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British Columbia Electrification Impacts Study

Forecasting the Impact of Achieving British Columbia's Greenhouse Gas Emissions Targets on Provincial Electricity Consumption

DRAFT RESULTS FOR DISCUSSION PURPOSES

SUBMITTED TO

BC Hydro
September 29th, 2020

SUBMITTED BY

Navius Research Inc.
355 Burrard St., Suite 410
PO Box 48300 Bentall,
Vancouver BC V7X 1A1

Contact@NaviusResearch.com
www.naviusresearch.com

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Forward

The analysis and results described in this report are based on information from BC Hydro on the BC Hydro load forecast. Simplifying assumptions and adjustments were made to the source information to facilitate the analysis. The results of scenarios intended to mimic the BC Hydro load forecast with current climate policies and hypothetical stronger climate policies. The current policy scenario can be expected to provide energy demand projections that are similar to the load forecast but are not intended to be identical replications.

Executive Summary

Introduction

The greenhouse gas (GHG) reduction policies implemented by the government of British Columbia and the Government of Canada will change the quantity and type of energy consumed in British Columbia (BC) in the future. Specifically, GHG reduction policy may result in significant electrification of some energy end-uses, allowing the substitution of fossil fuels with renewable energy (e.g. wind, hydro, solar power), delivered via the electricity system. Electricity consumption may increase for end-uses where that fuel is not currently widely used, such as transportation, or where there is significant share of other fuel fuels consumed, such as building space and water heating.

This potential change in electricity consumption is of interest to BC Hydro. Understanding the drivers of energy consumption will help with the utility's electricity system planning. The extent of electrification is largely a function of electric technology capital and energy costs compared with the cost of the conventional and alternative fuels that may compete or complement the use of electricity in a low-GHG future. A further uncertainty is the design of the policy portfolios that will drive a reduction in GHG and emissions and may directly or indirectly require the use of low-carbon electricity.

The goal of this project is to analyse the uncertainty in future electricity demand created by current and potential energy and GHG policies as well as the cost and performance of emerging energy technologies whose adoption will be incentivized by these policies. In doing so, this analysis will provide reasonable bookends for future electricity consumption in BC, while explaining the drivers of this consumption (e.g. technology market shares, fuel shares by sector, use of alternatives e.g. biofuels). This report summarizes the draft final analysis of the potential for electrification in BC

Methodology

In this analysis, we used a technologically detailed, full-economic equilibrium, energy economy model to simulate how different GHG policy portfolios will affect electricity consumption in BC from the present to 2050.

We tested the impact of:

- **"Current policies", that are legislated or have firm announcements.** These include the BC carbon tax, rising to \$50/tCO_2e by 2022 and other policies that generally

date from the fist BC Climate Action Plan, released in 2008. This scenario also includes the announced light-duty (passenger) vehicle zero-emissions vehicle (ZEV) standard that requires a minimum fraction of sales be ZEVs and essentially phases out the sale of conventional vehicles by 2040. It also includes increased transmission and use of electricity by the natural gas sector (via the Dawson Creek Chetwynd transmission line, DCAT, and the Peace region transmission line, PRES).

- **"Stronger policies", which include a range of stronger incentives and regulatory policies, plus an emissions cap that achieves BC's 2040 and 2050 GHG emissions targets.** These are a 60% reduction relative to 2007 GHG emissions by 2040, and an 80% reduction by 2050.

Using the stronger policy scenario as a reference, we also tested how the forecast of electricity demand is affected by a policy portfolio that uses more technology and fuel neutral policies, but still achieves the same deep GHG reductions in 2040 and 2050. This policy portfolio has the same GHG cap, but it lacks the regulatory policies that might support specific technologies or fuels, such as the zero-emissions vehicle standard. As well, we tested the impact of a future with lower-cost plug-in electric vehicles and a future with higher cost biofuels.

Results and Conclusions

Of the dynamics tested, **BC's long-term electricity demand is most sensitive to the strength of climate policy**. In 2030, the difference between current policies and stronger policies is relatively small. The electricity demand forecast ranges from 62 to 65 TWh/yr. By 2050, the difference is much larger. In response to current policies, electricity demand grows to roughly 81 TWh/yr, whereas with stronger policies, it grows to almost 105 TWh/yr, a difference of 24 TWh/yr (+34%) (Summary Table 1).

Summary Table 1: BC electricity demand by scenario (TWh/yr)

	2015	2020	2025	2030	2035	2040	2045	2050
Current policies	51	53	58	62	67	72	77	81
Stronger policies	51	53	58	65	72	79	92	105
Stronger policies, tech. neutral	51	53	58	65	70	80	95	103
Stronger policies, low cost PEV	51	53	58	68	75	83	96	109
Stronger policies, high-cost biofuel	51	53	58	65	72	80	92	105

In response to stronger GHG reduction policies that will achieve the provincial GHG targets, **most of the incremental growth in electricity demand comes from the natural gas sector and the LNG sector**. 70% of the incremental demand comes from natural gas production. Another 20% of the incremental demand comes from the LNG sector, where the results indicate that LNG plants originally built with gas-fired drives may need to electrify in order achieve the GHG targets. The remaining 10% of incremental demand comes from transportation and buildings. Note that electricity demand for transportation must grow significantly in order to achieve deep GHG reductions. However, much of this load growth is already included in the current policy forecast since it includes the light-duty vehicle ZEV standard.

In contrast, **the other uncertainties tested in this analysis only shift total electricity demand in 2050 by a few TWh/yr relative to our reference forecast with stronger policies**:

- **On net, the stronger policy scenario has a similar impact on electricity demand as a more technology and fuel neutral policy portfolio. E**ven with technology and fuel neutral policies, electrification is still an important abatement action. On net, electricity demand in somewhat higher or lower in response to technology fuel neutral policies, depending on the year (Summary Table 1).
- **Lower-cost PEVs result in greater provincial electricity demand from 2030 all the way through to 2050.** In 2050, electricity demand is 4 TWh/yr higher than in the reference stronger policy scenario (roughly 4% higher) (Summary Table 1). Most of this change comes from increased adoption of medium and heavy-duty vehicles, where these eventually account for almost 45% of medium and heavy-duty transportation activity. The adoption of electric buses is relatively insensitive to reductions in their costs, as they gain a substantial market share at with all future battery costs considered in this analysis. The adoption of light-duty PEVs, would be affected by reduced PEV costs, but their uptake is largely defined by the ZEV standard that requires 95% of sales to be ZEVs by 2040.
- **Higher biofuel costs result in greater electrification of transportation, but little change in total provincial electricity demand.** The greatest change is the extent which medium and heavy-duty PEVs are used. However, several minor offsetting factors make electricity demand insensitive to biofuel costs (Summary Table 1). Specifically, higher biofuel costs result in slower economic growth that largely offsets additional electricity consumption for transportation.

In summary, this analysis shows that achieving BC's GHG reduction targets will result in substantially more electricity demand than would occur with current policies. The results do not show a future where other potential low-GHG energy pathways out-

compete electricity. Rather, these pathways, including energy efficiency, bioenergy and electrification, are complementary and all contribute to deep GHG reductions.

Key uncertainties and limitations of the analysis

Because electricity demand in a deep GHG reduction scenario is most sensitive to load growth in the transportation and natural gas sectors, the limitations and uncertainties in this analysis that relate to these sectors are the most important. Specifically, these uncertainties relate to how global LNG demand and demand for natural gas produced in BC are represented in the analysis. A further uncertainty results from the relatively aggregate representation of medium and heavy-duty vehicles in analysis.

An uncertainty that was not tested in this analysis is global LNG demand and demand for natural gas produced in BC, which could lead to lower electricity demand. In this forecast, BC produces at least 60% of the gas exported from the province as LNG. This accounts for between 1 and 2 bcf/day of BC's production during the forecast, or 15-25%. If global efforts to reduce GHG emissions also reduce foreign demand for LNG, then the BC natural gas and LNG production sectors would be smaller than forecasted as would their electricity demand. This could reduce electricity demand by at most 6-7 TWh/yr later in the forecast (e.g. 2040 through to 2050). As well, the analysis assumes a fixed minimum quantity of foreign investment in the BC natural gas sector. This assumption prevents the output of that sector falling more than 10% below what was assumed in the baseline current policy scenario. Consequently, this analysis does not show the full range of uncertainty in future electricity demand from these sectors.

There could be earlier potential for medium and heavy-duty PEVs than forecasted. A limitation of this analysis is that it has a general representation of medium and heavy-duty vehicles. Consequently, the results can only show a relatively aggregate representation of their potential to electrify. Medium and heavy-duty vehicles are very heterogeneous with respect to their size, what they do and how far they travel (or how much they carry) in a given day or year. By necessity, this diversity has been simplified in the analysis and medium and heavy-duty PEVs are represented conservatively, as long-range tractor trailers (where the PEV archetype can travel 600-700km per charge).

However, this characterization misses some of the low-range and high utilization uses of these vehicles where electrification would have a better business case, even with higher cost batteries. For example, this could include urban delivery vehicles, drayage trucks moving goods from ports to warehouses, and waste collection trucks. Electrification of these niches could occur earlier than shown in this analysis and

demand from medium and heavy-duty transportation could ultimately be larger and sooner than forecasted.

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1. Introduction

The greenhouse gas (GHG) reduction policies implemented by the government of British Columbia and the Government of Canada will change the quantity and type of energy consumed in British Columbia (BC) in the future. Specifically, GHG reduction policy may result in significant electrification of some energy end-uses, allowing the substitution of fossil fuels with renewable energy (e.g. wind, hydro, solar power), delivered via the electricity system. Electricity consumption may increase for end-uses where that fuel is not currently widely used, such as transportation, or where there is significant share of other fuel fuels consumed, such as building space- and water-heating.

This potential change in electricity consumption is of interest to BC Hydro. Understanding the drivers of energy consumption will help with the utility's electricity system planning. The extent of electrification is largely a function of electric technology capital and energy costs compared with the cost of the conventional and alternative fuels that may compete or complement the use of electricity in a low-GHG future. A further uncertainty is the design of the policy portfolios that will drive a reduction in GHG and emissions and may directly or indirectly require the use of low-carbon electricity.

The goal of this project is to analyse the uncertainty in future electricity demand created by current and potential energy and GHG policies as well as the cost and performance of emerging energy technologies whose adoption will be incentivized by these policies. In doing so, this analysis will provide reasonable bookends for future electricity consumption in BC, while explaining the drivers of this consumption (e.g. technology market shares, fuel shares by sector, use of alternatives e.g. biofuels).

While this is a forecast of electricity consumption in BC, it is independent of the BC Hydro load forecast. Nonetheless, within this analysis, the forecast of electricity consumption in the absence of new GHG policies has been approximately aligned with the 2019 BC Hydro load forecast to facilitate a comparison between the two. Similarly, while this is an analysis of how provincial GHG reduction policies will affect energy consumption and GHG emissions in the province, it is independent of the work the BC government has done in this regard. However, to facilitate a comparison with the government's own analysis, the methodology and policy assumption used in this analysis have been aligned to the greatest extent possible with what the BC government has used.

This report begins by describing the methodology, first with an overview of the energy-economy model used to produce the quantitative forecasts used in this analysis. The methodology section then goes on to explain the scenarios we tested with that model. The scenarios include a forecast of provincial energy consumption and GHG emissions under the influence of currently legislated GHG reduction policies which is compared against a scenario with stronger GHG reduction policies that will achieve BC's legislated emissions targets for 2040 and 2050. Variations of this policy scenario are compared against each other to understand how future electricity consumption is affected by the use of technology neutral versus prescriptive policies, lower-cost electric vehicles, and higher cost biofuels. After the methodology section, we present and explain the scenarios results. This is followed by summary discussion of the key results and conclusions stemming form this analysis. The appendices include the detailed technology and fuel research conducted for this analysis and greater detail on the archetypal building energy technologies (e.g. building envelopes, mechanical systems etc.).

2. Methodology

This section first qualitatively describes gTech, the energy-economy model used for this analysis. This is followed by a description of the fundamental inputs to gTech as well as key indicators that describe the future forecasted by gTech. The methodology also includes an overview of the scenario design for this analysis as well as the specific GHG policy scenarios and uncertain parameters that are tested in these scenarios.

2.1. Introduction to the gTech model

The gTech model is designed to simulate the impacts of policy on both technological adoption and the broader economy. It simultaneously combines an explicit representation of technologies (everything from vehicles to fridges to natural gas extraction technologies) with key economic transactions within an economy, allowing it to provide insight about policy impacts on broader economic indicators such as GDP, industrial competitiveness and household welfare. This framework differs from most other models, which either exclude explicit technologies or are not intended to simulate full economic impacts.

Some of gTech's key features are highlighted below:

- **Over 50 unique energy end-uses and 200 unique technologies available to meet the end-use demand in all sectors of the economy.** For example, the model accounts for (1) the electricity consumption and hot water demand for different archetypes of clothes washers, (2) how changing the stock of clothes washers influences the demand for hot water and (3) the energy consumption of hot water heaters.

- **An explicit simulation of technology choice and capital stock turnover.** Each technology/end-use has a unique lifespan. The existing stock of technologies gradually retires over time, leaving a gap between the demand for end-use services and the supply from existing technologies. This gap is filled with new stock. New stock is determined using a technology choice algorithm that allocates market share to new technologies based on (1) capital costs, (2) energy costs, (3) discount rates, (4) an elasticity that accounts for heterogeneous decision-making among consumers and (5) non-financial factors that influence technology choice.

- **Technology choice in gTech is behaviourally realistic as opposed to prescriptive.** gTech seeks to be "descriptive", meaning that it tries to forecast how households and firms will respond to energy/climate policy or to changes in economic

conditions (e.g., change in the price for natural gas). Models that are "prescriptive" seek to tell the user the best path towards achieving a specific objective, with a typical objective being to minimize financial costs. While prescriptive models serve a purpose, they are not forecasting tools. The reason is that households and firms do not use financial costs as their only criteria for selecting technologies; rather, they use a myriad of criteria of which financial costs are just one consideration.

- **gTech has comprehensive coverage of energy consumption and energy-related GHG emissions in British Columbia.** The model aligns with Statistics Canada energy use data and the British Columbian provincial by economic sector and inventory category.

- **gTech is simultaneously a full economic model, in addition to a bottom-up technology model.** gTech is classified as a "computable general equilibrium" or CGE model. In a nutshell, gTech simulates:

  - **70 sectors of the economy.**

  - **10 regions.** The version of the model used for this project explicitly simulates the economies of British Columbia, Alberta, Saskatchewan, Manitoba, Ontario, Québec, New Brunswick, Nova Scotia, and the "rest of Canada" (i.e., Newfoundland, PEI and the territories) and the United States.

  - **The markets for commodities, factors and policy mechanisms in every region of the model.** gTech ensures that ALL markets simulated within the model arrive at an equilibrium. Equilibrium is defined as supply being equal to demand. gTech ensures equilibrium in all the following markets:

    - Over 78 commodity and service markets. These commodity and service markets include everything from energy products (e.g., oil, refined petroleum products, petroleum coke, electricity); resource commodities (e.g., wheat, soy, corn); manufactured goods (e.g., petrochemicals, cement); and services (e.g., trucking transport, wholesaling/retailing margins, other services).

    - Factors markets, including four different classes of labor based on productivity and capital goods.

    - Policy compliance mechanisms. Some policies generate a market for compliance mechanisms (e.g., allowances under a cap-and-trade program or credits under a low-carbon fuel standard). Under these policies, the allowances distributed, auctioned or purchased must equal the allowances required by the entities participating in the market. In gTech, the price for these policy compliance mechanisms adjusts to achieve equilibrium in these policy markets.

- gTech can simulate how:
  - **Policies affect the economy.** gTech reports economic impacts on both expenditure- and income-based GDP. The former reflects impacts on consumption, investment, government expenditures and exports and imports, while the latter reports impacts on GDP produced by each of the 70 sectors in the model.
  - **Policies affect industrial competitiveness.** As an economic model, gTech explicitly simulates how policies affect industrial competitiveness. For example, if the cost of products and services increases in Nova Scotia but not in other jurisdictions, demand for Nova Scotia's products and services will fall.
  - **Policies in jurisdictions outside of BC affect the province.** Policies implemented outside of BC may have an impact on the province (e.g. the federal vehicle emissions standards or carbon pricing).
- **gTech contains an electricity supply cost curve that has been calibrated to information provided by BC Hydro:** This cost curve shows an increasing average production cost (in real terms) for electricity as demand grow relative to current levels. There are limitations on the functional forms that can be used in gTech, so the cost curve does not replicate the information provided by BC Hydro exactly for large changes in electricity demand, for example a doubling of current demand, which can occur in some scenarios by 2045 to 2050. In this case, model is conservative in showing somewhat higher electricity costs and prices.

2.2. Fundamental drivers and reference scenario indicators

Fundamental inputs to gTech include forecasts of economic activity, oil and gas commodity prices, and specific assumptions for activity in the liquefied natural gas (LNG) sector (Table 1).

Economic growth is aligned with the GDP growth assumption used by BC Finance, with growth averaging 2.14%/yr between 2015 and 2050. gTech does not explicitly use a population growth forecast. However, because GDP is aligned with BC Finance's forecast by adjusting labour productivity growth, gTech implicitly uses the same population growth assumption as BC Finance. Labour productivity growth, which is composed of population growth and productivity growth, averages 2.09%/yr.

Oil and gas prices are based on the Energy Information Agency's 2018 Annual Energy Outlook. The crude oil price forecast shows oil prices rising back to $106/bbl between the present and 2050 (2010 CAD for West Texas Intermediate oil). The price of natural remains relatively flat reach $5/mmbtu by 2050 (2010 CAD, price at Henry Hub).

LNG production is set at approximately 17 Mt/yr and is linked with the assumption that 60% of the natural gas required for this output is produced in BC. Electric LNG production is set at roughly 2.2 Mt/yr. The LNG assumption is not based on any specific projects, but it does approximate the production from Woodfibre LNG and the first phase of LNG Canada. Note that BC LNG production is set as a fraction of assumed foreign demand. This foreign demand is not affected by the GHG reduction policies simulated with the model, though the share of this foreign demand supplied by BC can vary somewhat if policies change the production cost of LNG in BC. Similarly, the quantity of LNG produced with electric drives can also change in response to GHG policies applied in various scenarios.

Table 2 shows some key indicators that describe the future forecasted by gTech, including activity in the upstream natural gas sector, building floor area, housing starts and retail spending. These are modelled results that come from forecasting a continuation of current GHG reduction policies.

Table 1: Fundamental drivers ($ value are 2010 CAD)

	Unit	2015	2020	2025	2030	2035	2050
GDP growth	%/yr	2.62%	2.71%	2.21%	2.01%	1.99%	2.02%
Labour productivity growth	%/yr	1.87%	2.16%	2.20%	2.08%	2.18%	2.10%
Natural gas price (Henry Hub)	$/mmbtu	4.5	4.0	4.3	4.4	4.4	4.5
Oil Price (WTI	$/bbl	84	69	80	86	92	106
Total LNG	Mt/yr	0	0	13	17	17	17
E-LNG	Mt/yr	0	0	1.7	2.2	2.2	2.2

Table 2: Scenario indicators ($ value are 2010 CAD)

	Unit	2015	2020	2025	2030	2035	2050
Natural gas production	bcf/day	4.8	5.0	6.1	6.8	7.2	7.9
Commercial and institutional floor area	Million m^2	103	116	126	136	146	182
Residential floor area	Million m^2	287	309	328	351	368	463
Housing starts*	New units/yr	33,683	33,573	32,360	38,156	32,721	59,058
Retail spending*	Billion $/yr	67	75	82	90	100	135

* Housing starts and retail spending are based on historic values indexed to growth in new residential floor area and activity in the wholesale and retail sector in gTech, respectively. The 2015 housing starts value is an average of 2013 to 2017.

2.3. Scenario design and summary

This section elaborates on the scenarios we tested in this analysis. These included several different policy scenarios based on current policies and stronger policies that can achieve BC's legislated GHG emission targets in 2040 and 2050. Additional scenarios explore the impact of using more technology neutral policies to reduce GHG emissions, the impact of lower plug-in electric vehicles costs and higher biofuel costs.

These scenarios explore three key dimensions: GHG policy, electrification technology cost and potential, and bio-energy cost and potential (as a major alternative or complement to electrification in a low-GHG future):

- The main policy uncertainties are the GHG target achieved by the policies and the types of policies used to achieve that target, notably whether they are relatively prescriptive or neutral regarding the technologies and fuels that are used to reduce GHG emissions
- Regarding the cost and potential of electrification technologies, the major uncertainty is the future cost of vehicle batteries. A further uncertainty is the extent to which they are used for medium and heavy-duty vehicles.
- Regarding the cost and potential of bio-energy, key uncertainties are the capital cost of 2nd generation biofuel plants (e.g. renewable natural gas, gasoline and diesel produced from ligno-cellulosic feedstock, that being woody or grassy material) and the availability and cost of feedstock.

To test the impact of GHG reduction policies on electrification, we used three policy scenarios, summarized in Figure 1. The first is a representation of current legislated policies as well as announced policies that are very likely to be implemented and are

included in BC Hydro's 2019 load forecast (i.e. "current policies"). Of note, this scenarios includes:

- A zero-emissions vehicle (ZEV) standard that requires sales of non-emitting light-duty vehicles (e.g. plug-in electric vehicles, PEVs)
- The assumption that electricity transmission to natural gas producing regions (DCAT and PRES lines) results in electricity consumption by the natural gas sector that consistent with the 2019 BC Hydro load forecast.

