Forecasting Canada's Expected Demand for Low-Carbon Fuels and Electric Vehicles in 2030

Results for a Canada-Wide Forecast to 2030

SUBMIT TED TO

Devin O'Grady
Natural Resources Canada

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SUBMITTED BY

Navius Research Inc.
Box 48300 Bentall
Vancouver BC V7X 1A1

NAVIUS PROJECT TEAM

Michael Wolinetz
Phone: 778-970-0355
Email: Michael@NaviusResearch.com

Navius Research Inc. ("Navius") is a private consulting firm in Vancouver. Our consultants specialize in analysing government and corporate policies designed to meet environmental goals, with a focus on energy and greenhouse gas emission policy. They have been active in the energy and climate change field since 2004 and are recognized as some of Canada's leading experts in modeling the environmental and economic impacts of energy and climate policy initiatives. Navius is uniquely qualified to provide insightful and relevant analysis in this field because:

- We have a broad understanding of energy and environmental issues both within and outside of Canada.
- We use unique in-house models of the energy-economy system as principal analysis tools.
- We have a strong network of experts in related fields with whom we work to produce detailed and integrated climate and energy analyses.
- We have gained national and international credibility for producing sound, unbiased analyses for clients from every sector, including all levels of government, industry, labour, the non-profit sector, and academia.

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Executive Summary

Context

The government of Canada is developing the Clean Fuel Standard (CFS) with the objective of achieving a 30 Mt/yr reduction in greenhouse gas (GHG) emissions in 2030, relative to what emissions would be in that year without the CFS or other policies that reduce the carbon intensity of fuels. One of NRCAN's mandates is to enable the supply of non-fossil renewable and low-carbon fuels (i.e. called low-carbon fuels for the remainder of the report) and plug-in electric vehicles (PEVs) that would allow compliance with the CFS, including liquid biofuels, renewable natural gas, solid biomass, and plug-in electric vehicles (PEVs). In that regard, government and industry are working together towards the successful implementation of the CFS under the umbrella of the Clean Fuel Steering Committee (CFSC). The CFCS is reviewing what conditions are required for investment in low-carbon fuel production in Canada and the adoption of low-carbon alternative fuel vehicles.

To inform the CFSC's planning for greater domestic supply of low-carbon fuels (liquid, gaseous, and solid) and greater adoption of light-duty PEVs, Navius will produce and report on two illustrative scenarios that forecast the demand for these fuels and technologies under the influence of the CFS and other existing energy and GHG policies in Canada to 2030

This report contains the final forecast of how the CFS will affect low-carbon fuel demand and electric vehicle adoption in Canada to 2030. It is an update to the draft report and results presented at the June 18th CFSC workshop in Ottawa. Notable changes to the analysis include several adjustments that have reduced the quantity of CFS compliance credits produced by PEVs. Nonetheless, electrification of transportation remains an important compliance action. These changes include:

- Omitting the British Columbia and Québec Zero-Emissions Vehicle sales requirements in one scenario.
- Adjusting how carbon price revenue is recycled in Alberta. It is now recycled entirely to households, as per the federal carbon price backstop, with no contributions to technology funds that subsidize low-emissions technologies like electric vehicles.
- Fixing an error that was leading to the premature retirement of diesel buses and replacement with electric buses in Ontario.

Methodology

This analysis was produced with the gTech model, which is well suited for studying the CFS because it:

- is a full economic model that can correctly simulate the action of a compliance credit market.
- is technologically explicit, allowing it to show the net-policy compliance offered by multiple technologies and fuels.
- is behaviourally realistic, allowing it to describe policy outcomes, rather than prescribe financial cost-optimized solutions.
- can simulate the interactions between policies, which will strongly affect the net-impact of the CFS.

The analysis includes two scenarios: one with "moderate" low-carbon fuel demand and one with "higher" demand. We have defined these two scenarios primarily through differences in our interpretation of how the CFS will be implemented and additional policies affecting renewable natural gas supply and electric vehicle demand (Summary Table 1). These scenarios are illustrative rather than prescriptive; our interpretation of the CFS in each scenario has been guided by the need to demonstrate different energy demand scenarios rather than evaluating one policy design versus another.

Summary Table 1: Representation of the CFS and Scenario Design (all $ are 2019 CAD)

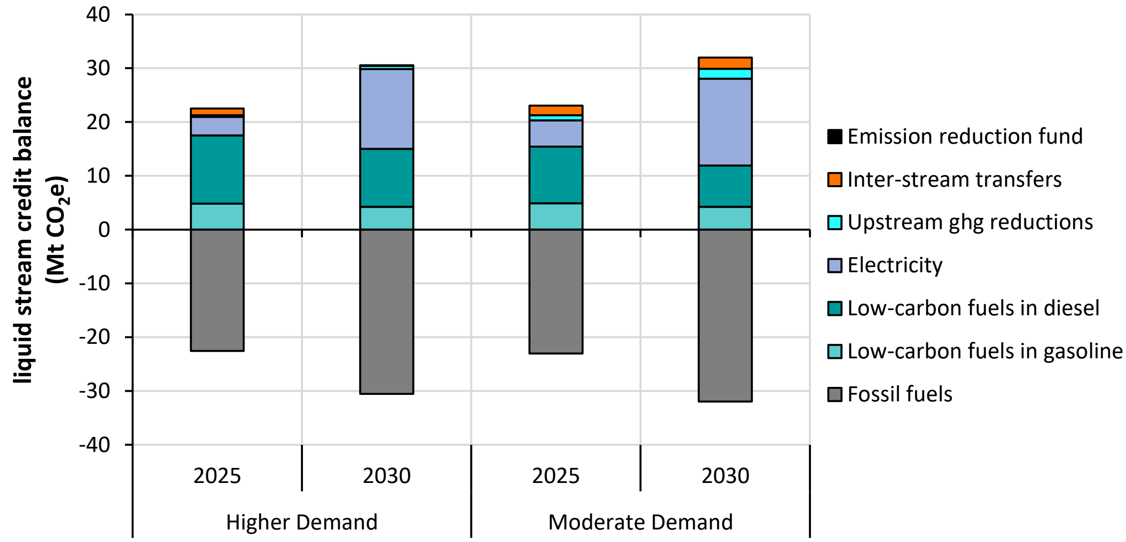
	Moderate Scenario	High Scenario
CFS % CI reduction and approximate $MtCO_2e$/yr credit generation in 2030		
Liquid, linear path:	3.6 g/MJ in 2022 to 10 g/MJ in 2030	Same as moderate
Gaseous, linear path to:	-2.5%, ~6 to 7 $MtCO_2e$/yr	-7.5% in 2030
Solid, linear path to:	-10%, ~1 $MtCO_2e$/yr	-15% in 2030
Other CFS design details:		
Policies benchmark	Will overlap with current and announced policies	Same as moderate
Inter-stream credit trading	10%	
Emission reduction fund, credit price (2019 CAD)	200 $/$tCO_2e$, adjusted for inflation, max 10% credits by pool from this action.	250 $/$tCO_2e$, adjusted for inflation, max 10% credits by pool from this action.
Upstream compliance	Included, with more "allowed" actions	Included, with fewer "allowed" actions
PEV policy support		
Federal PEV purchase incentive	Ongoing purchase incentives of $2,500/vehicle to 2025	Only the announced $300 million
ZEV sales requirements for light-duty vehicles	As announced in BC and Québec	Assuming these policies do not endure
Additional Policies		
Provincial renewable natural gas mandates	BC and Québec	BC and Québec

Results

Liquid fuel stream

The supply and demand for CFS compliance credits in the liquid fuel stream is shown in Summary Figure 1. Demand for CFS compliance credits (i.e. obligations under the policy) result from consuming fuels with carbon intensities over the regulated limit (typically fossil fuels). In both scenarios, roughly half of all compliance credits come from electricity used for transportation, though conventional biofuels (e.g. biodiesel and ethanol) and hydrogenation derived renewable diesel (HDRD) also play an important role in compliance. Key results relating to this fuel stream are in Summary Table 2.

Summary Figure 1: liquid stream compliance credit balance by scenario and year



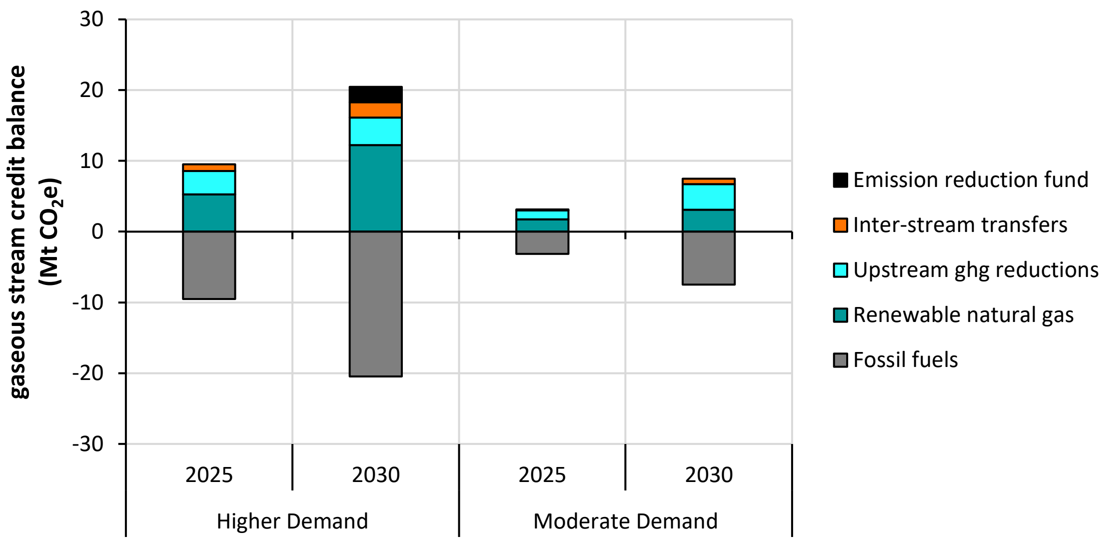
Summary Table 2: liquid fuel stream results

	Higher Demand Scenario		Moderate Demand Scenario	
	2025	**2030**	**2025**	**2030**
Credit price, 2019 \$/tCO_2e	113	115	111	113
Credit volume, tCO_2e/yr	22.5	30.5	23.1	32.0
Ethanol, PJ/yr (% gasoline volume)	109 (14%)	98 (14%)	109 (14%)	98 (14%)
Biodiesel, PJ/yr (% diesel volume)	62 (4%)	62 (4%)	62 (4%)	60 (4%)
HDRD, PJ/yr (% diesel volume)	106 7%)	83 (6%)	77 (5%)	38 (2.6%)
Electricity, PJ/yr	8	41	12	45
Electric light-duty vehicles on the road (thousand)	439	2,139	957	2,651
Electric buses on the road (thousand)	18	42	18	43
Electric medium/heavy-duty vehicles on the road (thousand)	34	309	34	310

Gaseous fuel stream

The supply and demand for CFS compliance credits in the gaseous fuel stream is shown in Summary Figure 2. In the moderate demand scenario, a significant amount of compliance (59%) comes from upstream reductions and inter-stream credit purchases. The use of renewable natural gas (RNG) is relatively limited. In the higher demand scenario, where the required carbon intensity reduction is much larger, upstream compliance and inter-stream credit purchases or purchases from the emissions reduction fund have a smaller proportional role. RNG becomes an important compliance action, accounting for 6% of natural gas volume in 2030. Key results relating to this fuel stream are in Summary Table 3.

Summary Figure 2: Gaseous stream compliance credit balance by scenario and year



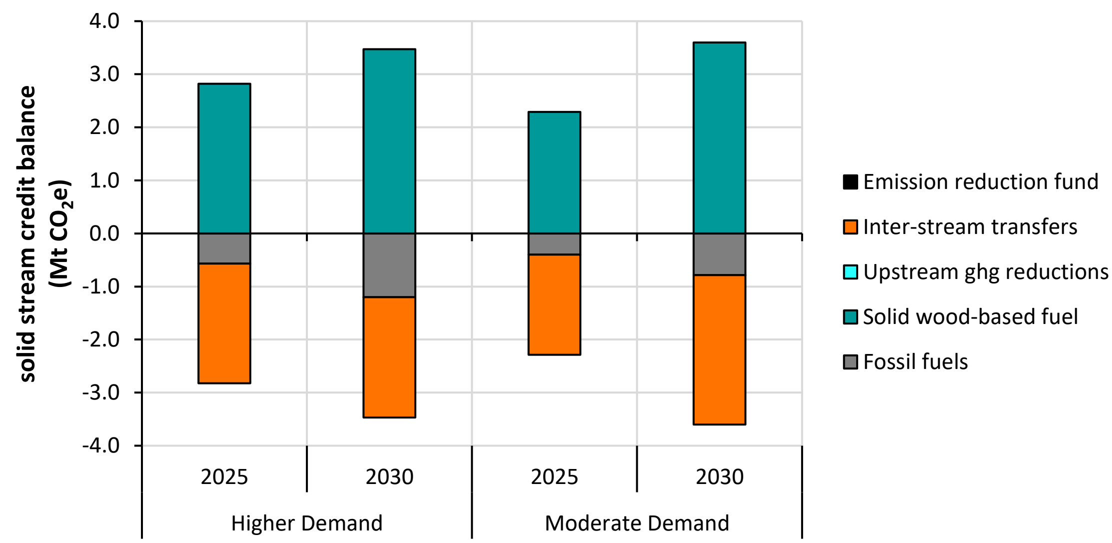
Summary Table 3: Gaseous fuel stream results

	Higher Demand Scenario		Moderate Demand Scenario	
	2025	**2030**	**2025**	**2030**
Credit price, 2019 \$/tCO_2e	248	251	111	149
Credit volume, tCO_2e/yr	9.5	20.4	3.1	7.5
RNG, PJ/yr (% gas volume)	105 (3%)	258 (6%)	34 (0.8%)	61 (1.3%)

Solid fuel stream

The supply and demand for CFS compliance credits in the solid fuel stream is shown in Summary Figure 3. The solid fuels covered by the CFS include coal and coke used in cement and lime production and in a handful of other manufacturing sectors. Coal consumption in regulated coal plants is excluded. Compliance can be achieved by substituting solid fossil fuels with solid wood-based fuels (specifically in this analysis, wood pellets). Because the compliance cost in the solid stream is lower than in the liquid and gaseous streams, the solid stream is a net credit seller to the other streams. Because the quantity of obligations in the solid stream is small (i.e. relatively less energy consumption is covered compared to other stream), sales of credits significantly increase the demand for credits and the quantity of wood fuel consumed in response to the CFS. Key results relating to this fuel stream are in Summary Table 4.

Summary Figure 3: Solid stream compliance credit balance by scenario and year



Summary Table 4: Solid fuel stream results

	Higher Demand Scenario		Moderate Demand Scenario	
	2025	2030	2025	2030
Credit price, 2019 $/t$CO_2$e	113	115	111	113
Credit volume, tCO_2e/yr	2.8	3.5	2.3	3.6
Credit sales to other streams, tCO_2e/yr	2.3	2.3	1.9	2.8
Wood, PJ/yr (% solid fuel energy)	35 (29%)	48 (37%)	28 (23%)	47 (37%)

Discussion and Conclusions

Conclusions

Key conclusions from this analysis are that:

- Electrification of transportation will be a significant compliance action in the liquid fuel stream, potentially supply half of all compliance credits. This volume of credits comes from the electrification of light-duty vehicles as well as buses and medium/heavy duty vehicles.
- As a consequence of the quantity of compliance credits produced by electrification of transportation, demand for biofuels such as ethanol, biodiesel and HDRD will not grow between 2025 and 2030, nor will there be a demand for more fungible liquid fuels (beyond HDRD) or fuels derived from ligno-cellulosic feedstocks.
- If the gaseous stream carbon intensity target is set to reduce emissions by approximately 7 $MtCO_2e$ GHG in 2030 (as measured by compliance credit generation, corresponding to a 2.5% carbon intensity reduction by 2030), it will almost entirely overlap with announced provincial policies including the British Columbian and Québec RNG standards and the British Columbian policies aimed at reducing upstream emissions in the natural gas sector.
- Alternatively, it would take a greater reduction in the average carbon intensity of the gaseous pool to result in an RNG fuel share in the range of 5-10%, the aspirational target envisaged by the Canadian Gas Association. In this situation, RNG demand in 2030 would be over 250 PJ/yr.
- The solid stream could very well be a net supplier of credits to the other fuel streams given that it will likely have the lowest compliance costs among the three fuel streams.
- The quantity of low-carbon fuel used in the solid stream is very sensitive to the purchase of solid stream credits for compliance in other fuel streams. The solid fuel stream is small compared to the other fuel streams, in terms of energy covered by the CFS. If 10% of compliance in those larger fuel streams is purchased from the solid fuel stream, demand for wood fuel in 2030 will be three to five times larger than what would occur if the CFS did not allow inter-stream trading.

