Analysis of the Proposed Canadian Clean Fuel Standard

Final Technical Report

SUBMITTED TO

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About Us

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

- We have a broad understanding of energy and environmental issues both within and outside of Canada.
- We use unique in-house models of the energy-economy system as principal analysis tools.
- We have a strong network of experts in related fields with whom we work to produce detailed and integrated climate and energy analyses.

We have gained national and international credibility for producing sound, unbiased analyses for clients from every sector, including all levels of government, industry, labour, the non-profit sector, and academia.

We are proud to have worked with the following clients:

- **Provincial, territorial and municipal governments:** Alberta, British Columbia, New Brunswick, Newfoundland and Labrador, Northwest Territories, Nova Scotia, Ontario, Vancouver
- **Federal government:** Environment and Climate Change Canada, Natural Resources Canada, National Roundtable on the Environment and the Economy
- **Utilities and the energy sector:** Advanced Biofuels Canada, BC Hydro, Canadian Association of Petroleum Producers, Canadian Gas Association, Kinder Morgan Canada, National Energy Board, Ontario Energy Board, Powerex Corp, Power Workers' Union, Spectra Energy, Western Canada Biodiesel Association
- **Non-profit and research:** Carbon Management Canada, Clean Energy Canada, Climate Action Network Canada, David Suzuki Foundation, Ecofiscal Commission, Electric Power Research Institute, Equiterre, Environmental Defense Fund, Pembina Institute, Pacific Institute for Climate Solutions

Executive Summary

Background

In late 2016, the Government of Canada announced its plan to introduce a national low-carbon fuel standard called the Clean Fuel Standard (CFS). A low-carbon fuel standard is a performance-based GHG reduction regulation that requires regulated parties (typically fuel suppliers) to reduce the lifecycle GHG intensity or carbon intensity (CI) of their fuels. In British Columbia and California, this type of policy puts a price on GHG emissions by creating a market for policy compliance credits. For this analysis, we assume the CFS will operate in a similar way. Fuel suppliers who provide energy with a CI below a specified target generate compliance credits while those who do not may purchase these credits for compliance. This credit market creates an incentive to supply and consume lower-carbon fuels like ethanol, biodiesel, renewable gasoline, renewable diesel, low-carbon electricity, renewable natural gas, hydrogen and biomass. However, unlike a conventional carbon tax or cap and trade,[1] the credit price only applies to the difference between a fuel's CI and the target CI. Furthermore, all credit revenue generated is recycled within the policy, meaning the low-carbon fuel standard will have a lower impact on energy prices than an equivalently priced carbon tax. In the past, low-carbon fuel standards have only been applied to transportation energy consumption, but the Government of Canada may apply the CFS to stationary energy consumption as well.[2]

Method

Navius Research was hired by Clean Energy Canada (CEC) to conduct a quantitative analysis of the CFS to support CEC's ongoing participation in the policy consultation process. This analysis forecasts Canada's energy consumption and GHG emissions from the present to 2030 under three scenarios (see section 2.1):

- **A reference scenario** that includes most existing GHG reduction policies in Canada, as well as many of the recently announced federal policies, such as the carbon price floor.

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[1] Note that a cap-and-trade is more like a low-carbon fuel standard if the cap-and-trade program allocates free emissions allowances to industrial facilities. In this case, the facilities are only paying a carbon price on a portion of their emissions.

[2] Environment and Climate Change Canada, 2017, *Clean Fuel Standard: Discussion Paper*, available from www.ec.gc.ca

- **A partitioned CFS scenario**, which includes all the policies in the reference scenario, but also adds the CFS, which has been partitioned between stationary and transportation energy consumption. The partitioning requires a 10% reduction in the average CI of transportation energy consumption by 2030, relative to a 2015 baseline (-12.5% from 2010). The CI reduction for stationary energy consumption was set so that abatement was equivalent to what would be achieved by a 5% renewable natural gas (RNG) blending requirement in 2030. This is equivalent to a -4% reduction in the average CI stationary fuels, relative to 2015. The total GHG reduction is somewhat more than 30 $MtCO_2e$ in 2030.
- **The CFS applied to transportation with a renewable-natural gas (RNG) mandate.** The third scenario, the transport CFS with an RNG mandate, has the same application of the CFS to transportation energy consumption. However, instead of applying a CI-based target to stationary energy consumption, the policy only requires a rising share of (RNG) within gaseous fuel consumption, where the blend must reach 5% by 2030.

Because ECCC's discussion paper proposes that the CFS cover transportation, buildings and industry, the scenarios were designed to produce GHG reductions from all three sectors. Preliminary analyses demonstrated that if CFS credits can be traded between stationary and transportation energy consumption, the policy would have almost no impact on transportation GHG emissions. Consequently, the partitioned CFS scenario has a separate CI requirement for transportation and stationary energy consumption.

This analysis uses two of Navius Research's in-house models, CIMS and OILTRANS, to forecast the impact of the CFS. CIMS models stationary energy consumption while OILTRANS models transportation energy consumption (see section 2.3):

- **CIMS** models how consumers and firms choose the technologies they use to satisfy their demand for energy end-uses such as space heating, lighting, industrial process heat, and electricity generation. The model simulates how policy affects the evolution of the stock of energy-using technologies in Canada as a function of sector activity, energy prices, technology costs and performance, as well as human behaviour. It has a detailed representation of the technologies in residential, commercial, and institutional buildings, manufacturing (six separate sectors), mining, oil and gas production, and electricity generation.
- **OILTRANS** is a transportation fuel market equilibrium model, which forecasts how the North American fuel markets evolve until 2030. The model has 11 individual regions representing seven regions in Canada, three in the United States and a single region to represent fuels production in the rest of the world that can export to

North America. The model represents 14 different transportation fuel pathways, and final transportation energy consumption is simulated using a CIMS-like model of transportation activity and technologies.

Energy-economy models like CIMS and OILTRANS provide a consistent framework to explore the impact of policies and technology assumptions. However, they have their limitation. While the suite of models used in this analysis has a detailed representation of current and emerging fuels and energy technologies, this does not eliminate the uncertainty in the cost and potential of emerging fuels and technologies. Rather it provides a platform to test how this uncertainty affects policy compliance, technology choice, energy prices etc. Furthermore, the models contain only a finite number of biofuel pathways, while in reality, there many more possible fuel and CI combinations possible. Finally, these models do not estimate the impact of the policy on economic growth or jobs and these results require an additional analysis.

EnviroEconomics used Navius Research's national level modelling to explore how the Clean Fuel Standard (CFS) may affect jobs and GDP. A two-step process adopted from NRTEE, 2012,[3] links financial expenditures by scenario to economic impacts: The incremental CFS capital and operating investments (i.e. changes in gross output) are first disaggregated or attributed into their constituent NAICS sectors. Next, the apportioned investments by NAICS are mapped to the corresponding Statistics Canada input-output multipliers. Results are produced by multiplying the change in gross output by NAICS sector to the associated economic impact multipliers to estimate the change in jobs or GDP.

Results and Discussion

How does the CFS reduce lifecycle GHG emissions?

The CFS can reduce GHG emissions in 2030 by more than 30 $MtCO_2e$/yr beyond what existing and proposed GHG policies can achieve. This GHG abatement is not sensitive to the designs of the CFS tested in this analysis. To achieve this outcome, the transportation energy CI must fall by 10% between 2015 and 2030. The stationary energy CI must fall by 4% between 2015 and 2030.

[3] Ibid.

What GHG abatement actions are used?

Increased biofuel consumption is the main driver of transportation GHG abatement. The biofuels that are consumed include ethanol, biodiesel, and hydrogenation-derived renewable diesel (HDRD). These fuels are commercially available and used in blends that are already compatible with current vehicles. Alternative fuel vehicles also play a role in transportation GHG abatement: the CFS incentivizes the use of E85, a fuel that is up to 85% ethanol, in flex-fuel vehicles (FFVs). Abatement through electrification of personal vehicles also shows strong growth. With the CFS in place, FFVs using E85 could account for 8% of light-duty vehicles on the road (1.7 million on the road using E85 vs. almost no E85 consumption without the CFS). Likewise, electric vehicles could account for 6% of light-duty vehicles in 2030 (1.2 million, roughly double what may occur without the CFS) (see section 3.3, Transportation).

When a CI-based policy is applied to stationary energy consumption, the main abatement actions are switching to renewable electricity and greater use of carbon capture and storage. Because of how the policy affects energy prices, it also induces more energy efficiency, increasing the GHG impact beyond what the CI reduction alone achieves. RNG consumption, which displaces fossil-natural gas, is the main abatement action with the RNG mandate (see section 3.3, Stationary).

What is the CFS abatement cost and how does the CFS affect energy prices and energy expenditures?

The price of transportation compliance credits under the CFS will be 150-180 $/tonne. The price of stationary credits will likely be lower, near 40 $/tonne (2015 CAD). However, because CFS is a GHG intensity-based policy, the full value of the CFS carbon price is not reflected in energy prices. This is because the CFS price applies only the difference between a fuel's CI and the target CI, while a carbon price would apply to a fuel’s full direct GHG intensity. Furthermore, The CFS is revenue-neutral from the perspective of fuel consumers in aggregate. While the CFS would impose a “tax” on fossil fuels, that revenue is returned through the compliance credit market as a “subsidy” on alternative fuels (see section 2.2).

The CFS will cause fossil fuel prices to increase compared to a scenario without the policy. However, the impact of the CFS on future energy costs is an order of magnitude smaller than the potential impact of the price of crude oil and natural gas. For example, the CFS may increase the retail price of gasoline by 5 cent/L in 2030, but if oil prices rise back to almost $90/bbl by 2030, the price of gasoline will increase by more than 40 cent/L (see section 3.4, Policy impact on energy prices).

Fuel switching and energy efficiency can allow consumers to reduce their annual energy costs relative to today, even if the CFS is implemented. For an energy-savvy citizen, household energy costs may decline from roughly $3,000/yr in 2015 to $2,000/yr, even with the CFS (2015 CAD). In 2030, this household's energy costs with the CFS are at most 26 $/yr higher than without the policy. For a more typical citizen, energy costs may only decline from $3,000/yr to $2,700/yr by 2030. In that year, household energy costs will be roughly $60/yr higher than without the CFS (see section 3.5).

How does the CFS change biofuel demand in Canada and North America and what are the implications for feedstock demand and liquid fuel production in Canada?

The CFS will likely double the quantity of biofuel consumed in Canada in 2030, compared to a scenario without the policy. Despite this growth in Canadian consumption, total North American biofuel consumption does not increase substantially. Three factors are responsible for the slow growth in continental biofuel consumption. First, energy efficiency prevents growth in overall transportation energy consumption. Second, this analysis assumes no change in US renewable fuels policy after 2018. Third, while Canadian biofuel consumption does grow, Canada only accounts for about 8% of North American transportation energy consumption. On net, North American biofuel consumption will likely only increase by 3% in 2030 relative to 2015. Consequently, the CFS will not significantly change the quantity of grains and oilseeds use for fuel in North America relative to today (see section 3.6).

The growing demand for biofuel is satisfied by increased biofuel imports and increased domestic biofuel production, which account for 56% and 44% of the supply respectively. Canadian ethanol production reaches almost 3.0 billion L/yr in 2030, requiring 7 Mt/yr of grain, equivalent to 13% of 2016 Canadian corn and wheat production. For context, Canadian ethanol production in 2016 was roughly 1.8 billion L/yr.[4] Canadian biodiesel and HDRD production reaches 2.7 billion L/yr in 2030, requiring 9 Mt/yr of oilseed, equivalent to 34% of 2016 Canadian soy and canola production (Assuming an averaged soy and canola oil content and not accounting for the contribution of waste oil and fat). For context, Canadian biodiesel production in 2016 was roughly 0.4 billion L/yr (see section 3.6).[5]

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[4] Dessureault, D. (2016). Canada Biofuels Annual 2016. USDA Foreign Agricultural Service, Global Agricultural Information Network

[5] Ibid.

Comparisons of feedstock requirements to current production provide context to the results, but they ignore how feedstock availability may change in the future. First, agricultural productivity is trending upwards. Total Canadian grain and oilseed production has increased by 30-40% between 2000 and 2016, but the seeded area for these crops has declined by 3% since the year 2000.[6] Second, any price or quantity constraint on agricultural feedstocks will create a market opportunity for biofuels produced from woody and grassy materials (i.e. ligno-cellulosic feedstock). While ligno-cellulosic biofuels are an emerging technology with an uncertain economic potential, the technical potential is large: Canadian production potential for these fuels is estimated at roughly 3,000 PJ/yr – equivalent to 120% of Canada's current liquid fuel consumption.[7]

What is the impact of the CFS on jobs and GDP?

The CFS shifts economic activity towards the biofuels production sectors, at the expense of investment and jobs in transportation, petroleum refining and conventional electricity generation. This analysis shows that the CFS could create a net-increase in employment and GDP relative to a scenario without the policy (see section 3.7). This growth is subject to the two key caveats of the jobs and GDP analysis:

- The results do not capture the expected reduction in overall economic productivity as costs rise due to higher carbon costs and technology choices made in the economy. I.e. it does not show how jobs and investments might have been allocated to more economically productive uses, which would reduce the net-positive impact of the CFS on the economy.
- The results do not show any increase in economic growth relative to the reference scenario resulting from avoided climate change damages. Including this would increase the net-positive impact of the CFS on the economy.

Relative to a scenario without the CFS, the partitioned CFS creates 28,000 additional direct and indirect jobs related to biofuel and renewable electricity production, at the expense of 17,000 fewer jobs in other sectors, creating a net-increase of 11,000 direct and indirect jobs (+0.3% of 2016 employment in the goods-producing industries

[6] Statistics Canada, 2017, *CANSIM 001-0010: Estimated areas, yield, production and average farm price of principal field crops*, available from www.statcan.gc.ca

[7] International Institute for Applied System Analysis, 2012, *Global Energy Assessment: Toward A Sustainable Future*, available from www.iiasa.ac.at

in Canada[8]). Including induced jobs increases the net-job impact to almost 16,000 by 2030. The CFS produces a similar change in GDP, where the direct and indirect GDP impact is a net-increase of $2.7 billion in 2030 (2015 CAD). Including the induced GDP impact changes the net-increase to $3.2 billion (2015 CAD).

The transportation CFS with the RNG mandate has a larger impact on Canadian jobs and GDP. However, the modelling does not account for RNG trade. All RNG production is assumed to occur in Canada which may overstate the number of jobs and GDP growth related to its production. In 2030, relative to a scenario without the transportation CFS and RNG mandate, that policy creates 31,000 jobs related to biofuel production, at the expense of 14,000 fewer jobs in other sectors. The net-change in direct and indirect employment is almost 17,000 jobs (+0.4% of 2016 employment in the goods-producing industries in Canada[9]). Including induced jobs increases the net-job impact to almost 24,000. The direct and indirect GDP impact is a net-increase of $4.0 billion in 2030 (2015 CAD). Including the induced GDP impact changes the net-increase to $4.7 billion (2015 CAD). Again, the assumption that all RNG is produced in Canada likely overstates the difference in economic impact between the partitioned CFS and the transport CFS with the RNG mandate.

What are the limitations and uncertainties of this analysis?

The limitations and uncertainties of this analysis come from uncertainty in future energy prices, technology costs and performance, as well as other energy and GHG policies. Subsequent analyses could address some of the uncertainties and limitations of this work. First, further sensitivity analysis on oil, natural gas, RNG and agricultural feedstock prices would illustrate how different assumptions may change the cost of complying with the CFS. Preliminary assessment of these drivers indicates that higher oil prices in particular can reduce the CFS credit price substantially while reducing the relative impact of the CFS on energy prices. For example, if the price of oil again rises towards $120/barrel, that can reduce or eliminate difference in production costs between petroleum fuels and biofuels. This change in turn reduces the strength of policy required to incentivize biofuel consumption.

Additional research should include some sensitivity analysis on the cost and potential of technologies. This could include assessing the impact of different costs, CIs, and supplies for emerging fuels. Public information on these fuels is sparse, but new information could be tested as it emerges. These fuels include those derived from

[8] Based on Statistics Canada, CANSIM, table 282-0008

[9] Based on Statistics Canada, CANSIM, table 282-0008

ligno-cellulosic feedstocks (e.g. cellulosic ethanol or renewable gasoline) and hydrogenation derived renewable diesel (HDRD), all of which were represented conservatively in this analysis, either with costs and/or CIs at the high-end of publicly available estimate. Specifically, the CI value of cellulosic ethanol used in this analysis is conservatively high and similar to conventional ethanol. Consequently, cellulosic ethanol saw little adoption in the forecast. This analysis also appears to be conservative in its representation of HDRD. This fuel is currently used in Canada, but the results show no adoption until 2030, indicating there is some benefit of HDRD not captured in the analysis.

Additional analyses could also test the impact of different assumptions for the cost and availability of alternative fuel vehicles. The forecast indicates that supplying E85 fuel at a price where owners of flex-fuel vehicles will use it is part of a least-cost compliance pathway. However, it is possible that automakers may cease supplying these vehicles before the CFS can create enough incentive for consumers to demand them. Alternatively, fuel suppliers may be reluctant to invest in E85 refueling infrastructure, which is essentially non-existent in Canada as of 2017. Therefore, testing a scenario without the availability of E85 will be important. On the other hand, this analysis represents no potential to use more ethanol in modern conventional vehicles capable of using higher ethanol blends (e.g. E30) and it is relatively conservative in its forecast of electric vehicle adoption, where new sales remain at less than 10% of the total by 2030, even with the CFS. Scenarios with lower-cost electric vehicles and earlier consumer acceptance of this technology are possible, as are scenarios with E30 capable vehicles.

Finally, future analyses could test the impact of policy uncertainty. This analysis does not consider a change in US renewable fuels policy, but what happens if the US continues to increase its biofuel blending rates under the Renewable Fuel Standard? The assumption in this analysis is that the volumes remain fixed at their 2018 values rather, with no further legislation to raise them in 2019 to 2022 as previously planned. This assumption slackens the demand for biofuel in North America, likely reducing the cost of these fuels somewhat. Similarly, what is the impact of renewed biofuel production and blending incentives in Canada or the US? Finally, this analysis does not consider the impact of a strong policy pushing greater adoption of zero-emissions vehicles. What would be the impact of a potential Canadian zero-emissions vehicle strategy or sales requirement on the CFS?

Table of Contents

1. Introduction

In late 2016, the Government of Canada (the Government) announced its plan to introduce the Clean Fuel Standard (CFS). It is a low-carbon fuel standard that will be applied nationally. The CFS' objective is to reduce Canadian greenhouse gas (GHG) emissions by 30 Mt/yr in 2030, relative to a scenario without the policy, contributing to Canada's target to reduce GHG emissions by 30% from 2005 levels in that same year.[10]

A low-carbon fuel standard is a performance-based GHG reduction regulation that targets fuel suppliers (or designated regulated party), requiring them to reduce the lifecycle GHG intensity or carbon intensity (CI) of their fuels. In addition to direct carbon emissions, lifecycle GHG emissions include upstream emissions associated with the production, processing, and transportation or transmission of the fuels. This type of policy puts a price on GHG emissions by creating a market for compliance credits. Fuel suppliers who provide energy with a CI below the target generate credits while those who do not may purchase these credits for compliance. Low-carbon fuel suppliers can generate credits and sell them to higher-carbon fuel suppliers, creating an incentive for low-carbon fuel supply and consumption. In this manner, the CFS can incentivize the use of alternative fuels including ethanol, biodiesel, renewable gasoline and diesel, low-carbon electricity, renewable natural gas, hydrogen and biomass.[11]

The first low-carbon fuel standard was enacted in California in 2007. Other jurisdictions that have adopted a similar policy include the European Union (EU) with its EU Fuel Quality Directive, British Columbia with the Renewable and Low Carbon Fuel Requirements Regulation, and most recently Oregon, with the Oregon Clean Fuel Standard. The low-carbon fuel standards in these jurisdictions only apply to transportation fuels. The Government of Canada is planning on taking its CFS a step further by applying it to transportation as well as stationary energy consumption in buildings and industry.[12]

The Government began its CFS consultation efforts in January 2017 with plans to engage stakeholders including provinces, territories, Indigenous Peoples, industries,

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[10] Environment and Climate Change Canada, 2017, *Clean Fuel Standard: Discussion Paper*, available from www.canada.ca/en/environment-climate-change/services/canadian-environmental-protection-act-registry/clean-fuel-standard-discussion-paper.html

[11] Ibid.

[12] Ibid.

and non-governmental organizations. It is planning a second round of consultations ending in mid-2018 in time to publish its proposed regulation.[13]

Navius Research (Navius) was hired by Clean Energy Canada (CEC) to conduct an analysis of the CFS to support CEC's ongoing participation in the consultation process. Navius used its OILTRANS and CIMS energy-economy models to forecast Canada's energy consumption and GHG emissions from the present to 2030. EnviroEconomics used the results to estimate the impact of the CFS on jobs and GDP growth by sector. The analysis includes three scenarios:

- The first scenario includes most existing GHG reduction policies in Canada, as well as many of the recently announced federal policies, such as the carbon price floor.
- The second scenario includes all the policies in the reference scenario, but also adds the CFS, which has been partitioned between stationary and transportation energy consumption. The partitioning requires a 10% reduction in the average CI of transportation energy consumption by 2030, relative to a 2015 baseline. The CI reduction for stationary energy consumption was set so that overall reduction is roughly 30 $MtCO_2e$ in 2030.
- The third scenario has the same application of the CFS to transportation energy consumption. However, instead of applying a CI-based target to stationary energy consumption, the policy only requires a rising share of renewable natural gas (RNG) within gaseous fuel consumption, where the blend must reach 5% by 2030.

This report summarizes the methodology and findings of the analysis. Section two of the report provides a description of the scenarios, the model, and the assumptions and inputs to the modelling. That section explains how the market for CFS compliance credits operates and how the CFS credit price differs from a conventional carbon price (e.g. from a tax or cap and trade). The results of the modelling are outlined in section three, which shows the CI reduction potential of the policy, the type of GHG abatement actions that are used, the cost of abatement, the impact on energy prices and expenditures, and the impact on biofuel and biofuel feedstock demand in Canada. Results also include a forecast of how the CFS will affect jobs and GDP growth by sector. Discussion and conclusions follow in section four, where key results, insights, and the uncertainty of the results are discussed and summarized.

[13] Environment and Climate Change Canada, 2017, *Clean Fuel Standard,* available from www.ec.gc.ca

2. Methodology

This section begins with a description of the three scenarios forecasted in this analysis, as well as an explanation of how compliance with the CFS occurs and how the CFS differs from other policies that put a price on GHG emissions. This is followed by a description of the modelling methodology used for the analysis. A summary of key assumptions concludes the methodology section.

2.1. Policy scenarios

This analysis includes three scenarios, one reference scenario without the CFS and then two alternative policy scenarios, each including a different potential design of the CFS.

The reference scenario

Canadian Policy

The reference scenario includes all existing GHG reduction policies in Canada. It also includes many of the recently announced federal policies including:

- The proposed floor on carbon pricing rising from 10 \$/tCO_2e in 2018 to 50 \$/ tCO_2e in 2022. We assume it is adjusted according to inflation to maintain its real value. We assume this carbon price, and all others included in the analysis, are applied to fuel blends such that the tax reflects the direct GHG emissions intensity of the blend (e.g. a 15% ethanol blend in gasoline would have a lower carbon cost than a 7.5% blend). Note that this differs from how some carbon prices are applied in Canada, for example in British Columbia, where the carbon tax is levied per liter of gasoline and diesel assuming a fixed biofuel content.
- The requirement to phase-out all conventional coal powered electricity generation by 2030
- The upstream oil and gas methane regulations which aim to reduce methane emissions in those sectors by 40-45% in relative to 2012 over the next five to ten years.

Additional detail on how existing provincial and federal GHG reduction policies are represented in the model is in Appendix A: "Detailed model inputs". Existing federal policies of note include:

- The renewable fuel standard that requires 5% renewable fuel by volume in gasoline and 2% renewable fuel by volume in diesel.
- The federal vehicle emissions standards on light and heavy-duty vehicles that require relatively large increases in the energy efficiency of new vehicles sold over the next decade.

Most provincial policies are included in this scenario. However, to simplify the analysis, it does not model the impact of the British Columbian Renewable and Low-Carbon Fuel Regulation under the assumption that, nationally, this policy will not have a GHG impact that is additional to what the renewable fuel standard and/or the CFS will achieve.

US Policy

Because North America has a relatively integrated market for liquid fuels, the reference scenario also includes US policies. Specifically, it includes Corporate Average Fuel Economy (CAFE) standards, analogous to the Canadian light-duty vehicle emissions standard. It also includes the US renewable fuel standard. The US Environmental Protection Agency expects to increase these biofuel requirements each year, based on goals defined in the Energy Independence and Security Act of 2007, which had the total biofuel volumes increasing at roughly 9% annually to 2022.[14] The percent change in volume from 2016 to 2017 is expected to be 6%. Because increased biofuel volumes are announced but not yet regulated, there is uncertainty in the future policy requirement. There is also a history of reducing the required amount of cellulosic fuels, which still remain near 0% of the fuel content. The overall volume has also been revised downward from the initial Energy Independence and Security Act of 2007: The 2017 total biofuel volume was planned to be 24 billion gallons/yr, whereas the actual legislated amount was 20% lower at 19.3 billion gallons/yr.[15] Therefore, we have only assumed an additional 6% increase in 2018, equivalent to 11.3% renewable fuel content by volume in gasoline and diesel in that year. Thereafter we assume the blending requirement remains constant. More detail on the US policies is described in Appendix A: "Detailed model inputs".

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[14] US Environmental Protection Agency, 2007, *Energy Independence and Security Act of 2007*, available from www.epa.gov

[15] US Environmental Protection Agency, 2017, Final Renewable Fuel Standards for 2017, and the Biomass-Based Diesel Volume for 2018, www.epa.gov/renewable-fuel-standard-program/final-renewable-fuel-standards-2017-and-biomass-based-diesel-volume

The partitioned CFS scenario

Why is the CFS partitioned? Draft analyses demonstrated that without a partition, most compliance would come from stationary energy consumption. In other words, if CFS credits can be traded between stationary and transportation energy consumption, the policy would have almost no impact on transportation GHG emissions. Because ECCC's discussion paper proposes that the CFS cover transportation, buildings and industry, the partition was added to ensure GHG reductions from all three sectors.

The second scenario includes all the policies in the reference scenario, but also adds the CFS, which is partitioned between stationary and transportation energy consumption and achieves roughly equal GHG reductions from each of these categories by 2030. The partition exists to ensure the policy has a substantive impact on all sectors. Total GHG abatement is approximately 30 Mt/yr in 2030 beyond the abatement that occurs in the reference scenario. This outcome was achieved by applying a schedule of CI reductions to transportation energy consumption, measured relative to a 2010 baseline that includes only gasoline and diesel consumption. The CI reductions are:

- -4% from 2010 in 2020
- -8% from 2010 in 2025
- -12.5% from 2010 in 2030

The CI reductions can also be expressed relative to 2015, including the low-carbon fuels consumed in that year. For example, the results in section 3 show that the 12.5% reduction from 2010 is equivalent to 10.4% reduction from the 2015 baseline described above. The target can be achieved by increasing the consumption share of fuels with CIs that are below the target. CIs are defined for each fuel and do not include indirect land-use change GHG emissions (i.e. GHG emissions from soils and biomass that may occur if biofuels increase the price of agricultural products, thereby increasing the incentive to convert forest and pasture to crop production). If there are indirect land-use change GHG emissions that occur in Canada, these would be accounted for within the National Inventory of GHG emissions, but with this policy design, they will not affect compliance with the CFS.

The CI reduction schedule for stationary energy consumption was defined to approximate the CI impact of the RNG blending mandate described below. The 2010 baseline is defined by primary energy consumption as recorded by Statistics Canada. That stationary energy CI reduction schedule is:

- -2.5% from 2010 in 2020
- -4.0% from 2010 in 2025
- -5.5% from 2010 in 2030

The stationary energy CI reduction is measured as an average across all stationary fuels.

The baseline excludes coal consumed in existing electricity generation plants because it is tentatively excluded from this policy given that it is already regulated by other polices. Likewise, coal consumed in these power plants is not covered by the CFS.