The second scenario include several incentive and regulatory policies paired with a hypothetical emissions cap that requires BC to achieve its 2040 and 2050 GHG targets (i.e. the stronger policy scenario). The incentives and regulatory policies include:

- Increases to the BC carbon tax
- A strengthening of the Renewable and Low-Carbon Fuel Requirement
- A ZEV standard that with some additional requirements for medium and heavy-duty vehicles
- A renewable natural gas (RNG) standard requiring a minimum blend of renewable fuel in the natural gas stream
- Incentives and requirements for the efficient electrification of buildings (e.g. with heatpumps)

The third policy scenario includes the emissions cap, but it lacks the incentives and regulatory policies that are more prescriptive of which technologies and fuels are used to reduce GHG emissions (i.e. the technology neutral stronger policy scenario). This scenario does not have any ZEV or RNG standards, requirements for the electrification of buildings or natural gas production, and it only includes the current version of the Renewable and Low-Carbon Fuel Requirement (i.e. the policy does not get stronger after 2020)

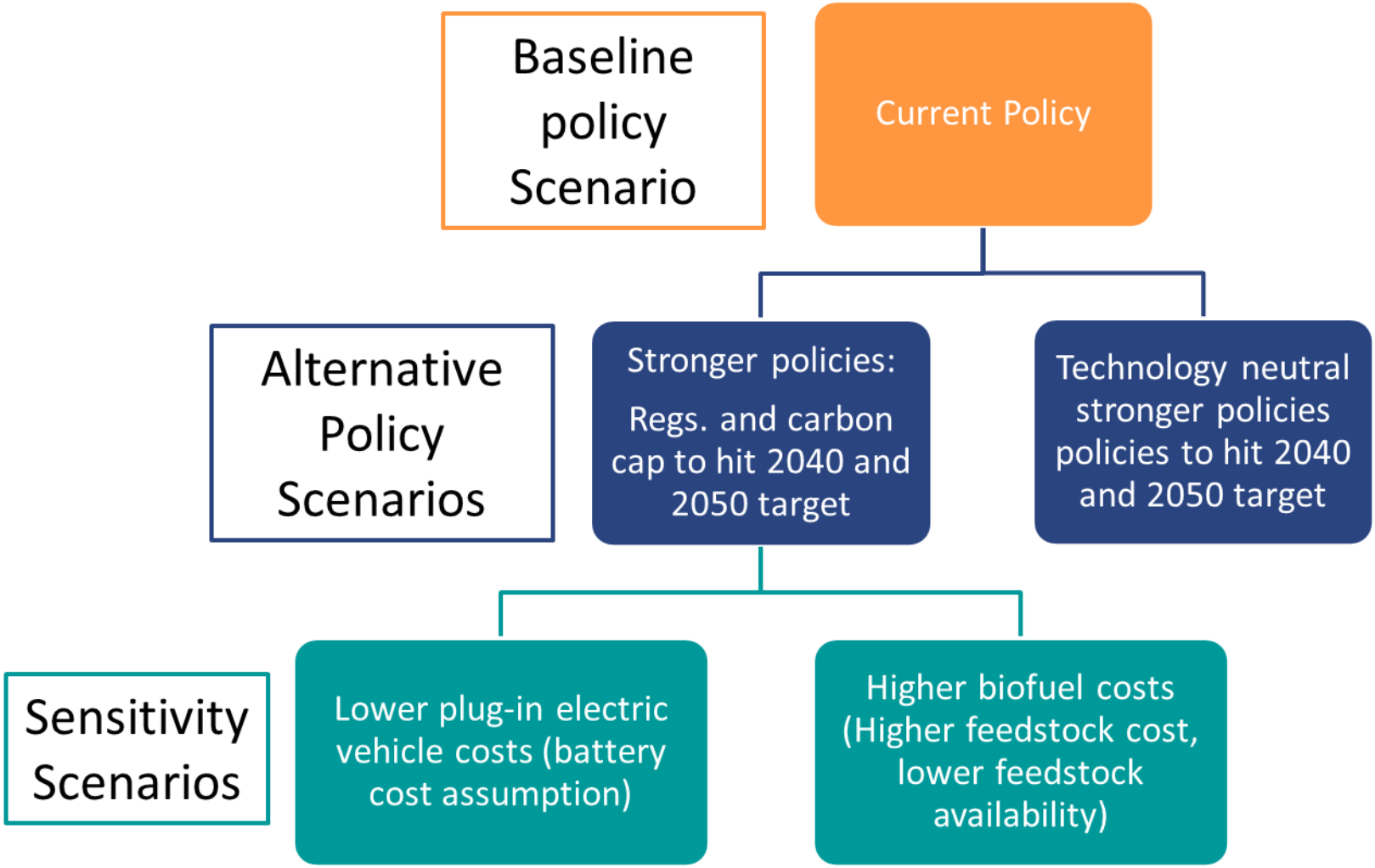
Both stronger policy scenarios include more stringent GHG reduction policies in the rest of North America, added to mitigate "carbon leakage" where BC industrial activity declines and moves to other jurisdictions. The strong policies outside of BC also ensure there is a greater demand for biofuel feedstocks in all regions of the model, adding a flexible yet realistic constraint on bioenergy use in BC. These policies in North America are represented by proxy using a carbon price that rises to \$250/tCO_2e by 2040. Note that this policy specification still makes BC a policy leader that ultimately

has somewhat stronger climate policies (i.e. the emissions cap in BC is binding, while the carbon price elsewhere is not).

The sensitivity analyses explore two scenarios additional scenarios, one with lower cost PEVs (based on battery cost assumptions) and one scenario with higher biofuel costs (Figure 1). This analysis was initially going to include a more optimistic biofuel cost scenario. However, the reference policy scenarios turned out to be relatively optimistic with regards to the quantity of bioenergy that was consumed, where it became a significant proportion of transportation energy consumption. Furthermore, preliminary testing of a lower cost bioenergy scenario resulted in significant demand for biofuels and their feedstocks, such that gTech could not find an equilibrium solution for this scenario. While this scenario yielded no direct results, we discuss it in the final section to this report, given that it indicates that biofuels can become a scarce resource when costs are low and carbon prices are high.

Specific policy details by scenario are described in the next section (2.4). Specific sensitivity analysis assumptions are described in section 2.5

Figure 1: Scenario Design Summary



2.4. Policy scenario inputs

Table 3 contains the detailed policy assumptions for each of the policy scenarios modelled in this analysis. Cells highlighted in green contain policy assumptions that are significantly different from the previous column (i.e. the scenario to the left in the table). Of note is the addition of GHG emission caps that align with the provincial targets for 2040 and 2050 in the stronger policy scenario, #2. The technology neutral stronger policy scenario differs from the reference stronger policy scenario because it lacks many of the specific regulatory policies from the stronger policy scenarios.

Table 3: Detailed policy assumptions by scenario

Policy	1. Current policies - (no new policies except firm announcements)	2. Stronger policy scenario	3. Technology and fuel neutral stronger policy scenario
Carbon tax, price, or cap	$50/tCO2e carbon tax (nominal) by 2022, with revenue recycled to cut labour taxes and provide lump sum payments to households.	The same carbon tax as in the current policy scenario, but with GHG emission caps aligned with provincial GHG targets (~25 Mt/CO2e in 2040, 12 Mt/CO2e in 2050)	Same as 2
Clean Energy Act	98% renewable electricity generation in 2030, 100% post-2040	Same as 1	Same as 1
Methane fugitive emission regulations	Oil and gas: ~45% reduction in fugitives by 2020	Oil and gas: Same 2020 target and then ~50% reduction by 2025	Same as 2
Formation CO_2 carbon capture and storage	-	Required for natural gas processing	Same as 2
Renewable natural gas	-	10% by 2030, 30% by 2050	None
Landfill gas regulation	Organics diversion and landfill gas control	Same measures, but greater stringency	Same as 2

Policy	1. Current policies - (no new policies except firm announcements)	2. Stronger policy scenario	3. Technology and fuel neutral stronger policy scenario
Renewable and low-carbon fuel requirement	-10% GHG intensity by 2020	-20% GHG intensity by 2030, *not including electrification*	None
Light-duty vehicle emission standards	118 gCO_2e/km by 2030 (-40%)	105 gCO_2e/km by 2030 (-40%)	105 gCO_2e/km by 2030 (-40%)
Light-duty zero-emissions vehicle (ZEV) mandate	36% sales in 2030, 70% by 2040, then 95% in 205 onward	Same as 1	None
Heavy-duty vehicle emission standards	-35% in tailpipe CO2 emissions for 2030 model year vehicles relative to 2010 model years vehicles	Same as 1	Same as 1
Heavy-duty vehicle ZEV mandate	-	Plug-in electric vehicles: 10% sales in 2030, 35% by 2050	None
		LNG-fuelled vehicles: 16% sales in 2030, 6% by 2050	None
Building codes for envelopes	Step code for new buildings, requiring net-zero ready by 2035	Same as 1	Same as 1
Building envelope retrofits	-	1.5%/yr of pre-2010 buildings are retrofitted to reduce heat load by 15-20%	None
Zero-emissions building policy	-	Heat pumps required for new/replacement space and water heating equipment after 2035	None
North American policy outlook	No new policies (except firm announcements): Includes the federal carbon pricing backstop ($50/tCO2e carbon price equivalent (nominal) by 2022	Stronger GHG policy is modelled by proxy in the rest of Canada and the U.S. by proxy using a carbon price that rises to $250/tCO2e by 2040	Same as 2

2.5. Sensitivity scenario inputs

The sensitivity scenario inputs below are all variations on the stronger policy scenario. The sensitivity analyses deal with vehicle battery costs and biofuel costs within the context of GHG reduction policies that will achieve BC's GHG targets in 2040 and 2050.

2.5.1. Vehicle battery cost sensitivity scenarios

The vehicle battery cost sensitivity scenarios affect the capital cost of all plug-in electric vehicle (PEV) technologies including light-duty vehicles, heavy-duty vehicles (represented archetypically as freight trucks) and buses.

PEV battery pack manufacturing costs are estimated at 350 $/kWh (2015 CAD) in 2015 based on Nykvist & Nilsson (2015).[1] A conservative assumption used for the reference policy scenarios for the future costs has costs falling to 163 $/kWh by 2030, based on the UBS bank's outlook for 2025 but delayed by five year (Table 4).[2] A more optimistic assumption used in the lower-PEV cost scenario is that battery pack manufacturing costs fall to 220 $/kWh in 2020 and 94 $/kWh (2015 CAD) by 2025 based on the expectations in Curry (2017),[3] then fall another 10% by 2030 (Table 4). We assume no further cost reductions after 2030 in any scenario.

Table 4: Battery pack manufacturing cost assumptions (2015 CAD/kWh)

	2015	2020	2025	2030
Conservative (i.e. reference)	$351	$221	$192	$163
Optimistic (lowest cost scenario)	$351	$223	$94	$84

Battery manufacturing costs are only one component of total vehicle capital costs which include the cost of other components (e.g. vehicle glider, electronics, engine and transmission where applicable) and wholesale and retail markups (i.e. sales margins). Table 5 shows the light-duty vehicle retail prices for electric vehicles as a function of the sensitivity scenario, compared with the price assumptions for a conventional vehicle. Table 6 and Table 7 show those assumptions for buses and heavy-duty

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

[2] UBS (2017). UBS Evidence Lab Electric Car Teardown – Disruption Ahead? UBS Evidence Lab, Global Research

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

vehicles. The development of vehicle prices as a function of battery pack manufacturing costs is explained in detail in "Appendix A:Electrification Technology Research" as are energy intensity of the technology archetypes and rational for which technology archetypes are represented in the analysis.

Table 5: Light duty-vehicle archetype capital costs by drivetrain and sensitivity scenario (based on sedan-sized vehicle) (2015 CAD)

	2015	2020	2025	2030
Conventional vehicle*	22,829	23,503	24,062	25,083
Conservative (i.e. reference)				
Plug-in hybrid (64km)	38,898	33,661	33,130	32,143
Battery Electric (320 km)	44,069	35,151	34,305	30,940
Optimistic (lower cost)				
Plug-in hybrid (64km)	38,898	30,746	29,413	29,110
Battery Electric (320 km)	44,069	32,619	26,621	25,779

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

Table 6: Bus archetype capital costs (including recharge infrastructure) by drivetrain and sensitivity scenario (2015 CAD)

	2015	2020	2025	2030
Diesel bus (conventional)	572,471	572,471	572,471	572,471
Battery electric bus (250 km)				
Conservative (i.e. reference)	741,575	638,194	613,291	604,171
Optimistic (lower cost)	741,575	638,409	598,252	574,971

Table 7: Heavy-duty-vehicle archetype capital costs (including recharge infrastructure) by drivetrain and sensitivity scenario (based on long-haul freight truck) (2015 CAD)

	2015	2020	2025	2030
Diesel truck	135,000	135,000	135,000	135,000
Diesel truck, high efficiency	148,000	148,000	148,000	148,000
Electric truck (500km):				
Conservative (i.e. reference)	700,507	398,084	323,158	294,383
Optimistic (lower cost)	700,507	398,706	279,570	209,753

2.5.2. High biofuel cost sensitivity scenario

The bio-energy cost and potential sensitivity scenarios affect the price of all 2nd generation biofuels represented in gTech: cellulosic ethanol, renewable gasoline, diesel and natural gas, all of which have agricultural and forestry residue as feedstocks. Because these sensitivity scenarios also change the quantity of feedstock

available, the maximum physical quantity of these fuels available in the model will also change. The maximum quantities are characterized as a function of economic activity the forestry and agriculture sectors, so the change is discussed in terms of how quantities produced assuming static 2010 activity for the forestry and agriculture sectors.

Biofuel costs

Given that 2nd generation biofuel plants are pre-commercial, their capital costs in the reference biofuel cost scenario are set at roughly double the preliminary cost estimated found in the literature. This assumption applies to renewable gasoline, and diesel. For cellulosic ethanol, the cost is the average value of the first plants noted in the literature. In the pessimistic scenario, the capital costs are 40% higher, which is also roughly equivalent to a doubling of the feedstock price, which could occur in case of strong demand for these fuels. The resulting capital costs and wholesale fuel costs (net of any distribution margins or taxes) are in Table 8. For context, the wholesale price of gasoline and diesel have generally been between $0.60/L and $0.80/L over the past decade. In all scenarios, renewable natural gas production cost is roughly $15/GJ (2015 CAD). The characterization of 2nd generation biofuels in this analysis are explained in greater detail in "Appendix A: Electrification Technology Research".

Table 8: 2nd generation biofuel plant capital costs and production costs by sensitivity scenario (2015 CAD)

	Capital Cost	Resulting fuel cost
Reference Assumptions		
Renewable gasoline and diesel	$6.50/L/yr capacity	$1.26/L
Cellulosic ethanol	$2.65/L/yr capacity	$0.68/L
High Cost Assumptions		
Renewable gasoline and diesel	$9.10/L/yr capacity	$1.52/L
Cellulosic ethanol	$3.71/L/yr capacity	$0.78/L

* Assuming residue cost of $82/ODt (average of forestry and agricultural residue production costs)

Residue for 2nd generation biofuel feedstock

The reference assumption for the maximum residue available in Canada is 34 million oven dry tonnes per year (ODt/yr) based 2010 activity in the agricultural and forestry sectors (Table 9). This quantity includes roadside forest harvest residue and the crop residue produced for corn and grain production, not already used for other purposes (roughly 25% available, with the rest primarily left it in the field for soil sustainability). The reference assumption does not include any urban wood waste, surplus wood waste from forest products mills (i.e. not used internally for energy), or purposely

grown energy crops. Further detail on this quantity is explained in "Appendix A: Electrification Technology Research".

The higher cost biofuel scenario assumes 10% more agricultural residue must be left in the field for soil sustainability, reducing the maximum amount available for feedstock by 20% (-3.5 ODt/yr based on 2010 activity). Similarly, this scenario has 20% less forest harvest residue (-3.1 ODt/yr based on 2010 activity) and total residue quantities, based on 2010 activity in the forestry and agriculture sector in Canada would be roughly 27 million oven dry tonnes (Table 9).

To put these quantities in context, if they were converted to renewable gasoline and diesel (18 GJ/ODt at 63% energy conversion efficiency from feedstock), they could replace 15% of 2010 Canadian gasoline and diesel consumption under the reference assumption and 12% in the pessimistic assumption. As well, the model includes the U.S. which can trade in residue and biofuels with Canada, and where residue and biofuel production capital costs also vary in the sensitivity analysis. Finally, first generation biofuels are and remain available in the model, where their production is constrained by a limited pool of land and crop prices.

Table 9: 2nd generation biofuel feedstock availability by sensitivity scenario (based on 2010 activity in the forestry and agriculture sector

	Forestry residue (million ODt/yr)	Agriculture residue (million ODt/yr)	Total (million ODt/yr)
Optimistic	21.2	24.7	45.9
Reference	15.7	18.2	34.0
High-cost biofuel	12.6	14.7	27.3

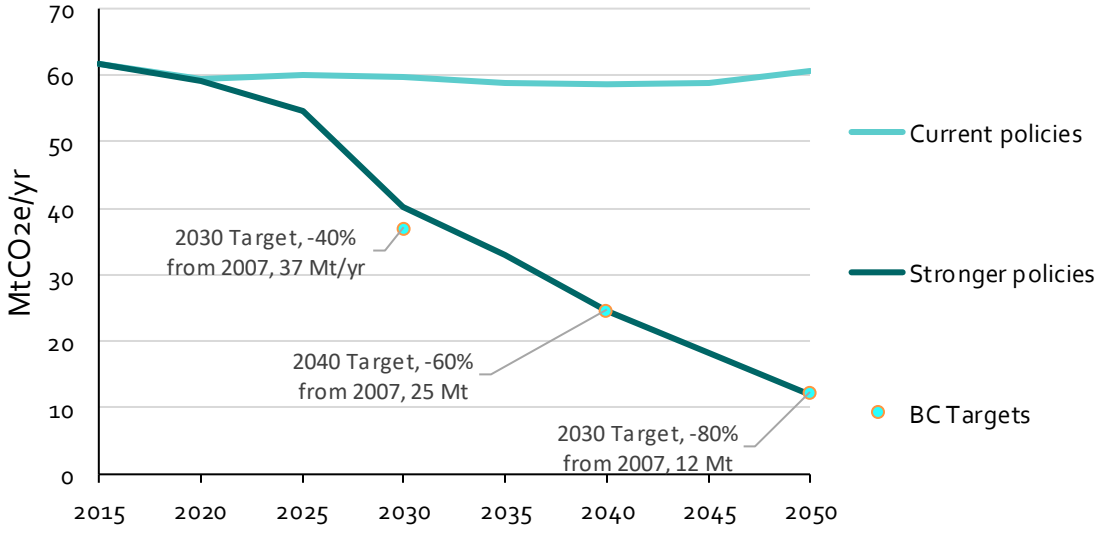
3. Results

The results chapter beings with a comparison of GHG emissions and electricity demand in the current policy scenario and the stronger policy scenario that achieves BC's 2040 and 2050 emissions targets. This is followed by explanatory results that describe the change in electricity demand in the stronger policy scenario in greater detail. The remaining sections of this chapter demonstrate how electricity demand is affected by 1) using technology and fuel neutral policies, 2) assuming lower costs for PEVs and 3) assuming higher costs for biofuels.

3.1. The impact of current and stronger GHG reduction policies

Implementation of stronger policies substantially reduce British Columbia's total GHG emissions from the present and relative to a scenario with current policies. With currently legislated policies, provincial GHG emissions are kept roughly constant until after 2045, despite a growing population and economy. By design, the stronger policy scenario hits the 2040 and 2050 emissions targets, roughly 25 and 12 $MtCO_2e/yr$ respectively (Figure 2). The modelling analysis has the limitation in that it could not solve for a scenario that also hit the 2030 target. Missing this target is a function of the design of the model and analysis and should not be interpreted as BC being unable or unwilling to achieve the target.

Figure 2: British Columbia GHG emissions by scenario



*Provincial GHG emissions and targets exclude emissions resulting from international aviation and marine travel.

Stronger GHG reduction policies increase electricity demand in British Columbia. With current policies, future provincial electricity consumption closely matches the 2019 BC Hydro load forecast. There are differences by sector, which can be further explored with the raw model results. Nonetheless, total electricity demand in the current policy scenario and the load forecast both reach roughly 67 TWh/yr in 2035. The stronger policies increase electricity consumption, though this change is most noticeable from 2035 onward (Figure 3). The stronger GHG reduction policies increase electricity demand, which reaches 103 TWh/yr in 2050 (24 TWh/yr higher than current policies in that year or +29%) (Table 10).

Figure 3: British Columbia electricity demand by scenario

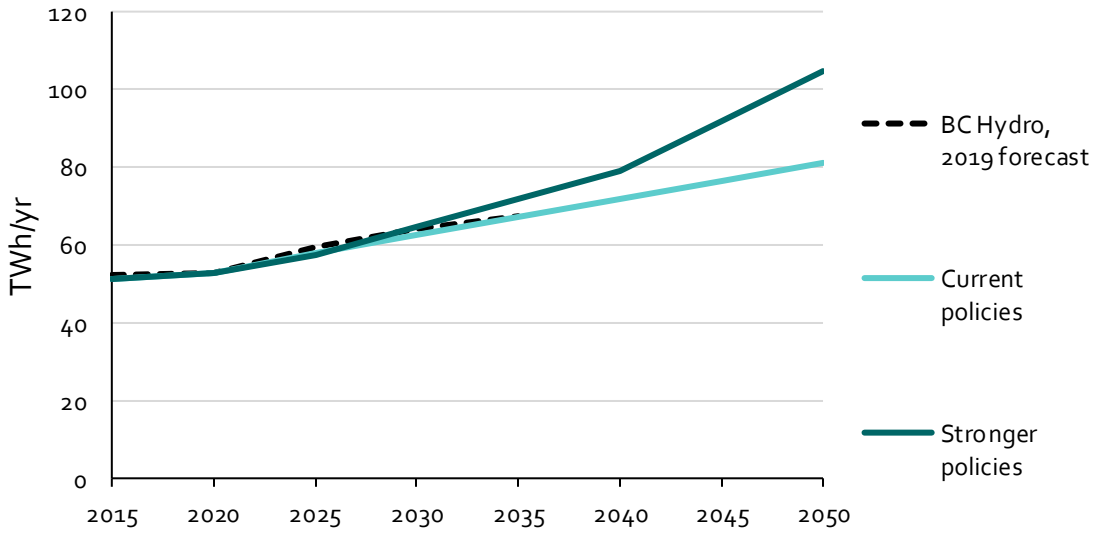


Table 10: British Columbia electricity demand by scenario (TWh/yr)

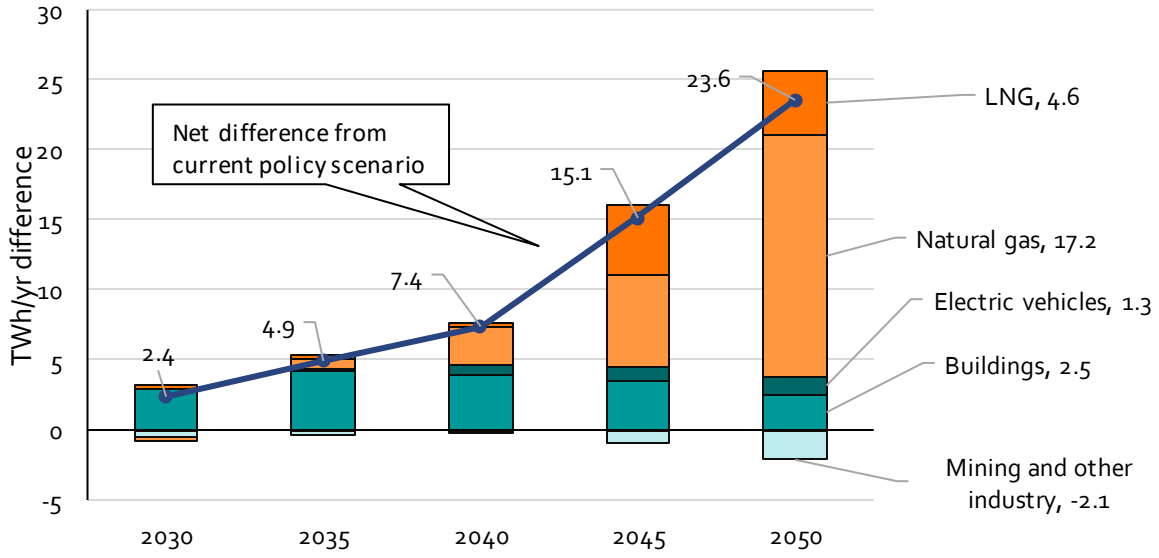
	2015	2020	2025	2030	2035	2040	2045	2050
BC Hydro, 2016 forecast	52.3	52.7	59.7	64.1	67.4			
Current policies	51.2	52.7	57.8	62.4	67.1	71.6	76.6	81.1
Stronger policies	51.2	52.7	57.7	64.7	72.1	79.1	91.7	104.7

*Demand exclude electricity consumption for aluminum production and electricity consumed from cogeneration in forest products sectors, where this demand is supplied by industry owned generation.

