015 Stratus Fertilizer Use Survey	Saskatchewan: 2012-2014 averages from Saskatchewan Crop Insurance Corporation Alberta: 2015 Alberta crop budget
Energy use	Used energy use data from canola as proxy based on the Prairie Crop Energy Model and 2011 Agriculture survey	2012 USDA ARMS survey	Prairie Crop Energy Model (PCEM) model, and tillage data from the 2011 Agricultural census

Dried peas were also not modelled in the CRSC reports. In this situation, the model relies on the CI for pea production in Canada calculated by Desjardins et al. (2016)[9]. In the future the inventory and modelling for dried peas will be improved.

General Approach for Agricultural Crop Residues Cultivation

In addition to agricultural field crops, the Fuel LCA Model includes the use of agricultural crop residues as feedstocks for low carbon fuels. 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 included in the Fuel LCA Model are listed below.



Given that most crop residues are currently left on agricultural fields, these residues have been treated as waste products in the Fuel LCA Model. As such, no upstream impacts from cultivation have been 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

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[9] Desjardins, R., Worth, D., Vergé, X., Maxime, D., VanderZaag, A., Dyer, J., & Arcand, Y. (2016). 18 Greenhouse Gas Emission Intensities of Agricultural Products. In R. L. Clearwater, *Environmental Sustainability of Canadian Agriculture: Agri-Environmental Indicator Report Series – Report #4.* Ottawa, ON: Agriculture and Agri-Food Canada.

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 assuming the collection is done by a diesel truck. The distance travelled is estimated based on crop yields, assuming a square field, and the number of passes to cover the field with average grain combine harvester head sizes. This process is illustrated in **Figure 8**. The collection process produces a functional unit of 1 kg of crop residues.

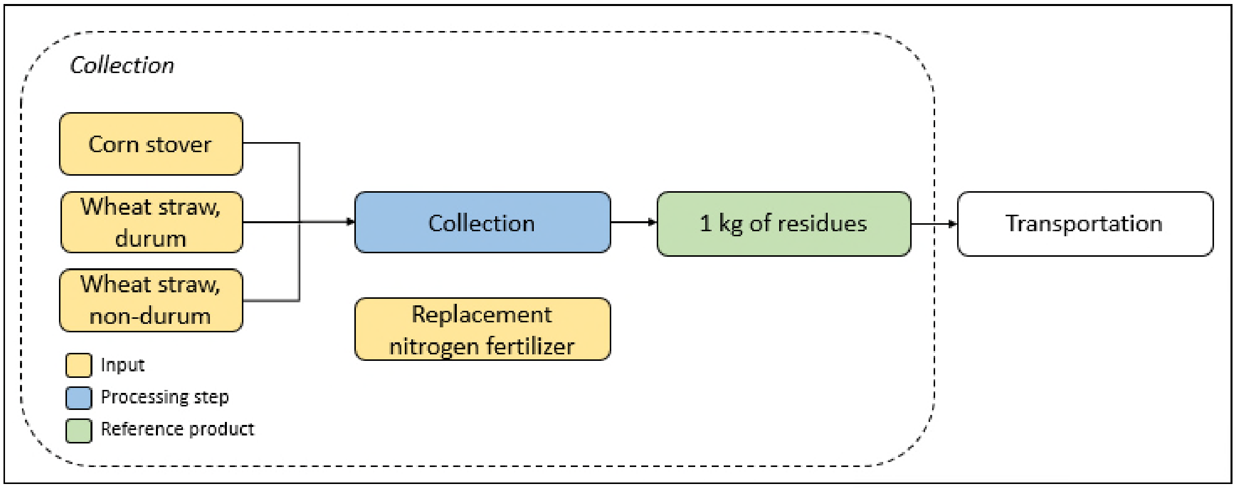

Figure 8: Crop residue collection process overview, which is a part of the extraction life cycle stage.

Geographical Scope for Agricultural Crop Residues Collection

The geographical scope for corn stover and wheat straw residues (durum and non durum) is only available for the national average. However, users can input regional specificities should regional data be available.

Allocation for Agricultural Crop Residues Collection

For the collection of agricultural crop residues, no allocation procedure was applied to the LCI dataset.

Data Sources for Agricultural Crop Residues Collection

The nitrogen content of crop residues was modelled based on Thiagarajan et al. (2018). Diesel consumption for harvesting were estimated based off yield data from the CRSC reports, while dimensions of the harvesting machinery were calculated based on an average harvester head size from North American manufacturers. The data is summarized in **Table 8**.

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Table 8: Main data sources for crop residues.

Data Type	Source
Nitrogen content of crop residues	Thiagarajan, A., Fan, J., McConkey, B.G., Janzen, H., Campbell, C.A. (2018). *Dry matter partitioning and residue N content for 11 major field crops in Canada adjusted for rooting depth and yield*. Can. J. Soil Sci. 98: 574-579
Diesel use for collection of crop residues	Yield data from the CRSC reports: (S&T)2 Consultants. (2017). *Carbon Footprint for Canadian Grain Corn.* Winnipeg, MB: Canadian Roundtable on Sustainable Crops. (S&T)2 Consultants. (2017). *Carbon Footprint For Canadian Wheat.* Winnipeg, MB: Canadian Roundtable on Sustainable Crops. Harvester head sizes: Compare Specifications. Case IH Agriculture. Retrieved from: https://www.caseih.com/northamerica/en-us/Pages/Comparison.aspx?family=GrainHeadsRigidCombine#

3.1.2 Harvesting of Wood Fibre Feedstock in Canada

General approach for Wood Fibres Harvesting

There are several low carbon fuel feedstocks produced at various points within the Canadian forest sector. The Canadian forest 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. The Fuel LCA Model includes the following wood fibre feedstocks:

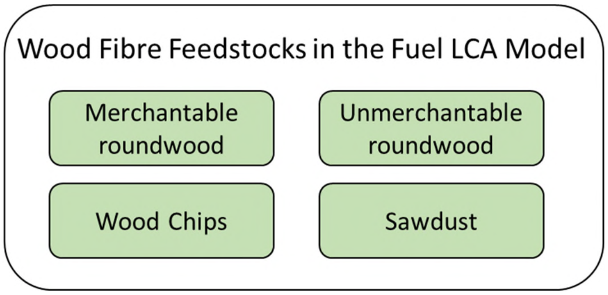

Figure 9 presents the process flow and interaction between the different wood fibre feedstocks included in the Fuel LCA Model. The extraction life cycle stage includes harvesting and processing of the aforementioned feedstock sources, and concludes with the production of the main wood fibre feedstocks.

Standing forest biomass is the primary feedstock source. While harvest wood residues and wood waste from construction and demolition are also alternative feedstock sources, both of these feedstocks do not have any associated GHG emissions. Indeed, as explained in **Chapter 3.1.4**, upstream GHG emissions are not allocated to waste feedstocks.

Merchantable roundwood and unmerchantable roundwood from standing forest biomass are modelled both as the main feedstocks and as intermediate products in the preparation of wood chips or sawdust as feedstocks. The LCI for merchantable logs includes fossil fuel use (diesel, propane and gasoline) and excludes any other material or chemical inputs (related to sylviculture, for example). Similarly, unmerchantable logs are modelled based on the amount diesel consumed related to forestry operations.

Once transported at the sawmill, merchantable logs are converted into lumber, a process which also generates both sawdust and wood chips, as well as other co-products (bark, shavings, trim ends and chipper fines). The modelling of both sawdust and wood chips therefore 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. Sawdust can be used directly as a feedstock for the hydrogen from gasification pathway (refer to **Chapter 3.3.8**) or can be further converted into wood pellets. Similarly, wood chips produced at the sawmill can be used as a feedstock to produce pyrolysis oil (refer to **Chapter 0**).

The chipping of harvest residues and unmerchantable roundwood at the forest roadside can be done using a wide range of technologies with varying capabilities and fuel consumption. The unit process for roadside chipping of wood biomass is based on an average diesel consumption value per amount of wood chipped based on the literature. Excluded processes and their justification are described in **Chapter 2.3.1**. The harvesting process produces a functional unit of 1 kg of wood fibre feedstock on a dry-mass basis.

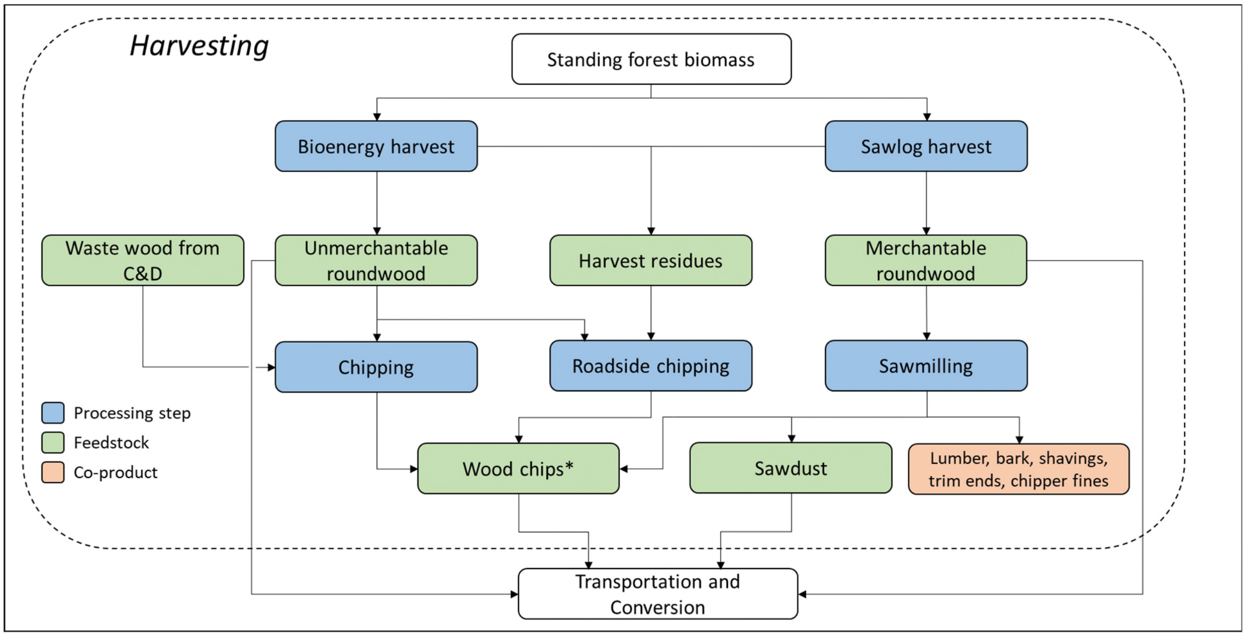

Figure 9: Harvesting process overview for wood fibre feedstocks. A mass-based allocation procedure was applied to both the sawdust and wood chips produced at the sawmill.

As described in **Chapter 2.7**, carbon emissions associated with direct land use change are included in the Fuel LCA Model in instances where feedstock production requires the conversion of land from existing use to bioenergy production. In the case of wood fibre feedstocks, since the existing Canadian forest sources require no conversion for bioenergy production, land use change emissions are not included in the LCI of wood feedstocks.

Geographical Scope for Wood Fibres Harvesting

Forest harvesting data is unavailable at the provincial level. Instead, the LCI for wood fibre feedstocks is grouped into three regional averages: Eastern Canada, Western Canada, and a national average. This is explained by the fact that the main data source for harvesting data comes from LCA studies on Canadian products from the Athena Sustainable Materials Institute, which aggregated data for Eastern Canada and for Canada as a whole. 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 Alberta and British Columbia, while “Eastern Canada” include mills in New Brunswick, Ontario, and Quebec. With respect to background energy systems, electricity grid carbon intensities are available at a provincial level.

Allocation for Wood Fibres Harvesting

For the harvesting of wood fibres, 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 both sawdust and wood chips therefore 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 Fibres Harvesting

The best publicly available LCI data for primary Canadian forest harvesting operations for merchantable roundwood is from the Athena Sustainable Materials Institute, who have completed a number of LCAs of Canadian forest products. 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 calculate/deduct values for Western Canada.

Canadian-specific data were 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 (CORRIM) in a 2012 LCA study on wood biomass collection and processing in the Southeast United States (Johnson et al., 2012).

For sawdust and wood chips produced at the sawmill, the most recent publicly available LCI data for Canadian sawmilling operations is also from the LCA studies carried out 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 (McKenchie et al., 2012). The default fuel consumption value for roadside chipping of whole trees is assumed to be the same as chipping of harvest residues. A summary of the data sources used are presented in **Table 9** below.

Table 9: Data sources for wood fibre feedstock harvesting.

Data Type	Source
Merchantable logs harvest and Sawmilling (sawdust, wood chips)	Athena Sustainable Materials Institute. (2018a). *A Cradle-to-Gate Life Cycle Assessment of Canadian Surfaced Dry Softwood Lumber.* Retrieved from http://www.athenasmi.org/wp-content/uploads/2018/07/CtG-LCA-of-Eastern-Canadian-Surfaced-Dry-Softwood-Lumber.pdf Athena Sustainable Materials Institute. (2018b). *A Cradle-to-Gate Life Cycle Assessment of Eastern Canadian Surfaced Dry Softwood Lumber.* Retrieved from http://www.athenasmi.org/wp-content/uploads/2018/07/CtG-LCA-of-Eastern-Canadian-Surfaced-Dry-Softwood-Lumber.pdf
Unmerchantable logs harvest	Johnson, L., Lippke, B., & Oneil, E. (2012). Modelling Biomass Collection and Woods Processing Life-Cycle Analysis. *Forest Prod. J. 62(4)*, 258-272.
Roadside chipping of harvest residues and unmerchantable logs	McKechnie, J. (2012). *Assessing the Greenhouse Gas Emissions Mitigation Potential through the Use of Forest Bioenergy.* Toronto, Ontario: Department of Civil Engineering, University of Toronto

3.1.3 Production of foreign feedstock

In instances where a feedstock is produced outside of Canada, the Fuel LCA Model will provide pre-defined CI values for the following foreign produced feedstocks:

- Canola
- Corn
- Sorghum
- Soybean
- Sugar Cane

These foreign feedstocks are modelled consistently with the methodological approach used to model domestically produced feedstocks in Canada, as presented in the section 3.

3.1.4 Collection of Waste Materials

Wastes from various agricultural, commercial, and industrial activities are used as feedstock for many of the low carbon fuel pathways, including ethanol, biodiesel, biogas/renewable natural gas, and solid fuel pathways. These feedstocks include municipal solid waste (MSW), wastewater treatment (WWT) sludge, oils and grease, animal fats, manure, and industrial/construction and demolition (C&D) waste.

By default and in line with ISO 14044 guidance, the upstream GHG emissions are not allocated to feedstocks that are considered waste products. Based on this decision, the life cycle carbon intensity for these feedstocks begins at waste collection and processing. Data and assumptions specific to each waste feedstock is presented in the corresponding section.

However, in the case of landfill gas, MSW, WWT sludge and livestock manure, the baseline scenario could result in significant methane emissions depending on existing legislation and management practices that vary among provinces. A national baseline scenario is set for each waste material type, namely landfill gas, MSW, WWT sludge and livestock manure, in order to be conservative and uniform among provinces as follows:

- When legislation exists in some provinces, the baseline will be set at the most stringent regulations.
- When no legislation exists, the baseline will be set based on common management practices for the given waste material.

The lifecycle analysis of the baseline scenario determines the avoided emissions that can be attributed to the fuel system as an avoided emission credit for the waste material used for fuel production.

3.2 Feedstock Transportation

Following extraction, the next life cycle stage in the Fuel LCA Model is the transportation of feedstock. In the Fuel LCA Model, transportation includes the transport of feedstock from source (forest, agriculture, waste recovery stream, etc.) to production facility (mills, distilleries, etc.).

Like feedstock extraction, the transportation of each feedstock is modelled as a foreground unit process (**Chapter 1.5.3**). Primary data include parameters such as the mode of transportation and average transportation distance. Other parameters related to transportation, such as fuel use and efficiency, are part of the background processes in the Fuel LCA Model. More information surrounding the background processes is presented in **Chapter 4.2**.

The following sections outline the system boundaries and modelling approach used for transportation of feedstocks in the Fuel LCA Model. This also includes default distances that were determined based on the modelling.

3.2.1 System Boundaries for Transportation

System Boundaries for Transportation

As stated, the system boundaries for transportation include the transportation of feedstocks from source to production facility, including all intermediate steps. For example, cattle by-products are transported from the slaughterhouse to the rendering plant; the beef tallow is then transported to the biodiesel plant. In the case of imported fuels and feedstocks, the model also includes transportation analysis to account for transport related emissions that occurs outside of the Canadian boundaries.

The modelling of transportation excludes the following:

- On-site transportation within the processing or conversion facility boundaries; and
- Transportation of all materials other than feedstocks (i.e. transportation of consumables, wastes and co-products are excluded)

3.2.2 Modelling Approach for Transportation

The modelling approach for transportation of feedstocks applies the same underlying assumptions and data used to model conventional fossil fuel pathways and background unit processes (**Chapter 4.2**). This includes the fact that transportation involves the same equipment and conventional fossil fuels currently used in Canada (i.e. biofuels are not used as an energy source for transportation).

The following sections provide an overview of the modelling approach for feedstock transportation.

Modes of Transportation by Feedstock Type

Table 10 lists the modes of transportation used and general considerations taken in modelling the transportation of each of the pre-defined feedstocks included in the Fuel LCA Model. Modelling parameters also included the load and distance required. Note that while transportation by ship is not included in the pre-defined pathways, it is available should a specific process require its usage.

Table 10. Summary of transportation processes to be modelled for low carbon fuels.

Feedstock Type	Modes of Transport	Modelling Considerations
Agricultural	Truck	Local supply is a key determinant for regional variability of feedstocks
	Rail	Considered for longer-distance transportation (anticipated to be more relevant in mature biofuels industry)
	Ship	Considered for imported feedstocks
Wood fibre	Truck	Local supply is a key determinant for regional variability of feedstocks; Wood fibre feedstocks require additional transportation steps depending on source and production pathway (e.g. transport to road-side wood chipping)
	Ship	Considered for imported feedstocks
Natural gas	Pipeline	Cross-provincial transportation of natural gas (as feedstock for hydrogen production)
Waste	Truck	Assumed based on proximity of conversion plants to population centres

Transportation Pathways and Utilization

The GHG emissions intensity of transportation depends on the degree that mobile equipment is efficiently utilized. The following approach was used to model the utilization of equipment:

- All local deliveries by truck are assumed to be one-way deliveries
- All deliveries by rail or long-distance truck are assumed to be one-way deliveries with the return trip utilized by other product systems. In these cases, the model only attributes the emissions of first trip to the biofuel pathway (i.e. one-way trip)

Product characteristics

Product characteristics for feedstocks and biofuels impact the GHG emissions resulting from transportation. Moisture content in feedstocks and biomass can vary substantially (between 5% and up to 40%), increasing the transportation load required to deliver the equivalent dry mass or energy content. The variation in the density of feedstocks (including packing factor) can also influence vehicle efficiency during transport. Vehicle capacity may be volume dependent (and not mass dependent) for lighter, high volume materials.

To account for these differences, the following approach and assumptions were made:

- Moisture content is included in the determination of the mass of the feedstock that is transported.
- The amount of feedstock being transported is determined by the mass of the cargo and not the volume. The assumption is that the density is high enough that mass is the determinant of fuel efficiency.

3.2.3 Default Distances for Transportation

Default distance and mode of transportation

The average transport distances in the pre-defined pathways are based on feedstock locations and existing or likely locations of processing facilities. In the absence of data, the locations of new production facilities are assumed to be similar to existing facilities, based on similar economic drivers (i.e. proximity to source and end users, labour and consumables). An average distance of 100 km between feedstock source and production facility is assumed, based on the following observations:

- Existing wood pellet facilities are adjacent or near forestry harvest operations and sawmills;
- Agricultural feedstocks for bioethanol facilities are typically regional sources (e.g. wheat in Saskatchewan and corn in Ontario);
- Short-distance transport improves the economic viability of biofuels and is expected to influence commercial viability of emerging technologies that have not reached commercial scale in Canada.

Based on this distance, trucking is the default mode of transportation for agricultural and forestry feedstocks. As the biofuels industry develops, longer distance transport may become more viable. In addition, users can input the mode of transportation and actual transportation distances in place of the pre-defined pathways. The average default distance for natural gas is based on previous modelling done for the background fossil fuel pathways, which are described in **Chapter 4:**. **Table 11** summarizes the default average distances.

Table 11. Average and default transportation distances for feedstocks.

Biofuel/Feedstock	Average Distance	Primary Mode
Agricultural	100 km	Truck
Wood fibre	100 km	Truck
Natural gas	2560 km	Pipeline
Waste	100 km	Truck

3.3 Fuel Conversion

The following section outlines the general approach for each conversion pathway in the Fuel LCA Model. This includes general assumptions, geographical scope, and main data sources.

There are a wide range of conversion technologies used to convert feedstocks to low carbon fuels depending on the desired end-use. Life cycle inventory data needs for conversion technologies include:

- Mass balance data for feedstock conversion efficiency;
- Energy inputs (electricity (grid and on-site generation, fuels); and
- Material inputs (chemicals, enzymes, etc.).

For biodiesel and ethanol production, primary data from Canadian producers was used to model the fuel conversion process. For other fuel conversion processes in other low carbon fuel pathways, literature was used and adapted to Canadian conditions where possible (e.g. background energy source).

For fuels produced outside of Canada, selected regionalized background LCI (e.g. electricity) of foreign regions are available in the Fuel LCA Model. For other background LCI data, such as chemical and fossil fuel inputs, users must use the default CI values developed for the Canadian context.

3.3.1 Bioethanol

The Fuel LCA Model includes the production of bioethanol from multiple feedstocks and engineering processes. Three categories for these pathways are described below: bioethanol from grains, cellulosic ethanol, and ethanol from yard trimmings. **Table 12** summarizes the pathways included based on feedstock and conversion type.

Table 12: List of feedstocks and conversion processes included in the Fuel LCA Model for the production of bioethanol.

Feedstock	**Conversion Process**
Barley, corn, wheat, dried peas, mixed grains	Wet and dry milling
Corn stover, wheat straw	Enzymatic pretreatment, C5 / C6 sugar fermentation, Distillation
Yard trimmings	Enzymatic pretreatment, C5 / C6 sugar fermentation, Distillation

Conversion Process Overview for Bioethanol from Grains

The conversion of grain feedstocks into bioethanol is modelled using a multi-step process. This includes starch extraction, liquefaction and saccarification, fermentation, and distillation and drying (**Figure 10**). Mixed grains, one of the feedstocks modelled, is a mixture of three feedstocks (barley, corn, and wheat). Starch extraction is modelled via wet milling or dry milling, while the remainder of the conversion process for grain to ethanol varies little among grain types. The conversion also produces several co-products. The pre-defined pathways each contain a single co-product output that represents the energy content of the co-products produced in the conversion process. Co-products considered in this calculation include barley brewer's grains, corn oil, distiller's dried grains (DDG), DDG with solubles (DDGS), pea protein concentrate (PPC), wet distiller's grains (WDG), and WDG with solubles (WDGS). The conversion process produces a functional unit of 1 MJ of bioethanol HHV.

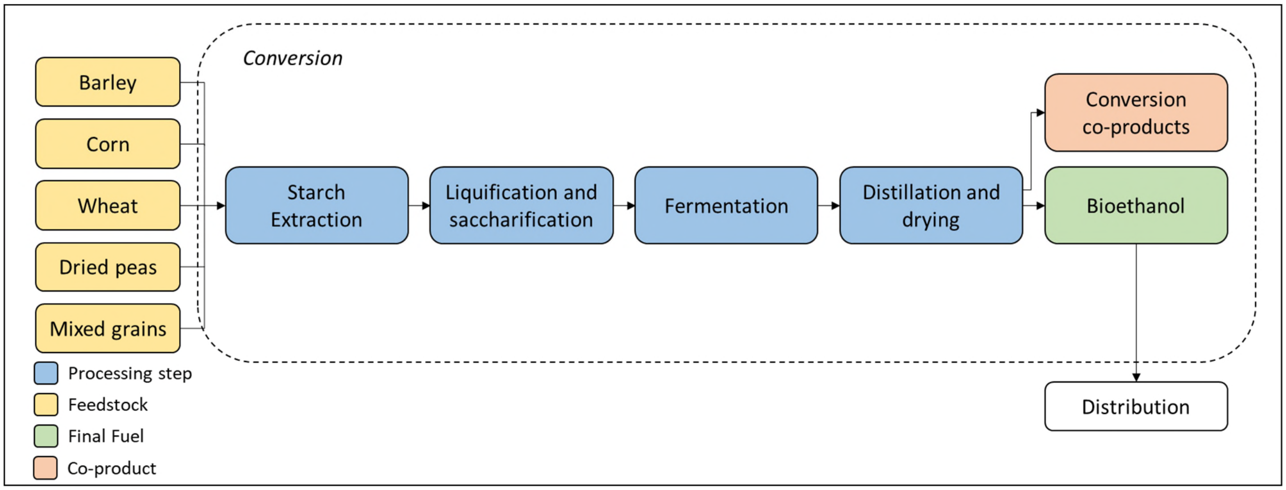

Figure 10: Main processing steps involved in the production of bioethanol. Bioethanol co-products depend on feedstocks involved and can include barley brewer's grains, corn oil, DDG, DDGS, PPC, WDG, and WDGS.

Geographical Scope for Bioethanol Conversion Processes

The bioethanol from grains conversion process was modelled based on Canadian production data from the Complementary Environmental Performance Reports (CEPR) that have been compiled by Natural Resources Canada (NRCan) as part of NRCan's ecoENERGY for Biofuels Program. The CEPR data was compiled to model a single national average approach for bioethanol conversion from grain. This assumes that the conversion process is the same across provinces. However, users of the model will be able to adapt the process model for a certain region by selecting province-specific building blocks for feedstocks and energy inputs.

Allocation for Bioethanol Conversion Processes from Grains

The predefined allocation procedure is based on energy content. The allocation of burdens to the co-products is performed according to the energy content of the products.

Data Sources for Bioethanol Conversion Processes

Detailed provincial and anonymized LCI data for Canadian grain bioethanol have been compiled by Natural Resources Canada (NRCan) as part of NRCan's ecoENERGY for Biofuels Program. The data is aggregated from information provided in the CEPR from 2012 to 2015 years of production. A summary of the main data sources used for modelling bioethanol conversion is presented in **Table 13**.

Table 13: List of data sources used in modelling bioethanol conversion from grains

Data Type	Data Source
Crop volumes produced and used nationally	Littlejohns, J., Rehmann, L., Murdy, R., Oo, A., & Neill, S. (2018, 2018). Current state and future prospects for liquid biofuels in Canada. *Biofuel Research Journal, 5*(1), 759-779.
Regional bioethanol production	Natural Resources Canada. (2019). *ecoENERGY for Biofuels Program*. Retrieved from https://www.nrcan.gc.ca/energy/alternative-fuels/biofuels/12358 Natural Resources Canada. (2019). *Confidential ethanol production data from ecoEnergy for Biofuels Complementary Environmental Performance Reports.*

Conversion Process Overview for Cellulosic Ethanol

The Fuel LCA Model includes the conversion of agricultural crop residues (corn stover and wheat straw) into cellulosic ethanol. Feedstock inputs undergo mechanical size reduction before a dilute-acid pre-treatment is applied to separate sugars from the cell walls of the feedstock materials. The resulting biomass then undergoes enzymatic hydrolysis in which a slurry and lignin is produced. The slurry is then fermented to convert the sugars to ethanol, while the lignin is used to produce electricity and heat. Distillation and dehydration steps are taken to remove water and residual solids from the ethanol. Conventional gasoline is combined with the distilled ethanol, denaturing it and producing fuel-grade ethanol. An overview of the cellulosic ethanol process is presented in **Figure 11**. The conversion process produces a functional unit of 1 MJ of cellulosic ethanol HHV.

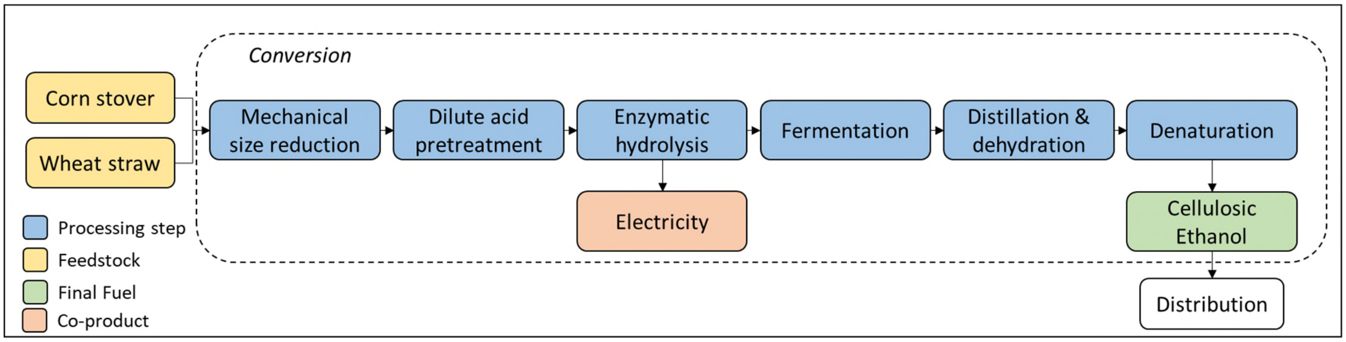

Figure 11: Main processing steps involved in the production of cellulosic ethanol. Electricity is produced from lignin and is recycled to the grid

The wheat straw to ethanol pathway was modelled with the same conversion efficiency assumptions for the sugars yielded from corn stover, but with lower sugar content from wheat straw. An additional assumption used in the Fuel LCA Model is the use of yeast to facilitate fermentation and the production of ethanol from sugars. The use of different microorganisms would garner different conversion efficiencies, but the pre-defined pathway is modelled assuming the use of this microorganism.

Geographical Scope for Cellulosic Ethanol Conversion Processes

The cellulosic ethanol 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. However, users of the model will be able to adapt the process model for a certain region by selecting province-specific building blocks for energy inputs. Since corn stover and wheat straw are treated as wastes in the Fuel LCA Model, they do not contribute to regional variations in emissions from soils. Cellulosic fuel production therefore has less influence from regionalization as the technologies for producing it do not need to vary by location.

Allocation for Cellulosic Ethanol Conversion Processes

Allocation occurs at the cellulosic ethanol facility between the ethanol as the primary product and the remaining solids that consist of hemicelluloses and lignin as the co-product. The most common use of the unused hemicelluloses fraction and the lignin co-products is to burn them for combined heat and power to fuel the ethanol production process. For the co-product electricity production from the ethanol refinery, the excess electricity is exported to the grid and, therefore, is assumed to displace the emissions from grid electricity produced in Canada.

Data Sources for Cellulosic Ethanol Conversion Processes

The data used to model the conversion of cellulosic ethanol from grain feedstocks were gathered from a 2011 study by the National Renewable Energy Laboratory (NREL) (Humbird, et al., 2011). Excluding feedstock, data for inputs to each step in the conversion process were obtained from the GREET tool (Lee, Han, & Wang, 2016) and the contribution to *Environmental Resource Letters* from Wang, Han, Dunn, Cai, & Elgowainy, 2012. The conversion of sugars to ethanol 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. **Table 14** lists the main data sources used in modelling the cellulosic ethanol conversion processes.

Table 14: List of data sources used in modelling cellulosic ethanol conversion processes.

Data Type	Source
Wheat straw processing steps	Humbird, D., Davis, R., Tao, L., Hsu, D., Aden, A., Schoen, P., … Duedgeon, D. (2011). *Process design and economics for biochemical conversion of lignocellulosic biomass to ethanol: dilute-acid pretreatment and enzymatic hydrolysis.* Golden, CO: National Renewable Energy Laboratory. Lee, U., Han, J., & Wang, M. (2016, October). *Argonne National Laboratories.* Retrieved from Well-to-Wheels Analysis of Compressed Natural Gas and Ethanol from Municipal Solid Waste: https://greet.es.anl.gov/publication-wte-2016 Wang, M., Han, J., Dunn, J., Cai, H., & Elgowainy, A. (2012). Well-to-wheels energy use and greenhouse gas emissions of ethanol from corn, sugarcane and cellulosic biomass for US use. *Environmental Resource Letters, 7*(4), 13.
Corn stover processing steps	Humbird, D., Davis, R., Tao, L., Hsu, D., Aden, A., Schoen, P., … Duedgeon, D. (2011). *Process design and economics for biochemical conversion of lignocellulosic biomass to ethanol: dilute-acid pretreatment and enzymatic hydrolysis.* Golden, CO: National Renewable Energy Laboratory. Lee, U., Han, J., & Wang, M. (2016, October). *Argonne National Laboratories.* Retrieved from Well-to-Wheels Analysis of Compressed Natural Gas and Ethanol from Municipal Solid Waste: https://greet.es.anl.gov/publication-wte-2016 Wang, M., Han, J., Dunn, J., Cai, H., & Elgowainy, A. (2012). Well-to-wheels energy use and greenhouse gas emissions of ethanol from corn, sugarcane and cellulosic biomass for US use. *Environmental Resource Letters, 7*(4), 13.

Conversion Process Overview for Ethanol Conversion from Yard Trimmings

The modelling of the ethanol from yard trimmings pathway is based on the modelling used for the cellulosic ethanol from corn stover pathway, with a few differences.

As yard trimmings contain a greater moisture content compared to corn stover, a greater mass of feedstock is required to be transported to the ethanol production facility in order to obtain the equivalent amount of dry-mass for the lignocellulosic conversion.

A result of the high moisture content of the feedstock relative to corn stover, more energy is required to dry the feedstock. Therefore, it assumed that the lignin that is produced as a co-product is combusted to dry the incoming feedstock instead of generating a surplus of electricity. **Figure 12** displays the conversion process overview for bioethanol from yard trimmings. The conversion process produces a functional unit of 1 MJ of bioethanol HHV.

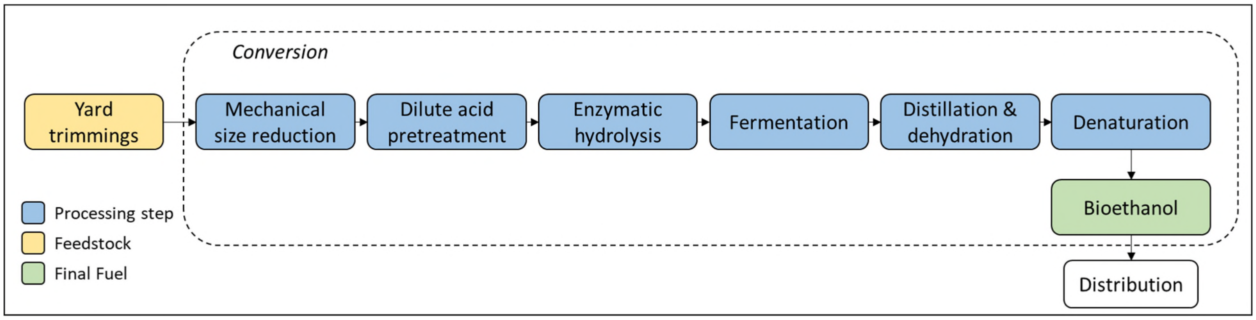

Figure 12: Main processing steps involved in the production of ethanol from yard trimmings. The production pathway was based on the modelling used in the cellulosic ethanol pathway.

3.3.2 Biodiesel

The Fuel LCA Model includes the production of biodiesel from multiple feedstocks and engineering processes. Three categories for these pathways are described below: biodiesel from oilseeds, biodiesel from beef tallow, and biodiesel from used cooking oil (UCO). **Table 15** summarizes the pathways included based on feedstock and conversion type.

Table 15: List of feedstocks and conversion processes included in the Fuel LCA Model for the production of bioethanol.

Feedstock	Conversion Process
Camelina, canola, soybean	Oil extraction, transesterification, refining
Beef tallow	Rendering/purification, high free fatty acid conversion, transesterification/refining
Used Cooking Oil	Purification, free fatty acid conversion, transesterification/refining

Conversion Process Overview for Biodiesel from Oilseeds

In the Fuel LCA Model, oilseeds are converted to biodiesel primarily via oil extraction and transesterification. During the conversion process there are two main co-products – primarily a protein-rich meal and glycerol. The system boundaries for the conversion life cycle stage and process flow for crop-based biodiesel production from oilseeds are summarized in **Figure 13**. Feedstocks include canola, soybeans, and camelina.

The conversion process modelling for biodiesel from oilseeds relied on Canadian production data collected and averaged from 2011-2015, provided by the CEPR. It was assumed that chemical and energy inputs were the same for soybean, camelina and canola seeds. Moreover, since it was not possible to distinguish the feedstocks in the CEPR data, an average of feedstocks properties have been used for the three different seeds. The conversion process is modelled with a functional unit of 1 MJ of biodiesel HHV.

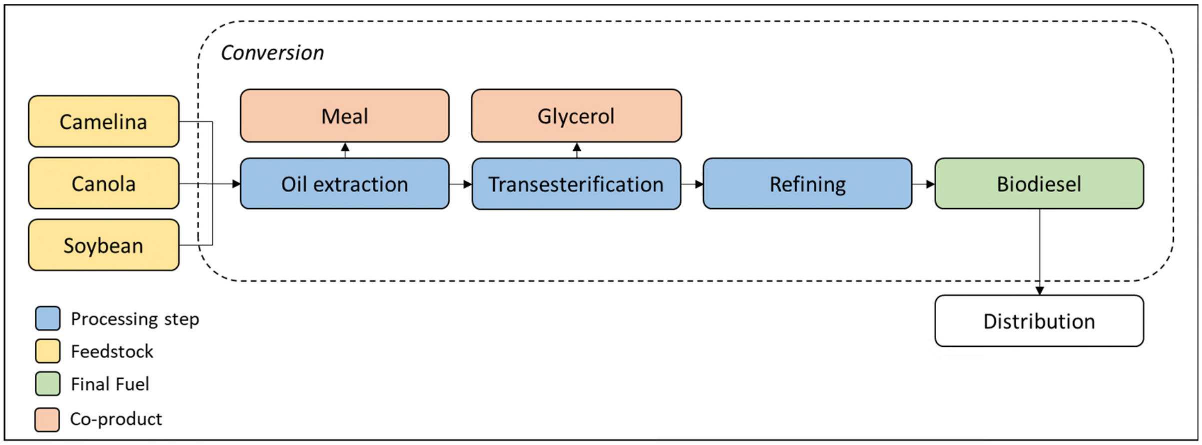

Figure 13: Main processing steps involved in the production of biodiesel. Biodiesel by-products include a protein-rich meal and glycerol.

Geographical Scope for Biodiesel Conversion Processes

The biodiesel conversion process was modelled based on Canadian production data from the CEPR that have been compiled by Natural Resources Canada (NRCan) as part of NRCan's ecoENERGY for Biofuels Program. The CEPR data was compiled to model a single national average approach for biodiesel conversion from oilseeds. This assumes that the conversion process is the same across provinces. However, users of the model will be able to adapt the process model for a certain region by selecting province-specific building blocks for feedstock and energy inputs.

Allocation for Biodiesel Conversion Processes from Oilseeds

The predefined allocation procedure is based on energy content. The allocation of burdens to the meal protein and glycerol in the oil extraction and transesterification step is performed according to the energy content of the products.

Data Sources for Biodiesel Conversion Processes

As with bioethanol conversion, detailed provincial and anonymized LCI data for Canadian mixed feedstock biodiesel have been compiled by Natural Resources Canada (NRCan) as part of NRCan's ecoENERGY for Biofuels Program. The data is aggregated from information provided in the CEPR from year 2011 to 2015. Additional literature sources were used to model the biodiesel oil extraction step. A summary of the main data sources used for modelling biodiesel conversion is presented in **Table 16**.

Table 16: List of data sources used in modelling biodiesel conversion from oilseeds

Data Type	**Source**
Oil extraction	Miller, P., & Kumar, A. (2013). Development of emission parameters and net energy ratio for renewable diesel from Canola and Camelina. *Energy, 58*, 426-437. Shonnard, D., Williams, L., & Kalnes, T. (n.d.). Camelina-derived jet fuel and diesel: Sustainable advanced biofuels. *Environ. Prog. Sustainable Energy, 29*, 382-392
Oilseed crop production and usage	Littlejohns, J., Rehmann, L., Murdy, R., Oo, A., & Neill, S. (2018, 2018). Current state and future prospects for

	liquid biofuels in Canada. *Biofuel Research Journal, 5*(1), 759-779.
National and regional biodiesel production	Natural Resources Canada. (2019). *Confidential biodiesel production data from ecoEnergy for Biofuels Complementary Environmental Performance Reports.* Natural Resources Canada. (2019). *ecoENERGY for Biofuels Program*. Retrieved from https://www.nrcan.gc.ca/energy/alternative-fuels/biofuels/12358

Conversion Process Overview for Biodiesel from Beef Tallow

The boundary of this pathway begins with the arrival of the cattle by-products from the slaughterhouse to the rendering plant and ends with the production of biodiesel. In the pre-processing stage, cattle by-products from the slaughterhouse are processed in a rendering plant to produce beef tallow, with meat and bone meal, water vapour, and cooking vapour as co-products. The cooking vapours are a waste stream and are excluded from the Fuel LCA Model's LCI calculations. The beef tallow is then converted to biodiesel through a conversion process that accounts for the high free fatty acid (FFA) content found in beef tallow. Glycerin, fatty acids and distillation heavies are produced as biodiesel co-products from the transesterification/refining process. **Figure 14** displays an overview of the biodiesel from beef tallow conversion process in the Fuel LCA Model. The conversion process produces a functional unit of 1 MJ of biodiesel fuel HHV.

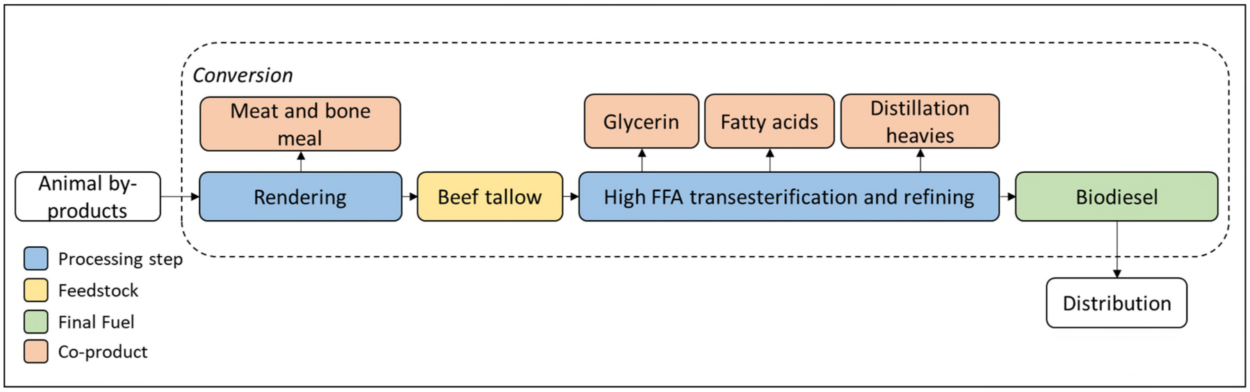

Figure 14: Main processing steps involved in the production of biodiesel from beef tallow. Co-products in the rendering process include meat and bone meal, and water/cooking vapour (excluded from the LCI). Co-products in the transesterification/refining process include glycerin, biodiesel heavies, and FFAs.

Geographical Scope for Waste Derived Biodiesel from Beef Tallow

The biodiesel from beef tallow conversion process was modelled based on U.S. data from the GREET model and a survey performed by the American National Biodiesel Board. The data was compiled to model a single national average approach for beef tallow conversion. This assumes that the conversion process is the same across provinces. However, users of the model will be able to adapt the process model for a certain region by selecting province-specific building blocks for energy inputs.

Allocation for Waste Derived Biodiesel from Beef Tallow

The pre-defined allocation procedure is based on energy content. The allocation of burdens to the meat and bone meal and beef tallow in the rendering step is performed according the energy content of the products. The allocation of burdens to the biodiesel, glycerin, fatty acid and distillation heavies in the transesterification step is performed according the energy content of the products.

Data Sources for Waste Derived Biodiesel from Beef Tallow

The conversion of biodiesel from beef tallow was modelled using data of an average US biodiesel conversion process to represent the average Canadian production. The 2016 GREET model was used for the beef tallow rendering process. The conversion stage for beef tallow biodiesel was modelled using the study from Chen et al., 2018 which uses data from a survey performed by the United States' National Biodiesel Board (NBB) in 2016. **Table 17** lists the main data sources used in the conversion of biodiesel from beef tallow.

Table 17: List of data sources used in modelling biodiesel conversion from beef tallow.

Data Type	Source
Beef Tallow Rendering	Chen, F., Qui, Z., Canter, C., Cai, H., Han, J., & Wang, M. (2017, October 9). Updates on the energy consumption of the beef tallow rendering process and the ration of synthetic fertilizer nitrogen supplementing removed crop residue nitrogen in GREET.
Transesterification and Refining	Chen, R., Qin, Z., Han, J., Wang, M., Taheripour, F., Tyner, W., Duffield, J. (2018). Life cycle energy and greenhouse gas emission effects of biodiesel in the United States with induced land use change impacts.

Conversion Process Overview for Biodiesel from Used Cooking Oil

The boundary of the conversion begins with the arrival of used cooking oil (UCO) at the rendering plant and ends with the production of biodiesel. First, yellow grease is produced from UCO through a two step purification process. Water is first mechanically removed from the used cooking oil. Any remaining water is then thermally removed. Similar to beef tallow, yellow grease has a higher FFA content than oil derived from oilseed crops. However, in the Fuel LCA Model, unlike the beef tallow biodiesel pathway, the biodiesel from UCO is first pre-processed to reduce the FFA content prior to transesterification. This FFA conversion process is based off a California GREET report in the U.S. consisting of a 50/50 average of acid esterification using sodium hydroxide to neutralize sulfuric acid, and the other half processed with continuous, non-acid esterification. After pre-treatment, yellow grease is processed through a biodiesel transesterification/refining process similar to that used for other crop-based vegetable oils. Co-products include glycerin, biodiesel heavies, and FFAs. **Figure 15** shows the main overview of biodiesel conversion from UCO in the Fuel LCA Model. The conversion process produces a functional unit of 1 MJ of biodiesel fuel HHV.

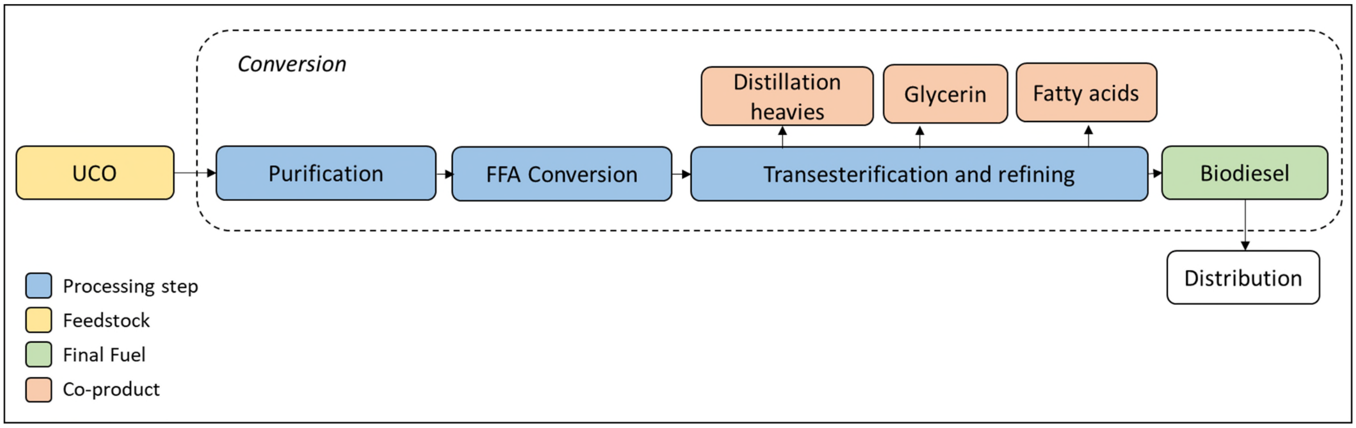

Figure 15: Main processing steps involved in the production of biodiesel from used cooking oil. Co-products in the transesterification process include glycerin, biodiesel heavies, and FFAs.

Geographical Scope for Waste Derived Biodiesel from Used Cooking Oil

The biodiesel from UCO conversion process was modelled based on Canadian and U.S. data from the GHGenius and GREET model, and a survey performed by the American National Biodiesel Board. The data was compiled to model a single national average approach for used cooking oil conversion to biodiesel. This assumes that the conversion process is the same across provinces. However, users of the model will be able to adapt the process model for a certain region by selecting province-specific building blocks for energy inputs.

Allocation for Waste Derived Biodiesel from Used Cooking Oil

The pre-defined allocation procedure is based on energy content. The allocation of burdens to the biodiesel, glycerin, fatty acid and distillation heavies in the transesterification step is performed according the energy content of the products.

Data Sources for Waste Derived Biodiesel from Used Cooking Oil

Data from GHGenius Version 4.03 was used for the modelling of the UCO purification process. Data from CA-GREET was used to model the FFA esterification stage. The conversion stage for biodiesel from UCO was modelled using data from a survey by the United State's National Biodiesel Board (NBB) in 2016. **Table 18** lists the main data sources used in the conversion of biodiesel from UCO.

Table 18: List of data sources used in modelling biodiesel conversion from UCO.

Data Type	Source
UCO Purification	(S&T)^2 Consultants Inc. (2013). GHGenius Model 4.03 Volume 2 Data and Data Sources. Ottawa, ON: Natural Resources Canada.
UCO FFA Esterification	California Environmental Protection Agency. (2009). Detailed California-GREET Pathway for Biodiesel Produced in California from Used Cooking Oil
Biodiesel Conversion	Chen, R., Qin, Z., Han, J., Wang, M., Taheripour, F., Tyner, W., Duffield, J. (2018). Life cycle energy and greenhouse gas emission effects of biodiesel in the United States with induced land use change impacts

3.3.3 Solid LCIF

Solid LCIFs are modelled using two feedstock sources: wood fibres and crop residues. The table below summarizes the pathways included based on feedstock and conversion type.

Table 19: List of feedstocks and conversion processes included in the Fuel LCA Model for the production of solid LCIFs.

Feedstock	Conversion Process	Fuel
Unmerchantable logs, Sawdust	Pelletization	Wood pellets
	Pelletization and steam treatment	Wood pellets, steam-treated
	Pelletization and torrefaction	Wood pellets, torrefied
Corn stover residues	Densification	Corn stover pellets

Conversion Process Overview for Solid LCIF from Wood Fibre Feedstocks

The Fuel LCA Model includes the conversion of wood fibre feedstocks into solid LCIFs. This group of fuels includes wood chips and wood pellets. Since wood chips are both a feedstock and final fuel, the production of wood chips as a fuel is explained in **Chapter 3.1.2**.

An overview of the conversion process of wood fibre feedstocks into wood pellets is presented in **Figure 16**. The conversion process produces a functional unit of 1 MJ of solid LCIF HHV.

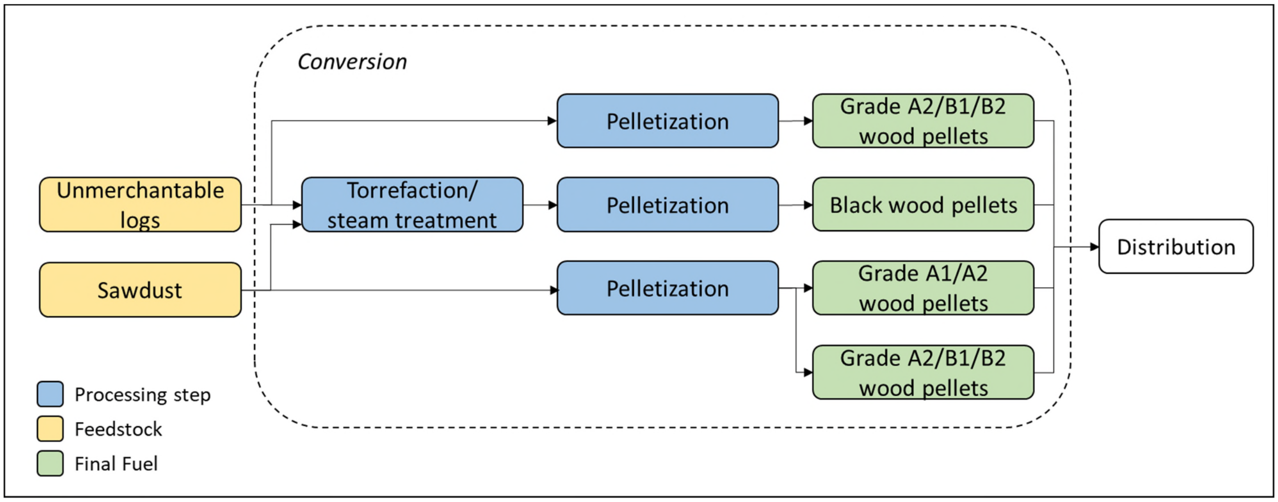

Figure 16: Main processing steps involved in the production of wood pellets.

The Fuel LCA Model covers three main conversion processes (pelletization, steam treatment and torrefaction) to produce wood pellets from unmerchantable logs or sawdust feedstocks. Wood pellets in the Fuel LCA Model are classified as follows:

- **Wood Pellets** – Grade A1/A2 and B1/B2 pellets made from any wood biomass source (i.e. harvested biomass, residues) produced through standard pelletization processes;
- **Thermally-treated Wood Pellets (black pellets)** – pellets made from wood biomass of any source (i.e. harvested biomass, residues) that are thermochemically treated by either stream treatment or torrefaction prior to pelletization.

The pelletization process which converts unmerchantable logs or sawdust into wood pellets was modelled based on the amount of electricity consumed at the pelletization plant. In the case of unmerchantable log feedstocks, the Fuel LCA Model includes an additional electricity use input to reflect the energy required related to the debarking and grinding of the logs prior to pelletization.

Thermal treatment of wood pellets using either steam-treatment or torrefaction processes is an emerging part of the wood pellets sector with no current commercial scale production in Canada. Torrefaction is a form of pyrolysis that results in partial thermal decomposition in the absence of oxygen. It is conducted between 200 and 300 degrees Celsius to remove volatiles from the wood prior to densification (Adams, et al., 2015). In developing default carbon intensity values for black pellets, energy use values (electricity/ natural gas) from the literature were used to characterize the production of both steam-treated and torrefied wood pellets.

The CI values are reported on the basis of one MJ of wood pellets produced with a moisture content equivalent to market level content. **Table 20** summarizes the moisture content of solid LCIFs included in the Fuel LCA Model, as well as the corresponding high heating value (HHV) based on data from Natural Resources Canada (Solid Biofuels Bulletin No. 2 Primer for Solid Biofuels).

Table 20: Moisture content of solid LFCs and corresponding high heating values (MJ/kg).

Solid LCIFs	Moisture content (%)	HHV (MJ/kg)
Wood chips (Grade A1)	10-25%	16-19
Wood chips (Grade A2)	25-35%	14-16
Wood chips (Grade B)	≥ 35%	≤ 14
Wood pellets (Grades A1, A2 and B)	≤ 10%	18-20
Wood pellets, steam-treated	≤ 10%	18-20
Wood pellets, torrefied	≤ 10%	18-20

The moisture content of solid LCIFs is an important parameter because it directly affects the HHV of solid LCIFs which is used as a conversion factor in the calculations of the LCI. Furthermore, the modelling of transportation and distribution of solid LCIFs to users also needs to take into account the moisture content. Indeed, the moisture content directly relates to the water mass of these solid LCIFs which needs to be considered in the calculation of transportation processes of fuels to users.

Geographical Scope for Solid LCIF Process from Wood Fibres

Conversion processes were modelled at the national level. The default pelletization and steam-treatment processes rely on LCI data on wood pellet production in Ontario. Since there are currently no torrefied wood pellet plants operating in Canada at a commercial scale, the modelling of the torrefaction process relies on European data from a 2015 LCA study on torrefied wood pellet production in Norway (Adams, et al., 2015). The electricity grid mix was adapted to be representative of the Canadian context. While there is only one building block for conversion the national level, wood fibres conversion processes can be modelled for a certain region by using the building blocks of feedstocks and other relevant inputs that have regional data available.

Allocation for Solid LCIF Processes from Wood Fibres

No allocation procedure was performed for solid LCIF produced from wood fibres.

Data Sources for Solid LCIF Processes from Wood Fibres

For the pre-defined pelletization and steam-treatment processes, LCI data on wood pellet production in Ontario was obtained from a 2016 publication (McKechnie et al., 2016). The data for black pellet production was based on a demonstration-scale plant in Norway, and was used to develop the default pathway for black pellets produced using steam-treated biomass. A summary of the main data sources used in wood fibre conversion into solid LCIFs is presented in **Table 21**.

Table 21: List of data sources used in modelling solid LCIF conversion from wood fibre feedstocks.

Data Type	**Source**
Pelletization and Steam-treatment of wood pellets	McKechnie, J., Saville, B., & MacLean, H. L. (2016). Steam-treated wood pellets: Environmental and financial implications relative to fossil fuels and conventional pellets for electricity generation. *Applied Energy 180*, 637-649.
Torrefied Wood Pellets	Adams, P. W., Shirley, J. E., & McManus, M. C. (2015). Comparative cradle-to-gate life cycle assessment of wood pellet production with torrefaction. Applied Energy 138, 367-380.

Conversion Process Overview for Solid LCIF from Crop Residues

The Fuel LCA Model includes the conversion of crop residues into solid LCIFs. 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.

The harvest residues collection process is explained in **Chapter 3.1.1**. The conversion process which occurs through the densification of crop residues results in the production of 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 use inputs for the pelletization process, as well as for the other steps. **Figure 17** outlines the conversion of corn stover residues in the Fuel LCA Model. The conversion process produces a functional unit of 1 MJ of residue pellets HHV.

The modelling of the densification process relies on Canadian data for the densification of wheat straw. As such, it is assumed that crop residue feedstocks, whether it be corn stover or wheat straw, would undergo the same densification process.

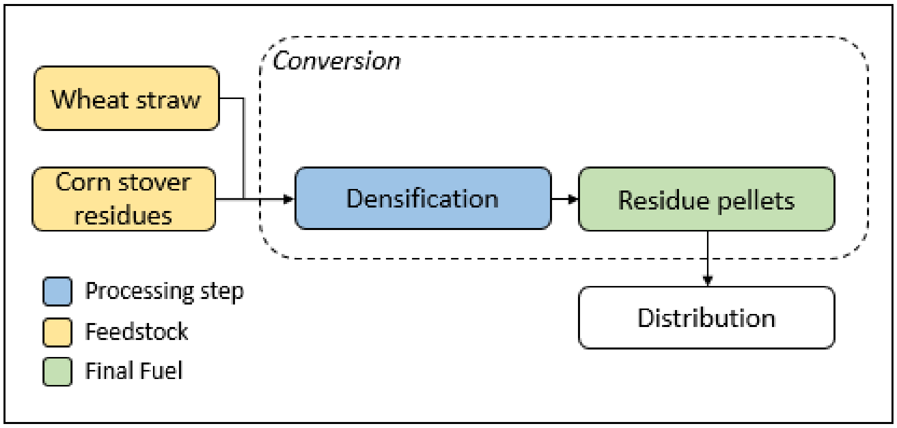

Figure 17: Main processing steps involved in the production of residue pellets.

Geographical Scope for Solid LCIF Processes from Crop Residues

The conversion process was modelled at the national level using data from a 2012 LCA study focusing on the densification of wheat straw pellets in the Canadian Prairies (Li X. et al., 2012). While there is only one building block for conversion the national level, the densification process can be modelled for a certain region by using the building blocks energy inputs representative of that region.

Allocation for Solid LCIF Processes from Crop Residues

No allocation procedure was performed for solid LCIF produced from crop residues.

Data Sources for Solid LCIF Processes from Crop Residues

The conversion process relied on data from a 2012 LCA study focusing on the densification of wheat straw pellets in the Canadian Prairies (Li X. et al., 2012). As mentioned, it is assumed that the densification process stays the same regardless of the type of crop residue feedstocks (corn stover or wheat straw). **Table 22** shows the main data sources used in the densification process.

Table 22: List of main data sources used in modelling solid LCIF conversion from crop residues.

Data Type	Source
Densification process	Li, X., Mupondwa, E., Panigrahi, S., Tabil, L., & Adapa, P. (2012). Life cycle assessment of densified wheat straw pellets in the Canadian Prairies. *International Journal of Life Cycle Assessment 17*, 420-431.

3.3.4 Pyrolysis Oil

Conversion Process Overview for Pyrolysis Oil

The Fuel LCA Model includes the production of bio oil from the pyrolysis of wood fibre feedstocks. This document will refer to this bio oil as pyrolysis oil. Fast pyrolysis is modelled over slow pyrolysis, because fast pyrolysis comparatively produces more pyrolysis oil.[10] Of the different types of fast pyrolysis

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[10] Danish Energy Agency. (2017). *Technology Data for Renewable Fuels.* Retrieved from www.ens.dk

conversion, the Fuel LCA Model includes two processes: mobile fast pyrolysis and stationary fast pyrolysis. Both processes use wood fibres as the feedstock (**Chapter 3.1.2**).

The boundary of the conversion process of both pyrolysis pathways begins with the arrival of the woodchips at the pryrolyzer and ends with the production of pyrolysis oil.

Both processes also produce two co-products along with the pyrolysis oil: solid biochar and non-condensable gases (NCG). In the mobile fast pyrolysis pathway, it is assumed that all of the NCG produced is reused for heating energy within the plant, while the biochar is sold to other end users. For stationary fast pyrolysis, it is assumed that all biochar and NCG are used by the pyrolysis system to dry incoming feedstock resulting in no additional fuel or biomass inputs needed for drying energy. **Figure 18** displays the visualization of pyrolysis oil conversion in the Fuel LCA Model. The conversion process produces a functional unit of 1 MJ of pyrolysis oil HHV.

Process emission factors in (S&T)^2 Consultants Inc.'s *The Addition of Pyrolysis Oil Pathways to GHGenius* were used in the stationary pyrolysis pathway. These same emission factors were used as a proxy in for the process emissions in the mobile fast pyrolysis pathway.

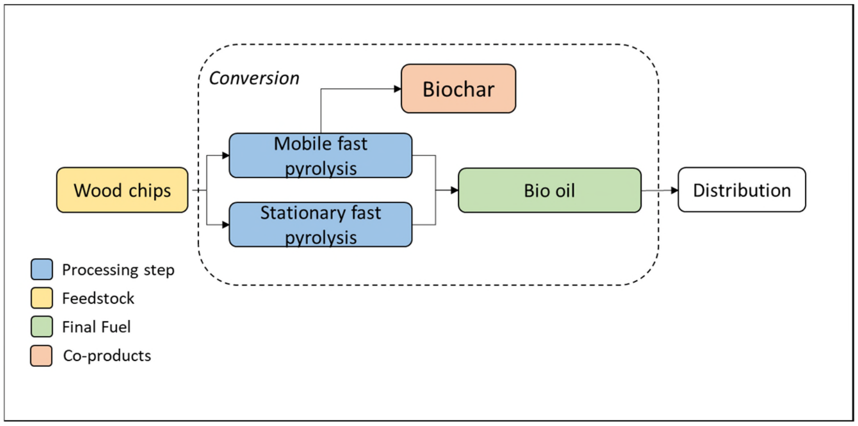

Figure 18: Main processing steps involved in the production of pyrolysis oil. Co-products include biochar and NCG. For mobile fast pyrolysis, NCG is recycled for heating use within the plant. For stationary fast pyrolysis, both NCG and biochar are recycled to dry incoming feedstock

Geographical Scope for Pyrolysis Oil Conversion

The pyrolysis oil conversion was modelled based on Canadian data from a Canadian study and the GHGenius model. The data was compiled to model single national averages for mobile fast pyrolysis and stationary fast pyrolysis. This assumes that the conversion process is the same across provinces. However, users of the model will be able to adapt the process model for a certain region by selecting province-specific building blocks for feedstocks and energy inputs.

Allocation for Pyrolysis Oil Conversion

The pre-defined allocation procedure is based on energy content. The allocation of burdens to the biochar and pyrolysis oil in the mobile fast pyrolysis step is performed according the energy content of the products. No allocation is performed in the stationary fast pyrolysis conversion step.

Data Sources for Pyrolysis Oil Conversion

The mobile fast pyrolysis process was based primarily on a recent publication by Ayer & Dias (2018), where operating data from a demonstration-scale mobile fast pyrolysis plant was used to model the life cycle impacts of the system in a Canadian context. Stationary fast pyrolysis information was based on GHGenius 4.03 ((S&T)^2 Consultants Inc., 2012). Ensyn provided mass balance and energy use data for their commercial scale system which produces bio oil, biochar, and NCG from wood feedstocks. **Table 23** lists the main data sources used in modelling pyrolysis oil conversion.

Table 23: List of main data sources used in modelling pyrolysis oil conversion from wood fibre feedstock.

Data Type	**Source**
Mobile fast pyrolysis process	Ayer, N. W., & Dias, G. M. (2018). Supplying renewable energy for Canadian cement production: Life cycle assessment of bioenergy from forest harvest residues using mobile fast pyrolsyis. *Journal of Cleaner Production 175*, 237-250.
Stationary fast pyrolysis process	(S&T)^2 Consultants Inc. (2011). The Addition of Pyrolysis Oil Pathways to GHGenius.

3.3.5 Renewable Natural Gas

Conversion Process Overview for RNG

The Fuel LCA Model includes the conversion of multiple bio feedstocks into renewable natural gas (RNG). The four feedstocks for RNG in the Fuel LCA Model are biogas from municipal landfills, wastewater treatment (WWT) sludge, municipal solid waste (MSW) organics, and livestock manure. Since the use of all four waste materials for low carbon fuel production results in significant and real methane reductions, the system boundary is 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 were not used for fuel production. Landfill gas is upgraded directly into RNG. The other three feedstocks are processed through anaerobic digestion to produce biogas, which is then upgraded to RNG. Digestate is produced through the digestion process of the anaerobic digestion. It is also assumed that the biogas produced is partially recycled in the plant. Anaerobic digestion for all three non-gaseous feedstocks were modelled the same way, using a process for digestion of WWT sludge. This assumption was required due to the low-resolution inventory data available from the CIRAIG study, which did not allow for the characterization of unique anaerobic digestion processes specific to the incoming feedstock type. **Figure 19** shows an overview of RNG production in the Fuel LCA Model. The conversion process produces a functional unit of 1 MJ of RNG HHV.

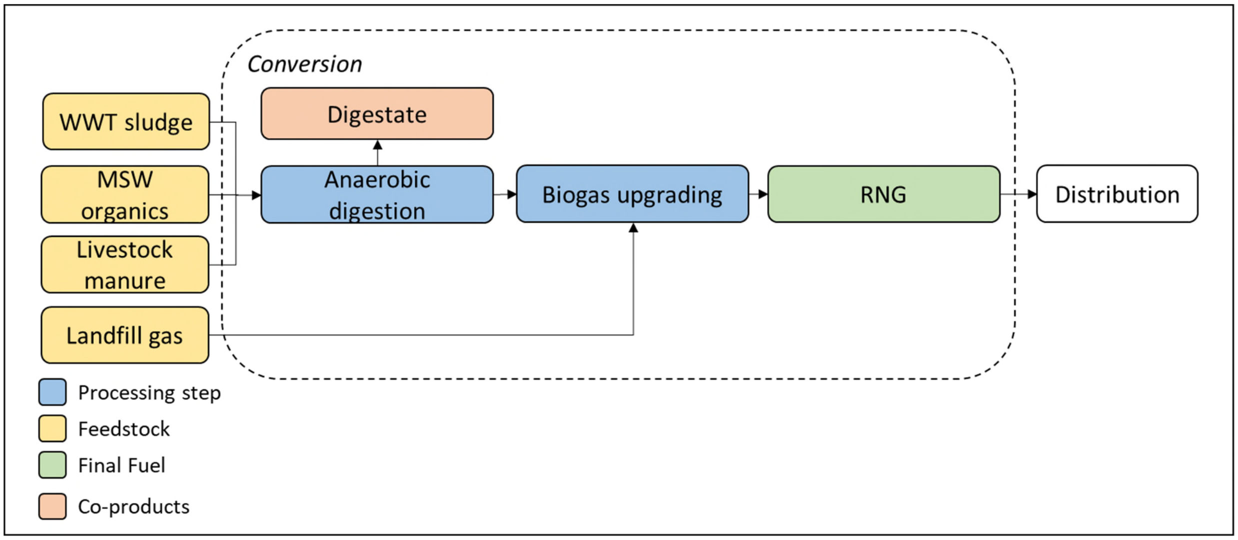

Figure 19: Main processing steps involved in the production of RNG from waste sources. Digestate is a co-product of the anaerobic digestion.

Geographical Scope for RNG Conversion

The renewable natural gas conversion processes were modelled based on Canadian production data that have been compiled by The International Reference Centre for the Life Cycle of Products (CIRAIG) as part of NRCan's study in 2019. The data was compiled to model a single national average approach for RNG conversion processes. This assumes that the conversion process is the same across provinces. However, users of the model will be able to adapt the process model for a certain region by selecting province-specific building blocks and energy inputs.

Allocation for RNG

The predefined allocation procedure is based on energy content. The allocation of burdens to the digestate from the anaerobic digestion step is performed according to the energy content of the products.

Data Sources for RNG

Data sources for biogas upgrading were based on a combination of primary data from a limited number of Canadian RNG producers and secondary data from the literature used to fill data gaps in the primary data set. This confidential data was compiled by CIRAIG (2019). The main data sources used in modelling RNG conversion are available in **Table 24**.

Table 24: List of main data sources used in modelling RNG from anaerobic digestion and landfill.

Data Type	Source
Canadian RNG producers	CIRAIG. (2019). *Technical Report: Data to Inform Life Cycle Assessment of Key Candian Renewable Natural Gas.* Prepared for Natural Resources Canada
Emission factors	British Columbia Ministry of Environment and Climate Change Strategy. (2017, December). *2017 B.C. Best Practices Methodology for Quantifying Greenhouse Gas Emissions: Including Guidance for Public Sector Organizations, Local Governments, and Community Emissions`.* Retrieved from Government of British Columbia:

	https://www2.gov.bc.ca/assets/gov/environment/climate-change/cng/methodology/2017-pso-methodology.pdf
Anaerobic digestion LCA	Lee, U., Han, J., Demirtas, M. U., Wang, M., & Tao, L. (2016, September). *Life cycle analysis of renewable natural gas and hydrocarbon fuels from wastewater treatment plants' sludge.* Retrieved from Argonne National Laboratories: https://greet.es.anl.gov/publication-sludge-2016

3.3.6 Hydrogen Derived Renewable Diesel (HDRD)

Conversion Process Overview of Hydrogen Derived Renewable Diesel (HDRD)

The Fuel LCA Model includes the conversion of canola oil and palm oil into hydrogenated derived renewable diesel (HDRD). HDRD production steps include pre-treatment of the feedstock oil to remove impurities, then the oil extraction to finally proceed to hydrotreatment with hydrogen and steam. The products are HDRD, propane, CO, and CO_2. The cultivation and modelling of canola oil is presented in **Chapter 3.1.1**. Since palm oil is not produced in Canada, literature was used to determine the emission of g CO_2/MJ of HDRD to calculate the carbon intensity for palm oil extraction (Usitalo, et al., 2014). **Figure 20** lists the main processing steps involved in the conversion of canola and palm oil into HDRD. The conversion process produces a functional unit of 1 MJ of HDRD HHV.

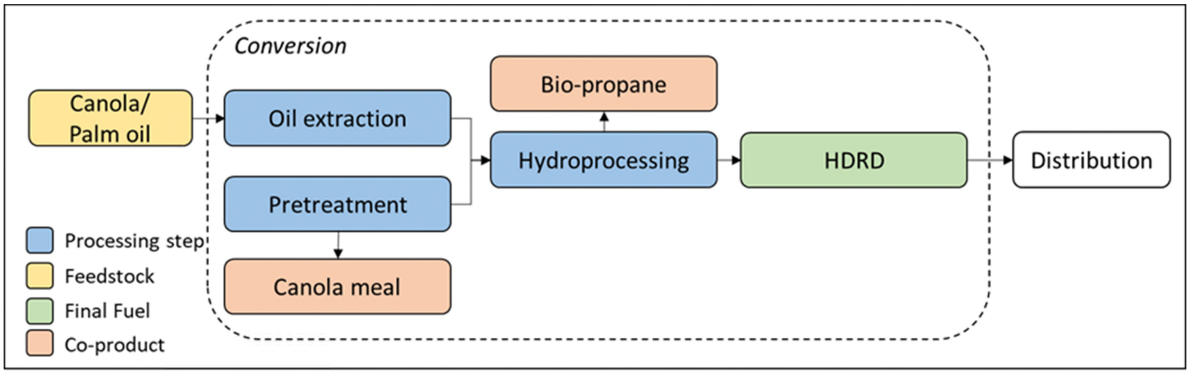

Figure 20: Main processing steps involved in the production of HDRD. Canola oil extraction results in canola meal as a side product. Propane is the main co-products of the hydrotreating step.

Geographical Scope for HDRD Conversion Processes

The HDRD conversion process was modelled based on U.S. and Canadian literature reviews. The data was compiled to model a single national average approach for HDRD conversion. This assumes that the conversion process is the same across provinces. However, users of the model will be able to adapt the process model for a certain region by selecting province-specific building blocks for feedstocks and energy inputs.

Allocation for HDRD Conversion

The predefined allocation procedure is based on energy content. The allocation of burdens to the meal protein in the oil extraction step is performed according to the energy content of the products. The bio-propane produced can be used as a fuel to displace conventional propane, therefore a displacement method has been used to account for this co-product.

Data sources for HDRD Conversion Processes

Data for the conversion of canola and palm oil to HRDR was obtained from a variety of literature sources. Since palm oil is not produced in Canada, the study performed by Usitalo et. al (2014) was primarily used in its modelling for HDRD conversion. A list of the main data sources used in the modelling of HDRD conversion is presented in **Table 25**.

Table 25: List of data sources used in modelling HDRD conversion from canola oil and palm oil.

Data Type	Source
Feedstocks/ Chemicals	$(S\&T)^2$ Consultants Inc. (2010). *Life cycle analysis of canola biodiesel.* Winnipeg, MC: Canola Council of Canada. Natural Resources Canada. (2012). *Study of Hydrogenation Derived Renewable Diesel as a Renewable Fuel Option in North America.* Ottawa, Ontario: Natural Resources Canada. Usitalo, V., Vaisanen, S., Havukainen, S., Hauvukainen, M., Soukka, R., & Louranen, M. (2014). Carbon footprint of renewable diesel from palm oil, jatropha oil, and rapeseed oil. *Renewable Energy, 69*, 103-113.
Energy Consumption	Antares Group, Inc. (2010). *Renewable fuels roadmap and sustainable biomass feedstock supply for New York, Appendix H: Technologies for biofuels production.* New York, NY: New York State Departments of Agriculture and Markets and Environmental Conservation. Miller, P., & Kumar, A. (2013). Development of emission parameters and net energy ratio for renewable diesel from Canola and Camelina. *Energy, 58*, 426-437.
Emissions	Argonne National Lab. (2018). GREET.
Life cycle CI values	Johnson, E. (2017). A carbon footprint of HVO biopropane. *Biofuels, Bioproducts & Biorefining, 11*, 887-896.

3.3.7 Biojet Fuel

Conversion Process Overview for Biojet Fuel

The Fuel LCA Model includes the production of hydroprocessed renewable biojet aviation fuel from biomass-derived feedstock. Two feedstocks were modelled for the conversion process: used cooking oil (UCO) and canola oil. Both feedstocks are converted into biojet fuel using a hydroprocessed esters and fatty acids (HEFA) process. In this process, the feedstock oils are subject to a high temperature catalytic hydrodeoxygenation process. The biojet fuel produced is synthetic paraffinic kerosene (SPK), while co-products include renewable diesel, naphtha, and light hydrocarbons (i.e. propane). **Figure 21** and **Figure 22** display the main processing steps in biojet fuel production. The use of each feedstock will result in different yields and energy requirements. The conversion processes for these pathways produces a functional unit of 1 MJ of biojet fuel HHV.

The boundary of the biojet fuel from canola pathway begins with the production of canola oil and ends with the production of biojet fuel. Canola oil is extracted from canola seeds where the same oil extraction process is used as in the biodiesel from canola pathway (**Chapter 3.3.2**). Naphtha and propane are produced as co-products from the hydroprocessing of canola oil.

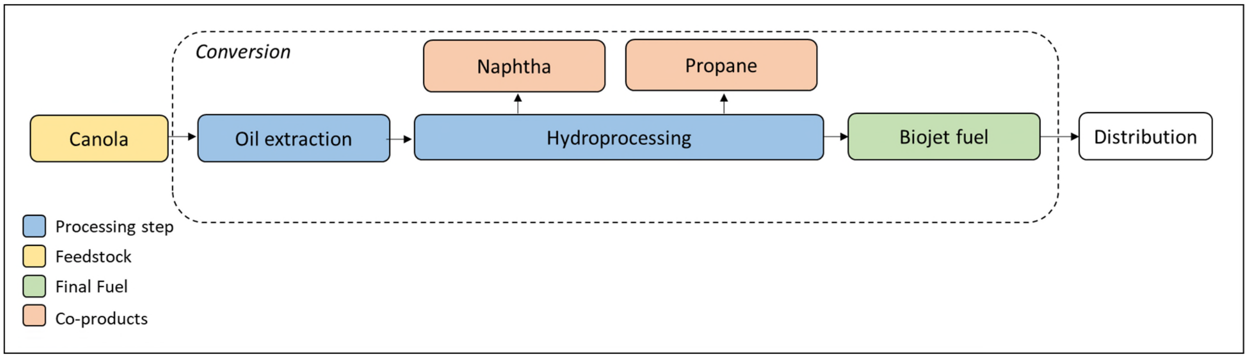

Figure 21: Main processing steps involved in the production hydroprocessed biojet fuel from canola. Naphtha and propane are co-products of the hydroprocessing step.

The boundary of the biojet fuel from UCO pathway begins with the arrival of UCO at the biojet fuel production facility and ends with the production of biojet fuel. UCO is first pretreated to remove solid particles and moisture. Next, the pretreated oil is hydroprocessed to produce biojet fuel. Renewable diesel, naphtha and propane are produced as co-products. The pretreatment and hydroprocessing unit processes are based on Aspen Plus modelling from Chu, P. L. (2014).

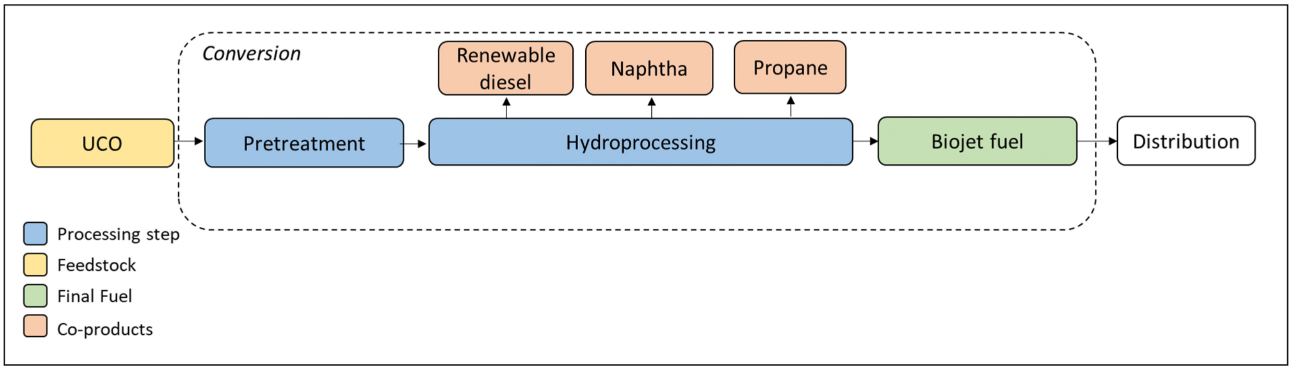

Figure 22: Main processing steps involved in the production hydroprocessed biojet fuel from UCO. Propane, naphtha, and renewable diesel are co-products of the hydroprocessing step.

Geographical Scope for Biojet Fuel Conversion Processes

The biojet fuel conversion processes were modelled based on a U. S. and Canadian study. The data was compiled to model single national averages for biojet fuel from canola and biojet fuel from UCO. This assumes that the conversion process is the same across provinces. However, users of the model will be able to adapt the process model for a certain region by selecting province-specific building blocks for feedstocks and energy inputs.

Allocation for Biojet Fuel Processes

The pre-defined allocation procedure is based on energy content. The allocation of burdens to the renewable diesel, naphtha, and propane in the hydroprocessing step is performed according the energy content of the products. Allocation is performed between naphtha and propane in the biojet fuel from canola pathway and is performed between renewable diesel, naphtha and propane in the biojet fuel from UCO pathway.

Data Sources for Biojet Fuel Conversion Processes

Data for the conversion of UCO to biojet fuel was obtained from Chu, P. L. (2014). UCO biojet fuel process inputs and yields from Chu, P. L. (2014) were determined through process modelling in Aspen Plus. Data for the conversion of Canola to biojet fuel was obtained from Han, J., Elgowainy, A., Cai, H., & Wang, M. Q. (2013). Data for soybean oil conversion to biojet fuel were used as a proxy for canola oil to biojet fuel. **Table 26** lists the main data sources used in modelling the biojet fuel conversion processes.

Table 26: List of data sources used in modelling biojet fuel conversion from UCO and canola.

Data Type	Source
UCO pretreatment and hydroprocessing steps	Chu, P. L. (2014). Environmental and Financial Performance of Aviation Biofuels. Retrieved from University of Toronto: https://tspace.library.utoronto.ca/handle/1807/82631
Canola hydroprocessing steps	Han, J., Elgowainy, A., Cai, H., & Wang, M. Q. (2013a). Life cycle analysis of bio-based aviation fuels. Bioresource Technology 150, 447-456.

3.3.8 Hydrogen

The Fuel LCA Model includes the production of hydrogen from three different chemical processes, each requiring different feedstocks. The pathways included are shown in **Table 27**. The following sections break down the conversion process overview by conversion type. Each of the three hydrogen production pathways in the Fuel LCA Model are based on systems modelled by the National Renewable Energy Laboratory (NREL) program in the United States using background reports and Aspen modelling software. All of the inventory data can be found in the 2013 NREL report.[11] The Fuel LCA Model also includes building blocks for hydrogen liquefaction which is part of the fuel distribution stage. The hydrogen liquefaction process was also modelled based on the 2013 NREL report.

*Table 27: List of feedstocks and conversion processes included in the Fuel LCA Model for the production of Hydrogen. *RNG includes natural gas produced from biogenic sources such as landfill gas.*

Feedstock	Conversion Process
Fossil natural gas	Steam methane reforming (SMR)
Renewable natural gas (RNG)*	Steam methane reforming (SMR)
Water	Electrolysis
Syngas (wood biomass, other)	Gasification & reforming of syngas

Conversion Process Overview for Hydrogen from SMR

The Fuel LCA Model includes the production of hydrogen from natural gas through steam methane reforming (SMR). In this process, methane from fossil natural gas or RNG reacts with steam in the presence of a catalyst to produce hydrogen, carbon monoxide, and carbon dioxide. The carbon monoxide and steam are reacted using a catalyst to produce carbon dioxide and more hydrogen,

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[11] Ramsden, T., Ruth, M., Diakov, V., Laffen, M., & Timbario, T. A. (2013). *Hydrogen Pathways: Updated Cost, Well-to-Wheels Energy Use, and Emissions for the Current Technology Status of Ten Hydrogen Production, Delivery, and Distribution Scenarios.* Retrieved from https://www.nrel.gov/docs/fy14osti/60528.pdf

followed by pressure-swing adsorption during which carbon dioxide and other impurities are removed to produce pure hydrogen.

The process begins with the production and transmission of RNG or natural gas to the conversion plant via gas pipeline. The process ends with the production of 1 MJ of hydrogen at the conversion plant gate and includes process emissions (CO_2, CH_4 and N_2O) as well. The Fuel LCA Model assumes that both conversion processes require the same quantities of natural gas and energy inputs. However, the CO_2 emissions generated during the conversion process are null in the case where RNG is used as a feedstock since these emissions are biogenic. Hydrogen leaks during production are assumed to be negligible and are therefore excluded from the model.

Figure 23 displays the main processing steps involved in the conversion of natural gas into hydrogen. Extraction of natural gas and production of RNG are found in **Chapter 4:** and **Chapter 3.3.5**, respectively. The conversion process produces a functional unit of 1 MJ of hydrogen fuel HHV.

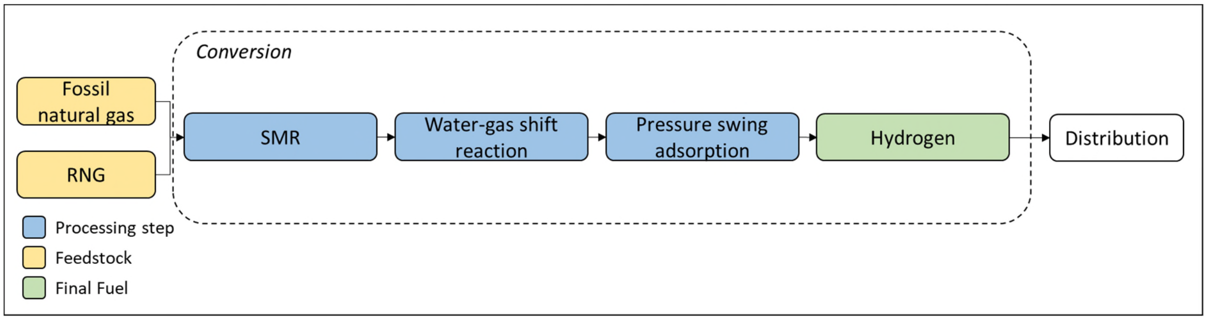

Figure 23: Main processing steps involved in the production of hydrogen from SMR.

Geographical Scope for Hydrogen Conversion from SMR

The SMR conversion process was modelled based on U.S. data from the National Renewable Energy Technology (NREL). The NREL data was compiled to model a single national average approach for hydrogen conversion from SMR. This assumes that the conversion process is the same across provinces. However, users of the model will be able to adapt the process model for a certain region by selecting province-specific building blocks for feedstocks and energy inputs. Users will also be able to select the appropriate RNG flow based on the type of RNG-producing technology (ex: RNG from landfill gas, RNG from anaerobic digestion of livestock manures, etc.).

Allocation for Hydrogen Conversion from SMR

No allocation procedure was performed for hydrogen produced from SMR.

Data Sources for Hydrogen Conversion from SMR

The conversion of both fossil natural gas and renewable natural gas to hydrogen using SMR were modelled using data compiled by the NREL in the U.S. for a centralized SMR facility using natural gas delivered by pipeline. Because there are few large-scale operating facilities which produce hydrogen, the NREL data is based on projected production scenarios for existing technologies at different scales. **Table 28** lists the main data sources used in modelling the conversion of hydrogen from natural gas.

Table 28: List of main data sources used in modelling hydrogen conversion from natural gas.

Data Type	Source
Natural gas conversion	Ramsden, T., Ruth, M., Diakov, V., Laffen, M., & Timbario, T. A. (2013). *Hydrogen Pathways: Updated Cost, Well-to-Wheels Energy Use, and Emissions for the Current Technology Status of Ten Hydrogen Production, Delivery, and Distribution Scenarios.* Retrieved from https://www.nrel.gov/docs/fy14osti/60528.pdf

Conversion Process Overview for Hydrogen from Electrolysis

The production of hydrogen from water occurs through a process called hydrolysis. In the Fuel LCA Model, hydrolysis was modelled using a centralized electrolysis plant, which uses an alkaline process powered by grid electricity with potassium hydroxide (KOH) as the electrolyte. Process water is demineralized and softened before being passed into an electrolyzer. The electrolyzer produces hydrogen and oxygen which are collected and fed into a gas/lye (KOH) separator system. Saturated hydrogen gas from the hydrogen/lye separator is fed to a gas scrubber subsystem which purifies the hydrogen.

The model only considered the electricity input for the electrolysis process to produce 1 MJ of hydrogen at the conversion plant gate. Process emissions (CO_2, CH_4 and N_2O) are not included. Other material inputs for the electrolysis process (e.g. electrolyte, water transport to electrolysis plant, etc.) were excluded since they were assumed to have a negligible contribution to the carbon intensity of the hydrogen production process. Hydrogen leaks during production are assumed to be negligible and are therefore excluded from the model.

Figure 24 displays the main processing steps in the conversion of water into hydrogen. The conversion process produces a functional unit of 1 MJ of hydrogen HHV.

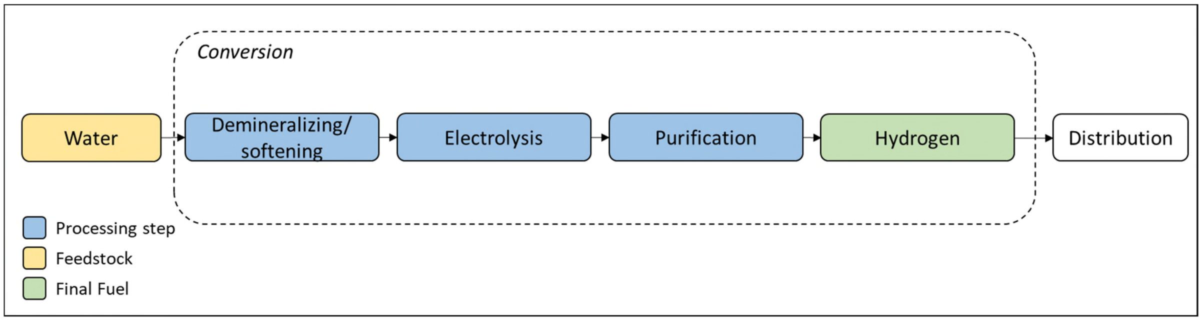

Figure 24: Main processing steps involved in the production of hydrogen from electrolysis.

Geographical Scope for Hydrogen Conversion from Electrolysis

The electricity input to the electrolysis process was based on U.S. data from the National Renewable Energy Technology (NREL). The NREL data was compiled to model a single national average approach for hydrogen conversion from electrolysis. This assumes that the conversion process is the same across provinces. However, users of the model will be able to adapt the pathway for a given region by choosing the appropriate provincial electricity grid mix.

Allocation for Hydrogen Conversion from Electrolysis

No allocation procedure was performed for hydrogen produced from electrolysis.

Data Sources for Hydrogen Conversion from Electrolysis

The conversion of water to hydrogen using hydrolysis was modelled using data compiled by the NREL in the United States for a centralized electrolysis facility powered by grid electricity. Because there are few large-scale operating facilities which produce hydrogen, the NREL data is based on projected production scenarios for existing technologies at different scales. **Table 29** lists the main data sources used in modelling the conversion of hydrogen from natural gas.

Table 29: List of main data sources used in modelling hydrogen conversion from natural gas.

Data Type	Source
Natural gas conversion	Ramsden, T., Ruth, M., Diakov, V., Laffen, M., & Timbario, T. A. (2013). *Hydrogen Pathways: Updated Cost, Well-to-Wheels Energy Use, and Emissions for the Current Technology Status of Ten Hydrogen Production, Delivery, and Distribution Scenarios.* Retrieved from https://www.nrel.gov/docs/fy14osti/60528.pdf

Conversion Process Overview for Hydrogen from Gasification/Reforming of Syngas

The Fuel LCA Model also includes the production of hydrogen from wood fibre biomass. In this process, the wood fibres are first dried and then sent to a gasification unit. The newly formed gas is then sent to similar reforming and water-gas shift reactions as in SMR processes. Finally, hydrogen is isolated using pressure swing adsorption.

The process includes the energy and woody feedstock of the gasification process, as well as the non-biogenic process emissions (CH_4 and N_2O) and ends with the production of 1 MJ HHV of hydrogen at the conversion plant. The model is based on the assumption that input and output values of the gasification process are identical for all three types of feedstocks (i.e. harvest residues from forestry, sawdust and wood chips). Furthermore, the model is based on the assumption that all of the char produced during the conversion process is burned for heating purposes. As such, no allocation procedure is applied since hydrogen is the only product of the conversion process. Hydrogen leaks during production are assumed to be negligible and are therefore excluded from the model.

Figure 25 displays the main processing steps in the conversion of wood fibres into hydrogen. The extraction and modelling of wood fibre feedstocks is available in **Chapter 3.1.2**. The conversion process produces a functional unit of 1 MJ of hydrogen fuel HHV.

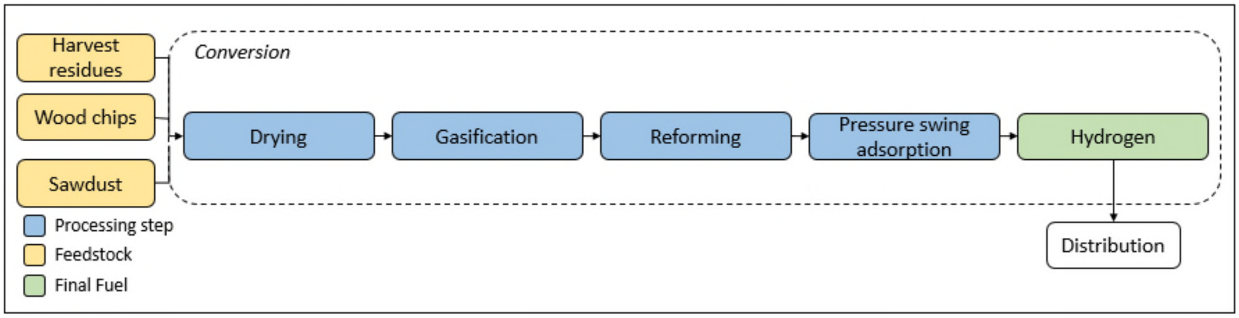

Figure 25: Main processing steps involved in the production of hydrogen from gasification/reforming of syngas.

Geographical Scope for Hydrogen Conversion from Gasification/Reforming of Syngas

The conversion process was modelled based on U.S. data from the National Renewable Energy Technology (NREL). The NREL data was compiled to model a single national average approach for hydrogen conversion from gasification of biomass feedstock. This assumes that the conversion process is the same across provinces. However, users of the model will be able to adapt the process model for a certain region by selecting province-specific building blocks for feedstocks and energy inputs.

Allocation for Hydrogen Conversion from Gasification/Reforming of Syngas

No allocation procedure was performed for hydrogen produced from gasification/reforming of syngas.

Data Sources for Hydrogen Conversion from Gasification/Reforming of Syngas

The conversion of wood fibres to hydrogen using gasification/reforming of syngas was modelled using data compiled by the NREL in the United States for a centralized facility for woody biomass gasification and reforming. **Table 30** lists the main data sources used in modelling the conversion of hydrogen from natural gas.

Table 30: List of main data sources used in modelling hydrogen conversion from natural gas.

Data Type	Source
Natural gas conversion	Ramsden, T., Ruth, M., Diakov, V., Laffen, M., & Timbario, T. A. (2013). *Hydrogen Pathways: Updated Cost, Well-to-Wheels Energy Use, and Emissions for the Current Technology Status of Ten Hydrogen Production, Delivery, and Distribution Scenarios.* Retrieved from https://www.nrel.gov/docs/fy14osti/60528.pdf

3.4 Fuel Distribution

Fuel distribution is the life cycle stage that bridges fuel conversion and end-use by the consumer. In the Fuel LCA Model, this includes the transportation of LCIFs from production facility to distribution facilities and then to consumer. Like the transportation life cycle stage, parameters related to distribution, such as fuel efficiency and fuel used during transportation, are part of the background processes in the Fuel LCA Model. More information surrounding the background processes is presented in **Chapter 4.2**.

3.4.1 System Boundaries for Distribution

The system boundaries for distribution include the transport of biofuels from production facility to distribution facilities and then to consumer. Like transportation, distribution excludes the following:

- Transportation occurring outside of Canada;
- On-site transportation (within facility boundaries); and
- Transportation of all materials other than feedstocks and biofuels (i.e. transportation of consumables, wastes and co-products are excluded)

3.4.2 Modelling Approach for Distribution

The distance each LCIF must travel to reach end-users depends on the location of production facilities, the properties and applications of the biofuel and the distribution of end-users. As the number of production facilities and technologies are expected to increase, assumptions are required to model the average default distance that biofuels travel.

The distance each LCIF must travel to reach end users was modelled based on conventional fossil fuel refining capacity in Canada. This approach is reasonable given the similarity of fossil and low-carbon transportation fuel markets and the blending of fossil and low-carbon fuels which occurs post-refining. The following steps were taken to estimate the average distance between production facilities, distribution centres and population centres across Canada:

1. Approximation of the location of biofuels production facilities based on the location of existing refinery capacity across Canada;
2. Calculation of the distance between production facilities and local population centres;
3. Calculation of the average distance to rural populations within the host province;
4. Calculation of the population weighted average to end-user;
5. Estimation of the average distance to market by calculating the production weighted average of production facilities in Canada.

While bioethanol and biodiesel production primarily serve local markets by truck, rail was incorporated into the model to provide an option for longer distance transport to local distribution facilities. The default distance for rail was modelled based on the weighted average distance between production centres in Saskatchewan and Ontario and population centers for each province and territory.

The average distance calculation for biomass was modelled based on existing production facilities in Canada. Unlike transportation biofuels, the market for biomass tends to be adjacent or nearby production facilities and is often associated with the forestry sector itself.

The production of renewable natural gas from municipal waste and wastewater treatment plant sludges occurs near population centres. As a result, it was assumed that the delivery of gas through existing pipeline distribution systems was local.

The transport of hydrogen requires compression, storage and dispensing facilities. Storage was assumed to be done using geologic formations that were adjacent to the production facility. A compressor is used to extract the hydrogen and reach pipeline pressure. Truck transportation can involve a tanker truck carrying compressed, gaseous hydrogen or liquefied hydrogen in cryogenic tanks.

3.4.3 Default Distances for Distribution

Based on the modelling approach explained in the previous section, default distances and modes of transportation for distribution were determined. **Table 31** lists the average default values based on the type of LCIF produced.

Table 31. Canadian average and default transportation distances for biofuels.

LCIF Type	Average distance	Primary mode	Modelling assumptions
Hydrogen	290 km	Truck	Based on the weighted average distances to deliver refined fuel products to markets
RNG	50 km	Pipeline	Based on the coincidence or proximity of population density and feedstocks (e.g. municipal solid waste)
Biomass (un-processed, pellet)	100 km	Truck	Based on the proximity of forestry production facilities to forestry sources (e.g. sawmills, etc.)
Liquid biofuel (from local distribution facilities to the user)	290 km	Truck	Based on the weighted average distances to deliver refined fuel products to markets
Liquid biofuel (from production plant to local distribution facilities)	600 km	Rail	Based on the weighted average distance between production centres in Saskatchewan and Ontario and population centers for each province and territory.

As with transportation, users of the Fuel LCA Model can define their actual modes of distribution and distances in place of the pre-defined pathways.

3.5 Fuel Combustion

Combustion represents the final life cycle stage in the Fuel LCA Model. In this stage, each LCIF has arrived at the end-user and is combusted. The following section describes the approach used in the Fuel LCA Model to model the combustion process.

3.5.1 Modelling Approach for Combustion

Biogenic Carbon

In remaining consistent with the Government of Canada's policy on biogenic carbon, as shown in Canada's National Inventory Report (2018), emissions of biogenic carbon from combustion are not included in the carbon intensity calculations in the Fuel LCA Model, as they are assumed to be sequestered at the next growing season.

Modelling Approach for Combustion by Fuel Type

Table 32 lists the main modelling approach taken for the combustion of each LCIF in the Fuel LCA Model, and includes main data sources. As hydrogen combustion does not release GHGs, there is no required combustion modelling based on the scope of the Fuel LCA Model. In most cases, methane and nitrous oxide are possible from the combustion. In these cases, the emission factors were obtained from the NIR (**Table 32**).

Table 32: Modelling approach and main data sources for the combustion of LCIFs included in the Fuel LCA Model.

Fuel	Modelling Approach	Data Sources
Bioethanol	Used overwhelmingly in the transportation sector, either neat (unblended) or blended with their fossil analogues; Modelled stoichiometrically and harmonized with the Canadian NIR report.	Government of Canada. (2018). *National Inventory Report 1990-2016: Greenhouse Gas Sources and Sinks in Canada*. Retrieved from https://unfccc.int/document/65715
Biodiesel	Used overwhelmingly in the transportation sector, either neat (unblended) or blended with their fossil analogues; Modelled stoichiometrically and harmonized with the Canadian NIR report.	Government of Canada. (2018). *National Inventory Report 1990-2016: Greenhouse Gas Sources and Sinks in Canada*. Retrieved from https://unfccc.int/document/65715
Solid LCIF	Modelled for two general applications, including industrial combustion of wood chips and corn stover pellets in furnaces, as well as the combustion of wood pellets in residential pellet stoves.	Government of Canada. (2018). *National Inventory Report 1990-2016: Greenhouse Gas Sources and Sinks in Canada*. Retrieved from https://unfccc.int/document/65715
Pyrolysis Oil	Modelled for combustion in an industrial furnace. Emissions factors for this combustion were derived from literature sources.	**Emission factors**: Ayer, N. W., & Dias, G. M. (2018). Supplying renewable energy for Canadian cement production: Life cycle assessment of bioenergy from forest harvest residues using mobile fast pyrolysis. *Journal of Cleaner Production* 175, 237-250.
RNG	Estimates of methane and nitrous oxide emissions associated with combustion of RNG were obtained from a summary of emissions factors for the British Columbia renewable fuels regulation.	British Columbia Ministry of Environment and Climate Change Strategy. (2017, December). *2017 B.C. Best Practices Methodology for Quantifying Greenhouse Gas Emissions: Including Guidance for Public Sector Organizations, Local Governments, and Community Emissions*. Retrieved from Government of British Columbia: https://www2.gov.bc.ca/assets/gov/environment/climate-change/cng/methodology/2017-pso-methodology.pdf
Biojet fuel	Modelled using Canadian NIR report.	Government of Canada. (2018). *National Inventory Report 1990-2016: Greenhouse Gas Sources and Sinks in Canada*. Retrieved from https://unfccc.int/document/65715

Chapter 4: Low Carbon Fuels: Background Unit Processes

Background unit processes are supporting units for the foreground unit processes in the Fuel LCA Model. As they are supporting processes, they have their own set of data sources and standards. There are four main categories of background unit processes in the Fuel LCA Model: fossil fuels, transportation and storage, electricity, and chemicals and other inputs. The following section describes the approach taken for each category of background unit process in the Fuel LCA Model.

4.1 Fossil Fuels

4.1.1 Overview of Fossil Fuels Modelling

As the production of most LCIFs relies on the input of fossil fuels in some capacity, multiple fossil fuel pathways are included in the Fuel LCA Model. The default CI values of these fossil fuel pathways are included into the proposed Regulations and are available in Part II. As such, the fossil fuel pathways were developed with the same data requirements and stringency levels as the foreground unit processes. Fossil fuel pathways are also included in the Fuel LCA Model as background unit processes.

The fossil fuel pathways are presented in **Chapters 4.1**, **4.2,** and **4.3**. An ISO critical review of the fossil fuel pathways was completed in summer 2020, which resulted in a positive verdict. Further information on the ISO critical review indicated above can be obtained upon request.

4.1.2 Scope of Fossil Fuels Modelling

The modelling of the fossil fuel pathways consisted of the same life cycle stages as those used for LCIF modelling: feedstock extraction, feedstock transportation (transmission), fuel conversion (processing, refining), fuel distribution (transmission, distribution), and fuel combustion (see **Figure 3**). While the life cycle stages are the same, the goal of the fossil fuels modelling is to create a national baseline, which will be used in the proposed Regulations and act as background data for the LCIF pathways. The main processing steps, system boundaries, and final products included in each life cycle stage for gaseous, liquid, and solid fossil fuels in the Fuel LCA Model are presented in **Figure 26**.

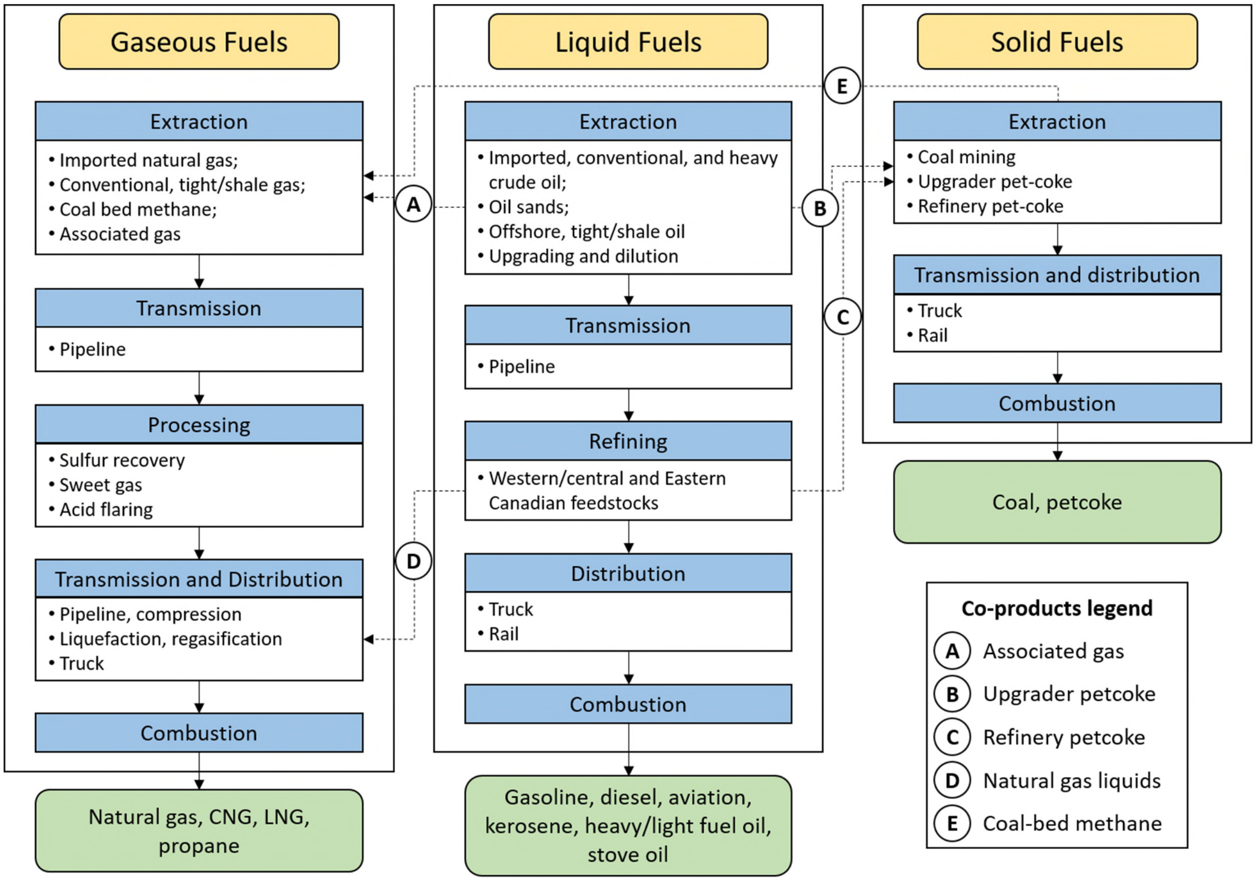

Figure 26. Life cycle stages for gaseous, liquid, and solid fossil fuels included in the Fuel LCA Model. Transmission represents the transportation life cycle stage, and processing and refining represent the conversion life cycle stage. Dashed lines represent co-products transferred between gaseous, liquid and solid pathways. Note that special process routes and other co-products are not represented above.

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

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

The carbon intensity values are expressed in grams of CO_2 equivalents (CO_2e) on the basis of one MJ of energy content based on the HHV of each fuel. The CIs for all fuels were calculated from well-to-tank (or to consumer) and from well-to-wheel (or 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 coproducts of multifunctional processes (for which there is more than one product). Allocation procedures based on mass content were used in some cases where energy data was not available.

4.1.3 Modelling Approach for 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. The following section summarizes the modelling approach taken for liquid, gaseous, 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 SAGD), offshore extraction, and imports from countries outside of Canada. Each of these feedstock sources was taken into account in determining the CI for fossil fuels in the Fuel LCA Model. While crude oil extraction occurs in many provinces within Canada, 95% of domestic production primarily takes place in Alberta and Saskatchewan. The Fuel LCA Model also considered crude oil imports from the United States and other international sources, which represent of 33% of domestic consumption.

Extracted crudes are transported via pipeline to refineries distributed in Central 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 (e.g., Eastern and Western Canada, and imports) and the refinery types. In this sense, each refinery product (e.g. aviation fuel, diesel, gasoline, kerosene, etc.) was modelled for Eastern and Western/Central Canada; Canadian pathways were derived based on the production-weighted average of both these pathways.

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), 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 (AER), the National Energy Board (NEB) and Statistics Canada. The carbon intensities of crude oil imports from other countries were based on data from the NEB and the Oil Climate Index.[12] 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 NGLs (associated gas) and upgrader petcoke, by using an energy-based allocation procedure and are not considered in the fossil fuel CI values.

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[12] OCI, 2018. Oil Climate Index, https://oci.carnegieendowment.org/. Accessed: December 1, 2018.

Refining of Liquid Fuels

Thirteen of the 16 Canadian refineries were modelled in detail based on 2016 data from Woods Mackenzie as well as the *Petroleum Refinery Life Cycle Inventory Model* (PRELIM). 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 (e.g. blended gasoline, jet fuel, ultra-low sulfur diesel, fuel oil, coke, liquid heavy ends, liquefied petroleum gas, etc.). 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.

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. Additional information is available in **Appendix B**: Previous Contract Work for the Fuel LCA Model.

Gaseous fuels

The CIs for gaseous fuels were calculated based on a production-weighted average of natural gas from Alberta (50.7%), British Columbia (21.7%), and imported natural gas from the United States (28%). The calculation of the default CI values for gaseous fuels was based on the approach used in the National Energy Technology Laboratory (NETL) 2016 study on US natural gas production.[13] Chemical compositions of natural gas for both Alberta and British Columbia were taken into account based on data complied by Greenpath Energy (2019)[14] to model the type and extent of processing and purification required to convert raw gas to pipeline specifications. Natural gas compositions were also used to calculate venting, flaring and fugitive emissions during the extraction and processing stages.

The carbon intensity of imported natural gas from the United States was based on the national average carbon intensity for natural gas from the NETL 2016 report.[13]

Extraction of Gaseous Fuels

Natural gas extraction processes were defined for each type of gas resource being developed. The LCI for the extraction stage includes venting, flared and fugitive emissions associated with the various operations (i.e. well completions and workovers, liquids unloading) and different equipment (e.g. water tanks, surface casing vent flow, pneumatic devices). As mentioned earlier, the drilling of wells and the manufacturing and installation of infrastructures were excluded from the system boundary given their negligible contribution to overall impacts.

Processing of Gaseous Fuels

The process to produce transmission-ready natural gas varies depending on the form of natural gas that is extracted and its composition. The LCI for gas processing includes electricity use, combustion emissions at processing facilities, as well as venting, flaring and fugitive emissions. Both the inventory

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[13] Skone, T. J., and Coauthors, 2016: Life Cycle Analysis of Natural Gas Extraction and Power Generation. http://www.osti.gov/servlets/purl/1480993/

[14] Greenpath Energy. 2019. Canadian Natural Gas Data – Collection for the Fuel LCA Modelling Tool. February 2019.

for Alberta and British Columbia relied on 2011 Alberta data from a detailed GHG emissions inventory of upstream oil and gas operations.[15] An allocation procedure based on energy content was used to allocate GHG emissions to co-products like NGLs (e.g. propane, butane, etc.) which are also produced at gas processing plants.

Production of compressed natural gas (CNG) and liquefied natural gas (LNG) were modelled based on the assumption that up until the point of compression or liquefaction, the life cycles of CNG and LNG are the same as pipeline specification natural gas.

Transmission and Distribution of Gaseous Fuels

The compression step associated with CNG production was modelled using data from GREET and the California Air Resources Board (CARB). The GHG emissions related to the liquefaction process were modelled using a Canadian study on LNG.[16]

The modelling of gas pipeline transport is further described in **Chapter 4.2.3**.

Solid fuels

The CI 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 carbon intensity of 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.[17] The scope of the analysis for coal was limited to thermal coal, including bituminous, sub-bituminous, and lignite coal. The CI value for imported coal from the U.S. was obtained from the GREET tool by Argonne National Laboratories.

Combustion emission factors

Emission factors related to combustion were based on Canada's NIR of GHG emissions. 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. Although useful energy generated from fuel combustion varies depending on the efficiency of the combustion device, the modelling of carbon intensity values for specific combustion types and devices (e.g. heating, transportation, and electricity) was beyond the scope of this project. As such, a single combustion emission factor per fuel based on HHV was applied to calculate the carbon intensity.

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[15] Clearstone Engineering Ltd., 2014: Volume 1: Overview of the GHG Emissions Inventory

[16] Sapkota, K., A. O. Oni, and A. Kumar, 2018: Techno-economic and life cycle assessments of the natural gas supply chain from production sites in Canada to north and southwest Europe. Journal of Natural Gas Science and Engineering, 52, 401–409, doi:10.1016/j.jngse.2018.01.048.

[17] Cheminfo Services Inc. & Clearstone Engineering Ltd. 2014. Compilation of a National Inventory of Greenhouse Gas and Fugitive VOC Emissions by the Canadian Coal Mining Industry. Final Report, March 31, 2014. Prepared for Environment Canada. Solicitation K8A42-12-0012.

Fossil fuels consumed outside of Canada

For cases where fossil fuels are produced and consumed outside of Canada, users of the Fuel LCA Model will be required to use default fossil fuel CI values developed for the Canadian context.

4.2 Transport and Storage

4.2.1 Overview of Transport and Storage Modelling

Transportation and storage-related unit processes were previously developed for fossil fuels, and were used extensively throughout the LCIF pathways. There are four modes of transportation and distribution included in the Fuel LCA Model:

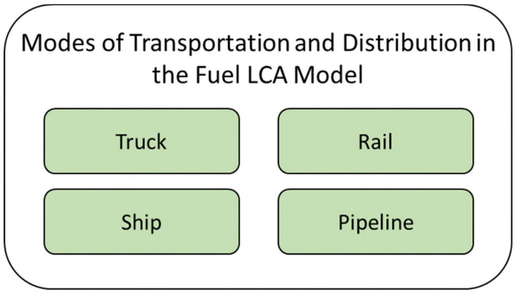


Table 33 shows the corresponding fuels used to power each mode of transportation.

Table 33: Transportation Unit Processes in the Fuel LCA Model.

Mode of transportation	Fuel used
Truck	Diesel
Train	Diesel
Tanker ship	Diesel
Pipelines (liquid)	Electricity
Pipelines (gas)	Natural gas and electricity
Geological storage	N/A
Light natural gas storage	N/A

4.2.2 Scope of Transport and Storage Modelling

As the fossil fuel consumption of each transportation mode is directly linked to the mass transported and the distance travelled, the CI for transportation are expressed in grams of CO_2 equivalents (CO_2e) per tkm (i.e. transport of one metric tonne of fuel over a distance of one kilometer). The life cycle assessment of transport processes considered the amount of fossil fuels consumed per tkm of transport, as well as fugitive, flaring and venting emissions related to natural gas pipelines. As previously stated, the manufacturing of fuel transportation infrastructure (i.e., pipelines, trucks, ships, and roads) was excluded from the model.

The LCI of storage processes includes the amount of natural gas consumed as well as fugitive, venting and flaring emissions.

4.2.3 Modelling approach

Fuel consumption data was gathered for each mode of transportation using Canadian and U.S. statistics as well as literature data. Similarly to the fossil fuel pathways, background transport processes were designed with the same data quality levels as the foreground unit processes. Each sub-section describes the modelling approach taken for that mode of transportation, with **Table 34** listing the references used.

Train transport

The amount of diesel consumed per tkm of train transport was based on 2016 data from Statistics Canada on the freight mass, the distance travelled and the annual quantity of diesel consumed. The calculated CI values based on Statistics Canada were in line with other published values (e.g. GHGenius, GREET, etc.).

Truck transport

The amount of diesel consumed per tkm of truck transport was calculated based on 2016 fuel efficiency data from the North American Council for Freight Efficiency (NACFE). Average freight and travel distances from Statistics Canada data for 2016 domestic shipments were also used.

Tanker ship transport

The amount of diesel consumed per tkm of tanker ship transport was calculated based on 2016 crude shipment data from Canada's National Marine Emissions Inventory Tool (MEIT).

Pipeline transport

The CI 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). The model used the same energy consumption value for crude, bitumen and diluent transport in pipelines, resulting in the same CI. For natural gas pipeline transport, GREET data from 2018 was used as a proxy, assuming that 98% of the energy comes from natural gas with the remainder coming from electricity. The model for gas pipeline also included fugitive emissions based on 2018 data compiled from Canadian Natural Gas Transmission and Distribution Companies (ORTECH Environmental 2018).

Storage

The amount of natural gas consumed for storage as well as storage-related emissions are based on 2016 data from Centro de Pensamiento Estratégico Internacional (CEPEI).

Table 34: Main references used in the modelling of transportation background unit processes.

Mode of Transportation	References
Train	Statistics Canada, 2016, "Table 23-10-0053-01 Railway industry diesel fuel consumption" available at https://www150.statcan.gc.ca/t1/tbl1/en/tv.action?pid=2310005301 Statistics Canada, 2017, "Table 23-10-0057-01 Railway industry summary statistics on freight and passenger transportation," available at https://www150.statcan.gc.ca/t1/tbl1/en/tv.action?pid=2310005701
Truck	NACFE, 2017, North American Council for Freight Efficiency, 2017 Annual Fleet Fuel Study, available at https://nacfe.org/annual-fleet-fuel-studies/# Statistics Canada, 2016, "Table 23-10-0219-01 Trucking commodity industry activities" available at https://www150.statcan.gc.ca/t1/tbl1/en/tv.action?pid=2310021901

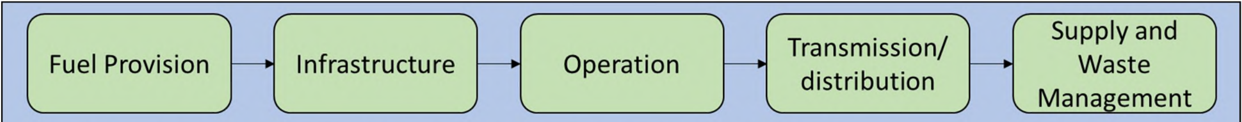
Tanker ship	National Marine Emissions Inventory Tool (MEIT), https://www.canada.ca/en/environment-climate-change/services/managing-pollution/marine-emissions-inventory-tool.html
Pipeline	Choquette-Levy, N., M. Zhong, H. MacLean, J. Bergerson, 2018, COPTEM: A Model to Investigate the Factors Driving Crude Oil Pipeline Transportation Emissions. Environmental Science & Technology. 52, 337–345. Argonne National Laboratories, 2018, GREET, Greenhouse gases, Regulated Emissions, and Energy use in Transportation Model ORTECH Environmental, 2018, Canadian Natural Gas Transmission and Distribution Companies 2016 Greenhouse Gas Inventory.
Storage	Centro de Pensamiento Estratégico Internacional (CEPEI), http://cepei.org/en/home-english/

4.3 Electricity

Scope of Electricity Modelling

Like the fossil fuel pathways explained in **Chapter 4.1**, default electricity CI values are included in the proposed Regulations and are available in Part II. These values were modelled using both direct and indirect electricity emissions. Direct emissions were modelled using the NIR and indirect emissions were modelled using *Conceptual and Analytical Frameworks for Environmental Evaluation of Electricity Generation in Canada* (CAFE3), developed by Environment and Climate Change Canada. The electricity pathways developed are also incorporated in the Fuel LCA Model as background unit processes.

The scope of electricity emission intensities in the Fuel LCA Model includes the following life cycle stages with respect to electricity production:



- **Fuel provision**: includes the extraction and refining of the fuels used to produce electricity.
- **Infrastructure**: pertains to the power plant and related infrastructures (e.g. hydroelectric dam, wind turbine, solar panel, etc.).
- **Operation**: covers electricity production and includes all services and products needed for this operation. Emission control systems such as carbon capture systems and pollution control systems for NO_x and SO_2 emissions are also included.
- **Transmission/distribution**: includes the infrastructure, equipment, products and services required to transport electricity from production sites to final users.
- **Supply and waste management**: pertains to all of the preceding stages covers all of the activities that stem from:
  - Resource procurement (water, energy, chemicals, materials), including the extraction, treatment and transformation of natural resources, and the various transports to the resource-use sites (i.e. pre-production, production, distribution, use and end-of-life management sites).
  - The transport and treatment/management of the waste generated during any of the product's life cycle stages, taking all of the possible recovery options into account.

Emissions for electricity pathways are categorized as either direct or indirect emissions. Direct emissions include emissions from combustion-derived electricity as well as emissions from the use of diesel generators as backup power supply for nuclear, hydro, wind, solar and tidal electricity generators.

Emissions occurring offsite, as is the case for uranium fuel production and processing for nuclear power generation, are excluded from the scope of the direct emission intensities but are included in within the scope of the indirect electricity emission intensities.

Indirect emissions can be defined as emissions that are not generated directly during the process of electricity production but that are part of the electricity generation and distribution life cycle. Examples of indirect emission sources include electricity transmission, use of sulfur hexafluoride during transmission, herbicides, wastewater treatment, production of concrete and steel used in infrastructure, infrastructure heating, lubricating oils, radioactive waste and vehicle operation. All emissions related to imported electricity are also considered indirect.

The LCI of each electricity pathway was built based on a functional unit of 1 MWh of electricity generated and distributed in Canada in 2017.

Modelling Approach for Electricity

The approach for determining the electricity emission intensities in the Fuel LCA Model consisted of relying upon publicly available data for direct emissions that were further augmented to account for indirect emissions. Direct emissions from electricity production were modelled based on Environment and Climate Change Canada's *National Inventory Report 1990-2016: Greenhouse Gas Sources and Sinks in Canada Part 3*[18], for the Milestone 2 and 3 reports referenced in Appendix B, and *National Inventory Report 1990-2018: Greenhouse Gas Sources and Sinks in Canada Part 3* for the table referred to in section 5.2. Indirect emissions were modelled using the *Conceptual and Analytical Frameworks for Environmental Evaluation of Electricity Generation in Canada* (CAFE3) developed by Environment and Climate Change Canada.

As the consumption intensities from the NIR present only the emission intensity in the form of grams of CO_2e per kWh, the emissions of each greenhouse gas were back-calculated based off the NIR's CO_2, CH_4 and N_2O generation emission intensities using the AR4-100 year time horizon. This allows for the calculation of emissions using the AR5-100 year time horizon values, which is consistent with the rest of the Fuel LCA Model. The emissions intensity of each GHG was calculated on the net electricity generation basis by considering energy losses during transmission and distribution as well as sulfur hexafluoride emissions.

The CAFE3 tool provides distinct emission intensities on a technology basis for each electricity pathway. Indirect provincial emission intensities were determined by weighting each generation technology's emission intensity in relation to its share in the overall provincial grid mix. A national indirect emission intensity was calculated by weighting each generation technology's emission intensity, at the provincial level, in relation to its share in the national grid mix. Note that the provincial and national grid mixes import from nearby jurisdictions, including the USA.

National Inventory Reports 1990-2016 and 1990-2018

The NIR provides emission intensities related to the generation of electricity by the Public Electricity and Heat Production category (IPCC Category 1.A.1.a) on a national and provincial level. Emission intensities reflect GHG emissions associated with electricity delivered by the grid. Auto producers who either

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[18] Government of Canada. (2018). *National Inventory Report 1990-2016: Greenhouse Gas Sources and Sinks in Canada.* Retrieved from https://unfccc.int/document/65715

partially or wholly generate electricity for their own use and who sell some of their electricity to the grid are excluded from the scope. The scope of electricity generation includes only main activity producers (i.e. entities whose main activity is the production of electricity). Emissions associated with the small amount of utility steam generation are therefore also included within the scope of the model.

Emission factors from the NIR are based on total fuel consumption by the public utility sector, as provided in the *Report on Energy Supply and Demand in Canada* (RESD), as well as electricity generation data based on CANSIM (2005–2013) and the publication *Electric Power Generation, Transmission and Distribution (EPGTD)* (Statistics Canada 57-202-X). Regional emission factors were only applied on coal and natural gas emissions. For the remaining fuels, national emission factors were applied as region-specific emission factors were not available. The complete methodology used to develop the GHG emission intensities is discussed in Chapter 3 and Annex 3.1 of the *National Inventory Report 1990-2016: Greenhouse Gas Sources and Sinks in Canada* report.

ECCC’s CAFE3 Tool

The CAFE3 tool is used to estimate indirect emissions associated with electricity generation from different sources, in Canada.

Note that in the case of co-generation where power stations generate electricity and useful heat as steam, an allocation procedure based on the energy content was used to split emissions between the electricity and the steam streams. This contrasts to how direct emissions were accounted for co-generation.

CAFE3 life cycle stage models use data from various sources. Infrastructure and fuel provision are primarily modeled using the ecoinvent v3.4 database (e.g. to model the cradle-to-gate emissions of fuels and materials) and completed with National Energy Board and Statistics Canada data, when available (for e.g. fuel mix composition). Operation stage data relies mostly on ecoinvent v3.4, the National Pollutant Release Inventory (NPRI) and US EPA. Transmission and distribution rely on ecoinvent v3.4 for infrastructure information and Natural Resource Canada and Hydro-Quebec for other parameters. The life cycle inventory of supply and waste management is largely based from ecoinvent v3.4 data, and supplemented with regionalized life cycle models developed by the CIRAIG for natural gas and biomass. When possible, up-to-date research is used to update key parameter values (e.g. GHG emissions from hydro reservoirs carbon dynamics in harvested forests). Missing data are completed with literature sources and proxies. CAFE3 integrates the uncertainty of all parameters used in the tool using a mixture of expert judgement and additional uncertainty based on a quality assessment (pedigree approach).

Users of CAFE3 have the possibility of adapting models and underlying data to model specific situations (specific producer), or to improve default data. They can also integrate grid integration impacts for variable renewable energy (VRE) and carbon sequestration and storage (CSS).

The emission inventory calculated by CAFE3 is translated to impact indicator scores using the IMPACT World+ Life Cycle Impact Assessment methodology. For the climate change impact category specifically, four models were implemented. The first, also serving as the basis for all four models, is a direct use of IPCC 2013 100-year horizon GWP factors. The others then either include albedo from land-use change, dynamic effect of carbon uptake and degradation for biomass, or both. Results used in the proposed Regulations are based on the first of these.

Other Data Sources

Statistics Canada Table 2510002001 "Electric power, annual generation by class of producer" was used to determine the proportion of electricity generated from renewables, nuclear and combustible fuels. The specific breakdown of combustible fuels was based on Statistics Canada (Table 2510002801 "Electricity generated from fossil fuels"). Electricity import and exports were determined based on literature values.

Electricity grid mixes from other countries

For cases where electricity used in the life cycle of LCIF is generated in other countries, the Fuel LCA Model will include default electricity CI values available in the 2018 GREET model.

4.4 Chemical Inputs

4.4.1 Chemicals

Chemicals used throughout the conversion processes of LCIF pathways include enzymes, acids and catalysts. The pre-defined CI for each of these chemicals is based on the 2018 GREET model emissions factors. In the specific case of sodium methylate (sodium methoxide), as a result of a lack of data within the GREET 2018 model, emissions values were determined using those of methanol (from natural gas) and the stoichiometry of the reaction producing sodium methylate from methanol. The following chemicals are included in the Fuel LCA Model.

Acetic acid	Alpha amylase	Ammonia
Ammonium sulfate	CaO (lime)	Calcium carbonate
Cellulose protein	Cellulose	Citric acid
Corn steep liquor	Diammonium phosphate	Gluco amylase
Hexane (n-hexane)	Hydrochloric acid	Methanol
Nitrogen gas	Phosphoric acid	Potassium hydroxide
Sodium hydroxide	Sodium methylate	Sulfuric acid
Urea	Yeast extract	Yeast

Geographical Scope for Chemicals

Due to a lack of Canadian-specific LCI data for these processes, the data used are derived from studies outside of Canada. This assumes that processes do not vary between regions.

Data Sources for Chemicals

Emissions factors for chemicals were taken from the GREET 2018 model. The full reference is listed in **Table 35**.

Table 35: Main data sources for the modelling of agrochemicals in the Fuel LCA Model.

Data Type	Source
Other chemicals, emissions values	Argonne National Lab. (2018). GREET.

4.4.2 Agrochemicals

The pre-defined CI values for synthetic fertilizers were determined using two different methods to provide two values for the fertilizer nutrient types (N, P, K and S). The first method used emissions factors from the GREET 2018 model. Canadian average emissions values were determined using these emissions factors along with nutrient ratios and 2014-2017 market shares from national statistics data and stoichiometric ratios. P fertilizer emissions values were not produced using this method for the model. The second method produced average Canadian CIs from AR5 GWP values published in the CRSC (Cheminfo, 2016) and the stoichiometry of products and nutrients. S fertilizer was not produced using this method for the model due to a lack of available data in the CRSC report.

In the absence of detailed Canadian data on the shares of each type of pesticide used in Canada on a given crop, the average pre-defined CI for pesticide was calculated as the average of the GREET 2018 emission factors for five primary pesticides in widespread use in Canada (atrazine, metolachlor, acetolachlor, cyanazine, and insecticides) for the relevant crops.

Geographical Scope for Agrochemicals

Due to a lack of Canadian-specific LCI data for fertilizers and pesticides, the data used are mainly derived from studies outside of Canada, or Canadian average data. This assumes that processes do not vary between regions.

Data Sources for Agrochemicals

Emissions factors for fertilizer products and pesticides were taken from the Argonne GREET 2018 model. AR5 GWP CI values were taken from the 2016 CRSC Carbon Footprints for Canadian Crops: Canadian Fertilizer Production Data report. The data sources are summarized in **Table 36**.

Table 36: Main data sources for the modelling of agrochemicals in the Fuel LCA Model.

Data Type	Source
Fertilizers, products emissions values	Argonne National Lab. (2018). GREET.
Fertilizers, products CIs	Cheminfo. (2016). *Carbon Footprints for Canadian Crops: Canadian Fertilizer Production Data Final Report.* Cheminfo Services.
Pesticides, active ingredient emissions values	Argonne National Lab. (2018). GREET.

Part II

Chapter 5: Credit Creation and Reference Values

The proposed Regulations provide several options to meet the carbon intensity (CI) limits. Credits will be created by primary suppliers and registered creators for actions taken in the following compliance categories:

1. Actions throughout the lifecycle of a fossil fuel that reduce its carbon intensity;
2. The supply of low-carbon-intensity fuels; and
3. Specific end-use fuel switching in transportation.

Under Compliance Category 1, the ability of a project to create credits will be governed by quantification methods provided by Environment and Climate Change Canada. The quantification methods refer to the Fuel LCA Model Methodology and to CI values included in the Fuel LCA Model such as the CI values for electricity generation intensities presented in **Chapters 5.2 and 5.3**.

Under Compliance Category 2, credit creation is possible through the supply of low carbon intensity fuels (LCIF). In order to create credits, a low CI fuel producer or foreign supplier would be required to obtain an approved CI value for each low CI fuel that they produce or import. The proposed Regulations would require the use of either the Fuel Lifecycle Assessment (LCA) Model to calculate facility-specific CI values using facility specific data, or the use of disaggregated default values available in the proposed Regulations. CI values must be determined for each type of feedstock used to create a LCIF. **Chapter 5.1** provides more information on the calculation methodology when a LCIF is created with more than one type of feedstock or when its production results in more than one co-product.

Under Compliance Category 3, credit creation is possible through end-fuel switching in the transportation sector from a higher carbon intensity fossil fuel to the following less carbon intensive fuels: natural gas and renewable natural gas (including compressed and liquefied), propane and renewable propane, and non-carbon energy carriers, such as electricity or hydrogen. The proposed Regulations require the use of:

- Either the Fuel LCA Model to calculate specific CI values using input data or default values, for those less carbon intensive fuels that are fossil fuels;
- Either the Fuel LCA Model to calculate specific CI values using input data or default values, for electricity; or
- Either the Fuel LCA Model to calculate specific CI values using input data or the use of a set of disaggregated default values, for LCIFs.

Chapters 5.2 and 5.3 contain the default CI values and the energy efficiency ratios to be used by registered creators for end-use fuel switching. For electricity, these carbon intensity values were calculated using the methodology explained in **Chapter 4.3**. To determine the default values for fossil fuels and hydrogen, the highest (i.e. most conservative) values were obtained from a review of data sources including California Low Carbon Fuel Standard Lookup Table, default values used in British Columbia's Renewable and Low Carbon Fuel Requirements Regulation and the highest values obtained from the sensitivity analysis conducted by EarthShift Global, LLC under contract by ECCC and explained in **Annexe 3**.

5.1 Determination of the proportion of the LCIF that is produced with each feedstock or that results in each co-product

A LCIF that is produced using more than one type of feedstocks is treated as if it were multiple fuels, each with a volume that is equal to the proportion of the LCIF that is produced with each type of feedstock. If a fuel production facility simultaneously processes more than one type of feedstock, as referred to in Section 83 of the proposed Regulations, the following methodology must be used to determine the volume of low carbon-intensity fuel produced with each type of feedstock:

$$Q^n{}_{Fuel\ i} = Y_{avg\ yield}\ x\ Q^n{}_{Feedstock\ i}$$

$Q^n{}_{Fuel\ i}$ is the quantity of fuel produced with a carbon-intensity pathway i during the compliance period n

$Y_{avg\ yield}$ is the facility's average yield for all feedstocks during the compliance period n

$Q^n{}_{Feedstock\ i}$ is the quantity of feedstock processed for carbon intensity pathway i at a facility during the compliance period n

Alternatively, participants or foreign suppliers have the option to provide chemical analysis data to support calculated yields to determine the quantity of fuel produced with each carbon intensity pathway.

5.1.1 Quarterly Material Balancing

All participants and foreign suppliers will be required to maintain an accounting system (computerized or manual) to maintain quarterly material balances of all feedstocks processed at the facility and fuels produced (as per Monitoring Plan in section 122 of the Proposed Regulations). For each calendar quarter, a participant or origin supplier must account for all feedstock processed at the facility and the corresponding fuel produced, including all fuel produced not solely the portion supplied to Canada. Feedstock quantities may not be counted more than once. The quantity of a low carbon intensity fuel for each carbon intensity pathway in the compliance period must be equal to or less than the actual yield at the facility.

5.1.2 More than one co-product

When more than one co-product are simultaneously produced, the participant or foreign supplier must either report all fuel produced with a single carbon intensity pathway, or assign different CIs to portions of the fuel produced as per the different co-products (for example corn ethanol with portions of distiller's grain sold dry and wet). LCIF volumes must be proportioned to the fraction of each co-product.

5.2 Default Carbon Intensity of Electricity by Province

The Fuel LCA Model determines grid emission intensities by modelling the direct and indirect emissions associated with electricity generation. Direct electricity emissions are those that originate from on-site emissions to the power plant. Data associated with direct emissions was collected from the *National Inventory Report (NIR) 1990-2018: Greenhouse Gas Sources and Sinks*. Indirect emissions are offsite emissions associated with fuel production, transmission and distribution losses and emissions related to the transport of fuels. This data was collected using the same NIR reports and modelled using Environment and Climate Change Canada's CAFE3 tool. Direct and indirect emissions were collected and used to model the direct and indirect impacts, as well as the total impact, which is a summation of the two. **Table 37** presents the provincial and national grid emission intensities for the year of 2018. The carbon-intensity of electricity in a province in which a charging station is located may be determined by the provincial values set out in **Table 37**.

