CANADIAN ENERGY RESEARCH INSTITUTE

Study No. 179
May 2019

CANADIAN
ENERGY
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ECONOMIC AND EMISSIONS IMPACTS OF FUEL DECARBONIZATION

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Economic and Emissions Impacts of Fuel Decarbonization

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ISBN 1-927037-64-5

May 2019
Printed in Canada

Front cover photo courtesy of Google images

Acknowledgements:
The authors of this report would like to extend their thanks and sincere gratitude to all peer reviewers representing governments, industry associations and consulting firms that provided insightful comments and essential data inputs required for the completion of this report, as well as those involved in the production, review and editing of the material, including but not limited to Allan Fogwill and Megan Murphy.

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Table of Contents

List of Figures

List of Tables

Acronyms and Abbreviations

AB 32	Assembly Bill 32 "California Global Warming Solutions Act"
AECO/AECO-C	Alberta Energy Company and Canadian benchmark price for natural gas
AEZ-EF	Agro-Ecological Zone Emissions Factor
BAU	Business as Usual
BC	British Columbia
BEV	Battery Electric Vehicle
BIOGRACE	Biofuel Greenhouse gas emissions: Align Calculations in Europe
CAD$	Canadian dollar
CAFE	Corporate Average Fuel Economy
CA-GREET	California Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation
CARB	California Air Resources Board
CARBOB	California Reformulated Gasoline Blendstock for Oxygenate Blending
CERI	Canadian Energy Research Institute
CFS	Clean Fuel Standard
CH4	Methane
CI	Carbon Intensity
CNG	Compressed Natural Gas
CO2eq/ CO2	Carbon Dioxide Equivalent/Carbon Dioxide
ECCC	Environment Canada and Climate Change
EER	Energy Economy Ratio
EPA	Environmental Protection Agency
ERT	Emission Reduction Target
eTRU	Electric Trailer Refrigeration unit
EU	European Union
EV	Electric Vehicle
FQD	Fuel Quality Directive
FT Diesel	Fischer-Tropsch diesel
gCO2eq	Grams of Carbon Dioxide Equivalent
GDP	Gross Domestic Product
GHG	Greenhouse Gas(es)
GHGenius	Greenhouse Gas Life cycle analysis model of fuels
GJ	Gigajoule
GTAP	Global Trade Analysis Project
HDRD	Hydrogenation-Derived Renewable Diesel
ICE	Internal Combustion Engine
ICEV	Internal Combustion Engine Vehicle
IO	Input-Output
IPCC	Intergovernmental Panel on Climate Change
LCA	Life Cycle Assessment
LCFS	Low Carbon Fuel Standard

LNG	Liquified Natural Gas
LPG	Liquified Petroleum Gas
MJ	Megajoule
MT/Mt	Million Tonnes (metric)
N2O	Nitrogen Oxide
NEB	National Energy Board
NHTSA	National Highway Traffic Safety Administration
NOx	Nitrogen Dioxide and Nitric Oxide
NRCan	Natural Resources Canada
OPGEE	Oil Production Greenhouse Gas Emissions Estimator
PHEV	Plug-in Hybrid Electric Vehicle
PJ	Petajoule
Pkm	Passenger-kilometres
RED	Renewable Energy Directive
RFS	Renewable Fuel Standard
SHS	Survey of Household Spending
US	United States

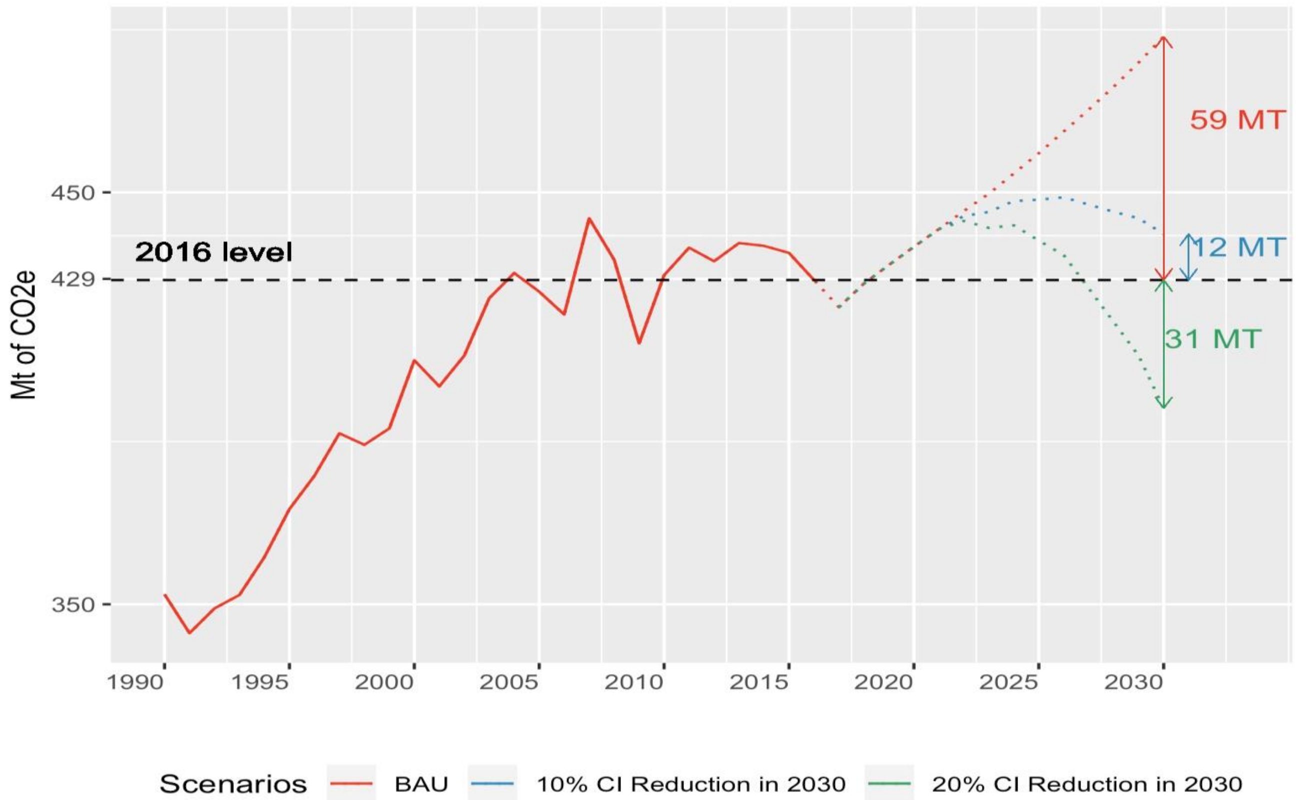
Executive Summary

Fuel decarbonization, also referred to as a low-carbon fuel standard, is a policy or regulation to reduce carbon-intensity (CI) usually in transportation fuels as compared to conventional petroleum fuels, such as gasoline and diesel. The most common low-carbon fuels are alternative fuels – which in the transportation sector include biofuels, propane, hydrogen, and electric vehicle charging and cleaner fossil fuels, such as natural gas. Traditionally, the main objective of fuel decarbonization is to decrease carbon dioxide emissions associated with vehicles powered by various types of internal combustion engines while considering the entire life cycle ("well to wheels") carbon footprint of transportation.

This project evaluates the potential greenhouse gas (GHG) emissions reduction of fuel decarbonization scenarios and their overall economic cost. The analysis takes into consideration the proposed Clean Fuel Standard of the federal government and explores two scenarios to reduce the carbon intensity of gaseous, liquid, and solid fuels against the Business as Usual (BAU) scenario. The study assesses how these three fuel types affect the industrial (including agriculture), transportation and building sectors.

Figure E.1 shows total emission reductions as compared to the 2016 emission level under alternative carbon intensity reduction scenarios. 2016 was chosen as it reflects the most recent year of detailed emissions data available. As shown in the Figure, scenarios that reduce carbon intensity by 10% will result in annual avoided emissions in the year 2030 of 47 million tonnes (MT) below Business as Usual but still 12 MT above the 2016 emission level. Under a 20% carbon intensity reduction scenario, emissions decrease by 31 MT below 2016 level. The largest emission reductions can be realized in the industrial and transportation sectors.

Figure E.1: Total Emissions – Canada (MT of CO2e)



Source: Historical data comes from Table 1 in Residential Sector, Table 1 in Commercial Sector, Table 3 in Industrial Sector, Table 2 in Agriculture sector, and Table 4 in Transportation Sector from the Comprehensive Energy Use Database from NRCan (2018a). The forecast is from CERI.

In 2030, the total cost impacts to the Canadian economy are estimated to be about $7.6 billion annually in a scenario with a 10% carbon intensity reduction and approximately $15 billion for a 20% carbon intensity as compared to the BAU with no carbon-intensity reduction. This is shown in Table E.1. The largest impact will be felt in industry, followed by transportation, buildings and agriculture (Figure E.2).

Carbon pricing stimulates market forces for finding the lowest-cost options to reduce emissions. Standards on fuels' carbon intensity are less flexible than carbon pricing and hence could be less cost-effective. The findings of this report show that the costs of fuel decarbonization would be between $163 (in the case of 10% CI reduction) and $170 (in the case of 20% CI reduction)[1] per tonne of GHG emissions, while federal carbon pricing reaches emission reductions by $50 per tonne. Although fuel standards are less cost-effective than carbon pricing, these standards are complimentary to carbon pricing to reduce emissions, since carbon pricing does not cover all sources of emissions, such as, for example, fugitive methane emissions.

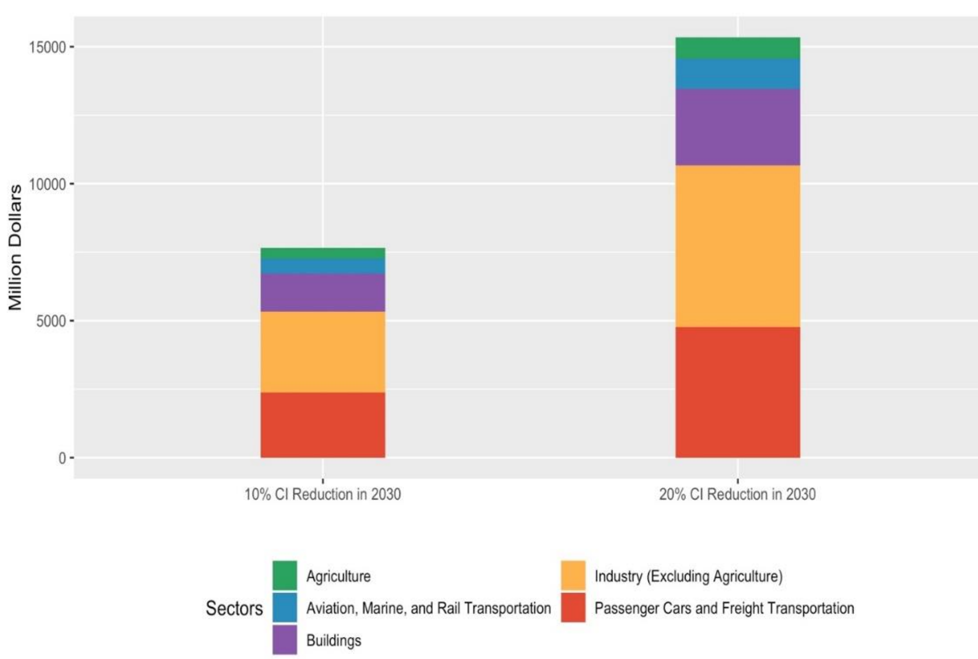
[1] The cost per tonne of GHG emissions is calculated by dividing the total cost of fuel decarbonization in each scenario by total emission reductions.

Table E.1: CFS Total Cost Impacts, $200 Credit Price

Carbon Intensity Reduction / Sector	Household (buildings)	Industry (including agriculture)	Passenger Cars and Light Trucks	Freight Trucks	Rail, Aviation, Marine	Total, Annually 2030 and After
	Additional Fuel Costs per Sector					
10% CI reduction	$42 per household or 2% increase in fuel cost	6% increase in fuel cost	$31 per vehicle or 1.4% increase in fuel cost	$150 per vehicle	-	-
20% CI reduction	$84 per household or 4% increase in fuel cost	13% increase in fuel cost	$62 per vehicle or 2.8% increase in fuel cost	$300 per vehicle	-	-
	Total Annual Cost Increase per Sector (million $CAD)					
10% CI reduction	$1,395	$3,322	$1,149	$1,237	$553	$7,656
20% CI reduction	$2,791	$6,645	$2,299	$2,475	$1,109	$15,319

Source: CERI

Figure E.2: Fuel Decarbonization Total Cost Impacts



Source: CERI

Retail prices for diesel and gasoline by 2030 with a maximum $200 credit price are expected to be between 5-6 cents per litre with 10% CI reduction target, and 10-11 cents with 20% CI reduction.

A $200 credit price will bring additional costs ranging from $0.94 per GJ (10% CI reduction) to $1.88 per GJ (20% CI reduction) in 2030 for gaseous fuels, which include natural gas, landfill and waste gases, still gas,[2] and coke oven gas. The largest impact is to be expected in the industry and building sectors. Natural gas is a large source of energy for buildings (46% of total consumption in 2016) and industry (40% of total consumption in 2016) with substantial existing supply infrastructure and limited opportunities to switch fuel without additional investments.

The impact on solids is expected to be the most significant as the starting intensities are higher relative to other fuels and the reduction is steeper in absolute terms. A $200 credit price will bring additional costs ranging from $1.76 per GJ (10% CI reduction) to $3.51 per GJ (20% CI reduction) in 2030. The fuels included here are coal, petroleum coke, and biomass. Solids play a significant role in steel manufacturing (47% of total solids consumption in the economy), electricity generation (41%), and cement manufacturing (4%).[3]

[2] Any form or mixture of gases produced in refineries by distillation, cracking, reforming, and other processes.
[3] Only domestic consumption is used. Exports are not included.

Chapter 1: Introduction

Fuel decarbonization, also referred to as a low-carbon fuel standard, is a policy or regulation to reduce carbon-intensity (CI) usually in transportation fuels as compared to conventional petroleum fuels, such as gasoline and diesel. The most common low-carbon fuels are alternative fuels – which in the transportation sector include biofuels, propane, hydrogen, and electric vehicle charging and cleaner fossil fuels, such as natural gas. Traditionally, the main objective of fuel decarbonization is to decrease carbon dioxide emissions associated with vehicles powered by various types of internal combustion engines while considering the entire life cycle ("well to wheels") carbon footprint of transportation.

The first ever low carbon fuel mandate in the world was initiated in California in 2007, with specific eligibility criteria defined by the California Air Resources Board (CARB) in 2009 and taking effect in 2011. Similar legislation was approved in British Columbia in April 2008 (adopted in 2011), and by the European Union which proposed its legislation in 2007 and was adopted in 2009. The state of Oregon also passed its legislation on a low-carbon fuel standard in 2015, taking effect in 2016. Several bills have been proposed in the United States for similar fuel decarbonization nationally but with less stringent standards than California. As of now, none have been approved. The US Environmental Protection Agency (EPA) issued its final rule regarding the expanded Renewable Fuel Standard (RFS2) for 2010 and beyond on February 3, 2010.

The Government of Canada will be implementing Clean Fuel Standard (CFS) Regulations under the Canadian Environmental Protection Act, 1999 to reduce Canada's greenhouse gas (GHG) emissions. The stated objective of the policy is to achieve 30 megatonnes of annual reductions in GHG emissions by 2030, contributing to Canada's effort to achieve its overall GHG mitigation target of 30% emission reduction below 2005 levels by 2030 (ECCC 2018). The CFS will establish lifecycle carbon intensity requirements separately for liquid, gaseous and solid fuels that are used in transportation, industry and buildings. This is the first policy in the world that will cover such a wide array of fuels; others have primarily focused on liquid transportation fuels. The goal is to have a performance-based approach that would incent innovation, development and use of a broad range of low carbon fuels, energy sources and technologies.

The Canadian Energy Research Institute (CERI) conducted this assessment to consider the broad options for fuel decarbonization that exist, and how those might impact Canada. The analysis considers the host of policies that have been implemented internationally as well as the proposed CFS regulations of the federal government. The analysis is based on two scenarios to reduce the carbon intensity by 10% and 20% for gaseous, liquid, and solid fuels against the Business as Usual (BAU) scenario. The study assessed how these three fuel types affect the industrial (including agriculture), transportation and building sectors.

Below is a summary of three jurisdictions for which some form of fuel decarbonization currently exists: California, the European Union, and British Columbia. The following section describes the proposed federal Clean Fuel Standard regulations.

California Fuel Decarbonization

California adopted its Low Carbon Fuel Standard (LCFS or Standard) in 2009. The executive action in 2007 targeted the high contribution of the transportation sector to GHG emissions – 40% of total emissions. The other concern was NOx emissions from the transportation sector (80%), and particulate matter (PM) emissions (95%) (CARB 2016).

The Standard aimed to reduce the carbon intensity of fuels by 10% by 2020 from a 2010 baseline. The standard regulation was confined to only transportation liquid fuels. A declining maximum carbon intensity limit for each year from 2011 to 2020 was stipulated to ensure gradual compliance. Implementation began on January 1, 2011.

Since the adoption, LCFS has been an evolving policy which ensured its flexibility and openness to meet stakeholder's concerns. It was changed in 2011, 2015, and in late 2018-early 2019. These changes are discussed in more detail later in this Chapter.

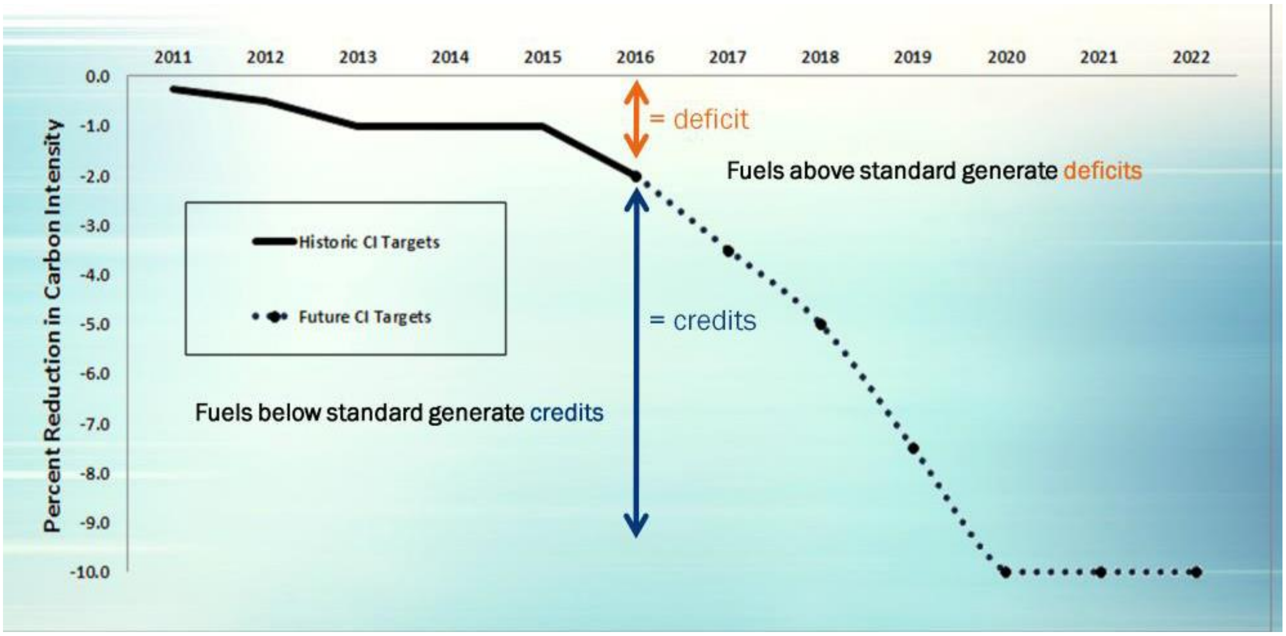
California had a recognized problem with air quality, which provoked the establishment of the California Air Resources Board (CARB), which oversees the Standard. LCFS is one of the key pillars to reduce CO2 emissions in California under Assembly Bill 32 (California Global Warming Solutions Act), passed in 2006. LCFS is aimed to compliment nine other measures of Assembly Bill 32 to "transform and diversify fuel pool, reduce petroleum dependency, and reduce emissions of other air pollutants"(CARB 2016).

The Standard's framework consists of several major elements: the establishment of carbon intensities (CIs) for fuels, declining targets for fuels from 2010 to 2020, and a cap-and-trade system which allows free-market trade of credits. It is a part of a set of programs in the state to reduce GHG emissions including the Advanced Clean Car Program, SB 375 and Cap and Trade Program.

Carbon intensity in California is measured in grams of CO2e emissions equivalent per megajoule of energy provided by that fuel (gCO2e/MJ). CI considers full-cycle emissions associated with producing, transporting, refining and consuming of fuels, including indirect land use (ILUC). To establish the CI, the CARB suggests producers use an approved tool and apply. After the application has been approved, the CI of the fuel is sealed until the next approval.

The standard is fuel-neutral, which means that the government does not prescribe which fuel or mix of fuels to be used (CARB 2016). It is up to providers of fuel to figure out how to comply with the required intensities. The declining reduction curve is presented in Figure 1.1.

Figure 1.1: Declining Carbon Intensity Curve



Source: (CARB 2016)

Fuels that have an intensity below the Standard for a particular year generate credits; if the intensity is higher than the regulation, the fuel generates deficits. The curve was intentionally backloaded to allow for companies to adapt – for the first 8 years the target intensity decreased by 5%. "Due to this program design choice, there has always been the expectation that excess credits generated in the early years of the program would be available for use in more stringent future years" (CARB 2016).

Expectedly, gasoline and diesel fuels intensities are higher than the target and have forced providers to buy credits. Conversely, providers of ethanol, biodiesel, and renewable diesel generate credits. Historically, LCFS primarily affected producers of petroleum and biofuels, or importers if the origin of the fuel is out of state.

All fuel producers and importers are regulated parties. There are exceptions to this rule, however. The providers of fuel, whose intensity is already below the 2020 target are exempt but can opt in the program and earn credits (e.g., electricity, hydrogen, natural gas and biogas providers).

The average target CIs for two major types of transportation fuels are provided in Table 1.1. The 2019 version (and previous revisions) of the Standard increased target intensities for 2020. Interestingly, this increase was caused by the CARB changing the 2010 baselines. For instance, for gasoline, the baseline was changed from 95.85 g/MJ to the latest revision of 100.45 g/MJ. After this change, the 2020 target requires only a 7.5% reduction from 2010, while 2030 targets a 20% reduction.

Table 1.1: Target Carbon Intensities for Gasoline and Diesel

	Diesel and Fuels Used as Substitutes	Gasoline and Fuels Used as Substitutes
Year	**Average CI (gCO2e/MJ)**	**Average CI (gCO2e/MJ)**
2010 baseline	100.45 (90.46 original)	99.44 (95.85 original)
2011	94.47	95.61
2012	94.24	95.37
2013	97.05	97.96
2014	97.05	97.96
2015	97.05	97.96
2016	99.97	96.50
2017	98.44	95.02
2018	96.91	93.55
2019	94.17	93.23
2020	92.92 (85.24 – original target of 2009)	91.98 (86.27 original target of 2009)
2021	91.66	90.74
2022	90.41	89.50
2023	89.15	88.25
2024	87.89	87.01
2025	86.64	85.77
2026	85.38	84.52
2027	84.13	83.28
2028	82.87	82.04
2029	81.62	80.80
2030 and subsequent years	80.36	79.55

Source: (CARB 2019)

To calculate lifecycle emissions per fuel, California requires stakeholders to use four tools:

- California Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (CA-GREET) – a direct intensity of fuel production and use
- Oil Production Greenhouse Gas Emissions Estimator (OPGEE) models to calculate direct carbon intensity of crude production and transport to a refinery
- Global Trade Analysis Project (GTAP) – indirect land use
- An Agro-Ecological Zone Emissions Factor (AEZ-EF) model was created to supplement GTAP's estimates of greenhouse gas emissions from various types of land conversions – supports GTAP in indirect land use assessments.

While each fuel has its CI (absolute number of emissions), the Board also operates with a relative number – an EER-adjusted CI or Energy Economy Ratio-adjusted CI. “The alternative fuel's CI value is divided by its Energy Economy Ratio (EER) in order to obtain the EER-adjusted CI value, representing the emissions which occur from the use of alternative fuel per MJ of conventional fuel displaced” (CARB Website). ERR values are provided in Table 1.2 (CARB 2019b).

Table 1.2: EER Values for Fuels Used in Light- and Medium- and Heavy-Duty Applications

Light/Medium-Duty Applications (Fuels used as gasoline replacement)		*Heavy-Duty/Off-Road Applications (Fuels used as diesel replacement)*		*Aviation Applications (Fuels used as jet fuel replacement)*	
Fuel/Vehicle Combination	*EER Values Relative to Gasoline*	*Fuel/Vehicle Combination*	*EER Values Relative to Diesel*	*Fuel/Vehicle Combination*	*EER Values Relative to Conven-tional Jet*
Gasoline (incl. E6 and E10) Or E85 (and other ethanol blends)	1	Diesel fuel Or Biomass-based diesel blends	1	Alternative Jet Fuel	1
CNG/ICEV	1	CNG or LNG (Spark-Ignition Engines)	0.9		
		CNG or LNG (Compression-Ignition Engines)	1		
		Electricity/BEV or PHEV* Truck or Bus	5.0		
Electricity/BEV, or PHEV	3.4	Electricity/Fixed Guideway, Heavy Rail	4.6		
		Electricity/Fixed Guideway, Light Rail	3.3		
On-Road Electric Motorcycle	4.4	Electricity/Trolley Bus, Cable Car, Street Car	3.1		
		Electricity Forklifts	3.8		
		eTRU	3.4		
		eCHE	2.7		
		eOGV	2.6		
H2/FCV	2.5	H2/FCV	1.9		
		H2 Fuel Cell Forklifts	2.1		
Propane	1.0	Propane	0.9		

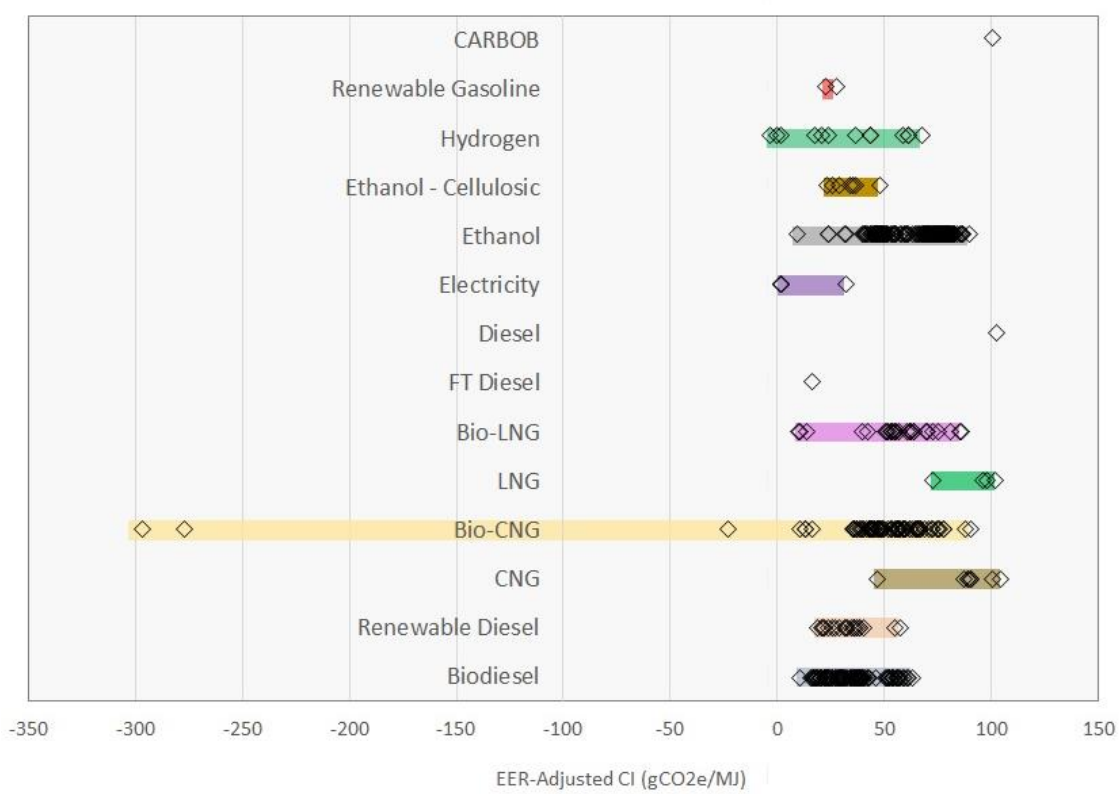
Source: (CARB 2019)

For instance, one of the hydrogen pathways is 117.67 gCO2e/MJ (absolute value), which is higher than the gasoline baseline. However, after dividing by the EER to account for the efficiency of the fuel cell vehicle, the EER-adjusted CI is (117.67/2.5) = 47.07, reflecting the life cycle GHG emission reduction benefits of the fuel. This approach allows the accommodation of different fuel-vehicle efficiencies.

The EER-adjusted CI accounts for the efficiency of different engines. 1 MJ of hydrogen produces more emissions than 1 MJ of gasoline, but the fuel cell engine uses less energy per km travelled than an ICE engine. Thus, the ERR-adjusted CI value results in fairer comparison of fuels regarding their emissions per the same amount of output, not per amount of energy.

Each marker in Figure 1.2 represents an individual certified fuel pathway carbon intensity, adjusted by the Energy Economy Ratio. The length of each bar indicates the range of carbon intensity that may be achieved by a fuel pathway. The wide range of carbon intensities is due to the lifecycle emissions methodology of the LCFS, variations in feedstock types, origin, raw material production processing efficiencies, and transportation which all contribute to an individual producer's fuel pathway CI. (CARB Website).[1]

Figure 1.2: ERR-CI Values of Certified Pathways (2018)



Source: (CARB 2016). Note: CARBOB - California Reformulated Gasoline Blendstock for Oxygenate Blending

[1] https://www.arb.ca.gov/fuels/lcfs/fuelpathways/pathwaytable.htm

The Standard includes interesting features which add flexibility and increase acceptance.

First, as it was mentioned, there are fossil fuels and industries which are exempt for various reasons. For instance, military equipment or vehicles crossing the border or fuels with intensities below the 2020 target (or 2030 target since 2019).

Second, there is a credit price cap of US$200 which provides consumer protection. This, according to CARB, “protects consumers, provides certainty regarding the maximum costs of compliance, and prevents extreme market volatility”.

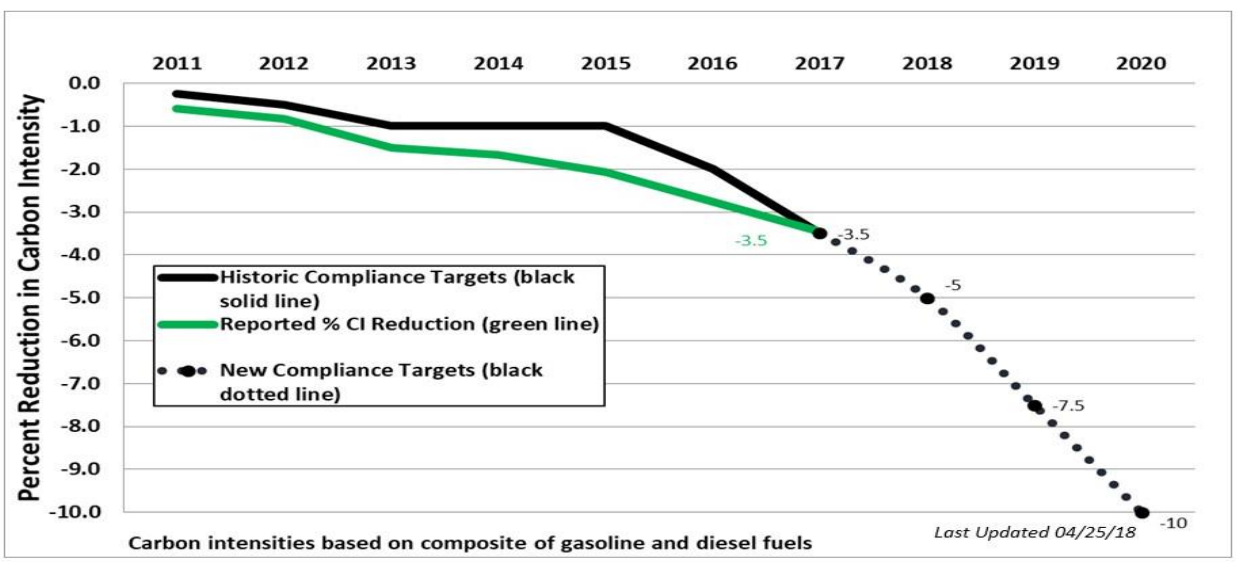
Third, there are additional credit opportunities. For instance, a refinery can get credits if it is going to use renewable hydrogen while producing gasoline or diesel. To get credits, it must replace at least 1% of fossil hydrogen used in production. Another way of getting credits for refineries is to invest in GHG reduction projects which would achieve at least 0.1 gCO2e/MJ reduction.

“The innovative crude credit provision support innovative technologies for solar steam or heat generation, solar- or wind-based electricity, and carbon capture and storage” (CARB 2016). LCFS also contains hydrogen and electricity provisions.

Results and Impacts

The Standard showed a mixed performance in curbing GHG emissions since 2010. On an intensity basis, the parties in aggregate have over-complied with the LCFS. The CI has decreased by 3.5% from 2010 to 2017 as shown in Figure 1.3.

Figure 1.3: Performance of LCFS in California, 2011-2017



This figure shows the percent reduction in the carbon intensity (CI) of California's transportation fuel pool. The LCFS target is to achieve a 10% reduction by 2020 by setting a declining annual target, or compliance standard. The compliance standard was frozen at 1% reduction from 2013-2015 due to legal challenges, contributing to a build-up of banked credits as regulated parties bringing new alternative fuels to market continued to over-comply with the standard. The program will continue post 2020 at a to be determined stringency.

Source: (CARB 2019a)

However, from the total emissions standpoint, the intended result was not achieved. Transportation emissions from all types of transport increased by 3.1% from 2010 to 2016 for all non-exempt subsectors as shown in Table 1.3.[2]

The transportation sector remains the largest contributor to GHG emissions of the state at 41%, followed by industry at 23% and electricity generation with 10%. CARB suggests that while the intensity policy coupled with better fuel efficiency was effective, a number of factors contributed to the overall increase of the absolute emissions. These include population growth, lower fuel prices, improved economic conditions, and higher overall employment.

Table 1.3: Emissions from Transportation in California

Sector	2009	2010	2011	2012	2013	2014	2015	2016
Transportation	*175.5*	*170.2*	*166.5*	*166.2*	*165.8*	*167.1*	*170.9*	*174.0*
Aviation	4.0	3.8	3.7	3.8	3.9	3.9	4.2	4.4
Not-Specified Transportation	6.7	7.2	6.7	6.6	6.7	6.9	6.8	6.7
Off Road	2.2	2.0	2.1	2.2	2.3	2.4	2.5	2.6
On Road	155.1	151.2	148.0	147.7	147.1	148.0	151.5	154.6
Rail	2.1	2.2	2.4	2.4	2.4	2.4	2.4	2.4
Water-borne	5.3	3.7	3.5	3.4	3.4	3.5	3.4	3.2

Source: (CARB 2018)

The renewable fuel content of gasoline increased. Ethanol went from 5% to over 10%. Biodiesel and renewable diesel have grown, increasing from 1% in 2012 to 15% in 2016 (CARB 2018).

Estimates for retail price changes come from the Oil Price Information Service provided by IHS Markit. They suggest that the Standard added $US 12-14 cents to the price per gallon of gasoline or $CAD 4.2-4.9 per litre.[3] Another estimate comes from the Fuel Institute Report which suggests the additional cost of 18 cents per gallon with US$219 credit price (or $CAD 6.2 per litre).[4]

In early 2019, California approved prolongation of the LCFS to 2030 and a further reduction in emissions by 20% from the 2010 baseline.

European Union

The European Union (EU) implemented a policy for low carbon fuel via two directives – the Renewable Energy Directive (RED) and the Fuel Quality Directive (FQD). A common fuel quality rule was established to "reduce greenhouse gas and air pollutant emissions and establish a single fuel market and ensure that vehicles can operate everywhere in the EU on the basis of compatible fuels".[5]

[2] https://www.arb.ca.gov/cc/inventory/data/data.htm
[3] https://www.sfchronicle.com/business/article/California-strengthens-climate-policy-aimed-at-13267344.php
[4] http://www.fuelsinstitute.org/Research/Market-Reactions-to-Low-Carbon-Fuel-Standard-Progr
[5] https://ec.europa.eu/clima/policies/transport/fuel_en

Before these directives were updated to focus on the intensity of the fuels, the EU promoted biofuels and other renewable fuels via the Biofuel Directive of 2003. This directive was aimed at replacing 5.75% of fossil fuels in transport with biofuels by 2010.

In April 2009, Directive 2009/30/EC was approved which amended several original Directives including the FQD. The 2009 directive included petrol, diesel, and gas-oil, and introduced a mechanism to monitor and reduce greenhouse gas emissions. The directive required a reduction of the greenhouse gas intensity of transport fuels by a minimum of 10% by 2020 from the 2010 baseline. The EU expects that "the 10% reduction target is likely to be mainly achieved through":

- the use of biofuels, electricity, less carbon intense (often gaseous) fossil fuels, and renewable fuels of non-biological origin (such as e-fuels)
- a reduction of flaring and venting at the extraction stage of fossil fuel feedstocks".[6]

The framework for low carbon fuels is largely laid in the subsequent updates of Directive 98/70/EC. The latest updates of the directive include Directive 2015/1513 of 15/09/2015 (various updates, substantial), Directive 2015/625 (laying out calculation methods) and Regulation 2019/1999 (updates of targets).

The directive sets a target for the reduction of life cycle greenhouse gas emissions. The "life cycle greenhouse gas emissions' means all net emissions of CO2, CH4 and N2O that can be assigned to the fuel (including any blended components) or energy supplied" (EU 2018). The EU includes "all relevant stages from extraction or cultivation, including land-use changes, transport and distribution, processing and combustion, irrespective of where those emissions occur" (EU 2018). The EU differentiates biofuels and renewable fuels which come from sources other than biomass. These fuels are called renewable liquid or gaseous fuels.

Each member state "shall designate the supplier or suppliers responsible for monitoring and reporting life cycle greenhouse gas emissions per unit of energy from fuel and energy supplied" (EU 2018). Electricity providers can also contribute to the reduction obligation if they can demonstrate that they can adequately measure and monitor electricity supplied for use in those vehicles.

The directive requires suppliers to reduce as gradually as possible life cycle greenhouse gas emissions per unit of energy from fuel and energy supplied by up to 10% by 31 December 2020, compared with the 2010 baseline. Milestones include:

(a) "6% by 31 December 2020
(b) an indicative additional target of 2% to be achieved through one or both of the following methods:
    (i) the supply of energy for transport supplied for use in any type of road vehicle, non-road mobile machinery (including inland waterway vessels), agricultural or forestry tractor or recreational craft;

[6] ibid

   (ii) the use of any technology (including carbon capture and storage) capable of reducing life cycle greenhouse gas emissions per unit of energy from fuel or energy supplied;

(c) an indicative additional target of 2% to be achieved through the use of credits purchased through the Clean Development Mechanism of the Kyoto Protocol" (EU 2018).

The EU places special importance on the biofuel sustainability to minimize the undesired impacts from their production. The fuel must meet at least two requirements. First, the greenhouse gas emissions from biofuels must be lower than from the fossil fuel they replace – at least 50% (for installations older than 5 October 2015) and 60% for newer installations.[7] Second, raw materials for biofuels cannot be sourced from land with high biodiversity or high carbon stock.[8]

These requirements are underpinned by EU concern that high global demand for biofuels can contribute to the conversion of lands originally covered with forests and wetlands into agricultural lands, which would lead to increased greenhouse gas emissions. Therefore, the directive does not allow biofuels to be sourced from the land with high biodiversity value that had one of the following statuses in or after January 2008 <u>whether or not it remains in such a status:</u>

- forests and other wooded lands
- areas designated for nature protection purposes
- highly biodiverse grasslands
- wetlands
- peatlands.

To account for this concern, the EU, in fact, limits the share of energy from biofuels "produced from cereal and other starch rich crops, sugars and oil crops and from crops grown as main crops primarily for energy purposes on agricultural land" and should not exceed 7% of the energy in transport.

Suppliers are to report annually to designated authorities the biofuel production pathways volumes of biofuels, and the life cycle greenhouse gas emissions per unit of energy (carbon intensities), including the provisional mean values of the estimated indirect land-use change emissions from biofuels. This approach differs with California where a pathway and an intensity for fuel is approved once for a specific period based on the application. The annual reporting allows for the recognition of evolving carbon intensities based on innovation.

However, in some cases, a default CI value can be used. Generally, the calculation of carbon intensity under the directive can be done in three ways:

- by using the default value
- by using default values of certain parts of the fuel value chain and calculated values for the rest of the value chain

[7] https://ec.europa.eu/clima/policies/transport/fuel_en
[8] ibid

- by calculating CI in full according to the methodology.

The default value could be used when the value of annualized emissions from carbon stock changes caused by land use change is zero. In the case when land use change is higher, the supplier should calculate CI for the fuel. The Directive provides an extensive list of biofuels; however, it does not differentiate the origin of those fuels, compared to California and British Columbia.