Stronger GHG reduction policies result in much greater electricity demand relative to current policies, with the greatest difference coming from the natural gas sector. To reach the legislated provincial GHG targets, the natural gas sector must substitute even more electricity consumption for natural gas consumption. With stronger policies, the incremental difference in demand from this sector, relative to the current policy scenario, rises to more than 17 TWh/yr in 2050 (Figure 4). The change is in fact smaller given that the stronger climate policies further slow economic growth resulting

in less transportation demand and less electricity demand at a given rate of PEV adoption. The forecast also indicates that hitting the 2050 target may require retrofitting liquefied natural gas plants to use low-carbon electricity, further increasing demand by another 4 to 5 TWh/yr in 2050 relative to the current policy scenario. Buildings also contribute to incremental demand, accounting for a large proportion of the difference in 2030 and 2035. Slower economic growth results in somewhat less industrial activity. However, the resulting reduced electricity demand from mining and other industrial sectors is a minor offset to overall load growth.

Figure 4: Difference in electricity demand, stronger policies versus current policies, broken down by sector



3.2. Explanatory results for electricity demand in the stronger policy scenario

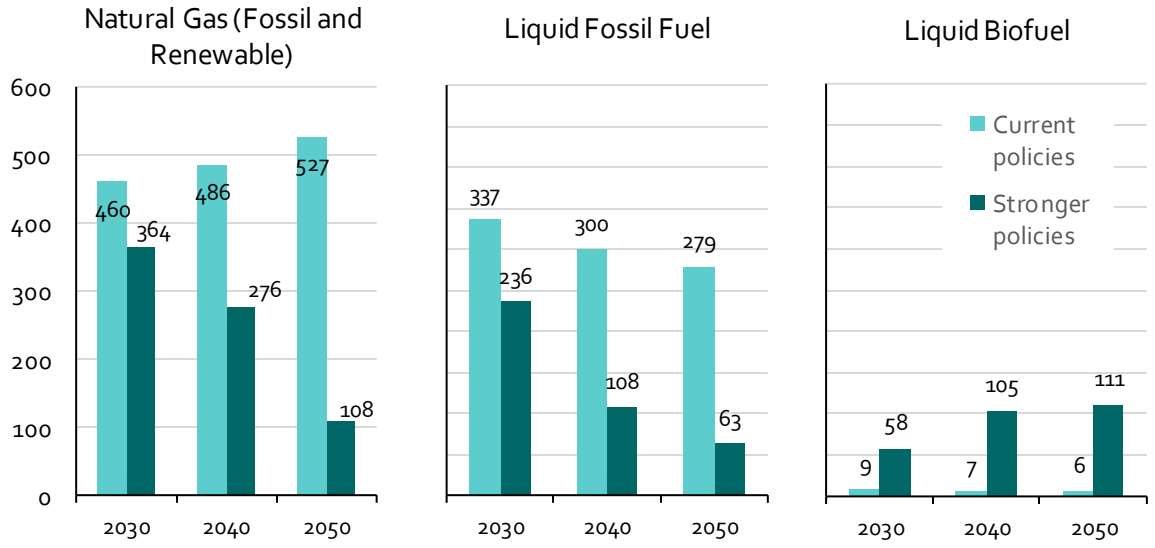
This section of the report goes into greater detail to explain the growth in electricity consumption that occurs in response to the stronger policies that achieve BC's GHG emissions targets. The details include an analysis of changes in other fuel consumption (e.g. gaseous and liquid fuels), changes in technology market shares (e.g. electric vs. non-electric technologies) and changes in activity and energy consumption by end-use in the relevant sectors.

3.2.1. Fuel Shares

Increased electricity demand occurs in response to GHG reduction policies when electricity, produced from low-GHG sources, is substituted for fossil fuels such as natural gas, gasoline and diesel.

The electrification that occurs in response to the strong policies results in substantially less liquid and gaseous fuel consumption by 2050, even when including biofuels. With current policies, gaseous fuel consumption grows between the present and 2050, whereas with strong policies it declines by approximately a factor of four, relative to today, to just 108 PJ/yr in 2050. 30% of that total is renewable natural gas, as required by regulation (Figure 5). Similarly, liquid fuel consumption declines relative to the current policy scenario to just 173 PJ/yr (fossil+biofuel), where two thirds of that is biofuel, much of it "drop-in" renewable gasoline and diesel produced from woody and grassy feedstocks.

Figure 5: British Columbian gaseous and liquid fuel consumption by scenario (PJ/yr)



3.2.2. Transportation

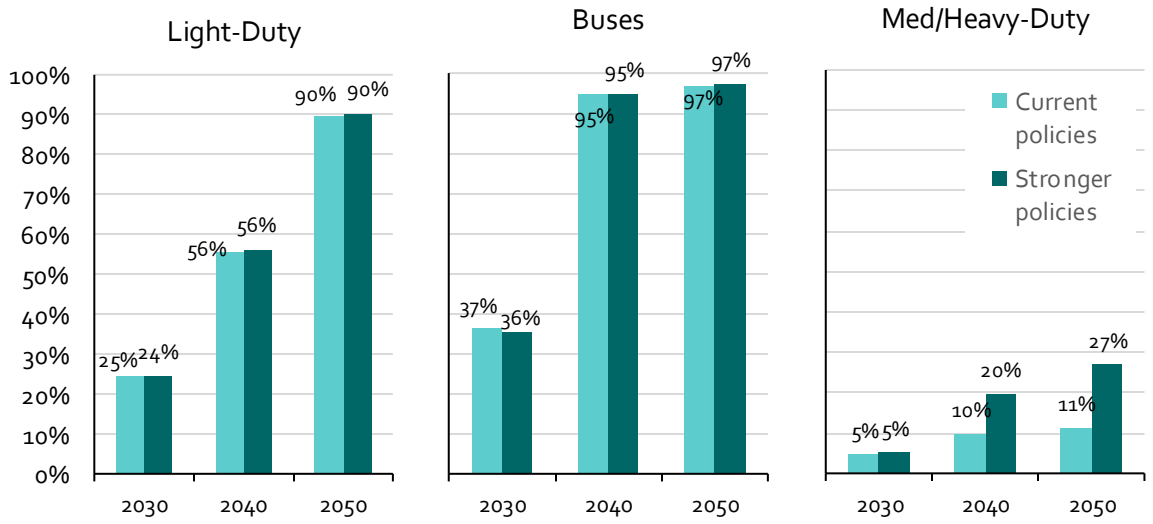
The reduction in liquid fuel consumption and the increase in electricity consumption for transportation in all scenarios, are both a result of the adoption of plug-in electric vehicles. As noted above, this change is driven by ZEV mandates that apply to light-duty vehicles (all scenarios) and to medium and heavy-duty vehicles (stronger policy scenarios). The light-duty ZEV mandate results in 24% of cars and passenger trucks on the road being electric by 2030, rising to 90% in 2050 (battery electric or plug-in

hybrid) (Figure 6). This is equivalent to 0.6 million vehicles in 2030 and 3.7 million in 2050[4].

Similarly, the total market share of medium and heavy-duty PEVs reaches 27% in 2050 with stronger policies (Figure 6). This fraction represents the share of sector activity (tonne kilometers travelled) that occurs by way of medium or heavy-duty PEVs. Because of the heterogeneity in the size, payloads and utilization of these vehicles, this market share is only roughly indicative of the number of vehicles on the road. Nonetheless, that market share expressed in 2050 in terms of vehicle numbers is approximately 29,000 class 8 tractor trailers[5].

The cost and utilization of a typical electric bus allows them to gain significant market share under either current policies or stronger policies (Figure 6). In either case, by 2050, almost all buses are electric, equivalent to roughly 21,000 electric buses on the road[6].

Figure 6: PEV total market share by scenario (% of total travel by PEVs, approximates % of vehicles on the road for light-duty vehicles and buses)



Most of the incremental electricity demand from transportation that occurs in response to stronger policies comes from medium and heavy-duty vehicles. Again,

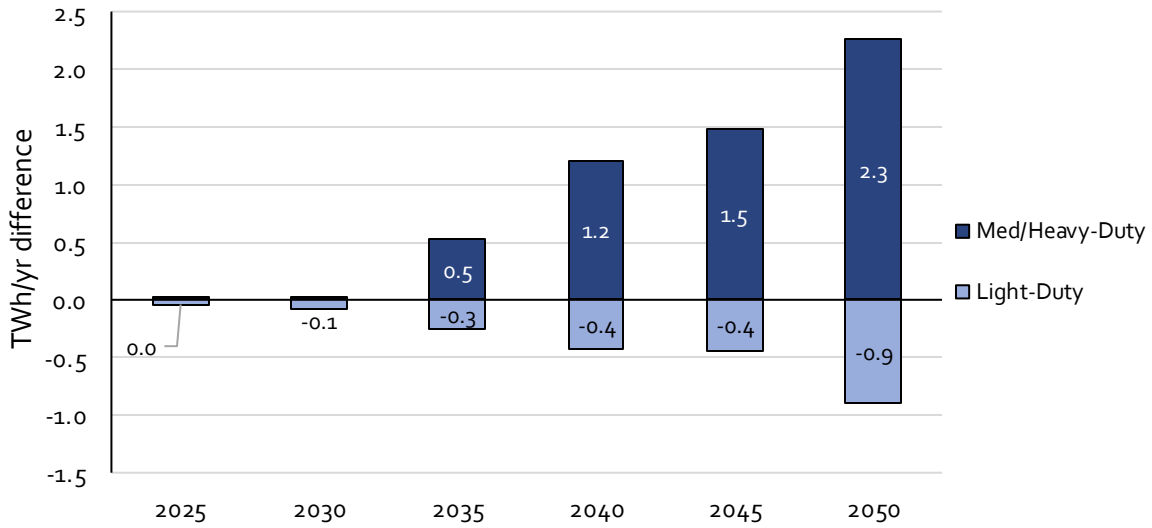
[4] Assuming 15,000 vehicle kilometers travelled per by each light-duty vehicle

[5] Assuming each truck has an average payload of 15 tonnes, travelling 60,000 km/yr

[6] Assuming each truck travels 65,000 km/yr with an average ridership of 12 passengers per km

this is because the baseline current policy scenarios includes a strong ZEV standard applied to light-duty vehicles and the rate of adoption of buses is insensitive to the GHG reduction policies. With stronger GHG policies, the incremental electricity demand from transportation grows from roughly 0 TWh/yr in 2030 to 2 TWh/yr in 2050 (total demand by transportation is roughly 3 and 15 TWh/yr in those year, respectively) (Figure 7). Slower economic growth in response to stronger GHG reductions policies results in somewhat reduced transportation demand, leading to the slight reduction in electricity consumption used by light-duty vehicle relative to the current policy reference forecast.

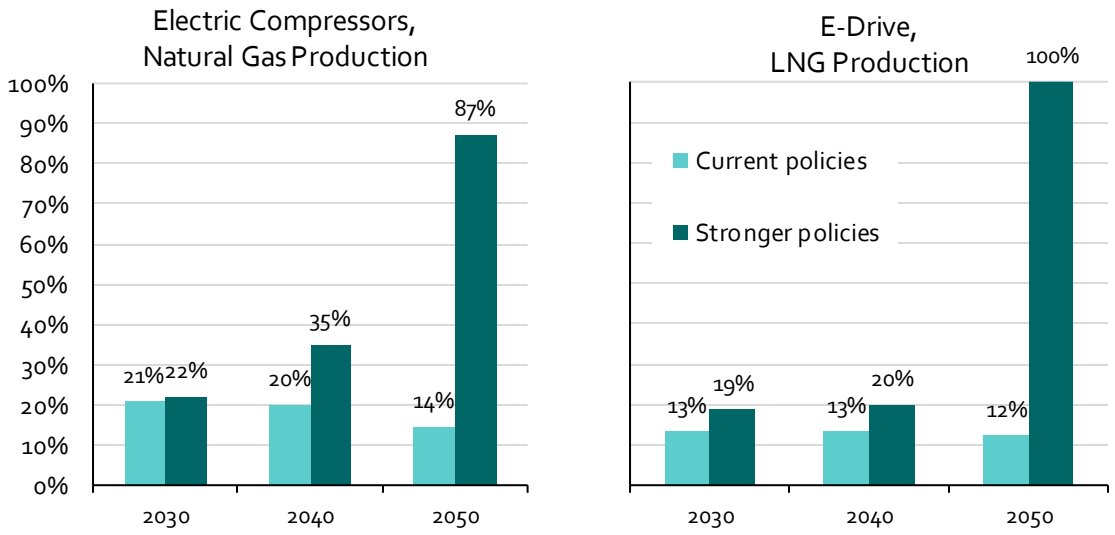
Figure 7: Incremental electricity demand from PEVs, stronger policies versus current policies, broken down by vehicle type



3.2.3. Natural gas

The change in electricity demand from the natural gas sector and LNG sector is largely a function of the adoption of electric compressors (rather than gas-fired) to transport or liquefy natural gas. With stronger GHG policies, the incremental electricity demand from the natural gas and LNG sectors grows from roughly 0 TWh/yr in 2030 to 17 TWh/yr in 2050 (total demand is roughly 7 and 29 TWh/yr in those years, respectively). To achieve the provincial GHG emissions targets specified in the strong policy scenario, a rising share of compressors in the natural gas sector must be electrified, with a total market share of 35% in 2040 and 87% in 2050 (Figure 8). Similarly, the stronger policies also result in the retrofit of some LNG plants to use e-drive. In 2050, achieving the legislated targets in the stronger policy scenario results in all LNG being produced with E-Drives (Figure 8).

Figure 8: Technology market share, % of natural gas and LNG production electrified by scenario



Reductions in natural gas and LNG production offset the increased electricity demand resulting from the electrification of these sectors. The implementation of strong GHG reduction policies, which apply across all regions of North America (i.e. what is included in the model) suppresses overall demand for natural gas. GHG reduction policies in BC are more stringent and come into force earlier, which further supresses growth in the provincial natural gas sector from 2035 through to 2040, where BC natural gas production is 10% lower than it otherwise would be with current GHG reduction policies (Table 11). Accordingly, electricity demand from the natural gas sector is lower than it otherwise would be. From 2045 onward, activity is closer to what it would have been with current policies, though still somewhat lower given that there is less demand for natural gas in North America. However, it is important to note that the modelling includes some constraints that prevent a further reduction in natural gas production in BC and the corresponding reduction in the sector's electricity demand. Notably, we have assumed a fixed quantity of foreign LNG demand, where 60% of that gas is produced in BC. We have also assumed a fixed amount of foreign investment in the BC natural gas sector, ensuring the sector output does not diverge significantly from what is in the baseline current policy scenario. Therefore, activity in both the natural gas and LNG sectors could be more sensitive to GHG policy than indicated in this analysis.

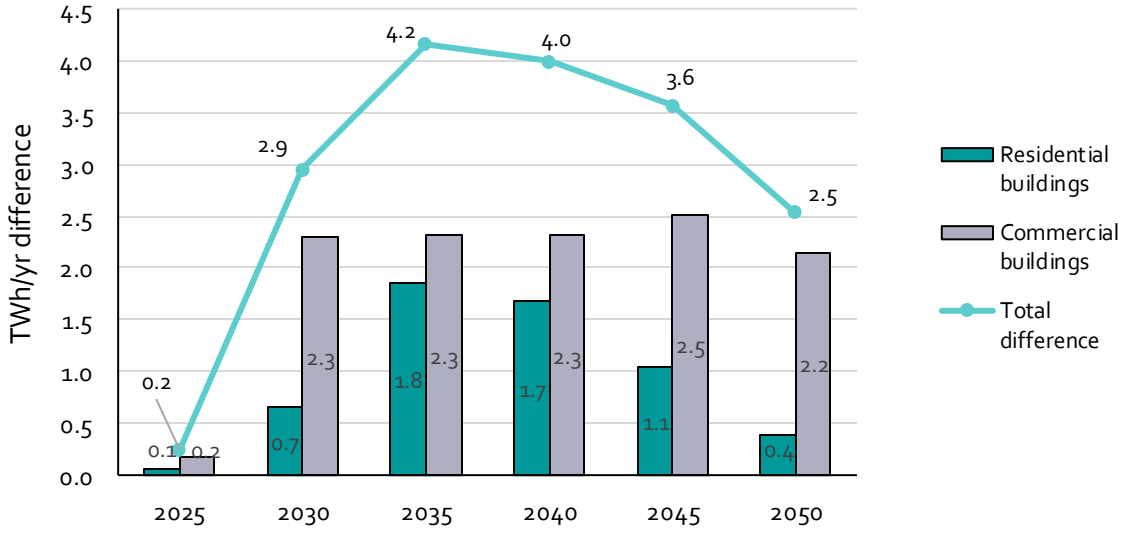
Table 11: Natural gas and LNG production in British Columbia by scenario

	2015	2020	2025	2030	2035	2040	2045	2050
Natural gas, bcf/day								
Current policies	4.8	5.0	6.1	6.8	7.2	7.4	7.6	7.9
Stronger policies	4.8	5.0	6.1	6.1	6.6	6.9	7.2	7.7
LNG gas, Mt/yr								
Current policies	0.0	0.0	13.0	17.2	17.2	17.2	17.2	17.2
Stronger policies	0.0	0.0	13.0	16.1	16.1	16.1	16.1	16.1

3.2.4. Buildings

Incremental electricity demand from buildings occurs in both residential and commercial/institutional buildings. With stronger GHG policies, the incremental electricity demand for buildings, relative to the current remains relatively constant between 2 and 4 TWh/yr between 2030 and 2050 (total demand is roughly 40 TWh/yr in 2030 and 47 TWh/yr in 2050) (Figure 9). The incremental demand from residential buildings declines over time as there is also some substation of resistance electric space and water heating with highly efficient heatpumps.

Figure 9: Difference in building electricity consumption by building type in the stronger policy scenario relative to the current policy scenario



Heatpumps for both space and water heating become dominant technologies in response to the stronger GHG reduction policies. This adoption is driven by the zero-emission buildings policy that requires the energy-efficient electrification and decarbonization of space and water heating in buildings. In residential buildings,

heatpumps provide over 60% of space heating by 2050, substituting for both electric resistance heating and heating from the combustion of fuels (e.g. natural gas) (Figure 10). By 2050, combustion provides only 16% of residential space heat, where half of this comes from wood (e.g. pellets and other wood or biomass fuel). In commercial and institutional buildings, 92% of space heat comes from heatpumps by 2050 with stronger GHG reduction policies (Figure 11). Note that the model does not represent the potential for biomass heating in commercial and institutional buildings, either through standalone systems or delivered by district energy. Therefore, the results may underestimate the biomass fuel share while overestimating the electricity fuel share somewhat.

Figure 10: Residential space heating technology market share

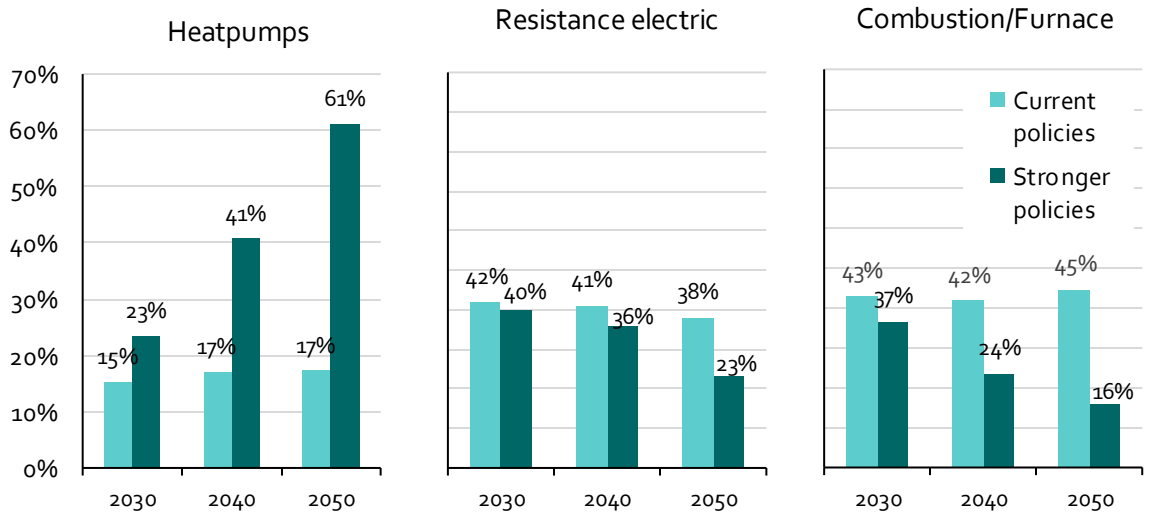
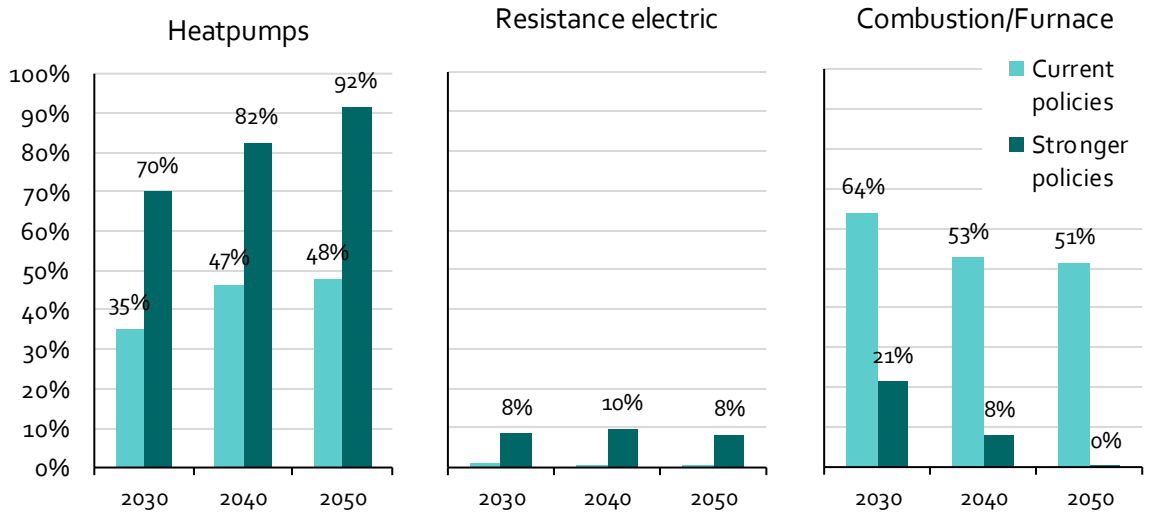
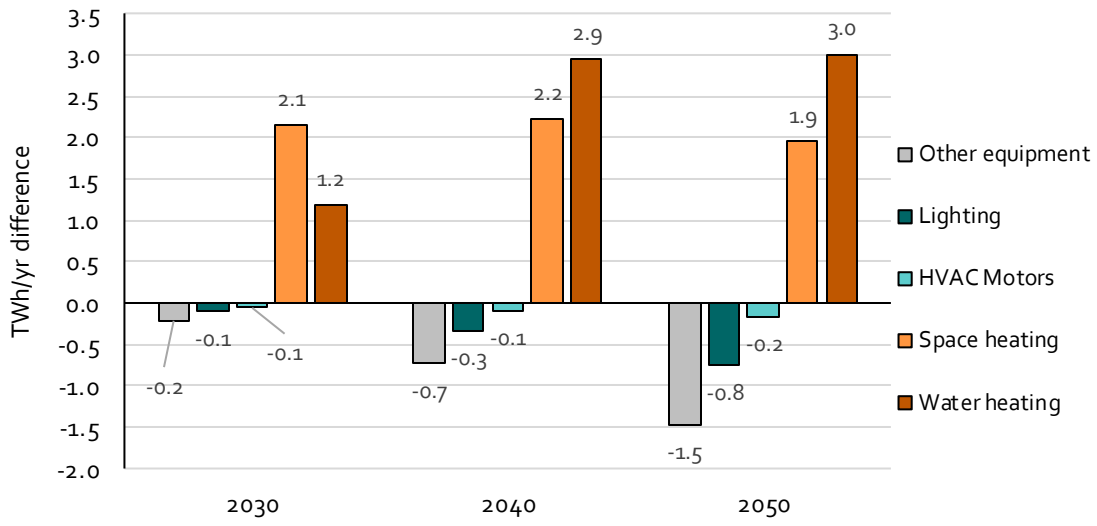


Figure 11: Commercial and institutional space heating technology market share



Fuel switching to electricity for space and water heating is offset by energy efficiency in other end-uses and slower growth in total building floor area. The stronger GHG policies result in more electricity consumption in buildings for space and water heating, relative to what would happen with current policies. However, some of this new load is offset by slower growth in electricity demand for lighting, plug-loads, motors used to for HVAC systems, and other equipment. In 2030 these changes offset about 20% of the incremental load growth. In 2050, they offset 50% of the incremental load growth (Figure 12). About half of this offset is a result of greater energy efficiency. The growth in provincial electricity consumption puts upward pressure on electricity prices, increasing the incentive to use more energy efficient equipment. The other half of the offset results from slower growth in floor area. With stronger GHG policies, the results show somewhat slower economic growth, resulting in less floor area in a given year than with current GHG policies (e.g. the services sectors grow more slowly and need less physical space).