For both the transportation and stationary CFS, we assume that compliance credits can be bought and sold amongst the regulated parties in order to achieve compliance at the least cost. Because abatement has been partitioned between stationary and transportation energy consumption, compliance credits cannot be traded between these categories of energy consumption. Compliance actions may include fuel switching and carbon capture and storage (CCS). CCS would be credited towards compliance either as a special project that is awarded credits, or by modifying the CI of the associated fuel. The CFS will change energy costs, so compliance with that policy may also increase energy efficiency, which will further reduce GHG emissions. However, energy efficiency does not generate CFS compliance credits. It merely increases the GHG Impact of the CFS beyond what would occur solely because of the CI reduction schedule.

The transportation CFS with a RNG mandate

The third scenario has the same application of the CFS to transportation energy consumption. However, instead of applying a CI-based target to stationary energy consumption, the policy only requires a rising share of renewable natural gas (RNG) within gaseous fuel consumption. The blend schedule is:

- 1% RNG in 2020
- 2.5% in 2025
- 5% RNG by 2030

By design, both versions of the CFS achieve the same GHG reduction in 2030, with similar results in 2020 and 2025.

2.2. Explanation of the Clean Fuel Standard compliance credit market

Our interpretation of the CFS is that it will be a market-based regulation that requires a reduction in the average CI of fuels sold in Canada. Similar policies already exist in California (the Low-Carbon Fuel Standard) and British Columbia (the Renewable and Low-Carbon Fuel Regulation). Assuming the CFS operates like these policies, it will create a price on GHG emissions through its compliance credit market. However, the CFS' carbon price is different from a conventional carbon price in three ways:

1. **The CFS price applies only to a portion of a fuel's CI, while a carbon price would apply to a fuel's full carbon intensity.** For gasoline, the CFS price would apply to the difference between its carbon intensity (87.3 g/MJ) and the target for carbon intensity (e.g. -12.5% or 76.4 g/MJ in 2030). This means that only 10.9 g/MJ or 12.5% of the fuel's CI are "taxed". On the other hand, a carbon tax or a cap-and-trade where all emissions credits are auctioned would apply a carbon price to a fuel's entire combustion GHG emissions.
2. **The CFS is revenue-neutral from the perspective of fuel consumers.** While the CFS would impose a "tax" on fossil fuels, it also provides a "subsidy" on alternative fuels. The total value of the tax on fossil fuels is always equal to the total value of the subsidy on alternative fuels. Therefore, unlike a conventional carbon price, the CFS does not lead to any financial transfers from fuel consumers to government.[16] However, it may lead to a transfer between consumers of different types of fuels. While consumers may use more expensive fuels, on-net they do not pay any carbon cost to the government or a regulated party.
3. **The CFS applies to lifecycle emissions, while the carbon prices implemented in Canada only apply to direct emissions from fuel combustion.** In Canada, all carbon prices (e.g., British Columbia's carbon tax, Alberta's carbon levy, Ontario/Quebéc's cap-and-trade program) apply to direct combustion emissions only. The CFS policy applies to direct GHG emissions and also includes emissions

[16] This statement is true if carbon taxes are charged based on the direct GHG intensity of fuels and energy content of fuels. However, this is not currently the case. The British Columbian carbon tax is applied through a per liter excise tax based on a fixed biofuel content in gasoline and diesel (see Government of British Columbia, Motor Fuel Tax and Carbon Tax, www2.gov.bc.ca/gov/content/taxes/sales-taxes/motor-fuel-carbon-tax). If the ethanol content increases, the energy content per liter will decline, but the carbon tax per liter will remain the same. Consequently, the carbon tax paid per unit of energy will increase, as will a consumer's carbon cost.

resulting from the production and transportation of fuels and their feedstocks. An implication of this lifecycle approach is that the CFS will take into account to emissions that occur outside of Canada if fuels are imported.

For example, the CFS policy on transportation requires a 12.5% reduction in the average life-cycle carbon intensity of fuels sold in Canada from 2010 levels by 2030, assuming only gasoline and diesel in the 2010 baseline. This reduction in CI is applied separately to the gasoline and diesel pools. The CI for gasoline used in this analysis is 87.3 gCO_2e/MJ, therefore, a 12.5% reduction would require fuels sold into the gasoline pool to have a "weighted average" CI target of 76.4 gCO_2e/MJ in 2030 (the average would be weighed on the energy content of fuels sold into the pool). The life-cycle carbon intensity for diesel used in this analysis is 93.6 gCO_2e/MJ, therefore weighted average CI target in 2030 would be 81.9 gCO_2e/MJ. For stationary energy consumption, the 2010 baseline for all fuels used in stationary applications is 41.2 g/MJ (see section 3.2). The CFS requires a 5.5% reduction in the CI of stationary fuels by 2030, meaning the consumption weighted average CI of these fuels must decline to 38.9 gCO_2e/MJ.

Under the CFS, fuels sold into each pool would either "supply" credits or "demand" credits. Fuels with a CI below the target would generate (i.e., "supply") credits equal to the difference between the target and the fuel's CI. The CFS creates a new market in which the supply for CFS credits must be equal to demand.[17]

In the CFS market, supply and demand for CFS credits arrive at an equilibrium by a flexible price for credits. If the weighted average CI for fuels sold is above the target, the "demand" for credits will exceed supply. In response, the price for credits would rise to provide a greater incentive to supply low-carbon fuels and to discourage the supply of higher-carbon fuels. If supply exceeds demand, the price would decline.

The quantity and value of credit supply and demand are a function of the average weighted CI target, the CI of individual fuels, and the equilibrium credit price. For example, if the CI of corn-based ethanol is 45.8 gCO_2e/MJ, then blending this ethanol into the gasoline pool in 2030 would generate 30.6 credits, measured in grams, per every MJ blended in 2030 (i.e., 76.4 – 45.8= 30.6 gCO_2e/MJ). The credit market effectively subsidizes the price of that fuel based on the quantity of credits it demands and the credit price. Likewise, if the CI of RNG is 2.0 gCO_2e/MJ, then blending this fuel into gasoline would generate 36.9 credits, measured in grams, for each MJ of RNG blended in 2030 (i.e. 38.9 - 2 = 36.9 gCO_2e/MJ).

[17] Supply can be greater than demand if the price for CFS credits is zero, but this outcome was not observed in the analysis.

Fuels with a carbon intensity above the target require (i.e., “demand”) credits before they can be added to a pool. The credit requirement would be equal to the difference between a fuel’s carbon intensity and the target for carbon intensity. In practice, only petroleum-based gasoline and diesel would require credits. In 2030, gasoline would require credits equal to 10.9 gCO_2e/MJ blended while diesel would require 11.7 gCO_2e/MJ blended. For stationary fuels, any fuel above the target would require credits. In 2030, natural gas (CI = 58 gCO_2e/MJ) would require credits equal to 19.1 gCO_2e/MJ consumed, while petroleum coke (CI = 104 gCO_2e/MJ) would require credits equal to 65.1 gCO_2e/MJ consumed. In all cases, the credit market effectively adds a price premium to those fuels based on the quantity of credits they demand and the credit price.

Note that the credit price represents the "marginal abatement cost", that being the cost of the most expensive GHG abatement action that is required to comply with the CFS. As explained in the results, Regulated parties will have the opportunity to reduce some GHG emissions using lower-cost actions, so the average abatement cost will be lower than the credit price.

2.3. Modelling framework

This analysis uses two models, CIMS and OILTRANS, to forecast the impact of the CFS. CIMS models stationary energy consumption while OILTRANS models transportation energy consumption. The models solve iteratively until they come to an internally consistent forecast for each scenario. Capital, operating and energy costs from both models were used by EnviroEconomics to forecast how the CFS will affect jobs and GDP. This section first describes the CIMS and OILTRANS models, as well as how the models interact and the strengths and limitations of this method. It concludes with a description of the methodology behind the jobs and GDP analysis.

The CIMS model

CIMS is maintained through frequent consulting and academic work by Navius Research and the Energy and Material Research Group at Simon Fraser University. CIMS models how consumers and firms choose the technologies they use to satisfy their demand for energy end-uses such as space heating, lighting, industrial process heat, and electricity generation. The model simulates how policy affects the evolution of the stock of energy-using technologies in Canada as a function of sector activity, energy prices, technology costs and performance, as well as human behaviour. It has a detailed representation of the technologies in the following sectors:

- Residential buildings

- Commercial and institutional buildings
- Industry, including chemicals, pulp and paper, cement and lime, iron and steel and other metal smelting, mining, and other manufacturing (a collection of less energy intensive industries producing wood products, food and beverages, textiles, transportation equipment etc.)
- Electricity generation
- Upstream bitumen, oil and gas production, and petroleum refining

CIMS includes seven regions: British Columbia, Alberta, Saskatchewan, Manitoba, Ontario, Québec an aggregate Atlantic province.

Technology choice decisions are based on financial costs as well as human behaviour:

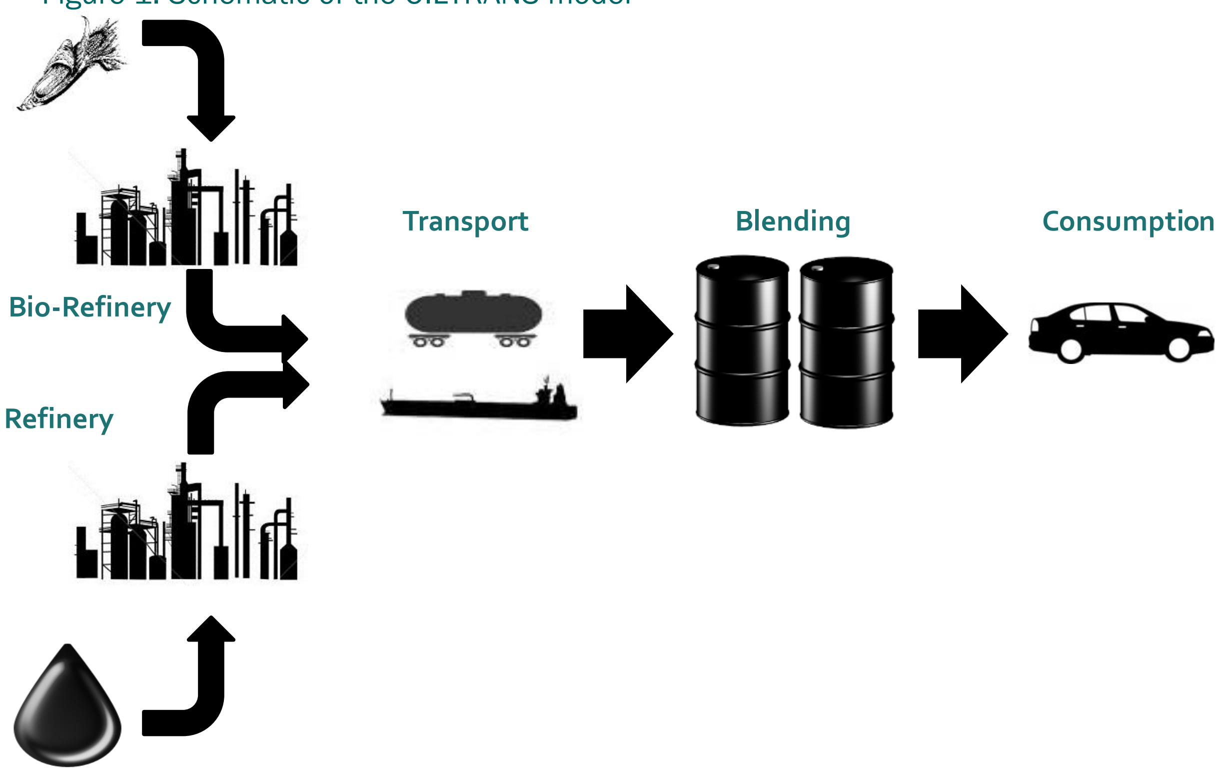
- **Capital costs**. Each technology has a unique capital cost, which can decline over time for emerging technologies (e.g. solar photovoltaic electricity generation costs decline according to an external assumption).
- **Fuel prices**. Everything else equal, an increase in the price of natural gas relative to electricity would encourage the adoption of electric technologies where a fuel switch is possible. Alternatively, if natural gas prices increase, it creates an incentive to invest in more energy efficiency gas-fuelled technologies. Note that the CFS may affect technology choice indirectly through the fuel price.
- **Non-financial factors** that influence decision making, which are primarily applied to new and emerging technologies. These can include
    - An aversion to upfront costs
    - A lack of familiarity or perceived risk of a new technology
    - A lack of technology supply
    - Technology specific issues such as the quality of services provided (e.g. fluorescent lighting has a different colour than incandescent lighting)
- **Various policies** that directly affect technology choice. While the CFS and other market based mechanism affect technology choice by changing energy prices, some regulatory policies may prescribe which technology must be used. For example these policies include building energy codes and appliance energy efficiency regulations.

CIMS integrates energy supply and demand, meaning that the energy consumed in CIMS must be produced somewhere. However, because liquid fuel production is modelled in OITLRANS and crude oil and natural gas production are largely driven by exports, only electricity supply and demand is integrated in this analysis. In short, if electricity consumption increases, this will increase investment in the electricity sector as well as energy consumption and potentially GHG emissions.

The OILTRANS model

OILTRANS is a transportation fuel market equilibrium model, which is designed to provide a forecast of how the North American fuel markets evolve until 2030. It is owned by Navius Research and maintained through ongoing consulting work. The model has 11 individual regions representing 7 regions in Canada, 3 in the United States and a single region to represent fuels production in the rest of the world that can export to North America. A schematic of the actors and processes included of the model is shown in Figure 1, with the model representing the production of biofuels feedstock, the processing of feedstocks into biofuels, the transportation of fuels to market, blending of biofuels and petroleum fuels as well as final consumption and vehicle choice that defines what fuels can be used (e.g. only a plug-in electric vehicle can use electricity).

Figure 1: Schematic of the OILTRANS model



OILTRANS ensures all markets represented within the model arrive at an equilibrium simultaneously (i.e. supply equals demand for all markets, including a policy compliance market. A key challenge with analyzing transportation markets is that many factors interact simultaneously to determine how the market will unfold. Furthermore all factors simultaneously affect all others. For example, a subsidy on electric vehicles is likely to have an immediate impact on the adoption of electric vehicles, but it is also likely to have secondary impacts throughout the entire fuels market in North America. Greater adoption for electric vehicles would reduce the demand for liquid fuels. Lower demand for liquid fuels would then affect markets further upstream. It could reduce the amount of biofuel required in North America, which would then affect the price for biofuels and the price for agricultural products used as feedstocks into producing biofuels. Completing the circle, this could change the price of liquid fuels which would affect the adoption of electric vehicles. The benefit of OILTRANS is that it connects each of these markets in the transportation sector within an internally consistent equilibrium framework.

OILTRANS accounts for the following markets (from supply to demand) and dynamics:

- **Agricultural markets:** The model accounts for the production of key agricultural commodities used as biofuel feedstocks (e.g., corn, canola, soy and wheat). Agricultural production occurs within each model region (e.g. Ontario, Alberta, Saskatchewan, etc). Agricultural producers are flexible in what and how much they produce each year, but there are limits to their ability to increase total agricultural production or to change the types of crops produced to respond to changes in prices (see "Feedstock cost" in the appendix). Following production, feedstocks can be shipped to another region or can be converted into biofuels domestically. One fuel pathway, HDRD derived from palm oil, animal fats and used cooking oil, can be imported from Asia, with appropriate marine shipping costs (see "Transportation margins for all fuels" in the appendix).

- **Biofuels manufacturing:** The model represents 15 unique biofuels pathways. Each pathway is differentiated by the type of biofuel produced (i.e., ethanol, biodiesel, renewable gasoline, renewable diesel and hydrogenated derived renewable diesel); the type of feedstock used to produce the biofuel (e.g., corn, soy, wood-residue, etc); the costs of production; and CI (see "Fuel pathways and carbon intensity of fuels" and "Biofuel cost of production" in the appendix).

- **Petroleum refining:** This sector converts crude oil into refined petroleum products (i.e., gasoline and diesel) at a given carbon intensity (see "Fuel pathways and carbon intensity of fuels" in the appendix).

- **The availability of alternative fuels and alternative fuel vehicles:** including natural gas (using a fixed external price forecast) and electricity (with the price informed by CIMS results).

- **The blending of liquid fuels** into the gasoline and diesel pools, respectively. This section of the model ensures:
  - Any constraints on blending biofuels are met. For example, “blend walls” prevent the share of ethanol from exceeding a set share of the gasoline pool (see "Substitutability between biofuels and refined petroleum products" in the appendix).
  - Compliance with most existing federal and provincial policies (e.g. minimum requirements for renewable fuel content) (see Existing GHG reduction policies" in the appendix).
  - Compliance with potential policies such as the CFS
- **Vehicle choice:** In total, the model accounts for 8 unique transportation end-uses (e.g., passenger vehicles, transit, light-duty freight, etc.) and a total of 40 technologies available to meet the demand for these end-uses. Again, all transportation energy consumption is included with the exception of energy used for aviation and from marine international fuel bunkers (see "Vehicle choice" in the appendix).

Interaction between CIMS and OILTRANS

CIMS and OILTRANS iterate to come to an equilibrium solution, where information from one model no longer changes the forecast of the other. The information that is passed from CIMS to OILTRANS includes:

- The price and CI of electricity in each Canadian province.
- The lifecycle GHG emissions reductions from stationary energy consumption that result from the CFS.

OILTRANS only passes the transportation lifecycle GHG emissions reductions to CIMS. For simplicity, OILTRANS does not send electric vehicle electricity consumption to CIMS. The GHG emissions associated with this electricity consumption are accounted in OILTRANS according to the CI of fuel. However, this method will slightly underestimate the energy consumption in the electricity sector, but the error is negligible: In 2030 with the CFS, electric vehicles still account for less than 0.8% of total electricity consumption.

Strengths and limitations of the CIMS OILTRANS method

The CIMS OILTRANS method has several strengths:

- It can properly model the market for CFS compliance credits that must come to equilibrium (supply and demand of credits is equal) with all revenue recycled within the policy (i.e. no financial transfers to the government).
- It can model the impact of the CFS within the context of existing policies.
- It covers all relevant sectors and energy end-uses with technological detail, allowing technology and fuel choices to respond to policy stringency, while still accounting for the rate at which the stock of technologies is retired and replaced.
- It has a detailed representation of biofuel production location, transportation costs, and blending constraints.

The methodology also has some important limitations:

- It has a finite number of biofuel pathways whose CI is exogenous i.e. individual pathways do not adjust in response to policy, the policy only changes which pathways are used. As well, not all possible pathways are represented (e.g. there is no pathway for a very low CI biofuel produced using bio-energy while also sequestering carbon or preventing methane emissions).
- The modelling methodology cannot simulate decisions made based on expectations for the future CFS credit price. Therefore, it cannot simulate compliance credit banking or borrowing, a flexibility mechanism that allows shifting compliance forwards and backwards in time to reduce the compliance cost of the policy.
- It does not eliminate the uncertainty in the cost and potential of emerging fuels and technologies. Rather it provides a platform to test how this uncertainty affects policy compliance, technology choice, energy prices etc.

Jobs and GDP analysis method

EnviroEconomics used Navius Research's national level modelling to explore how the Clean Fuel Standard (CFS) may affect jobs and investment. This analysis tests the two variants of this policy: the partitioned CFS and the transportation CFS applied with the renewable natural gas (RNG) mandate. Navius' result define the dollar value change in gross output (i.e. total economic activity) resulting from the changes in the use of fuels and technology that occur in response to the policy, measured relative to the reference scenario. The associated change in investment from the modelling generates a suite of macroeconomic indicators such as changes in employment and GDP which are also measured relative to the reference scenario.

There are several offsetting drivers of the CFS's economic impact: First, there is a surge in investment and economic activity resulting from increased biofuel production as well as a surge in end-use technology deployment within energy demand sectors in response to changes in energy prices. Second, there is a reduction in activity in other sectors that are related to conventional energy production (e.g. petroleum refining, fuel distribution, and conventional electricity generation). Third, there are indirect financial costs as productivity falls with rising prices attributable to the CFS:

- **A CFS induced expansion in the demand for low-carbon technology.** The CFS triggers a surge in induced technology investments, whether through the policy directly or indirectly via recycling of compliance credit revenues. The sellers and installers of the biofuel technology benefit as demand for their goods and services rise as do the suppliers of inputs into the technologies themselves. The dollar value of the deployed investment capital is often cited as the positive economic spin-off on goods and services used as intermediate inputs into the deployed technologies.
- **A CFS induced slowing or contraction of activity and sectors related to conventional energy production**. Increased investment in biofuel and low-carbon energy can come at the expense of investment in other conventional energy sources including fossil fuel extraction, refining and distribution or conventional electricity generation. This in turn changes the activity in sectors that provide inputs to the provision of these goods and services.
- **A reduction in economic productivity as costs rise due to the CFS.** Of course, someone must pay for the expansion of low-carbon technology, and there is an offsetting economic loss to the investment surge as carbon costs rise across the economy. The expenditures for CFS compliance raise costs across the economy which then lowers overall productivity and income. In those economic sectors that now must pay more to produce as a result of increased GHG costs, returns to capital and hence investment fall as demand shifts to lower carbon alternatives. Capital then reallocates within the economy to where returns are higher, increasing capital replacement and new investment in many emitting sectors. Investment from outside the jurisdiction could also fall when sector returns fall with the policy. In time, this reallocation alters the economic structure of the economy, favouring a transition to low-emission intensity producers and services. The cost of the transition is a function of policy, which can be designed efficiently or not. With efficient policy, the expectation is that the economy will grow marginally slower. Bad policy can be costly.

The following analysis of the CFS only accounts for the first two drivers, the shift in CFS induced investment with a slowing or contraction of investment in other sectors, but it does not account for the overall loss of economic productivity. Therefore, the analysis will show economic activity shifting from one sector to another, but it does not quantify the full economic productivity loss of this shift if labour and capital are drawn away from a sector where they would have produced more value added or a greater return on investment: these are the "full economic equilibrium" dynamics not captured in the methodology. A specific example would be the increased use of carbon capture and storage (CCS) in the oil sands in the partitioned CFS scenario. In this analysis, the increased investment required for CCS will increase direct investment and jobs in that sector and indirect jobs and investments in sectors that provide inputs. There will also be induced economic activity resulting from spending direct and indirect wages on unrelated good and services. However, this analysis will not show how the resources used for CCS might have been otherwise invested to create more value, for example in building more oil or bitumen extraction capacity, resulting in even greater induced economic activity. Therefore, the results only show part of the full economic impact of the CFS policies, and should be appropriately caveated when communicating the positive economic spin-offs attributed to the policy.

Despite this limitation, this "partial equilibrium" methodology is frequently used for economic analyses, including work done for the Conference Board of Canada[18] and the National Roundtable on the Environment and the Economy (NRTEE).[19] It is also consistent with almost all the economic impact analyses that determine the job impact of any major investment or project (e.g. a hydro dam, a pipeline etc., a new industrial facility). Regardless of the scale of the analysis, the limitations of a partial equilibrium analysis remain and should be communicated.

A further caveat is that the method does not account for climate change damages or how the CFS may or may not avoid these damages.

To link the scenario investment forecasts to economic impacts such as jobs, we followed a two-step process adopted from NRTEE, 2012.[20] The (incremental) CFS investments are first disaggregated or attributed into their constituent NAICS sectors. For example, disaggregating the total investment for a wind turbine includes supply components for the turbine generator, engineering services and steel for the tower, all of which can be attributed to a NAICS code. Table 1 provides an example of this mapping for a wind turbine to the associated NAICS sectors.

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[18] The Conference Board of Canada, 2017. The Cost of a Cleaner Future: Examining the Economic Impacts of a Reducing GHG Emissions. www.conferenceboard.ca/e-library/abstract.aspx?did=9021

[19] National Roundtable on Environment and Economy, 2012. Framing the Future: Embracing the Low Carbon Economy. Climate Prosperity, Report 6. http://nrt-trn.ca/wp-content/uploads/2012/10/framing-the-future-report-eng.pdf

[20] Ibid.

Next, the apportioned investments by NAICS are mapped to the corresponding Statistics Canada input-output multipliers.[21] To do this, we assume that the change in investment is equivalent to a change in gross output, which is the driver for the economic impact estimated by the multipliers. Results are produced by multiplying the change in gross output by NAICS sector to the associated economic impact multipliers to estimate the change in jobs or GDP. For example, the total employment multiplier for petroleum refineries (NAICS 324110) is 2.69 per million dollars of gross output change. The total employment multiplier is an amalgam of three economic impacts:

- Direct impacts triggered by the net changes in gross output;
- Indirect impacts which flow through the supply chain related to the gross output changes, creating additional impacts; and,
- Induced impacts when labor earnings and profits are spent, further creating impacts throughout the economy.

We use the jobs and GDP multipliers to estimate the economic impacts of the partitioned CFS and the transportation CFS with the RNG mandate. Incremental investment and jobs for the two scenarios are compared against the reference scenario which includes existing and some announced provincial and federal policies

Table 1: Example mapping of wind low-carbon technology sector to component NAICS Sectors

Tech./ Sector	Investment Costs	Component	Share of Investment (%)	Component NAICS Sector
Wind/ Electricity generation	Capital	Generating Set (Generator, Gearbox)	38%	333611 – Turbine and turbine generator set unit manufacturing
		Rotor & Nacelle Cover	18%	326198 – All other plastic product manufacturing
		Controls	7%	335990 – All other electrical equipment and component manufacturing
		Tower	10%	332319 – Other plate work and fabricated structural product manufacturing HS 730820 – Tower and Masts
		Construction Costs	24%	2300G0 – Other Engineering Construction
		Other Costs	2%	5413 – Professional, Scientific & Technical Services

[21] Input-Output National Multipliers, 2013. Industry Accounts Division / Statistics Canada. (15F0046X).

Tech./ Sector	Investment Costs	Component	Share of Investment (%)	Component NAICS Sector
	Operating	Operating & Maintenance	100%	2211 – Electric power generation, transmission and distribution

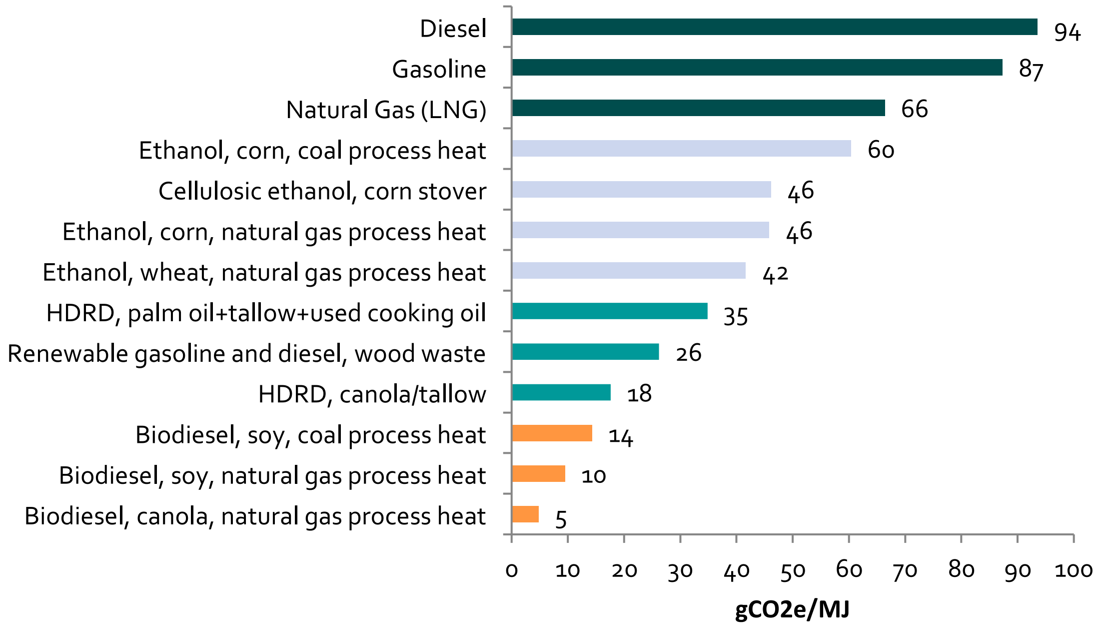
2.4. Summary of key assumptions

Table 2 contains a summary of key modelling assumptions with cross-references to where they are explained in more detail in the appendix. Figure 2 and Figure 3 show the transportation and stationary fuel pathways included in this analysis with their CIs. Many CI inputs are default results for Canada from the GHGenius 4.03a model. Emerging fuels such as cellulosic ethanol or renewable gasoline are generally represented conservatively, with CIs and production costs at the high end of the available estimates. More information and discussion of these assumption is in "Fuel pathways and carbon intensity of fuels" in the appendix.