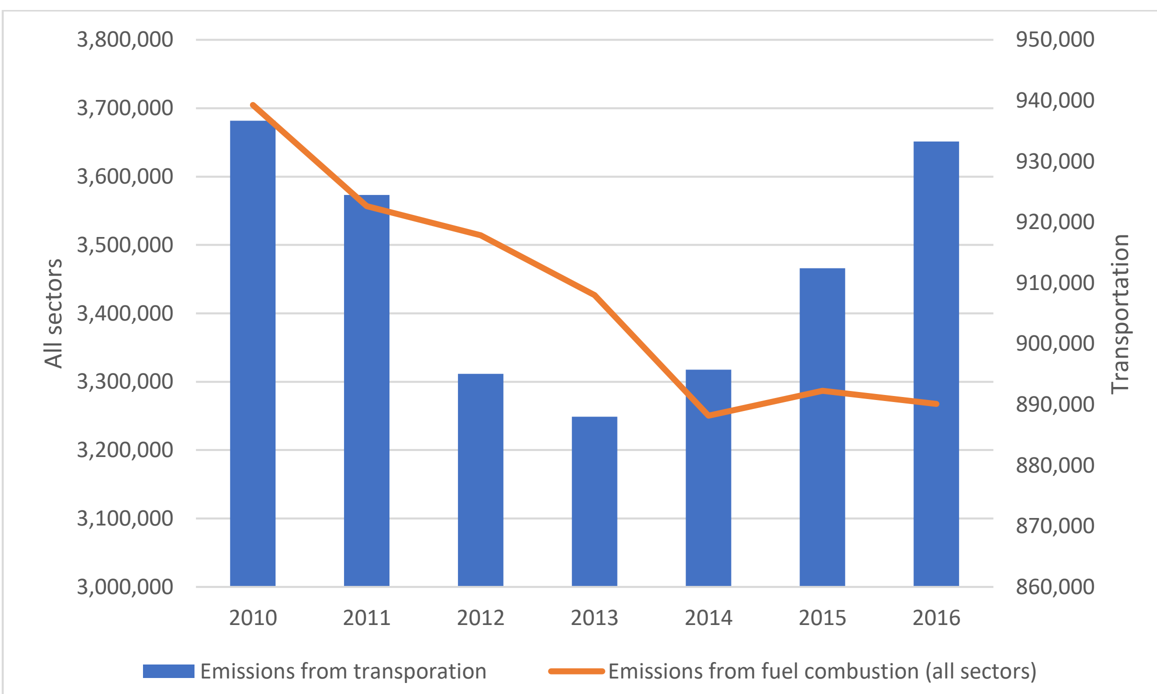
Similarly, for California and British Columbia, the regulation uses EER-adjusted CI values which allow for adjusting the intensity to consider the differences between fuels in useful work done, expressed in km/MJ. The onus of proving such adjustments is the supplier's responsibility.

In addition to the absolute value of the intensity, a Greenhouse Emission Saving is estimated and compared to the latest available actual average fossil fuel's CI. The saving is calculated as a ratio of fossil fuel CI and biofuel CI to carbon CI. This metric is essential for the EU to judge the sustainability of biofuels. As mentioned, the EU puts a stringent requirement that only biofuels which save 50-60% emissions compared to the latest fossil-based fuel should be used. This ruling eliminates 53% of fuels in the EU list if the 50% threshold is used, or 63% if the 60% threshold is used.

Results and Impacts

The overall fuel-related emissions in the EU (including gaseous and solids) decreased by 11.7% from 2010 to 2016. At the same time, emissions from the transportation sector fuel use have decreased by only 0.36% as shown in Figure 1.4.

Figure 1.4: EU Emissions from Fuel Combustion (CO2eq.MT)



Source: CERI based on EU statistics

In fact, the transportation sector performed the worst in terms of reducing emissions since 2010 across all sectors as shown in Table 1.4.

Table 1.4: EU Fuel Emissions by Industry

Industry	2010	2016	Reduction
Energy industry	1,448,683.69	1,195,879.29	-17%
Manufacturing and construction	536,066.42	474,695.04	-11%
Transport	936,663.68	933,262.57	0%
Households, industrial, commercial, agriculture, forestry, fishing	773,034.78	657,016.95	-15%
Other	8,689.37	6,811.48	-22%

Source: CERI, based on collected EU information

While other sectors' performance could have been impacted by other types of fuels – gaseous and solids, this is not likely for transportation. This means that the policy has not yet been effective in curbing the absolute level of CO2eq emissions in the transportation sector. In the directive the EU stressed that the member states need to implement reduction "as gradually as possible" and it remains to be seen which level of reductions will be achieved in the period 2016-2020.

Finally, there are currently no plans by the EU to extend the greenhouse gas reduction target beyond the year 2020.[9] Instead, the Commission has proposed to address the decarbonization of transport fuels after 2020 in the framework of a revised Renewable Energy Directive.[10] The major concern of the EU is that "food-based biofuels have a limited role in decarbonizing the transport sector due to the concern about their real contribution to the decarbonization of the transport sector" (EU Parliament 2017). In fact, the EU aims to reduce food-based biofuel content from 7% to 3.8% by 2030.

British Columbia

British Columbia adopted its Greenhouse Gas Reduction (Renewable and Low Carbon Fuel Requirements) Act (further referred to as Act) and Regulation in 2009. The Act was designed to avoid greenhouse gas emissions associated with the use of transportation fuels in British Columbia. The regulation sets both the minimum renewable content as well as requirements for greenhouse gas emission intensity reduction (BC Government 2017).

The Act required that suppliers have a minimum renewable fuel content of 5% for gasoline and 4% for diesel, on a provincial annual average basis. At the same time, suppliers had to progressively decrease the average carbon intensity of their fuels to achieve a 10% reduction in 2020 relative to 2010 (BC Government 2017). This requirement is like the original EU and California goals (California's updated goal for 2020 is 7.5%).

[9] https://ec.europa.eu/clima/policies/transport/fuel_en
[10] ibid

The framework of British Columbia's policy is similar in nature to California's and in fact, is referred to as LCFS by the government as well. The LCFS is intended to "reduce GHG emissions from fuel use; to diversify the supply of the fuels available to consumers; to provide incentives for low carbon fuels to be supplied at the expense of high carbon fuels" (2017/19 Review of BC-LCFS Compliance Pathways).

The regulation is not intended to promote any fuel over another, except through the valuation of full life cycle GHG benefits. The LCFS allows companies supplying less than 75 million litres per year to be exempt from the regulation.

The British Columbia framework consists of several major elements: a) establishing carbon intensity of fuel, b) credit trading, and c) agreements with the government.

A fuel producer may apply for a unique carbon intensity based on the calculation of its lifecycle parameters. Once approved any provider which supplies that fuel must use the approved carbon intensity. As part of the approval process, producers need to identify the feedstock being used to manufacture the fuel. In order to encourage producers to apply for specific intensities, the government sets a high default value of the intensity for fuel under the regulation. The LCA evaluation includes the full cycle of cultivation, production, processing, distribution, and combustion of the fuel.

The methodology accounts for direct land use change but does not account for effects related to indirect land use change. This means the change in emissions associated with a change in land use to compensate for the direct land use change is not tracked (i.e., changing the land use elsewhere to replace a loss of productivity in the principal jurisdiction). In California, it is tracked. In the EU, changes in land use that could increase that element of the emissions profile elsewhere are not allowed. In BC it is neither tracked nor prohibited. This is a significant difference from other considered jurisdictions.

The required intensities from 2016 to 2020 are provided in Table 1.5.

Table 1.5: Target Carbon Intensities in British Columbia (g CO_2e/MJ)

Compliance Period	Carbon Intensity Limit for Diesel Class Fuel	Carbon Intensity Limit for Gasoline Class Fuel
2017	90.02	83.74
2018	88.60	82.41
2019	87.18	81.09
2020 and beyond	85.28	79.33

Source: BC Government.

The LCFS is based on the market mechanism to reduce GHGs through credit trading between suppliers of fuel. A credit trading under the agreement started in 2015. The regulation also uses the concept of EER – energy effectiveness ratio – to adjust absolute intensities for drive train (engine) efficiencies. The energy effectiveness ratios are almost identical to California's (Table 1.6).

Table 1.6: Energy Effectiveness Ratios British Columbia

Fuel	Diesel Class Fuel Energy Effectiveness Ratio	Gasoline Class Fuel Energy Effectiveness Ratio
Petroleum-based diesel fuel or renewable fuel in relation to diesel class fuel	1.0	Not applicable
Petroleum-based gasoline, natural gas-based gasoline or renewable fuel in relation to gasoline class fuel	Not applicable	1.0
Hydrogen	1.9	2.5
LNG	1.0	Not applicable
CNG	0.9	1.0
Propane	1.0	1.0
Electricity	2.7	3.4

Source: BC Government

The regulation also allows suppliers to execute agreements with the government, typically referred to as “Part 3 Agreements”. The agreements are effectively extensions of the Act. They are intended to promote innovation, diversity and greater uptake of lower carbon fuels. “The agreements can be entered into if a fuel supplier takes actions or causes others to take actions that would have a reasonable possibility of reducing emissions using lower carbon fuels sooner than would have otherwise occurred without the action” (CERI Crude Oil Report, April 2017). These agreements are capped at 25% of annual compliance (more than one-quarter of the sum of all debits reported by Part 3 fuel suppliers during the previous compliance period).

Several parties (fuels) are exempt from the regulation:

- “Gasoline class fuel does not include fuel that, at the time of sale, the fuel supplier reasonably expects will be used in an aircraft”
- Suppliers with the volume under 75 million litres per year
- Supplies to Department of National Defense (Canada) to be used in military vessels, vehicles, aircraft or equipment for military operations.

Results and Impacts

The government of British Columbia reports broad compliance with the regulation. In terms of renewable content, the fuel suppliers maintained compliance for gasoline. The ethanol content levels increase from 5% in 2010 to 7.4% in 2016 exceeding the required 5%. For diesel, the content increased from 3% to 5.1% for the same period exceeding the required level of 4%. Thus, renewable fuel blending has been essentially the dominant method in achieving intensity-based targets. Table 1.7

provides annual renewable content in fuels in British Columbia. More information on British Columbia regulated fuels can be found in Appendix B.

Table 1.7: BC Renewable Content in Fuels

	2010	2011	2012	2013	2014	2015	2016
Total Gasoline	4,741.1	4,469.9	4,284.6	4,343.3	4,497.3	4,600.2	4,828.1
Non-exempt Gasoline	4,459.2	4,311.0	4,079.1	4,199.7	4,320.4	4,500.5	4,717.6
Exempt Gasoline	281.9	159.0	205.5	143.6	176.9	99.7	110.5
Ethanol	234.7	262.7	250.8	274.9	299.0	342.9	375.1
% Renewable Content	5.0%	5.7%	5.8%	6.1%	6.5%	7.1%	7.4%
Total Diesel	3,305.1	3,654.3	3,676.4	3,642.8	3,694.9	3,460.0	3,422.9
Non-exempt Diesel	2,977.2	3,459.2	3,530.8	3,525.7	3,520.6	3,349.5	3,305.9
Exempt Diesel	327.9	195.1	145.6	117.1	174.2	110.6	117.0
HDRD[A] and Biodiesel	91.7	155.6	158.7	192.6	226.6	221.2	178.7
% Renewable Content	3.0%	4.3%	4.3%	5.2%	6.0%	6.2%	5.1%

A – Hydrogenation-Derived Renewable Diesel

Source: BC Government

While total transportation energy use in the province increased by 6% from 2010 to 2016, the share of low carbon fuels increased as well, from 3.1% to 6% (Table 1.8). Ethanol, biodiesel and hydrogenation-derived renewable diesel (HDRD) gained the most in relative terms, however, in absolute terms, higher energy increases occurred for fossil and renewable content at 7.6 and 9.6 PJ.

Table 1.8: British Columbia Transport Fuel Usage, 2010-2016

	2010 (PJ)	2016 (PJ)	Difference (PJ)	Increase (%)
Gasoline	164.5	167.5	3.0	2
Diesel	127.7	132.3	4.6	4
Ethanol	5.5	8.8	3.3	60
Electricity	0.6	0.6	-	0
Biodiesel	2.3	3.9	1.6	70
HDRD	1.1	2.7	1.6	145
CNG	0	0.8	0.8	-
Propane	0	1.8	1.8	-
LNG	0	0.5	0.5	-
Hydrogen	0	0	3.0	-
Total	**301.7**	**318.9**	**17.2**	**6**
Including:				
Low carbon (all except gasoline and diesel)	*9.5*	*19.1*	*9.6*	*101*
Fossil	*292.2*	*299.8*	*7.6*	*3*
Share of low carbon %	***3.1%***	***6.0%***		

Source: CERI based on BC Government Data

The regulation and credit market proved to be efficient to incentivize fuel suppliers to procure low-intensity biofuels as illustrated in Table 1.9. For ethanol, the ratio of fuels with intensities over 30 gCO2eq/MJ changed from 100% to 83%, for biodiesel + HDRD – from 40% to 18%.

Table 1.9: Intensities of Biofuels in British Columbia

	Ethanol		Biodiesel + HDRD	
Intensity, gCO2ea/MJ	**0 – 30, share %**	**>30, share %**	**0-30, share %**	**>30, share %**
Year 2010	0%	100%	60%	40%
Year 2016	17%	83%	82%	18%

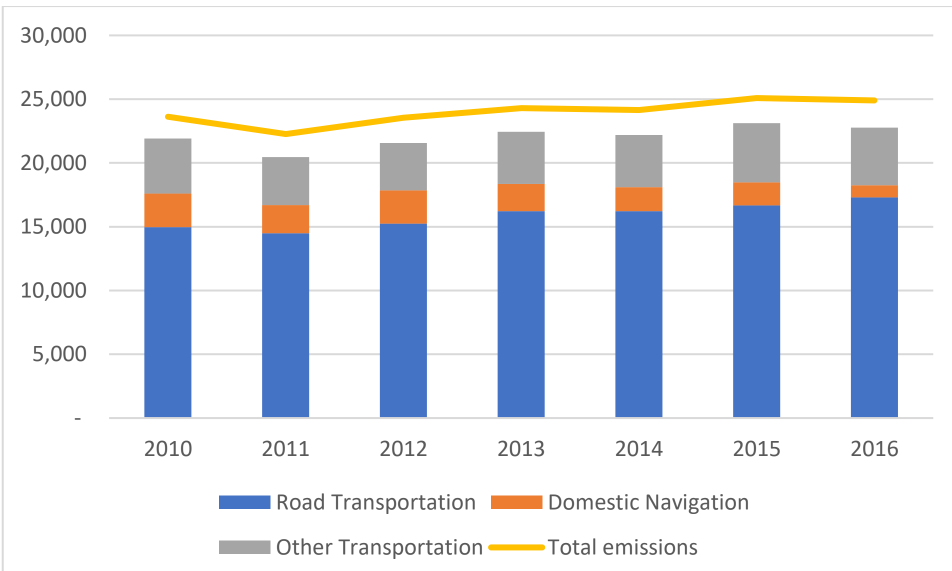
Source: CERI based on BC Government Data. (Note: Biodiesel and HDRD cannot be separated because BC reports them together.)

The BC Government states that the policy resulted in the avoidance of 1.13 million tonnes of CO2 emissions in 2016. This metric shows avoided lifecycle emissions compared to the Business as Usual case (no regulation was in place). The calculation involves the CI of fossil fuel displaced, energy effectiveness ratio (EER – the same in concept as ERR in California), CI of a renewable fuel and energy content of low carbon fuel.

However, avoided emissions should not be misunderstood with total emissions reduction from the transportation sector. Eventually, governments strive not only to avoid emissions but in fact reduce the absolute value of emissions from baseline levels. From 2010-2016, while successful on the intensity side, the policy has not produced such results: total regulated emissions (road, navigation, and other transport, excluding rail and aviation) increased by 3.9% for the period, while total transport emissions increased by 5.4%.

Road transport increased the most – by 15.5%, while "other" category, predominantly off-road vehicles, by 5.4%. Domestic navigation's emissions fell by 64%. Figure 1.5 presents the dynamic of emissions for the period.

Figure 1.5: BC Transportation Emissions (CO2eq kT)



Source: CERI based on BC Government Data

Looking ahead, the province looks to increase the carbon intensity reduction target to 20% by 2030 keeping the same baseline. This goal is consistent with California's intentions. The Act became a key contributing piece to CleanBC Pathway – a blueprint to reduce greenhouse gas emissions for the province. Within the CleanBC, British Columbia aims to obtain 6 MT of CO2eq reduction from the transportation sector by 2030. This will account for 31% of the total reductions planned in the document. Out of 6 MT, the cleaner fuels account for 4 MT or 66% (BC Government 2018).

Comparison of Three Jurisdictions

This section reviews three jurisdictions – California, the European Union and British Columbia. All jurisdictions have been running their fuel decarbonization policies for nine years now and present good cases for learning from their experiences and frameworks. Table 1.10 summarizes the regulations of those three jurisdictions.

Table 1.10: Comparison of LCF Standards

	California	European Union	British Columbia	Notes
First year of regulation	2011	2011	2011	
Baseline year	2010	2010	2010	
CI Reduction Target to 2020	7.5% (10% original)	10%	10%	
Renewable content min/max	Not federal. US RFS sets ethanol limit	No more than 7%	Min for gasoline 5% Min for diesel 4%	
CI estimate	Based on LCA (GREET model)	Based on LCA (BIOGRACE model)	Based on LCA (GHGenius model)	Different LCA tools are applied
CI procedure	The supplier does LCA, gov. agency approves, expiration date	LCA, using default values or a mix of default and calculated LCA	Default High CIs set to incentivize suppliers to do LCA	
Credit cap, $	\$200/tonneCO2eq.; under credit shortage, debits are carried forward. Potential for price to increase; penalties at \$1,000/ tonneCO2eq.	None	\$210/tonneCO2eq.	
Indirect land impacts	+ (included as part of LCA); direct land use change is included	+ (included as part of LCA). Cannot use biofuel from certain areas (even if they lost status)	- (Not included); direct land use change is included	
Economy Effectiveness Ratio-adjusted CI.	Yes	Option – need to prove a case	Yes	Adjusts CI for the efficiency of drive trains
Intensity curve	Gradual declining, backloaded (first 8 years decrease is by 5%); from 2018 onwards – linear change	Up to member states, "As gradual as possible"	Gradual declining, backloaded. BC is looking at adopting similar change as in California	
Credit trading	Yes	Yes	Yes	
Exemptions:	• not bio-mass fuels • supplies < 420 million MJ/year • LPG • Locomotives • Aircraft • Ocean-going vessels (does not apply to recreational and commercial craft) • Military purposes	No information found	• Aircraft • Suppliers with the volume under 75 million litres per year • Military purposes (incl. emergency response and humanitarian support)	

Additional credit opportunities	Yes. Provided as a rule to fossil-fuel providers.	No information found	Yes. Separate agreements for infrastructure investments	
Results (2010-2016)				
Renewable content	No requirements	No requirements	Overall share of low carbon fuels from 3.1% to 6% From 5% to 7.4% (gasoline) From 3% to 5.1% (diesel)	
Carbon intensity reduction	-3.5%	N/A	N/A (claimed to be reached by BC Govt)	
Change in total emissions compared to baseline (transportation)	+3.1% (regulated fuels)	-0.36% (all fuels)	+3.9% (only regulated fuels) +5.4% (all fuels)	
Policy to 2030	20% intensity decrease compared to 2010	No extension. Decrease food-based biofuel content to 3.8%, increased 'advanced biofuels'	20% intensity decrease compared to 2010 or 6MT of CO2eq.	
Specific requirements:		Biofuels CI should be at least 50-60% lower than fossil-based fuel's CI. Food-based biofuels should not be more than 7% of total energy content in transport.		

Canadian Federal Decarbonization Policies

Renewable Fuel Regulations

The current policy in Canada is the federally mandated Renewable Fuel Regulations (Government of Canada 2017) which requires a minimum renewable fuel content in gasoline and diesel fuels sold to consumers in Canada; for gasoline, the renewable content is set at 5% and for diesel fuel and heating distillate oil – it is 2%. The policy commenced in December 2010 and was expected to bring down GHG emissions by approximately 2 million tonnes per year (ECCC 2017) with half of the reduction accruing from the gasoline and the rest from diesel and heating oil. The regulations include a trading system and administrative, compliance and enforcement requirements such as record keeping and reporting.

Besides the reduction in GHG emissions, other goals included:

- Increasing the retail availability of renewable fuels through regulation;
- Supporting the expansion of Canadian production of renewable fuels;
- Assisting farmers in seizing new opportunities in this sector; and

- Accelerating the commercialization of new technologies.

The proposed Clean Fuel Standard (CFS) policy by the Federal Government will eventually replace the existing Renewable Fuels Regulations, however, in the short-term, these volumetric requirements will be maintained.

Proposed Clean Fuel Standard in Canada

The Government of Canada plans to put in place Clean Fuel Standard (CFS) Regulations under the Canadian Environmental Act, 1999 to reduce Canada's greenhouse gas (GHG) emissions. The objective of the proposed regulations is to achieve 30 megatonnes of annual reductions in GHG emissions by 2030, contributing to Canada's effort to achieve its overall GHG mitigation target of 30% emission reduction below 2005 levels by 2030 (ECCC 2018). The CFS will establish lifecycle carbon intensity requirements separately for liquid, gaseous and solid fuels that are used in transportation, industry and buildings. The goal is to have a performance-based approach that would incent innovation, development and use of a broad range of low carbon fuels, energy sources and technologies. This policy direction is broader than those used in the other three jurisdictions discussed; this one covers all fuel options and all sectors, while the others cover only liquid transportation fuels.

Similar to other fuel decarbonization policies, the Canadian CFS regulations will use a lifecycle approach to set carbon intensity values and requirements, accounting for greenhouse gases emitted to produce a unit of energy. This lifecycle approach will assess GHG emissions from all stages in a product's life, from cradle to grave (that is, from raw material extraction through materials processing, manufacture, distribution, use, repair and maintenance, and disposal or recycling where applicable). The goal is to drive actions that reduce GHG emissions throughout the lifecycle of fuels and fuel alternatives.

Indirect land use GHG emissions that may result from the CFS will not be considered in the design, at least initially. This differs from the California or EU policies but is similar to the BC policy. The regulation aims to achieve reductions from each of the transportation, building and industrial sectors. This will be achieved by setting separate carbon intensity requirements for subsets of fuels, as well as through rules around credit trading.

The CFS is planned to set separate carbon intensity requirements for liquid, gaseous and solid fuel streams. This approach will lead to emission reductions from fuels used in transportation, industries and buildings. Approximately 80% of liquid fuels are used for transportation. Setting a separate carbon intensity target for liquid fuels will ensure GHG reductions are achieved from transportation fuels.

Certain fuels will be excluded from the application of the carbon intensity requirements of the CFS, including fuels that are exported from Canada, fuels that are in transit through Canada, non-combustion end-uses of fossil fuels, and coal combusted at facilities that are covered by coal-fired electricity GHG regulations.

Fuel producers and importers, or in some cases distributors, will be subject to the CFS and will need to meet specific requirements for the fuels that they produce, import or distribute.

In the case of liquid fuels, the producers or importers of the liquid fuel (e.g., gasoline, diesel, and heavy fuel oil) will be the regulated parties. In the case of gaseous fuels, for pipeline-quality natural gas delivered via gas distribution pipeline systems, the distributors of the natural gas will be the regulated parties. For other gaseous fuels supplied to end-users other than through a gas distribution pipeline system (e.g., biogas, natural gas from producers), the regulated parties remain to be determined. In the case of solid fuels, the producers or importers of the fuel (e.g., coal and petroleum coke) will be the regulated parties.

Carbon intensity values will be expressed in grams of carbon dioxide equivalents (g CO_2e) per unit of energy in megajoules (MJ) and will account for GHG emissions over the lifecycle of a fuel. Carbon intensity values will not include an estimate of the impact of indirect land use change on GHG emissions.

Baseline carbon intensity values and carbon intensity requirements will be set for each fuel in a stream or for groupings that include some or all fuels in a stream. The CFS regulation will set carbon intensity requirements expressed either as absolute values or as percent reductions from relevant baselines. For example, liquid fuels will be subject to an annual maximum standard to 2030 of 10 grams of CO_2eq. per MJ reduction from the Canadian average CI of each fossil liquid fuel in 2016. This represents a decrease of approximately 10% to 12% in CI below 2016 fossil fuel CI values, depending on the fuel type.

The carbon intensity requirements will become more stringent over time, with the goal of achieving at least 30 Mt CO_2e of emission reductions annually commencing in 2030.

For renewable fuels, other low carbon fuels and energy sources and technologies, carbon intensity will be differentiated by type and origin of the fuel to reflect the GHG emissions associated with different feedstocks and technologies. In the case of crude oil-based fuels, the regulation will not differentiate among crude oil types, or on whether the crude oil is produced in or imported into Canada. A Canadian-average default carbon-intensity for crude oil produced, imported and consumed in Canada will be used. With respect to natural gas, setting carbon intensity requirements as noted above is the intended approach.

The CFS will provide a range of pathways for compliance, other than reducing the carbon intensity of the fuel produced or imported for use in Canada. A key pathway for fossil fuel suppliers to consider is to include renewable fuel content in their product.

It will be possible to generate compliance credits for actions that improve carbon intensity throughout the lifecycle of the fuel. One issue to be determined is whether to specify a minimum threshold for process improvements that qualify for credit creation. It will also be possible to generate credits through fuel switching and the deployment of energy sources and technologies that displace fossil fuels, such as electric vehicles.

Credits will be tradeable among regulated parties within each stream of fuels (liquid, gaseous and solid). Up to 10% of credit trading between the fuel streams will be considered. This approach offers compliance flexibilities to regulated parties to achieve emission reductions across the fuel types within the separate fuel streams.

Credits will not expire and there will be no limit to the number of credits that can be transferred among parties. There will also be no set limit to the number of times a single credit can be transferred and credits can be banked, with no limit on the number of credits that can be banked.

The Clean Fuel Standard regulations' referenced lifecycle GHG emission models and the carbon intensity values will be updated and revised periodically. Additionally, a review of the CFS will include future consideration of the treatment of renewable fuel requirements, whether the impacts of indirect land use change should be accounted for, and whether consideration should be given to other sustainability issues.

Comparison to Other Fuel Decarbonization Policies

Table 1.11 presents a summary of the comparison of the Canadian CFS regulation with the other three identified in the previous chapter.

Table 1.11: Comparison of Regulations

	California	European Union	British Columbia	Canadian CFS
First year of regulation	2011	2011	2011	2022 – liquids; 2023-gaseous/solids
Baseline year	2010	2010	2010	2005
Fuels covered	Liquid fuels	Liquid fuels	Liquid fuels	Liquid, gaseous and solid fuels
CI Reduction Target to 2020	7.5% (10% original)	10%	10%	10-12% for liquid fuels; unknown for gaseous/solids
Renewable content min/max	Not federal. US RFS sets ethanol limit	No more than 7%	Min for gasoline 5% Min for diesel 4%	No national min/max. Unknown if Prov. Levels will remain
CI estimate	Based on LCA (GREET model)	Based on LCA (BIOGRACE model)	Based on LCA (GHGenius model)	ECCC's new LCA tool (under development)
CI procedure	The supplier does LCA, gov. agency approves, expiration date	LCA, using default values or a mix of default and calculated LCA	Default High CIs set to incentivize suppliers to do LCA	LCA application, using CI
Credit cap, $	$200/tonneCO2eq.; under credit shortage, debits are carried forward. Potential for price to increase; penalties at $1,000/ tonneCO2eq.	None	$210/tonneCO2eq.	unknown
Indirect land impacts	+ (included as part of LCA); direct land use change is included	+ (included as part of LCA). Cannot use biofuel from certain areas (even if they lost status)	- (Not included); direct land use change is included	Not included

Economy Effectiveness Ratio-adjusted CI.	Yes	Option – need to prove a case	Yes	Potential
Intensity curve	Gradual declining, backloaded (first 8 years decrease is by 5%); from 2018 onwards – linear change	Up to member states, "As gradual as possible"	Gradual declining, backloaded. BC is looking at adopting similar change as in California	Unknown
Credit trading	Yes	Yes	Yes	Yes
Exemptions:	• not a biomass fuel • supplies < 420 million MJ/year • LPG • Locomotives • Aircraft • Ocean-going vessels (does not apply to recreational and commercial craft) • Military purposes	No information found	• Aircraft • Suppliers with the volume under 75 million litres per year • Military purposes (incl. emergency response and humanitarian support)	• Non-combustion end-uses of fossil fuels • Fossil fuels used as feedstock in industrial processes • Exported fuels, fuels in transit • Aviation gasoline • Fuels used for scientific research • Fuel imported that supplies engine of a conveyance • Coal-fired facilities covered under the federal regulations on retirement
Additional credit opportunities	Yes. Provided as a rule to fossil-fuel providers.	No information found	Yes. Separate agreements for infrastructure investments	Potential

Chapter 2: Analytical Methodology

Modelling Approach and Methodology

CERI has developed two scenarios in evaluating potential GHG emission reductions and cost implications of fuel decarbonization in Canada. The two scenarios are set in comparison to the Business as Usual (BAU) scenario. Emissions and costs modelling include three types of fuels – liquid, gaseous and solid – in three sector categories – industry (including agriculture), transportation, and buildings.

The BAU scenario only considers the existing federally mandated Renewable Fuel Regulations.

The first scenario or "10% CI reduction" evaluates emissions and cost impacts of applying a uniform 10% reduction in carbon intensity for all impacted fuels evaluated across all affected sectors. This represents a decrease of approximately 10% in CI below benchmark CI values, depending on the fuel type. This scenario includes all fuel types.

The second scenario "20% CI reduction" evaluates an alternative pathway to show the relationship between carbon intensity reduction and cost. The 2016 base year is used as it provides the most complete dataset from which to make the scenario assessments.

Table 2.1: Basic Parameters and Assumptions

Parameter	BAU	10% CI Reduction	20% CI Reduction
Base Year	2016	2016	2016
CI starting values	Renewable Fuel content only	Table 2.2	Table 2.2
CI Reduction schedule		Table 2.3	Table 2.4
CI Base Year		2018	2018
CI Reduction enforced		2022 – liquids/2023 – gaseous, solids	
Case Study: Aggressive Electric Vehicles Penetration in Transportation	50% and 90% penetration of electric vehicles in new sales in 2050	50% and 90% penetration of electric vehicles in new sales in 2050	50% and 90% penetration of electric vehicles in new sales in 2050
Case Study: Heavy-Duty Vehicle and Engine GHG Emission Regulations	Fuel economy improvement by 3% in 2030 compared to 2016	Fuel economy improvement by 3% in 2030 compared to 2016	Fuel economy improvement by 3% in 2030 compared to 2016

Source: CERI.

As shown in Table 2.2, carbon intensities used for modelling are for the year 2018. Assumed default intensities per fuel are taken from Environment and Climate Change Canada's (ECCC) Greenhouse Gas and Air Pollutant Emissions Projections for the year 2018.

Table 2.2: Default Carbon Intensities

Type	Fuel	CO2 eq Emitted (g/MJ)	
		2018 ECCC Base year CI for the study	BC (LCA), 2016 weighted average
Gaseous	Natural Gas Raw	57.46	
	Landfill Gases/ Waste	14.06	
	Natural Gas	46.94	
	Still Gas	51.26	
	Coke Oven Gas	36.73	
Liquid	Diesel	71.73	
	Heavy Fuel Oil	75.17	
	Aviation Gasoline	74.29	
	Gasoline	71.67	
	Jet Fuel	69.44	
	Kerosene	68.14	
	Light Fuel Oil	71.16	
	LPG	43.39	68.02
	Biodiesel	5.92	15.24
	Ethanol	2.4	41.00
Solid	Coal	91.17	
	Petroleum Coke	84.52	
	Coke	110.29	
	Biomass	5.59	

Source: ECCC, BC Government.

The federal government is currently developing a new Fuel Life Cycle Assessment (LCA) Modelling Tool which will be used to determine the carbon intensity of fuels in Canada. The Fuel LCA Modelling tool will be used to determine Canadian average carbon intensities for fossil fuels, which will be based on 2016 carbon intensities data. Imported liquid fossil fuels will be assigned the same carbon intensity value as the calculated Canadian average value.

Given LCA intensities are still under development, CERI used the carbon intensities as provided in Table 2.2. Some LCA values from ECCC's estimates are considerably lower than those used in BC. However, for this research, CERI used ECCC's estimates because of the lack of other consistent sources of intensities across all fuels. The implications of such a methodological decision will be discussed further.

For CERI's two scenarios, the schedule of increasing CI targets is modelled using California's original schedule. Tables 2.3 and 2.4 provide the schedules under two scenarios.

Table 2.3: 10% CI Reduction Scenario

2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Liquids	0%	0.5%	1%	1.5%	2.5%	3.5%	5%	6.5%	8%	10%
Solids, Gaseous	0%	0%	1%	1.5%	2.5%	3.5%	5%	6.5%	8%	10%

Table 2.4: 20% CI Reduction Scenario

2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Liquids	0%	1%	2%	3%	5%	7%	10%	13%	16%	20%
Solids, Gaseous	0%	1%	2%	3%	5%	7%	10%	13%	16%	20%

Note that for liquid fuels, carbon intensity reduction starts in the year 2022 and for gaseous and solids, the reduction starts in 2023 as per the Canadian federal policy timeline. Ten percent represents a common target used in the three jurisdictions reviewed – California, the EU and British Columbia. Under the Canadian CFS, for the liquid fuels stream, the annual maximum standard for 2030 will require 10 grams of CO2eq. per MJ reduction from the Canadian average CI of each fossil liquid fuel in 2016. This represents a decrease of 10-12% in CI below 2016 fossil fuel CI values, depending on the fuel type. Hence, this is the basis for CERI's assumption to use a 10% CI reduction scenario.

Emissions and Energy Demand Modelling

To estimate emissions coming from three categories of sectors, CERI first estimated future energy demand by sector. For buildings and transportation, CERI's proprietary Stock-Rollover models for houses/equipment stock and vehicle stock, respectively, were used to estimate future energy demand. For the industrial sector, CERI used detailed-level Input-Output (IO) tables for the year 2015 (the most recent data available) to obtain fuel expenditures in different industrial sectors, which were then used to calculate fuel volumes by dividing fuel expenditures by average fuel prices of each fuel. The next section describes emissions and energy demand modelling in greater detail.

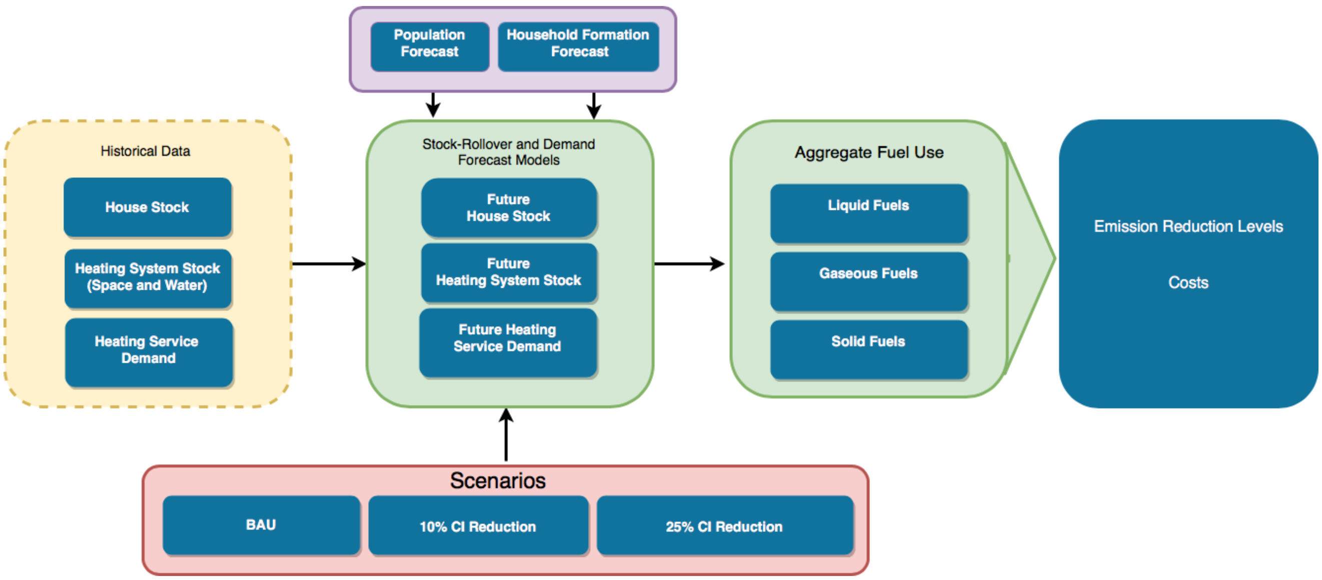
Buildings

To forecast emission reductions due to a fuel decarbonization requirement in buildings, CERI's Stock-Rollover model of houses and equipment stock (space heating, water heating, etc.) is combined with the energy use of each end-user reported in the Comprehensive Energy Use Database by Home Type (NRCan 2018a). Both housing and equipment Stock-Rollover models are outlined in greater detail in Appendix A, while Figure 2.1 illustrates the overall modelling approach of emission reductions in buildings.

In order to forecast future housing stock and future energy system needs by home type (i.e., single detached, single attached, apartments, and mobile homes), the population forecast from the National Energy Board (National Energy Board 2018) and household formation forecast from Statistics Canada (Statistics Canada 2016) was used. The emissions are then estimated for all three scenarios.

Since the equipment stock data is not available for the commercial building sector, the energy mix of the sector is used to forecast future energy use. Comprehensive Energy Use database (NRCan 2018a) provides energy use in the commercial/institutional sector. To estimate future energy use, CERI takes floor space of the sector as the activity factor and its average historical growth rate over the last ten years. Assuming the energy intensity of the sector (MJ per square meter of floor space) to be the same until 2030 as its value in 2016, the fuel use of the sector is forecasted.

Figure 2.1: Buildings Module

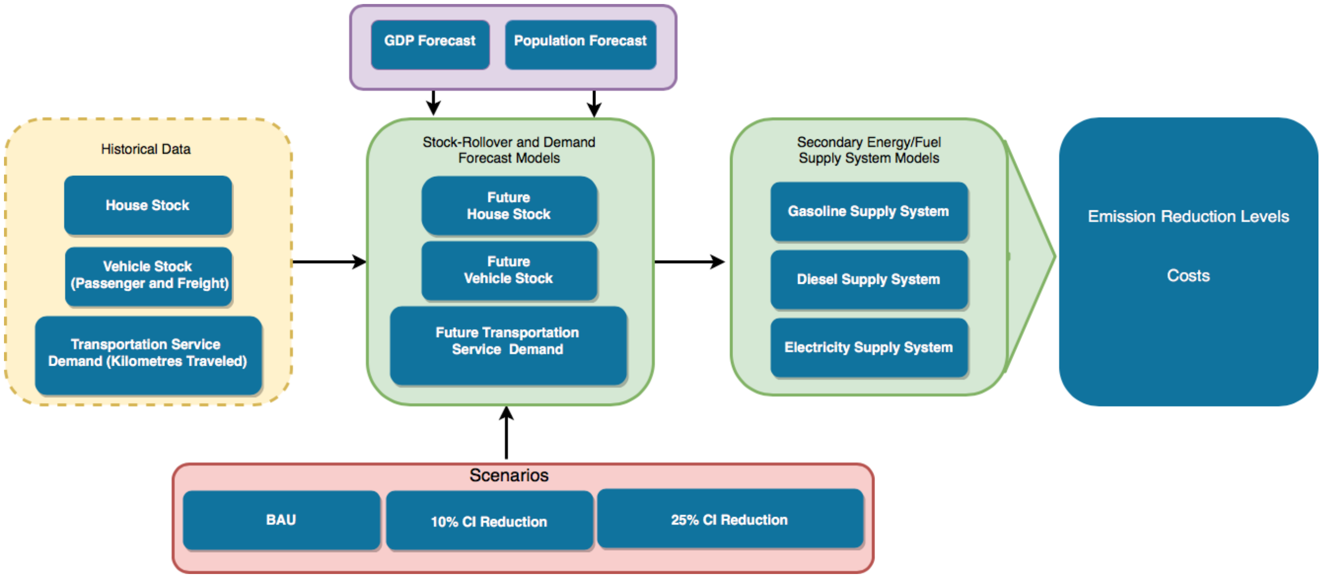


Transportation

Emission reductions forecast in the transportation sector is derived using CERI's stock-rollover model of vehicle stock along with the kilometres travelled reported by Comprehensive Energy Use database (NRCan 2018a) and Census 2016 (Statistics Canada 2018). Figure 2.2 shows the emissions reduction modelling approach for the transportation sector, and Appendix A provides more detail on the vehicle stock-rollover model. As in the case of building modelling, transportation-related emissions are forecasted for the scenarios.

