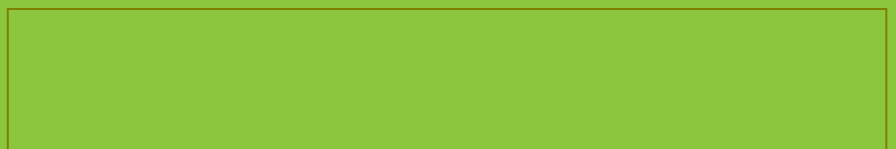


# **QUANTIFICATION PROTOCOL FOR DIRECT REDUCTIONS IN GREENHOUSE GAS EMISSIONS ARISING FROM FUEL SWITCHING FUEL IN MOBILE EQUIPMENT**

Draft Version

January 2012



**Disclaimer:**

The information provided in this document is intended as guidance only and is subject to periodic revisions. This document is not a substitute for the law. Please consult the *Specified Gas Emitters Regulation* and applicable legislation for all purposes of interpreting and applying the law. In the event that there is a discrepancy between this document and the *Specified Gas Emitters Regulation* or other legislation, the *Specified Gas Emitters Regulation* and other legislation prevail.

All Quantification Protocols approved under the *Specified Gas Emitters Regulation* are subject to periodic review as deemed necessary by the Department, and will be re-examined at a minimum of every 5 years from the original publication date to ensure methodologies and science continue to reflect best-available knowledge and best practices. Any updates to protocols occurring as a result of the 5-year and/or other reviews that are not due to legal requirements will apply at the end of the first credit duration period for applicable project extensions and for all new projects coming forward.

Where a project condition differs from approved government methodologies, or the project developer is unclear on protocol interpretation relative to their specific project, the project developer must contact Alberta Environment to discuss an appropriate interpretation and receive approval for any methodology changes prior to undertaking the project.

Any comments, questions, or suggestions regarding the content of this document may be directed to:

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## **Alberta Environment Related Publications**

Climate Change and Emissions Management Act  
Specified Gas Emitters Regulation  
Specified Gas Reporting Regulation

Alberta's 2008 Climate Change Strategy

Technical Guidance for Completing Annual Compliance Reports  
Technical Guidance for Completing Baseline Emissions Intensity Applications  
Additional Guidance for Co-generation Facilities  
Technical Guidance for Landfill Operators

Technical Guidance for Offset Project Developers  
Technical Guidance for Offset Protocol Developers  
Quantification Protocols (<http://environment.alberta.ca/02275.html>)

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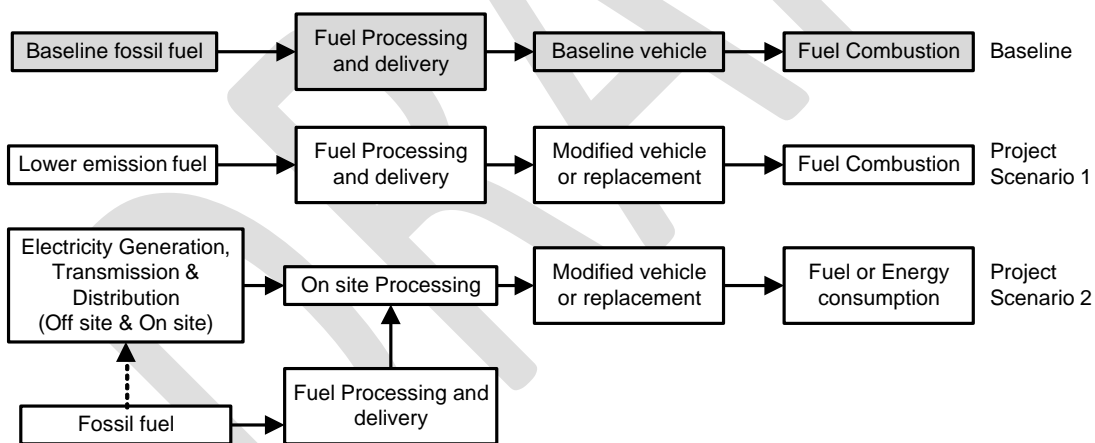
## Offset Project Description

This quantification protocol describes the process for quantifying greenhouse gas (GHG) emission reductions arising from reducing the GHG intensity of fuels consumed in powering mobile equipment, while maintaining an equal or greater level of service.

The opportunity for generating carbon credits with this protocol arises from the direct and indirect reductions of GHG emissions associated with the entire lifecycle of the baseline and project fuels. This includes direct emissions from combustion and indirect emissions related to fuel extraction, processing, and blending.

Replacement fuels include other fossil fuels, fossil fuel blends, or electricity. On a service provision basis, replacement fuels must demonstrate a lower GHG intensity compared to the displaced fuel. Services provided by mobile sources may include transportation of people or waste (e.g., transit buses or garbage collection fleets), transportation of cargo, and construction or other heavy equipment (e.g., forest harvesting, agriculture). The type of service provided must not be changed with application of fuel switching and or fuel switching technology.

**Error! Reference source not found.** shows a process flow diagram for the baseline and three potential project conditions for mobile sources.



**Figure 1: Generalized process flow for applicable baseline and project scenarios for mobile sources.**

### 1.1 Protocol Scope

The methodology in this protocol applies to the quantification of both direct and indirect GHG emission reductions resulting from the use of less GHG-intensive fuels in mobile technologies.

The proposed protocol will include the flexibility to allow for replacement of existing technology or systems consuming fossil fuel or electricity with new technology or systems

consuming lower emitting fuel or electricity. The protocol must be applied on a project-specific basis where a demonstrated lower lifecycle greenhouse gas intensity fuel is used.

For the purposes of this protocol, eligible fuel types would include but are not limited to:

- Diesel
- Gasoline
- Natural gas including compressed or liquefied natural gas (CNG or LNG)
- Fossil fuel blends or use of dual fuel engines (e.g., Diesel and CNG)
- Electricity
- Propane

Biogas, biomass, biofuels, and renewable fuels are explicitly excluded from the scope of this protocol as these are addressed by other Alberta Offset System protocols.

The proposed protocol is stackable with other Alberta Offset System protocols in the case of a project where excluded fuels are co-implemented with an eligible fuel under this protocol.

This protocol prescribes a static historic benchmark approach for determining the baseline condition. This ensures emission reductions account for an equal level of service between the baseline and the project condition. This also accommodates the emission reductions associated with a growth in service, where a lower GHG-intensive fuel is utilized in place of the higher intensive baseline fuel. Functional equivalence is achieved by using a common metric: units of carbon dioxide equivalent (CO<sub>2</sub>e), or unit of fuel consumed per unit of service defined in the project. The units used in the baseline must be identical to the units used in the project (e.g., passenger capacity km, tonnes km).

The baseline for mobile sources will incorporate applicable renewable fuel standards in place during the crediting period to ensure the intensity of the baseline fuel accurately reflects current standards.

At the time of publication of this protocol, the opportunity to reduce GHG emissions by displacing higher emitting fuels with lower emitting fuels has not been widely adopted. In Alberta, approximately 7.78 million tonnes CO<sub>2</sub>e are emitted by heavy-duty diesel vehicles for transport and related activities<sup>1</sup>. The displacement of diesel with lower emitting fuels represents the largest potential opportunity for reducing emissions from this protocol.

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<sup>1</sup> (2009-2010 NIR report)

Relevant greenhouse gas emissions for this protocol are shown in **Error! Reference source not found.**, and CO<sub>2</sub>e emission factors are described in **Appendix C**

**Table 1: Relevant Greenhouse Gases**

Specified Gas	Formula	100-year GWP	Applicable to Project
Carbon Dioxide	CO <sub>2</sub>	1	Yes
Methane	CH <sub>4</sub>	21	Yes
Nitrous Oxide	N <sub>2</sub> O	310	Yes
Sulphur Hexafluoride	SF <sub>6</sub>	23,900	No
Perfluorocarbons*	PFCs	Variable	No
Hydrofluorocarbons*	HFCs	Variable	No

\* A complete list of perfluorocarbons and hydrofluorocarbons regulated under the *Specified Gas Emitters Regulation* is available in Technical Guidance for Offset Project Developers.

## 1.2 Protocol Applicability

This protocol requires that project developers establish a static historic benchmark baseline for the project activity. The static benchmark should be established with three years of census (complete) information including the amount of fuel combusted and the service provided (e.g., transportation of people or freight, agriculture or forest harvesting). Flexibility (section 1.3) has been provided for establishing the baseline where three years of census information is not available, and for new projects.

Project developers must be able to demonstrate the offset project meets the requirements of the Alberta Offset System, the Specified Gas Emitters Regulation, the quantification protocol, and related guidance documents. In particular, the project developer must provide sufficient evidence to demonstrate:

- Verifiable records on fuel use for each year where an offset will be claimed.
- Verifiable records for the service provided for each year where an offset will be claimed. Acceptable service measures are;
  - passenger capacity km (transit projects),
  - tonnes km (freight transportation),
  - harvest m<sup>3</sup> hr (forest harvesting),
  - harvest area hr (agriculture).
- Comparable records suitable for establishing baseline condition.

### Additional eligibility criteria identified for use of this protocol:

1. Fuel must be consumed within Alberta. Where mobile emissions also occur outside Alberta, only the portion of fuel consumed within Alberta may be credited to the project or used to establish baseline.

2. Alternative fuel must have lower emission intensity when compared to the baseline fuel. Fuel comparison is based on service delivery and/or productivity (e.g., emissions per passenger capacity km, emissions per tonnes km) equivalent.
3. When the project requires replacement of existing vehicles, the services provided to the project by the new vehicles must remain the same as measured in the baseline. Quantity of service may change with implementation of a project.
4. Must demonstrate that the most likely baseline scenario is continuation of use of higher carbon intensive fuel.
5. No regulation requiring change in baseline fuel use.

### **1.3 Protocol Flexibility**

Three flexibility mechanisms are described for this protocol, as follows:

1. For projects where less than three years of census information is available to justify the static historic benchmark Baseline Condition, proponents may implement a statistical sampling alternative method described in **Appendix A**. This appendix provides example calculations including how the statistical sampling flexibility may be used.
2. For new projects where no historic data is available to justify the Baseline Condition, proponents may implement a Performance Standard Baseline. **Appendix B** provides guidance on the method to develop a performance standard baseline. Approval from Alberta Environment must be requested prior to implementing this mechanism. The Proponent must be able to demonstrate a methodology and sufficient data to justify the performance standard baseline in conformance with the guidance provided in this document and by Alberta Environment.

*Note: The above two flexibility mechanisms cannot be applied where suitable census information exists, or where sufficient historical data may be collected prior to project initiation (e.g., baseline data may be collected after project plan approval and before project initiation).*

3. More specific emission factors may be substituted for the generic emission factors indicated in this protocol document. The methodology for generation of these emission factors must ensure accuracy and conformance with the guidance provided in
4. **Appendix C**.

These flexibility mechanisms are provided to allow projects to proceed while maintaining conservativeness of the quantification and the integrity of the offsets quantified.

Use of any of these flexibility mechanisms must be clearly described in the project plan.

## 1.4 Glossary of Terms

Glossary term	Description
Additionality	An action that results in greenhouse gas emission reductions that is beyond business as usual and supplemental to all regulatory requirements.
Aggregated Projects	A collection of small projects using same quantification methodology that have been bundled to create a larger volume project for marketing, verification, and registration.
Alberta Emissions Offset Registry	A web-based platform that displays Alberta Offset Projects and tracks associated offset credits.
Alberta Environment	Regulator for the Specified Gas Emitters Regulation and Alberta Offset System.
Alberta Offset System	An option for large industrial emitters who need to comply with the province's greenhouse gas emissions reduction program is to purchase offset credits from other sectors that have voluntarily reduced their emissions in Alberta. Credits must be created using protocols approved by the Alberta government. The protocols outline how to quantify and verify emission reductions for different types of projects.
Alberta Renewable Fuels Standard (RFS)	A renewable fuels standard is a government requirement to blend renewable products into commercial fuels. Alberta's Renewable Fuels Standard (RFS) requires an average of two per cent renewable diesel in diesel fuel and five per cent renewable alcohol in gasoline sold in Alberta. Renewable fuels used to meet the RFS must demonstrate at least 25 per cent fewer greenhouse gas emissions than the equivalent petroleum fuel.
Baseline	A reference case against which the performance of the project is measured.
Biofuel	A type of fuel derived from biological carbon fixation and includes solid biomass, liquid fuels and various biogases.
Biogas	See Biofuel.
Biomass	Non-fossilized and biodegradable organic material originating from plants, animals and micro-organisms.
Business as Usual (BAU)	Projection of normal operating conditions that would have occurred in the absence of incentives or regulatory changes.
Carbon Dioxide Equivalent (CO <sub>2</sub> e)	The 100-year global warming potential average of a unit of greenhouse gas (e.g. methane) compared to an equivalent unit of carbon dioxide (reference gas).
CDM – Clean Development Mechanism	The Clean Development Mechanism (CDM) is one of the "flexibility" mechanisms defined in the Kyoto Protocol (IPCC, 2007).

Climate Change and Emissions Management Act	Legislation in Alberta passed in 2002, allowing Alberta Environment to manage greenhouse gas emissions in the province.
Climate Change Central	An arms-length organization contracted primarily by Alberta Environment to support delivery of a variety of climate change programs including consumer incentive programs and supporting delivery of the Alberta Offset System.
Compressed Natural Gas - CNG	CNG is made by compressing natural gas to 2900–3600 psi. CNG may be used as a lower greenhouse gas emission substitute for fossil fuels including gasoline, diesel, and propane/LPG.
Dual Fuel Engine	Typically diesel and natural gas, a Dual Fuel diesel engine is an engine that has been fitted with additional devices allowing it to utilize natural gas as a supplemental fuel.
Eligibility Criteria	Minimum requirements an offset project must meet to be eligible under the Alberta offset system.
EF - Emission Factor	A representative value that can be used to estimate the rate or quantity of greenhouse gas emissions released to the atmosphere or removed through sequestration processes.
Emission Reduction	Occurs when emissions released into the atmosphere by a source are decreased or eliminated.
Emission Removal	Occurs when CO <sub>2</sub> or CO <sub>2</sub> e is removed from the atmosphere through sequestration.
Fossil Fuel	Fossil fuels are fuels containing high carbon content formed by natural processes millions of years ago. Fossil fuels include coal, crude oil, and natural gas.
Fossil Fuel Blend	A mixture of fossil fuels with a different GHG emission profile than the unblended fuel.
Fugitive Emission	Fugitive emissions are unintentional emissions of gases or vapours.
Global Warming Potential (GWP)	Measures a greenhouse gas's relative warming effect on Earth's atmosphere compared with carbon dioxide expressed as a 100-year average.
Incremental	An eligibility criterion referring to a change in practice that results in additional emission reductions beyond business as usual.
Leakage	A shifting of greenhouse gas emissions outside a project boundary that is a result of the offset project.
Level of Assurance	Identifies the amount of work required to reach a stated level of comfort with an offset project.
Liquid Natural Gas Products - LNG	Liquefied natural gas or LNG is natural gas that has been converted to liquid form by cooling it to approximately -162 °C. Liquefied natural gas takes up about 1/600th the volume of natural gas in the gaseous state. LNG achieves a higher reduction in volume than compressed natural gas (CNG) so that the

	energy density of LNG is 2.4 times that of CNG.
Material Change in Emissions	A change in GHG emissions of 5% or more is considered material.
Offset Credit	A tradable credit issued per tonne of greenhouse gas emissions reductions expressed as CO <sub>2</sub> e.
Offset Project	An activity implemented by a project developer in accordance with a government-approved protocol that results in greenhouse gas emissions reductions or removals.
Offsets	See Alberta Offset System
Project Developer	A person who implements an offset project in accordance with a government-approved protocol.
Project Start Date	An eligibility criterion referring to the date when the greenhouse gases are initially reduced or removed by the offset project.
Protocol Developer	Person or company responsible for coordinating the development of a quantification protocol.
Protocol Sponsor	Company or organization promoting the development of a quantification protocol for an identified reduction/removal opportunity.
Quantifiable	An eligibility criterion requiring that the emissions and reductions of greenhouse gases be calculated and monitored or estimated in accordance with the requirements set out in an approved quantification protocol appropriate to the project type.
Quantification Protocol	A government-approved methodology that outlines appropriate baseline conditions, eligible sources and sinks, and emission reduction calculations for a specific emission reduction activity.
Real	An eligibility criterion requiring that the offset project be a specific and identifiable action that results in a net greenhouse gas emission reduction or removal after leakage is taken into account.
Regulated Facility	A facility located in Alberta that emits over 100,000 tonnes CO <sub>2</sub> e per year. The regulated facility may purchase offset credits for compliance under the Specified Gas Emitters Regulation.
Renewable Fuels Standard - RFS	see Alberta RFS
Replacement fuel	The type of fuel that will be used in the project (project fuel) to replace the fuel type that otherwise would be used (baseline fuel).
Reversal	A release of carbon sequestered or stored in a reservoir back to the atmosphere.
Sequestration	The process of storing carbon in a reservoir to prevent its release into the atmosphere.

