Biofuels in Canada 2023

Tracking biofuel consumption, feedstocks and avoided greenhouse gas emissions

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Errata

The labels for gasoline and diesel in table 18 were reversed in the Oct 31st, 2023, version. They were corrected as of the Nov 1st, 2023, version.

A calculation error linked gasoline consumption in 2022 in Alberta to the 2021 results. This has been corrected as of the Dec 14th, 2023 version.

About Navius Research

Navius Research is a private consulting firm, specializing in the analysis of policies designed to meet environmental goals, with a focus on energy and greenhouse gas emission policy. We are Canada's leading experts in forecasting the environmental and economic impacts of energy and greenhouse gas emissions policies.

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Executive Summary

There are many policies designed to increase the consumption of renewable and low-carbon fuels in Canada, and thus reduce transportation greenhouse gas (GHG) emissions. However, there is no detailed and comprehensive data source characterizing the impact of these policies. As such, Advanced Biofuels Canada has again engaged Navius Research to fill this information gap by updating the "Biofuels in Canada" report that has been released annually since 2016.

Objectives

The objectives of this project are to evaluate and communicate the impact of renewable and low-carbon fuel policies in Canada by:

1. Quantifying the volumes of renewable transportation fuels consumed in each Canadian province (i.e., biofuel), characterized by fuel type, feedstock, and carbon intensity (CI). The biofuels include ethanol, biodiesel and hydrogenation derived renewable diesel (HDRD). The analysis also includes fuels produced from renewable feedstocks that are refined with crude oil (i.e., co-processed fuels) and the impact of light-duty plug-in electric vehicles (PEVs).
2. Estimating their impact on GHG emissions.
3. Estimating how biofuel consumption may impact energy costs, including an analysis on the role of fuel taxation within this cost impact.

New Analysis and Updates to the Methodology

This year, the cost of fuel transportation by rail has been updated to align with the Rail Association of Canada's cost index. As well, rather than estimating plug-in electric vehicles on the road from sales data, that number is based on vehicle registrations published by Statistics Canada. Furthermore, this edition of Biofuels in Canada now includes E15 and B20R80 (20% biodiesel, 80% renewable diesel) in the estimates of tax cost per km driven for different fuels. Finally, the analysis includes some key methodological improvements made in the previous editions:

- The analysis includes an estimate of renewable fuel volumes and avoided GHGs for past years where data is not yet available (2022 in this case)
- The volume and GHG impact of renewable co-processed fuels is based on data from the government of British Columbia

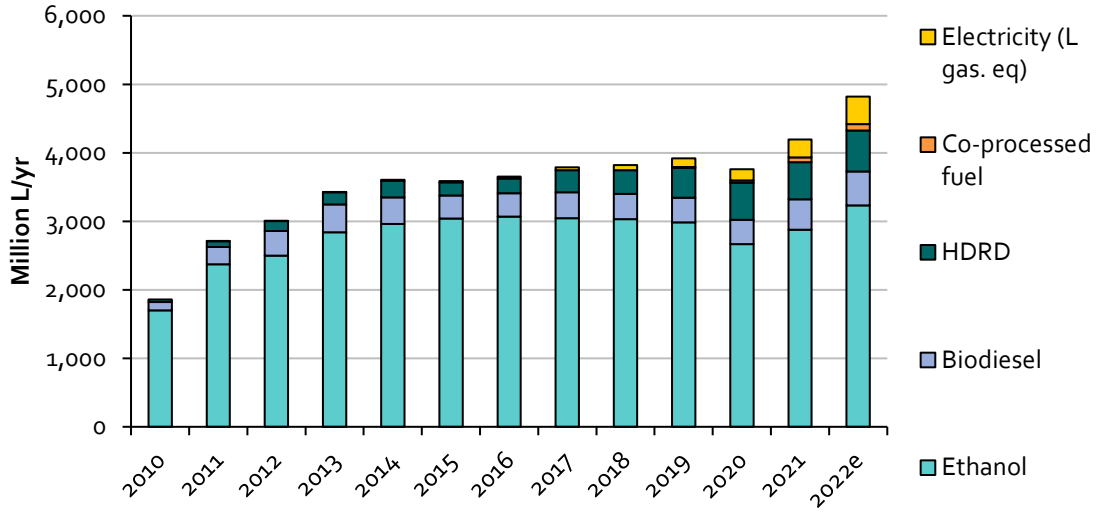
- The value of octane is estimated from wholesale gasoline prices rather than the retail prices.
- National gasoline and diesel consumption is based on Statistics Canada Data energy data rather than the Supply and Disposition of Petroleum Products tables.
- HDRD prices from 2015 onward are based on data from Diamond Green Diesel's financial reports, rather than from Neste's financial data.
- Tax rates used in the cost impact calculations now change by fiscal year rather than calendar year.

Fuel Consumption

In 2021, total renewable fuel consumption in Canada rebounded from the decline that occurred during COVID in 2020. As of 2021, ethanol consumption was 2,876 million L/yr, just below the pre-pandemic levels seen in 2019. Biodiesel consumption increased to 445 million L/yr in 2021, while HDRD consumption remained steady at about 540 million L/yr. Co-processed fuel consumption continued to rise, reaching 72 million L/yr in 2021. Also in 2021, the quantity of fuel displaced by PEVs hit a new high of 262 million L/yr (Figure 1).

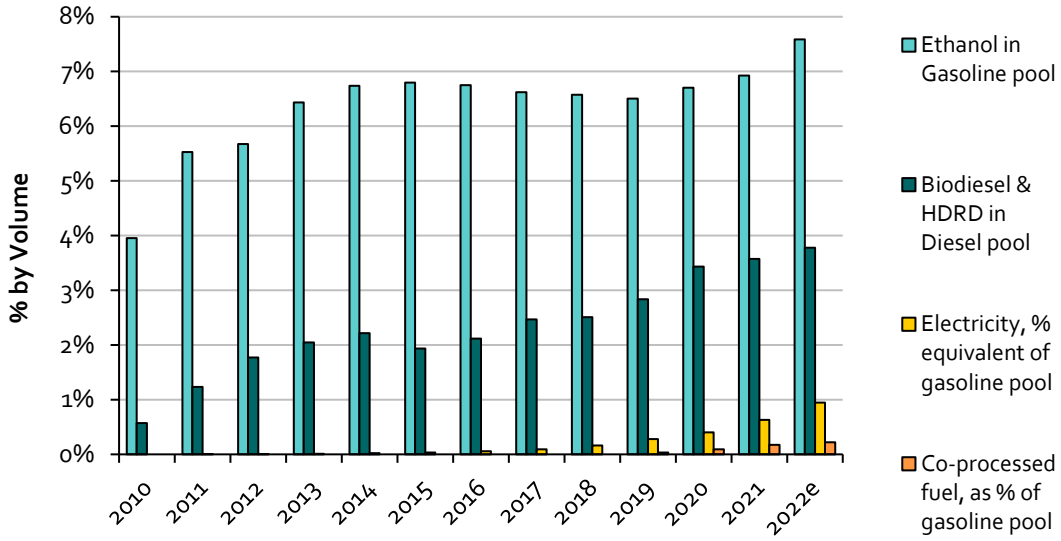
The 2022 estimate shows renewed growth in ethanol consumption, with the bulk of that change showing up in preliminary data released by Alberta. The data show that substantially more ethanol was blended in Alberta than is required by law, possibly to generate early CFR compliance credits. Likewise, the fuel displaced by electric vehicles is also estimated to have expanded significantly in 2022. Based on sales data, we estimate that this displaced gasoline volume increased by 1.5 times relative to 2021 to about 400 million L/yr (Figure 1).

Figure 1: Renewable and low-carbon transportation energy consumption in Canada, with estimate for 2022



2021 was the first year that renewable fuel in gasoline surpassed 7%. Ethanol was blended at 6.9% by volume and co-processed fuel, much of which is renewable gasoline, was equivalent to about 0.2% of the gasoline pool volume. Because of the apparent increase in ethanol blending in Alberta in 2022, the 2022 estimate for that year shows that renewable fuel in gasoline will approach 8%. Meanwhile, renewable fuel in diesel reached a new high of 3.6% by volume in 2021 (Figure 2).

Figure 2: Renewable fuel content by fuel pool, with estimate for 2022



Lifecycle GHG Emissions

Based on lifecycle carbon intensities reported by government contacts, government compliance reporting, and GHGenius 4.03a, renewable fuel consumption and light-duty PEVs have avoided 60 Mt CO_2e between 2010 and 2021. Annual avoided GHG emissions from renewable fuels increased to about 6.5 $MtCO_2e$/yr 2021, while emissions avoided by light-duty PEVs continued to grow rapidly, increasing to 0.7 $MtCO_2e$/yr.

Trends in biofuel carbon intensities in British Columbia and California indicate that biofuel production is becoming less emissions intensive. This is consistent with the default CI scores produced with the GHGenius 4.03a model. Therefore, a fixed amount of biofuel consumption avoids more GHG emissions in 2021 than it would have in 2010.

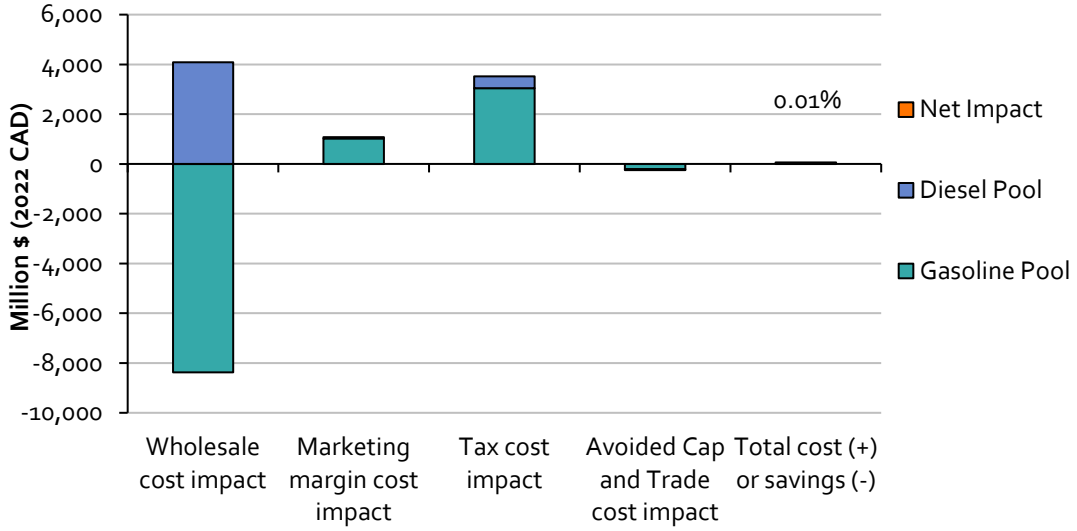
Cost Analysis

Figure 3 shows the cumulative consumer cost impact, by component, resulting from biofuel consumption between 2010 and 2021. The cost components are the wholesale cost, the marketing margin cost (i.e., distribution), the fuel tax cost (including carbon taxes), and avoided costs under emissions cap and trade policies (in Québec, Nova Scotia, and previously Ontario).

The wholesale cost impact is based on observed market prices for fuels and accounts for biofuel transportation costs and the octane value of ethanol, which allows a lower-cost gasoline blendstock to be used. While Canadian refiners may not capture the octane value of ethanol in all cases, this analysis assumes they do; higher octane fuels have a higher market price meaning refiners normally provide extra octane fuels for an additional charge (e.g., premium grade gasoline).

As of 2021, we estimate that the net-costs for fuel consumers in Canada have diverged by less than 0.01% relative to what they would have been without biofuel consumption (Figure 3).

Figure 3: Cumulative cost impact resulting from ethanol blending in the gasoline pool and biomass-based diesel blending in the diesel pool (2010-2021), total % change in data label



The total cost impact has a component related to wholesale fuel costs where, in the case of gasoline, the octane value of ethanol reduces wholesale fuel costs. The total cost also has components related to tax costs and distribution costs that exist because of the differences in energy density between fossil fuels and biofuels. Notably, because ethanol is roughly 33% less energy dense than gasoline, consumers must purchase more of it to obtain the same amount of energy. That exposes them to greater distribution costs based on our assumption that marketing margins in a $/L basis are not affected by biofuel blending rates.

Lower energy density also increases the tax consumers paid on biofuels since most fuel taxation (e.g., excise and carbon taxes) in Canada is charged per litre, regardless of how much energy is in that litre. Furthermore, percent sales taxes (e.g., PST, GST, HST) exacerbate the additional tax charge on fuels with lower energy density because they are applied on the 'tax in' fuel price. Nonetheless, because blended gasoline can have a lower per litre retail price than unblended gasoline in a "counterfactual" scenario without biofuels, our analysis suggests that the absolute amount of sales tax paid can be lower when gasoline is blended. In jurisdictions like Ontario, where there is a high sales tax tied to actual retail value (i.e., 13% HST), the savings on the sales tax impact may outweigh the increases due to federal and provincial fuel taxes.

Generally, consumers pay more taxes per kilometer driven when using biofuel blends. In 2021, on average in Canada (fuel consumption-weighted), a driver of a light-duty vehicle using gasoline with 10% ethanol (i.e., E10) will have paid an additional 2.6% more taxes per kilometre than when using E0 (i.e., pure gasoline). Similarly, a heavy-

duty vehicle driver will pay an additional 1.2% more taxes per kilometre when using diesel with 5% biodiesel (i.e., B5) than when using B0 (i.e., pure fossil diesel). In aggregate, Canadians have now paid an additional $3.5 billion in taxes from 2010 through 2021 as a result of renewable fuel blending (Figure 3).

Figure 4 shows the cumulative consumer cost divided by the cumulative avoided GHG emissions from 2010-2021 for the gasoline and diesel pools in Canada. The costs do not account for any co-benefits or costs other than those shown in Figure 3 (i.e., no accounting for reduced air pollution and reduced health impacts related to biofuel consumption). The abatement cost in the gasoline pool is -$119/t$CO_2$e versus $212/t$CO_2$e in the diesel pool. The negative abatement cost for ethanol is largely a consequence of its value in raising the octane of gasoline blends, though this value is offset partly by the additional distribution cost and tax burden associated with ethanol consumption. On net, based on average kilometers driven per year, renewable fuel consumption in Canada has saved a typical gasoline consumer (based on a typical light-duty vehicle) $7/yr (-0.3%), whereas it has cost a typical diesel consumer (based on a long-distance truck operator) an additional $345/yr (+0.9%).

Figure 4: GHG abatement cost, 2010-2021

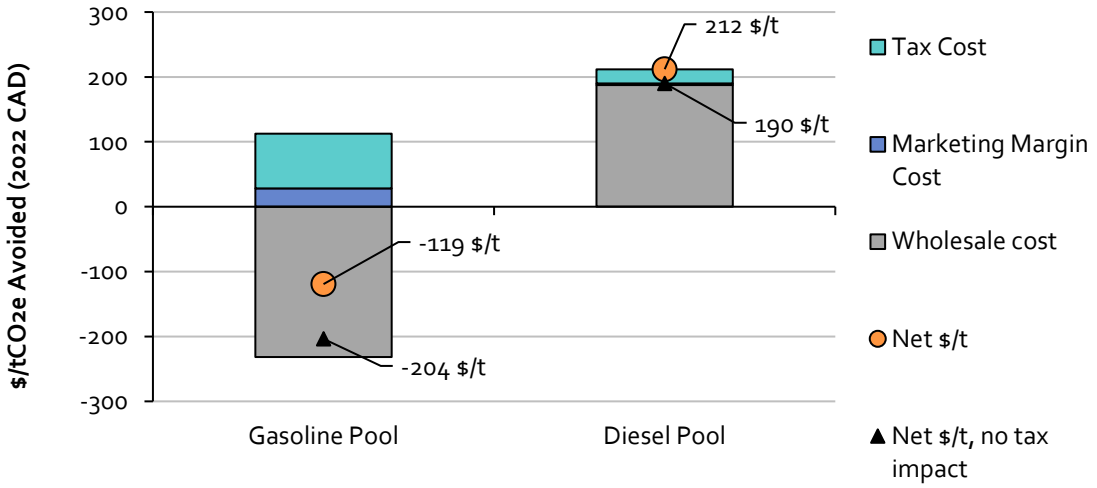


Table of Contents

Executive Summary i

1. Introduction 1

2. Canadian Policy Background 2

2.1. Renewable Fuel Blending Requirements 2
2.2. Carbon Pricing 10
2.3. Low-Carbon Fuel Production Incentives in Canada vs. the US 18
2.4. Low-Carbon Fuel Standards 20

3. Methodology 34

3.1. Process 34
3.2. Summary of Inputs 35
3.3. Updates to the Methodology 42

4. Results and Discussion 44

4.1. Fuel Consumption 44
4.2. Blending Rates 46
4.3. Lifecycle GHG Emissions 49
4.4. Cumulative Costs 59
4.5. GHG Abatement Cost 63
4.6. Consumer Cost Impact 64
4.7. Detailed Tax Costs 66
4.8. Electric Vehicles 68

5. Biofuel-Caused Reductions in Emissions from Gasoline Refining and Consumption ... 71

5.1. Potential Reduction in Refinery Emissions Due to Ethanol's High Octane 71
5.2. Reduction in Emissions Associated with Changing Gasoline Composition 73

6. Conclusions 76

Appendix A: Biofuel Type and Feedstock Assumptions and Data 78

Appendix B: Cost Analysis Methodology 85

Appendix C: Explanation of Changes to Cost Analysis Methodology Made in 2021 91

Appendix D: Plug-in Electric Vehicle Analysis Methodology 94

1. Introduction

There are many policies designed to increase the consumption of renewable and low-carbon fuels in Canada, and thus reduce transportation greenhouse gas (GHG) emissions. However, there is no detailed and comprehensive government source characterizing these policies and their impact.

Environment and Climate Change Canada and the US Department of Agriculture both provide reporting and estimates of biofuel consumption in Canada, while several provincial governments publish data describing fuel consumption in their provinces, sometimes with estimates of fuel carbon intensity (CI) and GHG emission impacts. Still, there is no comprehensive data source in Canada that allocates renewable fuel consumption by province using data from provincial regulators and no single source that communicates the impact of renewable fuel consumption on GHG emissions and fuel costs. Therefore, Advanced Biofuels Canada has again engaged Navius Research to fill this information gap by updating the "Biofuels in Canada" report that has been released annually since 2016.

The goals of this project are to evaluate and communicate the impact of low-carbon fuel policies in Canada. These policies drive the supply and consumption of biofuels or renewable fuels, terms that are used interchangeably in this report to describe low-carbon transportation fuels in Canada. The impact of these policies is estimated by quantifying the annual volumes of biofuels consumed in individual provinces and nationally from 2010 to 2021 (with estimates for 2022). These fuels are further characterized by type (i.e., gasoline, ethanol, diesel, biodiesel, co-processed renewable fuel etc.), feedstock, and CI. Using these volumes and CIs, we estimate the impact of biofuel consumption on GHG emissions and energy costs by province, with additional focus on how fuel taxation affects these costs. For context, the analysis also includes an estimate of how the growing fleet of light-duty plug-in electric vehicles (PEVs) in Canada affects GHG emissions and fuel consumption.

A further goal of this study is to provide transparent results that are publicly available. As such, there is a Microsoft Excel spreadsheet that contains the quantitative analysis and results used in this report ("Biofuels in Canada Analysis - 2023-10-31").

The remainder of this report provides an overview of the existing and upcoming renewable and low-carbon fuel policies in Canada and a discussion of carbon pricing policies. This is followed by a description of the analysis methodology and discussion of the results. The appendices contain more information on the cost analysis methodology and on our renewable fuel volume and feedstock data and assumptions.

2. Canadian Policy Background

This section summarizes the existing renewable fuel policies in Canada as of autumn 2023 at both the federal and provincial levels to provide an understanding of the regulations driving renewable fuel consumption. The existing and upcoming fuel tax and carbon pricing policies that affect the price of gasoline and diesel blends are also explained, as is the potential impact of the final Canadian *Clean Fuel Regulations* (CFR). Throughout this report, fuel CI refers to the lifecycle GHG emissions associated with each fuel, from feedstock production (e.g., an oil well or a corn farm) through to final consumption.

2.1. Renewable Fuel Blending Requirements

National Summary

The Canadian federal government enacted the *Renewable Fuels Regulations* (RFR) on August 23, 2010. This regulation mandates 5% renewable fuel by volume in the gasoline pool, and 2% renewable fuel by volume in diesel pool, which included distillate heating oil until its removal in 2013. The purpose of this policy is to reduce the amount of GHGs emitted from the combustion of gasoline and diesel fuels.

The gasoline blending requirement started December 15, 2010, whereas the diesel blending requirement began July 1, 2011. The federal regulation only requires compliance on average across Canada. This means that fuel sold across Canada may have very different biofuel blending rates, where over-compliance in one region is offset by undercompliance in another region.

In July 2022, the Government of Canada published the final *Clean Fuel Regulations* (CFR), based on similar policies already implemented in British Columbia and California.[1] Although this policy is primarily a CI-based performance standard, it replaces the blending requirements of the RFR as of the end of 2022 and retains the same minimum blending rates. Sections 6 and 7 of the CFR adopted the same volumetric requirement for low CI fuels (5% for gasoline, 2% for diesel), while

[1] Government of Canada, Canada Gazette, Part II, Volume 156, Number 14: Clean Fuel Regulations

expanding the types of eligible alternative fuels to be any 'low-carbon-intensity fuel' recognized under the regulation.[2]

Alongside the national policy, there are a variety of provincial policies which mandate specific volumes of renewable content in fuel pools. Table 1 summarizes the percentage of renewable fuel content (typically ethanol) to be blended with gasoline as mandated by various regulations at different levels of government in Canada. It is important to note that some quantities of gasoline and diesel are exempt from blending policies in Canada. For example, the gasoline and diesel pools in Newfoundland and Labrador are not covered by the minimum blending rates prescribed by the CFR, though they are still subject to its CI requirement. Newfoundland and Labrador, the Territories, as well as other regions north of 60 degrees latitude were exempt from the RFR. As described in the following sub-section, fuel blending regulations in both Ontario and Québec prescribe the biofuel content in diesel or gasoline based on the average CI of the biofuels relative to fossil diesel or gasoline, so the actual share of biofuel may vary from what is reported in the table.

Table 1: Gasoline biofuel blending policies

Region	2010	2011 to 2019	2020	2021	2022	2023
British Columbia	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%
Alberta	-	5.0%	5.0%	5.0%	5.0%	5.0%
Saskatchewan	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%
Manitoba	8.5%	8.5%	8.5%	9.25%	10%	10%
Ontario	5.0%	5.0%	10%	10%	10%	10%
Québec	-	-	-	-	-	10%
Canada	-	5.0%	5.0%	5.0%	5.0%	5%

Some provinces, namely the Atlantic provinces and, until 2023, the province of Québec, are not yet subject to provincial gasoline fuel blending policies. However, except for Newfoundland and Labrador, they were still regulated under the federal RFR (to December 31, 2022) and are subject to the volumetric requirement of the CFR. (Again, fuel in Newfoundland and Labrador is subject to the CI limit within the CFR.) These regions have been excluded from Table 1: New Brunswick, Nova Scotia, Newfoundland and Labrador, and Prince Edward Island.

[2] Ibid.

Similarly, Table 2 summarizes the prescribed percentage of biofuels to be blended in regulated diesel pools in Canada. The most common forms of biofuels blended into diesel include biodiesel and hydrogenation-derived renewable diesel (HDRD). As with gasoline, the share of biomass-based diesel required in Ontario and Québec is subject to a CI requirement and it may vary from what is reported in the table.

Table 2: Diesel biofuel blending policies

Region	2010	2011	2012 & 2013	2014 & 2015	2016	2017 to 2020	2021	2022	2023
British Columbia	3.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%
Alberta	-	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
Sask.	-	-	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
Manitoba	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	3.5%	5.0%	5.0%
Ontario	-	-	-	2.0%	3.0%	4.0%	4.0%	4.0%	4.0%
Québec	-	-	-	-	-	-	-	-	3%
Canada	-	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2%

As with gasoline regulations, some regions in Canada are not subject to any provincial or territorial diesel biofuel blending policies, but they are still regulated under the federal policy. These regions have been excluded from Table 2: New Brunswick, Nova Scotia, Newfoundland and Labrador, and Prince Edward Island.

Canada has a variety of renewable fuel policies at the federal and provincial levels of government that, besides prescribing different renewable fuel volumes (summarized in Table 1 and Table 2), vary in design and application, as described in the following sections.

British Columbia

The British Columbia low-carbon fuel standard (BC LCFS)[3] has two components. The first component defines the minimum renewable fuel content of gasoline and diesel at 5% and 4% by volume, respectively. This component came into effect January 1, 2010, with an initial 3% blending requirement for diesel which increased to 4% in 2011. The second component of the policy regulates the average CI of the fuels, as described in

[3] Referring to both the *Greenhouse Gas Reduction (Renewable & Low Carbon Fuel Requirements) Act* and the *Renewable & Low Carbon Fuel Requirements Regulation*, formerly referred to as the RLCFRR.

section 2.3. British Columbia has adopted a new *Low Carbon Fuel Act* which will replace the existing statute and regulation on January 1, 2024, subject to the adoption of new regulations.

Alberta

Alberta has the *Renewable Fuel Standard* which came into effect April 1, 2011. It mandates fuel producers to blend biofuels with gasoline and diesel. An average of 5% is required in the gasoline pool, while an average of 2% is required in the diesel pool.[4] However, Alberta's policy also specifies that the CI of the renewable content must be 25% lower than the corresponding CI of gasoline and diesel. In practice, most biofuels meet this criterion. For example, in 2011 the lifecycle CI of gasoline (as estimated by GHGenius 4.03a) was approximately 88.8 gCO_2e/MJ; in contrast, the default CI of ethanol from that model was 59% to 65% lower, depending on the ethanol feedstock. The CI of diesel in Alberta in 2011 was 96 gCO_2e/MJ, while the CI of biodiesel and HDRD in that province ranged from about 8 to 20 gCO_2e/MJ, or 79% to 92% lower than diesel (also based on GHGenius 4.03a). Note that Alberta uses a different version of the GHGenius model, so actual lifecycle CI values used in the policy may differ slightly.

Saskatchewan

Saskatchewan has *The Ethanol Fuel Act* and *Ethanol Fuel (General) Regulations* that regulate the volume of ethanol to be blended with gasoline (7.5% by volume) and establishes quality standards for the ethanol to be blended.[5] Saskatchewan also has *The Renewable Diesel Act* that started on July 1, 2012, mandating 2% renewable fuel by volume in diesel pools.[6]

Manitoba

Manitoba has the *Ethanol General Regulation* and the *Biodiesel Mandate for Diesel Fuel Regulation*. These policies mandate the blending of biofuels with gasoline and diesel pools. The first compliance period for the diesel policy began November 1, 2009, but was later revised to delay implementation until April 1, 2010. The ethanol

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[4] Government of Alberta, *Renewable Fuels Standard Regulation*

[5] Government of Saskatchewan, *The Ethanol Fuel Act, The Ethanol Fuel (General) Regulations*

[6] Government of Saskatchewan, *The Renewable Diesel Act*

policy mandated 8.5% renewable content by volume in gasoline since January 1, 2008, 9.25% as of 2021, and 10% as of 2022.[7] The biodiesel policy required 2% biodiesel by volume through 2020, rising to 3.5% in 2021 and 5% in 2022.[8]

Ontario

Ontario previously had the *Greener Gasoline – Bio-Based Content Requirements for Gasoline*[9] regulation mandating 5% ethanol content in gasoline, which was increased to a CI-adjusted requirement of 10% by volume beginning in 2020. Suppliers must meet the compliance target at all their facilities combined. In November 2020, the *Greener Gasoline* regulations were repealed and replaced with a new regulation, *O. Reg. 663/20: Cleaner Transportation Fuels: Renewable Content Requirements For Gasoline And Diesel Fuels*[10], which combines the *Greener Gasoline* and *Greener Diesel* regulations.

Like the previous regulations, the *Cleaner Transportation Fuels* regulation set requirements for a CI-adjusted bio-based fuel (e.g., ethanol) blend rate of 10% in 2020-24, 11% in 2025-27, 13% in 2028-29, and 15% in 2030 (summarized in Table 3). For example, between 2020 and 2024, the regulation requires 10% bio-based fuel content if the weighted average CI of the biofuel is approximately 46 gCO_2e/MJ (45% below a benchmark CI for gasoline) (Table 4 and Figure 5). If the CI of the biofuel is lower than 46 gCO_2e/MJ, then the blend rate may also be lower; if a higher CI fuel is used, a higher blend rate would be required to achieve compliance (Figure 5). Similarly, by 2030, the policy requires a 15% volumetric blend rate if the weighted average CI of the bio-based content is 42 gCO_2e/MJ (50% below a benchmark CI for gasoline). Volumes of renewable fuel may be transferred between the regulated parties, presumably bought and sold, to effectively allow compliance credit trading. Gasoline sold for marine, aviation or off-road use is exempt from the regulations or any gasoline with an octane rating (AKI) of 89 or greater (i.e., typically mid-grade and premium gasoline).