Table 37. Provincial and national grid emission intensities included in the Fuel LCA Model. Values are for the year of 2018 and are expressed in gram CO_2 *e/MJ.*

Province	Grid intensity ($g\ CO_2e$ / MJ)
Alberta	217
British Columbia	31
Manitoba	15
New Brunswick	95
Newfoundland & Labrador	20
Nova Scotia	245
Ontario	17
Prince Edward Island	71
Québec	7
Saskatchewan	222
Yukon	42
Northwest Territories	75
Nunavut	339
Canada	48

5.3 Electricity Generation Carbon Intensity by Technology

Table 38 displays carbon intensities of electricity generation for the technologies covered in the Fuel LCA Model. In the absence of provincial CI values, the national CI can be used.

Table 38: Provincial and national electricity generation intensities grouped by technology. In the absence of provincial CI values, the national CI can be used.

			CA	**AB**	**BC**	**MB**	**NB**	**NL**	**NS**	**ON**	**PE**	**QC**	**SK**	**YT**	**NT**	**NU**
Pathway type	**Pathway name**	**Impact breakdown**	**Impact (g CO_2e / MJ)**													
Biomass	Wood, cogeneration	Indirect	7	7	7	9	8	9	8	7	9	7	9	16	9	8
		Direct	5	5	5	5	5	5	5	5	5	5	5	5	5	5
		Total	**12**	**12**	**12**	**14**	**13**	**14**	**14**	**12**	**14**	**12**	**14**	**21**	**14**	**13**
	Wood, simple cycle	Indirect	12	12	12		13		14	13		12		21	14	13
		Direct	9	9	9		9		9	9		9		9	9	9
		Total	**21**	**21**	**21**		**22**		**23**	**22**		**21**		**30**	**23**	**22**
Coal	Bituminous	Indirect	32				34		34							
		Direct	312				312		312							
		Total	**344**				**345**		**346**							
	Lignite	Indirect	16			20							18			
		Direct	217			217							217			
		Total	**233**			**237**							**235**			
	Sub-bituminous	Indirect	24	25												
		Direct	199	199												
		Total	**223**	**223**												
Diesel, off-grid	Off-grid	Indirect	89	90	90	90	89	90	89	88	89	87	100	89	91	88
		Direct	219	219	219	219	219	219	219	219	219	219	219	219	219	219
		Total	**308**	**310**	**309**	**309**	**308**	**309**	**308**	**307**	**308**	**307**	**320**	**309**	**310**	**307**
Hydro	Reservoir	Indirect	9	10	10	10	11	10	11	9		9	11	18	11	
		Direct	1	1	1	1	1	1	1	1		1	1	1	1	
		Total	**9**	**11**	**10**	**11**	**11**	**11**	**11**	**10**		**9**	**11**	**19**	**12**	
	Run-of-river	Indirect	2	5	3	4	5	4	5	3		2	4	12	5	

		Direct	1	1	1	1	1	1	1	1		1	1	1	1	
		Total	**3**	**5**	**4**	**4**	**5**	**4**	**5**	**3**		**3**	**5**	**12**	**5**	
Natural gas	Cogeneration	Indirect	24	24	25		25	25		25		41	26	52	36	
		Direct	78	78	78		78	78		78		78	78	78	78	
		Total	**102**	**102**	**103**		**103**	**103**		**103**		**119**	**104**	**130**	**114**	
	Combined cycle	Indirect	28	28	29	30	29	30	29	29	29	28	30	58	41	
		Direct	92	92	92	92	92	92	92	92	92	92	92	92	92	
		Total	**120**	**121**	**121**	**122**	**121**	**122**	**122**	**121**	**122**	**120**	**122**	**150**	**134**	
	Converted boiler	Indirect	49			71			51							
		Direct	168			168			168							
		Total	**217**			**239**			**219**							
	Simple cycle	Indirect	42	42	43					42			44	82	61	
		Direct	144	144	144					144			144	144	144	
		Total	**186**	**187**	**187**					**186**			**188**	**226**	**205**	
Nuclear	CANDU	Indirect	5				7			5						
		Direct	1				1			1						
		Total	**6**				**7**			**6**						
Solar	Concentrated solar power	Indirect	13	14												
		Direct	1	1												
		Total	**13**	**15**												
	Photovoltaic	Indirect	16	17	15	17	19	21	18	17	18	17	17	29	20	20
		Direct	1	1	1	1	1	1	1	1	1	1	1	1	1	1
		Total	**17**	**17**	**16**	**18**	**19**	**22**	**19**	**17**	**19**	**17**	**18**	**29**	**20**	**21**
Wind	Onshore, 1-3M	Indirect	3	4	4	5	4	4	4	3	4	3	5	27	14	17
		Direct	1	1	1	1	1	1	1	1	1	1	1	1	1	1
		Total	**3**	**4**	**4**	**5**	**5**	**5**	**5**	**4**	**5**	**3**	**6**	**27**	**15**	**18**

Onshore, 1MW	Indirect	4	5	4	6	5	5	5	4	5	4	6	34	18	23
	Direct	1	1	1	1	1	1	1	1	1	1	1	1	1	1
	Total	**4**	**5**	**5**	**6**	**6**	**6**	**5**	**4**	**5**	**4**	**7**	**34**	**19**	**23**
Onshore, 2MW, concrete tower	Indirect	3									3				
	Direct	1									1				
	Total	**3**									**3**				
Onshore, 3MW	Indirect	4	5	5	6	6	6	6	5	6	4	7	39	22	27
	Direct	1	1	1	1	1	1	1	1	1	1	1	1	1	1
	Total	**5**	**6**	**6**	**7**	**6**	**6**	**6**	**5**	**6**	**5**	**7**	**39**	**22**	**28**

5.4 Default Values of Fossil Fuels and Energy Sources

For the purpose of sections 62 and subsections 84(2), 85(3) and (4) and 88(2) of the proposed Regulations, the carbon intensity of hydrogen, propane, liquefied petroleum gas, natural gas, liquefied natural gas and compressed natural gas is, at the election of the registered creator, the amount set out in item 7 of Schedule 5 of the Proposed Regulations or the following default values.

Table 39. Carbon intensity values for Fossil Fuels and Energy Sources.

Fuel or Energy Source	Default Carbon Intensity ($g\ CO_2e/MJ$)
Compressed Hydrogen	100
Liquefied Hydrogen	130
Propane	75
Liquefied Petroleum Gas	86
Natural Gas	62
Liquefied Natural Gas	113
Compressed Natural Gas	72

To determine the default values for fossil fuels and hydrogen, the highest (i.e. most conservative) values were obtained from a review of data sources including California Low Carbon Fuel Standard Lookup Table, default values used in British Columbia's Renewable and Low Carbon Fuel Requirements Regulation and the highest values obtained from the sensitivity analysis conducted by EarthShift Global, LLC under contract by ECCC and explained in **Annexe 3**.

5.5 Energy Efficiency Ratios for Electric and Hydrogen Fuel Cell Vehicles

The energy efficiency ratio is determined by comparing the efficiency of a vehicle powered by a reference fuel such as gasoline or diesel to that of one powered by an alternative energy source such as electricity or hydrogen. The proposed Regulations use this ratio to determine the amount of fossil fuel energy displaced by electric or hydrogen fuel cell vehicles in order to determine the quantity of avoided emissions.

The energy efficiency ratios set out in this document will be updated periodically and new vehicle types may be added to reflect new technologies or improved understanding of these technologies as they are deployed. Different adoption rates of alternative vehicles within their vehicle class may also lead to different sales-weighted averages.

Table 40. Energy Efficiency Ratios

Vehicle Type	**Energy Efficiency Ratio**
Light- and medium-duty electric vehicles	4.1
Heavy-duty electric vehicles	5.0
Electric marine vessels	3.1
Light- and medium-duty hydrogen fuel cell vehicles	2.1
Heavy-duty hydrogen fuel cell vehicles	1.9

5.5.1 Rationale

The energy efficiency of any vehicle depends on many factors, including the size or type of vehicle and how it is used. In general, an energy efficiency ratio (EER) for an internal combustion engine vehicle (ICEV) compared to a zero-emission vehicle (ZEV) is determined by the formula

$$EER = \frac{Efficiency_{ICEV} \times Energy\ Density_{ICEV}}{Efficiency_{ZEV} \times Energy\ Density_{ZEV}}$$

Electric Vehicles

The energy efficiency ratio for light- and medium-duty electric vehicles was calculated on the basis of Natural Resources Canada fuel consumption ratings, vehicle sales volumes within each vehicle class, and the energy density of gasoline presented in Schedule 1 of the proposed Regulations.

The Natural Resources Canada fuel consumption ratings are based on the 5-cycle testing procedure, which tests vehicles under city and highway conditions as well as operating a vehicle in cold weather, the use of air conditioners, and driving at higher speeds with more rapid acceleration and braking.

The energy efficiency of vehicles varies widely, especially depending on the size or class of the vehicle. The sales-weighted average efficiency of electric vehicles within a certain vehicle class were compared only to other vehicles within the same class. In order to determine a representative overall energy efficiency, each class-specific energy efficiency was scaled to the number of vehicle sales within that class.

In general, an energy efficiency ratio (EER) for an internal combustion engine vehicle (ICEV) compared to an electric vehicle (EV) is determined by the formula:

$$EER = \frac{Efficiency_{ICEV}\left(\frac{L}{100\ km}\right) \times Energy\ Density_{Gasoline}\left(\frac{34.7\ MJ}{L}\right)}{Efficiency_{EV}\left(\frac{kWh}{100\ km}\right) \times Energy\ Density_{Electricity}\left(\frac{3.6\ MJ}{kWh}\right)}$$

The energy efficiency ratio for other electric vehicles presented in this document are based on other studies into the use profile of these vehicle types, and will continue to be updated as more information is available.

Hydrogen Fuel Cell Vehicles

The Toyota Mirai and Hyundai Nexo were the only hydrogen fuel cell vehicles available in Canada in 2019, however official consumption ratings were not available from Natural Resources Canada. By using other rated efficiencies and comparing these vehicles to a Toyota Camry and a Hyundai Tucson, respectively, sales-weighted average values were not necessary, as the resulting energy efficiency ratios were very similar.

In general, an energy efficiency ratio (EER) for an internal combustion engine vehicle (ICEV) compared to a hydrogen fuel cell vehicle (FCV) is determined by the formula:

$$EER = \frac{Efficiency_{ICEV}\left(\frac{L}{100\ km}\right) \times Energy\ Density_{Gasoline}\left(\frac{34.7\ MJ}{L}\right)}{Efficiency_{FCV}\left(\frac{kg\ H_2}{100\ km}\right) \times Energy\ Density_{H_2}\left(\frac{141.24\ MJ}{kg}\right)}$$

For these two vehicles, the following energy efficiency ratios were determined.

Vehicle	$\mathbf{Efficiency_{FCV}}\left(\frac{\mathbf{kg\ H_2}}{\mathbf{100\ km}}\right)$	$\mathbf{Efficiency_{ICEV}}\left(\frac{\mathbf{L}}{\mathbf{100\ km}}\right)$	EER
Toyota Mirai	0.92	8*	2.1
Hyundai Nexo	1.05	9.1	2.1

**based on an average of five FWD non-hybrid Camrys with a range of 6.9-9.2 L/100 km.*

The energy efficiency ratio for heavy-duty hydrogen fuel cell vehicles presented in this document is based on other studies into the use profile of these vehicle types, and will continue to be updated as more information is available.

Appendix A: GHG Characterization Factors

The Fuel LCA Model includes several GHGs as environmental flows. The GHGs included in the Fuel LCA is displayed in **Table 41** below. It includes the GWP of each GHG, adapted from the IPCC's AR5.

Table 41: GWP 100-year of GHGs. Adapted from the IPCC's AR5.[19]

Acronym, Common Name or Chemical Name	Chemical Formula	GWP 100-year	Uncertainty
Carbon dioxide	CO_2	1	
Methane	CH_4	28	11.2
Fossil methane	CH_4	30	12
Nitrous Oxide	N_2O	265	79.5
Chlorofluorocarbons			
CFC-11	CCl_3F	4660	1631
CFC-12	CCl_2F_2	10200	3060
CFC-13	$CClF_3$	13900	2780
CFC-113	CCl_2FCClF_2	5820	1164
CFC-114	$CClF_2CClF_2$	8590	1718
CFC-115	$CClF_2CF_3$	7670	1534
Hydrochlorofluorocarbons			
HCFC-21	$CHCl_2F$	148	59.2
HCFC-22	$CHClF_2$	1760	704
HCFC-122	$CHCl_2CF_2Cl$	59	23.6
HCFC-122a	$CHFCLClFCl_2$	258	103.2
HCFC-123	$CHCl_2CF_3$	79	31.6
HCFC-123a	$CHClFCF_2Cl$	370	148
HCFC-124	$CHClFCF_3$	527	210.8
HCFC-132c	CH_2FCFCl_2	338	135.2
HCFC-141b	CH_3CCl_2F	782	312.8
HCFC-142b	CH_3CClF_2	1980	495
HCFC-225ca	$CHCl_2CF_2CF_3$	127	50.8
HCFC-225cb	$CHClFCF_2CClF_2$	525	210
(E)-1-Chloro-3,3,3-trifluoroprop-1-ene	trans-$CF_3CH=CHCl$	1	0.04
Hydrofluorocarbons			
HFC-23	CHF_3	12400	2480
HFC-32	CH_2F_2	677	270.8
HFC-41	CH_3F	116	46.4
HFC-125	CHF_2CF_3	3170	792.5
HFC-134	CHF_2CHF_2	1120	448

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[19] Myhre, G., D. Shindell, F.-M. Bréon, W. Collins, J. Fuglestvedt, J. Huang, D. Koch, J.-F. Lamarque, D. Lee, B. Mendoza, T. Nakajima, A. Robock, G. Stephens, T. Takemura and H. Zhang, 2013: Anthropogenic and Natural Radiative Forcing. In: *Climate Change 2013: The Physical Science Basis. Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change* [Stocker, T.F., D. Qin, G.-K. Plattner, M. Tignor, S.K. Allen, J. Boschung, A. Nauels, Y. Xia, V. Bex and P.M. Midgley (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA.

Acronym, Common Name or Chemical Name	Chemical Formula	GWP 100-year	Uncertainty
HFC-134a	CH_2FCF_3	1300	455
HFC-143	CH_2FCHF_2	328	131.2
HFC-143a	CH_3CF_3	4800	960
HFC-152	CH_2FCH_2F	16	6.4
HFC-152a	CH_3CHF_2	138	55.2
HFC-161	CH_3CH_2F	4	0.16
HFC-227ca	$CF_3CF_2CHF_2$	2640	660
HFC-227ea	CF_3CHFCF_3	3350	837.5
HFC-236cb	$CH_2FCF_2CF_3$	1210	484
HFC-236ea	CHF_2CHFCF_3	1330	532
HFC-236fa	$CF_3CH_2CF_3$	8060	1612
HFC-245ca	$CH_2FCF_2CHF_2$	716	286.4
HFC-245cb	$CF_3CF_2CH_3$	4620	924
HFC-245ea	$CHF_2CHFCHF_2$	235	94
HFC-245eb	$CH_2FCHFCF_3$	290	116
HFC-245fa	$CHF_2CH_2CF_3$	858	343.2
HFC-263fb	$CH_3CH_2CF_3$	76	30.4
HFC-272ca	$CH_3CF_2CH_3$	144	57.6
HFC-329p	$CHF_2CF_2CF_2CF_3$	2360	590
HFC-365mfc	$CH_3CF_2CH_2CF_3$	804	321.6
HFC-43-10mee	$CF_3CHFCHFCF_2CF_3$	1650	412.5
HFC-1132a	$CH_2=CF_2$	<1	-
HFC-1141	$CH_2=CHF$	<1	-
(Z)-HFC-1225ye	$CF_3CF=CHF(Z)$	<1	-
(E)-HFC-1225ye	$CF_3CF=CHF(E)$	<1	-
(Z)-HFC-1234ze	$CF_3CH=CHF(Z)$	<1	-
HFC-1234yf	$CF_3CF=CH_2$	<1	-
(E)-HFC-1234ze	trans-$CF_3CH=CHF$	<1	-
(Z)-HFC-1336	$CF_3CH=CHCF_3(Z)$	2	0.08
HFC-1243zf	$CF_3CH=CH_2$	<1	-
HFC-1345zfc	$C_2F_5CH=CH_2$	<1	-
3,3,4,4,5,5,6,6,6-Nonafluorohex-1-ene	$C_4F_9CH=CH_2$	<1	-
3,3,4,4,5,5,6,6,7,7,8,8,8-Tridecafluorooct-1-ene	$C_6F_{13}CH=CH_2$	<1	-
3,3,4,4,5,5,6,6,7,7,8,8,9,9,10,10,10-Heptadecafluorodec-1-ene	$C_8F_{17}CH=CH_2$	<1	-
Chlorocarbons and Hydrochlorocarbons			
Methyl chloroform	CH_3CCl_3	160	64
Carbon tetrachloride	CCl_4	1730	432.5
Methyl chloride	CH_3Cl	12	4.8
Methylene chloride	CH_2Cl_2	9	3.6
Chloroform	$CHCl_3$	16	6.4
1,2-Dichloroethane	CH_2ClCH_2Cl	<1	-
Bromocarbons, Hydrobromocarbons and Halons			

Acronym, Common Name or Chemical Name	**Chemical Formula**	**GWP 100-year**	**Uncertainty**
Methyl bromide	CH_3Br	2	0.8
Methylene bromide	CH_2Br_2	1	0.4
Halon-1201	$CHBrF_2$	376	150.4
Halon-1202	CBr_2F_2	231	92.4
Halon-1211	$CBrClF_2$	1750	437.5
Halon-1301	$CBrF_3$	6290	1258
Halon-2301	CH_2BrCF_3	173	69.2
Halon-2311 / Halothane	$CHBrCLClF_3$	41	16.4
Halon-2401	$CHFBrCF_3$	184	73.6
Halon-2402	$CBrF_2CBrF_2$	1470	367.5
Fully Fluorinated Species			
Nitrogen trifluoride	NF_3	16100	3220
Sulphur hexafluoride	SF_6	23500	4700
(Trifluoromethyl) sulphur pentafluoride	SF_5CF_3	17400	3480
Sulphuryl fluoride	SO_2F_2	4090	1022.5
PFC-14	CF_4	6630	1326
PFC-116	C_2F_6	11100	2220
PFC-c216	$c\text{-}C_3F_6$	9200	1840
PFC-218	C_3F_8	8900	1780
PFC-318	$c\text{-}C_4F_8$	9540	1908
PFC-31-10	C_4F_{10}	9200	1840
Perfluorocyclopentene	$c\text{-}C_5F_8$	2	0.08
PFC-41-12	$n\text{-}C_5F_{12}$	8550	1710
PFC-51-14	$n\text{-}C_6F_{14}$	7910	1582
PFC-61-16	$n\text{-}C_7F_{16}$	7820	1564
PFC-71-18	C_8F_{18}	7620	1524
PFC-91-18	$C_{10}F_{18}$	7190	1438
Perfluorodecalin (cis)	$Z\text{-}C_{10}F_{18}$	7240	1448
Perfluorodecalin (trans)	$E\text{-}C_{10}F_{18}$	6290	1258
PFC-1114	$CF_2=CF_2$	<1	-
PFC-1216	$CF_3CF=CF_2$	<1	-
Perfluorobuta-1,3-diene	$CF_2=CFCF=CF_2$	<1	-
Perfluorobut-1-ene	$CF_3CF_2CF=CF_2$	<1	-
Perfluorobut-2-ene	$CF_3CF=CFCF_3$	2	0.08
Halogenated Alcohols and Ethers			
HFE-125	CHF_2OCF_3	12400	2480
HFE-134 (HG-00)	CHF_2OCHF_2	5560	1390
HFE-143a	CH_3OCF_3	523	209.2
HFE-227ea	$CF_3CHFOCF_3$	6450	1290
HCFE-235ca2 (enflurane)	CHF_2OCF_2CHFCl	583	233.2
HCFE-235da2 (isoflurane)	$CHF_2OCHCLClF_3$	491	196.4
HFE-236ca	$CHF_2OCF_2CHF_2$	4240	1060
HFE-236ea2 (desflurane)	$CHF_2OCHFCF_3$	1790	716
HFE-236fa	$CF_3CH_2OCF_3$	979	391.6

Acronym, Common Name or Chemical Name	Chemical Formula	GWP 100-year	Uncertainty
HFE-245cb2	$CF_3CF_2OCH_3$	654	261.6
HFE-245fa1	$CHF_2CH_2OCF_3$	828	331.2
HFE-245fa2	$CHF_2OCH_2CF_3$	812	324.8
2,2,3,3,3-Pentafluoropropan-1-ol	$CF_3CF_2CH_2OH$	19	7.6
HFE-254cb1	$CH_3OCF_2CHF_2$	301	120.4
HFE-263fb2	$CF_3CH_2OCH_3$	1	0.04
HFE-263m1	$CF_3OCH_2CH_3$	29	11.6
3,3,3-Trifluoropropan-1-ol	$CF_3CH_2CH_2OH$	<1	-
HFE-329mcc2	$CHF_2CF_2OCF_2CF_3$	3070	767.5
HFE-338mmz1	$(CF_3)_2CHOCHF_2$	2620	655
HFE-338mcf2	$CF_3CH_2OCF_2CF_3$	929	371.6
Sevoflurane (HFE-347mmz1)	$(CF_3)_2CHOCH_2F$	216	86.4
HFE-347mcc3 (HFE-7000)	$CH_3OCF_2CF_2CF_3$	530	212
HFE-347mcf2	$CHF_2CH_2OCF_2CF_3$	854	341.6
HFE-347pcf2	$CHF_2CF_2OCH_2CF_3$	889	355.6
HFE-347mmy1	$(CF_3)_2CFOCH_3$	363	145.2
HFE-356mec3	$CH_3OCF_2CHFCF_3$	387	154.8
HFE-356mff2	$CF_3CH_2OCH_2CF_3$	17	0.68
HFE-356pcf2	$CHF_2CH_2OCF_2CHF_2$	719	287.6
HFE-356pcf3	$CHF_2OCH_2CF_2CHF_2$	446	178.4
HFE-356pcc3	$CH_3OCF_2CF_2CHF_2$	413	165.2
HFE-356mmz1	$(CF_3)_2CHOCH_3$	14	0.56
HFE-365mcf3	$CF_3CF_2CH_2OCH_3$	<1	-
HFE-365mcf2	$CF_3CF_2OCH_2CH_3$	58	23.2
HFE-374pc2	$CHF_2CF_2OCH_2CH_3$	627	250.8
4,4,4-Trifluorobutan-1-ol	$CF_3(CH_2)_2CH_2OH$	<1	-
2,2,3,3,4,4,5,5-Octafluorocyclopentanol	$-(CF_2)_4CH(OH)-$	13	5.2
HFE-43-10pccc124 (H-Galden 1040x, HG-11)	$CHF_2OCF_2OC_2F_4OCHF_2$	2820	705
HFE-449s1 (HFE-7100)	$C_4F_9OCH_3$	421	168.4
n-HFE-7100	$n\text{-}C_4F_9OCH_3$	486	194.4
i-HFE-7100	$i\text{-}C_4F_9OCH_3$	407	162.8
HFE-569sf2 (HFE-7200)	$C_4F_9OC_2H_5$	57	22.8
n-HFE-7200	$n\text{-}C_4F_9OC_2H_5$	65	26
i-HFE-7200	$i\text{-}C_4F_9OC_2H_5$	44	17.6
HFE-236ca12 (HG-10)	$CHF_2OCF_2OCHF_2$	5350	1337.5
HFE-338pcc13 (HG-01)	$CHF_2OCF_2CF_2OCHF_2$	2910	1164
1,1,1,3,3,3-Hexafluoropropan-2-ol	$(CF_3)_2CHOH$	182	72.8
HG-02	$HF_2C{-}(OCF_2CF_2)_2{-}OCF_2H$	2730	1092
HG-03	$HF_2C{-}(OCF_2CF_2)_3{-}OCF_2H$	2850	1140
HG-20	$HF_2C{-}(OCF_2)_2{-}OCF_2H$	5300	1325
HG-21	$HF_2C{-}OCF_2CF_2OCF_2OCF_2O{-}CF_2H$	3890	972.5

Acronym, Common Name or Chemical Name	Chemical Formula	GWP 100-year	Uncertainty
HG-30	$HF_2C–(OCF_2)_3–OCF_2H$	7330	1832.5
1-Ethoxy-1,1,2,2,3,3,3-heptafluoropropane	$CF_3CF_2CF_2OCH_2CH_3$	61	24.4
Fluoroxene	$CF_3CH_2OCH=CH_2$	<1	-
1,1,2,2-Tetrafluoro-1-(fluoromethoxy)ethane	$CH_2FOCF_2CF_2H$	871	348.4
2-Ethoxy-3,3,4,4,5-pentafluorotetrahydro-2,5-bis[1,2,2,2- tetrafluoro-1-(trifluoromethyl)ethyl]-furan	$C_{12}H_5F_{19}O_2$	56	22.4
Fluoro(methoxy)methane	CH_3OCH_2F	13	0.52
Difluoro(methoxy)methane	CH_3OCHF_2	144	57.6
Fluoro(fluoromethoxy)methane	CH_2FOCH_2F	130	52
Difluoro(fluoromethoxy)methane	CH_2FOCHF_2	617	246.8
Trifluoro(fluoromethoxy)methane	CH_2FOCF_3	751	300.4
HG’-01	$CH_3OCF_2CF_2OCH_3$	222	88.8
HG’-02	$CH_3O(CF_2CF_2O)_2CH_3$	236	94.4
HG’-03	$CH_3O(CF_2CF_2O)_3CH_3$	221	88.4
HFE-329me3	$CF_3CFHCF_2OCF_3$	4550	1137.5
3,3,4,4,5,5,6,6,7,7,7-Undecafluoroheptan-1-ol	$CF_3(CF_2)_4CH_2CH_2OH$	<1	-
3,3,4,4,5,5,6,6,7,7,8,8,9,9,9-Pentadecafluorononan-1-ol	$CF_3(CF_2)_6CH_2CH_2OH$	<1	-
3,3,4,4,5,5,6,6,7,7,8,8,9,9,10,10,11,11,11-Non-adecafluoroundecan-1-ol	$CF_3(CF_2)_8CH_2CH_2OH$	<1	-
2-Chloro-1,1,2-trifluoro-1-methoxyethane	CH_3OCF_2CHFCl	122	48.8
PFPMIE (perfluoropolymethylisopropyl ether)	$CF_3OCF(CF_3)CF_2OCF_2OCF_3$	9710	1942
HFE-216	$CF_3OCF=CF_2$	<1	-
Trifluoromethyl formate	$HCOOCF_3$	588	235.2
Perfluoroethyl formate	$HCOOCF_2CF_3$	580	232
Perfluoropropyl formate	$HCOOCF_2CF_2CF_3$	376	150.4
Perfluorobutyl formate	$HCOOCF_2CF_2CF_2CF_3$	392	156.8
2,2,2-Trifluoroethyl formate	$HCOOCH_2CF_3$	33	13.2
3,3,3-Trifluoropropyl formate	$HCOOCH_2CH_2CF_3$	17	6.8
1,2,2,2-Tetrafluoroethyl formate	$HCOOCHFCF_3$	470	188
1,1,1,3,3,3-Hexafluoropropan-2-yl formate	$HCOOCH(CF_3)_2$	333	133.2
Perfluorobutyl acetate	$CH_3COOCF_2CF_2CF_2CF_3$	2	0.08
Perfluoropropyl acetate	$CH_3COOCF_2CF_2CF_3$	2	0.08
Perfluoroethyl acetate	$CH_3COOCF_2CF_3$	2	0.08
Trifluoromethyl acetate	CH_3COOCF_3	2	0.08
Methyl carbonofluoridate	$FCOOCH_3$	95	38
1,1-Difluoroethyl carbonofluoridate	$FCOOCF_2CH_3$	27	10.8
1,1-Difluoroethyl 2,2,2-trifluoroacetate	$CF_3COOCF_2CH_3$	31	12.4
Ethyl 2,2,2-trifluoroacetate	$CF_3COOCH_2CH_3$	1	0.04
2,2,2-Trifluoroethyl 2,2,2-trifluoroacetate	$CF_3COOCH_2CF_3$	7	0.28
Methyl 2,2,2-trifluoroacetate	CF_3COOCH_3	52	20.8
Methyl 2,2-difluoroacetate	HCF_2COOCH_3	3	0.12

Acronym, Common Name or Chemical Name	Chemical Formula	GWP 100-year	Uncertainty
Difluoromethyl 2,2,2-trifluoroacetate	$CF_3COOCHF_2$	27	10.8
2,2,3,3,4,4,4-Heptafluorobutan-1-ol	$C_3F_7CH_2OH$	34	13.6
1,1,2-Trifluoro-2-(trifluoromethoxy)-ethane	$CHF_2CHFOCF_3$	1240	496
1-Ethoxy-1,1,2,3,3,3-hexafluoropropane	$CF_3CHFCF_2OCH_2CH_3$	23	9.2
1,1,1,2,2,3,3-Heptafluoro-3-(1,2,2,2-tetrafluoroethoxy)-propane	$CF_3CF_2CF_2OCHFCF_3$	6490	1298
2,2,3,3-Tetrafluoro-1-propanol	$CHF_2CF_2CH_2OH$	13	0.52
2,2,3,4,4,4-Hexafluoro-1-butanol	$CF_3CHFCF_2CH_2OH$	17	0.68
2,2,3,3,4,4,4-Heptafluoro-1-butanol	$CF_3CF_2CF_2CH_2OH$	16	6.4
1,1,2,2-Tetrafluoro-3-methoxy-propane	$CHF_2CF_2CH_2OCH_3$	<1	-
perfluoro-2-methyl-3-pentanone	$CF_3CF_2C(O)CF(CF_3)_2$	<1	-
3,3,3-Trifluoro-propanal	CF_3CH_2CHO	<1	-
2-Fluoroethanol	CH_2FCH_2OH	<1	-
2,2-Difluoroethanol	CHF_2CH_2OH	3	0.12
2,2,2-Trifluoroethanol	CF_3CH_2OH	20	8
1,1’-Oxybis[2-(difluoromethoxy)-1,1,2,2-tetrafluoroethane	$HCF_2O(CF_2CF_2O)_2CF_2H$	4920	1230
1,1,3,3,4,4,6,6,7,7,9,9,10,10,12,12-hexa-decafluoro-2,5,8,11-Tetraoxadodecane	$HCF_2O(CF_2CF_2O)_3CF_2H$	4490	1122.5
1,1,3,3,4,4,6,6,7,7,9,9,10,10,12,12,13,13,15,15-eico-safluoro-2,5,8,11,14-Pentaoxapentadecane	$HCF_2O(CF_2CF_2O)_4CF_2H$	3630	907.5

Appendix B: Previous Contract Work for the Fuel LCA Model

1. *Milestone 2: Methodology for Fossil Fuel Pathways and Baseline Carbon Intensities*
2. *Milestone 3: Methodology for Low Carbon Fuel Pathways and Default Carbon Intensities*

The technical reports (Milestone 2 and 3) were products developed by EarthShift Global, LLC under contract by ECCC. The milestone reports were submitted to ECCC to fulfill the development of fossil fuel baseline CI values and LCIF pre-defined CI values for the proposed Regulations as part of the Fuel LCA Modelling contract.

The reports present the methodology and data sources used to develop various fuel pathways and resulting baseline CI values for fossil fuels and LCIFs produced in Canada. All technical calculations and modelling used to develop the various fuel pathways and associated carbon intensities was carried out by the contractor EarthShift Global, LLC.

Milestone 2 – Final Report
Solicitation Number: 5000038224

Milestone 2: Methodology for Fossil Fuel Pathways and Baseline Carbon Intensities

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Glossary

General Terminology	
Aviation or Jet Fuel	Jet fuel consists of a mixture of between 5 and 16 carbon atoms per molecule depending on the type of jet fuel, and an HHV of 46.31 MJ/kg and a density of 7,998 grams/gal
Background and supporting unit processes:	Materials and energy used as part of a pathway including fertilizers, chemicals, regional grid electricity, etc. These unit processes will be available in the tool for viewing and use in new pathways.
Baseline pathway	Canadian diesel and gasoline pathways which the Clean Fuel Standard uses for reference carbon intensities. These pathways are built into the Fuel LCA Modelling tool and used for companionate analysis.
By-product	A subset of co-products, by-products generally do not have economic value but are not viewed as waste.
Characterization factor	A scalar quantity, or weighting factor, indicating the greenhouse gas potential (or Global Warming Potential, GWP) of an emission. A general term that may also refer to scale factors associated with other potential impacts.
Coal	Coal is a solid fuel comprised of mostly carbon with variable amounts of other elements such as hydrogen, sulfur, oxygen and nitrogen and an approximate HHV of 24 MJ/kg depending upon composition.
Co-product	A product which is created from any production or agricultural process, including silviculture, aquaculture, etc., which is not the prime economic driver of the activity. It can be any of two or more products coming from the same unit process or product system. Examples include corn cobs and husks (stover) co-produced with corn, glycerin which is produced as a co-product of biodiesel esterification, and animal fodder (feed) produced concurrently with the fermentation of ethanol and other alcohols.
Compressed Natural Gas	CNG is methane stored at high pressure that can be used in place of gasoline, diesel or liquefied petroleum gas with an HHV of 52.23 MJ/kg.
Cradle-to-consumer-gate carbon intensity	Greenhouse gases released into the atmosphere due to a fuel's production, processing and fuel delivery to the consumer. Emissions due to combustion are not included in the scope of a fuel's cradle-to-consumer-gate carbon intensity.
Cradle-to-combustion carbon intensity	Greenhouse gases released into the atmosphere due to a fuel's production, processing, fuel delivery to the consumer, and combustion. Technology specific combustion emissions are accounted for however, combustion efficiency and any additional energy losses are excluded from the scope of a cradle-to-combustion carbon intensity.
Database	A repository in the tool which collects pathways, background and supporting unit processes, characterization factors, pathway metadata, user metadata and other information as needed.

Diesel	Diesel is a fuel consisting of a mixture of carbon chains between 9 and 25 carbon atoms per molecule with an HHV of 45.77 MJ/kg and density of 3,206 grams/gal.
Gasoline	Gasoline is a fuel consisting of a homogeneous mixture of hydrocarbons between 4 and 12 carbon atoms per molecule with an HHV of 46.54 MJ/kg and a density of 2,836 g/gal. While gasoline sold to consumers in Canada is typically blended with ethanol, this report refers only to “neat” gasoline and does not including blending with ethanol as part of the carbon intensity calculations.
Heavy Fuel Oil	Heavy fuel oil is the fuel oil that contains residual oil left over from petroleum distillation with an HHV of 41.8 MJ/kg and a density of 0.98 kg/L.
Library	A set of information in the database available to all users but editable only by ECCC and/or its subcontractors. Includes pathways and other unit processes and the characterization factors, etc.
Light Fuel Oil	Also known as residual oil, light fuel oil has an HHV of 44 MJ/kg and a density of 0.96 kg/L.
Liquefied Natural Gas	LNG is natural gas that is predominantly methane with some ethane that has been cooled to form a liquid that facilitates safe transport and storage of non-pressurized fuel with an HHV of 52.23 MJ/kg.
Metadata	Information on a pathway or user which is useful in providing transparency, traceability, verifiability, and/or aids in carbon intensity calculations.
Impact Assessment Method	A specific set of characterization factors
Monte Carlo Analysis	Provides a probabilistic treatment of uncertainty associated with LCA data using Monte Carlo simulations with many steps, at each of which values are randomly sampled from the uncertainty information (e.g., min/max values, median/standard deviation, etc.) associated with each inventory entry, parameter, and/or characterization factor according to the distribution associated with that value.
New low carbon pathway	A pathway created by a tool user.
Propane	Propane is a three-carbon alkane with the chemical formal C_3H_8 and an HHV of 50.24 MJ/kg and a density of 1,920 grams/gal.
Petcoke	Petcoke is a carbon-rich solid remaining from the oil refining process that arises either from the final cracking process of splitting long chain hydrocarbons of petroleum into shorter chains or as a result of the production of synthetic crude oil from bitumen from oil sands. It has an approximate HHV of 31.31 MJ/kg depending on composition.

Stove oil	Also known as No. 1 fuel oil, this is a volatile distillate oil intended for vaporizing pot-type burners with an HHV of 46.2 MJ/kg and a density of 0.795 g/cm^3
Waste	Substances or objects which the holder intends or is required to dispose of
Fuel production-specific terminology	
%wt	Percentage on a weight basis
AER	Alberta Energy Regulator
API Gravity	American Petroleum Institute Gravity of crude oil
CBM	Coalbed Methane
CHOPS	Cold Heavy Oil Production with Sand
CHP	Combined Heat and Power
CI	Carbon intensity
CSS	Cyclic Steam Stimulation
CNG	Compressed Natural Gas
CTC	Cradle-to-combustion
CTCG	Cradle-to-consumer-gate
Dilbit	Diluent combined with bitumen
GHG	Greenhouse Gas
GREET	Greenhouse gases, Regulated Emissions, and Energy use in Transportation Model
HFO	Heavy Fuel Oil
HHV	High or Higher Heating Value
IPCC AR5	Intergovernmental Panel on Climate Change 5th Assessment Report
LCA	Life Cycle Assessment
LFO	Light Fuel Oil
LHV	Low Heating Value
LNG	Liquefied Natural Gas
LPG	Liquefied Petroleum Gas
NCR	Naphtha Catalytic Reformer
NG	Natural Gas
NGL	Natural Gas Liquids
OPGEE	Oil Production Greenhouse gas Emissions Estimator
PRELIM	Petroleum Refinery Life Cycle Inventory Model
SAGD	Steam-assisted gravity drainage
SCO	Synthetic Crude Oil
SOR	Steam-Oil Ratio

RFG	Refinery Fuel Gas
WOR	Water-Oil Ratio

Units

Unit	Description	Conversions
bbl.km	Barrel-kilometer	0.16 m^3.km
Wh	Watt-hour	3,600 MJ
kWh	Kilo watt-hours	1,000 Wh
GWh	Giga watt-hours	1,000,000 Wh
btu	British thermal unit	0.001056 MJ
kg	Kilogram	1,000 g
km	Kilometer	1,000 m
mile	mile	1609.35 m
t	Tonne	1,000,000 g
tkm	Ton-kilometer	1,000 kg.km
MJ	Megajoule	1,000,000 J
L or l	Liter	0.001 m^3

Important information about intermediate Carbon Intensity Values

The carbon intensity values provided in this report are cumulative from raw material extraction through the indicated process (cradle to gate). For example, the process “Crude, to refinery” therefore includes both the CI for the underlying crude extraction and the CI for the transport to the refinery. Similarly, the CI for each refinery output (e.g. diesel) includes all upstream emissions (extraction, transport, refining). For this reason, summing the CI values for each interim process will result in a total CI which is higher than the final calculated CI values in this study.

1. Executive Summary

As part of research efforts to support implementation of the Clean Fuel Standard (CFS), Environment and Climate Change Canada (ECCC) commissioned this life cycle assessment (LCA) project to: 1) quantify baseline carbon intensities (CI) for liquid, gaseous, and solid fossil fuels produced in Canada; 2) quantify default CIs for liquid, solid, and gaseous low carbon fuels produced in Canada; and 3) design a Fuel LCA Modelling Tool that can be used by Canadian fuel producers and stakeholders to quantify the life cycle carbon intensities of low carbon fuels for potential credit generation under the CFS (ECCC 2018a). The CI of a fuel is a quantitative representation of the total life cycle GHG emissions (expressed in kg of CO_2 equivalents) that occur during fuel extraction, processing, transmission, and combustion.

This project is comprised of four milestones, including:

- Milestone 1 – Development of the Conceptual Model;
- Milestone 2 – Methodology for Fossil Fuel Pathways and Baseline Carbon Intensities;
- Milestone 3 – Methodology for Low Carbon Fuel Pathways and Baseline Carbon Intensities; and
- Milestone 4 – Development of the Fuel LCA Modelling Tool and Documentation.

Work on Milestone 1 of the project was completed in January 2019 and summarized in a report submitted to ECCC (EarthShift Global, WSP, Introspective Systems 2019). Work on Milestone 2 of the project was completed in May 2019 and the present report provides a detailed summary of the work completed to update the work from Milestone 2, which was to develop the methodology and baseline CIs for fossil fuel pathways for 2016. This report includes detailed information on the modelling methods, data sources, fuel pathways, and CI results, as well as discussion and reporting of the uncertainty and limitations of the baseline fossil fuel CIs. This report is intended to clearly and transparently communicate how the CIs of Canadian fuels were calculated, the resulting CIs, and uncertainty analysis conducted on the background inventory data and impact assessment method.

The LCA methods used to determine the 2016 baseline CI values for Canadian fossil fuels were in accordance with the ISO 14040 and 14044 standards for LCA, but limited to the sole impact category of climate change. The system boundaries and summary of fuel pathways modeled are shown in Figure 1 below. Wherever possible, Canadian-specific data that reflects 2016 fossil fuel production operations were used.

For liquid fuels, the *Oil Production Greenhouse gas Emissions Estimator* (OPGEE) version 2.0 model was used to estimate GHG emissions from the production, processing and transport of crude oil. The *Petroleum Refinery Life Cycle Inventory Model* (PRELIM) version 1.4 was also used to model a mass- and energy-based representation of the refining process. These two models are unique in that they offer the ability to model the respective processes in detail for a specific facility or refinery. For the crude extraction and pre-processing as well as refining, the OPGEE and PRELIM models were used to calculate the CIs from these specific activities using data that reflects technologies currently in use in Canada. The GHG emissions from transmission, transportation and distribution of feedstocks and fuels were modeled using a combination of Canadian data, published literature, and best available proxies.

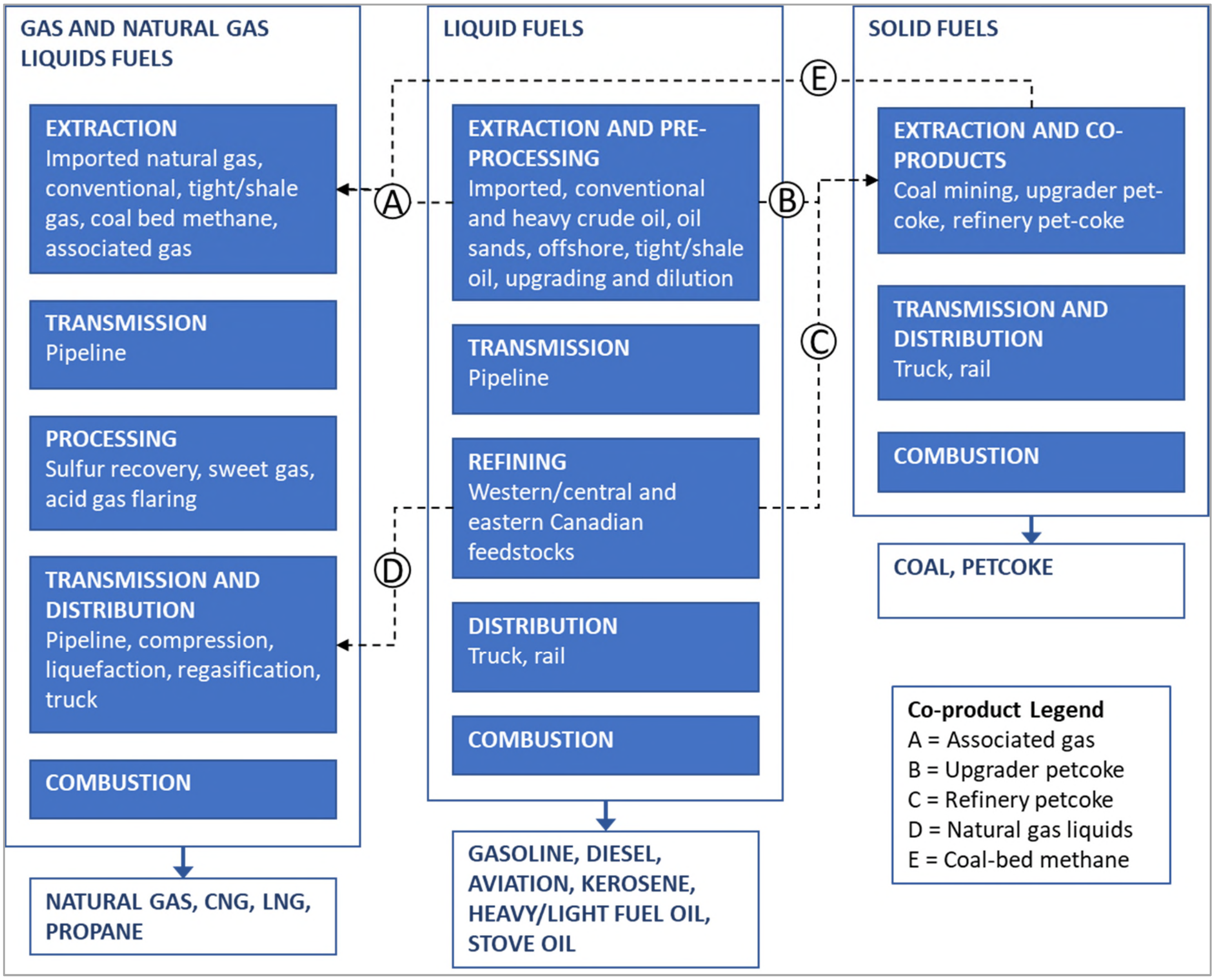


Figure 1. High-level process flow diagram showing typical process routes for gaseous, liquid and solid fuels (blue boxes) and resulting fuels (white boxes). Dashed lines represent co-products transferred between gaseous, liquid and solid pathways. Note that special process routes and other co-products are not represented above.

The CIs for gaseous fuels were calculated based on a production-weighted average of natural gas from Alberta, British Columbia, and imported natural gas from the United States. The calculation of CI values for gaseous fuels was based on the approach used in the National Energy Technology Laboratory (NETL) study on US natural gas production, and included the use of regionally-specific natural gas composition data to calculate venting, flaring, and fugitive emissions, and to model the type and extent of processing and purification required to convert raw gas to pipeline specifications.

The CI of petcoke was modeled based on results from both OPGEE and PRELIM to reflect the amount of petcoke that is produced and used from both upgrading and refining.

Efforts to model in a consistent way across all fuels were made despite the differences in tools and data available. For example, natural gas was modeled according to the different compositions of gas just as there are different qualities and types of crude feedstock for liquid fuels. The CIs for all fuels from cradle-to-consumer-gate(CTCG) and cradle-to-combustion(CTC) in units of g CO_2e/MJ (higher heating value, HHV, of fuel) are presented as well as the uncertainty based on the inventory (the 2.50% and the 97.5% headings indicate the interquartile range of uncertainty) are presented in Table 1 below.

For all fuels considered in this study, the results were in line with the literature both within and outside of Canada. Combustion emissions account for a significant portion of the emissions from all fuels while the upstream production accounts for between 20% and 25% of overall emissions. Therefore, efforts to reduce upstream fuel production emissions can be impactful, while reducing overall fuel consumption and switching to less carbon-intensive fuels provides substantial opportunities for improvements in GHG emissions from fuels.

Table 1: Carbon intensities of all fuels from CTCG and CTC [gCO_2e/MJ fuel HHV].

Fuel	Total Cradle-to-Consumer-Gate(WTCG)			Total Cradle-to-Combustion (CTC)		
	Mean	95% Confidence Interval		Mean	95% Confidence Interval	
		2.50%	97.5%		2.50%	97.5%
Gasoline	24	15	38	96	84	110
Aviation Fuel	19	12	31	88	76	101
Kerosene	19	12	29	87	76	99
Diesel	25	15	39	96	81	112
Light Fuel Oil (LFO)	24	15	37	95	84	110
Stove Oil	24	15	38	92	81	106
Pet-coke	22	19	26	101	95	107
Coal	6.5	4.2	9.4	100	83	120
Heavy Fuel Oil (HFO)	23	14	36	98	85	110
Natural gas	15	14	17	65	57	75
Propane	16	10	25	75	66	86
Compressed Natural Gas (CNG)	19	16	22	67	62	72
Liquified Natural Gas (LNG)	27	23	31	77	71	83

Uncertainty and levels of confidence where data gaps exist were considered in this work as well. This study is novel in that it examined the influence of uncertainty on CIs by using a pedigree matrix in a way that provides transparency into uncertainty within the Canadian-specific fuel context. The uncertainty that results from gaps, assumptions, and parameter variability in the life cycle inventory was evaluated, as well as the uncertainty associated with the IPCC characterization factors used to calculate carbon intensity. In general, the natural gas products exhibit less uncertainty than the liquid fuels from refining. This is driven by the higher variability arising from the range of crude oil types and associated extractions and characteristics, and wider array of refinery configurations, that need to be combined to generate a national baseline value.

While data gaps exist, the influence of these gaps on CIs was considered through uncertainty assessment so that the range of potential CIs can be considered for fossil fuels. It is recommended that these data gaps be filled by collecting additional primary data on extraction, refining and transport of fuels for future updates of these CIs. Moreover, the integration of the fuel CIs developed in this work into the calculation of Canadian electricity grid CIs and completing the loop by then using the updated grid CIs to update the fuel CIs will improve the internal consistency and quality of the underlying data and results. Finally, increased understanding of the CIs of imported fuels and feedstocks could reduce uncertainty in the fossil fuel CIs.

2. Introduction

The Government of Canada has announced its intent to develop a Clean Fuel Standard (CFS) to reduce Canada's greenhouse gas (GHG) emissions through the increased use of lower carbon fuels and alternative technologies. The objective of the CFS is to achieve 30 megatons of annual reductions in GHG emissions by 2030, contributing to Canada's effort to achieve its overall GHG mitigation target of 30% emissions reduction below 2005 levels by 2030. To achieve this goal, fossil fuel suppliers (e.g., refiners, natural gas distributors) will be required to reduce the carbon intensity of the fuels they produce or distribute for use in Canada's transportation, industry, and building sectors. The carbon intensity of a fuel is a quantitative representation of the total life cycle GHG emissions (expressed in kg of CO_2 equivalents) associated with production of 1 MJ of energy from that fuel, including feedstock extraction and processing, fuel production and upgrading, transport and distribution throughout the life cycle, and combustion of the fuel. Under the CFS, baseline carbon intensity values will be set for fossil fuels covered by the regulations based on the 2016 average carbon intensity of these fuels. These baselines will be used to establish the carbon intensity targets or requirements that fuel producers will have to meet for the fuels they supply. The carbon intensity requirements will be expressed as an absolute value set at a level lower than the baseline. These carbon intensity requirements will become more stringent over time. Non-fossil fuel producers, referred to as low carbon fuel producers, will not have their fuel production regulated by the CFS; however, low carbon fuel producers will be eligible to generate credits by supplying fuels that can be shown to have lower life cycle carbon intensities than the reference fossil fuel they would displace (ECCC 2018a).

The Fuel LCA Modelling Tool will be used to set baseline carbon intensity values for fossil fuel producers, as well as serve as a tool for low carbon fuel producers to quantify the life cycle carbon intensities of their fuels for potential credit generation under the CFS (ECCC 2018a).

In October of 2018, ECCC commissioned EarthShift Global, WSP and Quinn & Partners, and Introspective Systems to develop a robust, user-friendly, and transparent software tool based on the international ISO 14040 and 14044 LCA standards (ISO 2006a, ISO 2006b) and to develop carbon intensities using a life cycle approach for Canadian-specific fuel pathway data. This tool will be used to calculate the carbon intensity of existing and future Canadian fossil fuel and low carbon fuel pathways in support of the CFS policy and regulations. The project to develop the CFS carbon intensity software tool is comprised of four stages or milestones, including:

- Milestone 1 – Development of the Conceptual Model (completed January 31, 2019);
- Milestone 2 – Methodology for Fossil Fuel Pathways and Baseline Carbon Intensities (completed May 15, 2019);
- Milestone 3 – Methodology for Low Carbon Fuel Pathways and Baseline Carbon Intensities (Completed August 15, 2019); and
- Milestone 4 – Development of the Fuel LCA Modelling Tool and Documentation (to be completed by March 13, 2020).

Milestone 2 sets the baseline carbon intensities for the Clean Fuel Standard and is an important foundation for upcoming policy on clean fuels. As a result, research emphasis has been placed on more common fuels such as diesel and natural gas as well as areas which are unique to the fossil fuel pathways. Wherever possible, published LCAs and LCA models relating to the

Canadian situation (e.g. PRELIM) have been used as a basis for the pathway models. Where unit process models were not available, preference was given to published Canadian or North American data. In some cases, other GHG tools or US data have been used. Areas where additional time and/or research could refine the values used in the baseline have been noted as recommendations for future work.

This report is the report summarizing the work completed for Milestone 2, Task 2.3: A final report of the methodology and data sources as well as the final baseline carbon intensity values for the fossil fuel pathways. The Process Flow for the calculation of the pathway carbon intensities is detailed in the subsequent sections along with calculation results. This report has been prepared to address the relevant reporting requirements for a third-party report under Sections 5.1 and 5.2 of the ISO 14044 standards (ISO 2006b).

3. Goal and Scope Definition

According to ISO 14044, the first phase of an LCA is to define the Goal and Scope of the study. The goal of the study should clearly specify the following: the intended application; the reasons for carrying out the study; the intended audience; and whether the results are intended to be disclosed to the public. The scope of the study should include a description of the most important aspects of the study, including: the functional unit; system boundaries; cut-off criteria; allocation; impact assessment method; assumptions; and limitations.

The goal of Milestone 2 is to quantify the life cycle GHG emissions per unit of energy content (carbon intensity) of Canadian fossil fuel pathways for 2016 which will be set into Canadian regulation under the CFS to regulate the carbon intensities of fossil fuel producers to ensure that they meet reduction requirements. The results of the study and the methodology used to calculate the carbon intensities will be publicly available and will be used by fuel producers and ECCC policy analysts to compare the carbon intensity of current and future Canadian fuel pathways. These baseline carbon intensities and pathways will also be included in the Fuel LCA Modelling Tool for use in building low carbon pathways and comparing the carbon intensity of low carbon pathways to the baseline fossil fuels. Modelling used for the pathways will be open and transparent to the user within the tool and downloadable in unit process form for review and use in other applications. The Fuel LCA Modelling Tool will also be publicly-available so that policy analysts, fuel producers, and other researchers can use the tool to inform efforts to reduce the carbon intensity of Canadian fuels.

3.1 Function

The function of the liquid, solid, and gaseous fuel pathways analyzed in this study is to provide useable energy for transportation, industrial activities, and buildings in Canada. The fuel feedstocks considered in this analysis may serve other functions such as non-combustion uses (e.g., feedstocks, solvents or diluents) and use in industrial processes (e.g. steel production); however, these functions are not regulated under the CFS and are therefore excluded from the analysis (ECCC 2018). Some fuels are also produced and used onsite by the fuel producer to produce a finished fuel or in facility operations. The CFS will regulate some of these “self-produced and used fuels” and they are included within the scope of this analysis (ECCC 2018a).

3.2 Functional Unit

A functional unit is defined as the quantified performance of a product system for use as a reference unit (ISO 2006a). This facilitates determination of reference flows for the system(s) being studied.

In this case, the function under study is the provision of energy to power transportation, heating, and/or power generation. The functional unit is 1 MJ energy content based on the Higher Heating Value (HHV) at the regional distribution center.

The carbon intensity values are expressed in grams of carbon dioxide equivalents (g CO_2 e) per unit of energy content of the fuel in megajoules (MJ HHV). This is synonymous to the energy produced from fuel combustion for this report and the tool. Although useful energy generated from fuel combustion varies depending on the efficiency of the combustion device, the modelling of carbon intensity values for specific combustion types and devices (e.g. heating, transportation, electricity) was beyond the scope of this project. As such, the values represented in this report do not account for the thermal efficiency of the combustion.

3.3 System Boundaries

System boundaries are established in LCA to include the significant life cycle stages and unit processes, as well as the associated environmental flows in the analysis. This lays the groundwork for a meaningful assessment where all important life cycle stages and the flows associated with each alternative are considered. The general system boundaries for the Fuel LCA Modelling Tool include:

- **Extraction**: extraction of raw feedstock materials (e.g. mining of crude oil and coal);
- **Feedstock Transport**: transportation of raw or upgraded feedstock to the fuel producer, including any upgrading or processing required prior to transport;
- **Conversion**: processes for converting the feedstock into fuels, including any post-processing and upgrading to final fuel product;
- **Fuel Transport**: storage and handling of fuel, transport of finished fuel product to storage and to final user; and
- **Combustion**: combustion of the final fuel product by the end user, taking into consideration the efficiency of combustion.

Within each of these life cycle stages, the system boundary also includes the life cycle GHG emissions associated with the use of electricity inputs (both grid and onsite generation), fuel inputs, material inputs (e.g. chemicals), process emissions (e.g. venting and flaring), and transportation processes. The inclusion of emissions from these background processes are determined by cut-off criteria (see Sections 3.5 and 3.6).

3.4 Fuel Production System Descriptions

3.4.1 System Boundaries for Fossil Fuel Pathways

The scope of this milestone includes existing fossil fuel pathways currently available and used in Canada. It is expected that in the future, ECCC and/or its subcontractors will modify existing fossil fuel pathways to reflect system changes and efficiency improvements and update carbon intensity reduction targets. General system descriptions are provided below for the selected fossil fuels. The general system boundaries for the fossil fuel pathways are outlined in Figure 2.

3.4.2 Fossil Fuel Pathways

The Canadian fossil fuel pathways that will be included in the Fuel LCA Modelling Tool are summarized in Table 2 below. More detailed description of each individual pathway is provided in the following sections on extraction and pre-processing (gas, oil, imported gas and oil), transmission (gas pipeline, liquids pipeline, trucks, rail, and tankers), refining (transportation fuels, propane, petcoke), distribution (gas pipeline, liquids pipeline) and combustion. Figure 2 provides a high-level process flow diagram. Each section that follows provides an expanded process flow diagram with references to the interconnections between the fuel pathways.

The modelling of the fossil fuel pathways reflects regional differences where possible by using model parameters and intermediate flows such as grid electricity, transport distance and method, and variable input and output flows. Similarly, refining products represent several fuels (displayed as a single flow in the figure).

Table 2. Summary of Canadian fossil fuel pathways to be included in the Fuel LCA Modelling Tool.

General Pathways	Fuel Pathways
Liquid Fuels (Fossil)	Gasoline (all octane levels supplied) Diesel fuel (regular or low sulphur) Aviation turbo fuel (jet fuel) Heavy oil Light fuel oil Heavy fuel oil Kerosene Stove oil
Gas Fuels (Fossil)	Natural gas (pipeline specification) Compressed natural gas (CNG) Liquefied natural gas (LNG)
Natural Gas Liquids (Fossil)	Propane
Solid Fuels (Fossil)	Coal Petroleum coke

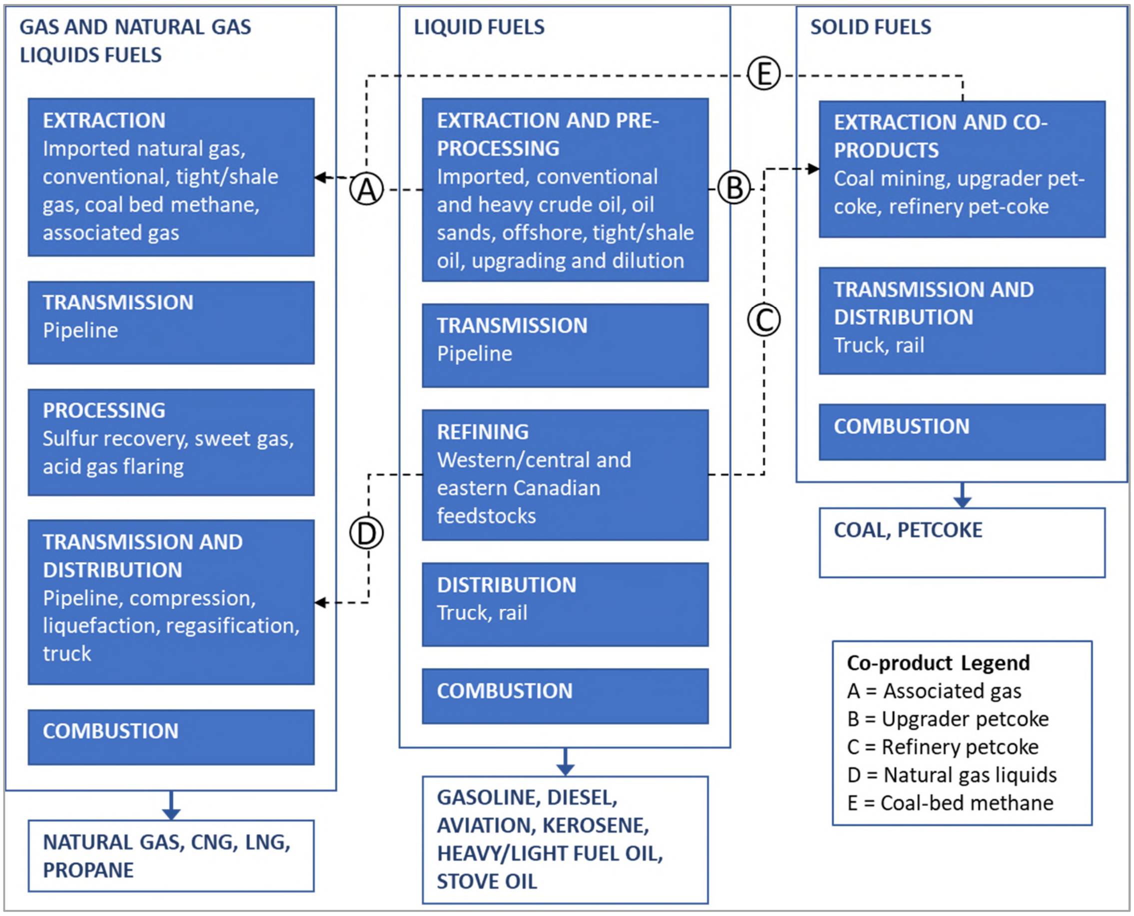


Figure 2: High-level process flow diagram showing typical process routes for gaseous, liquid and solid fuels (blue boxes) and resulting fuels (white boxes). Dashed lines represent co-products transferred between gaseous, liquid and solid pathways. Note that special process routes and other co-products are not represented above.

3.4.2.1 Liquid Fuels

Liquid fuels are derived from petroleum and are the dominant transportation fuels in the world. Most vehicles on the road, in the air or in open water today burn these fuels exclusively and contribute significantly to GHG emissions. Herein, the term “standard fuels” refers to fossil-based fuels as opposed to bio-based or low-carbon fuels or blends of fossil and bio-based fuels.

Standard fossil fuels are produced from feedstocks with conventional and unconventional extraction methods. Production methods relevant in Canada include conventional, offshore, tight or shale oil, oil sands mining and oil sands in-situ extraction. Oil sands derived bitumen requires further processing (pre-processing) before it is sent to refining. This involves upgrading to produce synthetic crude oil (SCO) or dilution to produce diluted bitumen. Upgrading uses fractional distillation or chemical treatment to reduce the viscosity, separate out heavy fractions, and reduce sulfur, nitrogen and metals. Processes for upgrading include vacuum distillation, de-asphalting, cracking and hydrotreating.

These refinery feedstocks are then transported through pipelines and other means to refineries where they are processed into various fuels, chemicals and other products. Crude oil is separated into different fuels via fractional distillation according to the boiling points of the various products.

The liquid transportation fuels are blended to various octane (in the case of gasoline) and cetane ratings (in the case of diesel) and to meet other performance requirements for applications. The heavier crude oil fractions (e.g., heavy fuel oil) are commonly used by ships. Kerosene has applications in jet fuel, heaters and lamps while stove oil is more likely burned in furnaces or boilers.

Production of fossil fuels stems from various geographic sources. Domestic production predominantly occurs in Alberta and Saskatchewan. Crude oil extraction in Canada occurs in British Columbia, Alberta, Saskatchewan, Manitoba, Newfoundland Labrador and Nova Scotia. Some crude oil is imported from the United States and other international sources, with various points of entry into Canada.

The majority of offshore extraction occurs off the coast of Newfoundland. Oil sands extraction occurs in Alberta at sites including the Athabasca, Cold Lake, Long Lake and Peace River locations. Extractions from oil sands sites require upgrading which primarily occurs in Alberta. Refineries are located in Alberta, British Columbia, New Brunswick Newfoundland and Labrador, Ontario, Quebec, and Saskatchewan.

3.4.2.2 Gaseous Fuels

Gaseous fossil fuels are produced from reservoirs via conventional drilling, pumping and compression methods as well as unconventional methods. These fuels, including compressed and liquefied natural gas, are traditionally used in boilers and power plants to generate heat and power, though they can also be used to drive vehicles adapted to run on them through a gas-to-liquids process. Natural gas deposits are primarily in the Western Canadian Sedimentary Basin which covers southwestern Manitoba, southern Saskatchewan, Alberta, northeastern British Columbia and the southwest corner of the Northwest Territories. It is notable that the majority of the natural gas produced in Canada employs an unconventional technique from extraction through processing. This gas is also commonly used as a feedstock for petrochemical production.

Canadian Natural Gas Market Overview

Domestic Production of Natural Gas

Canada is the world's fifth largest producer of natural gas and accounts for approximately five per cent of global production. Canadian natural gas supply generally exceeds domestic consumption and its natural gas markets are highly integrated with the United States (National Energy Board 2018b). In 2016, average Canadian production of marketable natural gas was over 430 million m^3 per day (Table 3). Nearly all of this production was from Western Canada, with Alberta and British Columbia accounting for 67% and 30%, respectively. Between 2014 and 2018, Canadian natural gas production was increasing overall due to steady increases in production in Alberta and British Columbia, while production has been steadily declining in all other Canadian provinces.

Table 3. Marketable natural gas production in Canada by province, 2014 to 2018 (1,000 m^3/day).

Year	British Columbia	Alberta	Saskatchewan	NWT & Yukon	Ontario	New Brunswick	Nova Scotia	Canada
2014	113,000	280,000	12,300	298	296	264	9,120	416,000
2015	119,000	287,000	12,200	231	307	156	5,480	424,000
2016	126,000	288,000	11,600	222	200	212	4,830	431,000
2017	127,000	302,000	11,400	24	218	96	3,510	444,000
2018	144,000	298,000	11,200	28	240	151	1,990	456,000

Note – Values are averages of NEB reported monthly averages for daily production levels (Canada Energy Regulator 2018)

Saskatchewan accounted for just under 3% of national daily production in 2016, and Canada's National Energy Board (NEB) estimates that 100% of Canadian natural gas production will come from Alberta, British Columbia, and Saskatchewan from 2025 onwards, with Saskatchewan contributing less than 2% of this future production (National Energy Board 2018f). Given that Alberta and British Columbia will continue to account for upwards of 96-98% of total Canadian natural gas production going forward, we have focused our carbon intensity calculations on production conditions for these two provinces.

The natural gas production volumes in Table 3 are expressed in daily production amounts. The Canadian Association of Petroleum Producers (CAPP) reports that in 2016, Canada produced approximately 156,807 billion m^3 of natural gas (CAPP 2019). A breakdown of total marketable natural gas production by province for 2016 is provided in Table 4.

Table 4. Total marketable natural gas production in Canada in 2016, broken down by province and expressed in volume, mass, and energy content (HHV).

Year	British Columbia	Alberta	Saskatchewan	Rest of Canada
Volume (m^3)	47,130,000,000	105,006,000,000	2,583,000,000	2,088,000,000
Mass (kg)	36,761,400,000	81,904,700,000	2,014,740,000	1,628,640,000
Energy (MJ)	1,920,050,000,000	4,277,900,000,000	105,230,000,000	85,064,000,000
Percent by volume (%)	30%	67%	2%	1%

Note: Volume data is from CAPP (2019). Mass is calculated with a density of 0.78 kg/m^3 (at 32F and 1atm) and production by energy calculated with a HHV of 52.2 MJ/kg (as per Section 4.10).

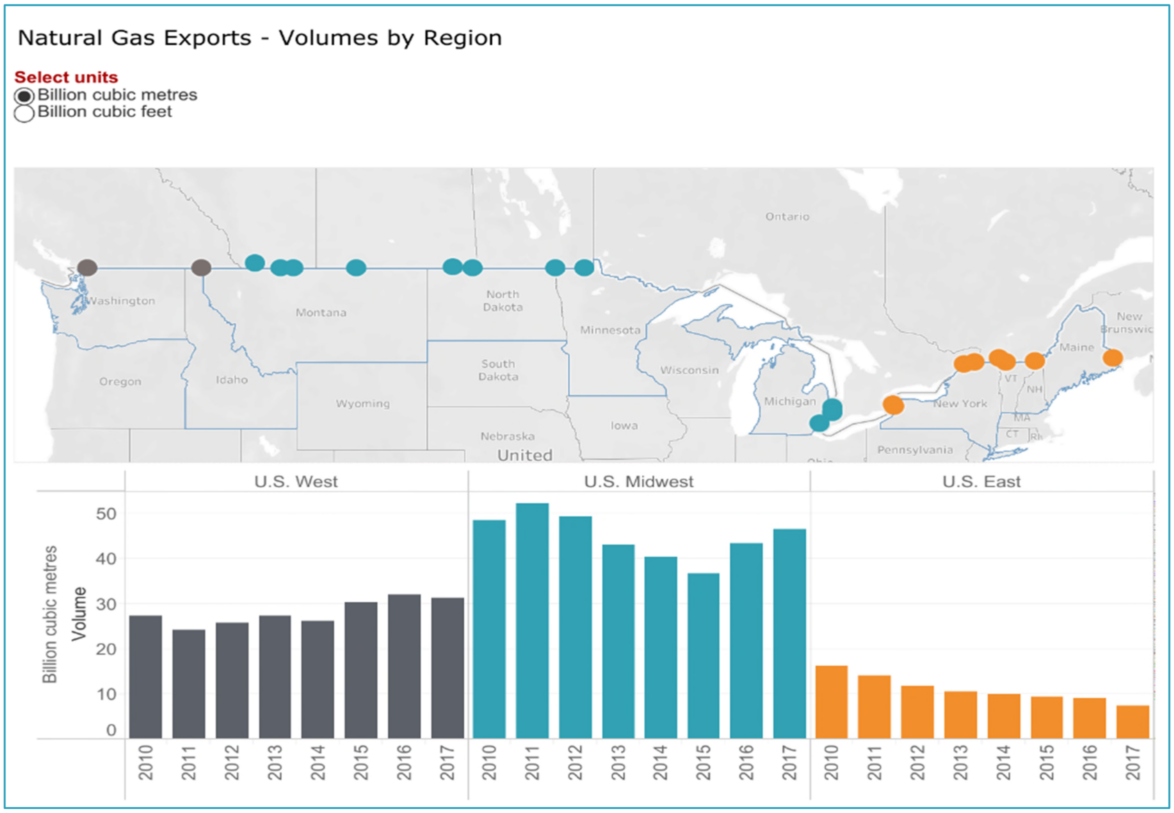
Imports and Exports

Canada is a net exporter of natural gas, with all exports going to the United States via pipeline. A summary of natural gas import and export totals between 2012 and 2017 is provided in Table 5.

Table 5. Summary of Canadian natural gas imports and exports between 2012 and 2017 expressed as total volume (billion m^3) (National Energy Board 2018g)

Year	Export Volume (billion m^3)	Import Volume (billion m^3)
2012	86.8	29.5
2013	80.9	25.5
2014	76.3	21.4
2015	76.0	19.2
2016	84.2	21.9
2017	85.1	24.9

All of Canada’s natural gas exports go to the United States and flow primarily by transmission pipelines across the border in Western Canada. The majority of natural gas imports flow by pipeline across the border into Ontario. A summary of exports by Canadian region is provided in Figure 3. (National Energy Board 2018g)


Natural Gas Exports - Volumes by Region

Select units
● Billion cubic metres
○ Billion cubic feet

Figure 3. Canadian natural gas exports by volume (billion cubic metres) and by region showing key border transmission nodes (National Energy Board 2018g).

Natural gas imports to Canada come from the United States via pipeline, with the exception of some imported LNG which is from overseas markets. The amount of imported LNG has been declining in recent years and only arrives at one facility in New Brunswick. In 2016, approximately 329,000 m^3 of LNG (gas equivalent) were imported to Canada from overseas markets (National Energy Board 2018g), which is less than 0.1% of total natural gas imports. Upon import, LNG undergoes a regasification process and enters the Canadian natural gas pipeline transmission system to reach other parts of Canada and the United States.

A summary of NEB regulated natural gas pipelines is shown in Figure 4.

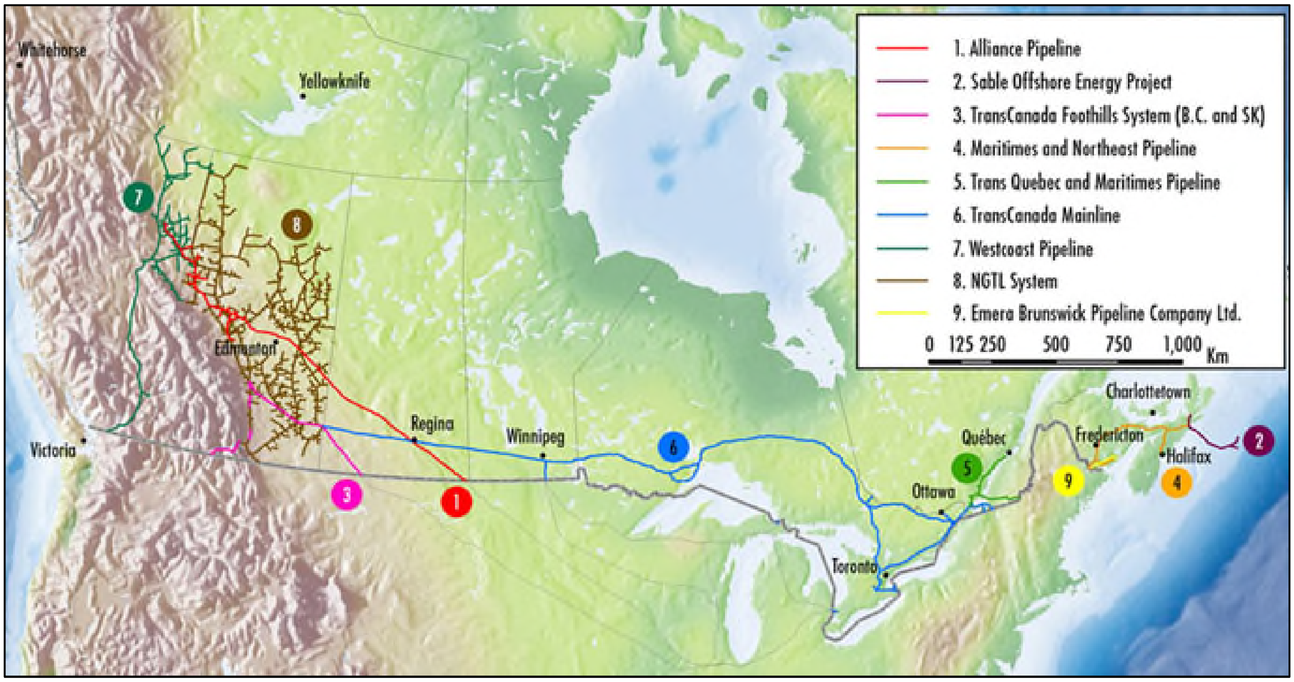


Figure 4. Locations of NEB regulated natural gas pipelines in Canada (Canada Energy Regulator 2016a)

Natural Gas Extraction

Natural gas extraction in Canada involves the development of either conventional or unconventional gas resources. Conventional natural gas resources are concentrations of gas that occur in discrete accumulations or pools that are surrounded by rocks with high porosity and permeability and beneath impermeable rock formations. Conventional gas pools are developed using vertical drilling and require minimal stimulation. Conventional oil and gas pools have historically been the primary exploration targets in Western Canada; however, in more recent years, unconventional gas resources have been increasingly developed.

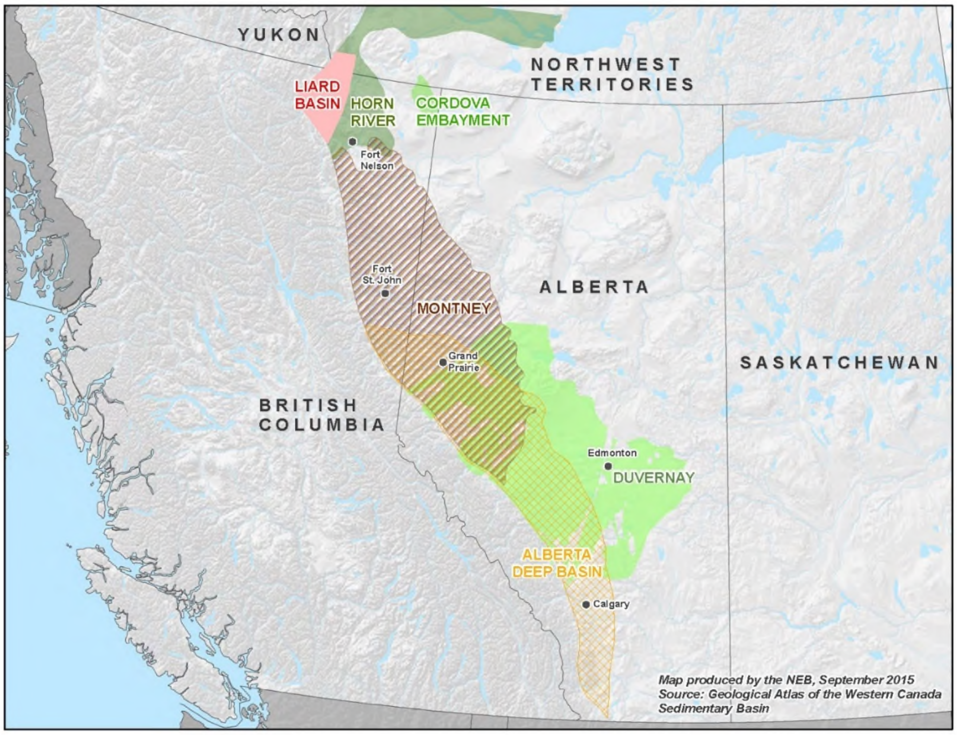
Unconventional natural gas resources are gas stored in pools where the permeability and porosity are so low that the resource cannot be extracted economically through vertical well bore drilling. Instead, unconventional natural gas resources typically require horizontal drilling, and in many cases, this must be followed by multistage hydraulic fracturing to achieve economic production (although in some instances horizontal drilling occurs without fracking).

Unconventional sources include (CAPP 2018a):

- Shale – Natural gas trapped within sedimentary shale rocks with low permeability. Commercial extraction requires horizontal drilling and hydraulic fracturing;
- Tight – Natural gas found within pores between organic-rich shales or low permeability sandstone, siltstone, limestone, or dolostone reservoirs. Commercial extraction typically requires horizontal drilling and hydraulic fracturing;
- Coalbed methane (CBM) – Natural gas trapped within coal seams, considered unconventional since gas is absorbed into the coal. Coalbed methane is extracted by drilling wells into coal seams and pumping out groundwater, reducing the pressure and allowing the methane to release from the coal to produce flowing natural gas (US EPA 2015).; and

- Associated (solution) – Natural gas produced during crude oil extraction. In some operations this gas is flared rather than produced for commercial use.

Within Western Canada, natural gas extraction is primarily from an area of key producing wells in the Western Canada Sedimentary Basin (WCSB) that span Alberta and British Columbia, most notably the Montney and Duvernay formations (Figure 5).



Map produced by the NEB, September 2015
Source: Geological Atlas of the Western Canada Sedimentary Basin

Figure 5. Key natural gas producing regions in the Western Canada Sedimentary Basin (Canada Energy Regulator 2016b).

Canadian natural gas production is dominated by tight gas extraction in Western Canada. Tight gas extraction accounted for 59% of natural gas production in 2016, followed by conventional (22%) and associated gas (12%) (Table 6). Extraction from shale and coalbed methane accounted for 3% and 4%, respectively. According to the NEB, future growth in natural gas extraction will be primarily from tight and shale resources (National Energy Board 2018f).

Table 6. Percent contribution by extraction type for Canadian natural gas production from 2014 to 2017 (Adapted from NEB 2018f).

Year	Conventional	Tight	Shale	Associated	Coalbed methane
2014	29%	50%	4%	12%	5%
2015	25%	55%	3%	12%	4%
2016	22%	59%	3%	12%	4%
2017	20%	62%	3%	11%	4%

Canadian natural gas extraction by type is summarized by region of production in Table 7. The primary regions supporting Canadian production in 2016 were tight gas extraction in the BC Montney formation (22%) and Alberta Deep Basin (22%), as well as Western Canadian conventional natural gas production (20%).

Table 7. Summary of Canadian natural gas production by region of production between 2014 and 2018 expressed as per cent contribution to total production by volume (NEB 2018f).

	Solution	CBM	Tight				Shale			Conventional	
	Western Canada		Montney		Deep Basin	West. Canada Other	Duvernay	Horn River	West. Canada Other	Western Canada	Rest of Canada
Year			AB	BC	AB						
2014	12%	5%	5%	16%	21%	8%	0%	3%	0%	27%	2%
2015	12%	4%	7%	19%	22%	7%	1%	3%	0%	24%	1%
2016	12%	4%	9%	22%	22%	7%	1%	2%	0%	20%	1%
2017	11%	4%	11%	23%	22%	6%	1%	2%	0%	19%	1%

The natural gas that is extracted from conventional and unconventional sources is generally classified into three types, including dry natural gas, wet natural gas, and associated natural gas (Clearstone Engineering Ltd. 2014). The post-extraction processing required to produce transmission-ready natural gas varies depending on which form of natural gas is extracted. This is explored in more detail in the natural gas modelling section of the report (Section 4.8)

3.4.2.3 Natural Gas Liquids

Overview of Canadian NGL and Propane Production

Natural gas liquids (NGLs) are heavier hydrocarbons such as ethane, butane, propane, and pentanes that are contained in raw natural gas (National Energy Board 2018h). Propane and other NGLs are recovered from the processing of raw natural gas at natural gas plants and are also produced in crude refining during the cracking of petroleum. Mixed NGLs are sent from natural gas field plants to centralized, large-scale fractionation plants where specific end products are produced (AER 2019c). NGLs are also recovered from gas reprocessing plants (or straddle plants) that are located along natural gas transmission lines to remove NGLs from marketable pipeline gas. NGLs recovered from straddle plants are also sent to fractionation plants for processing into marketable end products (e.g. propane) (AER 2019b)

Propane is a naturally occurring alkane found within petroleum deposits and natural gas accumulations found in reservoirs made of sandstone and carbonate rock (NRC 2019a). Approximately 90% of propane production in Canada is from the processing of NGLs at natural gas plants, with the other 10% produced as a co-product from petroleum refineries. Canada is the world's fourth-largest propane producer, with 2016 production levels reaching 23,200 m^3/day (Table 8). Overall production has generally been declining in recent years, with Nova Scotia no longer producing propane as of 2018 and declining production in Alberta.

Table 8. Canadian propane production by province for 2014 – 2018, expressed in thousand cubic metres per day (Source: NEB 2018i).

Province	2014	2015	2016	2017	2018
British Columbian	1.2	1.0	0.9	1.0	1.1
Saskatchewan	0.6	0.6	0.6	0.5	0.5
Nova Scotia	0.7	0.6	0.5	0.5	0.0
Alberta	18.2	17.4	16.9	16.0	15.3
Adjustment	5.2	5.2	5.2	5.2	5.2
Canada Total	26.0	24.9	24.1	23.2	22.2

Propane production in Canada is dominated by Western Canadian producers, and in particular Alberta, which accounts for over 70% of Canadian production. In 2016, gas processing plants accounted for just under 88% of Canadian propane production (Conference Board of Canada) (Table 9).

Table 9. Overview of 2016 Canadian propane industry.

2016 Canadian Propane Profile	Amount (m^3)	Source/Comment
Total domestic production (m^3)	9,182,000	CAPP Statistics Handbook (2019)
○ Alberta	7,578,000	Production from gas processing facilities only
○ British Columbia	1,065,000	Production from gas processing facilities only
○ Saskatchewan	440,000	Production from gas processing facilities only
○ Nova Scotia	100,000	Production from gas processing facilities only
Total propane exports (m^3)	6,660,000	(NEB 2018i). All exported to the United States
Total propane imports (m^3)	357,000	(US EIA 2019). All imported from the United States
Breakdown of domestic production:		(NEB 2018f)
- Crude refineries	7.8%	
- Crude extraction NGLs	4.5%	
- Gas processing plants	87.7%	

3.4.2.4 Solid Fuels

Solid fuels include coal and petroleum coke (or petcoke). Coal is a solid fuel primarily composed of carbon that is mined from rock formations. There are several types of coal including lignite, sub-bituminous, bituminous, anthracite and graphite, though graphite is not commonly used as fuel. As a fuel, coal is used to generate electricity or heat. Petroleum coke is a solid carbonaceous fuel derived from oil refining. While some petcoke is further processed for metallurgical use, ‘raw’ or ‘green’ petcoke is used for energy and manufacturing.

Petcoke

Petcoke Overview

Petroleum coke, or petcoke, is a carbon-dense solid residue co-product from crude oil processing. Raw or “Green” (non-calcined) petroleum coke, also called fuel (pet)coke, is used primarily for energy and manufacturing. Petcoke may be further refined by firing green coke in rotary kilns to produce calcined petcoke, which is generally used for anodes in aluminum production. Calcined petcoke is not used as fuel.

The two petcoke sources are:

- Refinery Petcoke – petcoke produced as a coproduct of refining heavy crude oils, including bitumen
- Upgrading Petcoke – petcoke produced as a coproduct of upgrading bitumen to synthetic crude that will be refined elsewhere

Petcoke is produced from heavier crude oils, derived from the cracking of long chain hydrocarbons into shorter chains from petroleum in coker units. The proportion of coke generally scales with the heaviness of the crude. It is also produced during oil sands upgrading to synthetic crude oil from bitumen. Bitumen creates the by-product of petcoke and is commonly extracted from Canadian oil sands located in Alberta. This petcoke source is generally a waste and is stockpiled.

Fuel-grade petcoke is used in concrete production, electricity generation either alone or cofired with coal, and other industries as a source of heat, power or as a source of carbon. It is also used in petroleum refining and upgrading operations. Refinery petcoke is marketed as a product.

Canadian Petroleum Coke (Petcoke) Production & Demand

Canadian upgraders and refineries together produce a significant quantity of petcoke (Table 10 and Table 11). Over the past five years, Canada has accounted for about 1% of global petcoke production (in 2016, Canada ranked 12th in petcoke production) (United Nations Statistics Division 2019).

Much of the provincial production data are suppressed, as Table 10 illustrates. The production of refinery petcoke in Ontario is primarily from the Sarnia refineries, where Western crude is used as the input crude. These results are also reflected in the detailed PRELIM refinery models, described in detail in Section 4.6.

Table 11 shows the production and utilization of upgrading petcoke produced over the last five years. The majority of production is stockpiled, on average of about 77% of annual upgrader petcoke production over the past five years (82% in 2016, the baseline year). Of the remainder, some is used internally by the upgrader. A small fraction of production is used externally of the facility (6% in 2016), much of which is primarily exported.

Table 10: Supply and disposition of Canadian refinery petcoke production between 2013 and 2017 expressed as annual production (m^3) and provincial share (%) where data are available* (Statistics Canada 2018).

Year	Canada	% Share of Production							
	m^3	British Columbia	Alberta	Saskat-chewan	NWT, Yukon & Nunavut	Ontario	Manitoba	Quebec	Atlantic Provinces
2013	1,173,276	-	31%	-	-	27%	-	-	-
2014	1,270,723	-	34%	5%	-	22%	-	-	-
2015	930,723	-	33%	18%	-	43%	-	-	-
2016	1,020,921	-	42%	5%	-	49%	-	-	-
2017	937,679	-	48%	-	-	-	-	-	-

**Note that much of the provincial level data are suppressed and may be the source of the year to year changes. Production volumes may include green and calcined petcoke with an average density of 1.2-1.6 and 1.9-2.1 g/cm^3 respectively.*

Table 11: Summary of Canadian upgrading petcoke production and utilization between 2013 and 2017, Alberta (1000 t) (Alberta Energy Regulator 2016, 2015, 2014, 2013)

Year	Annual Production (1000 t)	Stockpile (year-end) (1000 t)	Internal use (% of annual production)	External use (% of annual production)
2013	8,638	83,622	11%	12%
2014	8,900	90,046	12%	16%
2015	10,633	98,313	10%	12%
2016	8,902	105,630	11%	6%
2017	10,131	113,393	18%	6%

Globally, cement production consumes about 25% of produced petcoke, about 18% is used for electricity generation and another 15% in other areas of industry; about a third of petcoke is upgraded and used for aluminum production and other metallurgy (Tao 2015). While petcoke is used for electricity production and manufacturing, a large fraction of production – primarily that from upgrading, as previously mentioned – is unused and stockpiled.

Market analysts estimate the global petcoke market at around $20bn in 2016 with an expected annual growth of about 9% annually over the next five years, driven primarily by growth in India and China.[1]

The modelling of petcoke is discussed in Section 4.7. Petcoke consumed within the upgrader or refinery where it was produced generates emissions that are attributed to the resulting fuels produced. Petcoke produced in Canada and consumed outside of the production facility is modeled as a byproduct with its own fuel pathway and the emissions associated with its production are allocated to it based on energy content. The remainder of petcoke produced is stockpiled on site and, for the purposes of this model, considered to be a waste stream of low or no economic value. As a result, stockpiled petcoke does not receive an allocation of the production related emissions.

Under the Clean Fuel Standard, there is a separate GHG reduction target for “Self-Produced and Used Fuels”[2]. Internal use of petcoke in Table 11 falls under this category. However, from a modelling perspective, the internal use of petcoke is contained within the process boundary as use of an internal stream and thus its contribution to the CI of upgrading is already included in that value; it is not included in the amount of byproduct and waste petcoke produced from the facility.

Coal

Coal Overview

Coal is a mineral deposit rich in carbon content that has formed from millions of years of compaction and chemical changes to decayed plant material. It is one of Canada’s most abundant fossil fuels, with an estimated 6.6 billion tonnes of recoverable coal reserves (CAC 2019). Over 90% of Canada’s coal deposits are found in western provinces like British Columbia, Alberta, and Saskatchewan (Figure 6).

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[1] See, e.g. https://www.globenewswire.com/news-release/2018/08/08/1549001/0/en/Global-Petroleum-Coke-Market-Will-Reach-USD-33-06-Billion-By-2024-Zion-Market-Research.html, https://www.alliedmarketresearch.com/petroleum-coke-market, https://www.reuters.com/brandfeatures/venture-capital/article?id=61034

[2] “In the solid fuel stream, some self-produced and used fuels will have a separate carbon intensity compliance obligation. These include coal used at coal mines and petroleum coke produced at refineries and upgraders.”(ECCC 2018a).

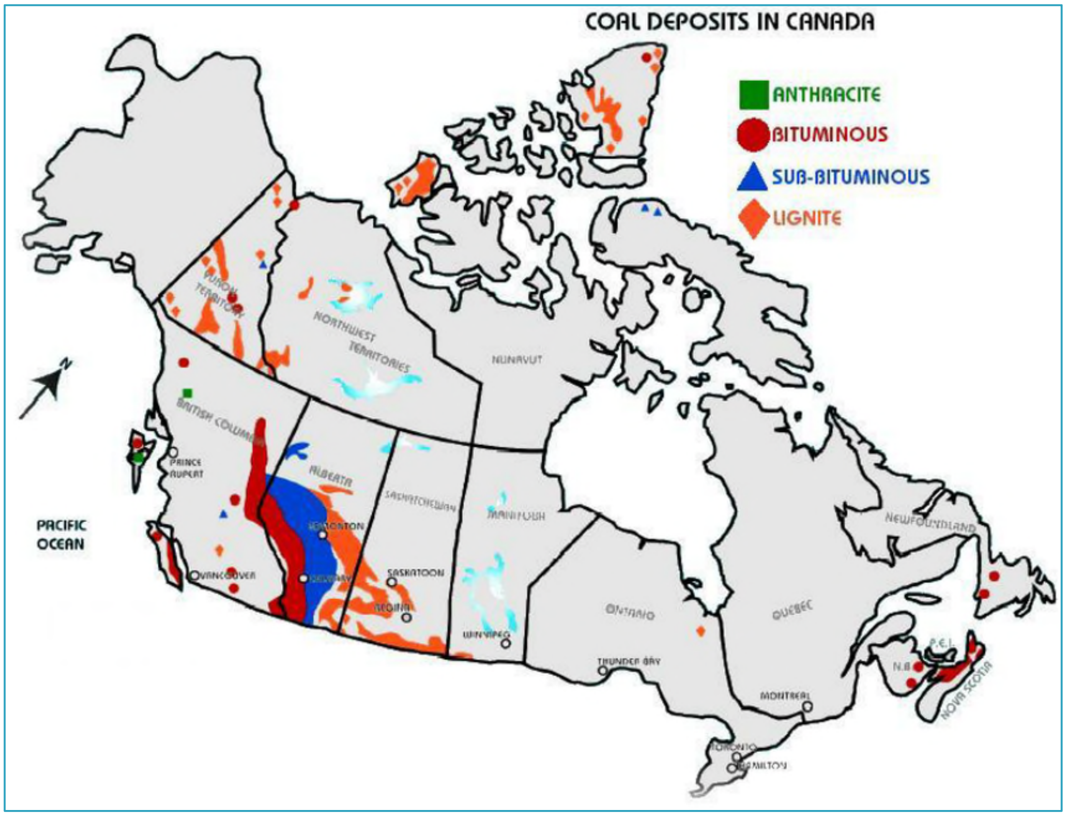

Figure 6. Canadian coal deposits broken down by coal type and by province (Höök et al. 2008)

Coal is classified into types based on its hardness and energy content. There are four types of coal found in Canada, including (CCA 2019):

- Anthracite – a hard, glossy coal with high energy content that is used for space heating and steel making;
- Lignite – the lowest rank of coal, often called brown coal, that is used almost exclusively for electricity generation;
- Bituminous – dense, black coal used as a coking coal for steel manufacturing or for electricity generation; and
- Sub-bituminous – a coal with properties ranging between lignite and bituminous. It generally has a lower sulphur content than other types and is typically used in electricity generation.

Canada currently has 24 permitted coal mines, of which 19 are in operation, and they are located primarily in Western Canada, including 10 mines in British Columbia and 9 mines in Alberta. Deeper coal deposits are mined using vertical or horizontal shafts (underground); however, all underground coal mining ceased in Canada in 2015 (CCA 2019), and Canadian coal production is dominated by surface mining for relatively shallow deposits (i.e. open pit or strip mining).

Canadian Coal Production

Canadian coal production is generally broken down by metallurgical coal, which is used as an input to steel making, and thermal coal, which is used as a fuel, primarily for electricity generation. In 2016, Canadian coal mines produced approximately 61 million tonnes of coal, with thermal coal accounting for about 52% of this production (Table 12). Canada is a net exporter of coal, exporting over 30 million tonnes of coal in 2016, and importing just over 6.3 million tonnes, primarily from the United States.

Table 12. Canadian coal production in metric tonnes for 2016 broken down by type and including domestic production, exports, and imports (NEB 2018f).

Coal Type	Production (tonnes)	Exports (tonnes)	Imports (tonnes)	Domestic Demand (tonnes)
Thermal	31,430,000	2,207,000	2,857,000	30,380,000
Metallurgical	29,550,000	28,570,000	3,451,000	6,130,000
Total	61,000,000	30,780,000	6,308,000	36,510,000

For the purposes of the Clean Fuel Standard, this study is focused on calculating the carbon intensity of thermal coal only, including its production and use in coal-fired electricity generation stations. Although the Government of Canada introduced federal legislation in 2016 to phase-out the use of coal-fired electricity in Canada by 2030, there are still several provinces where coal comprises a significant source of electricity, including Alberta, Saskatchewan, Manitoba, New Brunswick, and Nova Scotia (Figure 7). Canadian coal-fired electricity consumed over 30 million tonnes of coal in 2016 (NRC 2019b), accounting for over 83% of domestic demand (Table 12).

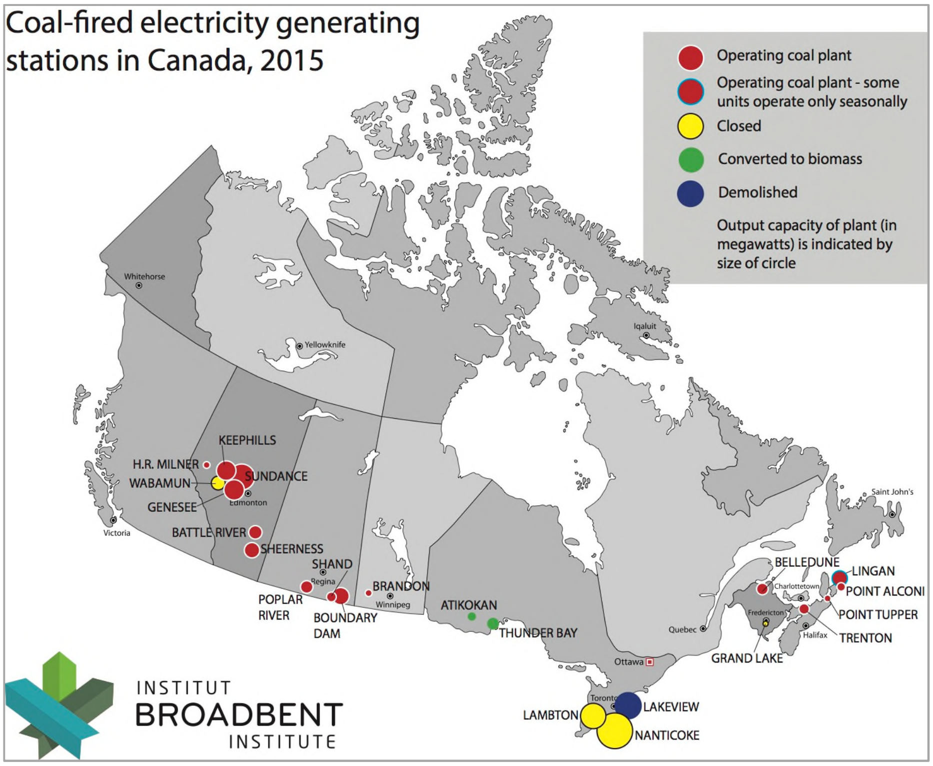

Figure 7. Locations of coal-fired electricity generation stations in Canada in 2015, including plants that have been closed, converted, and demolished. (Broadbent Institute 2015)

3.5 Cut-Off Criteria

Cut-off criteria are used in LCA practice for the selection of processes or flows to be included in the system boundary. The processes or flows below these cut-offs or thresholds may be excluded from the study. Several criteria are used in LCA practice to decide which inputs are to be considered, including mass, energy, and environmental significance. As noted in ISO 14044, making the initial identification of inputs based on mass contribution alone may result in important inputs being omitted from the study. As such, energy and environmental significance should also be used as cut-off criteria, particularly in studies intended to support comparative assertions made to the public. Options for cut-off criteria specified in ISO 14044 include:

- Mass: inclusion of all inputs that cumulatively contribute more than a defined percentage to the mass input of the product system being modeled.
- 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 contribute more than an additional defined amount of the estimated quantity of individual data of the product system that are specially selected because of environmental relevance.

Similar cut-off criteria may also be used to identify which outputs should be traced to the environment (e.g. emissions, wastes).

For this study, every effort was made to include all the relevant flows associated with the fuel pathways studied and cut-off criteria did not need to be used with the exception of the excluded processes listed in Section 3.6. During the interpretation phase, a 1% of environmental significance criterion, as calculated by the impact assessment method, was used to test the sensitivity of the results to assumptions and data substitutions made. Results of an economic input-output analysis for relevant sectors was conducted to inform the cut-off decisions for the processes summarized in Section 3.6, and a summary of these results is provided in Appendix E. Cut-off criteria and decisions on the exclusion of processes were applied at the individual process levels. These cut-offs are diffused throughout the system, and a cumulative threshold for these cut-off criteria was not calculated. It is noted that a sum of the impacts of all the excluded processes may not be negligible, and this is a limitation of the study due to the chosen system boundaries.

3.6 Excluded Processes

Typically, in an LCA, some aspects within the system boundaries are excluded due to statistical insignificance or irrelevancy to the goal. For example, the impacts of manufacturing and maintaining infrastructure associated with transportation systems and combustion technologies are highly variable and their contributions to carbon intensity are negligible, so they are commonly excluded from LCAs of energy systems. The specific processes excluded from calculations of the CI of Canadian fossil fuels include:

- Construction and decommissioning of mines and drilling sites;
- Construction and decommissioning of production facilities including refineries and upgraders;
- The manufacturing of fuel transportation infrastructure (i.e., pipelines, trucks, ships, roads);
- The manufacturing of fuel combustion infrastructure (i.e., vehicles, boilers);
- Oil and gas exploration;

- GHG emissions associated with exported fuels;
- Research and development activities; and
- Indirect activities associated with fuel production, such as marketing, accounting, and legal activities.

Data for the processes excluded are in most cases highly proprietary and unavailable. The activities in general are also highly variable from project to project. Environmental Input Output data from the US indicates that the impacts from these activities are relatively small (<2%), so until we can measure them more accurately on a fuel by fuel basis, keeping them outside the boundary provides a more solid basis for comparison (NETL, 2014). This rationale applies to each of the excluded processes. See Appendix E for a summary of the I/O results that were used to inform the cut-off decisions.

It is also noted that since the Fuel LCA Modelling Tool does not rely on licensed LCA databases (e.g. ecoinvent), there are potentially other smaller life cycle activities that are excluded by indirect omission. The data sets in LCA databases typically include activities such as infrastructure manufacturing, waste and wastewater treatment, energy used to power combustion devices, etc. From a cumulative standpoint, these life cycle activities that make smaller contributions in isolation may not be negligible in total, and this is a limitation of the study due to the system boundaries chosen.

3.7 Assumptions

Based on data availability, several assumptions have been made and were tested to determine if they exceed the 1% environmental significance cut-off employed.

3.7.1 Fossil Fuel Pathway Assumptions

Assumptions for the fossil fuel pathways focus on the activities excluded from the system boundary-based significance (i.e. cut-off criteria), availability of data, and predetermined project scope and system boundaries. Processes excluded from the system boundary include exploration, drill site or mine establishment, and construction and decommissioning of processing and transportation infrastructure. Note that the OPGEE model ascribes low significance to many of these processes as they contribute less than 0.01g CO_2e per MJ produced (El-Houjeiri, et al., 2017). Further detail on modelling assumptions for each fuel pathway is provided in the pathway-specific sections.

3.7.2 Fossil Fuel Land Use Change

A review of existing tools and prominent studies on the life cycle GHG emissions from fossil fuel pathways indicated that emissions from direct Land Use Change (LUC) are generally either excluded or included with a low level of precision using average emissions factors (Wang et al., 2018; GHGenius, 2018; Masnadi, et al., 2018; OCI, 2018; Yet et al., 2010). Direct LUC is different from indirect LUC because direct LUC refers to land whose purpose has been changed (e.g., forest land has become crop-land), while indirect LUC refers to changes spurred around the world by the expansion of an economic activity (e.g., expanded corn ethanol production and demand causing an increase in corn crop land in the world through the conversion of existing crop land to corn or conversion of other land uses, like forests, to corn). Quantifying indirect LUC requires global economic modelling and is not included in this scope.

GHGenius does not include emissions from LUC for crude oil and natural gas pathways. The tool does include LUC for coal mining, using an average global (not Canadian-specific) value from the International Energy Agency (IEA) for surface mining, and scaling that emissions factor down somewhat arbitrarily to assign emissions to underground coal mining. GREET does not include LUC for natural gas and crude oil production. For some specific types of crude extraction (e.g. Bakken shale), there are GREET study reports that include a general emissions factor from the OPGEE tool, but this is not consistently applied across all pathways. These factors are not Canadian-specific. The Oil Climate Index (OCI) research on crude oil relies on the general emissions factors from OPGEE to account for emissions from LUC. These factors are not Canadian-specific. The latest NETL report on U.S. natural gas production does include emissions associated with LUC. This includes estimates on the amount and type of land use change resulting from natural gas well construction and the use of general U.S. emissions factors for land use change from the EPA, expressed according to land use type.

In general, although significant attention has been given to GHG emissions from LUC for bioenergy production, GHG emissions from LUC for fossil fuel systems have not been examined in a systematic manner (Yet et al., 2010). The study from Yeh et al. indicated that LUC accounted for small to modest portions of life cycle GHG emissions for Alberta conventional oil (0.1% - 4%) and surface mining of oil sands (0.9%-11%). This could introduce significant uncertainty into the results.

Based on a review of the literature cited above, the project team developed a list of concerns about including LUC for fossil fuel systems, including

- Consistency with low carbon fuel (LCF) modelling:
    - While including some sort of LUC with fossil fuels would be more consistent since LUC will be included for LCF, the same methodology would not be used to estimate emissions from LUC for the two fuel groups;
    - GHG emissions from LUC in LCF pathways will be based on land conversion for agricultural uses for all agricultural feedstocks and emissions factors established from published literature; and
    - LUC in fossil fuel pathways could be based on land conversion for multiple uses (e.g., mining) and will not universally apply to all fuels (i.e., may apply for shale, may not apply for imported crude and non-oil sands).
- Data availability
    - The data would be directly from literature and be, at best, estimates of the 2016 Canadian context; and
    - The inclusion of LUC using average literature values could introduce more uncertainty in the results than it aids in the understanding of the actual carbon intensity of the fossil fuels.
- Other models and data sources – lack of consensus on methodology and data sources
    - GHGenius does not include LUC for crude or natural gas;
    - GREET does not include LUC for all crude sources and not for natural gas:
    - The NETL modelling does include LUC, but it is specific to U.S. emissions factors and type of land converted; and
    - The reliance by other tools and studies on external literature sources indicates a lack of consensus on the calculation methodology and data sources for including representative fossil fuel LUC in carbon intensity calculations.

Based on these considerations and the findings of the literature review, land use change was excluded from the system boundary for the fossil fuel pathway baseline carbon intensity values. The available literature values noted above could be included as an option to toggle on and off in the Fuel LCA Modelling Tool with a note about the lack of consensus in the scientific community. *We recommend considering the inclusion of LUC in future updates to the model should a better information on a calculation methodology and data sources emerge in the Canadian context.*

3.8 Co-Product Allocation

While conducting an LCA, allocation situations occur where the studied system is a multifunctional process and not all outputs (or functions) are used for the considered functional unit. According to ISO 14044, allocation of the process inputs 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 (mass or energy content, for example) or other relationships (economic value, etc.) should be used (ISO 2006b).

As part of developing the CFS, ECCC will define an approach for modelling multi-function systems, including a specified default approach for co-product allocation. ECCC issued a policy note on co-product allocation, and the current approach for the Fuel LCA Modelling Tool is based on this interim policy note (see Appendix A of the Milestone 1 report (EarthShift Global, WSP, Introspective Systems 2019). The current ECCC directive for co-product allocation is that when allocation is unavoidable, allocation should be based on underlying physical relationships. As stated in ISO 14044, allocation "should reflect the way in which inputs and outputs are changed by quantitative changes in the products or functions delivered by the system". In fuel production systems, energy content, also known and referred to as the HHV, is generally recognized as the most appropriate metric. This allocation method offers the objectivity required for regulatory purposes and eliminates the subjectivity from the substitution and economic allocation methods. As such, ECCC recommends a hybrid approach, where the main method of allocation is by the physical relationship with energy content (mass content can be used as a proxy if energy data are not available). However, where applicable, emissions should not be applied to unused co-products (i.e. electricity produced by cogeneration would be attributed all the emissions if there is no heat user).

The choice of allocation method, while useful for standardization, transparency and clarity in decision making, is in fact a model choice and there are no "correct" or "right" ways to allocate. Allocation by energy will be used as the default approach, and the administrator version of the tool will allow for different allocations in the fossil fuels baseline to be tested. Where allocation may be insufficient, and displacement more relevant, the displacement method can be used.

The need to allocate environmental burdens between products and co-products arises at several points in the life cycles of several fossil fuel pathways, including:

- Natural gas processing facilities that produce marketable natural gas and various NGL products:
    - Each are sold to different industries in different markets; sulphur may be stockpiled until a purchaser has been found. Data on sulphur production volumes from natural gas processing facilities was limited and therefore the impacts of sulphur-recovery (i.e. sour processing) were only allocated to the NGLs and not to sulphur.
- Heavy crude oil and bitumen upgrading facilities that produce petroleum coke and sulphur as co-products:

  - Each are sold to different industries in different markets, and some may be stockpiled for future use or for future purchase
- Crude oil refineries that produce petrochemical feedstocks, petroleum coke, and lubricants as co-products;
  - Each are sold to different industries in different markets, and some may be stockpiled

For the purposes of this study, there has been no allocation of environmental burdens to other non-fuel co-products from crude oil refineries such as mineral oil and asphalt.

For several of the energy pathways modelled in this study, wastes from other industrial activities are also used as feedstocks. The identification of an energy feedstock as a co-product or a waste has significant implications for the allocation of environmental burdens. In section 4.3.4.2 of the ISO 14044 standards, it is stated that environmental burdens should only be allocated to co-products and not to waste products (ISO 2006b). A waste is defined as a substance or object intended for disposal, while a co-product is defined as any of two or more products coming from the same unit process or product system (ISO 2006b). In Milestone 2, this distinction is important for the petcoke pathway. The allocation of emissions to the petcoke fuel pathway are discussed in Section 4.7.

3.9 Impact Assessment Method

Impact assessment methods are used in LCA to convert life cycle inventory (LCI) data (environmental emissions and raw material extractions) into a set of potential environmental impacts.

The objective of this study is to calculate carbon intensity values for fossil fuel and low carbon fuel pathways, expressed in grams of CO_2 equivalents per MJ of energy. The carbon intensities calculated in this study primarily include contributions to global warming from CO_2, CH_4, N_2O, and SF_6 using characterization factors from the IPCC for a 100-year time horizon. Other GHG emissions could be included in future iterations of the Fuel LCA Modelling tool, however the inventories compiled for this project consist primarily of these four emissions. The 100-year time horizon is used as it is the characterization factor most-widely applied in fuels LCA thus facilitating ease of comparison to other study results, and the 100-year timeframe was recently confirmed by the United Nations Environment Program's Life Cycle Initiative as the preferable metric in LCA for short-term effects of climate change[3]. In this study the fossil methane factor of 30 was used for methane emissions. Table 13 provides a summary of the most recently updated characterization factors to calculate CO_2e from the IPCC.

Table 13. Characterization factors for GHG emissions used to calculate fossil fuel CIs

Gas	IPCC AR5 GWP 100, including biogenic carbon
CO_2	1
CH_4 (fossil)	30
CH_4 (biogenic)	28
N_2O	265
SF_6	23,500

Source: IPCC 2013 – Appendix 8A, Table 8A1

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[3] https://www.lifecycleinitiative.org/download/5746/ to justify the use of GWP100

A complete list of greenhouse gases, impact factors, and the associated uncertainty can be found as an appendix to the Milestone 1 report (EarthShift Global, WSP, Introspective Systems 2019.

3.10 Limitations of the Study

The work done under this project only pertains to fuels produced and consumed in Canada. Any conclusions or assumptions should not be applied to fuels developed or used elsewhere. Fossil fuel models will pertain to average fuel consumption mixes in Canada as of 2016. Where production processes differ, the results will not be valid. Data limitations for specific fuel pathways are noted in the sections of each pathway. It is notable that, while there were data limitations for crude oil products, more Canadian industry-specific data were available relative to what was available for modelling natural gas.

3.11 Limitations of LCA Methodology

The ability of LCA to consider the entire life cycle of a product makes it an attractive tool for the assessment of potential environmental impacts. Nevertheless, similar to other environmental management analysis tools, LCA has several limitations. These can be related to data quality and unavailability of potentially relevant data.

The CFS is narrowly focused on carbon intensity or global warming potential. As a result of this narrow focus, fuels which offer the required reduction in carbon intensity could in fact have unquantified environmental impacts that are higher than the baseline in other areas, such as eutrophication (excess nutrients), particulate emissions or toxicity. To understand the broader environmental implications of a fuel pathway, a full LCA conformant with ISO 14044 is recommended.

Please note that any life cycle impact assessment results are relative expressions and do not predict impacts on category endpoints (e.g. human health, wildlife species), exceedance of thresholds, or risks.

4. Life Cycle Inventory

4.1 LCI Data Collection

The scope of the project did not allow for new primary data collection for fuel producers, so the LCI is comprised of a range of secondary data on Canadian fuel pathways. Data sources include government publications and statistics, industry publications and statistics, output from recognized and publicly-available modelling tools (mostly for fossil fuels), as well as literature data to fill gaps that are not addressed by these more formal secondary data sources. The following sections outline the data sources and data gaps for fossil fuels. More detailed information on data sources is also provided in Appendix A. The LCI data and calculations have been carefully documented to ensure transparency and include detailed meta data and uncertainty information that is stored in the data documentation template. The selection of data for use was guided by data quality preferences developed for the project and by ISO guidance on data consistency and completeness. The data used for each fuel type is summarized in its respective section.

4.2 Life Cycle Inventory Data

Below is an overview of the data sources used in Milestone 2 and identification of data gaps.

4.2.1 LCI Sources and Data Gaps for Fossil Fuel Pathways

Several data sources exist for the various aspects of the fossil fuel pathways including existing open-source models, public databases and published reports. The *Oil Production Greenhouse gas Emissions Estimator* (OPGEE) version 2.0 model is an engineering-based model that estimates GHG emissions from the production, processing and transport of crude oil. The *Petroleum Refinery Life Cycle Inventory Model* (PRELIM) version 1.3 is a mass- and energy-based representation of the refining process that allows for the estimation of GHG emissions from blended gasoline, jet fuel, ultra-low sulfur diesel, fuel oil, coke, liquid heavy ends, liquefied petroleum gas (optional), petrochemical feedstocks (optional), asphalt (optional). In addition to these models, several public data sources have been leveraged in this project including:

1. Alberta Energy Regulator, Statistical Reports (ST), https://www.aer.ca/providing-information/data-and-reports/statistical-reports
2. C-NLOPB, Canada-Newfoundland and Labrador Offshore Petroleum Board.
3. National Energy Board, Estimated Production of Canadian Crude Oil and Equivalent, https://www.nebonegc.ca/nrg/sttstc/crdlndptrlmprdct/stt/archive/stmtdprdctnrchv-eng.html
4. Natural Resources Canada, Basin database, available at http://basin.gdr.nrcan.gc.ca/index_e.php
5. International Association of Oil and Gas Producers (IOGP) Annual GHG Data: www.IOGP.org
6. National Energy Technology Laboratory (NETL) Baseline Data https://www.netl.doe.gov/
7. Petrinex Alberta Public Data https://www.petrinex.ca/PD/Pages/APD.aspx
8. Statistics Canada: https://www.statcan.gc.ca/eng/start
9. Woods Mackenzie Downstream Oil Refinery Data, available for purchase: https://www.woodmac.com/

Data from these sources were compiled as a part of this project from a subcontractor called AFARA as well to aid in modelling crude supply characteristics and refinery configurations. Finally, literature resources were also a prime source of data for the fossil fuel pathways. Cooney, et al., 2017 presents a useful methodology that is used to inform and benchmark baseline fossil fuel carbon intensity values. Orellana, et al., 2018 provides a statistical model for in-situ oil sands extraction operations. Data useful for crude oil with country-level upstream carbon intensities can be sourced from Masnadi et al., 2018. And Sleep et al., 2018 adds Canadian specificity to methodology and data for oil sands extraction and upgrading operations. Literature provided by Environment and Climate Change Canada, such as the literature review of upstream natural gas emissions intensity (D'Antoni, 2018) is also used in this work.

Transmission and distribution data relied on the Open Canada website (https://open.canada.ca/en) amongst other sources. Data from 2016 were useful in determining actual energy consumption in transport and production and consumption by region. Specific references to data used are provided within the sections that describe the full fuel pathway and Section 4.9.

4.3 Data Quality Requirements

The life cycle inventory (LCI) data used in the fossil fuel modelling is a mixture of data that is either specific to Canadian systems, data from other jurisdictions that is considered adequately representative and modified to include Canadian energy and emissions, or data from other jurisdictions that is considered adequately representative without revision. The LCI data also include a mixture of official data based on measurements by producers that report data, as well as non-verified data obtained from the literature that is modified with expert judgment and assumptions.

The ISO standards indicate that data quality requirements should be specified to enable the goal and scope of the LCA to be met (ISO 2006). In this section, we outline a set of data quality requirements for the life cycle of Canadian fossil fuel production, including a decision tree that has been used to guide decisions on data collection.

4.3.1 Foreground Unit Processes

The foreground unit processes for this project include the primary activities involved in extracting and producing the fuel feedstocks, transporting and processing feedstocks, converting feedstocks to the final fuel product, and the emissions per MJ of energy content (HHV). Due to the importance of these activities in quantifying carbon intensity and determining the representativeness of the CFS tool for Canadian fuel pathways, we have made every attempt to use the highest quality Canadian data to characterize the inputs and outputs of all foreground unit processes. More specific data quality requirements for foreground unit processes are shown below in order of priority:

1. Regionally-specific Canadian data from official sources (e.g. producers, government statistics, data collected for Canadian life cycle inventory databases) for the specific industry/technology under study.
2. Regionally-specific Canadian data from published literature and academic studies.
3. Canadian-average data from official sources for the specific industry/technology under study (e.g. producers, government statistics).
4. Regionally-specific or national average Canadian data from non-official sources for the specific industry/technology under study.
5. North American data using the same hierarchy above.
6. United States data from official sources from the specific industry/technology under study, updated to reflect Canadian background energy systems or conditions where possible.
7. United States data from official sources from the specific industry/technology under study.
8. Official data from outside Canada and the United States for the specific industry/technology under study.

In general, the level of data quality for foreground processes decreases as one moves down this hierarchy. This is reflected in the data quality assessment and accounted for in the uncertainty analysis.

4.3.2 Background Unit Processes

The background unit processes for this project include upstream activities that support foreground process activities, for example the production of electricity to supply an industrial activity. Although in the background, these activities can still make significant contributions to the life cycle GHG emissions of Canadian fuel pathways; however, some background activities have low to negligible influence on the carbon intensity of Canadian fuel pathways (e.g. fuels transported by pipeline for short distances, small percentages of crude transported by tanker ship) and the data quality requirements are therefore less stringent for these unit processes. The data quality requirements for background unit processes are the same as those identified above for foreground unit processes, with the exception that non-verified data from outside Canada and the United States may be considered for instances where the process being modeled is not a significant contributor of life cycle GHG emissions. This does not mean that these data are not included. It means that the data are included, but from sources that are not specific to Canada or the timeframe of modelling in lieu of specific data availability.

4.3.3 Fossil Fuel Pathways

As noted earlier in this section, data quality preferences for fossil fuel pathways are stringent due to the use of carbon intensity values for fossil fuels to regulate fossil fuel producers to meet legislated reduction targets. Further data quality preferences specific for fossil fuels are outlined below.

Preferred Level of Aggregation for Empirical and Modelled Data

1. Canadian individual fuel pathway data (e.g. individual extraction site, upgrading facility, pipeline, refinery, etc.)[4]
2. Canadian aggregated fuel pathway data (e.g. average Alberta in-situ extraction facility, refinery, etc.)
3. Modelled fuel pathway data using Canadian parameters (e.g. average steam-to-oil ratio, API, pipeline distances, etc.)
4. USA or International fuel pathway data (e.g. as proxy data applied to Canadian context).

Permitted Data Sources[5]

1. Public/open source government or industry-reported data
2. Public/open source academic/institutional data
3. Modelled, estimated data

Data from specific refineries in Canada were used to model in PRELIM and results were aggregated based on their location (e.g., Eastern and Western Canada), the source locations crude products they intake (e.g., Eastern and Western Canada, and imports), the location of use of the products produced, and similarity of refinery type.

4.4 Modelling Approach and Carbon Intensity Calculations for Fossil Fuels

This section describes the overarching modelling approach followed for carbon intensity calculations for fossil fuels. The overall process involves using the OPGEE and PRELIM models for crude oil products and supplementing their default model parameters (e.g. operating practices, production slates and upstream CIs) with typical operating parameters observed in the Canadian oil and gas industry. This approach aligns with the methods used by the U.S. National Energy Technology Laboratory (NETL) (NETL, 2014). Facility-level reported and

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[4] The level of dis-aggregation has been adjusted based on available data and project resources.

[5] Note that proprietary data has not been accepted.

modeled GHG emissions have been used to then assess, validate and/or refine the model parameters and results.

Key steps in the approach are described below to develop and validate results. Each step involved advisor review and feedback. While presented in sequence, the overall approach included an iterative process of development, analysis, review and revision before finalizing the fuel pathway CIs. The iterative approach to modelling is shown schematically in Figure 8.

Steps to Develop Fuel Pathway CIs

1. Apply existing process stage level LCA and/or life cycle carbon intensity models where possible (e.g. OPGEE/PRELIM) and for all relevant processes in Canada.
2. Finalize and reconcile collected data:
    a. Collect significant operating parameters required to prepare OPGEE and PRELIM models (see Sections 4.5 and 4.6, respectively); collect data on production volumes and distribution of feedstocks, intermediate products and transportation fuels in Canada and high or low heating values.
    b. Use collected data on process operating parameters required by existing LCA and/or life cycle carbon intensity models (e.g. steam-to-oil ratio for SAGD facilities, reservoir depth/pressure, API, source location, high and low heating values) from sources including Wood Mackenzie (WM) data, Alberta Energy Regulator (AER) data, and data from ECCC’s contract with AFARA. The data collected is representative of Canadian operations, however, may not include an exhaustive assessment of all individual Canadian operations.
    c. Identify assumptions, estimations and default modelling parameters required to address data gaps. Examples of assumptions include, but are not limited to, the extraction, upgrading and refinery configurations modeled in OPGEE and PRELIM and the crude assay matches selected from the PRELIM crude library.
3. Input parameters in existing LCA and/or life cycle carbon intensity models to generate GHG emissions Carbon Intensities (CIs) including (though not limited to):
    a. Updated 2016 Electricity CIs provided by ECCC
    b. Crude and Natural gas import CIs
    c. Wood Mackenzie data
    d. AFARA data
    e. ORTEC data
    f. AER Data
4. Conduct a market assessment to develop a model of the inputs and destinations of intermediate products and distribution of transportation fuels.
5. Link process stage level processes together using the results of the market assessment. Links form the connections between extraction, pre-processing, transmission, refining, distribution and combustion).
    a. Note that complete fuel pathways have been matched to ensure crude oil production technologies are matched with midstream refining technologies.
6. Use the Brightway module within the Spinney tool (EarthShift Global, WSP, Introspective Systems. 2019) to calculate cradle to gate CIs.

Steps to Validate and Refine CIs

1. Compare model results to government reported facility-level GHG data:

    a. Compare government-reported data (GHGRP 2016) to modeled results in OPGEE at a facility level where possible
    b. Use PRELIM to allocate overall refinery emissions to individual products on an energy basis and at a process unit level
    c. Use PRELIM to estimate hydrogen requirements throughout the refinery and estimate the GHG emissions from additional hydrogen production
    d. Compare individual facility reported emissions (ECCC 2018d) to those calculated using PRELIM and identify discrepancies (if any)
    e. If major discrepancies are apparent, check modelling assumptions and test assumptions for changes in results that reconcile or can help explain differences

2. Validate and refine the results with other existing models and literature:
    a. Examine CIs with noticeable discrepancies between modeled and reported emissions; use results from other models (e.g., GREET, GHGenius or literature) to further check and refine assumptions
    b. Test assumptions and default operating parameters for changes in results that reconcile or can help explain differences

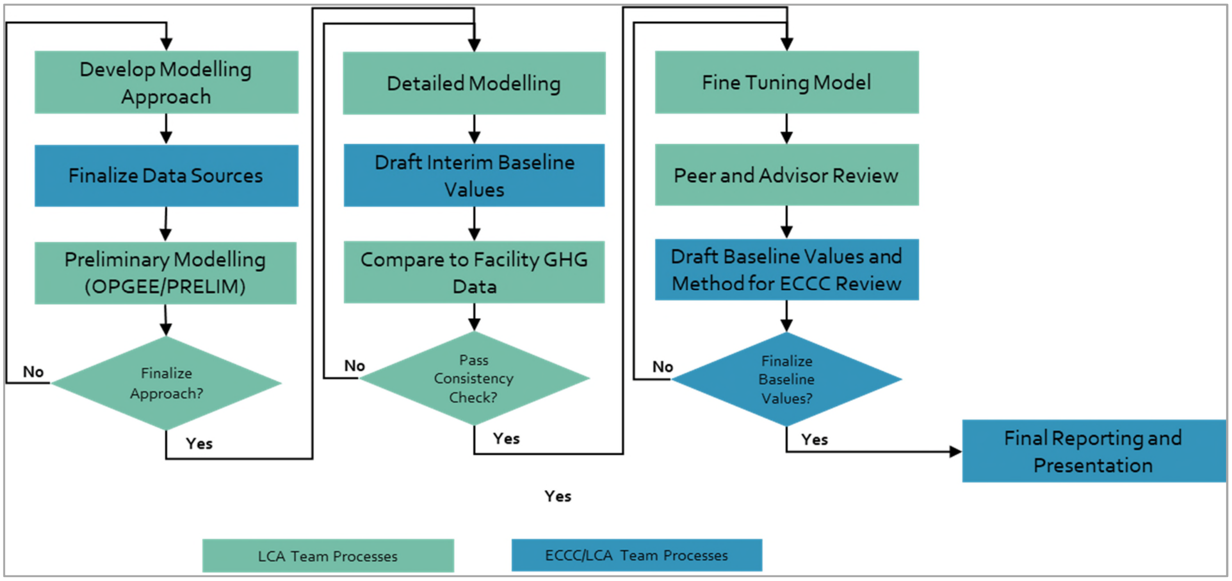

Figure 8: Iterative workflow diagram for fossil fuel modelling

Process-level Aggregation

This approach involves developing process-level modules representing key stages (e.g. extraction, upgrading, refining), which are then assembled to represent fuel pathways. Process-level modules are assembled from unit processes linked by flows of energy and materials. Similar to unit processes, process-level modules can be assembled to represent complete systems and fuel pathways.

The granularity of life cycle carbon intensity results in this study is limited to the process-level. Process-level modules are used to reflect varying levels of detail based on data availability, to anonymize facility-level data and to show important distinctions in production methods. In general, reservoir/product type, production technology and/or region has been reflected at the process-level.

In summary, fuel pathways have been modelled and aggregated principally in three levels:

- Level 3 – Unit Processes: Facility level or more detailed processes
- Level 2 – Process-level modules: Unit processes combined to process groups that represent relevant technologies, regions, and input/output variations
- Level 1 – System-level: Connected process groups representing full pathways

Level 3 processes are not presented in order to focus on the industry rather than individual facilities. These processes comprise facility-level modelling including those performed using OPGEE and PRELIM (e.g. an individual refinery).

Level 2 processes are depicted in the process flow diagram (Figure 9) and in the modelling in Spinney. Level 2 processes are the modular building blocks of the model and are typically composed of several Level 3 processes (e.g. western and central Canadian refineries or all in-situ extraction facilities). Level 2 processes link together based on their feedstock (inputs) and products (outputs) to form individual Level 1 fuel pathways. Level 2 processes contain their own supply chain processes to capture other consumables, wastes and byproducts relevant to the specific process stage.

The representative processes at a technology level (e.g. surface oils sands mining vs. in-situ extraction) include regional variation where relevant (e.g. Western/Central Canadian refining vs. Eastern Canadian refining). This level of aggregation has been adjusted to reflect the availability of data for particular process stages, technologies and sectors.

This approach provides enough resolution and flexibility to model the variety of conventional fuel pathways, processes and technologies in Canada. In the future, the process-level models can be further aggregated or disaggregated as needed to support users of the tool. For instance, the model can include a volume-weighted average of upstream processes to establish a single GHG intensity for refinery feedstocks.

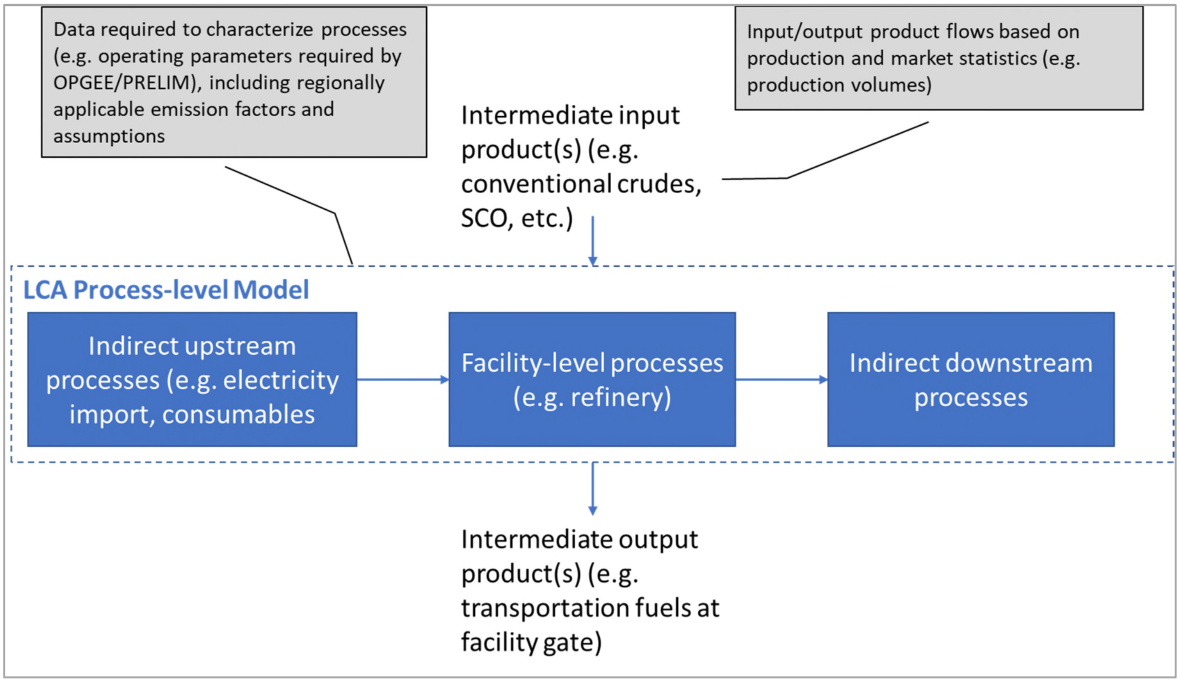

Figure 9. Schematic representation of a generic process-level (level 2) module used to assemble fuel pathway models.

Approach Advantages

The key steps outlined above were developed to align with previous approaches applied to relevant transport fuel LCAs and life cycle carbon intensity studies, utilize current and open source LCA and life cycle carbon intensity modelling tools and incorporate Canadian-specific data. This approach:

- Utilizes existing and industry leading LCA/carbon intensity models PRELIM and OPGEE
- Applies system boundaries consistent with LCA and life cycle carbon intensity calculations
- Enables aggregation of process-stages to be representative of several facilities, thereby anonymizing site-level data
- Enables linking of upstream and refining processes to be adjusted to reflect regional Canadian production, including imports and exports
- Increases confidence in values by introducing additional checks
- Integrates the use of newly available data sources

4.4.1 Fossil Fuel Pathway Fundamental Equations

Carbon emissions have been calculated for each individual fossil fuel pathway (Level 1) as a sum of the emissions from each process-level module (Level 2) included in its supply chain. The calculation is represented by Equation 1 below:

$$CI_{L1,i} = \frac{\sum_{j=1}^{n} CI_{L2,j} E_{L2,j}}{E_{L1,i}} \qquad \text{(Eq. 1)}$$

Where

$CI_{L1,i}$ = GHG emissions (‘carbon’) intensity of individual fuel pathway, i (gCO_2e/MJ HHV)

$CI_{L2,j}$ = GHG emissions (‘carbon’) intensity of process-level (Level 2) module, j (gCO_2e/MJ HHV)

$E_{L2,j}$ = Energy content of fuel required from process-level (Level 2) model, j (MJ HHV)

$E_{L1,i}$ = Energy content of final fuel product, i (MJ HHV)

and

i and j denote the specific final transportation fuel (Level 1) and the corresponding subset of process-level modules (Level 2) comprising its supply chain

Baseline fossil fuel pathways consist of several individual pathways representing different technology and transportation routes. For example, the GHG emissions intensity of diesel contains a different blend of imports and domestic extraction, refining and transportation methods based on where it is consumed within Canada. Baseline carbon intensity values for fossil fuel pathways are calculated using an energy-weighted average of individual fuel pathways representing the overall Canadian fuel mix for that pathway. The calculation is represented by Equation 2 below:

$$CI_{Fuel} = \sum_{i=1}^{n} w_i CI_{L1,i} \qquad \text{(Eq. 2)}$$

Where

CI_{Fuel} = Baseline carbon intensity for fuel pathway
w = Relative contribution (weight %) of fuel source pathway, *i* to Canadian fuel mix

4.5 Crude Oil Feedstocks

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 SAGD), offshore extraction, and imports from countries outside of Canada. The following sections detail the modelling of these feedstocks.

Crude oil is primarily extracted from Western Canada. As illustrated in Figure 10, crude oil extraction is transported via pipeline to refineries regionally distributed in Central and Western Canada as an average refinery blendstock. Western Canada accounts for 95% of domestic oil production, while 33% of refinery input products in Canada are imported for domestic consumption. These imports arrive through ports, particularly in Eastern and Atlantic Canada. Eastern Canada crude oil pathways are illustrated in Figure 11.

Modelling of Canadian extraction was conducted in OPGEE, an engineering-based model that estimates GHG emissions from the production, processing, and transport of crude oil. Data sources for this modelling are described in Section 4.2.1.

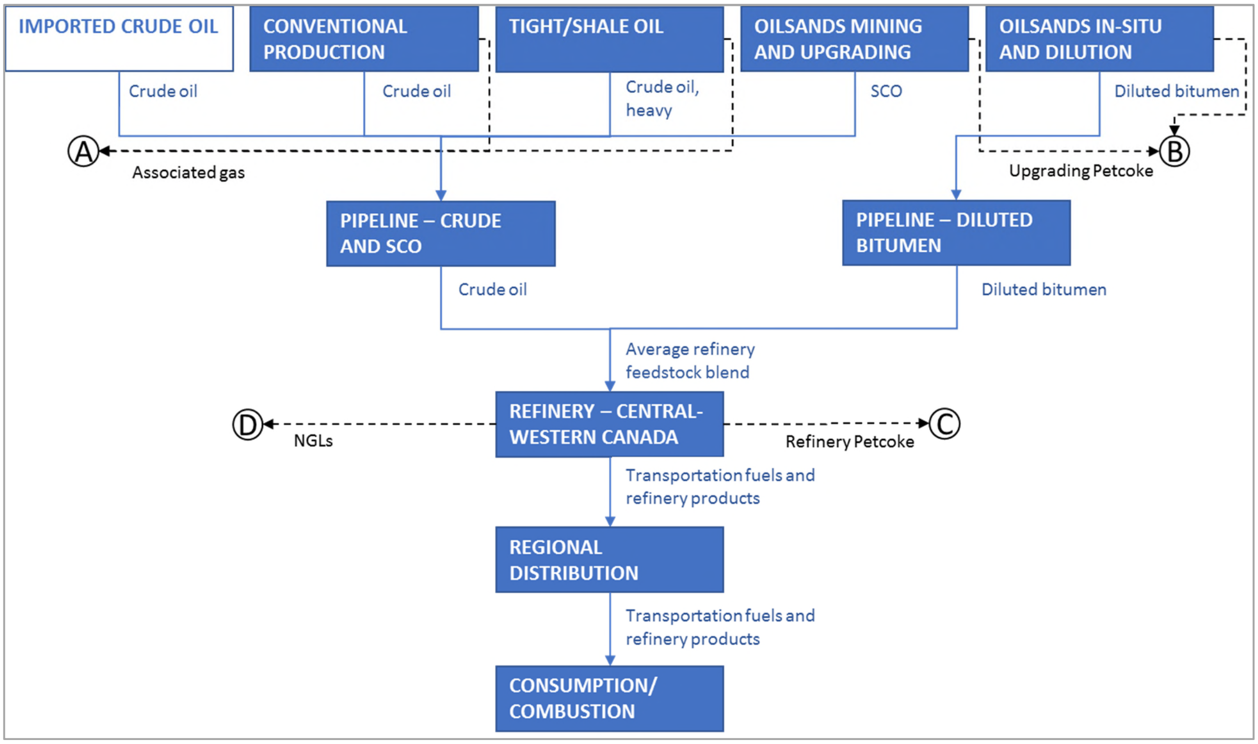

Figure 10: System boundaries for crude oil feedstocks showing typical process routes from extraction through refining, distribution, and combustion (Western and Central Canada).