Scope	An eligibility criterion that refers to the Offset Project requirements stated in Section 7 of the Specified Gas Emitters Regulation.
Sink	Any process, activity or mechanism that removes greenhouse gases from the atmosphere.
Source	Any process or activity that releases greenhouse gases into the atmosphere.
Specified Gas Emitters Regulation	The regulation passed under the Climate Change and Emissions Management Act that enables the Alberta Offset System.
Third Party Verifier	A person or organization that meets the requirements of a third party auditor stated in Section 18 of the Specified Gas Emitters Regulation (see Verification).
Unique	An eligibility criterion that requires that a greenhouse gas reduction or removal be used only once to create an offset credit.
Validation	An optional process that is used to assess a project condition, including quantification methodologies, before the project is implemented.
Verifiable	An eligibility criterion requiring that a Third Party Verifier be able to confirm that the reductions or removals have been achieved as claimed.
Verification	An independent third party review of a project to assess project operating conditions against the baseline conditions to confirm the Offset Credits being claimed.

## 2.0 Baseline Condition

The baseline condition is defined by the fuel or mix of fuels which were consumed in the condition prior to displacing these fuels with lower emitting alternatives. Fossil fuels are consumed to provide services including hauling of freight or passengers, or operation of heavy equipment (e.g., harvesting). Specifically, project developers must be able to demonstrate the types and amounts of fuels consumed in the baseline and the level of service or productivity provided.

The protocol requires that the baseline be established using measures of productivity per unit of fuel consumed. Productivity measures are then used to calculate baseline emissions based on the estimated quantity of fuel required to provide the same level of service as the known (measured) project condition.

This protocol prescribes a **Static, Historic Benchmark** approach for determining the baseline condition. This ensures emission reductions account for an equal level of service between the baseline and the project condition. This also accommodates the emission reductions associated with a growth in service provided, where lower GHG-intensive fuel(s) is/are utilized in place of the higher intensive baseline fuel(s). Functional equivalence is achieved by using a common metric of units of carbon dioxide equivalent (CO<sub>2</sub>e), and

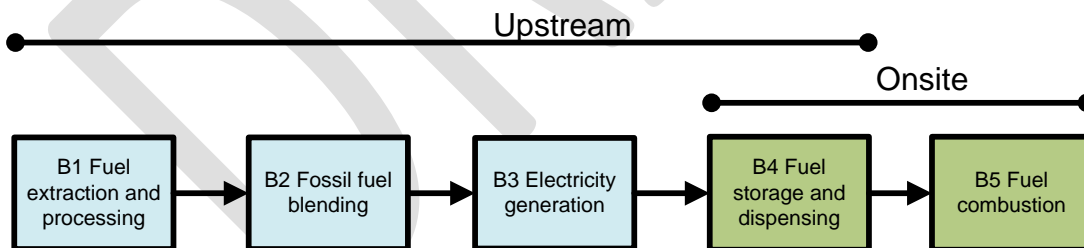
measures of service defined in the project. The units used to establish the baseline must be identical to the units used in the project (e.g., passenger km, tonnes km).

Assumptions made with the historic benchmark baseline approach include:

- A common metric for service or productivity between baseline and project conditions (e.g., tonnes km, passenger capacity km)
- Three years of historical baseline census information
- Technological or regulatory changes in fuel and efficiency will be applied to the baseline, including:
  - Use of current emission factors and methodologies as described in
  - **Appendix C;**
  - Adjustments for mandates which lower the GHG intensity of the baseline fuel(s), (i.e. Renewable Fuel Standards and Low-Carbon Fuel Standards, or similar regulatory program); and
  - Adjustments to emission factors for sector level mandatory technological changes in engine efficiency that occur during the credit project period.

For projects where the service has not been supported in the past (e.g., a town is establishing bus service or curb side garbage pickup for the first time), the historic benchmark baseline is not applicable. In this case a **Static, Performance Standard** approach can be used and is included as a flexibility mechanism.

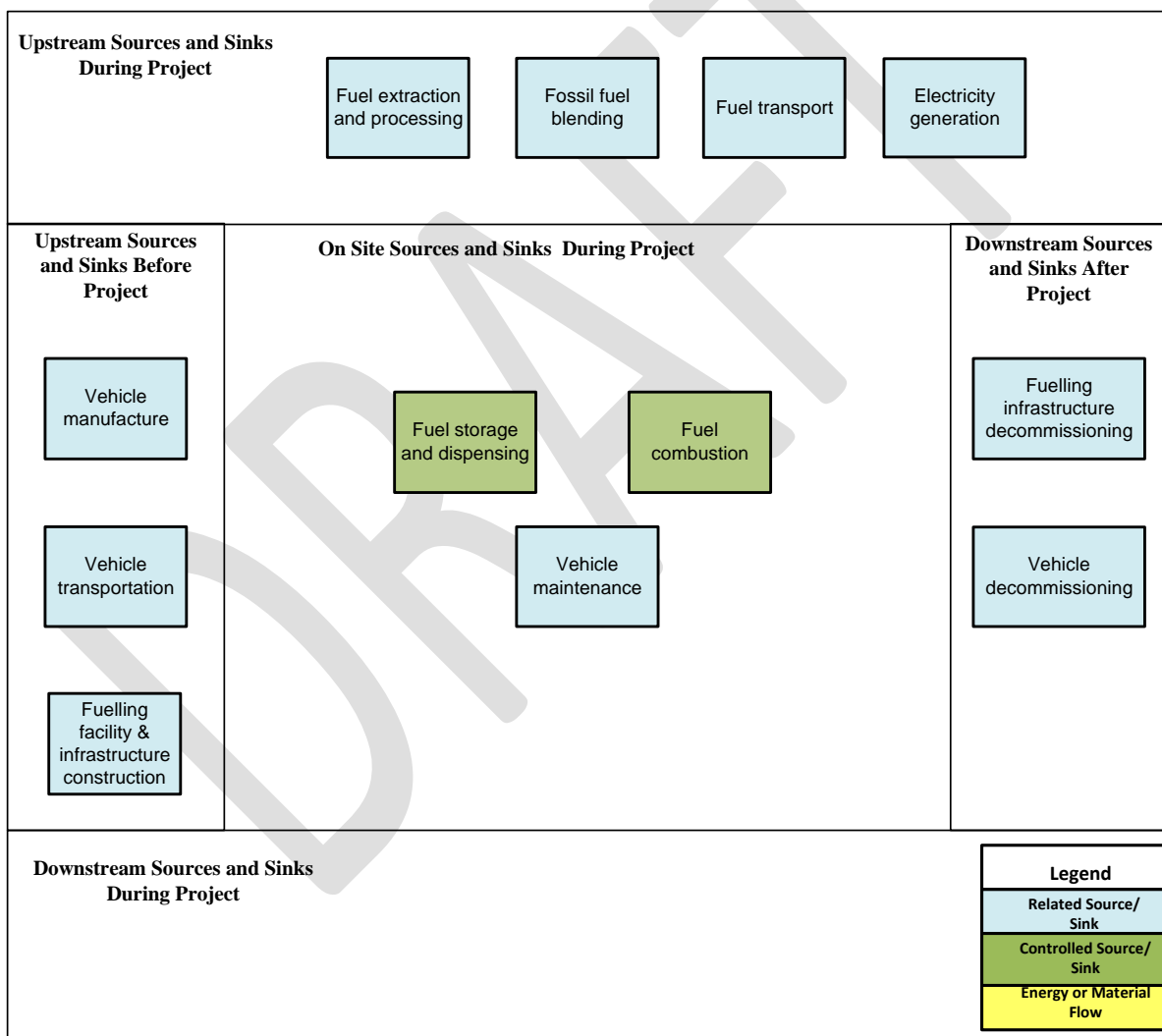
This protocol is applicable to a large variety of fuel switching projects. Some baselines may have additional processing or handling of the fuel feedstock and this may occur onsite or upstream. Figure 2 below shows the process flow for the baseline condition.



**Figure 2: Process Flow Diagram for the Baseline Condition.**

Sources and sinks (SS's) for each action are assessed based on guidance provided by Environment Canada and are classified as follows:

- Controlled: The behaviour or operation of a controlled source and/or sink is under the direction and influence of a Project Developer through financial, policy, management, or other instruments.
- Related: A related source and/or sink has material and/or energy flows into, out of, or within a project but is not under the reasonable control of the project developer.
- Affected: An affected source and/or sink is influenced by the project activity through changes in market demand or supply for projects or services associated with the project.



**Figure 3: Baseline Sources and Sinks for the Fuel Switching in Mobile Equipment Protocol.**

**Table 2: Baseline Sources and Sinks for the Fuel Switching Protocol.**

Sources/Sinks	Description	Controlled, Affected, Related
<b><i>Upstream Sources and Sinks Before Project</i></b>		
Fossil fuel extraction and processing.	Activities associated with the extraction and production of diesel or gasoline fuel from crude oil or other feedstock (such as biomass in the case of biodiesel blends).	Related
Fossil fuel blending	Energy associated with production of a blended fuel composed of two or more fossil fuels. Does not include bio fuels.	Related
Vehicle manufacture	Emissions associated with vehicle manufacturing. This includes emissions from assembly plant (electrical power, heating, cooling), materials used in manufacturing, lube oils (production and use) and transport of materials to the assembly facility.	Related
Vehicle transportation	Emissions related to the transportation of the vehicle from the point of manufacture to Alberta. Transportation may include ship, rail and road components.	Related
Fuelling facility and infrastructure construction	Emissions sources for construction of alternative fuelling facility and associated infrastructure. This includes material and material transportation, assembly, heating and lighting used during construction, as well as facility testing and start-up.	Related
<b><i>Upstream Sources and Sinks During Project</i></b>		
Fuel transport	Transport of fossil fuel from the production facility to the end use location by pipeline, rail, or road. In addition to rail and or truck emissions, emission sources include energy required to pump, compress, or transfer fuel.	Related
Electricity Generation	In the case where electricity is a baseline fuel displaced by a lower-emitting fuel in the project, this electricity would have been generated by a mix of sources on the transmission grid or on-site.	Related
<b><i>Onsite Sources and Sinks During Project</i></b>		
Fuel storage and dispensing*	Infrastructure for storage of fuel and dispensing of fuel to vehicles. This includes energy to move (pump), compress, cool, or meter fuel as well as losses due to spills, evaporation, or other fugitive emissions. Emissions for storage and dispensing may be from fuel consumed on site to provide the required energy or from electrical energy use.	Controlled
Fuel combustion	Combustion of fuel during vehicle operation.	Controlled
Vehicle maintenance	All activities associated with vehicle maintenance. This may include engine oil, lubricants, and replacement tires as well as maintenance facility power, heating and cooling emissions.	Affected
<b><i>Downstream Sources and Sinks During Project</i></b>		
<b><i>Downstream Sources and Sinks After Project</i></b>		
Fuelling infrastructure decommissioning	Decommissioning of infrastructure for temporary storage of fuel and dispensing of fuel to vehicles. Emissions sources include demolition equipment, transport and recycling of materials, transport and disposal of non recyclable material, and site reclamation.	Related
Vehicle decommissioning	Vehicle decommissioning emission sources include demolition equipment, transport of vehicle to the decommissioning facility, transport and recycling of materials, transport and disposal of non recyclable material.	Related

\* may occur onsite and/or upstream.

### 3.0 Project Condition

The project condition is defined by the emissions associated with the use of fuel(s) with lower life-cycle GHG emissions intensities in comparison to the fuel or fuel mixes previously consumed under the baseline condition.

Fuel use and levels of service during the Project are measured directly, and then compared to an amount of fuel that would have been consumed under baseline conditions to provide the same service.

This protocol is applicable to a large variety of fuel switching projects. Some projects may have additional processing or handling of the fuel feedstock (e.g., compression of natural gas to CNG or LNG) or generation of power, and this may occur onsite or upstream. Figure 4 below shows a simplified process flow for the project condition.

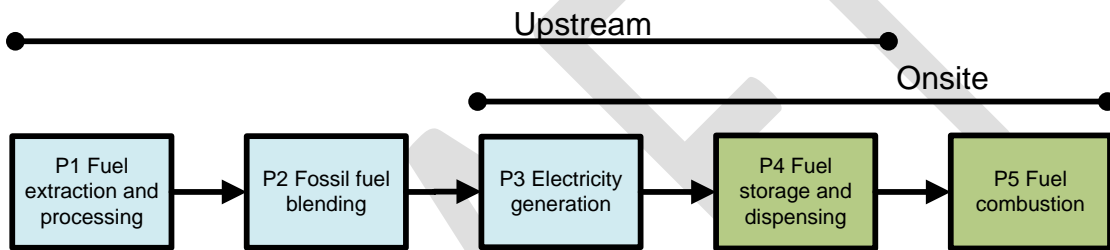


Figure 4: Process Flow Diagram for the Fuel Switching Project Condition.

#### 3.1 Identification of Project Sources and Sinks

SS's for the switching of fuels in mobile equipment were identified for the Project Condition by reviewing the Technical Seed Document and the relevant Process Flow Diagram. This process confirmed that sources and sinks identified in **Error! Reference source not found.** address the full scope of eligible project activities under this protocol.

These sources and sinks have been further refined according to the life cycle categories identified in **Error! Reference source not found.** below. These sources and sinks are further classified as controlled, related, or affected as described in **Error! Reference source not found.** below.

This protocol quantifies a direct and indirect reduction in greenhouse gas emissions resulting from a switch to a less GHG-intensive fuel. Thus, sources and sinks are similar to the baseline condition sources and sinks already discussed.