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[7] Government of Manitoba, *The Biofuels Act,* Ethanol General Regulation

[8] Government of Manitoba, *The Biofuel Act,* Biodiesel Mandate For Diesel Fuel Regulation

[9] Government of Ontario, O. Reg. 535/05: *GREENER GASOLINE - BIO-BASED CONTENT REQUIREMENTS FOR GASOLINE*

[10] Government of Ontario, O. Reg. 663/20: *CLEANER TRANSPORTATION FUELS: RENEWABLE CONTENT REQUIREMENTS FOR GASOLINE AND DIESEL FUELS*

Table 3: Volumetric low-carbon renewable fuel blending requirements in Ontario

	2020	2020-2024	2025-2027	2028-2029	2030
In gasoline	5%	10%, CI adjusted	11%, CI adjusted	13 %, CI adjusted	15%, CI adjusted
In diesel	4%, CI adjusted (no change to 2030)				

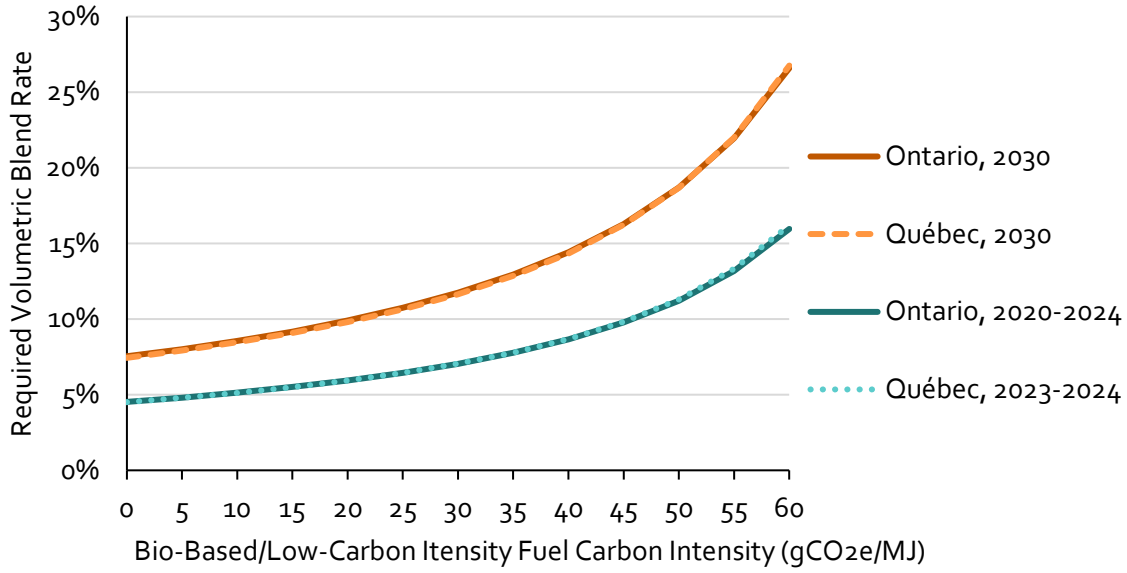
Table 4: Threshold CI values where required blending rate = actual blending rate in Ontario, gCO_2e/MJ (based on GHGenius 4.03 a or b)

	2020	2020-2024	2025-2027	2028-2029	2030
In gasoline	Any	45.9	45.9	45.9	41.7
In diesel	27.6				

Along with the ethanol regulation, the *Greener Diesel Regulation* was also repealed and replaced with the *Cleaner Transportation Fuels* regulation. The new regulation maintains the standard from the *Greener Diesel Regulation* which requires 4% biofuel blend subject to the weighted average CI of the biofuel, which must be at least 70% below the reference CI for diesel fuel. For context, the average reported CI of biodiesel sold in Ontario in 2020 was 6.14 gCO_2e/MJ (about 93% lower than diesel), which would require a 3% blend rate (Figure 6).

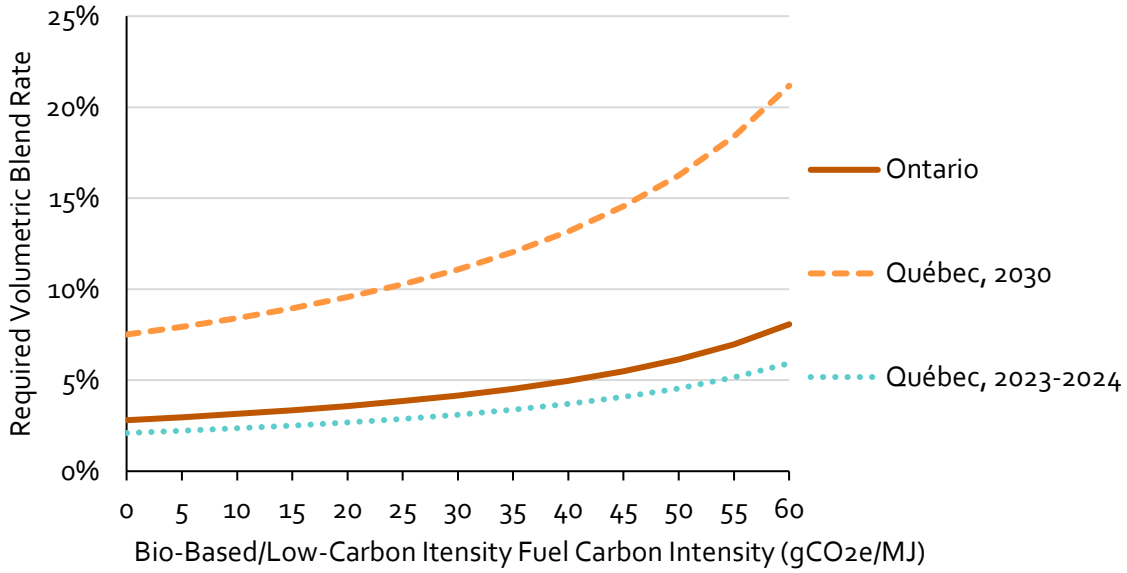
To allow some compliance flexibility during the COVID-19 pandemic, the Ontario Ministry of Environment merged the 2020 and 2021 compliance periods, meaning fuel suppliers could achieve compliance by blending at a rate above the standard in 2021 if they were to fall below the standard in 2020 (or vice versa).

Figure 5: Volumetric blend rates of renewable fuel **in gasoline** required to comply with the Ontario and Québec regulations prior to 2025 and in 2030



Note: Similar curves exist for 2025-2027 and 2028-2029 in both provinces. The volumetric blend rates **in gasoline** apply to the regulated fuel pool (i.e., net of exclusions for fuel consumed in some geographic areas, premium gasoline in Québec and mid-grade and premium gasoline in Ontario etc.)

Figure 6: Volumetric blend rates of renewable fuel **in diesel** required to comply with the Ontario regulation and the Québec regulation prior to 2025 and in 2030



Note: A similar curve exists for Québec for 2025-2027 and 2028-2029. The volumetric blend rates **in diesel** apply to the regulated fuel pool (i.e., net of exclusions for fuel consumed in some geographic areas)

Québec

Québec finalized a provincial fuel blending policy in December 2021. As of January 1st, 2023, this policy requires 10% low-carbon fuel content in gasoline, rising to 12% in 2025, 14% in 2028 and 15% in 2030 (Table 5). The diesel blending requirement begins at 3% low-carbon fuel content in 2023, rising to 5% in 2025 and 10% by 2030 (Table 5).[11] The policy excludes premium gasoline, heating oil, and fuel used for air, marine and rail transport. It also excludes fuel consumption in northern and far-eastern Québec (other areas are also excluded for 2023, the first year that the policy will be in force). It permits buying and selling compliance credits between the regulated parties as well as banking up to 20% of any overcompliance for use in the following year. Overcompliance in the diesel pool can be used for compliance in the gasoline pool on a one-to-one volume basis. Overcompliance in the gasoline pool may be used for compliance in the diesel pool, but that volume is discounted by two-thirds (i.e., one litre beyond what is required in the gasoline pool only counts for 1/3 of a litre of in the diesel pool).

Table 5: Volumetric low-carbon renewable fuel blending requirements in Québec

	2023-2024	2025-2027	2028-2029	2030
In gasoline	10%, CI adjusted	12%, CI adjusted	14 %, CI adjusted	15%, CI adjusted
In diesel	3%, CI adjusted	5%, CI adjusted (2025 through 2029)		10%, CI adjusted

Table 6: Threshold CI values where required blending rate = actual blending rate in Québec, gCO_2e/MJ (based on GHGenius 4.0c)

	2023-2024	2025-2027	2028-2029	2030
In gasoline	45.7	45.7	41.9	41.9
In diesel	27.9	27.9	23.2	23.2

As in Ontario, the actual volumetric blend rate of renewable fuels will be a function of the CI of those fuels. For example, the actual blend rate in gasoline in 2030 will be equal to the regulated value, 15%, only if the average weighted CI of the renewable fuel is about 42 gCO_2e/MJ (50 % lower than reference gasoline CI) (Table 6, Figure 5). The blend rate in gasoline could be less than 10% by volume in 2030 if the average weighted CI of the renewable fuel is less than 21 gCO_2e/MJ (Figure 5). Similarly, the required blend rate in diesel in 2030 will be equal to the regulated value, 10%, only if the average CI of the blended fuels is about 23 gCO_2e/MJ (75% lower than reference

[11] Gouvernement du Québec, 2021, *Regulation respecting the integration of low-carbon-intensity fuel content into gasoline and diesel fuel.*

diesel CI) (Table 6). More typical average CI scores for biomass-based diesel around 10 gCO_2e/MJ would require a blend rate closer to 8.4% (Figure 6).

Because Québec is a large fuel market, this regulation will significantly affect renewable fuel consumption in Canada. By 2024, when most fuel consumption in Québec is covered by the policy, the 10% blending rate in gasoline might require roughly 670 million L of ethanol consumption in Québec (or other bio-based gasoline), equivalent to about 23% of current national ethanol consumption. The 3% biomass-based diesel blending requirement might require about 180 million L of renewable fuel, equivalent to about 20% of current Canadian consumption of these fuels.[12] This fuel consumption may not be completely incremental to what would have happened without the new regulation as it will overlap with the CFR. However, this policy will nonetheless produce a step-change in Canadian renewable fuel consumption.

The Yukon

The Yukon announced that they intend to introduce bio-based diesel and ethanol blending mandates by 2025 that "align with the percentage [...] by volume in leading Canadian jurisdictions", aiming for 20% renewable content in the diesel pool and 10% in the gasoline pool.[13] Draft regulations have not yet been published.

2.2. Carbon Pricing

British Columbia Carbon Tax

The British Columbia (BC) carbon tax was introduced at $\$10/tCO_2e$ in 2008 and increased to $\$30/tCO_2e$ by 2012 and has since risen in multiple steps to $\$65/tCO_2e$ as of April 1, 2023 (Table 7).[14] The BC carbon tax will rise to $\$170/tCO_2e$ by 2030, consistent with the federal backstop carbon price.[15] Each $\$5/tCO_2e$ increment increased the tax on gasoline by 1.11 ¢/L and the tax on diesel by 1.28 ¢/L, while the

[12] Approximated based on estimated gasoline and diesel consumption in Québec in 2021, assuming 10% of each fuel pool is exempt with an ethanol CI of 40 gCO_2e/MJ and a biomass-based diesel CI of 10 gCO_2/MJ.

[13] Government of Yukon, 2020, *Our Clean Future: A Yukon strategy for climate change, energy and a green economy*

[14] Government of British Columbia, British Columbia's Carbon Tax

[15] Greenhouse Gas Pollution Pricing Act, Schedule 4

$15/tCO$_2$e increments increase those prices by about 3 and 4 ¢/L respectively (Table 7).[16]

The tax rate on gasoline and diesel is based on emissions factors that approximate a 5% volumetric biofuel blending rate in the province (i.e., the tax is reduced by 5% to recognize biofuel blend components under the BC LCFS), resulting in a tax of 14.31 ¢/L on gasoline and 16.85 ¢/L on diesel as of autumn, 2023. The tax is applied equally to each litre of fuel, fossil and renewable, and is not adjusted for tailpipe or lifecycle GHG emissions of alternative fuels.

Table 7: British Columbia carbon tax rates (nominal CAD)

	2012-2017	2018-2019	2019-2021	2021-2022	2022-2023	2023-2024
Tax rate, $/tCO$_2$e	30	35	40	45	50	65
Gasoline, ¢/L	6.7	7.8	8.9	10.0	11.1	14.3
Diesel, ¢/L	7.7	9.0	10.2	11.7	13.0	16.9

Alberta Carbon Levy

Alberta implemented a $20/tCO$_2$e carbon levy in 2017, which rose to $30/tCO$_2$e in 2018.[17] Similar to British Columbia, the application of the levy to gasoline and diesel used fuel emissions factors that reduce the rate by the prescribed biofuel blend level (i.e. 5% ethanol by volume in gasoline and 2% by volume biodiesel in diesel) (Table 8). However, unlike British Columbia, Alberta's carbon levy exempted 100% of the biofuel component of blends that exceeded 10% in gasoline and 5% in diesel.

The Alberta carbon levy was repealed by the newly elected provincial government in 2019.[18] Consequently, as of 2020, gasoline and diesel purchases were subject to the federal carbon pricing backstop discussed below (see Table 13 on page 18).

Table 8: Alberta carbon levy rates on gasoline and diesel (nominal CAD)

	2017	2018 and early 2019	2020 and thereafter
Gasoline, ¢/L	4.5	6.7	Current federal backstop carbon price
Diesel, ¢/L	5.4	8.0	

[16] Ibid.

[17] Government of Alberta, Carbon Levy Rates

[18] Government of Alberta, Carbon Tax Repeal

Ontario Cap and Trade

The Ontario GHG emissions cap and trade program was in effect between January 1st, 2017, and July 2018. The first credit auction was held in January 2018 and the system linked with the cap-and-trade program in California and Québec. However, the program was cancelled later that year by the newly elected provincial government, and all trading was stopped on July 3rd, 2018.[19] As of 2019, gasoline and diesel sales in Ontario are subject to the federal carbon pricing backstop described below (see Table 13 on page 18).

Like the Québec cap and trade system, fuel suppliers had to hold credits for the emissions resulting from the refined petroleum products (gasoline, diesel) they distributed when the cap was in effect; biofuels were not subject to the system. The credit price imbedded in wholesale gasoline and diesel prices at the time indicated that the carbon cost was spread evenly across all fuel blends, regardless of their renewable fuel content.

The average credit price in 2017 was $18.2/t$CO_2$e, roughly 4.3 ¢/L on gasoline and 4.8 ¢/L on diesel. The average credit price in 2018 was $18.6/t$CO_2$e up until the program was cancelled.[20]

Québec Cap and Trade

The Québec GHG emissions cap and trade system began in 2013 and suppliers of transportation fossil fuels (gasoline, diesel) were included as of 2015. It applies to fuel suppliers who must hold credits for the emissions resulting from the fossil fuels they distribute; tailpipe CO_2 emissions from biofuels are exempt from the cap-and-trade system. The emissions credit price affects the wholesale price of fuels. However, until recently, wholesale gasoline and diesel pricing generally has not shown a price differentiation between fossil-biofuel blends and fuels without biofuels.

The system has a price floor, which is a minimum price for credit trades. The price floor began in 2013 at $10.75/t$CO_2$e (nominal CAD) and rises by 5% plus inflation each

[19] Financial Accountability Office of Ontario, 2018, Cap and Trade: A Financial Review of the Decision to Cancel the Cap and Trade Program

[20] Government of Ontario, 2018, *Past auction information and results*

year.[21,22] However, because the Québec system is linked with the California cap and trade program, there is a joint minimum price that applies to both jurisdictions (the higher of the two systems). While the California minimum price increases at the same rate, the actual minimum credit price in the joint program will be a function of the CAD/USD exchange rate. In practice, the average annual credit price remained slightly above the price floor until about 2020, though it has risen well above the floor as of 2023[23] (Table 9).

Table 9: Québec cap and trade average annual credit settlement price and estimated price impact on gasoline and diesel (nominal CAD)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Credit price, $/tCO$_2$e	13.4	16.07	17.29	18.85	19.3	22.0	22.8	27.7	36.9	41.8
Gasoline, ¢/L	3.3	3.9	4.2	4.6	4.7	5.3	5.5	6.7	9.0	10.2
Diesel, ¢/L	3.6	4.4	4.7	5.1	5.2	6.0	6.2	7.5	10.0	11.3

Nova Scotia Cap and Trade

Nova Scotia's GHG emissions cap and trade system took effect on January 1, 2019, with the first compliance period lasting from 2019 to 2022. A floor price of $20/tCO2e was in place for the first auction in 2020. The floor price was scheduled to increase at 5% per year plus inflation. Fuel suppliers had to purchase allowances for only 20% of the emissions on fuels (including gasoline and diesel) that they import into the province for combustion.[24] The Nova Scotia cap and trade quantification, reporting, and verification regulations specified that fuel suppliers do not have to purchase allowances for CO_2 emissions from biofuels.[25]

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[21] Government of Québec, 2018, Québec cap-and-trade system for greenhouse gas emissions allowances (C&T): Technical Overview

[22] Government of Québec, 2022, The Carbon Market: Auctions

[23] Government of Québec, The Carbon Market, Auction Proceeds Allocated to the Electrification and Climate Change Fund

And

California Air Resources Board, Summary of Transfers Registered in CITSS By California and Québec Entities in 2019, April 15 2020

[24] Government of Nova Scotia, 2020, Cap-and-Trade Program Regulations

[25] Government of Nova Scotia, s. 17 (2) Quantification, Reporting and Verification Regulations

As of July 1st 2023, the cap and trade program was replaced with the federal carbon price on retail fuels (see Table 13 on page 18) paired with a provincial Output-based Pricing System for large industrial GHG emitters.[26]

Nova Scotia's provincial government regulates the price of motor gasoline and diesel, including the allowable pass-through of costs associated with the former cap-and-trade system and the newly implemented *Clean Fuel Regulations*. The petroleum product pricing regulation specifies that fuel suppliers may recover 20% of the auction price floor at a fixed CI of 2.36 kgCO_2e/L gasoline from retail sales.[27] If an auction settles above the floor price, a price adder is applied to the pricing formula to support cost recovery. This cap-and-trade credit price impact on fuel prices ranged from 1.0 ¢/L to 1.9 ¢/L on gasoline and between 1.1 ¢/L and 2.2 ¢/L on diesel from 2020 through 2023.

New Brunswick Carbon Tax

New Brunswick introduced a provincial carbon tax in April 2020 to replace the federal fuel charge associated with the carbon pricing backstop. The New Brunswick tax followed the rate schedule of the federal *Greenhouse Gas and Pollution Pricing Act* (GGPPA) and applies the same tax rate to bio-based and petroleum fuels. The carbon tax exemptions aligned with New Brunswick's Motor Fuel Tax exemptions, extending further than most other provinces to exempt almost all off-road fuel consumption from the carbon tax, including manufacturing, mining, and home heating.[28]

As of July 1st, 2023, the New Brunswick tax was replaced with the federal carbon tax,[29] with the rate rising to \$65/tCO_2e for 2023/2024 (see Table 13 on page 18).

In tandem with the introduction of the provincial carbon tax, New Brunswick amended its fuel tax regulations to reduce the motor fuel tax on gasoline and diesel. Gasoline and diesel excise taxes were reduced by 4.63 and 6.05 ¢/L respectively in 2019, resulting in an effective net carbon price of only 2 ¢/L from April 2020 to April 2021. The change in provincial fuel taxes remains as of 2023/204, even with the re-introduction of the federal carbon tax. Consequently, the net carbon price impact has

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[26] Government of Nova Scotia, 2020, Cap-and-Trade Program Regulations

[27] Government of Nova Scotia, Petroleum Product Pricing Regulations

[28] Government of New Brunswick (accessed via CanLII), *Gasoline and Motive Fuel Tax Act*

[29] Government of New Brunswick, 2023, Province opts for federal backstop on carbon pricing

since risen to approximately 10-11 ¢/L with subsequent increases to the carbon tax rate (Table 10).[30]

New Brunswick is not alone in adjusting fuel tax rates to mitigate increase in retail fuel prices. Since 2022, other provinces have introduced multi-year fuel tax holidays to address the high cost of fuels resulting from volatile crude oil prices as well as rising carbon costs. For example, Alberta has set its fuel tax rates on gasoline and diesel to zero since April 2022, while Ontario reduced its fuel tax rates by about 40%.[31]

Table 10: New Brunswick carbon tax

	2020-2021	2021-2022	2022-2023	2023-2024
Carbon Tax rate, $/tCO$_2$e	$30	$40	$50	$65 *
Gasoline Carbon Price (¢/L)	6.63	8.84	11.05	14.31
Gasoline, Change to Fuel Tax from 2019, ¢/L	-4.63	-4.63	-4.63	-4.63
Gasoline, Net Carbon Price, ¢/L	**2.00**	**4.21**	**6.42**	**9.68**
Diesel Carbon Price (¢/L)	8.05	10.73	13.41	17.28
Diesel, Change to Fuel Tax from 2019, ¢/L	-6.05	-6.05	-6.05	-6.05
Diesel, Net Carbon Price, ¢/L	**2.00**	**4.68**	**7.36**	**11.23**

*Federal rather than provincial carbon tax rate

Newfoundland and Labrador

In 2019, Newfoundland and Labrador also implemented a carbon tax that satisfied the fuel charge requirements of the federal backstop under the GGPPA. As in New Brunswick, the tax did not apply to heating oil and its implementation occurred in conjunction with a reduction in other fuel taxes. However, these were a removal of the temporary taxes that had been implemented to stabilize provincial finances. A 4 ¢/L gasoline tax and a 5 ¢/L diesel tax were removed,[32] bringing these provincial fuel taxes back to their 2015 values. As of fall 2022, the carbon price on gasoline and

[30] Government of New Brunswick (accessed via CanLII), Gasoline and Motive Fuel Tax Act

[31] NRCAN, Fuel Consumption Taxes in Canada

[32] Government of Newfoundland and Labrador, 2018, Provincial Government Releases Federally-Approved Made-in-Newfoundland and Labrador Approach to Carbon Pricing

diesel was consistent with a $50/tCO$_2$e carbon price, about 11 ¢/L on gasoline and 13 ¢/L on diesel (Table 11).[33]

As of July 1st, 2023, Newfoundland and Labrador also replaced the provincial tax with the federal tax (see Table 13 on page 18).[34]

Table 11: Newfoundland and Labrador carbon tax

	2019-2021	2021-2022	2022-2023
Carbon Tax rate, $/tCO$_2$e	$20	$40	$50
Gasoline Carbon Price (¢/L)	4.42	8.84	11.05
Diesel Carbon Price (¢/L)	5.37	10.73	13.41

Prince Edward Island

Prince Edward Island's (PEI's) carbon tax also came into force in April 2019. Like other provinces, it excluded some off-road uses, for farming, fishing and aquaculture, as well as heating oil (and propane).[35] As of 2022, the tax was consistent with a $50/tCO$_2$e carbon price, as per federal requirements (Table 12).[36] Like the rest of the Atlantic provinces, PEI adopted the federal carbon price as of July 1st, 2023, thus increasing the carbon price to $65/tCO$_2$e (see Table 13 on page 18).[37]

Also, in keeping with other provinces, PEI reduced provincial fuel taxes around the same time that carbon pricing was implemented. The provincial fuel tax on gasoline and diesel were reduced by 4.6 ¢/L and 6.0 ¢/L since 2019.[38]

[33] Government of Newfoundland and Labrador, 2022, Provincial Carbon Tax Rates

[34] Government of Newfoundland and Labrador, 2023, Public Advisory: Information for Wholesalers and Retailers of Carbon Products on the Repeal of Provincial Carbon Tax

[35] Government of Prince Edward Island, Carbon Levy on Fossil Fuels and Rates of Carbon Levy on Fossil Fuels for 2020 to 2022

[36] Ibid.

[37] Government of Prince Edward Island, Carbon Levy on Fossil Fuels

[38] NRCAN, Fuel Consumption Taxes in Canada

Table 12: PEI carbon tax

	2019-2020	2020-2022	2022-2023
Carbon Tax rate, $/tCO$_2$e	$20	$30	$50
Gasoline Carbon Price (¢/L)	4.42	6.63	11.05
Diesel Carbon Price (¢/L)	5.37	8.05	13.41

Federal Carbon Pricing Backstop

The GGPPA carbon pricing backstop applies directly to provinces that chose to not to implement an equivalent carbon pricing system of their own. Prior to July 1st, 2023, these included Saskatchewan, Manitoba, Ontario. As of fall 2023, the federal carbon price also applies to Nova Scotia, New Brunswick, Newfoundland and Labrador, and PEI. British Columbia and Québec continue to use their own carbon pricing systems, which are deemed to be of equal or greater stringency to the federal backstop price.

The federal carbon price backstop began at $20/tonne in 2019 and increased by $10/yr to $50/tonne in 2022.[39] In 2023, the price began to increase by $15/yr and is scheduled to reach $170/tCO$_2$e in 2030.[40] The fuel charge rates shown in Table 13 account for the minimum volumetric renewable fuel content required in Canada (5% in gasoline and 2% in diesel) by reducing the rates by 5% on gasoline and 2% on diesel. Biofuel volumes pay the same rate as the fossil fuel (i.e., gasoline or diesel) up to 10% in gasoline and 5% in diesel; biofuels used in blends greater than 10% (e.g., >E10) in gasoline or 5% (e.g., >B5 or >R5[41]) in diesel are fully exempt from the carbon price.[42] As of 2023, the carbon levy rates are about 14 ¢/L on gasoline and 17 ¢/L on diesel. If the price follows the announced schedule, the rate will more than triple, increasing to about 38 ¢/L on gasoline and 46¢/L on diesel in 2030.

[39] Government of Canada, 2019, *Fuel Charge Rates*

[40] Government of Canada, 2021, Update to the Pan-Canadian Approach to Carbon Pollution Pricing 2023-2030

[41] A caution to readers of the GGPPA legislation: Biodiesel within that statute refers to bio-based diesel fuel substitutes, including biodiesel (i.e., FAME) and HDRD.

[42] McKenna, C., Morneau, W.F., 2018, Explanatory Notes Relating to the Greenhouse Gas Pollution Pricing Act and Related Regulations . See section 8(5) and section 8(6) of GGPPA.

Table 13: Federal backstop carbon levy rates on gasoline and diesel blends up to E10 and B5/R5 (nominal CAD)[43]

	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024
Carbon price, $/tCO2e	$20	$30	$40	$50	$65
Gasoline, ¢/L	4.42	6.63	8.84	11.05	14.31
Diesel, ¢/L	5.37	8.05	10.73	13.41	17.28

Because this carbon price does not differentiate by blend rates up to E10 and B5/R5, there is a foregone price incentive to use lower-carbon fuels and a foregone cost savings for consumers of these fuels. This impact will increase substantially as the carbon price increases. For example, once the carbon price reaches $170/tCO$_2$ in 2030, the current design of the federal carbon pricing backstop overtaxes E10 by about ¢2.6/L and it overtaxes B5/R5 by about ¢1.5/L. Note that the surtax in this example does not account for additional taxation on biofuels due to their lower energy densities and tax rates that are set per-litre rather than per unit of energy. Based on estimated fuel consumption in 2022 (about 42 billion L of blended gasoline and 28 billion L of blended diesel) and assuming widespread E10 and B5/R5 consumption, the federal carbon tax design would have consumers pay an additional $1.5 billion per year in 2030.