Limitations and Uncertainties

There are several uncertainties and limitations of this analysis that could not be addressed within the scope of this project. Nonetheless, studying these issues would provide additional insights into the potential impact of the CFS on low-carbon fuel and electric vehicle demand. These include better providing a better understanding of:

- The impact of alternative RNG production costs and carbon intensity values.
- The impact of including hydrogen fuel-cell or combustion vehicles.
- The impact of more pessimistic assumptions for electric vehicles adoption (e.g. costs, consumer aversion to new technology, lack of supply, lower energy efficiency ratios).
- The impact of excluding the octane value of ethanol.
- The impact of more restrictive blending constraints on biodiesel.
- The impact of including more types of wood fuel or a greater variety of end-uses where wood fuel can be consumed.

Table of Contents

1. Introduction

Context

The government of Canada is developing the Clean Fuel Standard (CFS) with the objective of achieving a 30 Mt/yr reduction in greenhouse gas (GHG) emissions in 2030, relative to what emissions would be in that year without the CFS or other policies that reduce the carbon intensity of fuels. One of NRCAN's mandates is to enable the supply of non-fossil renewable and low-carbon fuels (i.e. called low-carbon fuels for the remainder of the report) and plug-in electric vehicles (PEVs) that would allow compliance with the CFS, including liquid biofuels, renewable natural gas, solid biomass, and plug-in electric vehicles (PEVs). In that regard, government and industry are working together towards the successful implementation of the CFS under the umbrella of the Clean Fuel Steering Committee (CFSC). The CFCS is reviewing what conditions are required for investment in low-carbon fuel production in Canada and the adoption of low-carbon alternative fuel vehicles.

To inform the CFSC's planning for greater domestic supply of low-carbon fuels (liquid, gaseous, and solid) and greater adoption of light-duty PEVs, Navius will produce and report on two illustrative scenarios that forecast the demand for these fuels and technologies under the influence of the CFS and other existing energy and GHG policies in Canada to 2030.

Function of the CFS

The CFS is being designed to reduce the life-cycle carbon intensities of solid, liquid and gaseous fuels sold in Canada. The life-cycle carbon intensity (henceforth simply called carbon intensity) of a fuel accounts for both direct greenhouse gas (GHG) emissions associated with fuel consumption and upstream GHG emissions associated with fuel and feedstock production, processing and transportation. The CFS will notionally reduce GHG emissions by 30 million tonnes of carbon dioxide equivalent (Mt CO_2e) by 2030, measured relative to a baseline that is defined without that policy. However, it is an intensity-based policy, which will interact with other emerging provincial policies, so the ultimate GHG reduction that will be achieved by the policy is uncertain.

The CFS differs from regulations that require renewable content in fuels because it **creates a new market for compliance.** This new market allows firms to trade their compliance obligations towards the policy (e.g., in the form of compliance credits).

The Clean Fuel Standard will provide several options to meet the carbon intensity limits. Credits will be created by primary suppliers and by parties that are not primary suppliers (voluntary credit creators) for actions taken in the following compliance categories:

- **Category 1: Actions throughout the lifecycle of a fossil fuel that reduce its carbon intensity (the "upstream" component of the policy).** There are many options and technologies available to reduce GHG emissions associated with the production of fuels, such as carbon capture and storage (CCS) and the electrification of natural gas processing. Where these reduce the carbon intensity of a regulated fuel (e.g. gasoline, diesel, natural gas), they may also count towards compliance.
- **Category 2: The supply of low carbon intensity fuels into each fuel stream (the "downstream" component of the policy).** Biofuels can be blended into any of the fuel streams or used in their neat form.
- **Category 3: Specific end-use fuel switching in transportation (the "downstream" component of the policy).** Greater use of alternative-fuel vehicles, such as PEVs, can also count towards carbon intensity reductions. End-use fuel switching in the transportation sector from a higher carbon intensity fossil fuel to the following less carbon intensive fuels will be eligible for credit creation: natural gas and renewable natural gas, hydrogen, propane and renewable propane, and non-carbon energy carriers, such as electricity or hydrogen.
- **Using policy "flexibility" mechanisms**, including (1) inter-stream trading (allowing the different streams to exchange compliance obligations) and (2) a fund compliance mechanism, where a regulated party will be able to meet up to 10% of its annual compliance requirement by making a payment at a set price into a list of approved funds in lieu of direct abatement.

Contents of the report

The following section explains the methodology of this analysis and includes a summary of the modelling framework used, how the CFS is represented in each scenario, and the characteristics of the policy compliance actions included in the analysis.

The methodology is followed by the forecast results and discussion, focussing on what actions are used to comply with the CFS, how each of these actions reduce the carbon intensity of each fuels stream, fuel shares and market shares of compliance actions and total low-carbon fuel demand and PEV demand. The report ends with a summary of key conclusions from this work. Additional details on our characterization of bioenergy is included in the appendix.

2. Methodology

In the final report, this section will begin with a complete overview of the gTech model rather than a summary. The current methodology section describes fundamental drivers to the forecast we will produce. This is followed by a description of uncertainties in how the CFS will be implemented and how we will use these uncertainties, paired some differing technology assumptions, to create two scenarios with “moderate” and “higher” low-carbon fuel demand. This is followed by a list of other policies included in the forecast. The section concludes with a summary of key technology and fuel assumptions to be used in the analysis.

2.1. Summary of the Modelling Framework

The CFS is a complex policy that can have complex effects on Canada’s energy and economic system. Consequently, a complex model is required to properly forecast the policy’s effects. gTech offers the most extensive analytic capabilities of any energy-economic model available in Canada. The model is used by governments, firms and non-governmental organizations to forecast the environmental and economic impact of climate policies. gTech is well suited for studying the CFS because:

- **gTech is a full economic model that can correctly model the impact of a compliance credit market.** gTech is a computable general equilibrium (CGE) model, meaning it represents all transactions between all sectors of the economy throughout its forecasts. Being a CGE model, gTech can simulate the market for compliance credits created by policies like the CFS, while accounting for how this market is influenced by other dynamics in the energy system, including: the price for oil, the price for agricultural feedstocks, the cost of biofuels manufacturing and the cost of transporting fuels between regions and the design of other policies, both with and without compliance markets of their own. Models with a partial or static representation of the economy cannot simulate the impact of policies that create a market for compliance. Instead, results will be based on additional assumptions such as credit price and volumes available from flexibility mechanisms (e.g. trade between, streams, upstream compliance). As well, because gTech is a CGE model, it is also ideally suited for forecasting how policies affect economic activity (e.g., gross domestic product, competitiveness, household income, etc.)
- **gTech is technologically explicit, allowing it to show the net-policy compliance offered by multiple technologies and fuels.** gTech is not a conventional CGE model, which typically do not include any explicit representation of energy technologies or

fuel pathways. gTech explicitly simulates how households and firms may use over 200 different technologies to provide themselves with energy services (e.g. transportation, heating, light). It also includes 10 conventional and emerging biofuel pathways. Consequently, gTech can forecast how a CFS will affect technology and fuel adoption in both the upstream oil and gas sectors and downstream energy demand sectors.

- **gTech is behaviourally realistic, allowing it to describe policy outcomes, rather than prescribe financial cost-optimized solutions.** Technological choice is strongly influenced by behaviour. In some cases, behaviour has as much or more influence on the decision than financial costs (e.g., this is especially important regarding technology choice for transportation). gTech includes three behavioural dynamics, allowing it to describe how policies will influence technology choice:

  First, gTech accounts for people's non-financial preferences; it does not assume people only want to minimize their financial costs, rather people will pay for what they want (e.g. a large powerful vehicle). Second, it accounts for realistic time preferences for money; consumers and firms are often unwilling to spend more now to save money far in the future. Finally, it accounts for heterogeneity. Given the same circumstances, people will choose to use different technologies (e.g. some buyers will pay a premium for an electric vehicle, while others would never choose one over a conventional vehicle).

- **gTech can simulate the interactions between policies, which will strongly affect the net-impact of the CFS.** A CFS is one of many policies applied to Canada's transportation, buildings and industrial sectors. For example, the transportation sector is already subject to many policies, including (1) excise taxes; (2) provincial and federal renewable fuel requirements; (3) federal vehicle emissions standards; and (4) mandates for zero emissions vehicles (Québec and proposed in BC). Likewise, buildings and industry will be affected by policies such as carbon prices and renewable natural gas requirements, which will also interact with the CFS. gTech can forecast the interactions amongst all these policies, correctly accounting for policy overlap, preventing any double counting of policy impacts.

2.2. Fundamental Scenario Drivers

The gTech forecast of energy demand and technology adoption is a simulated result. These results are driven by many factors, but the fundamental trends results from external assumptions about economic growth, activity by sector and energy prices, notably crude oil and gas prices.

GDP growth by province in the forecast is calibrated by province to the fiscal sustainability report forecast produced by the Parliamentary Budget Office[1]. The activity of individual sectors is a function of how they relate to each other in terms of economic inputs and outputs. In the starting year of the forecast, these relationships are based on the Statistics Canada System of Macroeconomic Accounts, but the relationships may vary during the forecast as the prices of inputs and outputs change.

Future activity in the oil and gas sectors is determined separately, resulting is a small deviation from the calibrated GDP forecast. This activity is based on the reference projection in the Natural Energy Board's report on Canada's Energy Future[2].

Oil and gas prices are calibrated to the reference case prices used by the Natural Energy Board in its annual Canada's Energy Future Report[3]:

- Natural gas prices rise to $5.1/MMBtu, or 4.9 $/GJ, (2019 $CAD) by 2030. After the model has been calibrated to the external forecast, the price for natural gas is determined within in the model based on supply and demand for natural gas in North America.
- Crude oil prices rise to $92 (2019 $CAD) by 2030. The price for oil is an external input to the model (i.e., based on an assumed global price).

2.3. Representation of the CFS and Scenario Design

2.3.1. Key design features of the CFS

The carbon intensity reduction required in the liquid, gaseous and solid fuel streams and the trajectory of carbon intensity reductions

Carbon intensity reduction requirements for liquid fuels will start in 2022, requiring a 3.6 g CO_2e/MJ reduction for all liquid fossil fuels, increasing by 0.8 g CO2e/MJ

[1] Parliamentary Budget Office. (2018). Fiscal Sustainability Report 2018. Available from: link

[2] Natural Energy Board. (2018). Canada's Energy Future. Available from: link

[3] Ibid.

annually to achieve a 10 CO_2e/MJ carbon intensity reduction requirement in 2030. This 2030 carbon-intensity reduction requirement represents a decrease of 10.7% in carbon intensity below 2016, depending on the fuel type. According to the Proposed Regulatory Approach[4] published by ECCC in June 2019, the carbon intensity requirement for the liquid fuel stream in 2030 is equivalent to up to 23 MtCO2e/yr relative to the policy baseline, as measured by the quantity of credits generated under the CFS. However, depending on the growth of liquid fuel consumption and what low-carbon fuels are supplied, the quantity of credits generated could be different.

The corresponding carbon intensity targets are not yet defined for the solid and gaseous fuel streams. For the purpose of this analysis, the carbon intensity target for the gaseous pool is expected to reduce emissions by 6 to 7 MtCO2e/yr relative to the policy baseline, while the solid fuel stream will achieve another 1 MtCO2e/yr reduction. Corresponding fuel stream carbon intensity targets would need to be set to achieve this outcome. As well, the trajectory of the carbon intensity requirement will be linear for the liquid stream, but it has not been defined for the other streams (e.g. linear, greater reduction initially vs. later).

The formula to calculate the number of annual obligations (debits) is the same as what is presented in Annex III of the Proposed Regulatory Approach produced by Environment and Climate Change Canada.

The policy benchmark

The CFS is notionally supposed to reduce GHG emissions by 30 Mt CO_2e in 2030 relative to a benchmark scenario without that policy. However, it is not clear whether that benchmark scenario includes current GHG policies (i.e. those that are legislated), or current ***and*** announced GHG policies (e.g. the newly announced Clean BC plan. See the full list of policies in the gTech forecast in the next section, 2.4). Announced policies include the upcoming British Columbian zero-emissions vehicle standard, renewable natural gas standard, and GHG reduction regulations on the upstream natural gas sector. These regulations require formation CO_2 to be captured and stored, and electrification of a substantial proportion of natural gas extraction and processing operations in the province. Together, these policies are expected to reduce GHG emissions by roughly 7 MtCO_2e/yr.

If the CFS scenario has a benchmark that includes current and announced policies, the CFS will have an impact that is incremental to these policies. In this case, the CFS will reduce GHG emissions by roughly 30 MtCO_2e/yr, beyond the newly announced BC

[4] Environment and Climate Change Canada (2019). Clean Fuel Standard Propose Regulatory Approach. Link

policies, and the total impact in this example would be 37 $MtCO_2e$/yr. On the other hand, if the CFS does not account for these policies, then it's impact will overlap with them and the total impact on GHG emissions and energy demand will be smaller. In this case, the impact of the CFS will not be incremental to the 7 $MtCO_2e$/yr expected from newly announced BC polices, and the total impact would be 30 $MtCO_2e$/yr.

The Proposed Regulatory Approach provides the following information in terms of overlap with other policies and regulations:

- Participants will have the possibility to create credits for actions that include current federal and provincial renewable fuel mandates and the BC Low Carbon Fuel Standard, and the current supply of electricity to electric vehicles;
- A GHG emission reduction project along the lifecycle of fossil fuels that overlaps with the compliance requirements or enables the creation of credits under federal, provincial or territorial carbon pollution pricing systems will be eligible to create credits;
- A GHG emission reduction project that meets the criteria for compliance category 1 and that overlaps with BC's Low Carbon Fuel Standard, such as co-processing biocrudes at a refinery, will be eligible to create credits
- The incrementality of emission reductions for projects along the lifecycle of fossil fuels will be assessed in the development of quantification methodologies for those projects.

Credit trading between fuel streams

The CFS will allow compliance credits from one fuel stream to be used for compliance in another fuel stream (e.g. credits from the liquid fuel stream can be used for compliance in the gaseous fuel stream). 10% of compliance in one fuel stream can be achieved by purchasing credits from the other fuel streams. Inter-stream credit trading can potentially reduce the cost of compliance, but it would also reduce physical compliance (e.g. increasing demand for low-carbon fuels) in one fuel stream while increasing it in another.

Credit clearance market

The CFS will establish a Credit Clearance Mechanism. Participation in the Credit Clearance Mechanism will be mandatory for a primary supplier with a credit shortfall for a given compliance period. If there are not enough credits available in the Credit Clearance Mechanism for all primary suppliers to satisfy their outstanding reduction requirement, each primary supplier will need to acquire a pro-rated amount of the available credits, as detailed below. The Clean Fuel Standard regulations will set a maximum price for credits acquired, purchased or transferred in the Credit Clearance Mechanism.

Fund compliance mechanism

The CFS will allow primary suppliers to offset up to 10% of their annual liquid stream reduction requirement for a compliance period by payment at a fixed price into an approved fund that invests in, and obtains GHG emissions reductions, in the short term. The CFS regulations will set out the criteria that a fund will have to meet in order to be eligible to receive Clean Fuel Standard contributions. Environment Climate Change Canada will maintain a list of approved funds. A primary supplier will be able to choose the approved fund or funds to which it contributes. The fund compliance mechanism can limit total compliance costs, but it may also limit the impact of the CFS on low-carbon fuel and PEV demand if the funds if the fund is involved in other GHG reduction activities.

Upstream credit generation

The CFS may allow compliance credits to be generated by the upstream oil and gas sectors and the petroleum refining sector. Credit generation may occur if specific projects are undertaken to reduce the GHG emissions associated with fossil fuel production. These could include capturing and storing the formation CO_2 released during natural gas production, electrifying some natural gas operations (e.g. using electric motors instead of using gas-fired turbines to pressurize gas extraction and gathering lines, where transmission is available), capturing and storing the CO_2 released during hydrogen production at refineries and bitumen upgraders. If the CFS allows upstream credit generation, it could reduce the impact of the policy on low-carbon fuel and PEV demand, while preserving the desired GHG impact.

The ability of a project to create credits will be governed by a quantification methodology provided by Environment and Climate Change Canada for specific types of projects. Environment and Climate Change Canada has prioritized and is undertaking the development of quantification methodologies for the following project types, and will take into consideration existing emission reduction accounting methodologies or offset protocols in other jurisdictions: carbon capture and storage; enhanced oil recovery; low-carbon intensity electricity integration; methane reductions that are additional to regulatory requirements; co-generation; electrification; and co-processing of biocrudes in refineries and upgraders.

The Proposed Regulatory Approach includes co-processing of biocrudes in refineries and upgraders in compliance category 1(upstream GHG reductions). For the purposes of this analysis, they are included as renewable fuel consumption, and export of these fuels would not generate credits.