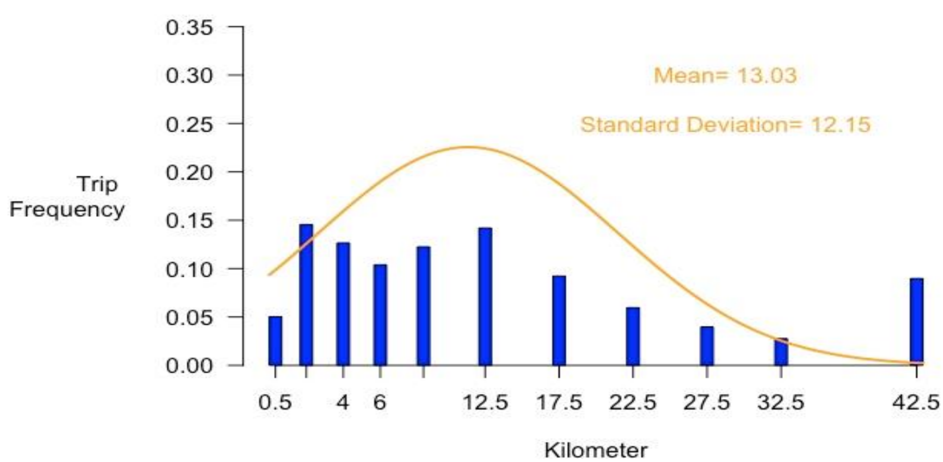
CERI's vehicle stock-rollover model provides a stock of different types of vehicles by retiring older vehicles based on their vintage (year of production). The average lifetime of a vehicle is assumed to be 17 years. The vehicle stock can also be decomposed to conventional (gasoline and diesel) vehicles and electric vehicles (EVs) based on assuming different penetration rates for EVs. Based on CERI's recent Study 178 "Economic and Greenhouse Gas Emissions Impacts of Alternative Transportation Scenarios for Canadian Cities", we assume EV's share to be 10% of annual new sales in the year 2050.

Figure 2.2: Transportation Module



Statistics Canada's Census 2016 (Statistics Canada 2018) provides the distribution of daily kilometres travelled by household. Figure 2.3 shows the distribution of travel distance in Canada in 2016.

Figure 2.3: Distribution of Daily Kilometers Travelled by Household (Commuting) in Canada, 2016



The above distribution can be derived for both passenger cars and public transit trips from Statistics Canada's Census 2016 (Statistics Canada 2018). The Census 2016 dataset only covers commuting (i.e., work-related) trips. To capture the distribution of total commuting and non-commuting trips, the ratio of non-commuting trips to commuting trips in each year is inferred to reconcile the calculated total kilometres travelled in 2016 to the historical total kilometres travelled from Natural Resources Canada (NRCan 2018a). In addition, since Census 2016 provides no information on the distance of non-work trips, CERI exploits the US National Household Travel Survey (2017) to infer the average ratio of non-work trip distance to work trip distance.

Having the number and distance of daily trips for both commuting and non-commuting trips, CERI forecasts the number of future trips and kilometres travelled. This assumes that the trip rate (total trips divided by population) until 2030 will be the same as this rate in the 2016 Census data. Based on this assumption, a total number of trips (and kilometres travelled) is calculated using the constant trip rate and the NEB's population forecast.

CERI assumes the fuel economy standards of the current vehicles on roads which are reported by Natural Resources Canada (NRCan 2018b) to decline with its average growth rate over the last 10 years. Figures 2.4 and 2.5 show fuel economy of on-road vehicles and CAFE standards for passenger cars and light trucks in Canada, respectively. CAFE standards until 2050 are assumed to remain the same as their last available value for the year 2025. In each year the stock of vehicles consists of vehicles with different vintages. To calculate fuel demand under each scenario, CERI assumes each vehicle in the stock has CAFE standards specific to its vintage.

Figure 2.4: Fuel Economy – Passenger Cars (litres of gasoline/100 km)

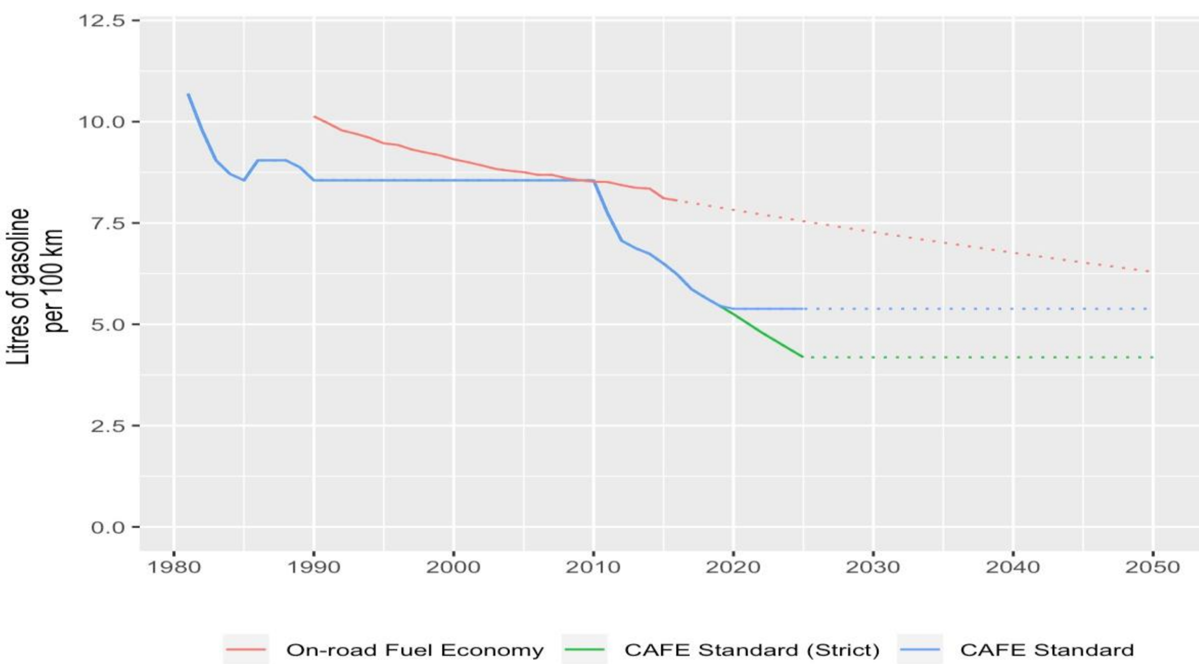
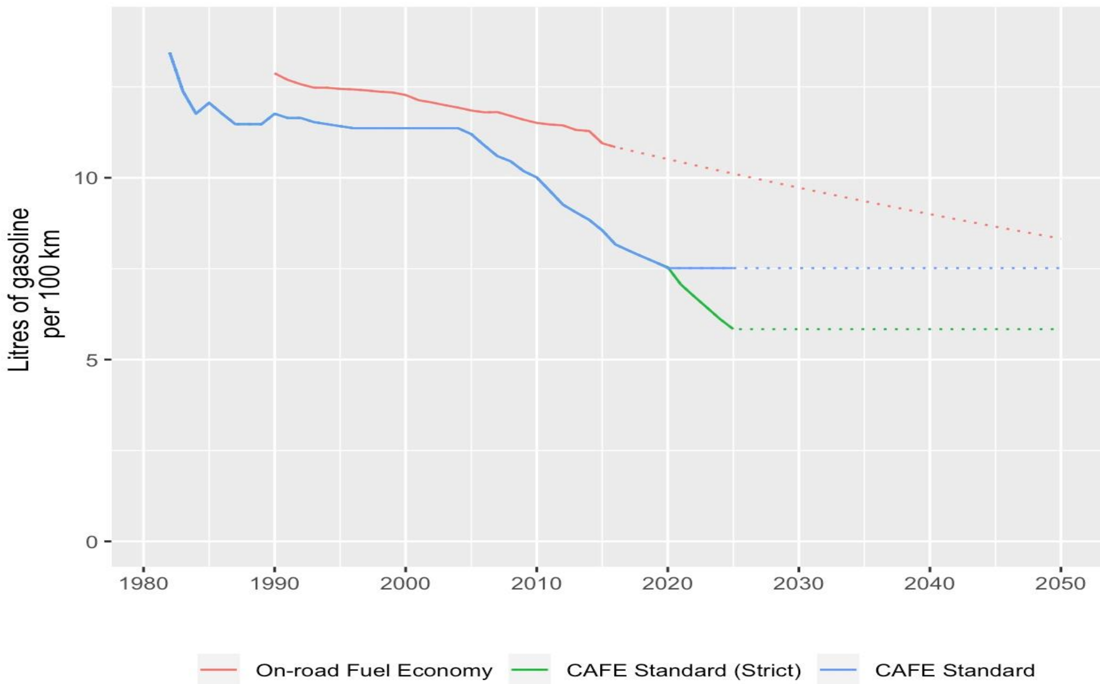


Figure 2.5: Fuel Economy – Light Trucks (litres of gasoline/100 km)



The on-road fuel economy is taken from NRCan (2018a). CAFE standards for years prior to 2017 are taken from Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards: Final Rule (US EPA and US DOT (NHTSA) 2010). For years after 2017, CAFE standard is adopted from the Safer Affordable Fuel-Efficient (SAFE) Vehicles Rule for Model Years 2021-2026 Passenger Cars and Light Trucks: Notice of Proposed Rulemaking (US DOT (NHTSA) and US EPA 2018). Strict CAFE illustrates 2017 and Later Model Year Light-Duty Vehicle Greenhouse Gas Emissions and Corporate Average Fuel Economy Standards: Final Rule (US EPA and US DOT (NHTSA) 2012).

CERI uses CAFE Standard (the blue line in the above figures) in this study to forecast fuel consumption.

Other Transportation Modes (Freight, Air, Rail, and Marine)

Comprehensive Energy Use database (NRCan 2018a) provides energy use in freight, air, rail, and marine transportation. CERI uses Passenger-kilometres (Pkm) for passenger air and rail transportation and Tonne-kilometers (Tkm) for freight air, freight rail, and marine transportation as the activity factors. It is assumed that these activity factors will grow based on their average historical growth rate over the last ten years. Assuming energy intensity of each subsector (MJ per Pkm and MJ per Tkm) to remain the same until 2030 as its value in 2016, CERI derived fuel use in each sub-sector by using the activity drivers and energy intensities.

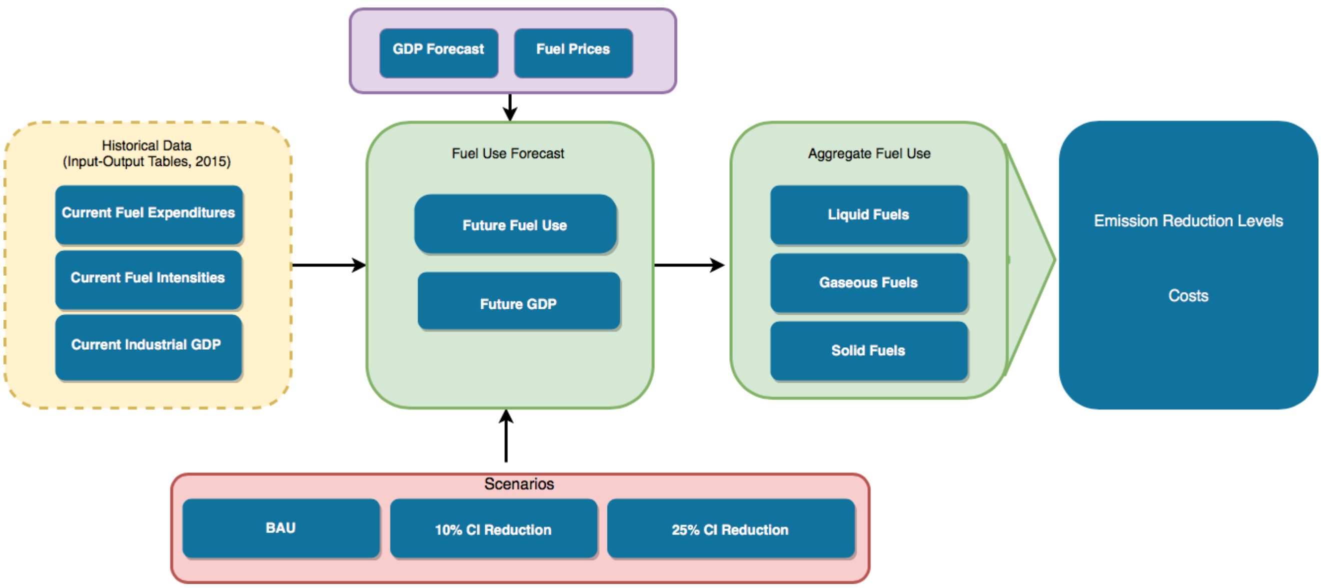
Industry

To calculate GHG emission reductions in the industrial sector, CERI used the 2015 detailed-level Input-Output (IO) tables (Statistics Canada 2019) (Statistics Canada 2014) that provide fuel expenditures in different industries. Fuel use quantities (in MJ) can then be calculated by dividing fuel expenditures

from IO tables by average prices of each fuel (per MJ). Average prices are obtained from Canadian and US public sources.

To forecast fuel use, CERI used the GDP growth rate forecast from the NEB (National Energy Board 2018) and each industry's share of total value-added (from IO tables in the year 2015) to forecast GDP. Assuming fuel quantity per dollar of value-added in each industry until 2030 will remain the same as its value in 2015, CERI forecasts fuel use in each industry by multiplying the fuel intensity of the industry and the industry's GDP for the years after 2015 until 2030. Figure 2.6 illustrates the overall modelling approach to emission reductions in the industrial sector. Note that this analysis does not include autonomous technological changes which could increase the energy efficiency of industry, and thus decrease their overall fuel demand.

Figure 2.6: Industry Module



Agriculture

Given the importance of the agriculture sector to support the supply of agricultural feedstock to biofuels producers, CERI evaluated this sector individually within the Industry section. The Comprehensive Energy Use database (NRCan 2018a) provides energy use in the agriculture sector. Using the GDP value of the sector as the activity driver and assuming energy intensity of the sector (MJ per dollar of its GDP) to remain the same until 2030, CERI derived fuel use of the sector by fuel. Using carbon intensities under different scenarios, GHG emissions of the sector are forecasted.

Cost Modelling

One of the objectives of the study is to estimate potential fuel cost impacts of a broad fuel decarbonization policy for the country. This section presents several scenarios and sensitivities with regard to cost to consumers depending on the carbon intensity reduction schedule and credit price. The methodology for cost modelling is presented in Appendix C.

We assume a credit trading system, similar to the one suggested by the Canadian government for its new CFS. The compliance costs along with the demand for and supply of credits will determine the price of a credit.

To ensure compliance, the suppliers of fuels with the fuel intensity above the target will either have to find ways to get the intensity below the benchmark for that year (e.g., by blending with biofuels to liquids or adding renewable gas to natural gas) or will have to buy credits from suppliers with fuel intensity below the target. There could be partial solutions when both mechanisms work. For instance, if a gasoline producer's fuel, even after blending, is exceeding the CI benchmark, the producer will have to buy credits for the difference.

The carbon intensity reduction schedule is also instrumental in determining the cost implications of a policy. More importantly, the difference between a target CI and a benchmark CI might indicate increasing costs if CI's become more stringent.

In the initial years, if an intensity reduction schedule is going to be gradual, it is probable that credits generation in the credit bank will outpace deficits. At the same time, if the behaviour of credit market participants is similar to what was observed in other jurisdictions, the price of credits will not be minimal due to an oversupply of credits. This is because fossil fuel providers will start buying cheap credits for future use.

For instance, six years into California's LCFS, the credit market had been generating more credits than deficits, raising total credits bank volume to 10 million metric tonnes of CO2eq.; however, the price for the same period grew to $100 before the annual deficits started to prevail over credits and cumulative bank volume started to decline.

The other uncertainty lies with how a fuel provider can address additional compliance costs due to regulation. There are several options here. The parties which will buy credits (e.g., petroleum fuel producers or importers) may pass those additional costs onto consumers in the form of higher-priced gasoline, diesel or other products or absorb these costs in full or in part. On the other hand, the suppliers which will receive credits may choose to improve their profitability by keeping revenues generated by selling credits or to decrease sales prices using the additional revenue to be more competitive. Over time, the price signals from the market will determine the credit price. For the study, CERI makes several assumptions which are more likely to occur and are consistent with the literature.

Assumptions:

- The carbon intensity of fossil-based fuels (gasoline, natural gas, diesel, jet fuel, etc.) will not change over the period 2020-2030, i.e., the time period is not long enough to assume a technological improvement in processes and technologies.[1]
- The regulated party who buys credits will pass additional cost onto consumers.

[1] Some analysts suggest that there will be a significant emission reduction in upstream oil sands and conventional oil sector. CERI does not consider these here.

- The party who sells credits will retain them as part of their profits (not passed on consumers).
- Assumed default carbon intensities per fuel are taken from ECCC's Greenhouse Gas and Air Pollutant Emissions Projections–2018. The intensities are shown in Table 2.1.

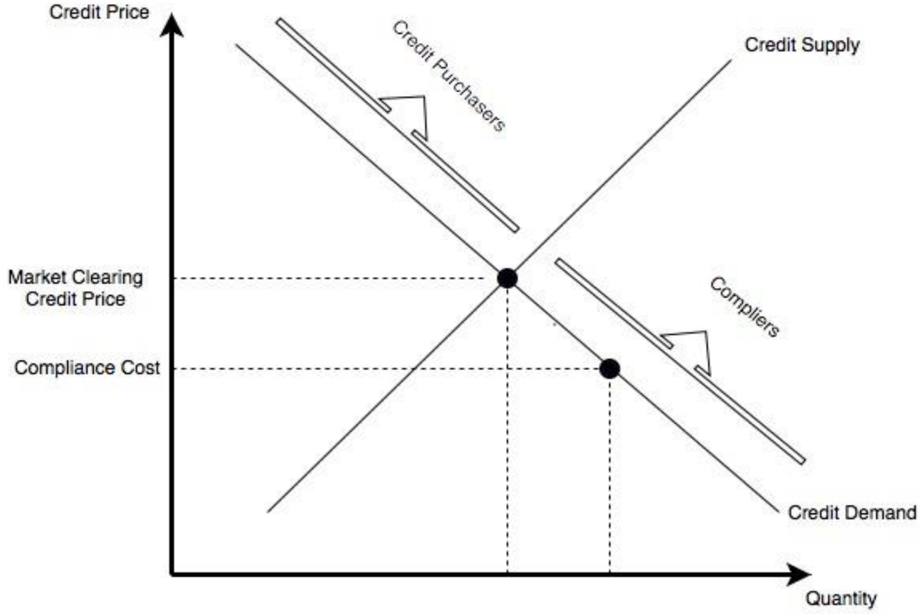
The schedule of increasing CI targets is modelled using California's original schedule and is done for two scenarios: 10% CI reduction and 20% CI reduction. Tables 2.2 and 2.3 provided the schedules under the two scenarios.

Two price estimates for credits are used, \$50/T of CO2eq. and \$200/T of CO2eq. Fifty dollars represents an estimate of the level which could be reached in the first several years based on what has been observed in other jurisdictions. This level is equal to the Canadian federal level of carbon pricing. However, carbon pricing does not play a role in setting the credit price. Two hundred dollars represents a possible price for credit under a CFS framework which could be reached by 2030. BC's credits have recently been trading between CAD\$164-171 and California is close to US\$185 (CAD\$240), both in year seven of their regulation.

As mentioned, regulated parties will seek a most cost-efficient way to comply and only those whose costs are higher than the credit price are expected to buy credits. Figure 2.7 presents an illustrative case of supply and demand of the credit market and shows both Credit Purchasers and Compliers. As shown in the Figure, the market-clearing price in the credit market represents an upper bound for compliance costs. In fact, for compliers, compliance costs will be marginally below the credit purchasing price but will not be zero or insignificant. Possible ranges of compliance in the liquid market are discussed further.

Since it is assumed in this study that all fuel providers (both credit purchasers and compliers) face the same price per tonne of GHG reduction (\$200 per tonne of CO2eq), cost estimates in this study represent an upper bound of the actual costs in the economy if the credit clearing price on the market was, in fact, \$200. CERI does not suggest that \$200 is the maximum compliance cost or credit price.

Figure 2.7: Credit Market Supply and Demand



Source: CERI

CERI did not model the possible future price of credits, hence $200 was an exogenous variable for cost determination; however, several considerations suggest that this price is a plausible assumption.

First, this level is observed in other jurisdictions for liquid fuels credit markets.

Second, the blending can produce a similar compliance cost in the range of $190-200[2] based on factual observed intensities and historical prices of fuels. Two factors play a key role in the compliance cost for blending:

1. The price difference between fossil fuel and renewable fuel – the higher the difference the higher the compliance costs will be.
2. The difference in CI intensities for the fossil fuel and the renewable fuel - the less the difference the higher the compliance cost will be. The compliance cost is the more sensitive of the two.

Appendix E shows the possible costs of compliance depending on these factors.

It is uncertain how these factors will evolve in the future, but they will depend on a) supply and demand of fossil-based fuels b) supply and demand of biofuels, c) innovations on carbon emissions

[2] Based on the following assumptions:
For gasoline: gasoline CI 88.14 g/MJ (BC RLCFR regulation), ethanol CI 41 g/MJ (BC weighted average ethanol CI in 2016), needed intensity in 2030 – 69.81 (estimated 2030 target based on BC target of 79.3 for 2020), gasoline wholesale price 59 cents, ethanol price 90 cents (Nov 2015), assuming in 2030 will be the same differential.
For diesel: diesel CI 94.76 g/MJ (BC RLCFR regulation), CI 15.24 g/MJ (BC weighted average biodiesel CI in 2016) , needed intensity in 2030 – 75.04 (estimated 2030 target based on BC target of 85.28 for 2020), diesel wholesale price 65 cents, biodiesel price 120 cents (Nov 2015), assuming in 2030 will be the same differential.

reduction in the fossil fuel value chain, and d) availability of low CI biofuels options in the future as demand for these fuels will grow.

Third, existing buildings and industry sectors may find it difficult to switch fuels (e.g., from natural gas) in order to comply, thus those fuel providers could be a substantial part of demand in the credits market pushing the credit price up.

Chapter 3: Emissions Impacts

This chapter provides the emission reduction by scenario, by sector and the fuel used.

Buildings

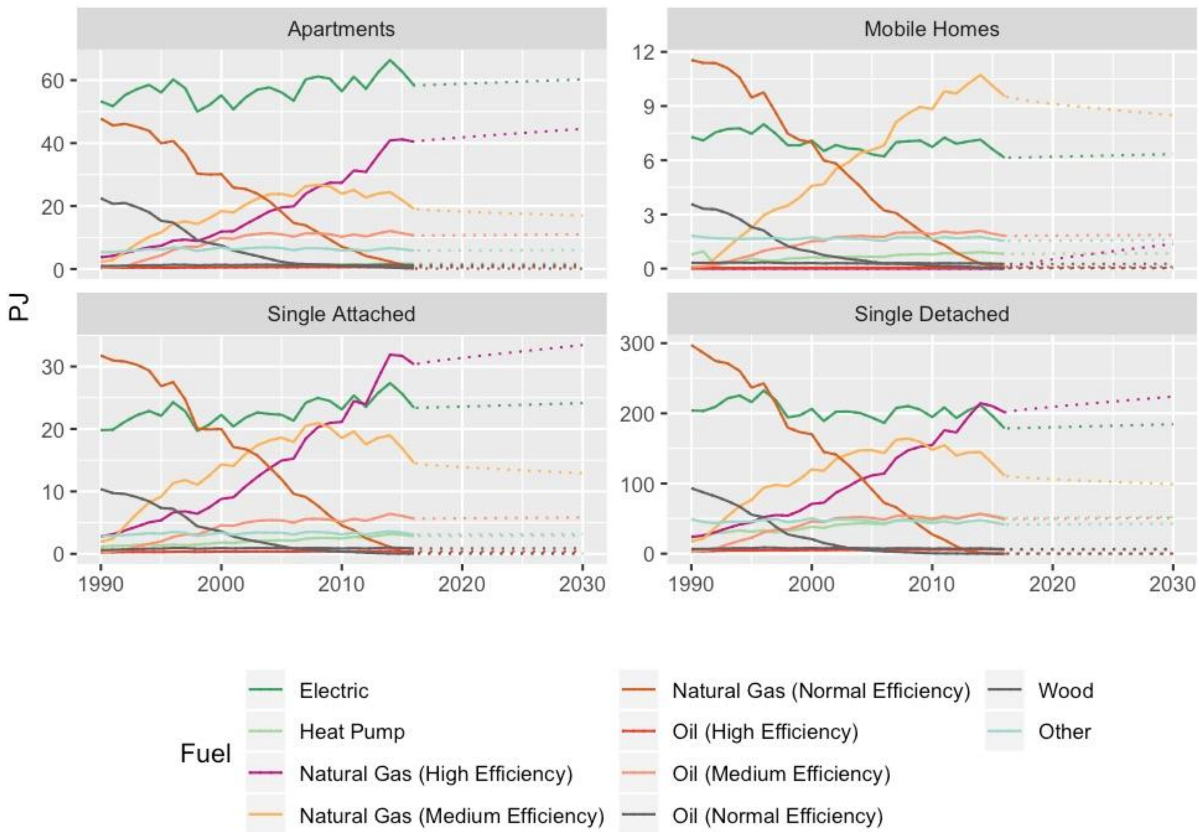
Buildings are split into residential and commercial groupings. Under the residential grouping, four classes of buildings are evaluated – single attached, single detached, apartments, and mobile homes. Figure 3.1 shows the total energy use by fuel in the residential building sector by home type, followed by Figure 3.2 that shows the commercial sector's energy use.

As depicted in Figure 3.1, not surprising, the residential sector's preferred choices for space heating are electricity and natural gas, both have dominant shares among the four types of residence. However, oil products are still used, predominantly outside of large urban centers; in some cases, it is the only choice of fuel that is available.

Looking ahead, high-efficiency natural gas use is growing the fastest (except for mobile homes that are not equipped to run on natural gas), followed by less growth in electricity for space heating. Use of crude oil products is reduced significantly over time.

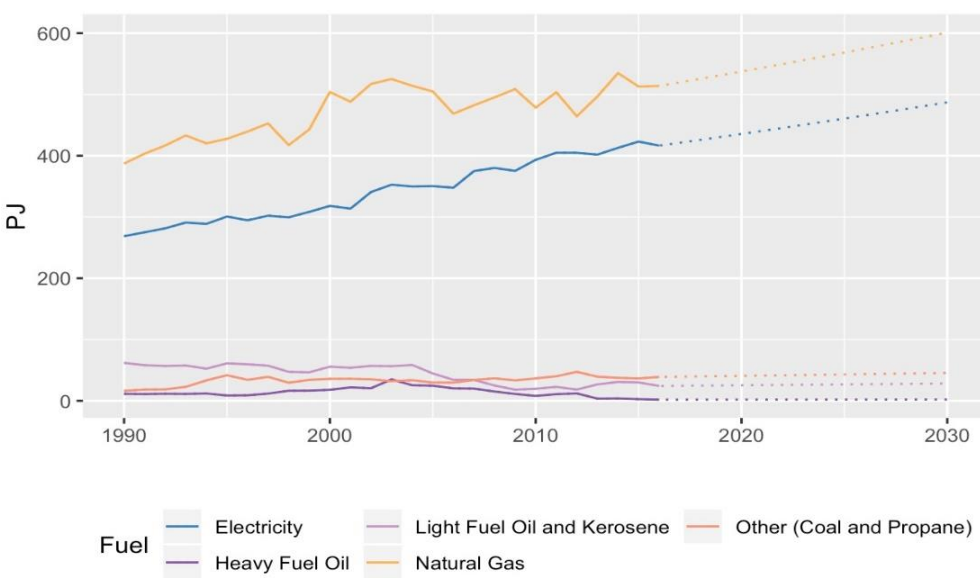
Commercial buildings experience a similar trend as the residential sector – the use of natural gas and electricity is estimated to grow, whereas demand for crude oil products, coal and propane continues to be flat.

Figure 3.1: Secondary Energy Use for Space Heating by Fuel and Home Type



Source: Tables 39, 42, 45, and 48 in Residential Sector of Comprehensive Energy Use Database from NRCan (2018a) and CERI

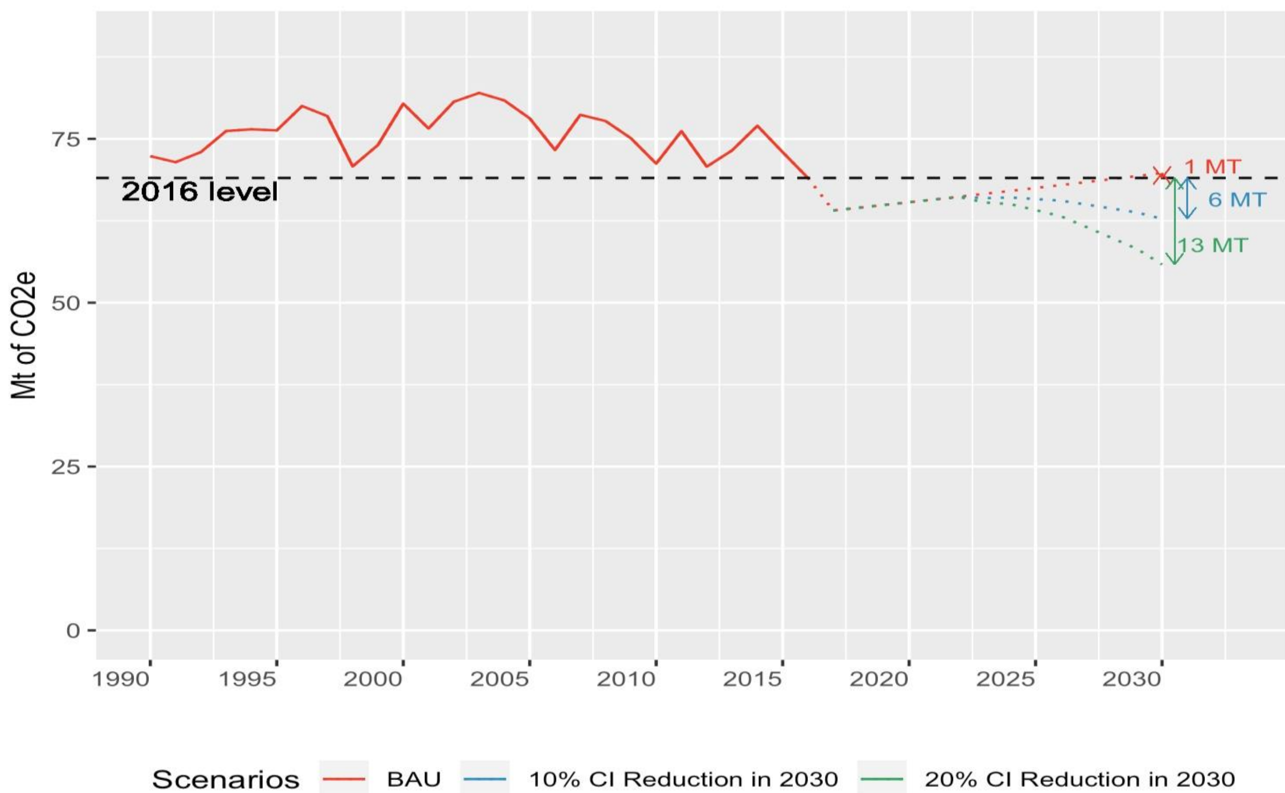
Figure 3.2: Commercial/Institutional Sector Secondary Energy Use



Source: Table 1 in Commercial Sector of Comprehensive Energy Use Database from NRCan (2018a) and CERI

Aggregating over all buildings (residential and commercial) and all end uses (space heating and water heating), CERI calculated fuel use in buildings. Using carbon intensities under different scenarios, GHG emissions associated with buildings are forecasted as shown in Figure 3.3. This figure shows that emissions from buildings will be close to its 2016 level, which is just under 70 MT, even under the BAU scenario. In other words, without doing anything, it is estimated that emissions from buildings will be around 2016 levels. Under the CI of 10% reduction, 6 MT of emission reduction can be achieved, and under the more stringent 20% reduction in CI, an overall 13 MT of emission reduction can occur.

Figure 3.3: Emissions from Buildings (excluding electricity) – Canada

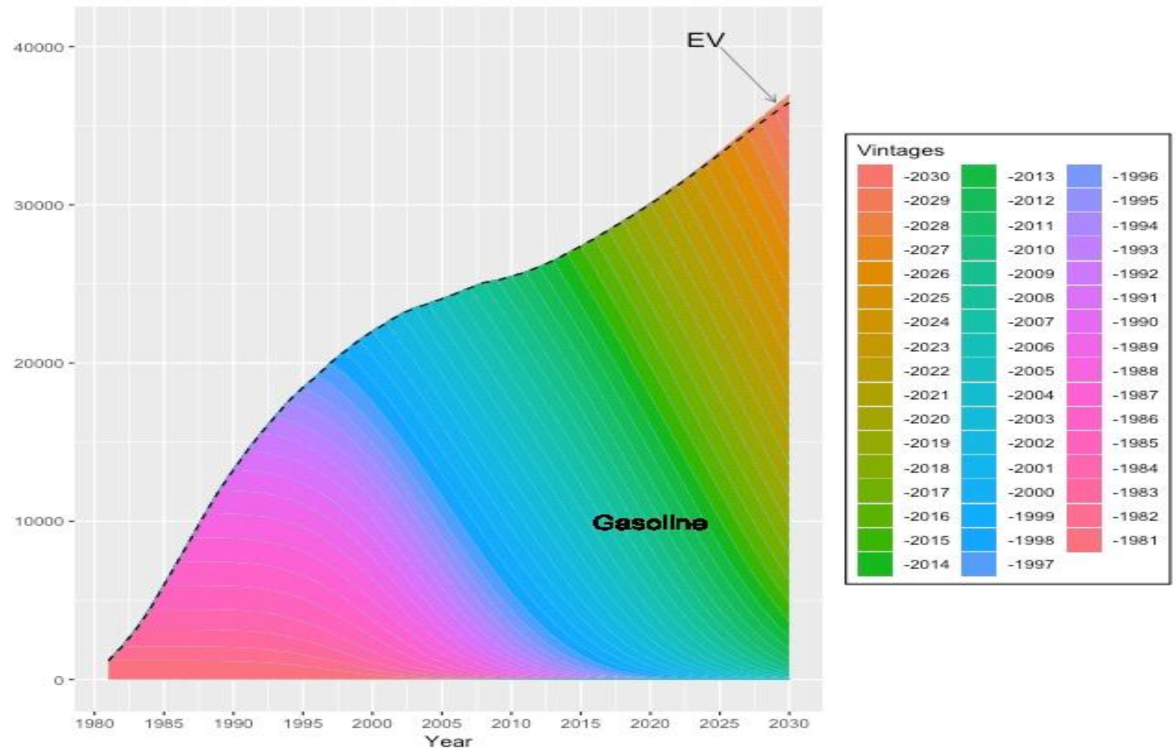


Source: Table 1 in Residential Sector and Table 1 in Commercial Sector of Comprehensive Energy Use Database from NRCan (2018a) and CERI.

Transportation

Fuel demand for the transportation sector was determined by first modelling vehicle stock levels in the future. Figure 3.4 shows the stock of passenger cars and light trucks in Canada from 1981 to 2030 under the BAU penetration of EVs (10% of annual new sales in the year 2050).

Figure 3.4: Stock of Passenger Cars and Light Trucks in Canada: 1981 to 2030

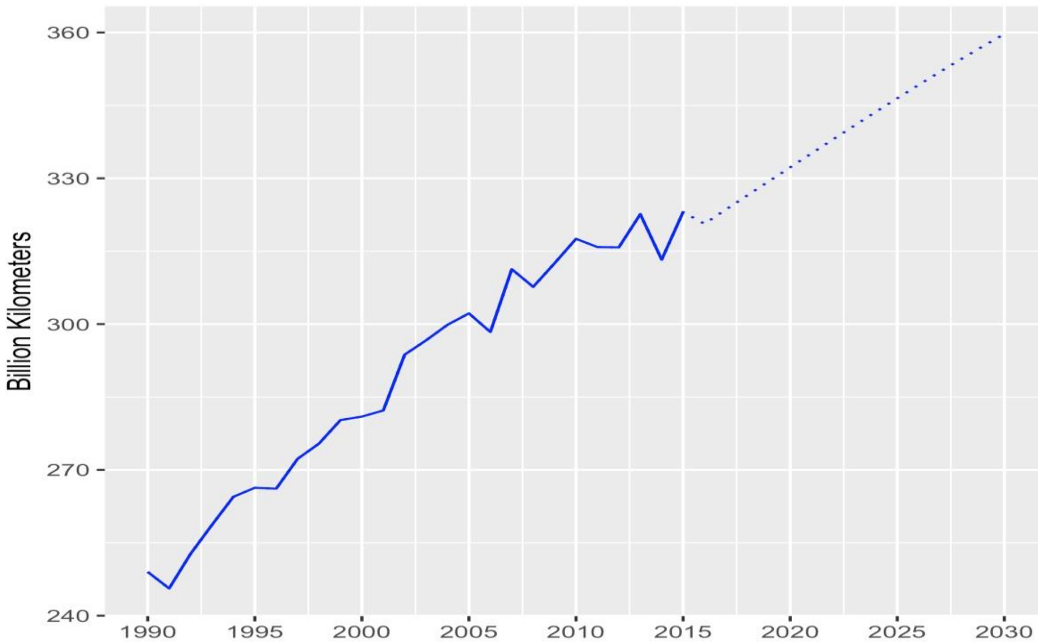


Source: Table 32 in the Transportation Sector of Comprehensive Energy Use Database from NRCan (2018a) and CERI

Vehicle stock is forecast to increase, reaching over 35 million passenger cars and light trucks on the road by 2030. Vehicles powered by traditional transportation fuels such as diesel and gasoline are still dominant in the future. Even with EV's assumed to be 10% of new annual sales by 2050, the total share of EV's in the total vehicle stock is small. This EV assumption is tested and results for more aggressive EV penetration is presented later in this chapter.

A total number of trips (and kilometres travelled) is calculated using the constant trip rate as described in the previous chapter and the NEB's population forecast. Figure 3.5 shows total kilometres travelled by passenger cars. Total travelling kilometres are forecast to increase, reaching 360 billion kilometres travelled in 2030 in Canada.

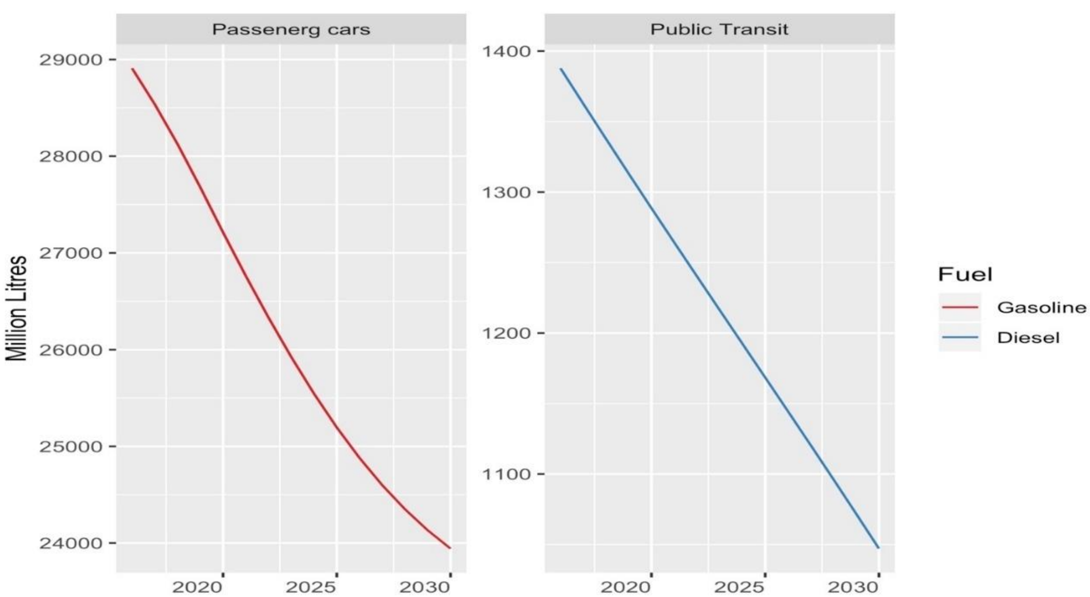
Figure 3.5: Annual Total Kilometres Travelled by Passenger Cars – Canada



Source: Tables 30 and 36 in Transportation Sector of Comprehensive Energy Use Database from NRCan (2018a) and CERI

Then, total fuel consumption is calculated using the forecasted values of total kilometres travelled by passenger cars and public transit, the share of electric and conventional vehicles in the vehicle stock and the fuel economy of the different vehicle types. Considering the assumption on the penetration of EV vehicles, Figure 3.6 shows total gasoline and diesel demand from passenger cars and public transit.