Table 14: The surtax/foregone price incentive on E10 and B5/R5 in relation to the announced federal carbon pricing schedule

	2023	2024	2025	2026	2027	2028	2029	2030
Carbon Price, $/tCO2e	65	80	95	110	125	140	155	170
Gasoline, ¢/L	14.37	17.68	21.00	24.31	27.63	30.94	34.26	37.57
Diesel, ¢/L	17.43	21.46	25.48	29.50	33.53	37.55	41.57	45.59
Surtax/foregone price incentive on E10, ¢/L	1.0	1.2	1.5	1.7	1.9	2.2	2.4	2.6
Surtax/foregone price incentive on B5/R5, ¢/L	0.6	0.7	0.8	1.0	1.1	1.2	1.4	1.5

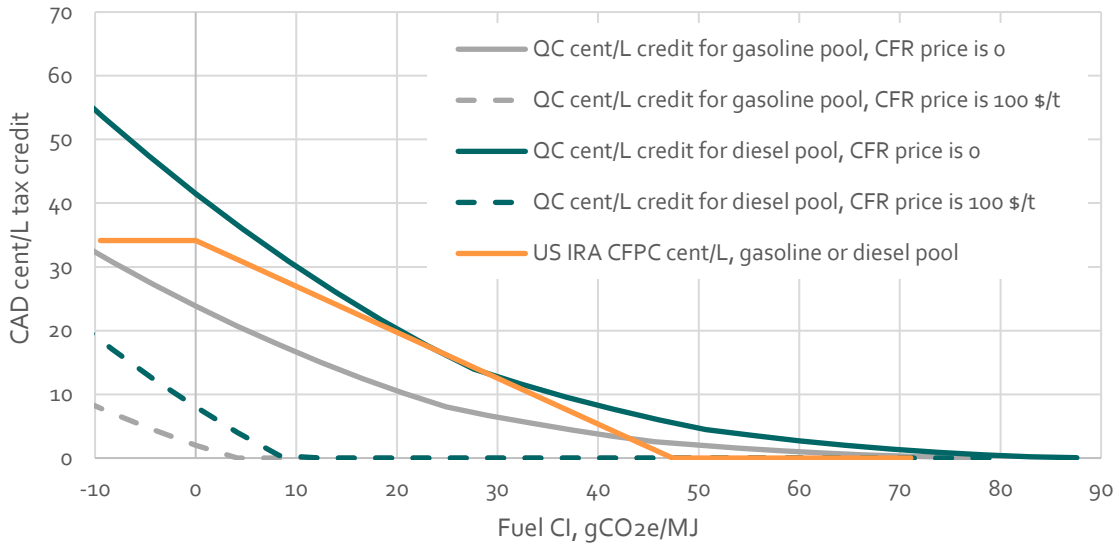
2.3. Low-Carbon Fuel Production Incentives in Canada vs. the US

Québec has introduced a tax credit to support biofuel production in that province, but it will likely have no impact when stacked with the CFR. The policy provides a gross refundable production tax credit for fuels produced and consumed in Québec. The gross credit is in the range of 20-40 ¢/L for a typical biomass-based diesel fuel (CI

[43] Government of Canada, 2019, *Fuel Charge Rates*. www.canada.ca/en/revenue-agency/services/forms-publications/publications/fcrates/fuel-charge-rates.html

between 0 to 20 gCO_2e/MJ, when the CFR price is 0, Figure 7). The gross tax credit for ethanol would likely fall between 5-15 ¢/L (CI 15 to 40 gCO_2e/MJ, when CFR price is 0, Figure 7). However, the actual tax credit is net of other policy support earned by that fuel. If a fuel earns even $100/t$CO_2e$ per CFR credit it generates, the net tax credit is zero unless the fuel's CI is less than about 5 gCO_2e/MJ (Figure 7, QC trend lines with a CFR price of $100/t).[44]

Figure 7: Production tax credit for low-carbon fuels produced and consumed in Québec (assuming no CFR credit value) versus the US production tax credit



In contrast, the US Clean Fuels Production Credit (CFPC) will provide a CI-dependent tax credit ranging from 0 to about 34 ¢/L (CAD) for low-carbon gasoline and diesel substitutes produced in the US, regardless of where they are consumed or what other policy support they have. The CFPC also provides a bonus incentive rate for low-carbon aviation fuels of about 1.75x the base rate given to gasoline and diesel substitutes. The CFPC comes into force in 2025 and replaces the biomass-based diesel blenders tax credit, which currently provides a $1/gallon (USD) incentive for biomass-based fuels blended with diesel in the US. The CFPC is scheduled to be in force until the end of 2027, but like the previous tax credit, its duration could be extended. Because it has no claw-back related to other policy support, a US-based low-carbon fuel producer

[44] Assemblée National du Québec, 2022, Projet de loi no 6 (2023, chapitre 2), Loi donnant suite à des mesures fiscales annoncées à l'occasion du discours sur le budget du 22 mars 2022 et à certaines autres mesures

And

Revenue Québec, 2023, Tax Credit for Biofuel Production in Québec

supplying fuel to Québec would benefit from both the CFPC and the CFR while a Québec-based producer would likely only earn CFR credits.[45]

Nationally, there have been no producer tax credits available in Canada since the ecoEnergy for Biofuels program expired in 2017 and the Alberta Bioenergy Producer Program expired in March 2020. The federal program provided Canadian producers with 10 ¢/L for gasoline substitutes and 26 ¢/L for diesel substitutes when it started in 2008/2009; rates declined annually, falling to between 3 and 4 ¢/L in the program's final year.[46] The Albertan program provided 10 ¢/L for ethanol, 13 ¢/L for renewable diesel, biodiesel and pyrolysis oil and 14 ¢/L for "advanced" fuels (e.g., ligno-cellulosic derived drop-in fuels).[47]

2.4. Low-Carbon Fuel Standards

British Columbia Low-Carbon Fuel Requirement

The CI component of the BC LCFS came into effect July 1st, 2013, with a schedule that required a 10% reduction in average fuel CI by 2020 relative to a 2010 baseline. In July 2020, a reduction requirement of -20% by 2030 was established and the requirement scheduled for 2020 was delayed due to the COVID-19 pandemic. Subsequently, in December 2022, a new target of -30% has been legislated for 2030 and beyond.[48,49]

The CI component of the policy has resulted in blending renewable fuels at volumes greater than the minimum 5% in gasoline and 4% in diesel. However, renewable fuel blending is not the only action that can satisfy the low-carbon fuel requirement of the LCFS. If the minimum renewable fuel blending standard is met, the CI requirement of the LCFS can also be met by switching to lower carbon transportation energy sources such as natural gas, electricity, or hydrogen. In other words, while this LCFS policy is

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[45] H.R. 5376 — 117th Congress: Inflation Reduction Act of 2022

[46] Government of Canada, ecoEnergy for Biofuels Program

[47] Government of Alberta, 2017, Bioenergy Producer Program Outline

[48] Government of British Columbia, BC-LCFS Requirements

[49] Government of British Columbia, BC Reg. 394/2008, *RENEWABLE AND LOW CARBON FUEL REQUIREMENTS REGULATION*

likely to encourage more renewable fuel consumption, it does not prescribe this consumption.

Nonetheless, electricity will likely be an important source of compliance credits, in addition to renewable fuels. The ministry responsible for the policy recently clarified which parties own the compliance credits produced from electricity supply. As of January 1st, 2022, the credit generator is the party that supplied the electricity to vehicles through the final supply equipment (i.e., the charging station), so long as it can measure or accurately estimate the electricity consumption. Therefore, that party will either be an electric utility or a charging network operator. However, transit operators will continue to own and report credits from pre-existing electric transit vehicles (i.e., routes operating prior to January 1st, 2021).[50]

The LCFS in British Columbia need only be met on average by suppliers of gasoline and diesel in the provincial market. Compliance credits can be traded amongst suppliers, and parties that do not comply will pay a penalty rate of 600 $/t$CO_2$e for a compliance shortfall[51], up from 200 $/t$CO_2$e prior to 2023. As of October 2023, credits were trading at an average annual value of $465/t$CO_2$e.

The legislation governing the BC LCFS allows the program director to issue "Part 3 Agreement" credits. These are credits issued to fuel suppliers for projects that the director "is satisfied {…} has a reasonable possibility of reducing the amount of carbon dioxide equivalent emissions resulting from the use of Part 3 fuels".[52] The director may issue credits for a project which will also generate credits once it is completed (e.g., provide credits to finance the capital investment in a project, which will subsequently generate further credits once it is operating and supplying of low-carbon fuel). The allowable volume of credits for Part 3 Agreements is up to 25% of the sum of all debits in the previous compliance period. Credits granted under a Part 3 agreement are interchangeable with credits produced via blending low-carbon fuels (i.e., credits granted via Part 3 Agreements reduce the volume of renewable fuel needed to achieve compliance with the policy).

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[50] British Columbia Ministry of Energy, Mines and Low Carbon Innovation, 2022, Information Bulletin RLCF-020, Part 3 Fuel Supplier and reporting requirements for electricity

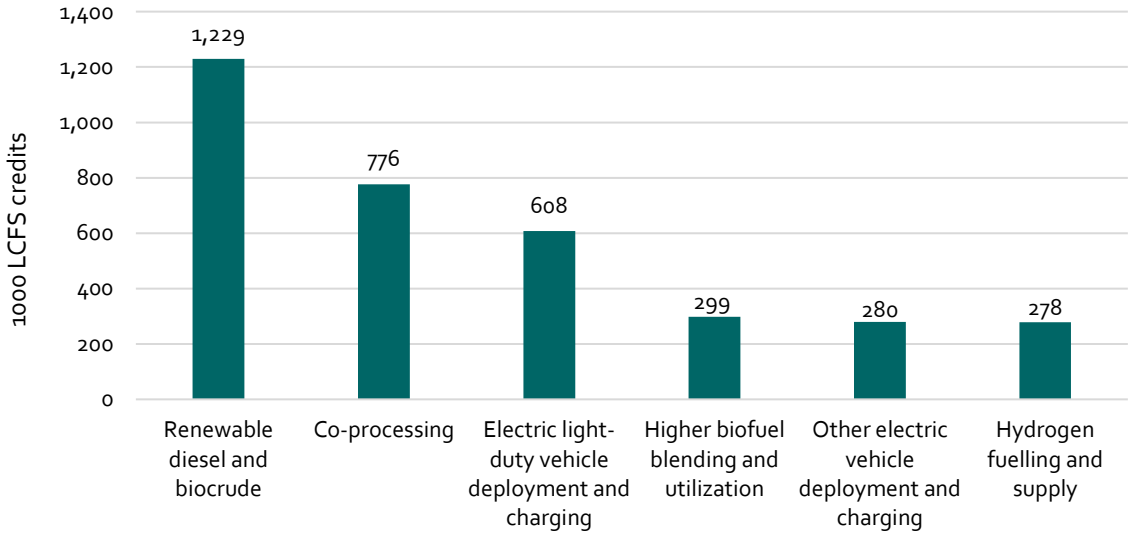
[51] Ibid.

[52] *Greenhouse Gas Reduction (Renewable and Low Carbon Fuel Requirements) Act*, RSBC 2008, c. 16, s. 8.01

Under the new *Low Carbon Fuels Act*, which will replace the existing *Greenhouse Gas Reduction (Renewable and Low Carbon Fuel Requirements) Act*, these agreements will now be referred to as "Initiative Agreements"[53].

A description of projects to-date that have been awarded Part 3 Agreements and the associated volume of credits is published by the B.C. Government in Information Bulletin RLCF-014[54]. From 2014 to 2020, 51 projects have been allocated 3.5 million LCFS credits (approximately the maximum allowable). About 58% of the total credits have been awarded to projects involved in co-processing and the production of biocrude and renewable diesel. Another 18% were awarded to support the deployment of light-duty electric vehicles and charging infrastructure (primarily to fund the incentive available through the British Columbia Scrap-It program administered by Shell Canada). The remaining credits have been awarded to projects supporting the electrification of other transportation modes (e.g., heavy-duty, marine), the development of hydrogen refuelling infrastructure, and the deployment of refuelling infrastructure capable of supplying higher biofuel blends (e.g., B20) (Figure 8).

Figure 8: LCFS credits issued under Part 3 Agreements, 2014-2020



[53] Bill 15, Low Carbon Fuels Act, 3rd Session., 42nd Parliament, British Columbia, 2022

[54] Government of British Columbia (August 2023). *Information Bulletin RLCF-014: Projects supported under Part 3 Agreements.* Available at: https://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/electricity-alternative-energy/transportation/renewable-low-carbon-fuels/rlcf-014_projects_supported_under_part_3_agreements.pdf

The Clean Fuel Regulations

The Canadian federal government has finalized a LCFS-style regulation called the *Clean Fuel Regulations* (CFR), previously referred to as the Clean Fuel Standard during regulatory development. Like the British Columbia LCFS and the similar California *Low Carbon Fuel Standard*, the CFR requires a reduction in the life-cycle CI of gasoline and diesel fuels. Similar regulations for gaseous and solid fuels were previously expected to be created along with the regulation on liquid fuels but were cancelled in December 2020.

The final version of the CFR was published in July 2022, and the following details are based on the final regulation.[55] The first compliance period with CI limits for gasoline and diesel is July 1st, 2023, to December 31st 2023. The regulated CI target for gasoline and diesel fuels in 2030 is 81 gCO_2e/MJ for gasoline and 79 gCO_2e/MJ for diesel, 14 gCO_2e/MJ lower than a 2016 benchmark for the respective fossil fuels and equivalent to roughly a 15% reduction in CI. The initial 2023 compliance period requires a CI reduction of 3.5 gCO_2e/MJ. The emissions intensity limit is lowered by 1.5 gCO_2e/MJ annually until the target is reached in 2030.

On December 31st, 2022, the CFR superseded the earlier *Renewable Fuel Regulations* though the CFR will maintain the same minimum blending rates for low CI fuels in both the gasoline and diesel pools (5% and 2% by volume, respectively). Any surplus RFR credits owned by obligated parties at the end of 2022 were automatically rolled over into CFR credits for use in 2024. Credit generation from the RFR is based on a default CI and energy density for renewable fuels in gasoline and diesel (i.e., as if the fuels blended under the RFR were ethanol and biodiesel with CI scores of 59 gCO_2e/MJ and 35 gCO_2e/MJ, respectively).

Notably, in the period from date of CFR publication (June 21st, 2022) to December 31st, 2022, the same volume of biofuels can simultaneously earn RFR and CFR credits, if the supplier is registered under the CFR credit and tracking system. The CFR also has an 'early credit' generation period from June 21st, 2022 to June 30th, 2023. Therefore, in the second half of 2022, the 'RFR rollover' credits and 'CFR early generation' creates may be double counted, creating an additional incentive to blend biofuels in the second half of 2022.

Table 15 summarizes credit and debit generation during 2022 and 2023 related to fuel supply (credits may be generated in other ways, described below). In 2023,

[55] Government of Canada, 2022, Canada Gazette, Part II, Volume 156, Number 14: Clean Fuel Regulations

suppliers of gasoline and diesel will only generate debits (i.e., a compliance obligation) during the first compliance period, from July 1st, 2023 to December 31st 2023 (row 1 in the table). In contrast, fuel suppliers could generate early credits from the date of the final regulation publication to the start of the first compliance period (June 21st, 2022, to June 30th 2023) and regular credits during the first compliance period (rows 2 and 3 in the table). Finally, fuel suppliers could generate additional CFR compliance credits from any surplus RFR credits they held at the end of 2022 (row 4 in the table).

Table 15: Fuel-based CFR credit and debit generation, 2022 and 2023, in the first and second half of each year (H1 and H2)

Credit/Debit type	2022		2023	
	2022, H1	2022, H2	2023, H1	2023, H2
1) Debits generated from gasoline and diesel supply				
2) Early credits generated from low-carbon fuel supply*				
3) Regular credits generated from low-carbon fuel supply				
4) Credits generated from overcompliance with RFR				

* For participants registered in the CFR credit and tracking system

Like the British Columbian and Californian LCFS policies, credits can be generated by blending renewable and low-carbon fuels into petroleum fuels (i.e., "compliance category 2" credits). The quantity of credit generation is a function of the reduction in fuel CI resulting from this blending. The CI of fuels is defined using a lifecycle approach like what is used in California and British Columbia but calculated using a new lifecycle assessment modelling tool built for the CFR.[56]

Credits can also be generated by switching transportation energy consumption to other low-carbon alternatives including natural gas, electricity, and hydrogen (i.e., "compliance category 3"). While fuel producers and importers (i.e., the fuel suppliers) are required by the policy to reduce the CI of gasoline and diesel fuels, suppliers of these low-carbon alternatives (i.e., compliance category 2 and 3) can generate and also trade compliance credits. The credits generated by compliance categories 2 and 3 can be sold to other registered CFR participants.

There are some important constraints on the generation of credits from electric light-duty vehicles, primarily to reduce the long-term overlap of the CFR with other policies

[56] See The Fuel Life Cycle Assessment Model

that will drive the adoption of these vehicles. First, charging network operators can only generate credits from residential charging stations if they were built prior to 2030. Second, there will be no credit generation from residential charging stations after 2035. Finally, charging network operators must reinvest the credit revenue they earned from residential and public chargers by reducing the cost of PEV ownership, or by investing in more public and residential chargers. Charging site hosts that generate credits from commercial vehicle charging are not constrained in this way.

Compliance credits can also be generated by parties that reduce GHG emissions related to petroleum fuel production, namely during oil extraction, upgrading, and refining (i.e., "compliance category 1"). For example, these actions include the integration of lower-carbon hydrogen inputs, integration of renewable energy, or the use of carbon capture and storage. These provisions significantly expand the pool of available credits compared to other LCFS-type programs in British Columbia and California.

Other options are available to increase the flexibility of compliance. In addition to credit trading and banking for future use, obligated parties may obtain up to 10% of their credits from CI reductions in gaseous fuels (i.e., by blending low-carbon gaseous fuels, with credits calculated in a similar lifecycle manner). Likewise, up to 10% of a supplier's deficit of compliance credits may be purchased for $\$350/tCO_2e$ (plus an inflation factor) by contributing to an abatement or technology fund. Additionally, the previously mentioned credits for early actions from all compliance categories and overcompliance with the RFR may be generated in 2022 - 2023 and used later. Finally, compliance credit shortfalls of up to 10% of the total value of debits (i.e., equivalent to 10% of the excess tonnes emitted) can be deferred into the subsequent five compliance periods. In this case, the quantity of deferred credits must be "repaid" with future compliance and grow by 5% annually.

Impact of Low-Carbon Fuel Standards on Retail Fuel Prices in Markets Without Price Regulation

LCFS-style policies create a market-based incentive to supply low-carbon fuels because this action generates compliance credits which can be sold in their associated market or utilized to meet compliance obligations. The price of credits will rise until it is high enough to incentivize fuel suppliers to comply with the policy. In a properly functioning market, the credit price will be equal to the GHG abatement cost of the costliest marginal action required for compliance, including ancillary costs like fuel distribution and blending, or even foregone revenues from fuel refining and sales. All other actions taken to comply with the policy will be less costly. Therefore, the

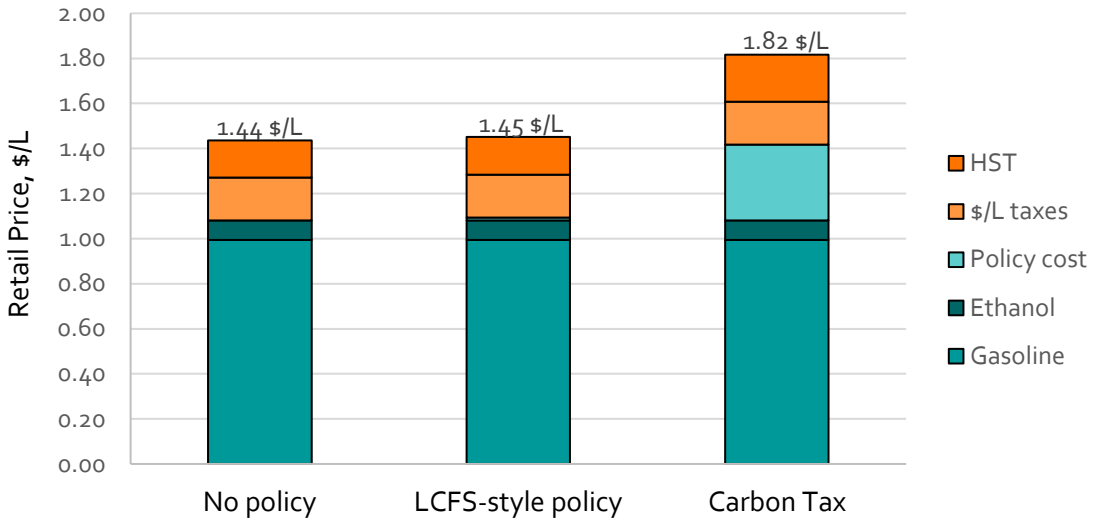
average cost of compliance and the average carbon abatement cost associated with the policy is less than the credit price.

LCFS credit prices and carbon tax rates are often improperly compared when assessing the impact on retail fuel prices. A LCFS credit price and a carbon price with the same $/tCO$_2$e value have a very different impact on retail fuel prices. The difference exists for two reasons. First, a carbon tax applies to 100% of the direct GHG emissions (i.e., tailpipe) associated with a fuel while, on-net, a LCFS credit price only applies to the portion of a fuel's lifecycle GHG emissions above a given threshold (i.e., the required CI reduction in a given year). Second, the LCFS policies in Canada do not produce any financial transfer to the government like a carbon tax does (unless it has a ceiling price for credits where a subset of compliance credits might be purchased from the government).

Using the example of retail fuel prices that were typical in Ontario in 2022 and gasoline containing 10% ethanol by volume (E10), a LCFS policy with a credit price of 150 $/ tCO$_2$e and the same CI limit as the CFR in 2025 (88.5 gCO$_2$e/MJ) would result in an E10 price of 1.45 $/L versus 1.44 $/L without an LCFS. The net retail-price impact is about 1 ¢/L. In contrast, a carbon tax of 150 $/tCO2e would result in an E10 price of 1.82 $/L (Figure 9), with a net price impact of 38 ¢/L (34 ¢/L and 4 ¢/L in additional sales tax). Note that carbon tax revenue recycling is not considered here, though it could mitigate the cost impact for consumers if that revenue were used to lower income tax or returned to households as a lump sum payment. Nonetheless, the price impact at the pump with a carbon tax would remain significantly higher than with a LCFS policy.

LCFS policies have a different impact on retail prices because they act like a "feebate" on fuels that have CI's above and below the average life-cycle CI target. In a competitive fuel market, the policy applies a "fee" to fuels with CIs above the target, but all the revenue earned from the "fee" ultimately becomes a "rebate" to fuels with CI's that are below the target.

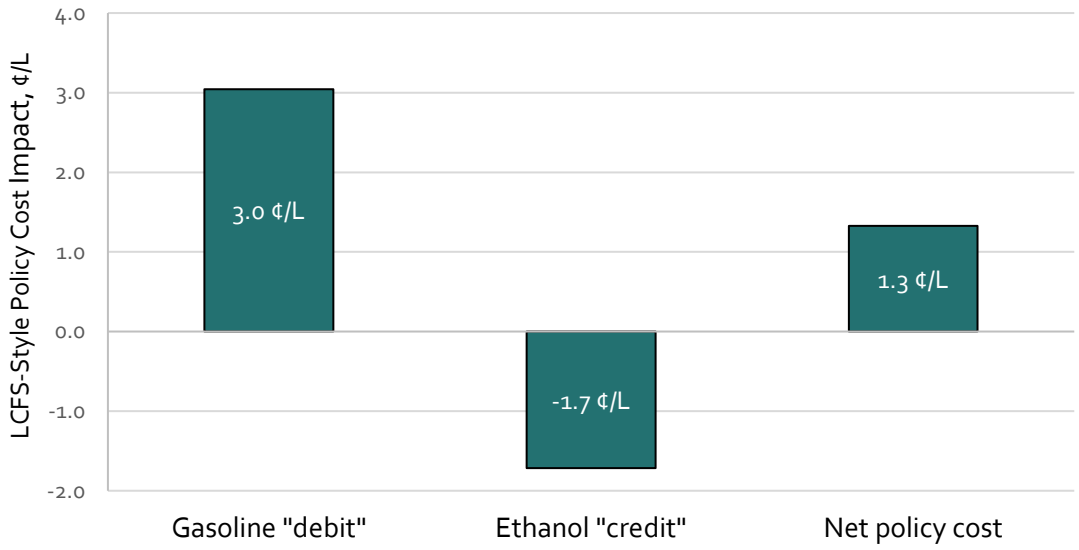
Figure 9: Impact of an LCFS-style policy vs. carbon tax on E10 retail prices in Ontario in 2022, LCFS credit price is equal to the carbon tax $/tonne CO_2e value ($150 t/CO_2e)



Note: wholesale fuel costs and fuel taxes are based on Ontario in 2022. LCFS credit price and carbon tax are 150 $/tonne. In the example, the gasoline CI is 95 gCO_2e/MJ (baseline value in the CFR), the ethanol CI is 40 gCO_2e/MJ, and the LCFS-style policy target CI is 88.5 gCO_2e/MJ (2025 gasoline pool target for the CFR).

This "feebate" is illustrated with the example of E10 in Ontario again. Supplying fuels creates "debits" (i.e., the "fee") that must be offset by "credits" (i.e., the "rebate") generated by the provision of low-carbon fuels (or other compliance actions). If petroleum-derived gasoline has a life-cycle CI of 95 gCO_2e/MJ and the target for 2030 is 14 gCO_2e/MJ lower, the "fee" on the gasoline component in that year would be 3 ¢/L on E10 when the compliance credit price is 150 $/t$CO_2e$. The ethanol component of the E10 would earn a "rebate" of 1.7 ¢/L of E10, when the CI of ethanol is 40 gCO_2e/MJ. Assuming a functioning and somewhat competitive fuel market where the LCFS costs and benefits are mostly passed to the consumer, that policy would increase the price of E10 by 1.3 ¢/L (Figure 10) plus another 0.2 ¢/L from increased sales tax.

Figure 10: Breakdown of an LCFS-style policy's cost impact on E10 retail price with a hypothetical $150/tCO2e credit price



Note: LCFS credit price and carbon tax are 150 $/tonne. In the example, the gasoline CI is 95 gCO_2e/MJ (baseline value in the CFR), the ethanol CI is 40 gCO_2e/MJ, and the LCFS-style policy target CI is 88.5 gCO_2e/MJ (2025 gasoline pool target for the CFR).

The GHG abatement cost broadly perceived by consumers under a LCFS-style policy is defined by the average abatement costs of the actions used to make that consumer's fuel compliant with the policy. This abatement cost is not solely defined by the policy credit price, which represents the abatement cost of the next costliest action needed for overall policy compliance (i.e., the marginal cost). In reality, most compliance in response to LCFS-style policies is generated internally by fuel providers when blending low-carbon fuels. Only a subset of compliance is purchased as credits at the marginal abatement price of the policy, so the credit price does not represent the average abatement cost. For example, since the start of British Columbia's low-carbon fuel requirement in 2013 to 2022 (the most recent year with complete data), 15% of compliance credits were obtained by trading through the credit market, while 85% of the credits were self-generated by fuel providers when blending lower-carbon fuels.[57]

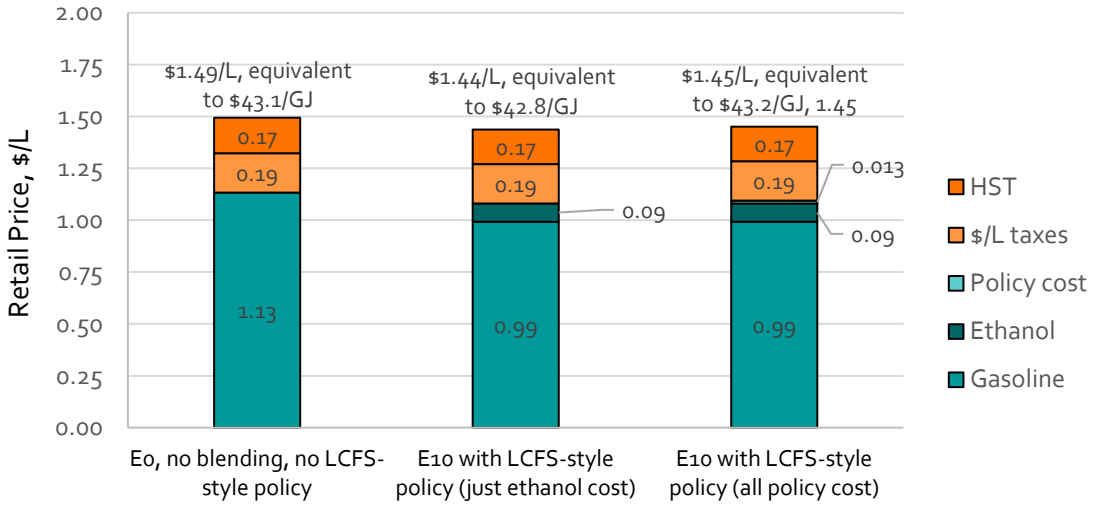
The previous Ontario example shows that average abatement cost of renewable fuel blending and the credit price are not the same. A comparison of some hypothetical fuel prices reinforces this point. For E10 sold in Ontario in 2022, the abatement cost

[57] Government of British Columbia, 2022, RLCF-007-2022 Renewable and Low Carbon Fuel Requirements Regulation Summary for 2010 – 2022

Government of British Columbia, 2023, BC-LCFS Credit Market Data (2015 to present)

perceived by a consumer resulting from ethanol blending is negative $50/tCO$_2$e (accounting for both the lower cost per litre and lower energy density of E10). Therefore, at 2022 prices, blending to E10 resulted in a savings (compare the "E0, no policy" vs. "E10, just ethanol" costs in Figure 11). If that E10 were also subject to the 2025 CFR CI limit, hypothetically resulting in a credit price of $150/tCO$_2$e, the cost E10 would increase by about 1 ¢/L since some credit purchases would be required for compliance (see the "E10, all policy" cost in Figure 11). The resulting average abatement cost of using E10 in this example is $15/tCO$_2$e, much less than the marginal credit price.

Figure 11: Inputs to calculating the average GHG abatement cost when using E10 and compliance credits to comply with a hypothetical LCFS-style policy



Note: LCFS credit price is $150/tCO$_{2e}$. The gasoline CI is 95 gCO2e/MJ, the ethanol CI is 40 gCO2e/MJ, and the LCFS target CI is 81 gCO2e/MJ. Gasoline without ethanol must be produced with a higher octane and is more expensive than the gasoline blendstock used with ethanol (i.e., $1.13/L vs. $1.10/L, or a gasoline cost of $1.08/L of E10).

When calculating these abatement costs, recall that ethanol is roughly 33% less energy dense than gasoline; thus, in this example, E10 results in a cost savings on a per GJ basis when it costs about 3% by volume less than E0 (this energy density difference is accounted for in the abatement costs). Consistent with the cost-impact methodology used later in this analysis, the gasoline in the E0 fuel is more expensive than the gasoline used with E10 because it must be produced with a higher-octane rating rather than having its octane raised with the addition of ethanol. This octane value brings down the abatement cost of using ethanol to comply with the LCFS-style policy. While there is some uncertainty in the magnitude of the octane value of ethanol, that uncertainty does not change the fact that:

- The average abatement cost experienced by a consumer within an LCFS-style policy is not the same as the credit price.
- The credit price does not create a carbon cost on the full CI of the fuel, just the difference from the targeted CI limit in a given year.
- Consequently, equivalent LCFS credit prices and carbon tax have a very different retail price impact: For example, a carbon tax of $\$150/tCO_2e$ has a much higher retail price impact than a LCFS credit price of $\$150/tCO_2e$.

Impact of Low-Carbon Fuel Standards on Retail Fuel Prices in Markets with Price Regulation

The Atlantic provinces have regulated maximum prices for gasoline and diesel. Consequently, the relevant energy regulators need to adjust their rules to account for any additional costs incurred by fuel suppliers to comply with the CFR. Ideally, they would change the maximum fuel prices to account for the costs incurred by the fuel suppliers. In other words, the maximum prices would rise and fall as a function of the average cost of compliance.