Table 2: Summary of key modelling assumptions

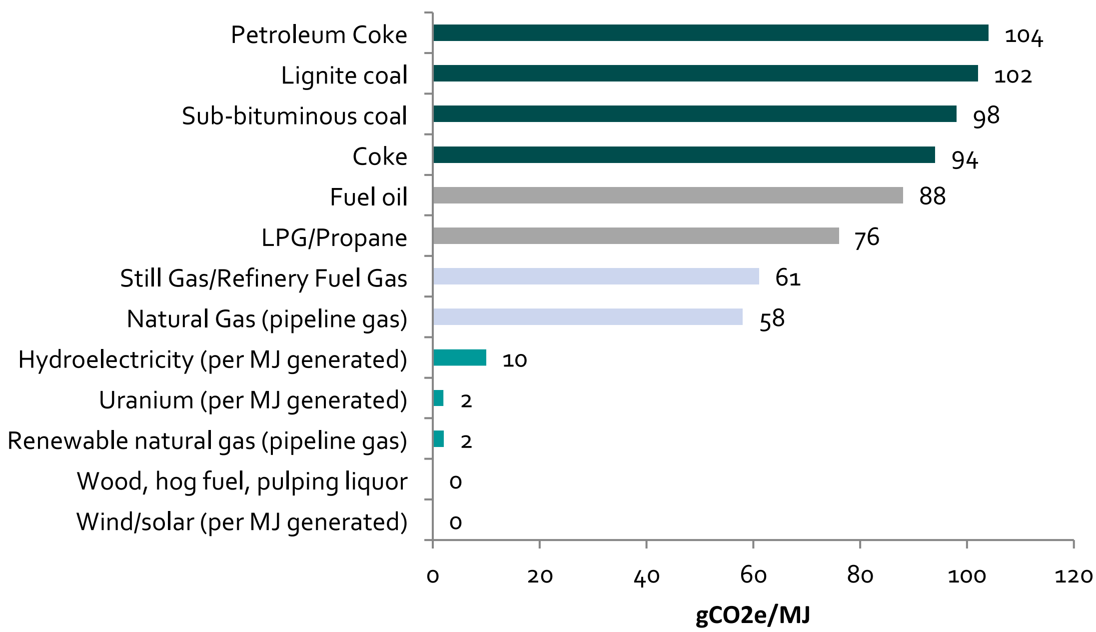
Assumption	Summary	Cross-reference to appendix
Sector activity	Driven by population growth of 0.9%/yr, GDP growth of 1.8%/yr	See "Sector activity"
Flex-fuel vehicles	Available during the simulation at a $200 premium. Fueling with E85 is a simulated result	See "Vehicle choice"
Electric vehicles	Based on battery pack costs falling from 400 $/kWh in 2015 to 125 $/kWh by 2029	
Ethanol blending constraint	For conventional vehicles, 10% ethanol by volume currently, rising to 15% thereafter	See "Substitutability between biofuels and refined petroleum products"
Biodiesel blending constraint	5% currently rising to 10% by 2025	
Price of oil	49 $/bbl rising to 88 $/bbl by 2030 (2015 USD)	See "Price of oil"
Price of natural gas	Wholesale price of 3.9 $/GJ rising to 5.5$/GJ by 2030 (2015 CAD)	See "Price of natural Gas"
Price of renewable natural gas	Wholesale price of 15 $/GJ (2015 CAD)	See "Price of renewable natural gas"
Ethanol production cost	~ 0.55 $/L with the price of corn at 140 $/tonne (2015 CAD)	See "Biofuel cost of production"
Biodiesel production cost	~ 0.9 $/L with the price of soy oil at 800 $/tonne (2015 CAD)	
HDRD production cost	~ 1.1 $/L with the price of canola oil at 907 $/tonne (2015 CAD)	

Figure 2: Transportation fuel pathways and lifecycle carbon intensities (excluding indirect land-use change GHG emissions)



*The CI of electricity used for transportation is a function of the simulated electricity GHG intensity in each province and the relative the energy efficiency of an electric drive train versus a conventional drivetrain (3.4x in the analysis)

Figure 3: Stationary fuel pathways and lifecycle carbon intensities



3. Results

This chapter presents a forecast of how the CFS may impact Canada's energy-economy system. The chapter is organized as follows:

- Section 3.1 describes how the CFS policy functions and how compliance is achieved under the policy. While the CFS generates a price per unit of GHG emissions, this policy is not equivalent to a carbon price. This section seeks to clarify the differences between a conventional carbon price and the price for “credits” under a CFS.
- Section 3.2 explains how the two variants of the CFS will reduce lifecycle GHG emissions relative to a reference scenario without the policy. It also shows how the lifecycle GHG intensity of stationary and transportation energy consumption must change to achieve that GHG reduction, providing a potential GHG intensity schedule that could be used in the policy.
- Section 3.3 illustrates a projection for the GHG abatement actions used in response to the CFS and the extent to which each action contributes to total emissions reductions.
- Section 3.4 describes the abatement cost of the policy. It also illustrates the policy's impact on energy prices and energy costs.
- Section 3.6 explores how the CFS changes biofuel supply and demand in Canada and North America, showing the extent to which the policy changes (1) the continental biofuel demand, (2) Canadian liquid fuel production, and (3) the quantity of agricultural feedstock used for fuels.
- Section 3.7 forecasts how the CFS will affect jobs and GDP growth.

3.1. Policy compliance and credit price

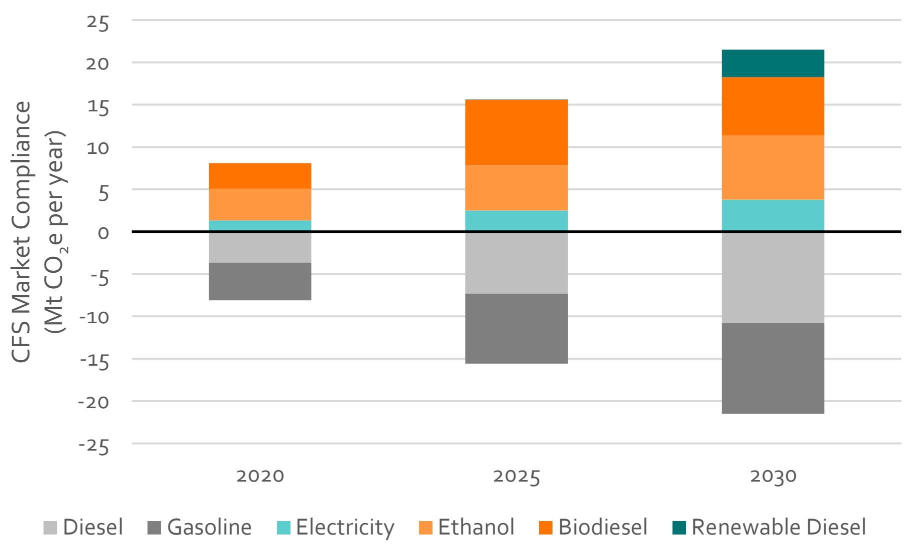
The CFS is a market based regulation that requires a reduction in the average CI of fuels sold in Canada. Compliance occurs when the supply and demand for CFS compliance credits is equal. This section illustrates that balance of credits, how compliance is achieved, and the resulting credit price. In the second alternate scenario, the market-based CFS is applied only to transportation energy consumption, with a RNG mandate applied to stationary energy consumption. Because the RNG mandate does not create a market for compliance credits, this variation of the policy is not examined in this section.

CFS on transportation

The CFS creates a new market in which the supply for CFS credits must be equal to demand. Figure 4 illustrates how compliance is achieved in the transportation sector in both CFS scenarios (note that the analysis examined two separate policies on stationary emissions, but this variation has little impact on the transportation sector). Under the policy, blending petroleum-based gasoline and diesel into their respective pools "demands" 22 Mt CO2e of credits in 2030, increasing the price of gasoline and diesel according to the cost of obtaining those credits. These credits are "supplied" by alternative lower-carbon intensity fuels, including electricity (4 Mt), ethanol (8 Mt), biodiesel (7 Mt) and renewable diesel (3 Mt), which add to 22 Mt CO2e. Supplying credits reduces the price of the lower-carbon fuels based on the revenue generated by selling credits. The associated quantity of energy consumption by fuel is in Table 3.

Note that the supply and demand of credits are measured relative to an artificial 2010 base year with only gasoline and diesel consumption. Therefore, the supply of credits is not the same as GHG abatement in any given year since abatement is measured relative to a counterfactual forecast, not the 2010 base year.

Figure 4: Transportation CFS market compliance



Note: For simplicity minor sources of compliance have been aggregated with other categories: ethanol includes renewable gasoline and while biodiesel includes natural gas (which supplies a total of 0.4 Mt in 2030).

Table 3: Transportation Energy consumption in the partitioned CFS (PJ/yr)

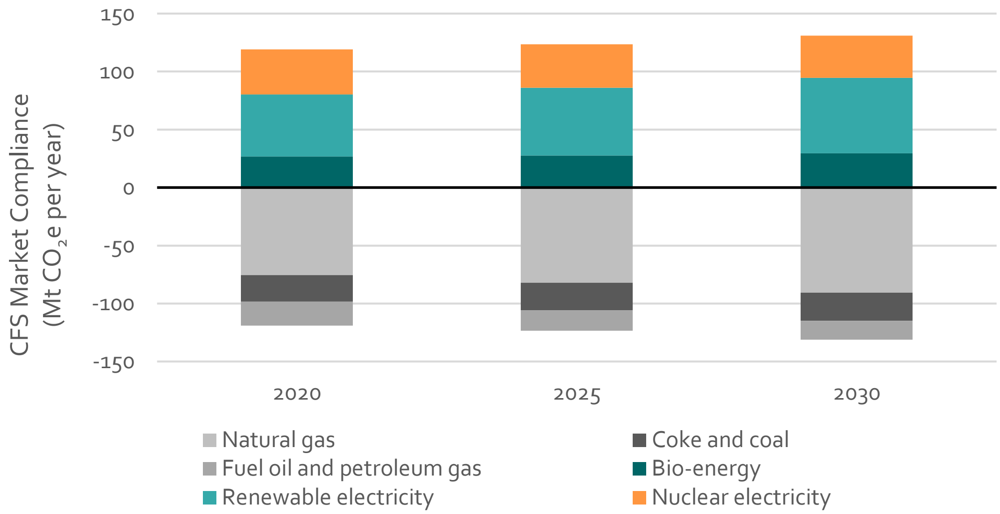
	2020	2025	2030
Diesel	971	946	921
Gasoline	1279	1149	984
Biodiesel	33	95	88
Ethanol	81	125	186
Cellulosic ethanol	11	11	17
HDRD	0	0	46
Other renewable gasoline and diesel	0	0	1
Electricity	6	13	20
Natural gas	10	17	25
Propane and Natural gas liquids	7	5	2

CFS on stationary combustion sources

The supply of CFS credits must also be equal to demand. When the CFS credit market is applied to stationary energy consumption, the largest supply of credits comes from renewable electricity generation: Hydroelectricity with a growing share of wind and solar generation. Other fuels supplying credits are nuclear electricity and bio-energy, which is primarily spent pulping liquor and woody biomass consumed by the wood products and pulp and paper sectors. Net-demand for compliance credits results from fossil fuel consumption. Although natural gas is the least carbon-intensive fossil fuel, it produces the greatest net-demand for credits due to the quantity that is consumed throughout Canada. The associated quantity of energy consumption by fuel is in Table 4.

Like the transportation CFS credit market, the supply of stationary credits does not correspond to GHG abatement relative to a scenario without the policy. Rather it is the quantity of GHG avoided relative to a fictional baseline without any of the low-carbon fuels that supply credits.

Figure 5: Stationary CFS market compliance



Note: Bio-energy includes spent pulping liquor and biomass with a small amount of renewable natural gas.

Table 4: Stationary energy consumption in the partitioned CFS (PJ/yr)

	2020	2025	2030
Natural Gas	4601	4952	5395
Coal	804	727	420
Fuel Oil	201	142	113
Still-gas/LPG	567	554	547
Petroleum Coke	79	85	83
Biomass	379	406	444
Spent-pulping liquor	282	276	276
Biogas	3	11	26
wind/solar	102	154	228
Hydro	1641	1749	1882

Primary renewable energy used for electricity generation (wind, solar and hydro) is measured in a 1:1 ration based on the associated electricity production. Coal includes what is consumed at existing power plants and is not included in the CFS in this analysis.

Credit price

The modeling conducted for this analysis estimates the CFS credit price where supply and demand for credits are equal. Because the credit market for stationary and transportation energy consumption are kept separate, there are two different credit prices. These price forecasts are shown in Table 5. The price is a function of various dynamics in the model, of which some offset. These include:

- **The stringency of the CFS increases over time**, necessitating a higher CFS price later in the forecast.

- **The price for oil and natural gas increases over is rising over time,** which partially offsets the increase in policy stringency. Leading fossil fuel commodity forecasts suggest that real price of crude oil and natural gas will increase between now and 2030 (see "Energy Prices" in the appendix). Higher crude oil and natural gas prices reduce the price spread between these fuels and their lower-carbon alternatives. Therefore, a higher price for oil and natural gas also reduces the credit price required to achieve equilibrium in the CFS market.
- **The thresholds at which additional compliance must come from higher cost compliance actions.** This is most evident in the transportation credit price in 2030. The gasoline and diesel pools arrive at a threshold in which more costly alternative fuels become necessary. The volume of ethanol and biodiesel that can be consumed in conventional vehicles is constrained (assuming 15% ethanol and 10% biodiesel by volume in 2030). Once these constraints become binding, compliance with the policy requires more costly actions such as increasing the share of flex-fuel vehicles using 85% ethanol blends, increasing the supply of renewable diesel, and increasing the rate of adoption of electric vehicles. All of these actions may require a higher CFS credit price.

As shown in section 3.4, the difference between the CFS and a conventional carbon price mean that the relatively high CFS credit price has a much lower impact on energy prices and costs than would a conventional carbon tax with the same $/tonne value.

Table 5: CFS credit price (2015 CAD/tonne CO_2e)

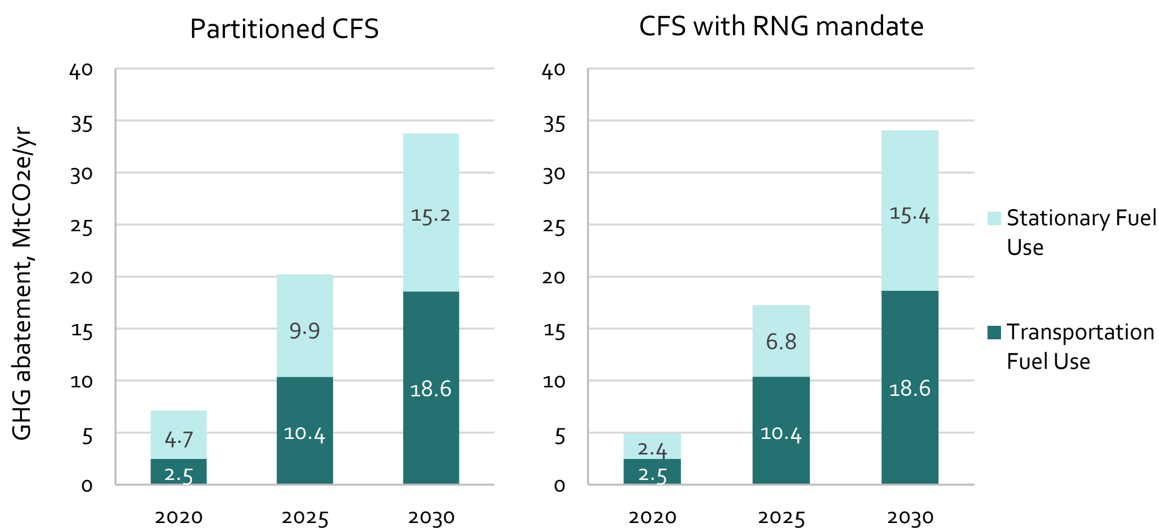
	2020	2025	2030
Transportation	158	150	182
Stationary	18	27	38

3.2. Lifecycle GHG emissions and GHG intensity

GHG abatement

Both options for the CFS were designed to achieve a similar impact on GHG emissions, achieving a reduction of 34 Mt/yr in 2030 relative to a scenario without the policy (Figure 6). By design, both policy options get approximately equal abatement from transportation and stationary energy consumption by 2030: 55% of the abatement comes from transportation energy consumption, with the remaining 45% from stationary energy consumption.

Figure 6: Abatement of lifecycle GHG emissions relative to the reference scenario



GHG Intensity

The CFS reduces GHG emissions because it requires a reduction in the average CI of transportation and stationary energy consumption, relative to what they would be without the policy. Table 6 shows the average CI for stationary and transportation energy consumption for 2010 and 2015, as well as the projected CI estimates from 2015 to 2030. The CI for stationary energy consumption excludes coal consumed in existing power plants. Because coal fired power plants are already regulated, they are tentatively excluded from the CFS, so the average stationary CI in Table 6 is lower than the true Canadian average.

Table 6 shows that the model is well calibrated. The average modelled CI of transportation energy consumption is only 0.6% lower than the data in 2015. The stationary CI is 0.7% lower.

Between 2015 and 2030, the transportation energy CI declines from the 2015 value by 10.4%. This change is equivalent to a 12.5% reduction from a 2010 baseline that assumes only gasoline and diesel consumption (The average CI is 89.5 gCO_2e/MJ). Without the CFS, the CI of transportation energy will likely only decline by 2.3% between 2015 and 2030.

From 2015 to 2030, the stationary energy CI declines by 3.9% when the CFS is applied to stationary energy consumption. The reduction is 4.4% with a 5% RNG mandate in 2030. Without these policies, the CI of stationary energy will likely only decline by 0.7% between 2015 and 2030.

Table 6: Average Carbon Intensity of transportation and stationary energy consumption in Canada, gCO2e/MJ

	2010	2015	2020	2025	2030	% change from 2010	% change from 2015
Transportation Energy							
Statistics Canada	89.9	88.1					
Reference		87.6	86.9	86.2	85.6	-4.6%	-2.3%
Partitioned CFS		87.6	86.2	82.4	78.5	-12.5%	-10.4%
CFS w. RNG mandate		87.6	86.2	82.4	78.5	-12.5%	-10.4%
Stationary Energy							
Statistics Canada	41.2	40.7					
Reference		40.5	40.7	40.4	40.2	-2.4%	-0.7%
Partitioned CFS		40.5	40.2	39.5	38.9	-5.5%	-3.9%
CFS w. RNG mandate		40.5	40.4	39.7	38.7	-6.0%	-4.4%

Sources for Statistics Canada values include: CANSIM 128-0016, 127-0004, 128-0006, and Wolinetz, M., Hein M., 2017, *Biofuels in Canada*.

The stationary energy consumption GHG intensity is calculated based on all fossil fuels except coal used in current coal plants. It includes biomass, bio-gas, and spent pulping liquor and waste fuel (primarily biomass). Primary energy used for hydroelectricity/wind/solar generation is included and accounted at a 1:1 ratio for energy input to electricity output. Nuclear energy is included and accounted at a 3:1 ratio for energy input to electricity output.

3.3. Abatement actions

Transportation

Greater biofuel consumption achieves most of the GHG abatement relative to the reference scenario during the forecast (see Figure 7). Most of the increase in biofuel consumption comes from first generation biofuels: mature technologies with existing production capacity. The increase in ethanol is mostly derived from wheat and corn. Cellulosic ethanol (i.e., second generation ethanol which is produced from the non-edible portion of plants) offers a minimal contribution to the total reduction. First-generation ethanol offers the greatest contribution despite an increase in agricultural prices, which in 2030 are in the range of 3 to 4% higher than without the CFS (i.e. corn, wheat, canola oil and soy oil prices). Cellulosic ethanol sees little adoption: the information used to characterize this fuel indicates that it is costlier to manufacture than conventional ethanol and we have assigned it a conservative CI, meaning it provides little additional reduction GHG emissions.

While cellulosic ethanol does not offer a significant contribution, this result could be sensitive to the level of policy implemented in the United States or its CI. In the current analysis, the United States does not move beyond its current policies for transportation fuels. However, US policy could spur greater biofuel demand, which in turn could have a greater impact on agricultural prices. Should the US expand their policy between now and 2030, cellulosic ethanol may become a more important abatement action in Canada and/or the US. Also, if cellulosic ethanol can be produced commercially with a lower CI than assumed in this analysis, it could also see greater adoption.

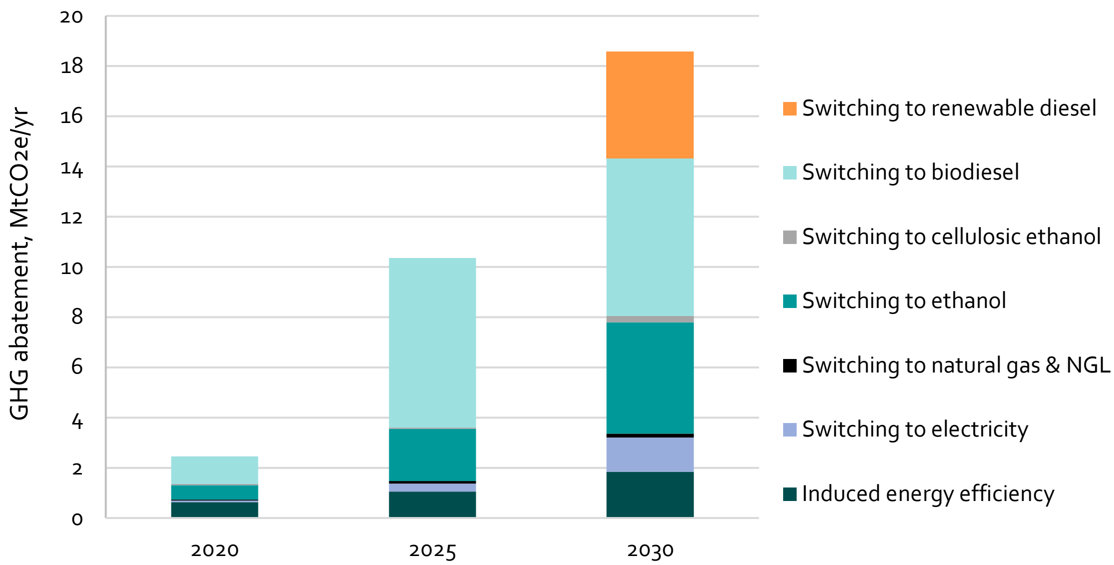
Increased biodiesel provides approximately one third of total abatement by 2030. Hydrogenation-derived renewable diesel (HDRD) accounts for roughly a fifth of total abatement in 2030, but is not used before then. While HDRD is currently consumed in Canada, this analysis suggests the CFS alone will not increase consumption above what is already consumed until 2030. This indicates that HDRD is represented conservatively in this analysis in terms of its cost, or that there is some benefit to the fuel not captured in the analysis. Furthermore, this analysis does not represent the Ontario Greener Diesel Regulation or the BC low-carbon fuel regulation policies that might increase HDRD consumption before 2030. This was a necessary simplification and done under the assumption that these policies would not have a GHG impact that is additional to the renewable fuel standard (reference scenario) or the CFS (in the CFS scenarios). However, it is possible that these omitted policies would result in different regional fuel consumption than shown here.

In addition to reducing the average carbon intensity of fuels consumed in Canada, the CFS is likely to "induce energy efficiency". Energy efficiency does not generate compliance credits. Instead, it is a result of the CFS increasing energy costs which produces GHG abatement beyond what is required by the CI reduction schedule. The CFS causes a small increase in the price of transportation fuels, which: (1) induces mode switching (e.g. more transit ridership), (2) increases the market share of smaller vehicles, and (3) increases the adoption of fuel efficient vehicles. While these changes are small, cumulatively across all of Canada, they reduce GHG emissions in 2030 by 1.8 $MtCO_2e$/yr.

Finally, switching to electricity reduces transportation lifecycle-GHG emissions by 1.4 $MtCO_2e$/yr in 2030. While this action only accounts for 10% of total abatement in 2030, it shows the largest rate of growth between 2025 and 2030.

Note that Figure 7 only shows the results for the partitioned CFS; the impact of the transportation CFS with the RNG mandate is almost identical. The rest of this report will only show and discuss transportation results from the partitioned CFS scenario.

Figure 7: Abatement of transportation lifecycle GHG emissions by action, relative to the reference scenario



The CFS increases the renewable content of the gasoline and diesel pools (i.e. the total volume of gasoline and diesel and their respective substitutes). The ethanol content in the gasoline pool is 10% by volume in 2020 (see Figure 8). The ethanol content by volume rises to over 15% and 24% in 2025 and 2030, respectively.

Automakers do not warranty vehicles for gasoline consumption that contains more than 15% ethanol by volume. Achieving an ethanol blend above 15% requires (1) a greater adoption of flex-fuel vehicles (FFVs), which can consume up to an 85% ethanol blend; and (2) greater access to E85 in fueling stations. The analysis suggests that, by 2030, approximately 9% of light-duty vehicles are FFVs consuming E85. For context, in 2015, Canada consumed 2.8 billion L/yr of ethanol.[22] The CFS could more than triple that volume, with ethanol consumption in Canada reaching 9 billion L/yr in 2030.

Biodiesel content in the diesel pool is 3.5% in 2020, rising to 10% in 2025. By 2030, renewable diesel substitutes account for 13% of the diesel pool. One third of that volume is HDRD. For context, Canada consumed 0.6 billion L/yr of biodiesel and HDRD in 2015.[23] With the CFS, that volume could increase by a factor of 6, reaching almost 4 billion L/yr in 2030. Note that these results are not showing the continuation of

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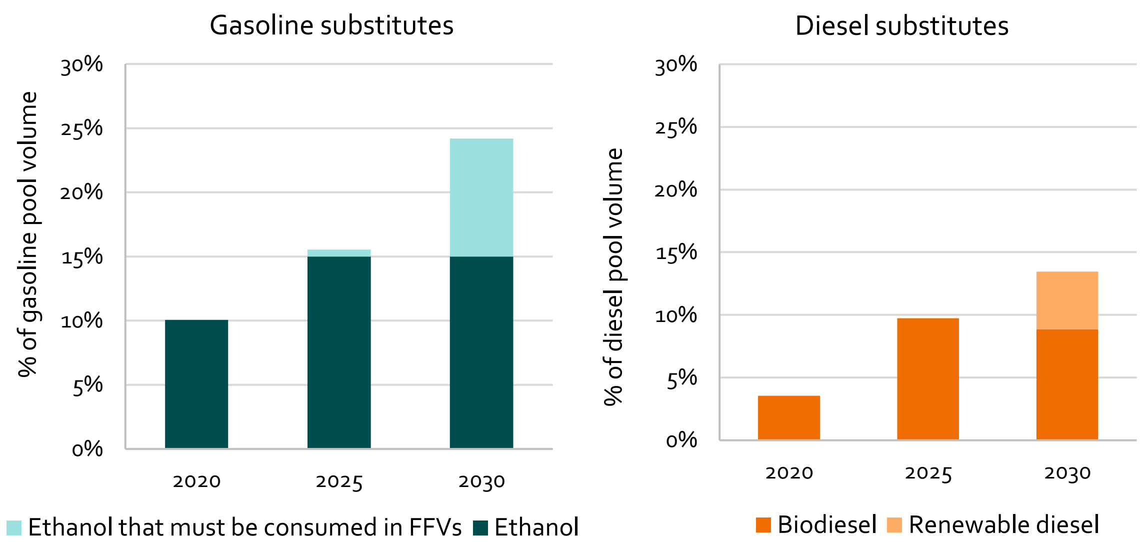
[22] Wolinetz, M., Hein, M., 2017, *Biofuels in Canada 2017*, Navius Research

[23] Ibid

current HDRD consumption that will likely be supported by Ontarian and British Columbian fuel regulations.