2.3.2. CFS Scenario Design

This analysis includes two scenarios: one with “moderate” low-carbon fuel demand and one with “Higher” demand. We have defined these two scenarios primarily through differences in our interpretation of how the CFS will be implemented (Table 1) and additional policies affecting renewable natural gas supply and electric vehicle demand. These scenarios are illustrative rather than prescriptive; our interpretation of the CFS in each scenario has been guided by the need to demonstrate different energy demand scenarios rather than evaluating one policy design versus another.

Table 1 summarizes the two scenarios. For both scenarios, we have assumed:

- **The same carbon intensity targets in the liquid fuel stream**, which rises linearly from 3.6 g/MJ in 2022 to 10 g/MJ in 2030. Relative to the liquid class credit reference carbon intensity of 92.7 gCO_2e/MJ, this target corresponds to a 6.4% reduction in 2025 and a 10.7% reduction in 2030.
- **That the CFS is not incremental to current and new policies**. In other words, the policy benchmark does not account for these policies and there can be an overlap in the actions these policies require (e.g. a requirement to use renewable natural gas in a province will generate CFS compliance credits for that consumption).
- **That 10% inter-stream credit trading is allowed and 10% of credits in a fuel stream can come from the emissions reduction fund**. I.e. 10% of compliance credits in a given year for a given fuel stream can be purchased from the other two fuel streams if there are surplus credits in those streams. Note that because of the relative size of the fuels streams, this could still result in significant credit sales from a small fuel stream to a large fuel stream. For example, if there are credit sales from the solid fuel stream to the liquid fuel stream, it could double or triple the quantity of physical compliance achieved in the solid fuel stream. Similarly, 10% of credits can be obtained by paying into the emission reduction fund.

In both scenarios, fuels used as feedstocks or materials (e.g. natural gas used for hydrogen production, coke used for steelmaking and carbon anode production in aluminum smelters) are excluded from the CFS, as is coal used in regulated coal-fired power plants. Fuels used for international marine and air transportation are also excluded as is "own-use" natural gas, which is the unprocessed natural gas that is consumed by gas producers and processors.

The moderate demand scenario has:

- Carbon intensity targets that notionally achieve the 6-7 $MtCO_2e$ impact in the gaseous pool, as measured by the quantity of credits generated (-1.1% in 2025, and -2.5% in 2030) and the ~1 $MtCO_2e$ target in the solid pool (-4.4% in 2025 and -10% in 2030).

- A price of $200/tCO2$_2$e (2019 CAD) adjusted for inflation, for purchasing credits from the emission reduction fund.

- More allowed upstream compliance, which again may limit the demand for low-carbon fuels. This is represented in the model as more "allowed" abatement actions with no limit on the quantity of compliance achieved in this way.

- Greater policy support for light-duty PEVs, assuming the current federal subsidy, currently $5,000 dollars per vehicle, falls to $2,500 per vehicle in 2020 and continues with unlimited funding to 2025 (2019 CAD). This will result in more compliance from electrification and less from low-carbon fuel consumption.

- The Zero-Emissions Vehicle sales requirements as announced in BC and Québec:

  - In BC. the zero-emissions vehicle (ZEV) standard, which we assume will require 10% PEV sales in 2025 and 30% in 2030.

  - In Québec, the ZEV mandate, which we assume results in 12% PEV sales in 2025 and 15% in 2030.

The higher demand scenario has:

- More stringent carbon intensity targets for both the gaseous and solid fuel streams. The target for the gaseous stream is set to -7.5% in 2030 to align renewable natural gas consumption with the Canadian Gas Association's aspirational target for a 5-10% fuel share by 2030. The solid fuel stream carbon intensity target is set to -15%.

- A price of $250/tCO2$_2$e (2019 CAD) adjusted for inflation, for purchasing credits from the emission reduction fund.

- Less upstream compliance which is modelled as fewer allowed compliance actions. Specifically, we have excluded compliance from the electrification of compressors in natural gas production and processing as well as compliance from emissions reductions for heat production in the oil sands.

- Subsidies for light-duty PEVs, but with the maximum amount capped at the $300 million funding that is committed. Consequently, this policy has a small impact on the total stock of electric vehicles and the credit generation from these vehicles.
- No ZEV sales requirement, assuming these policies do not endure and are repealed.

Note that neither scenario explicitly includes a credit clearance market, therefore the price of compliance credits will always rise to the marginal compliance cost (i.e. the GHG abatement cost of the most expensive action required for compliance).

Table 1: Representation of the CFS and Scenario Design (all $ are 2019 CAD)

	Moderate Scenario	High Scenario
CFS % CI reduction and approximate $MtCO_2e$/yr credit generation in 2030		
Liquid, linear path:	3.6 g/MJ in 2022 to 10 g/MJ in 2030	Same as moderate
Gaseous, linear path to:	-2.5%, ~6 to 7 $MtCO_2e$/yr	-7.5% in 2030
Solid, linear path to:	-10%, ~1 $MtCO_2e$/yr	-15% in 2030
Other CFS design details:		
Policies benchmark	Will overlap with current and announced policies	Same as moderate
Inter-stream credit trading	10%	
Emission reduction fund, credit price (2019 CAD)	200 $/$tCO_2e$, adjusted for inflation, max 10% credits by pool from this action.	250 $/$tCO_2e$, adjusted for inflation, max 10% credits by pool from this action.
Upstream compliance	Included, with more "allowed" actions	Included, with fewer "allowed" actions
PEV policy support		
Federal PEV purchase incentive	Ongoing purchase incentives of $2,500/vehicle to 2025	Only the announced $300 million
ZEV sales requirements for light-duty vehicles	As announced in BC and Québec	Assuming these policies do not endure
Additional Policies		
Provincial renewable natural gas mandates	BC and Québec	BC and Québec

2.4. Policies Beyond the CFS

In addition to the CFS and other hypothetical policies mentioned in the previous section, the following policies have been implemented or announced at a federal or provincial level and are included in the modeling:

- Federal carbon pricing: The federal government requires a carbon price of $50 per tonne CO_2e by 2022 and will implement a backstop price in provinces without an equivalent program. For simplicity, we assume this carbon price applies in all provinces and territories except British Columbia and Quebec. For industry, the federal output-based performance standard (OBPS) will apply. Revenues collected are envisioned to be recycled into GHG abatement. Although the allocation of this revenue is highly uncertain, we have assumed that some of this revenue is likely to fund abatement in the oil and gas sector.

- Federal renewable fuel requirements, which are ultimately rolled into the CFS: These requirements mandate 5% renewable content in gasoline and 2% for diesel (by volume).
- Existing provincial renewable fuel requirements, including an increase in Ontario's requirement to 10% starting in 2020.
- Federal vehicle emissions standards on light and heavy-duty vehicles, where the regulation on light-duty vehicle follows the schedule to 2025 (falling to a fleet average of 119 gCO_2e/km after 2025).
- Federal regulations on methane emissions from the oil and gas sector.
- A phase out of coal-fired electricity generation: In some regions, we include required targets for renewable generation to replace the coal generation: 30% renewable generation in Alberta by 2030 and 40% in Nova Scotia and New Brunswick by that same year.
- British Columbia's Clean BC initiatives, notably six policies that could have a strong interaction with the CFS. These include:
  - A renewable natural gas standard, which requires 15% of natural gas sold in the province come from renewable sources by 2030, excluding gas consumed by the upstream oil and gas sector.
  - Electrification of natural gas production activities.
  - Capturing formation carbon dioxide during natural gas processing.
  - An increase in the stringency of the Low Carbon Fuel Standard (LCFS), that would require a 20% reduction in the life-cycle carbon intensity of liquids fuels sold.
  - An increase in the stringency for the average tailpipe emissions of new sales of internal combustion vehicles.
  - An increase in the Carbon Tax, in line with the federal carbon price ($50 per tonne CO_2e by 2021).
- Quebec's cap and trade program, with credit prices rising to $27 per tonne CO_2e by 2025 and 35 per tonne CO_2e by 2030 (in current, 2019, CAD). The credit price assumption is based on the announced price floor, which has thus far served as a reasonable proxy for credit price.

2.5. CFS Compliance Actions

The gTech mode contains a substantial amount of detail on energy consuming technologies and fuels. Technologies and fuels are represented archetypally, meaning multiple possibilities are represented by a single characterization. For example, the range of plug-in electric transportation options are represented with four technology archetypes, two for light-duty vehicles, one for buses and one for heavy-duty vehicles. gTech includes eight archetypes of liquid biofuels and three archetypal gaseous biofuels, as well as opportunities to substitute solid fossil fuels for biomass. Low-carbon fuel imports (and consumption) from the US generates compliance credits, while exports of these fuels, or trade in feedstocks does not count towards compliance.

Using archetypes is a necessary simplification of the real-world. This is especially true for emerging energy and technology pathways. For example, there are many pathways for the bio- or thermochemical conversion of biomass to fuels. gTech only represents three of them, but these archetypes must serve as a catchall for all pathways, whether they be standalone production of fuels or co-production with fossil fuels (e.g. renewable gasoline and diesel components produced from co-processing of biocrude and fossil crude oil). This analysis is not including co-processed biocrude as an upstream compliance action, though this designation has been proposed.

Note that gTech does not currently include "power to gas" where electricity (or perhaps specifically renewable electricity) is used to produce hydrogen that is injected into the natural gas grid at a rate where there are no equipment capability issues (e.g. less than 5%). We review this technology periodically to determine whether adding it will improve this analysis. Currently, the literature still indicates that even when using optimistic assumption, the production cost of "power to gas" is well above other sources of low-carbon gaseous fuels included in this analysis , e.g. $30/GJ, based on "future" capital costs reductions noted by the US Department of Energy, assuming 66% electrolyzer efficiency[5] with low-carbon electricity available at $60/MWh[6].

We exclude this technology from the analysis only on the basis that including it adds complexity to the model without changing the results; Based on other inputs, there will be no demand for power to gas within the time-frame and strength of policies examined in this analysis. This does not preclude the use of power to gas in some real-

[5] i.e. 1.5 units of electrical energy are required to produce one unit of hydrogen energy

[6] US DOE (2018). Future Central Hydrogen Production from PEM Electrolysis version 3.101.xlsm by DOE Hydrogen and Fuel Cell Program. www.hydrogen.energy.gov/h2a_prod_studies.html

world instances where low-cost and low-carbon electricity is available, potentially with a more efficient electrolyzer. Our discussion of any demand for renewable natural gas, beyond what is produced in anaerobic digestors, or collected from landfills, will allude to this possibility.

The remainder of this section describes our assumptions for:

- Fuel carbon intensity
- Fuel production costs
- Fuel constraints
- Alternative fuel vehicles (e.g. PEVs)
- Upstream action abatement costs (relevant for the “moderate” scenario where these actions can generation CFS compliance credits)

2.5.1. Fuel Carbon Intensities

The lifecycle carbon intensities for fossil fuels were provided by Environment and Climate Change Canada (ECCC) and were determined as part of the development of the Fuel Lifecycle Assessment Modelling Tool. The carbon intensities for biofuels in the liquid fuel stream, as well as their annual rate of decline from 2020 to 2030 (Table 2), are based on the values used in the modelling done by the World Agriculture Economic and Environmental Service for Advanced Biofuels Canada.

The carbon intensity of electricity is based on the lifecycle GHG intensity of fuels used for electricity generation in gTech, therefore the results vary by year and province (Table 3) as a function of the policies simulated (see section 2.4). Note that hydroelectricity has a non-zero carbon intensity due to methane emissions from hydro reservoirs.

The lifecycle carbon intensity of fossil natural gas and propane used in the gaseous stream was also provided by ECCC, as were the carbon intensities of coal and petroleum coke. These values were determined as part of the development of the Fuel Lifecycle Assessment Modelling Tool. The carbon intensity of renewable natural gas is judgementally set to 10 g CO_2e/MJ. That value is uncertain but is typically quoted in the range of 5-15 g CO_2e/MJ, depending on whether any input energy is required for its production and how much methane leaks during the process. The carbon intensity of torrefied wood pellets was judgementally set to 11 g CO_2e/MJ, which is also uncertain and will benefit from expert review.

Note that for simplicity in the modelling, we chose to use wood pellets as the compliance action in the solid fuel pool. This fuel has much greater substitutability with solid fossil fuels and offers more flexibility in getting the model to "solve" (i.e. compliance can be achieved). Improved modelling of the CFS would also account for potentially lower-cost compliance actions such as wood chips and actions that are not yet commercialized, such as torrefied wood pellets.

Table 2: Liquid Fuel Stream Carbon Intensity Assumptions

Fuel	Lifecycle carbon intensity, gCO_2e/MJ, in 2020	% annual carbon intensity reduction to 2030
Gasoline	92.0	-
Diesel	100.0	-
Ethanol (corn/wheat)	45.8	1.25%
Biodiesel (canola)	9.8	1.25%
Hydrogenated renewable diesel	17.6	0.5%
Cellulosic ethanol	25.0	2.0%
2nd gen. renew. gasoline/diesel	26.2	1.8%
CNG	65	-
LNG	73	-

Table 3: Electricity Carbon Intensity Assumptions by year, gCO_2e/MJ

Province	2020	2025	2030
British Columbia	11.0	11.0	10.4
Alberta	121.0	96.2	72.9
Saskatchewan	214.0	184.8	109.1
Manitoba	10.8	10.7	10.6
Ontario	15.0	12.6	12.3
Québec	10.1	10.7	10.7
New Brunswick	108.7	94.7	67.4
Nova Scotia	181.4	164.3	88.4
Newfoundland	11.3	11.9	13.7

Table 4: Gaseous and solid Fuel Stream Carbon Intensity Assumptions

Fuel	Lifecycle carbon intensity, gCO_2e/MJ
Fossil natural gas	62.0
Renewable natural gas (from landfill gas, on farm anaerobic digesters, thermochemical/2nd generation production)	10.0
Propane	75.0
Coal	97
Petroleum Coke	110
Woood pellets	10

2.5.2. Fuel Costs

Table 5 has fuel production costs derived from inputs to gTech. These are examples of production costs subject to feedstock and energy prices which may change as the price of inputs, notably feedstocks changes. These production costs should be representative of wholesale prices for fuels but will not reflect pricing volatility that results from shorter term (1-5 year) imbalances in supply and demand. For example, hydrogenated renewable diesel has been priced as high as 1.6 $/L[7] (2019 CAD) in recent years, well above our estimated production cost of 1.2 $/L (2019 CAD, see Table 5). The price of fuels in gTech is nonetheless subject to transportation costs, retail margins and taxes, all of which are simulated within the model.

The production cost of commercialized biofuels like ethanol, biodiesel and hydrogenated renewable diesel is most sensitive to the price of the agricultural commodity that serves as the feedstock (e.g. corn, canola). In other words, agricultural prices create the largest uncertainty in the production cost. For emerging biofuels made from ligno-cellulosic material (i.e., woody or grassy material), the production cost is more sensitive to the plant capital cost and utilization (i.e., does it produce as expected?).

The values in Table 5 show typical fuel prices and abatement costs that could result from the modelling inputs. However, actual prices and abatement costs are a simulated result, that depends on how the price of inputs to fuel production change during the forecast. For example if the delivered cost of crop residues is less than the $84/dry tonne shown in Table 5, which could occur in a low demand situation, the production cost of renewable natural gas produced from these residues would also be lower. As well, gTech assumes a degree of heterogeneity meaning there is a distribution applied to technology and fuels costs as calculated in the model. In practical terms, this means we assume that some amount of abatement from each action can occur at both lower and higher abatement costs than are shown in Table 5.

The number of compliance credits produced from each low-carbon fuel is calculated using the formulae supplied in Annex V of the CFS Proposed Regulatory Approach produced by Environment and Climate Change Canada.

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[7] Neste (2018). Neste Annual Report 2017. Available from: link.

Table 5: Examples of fuel costs and abatement costs resulting from modelling assumptions (priced in 2019 CAD)

	Production Cost $/GJ	Abatement Cost $/tCO₂e *	Feedstock costs used for calculation (actual costs are simulated)
Liquid fuels			
Ethanol	27.6	-141	Corn at $202/tonne
Biodiesel	29.6	110	Canola seed at $494/tonne
Hydrogenated renewable diesel	31.3	148	Canola seed at $494/tonne
Cellulosic ethanol	32.0	192	Feedstock at $84/dry tonne
2nd gen. renewable gasoline/diesel	43.5	370	Feedstock at $84/dry tonne
Gaseous fuels			
Landfill gas and production from anaerobic digestion	12.5	137	
2nd gen. renewable natural gas	19.4	270	Feedstock at $84/dry tonne
Solid fuels			
Wood pellets (delivered cost)	9	76	Assuming $100/dry tonne delivered, chipped and graded

* Abatement costs for downstream opportunities presented in this table are calculated based on production costs using the fuel carbon intensities noted in section 2.5.1 and using typical 2010 wholesale prices for fossil gasoline and diesel ($19/GJ in 2019 CAD), fossil natural gas ($5.4/GJ in 2019 CAD) and coal ($2.4/GJ, delivered in 2019 CAD). The costs are priced in 2019 Canadian Dollars based on model inputs with a given feedstock cost; these are not necessarily the costs that result in the forecast for 2019 or any other year.

