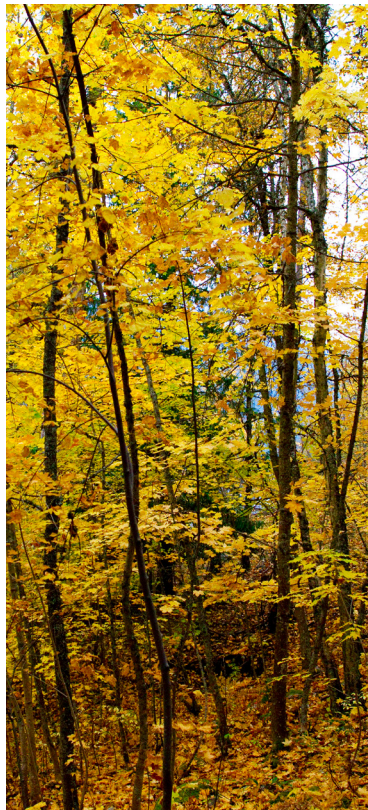




National Energy Board

Office national de l'énergie

AN ENERGY MARKET ASSESSMENT



Canada's Energy Future **2017**

ENERGY SUPPLY AND DEMAND PROJECTIONS TO 2040

Canada

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Letter from the Chair and CEO of the National Energy Board

I am pleased to present the latest edition of the National Energy Board's *Energy Futures* series *Canada's Energy Future 2017: Energy Supply and Demand Projections to 2040* (Energy Futures 2017). This edition marks an impressive milestone – it has been 50 years since the NEB published its first long-term supply and demand outlook in 1967. Energy in Canada has undergone numerous changes over that past half century, including a near tripling of hydroelectric electricity generation, the development of the oil sands, and dramatic improvements in energy efficiency across the entire economy.

The next 50 years will again be defined by continuous change. Canada's transition to a lower carbon future is underway, yet the path and duration of this transition is far from certain. Critically important to guiding this transformation will be an informed, fact-based and credible dialogue among all Canadians.

Energy Futures 2017 is one component of that dialogue, providing Canada's only publically available long-term energy supply and demand outlook that covers all provinces and territories and all energy commodities. Importantly, this report provides a baseline for discussing how Canada's energy future could unfold.

The evolution of climate policies and energy technologies will be an important part of Canada's transition to a lower carbon economy. Energy Futures 2017 explores these factors by introducing two new cases in addition to the Reference Case, our baseline outlook. The Higher Carbon Price Case explores the impact of higher carbon pricing while the Technology Case considers greater adoption of select emerging energy technologies related to both production and consumption.

I found the differences between the three cases particularly insightful. They highlight the importance of both current and future climate policies and technologies in bending the curve of Canada's fossil fuel use trajectory. In the Higher Carbon Price and Technology cases, fossil fuel consumption begins to decline in a meaningful way.

Energy Futures 2017 was not constructed with Canadian GHG emission targets as the ultimate goal and the results should not be interpreted as representing a ceiling on Canada's potential for GHG emission reductions. Rather, the cases illustrate the impact climate policy and technology can have on Canada's energy system.

I would like to thank the numerous technical experts at the NEB who prepare these projections, as well as the key partners with whom the Energy Futures team collaborates, particularly Statistics Canada, Environment and Climate Change Canada and Natural Resources Canada. Their data and expertise are a key component of this work.



C. Peter Watson, P. Eng. FCAE
Chair and CEO

EXECUTIVE SUMMARY

The National Energy Board's (NEB) *Energy Futures* series explores how possible energy futures might unfold for Canadians over the long term. This analysis is not a prediction of what will take place, nor does it aim to achieve certain goals like Canada's climate targets. Rather, Energy Futures employs economic and energy models to make projections based on a certain set of assumptions given past and recent trends related to technology, energy and climate policies, human behaviour, and the structure of the economy.

- *Canada's Energy Future 2017 – Supply and Demand Projections to 2040* (Energy Futures 2017) considers three cases:
 - The Reference Case is based on a current economic outlook, a moderate view of energy prices, and climate and energy policies announced at the time of analysis.
 - The Higher Carbon Price Case considers the impact on the Canadian energy system of higher carbon pricing than in the Reference Case.
 - The Technology Case considers, in addition to higher carbon prices, the impact on the Canadian energy system of greater adoption of select emerging production and consumption energy technologies.