In the absence of data from the nascent CFR credit market or information about how fuel suppliers in Atlantic Canada will comply with the CFR, the energy regulators made the following interim adjustments to the maximum fuel prices in July 2023:

- The price of gasoline and diesel in Newfoundland and Labrador and Nova Scotia was increased by about 4 ¢/L, based on the assumption of compliance via credit purchases from the CFR credit clearance mechanism at $\$300/tCO_2$.[58,59]
- New Brunswick developed a cost of carbon adjustment, based on the value of imported renewable diesel, inferred from US fuel policy credit prices (the California

[58] Newfoundland and Labrador Board of Commissioners of Public Utilities, 2023, Media Release, Thursday, July 6, 2023 Weekly Adjustment of Maximum Prices of Regulated Petroleum Products: Gasoline and Diesel Motor Fuels Adjustments Related to the Federal Clean Fuel Regulations

[59] Nova Scotia Utility and Review Board, 2023, Application of New Fuel Charges (Carbon Tax) and Clean Fuel Costs to Gasoline and Diesel Oil Prices

Nova Scotia Utility and Review Board, 2023, Order M10853

LCFS credit and the US *Renewable Fuel Standard* D4 credit).[60] The cost of carbon adjustment as of October 15th, 2023, was about 5 ¢/L.[61]

- PEI has yet to determine a CFR price adjustment and will hold hearings on the matter on November 6th, 2023.[62]

While these price adjustments are subject to upcoming reviews, it is likely that they are overestimating the cost of complying with the CFR. The regulators are implicitly assuming that compliance can occur only through two of the highest cost actions: blending imported renewable diesel or purchasing credits from the compliance clearance mechanism. In reality, fuel suppliers in Atlantic Canada have other lower cost methods of compliance, such as ethanol blending. Notably, Irving oil states that it can blend up to 10% ethanol in its product from the Saint John Refinery[63] and up to 15% ethanol at its Halifax terminal.[64] Ethanol blending is currently making the average cost of compliance less than the benchmarks set by the energy regulators in Atlantic Canada. Consequently, the interim price adjustments are compensating fuel suppliers for costs they are likely not incurring.

Abatement Costs with Foregone Refining Margins

The abatement actions that a fuel provider might use in response to a LCFS-style policy are significantly influenced by their costs. However, to understand which actions are considered, it is important to include all costs, or perceived potential costs, that a fuel provider might experience when thinking about how to comply with the policy. In addition to the direct cost of an abatement action, a fuel provider might also consider the indirect cost of that action, such as how it might change their revenues. For example, a refinery earns a margin on the product it refines (i.e., the refining margin) and refining and selling less product would reduce its revenues (i.e., there would be foregone refining margins on lower sales of refined petroleum products).

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[60] New Brunswick Energy and Utilities Board, 2023, Matter No. 549

[61] New Brunswick Energy and Utilities Board, Price Schedule - New Brunswick Maximum Allowable Prices and Delivery Cost, Accessed October 18th, 2023

[62] Prince Edward Island Regulatory & Appeals Commission, 2023, Notice of Hearing Pricing Model and Margins for Petroleum Products

[63] Irving Oil, 2020, Report on Sustainability

[64] Irving Oil, 2022, Report on Sustainability

Notably, when selling biofuels purchased from another producer, this action could reduce the quantity of gasoline or diesel that the refinery may sell. If this outcome is expected, the value of the foregone refining margin will be included in the abatement cost.

The following example illustrates that the foregone refining margin could change the relative abatement costs of two actions available to a fuel provider. In this case, a fuel provider can reduce emissions by blending additional biodiesel into their diesel fuel, or by adding carbon capture and storage (CCS) at their refinery process heat unit. The calculations use the following assumptions:

- Abatement from CCS is \$350/tCO_2e reduction as is the credit price in this example.
- The fuel provider does not need additional investments in blending infrastructure.
- The fuel provider assumes the prices, CI values and fuel densities recorded for 2022 in the Biofuels in Canada analysis are representative of future conditions (using Canada fuel-weighted averages): biodiesel costs \$2.08/L with a \$0.05/L transportation cost, has a CI of 4.5 gCO_2e/MJ and a density of 35.4 MJ/L; wholesale diesel (B0) sells for \$1.36/L with a CI of 93.9 gCO_2e/MJ, and a density of 38.7 MJ/L. The refining margin (net revenue) is \$0.64/L.[65]
- The fuel provider cannot pass the additional costs on to the consumers.

Based on fuel costs and properties alone, the abatement cost of blending additional biodiesel is \$279/tCO_2e. This is the abatement cost if the fuel provider can find an alternative market for all of its prior diesel production (e.g., in a region without an LCFS-style policy) and blending additional biodiesel has no impact on overall diesel sales. Therefore, the fuel provider would first choose to reduce emissions by blending biodiesel and might also invest in CCS since both abatement actions are less than the credit price.

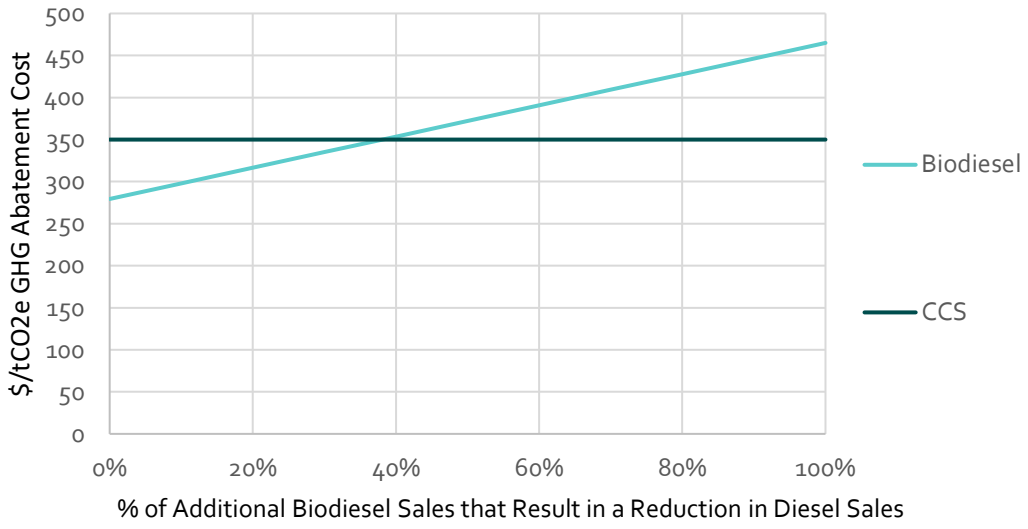
However, if selling more biodiesel does reduce diesel sales and results in a foregone refining margin, then the fuel provider loses \$0.64 for each litre of diesel not sold. To reduce GHG emissions by one tonne, the fuel provider would have to sell 11.2 GJ of biodiesel, equivalent to 289 L of diesel. If the biodiesel sales completely displace an energetically equivalent amount of diesel, then there is \$186 in foregone refining margin per tonne of GHG reduction and the net abatement cost is \$465/tonne, greater than the assumed credit price in this example. In this case, the fuel provider

[65] Kalibrate, https://charting.kalibrate.com/

would only choose to abate emissions with CCS and would not blend more biodiesel since its abatement cost is greater than the credit price.

It is likely that the impact of additional biodiesel blending on diesel sales is somewhere between the maximum and minimum cases explained above. Still, the abatement cost of biodiesel in this example is sensitive to its impact on diesel sales. If just over 40% of the additional biodiesel sales offset an energetically equivalent amount of diesel sales, CCS is the lower cost abatement action (Figure 12). In reality, this would be further complicated by changes in corporate income tax, lost crude oil production and/or retail revenues for integrated refiners, potential changes in wholesale or retail prices, and economies of scale (i.e., it costs less per litre to refine greater volumes). Nonetheless, this example indicates why a fuel provider might prefer to reduce the emissions intensity of their fuels rather than blend biofuels, even when that latter action appears to have a lower abatement cost.

Figure 12: Relative abatement cost of blending biodiesel versus capturing and storage of CO_2e as a function of how biodiesel sales affect diesel sales.



3. Methodology

3.1. Process

Table 16 summarizes the tasks we undertook in this study as well as our approach for each of these tasks.

Table 16: Study method by task

Task	Approach
1. Tabulate renewable fuel and fossil fuel use	Provincial and federal renewable and low carbon fuel regulation compliance data (published, direct communication) were collected. The data in this report includes January 1, 2010, to December 31, 2021, the most recent data period available for most jurisdictions (but also includes 2022 data from British Columbia, Alberta and Saskatchewan). Biofuel products were defined as: ethanol, biodiesel, hydrogenation-derived renewable diesel (HDRD), as well as co-processed renewable fuels. These products were further disaggregated by biomass feedstocks as identified and estimated from personal correspondences with government contacts and biofuel market experts, publications, or based on region of origin. Fossil fuel consumption is taken from government regulator data where available and otherwise from Statistics Canada data.
2. Characterize biofuel CI and GHG reductions	Carbon intensities (CI) were taken from government regulator data where available and otherwise defined with GHGenius (v.4.03a) with a review by government contacts and industry experts. Energy efficiency (i.e., change in energy per km) impacts (or lack thereof) are defined by literature review. These assumptions were used to estimate the GHG impact of biofuel. Furthermore, this report illustrates how average CI of fuel types (e.g., ethanol, biodiesel) can change through time using the data on fuels registered under the British Columbia's fuels policy. This province is used as a case study because it is one of the few jurisdictions where CI is documented by fuel.
3. Estimate the impact of biofuel on energy costs	Wholesale ethanol and biodiesel prices from the Chicago Mercantile Exchange (CME) were used to estimate the landed price (based on typical rail shipping rates) of these fuels in major Canadian cities. Regular gasoline and diesel prices were used in these cities (Kalibrate data) to estimate the unblended wholesale price of the petroleum fuels. HDRD prices were estimated using Diamond Green Diesel's financial materials for investors. These prices, along with marketing margins and taxes were then used to quantify how biofuels may have affected the fuel costs for consumers, accounting for the volumetric energy content of biofuels and the impact of ethanol on the octane rating of gasoline/ethanol fuel blends.

	Task	Approach
4.	Estimate fuel displaced by PEVs	PEV sales data from Statistics Canada was used to estimate the stock of these vehicles by province. The fuel displaced by PEVs is estimated assuming EVs are driven the same annual distance as gas vehicles and the energy effectiveness ratio is from the final *Clean Fuel Regulations*, with the average energy intensity of PEVs based on a weighted average of vehicles sold in 2021.
5.	Produce estimated results for 2022	For provinces where no 2022 data was yet available, all results (volumes, GHG and cost impacts) were estimated for 2022, assuming constant biofuel blending rates from 2021, or a trend based on a change in the regulated fuel blending rate, and Statistics Canada data to define the size of the gasoline and diesel pools. Carbon intensities for 2022 are taken from GHGenius or assumed based on provincial data for 2021.

3.2. Summary of Inputs

Table 17 summarizes the data and assumptions used in this analysis to complete tasks 1 through 4. The data used in the analysis was either obtained through direct communication with government contacts or from published data (represented in green). Some data required assumptions (represented in yellow). For example, for regions that do not collect data on biofuel CI as part of their regulations, the default CI from GHGenius was assumed to be representative of the average biofuel consumed in that region. The assumptions used to complete task 5 (estimate results for 2022) are described following the discussion of Table 17 below.

Discussion of Inputs

Table 17 also flags the greatest uncertainties in orange, representing data gaps. For example, neither Québec nor the Atlantic provinces have reporting mandates for biofuels blended into transportation fuels. To infer the volume of ethanol, biodiesel, and HDRD consumed in these provinces, we used the difference between national consumption totals, reported by Environment and Climate Change Canada (ECCC) for 2011-2021[66,67] and the data we collected. Therefore, the resulting biofuel consumption reported for Québec and the Atlantic provinces is particularly uncertain

[66]Environment and Climate Change Canada, 2016, Renewable Fuels Regulation Report: December 15, 2010 to December 31, 2012. Available on Google Drive.

[67] Environment and Climate Change Canada, 2020, Open Data: Renewable Fuels Regulations 2013, 2014, 2015, 2016, 2017,2018, 2019, 2020 and 2021. Available on Google Drive.

since it is the difference between federal data and the sum of provincial data, all of which is collected using different methodologies.

While ECCC data defines total renewable fuel consumption in most years, there are some exceptions. For example, for 2019, we increased the national total consumption of biomass-based diesel relative to what was reported by ECCC, from 786 to 792 million L/yr, because the sum of fuel used for compliance with provincial regulations was more than the reported national volume used for compliance with the federal renewable fuel regulations. This decision is based on information from industry contacts indicating that some renewable fuel imports from the U.S. were not included in ECCC reporting for the RFR. This situation highlights some of the uncertainty in the data and the difficulty with data collection and analysis. Provincial data is not collected in the same way as federal data and these sources are not reconciled with each other. Furthermore, prior to 2022, it was difficult to calculate biomass-based diesel consumption using production and trade data because HDRD did not have its own harmonized system (HS) code. The lack of an HS code over much of the period covered by this analysis makes the quantity of this fuel imported into Canada uncertain. To date, much of the renewable diesel imported into Canada is still not reported under the correct HS code.

Because ECCC does not report renewable fuel consumption in 2010, consumption in that year is based on the US Department of Agriculture Global Agricultural Information Network (USDA GAIN).

The relative split between biodiesel and HDRD remains an uncertainty for all regions other than British Columbia and Alberta. The Ontario government reported that more HDRD was used for compliance than biodiesel. For 2020 and earlier, an 80:20 ratio of HDRD to biodiesel is assumed in Ontario and Québec (for years where our analysis shows consumption). No HDRD consumption is assumed in Saskatchewan, and the Atlantic region, or for Manitoba prior to 2021. Specific assumptions for biodiesel and HDRD and the associated carbon intensities are listed in “Appendix A: Biofuel Type and Feedstock Assumptions and Data”.

CI values are mostly from GHGenius 4.03a, except in Ontario and British Columbia where provincial governments provided data on CIs used for compliance. However, the CI for gasoline in all years and regions has been increased by 7 gCO_2e/MJ relative to the value from GHGenius, such that the combustion (i.e., tailpipe) GHG intensity is approximately 70 gCO_2e/MJ, based on input from (S&T)^2 Consultants. The updated gasoline CIs closely align with what is in the latest GHGenius version 5.02 and the gasoline combustion GHG coefficient used by ECCC in the National Inventory Report. These sources account for emissions of carbon monoxide and volatile organic

compounds such as acetone or toluene that oxidize to CO_2 in the atmosphere. For example, ECCC uses a combustion GHG coefficient of 67 to 71 gCO_2e/MJ for light-duty vehicles operating under tier 1 and tier 2 emissions standards,[68] whereas GHGenius 4.03a uses 63 gCO_2e/MJ.

2022 Estimate

As noted above in Table 16, results for 2022 in most regions are estimates that are based on several inputs and assumptions for fuel volumes, blend rates and fuel CI. This year, British Columbia, Alberta and Saskatchewan provided preliminary data for 2022. We used a variety of methods to estimate 2022 fuel volumes for other provinces. For Manitoba, we assumed compliance with the new blending rates (10% in gasoline and 5% in diesel). In Ontario, Québec and the Atlantic provinces we assumed a constant blending rate from 2021 through to 2022. CI scores for all of these provinces are based on GHGenius 4.03a, except for British Columbia and Ontario where they are based on compliance data (for 2022 in British Columbia and set equal to 2021 values in Ontario).

We estimated the size of the gasoline and diesel pools in 2022 for most provinces, excluding Alberta and British Columbia, and the diesel pool in Saskatchewan, where this information was included in the 2022 data. The estimate is based on using Statistics Canada data (Table 25-10-0081-01 Petroleum products by supply and disposition, monthly). For 2022, gasoline and diesel consumption data are available from Statistics Canada only at a Canada-wide level, rather than disaggregated by province, as it was in 2019 and earlier. Therefore, consumption by province for 2022 in the analysis is a function of consumption in 2021 multiplied by the change in national consumption between those years. For example, nationally there was a 3% increase in gasoline demand from 2021 to 2022 (a continued rebound after the height of the COVID pandemic). Therefore, we assume that gasoline consumption in 2022 was 3% larger than it was in each province in 2021 (where 2021 consumption is provided from fuel blending regulation data or taken from Statistics Canada energy data - Statistics Canada Table: 25-10-0030-01: Supply and demand of primary and secondary energy in natural units).

[68] Environment and Climate Change Canada, 2019, National Inventory Report 2019, Emissions Factors Table A6-12

Table 17: Summary of Inputs (data in green, assumptions in yellow, major uncertainties in orange)

	BC	Alberta	Saskatchewan	Manitoba	Ontario	Quebec	Atlantic
Gasoline volume	RLCFRR Summary: 2010-2022. Gasoline and diesel volumes are the total, not the non-exempt volume	2011-2022: From govt. contact. For 2010 Statistics Canada Table: 25-10-0030-01: Supply and demand of primary and secondary energy	Statistics Canada Table: 25-10-0030-01: Supply and demand of primary and secondary energy	Data from govt. contact to 2019, estimated for 2020 onward	Data from govt. contact to 2021	Statistics Canada Table: 25-10-0030-01: Supply and demand of primary and secondary energy	Statistics Canada Table: 25-10-0030-01: Supply and demand of primary and secondary energy
Ethanol fuel volume		Data from govt. contact	Average % blending rate to 2022 provided by govt. contact			Difference between national total reported under the RFS by ECCC[1] and sum from other provinces, pro-rated to QC and Atlantic CDA	Difference between national total reported under the RFS by ECCC[1] and sum from other provinces, pro-rated to QC and Atlantic CDA
Diesel volume		2011-2022: From govt. contact. For 2010 Statistics Canada Table: 25-10-0030-01: Supply and demand of primary and secondary energy	Data through to 2022 from govt. contact		2018-2021: data from govt. contact. 2010 to 2017 Statistics Canada Table: 25-10-0030-01: Supply and demand of primary and secondary energy.	Statistics Canada Table: 25-10-0030-01: Supply and demand of primary and secondary energy	Statistics Canada Table: 25-10-0030-01: Supply and demand of primary and secondary energy, diesel fuel oil
Biodiesel and HDRD volume		Data to 2022 from govt. contact	Data from govt. contact		Data for 2018-2021 from Gov't. Provisional data from govt. contact for 2015. Estimates for 2016 and 2017.	Same method as for ethanol	Same method as for ethanol

	BC	Alberta	Saskatchewan	Manitoba	Ontario	Quebec	Atlantic
Biofuel feedstock	RLCFRR Summary: 2010-2022. Gasoline and diesel volumes are the total, not the non-exempt volume	Assumptions reviewed by govt. contacts and (S&T)[2] Consultants					
Fuel Carbon Intensity	RLCFRR Summary: 2010-2020. Gasoline and diesel volumes are the total, not the non-exempt volume	GHGenius 4.03a by year for Alberta	GHGenius 4.03a by year for Saskatchewan	GHGenius 4.03a by year for Manitoba	Ethanol: GHGenius 4.03a by year for Ontario for 2010-2019, data from govt. contact for 2020 and 2021. Biodiesel/HDRD: avg. from govt. contact for 2015 and 2018-2021, estimated for 2010-2013, 2016 and 2017	GHGenius 4.03a by year for Québec	GHGenius 4.03a by year for Canada East
Wholesale gasoline and diesel price	Kalibrate,[2] for Vancouver	Kalibrate,[2] for Calgary	Kalibrate,[2] for Regina	Kalibrate,[2] for Winnipeg	Kalibrate,[2] for Toronto	Kalibrate,[2] for Montreal	Kalibrate,[2] for Halifax, Saint John, Charlottetown, and St Johns
Wholesale ethanol price	Chicago Mercantile Exchange futures price[3]						
Wholesale biodiesel price	Chicago Mercantile Exchange spot price[3]						
Wholesale HDRD price	Diamond Green Diesel Investor Financials from January 2015 onward, Neste Oyj for 2010 to 2014[6]						
Marketing margin	Kalibrate marketing,[2] for Vancouver	Kalibrate marketing,[2] for Calgary	Kalibrate marketing,[2] for Regina	Kalibrate marketing,[2] for Winnipeg	Kalibrate marketing,[2] for Toronto	Kalibrate marketing,[2] for Montreal	Kalibrate marketing,[2] for Halifax, Saint John, Charlottetown, and St Johns
Fuel Taxes, including carbon tax cost	NRCAN, Fuel Consumption Taxes in Canada[7]						

	BC	Alberta	Saskatchewan	Manitoba	Ontario	Quebec	Atlantic
Carbon prices	Government of BC, British Columbia's Carbon Tax[8]	Government of Alberta, Alberta's Carbon Levy[9] and Government of Canada[10]	Government of Canada, Greenhouse Gas Pollution Pricing Act[10]	Government of Canada, Greenhouse Gas Pollution Pricing Act[10]	Government of Ontario, past auction information and results[11] and Government of Canada[10]	Government of Québec, The Carbon Market[12]	Government of Canada, Greenhouse Gas Pollution Pricing Act[10] and Nova Scotia Cap-and-Trade Program Auction of Emission Allowances[13]
Biofuel transportation cost	5-13 $/bbl (2018), applied to biofuels based on distance between Chicago and representative city[4]. Compared with rail freight rates listed by the Canadian Railway Association and inflated by their rail freight cost index[16].						
Ethanol octane	Used a value of 113, corresponding to ethanol used in low concentration blends						
Value of octane	Value in $/octane point/L based on difference in the bulk price of regular and premium gasoline in the United States[5]						
Energy efficiency	Assume vehicle energy efficiency (e.g., km/GJ fuel consumed) is constant regardless of the blend.[14]						
Refinery and gasoline GHG intensity	Assume that petroleum refining and gasoline blendstock GHG intensity is independent of the biofuel blend.						
Impact of biofuels on refining and marketing margins	Assume the refining margins for petroleum fuels would be same in a counterfactual scenario without biofuel blending. The refining margin is the $/L net revenue of refiners, embedded in gasoline and diesel wholesale prices from Kalibrate Marketing. Also assume the marketing margin would be the same if there were no biofuel. The marketing margin is the $/L net revenue of the fuel retailers.						
Electric vehicle sales, activity, and GHG intensity	Plug-in electric vehicle (PEV) sales are provided by Statistics Canada for 2011-2022 (Table: 20-10-0021-01). PEV stocks are from Statistics Canada for 2011-2021 (Table: 23-10-0308-01), while the 2022 stock is inferred from sales. Average annual mileage assumed to be equal to the average for conventional light-duty vehicles since 2010 in the NRCan comprehensive energy use database. PEV assumed to use 0.2 kWh/km, and plug-in hybrids assumed to travel 69% of annual km using electricity. Electricity direct GHG intensity by province is from the National inventory report, with upstream emissions inferred from the lifecycle electricity GHG intensities listed in Schedule 5, Canada Gazette, Part I, Volume 154, Number 51: Clean Fuel Regulations.						

1) ECCC, Open Data reported under the Renewable Fuels Regulations, 2010 through 2021. National total for biomass-based diesel in 2018 and 2019 was increased slightly based on information and data from industry and government contacts.

2) Kalibrate

3) Chicago Mercantile Exchange ethanol futures. Biodiesel prices are from an OPIS subscription.

4) Gallagher, Paul and Denicoff, Marina. 2015. Ethanol Distribution, Trade Flows, and Shipping Costs, Iowa State University Economics Technical Reports and White Papers

5) EIA. 2021. Petroleum & Other Liquids: Refiner Gasoline Price by Grade and Sales Type

6) Darling Ingredients. 2023. Investor Relations

7) Natural Resources Canada. Fuel Consumption Taxes in Canada

8) Government of British Columbia. British Columbia Carbon Tax

9) Government of Alberta. 2019. About tax and levy rates and prescribed interest rates. Note that the current source includes no mention of past carbon levy rates

10) Government of Canada, 2018, *Greenhouse Gas Pollution Pricing Act*

11) Government of Ontario. Past auction information and results

12) Government of Quebec. The Carbon Market: Cap-and-Trade Auction Notices and Results

13) Government of Nova Scotia, Nova Scotia Cap-and-Trade Program

14) 113 to 115 is a typical value for blends cited by EIA. This value corresponds to ethanol used in low concentration blends. The octane rating of pure ethanol is 100.

15) Most evidence indicates that there is no change in energy efficiency (see literature review in 2019 Biofuels in Canada report):

Niven, R.K., 2005, Ethanol in gasoline: environmental impacts and sustainability review article. Renewable and Sustainable Energy Reviews 9, 535-555. doi.org/10.1016/j.rser.2004.06.003

Yan, X. et al., 2013, Effects of Ethanol on Vehicle Energy Efficiency and Implications on Ethanol Life-Cycle Greenhouse Gas Analysis. Environmental Science & Technology 47, 5535-5544. DOI: 10.1021/es305209a

US Environmental Protection Agency, 2016, Draft Technical Assessment Report: Midterm Evaluation of Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards for Model Years 2022-2025.

Coordinating Research Council, 2018, Renewable Hydrocarbon Diesel Fuel Properties and Performance Review (CRC Report No. DP-08-18).

16) Railway Association of Canada, 2023, Rail Trends 2022

3.3. Updates to the Methodology

This current edition of the Biofuels in Canada analysis includes some methodological changes that affect the results for 2020 and prior years:

- **Renewable fuel rail transportation costs:** Renewable fuel prices in each province are taken in Chicago and then adjusted to include rail transportation costs. These costs were previously inflated each year using the consumer price index. As of 2022, they are now inflated using the Railway Association of Canada's rail cost index available in the annual Rail Trends reports (i.e. index of freight revenue per revenue tonne mile). On average, this change has slightly reduced the cost of renewable fuels over the time-horizon of the analysis.
- **Total PEV stock:** Statistics Canada now publishes total vehicle registrations by powertrain in Table 23-10-0308-01. This data is used to define the stock of PEVs by province rather than estimating this stock from sales data. This change has reduced our estimate for the number PEVs operating in Canada in 2020 by about 20,000 vehicles, or 0.1% of the total light-duty vehicle population.

As a reminder, the 2021 and 2022 edition of this analysis included some important methodological changes that remain in this update:

- **Co-processed fuels:** The volumes and CI of co-processed fuels produced and consumed in British Columbia are now based on government data.
- **Change in use of Statistics Canada data:** The model was updated to account for how Statistics Canada's Report on Energy Supply and Demand (RESD) includes ethanol in volumes of motor gasoline but does not include volumes of biodiesel in the diesel volumes.
- **Estimated Octane Value from Wholesale Prices:** Starting with the 2021 Biofuels in Canada analysis, the model uses bulk wholesale gasoline prices to better reflect the cost and value of octane. The impact and reasoning behind this change is discussed in more detail in Appendix C: Explanation of Changes to Cost Analysis Methodology Made in 2021.
- **Change in Statistics Canada Data Source:** Due to discontinuation of provincial-level fuel demand data in the Supply and Disposition of Petroleum Products tables, the model is uses Statistics Canada's data on energy consumption.
- **HDRD Price Data:** Starting in the 2021 analysis, the HDRD prices implied in Diamond Green Diesel's financial materials were used in place of the Neste data for

prices starting in January 2015. Imports from the U.S. are eligible for a $1 USD/Gallon blenders' tax credit, which would be passed through to export prices. The U.S. imports are assumed to be the price-setting supply in the Canadian market.

- **Mid-Year Tax Changes:** The gasoline and diesel cost analyses were adjusted to include a month-by-month representation of fuel taxes to reflect the fact that tax rates typically change with governments' fiscal year (e.g., after March 31st), rather than the calendar year.
- **Light-duty PEVs** Estimates for energy consumption and avoided GHG emissions for PEVs have been included, starting in the 2021 update, to quantify the role of these other low-carbon transportation options alongside blended biofuels. PEV sales and registrations are reported in Statistics Canada data, but the energy and GHG impact must also be estimated, using the methodology described in Appendix D: Plug-in Electric Vehicle Analysis Methodology.

Box 1: What is Co-Processing?

Co-processing is the process of refining vegetable/animal oils with crude oil at a petroleum refinery to create one blended output. For example, vegetable oil or tallow is added directly to intermediate petroleum distillates; they then are further refined together.

In contrast, ethanol, biodiesel, and HDRD are manufactured by stand-alone plants or dedicated production lines within a refinery. Finished biofuels are then mixed with gasoline and diesel.

As of 2023, the combined co-processing capacity in British Columbia (Parkland and Tidewater) is in the range of 100 million litres of co-processed feedstock per year. For reference, total biodiesel and HDRD consumption in BC was about 500 million litres in 2022.

4. Results and Discussion

The results section summarizes data on the biofuel content of transportation fuels sold in Canada, including an estimate of the quantity of electricity consumed by light-duty PEVs. Also included in the results is an analysis of the avoided GHG emissions, and cost impacts resulting from blending ethanol, biodiesel and HDRD with gasoline and diesel (co-processed fuels and PEVs are not part of the cost analysis). This analysis also presents data on light-duty PEV sales and the total number of light-duty PEVs on the road. The results in this section are reported at a national level, though these national results are an aggregation of provincial level analysis. The analysis and corresponding data on individual provinces are in the associated excel spreadsheet, named " Biofuels in Canada Analysis - 2023-10-31".

4.1. Fuel Consumption

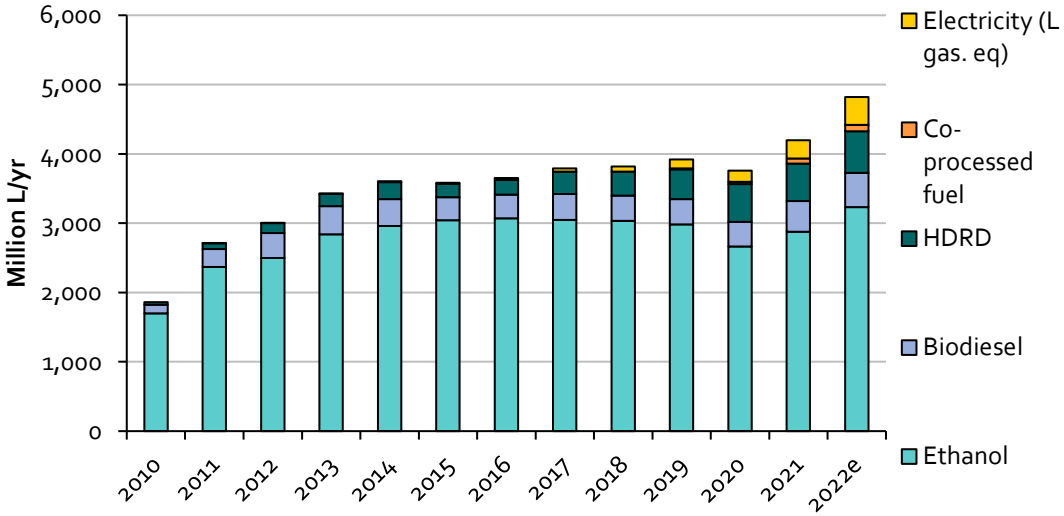
Figure 13 and Table 18 summarize the fuel consumption data and light-duty PEV electricity consumption (expressed in terms of litres of gasoline equivalent). In 2021, total renewable fuel consumption in Canada rebounded from the decline that occurred during COVID in 2020 and surpassed consumption prior to the pandemic. As of 2021, ethanol consumption was 2,876 million L/yr, just below the pre-pandemic levels seen in 2019. Biodiesel consumption increased to 445 million L/yr in 2021 while HDRD consumption remained steady at about 540 million L/yr. Co-processed fuel consumption continued to rise, reaching 72 million L/yr in 2021, as did the quantity of fuel displaced by PEVs, hitting a new high of 262 million L/yr (gasoline equivalent).