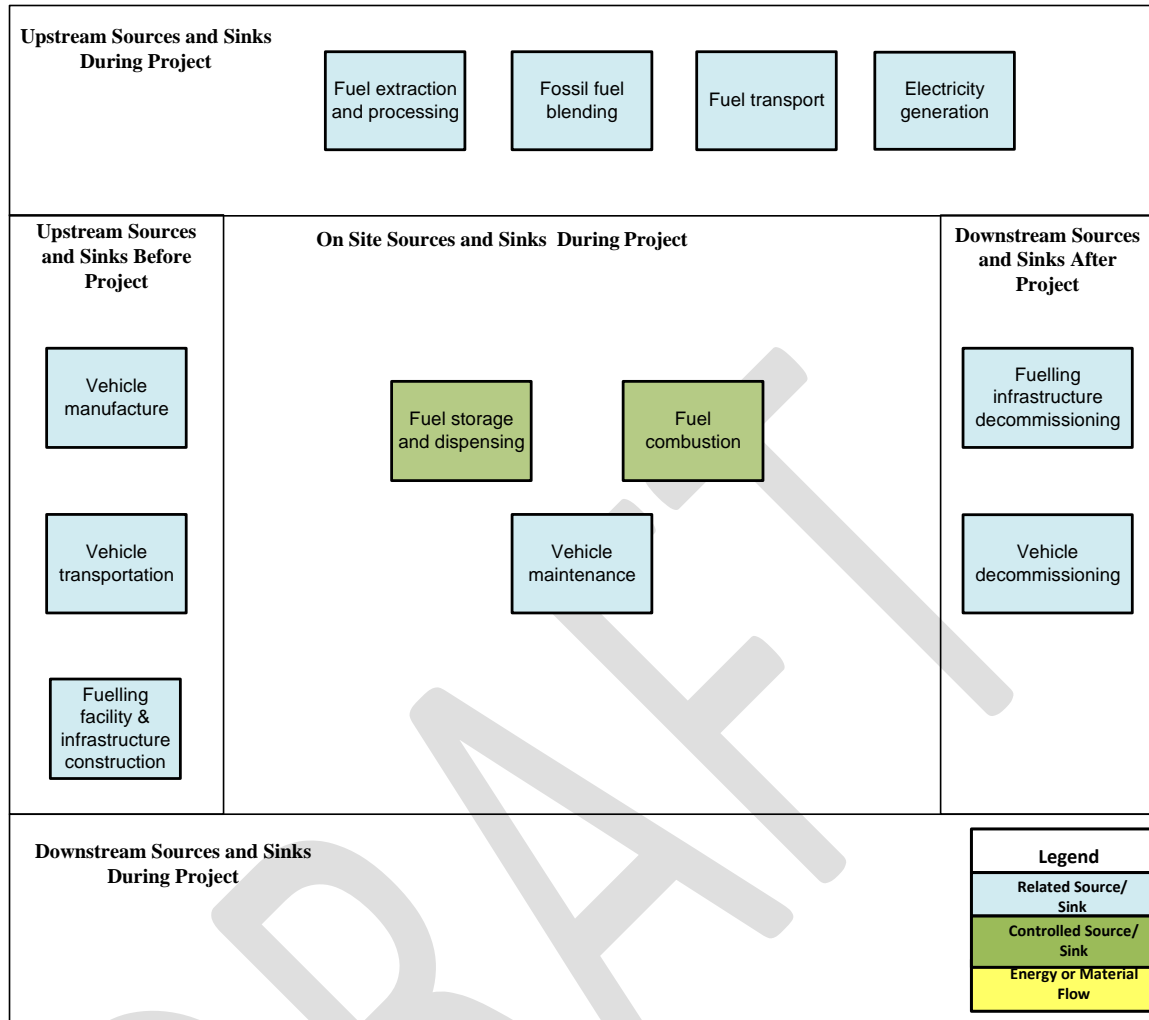


Figure 5: Project Conditions Sources and Sinks for Fuel Switching Protocol.

**Table 3: Project Condition Sources and Sinks for the Fuel Switching Protocol.**

Sources/Sinks	Description	Controlled, Affected, Related
<b><i>Upstream Sources and Sinks Before Project</i></b>		
Fuel extraction and processing	Energy is consumed during the extraction and production of fuels from crude oil or other feedstocks.	Related
Fossil fuel blending	Energy is consumed during the production of a blended fuel composed of two or more fossil fuels.	Related
Fuel transport	Transport of fossil fuel from the production facility to the end use location by pipeline, rail, or road. In addition to rail and or truck emissions, emission sources include energy required to pump, compress, or transfer fuel.	Related
Electricity Generation*	In the case where electricity is a baseline fuel displaced by a lower-emitting fuel in the project, this electricity would have been generated by a mix of sources on the transmission grid or on-site.	Related
Fuelling facility construction	Emissions sources for construction of alternative fuelling facility and associated infrastructure. This includes material and material transportation, assembly, heating and lighting used during construction, as well as facility testing and start-up.	Related
<b><i>Upstream Sources and Sinks During Project</i></b>		
Vehicle manufacture	Emissions associated with vehicle manufacturing. This includes emissions from assembly plant (electrical power, heating, cooling), materials used in manufacturing, lube oils (production and use) and transport of materials to the assembly facility.	Related
Vehicle transportation	Emissions related to the transportation of the vehicle from the point of manufacture to Alberta. Transportation may include ship, rail and road components.	Related
<b><i>Onsite Sources and Sinks During Project</i></b>		
Fuel storage and dispensing*	Emissions for storage and dispensing may be from fuel consumed on site to provide the required energy or from electrical energy use. Depending on the fuel type, the energy to move (pump), compress, cool, or meter fuel as well as losses due to spills, evaporation, or other fugitive emissions may differ considerably between project and baseline conditions. This includes incremental changes of electrical energy use for different fuel types.	Controlled
Fuel combustion	Combustion of fuel during vehicle operation will result in a direct emission from the vehicle tailpipe.	Controlled
Vehicle maintenance	All activities associated with vehicle maintenance. This may include engine oil, lubricants, and replacement tires as well as maintenance facility power, heating and cooling emissions.	Affected
<b><i>Downstream Sources and Sinks After Project</i></b>		
Vehicle decommissioning	Vehicle decommissioning emission sources include demolition equipment, transport of vehicle to the decommissioning facility, transport and recycling of materials, transport and disposal of non recyclable material.	Related
Fuelling infrastructure decommissioning	Emissions sources for decommissioning of alternative fuelling infrastructure include demolition equipment, transport and recycling of materials, transport and disposal of non recyclable material, and site reclamation.	Related

\* may occur onsite and or upstream.

## 4.0 Quantification

Each of the SS's from the Baseline and Project Conditions were compared and evaluated as to their relevancy to determine the scope for reductions quantified under this protocol.

Sources and sinks were either included or excluded depending on how they were impacted by the project condition. Sources not expected to change between baseline and project condition are excluded from quantification.

Where the quantity of emissions generated changes as a result of the project, in comparison to the baseline, the associated emissions are included for quantification. All sources and sinks identified above are listed in **Error! Reference source not found.** Each source and sink is listed as included or excluded. Justification for these choices is provided.

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**Table 4: Comparison of Sources/Sinks.**

Identified Sources and Sinks	Baseline (C, R, A)*	Project (C, R, A)*	Include or Exclude from Quantification	Justification for Inclusion/Exclusion
<b>Upstream Sources/Sinks</b>				
Fuel extraction and processing	R	R	<b>Include</b>	This source/sink is project dependent. Additional emissions from project alternative fuel processing and extraction may occur depending on the fuel type. This source/sink may be excluded where emissions occur onsite (see storage and dispensing), where project emissions are within 5% of baseline emissions, or when baseline emissions are greater than project emissions.
Fossil fuel blending	R	R	<b>Include</b>	The energy required for fossil fuel blending of replacement fuel will reduce the potential offset as it is additional to baseline fuel. Fossil fuel blending may also occur in the baseline. Fossil fuel blending would be excluded for projects where it does not occur.
Vehicle manufacture	R	R	<b>Exclude</b>	Little difference is expected between project and baseline vehicle manufacturing emissions, because project and baseline vehicles are required to provide comparable service and will also be comparable in general construction. It is anticipated that both project and baseline vehicles would originate from outside Alberta and the scale of potential projects results in a low expected magnitude of emission.
Vehicle transportation	R	R	<b>Exclude</b>	This source/sink represents an inconsequential fraction of total vehicle lifetime emissions. It is anticipated that both project and baseline vehicles would originate from outside Alberta and additional transportation is likely minimal and prohibitive to quantify accurately. The scale of potential projects results in a low expected magnitude of emission.
Fuel transport	R	R	<b>Exclude</b>	Emissions from fuel transportation within Alberta are expected to remain the same (e.g., fuel blends) or decrease (e.g., CNG, LNG) under the project condition. Thus it is conservative to exclude fuel transportation emissions.

Identified Sources and Sinks	Baseline (C, R, A)*	Project (C, R, A)*	Include or Exclude from Quantification	Justification for Inclusion/Exclusion
Fuelling facility and infrastructure construction	R	R	<b>Exclude</b>	Differences in facility construction between project and baseline are expected to be minimal. Given the small scale and wide variety of potential project types it would be prohibitively costly to collect the required baseline and project construction emission information.
Electricity Generation	R	R	<b>Include</b>	Where electricity is a baseline fuel, the transition to a lower-emitting alternative during the project will result in a reduction of GHG emissions. Alternatively, where a higher-emitting fuel is displaced by electricity during the project, a reduction of emissions, in comparison to the Baseline Condition, is achieved.
<b>Onsite Sources/Sinks</b>				
Fuel storage and dispensing	C	C	<b>Include</b>	Emissions for storage and dispensing may be from fuel consumed on site to provide the required energy or from electrical energy use. Depending on the fuel type, the energy to move (pump), compress, cool, or meter fuel as well as losses due to spills, evaporation, or other fugitive emissions may differ considerably between project and baseline conditions. This includes incremental changes of electrical energy use for different fuel types.
Fuel combustion	C	C	<b>Include</b>	CO <sub>2</sub> , CH <sub>4</sub> , and N <sub>2</sub> O emissions will be different between project and baseline fuels.
Vehicle maintenance	A	A	<b>Exclude</b>	Magnitude of change in maintenance is expected to be minimal over vehicle lifetime and prohibitively costly to quantify.
<b>Downstream Sources/Sinks</b>				
Fuelling infrastructure decommissioning	R	R	<b>Exclude</b>	Both baseline and project conditions require similar scale of refuelling infrastructure.
Vehicle decommissioning	R	R	<b>Exclude</b>	Project and baseline condition vehicles are required to provide comparable service and will be comparable in general construction and decommissioning emissions.
<b>Other</b>				
<b>None</b>				

\* C is Controlled, R is Related, and A is Affected

## 4.1 Quantification Methodology

The general quantification approach for greenhouse gas emissions quantification under this protocol is shown below. Each equation is described and broken down in greater detail under individual subheadings, and where required, emissions factors<sup>2</sup> are provided.

The general equation for calculation of emission reductions is:

$$\text{Emission Reduction} = \text{Emissions}_{\text{Baseline}} - \text{Emissions}_{\text{Project}}$$

$$\text{Emissions}_{\text{Baseline}} = \text{Emissions}_{\text{upstream baseline}} + \text{Emissions}_{\text{fuel combustion}}$$

OR

$$\text{Emissions}_{\text{Baseline}} = \text{Emissions}_{\text{fuel extraction and processing}} + \text{Emissions}_{\text{fossil fuel blending}} + \text{Emissions}_{\text{electricity generation}} + \text{Emissions}_{\text{fuel storage and dispensing}} + \text{Emissions}_{\text{fuel combustion}}$$

$$\text{Emissions}_{\text{Project}} = \text{Emissions}_{\text{upstream project}} + \text{Emissions}_{\text{fuel combustion}}$$

OR

$$\text{Emissions}_{\text{Project}} = \text{Emissions}_{\text{fuel extraction and processing}} + \text{Emissions}_{\text{fossil fuel blending}} + \text{Emissions}_{\text{electricity generation}} + \text{Emissions}_{\text{fuel storage and dispensing}} + \text{Emissions}_{\text{fuel combustion}}$$

**Note: the methods described as the preferred approach to quantification calculate upstream emissions in a single step that incorporates all the included SS's.**

Where:

Emissions<sub>Baseline</sub> = sum of the emissions included under the Baseline Condition.

Emissions<sub>Project</sub> = sum of emissions included under the Project Condition.

Discount Factors:

Because the protocol is basing the quantification on project metered fuel consumption, and the emission reduction is an immediate and direct reduction (i.e., no capture or storage), a risk discount factor is not required.

## 4.2 Baseline Condition Quantification

For the included sources and sinks, the baseline emissions are:

$$\text{Emissions}_{\text{Baseline}} = \text{Emissions}_{\text{upstream}} + \text{Emissions}_{\text{fuel combustion}}$$

Where:

$$\text{Emissions}_{\text{upstream}} = \text{Emissions}_{\text{fuel extraction and processing}} + \text{Emissions}_{\text{fossil fuel blending}} + \text{Emissions}_{\text{electricity generation}} + \text{Emissions}_{\text{fuel storage and dispensing}}$$

<sup>2</sup> CO<sub>2</sub>e emission factors are sum of CO<sub>2</sub>, CH<sub>4</sub> and N<sub>2</sub>O emissions.

$$\mathbf{Emissions}_{fuel\ combustion} = \mathbf{Quantity}_{baseline\ fuel} \times \mathbf{EF}_{baseline\ fuel}$$

And:

$$\mathbf{Emissions}_{fuel\ extraction\ and\ processing} = \mathbf{Quantity}_{baseline\ fuel} \times \mathbf{EF}_{extraction\ and\ processing}$$

$$\mathbf{Emissions}_{fossil\ fuel\ blending} = (\sum \mathbf{Quantity}_{blended\ fuel}) \times \mathbf{Energy}_{per\ unit\ volume\ blended} \times \mathbf{EF}_{energy}$$

$$\mathbf{Emissions}_{electricity\ generation} = \mathbf{Baseline\ kWh} \times \mathbf{EF}_{electricity}$$

$$\mathbf{Emissions}_{fuel\ storage\ and\ dispensing} = (\mathbf{Energy}_{dispensing} \times \mathbf{EF}_{energy}) + (\mathbf{Quantity}_{fugitive\ emissions} \times \mathbf{EF}_{baseline\ fuel})$$

Depending on the fuel type, fuel blending and electricity generation may be excluded.

*Note: For gasoline and diesel a single combined emission factor (upstream and combustion) that incorporates the Alberta Renewable Fuels Standard should be used.*

#### **4.2.1 Emissions upstream**

Upstream emissions are all emissions upstream of combustion and include fuel extraction and processing (B1), fossil fuel blending (B2), electricity generation (B3) and fuel storage and dispensing (B4).

##### **4.2.1.1 B1 - Fuel extraction and processing**

Emissions for fuel extraction and processing are quantified from an estimated Quantity of baseline fuel. The quantity of baseline fuel is estimated using measures of service provided per unit of baseline fuel incorporated in the Static Historic Benchmark. Fuel extraction and processing can be quantified separately or combined with the other included upstream sources by use of emission factors from GHGenius or other approved sources as described in **Appendix C**.

For fuel blends, the emissions from fuel extraction and processing for each type of fuel in the blend would be quantified separately and added together.

##### **4.2.1.2 B2 - Fossil fuel blending**

Some baseline fuels may be blends of different fossil fuels, though this condition is more likely in the project than in the baseline. The energy used to combine and blend the fuels together is the source that must be quantified if a fossil fuel blend is used, otherwise this source is excluded from the quantification.

The emissions for fossil fuel blending are determined using the same Quantity of baseline fuel estimated for B1 above multiplied by the energy per unit of fuel blended and the emission factor for the energy source used to do the blending.

Fossil fuel blending is additional to the normal fuel processing that occurs.

##### **4.2.1.3 B3 - Electricity generation**

If electricity is a fuel in the baseline then it must be included in the historic benchmark as kWh per unit of service or productivity. Where electricity is not a fuel in the baseline, this source would be excluded from the quantification.

In the case where electricity is a baseline fuel displaced by a lower-emitting fuel in the project, this electricity would have been generated by a mix of sources on the Alberta transmission grid or on-site. The amount (kWh) of electricity would be determined in the same manner as fossil fuel by using the historic baseline. Emissions would be quantified using the Alberta grid emission factor supplied by Alberta environment or approved project specific emission factor for on-site generation.

#### 4.2.1.4 B4 - Fuel storage and dispensing

Emissions for fuel storage and dispensing are quantified from the same Quantity of fuel estimated using the same Static Historic Benchmark as described for B1 and B2. The energy required per unit of fuel dispensed may be included in the baseline and used to quantify emissions from fuel dispensing. Fuel storage and dispensing can be quantified separately or combined with the other included upstream sources using GHGenius or other approved sources as described in **Appendix C**.

In addition to the energy used to dispense the fuel, this source includes an estimate of fugitive emissions where dispensing is conducted onsite and is controlled. Quantification of fugitive emissions is difficult, but they may be measured simply as the difference between the volume deposited into a storage tank and the volume successfully dispensed from the tank. In the case of onsite dispensing it would be the difference between fuel dispensed and fuel received by the vehicle. GHGenius does incorporate estimates of fugitive emissions in its upstream emission factors and should be used. Alternatively, the manufacturer of the refuelling technology may supply estimates of fugitive emissions that could be included in the quantification.