Key Findings

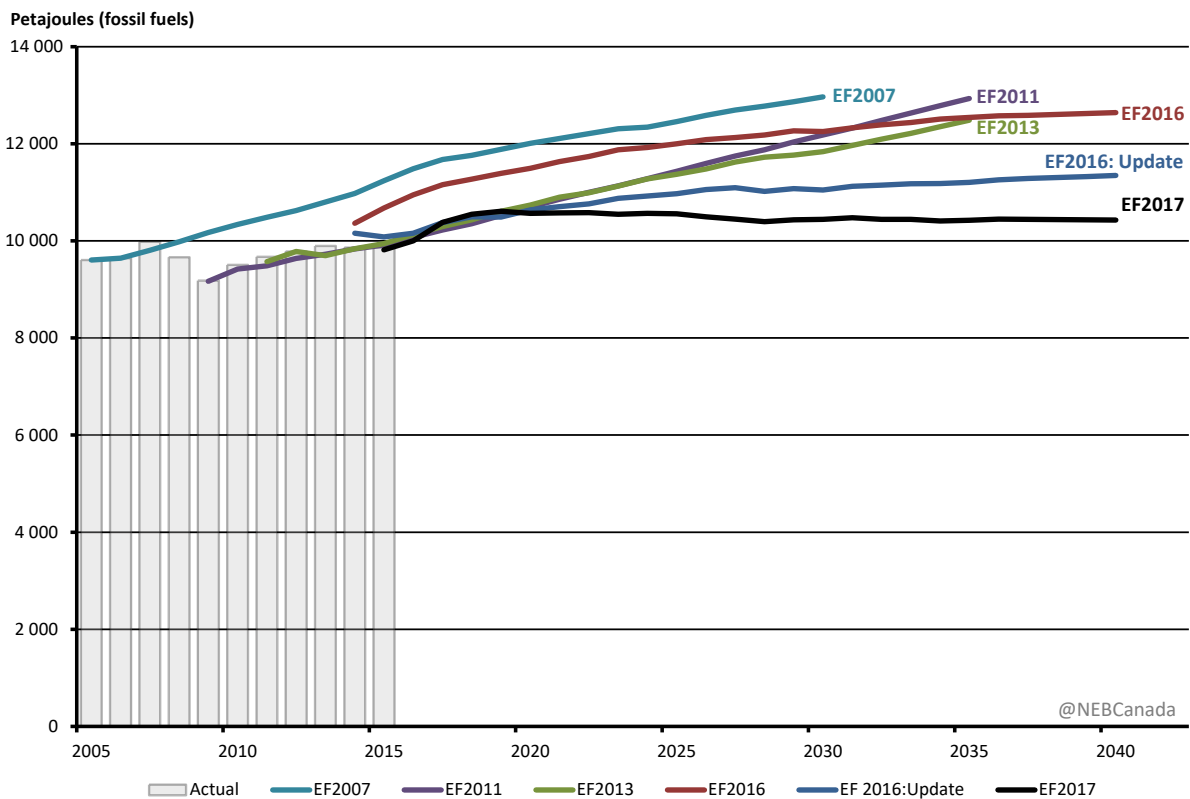
- 1. The Energy Futures 2017 Reference Case is the first Reference Case in the Energy Futures series where fossil fuel consumption peaks within the projection period.**
- 2. Canadian fossil fuel consumption in the Higher Carbon Price Case is 8% lower than in the Reference Case, and 13% lower in the Technology Case by 2040.**
- 3. Renewable capacity grows quickly, with wind capacity doubling and solar more than tripling by 2040 in the Reference Case.**
- 4. Despite different energy outcomes, economic growth is similar in all three scenarios in Energy Futures 2017.**
- 5. Future policies and technology trends, both domestically and globally, will shape Canada's sustainable energy future.**

Key Finding 1: The Energy Futures 2017 Reference Case is the first baseline projection in the *Energy Futures* series* where fossil fuel consumption peaks within the projection period.