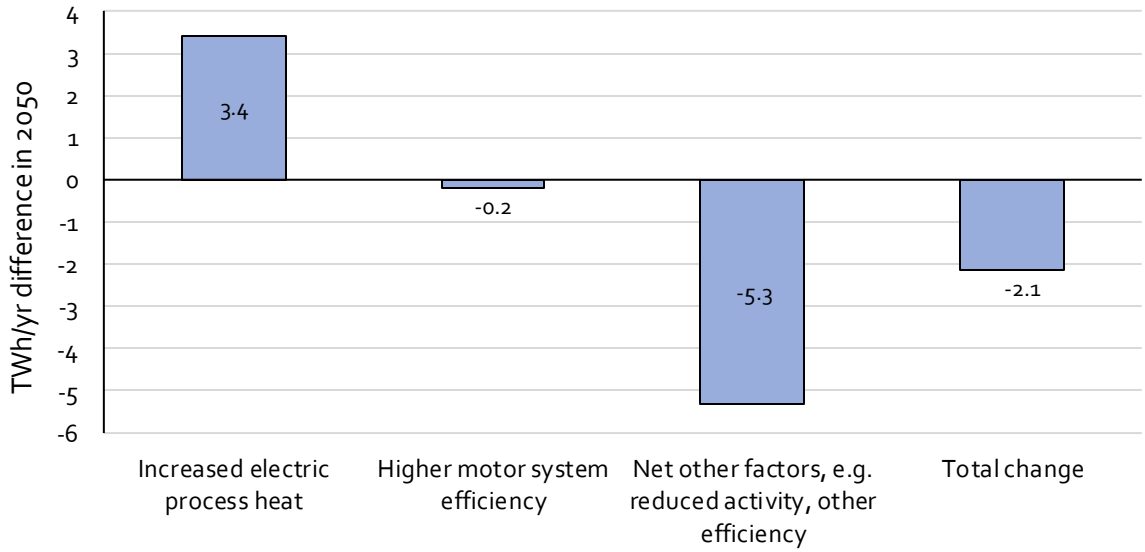
Figure 12: Difference in building electricity consumption by end-use in the stronger policy scenario relative to the current policy scenario



3.2.5. Mining and other industry

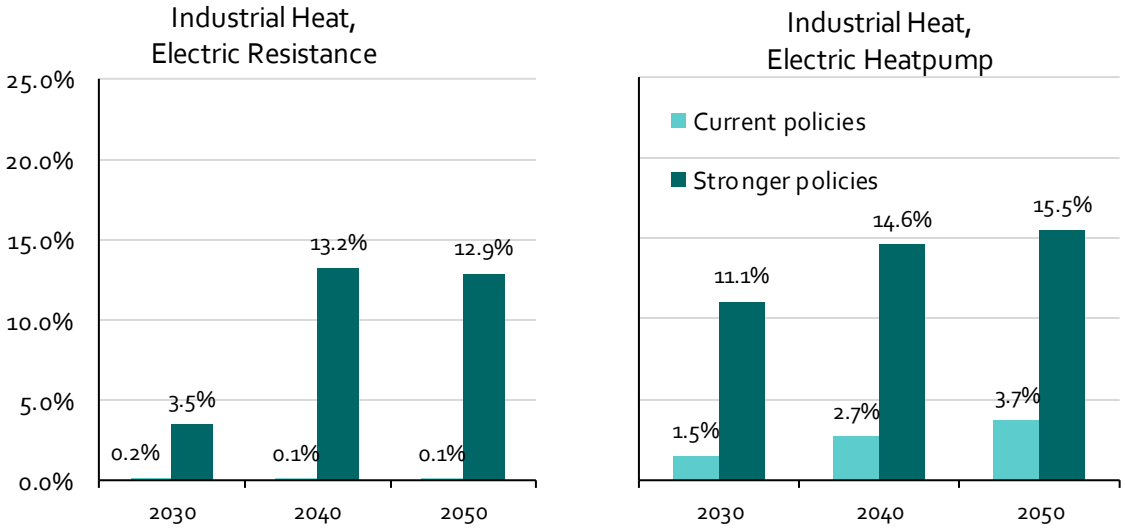
Electricity consumption from mining and other industry (i.e. not natural gas or LNG) is affected by several offsetting factors that ultimately result in relatively little difference between a future with stronger GHG policies relative to current GHG policies. With stronger GHG policies, there is little incremental electricity demand from mining and other industry during the forecast (total demand is roughly 13 TWh/yr in 2030 and 14 TWh/yr in 2050). The offsetting drivers of industrial electricity demand are a switch to electricity for process heat, changes in sector activity, and other electrical efficiency. There is an increase in electric process heat, supplied by electric resistance or industrial heat pumps, equivalent to 3.4 TWh/yr in 2050 (relative to current policies). However, this electricity consumption is more than offset by the adoption of more efficient motor systems (in response to higher electricity prices, -0.2 TWh/yr) and slower economic growth resulting in less sector activity (-5.3 TWh/yr) (Figure 13). Note that any change in demand related to electric transportation is included with medium and heavy-duty vehicles.

Figure 13: Change in mining and other industrial electricity demand (2050) in the stronger policy scenario relative to the current policy scenario



The use of electricity for industrial heat increases in response to the stronger GHG reduction policies. Lower temperature process heat is supplied by industrial heat pumps drawing on ambient heat or providing active heat recovery from waste heat streams. By 2050, with the stronger GHG policies, heat pumps supply almost 16% of industrial process heat, which represents roughly 80% of the technical potential for this technology in the model (where we have limited heat pumps to supplying heat at 100 °C or lower) (Figure 14). Resistance electric heating provides another 12% of industrial process heat, where further adoption is limited by the energy cost relative to the extent of GHG reduction required in BC.

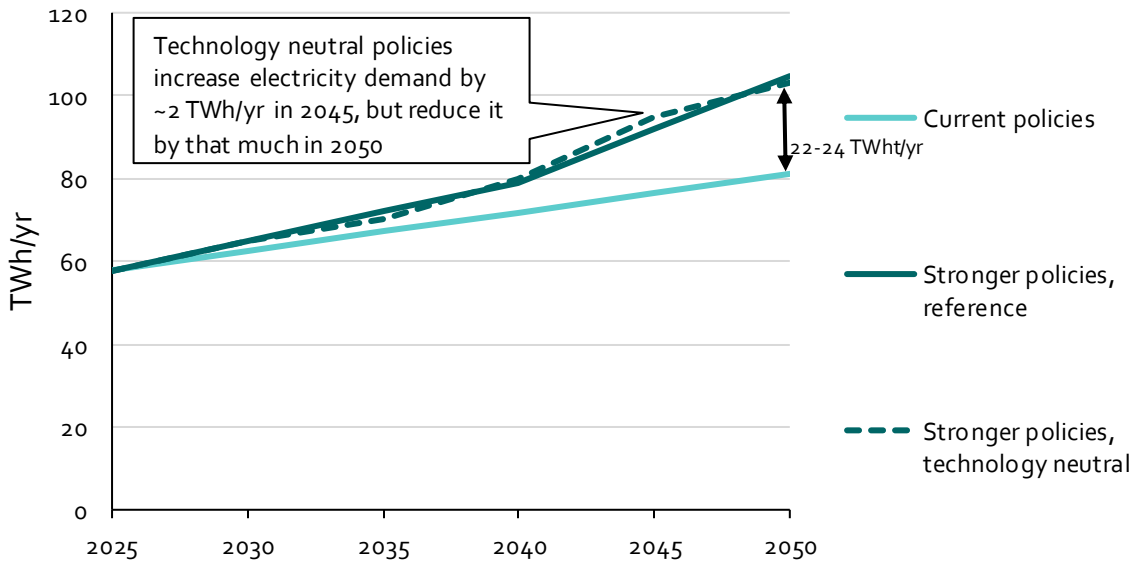
Figure 14: Electric industrial process heat technology market shares by scenario, % of total heat demand



3.3. Impact of technology and fuel neutral policies

On net, a strengthening of the current regulatory policies (the stronger policy scenario) will result in a very similar amount of electricity consumption compared to using technology and fuel neutral policies. The difference is small relative to the change in electricity demand associated with achieving provincial GHG reduction targets. In 2045, a technology and fuel neutral policy portfolio will result in electricity demand that is 3 TWh/yr higher than a more technology prescriptive portfolio (i.e. the reference stronger policy scenario). Conversely, using technology neutral policies results in less electricity demand in 2050. In contrast, electricity demand is still 22 to 24 TWh/yr higher in 2050 than under current policies (Figure 15), regardless of the design of the policies used to achieve the legislated GHG targets.

Figure 15: British Columbia electricity demand, technology neutral stronger policy scenario versus the reference stronger policy scenario



Most of the difference in electricity demand between the technology and fuel neutral policies and the reference stronger policies comes from transportation, though increased demand from other sectors offsets this change. With technology and fuel neutral policies (i.e. no ZEV standard), there is less adoption of light-duty PEVs than in the reference stronger policy scenario. There are also fewer medium and heavy-duty PEVs and total electricity demand from transportation in 2050 is almost 5 TWh/yr lower than with the reference stronger policy scenario (Figure 16). In that year, 55% of light-duty vehicles are PEVs, versus 90% with the reference stronger policy scenario. Likewise, medium and heavy-duty PEVs only account for 22% of activity (tonne km

travelled) in 2050 versus 26% with the reference strong policy scenario (Figure 17). Compliance with the provincial GHG reduction target is achieved in other ways: More vehicles are hybrids (rather than plug-in hybrids or battery electric), biofuel consumption is 30% greater (roughly 142 PJ/yr, which necessitates significant biofuel imports) and there is greater GHG reductions in other sectors (e.g. greater electrification of the natural gas sector must occur sooner to hit the interim 2045 target).

More than half of the reduction in electricity demand from transportation that occurs with technology and fuel neutral policies is offset by increased electricity demand in buildings. Without the zero-emissions building policy which requires new heating systems to be heat pumps after 2035, demand from buildings is almost 5 TWh/yr higher by 2050, relative to the reference stronger policy scenario. The total market share of heat pumps for both space and water heating is lower across residential, commercial and institutional buildings. For example, in residential buildings in 2050, heatpumps provide for 38% of space heating energy versus 61% in the reference stronger policy scenario, with the difference made up by resistance electric heating.

Figure 16: Difference in electricity demand, technology neutral stronger policy scenario versus the reference stronger policy scenario

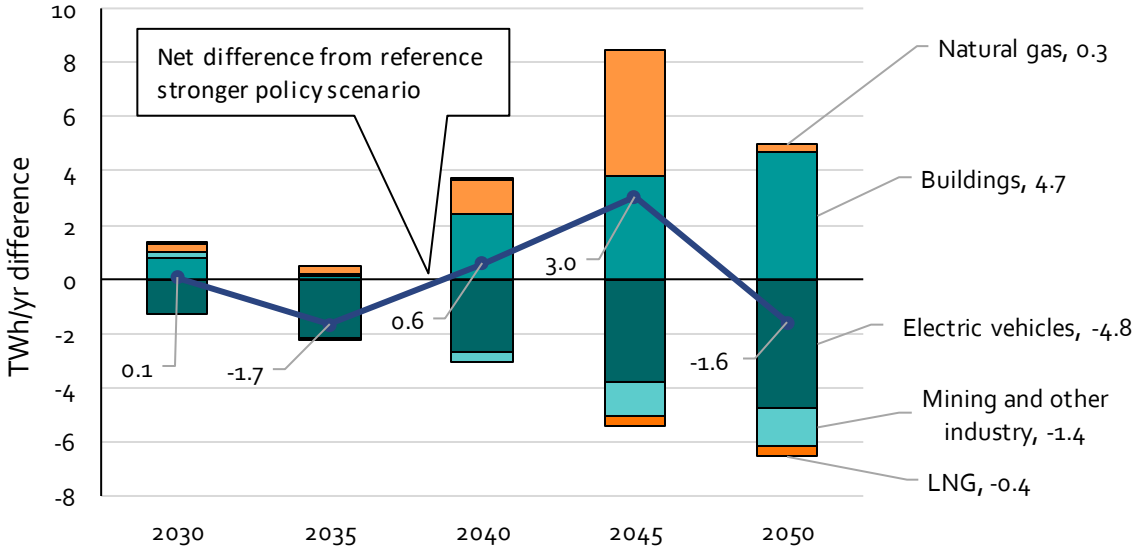
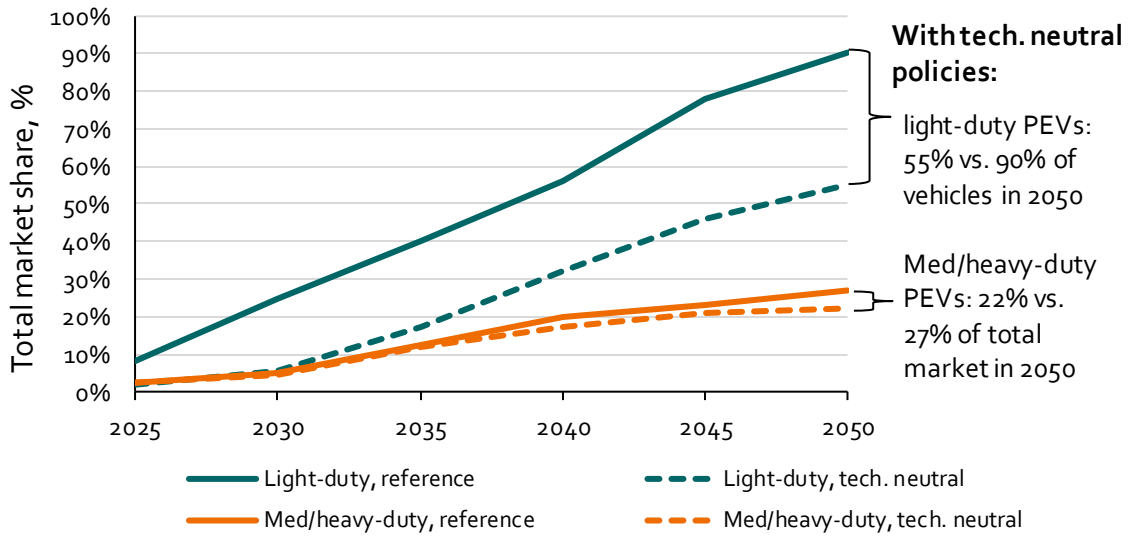


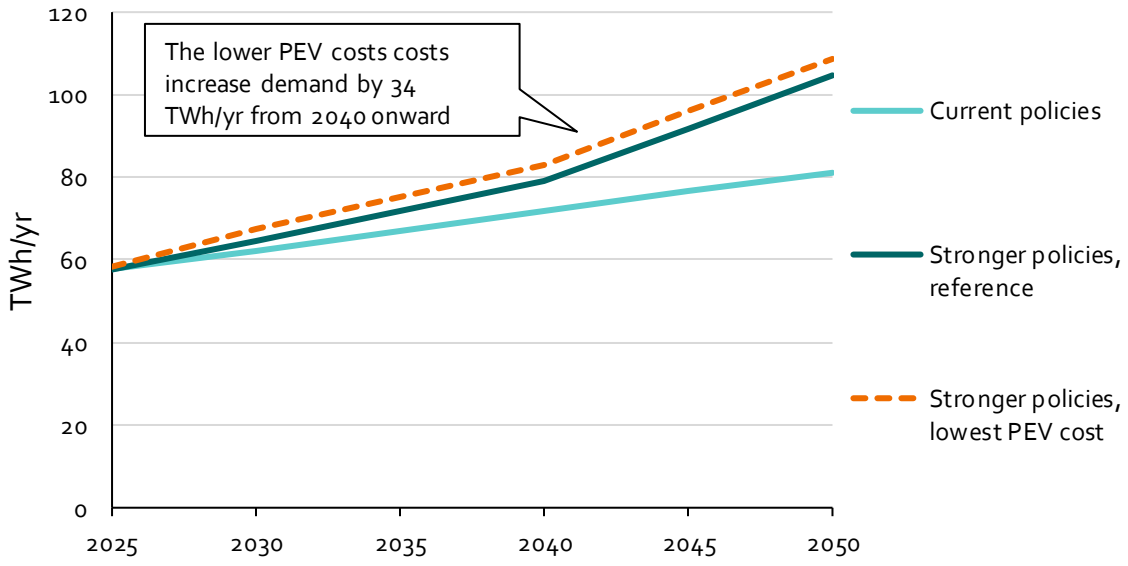
Figure 17: Total market share of PEVs, technology neutral stronger policy scenario versus the reference stronger policy scenario



3.4. Impact of lower plug-in electric vehicle costs

Lower PEV costs result in greater provincial electricity demand from 2030 all the way through to 2050. Recall that with the lower PEV cost assumption, battery pack manufacturing costs fall to $84/kWh in 2030 (2015 CAD), compared to $163/kWh in that same year in the reference policy scenarios. With lower costs, the purchase price of a light-duty battery electric vehicle is roughly $4,000 lower from 2030 through to 2050 (at $2,000 difference for a plug-in hybrid). Similarly, the purchase costs of the archetypal electric heavy-duty vehicle and bus represented in the model are $80,000 and $30,000 lower, respectively. The lowest PEV cost assumptions increase total electricity demand by about 3 TWh/yr in 2030 and 4 TWh/yr in 2050 relative to the reference stronger policy scenario (Figure 18 and Figure 19).

Figure 18: British Columbia electricity demand, stronger policy scenario with lower PEV costs versus the reference stronger policy scenario



Lower PEV costs naturally have the greatest impact on the electricity demand from the transportation sector. Electricity demand from transportation increases by 4 TWh/yr in 2050 when using the lower PEV cost assumption (Figure 19). About two thirds of that impact comes from greater adoption of electric medium and heavy-duty PEVs, where the total market share reaches 45% by 2050, versus 27% in the reference stronger policy scenario (Figure 20). Again, this market share reflects the proportion of sector activity (i.e. tonne kilometers travelled) that occurs on PEVs and can loosely be associated with the percent of vehicles on the road.

One third of the change in transportation electricity consumption comes from light-duty vehicles. While the ZEV standard still defines the total market share of PEVs, lower battery costs result in greater adoption of battery electric vehicles over plug-in hybrids. Because battery electric vehicles are powered only with electricity, more of them on the road results in more electricity consumption.

Figure 19: Difference in electricity demand, strong policies with lower PEV costs versus the reference stronger policy scenario

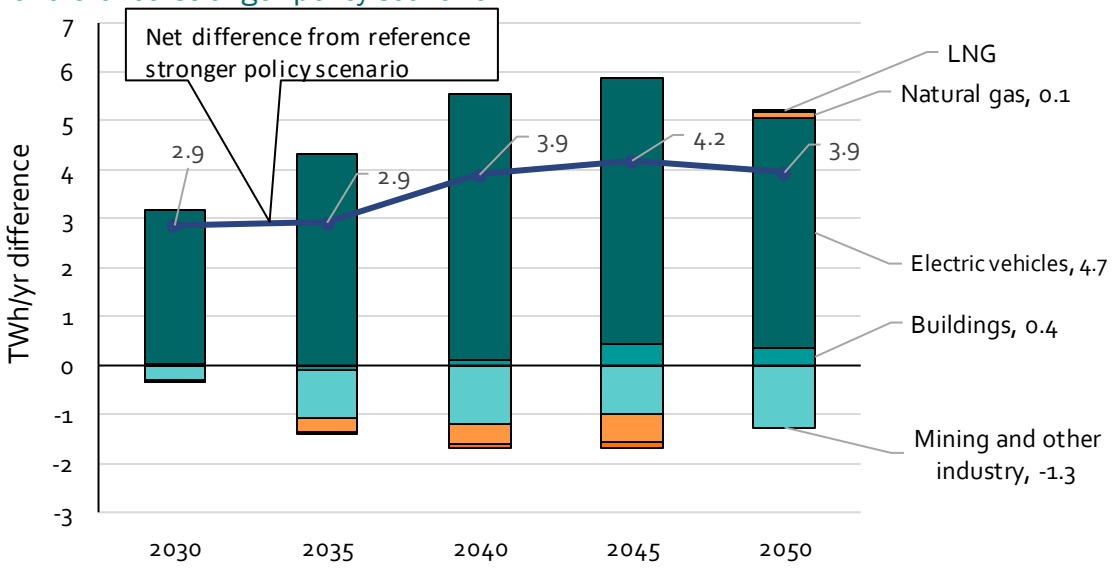
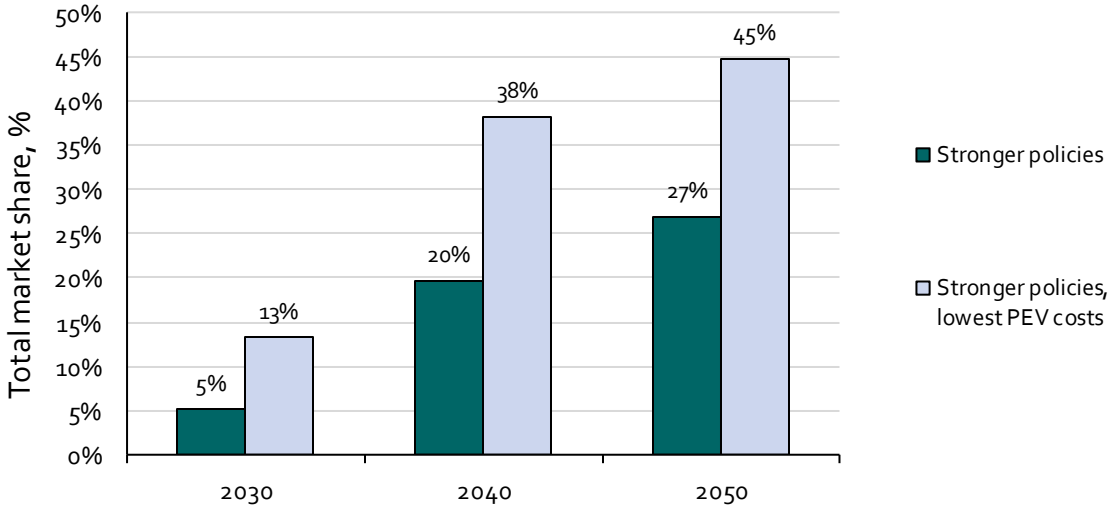


Figure 20: Medium and heavy-duty PEV total market share (% of tonne km travelled via PEVs, which is somewhat indicative of the % of vehicles on the road)



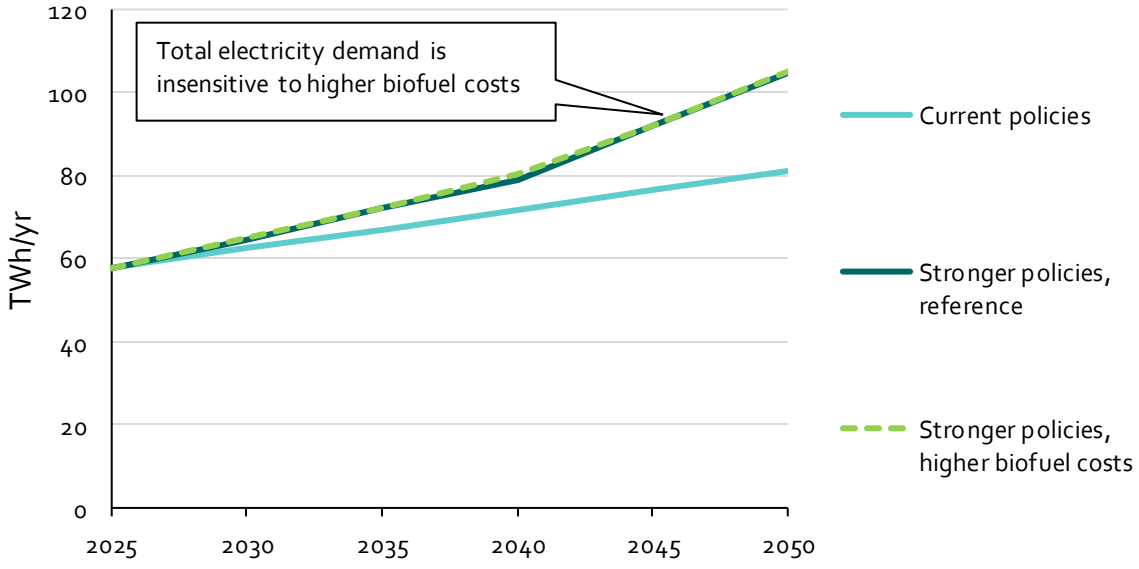
Reducing PEV costs reduces the cost of transportation in a GHG constrained world and this has indirect impacts on the electricity demand from other sectors. For example, reduced transportation costs increase economic growth, relative to the reference stronger policy scenario. Most noticeable is the additional growth in the service sectors which results in greater demand for physical floorspace and increased electricity consumption in buildings (demand in 2050 is about half a TWh/yr higher in

2050, relative to the reference stronger policy scenario) (Figure 19). As well, the lowest PEV costs result in cheaper GHG abatement from the transportation sector. This sector yields relatively more GHG reductions, meaning fewer reduction are needed from other sectors to achieve the 2040 and 2050 GHG emissions target. Consequently, there is less abatement from electrification from the industrial sectors: mining, other industry, natural gas and LNG. Collectively demand in these sectors is 1 to 2 TWh/yr lower in 2050 when assuming the lowest PEV costs, compared to the reference stronger policy scenario (Figure 19).