*Note: For baseline conditions where the refuelling was not controlled by the project developer this source may be difficult to include due to lack of suitable data. It is conservative to exclude this source from the baseline quantification but still include it in the project.*

#### 4.2.2 B5 - Fuel combustion

The Quantity of baseline fuel combusted is estimated using the Static Historic Benchmark. Emissions are calculated as Quantity of fuel multiplied by the emission factor (Appendix C) specific to the type of fuel. For fuel blends, or when multiple fuel types are included in the baseline (e.g., dual fuel or multi fuel engines) the amount of each fuel type would be determined and quantified separately.

### 4.3 Project Condition Quantification

$$Emissions_{Project} = Emissions_{upstream} + Emissions_{fuel\ combustion}$$

Where:

$$Emissions_{upstream} = Emissions_{fuel\ extraction\ and\ processing} + Emissions_{fossil\ fuel\ blending} +$$

$$Emissions_{electricity\ generation} + Emissions_{fuel\ storage\ and\ dispensing}$$

$$Emissions_{fuel\ combustion} = Quantity_{project\ fuel} \times EF_{project\ fuel}$$

And:

$$Emissions_{fuel\ extraction\ and\ processing} = Quantity_{project\ fuel} \times EF_{extraction\ and\ processing}$$

$$Emissions_{fossil\ fuel\ blending} = (\sum Quantity_{blended\ fuel}) \times Energy_{per\ unit\ volume\ blended} \times EF_{energy}$$

$$\begin{aligned} \text{Emissions}_{\text{electricity generation}} &= \text{Project kWh} \times \text{EF}_{\text{electricity}} \\ \text{Emissions}_{\text{fuel storage and dispensing}} &= (\text{Energy}_{\text{dispensing}} \times \text{EF}_{\text{energy}}) + (\text{Quantity}_{\text{Fugitive emissions}} \times \text{EF}_{\text{project fuel}}) \end{aligned}$$

Depending on the fuel type, fuel blending and electricity generation may be excluded.

*Note: Use of a combined upstream emission factor is the default quantification method. Depending on the fuel type, fuel blending and electricity generation may be excluded.*

#### **4.3.1 Emissions<sub>upstream</sub>**

Upstream emissions are all emissions upstream of combustion and include fuel extraction and processing (P1), fossil fuel blending (P2), electricity generation (P3) and fuel storage and dispensing (P4).

##### **4.3.1.1 P1 - Fuel extraction and processing**

Emissions for fuel extraction and processing are quantified from the measured Quantity of project fuel. The Quantity of project fuel may be established using records of fuel purchase and use or directly through metering. Fuel extraction and processing can be quantified separately or combined with the other included upstream sources by using emission factors from GHGenius or other approved sources as described in Appendix C.

For fuel blends, the emissions from fuel extraction and processing for each type of fuel in the blend would be quantified separately and added together.

##### **4.3.1.2 P2 - Fossil fuel blending**

Some project fuels may be blends of different fossil fuels. The energy used to combine and blend the fuels together is the source that must be quantified if a fossil fuel blend is used; otherwise this source is excluded from the quantification.

The emissions for fossil fuel blending are determined using the same measured Quantity of fuel multiplied by the energy per unit of fuel blended and the emission factor for the energy source used to do the blending.

##### **4.3.1.3 P3 - Electricity generation**

Where a higher-emitting fuel is displaced by electricity during the project, a reduction of emissions, in comparison to the Baseline Condition, is achieved. If electricity is a fuel in the project then it must be measured. The amount (kWh) of electricity can be established using power purchase records or directly through metering. Where electricity is not a fuel in the project and is not generated onsite for use in fuel storage and dispensing (e.g., onsite natural gas compression), this source would be excluded from the quantification.

In the case where electricity is included as a fuel in the project, this electricity would have been generated by a mix of sources on the Alberta transmission grid, or on-site. The amount (kWh) of electricity must be metered and emissions would be quantified using

the Alberta grid emission factor supplied by Alberta Environment or with approved project specific emission factor for on-site power generation.

#### **4.3.1.4 P4 - Fuel storage and dispensing**

Fuel storage and dispensing can be quantified separately or combined with the other included upstream sources by use of GHGenius or other approved sources as described in Appendix C.

Emissions for fuel storage and dispensing are quantified from total metered energy used to dispense the fuel.

In addition to the energy used to dispense the fuel, this source may include an estimate of fugitive emissions where dispensing is conducted onsite and is controlled. Project proponents must show that fugitive emissions in the project case are not higher than the baseline case, or must include some fugitive emissions in the quantification.

Quantification of fugitive emissions is difficult, but may be measured simply as the difference between the volume deposited into a storage tank and the volume dispensed from the tank. In the case of onsite dispensing it would be the difference between gas dispensed and gas received by the vehicle. Records of fuel supplied to the refuelling station, and of fuel dispensed from the station may be used to substantiate the exclusion or inclusion of fugitive emissions in the quantification.

The preferred approach when dispensing is not controlled by the project is to use GHGenius, which incorporates estimates of fugitive emissions for most fuel feedstocks. Alternatively, the manufacturer of the refuelling technology may supply estimates of fugitive emissions that could be included in the quantification. How fugitive emissions will be handled must be included in the project plan and should be reviewed prior to project start to ensure that the standards for verification can be met.

#### **4.3.2 P5 - Fuel combustion**

The Quantity of project fuel combusted is estimated using the measured Quantity of fuel and the assumption that all fuel is combusted. Emissions are calculated as Quantity of fuel multiplied by the appropriate fuel emission factor (see Appendix C). For fuel blends, or when multiple fuel types are included in the project (e.g., dual fuel or multi fuel engines) the amount of each fuel type would be determined and quantified separately.

**Table 5: Quantification Methodology.**

Source/Sink	Parameter / Variable	Unit	Measured/ Estimated	Method	Frequency	Justify measurement or estimation and frequency
<b>Baseline Condition</b>						
$Emissions_{Baseline} = Emissions_{upstream} + Emissions_{fuel\ combustion}$ Where: $Emissions_{upstream} = Emissions_{fuel\ extraction\ and\ processing} + Emissions_{fossil\ fuel\ blending} + Emissions_{electricity\ generation} + Emissions_{fuel\ storage\ and\ dispensing}$ $Emissions_{fuel\ combustion} = Quantity_{baseline\ fuel} \times EF_{baseline\ fuel}$						
B1* Fuel extraction and processing	$Emissions_{fuel\ extraction\ and\ processing} = Quantity_{baseline\ fuel} \times EF_{extraction\ and\ processing}$					
	$Quantity_{baseline\ fuel}$	Litres, m <sup>3</sup> , or kg	Estimated	Static historic benchmark or performance standard baseline.	Annually	The amount of baseline fuel is estimated from direct measurements of services provided by the project condition. Services supplied in the project condition must be identical to services supplied in the baseline historic benchmark or performance standard.
	$EF_{extraction\ and\ processing}$	gCO <sub>2</sub> e per unit of fuel	Estimated	From GHGenius model or other approved source for Alberta.	Periodic	Emission factors for upstream fuel extraction and processing are periodically updated for Alberta in GHGenius. Due to the many factors that must be considered for this SS, periodic updates are all that is available. Must use most recent version of GHGenius or other approved source.
B2*	$Emissions_{fossil\ fuel\ blending} = (\sum Quantity_{blended\ fuel}) \times Energy_{per\ unit\ volume\ blended} \times EF_{energy}$					

Source/Sink	Parameter / Variable	Unit	Measured/ Estimated	Method	Frequency	Justify measurement or estimation and frequency
Fossil fuel blending	<b>Quantity</b> <i>blended fuel</i>	Litres, m <sup>3</sup> , or kg	Estimated	Quantity of each constituent fuel in the blend is calculated proportionally from the total estimated baseline fuel.	Annually	This SS is only included if it occurred in the baseline. The quantity would be estimated from the quantity of baseline fuel calculated using a historic benchmark or performance standard baseline. Must be calculated annually during the project credit period.
	<b>Energy</b> <i>per unit volume blended</i>	kWh per unit of fuel blended	Measured or estimated	From records of energy required to blend the constituent types together.	Periodic	Reviewed periodically when technology or process changes occur.
	<b>EF</b> <i>energy</i>	CO <sub>2</sub> e per unit of energy	Estimated	From approved Alberta emission factor source.	Periodic	Emission factor for electric power supplied from the Alberta grid is provided by Alberta Environment and is periodically reviewed. Must use most recent Alberta Environment emission factor or an approved project-specific emission factor if energy is supplied for a source other than the Alberta electric grid.
B3 Electricity generation	<b>Emissions</b> <i>electricity generation</i> = <b>Baseline kWh X EF</b> <i>electricity</i>					
	<b>Baseline kWh</b>	kWh	Estimated	Static historic benchmark or performance standard baseline.	Annually	Where electricity is a baseline fuel, the use must be included in the baseline as energy per unit of service provided. The kWh are estimated from the measured quantity of service provided in the project multiplied by the baseline kWh per unit of service. This is a static measure and once established will be unchanged throughout the project credit period.

Source/Sink	Parameter / Variable	Unit	Measured/ Estimated	Method	Frequency	Justify measurement or estimation and frequency
	<i>EF<sub>electricity</sub></i>	CO <sub>2</sub> e per unit of energy	Estimated	From approved Alberta Environment or project specific approved source.	Periodic	Emission factor for electric power supplied from the Alberta grid is provided by Alberta Environment and is periodically reviewed. Must use most recent Alberta Environment emission factor or an approved project specific emission factor if energy is supplied from a source other than the Alberta electric grid.
B4* Fuel storage and dispensing	<i>Emissions<sub>fuel storage and dispensing</sub> = (Energy<sub>dispensing</sub> X EF<sub>energy</sub>) + (Quantity<sub>fugitive emissions</sub> X EF<sub>baseline fuel</sub>)</i>					
	<i>Energy<sub>dispensing</sub></i>	kWh	Estimated	From records of energy required to dispense baseline fuel (historic baseline), or from GHGenius model or other approved source for Alberta.	Periodic	Historic baseline, GHGenius model, or the manufacturer's specifications may be used. The energy for dispensing may be captured in the historic baseline as energy required per unit of fuel dispensed. Alternatively, the energy per unit of fuel dispensed may be used if the dispensing equipment is known and controlled by the project developer. Energy required for dispensing are periodically updated for Alberta in GHGenius. Must use most recent version of GHGenius or other approved source.
	<i>EF<sub>energy</sub></i>	CO <sub>2</sub> e per unit of energy	Estimated	From approved Alberta emission factor source.	Periodic	Emission factor for electric power supplied from the Alberta grid is provided by Alberta Environment and is periodically reviewed. Must use most recent Alberta Environment emission factor or an approved project specific emission factor if energy is supplied from a source other than the Alberta electric grid.

Source/Sink	Parameter / Variable	Unit	Measured/ Estimated	Method	Frequency	Justify measurement or estimation and frequency
	<i>Quantity<sub>fugitive emissions</sub></i>	Litres, m <sup>3</sup> , or kg	Estimated	From records of fugitive emissions or from manufacturers reports of fugitive emissions per unit of fuel dispensed. May also be estimated with GHGenius model or other approved source for Alberta.	Periodic	Historic baseline, GHGenius model, or the manufacturer's specifications may be used. The quantity of fugitive emissions may be captured in the historic baseline as fugitive emissions per unit of fuel dispensed. Alternatively, the manufacturer's reported fugitive emissions per unit of fuel dispensed may be used if the dispensing equipment is known and controlled by the project developer. Emissions factors for dispensing are periodically updated for Alberta in GHGenius. Must use most recent version of GHGenius or other approved source.
	<i>EF<sub>baseline fuel</sub></i>	CO <sub>2</sub> e per unit of fuel	Estimated	From Environment Canada or other approved Alberta source.	Periodic	Must use most current approved emission factor for Alberta. Appendix C provides emissions factors including Alberta RFS.
B5 Fuel combustion	<i>Emissions<sub>fuel combustion</sub> = Quantity<sub>baseline fuel</sub> X EF<sub>baseline fuel</sub></i>					
	<i>Quantity<sub>baseline fuel</sub></i>	Litres, m <sup>3</sup> , or kg	Estimated	Static historic benchmark or performance standard baseline.	Annually	The amount of baseline fuel is estimated from direct measurements of services provided by the project condition. Services supplied in the project condition are identical to services supplied in the baseline historic benchmark or performance standard.
	<i>EF<sub>baseline fuel</sub></i>	CO <sub>2</sub> e per unit of fuel combusted	Estimated	From Environment Canada reference documents.	Annually	Must use most current approved emission factor for Alberta. Appendix C provides emissions factors including Alberta RFS.

Source/Sink	Parameter / Variable	Unit	Measured/ Estimated	Method	Frequency	Justify measurement or estimation and frequency
<p><b>Project Condition</b>  <math>Emissions_{Project} = Emissions_{upstream} + Emissions_{fuel\ combustion}</math>                      Where:  <math>Emissions_{upstream} = Emissions_{fuel\ extraction\ and\ processing} + Emissions_{fossil\ fuel\ blending} + Emissions_{electricity\ generation} + Emissions_{fuel\ storage\ and\ dispensing}</math>  <math>Emissions_{fuel\ combustion} = Quantity_{project\ fuel} \times EF_{project\ fuel}</math></p>						
P1* Fuel extraction and processing	$Emissions_{fuel\ extraction\ and\ processing} = Quantity_{project\ fuel} \times EF_{extraction\ and\ processing}$					
	$Quantity_{project\ fuel}$	Litres, m <sup>3</sup> , or kg	Measured	Metered Quantity and or fuel purchase records.	Annually	The amount of project fuel is a direct measure of fuel used annually during the project credit period.
	$EF_{extraction\ and\ processing}$	gCO <sub>2</sub> e per unit of fuel	Estimated	From GHGenius model or other approved source for Alberta.	Periodic	Emission factors for upstream fuel extraction and processing are periodically updated for Alberta in GHGenius. Due to the many factors that must be considered for this SS, periodic updates are all that is available. Must use Appendix C that incorporates the most recent version of GHGenius, or other approved source.
P2* Fossil fuel blending	$Emissions_{fossil\ fuel\ blending} = (\sum Quantity_{blended\ fuel}) \times Energy_{per\ unit\ volume\ blended} \times EF_{energy}$					
	$Quantity_{blended\ fuel}$	Litres, m <sup>3</sup> , or kg	Measured	Quantity of each constituent fuel in the blend is calculated proportionally from the total project fuel Quantity or from fuel purchase records.	Annually	The amount of blended project fuel is calculated as a direct measure of fuel used annually during the project credit period.

Source/Sink	Parameter / Variable	Unit	Measured/ Estimated	Method	Frequency	Justify measurement or estimation and frequency
	<i>Energy per unit volume blended</i>	kWh per unit of fuel blended	Estimated	From records of energy required to blend the constituent fuel types together.	Periodic	Reviewed periodically when technology or process changes occur.
	<i>EF<sub>energy</sub></i>	CO <sub>2</sub> e per unit of energy	Estimated	From approved Alberta emission factor source.	Periodic	Emission factor for electric power supplied from the Alberta grid is provided by Alberta Environment and is periodically reviewed. Must use most recent Alberta Environment emission factor or an approved project-specific emission factor if energy is supplied from a source other than the Alberta electric grid.
	<b><i>Emissions<sub>electricity generation</sub> = Project kWh X EF<sub>electricity</sub></i></b>					
P3 Electricity generation	<b><i>Project kWh</i></b>	kWh	Measured	Energy produced or used onsite must be metered.	Annually	Where electricity is a baseline fuel, the transition to a lower-emitting alternative during the project will result in a reduction of GHG emissions. Alternatively, where a higher-emitting fuel is displaced by electricity during the project, a reduction of emissions, in comparison to the Baseline Condition, is achieved.
	<i>EF<sub>electricity</sub></i>	CO <sub>2</sub> e per unit of energy	Estimated	From Alberta Environment or approved project specific source.	Periodic	Emission factor for electric power supplied from the Alberta grid is provided by Alberta Environment and is periodically reviewed. Must use most recent Alberta Environment emission factor or an approved project-specific emission factor if energy is supplied from a source other than the Alberta electric grid.