Figure 8: Gasoline and diesel substitutes in the CFS scenarios (results are shown only for the partitioned CFS scenario)



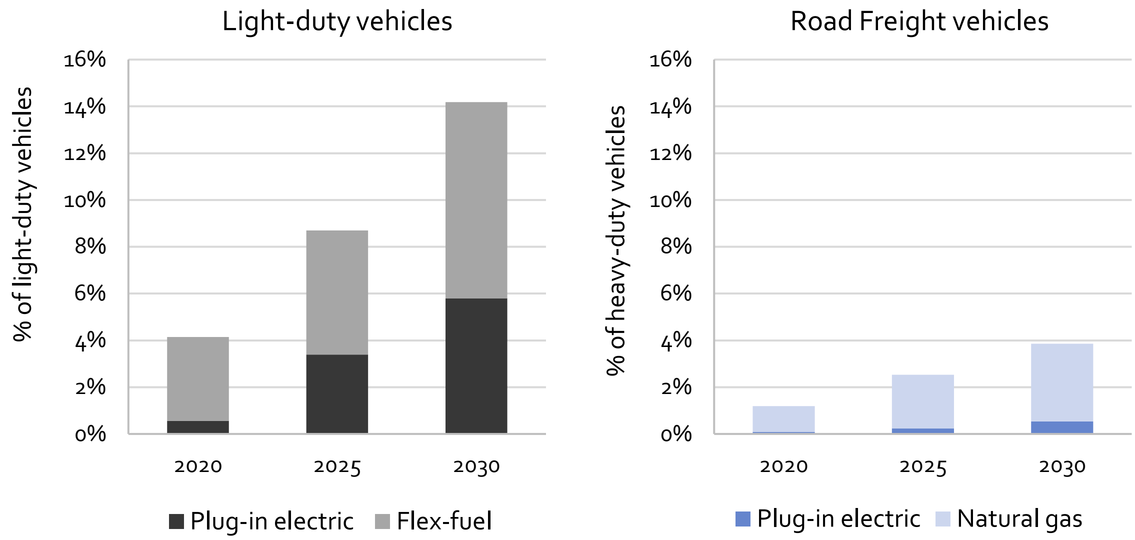
The CFS also changes the rate of alternative-fuel vehicle adoption (Figure 9). That policy doubles the rate of light-duty plug-in electric vehicle (PEV) adoption. By 2030, almost 6% of light-duty vehicles are PEVs, versus 3% without the CFS. This corresponds to PEVs accounting for roughly 9% of new vehicle sales in 2030, with 1.2 million PEVs on the road by 2030. The CFS also increases the market share of FFVs that consume E85, which account for 9% of light-duty vehicles by 2030. This result demonstrates that supplying E85 at a price where FFV owners will buy it is part of a least-cost compliance pathway. However, there is some uncertainty in the future availability of FFVs and the development of E85 refueling infrastructure, which is further discussed in section 4, "What GHG abatement actions are used?"

The road freight sector sees a smaller switch towards alternative fuel vehicles. With the CFS, natural gas-fuelled trucks account for 4% of road freight activity (tonnes km travelled) in 2030 versus 3% without the CFS. The CFS also drives greater electrification of road-freight, but electrification is constrained to light-freight trucks in this analysis. Light-freight accounts for a relatively small portion of Canada's total road freight tonnage (8%) and fuel consumption (19%).[24] Therefore, even substantial electrification of this end-use would account for a limited amount of freight activity. By

[24] Office of Energy Efficiency, 2017, Comprehensive Energy Use Database, Natural Resources Canada

2030 electric freight trucks account for 0.5% of total road freight tonne-kilometers travelled (i.e., including heavy- and medium-freight), but 6% of light-freight truck activity.

Figure 9: Alternative fuel vehicles in the CFS scenarios, % of vehicles on the road



The fraction of vehicles is measured based on activity by technology type: % of vkm vehicle kilometers travelled) for light-duty and % of tkm (tonne-kilometers travelled, i.e. moving one tonne of freight one km) for road freight vehicles.

Stationary

The partitioned CFS drives significantly different abatement actions relative to the RNG mandate. In the partitioned CFS, consumers and firms make decisions based on the combined carbon price implied by the CFS compliance credit price and other carbon prices that exist in each province. With the RNG mandate, there is no additional market signal to reduce GHG emissions, just a requirement to change the composition of natural gas. Figure 10 shows the abatement actions used to reduce GHG emissions in response to both policy options.

The partitioned CFS seeks to drive multiple actions to reduce emissions, using a market based approach:

- **Induced energy efficiency.** The policy induces greater energy efficiency through a higher price for energy. In 2030, the improvement in energy efficiency reduces emissions by 2 $MtCO_2e$/yr relative to a scenario without the CFS. Energy efficiency does not generate compliance credits. Instead, it is a result of the CFS increasing energy costs which produces GHG abatement beyond what the required CI reductions would achieve.

- **Fuel switching to low-carbon electricity.** The CFS also incentivizes fuel switching to electricity through a reduction in electricity prices relative to other fuel prices. The CFS policy functions as a "tax" on fuels with higher CIs and a "subsidy" on fuels with lower CIs. As electricity generated in Canada has, on average, a lower CI than other fossil fuels, the CFS effectively "subsidizes" electricity consumption, while "taxing" fossil fuels. Electricity consumption increases by 16.7 TWh/yr in 2030 relative to a scenario without the CFS (+2.5%).

  This additional electricity consumption is provided by additional low-carbon electricity generation. The policy induces greater construction of wind, solar, and hydro capacity, with an incremental increase in nuclear capacity in Ontario. Note that the policy excludes coal generation, which means that incremental reductions can only be achieved by switching natural gas capacity with lower-emitting options.

  The reduction achieved by greater electrification of Canada's energy system and GHG reductions from the electricity sector itself amount to 6 Mt CO_2e in 2030.

- **Carbon capture and storage.** The policy also increases the use of carbon capture and storage (CCS) relative to the reference scenario (4.5 MtCO_2e/yr). In this analysis, CCS reduces the effective CI of the associated fuel or process. In reality, CCS projects could be awarded compliance credits based on their avoided GHG, or the CI of the associated fuel could be adjusted. Although the abatement cost of CCS is higher than the stationary credit price, the CFS in this analysis is designed so that its credit price is incremental to existing carbon prices (e.g., the federal carbon pricing benchmark, which is mandated to rise to $50 per tonne CO_2e by 2022). The CFS credit price combined with the federal carbon price floor is 88$/t$CO_2$e in 2030. The additional reductions from CCS occur mostly in Alberta's oil sands:

  - Additional hydrogen production at bitumen upgraders using CCS (average abatement cost assumption: 54 2015 CAD/tCO_2e in 2030).[25]

  - Additional CCS used with oxy-fuel combustion for in-situ bitumen extraction (average abatement cost assumption: 85 2015 CAD/tCO_2e in 2030).[26]

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[25] Det Norske Veritas (2010). Global Technology Roadmap for CCS in Industry, Sectoral Assessment: Refineries. United Nations Industrial Development Oganization.

[26] Navius assumption based on early deployment of natural gas-fuelled direct contact steam generation, described in:

Cairns, P., E. (2013) . High Pressure Oxy-fired (HiPrOx) Direct Contact Steam Generation (DCSG) for Steam Assisted Gravity Drainage (SAGD) Application. University of Ottawa, Thesis submitted to the Faculty of Graduate and Postdoctoral Studies In partial fulfillment of the requirements For the M.A.Sc. degree in Chemical Engineering.

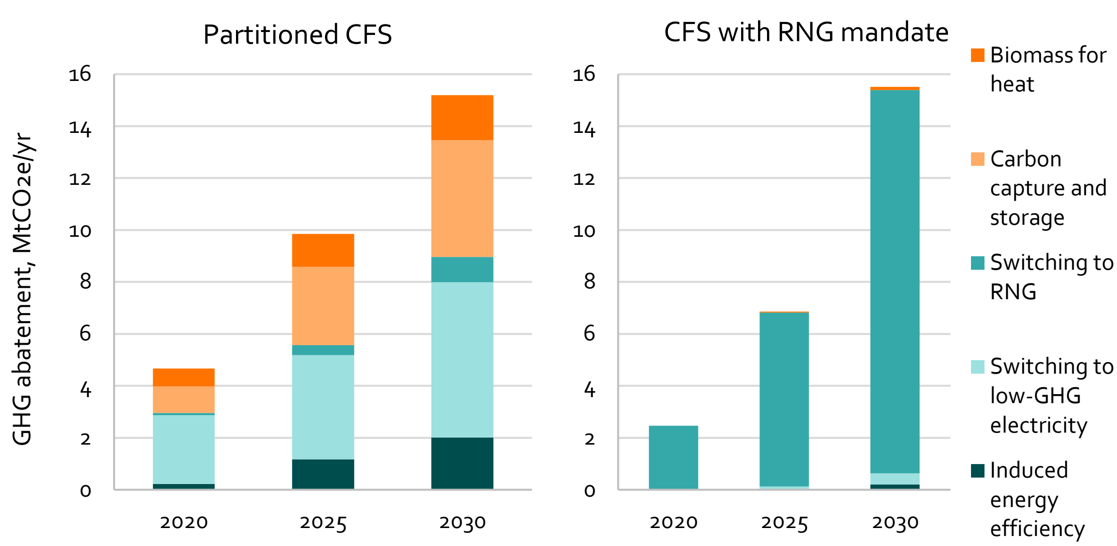
Gas Technology Institute (2017). Direct Contact Steam Generator. Available at www.gastechnology.org/Solutions/Documents/PowerGen_DCSG_flyr_June2017.pdf

- ➢ Additional CCS used with process heat and power generation at bitumen upgraders (average abatement cost assumption: 110 2015 CAD/tCO_2e in 2030).[27]

While the average CCS abatement cost may exceed the combined credit price in 2030, the actual abatement cost will vary from facility to facility and as a result of other factors (e.g., the price for CO2 for enhanced oil recovery provides a further benefit to CCS). Therefore, a subset of these CCS opportunities contributes to GHG reductions by 2030.

- **Switching to bioenergy.** Finally, the partitioned CFS also induces switching to bioenergy. More biomass is used for heat in the manufacturing sectors (e.g. wood products, pulp and paper), reducing emissions by 1.7 MtCO_2e/yr in 2030. The policy also incentivizes some consumption of RNG, reducing GHG emissions by another 1 MtCO_2e/yr in 2030. This change results from a 0.5% share of RNG in gaseous fuels (28 PJ/yr, Figure 11). Like the CCS, the average abatement cost of this action exceeds the credit price, but our analysis accounts for the fact that some supply may be cheaper, or some consumers may be more willing to pay for it.

Figure 10: Abatement of stationary lifecycle GHG emissions by action, relative to the reference scenario

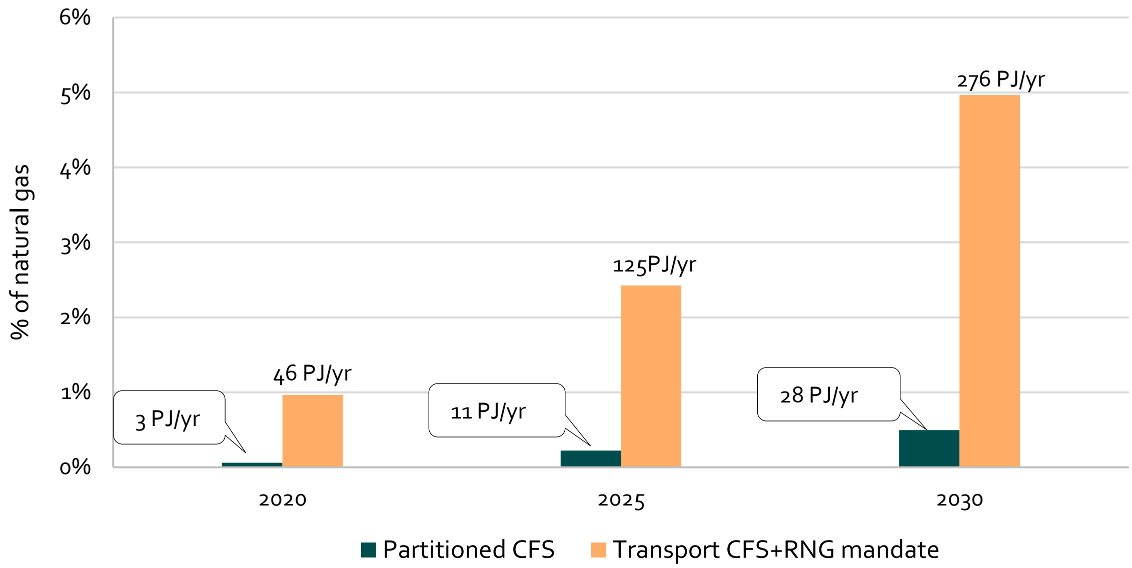


In contrast to the partitioned CFS, which incentivizes several abatement actions, the RNG mandate mainly reduces GHG emissions by requiring a RNG blend of 5% by

[27] Det Norske Veritas (2010). Global Technology Roadmap for CCS in Industry, Sectoral Assessment: Refineries. United Nations Industrial Development Ogranization.

volume in 2030, equivalent to 276 PJ/yr (Figure 11). Because a higher RNG blend increases the average price of gaseous fuel, it also induces some additional energy efficiency and renewable electricity generation. The RNG mandate provides no incentive to use carbon capture and storage.

Figure 11: Renewable natural gas blending and consumption in the CFS scenarios



3.4. Credit price vs. financial abatement cost, energy prices, and energy cost impact

Credit price and financial abatement cost

Figure 12 shows three perspectives on the GHG abatement cost for transportation in response to the partitioned CFS to illustrate the difference between the credit price and the resulting financial costs to consumers and firms. The compliance credit price represents the marginal abatement cost, i.e. the abatement cost of the highest-cost abatement action required to achieve the target.

The figure also shows two measures of average financial abatement costs. The first average financial abatement cost only accounts for the change in energy expenditures in each year divided by the reduction in GHG emissions in that same year. In 2020, energy costs decline because of the policy, implying that consumers and firms have reduced their energy consumption. An example would be purchasing higher cost vehicle that is more energy efficient, or switching to a smaller vehicle. In 2025 and 2030, this cost is positive indicating that GHG abatement comes at the expense of higher fuel costs (e.g. biodiesel vs. diesel).

The second measure of average financial abatement cost accounts for the change in energy and capital expenditures (annualized and discounted). This abatement cost is negative because the policy increases energy prices, in turn suppressing activity and investment in the transportation sector. For example, this change results from mode shifting and more sales of smaller vehicles, which has a larger impact on expenditures than any investment in higher-cost alternative fuel vehicles such as PEVs. This change in investment is further described in the jobs and GDP results.

It is important to recognize that financial costs are not the sole factor that influences decision making. In addition to financial costs, households have preferences towards individual technologies. A policy that induces them to alter their preferred choice would impose a cost, even if that cost is not financial. For example, a household that can no longer afford an SUV, and therefore purchases a smaller car, would be less happy with the change, even though that change reduces their financial cost.

An additional caveat with this analysis is that financial costs are based on a financial discount rate of 6%, while research into people's time preference for money indicate that households and firms implicitly discount rates that exceed a financial rate, in the range of between 20% and 30%,[28] but even as high as 70%.[29] Therefore, financial costs are not the same as the actual cost of the policy imposed on households and firms.

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[28] Horne, M., Jaccard, M., Tiedmann, K. (2005). Improving behavioral realism in hybrid energy-economy models using discrete choice studies of personal transportation decisions. Energy Economics 2005 27(1) pp59-77.

[29] Ewing, G., Sarigollu, E., (2000). Assessing consumer preferences for clean-fuel vehicles: a discrete choice experiment. J. Public Policy Mark. 19, 106–118.

Figure 12: Compliance credit prices and average abatement costs for transportation energy consumption, Partitioned CFS Scenario

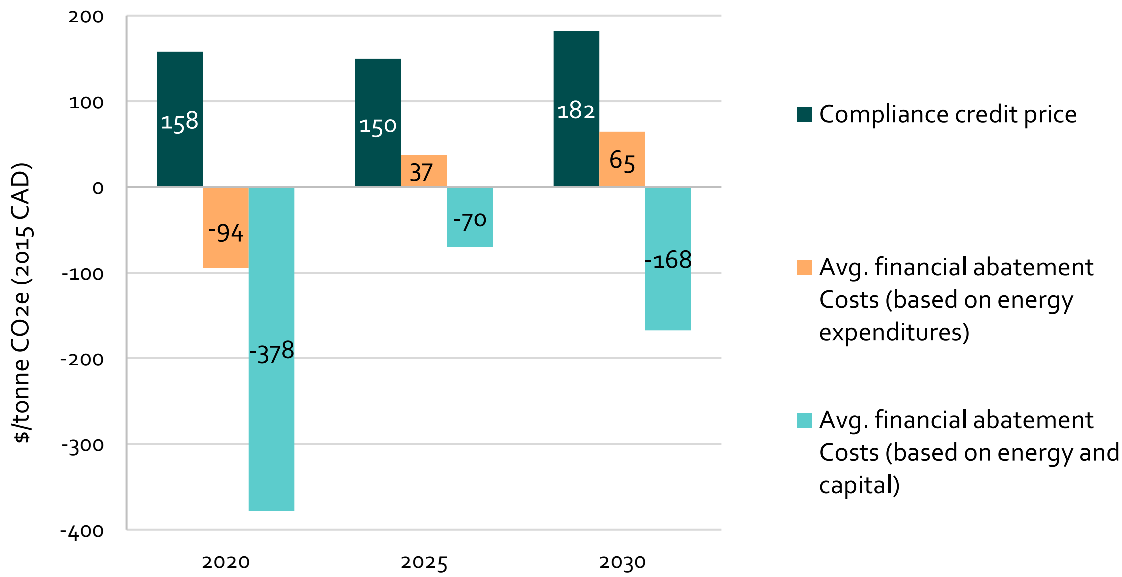


Table 7 shows the credit price for stationary energy consumption. For the RNG mandate, the "credit price" is the marginal abatement cost estimated from the natural gas and RNG price assumptions. Key points are that:

- The credit price in the partitioned CFS is much lower than the marginal abatement cost of RNG, even though both policy variants achieve the same GHG reduction by 2030. However, when comparing the CFS credit price and the RNG abatement cost, it is important to remember that the impact of both scenarios is measured relative to a scenario with existing policies, namely carbon pricing defined by the federal carbon price floor ($50/tonne by 2022). Therefore the incremental RNG abatement cost that is most comparable to the CFS credit price is actually roughly $50/tonne lower (i.e. $120/tonne).
- The average financial abatement cost in the partitioned CFS, when measured by energy expenditures, is lower than the credit price.

Because stationary energy consumption is simulated by a model that assumed heterogeneous costs, it is difficult to infer a measure of a financial abatement cost that includes capital costs and that result is not shown.

Table 7: Compliance credit prices and average abatement costs for stationary energy consumption, 2015 CAD/tonne CO_2e

Scenario	2020	2025	2030
Partitioned CFS			
Compliance credit price	24	29	34
Avg. financial abatement costs (based on energy expenditures)	-204	-87	-62
CFS w. RNG mandate			
Compliance credit price[a]	180	174	171
Avg. financial abatement Costs (based on energy expenditures)	180	171	165

[a] The RNG mandate does not have a compliance credit price. We have provided a marginal abatement cost estimated on the prices of fossil- and bio- natural gas. Note that compare the RNG abatement cost to the CFS credit price, one should subtract the value of other carbon prices (i.e. the RNG credit price is roughly $50/tonne lower).

In summary, the credit price and abatement cost results demonstrate the following points:

- The CFS credit price is the abatement cost of the costliest action required for compliance; the average abatement cost is always lower than the credit price.
- When measured by financial expenditures, the average cost of abatement is confounded by changes in activity and technologies.
- The financial cost of abatement is not the same as the costs perceived by consumers and firms; a strong policy may still be required to incentivize changes that save money.
- The CFS will incentivize lower cost-abatement actions from stationary energy consumption than what is required by the RNG mandate.

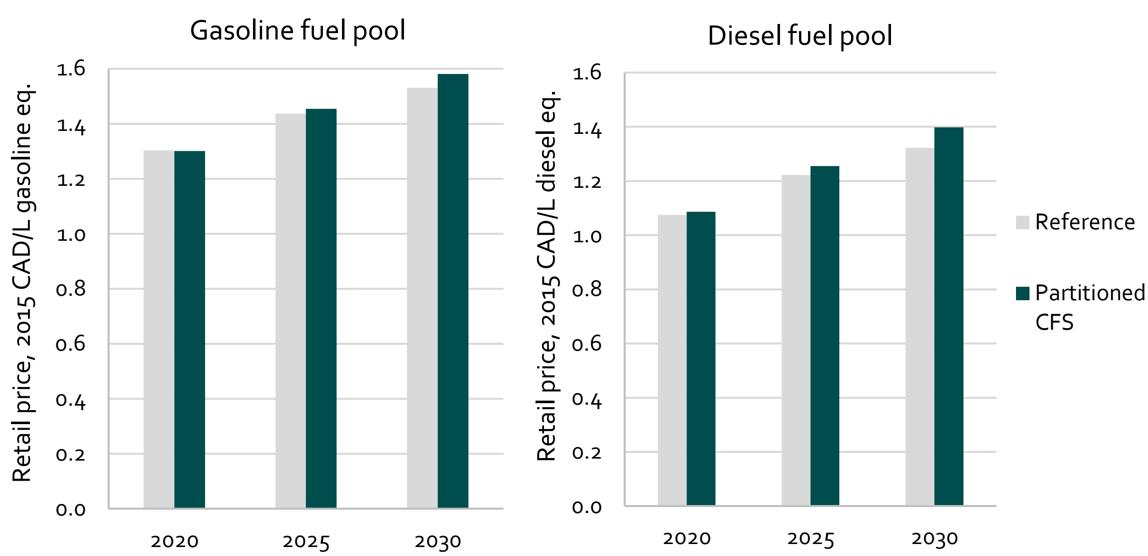
Policy impact on energy prices

The CFS increases the retail price of the gasoline and diesel pools (see Figure 13). Biofuels are typically more expensive than retail fuels when measured per unit of energy delivered. On the other hand, ethanol increases the octane rating of gasoline, which reduces the cost of the gasoline blendstock that it is added to (see Octane Value of Ethanol in the appendix). Furthermore, because biofuels have a different energy density than fossil fuels, but retain the same per-liter fuel taxes, changing biofuel consumption can change the amount of tax paid per unit of energy purchased. This is especially true of ethanol which has an energy density about two thirds that of gasoline.

In 2030, the retail price of the gasoline pool is 3% higher than it would otherwise be without the CFS (5 cent/L gasoline equivalent). Likewise, in 2030 the retail price of diesel pool is almost 6% higher than it would otherwise be without the CFS in the 2030 (7 cent/L diesel equivalent).

Almost half of the CFS-induced price increase in the gasoline pool is caused by a growing fuel-tax burden. Ethanol has a lower energy density than gasoline (i.e. less energy per liter), but the fuels have the same per-liter fuel taxes. For example, the Federal and Ontarian fuel taxes amount to 24.7 cent/L of gasoline. Assuming ethanol does not change the energy efficiency of a vehicle (i.e. energy per km is constant but L/100km declines), the tax incidence is about 30% higher on the ethanol consumption, equivalent to about 37.5 cent/L of gasoline equivalent. The difference in taxation amounts to 1.9 cent/L gasoline equivalent when there is a 15% ethanol blend in 2030. The increased tax burden per unit of energy accounts for 40% of the increase in the gasoline pool retail price caused by the CFS.

Figure 13: Retail transportation fuel blend prices, including CFS compliance cost and other carbon prices. Prices are a weighted average for Canada.

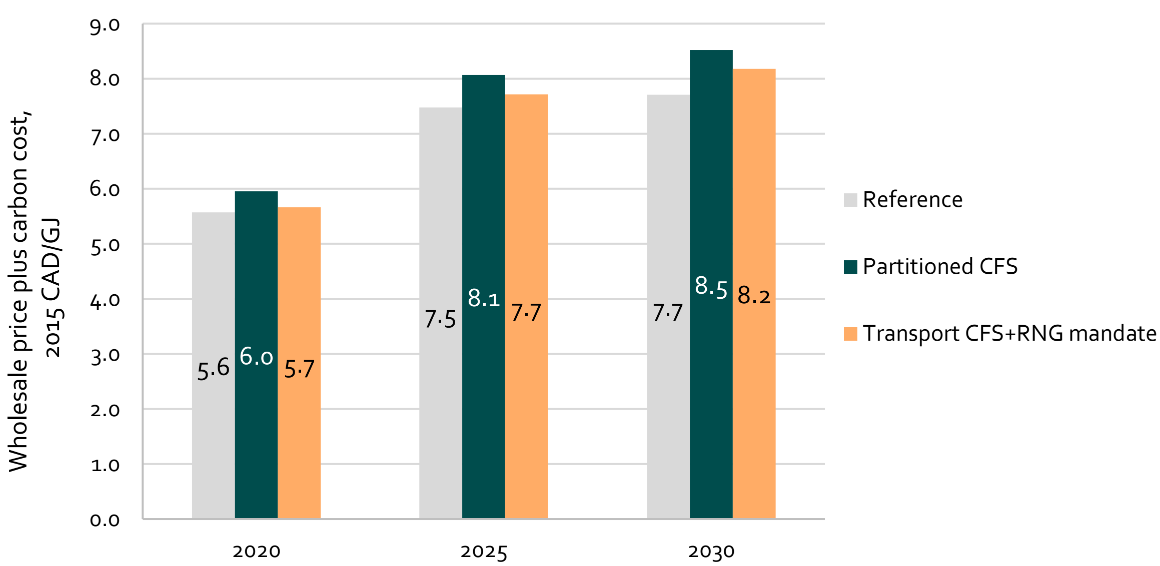


Both the partitioned CFS and the RNG mandate increase the price of gaseous fuel (Figure 14), with the partitioned CFS having a larger price impact relative to the reference scenario. The partitioned CFS scenario increases the price of natural gas because fuel supplier must purchase compliance credits, resulting in a financial transfer from natural gas consumers to other energy consumers (e.g. consumers of renewable electricity, biomass). Conversely, the RNG mandate only increases the price because it requires greater consumption of a higher priced fuel. By 2030, the partitioned CFS increases the wholesale price of natural gas by 0.8 $/GJ, while the

RNG mandate only increases the price by 0.5 $/GJ (2015 CAD). These are equivalent to a 10% and 6% increase, respectively, in the reference wholesale price of natural gas in 2030 shown in Figure 14. Because retail prices also include distribution costs and taxes, the percent increase to retail prices will be smaller. For example, a typical residential customer in British Columbia currently pays an additional 6.5 $/GJ for delivery, storage and basic charges.[30] Assuming this retail margin, the policy induced costs changes would amount to a 3.5 to 5.5 % increase in the 2030 retail price.

It may appear counter-intuitive that the RNG mandate has less impact on natural gas prices, even though the RNG abatement cost is higher than the price of stationary CFS credits. However, they are different policies that act in fundamentally different ways. Even with 5% RNG content in 2030, the CI of the blend would be 55 g/MJ, 16 g/MJ above the target for the consumption weighted average CI of stationary fuels (see Table 6). The gas supplier would still need to purchase CFS credits with an additional price impact of 0.6 $/GJ. As well, the CFS's impact on natural gas prices cannot be viewed in isolation; it also subsidizes lower-carbon fuels. As such, one cannot assume that the CFS will have less impact on the price of natural gas than the RNG mandate just because the apparent marginal GHG abatement cost is lower.