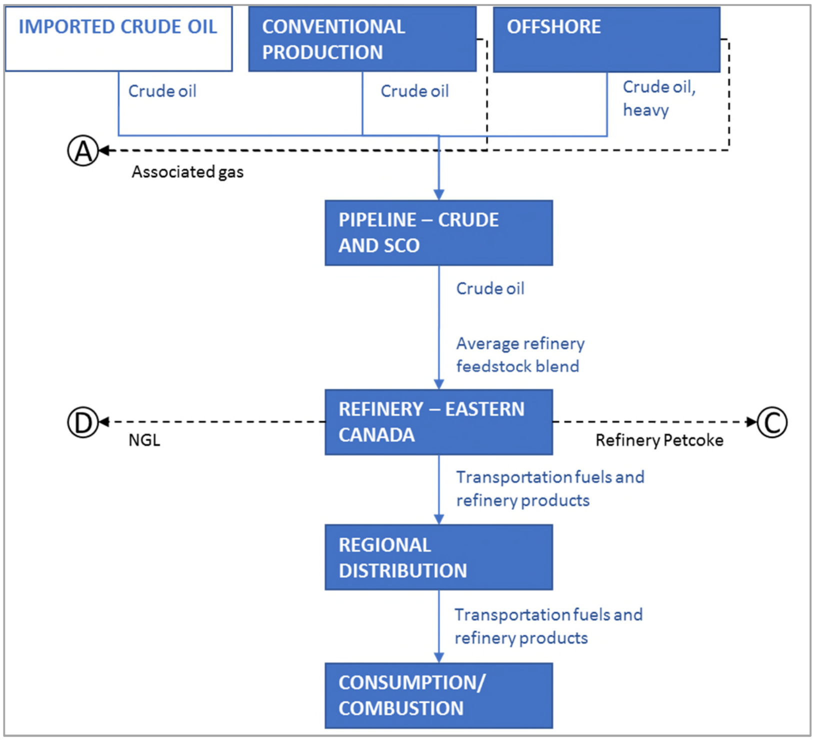

Figure 11: System boundaries for crude oil feedstocks showing typical process routes from extraction through refining, distribution, and combustion (Eastern Canada).

4.5.1 Production Methods

Imported Crude Oil Feedstock

Crude oil is imported from many countries into Canada for refining into products used in Canada. Carbon Intensities for these imported crudes were provided by ECCC according to Table 14. These estimates were based on the total Canadian crude imports by country from the NEB and data from the Canadian International Merchandise Trade Database. Each country was assigned a CI based on the availability of a matching crude blend from the Oil Climate Index (OCI, 2018). The average CI for imported crude oil provided by ECCC is summarized in Table 15. Note that transportation is not included in the CIs in the table below. It is accounted for in the transportation and distribution calculations. Crude oil is imported to Canada through the US and to Canadian ports for processing in Canadian refineries. Refineries in Quebec and the Atlantic provinces rely principally on imports, while refineries in Ontario and Western provinces contain a blend of imported and domestic feedstocks, including oil sands-derived products.

Table 14: Crude Imports to Canada

Country	Percent of Imports in 2016	CI (g CO_2e / MJ)	Import Volume (bbl / yr)
Algeria	11.7%	19.78	33,768,812
Azerbaijan	1.0%	6.49	2,886,223
Colombia	0.8%	7.37	2,020,356
Denmark	0.2%	7.23	577,245
Kazakhstan	2.6%	6.52	7,504,180
Nigeria	10.20%	17.07	29,439,477
Norway	5.7%	9.17	16,451,472
Saudi Arabia	11.9%	5.99	34,346,056
United Kingdom	1.4%	10.25	4,040,712
United States	52.10%	15.40	150,660,852

Table 15: Average CI for imported crude oil

Carbon Intensity	Amount
CI of Imported Crudes (LHV)	14.0 gCO_2e / MJ HHV
HHV/LHV (average from OPGEE)	1.06
CI for Crude Oil Imports (HHV)	**13.2 gCO_2e / MJ LHV**

Conventional Crude Oil Extraction

Conventional oil production refers to oil and gas reservoirs accessible by conventional drilling techniques. Oil and gas in these reservoirs flow to the surface under the pressure of the reservoir and mechanical pumps. Conventional oil processing stages include exploration, drilling, production and decommissioning. Conventional oil production is typically less expensive, technically complex, and energy and GHG intensive compared to unconventional production.

The products generated by conventional facilities include light, medium and heavy crude oil, natural gas and natural gas liquids. Most Canadian conventional oil is produced in Alberta and

Saskatchewan. As reservoirs become increasingly challenging to access, the share of conventional oil production is declining.

Offshore Conventional Crude Oil Extraction

Offshore oil and gas production involve similar processes to conventional, onshore production. However, the additional challenges of operating in a marine environment increase the cost and complexity of offshore facilities, including drilling under water, construction of offshore platforms and storage and transportation of oil and gas products to the mainland.

Offshore production in Canada occurs in the Atlantic provinces and accounts for roughly 5% of crude oil production by volume.

Tight (Shale) Oil

Tight or shale oil production involves accessing oil and gas entrained in impermeable limestone and shale formations. Production involves horizontal well drilling and hydraulic fracturing (or fracking) to break apart the limestone and shale in order to liberate the oil and gas. The additional processing requirements can result in additional energy consumption and GHG emissions. The GHG emissions intensity per barrel produced is influenced by the extent of venting and flaring of reservoir gases occurring at each specific facility.

Tight oil facilities produce crude oil. Production in Canada occurs within the Western Canadian Sedimentary Basin. The proportion of tight oil derived crude oil has been rising.

Oil sands Surface Mining and Upgrading

Surface oil sands extraction involves the open pit mining of bitumen reserves located within 75 m of the surface. Mining involves mobile equipment to extract and haul oil sands. The extracted oil sands is mixed with water to create a slurry which is then transported to a production facility. Bitumen is then gravity separated from the water and sand. At this stage, diluent can be added to reduce viscosity and help remove remaining sands.

Most mined bitumen requires upgrading before refining. Upgrading creates a lighter oil product suitable for processing at refineries. Upgrading involves the removal of sulfur through hydrotreating and conversion to lighter oil through coking or hydroconversion. Coking involves thermal cracking of large hydrocarbon molecules to produce lighter products and a solid by-product or waste called pet-coke. Hydroconversion involves cracking via the addition of hydrogen.

Upgrading facilities produce synthetic crude oil (SCO). SCO refers to a light crude oil product derived from upgraded bitumen. All surface oil sands derived products originate in the Athabasca region of Alberta.

In-situ Oil Sands Extraction and Dilution

Most oil sands reserves are inaccessible to surface mining and require in-situ extraction techniques. In-situ bitumen extraction typically involves the injection of steam into the reservoir to reduce the viscosity of the bitumen. This allows the bitumen to be pumped to the surface. Steam-assisted gravity drainage (SAGD) and cyclic steam stimulation (CSS) are two techniques used commercially. Each involve surface plants to generate steam for injection and then separate the return water from the bitumen for treatment and recycling. Due to the steam generation and post processing, in-situ operations are more energy and GHG intensive than conventional extraction techniques.

As extracted bitumen from in-situ operations is diluted, typically using natural gas condensates to produce diluted bitumen (dilbit), a product light enough to be transported by pipeline to refineries for further processing. In select cases, bitumen may be upgraded instead of diluted. For these facilities, the upgrading process is reflected in the unit processes (level 3) and grouped with the rest of in-situ extraction facilities at the process level (level 2). All in-situ oil sands derived products originate in the Athabasca region of Alberta.

4.5.2 Modelling

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. These processes include conventional onshore and offshore oil production and unconventional production including oil sands mining and in-situ extraction, bitumen upgrading and dilution, and hydraulic fracturing at tight or shale oil reservoirs.

Level 2 process models were developed that consisted of groups of facilities with similar processes. These processes were selected to capture the variation in production method, facilities or regions relevant for each fuel pathway. These process models form the building blocks of the fuel pathways. The extraction and pre-processing groups represented by Level 2 models are described in the previous section.

The products of extraction and pre-processing are light to heavy crude oil, synthetic crude oil (upgraded bitumen) and diluted bitumen (bitumen diluted by condensate or SCO to meet pipeline specification). The process of adding diluent for transport, recovering the diluent at the refinery and return transport are each captured in their respective processes. The products are characterized by energy content, diluent content and API, amongst other properties. These products form the blended feedstocks input to the refinery models.

The methodology for modelling extraction and pre-processing operating parameters in OPGEE was based on the methodologies outlined in the 2018 Science paper (Masnadi et al., 2018). The OPGEE processes include the heater/treater, stabilizer column, upgrading, associated gas processing path, flaring, venting, diluent process, among others.

OPGEE models were developed to represent individual facilities and production methods in Canada by assigning technologies and input operating parameters. Government data sources including AER, NEB and Statistics Canada were used select appropriate technology pathways and operating parameters. When facility-level operating parameters were not available, industry, provincial or default parameters were used in order of preference. OPGEE has several primary and secondary facility-level operating parameters that influence the modelling of the production and upgrading of crude. These parameters are summarized in Table 16.

Table 16: Facility-level production and operating parameters

Primary Parameters	Secondary Parameters
Steam flooding (yes/no)	Upgrading (yes/no)
Steam-to-oil ratio (SOR)	Field depth
API gravity	Productivity index
Water-to-oil ratio* (WOR)	Number of producing wells
Flaring-to-oil ratio	Oil production volume

* Refers to the amount of water produced with oil.

Previous studies indicate that if these parameters are included in the analysis, the result would be largely free from systematic bias and are be accurate within approximately 1gCO_2e/MJ LHV. (Brandt, et al., 2015; Tripathi, et al., 2017; AER, 2018).

Venting and flaring practices can have a significant impact on GHG emissions intensity. Venting releases CH_4, a powerful GHG and flaring generates CO_2 emissions from fuels that could be otherwise recovered or utilized in production. These practices were modelled using actual reported facility level data when available. In Alberta and Saskatchewan, regionally averaged industry data was applied when facility level data was unavailable. Most Alberta in-situ facilities had facility specific flaring emissions rates available from presentations in AER. Alberta flaring and venting for conventional and EOR operations were assigned based on company-level data in AER60B by proxying the flaring and venting rate of the largest producer of the crude oil in the specific region for the entire basin for that specific production method. Saskatchewan venting and flaring rates were taken from the 2016 Saskatchewan Fuel, Flare, and Vent report. Venting and flaring rates from all facilities have been averaged for crude product types by production method for each of the four main basins. Newfoundland venting and flaring data was taken from the OPGEE model runs presented in the 2018 Science paper (Masnadi et al., 2018).

GHG emissions results from OPGEE were compared to reported GHG emissions from facilities in Canada based on the Greenhouse Gas Reporting Program (GHGRP, 2018) reported 2016 emissions as well as the modelled results of the 2018 Science paper (Masnadi et al., 2018). Facilities with GHG emission intensities outside of 20% were further analyzed to confirm that the modelled result reflected Canadian production. Differences between the modelled result and the Science paper were typically due to replacing OPGEE default parameters with facility-specific 2016 data. The facility-specific parameters that had the largest impact on CI relative to the Science paper were venting and flaring rates, water to oil ratios, number of well pairs. Facility-specific parameters were returned to defaults to confirm that the modelling results in both models converged.

Differences between the modelled result and GHGRP arose from differences in system boundaries when matching LCA emission sources to the activities included in GHGRP reporting (principally direct, energy-based GHG emissions). Uncertainty was also introduced by dividing GHGRP emissions data by NEB production data to calculate carbon intensity.

Some facilities were excluded from the modelling if their production level was small and not representative of the broader industry, if data on the operating parameters necessary for modelling were not available (e.g., steam to oil ratio) or if there was a significant discrepancy between reported emissions and modeled emissions that could not be reconciled. The coverage of facilities after deducting for exclusions is presented in Table 22.

Extraction and pre-processing yields natural gas and NGLs (associated gas) and upgrader petcoke relevant to the gas and solid fuel pathways models. Associated gas is produced and fed into the natural gas pathway model. Petcoke produced during upgrading is either consumed or stockpiled on site or sold off-site to downstream consumers. The treatment of petcoke that is sold from upgrading is discussed in Section 3.4.2.4. In both cases, an energy-based allocation is applied. Production of other co-products during extraction and post-production were minor and not considered.

The effects of land use change have been excluded from the analysis to align with the modelling of other parts of the conventional fuel pathways. Land use change is discussed in further detail in Section 3.7.2.

The modelling approach for extraction and pre-processing began with a review of the Canadian industry to assess production technologies, volumes and regional variations affecting GHG emissions as illustrated in Table 17. Electricity grid emissions for modelling in OPGEE are provided in Table 18. These values were provided by ECCC to reflect 2016 data based on the results of a separate study. The values include GHG emissions associated with fuel production upstream of electricity generating facilities. See Appendix C for more information.

Table 17: Combinations of regional and technological variations representing Canadian extraction and pre-processing

Province	Source	Production method	Post-production method	Output product
Alberta	Oil sands - Surface	Mining	Delayed coking	SCO
		Mining	Hydroconversion	SCO
		Mining	Combined hydroconversion and fluid coking	SCO
		Mining	Dilution	Dilbit
	Oil sands - In-situ	SAGD	Delayed coking	SCO
		SAGD	Dilution	Dilbit
		CSS	Dilution	Dilbit
	Conventional - medium oil	Primary	NA	Medium oil
		Enhanced Oil Recovery	NA	Medium oil
	Tight oil	Drilling/Hydraulic fracturing	NA	Light oil
	Conventional - Heavy oil	CHOPS (Cold Heavy Oil Production with Sand)	NA	Heavy oil
Saskatchewan	Conventional - Light oil	Drilling	NA	Light oil
	Conventional - Heavy oil	CHOPS (Cold Heavy Oil Production with Sand)	NA	Heavy oil
	Conventional - Heavy oil	Drilling	NA	Heavy oil
	Conventional - Medium oil	Enhanced Oil Recovery	NA	Medium oil
	Heavy oil - In-Situ	SAGD	Delayed coking	SCO
Newfoundland and Labrador	Offshore	NG reinjection/water flooding	NA	Light oil

Table 18: 2016 grid emission factors have been used for each of the three regions

Province	Direct impacts (tCO$_2$e/GWh)	Indirect impacts (tCO$_2$e/GWh)	Total (tCO$_2$e/GWh)
AB	900	45	945
NL	40	20.7	60.7
SK	754	62	816

The National Energy Board (NEB) was used as the source of data for 2016 estimated production of Canadian crude oil and equivalents as show in Table 19 (NEB, 2018).

Canadian production for each source type was separated into two regions aligning with the refining process models: western and central Canada (all provinces west of and including Ontario), and eastern Canada (all provinces east of and including Quebec). This division was made to represent similar feedstocks input to refining (see Section 3.4.2). The Eastern Canada refining model is dominated by lighter feedstocks from offshore production and crude oil imports. In contrast, the Western/Central Canada model has heavier feedstocks and oil sands derived production. Production by process group for Eastern (Quebec and Atlantic Canada) and Western/Central (Ontario and Western provinces) blended feedstock is presented in Table 20.

Table 19: 2016 Estimated Annual Production 2016 of Canadian Crude Oil and Equivalent

Province	Source	Production method	Post-production method	Output product	Production included (million bbl/yr)
Alberta	Oil sands - Surface	Mining	Delayed coking	SCO	141
		Mining	Hydroconversion	SCO	94
		Mining	Combined hydroconversion and fluid coking	SCO	118
		Mining	Dilution	Dilbit	68
	Oil sands - In-situ	SAGD	Delayed coking	SCO	76
		SAGD	Dilution	Dilbit	254
		CSS	Dilution	Dilbit	86
	Conventional - medium oil	Primary	NA	Medium oil	55
		Enhanced Oil Recovery*	NA	Medium oil	25
	Tight oil	Drilling/Hydraulic fracturing	NA	Light oil	118
	Conventional - Heavy oil	CHOPS (Cold Heavy Oil Production with Sand)	NA	Heavy oil	43
Saskatchewan	Conventional - Light oil	Drilling	NA	Light oil	63
	Conventional - Heavy oil	CHOPS (Cold Heavy Oil Production with Sand)	NA	Heavy oil	22
	Conventional - Heavy oil	Drilling	NA	Heavy oil	30
	Conventional - Medium oil	Enhanced Oil Recovery*	NA	Medium oil	2
	Heavy oil - In-Situ	SAGD	Delayed coking	SCO	33
Newfoundland and Labrador	Offshore	NG reinjection/water flooding	NA	Light oil	77

** Enhanced Oil Recovery includes water flooding and gas injection.*

Table 20: Production by process group for Eastern and Western/Central blended feedstock (million bbl, 2016)

Extraction and Pre-processing Type	Refining	
	Eastern	**Western/Central**
Conventional*	-	207
Oil sands Mining	-	340
Oil sands Insitu (and Heavy Crude SAGD)**	-	677
Tight Oil	-	112
Offshore	77	-
Total	77	1,336

*Excludes one heavy oil facility using SAGD
**Includes one heavy oil facility using SAGD; figure includes condensate and bitumen to represent diluted bitumen
Source: NEB 2016

To establish the proportion of each upstream product/process type to the Western/Central and Eastern refinery model, respectively, an analysis of imports and exports was performed. Table 21 provides an estimate of production and net exports based on NEB and Statistics Canada 2016 data. The remaining production after subtracting exports represents the contribution of each source to domestic refineries and is presented in Table 21.

In this analysis, each production source was assumed to equally contribute to the volume of exports. A sensitivity analysis was performed to evaluate the impact of this assumption on the GHG intensities of each fuel pathway. The analysis examined the change in intensity resulting from changing the contribution of each extraction source to exports. By setting the source of exports to the lowest CI production methods, the maximum impact on cradle-to-combustion emissions was determined. The result was a maximum change in intensity was a 0.5% increase in the cradle-to-combustion GHG intensity of each liquid transportation fuel.

Table 21: 2016 Crude oil production, export and imports

	Refinery - Eastern	Refinery - Western/Central
Production	77	1,336
Exports	(65)	(1,071)
Consumption of domestic feedstocks	11	266
Imports	212	83
Total refinery inputs	**224**	**349**

All figures reported as million bbl crude oil (2016)

The coverage for the production (volume-weighted) for each grouping of level 2 processes is given in Table 22. For facilities where parameters were not available, default values in OPGEE were used.

Table 23 presents a snapshot of OPGEE parameters showing parameters with high and low facility-level data coverage. For facilities where parameters were not available, Canadian industry-average approximate values or default OPGEE values were used.

The model does not consider the impact of cogeneration and sold electricity for in-situ oil sands facilities. A sensitivity analysis was performed to evaluate the impact of adding cogeneration at every in-situ extraction facility modelled. The impact of this change was a 10-15% reduction in GHG emissions for in-situ extraction facilities resulting in approximately 1 gCO_2e/MJ lower transportation fuel intensities on a cradle-to-combustion basis.

Table 22: Production volume weighted parameter coverage for each grouping (level 2 processes)

Province	Source	Production method	Post-production method	Output product	Coverage by ability to model (%)*
Alberta	Oil sands - Surface	Mining	Delayed coking	SCO	100%
		Mining	Hydroconversion	SCO	100%
		Mining	Combined hydroconversion and fluid coking	SCO	100%
		Mining	Dilution	Dilbit	100%
	Oil sands - In-situ	SAGD	Delayed coking	SCO	90%
		SAGD	Dilution	Dilbit	90%
		CSS	Dilution	Dilbit	87%
	Conventional - medium oil	Primary	NA	Medium oil	78%
		Enhanced Oil Recovery	NA	Medium oil	78%
	Tight oil	Drilling/Hydraulic fracturing	NA	Light oil	67%
	Conventional - Heavy oil	CHOPS (Cold Heavy Oil Production with Sand)	NA	Heavy oil	63%
Saskatchewan	Conventional - Light oil	Drilling	NA	Light oil	67%
	Conventional - Heavy oil	CHOPS (Cold Heavy Oil Production with Sand)	NA	Heavy oil	78%
	Conventional - Heavy oil	Drilling	NA	Heavy oil	67%
	Conventional - Medium oil	Enhanced Oil Recovery	NA	Medium oil	89%
	Heavy oil - In-Situ	SAGD	Delayed coking	SCO	80%
Newfoundland and Labrador	Offshore	NG reinjection/water flooding	NA	Light oil	97%

*Based on coverage of primary and secondary operating parameters

The outputs from OPGEE include GHG intensity, products and co-products. The primary products are crude oil, SCO, and diluted bitumen. Co-products include natural gas, natural gas liquids (NGL), and petroleum coke.

Canadian-specific upstream emissions associated with diesel, natural gas and other energy sources were input into OPGEE based on a pre-finalized output of the life cycle carbon intensity model (i.e. in a recursive process).

Upstream emissions from diluent were approximated using the natural gas fuel pathway results. In the model, the diluent is carried to the refinery as part of the diluted bitumen flow, where it contributes to the production slate. This approach effectively attributes the net increase in GHG emissions from transporting and recovering diluent to the other transportation fuels produced at the refinery.

Results were compared against those in the Science paper (Masnadi et al., 2018) and facility GHG data (GHGRP). At a facility level, the comparison was used to identify outliers and confirm the reasonableness of the operating parameter data and modelling result. The data was then aggregated to the Level 2 processes via volume-weighting. GHG emissions were allocated to products and co-products based on energy output.

Table 23: Default Parameters used in OPGEE

Parameters with high data coverage		Parameters with low data coverage	
Parameters included for most facilities	Data sources	Default parameters used for most facilities	Parameter set to zero for most facilities
Field depth – Secondary parameter*	Brandt, et al., 2018	Field age	Gas lifting injection ratio
Number of producing wells – Secondary parameter*	Brandt, et al., 2015, Tripathi, et al., 2017	Number of water injecting wells	Gas flooding injection ratio
Reservoir pressure*	AER In-situ performance	Production tubing diameter	Fraction of required electricity generated onsite
Water-to-oil ratio (WOR)* – Primary Parameter	AER Report ST53	Productivity index – Secondary parameter	Fraction of steam generation via cogeneration
Steam-to-oil ratio (SOR)* – Primary Parameter	AER Report ST53	Reservoir temperature	Fraction of steam generation via solar thermal
Flaring-to-oil ratio (FOR)* – Primary Parameter	AER In-situ performance, AER Report ST53 2016 Saskatchewan Fuel, Flare, and Vent,	Gas composition and Gas-to-oil ratio (GOR)	
Venting-to-oil ratio*	AER In-situ performance 2016 Saskatchewan Fuel, Flare, and Vent,	Water injection ratio	
Oil production rate** – Secondary parameter	AER Report AT60B 2017, AER In-situ performance, AER Report ST53, AER report ST39 2016	Fraction of remaining natural gas reinjected Fraction of produced water reinjected	
API gravity** – Primary Parameter	Monthly Production Summary for the Hibernia Field, White Rose Field, North Amethyst, Terra Nova field 2016, Canada Newfoundland & Labrador Offshore Petroleum Board	Volume fraction of diluent Fugitive emissions	

* Most facilities ** All facilities

4.5.3 Extraction and Upgrading Results

A summary of the upstream extraction and pre-processing carbon intensities is given in Table 24.

Table 24: Model results for carbon intensities of extraction and pre-processing (per MJ of feedstock to refining)

Product Type	Product	Oil/Dilbit/SCO (%)	NG (%)	NGL (%)	gCO_2e/MJ (HHV, AR5-100)
Crude oil (Conventional)	Crude Oil	90.4%	7.9%	1.8%	11.2
SCO (Oil Sands)	SCO	93.5%	3.6%	2.3%	23.9
Dilbit (Oil Sands)	Dilbit	99.4%	0.0%	0.4%	14.5
Crude oil (Tight Oil)	Crude Oil	98.1%	0.0%	1.9%	6.3
Crude oil (Offshore)	Crude Oil	87.9%	4.4%	4.4%	6.0
Natural Gas					16.1
NGL					15.2
Petcoke (from Upgrader)					22.3

Table 25 presents the proportion of each upstream product/process type to the Western/Central and Eastern refinery, respectively. An analysis of imports and exports of crude oil, SCO and diluted bitumen was performed based on NEB and Statistics Canada 2016 data to estimate refinery inputs. Increasingly, western Canadian feedstocks are being processed in Quebec. However, as an approximation of 2016 production, the model applied western feedstocks exclusively to the western/central refinery.

Table 25: Proportion of each upstream product/process type to Canadian region

Extraction and Pre-processing	Refinery - Eastern	Refinery - Western/Central
Crude Oil (Conventional)	-	0.12
SCO (Oil sands - Mining)	-	0.19
Diluted Bitumen (Oil sands - In-situ)	-	0.39
Crude Oil (Tight Oil)	-	0.06
Conventional (Offshore)	0.05	-
Crude Oil (Imports)	0.95	0.24
Total	**1.00**	**1.00**

All figures proportional share of 1MJ blended feedstock

4.6 Crude Oil Refining, Products and Blending

4.6.1 Crude Oil Refining

Thirteen of the 16 Canadian refineries were modeled in detail, representing 96% of the total capacity and 98% of refining emissions. The modelling of crude refining and the production of refinery products employed data from Woods Mackenzie (WM) and AFARA (a third-party subcontractor hired to collect data) which included data from many sources[6]. It should be noted that much of the detail about the refineries and crudes is proprietary to those refineries and will not be made public. Crude data provided represent one year (2016) of production and do not account for seasonal variability as this information was not available from the data providers.

PRELIM is a mass and energy-based model that allows for the estimation of GHG emissions from refining. The crude streams from the crude slate percentage WM worksheet were used to match to an appropriate assay in PRELIM. When AFARA had more detailed crude slate % than WM, AFARA was used to determine crude assays in PRELIM. Wood Mackenzie refinery products were matched to PRELIM product slates based on characteristics of the crude including location of production and API. Key crude assay properties include the volume flow (in both barrels per day and cubic meters per day), mass flow (kg/day), sulfur (wt%), nitrogen (mass ppm), API gravity (oAPI), density (kg/cubic meter), hydrogen (wt%), Microcarbon residue or MCR (wt%), characterization factor (Watson characterization factor or Kw approx.) and Depositional History Curve or DHc (MJ/kg). Many assays are available through CrudeMonitor.ca

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[6] Provincial and federal regulators: NEB, AER, ECCC; Industry associations: CAPP, CFA, CEPA; Government sources and data bases: StatsCAN, Petrinex, CCME, GoA; Academic publications: University of Calgary School of Public Policy; Think tanks: CERI; Operators: Shell, Husky, Imperial Oil, Suncor, Chevron; Consultants: Kent Group, IHS Market; Journals: Oil & Gas Journal; Other publications: Oil Sands Magazine; Fee-based reports: API, Solomon, IHS, and Wood Mackenzie, and; and Crude Assays: Operators, Crude Quality Inc., Colorado School of Mines, Environment Canada, Oil Transport Information

and through company websites. These product slates were matched based on the information in Table 26. The yield weight percentages for each product were summed per PRELIM product slate per refinery. The default electricity carbon intensity values for Canadian provinces were updated to reflect the values provided by ECCC that reflect 2016 (Table 27). Direct electricity emissions are those that originate from on-site emissions to the power plant and indirect are offsite emissions associated with fuel production, transmission and distribution losses and emissions related to transport of fuels. Detailed documentation on the calculation of the electricity grid CIs is provided in Appendix C. Electricity Intensities in the Clean Fuel Standard's LCA Modelling Tool. The default natural gas upstream production CI value for Canada was also updated to reflect the CI calculated in this work.

The modeled refineries represent 96% of total capacity and 98% of refining emissions. The refinery capacity for excluded refineries, Husky-Prince George, Husky-Lloyminister, and Gibson-Moose Jaw refineries, comprise 4% of the total capacity and only 2% of total GHG emissions stems from these refineries. This combined with the lack of data available to model these refineries lead to their exclusion from the modelling.

Table 26: Matching of WM refinery products to PRELIM product slates

Wood Mackenzie	PRELIM Product Slate
Diesel - Ultra Low Sulphur	ULSD
BTX - Standard	Petrochemical Feedstocks
Fuel Oil - Low Sulphur	Liquid Heavy Ends
Gasoline - Regular Unleaded	Blended Gasoline
LPG - Standard	Liquefied Petroleum Gas (LPG)
Naphtha - Standard	Blended Gasoline
Petroleum Coke - Standard	Coke
Refinery Fuel - Standard	Refinery Fuel Gas
Bitumen - Standard	Asphalt
Gasoil - Low Sulphur	Fuel Oil
Gasoline - Premium Unleaded	Blended Gasoline
Jet/Other Kerosene - Standard	Jet-A/AVTUR
Sulphur - Standard	Sulfur
Fuel Oil - High Sulphur	Liquid Heavy Ends
Diesel - Standard	ULSD
Lubricants - Standard	Liquid Heavy Ends
Other Products - Standard	Liquid Heavy Ends
Propylene - Standard	Petrochemical Feedstocks

PRELIM has three basic categories of refinery types (Hydroskimming, Medium Conversion and Deep Conversion) and 10 combinations of process units. The process unit parameters used in PRELIM include crude assay information (e.g., distillation curve, hydrogen content), energy requirements for processing, yields of intermediate products and the specifications of intermediate products such as API, sulfur content and hydrogen content. Detailed process unit configuration descriptions can be found in the PRELIM modelling documentation (Abella et al., 2017).

Initial GHG emissions results from PRELIM use low heating values and 100-year AR5 global warming potentials, but can be adjusted to also report by high heating value and 20-year AR5 global warming potential. Data sources for this modelling are described in Section 4.2.1. The method for matching refinery data to refinery unit configurations and crude inputs followed the method employed in the 2014 National Energy Technology Laboratory (NETL) study (NETL., 2014). The throughput/capacity ratio of each refinery is determined based on the WM 2016 datasets and AFARA report, in which refinery actual throughputs (mbpd: thousand barrels per day) and refinery capacities are reported (mbpd), respectively.

Table 27: Electricity carbon intensities for Canadian provinces (units are t CO_2e/GWh) (see Appendix C for methods and sources for electricity CIs)

	Direct impacts	Indirect impacts	Total
AB	900	45	945
BC	11	67	78
MB	2.1	20.6	23
NB	345	46	391
NL	40	21	61
NS	689	87	776
ON	38	22	60
PEI	26	242	268
QC	1.3	10.9	12
SK	754	62	816
YK	47	Out of Scope	Out of Scope
NWT	209	Out of Scope	Out of Scope
NU	759	Out of Scope	Out of Scope
CA	145	27	172

The products of refining include gasoline, diesel, jet fuel, residual fuel oil, petroleum coke and other products such as petrochemicals. The treatment of petcoke that results from refining is discussed in Section 4.7.2. Where sufficient data were available, each refinery was modeled separately in PRELIM and the results were aggregated into representative Eastern and Western Refineries. This grouping was based on both the source and type of input feedstocks and the location of use of products and is illustrated in Table 28. The refineries were volume-weighted into the western/central and eastern categories. This represents 13 of the 16 total refineries in Canada. Note that Gibson Energy-Moose Jaw, SK, Husky-Prince George, BC, Husky-Lloydminster, AB were not included due to lack of data availability on key PRELIM input parameters and their relatively low contribution to total reported emissions and production. Also, note that fuel oil is only produced at the Edmonton Suncor, Sarnia Suncor, Regina, Come By Chance and Saint John refineries. The low emission factors (by direct separation from the crude distillation unit as atmospheric gas oil, so no further processing is required, hence the low emission factors) are calculated. PRELIM version 1.4 does separate gas oil as a separate product from the crude distillation unit, viewed as fuel oil, and which does not go through other processing units. The effect on overall refinery and other product emissions are also taken into account. Note that if the product is separated from the crude distillation unit, it is light fuel oil. In PRELIM, this is called light fuel oil. If it is a liquid heavy end, it is likely to become marine fuel oil (also known as bunker fuel).

An import analysis to the refineries is given in Table 29 and a feedstock mix for refining is given in Table 30. The weightings used to average the Eastern and Western Canada fuels into the one Canadian average are provided in Table 31. These are the weighting of the respective fuels from Western/Central and Eastern Canada used to calculate the Canadian average. All Ontario refineries are in the Western/Central Canada group. Imports by province are based on StatsCanada data. Note that StatsCanada data does not provide imports for every province due to confidentiality of individual facilities. The model approximates the feedstock mix for refining by grouping Ontario refineries into the Western/Central group. Quebec was grouped with Eastern Canada. The lack of western feedstocks to Quebec is an approximation of the model and does not have a significant impact on the Canadian cradle-to-combustion CI.

Table 28: Refinery groupings (Refinery name, Province)

Western/Central Canada	Eastern Canada
Burnaby, BC	Come by Chance, NL
Edmonton Imperial, AB	Jean Gualin, QC
Scotford, AB	Montreal Suncore, QC
Edmonton Suncor, AB	Saint John, NB
Regina, SK	
Nanticoke, ON	
Sarnia Imperial, ON	
Sarnia Shell, ON	
Sarnia Suncor, ON	

Table 29: Import analysis to the refineries

Extraction and Pre-processing	Refining	
	Eastern	**Western/Central**
Production	77	1,336
Exports	(65)	(1,071)
Consumption of domestic feedstocks	11	266
Imports	212	83
Total refinery inputs	224	349

Source: NEB 2016 Data; Stats Canada, 2018

Table 30: Feedstock mix for refining

Extraction and Pre-processing	Refining	
	Eastern	**Western/Central**
Crude Oil (Conventional)	-	0.12
SCO (Oil sands - Mining)	-	0.19
Diluted Bitumen (Oil sands - In-situ)	-	0.39
Crude Oil (Tight Oil)	-	0.06
Conventional (Offshore)	0.05	-
Crude Oil (Imports)	0.95	0.24
Total	1.00	1.00

All figures proportional share of 1MJ blended feedstock. Data are based on Stats Can, 2016 and also include Ontario.

Table 31: Weighted Average Production of Fuels for Eastern and Western Canada and average (MJ Crude required to Produce 1 MJ Product Slate)

Product Slate	Western/Central	Eastern	Canada Average
Blended Gasoline	0.95	0.97	0.96
Jet-A/AVTUR	0.96	0.99	0.98
ULSD	1.04	1.07	1.05
Fuel Oil	1.11	1.12	1.11
Coke	1.15	-	1.15
Liquid Heavy Ends	1.13	1.12	1.13
Liquefied Petroleum Gas (LPG)	0.69	0.70	0.70

Additionally, reported GHG emissions for Canadian facilities were used as a quality assurance check against calculated emissions. Note that the reported emissions for some refineries do not include emissions from the production of hydrogen required for refining if the hydrogen is not produced by facilities owned by the refinery operator because it was not mandatory to report this in 2016. The GHG emissions from additional hydrogen production based on required hydrogen calculated in PRELIM were added to reported emissions to account for non-reported emissions. The results of this check are not shown because they are for each individual refinery and not for the aggregated Eastern and Western/Central or Canadian average. The LPG refining CI was found to be comparable to literature values illustrated in the figure below.

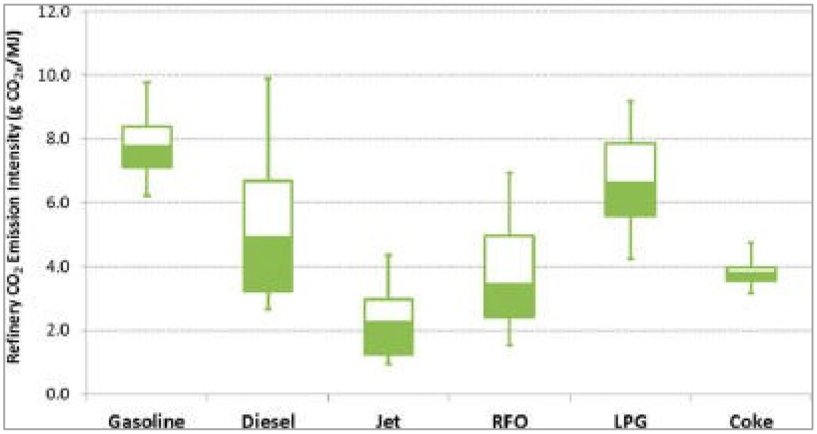

Figure 12: Reference refinery GHG emissions intensities for petroleum products at US refineries (Elgowainy, et al., 2014)

PRELIM configurations were based on WM and AFARA unit capacities; default configurations were used if information was not available in WM. PRELIM was also run with the product slate percentages manually adjusted; the product slates were based on WM. Key process unit capacities of each refinery are available from the AFARA report, from which their throughputs were calculated using the refinery's throughput/capacity ratio. The throughput of each process unit is then compared with the refinery's throughput to determine the fraction (%) of crude input that is processed by this unit. The default PRELIM crude input throughput is assumed to be ~100,000 bbl/d. This throughput must be scaled to actual individual refinery throughput (e.g., Burnaby is 48 mbpd) in 2016 which in turn must be scaled to throughputs of each process unit. The fraction (%) of the crude input slate that passes through that unit was compared with those of WM 2016 to ensure that they are equal to or less than the Wood Mackenzie percentage values.

Some manual adjustments were made to the PRELIM runs to ensure that all of the emissions associated with hydrogen production required to produce fuels were accounted for and so that the emissions from onsite combustion of refinery fuel gas were included in the carbon intensities from refining. For example, manual manipulation in PRELIM was performed to ensure that enough hydrogen was added to the RFG to meet the specification and produce the petrochemicals and LPG reported for each facility. This means that some of the default parameters in PRELIM were manually adjusted based on additional data availability. Additionally, a sensitivity analysis was done on each individual refinery run of PRELIM with high CI fuel oil and low CI fuel oil to check the effect of this assumption on the CIs of the other fuels. The result of this analysis was that the CIs of other fuels were not sensitive to the assumed CI of RFG and fuel oil (note results are not shown because they are for each individual refinery not for the combined Eastern and Western/Central refineries or for the Canadian average refinery).

Hydrogen production emissions is controlled by the steam methane reformer (SMR), which is essentially reflected by the use of natural gas both as feed and fuel for heat. The hydrogen production emission parameters were not changed. Instead, the portion of hydrogen that must be purchased in order to mitigate emissions was calculated and calibrated in addition to process unit throughput matching based on newly published data (Jing, Monfort, El-Houjeriri, & Bergerson, 2019).

Refinery fuel gas (RFG) can be collected from naphtha reformer, hydrotreaters, fluid catalytic cracker (FCC), and gas oil hydrocracker. The reformer needs to produce hydrogen. Thus, if the fuel gas yield rate of the reformer is set too high, it will consume hydrogen, which is not what would happen at the refinery. Hydrotreaters also require hydrogen to remove sulfur, but the hydrotreater fuel gas production is relatively small. The most sensitive parameters are FCC and gas oil hydrocracker fuel gas yields. In PRELIM, the yield rate for FCC is controlled by the calculations for the coking facility. The default value for this parameter is 5.5%, but is can be changed 20-30% to match RFG yield, and this will lower the total refinery emissions since no hydrogen is needed at FCC. The yield of gas-oil hydrocracker (GO-HC) is controlled by the process correlations which show the yield correlation of light ends with chain length of 3 (C3) and lighter. This yield can be increased for higher refinery fuel gas (RFG) yield, which automatically decreases the yield of 400+ degree Fahrenheit streams (diesel and fuel oil). Since C3 and lighter has higher hydrogen contents than other products from GO-HC, it therefore consumes relatively more hydrogen and can increase the overall refinery emissions.

It should be noted that refineries deploy FCC feed hydrotreater mainly to 1) reduce sulfur, nitrogen, metal contents in order to extend catalyst cycle time and save energy, 2) saturate aromatics and reduce heavy components for better cracking and coke minimization, 3) reduce light cycle oil (eventually diesel) production and achieve more gasoline yield based on market dynamics. Therefore, FCC feed hydrotreating is mostly needed when the crude slate is heavy sour, or when gasoline needs to be maximized. But, FCC feed hydrotreating is not necessarily a must. FCC post (or gasoline) hydrotreating, which is less hydrogen- and emission-intensive, can also be used when feed is not hydrotreated in order to meet environmental regulations and/or if the refiner is not under pressure to pursue gasoline yield maximization. In rare cases, refineries could have both FCC feed and post hydrotreater when their feed is heavy sour, and they expect to maximize gasoline yield. Publicly-available data shed some light on which refineries use this technology, but not was not all-inclusive of each refineries' technology or use of hydrogen.

Among all 13 refineries, only five of them have an FCC feed hydrotreater according to the Wood Mackenzie 2016 datasets. Another five of them have FCC post hydrotreater (also known as FCC naphtha hydrotreater or FCC gasoline hydrotreater), while the remaining three have no FCC unit or FCC hydrotreater. Therefore, instead of using the default FCC feed hydrotreater setting for all refineries, our updated PRELIM modelling in PRELIM 1.4 work applies FCC post hydrotreater for Burnaby, Edmonton Imperial, Nanticoke, Regina, and Sarnia Shell. As an indication of why some refineries use an FCC post hydrotreater, it is notable that both Edmonton Suncor and Sarnia Imperial take a large portion of heavy West Canadian Select crude, which may be the main reason why they have FCC feed hydrotreaters. Jean Gaulin, Montreal Suncor, and Saint John mostly process medium to light crudes, therefore, they have FCC feed hydrotreater possibly to increase their gasoline yield.

The throughput/capacity ratio of each refinery was determined based on the Wood Mackenzie 2016 datasets, where crude input per year is converted properly and used as throughput. Key process unit capacities are available from the Wood Mackenzie 2016 datasets, from which their throughputs can be obtained using refinery throughput/capacity ratio. Process unit throughputs were also compared against refinery throughput to determine their operation efficiencies.

PRELIM crude input is approximately 100,000 bbl/d, to which throughputs of key process units are compared. The same throughput percentages are obtained for each process unit. These percentage values were double-checked to ensure that they are equal to or less than, or at least did not exceed the Wood Mackenzie percentage values by a significant amount. In this way, it was ensured that the PRELIM modelling did not violate any process unit throughput constraints.

Data on which refineries use cogeneration were not publicly-available. It is notable that if cogeneration (gas turbine & heat recovery steam generator) is applied, most refineries would have increased emissions. This is because in PRELIM, fuel input for a gas turbine is considered as heat to be added to refinery's heat load (NG combustion). Therefore, produced electricity and steam would have no emissions. Supplementary electricity and steam are needed for business as usual operation. In Canada, provinces such as Newfoundland, Ontario, Quebec, and BC have electricity emission factors that are much lower than natural gas combustion. Therefore, it is not likely to be environmentally- or economically-viable to run cogeneration in these provinces. However, in provinces like Alberta and Saskatchewan, electricity emission factors are much higher that natural gas combustion, therefore, it could be more suitable to have cogeneration. Still, without information on the use of cogeneration at any of the refineries, the assumption could not be made that any particular refinery was using cogeneration. In lieu of these data, a sensitivity analysis was run on each individual refinery in which it was assumed that all refineries used cogeneration. As expected, this increased emissions at some refineries and reduced it at others based on geography. Still, the increase or decrease ranged between -8% and +7% of the refinery emissions to as high as 8%. Overall, this would not lead to an appreciable change in the CI of individual fuels from CTCG or CTC.

To test the impact of different natural gas upstream emissions intensities on a refinery emissions estimate, another refinery was used as an example test case. This refinery's base case refinery emissions were 53.7 kg CO_2e/bbl crude. PRELIM by default adopts 10.8 g CO_2e/MJ for natural gas upstream emissions. Based on literature data, the values 6 and 15 g CO_2e/MJ were tested as two extreme cases. When 6 g CO_2e/MJ for natural gas is selected, refinery emissions are reduced to 51.2 kg CO_2e/bbl crude (4.7% decrease); when 15 g CO2e/MJ for natural gas is selected, refinery emissions increase to 55.9 kg CO_2e/bbl crude (4.1% increase). Overall, these changes would likely not appreciably affect the final CTC CI of the fuels.

A summary of the refinery inputs for the manual product slates and the mapping of input crude data to PRELIM crude inputs is provided in Table 32 and Table 33. The crude assay mass ratios and final volume intake by refinery and aggregation are provided in Table 34. Note that the crude assay name that is matched to the refinery intake may be matched because it met the assay characteristics of the reported crude input, not because the name of the crude matched precisely. This is why some of the crude assay inputs to East aggregation regions may have the word "Western" in them and vice versa.

Table 32: Weighted Average (thousand barrels/day)

Crude name and source data	West	East	API	Specific Gravity	Sulphur	Density (kg/m^3)
Albian Heavy Synthetic_Crude Monitor_New	7.3	-	19.4	0.9	2.6	936.8
Midale_Crude Monitor	11.1	-	29.6	0.9	2.3	877.5
Syncrude Synthetic_Crude Monitor	156.0	-	33.6	0.9	0.2	856.2
Mixed Sweet Blend_Crude Monitor	202.9	33.4	40.0	0.8	0.3	824.5
Western Canadian Select_Crude Monitor	69.7	11.6	20.5	0.9	3.4	929.8
Suncor Synthetic A_Crude Monitor_Old	87.0	-	33.5	0.9	0.2	856.7
Cold Lake_Crude Monitor_New	40.3	-	20.4	0.9	4.0	930.4
Light Sour Blend_Crude Monitor_New	1.9	12.8	37.9	0.8	0.9	834.7
Suncor Synthetic A_Crude Monitor_New	68.6	29.8	33.5	0.9	0.1	856.7
Suncor Synthetic H_Crude Monitor_New	78.0	-	19.1	0.9	3.0	938.6
Lloyd Blend_Crude Monitor_New	65.8	-	21.4	0.9	3.5	924.7
Louisiana light sweet_Stratiev	-	52.8	36.1	0.8	0.3	844.0
Bonny Light_Chevron	-	82.1	32.7	0.9	0.2	860.8
Ekofisk_Statoil	-	46.3	38.4	0.8	0.2	832.4
West texas intermediate_Stratiev	-	70.9	40.8	0.8	0.3	821.0
Forties Blend_BP	-	10.1	38.6	0.8	0.7	831.0
Algerian Condensate_BP	-	92.9	68.4	0.7	0.0	707.1
Synthetic Sweet Blend_Crude Monitor	-	100.3	33.6	0.9	0.1	856.2
Eagle Ford Ultralight_Platts	-	7.2	43.1	0.8	0.1	809.6
Western Canadian Blend_Crude Monitor	-	22.9	20.6	0.9	3.3	929.1
Azeri Light_Chevron	-	21.1	36.1	0.8	0.1	843.5
Canada Hibernia_Chevron	-	65.0	33.5	0.9	0.6	856.6
Russian Export Blend_Stratiev	-	35.4	31.8	0.9	1.3	867.0
Ekofisk_BP	-	1.7	38.4	0.8	0.2	832.0
Arab Light_Stratiev	-	106.1	33.4	0.9	1.6	858.0
Angola Girassol_Exxon	-	23.2	29.9	0.9	0.3	876.7

Table 33: Crude Type Mapping from WM and AFARA data sources to PRELIM

PRELIM Crude Name Match	WM / AFARA Crude Name for Matching			
Albian Heavy Synthetic_Crude Monitor_New	Albian Heavy Synthetic			
Midale_Crude Monitor	Midale			
Syncrude Synthetic_Crude Monitor	Oil Sands Synthetic			
Mixed Sweet Blend_Crude Monitor	Mixed Sweet Blend	W. Canada Conventional Light Sweet (Alberta)	AB Light - Light (Mixed Sweet Blend - 72% and Mixed Sour Blend - 28%)	ON Light - Light Sweet SCO (Mixed Sweet Blend and Mixed Sour Blend)
Western Canadian Select_Crude Monitor	Western Canadian Select	AB Bitumen - Dilbit (Western Canadian Select)		
Suncor Synthetic A_Crude Monitor_Old	Oil Sands Synthetic			
Cold Lake_Crude Monitor_New	Cold Lake			
Light Sour Blend_Crude Monitor_New	Light Sour Blend			
Suncor Synthetic A_Crude Monitor_New	Oil Sands Synthetic			
Suncor Synthetic H_Crude Monitor_New	Suncor Synthetic H			
Lloyd Blend_Crude Monitor_New	Lloyd Blend			
Louisiana light sweet_Stratiev	Light Louisiana Sweet			
Bonny Light_Chevron	Bonny Light	Nigeria - Light (AKPO and Brass River)		
Ekofisk_Statoil	Ekofisk Blend			
West texas intermediate_Stratiev	West Texas Intermediate			
Forties Blend_BP	Forties Blend			
Algerian Condensate_BP	Saharan Blend	Algeria - Ultra-Light Sweet (Algeria Saharan Blend)		
Synthetic Sweet Blend_Crude Monitor	AB SCO - Light Sweet SCO (Synthetic Sweet Blend)			

PRELIM Crude Name Match	WM / AFARA Crude Name for Matching			
Eagle Ford Ultralight_Platts	US Eagle Ford (TX) - Ultra-Light Sweet	US WTI Light - Light Sweet (US Texas Spraberry)		
Western Canadian Blend_Crude Monitor	AB Heavy - Heavy Sour (Western Canadian Blend)			
Azeri Light_Chevron	Kazakhstan CPC Blend - Ultra Light Sour (Kazakhstan Tengiz)			
Canada Hibernia_Chevron	White Rose	W. Canada Conventional Light Sweet (Alberta)	Hibernia	
Russian Export Blend_Stratiev	ESPO	US North Dakota - Light Sweet (US Bakken - No flare)		
Ekofisk_BP	Ekofisk Blend			
Arab Light_Stratiev	Arab Light			
Angola Girassol_Exxon	Ceiba	Castilla		

Table 34: Crude assay mass ratios and final volume intake by refinery and aggregation*

Refinery	Aggregation Region	Crude Assays	Mass Ratios	Final Intake Volume (thousand b/day)
Burnaby	West	Syncrude Synthetic_Crude Monitor	62%	29.69
Burnaby	West	Mixed Sweet Blend_Crude Monitor	38%	18.15
Edmonton Imperial	West	Mixed Sweet Blend_Crude Monitor	69%	112.62
Edmonton Imperial	West	Western Canadian Select_Crude Monitor	29%	47.26
Edmonton Imperial	West	Syncrude Synthetic_Crude Monitor	2%	3.58
Scotford	West	Suncor Synthetic A_Crude Monitor_Old	100%	86.99
Edmonton Suncor	West	Cold Lake_Crude Monitor_New	31%	40.27
Edmonton Suncor	West	Light Sour Blend_Crude Monitor_New	1%	1.86
Edmonton Suncor	West	Suncor Synthetic A_Crude Monitor_New	34%	45.24
Edmonton Suncor	West	Suncor Synthetic H_Crude Monitor_New	34%	44.38
Regina	West	Lloyd Blend_Crude Monitor_New	59%	65.85
Regina	West	Syncrude Synthetic_Crude Monitor	41%	44.84
Come by Chance	East	Louisiana light sweet_Stratiev	38%	35.44
Come by Chance	East	Bonny Light_Chevron	20%	18.97
Come by Chance	East	Ekofisk_Statoil	17%	16.06
Come by Chance	East	West texas intermediate_Stratiev	17%	15.38
Come by Chance	East	Forties Blend_BP	7%	6.40
Come by Chance	East	Algerian Condensate_BP	1%	0.85
Jean Gaulin	East	Algerian Condensate_BP	40%	92.10
Jean Gaulin	East	Synthetic Sweet Blend_Crude Monitor	35%	81.20

Refinery	Aggregation Region	Crude Assays	Mass Ratios	Final Intake Volume (thousand b/day)
Jean Gaulin	East	Western Canadian Select_Crude Monitor	5%	11.60
Jean Gaulin	East	Eagle Ford Ultralight_Platts	3%	7.20
Jean Gaulin	East	Western Canadian Blend_Crude Monitor	3%	8.10
Jean Gaulin	East	Azeri Light_Chevron	9%	21.10
Jean Gaulin	East	Bonny Light_Chevron	5%	11.50
Montreal Suncor	East	West texas intermediate_Stratiev	27%	33.54
Montreal Suncor	East	Suncor Synthetic A_Crude Monitor_New	24%	29.76
Montreal Suncor	East	Canada Hibernia_Chevron	30%	37.61
Montreal Suncor	East	Russian Export Blend_Stratiev	15%	19.10
Montreal Suncor	East	Forties Blend_BP	3%	3.69
Montreal Suncor	East	Ekofisk_BP	1%	1.71
Nanticoke	East	Mixed Sweet Blend_Crude Monitor	35%	33.39
Nanticoke	East	Light Sour Blend_Crude Monitor_New	13%	12.75
Nanticoke	East	Synthetic Sweet Blend_Crude Monitor	20%	19.10
Nanticoke	East	Western Canadian Blend_Crude Monitor	15%	14.80
Nanticoke	East	Russian Export Blend_Stratiev	17%	16.26
Sarnia Imperial	West	Syncrude Synthetic_Crude Monitor	50%	51.59
Sarnia Imperial	West	Mixed Sweet Blend_Crude Monitor	29%	30.11
Sarnia Imperial	West	Western Canadian Select_Crude Monitor	22%	22.40
Sarnia Shell	West	Mixed Sweet Blend_Crude Monitor	49%	32.30
Sarnia Shell	West	Syncrude Synthetic_Crude Monitor	40%	26.31
Sarnia Shell	West	Albian Heavy Synthetic_Crude Monitor_New	11%	7.28
Sarnia Suncor	West	Suncor Synthetic H_Crude Monitor_New	43%	33.62
Sarnia Suncor	West	Suncor Synthetic A_Crude Monitor_New	30%	23.39
Sarnia Suncor	West	Midale_Crude Monitor	14%	11.10
Sarnia Suncor	West	Mixed Sweet Blend_Crude Monitor	12%	9.70
Saint John	East	Arab Light_Stratiev	38%	106.06
Saint John	East	Bonny Light_Chevron	19%	51.59
Saint John	East	Ekofisk_Statoil	11%	30.25
Saint John	East	Canada Hibernia_Chevron	10%	27.36
Saint John	East	West texas intermediate_Stratiev	8%	21.95
Saint John	East	Louisiana light sweet_Stratiev	6%	17.36
Saint John	East	Angola Girassol_Exxon	8%	23.20

* Source: WM data

4.6.2 Crude pipeline energy use and emissions

Transport, liquid pipeline\CA

Crude is transported to refineries predominantly through a network of pipelines across Canada. Each pipeline has its own diameter, length, flow rate, roughness and pressure drop. All of these parameters contribute to the energy required to move the crude through the pipeline. The viscosity of the crude also affects the energy requirements.[7]

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[7] While a pipeline by pipeline and fuel type by fuel type model is possible, the time required to do this level of modelling is beyond the scope of this project. This is an area which could be focused on in future work.

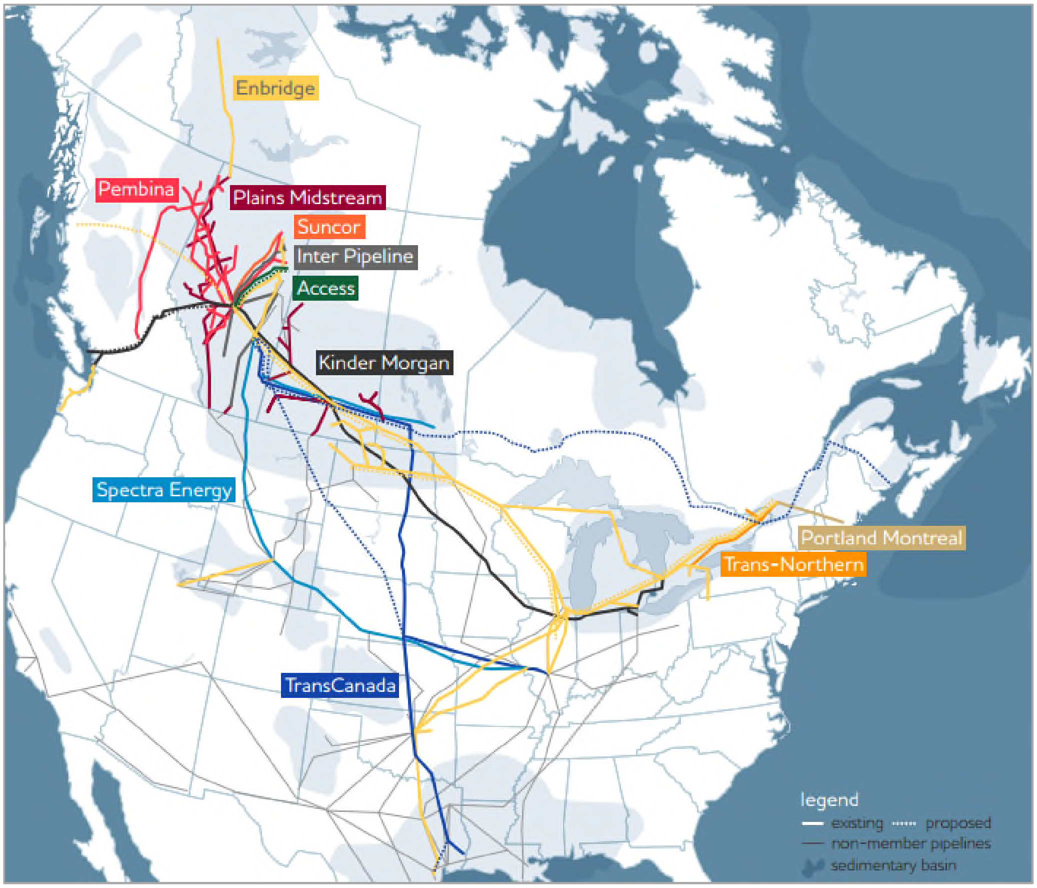

Figure 13: Map of Canadian liquids pipelines (and some US pipelines) (Source: Pipeline Education Pipeline - Energy Education)

In crude pipelines, grid electricity is used to power the pumps. Choquette-Levy et al (Choquette-Levy et al. 2018a) have calculated the energy intensity and carbon intensity per bbl·km for each pipeline in North America. The energy intensity weighted average was calculated for pipelines with at least one end in Canada, with the result of 3.7 Wh/bbl·km with a maximum of 20.3 Wh/bbl·km and a minimum of 0.53 Wh/ bbl·km (see spreadsheet "*3-9-0 crude pipeline efficiency calculations.xls*"). The distribution of energy intensity appears to be lognormal. The square of the geometric standard deviation (needed to define the variability) is calculated to be 14.0. As can be seen in Figure 13, the modeled pipelines span the continent. To provide continuity with the remaining pathway modelling and to enable rapid model updating, the average Canadian grid mix is used in the unit process. The impacts of the Alberta grid are included in the uncertainty analysis as a worst-case scenario.

As can be seen from Table 35, the distribution is in line with other models.

Table 35: Comparison of energy requirements for crude pipeline model with similar models.

Function	This Study	GHGenius	GREET
Electricity required to transport one barrel of crude one kilometer	3.7 Wh/bbl.km (lognormal distribution with a geometric standard deviation of 14 Wh/bbl.km)	2.8 Wh/bbl.km	8-10 Wh/bbl.km

Table 36: Energy use and emissions for crude transport (other than bitumen) through the pipeline, expressed per bbl/km of transport.

Exchange	Quantity	Unit	Description
Outputs			
Transport, liquid pipeline {CA}	1	bbl/km	
Inputs			
Electricity at grid, 2016 average {CA}	3.7	Wh	Average Canadian grid used as transport is across Canada. Uncertainty applied to include the Alberta grid as part of the assessment.

The transport of refined crude products from refinery to distribution centre may also include truck and rail shipments. For the purposes of this study, truck and rail shipments were excluded as an approximation. Note that downstream truck deliveries to end-users was considered.

As the study included the transport of bitumen and diluent in Canadian crude pipelines, they have been modeled using the same amount of energy and result in the same emissions as the transport of crude via pipeline. This approach is consistent with other tools such as GREET and GHGenius, as well as the Ecoinvent database for LCA.

4.6.3 Crude Products Blending and Combustion

While crude products, such as gasoline are blended with ethanol to achieve octane and other specifications, the production of these bio-based fuels (including ethanol and biodiesel) is not included in the system boundary of the fossil fuel pathways. Furthermore, the combustion emissions from these fuels account only for the emissions from the fossil fuel, not the bio-based fuel components. The transport and distribution of blended products is included in the transportation and distribution of fuels. Combustion is addressed in Section 4.10.

Crude

About 97% of all crude and natural gas in Canada is transported via pipeline (Conca 2018). 550 billion barrels of oil year are exported via tanker ship and 140,000 b/d were transported via train in 2017 (CAPP 2018b).

Petroleum fuels

Petroleum fuels are transported through various means, including pipeline, train, tanker ships and trucks. As there is insufficient data available to assess the per cent of each mode and because the impacts of pipeline, train and tanker shipments are a fraction of the overall impact, petroleum fuels have been approximated as 100% truck transport. While GHGenius shows a percentage transported via pipeline/conveyor and rail, the majority is shipped via truck. GREET shows about 70% of fuels transported via truck, and the remainder by water.

Approximating fuel transport as 100% by truck results in less than a 1% contribution to cradle-to-combustion emissions. As the impact of this decision on GHG emissions is before the cut-off criteria, more detailed modelling of transportation modes have not been explored further.

Table 37: Summary table of activity data

Coal	Natural Gas	Crude oil	Petroleum fuels	Petcoke and Coal
100 % rail	100% pipeline (internal consumption)	97% pipeline 3% train (except offshore transported via tanker ship)	Unknown combination of pipeline, train, tanker ship and truck, modeled as 100% truck.	Combination of train and truck, modeled based on use location.

4.6.4 Crude Distances and methods of transport

The modeled distances and methods employed to transport extracted crude to refineries is summarized in the table below. These distances and modes of transport are used to form the baseline CI for each fuel pathway. The unit processes in the model will contain model parameters (e.g. load and distance) so that they can be adapted to the specific conditions relevant for custom scenarios

The distance crude oil must travel to reach the refineries depends on the location of the reservoir, production facility or point of entry (in the case of imports) and the refinery. The following steps were taken to estimate the average distance between production facilities and refineries across Canada:

1. Determine the location of reservoirs, production facilities and points of entry across Canada
2. Calculate the distance between each location and their refineries
3. Calculate a weighted average per source-refinery pair based on production capacity
4. Estimate the average distance to refineries by calculating the production weighted average of production facilities in Canada

Table 38: Transportation distances and methods of extracted crude to refining

Source	Destination	Distance (km, one-way)	Mode	Uncertainty
Offshore	Refinery (Eastern Canada)	350	Tanker	10%
Oil sands (Surface)*	Refinery (Western-Central Canada)	1480	Pipeline	20%
Oil sands (In-situ)*	Refinery (Western-Central Canada)	1480	Pipeline	20%
Crude Oil Imports	Refinery (Eastern Canada)	100	Pipeline	20%
Conventional Oil	Refinery (Western-Central Canada)	900	Pipeline	10%
Tight (Shale) Oil	Refinery (Western-Central Canada)	880	Pipeline	20%

* Note that the long distance to refinery for oilsands products is a result of their consumption in Ontario refineries

The transportation distances and methods of products from refining to market is summarized in Table 39 (NEB 2018c NEB 2014; NEB 2016b; CAPP 2018c; AO&GI, 2016).

Table 39: Transportation distances to deliver refined products to market (by truck)

Refinery Model	Production-weighted average distance (km, one way)	Uncertainty
Western/Central	275	20%
Eastern	312	20%
All	291	20%

4.6.5 Importing of Refined Fuels

Imported fuels make up a significant portion of the liquid fossil fuels consumed in Canada. For some liquid fuels, imports may account for upwards of 40% of available fuels in the market for specific fuels in a given year. Refined fuels are imported from a wide range of countries, however, over 70% of Canadian imports are produced in the U.S.

Sufficient data on the country-specific CI of extraction and refining of imported fuels were not readily available and collection of these data were beyond the scope of this project. In order to include imported refined fuels in the Canadian average baseline CI, it was assumed that the CI of imported fuels is equivalent to the CI of Canadian fuels delivered to the consumer.

For the transport of imported refined fuels, transport which occurs outside of Canadian borders has been excluded based on the system boundaries defined for the CFS. For transport of imported refined fuels within Canada, it was assumed that the fuels would be transported by truck over the same distance that was estimated for imported crude products (see Table 38). After this transport from the border to a central depot, it was assumed that imported refined fuels are sold and distributed to consumers via the same distribution network modelled for domestically-produced fuels.

Data on the percentage of available liquid fuels supplied by imports was obtained from Statistics Canada.

Table 40: Share of available refined fuels supplied by imports in Canada in 2016 (Statistics Canada 2019a)

Fuel	Amount Imported in 2016	Share of Available Fuels in 2016
Aviation fuel	2,367,210	30%
Gasoline	9,456,539	22%
Diesel	1,857,476	7%
Heavy fuel oil	829,164	42%
Light fuel oil	NA	42%*
Stove oil	NA	42%*
Kerosene	NA	30%*

**Note – due to confidentiality reasons, data on the share of imported light fuel oil, stove oil, and kerosene were not provided in the Statistics Canada report. As a proxy, it was assumed that the share of available fuels in 2016 for light fuel oil and stove oil was the same as for heavy fuel oil, and the kerosene was the same as aviation fuel.*

For solid and gaseous fossil fuels, the inclusion of imported fuels is described in the modelling approach in each of those sections of the report.

4.6.6 Results for Crude Oil Refining and Liquid Fuel Products

The carbon intensities per fuel type with the weighted averages for eastern and western Canada as well as the Canadian average is given in Table 41. Table 42 provides a comparison to other reported values. Drivers of differences between reported and calculated values include the regions of production (e.g., US versus Canada), age of data (e.g., 2014 assumptions in NETL, versus 2016 assumptions in this study), background data assumptions (e.g., electricity data were modified in this study to reflect ECCC-provided data instead of PRELIM defaults), and use of values calculated in this study (e.g., natural gas CIs for Canada). Table 42 shows that the PRELIM results agree with literature values on a refinery basis. For gasoline, the difference between updated PRELIM results (at the national level) and US values ranges from -22% to 15%. For jet, PRELIM estimate is 48%-71% higher than US values. For diesel, such differences range from -1% to 50%. If we compare against another Canadian estimate GHGenius, PRELIM underestimates gasoline, jet and diesel refining CI by 2%, 49%, and 26%, respectively.

Table 41: Weighted average refinery CI (g CO_2e/MJ product)

Product	West	East	Canada Average
Blended Gasoline	9.18	8.16	8.63
Jet-A/AVTUR	3.80	3.41	3.48
ULSD	7.65	6.69	7.25
Fuel Oil	5.89	6.13	5.95
Coke	2.77	-	2.77
HC Resid	-	-	-
Liquid Heavy Ends	5.15	2.83	3.70
Liquefied Petroleum Gas (LPG)	10.15	9.45	9.81
Petrochemical Feedstocks	10.11	10.56	10.27
Asphalt	1.75	1.62	1.67

Table 42: Refinery CI comparison (gCO_2e/MJ product)

Product	Canada Average (this study)	NETL, 2014[1]	GREET, 2018[2]	GHGenius v1.03
Blended Gasoline	8.63	10.9	7.3	8.6
Jet-A/AVTUR	3.48	2.3	2.0	6.7
ULSD	7.25	7.1	4.7	9.6
Fuel Oil	5.95	8.9	-	2.1
Coke	2.77	1.8	3.7	-
Liquid Heavy Ends	3.70	5.3	3.2	-
Liquefied Petroleum Gas (LPG)	9.81	-	6.1	2.1
Petrochemical Feedstocks	10.27	-	-	-
Asphalt	1.67	-	-	-

1. Cooney, G. et al. Updating the U.S. life cycle GHG petroleum baseline to 2014 with projections to 2040 using open-source engineering-based models. Environ. Sci. Technol. 51, 977–987 (2017).
2. Elgowainy, A. et al. Energy Efficiency and Greenhouse Gas Emission Intensity of Petroleum Products at U.S. Refineries. Environ. Sci. Technol. 48, 7612–7624 (2014).

The liquid fuel CIs are reported in Table 43 next to reported emissions from various other sources (US and otherwise as noted). The cradle-to-combustion level results also align well with literature reports. For example, for gasoline, jet and diesel, the results (at the national level) are -1% to 4% higher, 7% to 10% higher, and 11% to 18% higher than US values. If we compare them PRELIM estimates against other Canadian values, then the differences range from -5% to 3% for gasoline, 1% higher for jet, and 6% to 9% for diesel. Differences for some products become larger on a CTC basis possibly due to the difference in calculating combustion emissions. For example, for gasoline, although the refining emissions are close to literature reports, the CTC results are lower than most reported data. This could be in part due to the combustion emissions of 67 g CO_2/MJ for gasoline used in this study compared to that of GREET US 2018 and GHGenius Canada 2018 which use 72 and 71 g CO_2e/MJ, respectively.

For diesel, in this study, combustion emissions are 77 g CO_2/MJ, while in GREET US 2018 and GHGenius Canada 2018 they are 72 and 71 g CO_2e/MJ, respectively.

Table 43: Cradle-to-combustion CI comparison (gCO_2eq/MJ product)

Product	Canada Average (this study)	NETL, 2014[1]	NRCan[2]	GREET US[3]	GHGenius 2018[4]	US CARB[5]	EU[6]	US ARF2 Baseline[7]	Canada BC[8]
Blended Gasoline	95	90	-	95	92	90	87	92	88
Jet-A/AVTUR	88	82	89	-	87	-	-	-	-
ULSD	96	86	-	95	95	89	89	91	95

1. Masnadi et al, 2018, Table 1 refining, US PADD buildup, well-to-wheels
2. NRCan's Sky's the limit challenge
3. U.S. EPA. Lifecycle Greenhouse Gas Results. Available at: https://www.epa.gov/fuels-registration-reporting-and-compliance-help/lifecycle-greenhouse-gas-results. (Accessed: 27th August 2019)
4. Natural Resources Canada. GHGenius 5.0e. (2019). Available at: https://www.ghgenius.ca/.
Elgowainy, A. et al. Energy Efficiency and Greenhouse Gas Emission Intensity of Petroleum Products at U.S. Refineries. Environ. Sci. Technol. 48, 7612–7624 (2014).
5. California Air Resources Board (CARB). No Title. Available at: https://ww3.arb.ca.gov/fuels/lcfs/121409lcfs_lutables.pdf.
Cai, H. et al. Well-to-Wheels Greenhouse Gas Emissions of Canadian Oil Sands Products: Implications for U.S. Petroleum Fuels. Environ. Sci. Technol. 49, 8219–8227 (2015).
6. European Commission. Fuel Quality. Available at: https://ec.europa.eu/clima/policies/transport/fuel_en.
7. U.S. EPA. Lifecycle Greenhouse Gas Results. Available at: https://www.epa.gov/fuels-registration-reporting-and-compliance-help/lifecycle-greenhouse-gas-results. (Accessed: 27th August 2019)
8. Government of British Columbia. Carbon Intensity Records under the Renewable and Low Carbon Fuel Requirements Regulation. Available at: https://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/electricity-alternative-energy/transportation/renewable-low-carbon-fuels/rlcf006_-_carbon_intensity_records.pdf.

Sources of differences between reported values and calculated values are numerous. Differences in the feedstocks drive differences in emissions throughout the pathway from extraction through pre-processing (where applicable), and to refining. For example, overall upstream emissions from extraction and pre-processing in Canada should be higher in Canada than in other regions such as the United States, though the refining emissions will be lower. This difference is driven by the fact that Canada produces a lot of heavy product from extraction, but much of that is exported for refining outside of Canada. Moreover, Canada imports a lot of light product for refining. At the point of refining, these feedstocks are blended, and blended fuels full life cycle emissions include other blended fuels which the results from this analysis do not include (e.g., ethanol blended with gasoline). The United States, by comparison, conducts a lot of deep conversion in refining which results in higher emissions. It is also difficult to compare the results from other models directly to CIs presented from this study since, not only do other models and studies use different source data from different years with different assumptions, but not all modeled results are from the Canadian perspective and, not all produce the same slate of products. Some facilities, for example, do not produce heavies. The NETL study, for example, conducted the analysis based on modelling that did not produce heavy products such as heavy fuel oil. The allocation methods and assumptions of carbon emissions to the full product slate (including petrochemical feedstocks and other products like asphalt) can have significant impacts on the final CI of fuels.

In the comparison between Western/Central-grouped versus Eastern-grouped Canadian refineries, there is an increase in emissions intensity from Western/Central refineries over Eastern, though it is not very significant (for example, Western/Central gasoline refining emissions 8.8 gCO_2e/MJ, versus 8.16 gCO_2e/MJ for Eastern gasoline refining). Tight oil domestic CI is lower than crude oil imports. The in-situ oil extraction CI is close to that of the import crude values. Only the oil sands crude has notably higher CIs among the crudes considered in this study. The origin of the crude feedstock (and its corresponding CI) into refineries plays a significant role in the final fuel CI from production. Imported crude CIs were on par with that of domestically-produced crudes (with the exception of crudes derived from oil sands). Note that calculation of the import values was not within the scope of this work, but was provided by ECCC. In all of the liquid pathways, there is a fair amount of imported feedstock being used. Therefore, developing a better understanding of imports is important. Imported feedstocks could be an increasingly important part of the landscape of fuels in Canada and future work could be focused on developing data on imported fuels and feedstocks.

The full carbon intensities from cradle-to-consumer-gate(CTCG) and cradle-to-combustion(CTC) are presented in Table 44. The same sources of modelling variability noted above drive the differences in the CTCG comparison between the results and GHGenius.

Table 44: Carbon intensities for fossil fuels (gCO_2e/MJ HHV)

	Study Results		GHGenius (5.0c)	
Product	**CTCG**	**CTC**	**CTCG**	**% Difference**
Blended Gasoline	24	95	22	8%
Aviation Fuel	19	88	19	1%
Kerosene	19	87	19	0%
Diesel	24	96	22	9%
Light Fuel Oil	24	95	15	39%
Stove Oil	24	92	15	39%
Pet-coke	22	104	13	41%
Heavy Fuel Oil	22	97	15	33%

The following tables provide the detailed results for each individual fuel through the pathway and the uncertainty results for each fuel. The quantity column (measured in MJ) indicates the quantity contribution of each blendstock or source fuel to the total blendstock indicated. The carbon intensity (measured in gCO_2e/MJ) is presented for the intermediate as well as the final products. The uncertainties are presented both by inventory, and impact assessment with inventory. The 2.50% heading indicates the interquartile range of uncertainty and the 97.5% heading indicates the 1.5x interquartile range. SD stands for standard deviation and CV is the coefficient of variance. Detailed discussion of the implications of the uncertainty analysis throughout the project is provided in Section 5.2.1. The violin plots presented in this section illustrate the uncertainty observed in the at consumer and at combustion CIs accounting for the uncertainty in the inventory data and characterization factors. In general, the shape of the distribution of the uncertainty in the violin plots indicates that the CIs are highly concentrated around the median CI value (indicated by the shape of the plot being wide in the middle and thin at the ends). This indicates that the sources of uncertainty in the analysis do not cause the results to stray far from the median calculated value.

Table 45: Gasoline Carbon Intensity Results and Uncertainty

Gasoline		
	Quantity [MJ]	**Carbon Intensity [g CO_2e/MJ]**
Eastern Blendstock	1	15
Offshore crude to refinery, Eastern	0.0498	0.3
Crude oil imports to refinery, Eastern	0.951	14
	Quantity [MJ]	**Carbon Intensity [g CO_2e/MJ]**
Western Blendstock	1	16
Oil sands, surface, to refinery, Western	0.194	4.7
Oil sands, in situ, to refinery, Western	0.386	6.2
Conventional oil to refinery, Western	0.118	1.3
Tight (shale Oil) to refinery, Western	0.0639	0.4
Gasoline, Eastern at refinery	1	23
Eastern Blendstock	0.974	14
Gasoline, Western at refinery	1	24
Western Blendstock	0.96	15
Gasoline at consumer, total	1	24
Gasoline, at consumer, average {CA}	0.78	19
Gasoline, Eastern	0.394	8.9
Gasoline, Western	0.386	9.3
Transport, truck	0.00633	0.6
Gasoline, imported, at consumer	0.22	5.4
Gasoline, combusted	1	95
Combustion	1	70
Gasoline at consumer, avg	1	24

Uncertainty on inventory and characterization factors, at consumer							
Impact category	**Unit**	**Mean**	**Median**	**SD**	**CV**	**2.50%**	**97.5%**
IPCC GWP 100a	g CO_2 eq/MJ	24	24	5.8	24	15	38
Confidence interval:	95						

Uncertainty on inventory and characterization factors, at combustion							
Impact category	**Unit**	**Mean**	**Median**	**SD**	**CV**	**2.50%**	**97.5%**
IPCC GWP 100a	g CO_2 eq/MJ	96	96	6.9	7.2	84	110
Confidence interval:	95						

Table 46: Diesel Carbon Intensity Results and Uncertainty

Diesel		
	Quantity [MJ]	**Carbon Intensity [g CO$_2$e/ MJ]**
Eastern Blendstock	**1**	**15**
Offshore crude to refinery, Eastern	0.0498	0.3
Crude oil imports to refinery, Eastern	0.951	14
Western Blendstock	**1**	**16**
Oil sands, surface, to refinery, Western	0.194	4.7
Oil sands, in situ, to refinery, Western	0.386	6.2
Conventional oil to refinery, Western	0.118	1.3
Tight (shale Oil) to refinery, Western	0.0639	0.4
Crude oil imports to refinery	0.238	3.6
Diesel, Eastern at refinery	**1**	**23**
Eastern Blendstock	1.08	16
Diesel, Western at refinery	**1**	**24**
Western Blendstock	1.01	17
Diesel at consumer, total	**1**	**24**
Diesel, at consumer, average {CA}	**0.93**	**23**
Diesel, Eastern	0.477	11
Diesel, Western	0.461	11
Transport, truck	0.00633	0.80
Diesel, imported, at consumer	**0.07**	**1.7**
Diesel, combusted	**1**	**96**
Combustion	1	72
Diesel at consumer, avg	1.01	24

Uncertainty on inventory and characterization factors, at consumer							
Impact category	**Unit**	**Mean**	**Median**	**SD**	**CV**	**2.50%**	**97.5%**
IPCC GWP 100a	g CO$_2$ eq/MJ	25	24	6.1	25	15	39
Confidence interval:	95						

Uncertainty on inventory and characterization factors, at combustion							
Impact category	**Unit**	**Mean**	**Median**	**SD**	**CV**	**2.50%**	**97.5%**
IPCC GWP 100a	g CO$_2$ eq/MJ	96	95	7.7	8.0	81	110
Confidence interval:	95						

Table 47: Kerosene Carbon Intensity Results and Uncertainty

Kerosene		
	Quantity [MJ]	**Carbon Intensity [g CO_2e/ MJ]**
Eastern Blendstock	**1**	**15**
Offshore crude to refinery, Eastern	0.0498	0.3
Crude oil imports to refinery, Eastern	0.951	14
Western Blendstock	**1**	**16**
Oil sands, surface, to refinery, Western	0.194	4.7
Oil sands, in situ, to refinery, Western	0.386	6.2
Conventional oil to refinery, Western	0.118	1.3
Tight (shale Oil) to refinery, Western	0.0639	0.4
Crude oil imports to refinery	0.238	3.6
Kerosene, Eastern at refinery	**1**	**18**
Eastern Blendstock	0.999	15
Kerosene, Western at refinery	**1**	**19**
Western Blendstock	0.912	15
Kerosene at consumer, total	**1**	**19**
Kerosene, at consumer, average {CA}	**0.7**	**13**
Kerosene, Eastern	0.356	6.4
Kerosene, Western	0.344	6.4
Transport, truck	0.00633	0.6
Kerosene, imported, at consumer	**0.3**	**5.8**
Kerosene, combusted	**1**	**87**
Combustion	1	68
Kerosene at consumer, avg	1	19

Uncertainty on inventory and characterization factors, at consumer							
Impact category	**Unit**	**Mean**	**Median**	**SD**	**CV**	**2.50%**	**97.5%**
IPCC GWP 100a	g CO_2 eq/MJ	19	18	4.6	24	12	29
Confidence interval:	95						

Uncertainty on inventory and characterization factors, at combustion							
Impact category	**Unit**	**Mean**	**Median**	**SD**	**CV**	**2.50%**	**97.5%**
IPCC GWP 100a	g CO_2 eq/MJ	87	87	6.2	7.1	76	99
Confidence interval:	95						

Table 48: Aviation Fuel Carbon Intensity Results and Uncertainty

Aviation Fuel		
	Quantity [MJ]	**Carbon Intensity [g CO_2e/ MJ]**
Eastern Blendstock	**1**	**15**
Offshore crude to refinery, Eastern	0.0498	0.3
Crude oil imports to refinery, Eastern	0.951	14
Western Blendstock	**1**	**16**
Oil sands, surface, to refinery, Western	0.194	4.7
Oil sands, in situ, to refinery, Western	0.386	6.2
Conventional oil to refinery, Western	0.118	1.3
Tight (shale Oil) to refinery, Western	0.0639	0.4
Crude oil imports to refinery	0.238	3.6
Aviation fuel, Eastern at refinery	**1**	**18**
Eastern Blendstock	0.99	15
Aviation fuel, Western at refinery	**1**	**19**
Western Blendstock	0.91	15
Aviation fuel at consumer, total	**1**	**19**
Aviation fuel, at consumer, average {CA}	**0.7**	**13**
Aviation fuel, Eastern	0.356	6.4
Aviation fuel, Western	0.344	6.4
Transport, truck	0.00633	0.6
Aviation fuel, imported, at consumer	**0.3**	**5.8**
Aviation fuel, combusted	**1**	**88**
Combustion	1	69
Aviation fuel at consumer, avg	1	19

Uncertainty on inventory and characterization factors, at consumer							
Impact category	**Unit**	**Mean**	**Median**	**SD**	**CV**	**2.50%**	**97.5%**
IPCC GWP 100a	g CO_2 eq/MJ	19	19	5.0	26	12	31
Confidence interval:	95						

Uncertainty on inventory and characterization factors, at combustion							
Impact category	**Unit**	**Mean**	**Median**	**SD**	**CV**	**2.50%**	**97.5%**
IPCC GWP 100a	g CO_2 eq/MJ	8	8	6.3	7.1	76	101
Confidence interval:	95						

Table 49: Heavy Fuel Oil Fuel Carbon Intensity Results and Uncertainty

Heavy Fuel Oil		
	Quantity [MJ]	**Carbon Intensity [g CO_2e/ MJ]**
Eastern Blendstock	**1**	**15**
Offshore crude to refinery, Eastern	0.0498	0.3
Crude oil imports to refinery, Eastern	0.951	14
	Quantity [MJ]	**Carbon Intensity [g CO_2 e/MJ]**
Western Blendstock	**1**	**16**
Oil sands, surface, to refinery, Western	0.194	4.7
Oil sands, in situ, to refinery, Western	0.386	6.2
Conventional oil to refinery, Western	0.118	1.3
Tight (shale Oil) to refinery, Western	0.0639	0.4
Crude oil imports to refinery	0.238	3.6
Heavy fuel oil, Eastern at refinery	**1**	**19**
Eastern Blendstock	1.12	17
Heavy fuel oil, Western at refinery	**1**	**23**
Western Blendstock	1.09	18
Heavy fuel oil at consumer, total	**1**	**22**
Heavy fuel oil, at consumer, average {CA}	**0.58**	**13**
Heavy fuel oil, Eastern	0.292	5.7
Heavy fuel oil, Western	0.288	6.6
Transport, truck	0.00633	0.5
Heavy fuel oil, imported, at consumer	**0.42**	**9.4**
Heavy fuel oil, combusted	**1**	**97**
Combustion	1	75
Heavy fuel oil, at consumer		22

Uncertainty on inventory and characterization factors, at consumer							
Impact category	**Unit**	**Mean**	**Median**	**SD**	**CV**	**2.50%**	**97.5%**
IPCC GWP 100a	g CO_2 eq/MJ	23	22	5.7	25	14	36
Confidence interval:	95						

Uncertainty on inventory and characterization factors, at combustion							
Impact category	**Unit**	**Mean**	**Median**	**SD**	**CV**	**2.50%**	**97.5%**
IPCC GWP 100a	g CO_2 eq/MJ	98	97	6.9	7.1	85	110
Confidence interval:	95						

Table 50: Light Fuel Oil Fuel Carbon Intensity Results and Uncertainty

Light Fuel Oil		
	Quantity [MJ]	Carbon Intensity [g CO_2e/ MJ]
Eastern Blendstock	**1**	**15**
Offshore crude to refinery, Eastern	0.0498	0.3
Crude oil imports to refinery, Eastern	0.951	14
	Quantity [MJ]	Carbon Intensity [g CO_2 e/MJ]
Western Blendstock	**1**	**16**
Oil sands, surface, to refinery, Western	0.194	4.7
Oil sands, in situ, to refinery, Western	0.386	6.2
Conventional oil to refinery, Western	0.118	1.3
Tight (shale Oil) to refinery, Western	0.0639	0.4
Crude oil imports to refinery	0.238	3.6
Light fuel oil, Eastern at refinery	**1**	**23**
Eastern Blendstock	1.14	17
Light fuel oil, Western at refinery	**1**	**23**
Western Blendstock	1.07	17
Light fuel oil at consumer, avg	**1**	**24**
Light fuel oil, at consumer, average {CA}	**0.58**	**14**
Light fuel oil, Eastern	0.292	6.7
Light fuel oil, Western	0.288	6.7
Transport, truck	0.00633	0.5
Light fuel oil, imported, at consumer	**0.42**	**10**
Light fuel oil, combusted	**1**	**95**
Combustion	1	71
Light fuel oil, at consumer	1	24

Uncertainty on inventory and characterization factors, at consumer							
Impact category	**Unit**	**Mean**	**Median**	**SD**	**CV**	**2.50%**	**97.5%**
IPCC GWP 100a	g CO_2 eq/MJ	24	23	5.7	24	15	37
Confidence interval:	95						

Uncertainty on inventory and characterization factors, at combustion							
Impact category	**Unit**	**Mean**	**Median**	**SD**	**CV**	**2.50%**	**97.5%**
IPCC GWP 100a	g CO_2 eq/MJ	95	95	7.1	7.4	84	110
Confidence interval:	95						

Table 51: Stove Oil Fuel Carbon Intensity Results and Uncertainty

Stove Oil		
	Quantity [MJ]	Carbon Intensity [g CO_2e/ MJ]
Eastern Blendstock	**1**	**15**
Offshore crude to refinery, Eastern	0.0498	0.3
Crude oil imports to refinery, Eastern	0.951	14
Western Blendstock	**1**	**16**
Oil sands, surface, to refinery, Western	0.194	4.7
Oil sands, in situ, to refinery, Western	0.386	6.2
Conventional oil to refinery, Western	0.118	1.3
Tight (shale Oil) to refinery, Western	0.0639	0.4
Crude oil imports to refinery	0.238	3.6
Stove oil, Eastern at refinery	**1**	**23**
Eastern Blendstock	1.14	17
Stove oil, Western at refinery	**1**	**23**
Western Blendstock	1.07	17
Stove oil at consumer, avg	**1**	**24**
Stove oil, at consumer, average {CA}	**0.58**	**14**
Stove oil, Eastern	0.292	6.7
Stove oil, Western	0.288	6.7
Transport, truck	0.00633	0.5
Stove oil, imported, average	**0.42**	**10**
Stove oil, combusted	**1**	**92**
Combustion	1	68
Stove oil at consumer, avg	1	24

Uncertainty on inventory and characterization factors, at consumer							
Impact category	**Unit**	**Mean**	**Median**	**SD**	**CV**	**2.50%**	**97.5%**
IPCC GWP 100a	g CO_2 eq/MJ	24	23	6.1	25	15	39
Confidence interval:	95						

Uncertainty on inventory and characterization factors, at combustion							
Impact category	**Unit**	**Mean**	**Median**	**SD**	**CV**	**2.50%**	**97.5%**
IPCC GWP 100a	g CO_2 eq/MJ	92	92	6.6	7.1	81	106
Confidence interval:	95						

4.6.7 Data Gaps in Upstream Extraction and Refining

There are several important limitations to this work. First, each refinery is unique. PRELIM was not designed to represent specific refineries at a given point in time. Every effort has been made to tailor model runs to best represent each refinery operating in Canada but a deficiency in public data made this challenging. While there are some literature values that are available in the public domain to compare PRELIM estimates to, estimates of individual refineries lack the complete set of emissions (e.g., hydrogen production and purchase, onsite combusted natural gas upstream emissions intensity), which complicates comparisons. Aggregate emissions intensities in the public domain do not provide sufficient detail to understand the factors that drive differences between these estimates and PRELIM. This analysis could be made more comprehensive and robust in the future if more detailed data were made available including the following.

Data gaps related to the upstream extraction and preprocessing for input into the OPGEE model include:

- Alberta: Venting and flaring values by facility are available for some oil sands in-situ facilities in their presentations in the AER website. When available, this data was used in the model. However, the AER data may under-report actual venting and flaring (e.g. in cases where it is below a certain threshold) leading to a potential for a systematic error in the results. All other data are provided on a company basis rather than by production method type or facility. As a region, average flaring and venting data by province was used for facilities which did not provide this information.
- Saskatchewan: All production volumes, venting and flaring data are provided on a “basin” basis (i.e. Lloydminster, Estevan, Swift Current, and Kindersley). The documents do not indicate what type of production facilities these data are compiled from, i.e. proportion of Lloydminster oil production from SAGD is not available in government provided data. Therefore, SK data are aggregated on a basin basis, instead of a facility or production method basis. Only where information was available in other sources (i.e. SAGD, CHOPS) about production volumes and originating basins, were data pulled out to model by production type.
- Newfoundland: For the inputs required for modelling in OPGEE, only production volumes are available in public government reports (other data provided in government reports on spills, production by wells, etc. is not relevant for OPGEE modelling). All other data required for OPGEE modelling were gathered from previously existing articles, facility level websites.
- Data on tight oil production by facility were not available. Any specific documentation on facility-level production methods and parameters were also not available. Only the overall production volume and field depth were available from public sources. Therefore, assumptions were made for venting and flaring, and modelling was performed using the US Bakken basin as the proxy.
- Productivity index data are not available for any facilities, which is a secondary parameter for OPGEE modelling.

Data gaps related to the refining for input into the PRELIM model include:

- Crude Intake: AFARA was not able to provide Total Volume Intake of Crude for all refineries. In this analysis, outside sources and some estimation (refinery websites, refinery annual reports) were used to determine Total Volume Intake of Crude for the refineries without the AFARA source.
- Crude Type: Wood Mackenzie provided Oil Sands Synthetic as a crude type for many refineries. This crude could have a wide range of characteristics, however, and is used

as a generic term for all medium synthetic crude coming from West Canada. More detail on exactly which crude is being used per refinery could have resulted in closer approximations in PRELIM.

- Refineries were modeled assuming they had no cogeneration unit. PRELIM modelling could have been further refined the use of a cogeneration unit at each refinery was known.
- Refinery emissions data: direct reported refinery emissions data could be used in lieu of a model, as PRELIM is not designed to represent specific refineries with unique processing unit combinations. If accurate reported emissions data (especially including hydrogen emissions) were available, they could be used to improve the CI on a per barrel of crude basis.
- Hydrogen consumption and generation for each refinery: Prior to 2019, hydrogen related emissions were not required to be reported to ECCC, but now they are. Refinery-reported hydrogen production and purchase data could be used to create a better estimate of GHG emissions due to hydrogen.
- Time-related data: A timeseries of data for multiple years to better understand the dynamics of how a refinery changes conditions, input crudes and output slates over time in response to market signals, outages and other factors would improve the representativeness of the results.

4.7 Petcoke

4.7.1 Modelling Approach Overview

The pathways for the production of Canadian petcoke from both refining and upgrading, and associated modelling routes, are shown in Figure 14.

The fate of the petcoke is determined in the modelling of the 2016 baseline CI. While both refineries and upgraders make significant quantities of petcoke in Canada, it is a marketable product for refineries and a primarily by-product for upgraders as it lacks a market.

The bulk of petcoke produced by upgraders is stockpiled – 82% of production in 2016 (see Section 3.4.2.4). Of the remainder, some is used internally to the upgrader, contributing to the CI of the upgrading process. That is, the internal use of upgrading petcoke by upgraders is contained within the process boundary as use of an internal stream and thus its contribution to the CI of upgrading is already included in that value; it is not included in the amount of by-product petcoke produced from the facility. A small fraction of upgrader petcoke is sold for off-site consumption. In these cases, the petcoke is considered a co-product and allocated upstream GHG emissions to it based on an energy-allocation approach. In this case, the LCA tool can be updated to reflect the changing market conditions for petcoke.

Stockpiled upgrader by-product petcoke is considered a waste, and thus it bears no separate impact. It is possible that stockpiled petcoke will be sold and combusted in the future, thereby generating considerable GHG emissions.

Refinery petcoke is produced from refining heavy crude oil, which is processed in Western Canada, not light sweet crude.

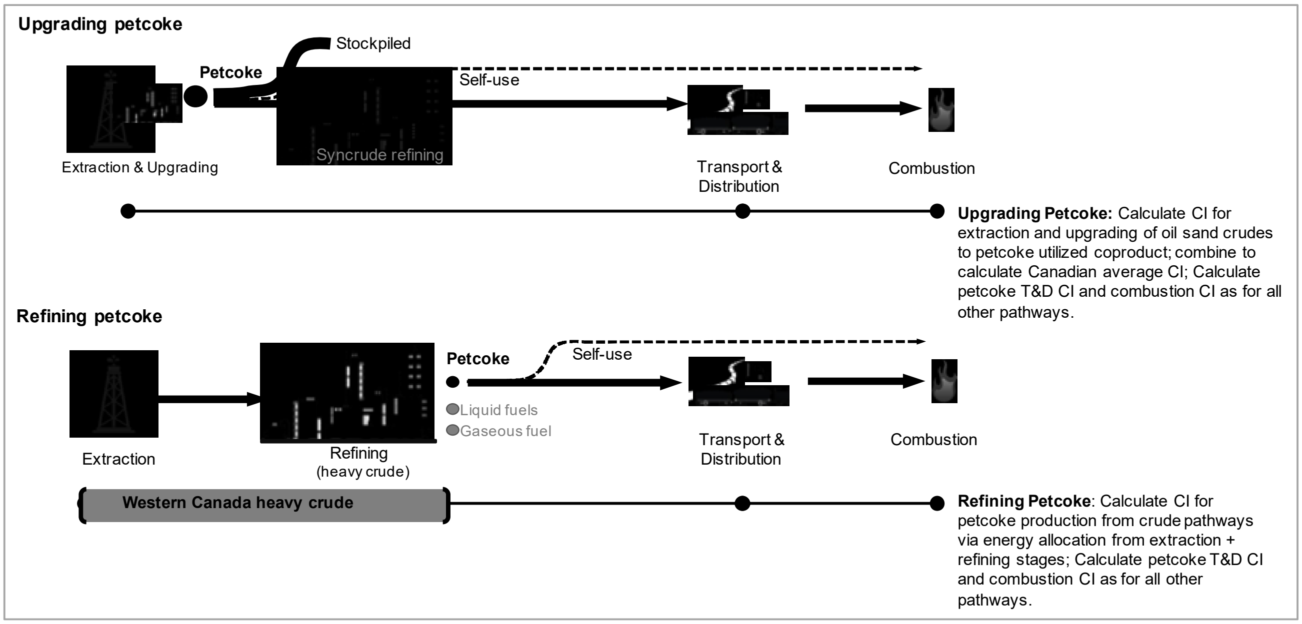

Figure 14: Process flow and modelling routes for the petcoke pathway. The average pathway for petcoke is the sum of the production and downstream CIs. Petcoke from upgrading that is stockpiled is treated as a waste.

In keeping with the coproduct approach, a system-level CI for petcoke production is calculated by allocating the Western Canadian average crude extraction and refining CI on an energy basis, for the refinery products (Section 4.6) and allocating the extraction and upgrading CI on an energy basis for the utilized share of production. This production CI is combined with process-level models representing key downstream life cycle stages (e.g., transmission, distribution, and combustion) to represent the fuel pathway CI per unit of fuel used. Each of these is discussed in the following sections.

As a solid fuel, venting, flaring and fugitive emissions are not included explicitly for petcoke (upstream, they are captured by the crude extraction and refining CIs described in the Crude Oil Extraction and Refining Greenhouse Gas Intensity Modelling and Data Summary). This approach allows for consistency with other crude-based pathways (models).

The general formula for the pathway calculation is presented in Section 4.4.1.

4.7.1.1 Petcoke Composition

The average compositional ranges for energy petcoke (also referred to as green, raw, or uncalcined) are presented in Table 52. Petcoke composition is a function of crude type, but compositional ranges are relatively narrow compared to raw natural gas and extracted crudes. Data correlating petcoke composition with production source are not generally available. Data for Canadian and average fuel petcoke composition was compiled from industry producers and vendors and technical reports.

Table 52: Petcoke composition and energy content.[8]

Elemental	mass %
C	89 -- 92%
H	3.7 -- 5%
O	1 -- 3%
N	0.5 -- 3%
S	1 -- 6%
General	**mass % unless otherwise noted**
Total Moisture	7 -- 13%
Ash (dry basis)	0.2 -- 3%
Volatile Matter (dry basis)	8 -- 15%
Sulphur (dry basis)	5.5 -- 8%
Energy Content (HHV)	32 -- 34 MMBtu/t 42.4GJ/m^3
Density	1,350 – 1,450 kg/m^3

4.7.2 Petcoke System Descriptions and Boundaries

4.7.2.1 Upstream (cradle-to-gate)

GHG emissions result from all of the upstream activities. As a co-product of refining and a by-product of extraction and upgrading, these are already calculated as part of the crude oil-based liquid fuels and integrated into a Canadian average GHG emissions value.

These calculations are described in Sections 4.5.2 and 4.6.1

Domestic petcoke production

The production impacts were calculated in the OPGEE and PRELIM models used to calculate the liquid petroleum fuels. This is detailed in the crude extraction and crude refining modelling in Sections 4.5.2 and 4.6.1, respectively). As Figure 15 shows, the Western Canada average crude, from the OPGEE models, is used as an input to the PRELIM

To avoid duplication or risk introducing inconsistencies, petcoke production emissions are calculated by allocating the appropriate share of the Western Canadian average crude extraction and refining emissions (for refinery petcoke) and upgrading emissions (for upgrading petcoke), using the share of feedstock energy contained in the coproduct. The calculation approach is shown below; the coproduct energy share is calculated as part of the extraction and refining modelling.

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[8] Compositional data from (Suncor 2019; Viva Carbon 2019; Future Carbon Solutions 2019; Andrews and Lattanzio 2013; National Energy Board 2019, EPA 2016a, API 2000).

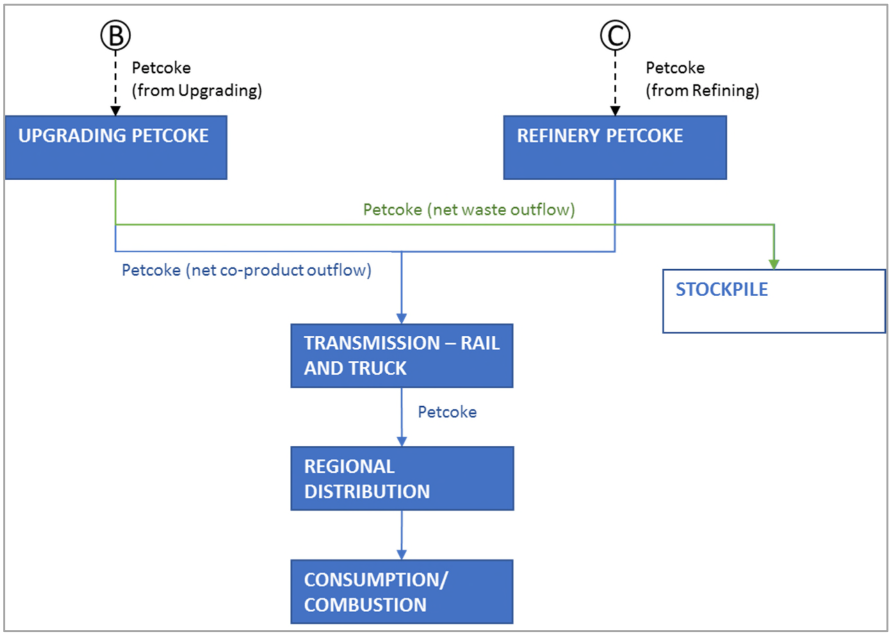

Figure 15: General process flow diagram for the petcoke pathway subsequent to petcoke production in Canada. Refinery petcoke (C) is combined with the co-product fraction of upgrading petcoke (B) before combined transport, distribution and combustion.

Crude extraction and refining emissions and coproduct energy shares are modeled as described in the previous sections. The consistency of the Canadian averages is preserved by making a single allocation based on energy content after the average CI for extraction and refining has been calculated. The full pathway then includes the transmission and distribution and the combustion.

4.7.2.2 Imported petcoke

From a modelling perspective, imported petcoke is assigned the same CI value as Canadian domestic petcoke.

The Point Aconi power station in Nova Scotia, one of the heaviest users of petcoke in the country, imports its petcoke from Detroit, which is a byproduct of refining crude from the Alberta oil sands (Austen 2018). As the crude source is a Canadian one and detailed data are not available for the Detroit refinery, Canadian petcoke impacts are used as a proxy, consistent with the handling of other imports,

Other petcoke

Any exported petcoke and petcoke used for non-fuel purposes are allocated the same production CI as petcoke. Imported petcoke primarily comes from the US and at least for the Point Aconi power generating station, as mentioned above, it is produced from Canadian crude. Canadian petcoke is therefore used as a proxy for this imported petcoke.

4.7.3 Petcoke Distribution

The annual use of petcoke varies greatly as shown in Table 53, making distribution highly uncertain. In addition, Statistics Canada has not provided data for some sectors in some years due to confidentiality reasons. Due to these data gaps, consumption rates could not be averaged over the years 2013 - 2017 to compensate for that variability. As such, we used 2016 data to calculate the transport distance, as this is the most recent year with complete data.

Table 53: Canadian Petcoke consumption by industry

	Tonnes Consumed Annually				
	2013	2014	2015	2016	2017
Upgraded (Petroleum and coal products manufacturing [324])	1,220,009	-	-	1,136,257	-
Steel and aluminum manufacturing (Primary metal manufacturing [331])	-	-	-	15,118	5,493
Concrete production (Non-metallic mineral product manufacturing [327])	558,552	-	-	629,597	
Power generation, New Brunswick	296,492	348,980	261,494	330,122	334,757
Power generation, Nova Scotia	520,245	391,348	432,826	390,036	276,890

Sources: (Statistics Canada 2018b), (Statistics Canada 2018c)

The petcoke use with the highest certainty is power production by the Point Aconi power station mentioned above. This is modeled as transport by train from Detroit to Port Hawkesbury and by truck from Port Hawkesbury to Point Aconi.

With as much of 50% of the annual production of petcoke in Ontario, distribution to the New Brunswick power stations is assumed to be from Sarnia, ON to the only coal burning station in New Brunswick in Belledune (Wikipedia 2017). As the station is on the train line, no trucking is included. Details of which steel and aluminum plants use petcoke are not available, however, nearly all of these producers are along the Great Lakes St. Lawrence Seaway (McKay 2006, updated 2015)) (Wikipedia 2019). Transportation is modeled from Sarnia to Kingston, ON. This is assumed to be by rail. Use of petcoke in cement kilns has the most uncertainty as it is not clear where the cement kilns are and where the petcoke is coming from. Because it is known to be economically viable, the average rail distance for other uses with the truck distance for the Port Aconi power station has been used as proxy with a high uncertainty applied through the pedigree matrix. Upgrading is typically internal to the crude processing facility so is not included in the distribution calculations, as petcoke is moved internally from initial processing to the upgrader, rather than from one facility to another.

Table 54: Estimated transport distances for Petcoke in Canada

	Starting Location	Ending Location	Distance (km)	Starting Location	Ending Location	Distance (km)
Steel and aluminum manufacturing (Primary metal manufacturing [331])	Sarnia	Kingston, ON	539*	-	-	-
Concrete production (Non-metallic mineral product manufacturing [327])	-	-	1,466*	-	-	150*
Power generation, New Brunswick	Sarnia	Belledune	1,642*	-	-	-
Power generation, Nova Scotia	Detroit	Port Hawkesbury	2,219*	Port Hawkesbury	Point Aconi	150*
Weighted distance			**935**			**100**

*Distance source: Google Maps

4.7.4 Petcoke Combustion

The average petcoke composition (Table 52) was used to estimate uncertainties GHG emissions from combustion. Because petcoke is a coproduct of crude refining, the compositional variation is absorbed by the averaging involved in creating the crude production and refining process in the petroleum pathways, and the only other response to composition is in the combustion stage.

4.7.5 Baseline 2016 Carbon Intensity Results for Petcoke

Baseline carbon intensities for Canadian petcoke (refinery) as are summarized in Table 55 and Table 56. Table 55 shows the carbon intensities for production of the petcoke resource. The cradle-to-refinery gate carbon intensity allocated (energy basis) to refinery petcoke is 22 g CO_2 e/MJ, 87% of which is contributed by crude extraction. The cradle-to-upgrader gate carbon intensity allocated (energy basis for the externally utilized share of petcoke production) to upgrader petcoke is 21 g CO_2 e/MJ, arising from the combined extraction and upgrading process. The calculation of these carbon intensities is described in Sections 4.5 (extraction) and 4.6 (refining).

Table 55. Carbon intensity for Canadian average petroleum coke (petcoke), to two significant digits. Calculation of these values is presented in Sections 4.5.2 and 4.6.1.

Resource Type	Input	Unit	Carbon Intensity	Unit
Petcoke (Oil Extraction)	**1**	**MJ**	**22**	**g CO_2e**
Petcoke, Western at refinery	**1**	**MJ**	**21**	**g CO_2e**
Western Blendstock	1.2	MJ	18	g CO_2e

The 2016 baseline carbon intensity for Canadian average petcoke (refinery) is 104 g CO_2 e/MJ (Table 56). Nearly 80% of these life cycle emissions arise from combustion (82 g CO_2 e/MJ), while upstream production and distribution account for 21% of life cycle GHG emissions (22 g CO_2 e/MJ).

Table 56. Baseline carbon intensity results for 2016 Canadian average petroleum coke (petcoke), to two significant digits.

	Input	Unit	Carbon Intensity	Unit
Petcoke at consumer	**1**	**MJ**	**22**	**g CO_2e**
Petcoke, Western	0.728	MJ	15	g CO_2e
Petcoke, (Oil Extraction)	0.272	MJ	6.1	g CO_2e
Transport, train, diesel	0.00294	tkm	0.5	g CO_2e
Transport, truck	0.0023	tkm	0.4	g CO_2e
Petcoke, combusted	**1**	**MJ**	**104**	**g CO_2e**
Combustion	1	MJ	82	g CO_2e
Petcoke at consumer, average	1	MJ	22	g CO_2e

Comparison of these values for the petcoke CI and GHG emission calculators for fossil fuels is in Table 57. Despite the limitation on comparability between other values and those calculated here imposed by the handling of stockpiled petcoke and allocation and the national average, agreement is good. The GREET CTCG for petcoke production is for petcoke from Canadian oil extraction, resulting in the high agreement between the GREET CTCG value and the CI for production from Oil Extraction here.

Table 57. Comparison of calculated carbon intensity values for petcoke from extraction to consumer (pre-combustion) from this study with other calculators (g CO_2e/MJ)

CTCG				CTC	GHGenius (5.0c)	GREET 2018 (U.S.)	GREET 2018 (U.S.)	GREET2018 (U.S.)
	Refinery	Oil Extraction	Canada average petcoke	CTC	CTCG	CTCG	CTC *	CTC**
Petcoke	15	6.1	22	105	13	5.8	92	107

**Values in this column use stoichiometric combustion calculated from default GREET values; ** combustion for in stationary use of petcoke.*

Uncertainty was incorporated into the petcoke pathway as described in the methods section of the report. Uncertainty in the study results was accounted for by assigning distributions to input data based on either known or calculated ranges or use of a pedigree matrix to generate standard deviations. In addition, a “fit for purpose” assessment was done on the background data supporting the input values using a pedigree matrix, and uncertainty was applied to the IPCC characterization factors. The results of the uncertainty analysis for petcoke are summarized in Table 58. The 2.50% heading indicates the interquartile range of uncertainty and the 97.5% heading indicates the 1.5x interquartile range. SD stands for standard deviation and CV is the coefficient of variance.

With uncertainty on the inventory data included, the CTCG (at consumer) CI of petcoke ranges from 19 g CO_2 e/MJ and a higher end of 26 g CO_2 e /MJ, but is fairly tightly centered around the median value (Section 5.2.1 shows additional uncertainty results). Likewise, the At Combustion CI of petcoke ranges from 95 g CO_2 e /MJ and a higher end of 110 g CO_2 e /MJ and is also fairly tightly centered around the median value.

Table 58. Results of uncertainty analysis on carbon intensity of 2016 Canadian average petroleum coke (petcoke), including uncertainty on the life cycle inventory, uncertainty on the characterization factors, and fit for purpose uncertainty on the unit processes modelled.

Impact Category	Unit	Mean	Median	SD	CV	2.50%	97.5%
Petcoke, at consumer							
Uncertainty on inventory and characterization factors							
IPCC GWP 100a	g CO_2 e	22	22	1.7	7.7	19	26
Confidence Interval	95						
Petcoke, combusted, average process per MJ {CA}							
Uncertainty on inventory and characterization factors							
IPCC GWP 100a	g CO_2 e	101	101	3.1	3.1	95	110
Confidence Interval	95						

Results of the uncertainty analysis for petcoke both at the consumer and at combustion (Table 58) indicated that incorporating uncertainty on the IPCC characterization factors had a negligible effect on the overall uncertainty of the petcoke CI.

4.7.6 Data gaps in petcoke distribution and use

In addition to the data gaps in upstream extraction and refining in Section 4.6.7, other data gaps for petcoke distribution and use include:

- **Production Volumes**: Data on production volumes are inconsistent and/or suppressed, which limits the ability to accurately map transportation and distribution rates at a granular enough resolution for provincial and national averaging. In this analysis, the magnitude of stockpiled petcoke decreased the importance of this gap, and secondary and tertiary sources used to address the next gap provided inferential data. The necessary data is potentially extant, and the gap could be addressed by release of suppressed provincial data or by sponsored research would be useful.

- **Petcoke Fate**: Robust, comprehensive national and provincial data on uptake, exports, imports, and use are lacking and are not reported or made available consistently. Likewise, use and long-term fate of stockpiled petcoke remains highly questionable both because data is sparse and industry is actively exploring options for use of this material. These introduce significant uncertainty for transport. Collection of more granular data on the fate of petcoke in the market as well as detailed import/export data are necessary to resolve this. In this analysis, the data available was used to interpolate material movement. The necessary data are potentially extant, although likely to be very inconsistent due to the variety of sectors and agents involved. This is potentially resolvable with significant additional time and/or research and would be best supported by enhanced accounting and reporting.
- **Composition**: Detailed compositional data from producers at the facility level are not available, nor is it widely tracked or provided by distributors and other supply chain members. Composition of petcoke does vary with source, which impacts emissions. Extraction intensity and product compositions based on crude assays are already accommodated in the models used here for crude extraction and refining. Literature and key source reports provided ranges for key compositional parameters, and these averages were used for the downstream CI. Long term, this gap could be resolved by detailed linking of final petcoke composition to production source, either through reporting or direct sampling.

4.7.7 Coal

4.7.7.1 Modelling Approach Overview

The general system boundary and process flow for Canadian coal production and use is outlined in Figure 16. Coal extraction is assumed to occur entirely in Western Canada, with the negligible amount of coal produced in Nova Scotia (<1%) excluded from the analysis. The scope of the analysis is limited to extraction and use of thermal coal, including bituminous, sub-bituminous, and lignite coal, with metallurgical coal excluded since it is not typically used as a fuel. Imported bituminous coal from the United States is also used to meet part of the Canadian demand for thermal coal and is included in the scope of the analysis. The different types of coal are extracted via surface mining in each respective province, and are then transported by rail and truck directly to thermal power plants for combustion in each of five Canadian provinces.

The GHG emissions associated with the life cycle of coal production and use in Canada are primarily due to:

- Fuel combustion in stationary equipment at coal mines;
- Fuel combustion in mobile equipment at coal mines;
- Venting of methane during coal extraction;
- Fugitive emissions from coal mining activities;
- Fuel combustion in trains and trucks used for transport of coal to power plants; and
- Emissions from electricity generation at coal-fired power plants.

One of the key differentiating factors in the life cycle GHG emissions for coal mining and use is the energy density of each type of coal, where coals that are less energy dense have higher carbon intensity since more material needs to be extracted and combusted to yield an equivalent amount of useful energy. The differences in energy density are reflected in the life cycle carbon intensity calculations and are summarized below (Statistics Canada 2019):

- Bituminous coal – AB: 25.42 MJ/kg
- Sub-bituminous coal – AB: 19.15 MJ/kg
- Lignite coal – SK: 15.00 MJ/kg
- Bituminous coal – BC: 26.02 MJ/kg
- Bituminous coal – US: 29.82 MJ/kg

These differences in energy content and related combustion emissions profiles mean that the carbon intensity of electricity generation using coal in a given province depends heavily on the source of coal that is combusted. Unfortunately, data on the specific source of all coal that is combusted in thermal power plants are not readily available. There is also a lack of data on the source of all Canadian imports of coal. As such, some assumptions have been made about the sources of coal used to meet thermal energy demand in each of the five provinces with coal-fired electricity plants (Table 59). For imported coal, Natural Resources Canada reports that up to 75% of imported coal to Canada is from the United States (NRC 2019b). For the purposes of this study, it was assumed that all imported coal was from the US.

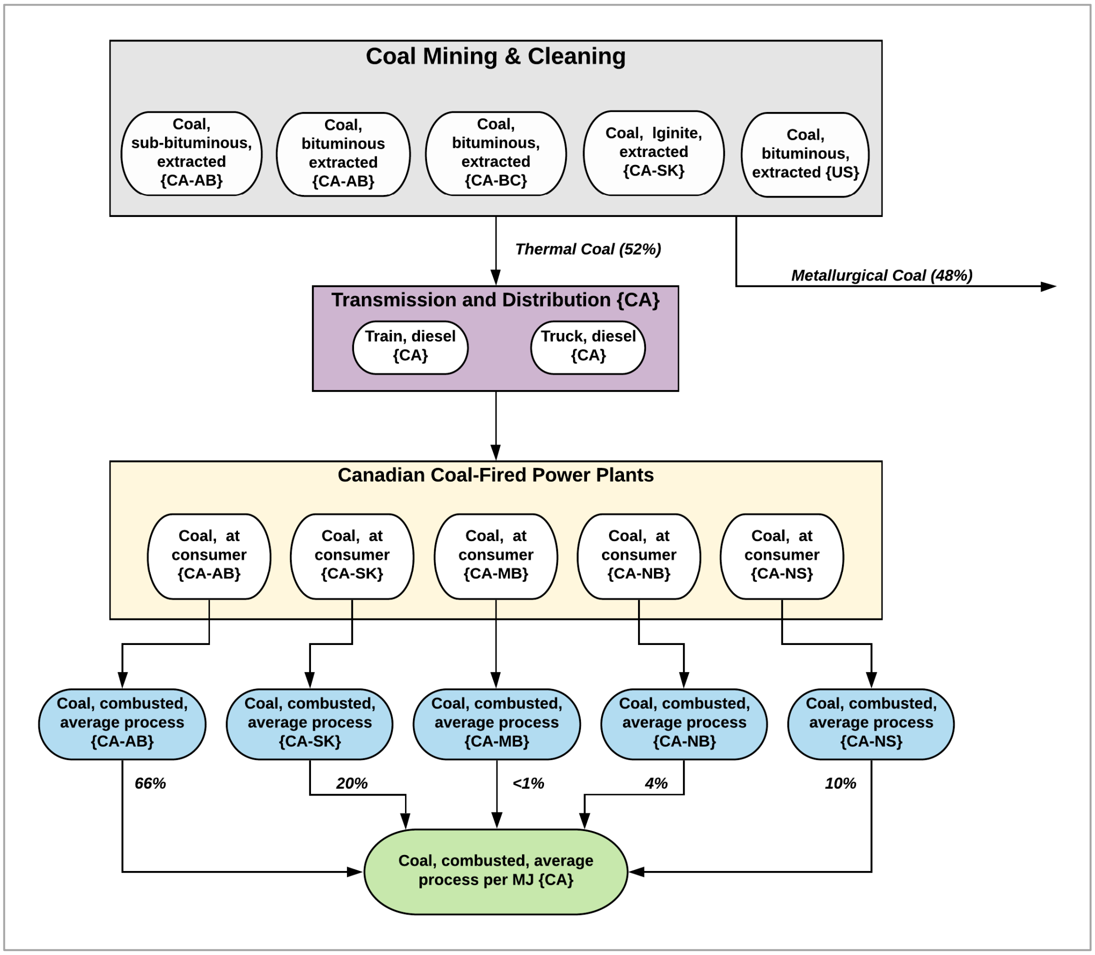

Figure 16. System boundary and process flow for calculating the 2016 baseline carbon intensity for Canadian thermal coal.

Ultimately these assumptions about the source of coal for each province's thermal electricity generation have very little influence on the Canadian average baseline carbon intensity, as the same amount of each type of coal is extracted and combusted regardless of these sourcing assumptions. While these assumptions do influence transport differences, the contribution of rail and truck transport to the overall carbon intensity of coal is negligible. These assumptions do, however, influence the GHG emissions associated with electricity generation for each province, and as such, these results should not be used to make determinations about the carbon intensity of provincial electricity generation.

Table 59. Thermal energy demand and coal supply assumptions for Canadian provinces with coal-fired power plants (Thermal energy demand adapted from Statistics Canada (2019), other values calculated).

Province	Total Coal for Thermal Energy in 2016 (tonnes)	Sourced from Alberta (tonnes)	Sourced from Saskatchewan (tonnes)	Sourced from British Columbia (tonnes)	Sourced from US (tonnes)
Alberta	21,270,000	21,270,000			
Saskatchewan	6,360,000	1,540,000	2,220,000	2,603,000	
Manitoba	15,200	15,200			
New Brunswick	1,330,000	477,000			857,000
Nova Scotia	3,102,000	1,102,000			2,000,000

4.7.7.2 Life Cycle Inventory

Coal Extraction

The life cycle inventory for Canadian coal extraction was based primarily on data from a 2014 GHG emissions inventory for Canadian coal mining between 1990 – 2012 (Cheminfo Services Inc. & Clearstone Engineering Ltd. 2014). In this study, a combination of mining company surveys and field research was used to compile energy inputs and emissions from coal mining and processing activities in Canada. Data from the 2012 production year were used since they were the most recent data available to characterize Canadian coal mining operations. Data from this study were expressed as an average per tonne of coal extracted in 2012, and include data on energy inputs and emissions for coal mining, coal washing, and coal crushing and stacking. These “per tonne” data were adapted to compile a LCI for extraction and processing of each type of thermal coal based on the energy density of each coal type. These data are summarized in Table 60.

The Canadian average data provided in the Cheminfo & Clearstone study included fugitive emissions from mining operations, but did not include venting emissions. Proxy data on venting of methane from coal mining was obtained for U.S. operations from the GREET 2018 model, based on a study by Burnham et al. (2011). In addition, there were two instances in the Cheminfo & Clearstone data where an energy input was identified as “other”. In these instances, it was assumed that heavy fuel oil was used.

The GHG emissions associated with upstream fuel production and with fuel combustion (for example, for natural gas) were modeled using the Canadian average baseline CI for 2016 fuels developed in the present study.

The GHG emissions for imported coal from the US were obtained from the GREET tool by Argonne National Laboratories (ANL, 2018). Upstream emissions for average US coal in GREET are estimated to be 5.8 g CO_2e per MJ of coal, which includes coal mining and cleaning, non-combustion emissions from coal mining and coal cleaning (i.e. venting and fugitive emissions), and coal transportation within the US.

Table 60. Life cycle inventory data for Canadian average mining operations, expressed per MJ of coal extracted and processed, broken down by province and coal type. (Adapted from Cheminfo Services Inc. & Clearstone Engineering Ltd. 2014).

		Coal, bituminous, extracted {CA-AB}	Coal, sub-bituminous, extracted {CA-AB}	Coal, bituminous, extracted {CA-BC}	Coal, lignite, extracted {CA-SK}
Inputs	**Unit**				
Stationary Fuel Combustion					
Coal	MJ	1.20E-03	1.60E-03	1.20E-03	2.00E-03
Natural gas	MJ	3.20E-03	4.20E-03	3.10E-03	5.40E-03
Diesel	MJ	4.30E-04	5.70E-04	4.20E-04	7.30E-04
Propane	MJ	9.84E-05	1.30E-04	9.61E-05	1.70E-04
Heavy fuel oil	MJ	7.87E-07	1.04E-06	7.69E-07	1.33E-06
Blasting					
Diesel	MJ	2.29E-04	3.00E-04	2.23E-04	3.88E-04
Heavy fuel oil	MJ	1.42E-05	1.88E-05	1.38E-05	2.40E-04
Mobile Equipment					
Diesel	MJ	1.20E-02	1.60E-02	1.17E-02	2.04E-02
Gasoline	MJ	2.10E-04	2.80E-04	2.03E-04	3.50E-04
Outputs	**Unit**				
Coal, extracted	MJ	1	1	1	1
Venting					
Methane	kg	4.38E-05	4.38E-05	4.38E-05	4.38E-05
Fugitive Emissions					
Carbon dioxide	kg	4.21E-06	5.59E-06	4.11E-06	7.13E-06
Methane	kg	2.03E-05	2.69E-05	1.98E-05	3.44E-05

Transmission

In 2016, only 2.6 million tonnes out of 61 million total produced were used for industrial energy (the rest were exported or used in iron and steel production). 30-40 MT are transported by rail. In 2016, 37 million tonnes of coal were exported via waterways (CAPP 2019.). This indicates that essentially all coal is shipped via rail. The transmission of extracted coal from the mine site to thermal power plants in Canadian provinces was assumed to be done primarily by rail. Rail transport distances were estimated by assuming central locations in the source province and calculating the average distance to the known locations of thermal power plants. For all provinces except Nova Scotia, it was assumed that rail transport could reach directly to the power plants. In the case of Nova Scotia, an average distance of 150 km was assumed to deliver coal by truck to power plants that were not on central rail lines. Estimated transport distances for coal transmission are summarized in Table 61.

Table 61. Rail and truck transportation distances for delivery of Canadian coal from extraction to thermal power plant.

Coal Source	Destination	Rail Distance (km)	Truck Distance (km)
Alberta	Nova Scotia	4,782	150
Alberta	New Brunswick	4,382	
Alberta	Manitoba	1,148	
Alberta	Saskatchewan	950	
Alberta	Alberta	16.8	
Saskatchewan	Saskatchewan	15.3	
British Columbia	Saskatchewan	1,568	
United States	New Brunswick	3,000	
United States	Nova Scotia	3,000	

Combustion at Power Plant

The GHG emissions from combustion of coal were estimated using emissions factors from Canada's National Inventory Report (ECCC 2018b). Emissions factors for carbon dioxide are specific to the type and source of coal combusted. Emissions factors for methane and dinitrogen monoxide are average estimates for coal-fired electricity. Emissions factors by coal type and source are summarized in Table 62.

Table 62. Summary of combustion emissions for use of coal in Canadian thermal power plants, expressed per MJ of coal combusted (Adapted from ECCC 2018b).

Emission	Unit	Bituminous Coal {CA-AB}	Sub-bituminous Coal {CA-AB}	Lignite Coal {CA-SK}	Bituminous Coal {US}
Carbon dioxide	kg	0.0856	0.0918	0.0968	0.0889
Methane	kg	8.58E-07	8.36E-07	8.58E-07	7.48E-07
Dinitrogen Monoxide	kg	1.25E-06	1.22E-06	1.25E-06	1.09E-06

4.7.8 Baseline 2016 Carbon Intensity Results for Coal

Baseline carbon intensities for 2016 Canadian average coal are summarized in Table 63. The Canadian average carbon intensity from extraction to power plant is approximately 4.9 g CO_2 e per MJ of coal extracted and delivered. These upstream emissions account for approximately 5% of total life cycle GHG emissions. These "coal, at consumer" processes account for coal mining and processing and then transmission of coal to power plants in each province.

The 2016 baseline carbon intensity for Canadian average coal is 96 g CO_2 e/MJ. Over 90% of these life cycle emissions are a result of coal combustion, with a Canadian average of about 91 g CO_2 e per MJ of coal combusted.

Table 63. Baseline carbon intensity results for 2016 Canadian average coal, expressed in kg CO_2 e per MJ of coal at consumer, and MJ of coal combusted.

	Input	Unit	Carbon Intensity	Unit
Coal, at consumer {CA}	**1**	**MJ**	**5.0**	**g CO_2e**
Coal, at consumer {CA-AB}	0.663	MJ	2.7	g CO_2e
Coal, at consumer {CA-SK}	0.198	MJ	1.0	g CO_2e
Coal, at consumer {CA-MB}	0.00047	MJ	2.4E-03	g CO_2e
Coal, at consumer {CA-NB}	0.0416	MJ	0.3	g CO_2e
Coal, at consumer {CA-NS}	0.0967	MJ	0.8	g CO_2e
Coal, combusted, average process per MJ {CA}	**1**	**MJ**	**96**	**g CO_2e**
Coal, combusted, average process {CA-AB}	0.663	MJ	64	g CO_2e
Coal, combusted, average process {CA-SK}	0.198	MJ	19	g CO_2e
Coal, combusted, average process {CA-MB}	0.00047	MJ	0.1	g CO_2e
Coal, combusted, average process {CA-NB}	0.0416	MJ	4.1	g CO_2e
Coal, combusted, average process {CA-NS}	0.0967	MJ	9.6	g CO_2e

As described in the methods section of the report, uncertainty in the study results was accounted for by assigning distributions to input data based on either known or calculated ranges or use of a pedigree matrix to generate standard deviations. In addition, a "fit for purpose" assessment was done on the background data supporting the input values using a pedigree matrix, and uncertainty was applied to the IPCC characterization factors. The results of the uncertainty analysis for coal are summarized in Table 64. The 2.50% heading indicates the interquartile range of uncertainty and the 97.5% heading indicates the 1.5x interquartile range. SD stands for standard deviation and CV is the coefficient of variance.

Table 64. Results of uncertainty analysis on carbon intensity of 2016 Canadian average coal, including uncertainty on the life cycle inventory, uncertainty on the characterization factors, and fit for purpose uncertainty on the unit processes modelled.

Impact Category	Unit	Mean	Median	SD	CV	2.50%	97.5%
Coal, at consumer {CA}							
Uncertainty on inventory and characterization factors							
IPCC GWP 100a	g CO_2 e	6.5	6.4	1.4	21	4.2	9.4
Confidence Interval	95						
Coal, combusted, average process per MJ {CA}							
Uncertainty on inventory and characterization factors							
IPCC GWP 100a	g CO_2 e	100	100	9.4	9.4	83	120
Confidence Interval	95						

Results of the uncertainty analysis for coal, at consumer showed a fairly large spread in the potential result, from a lower end of 4.2 g CO_2e/MJ and a higher end of 9.4 g CO_2e /MJ, which is approximately 80% higher than the main result. For the full life cycle carbon intensity of coal, from extraction through combustion, results of the uncertainty analysis showed a slightly tighter spread in the possible outcomes, ranging approximately from a low of 83 g CO_2e /MJ up to a high of 120 g CO_2e /MJ. The low end of this range is not very likely to occur given that the combustion emissions for coal alone are generally higher than this amount. The high end of this range could be reached depending on the type of coal combusted and the efficiency of the combustion technology. As shown in the life cycle inventory, there can be significant differences in combustion emissions for coal depending on the source.

Results of the uncertainty analysis for coal both at the consumer and at combustion indicated that including uncertainty data on the IPCC characterization factors had a negligible effect on the overall uncertainty of the results.

4.7.9 Data Gaps and Limitations for Canadian Coal Carbon Intensity

In compiling the LCI and calculating the Canada average carbon intensity of coal, a number of data gaps and limitations were identified to inform future research and model updates.

- **LCI Data on Coal Extraction** – There are limited data available to characterize the extraction and processing of coal in Canada. Although the LCI data used in the present study are based on Canadian operations, the data are from the 2012 production year and may not reflect current practices and technology. For example, with ongoing efforts to improve industrial energy efficiency, the energy consumption data from 2012 may not reflect industry practices for 2016.
- **Fugitive Emissions** – Similar to the LCI data on coal extraction, data on the fugitive emissions of methane from coal mining are somewhat dated and based heavily on calculated estimates. More recent field research on fossil fuel extraction and processing systems has indicated that fugitive emissions have been historically underestimated. More recent, empirical estimates of fugitive emissions for Canadian coal mining could improve the representativeness of the carbon intensity modelling.
- **Market Data on Coal Use** – A significant amount of data collected by the Government of Canada on coal production at the provincial level is suppressed to protect confidentiality. As noted in the previous sections, the result of this is that assumptions

must be made about the sources of coal that are used in each province to fuel thermal electricity plants. Given the influence of coal source on coal combustion emissions, better resolution on the actual flows of coal between provinces and with international coal suppliers could improve the accuracy of the carbon intensity calculations.

4.8 Gaseous Fuels

4.8.1 Pipeline Specification Natural Gas

4.8.1.1 Modelling Approach Overview

The general system boundary and process flow diagram for pipeline specification natural gas in Canada is shown in Figure 17. Raw natural gas is extracted from different natural gas resource types (e.g. conventional, shale, etc.) or from pockets of gas in coal seams (CBM), or gas recovered during crude extraction (associated). Raw gas is delivered to field processing plants by way of gas batteries and gathering systems, and then processed to remove H_2S and other impurities to yield pipeline specification natural gas. Natural gas is then delivered to end users via a large network of transmission and distribution pipelines across Canada, ending with combustion in energy generation processes.

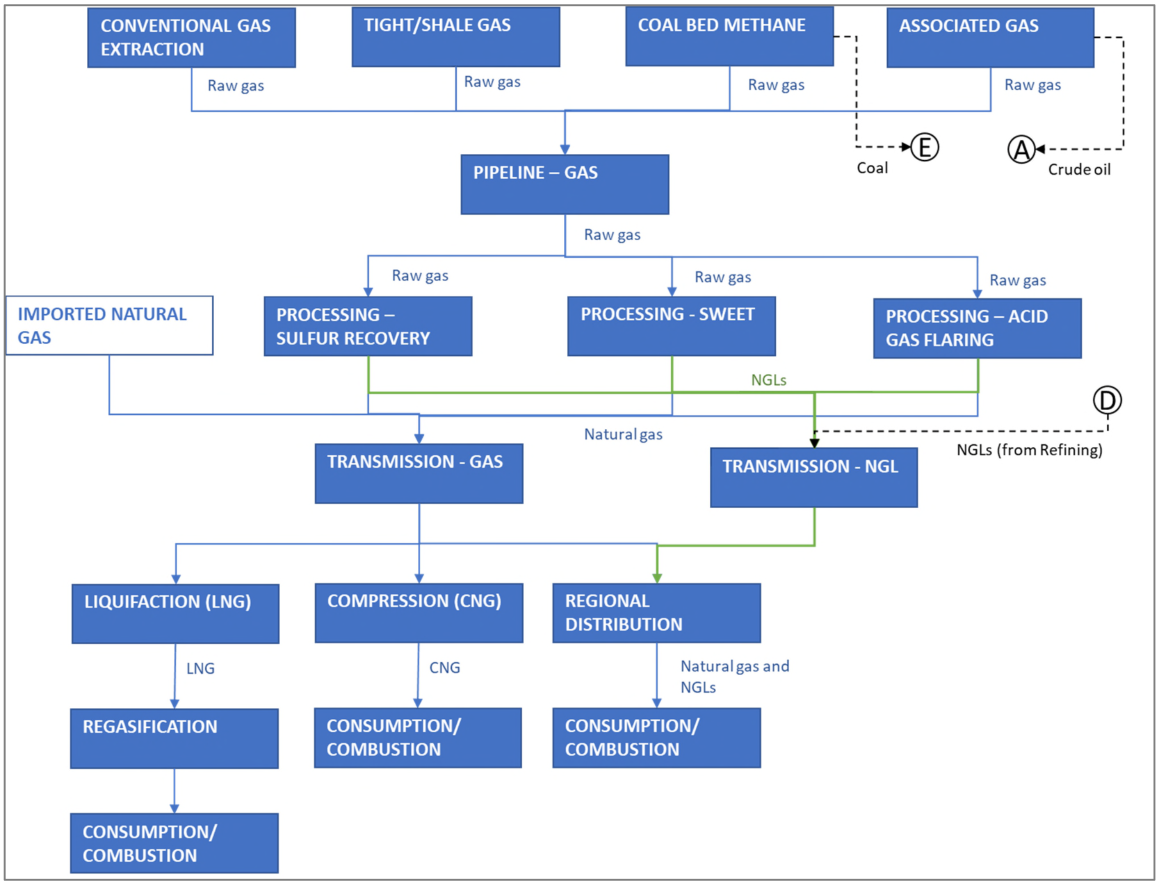

Figure 17: General process flow diagram for production of pipeline specification natural gas in Canada, including extraction, processing, transmission, distribution, and combustion.

Imported natural gas from the United States also flows through the Canadian natural gas transmission and distribution system and forms a significant component of the natural gas supply in Canada. This imported gas arrives at pipeline specification and does not require further processing.

The GHG emissions associated with the life cycle of pipeline specification natural gas in Canada are primarily due to:

- Fuel combustion and electricity generation to supply energy to equipment at various points in the life cycle;
- Emissions from venting and flaring of natural gas during extraction, processing, and transmission activities; and
- Fugitive emissions of natural gas due to equipment leaks and unplanned releases across life cycle activities.

The magnitude of the GHG emissions from these sources depends on several factors, including (Skone et al. 2016):

- Natural gas composition (i.e. concentrations of CH_4 and CO_2 in the gas);
- The resource type (e.g. conventional, tight, etc.) that is extracted and related gas production activities (e.g. workovers, liquids unloading, etc.);
- The type and extent of processing and purification required to convert raw gas to pipeline specifications;
- Facility emissions management procedures (e.g. amount of flaring vs. venting); and
- The quantity of extraction and processing equipment and natural gas loss rates from this infrastructure (i.e. potential for fugitive emissions).

These factors influencing life cycle GHG emissions also tend to vary from province to province as the nature of the natural gas resource changes, the extent of natural gas extraction and processing changes, and as emissions management practices change (e.g. flaring). The GHG emissions from natural gas extraction and processing are also influenced by the underlying electricity mix that supplies the grid in each province.

Recognizing the importance of these factors in determining the life cycle GHG emissions of natural gas, the modelling approach used to calculate the carbon intensity of Canadian natural gas production included:

- Compilation of production-weighted average natural gas composition data for both Alberta and British Columbia;
- Incorporation of AB and BC natural gas composition data into calculation of venting, flaring, and fugitive emissions from natural gas extraction and processing in each province;
- Use of natural gas composition data to determine the type and extent of processing required to produce pipeline specification natural gas in each province;
- Calculation of carbon intensity for production-weighted cradle-to-processor gate average natural gas in each province; and
- Calculation of production-weighted Canadian natural gas carbon intensity incorporating provincial average natural gas from AB and BC and imported natural gas from the United States.

The core of this approach was development of production-weighted carbon intensities for average natural gas produced in Alberta and British Columbia, which account for over 97% of total Canadian natural gas production by volume and energy content. An overview of this modelling process is shown for Alberta in Figure 18.