Source/Sink	Parameter / Variable	Unit	Measured/ Estimated	Method	Frequency	Justify measurement or estimation and frequency
P4* Fuel storage and dispensing**	<b><i>Emissions<sub>fuel storage and dispensing</sub></i></b> = ( <b><i>Energy<sub>dispensing</sub></i></b> X <b><i>EF<sub>energy</sub></i></b> ) + ( <b><i>Quantity<sub>fugitive emissions</sub></i></b> X <b><i>EF<sub>project fuel</sub></i></b> )					
	<b><i>Energy<sub>dispensing</sub></i></b>	kWh	Measured or from reported values	Measured directly or from records of reported energy required to dispense project fuel.	Periodic	Measured energy use must be used. If the dispensing equipment is not controlled by the project developer then it may be estimated from reported energy use and quantity of fuel dispensed.
	<b><i>EF<sub>energy</sub></i></b>	CO <sub>2</sub> e per unit of energy	Estimated	From approved Alberta emission factor source.	Periodic	Emission factor for electric power supplied from the Alberta grid is provided by Alberta Environment and is periodically reviewed. Must use most recent Alberta Environment emission factor or an approved project-specific emission factor if energy is supplied from a source other than the Alberta electric grid.
	<b><i>Quantity<sub>fugitive emissions</sub></i></b>	Litres, m <sup>3</sup> , or kg	Measured or Estimated	From records of fugitive emissions or from manufacturers reports of fugitive emissions per unit of fuel dispensed. May also be estimated with GHGenius model or other approved source for Alberta.	Periodic	Measured, GHGenius model, or the manufacturer’s specifications may be used. The Quantity of fugitive emissions may be measured during the project period for onsite equipment under the control of the project developer. Alternatively, the manufacturer’s reported fugitive emissions per unit of fuel dispensed may be used if the dispensing equipment is known and controlled by the project developer. If the dispensing equipment is not controlled by the project developer then the most recent version of GHGenius or other approved Alberta source may be used.

Source/Sink	Parameter / Variable	Unit	Measured/ Estimated	Method	Frequency	Justify measurement or estimation and frequency
	$EF_{project\ fuel}$	CO <sub>2</sub> e per unit of fuel	Estimated	From Environment Canada or other approved Alberta source.	Periodic	Must use most current approved emission factor for Alberta. Appendix C provides emissions factors including Alberta RFS.
P5 Fuel combustion	$Emissions_{fuel\ combustion} = Quantity_{project\ fuel} \times EF_{project\ fuel}$					
	$Quantity_{project\ fuel}$	Litres, m <sup>3</sup> , or kg	Measured	Metered Quantity and or fuel purchase records.	Annually	The amount of project fuel is measured directly for each year during the project credit period.
	$EF_{project\ fuel}$	CO <sub>2</sub> e per unit of fuel combusted	Estimated	From Environment Canada reference documents.	Annually	Must use most current approved emission factor for Alberta. Appendix C provides emissions factors including Alberta RFS.

\* Note: The preferred method is that upstream emissions be quantified together using GHGenius or other approved Alberta sources. These SS's are provided here separately for completeness and to facilitate projects where they are separate (e.g., onsite compression or processing).

\*\* May be broken into fuel feedstock and onsite SS's, each require separate quantification (e.g., onsite natural gas compression requires quantification for the natural gas feedstock to the compression facility and a second quantification for compression and dispensing of CNG).

## **5.0 Data Management**

Data quality management must be of sufficient quality to fulfill the quantification requirements and be substantiated by actual records for the purpose of verification and for any subsequent government audits.

The project developer shall establish and apply quality management procedures to manage data and information. Written procedures must be established for each measurement task outlining responsibility, timing and record location requirements. The greater the rigour of the management system for the data, the more easily verification/audit will be conducted for the project.

### **5.1 Project Documentation**

Minimum documentation required for this protocol includes:

#### **5.1.1 Project Eligibility Documentation**

- Time and location when project began and activities occurred, including
  - Actions were taken after January 1, 2002 based on fuel procurement and technology procurement records.
  - Have occurred in a period acceptable under Offset System Program Rules
  - In Alberta, including proof of service delivery in Alberta and fuel consumption related to that service.
- The alternative fuel consumed by the Project is not industry standard practice.
- The emission reductions claimed are owned by the Project Proponent by proof of fuel and technology purchases.
- Project is not required by law.

#### **5.1.2 Project Quantification Documentation**

- Level of service including:
  - Distance travelled by providing vehicle operations/maintenance logs or GPS tracking.
  - Equipment capacity including hauling records from weight scales, vehicle capacity in persons carried, etc.
- Amount of energy consumed in fuel storage and dispensing through metered energy consumption and/or proof of purchase of energy.
- Quantity of fuel consumed in mobile equipment through metered dispensing and/or proof of purchase of fuel.

### 5.1.3 Baseline Condition Documentation

Documentation and related proofs are the same between the Project and Baseline Conditions in most cases. Three years of historical data are required or project developers may use the flexibility mechanism. Baseline documentation includes:

- Level of service including:
  - Distance travelled by providing vehicle operations/maintenance logs or GPS tracking.
  - Equipment capacity including hauling records from weight scales, vehicle capacity in persons carried, etc.
- Amount of energy consumed in fuel storage and dispensing through metered energy consumption and/or proof of purchase of energy.
- Quantity of fuel consumed in mobile equipment through metered dispensing and/or proof of purchase of fuel.

If the flexibility mechanism(s) are used then the following documentation must also be provided:

- Description of sampling design and criteria used in its development.
- Results of sampling including summary statistics.
- Rational for decision based on results.
- Third party validation of methods used and results obtained.

## 5.2 Record Keeping

Alberta Environment requires that project developers maintain appropriate supporting information for the project, including all raw data for the project for a period of 7 years after the end of the project crediting period. Where the project developer is different from the person implementing the activity, as in the case of an aggregated project, the individual projects and the aggregator must both maintain sufficient records to support the offset project. The project developer must keep the information listed below in addition to any other supporting records and disclose all information to the verifier and/or government auditor upon request.

### Record-Keeping Requirements:

Data Requirement	Examples of Acceptable Records Description	Why it is Required
Fuel use (baseline and project)	Commercial grade meter of fuel and/or power dispensed or used. Purchase records for fuel and/or power.	Quantification and Verification
Measurement equipment	Description of meters used and calibration records or standards of calibration. Meter model number, serial number, and manufacturer's calibration procedures. For commercial purchases, proof of commercial grade metering from the supplier is required.	Verification
Map or other proof of location	Map or description showing location of fuel purchase and use in Alberta. May include: GIS tracking logs, truck logbooks or onboard computer data, location maps such as city boundaries, forest harvest unit or	Verification

	section location.	
Baseline calculations	Three years of raw data in database and/or spreadsheet format. If sampling was used, require also summary statistics and methods used to calculate statistics. A record of all adjustments made to raw baseline data with justifications.	Quantification and Verification
Project calculations	Raw data and calculations in database and/or spreadsheet format.	Quantification and Verification
Proof of purchase or modification date for project vehicle	Dated commercial transaction records and description of modification or purchase requirements.	Verification
All calculations of greenhouse gas emissions/reductions and emission factors used	Spreadsheet format or hardcopy with formula and emission factors included.	Quantification and Verification

In order to support the third party verification and the potential supplemental government audit, the project developer must put in place a system that meets the following criteria:

- All records must be kept in areas that are easily located,
- All records must be legible, dated and revised as needed,
- All records must be maintained in an orderly manner,
- All documents must be retained for 7 years after the project crediting period,
- Electronic and paper documentation are both satisfactory,
- Copies of records should be stored in two locations to prevent loss of data.

*Note: Attestations are not considered sufficient evidence that an activity has occurred and will not be accepted by Alberta Environment as proof that the activity took place.*

### **5.3 Quality Assurance/Quality Control Considerations**

Quality Assurance/Quality Control can also be applied to add confidence that all measurements and calculations have been made correctly. These include, but are not limited to:

- Ensuring that the changes of fuel type continue to function as planned and achieve greenhouse gas reductions,
- Ensuring that the measurement and calculation system and greenhouse gas reduction reporting remains in place and accurate,
- Checking the validity of all data before it is processed, including emission factors, static factors, and acquired data,
- Performing recalculations of quantification procedures to reduce the possibility of mathematical errors,
- Storing the data in its raw form so it can be retrieved for verification,
- Protecting records of data and documentation by keeping both a hard and soft copy of all documents,
- Recording and explaining any adjustment made to raw data in the associated report and files,

- A contingency plan for potential data loss.

#### **5.4 Liability**

Offset projects must be implemented according to the approved protocol and in accordance with government regulations. Alberta Environment reserves the right to audit Offset credits and associated projects submitted to Alberta Environment for compliance under the *Specified Gas Emitters Regulation* and may request corrections based on audit findings.

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## 6.0 References

National Inventory Report 1990–2008: Greenhouse Gas Sources and Sinks in Canada.  
Available from

[http://unfccc.int/national\\_reports/annex\\_i\\_ghg\\_inventories/national\\_inventories\\_submissions/items/5270.php](http://unfccc.int/national_reports/annex_i_ghg_inventories/national_inventories_submissions/items/5270.php)

Specified Gas Emitters Regulation. Climate Change and Emissions Management Act.  
Alberta Queen's Printer. Available online:

[http://www.qp.alberta.ca/documents/Regs/2007\\_139.pdf](http://www.qp.alberta.ca/documents/Regs/2007_139.pdf)

Technical Guidance for Offset Protocol Developers. Version 1.0. January 2011.

Available online: <http://carbonoffsetsolutions.climatechangecentral.com/offset-protocols/approved-Alberta-protocols>

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**Appendix A Example of Baseline and Project Condition  
Calculation and Guidance on Applying Flexibility  
Mechanisms I & II**

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The general equation for calculation of emission reductions is:

$$\text{Emission Reduction} = \text{Emissions}_{\text{Baseline}} - \text{Emissions}_{\text{Project}}$$

Where:

$\text{Emissions}_{\text{Baseline}}$  = sum of the emissions included under the Baseline Condition.

$\text{Emissions}_{\text{Project}}$  = sum of emissions included under the Project Condition.

For the included sources and sinks, the baseline emissions are:

$$\text{Emissions}_{\text{Baseline}} = \text{Emissions}_{\text{upstream}} + \text{Emissions}_{\text{fuel combustion}}$$

Where:

$$\text{Emissions}_{\text{upstream}} = \text{Emissions}_{\text{fuel extraction and processing}} + \text{Emissions}_{\text{fossil fuel blending}} + \text{Emissions}_{\text{electricity generation}} + \text{Emissions}_{\text{fuel storage and dispensing}}$$

$$\text{Emissions}_{\text{fuel combustion}} = \text{Quantity}_{\text{baseline fuel}} \times \text{EF}_{\text{baseline fuel}}$$

And:

$$\text{Emissions}_{\text{fuel extraction and processing}} = \text{Quantity}_{\text{baseline fuel}} \times \text{EF}_{\text{extraction and processing}}$$

$$\text{Emissions}_{\text{fossil fuel blending}} = (\sum \text{Volume}_{\text{blended fuel}}) \times \text{Energy}_{\text{per unit volume blended}} \times \text{EF}_{\text{energy}}$$

$$\text{Emissions}_{\text{electricity generation}} = \text{Baseline kWh} \times \text{EF}_{\text{electricity}}$$

$$\text{Emissions}_{\text{fuel storage and dispensing}} = (\text{Energy}_{\text{dispensing}} \times \text{EF}_{\text{energy}}) + (\text{Volume}_{\text{fugitive emissions}} \times \text{EF}_{\text{baseline fuel}})$$

**Note: For gasoline and diesel a single combined emission factor (upstream and combustion) that incorporates the Alberta Renewable Fuel Standard should be used.**

For the included sources and sinks, the project emissions are:

$$\text{Emissions}_{\text{Project}} = \text{Emissions}_{\text{upstream}} + \text{Emissions}_{\text{fuel combustion}}$$

Where:

$$\text{Emissions}_{\text{upstream}} = \text{Emissions}_{\text{fuel extraction and processing}} + \text{Emissions}_{\text{fossil fuel blending}} + \text{Emissions}_{\text{electricity generation}} + \text{Emissions}_{\text{fuel storage and dispensing}}$$

$$\text{Emissions}_{\text{fuel combustion}} = \text{Quantity}_{\text{project fuel}} \times \text{EF}_{\text{project fuel}}$$

And:

$$\text{Emissions}_{\text{fuel extraction and processing}} = \text{Quantity}_{\text{project fuel}} \times \text{EF}_{\text{extraction and processing}}$$

$$\text{Emissions}_{\text{fossil fuel blending}} = (\sum \text{Volume}_{\text{blended fuel}}) \times \text{Energy}_{\text{per unit volume blended}} \times \text{EF}_{\text{energy}}$$

$$\text{Emissions}_{\text{electricity generation}} = \text{Project kWh} \times \text{EF}_{\text{electricity}}$$

$$\text{Emissions}_{\text{fuel storage and dispensing}} = (\text{Energy}_{\text{dispensing}} \times \text{EF}_{\text{energy}}) + (\text{Volume}_{\text{Fugitive emissions}} \times \text{EF}_{\text{project fuel}})$$

**Note: Use of a combined upstream emission factor is the default quantification method. Depending on the fuel type, fuel blending and electricity generation may be excluded.**

#### Example. Project Scenario 1 - Mobile Source Simple Case with Combined Emission Factors

**Project scenario:** Ten new CNG public transportation busses instead of 10 diesel busses in large urban system. In this example CNG is not produced on site but is purchased from a commercial facility.

**Baseline scenario (BAU case):** continued use of 10 diesel busses.

**Project plan:** CNG is a lower greenhouse gas emission fuel than diesel fuel. The project condition quantification will include measures of service provided (passenger capacity and distance traveled) as well as fuel used. The measures of service provided during the project (i.e., passenger capacity and km) will be used to estimate baseline fuel volume using a historic benchmark. Once calculated, fuel volume will be used to estimate emissions from combustion and upstream of combustion by the application of approved emission factors.

**Calculations.** The example calculations are broken down into steps, explained in Parts A through F.

#### A) Baseline Historic Benchmark Calculations

During the project planning phase the proponent identified the need for establishing the required historic benchmark baseline. This should be the first step in all projects as failure to establish the baseline will halt the project.

The current (baseline) bus fleet contains 100 busses each with a 50 passenger capacity (number of seats). Three years of baseline census information for the entire 100 bus fleet were available as follows:

year	Litres	Passenger capacity	km traveled
1	3400000	5000	8800000
2	3500000	5000	8750000
3	3300000	5000	8000000

The passenger capacity km per litre (Pcap km per L) was calculated for each year as:

$$\text{Pcapkm/L}_{\text{year}} = (\text{passenger capacity} \times \text{km}) / \text{litres}$$

$$\text{Pcapkm/L}_{\text{Year 1}} = (5000 \times 8800000) / 3400000 = 0.000077$$

$$\text{Pcapkm/L}_{\text{Year 2}} = (5000 \times 8750000) / 3500000 = 0.000080$$

$$\text{Pcapkm/L}_{\text{Year 3}} = (5000 \times 8000000) / 3300000 = 0.000083$$

The average for the three years is used as the historic benchmark baseline and is calculated as:

$$\text{Pcapkm/L}_{\text{baseline}} = (\text{Pcapkm/L}_{\text{Year 1}} + \text{Pcapkm/L}_{\text{Year 2}} + \text{Pcapkm/L}_{\text{Year 3}}) / 3 = 0.00008$$

Later calculations will also require baseline passenger capacity. This is calculated as the average passenger capacity used to establish the baseline:

$$\text{Pcap}_{\text{baseline}} = (\text{Passenger capacity}_{\text{year 1}} + \text{Passenger capacity}_{\text{year 2}} + \text{Passenger capacity}_{\text{year 3}}) / 3 \\ \text{years} = 5000$$

**Note:** because three complete years were available there was no need to establish a monitoring program to collect the required data. The baseline is created from a census of the entire bus fleet, and not a representative sample, therefore there is no need to calculate confidence intervals for the data because a complete census is assumed to provide the true (actual) value.