Fossil fuel use in Canada peaks early in the Reference Case projection. Improving energy efficiency, somewhat slower economic and population growth projections than in previous outlooks, and climate change policies introduced by various federal and provincial governments underlie this change in trajectory.

FIGURE S.1

Canadian Fossil Fuel Use Projections, Recent Energy Futures Reports, Reference Case

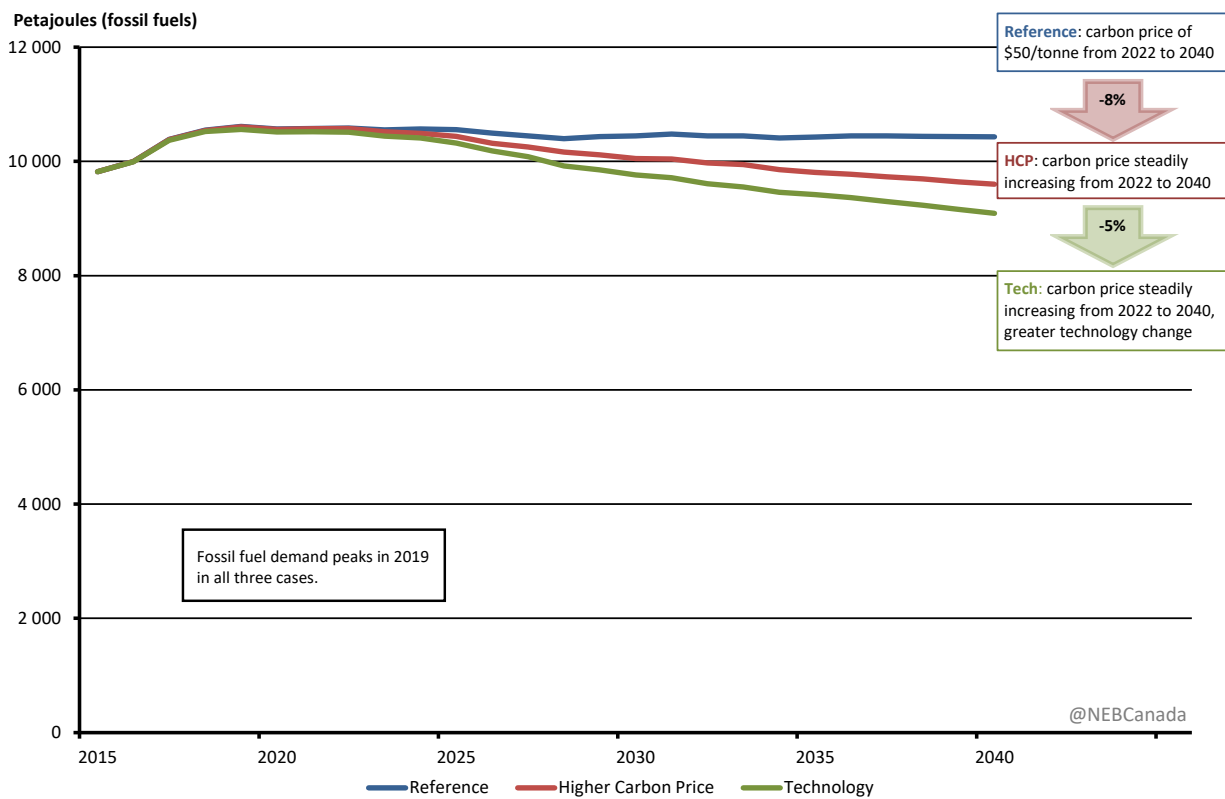


* The series of reports entitled *Energy Futures* commenced in 2007.

Key Finding 2: Canadian fossil fuel consumption in the Higher Carbon Price Case is 8% lower than in the Reference Case, and 13% lower in the Technology Case by 2040.

Climate policies and the pace of technological development will drive future energy use trends. In the Higher Carbon Price Case fossil fuel use is 8% lower compared to the Reference Case as Canadian households and businesses become more energy efficient. In the Technology Case, greater use of emerging energy technologies results in fossil fuel use that is 5% lower than in the Higher Carbon Price Case and 13% below the Reference Case.