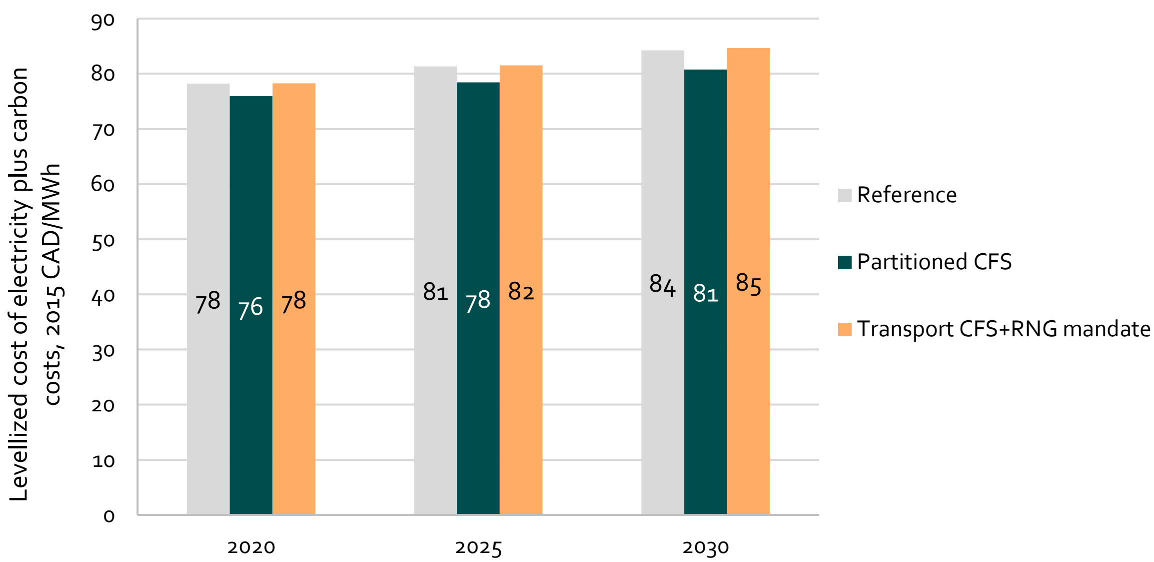
Figure 14: Wholesale natural gas blend price, including CFS compliance cost and other carbon prices



30 FortisBC (2017). Mainland Rated. www.fortisbc.com/NaturalGas/Homes/Rates/Mainland/Pages/default.aspx. Accessed October 3 2017.

The partitioned CFS reduces the average cost of electricity generation in Canada (Figure 15). This change in cost occurs because any low-GHG electricity supplier (e.g. hydro, wind, solar, nuclear) becomes a seller of compliance credits, with the credit value reflected in the cost of electricity, and ultimately retail electricity prices. This price impact is greater in provinces with low-carbon electricity grids: British Columbia, Manitoba, Quebec, Ontario, and to some extent, the Atlantic Provinces. However, because the CFS does not cover existing coal generation, it also yields a small reduction in the price of electricity in Alberta and Saskatchewan.

Figure 15: Levelized cost of electricity generation, including CFS compliance cost and other carbon prices. Costs are a weighted Canadian average.



3.5. Archetypal energy cost analysis

Changes in fuel prices should not be confused with changes in energy costs. Higher fuel prices create more incentive to use energy efficient technologies, which can mitigate the change in price. As well, energy costs are often much more sensitive to the future price of energy commodities (e.g. the price of crude oil), than they are to GHG reduction policy.

Three archetypal examples of households illustrate the potential impact of the CFS on energy costs while also showing the change in energy costs from 2015 to 2030 for all scenarios (Figure 16, Figure 17, and Figure 18). The household archetypes all use the same amount of energy in 2015, but in this example, they are willing and able to make different technology choices to 2030. The archetypes include:

- The "early adopter", which generally has the most advanced and energy efficient technology in a given year.
- The "typical" household that uses energy technologies that are typical of what occurs in the modelling results.
- The "capital constrained" household that is either unwilling or unable to make any technological changes between 2015 and 2030.

The energy end-uses included in this example are:

- Space heating (technologies are gas furnaces and building envelopes)
- Water heating
- Major and minor appliances in the home
- Lighting
- Transportation via private light-duty vehicle

Table 8 lists the assumptions in this example that are common to all archetypes. Table 9 lists the technology choice assumptions that vary by archetype and year.

Table 8: Assumptions common to all archetypes

Assumption	Value
Region	Ontario
Reference electricity price	16 cent/kWh in 2015 rising to 19 cent/kWh in 2030 (2015 CAD), consistent with inputs to CIMS
Reference gasoline price	1.03 $/L in 2015 rising to 1.54 $/L in 2030 (2015 CAD), based on OILTRANS results
Reference natural gas price	9 $/GJ in 2015 rising to 12 $/GJ in 2030 (2015 CAD), consistent with inputs to CIMS
Home floor area	200 m^2
Vehicle km travelled/yr	15,000 km/yr
Lighting energy intensity	0.03 GJ/m^2 falling to 0.01 GJ/m^3, assuming greater LED adoption
Electricity for major and minor appliances	Constant at 14.4 GJ/yr, based on NRCAN comprehensive energy use database
Hot water demand	70 m^3/yr, heated up by 50C

Table 9: Assumptions that vary by archetype

Assumption by archetype	2015	2020	2025	2030
Building envelope				
Early adopter	Typical year-2000 vintage. Heat load: 0.27 GJ/m²	2015 vintage home, approx. code compliant: 0.19 GJ/m²	2015 vintage home, approx. code compliant: 0.19 GJ/m²	Net-zero ready home: 0.07 GJ/m²
Typical	Typical year-2000 vintage. Heat load: 0.27 GJ/m²	Same, but with energy retrofit: Heat load: 0.23 GJ/m²	Same, but with energy retrofit: Heat load: 0.23 GJ/m²	2015 vintage home, approx. code compliant: 0.19 GJ/m²
Capital constrained	Typical year-2000 vintage. Heat load: 0.27 GJ/m²	Typical year-2000 vintage. Heat load: 0.27 GJ/m²	Typical year-2000 vintage. Heat load: 0.27 GJ/m²	Typical year-2000 vintage. Heat load: 0.27 GJ/m²
Gas furnace				
Early adopter	80% efficient	Highest efficiency, 98%	Highest efficiency, 98%	Highest efficiency, 98%
Typical	80% efficient	New, 90%	New, 90%	New, 90%
Capital constrained	80% efficient	80% efficient	80% efficient	80% efficient
Gas water heater				
Early adopter	60% efficient	92% efficient, on-demand	92% efficient, on-demand	92% efficient, on-demand
Typical	60% efficient	70% efficient	70% efficient	70% efficient
Capital constrained	60% efficient	60% efficient	60% efficient	60% efficient
Vehicle				
Early adopter	Car, 8L/100km	Hybrid, 4.5L/100km	Hybrid, 4.5L/100km	Plug-in hybrid, 70% of annual km on electric drive
Typical	Car, 8L/100km	More efficient car, 6 L/100km	More efficient car, 6 L/100km	Hybrid, 4.5L/100km
Capital constrained	Car, 8L/100km	Car, 8L/100km	Car, 8L/100km	Car, 8L/100km

The primary drivers of energy costs in these examples are the changes in reference energy prices and the technologies used by the households. These drivers change household energy costs by +/- $1000/yr between 2015 and 2030, depending on the archetype (Figure 16 and Figure 17).

The impact of the CFS on household energy costs is an order of magnitude smaller than the impact of the primary drivers. The CFS will have almost no impact on annual energy cost for the "typical" household in 2020. In 2025, the policy will increase energy costs by 25-30 $/yr (+1% relative to the reference). In 2030, the CFS will increase those costs by 55-60$/yr (2015 CAD), roughly +2% relative to the reference (Figure 18). Although the CFS will increase energy costs relative to the reference scenario, even the modest technological changes attributed to the "typical" household reduce its annual energy costs in 2030 by roughly $200/yr (7%) relative to 2015 (Figure 16 and Figure 17). Note that many of the changes in this example, such the improved furnace, water heater and building envelope are already regulated and will happen as capital stock is replaced. The changes also offer a return on investment. For example, switching to LED lighting from halogen lighting will likely pay-off in less than a year.[31] In 2030, switching to the hybrid car from the efficient car in this example implies a 37% return on investment.[32] Likewise, switching to the PHEV from the efficient car in this example implies a 12% return on investment.[33]

The policy cost impacts for the "early adopter" are even lower and sometimes negative (-$7/yr to +26 $/yr in 2030, Figure 16). Total energy costs decline by roughly $1000/yr by 2050 (-33%) regardless of the policy in place.

Households that are unwilling or unable to change their technology choices will see the largest policy impact on their energy costs, with an increase of around $100/yr in 2030 or 2.7% relative to the reference scenario (Figure 18). Again, the larger driver in this case is not the policy: energy costs without the CFS increase by roughly $1000/yr (+33%) between 2015 and 2030 (Figure 16, Figure 17)

A final insight is that although the two versions of the CFS will have a different impact on stationary energy prices, the overall policy impact on household energy costs is not sensitive which version is implemented. The only noticeable difference is for consumers who use more electricity (e.g. the "early adopter" in 2030), where the partitioned CFS will likely reduce their energy cost relative to the transportation CFS with the RNG mandate. This result is especially true of consumers that live in provinces that have a low-GHG electricity grid.

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[31] Assuming 2hr per day, Halogen: 2 year life, 50W/400 lumen and purchase cost of $2, LED: 15 year life, 5 W/400 lumen and purchase cost of $6.

[32] 15,000 km/yr, efficient car uses 6 L/100km, the hybrid uses 4.5 L/100km at a premium of $1,300 (2015 CAD) in 2030

[33] 15,000 km/yr, efficient car uses 6 L/100km, the PHEV uses on average 1.4 L/100km and 0.18 kWh/km at a premium of $5,200 (2015 CAD) in 2030

The archetypal cost analysis was conducted for other provinces as well, but they are not reported here. Results differed from the Ontario case study somewhat, but the overall trends and conclusions are similar.

Figure 16: Stationary energy costs by household archetype, scenario and year (2015 CAD/yr/household), including natural gas and electricity used in the home

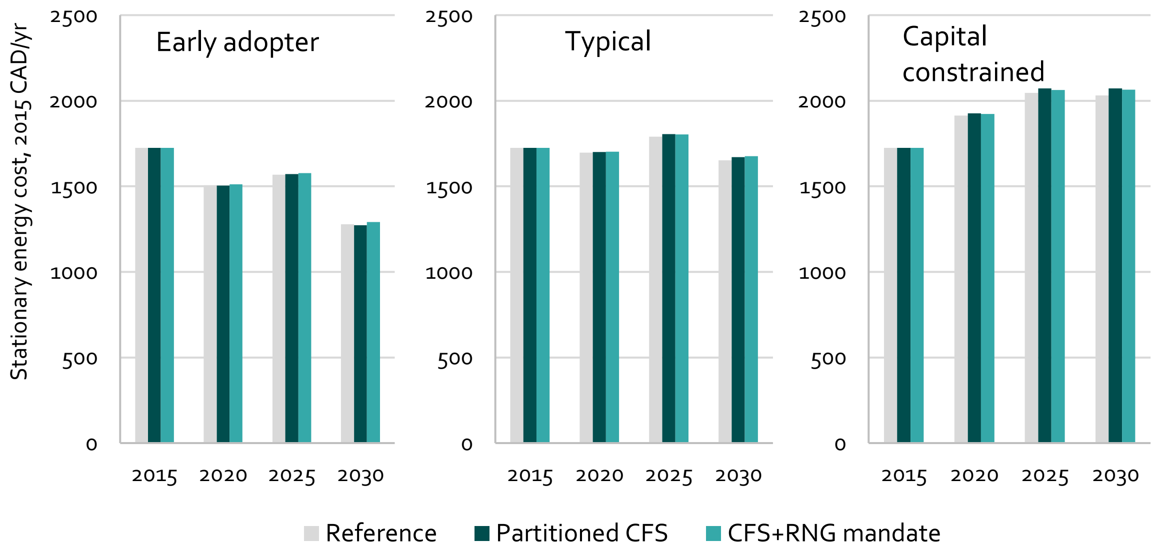


Figure 17: Transportation energy costs by household archetype, scenario and year (2015 CAD/yr/household), including gasoline and electricity used in a vehicle

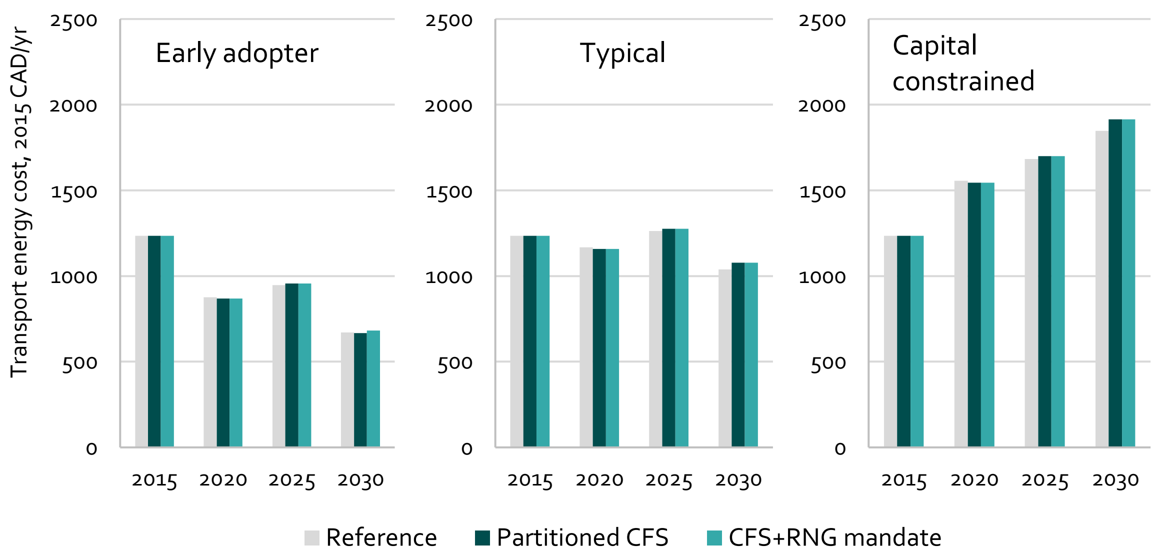
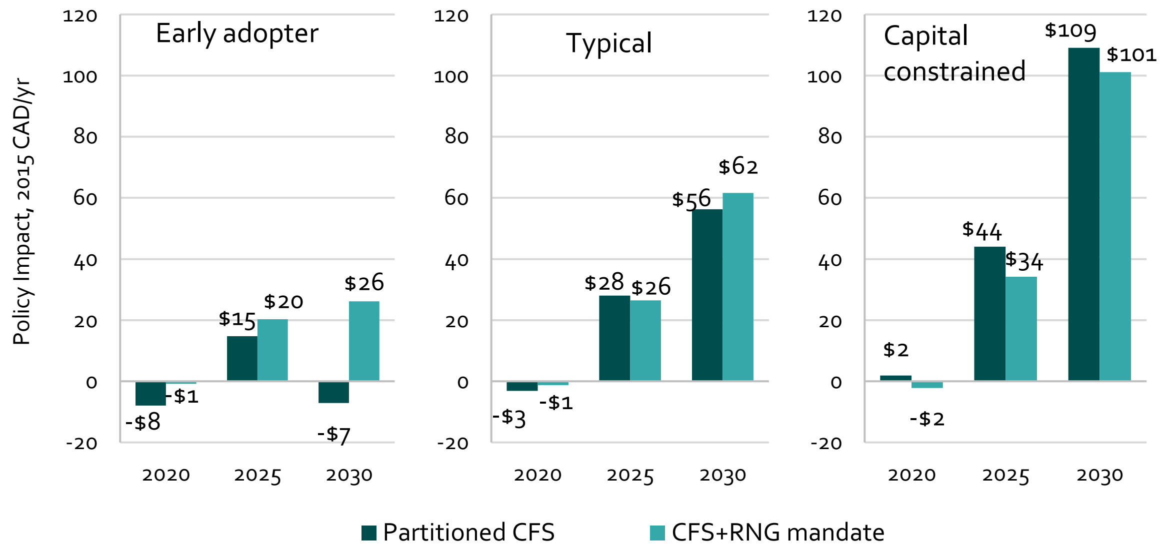


Figure 18: CFS impact on energy costs by household archetype, scenario and year (2015 CAD/yr/household)



3.6. Feedstock requirements and biofuel supply and demand

If the CFS is implemented, Canadian consumption of ethanol will likely require more than 21 Mt/yr of grains, or 4% of current (2016) North American corn and wheat production (Table 10). The results indicate that in 2030, somewhat less than 40% of the ethanol consumed in Canada in 2030 will be produced domestically. Canadian grain used for fuel will reach roughly 7 Mt/yr, equivalent to 13% of current Canadian production.[34] For context, a significant amount of North American grain is already used for fuel: Roughly one third of US corn is already used for fuel.[35] As well, agricultural productivity has been growing: Canadian corn and wheat production has increased by 30-40% since the year 2000, while the land used for this production has declined by 10%.[36]

With the CFS, Canadian biodiesel and HDRD consumption in 2030 will require approximately 13 Mt/yr of oilseed (e.g. canola and soy), equivalent to 9% of current (2016) North American oilseed production (Table 10). Results indicate that in 2030,

[34] Statistics Canada, CANSIM table 001-0010

[35] USDA, 2017, Bioenergy statistics, table 5

[36] Statistics Canada, CANSIM table 001-0010

roughly 70% of Canadian biodiesel and HDRD consumption will be produced in Canada, requiring feedstock that is equivalent to 34% of current Canadian soy and canola production. For context, about a third of the current oilseed crop is already used to produce biofuel in North America[37] and canola and soy productivity in Canada has also increased by roughly 30% since the year 2000. However, a comparison of feedstock requirements to oilseed production alone exaggerates the oilseed demand because it excludes important feedstocks such as corn oil and waste products like cooking oil and animal fats. Waste products alone were the feedstock for roughly half of the biodiesel and HDRD consumed in Canada in 2015.[38]

Table 10: Feedstock requirements of biofuel consumed in Canada with the CFS

	2020	2025	2030
Ethanol			
Canadian consumption, billion L/yr	4.1	6.0	9.0
Grain required for Canadian consumption, Mt/yr	9.7	14.4	21.5
% of 2016 North American corn + wheat production	2%	3%	4%
Grain required for Canadian production, Mt/yr	7.3	5.1	7.1
% of 2016 Canadian corn + wheat production	13%	9%	13%
Biodiesel/HDRD			
Canadian consumption, billion L/yr	0.9	2.7	3.7
Oilseed required for Canadian consumption, Mt/yr	3.1	9.0	12.6
% of 2016 North American canola + soy production	2%	7%	9%
Oilseed required for Canadian production, Mt/yr	2.1	5.8	9.0
% of 2016 Canadian canola + soy	8%	22%	34%

Grain requirements for ethanol assume 2.4 kg/L. Oilseed requirements for biodiesel and HDRD assume 0.9 kg vegetable oil per L of fuel, with the oil content of oilseed at 28% by mass (an average of what is typical of soy and canola). Comparison to North American production based on CANSIM 001-0010 and USDA bioenergy statistics.

Although the CFS increases biofuel demand in Canada relative to today, total biofuel consumption in North America peaks in 2020 and then declines thereafter, even with the CFS (Figure 19). This is a function of vehicle emissions standards in Canada and the United States that will reduce transportation energy consumption in North America, offsetting the increased rate of biofuel consumption. As well, North American consumption is largely driven by US consumption where no new fuel policies implemented during the forecast. In the CFS scenario, Canadian biofuel consumption accounts for only 6% of the North American total in 2020, rising to 17% by 2030. In

[37] USDA, 2017, Bioenergy statistics, table 5

[38] Wolinetz, M., Hein, M., 2017, *Biofuels in Canada 2017*, Navius Research

that year, North American biofuel consumption is only 3% larger than in 2015, or 10% larger than it would have been without the CFS.

Figure 19: North American biofuel demand

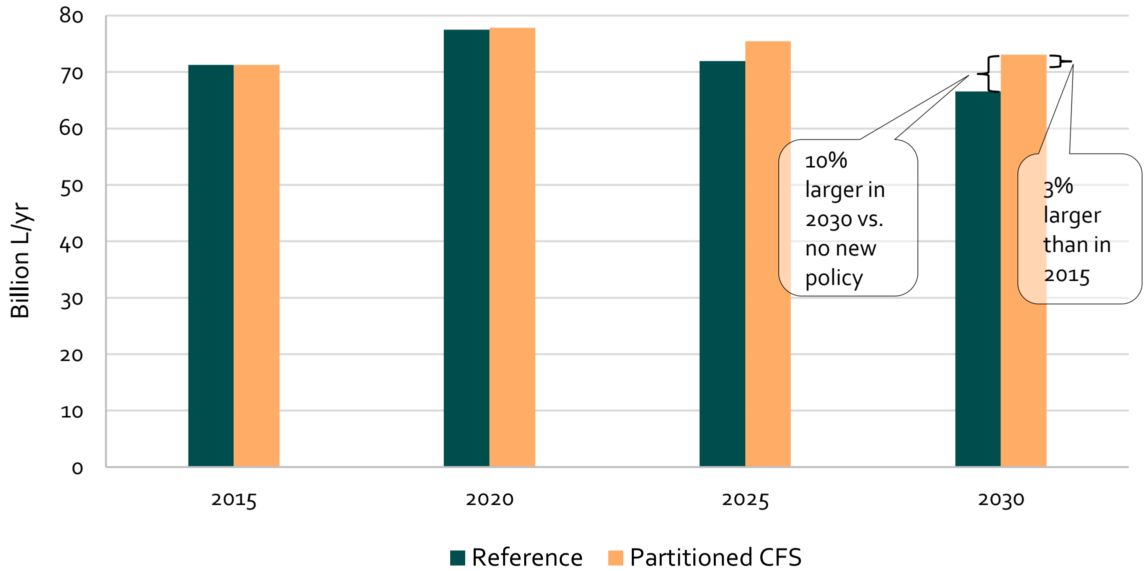
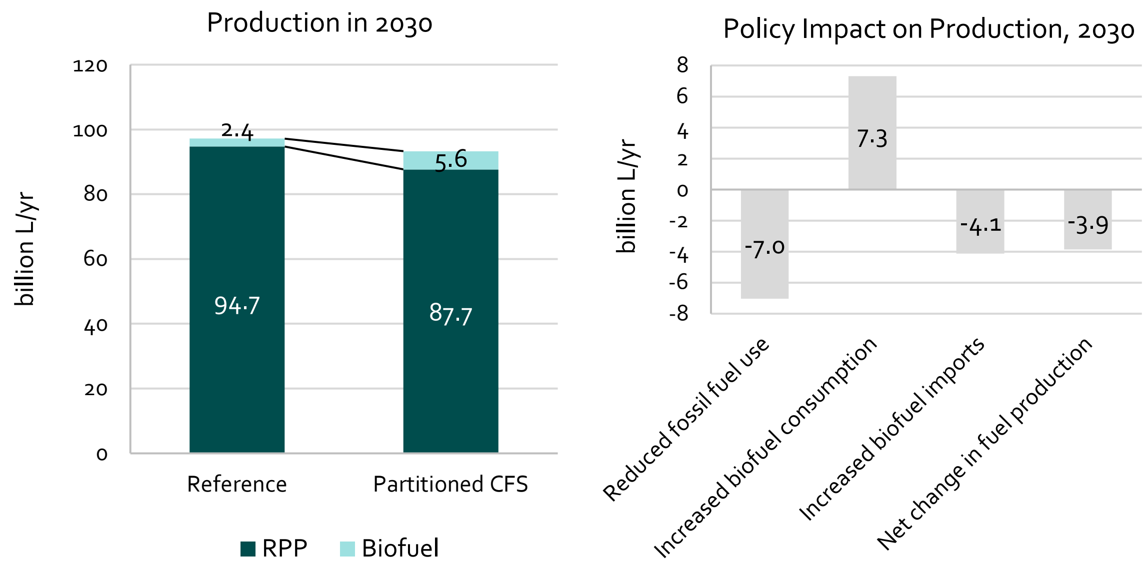


Figure 20 shows the impact of the CFS on liquid fuel production in Canada in 2030 when that impact is largest. The right panel compares liquid fuel production with and without the CFS, while the left panel decomposes the policy-induced change in fuel production into the main drivers of this change. Without new policy, total liquid fuel production, including biofuels, is 97.2 billion L/yr. Biofuels account for only 2.4 billion L/yr, or 2.5% of the total. The CFS doubles biofuel production relative to the reference scenario, increasing production to 5.6 billion L/yr in 2030.

On net, the CFS reduces total liquid fuel production in Canada 3.9 billion L/year. This change is a function of reduced fossil fuel use, drive by a reduction in total transportation energy consumption and the substitution of gasoline and diesel with biofuels. The increased volume of biofuel consumption more than offsets the reduction in fossil fuel consumption. However, the policy also increases net-imports of biofuel from the US. Only about half of the additional biofuel consumption created by the CFS is supplied from Canada, resulting in a 4% net-reduction in Canadian liquid fuel production relative to the reference scenario.

Figure 20: Policy impact on liquid fuel production in Canada



3.7. Jobs and Investment

Economic impact driver: Gross output

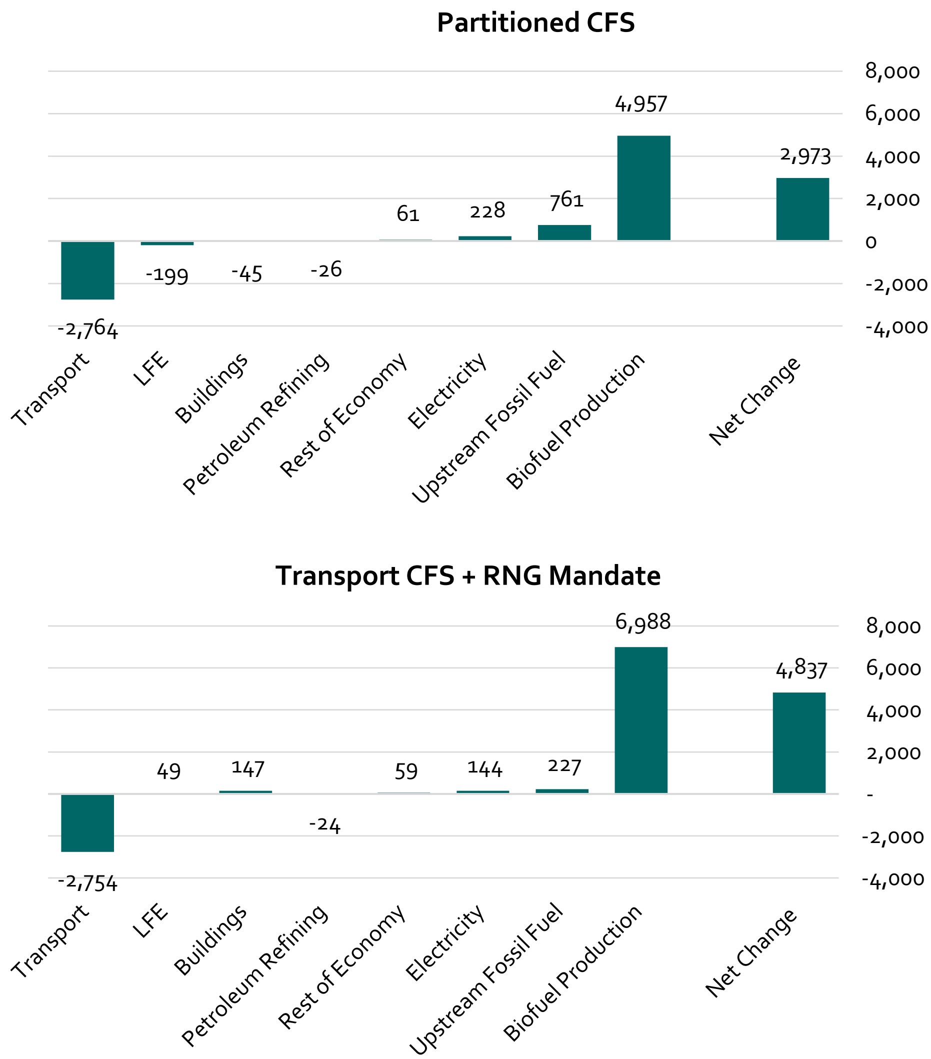
Both versions of the CFS produce a net-increase in gross output in Canada. In other words, they increase total economic activity in the production of goods and services relative to the reference scenario. The total net increase in gross output for the partitioned CFS is estimated at $2.97 billion in 2030 and $4.84 billion for the transportation CFS with the RNG mandate (Figure 21). The change in gross output is the driver of changes in employment and GDP. An important caveat is that the results do not capture the expected reduction in productivity as costs rise due to overall carbon costs and technology choices made in the economy. Nor do the results show any increase in economic growth relative to the reference scenario resulting from avoided climate change damages.

The transport CFS with the RNG mandate scenario creates a 63% larger increase in gross output than the partitioned CFS. The biggest difference comes from biofuel production (includes RNG), which is 41% bigger with when there is an RNG mandate. The difference in biofuel production between the scenarios relates to increased RNG production, which is assumed to occur in Canada. This is an important caveat as there could be “imports”: actual physical import of RNG, or the purchase of RNG where consumption occurs elsewhere (e.g. in the US) but the GHG reduction is attributed to the Canadian buyer. In that situation, the difference between the two scenarios would be smaller.