Table 18: Canadian fuel consumption in million litres per year

Fuel type	2016	2017	2018	2019	2020	2021	2022e
HDRD	215	323	344	432	543	541	597
Biodiesel	341	376	367	360	356	445	494
Ethanol	3,069	3,047	3,034	2,985	2,665	2,876	3,234
Co-processed				14.5	35.6	72.0	93.8
Electricity*	26.6	42.9	74.4	127.8	159.1	262.6	402.4
Gasoline (Pure)	42,391	42,996	43,096	42,896	37,093	38,646	39,377
Diesel (Pure)	25,754	27,644	27,618	27,167	25,250	26,627	27,595

*Electricity consumption is measured in terms of volume of gasoline equivalent (i.e., what would have been consumed if PEVs were conventional vehicles). This calculation assumes that PEVs are 4.1 times more energy efficient than conventional vehicles, as per the assumption used in the *Clean Fuel Regulations*.[69]

Figure 13: Renewable and low-carbon transportation energy consumption in Canada



The 2022 estimate shows renewed growth in ethanol consumption, with the bulk of that change showing up in preliminary data released by Alberta. The data show that substantially more ethanol was blended in Alberta than is required by law, possibly to generate early CFR compliance credits. Likewise, the fuel displaced by electric vehicles is also estimated to grow rapidly in 2022. Based on sales data, we estimate that quantity increasing by 1.5 times relative to 2021 to about 400 million L/yr.

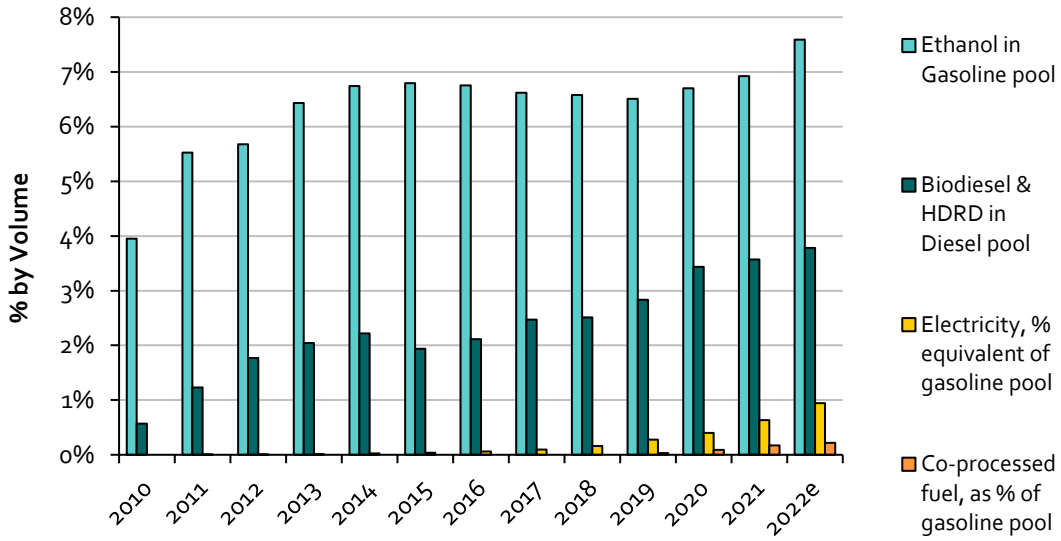
[69] Government of Canada, Canada Gazette, Part II, Volume 156, Number 14: Clean Fuel Regulations

Note that the volume of HDRD consumed in total and by province is more uncertain compared to other biofuels. HDRD was only recently given a Harmonized System (HS) code within trade data, making it difficult to quantify biomass-based diesel consumption in Canada using import, export, and production data. All reasonable assumptions regarding HDRD trade indicate that the total volume consumed in Canada is in the vicinity of what is reported in this analysis and by Environment and Climate Change Canada. Regarding the breakdown of HDRD consumption by province, only British Columbia and Alberta report HDRD consumption separately from biodiesel. For other provinces, we use advice from industry experts to allocate the remaining HDRD consumption.

4.2. Blending Rates

Figure 14 shows the percentage of renewable fuel in the gasoline pool (ethanol) and in the diesel pool (biodiesel and HDRD). Due to the uncertainty in the volume of HDRD consumed in Canada, biodiesel and HDRD are grouped together to avoid misrepresenting the data. The percentages are based on total fuel consumption, including all fossil and renewable fuel volumes as well as gasoline and diesel volumes exempted from biofuel blending policies. As well, the content does not include any policy-based adjustments to the renewable fuel share (e.g., a volume-equivalency bonus awarded for using for low-CI feedstocks or fuels, as is the case in Ontario's *Cleaner Transportation Fuels* regulation). Co-processed fuel volume and gasoline consumption displaced by light-duty PEVs are shown as a percent of the gasoline pool.

Figure 14: Renewable fuel content by fuel pool, 2010 to 2021, estimate for 2022



2021 is the first year that renewable fuel in gasoline surpassed 7%. Ethanol was blended at 6.9% by volume and co-processed fuel, much of which is renewable gasoline, was equivalent to about 0.2% of gasoline pool volume. Because of the apparent increase in ethanol blending in Alberta in 2022, the 2022 estimate for that year shows that renewable fuel in gasoline will approach 8%. Meanwhile, renewable fuel in diesel reached a new high of 3.5% by volume in 2021 (Figure 14).

The national average blend rates are above what is required by the federal *Renewable Fuels Regulation* (RFR), in part a result of stacking provincial policies with the federal regulation. For example, once a regulation drives investment in blending infrastructure, it generally results in over-compliance in most provinces, possibly due to the low-cost octane provided by ethanol. In the gasoline pool, the blend rate required by the RFR is 5% but the volumetric blend rate of ethanol in gasoline was 6.9% in 2021 (Figure 15). In the diesel pool, the British Columbia and Ontario policies in particular stack with the federal regulation to increase the quantity of biomass-based diesel by about 80% beyond what is required for simple volumetric compliance with the RFR (3.5% vs. 2% in 2021, Figure 16).

Figure 15: Renewable fuel in the gasoline pool in 2021 versus the regulated blend rate, excluding co-processed fuel volumes.

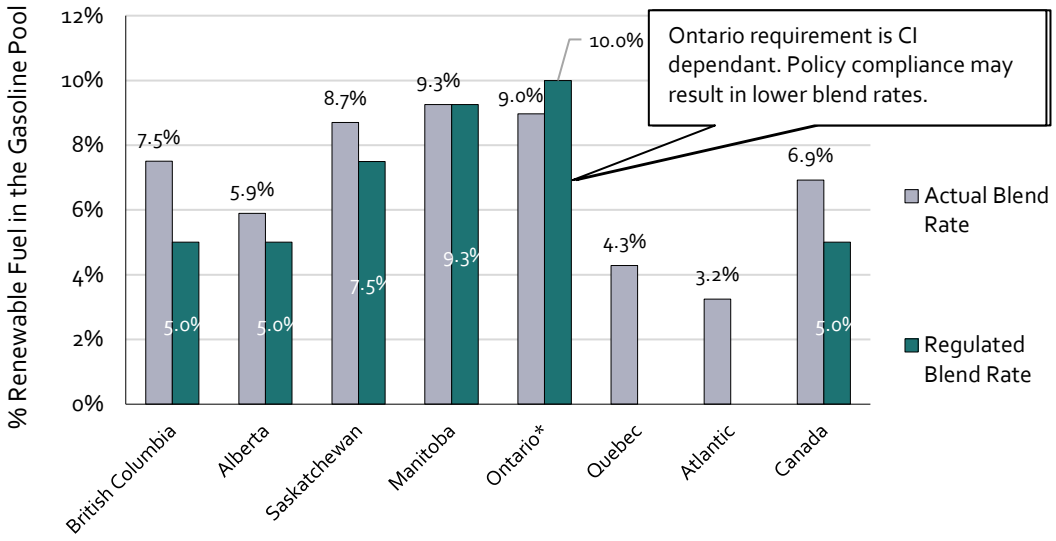
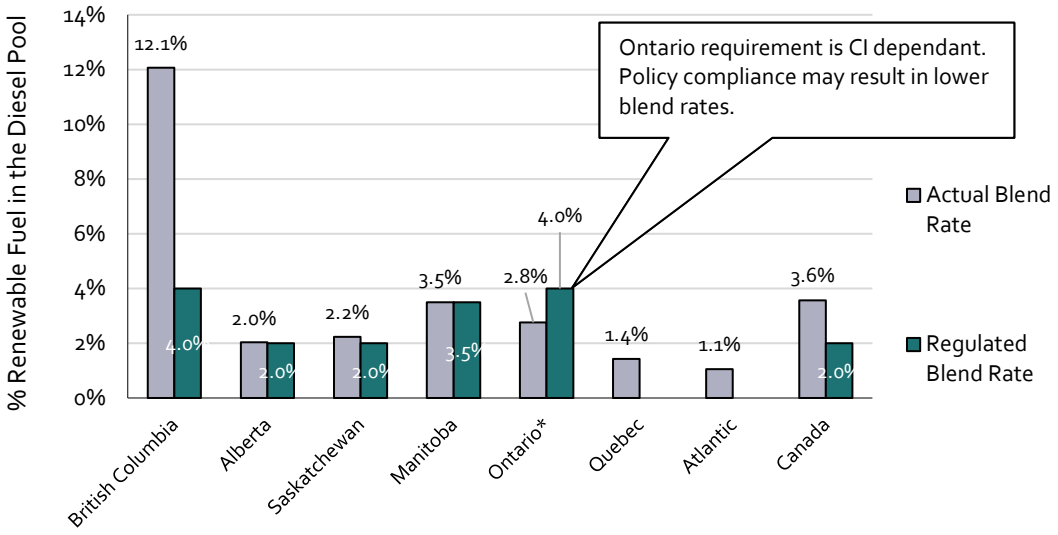


Figure 16: Renewable fuel in the diesel pool in 2021 versus the regulated blend rate



This current rate of renewable fuel blending means that, on average, fuel suppliers are already in compliance with the *Clean Fuel Regulations* (CFR) and will not need to take additional compliance actions until at least 2025. Figure 17 illustrates this outcome by showing the hypothetical generation of CFR credits and debits during the first three compliance periods (i.e., to the end of 2025). In the following figure, we assume fuel consumption, blending rates and CIs remain constant at the 2022 values estimated in this edition of Biofuels in Canada. As described in section 2.3 of this report:

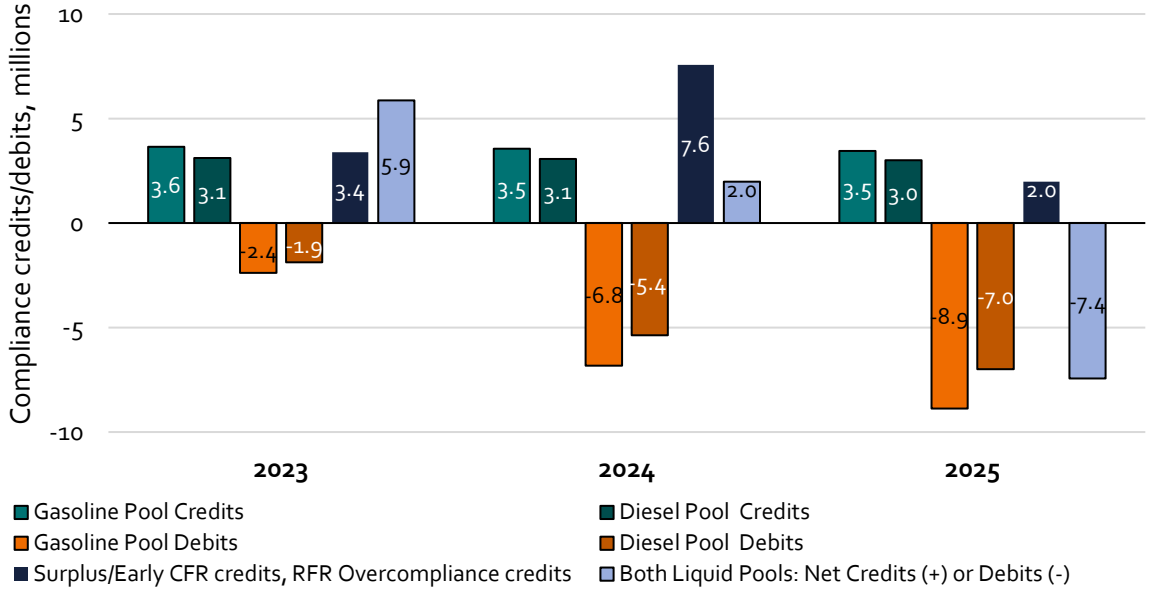
- CFR debits are not produced until the second half of 2023.
- Early CFR compliance credits could be obtained starting in the second half of 2022.
- Overcompliance with the RFR, which ends at the end of 2022, produced CFR credits that can be used as of 2024 (as described in section 2.3 of this report or in section 169(1) and 170(1) of the CFR).[70]

Based on these inputs, there is a surplus of almost six million CFR credits at the end of 2023, declining to a surplus of about two million credits by the end of 2024. By 2025, current blending rates result in a net debit, meaning fuel suppliers would need to take additional actions to comply with the CFR (Figure 17). This is a conservative conclusion, since it does not account for additional credit generation under compliance categories 1 and 3 (i.e., GHG reductions in upstream fuel production and for fuel switching), debit reductions from the increased use of PEVs, or the additional

[70] www.gazette.gc.ca/rp-pr/p2/2022/2022-07-06/html/sor-dors140-eng.html

credit generation from increased renewable fuel consumption driven by the rising stringency of some provincial regulations (i.e., British Columbia, Ontario, Québec). Therefore, this analysis shows that the CFR policy may drive greater renewable and low-carbon fuel blending by 2025 at the earliest.

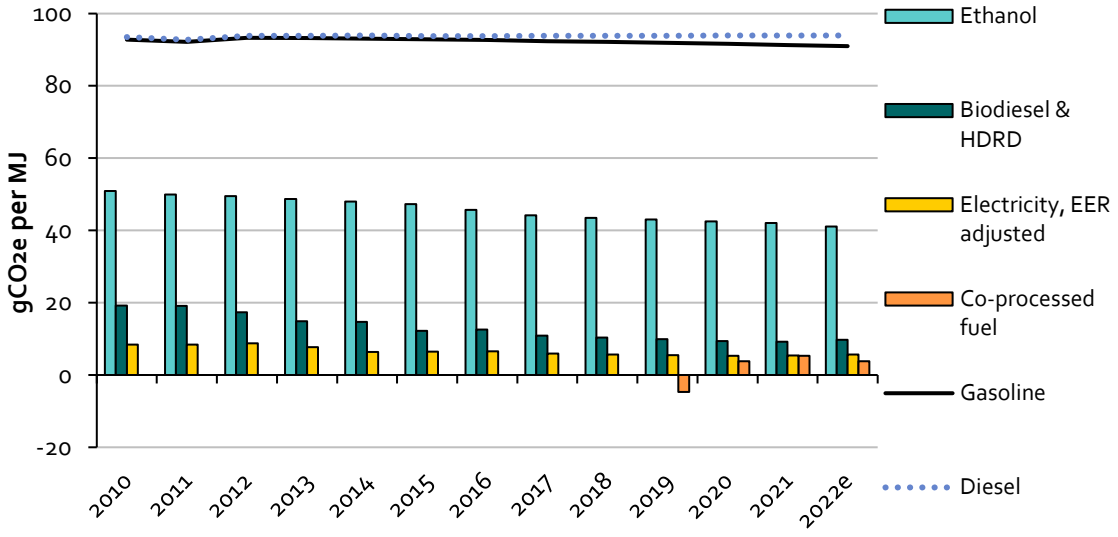
Figure 17: Hypothetical credits and debits created under the CFR in its first three compliance periods (for fuels only, i.e., just compliance category 2)



4.3. Lifecycle GHG Emissions

Figure 18 shows the estimated lifecycle CI (i.e., well to wheels or farm to wheels) of transportation fuels in Canada between 2010 and 2021, with an estimate for 2022e. Due to uncertainties in volume, feedstock and CI, biodiesel and HDRD are grouped together.

Figure 18: Lifecycle CI by fuel type within Canada, from 2010 to 2021 with an estimate for 2022.



The national average CI for ethanol in 2021 was 42 gCO_2e/MJ, 17% below the value in 2010. The weighted average for the biomass-based diesel CI in 2021 was 9 gCO_2e/MJ, 52% below the value in 2010 (Figure 18). The causes of this change are a decline in fuel CI from the British Columbia LCFS and the Ontario Cleaner Transportation Fuels Regulation, as well as the year over year CI reductions estimated with the GHGenius model. The CI of co-processed fuels reported in the British Columbian LCFS compliance data is about 5 gCO_2e/MJ (see Box 2 on page 58 for more information about the CI of co-processed fuels). The average CI for electricity is about 5 gCO_2e/MJ. This CI is low because it is adjusted by an energy effectiveness ratio (EER) of 4.1 (i.e., per km, PEVs use 4.1 times less energy than a conventional vehicle). Furthermore, it is weighted by electricity consumption by province, where most PEVs are in British Columbia, Ontario and Québec, which have low-CI electricity.

GHG emissions resulting from direct land use changes (DLUC) are included in the lifecycle CI of biofuels. DLUC include the GHG emissions resulting from the conversion of pasture or forest to crop land, with the former often being a larger carbon sink than crop land. When reporting carbon intensities, some policies, such as the California *Low-Carbon Fuel Standard*, include "indirect land-use change" (ILUC) emissions in the carbon intensities of biofuels. ILUC emissions are one type of "indirect effect" emissions that are applied to biofuels under the assumption that biofuel production increases agricultural commodity prices which indirectly result in more pasture and forest being converted to crop production. The data systems and lifecycle modelling to support accurate measurement of indirect-effect emissions for all fuels (liquid fossil and renewable fuels, electricity, hydrogen) are the subject of on-going research and

policy debate. At present, Canadian policymakers do not include ILUC, but there has been speculation that they may include them in the future.[71] The lifecycle model developed for the *Clean Fuel Regulations* does not incorporate ILUC emissions for any fuel. Therefore, compliance credit generation is not affected by ILUC, except for cases where the biofuel would adversely impact biodiversity.[72]

For most provinces, the CI estimates in Biofuels in Canada were based on average fuel CI from GHGenius 4.03a. For British Columbia, the CIs are reported in provincial LCFS compliance reports to 2022 (note that CI values prior to December 31st, 2014, come from GHGenius 4.01b. Likewise, Ontario provides an average CI value for biomass-based diesel.

Meanwhile, the national CI of electricity is based on a transportation-consumption weighted average of direct emissions intensity by province from 2010 to 2021, reported in Canada's National Inventory Report[73] (NIR), adjusted to include upstream and indirect GHG emissions (e.g., related to fuel production as well as consumption for electricity generation). The upstream and indirect GHG emissions intensity added to the NIR value is based on the difference between NIR emissions intensity by province and the default electricity CI by province reported in the *Clean Fuel Regulations*.[74] This CI value is divided by an energy efficiency ratio of 4.1 (i.e., EER, the ratio of energy used by conventional vehicle to a PEV). This provides a consistent comparison with liquid fuel based on energy used per km travelled.

The results in Figure 18 show that the biofuels consumed in Canada offer significant lifecycle CI reductions relative to gasoline and diesel. The data implies that, on average in 2021, ethanol sold in Canada was 54% less carbon intensive than gasoline, while biodiesel and HDRD were about 90% less carbon intensive than diesel. As of 2021, the EER adjusted CI of electricity was about 94% less than gasoline. This difference is a function of the energy efficiency of PEVs (i.e., the EER), the low average CI of electricity generation in Canada overall, and the fact that most PEV adoption to date has been concentrated in provinces where electricity generation has a particularly low CI, namely British Columbia, Ontario and Québec.

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[71] Meyer, C., *Canada's Math May Overlook Carbon Pollution from Biofuels,* Canada's National Observer, April 18th, 2018

[72] Government of Canada, 2022, Canada Gazette, Part II, Volume 156, Number 14: Clean Fuel Regulations

[73] Government of Canada, 2021, National Inventory Report 1990-2019: Greenhouse Gas Sources and Sinks, Part 3

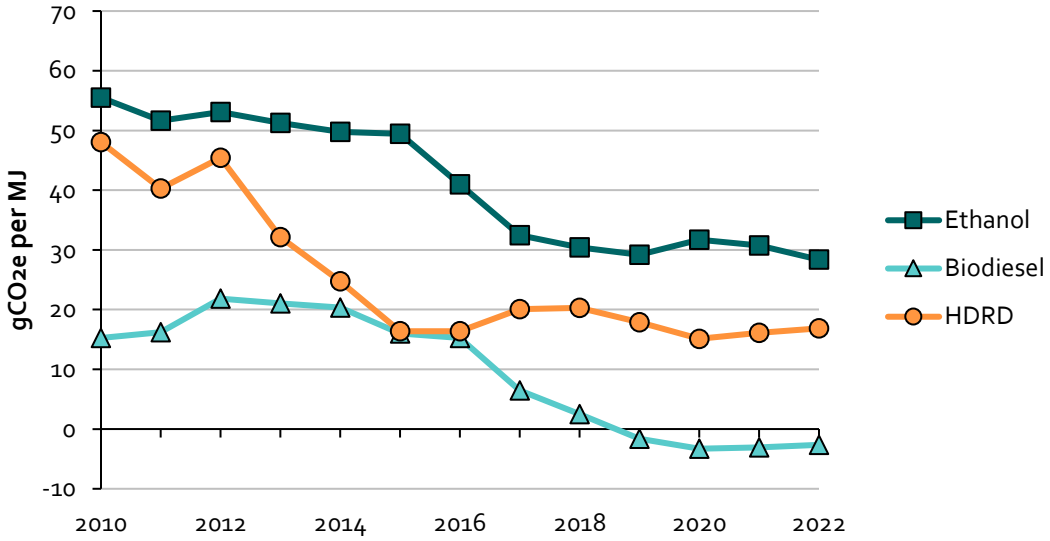
[74] Government of Canada, 2022, Canada Gazette, Part II, Volume 156, Number 14: Clean Fuel Regulations

Figure 18 also suggests that the CIs of ethanol, biodiesel, and HDRD are decreasing over time. In part, this is because the regional CIs used to produce Figure 18 are based on default data from GHGenius 4.03a. That dataset extrapolates from historical trends and assumes that the GHG intensity of inputs to biofuel production continue to decline over time, hence the fuel CI declines as well (e.g., reduced GHG emissions associated with cleaner electricity consumption for biofuel refining, process improvements, increased agricultural yields, and reduced fertilizer inputs per area farmed, etc.).

Nonetheless, the CI values for biofuels consumed in Ontario and in British Columbia, which are based on data rather than modelling results, indicate a similar trend of an overall decline in the CI of biofuels. Likewise, reporting from the California and Oregon low-carbon fuel standards (LCFS) also show a similar decline in CI values. These empirical data sources give greater confidence in the modelled CI values used in this analysis. Furthermore, given that the measured CI values occur across multiple jurisdictions, it is likely that they represent true reductions in CI rather than "fuel shuffling", where renewable fuels with low CIs are sold in regulated jurisdictions, while fuels with higher CIs are sold in jurisdictions without policies that regulate this metric. The broader monitoring of CIs that will occur with the *Clean Fuel Regulations* will provide another opportunity to test this hypothesis.

Focusing on British Columbia, the CI of ethanol decreased by 49%, the CI of biodiesel decreased by 117%, and the CI of HDRD decreased by 65% from 2010 to 2022 (Figure 19). Continuing the trend started in 2019, the emissions associated with biodiesel in British Columbia are negative, meaning that the cultivation and production of biodiesel leads to an overall decrease of global GHG emissions. In Ontario, the average reported CI for bio-based diesel decreased from 12 to 5 gCO2e/MJ between 2015 and 2021.

Figure 19: Lifecycle CI by fuel type for British Columbia



Similarly, the California LCFS has had a substantial impact on the CIs of biofuels used in that state and has supported investments that will lead to step-changes in ethanol CI. With the LCFS in force, California has recorded substantial declines in the carbon intensities of conventional biofuels. Between 2011 and the first quarter of 2022, the CI of ethanol and biodiesel both decreased by about 30%.[75]

A spatial analysis of corn and soy production indicates that some of these CI reductions are likely the result of improved farming practices which may have been the response to a market signal for lower-carbon biofuels. Specifically, conservation tilling, use of cover crops, and more efficient use of fertilizer can substantially reduce the CI of ethanol and biodiesel relative to a typical corn/soy crop rotation (by 30-50 gCO_2e/MJ).[76]

California's LCFS also supports investment in ethanol production with carbon capture and storage (CCS). When ethanol is produced from grains via fermentation, it emits a large and relatively pure stream of carbon dioxide. Capturing and storing this carbon dioxide creates a stepwise reduction in the CI of ethanol (40%-45%). Ethanol with CCS was recognized as a fuel pathway within the California LCFS,[77] coinciding with

[75] California Air Resources Board, LCFS Quarterly Data Spreadsheet, accessed October, 2023.

[76] Liu, X., Kwon, H., Northrup, D. & Wang, 2020, M. Shifting agricultural practices to produce sustainable, low carbon intensity feedstocks for biofuel production. Environmental Research Letters 15, 084014, doi:10.1088/1748-9326/ab794e

[77] California Air Resources Board, 2020, *Low Carbon Fuel Standard*, Design Based Pathway Application No. D000.

additional funding being directed towards the deployment of this abatement practice at a facility that supplied fuel to California, the Red Trail Energy ethanol plant in North Dakota.[78] Along with the ADM plant in Decatur, Illinois, this plant has since become among the first ethanol plant using CCS, capturing 180 ktCO_2/yr, reducing the CI of the resulting ethanol by about 40 gCO_2e/MJ.[79]

Figure 20 shows the avoided lifecycle GHG emissions in Canada resulting from low-carbon renewable fuel consumption and electricity consumption by light-duty vehicles. Again, the avoided emissions are based on the quantities and CIs of the fuels described above, assuming renewable fuels displace an equal amount of fuel energy from their fuel pool (i.e., ethanol displaces gasoline, biodiesel and HDRD displace diesel) and electricity displaces gasoline by a factor of 4.1. This analysis shows that the avoided GHG emissions in Canada resulting from biofuel consumption, including co-processed fuels, has risen to 6.6 MtCO_2e/yr in 2021. Avoided emissions from PEVs are growing rapidly, adding another 0.7 MtCO_2e/yr, bringing total avoided emissions in 2021 to 7.3 MtCO_2e/yr. Cumulative national avoided GHG emissions from 2010 to 2021 are 60 MtCO_2e. Further growth in biofuel consumption and PEV adoption will likely push the annual GHG abatement to more than 8 MtCO_2e/yr in 2022.

[78] North Dakota Industrial Commission, 2020, North Dakota Industrial Commission Awards $500,000 for Development of a Blueprint for a Carbon Capture and Storage Facility

And

Ethanol Producer Magazine, 2021, USDA awards $25M loan to Red Trail Energy for CCS project

[79] Ethanol Producer Magazine, 2022, Red Trail Energy Begins Carbon Capture And Storage

Figure 20: Avoided lifecycle GHG emissions 2010-2021, with an estimate for 2022

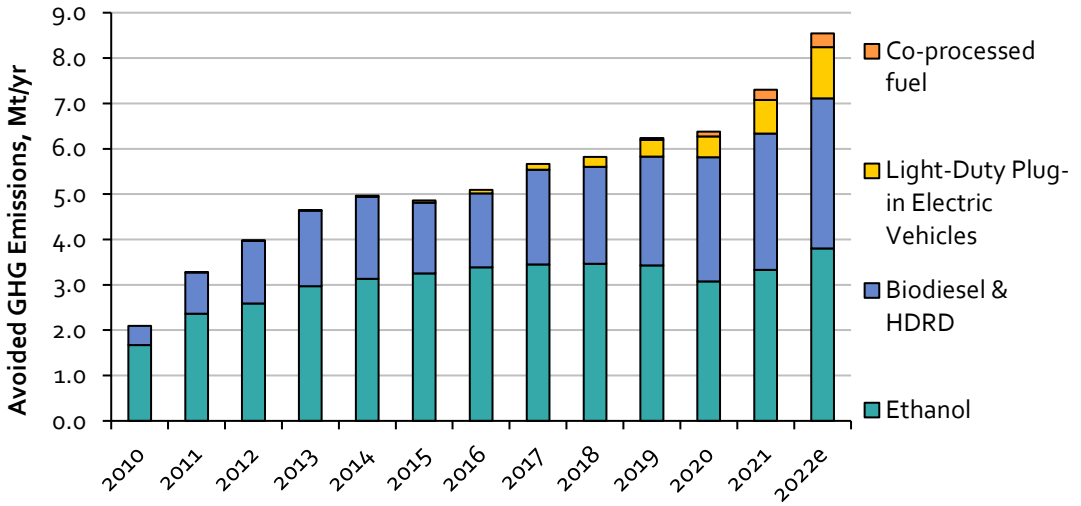
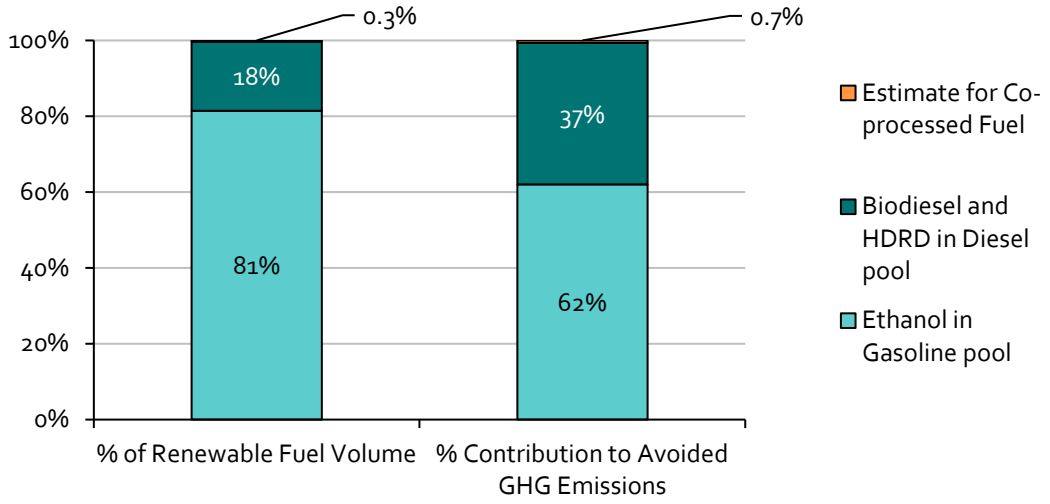


Figure 21 shows the percentage of renewable fuel volume in the gasoline and diesel pools compared with the percentage of avoided GHG emissions resulting from renewable fuel consumption in either pool. Co-processed fuels are shown as a separate category. Ethanol accounted for 81% of the renewable fuel volume consumed during the 2010-2021 period, but only 62% of the avoided GHG emissions. Biodiesel and HDRD, which generally have lower CIs than ethanol, yielded a proportionally larger GHG impact; these fuels accounted for 18% of renewable fuel consumption, but 37% of the avoided GHG emissions. Because co-processed fuel only entered the market in 2019, it accounts for a small share of the cumulative volume and avoided GHG emissions. Note that the inclusion of co-processed fuel does create a rounding error which impacts the graph below.