The production-weighted average carbon intensity for Alberta is based on energy use and emissions from five types of natural gas resource extractions, a number of common gathering and processing steps (e.g. batteries, straddle plants), and three natural gas processing pathways which require increasingly more intensive gas processing as H_2S content increases, including sweet, slightly sweet, and sour gas processing. Average Alberta gas composition is used both in calculating emissions from venting, flaring, and fugitives, and also in determining the proportion of Alberta natural gas that passes through each of the three different processing types.

A similar overview for British Columbia is shown in Figure 19, indicating the production weights for the three different resource types and three different processing types. It is important to note that resource types (e.g. conventional) are not directly linked with processing types (e.g. sour), but rather a production-weighted provincial average carbon intensity was calculated for each life cycle stage (i.e. extraction, processing). As an example, the carbon intensity of natural gas extraction in British Columbia was calculated by scaling the extraction emissions relative to the contribution of each resource type (e.g. tight, shale, etc.).

Modelling of associated gas produced during oil extraction and pre-processing is based on the results of OPGEE model runs described in section 4.5. GHG emissions at extraction and pre-processing at individual facilities were modelled in OPGEE and allocated to oil and gas products based on the energy content of each product. A sum of the associated gas produced from all facility-level runs was used to calculate an average carbon intensity for associated gas.

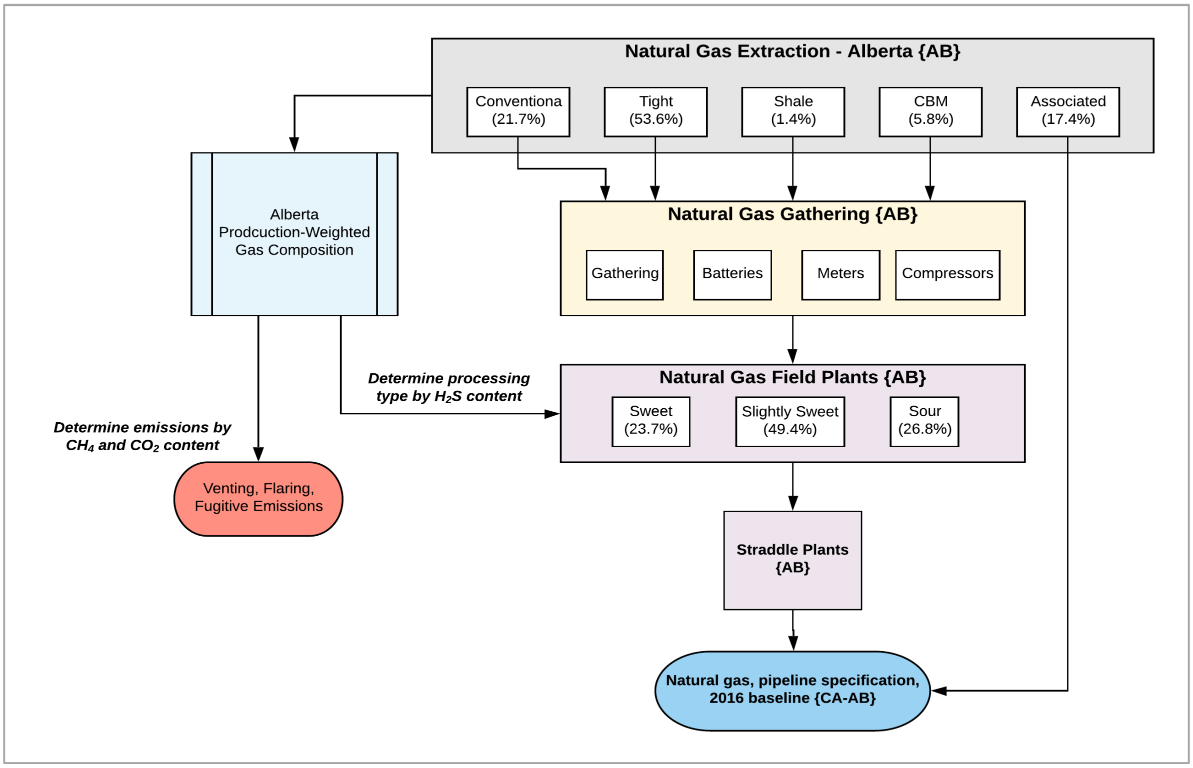

Figure 18. Modelling approach for Alberta natural gas production.

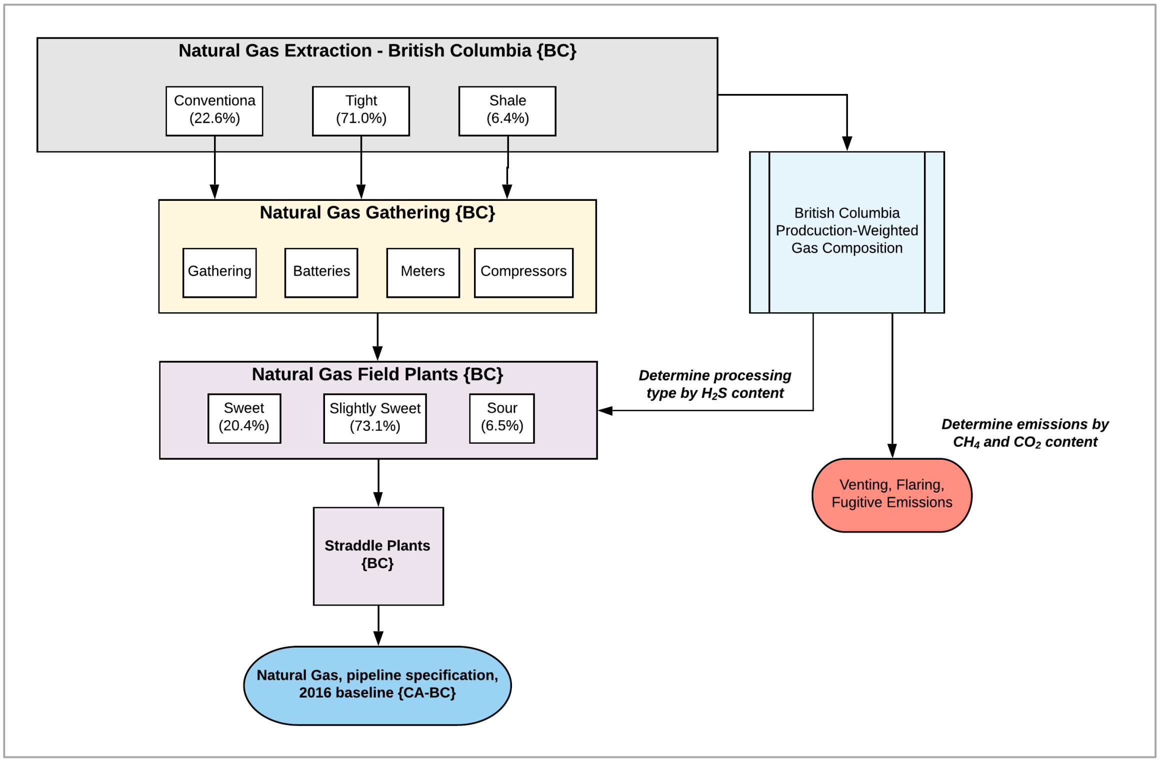

Figure 19. Modelling approach for British Columbia natural gas.

To model the carbon intensity for average Canadian natural gas, we modelled a production-weighted average of natural gas from Alberta, British Columbia, and imported natural gas from the United States (Figure 20). We then modelled the transmission, storage, and distribution via average Canadian pipelines and storage (natural gas, at consumer) and the average combustion emissions from natural gas (natural gas, combusted).

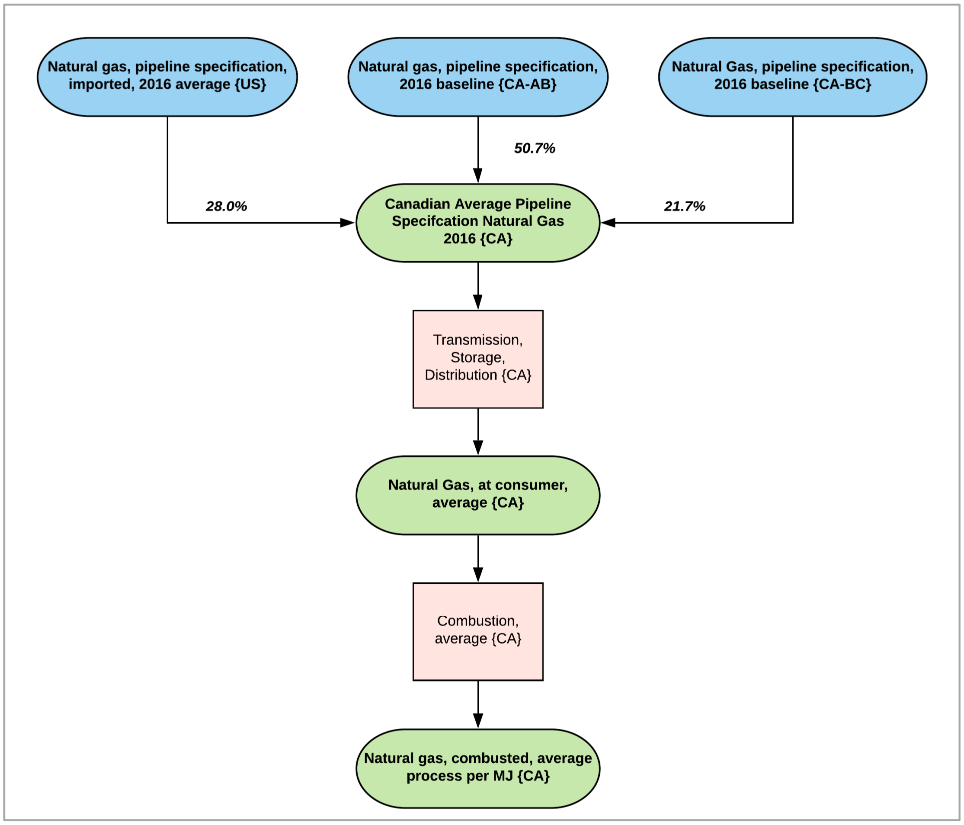

Figure 20. Modelling approach for Canadian average natural gas.

In the following sections, a more detailed summary of the carbon intensity calculations for natural gas is provided, including LCI data for key extraction and processing steps.

4.8.1.2 Natural Gas Carbon Intensity Calculation Overview

This section provides an overview of the calculation steps that were followed to determine Canadian average carbon intensity values for pipeline specification natural gas. The overall approach is based on the approach used in the 2016 NETL study on U.S. natural gas production (Skone et al. 2016), as well as a similar approach used in a detailed GHG emissions inventory of upstream oil and gas operations in Canada in 2011 (Clearstone Engineering Ltd. 2014). In the NETL study, carbon intensities were modeled for 20 key producing regions in the US according to extraction technology (e.g. conventional, shale, etc.) and then averaged to develop values for overall U.S. production. For each producing region, an average natural gas composition was used to estimate venting, flaring, and fugitive emissions from extraction and processing. Thus, regionally specific natural gas composition data and production technologies were the central determining factors of life cycle GHG emissions for U.S. natural gas production. These regionally specific values were then used to develop a production-weighted national average for US natural gas.

For the present study, we did not have access to regionally specific natural gas composition data that is linked to extraction technology type. This is in-part a result of a lack of publicly available data in this regard, as well as a lack of time and resources that would be required to attempt to build this dataset from existing industry reports; however, there were natural gas composition data available for all producing wells in Alberta and British Columbia for 2017 which were used to develop a set of average raw gas composition data for each. In following the NETL approach, we then used these composition data sets to calculate emissions from venting, flaring, and fugitives, as well as to determine the type of processing that would be required to convert the raw gas to pipeline specifications.

A general summary of the calculation steps is provided below:

A. Developed Natural Gas Compositions and Provincial Cradle-to-Pipeline Models

- Determined average natural gas composition for three natural gas categories within each province (British Columbia and Alberta) based on a production-weighted average of the composition data. The composition components were reduced to include methane, carbon dioxide, and hydrogen sulfide.
- Matched each gas composition with the appropriate gas processing plant archetype (i.e. sour, slightly sour, sweet).
- Set up cradle-to-processor gate carbon intensity models for each province based on resource extraction type (conventional, shale, tight, coalbed methane, associated), natural gas composition type, and natural gas processing type. Natural gas from each resource type was assumed to go through a weighted-average processing step based on the natural gas composition bins defined for each type (e.g. sweet, sour, etc.) (see Table 65).

B. Calculated Provincial Average CI for Pipeline Specification Natural Gas for Each Province

- Using the models from A, we calculated GHG emissions for each cradle-to-pipeline model and developed a production weighted CI for natural gas from each province.
    a. Natural gas, pipeline specification, 2016 baseline {CA-AB}
    b. Natural gas, pipeline specification, 2016 baseline {CA-BC}

C. Calculated CI for Imported Natural Gas

In addition to natural gas produced in Canada, imported natural gas from the United States enters the Canadian transmission system at various points along the border, primarily in Ontario and Western Canada. The carbon intensity of imported natural gas from the United States was based on the national average carbon intensity for natural gas from the NETL 2016 report (Skone et al. 2016). The NETL value included some emissions sources that were not part of the system boundary for the CFS project, including land use and well construction. The emissions associated with these activities were subtracted from the NETL value, as well as emissions associated with natural gas distribution, which is modeled for the Canadian pathways already. This was incorporated with emissions for the remaining transmission, distribution, and combustion that the gas undergoes once brought into the Canadian system. The upstream NETL value for average natural gas in the US was is 14.8 g CO_2e /MJ. As noted, emissions associated with land use (0.176 g CO_2e /MJ), well drilling and construction (0.0698 g CO_2e /MJ) and distribution (2.61 g CO_2e /MJ) were subtracted, giving a final carbon intensity value for imported natural gas of approximately 12 g CO_2 e/MJ.

D. Calculated Canadian Average CI for Cradle-to-Pipeline Models for each Technology

- We calculated a production-weighted average cradle-to-pipeline model CI based on natural gas from Alberta (50.7%), British Columbia (21.7%), and the US (28%).
- We modeled the CI of average Canadian pipeline transmission, storage, and distribution of natural gas

   a. Natural gas, at consumer, average {CA}

- We modeled the combustion of natural gas and completed the life cycle CI calculations by incorporating combustion with upstream calculations
   a. Natural gas, combusted, average process per MJ {CA}

4.8.1.3 Life Cycle Inventory and Modelling for Canadian Natural Gas

Natural Gas Composition

The composition of raw natural gas (i.e. the percentage of constituents such as CH_4, H_2S, CO_2, etc.) is a key determinant of the level of processing required to produce pipeline-ready product, and also is a key determinant of the amounts of GHGs that are emitted from various life cycle activities such as venting, flaring, and fugitive emissions. As such, natural gas composition is a key parameter for developing life cycle GHG emissions inventories for natural gas that are representative of different production regions and production practices (Skone et al. 2016). The composition of raw natural gas is highly variable from region to region, and at times even for wells within the same geologic formation. Given the large number of natural gas wells in production in Canada (over 100,000 (CAPP 2019)), it was not feasible to fully characterize and incorporate the composition of all raw natural gas extracted in Canada in 2016, and the use of a single average composition to represent Canadian natural gas may not capture the full spectrum of the resource due to this high variability. As such, we have taken a more consistent approach of statistically grouping average ranges of natural gas composition for both Alberta and British Columbia.

Data on natural gas composition at the well-head for producing formations in Alberta and British Columbia were compiled by Greenpath Energy (2019) and were derived from Alberta Energy Regulator (AER) reports, geoSCOUT data summaries, and data from the British Columbia Oil and Gas Commission (BCOGC). British Columbia data on natural gas composition were expressed relative to production type (i.e. conventional, shale, etc.); however, Alberta data were not expressed in this way, and there was insufficient data to fully reconcile the Alberta composition data with extraction type.

Based on the distribution of compositions across all wells in AB and BC (representing > 96% of natural gas production in both 2016 and 2017), we used binned average compositions based on weight per cent, rather than highly granular compositions. Thus, for CH_4 there were three average composition mixes (low, peak, and high), and for H_2S there were three mixes of composition based on H_2S content, including sweet, slightly sour, and sour.

The natural gas composition bins are summarized in Table 65. These composition data were used to calculate the mass of CH_4 and CO_2 in the average raw gas extracted in each province, and the “peak” values were used to calculate emissions from the release of natural gas from venting, flaring, and fugitive releases. In addition, uncertainty analysis conducted on the study results included the consideration of uncertainty related to gas composition and its potential influence on carbon intensity.

While there is no clearly defined link between resource type (e.g. shale, conventional) and the type of natural gas extracted (e.g. dry, wet), most natural gas extracted in Canada is “wet” to some degree and requires further processing and purification. The one exception is coalbed methane (CBM), which is produced from coal beds and is mostly composed of methane, with small amounts of nitrogen, carbon dioxide, and heavier hydrocarbons like ethane. Coalbed methane does not contain H_2S and so is considered a dry or sweet gas (AER 2019b) and requires very little processing to achieve pipeline specifications.

Table 65. Natural gas composition averages for Alberta and British Columbia for 2017.

	Mean (mol %)	Min (mol %)	Max (mol %)	Production Volume (m^3)	Production Weight %
Alberta – H_2S					
Sweet	0.000416	0.00	0.00099	26,921,093	23.7
Slightly sour	0.0106	0.00117	0.0164	56,133,995	49.4
Sour	0.0648	0.0201	0.2288	30,473,919	26.8
Alberta CH_4					
Peak	0.858	0.8346	0.8759	62,560,097	55.1
Low	0.7875	0.6089	0.8279	21,912,555	19.3
High	0.925	0.8802	0.9827	29,056,356	25.6
Alberta CO_2					
	0.01469	0.00053	0.15	-	-
British Columbia – H_2S					
Sweet	0.0000457	0.00	0.001	10,148,293	20.4
Slightly sour	0.00267	0.00135	0.01495	36,345,050	73.1
Sour	0.0373	0.018	0.1382	3,208,085	6.5
British Columbia – CH_4					
Peak	0.8419	0.8335	0.87193	41,588,372	83.7
Low	0.8053	0.7429	0.8276	1,439,642	2.9
High	0.9176	0.8814	0.9577	6,673,414	13.4
British Columbia – CO_2					
	0.01756	0.0004	0.1544	-	-

Natural Gas Extraction

Extraction Modelling Approach

Natural gas extraction processes differ depending on the type of gas resource being developed (conventional or unconventional) and the geological characteristics of where the gas sits (depth, porosity, etc.). These factors also influence the carbon intensity of natural gas extraction, as the composition of the raw natural gas extracted determines the methane and carbon dioxide emissions from venting, flaring, and fugitive emissions. Gas extraction is further differentiated by the drilling technology and infrastructure (e.g. vertical drilling for conventional vs. hydraulic fracturing and horizontal drilling); however, the drilling of wells and manufacturing and installation of natural gas extraction infrastructure are excluded from the system boundary as these are one-time emissions that typically account for less than 1% of life cycle GHG emissions over the full life of a well (Skone et al. 2016).

Emissions from natural gas extraction were estimated based on modelling for average extraction activities by resource type (conventional, tight, etc.) for both Alberta and British Columbia. The natural gas extraction models are differentiated by resource type, province, and gas composition at the well. Key factors that influence the carbon intensity of natural gas extraction also include:

- Gas Composition: Production-weighted gas composition for methane and carbon dioxide were determined for each province. These compositions were used to calculate methane and carbon dioxide emissions from venting and flaring.
- Extent of New and Active Gas Wells: Extraction emissions for any given year are dependent upon the number of newly established gas wells and the number of active gas wells.
- Extent of Operating Facilities and Components: Extraction emissions also include fugitive emissions from extraction equipment and facilities, which are based on the number of operating facilities and the amount and type of equipment being used at each facility type.

Data sources and modelling considerations for natural gas extraction are summarized in Table 66.

Table 66. Summary of data sources for natural gas extraction modelling.

Emissions Source	Modelling	Data Sources
Well completions	Emissions from well completions include vented and flared natural gas. The amount of gas emitted is based on the number of well completions for 2016 and venting and flaring emissions factors for conventional and unconventional wells. It was assumed that 53% of gas is captured and conserved, with the remaining gas being flared. The amounts of methane and carbon dioxide emitted were calculated using gas composition data compiled for Alberta and British Columbia.	• Well completions – CAPP Statistical Handbook (CAPP 2019). • Gas emissions factors – Tyner & Johnson 2014 • Emissions rates from flared natural gas – calculated from Skone et al. 2016 using AB and BC gas composition data. • Gas composition – Developed production-weighted average CH_4 and CO_2 contents for AB and BC using 2017 reported data from Greenpath Energy (2019).
Well workovers	Emissions from well workovers include vented and flared natural gas. The amount of gas emitted is based on the number of active gas wells in AB and BC in 2016 and emissions factors for gas released according to well type. The amounts of methane and carbon dioxide emitted were calculated using gas composition data compiled for AB and BC.	• Active well populations for AB and BC – CAPP Statistical Handbook (CAPP 2019). • Gas emission factors by well type – Skone et al. 2016 • Emissions rates from flared natural gas – calculated from Skone et al. 2016 using AB and BC gas composition data. • Gas composition – Developed production-weighted average CH_4 and CO_2 contents for AB and BC using 2017 reported data from Greenpath Energy (2019).
Liquids unloading	Emissions from liquids unloading are from vented natural gas. It was assumed that no flaring was done for gas emitted during liquids unloading activities. The amount of gas emitted is based on the number of active gas wells in AB and BC and an average gas emissions factor per well per month. The amounts of methane and carbon dioxide emitted were calculated using gas composition data compiled for AB and BC.	• Active well populations for AB and BC – CAPP Statistical Handbook (CAPP 2019). • Gas emission factors by well type – Skone et al. 2016 • Gas composition – Developed production-weighted average CH_4 and CO_2 contents for AB and BC using 2017 reported data from Greenpath Energy (2019).
Produced water tanks	Emissions from produced water tanks are from vented natural gas. It was assumed that no flaring was done for gas emitted from produced water tanks. The amount of gas emitted is based on the number of active gas wells in AB and BC, an average number of barrels of water produced per well, and an average methane emissions	• Active well populations for AB and BC – CAPP Statistical Handbook (CAPP 2019). • Barrels of water produced per well for AB – Alberta Petrinex reported volumetric data • Methane emission factor per barrel – Skone et al. 2016

	factor per barrel. The amount of methane emitted was calculated using gas composition data compiled for AB and BC. Produced water tank emissions were attributed to well types based on 2016 production weights.	• Gas composition – Developed production-weighted average CH_4 and CO_2 contents for AB and BC using 2017 reported data from Greenpath Energy (2019).
Surface casing vent flow	Emissions from surface casing vent flow are from vented natural gas. It was assumed that no flaring was done for gas emitted from this source. The amount of gas emitted is based on the number of active gas wells in AB and BC and an hourly gas emission factor per well. The amounts of methane and carbon dioxide emitted were calculated using gas composition data compiled for AB and BC. SCVF emissions rates were attributed to well types based on 2016 production weights.	• Active well populations for AB and BC – CAPP Statistical Handbook (CAPP 2019). • Gas emission factors by well type – Clearstone Engineering Ltd. 2018 • Gas composition – Developed production-weighted average CH_4 and CO_2 contents for AB and BC using 2017 reported data from Greenpath Energy (2019).
Pneumatic devices	Emissions from pneumatic devices are from vented natural gas. It was assumed that no flaring was done for gas emitted from this source. The amount of gas emitted is based on the number of operating facilities, the number and types of equipment used, and emissions factors for equipment types. Data were only available for AB gas facilities, so they were extrapolated to BC based on a calculated ratio of facilities to active wells. The amount of methane emitted was calculated using gas composition data compiled for AB and BC. Pneumatic device emissions rates were attributed to well types based on 2016 production weights.	• Active well populations for AB and BC – CAPP Statistical Handbook (CAPP 2019). • Alberta facility counts – Clearstone 2018, AER ST102 (2019e) • Alberta equipment types and counts – Clearstone 2018 and Greenpath Energy • Emissions factors for equipment - calculated from Prasino Group (2013), Clearstone Engineering Ltd. 2018. • Gas composition – Developed production-weighted average CH_4 and CO_2 contents for AB and BC using 2017 reported data from Greenpath Energy (2019).
Fugitive emissions	The amount of fugitive gas emitted is based on the number of operating facilities, the number and types of equipment used, and emissions factors for equipment types. Data were only available for AB gas facilities, so they were extrapolated to BC based on a calculated ratio of facilities to active wells. The amount of methane emitted was calculated using gas composition data compiled for AB and BC. Fugitive emissions rates were attributed to well types based on 2016 production weights.	• Active well populations for AB and BC – CAPP Statistical Handbook (CAPP 2019). • Alberta facility counts – Clearstone Engineering Ltd. 2018, AER ST102 (2019e) • Alberta equipment types and counts – Clearstone Engineering Ltd. 2018 and Greenpath Energy 2019. • Emissions factors for equipment - calculated from Prasino Group (2013), Clearstone Engineering Ltd. 2018. • Gas composition – Developed production-weighted average CH_4 and CO_2 contents for AB and BC using 2017 reported data from Greenpath Energy (2019).

In the following sections, the modelling of different extraction activities is described and LCI data is provided. Key emissions results are summarized in Table 67 and Table 68.

Modelling and LCI Data for Natural Gas Extraction

Well Completions

Well completions are activities following well drilling and preceding commercial production and that occur once over the life of the well. These activities result in the release of raw natural gas, which is then either captured for reuse, flared to reduce methane emissions, or vented directly to the air. Relative to conventional wells, shale and tight gas well completions typically have higher completion emissions due to methane contained in the flowback from hydraulic fracturing (Skone et al. 2016).

Calculated emissions from well completions for 2016 in Alberta and British Columbia were based on the number of wells completed by type (conventional vs. unconventional), the amounts of natural gas emitted that were captured, flared, or vented, and the amounts of methane and carbon dioxide contained in the emitted natural gas (represented by production-weighted provincial average compositions).

Well Workovers

Well workovers are necessary for cleaning wells and re-stimulating natural gas production. Workovers occur periodically over the life of the well (Skone et al. 2016). Natural gas is released during well workovers and is either flared or vented to the air. The level of flaring can vary by resource type and location. Emissions of natural gas from periodic well workovers were calculated based on the number of active wells in each province, estimated gas emission rates for each resource type, and the ratio of gas that is flared or vented. Flared and vented emissions were based on production-weighted methane and carbon dioxide concentrations calculated for each province.

Table 67. GHG emissions from venting and flaring during well completion and well workover activities, expressed relative to resource type and province for 2016 production. Emissions are expressed in g/MJ of marketable natural gas for each emission type.

	Amount Flared (kg)	CH$_4$ – Flaring (g/MJ)	CO$_2$ – Flaring (g/MJ)	N$_2$O – Flaring (g/MJ)	Amount Vented (kg)	CH$_4$ – Venting (g/MJ)	CO$_2$ – Venting (g/MJ)
Well Completions							
Alberta							
Conventional	28,704	5.53E-07	8.8E-05	2.87E-09	144	1.43E-07	2.45E-09
Tight	69,494,000	5.42E-04	8.64E-02	2.82E-06	349,200	3.46E-04	5.93E-06
Shale	2,150,000	6.21E-04	9.88E-02	3.22E-06	10,800	1.61E-04	2.75E-06
British Columbia							
Conventional	9,660	3.99E-07	6.35E-05	2.07E-09	48.5	1.01E-07	2.11E-09
Tight	23,388,000	3.07E-04	4.89E-02	1.59E-06	117,500	7.80E-05	1.63E-06
Shale	723,300	1.04E-04	1.66E-02	5.42E-07	3,630	2.65E-05	5.54E-07
Well Workovers							
Alberta							
Conventional	64,250	1.24E-06	1.97E-04	6.42E-09	81,770	8.11E-05	1.39E-06
Tight	340,800,000	2.66E-03	4.24E-01	1.38E-05	433,742,000	1.74E-01	2.99E-03
Shale	1,392,000	4.02E-04	6.40E-02	2.09E-06	1,772,000	2.64E-02	4.51E-04
Coalbed methane	1,031,000	7.44E-05	1.18E-02	0.00	1,312,000	1.95E-02	3.34E-04
British Columbia							
Conventional	3,450	1.42E-07	2.26E-05	7.39E-10	4,390	9.15E-06	1.91E-07
Tight	38,315,000	5.03E-04	8.01E-02	2.61E-06	48,765,000	3.24E-02	6.75E-04
Shale	179,600	2.59E-05	4.13E-03	1.35E-07	228,500	1.67E-03	3.48E-05

Liquids Unloading

Liquids unloading is a routine operation for natural gas wells to maintain gas flow by removing accumulated liquid in the well. These vented emissions can be significant and can vary by well type, and also vary depending on whether a plunger lift system is used or not (Skone et al. 2016). Emissions from liquids unloading are assumed to be vented and not captured or flared.

Surface Casing Vent Flow

When a gas well is drilled, it must be cased with steel pipe to provide stability and ensure fluids are contained within the well. Surface casing vent flow and gas migrations can occur due to imperfections in the seals that result from drilling or cementing conditions. Surface casing vent flow involves the movement of gas which can result in emissions of natural gas to the atmosphere. These emissions are vented and are not flared. Emissions from this source were calculated using an emissions factor from field testing by Clearstone Engineering and multiplying this by the number of active wells in each province. It was assumed that the emissions factor is the same for both Alberta and British Columbia.

Produced Water Tanks

Produced water tanks are used to store and transport the brine solution that condenses out of the gas or that is cleared from the well during liquids unloading. These water tanks are a source of emissions as natural gas is sometimes vented from the tanks and released directly to the atmosphere. Emissions from produced water tanks were estimated based on the amount of produced water from each well, and an emissions factor for the amount of methane released per barrel of water (for data sources see Table 66). Water production data was only available for Alberta, so the amount of water produced per well was assumed to be equivalent for extraction in British Columbia, and then multiplied by the number of active gas wells in British Columbia.

Pneumatic Devices

Pneumatic devices are used for the routine opening and closing of valves and use of other control equipment during extraction. They operate on a continuous basis and vent emissions directly to the atmosphere without flaring (Skone et al. 2016).

Emissions from pneumatic devices were estimated based on facility and equipment counts and estimated natural gas emissions rates for each type of device. Facility and equipment counts were not available for British Columbia, so Alberta facility and component counts were extrapolated to British Columbia based on a calculated ratio of active wells to facilities.

Table 68. GHG emissions from activities associated with liquids unloading, pneumatic devices, produced water tanks, and fugitive emissions during natural gas extraction, expressed relative to resource type and province for 2016 production.

	Amount Vented (kg of natural gas)	CH_4 – Venting (g CH_4/MJ)	CO_2 – Venting (g CO_2/MJ)
Liquids Unloading			
Alberta			
Conventional	116,187,000	0.115	0.002
Tight	174,280,000	0.07	0.001
Shale	13,811,000	0.206	0.004
Coalbed methane	55,243,000	0.206	0.004
British Columbia			
Conventional	6,234,000	0.013	0.0003
Tight	19,594,000	0.013	0.0003
Shale	1,781,000	0.013	0.0003
Surface Casing Vent Flow			
Alberta			
Conventional	29,155,000	0.0289	0.0005
Tight	43,732,000	0.0176	0.0003
Shale	3,466,000	0.0516	0.0009
Coalbed methane	13,862,000	0.0516	0.0009
British Columbia			
Conventional	1,564,000	3.26E-03	6.81E-05
Tight	4,917,000	3.26E-03	6.81E-05
Shale	447,000	3.26E-03	6.81E-05
Produced Water			
Alberta			
Conventional	12,089,000 bbl.	7.10E-04	-
Tight	18,134,000 bbl.	4.32E-04	-
Shale	1,437,000 bbl.	1.27E-03	-
Coalbed methane	5,748,000 bbl.	1.27E-03	-
British Columbia			
Conventional	648,700 bbl.	8.17E-05	-
Tight	2,039,000 bbl.	8.17E-05	-
Shale	185,300 bbl.	8.17E-05	-
Pneumatic Devices			
Alberta			
Conventional	27,352,000	1.32E-03	2.26E-05
Tight	Above is total amount vented for Alberta for 2016	3.26E-03	5.58E-05
Shale		8.81E-05	7.18E-03
Coalbed methane		3.52E-04	6.03E-06
British Columbia			
Conventional	14,522,000	1.59E-03	3.32E-05
Tight	Above is total venting in BC 2016	5.01E-03	1.04E-04
Shale		4.55E-04	9.49E-06
Fugitive Emissions			
Alberta			
Conventional	60,339,000	5.99E-02	1.02E-03
Tight	125,048,000	5.03E-02	8.61E-04
Shale	335,300	4.99E-03	8.54E-05
Coalbed methane	9,177,000	3.41E-02	5.85E-04
British Columbia			
Conventional	2,781,000	5.80E-03	1.21E-04
Tight	10,398,000	6.90E-03	1.44E-04
Shale	26,370	1.93E-04	4.02E-06

Fugitive Emissions

Aging or improperly operating equipment can be sources of fugitive emissions due to leaks from extraction equipment and facilities. These emissions are primarily from flanges, connectors, valves, and open-ended lines (Skone et al. 2016). Fugitive emissions from natural gas extraction were calculated using component leak rates from Clearstone Engineering, facility and component counts to estimate the amount of leakage, and natural gas speciation for average Alberta and British Columbia raw gas. Facility and equipment counts were not available for British Columbia, so Alberta facility and component counts were extrapolated to British Columbia based on a calculated ratio of active wells to facilities.

Natural Gas Processing

Processing Modelling Approach

Natural gas processing is done via a network of gas processing plants that perform various functions depending on the origins and composition of the gas, which determines the level of processing required to achieve pipeline specifications. As shown in Figure 21, raw gas from wells travels through a network of processing facilities before reaching transmission pipelines. This network includes:

- Gathering systems;
- Field processing plants;
- Fractionation plants; and
- Straddle plants.

The processing steps for natural gas are primarily determined by the composition of the gas, as the post-extraction processing required to produce transmission-ready natural gas varies depending on which form of natural gas is extracted. Dry natural gas, which is raw natural gas from relatively shallow wells (less than 1,000 m deep) that is typically comprised of 95% methane, contains very little heavy hydrocarbons and impurities and so rather than undergoing processing and purification, dry natural gas is typically collected in low-pressure gathering systems and conducted to gas batteries where it is dehydrated and compressed into a gas transmission system (Clearstone Engineering Ltd. 2014).

Wet natural gas is raw gas from wells that requires processing to remove condensable hydrocarbons, and in addition to dehydration, may require sweetening to remove excessive levels of CO_2 and H_2S. Wet natural gas is collected at higher pressures and transported to gas plants for processing and purification using both heated and dehydrated gathering systems. Heated gathering systems use line heaters to maintain the gas above a critical temperature. Dehydrated gathering systems remove water vapour from the process gas using absorption or desiccant dehydrators (Clearstone Engineering Ltd. 2014).

Associated gas, which is also referred to as solution gas, is raw natural gas that is produced from oil wells in association with oil production. It is usually rich in condensable hydrocarbons and may contain some CO_2 and H_2S. It is typically used for on-site fuel requirements and any surplus gas is either vented or flared, re-injected into the well to maintain reservoir pressure, or produced into a gas gathering system for processing and purification (Clearstone Engineering Ltd. 2014).

The general steps required to process natural gas for pipeline transmission include:

- **Acid Gas Removal (AGR)** – Also called sweetening, is the removal of H_2S from raw natural gas. AGR systems use solvents to attract H_2S and CO_2 and then a solvent stripping process which uses reboilers to remove acid gases. Reboilers are powered by natural gas, and the process also releases CO_2 emissions from the amine solution. There is also venting of natural gas during this process.

- **Dehydration** – Dehydration is used to remove water from raw natural gas to make it suitable for pipeline transport and to increase its heating value. Emissions from this process include combustion and venting.
- **Liquids Separation** – Separators use propane refrigeration to chill natural gas and allow for the separation of natural gas from natural gas liquids (NGL). The NGLs are a marketable co-product and thus the emissions from electricity and fuel consumption must be allocated, as well as emissions from venting and flaring.
- **Compression** - Compressors are used to increase the gas pressure for pipeline distribution and consume energy during operation and are also used to produce CNG after transmission. The amount of energy used is dependent on the pressure of the incoming gas and the required pressure for pipeline specifications, and thus introduces uncertainty. In addition to fuel consumption, compressors also have fugitive CH_4 emissions. Natural gas compression occurs after processing and prior to entering the transmission pipeline. In addition, natural gas compressors are located along natural gas transmission pipelines to ensure that the appropriate pressure is maintained for continuous flow. Compression for pipeline transmission is being modelled separately in Milestone 2 and has been incorporated with CNG pathway calculations.

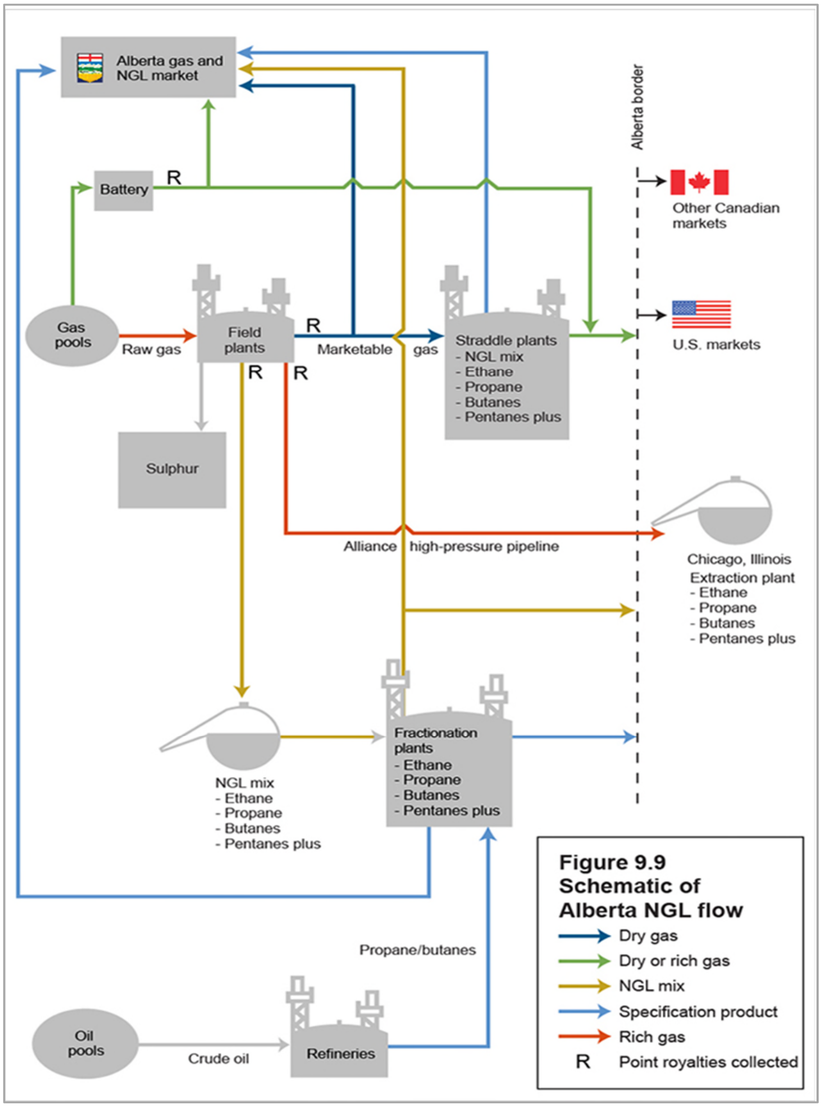

Figure 21. Flow of natural gas products from extraction through to market for Alberta natural gas and NGLs sector (AER 2019c).

In the following sections, each of these steps in natural gas processing is described and LCI data is provided for the operation of various plants, including their outputs and interconnections. A summary of modelling steps and data sources is provided in Table 69.

Table 69. Modelling and data sources summary for natural gas processing.

Processing Emissions Source	Modelling	Data Sources
Electricity use	Electricity consumption data for all types of gas processing plants were only available as a 2011 total for Alberta. These data were converted to an amount of electricity per m^3 of gas processed and then used to represent electricity consumption for each plant type for 2016 in AB and BC. The specific provincial electricity grids were used to model electricity production and emissions in each province.	• Electricity consumption per processing facility type, per m^3 of gas processed in Alberta – Clearstone Engineering Ltd. 2014 • Direct and indirect emissions from electricity production in AB and BC – ECCC electricity tool
Fuel combustion	Emissions from fuel combustion at gas processing facilities were only available as a 2011 total for Alberta. These data were converted to an amount of electricity per m^3 of gas processed in 2011 and then used to represent emissions from fuel combustion for each plant type for 2016 in AB and BC.	• Fuel combustion emissions per processing facility type, per m^3 of gas processed in Alberta – Clearstone Engineering Ltd. 2014
Venting	Emissions from venting of gas at processing facilities were only available as a 2011 total for Alberta. These data were converted to an amount of emissions per m^3 of gas processed in 2011 and then used to represent emissions from fuel venting for each plant type for 2016 in AB and BC.	• Venting emissions per processing facility type, per m^3 of gas processed in Alberta – Clearstone Engineering Ltd. 2014
Flaring	Emissions from gas flaring at processing facilities were only available as a 2011 total for Alberta. These data were converted to an amount of emissions per m^3 of gas processed in 2011 and then used to represent emissions from flaring for each plant type for 2016 in AB and BC.	• Flaring emissions per processing facility type, per m^3 of gas processed – Clearstone Engineering Ltd. 2014
Fugitive emissions	The amount of fugitive gas emitted is based on the number of processing facilities, the number and types of equipment used, and emissions factors for equipment types. Data were only available for AB gas processing facilities, so they were extrapolated to BC based on a calculated ratio of facilities to active wells. The amount of methane emitted was calculated using gas composition data compiled for AB and BC.	• Alberta facility counts – Clearstone 2018, AER ST102 (2019e) • Alberta equipment types and counts – Clearstone Engineering Ltd. (2018) and Greenpath Energy (2019) • Emissions factors for equipment – ECCC 2019 (calculated from Prasino Group (2013)), Clearstone Engineering Ltd. (2018). • Gas composition – Developed production-weighted average CH_4 and CO_2 contents for AB and BC using 2017 reported data from Greenpath Energy (2019).
Co-products	Most gas processing facilities produce both marketable gas and a range of NGLs (e.g. propane, butane, etc.). The exceptions are gathering systems and gas batteries. For all other processing facility types, GHG emissions were allocated to marketable gas and NGLs based on energy content. Energy allocations were based on the product slate (i.e. mass of each product produced per unit of marketable gas) and the respective energy content of each product.	• Product slates, inputs and outputs for Alberta gas processing facilities – AER ST50 report for 2016c.

Modelling and LCI Data for Natural Gas Processing

Gathering Systems

Gathering is the movement of raw natural gas from wellheads to processing facilities via a network of smaller-diameter pipelines in gas producing regions. Feeder pipelines are used to transport natural gas and natural gas liquids from various facilities and storage tanks to transmission pipelines (CAPP 2018a). These systems consume energy to compress, heat, and move natural gas, and also produce emissions from venting, flaring, and fugitive releases. The components of the gathering system generally include compressors, the gathering pipelines and facilities, and metering/regulations stations. Energy consumption and emissions for an average Alberta gathering system are summarized in Table 70.

Table 70. Energy use and emissions from natural gas gathering activities and batteries for 2016, expressed per MJ of marketable natural gas produced (adapted from Clearstone Engineering Ltd. 2014). Operating data are assumed to be equivalent between Alberta and British Columbia with the exception of fugitive emissions, which are shown separately for British Columbia.

Inputs and Emissions	Compressors	Gathering System	Meter/Regulation Station	Batteries
Electricity Use (kWh/MJ)	2.0E-06	1.14E-04	1.04E-05	2.71E-05
Natural Gas Use (MJ/MJ)	0.02			3.0E-4
Fuel Combustion Emissions (g/MJ)				
CO_2	2.6E-01	6.76E-01	0	7.08E-01
CH_4	6.0E-04	1.46E-04	0	1.15E-03
N_2O	2.5E-05	6.33E-05	0	5.15E-05
Flaring Emissions (g/MJ)				
CO_2	8.0E-04	1.0E-02	0	2.38E-02
CH_4	4.6E-06	6.26E-05	0	1.49E-04
Venting Emissions (g/MJ)				
CH_4	2.2E-03	9.80E-03	2.0E-04	8.03E-03
CO_2	-	3.86E-04	0	3.86E-04
Fugitive Emissions (g/MJ)				
CH_4	1.52E-03	6.18E-04	0	9.31E-03
CO_2	2.61E-05	1.29E-05	0	1.59E-04
British Columbia Fugitives (g/MJ)				
CH_4	2.01E-04	6.18E-04	0	1.01E-03
CO_2	4.20E-06	1.30E-05	0	2.11E-05

Natural Gas Processing

The natural gas composition groupings summarized in Table 65 were used to create processing pathways that were based on the level of processing required to reach natural gas pipeline specifications. A summary of those pathways is below:

- Dry gas (only applies to CBM) – Dry gas was assumed to require minimal processing due to low H_2S content. After extraction, raw natural gas from CBM was modelled as going through gathering, then to a gas battery, and then to transmission.
- Sweet gas – Sweet gas was modelled as going through gathering, acid gas removal, then passing through a straddle plant and then transmission.
- Slightly sour gas – Slightly sour gas was modelled as going through gathering, higher level of acid gas removal, then through a straddle plant and to transmission.
- Sour gas – Because of its higher H2S content, after extraction we modelled sour gas as passing through a gathering system, then so a sulphur recovery plant, and then through a straddle plant before transmission.

The energy and emissions associated with each type of processing step are summarized in Table 71 and Table 72.

Table 71. Energy use and emissions for various natural gas processing plant types, expressed per MJ of marketable natural gas produced. Operating data are assumed to be equivalent between Alberta and British Columbia with the exception of fugitive emissions, which are shown separately for British Columbia. Co-product allocation ratios are shown for each plant type based on energy content of the co-products.

Inputs and Emissions	Sweet	Slightly Sour	Sour
Electricity Use (kWh/MJ)	2.66E-04	1.15E-03	2.22E-03
Natural Gas Use (MJ/MJ)	1.86E-03	3.33E-03	1.78E-02
Fuel Combustion Emissions (g/MJ)			
CO_2	9.28E-01	3.55E+00	2.40E+00
CH_4	1.83E-03	6.75E-03	1.40E-03
N_2O	7.33E-05	2.46E-04	7.00E-05
Flaring Emissions (g/MJ)			
CO_2	3.67E-02	2.24E-01	7.28E-02
CH_4	2.04E-04	1.33E-03	4.57E-04
Formation Emissions (g/MJ)			
CO_2	4.35E-02	4.90E-01	1.99E+00
Venting Emissions (g/MJ)			
CH_4	8.45E-04	2.28E-03	4.38E-04
CO_2			
Fugitive Emissions (g/MJ)	4.10E-03	1.59E-03	6.52E-04
CH_4	7.01E-05	2.72E-05	1.12E-05
CO_2	2.66E-04	1.15E-03	2.22E-03
British Columbia Fugitives (g/MJ)			
CH_4	6.94E-04	2.44E-04	6.07E-05
CO_2	1.45E-05	5.08E-06	1.27E-06
Energy Allocation to Co-Products			
Marketable Gas	89.2%	82.2%	76.6%
Propane	0.1%	0.19%	1.7%
Other NGLs	10.6%	17.6%	21.6%

Table 72. Energy use and emissions for various natural gas processing plant types, expressed per MJ of marketable natural gas produced.

Inputs and Emissions	Straddle Plant	Fractionation
Electricity Use (kWh/MJ)	2.01E-04	5.15E-04
Natural Gas Use (MJ/MJ)	1.86E-03	3.59E-04
Fuel Combustion Emissions (g/MJ)		
CO_2	2.64E-01	9.35E-01
CH_4	1.84E-05	4.39E-05
N_2O	6.74E-06	1.26E-05
Flaring Emissions (g/MJ)		
CO_2	2.14E-03	1.88E-01
CH_4	1.32E-05	1.17E-03
Formation Emissions (g/MJ)		
CO_2	2.39E-02	-
Venting Emissions (g/MJ)		
CH_4	1.43E-04	8.85E-04

CO_2		-
Fugitive Emissions (g/MJ)	1.20E-09	
CH_4	2.06E-11	2.81E-09
CO_2	2.01E-04	4.81E-11
British Columbia Fugitives (g/MJ)		
CH_4	2.63E-09	6.14E-09
CO_2	5.49E-11	1.28E-10
Energy Allocation to Co-Products		
Marketable Gas	89%	19%
Propane	2%	17%
Other NGLs	9%	64%

4.8.2 Other Gaseous Fuels

4.8.2.1 Propane

Propane production is done across a network of different crude and gas processing operations. Many different types of gas processing facilities remove NGLs that contain propane, and since these are valuable co-products, many different plants contribute to propane production. Based on reported production levels for 2016 for Alberta gas processing facilities, the share of production associated with teach processing facility type was calculated (Table 73) (Source: AER ST50).

Propane is a co-product from all of these crude or natural gas processing facilities, which are dedicated to producing other primary products such as marketable natural gas and crude products. The one exception is fractionation plants, which are dedicated to processing NGLs and for which propane is a primary product. The upstream emissions associated with natural gas extraction, gathering, and processing were allocated to propane based on the production-weighted energy content of each co-product. For most facilities, this allocation results in a relatively small portion of upstream emissions being allocated to propane due to the dominance of marketable gas production (Table 73).

Table 73. Breakdown of propane producing facilities and contribution to provincial propane production for 2016 (Based on AER ST50) and including energy allocation to propane per facility.

Propane Source	Alberta	British Columbia	Energy Allocation to Propane
Crude refineries	8.9%	-	
Crude extraction	5.1%	-	
Sour gas plants	17.2%	20%	7.4%
Sweet gas plants	2.6%	3%	1.3%
Slightly sour gas plants	0.9%	1%	1.0%
Straddle plants	13.8%	16%	9.9%
Fractionation plants	51.6%	60%	21.1%

The calculations of the energy allocation to propane from each facility type were based on data for the 2016 product slates by facility type. These data are summarized in the Natural Gas Calculation Workbook provided as an appendix to this report. Data on the amount of raw natural gas input required to produce 1 MJ of propane for each facility were obtained from these facility data, and the product slates were used along with energy content for the various outputs (e.g. marketable gas, propane, ethane, etc.) to calculate the energy allocation factors summarized in Table 73. These allocation factors were used along with the technology share percentages to determine the carbon intensity of producing propane in each type of facility, and combining them together to account for an average MJ of propane. The carbon intensity of producing propane from each facility type was then combined with the carbon intensity of propane produced from refineries and from crude extraction to determine the CI for an average MJ of propane in Canada. Further details on these calculations are provided in the Natural Gas Workbook and in the associated data sheets.

Given the dominance of Alberta and British Columbia in Canadian propane production, the baseline carbon intensity for propane was calculated based on the relative propane production from those two provinces and excluding other provinces with more negligible contributions.

4.8.2.2 Compressed Natural Gas and Liquefied Natural Gas

Compressed natural gas (CNG) and liquefied natural gas (LNG) are products that consist of pipeline specification natural gas[9] which is either compressed or liquefied to facilitate transportation and/or use as a fuel in mobile applications. Both of these products are emerging in importance but at present, and in 2016, had limited markets and production in Canada. LNG is primarily produced to export natural gas from Canada to other countries and there is no national reported data on Canadian domestic consumption of LNG. At present CNG production is mostly limited to fueling selected applications such as specific municipal bus fleets, although many of these may be from biogenic CNG sources. Similar to LNG, there is no reported domestic production and consumption of CNG in Canada. As such, CNG and LNG pathways have been modelled as extensions of the pipeline specification natural gas pathways.

The production of CNG involves a compression step after pipeline transport of marketable natural gas, and there is energy use and emissions associated with this step. When CNG is decompressed for certain applications, energy is released in the process and any GHG emissions associated with this process would be negligible. For the baseline carbon intensity calculations, the production of CNG was modeled by assuming that up until the point of compression and including combustion, the life cycle of CNG is the same as pipeline specification natural gas. This includes extraction, processing, transmission, and combustion. Emissions associated with natural gas compression to produce CNG were obtained from GREET 2018 and the California Air Resources Board (California Air Resources Board 2019) calculator for CNG and are 3.18 g CO_2 e/MJ of gas compressed.

The production of LNG involves a liquefaction process prior to transport, and typically a regasification process after transport to return LNG to pipeline natural gas properties. During liquefaction, natural gas is liquefied by cooling it to a cryogenic temperature of -155 degrees Celsius in a refrigerant cycle. A recent study of producing LNG in Canada estimated that the GHG emissions from an average liquefaction process are approximately 8.35 g CO_2 e/MJ of natural gas processed. During regasification, LNG is converted back to natural gas by providing vaporizing heat through fuel combustion. Emissions for this process were estimated at 2.63 g CO_2 e/MJ in the same study as above (Sapkota et al. 2018).

The pathways modeled for CNG and LNG were extensions of average Canadian pipeline natural gas pathways, including a Canadian average for all sources of natural gas (i.e. conventional, shale, etc.) and a Canadian average where it assumed that CNG and LNG are produced individually from each natural gas source. The average natural gas produced in these

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[9] It is noted that CNG can also be derived from biogenic sources of natural gas such as landfill gas, but for the present study it is assumed that CNG is produced from fossil-based natural gas.

pathways was based on the same data and assumptions at the pipeline specification natural gas, except that the additional compression, liquefaction, and regasification steps were added.

4.8.3 Natural gas pipeline energy use and emissions

Natural gas has many of the same complexities as the crude pipelines but has not yet been modeled in detail and some of the data required to do so are not readily available. Based on Choquette-Levy et al., Choquette-Levy et al., "COPTEM: A Model to Investigate the Factors Driving Crude Oil Pipeline Transportation Emissions" (Choquette-Levy et al. 2018b), crude pipeline data in the 2014 GREET model is a reasonable proxy for Canadian crude pipeline transmission. Discussions with the Canadian Energy Pipeline Association (CEPA) indicated that there is more reliance on turbines in Canada and more reciprocating engines in the US (Beamish 2019). While this indicates the Canadian pipelines are less efficient than US pipelines, lacking better data, the 2018 GREET (Michael Wang, et al. 2018) natural gas pipeline model has been used as a proxy for natural gas in the default pathway model. Table 75 shows the values from the different studies. GHGenius uses statistical data to calculate the average energy required to transport natural gas. The last year for which it has actual statistics is 2010 for which the energy is calculated to be 1600 BTU/ton-mile, agreeing well (GHGenius 2018). 98% of the energy is expected to come from natural gas. The remainder is coming from electricity. As in the crude transport, the Canadian average grid is used for the electricity, based on the extensive pipeline network as shown in Figure 22.

In addition to combustion emissions from the energy required to move the gas, natural gas pipelines have fugitive, venting and flaring emissions. Actual data from 2016 have been used to capture these emissions at the transmission and distribution stages. These data are for total annual production so are not easily calculated per tkm. Instead, they have been calculated per m^3 of production (ORTECH Environmental 2018). Uncertainties are applied per ORTECH Environmental (ORTECH Environmental 2018).

Table 74: Comparison of energy requirements for natural gas pipeline model with similar models.

Function	This Study	GHGenius	GREET
Energy required to transport one barrel of crude one mile	1,640 BTU/ton-mile	1,600 BTU/ton-mile	1,641 BTU/ton-mile

Table 75: 2016 reported transmission and distribution emissions

		Transmission (t/m3 natural gas)	Distribution (t/m3 natural gas)
CO_2	Venting	3.73E-09	1.71E-10
	Flaring	4.73E-08	2.60E-10
	Fugitives	2.42E-09	5.01E-09
	Emergency Response	1.33E-12	2.13E-10
CH_4	Venting	1.89E-07	6.46E-09
	Flaring	2.82E-10	1.77E-12
	Fugitives	1.22E-07	1.58E-07
	Emergency Response	7.90E-11	1.46E-08
N_2O	Venting	0.00E+00	0.00E+00
	Flaring	5.84E-14	2.67E-17

	Fugitives	0.00E+00	0.00E+00
	Emergency Response	0.00E+00	0.00E+00

Source: CEPEI (data compiled for Canadian Natural Gas Transmission and Distribution Companies 2016 Greenhouse Gas Inventory) (ORTECH Environmental 2018)

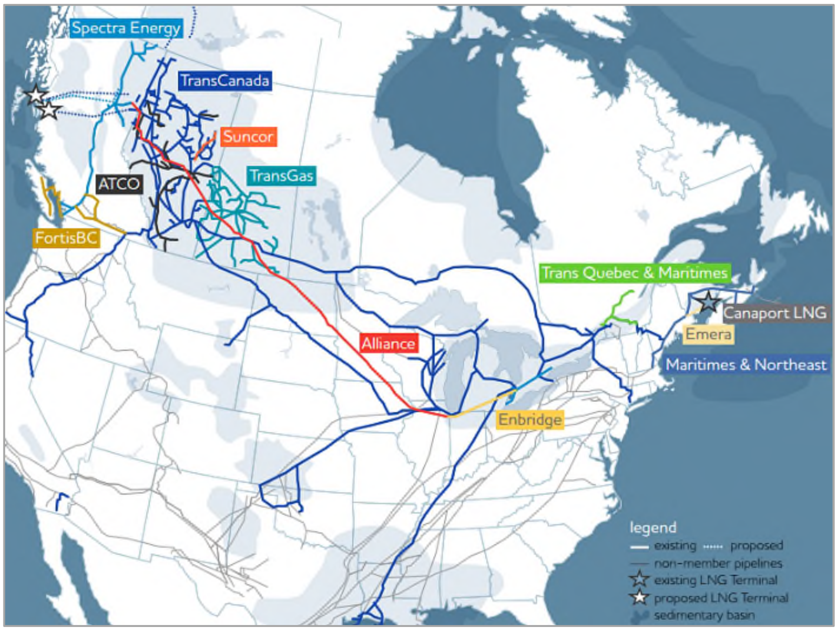

Figure 22: Natural gas pipelines extend fully across Canada and into the US. Source: Pipeline Education

Table 76: Energy use and emissions for transport of natural gas through the pipeline, expressed per ton.mile of transport.[10]

Exchange	Quantity	Unit	Description
Outputs			
Transport, gas pipeline {CA}	1	Ton.mile	
Inputs			
Natural gas, combustion average process {CA}	1641 * FractionByGas	btu	
Electricity at grid, 2015 average {CA)	1641 * FractionByElectricity	btu	Average Canadian grid used as transport is across Canada.
Parameters			
FractionByGas	0.98		
FractionByElectricity	1-FractionByGas		

4.8.3.1 Average Distance Natural Gas is Transported

To calculate an average intensity, the distance the gas travels to each province can be multiplied times the consumption within the province. As the pipelines are not individually modeled, the entire distance from production to use is estimated for each region. It may be important to note that while the pipeline networks are extensive, the gas does not actually travel through the entire pipeline and travels only the distance from extraction to refinery, refinery to

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[10] More detailed modelling using the Choquette-Levy et al., model would improve this dataset.

use. Most provinces with significant natural gas use also produce natural gas (NEB 2017b). The transportation distance for those provinces was assumed to be the distance between the gas producing region and the major city or the distance between two major cities in gas producing regions.

Table 77: Natural gas transport distance approximations for production within the province.

Province	Natural Gas Pipe Starting Point	Destination	Distance
BC	Fort Nelson	Vancouver	2,858 km*
AB	Edmonton	Calgary	299km*
SK	Saskatoon	Regina	258 km*
Ontario	Queenston	Toronto	128 km*
NB	Elgin	Fredericton	161 km*
Nova Scotia	Panuke (offshore)	Halifax	250 km (Encana Corporation, 2019)

*Source: Google maps transportation mapping

New Brunswick and Nova Scotia also import natural gas. To assess those impacts as well as those of the remaining provinces, the natural gas was assumed to come from Calgary, in the middle of the largest production area in Canada and be transported to the capital city of the province. For the Maritime provinces, the natural gas is assumed to come from Goldsboro, NS.

Table 78: Natural gas import transport distance approximations.

Province	Natural Gas Pipe Starting Point	Destination	Distance
Manitoba	Calgary	Winnipeg	1327 km*
Ontario	Calgary	Toronto	3416 km*
Quebec	Calgary	Quebec City	4837 km*
New Brunswick	Panuke (offshore)	Fredericton	750 km (Encana Corporation, 2019)
Nova Scotia	Panuke (offshore)	Halifax	250 km (Encana Corporation, 2019)

*Source: Google maps transportation mapping

While the distances to other places in Canada, such as Newfoundland and Labrador, may be large, resulting in high carbon intensities per MJ, the amount of gas used is very low. The lowest consumption of all the provinces listed, New Brunswick, is only about 0.3% of the total. As the remaining provinces and territories consume even less, their impacts have been ignored.

Weighting these distances by the consumption volumes and per cent obtainable locally from the National Energy Board's *Canadian Marketable Natural Gas Production*, we get 2,560 km. (See *3-9-2 Natural gas weighted transport distance calculations.xlsx* for the detailed calculations for 2016). The 3% of natural gas which is not transported by pipeline is also exported via tanker.

4.8.4 Baseline 2016 Carbon Intensity Results for Gaseous Fuels

In the following sections, baseline 2016 carbon intensity results for gaseous fuels are presented for extraction to processor gate (at consumer) and for extraction to combustion (combusted). All results are expressed in grams of CO_2 equivalents per MJ of fuel (using HHV). Results of the uncertainty analysis are also summarized for each fuel (both at consumer and at combustion) to provide an assessment of the potential variability and range of the study results. Lastly, the Canadian baseline carbon intensity values for 2016 are compared with carbon intensity values from other literature and calculation tools to provide a check on the general accuracy of our calculations.

4.8.4.1 Pipeline Specification Natural Gas

Baseline carbon intensities for Canadian pipeline specification natural gas are summarized in Table 79 and Table 80. Provincial average carbon intensities from cradle-to-processor gate for Alberta and British Columbia pipeline specification natural gas are 16 g CO_2 e/MJ and 8.5 g CO_2 e/MJ, respectively. Natural gas extraction and processing is more carbon-intensive in Alberta due to a number of factors, including significantly greater numbers of operations leading to higher levels of venting and fugitives, the use of associated gas from crude extraction which has the highest GHG emissions per unit of all Western Canadian extraction sources, and reliance on a more carbon-intensive electricity grid to power gas processing facilities.

Table 79. Carbon intensity for pipeline natural gas, provincial average for well to processor gate for Alberta and British Columbia

Resource Type	Input	Unit	Carbon Intensity	Unit
Natural gas, pipeline spec, 2016 baseline {CA-AB}	**1**	**MJ**	**16**	**g CO_2 e**
Natural gas, pipeline spec, conventional	0.217	MJ	3.3	g CO_2 e
Natural gas, pipeline spec, tight	0.536	MJ	9.2	g CO_2 e
Natural gas, pipeline spec, shale	0.014	MJ	0.3	g CO_2 e
Natural gas, pipeline spec, CBM	0.058	MJ	0.7	g CO_2 e
Natural gas, pipeline spec, associated	0.174	MJ	2.9	g CO_2 e
Natural gas, pipeline spec, 2016 baseline {CA-BC}	**1**	**MJ**	**8.5**	**g CO2e**
Natural gas, pipeline spec, conventional	0.226	MJ	1.8	g CO2e
Natural gas, pipeline spec, tight	0.71	MJ	6.2	g CO2e
Natural gas, pipeline spec, shale	0.065	MJ	0.5	g CO2e

The 2016 baseline carbon intensity for Canadian average natural gas is 64 g CO_2 e/MJ. Over 75% of these life cycle emissions are a result of natural gas combustion (50 g CO_2 e/MJ), while upstream extraction and processing account for approximately 22% of life cycle GHG emissions (14 g CO_2 e/MJ).

Table 80. Baseline carbon intensity results for 2016 Canadian average pipeline specification natural gas.

	Input	Unit	Carbon Intensity	Unit
Natural gas at consumer, average {CA}	**1**	**MJ**	**14**	**g CO_2 e**
Natural gas, pipeline spec, 2016 baseline {CA-AB}	0.507	MJ	8.1	g CO_2 e
Natural gas, pipeline spec, 2016 baseline {CA-BC}	0.217	MJ	1.8	g CO_2 e
Natural gas, pipeline spec, imported, 2016 average {US}	0.28	MJ	3.4	g CO_2 e
Transport, gas pipeline	0.0492	tkm	0.2	g CO_2 e
Transmission, gas pipeline non-combustion emissions	0.015	m^3	0.1	g CO_2 e
Geological storage, gas	0.03	m^3	5.0E-05	g CO_2 e
Distribution, gas pipeline non-combustion emissions	0.015	m^3	8.1E-05	g CO_2 e
Natural gas combusted, average process per MJ {CA}	**1**	**MJ**	**64**	**g CO_2 e**
Natural gas, at consumer	1	MJ	14	g CO_2 e
Combustion	1	MJ	50	g CO_2 e

As described in the methods section of the report, uncertainty in the study results was accounted for by assigning distributions to input data based on either known or calculated ranges or use of a pedigree matrix to generate standard deviations. In addition, a “fit for purpose” assessment was done on the background data supporting the input values using a pedigree matrix, and uncertainty was applied to the IPCC characterization factors. The results of the uncertainty analysis for pipeline specification natural gas are summarized in Table 81. The

2.50% heading indicates the interquartile range of uncertainty and the 97.5% heading indicates the 1.5x interquartile range. SD stands for standard deviation and CV is the coefficient of variance.

Results of the uncertainty analysis for natural gas, at consumer showed a relatively tight range on the results of between 14 and 17 g CO_2 e/MJ. For the full life cycle carbon intensity of natural gas, from extraction through combustion, results of the uncertainty analysis showed a slightly larger spread in the possible outcomes, ranging approximately from a low of 57 g CO_2 e /MJ up to a high of 75 g CO_2 e/MJ and mean of 65 g CO2 eq./MJ. Results of the uncertainty analysis for natural gas both at the consumer and at combustion indicated that including uncertainty data on the IPCC characterization factors had a negligible effect on the results.

Table 81. Results of uncertainty analysis on carbon intensity of pipeline specification natural gas, including uncertainty on the life cycle inventory, uncertainty on the characterization factors, and fit for purpose uncertainty on the unit processes modelled.

Impact Category	Unit	Mean	Median	SD	CV	2.50%	97.5%
Natural gas, at consumer							
Uncertainty on inventory and characterization factors							
IPCC GWP 100a	g CO_2 e	15	15	0.7	4.8	14	17
Confidence Interval	95						
Natural gas, combusted, average process per MJ {CA}							
Uncertainty on inventory and characterization factors							
IPCC GWP 100a	g CO_2 e	65	65	4.6	7.1	57	75
Confidence Interval	95						

4.8.4.2 Propane

The 2016 baseline Canadian average carbon intensity for propane is 74 g CO_2 e/MJ (Table 82). Just over 82% of the life cycle GHG emissions are from propane combustion, while the pre-combustion emissions accounted for just under 19% of total emissions. The greatest contributor to upstream emissions was the production of propane from crude and natural gas in Alberta, at over 14% of total emissions.

Table 82. Carbon intensity results for 2016 Canadian average propane. Results expressed relative to 1 MJ of energy from propane at HHV.

	Input	Unit	Carbon Intensity	Unit
Propane, at consumer, average {CA}	**1**	**MJ**	**13**	**g CO_2 e**
Propane, from crude and natural gas, average {CA-AB}	0.84	MJ	11	g CO_2 e
Propane, from natural gas, average {CA-BC}	0.122	MJ	0.4	g CO_2 e
Propane, imported, average {US}	0.037	MJ	0.6	g CO_2 e
Transport, train, diesel	0.0382	tkm	0.7	g CO_2 e
Transport, truck, diesel	0.00547	tkm	0.7	g CO_2 e
Propane, combusted, average process per MJ {CA}	**1**	**MJ**	**74**	**g CO_2 e**
Propane, at consumer	1	MJ	13	g CO_2 e
Combustion	1	MJ	61	g CO_2 e

The results of the uncertainty analysis for propane are summarized in Table 82. The 2.50% heading indicates the interquartile range of uncertainty and the 97.5% heading indicates the 1.5x interquartile range. SD stands for standard deviation and CV is the coefficient of variance. Results of the uncertainty analysis for propane, at consumer showed a relatively wide range on the results of between 10 and 25 g CO_2 e/MJ (Table 83). For the full life cycle carbon intensity of propane, from extraction through combustion, results of the uncertainty analysis showed a slightly greater spread in the possible outcomes, ranging approximately from a low of 66 g CO_2

e/MJ up to a high of 86 g CO_2 e/MJ. Results of the uncertainty analysis for propane both at the consumer and at combustion indicated that including uncertainty data on the IPCC characterization factors increased the uncertainty in the study results slightly, although more pronounced for propane at consumer.

Table 83. Results of uncertainty analysis on carbon intensity of 2016 Canadian average propane, including uncertainty on the life cycle inventory, uncertainty on the characterization factors, and fit for purpose on the unit processes modelled.

Impact Category	Unit	Mean	Median	SD	CV	2.50%	97.5%
Propane, at consumer							
Uncertainty on inventory and characterization factors							
IPCC GWP 100a	g CO_2 e	16	15	3.7	23	10	25
Confidence Interval	95						
Propane, combusted, average process per MJ {CA}							
Uncertainty on inventory and characterization factors							
IPCC GWP 100a	g CO_2 e	75	75	5.3	7.0	66	86
Confidence Interval	95						

4.8.4.3 Compressed Natural Gas

The 2016 baseline Canadian average carbon intensity for CNG is 67 g CO_2 e/MJ (Table 84). Approximately 75% of the life cycle GHG emissions are from CNG combustion, while the pre-combustion emissions accounted for 25% of total emissions. The key differentiating factor between CNG and pipeline natural gas is the additional compression process required prior to use in a vehicle or mobile combustion unit. The carbon intensity of this compression process was based on an average value from the literature, and could vary from this estimate depending on the energy source and efficiency for different compression technologies.

Table 84. Carbon intensity results for 2016 Canadian average CNG.

	Input	Unit	Carbon Intensity	Unit
CNG, at consumer, average {CA}	**1**	**MJ**	**17**	**g CO_2 e**
Natural gas, at consumer	1	MJ	14	g CO_2 e
Compression	1	MJ	3.2	g CO_2 e
CNG, combusted, average process per MJ {CA}	**1**	**MJ**	**67**	**g CO_2 e**
Compressed natural gas, at consumer	1	MJ	17	g CO_2 e
Combustion	1	MJ	50	g CO_2 e

The results of the uncertainty analyses for compressed natural gas are summarized in Table 85. The 2.50% heading indicates the interquartile range of uncertainty and the 97.5% heading indicates the 1.5x interquartile range. SD stands for standard deviation and CV is the coefficient of variance. Results of the uncertainty analysis for CNG, at consumer showed a relatively tight range on the results of between 16 and 22 g CO_2 e/MJ (Table 85). For the full life cycle carbon intensity of CNG, from extraction through combustion, results of the uncertainty analysis showed a slightly greater spread in the possible outcomes, ranging approximately from a low of 62 g CO_2 e/MJ up to a high of 72 g CO_2 e/MJ. Results of the uncertainty analysis for CNG both at the consumer and at combustion indicated that including uncertainty data on the IPCC characterization factors had a negligible effect on the overall uncertainty of the results.

Table 85. Results of uncertainty analysis on carbon intensity of 2016 Canadian average CNG, including uncertainty on the life cycle inventory, uncertainty on the characterization factors, and fit for purpose on the unit processes modelled.

Impact Category	Unit	Mean	Median	SD	CV	2.50%	97.5%
CNG, at consumer							
Uncertainty on inventory and characterization factors							
IPCC GWP 100a	g CO_2 e	19	19	1.6	8.5	16	22
Confidence Interval	95						
CNG, combusted, average process per MJ {CA}							
Uncertainty on inventory and characterization factors							
IPCC GWP 100a	g CO_2 e	67	67	2.4	3.6	62	72
Confidence Interval	95						

4.8.4.4 Liquefied Natural Gas

The 2016 baseline Canadian average carbon intensity for LNG is 75 g CO_2 e/MJ (Table 86). Approximately 66% of the life cycle GHG emissions are from LNG combustion, while the pre-combustion emissions accounted for 33% of total emissions. The key differentiating factor between LNG and pipeline natural gas is the additional processing steps of liquefaction for transport, and then regasification after transport. The carbon intensity of these processes was based on average values from the literature, and could vary from this estimate depending on the energy source and efficiency for different LNG technologies.

Table 86. Carbon intensity results for 2016 Canadian average LNG.

	Input	Unit	Carbon Intensity	Unit
LNG, at consumer, average {CA}	**1**	**MJ**	**25**	**g CO_2 e**
Natural gas, at consumer	1	MJ	14	g CO_2 e
Liquefaction	1	MJ	8.4	g CO_2 e
LNG storage, average	0.0245	m3	4.1E-06	g CO_2 e
Regasification	1	MJ	2.6	g CO_2 e
LNG, combusted, average process per MJ {CA}	**1**	**MJ**	**75**	**g CO_2 e**
Liquefied natural gas, at consumer	1	MJ	25	g CO_2 e
Combustion	1	MJ	50	g CO_2 e

The results of the uncertainty analyses for liquified natural gas are summarized in Table 87. The 2.50% heading indicates the interquartile range of uncertainty and the 97.5% heading indicates the 1.5x interquartile range. SD stands for standard deviation and CV is the coefficient of variance. Results of the uncertainty analysis for LNG, at consumer showed a range on the results of between 23 and 31 g CO_2 e/MJ (Table 87). For the full life cycle carbon intensity of LNG, from extraction through combustion, results of the uncertainty analysis showed a slightly greater spread in the possible outcomes, ranging approximately from a low of 71 g CO_2 e/MJ up to a high of 83 g CO_2 e/MJ. The potential spread in CI value for LNG is slightly greater than for natural gas, due primarily to the uncertainty associated with the liquefaction and regasification processes, for which the data are based on single sources of secondary data. Results of the uncertainty analysis for LNG both at the consumer and at combustion indicated that including uncertainty data on the IPCC characterization factors had a negligible effect on the overall uncertainty of the results.

Table 87. Results of uncertainty analysis on carbon intensity of 2016 Canadian average LNG, including uncertainty on the life cycle inventory and uncertainty on the unit process fit for purpose and characterization factors.

Impact Category	Unit	Mean	Median	SD	CV	2.50%	97.5%
LNG, at consumer							
Uncertainty on inventory and characterization factors							
IPCC GWP 100a	g CO_2 e	27	27	2.0	7.6	23	31
Confidence Interval	95						
LNG, combusted, average process per MJ {CA}							
Uncertainty on inventory and characterization factors							
IPCC GWP 100a	g CO_2 e	77	77	3.1	4.0	71	83
Confidence Interval	95						

4.8.4.5 Comparison with Literature Results

This study represents one of the most recent and comprehensive efforts to quantify the carbon intensity of gaseous fuels in Canada. In effort to provide a check on the results to determine if they are in a reasonable range, we compared the results for all four fuels with a number of literature sources and other GHG emission calculators for fossil fuels (Table 88). The majority of these studies were based on US conditions and operations, with some limited Canadian data.

For pipeline natural gas, the carbon intensities calculated in the present study were well within the range of values cited in the literature, both at consumer (pre-combustion) and at combustion (full life cycle). The US GREET model provides values for pipeline natural gas that are somewhat higher than values from our study, and this is due primarily to their assumption of higher combustion emissions. When stochiometric combustion emissions were used instead of the published GREET values, the life cycle carbon intensity results were much more in line with our study.

Carbon intensity values from the present study for CNG, LNG, and propane were also well within range of several literature values, both at consumer and at combustion.

Table 88. Comparison of carbon intensity values for gaseous fuels from extraction to consumer (pre-combustion) from this study with literature

Fuel	This Study	NETL (U.S.)	Littlefield et al. (U.S.)	GHGen-ius	BC RLCF	ICF (U.S.)	Sapkota et al. (Can)	GREET (U.S.)	GREET (U.S.)	GREET (U.S.) *
At consumer										
Natural gas	14	15	14			14-15		14		
Propane	13			11				17		
CNG	17			13				20		
LNG	25						25-34	*15*		
At combustion**										
Natural gas	64	63	62			62-63			70-79	64
Propane	74			72	64				74	
CNG	67			61					77	70
LNG	75				75		76-86		80	75

**GREET values in this column are shown with stoichiometric combustion values instead of the default GREET values for combustion. **Combustion values were not available for NETL, Littlefield et al, and GHGenius, so the combustion values for each fuel from the present study were added to the published "at consumer" values to get an estimate of the full life cycle carbon intensity.*

4.8.5 Data Gaps and Limitations for Carbon Intensity of Canadian Gaseous Fuels

In compiling the LCI and calculating the Canada average carbon intensity of gaseous fuels, a number of data gaps and limitations were identified to inform future research and model updates.

- **LCI Data on Natural Gas Extraction** – LCI data and assumptions on emissions management (i.e. venting and flaring) for natural gas extraction in this study were derived primarily from literature sources, with some primary data collected on Canadian operations in Alberta. Data collection from British Columbia and Alberta natural gas extraction facilities at the unit process level could improve the representativeness of the baseline carbon intensity modelling.
- **Fugitive Emissions** – Estimates of fugitive emissions from natural gas extraction and processing were based primarily on literature values, with some primary data on equipment counts and leakage rates from Alberta. More recent studies have indicated that fugitive emissions from upstream oil and gas activities have historically been underestimated. More field-level research and/or better data from producers on fugitive emissions could improve the representativeness of the baseline carbon intensity modelling.
- **Mass Balance for Midstream Activities** – Data on the inputs and outputs of Canadian natural gas gathering and processing are limited, and the best available data used in this study were from 2011 operations. Unit process level data on the composition and amounts of natural gas moving from well head to processor would improve this, as would more detailed data on the product slates (i.e. marketable gas, NGLs) and energy use and emissions for processing facilities. The development of a calculation tool like PRELIM for natural gas processing could potentially facilitate improvements in this respect.
- **Data for British Columbia** – There are a number of instances in the calculation of baseline carbon intensity for natural gas where data and information for Alberta were assumed to be representative of British Columbia operations due to a lack of data on BC natural gas systems. The representativeness of the results could be improved if more data on BC natural gas operations was collected. In some instances, the required data may already be compiled by the BCOGC but may not be publicly available.
- **LCI Data for CNG and LNG** – Markets for CNG and LNG are still under development in Canada but are expected to grow in the near to medium term. The collection of data on the production and use of CNG and LNG in Canada, including inputs and emissions for the additional processing steps required, and on the transmission of these fuels to end users in Canada, could help to improve the accuracy of the baseline carbon intensity values in the future.

4.9 Common Transport Modes

Trucks, trains and tanker ships move many different fuels and are integral to the life cycle of most of the fuels modeled here.

4.9.1 Train transport model

Trains are used to transport coal, petcoke, and some refinery products. As the train's diesel consumption is directly related to the mass transported and the distance traveled, the model uses units of tkm (metric tonne*kilometers) so it can be used in any fuel pathway. The method used in Nimana et al. (Nimana et al. 2017) to calculate the diesel consumption per km, is a straightforward way to assess the impacts of train transport of fuels in Canada. Statistics

Canada has data on the amount of freight transported, the distance traveled, and the diesel consumed for 2016 and other years (Statistics Canada 2016b) (Statistics Canada 2017). 1,803,872,000 liters of fuel were consumed for freight transport in 2016. A total of 395,888,969,000 tkm of paid freight were transported in that year resulting in an average of 0.00456 liters per tkm of freight. This value takes into consideration average loading, therefore, there is no need to take an empty return trip into consideration. The US EPA Office of Transportation and Air Quality provides an approximate value of 400 ton-miles per gallon or 0.0065 liters/tkm for 2009 (US EPA 2009). 2007 data from the Association of American Railroads provides an average of 436 ton-miles per gallon (0.0059 liters/tkm) and a high of 518 ton-miles per gallon (0.0050 liters/tkm) for Canadian Pacific Railroad operations in the US (Jackson 2008). GHGenius uses values for 2013 of 0.00514 liters/tkm for Canada and 0.00559 liters/tonne km for the US. GREET uses a value of 0.0051 liters/tkm.

Table 89: Comparison of energy requirements for train transport model with similar models.

Function	This Study	US EPA (US EPA 2009)	Association of American Railroads (Jackson 2008)	GHGenius	GREET
Liters of diesel required to transport one tonne of material one kilometer	0.00456 l/tkm	0.0065 l/tkm	0.0050-0.0059 l/tkm	0.00514 l/tkm (Canadian) 0.00559 l/tkm (US)	0.0051 l/tkm

Considering the apparent annual efficiency increases indicated from the Statistics Canada data shown in Table 90 and the better performance by Canadian shippers indicated by GHGenius, the calculated value is in line with other published values.

Table 90: Canadian freight train fuel consumption by year

	2012	2013	2014	2015	2016
Diesel, Freight (1000 liters)	1,954,550	1,922,153	1,992,089	1,926,893	1,803,872
Revenue freight (1000 tkm)	371,074,437	386,132,246	415,461,717	411,812,880	395,888,696
calculated liters/tkm	0.00527	0.00498	0.00479	0.00468	0.00456

Source: Statistics Canada 2016b.

Calculation details can be found in *Freight train diesel consumption 2016.csv*.

Table 91: Energy use and emissions for train transport, expressed per tkm of transport

Exchange	Quantity	Unit	Description
Outputs			
Transport, train, diesel {CA}	1	Tkm/tkm	
Fugitive emissions			

Inputs			
Combustion, Diesel {CA}	0.00456	Liters	

4.9.2 Truck transport model-long haul large vehicles

Trucks are used to transport coal, petcoke, and some refinery products. As the truck's diesel consumption is directly related to the mass transported and the distance traveled, the model uses units of tkm (metric tonne*kilometers) so it can be used in any fuel pathway. Statistics Canada stopped collecting data on truck fuel use in 2009. The North American Council for Freight Efficiency (NACFE) provides annual statistics on North American truck fleets (NACFE 2017). According to the annual report from 2017, in 2016, 4% of all fleets had adopted CNG fuel. Average fuel efficiency is 7.11 mpg (3.02 km/liter). Truck transport fuel consumption is modeled using the 2016 fuel efficiency from NACFE and 9250 kg average mass and 473 km average distance of 2016 domestic shipments from Statistics Canada to provide a fuel consumption of 0.0358 liters per tkm.

$$\frac{1}{3.02\ \text{km/liter} \times 9.25\ \text{tonnes}} = 0.0358\ \text{liters/tkm.}$$

While Canadian GHG limitation regulations affect new vehicle sales, not all vehicles utilized in a given year will be of the same model year, limiting the utility of the regulation for predicting GHG emissions or fuel use. Statistics Canada provides total freight tonne·km (Statistics Canada 2016a), and Transport Canada provides data on diesel for road transport (Transport Canada 2018), however, the fuel use is not broken down between passenger cars, trucks and bus fleets, therefore it is not possible to do a top down inventory. The National Inventory Report provides 2016 emissions for the heavy duty diesel vehicles used to transport fuels as 45,800 kt CO_2 e (ECCC 2018d). This was calculated using the values from the ECCC unpublished report Updated CO_2 Emission Factors for Gasoline and Diesel Fuel of 2680.5 kg CO_2/m^3 (Tobin 2017). Unfortunately, the Statistics Canada data cannot be broken down in the same way.

These results are well within the expected results for trucking as can be seen in Table 92.

Table 92: Comparison of energy requirements for truck transport model with similar models.

Function	This Study	GHGenius	GREET	Ecoinvent (Weidema, et al., 2013)
Liters of diesel required to transport one tonne of material one kilometer	0.0358 l/tkm	0.0516 l/ tkm	0.0236 l/tkm	0.0226- 0.231 l/tkm

Table 93: Energy use and emissions for truck transport, expressed per tkm of transport

Exchange	Quantity	Unit	Description
Outputs			
Transport, truck {CA}	1	Tonne-km	
Fugitive emissions			
Inputs			
Combustion, Diesel	0.0358	Liters	

4.9.3 Tanker ship energy use and emissions

A very small amount of crude is transported via tanker ship within Canada, primarily from offshore sites. Much of the Canadian crude imports are through tanker transport. The Canadian Coast Guard has provided data for actual 2016 crude shipments within Canada and imported into the country (see Appendix D. Canada's 2015 National Marine Emissions Inventory Tool (MEIT)). These data were analyzed and while there was significant variability in both the distance traveled and the efficiency and emissions, they reflect actual practice. Even so, several outliers were omitted from the data, such as a six km trip from one berth to another that lasted for five days.

Average fuel use for crude imports was 0.0637 MJ/tkm with a standard deviation of 0.099 MJ/tkm. Emissions were of 4.78 g CO_2/tkm, 2.45 g CH_4/tkm and 1.73 g N_2O/tkm with similarly large standard deviations. Shorter hauls were more intensive with average fuel use of 0.816 MJ/tkm and a standard deviation of 0.99. Table 94 compares these values with other models, indicating that imports are in a similar range to the values used elsewhere, but that the offshore, shorter hauls have lower efficiency than has been captured before.

Table 94: Comparison of energy requirements for tanker transport model with similar models.

Function	This Study (Imports, International)	This Study (Offshore, Coastal)	Shipping Federation of Canada	GHGenius	GREET
MJ fuel required to transport one tonne of material one kilometer	0.0637 MJ/tkm, std dev 0.099	0.816 MJ/tkm, std dev 0.99	0.164 MJ/tkm	0.06 MJ/tkm	0.133 MJ/tkm

Table 95: Energy use and emissions for International tanker ship transport, expressed per tkm of transport

Exchange	Quantity	Unit	Uncertainty
Outputs			
Transport, tanker ship, diesel {CA}	1	tkm	
Carbon dioxide, fossil	4.78E-6	t	Normal distribution with std dev 7.4E-6
Methane, fossil	2.45E-10	t	Normal distribution with std dev 5.4E-10
Nitrous oxide	1.73E-10	t	Normal distribution with std dev 2.3E-10
Inputs			
Diesel, combustion average process per MJ {CA}	0.0637	MJ	Normal distribution with std dev 0.099

Table 96: Energy use and emissions for Coastal tanker ship transport, expressed per tkm of transport

Exchange	Quantity	Unit	Uncertainty
Outputs			
Transport, tanker ship, diesel {CA}	1	tkm	
Carbon dioxide, fossil	6.12E-5	t	Normal distribution with std dev 7.5E-5
Methane, fossil	4.02E-9	t	Normal distribution with std dev 5.9E-9
Nitrous oxide	1.89E-9	t	Normal distribution with std dev 2.1E-9
Inputs			
Diesel, combustion average process per MJ {CA}	0.816	MJ	Normal distribution with std dev 0.99

4.10 Combustion

Emission factors and HHVs for combustion of fuels were provided by ECCC and originally sourced from the latest available data from Canada’s National Inventory Report. Through personal communication with a Canada NIR representative, ECCC was provided with 2016 emissions factors in g/L and HHVs in MJ/l for the relevant liquid fossil fuels. These combustion emissions factors were based on an average of the most commonly-used combustion technologies for each fuel, which for liquid fuels is for the transport sector. More detailed data and calculations for the combustion emissions factors are summarized in the Combustion Emissions Workbook which is provided as an appendix to this report along with the relevant data sheets. The determination of emissions factors generally consisted of estimating the ratios of the main sectors/end users for liquid fossil fuels, linking between a given sector/end user and an emission factor (or group of emissions factors), and calculating a weighted average emissions factor for each fossil fuel. For other fossil fuels (i.e. gaseous and solid fuels), the Canada NIR representative provided 2016 emissions factors and HHVs and the emissions factors were selected from these data for the most common end use. In the case of coal, there are both multiple sources of coal with different GHG emissions factors and multiple GHG emissions factors for different types of combustion methods for coal. A summary of the combustion emissions factors for coal are provided in more detail in Table 62 in Section 4.7.7.2.

As the emissions factors data are presented per volume of fuel, additional data on the densities and heating values of each fuel were used to convert to GHG emissions per low and high heating value of fuel. The individual emissions per gas are presented in table Table 97. Note that another name for stove oil is No. 1 heating oil which has the same characteristics as kerosene. Since CNG and LNG are compressed forms of natural, they were assumed to have the same emissions as natural gas. Emissions factors for gaseous fuels were converted to mass using the density of natural gas and its HHV. Densities and HHVs of the fossil fuels are presented in Table 98. The primary source for these data is the Canada NIR data provided by ECCC, and these are supplemented with data from GREET 2018 and The University of Brimingham, UK Energy and Fuel Data Sheet (ANL, 2018; ECCC, 2018d; Staffel, 2011). The combustion emissions used in calculating the final fossil fuel CIs, as well as points of comparison and benchmarking, are shown in Table 99.

Table 97: Summary of GHG emissions factors for fossil fuels used to calculate carbon intensity (Source: Canada NIR 2019).

Fuel	CO_2	Unit	CH_4	Unit	N_2O	Unit	CO_2e*	Units
Gasoline	2,307	g CO_2/L	0.516	g CH_4/L	0.118	gN_2O/L	2,354	gCO2e/L
Diesel	2,681	g CO_2/L	0.106	g CH_4/L	0.213	gN_2O/L	2,568	gCO2e/L
Aviation Fuel	2,560	g CO_2/L	0.022	g CH_4/L	0.071	gN_2O/L	2,579	gCO2e/L
HFO	3,156	g CO_2/L	0.143	g CH_4/L	0.070	gN_2O/L	3,179	gCO2e/L
LFO	2,753	g CO_2/L	0.031	g CH_4/L	0.012	gN_2O/L	2,757	gCO2e/L
Kerosene	2,560	g CO_2/L	0.009	g CH_4/L	0.028	gN_2O/L	2,568	gCO2e/L
Stove Oil	2,560	g CO_2/L	0.009	g CH_4/L	0.028	gN_2O/L	2,568	gCO2e/L
Natural Gas	1,938	g CO_2/L	0.037	gCH_4/L	0.033	gN_2O/L	1l948	gCO2e/L
CNG	1,938	g CO_2/L	0.037	gCH_4/L	0.033	gN_2O/L	1l948	gCO2e/L
LNG	1,938	g CO_2/L	0.037	gCH_4/L	0.033	gN_2O/L	1l948	gCO2e/L
Propane	1,515	g CO_2/L	0.024	g CH_4/L	0.108	gN_2O/L	1544	gCO2e/L
Petcoke	3,778	g CO_2/L	0.12	g CH_4/L	0.027	gN_2O/L	3789	gCO2e/L

*IPCCAR5 GWP 100

Table 98: Fossil fuel heating values and densities

Heating Values and Densities	LHV	Units	HHV	Units	Density	Units
Gasoline	43.5	MJ/kg	44.7	MJ/kg	2,836	grams/gal
Diesel	42.8	MJ/kg	45.3	MJ/kg	3,206	grams/gal
Aviation Fuel	43.3	MJ/kg	47.2	MJ/kg	2,998	grams/gal
Heavy Fuel Oil	39.0	MJ/kg	43.4	MJ/kg	0.98	[kg/l]
Light Fuel Oil	38.4	MJ/kg	40.4	MJ/kg	0.96	[kg/l]
Kerosene	43.1	MJ/kg	47.1	MJ/kg	0.8	g/cm3
Stove Oil	43.1	MJ/kg	47.1	MJ/kg	0.8	g/cm3
Natural Gas	47.1	MJ/kg	52.2	MJ/kg	22	gms/ft3
Compressed Natural Gas*	47.1	MJ/kg	52.2	MJ/kg	**	**
Liquified Natural Gas*	47.1	MJ/kg	52.2	MJ/kg	**	**
Propane	46.3	MJ/kg	50.2	MJ/kg	1,920	grams/gal
Petcoke	29.5	MJ/kg	33.1	MJ/kg	1400	kg/m3

*At 1atm and 32F

**Does not apply by volume, only by mass

Table 99: Fossil fuel combustion emissions

Comparison to other sources	LHV	HHV	ECCC Interim Baseline Values	ECCC 2018d	Energy and Fuel Data Sheet	Units
Gasoline	73.2	70.4	68.7	71.7	70.8	gCO_2e/MJ
Diesel	75.8	71.5	74.2	71.7	74.3	gCO_2e/MJ
Aviation Fuel	75.3	69.0	74.2	74.3	-	gCO_2e/MJ
Heavy Fuel Oil	83.4	74.8	75.2	75.2	-	gCO_2e/MJ
Light Fuel Oil	74.8	71.1	71.8	71.2	-	gCO_2e/MJ
Kerosene	75.0	68.1	68.2	68.1	72.0	gCO_2e/MJ
Stove Oil	75.0	68.1	-	-	-	gCO_2e/MJ
Natural Gas	53.2	48.0	-	46.9	56.9	gCO_2e/MJ
Compressed Natural Gas	53.2	48.0	-	-	-	gCO_2e/MJ
Liquefied Natural Gas	53.2	48.0	-	-	-	gCO_2e/MJ
Propane	66.5	60.5	-	-	-	gCO_2e/MJ
Petcoke	91.9	81.7	-	84.5	-	gCO_2e/MJ

4.11 Quantifying Data Quality and Uncertainty

In practice, all data used in an LCA or life cycle carbon intensity study is a mixture of measured, estimated and calculated data. To evaluate the quality of the data used for modelling the fuel pathways, Data Quality Indicators (DQI) are used to assess each flow and linked pathway using a data quality matrix approach. These scores are also used to assess uncertainties on the data and subsequently assess the uncertainty of the model and the results.

Accounting for uncertainty is an important aspect in development of the Fuel LCA Modelling Tool because this information provides appropriate context for decision-making when evaluating the potential carbon intensity of alternative fuel pathways, and because it influences the modelling process itself. The Conceptual Model was developed to include uncertainty analysis capabilities for input values, modelling choices, and uncertainty propagation and interpretation. For advanced users aiming to inform policy decisions, uncertainty information can be particularly helpful in identifying a preferred fuel pathway among several options in a way that is transparent and can be justified. This can include comparative decisions among different available pathways, or to compare potential variations in carbon intensity for a single pathway in order to define regulatory targets.

The model distinguishes between two types of uncertainty: parameter and model. Parameter uncertainty is the uncertainty concerning input values. In the case of LCA models, this refers to the amount of a flow. For instance, uncertainty on the number of kWh of electricity required in a certain fuel conversion process, or uncertainty in the amount of carbon emitted during combustion of a fuel. The uncertainty in inventory data can derive from a lack of knowledge of a certain system, or from variability. Uncertainty in combustion emissions, for instance, may be from differences in engine technology, processing facilities, and/or atmospheric temperatures on the day of the emissions measurement. The more variability the inventory can reflect, the less uncertainty there is, although this also makes the results less generalizable. For example, consider the inventory for a certain crop for which production and yield can vary depending on the soil type and farming practices. An average inventory on a per kg basis of harvested crop would combine the range of inputs representing the different soil types and farming practices. The uncertainty in such an inventory is partially due to this variability. Another approach is to create several versions of the inventory to account for both sources of variability: soil type and farming practices. In the case of four different soil types and five different farming practices, one could have twenty different processes.

Further parameter uncertainty has been applied to the fit for purpose of the underlying data. This takes into account the use of data which are not ideal because they come from a different geographic location, time period, or technology. Often the life cycle inventory is derived from multiple studies where the most representative and generalizable inventory is obtained from a combination of information. Therefore, an LCA model, for pragmatic reasons, must balance variability so that the inventory is representative enough and applicable. Uncertainty due to lack of knowledge is included as parameter uncertainty.

The uncertainty of the fossil fuel pathway parameters has been modeled in one of two ways as shown in the decision trees in Appendix B of the Milestone 1 report (EarthShift Global, WSP, Introspective Systems 2019). Where a range of values is available based on different refineries, reports, or calculations, the full range is used using a uniform distribution. Where a range is not known, the pedigree matrix is applied as a Bayesian method of assessing probability.

The exception to this hierarchy is the modelling of the liquid pipelines where an actual distribution was available. In this case, a lognormal distribution was applied with a geometric standard deviation as calculated from the various pipelines.

Uncertainty data for combustion emissions factors was either derived from data in the Canada NIR or calculated in the absence of NIR data. For fuels where emissions factors were provided for a range of technology types (e.g. different types of gasoline vehicles), a minimum and maximum emissions factor for each GHG (i.e. CO2, CH4, N2O) was obtained by taking the high and low values in the table of emissions factors for that technology type. Values for marine transport, rail transport, and off-road transport were excluded from this process due to the significant difference in magnitude. In instances where these high and low emissions factors were not available, we calculated a minimum and maximum emissions factor by applying a +/- range of 2.5% for a uniform distribution. The uncertainty parameters for combustion emissions are provided in the Combustion Emissions Workbook, which is provided as an appendix to this report, as well as in the relevant data sheets.

Uncertainty was also applied to the IPCC characterization factors to determine the influence on the overall study results. Minimum and maximum values for characterization factors were obtained from the IPCC AR5 report (IPCC 2013, Appendix 8A, Table 8A1*)*. The ranges for uncertainty on characterization factors are provided in the appendix of the Milestone 1 report (EarthShift Global, WSP, Introspective Systems 2019).

5. Interpretation

5.1 Interpretation

This is the first comprehensive, transparent study of Canadian fossil fuels to be conducted which includes uncertainty in the calculation of carbon intensity. It includes detailed modelling of Canadian crude oils and 13 Canadian refineries, spanning the breadth of technology used in Canada. Where facility specific data were not available to create unit process level inventories, in most cases actual annual composite Canadian data were used. Uncertainty has been applied at the unit process level to quantities of inputs, emissions and products as well as to the fit for purpose of the underlying data, and at the impact level to the characterization factors.

The results presented align well with publicly available data from Canada, the US and elsewhere. The uncertainty of the results may be surprising to some readers as the variability of outputs from refineries is much higher than many studies have represented. While the study points out a number of areas where filling data gaps would reduce the uncertainty, this variability from refinery to refinery is not likely to decrease over time. Uncertainty in the impact categories had minimal impact on the results.

5.2 Data Quality

Data quality indicators include reliability, completeness, temporal representation, geographical representation and technical correlation of the underlying data used in the model to the reality of the system. Indicators of data quality are presented in Table 100.

Table 100: Data Quality Assessment

Data Quality Requirement	Explanation
Temporal coverage	Data were collected from various sources as noted in previous sections of this report. Every effort was made to ensure that these data represented 2016 conditions. The electricity carbon intensities provided by ECCC represent 2016 and some of the data in the natural gas modelling represent years preceding 2016, such as the 2011 data from Clearstone which were used to model natural gas processing (as noted in the natural gas pathway documentation). Inventory data for coal extraction are also several years older than 2016 and the temporal coverage could be improved with more recent data. Data represent one full year of production. Therefore, temporal coverage is considered to be adequate for all inventory data.
Geographical coverage	The primary data collected for this study represent Canadian operations with adequate coverage of regional and provincial activities such as extraction, preprocessing and refining. Geographic coverage is generally considered to be adequate for all inventory data. Although much of the inventory data and emissions factors used to model natural gas extraction and processing were representative of Canadian conditions, some key data points for natural gas extraction were derived from Skone et al. (2016) and are based on US average conditions.
Technology coverage	The technologies used in modern Canadian extraction, preprocessing, transportation, refining, blending and combustion of fuels are reflected in this study. It is worth noting that this is a snapshot in time representing these technologies as they existed in 2016 as technologies in this space evolve and improve over time. As such, the technology coverage is considered to be good for the inventory data used in this study.
Precision	Since the primary data for modelling were based on primary information collected from actual reported Canadian data and, for most processes, these data were available for technologies, energy and material inputs and associated activities, precision is considered to be high. No measured data were collected, therefore, variability and precision associated with measurement devices cannot be assessed.
Completeness	All material flows were modeled with either primary or secondary data and checked for mass and energy balance. Therefore, data completeness is considered to be sufficient for this study.

	The study does not include the evaluation of additional impact categories (e.g., other impacts to water and air quality), which may limit the utility of the results in driving internal decision making. Additionally, this study does not include the evaluation of toxicity impacts, such as the indicators human toxicity (cancer and non-cancer) and ecotoxicity, because the precision of the current LCA characterization factors are within a factor of 100 to 1,000 (Rosenbaum, et al., 2008). While this is a substantial improvement over previously available toxicity characterization models, it is still significantly higher than that of other impacts addressed in this study. Also, given the limitations of the characterization models for each of these factors, toxicity results should not be used to make any comparative assertions, and this is a comparative analysis.
Representativeness	All material and energy inputs were modeled using primary data sources for Canada in 2016 where available. Additional data sources were used according to the data quality preferences hierarchy in the section above. In this way, the data largely reflect Canadian operations on 2016 for pathways modeled. Note that the electricity carbon intensities were from 2015 and some data for natural gas modelling are also from years preceding 2016 (as noted in the natural gas section) Therefore, representatives is considered to be adequate for this study.
Consistency	All secondary data are considered to be internally consistent as they have been modeled according the same modelling principles and guidelines stated in this report. For this study, every effort was made to include all the relevant flows associated with the fuel pathways studied. A 1% mass and energy-based cut-off was considered in the analysis to account for catalysts and other materials of small quantity. Therefore, consistency is generally considered to be adequate. Although the secondary sources used were considered to be internally consistent, there are limitations with relying on a mixture of secondary sources in terms of relative consistency. For example, there are inconsistencies with the modelling approach between the study which produced the emissions factors for Canadian electricity and this study.
Reproducibility	While all data used in this study are publicly available, some data sources, such as those from AER and Wood Mackenzie, require purchase and, therefore, may not be accessible for the purposes of reproducibility of this study. Still, every effort has been made to document inputs and assumptions used in modelling these pathways to ensure reproducibility of the results without access to the primary data. If a hypothetical study team were to purchase the same data in addition to the free data used in this study, the methodology description in this report would be a sufficient guideline to reproduce the results presented herein. Therefore, reproducibility is considered to be good.
Sources	Sources for data in this study are extensive and documented throughout this report, in the references section and in Appendix A on data source summaries.
Uncertainty	Input uncertainty and data variability were assessed to be moderate and model precision assessed to be good. The major source of variability and uncertainty in the study are data gaps in extraction, preprocessing, refining and transport as noted throughout the report. Uncertainty analysis was performed on all inventory data and the results of this analysis are discussed in the section on uncertainty.

While every effort was made to develop complete models for each fuel pathway, this work represents the first step towards development of a comprehensive database and model of carbon intensity for Canadian fossil fuels. A large number of pathways have been modeled at a relatively high level of detail within a short period of time; however, the level of completeness for the present work is not comparable with established commercial and institutional databases and tools for modelling the carbon intensity of fuels. These other tools (e.g. GREET) and databases (e.g. ecoinvent) have been developed and refined over many years, and include GHG emissions from a number of life cycle activities that are not included in the present iteration of the Fuel LCA Modelling Tool for fossil fuels (e.g. infrastructure, chemical and material inputs, wastewater treatment, etc.).

In terms of consistency, there are limitations associated with the reliance on a number of different independent studies to develop the inventory and CI calculations for this study. There are relative inconsistencies between these background studies which could influence the overall consistency of the modelling and the reliability of the results. This is particularly the case for natural gas, where background data on venting, flaring, and other supply chain emissions were derived from a combination of studies from different geographic regions and different time periods. The level of consistency should be an area targeted for improvement in future updates of the Fuel LCA Modelling Tool.

5.2.1 Uncertainty

As indicated above, uncertainty was applied to the amounts and fit for purpose of input and emissions data either using the variability in the process or using the pedigree matrix described in the Milestone 1 report (EarthShift Global, WSP, Introspective Systems 2019). Uncertainty was also applied to the characterization factors based on the IPCC 2013 report as shown in Appendix F of the Milestone 1 report.

Uncertainty of the Life Cycle Inventory

The results of the uncertainty assessment are illustrated in the violin plots below for the CTCG CI (Figure 23) and CTC CI (Figure 24). These include uncertainty from the inventory data alone. Each “violin” can be seen as a probability density curve which is mirror imaged. The width of the violin at a given value is proportional to the probability of that value; values in the widest portions of the violin are more probable than those in the thin tails of the distribution. There is a 90% probability the value lies within the lighter, outer envelope, while the darker core shows the 50% confidence limit.

The CIs are highly concentrated around the median CI value, as indicated by the shape of the distribution of the uncertainty in the violin plots. This indicates that the sources of uncertainty in the analysis do not cause the results to stray far from the median calculated value.

The upstream, or “at consumer” uncertainties are notably lower for coal, petcoke, and gaseous fuels relative to liquid fossil fuels. This is due primarily to the more complex modelling required for crude extraction and refining, which provide greater opportunity for variability in the results. For fuels at combustion, the spread around the mean is generally greater for all fuels, and most notably for coal, which is due to the high level of uncertainty for coal combustion emissions. These emissions are heavily dependent upon the type of coal combusted and on the performance of the combustion device, which has not been modeled specifically in this analysis, resulting in a higher level of uncertainty. Further discussion of uncertainty analysis results for specific pathways is provided in each fuel pathway sub-section in Section 4.

In general, transport is considered one of the most uncertain portions of a pathway as it can be affected by everything from weather patterns to import tariffs. Efficiency measures also change the impacts of transport on an annual basis as discussed in the sections above. Further, the type of vehicle can affect the impacts. The quality of the data available for each of the transport methods and the application of those methods have been applied using either a range as described in the sections above or the pedigree matrix.

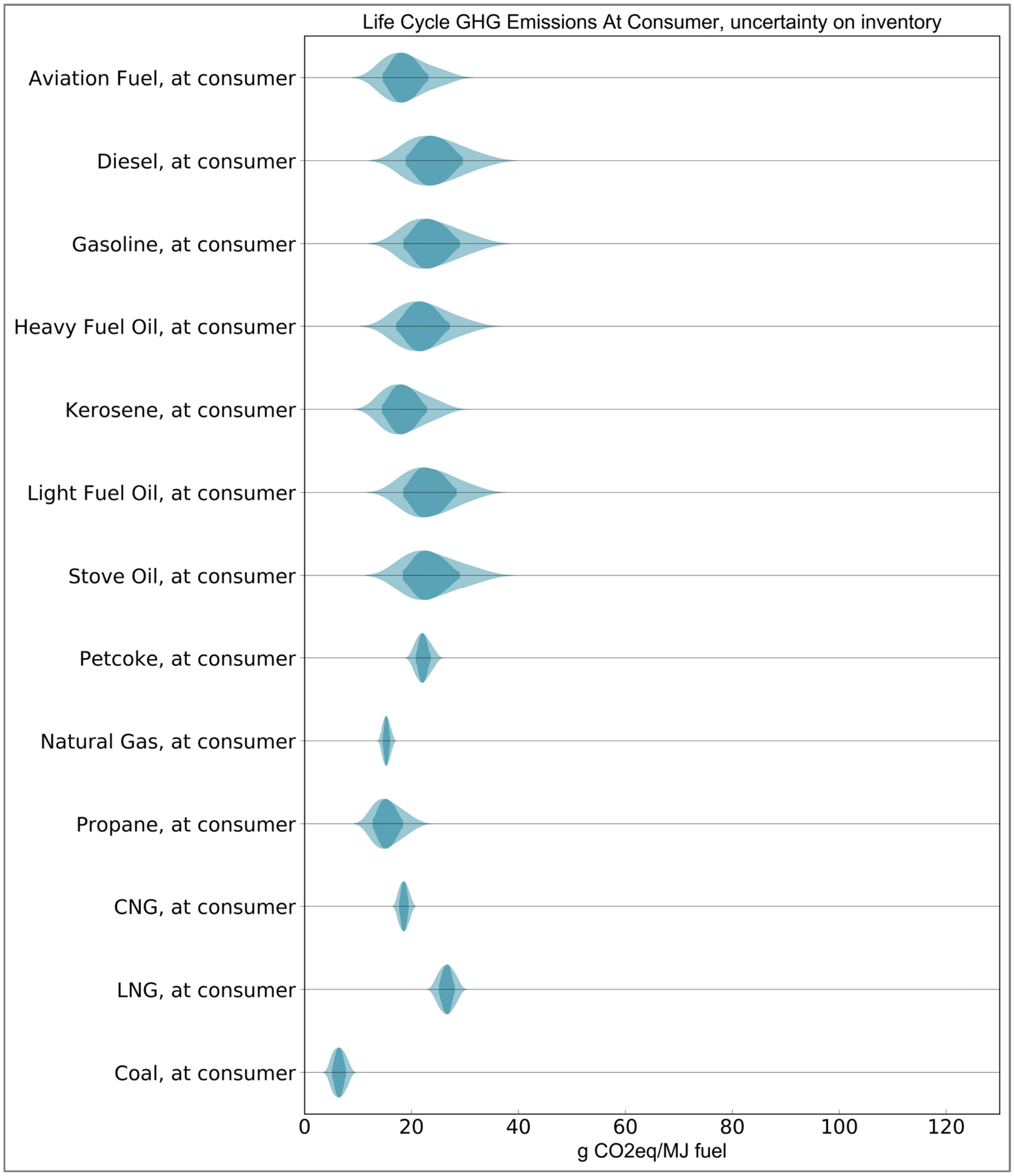

Figure 23: Uncertainty results for CI of fuels at consumer with uncertainty applied to the life cycle inventory.

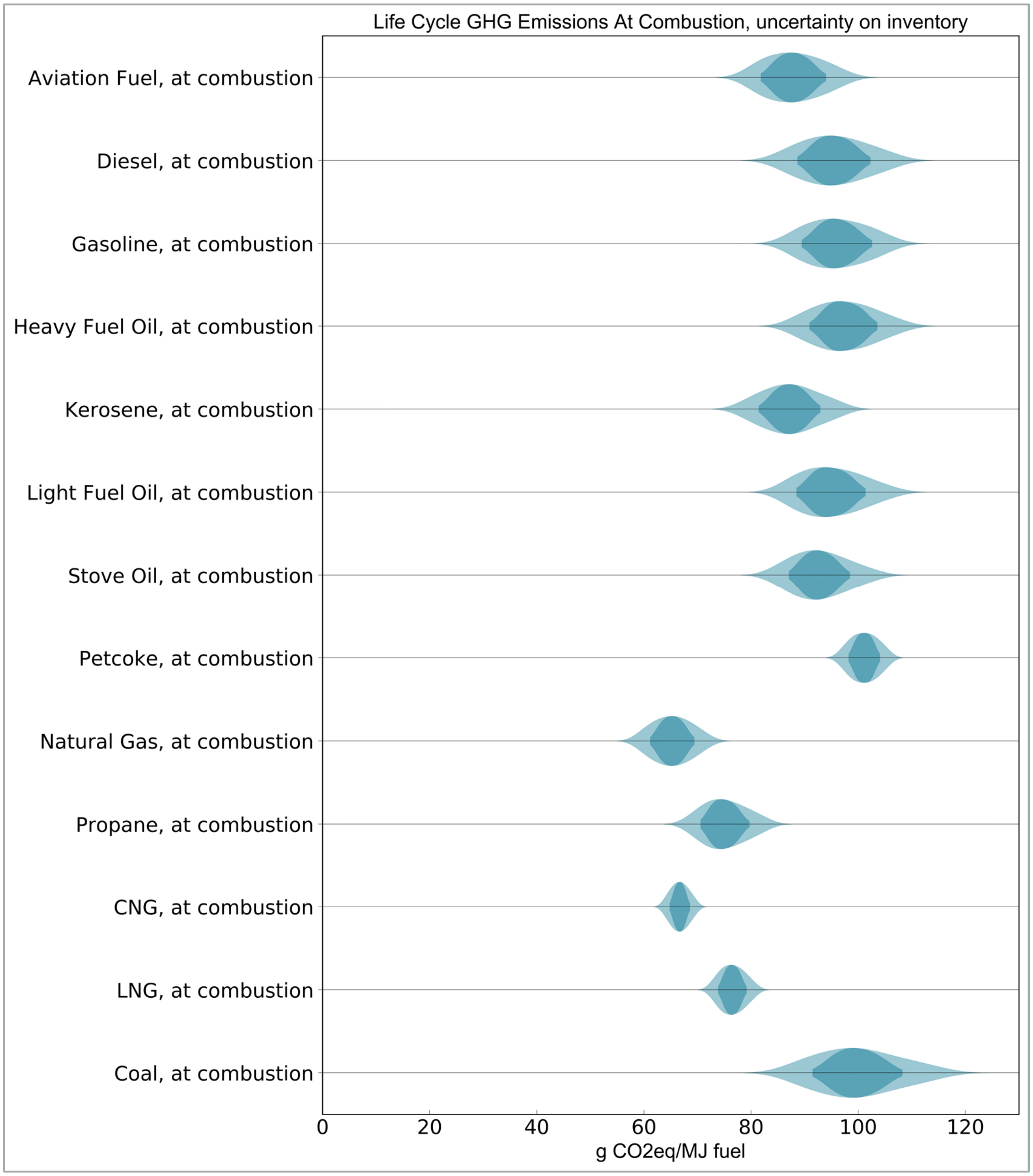

Figure 24: Uncertainty results for CI of fuels at combustion with uncertainty applied to the life cycle inventory.

Uncertainty of the Life Cycle Inventory and characterization factors

In this second set of violin plots in Figure 25 and Figure 26 we provide results with uncertainty applied to both the life cycle inventory and to the characterization factors used to calculate the CI. The uncertainty ranges applied to the characterization factors are from the IPCC AR5 (IPCC 2013 – Appendix 8A, Table 8A1).

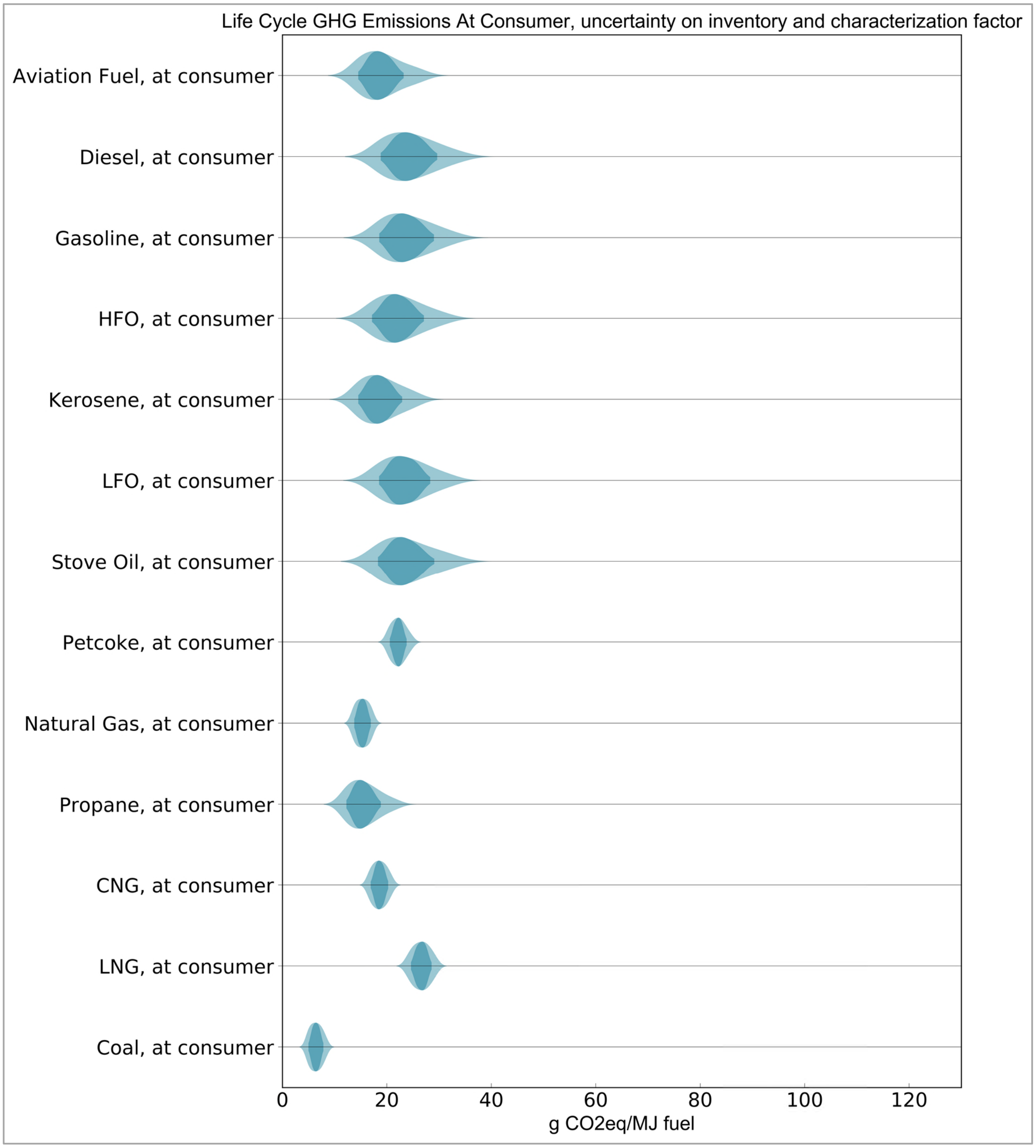

Figure 25: Uncertainty results for CI of fuels at consumer with uncertainty applied to both the life cycle inventory and carbon intensity characterization factors.

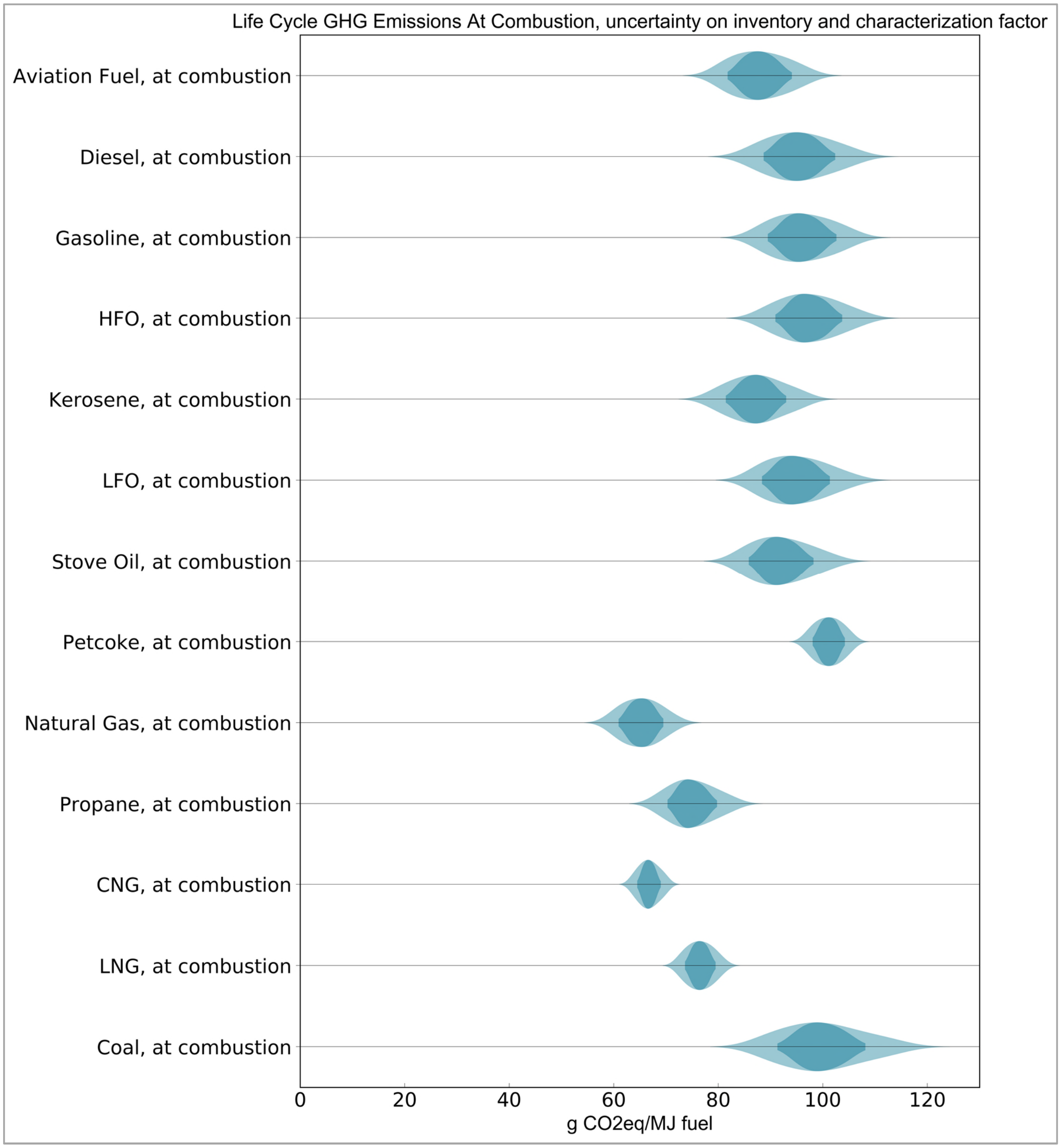

Figure 26: Uncertainty results for CI of fuels at combustion with uncertainty applied to both the life cycle inventory and carbon intensity characterization factors.

Despite natural gas being the pathway most sensitive to uncertainty in characterization factor (because of the share of methane emissions is highest for it), the final CV for the natural gas pathway varies little in response to the inclusion of uncertainty on the methane characterization factor. While the IPCC report (Table 8.A.1 beginning on page 731) provides +/- 40% uncertainty the on the methane characterization factor, the natural gas CV with uncertainty on the characterization factors increased by only about 1% over that with uncertainty only on the inventory.

The small change in the CV for natural gas arises from three factors. First, that CO_2 is the dominant emission and that the uncertainty on the CO_2 characterization factor from IPCC is 0 (fixed value), with small uncertainties on other characterization factors; second, that the CV with uncertainty on the inventory alone is already reflective of the high uncertainty of the methane inventory (and underlying/associated inventories). Finally, that the role of the methane in the CI mitigates the influence of the methane CF uncertainty. Methane contributes about 12% of the total CI, and the additional uncertainty is scaled by that amount. Taking three standard deviations from the mean as a reasonable estimation of the value at the extrema, the 40% variation is approximately 13% (40%/3), so that the additional contribution to the final CV is only about 1.5% (12%*13%).

5.2.2 Limitations

As with any study, there are limitations in the application of the results of this study. For this study, since only one impact category of environmental impact was considered, the interpretation of these results is limited to discussion only of GHG emissions impacts from fossil fuel production and use on the environment. Statements on the holistic impact of fossil fuels on the environment should not be made based on these results. The results also apply only to the perspective of an attributional allocation based on high heating value. Other allocations and perspectives may produce different results. Data are being gathered to allow other allocation methods to be available in the tool when is it completed.

Application of interpretation of these results should note that this study is a snapshot in time. With time, technologies, markets and supply chains will shift which will inevitably alter the carbon intensities of the consider fossil fuel pathways. Data gaps identified throughout this study introduce some limitations in the applicability of the results and comparability with reported GHG emissions, though efforts have been made to explain and rectify discrepancies between reported and calculated emissions. Finally, the models used in this analysis (OPGEE and PRELIM) undergo revisions and, as such, input of the same data into updated versions of these models may yield different results and should be interpreted with consideration for the models' change logs.

5.3 Conclusions and recommendations

5.3.1 Conclusions

While there were differences in the available data for each fuel type, this work harmonized the modelling to provide as consistent a result as possible. Natural gas, for example, was modeled in terms of natural gas composition, reflecting how the crude modelling was based on crude qualities/assays, and the results align well with other studies inside and outside of Canada.

The detail with which the pathways were modeled provided visibility into data gaps and where future effort should be focused. Additionally, several of the pathways identified dramatic variation year over year. Applying uncertainty to these data gaps and variability provided additional insights into how critical gathering additional data and considering a longer time period may be.

CIs external to the scope of this project play a key role in the results. In particular, there is a considerable amount of imported fuels and crude which influence the final results. On the other hand, the CIs of this project could better inform the electricity CIs, particularly those regions relying more heavily on fossil fuels.

Lastly, through the life cycle, the combustion phase has significantly higher impact than the fuel production phase which is on the order of 20%-25% of the life cycle. This indicates that there are still benefits to be gained from reducing emissions from production but reducing combustion emissions overall by switching to lower carbon renewable fuels offers the most area for improvement.

5.3.2 Recommendations

Recommendations on addressing data gaps and modelling issues for the carbon intensity of each fossil fuel have been provided at the end of each respective section. It is our recommendation that future updates to these baseline carbon intensities address these known data gaps. In general, direct collection of data on inputs and outputs from facilities would improve the data quality over data collected from public reports and purchased datasets. Additionally, the results for both electricity and the fuels would be more robust if the electricity pathways were rolled into the model. This would allow the electricity pathways to link to the fuels and the fuel pathways to link to the electricity, keeping both up to date. It is also recommended that future analysis include the impact of fossil fuel production and consumption in Canada on other impact categories such as impacts to water consumption, water quality, and other emissions to air so that results can support a wholistic evaluation of environmental impacts from fossil fuels. Data gaps to be filled for each fuel and processing step are described in detail in the preceding sections.

Similar recommendations can be made for the natural gas and petcoke methodologies and some of the data gaps noted above apply to natural gas and petcoke production as the modelling in OPGEE and PRELIM fed into the calculations of these pathways.

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Appendix A. Data Source Summaries

Fossil Fuel Data Sources Summary

Number	Reference	Application
1	Oil Production Greenhouse gas Emissions Estimator (OPGEE) Model (on server)	Engineering-based model that estimates GHG emissions from the production, processing, and transport of crude oil
2	Petroleum Refinery Life Cycle Inventory Model (PRELIM) Model (on server)	Mass and energy based representation of the refining process that allows for the estimation of GHG emissions
3	GreenHouse gas emissions of current Oil Sands Technologies (GHOST) Model	Quantifies the GHG emissions associated with the production of bitumen via surface mining and in situ methods as well as the upgrading of the produced bitumen to synthetic crude oil.
4	Alberta Energy Regulator, Statistical Reports (ST), https://www.aer.ca/providing-information/data-and-reports/statistical-reports	Well site locations, gathering systems, production volumes, drilling activities, in situe oil sands production summaries, gas production summaries, facilities lists, bitumen production, monthly flaring, venting and production data
5	C-NLOPB, Canada-Newfoundland and Labrador Offshore Petroleum Board.	Offshore oil and gas extraction
6	National Energy Board, Estimated Production of Canadian Crude Oil and Equivalent, https://www.neb-one.gc.ca/nrg/sttstc/crdlndptrlmprdct/stt/stmtdprdctn-eng.html	Estimated production of Canadian Crude oil, petroleum products, natural gas, natural gas liquids
7	Natural Resources Canada, Basin database, available at http://basin.gdr.nrcan.gc.ca/index_e.php	Basin data
8	International Association of Oil and Gas Producers (IOGP) Annual GHG Data: www.IOGP.org	Gaseous emissions, energy consumption, flaring, aqueous discharges
9	National Energy Technology Laboratory (NETL) Baseline Data https://www.netl.doe.gov/	Technology types, energy consumption for extraction, refining, transport
10	Cooney, G., Jamieson, M., Marriott, J., Bergerson, J., Brandt, A., and Skone, T. 2017. Updating the US Life Cycle GHG Petroleum Baseline to 2014 with Projections to 2040 Using Open-Source Engineering-Based Models. Envi Sci & Tech. 51:977-987 (on server)	Methodology useful to inform and benchmark baseline values.
11	Orellana, A., Laurenzi, I., MacLean, H., and Bergerson, J. 2018. Statistically Enhanced Model of In Situ Oil Sands Extraction Operations: An Evaluation of Variability in Greenhouse Gas Emissions. Envi Sci & Tech. 52:947-954 (on server).	Data relevancy to oil sands
12	Masnadi, M., El-Houjeiri, H., Schunack, D., Li, Y., Englander, J., Badahdah, A., Monfort, J., Anderson, J., Wallington, T., Bergerson, J., Gordon, D., Koomey, J., Przesmitzki, S., Azevedo, I., Bi, X., Duffy, J., Heath, G., Keoleian, G., McGlade, C., Meehan, D., Yeh, S., You, F., Wang, M., and Brandt, A. 2018. Global Carbon Intensity of Crude Oil Production. Science. 361:851. (on server)	Data useful for crude oil with country-level upstream carbon intensities

13	Sleep, S., Laurenzi, I., Bergerson, J., and MacLean, H. 2018. Evaluation of Variability in Greenhouse Gas Intensity of Canadian Oil Sands Surface Mining and Upgrading Operations. Envi Sci & Tech. In press. (on server)	Methodology and data useful for oil sands and upgrading
14	Canadian Fuels Association contact Brian Ahearn (brianahearn@canadianfuels.ca) person to email	data on flow of products throughout Canada as well as more detailed refinery capacity and crude slate data - suggested that ECCC provide introduction
15	Upstream natural gas emission intensity review of existing literature (provided by ECCC) (on server)	upstream natural gas emissions intensities
16	Petrinex	data coverers wells and batteries but they may need to look at other publications for similar data for other facility types
17	https://www.petrinex.ca/PD/Pages/APD.aspx	Monthly oil and gas production data by facility (or at least wells with the necessary links to aggregate wells to facilities). Also contains reported vented, flared, fuel and fugitive gas volumes. Additional reports on website provide background and definition help. Volume of product is (m3 for liquids, e3m3 for gas (thousand cubic meters))
18	https://www.aer.ca/providing-information/data-and-reports/statistical-reports/st60b	Annual flaring and venting report summarizing the aggregated results of the reported volumes
19	https://www.aer.ca/providing-information/data-and-reports/statistical-reports/st13	Alberta Gas Plant/Gas Gathering System Statistics
20	https://www.aer.ca/providing-information/data-and-reports/statistical-reports/st39	Alberta Mineable Oil Sands Plant Statistics Monthly Supplement
21	https://www.aer.ca/providing-information/data-and-reports/statistical-reports/st53	Alberta In Situ Oil Sands Production Summary
22	https://www.saskatchewan.ca/business/agriculture-natural-resources-and-industry/oil-and-gas/oil-and-gas-news-and-bulletins/oil-and-gas-statistical-reports	As Saskatchewan also reports into Petrinex, much of the same type of data is available and can be found on their website here: Oil and Gas Statistical Reports, Saskatchewan Fuel, Flare, and Vent – annual gas volumes by facility for all facility types, Gas Plant Report – has info on natural gas liquids production from gas plants
23	https://www2.gov.bc.ca/gov/content/industry/natural-gas-oil/statistics	BC is where we have the least amount of data as they only recently started reporting into Petrinex. In the past we have simply modelled BC using AB data as we do not have anything better. We know this is not great as their industry is relatively new compared to other provinces. What little data is available can be found here
24	https://www.geologic.com/products/geoscout/	OPGEE inputs for Western Canada Crude oils software that allows you to extract the data

25	https://ihsmarkit.com/products/accumap-accuLogs-training.html	OPGEE inputs for Western Canada Crude oils description of the company reported data that is managed by IHS Cera.

Appendix B. Pricing data

In order to provide the opportunity for ECCC and other users of the CF tool to allocate impacts based on economics, as part of the Milestones 2, 3 and 4, the EarthShift Global team is collecting pricing data for all unit processes. This enables allocation on both price and value added. Not all pricing has been gathered at this point, but progress to date is included.

- All costs and prices are given in Canadian dollars unless specified.

Crude (not bitumen) pipeline

Transport, liquid pipeline {CA}

The cost per bbl·km of $0.00181 was derived from the 2015 revenues for each pipeline given in the National Energy Board (NEB) report *Canada's Pipeline Transportation System 2016* (NEB, 2016a) divided by the length of the pipeline. Pipeline lengths were obtained from the following sources in order of preference: the Choquette-Levy et al paper, the NEB report and Wikipedia. Details of the calculation can be found in the *3-9-1 Crude pipelines cost.xls* workbook.

Truck transport

Transport, train diesel {CA}

NACFE provides the 2016 revenue per tkm of $311.56 (NACFE 2017) which is used as the average price.

Train transport model-long haul large vehicles

Canadian Pacific reports 2016 earnings of $6,232 million over 135,952 million tonne miles for a cost of $0.0286/tonne·km (Canadian Pacific Railway Limited 2017). Canadian National reports 2016 freight earnings of $11,326 million over 214,327 million tonne·miles for a cost of $0.0330/tonne·km (Canadian National Railway 2017). The weighted average of these two is $0.0313/tonne·mile. (Note that the total freight reported by these two companies is somewhat greater than that reported by Statistics Canada.)

Crude Refining

The crude refining process yields a number of co-products. In the baseline analysis the GHG emissions associated with refining are allocated according to the energy content of the various co-products in the product slate. To enable economic allocation of refinery outputs, pricing data has been collected from PRELIM and is summarized in the table below.

Table 101. Economic parameters for co-products of crude refining from PRELIM, expressed in CDN $.

			Coking	Hydrocracking
Products	$/bbl (CDN)	MJ/bbl (CDN)	$/MJ (CDN)	$/MJ (CDN)
Blended gasoline	97.64	4,823	0.020	0.020
Jet-A/AVTUR	90.12	5,333	0.017	0.017
ULSD	89.36	5,459	0.016	0.016
Fuel Oil	85.35	5,493	0.016	0.016
Liquid Heavy Ends	53.52	6,440	0.008	0.008
Coke	10.43	6,596	0.002	0.008
Hydrogen	0.01	1.72	0.008	0.008
RFG	0.03	8.64	0.003	0.003
Surplus RFG	0.03	8.64	0.003	0.003
Sulphur ($/kg)	-	-	0.080	0.080
LPG	0.24	15.10	0.016	0.016
Petrochemical feedstocks	-	-	0.021	0.021
Asphalt	65.01	6,447	0.010	0.010
HC Residue	53.52	6,461	0.008	

Appendix C. Electricity Intensities in the Clean Fuel Standard's LCA Modelling Tool

C1. Approach

The approach for determining the electricity emission intensities in the Clean Fuel Standard's LCA modelling tool consists of relying upon publicly-available data that are further augmented by ECCC to account for indirect emissions. The direct and indirect emission intensities are modelled using Environment and Climate Change Canada's *National Inventory Report (NIR) 1990-2015: Greenhouse Gas Sources and* Sinks in Canada and Environment and Climate Change Canada's internal tool respectively. Provincial and national grid emission intensities for the year of 2015 are provided as seen in Table C 1.

	Direct Impacts (NIR 2017 Annex 13 Part III)	Indirect Impacts (ECCC Internal Tool)	Indirect Impact Uncertainty Range		Total
			Min.	Max.	
AB	900	45	37.8	70.5	945
BC	11	67	58.1	89.8	78
MB	2.1	20.6	16.7	37.4	23
NB	345	46	40.2	66.9	391
NL	40	21	17.0	38.3	61
NS	689	87	75.8	128.1	776
ON	38	22	19.5	34.8	60
PEI	26	242	212.1	297.3	268
QC	1.3	10.9	8.2	21.9	12
SK	754	62	52.1	96.9	816
YK	47	Out of Scope	-	-	Out of Scope
NW	209	Out of Scope	-	-	Out of Scope
NU	759	Out of Scope	-	-	Out of Scope
CA	145	27	22.9	43.9	172

Table C 1: Provincial and national grid emission intensities included in the Clean Fuel Standard's LCA modelling tool. Values are for the year of 2015 and are expressed in tonne CO_2 e/GWh.

C2. National Inventory Report 1990-2015: Greenhouse Gas Sources and Sinks in Canada Part 3

The NIR provides emission intensities related to the generation of electricity by the Public Electricity and Heat Production category (IPCC Category 1.A.1.a), on a national and provincial level. Auto-producers who either partially or wholly generate electricity for their own use and also may sell some of their electricity to the grid are excluded from the scope. The scope of electricity generation includes only main activity producers, entities whose main activity is the production of electricity. The emissions associated with the small amount of utility steam generation are therefore included within the scope of this category. Emission intensities reflect GHG emissions associated with electricity delivered by the grid. Energy losses in transmission and distribution are not considered.

GHG emissions reflect emissions from combustion-derived electricity. Emissions occurring offsite, as is the case for uranium fuel production and processing for nuclear power generation, are excluded from the scope. Additionally, nuclear, hydro, wind, solar and tidal electricity generators only emit small quantities of GHGs from the use of diesel generators as backup power supply.