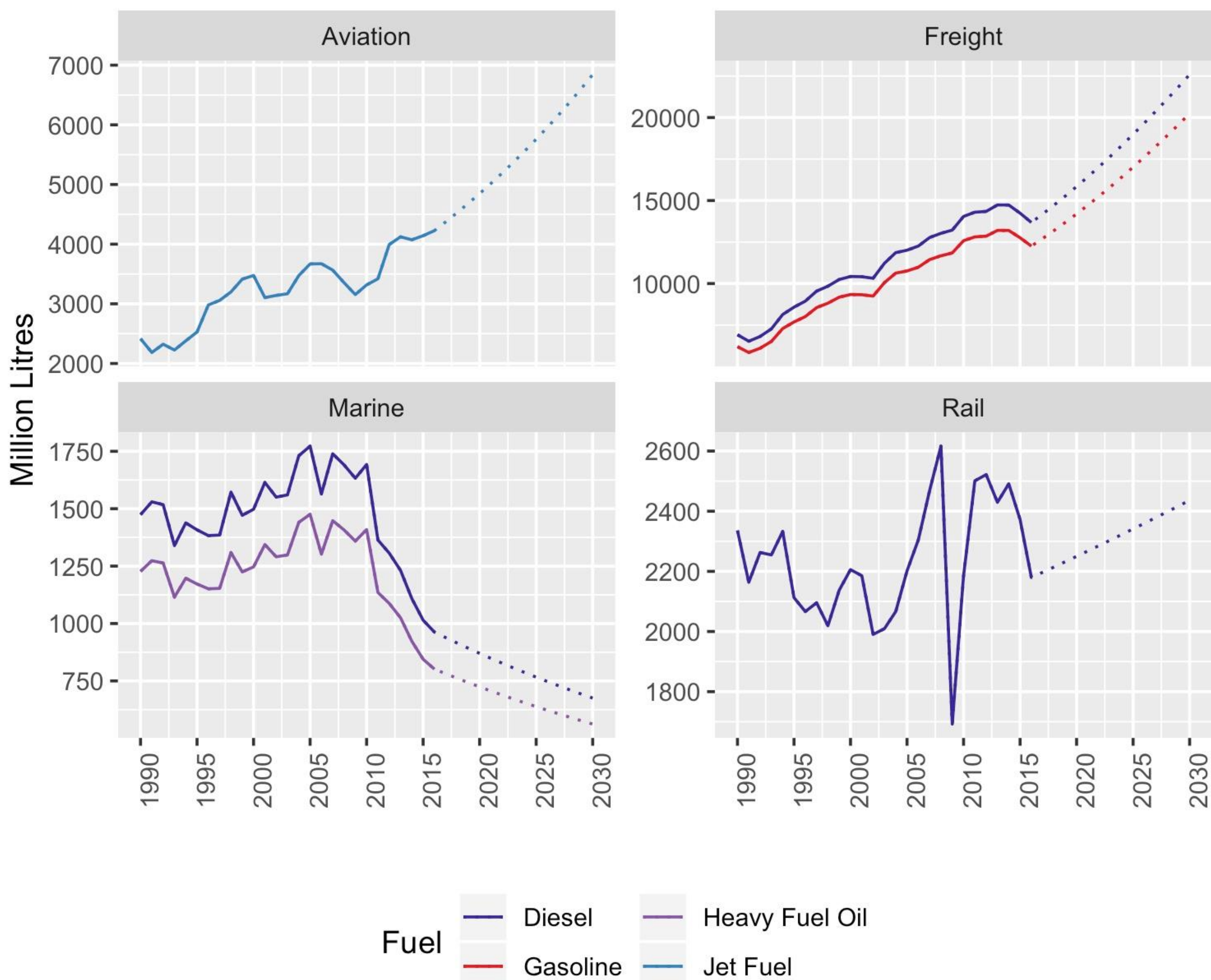
Figure 3.6: Annual Fuel Consumption in Passenger Cars and Public Transit – Canada



While total kilometres travelled increase, total fuel consumption is forecasted to decrease from now to 2030. For passenger cars, demand is set to decline by about 5 billion litres (or 17%) from 2018 to 2030, whereas public transportation will experience a decline of about 3.5 billion litres (or 25%) in the same period. The decline in gasoline and diesel demand is partly due to CAFE standards for new passenger cars, the fuel economy of public transit (assuming that fuel economy of the public transit vehicles follows the same trend as the last ten years) and partly due to the penetration of electric vehicles.

In comparison to passenger and public transit vehicles, other transportation modes display an increase in fuel consumption, with the exception of marine transportation. Since our scenarios only apply to domestic flights within Canada, for aviation CERI considered 60% of total passenger kilometres travelled in Canada is associated with domestic flights.

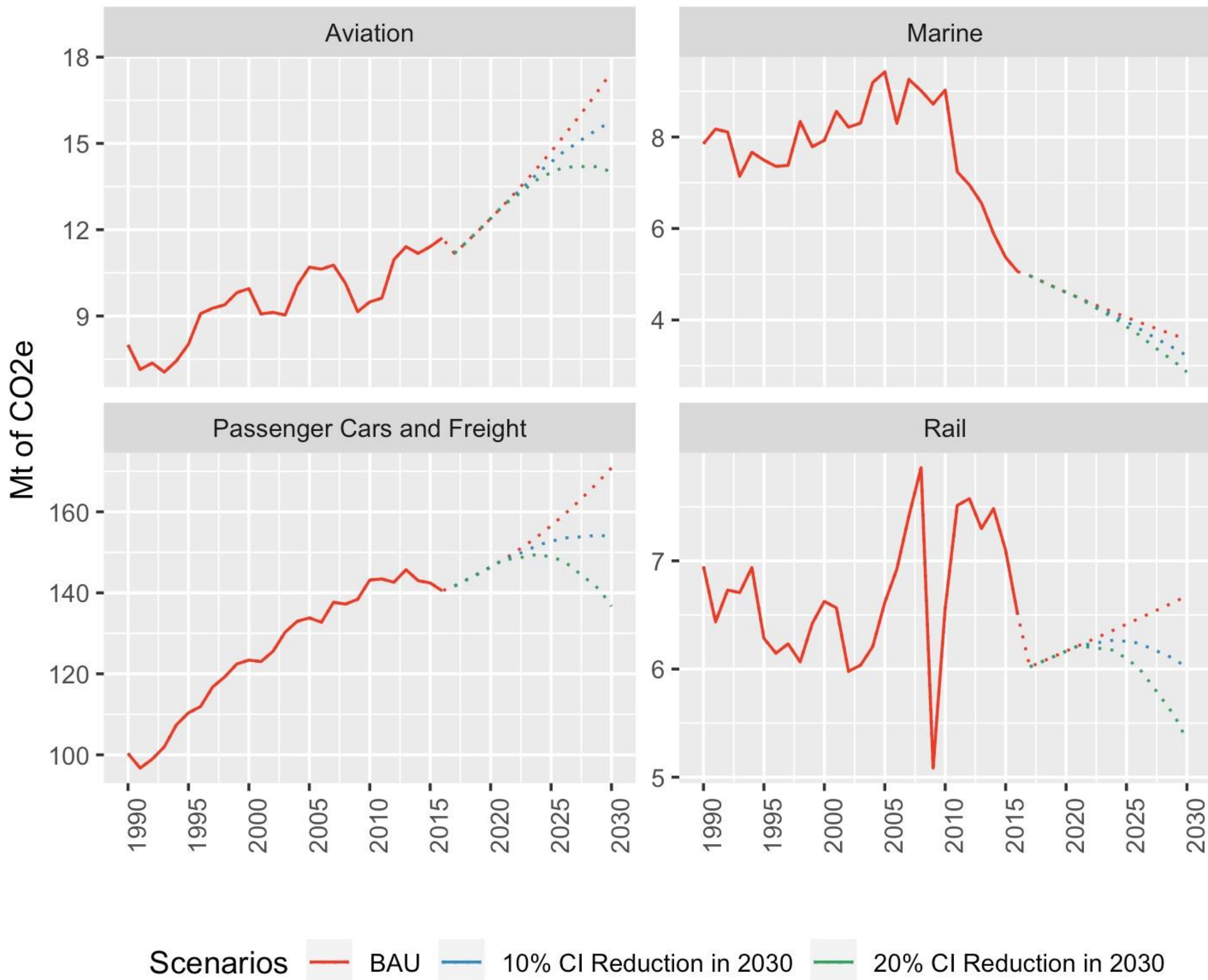
Figure 3.7: Fuel Consumption in Transportation – Canada



Source: Tables 12, 19, 25, 28, and 36 in Transportation Sector of Comprehensive Energy Use Database from NRCan (2018a) and CERI.

Using carbon intensities of fuels under different scenarios, GHG emissions of each subsector is calculated. Figure 3.8 illustrates the results for the transportation subsectors. Depicted in Figure 3.8 is a trend that shows that under BAU conditions, emissions are set to grow. When a carbon intensity reduction of 20% is applied this will produce emission reductions. Under the CI of 10% reduction, results are mixed.

Figure 3.8: Emissions in Transportation – Canada (Mt of CO2e)

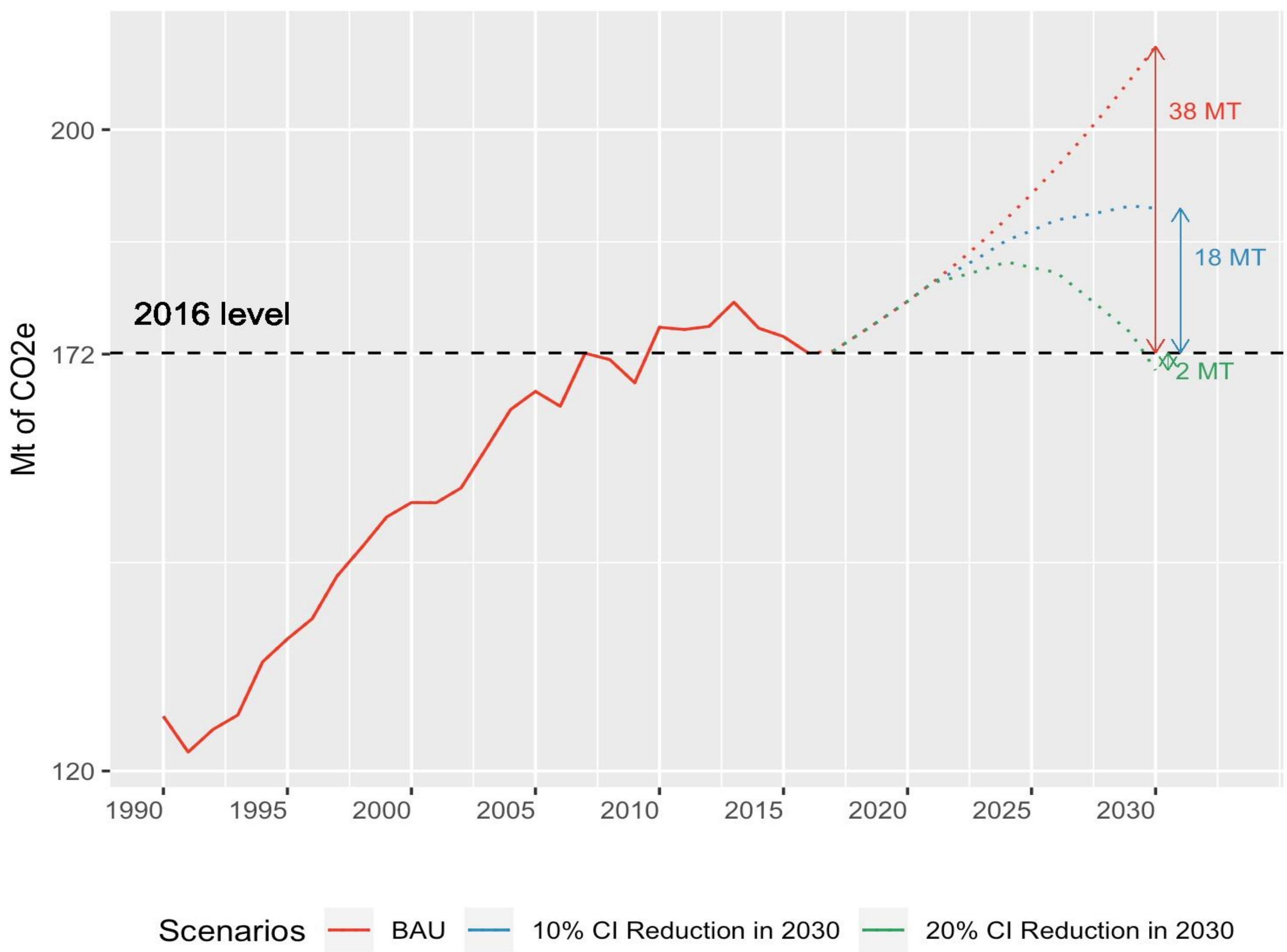


Source: Tables 12, 19, 25, 28, and 36 in Transportation Sector of Comprehensive Energy Use Database from NRCan (2018a) and CERI

Aggregating all four subsectors in transportation, Figure 3.9 shows the total emissions from the transportation sector under different scenarios. This figure shows that emissions from the transportation sector will continue to grow above its 2016 level under the BAU scenario. In fact, emissions will grow by 38 MT above the 172 MT level in 2016. Using a CI reduction of 10% is not enough to decrease transportation emissions (in fact, emissions grow by 18 MT above the 2016 level), however, avoided emissions in 2030 will amount to 20 MT (the difference between BAU emissions

and CI reduction 10% emissions). Under a more stringent 20% reduction in CI's, an overall 2 MT of emission reduction below 2016 levels can occur. One study by Vass and Jaccard (Vass and Jaccard 2017) shows that to achieve the emission reductions required from Canadian transport to meet its 2030 Paris target in an economically efficient manner, a national CFS would require a reduction in average fuel intensity for transport of 15 to 20% by 2030 relative to 2015.

Figure 3.9: Emissions from Transportation – Canada (Mt of CO2e)

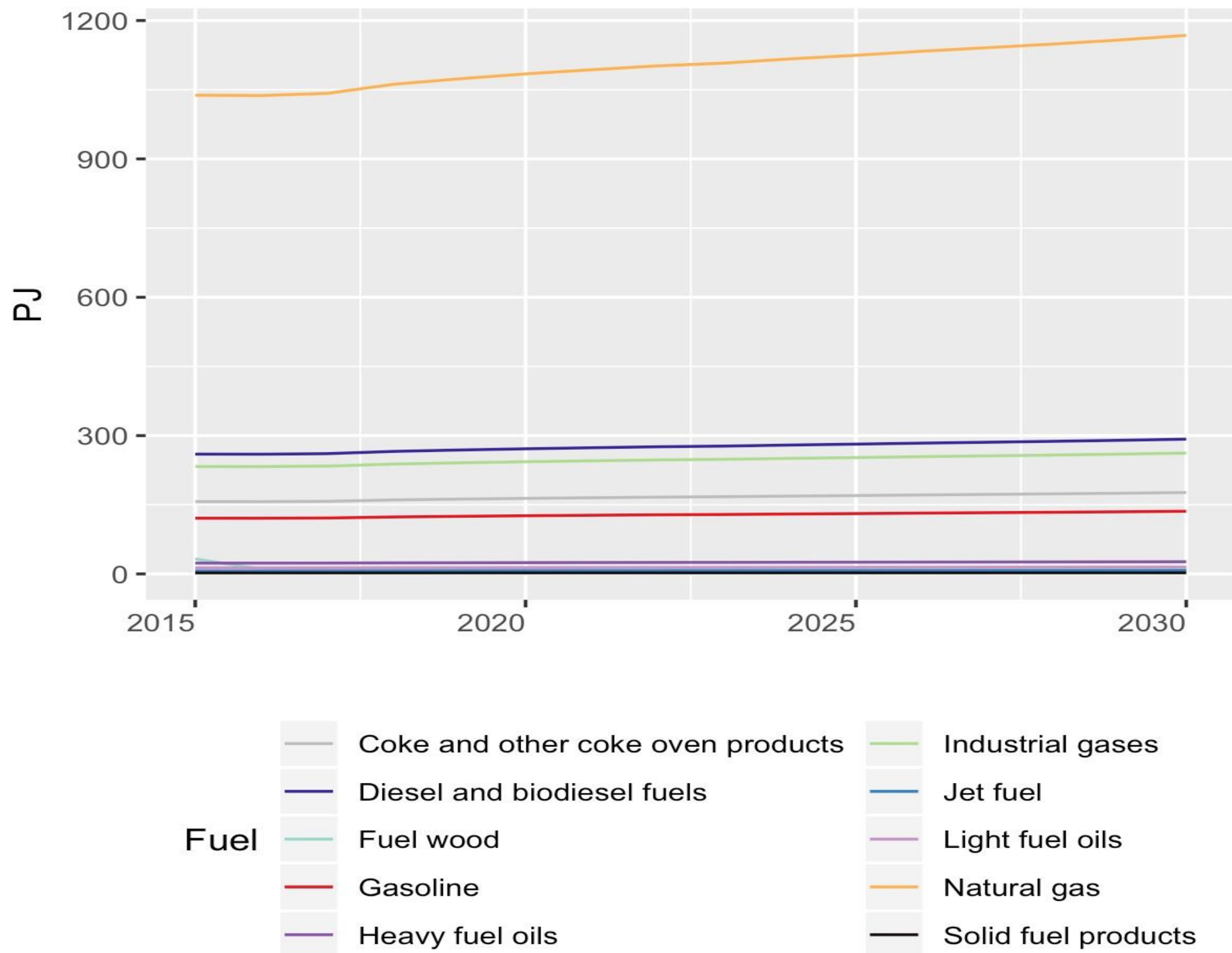


Source: Table 4 in Transportation Sector of Comprehensive Energy Use Database from NRCan (2018a) and CERI. Note: 10% penetration of EVs in new sales in 2050. International flights are excluded. The Aviation sector only includes domestic flights.

Industry

Figure 3.10 shows the fuel consumption for impacted industries. The consumption is split by fuel type for all industries. The industrial demand is made up of various fuels as identified in the Figure, of which natural gas and natural gas liquids are predominant.

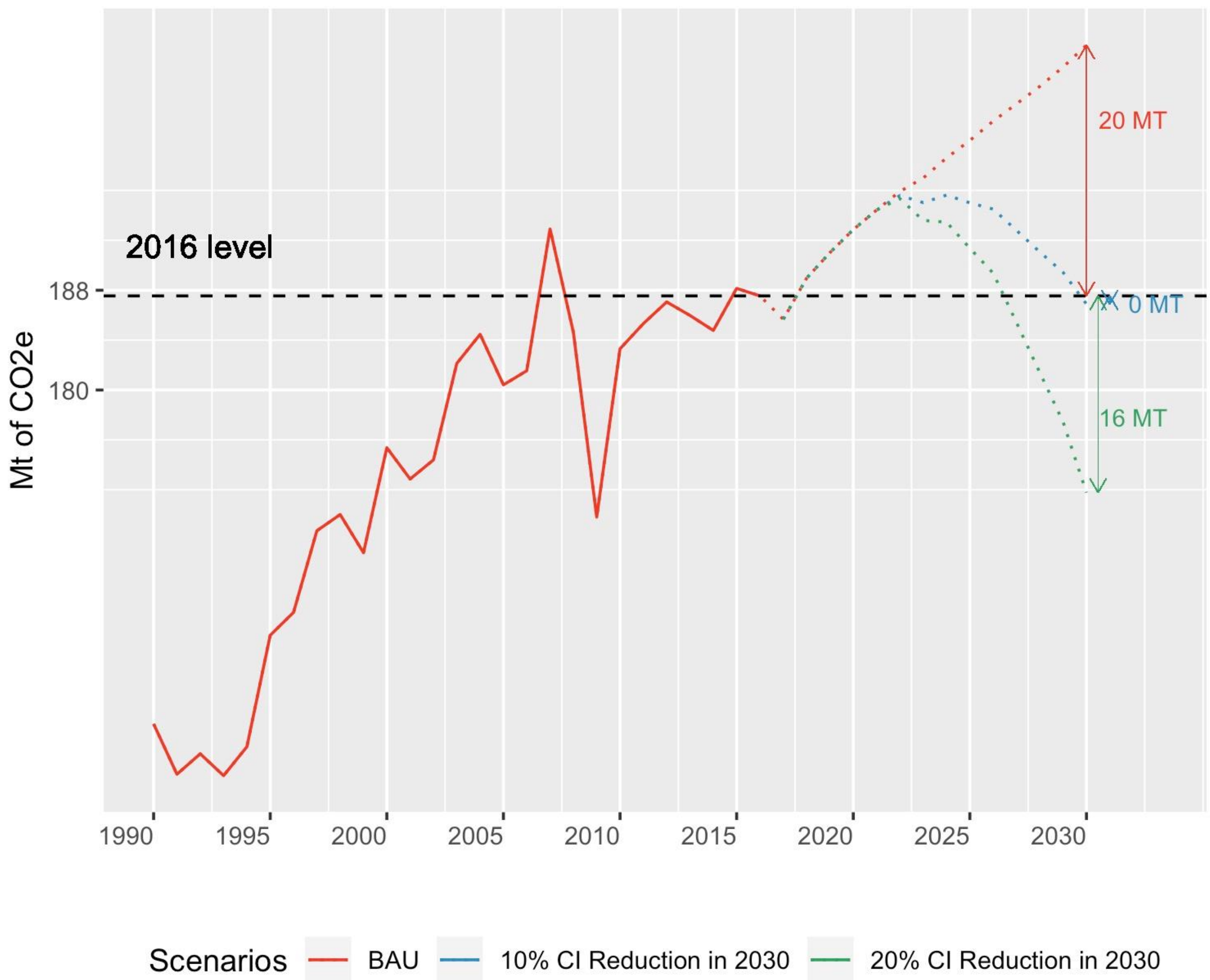
Figure 3.10: Fuel Consumption by Industry – Canada



Source: 2015 Detailed-level Input-Output (IO) Tables (Statistics Canada 2019) and CERI

Using carbon intensities of fuels under different scenarios and aggregating all industries results in total GHG emissions forecasts as shown in Figure 3.11.

Figure 3.11: Emissions from Industry Sector (Including Agriculture) – Canada



Source: Table 3 in Industrial Sector of Comprehensive Energy Use Database of NRCan (2018a) and CERI

Similar to the transportation sector, the industry sector exhibits an increase in BAU emissions of 20 MT above the 2016 level of 188 MT. A CI reduction of 10% will produce avoided emissions in the order of 20 MT, but no emission reduction; in fact, emissions will be around the 2016 level. Under a 20% CI reduction, emissions will be 16 MT lower than 2016 levels.

Agriculture

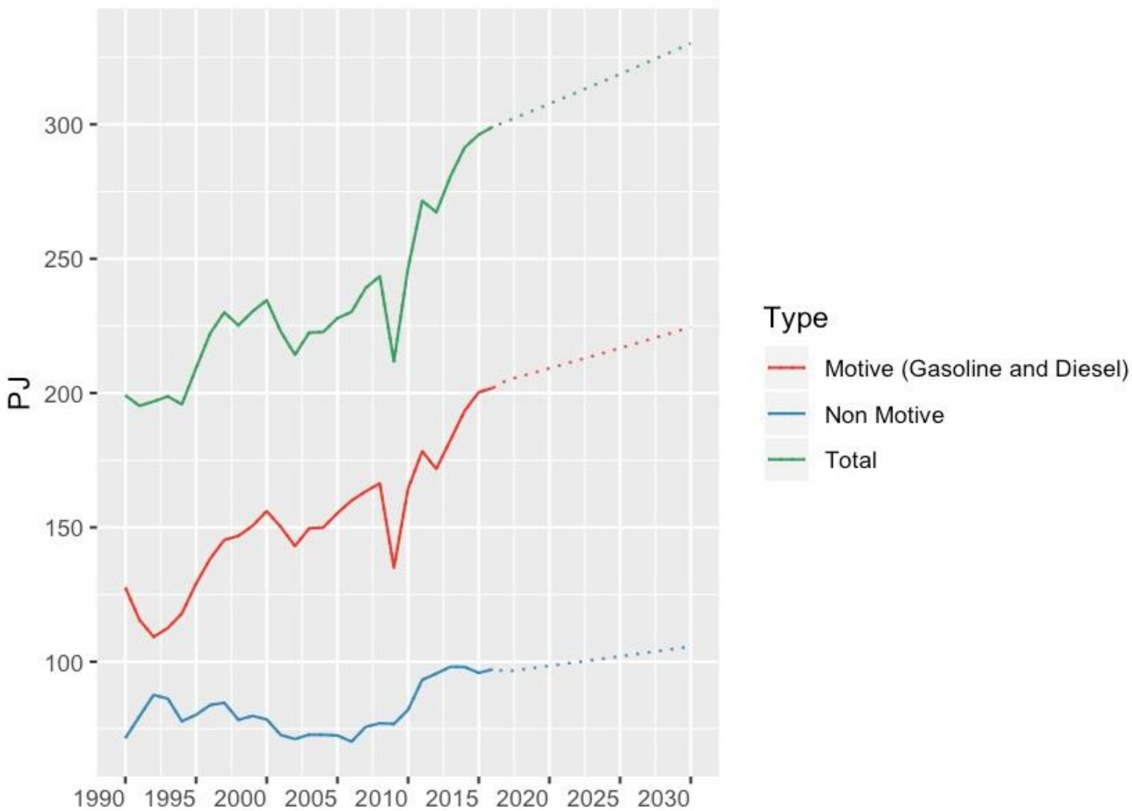
The amount of energy used in the agricultural sector has steadily increased over the last 10 years. In 2016 approximately 299 petajoules were consumed,[1] with motive energy uses accounting for over

[1] http://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/showTable.cfm?type=CP&sector=agr&juris=ca&rn=1&page=0

68% (Figure 3.12). Out of seven fuels used, diesel provided over 47% of nationwide agriculture energy needs (Figure 3.13) followed by gasoline (20%), and electricity and natural gas (12.7%).

The future demand for fuels is estimated to grow by 0.7% annually and reach 290.4 PJ in 2030 from 263 PJ in 2015.

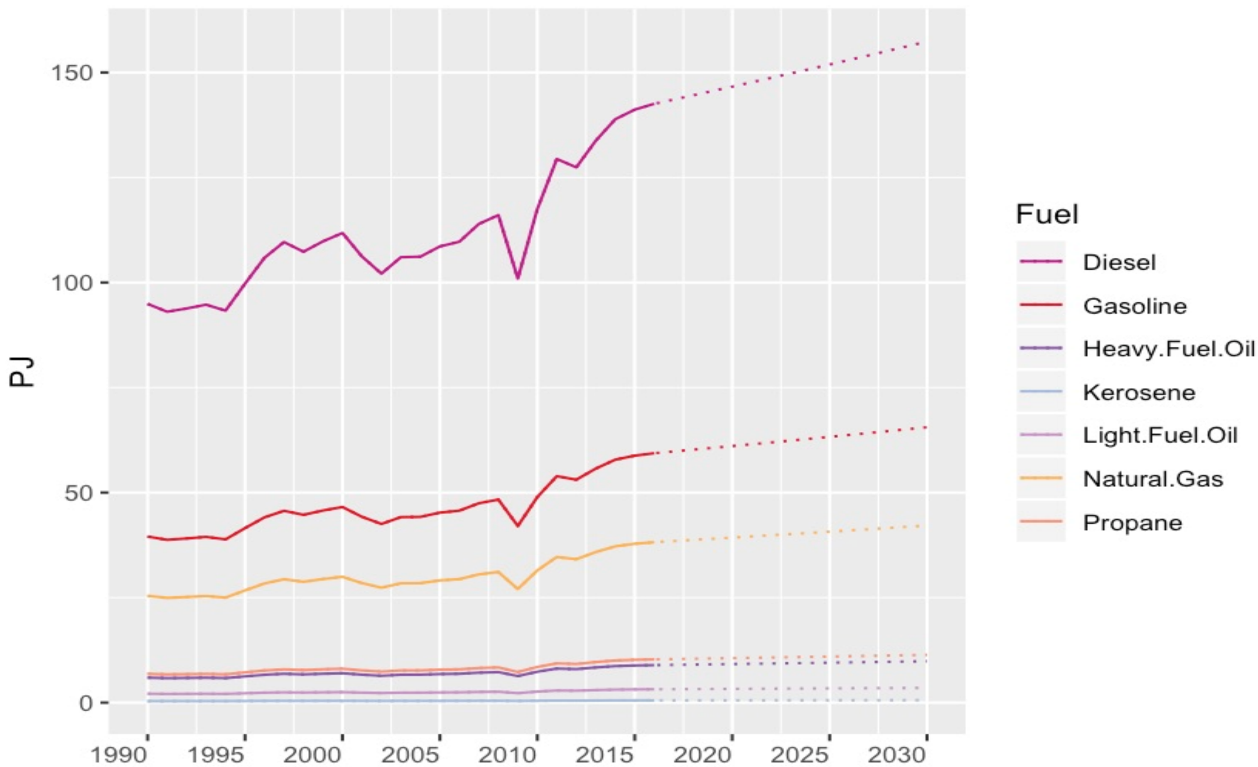
Figure 3.12: Agriculture Energy Consumption by Type – Canada



Source: Table 2 in Agriculture Sector of Comprehensive Energy Use Database of (NRCan 2018a)

In 2016, total energy use was 299.1 PJ, motive energy use was about 201.9 PJ and the rest – 97.2 PJ – was generated from non-motive energy sources. Motive energy sources refer to diesel fuel and gasoline, non-motive sources are listed in the next figure. 2030 projections show a steady increase in energy use.

Figure 3.13: Agriculture Energy Use by Fuel – Canada

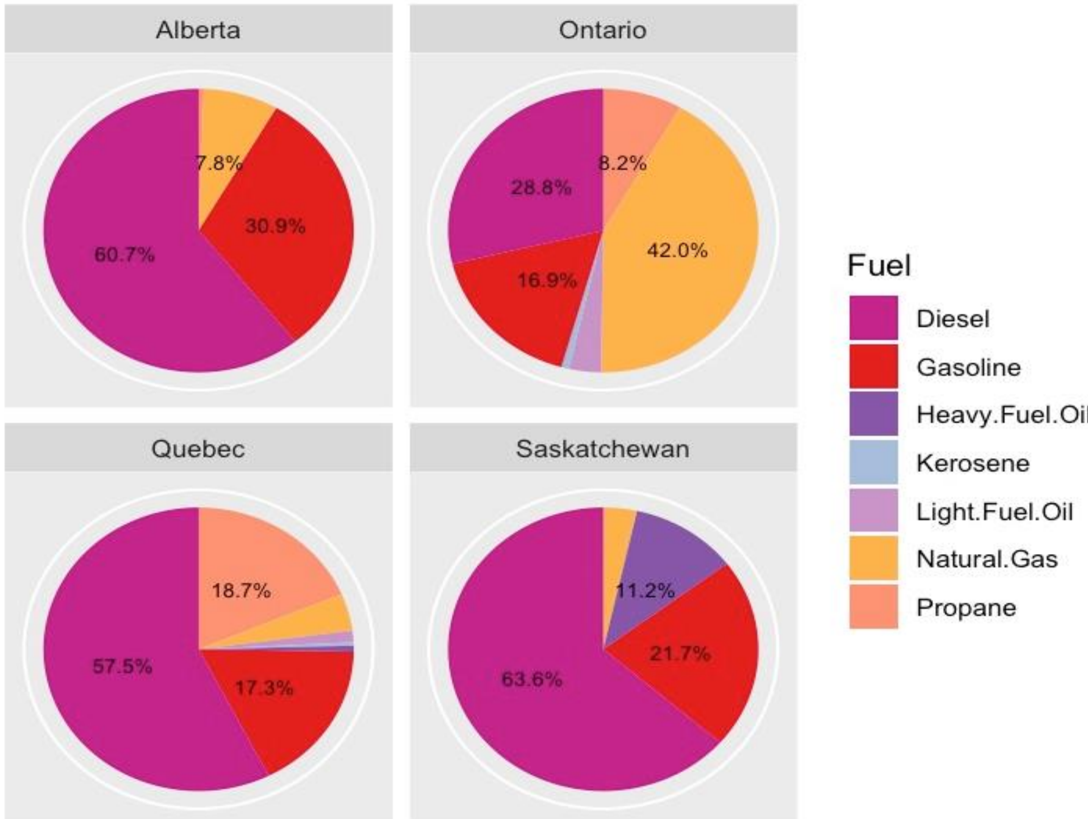


Source:(NRCan 2018a)

In 2016, diesel fuel supplied about 142.5 PJ of energy, followed by gasoline with 59.4 PJ, natural gas and electricity at 38.2 PJ and 36.1 PJ, respectively. Propane provided about 10.3 PJ, heavy fuel oil – 8.9 PJ, light fuel oil – 3.2 PJ, and kerosene at only 0.5 PJ

In most provinces both diesel and gasoline use is on an upward trend and diesel fuel share dominates in total consumption. Figure 3.14 illustrates fuel shares for the top four provinces in terms of the agriculture sector's contribution to GDP in 2016 (in $2007): Ontario ($4,969 million), Saskatchewan ($3,901 million), Quebec ($3,395 million), and Alberta ($3,230 million). Together, these provinces account for over 80% of energy consumption in the agriculture sector in Canada. In Ontario and British Columbia, natural gas has started to play a more significant role and has surpassed gasoline demand in the sector. A provincial breakdown of fuel consumption in agriculture from 1990 to 2015 can be found in Appendix A.

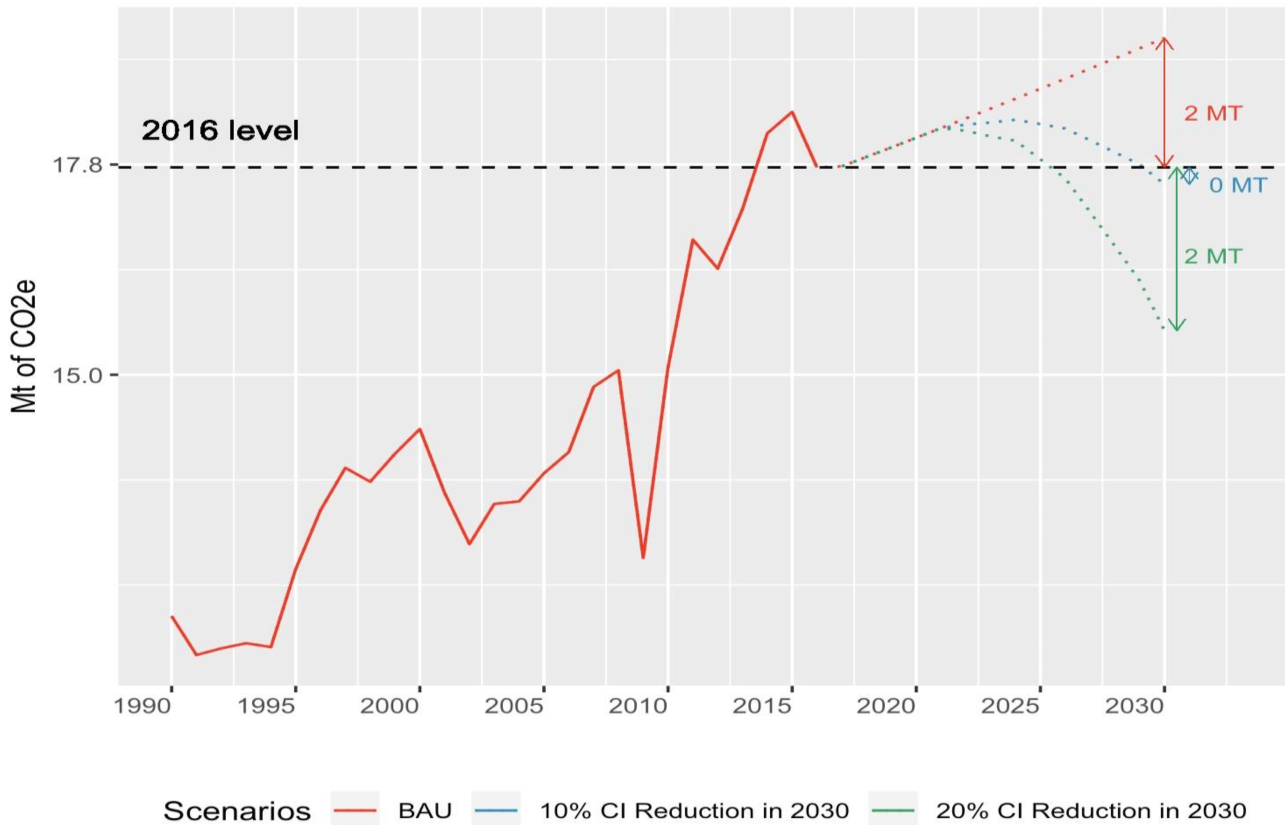
Figure 3.14: Top Agriculture Provinces – 2016 Energy Use



Source: Provincial Tables in Agriculture Sector of Comprehensive Energy Use Database of (NRCan 2018a) and CERI

Using carbon intensities under different scenarios, GHG emissions of the agriculture sector are calculated as shown in Figure 3.15. Overall emissions from agriculture have been rising since 2010, surpassing 17.8 MT in 2016. Under the BAU, emissions rise by an additional 2 MT in 2030; under the CI of 10% reduction, emissions will be around the 2016 level in 2030 and avoided emissions amount to 2 MT. Under the CI of 20% reduction, emissions are 2 MT below the 2016 level.

Figure 3.15: Emissions from Agriculture (excluding electricity) – Canada



Source: Table 2 in Agriculture Sector of Comprehensive Energy Use Database of NRCan (2018a) and CERI.

Total Emissions from All Sectors

Table 3.1 shows emission reductions in each sector as compared to the 2016[2] emission level under alternative carbon intensity reduction scenarios. As shown in the table, the 10% CI reduction scenario will result in avoided emissions in the year 2030 of 47 MT (59 MT - 12 MT) of CO2eq. below BAU in 2030 but still 12 MT above the 2016 emission level. A uniform carbon intensity reduction rate of 20%, our second scenario, is demonstrated to reach 31 MT below 2016 levels.

[2] 2016 is the last year that energy and GHG emissions are available from the Comprehensive Energy Use database (NRCan 2018a).

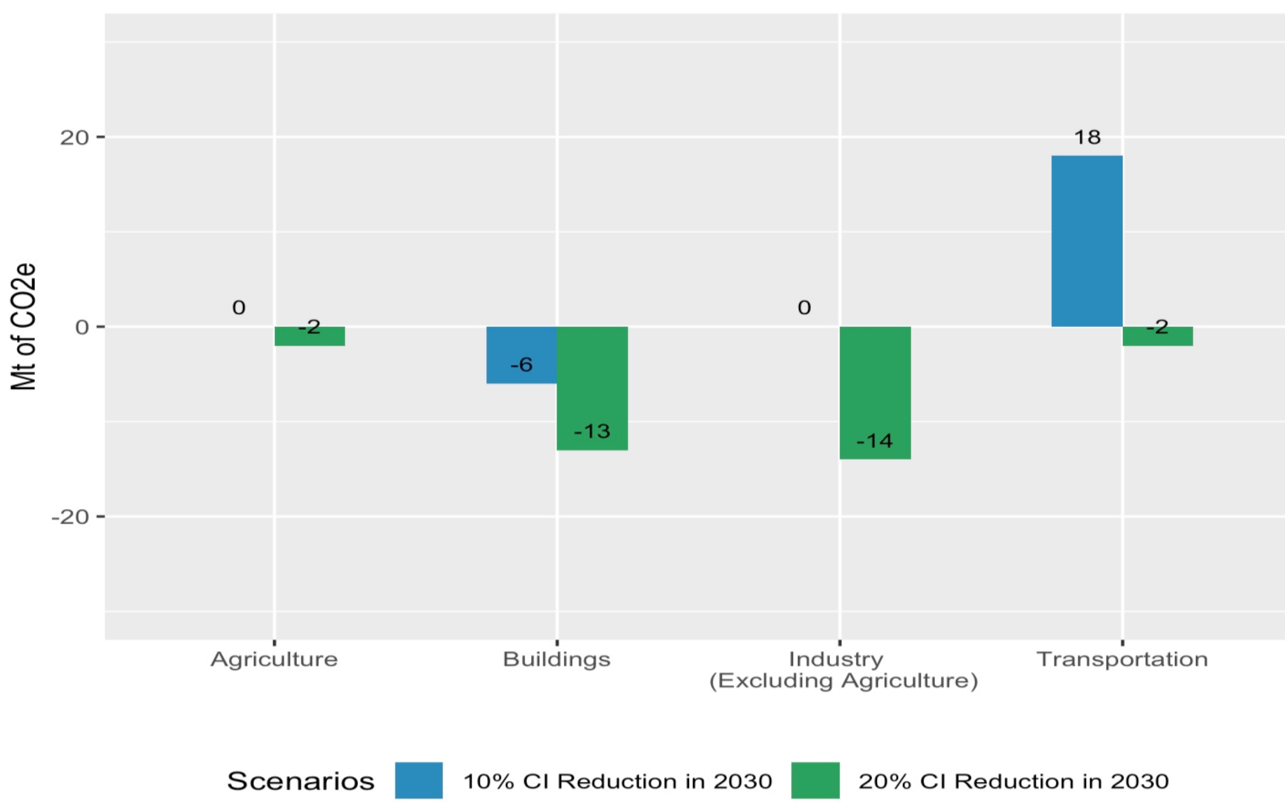
Table 3.1: Change of Emissions in 2030 Compared to 2016 Levels (MT of CO2e) – 10% EV Penetration in 2050

Sectors \ Carbon Intensity Reduction in 2030	BAU	10%	20%	25%	30%	35%
Transportation (10% penetration of EV in new sales in 2050)	38	18	-2	-12	-22	-32
Buildings	1	-6	-13	-17	-20	-24
Industry (Excluding Agriculture)	18	0	-14	-29	-38	-47
Agriculture	2	0	-2	-3	-4	-5
Total	59	12	-31	-61	-84	-108

Source: CERI

Isolating the two scenarios from Table 3.1 – CI of 10% and CI of 20% reduction – and comparing emission reductions in 2030 to 2016 levels are shown in Figure 3.16, by sector.