Figure 21: Cumulative % of total renewable fuel volume vs. cumulative % of avoided GHG Emissions from 2010 to 2020.



The GHG impacts in these results are calculated assuming that renewable fuel blending does not change vehicle energy efficiency (i.e., energy per km). While the weight of evidence supports this assumption, it is possible that renewable fuel blends have increased energy efficiency and the GHG impact is very sensitive to this assumption. A meta-analysis by Geringer et al. (2014) found that at the 50th percentile, E10 increased engine energy efficiency by 1.8%.[80] Scaling this impact to the ethanol blend rates in our analysis, this increase in efficiency would increase the cumulative GHG impact from ethanol by about 50%, or 19 $MtCO_2e$ from 2010 through 2021. Similarly, the GHG avoided in 2021 would increase by 1.6 $MtCO_2e/yr$.

Furthermore, the GHG impacts are calculated under the assumption that renewable fuel blending does not affect the combustion GHG emissions of the fossil fuels blended with the biofuel (just the emissions of the blend itself), nor the GHG intensity of petroleum refining. However, ethanol increases the octane rating of the overall fuel blend, meaning the gasoline blendstock can have a lower octane rating than if no ethanol were used. Consequently, ethanol blending could reduce refinery emissions if the production of lower octane gasoline is less carbon intensive. Similarly, using ethanol to raise the octane of gasoline blends can change the chemical composition of the gasoline blendstock. For example, it may have fewer octane raising 'aromatic' compounds. Aromatic compounds have a higher combustion (i.e., tailpipe) emissions intensity than gasoline on average. Consequently, raising octane with ethanol could

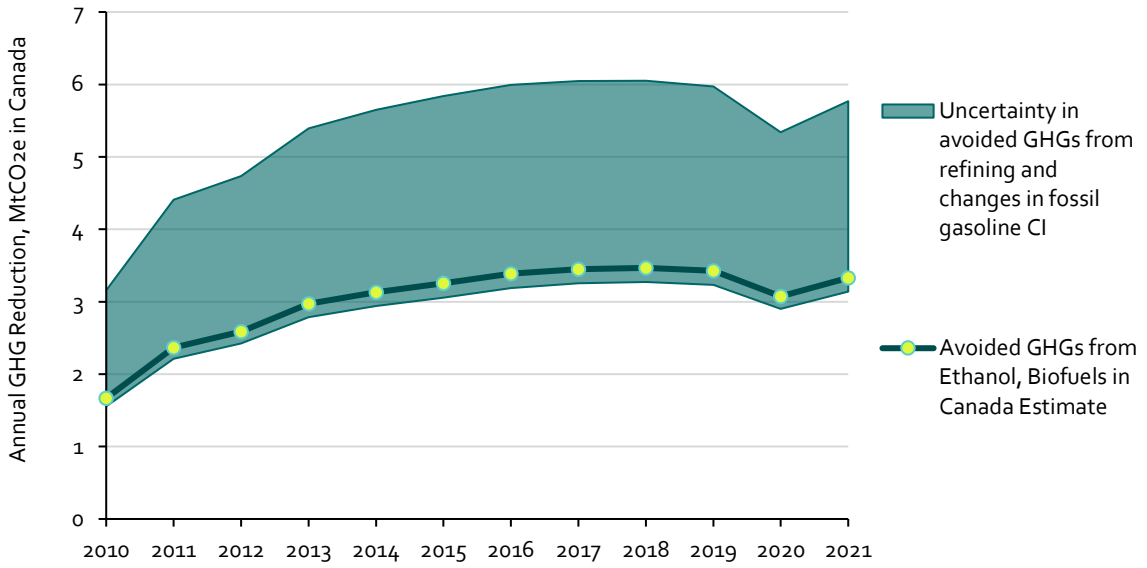
[80] Geringer, B., Spreitzer, J., Mayer, M., Martin, C, 2014, *Meta-analysis for an E20/25 technical development study - Task 2: Meta-analysis of E20/25 trial reports and associated data*, Institute for Powertrains and Automotive Technology, Vienna University of Technology

reduce the combustion emissions intensity of the gasoline blendstock. Section 5 of this report contains a “deep dive” on this subject.

These additional emission reductions from foregone refinery emissions and lower aromatic content in gasoline blendstocks are uncertain. Estimates from our literature review suggest the change to refinery emissions in 2021 could range from a 1.4 $MtCO_2e/yr$ decrease to a 0.2 $MtCO_2e/yr$ increase (see section 5.1 for more details). Estimates for emission reduction from changing chemical composition of the fossil portion of gasoline are more consistent in direction, ranging from an additional reduction of 0.3 to 1.0 $MtCO_2e/yr$ (see section 5.2 for more details). Figure 22 illustrates this uncertainty in the ethanol GHG impact. The high end of that range (i.e., more GHG abatement) is almost 75% greater than what is reported in Biofuels in Canada, consistent with:

- A 1.5gCO_2e/MJ reduction in the CI of refining petroleum gasoline for use with E10
- An 8% reduction in the higher CI aromatics within the gasoline blendstock used with E10 relative to the blendstock used with E0

Figure 22: Range of uncertainty in ethanol GHG reductions related to refineries and gasoline composition



Box 2: How is the Carbon Intensity of Co-Processing Defined?

Clean Fuel Regulations

Under the CFR, the volume of co-processed renewable fuel is limited to the biogenic portion of finished fuels which leave the refinery. Facilities can estimate renewable fuel volumes using "incremental allocation": The facilities compare a "benchmark" scenario using only petroleum feedstocks with a test scenario using the maximum flow of the low-CI feedstock. Then, the actual amount of low-CI feedstock is used to define the renewable content of the finished fuel based on those maximum/minimum bookends. Refineries must also submit samples for radiocarbon testing once per month to verify the biogenic portion of the finished products.

The CI of the renewable fuel volume is defined with the Fuel LCA Model where the energy and material inputs are estimated via incremental allocation. Any hydrogen input must use the pre-defined CI of hydrogen produced via steam methane reforming (presumably to avoid double counting credits generated from low-CI hydrogen production). Only products that leave the refinery are eligible to create CFR credits; the GHG reduction associated with own-use of biofuels at the refinery should be reflected in the CI of the finished fuels via crediting as co-products in the assessment (e.g., a bio-propane used for on-site heat generation reduces the CI of the renewable gasoline and diesel products).

BC Low Carbon Fuel Standard

The B.C. Ministry of Energy, Mines, and Low-Carbon Innovation currently has a draft *Coprocessing Methodology Protocol* posted for comment on their website[1]. Unlike the federal protocol for the CFR, the draft BC protocol does not allow the use of incremental allocation for determination of renewable fuel volumes, instead proposing radiocarbon testing on daily (or batch) samples, conducted once monthly. The use of radiocarbon testing to determine fuel volumes would also apply to co-products used within the refinery. Estimation of hydrogen use, a key input to the LCA, can be done via "step test" (effectively a much shorter-duration incremental allocation), stoichiometric allocation, or statistical regression. Other material and energy inputs, which tend to be secondary in their importance, could be estimated by incremental allocation or step test.

The draft protocol did not include insight into how existing co-processing projects, which have been operating in BC since 2019, have estimated their CIs.

Sources:

Government of Canada (2022). Clean Fuel Regulations: Quantification Method for Co-processing in Refineries Version 1.0.

Government of British Columbia (2023). B.C. Low Carbon Fuel Standard: Coprocessing Methodology Protocol.

4.4. Cumulative Costs

This section describes the cost impact resulting from the renewable fuel consumption described above, focusing on the impact of renewable fuel blending on consumer fuel expenditures. Refer to Appendix B: Cost Analysis Methodology for a detailed explanation of the methodology used for this cost analysis. Note that this cost analysis does not include the impact of co-processed fuels or PEVs.

Renewable fuel consumption may change overall fuel costs for three reasons:

- First, the commodity price per volume of renewable fuels may be different from the price of the petroleum fuels they replace.
- Second, the energy content per volume of fuel may differ. For example, the energy contained in one litre of ethanol is approximately 33% lower than it is for gasoline. The energy content of biodiesel is approximately 9% lower than it is for diesel fuel. We have assumed no change in energy efficiency (i.e., distance per unit of energy) resulting from renewable fuel use. In other words, if a renewable fuel has less energy content per volume, we assume the volume of fuel consumed rises proportionally, so a consumer is buying more litres of fuel to drive the same distance.
- Finally, cost reductions may arise due to different biofuel properties, such as: changes in fuel octane value (i.e., the anti-knock index of a gasoline blend); combustibility (i.e., the extent to which more complete combustion occurs with biofuel use, minimizing air pollution and associated health impacts); and, lubricity (i.e., the extent to which biodiesel fuel reduces friction and wear in the engine). Of these biofuel properties, this cost analysis only accounts for the octane value of ethanol.

Gasoline in North America must meet a standard octane value before it can be sold to the consumer. Refiners have various methods to raise the octane value of gasoline blendstock, one of which is the addition of ethanol to gasoline. The U.S. Energy Information Administration (EIA) estimates that American refiners produce gasoline blendstock with octane 84, which is raised to 87 (regular gasoline) with the addition of ethanol.[81] When used in a gasoline blend, ethanol has an octane rating of 113.[82]

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[81] U.S. Energy Information Administration, 2013, Price spread between regular and premium gasoline has changed over time. https://www.eia.gov/todayinenergy/detail.php?id=11131

[82] 113 to 115 is a typical value for blends cited by EIA https://www.eia.gov/todayinenergy/detail.php?id=11131. This value corresponds to ethanol used in low concentration blends. The octane rating of pure ethanol is 100.

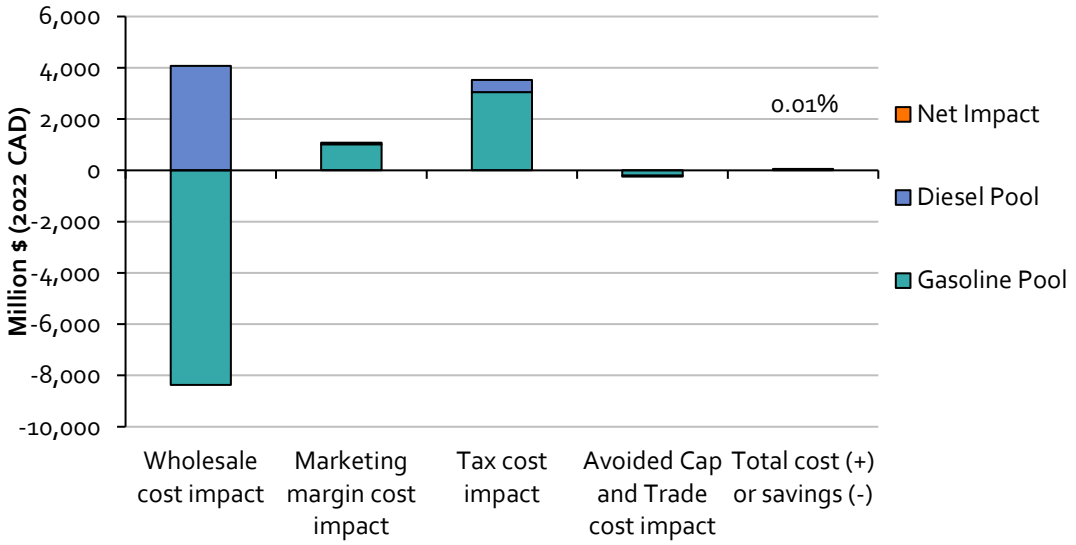
Consequently, the ethanol can be blended with a lower-octane gasoline blendstock. The price spread between regular gasoline (octane 87) and premium gasoline (octane 91 or more) implies that raising octane imposes a cost. Therefore, using lower-octane gasoline blendstock with ethanol is a potential cost-saving opportunity that contributes to the business case of using ethanol.

Note that we do not know if Canadian refiners are capturing the octane value of ethanol. In this analysis, we assume they do. Therefore, the cost analysis presents a reasonable scenario of what the cost of using renewable fuel could be, though the octane costs savings may not be realized in all cases.

This value of octane is only included insofar as it reduces the cost of gasoline blendstock used with ethanol; any energy or GHG reduction that may occur at the refinery due to producing a lower octane blendstock is not included (see the discussion of energy efficiency on page 56 and the discussion of additional GHG impacts shown in Figure 22 on page 57).

Figure 23 shows the cumulative change in consumer fuel costs resulting from renewable fuel blending in Canada from the start of 2010 to the end of 2021. We estimate that the net-costs have diverged by less than 0.01% relative to what they would have been without biofuel consumption.

Figure 23: Cumulative cost impact resulting from ethanol blending in the gasoline pool and biomass-based diesel blending in the diesel pool (2010-2021), total % change in category.



The net impact on consumer cost comes from both the gasoline and diesel pools and is composed of a wholesale cost, a marketing margin cost, a tax cost, and an avoided GHG cap and trade cost.

The wholesale cost, including the commodity cost and the refining margin, is the net cost and revenue for fuel refining, where we assume that differences in wholesale prices are reflected in retail prices. This cost component includes the octane value of ethanol but does not include other cost benefits like reduced air pollution and health impacts. The wholesale cost of using ethanol in the gasoline pool is negative due to the octane value of ethanol which reduces the cost of the gasoline blendstock. Without ethanol, the cost of the gasoline would have otherwise been higher, generally between ¢2/L and ¢3/L over the course of this analysis depending on the value of octane each year. For the gasoline pool, we find that the wholesale cost impact is a savings of $8.4 billion from 2010 to 2021. In contrast, in the diesel pool, the impact of wholesale prices results in a cumulative cost of $4.1 billion over the same period. This reflects the fact that biomass-based diesel is generally more expensive than conventional diesel. This is particularly the case with the premium-priced HDRD, where in most years fuel suppliers could have mitigated biomass-based diesel costs by substituting biodiesel for HDRD.

Note that these wholesale costs do not include the price-moderating impact of additional biofuel supplied to a tight fuel market. All else being equal, greater supply of alternatives to crude oil will reduce global demand for oil, resulting in a lower oil price. For example, a recent US study estimated that in the current diesel market, the additional supply of biomass-based diesel dampened diesel prices between 8 percent and 19 percent.[83]

The marketing margin cost is the net cost and revenue for retail fuel marketers (e.g., includes terminal costs, transport, and distribution from terminals to retail fueling stations). Marketing margins are based on historic data and we have assumed they would have been the same even if no renewable fuel had been used. Margins generally range from 6 to 12 cent/L, depending on the region and fuel in question. Because biofuels are less energy dense than petroleum fuels, using biofuels involves consuming a greater volume of fuel. Therefore, we have assumed the marketing cost is higher (e.g., more fuel delivery trucks are needed to carry the same amount of energy to fuelling stations). This is most noticeable with ethanol within the gasoline pool because it is roughly 33% less energy dense than gasoline. Ethanol consumption

[83] World Agricultural Economics and Environmental Services, 2022, The Offsetting Impact of Expanded Biomass Based Diesel Production on Diesel Prices.

increased the marketing cost paid by consumers by $1 billion between 2010 and 2021. Because diesel and HDRD are only slightly less energy dense than petroleum diesel, the cumulative change in the marketing cost in the diesel pool is only $57 million for the same period.

The tax cost results from the application of taxes based on the volume of fuel sold (this includes excise taxes paid "at the pump" as well the carbon taxes and levies where biofuels are not exempt) and sales taxes (e.g., GST and HST). The federal excise tax is $0.10/L for gasoline and $0.04/L for diesel. Provincial excise taxes range from zero to $0.27/L. As mentioned earlier, because biofuels are less energy dense than petroleum fuels, a consumer must purchase a greater volume of fuel to obtain the same amount of energy. When taxes are charged per litre, consumers who purchase blended gasoline pay more tax. Furthermore, percent sales taxes (e.g., PST, GST, HST) exacerbate the additional tax charge on fuels with lower energy density because they are applied on the 'tax in' fuel price.

Between 2010 and 2021, our analysis shows that consumers in Canada have paid an additional $3.0 billion in taxes for gasoline as a direct consequence of fuel blending, while the comparable figure for diesel purchases is $470 million. The difference in scale is again because biomass-based diesel is relatively closer in energy density to conventional diesel than ethanol is to conventional gasoline.

These Canada-wide tax cost results contain some important variation across jurisdictions. Since blended gasoline can have a lower per litre retail price than the unblended gasoline in the "counterfactual" scenario, our analysis suggests that the absolute amount of sales tax paid can be lower when gasoline is blended. In jurisdictions like Ontario, where there is a high sales tax tied to actual retail value (i.e., 13% HST), the savings on the sales tax can sometimes outweigh the increases due to federal and provincial fuel taxes.

The avoided cap-and-trade costs arise from the GHG emissions cap and trade systems operating in Québec, since 2015, and in Ontario, for 2017 to mid-2018, and Nova Scotia from 2019 to mid-2023. The cap-and-trade systems add a carbon cost to gasoline and diesel that will affect the wholesale price of these fuels. Low-carbon renewable fuel CO_2 emissions are exempt from the cap-and-trade systems, but minor emissions from CH_4 and N_2O are accounted for.[84] However, historically, there has been no price distinction between fuels with and without renewable fuels at the wholesale 'rack' for fuel distribution, indicating that the cap-and-trade cost is being spread evenly

[84] See Table 30-1 in Government of Québec, *Regulation respecting mandatory reporting of certain emissions of contaminants into the atmosphere*

across all fuels. The avoided cap and trade costs represent the additional carbon costs that would have been incurred without renewable fuel consumption (i.e., in a counterfactual scenario). The cumulative cap-and-trade cost impact from 2010 to 2021 is a savings of $206 million and $38 million in the gasoline and diesel pools, respectively.

There are several important caveats with regards to the cost analysis and how it will be borne by consumers. First, the wholesale prices of the fuels are by far the largest determinants of the cost impact. As noted above, we assume that differences in wholesale prices are reflected in retail prices but, given the dynamics of price setting, this may not be the case in all Canadian fuel markets at all times. Furthermore, the marketing margin will be affected by this price setting and that margin, on a per litre basis, may not be independent of the renewable fuel content as we have assumed. As well, the wholesale prices are based on commodity prices listed on the Chicago mercantile exchange. While these are indicative of the prices paid for fuels, actual contracts will be settled relative to this price and wholesale costs could be different than those calculated in this analysis. Anecdotally, bulk purchasers of renewable fuels will exert their market power to negotiate contracts where the Chicago price is an upper limit. Therefore, our method is conservative and may overestimate the wholesale price of renewable fuels.

A further uncertainty in the cost analysis is the impact of renewable fuel blends on energy efficiency (defined here as unit of energy required per unit of distance traveled). The weight of evidence suggests that energy efficiency has not been impacted by current blending rates and there is no efficiency change included in the cost analysis. Yet, the results would be dramatically changed if this were revised. Again, using the example based on the analysis of Geringer et al. (2014), if E10 yielded a 1.8% improvement in energy efficiency (scaled to actual blend rates), consumers would have saved another $8.2 billion from 2010 through 2021, equivalent to about a six-fold increase in the cumulative cost savings resulting from renewable fuel consumption.

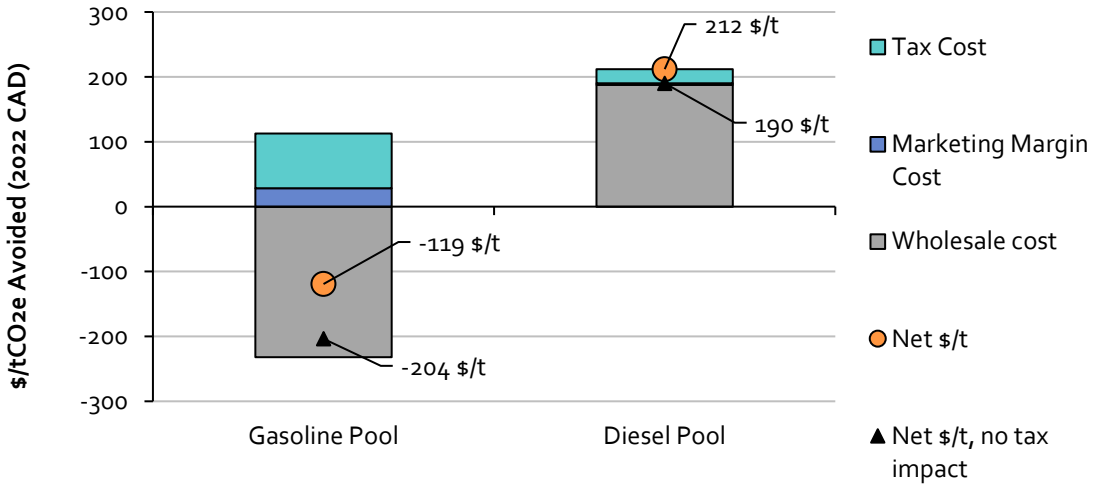
4.5. GHG Abatement Cost

Figure 24 shows the GHG abatement cost of renewable fuel blending in Canada from the perspective of consumers. The abatement cost is the cumulative cost impact by source (including the wholesale cost, marketing cost and tax cost), divided by the cumulative avoided GHG emissions between 2010-2021 for the gasoline and diesel pools. Avoided cap-and-trade costs are not included in this calculation, nor are any additional costs savings, co-benefits (e.g., reduced health costs resulting from

reductions in air pollution), or possible GHG reductions associated with the use of renewable fuels besides the differences included in the CIs used in this analysis (specifically: the impact of ethanol blending on vehicle energy efficiency, refinery GHG intensity, and fossil gasoline GHG intensity are not included).

For interest, net abatement costs without the tax cost impact are shown. In other words, Figure 24 shows the net abatement cost if excise taxes, sales taxes, and carbon taxes on fuels had the same $/energy value for gasoline and ethanol, and for diesel, biodiesel and HDRD (i.e., taxes were applied on an energetic basis rather than volumetric).

Figure 24: GHG abatement cost, with and without volumetric tax penalty 2010-2021



The cost of abatement from ethanol blending is -$119/t$CO_2$e (Figure 24). Furthermore, the results suggest that excise and carbon taxes on fuels have a significant impact on the net dollar value per tonne CO_2e abated, which would be -$204/t$CO_2$e if the excise taxes on ethanol and gasoline were equivalent on an energy basis. The abatement cost in the diesel pool is $212/t$CO_2$e, or $190/t$CO_2$e if fuel taxes were based on energy rather than volume.

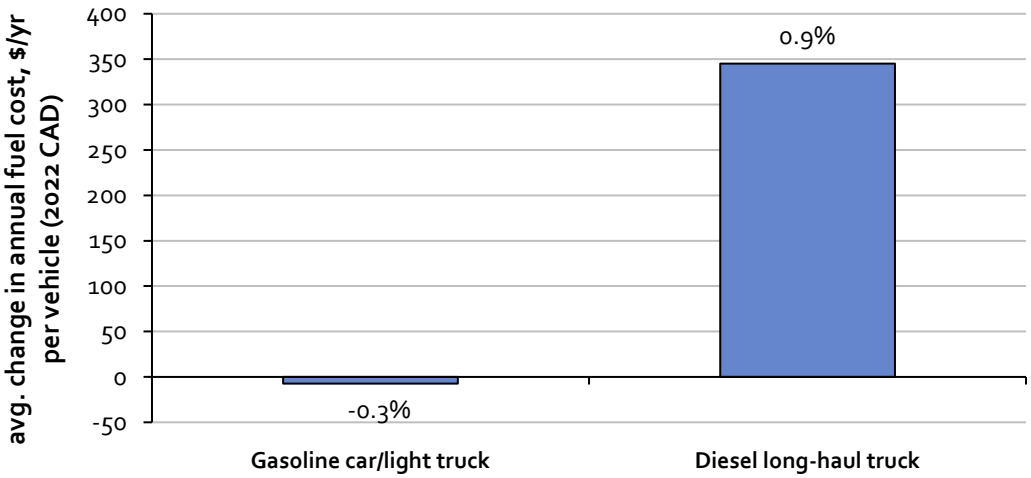
4.6. Consumer Cost Impact

Figure 25 shows the cost impact expressed as a change in average annual fuel expenditures for archetypal consumers. For the gasoline pool, the archetypal consumer uses a light-duty vehicle (i.e., car or pickup truck) to travel approximately 15,500 km per year with an average fuel economy of 9.5 litres per 100 km travelled. For the diesel pool, the archetypal consumer is a heavy-duty truck operator who uses a tractor-trailer combination to travel approximately 86,700 km per year with a fuel

economy of 31.4 litres per 100 km travelled. These archetypes reflect the average statistics of Canadian consumers in 2020 as reported by Natural Resource Canada in the Comprehensive Energy Use Database.

The average consumer of gasoline saved $7/yr (-0.3%) because of ethanol blending in Canada. A typical heavy-duty diesel consumer spent an additional $345/yr (+0.9%) because of biodiesel and HDRD blending (Figure 25). The higher cost for the diesel archetype could have been mitigated if more biodiesel and less HDRD had been used. This outcome was technically feasible given that on average in Canada, biodiesel has only accounted for between 1 to 1.6% of the diesel pool volume during the twelve-year study period, while a 2% average annual blend is considered feasible by even the most conservative fuel supplier. In contrast, biodiesel has generally accounted for 3% to 4.5% of the US diesel pool over the same period.[85] The expectation of ongoing biodiesel and HDRD price spreads could result in increased use of biodiesel (putting upward pressure on biodiesel prices) or increased investment in HDRD supply (putting downward pressure on its price); based on recent capital investment activity, the latter case is actively underway in the US and Canada.

Figure 25: Archetypal fuel consumer cost impact, annual average 2010-2022



Finally, since the impact of ethanol blending results in a cost savings, it implies that the ethanol blending mandates in Canada might not be causing substantial changes to fuel use. In other words, since ethanol is a cost effective means of boosting octane, refiners may be incentivized to blend ethanol regardless of whether the blending

[85] US Energy Information Agency, 2023, September 2023 Monthly Energy Review, Tables 3.7, 10.4a 10.4b

mandate is present or not. Fuel suppliers have historically over-complied with provincial volumetric blending mandates in every year in most provinces, supporting this hypothesis.

Despite this motivation to over-comply with gasoline blending mandates, policy design can still ensure that these regulations have an additional impact on GHG emissions. For example, the British Columbia LCFS constrains the CI of ethanol to increase the avoided GHG emissions. Furthermore, while the results of this analysis indicate that ethanol use may be 'voluntary', it is possible that the mandates are forcing refiners to use ethanol to boost octane rather than some other method that might result in greater GHG emissions.

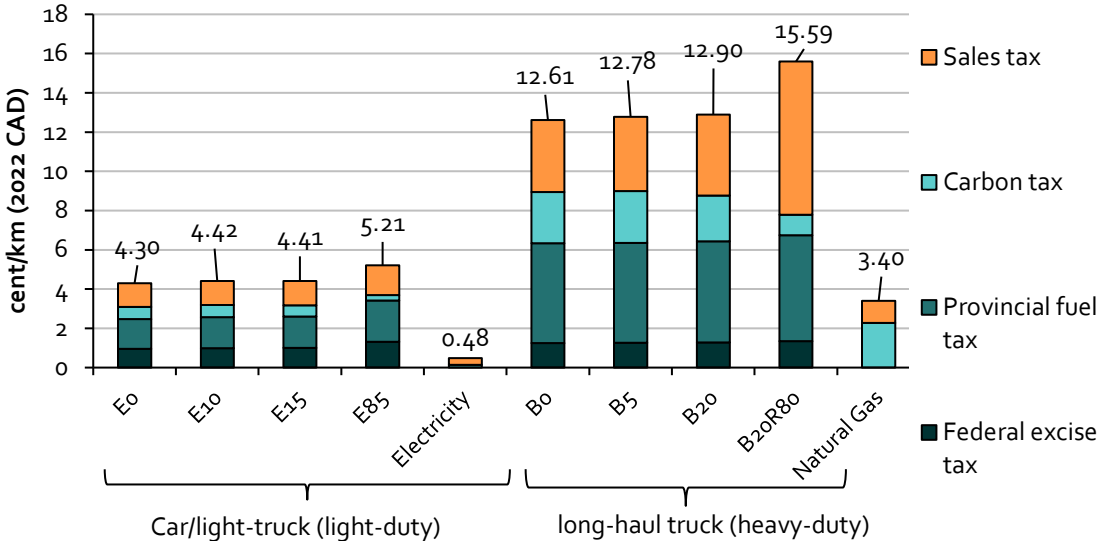
4.7. Detailed Tax Costs

A breakdown of fuel taxes per-km-travelled by tax type for different biofuel blends illustrates why there is a tax cost impact associated with biofuel consumption. Taxes per km are calculated using the same archetypal consumers of gasoline and diesel as in Figure 25 (a light-duty gasoline vehicle and a long-haul diesel tractor-trailer).