Electricity generation intensity values were derived for each fuel type using GHG emission estimates and electricity generation data. GHG emissions are based on the total fuel consumed by the public utility sector, as provided in the RESD,1 while generation data are from CANSIM (2005– 2013) and the EPGTD publication (1990–2004). Regional emission factors are applied for coal and natural gas emissions however, for the remaining fuels, region-specific emission factors were not available and nationally reported emission factors are applied. The complete methodology used to develop the GHG emission intensities is discussed in Chapter 3 and Annex 3.1 of the *National Inventory Report 1990-2015: Greenhouse Gas Sources and Sinks in Canada* report.

Several Statistics Canada sources were used to provide electricity production and fuel consumption values. Publications include the *Report on Energy Supply and Demand in Canada* (RESD) (Statistics Canada 57-003-X), *Electric Power Generation, Transmission and Distribution* (EPGTD) (Statistics Canada 57-202-X) and CANSIM (Tables 1270006,127-0007 and 127-0008).

C3. ECCC Internal Tool

C 3.1. Scope

The tool is used to estimate the indirect segment of electricity emissions. Indirect emissions can be defined as emissions that do not stem from electricity generating processes. Examples of indirect emission sources include electricity transmission, use of sulfur hexafluoride during transmission, herbicides, waste water, concrete, steel, infrastructure heating, lubricating oils, radioactive waste and vehicle operation.

C 3.1.1. Functional Unit

The tool is designed to evaluate potential environmental impacts of electricity generation from different sources, in Canada. In order for the tool’s results to be included in the Clean Fuel Standard’s LCA modelling tool, a functional unit of producing and delivering 1 MWh of electricity generated and distributed in Canada in 2017 was used. 2015 Canadian grid mixes were applied. The tool uses the 2013 global warming potentials implemented by the IPCC.

C. 3.1.2. Allocation Rules

Default allocation is made based on energy content. In the case of cogeneration, the allocation factor splits emissions intensities (CHP operation, infrastructures when relevant and fuel supply too) on an energy content basis to prevent the steam emissions from being included in the electricity emissions.

C 3.1.3. System Boundaries

The tool assesses the carbon inensity of electricity production in Canada, from resource mining and extraction, processing and electricity production steps, and subsequent grid step. The life cycle of all pathways is divided in four main life cycle steps, namely: fuel provision (when applicable), infrastructure construction, operation, and transmission/distribution.

Details on the lifecycle stages follow:

- The Fuel provision stage includes the extraction and refining of the fuel used to produce the electricity.
- The Infrastructure stage pertains to the plant and equipment construction itself.

- The Operation stage includes the production of electricity and all the services and products needed for this operation. Along with this stage, two sub-stages (emissions control system) appear for some pathways: the carbon capture system and the pollution control (NO_x and SO_2 emissions control).
- The Transmission/Distribution includes the infrastructure, equipment, products and services required to transport the electricity from the production site to the final user.
- The Supply and Waste management sub-systems respectively pertain, for each of the preceding subsystems, to all of the activities that stem from:
    - Resource procurement (water, energy, chemicals, materials), including the extraction, treatment and transformation of natural resources, and the various transports to the resource-use sites (i.e. pre-production, production, distribution, use and end-of-life management sites).
    - The transport and treatment/management of the waste generated during any of the product's life cycle stages, taking all of the possible recovery options into account.

C 3.1.4. Geographical and temporal boundaries

Some processes within the system boundaries might take place anywhere or anytime, as long as they are needed to achieve the functional unit.

For example, the processes associated with the supply, and the waste management (background processes) can take place in Canada or elsewhere in the world. In addition, certain processes may generate emissions over a longer period than 2017. This applies to landfilling, which causes emissions (biogas and leachate) over a period whose length (several decades to over a century/millennium) depending on the design and operation of the burial cells and how the emissions are modeled in the environment.

C 3.1.5. Electricity Generation Pathways

Electricity pathways included in the tool include:

- Coal steam boilers with or without carbon capture systems (CCS) using different fuels (bituminous, sub-bituminous and lignite);
- Natural gas combined cycle or simple cycle turbines with or without CCS using conventional or unconventional (shale gas) natural gas;
- Biomass steam boiler with or without CCS and cogeneration boiler using biomass originating from forest, either standing wood or residue (pellets or wood chips burned in simple cycle or cogeneration plants);
- Hydropower from reservoir or run of river types;
- Onshore wind power.
- Natural gas converted boilers: this model covers the electricity produced from natural gas in ancient coal-powered plants.
- Combined heat and power (natural gas): the model covers electricity produced from natural gas originating from conventional and unconventional sites, specifically, shale gas. Cogeneration of electricity and heat is covered in this pathway.
- Solar thermal: This model covers electricity produced in concentrated solar thermal plants. As all the renewables, fuel provision stage is excluded for this pathway.
- Solar photovoltaic: This model covers electricity produced by photovoltaic panels. As all the renewables, fuel provision stage is excluded for this pathway. Different technologies and installed powers will be included in this pathway as their life cycle inventory differ.
- Nuclear: this model covers the CANDU technology of electricity production from nuclear fusion.
- Diesel (off-grid generation): this model covers the electricity produced from diesel in off-grid sites, mainly in the northern regions of the country.

- Utility-scale natural gas boilers: The model covers electricity produced from natural gas originating from conventional and unconventional sites using boilers.

C 3.2. Data Sources

Infrastructures and fuel supply are modeled using data from the ecoinvent 3.4 database as main basis and completed with Canadian and provincial data for the main parameters (installed power, provenance of the raw materials, location of mines, etc.) when available. The Operation stage data relies on Canadian data, namely NPRI for emissions, national and province statistics for other key parameters as efficiency, exchanges with other regions, etc. Transmission and distribution relies on ecoinvent 3.4 for infrastructure information and on Canadian and provinces statistics for the key parameters (km on line, losses during transport). Missing data are completed with literature sources and proxies.

C 3.3. Methodology

The tool provides emission intensities on a technology basis. A provincial emission intensity is determined by weighting each technology in relation to its share in the overall provincial grid mix. A national emission intensity is determined by weighting each technology in relation to its share in the national grid mix.

Appendix D. Canada's 2015 National Marine Emissions Inventory Tool (MEIT)

D 1. Approach

MEIT was used to calculate GHG emissions related to the marine shipping of crude oil in Canada. This includes marine shipping of crude oil within-Canada, and international crude imports. The MEIT contains marine transportation emissions data separated by cargo type. MEIT data for each trip includes ship type, trip start time, trip end time, origin, destination, activity time, distance, fuel consumption, GHG emissions cargo type and cargo quantity.

D 2. Background

Canada's National Marine Emissions Inventory is Canada's first and only source of data on marine emissions. It was developed by Environment and Climate Change Canada (ECCC), with assistance from a contractor, to understand and reduce emissions of air pollutants and greenhouse gases from marine vessels. It is a comprehensive inventory of air pollutant and greenhouse gas emissions from commercial marine vessels, both domestic and international, operating in Canadian territorial waters, and is assessed at the national and regional levels, as well as by port, terminal, and vessel type.

In 2016, ECCC updated the inventory using 2015 data from the Information System on Marine Navigation (INNAV1) from Canadian Coast Guard (CCG). This resulted in a comprehensive inventory of shipping activity, energy use, and emissions of air pollutants and greenhouse gases emissions from commercial marine vessels in Canada. The inventory now includes all commercial marine vessel classes tracked by the CCG within Canada's territorial waters, as well as smaller commercial craft such as ferries, tugboats and fishing vessels that are not fully represented in the CCG movement data. All coastal areas as well as inland rivers and lakes are included in the inventory.

D 3. Boundaries

The geographical boundaries for the national inventory include Canada's territorial waters) as well as all inland rivers and lakes with significant commercial marine activity. Canada's territorial waters extend 200 nautical miles offshore, with the exception of a portion of eastern Canada where a shared boundary exists between Canada and Greenland.

Also included in the revised inventory are marine emissions associated with Offshore Platforms and Mobile Drilling Units in the Hibernia oil fields about 300 km east of Newfoundland, and in the Panuke oil fields about 300 km off the coast of Nova Scotia.

Operational boundaries for the inventory include all commercial marine vessels, with emissions distinguished by:

- Domestic and international voyages;
- Class of vessel (e.g., Merchant Container, Merchant Bulk);
- Type of engine (propulsion, auxiliary) as well as boilers;
- E Modes of activity, including underway, berthing and anchoring;
- Underway engine size (installed capacity in kW as well as cylinder size in litres); and
- Modes of activity, including underway, berthing and anchoring.
- Type of emission (exhaust and fugitive); and
- Fuel type (distillate and residual oils)

Underway activity is defined to be all ship movements, regardless of speed. Berth activity occurs when a ship is stationary at any identifiable berth location in Canada (e.g., terminal, wharf or wharf section). Anchor activity occurs at all other times when a ship is stationary.

D 4. Emissions Sources

The Emission Sources included in the MEIT are:

- Main Engine emissions, while underway and maneuvering (or at low load for vessels without main engines when at berth and anchor);
- Auxiliary Engine emissions, all modes of operation including berth and anchor;
- Boiler emissions, all modes of operation; and
- Fugitive emissions of volatile organic compounds (VOCs) from marine petroleum transport in tankers and tanker barges.

D 5. Marine Fuels

Merchant class vessels/Ocean Going Vessel, traditionally use heavy fuel oil (HFO), which is a residual oil and has a higher sulphur content than most other fuels, about 2-3% by weight. Pre-Emission Control Area standards, these vessels did not have to fuel-switch when coming into Canadian waters. Other marine fuels are MDO (Marine diesel oil) and MGO (Marine gas oil), which are refined, less viscous, and have reduced fuel sulphur.

D 6. General Emissions Calculation Method

MEIT is an activity-based inventory, as opposed to a fuel-consumption based inventory. On the basis of INNAV and Automatic Identification Systems data, it is possible to follow the route of any vessel in the database and to estimate its energy demand, fuel consumption and pollutant exhaust along each route. An activity-based inventory links emission factors (in grams of emissions per kWh of energy consumed) and activity measures that provide estimates of energy consumed by the ship's engines. For the ship's boiler, fuel-based emission factors are used, i.e. kg emissions per tonne of fuel consumed by the boiler.

MEIT uses an activity-based calculation method, expressed with the equation:

$$E = \sum_i \{(ME * LF_{ME} * \Delta T * EF_{ME}) + (AE * LF_{AE} * \Delta T * EF_{AE}) + (BO * \Delta T * EF_{BO})\} \quad (1)$$

where the essential ship emission parameters are:

- E = Emissions, summed across all modes (Underway, Anchor, Berth)
- ME = Main Engine Capacity or Maximum Continuous Rating (MCR) in kW
- AE = Total Auxiliary Engine Capacity, in kW
- LF = Engine Load Factor (as a function of speed between segments)
- EF = Emission Factor, in g/KWh for engines and kg/tonne fuel for boilers
- BO = Boiler fuel consumption rate in tonnes/hr
- ΔT = Time in mode (Underway, Berth, Anchor,), in hours

Equation 1 forms the basis for the MEIT, and the reliability of the inventory relies on the use of the most accurate and most up-to-date ship emission parameters: emission factors, vessel characteristics and engine ratings, the best estimates of vessel speed, load factors, and time spent in each mode.

The methodology for estimating main engine load is a critical factor for estimating emissions. MEIT estimates engine load dynamically, from the instantaneous vessel speed. The basis for this is the Propeller Law, which is:

$$LF = (V_{inst}/V_{max})^3 \qquad (2)$$

Where:

- LF = engine load factor
- V_{inst} = vessel speed through water, calculated from INNAV data and corrected using the Webtide prediction model
- V_{max} = maximum or design speed of the vessel, from vessel characteristics data

However other factors can change main engine load significantly, such as how low the vessel sits in the water (instantaneous draught), how clean the hull is, and how rough the weather. In accordance with the methods and assumptions used by the 3rd International Marine Organization (IMO) GHG Study, MEIT uses the Admiralty Formula for estimating main engine load, which assumes that power is related to hull displacement to the power of 0.6667:

$$LF =\{ (t_{ins}t/t_{max})^{0.6667*}(V_{inst}/V_{max})^3\}/(\eta_w*\eta_f) \qquad (3)$$

Where:

- t_{ins} = instantaneous draught (indication of how laden is the ship), m
- t_{max} = maximum draught of the ship, m
- η_w = weather roughness efficiency reduction factor, set to 0.90 for coastal waters
- η_f = hull fouling efficiency reduction factor, set to 0.91 as per the 3rd IMO GHG Study

D 7. Data Sources

Several primary datasets are used to obtain both vessel activity and vessel characteristics:

- Canadian Coast Guard Data - called INNAV, this is movements data recorded for all commercial marine vessels larger than 200 GT that operated in Canadian waters in 2015 (vessel identification, speed, lat/long, origin/destination, time stamp);
- Data from Automatic Identification Systems - AIS is an automated tracking system of equipped vessels, a broadcast transponder system which operates in the VHF mobile maritime band. AIS historical positional data was obtained from IHS Maritime & Trade for commercial vessel activity in the Canadian Arctic (vessel identification, speed, lat/long, origin/destination, time stamp); and
- Lloyd's Seaweb data for vessel characteristics (vessel size, engine capacities, design speed, build year).

Data from other inventories, port authority websites, project stakeholders and AISLive (a dynamic marine traffic monitoring tool from IHS Maritime) among other sources were also incorporated into the tool.

Appendix E. Supporting Data for Cut-Off Decisions

The following results were generated to guide decisions around exclusion of processes from the fossil fuel life cycles. All data come from the CEDA 4 US Environmental Input/Output database. Reference can be found here: https://pubs.acs.org/doi/abs/10.1021/acs.est.9b00084

Table 102. All other petroleum and coal products manufacturing, contribution to total impact of the sector

	kg CO2 eq	Percent of total contribution
All other petroleum and coal products manufacturing	0.57564	41.2%
Petroleum refineries	0.401054	28.7%
Oil and gas extraction	0.101845	7.3%
Electric power generation, transmission, and distribution	0.08077	5.8%
Other basic organic chemical manufacturing	0.044006	3.1%
Petrochemical manufacturing	0.042443	3.0%
Natural gas distribution	0.03736	2.7%
Pipeline transportation	0.020912	1.5%
All other basic inorganic chemical manufacturing	0.008358	0.6%
Management of companies and enterprises	0.006924	0.5%
Wholesale trade	0.004722	0.3%
Truck transportation	0.004091	0.3%
Plastics material and resin manufacturing	0.003903	0.3%
Paperboard container manufacturing	0.003818	0.3%
Coating, engraving, heat treating and allied activities	0.003636	0.3%
Nonresidential maintenance and repair	0.003146	0.2%
Coal mining	0.003025	0.2%
Scientific research and development services	0.002528	0.2%
All other	0.049563	3.5%

Table 103: Natural gas distribution, contribution to total impact

	kg CO2 eq	Percent of total contribution
Natural gas distribution	2.149767	82.2%
Pipeline transportation	0.209622	8.0%
Oil and gas extraction	0.148947	5.7%
Coal mining	0.031959	1.2%
Petroleum refineries	0.005411	0.2%
Natural gas distribution	0.0052	0.2%
Electric power generation, transmission, and distribution	0.004379	0.2%
Rail transportation	0.004137	0.2%
Ornamental and architectural metal products manufacturing	0.002962	0.1%
All other	0.052045	2.0%

Table 104: Petroleum refineries, contribution to total impact

	kg CO_2 eq	Percent of total contribution
Petroleum refineries	1.244085	67.0%
Oil and gas extraction	0.258896	13.9%
Petroleum refineries	0.131072	7.1%
Electric power generation, transmission, and distribution	0.052593	2.8%
Natural gas distribution	0.045334	2.4%
Pipeline transportation	0.040938	2.2%
Other basic organic chemical manufacturing	0.013204	0.7%
Petrochemical manufacturing	0.010709	0.6%
All other basic inorganic chemical manufacturing	0.010267	0.6%
Wholesale trade	0.004479	0.2%
Nonresidential maintenance and repair	0.003809	0.2%
Management of companies and enterprises	0.003349	0.2%
All other	0.035556	1.9%

Table 105: Other basic organic chemical manufacturing (includes ethanol production), contribution to total impact

	kg CO_2 eq	Percent of total contribution
Other basic organic chemical manufacturing	1.762082	64.9%
Petrochemical manufacturing	0.268631	9.9%
Electric power generation, transmission, and distribution	0.134061	4.9%
Petroleum refineries	0.102316	3.8%
Natural gas distribution	0.081962	3.0%
Grain farming	0.059237	2.2%
All other basic inorganic chemical manufacturing	0.034874	1.3%
Alkalies and chlorine manufacturing	0.023938	0.9%
Plastics material and resin manufacturing	0.02192	0.8%
Fertilizer manufacturing	0.018851	0.7%
All other crop farming	0.0166	0.6%
Industrial gas manufacturing	0.009872	0.4%
Rail transportation	0.009333	0.3%
Wholesale trade	0.009172	0.3%
All other chemical product and preparation manufacturing	0.008582	0.3%
Fats and oils refining and blending	0.008433	0.3%
Management of companies and enterprises	0.008333	0.3%
All other	0.13049	4.8%

Table 106: Fats and oils refining and blending, contribution to total impact

	kg CO_2 eq	Percent of total contribution
Soybean and other oilseed processing	0.340427	21.8%
Oilseed farming	0.312675	20.0%
Fats and oils refining and blending	0.227836	14.6%
Grain farming	0.076857	4.9%
Wet corn milling	0.066555	4.3%
Electric power generation, transmission, and distribution	0.066358	4.3%
Animal (except poultry) slaughtering, rendering, and processing	0.035988	2.3%
Natural gas distribution	0.034197	2.2%
Rail transportation	0.019283	1.2%
Cattle ranching and farming	0.018284	1.2%
Cotton farming	0.011743	0.8%
Truck transportation	0.010568	0.7%
Paperboard container manufacturing	0.010233	0.7%
Other plastics product manufacturing	0.010149	0.7%
Dairy cattle and milk production	0.009387	0.6%
Wholesale trade	0.008834	0.6%
All other crop farming	0.008725	0.6%
Plastics bottle manufacturing	0.008538	0.5%
All other paper bag and coated and treated paper manufacturing	0.005617	0.4%
Coal mining	0.005051	0.3%
All other	0.267901	17.2%

Appendix F. Fossil Fuel Carbon Intensity Results Summary

<see Excel sheet provided with report>

Appendix G. Summary of Responses to Critical Review Panel

<see Excel sheet provided with report>

Milestone 3 – Final Report

Solicitation Number: 5000038224

Milestone 3: Methodology for Low Carbon Fuel Pathways and Default Carbon Intensities

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Glossary

General Terminology	
Background and supporting unit processes:	Materials and energy used as part of a pathway including fertilizers, chemicals, regional grid electricity, etc. These unit processes will be available in the tool for viewing and use in new pathways.
Baseline pathway	Canadian diesel and gasoline pathways which the Clean Fuel Standard uses for reference carbon intensities. These pathways are built into the Fuel LCA Modeling tool and used for companionate analysis.
By-product	By-products generally do not have economic value and are treated as wastes.
Characterization factor	A scalar quantity, or weighting factor, indicating the greenhouse gas potential (or Global Warming Potential, GWP) of an emission. A general term that may also refer to scale factors associated with other potential impacts.
Co-product	A product which is created from any production or agricultural process, including silviculture, aquaculture, etc., which is not the prime economic driver of the activity. It can be any of two or more products coming from the same unit process or product system. Examples include corn cobs and husks (stover) co-produced with corn, glycerin which is produced as a co-product of biodiesel esterification, and animal fodder (feed) produced concurrently with the fermentation of ethanol and other alcohols.
Database	A repository in the tool which collects pathways, background and supporting unit processes, characterization factors, pathway metadata, user metadata and other information as needed.
Library	A set of information in the database available to all users but editable only by ECCC and/or its subcontractors. Includes pathways and other unit processes and the characterization factors, etc.
Metadata	Information on a pathway or user which is useful in providing transparency, traceability, verifiability, and/or aids in carbon intensity calculations.
Method	A specific set of characterization factors
Monte Carlo Analysis	An assessment of uncertainty created by running a calculation over and over again (typically more than 1000 times) while varying the underlying uncertainty differently each time.
New low carbon pathway	A pathway created by a tool user.
Waste	Substances or objects with no economic value for which the holder intends or is required to dispose of
Fuel production-specific terminology	
%wt	Percentage on a weight basis
CHP	Combined Heat and Power
CI	Carbon Intensity
CNG	Compressed Natural Gas
GHG	Greenhouse Gas
GREET	Greenhouse gases, Regulated Emissions, and Energy use in Transportation Model
HFO	Heavy Fuel Oil
HHV	High Heating Value
IPCC AR5	Intergovernmental Panel on Climate Change 5th Assessment Report
LCA	Life Cycle Assessment
LFO	Light Fuel Oil
LHV	Low Heating Value
LNG	Liquefied Natural Gas
LPG	Liquefied Petroleum Gas
MSW	Municipal solid waste
NG	Natural Gas

NGL	Natural Gas Liquids
RNG	Renewable natural gas
RU	Regional Unit
SOC	Soil organic Carbon
UCO	Used cooking oil
WWT	Wastewater treatment

Units

Unit	Description	Conversions
bbl.km	Barrel-kilometer	0.16 m^3.km
Wh	Watt-hour	0.0036 MJ
kWh	Kilo watt-hours	1,000 Wh
MWh	Mega watt-hours	1,000,000 Wh
btu	British thermal unit	0.001056 MJ
kg	Kilogram	1,000 g
km	Kilometer	1,000 m
mile	mile	1609.35 m
t	Tonne or ton	1,000,000 g
tkm	Tonne-kilometer	1,000 kg.km
MJ	Megajoule	1,000,000 J
l	Liter	0.001 m^3

1. Introduction

The Government of Canada has announced its intent to develop a Clean Fuel Standard (CFS) to reduce Canada's greenhouse gas (GHG) emissions through the increased use of lower carbon fuels and alternative technologies. The objective of the CFS is to achieve 30 megatons of annual reductions in GHG emissions by 2030, contributing to Canada's effort to achieve its overall GHG mitigation target of 30% emissions reduction below 2005 levels by 2030. To achieve this goal, fossil fuel suppliers (e.g., refiners, natural gas distributors) will be required to reduce the carbon intensity of the fuels they produce or distribute for use in Canada's transportation, industry, and building sectors. The carbon intensity of a fuel is a representation of the total life cycle GHG emissions (expressed in kg of CO_2 equivalents) associated with production of 1 MJ of energy from that fuel, including feedstock extraction and processing, fuel production and upgrading, transport and distribution throughout the life cycle, and combustion of the fuel. Under the CFS, baseline carbon intensity values will be set for fossil fuels covered by the regulations based on the 2016 average carbon intensity of these fuels. These baselines will be used to establish the carbon intensity targets or requirements that fuel producers will have to meet for the fuels they supply. The carbon intensity requirements will be expressed as an absolute value set at a level lower than the baseline. These carbon intensity requirements will become more stringent over time. Non-fossil fuel producers, referred to as low carbon fuel producers, will not have their fuel production regulated by the CFS; however, low carbon fuel producers will be eligible to generate credits by supplying fuels that have lower life cycle carbon intensities than the reference fossil fuel they would displace (ECCC, 2018).

The Fuel LCA Modeling Tool will be used to set baseline carbon intensity values for fossil fuel producers, as well as serve as a tool for low carbon fuel producers to submit the life cycle carbon intensities of their fuels for potential credit generation under the CFS (ECCC 2018a).

In October of 2018, ECCC commissioned EarthShift Global, WSP and Quinn & Partners, and Introspective Systems to develop a robust, user-friendly, and transparent software tool that is compliant with the ISO 14040 and 14044 LCA standards (ISO, 2006a) (ISO, 2006b) and contains Canadian-specific fuel pathway data. This tool will be used to calculate the carbon intensity of existing and future Canadian fossil fuel and low carbon fuel pathways in support of the CFS policy and regulations. The project to develop the CFS carbon intensity software tool is comprised of four stages or milestones, including:

- Milestone 1 – Development of the Conceptual Model (completed Jan 31, 2019);
- Milestone 2 – Methodology for Fossil Fuel Pathways and Baseline Carbon Intensities (completed May 15, 2019);
- Milestone 3 – Methodology for Low Carbon Fuel Pathways and Default Carbon Intensities (to be completed by August 15, 2019); and
- Milestone 4 – Development of the Fuel LCA Modeling Tool and Documentation (to be completed by March 13, 2020).

Milestone 3 sets the model building blocks and foundational carbon intensities for low carbon fuels under the CFS and is an important foundation for upcoming policy on clean fuels. Wherever possible, published LCAs and LCA models relating to the Canadian situation have been used as a basis for the pathway models. Where unit process models were not available, preference was given to published Canadian or North American data. In some cases, other GHG tools or US data have been used. Areas where additional time and/or research could refine the values used in the baseline have been noted as recommendations for future work.

This report summarizes the work completed for Milestone 3, Task 3.3: A final report of the methodology and data sources as well as the carbon intensity values for the low carbon fuel pathways. This report has been prepared to address the relevant reporting requirements for a comparative LCA under the ISO 14044 guidelines.

Part I: General Methods and Approach

2. Goal and Scope Definition

According to ISO 14044, the first phase of an LCA is to define the Goal and Scope of the study. The goal of the study should clearly specify the following: the intended application; the reasons for carrying out the study; the intended audience; and whether the results are intended to be disclosed to the public. The scope of the study should include a description of the most important aspects of the study, including: the functional unit; system boundaries; cut-off criteria; allocation; impact assessment method; assumptions; and limitations.

The goal of Milestone 3 is to develop unit process building blocks and foundational carbon intensity values for Canadian low carbon fuel pathways. In contrast to Milestone 2, where the goal was to develop baseline carbon intensity values specifically for 2016 that will be set into Canadian regulations, the goal for Milestone 3 is to develop the unit process building blocks that low carbon fuel producers can use in the Fuel LCA Modelling Tool to calculate the carbon intensity of their unique low carbon fuel production processes. In addition, the goal is to calculate foundational carbon intensities for low carbon fuel pathways that are currently being produced in Canada, or that are expected to be produced in the next 5 years.

The results of the study and the methodology used to calculate the carbon intensities will be publicly available and will be used by fuel producers and ECCC policy analysts to compare the carbon intensity of current and future Canadian fuel pathways. These foundational carbon intensities and pathways will also be included in the Fuel LCA Modeling Tool, to be built in Milestone 4, for use in building low carbon pathways and comparing the carbon intensity of low carbon pathways to conventional fossil fuels. Modeling used for the pathways will be open and transparent to the user within the tool and downloadable in unit process form for review and use in other applications. The Fuel LCA Modeling Tool will also be publicly available so that policy analysts, fuel producers, and other researchers can use the tool to inform efforts to reduce the carbon intensity of Canadian fuels. As such, the study will be completed following the ISO 14040 and 14044 requirements for a full comparative LCA intended to support comparative assertions.

2.1 Function

The function of the liquid, solid, and gaseous fuel pathways analyzed in this study is to provide useable energy for transportation, industrial activities, and buildings in Canada. The fuel feedstocks considered in this analysis may serve other functions such as non-combustion uses (e.g., feedstocks, solvents or diluents) and use in industrial processes (e.g. steel production); however, these functions are not regulated under the CFS and are therefore excluded from the analysis (ECCC, 2018). Some fuels are also produced and used onsite by the fuel producer to produce a finished fuel or in facility operations. The CFS will regulate some of these “self-produced and used fuels” and they are included within the scope of this analysis (ECCC, 2018).

2.2 Functional Unit

A functional unit is defined as the quantified performance of a product system for use as a reference unit (ISO 2006a). This facilitates determination of reference flows for the system(s) being studied.

In this case, the function under study is the provision of fuel to power transportation, heating, and/or power generation. The functional unit is 1 MJ of fuel measured using the High Heating Value (HHV) at the regional distribution center.

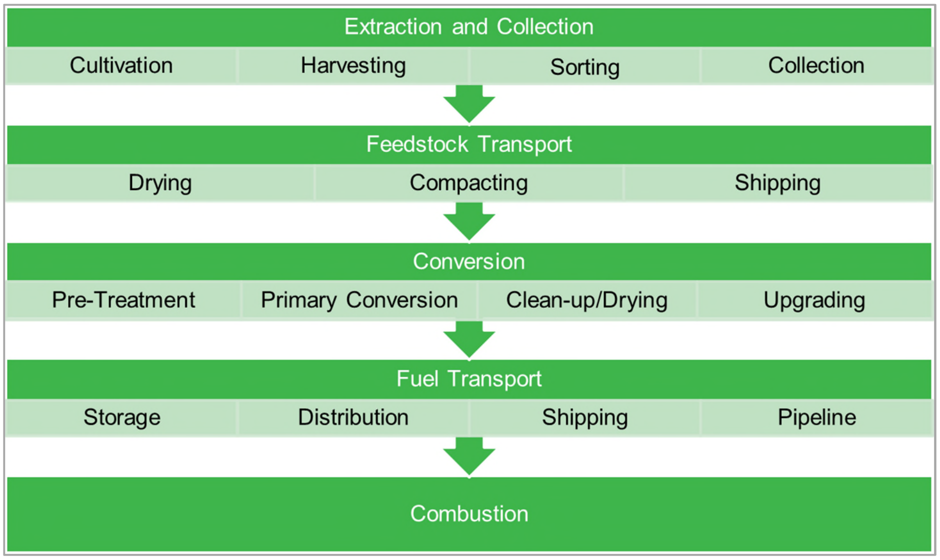
The carbon intensity values are expressed in grams of carbon dioxide equivalents (g CO_2 eq.) per unit of energy produced from combustion of the fuel in megajoules (MJ). Energy produced from fuel combustion is based on HHV and can be considered using different combustion efficiencies specific to the combustion type (e.g. heating, transportation, electricity). A single default combustion emission factor per fuel has been applied to generate the carbon intensity in most instances.

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 environmental flows in the analysis. This lays the groundwork for a meaningful assessment where all important life cycle stages and the flows associated with each alternative are considered. The general system boundaries for the Fuel LCA Modelling Tool are consistent between fossil fuels and low carbon fuels, and include (Figure 1):

- **Extraction and Collection**: extraction of raw feedstock materials (e.g. cultivation of corn) or collection of co-products used as feedstock (e.g. forest harvest residues);
- **Feedstock Transport (transmission)**: transportation of raw or upgraded feedstock to the fuel producer, including any upgrading or processing required prior to transport;
- **Conversion**: processes for converting the feedstock into fuels, including any post-processing and upgrading to final fuel product;
- **Fuel Distribution**: storage and handling of fuel, transport of finished fuel product to storage and to final user; and
- **Combustion**: combustion of the final fuel product by the end user, taking into consideration the efficiency of combustion.

Within each of these life cycle stages, the system boundary also includes the life cycle GHG emissions associated with the use of electricity inputs (both grid and onsite generation), fuel inputs, material inputs (e.g. chemicals), process emissions (e.g. venting and flaring), transportation processes, and direct land use change. The inclusion of emissions from these background processes are determined by cut-off criteria (see Sections 2.5 and 2.6).



Within each life cycle stage, the system boundary includes life cycle GHG emissions associated with:

- Electricity inputs
- Fuel inputs
- Material inputs
- Process emissions
- Transportation
- Direct land use change

Figure 1. General system boundary for fossil fuels and low carbon fuels in the Fuel LCA Modelling Tool.

2.4 Fuel Production System Descriptions

Detailed descriptions of the system boundaries and fuel production systems are provided for each of the fuel pathways in Sections 4 through 11 in Part II of this report.

2.5 Cut-Off Criteria

Cut-off criteria are used in LCA practice for the selection of processes or flows to be included in the system boundary. The processes or flows below these cut-offs or thresholds may be excluded from the study. Several criteria are used in LCA practice to decide which inputs are to be considered, including mass, energy, and environmental significance. As noted in ISO 14044, making the initial identification of inputs based on mass contribution alone may result in important inputs being omitted from the study. As such, energy and environmental significance should also be used as cut-off criteria, particularly in studies intended to support comparative assertions made to the public. Options for 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 (e.g. mass).

Similar cut-off criteria may also be used to identify which outputs should be traced to the environment (e.g. emissions, wastes).

For this study, every effort was made to include all the relevant flows associated with the fuel pathways studied. During the interpretation phase, a 1% of environmental significance criterion, as calculated by the impact assessment method, was used to test the sensitivity of the results to assumptions and data substitutions made. Results of an economic input-output analysis for relevant sectors was conducted to inform the cut-off decisions, and a summary of these results is provided in Appendix D2. We also considered a 1% mass and energy-based cut-off to account for catalysts and other materials of small quantity. These cut-offs are diffused throughout the system, thus cumulative threshold for these cut-off criteria cannot be calculated using open source and transparent data as required for this study. In most, if not all cases, the cut off of these materials has been justified in the literature.

2.6 Excluded Processes

Typically, in an LCA, some aspects within the system boundaries are excluded due to statistical insignificance or irrelevancy to the goal. For example, the impacts of manufacturing and maintaining infrastructure associated with transportation systems and combustion technologies are highly variable and their contributions to life cycle impacts are negligible, so they are commonly excluded from LCAs of energy systems. The specific processes excluded from calculations of the CI for Canadian low carbon fuels include:

- Construction and decommissioning of agricultural equipment and facilities;
- Construction and decommissioning of forestry equipment and wood processing facilities;
- Construction and decommissioning of fuel conversion facilities and associated equipment;
- The manufacturing of fuel transportation infrastructure (i.e., pipelines, trucks, ships, roads);
- The manufacturing of fuel combustion infrastructure (i.e., vehicles, boilers);
- Solid waste management processes and wastewater treatment processes;
- GHG emissions associated with exported fuels;
- Research and development activities; and
- Indirect activities associated with fuel production, such as marketing, accounting, commuting, and legal activities.

Data for the processes excluded are in most cases highly proprietary and unavailable. The activities in general are also highly variable from project to project. Environmental Input Output data from the US indicates that the impacts from these activities are relatively small (<2%), so until we can measure them more accurately on a fuel by fuel basis, keeping them outside the boundary provides a more solid basis for comparison. This rationale applies to each of the excluded processes. See Appendix D2 for a summary of the I/O results that were used to inform the cut-off decisions.

It is also noted that since the Fuel LCA Modelling Tool does not rely on licensed LCA databases (e.g. ecoinvent), there are potentially other smaller life cycle activities that are excluded. The data sets in LCA databases typically include activities such as infrastructure manufacturing, waste and wastewater treatment, energy used to power combustion devices, etc. From a cumulative standpoint, these life cycle activities that make smaller contributions in isolation may not be negligible in total.

2.7 Assumptions

Based on data availability, several assumptions have been made and were tested to determine if they exceed the 1% environmental significance cut-off employed (except where noted that specific processes will be excluded). The assumptions for each fuel are documented in the report.

Some of the assumptions for the low carbon fuel pathways result in activities excluded from the system boundary based on both the cut-off criteria and the availability of data. Further detail on modeling assumptions for each fuel pathway is provided in the pathway-specific sections in Sections 4 through 11 of Part II.

2.8 Co-Product Allocation

While conducting an LCA, allocation situations occur where the studied system is a multifunctional process and not all outputs (or functions) are used for the considered functional unit. According to ISO 14044, allocation of the process inputs 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 (mass or energy content, for example) or other relationships (economic value, etc.) should be used (ISO 2006b).

As part of developing the CFS, ECCC will define an approach for modeling multi-function systems. The current ECCC directive for co-product allocation is that when allocation is unavoidable, allocation should be based on underlying physical relationships. As stated in ISO 14044, allocation "should reflect the way in which inputs and outputs are changed by quantitative changes in the products or functions delivered by the system". In fuel production systems, energy content, also known and referred to as the heating value, is generally recognized as the most appropriate metric. This allocation method offers the objectivity required for regulatory purposes and eliminates the subjectivity from the substitution and economic allocation methods. As such, ECCC recommends a hybrid approach, where the main method of allocation is by the physical relationship with energy content (mass content can be used as a proxy if energy data are not available). However, where applicable, emissions should not be applied to unused co-products (i.e. electricity produced by cogeneration would be attributed all the emissions if there is no heat user).

The choice of allocation method, while useful for standardization, transparency and clarity in decision making, is in fact a model choice and there are no "correct" or "right" ways to allocate. Allocation by energy will be used as the default approach, and the administrator version of the tool will allow for different allocations in the low carbon fuel pathways to be tested. Where allocation may be insufficient, and displacement more relevant, the displacement method can be used.

The need to allocate environmental burdens between products and co-products arises at several points in the life cycles of several low carbon fuel pathways, including:

- Anaerobic digestion, which produces both biogas and digestate;
- Agricultural and forest residues derived from primary cultivation and harvesting that are used to produce biofuels;
- Vegetable oil and meal produced from agricultural crops such as canola and soy;
- Animal feed or combined heat and power production from distillers' grains co-product of corn grain ethanol;
- Electricity generation from combustion of lignin in cellulosic ethanol production;
- Commodity chemical and other product production from lignin and hemicelluloses from cellulosic ethanol production; and
- Several low carbon fuel conversion processes which produce multiple outputs (e.g. biodiesel and glycerine).

For several of the energy pathways modelled in this study, wastes from other industrial activities are also used as feedstocks. The identification of an energy feedstock as a co-product or a waste has significant implications for the allocation of environmental burdens. In section 4.3.4.2 of the ISO 14044 guidelines, it is stated that environmental burdens should only be allocated to co-products and not to waste products (ISO 2006b). A waste is defined as a substance or object intended for disposal, while a co-product is defined as any of two or more products coming from the same unit process or product system (ISO 2006b).

In this study, system boundary expansion was used only in cases where an alternative co-product is a direct substitution for a fossil-based fuel or electricity. For all other co-products, allocation was made considering HHV, with the exception of forestry products. Because the majority of forestry products are used for and their value derived from non-fuel purposes, they are allocated based on mass, as per common convention.

Each baseline and foundational unit process in the Fuel LCA Modelling Tool will include data on HHV, LHV, mass, carbon content and hydrogen content. Provided this information is available, the user of the tool will be able to select the method of co-product allocation based on these factors. This will allow the user to change the allocation method throughout the pathway to see the results.

Waste products are handled differently than coproducts and separate empty unit processes will need to be created for user’s waste processes that are not in the database. The use of wastes as fuel feedstocks is an example of material recycling, and in this study we are using the cut-off approach to model recycling. The cut-off approach is part of an attributional LCA approach, and using this approach, if a waste material (first life) is used for another purpose (second life) 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 and handling of the material. The system boundary ends there, and any further environmental burden or benefit created by the second life is reliant upon market changes, and can only be modeled using market-based recycling, which is a consequential LCA modelling approach. As an example, if a low carbon fuel producer obtains organics from the MSW stream to produce ethanol, the first life (i.e. the producer of the organic waste) takes no burdens for disposal, while the second life (i.e. the low carbon fuel producer) takes no burdens for the production, collection, and storage of the organics. Using a consequential LCA approach, we might also model the changes in GHG emissions that would occur due to the removal of these organics from the waste stream; however, the carbon intensity calculations for fossil fuels and low carbon fuels are based on an attributional approach, and if consequential modelling is applied to waste feedstocks, then consequential modelling must be applied throughout the project. Background material on modelling recycling in LCA is provided in Appendix D. In the case that a waste product becomes a coproduct, it will have to be added to the unit process complete with its mass, HHV, LHV, density, carbon content, and hydrogen content.

For the purposes of the Milestone 3 report and results, a limited set of co-product allocation models have been developed based primarily on energy content, with some displacement and mass-based allocation in specific instances. During completion of the Fuel LCA Modelling Tool in Milestone 4, further data will be collected to add to the tool to enable multiple allocation and displacement options, including:

- Economic data for main products and co-products;
- Mass data for main products and co-products (where not presently defined);
- Definition of reference cases (business as usual) for displacement modelling; and
- Carbon intensity of selected materials and fuels that are displaced by co-products in the bioenergy pathways.

These data will be limited to the specific co-product allocation and displacement instances that are defined for the low carbon fuel pathways in the Milestone 3 report.

2.9 Impact Assessment Method

Impact assessment methods are used in LCA to convert life cycle inventory (LCI) data (environmental emissions and raw material extractions) into a set of environmental impacts.

The objective of this study is to calculate carbon intensity values for fossil fuel and low carbon fuel pathways, expressed in grams of CO_2 equivalents per MJ of energy. Carbon intensities include contributions to global warming from CO_2, CH_4, and N_2O, and others as appropriate, based on the IPCC factors for a 100-year time horizon. The 100-year time horizon is used as it is the characterization factor most-widely applied in fuels LCA thus facilitating ease of comparison to other study results. In this study the fossil methane factor of 30 was used for methane emissions. Table 1 provides a summary of the most recently updated characterization factors to calculate CO_2 eq from the IPCC. A complete list of greenhouse gases, impact factors, and the associated uncertainty can be found as an appendix to the Milestone 1 report (EarthShift Global, WSP, Introspective Systems 2019).

Table 1. Characterization factors for calculating carbon intensities using IPCC AR5 GWP 100.

Greenhouse Gas	IPCC AR5 GWP 100, excluding biogenic carbon
CO_2	1
CH_4 (fossil)	30
CH_4 (biogenic)	30
N_2O	265
Sulfur hexafluoride	23,500

2.10 Limitations of the Study

The work done under this project only pertains to fuels developed and used in Canada. Any conclusions or assumptions should not be applied to fuels developed or used elsewhere, where if production processes differ, the results will not be valid. Many of the low carbon fuels modelled in this report are not currently being produced at commercial scale in Canada, and so data and information on Canadian production systems is limited or not available. As such, the modelling for some pathways is based heavily on data from the literature and assumptions to extrapolate literature values to Canadian applications. This may result in significant over- or under-estimation of CI values in comparison with actual producer results.

2.11 Limitations of LCA Methodology

The ability of LCA to consider the entire life cycle of a product makes it an attractive tool for the assessment of potential environmental impacts. Nevertheless, similar to other environmental management analysis tools, LCA has several limitations. These can be related to data quality and unavailability of potentially relevant data.

The CFS is narrowly focused on carbon intensity or global warming potential. This means that fuels which offer the required reduction in carbon intensity may, in fact have worse environmental impacts than the baseline in other areas, such as water scarcity, eutrophication (excess nutrients), particulate emissions or toxicity. To understand the broader implications of a fuel pathway, a full LCA compliant with ISO 14044 is recommended.

Additionally, some environmental impacts are not included even in a full LCA, such as species migration and noise.

It should be kept in mind that even if a study has been critically reviewed, the impact assessment results are relative expressions and do not predict impacts on category endpoints (e.g. human health, wildlife species), exceedance of thresholds, or risks. If potential risks are associated with a pathway, an environmental and human health risk assessment and/or hazard assessment is recommended.

3. Modelling Approach for Low Carbon Fuels

3.1 Selection of pathways

The number of low carbon fuel pathways in research and development is large and growing. The scope and timing of this milestone did not allow for inclusion of all pathways, so a concerted effort was made to choose the most useful pathways with these attributes:

- Are in commercial production in Canada or elsewhere in the world, or whose viability is considered promising;
- Have feedstocks readily available in Canada; and
- Have publicly available research results to enable modeling.

Further streamlining chose pathways most likely to be brought to commercial scale. This selection was made in consultation between ECCC, the CFS team, and the authors in Milestone 1 of this project (EarthShift Global, WSP, Introspective Systems, 2019a).

3.2 LCI Data Collection

The scope and timing of this project did not allow for the project team to collect primary data from Canadian low carbon fuel producers. As such, data collection to develop the LCI was based on review and compilation of data from a range of secondary sources on Canadian fuel pathways. Data sources used included government publications and statistics, industry publications and statistics, other fuel LCA modelling tools, as well as literature data for low carbon fuel systems with little or no current production in Canada. The exception to this approach was for ethanol and biodiesel production, where several years of primary operating data was available for a large segment of Canadian ethanol and biodiesel producers. A brief overview of the LCI data considerations for low carbon fuels is provided below.

3.2.1 LCI Sources for Low Carbon Fuel Pathways

In general, the low carbon fuel pathways are not as well-established as the fossil fuel pathways, with many in earlier stages of development and having not reached commercial-scale production. The availability of Canadian-specific data was limited for several of the low carbon pathways as a result, requiring decisions to be made on what to include and ensuring proper documentation of data quality.

Aside from hydrogen, the low carbon fuel pathways are generally based on three feedstock types, including agricultural feedstocks, wood fibre feedstocks, and waste feedstocks.

3.2.1.1 Low Carbon Fuel Feedstock Extraction and Collection

Agricultural Feedstocks

Primary and secondary products (products, co-products and wastes) from several key Canadian crops supply feedstock for a large portion of the low carbon fuel pathways. These key feedstocks include primary products, co-products and residues from: corn; wheat; soy; canola; barley; and camelina. There can be considerable variation in the carbon intensity of these feedstocks across different regions of Canada, and efforts were made to capture regional variability for these feedstocks. The agricultural LCI and associated carbon intensity values are described in more detail in Section 4.

Dr. Nathan Pelletier’s ongoing research to develop a LCI database for key Canadian crops (Canadian Agri-food Life Cycle Data Centre (CALDC)) provided a significant amount of the required data to develop regionally-defined carbon intensity values for all of these crops with the exception of camelina and peas. Key features of the CALDC will include:

- A publicly available tool, with a user-friendly web interface;
- Maximally interoperable with other LCI databases and LCA software packages, including any eventual Canadian or North American LCI data repositories;
- Data set import and export functionalities;
- Transparent data quality/uncertainty reporting based on existing best practices;
- Periodically updated;
- Hosting LCI datasets for the majority of common agri-food supply chain activities and commodities in Canada; and
- Supported by and utilized by a partnership of industry, government, and academic stakeholders.

While the database is not yet online, the data are readily available upon request.

Additional data for agricultural feedstocks and validation of the CALDC LCI data was obtained through consultation and reporting from Agriculture and Agri-Food Canada. More specific data sources for agricultural feedstocks are summarized in Section 4.

Wood Fibre Feedstocks

Primary and secondary products from wood harvesting and wood product manufacturing also supply feedstock for a large number of fuel pathways, including pyrolysis oils, several solid fuel pathways, as well as hydrogen, biogas, and renewable natural gas (RNG). These feedstocks are derived from primary forest harvest, primary harvest residues, sawmill and wood product manufacturing residues, and construction and demolition waste. There has been a significant amount of LCI data generated for the life cycle of a number of these wood feedstocks in different Canadian provinces. There are some aspects of wood fuel pathways that vary from region to region, including harvesting practices (i.e. fuel use), feedstock availability, and background energy systems for wood feedstock processing (e.g. electricity use during pelletization). These variations are accounted for where possible. More specific data sources for wood fibre feedstocks are summarized in Section 10.3.1.

Wastes

Wastes from various agricultural, commercial, and industrial activities are used as feedstock for many of the low carbon fuel pathways, including ethanol, biodiesel, biogas/RNG, and solid fuel pathways. These feedstocks include municipal solid waste (MSW), wastewater treatment (WWT) sludge, oils and grease, animal fats, manure, and industrial/Construction and Demolition (C&D) waste. In line with ISO 14044 guidance, the upstream GHG emissions are not allocated to feedstocks that are considered waste products. Based on this choice, the life cycle carbon intensity for these feedstocks begins at waste collection and processing. More specific data sources and assumptions for waste feedstocks are provided in each of the fuel pathway sections in Part II.

3.2.1.2 Low Carbon Fuel Conversion

There are a wide range of conversion technologies used to convert feedstocks to low carbon fuels depending on the desired end-use. Life cycle inventory data needs for conversion technologies include:

- Mass balance data for feedstock conversion efficiency;
- Energy inputs (electricity (grid and on-site generation, fuels); and
- Material inputs (chemicals, enzymes, etc.).

For biodiesel and ethanol production, primary data from Canadian producers was used to model the fuel conversion process. For other fuel conversion processes in other low carbon fuel pathways, literature was used and adapted to Canadian conditions where possible (e.g. background energy source). More specific data sources for low carbon fuel conversion technologies are outlined in each of the fuel pathway sections in Part II.

3.2.1.3 Low Carbon Fuel Combustion

The system boundary for calculation of carbon intensity values for low carbon fuels in the Fuel LCA Modelling tool includes GHG emissions from combustion of low carbon fuels for industrial energy, space heating, and transportation. Data on the GHG emissions from low carbon fuel combustion were obtained from Canadian government emissions factors used in other government programs for GHG emissions accounting. In instances where specific emissions factors for low carbon fuels were either not available from the Canadian government, or for which it was determined that higher quality data could be obtained, these emissions factors were supplemented with values from literature and other government carbon regulatory programs and tools (e.g. GREET, CARB, or GHGenius 4.03). An explanation of the treatment of biogenic carbon emissions from fuel combustion is provided in Section 3.5.3.

3.2.2 LCI Data for Commonly Used Unit Processes

Throughout the low carbon fuel pathways there are a number of commonly used unit processes that are used in multiple unit processes. These include:

- **Materials and Chemicals**
    - Fertilizers;
    - Herbicides;
    - Pesticides;
    - Enzymes;
    - Acids;
    - Catalysts;
    - Other chemicals as identified during Milestones 2 and 3.
- **Electricity**
    - Provincial electricity grids;
    - Individual electricity generation types.
- **Fuels**
    - Natural gas combusted in equipment;
    - Diesel combusted in equipment;
    - Heavy and light fuel oil in equipment;
    - Gasoline combusted in equipment;
    - Propane combusted in equipment.
- **Transportation**
    - Tractor trailer, diesel;
    - Tractor trailer, gasoline;
    - Truck, diesel;
    - Truck, gasoline;
    - Train, diesel;
    - Container ship;
    - Pipelines.
- **Process Emissions**
    - On-field nitrogen emissions from fertilizers;
    - On-field emissions from tilling.

Inventory data for these commonly used unit processes are being stored in the CFS Modelling Tool data library so that all fossil fuel and low carbon fuel pathways can use them. For example, fossil fuel production and transport processes that were modelled in Milestone 2 were also used in Milestone 3 to provide inventory data for low carbon fuel life cycle activities. Data sources for other commonly used processes are summarized in each of the individual fuel pathway sections in Part II.

More details on the LCI data and the sources used to compile the LCI are provided in the individual fuel pathway sections in Part II of the report. The LCI data and calculations have been carefully documented to ensure transparency and the data templates developed include detailed meta data and uncertainty data. The data sheets and supporting calculations sheets (where required) have been provided as a supporting information package with this report. The selection of data for use was guided by data quality preferences developed for the project and by ISO guidance on data consistency and completeness.

3.3 Data Quality Preferences

The LCI data used in the low carbon fuel modeling is a mixture of data that is either specific to Canadian systems, data from other jurisdictions that is considered adequately representative and modified to include Canadian energy and emissions, or data from other jurisdictions that is considered adequately representative without revision. The LCI data also include a mixture of verified (audited) data based on measurements by producers that report data, as well as non-verified data obtained from the literature that was modified with expert judgment and assumptions.

The ISO guidelines indicate that data quality requirements should be specified to enable the goal and scope of the LCA to be met (ISO, 2006b). In this section, we outline a set of data quality preferences established for the Fuel LCA Modelling Tool and that were applied in modelling low carbon fuel pathways.

3.3.1 Foreground Unit Processes

The foreground unit processes for this project include the primary activities involved in extracting and producing the fuel feedstocks, transporting and processing feedstocks, converting feedstocks to useful energy, and emissions from the energy application. Due to the importance of these activities in quantifying life cycle impacts and determining the representativeness of the CFS tool for Canadian fuel pathways, we have made every attempt to use the highest quality Canadian data to characterize the inputs and outputs of all foreground unit processes. More specific data quality requirements for foreground unit processes are shown below in order of priority:

1. Regionally specific Canadian data from verified sources (e.g. producers, government statistics, data collected for Canadian life cycle inventory databases) for the specific industry/technology under study.
2. Regionally-specific Canadian data from published literature and academic studies.
3. Canadian-average data from verified sources for the specific industry/technology under study (e.g. producers, government statistics).
4. Regionally-specific or national average Canadian data from non-verified sources for the specific industry/technology under study.
5. North American data using the same hierarchy above.
6. United States data from verified sources from the specific industry/technology under study, updated to reflect Canadian background energy systems or conditions where possible.
7. United States data from verified sources from the specific industry/technology under study.
8. Verified data from outside Canada and the United States for the specific industry/technology under study.

In general, the level of data quality for foreground processes decreases as one moves down this hierarchy. This is reflected in the data quality assessment and accounted for in the uncertainty analysis.

3.3.2 Background Unit Processes

The background unit processes for this project include upstream activities that support foreground process activities, for example the production of electricity to supply an industrial activity. Although in the background, these activities can still make significant contributions to the life cycle GHG emissions of Canadian fuel pathways; however, some background activities have low to negligible influence on the carbon intensity of Canadian fuel pathways (e.g. fuels transported by pipeline for short distances, small percentages of crude transported by tanker ship) and the data quality requirements are therefore less stringent for these unit processes. The data quality requirements for background unit processes are the same as those identified above for foreground unit processes, with the exception that non-verified data from outside Canada and the United States may be considered for instances where the process being modeled is not a significant contributor of life cycle GHG emissions. This does not mean that these data are not included. It means that the data are included, but from sources that are not specific to Canada or the timeframe of modeling in lieu of specific data availability.

3.4 Quantifying Data Quality and Uncertainty

In practice, all data used in an LCA study is a mixture of measured, estimated and calculated data. To evaluate the quality of the data used for modeling the fuel pathways, Data Quality Indicators (DQI) are used to assess each flow and linked pathway using a data quality matrix approach. These scores are also used to assess uncertainties on the data and subsequently assess the uncertainty of the model and the results.

Accounting for uncertainty is an important aspect in development of the Fuel LCA Modeling Tool because this information provides appropriate context for decision-making when evaluating the potential carbon intensity of alternative fuel pathways, and because it influences the modeling process itself. The Conceptual Model was developed to include uncertainty analysis capabilities for input values, modeling choices, and uncertainty propagation and interpretation. For advanced users aiming to inform policy decisions, uncertainty information can be particularly helpful in identifying a preferred fuel pathway among several options in a way that is transparent and can be justified. This can include comparative decisions among different available pathways, or to compare potential variations in carbon intensity for a single pathway in order to define regulatory targets.

The model distinguishes between two types of uncertainty: parameter and model. Parameter uncertainty is the uncertainty concerning input values. In the case of LCA models, this refers to the amount of a flow. For instance, uncertainty on the number of kWh of electricity required in a certain fuel conversion process, or uncertainty in the amount of carbon emitted during combustion of a fuel. The uncertainty in inventory data can derive from a lack of knowledge of a certain system, or from variability. Uncertainty in combustion emissions, for instance, may be from differences in engine technology, processing facilities, and/or atmospheric temperatures on the day of the emissions measurement. The more variability the inventory can reflect, the less uncertainty there is, although this also makes the results less generalizable. This means that when we develop very process and technology-specific data sets, it reduces uncertainty in the data relative to that specific process or technology, but in turn it means that this data set is not as useful to apply to a broader range of processes or technologies in that sector. For example, consider the inventory for a certain crop for which production and yield can vary depending on the soil type and farming practices. An average inventory on a per kg basis of harvested crop would combine the range of inputs representing the different soil types and farming practices. The uncertainty in such inventory is be partially due to this variability. Another approach is to create several versions of the inventory to account for both sources of variability: soil type and farming practices. In the case of four different soil types and five different farming practices, one could have twenty different processes.

Further parameter uncertainty has been applied to the fitness for purpose of the underlying data. This takes into account the use of data which are not ideal because they come from a different geographic location, time period, or technology.

Often the life cycle inventory is derived from multiple studies where the most representative and generalizable inventory is obtained from a combination of information. Therefore, an LCA model, for pragmatic reasons, must balance variability so that the inventory is representative enough and applicable. Uncertainty due to lack of knowledge is included as parameter uncertainty.

The uncertainty of the fossil fuel pathway parameters has been modeled in one of two ways as shown in the decision trees in Appendix B of the Milestone 1 report (EarthShift Global, WSP, Introspective Systems 2019). Where a range of values is available based on different refineries, reports, or calculations, the full range is used using a uniform distribution. Where a range is not known, the pedigree matrix is applied as a Bayesian method of assessing probability.

3.5 Modeling Approach and Carbon Intensity Calculations for Low Carbon Fuels

In contrast to the LCA modelling work completed in Milestone 2, many of the low carbon fuel pathways are not well-established commercial fuels in Canada, and in some cases very limited information is available on Canadian production and use, if at all. In many instances, only literature data is available, or only single data sets from demonstration-scale or theoretical production simulations. The notable exceptions to this are ethanol and biodiesel, for which very reliable Canadian LCI data were available on feedstock production and fuel conversion. As a result of this, the CI calculations for low carbon fuels are generally not production-weighted averages for a single year of production as the fossil fuel CI values were in M2; rather, in most cases the CI values for low carbon fuels are representative of single facilities or average data for a typical feedstock or conversion technology configuration. The expectation is that users of the Fuel LCA Modelling Tool will provide more representative and robust Canadian data over time.

Based on this, while the primary objective for Milestone 2 was to develop baseline carbon intensity values for fossil fuel production and use in 2016 to be used in Clean Fuel Standard (CFS) regulations, the primary objective in Milestone 3 is to develop default carbon intensities for low carbon fuel pathways along with a collection of basic unit processes that could support future use of the LCA Modelling Tool. This will allow low carbon fuel producers to develop carbon intensities for their unique low carbon fuel pathways by using and modifying the basic unit processes provided using more recent data or more Canadian-specific and process-specific data.

The following sections provide a brief overview of the modelling approach for low carbon solid fuels, as well as discussion of some key methodological issues to be addressed in the modelling.

3.5.1 Development of Unit Process Building Blocks

The overall modelling approach for Milestone 3 is to develop unit processes to serve as building blocks for current and future modelling work in the Fuel LCA Modelling Tool. This is in contrast to the development of production-weighted 2016 average CI values for fossil fuels in Milestone 2. The low carbon fuels industry is still in development in Canada with many different emerging technologies; however, many of these emerging technologies are reliant on a core set of feedstock sources and conversion processes that are relevant for many different pathways. For example, in the case of fuel pathways that rely on wood biomass or agricultural feedstocks this approach is particularly relevant since there are a variety of fuel feedstocks that may be used in any fuel conversion process, and these are all based on a basic set of feedstocks that are produced within the Canadian forestry supply chain (or in the case of corn stover pellets, from the Canadian agricultural industry) and within the Canadian agricultural sector. So even in an instance where a low carbon fuel producer has developed a novel fuel conversion technology for biomass energy, they will still need modelling data for cultivation, harvesting, pre-processing, and transport of the required feedstocks. The building blocks approach also allows users of the Fuel LCA Modelling Tool to easily quantify the GHG emissions associated with alternative feedstocks that are available to them, for example to inform the decision whether to use sawmill residuals or unmerchantable roundwood as a feedstock by providing the ability to quickly model the CI for different feedstocks that can serve the same purpose.

The use of this building blocks approach is also intended to account for the lack of available data to model Canadian low carbon fuel systems. By taking this approach, even in cases where only literature data is available, or where no data is available, unit processes can still be developed and included as placeholders in the Fuel LCA Modelling Tool and can then be updated by tool users when data is available in the future.

The modelling work in Milestone 3 also relies heavily on fossil fuel unit processes that were developed in Milestone 2, including fuel inputs to machinery and equipment (e.g. diesel, natural gas, etc.) and transportation processes (e.g. trucks, rail, pipelines). These unit processes are stored in the ECCC Fuels database and have been incorporated into the low carbon fuel pathway models where needed.

3.5.2 Regional Variation

A number of aspects of low carbon fuel production systems in Canada are influenced by changing conditions across different regions of Canada. Although there is presently a lack of well-established, regionally-based low carbon fuel producers in Canada, the incorporation of regional variability is important and may provide useful data for informing low carbon fuel producers about the most suitable locations and feedstock options from a carbon intensity standpoint.

There are a number of regional factors which could influence carbon intensity for low carbon fuels. These include:

- Differences in fuel consumption in forest harvesting, sawmilling and other processing activities;
- Inputs and crop management practices for Canadian crops across different provinces and regions;
- Background energy systems such as variations in electricity grids providing energy to fuel conversion processes; and
- The sourcing of regional/provincial feedstocks could also influence transport distances and modes for feedstock delivery and final fuel delivery.

These differences have been reflected in the modelling as much as possible within the confines of the available data. Particular emphasis was placed on accounting for differences in the carbon intensity of provincial electricity grids, as electricity inputs are significant contributors to the life cycle carbon intensity of many of the low carbon fuel pathways, in particular because many of the fuel conversion processes are energy intensive and rely on electricity. More specific details on the inclusion of regional variability are provided in each of the fuel pathway sections in Part II.

3.5.3 Biogenic Carbon and Land Use Change

In remaining consistent with the Government of Canada’s policy on biogenic carbon, as shown in Canada’s National Inventory Report (Government of Canada, 2018), emissions of biogenic carbon from combustion of low carbon fuels were not included in the carbon intensity calculations. Biogenic carbon emissions will be calculated and reported separately from the default carbon intensity values.

Carbon emissions associated with direct land use change were included in instances where feedstock production requires the conversion of land from existing use to bioenergy production; however, it has generally been 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. As the Canadian low carbon fuel industry grows in scale, this assumption may need to be revisited and revised. Some specific instances of direct land use change has been modelled for Canadian crops, such as carbon emissions from tillage practices and changes in annual/perennial crops. During development of the Fuel LCA Modelling Tool in Milestone 4, generic factors for GHG emissions from other direct conversion of standard land use types (e.g. conversion of forest to agriculture) will be added where available so that DLUC can be quantified in the future. These emissions factors will be drawn from the literature and may require additional refining and updating in future iterations of the tool. Following a Canadian policy decision, indirect land use change (iLUC) is excluded from the carbon intensity calculations. More specific details on the inclusion of land use change is provided in each of the fuel pathway sections in Part II.

Part II: Low Carbon Fuel Pathway Models and Carbon Intensity Results

4. Agricultural Systems for Crop-Based Low Carbon Liquid Fuels

Life cycle inventories for commodity field crop production were compiled for six crops: corn, wheat, barley, canola, soybean, and camelina[1]. These are used to calculate Carbon Intensity values for both harvested crops and crop residues. This section describes methods used to compile and calculate provincial, production-weighted life cycle inventories and the associated Carbon Intensities for major cereal grain and oilseed crops in Canada for the crop-based low carbon fuel pathways and other uses.

The Carbon Footprint Methodology report from the Canadian Roundtable for Sustainable Crops (CRSC) carbon footprint studies, along with the crop-specific CRSC reports for corn, wheat, barley, canola and soybean, were the main sources of data for compiling these inventory tables. The camelina inventory was largely constructed using data provided by Smart Earth Seeds and Saskatchewan Agriculture, but on a similar methodological basis so as to ensure comparability across inventories. Crop residue data were updated for all crops based on recent literature. Seeding rates and pesticide application rates for canola were also updated. Inventories were first compiled at the reconciliation unit level in keeping with the CRSC reports, then scaled on a production-weighted average basis to the provincial level. Similarly, the provincial level values are used to calculate production-weighted average national values. The agricultural LCIs are used to calculate provincial and national average carbon intensities for use in the crop-based (Section 5) and residue based (Section 6) low carbon fuels.

4.1 Overview of Agricultural LCI Development

Life cycle inventories for field crop production were first compiled at the reconciliation unit level, based on the CRSC reports and other sources. These are provided in Dataset[2] A1. Production and area of farms were subsequently used to calculate production-weighted inventories for each crop and province. These data are provided in Dataset A2. The methods for inventory data collection are described in (S&T)2 Consultants Inc. (2017), and most data are derived from the related CRSC Carbon Footprint study reports for each crop (with the exception of camelina, which was not considered in the CRSC studies) ((S&T)2 Consultants Inc., 2017a, 2017b, 2017c, 2017d, 2017e, 2017f).

The CRSC studies represent the current best available source of Canadian field crop life cycle inventory data. Additional data and updated data were obtained for crop

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[1] A detailed LCI for Canadian peas is anticipated to be incorporated into the CALDC library during 2020. In the interim, the carbon intensity (Desjardins, et al., 2016) has been used.

[2] Dataset A1 and Dataset A2 are available as Excel files with the raw data (A1) along with the weighted and aggregated data (A2). Any specific issues for each data category or production process, as well as issues with individual data points, are noted as comments in the appropriate cell in those workbooks.

residues from (Thiagarajan, Fan, McConkey, Janzen, & Campbell, 2018). Updated data for pesticide application rates and seeding rates for canola were obtained from a report on GHG emissions for canola oilseed submitted by Canada to the EU as per Renewable Energy Directive requirements for accessing the EU biofuel feedstock market (European Commission, 2016). Finally, an LCI was developed for camelina using comparable methods.

4.1.1 Production-weighting

The first set of crop inventories (Dataset A1) are reported at the reconciliation unit (RU) level, as per the CRSC reports. The second set of inventories (Dataset A2) are production-weighted provincial average inventories. This dataset (Dataset A2) was created by scaling the Dataset A1 using production-weighted average data for each RU in a given province. In addition, the Dataset A2 includes calculations for nitrous oxide (N_2O) emissions related to nutrient management and crop residues.

It should be noted that despite the ambition of achieving RU-level resolution in the CRSC studies, many data were only available at coarser levels of spatial resolution (for example, provincial, regional, or national data). National data, such as direct energy use for corn and soybean and pesticide application for barley, were not scaled down to province level, as it would incorrectly represent the spatial resolution of data. However, when provincial data for one province were used as proxy data for other provinces, such as pesticide application for corn, wheat, and soybean, provincial averages (production-weighted) were calculated for Dataset A2, implying that there was downscaling for some provinces. These factors were incorporated into the crop-specific uncertainty factors for each crop.

4.2 Scope of the agricultural LCI

Activities spanning soil preparation until harvesting and storage were considered for corn, wheat, barley, canola, soybean, and camelina. Separate inventories were developed for durum wheat and all other varieties of wheat. For other crops, different varieties and cultivars were aggregated in one inventory. The inventories are expressed in terms of a functional unit of one tonne of grain or oilseed, with assumed moisture contents as per Table 2.

According to Smart Earth Seeds, the leading contractor for camelina breeding and production, 8% moisture is optimal for camelina grain storage (Smart Earth Seeds, 2019). The Saskatchewan Crop Planning Guides (Government of Saskatchewan, 2017, 2018, 2019) also recommend <8% moisture for safe storage of camelina, hence this value was adopted for the camelina inventory.

Table 2. Moisture content of studied field crops

Crop	Moisture content (%)	Dry matter (%)
corn	14.5	85.5
wheat	13.5	86.5
durum wheat	14.5	85.5
barley	13.5	86.5
canola	8.5	91.5
soybean	12.0	88.0
camelina	8.0	92.0

Reported data for each inventory includes the direct inputs into the crop production process, but excludes:

- the (upstream) production of those inputs, such as:
    - production of field inputs, such as seeds, fertilizers, and pesticides
    - production of energy, such as fuel production, and electricity generation
    - on-farm production of renewable energy, such as solar, wind, and biomass combustion
    - ancillary operations, such as work area lighting and heating
    - manufacture, maintenance and decommissioning of capital equipment
- the subsequent (downstream) use phase of the output grains and oilseeds, such as:
    - further processing into food products or animal feed
    - transport and distribution
- waste streams, such as:
    - disposal of process wastes
    - straw and stover,
    - field emissions from manure application, which was allocated to the corresponding livestock system
- upstream inputs for irrigation water.

A key contention in carbon footprint and LCA methodology is whether or not to include soil carbon changes as part of the modeling. These LCIs include the calculation of soil carbon changes resulting from three types of land management changes: perennial to annual, reduced summer fallow, and reduced tillage, as per the CRSC methodology (this is discussed further in the section Soil Organic Carbon Changes, below).

The geographical coverage of the LCIs includes all RUs with more than 10,000 ha of cropland (before distinguishing between types of crop grown). For camelina, although agronomic experiments have been carried out in all of Western Canada (Smart Earth Seeds, Johnson et al. 2010), they were primarily conducted in Saskatchewan. Until more information becomes available, it was assumed that all camelina production is occurring in Saskatchewan. Since most camelina production is occurring in Rural Municipalities within the brown and dark brown soil zones in Saskatchewan (Vakulabharanam, 2014), which mostly fall within the Semiarid Prairies (RU 30), it was assumed that all camelina production falls within RU 30. Li & Mupondwa (2014) also assumed that camelina was grown in the brown and dark brown soil zones, when they calculated N_2O emissions.

Although the inventories are intended to represent average production within a one year time frame, the temporal representativeness of specific data points often varies. Temporal coverage may vary between data categories (e.g. seeding rate), and even within data points in the same data category, as per best available data sources. Specific temporal coverages are described in the subsequent sections.

Eight production processes were included: tillage, seeding, irrigation, fertilizer application, 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 were considered for all processes. Crop residues left on the field after harvesting were also included. Figure 2 illustrates the process flow, including the inputs considered, and functional unit.

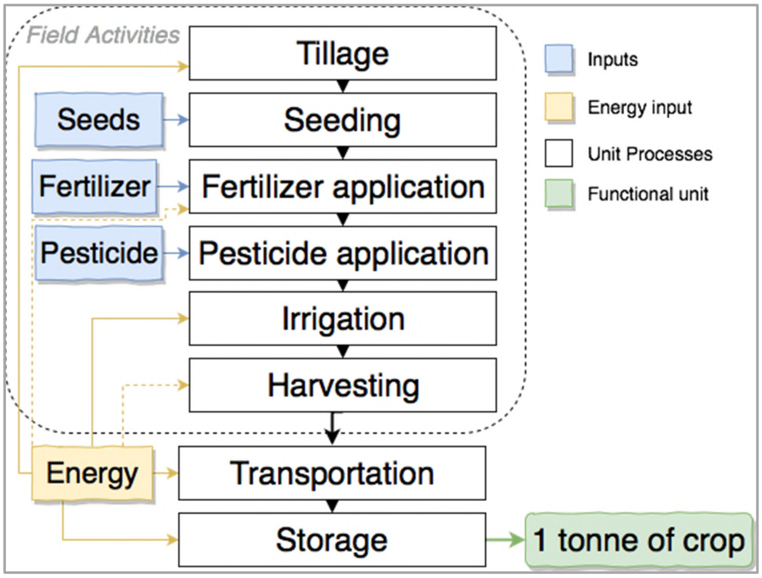

Figure 2. Process Flow Diagram, including inputs, processes and functional unit of studied crops

Technological coverage also varies, in particular with respect to tillage operations and types of fertilizers. Type of tillage was considered for the calculation of (a) tillage energy use in the form of diesel fuel consumption, (b) Emission Factor 1 for direct N_2O emissions, and (c) soil carbon changes. Three tillage types were modeled: (1) conventional tillage or intensive tillage (IT), (2) reduced tillage (RT), and (3) direct seeding or no-tillage (NT). Types of fertilizer used are distinguished by province, but generally not by crop, and time of application is not distinguished.

4.3 Data Sources

Data sources used in the CRSC Carbon Footprint Reports were:

- Yield and production data were obtained from Statistics Canada (from the now-retired CANSIM Table 001-0071), on a Small Area Data (SAD) basis for all provinces except the Atlantic Canada provinces, where data was obtained at the province level.
- Fertilizer application rates were obtained from

  - the Manitoba and Saskatchewan Crop Insurance programs, which provide detailed, long-term databases for fertilizer application rates that are geo-referenced for each crop that is insured (Saskatchewan Crop Insurance Corporation, 2019) (Saskatchewan Crop Insurance Corporation, 2015);
  - Fertilizer Use Surveys by Stratus Ag Research (Stratus Ag Research, 2015); and
  - Provincial field crop budgets
- Fertilizer type by province were obtained from
  - Statistics Canada (2016), based on shipments to provinces; and
  - Fertilizer Use Surveys by Stratus Ag Research (Stratus Ag Research, 2015)
- Pesticide use data were obtained from Farm and Food Care Ontario (2015) for 2013 and 2014, Group Ageco (2015), USDA NASS (2015), and USDA (n.d.)
- Data for direct energy use were obtained from Prairie Crop Energy Model (PCEM) (uncited), tillage data from the 2011 Agricultural Census (uncited), and USDA (2012).
- RU-specific N_2O emission factors for 2014 were obtained from the National Inventory Report by AAFC (AAFC, 2015)
- RU-specific soil carbon changes were provided by AAFC, and were calculated based on IPCC (2006) methods as adapted for Canada

More detailed information about data sources can be found in the individual subsections under Section Data categories, and as comments on individual cells in the LCI tables (Datasets A1 and A2).

Additional data sources are:

- Crop Residues from Thiagarajan et al. (2018), which referenced Fan et al. (2017), from which more details were obtained
- Seeding rates and pesticide application rates from the report on GHG emissions of cultivation of canola oilseed in Canada submitted to the European Commission (2016)
- Data sources used for camelina are varied and not comparable to the other five crops. Growing camelina is by contract only, and contractors may not share all information they have. Data sources are provided in the individual subsections under Section Data categories.

These data sources are provided in References list.

4.4 Data categories in the Agricultural LCI

4.4.1 Production data

Harvested area and production data were obtained from Statistics Canada (2012, 2013, 2014) on a Small Area Data (SAD) basis from the now retired CANSIM Table 001-0071 and used to calculate the yield, based on the average from three years from 2012 to 2014. SAD was converted to an RU basis by assuming an equal distribution of production through the small area region and using GIS software to aggregate and or divide the Small Area Data to the appropriate RU.

Yield was recalculated for these LCI tables in order to calculate the additional inventory items to the appropriate level of precision. Harvested area and production data were obtained directly from the CRSC reports and were not recalculated.

For Dataset A2, harvest area and production were aggregated to the provincial level, from which provincial average yield was calculated. These values were used for all subsequent production weighting and provincial averaging.

Camelina is not one of the fifteen Canadian Principal Field Crops for which production data are available from Statistics Canada. Further, unlike other more established field crops, camelina yields will fluctuate, as reflected by the Saskatchewan Crop Planning Guides from 2017 to 2019, and will increase as new cultivars are being developed and added to commercial production (e.g. MIDAS and SES0787LS (Smart Earth Seeds, 2019)). Area grown in Saskatchewan was assumed to be 1459 ha, based on the average camelina acreage for 2016 to 2018 from Saskatchewan Crop Insurance Corporation (SCIC) customers (Saskatchewan Crop Insurance Corporation, 2019), and assuming that 73% of camelina growers in Saskatchewan are SCIC customers.[3] Camelina yield was taken to be 1.129 tonnes/ha, based on the average yield of Saskatchewan Crop Insurance Corporation (SCIC) customers from 2016 to 2018, which roughly coincides with the yield of the calena cultivar (Smart Earth Seeds, n.d.).

4.4.2 Seeding Rates

Higher quality data were available for seeding rates of canola in RU 23 and 24 in Manitoba, RU 28, 29 and 30 in Saskatchewan, and RU 34, 35 and 37 in Alberta based on the European Commission (2016) canola report, which was derived from the 2011 survey of canola farmers by the Canola Council of Canada. A value of 5.6 kg/ha has been assumed for the RUs in NB and BC based on the recommended seeding rate from the Saskatchewan Crop Planning Guide 2015, according to the CRSC Canola report. 5.6 kg/ha also corroborates with the canola guidelines from Manitoba Agriculture (2018) and the 2019 Saskatchewan Crop Planning Guide (Saskatchewan Agriculture, 2019).

From the CRSC reports, actual data on seeding rates for field crops in Canada were only found for Quebec (CECPA, 2016) and were based on a relatively small sample of producers. Recommended seeding rates are included in the Manitoba MyFarm Crop Calculator (Manitoba Agriculture, 2016), Saskatchewan Crop Planning Guide (Saskatchewan Agriculture, 2016), and the Ontario Field Crop Budgets (Ontario Ministry of Agriculture, 2015). The Saskatchewan Crop Planning Guide reports seeding rate recommendations for each soil zone, as well as values for both feed and malting barley, whereby the average of the two was used. For the other provinces and other crops, inventory data relied on USDA (2009, 2010, n.d.) ARMS data, and averages or assumptions from the other provinces.

Camelina seeding rate was assumed to be 6.7 kg/ha according to the 2019 Saskatchewan Crop Planning Guide (Saskatchewan Agriculture, 2019). The guide also estimated that there are 650,000 seeds/kg, which gives a seeding rate of approximately

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[3] SCIC insures between 73% to 75% of seeded acres for annual grain crops in Saskatchewan.

4.4 million seeds/ha. This is roughly comparable to the seeding rate of 5.5 to 7 million seeds/ha in a field trial conducted in Saskatchewan (Johnson et al., 2010).

4.4.3 Fertilizer Application Rates

The following table (Table 3) summarizes the data sources from the CRSC reports that were used as the basis of fertilizer application rates for each crop and province.

Table 3. Data sources for fertilizer application rates of different crops

Crop	Provinces	Sources	Years
corn, wheat, barley, canola, soybean	Manitoba	Manitoba Management Plus Program	Average of 2012-2014 (citation year 2015)
wheat, durum wheat, barley, canola	Saskatchewan	Saskatchewan Crop Insurance Corporation	Average of 2012-2014 (citation year 2015, 2016)
corn	Ontario and Quebec	Stratus Fertilizer Use Survey	2015 and 2016
wheat	Ontario and Quebec	Stratus Fertilizer Use Survey	2016
	Alberta		2015
durum wheat	Alberta	Alberta crop budget	2015
barley, canola	Alberta	Stratus Fertilizer Use Survey	2016
barley	Ontario	Field crop budget	2016 (citation year 2015)
barley	Quebec	CECPA benchmarking report	2014 (citation year 2016)
soybean	Ontario and Quebec	Stratus Fertilizer Use Survey	2015
camelina	Saskatchewan	Crop Planning Guide	2019

No data or crop budget was available for the other provinces; therefore, assumptions or national average values were used.

Since data from the CRSC Canola Carbon Footprint report was the most recent source, it was used to calculate fertilizer application rate for canola.

Fertilizer application rates for camelina were assumed to be 74-22-0-17 kg/ha for N-P-K-S respectively (Saskatchewan Agriculture, 2019). The N application rate corroborates with Li and Mupondwa (2016), who reported that recommended N application rates range from 60 to 100 kg/ha, and is not far from Smart Earth Seeds' maximum N requirements of 67 and 100 kg/ha for Brown and Black soil zones respectively (Smart Earth Seeds, 2019).

4.4.4 Types of Synthetic Nitrogen Fertilizer Used

The type of Nitrogen fertilizer applied is provided from the Fertilizer Use Survey for Ontario and Quebec for corn and soybean (Stratus Ag Research, 2016) For all other regions and other crops, data from Statistics Canada (2016) on fertilizer shipments to provinces (by type) for the July 2014 to June 2015 period was used. These data are not crop-specific. The Statistics Canada data were comparable to the Fertilizer Use Survey data for Ontario and Quebec wheat, and for Alberta barley.

This data category is only provided in the first set of LCI tables (Dataset A1), and not in Dataset A2, because: (1) the fractions from both the Stratus Fertilizer Use surveys and from Statistics Canada do not match up with the fertilizer application rate reported in terms of elemental N, P, K and S; (2) total quantity (by weight, volume, etc.) of fertilizer used was not reported; and (3) they are not needed for calculating N_2O emissions, according to the CRSC method.

Fertilizer type data for canola for RU 23 and 24 in Manitoba, RU 28, 29 and 30 in Saskatchewan, and RU 34, 35 and 37 in Alberta based on the European Commission's canola reports.

4.4.5 Crop Residues

The CRSC reports used values for crop residue mass and nitrogen from Janzen et al. (2003), a Canadian-specific study, and also used averages calculated using Janzen et al., other studies, and IPCC values.

Thiagarajan et al. (2018) updated the values provided by Janzen et al. (2003) for 11 crops in Canada, including wheat, corn, barley, soybean and canola, based on new Canadian-specific references. No distinction was made between wheat and durum wheat. For camelina, generic values for oilseed crops from Fan et al. (2017) were used for the calculation of crop residue mass, and canola values were used for calculating crop residue N.

According to Thiagarajan et al., the partitioning of the total dry matter of a plant into belowground residue (BGR), seed mass (G), and aboveground residue (AGR) is dependent on the seed yield (Y), which is also understood as G over area. The AGR for grain crops is often estimated using the harvest index (HI), which refers to the ratio of seed mass (G) to total shoot mass (G + AGR). The BGR is frequently estimated from shoot mass based on the root/shoot ratios (RSR) based on the entire rooting depth. These values were used to calculate Crop Residue N.

Mass above ground

The crop residue mass above ground in the CRSC Carbon Footprint reports is $\frac{AGR}{G}$.

From Thiagarajan et al. (2018), $= \frac{G}{G+AGR}$. Rearranging, $\frac{AGR}{G} = \frac{1}{HI} - 1.$

It had been previously shown that there is a linear relationship between HI and Y, i.e. $HI = I_c + S_c{*}Y$, where I_c is the intercept and S_c is the slope of the harvest index-yield relationship. Slopes and intercepts are provided for each crop.

Rearranging, $\frac{AGR}{G} = \frac{1}{I_c+S_c{*}Y} - 1$

Since yield is RU-specific, RU-specific values for crop residue mass above ground were calculated for the LCI tables.

It must be noted that these values are on the basis of G, which is dry grain or seed mass. To be functionally equivalent with the rest of the data based on the functional unit (see Scope), crop residue mass above ground is multiplied by weight percent of dry grain or oilseed in the total weight of the grain or oilseed inclusive of moisture content. This was done for the aggregated and production weighted set of LCIs (Dataset A2).

Mass below ground

The crop residue mass below ground in the CRSC Carbon Footprint reports is $\frac{BGR}{G}$

Thiagarajan et al. (2018) provided three equations for dry matter partitions, including $BGR(in\ kg/tonne) = \frac{RSR*Y}{I_c+S_c*Y}$, where RSR is the root/shoot ratio.

This can be adapted into a ratio:

$$\frac{BGR}{G} = \frac{RSR}{I_c + S_c * Y}$$

RSR values were provided for each crop.

Since yield is RU-specific, RU-specific values for crop residue mass below ground were calculated.

Crop residue mass below ground was also calculated to be functionally equivalent (per tonne of moist grain or oilseed) with the rest of the inventory data for the second set of LCIs (Dataset A2).

Nitrogen concentrations

Nitrogen concentrations of above and below ground crop residues were updated for each crop in Thiagarajan et al. (2018) on the basis of dry matter. It is expected that N content per dry matter would not change across regions, hence Canada-specific data are sufficient, and RU-specific Crop Residue N can be determined. Mean values are reported in the LCI tables.

There are two exceptions. The below ground Nitrogen value for soybean still uses the values from Janzen et al. (2003) because no update was provided in Thiagarajan et al. (2018). Values intended for canola were used for camelina, since both are oilseed crops and are produced in a similar manner.

4.4.6 Pesticide application rate

Pesticide application rates for canola have been updated with RU-specific data for RU 23 and 24 in Manitoba, RU 28, 29 and 30 in Saskatchewan, and RU 34, 35 and 37 in Alberta based on the European Commission’s canola report, which was based on data from the 2011 Canola Council survey. The value of 0.80 a.i. kg / ha was used for the other RUs, according to the CRSC Methodology Report.

From the CRSC reports, actual pesticide application rate was only available for Ontario from a 2014 pesticide survey (Farm & Food Care Ontario, 2015), and for Quebec wheat from Group Ageco (2015). The USDA NASS (2015) data was used for durum wheat. The USDA (n.d.) ARMS survey was consulted for barley. Application rates for the other provinces and other crops are based on the assumption that they were the same as the provinces with data available.

For camelina, the Saskatchewan Crop Planning Guides from 2017 to 2019 recommends the Assure II herbicide and seeding early onto a clean field for pest control. Most producers use about 0.3L/ac of Assure II, (Smart Earth Seeds, 2019), which has an active ingredient concentration of 96 g/L (E.I. du Pont Company, 2016). In addition, most producers also use the Roundup WeatherMax for pre-harvest aid at 0.68L/ac due to the pre-seed burn-off of the active ingredient glyphosate (Smart Earth Seeds, 2019), at a concentration of 540g/L (E.I. du Pont Company, 2017), consistent with that used in the Ontario Food & Farm Care Survey. The total pesticide application rate was calculated to be 0.160 kg/ha. The rate for camelina is lower than that for the other crops.

4.4.7 Direct Energy Use

Energy is used for cultivation, irrigation, trucking, and storage.

According to the CRSC Carbon Footprint Methodology, the cultivation energy for the Prairie Provinces for wheat, durum wheat, barley and canola was calculated from the Prairie Crop Energy Model (PCEM) model, and tillage data is from the 2011 Agricultural census. Cultivation fuel use for non-Prairie provinces were calculated based on tillage practices and typical fuel use values for each type of tillage.

Irrigation energy is included for RUs in Western Canada (BC, Alberta, Saskatchewan and Manitoba) with more than 1% irrigated area. These were RU 35 and 37 in Alberta, and RU 41 and 42 in BC. It was thus assumed that none of the corn and soybean area is irrigated for the purposes of calculating energy use. Therefore, the USDA (2012) ARMS survey data for non-irrigated states were taken for cultivation fuel use for corn and soybeans.

For corn and soybeans, direct energy use was not aggregated because there appeared to be an error in the calculation of aggregated energy use in the CRSC reports, where the per hectare unit for cultivation and the per tonne unit for trucking and storage were conflated. It is likely that the same error was present in the canola energy use summary for Electricity. Steps to correct this error are suggested in a comment on the “Electricity” data category for canola.

Trucking energy use is calculated by using 6.6 MJ/tonne-km of diesel fuel for a mid-size truck, multiplied by an average of 5 km between field and storage bin, to obtain 0.86 litres of diesel per tonne of grain or oilseed.

Storage energy use is calculated by assuming that 0.5 kWh/tonne of electricity is used for moving grain from a truck into a bin and then back into a truck, and another 2 kWh/tonne of electricity is used for aeration of the storage bin.

The European Commission’s canola report provides detailed diesel fuel use calculations and data for canola. The values were similar to the values from the CRSC Canola Carbon Footprint report. The latter was used for the LCI tables for methodological consistency.

Energy use values for natural gas and gasoline were frequently zero when irrigation energy use was not considered, and values for liquid petroleum gas (LPG) was only reported for soybean. Data categories with zero values from the CRSC Carbon Footprint reports, such as LPG, were removed, to distinguish lack of reporting from when reported values are zero.

Direct energy use was not provided in Li & Mupondwa (2014)’s camelina cultivation life cycle inventory. The values for canola were used for camelina, since both are oilseed crops and are produced in a similar manner.

4.4.8 Nitrogen Rates

Nitrogen rates were retotaled to reflect the change in Crop Residue N based on more recent data. These values were used to calculate N_2O emissions in the section N_2O Emissions.

Synthetic N

Synthetic N rates can be calculated by converting the N fertilizer application rate from a per hectare basis to a per tonne basis.

Crop Residue N

Crop Residue N refers to the Nitrogen emissions from the decomposition of the remaining plant matter left on the field after a crop is harvested. The following equation for the amount of nitrogen contained in crop residue on a per tonne basis was derived from matching the mass and nitrogen concentration values for aboveground and belowground biomass (the data provided under the data category Crop Residues) with the Crop Residue N values in the individual CRSC crop reports.

$$\left(\frac{AGR}{G} * above\ ground\ N + \frac{BGR}{G} * below\ ground\ N\right) * \%\ dry\ matter$$

AGR refers to the above ground crop residue, and BGR the below ground crop residue, and both were given on the basis of dry grain or seed in the first set of LCI tables (Dataset A1). This results in RU-specific crop residue N values, since it is expected that N content per dry matter would not change across regions. Finally, the g_{N} / kg_{grain} unit obtained from the multiplication can be assumed to scale up directly to $kg_{N} / tonne_{grain.}$

Calculating using this equation and the old Crop Residue values in the CRSC reports produces values that match the Crop Residue N reported in the CRSC reports to ±0.1 kg/tonne for corn, wheat, barley, and canola. There are two exceptions, for which the calculation produced different results: durum wheat and soybean.

For durum wheat, we think that the difference is due to a miscalculation, whereby the % dry matter of wheat was used instead of the % dry matter of durum wheat.

For soybean, we were unable to determine how Crop Residue N was calculated, hence have left the value as 22.7 kg/tonne, extracted from the CRSC Barley Carbon Footprint report, for all RUs.

The final nitrogen rates were retotaled based on these changes.

Soil mineralization N

A default C:N ratio of 10:1 is used to calculate the mineralized N from the soil C, consistent with IPCC guidelines. No further explanation was provided on how mineralized N was calculated.

From the inventory tables, it can be computed that the ratio of total SOC change to soil mineralization N is consistently between 36 and 37 for all RUs, except for those in the Prairies, where soil mineralization N is always zero.

Hence, for camelina, since all production is in the Prairie provinces, soil mineralization N is always zero.

4.4.9 N_2O Emissions

Calculations for N_2O emissions (direct and indirect) were completed using the methodology described in the CRSC Carbon Footprint Methodology Report as follows.

Direct

Direct N_2O emissions were calculated using the Canadian Tier 2 Methodology, excluding manure, and the Emission Factor 1 was modified by AAFC to include adjustments for tillage type, topography, irrigation practices. The formula used is:

$$N_2O = (F_{SN} + F_{CR} + F_{SOM}) * EF_1$$

where

N_2O = annual direct N_2O–N emissions from N inputs to managed soils, kg $_{N2O-N}$ / yr

F_{SN} = annual amount of synthetic fertilizer N applied to soils, kg $_N$ / yr

F_{CR} = annual amount of N in crop residues (above-ground and below-ground), returned to soils, kg $_N$ / yr

F_{SOM} = annual amount of N in mineral soils that is mineralized, in association with loss of soil C from soil organic matter as a result of changes to land use or management, kg $_N$ / yr

EF_1 = Emission Factor 1, kg $_{N2O\text{-}N}$ / kg $_N$

The N rates in the brackets sum up to “Total N”, which was used for the calculations.

Indirect, volatilization

Indirect N_2O emissions from volatilization follow the Tier 1 Methodology from the IPCC GHG Guidelines (2006) and do not use Canada-specific values. Manure was excluded. The formula used is:

$$N_2O_{(ATD)} = (F_{SN} * Frac_{GASF}) * EF_4$$

where

$N_2O_{(ATD)}$ = annual amount of N_2O–N produced from atmospheric deposition of N volatilized from managed soils, kg $_{N2O-N}$ / yr

$Frac_{GASF}$ = fraction of synthetic fertilizer N that volatilizes as NH_3 and NOx, unitless or kg $_{N\ volatilized}$ / kg $_{N\ applied}$ **= <u>0.10</u>**

EF_4 = Emission factor 4 for N_2O emissions from atmospheric deposition of N on soils and water surfaces, unitless or [kg$_{N2O-N}$ (kg $_{NH3-N\ +\ NOx-N\ volatilised}$)$^{-1}$] **= <u>0.01</u>**

Indirect, leached

A modified Canadian Tier 1 Methodology was used to determine indirect leached N_2O emissions. Manure was excluded. The formula used is:

$$N_2O_{(L)} = (F_{SN} + F_{CR} + F_{SOM}) * Frac_{LEACH} * EF_5$$

where

$N_2O_{(L)}$ = annual amount of N_2O–N produced from leaching and runoff of N additions to managed soils in regions where leaching/runoff occurs, kg $_{N2O-N}$ / yr

$Frac_{LEACH}$ = fraction of all N added to/mineralized in managed soils in regions where leaching/runoff occurs that is lost through leaching and runoff, unitless or [kg_{N} / $kg_{N\ additions}$].

EF_5 = Emission factor 5 for N_2O emissions from N leaching and runoff, unitless or [$kg_{N2O–N}$ / $kg_{N\ leached\ and\ runoff}$] = **0.0075**

4.4.10 Soil Organic Carbon Changes

Soil organic carbon (SOC) changes were calculate for management activity changes on cropland remaining cropland. There are three potential sources of SOC change to consider in this context:

1. Mineral soil management practices resulting in reductions in carbon losses, or in some cases a sink, include:
    a. Reducing summer fallow
    b. Increasing no till and reduced till
    c. Reestablishment of perennial vegetation
    d. Yield promoting practices
    e. Irrigation
    f. Manure application
    g. Fertilization
2. CO_2 emissions from cultivation of organic soils.
3. CO_2 emissions and removals from changes in woody biomass from specialty crops.

Only (a) reducing summer fallow, (b) increasing conservation tillage practices, and (c) reestablishment of perennial vegetation were included in the CRSC calculations. Supporting information was not provided in the CRSC methodology report.

The annual change in soil carbon from conventional practices resulting from changes in tillage practices, reduced summer fallow, and the change from perennials to annual crops, as calculated by AAFC for each of the RUs, is reported and utilized on a per hectare basis, up to the 2014 crop year. Similar to the lost carbon from conventional practices, these values are taken as crop-agnostic in the CRSC calculations and in this study.

Both Datasets A1 and A2 show these values on a per tonne basis for each crop in each area (RU for Dataset A1, province for Dataset A2) of production based on yield.

4.5 Data Gaps and Uncertainty in the Agricultural LCI

Little information is available in the CRSC Carbon Footprint reports on variability. Spread was occasionally provided for individual data points. For example, a range of values was reported in the CRSC Barley Carbon Footprint report for seeding rates per RU in Saskatchewan, to reflect the different values for feed and malting barley.

Variability was reported in the updated values for the mass and nitrogen concentration of crop residues from Thiagarajan et al. (2018) and Fan et al. (2017). Mean values were used for the data points.

Spatial variability is seen between RUs and provinces, which is what these inventories aim to show. There would also be spatial variability within an RU, but this was not reflected. To minimize temporal variability, the CRSC reports attempted to use data that is recent and from a similar time period. Variability between objects was said to have little consequence on the CRSC studies.

The treatment of Soil Organic Carbon (SOC) relied on an approximation that the annual change in soil carbon resulting from changes in tillage practices, reduced summer fallow, and the change from perennials to annual crops could be treated as the same for each crop type in each RU. There is a high degree of both variability and uncertainty associated with SOC changes from agricultural land transformation. Additional research is needed to better associate these processes with specific crops and decrease their overall uncertainty.

In the CRSC methodology report, data quality was assessed to be “quite good” for crop yields and fertilizer application rates, “not as good” for direct energy use, and “poor” for pesticide application rates.

4.6 Agrochemicals upstream emissions

As described above, the CALDC library has N, P, K and S nutrient use, as well as pesticide application rates, as extracted from the CRSC reports and related sources. The CI values for N, P and K nutrients from Canadian fertilizers have been taken from a fertilizers report prepared for the CRSC analysis (Cheminfo , 2016), based on 2014 market data and detailed producer data. S nutrient and pesticide CI values from detailed LCI data for fertilizer and pesticide inputs are taken from the GREET2018 model (ANL, 2018).

There are five primary pesticides in widespread use for the relevant crops. In the absence of detailed data in the LCI as to the share of each type used on a given crop or the data analogous to that for Canadian fertilizer shipments to agriculture, the upstream emissions for pesticides are treated as an average of the emissions for each of the five pesticides.

Table 4 shows the nutrient and pesticide CIs used for the crop-based low carbon fuel pathways.

Table 4: Nutrient and pesticide cradle-to-farm emissions used in the pathways, in grams per kg.

Input				**CO_2 eq.**
N, per kg				3,180
P, per kg				930
K, per kg				278
	CH_4	**N_2O**	**CO_2**	**CO_2eq**
S, per kg	8.51	0.056	2,829.6	3,083
Pesticide, per kg a.i.	32.32	0.329	18,820	19,880

As the Canadian-specific report (Cheminfo , 2016) has only the aggregated CO2eq values, a separate set of processes have been developed to make the individual CH_4, N_2O and CO_2 contributions available; this is based on 2014-2017 market data (Statistics Canada, 2019), nutrient balances, and individual contributions for each fertilizer from the GREET2018 LCI; these values can be found in Table 112, Table 111, and Table 113 in Appendix section 0 A1. Agrochemicals Carbon Intensity Data.

4.7 Carbon Intensity values for Crops

4.7.1 Key LCI data

Management practice LCI data for relevant grain crops and oilseed crops are summarized in Table 5 and Table 6, respectively. Table 7 provides a summary of energy inputs to crop cultivation and management.

Table 5: Grain crop management practice data per tonne of harvested crop (dry matter basis as compiled for the CALDC Agricultural LCIs based on the CRSC reports and other sources.

Province	Production Data			Seeding Rates	Fertilizer application rate				Pesticide application rate
	Harvest Area, ha	Production, T	Yield, T/ha	kg/T	N, kg/T	P, kg/T	K, kg/T	S, kg/T	Active Ingredient kg/T
Corn									
NS	13,600	101,467	7.46	2.68	20.00	5.006	5.006	1.001	0.26
PE					20.00	4.996	4.996	1.004	
NB					20.00	4.994	4.994	0.993	
PQ	381,865	3,429,257	8.9803	2.38	16.40	5.101	5.101	0.499	
ON	846,727	8,398,858	9.9192	2.15	14.20	4.327	6.934	0.701	
MB	137,889	1,005,621	7.2930	3	17.64	5.229	3.463	1.166	
Wheat									
NS	13,701	46,934	3.43	33.6	21.84	6.794	1.941	0.971	0.20
PE					27.02	8.407	2.402	1.201	
NB					29.34	9.129	2.608	1.304	
PQ	52,491	170,909	3.2560	58.4	13.4	2.9	6.91	0.28	0.25
ON	385,759	1,995,152	5.1720	24.2	21.1	7.0	4.76	2.20	0.13
MB	1,196,583	4,193,901	3.5049	5.3	27.2	10.0	2.43	1.16	0.20
SK	3,735,009	10,508,747	2.8136	114.4	26.9	9.5	1.19	1.56	0.25
AB	2,244,640	7,967,484	3.5496	32.4	27.2	6.6	2.82	0.74	0.20
BC	13,084	43,729	3.3422	34.4	26.9	8.4	2.39	1.20	0.21
Barley									
NS	37,266	119,867	3.22	34.2	24.2	8.1	3.2	1.61	0.30
PE					22.7	7.6	3.0	1.52	
NB					25.3	8.4	3.4	1.69	
PQ	59,366	190,275	3.2051	53.0	24.3	14.7	10.92	1.56	
ON	39,902	136,554	3.4222	39.2	22.8	8.8	6.72	1.46	

MB	158,771	554,723	3.4939	30.6	23.3	9.5	2.41	1.16	
SK	844,085	2,477,764	2.9354	123.5	24.3	9.2	1.60	1.38	
AB	1,097,281	4,001,527	3.6468	30.2	22.4	8.3	2.16	1.95	
BC	9,113	29,156	3.1994	34.4	23.4	7.8	3.13	1.56	

Table 6: Oilseed crop management data per tonne of harvested crop (dry matter basis), as compiled for the CALDC Agricultural LCIs based on the CRSC reports and other sources.

Province	**Production Data**			**Seeding Rates**	**Fertilizer application rate**				**Pesticide application rate**
	Harvest Area, ha	Production, T	Yield, T/ha	kg/tonne	N, kg/T	P, kg/T	K, kg/T	S, kg/T	Active Ingredient kg/T
Canola									
NB	2,200	4,633	2.106	2.659	47	14	3.8	7.1	0.42
MB	1,272,119	2,397,762	1.885	8.8	57	18	4.0	9.3	
SK	4,112,144	7,261,064	1.766	9.3	54	16	1.7	9.8	
AB	2,247,367	4,856,114	2.161	7.7	45	14	7.9	8.8	
BC	16,305	30,799	1.889	8.9	47	16	4.2	7.9	
Soybean									
NS	33,300	82,167	2.47	26.5	2.04	5.433	11.884	0.306	0.61
PE					2.46	6.548	14.324	0.368	
NB					2.73	7.269	15.902	0.409	
PQ	301,381	856,246	2.841	26.4	2.64	2.957	4.681	0.317	
ON	1,109,257	3,472,397	3.130	22.4	1.66	4.934	13.793	0.231	
MB	295,625	694,737	2.350	34	1.85	13.643	5.937	1.213	
Camelina									
MB	304	510	1.7	4.0	44	13	0	10	0.16
SK	2,221	2,506	1.13	5.9	66	19	0	15	0.16

One of the objectives for the Fuel LCA Modelling Tool is to be able to reflect regional or provincial differences in carbon intensity for low carbon fuels. The provincial-level LCI data in the CALCD accommodate this.

Table 7. Agricultural energy use data per tonne of harvested crop (dry matter basis) for grain crops, as compiled for the CALDC Agricultural LCIs based on the CRSC reports and other sources.

Province	Direct Energy Use for Cultivation (on-farm)					Energy Use for Storage	Energy Use for Trucking
	Diesel, L/tonne	Gasoline, L/tonne	Natural gas, MJ/tonne	LPG, L/tonne	Electricity, kWh/tonne	Electricity, kWh/tonne	Diesel, L/tonne
Corn							
NS	3.99	1.9	7.04	2.0	1.9	2.5	0.86
PE							
NB							
PQ							
ON							
MB							
Wheat							
NS	7.9	0.0	0.0	0.0	0.61	2.5	0.86
PE	9.8	0.0	0.0	0.0	0.75		
NB	10.6	0.0	0.0	0.0	0.82		
PQ	10.5	0.0	0.0	0.0	34.0		
ON	6.5	0.0	0.0	0.0	37.6		
MB	9.8	0.0	0.0	0.0	39.3		
SK	9.5	0.0	0.0	0.0	39.0		
AB	8.9	0.0	0.0	0.0	39.4		
BC	8.0	0.0	0.0	0.0	40.0		
Barley							
NS	32.6	0.0	0.0	0.0	0.0	2.5	0.86
PE	32.6	0.0	0.0	0.0	0.0		
NB	32.6	0.0	0.0	0.0	0.0		
PQ	34.3	0.0	0.0	0.0	0.0		
ON	33.8	0.0	0.0	0.0	0.0		
MB	37.8	0.0	0.0	0.0	0.0		
SK	29.6	0.0	0.0	0.0	0.0		
AB	30.7	0.0	0.0	0.0	0.0		
BC	28.5	0.0	0.0	0.0	0.0		

Table 8. Agricultural energy use data per tonne of harvested crop (dry matter basis), for oilseed crops, as compiled for the CALDC Agricultural LCIs based on the CRSC reports and other sources.

Province	Direct Energy Use for Cultivation (on-farm)					Energy Use for Storage	Energy Use for Trucking
	Diesel, L/tonne	Gasoline, L/tonne	Natural gas, MJ/tonne	LPG, L/tonne	Electricity, kWh/tonne	Electricity, kWh/tonne	Diesel, L/tonne
Soybean							
NS	9.00	3.34	0.0	0.03	3.00	2.5	0.86
PE							
NB							
PQ							
ON							
MB							
Canola							
NB	15.5	0.0	0.0	0.0	1.2	2.5	0.86
MB	18.4	0.0	0.0	0.0	1.3		
SK	15.2	0.0	0.0	0.0	1.4		
AB	13.5	0.0	24.0	0.0	4.4		
BC	15.7	0.1	128.8	0.0	18.8		
Camelina							
MB	20					2.5	0.86
SK	22.6					2.5	0.86

Peas are not yet included in the CALDC LCI dataset, so the Canadian Agricultural summary value (0.38 kg CO_2 eq./kg dry matter) has been used (Desjardins, et al., 2016).

4.7.2 Calculated CI values for crop production

Canadian average and provincial CIs for the included crops are presented in Table 9. The results of the uncertainty analysis on Canadian average production for these crops are shown in Table 11.

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Table 9. Provincial and Canadian average (production weighted) carbon intensity values (cradle to gate) including SOC contributions for key crop feedstocks, expressed in g CO_2 eq./kg of crop produced (dry matter basis), shown with CRSC reported values (previously cited reports; values with "~" are estimated from Churchill & O'Connor 2017).

	Grain Crops					Oilseed Crops		
CI (g CO_2eq/kg)	**Corn**	**Wheat**	**Durum Wheat**	**Barley**	**Dry Peas***	**Canola**	**Soybean**	**Camelina****
Canada Average	350	180	75	150	380	380	410	-
Alberta	-	170	440	130		390	-	-
British Columbia	-	310	-	420	-	620	-	-
Manitoba	180	240	-	210		580	20	390
New Brunswick	480	780	-	740	-	1,300	580	-
Nova Scotia	650	980	-	1,200	-	-	950	-
Ontario	340	530	-	680	-	-	430	-
Prince Edward Island	460	770	-	720	-	-	570	-
Quebec	440	690	-	820	-	-	610	-
Saskatchewan	-	79	30	72		310	-	140
CRSC Canada Average	370	230	~80	196		383	~580	

* Dry peas value from Desjardins et al 2018. **Because there is so little camelina produced in Canada currently, almost all in Saskatchewan, a Canadian average value is not calculated.

For grain crops, the production impacts in all provinces and at the national level are driven by nutrient use and SOC changes with land conversion. For canola and camelina, nutrients use and SOC changes dominate, and for soybeans, the pesticide use contribution is about equivalent with that of nutrients use. Higher CIs in Manitoba and New Brunswick, particularly for canola (NB) and barley (MB), are driven by higher N2O emissions and net soil carbon loss. These are consistent with the large variation in net GHG emissions reported as part of the CRSC effort.

Results for Canadian average crops are in good agreement with the CRSC analysis. Differences between the current analysis and CRSC values are generally due to differences in upstream processes. While the inventory data is primarily derived from the CRSC reports as described above, upstream processes differ in some cases. In particular, we have updated the analysis using the 2016 grid electricity model year in place of 2014, and all fuels use the pathways developed during Milestone 2. Additionally, we have augmented the N, P, K nutrient emissions with processes for pesticides and S nutrients.

Because SOC values are more speculative, CI values without SOC are shown in Table 10.

Table 10. Provincial and Canadian average (production weighted) carbon intensity values (cradle-to-gate) *excluding* SOC contributions for key crop feedstocks, expressed in g CO_2 eq./kg of crop produced (dry matter basis).

	Grain Crops					Oilseed Crops		
CI (g CO_2eq/kg)	Corn	Wheat	Durum Wheat	Barley	Dry Peas*	Canola	Soybean	Camelina**
Canada Average	270	300	250	270	*380*	610	160	-
Alberta	-	300	320	250	-	580	-	-
British Columbia	-	340	-	350		660	-	-
Manitoba	210	300	-	280	-	710	110	530
New Brunswick	370	540	-	490		980	240	-
Nova Scotia	400	490	-	570		-	280	-
Ontario	250	370	-	420		-	160	-
Prince Edward Island	360	510	-	460		-	230	-
Quebec	310	360	-	500	-	-	210	-
Saskatchewan	-	270	240	260		600	-	630

* Dry peas value from Desjardins et al 2018. **Because there is so little camelina produced in Canada currently, almost all in Saskatchewan, a Canadian average value is not calculated.

4.7.3 Data quality and uncertainty in crop production CIs

Table 11 presents the results of the uncertainty analysis on for the CI of Canadian average production for each crop. Where possible, the range is based on minimum and maximum values from provincial values, in preference to a pedigree matrix.

The results show a high degree of uncertainty, which is typical of agricultural systems, and reflect the extent of variation amongst provinces. This differs from the average values in Table 9, which are production weighted and thus reflect most probable values.

The lower bound of the 95% confidence level (2.50%) suggests other significant factors beyond expected agricultural process variation. The negative values are a result to the dominant SOC values. Figure 3 explores this more detail, showing the total (left) and the SOC contribution (right).

Table 11: Results of uncertainty analysis on crop production cradle-to-gate CIs in the CALDC library.

Crop	Mean	Median	Standard Deviation	2.50%	97.50%	Standard Error of the Mean	Unit
Grain Crops							
Corn	410	390	140	230	730	3.2	g CO_2 eq/kg
Wheat	530	490	240	200	1,200	5.4	g CO_2 eq/kg
Durum Wheat	170	150	160	-90	550	3.6	g CO_2 eq/kg
Barley	670	620	280	260	1,400	6.3	g CO_2 eq/kg
Oilseed Crops							
Canola	460	470	180	77	780	3.9	g CO_2 eq/kg
Camelina (SK)	490	400	330	130	1,400	7.3	g CO_2 eq/kg
Soybean	150	160	400	-720	910	8.9	g CO_2 eq/kg

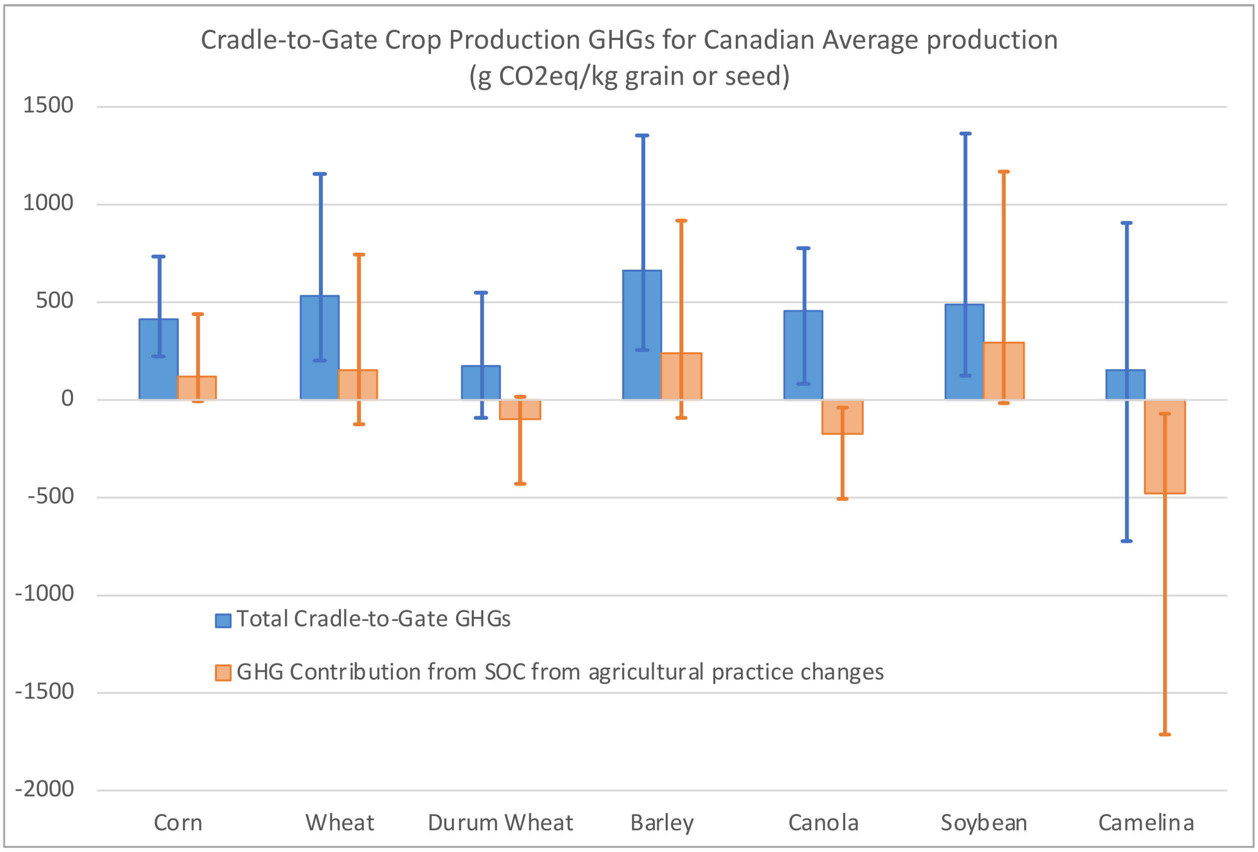

Figure 3: Carbon Intensities Canadian average grain and oilseed crops total (left, blue) and contribution from land transformation (SOC) (right, orange), showing significance of SOC uncertainty.

Figure 3 shows CI results with uncertainty for Canadian average crops. They exhibit high uncertainty and a significant contribution from soil organic carbon arising from changes in management practice. It illustrates the challenge of incorporating management practice change land transformation values as well as underlying data gaps. As discussed above, the approximation the annual change in soil carbon resulting from changes in tillage practices, reduced summer fallow, and the change from perennials to annual crops is the same for all crops compounds the already high uncertainty (the CRSC study classified emissions data quality as “poor”) with potentially misleading estimates for SOC changes for some crops. The net result is an extremely high uncertainty at the provincial and national level for GHGs from land transformation and for total crop GHGs (see Figure 3).

4.7.4 Data Gaps for Crop Production CIs

- Soil organic carbon approximations. There is a high degree of uncertainty associated with SOC changes from agricultural land transformation already; by not applying any production weighting for crops produced in a given RU or province, that uncertainty is compounded and, in some cases, results in unexpected negative emissions. Additional research is needed to better associate these processes with specific crops and decrease their overall uncertainty.
- Canola in Ontario (and data for other small contributors to various crops)

4.8 Carbon Intensity values for crop residues

Collecting and removing crop residues adds additional energy use and nutrient replacement above conventional crop production, as well as potential water use and emissions changes. Crop residues thus differ from a simple waste and require an independent Carbon Intensity value. Through discussions with ECCC, it was decided that in the interests of transparency, and to avoid allocation, a highly simplified crop residue process is used. This approach is described below.

4.8.1 Approach Summary

Current practice in Canada, to which the CSRC data relates, has minimal residue collection and negligible amounts used for bioenergy. Residue collection is therefore treated as a collection of practices additional to that data. A CI for residues is developed based on 1) replacement of N in collected residues assuming application of equivalent amounts of nutrient; and 2) a coarse estimate for diesel use in collection of residues as an additional harvesting pass over the fields. This is calculated per tonne of collected biomass. Together these provide a rough estimate to contribute to the CI of crop residues for use in bioenergy production.

Removal of residues can also change yields, water demand, demand for nutrients other than N, and field emissions; however, these processes are more complex and uncertain than can be accommodated here and are omitted from the CI. The uncertainty on the CI reflects these assumptions.

The approach used here ensures the residues carry a non-zero impact that can be clearly related back to the quantity of residue used. For example, if a given producer decides that they are working with a farmer and collecting, e.g., 30% of the crop residue in those fields, the calculated CI will give a coarse sense for it. Future work is anticipated to refine the handling of crop residues in the Tool. The approach here is intentionally over-simplified, with the expectation that it will provided an initial, transparent, framework for future modelers.

Nutrient Replacement and Biomass Yield

Residues carry a non-zero impact that can be clearly related back to the quantity of residue used. For example, if a given producer decides that they are working with a farmer and collecting, e.g., 30% of the crop residue in those fields, the calculated CI will give a coarse sense for it. Future work is anticipated to refine the handling of crop residues in the Tool.

The quantity of N removed from the field in collected biomass is calculated using the N content in Table 12 and the biomass yields from CRSC data. The content of other nutrients and micronutrients in crop biomass are not included in the CRSC data.

Table 12: Nitrogen content in above ground biomass for cellulosic ethanol feedstocks used here, in kg N per tonne dry matter (residue) (Thiagarajan et al 2018), used for calculating the nutrient replacement contribution to the crop residue Carbon Intensity.

	Mean	Standard Deviation	Unit
Wheat straw	6.64	3.15	kg N/t Dry Matter
Corn stover	9.37	2.59	kg N/t Dry Matter

To account for the fact that only a portion of the N in the harvest residues is available to the crop, a range of 0% to 72% with a peak of 58% is applied. The Canadian average CI for nutrient N is then used to calculate the impact of replacing the removed nutrient.

Energy Use

The vehicle and diesel use in residue collection is treated as an additional transportation impact, using a simple heavy-duty diesel truck as a proxy. Distance is estimated based on per hectare yields, assuming a square field, and the number of passes to cover the field with average grain combine harvester head sizes[4].

To collect residues uniformly across the entire field, these averages give rise to travel distances between 0.8 and 1.9 km per ha, with an average of 1.1 km/ha. Calculated distances for collection are shown in Table 13 with their underlying yields.

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[4] Cutting widths, compiled from grain combine harvester comparison charts at https://www.caseih.com/northamerica/en-us/Pages/Comparison.aspx?family=GrainHeadsRigidCombine#, generally range from 5.2m to 12.5m, with an average of 8.9m; the width offered by the greatest number of manufactures is 9.14m.

Table 13: Canadian provincial and national average crop residue yields and generalized collection distance for wheat straw and corn stover used for estimating the residue collection contribution Carbon Intensity.

Province	Crop residues yield (mass), tonne biomass (dry)/ha			Average distance covered for collection, km per tonne biomass (dry)		
	Corn Stover	Wheat Straw, non-Durum	Wheat Straw, Durum	Corn Stover	Wheat Straw, non-Durum	Wheat Straw, Durum
Nova Scotia	7.000	4.428		0.161	0.254	
Prince Edward Island	7.224	3.247		0.156	0.347	
New Brunswick	6.501	2.866		0.173	0.393	
Quebec	7.560	4.464		0.149	0.252	
Ontario	7.894	5.485		0.143	0.205	
Manitoba	6.795	3.103		0.166	0.363	
Saskatchewan		2.562			0.440	
Alberta		3.863	3.957		0.292	0.285
British Columbia		3.265	3.825		0.345	0.294
National Average, Production Weighted	7.712	3.319	3.936	0.146	0.359	0.286

4.8.2 Calculated Carbon Intensity Values for Crop Residues

The following tables show the provincial and national average CIs for the feedstock contribution to the crop residue cellulosic ethanol pathways. Table 14 shows the CI for corn stover, and Table 15 that for wheat straw. Table 16 presents the results of the uncertainty analysis for corn stover and wheat straw.

Table 14: Provincial and national average (production weighted) Carbon Intensity values for corn stover from collection, replacing N removed in the collected biomass, and the combined total, in kg CO2eq/tonne (dry matter).

Province	Collection, kg CO2eq/tonne (dry matter)	replacement (58%), kg CO2eq/tonne (dry matter)	Combined kg CO2eq/tonne (dry matter)
Nova Scotia	0.022	17.28	17.304
Prince Edward Island	0.022	17.28	17.304
New Brunswick	0.024	17.28	17.306
Quebec	0.021	17.28	17.303
Ontario	0.020	17.28	17.302
Manitoba	0.023	17.28	17.305
National Average, Production Weighted	0.020	17.28	17.302

Table 15: Provincial and national average (production weighted) Carbon Intensity values for wheat straw (Durum and non-Durum varieties) from collection, replacing N removed in the collected biomass, and the combined total, in kg CO2eq/tonne (dry matter).

	Wheat straw, non-Durum			Wheat straw, Durum		
Province	Collection	58% N replacement	Combined	Collection	58% N replacement	Combined
Nova Scotia	0.035	12.2	12.282			
Prince Edward Island	0.048	12.2	12.295			
New Brunswick	0.054	12.2	12.301			
Quebec	0.035	12.2	12.282			
Ontario	0.028	12.2	12.275			
Manitoba	0.050	12.2	12.297			
Saskatchewan	0.061	12.2	12.308			
Alberta	0.040	12.2	12.287	0.039	12.2	12.286
British Columbia	0.048	12.2	12.295	0.041	12.2	12.288
National Average, Production Weighted	0.050	12.2	12.297	0.040	12.2	12.287

4.8.3 Uncertainty Analysis of Crop Residue CIs

The agricultural residue CIs are more speculative than the crop production CIs. Because they are currently a residue of crop production rather than a co-product, they do not carry any of the grain/primary crop production impacts (i.e., they are not an allocated process). However, there are impacts specifically associated with the collection and removal of these residues. Data specific to these practices are not available, so simplified processes were created for the residues, as described in Section. 4.8.

CIs range from nearly zero to 20-30 g CO_2 eq/kg dry matter, driven by the wide uncertainty around how much of the nutrient in the biomass residue removed would have been available for the crop and thus must be replaced (0-72%). Energy use for the passes over the field to collect the biomass make a much smaller contribution.

Table 16: Results of uncertainty analysis on crop residue CIs.

Biomass	Mean	Median	Standard Deviation	2.50%	97.50%	Standard Error of the Mean	Unit
Corn stover	0.0130	0.0113	0.0078	0.0023	0.0330	0.0002	kg CO_2 eq/kg dry matter
Wheat straw, non-Durum	0.0092	0.0079	0.0061	0.0014	0.0246	0.0001	kg CO_2 eq/kg dry matter
Wheat straw, Durum	0.0091	0.0079	0.0059	0.0015	0.0244	0.0001	kg CO_2 eq/kg dry matter

4.8.4 Data Gaps for Agricultural Residues CIs

- Field-level collection fraction response: In an actual implementation, a given project is most likely to involve collection of a fraction of the field's total residues, and research has thus far shown a relationship between field response and share of material collected more complex than the simple linear residue mass: field-level response assumption necessitated here. *Additional research and reporting needed.*
- Residue collection energy use - distance traveled in field, truck vs. harvester or truck and trailer, collection fraction. *Additional reporting and some research needed.*
- Field level yield and nutrient needs response - as each pass over the field can compact soil which may affect yields and removal of residue may alter both nutrient (N and others) and water needs, additional data is needed around yield responses to residue collection. *Additional research and reporting needed.*
- Impact of residue collection on field emissions -- *additional research and reporting needed.*

5. Conventional Crop-Based Low Carbon Liquid Fuels

5.1 System Boundaries and Descriptions for Conventional Crop-based Low Carbon Liquid Fuels

Low Carbon liquid fuels can be produced from a variety of renewable Canadian crops, whether grains (e.g., conventional bioethanol) or oilseeds (e.g., biodiesel), as well as agricultural residues or purpose-grown biomass (lignocellulosic ethanol and advanced biofuels). Lignocellulosic agricultural residues are also used as low carbon liquid fuels. Bioethanol and biodiesel are in commercial production and use and are considered conventional crop-based fuels. All other fuels are considered unconventional within this report. Conventional crop-based liquid fuels are typically blended with their fossil analogues for use in internal combustion engines, although advanced processes to produce drop-in fuels as direct replacements for their fossil analogues are emerging. Low carbon liquid fuels are typically used for transportation of passengers and goods, with some biodiesel also used for heating.

The Canadian crop-based low carbon liquid fuels incorporated in the Fuel LCA Modelling Tool are summarized in Table 17. Cereal grains are used for starch-based ethanol from fermentation, while oilseeds are processed and refined for oil-based fuels. Lignocellulosic residual biomass from these crops, primarily corn stover or wheat straw, may be used after additional processing for ethanol via fermentation[5].

Table 17. Summary of crop-based low carbon liquid fuel pathways including descriptions of fuel feedstock source, conversion processes, process energy carrier outputs, and expected end use to be modelled (feedstocks marked with an asterisk are not modelled in detail here).

Fuel	Feedstock	Conversion Process	End Use
Bioethanol	Grain corn Wheat Barley *Peas**	Starch extraction Liquefication and saccharification Fermentation Ethanol recovery	Transportation
Biodiesel	Canola Soybean Camelina	Oil extraction Transesterification Refining	Transportation (heating)
Lignocellulosic Ethanol	Corn stover Wheat straw	Pretreatment Saccharification Fermentation Ethanol recovery	Transportation

Detailed provincial and anonymized LCI data for Canadian grain bioethanol and Canadian mixed feedstock biodiesel have been compiled by NRCan as part of the NRCan's ecoENERGY for Biofuels Program, which ran between 2008 and 2017 (Natural Resources Canada, 2019). The data is aggregated from information provided in Complementary Environmental Performance Reports (CEPR). While reported data drops sharply from 2016 on, the CEPR data still provides a valuable picture of industry

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[5] Other routes, both biochemical and thermochemical, are also possible, though primarily at research or pilot scales.

average production. This data has been used to develop Canadian average bioethanol and biodiesel pathways. In addition, genericized templates of these have been developed.

5.1.1 Starch Based Fuels

Crop production and use

Canadian agriculture produces a variety of grains that, among their other uses, serve as low carbon fuel feedstocks. The starch they contain is hydrolyzed to sugar (glucose) and thence to bioethanol via fermentation. The conversion of grains to ethanol in industrial plants (also referred to as distilleries) also produce livestock feed and supplements, and, sometimes, other co-products.

The Canadian bioethanol industry is an expanding sector of the economy, producing fuel ethanol for domestic use (US Department of Agriculture, 2018; National Energy Board Canada, 2016). At the end of 2018, there were 15 operational conventional bioethanol plants in Canada, of which 13 are crop-based[6]. A summary of capacity provided by currently operational plants is provided in Table 18.

Canadian bioethanol production is dominated by Ontario, which produces more than 60% of Canada's annual bioethanol, from corn, and Saskatchewan, primarily from wheat, which accounts for about 18%. The remaining 22% comes from Alberta, Manitoba, and Quebec, each of which provide 3-10% of annual production (Ethanol Producer Magazine, 2019).

Table 18. Capacities of operational crop-based bioethanol plants in Canada as of September 2018, shown by location, feedstock, annual capacity in million litres, and co-products (Ethanol Producer Magazine, 2019).

Plant Location	Province	Feedstock	Ethanol Capacity (million L/year)	Co-products
Red Deer	Alberta	Other Grains (primarily wheat, some barley or corn)	45	Wheat flour, Gluten, CO_2, Feed
Minnedosa	Manitoba	Corn	129	Distiller's dried grains with solubles (typically used for feed or food additives, often called DDGS)
Chatham	Ontario	Corn	200*	Industrial alcohols, Corn oil, Livestock feed
Johnston	Ontario	Corn	261	Corn oil, CO_2, Feed
Tiverton	Ontario	Corn	32*	Industrial alcohols, Feed
Aylmer	Ontario	Corn	380	Feed
Havelock	Ontario	Corn	80	Feed
Sarnia	Ontario	Corn	400	Feed
Varenes	Quebec	Corn	174	Corn oil, Feed
Llyodminster	Saskatchewan	Grains (primarily wheat)	129	Feed
Unity	Saskatchewan	Grains (primarily wheat, some barley)	25	Industrial ethanol, Feed

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[6] The others are based on waste, covered elsewhere.

Lanigan	Saskatchewan	Grains (primarily wheat, some barley or corn)	14	Feed
Belle Plaine	Saskatchewan	Grains (primarily wheat)	151	Feed

* total alcohols

Canadian bioethanol producers use several grain crops to produce ethanol. Table 19 shows the crop volumes produced and used nationally (from (Littlejohns, Rehmann, Murdy, Oo, & Neill, 2018)) along with the share of ethanol production capacity provided by each.

Table 19: Grain crop feedstocks used in 2016 (Littlejohns, Rehmann, Murdy, Oo, & Neill, 2018)

Crop	Seed area (thousand Ha)	Production (MT)	Biofuel use (MT)	CEPR Reported Share of production 2012-16, Eastern Canada*	CEPR Reported Share of production 2012-16, Western Canada*	CEPR Reported Share of national production, 2012-16
Grain corn	1345	13193	3250	100%	4%	97%
Wheat	9420	31729	950		96%	3%
Barley	2586	8784	-	-	-	-
Dry peas	1715	4836	-	-	-	-

* average over 2012-2016, from CEPR data (Natural Resources Canada, 2019)

Table 20 shows national regional ethanol production over 2012-2016 (Natural Resources Canada, 2019). The primary bioethanol feedstocks have been corn and wheat (97% and 3%, respectively, over 2012-2016 according to producer supplied data under ecoEBE (Natural Resources Canada, 2019), as shown in Table 20). Barley and other starches provided small amounts of ethanol. (Both corn stover and wheat straw are being used and explored for lignocellulosic ethanol, as are other agricultural residues; this fuel pathway is described in Section 6).

Table 20: Crop-based bioethanol production in Canada, 2012-2016, in ML (Natural Resources Canada, 2019) from CEPR (ecoEBE) data.

Million L	2012-13	2013-14	2014-15	*2015-16*
Total	1,695	1,703	1,718	*569*
Western Canada	485	489	489	*20*
Eastern Canada	1,210	1,214	1,229	*549*
Share west (%)	29%	29%	28%	*4%*
Share east (%)	71%	71%	72%	*96%*
Share corn (%)	81%	81%	80%	*97%*
Share wheat (%)	19%	19%	20%	*3%*

While changes in production incentives lead to a precipitous drop in participation from mid-2015 on, the CEPR data still provides a valuable picture of average production

Conversion to bioethanol

There are two conversion process types for the production of bioethanol from grains: wet and dry milling. Dry milling is dominant for bioethanol production (Littlejohns, Rehmann, Murdy, Oo, & Neill, 2018), although about 10% of production is via wet milling. The two processes differ primarily in the initial treatment of the grains for starch extraction and the total water use. Both processes are highly integrated in commercial production. The conversion process for grain to ethanol varies little among grain types.

The first part of bioethanol production from grain releases the starch. In dry milling, the grain is ground, mashed and cooked to release the starch. In wet milling, the grain is fractionated by steeping, resulting in germ, gluten, and fibre along with starch. The starch produced undergoes enzymatic hydrolysis to release glucose, a six-carbon sugar, for fermentation by industrial yeast. The fermentation process yields an ethanol- and protein-rich broth sometimes referred to as wine or beer. It also releases CO_2 as the glucose is converted into ethanol. After fermentation, the ethanol is recovered from the broth and dried, first undergoing distillation, then drying over molecular sieves to remove the remaining water from the azeotropic solution, and finally, for fuel ethanol, a denaturant, often a small fraction of gasoline, is added, making it unsuitable for human consumption. The stillage residue post-distillation undergoes further processing to remove water reused in the process and produce wet and/or dry distillers' grains and solubles, widely used in livestock feed.

As mentioned, a highly-integrated conversion process, whether wet or dry milling, yields important co-products – key livestock feeds and feed supplements, and in some cases other alcohols and corn oil. Some facilities also capture the CO_2 resulting from fermentation and compress it for use in beverage and other markets. Table 18 shows the co-products reported by each producer.

The system boundaries and process flow for conventional bioethanol production from grain are summarized in Figure 4.This includes wheat, corn, and some barley, rye or minor contributing grains (grains other than wheat, corn and barley are not included in the inventories).

Fuel Ethanol Combustion

Crop-based low carbon liquid fuels are used overwhelmingly in the transportation sector, either neat (unblended) or blended with their fossil analogues. The emissions from combustion of ethanol depend on efficiency and type of vehicle. As it is not feasible to capture the full range of possible combustion scenarios for the vehicle fleet, in the Fuel LCA Modelling Tool the combustion of crop-based conventional bioethanol will be modelled stoichiometrically and harmonized with the Canadian NIR report. A representative vehicle is used here for each fuel (see Section 5.3.5). However, as the carbon emissions from combustion of crop-based conventional bioethanol are entirely biogenic, they are not included in the carbon intensity for the crop-based conventional bioethanol pathway.

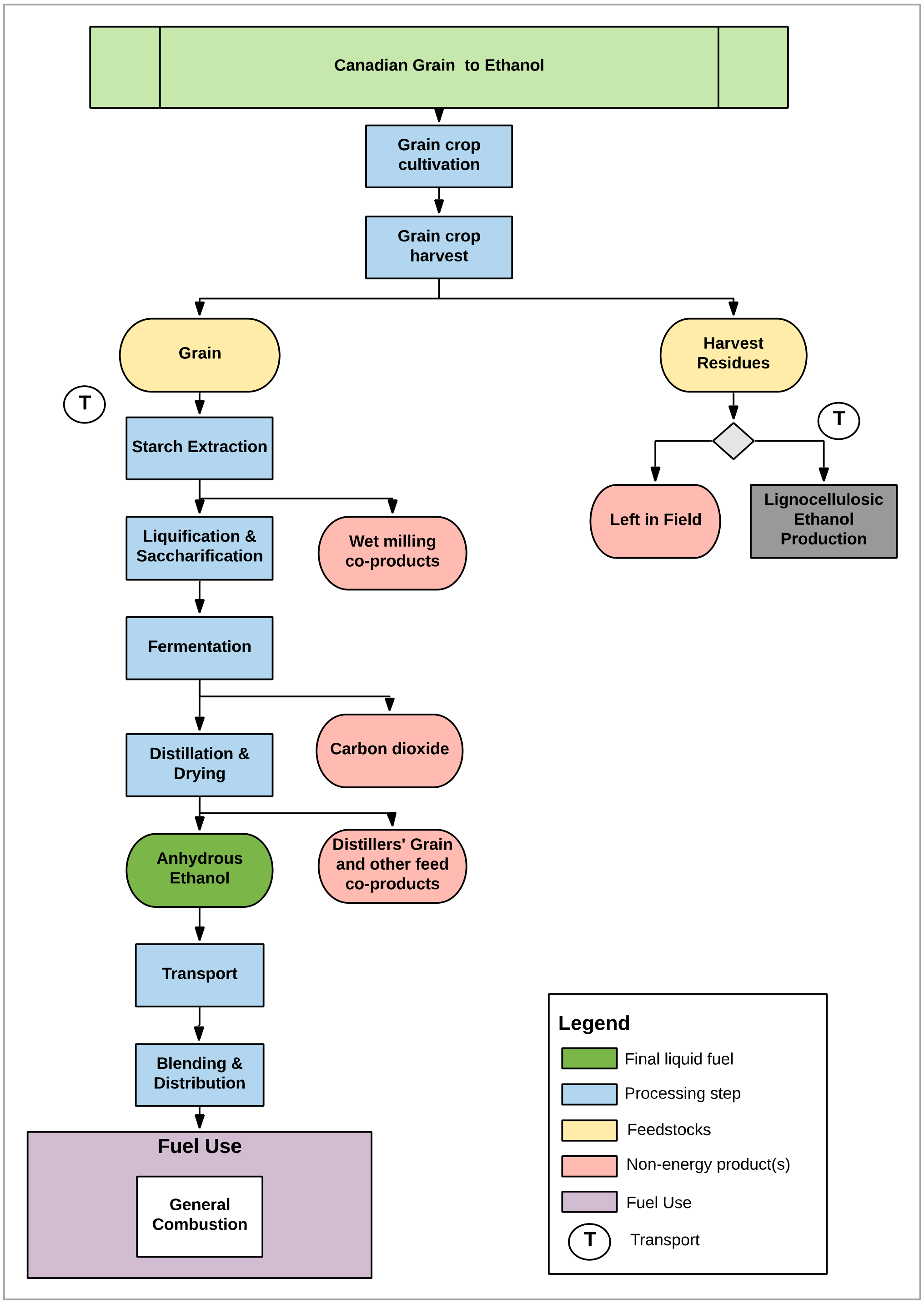

Figure 4. System boundaries and life cycle activities for bioethanol derived from grain crop feedstocks, from cultivation to combustion.

5.1.2 Oilseed Based Fuels

Crop production and use

Canadian agriculture produces a variety of oilseeds that, among their other uses, serve as low carbon fuel feedstocks. The oil they contain is extracted and then chemically converted to biodiesel. The conversion of oilseeds, or oil from oilseeds to biodiesel in industrial plants (also referred to as mills or refineries) also produces protein meal and sometimes, other co-products.

At the end of 2017, there were 10 operational biodiesel plants in Canada, of which four are crop-based[7]. Together, these crop-based facilities accounted for 78% of capacity at that point (Biodiesel Magazine, 2019). Over the last several years, more than 70% of biodiesel produced in Canada has been from edible oils (Littlejohns, Rehmann, Murdy, Oo, & Neill, 2018). A summary of currently operational plants is provided in Table 21.

Table 21. Operational crop-based biodiesel plants in Canada as of December 2017, shown by location, feedstock and annual capacity in million litres (Biodiesel Magazine, 2019).

Plant Location	Province	Feedstock	Biodiesel Capacity (million L/year)
Lloydminster	AB	Canola	265
Dain City	ON	Canola Oil/Soy Oil	170
Foam Lake	SK	Non-Food Grade Canola Oil	14
Lethbridge	AB	Oilseeds and animal fats	71

Canadian crop-based biodiesel production is dominated by Alberta, which accounted for about 54% of crop-based biodiesel, from canola seed or oil, followed by about 33% from Ontario, based on a mix of canola and soybean, and Alberta, which supplies another 14% from some combination of oilseeds and animal fats (Biodiesel Magazine, 2019).

Canadian biodiesel producers use two primary crops to produce biodiesel: canola and soybean. Table 22 shows the crop volumes produced and used nationally (from (Littlejohns, Rehmann, Murdy, Oo, & Neill, 2018)) along with share of biodiesel production provided by each. Table 23 shows national and regional biodiesel production over 2012-2016 (Natural Resources Canada, 2019).