Overall, the CFS increases the rate of investment in biofuel production, but this is offset by slower growth and investment in the transport sector. The impacts on transportation are similar in both scenarios, with relatively minor impacts in other sectors. Reduced gross output in the transportation sector is not concentrated in any one segment; it results from a general reduction in investment due to slightly higher energy prices that drive some mode shifting (e.g. more transit), and shift in sales towards smaller, lower-cost, vehicles. This reduction in gross output in transportation is only partially offset by increased adoption of higher costs vehicles, such as electric vehicles. A policy that incentivizes even more adoption of these vehicles could increase gross output in the transportation sector. On net, gross output in the transportation sector grows at 2.15%/yr with the CFS rather than 2.22% without the CFS.

Compared to transportation and biofuels, the CFS produces a relatively small reduction in the gross output of the petroleum refining sector in 2030. This sector was not growing even without the CFS, so a policy induced reduction in activity does not significantly change the capital investments that occur in the forecast. A caveat to this result is that the model does not adjust upstream oil and gas production as a function of policy impact. Implicitly, this means the methodology assumes that the CFS does not affect oil and gas commodity prices or production costs to significantly change economic activity in these upstream sectors.

Figure 21: Changes in gross output by scenario and sector relative to the reference in 2030 (2015 million CAD)

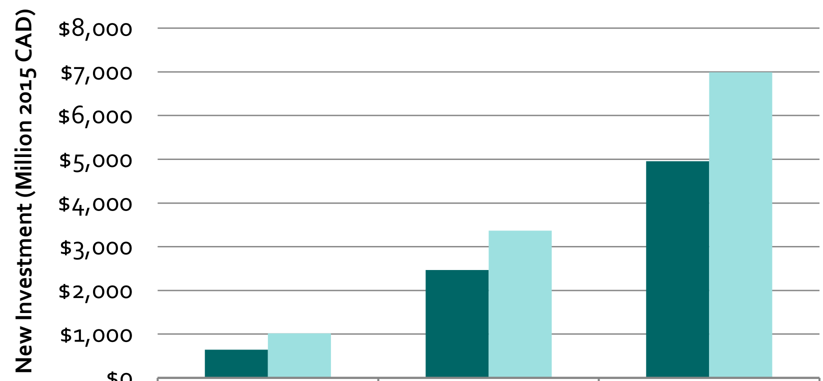


*LFE are industrial large final emitters that are not included in other sectors.

Each version of the CFS drives significant increases in gross output in the biofuel sector as production of different biofuels ramps up to meet the mandate. Additional gross output in the biofuel sector is larger for the scenario with the transport CFS and the RNG mandate. It increases to almost $7 billion annually by 2030 (Figure 1), with a growth rate greater than 20%/yr between 2020 and 2030 (Figure 22). Comparing the change in gross output against historical investment, the biofuel expansion alone in

2030 is equivalent to between 2.4% and 3.4% of historical annual investment for all firms in Canada.[39]

Figure 22: Change in gross output in the biofuel production sectors relative to the reference scenario (2015 million CAD)

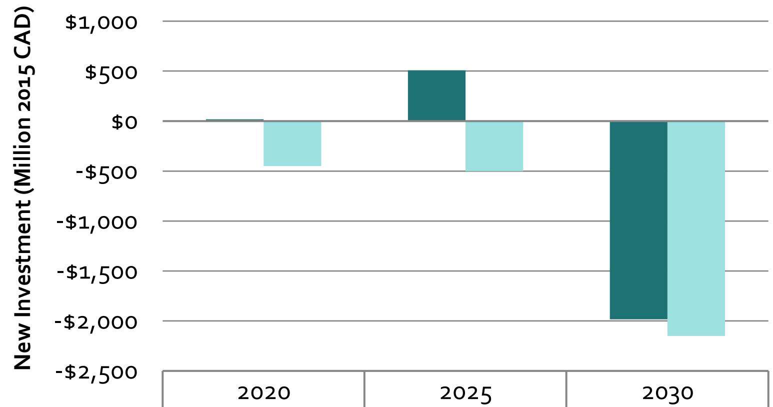


	2020	2025	2030
Partitioned CFS	$644	$2,466	$4,957
Transport CFS + RNG mandate	$1,016	$3,370	$6,988

Gross output in other sectors declines somewhat relative to the reference case by 2030 (Figure 23), again primarily due to reduced investment in the transportation sector. However, the investment pathways to 2030 are not uniform across each scenario. The partitioned CFS shows an expansion in gross output earlier in the forecast, relative to the reference scenario. This change is driven by fuel switching to electricity, which more than offsets reduced investment in other sectors. The transport CFS with the RNG mandate reduces gross output in all years relative to the reference.

[39] Total firm investment averaged $205.26 billion annually over the 2000 to 2013 period (Statistics Canada CANSIM 31-0002).

Figure 23: Change in gross output in non-biofuel production sectors relative to the reference scenario (2015 million CAD)



	2020	2025	2030
Partitioned CFS	$17	$509	-$1,985
Transport CFS + RNG mandate	-$451	-$502	-$2,151

Economic Impacts: Employment

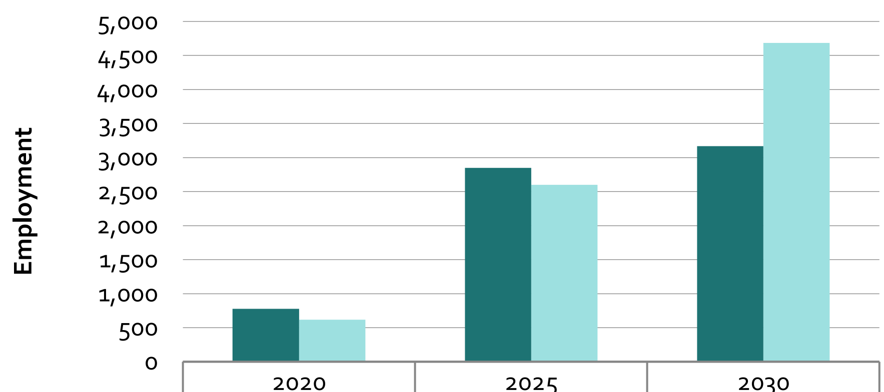
Employment is higher in the CFS scenarios than in the reference scenario. In the partitioned CFS scenario, there are roughly 4,300 more full-time equivalent direct and indirect jobs in 2020, rising to 14,00 in 2025 and over 11,100 in 2030 (Figure 24). This net-change in jobs in 2030 relative to a scenario without the CFS or RNG mandate is equivalent to about +0.3% of all 2016 employment in the goods-producing industries in Canada.[40] Induced jobs amount to another 4,000 to 5,000 in 2025 through to 2030. The reduction in total additional jobs in the partitioned CFS scenario that occurs between 2025 and 2030 is a result of additional construction jobs staying relatively constant but with less job growth in other sectors such as transportation.

The partitioned CFS creates roughly 5,000 additional direct construction jobs in the electricity and biofuel production sectors from 2025 to 2030. However, this will likely come at the expense of slower job creation in conventional power plants and industry, as well as in sectors related to transportation (the negative "direct operating jobs" impact in Figure 25, and negative direct and indirect jobs by sector in 2030, Figure 27). Note that in the figures, job impacts are allocated to the sectors where there is a change in gross output. For example, a change in transportation gross output reduces jobs in fossil fuel distribution, refining, and extraction. Because these job impacts are a function of the transportation employment multiplier, they appear in the transportation sector result.

40 Based on Statistics Canada, CANSIM, table 282-0008

The transportation CFS with the RNG mandate creates more additional employment by 2030 than the partitioned CFS, with almost 17,000 additional direct and indirect jobs relative to the reference scenario in 2030 (Figure 24). This net-change in jobs in 2030 relative to a scenario without the CFS or RNG mandate is equivalent to about +0.4% of all 2016 employment in the goods-producing industries in Canada.[41] Additional induced jobs are roughly 4,000 in 2025, rising to 7,000 by 2030. The CFS with the RNG mandate has more employment because of greater RNG demand, which increases economic activity and jobs in the biofuel production sectors (Figure 27). However, all RNG production is assumed to be supplied within Canada. Any RNG imports would reduce the investment, employment and GDP growth of the biofuels production sector, narrowing the difference in economic impact between the two versions of the CFS. The transportation CFS creates fewer additional construction jobs because it incentivizes less new electricity generation and construction of renewable electricity capacity (Figure 26).

Figure 24: Changes in total employment relative to the reference scenario, all sectors (Direct, Indirect and Induced in 2020, 2025 and 2030)



	2020	2025	2030
Partitioned CFS	778	2,848	3,166
Transport CFS + RNG mandate	620	2,601	4,683

[41] Based on Statistics Canada, CANSIM, table 282-0008

Figure 25: Breakdown of changes in employment relative to the reference scenario (Partitioned CFS scenario)

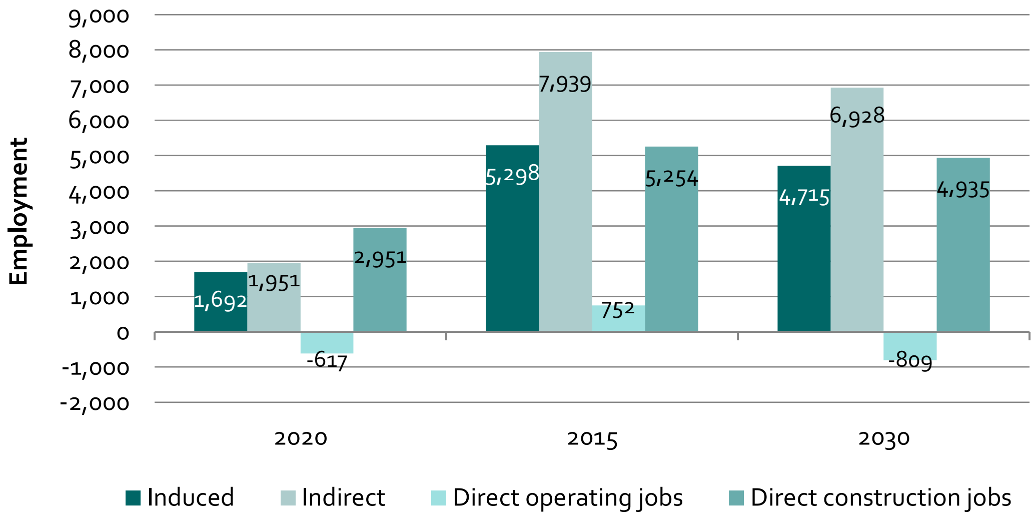


Figure 26: Breakdown of changes in employment relative to the reference scenario (Transport CFS + RNG mandate)

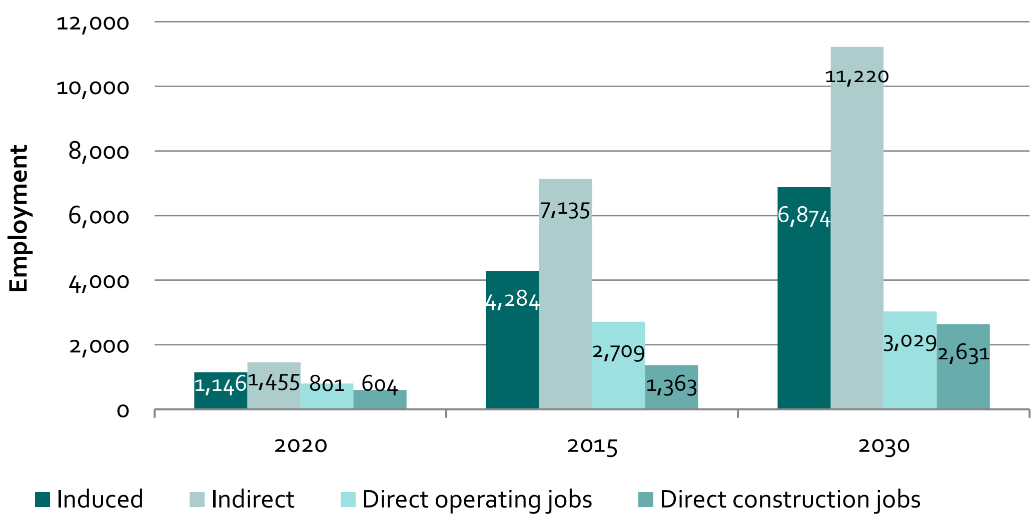
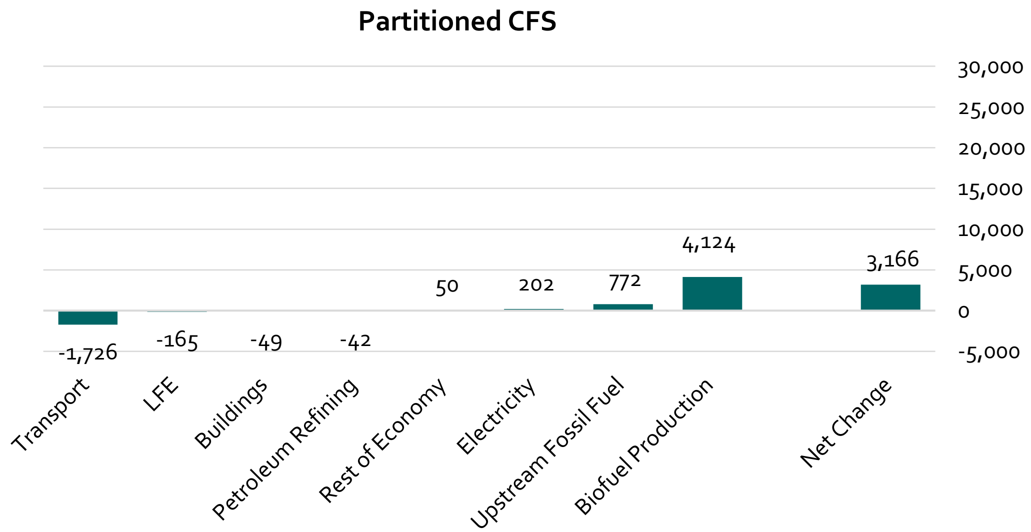
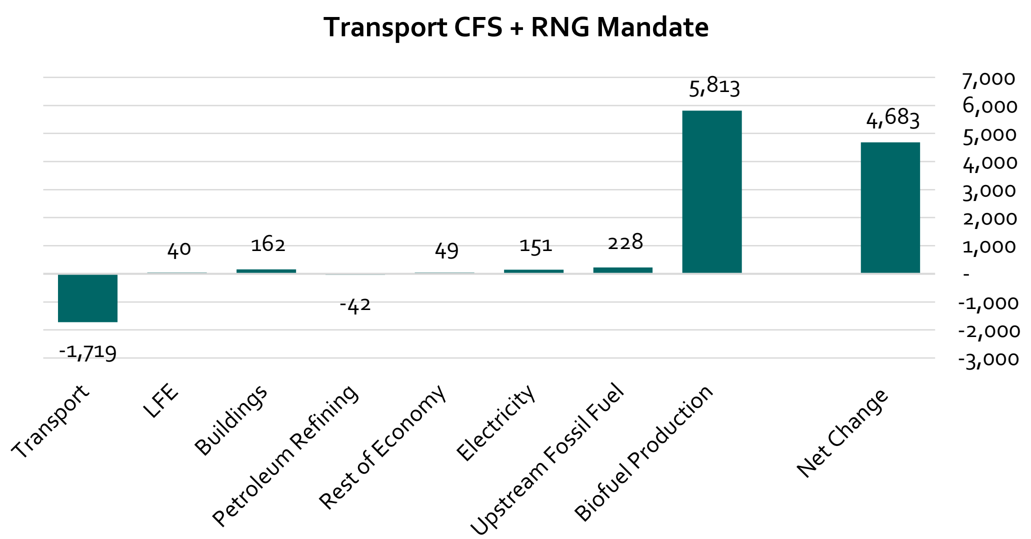


Figure 27: Changes in total employment by scenario and sector relative to the reference in 2030 (Direct and indirect)





Notes: LFE are industrial large final emitters that are not included in other sectors. Job impacts are allocated to the sector which saw a change in gross output. For example, the transportation category includes job impact related to fossil fuel distribution, refining and extraction as defined by the transportation sector impact multiplier.

Economic Impacts: GDP

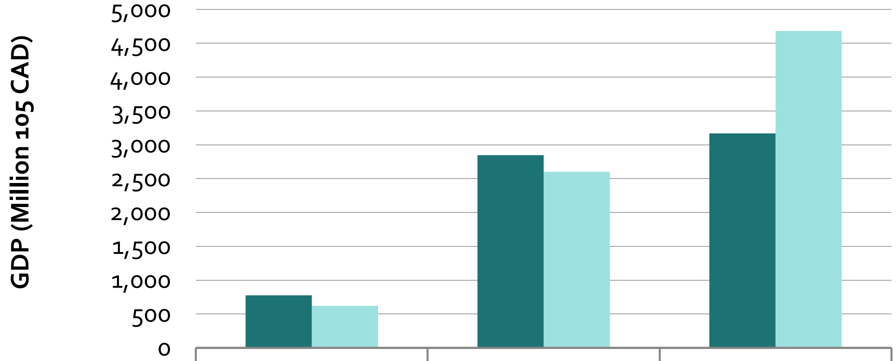
The results also show that GDP grows faster with the CFS relative to the reference scenario, with the changes by year, sector and scenario mirroring the changes in gross output and employment (Figure 28 and Figure 29). With the partitioned CFS, direct and indirect GDP is on-net $2.7 billion larger than in the reference scenario by 2030. That change is equivalent to a 0.5% increase in the 2016 GDP of the goods-producing industries in Canada.[42] Including induced GDP impacts, the net change in GDP in 2030 is +$4.1 billion. Again, this change is net of increased GDP related to biofuels production, and reduced GDP related to reduced investment and activity, primarily in the transportation sector and flowing through into fossil fuel distribution, refining and extraction. With the transport CFS and RNG mandate, direct and indirect GDP is $4.0 billion higher in 2030, equivalent to +0.7% of the 2016 GDP in the goods-producing industries in Canada.[43] Including induced GDP impacts, the net increase in GDP in 2030 is $5.8 billion. Growth in both scenarios is subject to the three caveats of this analysis:

- The results do not capture the expected reduction in economic productivity as costs rise due to overall carbon costs and technology choices made in the economy. I.e. It does not show how jobs and investments might have been allocated to more economically productive uses with even greater induced economic activity, which would reduce the net-positive impact of the CFS on the economy.
- The results do not show any increase in economic growth relative to the reference scenario resulting from avoided climate change damages. Including this would increase the net-positive impact of the CFS on the economy.
- The analysis assumes that RNG is produced in Canada rather than imported from the US. Accounting for RNG trade would reduce the difference in economic impact between the two versions of the CFS.

[42] Based on Statistics Canada, CANSIM, table 282-0008.

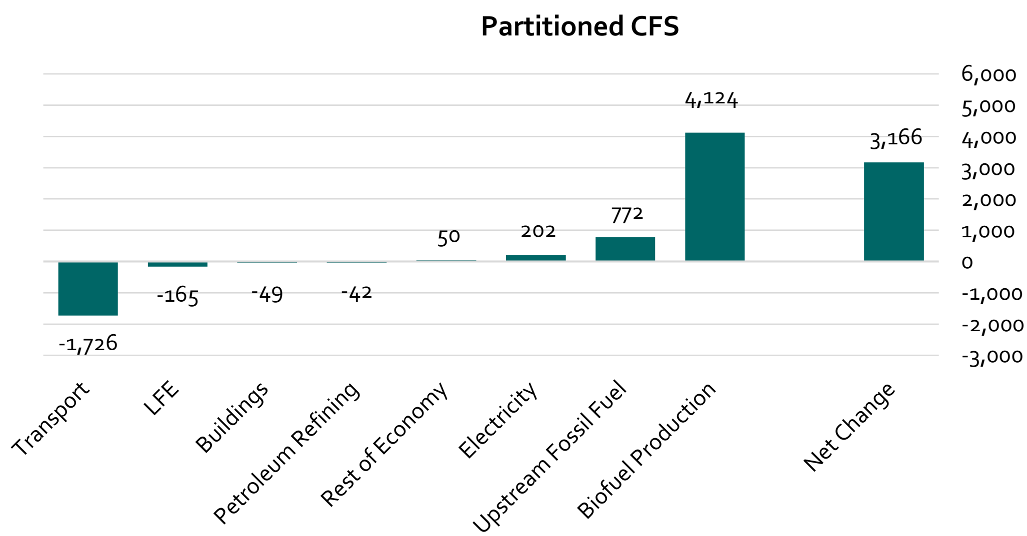
[43] Ibid.

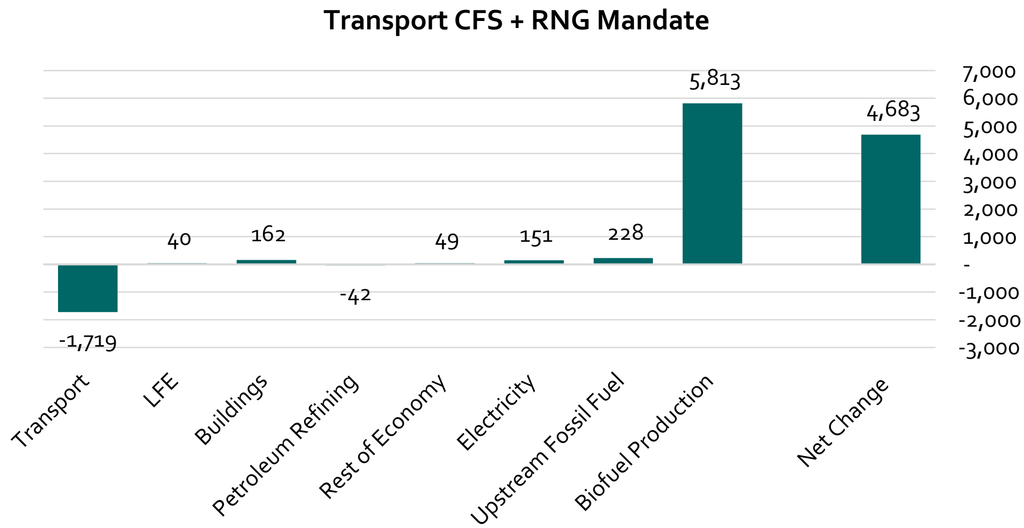
Figure 28: Net GDP All Sectors ($M 2015) (Direct and Indirect)



	2020	2025	2030
Partitioned CFS	778	2,848	3,166
Transport CFS + RNG mandate	620	2,601	4,683

Figure 29: Net GDP by Scenario and Sector, 2030 ($M 2015) (Direct and Indirect)





Notes: LFE are industrial large final emitters that are not included in other sectors. GDP impacts are allocated to the sector which saw a change in gross output. For example, the transportation category includes GDP impact related to fossil fuel distribution, refining and extraction as defined by the transportation sector impact multiplier.

4. Discussion of conclusions and uncertainties

How does the CFS reduce lifecycle GHG emissions?

Key points:

- The CFS can reduce GHG emissions in 2030 by more than 30 $MtCO_2e$/yr beyond what existing and proposed GHG policies can achieve.
- GHG abatement relative to the reference scenario is not sensitive to the designs of the CFS tested in this analysis.
- Transportation energy CI must fall by 10% between 2015 and 2030. Stationary CI must fall by 4% between 2015 and 2030.

The CFS can reduce Canada's GHG emissions by an additional 30-35 $MtCO_2e$/yr in 2030 relative to what existing and announced policies will achieve. This result is not sensitive to the variations of the CFS tested here: both the partitioned CFS and the CFS intensity standard on transportation energy paired with the RNG blending mandate can be designed to have a similar impact on national GHG emissions.

The CFS reduces GHG emissions by requiring the weighted average CI of transportation and stationary fuels to decline faster than it would without the policy. GHG abatement is divided roughly evenly between transportation and stationary energy consumption if the transportation CI must decline by roughly 10% from 2015 by 2030 and the stationary energy CI declines by 4% during that same period. This change corresponds to a 19 $MtCO_2e$/yr reduction in transportation lifecycle GHG emissions and a 15 $MtCO_2e$/yr reduction in stationary lifecycle GHG emissions, relative to the reference scenario in 2030. Alternatively, pairing the same transportation CI schedule with a 5% RNG blending requirement in 2030 will achieve a similar result.

What GHG abatement actions are used?

Key points:

- Increased biofuel consumption is the main driver of transportation GHG abatement
- The biofuels are commercially available and used in blends that are already compatible with current vehicles.

- Alternative fuel vehicles also play a role in transportation GHG abatement: the CFS incentivizes the use of E85 in FFVs and abatement through electrification of personal vehicles shows strong growth. In 2030, there are 1.2 million electric vehicles on the road versus only 0.7 million without the policy
- When a CI-based policy is applied to stationary energy consumption, the main abatement actions are switching to renewable electricity, increased energy efficiency and CCS. Substitution of natural gas with RNG is the main abatement action with the RNG mandate.

Both variations of the CFS have the same impact on transportation energy consumption. Increased biofuel consumption is the main driver of GHG reductions. The biofuels are already commercially available: sugar/starch-based ethanol, biodiesel and some HDRD. This analysis indicates that the CFS will likely not require or incentivize the use of emerging biofuels derived from woody or grassy materials (i.e. ligno-cellulosic feedstocks). However, to comply with the CFS using typical current biofuels, the rate of biofuel blending (i.e. % by volume) must increase relative to today, while remaining compatible with current new vehicles. By 2030, regular gasoline should contain 15% ethanol by volume, which is already compatible with vehicles manufactured after 2001.[44] The stock of flex-fuel vehicles (FFVs) needs to remain near current levels, but CFS will likely provide enough incentive for them to consume E85. The biodiesel blend should increase to 10% by volume on average over the year. Biodiesel blends as high as 20% can be used in modern vehicles without modification[45] and are already available in some US states.[46]

Electrification of personal vehicles and some light-freight vehicles also contributes to the abatement of transportation GHG emissions. This abatement action sees rapid growth from 2025 to 2030, indicating greater potential for compliance after the forecast.

The actions that are used to reduce stationary GHG emissions are very sensitive to the design of the CFS. If the CFS applies a CI schedule to stationary energy consumption, the policy reduces GHG emissions by increasing low-carbon electricity generation and consumption, increasing stationary energy efficiency, and incentivizing some

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[44] United States Environmental Protection Agency, 2017, *Gasoline Standards: Ethanol Waivers (E15 and E10)*, available from www.epa.gov

[45] U.S. Department of Energy, 2017, *Alternative Fuels Data Center: Biodiesel Blends*, available from www.afdc.energy.gov

[46] Minnesota Department of Agriculture, 2017, *About the Minnesota Biodiesel Program*, available from www.mda.state.mn.us

development of carbon capture and storage in the oil sands. If instead the policy uses a RNG mandate, almost all abatement comes from switching to RNG.

There are uncertainties in the cost and abatement potential of fuel pathways and alternative fuel vehicles. As well, there are limitations to this analysis with regards to how it represents these GHG reduction opportunities. Both create some uncertainty in which abatement actions are used in response the CFS.

The model includes a fixed number of static fuel pathways. GHG emissions decline by switching between pathways, but the pathways themselves do not respond to the policy. For example, the model will not show ethanol production switching to use biomass for process energy because this pathway is not currently included in the model.

Additionally, the model does not include some of the lowest carbon fuel pathways including ethanol and biodiesel produced from waste products. The GHGenius default CI for biodiesel produced from waste oils and tallow are 4 g/MJ and -20.7 g/MJ, respectively. [47] Ethanol produced from cellulosic feedstocks can also have negative CI, especially if that fuel production diverts waste away from where it can decompose to release methane to the atmosphere. For example, the Enerkem facility in Edmonton Alberta has recently started producing ethanol derived from municipal waste. This fuel has CI registered under the British Columbian fuel regulation that is -54.8 g/MJ.[48] Likewise, some estimates of the CI of cellulosic ethanol are much lower than the default value for corn stover from the GHGenius model. That fuel has a CI of 43 g/MJ,[49] which is the upper limit of the fuel's carbon intensity, but other estimates find cellulosic ethanol CI as low as 1.6/MJ. [50] The parameterization of cellulosic ethanol was purposely conservative, but it is clearly possible that the fuel could play a greater role under the CFS if it is fully-commercialized with a lower CI.