In most situations three years of complete census information will not be available to establish the baseline. Flexibility in establishing the baseline using sample data is permitted. Table A1 below describes the use of the flexibility mechanisms to establish a historic benchmark baseline

where census information is unavailable or is incomplete. Table A2 describes the flexibility mechanism to establish a performance standard baseline where the services provided are new (e.g., new bus service or garbage pickup where none existed before). To ensure that alternative methods for establishing a baseline is conservative, the upper bound of the 95<sup>th</sup> percentile confidence interval is used rather than the mean.

Table A1 uses the project example of busses and the units of passenger capacity km per Litre. The methods described in Table A1 are applicable to all project types including units for transportation (tonnes hauled km per L), agriculture (area hour per L), and forest harvesting (harvest volume hr per L).

**Note: A performance baseline may not be used for expansion of existing services. A performance standard baseline only applies to projects where the service provided is new.**

**Table A1. Flexibility Mechanism for Calculating Static Historic Benchmark Baseline using a Subsample.**

Alternate method for calculating historic benchmark using subsample
<b>Issue:</b> no census information or incomplete information is currently available.
<b>Plan:</b> monitor one years worth of fuel consumption and distance traveled for a sample of busses.
<b>Considerations:</b> need a statistically representative sample of bus fuel use and distance traveled. Must select appropriate sample size and operating conditions (e.g., differences between winter and summer fuel use).
<b>Step 1:</b> select a number of busses at random from the current fleet that are comparable to the replacement busses. The larger the sample size the greater the confidence in the estimation.
<b>Step 2:</b> for each of the selected busses monitor total fuel used and total km traveled over one full year.
<b>Step 3:</b> calculate the passenger capacity km per litre (Pcap km per L) for each bus as in the example above.
<b>Step 4:</b> calculate summary statistics including the mean, standard deviation from the mean, and 95% confidence interval for the busses. Include summary statistics in the project supporting documentation.
<b>Step 5:</b> use the summary statistics to establish what the historic baseline (Pcap km per L) value should be. The <u>upper bound</u> of the 95th percentile confidence interval should be used. This will ensure that the quantification meets the requirements to be conservative and not overestimate.

**Table A2. Flexibility Mechanism for Developing a Static Performance Standard Baseline.**

<b>Guidance for development of a Static Performance Standard Baseline</b>
<b>Issue:</b> there is no history of the activity upon which to develop a Historic Benchmark Baseline. For example; a growing rural community introducing bus service or curb side garbage pickup for the first time.
<b>Plan Option 1:</b> identify a suitable analogous community and initiate monitoring as described for establishing a historic benchmark baseline using a subsample.
<b>Plan Option 2:</b> acquire a number of baseline vehicles and operate them under normal conditions in the project area and employ the methods described in establishing a historic benchmark baseline using a subsample.
<b>Plan Option 3:</b> obtain 3 years of existing data from a suitable analog community for the baseline activity.
<b>Considerations:</b> As with the historic benchmark sub sampling flexibility mechanism a statistically representative sample of fuel use and service provided must be collected. Additional considerations include: terrain and traffic densities are similar to the proposed project area, level of service and distances traveled must be comparable to the proposed project, and services provided must be representative of the business as usual scenario (e.g., cannot select an old inefficient fleet of vehicles to use for establishing the performance baseline). Because this protocol relies on measure of service provision, the manufacturers supplied estimates of fuel consumption cannot be used. The performance baseline must be established using data collected in Alberta under normal operating conditions.
<b>Step 1:</b> select an option (1, 2, or 3) as described above and justify selection.
<b>Step 2:</b> for options 1 and 2, determine the appropriate sampling frequency and sample size. For Option 3 acquire and describe the source of the data.
<b>Step 3:</b> for options 1 and 2 follow the steps described for establishing a historic benchmark baseline using a subsample. For option 3 have the baseline data validated by a third party and or Alberta environment.
<b>Step 4:</b> for all options (1,2,3) calculate summary statistics including the mean, standard deviation from the mean, and 95% confidence interval for the data collected. Include summary statistics in the project supporting documentation.
<b>Step 5:</b> use the summary statistics to establish what the historic baseline value should be. The upper bound of the 95th percentile confidence interval should be used. This will ensure that the quantification meets the requirements to be conservative and not overestimate.

**B) Project start and monitoring**

Initiate and monitor the project. After one full year of monitoring the 10 CNG busses resulted in the following data.

Bus #	kg CNG	Passenger	
		capacity	km
1	6393.6	50	80,000
2	6233.8	50	78,000
3	6793.2	50	85,000
4	6473.5	50	81,000
5	6553.4	50	82,000
6	6633.4	50	83,000
7	7033.0	50	88,000
8	6713.3	50	84,000
9	5754.2	50	72,000
10	6313.7	50	79,000
<b>Project Total</b>	<b>64,895</b>	<b>500</b>	<b>812,000</b>

**C) Baseline fuel quantity calculation (using the historic benchmark)**

In order to perform the required calculations we first need to determine the quantity of baseline fuel combusted. The units for the quantity of fuel will depend on the fuel type and may be a volume measured in litres or m<sup>3</sup>, a weight measured in kilograms or tonnes, or a unit of energy such as kWh or joules. The fuel units must be the same as used to establish the historic benchmark baseline. In this example the fuel is diesel and is measured in litres. The litres are estimated from the total passenger capacity and km traveled using the historic benchmark from Part A above and the following formula:

$$\text{Quantity}_{\text{baseline fuel}} = (\text{total project passenger cap} \times \text{total project km}) \times \text{Pcapkm/L}_{\text{baseline}} \times (\text{Pcap} / \text{total project passenger cap})$$

Where:

total project passenger cap = 500 (passenger capacity of the 10 project replacement busses)

total project km = 812,000 (monitored during project)

Pcapkm/L<sub>baseline</sub> = 0.00008 (from historic benchmark baseline)

Pcap<sub>baseline</sub> = 5000 (total passenger capacity used to establish the historic benchmark baseline)

Thus:

$$\text{Quantity}_{\text{baseline fuel}} = (500 \times 812,000) \times 0.00008 \times (5000 / 500) = 324,800 \text{ L}$$

This is the litres of baseline fuel (diesel) that would have been combusted in the absence of the project (i.e., by diesel busses instead of CNG project busses).

**D) Baseline emissions calculations**

Calculate the baseline emissions for combustion and upstream of combustion. Baseline emissions are calculated as follows:

$$\text{Emissions}_{\text{Baseline}} = \text{Emissions}_{\text{upstream}} + \text{Emissions}_{\text{fuel combustion}}$$

Because there is no additional fuel blending in this example we can exclude it. Thus baseline upstream emissions are simplified as:

$$\text{Emissions}_{\text{upstream}} = \text{Emissions}_{\text{fuel extraction and processing}} + \text{Emissions}_{\text{fuel storage and dispensing}}$$

Fuel extraction and processing as well as fuel storage and dispensing contain many individual elements as described in Appendix C. Using an emission factor that also includes Alberta RFS we can determine the greenhouse gas emissions from baseline fuel combustion and from upstream of combustion. Also, because emissions upstream of fuel combustion are determined per unit of fuel, we can calculate upstream emissions and combustion emissions in a single step using the combined emission factor for diesel fuel in Alberta (emission factors are provided in Appendix C). This is the preferred method of baseline fuel emissions quantification.

$$\text{Emissions}_{\text{Baseline}} = \text{Quantity}_{\text{baseline fuel}} \times \text{EF}_{\text{combined baseline diesel fuel}}$$

Where:

$$\text{Quantity}_{\text{baseline fuel}} = 324,800 \text{ L}$$

EF<sub>combined baseline diesel fuel</sub> (CO<sub>2</sub>e) = 3674.5 g/L (includes RFS, combustion and upstream of combustion)

Thus:

$$\text{Emissions}_{\text{Baseline}} = 324,800 \text{ L} \times 3674.5 \text{ g/L}$$

$Emissions_{Baseline} = 1,193,477,600 \text{ g CO}_2\text{e} = 1193.5 \text{ tonnes CO}_2\text{e}$  (divide by 1,000,000 to get tonnes)

### E) Project emissions calculation

Calculate the project condition emissions. Project condition emissions are obtained primarily from direct measurement of fuel and energy use combined with estimates of upstream emissions.

$$Emissions_{Project} = Emissions_{upstream\ project} + Emissions_{fossil\ fuel\ blending} + Emissions_{fuel\ combustion\ project}$$

As with the baseline there is no fuel blending so it can be excluded:

$$Emissions_{Project} = Emissions_{upstream\ project} + Emissions_{fuel\ combustion\ project}$$

Using the measured amount of CNG combusted and the provided emission factors for natural gas in Alberta we can calculate emissions from fuel combustion as:

$$Emissions_{fuel\ combustion\ project} = Quantity_{project\ fuel} \times EF_{project\ fuel}$$

The units for the quantity of fuel (e.g., Litres, kg, or m<sup>3</sup>) and the emission factor must be the same. In some cases it will be necessary to convert the units (e.g., m<sup>3</sup> to kg). The factors and assumptions used to convert the units must be included in the project documentation. In this example we will use the combined CO<sub>2</sub>e emission factor from Appendix C of 2760.6 g/kg of natural gas.

$$Emissions_{fuel\ combustion\ project} = 64,895 \text{ kg} \times 2760.6 \text{ g/kg CO}_2\text{e}$$

$$Emissions_{fuel\ combustion\ project} = 179,149,000 \text{ g CO}_2\text{e} = 179.1 \text{ tonnes CO}_2\text{e}$$

Unlike the baseline we cannot use a single combined emission factor for emissions upstream of combustion because the emissions for compression of the natural gas and for onsite storage and/or dispensing of the compressed gas will vary by project. Therefore:

$$Emissions_{upstream\ project} = Emissions_{fuel\ extraction\ and\ processing} + Emissions_{fuel\ storage\ and\ dispensing}$$

Where (for this example project):

$Emissions_{fuel\ extraction\ and\ processing}$  = Emissions from extraction, processing and delivery of the natural gas to the CNG refueling facility.

$Emissions_{fuel\ storage\ and\ dispensing}$  = Emissions to compress, store and dispense the natural gas at the CNG refuelling facility.

Appendix C provides the upstream emission factor (in units of CO<sub>2</sub>e) for the natural gas feedstock as 433.6 g/kg. Thus:

$$Emissions_{fuel\ extraction\ and\ processing} = 64,895 \text{ kg} \times 433.6 \text{ g/kg CO}_2\text{e}$$

$$Emissions_{fuel\ extraction\ and\ processing} = 28,138,472 \text{ g CO}_2\text{e} = 28.1 \text{ tonnes CO}_2\text{e}$$

In this example the project is purchasing its CNG from a commercial facility that is not under the control of the project. The commercial CNG refueling facility reports its energy to compress and

dispense CNG (this information would be required). The reported energy use and kg dispensed must be from commercial grade meters. The energy use reported is 3 kWh to compress and dispense one kg of natural gas. This is equivalent to 0.003 MWh/kg of natural gas. To determine the emissions we must use the approved emission factor of 0.882 tCO<sub>2</sub>e/MWh for electricity use in Alberta<sup>3</sup> and determine the tCO<sub>2</sub>e/kg of natural gas dispensed as shown below. Below is an example of the data that must be provided in the project plan and/or project report.

Value	Units	Description
3	kWh/kg	Reported from commercial refuelling facility (not project controlled)
0.003	MWh/kg	Conversion from kWh to MWh per kg of natural gas dispensed
0.882	tCO <sub>2</sub> e/MWh	Grid Emission factor (from Alberta Environment)
0.002646	tCO <sub>2</sub> e/kg	(MWh/kg X tCO <sub>2</sub> e/MWh). Tonnes CO <sub>2</sub> e per kg of natural gas dispensed

$$\text{Emissions}_{\text{fuel storage and dispensing}} = 64,895 \text{ kg} \times 0.002646 \text{ tonnes CO}_2\text{e/kg} = 171.7 \text{ tonnes CO}_2\text{e}$$

The value 0.002646 tonnes CO<sub>2</sub>e/kg used above is essentially a project specific emission factor for compression and dispensing of fuel. This value must be recalculated for each reporting period throughout the lifetime of the project.

Now the upstream emissions can be quantified by bringing together the emissions from extraction and processing of the natural gas feedstock and the emissions from compression, storage and dispensing of the natural gas at the CNG refueling facility. These are the emission sources in this example project.

$$\text{Emissions}_{\text{upstream project}} = \text{Emissions}_{\text{fuel extraction and processing}} + \text{Emissions}_{\text{fuel storage and dispensing}}$$

$$\text{Emissions}_{\text{fuel extraction and processing}} = 28.1 \text{ tonnes CO}_2\text{e}$$

$$\text{Emissions}_{\text{fuel storage and dispensing}} = 171.7 \text{ tonnes CO}_2\text{e}$$

$$\text{Emissions}_{\text{upstream project}} = 28.1 + 171.7 = 199.8 \text{ tonnes CO}_2\text{e}$$

The project emissions from upstream and from combustion can now be added together to get the total project emissions.

$$\text{Emissions}_{\text{Project}} = \text{Emissions}_{\text{upstream project}} + \text{Emissions}_{\text{fuel combustion project}}$$

$$\text{Emissions}_{\text{upstream project}} = 199.8 \text{ tonnes CO}_2\text{e}$$

$$\text{Emissions}_{\text{fuel combustion project}} = 179.1 \text{ tonnes CO}_2\text{e}$$

$$\text{Emissions}_{\text{Project}} = 199.8 + 179.1 = 378.9 \text{ tonnes CO}_2\text{e}$$

## F) Emission Reduction Calculation

The final step is to calculate the emission reduction. Emission reductions are:

$$\text{Emission Reduction} = \text{Emissions}_{\text{Baseline}} - \text{Emissions}_{\text{Project}}$$

$$\text{Emissions}_{\text{Baseline}} = 1193.5 \text{ tonnes CO}_2\text{e}$$

$$\text{Emissions}_{\text{Project}} = 378.9 \text{ tonnes CO}_2\text{e}$$

$$\text{Emission Reduction} = 1193.5 - 378.9 = 814.6 \text{ tonnes CO}_2\text{e}$$

<sup>3</sup> Contact Alberta Environment to obtain the most recent energy emission factors.

## **Appendix B Example of Baseline and Project Condition Calculations with Onsite Natural Gas Compression**

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**Example 2. Project Scenario 2 - Mobile Source with On-site Fuel Compression**

This example will use the same conditions as Example 1 above except that onsite compression of natural gas will be included in the project.

**Project scenario:** Ten new CNG public transportation buses instead of 10 diesel buses in large urban system. The buses are fueled from a dedicated (controlled) CNG station located at the maintenance yard.

**Baseline scenario (BAU case):** continued use of 10 diesel buses.

**Project plan:** CNG is a lower greenhouse gas emission fuel than diesel fuel. The project condition quantification will include measures of service provided (passenger capacity and distance traveled) as well as fuel used. The measures of service provided during the project (i.e., passenger capacity and km) will be used to estimate baseline fuel volume using a historic benchmark. Once calculated, fuel volume will be used to estimate emissions from combustion and upstream of combustion by the application of approved emission factors.

**Calculations:** The example calculations are broken down into steps, explained in Parts A through F.

**A) Baseline Historic Benchmark Calculations**

During the project planning phase, the proponent identified the need for establishing the required historic benchmark baseline. This should be the first step in all projects as failure to establish the baseline will halt the project.

The current (baseline) bus fleet contains 100 busses each with a 50 passenger capacity (number of seats). Three years of baseline information for the entire 100 bus fleet were available as follows:

year	Litres	Passenger capacity	km traveled
1	3400000	5000	8800000
2	3500000	5000	8750000
3	3300000	5000	8000000

The average passenger capacity km per litre (Pcap km/L) and passenger capacity (Pcap) are unchanged from Example 1:

$$Pcap_{km/L \text{ baseline}} = 0.00008$$

$$Pcap_{\text{baseline}} = 5000$$

**B) Project start and monitoring**

Initiate and monitor the project. After one full year of monitoring the 10 CNG buses resulted in the following data (unchanged from example 1).