Figure 3.16: Change of Emissions in 2030 Compared to 2016 Levels

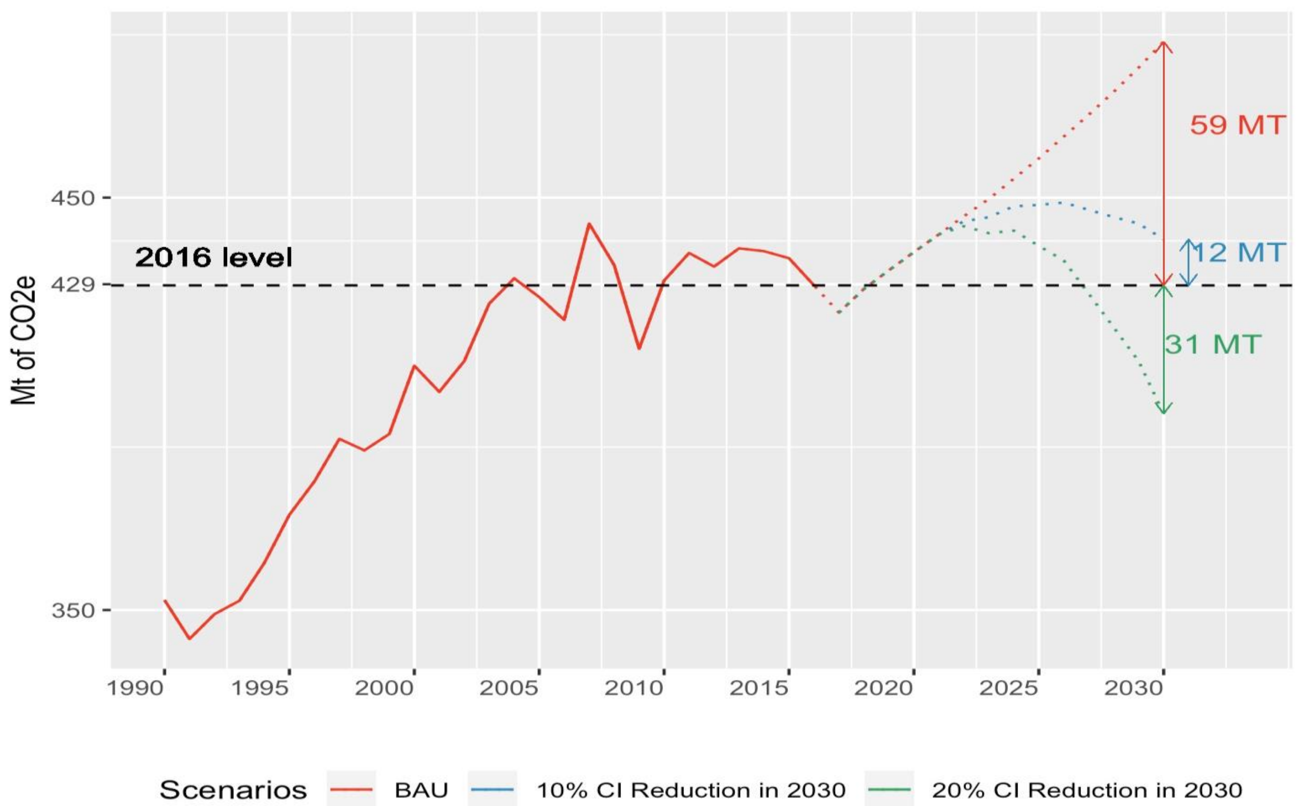


Source: CERI

The largest emission reductions can be realized in the very energy-intensive transportation sector, where fuel substitutability is limited.

Summing up emissions for all sectors (i.e., buildings, transportation, industry, and agriculture), Figure 3.17 shows total emissions in the Canadian economy under three scenarios – BAU, CI 10% reduction and CI 20% reduction.

Figure 3.17: Total Emissions – Canada



Source: Historical data comes from Table 1 in Residential Sector, Table 1 in Commercial Sector, Table 3 in Industrial Sector, Table 2 in Agriculture sector, and Table 4 in Transportation Sector from the Comprehensive Energy Use Database of NRCan (2018a) and CERI

Case Study: Aggressive Electrification in Transportation

This section explores the effects of more rapid penetration of electric vehicles in the transportation sector. In the previous sections, the penetration rate of electric vehicles in the transportation sector (i.e., passenger cars and freight) was 10% of new vehicle sales in the year 2050. The following tables and figures show emission reductions in all sectors if the penetration rates of EVs increase to 50% and 90% of the new vehicle sales in 2050.

Table 3.2 and Figure 3.18 illustrate a case of EV's at 50% penetration rate and Table 3.3 and Figure 3.19 illustrate a case of EV's at 90% penetration. With more aggressive electrification of the

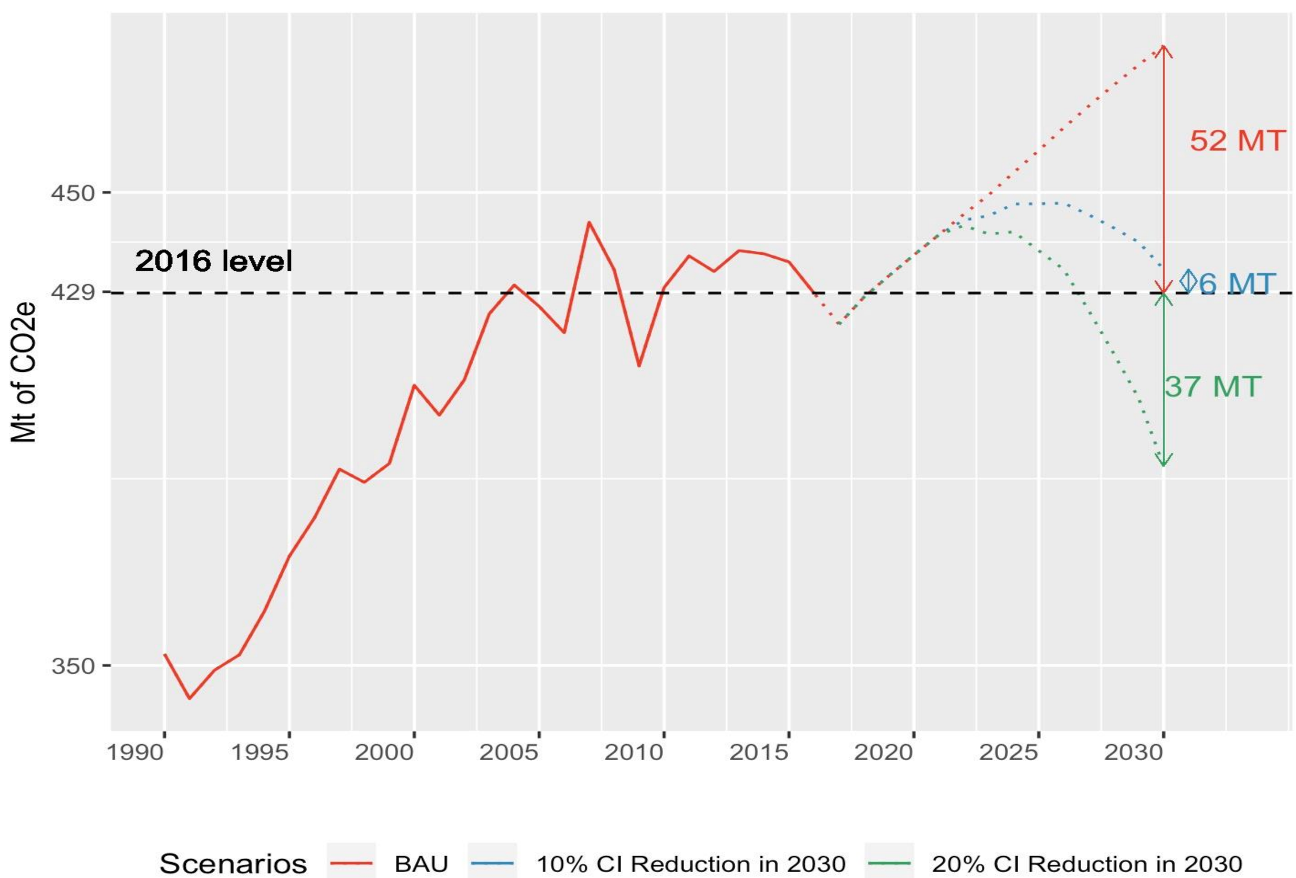
transportation fleet, reducing carbon intensities in 2030 by a rate of 20% would reach emission reduction of 37 MT below 2016 levels.

Table 3.2: Change of Emissions in 2030 Compared to 2016 Levels (MT of CO2eq) – 50% EV Penetration in 2050

Sectors \ Carbon Intensity Reduction in 2030	BAU	10% (CFS)	20%	25%	30%	35%
Transportation (50% penetration of EVs in new sales in 2050)	31	12	-8	-17	-27	-37
Buildings	1	-6	-13	-17	-20	-24
Industry (Excluding Agriculture)	18	0	-14	-29	-38	-47
Agriculture	2	0	-2	-3	-4	-5
Total	52	6	-37	-66	-89	-113

Source: CERI

Figure 3.18: Total Emissions Compared to 2016 Levels - 50% EV Penetration in 2050



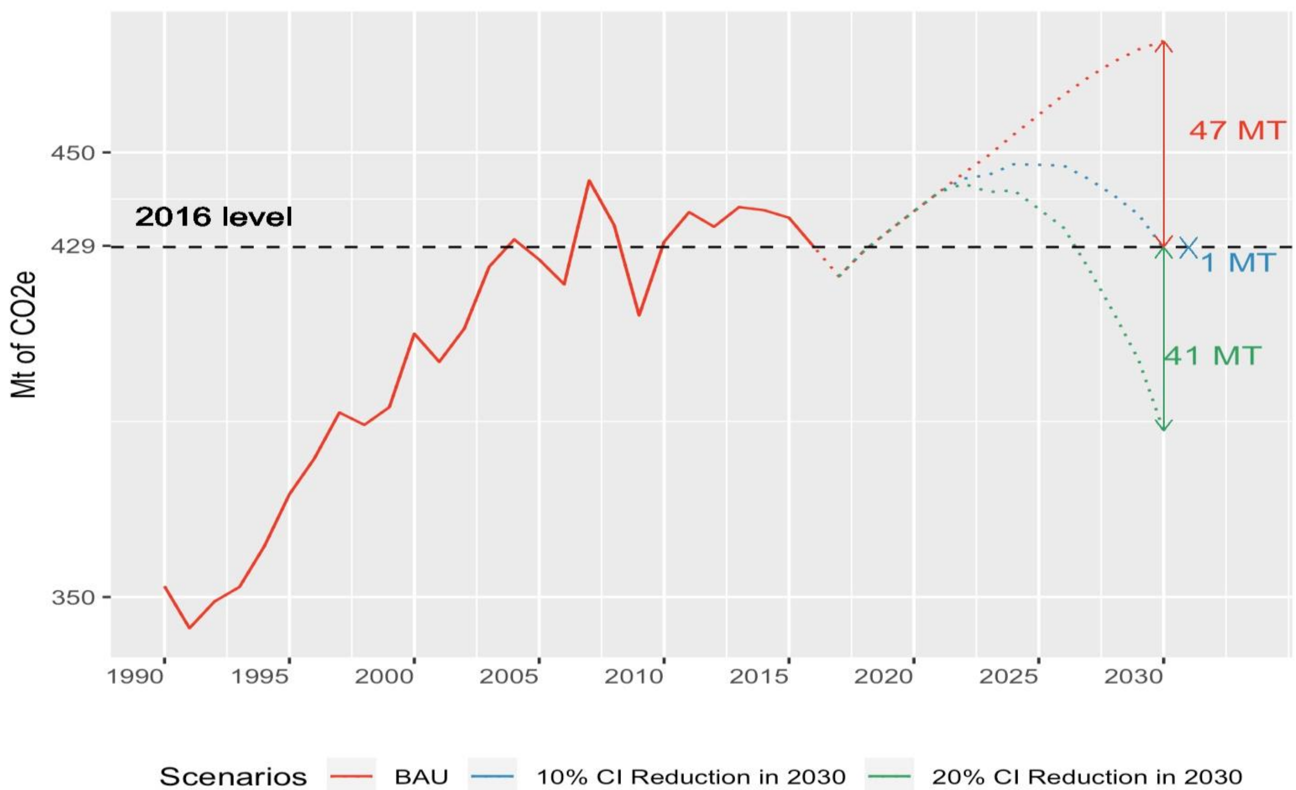
Source: NRCan (2018a) and CERI

Table 3.3: Change of Emissions in 2030 Compared to 2016 Level (MT of CO2eq) – 90% EV Penetration in 2050

Sectors \ Carbon Intensity Reduction in 2030	BAU	10% (CFS)	20%	25%	30%	35%
Transportation (90% penetration of EVs in new sales in 2050)	26	7	-12	-22	-31	-41
Buildings	1	-6	-13	-17	-20	-24
Industry (Excluding Agriculture)	18	0	-14	-29	-38	-47
Agriculture	2	0	-2	-3	-4	-5
Total	47	1	-41	-71	-93	-117

Source: CERI

Figure 3.19: Total Emissions Compared to 2016 Levels – 90% EV Penetration in 2050

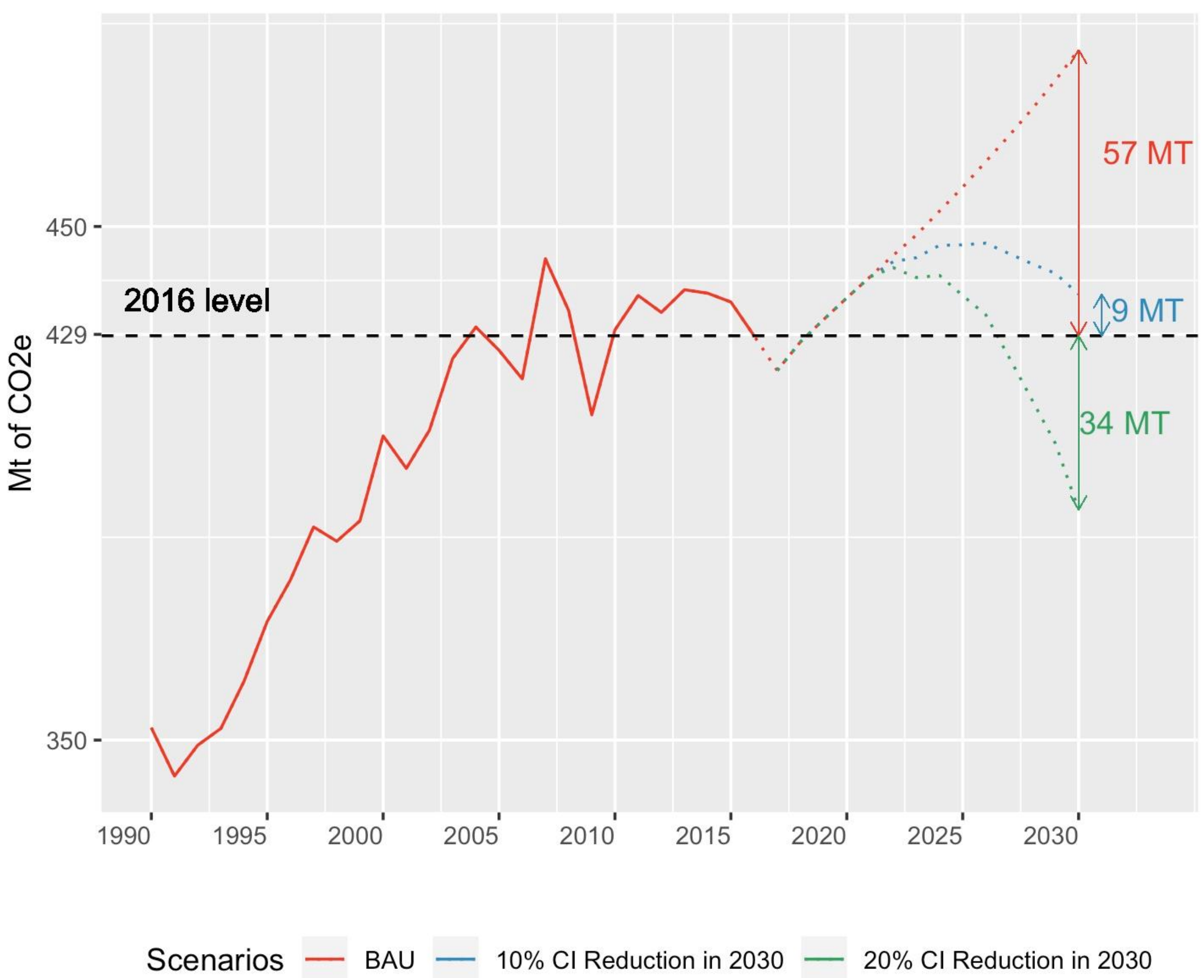


Source: NRCan (2018a) and CERI

Case Study: Heavy-Duty Vehicle and Engine Greenhouse Gas Emission Regulations

CAFE Standards used in the previous sections were only for passenger cars and light trucks. However, Heavy-Duty Vehicle and Engine Greenhouse Gas Emission Regulations will introduce higher standards for heavy-duty vehicles and engines in the model year 2021, and they will increase in stringency up to the model year 2027 to give heavy-duty vehicle manufacturers and owners time to adapt. Based on this regulation, the CO2 emission standard (g/tonne- mile) for 2017 and subsequent model years will improve by around 3% compared to model years 2014 to 2016 (see tables 5 and 6 in Environment Canada (2015)). Therefore, this case study assumes the fuel economy of heavy-duty vehicles will improve by 3% in 2030 compared to 2016. With this improvement in fuel economy of the freight transportation, as shown in Figure 3.20, reducing carbon intensities by 20% will result in 34 MT total emission reduction (for all sectors) below 2016 levels.

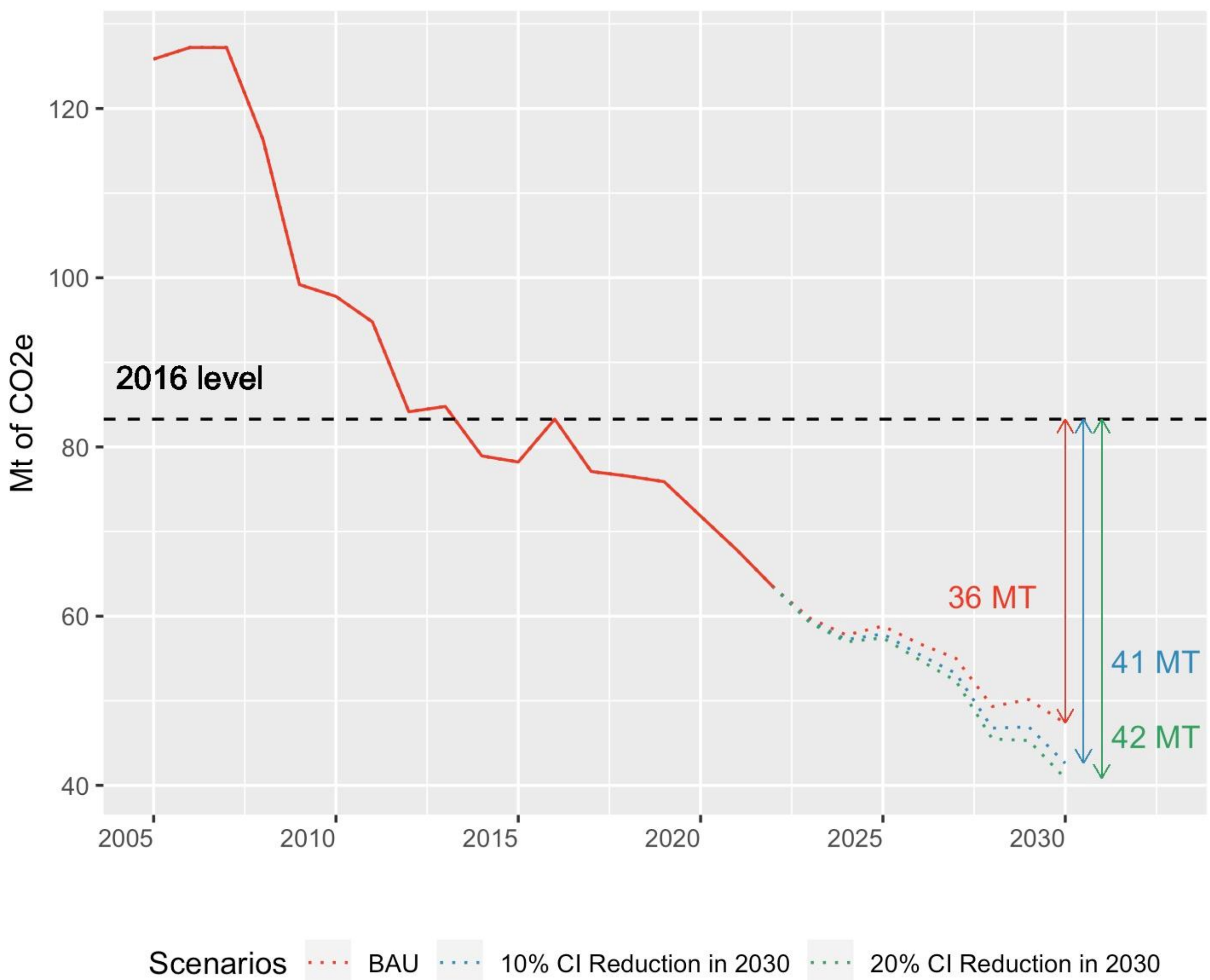
Figure 3.20: Total Emissions Compared to 2016 Levels with Improvement in Fuel Economy of Heavy-Duty Vehicles



Case Study: Electricity Generation

Since electricity was excluded in the previous sections, emissions from electricity generation are examined separately. Figure 3.21 shows emissions from electricity generation under different scenarios. Historical and future generation by fuel from Canada's Energy Future 2018 (National Energy Board 2018) is used to calculate emissions under different scenarios. As shown in the Figure, emissions from electricity generation will remain under 2016 levels even under the BAU scenario.

Figure 3.21: Total Emissions – Electricity Generation – Canada



Source: Canada's Energy Future 2018 of National Energy Board (2018) and CERI

Chapter 4: Fuel Cost Implications

This chapter provides the impact on retail prices and costs due to fuel decarbonization under two CI reduction scenarios and two credit price options. The first section shows the cost implications for different fuels and fuel types. The second section provides sector-wide cost impacts. Dollar values are expressed in Canadian 2015 dollars unless otherwise specified.

Cost Impacts by Fuel

Modelling results are presented in Table 4.1 and Figure 4.1.

Table 4.1: Fuel Decarbonization Price Impacts

Carbon Credit Price	Diesel		Gasoline		Gaseous (median of all fuels)		Liquids (median of all fuels)		Solids (median of all fuels)	
	CI 10%	CI 20%	CI 10%	CI 20%	CI 10%	CI 20%	CI 10%	CI 20%	CI 10%	CI 20%
	$ / litre				$ / GJ					
$50	0.01	0.03	0.01	0.02	0.23	0.47	0.35	0.70	0.44	0.88
$200	0.06	0.11	0.05	0.10	0.94	1.88	1.41	2.81	1.76	3.51

Source: CERI

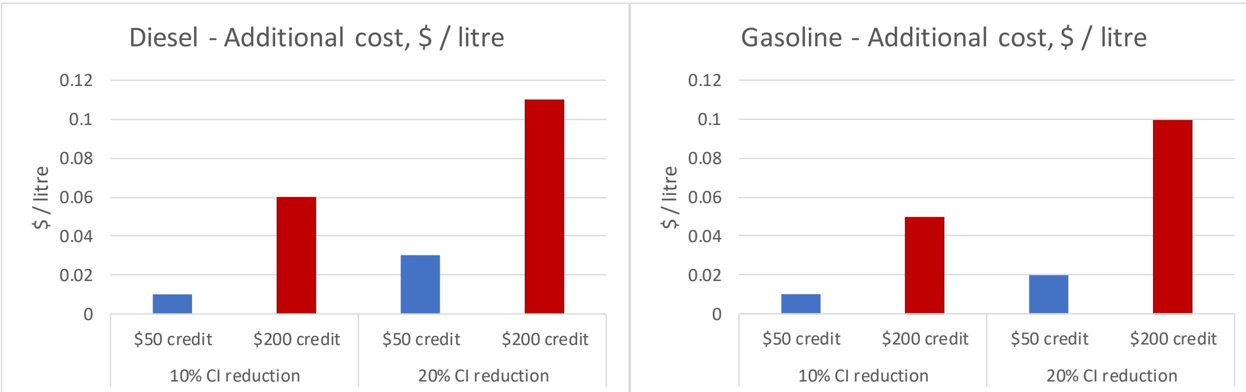
It is important to note that CERI assumes that all costs of credits will be passed onto consumers while credit receivers will keep all revenues. As such, these estimates represent the maximum predicted prices provided that other assumptions hold true. This cost of the credit does not include full compliance costs.

The national retail average price of regular gasoline in 2019 was 109 cents per litre.[1] Additional costs for diesel and gasoline by 2030 with a $200 credit price are expected to be between 5-6 cents per litre with a 10% CI reduction target, and 10-11 cents with a 20% CI reduction.

The results are consistent with other estimates of a $US 12-14 cent increase per gallon in California ($CAD 4.2-4.9 per litre) which aimed at a 10% CI reduction.

[1] https://www.nrcan.gc.ca/energy/fuel-prices/gasoline-reports/18031#link3

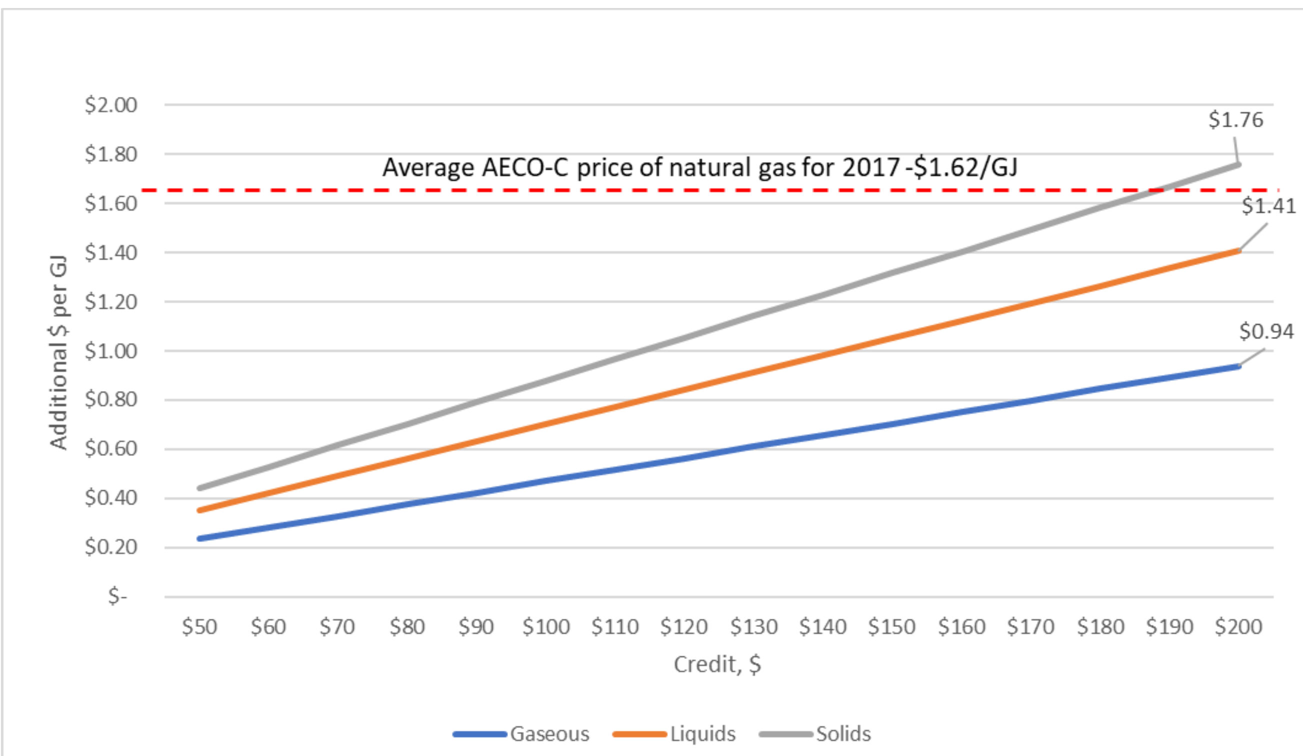
Figure 4.1: Additional Costs for Diesel and Gasoline



Source: CERI

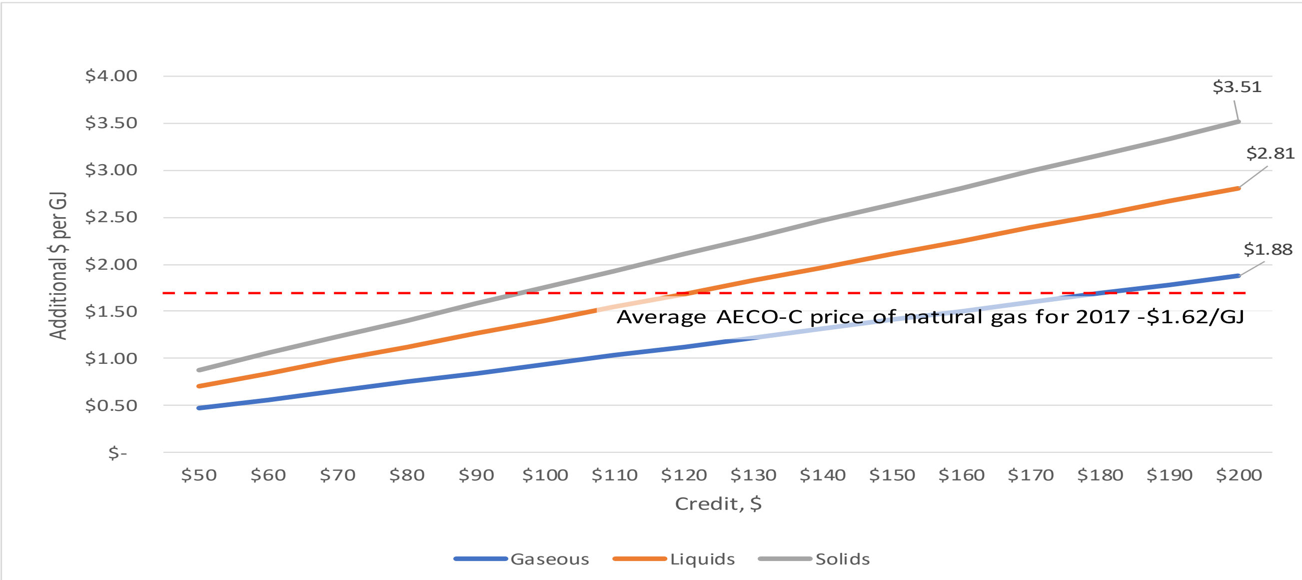
To better illustrate the magnitude of cost implications for gaseous, liquids and solids, expressed in dollar per gigajoule of energy (GJ), Figures 4.2 and 4.3 depict cost curves for three fuel types under CERI's two CI reduction scenarios. Natural gas price per GJ is shown for illustration purposes only as this price is well understood by both industry and households.

Figure 4.2: Additional Cost per GJ of Fuel, 10% CI Reduction



Source: CERI

Figure 4.3: Additional Cost per GJ of Fuel, 20% CI Reduction



Source: CERI

A $200 credit price will bring additional costs ranging from $0.94 per GJ (10% CI reduction) to $1.88 per GJ (20% CI reduction) for gaseous fuels, which include natural gas, landfill and waste gases, still gas, and coke oven gas. If the average 2017 AECO hub (Alberta) price of CAD$1.62/GJ is taken for comparison, these costs will constitute a 58-116% increase in price. The largest impact is to be expected for industry and buildings. Natural gas is a large source of energy for buildings (46% of total consumption in 2016) and the industry (40% of total consumption in 2016) with substantial existing supply infrastructure and limited opportunities to switch fuel without additional investments.

The impact on solids is expected to be the most significant as the starting intensities are higher relative to other fuels and the reduction is steeper in absolute terms. A $200 credit price will result in additional costs from $1.76 per GJ (10% CI reduction) to $3.51 per GJ (20% CI reduction) for these fuels, which include coal, petroleum coke, and biomass. Solids play a significant role in steel manufacturing (47% of total solids consumption), electricity generation (41%), and cement manufacturing (4%).[2]

Detailed results of additional costs per fuel per year are provided in Appendix C.

Cost Impacts by Sector

This section presents overall cost impacts for different sectors: households (i.e., residential buildings), industry, transportation, and agriculture, and the Canadian economy overall.

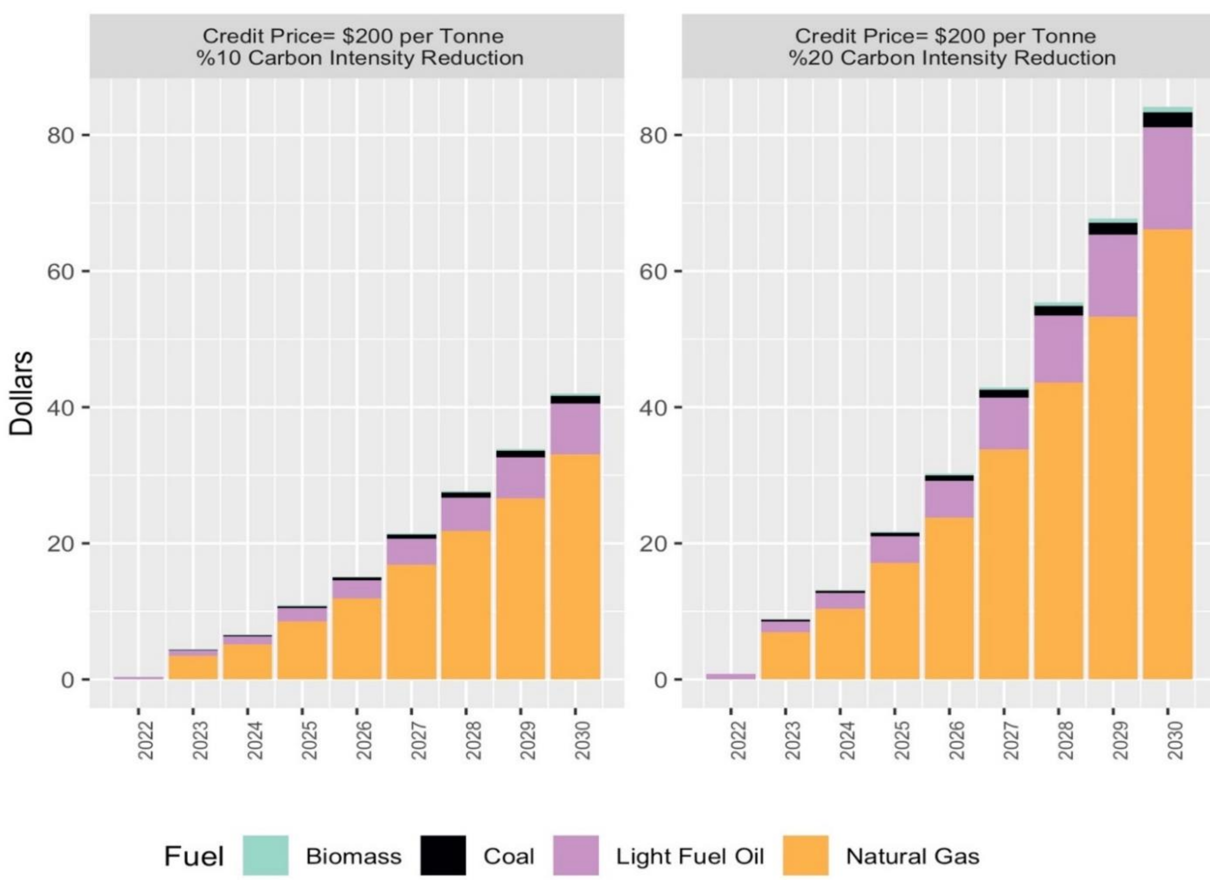
[2] Only domestic consumption is used. Exports are not included.

Households

To calculate additional costs per household (only the residential sector is considered), CERI used calculated costs per fuel from the previous section and energy demand by fuel forecast presented in Chapter 3 to estimate the total annual costs for the residential buildings sector, which is then divided by the number of households in each year of the forecast. The total annual additional costs for residential buildings will be $708 million and $1,416 million in 2030 for 10% and 20% carbon intensity reduction, respectively (see Appendix D to view annual total cost curves).

Figure 4.4 illustrates that, in 2030, the additional annual cost per household will reach $42 if the credit price is $200 per tonne and carbon intensities reduce at 10% in 2030; $84 in the case of 20% carbon intensity reduction. According to the Survey of Household Spending (SHS) in 2017,[3] on average, a Canadian household spends $2,078 per year on fuels (except for gasoline). This means that the additional cost per household represents a cost increase of 2%-4% in the year 2030 depending on the credit price.

Figure 4.4: Annual Additional Costs per Household – Canada



Source: CERI

[3] https://www150.statcan.gc.ca/t1/tbl1/en/tv.action?pid=1110022201

Industry

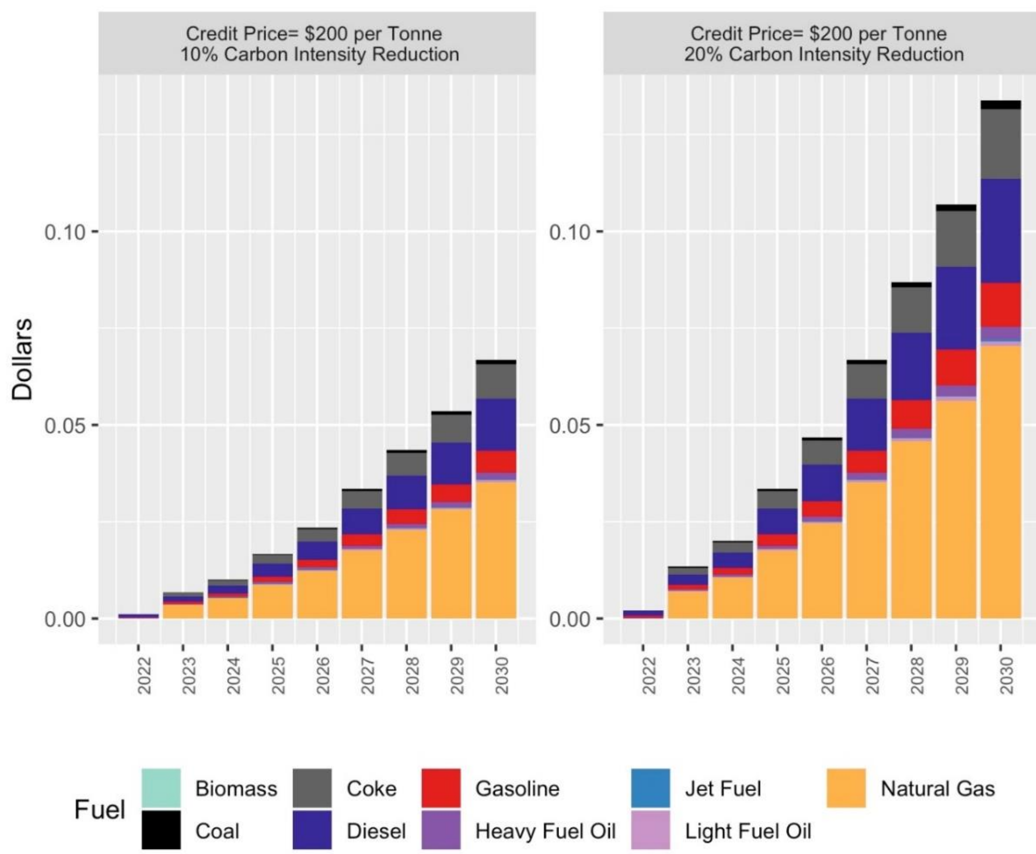
To calculate additional costs for industry (including the agriculture sector), CERI used calculated costs per fuel from the previous section and energy demand by fuel forecast presented in Chapter 3 to estimate the total annual costs.

The total annual additional costs for the industrial sector will be $3,322 million and $6,645 million in 2030 for 10% and 20% carbon intensity reduction, respectively (see Appendix D to view annual total cost curves). These additional costs are due to both an increase in fuel demand and an increase in fuel costs because of target carbon intensity reductions and buying credits.

To isolate the impact caused by credit purchasing only, CERI kept the demand flat from 2015 to 2030, multiplied it by additional costs per fuel and divided by total fuel expenditure of the industrial sector in 2015 ($43.6 billion on fuels in 2015, excluding electricity).

Figure 4.5 illustrates that, in 2030, the additional annual cost (only due credit purchasing) will reach 6 cents per dollar of fuel expenditures if the credit price is $200 per tonne and carbon intensities reduce at 10%; 13 cents per dollar in the case of 20% carbon intensity reduction.