FIGURE ES.2
Fossil Fuel Use, All Cases

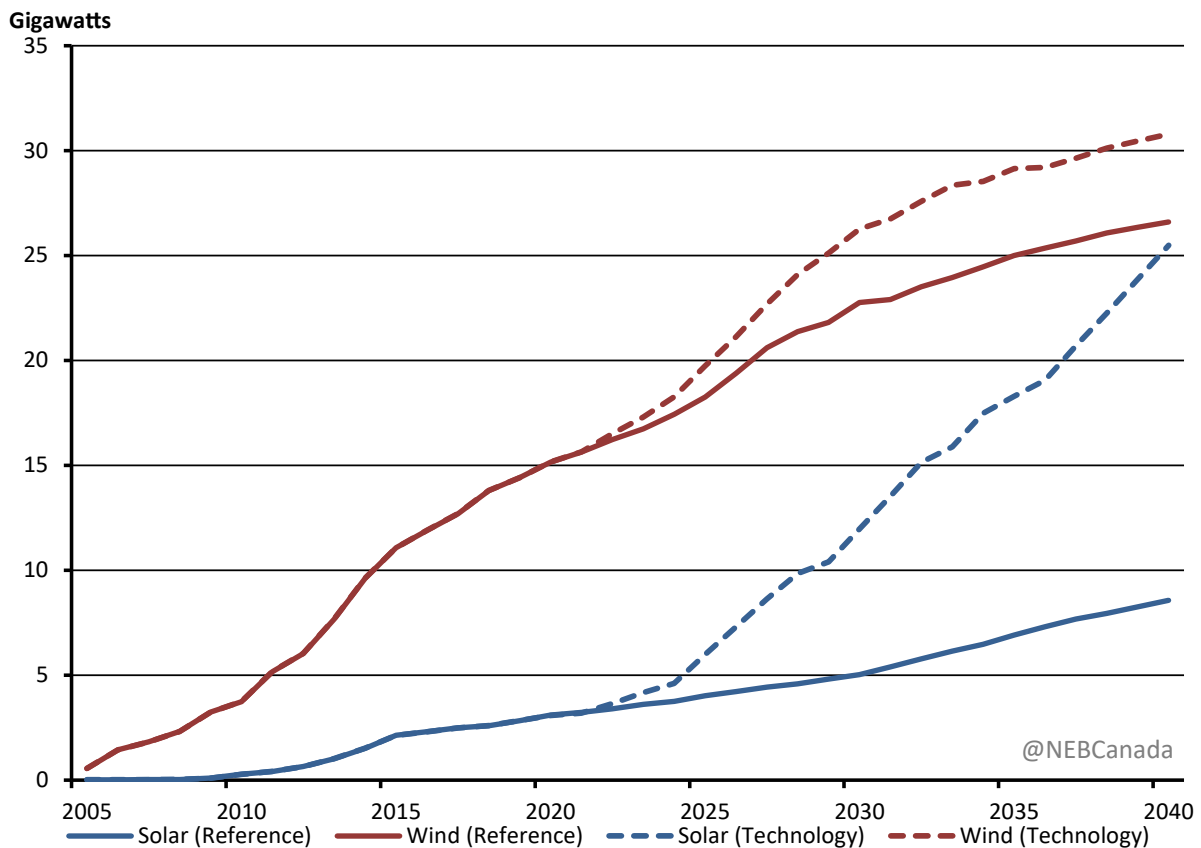


Key Finding 3: Renewable capacity grows quickly, with wind doubling and solar more than tripling by 2040 in the Reference Case.

Canada's already low emitting electricity sector continues to get greener. Solar capacity increases from just over 2 GW in 2015 to over 8 GW in 2040 in the Reference Case. Lower solar costs result in even greater growth in solar in the Technology Case, with capacity reaching 25 GW in 2040. Wind capacity increases from 11 GW in 2016 to over 26 GW by 2040 in the Reference Case, and nearly 31 GW in the Technology Case. In all cases, traditional coal-fired capacity falls considerably and is replaced by a combination of renewables, natural gas and coal equipped with carbon capture and storage technology. By 2040, 82% of generation in Canada is from non-emitting sources in the Reference Case, and 86% in the Technology Case, compared to 80% in 2016.