On average in Canada in 2021, the archetypal gasoline user paid 3% more tax per km when using E10 rather than E0. A similar trend exists for diesel fuel, where an archetypal vehicle user consuming B5 pays 1.3% more tax per km travelled (Figure 26). Again, much of this additional taxation (i.e., a "surtax") relates to the lower energy density of biofuels and the fact that most fuel taxes are applied per litre. The impact of volumetric taxation is further exacerbated for higher blends of ethanol, such as E15 or E85. In contrast, other alternative fuel vehicles that run on electricity, hydrogen, or renewable natural gas are exempt from provincial fuel taxes and federal excise taxes and pay a much lower overall tax per km.

The tax impacts in Figure 26 are fuel-consumption-weighted averages for Canada and are not specific to any province. However, there are important regional differences hidden within that average. For example, biofuel users will pay less sales tax per km (charged as a % of the fuel price) when there is a sufficiently large volumetric price discount between the biofuel blend and the unblended fossil fuel (i.e., the $/L price of the biofuel is lower). Furthermore, Québec and Nova Scotia had cap and trade systems in 2021 rather than carbon taxes (i.e., the carbon tax value in the figure would be zero). As well, the British Columbian carbon tax does not exempt renewable fuel blends above 10% in gasoline or 5% in diesel. However, in provinces where the federal carbon price is in force, the renewable portion of the E15, E85, B20, and B20R80 are exempt from the carbon price (this is why the national average carbon tax on B20R80 is relatively small).

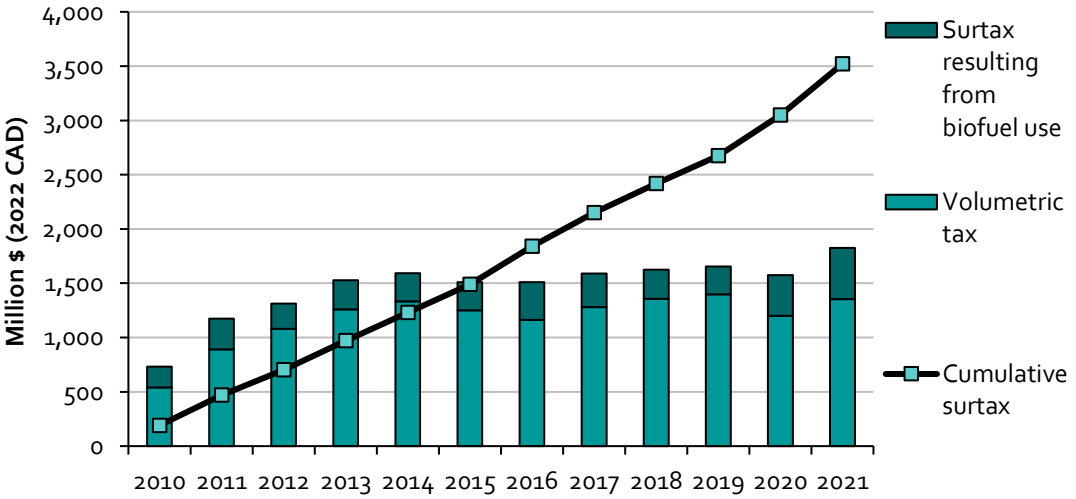
Figure 26: Fuel taxes and carbon costs for archetypal fuels and consumers, illustrative fuel consumption weighted average for Canada in 2021 (total shown in data label)



B20R80 is 20% biodiesel and 80% renewable diesel

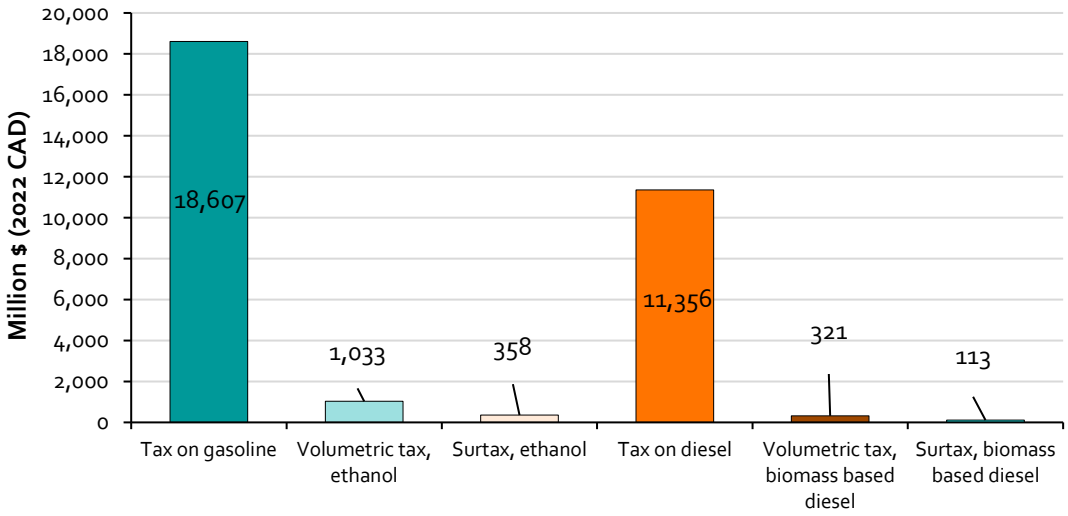
In 2021, these "surtaxes" paid on biofuels amounted to an extra 35%/yr, or roughly $472 million (2020 CAD), relative to the tax that would have been paid if taxes were assessed equally on a "per unit of energy" basis instead of a "volumetric" basis within the gasoline and diesel pools (Figure 27). The cumulative surtax cost impact since 2010 rose to about $3.5 billion (2020 CAD) in 2021 (note, this is the same as the total tax cost impact shown in Figure 23).

Figure 27: Breakdown of fuel taxes paid on biofuels in Canada, with cumulative "Surtax" paid



Taxes paid on ethanol in Canada in 2021 account for 6.7% of the total taxes paid on fuel from the gasoline pool, where the "surtax" on ethanol is 1.6% of that total (i.e., the surtax is about a quarter of the total tax paid on ethanol). Taxes paid on biomass-based diesel represent 3.7% of the total taxes paid on the diesel pool in Canada in 2021. The "surtax" on biomass-based diesel is about 1.0% of that total (i.e., the surtax is about one quarter of that total paid of biomass-based diesel) (Figure 28).

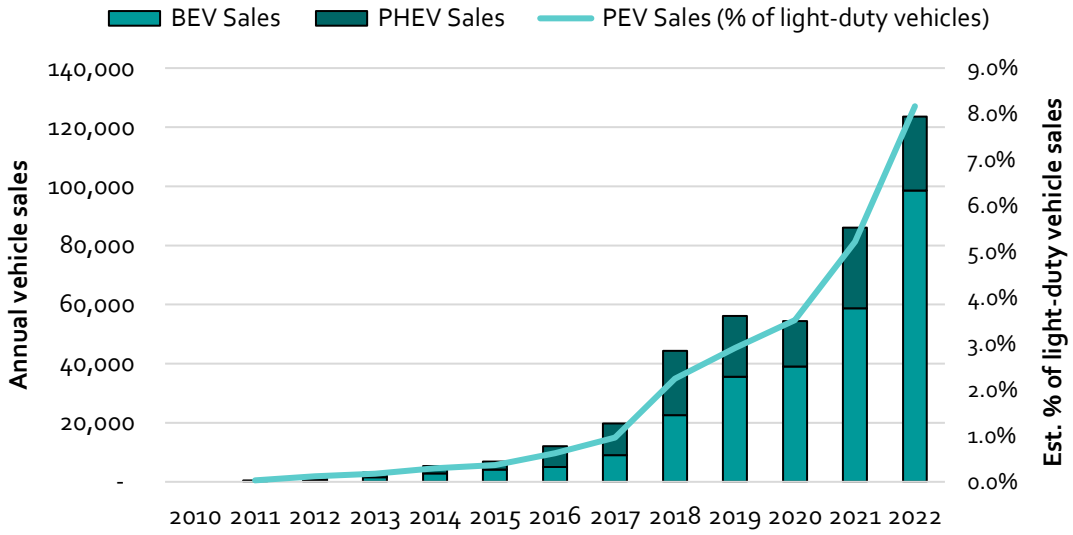
Figure 28: Breakdown of taxes paid on the gasoline and diesel fuel pools in 2021



4.8. Electric Vehicles

This analysis estimates how light-duty PEVs have affected gasoline consumption and GHG emissions. This broader classification can be broken down into "Battery Electric Vehicles" (BEVs) and "Plug-in Hybrid Electric Vehicles" (PHEVs), which are disaggregated in Figure 29 below. The former category is composed of cars which consume only electricity, while the second, PHEVs, also have on-board auxiliary engines which consume liquid fuel and can be used to extend their range.

Figure 29: Sales of light-duty PEVs in Canada, 2010 - 2022



Source: Statistics Canada, New Motor Vehicle Registrations, Table: 20-10-0021-01

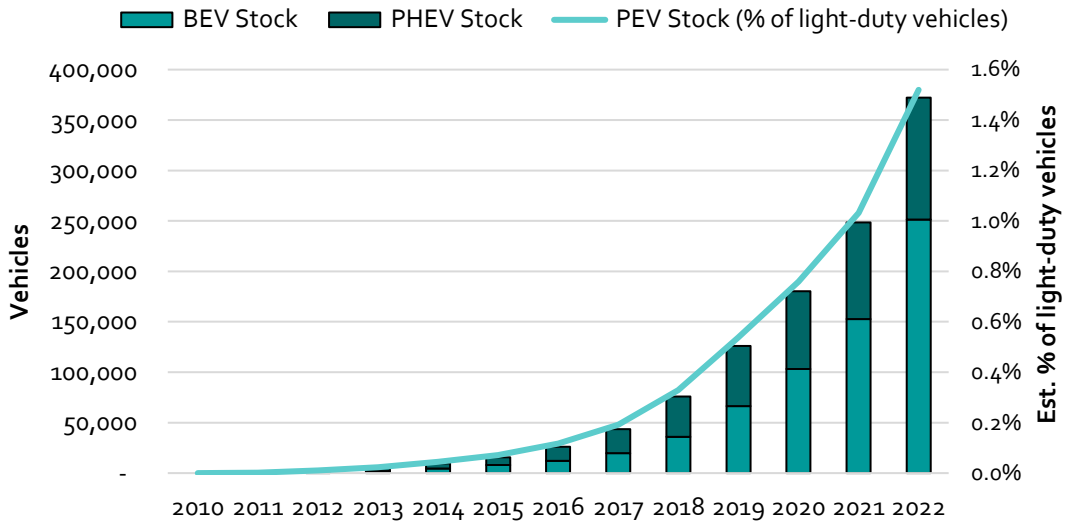
In 2021, PEVs accounted for 5.2% of light-duty vehicle sales in Canada, rising to 8.2% in 2022, equivalent to nearly 86,000 PEV sales in 2021 and 124,000 in 2022 (Figure 29). These relatively high sales rates for PEVs are heavily weighted by sales in specific provinces. In British Columbia, for example, more than 16% of car sales were PEVs in 2022. Comparably, PEVs accounted for 12% of vehicle sales in Québec and more than 6% in Ontario. In other provinces and regions, such as in Atlantic Canada, and in the prairies (Alberta, Saskatchewan, and Manitoba), PEVs accounted for between 2% and 3% of total light-duty vehicle sales in 2022.

Because a relatively small fraction of vehicles on the road are purchased new every year, PEVs represent a smaller fraction of Canada's vehicle stock than vehicle sales. PEVs accounted for 1.5% of the light-duty vehicles on the road in Canada in 2022, up from 1.0% in 2021 (Figure 30). The stock of PEVs is split about 70:30 between BEVs and PHEVs and is concentrated in the same provinces that have higher PEV sales.

We expect this trend in PEV sales and PEVs on the road to continue. The federal government has proposed amending its passenger automobile and light truck GHG emission regulations to establish legally binding zero-emissions vehicle sales targets. The targets are 20% of light-duty vehicle sales by 2026, rising to 60% by 2030, and

100% by 2035.[86] This would result in PEVs being about 5% of vehicles on road in 2026, rising to 16% in 2030 and 40% by 2035.[87]

Figure 30: Light-Duty PEVs on the Road, 2010 - 2022



Source: Statistics Canada, New Motor Vehicle Registrations, Table: 23-10-0308-01

[86] Government of Canada, Canada Gazette, Part I, Volume 156, Number 53: Regulations Amending the Passenger Automobile and Light Truck Greenhouse Gas Emission Regulations

[87] Transport Canada, 2022, Canada's Zero-Emission Vehicle (ZEV) sales targets

5. Biofuel-Caused Reductions in Emissions from Gasoline Refining and Consumption

This section provides descriptions and estimates for two potential GHG benefits of ethanol blending that have not been included in Biofuels in Canada: first, that the high-octane value of ethanol reduces the emissions intensity of refining gasoline because refineries can produce a lower octane blendstock. Second, that high-octane components of gasoline that are replaced by ethanol, largely aromatics, are more carbon intensive than baseline gasoline. Consequently, ethanol could reduce the combustion (i.e., tailpipe) GHG emissions associated with gasoline blendstock consumption beyond the levels estimated in this analysis.

Our research shows that the effect of ethanol on refinery emissions and gasoline composition is uncertain but likely not zero. Estimates for how ethanol blending affects refinery emissions range from a modest decrease to small increase. Research more consistently suggests that ethanol blending will reduce emissions by changing the composition of the fossil portion of gasoline, but it remains challenging to evaluate what the composition of gasoline would have been absent ethanol blending. Because of the uncertainty, these impacts are only discussed below and are not currently included in the calculation of GHG emissions or cost impacts.

5.1. Potential Reduction in Refinery Emissions Due to Ethanol's High Octane

Refineries have a selection of feedstocks and processes that they can use to comply with the octane, vapour pressure, and other requirements of the Canadian fuel quality standards for gasoline. In addition to reducing overall demand for crude oil, ethanol blending specifically displaces reformate, alkylate, aromatics, or other high-octane ingredients in gasoline blending which are more energy-intensive to produce than the low-octane outputs from atmospheric or vacuum distillation.

For example, using ethanol as a source of octane would allow a refiner to operate their catalytic reformer, which transforms low-octane naphtha into higher octane reformate, at a lower severity. The octane specifications that were previously being met with reformate can now be achieved with ethanol; a less refined blendstock can be used to achieve the same octane result, which means that refinery emissions and costs to produce gasoline blendstock could be lower.

A report prepared by Life Cycle Associates for the Renewable Fuels Association used a figure of 1g CO_2e/GJ-gasoline for the difference in refinery GHG intensity between E0 and E10.[88] The citation for that number, *Kwasniewski 2015*, is unfortunately not included in the works cited in their report.

The one publicly available paper by Kwasniewski in 2015 compares refinery emission between E10 and E30 cases. In the two 88-octane fuel scenarios, the E30 fuel showed a 0.7-1gCO_2e/MJ reduction in refinery GHG emissions compared to the E10 fuel.[89] Another US paper found a 6% and 12% reduction in refining GHG emissions compared to E10 for E20 and E30 blends, respectively.[90] In other words, this GHG impact applies when going from typical current ethanol blending rates to mid- to high ethanol blending rates and does not directly inform what the impact would be for a shift from E0 to E10.

A paper from 2009 examining the European gasoline market compared refining GHG intensity of fossil gasoline using MBTE as a source of octane for E5 fuel. The authors found a 2.3 gCO_2e/MJ reduction in refinery emissions in the E5 case, partially offset by a 1.1 gCO_2e/MJ difference in the CI of ethanol and MTBE production, resulting in a net impact of 1.2 gCO_2/MJ.[91] Unfortunately, this paper compares ethanol blending with a scenario that is not fully relevant to present-day Canada, that being where a refinery produces sub-octane blendstock and blends with MTBE (rather than using internal processes to achieve the required octane rating).

A 2021 analysis by the consultancy Transport Energy Strategies critiqued existing literature on this subject, finding that ethanol blending would cause a small increase, not decrease in refinery emissions.[92] Catalytic reformers also produce hydrogen, and the emissions from producing the foregone hydrogen via steam methane reforming would undo the emissions benefit of less severe operation of the catalytic reforming.

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[88] Unnasch, S., & Parida, D. (2021). *GHG Emissions Reductions due to the RFS2-A 2020 Update.* Life Cycle Associates, LLC

[89] Kwasniewski, V., Blieszner, J., & Nelson, R. (2015). Petroleum refinery greenhouse gasemission variations related to higher ethanol blends at different gasoline octane rating and pool volume levels. *Biofuels, Bioproducts, Biorefining*, 10:36-46

[90] Hirshfeld, D. S., Kolb, J. A., Anderson, J. E., Studzinski, W., & Frusti, J. (2014). Refining Economics of U.S. Gasoline: Octane Ratings and Ethanol Content. *Env. Science and Technology*, 48: 11064−11071

[91] Croezen, H., & Kampman, B. (2009). The impact of ethanol and ETBE blending on refinery operations and GHG emissions. *Energy Policy*, 37: 5226–5238

[92] Klein, T., Clark, N., Higgins, T., & McKain, D. (2021). *Well-to-Wheels Carbon Intensity for Ethanol Blended Fuels.* Transport Energy Strategies

They estimate that ethanol would increase refinery emissions by 0.2 gCO2e/MJ gasoline. However, given that current policies (e.g., the compliance category 1 of the *Clean Fuel Regulations*, federal tax credits for carbon capture and storage (CCS)) incentivize the use of CCS with hydrogen production at refineries, this insight might not apply in Canada in the future.

In short, estimates in the literature for how ethanol blending affects refinery emissions range from a modest decrease in emissions (2.5 gCO_2e/MJ) to a small increase in emissions when hydrogen production is considered (0.2 gCO_2e/MJ).

5.2. Reduction in Emissions Associated with Changing Gasoline Composition

The methodology used to calculate avoided GHG emissions resulting from ethanol blending in this analysis assumes that ethanol displaces conventional fossil gasoline, and that the emissions benefit of this is equal to the difference in lifecycle CI between the gasoline and ethanol. However, because ethanol displaces other octane-enhancing ingredients in gasoline, this methodology has the potential to understate the tailpipe emissions benefit of ethanol. For comparison, the exhaust emissions of conventional gasoline and the high-octane aromatics portion of gasoline are presented below.

Table 19: CI of Gasoline versus Aromatics/Olefins in GHGenius 4.03a

Fuel	Exhaust Emissions (gCO2e/MJ)
Conventional Canadian Gasoline Blend	62,961
Aromatics in Conventional Canadian Gasoline Blend (i.e., the high-octane portion)	73,224

The challenge with quantifying the emissions effect of the changing chemical composition of gasoline is twofold: first, accurately developing a counterfactual as to what would be in the gasoline in a no-ethanol case, and second, actually measuring the relatively small change to emissions in experimental settings. Various studies have looked at this, mainly focusing on how ethanol affects emissions of criteria air contaminants, not GHGs. Two studies were identified that summarized estimates for CO_2 in addition to air pollutants.

A literature review by consultancy Transport Energy Strategies found that "a 1% change in ethanol would correspond to a change in aromatic level of about 0.8%". Using this ratio of substitution between ethanol and aromatics, the authors' estimate

of CI for a blended E10 fuel was 1.4% lower than the baseline estimate that didn't consider changing composition of the fuel.[93]

An EPA study found a 1.8% reduction in CI between an E10 tier-3 test fuel and an E0 tier-2 test fuel, caused by the 8.5 percentage point reduction in aromatics in the E10 test fuel.[94] This change in CI is for the blended fuel itself, seemingly including biogenic carbon, indicating a change in the CI of the pure gasoline component. Another study also estimated a 1 to 2% reduction in CO_2 emissions between E0 and E10 but found none of the results for CO_2 emissions between E10 and E0 were statistically different at any reasonable level of significance.[95]

The largest study identified, the EPAct Tier 2 Gasoline Fuel Effects study, did collect the data for CO_2, but didn't publish or summarize the conclusions for CO_2 in the report (the focus was CACs).[96] One meta-analysis of the literature on the effect of ethanol and tailpipe emissions found that "Variability between studies in itself suggests that many studies should not be used to predict real-world emissions effects", in part because the fuel blends used in laboratory testing do not always reflect real world fuel composition.[97] This critique was largely driven by the use of "match" blended fuels in emissions studies, in which fuels are blended to match specific properties such as 50% distillation temperature or aromatic content, leading to fuel blends which may not reflect real-world fuels that are sold, which may be "splash" blended, thereby foregoing the benefits attributed to the "match" blended fuels.[98]

There is a compelling argument that ethanol should reduce the CI of the gasoline due to lower aromatic content, but the effect is small enough that it is hard to quantify in

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[93] Klein, T., Clark, N., Higgins, T., & McKain, D. (2021). *Quantifying Ethanol CI Benefits in Gasoline Composition.* Urban Air Institute

[94] Butler, A., Warila, J., Fernandez, A., & Hart, C. (2018). *Effect of Fuel Composition on Fuel Economy and CO2 Emissions in LD Gasoline Vehicles [slide deck].* US EPA Office of Transportation & Air Quality

[95] Yuen et al. (2019). *Comparison of real-world vehicle fuel use and tailpipe emissions for gasoline-ethanol fuel blends,* Fuel, 249: 352-364

[96] United States Environmental Protection Agency. (2013). *Assessing the Effect of Five Gasoline Properties on Exhaust Emissions from Light-Duty Vehicles Certified to Tier 2 Standards: Analysis of Data from EPAct Phase 3 (EPAct/V2/E-89) Final Report.* US EPA

[97] Nigel Clark Et Al. (2018). *Effects of Ethanol Blends on Light-Duty Vehicle Emissions: A Critical Review.* Urban Air Initiative

[98] Splash blending refers to mixing gasoline by splashing ethanol into an otherwise finished but suboctane fuel. Match blending refers to creating an ethanol fuel blend that matches certain characteristics of a non-ethanol blend, such as 50% distillation temperature or aromatic content.

experimental settings and even harder to define in real-world usage. Given the size of gasoline pool, even a 1% change in the CI of the fossil portion of gasoline would yield more than a million tonnes of annual emission reductions in Canada. Compared to the emissions effect of ethanol displacing gasoline, the effect of changing fuel composition is secondary but still potentially significant.

6. Conclusions

The aim of this study is to provide a comprehensive analysis of the volumes of renewable and low-carbon transportation fuels consumed in Canada as well as the impact of this fuel consumption on GHG emissions and consumer fuel expenditures. Key conclusions from this study are summarized below.

Renewable fuel consumption and electric vehicles

The renewable content in gasoline and diesel pools has continued to increase from 2010 to 2021. The volume of ethanol consumed in Canada each year has increased from roughly 1,700 million L/yr in 2010 to 2,876 million L/yr in 2021. Biomass-based diesel consumption continued to increase, hitting a new of high of 986 million L/yr in 2021. Most of the year-over-year growth from 2020 was due to increased biodiesel consumption, while HDRD consumption was relatively static.

Our estimate for 2022 shows an inflection point with greater growth in ethanol consumption. Preliminary data indicates that much of this growth occurs in Alberta. Blending beyond what is required by the Albertan fuel regulation indicates additional renewable fuel supply with the intent of banking CFR credits. The estimated fraction of renewable fuel in gasoline in 2022 is approaching 8%, while that fraction in diesel is about 4%. At these blending rates, fuel suppliers would not need to take any additional action to comply with the CFR until the third compliance period in 2025.

Electric vehicle sales in Canada surpassed 5% in 2021 and 8% in 2022. As of 2022, electric vehicles account for about 1.5% of light-duty vehicles on the road in Canada (about 375,000 vehicles).

Avoided GHG emissions

The cumulative GHG emissions avoided between 2010 and 2021 are 60 $MtCO_2e$, including the contribution from PEVs and co-processed fuels. Annual avoided emissions from all sources surpassed 7 Mt CO_2e/yr in 2021 and are estimated to reach almost 8.5 Mt CO_2e/yr by 2022.

Cost Impacts

Between 2010 and 2021, blending ethanol, diesel, and HDRD with conventional transportation fuels increased consumer fuel costs in Canada by 0.01% or $60 million (2022 CAD) relative to what they would have been without renewable fuels. The octane value of ethanol creates a substantial savings that offsets other costs associated with

renewable fuel consumption. Assuming no other co-benefits related to biofuels other than this octane value, the GHG abatement cost for ethanol consumption is negative, -$119/t$CO_2$e, whereas the abatement cost for biomass-based diesel use is positive at $212/t$CO_2$e. Ethanol blending reduced the annual fuel costs of a typical driver by $7/yr (-0.3%) over the study period, relative to a scenario without ethanol consumption. Biodiesel and HDRD blending increased the annual fuel costs of a typical long-haul trucker by $343/yr (+0.9%).

Taxation impacts

Biofuel consumption, especially ethanol, has increased the fuel tax burden on consumers while generating additional tax revenue ('surtaxes') for governments in Canada. This impact comes from fuel taxes that are applied per litre, such as excise taxes as well as carbon taxes/levies/fuel charges. The application of sales taxes on the "tax-in" price amplifies the volumetric surtax impact.

Because biofuels are generally less energy dense than petroleum fuels, using biofuels involves consuming a greater volume of fuel and paying more tax than if taxes were applied on an energetic basis. Consequently, consumers pay more tax per kilometer when using biofuel blends, all else being equal. This impact is most noticeable with ethanol because it is roughly 33% less energy dense than gasoline, though the impact varies from year to year as a function of the variation in spread between ethanol and gasoline prices and the value of octane from ethanol. This tax structure has cost gasoline consumers an additional $3.0 billion (2022 CAD) during the twelve-year study period (2010 to 2021). The corresponding surtax cost on diesel consumers during that period was roughly $0.5 billion (2022 CAD). Without these additional tax costs, renewable fuel consumption during the study period would have saved consumers about $3.5 billion rather than costing them $60 million.

Appendix A: Biofuel Type and Feedstock Assumptions and Data

In this analysis, data were collected on the volume of renewable fuels blended into gasoline and diesel — characterized as ethanol, biodiesel, or HDRD. However, to calculate the lifecycle CI of the various biofuels sold in Canada, it was necessary to further disaggregate these data by feedstock, and in some cases disaggregate biomass-based diesel volumes into biodiesel and HDRD.

Feedstock data and guidance on the split between HDRD and biodiesel was obtained from personal correspondences with government contacts or obtained from various publications. However, data for every region and every fuel was not available. For this reason, various assumptions were made to fill these gaps. The following lists summarize the assumptions and sources we used to define fuel types and feedstocks and volumes by region in Canada.

Assumptions for British Columbia

Feedstock data was obtained from the government of British Columbia.[99] The data is essentially used “as-is” with little need for assumptions or interpretation:

1. In some years, there are minor summation errors in the data published by the British Columbia government. We used an "Unknown" feedstock category to make the total fuel volume from individual feedstocks equal to the total reported volumes. These values were calculated to fill the gap and are not numbers reported by the British Columbia government.

2. BC reporting does not distinguish between feedstocks used for biodiesel or HDRD, we assume that tallow, yellow grease, biodiesel bottoms, fatty acid distillates and palm oil byproducts are used for HDRD. Some soy feedstock for HDRD is also assumed to ensure total biodiesel and HDRD consumption matches the data.

3. Renewable fuel by feedstock in 2022 is based on the total reported in data, pro-rated based on 2021.

[99] Ministry of Energy and Mines, 2022, Renewable and Low Carbon Fuel Requirements Regulation Summary: 2010-2020

Assumptions for Alberta

1. 2011 to 2021 fuel volumes were collected via personal correspondences with the Alberta government.

2. Ethanol feedstock volumes are estimated based on the types of feedstocks processed in Alberta's facilities. We estimate a substantial amount of corn-based ethanol, based upon a review with Don O'Connor of (S&T) ^{2} Consultants.

3. We assume that biodiesel feedstocks are canola and soy, as indicated through personal correspondence with Alberta Government. We assume a greater proportion of soy than canola based on review with Don O'Connor of (S&T)2 Consultants (80% soy as of 2020).

4. 2010 gasoline and diesel sales by volume were retrieved from Statistics Canada Table: 25-10-0030-01 (formerly CANSIM 128-0017).

5. Alberta's provincial regulation and the federal regulation didn't become effective until 2011. Since we do not have data for 2010, we are assuming that there was no renewable content in 2010.

6. Gasoline and diesel data received from the Alberta government represents unblended volumes.

7. The proportion of biodiesel vs. HDRD in all years prior to 2017 is based on data reported for 2017. The split is based on data thereafter, except for 2022, which is based on the ratio in 2021.

8. We assume the feedstocks used for HDRD in Alberta are proportionally the same as what is used in British Columbia, given that they are likely sourced from the same imports.

Assumptions for Saskatchewan

1. Ethanol content for 2010-2012 and 2015 to 2020 is based on data provided in correspondence with the Saskatchewan government. We've received indication that in 2013-2014 ethanol content remained between 9.1%-9.2%. Biomass based diesel volumes from 2012-2020 are based on data provided by Saskatchewan.