Table 22: Oilseed crop feedstocks and the share of biodiesel feedstock represented by each for 2016 (Littlejohns, Rehmann, Murdy, Oo, & Neill, 2018)

Crop	Seed area (thousand Ha)	Production (MT)	Biofuel use (MT)	Share of production, Western Canada*	Share of production, Eastern Canada*	Share of national production*
Canola	8236	19600	550	100%	31%	81%
Soybeans	2212	6463	333	3%	33%	10%
Corn oil					37%	9%

* average over 2011-2015, from CEPR data (Natural Resources Canada, 2019)

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[7] The others are based on animal fats and used cooking oils; these processes are covered elsewhere in the document (Section 7).

Table 23: Crop-based biodiesel production in Canada, 2011-2017, in Megaliters (Natural Resources Canada, 2019).

	2011-12	2012-13	2013-14	2014-15	*2015-16*	*2016-17*
Total	121	101	126	124	*18*	*12*
Eastern Biodiesel	111	92	118	110	*2*	*1*
Western Biodiesel	9	8	9	14	*16*	*10*
Share East (%)	92%	92%	93%	88%	*13%*	*12%*
Share West (%)	8%	8%	7%	12%	*87%*	*88%*
Share Canola Oil (%)	83%	100%	93%	91%	*13%*	*12%*
Share Soybean oil (%)	10%	0%	5%	6%	*0%*	*0%*
Share Camelina Oil (%)	0%	0%	0%	0%	*0%*	*0%*
Share other crop (corn oil or canola seed) (%)	7%	0%	1%	4%	*0%*	*0%*

The marked decrease in production volume and feedstock values in Table 23 for 2015-2016 and 2016-2017 reflect a change in number of facilities reporting CEPR data, not a change in actual production.

Conversion to biodiesel

Oilseeds are converted to biodiesel primarily via oil extraction and transesterification. As mentioned, the milling and conversion process(es) yields important co-products – primarily a protein-rich meal and glycerol. The system boundaries and process flow for crop-based biodiesel production from oilseeds are summarized in Figure 5. This includes canola, soybeans, and other oilseeds.

Biodiesel Combustion

Crop-based low carbon liquid fuels are used in overwhelmingly in the transportation sector, either neat (unblended) or blended with their fossil analogues. Biodiesel blends are also sometimes used in generators and boilers. The emissions from combustion of biodiesel depend on efficiency and type of vehicle or engine and the blend level. As it is not feasible to capture the full range of possible combustion scenarios for the vehicle fleet, in the Fuel LCA Modelling Tool the combustion of crop-based biodiesel will be modelled stoichiometrically and harmonized with the Canadian NIR report. A representative vehicle is used here for each fuel (see Section 5.3.5). However, while the bulk of the carbon emissions from combustion of crop-based biodiesel are biogenic and as such are not included in the default carbon intensity for the crop-based biodiesel pathway, the carbon emissions attributable to fossil methanol used in the transesterification process will contribute. These have been be calculated stoichiometrically.

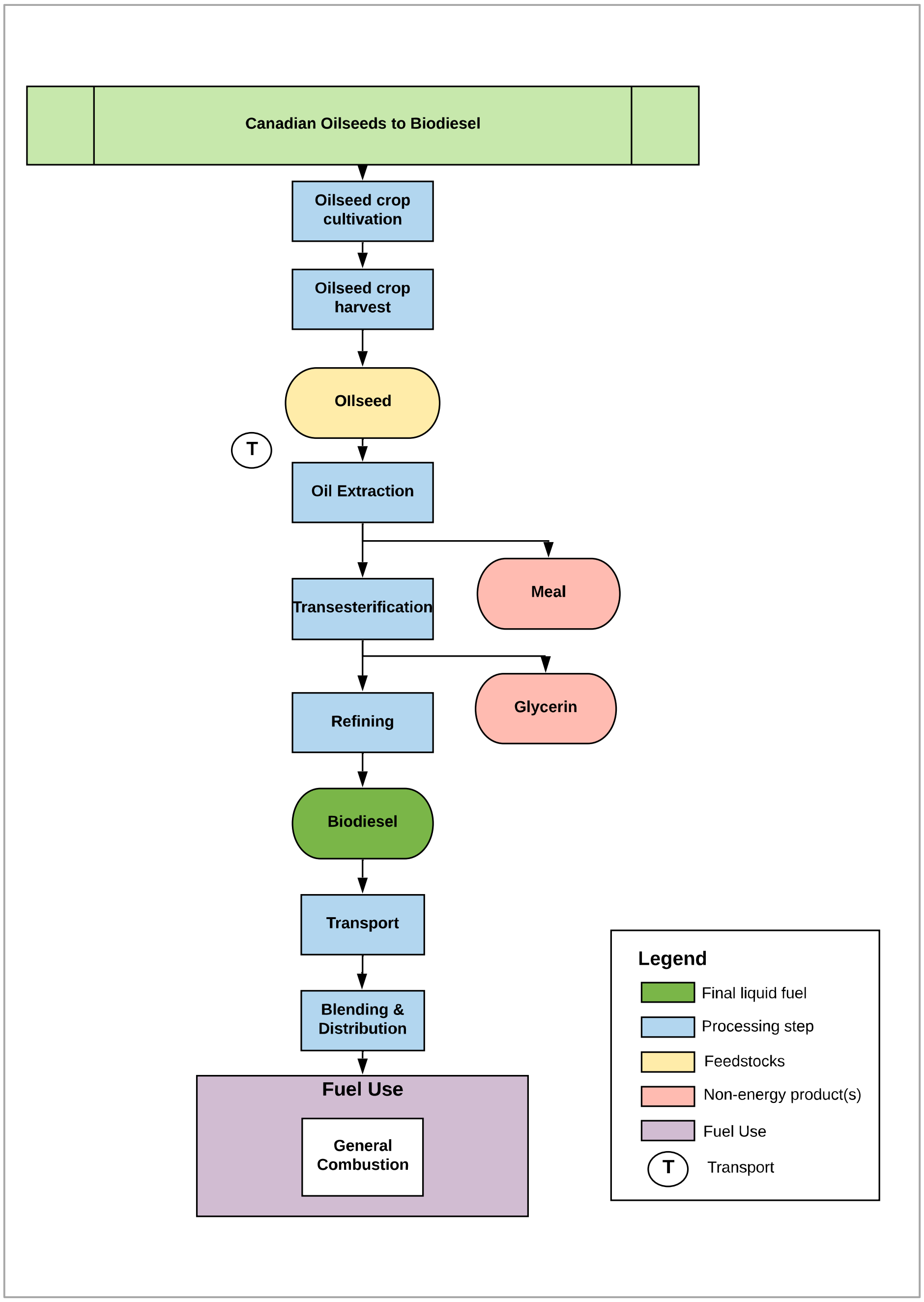

Figure 5. System boundaries and life cycle activities for biodiesel derived from oilseed crop feedstocks, from cultivation to combustion.

5.2 Modelling Approach for Conventional Crop-based Low Carbon Liquid Fuels

5.2.1 Development of Unit Process Building Blocks

The overall modelling approach for Milestone 3 is to develop unit processes to serve as building blocks for current and future modelling work in the Fuel LCA Modelling Tool. In the case of crop-based low carbon liquid fuels this approach is particularly relevant since there are a variety of crop feedstocks that may be used in any fuel conversion process of the matching type (i.e. cereal grains to ethanol via saccharification and fermentation of extracted starch or oilseeds to biodiesel via transesterification of the extracted oil), and these are all based on a basic set of feedstocks that are produced within the Canadian agricultural industry, and a set of conversion processes associated with the conversion type.

The key building blocks for crop-based low carbon liquid fuels are summarized from a modeling perspective in Figure 6. They include feedstock crop production activities; transportation to processing; conversion to starch- or oil-based fuel; transportation, blending and/or storage, and distribution; and combustion. With these building blocks in place, reflecting regional variation where possible (*e.g.,* differences in crop yields, agrichemical inputs, fuel consumption, differences in electricity grids, *etc*.), users of the Fuel LCA Modelling Tool who want to build a crop-based biofuel process can select the appropriate feedstock(s) from the available building blocks and pull them in to their specific fuel production pathway. They can also copy and modify these building blocks with their own more recent or process-specific data.

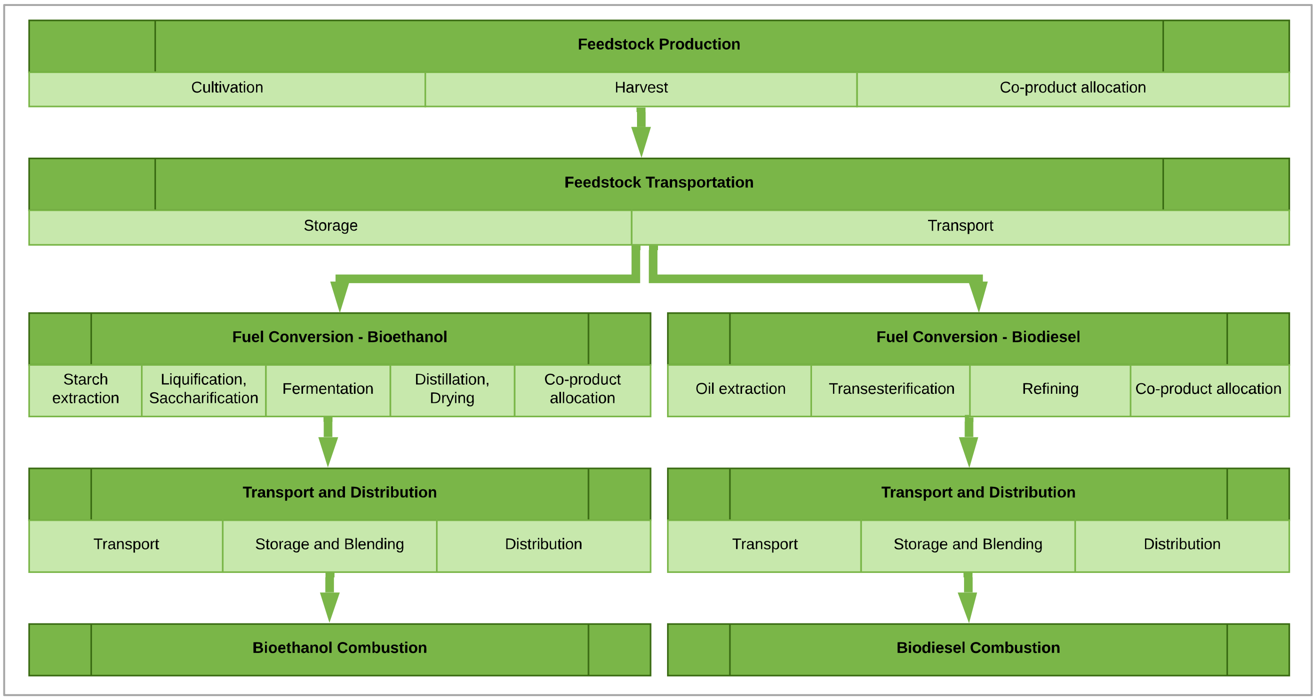

Figure 6: Building blocks of the crop-based conventional biofuels pathways

5.2.2 Regional Variation

The primary regional variations for crop-based low carbon liquid fuels arise from the production of the feedstock more than the conversion technology. These will influence carbon intensity, as they reflect differences in crop management practices reflecting to the local microclimate. These include crop yield, agrochemical use, water use, and some harvest practices, including highly localized variation in harvest residue collection. The latter variation affects the crop residue-derived lignocellulosic fuels. Other regional variation can arise from background energy systems such as variations in electricity grids providing energy to fuel conversion processes. The sourcing of regional/provincial feedstocks could also influence transport distances and modes for feedstock delivery and final fuel delivery.

These differences are reflected in the modelling as much as possible within the confines of the available data. For example, crop management and harvesting data is available at a provincial level but may vary for an individual producer. Thus, tool users will need to choose a unit process from the most appropriate region or choose the unit process for Canadian average management and harvesting or would need to model more specific harvesting data in this version of the Fuel LCA Modelling Tool. In such cases, the tool user could then modify a copy of an existing unit process or build their own from scratch to reflect their case based on the data they have available[8].

With respect to background energy systems, electricity grid carbon intensities are available at a provincial level based on work completed in Milestone 2, as are some fuels (e.g., diesel), and have been incorporated into the unit processes available for modelling crop-based low carbon liquid fuels. For example, modelling the production of corn bioethanol in Ontario could include the use of Ontario electricity to power the grain handling and conversion process.

5.2.3 Co-Product Allocation

The need to address co-product allocation is a prominent issue for crop-based low carbon liquid fuels as all conventional fuel processes produce multiple saleable products. In addition, agricultural residues from both grain and oilseed crops used for conventional biofuels may be a co-product of the crop production system, or may be considered a waste. Both the conversion of grain crops and oilseeds to fuels provide substantial co-products from primary processes including livestock feeds and other goods. The upstream carbon intensity from their production as part of the fuel production process must be allocated between the primary product and the co-products. In the future as unconventional fuels gain market share, agricultural residues, such as corn stover from corn cultivation, will need to be considered as co-products from primary processes and the upstream carbon intensity from their production will have to be allocated between the primary product and the co-products, influencing the carbon intensity of both the primary crop and the utilized residue.

As discussed above (Section 2.8), the choice of allocation approach must be well-documented and transparent, including a clear rationale and sensitivity analysis to show the influence on the study results. Different allocation decisions significantly affect final results (Wang, Huo, & Arora, 2011), and has demonstrated to influence the ability of a fuel to meet a greenhouse gas reduction target (Kaufman, Meier, Sinistore, & Reinemann, 2010).

In Milestone 1 and 2 it was established through discussions with ECCC that upstream carbon intensity would be allocated to co-products according to energy content. Milestone 3 has continued this process. More generally, using the building blocks approach for the Fuel LCA Modelling Tool, the capability to choose different allocation approaches will be incorporated in the tool. For example, allocation of upstream impacts to extracted oil and protein co-products from oil seeds is often done by mass in the literature and other established tools (Wang, Huo, & Arora, 2011), and may be

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[8] In the same way, higher resolution processes, such as at the reconciliation unit level, can readily be added by users and administrators, simply by editing a copy of an existing provincial process and updating values to those they have collected in their research or reporting.

determined to be a more appropriate way of allocating for crop-based low carbon fuel feedstocks. Either allocation by mass or energy are\ consistent with the ISO 14044 guidelines since both ways of allocating are based on a physical relationship between the inputs and outputs of the system. In other instances, there may be good rationale to use displacement instead of allocating.

5.2.4 Biogenic Carbon and Land Use Change

In remaining consistent with the Government of Canada's policy on biogenic carbon, as shown in Canada's National Inventory Report (Government of Canada, 2018), emissions of biogenic carbon from combustion of crop-based low carbon liquid fuels is not included in the carbon intensity calculations. Biogenic carbon emissions will be calculated and reported separately from the default carbon intensity values.

Carbon emissions associated with direct land use change will be included in instances where feedstock production requires the conversion of land from existing use to bioenergy production. In the case of crop-based low carbon fuels, this would arise with the conversion of new agricultural land, and, potentially, with use of previously fallow land. The method for including direct land use change will require further and ongoing discussion with ECCC. The results of the uncertainty analysis on Canadian average production for these crops are shown in Table 35.

Data quality and uncertainty in crop production, land occupation and transformation is both a significant contributor and highly uncertain. Indirect land use change is excluded from the carbon intensity calculations.

5.3 Life Cycle Inventory for Conventional Crop-based Low Carbon Liquid Fuels

5.3.1 Feedstock Production – Agricultural Cropping Systems

Feedstock production for crops included in the crop-based low carbon liquid fuels were modelled using the GHG emissions from Canadian cultivation. This is described in Section 4. Agricultural Systems for Crop-Based Low Carbon Liquid Fuels. Relevant crops covered in the CALCD agricultural LCI are summarized in Table 24. The CI values for these crops can be found in Table 9 and Table 10, in Section 4.7.

Table 24. Crops included or to be included (italics) in the CALDC agricultural LCI library.

Grains	Oilseeds
Corn	Canola
Wheat	Soybean
Barley	Camelina

5.3.2 Storage and transport

Transport of harvest grain and oilseed from the field to the silo and storage sites is included in the CALCD library. Transport of the grain or oilseed to distilleries and mills is modeled by estimating average transport distance based on crop production locations and using unit processes for truck and rail transport developed in Milestone 2. The values used are shown in Table 25. Further details are provided in Appendix B.

Table 25. Transportation modes and distances for crop-based conventional biofuel feedstocks.

Life Cycle Stage	Biofuel/Feedstock	Average Distance	Primary Mode
Feedstock Transport	Agricultural feedstocks (grain, seed)	100 km	Truck

5.3.3 Fuel Production

Detailed provincial and anonymized LCI data for Canadian grain bioethanol and Canadian oilseed biodiesel has been compiled by NRCan as part of the NRCan's ecoENERGY for Biofuels Program, which ran between 2008 and 2017 (Natural Resources Canada, 2019). The data is aggregated from information provided in Complementary Environmental Performance Reports (CEPR). The data tables are attached as Appendix D (bioethanol) and Appendix E (biodiesel). For these models, the CEPR data has been corrected for unit inconsistencies in reporting of material inputs where necessary[9]. The CEPR data has been used to develop Canadian average bioethanol and biodiesel pathways. In addition, pathway templates have been developed for common routes.

Inputs below a (mass) cutoff of 0.1% are excluded, except for enzymes and yeast. Analysis of the CEPR data shows no systemic shifts over the 2009/10-2015 period, so the reported data are averaged over the period (omitting mid-2015 on as producer response rates decline dramatically with production incentives) and the facilities to develop the processing portion of the pathway. Some bioethanol facilities make excess electricity, but the net electricity purchased from grid is always positive. For transparency, if an electricity coproduct is exported to grid, it is included as a negative flow (i.e., used to displace an equivalent amount of the grid electricity purchased).

Table 26. Mass balance and material and energy inputs for production of bioethanol from grains for Canadian facilities, from averaged (2012-2016) producer data (CEPR).

Bioethanol Production	Canadian Average	Dry Mills	Wet Mills	Dry Mill Corn	Wet Mill Wheat
Starch Sources	Mixed Grains (wheat, corn, barley)	Mixed Grains (wheat, corn, barley)	Mixed Grains (wheat, corn, barley)	Corn	Wheat
Dominant Region	West/Alberta, Manitoba, Saskatchewan	West/Alberta, Manitoba, Saskatchewan	West/Alberta, Manitoba, Saskatchewan	West/Ontario	West/Saskatchewan
Feedstock					
Corn (kg)	0.0823	0.0925	0.0055	0.1026	-
Wheat (kg)	0.0218	0.0116	0.0987	-	0.1139
Barley (kg)	0.0008	-	0.0067	-	-
Material & Energy Inputs					
Natural Gas (MJ)	0.4039	0.3683	0.6716	0.3590	0.6967
Electricity from Grid (kWh)	0.00931	0.00870	0.0139	0.0074	0.0193
LFO (MJ)	0.00058	0.00065	-	0.00081	-
HFO (bunker c) (MJ)	0.00161	0.00183	-	0.00226	-

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[9] In several cases a producer's reported value for an input for a year was given in kilograms rather than tonnes, as evidenced by a deviation of approximately three orders of magnitude from other values.

alpha-amylase (kg)	0.00051	2.81E-05	0.00048	2.42E-05	0.00069
glucoamylase (kg)	0.00119	5.27E-05	0.00078	5.28E-05	0.00085
Yeast (kg)	5.90E-06	4.13E-06	1.94E-05	3.89E-06	1.24E-05
Ammonia (kg)	8.43E-05	9.55E-05	-	0.00012	-
Caustic soda (kg)	0.00025	0.00022	0.00046	0.00016	0.00038
Urea (kg)	0.00021	0.00021	0.00016	0.00019	0.00020
Sulphuric acid (kg)	0.07556	0.08485	0.00639	0.10011	0.02923
Uncaptured fermentation CO2 emissions (kg)	0.0134	0.0151	-	0.01304	-
Captured fermentation CO2 emissions (kg)	0.0043	0.0048	-	0.00443	-
*Outputs***					
Bioethanol (MJ)	1	1	1	1	1
Electricity to grid (kWh)	-3.45E-05	-3.89E-05	-	-4.85E-05	-
Combined feed, dry basis (MJ)	0.667	0.640	0.868	0.636	0.560
DDG (MJ)	0.1018	0.1018	0.1018	0.0403	-
WDG (MJ)	0.1087	0.1087	0.1087	0.0577	-
DDGS (MJ)	0.3328	0.3328	0.3328	0.3440	0.7307
WDGS (MJ)	0.2297	0.2297	0.2297	0.5120	-
Corn oil (MJ)	0.0050	0.0056	-	0.0070	-

**The pathway is for undenatured fuel ethanol, so gasoline is not included in the inventory. **Note – Where coproduct values were not provided in MJ, the energy contents used are from* (Heuzé V., 2017; DM INRA-CIRAD-AFZ , n.d.). *A summary table is in Appendix A2, Table 114.*

Table 27. Mass balance and material and energy inputs for extraction of bio oils from oilseeds in an average Canadian facility from literature (Chen, et al., 2018) (Shonnard, Williams, & Kalnes) (Miller & Kumar, 2013) (Li & Mupondwa, 2014)

Biodiesel Production	**Soybean oil Amount (per kg of oil)**	**Canola oil Amount (per kg of oil)**	**Camelina oil Amount (per kg of oil**
Inputs			
Oil seed (kg dry matter)	4.6	2.2	2.9
Natural gas (MJ)	4.1	2.43	1.812
Electricity (kWh)	0.194	0.114	0.0304
Light Fuel Oil (MJ)	0.03	0	0
Heavy Fuel Oil (MJ)	0	0	0
Hexane (kg)	0.0012	0.023	0.024
Outputs			
Biooil	1	1	1
Meal/Cake, dry mass	3.5	1.11	1.71
*Output energy contents (HHV)**			
Biooil, MJ/kg	39.3	39.3	1
Meal/Cake, MJ/kg	19.7	19.4	22.1

***Note – Biooils and coproduct values when not provided in MJ use energy contents from* (Heuzé V., 2017; DM INRA-CIRAD-AFZ , n.d.). *A summary table is in Appendix A2, Table 114.*

Table 28. Mass balance and material and energy inputs for production of biodiesel form bio oils in an average Canadian facility from producer data (CEPR) and literature (Chen, et al., 2018).

Biodiesel Production	Producer Data (per MJ of biodiesel)	Generic (literature) Vegetable Oil (per MJ of biodiesel)
Inputs		
Oilseed oil	0.272	0.0248
Natural gas (MJ)	0.0912	0.0294
Electricity (kWh)	0.00306	0.00102
Biodiesel distillation bottoms (MJ)	0.0262	1.24E-05
Light Fuel Oil (MJ)	0.000346	
Recycled grease (MJ)	0.00108	
Methanol (kg)	0.00272	0.00269
Sulfuric acid (kg)	0.000326	2.49E-06
Hydrochloric acid (kg)	0	6.22E-05
Sodium methylate (kg)	0.000378	0.000122
Sodium hydroxide (kg)	1.21E-05	9.96E-06
Potassium hydroxide (kg)	0.000441	0
Nitrogen gas (kg)	0	5.47E-05
Phosphoric acid (kg)	0	9.96E-06
Outputs		
Glycerol (kg)	0.0042	0.00226
Biodiesel distillation bottoms (kg)	0.00096	7.47E-05
Fatty acids (kg)	0	0.000107

**Note – The energy contents of the co-products include (Chen et al. 2018): glycerol - 18.56 MJ/kg; biodiesel distillation bottoms – 39.47 MJ/kg; fatty acids – 39.47 MJ/kg. The energy content of biodiesel is 29.67 MJ/kg.*

In the Fuel LCA Modelling Tool, uncertainty analysis will be used to capture the influence of the range in energy and materials consumption evident in the compiled Complementary Environmental Performance Reports on the default carbon intensity.

The facility level and aggregate data provided for Canadian bioethanol producers (Natural Resources Canada, 2019) do not distinguish between wet and dry milling. However, the inputs and co-products in the unit process accessible in the Fuel LCA Modelling tool will readily adaptable by the user to accommodate either (or other variations).

The carbon intensity for electricity, fuels and natural gas was obtained from the results of the Milestone 2 work on carbon intensity of Canadian fossil fuels (EarthShift Global, WSP, Introspective Systems, 2019). The default carbon intensity of crop-based bioethanol and biodiesel was modeled using a Canadian average electricity grid; however, users of the Fuel LCA Modelling tool will be able to incorporate regional electricity and fuel sources to calculate the carbon intensity for production in different provinces.

These values reflect the types of variation that may be observed in fuel production LCI data. This variation is captured in the uncertainty analysis but may also be addressed by the addition of more specific data from low carbon fuel producers using the Fuel LCA Modelling Tool.

5.3.4 Fuel Transport

Moisture content, and its associated effect on density, is important consideration for feedstock transport. As such, the feedstock transport must account for the density variation between crop-based feedstocks, whether grain or oilseed.

The transportation of both feedstocks and final liquid fuels are primarily via truck and rail. In modelling this transport, we use the truck and train unit processes that were created in Milestone 2 (EarthShift Global, WSP, Introspective Systems, 2019) to capture the upstream and combustion emissions associated with these modes of transport.

Transportation modes and distances are addressed **in Appendix B**. Table 29 summarizes the relevant transportation modes and distances used in this analysis. While both ethanol and biodiesel are also transported by rail, with about 70% of North American ethanol transported by rail to market (RFA, 2017), only 5-10% of Canadian fuel products were distributed via rail from primary terminal in 2016 (Kent Group, 2017).

Table 29. Transportation modes and distances for crop-based biofuel fuels.

Life Cycle Stage	Biofuel/Feedstock	Average Distance	Primary Mode
Fuel Transport	Biofuels (liquids)	600 km	Rail
Fuel Distribution	Biofuels (liquids)	290 km	Truck

5.3.5 Combustion

Fuel characteristics and emissions factors for combustion of crop-based conventional biofuels are summarized in Table 30.

Table 30. Characteristics and combustion emissions of ethanol and biodiesel (Government of Canada, 2018).

Fuel	Application	Density	High Heating Value	Carbon Content	CO_2 (g/L fuel)	Carbon source	Fossil CO_2 (g/L fuel)
Ethanol	Transportation	789.3kg/m^3	29.67 kJ/g	52.14%	1,508	biogenic	0
Biodiesel	Primarily Transportation	882kg/m^3	39.89 kJ/g	75.6%	2,472*	biogenic & fossil	139.6**

** fossil diesel emissions used in NIR.*

*** from fossil methanol used in production. This value has some additional variability because it is tied to the methanol mass balance in the transesterification process and is calculated as part of the pathway.*

Table 31. Representative transport combustion emissions of ethanol and biodiesel, from Table A6-12 (Government of Canada, 2018).

Fuel	Mode	CO_2 g/L fuel	CH_4 g/L fuel	N_2O g/L fuel
Ethanol	Light-duty Gasoline Vehicles (LDGV), Tier 2	2,307	0.014*	0.022*
Biodiesel	Heavy-duty Diesel Vehicles (HDDV), Moderate Control	2,472	0.014**	0.082**

** fossil gasoline emissions used in NIR; ** fossil diesel emissions used in NIR.*

Fuel Combustion – Bioethanol

Bioethanol is primarily for transportation. At present, it considered for use in transportation blended with conventional gasoline.

The CO_2 emissions from combustion of crop-based bioethanol are biogenic since they are from agricultural feedstocks. As such, although these emissions are included in the tool and reported separately in the data sheets; they are not included in the default carbon intensity values for crop-based low carbon liquid fuels. Tool users will be able to include or exclude biogenic carbon in their analyses.

Fuel Combustion – Biodiesel

Biodiesel can be used in various energy applications, primarily transportation but also including combustion in industrial or residential boilers and generators. At present, biodiesel is most often considered for use in transportation when blended with conventional diesel.

Most of the CO_2 emissions from biodiesel combustion are biogenic since they are from agricultural feedstocks. As such, although these emissions are included in the tool and reported separately in the data sheets; they are not included in the default carbon intensity values for low carbon solid fuels. However, the methanol used in transesterification maybe from fossil or bio-based.

The Canadian National Inventory Report does not provide specific emission factors for CH_4 and N_2O for biodiesel (Government of Canada, 2018), instead utilizing emissions factors for the combustion of fossil fuel-based diesel. To augment this, literature values for biodiesel combustion and the non-biogenic emissions attributable to the use of fossil-fuel-derived methanol have been incorporated.

For the default crop-based biodiesel pathways in the Fuel LCA Modelling Tool, the modelled end use will be direct combustion. Emissions factors for this combustion will be derived from literature sources. The direct combustion emissions can be scaled by the user for efficiency and other characteristics of the engine (stationary or mobile) in which it is used.

5.3.6 Modelling and Life Cycle Inventory for bioethanol from dried peas

A carbon intensity value for conventional bioethanol from dried peas has been developed to support a template pathway in the final tool. As a highly speculative pathway, it requires more approximations than other pathways, and the increase in uncertainty should be kept in mind. The approach described here is a useful screening approach.

Feedstock Production and Transport

The Canadian Roundtable on Sustainable Crops (CRSC) life cycle analysis did not include LCI data for pea cultivation in Canada, and as such, this feedstock is not included in the CALCD dataset. The CI for pea production in Canada, 0.38 kg CO_2 eq./kg dry matter, was obtained from table 18-2 in Desjardins et al (2016). Transport distances for feedstock delivery were assumed to be the same as for corn or wheat.

Processing of Feedstock into Fuel

Process data is not available for bioethanol using dried peas as a feedstock, and there are currently no commercial processes using it in Canada. There is one report of starch extracted from peas being added to mixed grain processing, but anecdotal data indicates that dried pea starch is sometimes added with other grain feedstocks in more common practice.

The key parameters needed are 1) ethanol yield per kilogram of grain/legume; 2) co-product type, amount and energy density; and 3) change in energy and input needs from the base grains that have been modelled for other pathways.

In cases where process data is not available, the bioethanol from grain fermentation process developed from producer-reported data has been used as a base case and scaled using the differences in ethanol yield between the grain of interest and corn. Because ethanol is produced from the starch portion of the grain, the starch content can be used as a proxy for ethanol yield to allow for scaling of the process emissions. This is equivalent to scaling each of the inputs relative to the ratio of feedstock starch content to corn and assuming that there are not other factors specific to the feedstock.

To develop the value for a pea-based bioethanol CI, the starch content (51.5%, or 69.9% that of corn, on a dry matter basis (Heuzé V., 2017) (DM INRA-CIRAD-AFZ , n.d.) has been used to estimate the ethanol yield from pea relative to that from corn. In the absence of data specific to the pea process or legumes/pulses generally, the unallocated life cycle processing emissions are scaled by the difference in yield. As corn and wheat process emissions differ and peas are legumes rather than cereal grains, the mixed grains (corn, wheat, barley) producer process is used here, and the corn and wheat process emissions (scaled) are used to set a range for uncertainty analysis.

Like the grains currently used for conventional bioethanol production, the legume pea also produces nutrient rich residue, pea protein concentrate. To estimate co-product yields, the protein in the legume is assumed to be entirely converted into the pea protein concentrate. The literature value of 22.8MJ/kg was used for the protein content of peas (Heuzé V., 2017) and the energy content of pea protein concentrate (DM INRA-CIRAD-AFZ , n.d.).The process and upstream emissions are allocated between the bioethanol product and pea protein co-product on an energy basis (45% to pea protein coproduct, in line with corn’s 49% allocation and wheat’s 42%).

5.4 Carbon Intensity Results for Conventional Crop-Based Low Carbon Liquid Fuels

5.4.1 Carbon Intensities for Crop-based Bioethanol

Table 32 shows the CI values for a variety of pathways and templates. These are intended to provide an easy starting point for modelling many province-specific processes and feedstocks. The top set of pathways uses producer data reported under the ecoEBE program for the grain to bioethanol block, while the lower set of template pathways use literature data.

Table 32. Provincial and Canadian average cradle-to-grave carbon intensity values for key crop-based conventional biofuels, expressed in g CO_2 eq./MJ of fuel.

Crop-based fuel pathway	Carbon Intensity (g CO_2 eq./MJ)
Bioethanol	
Bioethanol – Producer Sourcing and Operating Data	
Canadian Average Bioethanol from Mixed Grains, Producer Sourcing & Processing Data	45
Dry milling from Mixed Grains, Canadian Average, Producer Sourcing & Processing Data	41
Wet milling from Mixed Grains, Canadian Average, Producer Sourcing & Processing Data	40
Dry milling from Corn, Canadian Average, Producer Sourcing & Processing Data	42
Wet milling from Wheat, Canadian Average, Producer Sourcing & Processing Data	51
Bioethanol – Approximated with Producer Sourcing and Operating Data	
Canadian Average Bioethanol from Dry Peas, Estimated* Sourcing & Processing	55
Canadian Average Bioethanol from Barley, Average Sourcing & Estimated* Processing	35

Of the 14 facilities, ten are dry mill (seven are corn exclusively) and four wet mill. Only two facilities are using exclusively wheat, and are wet milling. The CI for bioethanol from wheat via wet milling is correspondingly less robust. In addition to the producer-reported data pathways, the dried pea and barley pathway CIs are included with a pathway based on scaled inventories from the producer data. For both, the pathway and CI should be taken as a starting point for development of a more detailed representative pathway. The CALDC does not yet contain an inventory for dried peas, so the dried pea ethanol CI appears higher than the others but is likely to decrease when the CRSC-based dried pea is added.

Table 33 shows the carbon intensity values for bioethanol production based on current operations and the CEPR reporting data, total and broken down by life cycle stage for different levels of technology and feedstock aggregations.

Table 33: Carbon intensity values for currently produced grain-based bioethanol (producer data 2012-2016), per MJ of fuel produced, allocated with harvesting coproducts by mass and processing coproducts by energy share, to two significant figures.

Life Cycle Stage	Canadian Average	Dry Mills	Wet Mills	Dry Mill Corn	Wet Mill Wheat
Life Cycle Stage	Mixed Grains (wheat, corn, barley)	Mixed Grains (wheat, corn, barley)	Mixed Grains (wheat, corn, barley)	Corn	Wheat
Feedstock Production	20	21	11	22	13
Feedstock Transportation	0.9	0.9	0.9	0.9	1.1
Process emissions	23	18	27	18	35
Transport & Distribution	0.8	0.8	0.8	0.8	0.8
Combustion	0.4	0.4	0.4	0.4	0.4
Total	45	41	40	42	51

Table 34 total and building block contributions to the CI for bioethanol from dried peas and bioethanol made entirely from barley (as opposed to the Mixed Grains process in the CEPR data), neither of which had data in the CEPR materials. Both use a yield-scaled mixed grains bioethanol average process from CEPR data.

The CI to make bioethanol from dried peas with a protein-rich coproduct is allocated (energy basis) to give the values here. The bioethanol from barley CI is also allocated (energy basis) between the bioethanol and coproduct. The primary contributors to the life cycle GHG emissions are the feedstock production and emissions associated with energy use and chemical inputs for conversion to ethanol.

Table 34. Carbon intensity for ethanol produced from pea starch and barley based on scaling the CEPR process, expressed in g CO_2 eq. per MJ of ethanol.

Life Cycle Stage	Dried Peas (g CO2eq/MJ)	100% Barley (g CO2eq/MJ)	Unit
Feedstock Production	29	10	g CO_2 eq./MJ
Feedstock Transport	1.3	1.1	g CO_2 eq./MJ
Ethanol Production	23	22	g CO_2 eq./MJ
Transport & Distribution	0.8	0.8	g CO_2 eq./MJ
Combustion	0.4	0.4	g CO_2 eq./MJ
Total	55	32	g CO_2 eq./MJ

The significantly lower fraction of starch in dried peas compared to the other grains, including barley, results in a much higher feedstock demand and consequently a significantly higher CI value for Bioethanol from (100%) Dried Peas. In contrast, the CI and contributions for Bioethanol from 100% Barley is in the same range as the other CIs.

Results of the uncertainty analysis on the bioethanol pathways are shown in Table 39. The CI values for all pathways show broad uncertainty ranges, dominated by uncertainty in the crop production CI. The range on the wet mill mixed grain CI is larger because of the higher variability in that data and the smaller number of facilities.

Table 35. Results of uncertainty analyses for crop-based bioethanol based on producer data, g CO_2 eq/MJ ethanol. Results based on Monte Carlo analysis of 2,000 runs with a confidence interval of 95%.

Final CI	Mean	Median	SD	Min (2.5%)	Max (97.5%)
Bioethanol – – Producer Sourcing and Operating Data					
Canadian Average Bioethanol from Mixed Grains, Producer Sourcing & Processing Data {CA}					
45	52.9	51	12	36.1	80.2
Dry milling from Mixed Grains, Canadian Average, Producer Sourcing & Processing Data {CA}					
41	47.1	45.4	11	31.1	73.1
Wet milling from Mixed Grains, Canadian Average, Producer Sourcing & Processing Data {CA}					
40	62.2	59.7	16	38.7	102
Dry milling from Corn, Canadian Average, Producer Sourcing & Processing Data {CA}					
42	45.8	44.1	10	30.5	70.5
Wet milling from Wheat, Canadian Average, Producer Sourcing & Processing Data {CA}					
51	78.1	74.7	20	47	128
Bioethanol – Approximated with Producer Sourcing and Operating Data					
Canadian dry mill bioethanol from Canadian Dried Peas {CA}					
55	79.8	56.6	85	29	269
Canadian dry mill bioethanol from Canadian Barley {CA}					
35	87.8	67.7	70	31	269

The uncertainties for the CI values for all pathways are high primarily due to uncertainty in the agricultural production (i.e., what the intensity associated with any particular kg of grain in Canada, which could range from the minimum fount nationally to the maximum found national), and, in the case of dried peas and 100% barley, lack of dedicated process data. In fact, the agricultural uncertainty overwhelms uncertainties in the other life cycle stages with the exception of bioethanol from dried peas, which is a more speculative pathway based on approximations to the CEPR process. The dried peas, higher protein pulses, deviate more from the underlying process than does the grain barley. The Barley conversion process is much better represented by the CEPR data, as it is a feedstock in mixed production, and because its composition has more in common with the other grains, but barley production impacts are variable.

5.4.2 Carbon Intensities for Crop-based Biodiesel

The pathway carbon intensity values, from crop production though to combustion at the user, for oilseed crop-based biodiesel are shown in Table 36. The two sets of pathways use producer data reported under the ecoEBE program for the oil to biodiesel block and oilseed-specific literature data for the oil extraction block (top) or literature values for both blocks (bottom). The CI values from each are nearly identical.

Table 36. Provincial and Canadian average cradle-to-grave carbon intensity values for included crop-based biodiesel pathways, expressed in g CO_2 eq./MJ of fuel.

Crop-based fuel pathway	Carbon Intensity (g CO_2 eq./MJ)
Biodiesel – Producer Operating Data for Oil to Biodiesel	
Canadian Average Biodiesel from Canola, Producer Processing Data	31
Canadian Average Biodiesel from Soybean, Producer Processing Data	36
Canadian Average Biodiesel from Camelina, Producer Processing Data	22
Biodiesel – Generic Vegetable Oil to Biodiesel Template Pathways	
Canadian Biodiesel from Canadian Canola	24
Canadian Biodiesel from Canadian Soybean	29
Canadian Biodiesel from Canadian Camelina	16

As described in Section 3, a building block approach has been used to develop CI values for conventional crop-based biofuels to provide CI values and easily modifiable templates in the Tool to facilitate modeling. Oilseed-based building block and cumulative biodiesel CI values are shown in Table 37 and Table 38. Table 37 uses producer data reported under the ecoEBE program for the oil to biodiesel block, while the values in Table 38 are based on literature data for general vegetable oil to biodiesel conversion. In both cases, oil extraction is represented by building blocks for each of the feedstocks developed from literature.

Table 37: Building block and cumulative carbon intensity values for oilseed-based biodiesel based on oilseed specific extraction and current (2012-2016) biodiesel production (producer data) for biodiesel conversion, per MJ of fuel produced, impacts allocated with coproducts by energy share.

Life Cycle Stage	Canola	Soy	Camelina	Unit
Feedstock Production	13	17	5.1	g CO_2e/MJ
Feedstock Transportation	0.5	0.6	0.5	g CO_2e/MJ
Oil extraction @ Mill/Refinery	2.7	4.2	1.6	g CO_2e/MJ
Oil to Biodiesel Conversion @ Mill/Refinery	9.8	9.8	9.8	g CO_2e/MJ
Transport & Distribution	*0.6*	*0.6*	*0.6*	g CO2e/MJ
Combustion (non-biogenic)	4.4	4.4	4.4	g CO_2e/MJ
Total	31	36	22	g CO_2e/MJ

Table 38 Building block and cumulative carbon intensity values for oilseed-based biodiesel based on oilseed specific extraction and literature data for biodiesel conversion per MJ of fuel produced, impacts allocated with coproducts by energy.

Life Cycle Stage	Canola	Soy	Camelina	Unit
Feedstock Production	13	16	4.9	g CO_2e/MJ
Feedstock Transportation	0.5	0.6	0.5	g CO_2e/MJ
Oil extraction @ Mill/Refinery	2.6	4.0	1.6	g CO_2e/MJ
Oil to Biodiesel Conversion @ Mill/Refinery	3.5	3.5	3.5	g CO_2e/MJ
Transport & Distribution	0.6	0.6	0.6	g CO2e/MJ
Combustion (non-biogenic)	4.5	4.5	4.5	g CO_2e/MJ
Total	24	29	16	g CO_2e/MJ

The producer-specific reported data which underpins the production CIs in Table 38 are in very good agreement with the literature-based processes in Table 37. The only significant difference between the two arises from a much higher reported natural gas usage in the producer (CEPR) data, which differs by a factor of 3, and leading to the higher CI for oil to biodiesel and total CI seen in the industry pathway.

Results of the uncertainty analysis on the biodiesel pathways are shown in Table 39. The deviation between the single point CI and the mean values arises from the large, highly variable ranges for the feedstock production (agriculture) stage, which is attributable to the SOC range and impact.

Table 39. Results of uncertainty analyses for crop-based biodiesels. Results based on Monte Carlo analysis of 2,000 runs with a confidence interval of 95%.

Final CI	Mean	Median	SD	Min (2.5%)	Max (97.5%)
Literature-based oil extraction and Producer data (CEPR) conversion to biodiesel					
Canadian biodiesel from Canadian canola seeds {CA}					
31	44.8	30.5	45.6	14.2	171
Canadian biodiesel from Canadian soybeans {CA}					
36	62.4	40.9	65.9	17.7	228
Canadian biodiesel from Canadian camelina seeds {CA}					
22	23.9	20.9	36	-2.9	93.1
Literature-based oil extraction and conversion to biodiesel					
Canadian biodiesel from Canadian canola seeds {CA}					
24	45.3	30.4	54.8	14.4	169
Canadian biodiesel from Canadian soybeans {CA}					
29	67.2	39.4	100	17.5	279
Canadian biodiesel from Canadian camelina seeds {CA}					
16	17.8	14	29	-2.4	79.6

The CI values for all pathways show high levels of uncertainty, primarily arising from uncertainty in the crop production CI. This large uncertainty overwhelms uncertainties in the other life cycle stages. This is particularly apparent in the CI for camelina-based fuels. As a currently very low production crop, agricultural practice data is highly uncertain, resulting in the high ranges for camelina; the negative minimum values reflect the range in soil organic carbon emissions associated with management practice change and may suggest potential for some carbon sequestration with camelina.

Oilseeds represent a small share of current Canadian biodiesel production. The oil to biodiesel process built from the operating data contained in the CEPR thus doesn't align as well with oilseed practices. In these cases, the generic, literature-based pathway may represent a better starting point.

5.5 Data Gaps and Limitations for Conventional Crop-Based Low Carbon Liquid Fuels

Data gaps relevant for the crop-based low carbon liquid fuels include:

- Cultivation
    - Detailed land management information (e.g. extent of till/no till) and spatially-explicit monitoring of
        - Consolidation and storage variability
        - Distance and mode variation
- Production
    - Consistent co-product energy (and other input) use data, which would facilitate alternative allocation approaches
    - The CEPR data indicate that there was only a single facility from which surplus electricity was exported from crop-based bioethanol producers during the reporting period (data spans 2008/09 to 2016/17, with good coverage 2010/11-2015). This case is reflected in the corn pathway, but anecdotal reports suggest electricity export is more frequent.
    - Because oilseeds represent a small share of current Canadian biodiesel production compare to other oils, the operating data contained in the CEPR may not align well with oilseed practices. As the CEPR data is no longer updated and

    is used to create a snapshot process, data from other producer reporting schemes may fill this gap. Literature-based processes have been built as templates to use with vegetable and other oils for biodiesel.
    - Ongoing and updated operating data associated with a selection of technology types would allow for defensible association of technology pathway in cases where there are multiple and substantively differing technology routes. For example, the conventional bioethanol process based on CEPR data is a hybrid of technology and feedstock.
- Dried Peas and other feedstocks not captured in the producer data
    - Feedstock-specific differences in processing energy and input demands. Process emissions differ significantly even between wheat and corn, which are more similar to each other than to peas (and other legumes/pulses), which have a much higher protein content (2-2.5x). While scaling the process emissions relative to yield is a reasonable first-order approximation, the difference between crop families increases the uncertainty significantly.
    - Detailed agricultural practice data for cultivation, harvest and storage of peas in Canada.

6. Unconventional Crop-Based Low Carbon Liquid Fuels

6.1 Introduction to Unconventional Crop-based Low Carbon Liquid Fuels

As discussed in Section 5, low carbon liquid fuels can be produced from a variety of renewable Canadian crops, whether grains (e.g., conventional bioethanol) or oilseeds (e.g., biodiesel), as well as agricultural residues or purpose-grown biomass (lignocellulosic ethanol and advanced biofuels). Lignocellulosic agricultural residues are also used as low carbon liquid fuels. Bioethanol and biodiesel are in commercial production and use and are considered conventional crop-based fuels. All other fuels are considered unconventional within this report.

The Canadian unconventional crop-based low carbon liquid fuels incorporated in the Fuel LCA Modelling Tool are summarized in Table 40. Cereal grains are used for starch-based ethanol from fermentation, while oilseeds are processed and refined for oil-based fuels. Lignocellulosic residual biomass from these crops, primarily corn stover or wheat straw, may be used after additional processing for ethanol via fermentation[10].

Table 40. Summary of crop-based low carbon liquid fuel pathways including descriptions of fuel feedstock source, conversion processes, process energy carrier outputs, and expected end use to be modelled (feedstocks marked with an asterisk are not modelled in detail here).

Fuel	Feedstock	Conversion Process	End Use
Lignocellulosic Ethanol	Corn Stover Wheat straw	Enzymatic pretreatment C5 / C6 sugar fermentation Distillation	Transportation fuel
Hydrogen-Derived Renewable Diesel (HDRD)	Canola oil (Canadian) Palm oil (imported)	Hydro-processing Hydro-treatment	Transportation fuel
Renewable Biojet Fuel	Canola oil Used cooking oil	Hydro-processing Hydro-treatment	Transportation fuel

6.2 Cellulosic Ethanol

6.2.1 System Boundaries and Descriptions for Cellulosic Ethanol

Cellulosic ethanol can be produced from any source of cellulose such at grasses, trees and the unharvested parts of grain crops. It is of particular interest due to the low cost of cellulosic feedstocks; however, cellulose is more difficult to convert into fuels than the sugars and oils produced from grains and seeds.

Of particular interest as a cellulosic resource in Canada are corn stover and wheat straw. Corn stover and wheat straw are the above-grown portions of the plants without the grain. This includes stems, stalks, leaves and, in the case of corn, cobs. Both starch and cellulose are polymers of glucose (sugar). Starch is a linear polymer of glucose though it can sometimes be branching. Cellulose can form branching chains of glucose

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[10] Other routes, both biochemical and thermochemical, are also possible, though primarily at research or pilot scales.

as well as fairly long linear chains (particularly alpha cellulose). This combined with the 5 carbon sugar linkages not typically present in starch can make breaking down the structure of cellulose into sugars more energy intensive than that of starch. Hemicelluloses found in biomass cell walls are composed of both 5 and 6 carbon sugars which can also be converted to ethanol once these sugars are extracted from the biomass feedstock.

The differing structures of starch (linear) and cellulose (branching) are rooted in their different functions within the plant. Starch, which is, in the case of corn and wheat is primarily found in the grain at harvest, is an easily-accessible source of sugar for a growing seedling. Cellulose, the most abundant polymer of sugar on Earth, branches within the cell wall matrix of plants along with hemicelluloses and lignin to form the strong structural architecture of plants that allows them to grow tall. Thus, cellulose is not as easily accessible as a form of sugar feedstock as starch. Nevertheless, technologies have been developed to liberate the sugars from the cellulose in this matrix. Just like the glucose derived from starch, glucose from cellulose can be fermented to produce ethanol and used as a transportation fuel. The key difference between ethanol production from starch, like corn grain ethanol, and cellulosic ethanol, is not only in the feedstock, but in the addition of the pretreatment step in cellulosic ethanol production that liberates glucose from the cellulose, hemicelluloses and lignin in the cell wall. There are dozens of patented pretreatment techniques including adding acids or bases to the feedstock, exposing the feedstock to high temperature or pressure, mechanical separation and combinations of all of these (Sinistore, 2012).

The cellulosic ethanol fuels chosen to be included in the Fuel LCA Modelling Tool are summarized in Table 41. The primary difference between the two is the feedstock, which will affect the sugar yields and thus, the resulting ethanol, and potential co-product quantities.

Table 41. Summary of cellulosic ethanol fuel pathways including descriptions of fuel feedstock source, conversion processes, process outputs, and expected end use.

Fuel	Feedstock	Conversion Process	End Use
Cellulosic Ethanol	• Corn Stover	• Enzymatic pretreatment • C5 / C6 sugar fermentation • Distillation	• Transportation fuel
Cellulosic Ethanol	• Wheat Straw	• Enzymatic pretreatment • C5 / C6 sugar fermentation • Distillation	• Transportation fuel

Further descriptions of these fuels as well as an overview of the modelling approach and a summary of the data sources that were used to develop the life cycle inventory (LCI) for cellulosic ethanol are provided in the sections below.

Crop Residues

Cellulosic ethanol can be produced from a variety of feedstocks, but of primary interest to this analysis is the use of the crop waste corn stover or wheat straw. The difference between a crop residue and a crop waste is that a residue is deemed to have economic value, while a waste is deemed to have no economic value. Currently there is no commercial market for corn stover or wheat straw, thus production is based on information about the production of corn and wheat grain with expansion of the system boundaries to apply a burden to the corn stover and wheat straw to replace the nitrogen that is removed from the system when the stover and straw are harvested. The removal of this nitrogen requires increased inputs of nitrogen fertilizer in following years of production. Additionally, harvesting the corn stover and wheat straw requires an additional pass through the fields with a harvester. Therefore, the emissions from burning diesel to run this harvester are also assigned to the corn stover and wheat straw. These GHG emissions values for the additional N fertilizer and harvesting are given in Section 4.

6.2.2 Modelling Approach for Cellulosic Ethanol

The following sections provide a brief overview of the modelling approach for low carbon fuels, as well as discussion of the key methodological issues addressed in the modelling, the life cycle inventory data used, results and data gaps and limitations.

Development of Unit Process Building Blocks

The overall modelling approach for Milestone 3 is to develop unit processes to serve as building blocks for current and future modelling work in the Fuel LCA Modelling Tool. For cellulosic ethanol, the major building blocks of modeling will be the regional production of the two feedstocks, feedstock transport, pretreatment, fermentation, distillation and denaturation, fuel transport, blending and distribution, and combustion. Regional differences in feedstock production reflect different applications of inputs such as fertilizers and differing yields based on location. The major building blocks are illustrated in Figure 7.

Using this building blocks approach, even in cases where only literature data are available, or where no data is available, unit processes can still be developed and included as placeholders in the Fuel LCA Modelling Tool and can then be updated by tool users when data are available.

The modelling work in Milestone 3 relies heavily on fossil fuel unit processes that were developed in Milestone 2, including fuel inputs to machinery and equipment (e.g. diesel, natural gas, etc.) and transportation processes (e.g. trucks, rail, pipelines). These unit processes have been pulled from the ECCC Fuels database and incorporated into the low carbon fuel pathway models where needed. Systems outside of the system boundary of this analysis include on-farm and refinery equipment production, construction and decommissioning of ethanol refineries, and construction and decommissioning of combustion infrastructure. Significant modeling considerations include the inclusion or exclusion of direct and indirect land use change, allocation methods between grain and non-grain portions of the feedstock, potential applications of ethanol refinery co-coproducts and associated allocation, and combustion emissions of neat or blended fuels.

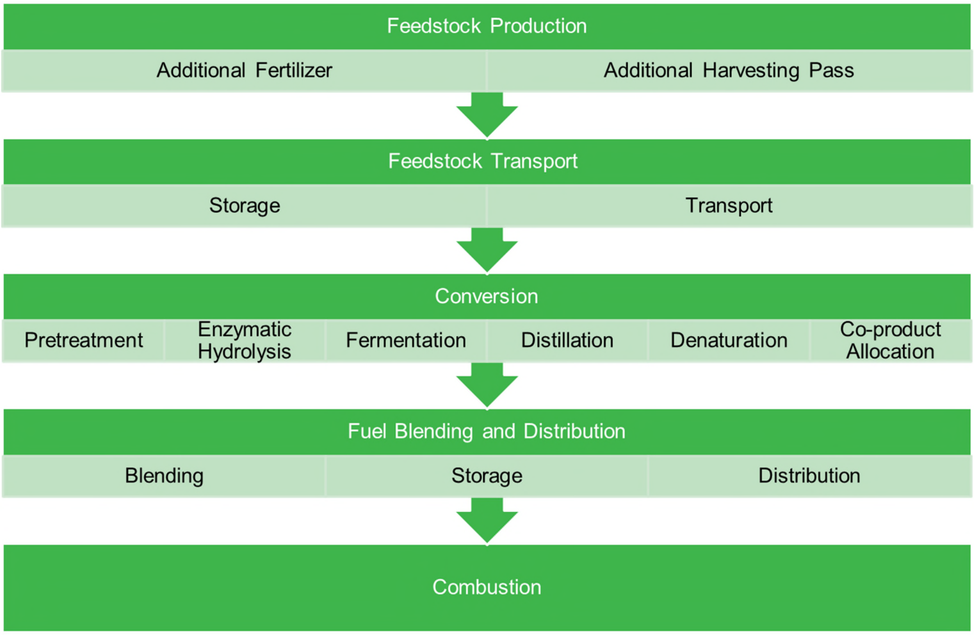

Figure 7: Building blocks of the cellulosic ethanol pathway

Regional Variation

Regional variations affect the yield and emissions from soils of different crops and thus the carbon intensities of the resulting fuels. Crop management practices that vary by region such as tillage practice, fertilizer and pesticide application rates will influence GHG emissions in addition to weather and soil variations over space and time. Since corn stover and wheat straw are treated as wastes in this study, they do not contribute to these regional variations in emissions from soils. Cellulosic fuel production has less influence from regionalization as the technologies for producing it do not need to vary by location. The major source of regional variation for fuel production is the electricity grid from which power is drawn for the conversion process. The distance which feedstocks must travel to reach a cellulosic ethanol facility will vary. Since, at the time of this writing, there are no commercial-scale corn stover or wheat straw cellulosic ethanol facilities, this distance has been based on assumptions about the locations of theoretical plants and will be described in greater detail in the description of transportation modeling. Regional nitrogen fertilizer requirements variation has been captured by modeling crop production by reconciliation unit (RU) which was developed by AAFC and ECCC as the smallest spatial unit at which activity data on crop production could be harmonized ((S&T)2 Consultants Inc., 2017c). With respect to background energy systems, electricity grid carbon intensities are available at a provincial level based on work completed in Milestone 2, as are some fuels (e.g. diesel), and have been incorporated into the unit processes available for modelling solid low carbon fuels.

Co-Product Allocation

Since the corn stover and wheat straw are treated as waste products from the production of corn grain and wheat in this study, they are not considered to be co-products of crop production. Therefore, these wastes do not receive burdens from the production of corn grain or wheat. Since corn stover and wheat straw are treated as wastes, none of the upstream GHG associated with corn and wheat cultivation are allocated between the corn product and corn stover co-product and the wheat grain and wheat straw co-product, respectively. Instead, GHG emissions from the production of ammonia fertilizer to replace the nitrogen in the stover and straw represent the burdens of the stover and straw removal. Additionally, GHG emissions from the combustion of diesel for the additional pass with a harvester to remove the stover and straw is included.

One point at which allocation can occur is at the cellulosic ethanol facility between the ethanol as the primary product and the remaining solids that consist of hemicelluloses and lignin as the co-product. Often, the fermentation can take advantage of the presence of five and six carbon sugars in the hemicelluloses, but some sugars generally remain. Moreover, the lignin cannot be fermented, but has some valuable applications. The most common use of the unused hemicelluloses fraction and the lignin co-products is to burn them for combined heat and power to fuel the ethanol production process. Often, excess electricity is generated as well, and this could be exported to the grid to offset electricity production by conventional means in that grid region.

The choice of allocation approach must be well-documented and transparent, including a clear rationale and sensitivity analysis to show the influence on the study results as it has been demonstrated to influence the ability of a fuel to meet a low carbon fuel policy (Kaufman, Meier, Sinistore, & Reinemann, 2010). For the electricity co-product of the cellulosic ethanol refinery, this excess electricity will provide a credit to the ethanol system for displacing the Canadian average grid. For the co-product electricity production from the ethanol refinery, the excess electricity will be exported to the grid and, therefore, is assumed to displace the emissions from grid electricity produced in Canada. A Canadian average electricity grid value was used because there are no specific locations in which corn stover or wheat straw cellulosic ethanol is being produced commercially in Canada. In the future, the user will be able to modify the co-products of ethanol production and the allocation method used, as well as the provincial electricity grid that is displaced. Note that the displacement of grid electricity with the electricity that could be produced by a future cellulosic ethanol plant is a documented method of allocation avoidance in the literature (Cronin, et al., 2017) (Kaufman, Meier, Sinistore, & Reinemann, 2010) (Sinistore, 2012). Furthermore, LCAs of sugarcane ethanol production apply the same displacement method to account for the excess electricity produced from the combustion of the bagasse co-product of sugar extraction from sugarcane (Wang, Han, Dunn, Cai, & Elgowainy, 2012). Double-counting of this electricity on the grid is avoided in the calculation of the CI of cellulosic ethanol because the background electricity grid mix used for Canada does not include electricity from cellulosic ethanol plants because none currently operate at a commercial scale in Canada.

Biogenic Carbon and Land Use Change

In remaining consistent with the Government of Canada’s policy on biogenic carbon, as shown in Canada’s National Inventory Report (Government of Canada, 2018), emissions of biogenic carbon from fermentation or combustion of cellulosic ethanol are assumed to be zero and therefore do not contribute to the GHG emissions of the fuel. The carbon balance into and out of the system have been evaluated to ensure masses balance and is well documented in the ethanol production literature (Humbird, et al., 2011). While removal of stover and straw can affect the long-term soil carbon balance this impact must be calculated in a spatially-explicit way that accounts for the specific climate, soil type, topography, land use, crop type, and crop rotation over time which require a dynamic parametric model (Sinistore, 2012).

Carbon emissions associated with direct land use change will be included in instances where feedstock production requires the conversion of land from existing use to bioenergy production. In the case of annual crops that are already produced in Canada, including corn and wheat, direct LUC is not included because a change in land use is not occurring. Indirect land use change (iLUC) is excluded from the carbon intensity calculations. Any changes in land management practices, such as the removal of the stover and the wheat straw from the fields, is included in this analysis.

6.2.3 Life Cycle Inventory for Cellulosic Ethanol

Agricultural Production

Since corn stover and wheat straw are classified as wastes in this study, no burdens from the agricultural production of corn or wheat grain are apportioned to the stover or straw. Instead, only the burden from additional ammonia fertilizer that must be added to the land as a result of the removal of N from the land in the stover and straw and the GHG emissions from an additional pass in the field to harvest the residues are included in the cellulosic ethanol CI. This is calculated according to the N content of the stover and straw and the amount of stover and straw used to make fuel. These data are summarized in Section 4.8.

Cellulosic Ethanol Production

Cellulosic ethanol differs from ethanol made from starch in five major ways. First, the cellulosic feedstock requires pretreatment to liberate the sugars from the cell walls of the plant material. Starch-based ethanol production often begins with mechanical breakdown such as in a hammer mill. The cellulosic feedstock may undergo some mechanical size-reduction, and then pretreatment. Many different technologies have been developed or are still under development to pretreat biomass. Some are specific to the type of biomass, while others are more general. Some of the only pilot-level cellulosic ethanol production facilities that have produced sizable quantities of cellulosic ethanol, such as the Iogen facility (Ontario, Canada) used dilute acid (DA) pretreatment of wheat straw to produce cellulosic ethanol in 2004 (Mupondwa, 2017).

The second difference is in the enzymatic hydrolysis. Starch-based production uses alpha-amylase to break the long polymers of glucose into shorter dimers and monomers of glucose, but these enzymes will not break the beta-glucosidic bonds in cellulose. Therefore, different enzymes, called cellulases, capable of breaking these bonds are used in cellulosic ethanol production. The third difference between starch-based and cellulosic ethanol production is in the sugars. The cell wall matrix is made of cellulose, hemicelluloses and lignin. Hemicelluloses are a class of compounds made from both 5- and 6-carbon sugars (C5 and C6, respectively, also known as pentoses and hexoses). Both C5 and C6 sugars are liberated from the hemicelluloses, while cellulose yields only glucose, a 6-carbon sugar. The lignin fraction does not provide sugar to the process. In fact, lignin demonstrates recalcitrance which means that after it is pulled apart from the cell wall matrix, it can stick back to the cellulose and hemicelluloses, blocking the sites where enzymes would act to break down the sugar polymers. One of the major reasons why different pretreatment methods give different sugar yields is the pretreatments method’s proclivity to cause or prevent lignin recalcitrance.

The fourth difference is in fermentation. The organism used in fermentation of straight glucose (such as from starch) is *Saccharomyces cerevisiae* (commonly known as baker’s yeast), but this organism will not convert the C5s from the cellulosic feedstock efficiently. Therefore, different organisms are used in cellulosic ethanol fermentation and result in different ethanol yields. In some cases, the enzymatic hydrolysis and fermentation are conducted together in something called simultaneous saccharification and co-fermentation because this can lead to higher yields of ethanol than separate stages. In this study, enzymatic hydrolysis and fermentation are modeled as separate steps.

After fermentation, the final steps for ethanol production are very similar in cellulosic ethanol as they are in starch ethanol with the exception of the co-product output. The output of the fermentation step is a distillation step to separate the ethanol from water and solids. The resulting ethanol is distilled, dehydrated and then denatured with gasoline in the starch-based ethanol process, (e.g., corn ethanol) the solids remaining are generally used as animal feed The solid fraction from the cellulosic ethanol process is high in carbon-rich lignin, which has a variety of potential uses. The most common use is burning the solids to provide fuel for the ethanol conversion process. Lignin has many other uses, but they are generally not commercially or economically viable. Wastewater is also produced from the distillation column and is treated on site. A process diagram that illustrates all of the stages of cellulosic ethanol production is provided in Figure 8 and additional details on each step are in the following sections.

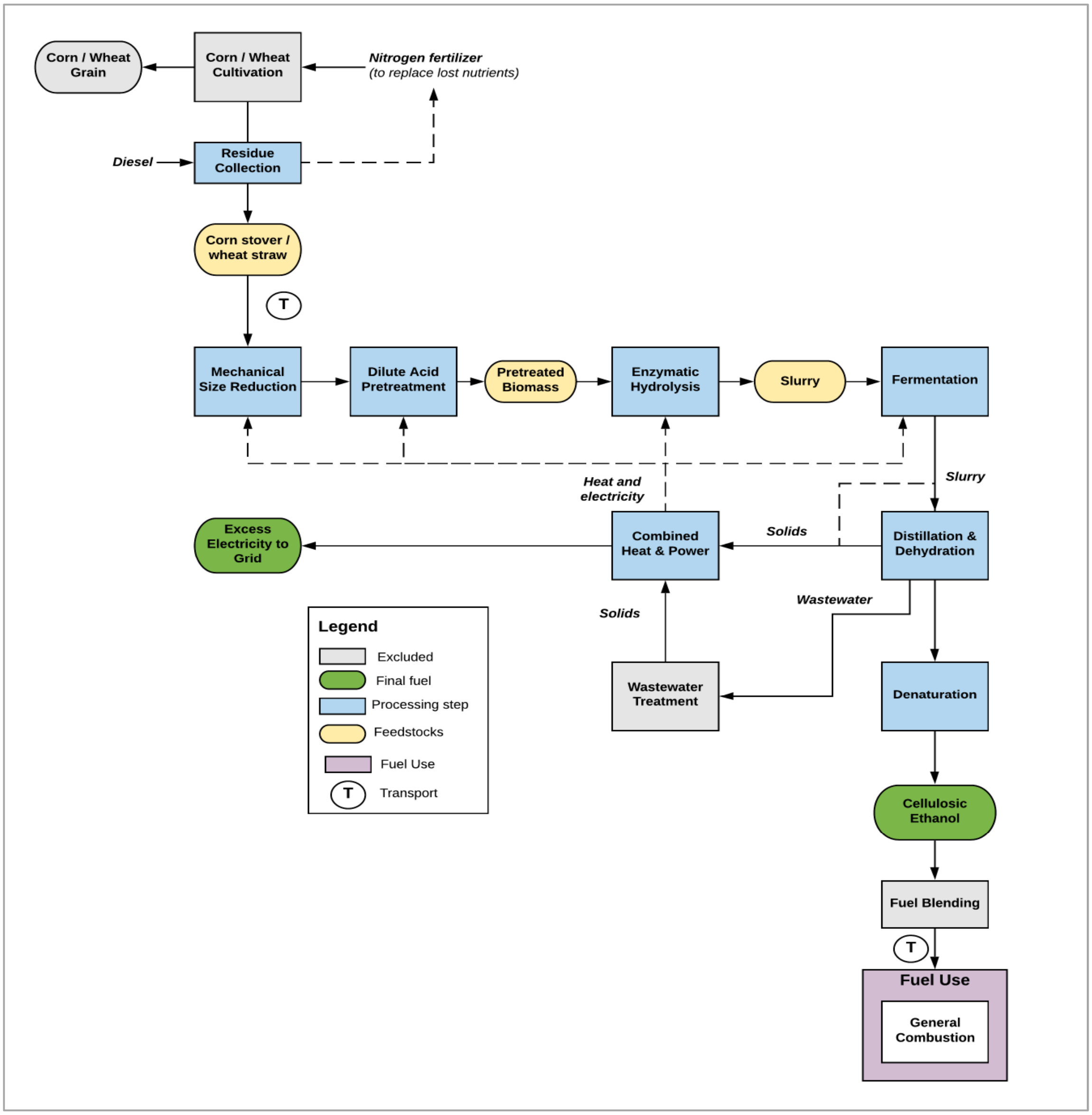

Figure 8: Process flow diagram of cellulosic ethanol production

Data for the cellulosic ethanol refinery from pretreatment through ethanol production and other process steps were obtained from a 2011 study by the National Renewable Energy Laboratory (Humbird, et al., 2011). This study assumed a plant size where 773,000 dry US tons (701,253 MT) of corn stover are processed per year, with a 76% theoretical ethanol yield or 79 gallons of ethanol per dry ton of corn stover. This gives an annual yield of 61,067,000 gallons of ethanol or 231,163,741 liters. This analysis follows the same assumptions as the NREL study. Wheat straw has a different sugar composition from corn stover, most notably, no sucrose and higher glucan (cellulose) and xylan fractions which yield more fermentable sugar per kilogram of feedstock input. Wheat straw also, however, has a higher lignin fraction than corn stover, and as discussed above, lignin has been demonstrated to inhibit enzymatic hydrolysis and fermentation of sugars (Saha, Iten, Cotta, & Wu, 2005). This study modeled the wheat straw to ethanol pathway with the same conversion efficiency assumptions for the sugars yielded from corn stover in the NREL study, but with lower sugar content from wheat straw. Therefore, the yield of ethanol from the same quantity of wheat straw (773,000 dry US tons) will be 57,508,000 gallons of ethanol or 217,694,000 liters, with a 72% theoretical yield of 74 gallons of ethanol per try ton of wheat straw which is in line with the findings of other studies on wheat straw conversion to ethanol with dilute acid pretreatment and enzymatic hydrolysis given the lower sugar yield of wheat straw compared to corn stover (Novy, Longus, & Nidetzky, 2015).

Dilute Acid Pretreatment

The pretreatment step in cellulosic ethanol production liberates glucose from the cellulose, hemicelluloses and lignin in the cell wall. There are dozens of patented pretreatment techniques including adding acids or bases to the feedstock, exposing the feedstock to high temperature or pressure, mechanical separation and combinations of all of these (Sinistore, 2012).

One of the most common and well-developed methods of pretreatment is called dilute acid (DA) (Cronin, et al., 2017; Mupondwa, 2017). In this method dilute sulfuric acid (H_2SO_4) is combined with the biomass at high temperature for a short time. After this process is complete, ammonia (NH_4) is added to the pretreated slurry to raise its pH from approximately 1 to 5 in preparation for enzymatic hydrolysis. Data for the DA pretreatment were obtained from a 2011 study by the National Renewable Energy Laboratory (Humbird, et al., 2011). Specifics about the conversion efficiencies between biomass to sugar and sugar to ethanol are provided in Appendix A. Overall inputs to the pretreatment, enzymatic hydrolysis, and fermentation are summarized in Table 42. Life cycle inventory data for these inputs, other than the feedstock, have been obtained from GREET (Wang, Han, Dunn, Cai, & Elgowainy, 2012).

Enzymatic Hydrolysis and Fermentation

The 2011 NREL study also specified the inputs used for fermentation (Humbird, et al., 2011). As noted above, a different organism is used in fermentation in cellulosic production. The assumption in this study is the use of recombinant *Zymomonas mobilis*. The conversion efficiencies for C6 and C5 sugars to ethanol are 90% and 80%, respectively, when DA pretreatment is used. Note that different pretreatment methods lead to different ethanol yields from C6 and C5 sugars. Enzymatic hydrolysis occurs in a continuous reactor in which the pretreated biomass is combined with the cellulases and heated. This process results in a partially-hydrolyzed slurry. The hydrolysis is completed in batches in parallel bioreactors, after which the resulting slurry is cooled. In preparation for fermentation, the cooled slurry is inoculated with the microorganism. The complete residence time is approximately five days. Cellulose enzymes can be produced on site or purchased from outside vendors. The NREL study models on-site enzyme production. While some technologies have an added step to separate C5 and C6 sugars for fermentation in different reactors, the NREP study assumes co-fermentation.

Table 42: Inputs to pretreatment, hydrolysis and fermentation

Inputs
Feedstock (corn stover or wheat straw)
Sulfuric acid (93%)
Ammonia
Corn steep liquor
Diammonium phosphate
Sorbitol
Glucose
SO_2
Enzyme nutrients
Caustic
Lime
Cooling tower chemicals
Fresh water

Distillation, Dehydration and Denaturation, Co-product and Wastewater Treatment

The 2011 NREL study also specified the inputs used for distillation, dehydration and denaturation. Distillation uses a distillation column (similar to that used in fossil liquid fuel separation) to separate ethanol, water and residual solids. The distillation can only remove 95% of the water, however, and the remaining azeotropic mixture must be dehydrated to 99.5% ethanol with a vapor-phase molecular sieve which adsorbs water and allows ethanol to pass through. The solids that result from distillation are rich in lignin and contain some sugars. As noted above, the most common treatment for solids is to burn them in a combined heat and power (CHP) facility to generate heat and power for the cellulosic ethanol production. Distillation also results in liquid wastewater which must be treated. Since this water is rich in sugars, it is anaerobically digested to produce methane which can be combusted with the lignin solids to produce additional process heat and power for ethanol production. This combustion often results in an excess of electricity that can be exported to the local grid. As noted in the allocation section, allocation is avoided for this co-product allocation by applying system expansion or displacement of grid electricity. The total amount power generated by the CHP for the ethanol plant size modelled is 41MW per year according to the NREL study (Humbird, et al., 2011). This results in a total production of 1,437,833 GJ per year, while the annual demand of electricity from the ethanol plant is 873,830 GJ. The difference is assumed to be exported to the grid to displace the average Canadian grid carbon intensity on a MJ to MJ basis.

Feedstock and Fuel Transport and Fuel Blending and Distribution

An overview of the modelling for feedstock and fuel transport is provided in Appendix B. One important factor in the fuel blending is that, before leaving the ethanol production facility, the ethanol is denatured with 2 to 5% conventional gasoline. Later blending to fuel grade results in common blends of E10 (10% ethanol and 90% gasoline) and E85

(85% ethanol and 15% gasoline). Although, E85 is no longer used in Canada (there are no more pumps available for this fuel blend), increasingly, E15 blends are becoming mainstream in the US and may be used in Canada in the future. This scope, however, considers only the unblended (“neat”) fuel production.

The transportation of feedstocks and final cellulosic ethanol will be done largely by truck and rail. In modelling this transport, we will use the truck and train unit processes that were created in Milestone 2 to capture the upstream and combustion emissions associated with these modes of transport.

Cellulosic Ethanol Combustion

At the point of combustion, all of the carbon in the cellulosic ethanol fuel is biogenic carbon, not fossil carbon. Therefore, the combustion of this carbon results in no net addition to the fossil emissions from the fuel. In this way, the combustion emissions from burning cellulosic ethanol (neat, unblended) are zero. Methane and other types of GHG emissions are possible from the combustion of cellulosic ethanol, and these emissions are dependent upon the combustion efficiency of the engine in which the fuel is burned and the blend of the fuel being combusted. As a placeholder, emissions factors for methane (0.14 g/L, 6.03E-06 kg/MJ) and nitrous oxide (0.022 g/L, 9.47E-07 kg/MJ) were used from Canada’s National Inventory Report (Government of Canada, 2018) for bioethanol. These emissions factors from the NIR are in turn based on conventional gasoline. Characteristics of ethanol (regardless of feedstock) are given in Table 43.

Table 43. Characteristics of ethanol (Government of Canada, 2018).

Fuel	Application	Density	High Heating Value	Carbon Content	Biogenic CO_2 (g/L fuel)
Ethanol	Transportation fuel	789.3kg/m^3	29.67 kJ/g	52.14%	1,508

6.2.4 Carbon Intensity Results for Cellulosic Ethanol

Carbon Intensities

The carbon intensities of corn stover and wheat straw ethanol, total and per life cycle phase, are given in Table 44. Since all of the heat and electricity requirements for the facility are met by the CHP fed by the co-products of ethanol production and those products contain only biogenic carbon, the GHG impacts are assumed to be zero for the CHP. Note that the many of the GHG emission in this table are non-zero, but the values are less than 1% of the impact so are reported as zero. This may affect sums due to rounding.

The primary inputs to the other phases of ethanol production are chemicals used to treat the biomass (e.g., sulfuric acid) and the on-site production of the cellulase for enzymatic hydrolysis. Previous studies have excluded cellulase production in some cases due to lack of available data on production (Kaufman, Meier, Sinistore, & Reinemann, 2010). The GHG emissions from on-site cellulase production were sourced from GREET. It is clear from the results below that the credit provided for the displacement of Canadian grid electricity is a significant driver of the overall CI of the cellulosic ethanol as it offsets all of the emissions from both agricultural and industrial production. The same credits are applied in well-established LCAs of sugarcane ethanol production for the electricity co-product produced from burning bagasse for process heat and power with excess exported to the local grid (Wang, Han, Dunn, Cai, & Elgowainy, 2012). Previous studies acknowledge that it is unrealistic to assume that no electricity is exported to the grid and have also used a variety of assumptions for the amount of electricity exported to the grid (Kaufman, Meier, Sinistore, & Reinemann, 2010). If the fraction of low-carbon renewable energy increases over time, the credit to the cellulosic ethanol system will decrease. Without this credit, the CIs for corn stover and wheat straw ethanol would be 31 and 32 gCO_2e/MJ HHV, respectively which is significantly higher than the negative values in the table below. In addition, it is higher than the cradle to gate impacts of fossil fuels, but due to the biogenic carbon content, lower than the impacts of combusted fossil fuels. Given that there are no commercial scale cellulosic ethanol facilities currently operating in Canada, this electricity credit is not accounted for in the modeling of the Canadian energy grid.

Feedstock production contributes more than 1% to the total CI, but phases such as feedstock and fuel transportation and distribution do not contribute significantly (<1%) to the overall cellulosic ethanol CI from either corn stover or wheat straw. The uncertainty assessment for corn stover and wheat straw ethanol is provided in Table 45. The uncertainty is presented based on the uncertainty in the underlying data. The 2.5% heading indicates the interquartile range of uncertainty and the 97.5% heading indicates the 1.5x interquartile range. SD stands for standard deviation, CV is the coefficient of variance and SEM is the standard error of the mean. This uncertainty analysis of corn stover ethanol indicates that the range of CIs are between -44 and 15 gCO_2e/MJ corn stover ethanol HHV, indicating great potential variability in the result. Similarly for wheat straw ethanol, the uncertainty analysis reveals large variability, with the range of potential CIs between -33 and 18 gCO_2e/MJ.

Table 44: Carbon intensities of corn stover and wheat straw ethanol, total and by life cycle phase

Life Cycle Phase	g CO_2e/ MJ corn stover ethanol HHV	g CO_2e/ MJ wheat straw ethanol HHV
Corn Stover Production	2.5	-
Wheat Straw Production	-	1.9
Feedstock Transport	1.9	2.0
Pretreatment	2.0	2.1
CS Enzymatic Hydrolysis & Fermentation	24	-
WS Enzymatic Hydrolysis & Fermentation	-	25
Distillation & Dehydration	0.0	0.0
Wastewater Storage Utilities	0.0	0.0
Lignin Combustion Exported Electricity Credit	-38	-41
Fuel Distribution	0.8	0.8
Fuel Combustion	0.4	0.4
Total	**-6.4**	**-8.8**

Note that some values appear to be zero due to limiting the number of significant figures in these results to 2.

Table 45: Uncertainty analysis for corn stover and wheat straw ethanol

Cellulosic ethanol, from corn stover (gCO_2e/MJ corn stover ethanol HHV)							
CI	**Mean**	**Median**	**SD**	**CV**	**2.50%**	**97.50%**	**SEM**
-6.9	-9.1	-7.6	18.8	-161%	-43.8	15.0	0.00033
Cellulosic ethanol, from wheat straw (gCO_2e/MJ wheat straw ethanol HHV)							
CI	**Mean**	**Median**	**SD**	**CV**	**2.50%**	**97.50%**	**SEM**
-8.8	-10.8	-8.5	17.6	-164%	-32.5	17.5	0.00039

6.2.5 Data Gaps and Limitations for Cellulosic Ethanol

In preparation of the report and CI values for cellulosic ethanol, a number of data gaps and limitations have been highlighted to inform further research, including:

- Lack of a Canadian-specific process model for cellulosic ethanol production which required the use of a well-cited US study: Note that the processing conditions and technology for cellulosic ethanol are not anticipated to vary based on the location of the ethanol plant (e.g., Canada versus the US), but more so based on the company-specific technology and intellectual property involved in the production. If there are companies with viable technologies applying to produce cellulosic ethanol at the commercial scale (e.g., 25 million gallons/year or more), then their technology could be used to improve the modeling of a Canadian cellulosic ethanol production scenario.
- Spatially explicit crop modeling to determine GHG emissions, such as N_2O, from soils and soil carbon change (e.g., emission or sequestration over time) as a result of stover and straw removal and the addition of N fertilizer replacements: The IPCC Tier 2 equations were used to approximate GHG emissions from the application of nitrogen fertilizers, which is an acceptable and well-documented method, but further precision could be added with spatially explicit crop modeling which did not fit within the scope or timeline of this project.
- Spatially explicit crop modeling to determine the soil organic carbon changes over time due to the removal of corn stover and wheat straw;
- Documentation on the input of diammonium phosphate (DAP) per kg of feedstock treated during enzymatic hydrolysis and fermentation were not detailed enough in the NREL process document to determine the exact quantities required.

6.3 Hydrogenation-Derived Renewable Diesel (HDRD)

6.3.1 System Boundaries and Descriptions for HDRD

Hydrogenation-Derived Renewable Diesel (HDRD) is a type of renewable or “green” diesel that is produced from the same feedstock as biodiesel using a different process. The resulting fuel composition is similar to petroleum diesel with primarily saturated straight chain (C12-C18) hydrocarbons. While biodiesel, is produced by transesterification and produces glycerol as a co-product, HDRD is produced by hydro-processing with the co-products of bio-based propane, carbon monoxide (CO) and carbon dioxide (CO_2). HDRD is produced from a wide variety of bio-based feedstocks, though the most common are animal fats and wastes (e.g., tallow and yellow grease) and vegetable oils (e.g., canola, soy and palm). The yield from production does not vary significantly based on the type of feedstock used (Natural Resources Canada, 2012).

HDRD can be made from fats and oils as they are composed primarily of triglycerides which have a glycerol backbone and three fatty acids. It is the aliphatic chain length and saturation degree of the fatty acids that determines the properties of the final HDRD product such as cold flow, density and energy content. Unlike biodiesel, HDRD can be produced from a wider-range of feedstocks because HDRD produces fully-saturated hydrocarbons that are not susceptible to oxidative instability and, during hydro-processing, free fatty acids can be converted to paraffin while in biodiesel processing, these acids can react with alkali catalysts creating soaps. HDRD can also take advantage of existing refining technologies used in conventional refineries to desulfurize fractional distillates like diesel oil. HDRD is currently produced in commercial quantities by Neste in Porvoo, Finland, Rotterdam, The Netherlands, and Singapore as well as by REG in Geismer, Louisiana, in the United States, but not yet at the commercial scale in Canada (McCormick & Alleman, 2016).

The HDRD processes that will be included in the Fuel LCA Modelling Tool are summarized in Table 46. The primary difference between the two is that HDRD from canola oil will be produced in Canada and HDRD from palm oil is imported as finished fuel.

Table 46. Summary of HDRD fuel pathways including descriptions of fuel feedstock source, conversion processes, process outputs, and expected end use.

Fuel	Feedstock	Conversion Process	End Use
HDRD (Canada-produced)	• Canola oil (Canadian)	• Hydro-processing • Hydro-treatment	• Transportation fuel
HDRD (imported)	• Palm oil	• Hydro-processing • Hydro-treatment	• Transportation fuel

Further descriptions of these fuels as well as an overview of the modelling approach and a summary of the data sources that were used to develop the life cycle inventory (LCI) for HDRD are provided in the sections below.

Crops

HDRD can be produced from a wide variety of feedstocks, but of primary interest to this analysis is the use of the canola oil from canola grown in Canada and imported HDRD from palm oil. Canola oil production is an established market in Canada, thus production is based on information about the current production of canola in Canada. Palm oil is not produced in Canada and, currently, all of the HDRD that is made from palm oil for use in Canada is imported. Therefore, the evaluation of palm oil-derived HDRD will be based on literature on the production of HDRD from palm oil outside of Canada.

As part of the modelling in Milestone 3 to develop default pathways for HDRD from canola oil, production has been modeled at a provincial level, from planting through to harvesting the canola and extracting the oil. The LCI data from this work will be used to model the feedstock production for canola oil by allocating the upstream GHG emissions associated with canola cultivation between the canola oil product and the remaining meal co-product. This allocation has been done based on the energy content of the primary oil product and the remaining meal co-product.

Canola

Canola oil is a co-product of canola cultivation. The oil is pressed from the seeds of the canola plant leaving behind the protein meal. Feedstock production for canola is based on allocation of the GHG emissions from Canadian canola cultivation between oil and other products. The upstream agricultural data have been developed in a separate modelling effort within M3 and are summarized in Section 4. Detailed LCI data on Canadian canola production broken down by province have been compiled by Dr. Nathan Pelletier based on reports from the Canadian Roundtable for Sustainable Crops (http://sustainablecrops.ca/). These data include GHG emissions associated with activities from cradle to farm gate, including fuel inputs, chemical inputs (i.e. fertilizers, pesticides), and on-field emissions associated with crop management practices (e.g. tillage, fallowing, etc.).

Palm oil

Oil palm is cultivated in tropical climates in places like Malaysia, Central Africa and Brazil. Since the import of HDRD from palm oil is primarily from Singapore, the Malaysian production has been selected as most representative of the palm oil used in HDRD production. Cultivation of palm for palm oil yields not only the palm oil, but also the palm kernels (from which palm kernel oil can be made) and biogas production from palm oil mill effluent (POME). Additionally, from the production of palm oil, fibers, shells and empty fruits are produced and burned for process heat and power at the palm oil facility (Usitalo, et al., 2014).

Since palm oil-derived HDRD is not produced in Canada, this report gives only a final carbon intensity (CI) for palm oil based on literature sources for palm HDRD produced in the Singapore region based on a 2014 study of renewable diesel from palm oil (Usitalo, et al., 2014).

6.3.2 Modelling Approach for HDRD

The following sections provide a brief overview of the modelling approach for HDRD fuels, as well as discussion of key methodological issues to be addressed in the modelling.

Development of Unit Process Building Blocks

The overall modelling approach for Milestone 3 is to develop unit processes to serve as building blocks for current and future modelling work in the Fuel LCA Modelling Tool. For HDRD the major building blocks of modeling with be the regional production of the canola oil in Canada or palm oil in Malaysia, feedstock transport, pretreatment, catalytic de-waxing, hydro-treatment, fuel transport, blending and distribution, and combustion. Regional differences in feedstock production reflect different applications of inputs such as fertilizers and differing yields based on location. The major building blocks are illustrated in Figure 9.

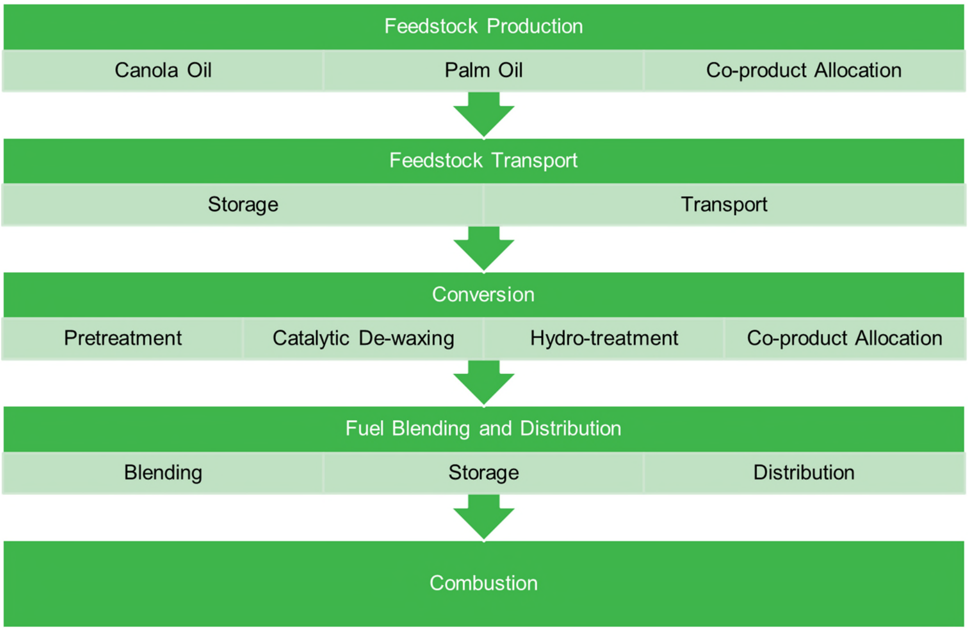

Figure 9: Building blocks of the HDRD pathway

Regional Variation

Regional variations affect the yield and emissions from soils of different crops and thus the carbon intensities of the resulting fuels. Crop management practices that vary by region such as tillage practice, fertilizer and pesticide application rates will influence GHG emissions in addition to weather and soil variations over space and time. HDRD fuel production has less influence from regionalization as the technologies for producing it do not need to vary by location. The major source of regional variation for fuel production is the electricity grid from which power is drawn for the conversion process. The distance which feedstocks must travel to reach an HDRD production facility will also vary.

Since at the time of this writing, there are no commercial-scale canola oil to HDRD production facilities in Canada, this distance is based on assumptions about the locations of theoretical plants and is described in greater detail in the description of transportation modeling.[11] Regional crop production variation is captured by modeling crop production by reconciliation unit (RU) which was developed by AAFC and ECCC as the smallest spatial unit at which activity data on crop production could be harmonized ((S&T)2 Consultants Inc., 2017c). With respect to background energy systems, electricity grid carbon intensities are available at a provincial level based on work completed in Milestone 2, as are some fuels (e.g. diesel), and has been incorporated into the unit processes available for modelling low carbon fuels.

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[11] According to data provided by ECCC on the imported and domestically-produced biodiesel and HDRD in Canada, no HDRD was produced in Canada between 2013 and 2017 though it was imported from The Netherlands, Singapore, and the United States.

Co-Product Allocation

There is a major point of co-product allocation between the canola oil and the rest of the canola seed also called meal or cake.

In Milestone 1 and 2 it was established through discussions with ECCC that upstream carbon intensity would be allocated to co-products according to energy content. Efforts have been made to use this approach consistently in modelling work for Milestone 3; however, using the building blocks approach for the Fuel LCA Modelling Tool, the capability to choose different allocation approaches will be incorporated in the tool. In canola production, all of the inputs to the agricultural system are required in order to produce both the oil and the other parts of the seed. Allocation between the oil and meal align with the method used in the biodiesel from canola oil section in using energy allocation. Allocation by mass and energy content of the respective products is possible and is consistent with the ISO 14044 guidelines on allocation as they represent a physical relationship between products. Using displacement would require identifying a suitable product that would be displaced by the production of the meal which is not as straightforward as it is with, for example, the co-product allocation in corn grain ethanol between the ethanol and the distillers' grains. In that case, the distillers' grains can displace the production of other types of animal feed. In the case of canola oil, the co-product canola protein meal is commonly fed to animals today, regardless of the use of the canola oil. It is hard to justify that the production of this meal displaces other products in the market because there is an established market for canola oil meal. In this study, energy content was chosen to allocate between the canola oil and the meal. In the future model that is built, the user will be able to modify the co-product allocation method used.

Another point at which allocation can occur is at the HDRD production facility between the HDRD as the primary product and the bio-propane, CO and CO_2 co-products. It is unlikely that the CO or CO_2 would be sold as valuable coproducts, but the bio-propane can be used as a fuel to displace conventional propane, therefore a displacement method has been used to account for this co-product. In this case, the production of the bio-propane displaces the GHG emissions from the production (not including combustion) of conventional Canadian propane as calculated in Milestone 2. A 2017 study of biopropane extraction from HDRD or renewable diesel facilities found that, of the twelve facilities operating in the world, only one could be confirmed to be producing bio-propane as of 2017 (Johnson E. , 2017).

Biogenic Carbon and Land Use Change

In remaining consistent with the Government of Canada's policy on biogenic carbon, as shown in Canada's National Inventory Report (NIR) (Government of Canada, 2018), biogenic carbon emitted from the combustion of the HDRD and its coproduct biopropane are assumed to be zero, and therefore, will not contribute to the GHG emissions of the fuel. The carbon balance into and out of the system has been evaluated to ensure mass balance.

Carbon emissions associated with direct land use change have been included in instances where feedstock production requires the conversion of land from existing use to bioenergy production. This is covered in Section 4. In the case of annual crops that are already produced in Canada, including canola, direct LUC is not included because land use change is not occurring. Indirect land use change (iLUC) is excluded from the carbon intensity calculations. Any changes in land management practices as a result of crop production for biofuels is included in this analysis, but these crop management changes have not been observed for the production of canola oil for HDRD compared to production of canola oil for other uses. Information on the land use change that may be occurring for palm oil-based HDRD are lacking and are a data gap of this study.

6.3.3 Life Cycle Inventory for HDRD

Canola

Agricultural Production and Oil Extraction

Canola (*Brassica napus*), also called rapeseed, is a crop commonly grown in Canada as an edible oil and for biodiesel production. Feedstock production for canola is based on allocation of the GHG emissions from Canadian canola cultivation between oil and other products such as canola meal. The energy allocation to canola oil is 72%. The inputs and outputs from canola production are provided in Section 4 on agricultural production.

Canola oil is extracted from seeds via crushing and solvent-extraction and yields about 40% to 45% oil and the remaining matter (55% to 65%) is protein meal or cake used as animal feed. The extraction process begins with cleaning the seeds and pre-conditioning them, then rolling the seeds, cooking and pressing them to yield some oil, then extracting additional oil from the seed press-cake with hexane. The oil then goes through solvent removal and toasting processes (Newkirk, 2009). Per tonne of canola oil produced, 114.5 kWh of electricity, and 2.34 GJ of natural gas are required ((S&T)2 Consultants Inc., 2010).

Palm Oil

Agricultural production

The palm plant (*Elaeis guineensis*) is cultivated in various tropic regions of the world. For this work, cultivation is assumed to occur in Malaysia, which has a tropical climate. Cultivation inputs, such as fertilizers and pesticides, as well as diesel and electricity follow the methods in a 2014 study on the carbon footprint of HDRD from palm oil cultivation (Usitalo, et al., 2014). Furthermore, from this same study, the amount of extracted oil, co-products and combustion of POME for oil extraction were used. Increasing cultivation of palm for oil (in fuel and other applications) is reported to be causing increases in logging of forests, conversion of rainforests and peatlands and decreases in the production of other crops such as rubber and coconut (Usitalo, et al., 2014). While this paper did consider iLUC, it did not calculate the direct land use change (dLUC) values. These land use change emissions are significant and have been considered within the scope of this study. The land use change considered in the study can occur from shifting land from peat soils, tropical mineral soils or from tropical grasslands to oil palm production. The dominant land cover in Malaysia is dense forest which is a combination of the peat swamp forest and tropical forest (approximately 60% total), but data are lacking to delineate between peat swamp forest and tropical rainforest (Geography of Malaysia, 2019; Butler, 2019). As of 2012, palm oil covered 15.4% of the total land area in Malaysia, which makes it difficult to determine if all palm oil harvested for production of HDRD in Singapore for export to Canada induced land use change or if some portion of that palm oil came from existing palm plantations that have been in production for 20 years or more (Palm oil production in Malaysia, 2019). Therefore, both land use change factors from peat swamp forest and from tropical forest are considered in this study with the more conservative approaching being to take the higher of the two factors.

Palm oil extraction begins with the separation of the fruit from the fiber. The fruit is then pressed to produce crude palm oil, which is clarified into filtered palm oil. As mentioned above, since palm oil-derived HDRD is not produced in Canada, this report gives only a final carbon intensity (CI) for palm oil based on literature sources for palm HDRD produced in the Singapore region based on a 2014 study of renewable diesel from palm oil (Usitalo, et al., 2014). No detailed modeling of the palm oil production is included in this study.

HDRD Production

HDRD differs significantly from biodiesel, though they share some common feedstocks. HDRD uses hydrotreatment with steam and hydrogen to create a fuel with a higher cetane number (70 to 90, compared to biodiesel at 45 to 55), higher energy content (44 MJ/kg LHV compared to 39 MJ/kg LHV) and by not using transesterification (Natural Resources Canada, 2012). Both fuels must meet the relevant ASTM and CGSB specifications for blending, which includes certain cetane ratings. The production technology considered in this study is only a stand-alone process, and does not include co-refining with a crude oil refinery. HDRD production steps include pretreatment of the feedstock oil to remove impurities, then proceeds to hydrotreatment with hydrogen and steam. The products are the HDRD, bio-propane, CO, and CO_2. For the hydrotreating process, hydrogen must be generated, likely by steam methane reforming, and the wastewater that is generated must be treated. A process diagram that illustrates all of the stages of HDRD production is provided in Figure 10 and additional details on each step are in the following sections.

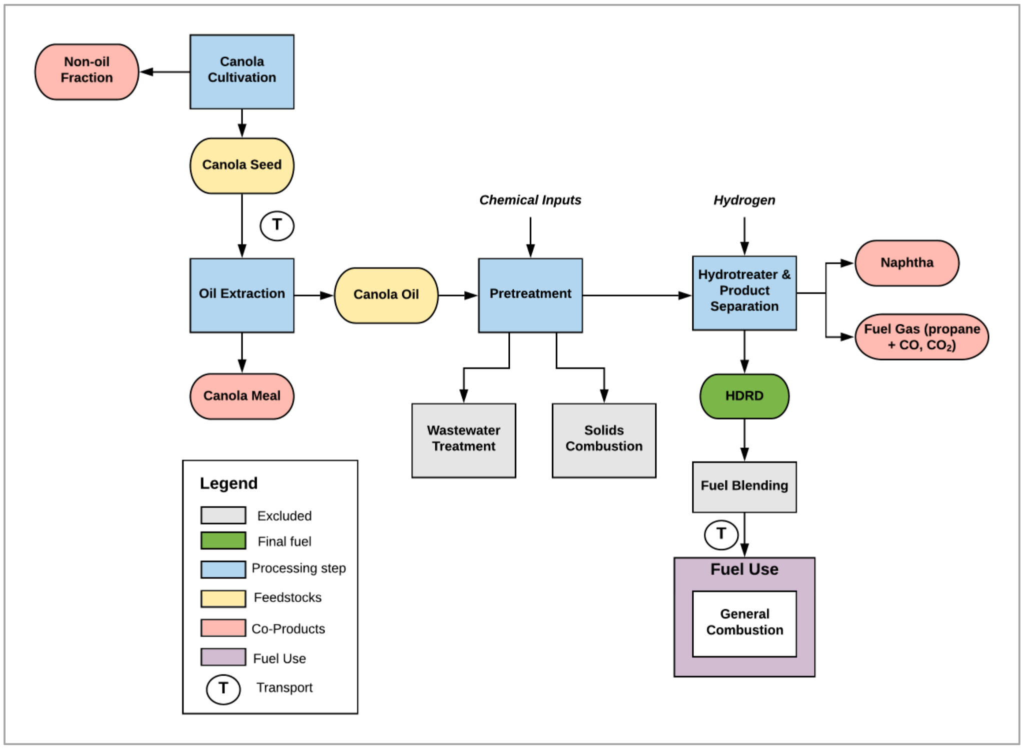

Figure 10: Process flow diagram of HDRD production

Data for the canola-based HDRD refinery from pretreatment through fuel production and other process steps were obtained entirely from literature sources including: a 2012 study published by Natural Resources Canada, and a 2014 study on the production of renewable diesel (HDRD) from rapeseed oil (a variant of canola oil), a renewable fuels roadmap for sustainable biomass feedstock and a published journal article on emissions parameters and energy consumption for renewable diesel (Natural Resources Canada, 2012; Usitalo, et al., 2014; Antares Group, Inc., 2010; Miller & Kumar, 2013). The Natural Resources Canada study identifies canola oil as a significant source of domestic feedstock for potential HDRD production in Canada as canola oil is not currently being used in Canada to produce HDRD.

Pretreatment

HDRD production begins with a feedstock pretreatment to prepare the feedstock for hydroprocessing. The quality of the feedstock determines if and to what extent pretreatment is required. Pretreatment is intended to address the potential alkali metals, phospholipids, and metalloids that could be present in the feedstock and which would reduce the efficacy of the hydroprocessing catalysts. Pretreatment can include the hydrogenation of the fatty acid chains to reduce the number of double bonds in the chain, but this is not included in this process modeling. The pretreatment requires inputs of water, chemicals, heat and electricity with outputs of pretreated oil, some losses, wastewater and solid waste. Table 47 summarizes the inputs to pretreatment for which data were available. The solid waste can be used for energy production. Wastewater undergoes wastewater treatment. Data on the precise amount of chemicals and other inputs other than electricity and natural gas per mass of oil treated or HDRD produced were lacking in the literature (Miller & Kumar, 2013).

Table 47: Inputs to HDRD pretreatment

Inputs	Amount	Unit
Electricity	2.2	kWh/MT seed
Steam	74.3	kg steam/kg seed
Chemicals	unknown	unknown

Hydro-treatment

The pretreated oil is then ready for hydrotreatment. During hydrotreatment, steam and hydrogen are added to help convert the triglycerides in the vegetable oil to saturated straight-chain hydrocarbons. Since, this reaction is exothermic, the addition of heat is not necessary. The reaction actually produces 160 BTU of heat per pound of oil treated (Antares Group, Inc., 2010). the additional demand for electricity is also very low. The inputs to HDRD hydrotreatment per liter of HDRD produced are provided in Table 48 (Miller & Kumar, 2013). The life cycle inventory data on hexane production were also sourced from literature (Miller & Kumar, 2013).

Table 48: Inputs to HDRD hydrotreatment

Inputs	Amount	Unit
Hydrogen	0.020	kg/L HDRD
Electricity	0.080	kWh/L HDRD
Natural Gas	5.6	MJ/ L HDRD
Hexane	0.22	kg/L HDRD

The co-products of this process include bio-naphtha, bio-propane, CO and CO_2. Since the carbon dioxide produced from this process originates from biogenic carbon sources, it is not considered an overall emission of fossil carbon. Hydrogen is a key input to the production of HDRD; therefore, hydrogen production must be considered as a part of the overall HDRD production process. Hydrogen is often produced by using a steam reformer. The hydrogen production via on-site reforming with liquid truck delivery CI was sourced from this Milestone 3 work (see Section 9) for use in the HDRD production CI calculation.

The conversion efficiency of oil to fuel is approximately 98% on an energy basis. Hydrogen consumption can be calculated based on a percentage of the feedstock input weight as 1.5 the weight percentage of the feedstock. The production of light hydrocarbons (e.g., bio-propane) is about 3.5 wt% of the mass of the input feedstock. Water consumption is estimated to be minimal for the hydrotreatment process (Antares Group, Inc., 2010).

Feedstock and Fuel Transport and Fuel Blending and Distribution

The transport of feedstock to HDRD producers and the transport of the final HDRD product to end users is described and modelled in the biodiesel section of this report to be in line with the transport of canola and canola oil for biodiesel production and in the distribution of finished fuels that are similar to diesel. Only the production of the neat or unblended fuel is considered in this report.

The transportation of feedstocks and final fuel will be done largely by truck and rail. In modelling this transport, the truck and train unit processes that were created in Milestone 2 to capture the upstream and combustion emissions associated with these modes of transport are used.

Combustion

At the point of combustion, all of the carbon in the HDRD fuel is biogenic carbon, not fossil carbon. Therefore, the combustion of this carbon results in no net addition to the fossil emissions from the fuel. In this way, the combustion emissions from burning HDRD (neat, unblended) are zero. Methane and other types of GHG emissions are possible from the combustion of HDRD, and these emissions are dependent upon the combustion efficiency of the engine in which the HDRD is burned and the blend of the fuel being combusted. As a placeholder, emissions factors for methane (0.14 g/L, 3.96E-06 kg/MJ) and nitrous oxide (0.082 g/L, 2.32E-06 kg/MJ) were used from Canada's National Inventory Report (Government of Canada, 2018) for biodiesel. Characteristics of HDRD (regardless of feedstock) are given in Table 49.

Table 49. Characteristics of HDRD (Natural Resources Canada, 2012; Argonne National Lab, 2018; Usitalo, et al., 2014).

Fuel	Application	Density (g/gal)	High Heating Value (MJ/kg)	Low Heating Value (MJ/kg)	Carbon Content (wt%)	Biogenic CO_2 (g/gal fuel)
HDRD	Transportation fuel	2,835	44.6	43.5	84.9%	2,400

6.3.4 Carbon Intensity Results for HDRD

Carbon Intensity of Canola Oil HDRD

The carbon intensity of canola oil HDRD, total and per life cycle phase, are given in Table 50. The hydrogen production and steam requirement for hydrotreatment are the large drivers of GHG emissions to HDRD production. After hydrogen production, feedstock production is the most significant driver, especially if seed and oil production are taken together. Transportation of seed, oil and final fuel are not large drivers of GHG emissions. Note that the GHG emissions credit for the production of biopropane is not zero, but the negative value is in the 4th decimal place and, for the purpose of consistency, results are reported with 2 significant figures. Thus, it is clear that the credit provided by the co-production of propane is not a significant source of GHG emissions savings. The uncertainty assessment for canola oil HDRD is provided in Table 51. The uncertainty is presented based on the uncertainty in the underlying data. The 2.5% heading indicates the interquartile range of uncertainty and the 97.5% heading indicates the 1.5x interquartile range. SD stands for standard deviation, CV is the coefficient of variance and SEM is the standard error of the mean. This uncertainty analysis of canola oil HDRD indicates that the range of CIs are between 51 and 59 g CO_2 eq/MJ HDRD HHV. This indicates that, given the uncertainty in the background data, the uncertain range is plus 9% to minus 6%.

Other studies have been conducted on HDRD or renewable diesel from palm oil, but many involve LUC, economic allocation and other aspects that are inconsistent with the system boundaries and scope of this assessment which make them not directly comparable. These values range from between 24 and 50 gCO_2e/MJ HDRD LHV (Johnson E. , 2017). Sources of differences between the CI for canola oil HDRD in this study and other studies include the canola oil production (this study uses canola oil production Canada and the other uses rapeseed oil production in Europe), transportation and distribution assumptions, the use of the Canadian grid electricity CI and the Canadian natural gas CI for inputs and propane CI for the displacement credit. Since most studies of this kind do not quantify any type of uncertainty, it is not possible to compare the uncertainty ranges to that of other studies.

Table 50: Carbon intensity of canola oil HDRD total and by life cycle phase

Stage	Amount	Unit
Canola seed	16	g CO_2 eq./MJ
Canola oil production	9.7	g CO_2 eq./MJ
Pretreatment	0.5	g CO_2 eq./MJ
Hydrotreatment	29	g CO_2 eq./MJ
Co-product propane credit	-1.9	g CO_2 eq./MJ
Fuel transport	0.5	g CO_2 eq./MJ
Combustion	0.7	g CO_2 eq./MJ
Total	**54**	g CO_2 eq./MJ

Table 51: HDRD from canola oil, average per MJ uncertainty (g CO_2 eq./MJ HDRD HHV)

Carbon Intensity	Mean	Median	SD	CV	2.50%	97.50%
54	57.9	54.3	19.2	33.1%	32.8	106

Carbon Intensity of Palm Oil HDRD

Based on the results of the 2014 study of the carbon impacts of palm oil HDRD produced in Singapore, the GHG emissions from 1 MJ (HHV) of palm HDRD are 24 g CO_2e/MJ HHV of HDRD without the inclusion of land use change (Usitalo, et al., 2014). This includes emissions from palm production, oil extraction, transportation, HDRD production, but does not include iLUC. When LUC is included, based on the same study, the CI rises to between 270 and 460 g CO_2e/MJ HHV of HDRD assuming that all of the palm oil produced to make the HDRD came from land converted from tropical forest land and tropical peaty swamp land, respectively. The most conservative approach would be to use the conversion from tropical peaty swamp land as it results in the highest CI. Since this is a large source of emissions, it should be clarified with producers of palm oil if land use change is occurring for the production of all Malaysian palm oil used to make HDRD in Singapore that is exported to Canada, and what the previous land use type was for that palm oil plantation.

A study by Usitalo, et al., 2014 study notes, however, that palm oil extraction does not result in significant GHG emissions if energy for extraction is derived from palm fibers and shells and if methane that results from POME production is collected. If POME methane is not collected, it can be a large source of emissions, therefore, it should be clarified with producers how POME is treated to confirm that this CI is reflective of the palm oil HDRD used in Canada.

6.3.5 Data Gaps and Limitations for HDRD

In preparation of the report and CI values for HDRD, a number of data gaps and limitations have been highlighted to inform further research, including:

- The process design documents used for this study did not enumerate the process chemical inputs to pretreatment phase of HDRD so they could not be accounted for. It is recommended to find another source for these data.
- Data on the exact type and amounts of solvents used in canola oil extraction are lacking.
- Information on the direct land use change that may be occurring and the resulting GHG emissions from this dLUC for palm oil-based HDRD are lacking.
- There is lack of consensus in the literature about the exact process energy and material inputs to the production of HDRD. It is recommended that these data be updated with data from an operational commercial facility should one be cited in Canada.
- The CI for palm oil HDRD is based on literature values only. It is recommended that data on production be collected from palm oil HDRD facilities providing fuel to Canada so that it can be modeled, or requiring the facilities to conduct life cycle assessments on their fuels and provide documentation of their calculated CIs.
- Palm oil extraction does not result in significant GHG emissions if energy for extraction is derived from palm fibers and shells and if methane that results from POME production is collected. If POME methane is not collected, however, it can be a large source of emissions. Therefore, it is recommended that ECCC clarify with palm oil HDRD producers how POME is treated to confirm that the CI reported in this study is reflective of the palm oil HDRD used in Canada.
- There is a lack of information about the source location of palm production for the HDRD produced in Singapore and exported to Canada. Information about the source location of palm production includes confirming that production is occurring in Malaysia, the age of the palm plantations (i.e., plantations that have been in production for 20 years or more) and, if the plantation has been in production for less than 20 years, the type of land use that preceded the palm plantation (i.e., whether it was tropical rainforest, peat swamp forest or another land use type). This lack of information was the determining factor for the conservative assumption that all palm for HDRD produced in Singapore and exported to the US was produced in Malaysia from land that was recently converted from tropical peaty swamp land.

6.4 Renewable Biojet Fuel

Biojet fuel is aviation fuel made from renewable, biomass-derived raw materials. Currently the primary production process for biojet is the hydroprocessed esters and fatty acids (HEFA) process which has already been done at commercial scale to produce renewable diesel and produces biojet as a co-product. The biojet product from this process is synthetic paraffinic kerosene (SPK). For other production pathways such as biomass gasification and Fischer-Tropsch (FT) synthesis, there are currently no operating facilities in Canada (Doyletech Corporation, 2018).

The HRJ process involves catalytic conversion of renewable oils into alkanes in a process that is comparable to conventional hydroprocessing of crude oil. Potential feedstocks for HRJ include vegetable oils from oilseed crops, UCO, tallow, and algal oils. The feedstock oils are subject to a high temperature catalytic hydrodeoxygenation process which produces mainly renewable diesel, with biojet, naphtha, and light hydrocarbons (i.e. propane) as typical co-products (Doyletech Corporation, 2018).

6.4.1 System Boundaries and Descriptions for Biojet Fuel

Two pathway templates were developed for biojet fuel for the Fuel LCA Modelling Tool, including biojet produced from used cooking oil (UCO) and from canola oil via hydroprocessing (HEFA, or hydroprocessed renewable jet fuel (HRJ)).

UCO is a mixture of used vegetable oils and fats produced by restaurants and other institutional kitchens. UCO can be pretreated and converted to biojet fuel using a hydroprocessing step that yields HRJ fuel and a number of other fuel co-products. Canola oil is derived from processing and extraction of Canadian canola oilseed crops, as described in Section 5.3. From a life cycle perspective, the production of biojet fuel from UCO originates with the production and use of cooking oils in restaurants; however, UCO from these sources is considered a waste product and no GHG emissions associated with upstream activities are attributed to them, which is consistent with a number of other LCAs of biodiesel from yellow grease (California Environmental Protection Agency, 2009) ((S&T)2 Consultants Inc., 2012) (Chen, et al., 2018) (University of Toronto, 2019). The system boundary for the life cycle carbon intensity of biojet fuel from UCO therefore begins at the restaurant gate, and includes transport of UCO, pre-treatment, HRJ fuel production, distribution, and combustion (Figure 11). For biojet from canola oil, the system boundary begins with average Canadian cultivation of canola oilseed crops.

6.4.2 Modelling and Life Cycle Inventory for Biojet from UCO

The system boundary for biojet fuel from UCO is shown in Figure 11. The basic model building blocks for this process include:

- Transport of UCO from restaurants to the processing plant;
- Pre-treatment of UCO;
- Biojet fuel production via hydroprocessing;
- Biojet fuel distribution; and
- Biojet fuel combustion.

After biojet fuel production, the life cycle activities and resulting GHG emissions for distribution are assumed to be the same as for crop-based biodiesel pathways. The life cycle inventory and modelling considerations for biojet from UCO are outlined below.

Transport of Used Cooking Oil (UCO)

For the Canadian average template developed for biojet fuel from UCO, it is assumed that UCO is transported by truck from restaurants within the same province as the biojet conversion plant over an average distance of 100 km. Users of the Fuel LCA Modelling Tool can modify this transport distance and/or add additional transport modes and distances to align with more specific supply chain configurations in the future.

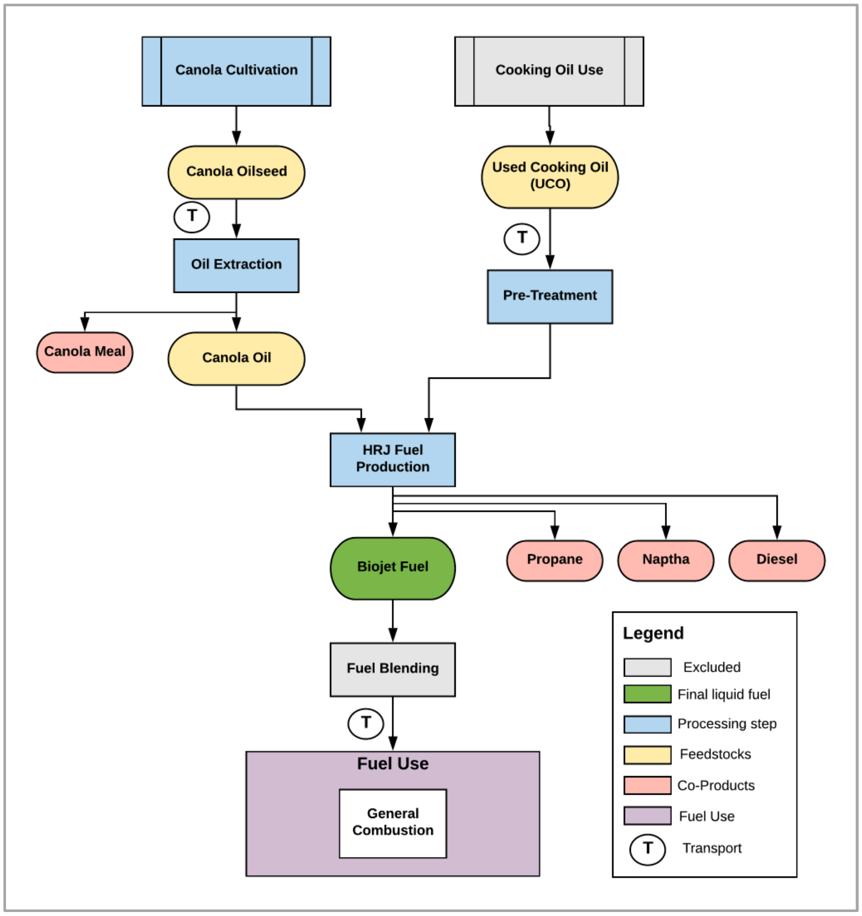

Figure 11. System boundaries for production of biojet fuel from UCO and canola oil.

UCO Pre-Treatment

Pretreatment of raw UCO is required to remove solid particles and the oil is then heat treated to remove moisture. The mass balance and energy intensity of pre-treating UCO for biojet fuel conversion were derived from a 2014 Canadian (Chu, 2014). These data were developed to represent the Canadian context, although are largely based on literature data and are not based on primary data collection. The mass balance and energy inputs for pre-treating 1 tonne of UCO are shown in Table 52.

Table 52. Mass balance and energy inputs for pretreatment of 1 tonne of UCO for biojet conversion.

Pretreatment	Amount
Inputs	
UCO (kg)	1,000
Transport of UCO to plant (tkm)*	100
Natural gas (MJ)	1,134
Electricity (kWh)	126.8
Outputs	
Pretreated UCO (kg)	1,000

**UCO is assumed to be transported 100 km*

Conversion of UCO to Biojet

After pre-treatment, UCO is processed through a hydroprocessing conversion process. The process converts the oils into fuels by using a reaction with hydrogen and energy to bring the process to the required temperature and pressure. A summary of the inputs and outputs of converting UCO to biojet is provided in Table 53. In addition to SPK, the conversion process yields a number of co-product fuels. This allocation was done according to the energy content of the outputs, resulting in 60.3% of the emissions associated with biojet conversion being allocated to the biojet fuel.

Table 53. Mass balance and material and energy inputs for conversion of UCO to biojet fuel via hydroprocessing (Chu, 2014).

	Amount
Inputs	
UCO (kg)	1,000
Hydrogen (kg)	26.3
Electricity (kWh)	2,835
Natural gas (MJ)	73
Outputs	
Propane (MJ)	3,120
Naphtha (MJ)	6,100
SPK (MJ)	23,100
Diesel (MJ)	6,000

**Note – The energy contents of the co-products include: propane – 50.2 MJ/kg; naphtha – 46.2 MJ/kg; SPK (biojet) – 46.3 MJ/kg; diesel – 45.8 MJ/kg.*

The GHG emissions associated with production and use of hydrogen, electricity, and natural gas were obtained from the Fuel LCA Modelling Tool based on previous modelling work in Milestone 2 and Milestone 3.

Biojet from UCO Distribution and Combustion

It is assumed that after conversion of biojet fuel from UCO that all other life cycle activities related to distribution are equivalent to those of the crop-based biodiesel pathways modeled in Milestone 3 (see Section 5.3). Due to the biogenic nature of the carbon emissions from biojet combustion, they are excluded from the CI calculations. Methane and other types of GHG emissions are possible from the combustion of biojet fuel, and these emissions are dependent upon the combustion efficiency of the engine in which the fuel is burned and the blend of the fuel being combusted. As a placeholder, emissions factors for methane (2.2 g/L, 5.81E-05 kg/MJ) and nitrous oxide (0.23 g/L, 6.07E-06 kg/MJ) were used from Canada's National Inventory Report (Government of Canada, 2018) for fossil aviation fuel.

6.4.3 Carbon Intensity of Biojet from UCO

The carbon intensity results for biojet fuel from UCO are summarized in Table 54. The CI for biojet from UCO is approximately 22 g CO_2 eq./MJ, which is 74% lower than fossil aviation fuel (86 g CO_2 eq./MJ). The reduction in CI is largely due to the biogenic nature of the carbon emissions from biojet fuel. The primary contributor to the life cycle GHG emissions is the biojet conversion process. These emissions are due to the use of hydrogen and natural gas. Hydrogen was assumed to be produced by SMR of fossil natural gas and has a relatively high CI. Feedstock transport and fuel distribution make relatively small contributions, as does pretreatment of the UCO.

Table 54. Carbon intensity results for biojet fuel produced from UCO, expressed in g CO_2 eq. per MJ of biojet energy.

Life Cycle Stage	Amount	Unit
Feedstock Transport	0.3	g CO_2 eq./MJ
Pretreatment of UCO	2.4	g CO_2 eq./MJ
HRJ Conversion	16	g CO_2 eq./MJ
Distribution	0.5	g CO_2 eq./MJ
Combustion	3.2	g CO_2 eq./MJ
Total	**22**	**g CO_2 eq./MJ**

6.4.4 Modelling and Life Cycle Inventory for Biojet from Canola Oil

The system boundary for biojet fuel from canola oil is shown in Figure 11. The basic model building blocks for this process include:

- Cultivation of canola oilseed crops;
- Extraction of canola oil;
- Transport of canola oil feedstock to biojet processing plant;
- Biojet fuel production via hydroprocessing;
- Biojet fuel distribution; and
- Biojet fuel combustion.

After biojet fuel production, the life cycle activities and resulting GHG emissions for distribution are assumed to be the same as for biojet from UCO. The life cycle inventory and modelling considerations for biojet from canola oil are outlined below.

Canola Cultivation and Oil Extraction

Cultivation and processing of the canola oil feedstock was based on the same cultivation and oil extraction processes modeled for canola biodiesel, as described in Section 5.3.

Transport of Canola Oil to Biojet Facility

For the Canadian average template developed for biojet fuel from canola oil, it is assumed that the canola oil is transported by truck from processors within the same province as the biojet conversion plant over an average distance of 100 km. Users of the Fuel LCA Modelling Tool can modify this transport distance and/or add additional transport modes and distances to align with more specific supply chain configurations in the future.

Conversion of Canola Oil to Biojet

The conversion of canola oil to biojet fuel via hydroprocessing is essentially the same process as for UCO, except that pretreatment is not required, and the inputs and yield of the process are slightly different than for UCO due to the different properties of canola oil (Han J. , Elgowainy, Cai, & Wang, 2013a). The inputs and outputs for biojet fuel conversion of canola oil are shown in Table 55. In addition to SPK, the conversion process yields a number of co-product fuels. Relative to the UCO conversion process, renewable diesel is not targeted in the canola oil conversion process and thus there is a greater yield of biojet fuel. This allocation was done according to the energy content of the outputs, resulting in 81.1% of the emissions associated with biojet conversion being allocated to the biojet fuel.

Table 55. Mass balance and material and energy inputs for conversion of UCO to biojet fuel via hydroprocessing.

	Amount
Inputs	
Canola oil (kg)	1,000
Hydrogen (MJ)	4,444
Electricity (kWh)	61
Natural gas (MJ)	7,782
Outputs	
Propane (MJ)	4,575
Naphtha (MJ)	3,418
SPK (MJ)	34,262

**Note – The energy contents of the co-products include: propane – 50.2 MJ/kg; naphtha – 46.2 MJ/kg; SPK (biojet) – 46.3 MJ/kg.*

Biojet from Canola Oil Distribution and Combustion

It is assumed that after conversion of biojet fuel from canola oil that all other life cycle activities related to distribution are equivalent to those of the crop-based biodiesel pathways modeled in Milestone 3 (see Section 5.3). Due to the biogenic nature of the carbon emissions from biojet combustion, they are excluded from the CI calculations. Methane and other types of GHG emissions are possible from the combustion of biojet fuel, and these emissions are dependent upon the combustion efficiency of the engine in which the fuel is burned and the blend of the fuel being combusted. As a placeholder, emissions factors for methane (2.2 g/L, 5.81E-05 kg/MJ) and nitrous oxide (0.23 g/L, 6.07E-06 kg/MJ) were used from Canada's National Inventory Report (Government of Canada, 2018) for fossil aviation fuel.

6.4.5 Carbon Intensity of Biojet from Canola Oil

The carbon intensity results for biojet fuel from canola oil are summarized in Table 56. The CI for biojet from canola is approximately 49 g CO_2 eq./MJ, which is 43% lower than fossil aviation fuel (86 g CO_2 eq./MJ). The reduction in CI is largely due to the biogenic nature of the carbon emissions from biojet fuel. The primary contributor to the life cycle GHG emissions is the biojet conversion process. These emissions are due to the use of hydrogen and natural gas. Hydrogen was assumed to be produced by SMR of fossil natural gas and has a relatively high CI. Production of the canola oil feedstock is also a significant contributor to the CI, and is a notable contrast to biojet from UCO where the waste feedstock only requires transport and pretreatment and makes a much smaller contribution to life cycle GHG emissions.

Table 56. Carbon intensity results for biojet fuel produced from canola oil, expressed in g CO_2 eq. per MJ of biojet energy.

Life Cycle Stage	Amount	Unit
Feedstock Production	14	g CO_2 eq./MJ
Oil Extraction	8.6	g CO_2 eq./MJ
HRJ Conversion	23	g CO_2 eq./MJ
Distribution	0.5	g CO_2 eq./MJ
Combustion	3.2	g CO_2 eq./MJ
Total	**49**	**g CO_2 eq./MJ**

6.4.6 Uncertainty

Uncertainty analysis was conducted for Canadian average biojet fuel from UCO and canola oil using Monte Carlo analysis. Results of the uncertainty analysis are shown in the violin plots in Section 12 and discussed relative to the uncertainty of other low carbon fuels in that section. Below in Table 57 the key results of the uncertainty analysis for both types of biojet fuel are summarized.

Table 57. Uncertainty analysis for biojet fuel produced from UCO and canola oil. Results based on Monte Carlo analysis with a confidence interval of 95%.

Final CI	Mean	Median	SD	Min (2.5%)	Max (97.5%)
Biojet fuel, from UCO, average {CA}					
22.0	22.4	22.0	3.90	16.0	31.2
Biojet fuel, from canola oil, average {CA}					
49.0	52.6	49.6	16.1	30.8	91.5

The uncertainty range for biojet from UCO is much tighter than for canola oil, with canola oil showing a potentially high upper range. This is due to the inherent uncertainty in modelling agricultural systems which increases the range of potential results.

6.4.7 Data Gaps and Limitations for Biojet Fuel

The primary limitation for modelling biojet fuel production in Canada is the lack of operating data for biojet conversion systems. More primary, Canadian-specific data on the material and energy outputs of hydroprocessing and other biojet conversion technologies would improve the robustness of the CI calculations. This would also allow for users of the Fuel LCA Modelling Tool to link conversion processes with other existing feedstocks in the tool that are commonly used for biojet fuel production (e.g. soybean, camelina, etc.).

7. Waste-Derived Low Carbon Liquid Fuels

7.1 Introduction to Waste-Derived Low Carbon Liquid Fuels

Waste-derived fuels are of interest because the feedstock itself carries no burden and because the use of waste for fuel diverts it from landfills, reducing the burden on land. While there are many different wastes that might be treated and several different treatment methods, the fuels considered for consideration here included those currently in use and one with high potential as a low carbon substitution.

Table 58. Summary of waste-derived liquid fuel pathways including descriptions of fuel feedstock source, conversion processes, process energy carrier outputs, and expected end use modelled.

Fuel	Feedstock	Conversion Process	End Use
Waste-Derived Biodiesel	Beef tallow Yellow grease	Rendering/purification Transesterification Refining	Transportation fuel
MSW-Derived Ethanol	MSW (yard trimmings)	Pretreatment Fermentation Ethanol recovery	Transportation fuel

7.2 Beef Tallow Biodiesel

Inedible fats and yellow grease are used in the production of chemicals, and increasingly used as feedstocks in the production of biodiesel and HDRD. These feedstocks can also be co-processed in a petroleum refinery. For example, West Coast Reduction is selling these feedstocks to BP Cherry Point refinery in Washington State, and more recently, to Parkland Refinery in Burnaby, B.C. When Canada's biodiesel industry started out, inedible fats and yellow grease were the predominant feedstocks used to produce fatty acid methyl esters (FAME). Over time, canola oil and, to a lesser extent, soy oil have replaced some of these waste fats and greases as the waste-derived biodiesel product has poorer cloud point properties. There is growing interest in alternatives to crop-based biodiesel feedstocks such as yellow grease from used cooking oil (UCO) and tallow from animal rendering (Han, Elgowainy, & Wang, 2013b). At present, biodiesel from these sources makes up a small proportion of Canadian biodiesel production, with tallow biodiesel accounting for less than 1% of total biodiesel production in 2017, and biodiesel from yellow grease accounting for just under 7% of total 2017 production (Wolinetz et al. 2019). Domestic production of these alternative types of biodiesel is currently concentrated in specific areas, mostly in Ontario and Québec (Wolinetz, Hein, & Moawad, 2019). A substantial amount of waste fats and greases is exported to other countries for biofuel production. Domestic use of these feedstocks could increase with co-processing at petroleum facilities or new HDRD facilities.

7.2.1 System Boundaries and Descriptions for Tallow Biodiesel

The template developed for tallow biodiesel in the Fuel LCA Modelling Tool is for biodiesel produced from beef tallow. Beef tallow is produced from the rendering of by-products from cattle slaughter. Cattle slaughter is a process to produce beef as well as a number of co-products and by-products including animal hides, offal, animal by-products, and other non-marketable wastes (Han, Elgowainy, & Wang, 2013b). The animal by-products are processed in rendering plants and this process results in the production of tallow, animal bone/meat meal, and wastewater. Beef tallow can then be used as input to biodiesel production.

From a life cycle perspective, the production of biodiesel from beef tallow originates with the rearing and slaughtering of livestock; however, the slaughterhouse by-products are considered a waste product and no GHG emissions associated with upstream activities are attributed to the by-products. This is a well-established modelling convention in the LCA literature (Han, Elgowainy, & Wang, 2013b) ((S&T)2 Consultants Inc., 2012) (Chen, et al., 2018). The system boundary for the life cycle carbon intensity of tallow biodiesel therefore begins at the slaughterhouse gate, and includes transport of animal by-products, rendering, upgrading of tallow, biodiesel conversion, distribution, and combustion (Figure 12).

Modelling and Life Cycle Inventory

The system boundary for biodiesel from beef tallow is shown in Figure 12. The basic model building blocks for this process include:

- Transport of slaughterhouse by-products to the rendering plant;
- Rendering of animal by-products to produce beef tallow;
- Upgrading of beef tallow (e.g. polishing, refining, and bleaching)[12]
- Transport of beef tallow from the rendering plant to the biodiesel production plant;
- Biodiesel production (for feedstock with high free fatty acids);
- Biodiesel distribution; and
- Biodiesel combustion.

After biodiesel production, the life cycle activities and resulting GHG emissions are assumed to be the same as for crop-based biodiesel pathways. The life cycle inventory and modelling considerations for biodiesel from beef tallow are outlined below.

Transport of Slaughterhouse By-Products

There are a limited number of certified slaughterhouses for cattle in Canada, and they are primarily located in Ontario (6 facilities), Alberta (6 facilities), and Quebec (3 facilities) (Agriculture and Agri-Food Canada, 2019), which are the provinces where Canadian beef production is centered. There are considerably more animal rendering and processing plants in Canada, but they are also heavily concentrated in Ontario, Quebec, and Alberta (CBC News, 2012). Data for 2017 indicate that all biodiesel produced from tallow was produced in Québec (Wolinetz, Hein, & Moawad, 2019).

We developed a Canadian average pathway for biodiesel production from beef tallow using average supply chain transport distances and average Canadian energy inputs. Transport of animal by-products from the slaughterhouse to the rendering plant is assumed to be by truck, and that slaughterhouse by-products are only transported to in-province rendering plants over an average distance of 100 km. Users of the Fuel LCA

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[12] Different biofuel processes have different tallow specifications. For example, co-processing operations prefer bleached tallow.

Modelling Tool will be able to modify transport distances and energy sources to reflect more specific conditions for biodiesel from beef tallow in the future.

Animal By-Product Rendering

The mass balance and energy intensity of animal by-product rendering are potentially quite variable depending on the facility ((S&T)2 Consultants Inc., 2012) (Chen, et al., 2017). For example, the energy required for the rendering process may vary considerably depending on the moisture content of the incoming animal by-products and the type of energy used may vary depending on system configuration at the rendering plant. Work by S&T2 Consultants for the GHGenius tool and for the California low carbon fuel program has included some Canadian tallow rendering data; however, more recent updates in the GREET tool indicate that previous values for energy use for beef tallow rendering have been significantly overestimated (Chen, et al., 2017). Although the data in GHGenius were developed to represent the Canadian context, these data are from the early-2000's and changes in industry practices may have led to changes in yield and energy intensity over time. As such, we have used the mass balance and energy inputs for production of 1 kg of tallow from rendering of animal by-products from the latest update to GREET, which are representative of average US production (Table 59).

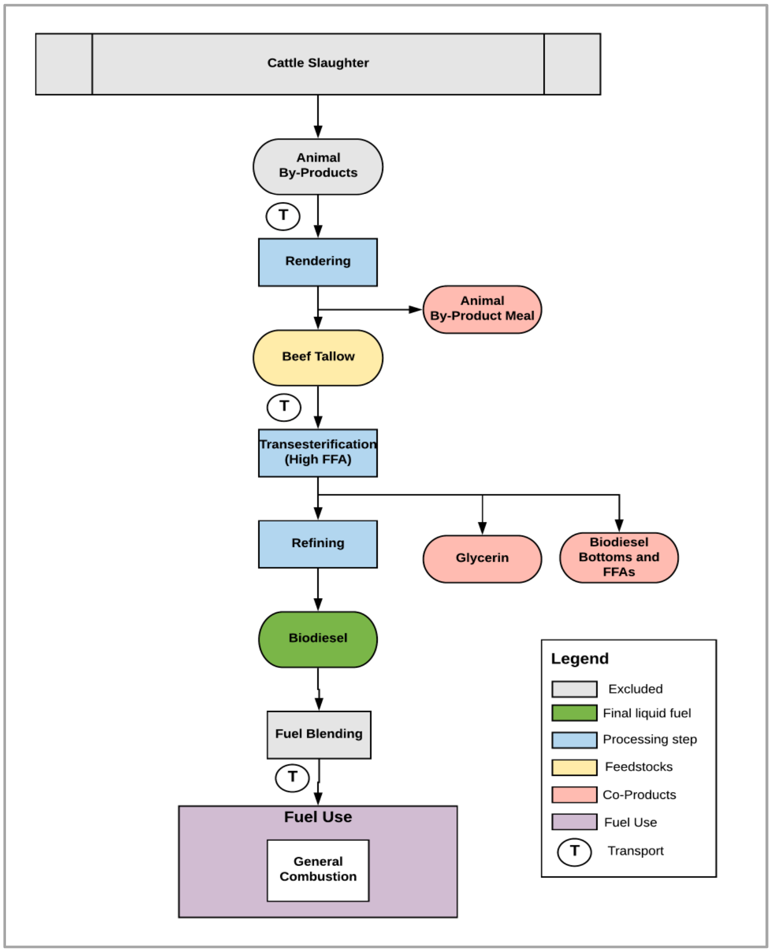

Figure 12. System boundaries for production of biodiesel from beef tallow.

The rendering process produces tallow as well as meat and bone meal and water/vapours from the cooking process. The cooking vapours are a waste stream and are excluded from the CI calculations. The emissions associated with rendering must therefore be allocated between the tallow and the meal. This allocation has been done according to the energy content of the co-products, which is estimated as 37.6 MJ/kg for tallow and 16.9 MJ/kg for meal (Denafas, Buinevicius, Urniezaite, Puskorius, & Rekasius, 2004). This results in allocation of 73% of the emissions to beef tallow and 27% to the meat and bone meal.

Table 59. Mass balance and energy inputs for rendering of 1 kg of beef tallow from slaughterhouse by-products in an average US facility (Chen, et al., 2017).

Rendering	Amount
Inputs	
Animal by-products (kg)	3.55
Transport of by-products to plant (tkm)**	0.5
Natural gas (MJ)	3.95
Residual fuel oil (MJ)	2.36
Fat/grease (MJ)	1.83
Electricity (kWh)	1.16
Co-Products	***Amount***
Tallow (kg)	1.0
Meat and bone meal (kg)	0.81
Wastes	***Amount***
Cooking vapours (kg)	1.74

**The allocated inputs are based on the energy content of the rendering products, including tallow at 37.6 MJ/kg, and animal by-product meal at 16.9 MJ/kg. Based on these energy content values, 73% of the emissions associated with the rendering process are allocated to the beef tallow.*

***Animal by-products are assumed to be transported 100km*

Transport of Tallow to Biodiesel Plants

For the Canadian average template developed for beef tallow biodiesel, it is assumed that beef tallow is transported by truck from rendering plants within the same province as the biodiesel plant over an average distance of 100 km. Users of the Fuel LCA Modelling Tool can modify this transport distance and/or add additional transport modes and distances to align with more specific supply chain configurations in the future.

Conversion of Tallow to Biodiesel

Biodiesel facilities that use waste feedstocks such as tallow do not require an oil extraction step, but do require a pre-treatment step to remove water, high levels of free fatty acids, and other impurities (University of Toronto, 2019). For the Fuel LCA Modelling Tool, the LCI for a biodiesel conversion process for feedstocks with high FFAs was used to reflect the additional pre-treatment required for tallow and the increased energy and material inputs to this process relative to converting vegetable oils with lower fatty acid contents (Chen, et al., 2018). These data are for an average US biodiesel conversion process and are used to represent average Canadian production. A summary of the inputs and outputs of converting beef tallow to biodiesel is provided in Table 60. Unlike conversion of vegetable oil feedstocks, this conversion process also yields significant amounts of biodiesel heavies and FFAs, such that the conversion process impacts were allocated between biodiesel, glycerol, heavies, and FFAs. This allocation was done according to the energy content of the outputs, as per Chen et al. (2018), resulting in 86% of the emissions associated with biodiesel conversion being allocated to the biodiesel.

The GHG emissions from electricity production are based on the 2016 average Canadian grid mix.