**The negative abatement cost includes the octane value of ethanol, set at roughly 30 cent/l here. It applies only to blends where incremental ethanol satisfies an incremental need to raise the octane in gasoline blendstock.

Note that the abatement cost for ethanol includes a value for increased octane rating provided by ethanol. Rather than defining this octane value based on price spreads between lower- and higher-octane gasoline blends, we have set it based on typical price spreads between ethanol and other gasoline blendstock components that also raise octane, specifically aromatics (benzene, toluene, xylene), using the method of Irwin and Good (2017).[8] The resulting octane value assumption for this analysis is roughly 30 cent/L ethanol and only applies where incremental additions of ethanol satisfy any remaining need to raise octane. The ethanol costs do not include any additional costs that could be associated with the accelerated renewal of fuel storage and dispensing equipment to allow compatibility with ethanol blends greater than 10% by volume.

8 Irwin, S.; Good, D. (2017). On the Value of Ethanol in the Gasoline Blend. *farmdoc daily* (7):48, Department of Agricultural and Consumer Economics, University of Illinois at Urbana-Champaign

More details on the bio-energy costs assumptions are in Appendix A: "Detailed Bio-Energy Cost Assumptions".

2.5.3. Fuel Constraints

There are constraints applied to low-carbon fuel consumption in gTech, representing both functional and perceived constraints on supply and use of fuels. In some cases, the constraints in gTech are necessary simplifications made while representing the real-world with a model.

In the liquid fuel stream:

- The maximum volumetric blend of ethanol with gasoline is 15% after 2020 and the maximum volumetric blend of biodiesel with diesel is 10%. gTech assumes no provision of E85. Some members of the CFSC feel that these blending rates are too aggressive (in particular B10), while other members have noted that they do not reflect the fact that in several US markets, blends greater than E15 and B10 are already use.
- There is no constraint on the blending of hydrogenated renewable diesel (HDRD), or on the fraction of thermochemically derived renewable gasoline and diesel blended/co-produced with fossil gasoline and diesel. Many suppliers report limiting HDRD to 30% to 40% by volume, but in practice, the simulations of the CFS never results in HDRD consumption that approaches these potential limits.
- Feedstock quantities are constrained because they are outputs of other sectors: Agricultural feedstocks are produced by the agriculture sectors and fuel producers will compete with other uses for these commodities, which are produced from a finite amount of land. Ligno-cellulosic feedstocks (wood and grassy material) in gTech are agriculture residue and forestry residue and their supply is constrained by activity in the agriculture and forestry sectors. Because the model allows trade of all commodities, feedstocks or fuel production is not constrained to domestic production. Again, exporting low-carbon fuels or trading feedstocks do not generate CFS compliance credits in the model.

In the gaseous fuel stream:

- There is no constraint on the fraction of renewable natural gas that can be mixed with fossil natural gas, whether it be produced from landfills, anaerobic digestors, or thermochemically produced from crop and forestry residue.

- However, not all end-uses of the landfill gas and or anaerobic digestor production are included in the model. Specifically, landfill gas used to generate electricity currently does not produce credits in this analysis (though it does exist in the model), and the model does not represent the use of biogas from anaerobic digestors for onsite heat and/or power production.
- Renewable natural gas produced from landfills is limited by activity in the waste management sector (i.e. a function of how many landfills there are). Renewable natural gas produced from anaerobic digestors is limited by activity in the animals and dairy subsectors of agriculture (i.e. a function of how much manure is available). The model does not represent production from municipal or industrial wastewater treatment, nor does it represent the use of crop residues in anaerobic digestors (though these can be used for thermochemical production) or source separated organics, nor does it represent the co-digestion of crop residues or food wastes with manure.

In the solid fuel stream:

- We have limited the use of wood-based fuels to industrial applications where coal and coke are already used as fuel (rather than feedstock), primarily cement and lime kilns as well as mining and some manufacturing sectors. For simplicity, this fuel is represented as wood pellets, which have substantial substitutability with coal (we assume no technical limit) and offer the most flexibility for getting the model to "solve" (i.e. compliance can be achieved). Improved modelling of the CFS would also account for potentially lower-cost compliance actions such as wood chips and yet to be commercialized fuels such as torrefied pellets.

2.5.4. Alternative Fuel Vehicles

Plug-in electric vehicles (PEVs)

Both scenarios proposed for this analysis use the same cost assumption for PEVs, with differential adoption rates driven by different interpretations of potential federal policy support. The quantity of credits generated from electric vehicles is calculated assuming that all potential credits are claimed using the formulae supplied in Annex V of the CFS Proposed Regulatory Approach produced by Environment and Climate Change Canada.

The PEV cost assumptions affect the capital cost of all PEV technologies including light-duty vehicles, heavy-duty vehicles (represented archetypically as freight trucks) and buses. PEV cost assumptions are based on battery pack manufacturing costs. These are estimated at 419 $/kWh (2019 CAD) in 2015 based on Nykvist & Nilsson (2015).[9] Battery pack costs fall to 264 $/kWh in 2020 and 112 $/kWh (2019 CAD) by 2030 based on the expectations in Curry (2017) (Table 6)[10].

Table 6: Battery pack manufacturing cost assumptions (2019 CAD/kWh)

	2015	2020	2025	2030
2019 CAD/kWh	$419	$264	$164	$112

Battery manufacturing costs are only one component of total vehicle capital costs which include the cost of other components (e.g. vehicle glider, electronics, engine and transmission where applicable) and wholesale and retail markups (i.e. sales margins). Table 7 shows the light-duty vehicle retail price assumptions for PEVs and Table 8 and Table 9 show those prices for buses and heavy-duty vehicles. The development of vehicle prices as a function of battery pack manufacturing costs and the rational for technology archetype choices can be explained in more detail upon request.

Table 7: Light duty-vehicle archetype capital costs by drivetrain (based on sedan-sized vehicle) (2019 CAD)

	2015	2020	2025	2030
Conventional vehicle*	$27,283	$28,088	$28,756	$29,977
PEVs				
Plug-in hybrid (64km)	$46,487	$38,304	$36,312	$35,417
Battery Electric (320 km)	$52,667	$40,582	$35,712	$31,932

* Conventional vehicle costs rise due to drivetrain efficiency improvements and vehicle light-weighting: the trend shown is a composite several separate archetypes in the model

Table 8: Bus archetype capital costs (including recharge infrastructure (2019 CAD)

	2015	2020	2025	2030
Diesel bus (conventional)	$684,156	$684,156	$684,156	$684,156
Battery electric bus (250 km	$886,251	$762,584	$722,623	$698,908

9 Nykvist, B., Nilsson, M., (2015). Rapidly falling costs of battery packs for electric vehicles. Nature Climate Change, 5, 329-332

10 Curry, Claire (2017). Lithium-ion Battery Costs and Market, Bloomberg New Energy Finance.

Table 9: Heavy-duty-vehicle archetype capital costs (including recharge infrastructure) (based on long-haul freight truck) (2019 CAD)

	2015	2020	2025	2030
Diesel truck	$161,337	$161,337	$161,337	$161,337
Diesel truck, high efficiency	$176,874	$176,874	$176,874	$176,874
Electric truck (500km)	$837,171	$475,408	$356,301	$284,770

The number of compliance credits generated per PEV in use is a function of how much fuel the vehicle offsets. In the CFS, or other low-carbon fuel standard policies, this offset is codified in the "energy efficiency ratio" or EER. A higher EER indicates a more efficient PEV relative to a conventional vehicle and greater reduction in fossil fuel consumption through electrification.

gTech uses an EER of 4.1 for light-duty vehicles and 5.0 for buses and heavy-duty vehicles, based on the values produced by Navius, 2018[11] and consistent with the Proposed Regulatory Approach published by Environment and Climate Change Canada.

Natural gas-fuelled vehicles

gTech also includes natural gas fuelled vehicles, using a CNG bus and LNG freight truck archetype. Because our past analyses indicated that these technologies play a relatively small role in compliance with the CFS, we have not elaborated on these technologies here. Details can be provided upon request.

2.5.5. Upstream Compliance

The CFS may allow actions that reduce the GHG intensity of fossil fuel production to produce compliance credits (i.e. upstream compliance). This opportunity is represented with four abatement actions (Table 10). Upstream credit generation for the gaseous stream can occur from the electrification of natural gas extraction, gathering, and processing (i.e. using electric compressors rather than gas fired compressors to pressurize gas) and the capture and storage of formation CO_2 released during gas processing. Upstream credit generation in the liquid fuel stream can occur from carbon capture and storage used with hydrogen production and heat production. Note that in this analysis, co-processed biocrude, represented by proxy with renewable fuels produced from ligno-cellulosic materials, are counted as compliance with low-carbon fuel consumption.

[11] Navius Research (2018). Review of British Columbia's RLCFRR Energy Effectiveness Ratios. Available from: link.

Table 10: Assumed Upstream Compliance Opportunities and Abatement Costs (2019 CAD)

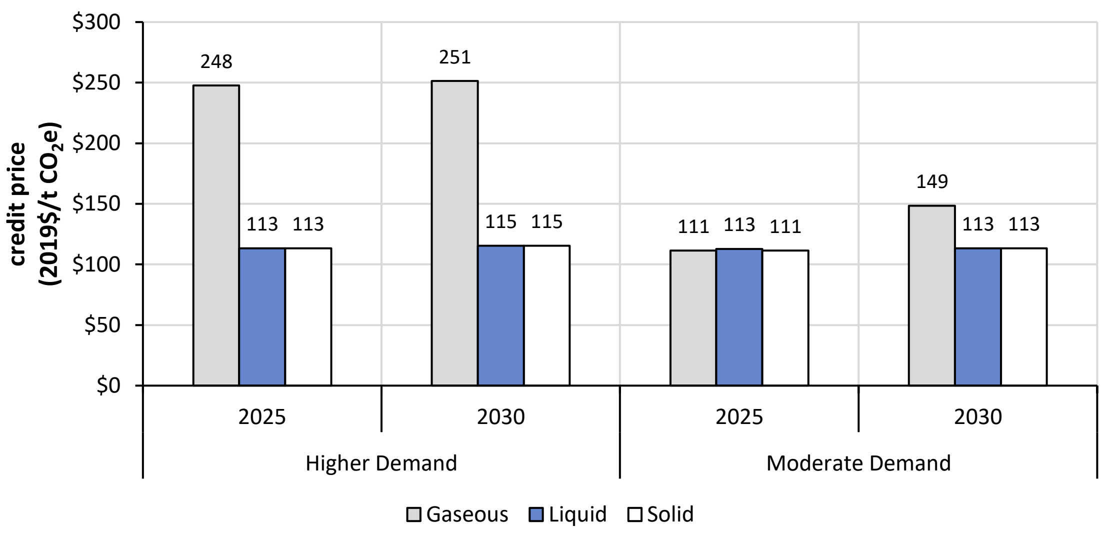
	Abatement Cost $/tCO_2e$	Notes
Carbon capture and storage of formation CO_2 in natural gas processing	149	
Electrification of natural gas production and processing	72 (in BC)	Varies by province due to electricity prices and carbon intensity.
Carbon capture and storage with hydrogen production at refineries and upgraders	102	
Carbon capture and storage with heat generation in the oilsands	335	

3. Results

3.1. The CFS market

The CFS creates three new markets for policy compliance credits in Canada, one for each fuel stream, with limited trade between them and unlimited trading within them. These markets operate like every other market: the compliance credit price will rise and fall until the supply for credits equals demand. Because of credit trading, credit prices in the liquid stream and the solid fuel stream equalize in both scenarios. In the both scenarios, the credit price for the liquid and solid fuel streams is in the range of 110 to 115\$/tCO_2e (2019 CAD) in both 2025 and 2030 (Figure 1). The gaseous stream has the highest compliance costs and consequently has the higher credit prices, which are relatively constant at roughly 250 \$/tCO_2e in the high demand scenario, a result of the very stringent carbon intensity target. Lower credit prices result with a less ambitious carbon intensity target, rising to 149 \$/tCO_2e by 2030 (moderate demand, Figure 1).

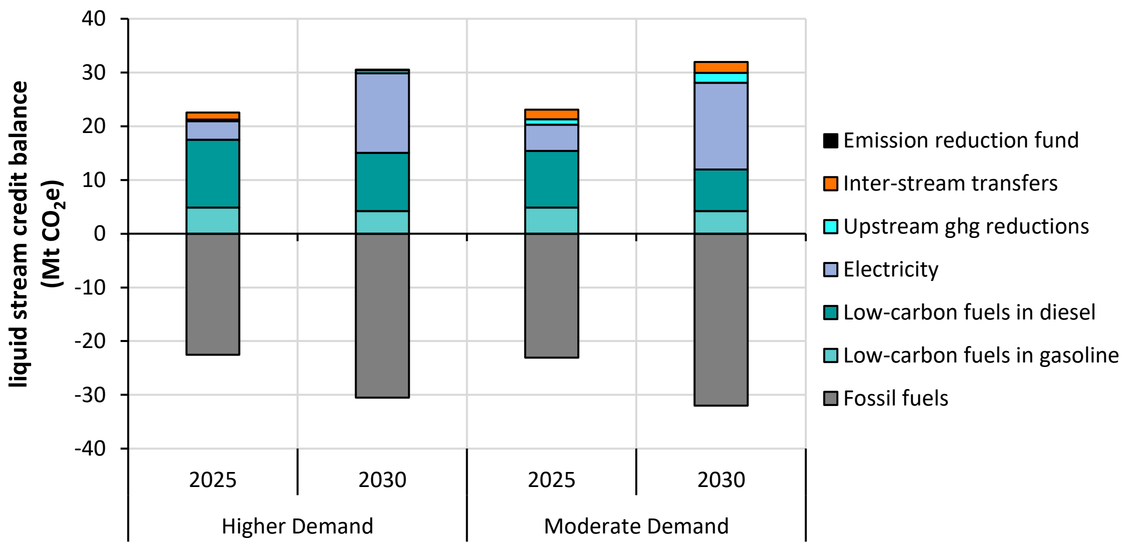
Figure 1: CFS compliance credit price by fuel stream, scenario, and year (2019 CAD)



Demand for credits is a function of the quantity of fuels consumed that have carbon intensities above the target in a given year (e.g. the negative bars resulting from fossil fuel consumption in the liquid pool in Figure 2). gTech forecasts how this demand for credits is supplied (i.e. what are the positive bars in Figure 2 comprised of?). This simulated result is based on the characterization of the CFS and other GHG policies and the compliance actions described in the previous section. As well, demand for credits in one fuel stream will increase if those credits are being sold into another fuel stream (i.e. with credit trading inside the 10% compliance limit).

Total demand for credits in the liquid fuel stream rises to roughly 22 $MtCO_2e$/yr in 2025 and 32 $MtCO_2e$/yr in 2030 in both scenarios (the negative bars in Figure 2). Most of this demand for credits results from gasoline and diesel consumption, though fuel oil and jet fuel contribute to demand as well (roughly 10% of total credit demand). The liquid fuel stream is a net buyer of credits from the solid fuel stream, so credit sales do not increase the demand for compliance credit generation in that stream (Figure 2). Total energy consumption covered by the liquid fuel stream is in Appendix B.

Figure 2: CFS liquid stream compliance credit balance by scenario and year



The supply of compliance credits comes from electric vehicles and the use of low-carbon fuels in gasoline, primarily ethanol, and in diesel, primarily biodiesel, HDRD (the positive bars in Figure 2). Electric vehicles provide a significant proportion of the liquid fuel stream credits in both scenarios by 2030, if all electricity supplied to PEVs is accounted for and claimed for credit generation. Electricity credits account for 50% of compliance in the moderate demand scenario, helped along by support for light-duty PEV sales from the British Columbian and Québec zero-emissions vehicle sales requirements. Without these policies, electricity accounts for a slightly smaller share of credit generation in 2030, at 49%. The impact of the ZEV sales requirement on the quantity of CFS credits produced from electricity is muted for two reasons. First, British Columbia and Quebec have growing PEV sales, even without the ZEV sales requirement, albeit with sales growing at a slower rate. Second, only half of the electrification credits come from light-duty passenger vehicles, while the remainder come from the electrification of buses and medium and heavy-duty vehicles. Sales of these vehicles are unaffected by the outcome of the two ZEV sales policies.