Bus #	kg CNG	Passenger	
		capacity	km
1	6393.6	50	80,000
2	6233.8	50	78,000
3	6793.2	50	85,000
4	6473.5	50	81,000
5	6553.4	50	82,000
6	6633.4	50	83,000
7	7033.0	50	88,000
8	6713.3	50	84,000
9	5754.2	50	72,000
10	6313.7	50	79,000
<b>Project Total</b>	<b>64,895</b>	<b>500</b>	<b>812,000</b>

Unlike in example 1, natural gas compression was done onsite so the energy required to operate the compression and refueling station was also monitored with a commercial grade meter. Total CNG refueling facility energy use for the project quantification year was 129,790 kWh. This was metered energy use and includes energy required for gas compression and for dispensing.

### C) Baseline fuel quantity calculation (using the historic benchmark)

Calculate the baseline emissions for combustion. Baseline Combustion emissions are unchanged from Example 1.

$$\text{Quantity}_{\text{baseline fuel}} = (\text{total project passenger cap} \times \text{total project km}) \times \text{Pcapkm} / \text{L}_{\text{baseline}} \times (\text{Pcap} / \text{total project passenger cap})$$

$$\text{Quantity}_{\text{baseline fuel}} = 324,800 \text{ L (calculation shown in Example 1)}$$

This quantity is the litres of baseline fuel (diesel) that would have been combusted in the absence of the project (i.e., by diesel busses instead of CNG project busses).

### D) Baseline emission calculations

Use the estimated baseline fuel volume to calculate the baseline emissions upstream of combustion. This is also unchanged from Example 1.

$$\text{Emissions}_{\text{Baseline}} = \text{Emissions}_{\text{upstream}} + \text{Emissions}_{\text{fuel combustion}}$$

Using a combined emission factor combustion and upstream of combustion the emission calculation becomes:

$$\text{Emissions}_{\text{Baseline}} = \text{Quantity}_{\text{baseline fuel}} \times \text{EF}_{\text{combined baseline diesel fuel}}$$

Where:

$$\text{Quantity}_{\text{baseline fuel}} = 324,800 \text{ L}$$

$$\text{EF}_{\text{combined baseline diesel fuel}} (\text{CO}_2\text{e}) = 3674.5 \text{ g/L (includes RFS, combustion and upstream of combustion)}$$

Thus:

$$\text{Emissions}_{\text{Baseline}} = 324,800 \text{ L} \times 3674.5 \text{ g/L} \times 3674.5 \text{ g/L}$$

$$\text{Emissions}_{\text{Baseline}} = 1193.5 \text{ tonnes CO}_2\text{e (divided by 1,000,000 to convert grams to tonnes)}$$

**E) Project emissions calculation**

Calculate the project condition emissions. Project condition emissions are obtained primarily from direct measurement of fuel and energy use combined with estimates of upstream emissions.

$$\mathbf{Emissions}_{\text{project}} = \mathbf{Emissions}_{\text{upstream project}} + \mathbf{Emissions}_{\text{fossil fuel blending}} + \mathbf{Emissions}_{\text{fuel combustion project}}$$

As with the baseline there is no fuel blending so it can be excluded:

$$\mathbf{Emissions}_{\text{project}} = \mathbf{Emissions}_{\text{upstream project}} + \mathbf{Emissions}_{\text{fuel combustion project}}$$

Where:

$$\mathbf{Emissions}_{\text{fuel combustion project}} = \mathbf{Quantity}_{\text{project fuel}} \times \mathbf{EF}_{\text{project fuel}}$$

$$\mathbf{Emissions}_{\text{upstream}} = \mathbf{Emissions}_{\text{fuel extraction and processing}} + \mathbf{Emissions}_{\text{fuel storage and dispensing}}$$

Calculation of emissions from fuel combustion remains the same as shown in Example 1. The combustion emission factor for a kg of natural gas is provided in Appendix C.

$$\mathbf{Emissions}_{\text{fuel combustion project}} = \mathbf{Quantity}_{\text{project fuel}} \times \mathbf{EF}_{\text{project fuel}}$$

$$\mathbf{Emissions}_{\text{fuel combustion project}} = 64,895 \text{ kg} \times 2760.6 \text{ g/kg CO}_2\text{e}$$

$$\mathbf{Emissions}_{\text{fuel combustion project}} = 179.1 \text{ tonnes CO}_2\text{e}$$

Unlike the first Example 1, natural gas is compressed onsite and the energy required must be included as a source in the project condition. In this example a single combined emission factor for upstream emissions cannot be used and each source must be examined and quantified separately.

$$\mathbf{Emissions}_{\text{upstream}} = \mathbf{Emissions}_{\text{fuel extraction and processing}} + \mathbf{Emissions}_{\text{fuel storage and dispensing}}$$

Where (unchanged from example 1):

$\mathbf{Emissions}_{\text{fuel extraction and processing}}$  = Emissions from extraction, processing and delivery of the natural gas to the CNG refueling facility.

$\mathbf{Emissions}_{\text{fuel storage and dispensing}}$  = Emissions to compress, store and dispense the natural gas at the CNG refuelling facility.

Appendix C provides the upstream emission factor (433.6 g/kg CO<sub>2</sub>e) for the natural gas feedstock and describes the sources included in the emission factor. Thus:

$$\mathbf{Emissions}_{\text{fuel extraction and processing}} = 64,895 \text{ kg} \times 433.6 \text{ g/kg CO}_2\text{e}$$

$$\mathbf{Emissions}_{\text{fuel extraction and processing}} = 28.1 \text{ tonnes CO}_2\text{e}$$

Fuel storage and dispensing is calculated from metered energy required to compress and dispense the compressed natural gas. Both the energy used and the amount of fuel dispensed must be metered and commercial grade meters are required for use of this protocol. Total metered energy used and total metered project fuel dispensed are the preferred method for quantification. In this example the refuelling facility is a dedicated source controlled by the project. However, in many cases the refuelling facility may be a commercial facility, as in

example 1, or may be controlled but also supply fuel outside the scope of the project to other vehicles. The required data collected for this example is shown below:

	Value	Unit	Description
A	129790	kWh	Facility energy use (includes compression and dispensing)
B	64895	kg	Kilograms of natural gas dispensed
A/B	2	kWh/kg	kWh per kg of natural gas dispensed
C = (A/B)/1000	0.002	MWh/kg	Conversion from kWh to MWh per kg of natural gas dispensed
D	0.882	tCO <sub>2</sub> e/MWh	Grid Emission factor (from Alberta Environment)
E = C X D	0.001764	tCO <sub>2</sub> e/kg	(MWh/kg X tCO <sub>2</sub> e/MWh). Tonnes CO <sub>2</sub> e per kg of natural gas dispensed

Because the facility only supplied fuel to the project the emissions can be calculated simply from energy use (kWh) and the Alberta emission factor for energy use (0.882 tCO<sub>2</sub>e per MWh). In this example we can easily multiply row A and row D from the required data table above.

$$\text{Emissions}_{\text{fuel storage and dispensing}} = (129790 \text{ kWh} / 1000 \text{ kWh/MWh}) \times 0.882 \text{ tCO}_2\text{e per MWh}$$

$$\text{Emissions}_{\text{fuel storage and dispensing}} = 114.5 \text{ tonnes CO}_2\text{e}$$

If the refuelling facility supplied fuel to vehicles other than the project vehicles, then the tonnes CO<sub>2</sub>e per kg of natural gas fuel dispensed would be used (shown as row E on the table above). This is the same as was done in the first example where fuel was supplied from a commercial facility. Note that row E from the table above is a project facility specific emission factor for compression and dispensing of fuel and must be recalculated for each reporting period throughout the lifetime of the project. For example:

$$\text{Emissions}_{\text{fuel storage and dispensing}} = \text{Quantity}_{\text{project fuel}} \times \text{tCO}_2\text{e per kg natural gas dispensed}$$

$$\text{Emissions}_{\text{fuel storage and dispensing}} = 64895 \text{ kg} \times 0.001764 \text{ tCO}_2\text{e/kg}$$

$$\text{Emissions}_{\text{fuel storage and dispensing}} = 114.5 \text{ tonnes CO}_2\text{e}$$

Once completed the upstream project emission can be brought together:

$$\text{Emissions}_{\text{upstream project}} = \text{Emissions}_{\text{fuel extraction and processing}} + \text{Emissions}_{\text{fuel storage and dispensing}}$$

$$\text{Emissions}_{\text{fuel extraction and processing}} = 28.1 \text{ tonnes CO}_2\text{e}$$

$$\text{Emissions}_{\text{fuel storage and dispensing}} = 114.5 \text{ tonnes CO}_2\text{e}$$

$$\text{Emissions}_{\text{upstream project}} = 28.1 + 114.5 = 142.6 \text{ tonnes CO}_2\text{e}$$

The project emissions from upstream and from combustion can now be added together to get the total project emissions.

$$\text{Emissions}_{\text{Project}} = \text{Emissions}_{\text{upstream project}} + \text{Emissions}_{\text{fuel combustion project}}$$

$$\text{Emissions}_{\text{upstream project}} = 142.6 \text{ tonnes CO}_2\text{e}$$

$$\text{Emissions}_{\text{fuel combustion project}} = 179.1 \text{ tonnes CO}_2\text{e}$$

$$\text{Emissions}_{\text{Project}} = 142.6 + 179.1 = 321.7 \text{ tonnes CO}_2\text{e}$$

**F) Emission Reduction Calculation**

The final step is to calculate the emission reduction. Emission reductions are:

$$\text{Emission Reduction} = \text{Emissions}_{\text{Baseline}} - \text{Emissions}_{\text{Project}}$$

$$\text{Emissions}_{\text{Baseline}} = 1193.5 \text{ tonnes CO}_2\text{e}$$

$$\text{Emissions}_{\text{Project}} = 321.7 \text{ tonnes CO}_2\text{e}$$

$$\text{Emission Reduction} = 1193.5 - 321.7 = 871.8 \text{ tonnes CO}_2\text{e}$$

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## **Appendix C** Default Emission Factors & Guidance on Use of Alternative Emission Factors

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## ***Emission factors, Combustion and Upstream***

A number of emission factors (EFs) are required for use of this protocol. These will include emission factors for baseline and project fuel combustion, fossil fuel blends or blending, and emissions upstream of combustion including fuel extraction, processing, and storage and dispensing.

The primary source for most emission factors is the GHGenius model<sup>4</sup>. The GHGenius model includes upstream emissions and can be used to derive Alberta-specific upstream emissions for a variety of fuels and feedstock. The other acceptable source recommended for use is the National Inventory Report<sup>5</sup> (NIR). The NIR is the Canadian Government's submission to the United Nations Framework Convention on Climate Change (UNFCCC), and Part Two of the Report contains both stationary and mobile emission factors for most of the fuels anticipated under the proposed protocol. For fuels not included in the NIR or GHGenius, alternative sources for emission factors may be used if approved by Alberta Environment. Approval of alternative sources for emission factors must be obtained prior to project start and included in the project plan.

To facilitate use of the proposed protocol, a combined upstream emission quantification including fuel extraction and processing as well as fuel storage and dispensing is recommended. When additional fuel processing occurs within a project (e.g., onsite natural gas compression for CNG or LNG vehicles) then the additional energy required would be quantified separately, and the appropriate emission factor would be applied.

Note: When the baseline fuel is gasoline or diesel, the Alberta Renewable Fuel Standard must be applied. Section 9.2.1 below provides a combined (upstream and combustion) emission factor for use in this protocol.

### ***GHGenius***

The GHGenius model has been developed for Natural Resources Canada over the past eleven years. GHGenius is capable of analyzing the energy balance and emissions of many contaminants associated with the production and use of traditional and alternative transportation fuels.

GHGenius is capable of estimating life cycle emissions of the primary greenhouse gases and the criteria pollutants from combustion sources. The specific gases that are included in the model include:

- Carbon dioxide (CO<sub>2</sub>),
- Methane (CH<sub>4</sub>),
- Nitrous oxide (N<sub>2</sub>O),
- Chlorofluorocarbons (CFC-12),
- Hydro fluorocarbons (HFC-134a),
- The CO<sub>2</sub>-equivalent of all of the contaminants above (CO<sub>2</sub>e).
- Carbon monoxide (CO),
- Nitrogen oxides (NO<sub>x</sub>),

<sup>4</sup> Available from <http://www.ghgenius.ca>

<sup>5</sup> Most recent NIR available from <http://www.ec.gc.ca/ges-ghg/>

- Non-methane organic compounds (NMOCs), weighted by their ozone forming potential,
- Sulphur dioxide (SO<sub>2</sub>),
- Total particulate matter.

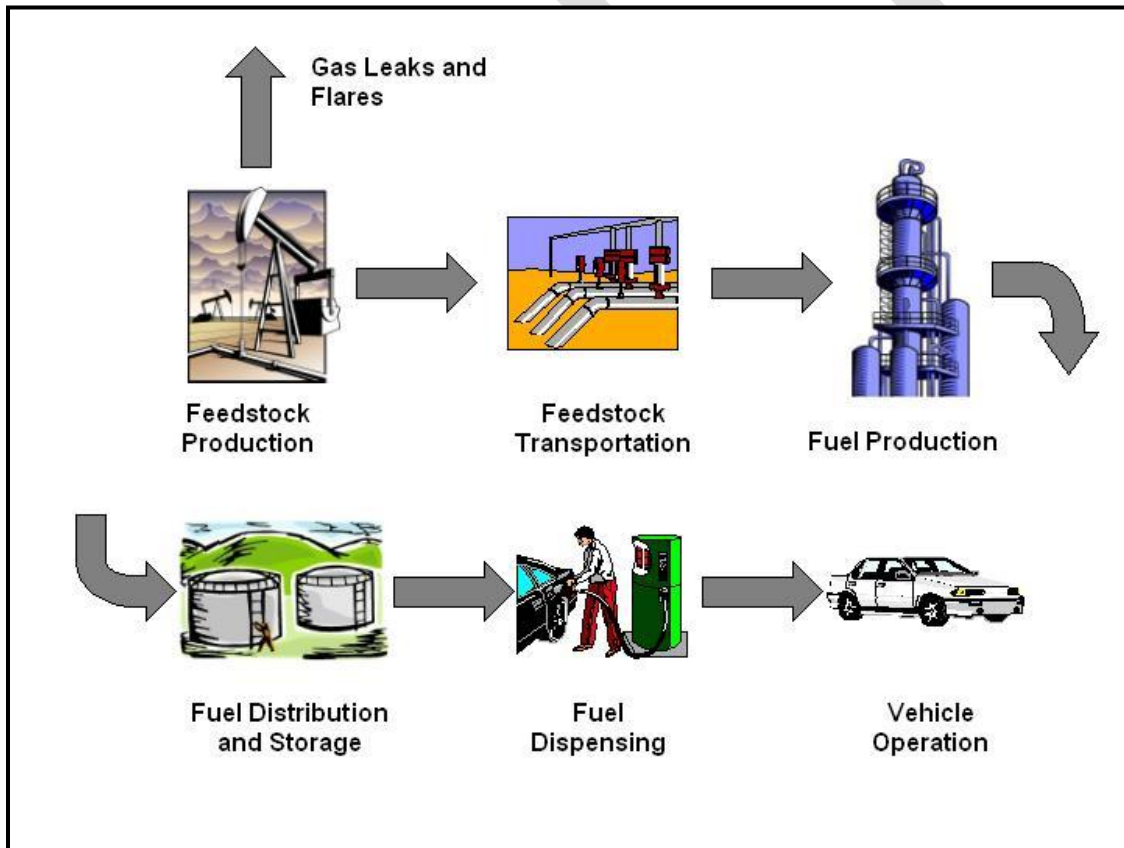
The model is capable of analyzing the emissions from conventional and alternative fuelled internal combustion engines or fuel cells for light duty vehicles, for class 3-7 medium-duty trucks, for class 8 heavy-duty trucks, for urban buses and for a combination of buses and trucks, and for light duty battery powered electric vehicles. There are over 200 vehicle and fuel combinations possible with the model.