Table 60. Mass balance and material and energy inputs for production of biodiesel from beef tallow in an average US facility (Chen, et al., 2018).

Biodiesel Production	Amount (per kg of biodiesel)	Amount (per MJ of biodiesel)
Inputs		
Beef tallow (kg)	1.1	0.0274
Natural gas (MJ)	2.163	0.0538
Electricity (kWh)	0.0864	0.00215
Biodiesel distillation bottoms (MJ)	0.0131	0.000326
Diesel (MJ)	0.0235	0.00059
Methanol (kg)	0.11	0.00274
Sulfuric acid (kg)	0.0001	2.49E-06
Hydrochloric acid (kg)	0.0036	8.96E-05
Sodium methylate (kg)	0.0052	0.00013
Sodium hydroxide (kg)	0.0007	1.74E-05
Potassium hydroxide (kg)	0.0006	1.49E-05
Nitrogen gas (kg)	0.0275	0.00068
Phosphoric acid (kg)	0.0003	7.46E-06
Citric acid (kg)	0.0004	9.96E-06
Outputs		
Glycerol (kg)	0.0815	0.00203
Biodiesel distillation bottoms (kg)	0.0243	0.000605
Fatty acids (kg)	0.0771	0.001919
Biodiesel (kg)	1	0.0337

**Note – The energy contents of the co-products include (Chen et al. 2018): glycerol - 18.56 MJ/kg; biodiesel distillation bottoms – 39.47 MJ/kg; fatty acids – 39.47 MJ/kg. The energy content of biodiesel is 29.67 MJ/kg.*

Biodiesel Distribution and Combustion

It is assumed that after conversion of tallow to biodiesel that all other life cycle activities related to distribution and combustion are equivalent to those of the crop-based biodiesel pathways modeled in Milestone 3 (see Section 5.3), and that final energy content of the biodiesel is equivalent to conventional biodiesels (29.67 MJ/kg).

7.2.2 Carbon Intensity of Biodiesel from Beef Tallow

The carbon intensity values for biodiesel from beef tallow are summarized in Table 61. The CI for beef tallow biodiesel is approximately 21 g CO_2 eq./MJ, which is 79% lower than fossil aviation fuel (100 g CO_2 eq./MJ). The reduction in CI is largely due to the biogenic nature of the carbon emissions from biojet fuel. The primary contributor to the life cycle GHG emissions is the rendering of beef tallow from slaughterhouse by-products, followed by biodiesel production. The rendering process is energy-intensive and will vary depending on the nature of the incoming by-products and the efficiency of the system. No impacts are attributed to the upstream rearing and slaughter of animals, so this feedstock CI is attributed entirely to the rendering process. Transport of feedstock and fuel make relatively minor contributions to life cycle GHG emissions.

Table 61. Carbon intensity results for biodiesel produced from beef tallow, Canadian average, expressed in g CO_2 eq. per MJ of biodiesel energy.

Life Cycle Stage	Amount	Unit
Feedstock Production	10	g CO_2 eq./MJ
Feedstock Transport	0.5	g CO_2 eq./MJ
Biodiesel Production	5.4	g CO_2 eq./MJ
Transport & Distribution	0.8	g CO_2 eq./MJ
Combustion	4.4	g CO_2 eq./MJ
Total	**21**	**g CO_2 eq./MJ**

7.3 Yellow Grease Biodiesel

7.3.1 System Boundaries and Descriptions for Yellow Grease Biodiesel

The default pathway for biodiesel produced from yellow grease in the Fuel LCA Modelling Tool is for biodiesel produced from used cooking oil (UCO) feedstock. UCO is a mixture of used vegetable oils and fats produced by restaurants and other institutional kitchens. This UCO can be converted to yellow grease through a purification process and then used as an input to biodiesel conversion similar to that of converting vegetable oils from oil seed crops (e.g. canola). From a life cycle perspective, the production of biodiesel from yellow grease originates with the production and use of cooking oils in restaurants; however, UCO from these sources is considered a waste product and no GHG emissions associated with upstream activities are attributed to them, which is consistent with a number of other LCAs of biodiesel from yellow grease (California Environmental Protection Agency, 2009) ((S&T)2 Consultants Inc., 2012) (Chen, et al., 2018) (University of Toronto, 2019). The system boundary for the life cycle carbon intensity of yellow grease biodiesel therefore begins at the restaurant gate, and includes transport of UCO, purification, pre-treatment, biodiesel conversion, distribution, and combustion (Figure 13).

The system boundary for biodiesel from yellow grease is shown in Figure 13. The basic model building blocks for this process include:

- Transport of UCO from restaurants to the processing plant;
- Purification of UCO to produce yellow grease;
- Transport of yellow grease from the processing plant to the biodiesel production plant;
- Pre-treatment of yellow grease;
- Biodiesel production;
- Biodiesel distribution; and
- Biodiesel combustion.

After biodiesel production, the life cycle activities and resulting GHG emissions are assumed to be the same as for crop-based biodiesel pathways. The life cycle inventory and modelling considerations for biodiesel from yellow grease are outlined below.

7.3.2 Modelling and Life Cycle Inventory

Transport of Used Cooking Oil (UCO)

Data for 2017 indicate that all biodiesel produced from yellow grease was produced in Ontario and Québec (Wolinetz, Hein, & Moawad, 2019); however, for the Canadian average template developed for yellow grease biodiesel, it is assumed that UCO is transported by truck from restaurants within the same province as the biodiesel plant over an average distance of 100 km. Users of the Fuel LCA Modelling Tool can modify this transport distance and/or add additional transport modes and distances to align with more specific supply chain configurations in the future.

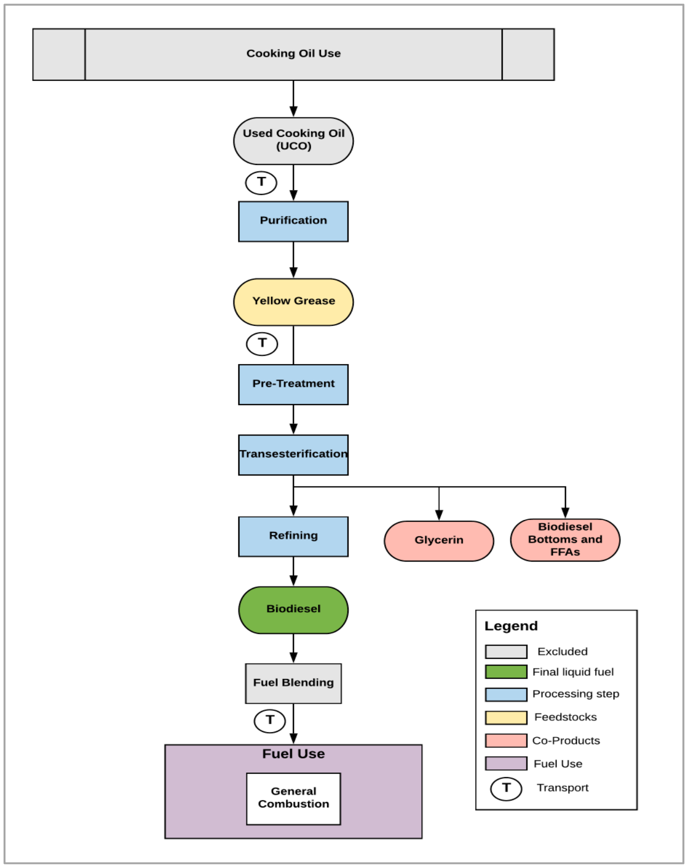

Figure 13. System boundaries for production of biodiesel from yellow grease derived from UCO.

UCO Purification

The mass balance and energy intensity of producing yellow grease by purifying UCO were derived from GHGenius. The data in GHGenius were developed to represent the Canadian context and are used here for the Canadian average pathway ((S&T)2 Consultants Inc., 2012). The mass balance and energy inputs for production of 1 kg of yellow grease from purification of UCO are shown in Table 62.

Table 62. Mass balance and energy inputs for purification of 1 kg of yellow grease from UCO ((S&T)2 Consultants Inc., 2012)

Purification	Amount
Inputs	
UCO (kg)	1.17
Transport of UCO to plant (tkm)*	0.0585
Natural gas (MJ)	0.76
Electricity (kWh)	0.098
Outputs	
Yellow grease (kg)	1
Wastes	
Wastewater (kg)	0.17

**UCO is assumed to be transported 100 km*

Transport of Yellow Grease to Biodiesel Plants

For the Canadian average template developed for yellow grease biodiesel, it is assumed that yellow grease is transported by truck from the processing plants within the same province as the biodiesel plant over an average distance of 100 km. Users of the Fuel LCA Modelling Tool can modify this transport distance and/or add additional transport modes and distances to align with more specific supply chain configurations in the future.

Conversion of Yellow Grease to Biodiesel

As an input to biodiesel conversion, yellow grease has a higher FFA content than oil derived from oil seed crops. As such, a pre-processing step is needed to reduce the FFA content before transesterification (California Environmental Protection Agency, 2009) (University of Toronto, 2019). Data on the energy inputs for pre-processing were obtained from the California-GREET project where an average energy consumption was calculated assuming that UCO is pre-treated using acid esterification and non-acid esterification on an approximately 50/50 basis (California Environmental Protection Agency, 2009). Energy inputs for this pre-treatment step include 0.385 MJ of natural gas per kg of biodiesel produced, and 0.0743 MJ of electricity per kg of biodiesel produced.

After pre-treatment, yellow grease is processed through a biodiesel conversion process similar to that used for other crop-based vegetable oils. A summary of the inputs and outputs of converting yellow grease to biodiesel is provided in Table 5. Unlike conversion of crop-based vegetable oil feedstocks, the conversion process for yellow grease also yields significant amounts of biodiesel distillation bottoms and FFAs, such that the conversion process impacts were allocated between biodiesel, glycerol, distillation bottoms, and FFAs. This allocation was done according to the energy content of the outputs, as per Chen et al. (2018), resulting in 94% of the emissions associated with biodiesel conversion being allocated to the biodiesel.

Table 63. Mass balance and material and energy inputs for production of biodiesel from yellow grease for an average US facility (Chen, et al., 2018).

	Amount (per kg of biodiesel)	Amount (per MJ of biodiesel)
Inputs		
Yellow grease (kg)	1	0.024895
Natural gas (MJ)	1.18	0.029377
Electricity (kWh)	0.0408	0.001017
Biodiesel distillation bottoms (MJ)	0.0005	1.24E-05
Methanol (kg)	0.108	0.0026887
Sulfuric acid (kg)	0.0001	2.49E-06
Hydrochloric acid (kg)	0.0025	6.22E-05
Sodium methylate (kg)	0.0049	0.000122
Sodium hydroxide (kg)	0.0004	9.96E-06
Nitrogen gas (kg)	0.0022	5.48E-05
Outputs		
Glycerol (kg)	0.0905	0.00225
Biodiesel distillation bottoms (kg)	0.003	7.47E-05
Fatty acids (kg)	0.0043	0.000107
Biodiesel (kg)	1	0.0337

**Note – The energy contents of the co-products include (Chen et al. 2018): glycerol - 18.56 MJ/kg; biodiesel distillation bottoms – 39.47 MJ/kg; fatty acids – 39.47 MJ/kg. The energy content of biodiesel is 29.67 MJ/kg.*

Yellow Grease Biodiesel Distribution and Combustion

It is assumed that after conversion of biodiesel from yellow grease that all other life cycle activities related to distribution and combustion are equivalent to those of the crop-based biodiesel pathways modeled in Milestone 3 (see Section 5.3), and that final energy content of the biodiesel is equivalent to conventional biodiesels (29.67 MJ/kg).

7.3.3 Carbon Intensity of Biodiesel from Yellow Grease

The carbon intensity results for biodiesel from yellow grease are summarized in Table 64. The CI for biodiesel from yellow grease is approximately 12 g CO_2 eq./MJ, which is 88% lower than fossil aviation fuel (100 g CO_2 eq./MJ). The primary contributor to the life cycle GHG emissions is biodiesel production, followed by combustion and feedstock production. Feedstock production for biodiesel from yellow grease is notably much lower than that for tallow as the rendering process is less energy intensive and tallow must be heated for transport.

Table 64. Carbon intensity results for biodiesel produced from yellow grease, expressed in g CO_2 eq. per MJ of biodiesel energy.

Life Cycle Stage	Amount	Unit
Feedstock Production	1.9	g CO_2 eq./MJ
Feedstock Transport	0.4	g CO_2 eq./MJ
Pre-Processing of Yellow Grease	0.8	g CO_2 eq./MJ
Biodiesel Production	3.8	g CO_2 eq./MJ
Transport & Distribution	0.8	g CO_2 eq./MJ
Combustion	4.4	g CO_2 eq./MJ
Total	**12**	**g CO_2 eq./MJ**

7.3.4 Uncertainty

Uncertainty analysis was conducted for Canadian average biodiesel from tallow and yellow grease using Monte Carlo analysis. Results of the uncertainty analysis are shown in the violin plots in Section 12 and discussed relative to the uncertainty of other low carbon fuels in that section. Below in Table 65 the key results of the uncertainty analysis for both types of biodiesel are summarized.

Results of the uncertainty analysis show a fairly tight range of possible outcomes at both the high and low end for both fuels. Most of the uncertainty is due to potential variations in energy intensity and yield of the rendering and pre-processing steps for tallow and UCO.

Table 65. Uncertainty analysis results for average Canadian biodiesel from beef tallow and from yellow grease. Results based on Monte Carlo analysis with a confidence interval of 95%.

Final CI	Mean	Median	SD	Min (2.5%)	Max (97.5%)
Biodiesel, from beef tallow, average {CA}					
20.7	20.7	20.4	3.09	15.5	27.6
Biodiesel, from yellow grease, average {CA}					
11.7	11.7	11.6	1.43	9.48	15.0

7.3.5 Data Gaps and Limitations for Waste Biodiesel

The primary limitations for modelling biodiesel production from tallow and yellow grease are a lack of recent, Canadian data on the material and energy inputs to tallow rendering, UCO pretreatment, and biodiesel conversion. Although primary data was available from CEPR for the LCI of ethanol and biodiesel conversion from a number of Canadian producers, there were gaps in this data and challenges with linking specific feedstocks to process which limited its applicability for modelling unique waste biodiesel conversion processes. For rendering and pretreatment, the data used are somewhat dated and also primarily from the U.S., so operating data from Canadian facilities could improve the reliability of the CI calculations for this part of the life cycle. In addition, due to the fossil component of methanol used in conversion, combustion emissions from biodiesel overall appear to be non-negligible despite the exclusion of biogenic carbon, so more representative data on combustion emissions is needed to solidify the modelling.

7.4 Ethanol from MSW

7.4.1 System Boundaries and Descriptions for Yellow Grease Biodiesel

The conversion of MSW to fuels is of increasing interest to low carbon fuel producers. In particular, food waste and yard trimmings that are part of the organics component of MSW can be good feedstocks for fuel because they have high energy content and their properties are very similar to other biomass feedstocks that are commonly used, such as wood biomass and crop-based feedstocks ((Lee, Han, & Wang, 2016).

There are a number of options for converting MSW to ethanol, including Enerkem’s conversion of non-recyclable MSW to ethanol, methanol, and other products through gasification[13], and other systems targeted at source-separated organics or organics in the MSW stream; however, there is no data publicly available to model the Enerkem process, and very limited data available to model MSW to ethanol overall. While users of the Fuel LCA Modelling Tool will be able to build their own unique MSW to ethanol pathways, the default pathway provided here is for conversion of yard trimmings from the organic component of MSW to ethanol via fermentation. Yard trimmings generally consist of grass, leaves, and wood and have characteristics similar to other lignocellulosic feedstocks modeled in this study, such as corn stover. As such, they can be converted to cellulosic ethanol via a similar hydrolysis and fermentation process as corn stover and wheat straw.

Since yard trimmings are a waste product, no GHG emissions associated with upstream activities such as production of yard waste or MSW collection systems are attributed to them, which is consistent with assumptions in other LCA studies (Lee, Han, & Wang, 2016) (Kalogo, Habibi, MacLean, & Joshi, 2007). The system boundary for the life cycle carbon intensity of ethanol from MSW therefore begins with the delivery of yard trimmings from a central MSW collection facility to an ethanol plant, and includes pre-treatment, fuel conversion, distribution, and combustion (Figure 13). The unit process building blocks for this process include:

- Transport of yard trimmings to the ethanol plant;

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[13] See Enerkem’s process description here: https://enerkem.com/about-us/technology/

- Dilute acid pre-treatment;
- Enzymatic hydrolysis and fermentation;
- Distillation and dehydration;
- Cellulosic ethanol distribution; and
- Cellulosic ethanol combustion.

In reviewing the modelling and results for waste-to-energy systems in the literature and in other modelling tools (e.g. GREET), the system boundary of the assessment often includes consideration of the emissions associated with current waste management practices to determine if there is a net increase or decrease in GHG emissions when redirecting wastes to fuel production. This balance depends heavily on what the current waste management practice is (e.g. landfilling, composting, etc.), projections of market changes if the waste is used for bioenergy, and on the fuel conversion process that is used to convert the waste feedstock into energy. As such, the CI of fuels produced from MSW reported in the literature can vary from jurisdiction to jurisdiction, and from pathway to pathway, and results in the limited amount of literature for converting MSW to ethanol indicate a high level of variability (Kalogo, Habibi, MacLean, & Joshi, 2007).

This approach to modelling the differences between a reference case and the bioenergy case is a form of consequential LCA modelling (market-based recycling model). As discussed in Section 2, the approach for the Fuel LCA Modelling Tool is to use a cut-off approach for the recycling or reuse of materials beyond the first life of the material. As such, any GHG emissions credit or burden associated with the redirection of these wastes to bioenergy production are not included within the boundary when calculating the CI of converting MSW to ethanol (the second life of the material).

7.4.2 Modelling and Life Cycle Inventory

Transport of Yard Trimmings

Yard trimmings collected within the MSW management system are assumed to be transported from a centralized MSW depot to an ethanol producer using an average diesel truck (as modelled in Milestone 2). The moisture content of the yard trimmings is assumed to be 60% (Lee, Han, & Wang, 2016), and the dry mass and mass of the moisture are accounted for in calculating the emissions from feedstock transport. As per the corn stover cellulosic ethanol conversion process, 0.143 kg (dry mass) of feedstock are required to yield 1 MJ of fuel (HHV), and at 60% moisture content this requires that 0.229 kg of feedstock be transported to the facility for every MJ of cellulosic ethanol produced. Since there are no current data available on existing supply chains for producers of MSW from ethanol in Canada, the feedstock transport distance is assumed to be 100 km, and requiring 0.0229 tkm per MJ of cellulosic ethanol. Users of the Fuel LCA Modelling Tool can modify this transport distance and/or add additional transport modes and distances to align with more specific supply chain configurations in the future. Users can also update the transport calculations to reflect alternative moisture content data in the future.

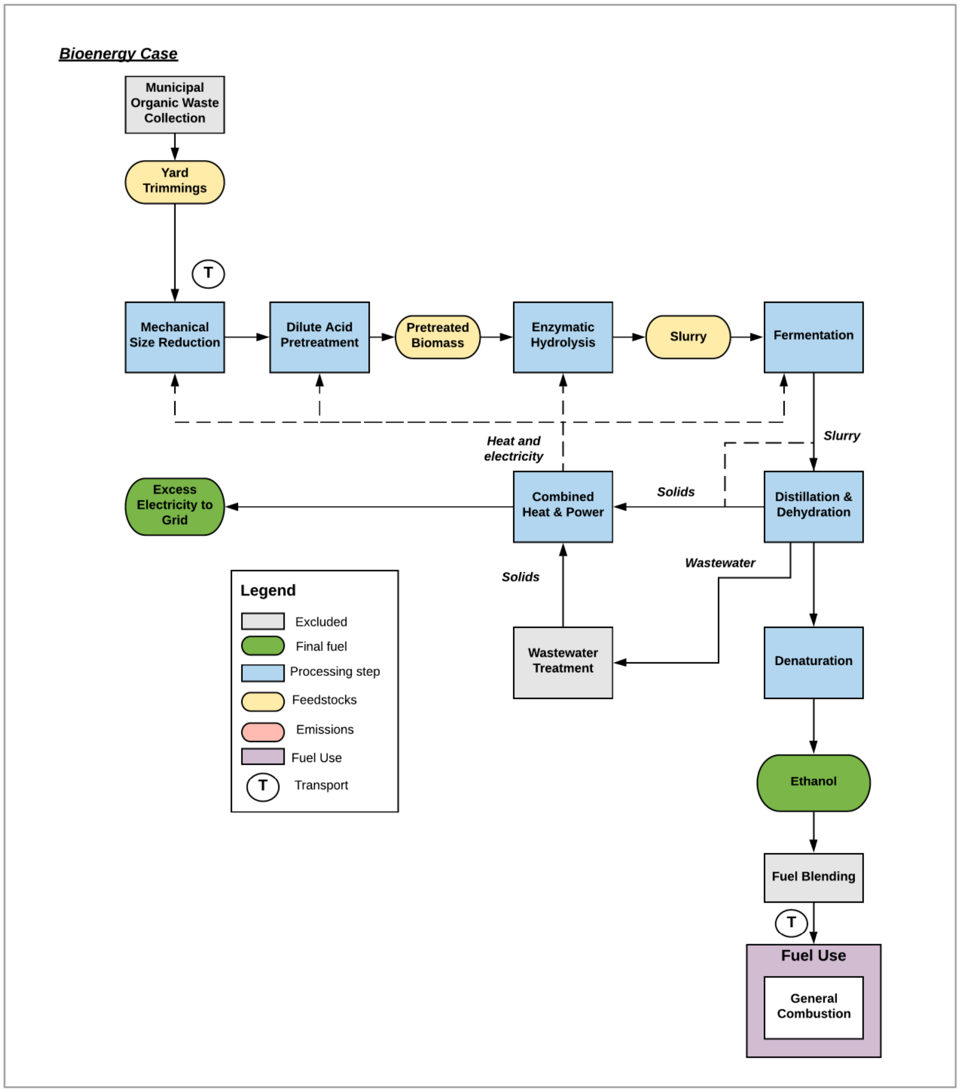

Figure 14. System boundaries for production of ethanol from yard trimmings derived from MSW.

Pretreatment and Conversion to Ethanol

The pretreatment and conversion of yard trimmings to ethanol was assumed to be done via the same cellulosic ethanol process that was modelled for conversion of corn stover to cellulosic ethanol. A similar assumption was made in modelling the conversion of yard trimmings to ethanol in the GREET tool (Lee, Han, & Wang, 2016). This conversion process includes mechanical size reduction, dilute acid pretreatment, and fuel conversion via hydrolysis and fermentation (see Section 6.2). As a result of the high moisture content of the feedstock relative to corn stover, more energy is required to dry the feedstock and so the conversion of yard trimmings to ethanol does not result in a surplus of electricity that could be sold to the grid. As such, unlike the conversion of corn stover for which surplus electricity is produced (see Section 6.2), there are no GHG emissions credits generated for conversion of yard trimmings. The additional energy needed to dry the incoming feedstock is estimated to be 0.61 mmBtu (~644 MJ) of natural gas per dry tonne of feedstock, as calculated in Lee et al. for an average US process (Lee, Han, & Wang, 2016). The cellulosic ethanol conversion process requires 0.143 kg (dry) of yard trimmings, such that an additional 0.092 MJ of natural gas is required per MJ of fuel produced.

MSW-Based Ethanol Distribution and Combustion

Since there are no established production and distribution supply chains for ethanol produced from MSW in Canada, it was assumed that fuel distribution to end users and fuel combustion would be equivalent to distribution and combustion of the crop-based bioethanol pathways modelled in Section 5. Cellulosic ethanol from yard trimmings was also assumed to have the same HHV as crop-based bioethanol.

7.4.3 Carbon Intensity of Ethanol from Yard Trimmings

The carbon intensity results for cellulosic ethanol from MSW yard trimmings are summarized in Table 66. For this average default pathway the CI is estimated to be approximately 30 g of CO_2 eq. per MJ of fuel (HHV) for neat/unblended fuel, which is approximately 67% lower than the CI estimated for conventional gasoline (92 g CO_2 eq./MJ). The primary contributor to the life cycle GHG emissions of the pathway is the conversion of the feedstock into cellulosic ethanol via hydrolysis and fermentation, accounting for 80% of life cycle GHG emissions. The key difference in CI between cellulosic ethanol from MSW and conventional gasoline is the combustion emissions. While gasoline combustion emissions are approximately 66 g CO_2 eq. per MJ, combustion emissions from waste-based cellulosic ethanol are nearly zero due to the biogenic nature of the carbon contained in the fuel.

Table 66. Carbon intensity results for cellulosic ethanol produced from yard trimmings from MSW, expressed in g CO_2 eq. per MJ of ethanol (HHV).

Life Cycle Stage	Amount	Unit
Feedstock Transport	3.0	g CO_2 eq./MJ
Pretreatment	2.0	g CO_2 eq./MJ
Hydrolysis and fermentation	24	g CO_2 eq./MJ
Transport & Distribution	0.8	g CO_2 eq./MJ
Combustion	0.4	g CO_2 eq./MJ
Total	**30**	**g CO_2 eq./MJ**

Uncertainty analysis was conducted for ethanol from MSW yard trimmings based on data quality and fit for purpose evaluations of the LCI data. Results of the Monte Carlo analysis indicate that the CI could vary significantly depending on the data and assumptions used, ranging from 76% higher than the default value, to 45% lower. The uncertainty of the results for ethanol from MSW is also shown in the violin plots in Section 12 of the report, including a comparison with the baseline CI value for conventional gasoline and for other bioethanol and cellulosic ethanol pathways.

Table 67. Uncertainty analysis results for average Canadian cellulosic ethanol from yard trimmings collected in MSW. Results based on Monte Carlo analysis with a confidence interval of 95%.

Final CI	Mean	Median	SD	Min (2.5%)	Max (97.5%)
Ethanol, from yard trimmings, average {CA}					
30.0	30.1	28.6	9.2	16.4	52.7

7.4.4 Data Gaps and Limitations for Ethanol from MSW

Since there are no data and very few existing MSW-to-ethanol producers in Canada, all of the LCI data used are based on previous studies from regions outside of Canada which were modified using assumptions and guidance from the literature. As such, the primary limitations for modelling cellulosic ethanol production from MSW is a lack of recent Canadian data on the material and energy inputs to the conversion process, and specific data on the feedstock(s) that would be used. For the purposes of building a default pathway for the Fuel LCA Modelling Tool, we have modelled the conversion of yard trimmings using a cellulosic ethanol conversion process; however, other feedstocks from MSW could be used, and other conversion processes could be used (e.g. gasification), which could change the CI substantially. As such, the CI results are generally limited to this specific pathway, and the uncertainty ranges provided should be used as upper and lower ranges of possible outcomes depending on variations in the technology and feedstock characteristics.

8. Renewable Natural Gas (RNG)

Renewable natural gas (RNG) is methane gas derived from organic materials and waste streams that has been produced and had impurities removed to a level that meets current natural gas pipeline specifications or vehicle fuel standards (Canadian Gas Association, 2014). RNG can typically be produced from anaerobic digestion or gasification of agriculture or agri-food residues (crop residues, livestock manure, food waste), forestry by-products (e.g. harvest residues), and MSW streams and WWT sludge. The biogas from these processes must then be upgraded to RNG by removing impurities to reach an appropriate methane concentration. RNG is considered a renewable energy feedstock due to the biogenic nature of the source, and the carbon released when RNG is combusted is biogenic in nature and therefore not counted as an increase in atmospheric carbon under the current national GHG inventory generation and reporting methods used in Canada.

In a 2019 study conducted for Natural Resources Canada, it was identified that there are currently 12 operational RNG production facilities in Canada, with two others expected to begin operation within the next 2 years (CIRAIG, 2019). These 14 facilities include:

- 2 facilities converting WWT sludge;
- 1 facility converting household organic wastes;
- 4 facilities converting organic wastes;
- 3 facilities converting dairy manure and off-farm wastes; and
- 4 facilities upgrading landfill gas.

Determining the CI of RNG systems is challenging due to a lack of primary data from the small number of current producers, and due to the potential variability in CI that could result from the use of the many different feedstocks available, and use of different forms of anaerobic digestion and upgrading technologies. A survey of current producers was conducted in the summer of 2019 and resulted in collection of some operating data from a small subset of 5 of the currently active producers (CIRAIG, 2019); however, these data were incomplete and were combined with literature data to produce average inventories for anaerobic digestion and biogas upgrading which are not specific to any given feedstock or technology.

For the purposes of the Fuel LCA Modelling Tool, we have established the basic model building blocks for 4 RNG pathways, including capture and upgrading of landfill gas, as well as anaerobic digestion and upgrading of biogas from 3 sources of organic materials, including WWT sludge, organics from MSW, and livestock manure. The lack of available data from Canadian producers limited the ability to develop high-resolution models of these four pathways, but instead allowed for the development of more generic building blocks for basic unit processes such as anaerobic digestion and biogas upgrading. It is expected that users of the Fuel LCA Modelling tool will use and expand upon these basic building blocks in the future to develop more specific pathways.

The following sections provide an overview of the system boundaries, modelling, and CI results for each of the 4 RNG pathways.

8.1 RNG from Landfill Gas

8.1.1 System Boundaries and Descriptions for RNG from Landfill Gas

Landfill gas is biogas generated from the decomposition of organic materials in municipal landfills. It is composed primarily of methane, but also contains carbon dioxide and several other substances in small amounts (e.g. hydrogen sulfide). Conventional practice is to flare landfill gas to convert most of the methane to carbon dioxide in order to reduce GHG emissions, and to reduce other criteria air pollutants (Mintz, Han, Wang, & Saricks, 2010). While landfills in some jurisdictions may also include energy generation from the capture of landfill gas, this is not the case in all instances and unused landfill gas represents a potential feedstock for RNG that is widely available.

Since landfill gas is a waste product originating from the organic fraction of MSW, no GHG emissions associated with upstream activities such as production of MSW or MSW collection systems are attributed to it, which is consistent with assumptions used in the GREET LCA model (Lee, Han, & Wang, 2016). In addition, it is assumed that the landfills from which landfill gas is obtained are already capturing this biogas for the purposes of flaring it to reduce methane emissions. As such, the energy use and emissions associated with capturing landfill gas using a blower system are also excluded from the system boundary since this would occur regardless of whether the biogas is directed to RNG production or not.

The system boundary for the life cycle carbon intensity of RNG from landfill gas therefore begins with the upgrading of captured landfill gas (Figure 15). The unit process building blocks for this process include:

- Upgrading of landfill biogas to RNG;
- Distribution and storage in the natural gas system; and
- Combustion.

In reviewing the modelling and results for waste-to-energy systems in the literature and in other modelling tools (e.g. GREET), the system boundary of the assessment often includes consideration of the emissions associated with current waste management practices to determine if there is a net increase or decrease in GHG emissions when redirecting wastes to fuel production. This balance depends heavily on what the current waste management practice is (e.g. landfilling, composting, etc.), projections of market changes if the waste is used for bioenergy, and on the fuel conversion process that is used to convert the waste feedstock into energy. As such, the CI of fuels produced from MSW reported in the literature can vary from jurisdiction to jurisdiction, and from pathway to pathway, and results in the limited amount of literature for converting MSW to ethanol indicate a high level of variability (Kalogo, Habibi, MacLean, & Joshi, 2007).

This approach to modelling the differences between a reference case and the bioenergy case is a form of consequential LCA modelling (market-based recycling model). As discussed in Section 2, the approach for the Fuel LCA Modelling Tool is to use a cut-off approach for the recycling or reuse of materials beyond the first life of the material. As such, any GHG emissions credit or burden associated with the redirection of these wastes to bioenergy production are not included within the boundary when calculating the CI of converting MSW to ethanol (the second life of the material).

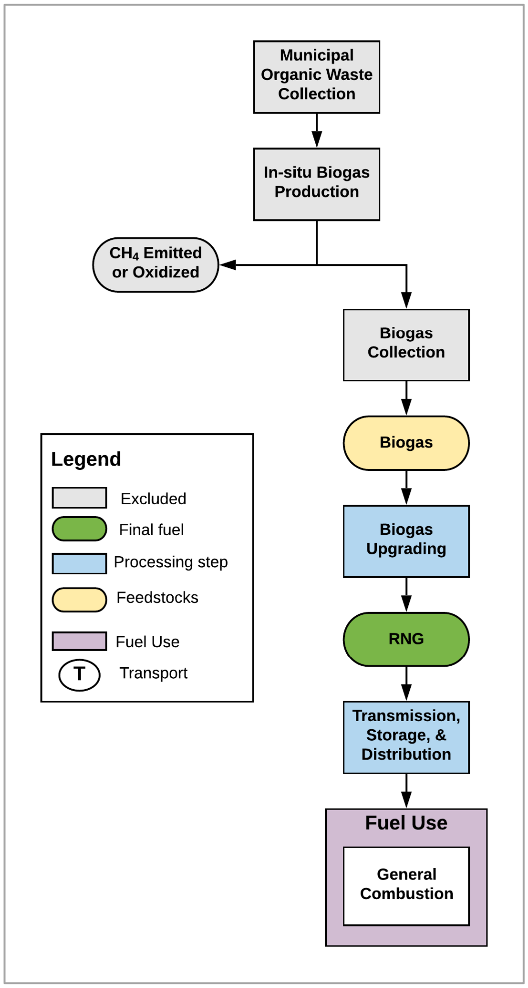

Figure 15. System boundaries for production of RNG from landfill gas.

8.1.2 Modelling and Life Cycle Inventory

Biogas Upgrading

The LCI for biogas upgrading is based on a combination of primary data from a limited number of Canadian RNG producers and secondary data from the literature used to fill data gaps in the primary data set. These confidential data were compiled by CIRAIG and shared with ECCC via NRCan for use in the Fuel LCA Modelling tool (CIRAIG, 2019). The life cycle GHG emissions associated with upgrading of landfill gas to RNG are based on energy consumption to power the process and direct process emissions of methane and carbon dioxide. These direct emissions are a function of the incoming biogas composition, and an average biogas composition profile was used from the literature since no specific Canadian data were available (CIRAIG, 2019). A summary of the inputs and outputs and biogas composition is provided in Table 68.

Table 68. Inputs, outputs, biogas composition, and RNG composition for upgrading of landfill gas to RNG in an average Canadian facility (CIRAIG, 2019).

	Amount (per 1 m3 of RNG)	Amount (per MJ of RNG)*
Inputs		
Biogas (m^3)	3.95	0.104
Electricity (kWh)	0.862	0.023
Activated carbon (kg)	0.001	2.63E-05
Outputs		
RNG (m^3)	1	0.026
Methane (kg)**	0.00163	4.29E-05
Carbon dioxide (kg)***	3.43	0.09
Landfill Gas Composition		
Methane, biogenic (%vol)	45	
Hydrogen (%vol)	0	
Cardon dioxide, biogenic (%vol)	40	
Nitrogen (%vol)	15	
Oxygen (%vol)	1	
Hydrogen sulfide (%vol)	0.0001	
Ammonia (%vol)	0.000005	
RNG Composition		
Methane, biogenic (%vol)	97.46	
Hydrogen (%vol)	0	
Carbon dioxide, biogenic (%vol)	0.78	
Nitrogen (%vol)	1.735	
Oxygen (%vol)	0.02	
Hydrogen sulfide (%vol)	0	
Ammonia (%vol)	0	

**Note – The energy content of RNG is 38 MJ/m3* (CIRAIG, 2019).

***Note – Methane emissions are assumed to be flared. Methane emissions would be higher in cases where emissions are only vented*

****Note – Carbon dioxide emissions from biogas upgrading are biogenic in nature and therefore excluded from CI calculations.*

Calculations of the methane and carbon dioxide emissions from the biogas upgrading process are summarized in the calculation sheets provided for RNG in the supporting material. Methane emissions from biogas upgrading were assumed to be flared at an efficiency of 99.5% therefore reducing methane emissions significantly. In instances where methane is not flared, the CI would be significantly higher. Activated carbon was excluded from the CI calculations for upgrading biogas due to the insignificant amount used and its low contribution to the life cycle CI. The composition of the RNG produced from this process is assumed to be the same regardless of the input biogas.

RNG Distribution and Combustion

Since there are no data available on established Canadian production and distribution supply chains for RNG, it was assumed that fuel distribution to end users would be equivalent to distribution of conventional natural gas modelled in Milestone 2 (EarthShift Global, WSP, Introspective Systems, 2019b). This is a reasonable assumption since it is expected that RNG would replace conventional natural gas in current distribution and use infrastructure.

Primary data were not available on the combustion emissions from RNG. Since the carbon contained in the fuel is biogenic, it is excluded from the CI calculations. Estimates of methane and nitrous oxide emissions associated with combustion of RNG were obtained from a summary of emissions factors for the British Columbia renewable fuels regulation (British Columbia Ministry of Environment and Climate Change Strategy, 2017). It is noted that methane and nitrous oxide emissions could vary depending on the efficiency of combustion, which is not reflected in this average case.

8.1.3 Carbon Intensity of RNG from Landfill Gas

The carbon intensity results for RNG produced from landfill gas are summarized in Table 69. For this average default pathway, the CI is estimated to be approximately 6.0 g of CO_2 eq. per MJ of fuel (HHV), which is approximately 91% lower than the CI estimated for conventional natural gas (67 g CO_2 eq./MJ). The primary contributor to the life cycle GHG emissions of the pathway is the upgrading of biogas, accounting for 88% of life cycle GHG emissions. The key difference in CI between RNG and conventional natural gas is the combustion emissions. While natural gas combustion emissions are approximately 53 g CO_2 eq. per MJ, combustion emissions from RNG are nearly zero due to the biogenic nature of the carbon contained in the fuel.

Table 69. Carbon intensity results for RNG produced from landfill gas, expressed in g CO_2 eq. per MJ of RNG (HHV).

Life Cycle Stage	Amount	Unit
Biogas upgrading	5.3	g CO_2 eq./MJ
Transport & Distribution	0.6	g CO_2 eq./MJ
Combustion	0.3	g CO_2 eq./MJ
Total	**6.0**	**g CO_2 eq./MJ**

Results of the uncertainty analysis for RNG produced from landfill gas are provided in Section 12.

8.2 RNG from WWT Sludge

8.2.1 System Boundaries and Descriptions for RNG from WWT Sludge

Biogas can also be generated from the anaerobic digestion of WWT sludge. WWT sludge is a by-product of municipal sewage treatment processes. Because the sludge is fairly homogenous and has a high energy content, it is a good potential feedstock for biofuels. Conventional practice is to process WWT sludge with an anaerobic digestion process which yields biogas and digestate. The biogas is typically flared to reduce methane emissions, and the digestate is used a soil amendment in agricultural fields (Lee U. , Han, Demirtas, Wang, & Tao, 2016). A survey of Canadian RNG producers in 2019 indicated two facilities that are expected to produce RNG from WWT sludge within the next two years, but otherwise no other recorded activity for this pathway.

Since the sludge is a waste product originating from WWT plants, no GHG emissions associated with upstream activities such as production of wastewater or collection and treatment of wastewater are attributed to it, which is consistent with assumptions used in the GREET LCA model (Lee U. , Han, Demirtas, Wang, & Tao, 2016).

The system boundary for the life cycle carbon intensity of RNG from WWT sludge therefore begins with the transport of sludge to an RNG facility (Figure 16). The unit process building blocks for this process include:

- Transport of WWT sludge to an RNG facility;
- Anaerobic digestion of the WWT sludge to produce biogas and digestate;
- Upgrading of biogas to RNG;
- Distribution and storage in the natural gas system; and
- Combustion.

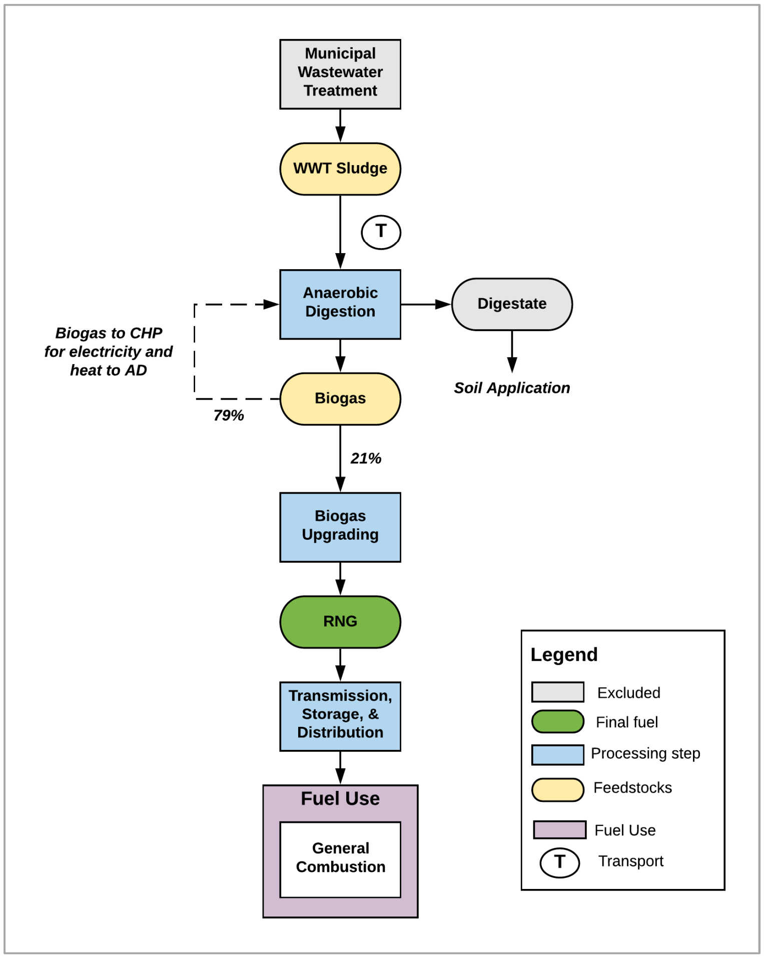

Figure 16. System boundaries for production of RNG from WWT sludge.

8.2.2 Modelling and Life Cycle Inventory

Transport of WWT Sludge

WWT sludge collection from WWT plants is assumed to be transported to an RNG producer using an average diesel truck (as modelled in Milestone 2). The moisture content of the WWT sludge is assumed to be 90% (Lee U. , Han, Demirtas, Wang, & Tao, 2016), and the dry mass and mass of the moisture are accounted for in calculating the emissions from feedstock transport. Based on data compiled by CIRAIG, it requires 1.196 kg (dry mass) of feedstock to yield 1 m^3 of biogas from anaerobic digestion. At 90% moisture content this requires that 2.27 kg of wet sludge be transported to the facility for every m^3 of biogas produced. Since there are no current data available on existing supply chains for producers of RNG from WWT sludge in Canada, the feedstock transport distance is assumed to be 50 km. Users of the Fuel LCA Modelling Tool can modify this transport distance and/or add additional transport modes and distances to align with more specific supply chain configurations in the future. Users can also update the transport calculations to reflect alternative moisture content data in the future.

Anaerobic Digestion

The anaerobic digestion of organic material was modeled from a combination of primary and secondary data compiled to develop an average Canadian anaerobic digestion process (CIRAIG, 2019). The average process modeled is based on an anaerobic digestion process that includes an onsite CHP plant which provides heat and electricity to the process. It is assumed that the CHP accounts for all the required energy of the process with the exception of a small amount of natural gas heat and grid electricity. The process yields biogas and digestate. A significant portion of the biogas produced is used to power the CHP unit, while the rest is directed to RNG production. The digestate is assumed to be stored in a closed location for potential future use as a soil amendment. The inputs and outputs of the average anaerobic digestion process are summarized in Table 73 below. The GHG emissions associated with production of biogas by anaerobic digestion were allocated between the biogas output and the digestate based on their energy content, resulting in 18.3% of the GHG emissions being allocated to biogas. With respect to the input of organic material to the process, the data compiled by CIRAIG were for an average process using a mixture of feedstocks; however, in order to model RNG pathways from individual organic feedstocks, it was assumed that the same total mass of organic material input would be required regardless of the feedstock used. This is a simplifying assumption because the incoming organics would have different moisture contents and properties; however, specific anaerobic digestion data were not available for each type of feedstock.

Table 70. Inputs and outputs for anaerobic digestion of organic material to produce biogas for RNG upgrading in an average Canadian facility (CIRAIG, 2019).

	Amount (per 1 m3 of biogas processed)
Inputs	
Organic material (kg)*	1.196
Sodium hydroxide (kg)	2.18E-05
Electricity, from grid (kWh)	0.145
Heat – from internal CHP (MJ)	4.65
Heat – from natural gas (MJ)	0.002
Outputs	
Biogas – to be upgraded to RNG (m^3)**	0.2086
Biogas – for use in CHP (m^3)**	0.7914
Heat – from CHP (MJ)	4.854
Electricity – from CHP (kWh)	2.127
Digestate (kg)***	8.581
Methane – from CHP (kg)	7.63E-05
Nitrous oxide – from CHP (kg)	2.81E-07
Methane – from digester (kg)	0.00307

**Note – Data collected by CIRAIG for the amount of organic material input was based on an average mix of different organic materials, including food waste, WWT sludge, used cooking oil, pig slurry, and cow slurry. In order to model a specific pathway (e.g. WWT sludge) a simplifying assumption was used that the total of these different inputs is the required mass of organic inputs of any type.*

***Note – The energy content of the biogas produced is 25 MJ/m3* (CIRAIG, 2019).

****Note – The energy content of the digestate is assumed to be 13 MJ/kg* (Durdevic, Blecich, & Lenic, 2018)

Upgrading of Biogas to RNG

The LCI for biogas upgrading is based on a combination of primary data from a limited number of Canadian RNG producers and secondary data from the literature used to fill data gaps in the primary data set. These confidential data were compiled by CIRAIG and shared with ECCC via NRCan for use in the Fuel LCA Modelling tool (CIRAIG, 2019). The life cycle GHG emissions associated with upgrading of biogas from anaerobic digestion to RNG are based on energy consumption to power the process and direct process emissions of methane and carbon dioxide. These direct emissions are a function of the incoming biogas composition, and an average biogas composition from anaerobic digestion was used from the literature since no specific Canadian data were available (CIRAIG, 2019). A summary of the inputs and outputs and biogas composition is provided in Table 71.

Table 71. Inputs, outputs, biogas composition, and RNG composition for upgrading of biogas from anaerobic digestion to RNG in an average Canadian facility (CIRAIG, 2019).

	Amount (per 1 m3 of RNG)	Amount (per MJ of RNG)*
Inputs		
Biogas (m^3)	3.95	0.104
Electricity (kWh)	0.862	0.023
Activated carbon (kg)	0.001	2.63E-05
Outputs		
RNG (m^3)	1	0.026
Methane (kg)**	0.0054	0.00014
Carbon dioxide (kg)***	2.53	0.067
Landfill Gas Composition		
Methane, biogenic (%vol)	65	
Hydrogen (%vol)	0	
Cardon dioxide, biogenic (%vol)	35	
Nitrogen (%vol)	0.2	
Oxygen (%vol)	0	
Hydrogen sulfide (%vol)	0.0005	
Ammonia (%vol)	0.0001	
RNG Composition		
Methane, biogenic (%vol)	97.46	
Hydrogen (%vol)	0	
Carbon dioxide, biogenic (%vol)	0.78	
Nitrogen (%vol)	1.735	
Oxygen (%vol)	0.02	
Hydrogen sulfide (%vol)	0	
Ammonia (%vol)	0	

**Note – The energy content of RNG is 38 MJ/m3* (CIRAIG, 2019).

***Note – Methane emissions are assumed to be flared. Methane emissions would be higher in cases where emissions are only vented*

****Note – Carbon dioxide emissions from biogas upgrading are biogenic in nature and therefore excluded from CI calculations.*

Calculations of the methane and carbon dioxide emissions from the biogas upgrading process are summarized in the calculation sheets provided for RNG in the supporting material. Methane emissions from biogas upgrading were assumed to be flared at an efficiency of 99.5% therefore reducing methane emissions significantly. In instances where methane is not flared, the CI would be significantly higher. Activated carbon was excluded from the CI calculations for upgrading biogas due to the insignificant amount used and its low contribution to the life cycle CI. The composition of the RNG produced from this process is assumed to be the same regardless of the input biogas.

RNG Distribution and Combustion

Since there are no data available on established Canadian production and distribution supply chains for RNG, it was assumed that fuel distribution to end users would be equivalent to distribution of conventional natural gas modelled in Milestone 2 (EarthShift Global, WSP, Introspective Systems, 2019b). This is a reasonable assumption since it is expected that RNG would replace conventional natural gas in current distribution and use infrastructure.

Primary data were not available on the combustion emissions from RNG. Since the carbon contained in the fuel is biogenic, it is excluded from the CI calculations. Estimates of methane and nitrous oxide emissions associated with combustion of RNG were obtained from a summary of emissions factors for the British Columbia renewable fuels regulation (British Columbia Ministry of Environment and Climate Change Strategy, 2017). It is noted that methane and nitrous oxide emissions could vary depending on the efficiency of combustion, which is not reflected in this average case.

8.2.3 Carbon Intensity of RNG from WWT Sludge

The carbon intensity results for RNG produced from anaerobic digestion and upgrading of WWT sludge are summarized in Table 72. For this average default pathway, the CI is estimated to be approximately 26 g of CO_2 eq. per MJ of fuel (HHV), which is approximately 61% lower than the CI estimated for conventional natural gas (67 g CO_2 eq./MJ). The primary contributor to the life cycle GHG emissions of the pathway is the anaerobic digestion of the WWT sludge, accounting for 38% of life cycle GHG emissions. The CI of biogas upgrading is noted to be higher than upgrading of landfill gas because the incoming biogas is assumed to have a higher methane content and thus emissions of unflared methane are higher. Feedstock transport also makes a significant contribution to total life cycle GHG emissions, accounting for 28% of emissions. This is because the WWT sludge has a very high moisture content when transported to the RNG facility. In an alternative scenario the WWT sludge may be dewatered prior to transport and this would require additional energy; however, these data were not available.

Table 72. Carbon intensity results for RNG produced from WWT sludge, expressed in g CO_2 eq. per MJ of RNG (HHV).

Life Cycle Stage	Amount	Unit
Feedstock transport to RNG facility	7.4	g CO_2 eq./MJ
Anaerobic digestion	10	g CO_2 eq./MJ
Biogas upgrading	8.1	g CO_2 eq./MJ
Transport & Distribution	0.6	g CO_2 eq./MJ
Combustion	0.3	g CO_2 eq./MJ
Total	**26**	**g CO_2 eq./MJ**

Results of the uncertainty analysis for RNG produced from WWT sludge are provided later in this section, and also in the violin plots in Section 12.

8.3 RNG from MSW Organics

8.3.1 System Boundaries and Descriptions for RNG from MSW Organics

Biogas can also be generated from the anaerobic digestion of organic materials found in MSW (e.g. food scraps). Organics, including yard trimmings and food scraps, constitute approximately 40% of the MSW stream in most Canadian municipalities (Environment Canada, 2013). Management of organics in MSW ranges from various forms of composting to anaerobic digestion systems, and a portion of organic household waste also ends up on the main solid waste stream that is sent to landfills. A survey of Canadian RNG producers in 2019 indicated that five facilities are currently producing RNG from organic waste streams.

Since the organics are a waste product, no GHG emissions associated with upstream activities such as production of the materials or collection and treatment of the materials are attributed to them. The system boundary for the life cycle carbon intensity of RNG from MSW organics therefore begins with the transport of organics from a central MSW collection point to an RNG facility (Figure 17). The unit process building blocks for this process include:

- Transport of organics to an RNG facility;
- Anaerobic digestion of the organics to produce biogas and digestate;
- Upgrading of biogas to RNG;
- Distribution and storage in the natural gas system; and
- Combustion.

8.3.2 Modelling and Life Cycle Inventory

Transport of Organics

Organics collected in MSW systems are assumed to be transported to an RNG producer using an average diesel truck (as modelled in Milestone 2). The moisture content of the organics is assumed to be 70% (Lee U. , Han, Demirtas, Wang, & Tao, 2016), and the dry mass and mass of the moisture are accounted for in calculating the emissions from feedstock transport. Based on data compiled by CIRAIG, it requires 1.196 kg (dry mass) of feedstock to yield 1 m^3 of biogas from anaerobic digestion. At 70% moisture content this requires that 2.03 kg of wet organics be transported to the facility for every m^3 of biogas produced. Since there are no current data available on existing supply chains for producers of RNG from MSW organics in Canada, the feedstock transport distance is assumed to be 50 km. Users of the Fuel LCA Modelling Tool can modify this transport distance and/or add additional transport modes and distances to align with more specific supply chain configurations in the future. Users can also update the transport calculations to reflect alternative moisture content data in the future.

Anaerobic Digestion

The anaerobic digestion process to convert organics from MSW to biogas for RNG production was assumed to be the same as the process for WWT sludge. This is a simplifying assumption that was required due to the low-resolution inventory data available from the CIRAIG study which did not allow for the characterization of unique anaerobic digestion processes specific to the incoming feedstock type. A summary of the average Canadian anaerobic digestion process is provided in the previous section.

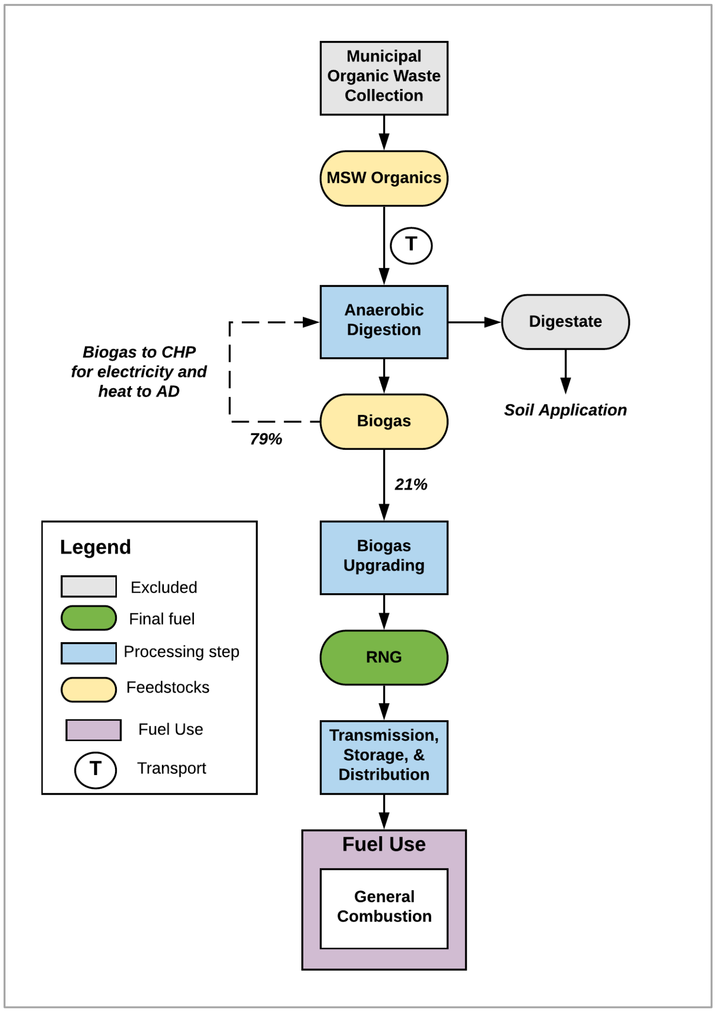

Figure 17. System boundaries for production of RNG from MSW organics.

Upgrading of Biogas to RNG

The upgrading process for biogas from anaerobic digestion of organics from MSW was assumed to be the same as that for WWT sludge and is based on an average Canadian process developed from a limited sample of Canadian producers and supplemented with literature data (CIRAIG, 2019). A summary of this process is provided in the previous section.

RNG Distribution and Combustion

Since there are no data available on established Canadian production and distribution supply chains for RNG, it was assumed that fuel distribution to end users would be equivalent to distribution of conventional natural gas modelled in Milestone 2 (EarthShift Global, WSP, Introspective Systems, 2019b). This is a reasonable assumption since it is expected that RNG would replace conventional natural gas in current distribution and use infrastructure.

Primary data were not available on the combustion emissions from RNG. Since the carbon contained in the fuel is biogenic, it is excluded from the CI calculations. Estimates of methane and nitrous oxide emissions associated with combustion of RNG were obtained from a summary of emissions factors for the British Columbia renewable fuels regulation (British Columbia Ministry of Environment and Climate Change Strategy, 2017). It is noted that methane and nitrous oxide emissions could vary depending on the efficiency of combustion, which is not reflected in this average case.

8.3.3 Carbon Intensity of RNG from MSW Organics

The carbon intensity results for RNG produced from anaerobic digestion and upgrading of MSW organics are summarized in Table 73. For this average default pathway, the CI is estimated to be approximately 26 g of CO_2 eq. per MJ of fuel (HHV), which is approximately 61% lower than the CI estimated for conventional natural gas (67 g CO_2 eq./MJ). The primary contributor to the life cycle GHG emissions of the pathway is the anaerobic digestion of the organics, accounting for 38% of life cycle GHG emissions. The CI of biogas upgrading is noted to be higher than upgrading of landfill gas because the incoming biogas is assumed to have a higher methane content and thus emissions of unflared methane are higher. Feedstock transport also makes a significant contribution to total life cycle GHG emissions, accounting for 25% of emissions. This is because the organics have a high moisture content when transported to the RNG facility.

Table 73. Carbon intensity results for RNG produced from MSW organics, expressed in g CO_2 eq. per MJ of RNG (HHV).

Life Cycle Stage	Amount	Unit
Feedstock transport to RNG facility	6.6	g CO_2 eq./MJ
Anaerobic digestion	10	g CO_2 eq./MJ
Biogas upgrading	8.1	g CO_2 eq./MJ
Transport & Distribution	0.6	g CO_2 eq./MJ
Combustion	0.3	g CO_2 eq./MJ
Total	**26**	**g CO_2 eq./MJ**

Results of the uncertainty analysis for RNG produced from MSW organics are provided later in this section and also in the violin plots in Section 12.

8.4 RNG from Livestock Manure

8.4.1 System Boundaries and Descriptions for RNG from Livestock Manure

Biogas can also be generated from the anaerobic digestion of livestock manure. Livestock manure contains high concentrations of nutrients that are useful for enhancing soil health and fertility. As such, conventional practice for livestock manure management on Canadian farms is to store the manure and apply it to agricultural fields as a soil amendment, with over 3.4 million hectares of land receiving animal manure as an amendment each year (Beef Cattle Research Council, 2016). The type of storage, length of storage, and the rate of seasonal application of manure will vary depending on the location and type of livestock operation (Beaulieu, 2004). As an alternative to storage and direct soil application through which much of biogas is lost, low carbon fuel producers can process livestock manure and convert it to RNG through a process of anaerobic digestion and upgrading. Through the anaerobic digestion process, the biogas produced can be captured and used for energy as well as directed to RNG upgrading, and the digestate produced from anaerobic digestion can be used as a soil amendment. This potential to capture and use the biogas as an alternative to fossil fuels has brought interest to this feedstock, although a survey of Canadian RNG producers in 2019 indicated only two facilities are currently producing RNG from livestock manure, with a third expected to begin operation within the next two years.

Since the manure is a waste product originating from livestock rearing, no GHG emissions associated with upstream activities such as feeding and rearing livestock or collection of manure on the farm are attributed to it, which is consistent with assumptions used in the GREET LCA model (Lee U. , Han, Demirtas, Wang, & Tao, 2016).

The system boundary for the life cycle carbon intensity of RNG from livestock manure therefore begins with the transport of manure to an RNG facility (Figure 18). The unit process building blocks for this process include:

- Transport of manure to an RNG facility;
- Anaerobic digestion of the manure to produce biogas and digestate;
- Upgrading of biogas to RNG;
- Distribution and storage in the natural gas system; and
- Combustion.

8.4.2 Modelling and Life Cycle Inventory

Transport of Organics

Livestock manure produced from Canadian farms is assumed to be transported to an RNG producer using an average diesel truck (as modelled in Milestone 2). The moisture content of the manure is assumed to be 88% (Lee U. , Han, Demirtas, Wang, & Tao, 2016), and the dry mass and mass of the moisture are accounted for in calculating the emissions from feedstock transport. Based on data compiled by CIRAIG, it requires 1.196 kg (dry mass) of feedstock to yield 1 m^3 of biogas from anaerobic digestion. At 88% moisture content this requires that 2.25 kg of wet manure be transported to the facility for every m^3 of biogas produced. Since there are no current data available on existing supply chains for producers of RNG from manure in Canada, the feedstock transport distance is assumed to be 50 km. Users of the Fuel LCA Modelling Tool can modify this transport distance and/or add additional transport modes and distances to align with more specific supply chain configurations in the future. Users can also update the transport calculations to reflect alternative moisture content data in the future.

Anaerobic Digestion

The anaerobic digestion process to convert livestock manure to biogas for RNG production was assumed to be the same as the process for WWT sludge. This is a simplifying assumption that was required due to the low-resolution inventory data available from the CIRAIG study which did not allow for the characterization of unique anaerobic digestion processes specific to the incoming feedstock type. A summary of the average Canadian anaerobic digestion process is provided in Section 8.2.

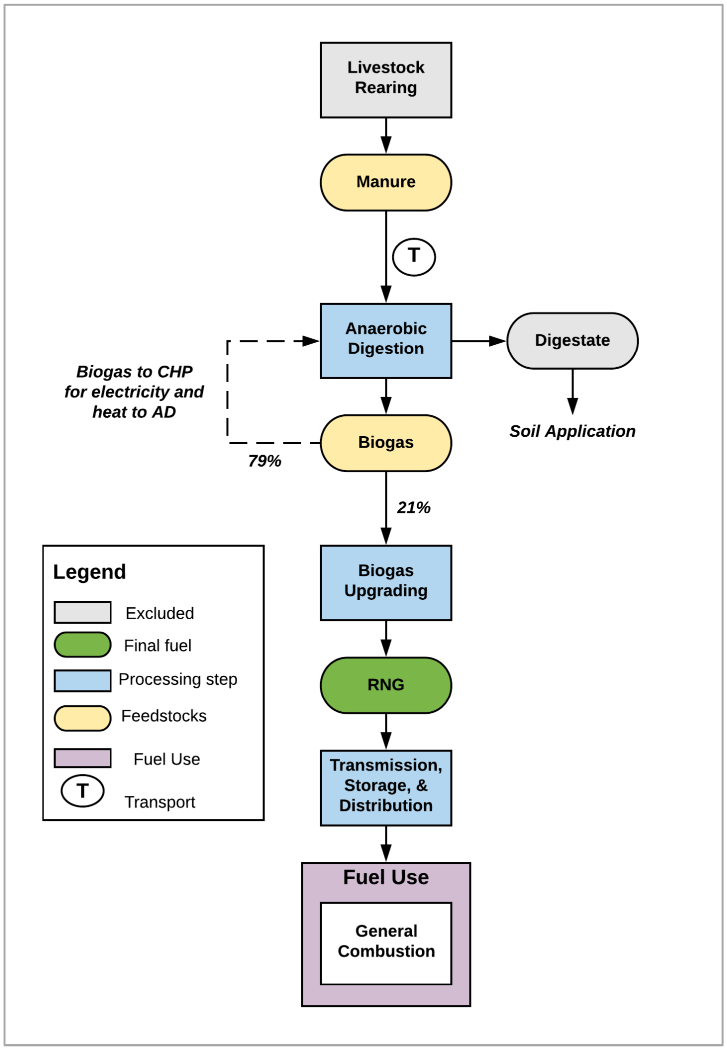

Figure 18. System boundaries for production of RNG from manure.

Upgrading of Biogas to RNG

The upgrading process for biogas from anaerobic digestion of livestock manure was assumed to be the same as that for WWT sludge and is based on an average Canadian process developed from a limited sample of Canadian producers and supplemented with literature data (CIRAIG, 2019). A summary of this process is provided in Section 8.2.

RNG Distribution and Combustion

Since there are no data available on established Canadian production and distribution supply chains for RNG, it was assumed that fuel distribution to end users would be equivalent to distribution of conventional natural gas modelled in Milestone 2 (EarthShift Global, WSP, Introspective Systems, 2019b). This is a reasonable assumption since it is expected that RNG would replace conventional natural gas in current distribution and use infrastructure.

Primary data were not available on the combustion emissions from RNG. Since the carbon contained in the fuel is biogenic, it is excluded from the CI calculations. Estimates of methane and nitrous oxide emissions associated with combustion of RNG were obtained from a summary of emissions factors for the British Columbia renewable fuels regulation (British Columbia Ministry of Environment and Climate Change Strategy, 2017). It is noted that methane and nitrous oxide emissions could vary depending on the efficiency of combustion, which is not reflected in this average case.

8.4.3 Carbon Intensity of RNG from WWT Sludge

The carbon intensity results for RNG produced from anaerobic digestion and upgrading of livestock manure are summarized in Table 76. For this average default pathway, the CI is estimated to be approximately 27 g of CO_2 eq. per MJ of fuel (HHV), which is approximately 60% lower than the CI estimated for conventional natural gas (67 g CO_2 eq./MJ). The primary contributor to the life cycle GHG emissions of the pathway is the anaerobic digestion of the organics, accounting for 37% of life cycle GHG emissions. The CI of biogas upgrading is noted to be higher than upgrading of landfill gas because the incoming biogas is assumed to have a higher methane content and thus emissions of unflared methane are higher. Feedstock transport also makes a significant contribution to total life cycle GHG emissions, accounting for 29% of emissions. This is because the manure has a high moisture content when transported to the RNG facility.

Table 74. Carbon intensity results for RNG produced from MSW organics, expressed in g CO_2 eq. per MJ of RNG (HHV).

Life Cycle Stage	Amount	Unit
Feedstock transport to RNG facility	7.9	g CO_2 eq./MJ
Anaerobic digestion	10	g CO_2 eq./MJ
Biogas upgrading	8.1	g CO_2 eq./MJ
Transport & Distribution	0.6	g CO_2 eq./MJ
Combustion	0.3	g CO_2 eq./MJ
Total	**27**	**g CO_2 eq./MJ**

8.5 Uncertainty Results for RNG

Uncertainty analysis was conducted for each of the four RNG pathways based on data quality and fit for purpose evaluations of the LCI data. Results of the Monte Carlo analysis indicate that the potential range for the CI of RNG from landfill gas is relatively tight, while the ranges for anaerobic digestion and upgrading of three different organic streams are considerably wider, particularly for the upper end of the range. This uncertainty is due to a number of factors, including the lack of specific data on the anaerobic digestion process that would be required for each different feedstock, and the potential variability in methane emissions from digestion and upgrading due to differences in practices and methane content of the biogas.

The uncertainty of the results for the RNG pathways is also shown in the violin plots in Section 12 of the report, including a comparison with the baseline CI value for conventional natural gas.

Table 75. Uncertainty analysis results for average Canadian RNG. Results based on Monte Carlo analysis with a confidence interval of 95%.

Final CI	Mean	Median	SD	Min (2.5%)	Max (97.5%)
Landfill Gas					
6.0	7.0	6.83	1.71	4.41	10.9
WWT Sludge					
31.0	38.4	37.1	10	22.6	61.6
MSW Organics					
26.4	37.2	36.1	9.7	22.5	59.6
Livestock Manure					
27.3	38.4	37.2	9.96	23.0	60.6

8.6 Data Gaps and Limitations for RNG

One of the key data gaps for RNG production in Canada is data on the specific anaerobic digestion processes that would be used for each type of organic feedstock. The data provided by CIRAIG on an average Canadian anaerobic digestion process are based on a small sample of RNG producers and are supplemented with literature values. These data are suitable for establishing an average base case unit process; however, there is considerable variability in the types of anaerobic digestion systems that could be used, and that may need to be used to accommodate specific feedstock types. More detailed work on anaerobic digestion in the GREET model indicate that the material and energy balance can vary substantially depending on the system used (Lee, Han, & Wang, 2016). There may also be variability in the material and energy inputs required for upgrading of different sources of biogas, and similar to anaerobic digestion, our model is currently limited to a single, average Canadian process based on data from a limited number of producers and supplemented with literature data. The reliance on these single average processes results in a lack of differentiation between RNG produced from different organic feedstocks, and this may not be reflective of actual conditions. It is likely that users of the Fuel LCA Modelling Tool will be able to supply data for their own anaerobic digestion and upgrading technologies and can therefore improve upon the average data used here. As such, the current CI results are generally limited to these average RNG pathways, and the uncertainty ranges provided should be used as upper and lower ranges of possible outcomes depending on variations in the technology and feedstock characteristics.

9. Hydrogen

9.1 System Boundaries and Technical Descriptions for Hydrogen Fuels

Hydrogen is currently produced globally in a variety of industrial processes as either a primary or secondary product, or in some cases as a waste product to be vented or flared to the atmosphere (Simons & Bauer, 2011). It has a wide range of physical and chemical applications, including use as a reactant in the petroleum and chemical industries, for upgrading heavy oil in oil sands applications, and to produce ammonia and methanol. It also has several engineering applications in the automotive, power generation, aerospace and telecommunications industries (Natural Resources Canada, 2015). There is considerable interest in hydrogen as a transportation fuel since there are no pollutants or GHGs emitted from hydrogen combustion.

Hydrogen is both an energy carrier and an energy source, and it is being increasingly developed for energy applications such as fuel cell electric vehicles (FCEVs). As an energy carrier, hydrogen is produced directly or indirectly from other energy sources such as fossil fuels, nuclear, hydro, solar, or wind power. The majority of hydrogen currently produced in North America is produced by steam-methane reforming (SMR), a process in which high-temperature steam is used to produce hydrogen from methane contained in sources such as natural gas. Globally, the production of hydrogen is primarily done via SMR; however, there is increasing interest in producing hydrogen from renewable sources (Olateju, Kumar, & Secanell, 2016). Methods for producing hydrogen fuel include biomass conversion, SMR of bio-based materials, and water splitting by photocatalysis, thermochemical cycles, and electrolysis. Hydrogen produced as a co-product in other processes may also be captured and used at the site of production or stored for use as a transportation fuel.

Despite growing interest in this sector, there is currently very little commercial scale production of hydrogen fuels for energy applications in Canada, although with a large and growing research and development industry, this is expected to change (MNP, 2018). Given the expected increases in development of hydrogen as a renewable fuel in Canada in the coming years, the Fuel LCA Modelling Tool for the Clean Fuel Standard (CFS) will include selected hydrogen production pathways to establish building blocks for policy makers and low carbon fuel producers to use as the industry develops. The hydrogen fuel pathways that will be included in the Fuel LCA Modelling Tool are summarized in Table 76.

Table 76. Summary of hydrogen fuel pathways including descriptions of fuel feedstock source, conversion processes, process outputs, and expected end use to be modelled.

Feedstock	Conversion Process	Outputs	End Use
• Fossil natural gas	• Steam methane reforming (SMR)	• Hydrogen • Carbon monoxide • Carbon dioxide	• Fuel cell
• Renewable natural gas (RNG)*	• Steam methane reforming (SMR)	• Hydrogen • Carbon monoxide • Carbon dioxide	• Fuel cell
• Water	• Electrolysis	• Hydrogen • Oxygen	• Fuel cell

Syngas (wood biomass, other)	Gasification Catalytic reaction	Hydrogen Carbon monoxide Carbon dioxide	Fuel cell

**RNG includes natural gas produced from biogenic sources such as landfill gas*

Further descriptions of these fuels are provided in Section 9.1.1. An overview of the modelling approach for hydrogen fuels is provided in Section 9.2, and a summary of the data sources used to develop the LCI for these fuels is provided in Section 9.3.

There are a number of existing and emerging technologies in different stages of development and deployment for producing hydrogen gas for energy applications. For the purposes of the Fuel LCA Modelling Tool, we have chosen to model three basic production technologies and one energy application in order to establish the modelling building blocks for hydrogen fuels for users of the tool, and to establish default carbon intensity values for average Canadian hydrogen energy. These production processes were selected because of their current or expected use and also based on data availability. SMR is currently the dominant technology for hydrogen production in Canada (Salkuyeh, Saville, & MacLean, 2017), while interest in electrolysis is growing with a large new facility proposed for production in Québec (Air Liquide, 2019). Hydrogen from syngas was selected to provide coverage of a technology using an alternative feedstock, in this case wood biomass.

The general system boundaries for hydrogen fuels are shown in Figure 19, and include feedstock production, fuel conversion through the three selected technologies, fuel storage, transmission and dispensing, and fuel use in a hydrogen fuel cell. The use of hydrogen in fuel cells is a zero-emissions process, so that no GHG emissions are associated with hydrogen's use in a fuel cell to power a vehicle or other energy applications. More detailed descriptions of the life cycle stages for hydrogen fuels are provided in the following sections.

9.1.1 Hydrogen Production

The three hydrogen production technologies modelled for the Fuel LCA Modelling Tool are based on systems modeled by the National Renewable Energy Technology (NREL) program in the U.S. using background reports and Aspen modelling software. Because there are few large-scale operating facilities, they are based on projected production scenarios for existing technologies at different scales for different technologies. The technical descriptions below are summaries based on the NREL reports from 2013 (Ramsden, Ruth, Diakov, Laffen, & Timbario, 2013) and 2009 (Ruth, Laffen, & Timbario, 2009) from NREL.

Steam Methane Reforming (SMR)

The majority of hydrogen currently produced in North America is produced by SMR, a process in which high-temperature steam is used to produce hydrogen from a methane source, such as natural gas. Methane reacts with steam in the presence of a catalyst to produce hydrogen, carbon monoxide, and carbon dioxide. The carbon monoxide and steam are reacted using a catalyst to produce carbon dioxide and more hydrogen, followed by pressure-swing adsorption during which carbon dioxide and other impurities are removed to produce pure hydrogen. This process can also be used to produce hydrogen from other fuels such as ethanol, propane, or gasoline.

There are many SMR technologies available depending on the required scale of production and intended applications for the hydrogen produced. For the purposes of establishing basic SMR pathways for the Fuel LCA Modelling Tool, we have modelled a centralized SMR system that uses pipeline natural gas as feedstock, such that this pathway links up well with the work in Milestone 2 in which we modelled Canadian average pipeline natural gas.

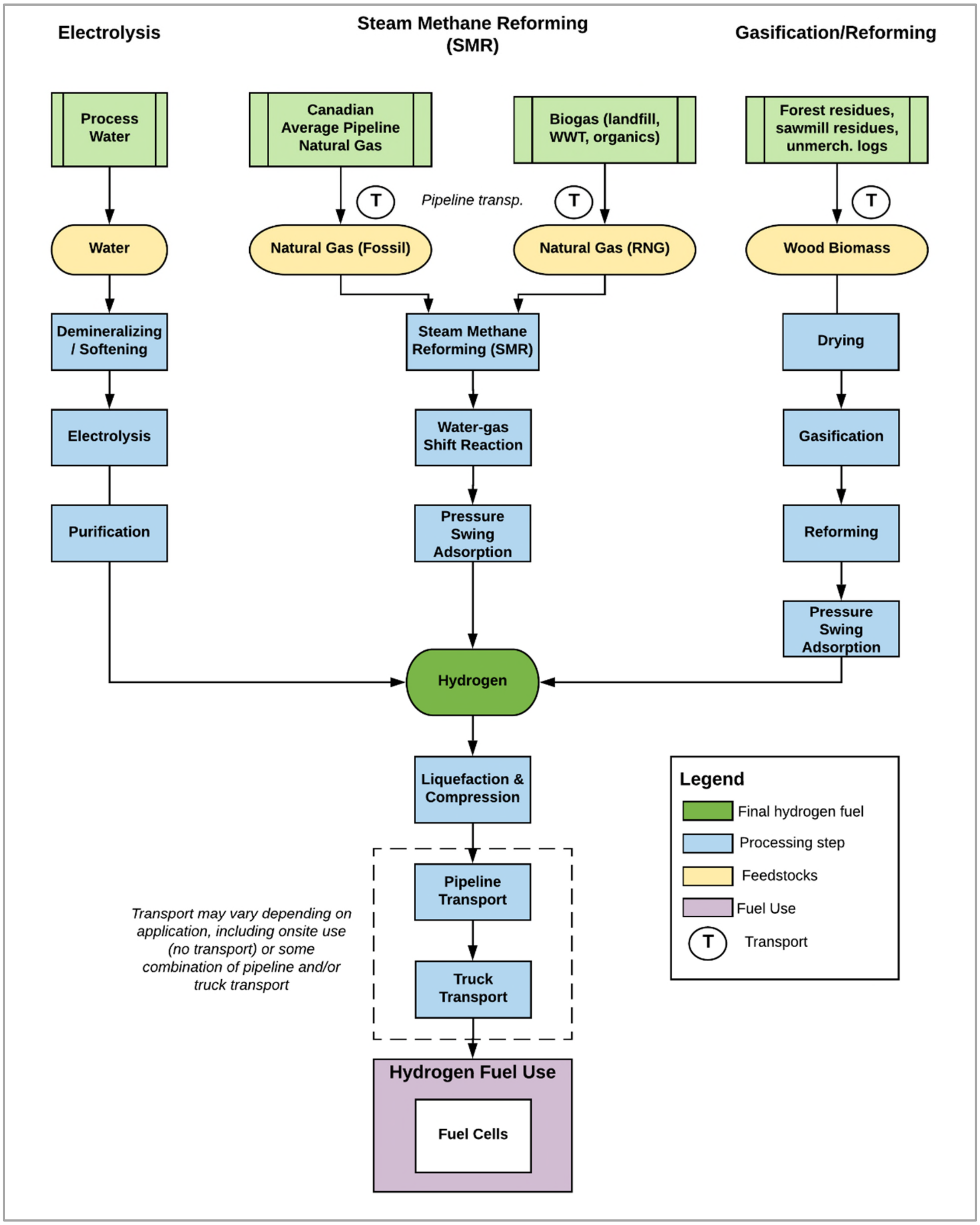

Figure 19. System boundaries and life cycle activities from extraction to use for hydrogen fuels derived from electrolysis of water, SMR of natural gas, and gasification/reforming of syngas from woody biomass.

This SMR system begins with natural gas being fed to the SMR plant via pipeline at a pressure of 450 psia. The natural gas is cleaned to remove any sulphur and then mixed with process steam and reacted over a nickel-based catalyst. This reforming reaction converts the methane to a mixture of CO and H_2 and is powered by offgas from the process and a small amount of natural gas (~10% of heating value of the offgas). Reforming is followed by a water-gas shift which converts the majority of the CO into CO_2 and H_2 (Ruth, Laffen, & Timbario, 2009). A pressure swing adsorption process is used to separate hydrogen from the other components in the shifted gas, with a part of the hydrogen product being recycled back into the adsorber to increase hydrogen concentration. Lastly, the CO and H_2 passes through a heat recovery step and is fed into a water-gas shift reactor to produce additional H_2 (Ruth, Laffen, & Timbario, 2009). The source of natural gas feedstock for SMR can either be from fossil natural gas or renewable natural gas (RNG). We will model both feedstocks for the Fuel LCA Modelling tool, basing feedstock production on pipeline natural gas as modelled in Milestone 2 (EarthShift Global, WSP, Introspective Systems, 2019b), and RNG as modelled in Milestone 3[14].

Electrolysis

Hydrogen fuel can also be produced from electrolysis. Electrolysis is the process of using electricity to separate water into hydrogen and oxygen in an electrolyzer. There are three primary types of electrolysis process used in hydrogen production, including (USOEERE, 2018):

- Alkaline – hydrogen gas is formed by passing electrons through an alkaline solution of sodium or potassium hydroxide mixed with water to form an electrolyte. A membrane is used to separate the anode from the cathode which separates the gases.
- Polymer Electrolyte Membrane - In this case, the electrolyte is a solid polymer and also acts as the membrane. Hydrogen ions flow through the polymer and combine with electrons at the cathode. Oxygen is collected at the anode.
- Solid Oxide – The solid oxide is again a solid electrolyte. In this case, steam combines with electrons at high temperature (500-800 degrees C) at the porous cathode to form hydrogen gas which passes through the cathode to be collected. The negatively charged oxygen ions pass through the solid electrolyte and react at the anode to form oxygen gas.

Similar to SMR, there are many different electrolysis technologies available to produce hydrogen using a number of different energy sources and sources of water. For the purposes of establishing a basic electrolysis pathway in the Fuel LCA Modelling Tool, we have modelled a centralized electrolysis plant using an alkaline process powered by grid electricity and using potassium hydroxide (KOH) as the electrolyte. This process represents a scaled-up version of a distributed electrolysis technology (1,500 kg hydrogen/day) with a production capacity of 52,300 kg/day (Ramsden, Ruth, Diakov, Laffen, & Timbario, 2013). Process water is demineralized and softened before being passed into the electrolyzer. The electrolyzer produces hydrogen and oxygen which are collected and fed into a gas/lye (KOH) separator system. The lye is produced and re-used within a closed-loop cycle. Saturated hydrogen gas from the hydrogen/lye separator is fed to a gas scrubber subsystem which purifies the hydrogen. The hydrogen gas is held in a small gas holder unit and is compressed to 435 psig. Following compression, the residual

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[14] The modelling of RNG is delayed until August/September of 2019 while a separate contractor collects data from Canadian RNG producers. At that time, the RNG hydrogen pathway will be completed.

oxygen is removed by the deoxidizer unit and the hydrogen gas is then dried and exits the process at 99.9998% purity (Ruth, Laffen, & Timbario, 2009).

Gasification and Reforming

Hydrogen can be produced from syngas that is derived from several different feedstocks, and there are several different types of technologies that can be used to convert syngas to hydrogen gas. For the purposes of the Fuel LCA Modelling Tool, we have modelled a system which converts woody biomass to hydrogen via a series of process steps, including gasification, catalytic steam reforming, and purification (Ruth, Laffen, & Timbario, 2009). This process was chosen because data were readily available and because the conversion process could be easily connected with existing wood biomass feedstock processes in the Fuel LCA Modelling Tool. In this conversion process, the incoming woody biomass is dried to 12% moisture content using a rotary dryer. The rotary dryer is powered primarily by the combustion of char that is produced during the gasification process. The endothermic gasification unit is powered by circulation of hot synthetic olivine, and the resulting gas is passed through cyclone separators to remove particulates, ash, and sand. Following gasification, the gas is passed through a similar process of reforming and water-gas shift reactions that is used in SMR technology. An adsorber unit is used to separate the hydrogen from the other components in the shifted gas stream (primarily CO_2 and unreacted CO, CH_4, and other hydrocarbons) (Ramsden, Ruth, Diakov, Laffen, & Timbario, 2013).

9.1.2 Distribution

Distribution of hydrogen gas from the production facility to the end user can be done by pipeline, truck, or some combination of the two modes. A transmission pipeline would extend from the production facility to the “city gate”, or some central distribution point from which the hydrogen is transported to the end user via truck. The pipeline system requires a compressor to increase hydrogen pressure from its production level to the pressure at the terminus of the transmission line (Ramsden, Ruth, Diakov, Laffen, & Timbario, 2013). Storage is assumed to be done using geologic formations that are adjacent to the production facility. A compressor is used to extract the hydrogen from storage and push it into the pipeline.

Truck transport of gaseous hydrogen involves the storage of hydrogen, the extraction of hydrogen from storage with a compressor, and transport in a tube trailer truck. Transport of liquid hydrogen by truck involves liquefaction of the hydrogen prior to transport, storage of liquid hydrogen in cryogenic storage tanks and transport via cryogenic trucks. The liquefaction of hydrogen is assumed to be powered by grid electricity. In the Fuel LCA Modelling Tool, the user will be able to modify this to other energy sources such as natural gas or other fuels.

Note: As hydrogen is extremely flammable and can be explosive when exposed to air in enclosed areas, hydrogen sensors are likely to be used at many places in the production, transmission and distribution facilities. As the sensors are considered to be part of the infrastructure, they are excluded from the inventory.

In some instances, hydrogen production may be done onsite, and distribution would not be required, for example if an electrolyzer is installed onsite.

9.1.3 Hydrogen Use

Hydrogen use is assumed to be in proton exchange membrane fuel cells for vehicle transportation. These cells operate essentially the same as the polymer electrolyte membrane electrolysis process in reverse, so instead of requiring electricity and water to create hydrogen, hydrogen is used to create electricity and water (Dhanushkodi, Mahinpey, Srinivasan, & Wilson, 2008). Therefore, there are no direct greenhouse gas emissions associated with use of hydrogen in fuel cell technology (Ahmadi & Kjeang, 2016) .

Use scenarios in the Fuel LCA Modelling Tool will be defined by the user locations and transmission and distribution distances.

Based on data from GREET, Table 77 summarizes some key parameters for final hydrogen fuel (Harrison, Remick, Martin, & Hoskin, 2010).

Table 77. Energy content and density values for gaseous hydrogen

Property	By Volume	By Mass
HHV	12.8 MJ/m^3	141.9 MJ/kg
Density	90.1 g/m^3	-

9.2 Modelling Approach for Hydrogen Fuels

The following sections provide a brief overview of the modelling approach for hydrogen fuels, as well as discussion of some key methodological issues to be addressed in the modelling.

9.2.1 Development of Unit Process Building Blocks

The modelling work in Milestone 3 relies heavily on fossil fuel unit processes that were developed in Milestone 2, including natural gas as an input to SMR production of hydrogen, fuel inputs to operate machinery and equipment (e.g. diesel, natural gas, etc.) and transportation processes (e.g. trucks, rail, pipelines). In addition, unit processes for wood biomass feedstocks and RNG feedstocks that are being developed in Milestone 3 will be used as building blocks in the hydrogen fuel pathways. These unit processes were used to model average hydrogen production. In addition, these unit process building blocks will be available in the ECCC Fuels database and can be incorporated into the hydrogen fuel pathway models or other pathways as needed.

9.2.2 Regional Variation

At present there is very little commercial production of hydrogen fuel specifically for energy applications in Canada, although hydrogen produced from existing commercial scale operations could be used in fuel cells or injected in pipelines to be blended as a fuel. The primary aspect of hydrogen production that will vary from region to region is the background energy system, such as variations in electricity grids providing energy to fuel conversion and compression processes. In addition, the provision of feedstocks for hydrogen production may vary from region to region within Canada, for example differences in carbon intensity for production of RNG or wood biomass feedstocks. The sourcing of regional/provincial feedstocks could also influence transport distances and modes for feedstock delivery and final fuel delivery.

For the development of default carbon intensity values for Canadian hydrogen fuels, average Canadian conditions and energy sources were used. Beyond these default calculations, users will have the ability to copy and modify the default processes and use alternative building blocks available in the tool (e.g. provincial electricity grid, a different wood biomass feedstock) and/or build new unit processes to pull into the hydrogen pathway models.

A number of basic building blocks are available in the Fuel LCA Modelling Tool to allow users to represent these differences in the modelling as much as possible within the confines of the available data. For example, forest harvesting data is available only for Western and Eastern Canada, and not a provincial level. As such, the wood biomass feedstocks used in hydrogen production are based on a unit process from either of these two regions, or the unit process for Canadian average harvesting. With respect to background energy systems, electricity grid carbon intensities are available at a provincial level based on work completed in Milestone 2, as are some fuels (e.g. diesel), and can be incorporated into the unit processes available for hydrogen fuels. For example, in modelling the production of hydrogen from electrolysis in British Columbia, a user could copy the Canadian default pathway and change the electricity grid to British Columbia electricity to power the process. Differences in regional electricity grids will be particularly relevant for the electrolysis pathway, as electricity is a key input. Users will be able to choose between different electricity grids by province or can choose a specific direct electricity source in the modelling tool, for example to use electricity directly from wind power.

9.3 Life Cycle Inventory for Hydrogen Fuels

9.3.1 Steam Methane Reforming (SMR)

Feedstock Production

Production of hydrogen via SMR was modeled with both fossil natural gas and renewable natural gas feedstocks. The carbon intensity of the upstream production of fossil natural gas was obtained from the Canadian average pathway for pipeline specification natural gas modeled in Milestone 2 (EarthShift Global, WSP, Introspective Systems, 2019b). This includes the extraction, processing, and transmission of fossil natural gas from Western Canada to hydrogen production locations via pipeline. For the purposes of the current version of the report, a recently published carbon intensity value for RNG in Canada was used to characterize the carbon intensity of producing RNG. In April of 2019, RNG produced by FortisBC was added to the Low Carbon Fuel Standard in British Columbia with a verified CI of 11 g CO_2 eq. per MJ (CISION, 2019). This RNG is produced from biogas derived from municipal organic waste in landfills and from farm wastes. Since the carbon contained in RNG is considered biogenic, the process emissions of carbon dioxide are excluded from the CI calculation. From the production gate, RNG is assumed to follow the same transmission path to hydrogen producers as fossil natural gas (i.e. average Canadian storage and pipeline transmission). The final carbon intensity of the upstream production of RNG will be obtained from the Milestone 3 modelling work that will be completed separately based on data collected by another ECCC contractor. This work will include multiple sources of RNG that can be incorporated into the Fuel LCA Modelling Tool, and is expected to be completed in August 2019.

Fuel Conversion

At present there are no publicly available Canadian-specific LCI data to model production of hydrogen gas via SMR of natural gas. The conversion of both fossil natural gas and renewable natural gas to hydrogen using SMR were modeled using data compiled by the National Renewable Energy Laboratory (NREL) in the U.S. for a centralized SMR facility using natural gas delivered by pipeline (Ramsden, Ruth, Diakov, Laffen, & Timbario, 2013). Although the GHGenius calculator includes pathways for hydrogen from SMR, they are not Canadian-specific and are based primarily on literature sources and theoretical systems. It was determined that the NREL data are potentially more representative of recent systems.

The inputs for production of 1 kg and 1 MJ of hydrogen gas via a centralized facility for SMR of natural gas are summarized in Table 78 below.

Table 78. Process inputs for production of 1 kg and 1 MJ of hydrogen via SMR (Ramsden, Ruth, Diakov, Laffen, & Timbario, 2013).

Input	Per kg H_2	Per MJ H_2*
Hydrogen Production		
Natural gas (feedstock)	165 MJ	1.16 MJ
Electricity	0.57 kWh	0.004 kWh
Process water	3.36 gal	0.024 gal
Cooling water	1.50 gal	0.011 gal
Outputs		
Carbon dioxide (process)	12,060 g	85.1 g

**HHV of hydrogen gas is 141.9 MJ/kg, so 1 MJ of hydrogen is 0.007 kg*

The carbon intensities for electricity and natural gas were obtained from the results of the Milestone 2 work on carbon intensity of Canadian fossil fuels (EarthShift Global, WSP, Introspective Systems, 2019b). The default carbon intensity of hydrogen produced via SMR was modeled using a Canadian average electricity grid; however, users of the Fuel LCA Modelling tool will be able to modify the electricity source to calculate the carbon intensity for hydrogen production in different provinces.

9.3.2 Electrolysis

At present there are no publicly available Canadian-specific LCI data to model production of hydrogen gas via electrolysis of water. The conversion of water to hydrogen using electrolysis was modeled using data compiled by the National Renewable Energy Laboratory (NREL) in the U.S. for a centralized electrolysis facility powered by grid electricity (Ramsden, Ruth, Diakov, Laffen, & Timbario, 2013).

The process inputs for production of 1 kg and 1 MJ of hydrogen via a centralized facility for electrolysis are summarized in Table 79 below.

Table 79. Process inputs per kg and MJ of hydrogen produced via electrolysis (Ramsden, Ruth, Diakov, Laffen, & Timbario, 2013).

Input	Per kg H_2	Per MJ H_2*
Hydrogen Production		
Electricity	50 kWh	0.35 kWh
Process water	2.94 gal	0.021 gal
Cooling water	0.11 gal	0.00077 gal

**HHV of hydrogen gas is 141.9 MJ/kg, so 1 MJ of hydrogen is 0.007 kg*

The carbon intensity for grid electricity was obtained from the results of the Milestone 2 work on carbon intensity of Canadian fossil fuels (EarthShift Global, WSP, Introspective Systems, 2019b).

The default carbon intensity of hydrogen produced via electrolysis was modeled using a Canadian average electricity grid, as well as for two specific provincial grids to show the potential variability of the CI based on the nature of the grid. In addition, users of the Fuel LCA Modelling tool will be able to modify the electricity source to calculate the carbon intensity for hydrogen production in different provinces, or using direct electricity sources to the electrolyzer such as wind power.

9.3.3 Gasification/Reforming of Syngas

At present there are no publicly available Canadian-specific LCI data available to model production of hydrogen gas via reforming of syngas. The conversion of syngas to hydrogen was modeled using data compiled by the National Renewable Energy Laboratory (NREL) in the U.S. for a centralized facility for woody biomass gasification and reforming (Ramsden, Ruth, Diakov, Laffen, & Timbario, 2013).

The inputs for production of 1 kg and 1 MJ of hydrogen via a centralized facility for reforming of syngas from woody biomass are summarized in Table 80 below.

Table 80. Process inputs to production of 1 kg and 1 MJ of hydrogen via gasification and reforming of wood biomass (Ramsden, Ruth, Diakov, Laffen, & Timbario, 2013).

Input	Per kg H_2	Per MJ H_2*
Hydrogen Production		
Wood biomass (feedstock)	13.5 kg	0.095 kg
Natural gas	6.22 MJ	0.044 MJ
Electricity	0.98 kWh	0.0069 kWh
Process water	1.32 gal	0.009 gal
Cooling water	79.3 gal	0.56 gal
Outputs		
Carbon dioxide (process)**	30,720 g	216.5 g

**HHV of hydrogen gas is 141.9 MJ/kg, so 1 MJ of hydrogen is 0.007 kg*

***Process carbon dioxide emissions are from a biogenic source and are therefore excluded from the CI calculations*

The carbon intensity for grid electricity and natural gas were obtained from the results of the Milestone 2 work on carbon intensity of Canadian fossil fuels (EarthShift Global, WSP, Introspective Systems, 2019b), and the carbon intensity for production of the wood biomass feedstock were obtained from modelling work on low carbon solid fuels in Milestone 3, including sawdust from average Canadian sawmilling, wood chips from forest harvest residues, and wood chips from unmerchantable roundwood.

The default carbon intensity of hydrogen produced via reforming of syngas was modeled using a Canadian average electricity grid and Canadian average wood biomass feedstocks; however, users of the Fuel LCA Modelling tool will be able to modify the electricity source to calculate the carbon intensity for hydrogen production in different provinces, or choose wood biomass feedstocks specifically from Western or Eastern Canada.

9.3.4 Distribution

Transmission of the natural gas is modeled as part of the Canadian average natural gas detailed in Milestone 2. Given the early stage of hydrogen fuel development for energy applications in Canada, there are no established hydrogen pipeline distribution networks in Canada, and relatively small distribution networks via truck. Depending on the facility type, size, and location, the distribution of hydrogen could be done via pipeline and/or truck, and truck transport could be done for gaseous hydrogen or liquid hydrogen. For the purposes of establishing low carbon fuel pathway templates, we have modeled generic transmission distances of 100 km via each of the possible methods to establish building blocks for these activities in the model. For the default Canadian average hydrogen results we have assumed transport by gas truck.

Once delivered to service stations, there is also energy consumption associated with the storage, compression, and dispensing of hydrogen fuel. The LCI data for different forms of transmission, distribution, and fuel dispensing were obtained from NREL in the U.S. (Ramsden, Ruth, Diakov, Laffen, & Timbario, 2013) and are summarized in Table 81 below.

Table 81. Energy inputs per kg and per MJ of hydrogen dispensed for hydrogen transmission via pipeline or truck and dispensing of hydrogen fuel at different types of fuel stations (Ramsden, Ruth, Diakov, Laffen, & Timbario, 2013).

Input	Per kg H_2	Per MJ H_2*
Pipeline Transmission		
Electricity – compressor	0.56 kWh	0.0039 kWh
Electricity – storage	0.01 kWh	0.00007
Truck Transport (gaseous)		
Electricity – terminal	1.31 kWh	0.92 kWh
Electricity – storage	0.01 kWh	0.00007 kWh
Diesel – truck	0.0589 gal	0.0004 gal
Truck Transport (liquid)		
Electricity - liquefaction	8.5 kWh	0.060 kWh
Electricity – terminal	0.03 kWh	0.00021 kWh
Diesel - truck	0.0076 gal	0.00005 gal
Dispensing		
Station – distributed from pipeline (300 psi)	4.4 kWh	0.031 kWh
Station – centralized from pipeline (300 psi)	4.4 kWh	0.031 kWh
Central – 220 psi inlet pressure	2.1 kWh	0.015 kWh
Central - gaseous	0.51 kWh	0.0036 kWh
Cryo-compressed dispensing	0.49 kWh	0.0034 kWh

**HHV of hydrogen gas is 141.9 MJ/kg, so 1 MJ of hydrogen is 0.007 kg*

***Converted from 0.0589 gal of diesel based on HHV of diesel is 45.8 MJ/kg, density is 3.21 kg/gal*

The carbon intensity for electricity and diesel were obtained from the results of the Milestone 2 work on the carbon intensity of Canadian fossil fuels (EarthShift Global, WSP, Introspective Systems, 2019b).

9.4 Carbon Intensity Results for Hydrogen Fuels

Carbon intensity results for hydrogen fuels are summarized in the following sections, including comparative pathway results and contribution analysis results for each type of hydrogen production.

9.4.1 Steam Methane Reforming

The carbon intensity results for various pathways of hydrogen produced from SMR are summarized in Table 82, including SMR of fossil natural gas and SMR of RNG.

The CI value for Canadian average hydrogen produced from SMR of fossil natural gas is between 104 and 114 g CO_2 eq. per MJ. This value varies somewhat depending on the mode of fuel distribution, with the use of liquid truck delivery resulting in a higher CI of 114 g CO_2 eq. per MJ due to the extra step of liquefaction, the use of pipeline delivery resulting in a lower CI of 104 g CO_2 eq. per MJ, and the use of gas truck delivery resulting in a CI of 110 g CO_2 eq. per MJ.

Table 82. Canadian average carbon intensity values for hydrogen fuel produced from SMR from fossil natural gas and renewable natural gas with alternative transmission modes, expressed in g CO_2 eq./MJ of fuel used in a fuel cell.

Hydrogen Fuel Pathway	Carbon Intensity (g CO_2 eq./MJ)
SMR of Fossil Natural Gas	
Hydrogen, from SMR of natural gas, gas truck delivery	110
Hydrogen, from SMR of natural gas, liquid truck delivery	114
Hydrogen, from SMR of natural gas, pipeline transmission	104
SMR of Renewable Natural Gas (from landfill gas)	
Hydrogen, from SMR of RNG from landfill gas, gas truck delivery	15
Hydrogen, from SMR of RNG from landfill gas, liquid truck delivery	18
Hydrogen, from SMR of RNG from landfill gas, pipeline transmission	7.9

The CI value for Canadian average hydrogen produced from SMR of RNG from landfill ranges from 7.9 to 18 g CO_2 eq. per MJ, again depending on the distribution mode. Comparing the Canadian average CI for hydrogen from SMR using gas truck delivery, the use of RNG as the feedstock results in an 86% decrease in life cycle GHG emissions. This is due primarily to the exclusion of process carbon dioxide emissions for SMR of RNG due to their biogenic source.

Contribution analysis results for Canadian average hydrogen produced from SMR of fossil natural gas and RNG delivered by gas truck are summarized in Table 83. Direct emissions of carbon dioxide from the SMR process account for 77% of life cycle GHG emissions, followed by feedstock production and transport which accounts for approximately 15% of emissions. In contrast to hydrogen from SMR of fossil natural gas, the carbon intensity for hydrogen from RNG is mainly due to the production of the RNG feedstock, as direct process carbon dioxide emissions are excluded from the CI due to their biogenic nature. For all other aspects of the life cycle besides feedstock production and direct process emissions, the CI is the same.

Table 83. Contribution analysis of the Canadian average carbon intensity of hydrogen fuel produced from SMR from fossil natural gas delivered by gas truck, expressed in g CO_2 eq./MJ of fuel used in a fuel cell.

Life Cycle Stage	Fossil Natural Gas (g CO_2 eq./MJ)	Renewable Natural Gas (g CO_2 eq./MJ)
Natural gas (feedstock for SMR)	15	5.8
Natural gas feedstock transmission	0.8	0.8
Process electricity	0.7	0.7
Direct process carbon dioxide emissions*	85	0

Geological storage	0.01	0.01
Truck transport	7.4	7.4
Fuel dispensing	0.6	0.6
Total	**110**	**15**

**Note that there are direct process emissions of CO_2 during SMR of RNG, but they are from a biogenic source and are therefore excluded from the CI calculations.*

9.4.2 Electrolysis

The carbon intensity results for various pathways of hydrogen produced from electrolysis in Canada are summarized in Table 83Table 84, including production from different background electricity systems to demonstrate potential variability in the results.

Table 84. Carbon intensity values for hydrogen fuel produced from electrolysis from fossil natural gas and renewable natural gas with alternative transmission modes, expressed in g CO_2 eq./MJ of fuel used in a fuel cell.

Hydrogen Fuel Pathway	Carbon Intensity (g CO_2 eq./MJ)
Hydrogen from Electrolysis – Canadian Average	
Hydrogen, from electrolysis, pipeline transmission {CA}	65
Hydrogen, from electrolysis, liquid truck delivery {CA}	75
Hydrogen, from electrolysis, gas truck delivery {CA}	71
Hydrogen from Electrolysis – Alberta	
Hydrogen, from electrolysis, pipeline transmission {CA-AB}	350
Hydrogen, from electrolysis, liquid truck delivery {CA-AB}	406
Hydrogen, from electrolysis, gas truck delivery {CA-AB}	360
Hydrogen from Electrolysis – British Columbia	
Hydrogen, from electrolysis, pipeline transmission {CA-BC}	29
Hydrogen, from electrolysis, liquid truck delivery {CA-BC}	34
Hydrogen, from electrolysis, gas truck delivery {CA-BC}	36

The Canadian average CI for hydrogen from electrolysis is between 65 and 75 g CO_2 eq. per MJ, with the differences in CI being accounted for by different fuel transmission modes. These CI results are based on the use of electricity derived from the average Canadian electricity grid. Since electricity is the primary input to hydrogen production via electrolysis, the CI results are very sensitive to the electricity grid used. To demonstrate the potential variability, CI results are presented in Table 84 for a province with a fossil fuel-based grid (Alberta) and a hydropower-based grid (British Columbia). The results indicate that the CI of hydrogen from electrolysis could range from as low as 29 g CO_2 eq. per MJ up to 406 g CO_2 eq. per MJ.

The contribution analysis summarized in Table 85 reaffirms this observation about the importance of electricity source, showing that for hydrogen produced from electrolysis from a Canadian average grid, the upstream emissions from electricity production account for nearly 85% of life cycle GHG emissions. Results in this table also show the contribution analysis for hydrogen with liquid truck delivery, where liquefaction of hydrogen prior to distribution accounts for 14% of life cycle GHG emissions.

Table 85. Contribution analysis of the Canadian average carbon intensity of hydrogen fuel produced from electrolysis delivered by liquid truck, expressed in g CO_2 eq./MJ of fuel used in a fuel cell.

Life Cycle Stage	Carbon Intensity (g CO_2 eq./MJ)
Electricity - process	63
Geological storage	0.01
Liquefaction	11
Truck transport - liquid	0.07
Fuel dispensing	0.6
Total	**75**

9.4.3 Gasification and Reforming of Syngas

The carbon intensity results for various pathways of hydrogen produced from gasification and reforming of syngas from wood biomass in Canada are summarized in Table 86, including production from different sources of wood biomass feedstocks.

Table 86. Canadian average carbon intensity values for hydrogen fuel produced from gasification and reforming of various wood biomass feedstocks and alternative transmission modes, expressed in g CO_2 eq./MJ of fuel used in a fuel cell.

Hydrogen Fuel Pathway	Carbon Intensity (g CO_2 eq./MJ)
Hydrogen from Gasification and Reforming of Sawdust	
Hydrogen, from gasification and reforming, from sawdust, gas truck delivery	15
Hydrogen, from gasification and reforming, from sawdust, liquid truck delivery	19
Hydrogen, from gasification and reforming, from sawdust, pipeline transmission	8.4
Hydrogen from Gasification and Reforming of Harvest Residues	
Hydrogen, from gasification and reforming, from harvest residues, gas truck delivery	16
Hydrogen, from gasification and reforming, from harvest residues, liquid truck delivery	20
Hydrogen, from gasification and reforming, from harvest residues, pipeline transmission	9.8
Hydrogen from Gasification and Reforming of Unmerchantable Roundwood	
Hydrogen, from gasification and reforming, from unmerchantable roundwood, gas truck delivery	17
Hydrogen, from gasification and reforming, from unmerchantable roundwood, liquid truck delivery	21
Hydrogen, from gasification and reforming, from unmerchantable roundwood, pipeline transmission	10

Results show that the Canadian average CI for hydrogen produced from gasification and reforming of syngas from wood biomass ranges between 8.4 and 21 g CO_2 eq. per MJ depending on wood biomass feedstock source and final fuel transmission mode. The use of wood chips from harvest residues with fuel transmission via pipeline resulted in the lowest Canadian average CI, while the use of wood chips from unmerchantable logs with fuel transmission via liquid truck resulted in the highest Canadian average CI.

The contribution analysis for hydrogen produced from gasification and reforming of syngas from sawdust and transmitted via pipeline shown in Table 87 indicate that upstream emissions from the processing and delivery of sawdust from Canadian sawmills made the largest contribution to life cycle GHG emissions at approximately 45% of the total. It is also noted that biogenic carbon dioxide emissions from the reforming process were excluded from the CI calculations.

Table 87. Contribution analysis of the Canadian average carbon intensity of hydrogen fuel produced from gasification and reforming of syngas from sawdust and delivered by pipeline transmission, expressed in g CO_2 eq./MJ of fuel used in a fuel cell.

Hydrogen Fuel Pathway	Carbon Intensity (g CO_2 eq./MJ)
Sawdust feedstock	3.2
Natural gas - process	2.7
Electricity - process	1.2
Direct process carbon dioxide emissions*	0
Geological storage	0.01
Pipeline transmission	0.7
Fuel dispensing	0.6
Total	**8.4**

**Note that there are direct process emissions of CO_2, but they are from a biogenic source and are therefore excluded from the CI calculations.*

9.4.4 Uncertainty Analysis

Uncertainty analysis was conducted for Canadian average hydrogen using Monte Carlo analysis. Results of the uncertainty analysis for hydrogen are shown in the violin plots in Section 12 and discussed relative to the uncertainty of other low carbon fuels in that section. Below in Table 88 the key results of the uncertainty analysis for hydrogen from each of the three sources are summarized.

Table 88. Uncertainty analysis results for average Canada hydrogen fuel. Results based on Monte Carlo analysis with a confidence interval of 95%.

Final CI	Mean	Median	SD	Min (2.5%)	Max (97.5%)
Hydrogen, from electrolysis, gas truck delivery, {CA}					
71.2	74.1	72.6	17.6	45.4	116
Hydrogen, from SMR of natural gas, gas truck delivery {CA}					
110	112	111	12.8	89.1	138
Hydrogen, from SMR of RNG from landfill gas, gas truck delivery {CA}					
15	16.8	15.5	5.29	-0.082	123
Hydrogen, from gasification and reforming of syngas, from sawdust {CA}					
16.4	16.8	15.9	5.23	9.73	29.5

Results of the uncertainty analysis show that there is greater uncertainty around the result for hydrogen from electrolysis, which has a wider range of potential outcomes. This is due to the fact that the carbon intensity of hydrogen from electrolysis is heavily influenced by the background electricity grid and the efficiency of the electrolysis process and shifts in these inputs can push the results higher or lower significantly. The uncertainty for hydrogen from SMR of RNG is also high, due to the relative uncertainty in the CI of producing RNG from landfill gas, and coupled with the uncertainty around the SMR conversion technology for RNG sources.

9.4.5 Data Gaps and Limitations for Hydrogen Fuels

The limitations of modelling the CI for Canadian hydrogen fuels are largely based on the lack of commercial-scale activity in this sector which means that assumptions must be made about technology and about the structure of the industry. Changes in technology efficiency (e.g. of electrolysis), changes in feedstock and energy systems, and changes in fuel distribution could lead to significant differences in the CI of average hydrogen fuel in Canada. Fortunately, as these details evolve over time with growth in the industry, the basic building blocks are in place for the primary hydrogen production technologies and feedstocks to facilitate the building of new models to calculate more representative CI values for Canadian hydrogen production activities.

10. Solid Low Carbon Fuels

10.1 System Boundaries and Technical Descriptions for Solid Low Carbon Fuels

Solid fuels can be produced from several different feedstocks in Canada, including wood biomass, agricultural residues, and industrial and municipal solid wastes. These solid fuels typically take the form of energy-dense pellets but may also include raw material precursors and process co-products (e.g. wood chips, corn stover). Solid low carbon fuels are typically used as energy feedstocks in industrial boilers and furnaces, for institutional or residential space heating, and for small-scale and large-scale electricity generation in thermal power plants.

The solid low carbon fuels that will be included in the Fuel LCA Modelling Tool are summarized in Table 89. Most of these fuels are derived from wood biomass feedstocks of various types, with the one exception being corn stover.

Table 89. Summary of solid low carbon fuel pathways including descriptions of fuel feedstock source, conversion processes, process outputs, and expected end use to be modelled.

Fuel	Feedstock	Conversion Process	End Use
Grade A1 Wood Pellets	• Clean sawmill residues	• Drying • Pelletization	• Heating • Electricity
Grade A2/B1/B2 Wood Pellets	• Unmerchantable standing trees • Forest harvest residues • Other sawmill residues • Construction &Demolition (C&D) waste	• Chipping • Drying • Pelletization	• Heating • Electricity
Black wood pellets (thermally treated wood pellets)	• Unmerchantable standing trees • Forest harvest residues • Sawmill residues • Construction & Demolition (C&D) waste	• Steam treatment • Torrefaction • Pelletization	• Electricity
Wood chips	• Unmerchantable standing trees • Sawmill residues	• Chipping • Drying	• Heating
Crop residues	• Corn stover	• Drying • Pelletization	• Heating

Further descriptions of these fuels are provided in Section 10.1.1. An overview of the modelling approach for solid low carbon fuels is provided in Section 10.2, and a summary of the data sources that were used to develop the LCI for these fuels is provided in Section 10.3.

10.1.1 Wood Biomass Fuels

There are several low carbon fuel feedstocks produced at various points within the Canadian forest sector. The Canadian forest 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. Within this flow of wood fibre, a number of solid low carbon fuel feedstocks are produced, including:

- Wood chips produced directly from harvested forest biomass (roundwood);
- Wood chips produced from primary forest harvest residues (i.e. branches, tops, also called bush residual etc.);
- Wood chips or other residuals from sawmilling (e.g. wood chips, bark, sawdust, shavings, also called hog fuel if used on site); and
- Used wood obtained from construction and demolition (C&D) waste streams.

Some of these wood biomass feedstocks may be used directly for energy in forest sector applications (e.g. for drying energy in sawmills), as a source of heat or steam in other industrial applications, or used as feedstock by industries complimentary to the forest sector such as pellet mills to produce more energy-dense fuels with a wide range of applications from residential space heating to large-scale electricity generation.

The Canadian wood pellet industry is a growing sector of the economy that is largely export driven, with major markets in Europe, the United States, and increasingly Asia (Bradburn & Lakhdari, 2017). At the end of 2016 there were 30 operational wood pellet plants in Canada, and as of early 2019 there are 46 operational wood pellet plants in Canada. A summary of currently operation plants is provided in Table 90. Bulk pellets are produced primarily for export markets, while bagged pellets are produced primarily for domestic heating applications.

Although there are operational wood pellet plants in several Canadian provinces, approximately 70% of Canadian wood pellet production occurs in British Columbia, with other top producing provinces being Québec, Ontario, Alberta, and New Brunswick (Bradburn, 2014). At present there is no commercial-scale production of thermal treated (black) wood pellets.

Table 90. Operational wood pellet plants in Canada in 2019, shown by location, share of bulk vs. bagged pellet production, and annual capacity in metric tonnes (Canadian Biomass Magazine, 2019).

Plant Location	Province	Bulk/Bagged (%)	Capacity (tonnes/year)
Prince George	British Columbia	100/0	350,000
Armstrong	British Columbia	80/20	72,000
Burns Lake	British Columbia	100/0	380,000
Strathnaver	British Columbia	100/0	230,000
Williams Lake	British Columbia	100/0	210,000
Houston	British Columbia	100/0	230,000
Lavington	British Columbia	100/0	300,000
Smithers	British Columbia	100/0	125,000
Vanderhoof	British Columbia	90/10	185,000
Princeton	British Columbia	70/30	110,000
Vanderhoof	British Columbia	NA	30,000
Chetwynd	British Columbia	100/0	100,000
Fort St. John	British Columbia	100/0	75,000
Terrace	British Columbia	100/0	75,000
Entwistle	Alberta	100/0	400,000
Grande Cache	Alberta	60/40	15,000
Manning	Alberta	80/20	15,000
La Crete	Alberta	80/20	140,000
Slave Lake	Alberta	50/50	60,000
Swan River	Manitoba	100/0	2,000

Elm Creek	Manitoba	80/20	10,000
Atikokan	Ontario	90/10	110,000
Thunder Bay	Ontario	100/0	45,000
St. Marys	Ontario	60/40	10,000
Hearst	Ontario	15/85	15,000
Dunkalk	Ontario	25/75	15,000
Springford	Ontario	10/90	25,000
New Liskeard	Ontario	75/25	80,000
Becancour	Quebec	100/0	15,000
Lac-Megantic	Quebec	NA	120,000
Sacre-Coeur	Quebec	NA	25,000
St-Felicien	Quebec	5/95	120,000
Shawinigan-Suyd	Quebec	<1/99	55,000
St. Paulin	Quebec	NA	60,000
Papineauville	Quebec	NA	34,000
Saint-Hyacinthe	Quebec	<1/99	30,000
Lac au Saumon	Quebec	100/0	47,000
Saint-Jean-Port-Joli	Quebec	70/30	7,000
Bristol	New Brunswick	15/85	40,000
St-Quentin	New Brunswick	40/60	90,000
Tracyville	New Brunswick	20/80	10,000
Belledune	New Brunswick	100/0	100,000
Shubenacadie	Nova Scotia	15/85	50,000
Upper Musquodobit	Nova Scotia	100/0	100,000
Summerford	Newfoundland & Labrador	NA	12,000
Bishop’s Falls	Newfoundland & Labrador	NA	1,000

The system boundaries and process flow for wood biomass solid fuels are summarized in Figure 20. This includes various wood biomass feedstocks from different activities in the forest sector supply chain, as well as waste wood obtained from C&D solid waste streams. Note that “Bioenergy Harvest” in Figure 20 refers to incremental harvesting of standing forest biomass above and beyond the business as usual commercial harvesting for lumber.

Wood Biomass Feedstocks

Canadian wood pellet producers use a variety of feedstocks depending on the intended use of the pellets. As shown in Table 91, the most commonly used feedstock is sawmill residues (90%), followed by hog fuel and whole roundwood.

Table 91. Wood pellet plant feedstocks used in Canadian wood pellet plants in 2016, in metric tonnes (Bradburn & Lakhdari, 2017).

	Bush Residual	Mill residues	Hog Fuel	Roundwood	Waste Wood	Total
AB	0	113,000	0	0	0	113,000
BC	21,000	1,733,500	136,000	96,000	16,000	2,002,500
SK	0	0	0	0	0	0
ON	0	87,000	0	0	9,000	96,000
QC	0	350,000	0	0	0	350,000
NB	0	192,000	0	0	0	192,000

NS	0	30,000	0	0	0	30,000
NL	0	200	0	0	0	200
Total	**21,000**	**2,505,700**	**136,000**	**96,000**	**25,000**	**2,783,700**
Canada	***0.75%***	***90%***	***4.8%***	***3.4%***	***0.9%***	

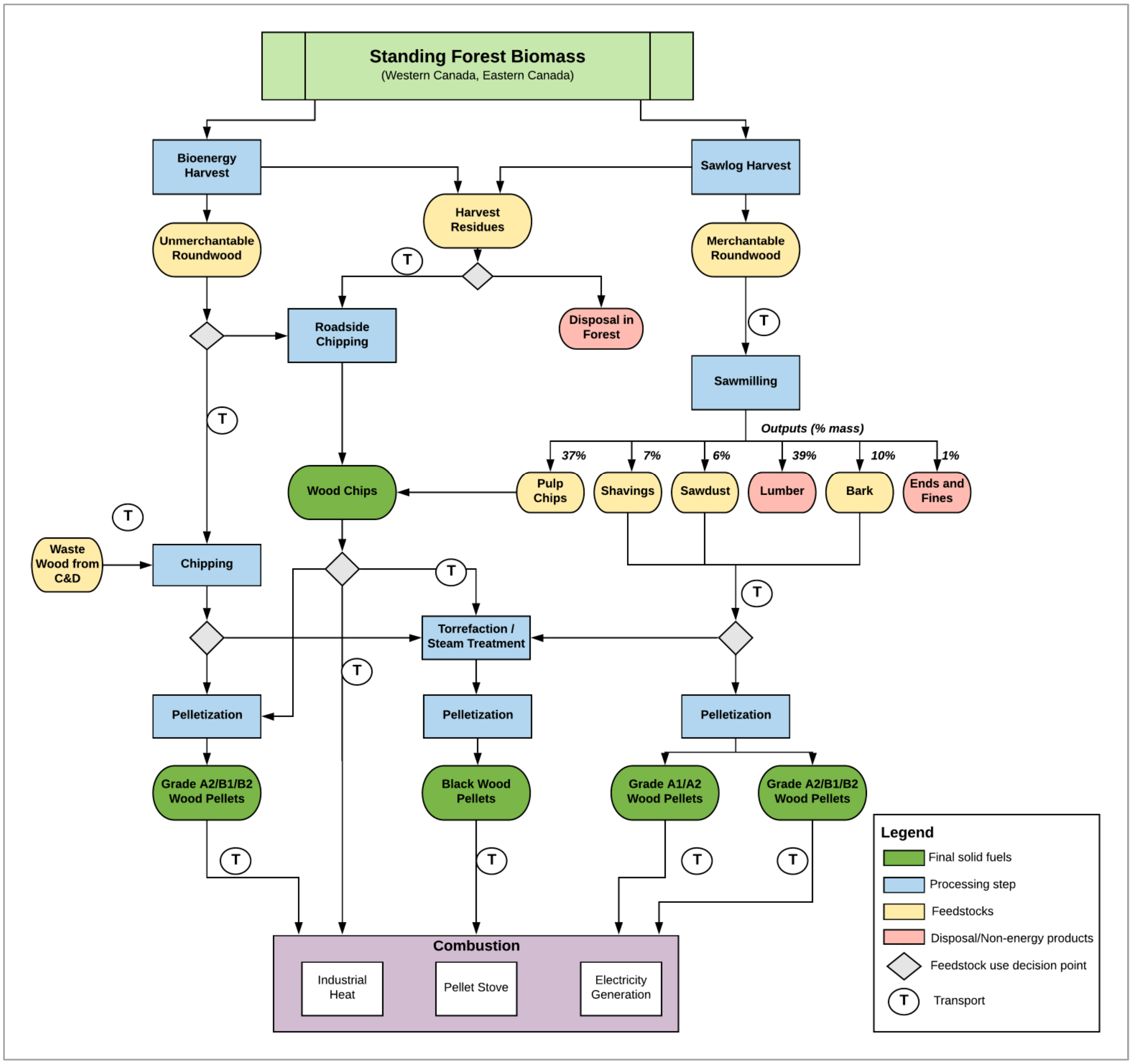

Figure 20. System boundaries and life cycle activities for solid fuels derived from wood biomass feedstocks, from extraction to combustion. Note that "Bioenergy Harvest" refers to incremental harvesting of standing forest biomass above and beyond the business as usual commercial harvesting.

Wood chips are also derived from multiple sources in the forest sector supply chain, ranging from roadside chipping of harvest residues to chipping of waste wood from C&D. The following sections provide an overview of the wood biomass feedstocks that were modelled for the Fuel LCA Modelling Tool.

Forest Harvest Residues (Bush Residual)

Forest harvest residues are comprised of tree stems, tops, and branches that are left after commercial harvest for merchantable roundwood. The management of these residues may vary from region to region in Canada depending on provincial forest management practices and also on the chosen harvest methods (e.g. cut-to-length, tree length, whole tree). Forest management plans and certification schemes typically require foresters to leave harvest residues on-site to support ecological functions (Roach & Berch, 2014). In other provinces, forest harvest residues are typically brought to the forest roadside to be either stockpiled or burned. When not left in the forest, these harvest residues can potentially be used for a number of low carbon fuel applications, such as being processed into wood chips for direct use, being chipped and used in wood pellet production, or for further fuel conversion such as pyrolysis; however, at present, this residues are rarely used for such applications in Canada.

The quantity of recoverable forest harvest residues varies by forest harvest technique. For example, in a study on Ontario forest harvesting for bioenergy it was indicated that recoverable residues ranged from up to 40% of merchantable volume for clear cuts, 20% of merchantable volume for shelterwood and thinning, and 0% for selection harvesting (McKechnie J. , 2012). These differences in recoverable residues are due primarily to the decision to harvest either the whole tree or to cut-to-length. Forest harvest techniques also vary from province to province; however, approximately 85% of forest harvesting in Canada is done by clearcutting (Statistics Canada, 2018).

After primary harvest, forest harvest residues are hauled to the roadside and chipped in roadside biomass processors prior to delivery to final use or for further bioenergy processing. In the context of solid fuels, wood chips produced from forest harvest residues may be used directly in energy applications or processed further into wood pellets or black pellets prior to use of a fuel. The life cycle activities associated with forest harvest residues therefore include the hauling of residues to the forest roadside, roadside chipping, and transport of wood chips to the producer or end user. At present the majority of these residues are left in the forest to decay and are considered a waste product. As such, the GHG emissions associated with primary forest harvesting are attributed to the primary forest products that are harvested. This modelling decision has been applied consistently in a number of LCAs of wood biomass energy (McKechnie J. , 2012) (Smyth, Kurz, Rampley, Lempriere, & Schwab, 2017) (McKechnie, Colombo, Chen, Mabee, & Maclean, 2011)

Sawmill Residues (Mill residues and hog fuel)

The production of lumber from Canadian sawmills results in a number of co-products from the sawing and planing of merchantable roundwood. These co-products, or residues, include parts of the roundwood that are sawn or planed to produce lumber, such as wood chips, sawdust, planer shavings, and various other wood ends and fines. The use of these residues varies considerably depending on the location and management practices of each sawmill. Some sawmill residues are used for onsite energy generation, some are transferred or sold to various users for energy applications and other product manufacturing (e.g. pulp and paper, animal bedding, etc.), and some are stockpiled or disposed of (Athena Sustainable Materials Institute, 2018a).

Harvesting of Merchantable Roundwood

The system boundary for sawmilling begins with primary harvest of merchantable roundwood in Canadian forests. This includes a number of activities, including forest thinning, fertilization, seedling growth, and replanting of logged forests. It also includes harvesting (e.g. feller buncher), delimbing, cutting, and hauling of roundwood from the forest to roadside, and from the roadside to the sawmill (Athena Sustainable Materials Institute, 2018a).

Sawmilling

Once delivered to the sawmill, merchantable softwood logs go through a process of sawing, kiln drying, and planing to produce lumber. The various sawmill residues are produced at different points in the process, as summarized in Table 92 below.

Table 92. Breakdown of the production of sawmill residues according to sawmill activity, by percent (Athena Sustainabile Materials Institute, 2012)

Residue	Sawing	Planing
Bark	100%	
Planer shavings		100%
Sawdust	97%	3%
Pulp chips	93%	7%
Trim ends		100%
Chipper fines	100%	
Wood waste (hog fuel)		100%

As noted, the disposition of sawmill residues will vary from operation to operation. In a 2012 study of the Canadian softwood lumber industry, the Athena Institute estimated the fate of different residue types according to end use (Table 93).

Table 93. Fate of sawmill residues for an average Canadian sawmill in 2012, shown as percent of total volume of residues produced (Athena Sustainabile Materials Institute, 2012).

Residue	Transferred*	Sold	Landfilled	Hog fuel	Stockpiled
Bark	21%	64%	3%	12%	1%
Planer shavings		71%		28%	1%
Sawdust		79%		21%	
Pulp chips	7%	93%			
Trim ends	7%	93%			
Chipper fines				100%	
Wood waste**	42%		58%		

**Transferred co-products are provided to other end users at no cost, as opposed to being sold to other end users.*

***Wood wastes are produced entirely during planing and are primarily landfilled and not used for other purposes*

The results of the analysis of residue use by the Athena Institute indicate that sawmill residues are almost fully utilized when considering their use onsite (hog fuel) and their use by other producers, with very little being stockpiled or landfilled.

Unmerchantable Roundwood

In addition to forest harvest and sawmill residues, another wood biomass feedstock option is the harvesting of roundwood from unmerchantable trees. Unmerchantable trees are those that are not suitable for timber or pulp for various reasons, including poor timber or fibre properties, they are diseased or deformed, or they are too small in diameter for sawmilling (Natural Resources Canada, 2018). In some instances, these trees are cut down and left on the forest floor in order to clear the way for harvesting of merchantable tree stands, while in other instances they are left standing. These unmerchantable trees are of increasing interest for bioenergy applications (International Energy Agency, 2019).

After harvest and hauling to the roadside, unmerchantable trees may be chipped at the roadside to produce wood chips for various applications or may be sent to wood pellet plants and debarked and/or chipped for production of white or black wood pellets. Unmerchantable trees may also be sent directly from harvest to CHP plants where they are chipped and combusted along with other wood biomass feedstocks.

Construction and Demolition Waste

Wood found in C&D waste could be another source of wood biomass feedstock for solid low carbon fuels; however, one of the barriers to use of this feedstock is the need for “clean” wood, i.e. wood that has not been chemically-treated or combined with other materials (i.e. plastics) in composite materials.

The use of C&D waste wood requires the collection and chipping of the wood and delivery of the wood to wood pellets plants or direct use of wood chips in heating applications.

Wood Biomass Fuel Conversion

The conversion of wood biomass feedstocks into final solid fuels takes various forms depending on the application and desired end use. In some instances, wood biomass feedstocks undergo a limited amount of sizing and/or drying, while in other instances they require more intensive processing. Process descriptions for the four solid low carbon fuels derived from wood biomass feedstocks are provided in the following sections.

Wood Chips

Wood chips are widely used as a solid fuel primarily for space heating or drying, as they are a locally available fuel that requires minimal processing (Natural Resources Canada, 2017a). Wood chips are typically produced during sawmilling operations, or from roadside chipping operations after forest harvest. Roadside chippers take numerous forms, including stationary and mobile units, and a range of size, power, and size reduction features (AEBIOM, 2008). In general, the production of wood chips involves the grinding or chipping of the wood followed by screening and air drying (Natural Resources Canada, 2017a).

Wood chips may be used directly for heating or drying energy or used as feedstock to produce brown or black wood pellets. The Canadian Standards Association (CSA) differentiate between Grade A (A1 and A2) and Grade B (B1 and B2) wood chips based on their source and properties such as ash and moisture content (Natural Resources Canada, 2017a). In general, Grade A wood chips derived from stem wood and milling processes are used for institutional space heating (e.g. schools, commercial buildings) while Grade B wood chips derived from chemically treated by-products and chemically untreated used wood are used for heavier industrial applications (e.g. pulp mills, district energy systems).

Based on the CSA classification, wood chips have a high heating value (HHV) of 10-11 MJ/kg and a density of 300-400 kg/m^3 (Natural Resources Canada, 2017b). This HHV is assumed to be for wood chips with a relatively high moisture content of 40-50%. Moisture content is the most important factor affecting calorific value for solid fuels, and the HHV and LHV for a given fuel will vary within a particular range depending on moisture content Figure 21.

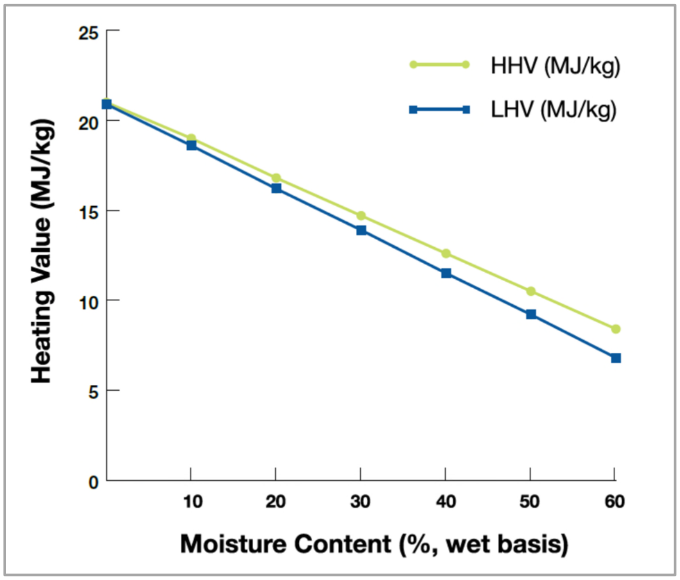

Figure 21. Relationship between HHV and LHV and moisture content for solid wood fuels (Natural Resources Canada, 2017b).

The moisture content for wood chips varies depending on the source and the level of drying that has been applied. Grade A1 wood chips have a moisture content of 10-25%, Grade A2 have a moisture content of generally 35% or lower, and Grade B wood chips generally have a moisture content of 35% or higher.

Wood Pellets

Wood pellets are a densified biomass fuel produced primarily from residues of traditional forestry operations such as sawmills and finished wood products manufacturing (Natural Resources Canada, 2017c). Forest harvest residues are also used, but to a lesser extent because they may contain higher amounts of bark and ash. Wood pellets are typically used for residential and institutional space heating, district heating plants, and electricity generation plants as a substitute for coal (Natural Resources Canada, 2017c).

According to the CAN/ISO-ISO 17225 solid biofuels standards, wood pellets are classified based on their source and properties, including Grade A (A1 and A2) and Grade B (B1 and B2). In general, Grade A1 and A2 wood pellets are used for residential or commercial heating applications and primarily come from mill residues (i.e. sawdust, shavings, and cut-offs) and stem wood. Grade A2 pellets can contain some logging residues and whole trees without roots. Grade B pellets are made from more diverse sources, and can include bark, residues from thinning and pruning, and chemically untreated used wood. The CSA also classifies industrial pellets (I1, I2, and I3) which are pellets used for more industrial uses such as electricity generation. Some key specifications for Grade A and Grade B wood pellets are summarized in Table 94.

Table 94. Properties of Grade A1, A2, and B wood pellets, as per the CAN/CSA-ISO 17225 Part 2 Standard (Natural Resources Canada, 2017c).

Property Class	Unit	Grade A1	Grade A2	Grade B
Moisture	% of weight	≤ 10	≤ 10	≤ 10
Ash	% of weight	≤ 0.7	≤ 1.2	≤ 2.0
Fines	% of weight	≤ 1.0	≤ 1.0	≤ 1.0
HHV	MJ/kg	≥ 18.6	≥ 18.6	≥ 18.6
Bulk density	kg/m^3	600 - 750	600 - 750	600 - 750

Aside from specific industry classifications, wood pellets also tend to be grouped according to their feedstock type and production process using terms like white pellets, brown pellets, and black pellets. A search through the literature and industry reports suggests that while the differentiation of black pellets is clear, there is a fair bit of inconsistency in the use of other terms such as “white” and “brown” to describe wood pellets. For the purposes of the Fuel LCA Modelling Tool, the following will be used:

- **Wood Pellets** – Grade A1/A2 and B1/B2 pellets made from any wood biomass source (i.e. harvested biomass, residues) produced through standard pelletization processes;
- **Thermally-treated Wood Pellets (black)** – pellets made from wood biomass of any source (i.e. harvested biomass, residues) that are thermochemically treated by either stream treatment or torrefaction prior to pelletization.

The different pathways for each type of pellet are shown in Figure 20.

Black wood pellets are considered advanced wood pellets, and as of the end of 2016, there was no commercial scale production of black wood pellets in Canada (Bradburn & Lakhdari, 2017). In contrast to standard wood pellets, black pellets include a thermal treatment step which decreases the moisture content and leads to a product with physical and chemical characteristic more similar to coal. This process makes the pellets more durable and gives them a higher energy density making them easier to use in coal-fired generating stations (Bradburn & Lakhdari, 2017).

Wood Biomass Fuel Combustion

Solid wood biomass fuels are used in a wide variety of applications and combusted in a large number of different combustion devices depending on the application. The emissions from combustion of solid wood biomass fuels will vary substantially depending on the type of combustion device. It is not feasible to capture the full range of possible combustion scenarios for each of the solid wood biomass fuels in the Fuel LCA Modelling Tool. The combustion of wood biomass solid fuels will be modelled for three general applications, including industrial combustion of wood chips in stoves, furnaces, and boilers, combustion of wood pellets in residential pellet stoves, and combustion of black pellets in large-scale electricity generation.

10.1.2 Crop Residue Fuels

Renewable solid fuel feedstocks are also produced within the agricultural sector, primarily from agricultural crop residues such as corn stover or wheat straw. Similar to wood residues, agricultural residues can be converted to energy-dense pellets and used for on-farm drying energy or sold to other end users; however, agricultural feedstocks contain silica, chlorine, and ash that cause serious problems during combustion. These feedstocks could be blended with wood and used in combustion, pyrolysis, or gasification.

For example, perennial grasses such as switchgrass or miscanthus can be combined with woody biomass and compressed into a pellet. Agricultural crop residues such as corn stover or wheat straw can also be used in this manner. If not blended, then solid fuels from agricultural residues require additional pretreatment.

Currently there is almost no commercial production of corn stover pellets or agri-wood pellets and very little information available on their production. In anticipation that solid fuels from perennials or crop residues may become more important in the development of low carbon fuels, a default pathway is included for pellets derived from corn stover.

Crop Residue Feedstocks

Corn stover is a waste product of corn cultivation. Corn stover refers to all of the above-ground parts of the corn plant except grain (i.e. stalks, leaves, and cobs). Approximately equal masses of stover and grain are produced during growth. In the United States, most corn stover is left on the fields, and about 5% of stover is removed for use in animal feeds and bedding ((Kim, Dale, & Jenkins, 2009). Farming practices vary from region to region, but it is assumed that Canadian practices are similar to those in the US in that most corn stover is currently left on corn fields after harvest and tilled into the soil over time.

Given that most crop residues are currently left on agricultural fields, these residues have been treated as a waste product in the Fuel LCA Modelling Tool and no upstream impacts from cultivation have been allocated to the residues. The removal of crop residues from agricultural fields requires additional energy for collection, and requires the input of additional nitrogen fertilizer to replace the lost nutrients from residue decay (Chen, et al., 2017).

Crop Residue Fuel Conversion

The conversion of corn stover into pellets requires the removal of corn stover from corn fields and processing in a densification plant. In general, this would require the removal, baling and transport of corn stover over a given distance to the densification plant. Because the stover contains nitrogen, which is being removed from the field, the field will require additional nitrogen (N) fertilizer the following year, which is included in the corn stover inventory (see Section 4.8.) The location of densification plants could vary depending on the scale of production, and smaller plants could be located closer to corn fields; however, there are no corn stover production facilities in Canada.

No information is available on corn stover densification processes in Canada. A 2012 publication by Li et al. describes an LCA of densifiying wheat straw pellets in the Canadian Prairies (Li X. , Mupondwa, Panigrahi, Tabil, & Adapa, 2012), and it is assumed that the densification process would be similar for corn stover, and in many ways similar to wood pellet production in overall process. The densification process generally includes a series of steps including receiving bales of residues, grinding, pelletizing, cooling, and screening. In addition, a recent publication on production of corn stover pellets in Idaho, US indicated that a corn starch binder may also be required to strengthen the densification of the corn stover (Tumuluru, Conner, & Hoover, 2016).

Crop Residue Fuel Combustion

Given the non-existent use of pellets made from corn stover in Canada, the default pathway in the Fuel LCA Modelling Tool will include combustion of corn stover pellets for heating. Future additions to the tool may include electricity generation should this pathway develop.

10.2 Modelling Approach for Solid Low Carbon Fuels

The following sections provide a brief overview of the modelling approach for low carbon solid fuels, as well as discussion of some key methodological issues to be addressed in the modelling.