3.5. Impact of higher biofuel costs

Higher biofuel costs have almost no net impact on electricity consumption in BC during most of the forecast (Figure 21). Recall, this scenario tests the impact of high costs for 2nd generation "drop in" fuels (i.e. those that are fully substitutable with gasoline and diesel and made from woody or grassy feedstocks). In this scenario, we tested capital costs that are 40% higher than in the reference scenario. In terms of the how this affects the production cost, it is approximately equal to doubling the feedstock costs. Renewable gasoline and diesel have a wholesale cost of $1.52/L (excluding distribution margins and taxes), versus $1.26/L in the reference stronger policy scenario. For context, gasoline and diesel have typically had a wholesale price of $0.60 to $0.80 over the past decade.

Figure 21: British Columbia electricity demand, stronger policy scenario with higher biofuel costs versus the reference stronger policy scenario

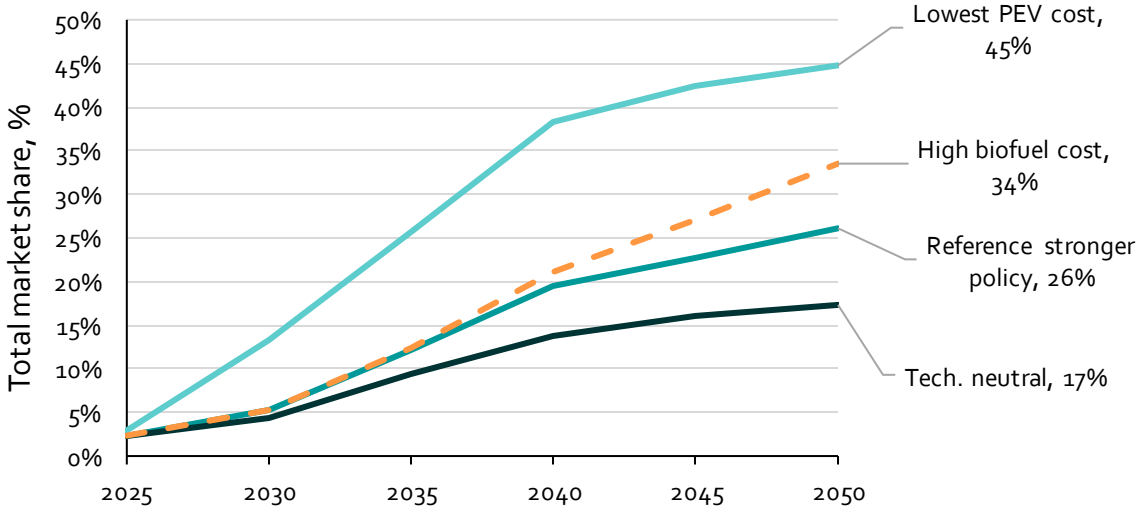


The rate of adoption of PEVs is largely defined by the ZEV standards and it is more sensitive to the battery cost than to biofuel costs. Regardless of the cost of biofuel,

the total market share of light-duty PEVs is constrained by the ZEV standard which requires 95% of new vehicle sales to be ZEVs from 2040 onwards. The market share of medium and heavy-duty PEVs is more sensitive to biofuel costs. In the reference stronger policy scenario, with lower biofuel costs, the market share of medium and heavy-duty PEVs is defined by the ZEV standard. The total market share reaches 26% by 2050 (versus 17% when there is no ZEV standard, as with the technology neutral policy scenario) (Figure 22). When biofuel costs are higher, that market share ultimately hits 34% in 2050 (still less than if PEV costs are lower) (Figure 22).

Additional PEVs do consume more electricity, but the difference is relatively small, and is mostly offset by changes in other sectors. For example, higher biofuel costs result in higher transportation costs in a GHG constrained world. This slows economic growth in many sectors, including services, which cause slower growth in floor area and electricity consumption in buildings.

Figure 22: Medium and heavy-duty PEV total market share, across all variants of the strong policy scenario (% of tonne km travelled via PEVs)



4. Discussion and Conclusions

In this analysis, we used a technologically detailed, full-economic equilibrium, energy economy model to simulate how different GHG policy portfolios will affect electricity consumption in BC from the present to 2050. We tested the impact of:

- "Current policies", that are legislated or have firm announcements
- "Stronger policies", which include a range of additional incentives and regulatory policies, plus an emissions cap that achieves BC's 2040 and 2050 GHG emissions targets.

Using the stronger policy scenario as a reference, we also tested how the forecast of electricity demand is affected by a policy portfolio that uses technology and fuel neutral policies to achieve the same deep GHG reductions in 2040 and 2050. As well, we tested the impact of a future with lower-cost PEVs and a future with higher cost biofuels.

Of the dynamics tested, **BC's long-term electricity demand is most sensitive to the strength of climate policy**. In 2030, the difference between current policies and stronger policies is relatively small. The electricity demand forecast ranges from 62 to 65 TWh/yr. By 2050, the difference is much larger. In response to current policies, electricity demand grows to roughly 81 TWh/yr, whereas with stronger policies, it grows to almost 105 TWh/yr, a difference of 24 TWh/yr (+29%).

In response to stronger GHG reduction policies that will achieve the provincial GHG targets, **most of the incremental growth in electricity demand comes from the natural gas sector and the LNG sector**. 70% of the incremental demand comes from natural gas production. Another 20% of the incremental demand comes from the LNG sector, where the results indicate that LNG plants originally built with gas-fired drives may need to electrify in order achieve the GHG targets. The remaining 10% of incremental demand comes from transportation and buildings. Note that electricity demand for transportation must grow significantly in order to achieve deep GHG reductions. However, much of this load growth is already included in the current policy forecast since it includes the light-duty vehicle ZEV standard.

In contrast, **the other uncertainties tested in this analysis only shift total electricity demand in 2050 by a few TWh/yr relative to our reference forecast with stronger policies**:

- **On net the stronger policy scenario and the technology neutral policy portfolio have a similar impact on electricity demand.** Even with technology and fuel neutral

policies, electrification is still an important abatement action. On net, electricity demand in 2050 is 3 TWh/yr lower than in the reference stronger policy scenario (roughly -2%).

- **Lower-cost PEVs result in greater provincial electricity demand from 2030 all the way through to 2050.** In 2050, electricity demand is 4 TWh/yr higher than in the reference stronger policy scenario (roughly 4% higher). Most of this change comes from increased adoption of medium and heavy-duty vehicles, where these eventually account for 45% of medium and heavy-duty transportation activity. The adoption of electric buses is relatively insensitive to reductions in their costs, as they gain a substantial market share at with all future battery costs considered in this analysis. The adoption of light-duty PEVs would be affected by reduced PEV costs but their uptake is largely defined by the ZEV standard that requires 95% of sales to be ZEVs by 2040.
- **Higher biofuel costs result in greater electrification of transportation, but little change in total provincial electricity demand.** The greatest change is the extent to which medium and heavy-duty PEVs are used. However, several minor offsetting factors make electricity demand insensitive to biofuel costs. Specifically, higher biofuel costs result in slower economic growth. Slower growth largely offsets the additional electricity consumption for transportation.

In summary, this analysis shows that achieving BC's GHG reduction targets will result in substantially more electricity demand than would occur with current policies. The results do not show a future where other potential low-GHG energy pathways out-compete electricity. Rather, these pathways, including bioenergy, energy efficiency and electrification, are complementary and all contribute to deep GHG reductions.

Because electricity demand in a deep GHG reduction scenario is most sensitive to load growth in the transportation and natural gas sectors, the limitations and uncertainties in this analysis that relate to these sectors are the most important.

An uncertainty that was not tested in this analysis is global LNG demand and demand for natural gas produced in BC, which could lead to lower electricity demand. In this forecast, BC produces at least 60% of the gas exported from the province as LNG. This accounts for between 1 and 2 bcf/day of BC's production during the forecast, or 15-25%. If global efforts to reduce GHG emissions also reduce foreign demand for LNG, then the BC natural gas and LNG production sectors would be smaller than forecasted as would their electricity demand. This could reduce electricity demand by at most 6-7 TWh/yr later in the forecast (e.g. 2040 through to 2050). As well, the analysis assumes a fixed minimum quantity of foreign investment in the BC natural gas sector. This

assumption prevents the output of that sector falling more than 10% below what was assumed in the baseline current policy scenario. Consequently, this analysis does not show the full range of uncertainty in future electricity demand from these sectors.

There could be earlier potential for medium and heavy-duty PEVs than forecasted. A limitation of this analysis is that it has a general representation of medium and heavy-duty vehicles. Consequently, the results can only show a relatively aggregate representation of their potential to electrify. Medium and heavy-duty vehicles are very heterogeneous with respect to their size, what they do and how far they travel (or how much they carry) in a given day or year. By necessity, this diversity has been simplified in the analysis and medium and heavy-duty PEVs are represented conservatively, as long-range tractor trailers (where the PEV archetype can travel 600-700km per charge).

However, this characterization misses some of the low-range and high utilization uses of these vehicles where electrification would have a better business case, even with higher cost batteries. For example, this could include urban delivery vehicles, drayage trucks moving goods from ports to warehouses, and waste collection trucks. Electrification of these niches could occur earlier than shown in this analysis and demand from medium and heavy-duty transportation could ultimately be larger and sooner than forecasted. As well, there are other concepts of electrification that could change the relative costs of electrifying medium and heavy-duty vehicles, such as in-road or overhead charging. Consequently, **we recommend ongoing study of the electrification of medium and heavy-duty vehicles**.

The analysis could not test the impact of lower biofuel costs on transportation electricity demand, but even the failure to do this indicates that the results are robust to this uncertainty: Low-cost biofuels leads to high demand, making them a scarce resource, which limits their use. The model could not solve for a scenario that aimed to test the impact of lower-cost 2nd generation "drop-in" biofuels (i.e. those that are fully substitutable with gasoline and diesel and made from woody or grassy feedstocks). Demand was high and the supply was too inflexible making it difficult for the model to solve. This "non-result" indicates that even if biofuels were cheaper, they would be a scarce resource and the that significant electrification of transportation (and buildings and industry) would still be required. In short, electrification and biofuels would be complementary abatement actions, just as this analysis has shown.

Finally, there are additional transportation modes that could electrify, but they are not included in this analysis. Consequently, electricity consumption for transportation could be higher than forecasted. Specifically, there will likely be niches for the electrification of marine and air transport. For example, Norled, a Norwegian ferry operator is already using a battery-electric ferry on one of its routes and has placed an

order for more of these vessels.[7] For aviation, Harbour Air, based in BC, has announced that it plans electrify its short-haul seaplanes,[8] and Airbus is testing the electrification of one of its regional turbo-fan powered aircrafts.[9] The model results provide an upper bound on this uncertainty. If all domestic marine and air travel included in the analysis were to electrify, this would increase total electricity demand by 7 to 11 TWh/yr in 2050, depending on the growth of these sectors.[10] For context, total electricity demand from PEVs grew to roughly 15 TWh/yr in 2050 in the stronger policy scenario, though the full electrification of on-road and off-road vehicles would increase that number to almost 25 TWh/yr. By analogy with the electrification of medium and heavy-duty vehicles observed in this study, actual electricity demand from marine and air travel would be a subset of the maximum. Given that electric boats and planes would likely be used for short and high-frequency routes, an approximate guess for that new load would be in the range of 2 to 4 TWh/yr by 2040 to 2050.

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[7] Corvus Energy. (2017). *World's First All-Electric Car Ferry*. Available from: www.corvusenergy.com

[8] Harbour Air Seaplanes (2019). *Harbour Air and magniX Partner to Build World's First All-Electric Airline.* Available from: link.

[9] Airbus (2019). *A Giant Leap Toward Zero-Emission Flight*. Available from: link.

[10] Assuming that electric propulsion has an end-use efficiency that is three times greater than combustion-based propulsion.

Appendix A: Electrification Technology Research

This appendix describes research conducted for the electrification potential review and how this information was used in the analysis. It covers six topics:

- The cost and potential for 2nd generation biofuels a as low-carbon fuel that competes with, or complements, GHG abatement through electrification.
- Updated cost assumptions for light-duty electric vehicles and assumptions for the energy intensity of these vehicles.
- The cost and potential for battery electric vehicles for bus transit.
- The cost and potential for battery electric vehicles for heavy-duty truck transport.
- The opportunity for low-energy electric heating in industry with industrial heat pumps.
- The cost and energy intensity of direct air carbon capture.

2nd Generation biofuels

In this report, 2nd generation biofuels refer to liquid and gaseous fuels produced from ligno-cellulosic feedstocks. These are cellulosic ethanol and renewable gasoline, diesel and natural gas produced from wood or grassy organic matter. These contrast with first generation biofuels which include starch ethanol and biodiesel. Starch ethanol is produced from sugary and starchy crops such as wheat and corn. Biodiesel is produced from oilseeds (e.g. canola and soy) and can also be produced from a limited quantity of used cooking oil and tallow (fat by-products from animal production). We also include hydrogenation derived-renewable diesel as a first-generation biofuel given that it can be produced from the same feedstocks as biodiesel.

Currently, 2nd generation biofuels are pre-commercial and their production is more technically advanced and costly than the production of first-generation biofuels. However, 2nd generation biofuel feedstocks are more plentiful than those for first generation biofuels and the commercialization of 2nd generation biofuel is generally viewed as a necessary for the widespread substitution of fossil fuels with bio-energy.

The following section describes the feedstocks available for 2nd generation biofuels in the model in terms of their source, quantity, and cost. Feedstock quantities are always

described in terms of dry mass (e.g. Oven dry tonnes or ODt). It then describes the fuel production pathways included in the model in terms of their capital and operating costs, their feedstock conversion efficiency and the lifecycle GHG intensity of the finished fuels. Based on these attributes, we can compare the quantity and cost of 2nd generation biofuels available within the model with the incumbent fuels: gasoline, diesel and natural gas.

Table 12 summarizes the feedstocks for 2nd generation biofuels represented in gTech. Table 13 summarizes the fuel production technologies. Production costs and GHG abatement costs are shown with the reference model inputs for biofuel plant capital costs (not necessarily the same as literature estimates). The fuel carbon intensities are calculated based on the 2010 GHG intensities for inputs like truck transportation and hydrogen production. If the GHG intensity of these inputs declines, so too will the biofuel carbon intensities and the abatement cost. The production potential (PJ/yr and fraction of gasoline/diesel or natural gas replaced) is only a snapshot for 2010 designed to give context to the quantity of fuel available.

Table 12: Summary of 2nd generation biofuel feedstock modelling assumptions

	Agriculture residue	Forestry residue	Total
Residue availability in 2010, million ODt/yr	18.2	15.7	33.9
Residue availability in 2010, PJ/yr	337	238	575
Plant-gate feedstock cost, 2010 CAD/ODt	69	80	74.5 (avg.)
Potential for greater future production	Modest: grows with food production	High: Forestry activity and residue supply could be roughly 70% higher than in 2010	-

Table 13: Summary of 2nd generation biofuel production modelling assumptions (reference inputs, not sensitivity scenario inputs). Costs in 2010 CAD.

	Renewable gasoline and diesel	Cellulosic ethanol	Renewable natural gas
Production costs, 2010 CAD assuming residue cost of $74.5/ODt	$1.14/L	$0.61/L	$13.4/GJ
Fuel lifecycle carbon intensity in 2010,[a] gCO_2e/MJ	20 (-77% from gasoline)	11 (-88% from gasoline)	6 (-90% from nat. gas)
Maximum production potential in 2010 if all feedstock available in 2010 were used for a given fuel, PJ/yr	384	263	453
Fraction of incumbent fuels replaced if all feedstock available in 2010 were used for a given fuel (% of 2010 Canadian consumption	15 % of gasoline and diesel	10% of gasoline and diesel	13% of natural gas
Abatement cost with model inputs (2010 CAD/tCO_2e)	185	80	162
Abatement cost when commercialized (2010 CAD/tCO_2e)	59	61	98

[a] Accounts for energy used for feedstock extraction, transport and transformation to fuel, as well as additional fertilizer requirement for agricultural residue, based on 2010 GHG intensity of these activities in gTech

[b] Abatement cost for renewable gasoline and diesel and cellulosic ethanol measured relative to a gasoline lifecycle GHG intensity of 85.7 gCO_2e/MJ, and as assumed wholesale price of $0.70/L (roughly $70/bbl USD for oil). Abatement cost for renewable natural gas measured relative to a natural gas lifecycle GHG intensity of 58 gCO_2e/MJ, and as assumed wholesale price of $5/GJ (2010 CAD).

Feedstocks

The 2nd generation biofuel feedstocks included in the model are agricultural and forestry harvest residues. Agricultural residues are the remainders of plants after harvest such as corn stover and wheat straw. Forestry harvest residues are the branches and treetops that are piled and left at the side of forest roads during logging. Residue availability is defined for each source in 2010 as a function of agricultural and forestry activity and the quantity can grow or shrink as the activity of the associated sector changes (i.e. more forestry activity produces more harvest residue).

Agricultural Residue

In 2010, the model includes 18.2 Mt/yr of agricultural residue that is sustainably available as a feedstock (Table 14). At roughly 18 PJ/million ODt, this residue contains 328 PJ. This quantity was estimated by deriving the quantity of residue available from each of the primary grain crops in Canada using the Biomass Inventory Mapping and

Analysis Tool (BIMAT) and its corresponding data.[11] Other crops produce significantly less residue and are not included. Only a portion of all available agricultural residues can be sustainably harvested as biofuel feedstock since more than 50% of it is kept on the ground for tilling to prevent erosion and to maintain soil nutrients. Roughly 20% of residue is used for as animal bedding for livestock production leaving less than 30% of residue available for fuel production. The sustainable amount of residue available per tonne of grain was multiplied by total grain production in 2010[12] to yield total residue production in that year.

Agricultural residue supply is tied to agricultural production in gTech in Canada and the USA. Therefore, the supply can increase if total agricultural production increases or if there is a shift in the composition of crops (e.g. more corn and less wheat would yield more residue). However, agricultural production is constrained in gTech assuming a fixed land-base, so the model will not allow runaway residue production, nor does it allow runaway production of first-generation biofuel feedstocks.

Table 14: Summary of agricultural residue availability in Canada in 2010, as represented in gTech (reference scenario inputs)

Parameter	Units	Barley	Corn	Oat	Wheat	Total[a]
Residue yield[b]	$ODt_{residue}/t_{grain}$	0.90	0.67	1.52	1.22	1.13
Portion available for energy[b]	%	21.3%	72.9%	28.7%	18.9%	28.5%
Residue available for energy	$ODt_{residue}/t_{grain}$	0.19	0.49	0.44	0.23	0.32
Grain production in 2010[c]	Mt	7.6	21.0	2.5	23.3	54.4
Residue available for energy in 2010	Million ODt	1.5	10.3	1.1	5.4	18.2

a Flax data is not shown since no flax residue is available for energy

b Source is BIMAT

c Source is Statistics Canada

Forestry Harvest Residue

In 2010, the model includes 15.7 million ODt/yr of forestry harvest residue that is sustainably available as a feedstock.[13] At roughly 18 PJ/ million ODt, this residue contains 238 PJ. This quantity of biomass comes from roadside piles of branches and

[11] Agriculture and Agri-Food Canada. (2017). *Biomass Agriculture Inventory Median Values*. Available from: www.open.canada.ca

[12] Statistics Canada, CANSIM 001-0017

[13] Yemshanov D., McKenney, D.W., Fraleigh, S., McConkey, B., Huffman, T., Smith, S., 2014, *Cost estimates of post harvest forest biomass supply for Canada,* Biomass and Bioenergy, 69, 80-94

tree tops that are produced during whole-tree harvesting with clear-cut logging. It is net of residue that is not available due to technical reasons (e.g. too dispersed to be extracted) or sustainability reasons (i.e. must be left to maintain nutrients, habitat and forest carbon).

Forestry activity in 2010 was relatively low compared to the annual allowable cut, also known as the wood supply, which is an estimate of what can be sustainably harvested from Canadian forests each year. In 2010, the forestry sector harvested 138.6 million m^3 of wood, but the wood supply was 69% larger, at 234.9 million m^3.[14] The wood supply has been relatively stable in the past, ranging from 223 to 250 million m^3/yr between 1990 and 2015. Therefore, if there is sufficient demand for Canadian wood products, then the quantity of forest harvest residue could as much as 70% larger (roughly 27 million ODt/yr).

Excluded Feedstocks

The analysis does not include forest product mills waste, urban wood waste and energy crops.