Figure 4.5: Annual Additional Costs per Dollar of Fuel Expenditures in the Industrial Sector (Including Agriculture) – Canada



Source: CERI

Agriculture Sector

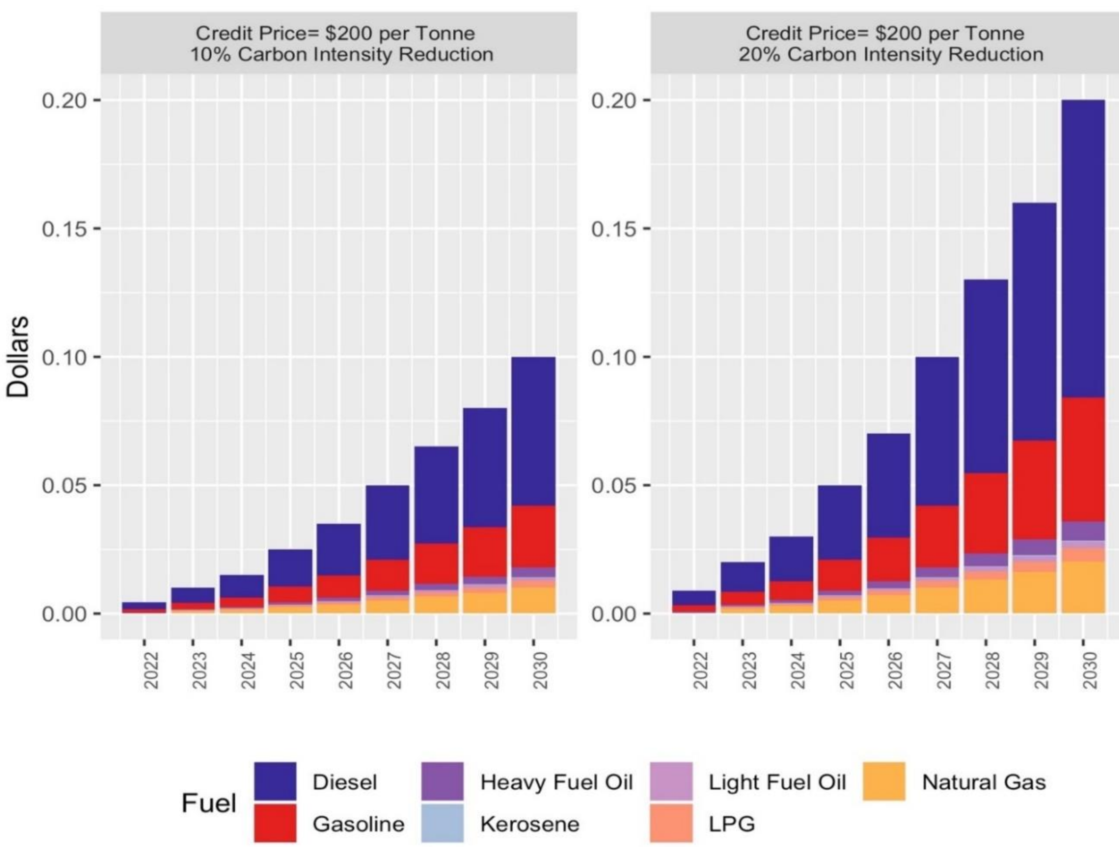
To calculate additional costs for the agriculture sector, CERI used calculated costs per fuel from the previous section and energy demand by fuel forecast presented in Chapter 3 to estimate the total annual costs.

The total annual additional costs for the agricultural sector will be $389 million and $780 million in 2030 for 10% and 20% carbon intensity reduction, respectively (see Appendix D to view annual total cost curves). These additional costs are due to both an increase in fuel demand and an increase in fuel costs because of target carbon intensity reductions and buying credits.

To isolate the impact caused by credit purchasing only, CERI kept the demand flat from 2015 to 2030, multiplied it by additional costs per fuel and divided by total fuel expenditure of the agriculture sector in 2015 ($3.5 billion on fuels in 2015, excluding electricity).

Figure 4.6 illustrates that, in 2030, the additional annual cost (only due to credit purchasing) will reach 10 cents per dollar of fuel expenditures if the credit price is $200 per tonne and carbon intensities reduce at 10%; 20 cents per dollar in the case of 20% carbon intensity reduction.

Figure 4.6: Annual Additional Costs per Dollar of Fuel Expenditures in the Agriculture Sector – Canada



Source: CERI

Oil and Gas Sector

To calculate additional costs for the oil and gas sector, CERI calculated costs per fuel from the previous section and energy demand by fuel forecast (presented in Chapter 3) for industries listed in Table 4.2 to estimate the total annual costs.

Table 4.2: Industries Included in the Oil and Gas Sector

Industry Code in Input-Output Tables	Industry	Fuel Expenditure (Thousand Dollars)	Share of Fuel Expenditure in Total Fuel Expenditure of the Oil and Gas Sector (Percent)
BS211113	Conventional oil and gas extraction	1,420,475	18
BS211114	Non-conventional oil extraction	1,607,670	21
BS21311A	Support activities for oil and gas extraction	869,441	11
BS221200	Natural gas distribution	53,038	1
BS23C200	Oil and gas engineering construction	383,576	5
BS324110	Petroleum refineries	1,195,187	15
BS3241A0	Petroleum and coal product manufacturing (except petroleum refineries)	126,690	2
BS325100	Basic chemical manufacturing	1,938,895	25
BS325900	Other chemical product manufacturing	55,692	1
BS326100	Plastic product manufacturing	101,630	1

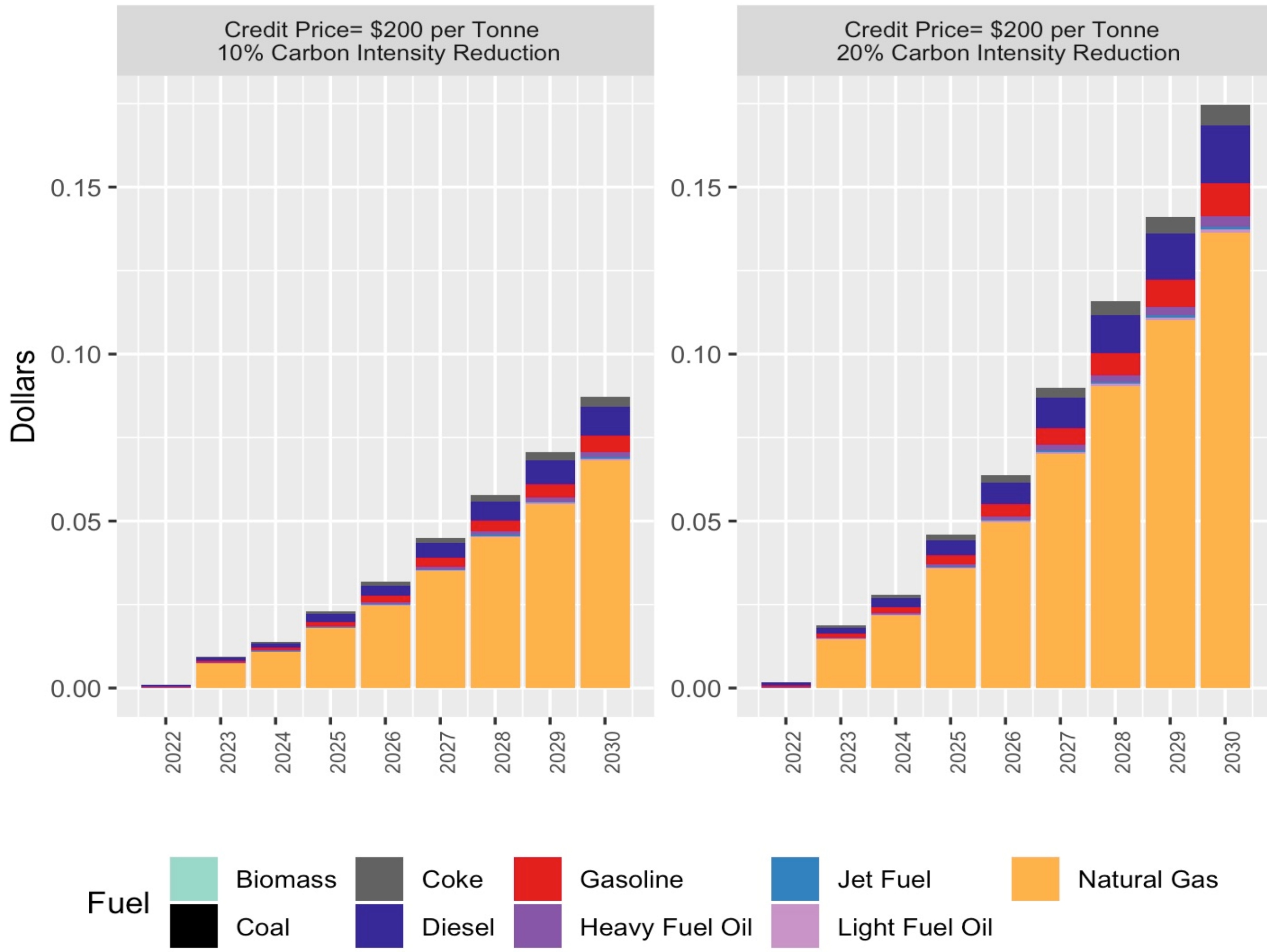
Source: 2015 Detailed-level Input-Output (IO) tables (Statistics Canada 2019)

The total annual additional costs for the oil and gas sector will be $1,007 million and $2,014 million in 2030 for 10% and 20% carbon intensity reduction, respectively (see Appendix D to view annual total cost curves). These additional costs are due to both an increase in fuel demand and an increase in fuel costs because of target carbon intensity reductions and buying credits.

To isolate the impact caused by credit purchasing only, CERI kept the demand flat from 2015 to 2030, multiplied it by additional costs per fuel and divided by total fuel expenditure of the oil and gas sector in 2015 ($8.8 billion on fuels in 2015, excluding electricity).

Figure 4.7 illustrates that, in 2030, the additional annual cost (only due credit purchasing) will reach 8 cents per dollar of fuel expenditures if the credit price is $200 per tonne and carbon intensities reduce at 10%; 17 cents per dollar in the case of 20% carbon intensity reduction.

Figure 4.7: Annual Additional Costs per Dollar of Fuel Expenditures in the Oil and Gas Sector – Canada



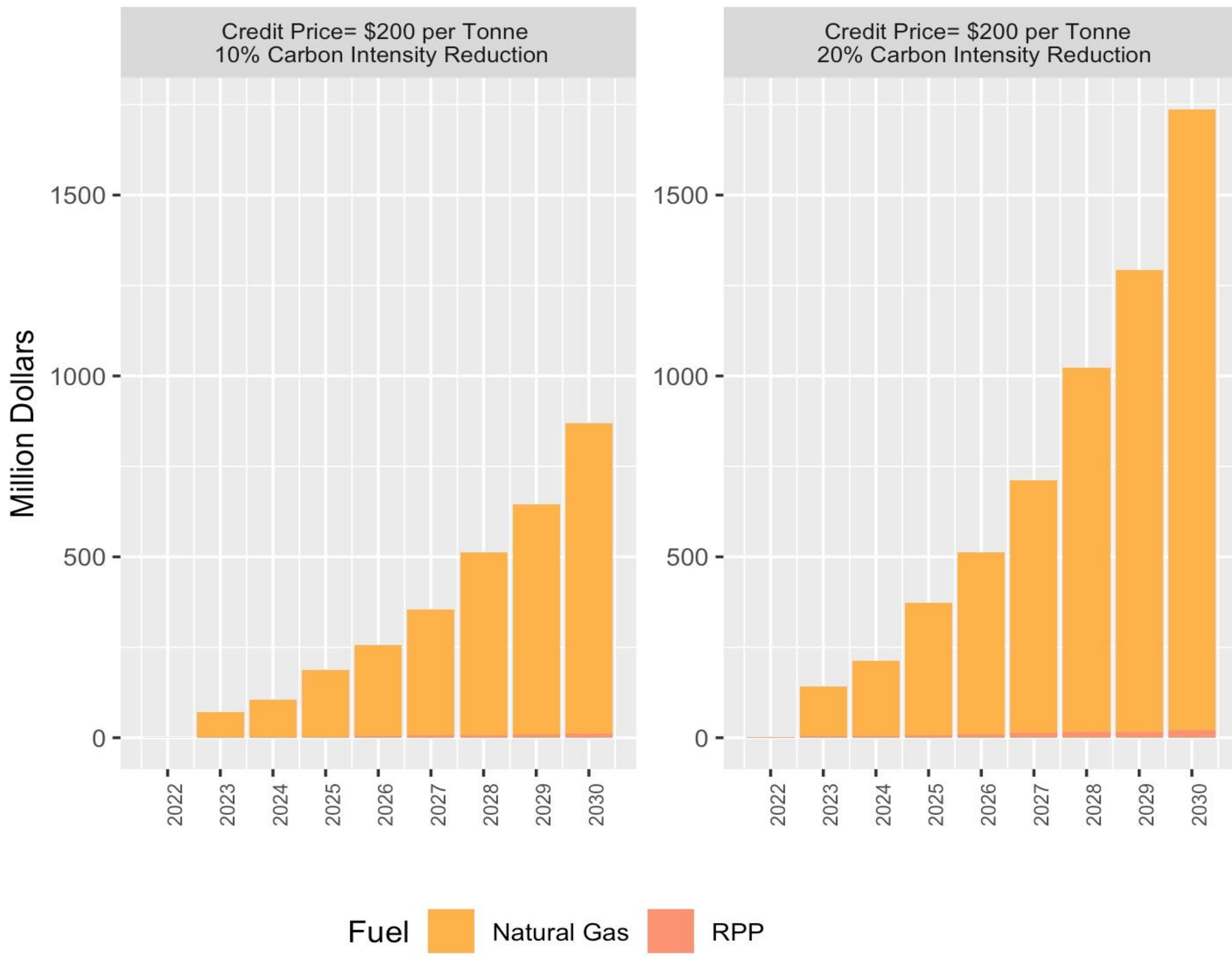
Source: CERI

Electricity Generation Sector

To calculate additional costs for the electricity generation sector, CERI used costs per fuel from the previous section and forecast of generation by fuel from Canada's Energy Future 2018 (National Energy Board 2018) to estimate the total annual costs.

The total annual additional costs for the electricity generation sector will be $868 million and $1,737 million in 2030 for 10% and 20% carbon intensity reduction, respectively (see Figure 4.8). Dividing these numbers by the total generation forecast from Canada's Energy Future 2018 (National Energy Board 2018) in 2030 (of 10,6624 GWh) results in 0.8 cents per kWh if the credit price is $200 per tonne and carbon intensities reduce at 10%; 1.6 cents per kWh in the case of 20% carbon intensity reduction.

Figure 4.8: Annual Additional Costs in the Electricity Generation Sector – Canada



Source: CERI

Transportation

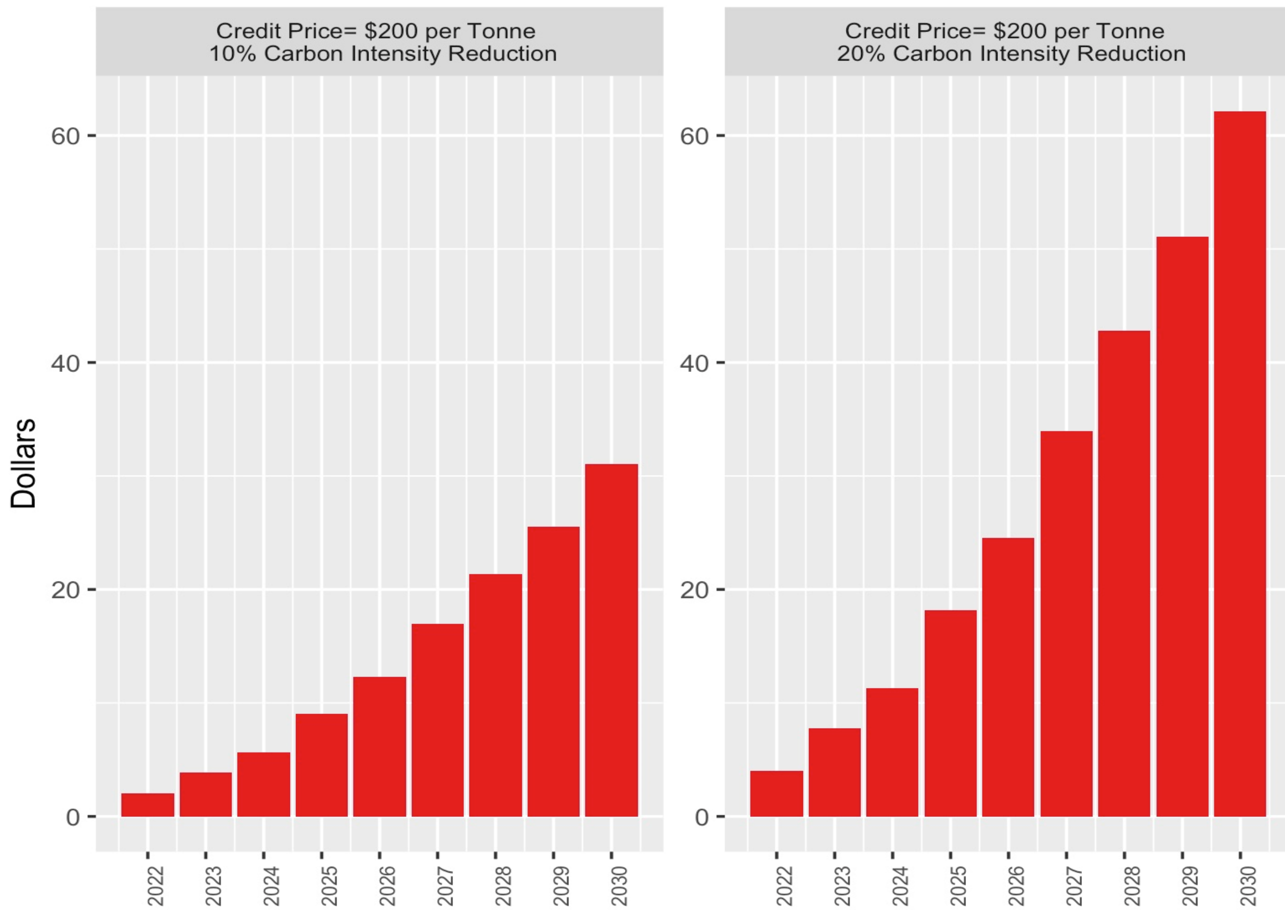
To calculate additional costs for the transportation sector, CERI used additional costs per each fuel and demand forecast to forecast the total costs in each transportation subsector (see Appendix D to view annual total cost curves). The regulation will impose total additional costs in 2030 of $1,149 million and $2,299 million in the case of 10% and 20% carbon intensity reduction for all passenger cars, respectively. For freight transport, total additional costs will be $1,237 million dollars and $2,475 million dollars in the case of 10% and 20% carbon intensity reduction, respectively.

By dividing the overall cost by the number of vehicles, CERI calculates the additional cost per vehicle. The calculation is done for gasoline and diesel separately. It is assumed that all passenger and light trucks run on gasoline and freight trucks – on diesel.

Figure 4.9 illustrates that, in 2030, the additional annual cost of gasoline per vehicle will reach $31 if the credit price is $200 per tonne and carbon intensities reduce at 10% in 2030, and $62 in the case of

20% carbon intensity reduction. According to the Survey of Household Spending (SHS), in 2017, on average, a Canadian household spent $2,142 dollars for gasoline,[4] which will translate to a fuel cost increase ranging from 1.4%-2.8%.

Figure 4.9: Annual Additional Gasoline Costs for Passenger Cars per Vehicle – Canada

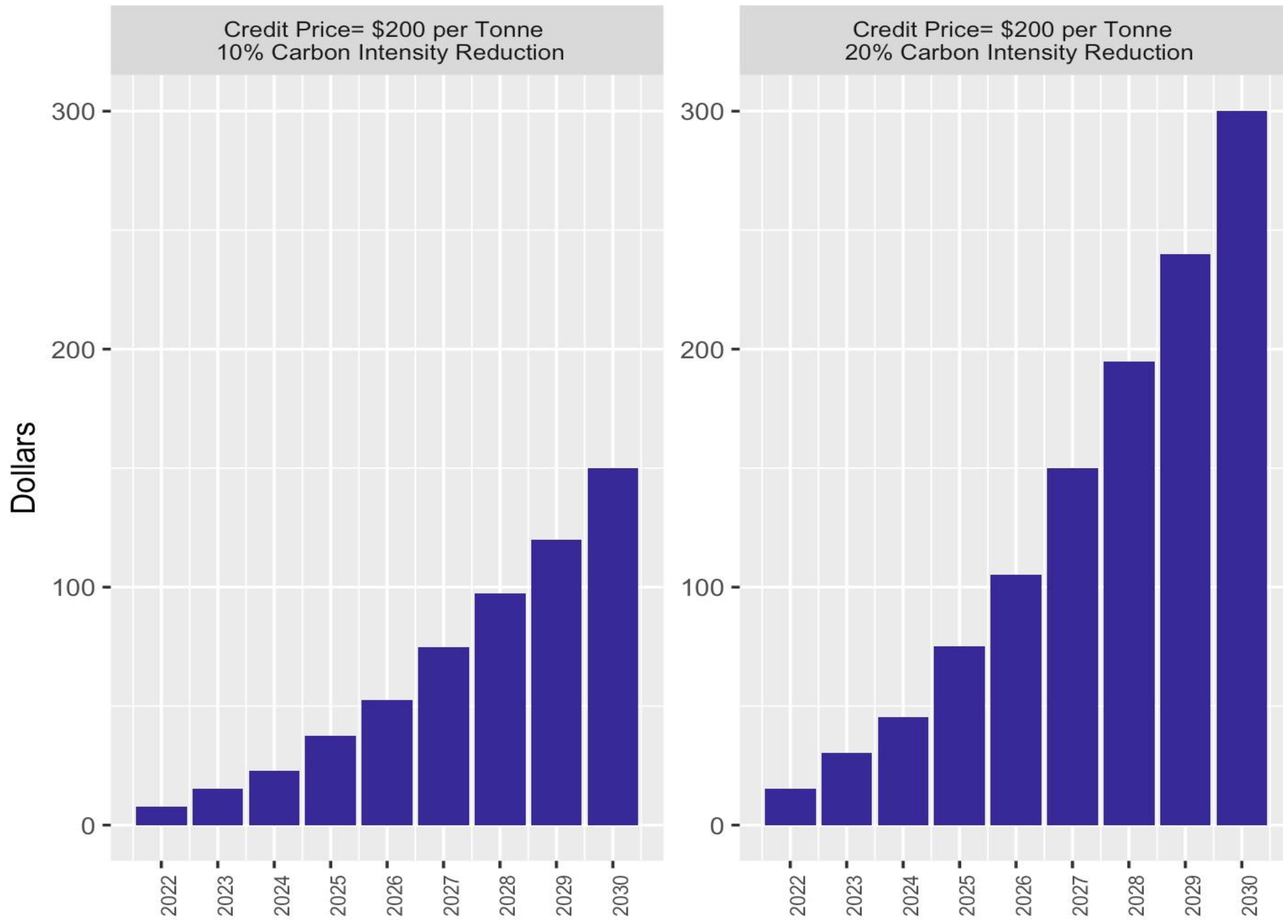


Source: CERI

Figure 4.10 shows that in 2030 the additional annual costs of diesel per vehicle will reach $150 if the credit price is $200 per tonne and carbon intensities reduce at 10% in 2030, and $300 in the case of 20% carbon intensity reduction.

[4] https://www150.statcan.gc.ca/t1/tbl1/en/tv.action?pid=1110022201

Figure 4.10: Annual Additional Diesel Costs for Freight Trucks per Vehicle – Canada

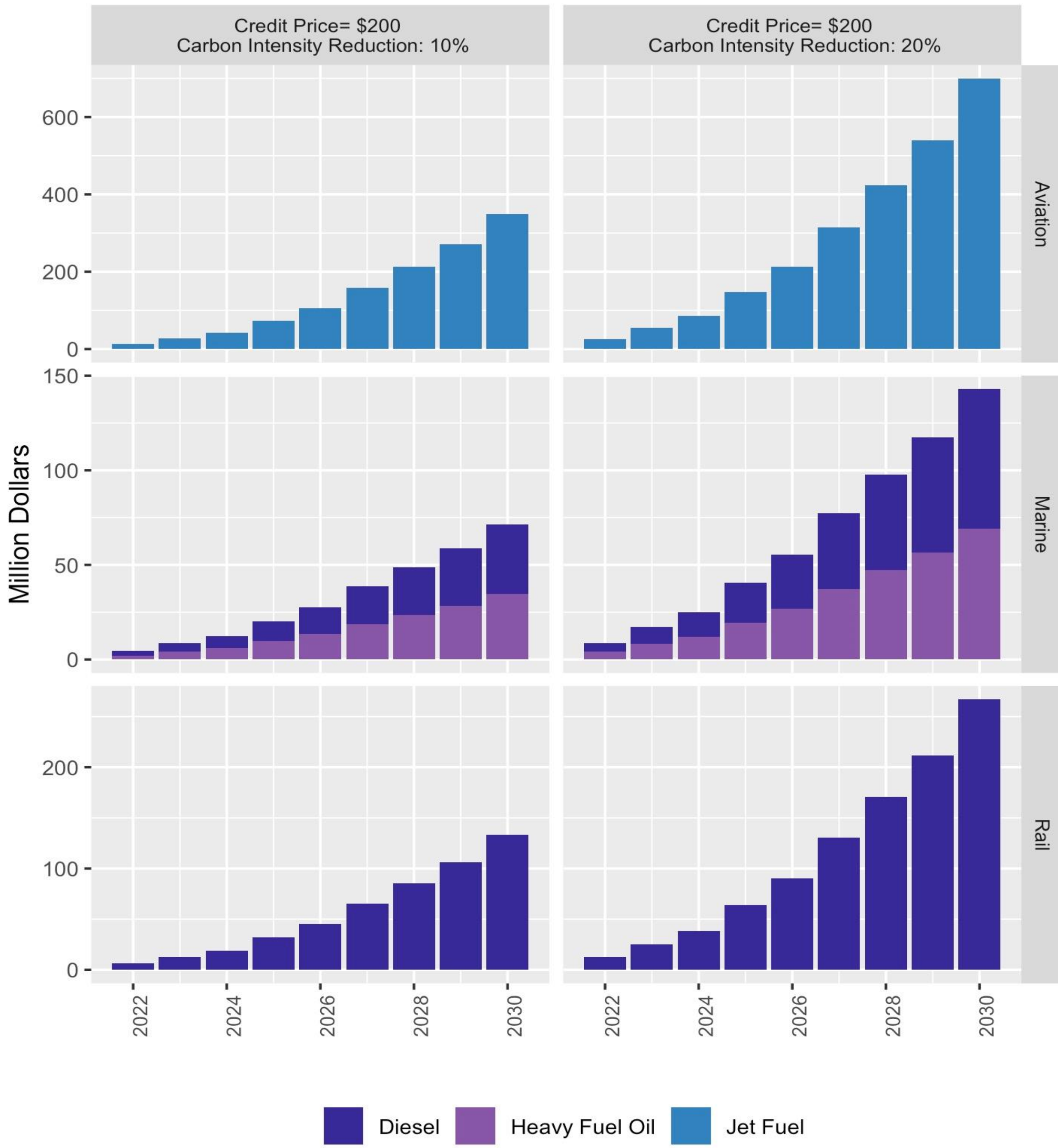


Source: CERI

For other subsectors in transportation, as shown in Figure 4.11, the additional annual costs in aviation would be $349 million in 2030 under 10% carbon intensity reduction and credit price of $200 per tonne. This number would be $71 million dollars for marine and $133 million for rail transportation.

In the case of a 20% reduction in carbon intensities, these additional annual costs would be $700, $142, $267 million dollars for aviation, marine, and rail transportation, respectively.

Figure 4.11: Annual Additional Fuel Costs in Aviation, Rail and Marine Transportation – Canada



Source: CERI

The total cost impacts for the Canadian economy are estimated to be $7.6 billion dollars annually in 2030 for the case of 10% CI reduction and $15 billion dollars annually in 2030 for the case of 20% CI reduction and onwards as compared to the BAU with no CI reduction (Tables 4.3 and 4.4). The largest impact will be felt in industry, followed by transportation, and households. Figure 4.12 illustrates the total costs for the two scenarios.

It is reasonable to assume that producers will want to remain competitive and will eventually pass all additional costs incurred due to new regulations onto final consumers. This will include products from the industry and agriculture sectors which compete on local and export markets with foreign products. The change in costs of Canadian products, and ultimately products' price competitiveness and companies' margins, will depend on the share of fuel costs in those products' costs. However, such an impact on the competitiveness of export sectors is beyond the scope of this study and may be part of a future research study.

Table 4.3: Fuel Decarbonization Total Cost Impacts, $200 Credit Price

Carbon Intensity Reduction / Sector	Household (buildings)	Industry (including Agriculture)	Passenger Cars and Light Trucks	Freight Trucks	Rail, Aviation, Marine	Total, Annually 2030 and after
	Additional fuel costs per sector					
10% CI reduction	$42 per household or 2% increase in fuel cost	6% increase in fuel cost	$31 per vehicle or 1.4% increase in fuel cost	$150 per vehicle	-	-
20% CI reduction	$84 per household or 4% increase in fuel cost	13% increase in fuel cost	$62 per vehicle or 2.8% increase in fuel cost	$300 per vehicle	-	-
	Total annual cost increase per sector (Million CAD$)					
10% CI reduction	$1,395	$3,322	$1,149	$1,237	$553	$7,656
20% CI reduction	$2,791	$6,645	$2,299	$2,475	$1,109	$15,319

Source: CERI

Table 4.4: Fuel Decarbonization Total Cost Impacts for Three Sectors, $200 Credit Price

Carbon Intensity Reduction / Sector	Agriculture	Oil and Gas	Electricity Generation
	Additional Fuel Costs per Sector		
10% CI reduction	10% increase in fuel cost	8% increase in fuel cost	0.8 cents per kWh
20% CI reduction	20% increase in fuel cost	17% increase in fuel cost	1.6 cents per kWh
	Total Annual Cost Increase per Sector (million $CAD)		
10% CI reduction	$389	$1,007	$868
20% CI reduction	$780	$2,014	$1,737

Source: CERI

Figure 4.12: Fuel Decarbonization Total Cost Implications

Source: CERI

Carbon pricing stimulates market forces for finding the lowest-cost options to reduce emissions. Standards on fuels' carbon intensity are less flexible than carbon pricing and hence could be less cost-effective. The findings of this report show that the costs of fuel decarbonization would be between \$163 (in the case of 10% CI reduction) and \$170 (in the case of 20% CI reduction)[5] per tonne of GHG emissions, while federal carbon pricing reaches emission reductions by \$50 per tonne. One study by Rivers and Wigle (Rivers and Wigle 2018) shows that reducing transportation emissions by 10% with a fuel standard would cost over three times as much as carbon pricing on a per-tonne basis. Although fuel standards are less cost-effective than carbon pricing, these standards are complimentary to carbon pricing to reduce emissions, since carbon pricing does not cover all sources of emissions, such as, for example, fugitive methane emissions.

[5] The cost per tonne of GHG emissions is calculated by dividing the total cost of fuel decarbonization in each scenario by total emission reductions.

Chapter 5: Conclusions

In summary, this report provided valuable insight into fuel decarbonization scenarios by providing an analysis of emission and cost impacts, not only for regulated fuels but also for various economic sectors and for the national economy. The complexity of this subject matter is evident. While this report produced an analysis of emission and cost impacts, it also shed some light into these complex issues.

Like other fuel decarbonization policies, the Canadian CFS regulations will use a lifecycle approach to set carbon intensity values and requirements, accounting for greenhouse gases emitted to produce a unit of energy. This lifecycle approach will assess GHG emissions from all stages in a product's life, from cradle to grave (that is, from raw material extraction through materials processing, manufacture, distribution, use, repair and maintenance, and disposal or recycling where applicable). The goal is to drive actions that reduce GHG emissions throughout the lifecycle of fuels and fuel alternatives.

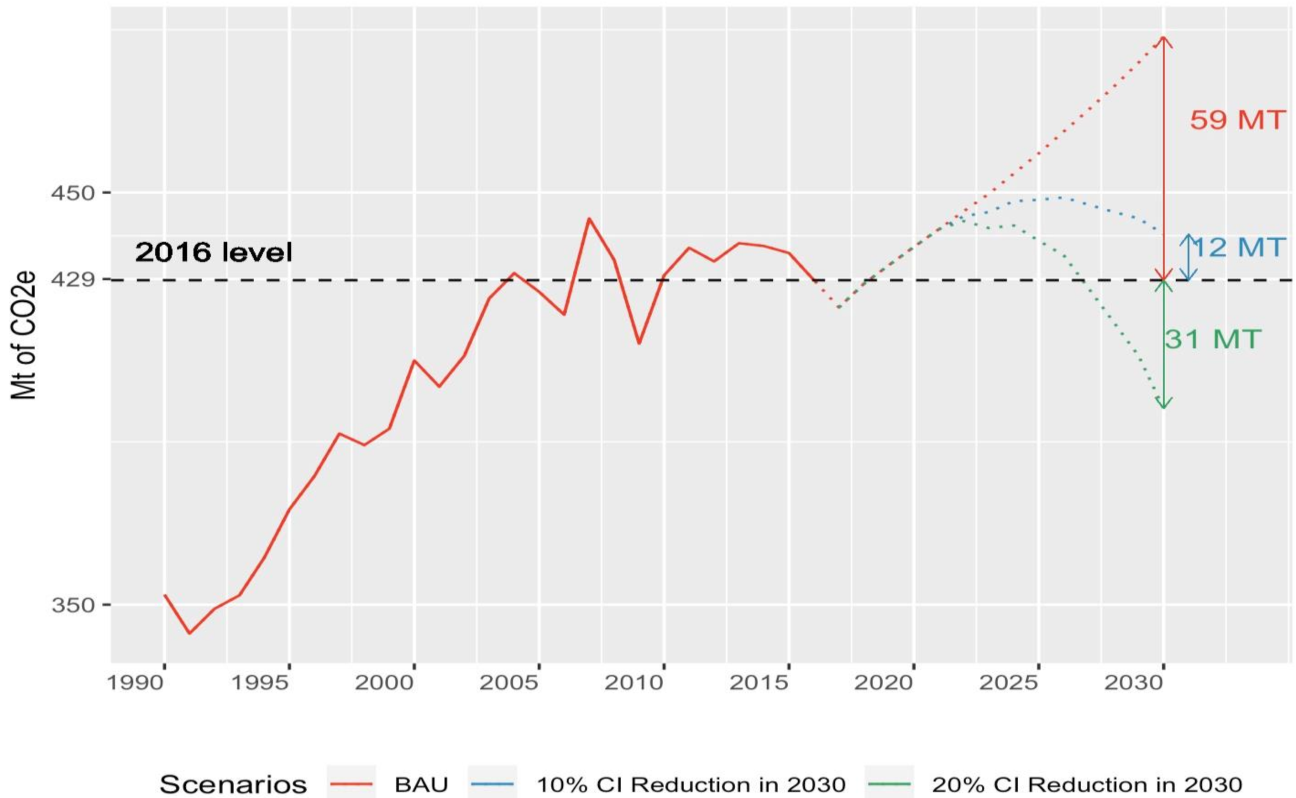
However, this is the first policy in the world that will cover such a wide array of fuels, others have primarily focused on liquid transportation fuels. The regulation aims to achieve reductions from each of the transportation, building and industrial sectors. This will be achieved by setting separate carbon intensity requirements for subsets of fuels, as well as through rules around credit trading. Indirect land use GHG emissions that may result from the CFS will not be considered in the design, at least initially. This differs from California or the European Union policies but is similar to the British Columbia policy.

The three jurisdictions that were evaluated in this report have been running their fuel decarbonization policies for nine years now and present good case studies for learning from their experiences and frameworks. The evolution of fuel decarbonization in three jurisdictions (California, BC, and the EU) shows that while carbon intensity reductions were achieved, the overall absolute emission reductions were not (except for minor reductions in the EU). This is interesting to note because the objective of other regulations in three jurisdictions was to achieve a reduction in carbon intensities of affected fuels and never included an overall emission reduction target by a certain year. This is different from the federal Canadian regulation that aims to achieve a 30 MT of annual reductions in GHG emissions by 2030 by means of reducing carbon intensities of affected fuels.

Going forward, it would be interesting to observe how CFS regulations will achieve its objective. In the meantime, the results of CERI's analysis are summarized below:

- CERI's Scenario of 10% CI reduction illustrated that avoided emissions in the year 2030 will be 47 MT as compared to the BAU scenario, but 12 MT above 2016 emissions level (Figure 5.1).
- CERI's Scenario of 20% CI reduction illustrated an emission reduction of 31 MT below the 2016 baseline (Figure 5.1).
- The largest emission reductions can be realized in the very energy-intensive transportation sector, followed by the industrial sector.
- In the case studies of higher penetration of electric vehicles and/or stricter CAFE standards, emission reductions are achieved with a lesser carbon intensity benchmark.

Figure 5.1: Total Emissions – Canada



Source: Historical data comes from Table 1 in Residential Sector, Table 1 in Commercial Sector, Table 3 in Industrial Sector, Table 2 in Agriculture sector, and Table 4 in Transportation Sector from the Comprehensive Energy Use Database from NRCan (2018a). The forecast is from CERI.

Because of fuel decarbonization, there will be additional costs on fuels:

- On gasoline and diesel: 5-11 cents per litre with a $200 cost of credit
- On gaseous fuels: $0.94-$1.88 per GJ with a $200 cost of credit.
- On solid fuels: from $1.76-$3.51 per GJ with a $200 cost of credit.

The total cost impacts for the Canadian economy are estimated to be $7.6 billion dollars annually in 2030 for the case of 10% CI reduction and $15.3 billion dollars annually in 2030 for the case of 20% CI reduction (Table 5.1). The largest impact will be in the order of highest to lowest total costs – industry, transportation, households, and agriculture.

Carbon pricing stimulates market forces for finding the lowest-cost options to reduce emissions. Standards on fuels' carbon intensity are less flexible than carbon pricing and hence could be less cost-effective. The findings of this report show that the costs of fuel decarbonization would be between $163 (in the case of 10% CI reduction) and $170 (in the case of 20% CI reduction)[1] per tonne of GHG

[1] The cost per tonne of GHG emissions is calculated by dividing the total cost of fuel decarbonization in each scenario by total emission reductions.

emissions, while federal carbon pricing reaches emission reductions by $50 per tonne. Although fuel standards are less cost-effective than carbon pricing, these standards are complementary to carbon pricing to reduce emissions, since carbon pricing does not cover all sources of emissions, such as, for example, fugitive methane emissions.

Table 5.1: Fuel Decarbonization Total Cost Impacts, $200 Credit Price

Carbon Intensity Reduction / Sector	Household (buildings)	Industry (including Agriculture)	Passenger Cars and Light Trucks	Freight Trucks	Rail, Aviation, Marine	Total, Annually 2030 and After
	Total Annual Cost Increase per Sector (million $CAD)					
10% CI reduction	$1,395	$3,322	$1,149	$1,237	$553	$7,656
20% CI reduction	$2,791	$6,645	$2,299	$2,475	$1,109	$15,319

Source: CERI

Within the industry sector, CERI highlighted the cost impacts for three industrial sectors: agriculture, oil and gas and electricity generation. These costs are identified in Table 5.2.

Table 5.2: Fuel Decarbonization Total Cost Impacts for Three Sectors, $200 Credit Price

Carbon Intensity Reduction / Sector	Agriculture	Oil and Gas	Electricity Generation
Total Annual Cost Increase per Sector (million $CAD)			
10% CI reduction	$389	$1,007	$868
20% CI reduction	$780	$2,014	$1,737

It is reasonable to assume that producers will want to remain competitive and will eventually pass all additional costs incurred due to new regulations onto final consumers. This will include products from the industry and agriculture sectors which compete on local and export markets with foreign products. The change in costs of Canadian products, and ultimately products' price competitiveness and companies' margins, will depend on the share of fuel costs in those products' costs. However, such an impact on the competitiveness of export sectors is beyond the scope of this study and may be part of a future research study.

Future research could entail analyzing the CFS regulations when the final details become available. Specifically, some of the challenges that need further evaluation might include:

- Harmonization of federal and provincial programs (specifically for BC): different CI schedules, targets, LCA tools, as well as credit trade markets and credit prices will complicate compliance
- The readiness of vehicle fleet and supporting infrastructure for high blending volumes (E15)
- Competitiveness of trade-exposed sectors
- Availability of low carbon fuels in Canada, and
- Level of preparedness of affected sectors – buildings, industry and transportation for the upcoming CFS regulations.