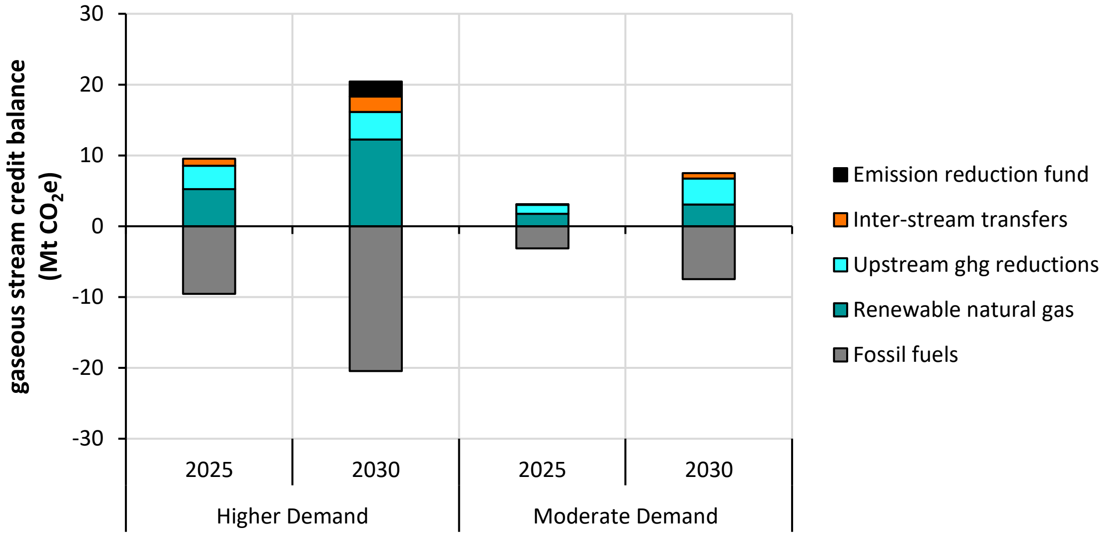
Credit generation from ethanol consumption accounts for roughly 21% of credits in 2025, falling to 14% of credits by 2030 (4.9 $MtCO_2e$/yr in 2025, 4.2 $MtCO_2e$/yr in 2030) (Figure 2). The declining contribution of ethanol to overall compliance is a function of the policies and assumptions used in this analysis: Gasoline demand declines (due to electrification and vehicle tailpipe emissions standards), but ethanol can not be consumed it greater quantities (fixed at 15% by volume) or with a lower carbon intensity (roughly 45 gCO_2e/MJ in 2020, falling by 1.25%/yr to 2030).

Credit generation from biodiesel and HDRD consumption accounts for roughly 45-55% of credits in 2025, falling to 20-30% of credits by 2030 (absolute credit generation falls from 11-13 $MtCO_2e$/yr in 2025 to 8-11 $MtCO_2e$/yr in 2030, Figure 2). The amount of compliance required from these two diesel substitutes is limited by the electrification of transportation. Without the ZEV sales requirements, there is ultimately more HDRD and biodiesel demand.

Neither scenario requires "second generation" fuels or biocrudes produced from ligno-cellulosic materials and/or fuels that are fully fungible with fossil gasoline or diesel. While this analysis did not include pyrolysis oil as a substitute for fuels oil or "biojet" as a substitute for aviation turbo fuel, by analogy, these would not have been required for compliance either.

Total credit demand and supply in the gaseous fuel stream is very different in each scenario, the result of the substantial difference in carbon intensity targets. In the higher demand scenario, most compliance in 2025 and 2030 comes from RNG consumption: 55% of the total in 2025 and 60% in 2030, 5.2 and 12.2 $MtCO_2e$/yr, respectively. In that same scenario, the gaseous fuel stream uses the maximum amount of credits available from the emissions reduction fund and inter-stream trading (10% each by 2030) (Figure 3). Upstream abatement is also important in this scenario, providing an additional 3 to 4 $MtCO_2e$/yr in 2025 to 2030 (the remaining 20% of compliance in 2030). Total energy consumption covered by the gaseous fuel stream is in Appendix B.

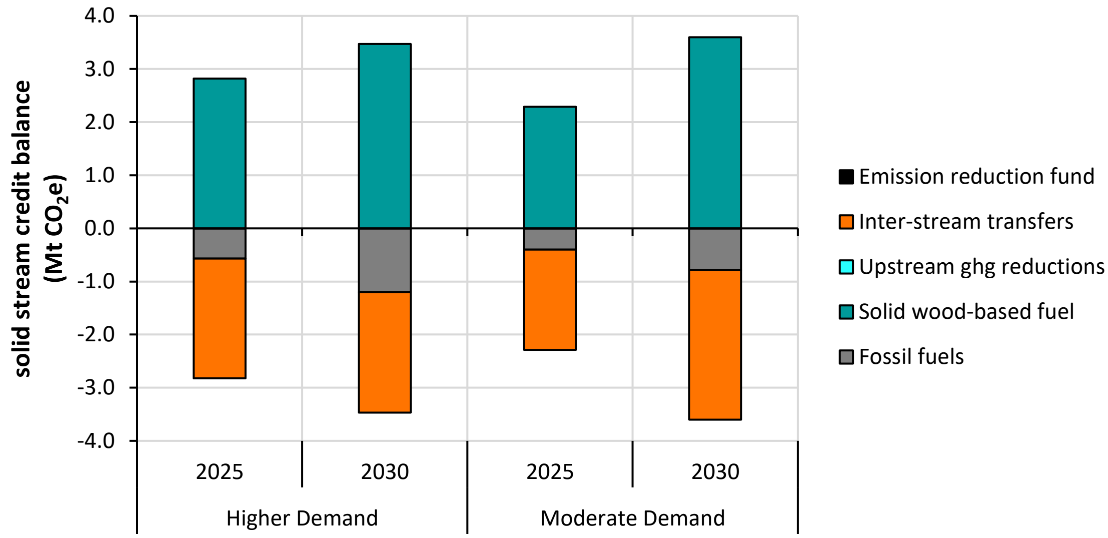
Figure 3: CFS gaseous stream compliance credit balance by scenario and year



In contrast, with a lower carbon intensity target in the gaseous pool (moderate demand scenario), RNG consumption accounts for a much smaller absolute quantity of credits (1.7 $MtCO_2e$/yr rising to 3.1 $MtCO_2e$/yr) (Figure 3, moderate demand). Upstream abatement, much of which will be required by announced policies in British Columbia, accounts for the remainder. 100% of the compliance from RNG consumption in 2025 is the result of the British Columbian and Québec blending mandates. In 2030, that value falls to 83%, with the CFS resulting in some additional renewable natural consumption elsewhere in Canada.

The demand for credits in the solid fuel stream (total of the negative bars in Figure 4) is largely driven credit sales to other streams rather than the requirement to reduce the carbon intensity of solid fuels. The proportional impact of credit sales to other streams is large for the solid fuel stream because the energy covered in this pool is small compared to the other streams. For example, in the higher demand scenario, 10% of compliance in the gaseous fuel stream is purchased from the solid fuel stream in 2025, where that 10% is equivalent to 170% of other credit demand related to solid fossil fuel consumption (Figure 4). In 2025, credit transfer to the liquid and gaseous streams quintuple the net-demand for credits in the solid stream, which is satisfied by increasing the quantity of solid wood-based fuels used. Recall that the solid fuel stream is small because it excludes most solid fuel consumption in Canada, that being coal in regulated power plants, “own” use by the forest products sectors, and coke in the steel smelting sector. The fuel stream primarily affects cement and lime production, which accounts for most solid fuel consumption covered by the CFS in this analysis, as well as a handful of manufacturing and metals sectors. Total energy consumption covered by the solid fuel stream is in Appendix B.

Figure 4: CFS solid stream compliance credit balance by scenario and year (note the different scale of the vertical axis)



3.2. Impact on Average Carbon Intensity

The impact of each compliance action on the carbon intensity of the fuel streams is proportional to credit generation. Consequently, most credit generation in the liquid fuel pool in both scenarios comes from electricity consumption, with important contributions from renewable fuels: ethanol, biodiesel and HDRD (Figure 5). In the gaseous fuel pool, RNG consumption has the greatest impact when the carbon intensity target is higher (higher demand, Figure 6), while the combined impact of credit purchases from other streams and upstream abatement accounts for most of the carbon intensity reduction when the target is lower (moderate demand, Figure 6). In the solid fuel pool, the carbon intensity reduction comes entirely from increased consumption of wood fuels, which could include chips, pellets and torrefied pellets (both scenarios, Figure 7). However, physical compliance and the actual carbon intensity reduction in that fuel pool (i.e. not adjusted for credit sales) can be much larger as result of credit sales to other fuels streams.

Figure 5: Liquid stream carbon intensity change, by action, scenario and year

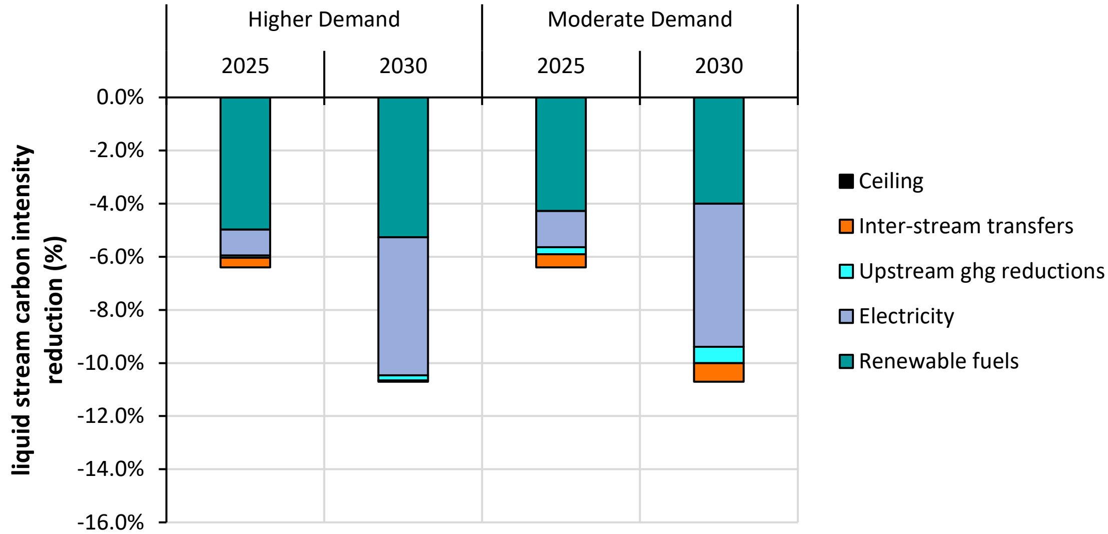


Figure 6: Gaseous stream carbon intensity change, by action, scenario and year

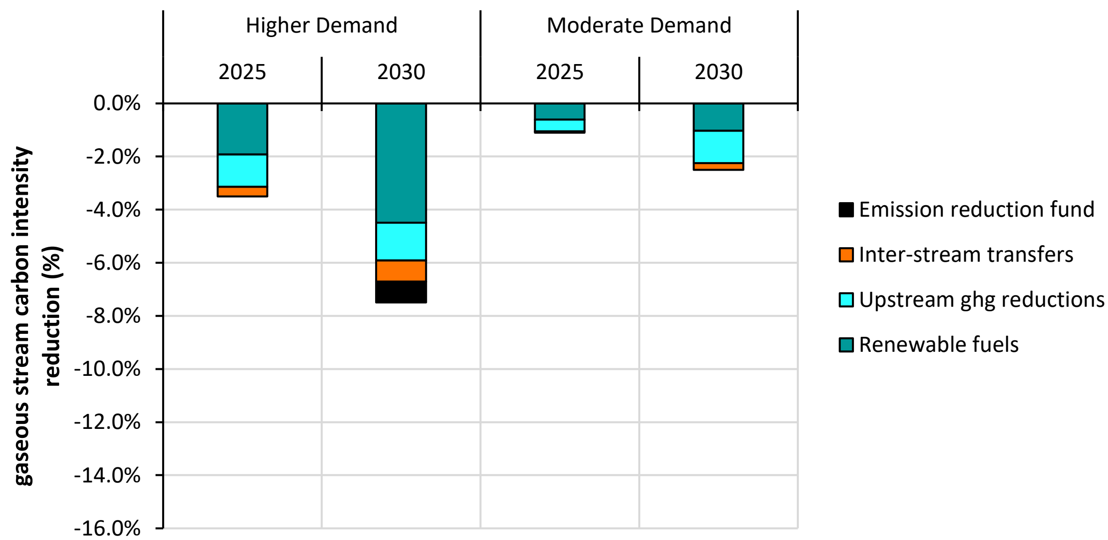
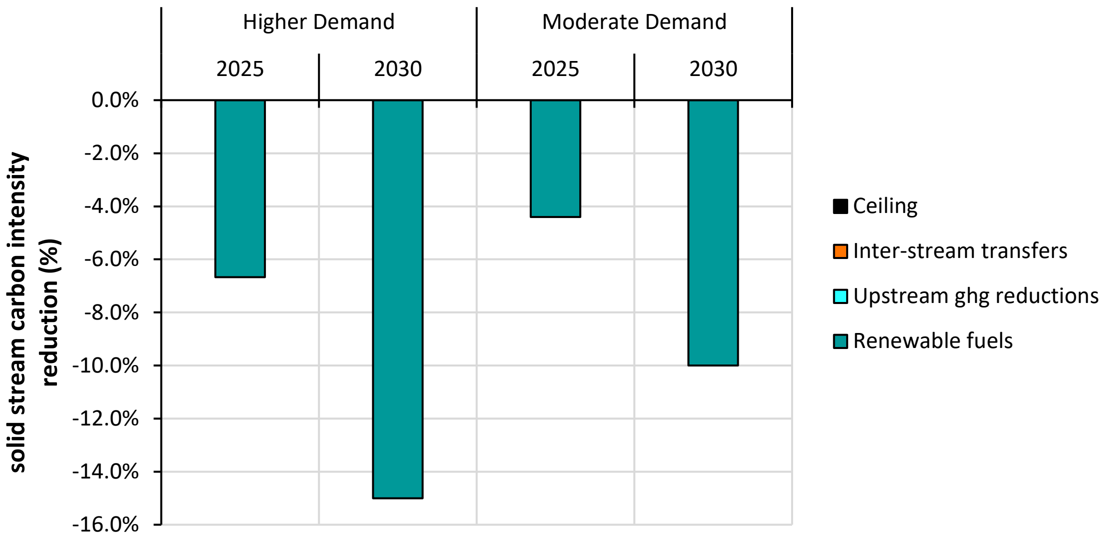


Figure 7: Solid stream carbon intensity change, by action, scenario and year

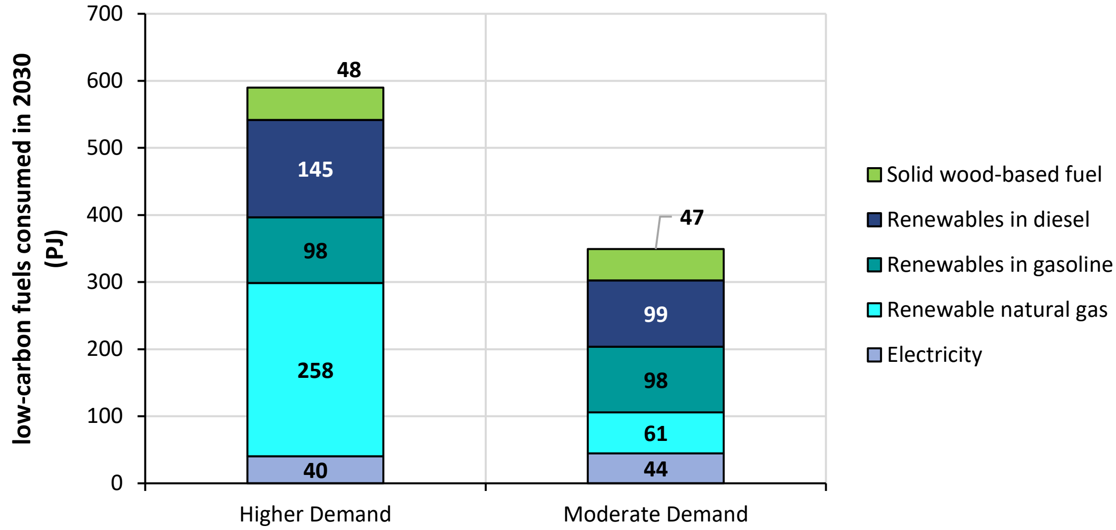


3.3. Low-Carbon Fuel Consumption and Electric Vehicle Adoption

3.3.1. Summary of Low-Carbon Fuel Demand

By 2030, total low-carbon fuel demand, including electricity used in vehicles, ranges between 349 and 589 PJ/yr (Figure 8). The variation in the total is mainly due to strength of carbon intensity target used in gaseous stream, with some additional variation resulting from the strength of the target used in the solid stream. Total RNG consumption ranges from 61 to 258 PJ/yr, while total consumption of wood-based fuel ranges from 47 to 48 PJ/yr. In the liquid fuel stream, electricity consumption ranges from 40-45 PJ/yr in 2030, while ethanol consumption (renewables in gasoline) is 98 PJ/yr, and biodiesel and HDRD consumption combined (renewables in diesel) ranges from 99-145 PJ/yr.