Forest product mill waste is a by-product of turning trees into forest products (e.g. lumber, panels). The quantity of mill residue is a function of demand for forest products and it similar in size to the harvest residue, estimated at 21 Mt/yr in 2005. However, it is generally already used for energy within the mills with some exported as wood pellets.[15] These other uses would compete against 2nd generation biofuels for wood feedstock, but the model does not currently account for this dynamic.

Urban wood waste primarily comes from deconstruction and urban silviculture. The supply is a function of the quantity produced per capita and the degree to which this waste is separated from the general waste stream for utilization. We estimate the quantity of urban wood waste available in Canada at 3 million ODt/yr based on a per capita production of 0.1 ODt/yr/person.[16] This quantity of wood is not insignificant, but because it is relatively small compared to agricultural and forest harvest residue, it is also not included in the analysis.

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[14] Government of Canada, National Forestry Database, access May 28, 2018

[15] Bradley, D., 2009, Canada Report on Bioenergy 2009, Climate Change Solutions, NTL - IEA Bioenergy Task 40 - Biotrade

[16] Estimates for urban wood waste vary from 0.07 ODt/capita/yr (Tetra Tech (2015). *2015 Demolition, Land-clearing, and Construction Waste Composition Monitoring Program*, presented to Metro Vancouver), to 0.3 ODt/capita/yr (Agriculture and Agri-Food Canada (2018). *Biomass Inventory Mapping and Analysis Tool*)

Energy crops are excluded from the analysis due to the significant uncertainty in their potential and their GHG impacts. Energy crops will compete with other land-uses including agriculture, forests, prairies and pastures, so it is difficult to quantify how much land may be used for energy crop production. Furthermore, energy crop production can have a very large impact on soil carbon, both positive and negative, depending what crops are grown and where they are grown.[17] In other words, their production can emit or sequester significant quantities of carbon.

Feedstock costs and carbon intensity

The "at-the-plant cost" of agricultural residue in the model is $69/ODt (Table 15). This cost is the sum of the residue's 'farmgate' and transportation costs. The farmgate cost is 63 $/ODt. based on a study crop residue extraction in Ontario.[18] Farmgate costs include harvest and nutrient replacement costs. Harvest costs come from chopping (for corn only), baling, collecting, and storing the residue. The nutrients in the residue that is removed from the fields must be replaced with fertilizers.

The transportation costs for agricultural residue are 6 $/ODt, informed by a study of corn stover transportation costs that are a function of distance travelled.[19] We used the BIMAT online tool to determine an average transportation distance of 40km. The distance is half the radius of an area that can produce roughly 0.72 million ODt/yr of residue (the input for an archetypal biofuel plant in gTech), measured at several locations across Canada using BIMAT.

The "at-the-plant cost" of forest harvest residue in the model is $80/ODt (Table 15). This is based on an assumed harvest cost of $52/ODt.[20] Yemshanov et al. (2014) estimated the transportation cost of forest residue to the nearest existing biomass cogeneration plants with costs ranging from $5/ODt to over 120 $/ODt. We use an average transportation cost of $28/ODt under the assumption that biofuel plants could be located to mitigate transportation costs (e.g. co-located at existing forest

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[17] US Department of Energy (2016) 2016 Billion-Ton Report

[18] Kludze, H., Deen, B., Weersink, A., van Acker, R., Janovicek, K., De Laport, A., McDonald, I. (2013). *Estimating sustainable crop residue removal rates and costs based on soil organic matter dynamics and rotational complexity*. Biomass and Bioenergy, 56, 607-618

[19] Petrolia, R., D. (2008). *The economics of harvesting and transporting corn stover for conversion to fuel ethanol: A case study for Minnesota.* Biomass and Bioenergy, 32, 603-612

[20] Yemshanov D., McKenney, D.W., Fraleigh, S., McConkey, B., Huffman, T., Smith, S., 2014, *Cost estimates of post harvest forest biomass supply for Canada,* Biomass and Bioenergy, 69, 80-94

products sites that do not have cogeneration and were not included in the analysis by Yemshanov et al. (2014)).

Table 15: 2nd generation biofuel feedstock production cost assumptions (2010 CAD/ODt)

	Agricultural residue	Forest harvest residue
Harvest/Extraction costs	$32	$52
Transportation to fuel plant	$6	$28
Nutrient replacement	$31	-
Total "at-the-plant" Cost	**$69**	**$80**

Note that the model is a general equilibrium model and all costs result from a corresponding demand for a good or service and will result in energy consumption and GHG emissions from that demand. For example, the transportation costs increase the activity in the truck transportation sector which increases energy consumption and GHG emissions in that sector. Likewise, nutrient replacement increases fertilizer production and the associated energy consumption and GHG emissions. Based on the gTech GHG intensity for truck transportation and fertilizer production in 2010, the carbon intensity of agricultural residue in 2010 is 0.09 $tCO_2e/t_{residue}$ (30% from extraction and transport, 70% from fertilizer). The carbon intensity of forest harvest residue in 2010 is 0.07 $tCO_2e/t_{residue}$ (100% from extraction and transport). The cost and GHG intensity of transportation and fertilizer production can change over time, meaning the feedstock production cost and lifecycle GHG intensity can change as well. These feedstock carbon intensities are further described in the context of biofuel lifecycle carbon intensity in the next section.

Fuel production cost and carbon intensity

The ligno-cellulosic feedstocks within the model (agriculture and forestry residue) can be used to produce three 2nd generation biofuels in gTech: Renewable gasoline and diesel, cellulosic ethanol, and renewable natural gas. The archetypal representations of these fuel production processes are based on plants that consume 0.72 Mt/yr of ligno-cellulosic feedstock.

Renewable gasoline and diesel are modelled as a single fuel pathway that is a perfect substitute for gasoline or diesel. The fuels are produced together via fast-pyrolysis of feedstock into a bio-crude and followed by treatment with hydrogen to upgrade the bio-crude to finished fuels. Model assumptions are in Table 16, which shows the literature estimate for an archetypal plant capital cost: $673 million (2010 CAD) for a plant producing 229 million L/yr. However, because this technology is pre-commercial and there is significant uncertainty in its capital cost, the technology has a 100% cost

premium in the reference policy analyses, raising the capital cost to $1,346 million (2010 CAD). Renewable gasoline and diesel production is mostly energy self-sufficient, though it does require some electricity as well as hydrogen which can be produced from natural gas.

Table 16: Renewable gasoline and diesel production archetype assumptions

Attribute	Value	Source
Archetype production, million L/yr	229	Jones et al. 2013[21]
Capital cost (literature estimate for for commercial plant), million 2010 CAD	$673	Jones et al. 2013
Capital cost (reference biofuel cost scenario), million 2010 CAD	$1,346	100% capital premium on above value
Operating cost, 2010 CAD $/L	$0.23	Jones et al. 2013
Electricity input, GJ/GJ fuel	0.08	GHGenius 4.03a/(S&T)² Consultants,[22] average for wood and agriculture residue
Hydrogen input, GJ/GJ_{fuel}	0.19	GHGenius 4.03a/(S&T)² Consultants, average for wood and agriculture residue
Feedstock input, $kg_{feedstock}/L_{fuel}$	3.15	GHGenius 4.03a/(S&T)² Consultants, average for wood and agriculture residue
Feedstock conversion efficiency, $GJ_{feedstock}/GJ_{fuel}$	63%	Derived from above assuming 18 $MJ/kg_{feedstock}$ and 35.5 MJ/L_{fuel}

The cellulosic ethanol fuel pathway in gTech is based on a biochemical process, using enzymes to produce ethanol from ligno-cellulosic feedstocks. The ethanol is functionally equivalent to ethanol produced from crops such as wheat or corn and it is not a perfect substitute for gasoline: We assume it can be blended at 15% by volume after 2020 once newer vehicles account for almost all vehicle stock. The capital cost assumption for cellulosic ethanol is $549 million (2010 CAD) for a 237 million L/yr plant, based on the observed cost of the first cellulosic ethanol plants (Table 17). The process is energy self-sufficient and produces a surplus of lignin which is assumed to be used for cogeneration of heat and power with some electricity export.

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

[22] (S&T)2 Consultants, 2012, Update of Advanced Biofuel Pathways in GHGenius

Table 17: Cellulosic ethanol production archetype assumptions

Attribute	Value	Source
Archetype production, million L/yr	237	Set equal to have annual feedstock demand as renewable gasoline/diesel
Capital cost (reference biofuel cost), million 2010 CAD	$569	IRENA 2013,[23] median of first plants
Capital cost (literature value for commercial plant, not used in this analysis), million 2010 CAD	$489	IRENA 2013, estimate once fully commercialized
Operating cost, 2010 CAD $/L	0.17	Jones et al. 2013
Electricity output, GJ/GJ fuel	-0.05	GHGenius 4.03a/(S&T)² Consultants
Feedstock input, Kg feedstock per L fuel	3.04	GHGenius 4.03a/(S&T)² Consultants
Feedstock conversion efficiency ($GJ_{feedstock}/GJ_{fuel}$)	43%	Derived from above assuming 18 $MJ/kg_{feedstock}$ and 35.5 MJ/L_{fuel}, not including electricity production

The 2nd generation renewable natural gas technology is based on the G4 Insights' pyrocatalytic hydrogenation process which produces natural gas from ligno-cellulosic material via fast pyrolysis and hydrogen treatment. The process is energy self-sufficient, meaning that the feedstock is used to produce the fuel, the required hydrogen and the energy for the process. The feedstock to gas conversion efficiency is 74% on an energy basis (Table 18). Once the technology is commercialized, we assume the capital cost for a plant producing 9.6 PJ/yr is $321 million based on a proposal for using the technology. However, the reference capital cost assumption used in the scenarios is twice that value to account for uncertainty in the commercialization of the process.

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

Table 18: Renewable natural gas production archetype assumptions

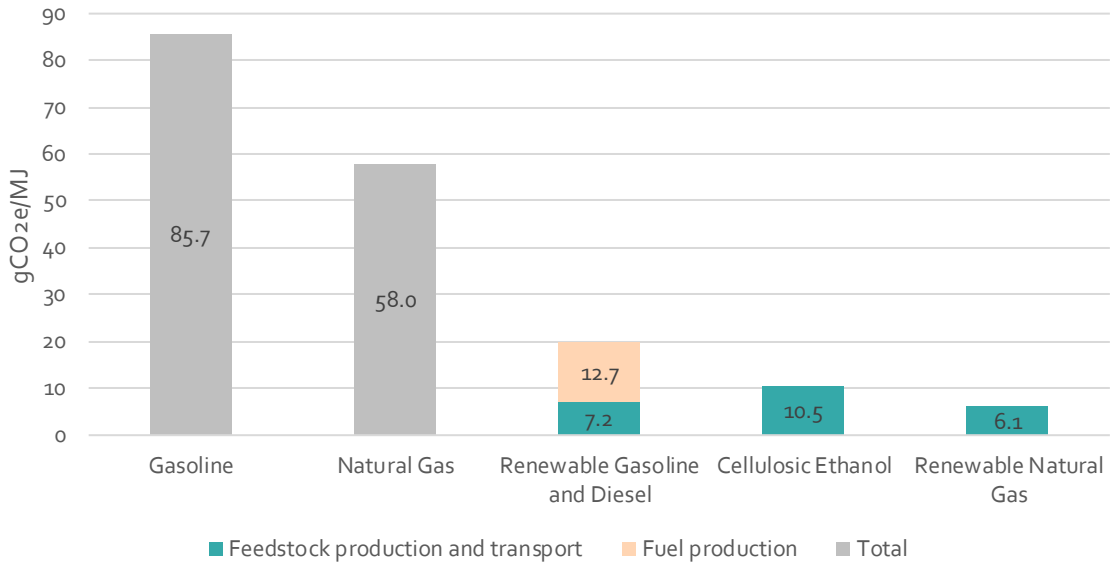
Attribute	Value	Source
Archetype production, PJ/yr	9.6	Set to have equal feedstock demand as other 2nd gen. fuel production archetypes
Capital cost (literature estimate for commercial plant), million 2010 CAD	$321	Chavez-Gherig et al., 2017[24]
Capital cost (reference biofuel cost), million 2010 CAD	$642	100% capital premium on estimated value
Operating cost, 2010 CAD $/GJ	1.18	Chavez-Gherig et al., 2017
Feedstock input, Kg feedstock per GJ fuel	75	G4 Insights[25]
Feedstock conversion efficiency ($GJ_{feedstock}/GJ_{fuel}$)	74%	G4 Insights

2nd generation biofuels provide a significant reduction in lifecycle carbon intensity (Figure 23). The carbon intensity of renewable gasoline/diesel and cellulosic ethanol are 77% and 88% lower than gasoline, respectively (excluding the GHG associated with intermediate inputs to biofuels, e.g. chemicals and enzymes). The carbon intensity of renewable natural gas is 90% lower than fossil natural gas. The carbon intensity of the biofuels mainly comes from diesel consumption (feedstock extraction and transport), fertilizer production (CO_2 by product GHG emissions during ammonia production) and hydrogen production (CO_2 by product GHG emissions during steam methane reformation, renewable gasoline and diesel only). If GHG reduction policy reduces the GHG emissions from these sources, the lifecycle carbon intensity of biofuels can decline further.

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

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

Figure 23: 2nd Generation Biofuel Carbon Intensity

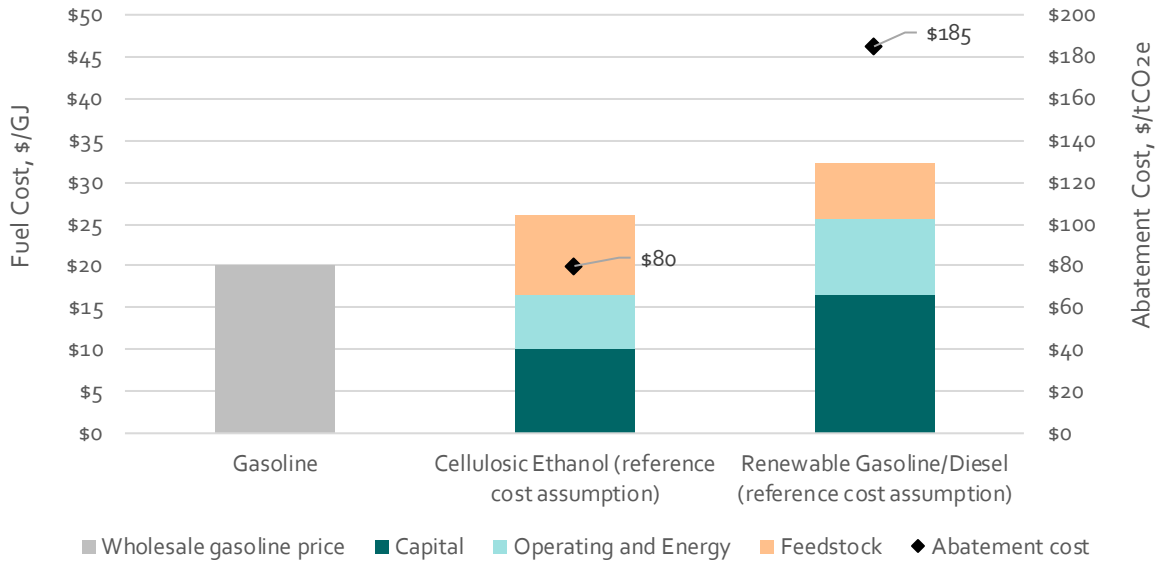


Gasoline and natural gas carbon intensity values from GHGenius 4.03a model, default Canadian values for 2016. Carbon Intensity of biofuels excludes GHG associated with intermediate inputs (e.g. chemicals). Electricity consumption GHG accounted assuming a 55% efficient natural gas-fired combined cycle power plant operating at 327 kg/MWh. Feedstock carbon intensity assumed 50% agricultural residue and 50% forest harvest residue.

With the reference biofuel cost scenario assumptions for 2nd generation biofuel production capital costs, the production cost for cellulosic ethanol is $26/GJ (2010 CAD, equivalent to $0.61/L). If the gasoline production cost is $20/GJ ($0.70/L, based on 70$/bbl US oil), the GHG abatement cost is $80/t$CO_2$e (Figure 24. With the reference biofuel cost scenario assumptions for renewable gasoline and diesel production capital costs, that fuel costs $32/GJ ($1.14/L), with an abatement cost relative to gasoline of $185/t$CO_2$e (Figure 24).

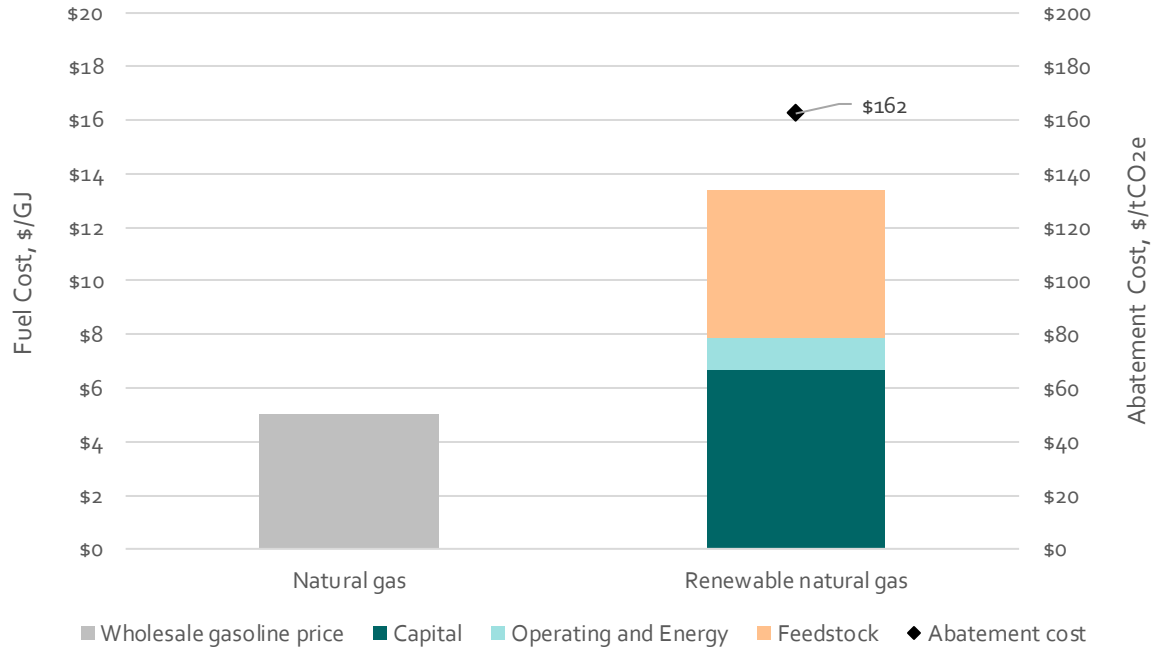
Similarly, the cost of renewable natural gas produced from ligno-cellulosic material is $13.4/GJ with using the reference scenario assumptions for its capital cost (Figure 25). At this cost, the abatement cost is $162/t$CO_2$e when the price of natural gas is $5/GJ (2010 CAD).

Figure 24: 2nd Generation Liquid Biofuel Production and Abatement Cost (2010 CAD)



The cost of gasoline is calculated assuming a $70/bbl price, a Canada/US exchange rate of 1.25 and a refining margin of $0.15 2010 CAD/L. Ligno-cellulosic feedstocks are assumed to cost $74/ODt, an average of agricultural and forestry harvest residue supply costs in gTech. The abatement cost of cellulosic ethanol does not account for an improvement in the energy efficiency of the vehicle and or a reduction in the cost of gasoline blendstock it is blended with due to lower octane requirements.

Figure 25: 2nd Generation Gaseous Biofuel Production and Abatement Cost (2010 CAD)



The cost of natural gas is assumed at $5/GJ. Ligno-cellulosic feedstocks are assumed to cost $74/ODt, an average of agricultural and forestry harvest residue supply costs in gTech.

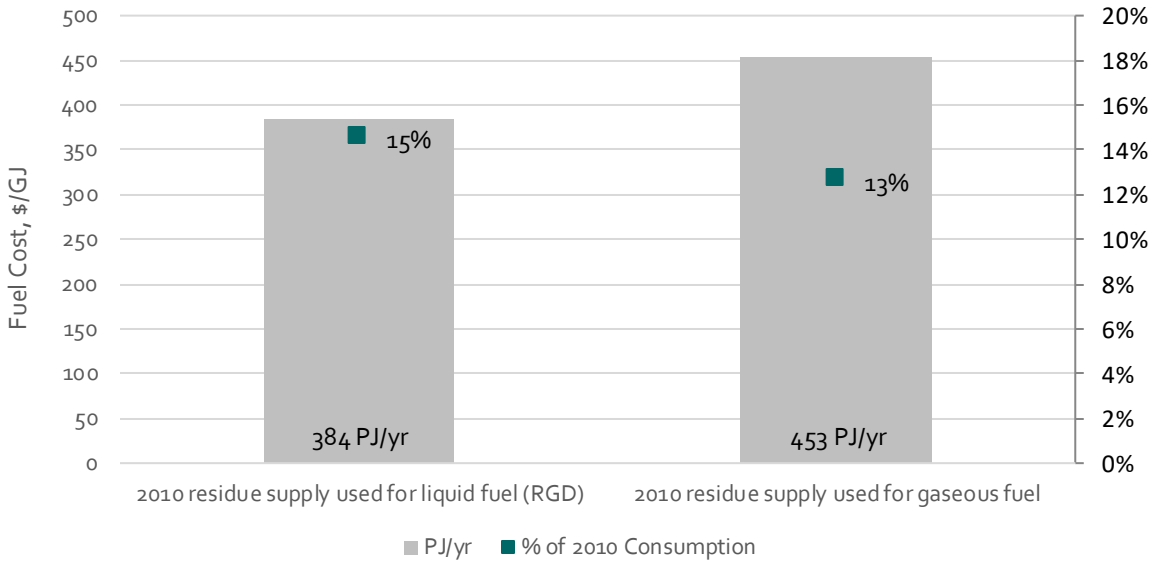
Production potential

If all residues available in gTech in 2010 were used to produced renewable gasoline and diesel then the quantity of fuel produced would be 384 PJ/yr (15% of gasoline and diesel consumption in Canada in 2010) (Figure 26). If that residue were used to produce gaseous fuel, the quantity of natural gas produced would be 453 PJ/yr (13% of fossil natural gas consumption in 2010, including own use and consumption of natural gas to generate electricity.

This estimation of the 2nd generation biofuel production potential is only meant to illustrate the magnitude available: it is a potentially significant low-carbon energy resource, but it cannot replace current fossil fuel consumption. There are some important caveats to keep in mind when interpreting this data:

- Residue production can increase: Somewhat more agricultural production is possible, though land is constrained in gTech, and up to 70% more forestry activity is possible with a proportional increase in forestry harvest residue.
- Fossil fuel consumption will decline in most scenarios where 2nd generation biofuels are used: GHG reduction policy will drive more energy efficiency and electrification. These will reduce the total quantity of fossil fuel required, be it fossil or bio-derived. Therefore, the fraction of fossil fuel than can be substituted with 2nd generation biofuels will be larger than shown in Figure 26.
- The USA has a substantial supply of residue that could be used for fuel. However, if there is strong GHG reduction policy in the US, there would be substantial new demand for bioenergy. Therefore, the impact of US on the supply of feedstock available for Canadian fuel consumption is important.
- Other residues are available and could increase the production potential. For example, urban wood waste could increase the potential shown in Figure 26 by another: e.g. urban wood waste is available and could increase the production potential by another 50-60 PJ/yr.