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Appendix A: Modelling Methodology and Assumptions

Housing Stock-Rollover Model

For each home type (single-detached, single-attached, apartments and mobile homes), the housing stock is projected for the years after 2016, using the following equation:

$$TH_{y+1j} = \sum_{\nu}^{y} TH_{\nu yj} \times (1 - \beta_{\nu y}) + [TH_{\nu yj} \times \beta_{\nu y} + NHH_{y+1}]\theta_{yj}$$

Where:

j: home types (single-detached, single-attached, apartments, mobile homes)
y: year, model year (2016 to 2030)
v: house vintages (1990 to year y)
TH_{y+1j}: the number of housing units of type j in year y+1
$TH_{\nu yj}$: the number of housing units of vintage v and type j in year y
NHH_{y+1}: the number of new households in year y+1
θ_{yj}: the share of housing unit type j in total housing units in year y
$\beta_{\nu y}$: the replacement coefficient for vintage v in year y

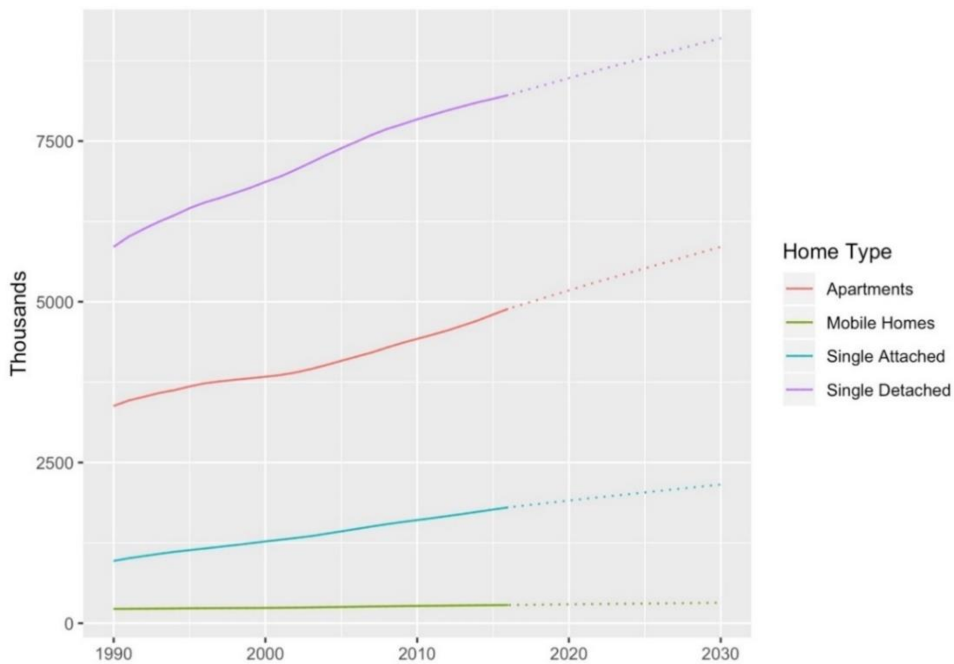
Based on this equation, housing units that are being renovated or retired are replaced with a new vintage and type of house ($TH_{\nu jy} \times \beta_{\nu y}$). New vintage housing units of different types are also added as the number of households in each region grows (NHH_{y+1}). Data for the new household formation for each province comes from StatsCan's Long-term household projections—2013 update (Statistics Canada 2013). The fraction of these new housing units ($TH_{\nu jy} \times \beta_{\nu y} + NHH_{y+1}$) that are being added to the stock of each home type (j) is determined by the ratio of each home type in the whole housing stock of the previous year (θ_{jy}).

The replacement coefficients are generated by a survival function that uses Poisson distribution, with a mean (λ) equal to the expected useful life of the building or equipment. The replacement coefficient for vintage v in year y is $\beta_{\nu y}$:

$$\beta_{\nu y} = e^{-\lambda} \frac{\lambda^{y-\nu+1}}{(y-\nu+1)!}$$

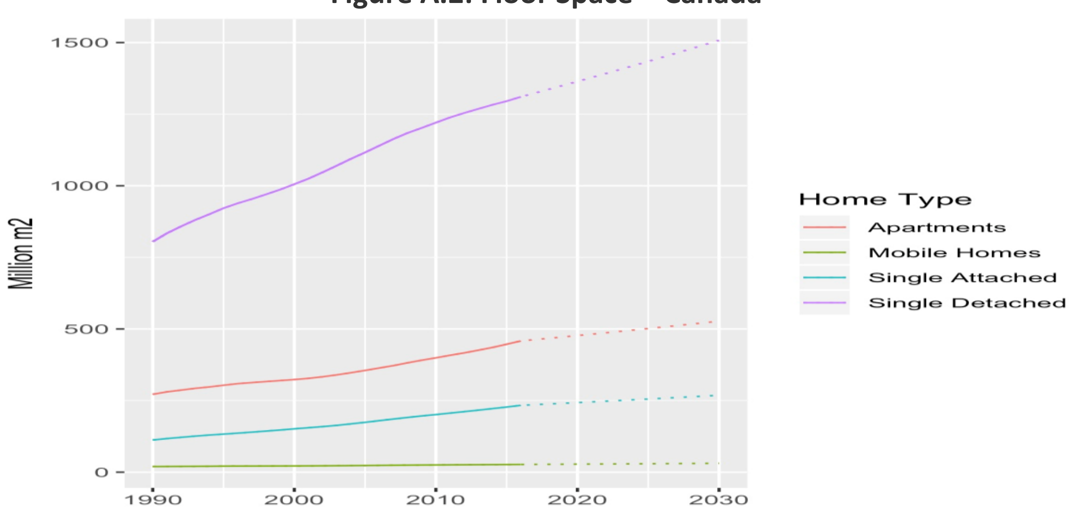
The Poisson distribution has a right-skewed density function, which becomes more bell-shaped around λ_at higher λ_values. For the housing stock, the expected lifetime is assumed to be 50 years, where "lifetime" is more precisely defined as the time before retirement or renovation. This housing stock projection for Canada and overall floor space are shown in Figures A.1 and A.2. These factors are used as activity drivers to calculate changes in the stock of equipment over time and the final energy consumption for each end-use.

Figure A.1: Housing Stock – Canada



Source: NRCan (2018a) and CERI

Figure A.2: Floor Space – Canada



Source: NRCan (2018a) and CERI

Equipment Stock

For years 1990-2016, for each end-use (space heating, water heating, and space cooling), and for each home type, only the total stock of each equipment system from 1990 to 2016 is available from the Comprehensive Energy Use database (NRCan 2018a). Since there is no information on the vintages of these system types, CERI uses a survival function to infer the stock of each vintage in each year. Using the survival function explained above, the number of the total stock of each equipment system is decomposed to the stock of each vintage. For example, the stock of vintage 1991 in the year 1991 ($EQP_{k1991\ 1991j}$) equals to the total stock of 1991 (EQP_{k1991j}), which data is available, minus whatever is remaining from the vintage 1990 in 1991 (which is the stock of vintage 1990 ($EQP_{k1990\ 1990j}$) minus the fraction of 1990 stock that has been replaced in 1991, $EQP_{k1990\ 1990j}\beta_{1990\ 1991}$). Similarly, for other years stock of each vintage is:[1]

$$EQP_{kyyj} = EQP_{kyj} - \sum_{\nu=1990}^{y-1} [EQP_{k\nu\nu j} - \sum_{t=\nu+1}^{y} EQP_{k\nu\nu j}\beta_{\nu t}]$$

k: end-uses (space heating, water heating, and space cooling)
j: home types (single-detached, single-attached, apartments, mobile homes)
y: year, model year (2016 to 2030)
v: equipment system vintages (1990 to year y)

For the equipment stock, the expected lifetime λ is assumed to be 15 years. Given the available data for the total stock of each equipment for years 1990-2016, the above process gives us the number of each vintage (vintage 1990 to vintage 2016) in that total stock of each year.

To forecast the equipment stock for projection of the years after 2016, the total number of the stock of equipment for end-use k and home type j equals to the total number of equipment for end-use k and home type j of all vintages before year y that are remaining after the replacement in year y plus the total new sales in year y+1($EQP_{ky+1y+1j}$):

$$EQP_{ky+1j} = EQP_{ky+1y+1j} + \sum_{\nu=1990}^{y} [EQP_{k\nu\nu j} - \sum_{t=\nu+1}^{y} EQP_{k\nu\nu j}\beta_{\nu t}]$$

Where the total new sales in year y+1 ($EQP_{ky+1y+1j}$) is the total number of new houses of type j plus a total number of equipment for end-use k of all vintages before year y+1 that was replaced in year y+1:

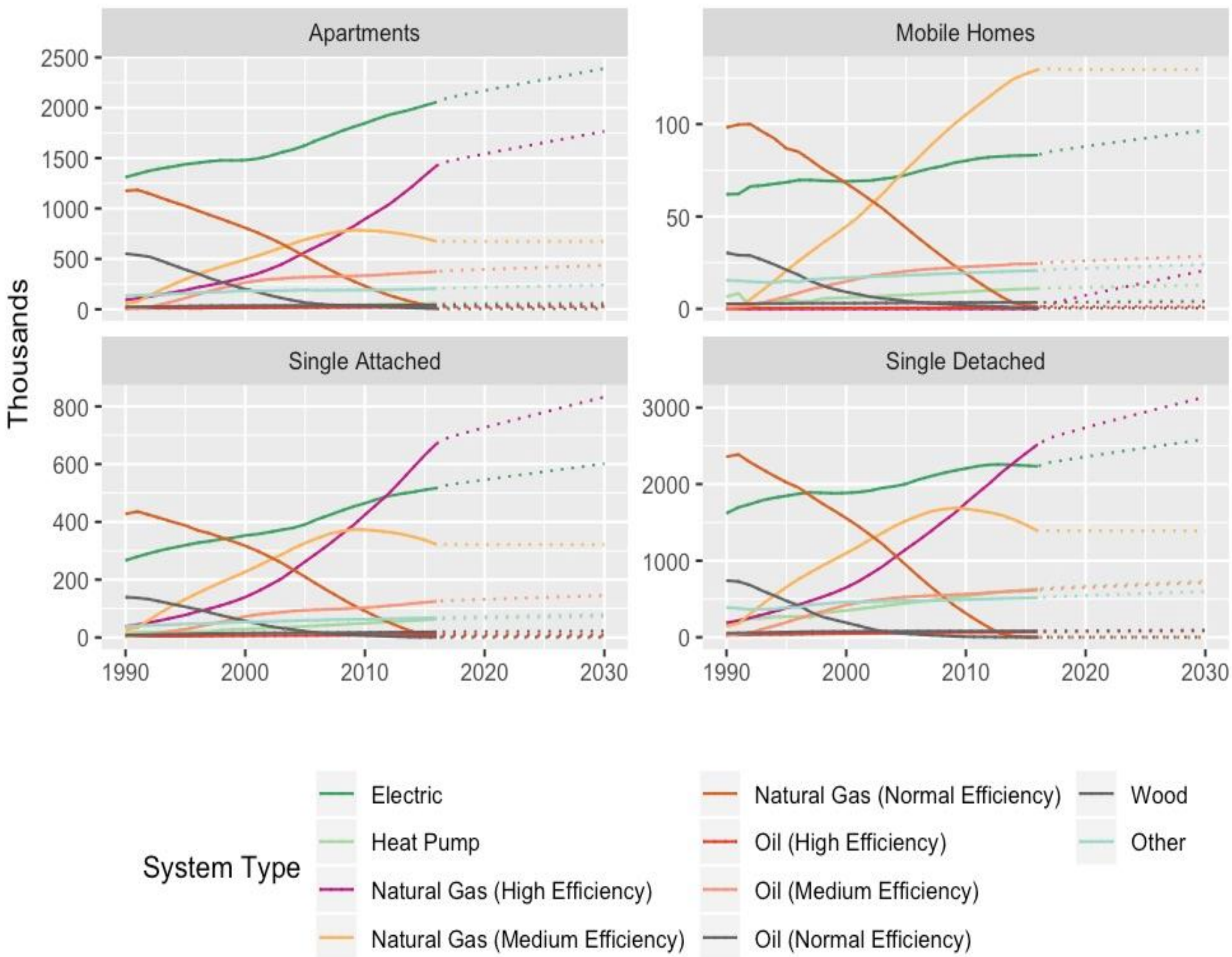
[1] Any form or mixture of gases produced in refineries by distillation, cracking, reforming, and other

$$EQP_{ky+1y+1j} = NH_{y+1j} + \sum_{\nu=1990}^{y+1} EQP_{k\nu\nu j}\beta_{\nu y+1}$$

$EQP_{ky+1y+1j}$ represents the new sales in each year. To decompose this number to all equipment types, the market shares of each equipment type for years after 2016 is needed.

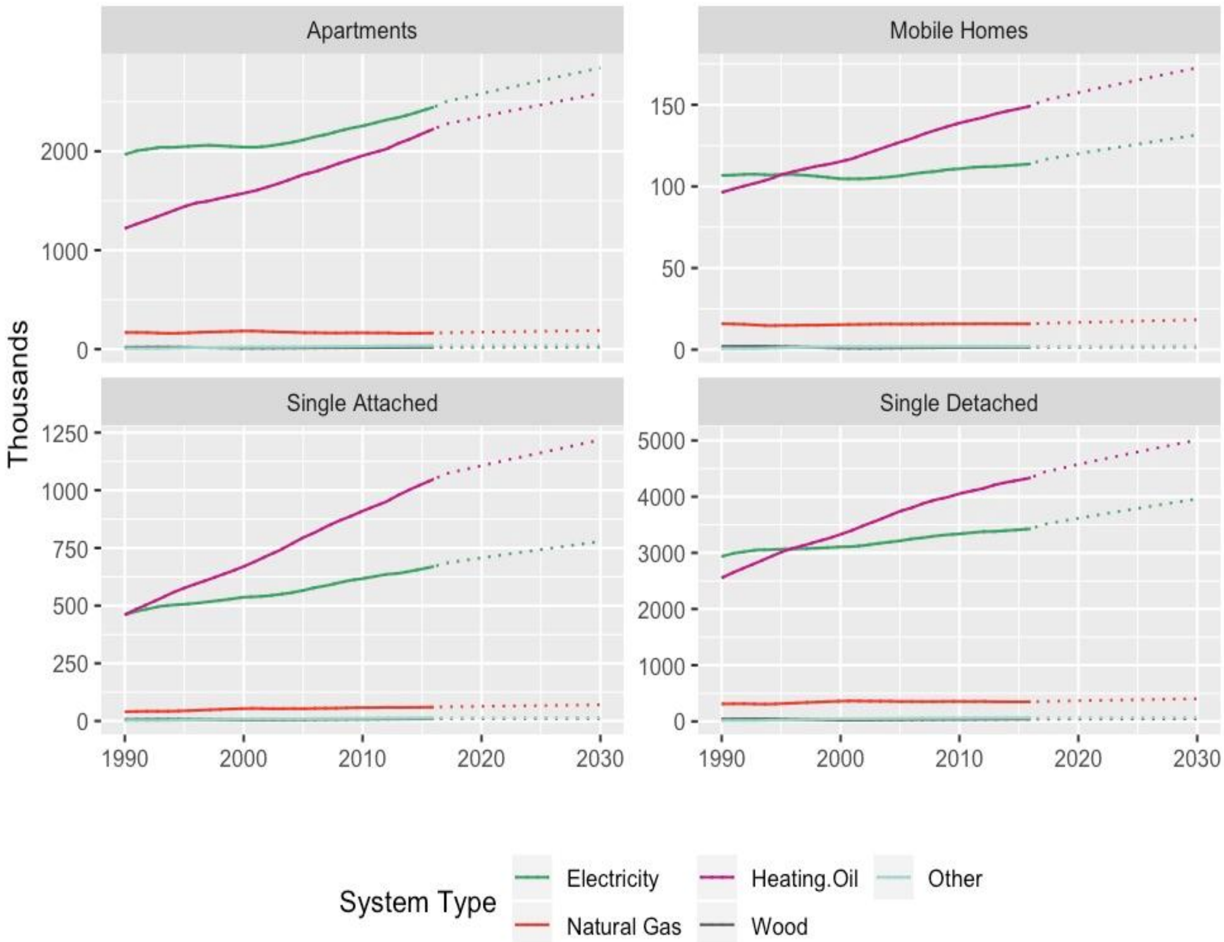
Figures A.3 and A.4 illustrate the modelling results on the total stock of end-use systems by home type.

Figure A.3: Space Heating System Stock – Canada



Source: NRCan (2018a) and CERI

Figure A.4: Water Heating System Stock – Canada



Source: NRCan (2018a) and CERI

Residential Final Energy Consumption

Final Energy for each end use and home type is assumed to be growing with its annual average rate over the last 10 years. To derive the total service demand of each end-use, in addition to the final energy, efficiency rates are needed. CERI uses a weighted average of the efficiency rates of all equipment systems where the weights are the market share of that equipment system over time. These market shares are derived from the above stock-rollover model.

$$EFF_{kyj} = \sum_{m} MKS_{kmyj} \times EFF_{kmyj}$$

where

$$MKS_{kmyj} = \sum_{\nu=1990}^{y} MKS_{km\nu yj}$$

k: end-uses in Table 1
m: equipment system (based on equipment systems specific to the end uses in Table A.1)
j: home types (single-detached, single-attached, apartments, mobile homes)
y: year, model year (2016 to 2030)
v: equipment system vintages (1990 to year y)

MKS_{kmvyj}: market share for vintage v of equipment system m for end use k home type j in year y

EFF_{kmyj}: energy efficiency of equipment system m for end-use k in year y (Table A.1).

Table A.1: Heating System Stock Efficiencies by System Type (%)

Heating Oil - Normal Efficiency	60
Heating Oil - Medium Efficiency	78
Heating Oil - High Efficiency	85
Natural Gas - Normal Efficiency	62
Natural Gas - Medium Efficiency	80
Natural Gas - High Efficiency	90
Electric	100
Heat Pump	190
Other	50
Wood	50
Dual Systems	80

Source: Comprehensive Energy Use database, Residential Sector, 2016, (NRCan 2018a)

Using the weighted average of energy efficiency rates and the final energy projection, the total service demand is the multiplication of these two:

$$TSD_{kyj} = EFF_{kyj} \times FE_{kyj}$$

TSD_{kyj}: total service demand for end-use k home type j in year y

EFF_{kyj}: average efficiency rate of equipment systems for end-use k home type j in year y

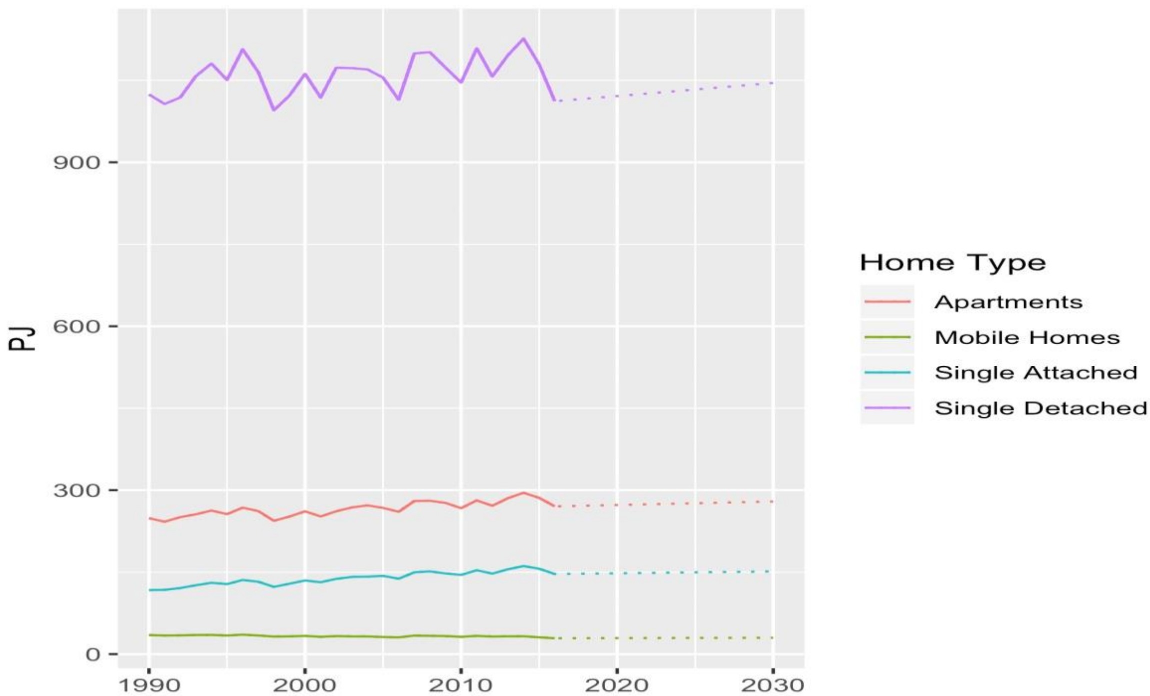
FE_{kyj}: residential final energy consumption of end-use k home type j in year y

The above total service demand is assumed to be the same under all scenarios. Energy use of each fuel (FE_{kmyj}) is calculated using this total service demand, the market shares of each equipment system (which is derived from the stock-rollover model) and the energy efficiency rates of each equipment system:

$$FE_{kmyj} = \frac{TSD_{kyj} \times MKS_{kmyj}}{EFF_{kmyj}}$$

Figure A.5 shows the total service demand in the building sector.

Figure A.5: Energy Service – Canada

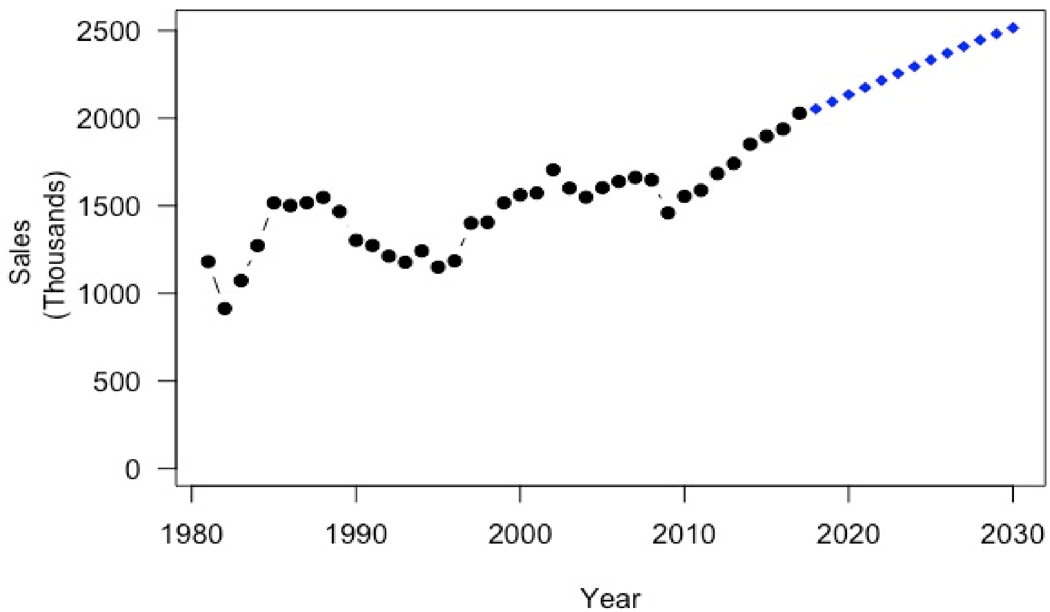


Source: NRCan (2018a) and CERI

Vehicle Stock-Rollover Model

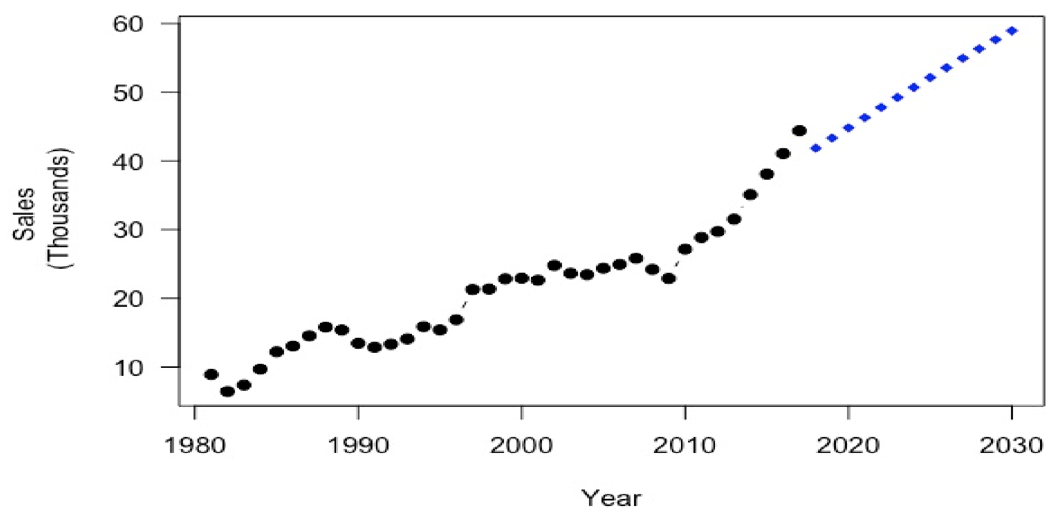
The vehicle stock-rollover model uses the annual sales of vehicles as additions to the stock of vehicles in each year. Statistics Canada provides monthly sales (table 20-10-0001-01) of passenger vehicles and trucks (minivans, sport-utility vehicles, light and heavy trucks, vans and buses) from 1981 and annual vehicle sales with more disaggregated categories (table 079-0004) including light, heavy trucks and buses from 2010. CERI used the annual data to infer the ratio of the different types of trucks in the monthly data. Since the monthly data covers a longer period of time it is used to forecast monthly new sales of vehicles until 2050. To forecast future annual vehicle sales, CERI used GDP and population as control variables. The forecasted annual vehicle sales for passenger cars in Canada are shown in Figure A.6 and for heavy trucks – Figure A.7.

Figure A.6: Annual Car Sales (Passenger Cars and Light Trucks) – Canada



Source: NRCan (2018a) and CERI

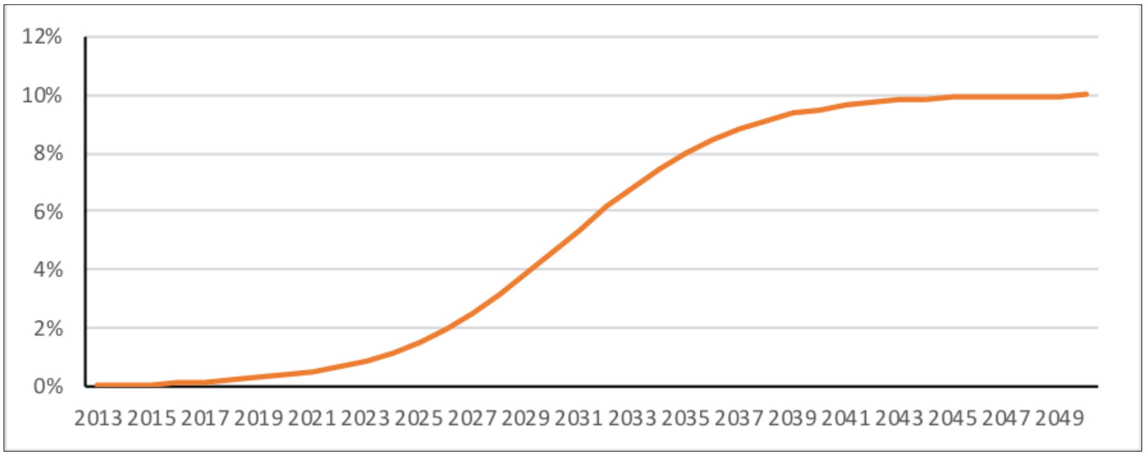
Figure A.7: Annual Heavy Truck Sales – Canada



Source: NRCan (2018a) and CERI

CERI uses a stock-rollover model to understand the changes in the vehicle stock over time. Annual sales forecasts derived in the previous section are used as the annual additions to the vehicle stock in each year. The penetration rates of electric vehicles in each year are shown in Figure A.8.

Figure A.8: EV Market Share (new car sales only)



Source: CERI

Annual Stock by Vintage

Similar to the model used by California PATHWAYS (2017), CERI calculates the number of vehicles retired each year (y) by vintage (ν: the year the vehicle was bought). At the end of each year (y), the fraction of vehicle stock that is retired equals to initial stock of that vehicle type (i: passenger vehicles, buses and trucks) multiplied by a replacement coefficient ($\beta_{\nu y}$).

$$S.RET_{iy} = \sum_{\nu}^{y} TV_{\nu iy} \times \beta_{\nu y}$$

where y is the vehicle stock year (2016 to 2030) and ν is the vehicle vintage, $S.RET_{iy}$ is the number of retired vehicles of type i in year y. $TV_{\nu iy}$ is the initial stock of a certain vintage ν of vehicle type i in year y, and $\beta_{\nu y}$ is a replacement coefficient for vintage ν in year y. The replacement coefficients are defined as:

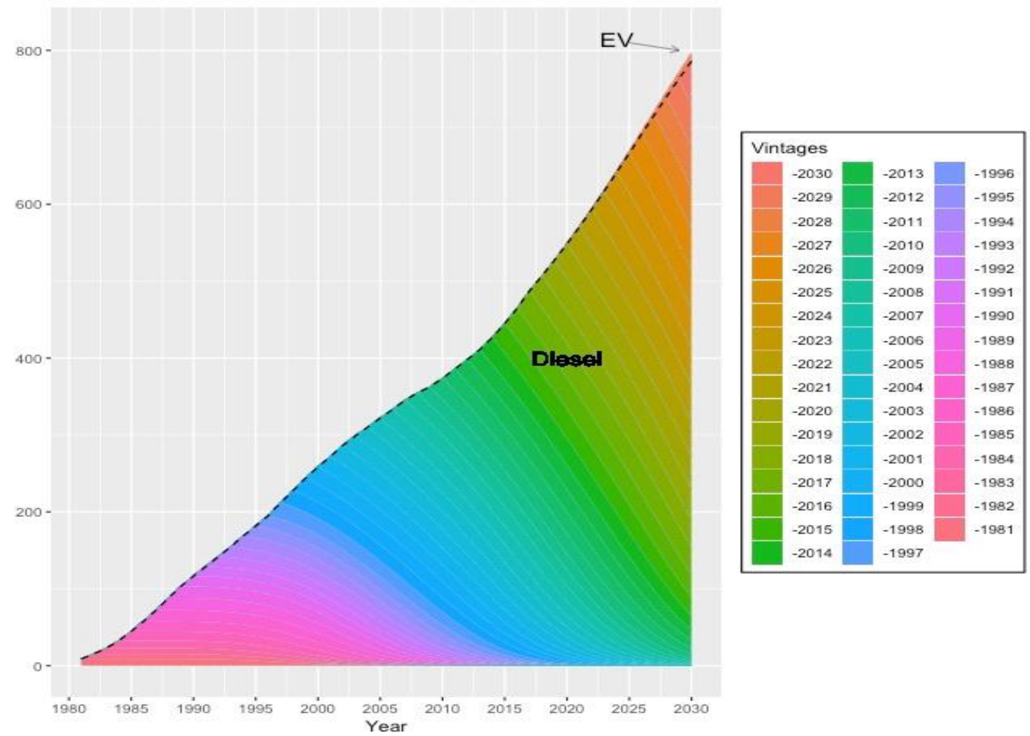
$$\beta_{\nu y} = e^{-\lambda} \frac{\lambda^{y-\nu+1}}{(y-\nu+1)!}$$

Replacement coefficients are generated by a survival function that uses Poisson distribution, with a mean equal to the expected useful life of each vehicle (λ). Similar to PATHWAYS (2017) λ of 17 years is used. The total stock of vehicles in each year is determined by adding the new vehicle sales (which is forecasted in the previous section) to the current stock after subtracting the number of retired vehicles:

$$TV_{iy+1} = \sum_{\nu}^{y} TV_{\nu iy} \times (1 - \beta_{\nu y}) + (TV_{\nu iy} \times \beta_{\nu y} + NV_{iy+1})$$

where TV_{iy+1} is the number of vehicles of type i (i.e., passenger vehicles, trucks, and buses) in year y+1, TV_{viy} is the number of vehicles of vintage ν and type i in year y, and NV_{iy+1} is the number of new vehicles (sales) of type i in year y+1. Figure A.9 shows the stock of heavy trucks in Canada under BAU penetration of EVs.

Figure A.9: Stock of Heavy Trucks in Canada from 1981 to 2030* (thousands)



*Each colour represents a vintage

Source: NRCan (2018a) and CERI

Total Fuel Demand

Total fuel consumption is calculated using the forecasted values of total kilometres travelled by passenger cars and public transit, the share of electric and conventional vehicles in the vehicle stock, and the fuel economy of different vehicle types. Since total kilometres travelled are derived from Statistics Canada's Census 2016 which shows households' travelling behaviour, the calculated gasoline and electricity demand are only for passenger transportation, not freight transportation. The fuel demand for each fuel type (i.e., gasoline, diesel, and electricity) is calculated as:

$$E_{jy} = KMT_{jy} \times FE_{jy} \times MKS_{jy}$$

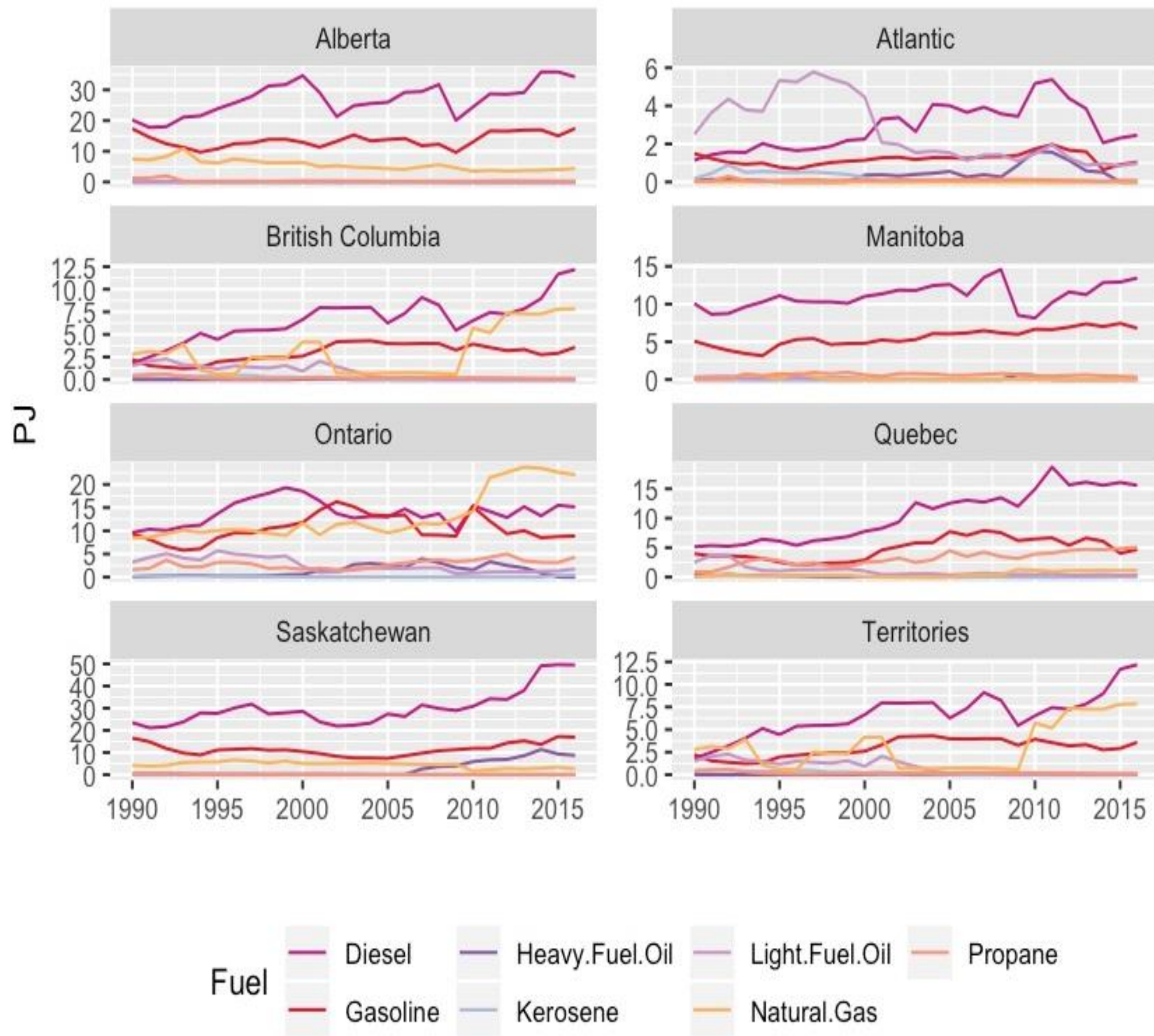
where E_{jy} is the total daily demand of fuel j (i.e., gasoline, diesel, or electricity) in year y, KMT_{iy} is total daily kilometres travelled by passengers by mode i (i.e., personal cars or public transit) in year y, EF_{jy} is the fuel economy (gasoline or diesel litres per kilometre) of fuel type j in year y, and MKS_{jy} shows the share of each vehicle type (i.e., electric or gasoline or diesel) in total vehicle stock in year y. These

shares are calculated for each fuel type from the stock of vehicles that were shown in the vehicle stock section.

Agriculture Energy Demand

Energy demand in the Agriculture Sector, by fuel use and by province, is shown in Figure A.10.

Figure A.10: Agriculture Energy Use by Fuel



Appendix B: British Columbia Regulated Fuels

This Appendix provides carbon intensities and energy that prevailed in the province of British Columbia.

Table B.1: BC Average Carbon Intensity for Fuels (gCO2eq./MJ)

	2010	2011	2012	2013	2014	2015	2016
Ethanol	55.51[A]	51.66[A]	53.11[A]	51.27[A]	49.74[A]	49.47	41.00
Electricity	11.94	11.94	11.94	11.48	11.00	11.00	11.00
Biodiesel	15.23[A]	16.20[A]	21.84[A]	21.06[A]	20.37[A]	15.98	15.24
HDRD	48.04[A]	40.30[A]	45.42[A]	32.11[A]	24.72[A]	16.37	16.40
CNG	59.74	59.74	59.74	61.21	62.14	62.14	62.14
Propane	78.29	78.29	78.29	73.66	68.44	68.15	68.02
LNG	-	66.54	66.54	64.18	63.26	63.26	63.26
Hydrogen	92.06	92.06	92.06	92.95	95.51	95.51	95.51

A – The calculation of average carbon intensity excludes fuels reported with default carbon intensity

Table B.2: BC Energy Use for Transportation (PJ)

	2010	2011	2012[A]	2013[B]	2014[C]	2015	2016
Gasoline	164.5	155.1	148.6	150.7	156.0	159.6	167.5
Diesel	127.7	141.2	142.1	140.8	142.8	133.7	132.3
Ethanol	5.5	6.2	5.9	6.5	7.1	8.1	8.8
Electricity	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Biodiesel	2.3	3.6	3.3	3.5	3.7	3.7	3.9
HDRD	1.1	2.2	2.5	3.6	4.6	4.4	2.7
CNG	0.0[D]	0.0[D]	0.2	0.3	0.4	0.6	0.6
Propane	0.0[E]	2.0	1.8	1.7	1.6	1.8	1.8
LNG	0.0	0.0	0.1	0.2	0.3	0.5	0.5
Hydrogen	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	301.8	310.9	305.3	307.9	317.1	313.0	318.7

Table B.3: BC Source Crop for Biofuels (million litres)

	2010	2011	2012	2013	2014	2015	2016
Barley & Wheat	-	-	-	6.4	12.8	0.2	1.0
Canola	38.6	71.1	48.1	62.4	76.8	90.2	96.1
Canola & Soy	3.2	2.7	39.2	19.6	-	-	-
Canola & Tallow	-	3.4	-	-	-	-	-
Corn	66.5	106.0	92.4	181.6	270.7	287.0	269.2
Corn Oil	-	-	-	3.5	7.1	1.5	1.3
Corn & Wheat	121.8	115.9	157.8	78.9	-	-	-
Refined Palm Oil (RPO)	30.6	42.4	56.9	43.3	29.7	-	-
Palm (RPO) & Rapeseed	-	-	5.6	2.8	-	-	-
Palm Sludge Oil (PSO)	-	-	-	46.4	92.7	71.6	43.7
Soy	14.8	2.8	-	7.6	15.2	10.8	10.3
Tallow	-	16.9	7.0	3.5	-	0.3	0.4
Unknown	25.6	29.6	2.5	1.6	0.6	-	-
Wheat	25.2	27.6	-	8.4	16.8	55.6	104.9
Yellow Grease (UCO)	-	-	-	1.6	3.2	46.8	26.9

Appendix C: Cost Scenarios

The estimate of the additional cost is calculated as follows:

Additional cost per fuel ($ / MJ) = (CI_base year – CI_target) / 1,000,000 * Credit_Price * 1,000,

Where

- CI_base year is ECCC estimates of carbon intensity per fuel from greenhouse gas and air pollutant emissions projections: 2018[25]
- CI_target is target CI for a particular year calculated as CI_base year * (1 - reduction percent for that year)
- Credit price

[25] https://www.arb.ca.gov/fuels/lcfs/fuelpat

Case: 10% CI reduction, $50 credit
Additional cost $ per MJ

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Natural Gas Raw	-	-	0.03	0.04	0.07	0.10	0.14	0.19	0.23	0.29
Landfill Gases/Waste	-	-	0.01	0.01	0.02	0.02	0.04	0.05	0.06	0.07
Natural Gas	-	-	0.02	0.04	0.06	0.08	0.12	0.15	0.19	0.23
Still Gas	-	-	0.03	0.04	0.06	0.09	0.13	0.17	0.21	0.26
Coke Oven Gas	-	-	0.02	0.03	0.05	0.06	0.09	0.12	0.15	0.18
Median Gaseous	**-**	**-**	**0.02**	**0.04**	**0.06**	**0.08**	**0.12**	**0.15**	**0.19**	**0.23**
Diesel	-	0.02	0.04	0.05	0.09	0.13	0.18	0.23	0.29	0.36
Heavy Fuel Oil	-	0.02	0.04	0.06	0.09	0.13	0.19	0.24	0.30	0.38
Aviation Gasoline	-	0.02	0.04	0.06	0.09	0.13	0.19	0.24	0.30	0.37
Gasoline	-	0.02	0.04	0.05	0.09	0.13	0.18	0.23	0.29	0.36
Jet Fuel	-	0.02	0.03	0.05	0.09	0.12	0.17	0.23	0.28	0.35
Kerosene	-	0.02	0.03	0.05	0.09	0.12	0.17	0.22	0.27	0.34
Light Fuel Oil	-	0.02	0.04	0.05	0.09	0.12	0.18	0.23	0.28	0.36
LPG	-	0.01	0.02	0.03	0.05	0.08	0.11	0.14	0.17	0.22
Biodiesel	-	0.00	0.00	0.00	0.01	0.01	0.01	0.02	0.02	0.03
Ethanol	-	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01
Median Liquids	**-**	**0.02**	**0.04**	**0.05**	**0.09**	**0.12**	**0.18**	**0.23**	**0.28**	**0.35**
Coal	-	-	0.05	0.07	0.11	0.16	0.23	0.30	0.36	0.46
Petroleum Coke	-	-	0.04	0.06	0.11	0.15	0.21	0.27	0.34	0.42
Coke	-	-	0.06	0.08	0.14	0.19	0.28	0.36	0.44	0.55
Biomass	-	-	0.00	0.00	0.01	0.01	0.01	0.02	0.02	0.03
Median Solids	**-**	**-**	**0.04**	**0.07**	**0.11**	**0.15**	**0.22**	**0.29**	**0.35**	**0.44**

Note: Only domestic consumption is used. Exports are not included.