10.2.1 Development of Unit Process Building Blocks

The overall modelling approach for Milestone 3 is to develop unit processes to serve as building blocks for current and future modelling work in the Fuel LCA Modelling Tool. In the case of solid low carbon fuels this approach is particularly relevant since there are a variety of fuel feedstocks that may be used in any fuel conversion process, and these are all based on a basic set of feedstocks that are produced within the Canadian forestry supply chain (or in the case of corn stover pellets, from the Canadian agricultural industry).

The key building blocks for wood biomass solid fuels are forest harvesting and sawmilling activities, from which multiple feedstocks are produced, including unmerchantable roundwood, forest harvest residues, wood chips, and various other sawmill residues (e.g. sawdust, planer shavings) (see Figure 19). With these building blocks in place, with regional variation reflected in their production where possible (e.g. differences in fuel consumption, differences in electricity grids, etc.), users of the Fuel LCA Modelling Tool that want to build a wood pellet process can choose the appropriate feedstock(s) from the available building blocks and pull them in to their specific pellet production pathway. They can also copy and modify these building blocks with their own more recent or process-specific data.

Using this building blocks approach, even in cases where only literature data is available, or where no data is available, unit processes can still be developed and included as defaults in the Fuel LCA Modelling Tool and be updated by tool users when data is available.

The modelling work in Milestone 3 also relies heavily on fossil fuel unit processes that were developed in Milestone 2, including fuel inputs to machinery and equipment (e.g. diesel, natural gas, etc.) and transportation processes (e.g. trucks, rail, pipelines). These unit processes will be pulled from the ECCC Fuels database and incorporated into the low carbon fuel pathway models where needed.

10.2.2 Regional Variation

There are some regional variations for solid low carbon fuels which could influence carbon intensity. These include fuel consumption in forest harvesting, fuel consumption in sawmilling and other processing activities, inputs and crop management practices for corn production (i.e. corn stover) and background energy systems such as variations in electricity grids providing energy to fuel conversion processes. The sourcing of regional/provincial feedstocks could also influence transport distances and modes for feedstock delivery and final fuel delivery.

These differences are reflected in the modelling as much as possible within the confines of the available data. For example, forest harvesting data is available only for Western and Eastern Canada[15], and not a provincial level. As such, tool users will need to choose a unit process from either of these two regions, or choose the unit process for Canadian average harvesting, and would not be able to choose provincially specific harvesting data in this version of the Fuel LCA Modelling Tool. With respect to background energy systems, electricity grid carbon intensities are available at a provincial level based on work completed in Milestone 2, as are some fuels (e.g. diesel), and will be incorporated into the unit processes available for modelling solid low carbon fuels. For example, modelling the production of wood pellets in British Columbia could include the use of British Columbia electricity to power the pelletization process.

10.2.3 Co-Product Allocation

Co-products from sawmilling operations, including sawdust, bark, and planer shavings, are a widely-used input for low carbon solid fuels. In modelling these feedstocks, there is a need to allocate the impacts of sawmilling across the various co-products. In Milestone 1 and 2 it was established through discussions with ECCC that the upstream carbon intensity of a process would be allocated to its co-products according to energy content. Effort has been made to use this approach consistently in modelling work for Milestone 3; however, using the building blocks approach for the Fuel LCA Modelling Tool, the capability to choose different allocation approaches will be incorporated in the tool. For sawmilling, allocation of upstream impacts to lumber and sawmilling co-products is often done by mass in the literature (Athena Sustainable Materials Institute, 2018a), and represents a more appropriate way of allocating for solid low carbon fuel feedstocks since sawmilling co-products are often valued for physical properties other than their energy content. The LCI data provided for Canadian sawmilling included a subdivision of material and energy inputs and material outputs expressed relative to each of the three phases of sawmilling (sawing, drying, and planing). These data allowed us to subdivide the impacts of the sawmilling process to each of the material outputs based on the percentage of each activity that is attributed to each co-product. For example, as shown in Table 97, 100% of the bark is produced from sawing, and 70% of the electricity consumption is attributed to sawing. As such, none of the impacts associated with drying and planing were attributed to bark since it is only produced during sawing. Other co-products from sawing included sawdust (97%), pulp chips (93%), and chipper fines (100%). Using these data, the 70% of total electricity used for sawing was then allocated to each of these co-products of sawing based on their relative masses. After the limits of subdividing the system were reached, mass allocation was used to finalize the attribution of impacts to each co-product. These calculations are summarized in the unit process data sheets for sawmilling which are provided as a separate appendix to the final report.

10.2.4 Biogenic Carbon

In remaining consistent with the Government of Canada’s policy on biogenic carbon, as shown in Canada’s National Inventory Report (Government of Canada, 2018), emissions

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[15] The Athena study included survey data from sawmills in British Columbia (7), Alberta (2), Ontario (7), Quebec (6), and New Brunswick (1). “Western” refers to mills in British Columbia and Alberta, while Eastern refers to mills in Ontario, Quebec, and New Brunswick.

of biogenic carbon from combustion of solid low carbon fuels are not included in the carbon intensity calculations. Biogenic carbon emissions are calculated and reported separately from the default carbon intensity values.

Carbon emissions associated with direct land use change will be included in instances where feedstock production requires the conversion of land from existing use to bioenergy production. Indirect land use change is excluded from the carbon intensity calculations.

10.3 Life Cycle Inventory for Solid Low Carbon Fuels

10.3.1 Solid Wood Biomass Fuels

Forest Harvesting

Merchantable Roundwood

The best publicly available LCI data for primary Canadian forest harvesting operations for merchantable roundwood is from the Athena Sustainable Materials Institute, who have completed a number of LCAs of Canadian forest products. 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 5 forest harvesting operators for 2015. These data are summarized in Table 95 and represent primarily mechanical logging (96-100%) of Canadian softwoods.

Table 95. Stump to roadside fuel consumption for average Canadian and average Eastern Canadian primary softwood harvesting in 2015, expressed relative to harvesting of 1 m^3 of softwood (Athena Sustainable Materials Institute, 2018a).

Input	Unit	Amount	Unit	Amount
	Canada		Eastern Canada	
Silviculture & Land Use*				
Seedlings planted	number/m^3	3.5	number/m^3	3.2
Aerial seeding	mg/m^3	92	mg/m^3	83
Area harvested	ha/m^3	0.0052	ha/m^3	0.0066
Energy Use by Fuel Type				
Diesel	l/m^3	2.17	l/m^3	3.06
Gasoline	l/m^3	0.16	l/m^3	0.18
Propane	l/m^3	0.01	l/m^3	0.01

**Data on silviculture and land use parameters are provided as context to the harvesting data. The Athena LCA models do not account for GHG emissions associated with seeding and planting.*

One of the objectives for the Fuel LCA Modelling Tool is to be able to reflect regional or provincial differences in carbon intensity for low carbon fuels. Unfortunately, the Athena Institute's most recent studies do not provide any LCI data for Western harvesting; however, in the 2012 version of this same report, in addition to the Canadian average, a breakdown of Western and Eastern forest harvesting data was provided. These data are summarized in Table 96 and are based on surveys of 15 producers for the 2006-2007 production year and represent predominantly mechanical harvesting (94-97%).

Table 96. Stump to roadside fuel consumption for Canadian primary softwood harvesting in 2006-2007, broken down by Eastern and Western Canada, expressed relative to harvesting of 1 m^3 of softwood (Athena Sustainabile Materials Institute, 2012).

Input	Unit	Amount	Unit	Amount	Unit	Amount
	Eastern Canada		Western Canada		Canada	
Silviculture & Land Use						
Seedlings planted	number/m^3	3.9	number/m^3	3.1	number/m^3	3.5
Aerial seeding	mg/m^3	82	mg/m^3	37.8	mg/m^3	92
Area harvested	ha/m^3	0.0066	ha/m^3	0.0036	ha/m^3	0.0052
Rotation age at harvest	years	87	years	102	years	94
Energy Use by Fuel Type						
Diesel	l/m^3	3.29	l/m^3	2.26	l/m^3	2.84
Propane	l/m^3	0	l/m^3	0.0013	l/m^3	0.0006
Electricity	kWh/m^3	0.0296	kWh/m^3	0.0296	kWh/m^3	0.0296

In comparing the harvesting LCI data from both Athena Institute reports, Canadian average and Eastern Canadian average diesel consumption decline by 24% and 7%, respectively. Propane consumption increases by over 150%, and gasoline use is reported instead of electricity consumption. In the interest of using the most recent LCI data while also being able to reflect regional differences in harvesting, we will use the 2012 regional breakdown to scale the diesel, propane, and gasoline combustion amounts for Western Canada. In the 2012 data, diesel consumption in Western Canada was 20% lower than the Canadian average.

Unmerchantable Roundwood

The forest harvest LCI data from the Athena Institute is for primary forest harvest for merchantable saw logs. This type of harvesting is done primarily by clear cutting (Statistics Canada, 2018). Unmerchantable trees may be harvested as part of a clear cut and brought to the forest roadside, or they may be harvested during more selective cutting operations such as thinning. The Fuel LCA Modelling Tool will include two alternative forest harvest unit processes to reflect the fact that unmerchantable roundwood may be extracted from the forest in different ways, including:

- Harvesting of unmerchantable trees by thinning operations and skidding to the forest roadside; and
- Skidding of previously harvested unmerchantable trees to the roadside.

Canadian-specific data were not available for these operations; however, in a 2012 LCA study of Southeast United States wood biomass collection and processing, the Consortium for Research on Renewable Industrial Materials (CORRIM) provided LCI data for thinning, skidding, and chipping of forest thinnings (Johnson, Lippke, & Oneil, 2012). These data will be used as the default values for fuel consumption for harvesting and skidding of unmerchantable trees in Canada:

- Felling (large biomass feller buncher) – 0.81 l of diesel/oven dry tonne
- Skidding (large biomass skidder) – 2.64 l of diesel/oven dry tonne

Users of the Fuel LCA Modelling Tool will be able to modify the fuel consumption amounts for these activities to reflect different technologies or different practices in the future.

Wood Chipping

The chipping of harvest residues and unmerchantable roundwood at the forest roadside can be done using a wide range of technologies with varying capabilities and fuel consumption. The unit process for roadside chipping of wood biomass is based on an average value for fuel consumption per amount of wood chipped from the literature. When using the Fuel LCA Modelling Tool, users will be able to modify the fuel consumption rate for the chipper if they have primary data or more appropriate literature data to use.

The default fuel consumption value for roadside chipping of forest harvest residues, including chipping and loading, is 4.3 litres of diesel per oven dry tonne of biomass processed. This value is from a study of wood biomass energy in Ontario from 2012 (McKechnie J. , 2012). The default fuel consumption value for roadside chipping of whole trees is assumed to be the same as chipping of harvest residues.

Sawmilling

The most recent publicly available LCI data for Canadian sawmilling operations is from LCAs carried out by the Athena Sustainable Materials Institute. In 2018 they published LCI data based on surveys of 23 Canadian sawmills. These data include material and energy inputs and an average product and co-product slate, and were also broken down to provide both a Canadian average (Athena Sustainable Materials Institute, 2018a) and Eastern Canadian average (Athena Sustainable Materials Institute, 2018b). The LCI data for production of lumber in Canadian sawmills is summarized in Table 97, including a subdivision of material and energy inputs and material outputs relative to each phase of the sawmilling process (sawing, drying, planing). These data were used to sub-divide the sawmill activities relative to the various co-products and reduce the amount of co-product allocation required.

Table 97. Life cycle inventory for the inputs and outputs of average Canadian and average Eastern Canadian sawmilling to produce softwood lumber in 2015, expressed per m^3 of lumber produced.

Material or Fuel	Units	Amount per m^3 of lumber	Units	Amount per m^3 of lumber	Sawing	Kiln Drying	Planing
	Canada		Eastern Canada		Canada		
Inputs							
Roundwood	kg (dry)	1,097	kg (dry)	1,111			
Hydraulic fluids	l	0.13	l	0.15	73%	5%	22%
Motor oils	l	0.29	l	0.22	67%	7%	26%
Greases	kg	0.01	kg	0.01	69%	8%	24%
Electricity	kWh	71.89	kWh	70.9	70%	9%	21%
LPG	l	0.18	l	0.28	39%	17%	44%
Gasoline	l	0.06	l	0.03	61%	11%	28%
Diesel	l	2.06	l	2.15	62%	11%	27%
Heating oil	l	0.46	l	0.92		100%	
Natural gas	m^3	4.67	m^3	0.8	16%	73%	11%
Hog fuel	kg (dry)	79.36	kg (dry)	106.18		100%	
Outputs							
Softwood lumber	kg	428	kg	408			
Bark	kg	105	kg	110	100%		
Planer shavings	kg	74	kg	78			100%
Sawdust	kg	66	kg	69	97%		3%
Pulp chips	kg	406	kg	426	93%		7%

Trim ends	kg	7	kg	7			100%
Chipper fines	kg	2	kg	2			
Wood waste	kg	9	kg	9	100%		

Unfortunately, data for sawmilling operations in Western Canada were not provided in the Athena Institute LCAs. For the default values in the Fuel LCA Modelling Tool, the use of sawmill residues from Western Canadian sawmills will use the Canadian average until more regionally specific data can be provided.

10.3.2 Pelletization

Within the pellet plants currently operating in Canada, there is a fair amount of variability in energy consumption and emissions associated with pelletization as a result of the use of different feedstocks and the production of different grades of wood pellets. As a result, individual pellet producers will be able to modify the unit process for pelletization in the Fuel LCA Modelling Tool to reflect their specific operations. For the default pelletization process, LCI data on wood pellet production in Ontario was obtained from a recent publication (McKechnie, Saville, & MacLean, Steam-treated wood pellets: Environmental and financial implications relative to fossil fuels and conventional pellets for electricity generation, 2016). The LCI data are summarized in Table 98.

Table 98. Energy inputs to pelletization, expressed per oven dry tonne of graded pellets produced in Ontario.

Input	Unit	Amount
Debarking and grinding - Electricity	kWh/dry tonne	3.75
Pellet production – Electricity	kWh/dry tonne	144
Pellet production – thermal energy	GJ/dry tonne	3.0
Wood pellet energy content	GJ/dry tonne	19

In another recent study of wood pellet production in Canada, Padilla-Rivera et al. used LCA to quantify the environmental impacts of wood pellet production by two different production plants in Québec. The LCI data from this study of 2014 production showed electricity consumption values that were both higher (163 kWh/tonne of pellets) and lower (93.7 kWh/tonne of pellets) than what is used by McKechnie et al. (2016), and also shows much higher thermal energy use by one producer, including use of diesel (3.22 MJ/tonne of pellets) and natural gas (1,400 MJ/tonne of pellets) (Padilla-Reivera, Barrette, Blanchet, & Thiffault, 2017). These values reflect the types of variation that may be observed in wood pellet production LCI data. This variation will be captured in the uncertainty analysis but may also be addressed by the addition of more specific data from low carbon fuel producers using the Fuel LCA Modelling Tool in the future.

Thermal Treatment

Thermal treatment of wood pellets is an emerging part of the wood pellets sector with no current commercial scale production in Canada. In developing default carbon intensity values for black wood pellets, we used the best available literature values to characterize the production of both steam-treated and torrefied wood pellets.

Steam-Treated Wood Pellets

A recent Canadian study quantified the life cycle environmental impacts of white pellets and black wood pellets produced in Ontario for use in electricity generation. The data for black pellet production are based on a demonstration-scale plant in Norway, and were used to develop the default pathway for black pellets produced using steam-treated biomass. The energy inputs to production of steam-treated wood pellets are summarized in Table 99.

Table 99. Energy inputs to the production of black wood pellets using stream-treated biomass in Ontario in 2014 (McKechnie, Saville, & MacLean, Steam-treated wood pellets: Environmental and financial implications relative to fossil fuels and conventional pellets for electricity generation, 2016).

Input	Unit	Amount
Debarking and grinding - Electricity	kWh/dry tonne	3.75
Pellet production – Electricity	kWh/dry tonne	120
Pellet production – thermal energy	GJ/dry tonne	3.8
Energy content	GJ/dry tonne	21

It is noted that the energy content of the thermal treated pellets is 21 GJ/dry tonne, which is 2 GJ higher than conventional pellets that were modeled in the same study (see Table 98). This difference is reflected in the model of wood pellet combustion for black pellets. LCI data for the upstream production of wood biomass feedstocks for black pellets are based on the modelling from Milestone 3.

Torrefied Wood Pellets

Black pellets can also be produced through a torrefaction process. Torrefaction is a form of pyrolysis that results in partial thermal decomposition in the absence of oxygen. It is conducted between 200 and 300 degree Celsius to remove volatiles from the wood prior to densification (Adams, Shirley, & McManus, 2015).

There are currently no commercial scale torrefied wood pellet plants operating in Canada, and no LCI data available for Canadian production of torrefied wood pellets. To model the default carbon intensity of black wood pellets from torrefaction, we used LCI data from a 2015 study on torrefied wood pellet production in Europe (Adams, Shirley, & McManus, 2015). This study compared the life cycle impacts of both torrefied wood pellets and conventional wood pellets. The LCI data from this study are summarized in Table 100.

Table 100. Life cycle inventory data for the production of torrefied black wood pellets and conventional graded pellets from chipped roundwood in Europe (Adams, Shirley, & McManus, 2015).

Input	Torrefied Black Pellets		White Pellets	
	Unit	Amount	Unit	Amount
Process heat*	MJ/tonne	4,000	MJ/tonne	1,560
Natural gas	m^3/tonne	14.5	m^3/tonne	36.7
Grinding – Electricity	kWh/tonne	77	kWh/tonne	260
Pelleting - Electricity	kWh/tonne	150	kWh/tonne	50
Bulk density	kg/m^3	800	kg/m^3	650
LHV	MJ/kg	22.0	MJ/kg	15.5
Moisture content	%	5	%	10

**Process heat is assumed to be provided by recirculated torrefaction gas. In some configurations this may be supplied by burning biomass or fossil fuels.*

Similar to thermal treated pellets, the energy content of torrefied pellets was shown to be higher than conventional pellets, along with higher bulk density and lower moisture content. These differences are reflected in the model of wood pellet combustion for black pellets. The HHV and carbon content of torrefied wood pellets can vary depending on the torrefaction conditions, but 21.5 – 22 MJ/kg is generally considered to be representative of average torrefied pellets (McNamee, et al., 2016). LCI data for the upstream production of wood biomass feedstocks for black pellets are based on the other solid low carbon fuel models from Milestone 3.

Feedstock and Fuel Transport

An important consideration for feedstock and final solid fuel transport is the moisture content, as many of the wood biomass feedstocks begin as “wet” materials with relatively high moisture content, such as chipped harvest residues, and then have much lower moisture content by the time they are processed into final fuels. For example, while sawdust from a sawmill may be shipped to a pellet mill at 30-40% moisture content, the final pellets shipped to the end user will likely have a moisture content of 5% or less. As such, the feedstock transport must account for the additional fuel consumption to transport wet materials, while the final solid fuel transport must account for the lower moisture content in the final fuel.

The transportation of feedstocks and final solid fuels was assumed to be all by truck and rail. In modelling this transport, we used the truck and train unit processes that were created in Milestone 2 to capture the upstream and combustion emissions associated with these modes of transport. Further discussion of transportation modelling is provided in Appendix B.

Combustion

Emissions factors for combustion of solid wood biomass fuels are summarized in Table 101 for industrial heating, pellet stove heating, and electricity generation. It is noted that these emissions factors are based on generic assumptions about combustion efficiency and moisture content of the wood fuel that were developed and are used by the Government of Canada. Future users of the Fuel LCA Modelling Tool will be able to modify these emissions factors based on the measured or projected characteristics of particular wood fuels and combustion devices. The efficiency of the combustion device influences the amount of feedstock required to deliver a MJ of useful energy, which is the functional unit of this study. As such, a lower efficiency device would need to consume more feedstock to deliver a MJ of useful energy relative to a more efficiency device. Assumed efficiency rates for combustion devices are:

- Pellet stove – 80% (U.S. EPA, 2019)
- Industrial furnace – 90% (Ayer & Dias, 2018)
- Electricity generation – 26% (McKechnie J. , 2012)

The CO_2 emissions from combustion are considered as biogenic carbon since they are from wood biomass feedstock. As such, although these emissions will be quantified and reported separately, they will not be included in the default carbon intensity values for low carbon solid fuels.

Table 101. Combustion emissions factors for the modelled solid wood biomass fuel applications (Government of Canada, 2018).

Feedstock	Application	CO_2 (g/kg fuel)	CH_4 (g/kg fuel)	N_2O (g/kg fuel)
Wood Chips	Industrial Combustion	840	0.09	0.06
Wood Pellets	Pellet Stove	1,652	4.12	0.059
Wood Pellets and Black Wood Pellets	Electricity Generation	840	0.09	0.06

10.3.3 Solid Fuels from Crop Residues

Feedstock Production

Feedstock production for corn stover pellets is based on the collection and transport of corn stover from corn fields, and the replacement of nitrogen using additional fertilizer application to the corn fields from which residues were removed. This modelling step is described in Section 4.8. From the farm gate, LCI data for the baling and delivery of corn stover to the densification plant were derived from literature sources, including an LCA of densified wheat straw pellets (Li X. , Mupondwa, Panigrahi, Tabil, & Adapa, 2012). Transport of corn stover bales from the field to the densification plant were modeled by estimating average transport distance based on corn production locations and using unit processes for truck and rail transport developed in Milestone 2.

Feedstock Conversion

LCI data for Canadian corn stover densification is not available. Data are available in the literature on the densification of wheat straw from the Canadian Prairies and the energy consumption for densification was used as a proxy. It is noted in the wheat straw LCA that a range of energy use values have been reported for densification of agricultural residues, from a low of 30 kWh/tonne to a high of 106 kWh/tonne (Li X. , Mupondwa, Panigrahi, Tabil, & Adapa, 2012). The value used for wheat straw densification in the Canadian Prairies is 74.4 kWh/tonne, which sits approximately in the middle of this range and provides a reasonable default value for the Fuel LCA Modelling Tool. In a simulation study for corn stover pellet production in Idaho, energy consumption for densification of corn stover was estimated to be 118 – 126 kWh/tonne depending on moisture content, and approximately 75-94 kWh/tonne when a 2% corn starch binder was used to enhance densification (Tumuluru, Conner, & Hoover, 2016). In the Fuel LCA Modelling Tool, uncertainty analysis will be used to capture the influence of this range in energy consumption on the default carbon intensity for corn stover pellets.

Fuel Combustion

Specific combustion emissions factors for corn stover in Canada were not available in the Canada NIR documentation. As an alternative, combustion emissions factors for corn stover pellets are based on emissions data from the United States Environmental Protection Agency (United States Environmental Protection Agency, 2016), as summarized below in Table 102.

Table 102. Combustion emissions factors for corn stover pellets, expressed per MJ of pellets combusted (United States Environmental Protection Agency, 2016).

Feedstock	Energy Content (HHV) (MJ/kg)	CO_2 (g/MJ)	CH_4 (g/MJ)	N_2O (g/MJ)
Corn Stover	8.7	118	0.032	0.0042

The CO_2 emissions from combustion are considered as biogenic carbon since they are from agricultural feedstock. As such, although these emissions will be quantified and reported separately, they will not be included in the default carbon intensity values for low carbon solid fuels.

10.4 Carbon Intensity Results for Solid Low Carbon Fuels

CI results for solid low carbon fuels are summarized in Table 103 below. Results are shown for three different end use applications, including combustion in a pellet stove, combustion in an industrial furnace, and combustion for electricity generation, each with different average combustion efficiencies.

Table 103. Canadian average carbon intensity values for solid low carbon fuel pathways for three energy applications and a range of biomass feedstocks, expressed in g CO_2 eq./MJ.

Solid Low Carbon Fuel Pathway	Carbon Intensity (g CO_2 eq./MJ)
Pellet Stove	
Wood pellets, from sawdust {CA}	15
Wood pellets, from unmerchantable roundwood {CA}	15
Industrial Furnace	
Wood chips, from harvest residues {CA}	5.6
Wood chips, from unmerchantable roundwood {CA}	6.9
Pellets, from corn stover {CA}	23
Electricity Generation	
Wood pellets, from sawdust {CA}	21
Black wood pellets, from sawdust, steam-treated {CA}	18
Black wood pellets, from sawdust, torrefied {CA}	24
Wood pellets, from unmerchantable roundwood {CA}	17
Black wood pellets, from unmerchantable roundwood, steam-treated {CA}	15
Black wood pellets, from unmerchantable roundwood, torrefied {CA}	21

The CI values for each application reflect different combustion efficiencies and so should not be compared directly across end uses. For electricity generation, wood pellets produced from unmerchantable logs had the lowest CI values at 15 (steam-treated) and 17 g CO_2 eq. per MJ (standard pellets). Torrefied wood pellets made from sawdust, which have a slightly greater HHV than standard wood pellets, had the highest carbon intensity per MJ of all the electricity generation options. For the industrial furnace end use, densified pellets from corn stover had the highest CI at 23 g CO_2 eq. per MJ, which was significantly higher than both types of wood chips modelled.

The primary contributors to the CI of solid low carbon fuels are the feedstock production and pelletization steps (Table 104). For conventional wood pellets, the harvesting and sawmilling activities to produce sawdust account for 33% of the life cycle GHG emissions and pelletization accounts for 24%. For torrefied wood pellets, the increased energy requirements to treat the pellets is the most notable change in the contribution analysis relative to other pellets, with pelletization accounting for 46% of total GHG emissions. This is why the torrefied pellets have the highest impact despite their improved energy density relative to other pellets. Feedstock and wood pellet transport are also shown to account for a non-negligible share of the overall carbon intensity of these solid fuels.

Table 104. Contribution analysis for Canadian average electricity generation from three different types of wood pellet, expressed per life cycle stage in g CO_2 eq./MJ of energy produced.

Life Cycle Stage	Carbon Intensity (g CO_2 eq./MJ)		
	Wood Pellets	Steam-Treated	Torrefied
Harvesting – merchantable logs	4.3	3.5	3.6
Sawmilling – sawdust	2.7	2.4	2.3
Feedstock transport	2.1	1.9	1.8
Pelletization	5.3	4.0	11
Pellet transport	2.8	2.5	2.4
Combustion - electricity	3.8	3.4	3.2
Total	**21**	**18**	**24**

10.4.1 Uncertainty Analysis

Uncertainty analysis was conducted for Canadian average solid low carbon fuels using Monte Carlo analysis. Results of the uncertainty analysis are shown in the violin plots in Section 12 and discussed relative to the uncertainty of other low carbon fuels in that section. Below in Table 105 the key results of the uncertainty analysis from each of the six sources are summarized.

Overall the results for solid low carbon fuels show a relatively high level of uncertainty, with max values for most fuels being nearly double the baseline value, and min values for most fuels being nearly 40-50% of the baseline value.

Table 105. Results of uncertainty analyses for selected solid low carbon fuels. Results based on Monte Carlo analysis of 2,000 runs with a confidence interval of 95%.

Final CI	Mean	Median	SD	Min (2.5%)	Max (97.5%)
Wood pellets, from sawdust, for electricity generation {CA}					
20.9	21.5	20.3	7.03	11.6	39.6
Wood pellets, steam treated, from sawdust, for electricity generation {CA}					
18.2	18.5	17.2	6.24	10	34.5
Wood pellets, torrefied, from sawdust, for electricity generation {CA}					
24.2	24.8	23.3	7.93	13.7	43.9
Wood chips, from unmerchantable roundwood, industrial furnace {CA}					
6.9	7.12	6.59	2.61	3.8	13.4
Pellets, from corn stover, industrial furnace {CA}					
22.8	22.9	21.9	7.29	12.3	40.3
Wood pellets, from sawdust, residential stove {CA}					
14.8	15	14.6	2.49	11.1	20.5

10.5 Data Gaps and Limitations for Solid Low Carbon Fuels

The Canadian average CI values for solid low carbon fuels are based on Canadian average electricity inputs. Electricity is one of the primary energy inputs for conversion of solid low carbon feedstocks (i.e. pelletization, thermal treating, etc.) and as such, the CI results are quite sensitive to the background electricity grid. For example, wood pellets produced from sawdust in Alberta for residential pellet stoves would have a CI of 25 g CO_2 eq./MJ, which is 66% higher than the Canadian average. This is a result of the greater reliance on fossil fuels for electricity generation in Alberta. In addition, the CI value for wood pellets is highly sensitive to the source of drying energy. While it has been assumed that average Canadian facilities primarily use biomass or process heat for drying energy, some pellet plants may use natural gas or heating oil, and this could lead to significantly higher CI values. For example, the Canadian average CI value for wood pellets from sawmill residues with natural gas drying energy would be 29 g CO_2 eq. per MJ, which is over 90% higher. The literature on wood pellet production also indicates that pelletization energy can vary significantly from facility to facility depending on a number of factors, and this has a significant influence on the overall CI value.

The primary data gap for solid low carbon fuels is a lack of operating data for Canadian wood pellet plants. The collection of primary data on the inputs and outputs of operating Canadian wood pellet plants would provide key information to develop more representative CI values and to develop a full grasp on the variability of their operating inputs and outputs.

11. Pyrolysis Oils

11.1 System Boundaries and Technical Descriptions for Pyrolysis Oils

Pyrolysis is the thermal decomposition of carbon-rich mass occurring in the absence of oxygen and is the fundamental chemical reaction that is the precursor to both combustion and gasification processes. Pyrolysis generally produces bio oil, solid biochar, and non-condensable gases (NCG) which are typically rich in combustible hydrocarbons. Pyrolysis processes are classified as either slow pyrolysis or fast pyrolysis. Slow pyrolysis takes several hours to complete and generally results in biochar as the main product (Roy & Dias, 2017). Fast pyrolysis takes seconds to complete and results in a higher yield of bio oil (~60%) (Danish Energy Agency, 2017).

Pyrolysis oil is a dark-brown, free-flowing liquid that is generally referred to as bio oil. Bio oil has several different characteristics relative to conventional oil, including a higher water content and a lower sulfur content than conventional oil. Bio oil can be stored, pumped, and transported similar to petroleum products but has a higher pH and its corrosive nature means that modifications are required for storage and transportation (Bradburn, 2014).

At present there is very little commercial-scale production of pyrolysis oils in Canada; however, there is growing interest in using pyrolysis to convert wood residues to bio oil as a substitute for fossil fuels in industrial heating applications (Ayer & Dias, 2018). A recent survey of the global pyrolysis oil market indicated that although there were up to 73 separate pyrolysis technology ventures in Canada in 2014, the majority of these were start-ups with little potential (Canadian Biomass, 2014). At present, Ensyn's commercial pyrolysis production system in Ontario is the only known Canadian facility that has been consistently producing pyrolysis oil at a commercial scale over the long term.

The system boundaries for pyrolysis oil production are closely linked with the system boundaries and life cycle activities associated with solid wood biomass fuels. As shown in Figure 22, feedstock production for pyrolysis oil is assumed to come from the same wood biomass feedstock sources as solid low carbon fuels. A more complete description of the system boundaries and life cycle activities is provided in the following sections.

11.1.1 Feedstock Production

Pyrolysis technologies can handle a range of biomass feedstocks, including residues from agriculture, forest residues, energy crops, and municipal solid wastes (Roy & Dias, 2017). Essentially almost any form of organic material can be introduced into a pyrolyzer; however, because the chemical properties of the feedstock have a significant influence on both the product yields and quality (Laird, Brown, Amonette, & Lehmann, 2009), the feedstocks used for pyrolysis oil production are carefully selected.

For the purposes of establishing building blocks and default carbon intensities for pyrolysis oil in the Fuel LCA Modelling Tool, the feedstocks available for the pyrolysis oils pathway will be derived from the wood biomass feedstocks described in Section 10.3.1 of the solid low carbon fuel summary (e.g. harvest residues, sawmill residues, unmerchantable roundwood). In the future this could be expanded to include agricultural residues once more data on pyrolysis of agricultural residues is available or provided by producers.

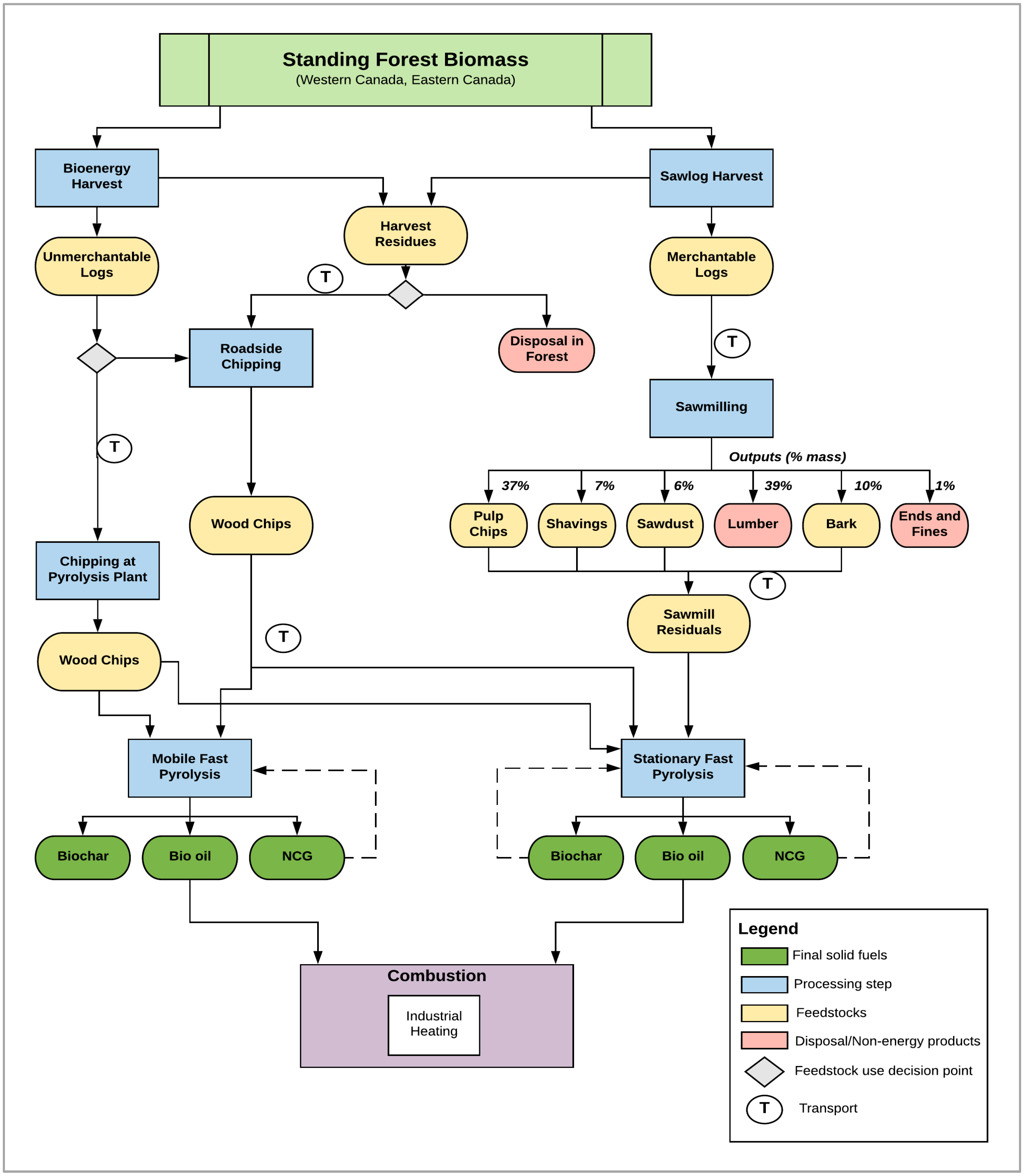

Figure 22. System boundaries and life cycle activities for bio oil production from two types of fast pyrolysis using wood biomass feedstocks, from extraction to combustion.

11.1.2 Fuel Conversion

The current potential for pyrolysis oil production in Canada is primarily centered on fast pyrolysis, and available LCI data for pyrolysis systems are generally for fast pyrolysis. In addition, fast pyrolysis systems are known to produce greater yields of bio oil than slow pyrolysis systems. During fast pyrolysis, biomass is converted at a very high heating rate

(10-1000 degrees C/s) for a very short residence time (0.5-2.0 seconds) producing volumes of bio oil in the range of 65-80% (on a dry mass basis) (Roy & Dias, 2017). Bio oil yield is highly dependent on feedstock properties and pyrolysis parameters, with wood biomass providing the highest yields. After cooling and condensing, the resulting bio oil has a heating value of about half that of conventional oil (Danish Energy Agency, 2017). The process gas produced during pyrolysis is typically used to provide drying energy for the incoming biomass. The biochar produced has a wide range of potential applications, including onsite energy use, substitution for coal or heavy fossil fuels in industrial boilers, or as a soil amendment.

The modelling of default pathways for pyrolysis oil will be based on two Canadian fast pyrolysis systems, including a mobile fast pyrolysis plant (Ayer & Dias, 2018) and a stationary fast pyrolysis plant (S&T2 Consultants Inc., 2011).

Mobile Fast Pyrolysis

To develop the basic unit process building blocks for a mobile fast pyrolysis system for converting wood biomass to bio oil, we used LCI data from a recent publication by Ayer & Dias (2018) where operating data from a demonstration-scale mobile fast pyrolysis plant was used to model the life cycle impacts of the system in a Canadian context. The fast pyrolysis plant modeled was a 50-tonne per day mobile plant that used steel-shot fluidized bed technology and a front-end feedstock drying system. Wood biomass is fed into the front-end unit where it is dried and pulverized before being fed into the pyrolysis chamber (Figure 23). On a mass basis, the mobile fast pyrolysis unit produces approximately 65% bio oil (at 17.7 MJ/kg energy content), 20% biochar (at 25.6 MJ/kg energy content), and 15% NCG (at 12.7 MJ/kg). NCG was assumed to be used for heating energy in the pyrolysis plant, while biochar was assumed to be sold to other end users.

Stationary Fast Pyrolysis

To develop the basic unit process building blocks for a stationary, commercial scale fast pyrolysis system for converting wood biomass to bio oil, we used LCI data and information from GHGenius 4.03 ((S&T)2 Consultants Inc., 2012). Ensyn provided mass balance and energy use data for their commercial scale system which produces bio oil, biochar, and NCG from wood feedstocks. It is assumed that all biochar and NCG are fully utilized by the pyrolysis system to dry incoming feedstock and therefore no additional fuel or biomass inputs are needed for drying energy. The process flow diagram for the Ensyn pyrolysis process is shown in Figure 24.

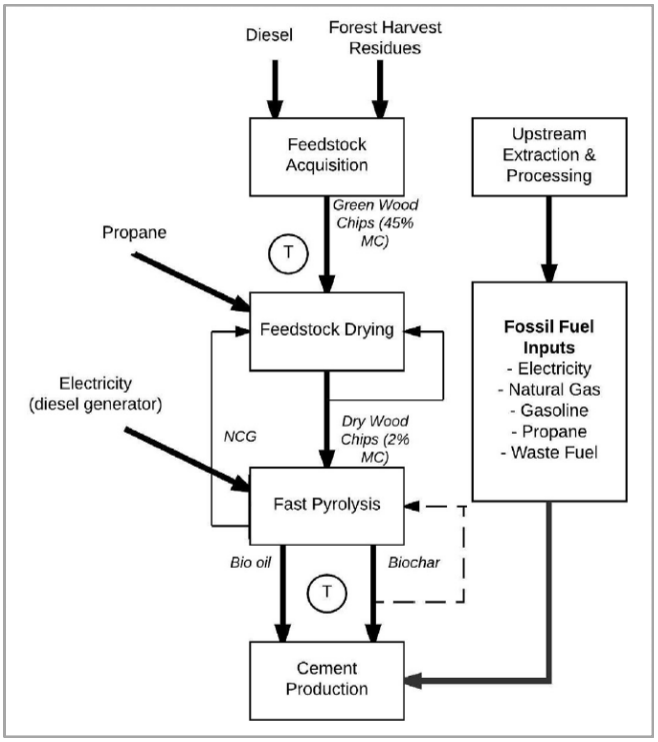

Figure 23. Overview of a mobile fast pyrolysis system using forest harvest residues to produce bio oil (Ayer & Dias, 2018).

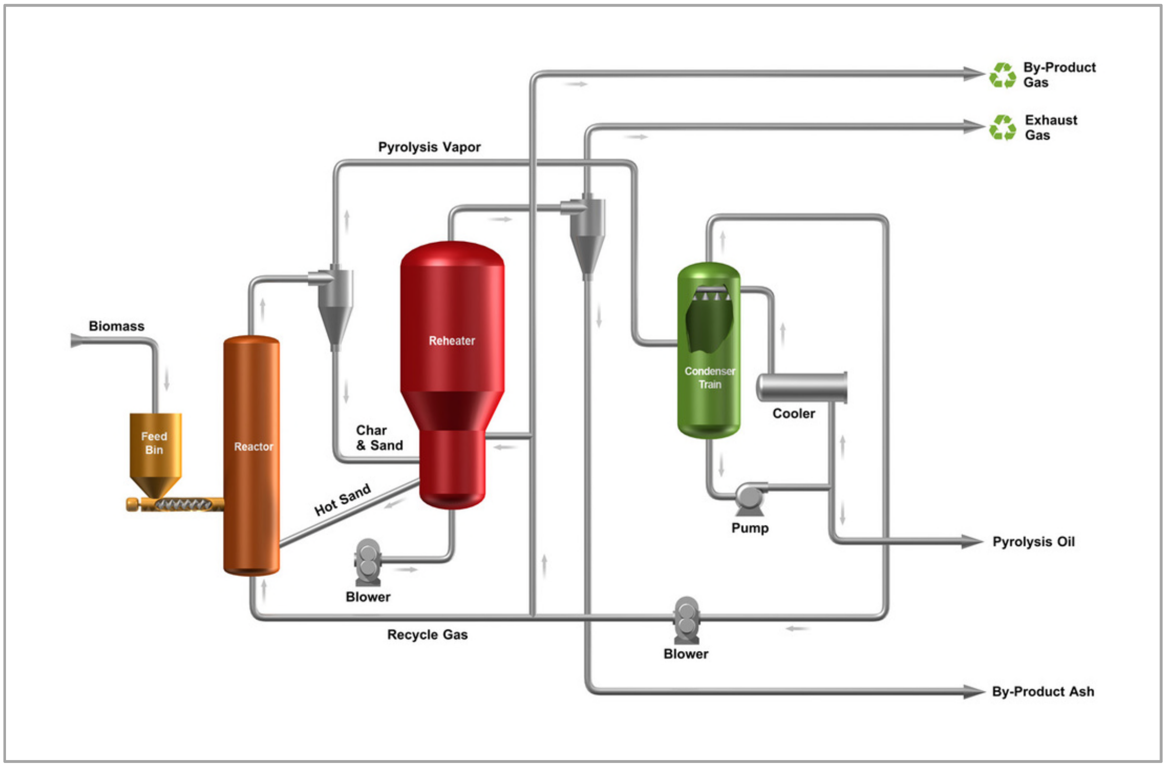

Figure 24. Process flow showing the components and steps in the Ensyn fast pyrolysis process for conversion of wood biomass to bio oil (http://www.ensyn.com/technology.html).

11.1.3 Fuel Combustion

Bio oil can be used in various energy applications, including combustion in industrial or residential boilers, cofired in power plants, blended with ethanol or diesel, or upgraded into transportation fuel (Roy & Dias, 2017). There are some challenges with each of these applications depending on the properties of the bio oil produced and the intended end use. At present, bio oil is most often considered for use in industrial furnaces and boilers due to its properties.

For the default pyrolysis oil pathways in the Fuel LCA Modelling Tool, the end use modelled for bio oil is combustion in an industrial furnace. Emissions factors for this combustion were derived from literature sources.

11.2 Life Cycle Inventory for Pyrolysis Oils

11.2.1 Feedstock Production

As shown in Figure 22, the feedstocks used in modelling bio oil production from fast pyrolysis are derived from the wood biomass feedstocks modelled for solid low carbon fuels (see Solid Wood Biomass Fuels). Transport of feedstocks to a pyrolysis plant was modeled using transport processes modeled in Milestone 2, including trucks and rail transport.

11.2.2 Fuel Conversion

Fuel conversion in mobile fast pyrolysis units was modeled using LCI data from Ayer & Dias (2018). The inputs and outputs required for feedstock drying and fast pyrolysis are shown in Table 106.

Table 106. Operating inputs and outputs for a 50 TPD mobile fast pyrolysis plant (Ayer & Dias, 2018). OD = oven dry mass; MC = moisture content.

LCI Data	Amount	Units
Feedstock Drying		
Inputs		
Green wood chips (50% MC)	3.21	kg
Propane	0.16	g
Dry wood chips (OD)	0.14	kg
Syngas (NCG)	0.23	kg
Outputs		
Dry wood chips (OD)	1.77	kg
Fast Pyrolysis		
Inputs		
Electricity (diesel generator)	0.075	kW
Dry wood chips – feedstock (OD)	1.54	kg
Dry wood chips – heating (OD)	0.09	kg
Outputs		
Bio oil (17.7 MJ)	1.0	kg
Biochar	0.31	kg
Syngas (NCG)	0.23	kg
Process Emissions		
Methane	0.0001	g

Fuel conversion of wood biomass to bio oil in a commercial scale stationary fast pyrolysis system will be modeled using LCI data from GHGenius 4.03 ((S&T)2 Consultants Inc., 2012). The operating inputs and outputs for the plant are summarized in Table 107.

Table 107. Operating inputs and outputs and process emissions for production of 1 l of bio oil from wood biomass feedstock in a commercial scale stationary fast pyrolysis system (S&T2 Consultants Inc., 2011).

LCI Data	Amount	Units
Inputs		
Dry wood	1.65	kg
Electricity	0.24	kWh
Natural gas	0.02	l
Outputs		
Bio oil (17.7 MJ/kg)	1.0	l
Process Emissions		
Methane	0.34	g/GJ of wood feedstock
Dinitrogen monoxide	1.01	g/GJ of wood feedstock

11.2.3 Fuel Combustion

Emissions factors for the combustion of pyrolysis oil derived from wood biomass for industrial heating will be obtained from Ayer & Dias (2018). These emissions factors for methane and dinitrogen monoxide were provided by Ensyn and based on testing of the bio oil produced in their commercial scale process. The emissions factor for biogenic carbon dioxide from pyrolysis oil is from an LCA study on production of bio oil using fast pyrolysis of wood biomass feedstock in the US (Steele, Puettmann, Penmetsa, & Cooper, 2012). The emissions factors are summarized in Table 108.

Table 108. Combustion emissions factors for pyrolysis oil derived from wood biomass in a fast pyrolysis process (Steele, Puettmann, Penmetsa, & Cooper, 2012) (S&T2 Consultants Inc., 2011).

Feedstock	Energy Content (HHV) (MJ/kg)	CO_2 (g/MJ)	CH_4 (g/MJ)	N_2O (g/MJ)
Pyrolysis oil (from wood)	17.5	146	0.0001	0.00005

The CO_2 emissions from combustion are considered as biogenic carbon since they are from wood biomass feedstock. As such, although these emissions will be quantified and reported separately, they will not be included in the default carbon intensity values for low carbon solid fuels.

11.3 Carbon Intensity Results for Pyrolysis Oils

CI results for pyrolysis oils are summarized in Table 109 below, including two different types of pyrolysis technologies. Results indicate that the CI for bio oil using mobile fast pyrolysis units to process chipped harvest residues and for larger-scale stationary pyrolysis of sawmill wood chips are essentially equivalent (7.9 and 7.4 g CO_2 eq. per MJ, respectively).

Table 109. Canadian average carbon intensity values for bio oil produced from mobile and stationary fast pyrolysis of wood biomass feedstocks, expressed in g CO_2 eq./MJ of fuel used in an industrial furnace.

Pyrolysis Pathway	Carbon Intensity (g CO_2 eq./MJ)
Bio oil, from mobile fast pyrolysis of harvest residues, for industrial furnace {CA}	7.9
Bio oil, from stationary fast pyrolysis of sawmill wood chips, for industrial furnace {CA}	7.4

For the mobile pyrolysis system, the primary contributors to life cycle GHG emissions are the various activities to provide wood chips for feedstock and for drying energy, including roadside chipping of harvest residues and transport of wet chips to the pyrolysis plant. For the stationary pyrolysis plant, the primary contributors to life cycle GHG emissions are the electricity use at the plant (47%) and the provision of wood chips from the sawmill (47%). Relative to the mobile pyrolysis unit, the stationary pyrolysis process is more energy intensive; however, all of the biochar produced is used onsite for drying energy which reduces the need for external inputs for drying energy such as natural gas, propane, or wood biomass. For the mobile pyrolysis system it was assumed that biochar is sold to external users; however, that system is capable of using biochar for heating, and therefore biochar could be used for drying energy in place of wood biomass, which is assumed to be the primary source in this model. This would lower the CI for mobile pyrolysis, and represents a modification that users of the Fuel LCA Modelling Tool could make depending on the set up of their system.

11.3.1 Uncertainty

Uncertainty analysis was conducted for Canadian average pyrolysis oil using Monte Carlo analysis. Results of the uncertainty analysis are shown in the violin plots in Section 12 and discussed relative to the uncertainty of other low carbon fuels in that section. Below in Table 110 the key results of the uncertainty analysis from each of the sources are summarized.

Overall the results for pyrolysis oil shows a relatively high level of uncertainty, with max values being more than or nearly double the baseline value, and min values being 50% or less of the baseline value.

Table 110. Results of uncertainty analyses for pyrolysis oils. Results based on Monte Carlo analysis of 2,000 runs with a confidence interval of 95%.

Final CI	Mean	Median	SD	Min (2.5%)	Max (97.5%)
Bio oil, mobile fast pyrolysis of harvest residues, for industrial furnace {CA}					
7.9	7.78	6.76	4.33	2.66	18.8
Bio oil, stationary fast pyrolysis of sawmill wood chips, for industrial furnace {CA}					
7.4	7.6	7.19	2.56	3.81	13.8

11.3.2 Data Gaps and Limitations for Pyrolysis Oils

Pyrolysis technologies are still an emerging part of the bioenergy sector and there is very little commercial production of pyrolysis oils for bioenergy. The data for stationary pyrolysis used in this analysis is quite dated and is not likely representative of newer operations and efficiencies. More recent primary data on pyrolysis systems for bio oil production are needed to develop more robust CI values. The results presented in this study for mobile fast pyrolysis are based on an energy allocation between bio oil, biochar, and syngas. Future users of the Fuel LCA Modelling Tool may benefit from expanding the boundary of the model to account for the use of biochar either within the pyrolysis process, or in off-site applications that could yield additional environmental benefits. Ultimately there is a wide range of pyrolysis systems being proposed, and a number of different feedstocks could potentially be used, so the system modeled in this study are very basic examples and may not be representative of the latest technology.

12. Interpretation and Conclusions

12.1 Interpretation

This study provides transparent modeling of low carbon fuels and carbon intensity values with uncertainty. It includes detailed modeling of Canadian feedstocks and conversation spanning the breadth of technology used in Canada along with many candidates for future fuels. Uncertainty has been applied at the unit process level to quantities of inputs, emissions and products as well as to the fitness for purpose of the underlying data, and at the impact level to the characterization factors.

The results presented align well with publicly available data from Canada, the US and elsewhere. The uncertainty of the results may be surprising to some readers as the variability of outputs from refineries is much higher than many studies have represented. While the study points out a number of areas where filling data gaps would reduce the uncertainty, this variability refinery to refinery is not likely to decrease over time. Uncertainty in the impact categories had minimal impact on the results.

12.1.1 Data Quality

Data quality was assessed using the pedigree matrix for uncertainty (Frischknecht, et al., 2007) on both the amount and the quality of the linked data. Data quality scores are summarized in the data sheets provided for each of the unit processes modelled.

12.1.2 Uncertainty

As indicated above, uncertainty was applied to the amounts and fitness for purpose of input and emissions data either using the variability in the process or using the pedigree matrix described in the Milestone 1 report (EarthShift Global, WSP, Introspective Systems 2019). Uncertainty was also applied to the characterization factors based on the IPCC 2013 report as shown in Appendix F of the Milestone 1 report.

In addition to the transport as discussed in Milestone 2, uncertainty in the clean fuel pathways derives from crop production, which varies greatly based on location, weather patterns in a given year and production processes, as well as from the conversion processes, many of which are still in pilot phase. This results in higher overall uncertainties in these pathways than in the more conventional pathways such as fossil fuel pathways, and to a certain extent, crop-based ethanol.

Another source of high uncertainty is in changes in soil carbon. Some studies show that practices such as no-till increase soil carbon, others indicate that it reduces the depletion of soil carbon (assumed here) and still others indicate that no-till simply moves the same amount of carbon storage from deeper regions to more shallow regions. A high range of uncertainty was applied to account for these contradictory results.

The results of the uncertainty assessment are illustrated in the violin plots below (Figure 25 and Figure 26) CIs at combustion. These include uncertainty from the inventory data alone. Each “violin” can be seen as a probability density curve which is mirror imaged. The width of the violin at a given value is proportional to the probability of that value; values in the widest portions of the violin are more probable than those in the thin tails of the distribution. There is a 90% probability the value lies within the lighter, outer envelope, while the darker core shows the 50% confidence limit.

The CIs are highly concentrated around the median CI value, as indicated by the shape of the distribution of the uncertainty in the violin plots. This indicates that the sources of uncertainty in the analysis do not cause the results to stray far from the median calculated value.

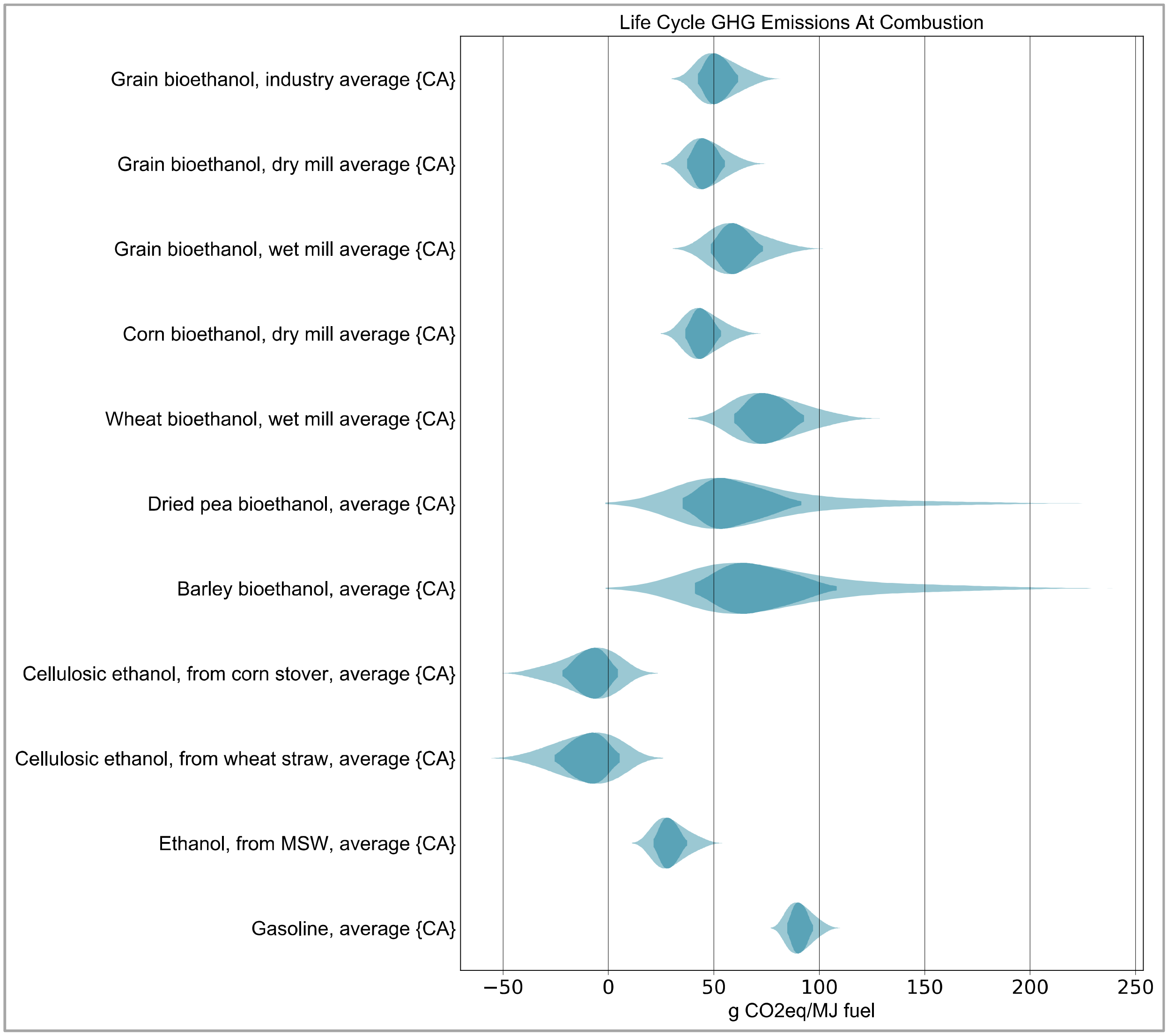

Figure 25. Uncertainty of combusted bioethanol products ("Grain" includes wheat, corn and barley unless otherwise specified), using producer reported ethanol mill facility data from CEPR reports for NRCan's ecoENERGY for Biofuels Program.

Figure 25 shows the uncertainty around the ethanol products. The top pathways are different technology and feedstock slices from industry reported data; all are less carbon intense than conventional gasoline, for which they are an analog. The most speculative processes, dried pea and pure barley bioethanols based on scaling producer-based pathways, show dramatically higher uncertainties than the other grain-based bioethanols, because the technology and agricultural CI uncertainties couple. While the electricity produced in cellulosic processes is likely to result in a credit, there is some probability there will still be an impact, and that will only increase as the rest of the grid gets cleaner.

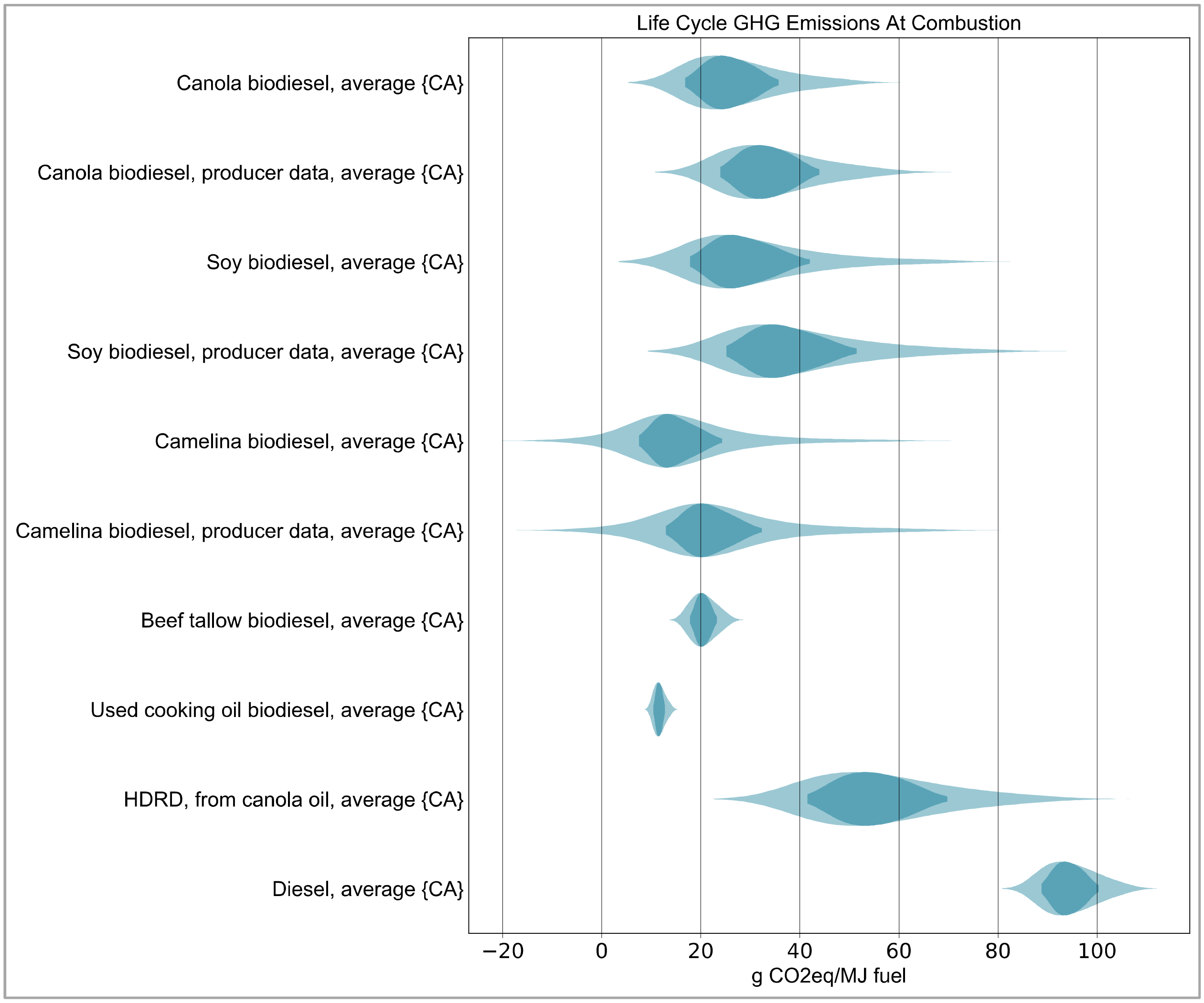

Figure 26. Uncertainty of combusted biodiesel products. 'producer data' processes represent values from CEPR reports for NRCan's ecoENERGY for Biofuels Program.

Figure 26 shows the uncertainty around the combusted CIs for biodiesels. Biodiesels from crops carry high uncertainties, again due to the feedstock uncertainties. The literature and producer-reported facility pathways are very similar because the agricultural uncertainty overwhelms uncertainties in the other life cycle stages. The impact of the large agricultural uncertainty is particularly apparent in the CI for camelina-based fuels. The wide range and negative minimum values reflect the range in soil organic carbon emissions associated with management practice change. The waste-derived biodiesels have lower uncertainty in the CI because the feedstocks carry no burden. Also, oilseeds represent a small share of current Canadian biodiesel production, so the fat-based pathways align more with facility parameters.

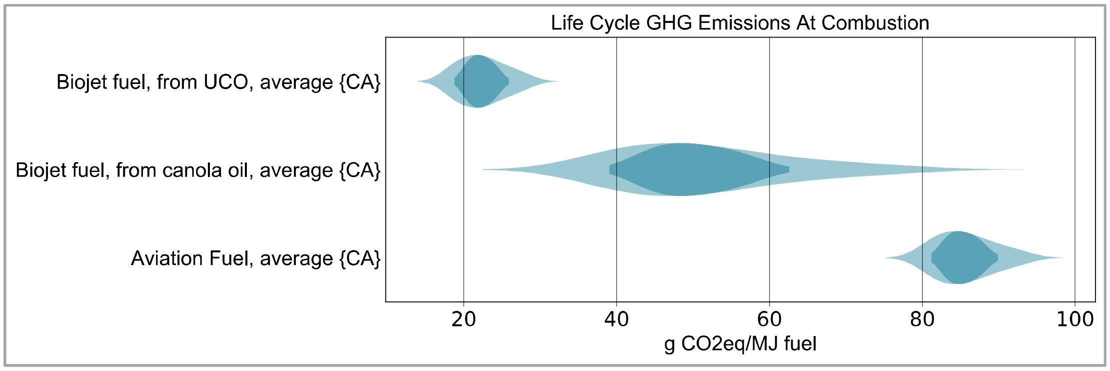

Figure 27. Uncertainty of combusted aviation products.

Figure 27 shows the uncertainty around the combusted CIs for biojet aviation fuels. Biojet fuels from crops carry far higher uncertainties, again due to the agricultural feedstock uncertainties and the more speculative nature of the HDRD pathway. Fuels from wastes have lower uncertainty in the CI because the feedstocks carry no burden.

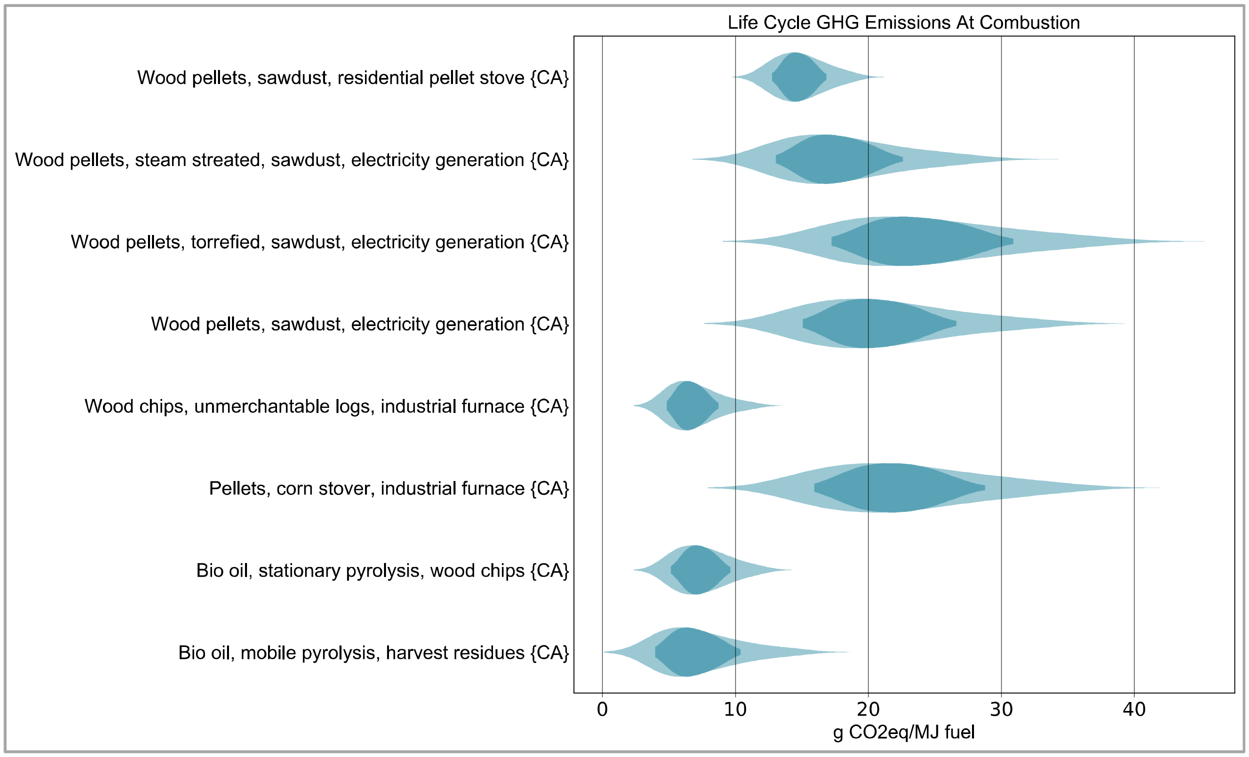

Figure 28. Uncertainties in carbon intensities from combustion of wood-derived fuels.

Wood-derived fuels have tighter distributions of the CI value as is shown in Figure 28. As no burden is assigned to the growth of the tree, there is significantly lower uncertainty in the feedstock. This is somewhat of an oversimplification, and future studies should consider work currently going on around forest carbon intensities and how they change over time.

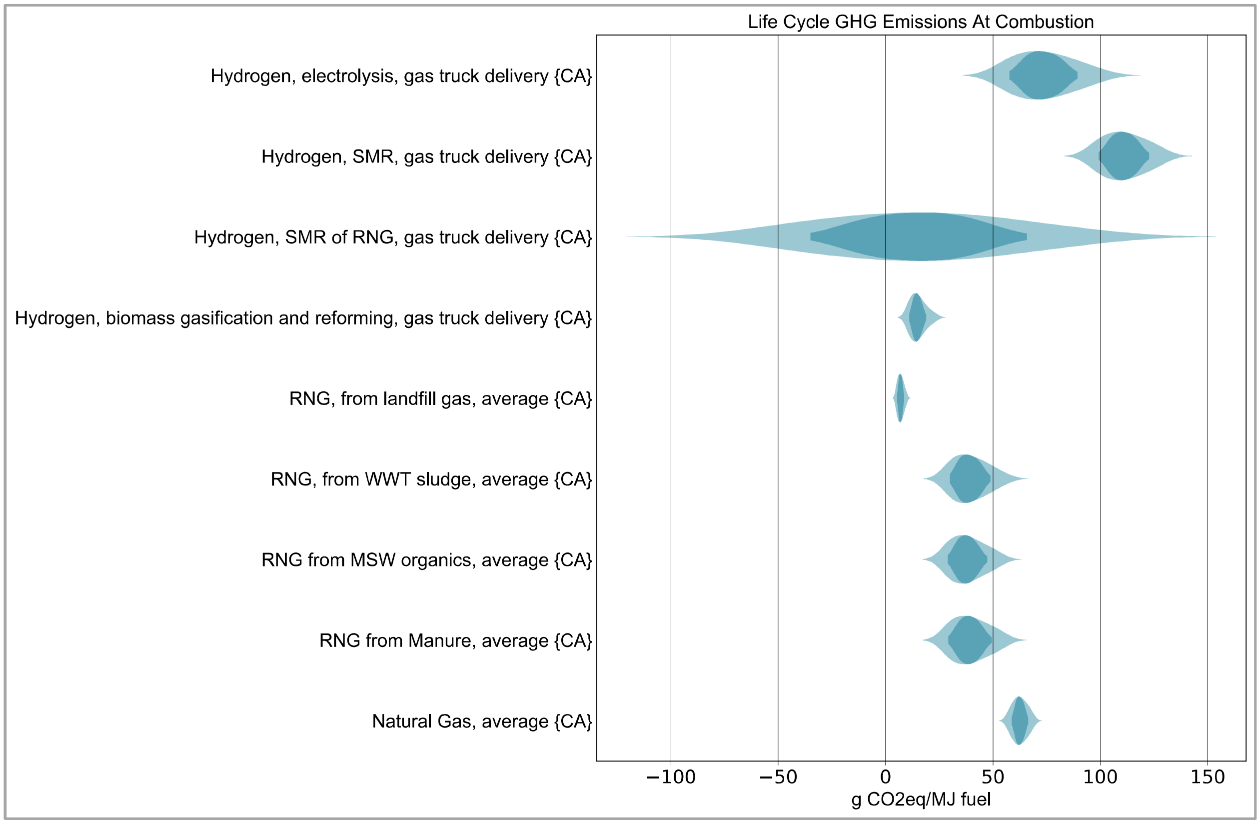

Figure 29. Uncertainty in carbon intensity of combusted hydrogen fuels.

Uncertainty in hydrogen electrolysis (Figure 29) is much higher than the other hydrogen production processes because the high variability in the electricity mix used to produce it. Standard SMR, while it has a relatively high uncertainty, is in the same range, or higher than most fossil fuels. Waste derived alternatives, such RNG and biogas, have generally both lower CIs and lower uncertainty because of lower impact in the feedstocks. Hydrogen produced via SMR of RNG shows a dramatic uncertainty range because both the SMR and RNG pathways are fairly uncertain, and when combined those uncertainties magnify.

12.2 Limitations

As with any study, there are limitations in the application of the results of this study. For this study, since only one impact category of environmental impact was considered, the interpretation of these results is limited to discussion only of GHG emissions impacts from fossil fuel production and use on the environment. Statements on the holistic impact of fossil fuels on the environment should not be made based on these results. The results also apply only to the perspective of an attributional allocation based on high heating value. Other allocations and perspectives may produce different results. Data are being gathered to allow other allocation methods to be available in the tool when is it completed.

Application of interpretation of these results should note that this study is a snapshot in time. With time, technologies, markets and supply chains will shift which will inevitably alter the carbon intensities of the considered fuel pathways. Data gaps identified throughout this study introduce some limitations in the applicability of the results and comparability with reported GHG emissions, though efforts have been made to explain and rectify discrepancies between reported and calculated emissions.

12.3 Conclusions and recommendations

12.3.1 Conclusions

The detail with which the pathways were modeled provided visibility into data gaps and where future effort should be focused. Additionally, several of the pathways identified dramatic variation year over year. Applying uncertainty to these data gaps and variability provided additional insights into how critical gathering additional data and considering a longer time period may be.

CIs external to the scope of this project play a key role in the results. In particular, there is a considerable amount of electricity which influences the final results. On the other hand, the CIs of this project could better inform the electricity CIs.

12.3.2 Recommendations

It is our recommendation that future updates to these baseline carbon intensities address known data gaps. In general, direct collection of data on inputs and outputs from facilities would improve the data quality over data collected from academic studies and public reports. Additionally, the results for both electricity and the fuels would be more robust if the electricity pathways were rolled into the tool. This would allow the electricity pathways to link to the fuels and the fuel pathways to link to the electricity, keeping both up to date. It is also recommended that future analysis include the impact of fuel production and consumption in Canada on other impact categories such as impacts to water consumption, water quality, and other emissions to air so that results can support a wholistic evaluation of environmental impacts from fossil fuels. Data gaps to be filled for each fuel and processing step are described in detail in the preceding sections.

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Appendix A: Supplemental Data and Information for Low Carbon Fuel Pathways

A1. Agrochemicals Carbon Intensity Data

The tables below expand upon the agrochemical CI data in Section 4.6 Agrochemicals upstream emissions

Table 111: Cradle-to-farm emissions for relevant agrochemical inputs included in GREET2018, in grams per kg. (ANL, 2018)

Input	CH4	N2O	CO2
Ammonia	7.55	0.05	2,382
Urea	5.48	0.04	1,048
Urea-Ammonium Nitrate Solution	11.82	5.44	3,302
Ammonium Nitrate	3.69	3.77	1,243
Ammonium Sulfate	2.04	0.01	679
Monoammonium Phosphate	2.29	0.02	960.
Diammonium Phosphate	2.84	0.02	1,113
Potash	1.01	0.01	541
Atrazine	25.07	0.26	14,703
Metolachlor	36.33	0.38	21,300
Acetochlor	36.64	0.39	21,479
Cyanazine	26.55	0.28	15,569
Insecticides	37.00	0.33	21,038

Upstream emissions from agrochemical inputs (fertilizers and pesticides) are used based on share of tracked fertilizers shipped to Canadian Agriculture, shown in Table 112.

Table 112: Canadian Fertilizer mix (Statistics Canada, 2019) and nutrient shares for each compound.

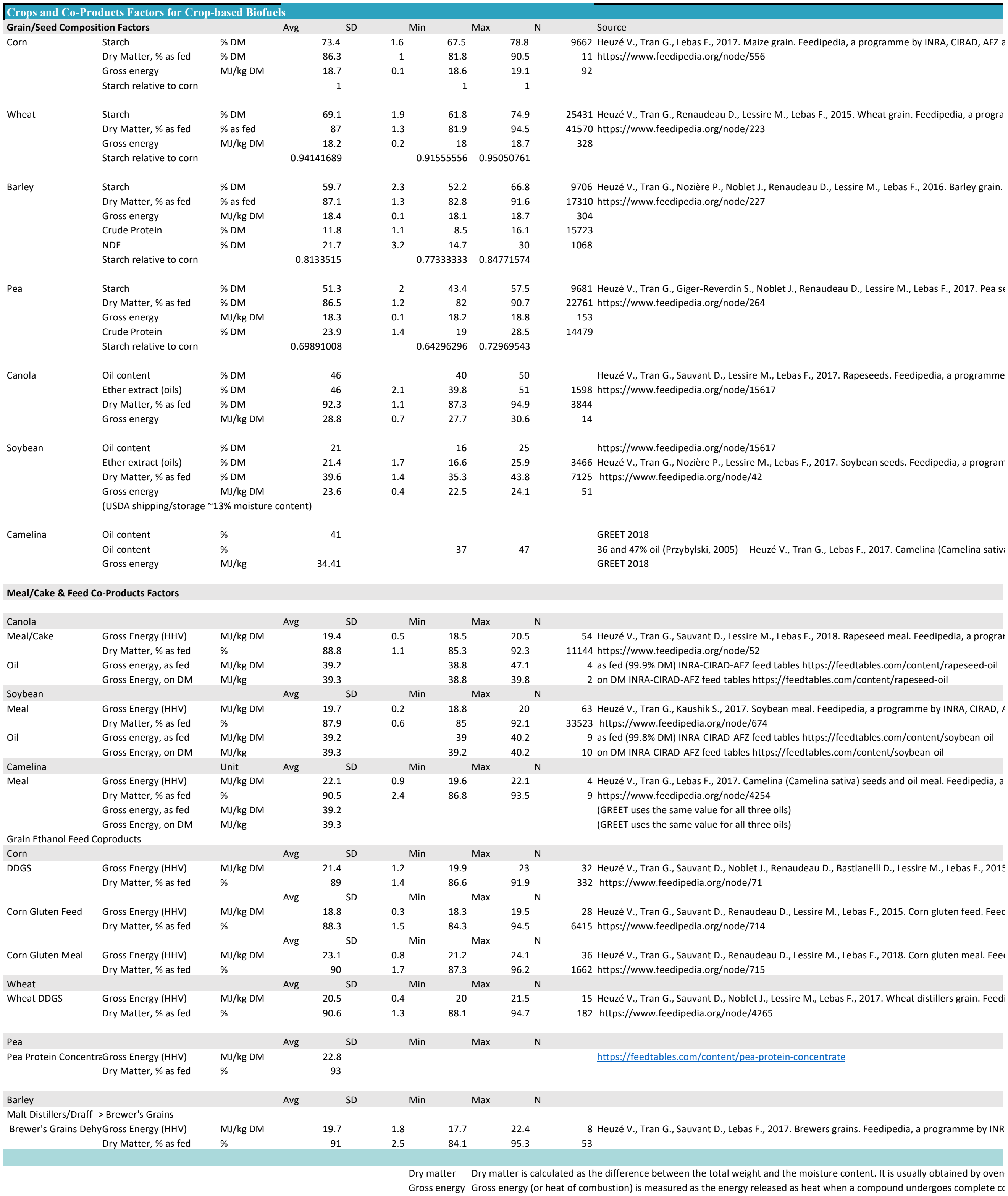
	Average Shares, 2014-2017					Nutrient Fraction, by mass			
	% total shipped	% of N	% of P	% of K	% of S	N	P	K	S
Ammonia	7%	8%				82%			
Urea	34%	40%				47%			
Urea ammonium nitrate	13%	16%				28%			
Ammonium nitrate/calcium ammonium nitrate	1%	1%				34%			
Ammonium sulphate	10%	11%			100%	28%			24%
Monoammonium phosphate	17%	20%	90%			18%	52%		
Diammonium phosphate	2%	2%	10%			18%	46%		
Potash	7%			100%				60%	
Other fertilizer products	9%								

Table 113: Nutrient and pesticide cradle-to-farm emissions based on 2014-2017 average market data (StatsCan 2019) and the GREET2018 LCI, in grams per kg.

Input	CH4	N2O	CO2
N, per kg	13.718	3.284	3602.149
P, per kg	3.054	0.027	1271.496
K, per kg	1.685	0.015	901.884
S, per kg	4.543	0.030	1511.345
Pesticide, per kg a.i.	32.316	0.329	18,817.815

A2. Grain, Seed, and Feed Compositional Factors

Table 114: Grain, Seed and Feed parameters used for crop-based biofuels.



Crops and Co-Products Factors for Crop-based Biofuels

Grain/Seed Composition Factors			Avg	SD	Min	Max	N	Source
Corn	Starch	% DM	73.4	1.6	67.5	78.8	9662	Heuzé V., Tran G., Lebas F., 2017. Maize grain. Feedipedia, a programme by INRA, CIRAD, AFZ a
	Dry Matter, % as fed	% DM	86.3	1	81.8	90.5	11	https://www.feedipedia.org/node/556
	Gross energy	MJ/kg DM	18.7	0.1	18.6	19.1	92	
	Starch relative to corn		1		1	1		
Wheat	Starch	% DM	69.1	1.9	61.8	74.9	25431	Heuzé V., Tran G., Renaudeau D., Lessire M., Lebas F., 2015. Wheat grain. Feedipedia, a prograı
	Dry Matter, % as fed	% as fed	87	1.3	81.9	94.5	41570	https://www.feedipedia.org/node/223
	Gross energy	MJ/kg DM	18.2	0.2	18	18.7	328	
	Starch relative to corn		0.94141689		0.91555556	0.95050761		
Barley	Starch	% DM	59.7	2.3	52.2	66.8	9706	Heuzé V., Tran G., Nozière P., Noblet J., Renaudeau D., Lessire M., Lebas F., 2016. Barley grain.
	Dry Matter, % as fed	% as fed	87.1	1.3	82.8	91.6	17310	https://www.feedipedia.org/node/227
	Gross energy	MJ/kg DM	18.4	0.1	18.1	18.7	304	
	Crude Protein	% DM	11.8	1.1	8.5	16.1	15723	
	NDF	% DM	21.7	3.2	14.7	30	1068	
	Starch relative to corn		0.8133515		0.77333333	0.84771574		
Pea	Starch	% DM	51.3	2	43.4	57.5	9681	Heuzé V., Tran G., Giger-Reverdin S., Noblet J., Renaudeau D., Lessire M., Lebas F., 2017. Pea se
	Dry Matter, % as fed	% DM	86.5	1.2	82	90.7	22761	https://www.feedipedia.org/node/264
	Gross energy	MJ/kg DM	18.3	0.1	18.2	18.8	153	
	Crude Protein	% DM	23.9	1.4	19	28.5	14479	
	Starch relative to corn		0.69891008		0.64296296	0.72969543		
Canola	Oil content	% DM	46		40	50		Heuzé V., Tran G., Sauvant D., Lessire M., Lebas F., 2017. Rapeseeds. Feedipedia, a programme
	Ether extract (oils)	% DM	46	2.1	39.8	51	1598	https://www.feedipedia.org/node/15617
	Dry Matter, % as fed	% DM	92.3	1.1	87.3	94.9	3844	
	Gross energy	MJ/kg DM	28.8	0.7	27.7	30.6	14	
Soybean	Oil content	% DM	21		16	25		https://www.feedipedia.org/node/15617
	Ether extract (oils)	% DM	21.4	1.7	16.6	25.9	3466	Heuzé V., Tran G., Nozière P., Lessire M., Lebas F., 2017. Soybean seeds. Feedipedia, a program
	Dry Matter, % as fed	% DM	39.6	1.4	35.3	43.8	7125	https://www.feedipedia.org/node/42
	Gross energy	MJ/kg DM	23.6	0.4	22.5	24.1	51	
	(USDA shipping/storage ~13% moisture content)							
Camelina	Oil content	%	41					GREET 2018
	Oil content	%			37	47		36 and 47% oil (Przybylski, 2005) -- Heuzé V., Tran G., Lebas F., 2017. Camelina (Camelina sativa
	Gross energy	MJ/kg	34.41					GREET 2018
Meal/Cake & Feed Co-Products Factors								
Canola			Avg	SD	Min	Max	N	
Meal/Cake	Gross Energy (HHV)	MJ/kg DM	19.4	0.5	18.5	20.5	54	Heuzé V., Tran G., Sauvant D., Lessire M., Lebas F., 2018. Rapeseed meal. Feedipedia, a prograr
	Dry Matter, % as fed	%	88.8	1.1	85.3	92.3	11144	https://www.feedipedia.org/node/52
Oil	Gross energy, as fed	MJ/kg DM	39.2		38.8	47.1	4	as fed (99.9% DM) INRA-CIRAD-AFZ feed tables https://feedtables.com/content/rapeseed-oil
	Gross Energy, on DM	MJ/kg	39.3		38.8	39.8	2	on DM INRA-CIRAD-AFZ feed tables https://feedtables.com/content/rapeseed-oil
Soybean			Avg	SD	Min	Max	N	
Meal	Gross Energy (HHV)	MJ/kg DM	19.7	0.2	18.8	20	63	Heuzé V., Tran G., Kaushik S., 2017. Soybean meal. Feedipedia, a programme by INRA, CIRAD, A
	Dry Matter, % as fed	%	87.9	0.6	85	92.1	33523	https://www.feedipedia.org/node/674
Oil	Gross energy, as fed	MJ/kg DM	39.2		39	40.2	9	as fed (99.8% DM) INRA-CIRAD-AFZ feed tables https://feedtables.com/content/soybean-oil
	Gross Energy, on DM	MJ/kg	39.3		39.2	40.2	10	on DM INRA-CIRAD-AFZ feed tables https://feedtables.com/content/soybean-oil
Camelina		Unit	Avg	SD	Min	Max	N	
Meal	Gross Energy (HHV)	MJ/kg DM	22.1	0.9	19.6	22.1	4	Heuzé V., Tran G., Lebas F., 2017. Camelina (Camelina sativa) seeds and oil meal. Feedipedia, a
	Dry Matter, % as fed	%	90.5	2.4	86.8	93.5	9	https://www.feedipedia.org/node/4254
	Gross energy, as fed	MJ/kg DM	39.2					(GREET uses the same value for all three oils)
	Gross Energy, on DM	MJ/kg	39.3					(GREET uses the same value for all three oils)
Grain Ethanol Feed Coproducts								
Corn			Avg	SD	Min	Max	N	
DDGS	Gross Energy (HHV)	MJ/kg DM	21.4	1.2	19.9	23	32	Heuzé V., Tran G., Sauvant D., Noblet J., Renaudeau D., Bastianelli D., Lessire M., Lebas F., 2015
	Dry Matter, % as fed	%	89	1.4	86.6	91.9	332	https://www.feedipedia.org/node/71
			Avg	SD	Min	Max	N	
Corn Gluten Feed	Gross Energy (HHV)	MJ/kg DM	18.8	0.3	18.3	19.5	28	Heuzé V., Tran G., Sauvant D., Renaudeau D., Lessire M., Lebas F., 2015. Corn gluten feed. Feed
	Dry Matter, % as fed	%	88.3	1.5	84.3	94.5	6415	https://www.feedipedia.org/node/714
			Avg	SD	Min	Max	N	
Corn Gluten Meal	Gross Energy (HHV)	MJ/kg DM	23.1	0.8	21.2	24.1	36	Heuzé V., Tran G., Sauvant D., Renaudeau D., Lessire M., Lebas F., 2018. Corn gluten meal. Feec
	Dry Matter, % as fed	%	90	1.7	87.3	96.2	1662	https://www.feedipedia.org/node/715
Wheat			Avg	SD	Min	Max	N	
Wheat DDGS	Gross Energy (HHV)	MJ/kg DM	20.5	0.4	20	21.5	15	Heuzé V., Tran G., Sauvant D., Noblet J., Lessire M., Lebas F., 2017. Wheat distillers grain. Feedi
	Dry Matter, % as fed	%	90.6	1.3	88.1	94.7	182	https://www.feedipedia.org/node/4265
Pea			Avg	SD	Min	Max	N	
Pea Protein Concentra	Gross Energy (HHV)	MJ/kg DM	22.8					https://feedtables.com/content/pea-protein-concentrate
	Dry Matter, % as fed	%	93					
Barley			Avg	SD	Min	Max	N	
Malt Distillers/Draff -> Brewer's Grains								
Brewer's Grains Dehy	Gross Energy (HHV)	MJ/kg DM	19.7	1.8	17.7	22.4	8	Heuzé V., Tran G., Sauvant D., Lebas F., 2017. Brewers grains. Feedipedia, a programme by INR
	Dry Matter, % as fed	%	91	2.5	84.1	95.3	53	

Dry matter	Dry matter is calculated as the difference between the total weight and the moisture content. It is usually obtained by oven
Gross energy	Gross energy (or heat of combustion) is measured as the energy released as heat when a compound undergoes complete cc

A3. Cellulosic Ethanol

Corn stover components and sugar conversion to ethanol are based on NREL 2011 report (Humbird, et al., 2011). Wheat straw analysis is based on a 2010 paper published in Biotechnology for Biofuels and will follow the same conversion assumptions for sugars as in the NREL 2011 study (Erdei, et al., 2010).

Table 115: Corn stover sugar composition and yield per 1,000 kg

Component sugar	% dry weight	Fraction	Yield	Unit
glucan (cellulose)	35.05	35.05%	350.5	kg glucan
xylan	19.53	19.53%	195.3	kg xylan
lignin	15.76	15.76%	157.6	kg lignin
arabinan	2.38	2.38%	23.8	kg arabinan
galactan	1.43	1.43%	14.3	kg galactan
mannan	0.6	0.60%	6	kg mannan
sucrose	0.77	0.77%	7.7	kg sucrose

Table 116: Wheat straw composition and yield per 1,000 kg

Component sugar	% dry weight	Fraction	Yield	Unit
glucan (cellulose)	38.8	38.80%	388	kg glucan
xylan	22.2	22.20%	222	kg xylan
lignin	18.5	18.50%	185	kg lignin
arabinan	4.7	4.70%	47	kg arabinan
galactan	2.7	2.70%	27	kg galactan
mannan	1.7	1.70%	17	kg mannan
sucrose		0.00%	0	kg sucrose

Table 117: Sugar conversion reaction during pretreatment

Input number of sugars	Input sugar type	Output number of sugars	Output sugar type	% converted to product	Ratio of conversion
1	glucan	1	glucose	9.90%	0.099
1	sucrose	1	glucose	100.00%	1
1	xylan	1	xylose	90.00%	0.9
Note: Sugar oligomers are considered soluble but not fermentable therefore xylan to xylose oligomer does not yield ethanol.					

Table 118: Sugar conversion during enzymatic hydrolysis

Input number of sugars	Input sugar type	Output number of sugars	Output sugar type	% converted to product
1	glucan	1	glucose	4.00%
1	glucan	0.5	cellobiose	1.20%
1	glucan	1	glucose	90.00%
1	cellobiose	2	glucose	100.00%

Table 119: Ethanol fermentation conversion description and percentages

Conversion description	Percent
Overall cellulose to ethanol conversion	87%
Xylose to ethanol fermentation conversion	79%

Appendix B: Transmission and Distribution

B1. Overview

The production, distribution and consumption of biofuels requires a series of transportation steps. This report provides an overview of the transportation processes required to model the variety of feedstocks and biofuels applicable in Canada.

The transportation unit processes that are included in the Fuel LCA Modelling Tool are summarized in Table 120. These models were applied selectively to represent the transportation steps involved in each feedstock and biofuels pathway. The unit processes in the Fuel LCA Modelling Tool will contain model parameters (e.g. load and distance) so that they can be adapted to the specific conditions relevant for each pathway.

Table 120. Summary of transportation processes to be modelled for low carbon fuels.

Mode of Transport	Feedstock Transport	Fuel Distribution	Regional/Proximity Considerations	Modelling Considerations and Parameters
Truck	• Agricultural • Forestry	• Conventional biofuels • Biomass (raw and pellet)	• Considered for local transportation and delivery of biofuel and biomass products to end users • Local supply is a key determinant for regional variability of feedstocks • End-user proximity is a key determinate for fuel distribution	• Load (mass) • Distance • Forestry feedstocks require additional transportation steps depending on source and production pathway (e.g. transport to road-side wood chipping) • Water content of feedstocks and biomass affects vehicle efficiency
Rail	• Agricultural	• Conventional biofuels	• Considered for longer-distance transportation (anticipated to be more relevant in mature biofuels industry)	• Load (mass) • Distance • Water content of feedstocks and biomass affects vehicle efficiency
Pipeline	• Natural gas	• Hydrogen • Renewable natural gas	• Cross-provincial transportation of natural gas (as feedstock for hydrogen production) • Local distribution networks for hydrogen and renewable natural gas	• Load (volume) • Distance

Further descriptions of these processes as well as an overview of the modelling approach and a summary of the data sources that were used to develop the LCI for modelling transportation are provided in the sections below.

B2. System Boundaries and Descriptions for Transportation

The system boundaries for transportation include the transportation of feedstocks and biofuels from origin to combustion in Canada. The boundaries include transportation between the facility boundaries of the process stages included in the Fuel LCA Modelling Tool. In the case of imported fuels and feedstocks, the origin is the point of entry into Canada.

Transportation processes typically include the following stages:

- Feedstock transportation – transport of feedstock from source (forest, agriculture, waste recovery stream, etc.) to production facility (mills, distilleries, etc.); and
- Fuel distribution – transport of biofuels from production facility to distribution facilities and then to consumer

The modelling of transportation excludes the following:

- Transportation occurring outside of Canada;
- On-site transportation (within facility boundaries); and
- Transportation of all materials other than feedstocks and biofuels (i.e. transportation of consumables, wastes and co-products are excluded)

Agricultural feedstocks

Biofuels including bioethanol, biodiesel, cellulosic ethanol and some biomass can be derived from agricultural feedstocks. Transportation of these feedstocks involves truck and rail shipments to regional production facilities. The resulting fuels are then transported to end users, typically by truck. The proximity of production facilities to source feedstocks and consumer markets is the largest determinant of transportation-related GHG emissions.

Over 97% of bioethanol production in Canada is derived from corn, with the balance coming from wheat (Natural Resources Canada, 2019). Ontario generates 60% of Canada's production, derived from corn, while 18% is produced in Saskatchewan, derived from wheat and corn. The remainder comes from other provinces (Ethanol Producer Magazine, 2019).

Saskatchewan currently accounts for 54% of Canadian crop-derived biodiesel production, which is derived from canola seeds or oil. Ontario is responsible for 33% of production, derived from canola and soybean feedstocks. The balance of production occurs in Alberta and is derived from oilseeds and animal fats (Biodiesel Magazine, 2019).

Cellulosic ethanol derived from corn stover and wheat straw, while not yet produced at a commercial scale, is expected to be similar to the transportation networks of existing bioethanol production facilities. Specifically, facilities are expected to be located in close proximity to source feedstocks and serve local markets.

Solid biofuels (biomass) pellets, while typically derived from forestry or waste-related feedstocks, can also be produced from agricultural crop residues including corn stover and wheat straw. There are no commercial-scale facilities in Canada. However, it is anticipated that these facilities would need to be situated in close proximity to both the feedstock source and end-user (e.g. on-farm drying, industrial boiler, generating station, etc.) in order to be economically viable.

Forestry feedstocks

Most solid biofuels (biomass) in Canada are derived from forestry feedstocks. Wood fibre feedstocks include:

- Unmerchantable logs - wood chips produced directly from harvested forest biomass that is not suitable for timber or pulp and paper production;

- Forest harvest residues - wood chips produced from primary forest harvest residues (i.e. branches, tops, etc.);
- Sawmill residues - wood chips or other residuals from sawmilling (e.g. wood chips, bark, sawdust, shavings); and
- Construction and demolition waste - used wood obtained from construction and demolition (C&D) waste streams.

Each feedstock results in different transportation pathways:

- Forest harvest residues and unmerchantable logs are typically transported by truck to road-side chippers before being sent by truck to the point of combustion (un-processed) or biomass processing facilities (pellets)
- Sawmill residues are transported by truck from the mill to the point of combustion (un-processed) or biomass processing facilities (pellets)
- C&D waste feedstocks require the collection and transportation of clean (untreated) wood to a local production facility. It is assumed that the supply would need to be centralized, nearby a production facility and in large enough volume to be economical

British Columbia makes up 70% of Canadian wood pellet production. Other top producing provinces include Québec and New Brunswick (Bradburn, 2014). In Canada, most wood feedstocks are made into pellets and 90% of pellet production is derived from sawmill residues.

Pellet production facilities tend to be located in close proximity to the source of their feedstocks (e.g. sawmills and forests). Biomass fuels are typically sent to industrial boilers and furnaces, distributed for institutional or residential space heating, or delivered to thermal power plants. The point of combustion for biomass fuels tends to be near the production facility to reduce transportation requirements.

Renewable Natural Gas

Renewable natural gas can be produced from municipal solid waste and sludge from wastewater treatment plants. Transportation of the gas can utilize existing natural gas pipelines if the gas is pre-treated to pipeline specifications. Un-treated renewable natural gas requires other means of transportation, including by truck. As a result, the end-users of un-treated gas tend to be in close proximity to renewable natural gas facilities.

More information on the transport and distribution for the renewable natural gas pathways will be provided later in Milestone 3 after completion of the sole-source contractor work.

Hydrogen

Hydrogen feedstocks include natural gas, renewable natural gas, syngas and water. Transportation of the feedstocks to the hydrogen production facility occurs via pipeline. Once produced, transmission of hydrogen gas from the production facility can include:

- Pipeline to a local distribution centre
- Trucking from the production facility or distribution centre to the end user (e.g. dispensing station)

In each case, the transport of hydrogen requires compression, storage and dispensing facilities. Storage is assumed to be done using geologic formations that are adjacent to the production facility. A compressor is used to extract the hydrogen and reach pipeline pressure.

Truck transportation can involve a tanker truck carrying compressed, gaseous hydrogen or liquefied hydrogen in cryogenic tanks.

B3. Modelling Approach for Transportation

The modelling approach for transportation processes in Milestone 3 focuses on providing unit processes that can be adapted to model relevant processes for the range of feedstock and biofuel pathways in Canada. This will allow the teams developing biofuel pathway models, including low carbon fuel producers, to develop carbon intensities for their unique low carbon fuel pathways by applying and modifying the basic unit processes provided in this report.

The following sections provide a brief overview of the modelling approach for transportation, as well as discussion of some key methodological issues to be addressed in the modelling.

Consistency with fossil fuel transportation models in Milestone 2

The unit processes for transportation of biofuels and their feedstocks applies the same underlying assumptions and data used to model conventional fossil fuel pathways in Milestone 2. This includes the following key assumptions and data:

- Transportation involves the same equipment and conventional fossil fuels currently used in Canada (i.e. biofuels are not used as an energy source for transportation);
- The energy and carbon intensity of equipment is the same as modelled during Milestone 2, including trucks, rail and gas pipelines;
- The system boundaries are consistent with Milestone 2, including the upstream emissions associated with conventional fuels used to power mobile equipment and excluding indirect land use change and production and decommissioning of mobile equipment and transportation infrastructure.

Additional modelling required to represent biofuels pathways include:

- Additional equipment and processes, when relevant;
- Default values for transportation distances;
- Analysis of distribution pathways and methods likely to be employed to produce, process and deliver biofuels in Canada;
- Regional analysis.

Development of Unit Process Building Blocks

The overall modelling approach for Milestone 3 was to develop unit processes to serve as building blocks for current and future modelling work in the Fuel LCA Modelling Tool. Unit processes representing transportation were selected and applied in each biofuel pathway. To ensure that the unit processes can cover each pathway, the following steps were taken:

- Review interim model development for each biofuel pathway;

- Identify transportation processes needed to model each pathway;
- Assess the variation across pathways and production methods, including regional and technological factors;
- Determine the most appropriate system boundaries for each unit process, such that the unit processes can be efficiently selected and applied to each pathway;
- Identify model parameters to allow for the customization of unit processes to reflect unique or changing conditions (e.g. load and transportation distance).

Regional Variation and Proximity

Regional variations in transportation arise from the variation in source locations for biofuel feedstocks, proximity of associated production facilities and proximity of end users (i.e. point of combustion). As the pathways being modelled are largely nascent or theoretical, average transportation distances are estimated using modelling assumptions and an underlying understanding of feedstock locations and population density in Canada.

Biofuel Feedstocks

Transport of feedstocks will assume the primary mode(s) or transport and estimate the average transport distance based on feedstock locations and existing or likely locations of processing facilities. In the absence of data, the locations of new production facilities are assumed to be similar to existing facilities, based on similar economic drivers (i.e. proximity to source and end users, labour and consumables). An average distance of 100 km between feedstock source and production facility is assumed, based on the following observations:

- Existing wood pellet facilities are adjacent or near forestry harvest operations and sawmills;
- Agricultural feedstocks for bioethanol facilities are typically regional sources (e.g. wheat in Saskatchewan and corn in Ontario);
- Short-distance transport improves the economic viability of biofuels and is expected to influence commercial viability of emerging technologies that have not reached commercial scale in Canada.

Based on this distance, trucking has been selected as the default mode of transportation for agricultural and forestry feedstocks. As the biofuels industry develops, longer distance transport may become more viable. As a result, rail transport will also be modelled and available to users of the tool.

Biofuel markets (end-users)

The distance biofuels must travel to reach end-users depends on the location of production facilities, the properties and applications of the biofuel and the distribution of end-users. As the number of production facilities and technologies are expected to increase, assumptions are required to model the average default distance that biofuels travel.

The distance biofuels and hydrogen must travel to reach end users is modelled based on conventional fossil fuel refining capacity in Canada. This approach aligns with Milestone 2 and is reasonable given the similarity of fossil and low-carbon transportation fuel markets and the blending of fossil and low-carbon fuels which occurs post-refining. The following steps were taken to estimate the average distance between production facilities, distribution centres and population centres across Canada:

1. Approximate the location of biofuels production facilities based on the location of existing refinery capacity across Canada;
2. Calculate the distance between production facilities and local population centres;
3. Calculate the average distance to rural populations within the host province;
4. Calculate the population weighted average to end-user;
5. Estimate the average distance to market by calculating the production weighted average of production facilities in Canada.

While bioethanol and biodiesel production primarily serve local markets by truck, rail has been incorporated into the model to provide an option for longer distance transport to local distribution facilities. The default distance for rail was modelled based on the weighted average distance between production centres in Saskatchewan and Ontario and population centers for each province and territory. An average one-way distance of 600 km resulted from the analysis.

The average distance calculation for biomass was modelled based on existing production facilities in Canada. Unlike transportation biofuels, the market for biomass tends to be adjacent or nearby production facilities and is often associated with the forestry sector itself. In this model, the default distance to transport un-processed wood biomass and pellets is set to 100 km.

The production of renewable natural gas from municipal waste and wastewater treatment plant sludges occurs near population centres. As a result, it is assumed that the delivery of gas through existing pipeline distribution systems is local. The default distance for transporting renewable natural gas by pipeline is set to 50 km.

Transportation Pathways and Utilization

The GHG emissions intensity of transportation depends on the degree that mobile equipment is efficiently utilized. Unless noted, the following approach was used to model the utilization of equipment:

- All local deliveries by truck are assumed to be one-way deliveries with an empty return trip. In these cases, the model attributes the emissions of the return trip to the biofuel pathway (i.e. two-way trip)
- All deliveries by rail or long-distance truck are assumed to be one-way deliveries with the return trip utilized by other product systems. In these cases, the model only attributes the emissions of first trip to the biofuel pathway (i.e. one-way trip)

Product characteristics

Product characteristics for feedstocks and biofuels impact the GHG emissions resulting from transportation. Moisture content in feedstocks and biomass can vary substantially (between 5% and up to 40%), increasing the transportation load required to deliver the equivalent dry mass or energy content. The variation in the density of feedstocks (including packing factor) can also influence vehicle efficiency during transport. Vehicle capacity may be volume dependent (and not mass dependent) for lighter, high volume materials.

To account for these differences, the following approach and assumptions were made:

- Moisture content will be included as an operating parameter in truck and rail transport unit processes. The user can enter the mass of biofuel (at pre-defined product specifications) and moisture content. The GHG emissions intensity will be based on total wet mass
- The vehicle capacity is determined by the mass of the cargo and not based on volume for all biomass and biofuels (the assumption is that the density is high enough that mass is the determinant of fuel efficiency)

B4. Lifecycle Inventory for Transportation

Transport modes and GHG intensity

Transport modes used to deliver biofuels feedstocks and biofuels include trucking, rail and gas pipeline. The modelling of the GHG intensity of each transport mode was developed during Milestone 2 for conventional fossil fuels. This data has been extracted from the Milestone 2 report and presented in Table 121. These values were used in combination with the Canadian default GHG intensities of the fuel sources to arrive at a GHG intensity for transportation in units of g CO_2 eq./tkm (total load/wet mass).

Table 121. Fuel consumption intensity of transport modes for feedstocks and biofuels

Mode of Transport	Fuel Intensity Value	Fuel Source
Truck	0.0358 liters/tkm.	• Diesel
Rail	0.00456 litres/tkm	• Diesel
Pipeline	1641 btu / ton.mile	• 98% natural gas • 2% electricity

Average transportation distances

In the absence of facility-specific location data, users of the tool can use the default distances in Table 122 reflecting approximated average feedstock transportation and fuel distribution in Canada. These distances were also used in calculating the default CI values for low carbon fuels. Refer to section B3 for the model basis for selecting default distances.

Table 122. Canadian average and default transportation distances for feedstocks and biofuels.

Life Cycle Stage	Biofuel/Feedstock	Average Distance	Primary Mode	Model Basis
Feedstock Transport	Forestry feedstocks	100 km	Truck	Approximated based on proximity of forestry production facilities to source (e.g. sawmills, etc.)
Feedstock Transport	Agricultural feedstocks	100 km	Truck	Assumed based on use of local feedstocks and favourable economics of short-distance transport

Feedstock Transport	Natural gas (feedstock for hydrogen)	2560 km	Pipeline	Approximated average distance used in Milestone 2 report
Feedstock Transport	Cooking oils / yellow grease	100 km	Truck	Assumed based on proximity of biodiesel facilities to population centres in Ontario
Fuel Distribution	Hydrogen	290 km	Truck	Assumed using method used in Milestone 2 report
Fuel Distribution	Renewable natural gas	50 km	Pipeline	Assumed based on coincidence of population density and feedstocks (e.g. municipal solid waste)
Fuel Distribution	Biomass (un-processed, pellet)	100 km	Truck	Approximated based on proximity of forestry production facilities to source (e.g. sawmills, etc.)
Fuel Distribution	Biofuels (liquids)	290 km	Truck	Approximated based on distance to population centres (aligning with Milestone 2 report)
Fuel Transport to Distribution Centre (Long Distance only)	Biofuels (liquids)	600 km	Rail	Approximated based on distance to population centres (aligning with Milestone 2 report)

Appendix C. Electricity Intensities in the Clean Fuel Standard's LCA Modeling Tool

C1. Approach

The approach for determining the electricity emission intensities in the Clean Fuel Standard's LCA modelling tool consists of relying upon publicly-available data that are further augmented by ECCC to account for indirect emissions. The direct and indirect emission intensities are modelled using Environment and Climate Change Canada's *National Inventory Report (NIR) 1990-2015: Greenhouse Gas Sources and* Sinks in Canada and Environment and Climate Change Canada's internal tool respectively. Provincial and national grid emission intensities for the year of 2015 are provided as seen in Table 123.

Table 123. Provincial and national grid emission intensities included in the Clean Fuel Standard's LCA modelling tool. Values are for the year of 2015 and are expressed in tonne CO_2 e/GWh.

	Direct Impacts (NIR 2017 Annex 13 Part III)	Indirect Impacts (ECCC Internal Tool)	Indirect Impact Uncertainty Range		Total
			Min.	Max.	
AB	790.0	78.9	60.7	126.2	868.9
BC	12.9	63.4	55.1	84.9	76.3
MB	3.4	21.5	17.8	40.2	24.9
NB	280.0	60.9	53.1	90.2	340.9
NL	32.0	22.2	18.5	39.6	54.2
NS	600	114.9	97.8	172.7	714.9
ON	40	26.7	23.8	39.9	66.7
PEI	20	263.2	235.9	319.8	283.2
QC	1.2	10.3	7.6	20.4	11.5
SK	660.0	73.4	62.9	112.8	733.4
YK	41.0	Out of Scope	-	-	Out of Scope
NW	390.0	Out of Scope	-	-	Out of Scope
NU	Confidential Data	Out of Scope	-	-	Out of Scope
CA	140.0	34.1	28.2	53.9	174.1

C2. National Inventory Report 1990-2015: Greenhouse Gas Sources and Sinks in Canada Part 3

The NIR provides emission intensities related to the generation of electricity by the Public Electricity and Heat Production category (IPCC Category 1.A.1.a), on a national and provincial level. Auto-producers who either partially or wholly generate electricity for their own use and also may sell some of their electricity to the grid are excluded from the scope. The scope of electricity generation includes only main activity producers, entities whose main activity is the production of electricity. The emissions associated with the small amount of utility steam generation are therefore included within the scope of this category. Emission intensities reflect GHG emissions associated with electricity delivered by the grid. Energy losses in transmission and distribution are not considered.

GHG emissions reflect emissions from combustion-derived electricity. Emissions occurring offsite, as is the case for uranium fuel production and processing for nuclear power generation, are excluded from the scope. Additionally, nuclear, hydro, wind, solar and tidal electricity generators only emit small qAnhydrousntities of GHGs from the use of diesel generators as backup power supply.

Electricity generation intensity values were derived for each fuel type using GHG emission estimates and electricity generation data. GHG emissions are based on the total fuel consumed by the public utility sector, as provided in the RESD,1 while generation data are from CANSIM (2005– 2013) and the EPGTD publication (1990–2004). Regional emission factors are applied for coal and natural gas emissions however, for the remaining fuels, region-specific emission factors were not available and nationally reported emission factors are applied. The complete methodology used to develop the GHG emission intensities is discussed in Chapter 3 and Annex 3.1 of the *National Inventory Report 1990-2015: Greenhouse Gas Sources and Sinks in Canada* report.

Several Statistics Canada sources were used to provide electricity production and fuel consumption values. Publications include the *Report on Energy Supply and Demand in Canada* (RESD) (Statistics Canada 57-003-X), *Electric Power Generation, Transmission and Distribution* (EPGTD) (Statistics Canada 57-202-X) and CANSIM (Tables 1270006,127-0007 and 127-0008).

C3. ECCC Internal Tool

C 3.1. Scope

The tool is used to estimate the indirect segment of electricity emissions. Indirect emissions can be defined as emissions that do not stem from electricity generating processes. Examples of indirect emission sources include electricity transmission, use of sulfur hexafluoride during transmission, herbicides, wastewater, concrete, steel, infrastructure heating, lubricating oils, radioactive waste and vehicle operation.

C 3.1.1. Functional Unit

The tool is designed to evaluate potential environmental impacts of electricity generation from different sources, in Canada. In order for the tool's results to be included in the Clean Fuel Standard's LCA modelling tool, a functional unit of producing and delivering 1 MWh of electricity generated and distributed in Canada in 2017 was used. 2015 Canadian grid mixes were applied. The tool uses the 2013 global warming potentials implemented by the IPCC.

C. 3.1.2. Allocation Rules

Default allocation is made based on energy content. In the case of co-generation, the allocation factor splits emissions intensities (CHP operation, infrastructures when relevant and fuel supply too) on an energy content basis to prevent the steam emissions from being included in the electricity emissions.

C 3.1.3. System Boundaries

The tool assesses the life cycle impacts of electricity production in Canada, from resource mining and extraction, processing and electricity production steps, and subsequent grid step. The life cycle of all pathways is divided in four main life cycle steps, namely: fuel provision (when applicable), infrastructure construction, operation, and transmission/distribution.

Details on the lifecycle stages follow:

- The Fuel provision stage includes the extraction and refining of the fuel used to produce the electricity.
- The Infrastructure stage pertains to the plant and equipment construction itself.
- The Operation stage includes the production of electricity and all the services and products needed for this operation. Along with this stage, two sub-stages (emissions control system) appear for some pathways: the carbon capture system and the pollution control (NO_x and SO_2 emissions control).
- The Transmission/Distribution includes the infrastructure, equipment, products and services required to transport the electricity from the production site to the final user.
- The Supply and Waste management sub-systems respectively pertain, for each of the preceding subsystems, to all of the activities that stem from:
    - Resource procurement (water, energy, chemicals, materials), including the extraction, treatment and transformation of natural resources, and the various transports to the resource-use sites (i.e. pre-production, production, distribution, use and end-of-life management sites).
    - The transport and treatment/management of the waste generated during any of the product's life cycle stages, taking all of the possible recovery options into account.

13.1.1 C 3.1.4. Geographical and temporal boundaries

Some processes within the system boundaries might take place anywhere or anytime, as long as they are needed to achieve the functional unit.

For example, the processes associated with the supply, and the waste management (background processes) can take place in Canada or elsewhere in the world. In addition, certain processes may generate emissions over a longer period than 2017. This applies to landfilling, which causes emissions (biogas and leachate) over a period whose length (several decades to over a century/millennium) depending on the design and operation of the burial cells and how the emissions are modeled in the environment.

13.1.2 C 3.1.5. Electricity Generation Pathways

Electricity pathways included in the tool include:

- Coal steam boilers with or without carbon capture systems (CCS) using different fuels (bituminous, sub-bituminous and lignite);
- Natural gas combined cycle or simple cycle turbines with or without CCS using conventional or unconventional (shale gas) natural gas;
- Biomass steam boiler with or without CCS and cogeneration boiler using biomass originating from forest, either standing wood or residue (pellets or wood chips burned in simple cycle or cogeneration plants);
- Hydropower from reservoir or run of river types;
- Onshore wind power.
- Natural gas converted boilers: this model covers the electricity produced from natural gas in ancient coal-powered plants.
- Combined heat and power (natural gas): the model covers electricity produced from natural gas originating from conventional and unconventional sites, specifically, shale gas. Cogeneration of electricity and heat is covered in this pathway.
- Solar thermal: This model covers electricity produced in concentrated solar thermal plants. As all the renewables, fuel provision stage is excluded for this pathway.
- Solar photovoltaic: This model covers electricity produced by photovoltaic panels. As all the renewables, fuel provision stage is excluded for this pathway. Different technologies and installed powers will be included in this pathway as their life cycle inventory differ.
- Nuclear: this model covers the CANDU technology of electricity production from nuclear fusion.
- Diesel (off-grid generation): this model covers the electricity produced from diesel in off-grid sites, mainly in the northern regions of the country.
- Utility-scale natural gas boilers: The model covers electricity produced from natural gas originating from conventional and unconventional sites using boilers.

C 3.2. Data Sources

Infrastructures and fuel supply are modeled using data from the ecoinvent 3.4 database as main basis and completed with Canadian and provincial data for the main parameters (installed power, provenance of the raw materials, location of mines, etc.) when available. The Operation stage data relies on Canadian data, namely NPRI for emissions, national and province statistics for other key parameters as efficiency, exchanges with other regions, etc. Transmission and distribution relies on ecoinvent 3.4 for infrastructure information and on Canadian and provinces statistics for the key parameters (km on line, losses during transport). Missing data are completed with literature sources and proxies.

C 3.3. Methodology

The tool provides emission intensities on a technology basis. A provincial emission intensity is determined by weighting each technology in relation to its share in the overall provincial grid mix. A national emission intensity is determined by weighting each technology in relation to its share in the national grid mix.

Appendix D. Supplemental Methods and Calculations Descriptions

D1. Handling Recycling in LCA

Introduction

Handling recycling of products in LCA is a special case of allocation. As shown in Figure 30, in recycling, a material has two or more lives. There are a number of different ways to consider how the burdens of these materials and the recycling process itself are divided. It is important to remember that there is no physical division between the two lives so there is no 'right' answer to the question. Different allocations are different ways of looking at the same system and will provide different insights. It is important, however, to be consistent within an analysis.

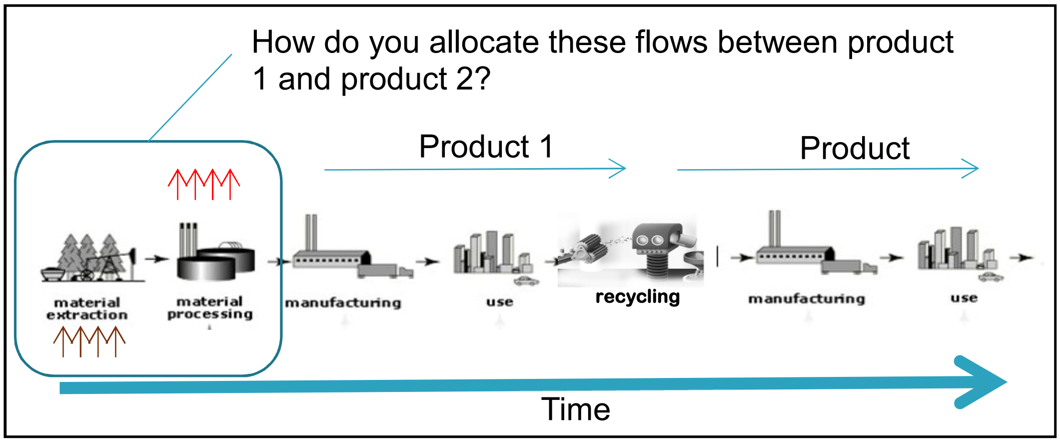


Figure 30. With recycling, two products are created at different times.

What do we need to consider?

Over the span of the two products, there are a number of activities that might be allotted to one or more of the lives, including the raw material extraction and initial processing, the collection, sorting and compost, reconditioning, packaging, transport, and what has been avoided through the reuse of the material. Different methods apportion those impacts differently to the first and second lives and may take into consideration further lives of the material. In addition to consistency between product systems, there must be consistency within a system: the same method should be used to apportion impacts at the beginning of a product life as well as at the end (e.g., incoming recycled material should be apportioned impacts through the same method as material leaving the system via the recycling bin.)

Before looking at each method in detail, it is important to start with a basic understanding of the two systems to be modeled as shown in Figure 31.

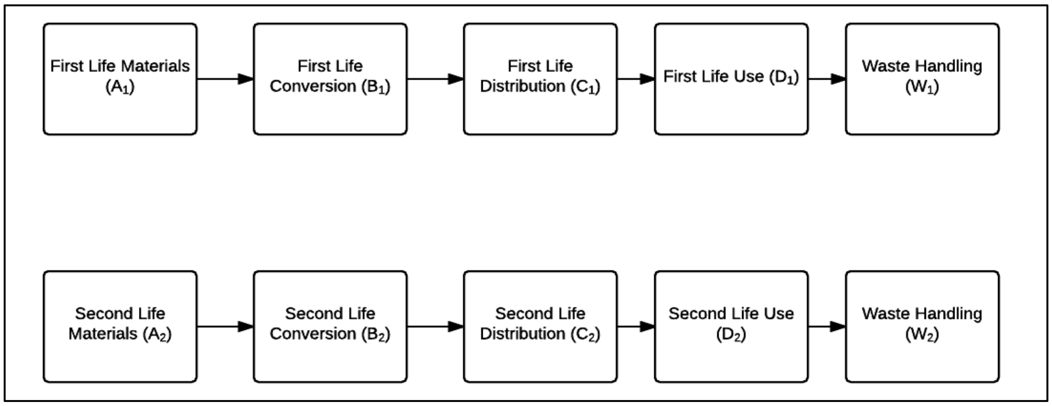


Figure 31. The processes needed to create a product which is put into the recycle bin at end of life (product 1) and the product created at time 2 (product 2) are designated by the subscript.

In both lives, there is a need for materials, conversion from materials into a product, distribution, use and then some kind of handling at end of life. These are denoted by the letters in parenthesis following the names (e.g., A_1, B_2, etc.). The subscript indicates which life the process belongs to. These indicators will be used in the equations for each LCA recycling method.

Closed Loop Allocation Procedure

ISO 14044 distinguishes two classes of recycled product: those that have the same properties as virgin material and those that have different properties (ISO 14044, 2006b). Specifically, section 4.3.4.3.3 of ISO 14044 states:

a) A closed-loop allocation procedure applies to closed-loop product systems. It also applies to open-loop product systems where no changes occur in the inherent properties of the recycled material. In such cases, the need for allocation is avoided since the use of secondary material displaces the use of virgin (primary) materials*.
b) An open-loop allocation procedure applies to open-loop product systems where the material is recycled into other product systems and the material undergoes a change to its inherent properties.

The closed loop procedure described in a) above also goes by these other names:

1. Open-loop with closed loop procedure (ISO 14049), (ISO/TR 14049:2000(E), 2000)
2. avoided burden approach,
3. end of life approach (supported by metals industry),
4. recyclability substitution approach (ILCD Handbook) (European Commission -Joint Research Centre -Institute for Environment and Sustainability, 2010),
5. closed-loop approximation (GHG Protocol) (Bhatia, et al., 2011)
6. 0/100 approach.

The Avoided Burden or Closed Loop approach is shown in Figure 32. If the product is landfilled, it must take the burden of Waste Handling (W_1). If it is recycled, it takes the burden of the refurbishment process (I) and gets credit for the amount passed on to the second life (A_2). The second life must take the burden of the virgin material which was displaced in the first life (A_2).

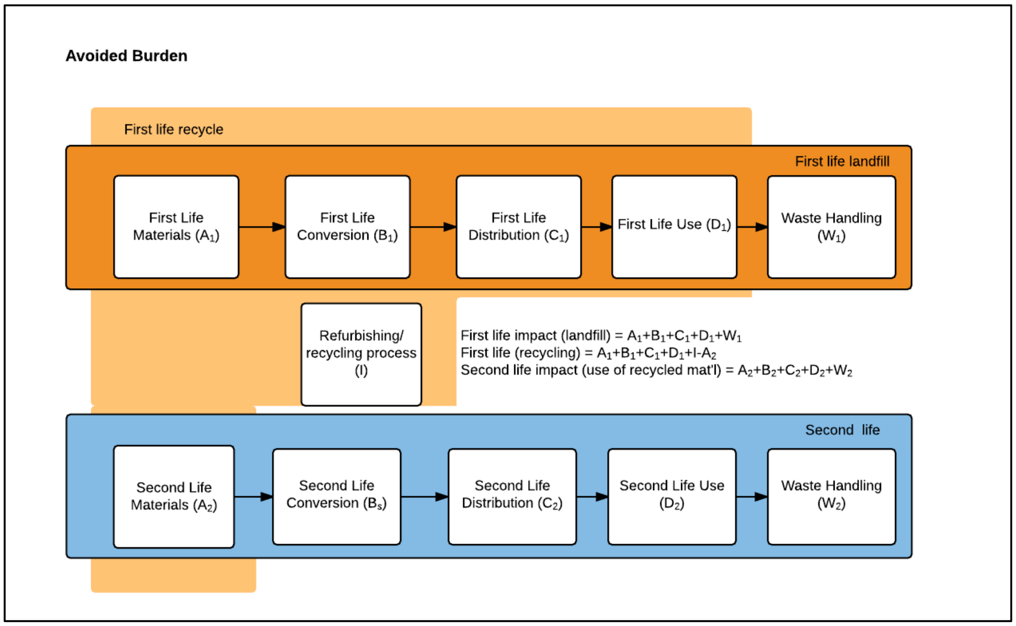


Figure 32. In the Avoided Burden or Closed Loop approach, the first life takes the burden of the recycling process but gets credit for the virgin material avoided by the second life.

The closed loop procedure encourages recycling at end of life, but does little to encourage the reuse of recycled products.

Open Loop Approaches

Economic Allocation

In economic allocation (Howard, Edwards, & Anderson, 1999), the recycled material created from the first life becomes a coproduct. The impacts of cradle to gate (A_1+B_1) are allocated between Product 1 and Product 2 based on their sale price. If the price of Product 1 is \$90 and the price of product 2 is \$10, The second life would take (10/(90+1)) or 10% of the burden of A_1+B_1. This method can be applied whether or not the material changes properties and is useful when the recycled product is very different from the initial product. The drawback of this method is that scrap costs can be volatile and the market in which product 1 is sold at time 1 may be very different from the market when it is recycled. Thus it is most useful for very short lived products where the economics are well understood. Economic allocation further drives market forces.

Number of uses

The number of uses approach (ISO/TR 14049:2000(E), 2000) is a method which is useful when a product degrades over consecutive life cycles and is supported by many in the paper industry (American Forest and Paper Association, 2006). Like the economic allocation method, the impacts of cradle to gate (A_1+B_1) are allocated between Product 1 and subsequent lives based on an allocation factor:

Allocation Factor for Primary product system = $(1-Z_1)+(Z_1/u)$

Allocation Factor for recycled product systems = $Z_1\ (u-1)/u$

where :

u is the number of uses (lives)

Z_1 is the percent recycled after the first use.

The drawback to the number of uses is that the modeler must know exactly how many times a product can be recycled and must know the percent being recycled at Time 2.

The number of uses method benefits both recycling at end of life and use of recycled material.

Cut off approach

One of the most used commonly used methods in LCA, the Cut Off approach (Frischknecht, LCI modelling approaches applied on recycling of materials in view of environmental sustainability, risk perception and eco-efficiency, 2010) draws a simple boundary between Product 1 and Product 2 at the point when the user of Product 1 puts the product in the recycle bin (Figure 33).

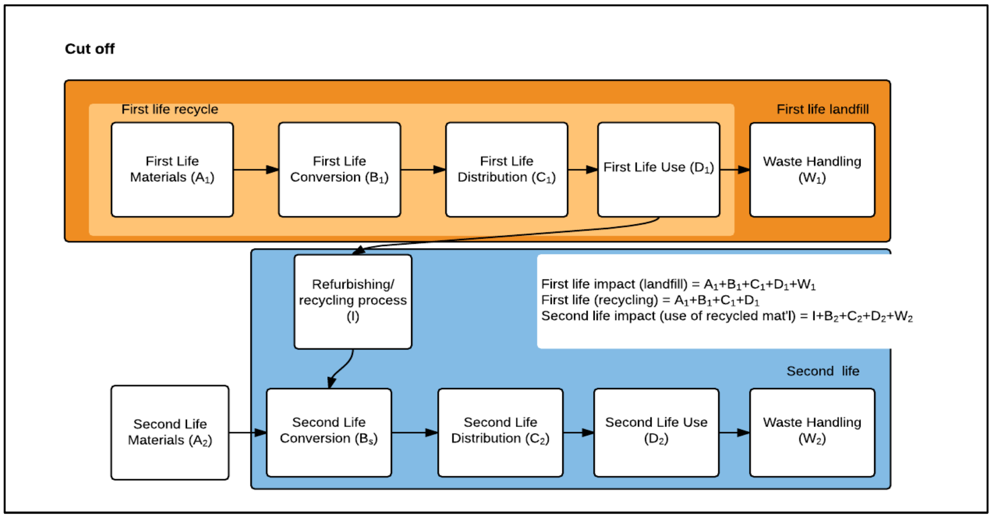


Figure 33. In the Cut-Off method, the first life takes burdens through disposal. The second life takes the material burden-free, with the exception of the refurbishing process.

This method is easier to apply than most other methods because it does not depend upon market conditions, number of uses or other data. The primary beneficiary of this approach is the user of recycled material. While the life cycle of Product 1 does not have to take the burden of landfilling or incineration, it gains no benefit from the reuse of the material.

As Frischknecht discusses in his 2010 article, the closed loop approaches are risk seeking because they borrow environmental loans from future generations. The Cut Off method, on the other hand, is risk averse: environmental burdens are strictly linked to the product that causes them, irrespective of any potential future use.

50/50 Approach

The 50/50 approach (which can also be adjusted based on how much useful material is generated from a kilogram of material at end of life) allocates 50% the burdens of (A_1+B_1) to each life (Ekvall, 2000). The equations for the impact look like this:

First life impact (landfill): $A_1 + B_1 + C_1 + D_1 + W_1$

First life (recycling): $A_1 + B_1 + C_1 + D_1 + 0.5 * I – 0.5 * (A_1 + B_1)$

Second life (use of recycled material: $0.5 * I + 0.5 * (A_1 + B_1) + B_2 + C_2 + D_2 + W_2$

In the 50/50 approach, both lives benefit from the reuse of material. If the allocation percent is 50%, it can be thought of as arbitrary, but ascertaining the exact values to use can be burdensome. This method is gaining traction with the steel industry where the amount of reused material is high and relatively well understood.

Market Model for System Expansion

The market model for system expansion or the market-based approach takes a consequential approach to end of life (Weidema, 2003). If a recycled material is fully utilized, meaning that all of the material which enters the recycling stream at end of life is reused, the consequence of using that material would be that another user would have to use virgin material. If a recycled material is underutilized, meaning that some of the material entering the recycling stream is either stockpiled, landfilled or incinerated, then the use of that material avoids the end of life impacts. The diagram for the market-based approach is a bit different from that for the other methods and is shown in Figure 34.

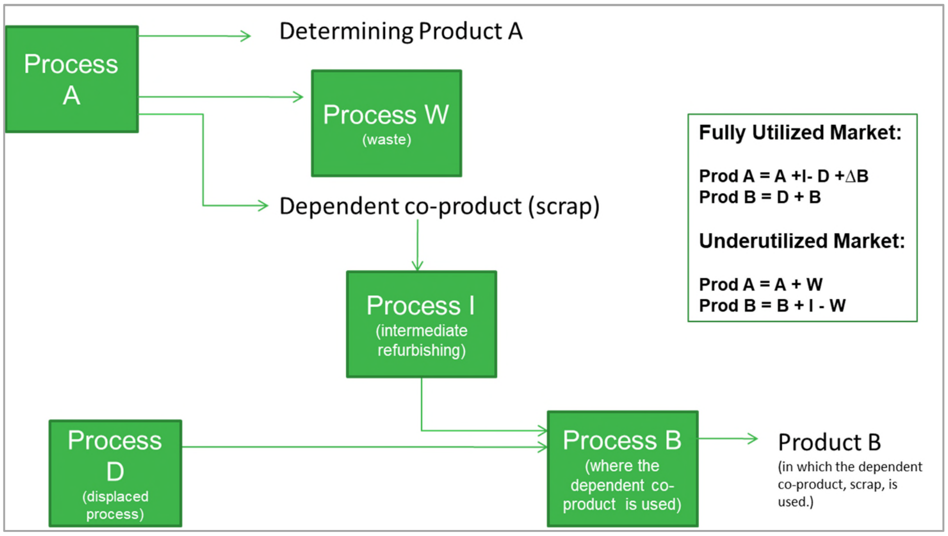


Figure 34. In the market-based approach, the burdens are allocated differently depending upon the market for recycled product.

This method is similar to the closed loop approach when recycled material is in demand. When there is little demand it is similar to Cut Off with the addition of burden for landfill or incineration for Product 1 and credit for that same end of life for Product 2.

The market-based approach requires a good understanding of market dynamics and the results will change as the market changes. *It is the only method for which different* *materials can be treated differently. It is also the only method which gives a credit for avoided landfill or incineration to the second life.* It is the method most often used in consequential studies.

Summary and Recommendations

When modeling either recycling at the end of life of a product or the reuse of a material, the choice of method will change the impacts of the product dramatically. It is important to keep a consistent perspective or burdens (and benefits) will be double counted: One cannot take a credit for something at end of life and at the same time avoid the burden of it at beginning of life.

When performing a comparative assertion, the use of the Market-Based approach under both conditions offers a comprehensive assessment of the differences between systems. Assuming a fully utilized market has the lowest impact for the first life and the highest impact for the second life. Assuming an underutilized market has the highest impact for the first life and lowest impact for the second life of any of the methods proposed to date. Thus, assessing scenarios under both conditions provides the full scope of impact.

The Market-Based approach also makes sense as a method for assessing a recycling process where the recycler has responsibility for collecting the waste material and redistributing useable product. Through its efforts, the recycler is reducing the amount of material going to landfill or incineration while reducing demands on virgin production.

Both the Market-Based approach and the Closed Loop approach seem to apply to fully utilized markets, such as aluminum and steel. Because these materials are often compared with products in underutilized markets, the Market-Based approach offers a more consistent way of modeling.

In most other cases, the Cut Off method is the preferred method for several reasons: results don’t change with changes in market conditions; it is straightforward to apply; it does not result in “credits” which are difficult to explain and justify; and it encourages the reuse of material while not discouraging recycling at end of life.

As repeated in this document, it is important that the method used is consistent:

1. At both beginning and end of life
2. For all product systems being compared

When methods are applied inconsistently, burdens may be double counted or applied inconsistently, resulting in unjustifiable conclusions.

D2. Supporting Data for Cut-Off Decisions

The following results were generated using to guide decisions around exclusion of processes from the fossil fuel and low carbon fuel life cycles. All data come from the CEDA 4 US Environmental Input/Output database. Reference can be found here: https://pubs.acs.org/doi/abs/10.1021/acs.est.9b00084

Table 124. All other petroleum and coal products manufacturing, contribution to total impact of the sector

	kg CO2 eq	Percent of total contribution
All other petroleum and coal products manufacturing	0.57564	41.2%
Petroleum refineries	0.401054	28.7%
Oil and gas extraction	0.101845	7.3%
Electric power generation, transmission, and distribution	0.08077	5.8%
Other basic organic chemical manufacturing	0.044006	3.1%
Petrochemical manufacturing	0.042443	3.0%
Natural gas distribution	0.03736	2.7%
Pipeline transportation	0.020912	1.5%
All other basic inorganic chemical manufacturing	0.008358	0.6%
Management of companies and enterprises	0.006924	0.5%
Wholesale trade	0.004722	0.3%
Truck transportation	0.004091	0.3%
Plastics material and resin manufacturing	0.003903	0.3%
Paperboard container manufacturing	0.003818	0.3%
Coating, engraving, heat treating and allied activities	0.003636	0.3%
Nonresidential maintenance and repair	0.003146	0.2%
Coal mining	0.003025	0.2%
Scientific research and development services	0.002528	0.2%
All other	0.049563	3.5%

Table 125: Natural gas distribution, contribution to total impact

	kg CO2 eq	Percent of total contribution
Natural gas distribution	2.149767	82.2%
Pipeline transportation	0.209622	8.0%
Oil and gas extraction	0.148947	5.7%
Coal mining	0.031959	1.2%
Petroleum refineries	0.005411	0.2%
Natural gas distribution	0.0052	0.2%
Electric power generation, transmission, and distribution	0.004379	0.2%
Rail transportation	0.004137	0.2%
Ornamental and architectural metal products manufacturing	0.002962	0.1%
All other	0.052045	2.0%

Table 126: Petroleum refineries, contribution to total impact

	kg CO_2 eq	Percent of total contribution
Petroleum refineries	1.244085	67.0%
Oil and gas extraction	0.258896	13.9%
Petroleum refineries	0.131072	7.1%
Electric power generation, transmission, and distribution	0.052593	2.8%
Natural gas distribution	0.045334	2.4%
Pipeline transportation	0.040938	2.2%
Other basic organic chemical manufacturing	0.013204	0.7%
Petrochemical manufacturing	0.010709	0.6%
All other basic inorganic chemical manufacturing	0.010267	0.6%
Wholesale trade	0.004479	0.2%
Nonresidential maintenance and repair	0.003809	0.2%
Management of companies and enterprises	0.003349	0.2%
All other	0.035556	1.9%

Table 127: Other basic organic chemical manufacturing (includes ethanol production), contribution to total impact

	kg CO_2 eq	Percent of total contribution
Other basic organic chemical manufacturing	1.762082	64.9%
Petrochemical manufacturing	0.268631	9.9%
Electric power generation, transmission, and distribution	0.134061	4.9%
Petroleum refineries	0.102316	3.8%
Natural gas distribution	0.081962	3.0%
Grain farming	0.059237	2.2%
All other basic inorganic chemical manufacturing	0.034874	1.3%
Alkalies and chlorine manufacturing	0.023938	0.9%
Plastics material and resin manufacturing	0.02192	0.8%
Fertilizer manufacturing	0.018851	0.7%
All other crop farming	0.0166	0.6%
Industrial gas manufacturing	0.009872	0.4%
Rail transportation	0.009333	0.3%
Wholesale trade	0.009172	0.3%
All other chemical product and preparation manufacturing	0.008582	0.3%
Fats and oils refining and blending	0.008433	0.3%
Management of companies and enterprises	0.008333	0.3%
All other	0.13049	4.8%

Table 128: Fats and oils refining and blending, contribution to total impact

	kg CO_2 eq	Percent of total contribution
Soybean and other oilseed processing	0.340427	21.8%
Oilseed farming	0.312675	20.0%
Fats and oils refining and blending	0.227836	14.6%
Grain farming	0.076857	4.9%
Wet corn milling	0.066555	4.3%
Electric power generation, transmission, and distribution	0.066358	4.3%
Animal (except poultry) slaughtering, rendering, and processing	0.035988	2.3%
Natural gas distribution	0.034197	2.2%
Rail transportation	0.019283	1.2%
Cattle ranching and farming	0.018284	1.2%
Cotton farming	0.011743	0.8%
Truck transportation	0.010568	0.7%
Paperboard container manufacturing	0.010233	0.7%
Other plastics product manufacturing	0.010149	0.7%
Dairy cattle and milk production	0.009387	0.6%
Wholesale trade	0.008834	0.6%
All other crop farming	0.008725	0.6%
Plastics bottle manufacturing	0.008538	0.5%
All other paper bag and coated and treated paper manufacturing	0.005617	0.4%
Coal mining	0.005051	0.3%
All other	0.267901	17.2%