Figure 26: Fuel production potential if the quantity of residue characterized in gTech in 2010 is converted to liquid fuels (renewable gasoline and diesel) or gaseous fuel: PJ/yr fuel (bars, left axis) and fraction of incumbent fossil fuel (points, right axis)



Updated assumptions for electric light-duty vehicles

We have used the following method to update the light-duty electric vehicle costs in gTech:

- Vehicle energy intensity, manufacturing costs, and PEV battery sizes are based on Moawad at al. (2016),[26] with the exclusion of PEV battery pack unit cost ($/kWh). The reference scenario vehicle inputs from Moawad et al. (2016) correspond to their medium technology and cost uncertainty scenarios.
- PEV battery pack manufacturing costs are 350 $/kWh (2015 CAD) in 2015 based on Nykvist & Nilsson (2015).[27] The reference assumption for their cost decline is somewhat conservative: costs fall to 163 $/kWh by 2030, loosely the UBS bank's outlook for 2025 but delayed by five year (Table 19).[28]

[26] Moawad, Ayman; Kim, Namdoo; Shidore, Neeraj; Rousseau, Aymeric (2016). Assessment of Vehicle Sizing, Energy Consumption, and Cost through Large-Scale Simulation of Advanced Vehicle Technologies, Argonne national Laboratory, Energy Systems Division

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

[28] UBS (2017). UBS Evidence Lab Electric Car Teardown – Disruption Ahead? UBS Evidence Lab, Global Research

- Other battery pack manufacturing cost assumptions are possible. A more optimistic assumption (lower cost scenario) might see battery pack manufacturing costs fall to 220 $/kWh in 2020 and 94 $/kWh (2015 CAD) by 2025 based on the expectations in Curry (2017),[29] then with further decline thereafter (e.g. another 10% by 2030) (Table 19).

Table 19: Battery pack manufacturing cost assumptions (2015 CAD/kWh)

	2015	2020	2025	2030
Reference	$351	$221	$192	$163
lower cost	$351	$223	$94	$84

- Vehicle retail prices include a markup from the manufacturing price. UBS (2017)[30] notes that a typical markup from manufacturing costs to dealership cost would allow the automaker to earn a 5% margin on direct manufacturing costs as well as indirect costs (research and development, sales and administration, amortization of manufacturing capital expenditures). The markup from the dealership cost to the retail price is typically another 15%. Altogether, the retail price is roughly 40% higher than direct manufacturing costs for light-duty vehicles. However, UBS (2017) finds that PEVs are likely currently selling at a lower markup (roughly 30%) but expects that markup to rise to 40% by around 2025. Therefore, although PEVs may become less costly to produce, some of that savings will accrue to the automaker through a larger markup. Therefore, for PEVs, we assume a 25% retail markup in 2015 and 2020, rising to 30% in 2025 and 40% in 2030. Conventional vehicles have a 40% markup on their manufacturing costs to retail price for all years in the analysis.

- The electric vehicle archetypes used in gTech are 320 km range battery electric vehicle (BEV) and a 64 km electric range plug-in hybrid electric vehicle (PHEV). Costs of a BEV-160 are shown in the figure below for further context.

Figure 27 shows vehicle purchase prices based on the above assumptions over time and by cost component. Figure 27 (i) shows the retail price range for each vehicle archetype for a sedan/mid-size car. The upper edge of each area is the retail price that corresponds with the gTech reference assumption, while the lower edge corresponds to the lower cost PEV assumption. Independent of battery costs, conventional vehicle costs rise due to drivetrain efficiency improvements and vehicle light-weighting (the trend shown is a composite several separate archetypes in gTech).

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

[30] UBS (2017). UBS Evidence Lab Electric Car Teardown – Disruption Ahead? UBS Evidence Lab, Global Research.

Meanwhile PEV costs fall, largely driven by battery manufacturing cost reductions. Lower-range BEV do not reach retail price parity with the conventional vehicle when using the reference assumption. However, price parity would occur by 2025 with the lowest cost assumption. The larger battery cost of the BEV-320 means that its price is higher than that of a conventional vehicle, regardless of the battery cost assumption. The PHEV price declines, also mainly as a function of battery cost reductions, but since this drivetrain maintains all CV components as well as all PEV components, the price ultimately remains highest in all scenarios by 2030.

Figure 27 (ii) shows the reference scenario vehicle prices broken by component:

- Currently PEV components (e.g. battery management systems, an electric motor and additional electrical components) offset the cost savings of not having CV components (e.g. engine, transmission, fuel or exhaust system)
- Some cost reductions on PEVs are offset by a larger markup between manufacturing cost and retail price (markup is constant in $ terms, due to the assumption of rising % markup)
- Battery costs become a relatively small component of PEV price by 2030. From 2020 to 2030 with the reference battery cost assumption (conservative), the price premium of the BEV-320 declines from $11,700 to $5,900. The price premium of the PHEV-64 declines from $10,200 to $7,000 over that same period.

Figure 27: Vehicle Retail Prices for Sedan Car Archetype (2015 CAD), *i* Ranges of Prices from 2015 to 2030 (Areas bounded by the reference and lower battery price assumptions) and *ii* Reference Scenario Prices by Component in 2020 and 2030

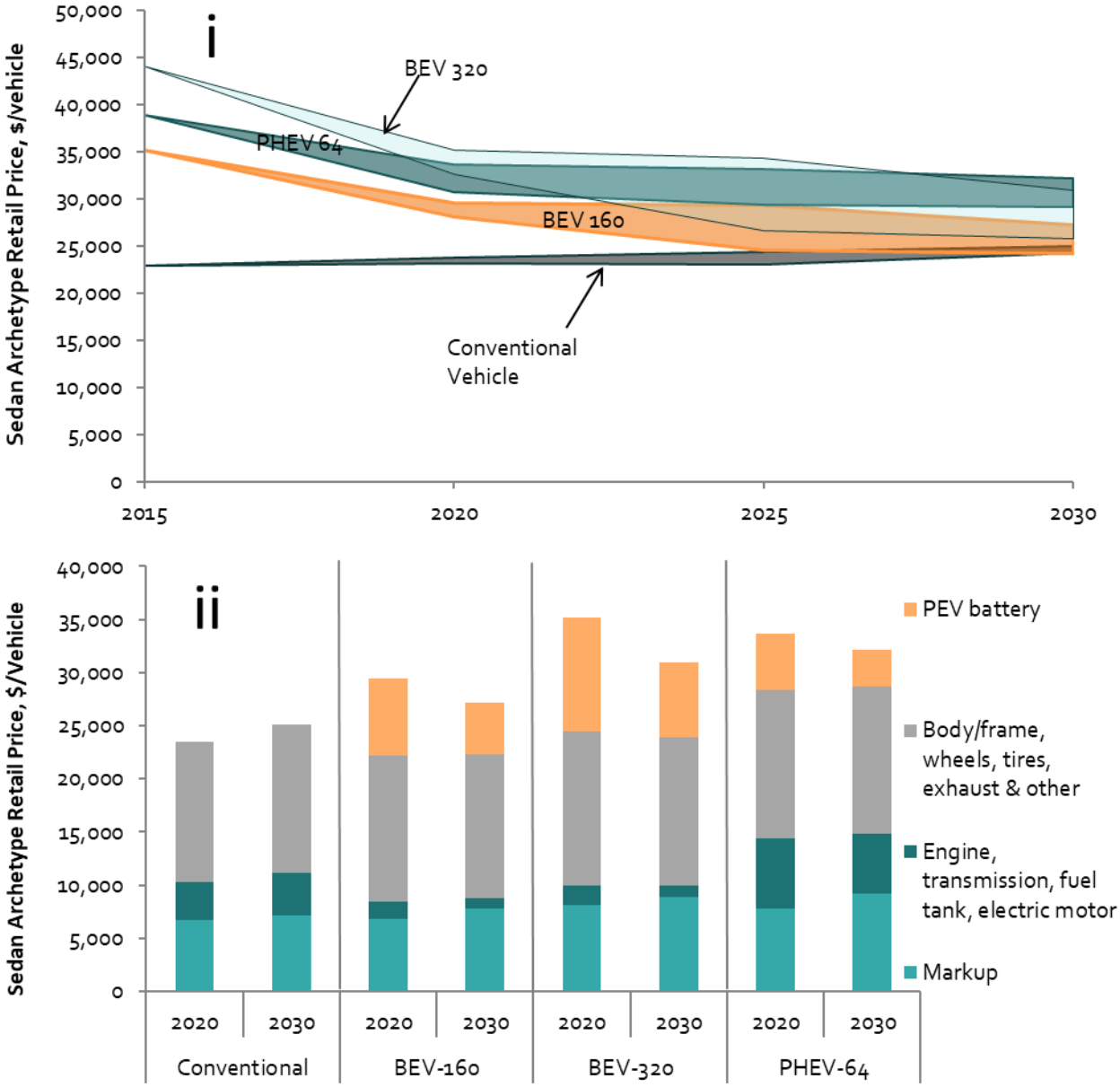


Table 20 shows the light-duty vehicle archetype energy intensity assumptions used in the model, also based on Moawad at al. (2016).[31] The values for the PHEV are shown

[31] Moawad, Ayman; Kim, Namdoo; Shidore, Neeraj; Rousseau, Aymeric (2016). Assessment of Vehicle Sizing, Energy Consumption, and Cost through Large-Scale Simulation of Advanced Vehicle Technologies, Argonne national Laboratory, Energy Systems Division

as an average of electric and gasoline powered kilometers. Energy intensity values are an average for all light-duty vehicle classes (e.g. compact vs. SUV) and correspond most closely to a larger car.

Table 20: Vehicle archetype energy intensity assumption, shown in GJ/1000vkm and natural units (L/100km and kWh/km)

	GJ gasoline /1000 vkm	GJ electricity /1000 vkm	L gasoline /100km	kWh electricity/km
Existing conventional vehicle	3.3		9.4	
New conventional vehicle	3.1		8.8	
Efficient conventional vehicle	2.3		6.7	
Hybrid	1.5		4.3	
PHEV, 60km	0.6	0.4	1.8	0.11
EV, 320 km		0.6		0.18

Plug-in electric buses

We define electric buses as vehicles propelled by electric motors primarily supplied by rechargeable batteries. This excludes trolley buses that are permanently connected to overhead cables.

E-buses have recently gained interest as cities look for ways to decrease their greenhouse gas emissions and reduce their local air pollution. It is likely the technology will soon be more economical than conventional diesel buses as battery costs continue to drop. Electric buses can currently outperform their diesel counterparts on a total cost of ownership basis. This occurs in medium-sized cities where bus routes average over 140 km/day. The primary barrier to adopting e-buses is their current high upfront costs. These include building the charging infrastructure network and purchasing costs of 20% to 60% more than diesel buses[32].

Electric buses are already a mature commercial technology. Electric buses make up around 13% of the total global municipal bus fleet, with 99% of the estimated 385,000 electric buses on the road these buses operating in China (in 2017). California is leading the adoption of the technology in North America while France has pledged to operate the most electric buses in Europe, 4,500 by 2025.[33]

[32] Bloomberg New Energy Finance. (2018). *Electric Buses in Cities: Driving Towards Cleaner Air and Lower CO_2*. Available from: www.about.bnef.com

[33] Ibid.

The long recharge time of electric buses present a challenge to operators. Charging options vary from the less costly "slow" plug-in overnight charging to the convenient wireless super-fast charging. These charging strategies are designed to meet the specific needs of each operator[34].

Most e-buses use different variants of lithium-ion battery technology to deliver a driving range between 100 and 400 km per charge. The Bloomberg New Energy Finance (BNEF) report on electric buses lists techno-economic information for three electric bus archetypes: a 110-kWh bus with a 90 km range, a 250-kWh bus with a 200 km range, and a 350-kWh bus with a 280 km range.[35]

We chose to model the 250-kWh archetype since it already outperforms diesel buses on a total cost of ownership basis and features a long enough range to meet most cities' demands. The cost of ownership is broken down into capital, operation and maintenance, carbon, and energy costs.

The capital costs of electric buses are further broken down into the bus's vehicle components cost, battery cost, and recharging infrastructure cost. We apply a 25% markup to the declining battery pack manufacturing cost discussed in the previous section "Updated assumptions for electric light-duty vehicles". The reference (conservative) assumption is that battery pack manufacturing costs fall from 320 $/kWh in 2015 to 200 $/kWh in 2020 and 147 $/kWh by 2030 (2010 CAD). The corresponding battery capital cost (including markup) is $175,000 per vehicle in 2015, falling to 50,000 by 2030. The vehicle cost component is $484,000 (Table 21). The total capital cost of an electric bus drops from $672,000 in 2015 to $547,000, almost reaching parity with diesel buses. The cost of a fast charging pantograph is included in the capital cost. We assume that each bus incurs 1/20th of the recharging system as capital cost. Our model assumes maintenance and operating costs to be $30,100 per year for electric buses and $40,150 for diesel as per the BNEF report. Finally, we use NRCan's assumption of 12.2 passengers per bus to find an electricity consumption of 0.37 GJ per thousand passenger kilometres travelled.

[34] Ibid.

[35] Ibid.

Table 21: Modelling Assumptions,[36] costs in 2010 CAD

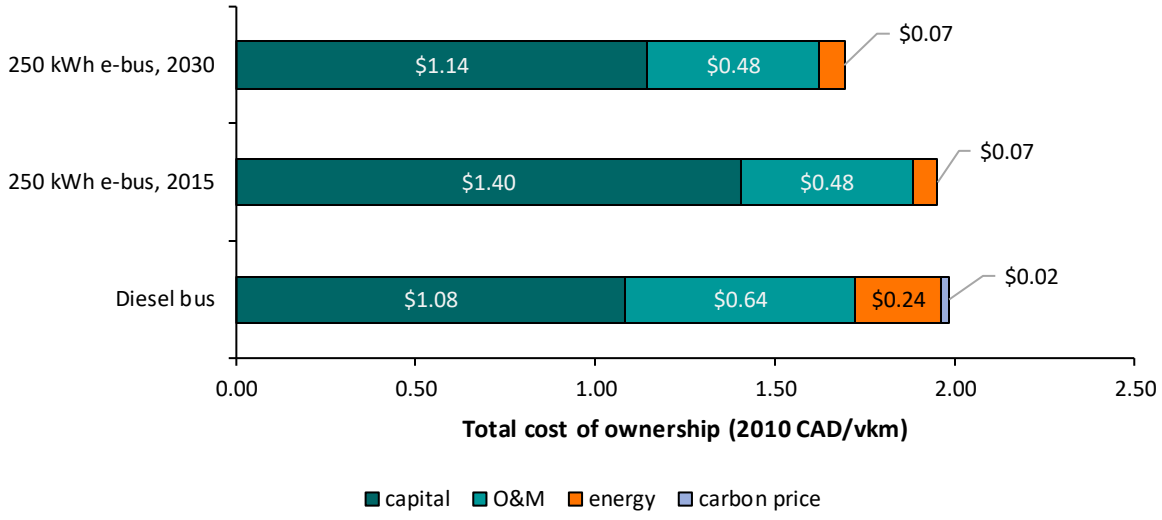
	EV 2015	EV 2030	Diesel
Capital cost without battery	*483,500*	*483,500*	*518,500*
Battery capital cost (with markup)	*174,700*	*50,200*	*0*
Other charging capital cost	*13,200*	*13,200*	*0*
Total capital cost	*671,400*	*547,000*	*518,500*
Operation & maintenance	*30,100*	*30,100*	*40,200*
MJ/vkm	2.4	2.4	11.2
MJ/pkm (avg. 12.2 passengers/km)	0.19	0.19	0.92

Figure 28 compares the model's cost assumptions for diesel and electric buses today and in the future. Costs are shows as levelized annual costs per person km travelled, assuming:

- 2015 and 2030 purchase costs with the reference (conservative) battery cost assumption
- $0.11/kWh electricity price, $0.90/L diesel price (excluding carbon tax), and $27.2 carbon price. All values in 2010 CAD.
- A 10% discount rate, 15-year lifetime, 62,000 kms/year travelled and 12.2 passengers.

[36] All costs shown in 2010 CAD. Assumed 2% inflation. Used a 1.271 USD to CAD exchange rate for 2018 values featured in BNEF report.

Figure 28: Comparison of total cost of ownership for electric and diesel buses[37]



Plug-in electric heavy-duty trucks

Heavy-duty vehicles (including what is often called medium-duty vehicles) could electrify just like passenger transportation. The technology has a promising application in the sector with ownership costs expected to outperform conventional trucks within the next few years.

Current technologies include plug-in electric trucks with fast charging terminals, or electric trucks using overhead catenary or in-road chargers. Catenary and in-road charging trucks have smaller batteries than plug-in electric trucks that can recharge while on the road via overhead pantographs or wireless induction charging that is installed over large portions of typical routes.[38] Consequently, these vehicles only need a short range to carry them between charging networks (e.g. 80km). Plug-in electric trucks are likely to be charged via high-power charging at pick-up and drop-off points[39]. Given that these PEVs are only just being commercialized, it is too early to know if on-road charging will be necessary to drive the adoption of electric trucks, but Tesla has promised an 800-km range from its battery electric semi-trucks. The company also

[37] Assumed 2015 and 2030 purchase costs, $0.11/kWh electricity price, $0.90/L diesel price (excluding carbon tax), and $27.2/t$CO_2$e carbon price. Assumed 10% discount rate, 15-year lifetime, 62,000 kms/year travelled and 12.2 passengers. All values in 2010 CAD.

[38] International Council on Clean Transportation. (2017). *Transitioning to zero-emission heavy-duty freight vehicles*. Available from: www.icct.org

[39] Tesla. (2018). *Tesla Semi*. Available from: www.tesla.com

expects that its trucks will be 17% less expensive to own once they are available in 2019.[40]

The International Council on Clean Transportation (ICCT) counted 19 medium-duty plug-in electric, 18 heavy-duty plug-in electric, and 11 on-road electric truck demonstration projects as of 2017. These projects are mostly being conducted in the United States and Europe[41]. We count over 620 electric trucks that have been deployed in these demonstration projects. The technology is at the very early stages of adoption (Canada's medium and heavy-duty truck fleet alone counts over 150,000 units) but there seems to be growing interest as shown with the 2,000+ pre-orders made for the Tesla Semi in the first quarter of 2018[42].

The model includes a PEV heavy-duty vehicle based on a long-haul battery electric semi similar to what Tesla has proposed, with an 800 kWh battery, good for 600 to 700 km of travel. Vehicles with in-road or overhead charging may offer a lower lifecycle cost, but there is the complication of whether the charging network is ever-built. The cost of operating a diesel truck is broken down into capital, operation and maintenance, carbon price and energy costs. The capital cost is divided into the vehicle components, battery, and charging infrastructure costs. The ICCT report provides a breakdown of the vehicle component costs to which we add our own battery cost assumptions discussed in "Updated assumptions for electric light-duty vehicles". The reference (most-conservative) assumption is that battery pack manufacturing costs fall from 320 $/kWh in 2015 to 200 $/kWh in 2020 and 147 $/kWh by 2030 (2010 CAD). The battery cost component also includes a 25% markup from manufacturing cost to vehicle cost. Charging infrastructure costs were assumed to be the same as for electric buses with 1/20th of the cost incurred by each truck. Capital costs drop from $634,500 in 2015 to $266,600 in 2030[43]. Note that our costs are much higher than Tesla's expected $120,000 to $185,000 (2018 USD) purchase cost in 2019. Operating costs are based on the ICCT's report showing that electric trucks are 17% less expensive to operate and maintain than diesel trucks. Table 22 shows

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[40] Ibid.

[41] International Council on Clean Transportation. (2017). *Transitioning to zero-emission heavy-duty freight vehicles*. Available from: www.icct.org

[42] Car and Driver. (2018). *Is Tesla's Semi on the Back Burner?* Available from: www.carandriver.com

[43] Costs are in 2010 CAD.

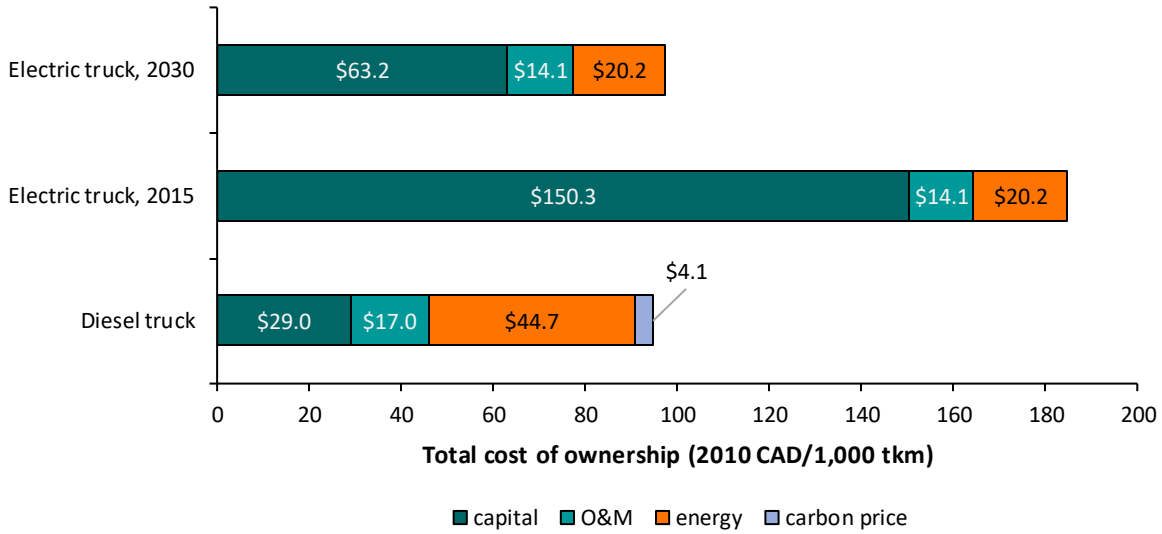
our modelled assumptions for electric and diesel trucks with the reference (conservative) battery pack manufacturing cost assumption

Table 22: Modelled assumptions for heavy-duty vehicles, costs in 2010 CAD

	EV 2015	EV 2030	Diesel
Capital cost without battery	*77,000*	*77,000*	*122,300*
Battery capital cost (with markup)	*544,200*	*176,400*	*0*
Other charging capital cost	*13,200*	*13,200*	*0*
Total capital cost	*634,500*	*266,600*	*122,300*
Operation & maintenance	*7,800*	*7,800*	*9,400*
MJ/vkm	4.1	4.1	12.7
MJ/tkm (avg. 6.1 tonne payload)	0.67	0.67	2.08

Figure 29 shows how the two technologies compare in 2015 and in 2030 with the reference (conservative) battery pack manufacturing cost assumption.

Figure 29: Total cost of ownership comparison for diesel and electric trucks[44]



Industrial heat pumps

Heat pumps use energy to run a refrigeration cycle which is the compression and expansion of a fluid. This cycle moves energy in the form of heat from a lower-temperature source to a higher-temperature sink. Both thermal energy (e.g. waste

[44] Assumed 2015 and 2030 purchase costs, $0.11/kWh electricity price, $0.90/L diesel price (excluding carbon tax), and $27.2/t$CO_2$e carbon price. Assumed 10% discount rate, 15-year lifetime, 91,000 kms/year travelled with an average payload of 6.1 tonnes, based on NRCAN comprehensive energy use database. All values in 2010 CAD.

heat, heat from combustion) and mechanical energy can drive the refrigeration cycle, where the quantity of energy transferred is typically much larger than the quantity of energy consumed by the heat pump. The focus of this research work is on mechanical heat pumps that use compression to drive the refrigeration cycle, with the compressor typically powered by an electric motor.