Figure 8: Low-carbon fuel consumption in 2030

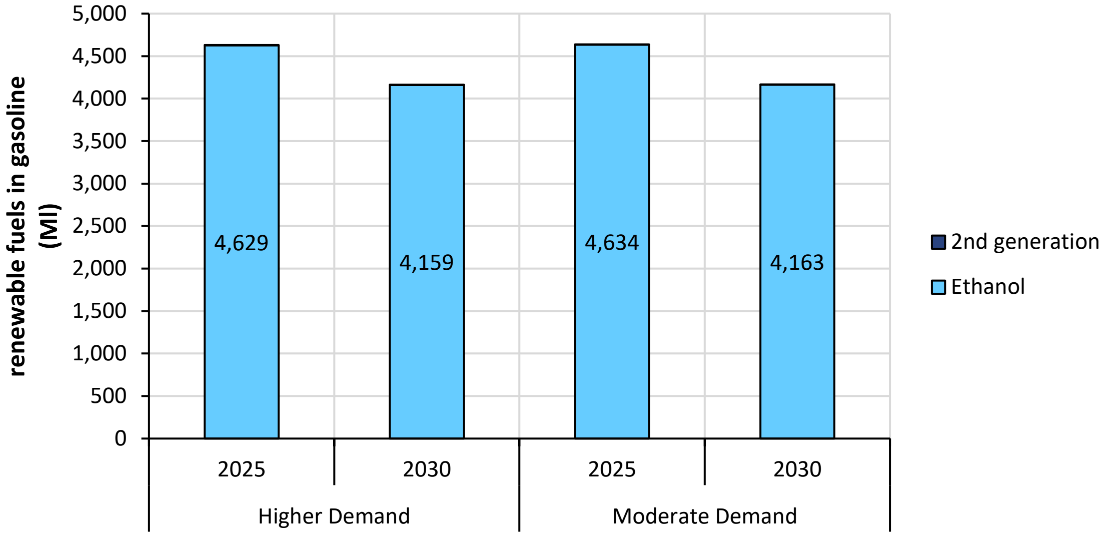


3.3.2. Liquid Fuel Stream

Compliance in the liquid fuel stream comes from ethanol consumption, biodiesel and HDRD consumption, and the adoption of electric vehicles. The results show that while the demand for liquid low-carbon fuels will likely be greater than it is presently, that demand could decline between 2025 and 2030 as the quantity of compliance from electric vehicles grows.

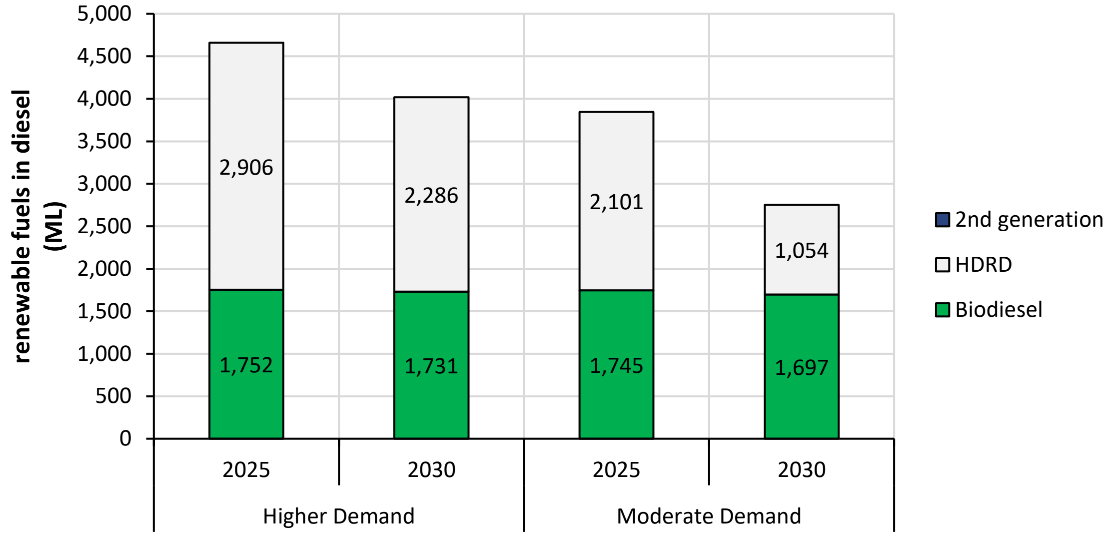
In 2025 and 2030, ethanol accounts for between 14% and 15% of the volume of gasoline consumed, regardless of the final CFS design represented in this analysis. However, because the total amount of gasoline is declining, as a result of electrification and tailpipe emissions standards, the total quantity of ethanol declines from roughly 4,600 million L/yr in 2025 to roughly 4,200 million L/yr in 2030 (Figure 9). More than 99.9% of the ethanol used is produced from grain, and the CFS does not incentivize any production of renewable gasoline or biocrude from ligno-cellulosic (wood or grassy) materials.

Figure 9: Consumption of renewable fuels in gasoline



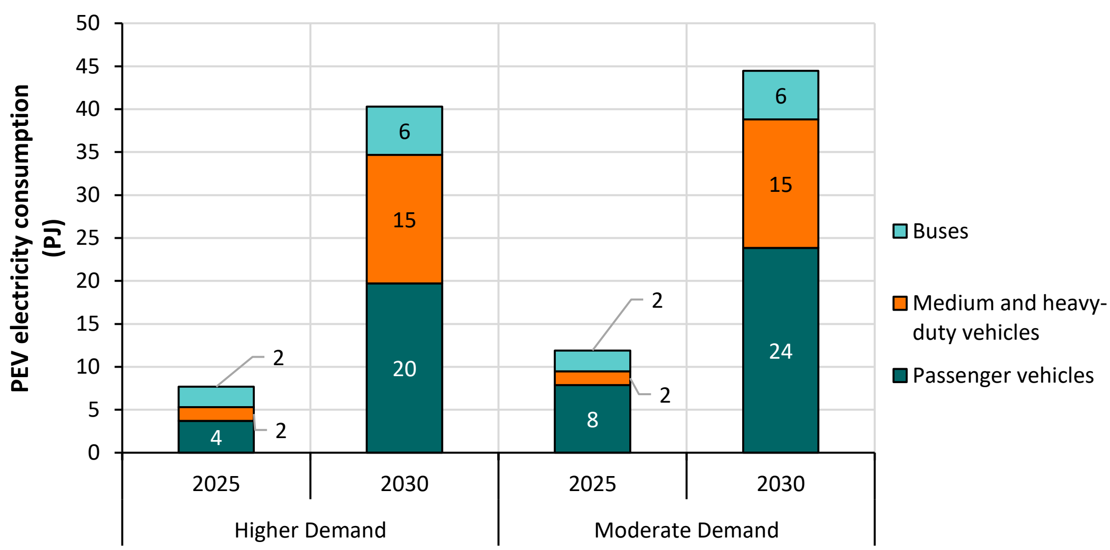
Like ethanol, the share of renewable fuels in diesel is not sensitive to the design of the CFS in this analysis, though it is sensitive to the quantity of credits generated from electricity consumption. For example, in both scenarios the total volume of renewable fuels in diesel and the percent volume decline from 2025 to 2030 as the number of electric vehicles on the road increases (Figure 10). Similarly, there is more renewable fuel blended with diesel in the higher demand scenario where the two ZEV sales requirements are not implemented. In that case (the higher demand scenario), renewable fuels account for 11% of the volume of diesel in 2025, falling to 10% in 2030 (Roughly 1,700 million L/yr biodiesel and 2,900 L/yr HDRD in 2025, with the volume of HDRD falling to roughly 2,300 million L/yr in 2030). In contrast, these fuels only account for 7% to of blended diesel volume in the moderate demand scenario (1,700 million L/yr biodiesel and 1,000 to 2,100 million L/yr HDRD) (Figure 10). As with renewable fuels in gasoline, the CFS does not result in any consumption of renewable diesel or biocrude produced from ligno-cellulosic feedstocks.

Figure 10: Consumption of renewable fuels in diesel



Approximately half of the required carbon intensity reduction in the liquid fuel stream comes from the electrification of vehicles. The amount of compliance, by vehicle type (e.g. passenger vs. buses), is approximately proportional to the amount of electricity consumed by each vehicle type. Therefore, in 2030, between 49% and 54% of the compliance from electricity comes from passenger vehicles (~20-24 PJ/yr), with the larger quantity corresponding to the moderate demand scenario that includes the ZEV sales requirements. Approximately another 15% of the electricity consumed for transportation comes from buses (~6 PJ/yr), and the final 35% comes from medium and heavy-duty vehicles (~15 PJ/yr) (Figure 11).

Figure 11: Electricity consumption by vehicle type

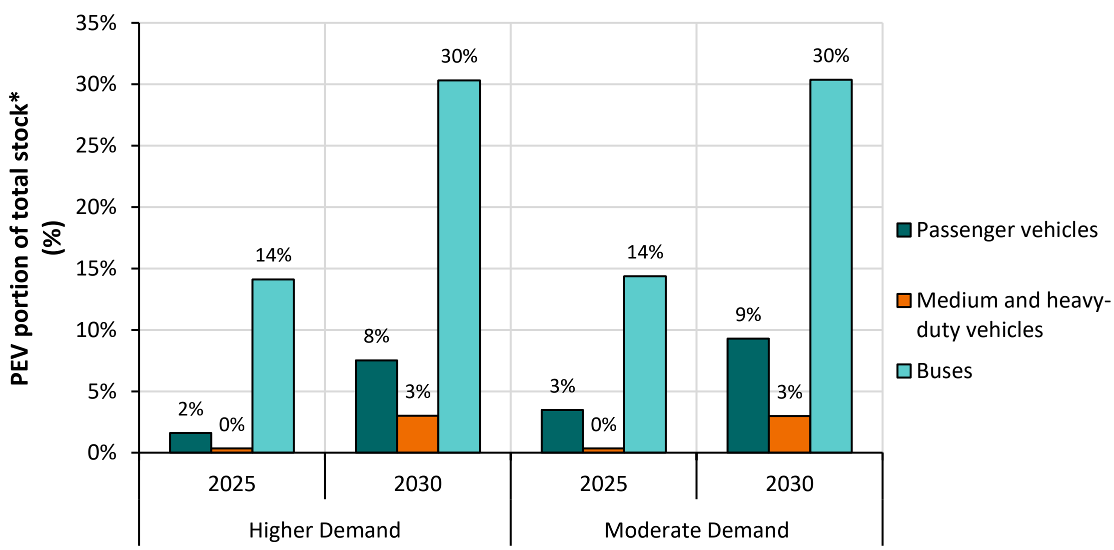


Recall, that this electricity consumption is a simulated result that is a function of how archetypal electric vehicles are represented in the model (e.g. costs, energy consumption, vehicles lifetime and stock turnover rates) and what policies they interact with. Total vehicle electricity demand in 2030 comes from:

- Roughly 2.1 to 2.6 million electric passenger vehicles on the road, or 8-10% of all passenger vehicles. In the moderate demand scenario, which includes the the ZEV sales requirements, this share of total stock requires new electric vehicles sales to account for 19% of total sales by 2030, where minimum sales requirements in British Columbia and Québec are 30% and 22% respectively in that year. New sales in the rest of Canada only need to reach 13% to 14% in 2030.
- Roughly 42 thousand electric buses on the road, or 30% of all buses, requiring electric bus sales to account for 80-90% of total sales by 2030.
- Roughly 300,000 thousand medium and heavy-duty vehicles on the road, or 3% of the total (as measured by energy consumption) (Figure 12), where sales must reach roughly 8% by 2030.

This forecast of electric vehicle adoption is uncertain. To the extent that it is optimistic, for example where light-duty electric vehicles sales grow substantially, even without the ZEV sales requirements, additional compliance in the liquid stream would likely come from increased biodiesel and HDRD consumption, or by using a similar amount of ethanol from lower-carbon sources (i.e. lower than we have assumed here at roughly 45 gCO_2e/MJ for corn and wheat derived ethanol in 2020, declining at 1.25%/yr to 2030).

Figure 12: Electric vehicle share of vehicles on the road, by vehicle type



*portion is for respective vehicle category. E.g., 2 to 3% of all passenger vehicles (not all vehicles) are PEVs in 2025

3.3.3. Gaseous Fuel Stream

As noted earlier, the quantity and fuel share of RNG is sensitive to the stringency of the carbon intensity target. With a lower target, such as -2.5% by 2030 (moderate demand scenario), a significant amount of compliance can come from upstream abatement and credit transfers from other fuel streams. The resulting RNG fuel share will be just 1.3% (61 PJ/yr) (moderate demand, Figure 13 and Figure 14). RNG consumption in this case will be largely concentrated in the provinces with RNG blending requirements. A stronger carbon intensity reduction target of -7.5% in 2030, combined with less upstream abatement, will bring the RNG fuel share closer to the carbon intensity reduction target: 2.6% in 2025 and 6.0% in 2030 (105 PJ/yr and 258 PJ/yr respectively, higher demand scenario in Figure 13, Figure 14).

Most of the RNG consumed in this forecast comes from “second generation” sources, namely thermochemical production from ligno-cellulosic material (i.e. woody or grassy material like forest harvest residue and crop residue). These could also include power to gas where electricity prices or technological developments allow economical production. The minority of the RNG comes from more conventional sources, such as anaerobic digestors or landfill gas collection.

This result is uncertain. First, thermochemical production of gas is not yet commercialized, so it may be impossible to produce the quantities shown in the forecast by 2025. In that case, gas would have to come from conventional sources. To the extent that these are available at roughly 19 $/GJ (2019 CAD), this uncertainty would not change the rest of the modelling.

Further uncertainty comes from the quantity of “conventional” RNG being produced, which could likely be larger. The results are only showing about 60% of the technical potential available in the model, where that potential relates to the size of the animal production and waste management sector. In other words, the economic output of those sectors is related to the quantity of feedstock available for RNG production, whether that is animal manure or waste in place within landfills. In this analysis, heterogeneous costs (i.e. we assume capital costs exists on a distribution around the value input into the model) and the rate of capital stock additions in the model are preventing actual production from reaching the technical potential. Furthermore, the model does not represent all possible sources of RNG produced from anaerobic digestion or decomposition: it does not represent production from wastewater treatment, source separated organics, or production from crop residues (this material all feeds into thermochemical RNG production in the model). If these were represented in the model, the “conventional” RNG production could very well be twice as large.

Again, to the extent that these are available at roughly 19 $/GJ (2019 CAD), including them would not change the results.