Case: 10% CI reduction, $200 credit
Additional cost $ per MJ

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Natural Gas Raw	-	-	0.11	0.17	0.29	0.40	0.57	0.75	0.92	1.15
Landfill Gases/Waste	-	-	0.03	0.04	0.07	0.10	0.14	0.18	0.22	0.28
Natural Gas	-	-	0.09	0.14	0.23	0.33	0.47	0.61	0.75	0.94
Still Gas	-	-	0.10	0.15	0.26	0.36	0.51	0.67	0.82	1.03
Coke Oven Gas	-	-	0.07	0.11	0.18	0.26	0.37	0.48	0.59	0.73
Median Gaseous	**-**	**-**	**0.09**	**0.14**	**0.23**	**0.33**	**0.47**	**0.61**	**0.75**	**0.94**
Diesel	-	0.07	0.14	0.22	0.36	0.50	0.72	0.93	1.15	1.43
Heavy Fuel Oil	-	0.08	0.15	0.23	0.38	0.53	0.75	0.98	1.20	1.50
Aviation Gasoline	-	0.07	0.15	0.22	0.37	0.52	0.74	0.97	1.19	1.49
Gasoline	-	0.07	0.14	0.22	0.36	0.50	0.72	0.93	1.15	1.43
Jet Fuel	-	0.07	0.14	0.21	0.35	0.49	0.69	0.90	1.11	1.39
Kerosene	-	0.07	0.14	0.20	0.34	0.48	0.68	0.89	1.09	1.36
Light Fuel Oil	-	0.07	0.14	0.21	0.36	0.50	0.71	0.93	1.14	1.42
LPG	-	0.04	0.09	0.13	0.22	0.30	0.43	0.56	0.69	0.87
Biodiesel	-	0.01	0.01	0.02	0.03	0.04	0.06	0.08	0.09	0.12
Ethanol	-	0.00	0.00	0.01	0.01	0.02	0.02	0.03	0.04	0.05
Median Liquids	**-**	**0.07**	**0.14**	**0.21**	**0.35**	**0.49**	**0.70**	**0.91**	**1.12**	**1.41**
Coal	-	-	0.18	0.27	0.46	0.64	0.91	1.19	1.46	1.82
Petroleum Coke	-	-	0.17	0.25	0.42	0.59	0.85	1.10	1.35	1.69
Coke	-	-	0.22	0.33	0.55	0.77	1.10	1.43	1.76	2.21
Biomass	-	-	0.01	0.02	0.03	0.04	0.06	0.07	0.09	0.11
Median Solids	**-**	**-**	**0.18**	**0.26**	**0.44**	**0.61**	**0.88**	**1.14**	**1.41**	**1.76**

Case: 20% CI reduction, $50 credit
Additional cost $ per MJ

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Natural Gas Raw	-	-	0.06	0.09	0.14	0.20	0.29	0.37	0.46	0.57
Landfill Gases/Waste	-	-	0.01	0.02	0.04	0.05	0.07	0.09	0.11	0.14
Natural Gas	-	-	0.05	0.07	0.12	0.16	0.23	0.31	0.38	**0.47**
Still Gas	-	-	0.05	0.08	0.13	0.18	0.26	0.33	0.41	0.51
Coke Oven Gas	-	-	0.04	0.06	0.09	0.13	0.18	0.24	0.29	0.37
Median Gaseous	**-**	**-**	**0.05**	**0.07**	**0.12**	**0.16**	**0.23**	**0.31**	**0.38**	**0.47**
Diesel	-	0.04	0.07	0.11	0.18	0.25	0.36	0.47	0.57	0.72
Heavy Fuel Oil	-	0.04	0.08	0.11	0.19	0.26	0.38	0.49	0.60	0.75
Aviation Gasoline	-	0.04	0.07	0.11	0.19	0.26	0.37	0.48	0.59	0.74
Gasoline	-	0.04	0.07	0.11	0.18	0.25	0.36	0.47	0.57	0.72
Jet Fuel	-	0.03	0.07	0.10	0.17	0.24	0.35	0.45	0.56	0.69
Kerosene	-	0.03	0.07	0.10	0.17	0.24	0.34	0.44	0.55	0.68
Light Fuel Oil	-	0.04	0.07	0.11	0.18	0.25	0.36	0.46	0.57	0.71
LPG	-	0.02	0.04	0.07	0.11	0.15	0.22	0.28	0.35	0.43
Biodiesel	-	0.00	0.01	0.01	0.01	0.02	0.03	0.04	0.05	0.06
Ethanol	-	0.00	0.00	0.00	0.01	0.01	0.01	0.02	0.02	0.02
Median Liquids	**-**	**0.04**	**0.07**	**0.11**	**0.18**	**0.25**	**0.35**	**0.46**	**0.56**	**0.70**
Coal	-	-	0.09	0.14	0.23	0.32	0.46	0.59	0.73	0.91
Petroleum Coke	-	-	0.08	0.13	0.21	0.30	0.42	0.55	0.68	0.85
Coke	-	-	0.11	0.17	0.28	0.39	0.55	0.72	0.88	1.10
Biomass	-	-	0.01	0.01	0.01	0.02	0.03	0.04	0.04	0.06
Median Solids	**-**	**-**	**0.09**	**0.13**	**0.22**	**0.31**	**0.44**	**0.57**	**0.70**	**0.88**

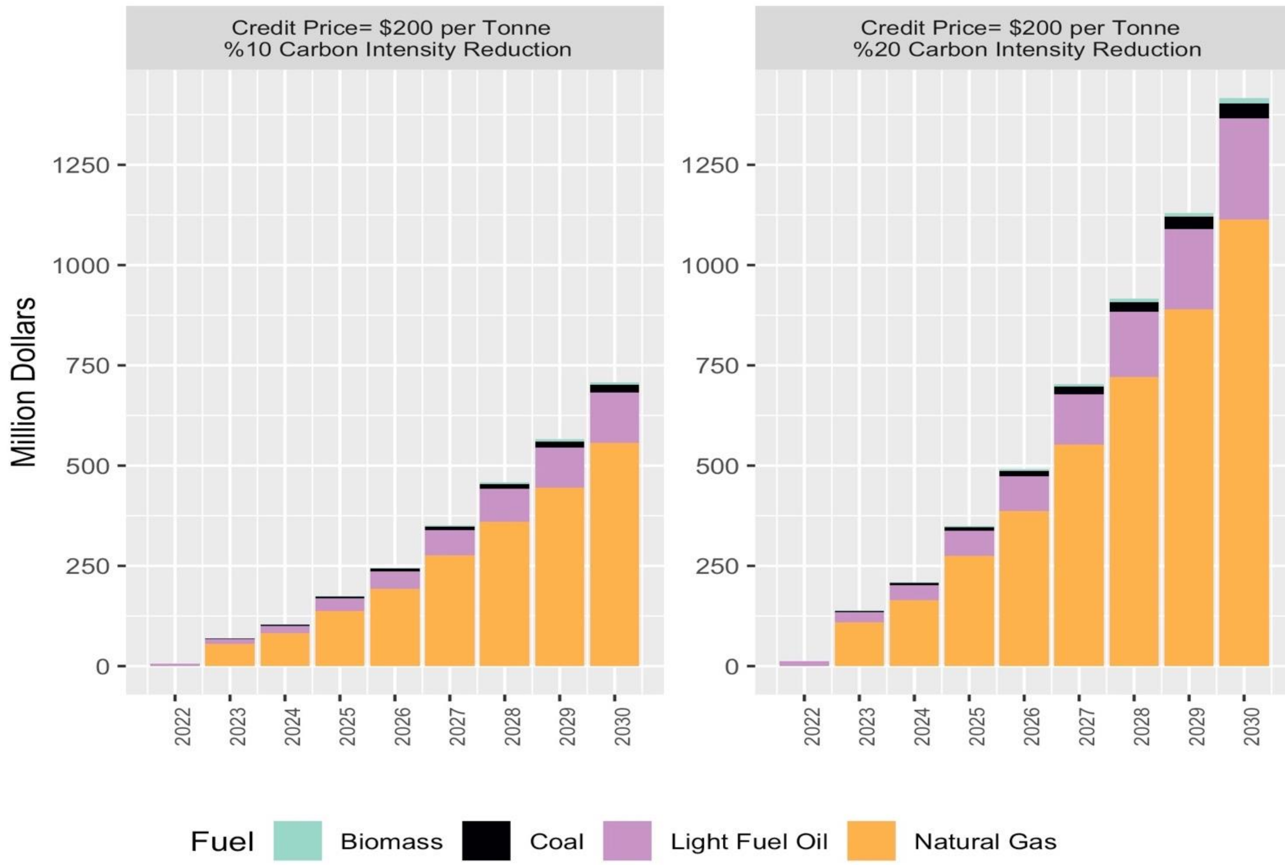
Case: 20% CI reduction, $200 credit
Additional cost $ per MJ

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Natural Gas Raw	-	-	0.23	0.34	0.57	0.80	1.15	1.49	1.84	2.30
Landfill Gases/Waste	-	-	0.06	0.08	0.14	0.20	0.28	0.37	0.45	0.56
Natural Gas	-	-	0.19	0.28	0.47	0.66	0.94	1.22	1.50	**1.88**
Still Gas	-	-	0.21	0.31	0.51	0.72	1.03	1.33	1.64	2.05
Coke Oven Gas	-	-	0.15	0.22	0.37	0.51	0.73	0.95	1.18	1.47
Median Gaseous	**-**	**-**	**0.19**	**0.28**	**0.47**	**0.66**	**0.94**	**1.22**	**1.50**	**1.88**
Diesel	-	0.14	0.29	0.43	0.72	1.00	1.43	1.86	2.30	2.87
Heavy Fuel Oil	-	0.15	0.30	0.45	0.75	1.05	1.50	1.95	2.41	3.01
Aviation Gasoline	-	0.15	0.30	0.45	0.74	1.04	1.49	1.93	2.38	2.97
Gasoline	-	0.14	0.29	0.43	0.72	1.00	1.43	1.86	2.29	2.87
Jet Fuel	-	0.14	0.28	0.42	0.69	0.97	1.39	1.81	2.22	2.78
Kerosene	-	0.14	0.27	0.41	0.68	0.95	1.36	1.77	2.18	2.73
Light Fuel Oil	-	0.14	0.28	0.43	0.71	1.00	1.42	1.85	2.28	2.85
LPG	-	0.09	0.17	0.26	0.43	0.61	0.87	1.13	1.39	1.74
Biodiesel	-	0.01	0.02	0.04	0.06	0.08	0.12	0.15	0.19	0.24
Ethanol	-	0.00	0.01	0.01	0.02	0.03	0.05	0.06	0.08	0.10
Median Liquids	**-**	**0.14**	**0.28**	**0.42**	**0.70**	**0.98**	**1.41**	**1.83**	**2.25**	**2.81**
Coal	-	-	0.36	0.55	0.91	1.28	1.82	2.37	2.92	3.65
Petroleum Coke	-	-	0.34	0.51	0.85	1.18	1.69	2.20	2.70	3.38
Coke	-	-	0.44	0.66	1.10	1.54	2.21	2.87	3.53	4.41
Biomass	-	-	0.02	0.03	0.06	0.08	0.11	0.15	0.18	0.22
Median Solids	**-**	**-**	**0.35**	**0.53**	**0.88**	**1.23**	**1.76**	**2.28**	**2.81**	**3.51**

Appendix D: Total Cost Impacts by Sector

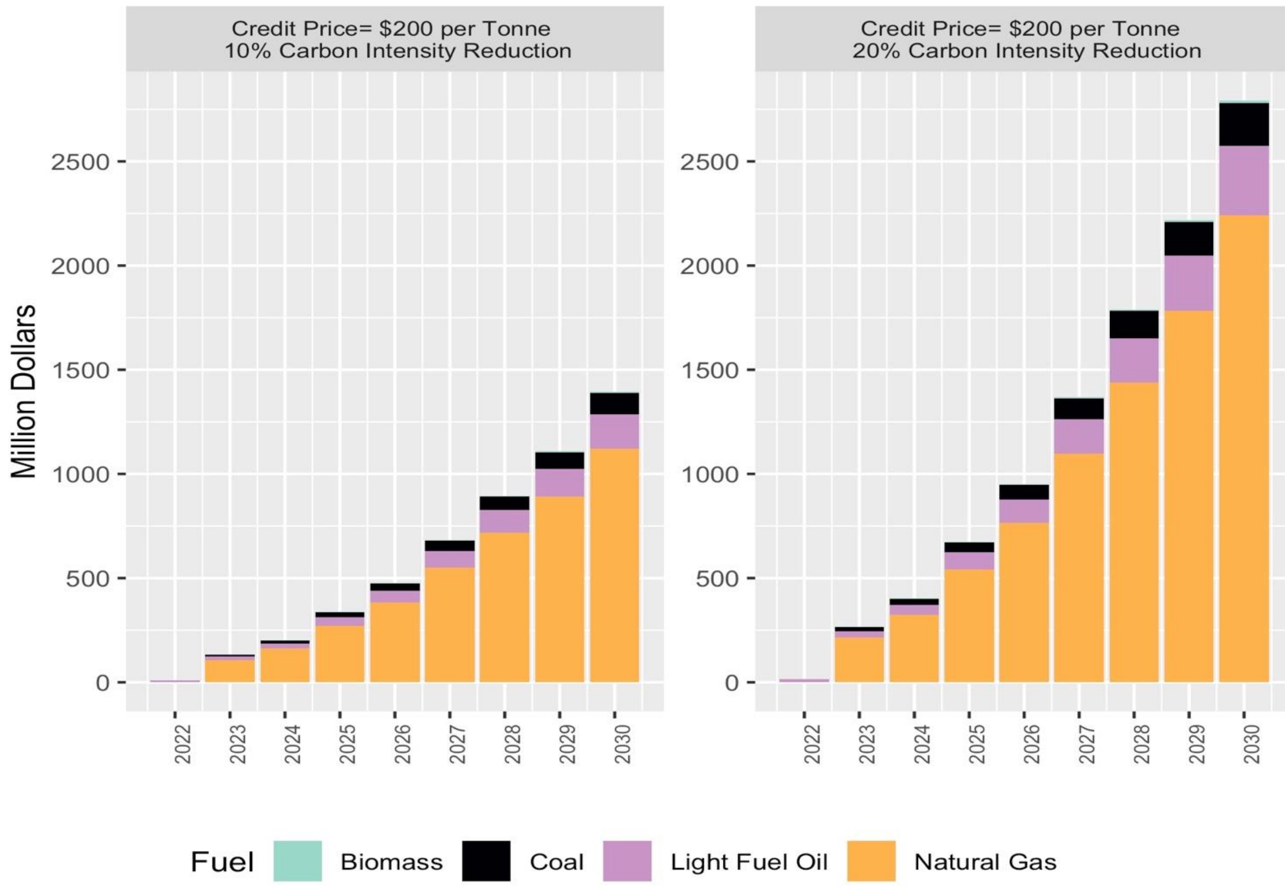
Figures D.1-D.7 are supplementary to the Cost Impact results. Figures in this Appendix illustrate the total annual additional costs by sector.

Figure D.1: Annual Additional Costs for Residential Buildings – Canada



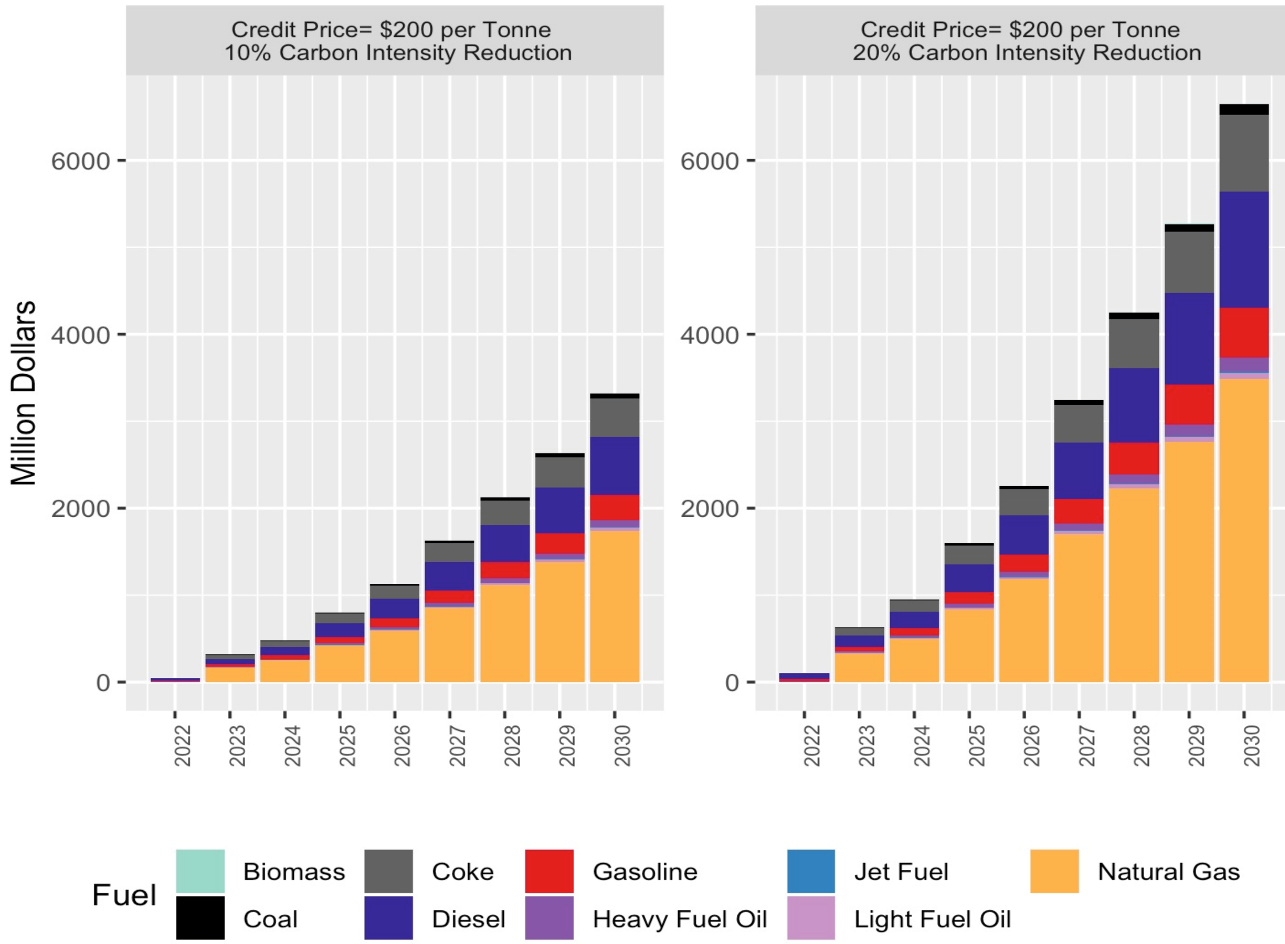
Source: CERI

Figure D.2: Annual Additional Costs for Total Buildings (Residential and Commercial) – Canada



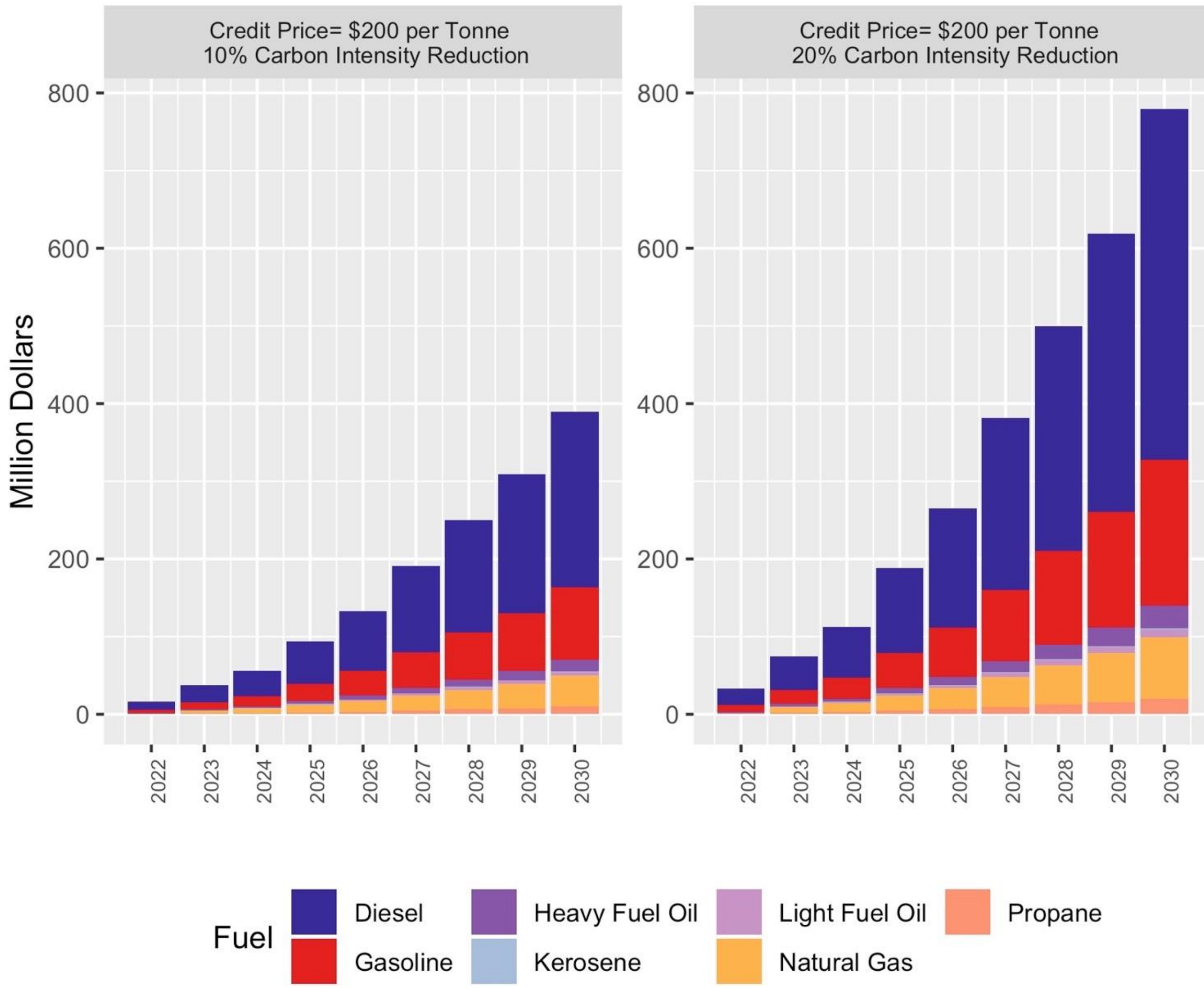
Source: CERI

Figure D.3: Annual Additional Costs in the Industrial Sector – Canada



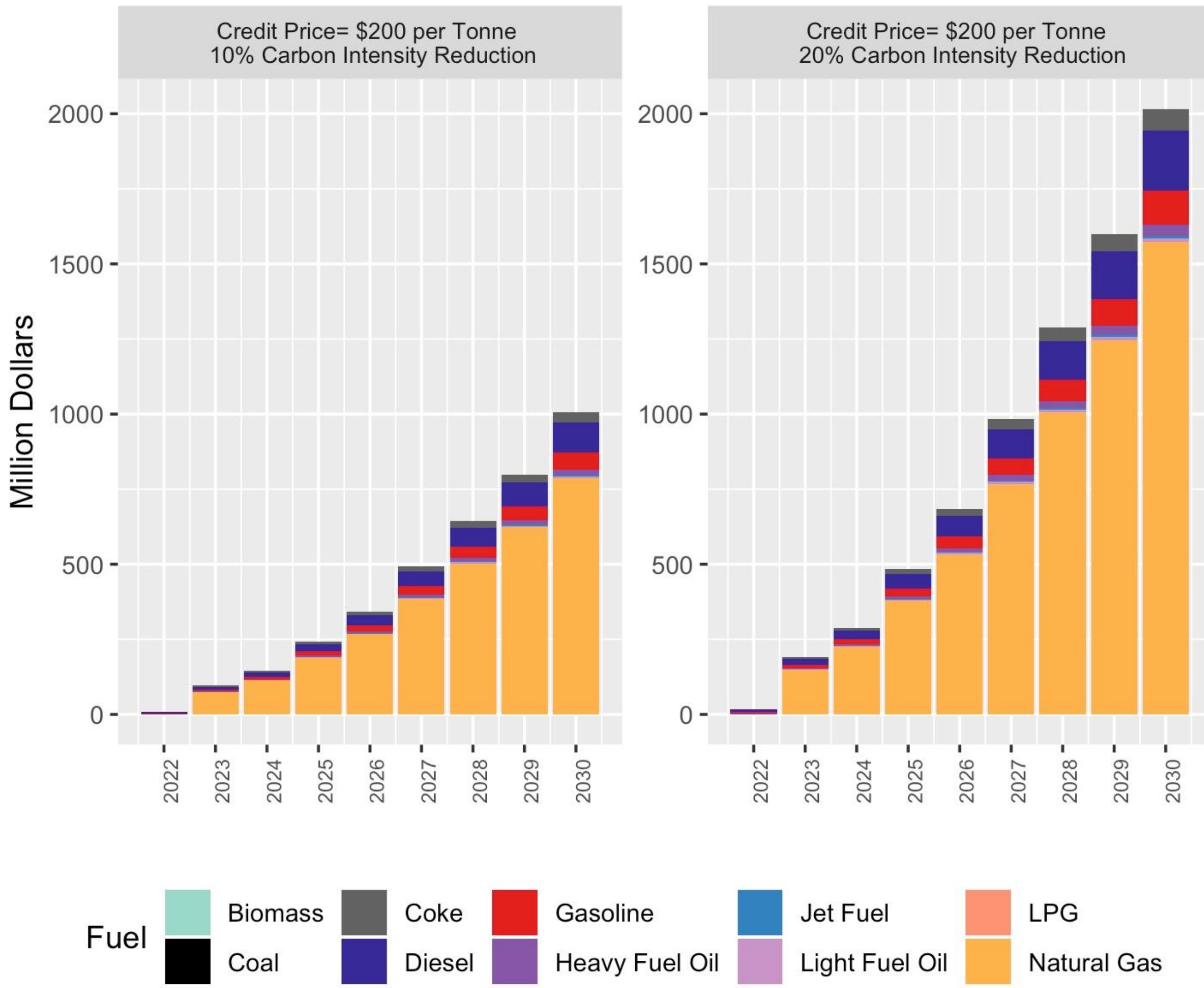
Source: CERI

Figure D.4: Annual Additional Costs in the Agriculture Sector – Canada



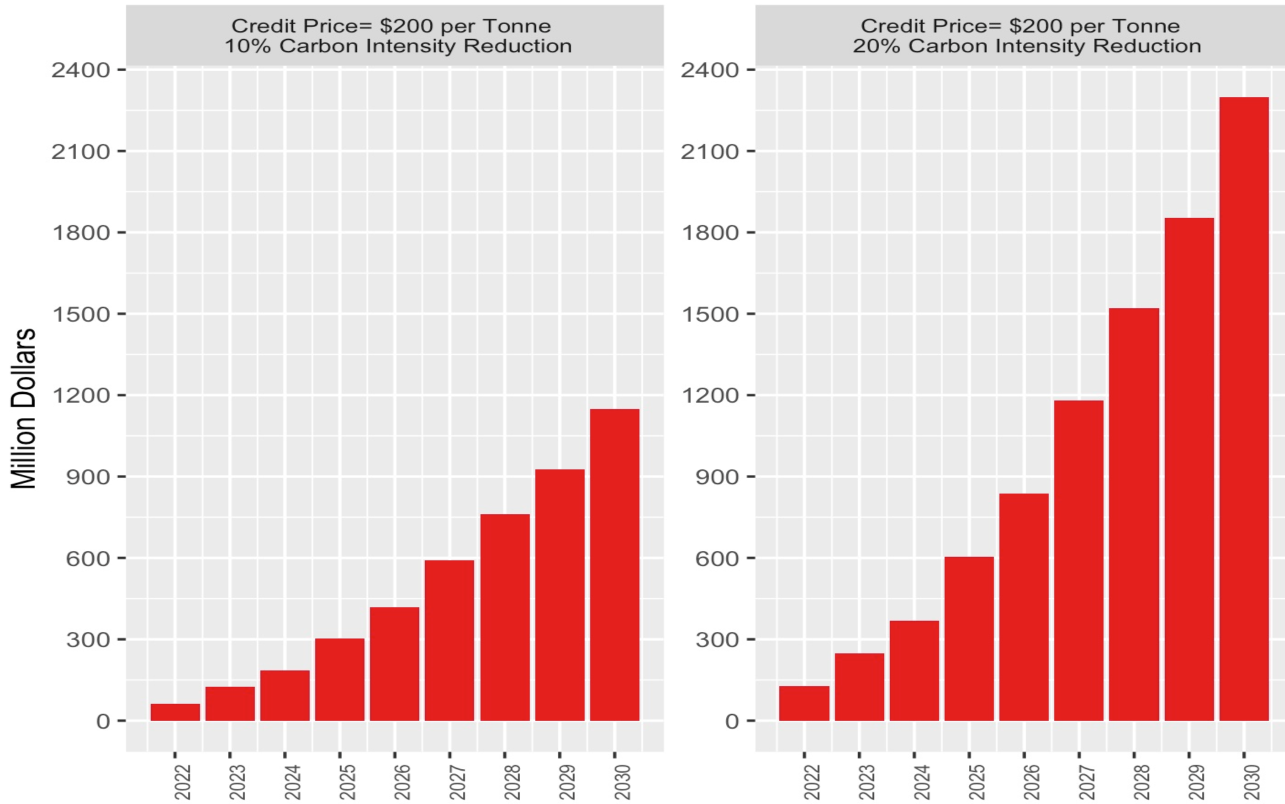
Source: CERI

Figure D.5: Annual Additional Costs in the Oil and Gas Sector – Canada



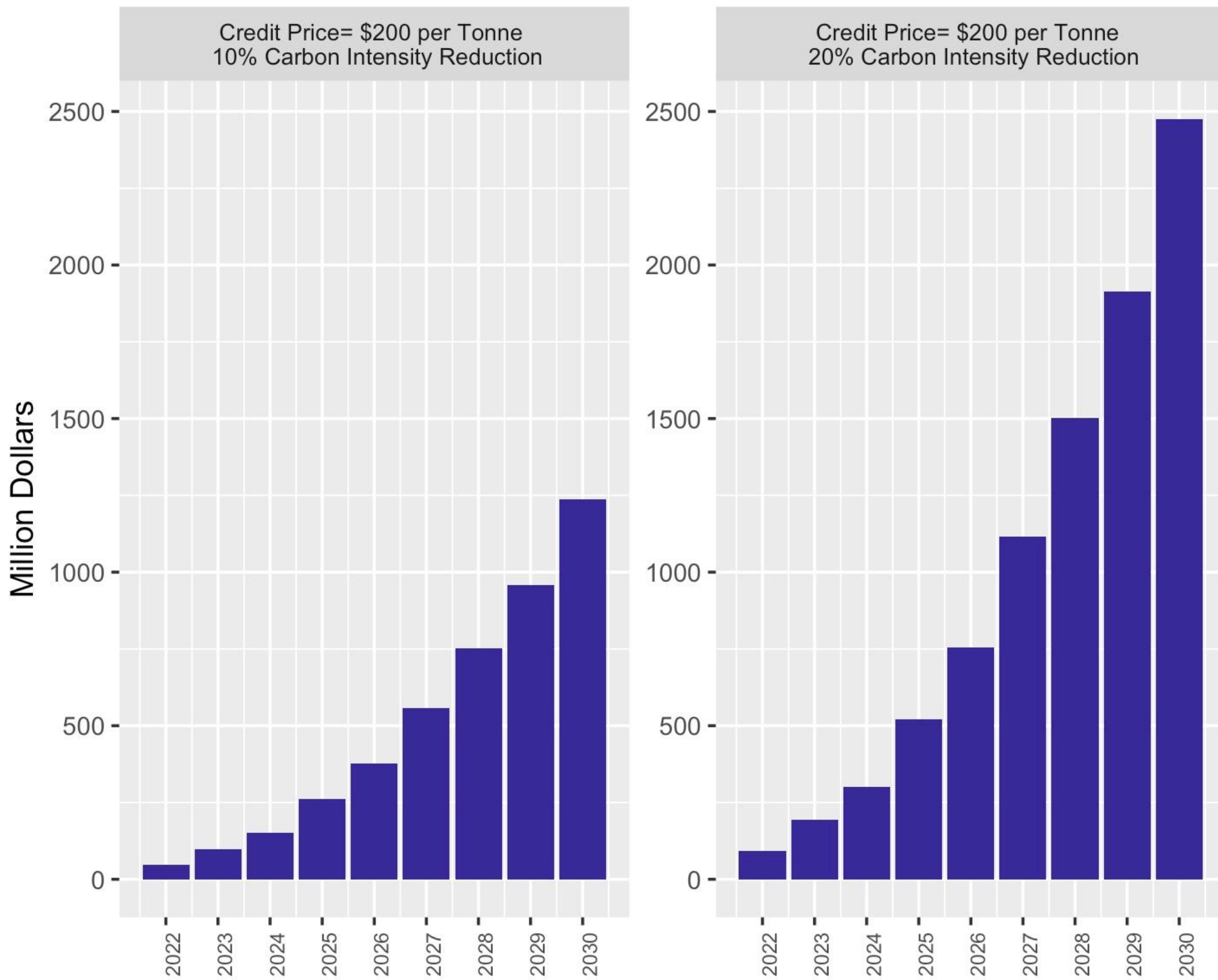
Source: CERI

Figure D.6: Annual Additional Gasoline Costs for Passenger Cars – Canada



Source: CERI

Figure D.7: Annual Additional Diesel Costs to Freight Trucks – Canada



Source: CERI

Appendix E: Compliance Costs via Blending

This appendix presents calculations for possible compliance costs via blending for gasoline and diesel fuels.

Assumptions:

For gasoline

- gasoline CI 88.14 g/MJ (BC RLCFR regulation)
- intensity needed in 2030 – 69.8 (estimated 2030 target based on BC target of 79.3 for 2020)

For diesel

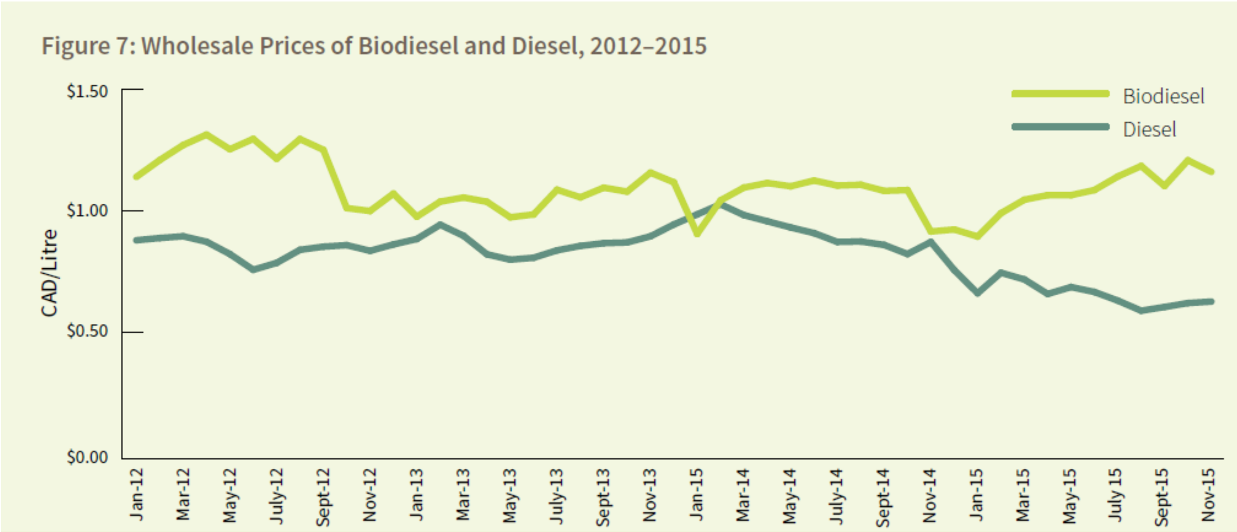
- diesel CI 94.76 g/MJ (BC RLCFR regulation)
- intensity needed in 2030 – 75.04 (estimated 2030 target based on BC target of 85.28 for 2020)

Compliance Cost for Biodiesel ($/ tonne of CO2eq)

	Wholesale Price Difference (Biodiesel – Diesel), $/litre								
Biodiesel CI, g/MJ	**0.1**	**0.2**	**0.3**	**0.4**	**0.5**	**0.6**	**0.7**	**0.8**	**0.9**
10	34	69	103	138	172	207	241	276	310
11	35	70	105	140	175	209	244	279	314
12	35	71	106	141	177	212	247	283	318
13	36	72	107	143	179	215	250	286	322
14	36	72	109	145	181	217	253	290	326
15	37	73	110	147	183	220	257	293	330
16	37	74	111	149	186	223	260	297	334
17	38	75	113	150	188	226	263	301	338
18	38	76	114	152	190	229	267	305	343
19	39	77	116	154	193	232	270	309	347
20	39	78	117	156	196	235	274	313	352
21	40	79	119	159	198	238	277	317	357
22	40	80	121	161	201	241	281	321	362
23	41	81	122	163	204	244	285	326	367
24	41	83	124	165	207	248	289	331	372
25	42	84	126	168	210	251	293	335	377

Note:

1) BC weighted average biodiesel CI in 2016 was 15.24 g/MJ.
2) Price differentials for wholesale prices of diesel and biodiesel for 2012-2015 (Source: Canada's Ecofiscal Commission)

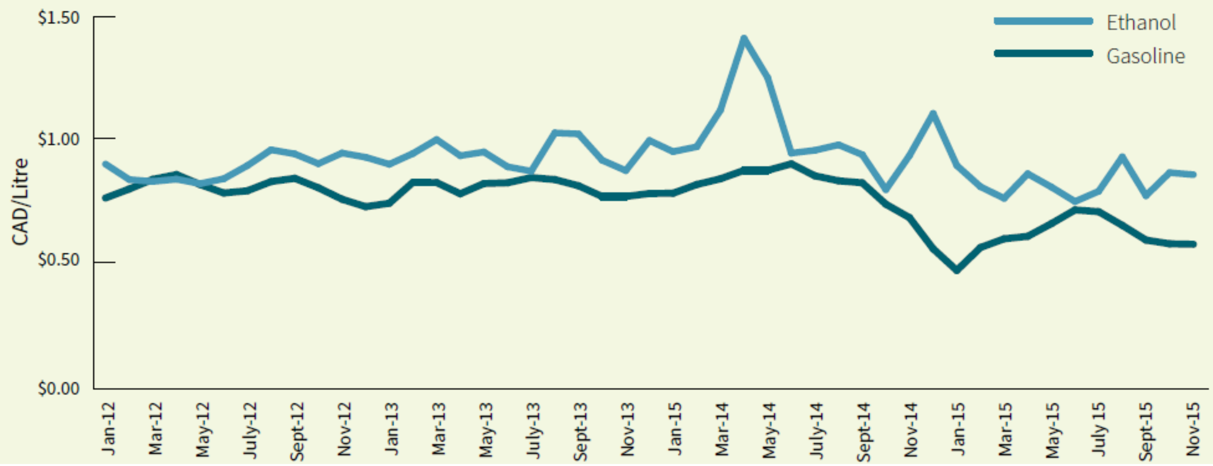


Compliance cost for gasoline ($/ tonne of CO2eq)

	Wholesale Price Difference (Ethanol - Gasoline), $/litre								
Ethanol CI, g/MJ	0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.8	0.9
34	54	108	162	216	270	324	378	432	486
35	55	110	165	220	275	330	385	440	495
36	56	112	168	224	280	336	393	449	505
37	57	114	172	229	286	343	400	457	515
38	58	117	175	233	292	350	408	467	525
39	60	119	179	238	298	357	417	476	536
40	61	121	182	243	304	364	425	486	547
41	62	124	186	248	310	372	434	496	558
42	63	127	190	253	317	380	444	507	570
43	65	130	194	259	324	389	453	518	583
44	66	132	199	265	331	397	464	530	596
45	68	136	203	271	339	407	474	542	610
46	69	139	208	278	347	416	486	555	624
47	71	142	213	284	355	426	498	569	640
48	73	146	219	291	364	437	510	583	656

Note:
1) BC weighted average gasoline CI in 2016 was 41 g/MJ.
2) Price differentials for wholesale prices of gasoline and ethanol for 2012-2015 (Source: Canada's Ecofiscal Commission)

Figure 6: Wholesale Prices of Ethanol and Gasoline, 2012–2015



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