Including lower-CI fuel pathways could reduce the total volume of biofuel needed to comply with the CFS, potentially also reducing the cost of compliance. The impact of any given fuel pathway would be constrained because the supply of each of fuel is limited. For example, Navius estimates that all animal fat wastes produced in Canada

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[47] GHGenius 4.03, 2017, *Default values for tallow and UCO in Canada*

[48] British Columbia Ministry of Energy, Mines and Petroleum Resources, 2017, *Information Bulleting RLCF-012 Approved Carbon Intensities*, available from www.gov.bc.ca

[49] GHGenius 4.03, 2017, *Default values for corn stover in Canada*

[50] California GREET, 2017, *Farmed trees-derived cellulosic ethanol carbon intensity*

can generate around 0.7 billion litres of biodiesel or about 15 to 20% of the biodiesel required to comply with the CFS in 2030. But in total, they could present a substantial opportunity to supply very-low CI biofuel. Enerkem's nameplate production capacity is roughly 40 million L/yr. If this were scaled to the population of Canada's four largest cities, the production would be 400 million L/yr. That is equivalent to 5% of the forecasted ethanol consumption in 2030 if the CFS is implemented, but would provide a GHG reduction that is over three times greater than what would results from using a typical corn-derived ethanol.

Another uncertainty is the price of RNG. This analysis used a single fixed price that is typical of the quantity of RNG consumed in the scenarios. By 2030, this forecast shows RNG consumption will reach at most 280 PJ/yr. A Canadian Gas Association report citing the Alberta Research Council estimates that Canada can generate almost 1,500 PJ of renewable natural gas from wastes, most of which can be produced for between $8 and $20/GJ.[51] However, until a market for RNG forms, the price estimates will remain theoretical and uncertain. Even the directionality of this uncertainty is uncertain; RNG prices could very well be higher or lower than assumed here.

The use of alternative fuel vehicles also creates uncertainty in the abatement actions used in response to the CFS. Other new policies could produce greater electric vehicle adoption than the CFS and would reduce the quantity of biofuels required for compliance. Canada is currently working on a zero-emissions vehicle (ZEV) strategy.[52] If this strategy results in a national ZEV mandate like Quebec's, 9-10% of new vehicles would need to be ZEVs by 2025.[53] This implies a rate of ZEV adoption that is 50% larger than what occurs in this forecast, likely meaning that the contribution of electric vehicles towards CFS compliance would change by a similar amount.

On the other hand, there is a risk that the stock FFVs will decline from current levels, which would likely increase the cost of CFS compliance relative to this forecast. FFVs currently make up approximately 7% of light-duty vehicles in the US and between 20% and 25% of all new light-duty vehicle sales in North America.[54] The production of FFVs

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[51] Canadian Gas Association, 2014, *Renewable Natural Gas Technology Roadmap for Canada*, available from www.cga.ca

[52] Government of Canada, 2017, *Government of Canada to develop a national Zero-Emissions Vehicle Strategy by 2018*, available from www.canada.ca

[53] Gouvernment du Québec, 2017, *Analyse d'impact réglementaire du projet de règlement d'application de la Loi visant l'augmentation du nombre de véhicules automobiles zero émission au Québec afin de réduire les émissions de gaz à effet de serre et autres polluants*, available from www.mddelcc.gouv.qc.ca

[54] BC Ministry of Energy and Mines, 2014, *Fuel Backgrounder to the 2014 RLCFRR Consultation*, available from www.gov.bc.ca

is incentivized by the US Corporate Average Fuel Economy standards. If this incentive is removed before the CFS can create consumer demand for FFVs, for example by incentivizing E85 consumption, the sale of FFVs could decline or end. Nonetheless, the US Energy Information Agency forecasts that FFVs will stabilize at 11% of all light-duty vehicles in the US.[55] A further uncertainty is the availability of E85 refueling infrastructure; the fuel is not compatible with some existing storage tanks and pumps. Research found no E85 stations that are currently operating in Canada. Nonetheless, in the US, where the Renewable Fuel Standard has created a policy incentive for E85 sales, 2% of fuelling stations in the US provide this fuel.[56] In contrast, Canadian policy to date has created no incentive to sell E85, so it is unsurprising that there is no E85 refuelling infrastructure. The difference in the US and Canadian markets suggests that policy can lead to investment in E85.

Clearly, there is uncertainty in the degree to which E85 will contribute to compliance with the CFS. The model results only indicate that investment in E85 refuelling infrastructure and selling that fuel at a price that where consumers will buy it is part of the least-cost compliance pathway. However, if there is no E85 available, the CFS credit price will increase to incentivize the use of other compliance actions. These could include more electric vehicles, more drop-in fuels or even actions not represented in this analysis such as the supply of low-CI cellulosic ethanol or the adoption of conventional vehicles capable of using higher ethanol blends such as E30.

What is the CFS abatement cost and how does the CFS affect energy prices and energy expenditures?

Key points:

- The price of transportation compliance credits under the CFS will be 150-180 $/tonne. The price of stationary credits will likely be lower, near 40 $/tonne (2015 CAD).
- Because the CFS is a GHG intensity-based policy with revenue recycling, the full value of the CFS carbon price is not reflected in energy prices.
- The impact of the CFS on future energy costs is an order of magnitude smaller than the potential impact of the price of crude oil and natural gas. For example, the CFS may increase the retail price of gasoline by 5 cent/L in 2030, but if oil prices rise

[55] United Stated Energy Information Agency, 2017, *Annual Energy Outlook 2017*, available from www.eia.gov

[56] Estimated from E85Prices.com, 2017, *Home Page*, available from www.e85prices.com

back to almost $90/bbl by 2030, that will increase the price of gasoline by more than 40 cent/L.

- The CFS will cause fossil fuel prices to increase compared to a scenario without the policy. However, fuel switching and energy efficiency can allow consumers to reduce their annual energy costs relative to today.

CFS compliance credits for transportation energy consumption remain between 150 and 180 $/tonne (2015 CAD) during the forecast. The credit price for stationary energy consumption is lower. It reaches 38 $/tonne (2015 CAD) in 2030, indicating that there are more low-cost abatement opportunities for stationary GHG emissions. Again, the credit prices are incremental to any other carbon price that exists during the forecast. The marginal abatement cost of RNG substitution somewhat analogous to the CFS compliance credit prices (i.e. they are all marginal costs). Based on model inputs for natural gas and RNG prices, the marginal abatement cost of RNG consumption in 2030 is 171 $/tonne (2015 CAD), or an additional 120 $/tonne when measured relative to the announced federal carbon price floor after 2022.

In all scenarios, the compliance credit price, or the marginal abatement cost, indicate the highest cost abatement action required to achieve the CI target or RNG blending mandate. The average abatement cost will be lower and financial expenditures (e.g. capital and energy costs) are influenced by how the CFS changes energy intensity and activity in each sector.

The CFS policy will likely increase energy prices. The retail price of gasoline blends will be near 5 cent/L higher in 2030, compared to a scenario without the CFS (2015 CAD). However, almost half of this increase relates to volumetric gasoline taxes (i.e. cent/L) applied to increasing quantities of ethanol. Because ethanol has a lower energy density than gasoline, it incurs more tax per unit of energy purchased. The retail price of diesel blends will likely be 7.5 cent/L higher in 2030 than they would be in a scenario without the CFS (2015 CAD). Similarly, natural gas prices will be roughly 0.5 $/GJ higher after 2025.

While the CFS does increase fossil fuel prices relative to a scenario without the policy, these energy prices are much more sensitive to the future price of crude oil and natural gas within the North American and global markets. For example, the impact of the CFS on household energy costs between 2015 and 2030 is an order of magnitude smaller than the impact of these fundamental drivers of energy prices. A typical household that makes energy efficiency improvements that are already regulated or incentivized by policy can keep its energy costs constant to 2030, even as energy prices increase as a result of oil and gas prices and GHG policy requirements. These changes include using a high-efficiency gas furnace and buying a more efficient vehicle.

How does the CFS change biofuel demand in Canada and North America and what are the implications for feedstock demand and liquid fuel production in Canada?

Key points:

- The CFS will likely double the quantity of biofuel consumed in Canada in 2030, compared to a scenario without the policy.
- Even though these biofuels are sourced from agricultural products, total North American biofuel consumption will likely only increase by 3% relative to 2015, indicating that the CFS will not significantly change the quantity of North American grains and oilseeds used for fuel.
- Canadian ethanol production reaches almost 3.0 billion L/yr in 2030, requiring 7 Mt/yr of grain, equivalent to 13% of 2016 Canadian corn and wheat production. For context, Canadian ethanol production in 2016 was roughly 1.8 billion L/yr.[57]
- Canadian biodiesel and HDRD production reaches 2.7 billion L/yr in 2030, requiring 9 Mt/yr of oilseed, equivalent to 34% of 2016 Canadian soy and canola production (Assuming an average soy and canola oil content and not accounting for the contribution of waste oil and fat). For context, Canadian biodiesel production in 2016 was roughly 0.4 billion L/yr.[58]

The CFS doubles Canadian biofuel consumption by 2030 relative to what consumption would be without that policy. That is equivalent to a 3 to 3.5 increase relative to consumption in 2015. With the CFS, ethanol consumption in 2030 will require roughly 20 Mt of grain, mostly corn and wheat. Biodiesel and HDRD consumption will require roughly 13 Mt of oilseed such as canola and soy, assuming no fuel produced from waste oil and fat. To put these quantities in context, the ethanol feedstocks required in 2030 are equivalent to 4% of the corn and wheat produced in North America in 2016. The oilseed required is equivalent to 34% canola and soy produced in North America in 2016.

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[57] Dessureault, D. (2016). Canada Biofuels Annual 2016. USDA Foreign Agricultural Service, Global Agricultural Information Network

[58] Ibid.

Canadian ethanol production will require 7 Mt/yr of grain in 2030, equivalent to 13% of 2016 Canadian corn and wheat production. Canadian biodiesel and HDRD production will require 9 Mt/yr of oilseed in 2030, equivalent to 34% of 2016 Canadian soy and canola production. However, the actual 2030 oilseed requirement could be 20-30% lower: This comparison assumes the average oil content is 28% by mass, whereas canola, the main oilseed crop in Canada, is closer to 40% oil by mass. As well, this oilseed requirement does not account for the contribution of waste oil and fats, which are the feedstock for roughly half of current Canadian biodiesel and HDRD.[59]

While Canadian biofuel consumption grows substantially in response to the CFS, the forecast of North American biofuel consumption only increases by 3% between 2015 and 2030. This result occurs because transportation energy consumption in North America declines after 2020, driven by vehicle emissions and fuel economy standards. As well, the US has no announced schedule to increase the rate of biofuel blending after 2019.[60] This 3% increase in continental biofuel consumption roughly equates to a 3% increase in the consumption of agricultural feedstocks over that period. To put that change in the context of how agricultural production has changed, total Canadian grain and oilseed[61] production has increased by 30-40% between 2000 and 2016, an average of roughly 2% per year. This change has been driven by productivity gains: The grain and oilseed yield per land area increased by a similar amount and the seeded area for these crops has declined by 3% since the year 2000.[62]

The forecast of continental biofuel consumption is subject to policy uncertainty: The US could choose to raise its renewable fuel standard. If the resulting demand for agriculture products were to outpace the supply, it will raise the price of these products. This in turn will raise the production cost of conventional biofuels, where feedstocks can represent 65-85% of the total production cost. This change would create a market opportunity for ligno-cellulosic derived fuels

A related policy uncertainty is the application of indirect land-use change (iLUC) emissions to the CI of biofuels. iLUC emissions are meant to account for any land-

[59] Wolinetz, M., Hein M., 2017, *Biofuels in Canada 2017*, Navius Research

[60] U.S. Environmental Protection Agency, 2017, *Renewable Fuel Standard Program: Proposed Volume Standards for 2018, and the Biomass-Based Diesel Volume for 2019*, available from www.epa.gov

[61] Grains and oilseeds include: Wheat, corn, barley, rye, oats, mixed grains, buckwheat, sunflower seed, canola, soy, flaxseed, safflower

[62] Statistics Canada, 2017, *CANSIM 001-0010: Estimated areas, yield, production and average farm price of principal field crops*, available from www.statcan.gc.ca

clearing that results indirectly from biofuel consumption: theoretically biofuels increase the price of agricultural products which increase the incentive to convert forest and pasture to crop fields, resulting in the release of stored carbon. If iLUC emissions are included in the CFS, it would increase the cost of compliance through the use first generation biofuel, by reducing the GHG abatement per unit of fuel consumed. It would also provide a market opportunity for ligno-cellulosic biofuels, which generally have low to no iLUC emissions if they are produced from wastes and crop residues.[63]

In both instances of policy uncertainty, ligno-cellulosic biofuels provide a technological means for compliance; there is a large potential to produce fuel from ligno-cellulosic feedstock. The U.S. Department of Energy found that second-generation biomass feedstocks have the potential to supply around 30% of all fuel consumption in the United States.[64] This is equivalent to 2.75 times Canada's current liquid fuel demand. Similarly, the Global Energy Assessment compiled several studies to estimate a Canadian production potential to be roughly 3,000 PJ – equivalent to 120% of Canada's current fuel consumption.[65]

While there is a greater risk of higher energy prices with ligno-cellulosic fuels, these fuels are not intrinsically more expensive than first-generation biofuel: higher capital costs and operating costs (e.g. for specialized enzymes) can be offset by lower costs for feedstocks which are generally waste products or agricultural residues. The current risk of high costs relates to the commercialization of these fuels, where a plant does not produce at its nameplate capacity, resulting in a high capital cost per unit of fuel produced.

What is the impact of the CFS on jobs and GDP?

Key points:

- The CFS shifts economic activity towards the biofuels production sectors, at the expense of investment in transportation
- This analysis shows that the CFS could create a net-increase in employment and GDP relative to a scenario without the policy

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63 California Environmental Protection Agency Air Resources Board, 2015, *Staff Report: Calculating Carbon Intensity Values from Indirect Land Use Change of Crop-based Biofuels*, available from www.arb.ca.gov

64 U.S. Department of Energy, 2016, *2016 Billion-Ton Report: Advancing Domestic Resources for a Thriving Bioeconomy*, available from www.energy.gov

65 International Institute for Applied System Analysis, 2012, *Global Energy Assessment: Toward A Sustainable Future*, available from www.iiasa.ac.at

In 2030, the CFS could create between 11,000-16,000 additional direct and indirect jobs compared to a scenario without that policy. Those jobs are equivalent to 0.3% to 0.5% of 2016 employment in the goods-producing industries in Canada. Induced jobs could amount to another 5,000 to 7,000 jobs by 2030. Also in 2030, the CFS could directly and indirectly increase GDP by $2.7-$4.0 billion compared to the reference scenario. That value is equivalent to an increase in 0.5% to 0.7% of the 2016 GDP of the goods-producing industries in Canada.[66]

This growth is subject to the two key caveats of the jobs and GDP analysis:

- The results do not capture the expected reduction in productivity as costs rise due to overall carbon costs and technology choices made in the economy. I.e. it does not show how jobs and investments might have been allocated to more economically productive uses, which would reduce the net-positive impact of the CFS on the economy.
- The results do not show any increase in economic growth relative to the reference scenario resulting from avoided climate change damages. Including this would increase the net-positive impact of the CFS on the economy.

What additional analysis of the CFS would be useful?

Future analyses could address some of the uncertainties and limitations of this work. First, some additional sensitivity analysis on oil, natural gas and agricultural feedstock prices would illustrate how different assumptions may change the cost of complying with the CFS. Preliminary assessment of these drivers indicates that higher oil prices can reduce the difference in production costs between fossil fuels and alternative fuels. Reducing this production cost spread will reduce the CFS credit price substantially while reducing the relative impact of the CFS on energy prices.

Second, the additional research should include more sensitivity analysis on the cost and potential of technologies. Because FFVs and E85 are an important abatement action in this analysis, a useful sensitivity analysis would test the impact of making these technologies unavailable, representing a situation where FFVs are no longer supplied by manufacturers or where there is a failure to develop E85 refueling infrastructure. Further sensitivity analyses should also assess the impact of different costs, CIs, and supplies of ligno-cellulosic fuels and HDRD. Ligno-cellulosic fuels could have lower CIs than assumed in this analysis, increasing their use for compliance with the CFS. Likewise, this analysis underestimates the current use of HDRD, indicating

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[66] Based on Statistics Canada, CANSIM, table 282-0008.

that the production cost assumption is too high, or that there is some other un-quantified benefit of this fuel. In either case, this analysis is conservative with regards to these emerging fuels, and the uncertainty is that they see greater use. Finally, additional analyses could test the impact of varying the cost of electric vehicles and the rate at which consumers may accept them as a mainstream technology. Again, this analysis is relatively conservative in its portrayal of electric vehicles, where sales are less than 10% of the total, even with the CFS. Again, the uncertainty is that lower costs or more rapid consumer acceptance of the technology will increase the role of electrification in response to the CFS.

Third, future analyses could test the impact of policy uncertainty. Specifically, what happens if the US continues to increase its biofuel blending rates under the Renewable Fuel Standard? This assumption slackens the demand for biofuel in North America, likely reducing the cost of these fuels somewhat. Similarly, what is the impact of renewed biofuel production and blending incentives in Canada or the US? Finally, this analysis does not consider the impact of a strong policy pushing greater adoption of zero-emissions vehicles. What is the impact of a potential Canadian zero-emissions vehicle strategy or sales requirement on the CFS?

Finally, additional reporting and analysis is also possible. For example, this could include a sectoral assessment of CFS compliance costs and how that policy changes the cost of production and the cost of energy services.

Appendix A: Detailed model inputs

This appendix describes key assumptions and inputs to the CIMS and OILTRANS models that forecast the impact of the CFS in Canada.

Sector activity

Sector activity in the modelling is based on the population and economic rates of growth in the National Energy Board's 2016 forecast: Between 2015 and 2030 the population grows at an average rate of 0.9%/yr and GDP grows at 1.8%/yr. In general, the impact of intensity based policies, such as the CFS, are not highly sensitive to sector activity. However, in this case, the stringency of the policy was set to reduce GHG emissions in 2030 by at least an additional 30 Mt/yr so the stringency does depend on activity: A smaller population and economy will reduce the absolute GHG reduction impact of an intensity based policy, while the same policy will have a larger absolute impact when applied to a larger population and economy.

Existing GHG reduction policies

Canadian federal policies

The following existing federal policies are in all three scenarios:

- The renewable fuel mandate that requires gasoline to have a minimum renewable content of 5% by volume and diesel to have a minimum renewable fuel content of 2% by volume.
- The light-duty vehicle emissions standard. Light-duty vehicle emissions standards in Canada are aligned with the US regulation, which require the average GHG emissions per km of new vehicles to fall by roughly an additional 30% relative to the current average new vehicle by 2025.[67,68]

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[67] Government of Canada, 2014, *Regulations Amending the Passenger Automobile and Light Truck Greenhouse Gas Emission Regulations*. Available from www.gazette.gc.ca

[68] National Highway Traffic Safety Administration, 2011, *2017-2025 Model Year Light-Duty Vehicle GHG Emissions and CAFE Standards: Supplemental*, available from www.nhtsa.gov

- The heavy-duty vehicle emissions which standard requires 2018 model-year vehicles to emit approximately 20% less than a pre-2014 model year vehicle, based on the energy intensity of the vehicles.[69]
- Energy efficiency standards for furnaces, water heaters and appliances (e.g. Requiring that new natural-gas fired furnaces be at least 90% energy efficient).

Canadian provincial policies

Additional provincial policies are represented in:

- **British Columbia:** Those implemented under the Climate Action Plan and later, including:
  - Building energy efficiency codes
  - The Clean Energy act (93% of generation must be non-GHG emitting)
  - A subsidy of $5,000 on the purchase on PEVs (Applied between 2015 and 2020)
  - The carbon tax, which we assume is aligned with the federal price floor ($50 real value) after 2022.
- **Alberta:**
  - The Carbon Levy, a carbon price applied to retail fuels, starting at 20 $/tCO_2e$ in 2017, ultimately aligning with the federal price floor ($50 real value) after 2022.
  - The Specified Gas Emitter Regulation, which applies a GHG intensity-based cap to industrial emitters. Again, we assume the implied price of this policy is aligned with the federal carbon price floor.
  - The electricity generation renewable portfolio standard, which is a commitment to replace two thirds of the closed coal generation capacity.
- **Saskatchewan:**
  - Have 50% of electricity generation capacity be renewable by 2030
- **Manitoba:**
  - A building energy code for houses and buildings

[69] Government of Canada, 2013, *Heavy-duty Vehicle and Engine Greenhouse Gas Emission Regulations*, available from www.laws-lois.justice.gc.ca

- **Ontario:**
  - The Western Climate Initiative GHG emissions cap, which we assume has a credit price of roughly 20$/t$CO_2$e in 2025 and 40$/tCO_2e in 2030. We assume credit prices reflect GHG caps that are consistent Canada's 2030 emissions target, therefore the price does not have to align with the federal carbon price floor.
  - A building energy code for houses and buildings
  - A subsidy of $10,000 on the purchase on PEVs (Applied between 2015 and 2020)
- **Québec:**
  - Participation in the Western Climate Initiative GHG emissions cap (same assumptions as for Ontario).
  - A building energy code for houses and buildings
  - A subsidy of $8,000 on the purchase on PEVs (Applied between 2015 and 2020)
  - A zero-emissions vehicle requirement that at least 10% of vehicle sales by 2025 and beyond are plug-in electric vehicles.
- **Atlantic provinces (represented) in aggregate in this analysis:**
  - A building energy code for government and institutional buildings, reflecting the policy in Newfoundland and Labrador

Sub-national renewable fuel requirements are not explicitly represented in the analysis under the assumption that only the federal policy is binding when averaged over total Canadian fuel consumption.

US policies

The US Renewable Fuel Standard (RFS) is included in all three scenarios in the analysis. It requires a minimum quantity of renewable fuel consumption based on four categories, each with defined feedstock and carbon intensity reduction relative to the petroleum fuels, inclusive of indirect land-use GHG emissions:[70]

[70] US Environmental Protection Agency, 2016, *Final Renewable Fuel Standards for 2017 and Biomass-Based Diesel Volume for 2018*, available from www.epa.gov

- Conventional biofuel must have a lifecycle carbon intensity reduction of at least 20% relative to petroleum fuels.
- Advanced biofuel must have a reduction of at least 50%.
- Renewable diesel/biodiesel must have a reduction of at least 50%.
- Cellulosic biofuel must have a reduction of at least 60%.

The required biofuel blends are currently set to 2016 (Table 11). In the model, we exclusively include the total requirement for biofuels as well as the requirement for biomass-based diesel, but do not include the GHG Intensity requirement. For example, the 2017 requirement is modelled as 10.7% average renewable fuel content, where one sixth of the biofuel volume must come from renewable diesel/biodiesel.

Table 11: Implied fuel blends by volumes in the US renewable fuel standard

Fuel type	2014	2015	2016	2017	2018 (assumed)
Cellulosic biofuel (min.)	0.0%	0.1%	0.1%	0.2%	
Biomass-based diesel (min.)	1.4%	1.5%	1.6%	1.7%	
Other Advanced biofuel (min.)	0.1%	0.1%	0.3%	1.1%	
Conventional biofuel (remainder)	7.7%	7.9%	8.1%	7.7%	
Total biofuel	**9.2%**	**9.5%**	**10.1%**	**10.7%**	**11.3%**

All values are ethanol-equivalent on an energy content basis, except for biomass-based diesel which is biodiesel-equivalent.

The US Environmental Protection Agency expects to increase the biofuel requirements each year, based on goals defined in the Energy Independence and Security Act of 2007, which had the total biofuel volumes increasing at roughly 9% annually to 2022.[71] The percent change in volume from 2016 to 2017 is expected to be 6%. Because increased biofuel volumes are announced but not yet regulated, there is uncertainty in the future policy requirement. Therefore, we have only assumed an additional 6% increase in 2018. Based on the energy demand forecast, we assume the regulation requires that renewable fuel account for 11.3% of total fuel volume.

As with Canadian, we are excluding an explicit representation of most US sub-national fuel policies, including the California Low-Carbon Fuel Standard, under the assumption that they will not materially affect national fuel consumption beyond what the federal policy will accomplish.

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[71] US Environmental Protection Agency, 2007, *Energy Independence and Security Act of 2007*, available from www.epa.gov

Vehicle choice

Vehicle choice is an important driver of the quantity and type of transportation energy consumption. Vehicle choice determines the average energy intensity of the vehicle fleet, which could become more efficient if consumers choose vehicles with greater fuel economy. Vehicle choice also affects what type of fuel or energy the vehicles consume, where the adoption of alternative fuel vehicles (AFVs) such as plug-in electric vehicles (PEVs) and natural gas engine trucks can have a significant impact on total transportation energy consumption and average carbon intensity.

Vehicle choice is endogenous to the OILTRANS model, meaning it is simulated as a part of the model's solution. The CFS credit price will affect vehicle choice which in turn affects the CFS credit price. In this example, the credit provides an incentive to purchase PEVs based on the extent which substituting electricity for gasoline and diesel consumption reduces GHG emissions in each province. The outcome of the simulation depends on how the vehicle choices are characterized, described below for flex-fuel vehicles, PEVs, natural gas-engine trucks. We also explain our rational for excluding other AFVs from the analysis, including those fuelled with propane, hydrogen and other biofuels such as dimethyl-ether.

Flex-Fuel Vehicles

Light-duty flex-fuel vehicles (FFVs) capable of using ethanol blends up to E85 are included in the model. The additional cost for FFVs is low and we have set purchase cost the premium for FFVs at $200 per vehicle. Whether or not a flex-fuel vehicle actually consumes E85 or conventional ethanol/gasoline blend is a modelled outcome.

Plug-in Electric Vehicles

The model includes a BEV and PHEV vehicle archetype. Vehicle costs are based on battery pack costs declining from around 400 $/kWh today to 125 $/kWh in 2029. Based on an industry average rate of decline of 10%/yr, consistent with past trends noted by Nykvist and Niellson (2015). At their lowest cost, the BEV and PHEV vehicles in the model still cost roughly $4,500 more than a conventional ICE vehicle (Table 12). BEV and PHEV light-freight trucks are also available in the model. They have a similar cost trajectory, reaching their lowest cost in 2029. In that year, the PHEV truck has a cost premium of $11,450 (+17% of the conventional truck capital cost), while the BEV truck has a cost premium of $21,000 (+30% of the conventional truck capital cost) (2015 CAD).

The rate at which PEV costs will decline and the ultimate cost floor are both uncertain. The values used in this analysis are somewhat conservative when compared to recent cost estimates. The UBS investment bank did a teardown of the Chevrolet Bolt electric car to estimate its cost. This process led UBS to conclude that total cost of ownership over a three-year lease contract for electric and conventional cars would be equal in the North American Market by 2025.[72] In other words, the fuel cost savings of the PEV would offset its higher capital costs (i.e. more depreciation and interest) during the lease period. This outcome is more consistent with electric vehicle battery pack costs declining to 125 $/kWh by 2025, four to five years sooner than we have assumed.

Table 12: Light-duty PEV incremental purchase costs (2015 CAD)

	Incremental cost, based on battery cost at 125 $/kWh
Plug-in hybrid, 30km electric range	$4,554
Plug-in hybrid, 60km electric range	$5,252
Electric vehicle, 150 km electric range	$4,220

We assume that the barriers to PEV adoption are relatively high due to lack of technology awareness, lack of vehicle supply and variety, and constraints on home-charging access. The implied costs of these barriers are equivalent to roughly half of the current incremental cost of PEVs and are calibrated to sales forecasts informed by the survey data and PEV focussed analysis done by Wolinetz and Axsen (2017).[73] Based on the work of Mau et al. (2008),[74] the implied cost of the barriers is dynamic, and declines as PEVs market share increases (i.e. they are largely gone when the new market share is more than 10%).

Note that while the model only includes an archetype for an electric-only vehicle with a 150 km range, this range does not necessarily constrain the adoption of this technology. The model accounts for range only in terms of capital cost and non-financial costs, which would include a cost associated with limited range. A longer range archetype would have a larger capital cost, but smaller non-financial costs, resulting in little change in market share. Finally, the model assumes a heterogeneous market, which serves to represent the range of technologies available to consumers in addition to the consumers' heterogeneous preferences for those technologies.