Figure 13: Renewable natural gas consumption

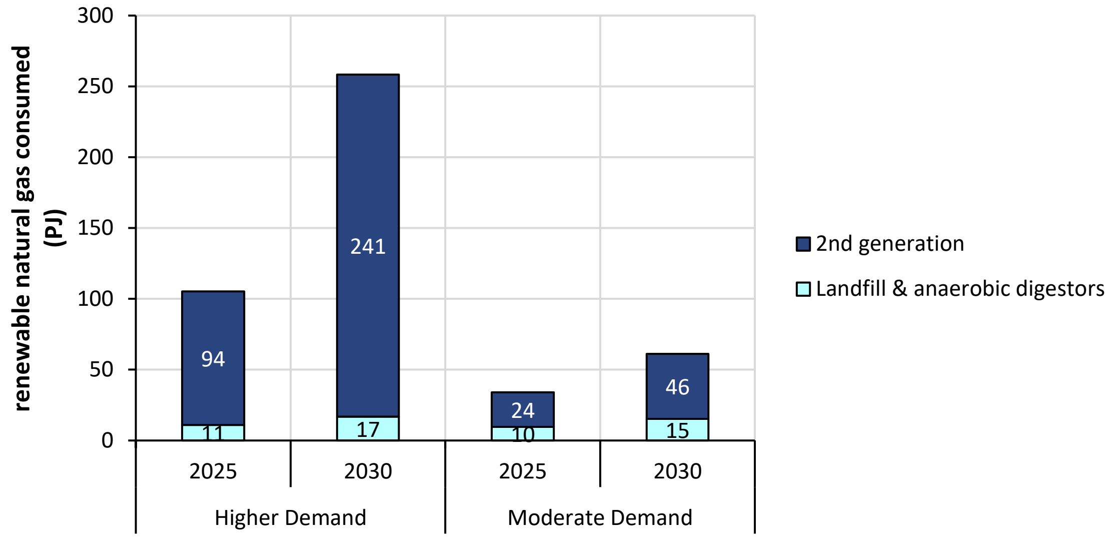
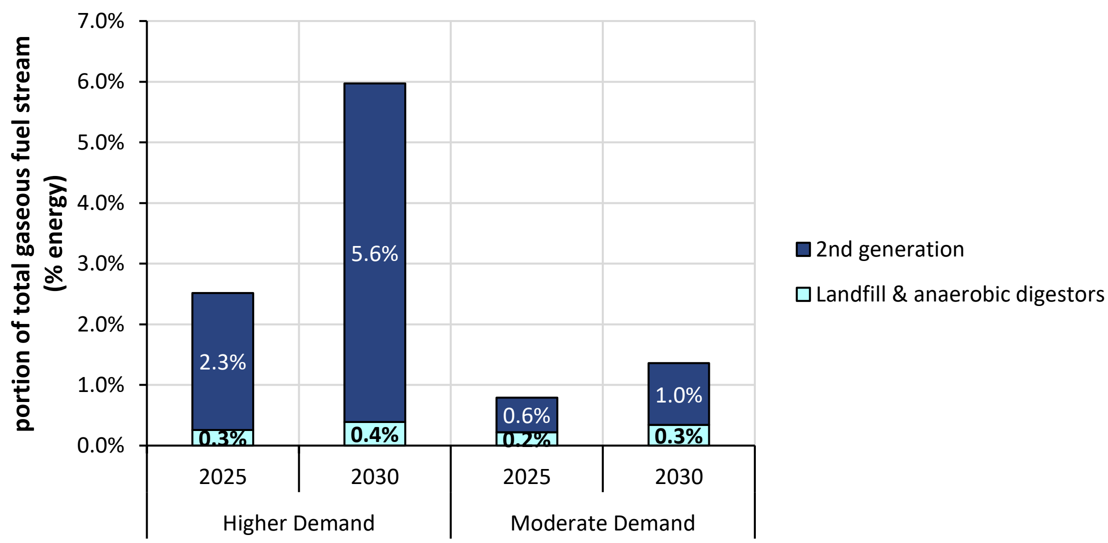


Figure 14: Renewable natural gas fuel share (% of total natural gas)



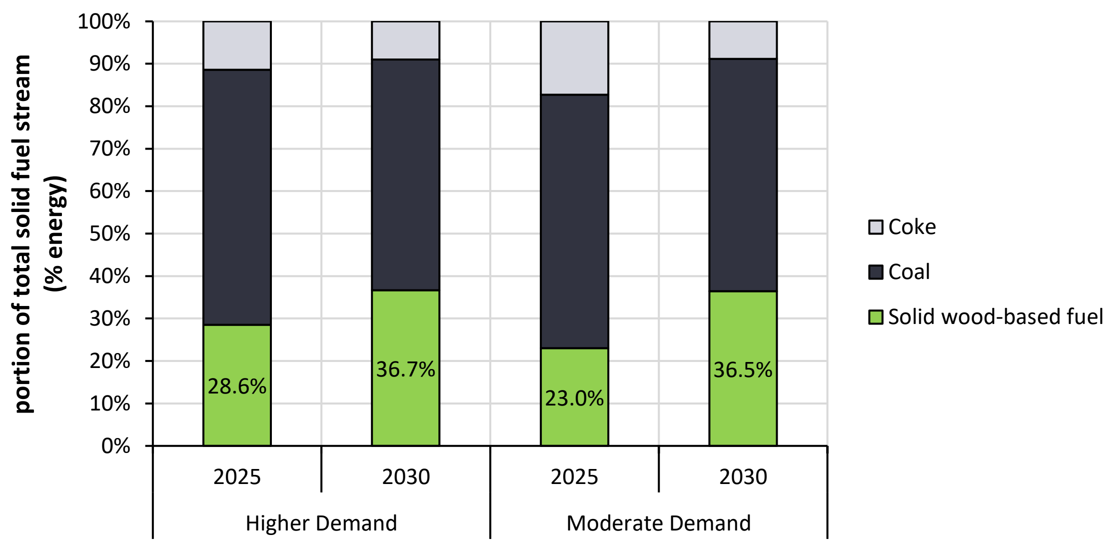
3.3.4. Solid Fuel Stream

Solid wood-based fuel consumption covered by the CFS ranges from 28-48 PJ/yr, equivalent to 1.5 and 2.7 million oven dry tonnes of wood consumption per year (assuming 18 GJ/oven dry tonne). For context, Canada exported 2.6 million tonnes of wood pellets in 2018,[12] so the wood consumption used for compliance under the CFS in this analysis is equivalent to 60% to 1007% of current export production.

In 2030, this wood fuel consumption accounts for between 37% of the covered solid fuels (by energy) in the higher demand scenario (Figure 15). With a lower carbon intensity reduction target, as is used in the moderate demand scenario, the wood fuel share ranges from roughly 23% (2025) to 37% (2030) (moderate demand, Figure 15). Cement and lime kilns can generally handle up to 20% chipped wood-waste in their fuel mix. Therefore, these results indicate that a more substitutable form of wood fuel such as pellets or torrefied pellets may be demanded in response to the CFS.

Recall that absolute quantity of wood consumed and its share in the solid fuel pool is quite sensitive to credits sales to the other fuel streams; the results show that these can increase the quantity of wood consumption that occurs in response to the CFS by a factor of 3 to 6, depending on the year and final design of the CFS. Therefore, the forecasted consumption of wood fuel is largely satisfying a demand for credits from the gaseous and liquid fuel streams rather than the requirement to reduce the carbon intensity of the solid fuel stream.

Figure 15: Solid stream fuel share (% of solid fuels covered by the CFS)



[12] Statistics Canada, Table 980-0044, 440131 Wood pellets, agglomerated

4. Discussion

Below we discuss some of the key conclusions based on the analysis, organized by fuel stream. This is followed by a discussion of the limitations of this study.

4.1. Conclusions

Liquid stream:

- Electrification of transportation will be a significant compliance action in the liquid fuel stream. While this outcome may be supported by minimum ZEV sales requirements for light-duty vehicle in British Columbia and Québec, roughly half of the credit generation is associated with the adoption of electric buses and other medium and heavy-duty electric vehicles. Relatively modest rates of vehicle electrification result in approximately half of compliance credits being generated by electric vehicles in 2030. This would correspond with roughly 8 to 9% of light-duty passenger vehicles on the road being electric, with 30% of all buses being electric, and 3% of medium and heavy-duty vehicles being electric. Total electricity demand from on-road vehicles in 2030 would be between 40 and 44 PJ/yr, with greater electricity demand corresponding with the success of the British Columbian and Québec ZEV sales requirements. Note that electric buses and medium and heavy-duty vehicles were not included among the electric vehicles generating credits in the forecast created by Environment and Climate Change Canada. This difference accounts for much of the discrepancy between that forecast and the one described in this analysis.

- The quantity of compliance credits generated by electricity consumption may be optimistic, especially if the ZEV sales requirements do not endure (as assumed in the higher demand scenario). For example, without the ZEV sales policies, the quantity and variety of electric vehicles available for sale may not be large enough to support the demand shown in the forecast. In this case, it is most likely that compliance would be achieved with more blending of more HDRD and biofuel with diesel. For example, biofuel blending rates in this forecast peak at roughly 4% by volume, less than the 10% allowed in this analysis.

- Although demand for biofuels such as ethanol, biodiesel and HDRD will be larger than they are today, the CFS will not significantly grow the demand for these fuels between 2025 and 2030, nor is it likely to create an incentive to use more fungible liquid fuels (beyond HDRD) or fuels derived from ligno-cellulosic feedstocks. Ethanol will account for 14% to 15% of gasoline by volume in 2030, with Canadian consumption around 4,500 million L/yr. The share of biodiesel will grow to roughly 4% by volume, equivalent to roughly 1,700 million L/yr in 2030. The share of HDR will be sensitive to the quantity of compliance achieved with electricity. When the total stock of electric vehicles is lower (e.g. in 2025 without ZEV sales requirements), HDRD demand could be as a high as 2,900 million L/yr. However, demand could be as low as 1,000 million L/yr in 2030 once the stock of electric vehicles grows, with the added support of the ZEV sales requirements.

Gaseous stream:

- If the gaseous stream carbon intensity target is set to reduce emissions by approximately 7 $MtCO_2e$ GHG in 2030 (as measured by compliance credit generation, corresponding to a 2.5% carbon intensity reduction by 2030), it will almost entirely overlap with announced provincial policies including the British Columbian and Québec RNG standards and the British Columbian policies aimed at reducing upstream emissions in the natural gas sector. The RNG fuel share will be relatively low, on the order of 1% of total natural gas consumption. In this case, RNG demand in 2030 would be approximately 61 PJ/yr.
- Alternatively, it would take a greater reduction in the average carbon intensity of the gaseous pool to result in an RNG fuel share in the range of 5-10%, the aspirational target envisaged by the Canadian Gas Association. In this situation, RNG demand in 2030 would be over 250 PJ/yr.
- The results show that most RNG will come from thermochemical conversion of forestry and crop residue into natural gas, but this result is to some extent a result of model limitations. For example, not all sources of RNG production from anaerobic digestion are represented in the model. Notably crop residues can only be used for thermochemical production and not anaerobic production. If this pathway were in the model and if thermochemical production is not commercialized at the production cost assumed in this analysis, then there would be more production of RNG with anaerobic digestion. In short, the sources of RNG supply are uncertain and multiple pathways, including anaerobic digestion, power to gas, and thermochemical conversion, could be used. Insofar as more RNG is available at approximately $19/GJ (the production cost of thermochemically produced RNG in the model), it would not change the results. If greater supply is available at less than this price, the gaseous stream credit price would be reduced. If RNG supply is available at a higher price, then it would increase the credit price. Because of limits on inter-stream credit trading and access to the emissions reduction fund, different RNG supply costs would not otherwise change the forecasts.

Solid stream:

- By 2030, solid fuel consumption under the CFS could range from 47 to 48 PJ/yr, equivalent to 2.6 million oven dry tonnes of wood (roughly the same size of wood pellet exports in 2018).
- The solid stream could very well be a net supplier of credits to the other fuel streams. This analysis considered the use of wood pellets. While this wood-based fuel is easier to substitute for coal or other solid fuels, it is more costly that using wood chips. If chips were included in the model, it would allow some lower cost use of wood fuel, but it would not materially change the results which are constrained by limits on inter-stream credit trading.
- The quantity of low-carbon fuel used in the solid stream is very sensitive to the purchase of solid stream credits for compliance in other fuel streams. The solid fuel stream is small compared to the other fuel streams, in terms of energy covered by the CFS. If 10% of compliance in those larger fuel streams is purchased from the solid fuel stream, demand for wood fuel in 2030 will be three to five times larger than what would occur if the CFS did not allow inter-stream trading.

4.2. Limitations and Uncertainties

There are many uncertainties and limitations of this analysis that could not be addressed within the scope of this project. Below we describe the likely impacts of addressing these uncertainties and limitations, including:

- **The impact of alternative RNG production costs and carbon intensity values**. RNG could be more costly than shown in this analysis and may have a higher lifecycle carbon intensity. Given the constraints of the CFS (e.g. limitations on inter-stream trading and access to the emissions reduction fund), this uncertainty would mainly affect the gaseous stream credit price, making it higher than shown in this analysis. The quantity of RNG demand would be largely unaffected, because it is defined but the CFS carbon intensity reduction requirement and the availability of other compliance actions (e.g. inter-stream credit purchases).
- **The impact of including hydrogen fuel-cell or combustion vehicles**. While these were not included in this analysis, we regularly monitor the cost and availability of hydrogen fuelled vehicles. At present, we are confident that including these technologies in the analysis would have a negligible impact on the action of the CFS from now to 2030.
- **The impact of lower EERs for electric vehicles or more pessimistic assumptions for electric vehicles adoption (e.g. costs, consumer aversion to new technology, lack of**

supply). Any assumption that reduces the rate of adoption of electric vehicles or reduces the quantity of compliance credits they generate would likely result in greater consumption of renewable fuels blended with diesel.

- **The impact of excluding the octane value of ethanol.** The octane value reduces the compliance cost of using ethanol. Significantly reducing or excluding the octane value would result in roughly half as much ethanol consumption, with the difference in compliance being made up by greater use of renewables fuels in diesel.
- **The impact of more restrictive blending constraints on biodiesel.** We assumed that biodiesel could be blended at a rate of 10% by volume. However, some stakeholders feel that this quantity is too high, noting that 5% is currently the upper limit the annual average blend rate for biodiesel in Canada (though not in some US jurisdictions). In practice, this assumption did not affect the results. However, it would become more important if there we less adoption of electric vehicles and if the net-cost of ethanol were higher due to a lower value for octane. In this case, the liquid stream credit price would rise, inducing greater HDRD consumption and possibly some consumption of biocrude or other ligno-cellulosic fuels by 2030.
- **The impact of including more types of wood fuel or a greater variety of end-uses where wood fuel can be consumed.** Adding these details would likely reduce compliance cost in the solid fuel pool. However, demand for wood fuel is mostly determined by credit sales to other streams and the solid fuel stream already has the lowest compliance cost and sells the maximum amount of credits to other fuel streams. Consequently, adding lower cost wood fuel or other end-uses for wood fuel would not change the quantity of solid wood fuel demanded.

Appendix A: Detailed Bio-Energy Cost Assumptions

Summary

Table 11 contains $/GJ and $/L production costs for liquid fuels, based on the inputs to gTech. The capital cost in these levelized production is calculated using a 15% annuity (i.e. a 15% discount rate with 30-year project life). Operating costs include labour, natural gas, electricity, maintenance and operation costs. Table 12 shows that information for renewable natural gas. These costs are example based on gTEch inputs, priced in 2010 Canadian Dollars (the currency year used in gTech); they are not necessarily the costs that result in the forecast for 2010 or any other year.

Feedstock and co-product costs are calculated using the commodity prices in the table, but the price may vary within a gTech forecast. Feedstock quantities are constrained because they are outputs of other sectors: Agricultural feedstocks are produced by the agriculture sectors and fuel producers will compete with other uses for these commodities, which are produced from a finite amount of land. Ligno-cellulosic feedstocks (wood and grassy material) in gTech are agriculture residue and forestry residue and their supply is constrained by activity in the agriculture and forestry sectors. Note that the renewable gasoline and diesel fuel archetypes serve as a placeholder for thermochemical conversion of biomass to fuels, either in standalone processes or through the co-production of gasoline and diesel from crude and biocrude.

Table 13 through Table 17 in the "Detailed Inputs" section provide more detail on the assumptions and sources behind the production costs in Table 11. Further detail on the production cost assumption for renewable natural gas from ligno-cellulosic feedstock is provided in the final section of the appendix. Reviewers of our work often feel our assumed production cost for this fuel is optimistic, and the appendix explains our choice of inputs.

The capital cost assumptions for ethanol and biodiesel were compared to more recent assumptions made by Doyletech (2018).[13] These capital costs are roughly 15% lower than what was assumed by Doyletech, but the values were not updated given that the

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[13] Doyletech Corporation (2018), Economic Impact Assessments of an Enhanced National Renewable Fuels Standard, and a New Clean Fuels Standard. Prepared for Renewable Industries Canada and Advanced Biofuels Canada.

cost of the ethanol and biodiesel comes mostly from feedstocks and changing the capital costs would only yield a 2-3% production cost difference.

Table 11: Summary of typical gTech liquid bio-energy production costs, based on modelling assumptions (priced in 2019 CAD*)

	Corn ethanol	Wheat ethanol	Soy biodiesel	Canola biodiesel	Canola hydrogenated renewable diesel	Ligno-cellulosic ethanol	Ligno-cellulosic renewable gasoline and diesel
Feedstock, $/t	202	240	472	495	495	84	84
Co-product $/t	190	190	385	200	n/a	n/a	n/a
Capital, $/GJ	4.3	4.3	2.5	2.5	4.7	14.8	24.1
Operating, $/GJ	5.6	7.2	6.2	5.0	3.7	9.3	11.5
Feedstock, $/GJ	23.5	27.4	61.1	28.8	29.9	10.8	7.9
Co-product, $/GJ	-5.7	-8.1	-40.2	-6.7	-6.9	-2.9**	0.0
Total, $/GJ	**27.7**	**30.7**	**29.6**	**29.6**	**31.3**	**32.0**	**43.5**
MJ/L	23.6	23.6	35.4	35.4	36.5	23.6	35.6
$/L	**0.65**	**0.72**	**1.05**	**1.05**	**1.14**	**0.76**	**1.55**

* Again, these costs are based on model inputs. They are priced in 2010 Canadian Dollars based on model inputs with a given feedstock cost; these are not necessarily the costs that result in the forecast for 2010 or any other year.

** Cellulosic ethanol does not produce an animal feed co-product like fuels produced from corn, wheat, soy and canola. However, cellulosic ethanol production results in surplus electricity sold to the grid because the lignin extracted from the feedstock is generally used as fuel for co-generation of heat and power. The co-product value in this example is calculated based on an electricity price of $84/MWh.