GHGenius can predict emissions for past, present and future years through to 2050 using historical data or correlations for changes in energy and process parameters with time that are stored in the model. The fuel cycle segments considered in the model are as follows:

- Vehicle Operation - Emissions associated with the use of the fuel in the vehicle. Includes all greenhouse gases.
- Fuel Dispensing at the Retail Level - Emissions associated with the transfer of the fuel at a service station from storage into the vehicles. Includes electricity for pumping, fugitive emissions and spills.
- Fuel Storage and Distribution at all Stages - Emissions associated with storage and handling of fuel products at terminals, bulk plants and service stations. Includes storage emissions, electricity for pumping, space heating and lighting.
- Fuel Production (as in production from raw materials) - Direct and indirect emissions associated with conversion of the feedstock into a saleable fuel product. Includes process emissions, combustion emissions for process heat/steam, electricity generation, fugitive emissions and emissions from the life cycle of chemicals used for fuel production cycles.
- Feedstock Transport - Direct and indirect emissions from transport of feedstock, including pumping, compression, leaks, fugitive emissions, and transportation from point of origin to the fuel refining plant. Import/export, transport distances and the modes of transport are considered. Includes energy and emissions associated with the transportation infrastructure construction and maintenance (trucks, trains, ships, pipelines, etc.)
- Feedstock Production and Recovery - Direct and indirect emissions from recovery and processing of the raw feedstock, including fugitive emissions from storage, handling, upstream processing prior to transmission, and mining.
- Feedstock Upgrading - Direct and Indirect emissions from the upgrading of bitumen to synthetic crude oil at a standalone facility, including fugitive emissions.
- Fertilizer Manufacture - Direct and indirect life cycle emissions from fertilizers, and pesticides used for feedstock production, including raw material recovery, transport and manufacturing of chemicals. This is not included if there is no fertilizer associated with the fuel pathway.
- Land use changes and cultivation associated with biomass derived fuels - Emissions associated with the change in the land use in cultivation of crops, including N<sub>2</sub>O from application of fertilizer, changes in soil carbon and biomass, methane emissions from soil and energy used for land cultivation.

- Carbon in Fuel from Air - Carbon dioxide emissions credit arising from use of a renewable carbon source that obtains carbon from the air.
- Leaks and flaring of greenhouse gases associated with production of oil and gas - Fugitive hydrocarbon emissions and flaring emissions associated with oil and gas production.
- Emissions displaced by co-products of alternative fuels - Emissions displaced by co-products of various pathways. System expansion is used to determine displacement ratios for co-products from biomass pathways.
- Vehicle assembly and transport - Emissions associated with the manufacture and transport of the vehicle to the point of sale, amortized over the life of the vehicle.
- Materials used in the vehicles - Emissions from the manufacture of the materials used to manufacture the vehicle, amortized over the life of the vehicle. Includes lube oil production and losses from air conditioning systems.

The main lifecycle stages for crude oil based gasoline or diesel fuel are shown in the following figure.



**Figure C1. Fuel Lifecycle Stages**

The GHGenius model can be accessed at [www.ghgenius.ca](http://www.ghgenius.ca). The website also has completed documentation on the model, its development and the fuel pathways. The current version of the model is GHGenius 4.00c. This version has been used to develop the following emission factors.

## Alberta Emission Factors

To extract the upstream emission factors for gasoline and diesel fuel in Alberta from GHGenius there are five steps to take.

- 1) Click "I Agree" on the opening sheet, ~cell E123. This opens the model.
- 2) Click "Alberta" on the Input sheet, ~ cell H2.
- 3) Set cell B3 to 2012. This sets the model to 2012.
- 4) Set cell B6 to 0. This selects the 1995 GWPs (CO<sub>2</sub>=1, CH<sub>4</sub>=21, N<sub>2</sub>O=310).
- 5) Click "Run Program" on the Input sheet, ~ cell A1.

The upstream emission factors expressed in g CO<sub>2</sub>e/GJ (HHV) can be found on the Upstream Emissions HHV sheet. The values for 100% gasoline and diesel fuel are found in columns D and F, rows 7 to 20. The results are shown in the following table.

**Table C1 Gasoline and Diesel Fuel Emission Factors**

<b>Fuel</b>	<b>Gasoline</b>	<b>Diesel Fuel</b>
Feedstock	Crude Oil	Crude Oil
	g CO <sub>2</sub> e/GJ (HHV)	
Fuel dispensing	459	470
Fuel distribution and storage	655	670
Fuel production	9,914	9,415
Feedstock transmission	374	383
Feedstock recovery	5,882	6,011
Feedstock Upgrading	5,628	5,752
Land-use changes, cultivation	246	246
Fertilizer manufacture	0	0
Gas leaks and flares	2,590	2,586
CO <sub>2</sub> , H <sub>2</sub> S removed from NG	0	0
Emissions displaced	-162	-162
<b>Total</b>	<b>25,587</b>	<b>25,372</b>

These are the emissions for the crude oil well drilling, crude oil, production, refining, distribution, and dispensing at the retail station. The emissions do not include the emissions from using the fuel in the vehicle. These emissions are shown in the following table, along with the upstream emissions. The exhaust emissions are found on the Exhaust Emissions sheet in GHGenius. The gasoline value is from cell C96 and the diesel fuel is from cell B142.

The emissions can also be found on a g/litre basis in GHGenius on sheet Lifecycle Emissions 2. Gasoline in cells C10 (exhaust) and the sum of C13 to C23 for upstream. Diesel in cells B 65 for exhaust and the sum of B68 to 78 for upstream. The previous table is shown on this basis in the following table.

**Table C2 Lifecycle Emissions - Energy Basis**

<b>Fuel</b>	<b>Gasoline</b>	<b>Diesel Fuel</b>
Feedstock	Crude Oil	Crude Oil
	g CO <sub>2</sub> e/GJ (HHV)	
Upstream Emissions	25,587	25,372
Combustion Emissions	63,694	70,294
Total Lifecycle Emissions	89,281	95,666

**Table C3 Lifecycle Emissions - Volumetric Basis**

<b>Fuel</b>	<b>Gasoline</b>	<b>Diesel Fuel</b>
Feedstock	Crude Oil	Crude Oil
	g CO <sub>2</sub> e/litre (HHV)	
Upstream Emissions	887.5	980.7
Combustion Emissions	2,209.3	2,717.1
Total Lifecycle Emissions (Alberta Renewable Fuel Standard)	3,096.9 (3,021.3)	3,697.8 (3,674.5)

Note to reviewers of the draft protocol. An additional upstream table with the Alberta RFS will be included in the next draft.

## Renewable Fuels

Gasoline and diesel fuel in Alberta are regulated by the Alberta Renewable Fuel Standard. Alberta's Renewable Fuels Standard (RFS) requires an average of two per cent renewable diesel in diesel fuel and five per cent renewable alcohol in gasoline sold in Alberta. Renewable fuels used to meet the RFS must demonstrate at least 25 per cent fewer greenhouse gas emissions than the equivalent petroleum fuel. This 25% reduction is determined on an energy basis. The renewable alcohol is measured on the basis of ethanol equivalent. The ethanol energy content in GHGenius is 67.98% that of gasoline (23.579 MJ/litre vs. 34.686 MJ/litre). This 5% ethanol represents 3.4% of the energy of the fuel and the emissions from the production and combustion of the ethanol must be 25% less than that of gasoline. The emissions for the E5 blend with a 25% reduction in GHG emissions are therefore 88,522 g CO<sub>2</sub>e/GJ (0.966\*89,281+0.034\*89,281\*0.75). The energy content of the E5 blend is 34.131 MJ/litre so the emissions are 3,021.3 g CO<sub>2</sub>e/litre (HHV). This would be the emission factor to be used for the gasoline baseline.

The renewable content in diesel could be met with biodiesel or renewable diesel. It is assumed that most will be met with biodiesel. The energy content of biodiesel is 35.4 MJ/litre and that of diesel fuel is 38.653. The 2% biodiesel thus represents 1.85% of the energy content of the blend. The emissions from the B2 blend with a 25% reduction in GHG emissions are therefore 95,224 g CO<sub>2</sub>e/GJ (0.9815\*95,666+0.0185\*95,666\*0.75). The energy content of the B2 blend is 38.588 MJ/litre so the emissions are 3,674.5 g CO<sub>2</sub>e/litre (HHV). This would be the emission factor to be used for the diesel baseline.

## Other Fossil Fuels

Propane and natural gas are two fuels that could be used in this protocol. The upstream emissions for each of these are described below. The same GHGenius model described above is used for these alternative fuels.

### Propane

Propane is used as a vehicle fuel in dedicated vehicles and in dual fuel vehicles. It is a gaseous fuel but under moderate pressure it is a liquid. Propane for transportation fuel use is usually dispensed as a liquid in litres. Propane is produced as a co-product from natural gas plants and at petroleum refineries. In GHGenius it is assumed to be 86% from gas plants and 14% from refineries in Alberta.

The upstream emissions are found in column N, rows 7 to 20 on the Upstream Emissions sheet. The GHGenius results for Alberta are shown in the following table.

**Table C4 Propane Upstream Emissions**

<b>Fuel</b>	<b>Propane (LPG)</b>
Feedstock	86% Gas Plants/14% Refineries
	g CO <sub>2</sub> e/GJ (HHV)
Fuel dispensing	471
Fuel distribution and storage	519
Fuel production	2,725
Feedstock transmission	54
Feedstock recovery	2,822
Feedstock Upgrading	0
Land-use changes, cultivation	36
Fertilizer manufacture	0
Gas leaks and flares	883
CO <sub>2</sub> , H <sub>2</sub> S removed from NG	752
Emissions displaced	-23
Total	8,238

**Table C5 Lifecycle Emissions - Propane**

<b>Fuel</b>	<b>Propane</b>	
Feedstock	86% Gas Plants/14% Refineries	
	g CO <sub>2</sub> e/GJ (HHV)	g CO <sub>2</sub> e/litre (HHV)
Upstream Emissions	8,238	209.8
Combustion Emissions	59,400	1,512.7
Total Lifecycle Emissions	67,638	1,722.5

The exhaust emissions for propane are found in cell O96 (59,400 g CO<sub>2</sub>e/GJ) on the exhaust emissions sheet. The lifecycle emissions are shown below. The emissions can also be found on a g/litre basis in GHGenius on sheet Lifecycle Emissions 2. Propane is in cells K10 (exhaust) and the sum of K13 to K23 for upstream.

### Natural Gas

Natural gas as a transportation fuel is usually dispensed in kilograms. It is a gaseous fuel stored and dispensed under pressure. In GHGenius, the energy and emissions associated with the dispensing of the fuel is included in the dispensing emissions but these emissions are dependent on the gas inlet pressure and the compressed pressure and in this protocol must be determined separately by the project. Accordingly they have been removed from the upstream emissions here.

The upstream emissions are found in column Q, rows 7 to 20 on the Upstream Emissions sheet. The GHGenius results for Alberta are shown in the following tables (table 9-6 and table 9-7). The exhaust emissions for natural gas are found in cell G96 (52,240 g CO<sub>2</sub>e/GJ) on the exhaust emissions sheet. The lifecycle emissions are shown below. The emissions can also be found on a g/kg basis in GHGenius on sheet Lifecycle Emissions 2. Natural gas is in cells G65 (exhaust) and the sum of G68 to G78 for upstream.

**Table C6 Natural Gas Upstream Emissions**

Fuel	Natural Gas
Feedstock	Natural Gas
	g CO <sub>2</sub> e/GJ (HHV)
Fuel dispensing	0
Fuel distribution and storage	1,354
Fuel production	1,485
Feedstock transmission	0
Feedstock recovery	2,210
Feedstock Upgrading	0
Land-use changes, cultivation	0
Fertilizer manufacture	0
Gas leaks and flares	2,269
CO <sub>2</sub> , H <sub>2</sub> S removed from NG	882
Emissions displaced	0
Total	8,201

**Table C7 Lifecycle Emissions – Natural Gas<sup>6</sup>**

Fuel	Natural Gas	
Feedstock	Natural Gas	
	g CO <sub>2</sub> e/GJ (HHV)	g CO <sub>2</sub> e/kg (HHV)
Upstream Emissions	8,201	433.6
Combustion Emissions	52,240	2,760.6
Total Lifecycle Emissions	60,441	3,194.2

<sup>6</sup> Excluding Compression Emissions

### ***Calculating a Single Combustion Emission Factor for Blended Fuel***

In addition to a complete switch of fuel type, this protocol is intended for use with switching to a lower greenhouse gas emission intensity fossil fuel blend. Depending on the quantification method selected, a single (combined) fuel emission factor may be used that incorporates all of the constituent fuels into a single unit of fuel (e.g., g/L), or separate emission factors for each constituent of the blended fuel may be used. Calculating greenhouse gas emissions using separate emission factors for each fuel constituent is recommended in most cases. This will simplify the calculations and reduce the chance of error. For mobile sources, a single (combined) emission factor may be used.

A single emission factor for mobile sources may apply to dual fuel engines that consume small quantities of diesel in combination with natural gas to overcome issues with compression ignition, or for engines that consume a fuel mixture that is blended prior to combustion. A single emission factor is not recommended for multi fuel engines that are capable of using different fuels types but only one at a time. For multi fuel engines each fuel would be tracked and quantified separately.

The emission factors required for use of this protocol must be from accepted sources (e.g., National Inventory Reports, Environment Canada, GHGenius) or be approved by Alberta Environment. Guidance on selection and use of emission factors for the Alberta Offset System is provided in the *Technical Guidance for Offset Protocol Developers (Version 1.0. January 2011)*.

The recommended method for calculating a single emission factor for fossil fuel blends is provided below. The following assumptions must be true to use the approach described.

- 1) Each constituent of the blended fuel must have an emission factor from an acceptable source.
- 2) The combustion efficiency of the blended fuel must be similar (within 5%) or better than each fuel combusted individually.

#### **Volume-based emission factor calculation:**

$$EF = \sum_{i,j} VF_{i,j} \times EF_j$$

Where:

EF is the combined emission factor for one unit of fuel composed of i volume of j constituent fuel

$VF_{i,j}$  is the volume (ratio) i of constituent fuel j in one unit of fuel

$EF_j$  is the emission factor for one unit of fuel j

Note: due to the Alberta requirement to separately report CO<sub>2</sub>, CH<sub>4</sub> and N<sub>2</sub>O emissions, the calculation may need to be repeated for each greenhouse gas.

#### **Example**

A hypothetical project fuel contains a blend of 80% standard diesel and 20% natural gas. The accepted emission factors for one unit (g/L) of diesel are 2663 CO<sub>2</sub>, 0.12 CH<sub>4</sub>, and 0.082 for N<sub>2</sub>O. For natural gas the accepted emission factors (g/L) are 1212 CO<sub>2</sub>, 0.5950 CH<sub>4</sub>, and 0.1170 for

N<sub>2</sub>O. Note that the units for each fuel are the same (i.e., g/L) – when the units for each constituent are different they must be converted to a common unit before calculating the combined emission factor.

$$EF = \sum_{i,j} Vol_{i,j} \times EF_j$$

Substituting the appropriate values for CO<sub>2</sub> into the equation for both fuel constituents yields the following:

$$EF_{CO_2} = (0.8 \times 2663) + (0.2 \times 1212)$$

$$EF_{CO_2} = 2372.8 \text{ g/L}$$

For emissions of CH<sub>4</sub> and N<sub>2</sub>O, do the same as for CO<sub>2</sub>:

$$EF_{CH_4} = (0.8 \times 0.12) + (0.2 \times 0.5950) = 0.215 \text{ g/L}$$

$$EF_{N_2O} = (0.8 \times 0.082) + (0.2 \times 0.1170) = 0.08902 \text{ g/L}$$

As a final step the global warming potential (GWP) of 21 for CH<sub>4</sub> and 310 for N<sub>2</sub>O can be used to convert to the required CO<sub>2</sub> equivalent units.

$$EF_{CH_4} = 4.515 \text{ g/L CO}_2\text{e}$$

$$EF_{N_2O} = 27.599 \text{ g/L CO}_2\text{e}$$