2. We assume that the proportion of biofuel in diesel is 0% HDRD and 100% biodiesel.

3. We assume that the feedstocks for ethanol are 70% wheat and 30% corn. We base this on correspondence with Don O'Connor of (S&T) ^{2} Consultants.

4. We assume that the primary feedstock for biodiesel is canola, based on correspondence with the government of Saskatchewan. However, as of 2020, we are assuming 50/50 canola/soy split based on input from Don O'Connor of (S&T)2 Consultants.

5. Gasoline volumes were retrieved from Statistics Canada Table: 25-10-0030-01 (formerly CANSIM 128-0017).

6. Diesel sales by volume for 2010-2012 and were retrieved from Statistics Canada Table: 25-10-0030-01 (formerly CANSIM 128-0017). Note that diesel consumption provided with regard to the provincial regulation does not align with Statistics Canada data after 2012, possibly due to an increase in diesel consumption for non-transport or other policy exempt uses of the fuel.

7. Diesel and biodiesel consumption in 2016 is an average of 2015 and 2017 values.

Assumptions for Manitoba

1. All volume data from 2010-2019 is from the Government of Manitoba, as reported under Manitoba's ethanol and biodiesel mandates.

2. We assume that ethanol feedstocks are wheat and corn, transitioning primarily to corn based on the feedstocks processed in Manitoba facilities as reported by Husky Energy and from discussion with industry contacts.

3. We assume that biodiesel feedstocks are 50/50 canola and soy based on personal correspondence with a government contact.

4. We assume there is no HDRD consumption prior to 2021, based on correspondence with Don O'Connor of (S&T)2 Consultants.

5. 2020 is estimated assuming compliance with the fuel regulation (constant blend rate from 2019).

6. 2021 and 2022 are estimated assuming compliance with the updated fuel regulation (where the increase in the diesel pool is soy HDRD, assuming imports by rail from the Sinclair facility in Wyoming).

Assumptions for Ontario

1. Ethanol volumes are based on data provided by the Government Ontario.

2. Bio-based diesel consumption volumes for are based on Government Data for 2014, 2015 and 2019 to 2021. From 2016 to 2018, volumes are estimated

assuming compliance with the Greener Diesel Regulation, 80% of volume is HDRD with CI based on Diamond Green Diesel from 2016 to 2018 (from CI registered under the BC RLCFRR), 20% is biodiesel with net-0 CI, 10% of diesel pool is distributed in Northern Ontario (based on 2015 data) and is exempted from the regulation prior to 2017.

3. Bio-based diesel in 2010-2013 is based on fuel tax exemption data with the HDRD share interpolated towards the known % in 2015.
4. We assume that ethanol is made from corn.
5. We assume biodiesel is 50% soy-based, while the remaining 50% is sourced equally from tallow and yellow grease, whereas we assume HDRD is made from tallow and yellow grease. These assumptions are based on a qualitative discussion with a government contact.
6. Diesel volumes for 2010-2017 are from retrieved from Statistics Canada Table: 25-10-0030-01 (formerly CANSIM 128-0017). Gasoline volumes and diesel volumes 2018-onwards are based on data provided by the Government.
7. Data for 2020 forms only half of a two-year compliance period that was created to respond to market constraints due to the COVID-19 pandemic.
8. For 2021, we assume biomass-based diesel is 40% biodiesel and 60% HDRD, based on 100% biodiesel consumption by lake freighters: www.cslships.com/en/media-center/news-events/csl-successfully-completes-worlds-largest-b100-biofuel-tests

Assumptions for Québec

1. Gasoline and diesel sales by volume were retrieved from Statistics Canada Table: 25-10-0030-01 (formerly CANSIM 128-0017).

2. Ethanol and biomass-based diesel volumes are uncertain and should be used with caution: They are estimated based on the difference between federal data reported by ECCC (or industry contacts) and total biofuel content collected for the other provinces. That difference is allocated to Québec and the Atlantic Provinces, pro-rating by population. Newfoundland and Labrador is excluded from the calculation since we have good confidence that very little biofuel is consumed there.

3. We assumed most biodiesel and HDRD is produced from tallow and that 80% of the biomass-based diesel volume is HDRD from 2014 onward (same as Ontario assumption used to 2020).

4. We assume ethanol feedstock is corn since there is a facility in Quebec that processes corn ethanol and imports are assumed to be corn ethanol.

Assumptions for the Atlantic region

1. Gasoline volumes are based on Statistics Canada energy supply and demand data (Table: 25-10-0029-01, energy use, final demand).

2. Diesel volumes are based on Statistics Canada energy supply and demand data (Table: 25-10-0029-01, energy use, final demand).

3. Ethanol and biomass-based diesel volumes are uncertain and should be used with caution: They are estimated based on the difference between federal data reported by ECCC (or industry contacts) and total biofuel content collected for the other provinces. That difference is allocated to Québec and the Atlantic Provinces, pro-rating by population. Newfoundland and Labrador is excluded from the calculation since we have good confidence that very little biofuel is consumed there.

4. We assume ethanol is from corn and biodiesel is from unknown feedstock to better align with ECCC national feedstock values.

Detailed Feedstock Results

Based on the assumptions outlined above, the feedstocks used to produce biofuels sold in Canada were estimated and summarized in Figure 31 and Figure 32. Figure 31 shows the renewable fuel content in the diesel pool in Canada from 2010 to 2021, with an estimate for 2022. The volume of fuel is shown by fuel type and feedstock: most biodiesel is from canola and soy, most HDRD is from palm oil by-products and tallow. Figure 32 shows the renewable fuel content in gasoline pool in Canada from 2010 to 2021 by fuel type and feedstock, with an estimate for 2022: most ethanol consumed in Canada is produced from corn, with 10-15% produced from wheat.

Figure 31: National results for renewable fuel consumption of diesel pool by fuel type and feedstock

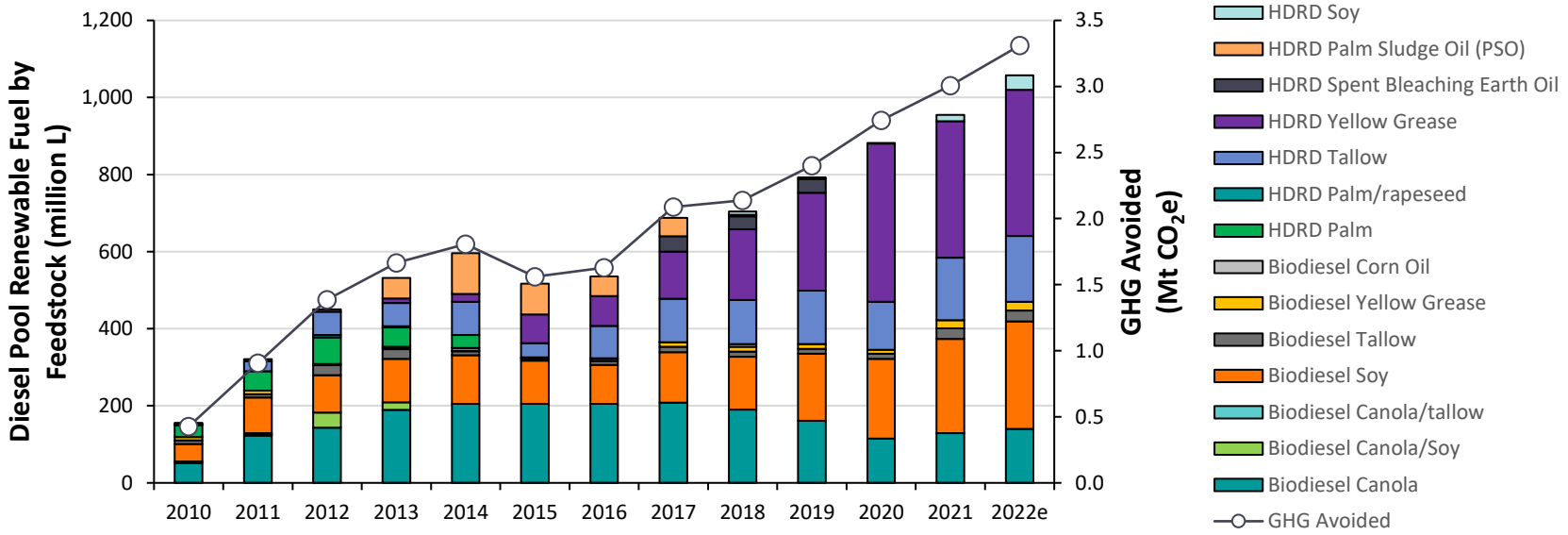
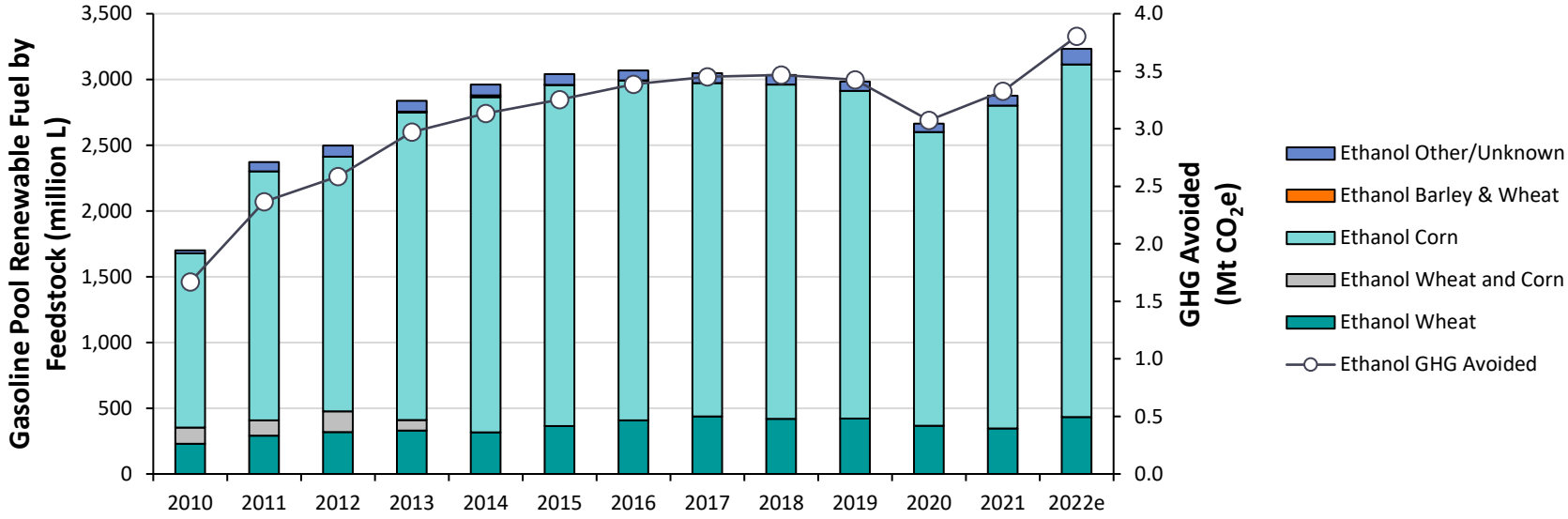


Figure 32: National results for renewable fuel consumption for gasoline pool by fuel type and feedstock



Appendix B: Cost Analysis Methodology

This appendix provides more detail on the methodology used for the cost analysis:

- The wholesale price of ethanol and biodiesel were obtained for 2010-2022.
  - Ethanol and biodiesel prices were based on monthly averages from Chicago Mercantile Exchange (CME) from 2010 to the end of 2022. Biodiesel prices are used net of the US biodiesel blenders tax credit.
- HDRD wholesale prices were estimated using Darling Ingredients', the parent company of Diamond Green Diesel, financial materials for investors. Prices were calculated annually as follows:

$$P_{HDRD} = \frac{Revenue}{Volume}$$

- Landed prices of ethanol and biodiesel were estimated for each province in Canadian dollars. These prices were based on a representative major terminal city in each province, with costs relative to the CME price based on typical fuel transport costs by rail. Distances between Chicago and each representative city are based on results from Google maps (road distances used to approximate rail distance). Transportation costs ranged from $5/bbl to $13/bbl, with a variable cost per kilometer that inversely scales with distance to account for economies of scale when shipping longer distances with rail, based on Gallagher and Denicoff (2015)[100] for 2013 and inflated using the Railway Association of Canada's rail cost index available in the annual Rail Trends reports (i.e. index of freight revenue per revenue tonne mile).[101]
- The wholesale price for blended gasoline and diesel for each year was obtained for each of the provinces in the analysis.

[100] Gallagher, Paul and Denicoff, Marina. 2015. Ethanol Distribution, Trade Flows, and Shipping Costs, Iowa State University Economics Technical Reports and White Papers Accessed from https://lib.dr.iastate.edu/econ_reportspapers/45

[101] Railway Association of Canada, 2023, Rail Trends 2022.

- These prices were based on monthly average wholesale price data for regular gasoline and diesel in representative cities in each province from collected by Kalibrate.[102]

- All values were converted to 2020 dollars[103] and Canadian currency from US dollars[104] and Euros.[105]

- Inputs for Atlantic Canada are constructed from provincial values averaged using population weights from Statistics Canada.[106]

- Inputs and results for Canada as a whole are calculated using fuel-consumption weighted averages, based on the fuel consumption reported in the analysis.

- The price of gasoline and diesel blendstock were estimated based on average reported blends in each year and the price of biofuel and blended fuel. For example, the price of gasoline blendstock ($P_{BOB,}$ Where BOB = blendstock of oxygenate blending) was calculated as:

$$P_{BOB} = \frac{P_{blend,reg} - P_{eth} * \%vol_{eth}}{\%vol_{BOB}}$$

  - Where $P_{blend,reg}$ is the price of the blended regular gasoline and P_{eth} is the price of ethanol in each region.

  - $\%vol_{eth}$ and $\%vol_{BOB}$ are the volume fraction of ethanol and gasoline blendstock in the regular gasoline, respectively (i.e. renewable or fossil component divided by total volume).

- The price of pure gasoline was estimated assuming the octane of that fuel would have had to be higher if no ethanol were added. In other words, we estimated the price of pure gasoline assuming the blendstock used with ethanol is sub-octane, and ethanol was used to boost its octane to 87. Without the addition of ethanol, pure gasoline would have had to be refined to a higher octane and its price would

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[102] Kalibrate, https://charting.kalibrate.com/

[103] CANSIM, 2018, Table 326-0020 Consumer Price Index

[104] Bank of Canada, 2022, Exchange Rates. http://www.bankofcanada.ca/rates/exchange/monthly-average-lookup/

[105] www.investing.com/currencies/eur-cad-historical-data

[106] Statistics Canada: Table 17-10-0009-01. Population estimates, quarterly.

be higher than the price of the sub-octane blendstock. To estimate this price, we used the following method:

- The blended fuel was assumed to have an octane value of 87 (regular) and the ethanol was assumed to have an octane value of 113 when used in a gasoline blend.[107]
- The implied cost per octane point was estimated for each year based on the difference between wholesale regular and premium gasoline prices in the US market[108] where that price spread better reflects the cost of octane than in the Canadian market.
- Our estimated price of pure sub-octane gasoline was decreased based on the implied cost per octane point and the estimated octane of the gasoline blendstock:

$$P_{gasoline,sub-octane} = P_{BOB} - \left(\frac{P_{blend,prem} - P_{blend,reg}}{O_{blend,prem} - O_{blend,reg}}\right) * \left(O_{gasoline,87} - O_{BOB}\right)$$

Where:

- $P_{gasoline,sub-octane}$ is the estimate price of pure gasoline if the gasoline blendstock is sub-octane.
- $P_{blend,prem}$ and $P_{blend,reg}$ are the price of premium and regular gasoline blends, respectively, based on US data.[109]
- $O_{blend,prem}$ and $O_{blend,reg}$ are the octane values of premium and regular gasoline blends, 92 and 87 respectively.
- $O_{gasoline,87}$ is the octane of regular gasoline blend (87).
- O_{BOB} is the octane of the gasoline blendstock. If it is refined sub-octane (i.e., below 87), with the intention of adding ethanol to increase the octane rating, then:

[107] 113 to 115 is a typical value for blends cited by EIA https://www.eia.gov/todayinenergy/detail.php?id=11131. This value corresponds to ethanol used in low concentration blends. The octane rating of pure ethanol is 100.

[108] EIA. 2022. Petroleum & Other Liquids: Refiner Gasoline Prices by Grade and Sales Type. Accessed from: https://www.eia.gov/dnav/pet/pet_pri_refmg_dcu_nus_m.htm

[109] ibid

$$O_{BOB} = \frac{O_{blend,reg} - O_{eth} * \%vol_{eth}}{\%vol_{BOB}}$$

Where:

- $O_{blend,reg}$ is the octane value of regular gasoline blend (87).
- $\%vol_{ethl}$ and $\%vol_{BOB}$ are the volume fraction of ethanol and gasoline blendstock in the regular gasoline, respectively.
- O_{eth} is the octane value of ethanol (113).

- The average price per litre cost/savings of blending ethanol and gasoline was estimated for each province in each year of the analysis based on the estimated price of pure gasoline and ethanol. For example, this price differential (P_{Δ}) in $/L for gasoline was calculated as:

$$P_{\Delta\$/L} = P_{blend,reg} - P_{gasoline,87}$$

- Similarly, the price per litre cost/savings of blending biodiesel and HDRD with pure diesel was estimated.
- The average $/GJ cost or savings that results from blending biofuel was estimated, assuming biofuel consumption does not change energy consumption. The following energy densities from GHGenius 4.03a were used to convert $/L price to $/MJ prices:
  - Ethanol= 23.6 MJ/L
  - Gasoline= 34.7 MJ/L
  - Diesel= 38.7 MJ/L
  - Biodiesel= 35.4 MJ/L
  - HDRD= 36.5 MJ/L
- The equation is:

$$P_{\Delta\$/MJ} = \frac{P_{blend,reg}}{MJ/L_{gasoline} * \%vol_{BOB} + MJ/L_{eth} * \%vol_{eth}} - \frac{P_{gasoline,87}}{MJ/L_{gasoline}}$$

- We then estimated the total fuel expenditures in each region and year with biofuels blended and for a counterfactual without biofuels blended:

- A counterfactual volume of gasoline and diesel was estimated that would have been consumed if no biofuels were blended into the fuel. This was calculated as the actual volume of fuel consumed multiplied by the ratio of the energy density (i.e., MJ/L) of gasoline to the energy density of the blend.
- Taxes and marketing margins were added to each price to get retail prices. Margins on $/L basis were obtained from Kalibrate[110] and are assumed to be independent of biofuel blending rates. Taxes, including carbon taxes and levies, are from NRCAN.[111] Taxes include federal and provincial fuel excise taxes, and sales taxes. Sales taxes were applied as a percent of the actual retail price and the calculated retail price for the counterfactual scenario without biofuels.
- The credit price impact of the cap-and-trade system in Ontario, Québec and Nova Scotia was assumed to already exist in reported wholesale gasoline and diesel blend prices. While biofuels are exempt from the cap-and-trade systems, the credit cost resulting from supplying gasoline and diesel was assumed to be spread evenly across all fuels, regardless of their biofuel content. For the counterfactual scenario with no biofuels, the additional cap and trade cost resulting from the gasoline and diesel that would have been consumed was based on average annual credit prices and added to the observed wholesale fuel price.[112,113,114]
- Retail prices were multiplied by volumes. For example: retail price of gasoline blend by volume consumed, or counterfactual retail price of gasoline by counterfactual volume. The same was done for diesel.
- The difference in cost in each year was calculated for each province for gasoline and diesel pools.

The change in fuel expenditures was shown for an archetypal consumer, broken down by component (i.e., change in wholesale fuel cost, additional margin cost, taxes). The

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[110] Kalibrate, https://charting.kalibrate.com/

[111] NRACN, 2022, Fuel Consumption Taxes in Canada, https://www.nrcan.gc.ca/energy/fuel-prices/18885

[112] Government of Ontario. Past auction information and results. Accessed from: https://www.ontario.ca/page/past-auction-information-and-results (note this data is longer available)

[113] Government of Ontario, 2018, *Past auction information and results*

[114] Government of Nova Scotia, 2021, Summary Results Report Nova Scotia Cap-and-Trade Program Auction of Emission Allowances

consumer archetype was defined to reflect the average statistics of Canadian consumers from 2010-2019[115] as reported by Natural Resource Canada, for the average L/100 km and annual km travelled. For the archetypal gasoline consumer, these values are 9.7 L/100 km and 15,788 km/yr. For the archetypal diesel consumer, these values are 32.0 L/100 km and 87,539 km/yr.[116,117]

[115] The NRCan National Energy Use Database has not yet been updated with values for 2020; the 2010-2019 averages were assumed to remain unchanged for 2020 and 2021.

[116] Natural Resources Canada, 2022, Energy Use Data Handbook Tables, Passenger Transportation Explanatory Variables.

[117] Natural Resources Canada, 2022, Energy Use Data Handbook Tables, Freight Transportation Explanatory Variables.

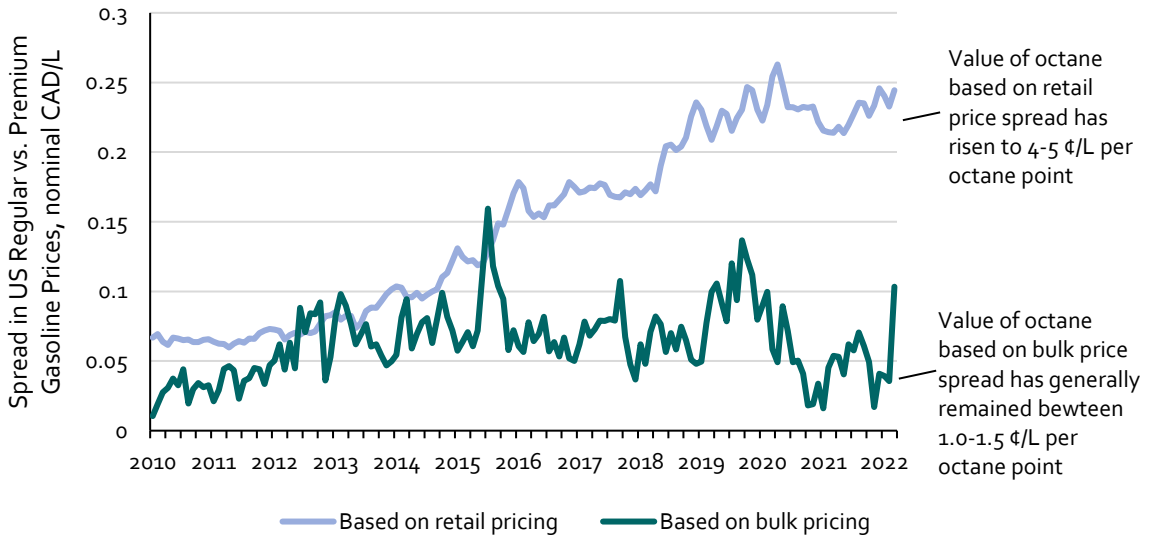
Appendix C: Explanation of Changes to Cost Analysis Methodology Made in 2021

Using Wholesale Instead of Retail Prices to Estimate Octane Value

Prior to the 2021 edition of the Biofuels in Canada analysis, the spread in retail prices between regular and premium gasoline was used as a proxy for the cost of increasing octane using a process other than ethanol blending. This assumption is key to the cost analysis – it determines how much additional cost would have been required to meet an octane value of 87 in regular gasoline had ethanol not been available.

Historically, retail and wholesale price spreads between premium and regular gas have been similar. However, since 2016 this spread has been gradually increasing, inflating the estimate for cost savings from the high blending octane of ethanol. Starting with the 2021 analysis, we used wholesale, rather than retail, price data to estimate the cost of octane. A comparison between the two is presented below.

Figure 33: Value of octane measured using retail and wholesale prices[118]



[118] EIA. 2022. Petroleum & Other Liquids: Refiner Gasoline Prices by Grade and Sales Type. Accessed from: https://www.eia.gov/dnav/pet/pet_pri_refmg_dcu_nus_m.htm

This methodological change resulted in a nearly $300/tCO$_2$e increase to the abatement cost of using ethanol, though the estimated average abatement cost since 2010 remains below zero (i.e., it still reduces emissions and prices).

Using wholesale, rather than retail prices, aligns our assumption for the value of octane in similar analyses that have been done in the U.S. and Mexico. Working for the U.S. EIA, consultants at Baker and O'Brien Inc. presented an engineering approach to the cost of octane by estimating the cost of using a catalytic reformer to increase the octane of gasoline.[119] That approach yields very similar results to our method of using the spread in U.S. wholesale prices, which is a lower cost than the value of octane implied by retail prices.

Likewise, a cost-benefit analysis of moving from MBTE to ethanol in Mexico used a similar approach to ours, taking the spread between regular and premium blendstock prices (as opposed to finished gasoline prices). That method results in a value of octane of about 0.9 cents per point per litre, similar to the average value of 1.3 cents per litre used in this report (also much lower than the value implied by the retail price spread).[120]

Assuming Premium Gasoline has an average Octane of 92, rather than 93

Paired with the difference in octane between regular and premium gasoline, the regular-premium price spread (discussed above) is used to estimate the refining/blending cost of increasing octane by one point. Our approach uses the formula below:

$$\text{Average Octane Cost (\$/L-ptAKI)} = \frac{\text{Price}_{\text{premium}} - \text{Price}_{\text{regular}}}{\text{AKI}_{\text{premium}} - \text{AKI}_{\text{regular}}}$$

"Regular" gasoline is generally agreed in North America to have an AKI rating of 87. Premium gasoline is more ambiguous – the EIA wholesale price data used in this report defines premium as having an AKI of "greater than 90". In some states, 93 is typical; 91 is typical in others. Past versions of this analysis have used 93, which results in a lower cost estimate per point of octane. Starting in 2021, the analysis uses

[119] Baker and O'brien Inc. (2018), Analysis of Gasoline Octane Costs, prepared for EIA: https://www.eia.gov/analysis/octanestudy/pdf/phase1.pdf

[120] Turner, Mason & Company, Mexico Fuel Ethanol Cost Benefit Analysis Study, May 2020

a value of 92 to reflect a more realistic estimate of the octane of the fuels represented in the premium price data.

Using Renewable Diesel Pricing Estimates from Diamond Green, rather than Neste

Previous years of the Biofuel in Canada report have estimated the cost of HDRD using investor materials published by Neste, which reflect all their global sales. Industry contacts critiqued this method, saying that it may over-state the average cost of HDRD because a substantial portion of Canadian HDRD is imported from the United States, where it is subject to a $1USD/gallon biomass-based diesel blenders tax credit, even if the fuel is exported.

Darling Ingredients, the parent company of Diamond Green Diesel, publishes equivalent financial materials to Neste, presenting revenue and sales volumes from their renewable diesel business segment, which are inclusive of the tax credit. Starting in 2021, this analysis uses these numbers to estimate the price of HDRD in Canada for 2016 and onward years (Neste data was used in previous years, where the DGD data is not available).

Appendix D: Plug-in Electric Vehicle Analysis Methodology

This year's report contains estimates for how PEV adoption to date has affected fuel consumption and lifecycle GHG emissions from transportation.

1. The primary data for this analysis is from Statistics Canada data for total motor vehicle registrations by province (i.e., cars on the road) and new motor vehicle registrations by province (i.e. cars sold that year) (tables 23-10-0067-01 and 20-10-0021-01). Table 20-10-0021-01, *New Motor Vehicle Registrations*, disaggregates vehicles by whether they were hybrid, plug-in hybrid, or battery electric (collectively called PEVs).
2. Certain provinces were missing PEV sales data (the "Canada" field was greater than the sum of the provinces for which data was available). These data gaps were filled by pro-rating the vehicles of unknown origin to the provinces with no data based on their populations. This adjustment affects only 3% of PEV sales.
3. Energy consumption of PEVs was estimated using the following assumptions:
   a. PEVs are driven the same amount as gas cars (about 15,000 km/year).
   b. PEVs use 19 kWh per 100km, an estimate of the sales weighted average of PEVs sold in Canada in 2021, with sales taken from GoodCarBadCar[121] and electric travel energy intensity taken from Natural Resources Canada.[122] We assume PHEVs have a utilization factor of 69% (this fraction of the vehicle's travel uses the electric drive is from electricity, the rest is from gasoline)[123].
   c. PEVs have an energy efficiency ratio of 4.1, reflecting the difference in efficiency between electric and internal combustion engines, based on the ration used in the Regulatory Analysis within the *Clean Fuel Regulations*.[124]

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[121] GoodCarBadCar, Automotive Sales Data and Statistics

[122] Natural Resources Canada, 2022, Fuel consumption ratings - Battery-electric vehicles 2012-2022 (2022-05-16)

[123] The International Council for Clean Transportation, 2020, Real-World Usage Of Plug-In Hybrid Electric Vehicles Fuel Consumption, Electric Driving, And CO2 Emissions.

[124] Government of Canada, Canada Gazette, Part II, Volume 156, Number 14: Clean Fuel Regulations

The following formula is used to estimate displaced gasoline consumption which also defines the avoided GHG abatement:

Displaced Gasoline (GJ/year) = Stock (vehicles)
∗ kilometers/year (km/vehicle-year) * fuel efficiency (kwh/km) * EER (GJ/GJ)*3.6

4. Finally, to estimate forgone emissions due to PEVs, the average carbon intensities of electricity by province and year from Canada's National Inventory Report are used.[125] Theses direct carbon intensities are supplemented by "upstream" lifecycle GHG emissions factors that are based on the difference between the direct GHG intensities in the National Inventory Report for 2019 and the CI for electricity noted for each province in the *Clean Fuel Regulation* draft legislation[126] in schedule 5, point 8 (e.g. to account for fuel production emissions, methane emissions from hydro reservoirs etc.)

[125] See Part 3, Table A13-1 through 11

[126] Government of Canada, Canada Gazette, Part I, Volume 154, Number 51: Clean Fuel Regulations