Table 12: Summary of gTech gaseous bio-energy production cost assumptions (priced in 2019 CAD)

	Landfill and digestor natural gas*	Ligno-cellulosic renewable natural gas
Feedstock, $/t	n/a	84
Co-product $/t	n/a**	n/a
Capital, $/GJ	10.8	11.0
Operating, $/GJ	1.9	1.2
Feedstock, $/GJ	0.0	7.2
Co-product, $/GJ	0.0**	0
Total, $/GJ	**12.7**	**19.4**

*Both renewable natural gas produced from landfills and anaerobic digestors are included in the model, defined from separate sources, but the resulting production costs are very similar.

**The model does not currently account for the value of digestate

Detailed Inputs

Table 13: Detailed ethanol (corn) and biodiesel (canola) production cost assumptions

Attribute	Ethanol	Biodiesel	Source
Archetype production, million L/yr	200	200	
Capital cost for the archetype, million 2010 CAD	$166	$143	APEC 2010[14]
Operating cost, 2019CAD $/L	0.06	0.10	APEC 2010
Natural gas input, GJ/GJ fuel	0.34	0.08	GHGenius 4.03a[15]
Electricity input, GJ/GJ fuel	0.03	0.01	GHGenius 4.03a
Feedstock input, Kg feedstock per L fuel	2.48	2.06	GHGenius 4.03a

Table 14: Detailed ligno-cellulosic ethanol production cost assumptions

Attribute	Value	Source
Archetype production, million L/yr	237	Modelling assumption, set equal to archetypal plant size used in Jones et al. 2013
Capital cost for the archetype, million 2019CAD	$680	IRENA 2013[16], median of first plants
Operating cost, 2019CAD $/L	0.20	IRENA 2013
Electricity output, GJ/GJ fuel	-0.05	GHGenius 4.03a, (S&T)² Consultants 2012[17]
Feedstock input, Kg feedstock per L fuel	3.04	GHGenius 4.03a, (S&T)² Consultants 2012
Feedstock conversion efficiency ($GJ_{feedstock}/GJ_{fuel}$)	43%	Implied based on feedstock per L of fuel

[14] Asia Pacific Economic Cooperation (2010). Biofuel Costs, Technologies and Economics in APEC Economies, APEC Energy Working Group.

[15] GHGenius 4.03a lifecycle analysis model, (S&T)² Consultants, www.ghgenius.ca

[16] International Renewable Energy Agency (IRENA) (2013). Road Transport: The Cost of Renewable Solutions.

[17] (S&T)² Consultants Inc. (2012). Update of Advanced Biofuels Pathways in GHGenius.

Table 15: Detailed ligno-cellulosic renewable gasoline and diesel production cost assumptions

Attribute	Value	Source
Archetype production, million L/yr	229	Jones et al. 2013[18]
Capital cost, million 2019CAD	$1,609	100% capital premium on Jones et al. 2013 value (i.e. triple the estimate)
Operating cost, 2019CAD $/L	0.27	Jones et al. 2013
Electricity input, GJ/GJ fuel	0.08	GHGenius 4.03a, $(S\&T)^2$ Consultants 2012, average for wood and agriculture residue
Hydrogen input, GJ/GJ_{fuel}	0.19	
Feedstock input, Kg feedstock per L fuel	3.15	
Feedstock conversion efficiency ($GJ_{feedstock}/GJ_{fuel}$)	63%	Implied based on feedstock per L of fuel

Table 16: Anaerobic digestor renewable natural gas production cost assumptions

Attribute	Value	Source
Archetype production, TJ/yr	23	ETSAP 2013[19]
Capital cost, million 2019CAD	1.7	
Operating cost, 2019CAD $/GJ	1.9	

18 Jones, S., Meyer, P., Snowden-Swan, L., Padmaperuma, A., Tan, E., Dutta, A., Jacobson, J., Cafferty, K., 2013, Process Design and Economics for the Conversion of Lignocellulosic Biomass to Hydrocarbon Fuels Fast Pyrolysis and Hydrotreating Bio-oil Pathway, National Renewable Energy Laboratory

19 IEA Energy Technology System Analysis Program (ETSAP) (2013). Biogas and Bio-syngas Production. Available from: link.

Table 17: Detailed ligno-cellulosic renewable natural gas production cost assumptions

Attribute	Value	Source
Archetype production, PJ/yr	9.59	Set to have equal feedstock demand as other ligno-cellulosic production archetypes
Capital cost, million 2019 CAD	$767	200% capital premium on estimated value used by Chavez-Gherig et al., 2017[20]
Operating cost, 2019CAD $/GJ	1.6	Chavez-Gherig et al., 2017
Hydrogen input, GJ/GJ_{fuel}	0	G4 Insights Inc.[21]
Feedstock input, Kg feedstock per GJ fuel	75	
Feedstock conversion efficiency ($GJ_{feedstock}/GJ_{fuel}$)	74%	

Literature Review of 2nd Generation Renewable Natural Gas Costs

Navius' archetype of renewable natural gas (RNG) production from wood waste has a production cost that is consistent with the lower values than reported by other sources, when controlling for inputs to the cost calculation (e.g. feedstock price, energy prices). Navius' capital cost assumption is somewhat higher than used by some sources, while the operating, maintenance (O&M) and other fixed costs are somewhat lower. Total production cost of renewable natural gas from ligno-cellulosic feedstock is $16.4/GJ.

The Hallbar (2017)[22] study of RNG supply in British Columbia, produced for the Government of BC, is often cited for the cost of renewable natural gas produced from wood waste. The cost is typically noted as $30/GJ, but this cost is the highest marginal cost that Hallbar considered in their supply curve. Costs for RNG produced from wood waste in their supply curve range from $20GJ to $36/GJ (2019 CAD, Figure 16). Hallbar's costs are based on the estimated cost of "wood gasification with

[20] Chavez-Gherig, A., Ducru, P., Sandford, M., 2017, The New Jersey Pinelands and the Green Hospital, NRG Energy Case Study

[21] G4 Insights, Our Technology, Accessed April 5th 2018

[22] Hallbar Consulting (2017). Resource Supply Potential for Renewable Natural Gas in B.C.

methanation", described in IEA (2014).[23] The costs in that document are in turn based on Carbo et al. (2011),[24] Mueller-Langan (2011),[25] Heyne (2013),[26] and Simell et. al (2014).[27] Related sources include Melin (2011)[28] (summarized in Heyne) and ECN (2014),[29] describing the same technology as Carbo et. al (2011), which is being developed at the Energy Research Centre of the Netherlands (ECN). Supply costs from these sources range from $18/GJ to $54/GJ, with a significant portion of that variation coming from a wide range of assumptions on energy prices, facility size, state of commercialization (e.g. first or a kind or not), amortization rates and feedstock prices (Figure 16). Note that these production costs are all based on hypothetical production plants.

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23 IEA Bioenergy (2014). Biomethane – status and factors affecting market development and trade.

24 Carbo, M., Smit, R., Drift, B.v.d, Jansen, D. (2011) Bio Energy with CCS (BECCS): Large potential for BioSNG at low CO2 avoidance cost. Energy Procedia, 4, 2011, pp 2950-2954.

25 Müller-Langer, F. (2011) Analyse und Bewertung ausgewählter zukünftiger Biokraftstoffoptionen auf der Basis fester Biomasse. Thesis, 2011, Technische Universität Hamburg-Harburg, Hamburg.

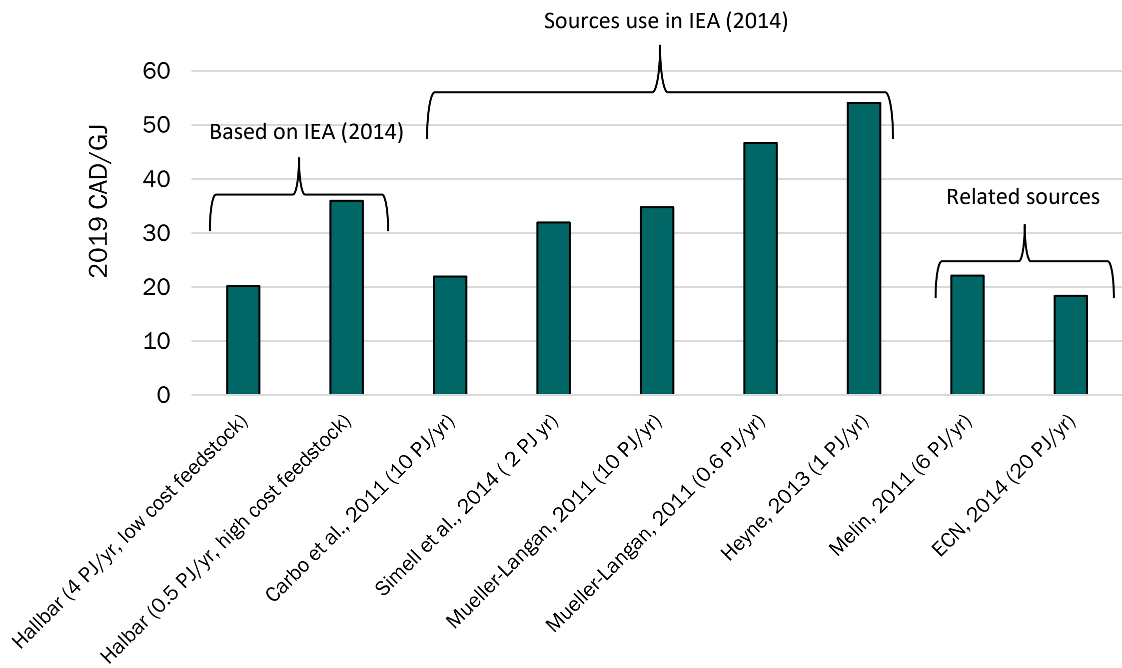
26 Heyne, S. (2013) Bio-SNG from the Thermal Gasification – Process Synthesis, Integration and Performance. Thesis, 2013, Chalmers University of Technology, Göteborg.

27 Simell, P., Hannula, I., Tuomi, S., Kurkela, E., Hiltunen, I., Kaisalo, N., Kihlman, J. (2014): Techno-economic study on bio-SNG and hydrogen production and recent advances in high temperature gas cleaning. In: Regatec 2014, Conference Proceedings; pp 39; Held J (editor).

28 Melin, K. (2011). Technoeconomical study of bio-SNG production from lignocellulosic biomass. Presented at: European Gas Technology Conference 2011, Copenhagen.

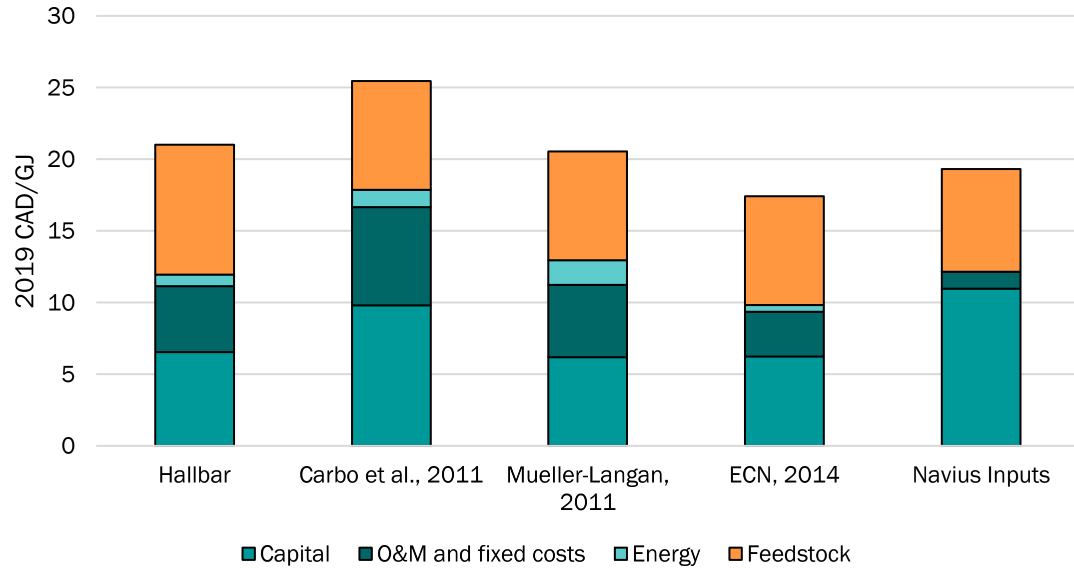
29 The Energy Research Centre of the Netherlands (ECN) (2014). The Economy of Large-Scale Biomass to Substitute Natural Gas (bioSNG) plants.

Figure 16: RNG from wood waste production costs reported by sources, 2010 CAD/GJ



Controlling for these inputs reduces the range of production cost estimates from 17.4 $/GJ to 25.5 $/GJ (Figure 17, only showing values for sources where this cost breakdown is possible based on stated assumptions). The production cost implied by Navius' inputs to the gTech model (as of June 2019) are 19 $/GJ (2010 CAD), though resulting costs can be somewhat higher or lower if input costs change during the forecast. For example, this might occur if GHG policy increased feedstock transportation costs, or if low demand resulted in slightly lower feedstock costs.

Figure 17: RNG from wood waste production costs by source using consistent assumptions, 2019 CAD/GJ by component



Halbar costs are only given for feedstock and "other", with other broken down according to the proportion of non-feedstock costs in Carbo et al. (2011). Production costs are based on a plant consuming 500 MW of input biomass operating 90% of the year (roughly 10 PJ/yr production). Capital annuities are 10% (roughly 10% discount rate over 30 years). Delivered wood waste costs $94 per oven dry tonne (4.3. $/GJ). Electricity costs $60/MWh and propane costs $12/GJ. Costs assume a "nth of a kind" plant (i.e. commercialized), which is especially important for the cost reported by Mueller-Langan (2011), where capital and some fixed costs decline by 39% relative to the reported estimate.

The Navius RNG from wood waste production archetype is based on the G4 insights Pyrocatalytic Hydrogenation process (rather than gasification with methanation), which is reported to be energy self-sufficient and can convert 74% of the input biomass energy into RNG (G4 Insights, 2018).[30] Consequently, the feedstock costs are somewhat lower than from other sources and there are not energy costs. Navius' assumptions for capital and operating costs are based G4 insights communicated to Chavez-Gherig et al. (2017),[31] with Navius judgmentally tripling the reported capital cost. The resulting capital cost for Navius' production archetype is somewhat higher than other estimates. O&M and other fixed operating costs are two to five times lower than estimated by other sources (1.9 to 5.7 $/GJ lower, 2019 CAD). Table 18 contains a summary of inputs to the costs shown in Figure 17.

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30 G4 Insights, Our Technology, Accessed April 5th, 2018

31 Chavez-Gherig, A., Ducru, P., Sandford, M. (2017). The New Jersey Pinelands and the Green Hospital, NRG Energy Case Study.

Table 18: RNG from wood waste technology archetype assumptions by source

	Carbo et al., 2011	Mueller-Langan, 2011	ECN, 2014	Navius, as of June 2019
Unit capital cost, 2010 CAD/kW input	1,628	1,028	1,037	1,926
GJ/yr production	9,933,840	9,933,840	9,933,840	10,501,488
Total capital, 2019 CAD	972,805,351	614,450,391	619,389,331	1,150,874,144
O&M, % of capital	5%	2%	3%	1%
Other fixed costs, % of capital	2%	3%	2%	
Other consumables, % of capital		4%		
Electricity, kWh/GJ	20	18	8	
Propane, GJ/GJ		0.05		
Conversion efficiency	70%	70%	70%	74%
Biomass feedstock, GJ/GJ	1.43	1.43	1.43	1.35

Appendix B: Energy Consumption by Fuel Stream

Table 19: Energy consumption by fuel stream, PJ/yr Moderate Demand Scenario

Fuel stream	Fuel	2025	2030
Liquid	Gasoline	961	863
	Diesel	1492	1457
	Jet Fuel	121	129
	Fuel Oil	211	189
	Biodiesel	62	60
	Ethanol	109	98
	HDRD	77	38
	Natural Gas in Transport	20	46
	Electricity (light-duty)	8	24
	Electricity (bus, med/heavy-duty	4	21
Gaseous	Natural Gas	4254	4380
	NGL/Propane	266	292
	RNG	34	61
Solid	Solid wood-based fuel	28	47
	Coal	72	70
	Coke	21	11

Table 20: Energy consumption by fuel stream, PJ/yr Higher Demand Scenario

Fuel stream	Fuel	2025	2030
Liquid	Gasoline	960	862
	Diesel	1460	1409
	Jet Fuel	121	129
	Fuel Oil	214	191
	Biodiesel	62	62
	Ethanol	109	98
	HDRD	106	83
	Natural Gas in Transport	21	47
	Electricity (light-duty)	4	20
	Electricity (bus, med/heavy-duty	4	21
Gaseous	Natural Gas	4060	4021
	NGL/Propane	259	273
	RNG	105	258
Solid	Solid wood-based fuel	35	48
	Coal	74	71
	Coke	14	12

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