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[72] UBS Global Research, 2017, *UBS Evidence Lab Electric Car Teardown – Disruption Ahead*

[73] Wolinetz, M., and Axsen, J., 2016, *How policy can build the plug-in electric vehicle market: Insights from the Respondent-based Preference And Constraints (REPAC) model, Technological Forecasting and Social Change*, available from http://dx.doi.org/10.1016/j.techfore.2016.11.022

[74] Mau, P., et al., 2008, *The `neighbor effect': Simulating dynamics in consumer preferences for new vehicle technologies. Ecological Economics*, 68(1-2): p. 504-516

Natural Gas

We have included natural gas fuelled trucks as a technology option for heavy-duty transportation. To simplify the model, we represent only one natural gas truck archetype, a liquefied natural gas (LNG) fuelled technology suitable for long-range and heavy-haul applications. Technology cost and performance is based on estimates by the UC Davis Institute of Transportation Studies[75]. Specifically, the upfront cost of the LNG truck is roughly $80,000 more (+50%) than a diesel truck.

We also represent barriers to initial adoption (lack of familiarity, lack of supply, and lack of fuelling) as an implied cost. These are set judgementally at an additional 75% of the LNG truck cost premium. While this is high, there are currently no North American manufacturers of LNG engines suited for long-distance heavy-duty service.[76] As with PEVs, these costs are dynamic and decline if the LNG truck market share grows.

Omitted Alternative Fuel Vehicles

There are several types of alternative fuel vehicles that are not included in the analysis:

- Hydrogen fuel cell vehicles (FCVs): While they can reduce transportation GHG emissions, they are not-yet fully commercialized and their cost and consumer acceptance of these vehicles are very uncertain.
- Propane vehicles: Propane is a minor transportation fuel and there is no expectation that this will change. Furthermore, propane vehicles have a similar GHG abatement potential and face similar barriers to adoption as natural gas-fuelled vehicles, which are included.
- Other biofuel alternative fuel vehicles: There are emerging biofuels that can only be consumed by specially designed vehicles. One such fuel is dimethyl ether, which requires a compatible engine and a dedicated fuel storage and distribution systems. Dimethyl ether can be produced from biological or petroleum feedstocks, but neither the fuel nor the vehicles are commercially available. To date the fuel has

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[75] Jaffe et al., 2015, *"NexSTEPS White Paper: Exploring the Role of Natural Gas in U.S. Trucking". UC Davis Sustainable Transportation Energy Pathways*, available from www.trb.org

[76] Truck News, 2014, *UPDATED: Cummins to "pause" development of 15L natural gas engine, leaving void in marketplace*, available from www.trucknews.com; LNG World News, 2014, *Volvo stalls North American LNG engine program*, available from www.lngworldnews.com

only been used in a handful of field tests.[77] Therefore, dimethyl ether and other emerging biofuels (e.g. bio-butanol) are not included in the analysis.

Substitutability between biofuels and refined petroleum products

Biofuels are not perfect substitutes for petroleum fuels. Table 13 outlines the blending constraint assumptions used in the analysis. The rational for these assumptions are explained below.

Table 13: Biofuel blend constraint assumptions, % by volume in gasoline (ethanol, renewable gasoline) or diesel (biodiesel, renewable diesel)

	2015	2020	2025 and thereafter
Ethanol	10%	15%	15%
Biodiesel	5%	6%	10%
HDRD	40%	40%	40%
Pyrolysis derived renewable gasoline and diesel	100%	100%	100%

Ethanol

All Original Equipment Manufacturers (OEMs) currently accept ethanol blends of E10 (10% ethanol and 90% gasoline by volume) for regular gasoline vehicles. While the US EPA has approved E15 for all vehicles manufactured after 2001, only certain manufacturers have agreed to extend warranty to vehicles using E15 citing compatibility issues between engine materials and ethanol.[78]

In this analysis, we assume that the turnover of the vehicle fleet allows the average ethanol blend used by regular vehicles (i.e. not FFVS) to increase to 15% by 2020. This maximum blend remains constant to 2030. While there is currently one non-FFV

[77] US Department of Energy, 2015, Dimethyl ether, available from www.afdc.energy.gov

[78] United States Environmental Protection Agency, Office of Transportation and Air Quality, 2011, *Regulatory Announcement: EPA Announces E15 Partial Waiver Decision*, EPA-420-F-11-003

approved to use an E25 blend, we assume that the majority will not have this capability.[79]

Biodiesel

Biodiesel is not a perfect substitute with biodiesel because the two fuels are not chemically analogous. Biodiesel has been typically blended in North America at rates between 3 and 5% without vehicle modifications, and most vehicle manufacturers explicitly warranty their vehicles against damage resulting from fuels containing at least 5% biodiesel. Many concerns with higher blends relate to cold-weather performance. However, biodiesel cold-flow issues can be mitigated with the addition of chemical agents (e.g. blending slightly different diesel fuels to optimize the blend to the weather). Diesel cold-flow performance is already adjusted in a similar manner. Biodiesel may be incompatible with older engine materials as it has increased solvency compared to petroleum diesel. This can lead to clogged engine filters which then require increasing the rate of oil and filter changes to avoid engine failure.

The Alternative Fuels Data Center states that no vehicle modifications are required for blends of up to 20% biodiesel (known as B20).[80] As well, many US retail locations sell blends that are greater than B5. For example, Pilot Flying J, a major US fuel retailer, sells B20 at 42% of its locations, and sells B10-B18 at another 10% of locations.[81]

The state of Minnesota demonstrates that many of the concerns associated with using higher biodiesel blends can be dealt with. The state has had a stringent biodiesel program despite it experiencing some of the coldest winters in the United States. The state changes its biodiesel content requirements for the summer and winter months. It requires 5% biodiesel content during the winter months and is set to require 20% content by 2018 during the summer months, up from the 10% required since 2014.[82]

In the analysis, the biodiesel blend limit is set to 5% until 2018 to reflect what is supplied with current fuel distribution infrastructure and blending practices which accommodate older vehicles. From 2019 to 2025, the biodiesel blend limit rises

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[79] Renewable Fuels Association, 2015, RFA Analysis Shows Uptick in Number of Automakers Who Have Approved E15 for Use in New Vehicles, www.ethanolrfa.org/2015/12/rfa-analysis-shows-uptick-in-number-of-automakers-who-have-approved-e15-for-use-in-new-vehicles/

[80] U.S. Department of Energy, 2017, *Alternative Fuels Data Center: Biodiesel.* www.afdc.energy.gov

[81] Pilot Flying J, 2017, *Fuel Prices*, available from www.pilotflyingj.com

[82] Minnesota Department of Agriculture, 2017, *About the Minnesota Biodiesel Program*, available from www.mda.state.mn.us

linearly to 10% averaged over the year. This assumption represents a situation where many refueling stations offer B20 when seasonally appropriate resulting in a 10% maximum average blend over the year.

Renewable gasoline and diesel

HDRD is theoretically interchangeable with petroleum-based diesel.[83] However, anecdotally, fuel providers operating under the British Columbia Renewable and Low-Carbon Fuel Regulation are limiting blends to 20%, and possibly up to 30%. The actual blend is not know because fuel suppliers do not have to report the blends they used, only total annual blended volumes. Unlike petroleum diesel, renewable diesel does not contain aromatics which cause elastomers seals to swell.[84] OEMs and fuel suppliers are concerned that using too much renewable diesel might cause seals in the fuel system to fail. To date, we are not aware of any such failures.

We use 40% by volume as an upper limit for HDRD blending based on this anecdotal evidence. We assume other sources of renewable gasoline and diesels are completely fungible with fossil-based gasoline and diesel. In practice, these assumptions have little impact on the model results; we observed no instances where these fuels approached even a 40% blend.

Existing biofuel production capacity in North America

Table 14 shows the existing biofuel production capacity by fuel type in 2017 included in the model. This capacity constrains production until after 2020, implying a three-year lead time to build new capacity. As such, the values in Table 14 include capacity that is idled, under construction, and proposed.[85]

Table 14: Biofuel production capacity in 2017 (1000 bbl/day)

	Sugar/Starch Ethanol	Cellulosic Ethanol	Biodiesel	HDRD
Canada	43	1	11	-
US	1098	18	222	14
Total	**1140**	**20**	**232**	**14**

[83] Neste Oil, 2017, *Neste MY Renewable Diesel,* www.neste.com/fi/en/neste-my-renewable-diesel

[84] NREL, 2016, *Renewable Diesel Fuel*, available from www.cleancities.energy.gov

[85] Biodiesel Magazine, 2017, *U.S. Biodiesel Plants,* available from www.biodieselmagazine.com; Ethanol Producer Magazine, 2017, *U.S. Ethanol* Plants, available from www.ethanolproducer.com

In the medium- and long-term, a potential market response to compliance with fuel regulations in Canada is to build new capacity. We assume that new biofuel capacity can be added if it is economic, where expected revenues exceed the investment and expected operating costs over the lifespan of the facility. Capacity can be added in any province or region in the model (e.g. the US) and exported to other regions.

Cost of blending capacity

Blending capacity is modeled as an additional cost to blending renewable fuels into gasoline and diesel fuel. Blending capacity is based on both the cost of the receiving terminal as well as the blending equipment. Costs related to the tanker cars are included in the cost for rail transport. The capital cost for blending capacity is $7,400 per barrel per day of capacity ($5,800 for the receiving terminal and $1,600 for the blending equipment). The quantity of blending capacity is not represented explicitly in the model; any resulting constraint is not represented in the near-term blending limits on biofuels, with the assumption that new blending capacity will be added if necessary.

Fuel pathways and carbon intensity of fuels

Table 15 shows the stationary fuel pathways covered by the CFS in this analysis and gives their CIs. The CIs are from the GHGenius 4.03a model. Note that electricity does not have a CI; that is a function of the fuels used to produce electricity. Zero-carbon electricity sources still have a CI, measured per unit of electricity generated. These CIs exclude GHG emissions associated with electricity distribution, but do include methane emissions (hydroelectricity) and fuel mining and transport (uranium). Coal is listed in the table, but those carbon intensities do not apply to coal used in existing power plants because they are excluded from the CFS and covered by another regulation in this analysis. For simplicity, we have given solid biomass a CI of 0 g/MJ, ignoring other non-CO_2 combustion GHG or avoided methane emissions. These fuels do emit methane and nitrous oxides when burned, which would put the CI in the range of 3 to 4 g/MJ. On the other hand, using these fuels may prevent them from decomposing anaerobicaly and producing even more methane.

Table 15: Lifecycle carbon intensities of transportation Fuels, g/MJ

Fuel	Upstream	Combustion	Total
Renewable natural gas (landfill, in pipeline)	2	-	2
Natural Gas (pipeline)	8	50	58
Sub-bituminous coal	6	92	98
Lignite coal	6	96	102
Coke	6	88	94

Fuel	Upstream	Combustion	Total
Fuel oil	15	73	88
LPG/Propane	15	61	76
Petroleum Coke	13	91	104
Still Gas/Refinery Fuel Gas (refining, upgrading only)	11	50	61
Spent pulping liquor (pulp and paper only)	-	-	-
Wood/hog fuel	-	-	-
Waste fuel (Cement sector only)	-	-	-
Hydroelectricity (per MJ of electricity generated)	10	-	10
Uranium (per MJ of electricity generated)	2	-	2
wind/solar (per MJ of electricity generated)	-	-	-

Table 16 shows the transportation fuel pathways covered by the CFS in this analysis and gives their CIs. The CIs are from the GHGenius 4.03a model and the biofuel CIs decline by 1% per year, consistent with the result of GHGenius. Indirect land-use change emissions are not included the biofuel CIs.

The CI assumption for some fuels is quite different from the default value in GHGenius. For example, that model gives the CI for pyrolysis derived fuels as -2 g/MJ. However based on an external review of our assumptions, we have judgementally set it at a 70% reduction relative to gasoline, or 27 g/MJ.

We also use a conservative value for the CI of cellulosic ethanol from corn stover. However, in this case it is the CI from GHGenius that is conservative, while many other estimates of the CI of cellulosic ethanol are lower.

The HDRD fuel pathways in this analysis include renewable diesel from canola and from palm oil. Currently, HDRD production in North America uses waste fats, but the canola-based HDRD pathway in this analysis approximates the GHG reduction potential of that pathway. This comparison can be inferred from the fuel CIs registered in the British Columbian Renewable and Low-carbon Fuel Regulation (RLCFR).[86] Those same policy records inform the palm-oil HDRD CI assumption. The CI of those fuels in the RLCFR is lower than expected, indicating that waste oils and fats are also part of the feedstock.

Electricity does not have a CI assumption. Instead, it is part of the data that is passed between the CIMS an OILTRANS models as they converge on a forecast solution. The

[86] British Columbia Ministry of Energy, Mines and Petroleum Resources, 2017, *Information Bulleting RLCF-012 Approved Carbon Intensities*, available from www.gov.bc.ca

credit value attributed to electrification of transport accounts for the energy efficiency associated with that fuel switch. Specifically, we use a factor of 3.4 (i.e. 3.4 MJ of gasoline or diesel displaced per MJ of electricity used), based on the value used in the British Columbian RLCFR.

Table 16: Lifecycle carbon intensities of transportation fuels, g/MJ, excluding indirect land-use change emissions. Carbon intensity is given for 2015, with biofuel values declining by 1%/yr

Fuel	Upstream	Combustion	Total
Gasoline	18	69	87
Diesel	22	72	94
Ethanol, corn, coal process heat	60	-	60
Ethanol, corn, natural gas process heat	46	-	46
Ethanol, wheat, natural gas process heat	42	-	42
Cellulosic ethanol, corn stover	46		46
Biodiesel, soy, coal process heat	14	-	14
Biodiesel, soy, natural gas process heat	10	-	10
Biodiesel, canola, natural gas process heat	5	-	5
HDRD, canola, natural gas process heat	18	-	18
HDRD, palm oil + waste fat, coal process heat	35	-	35
Pyrolysis derived renewable gasoline and diesel, wood waste	26	-	26
Natural Gas (LNG)	16	50	66

Energy Prices

Oil and gas commodity prices are taken from leading external forecasts. The price of oil is fundamental to defining the GHG abatement cost of alternative fuels vs. conventional fossil fuels. The natural gas commodity price defines the retail price of natural gas paid by stationary and transportation end-uses. The spread between the natural gas price and electricity and renewable natural gas (RNG) prices is an important driver to the CFS compliance cost for stationary energy consumption. Price assumptions and price inputs for crude oil, natural gas, RNG and electricity are explained below. Drivers of liquid biofuel prices are discussed later in the document.

Price of oil

The price for oil can influence the supply of biofuel available to Canada since higher oil prices may lead to biofuel blending over and above what policies require. Similarly, the current low oil price may reduce discretionary blending, leaving un-used biofuel production capacity.

The oil price forecast used in this analysis is based on the more recent US Energy Information Agency (EIA) 2017 Annual Energy Outlook.[87] The reference oil price assumption in this analysis is the EIA reference forecast and rises to $96 per barrel (2016 USD) by 2035 (Table 17). Retail petroleum production prices are simulated in OILTRANS as a function of the commodity price, exchange rates, returns to capital for refineries, refinery operating costs, distribution and marketing costs and fuel taxes.

Table 17: West Texas Intermediate oil price forecast (2016 USD per barrel)

	2015	2020	2025	2030
Reference (EIA ref)	49	69	80	88

Price of natural Gas

We used the National Energy Board's 2016 assumption for the benchmark wholesale price of natural gas (Table 18).[88] Retail natural gas prices by sector and province are from the same source.

Table 18: Benchmark natural gas price assumption

	2015	2020	2025	2030
EIA at Henry Hub (2010 USD/mmBtu)	2.9	3.85	4.1	4.25
Value in 2015 CAD used, $/GJ	3.87	5.02	5.39	5.54

Price of renewable natural gas

The Canadian Gas Association estimates that there is a supply of 1,500 PJ of RNG that can be produced at cost between $8 and $20/GJ.[89] Based on the quantity of RNG consumed in early iterations of this analysis, we used 15 $/GJ for the wholesale RNG price. We used the difference between the wholesale natural gas and RNG prices to define retail RNG based on the National Energy Board retail natural gas prices.

[87] Energy Information Agency, 2016, *Annual Energy Outlook 2016*, available from www.eia.gov

[88] National Energy Board of Canada, 2016, Canada's Energy Future 2016: Energy Supply and Demand Projections to 2040

[89] Canadian Gas Association, 2014, *Renewable Natural Gas Technology Roadmap for Canada*, available from www.cga.ca

Price of electricity

Retail electricity prices by sector and province from the National Energy Board 2016 reference scenario.[90]

Exchange rates

The exchange rate between Canada and the United States will affects the price for conventional fuels and biofuels in OILTRANS, and hence the incentive to deliver biofuels to different markets in North America. Note that for stationary energy consumption, which is modelled with CIMS, we do not simulate energy trade, so the exchange rate assumption has no impact.

Several major banks have provided recent forecasts for 2017 and 2018, shown in Table 19.[91] The average exchange rate forecast for 2018 shown in Table 19 provide the reference value used in this analysis: 0.75 USD/CAD to 2030.

Table 19: Exchange rate forecasts (CDN per USD)

	2017	2018
BMO Capital Markets Economics	0.75	0.77
CIBC World Markets Inc.	0.75	0.72
National Bank	0.74	0.74
TD Bank	0.74	0.76

Biofuel cost of production

The cost of production for biofuels determines the price that producers require to maintain or increase production. These costs can be affected by the cost of feedstocks, energy costs (e.g., the price for natural gas), other operating costs (e.g. labour), and the value of co-products such as distillers grains (DDGS) and glycerin. Table 20 summarizes these parameters for each biofuel production archetype in the analysis. Public data describing production costs is sparse. We have pulled data from the best available public sources, but there is still uncertainty in the inputs. For emerging pathways such as pyrolysis derived renewable diesel and gasoline (PDRD and PDRG respectively) and to some extent cellulosic ethanol, the costs are

[90] National Energy Board of Canada, 2016, Canada's Energy Future 2016: Energy Supply and Demand Projections to 2040

[91] BMO Capital Markets, 2017, *Canadian economic outlook*, available from www.economics.bmocapitalmarkets.com*; CIBC World Markets Inc., January 2017, Forecast summary*, available from www.cibcwm.com; National Bank, January 2017, *FOREX*, available from www.nbc.ca; TD Economics, March 2017, *Quarterly economic forecast*, available from www.td.com

representative of expected production costs once they are commercialized. In other words, the assumptions do not account for the additional costs associated with building a first-of-a-kind plant. A technological optimism factor of +50% capital cost is applied to the pyrolysis derived fuels to represent the additional costs, or the reduced capacity utilization, that might occur when commercializing a new fuel.

For simplicity we have excluded some fuel pathways from the table (e.g. ethanol using coal for process heat), but these pathways have analogous inputs.

Table 20: Biofuel production cost assumptions (2010 USD)

	Cellulosic ethanol [a]	PDRD, PDRG [b]	Sugarcane ethanol [c]	Corn ethanol	Wheat Ethanol	Canola biodiesel	Soy biodiesel	Canola HDRD [d]
Capital cost, $/bbl/day capacity	$82,376	$260,960	$48,158	$40,409	$40,409	$34,836	$34,836	$36,000
Feedstock	Corn Stover	Wood residue	Sugarcane	Corn	Wheat	Canola oil	Soy oil	Canola oil
Feedstock inputs, t/bbl	0.55	0.46	1.87	0.39	0.37	0.15	0.15	0.15
Natural gas input (heat, H_2), GJ/bbl		0.42		2.35	2.35	0.28	0.28	4.20
Other operating cost, $/bbl	$36	$37	$4	$18	$18	$13	$13	$6
Co-products:								
DDSG, t/bbl				0.12	0.12			
Glycerine, t/bbl						0.01	0.01	
Electricity export, MWh/bbl	0.15							
Feedstock price, $/t [e]	$66	$86	$26	$132	$149	$822	$721	$822
Co-product price, $/t [f]				$106	$106	$336	$336	
Source	Chovau et al., 2013[92]	Jones et al., 2013[93]	Junqueira et al., 2017[94]	IRENA, 2013[95]	IRENA, 2013	IRENA, 2013	IRENA, 2013	Eco-Ressources, 2012[96]

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92 Chovau, Degrauwe, Van der Bruggen. 2013. Critical analysis of techno-economic estimates for the production cost of lignocellulosic bio-ethanol. Renewable and Sustainable Energy Reviews 26, 307-321.

93 Jones, Meyer, Snowden-Swan, Tan, Dutta, Jacobsen, Cafferty, 2013. Process Design and Economics for the Conversion of Lignocellulosic Biomass to Hydrocarbon Fuels: Fast-Pyrolysis and Hydrotreating Pathway. National Renewable Energy Laboratory, Pacific Northwest National Laboratory, Idaho National Laboratory.

94 Junqueira et al., 2017. Techno-economic analysis and climate change impacts of sugarcane biorefineries considering different time horizons, Biotechnology for Biofuels, 10:50

95 International Renewable Energy Agency (IRENA), 2013, Road Transport: the Cost of Renewable Solutions.

a) The cost archetype uses lignin remaining from the process to generate steam and excess electricity

b) PDRG and PDRD are pyrolysis derived renewable diesel and gasoline, produced in a roughly 1:1 ratio. The capital cost is 50% higher than the value in the cited source

c) The cost archetype uses sugarcane residue (bagasse) to generate steam and electricity

d) A standalone hydrogenation derived renewable diesel plant, not integrated with a petroleum refinery

e) These are our reference feedstock price assumptions, actual prices may vary during the forecast

f) The DDSG price in 80% of the corn price. The glycerine price is based on IRENA (2013)

Table 21 compares the production costs in $/L produced resulting from the assumptions in Table 20. Production costs assume the price of natural gas is 5 $/GJ and the price of electricity is 60 $/MWh. Capital costs are amortized assuming a 30 year plant life, a 10% discount rate and 95% capacity utilization. Again, the capital cost for pyrolysis derived fuel shown in the table has been increased by 50% to account for the difficulties of commercializing a new fuel.

Table 21: Biofuel costs, $/L product (2010 USD)

	Cellulosic ethanol	PDRD, PDRG	Sugarcane ethanol	Corn ethanol	Wheat Ethanol	Canola biodiesel	Soy biodiesel	Canola HDRD
capital cost	$0.16	$0.50	$0.09	$0.08	$0.08	$0.07	$0.07	$0.07
Feedstock cost	$0.23	$0.25	$0.30	$0.32	$0.35	$0.76	$0.66	$0.76
Natural gas cost	-	$0.01	-	$0.07	$0.07	$0.01	$0.01	$0.13
Operating cost	$0.23	$0.23	$0.03	$0.11	$0.11	$0.08	$0.08	$0.04
Net-co-product/ electricity value	-$0.06	-	-	-$0.08	-$0.08	-$0.03	-$0.03	-
Total $/L	**$0.56**	**$1.00**	**$0.42**	**$0.50**	**$0.53**	**$0.88**	**$0.79**	**$1.00**

Octane Value of Ethanol

When ethanol is added to a petroleum gasoline blendstock, it raises the octane rating of the blend. The octane of gasoline can also be increased at the refinery, but this reduces the gasoline yield and incurs additional operating costs. Therefore octane has a value that can be attributed to additives that raise the octane.

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[96] EcoRessources Consultants, 2012, "Study of Hydrogenation Derived Renewable Diesel as a Renewable Fuel Option in North America – Final Report", Natural Resources Canada (NRCAN).

We assume the octane value of ethanol results in a net reduction in the cost the ethanol blended with gasoline. The octane value is based on the following method:

- The value per point of octane is based on the difference between regular (octane 87) and mid-grade gasoline (octane 89) wholesale prices, using historic fuel cost data published by Natural Resources Canada.[97] The price difference is divided by the octane difference to get the value per octane point per liter.
- We assume, conservatively, that ethanol has octane value of 100[98] and that the blended fuel has an octane rating of 87 (regular gasoline). The difference between the two is 13.
- The value per octane point per L is multiplied by the difference between the octane of ethanol and the octane of regular gasoline to give the octane value per L of ethanol.

Based on the above method, we give ethanol a fixed octane value of 0.22 $/L. This is, typical of Canadian markets, and corresponds to a value per octane point of 0.0165 $/L.

We assume this octane value reduces the cost of the gasoline it is blended with. With these assumptions, a 10% ethanol blend reduces gasoline cost by 2.2 cent/L. In reality, this octane value of ethanol may not be captured in all cases. If it is not, the corollary is that a higher octane gasoline blend (e.g. octane 88 when ethanol is 10% by volume), is being sold at the price of regular gasoline.

The octane value of ethanol could be further refined. For example, assuming the octane rating of ethanol in 100 is conservative. In low concentration blends, it may be as high as 115.[99] On the other hand, the spread in regular and premium gasoline prices in Canada is reported to be somewhat artificial and higher than the true production cost difference. However, both of these changes tend to cancel each other out and would lead to little difference in the modelled results.

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97 Natural Resources Canada,2017, *Transportation Fuel Prices*, available from www.nrcan.gc.ca

98 EIA, 2013, *Price spread between regular and premium gasoline has changed over time*, available from www.eia.gov

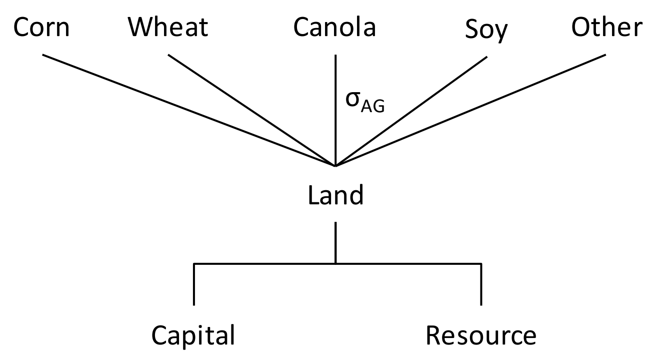
99 113 to 115 is a typical value for blends cited by EIA https://www.eia.gov/todayinenergy/detail.php?id=11131. This value corresponds to ethanol used in low concentration blends.

Feedstock cost

The version of OILTRANS used for this analysis has an explicit representation of agricultural production. The agriculture sector in OILTRANS produces 4 commodities: 1) corn, 2) soy, 3) wheat and 4) canola. The sector can expand overall production and substitute the production of one feedstock for another. However, the ability to alter agricultural production is constrained by an elasticity of transformation (i.e., the ease of substituting the production of one feedstock for another).

The structure for agricultural production is shown in Figure 30. The elasticity of transformation (σ_{AG}) recommended for the agricultural land sector is -1.5[100].

Figure 30: Schematic of the Agricultural Land sector



Agricultural production has been calibrated such that the reference case scenario under current policies aligns with the following feedstock prices (see Table 22).

Table 22: Biofuel feedstock cost assumptions, 2010 USD/tonne

	Ref
Corn	132
Wheat	149
Canola Oil	822
Soy Oil	721
Corn Stover	65
Wood Waste	86

[100] Choi S. 2004. "The Potential and Cost of Carbon Sequestration in Agricultural Soil: An Empirical Study with a Dynamic Model for the Midwestern U.S." Department of Agricultural, Environmental, and Development Economics, Ohio State University.

Reference prices based on www.indexmundi.com/commodities/

Transportation margins for all fuels

The cost, and therefore price, of biofuels in a specific region is based on the cost of delivering biofuels to that region. If biofuels, or any other fuel, are exported to various regions in Canada, the price will include both the cost of production as well as the cost of transport. The Canadian Fuels Association has indicated that ethanol cannot be shipped in multi-product pipelines; therefore it must be transported by boat, rail, or truck and blended at the point of consumption. Implicitly, we are assuming there are no biofuel specific pipelines built.

Rail is by far the most commonly used biofuel transport mode in the model and the most significant to the results. The cost of transporting biofuels by rail is inferred from the cost of transporting oil by rail from the EIA.[101] Table 23 shows this cost for transporting fuel, using rail costs to Ontario from two possible points of origin as an example. Marine and truck transport costs are available on request. As with rail, both take into account the point of origin and destination in determining the transportation cost.

Table 23: Cost of transporting biofuels to Ontario (2017 CDN)

	From Western Canada (Vancouver)	From US (Chicago)
km	4085	551
$/km/bbl	0.006	0.006
$/bbl	23.5	3.2

[101] Energy Information Administration, 2012, "Rail deliveries of oil and petroleum products up 38% in first half of 2012", available from www.eia.gov., accessed June 2015.

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