Although the most familiar application of heat pumps is for space and water heating in buildings, high capacity heat pumps can also be used in industry to provide heat for industrial processes. Industrial heat pumps can draw heat from several sources with a range of temperatures, from ambient air and water to process cooling water and process waste heat. Industrial heat pumps do not just provide passive heat recovery, but like their applications in buildings they take energy from a source and supply it at a higher temperature to the sink.

Currently, industrial heat pumps are not widely used. Barriers to their adoption include:

- **A lack of knowledge** about industrial heat pump technologies and a lack of attention to heat consumption within industrial facilities.
- **The high upfront costs** and long-payback periods. While heat pumps may reduce energy costs, their initial investment cost is higher than for a fossil fuel-fired boiler or heater. At current energy prices and with low (or no) cost for carbon emissions, industrial heat pumps are often not cost-competitive with gas-fired heat.
- **The limits on their supply temperature**.[45] Commercially available industrial heat pumps generally only provide heat at temperatures up to 100 °C, though new technologies could raise this maximum to 140 °C.[46]

Within the limits of their supply temperature, industrial heat pumps may be used for a range of end-uses that include drying, cooking, distillation, washing, and pre-heating. Case studies from Canada, Austria, Germany, France, and Denmark provide 42 examples of industrial mechanical heat-pumps used in a variety of manufacturing sectors (Table 23).[47] Each application is characterized by its coefficient of

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[45] International Energy Agency Heat Pump Centre (2014), *Application of Industrial Heat Pumps, Part 1 Final Report*

[46] Wolf, S., Lambauer, J., Blesl, M., Fahl, U., Voß A. (2002).*Industrial Heat Pumps in Germany: Potentials, Technological Development and Market Barrier,* European Council for an Energy Efficient Economy, Summer Study on Energy Efficiency in Industry

[47] International Energy Agency Heat Pump Centre (2014), *Application of Industrial Heat Pumps, Part 2 Final Report*

performance COP, which is a measure of how much heat is provided to the sink divided by the amount of energy used to move that heat from the source. The case studies are also characterized by their sink and source (i.e. supply) temperatures.

The COP depends the design of the heat pump and the on source and sink temperatures, with the difference in temperature know as the "lift".[48] The case studies provide examples that are currently economically viable, and they tend to have high COPs associated with smaller lifts and lower supply temperatures. Wider application of industrial heat pumps should see them used with larger lifts and higher supply temperatures (e.g. supply at 90-100 °C, with a lift of 50-70 °C). These conditions would result in lower COPs ranging from 2 to 3.[49] For example, commercially available heat pumps for lumber drying use ambient air to heat lumber kilns to temperatures as hot as 116 °C. These systems use 40-60% less energy than a direct or steam heated kiln.[50] If the conventional system is 85% energy efficient, this energy savings implies a COP between 1.4 and 2.2.

Table 23: Summary of industrial heat-pump case-studies

Sector	Number of examples	Range of COPs	Range of source temp. (ºC)	Range of sink (i.e. supply) temp. (ºC)
Food & beverage	20	3.4 to 10.7	-10 to 38	55 to 90
Other manufacturing*	14	3.5 to 5.6	22 to 43	50 to 87
Chemical manufacturing	3	3.7 to 5.0	18 to 35	45 to 60
Forest products	2	3 to 4	45	55 to105
Metal manufacturing	2	4.3	36	70
Pulp and paper	1	5.0	40	68

*Other manufacturing includes automotive, mechanical, metal processing, textiles

The archetype of industrial heat pumps in gTech provides low-temperature heat for industry, based on a closed-cycle mechanical compression using electricity to drive the refrigeration cycle. The capital cost and COP of this archetype depend on the assumed temperature lift and supply temperature: larger lifts and higher supply temperatures

[48] Ommen, T., Jensen, J.K., Markussen, W.B., Reinhold, L., Elmegaard, B. (2015) *Technical and Economic Working Domains of Industrial Heat Pumps: Part 1 - Single Stage Vapour Compression Heat Pump*, International Journal of Refrigeration, 55, 168-182

[49] Ibid.

[50] Nyle Systems, Lumber Drying Systems: Very High Temperature Dehumidification Systems, www.nyle.com/lumber-drying-systems/lumber-kiln-drying/dehumidifcation-kilns/vht-dh-systems/

will have higher capital costs and lower COP.[51] The archetype is based on a system that would apply across the broadest range of end-uses, with high supply temperatures (90-100 °C) and lift (70 °C). Under these conditions the COP is 2.5 and the capital cost is 840 $/kW (2010 CAD),[52] roughly three and a half times higher than for a natural gas combustion boiler (Table 24).

Table 24: gTech inputs for an industrial heat pump compared to a natural-gas boiler

Technology	Capital Cost (2010 CAD/kW)	Electricity, $GJ/GJ_{thermal}$	Natural gas, $GJ/GJ_{thermal}$
Industrial heat pump	838	0.4	-
Efficient gas boiler	233	-	1.1

We assume the industrial heat pump technology in gTech can supply heat to a maximum of 100 °C. Table 25 summarizes the share of heat demand that is 100 °C or less by sector. For most sectors, this share is based on a study of German industries that characterized heat consumption by sector and temperature.[53] Our assumption is that the temperature profile of heat demand by sector is the same in Canada (e.g. if 45% of the heat required for food and beverage manufacturing is at or below 100 °C in Germany, we assume that this fraction is representative for Canada). The fraction of heat below 100 °C in the forest products manufacturing sector (e.g. lumber and structural panels) is based on the fraction of thermal energy used for product drying estimated by Natural Resources Canada.[54]

[51] Ommen, T., Jensen, J.K., Markussen, W.B., Reinhold, L., Elmegaard, B. (2015) *Technical and Economic Working Domains of Industrial Heat Pumps: Part 1 - Single Stage Vapour Compression Heat Pump*, International Journal of Refrigeration, 55, 168-182

[52] Ibid.

[53] German Energy Agency (DENA) (2016), *Process Heat in Industry and Commerce: Technology Solutions for Waste Heat Utilisation and Renewable Provision*

[54] Natural Resources Canada (2009), *Status of Energy Use in the Canadian Wood Products Sector*

Table 25: Modelling assumptions for the fraction of industrial heat demanded at less than or equal to 100 °C, by sector

Sector	% of heat demand <= 100 °C
Food & beverage manufacturing, agriculture processing	45%
Other manufacturing	30%
Chemical and biofuel manufacturing	15%
Forest products	85%
Pulp and paper	20%
Mineral and metal mining	100%

Direct-air carbon capture

The UN recently released a report following up on the pledges made by national government during the 2015 Paris Climate Agreement. It concludes that pledges as of November 2017 cover no more than a third of the emission reductions needed to meet the targets[55]. The world will likely have to resort to carbon sequestration in addition to carbon reduction to avoid catastrophic climate change.

Direct air capture (DAC) is a carbon sequestration solution that directly captures CO_2 from the air. Multiple DAC technologies have emerged with developers claiming carbon abatement costs ranging from $20 to $140 per tonne. There is much uncertainty surrounding these numbers since these emerging companies are unlikely to share their cost assumptions publicly. Experts and academics estimate a more conservative abatement cost ranging from a couple hundred to a thousand dollars per tonne of carbon[56].

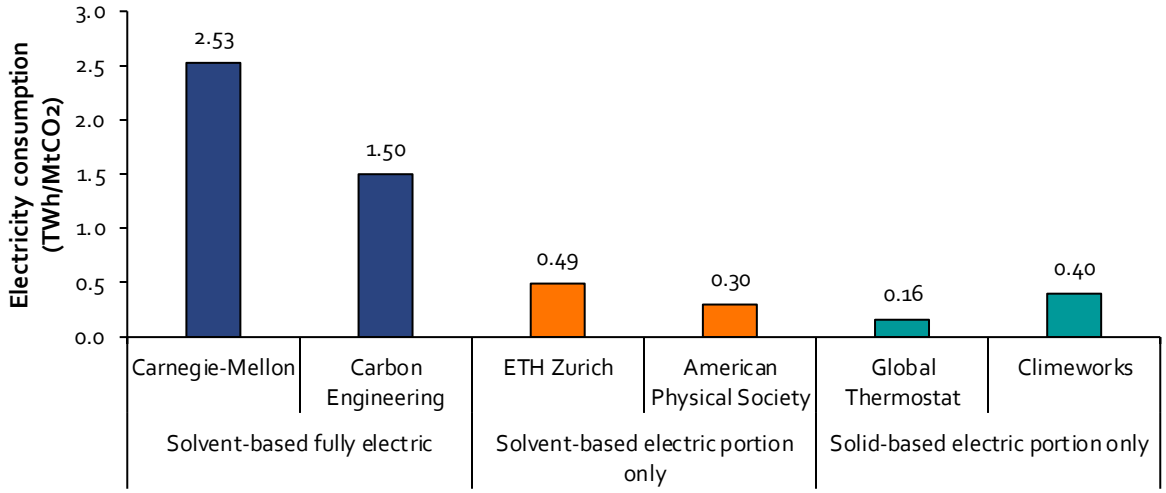
Direct air capture absorbs or adsorbs CO_2 from the air using one of two ways: liquid sorbent or solid adsorbent technology. Typical liquid sorbent applications use alkaline solutions to capture acidic gases such as CO_2. The mix is then heated to separate the CO_2. Solid adsorbents use a strong-base ion exchange resin to capture CO_2 at room temperature that is then separated through heat and humidification. Both technologies use energy for heating, for moving heat, and for moving air. Solid adsorbent technology will also use energy for cooling and drying. Electricity is used to power the movement of heat and air and for cooling. Low-carbon electricity could also be used for heating and drying given that the purpose of direct air capture is to reduce carbon emissions.

[55] UNEP (2017). *The Emissions Gap Report 2017*. United Nations Programme (UNEP), Nairobi. Available from: www.unep.org

[56] Ishimoto et al. (2017). *Putting costs of direct air capture in context*. Available from: www.papers.ssrn.com

The amount of electricity or heat demanded by the technologies varies for different technology developers as shown in Figure 30 below. It is unclear why the range differs so much from one technology to the next since, as mentioned earlier, companies are unlikely to share their proprietary designs. Note that the Carnegie-Mellon and Carbon Engineering numbers show total energy consumption, whereas the other sources only feature the electricity consumption portion of total energy. The figure shows that when only considering electricity consumption for work (and not heat), there is no clear correlation between the electricity consumed and the type of DAC technology, whether it be solvent- or solid-based.

Figure 30: Electricity consumption per $MtCO_2e$ abated using DAC



The use of grid-sourced electricity could be avoided with DAC systems if cogeneration is used on site. Carbon Engineering provides two alternatives for its design: a fully electric system or a cogeneration system producing heat and electricity from natural gas combustion.

We have chosen not to model this technology because of the lack of clarity both on energy consumption and on cost assumptions. The information above does indicate that direct air capture has the potential to become a significant electricity load on grid systems should it be widely adopted. Alternatively, if the technology is powered with gas-fuelled cogeneration, it would not create an additional load but could reduce the need for other GHG abatement, potentially from electrification, thus reducing electricity demand. It would therefore be wise to stay up to date on the development of this technology.

Appendix B: Building sector technology archetype assumptions

Building envelopes

The building envelope technology archetypes for the British Columbia (BC) region of the gTech model were developed in cooperation with RDH Building Science. The archetypes characterize BC's existing building stock and the thermal improvements associated with current and future building codes.

Building envelopes are disaggregated into nine building types, three vintages and three levels of new construction as shown in Table 26 and Table 27. Note that low-rise and high-rise apartment buildings are aggregated. RDH provided the data for these archetypes in three regions of BC (lower mainland, Kamloops and Prince George). These archetypes were aggregated to form a single representative region for use in gTech. Additional modifications to the archetypes were made to ensure that total floor space and demand for space conditioning aligned with Natural Resources Canada's Comprehensive Energy Use Database.

The costs are the portion attributed to the relevant elements of the building envelope and do not represent full construction costs. The costs for existing building envelopes are the cost to perform a comprehensive retrofit of the building envelope as would be required to meet new construction performance targets. RDH's general description of their approach in developing the archetypes is in the Appendix. Additional detail by archetype can be provided upon request.

Table 26: Residential building envelope archetypes

Building type	Archetype	Heating intensity (GJ/m²/yr)	Cooling intensity (GJ/m²/yr)	Cost (2018$/m²)
Single-family detached	pre-1980*	0.3869	0.0061	$540
	post-1980*	0.2688	0.0095	$540
	post-2000*	0.1691	0.0079	$540
	new standard	0.0840	0.0079	$709
	new efficient	0.0773	0.0079	$722
	new near zero	0.0308	0.0079	$797
Attached	pre-1980*	0.3040	0.0081	$421
	post-1980*	0.2112	0.0127	$421
	post-2000*	0.1329	0.0107	$421
	new standard	0.0751	0.0107	$553
	new efficient	0.0729	0.0107	$569
	new near zero	0.0241	0.0107	$618
Apartment	pre-1980*	0.1894	0.0028	$605
	post-1980*	0.1564	0.0028	$605
	post-2000*	0.0880	0.0040	$605
	new standard	0.0880	0.0040	$722
	new efficient	0.0640	0.0040	$737
	new near zero	0.0255	0.0040	$818

* cost for existing archetypes is retrofit costs to new standard efficiency envelope

Table 27: Commercial building envelope archetypes

Building type	Archetype	Heating intensity (GJ/m²/yr)	Cooling intensity (GJ/m²/yr)	Cost (2018$/m²)
Food retail	pre-1980*	1.0758	0.2548	$784
	post-1980*	1.0397	0.2594	$784
	post-2000*	0.1707	0.3653	$784
	new standard	0.1707	0.5461	$844
	new efficient	0.1004	0.4285	$865
	new near zero	0.0901	0.3677	$908
Office	pre-1980*	0.3491	0.1450	$493
	post-1980*	0.2577	0.1628	$493
	post-2000*	0.2048	0.1672	$493
	new standard	0.2048	0.0701	$715
	new efficient	0.1505	0.0550	$726
	new near zero	0.0883	0.0520	$759
Warehouse	pre-1980*	0.4481	0.0801	$270
	post-1980*	0.4049	0.0801	$270
	post-2000*	0.2206	0.0638	$270
	new standard	0.2206	0.0496	$391
	new efficient	0.1621	0.0339	$395
	new near zero	0.0952	0.0305	$410
Retail	pre-1980*	0.6949	0.0988	$498
	post-1980*	0.6392	0.1052	$498
	post-2000*	0.2766	0.1092	$498
	new standard	0.1707	0.0634	$537
	new efficient	0.1004	0.0497	$552
	new near zero	0.0901	0.0427	$587
Schools	pre-1980*	0.3606	0.0881	$353
	post-1980*	0.2877	0.0802	$353
	post-2000*	0.2325	0.0821	$353
	new standard	0.4430	0.1131	$641
	new efficient	0.1867	0.0541	$660
	new near zero	0.0876	0.0485	$705

Building type	Archetype	Heating intensity (GJ/m²/yr)	Cooling intensity (GJ/m²/yr)	Cost (2018$/m²)
Other	pre-1980*	0.2629	0.0581	$483
	post-1980*	0.2212	0.0611	$483
	post-2000*	0.1376	0.0660	$483
	new standard	0.1376	0.0581	$634
	new efficient	0.0771	0.0428	$645
	new near zero	0.0489	0.0378	$678

* cost for existing archetypes is retrofit costs to new standard efficiency envelope

Building floor area by type

The share of building floor area by building type (e.g. apartment, single family detached home) is a result of gTech rather than an input. Nonetheless, this result can be calibrated to expectations, such as an increasing share of residential building floor area in higher density building types (Table 28, showing the trend to 2030). The fraction of commercial and institutional floor area by building type is constant over time as gTech does not disaggregate the services sector into subsectors and all segments grow at the same rate (Table 29, showing the trend to 2030).

Table 28: Residential building area by building type (%)

	2015	2020	2025	2030
Apartment	20%	21%	22%	23%
Attached homes	11%	12%	12%	13%
Detached homes	69%	67%	66%	64%

Table 29: Commercial and institutional building area by building type (%)

	2015	2020	2025	2030
Food Service	5.5%	5.5%	5.5%	5.5%
Offices	38.1%	38.1%	38.1%	38.1%
Other	27.7%	27.7%	27.7%	27.7%
Retail	11.5%	11.5%	11.5%	11.5%
Schools and Education	12.4%	12.4%	12.4%	12.4%

Mechanical systems

Space and water heating archetypes are based on data from the US Energy Information Administration[57] and National Renewable Energy Laboratory[58]. These archetypes are shown in Table 30, Table 31 and Table 32. Costs for the residential technologies are given as costs for a unit sized for an individual household. The output attribute of each archetype represents typical utilization of each technology: the quantity of heating provided, or the volume of hot water provided (with a 46.5 °C temperature lift). Space cooling is a relatively small energy end-use in British Columbia and the space cooling technology archetypes are not currently included in this report.

Table 30: Residential space heating technology archetypes

End-use	Archetype	Capital cost (2018$)	Energy Efficiency (GJ_{out}/GJ_{in})	Output (GJ/yr)
Space heating*	Standard efficiency gas furnace	$4,746	90%	36.2
	Condensing gas furnace	$5,284	98%	36.2
	Electric baseboard	$3,040	100%	36.2
	Standard efficiency ASHP	$5,702	2.4	36.2
	High efficiency ASHP	$7,137	2.6	36.2
	High efficiency NGHP	$18,345	1.3	36.2

* equipment life is assumed to be 20 years for space heating

[57] Energy Information Administration. 2016. Analysis & Projections: Updated Buildings Sector Appliance and Equipment Costs and Efficiency. Available from: https://www.eia.gov/analysis/studies/buildings/equipcosts/

[58] National Renewable Energy Laboratory. 2018. National Residential Efficiency Measures Database. Accessed from: https://remdb.nrel.gov/

Table 31: Residential water heating technology archetypes

End-use	Archetype	Capital cost (2018$)	Energy Efficiency (GJ_{out}/GJ_{in})	Output (m^3/yr)
Water heating*	Standard efficiency gas water heater with tank	$705	59%	82.0
	High efficiency gas water heater with tank	$819	67%	82.0
	Standard efficiency electric water heater with tank	$671	92%	82.0
	High efficiency electric water heater with tank	$739	95%	82.0
	Standard efficiency ASHP water heater	$2,274	2.0	82.0
	Standard efficiency tankless gas water heater	$1,706	82%	82.0
	High efficiency tankless gas water heater	$2,161	96%	82.0

* equipment life is assumed to be 9 years for water heating

Table 32: Commercial space and water heating technology archetypes

End-use	Archetype	Capital cost (2018$/$m^2$)	Energy Efficiency (GJ_{out}/GJ_{in})	Output (GJ/m^2/yr)
Space heating*	Standard efficiency gas boiler	$10.06	80%	0.35
	High efficiency gas boiler	$10.67	85%	0.35
	Condensing gas boiler	$11.29	98%	0.35
	Standard efficiency electric boiler	$5.46	98%	0.35
	High efficiency GSHP	$41.91	5.0	0.35
	High efficiency ASHP	$14.09	3.2	0.35
Water heating*	Standard efficiency gas water heater with tank	$1.47	80%	0.10
	Condensing gas water heater with tank	$1.73	99%	0.10
	Standard efficiency electric water heater with tank	$1.61	98%	0.10
	Standard efficiency ASHP water heater	$4.90	2.0	0.10

* equipment life is assumed to be 25 years for space heating and 10 years for water heating

Major appliances

Table 33 and Table 34 show the technology assumptions for fridges and freezers. The technologies are based on data from the National Renewable Energy Laboratory.[59] The archetype of "existing" technology stock is calibrated to the NRCAN Comprehensive Energy Use Database (CEUD).[60] The energy consumption of electric and gas ranges are also calibrated to NRCAN's estimate for total stock and new stock in the CEUD (Table 35). The energy consumption of the induction range is based on a doubling of the cooktop energy efficiency, but with the cooktop only accounting for 35% of a range's annual energy consumption (remainder from oven).

The energy intensity of the existing stock of dishwashers and clothes washers is calibrated to the NRCAN CEUD (Table 36, Table 37). New stock represents units that are compliant with regulations. New efficient archetypes are based on units that represent the most efficient models available. Note that most energy related to clothes washing is consumed by the clothes dryers, with the intensity of drying related to the amount of water removed in the clothes washer. gTech currently does not represent how a more efficient clothes washer also reduces clothes drying energy consumption. The energy intensity of drying is calibrated to the NRCAN CEUD and clothes drying energy consumption is roughly proportional to the number of households in a forecast.

Note that gTech also includes energy (primarily electricity) consumption for other appliances and electronics. The quantity of electricity consumed is roughly proportional to the number of households in a forecast.

Table 33: Residential refrigerator technology archetypes

End-use	Archetype	Capital cost (2018$)	Energy Consumption (GJ/yr)
Refrigeration*	Existing	$922	2.00
	Standard Efficiency	$922	1.80
	Medium Efficiency	$1,090	1.43
	High Efficiency	$1,247	1.35

* equipment life is assumed to be 17 years for refrigeration

[59] NREL. National Residential Efficiency Measures Database. Accessed on October 18, 2017 from: https://www.nrel.gov/ap/retrofits/about.cfm

[60] Natural Resources Canada, Comprehensive Energy Use Database, http://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/menus/trends/comprehensive_tables/list.cfm

Table 34: Residential freezer technology archetypes

End-use	Archetype	Capital cost (2018$)	Energy Consumption (GJ/yr)
Freezers*	Existing	$519	1.46
	New	$524	1.35
	High Efficiency	$553	1.24

* equipment life is assumed to be 21 years for freezers

Table 35: Cooking range technology archetypes

End-use	Archetype	Capital cost (2018$)	Energy Consumption (GJ/yr)
Ranges*	Electric, high efficiency/induction	$1,300	1.54
	Electric, new	$600	1.88
	Electric, existing	$600	2.39
	Natural gas, existing	$700	4.43
	Natural gas, new	$700	4.41

* equipment life is assumed to be 20 years for ranges

Table 36: Dishwasher technology archetypes

End-use	Archetype	Capital cost (2018$)	Electrical Energy Consumption (GJ/yr)	Hot Water Consumption (m^3/yr)
Dishwashers*	Existing	$746	0.44	4.6
	New efficient, EF58	$756	0.29	3.4
	New most efficient, EF 94	$1,708	0.06	2.8

* equipment life is assumed to be 12 years for dishwashers

Table 37: Clothes washer technology archetypes

End-use	Archetype	Capital cost (2018$)	Electrical Energy Consumption (GJ/yr)	Hot Water Consumption (m^3/yr)
Clothes washers*	Existing	$613	0.32	8.2
	New, compliant with regulation (MEF~39)	$613	0.23	7.4
	New, efficient (MEF~67)	$764	0.07	1.4

* equipment life is assumed to be 12 years for clothes washers

Lighting

Table 38 shows the residential lighting technology archetypes. The archetypes are based on a 60W equivalent (roughly 850 lumens) serving 3.4 m^2 and operating for 652 hours/yr. The capital cost and energy consumption for commercial and institutional lighting is expressed per m^2 of floor area served (Table 39).

Table 38: Residential lighting technology archetypes

	Capital cost per 60W equivalent (2018$)	GJ/yr per 60W equivalent
Incandescent	0.25	0.041
Halogen	1.99	0.030
Compact fluorescent	2.74	0.009
LED	7.53	0.006

Table 39: Commercial and institutional lighting technology archetypes

	Capital cost per m^2 of floor space served (2018$)	GJ/yr m^2 of floor space served
Existing	14	0.15
New	14	0.10
New efficient	21	0.06

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