FIGURE ES.3

Solar and Wind Capacity, Reference and Technology Cases

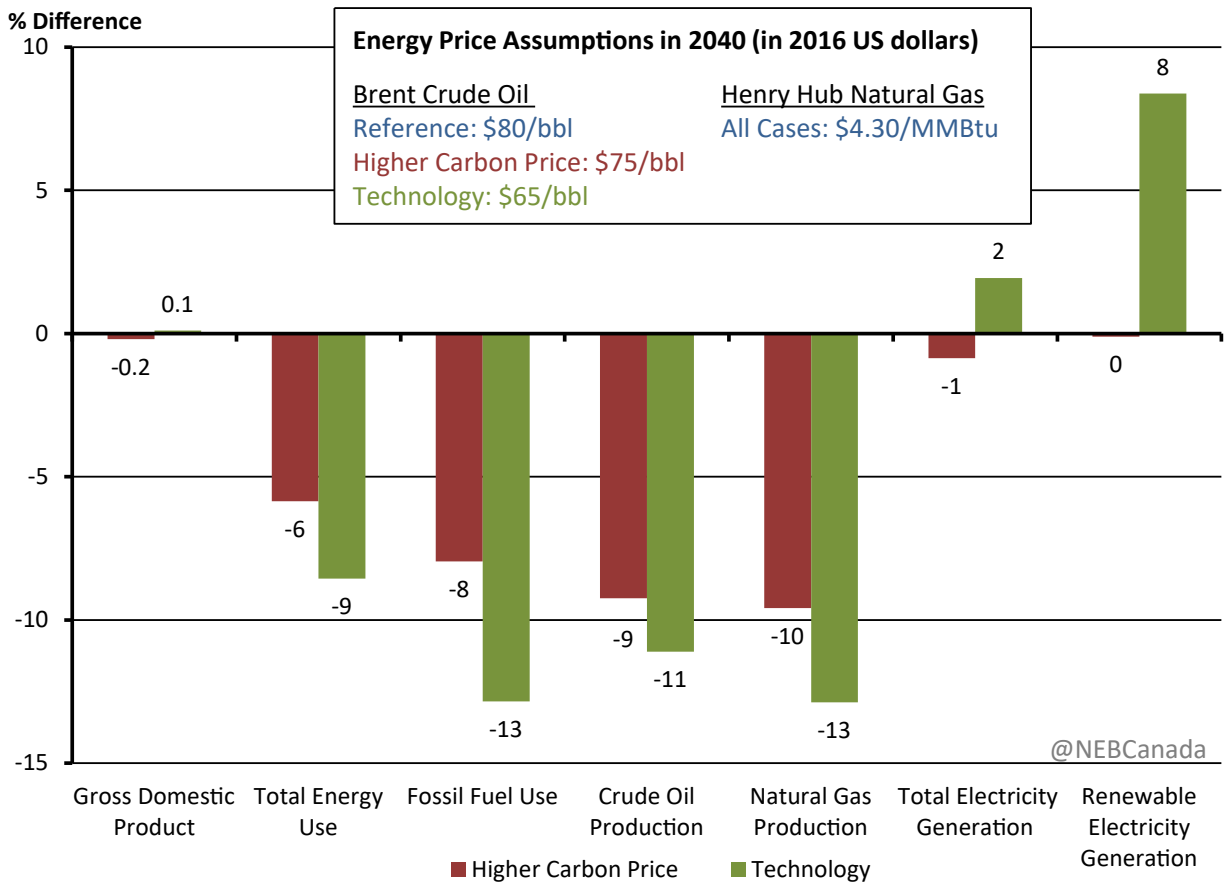


Key Finding 4: Despite different energy outcomes, economic growth is similar in all three scenarios in Energy Futures 2017.

Gross domestic product, a measure of the size of the economy, is 0.2% lower in the Higher Carbon Price Case than in the Reference Case, and 0.1% higher in the Technology Case, in 2040. In a scenario where other nations are also increasing the strength of their climate policies, higher carbon prices reduce fossil fuel consumption and have a limited impact on economic growth.

FIGURE 4

Per cent change in Various Measures compared to the Reference Case by 2040, Higher Carbon Price and Technology Cases

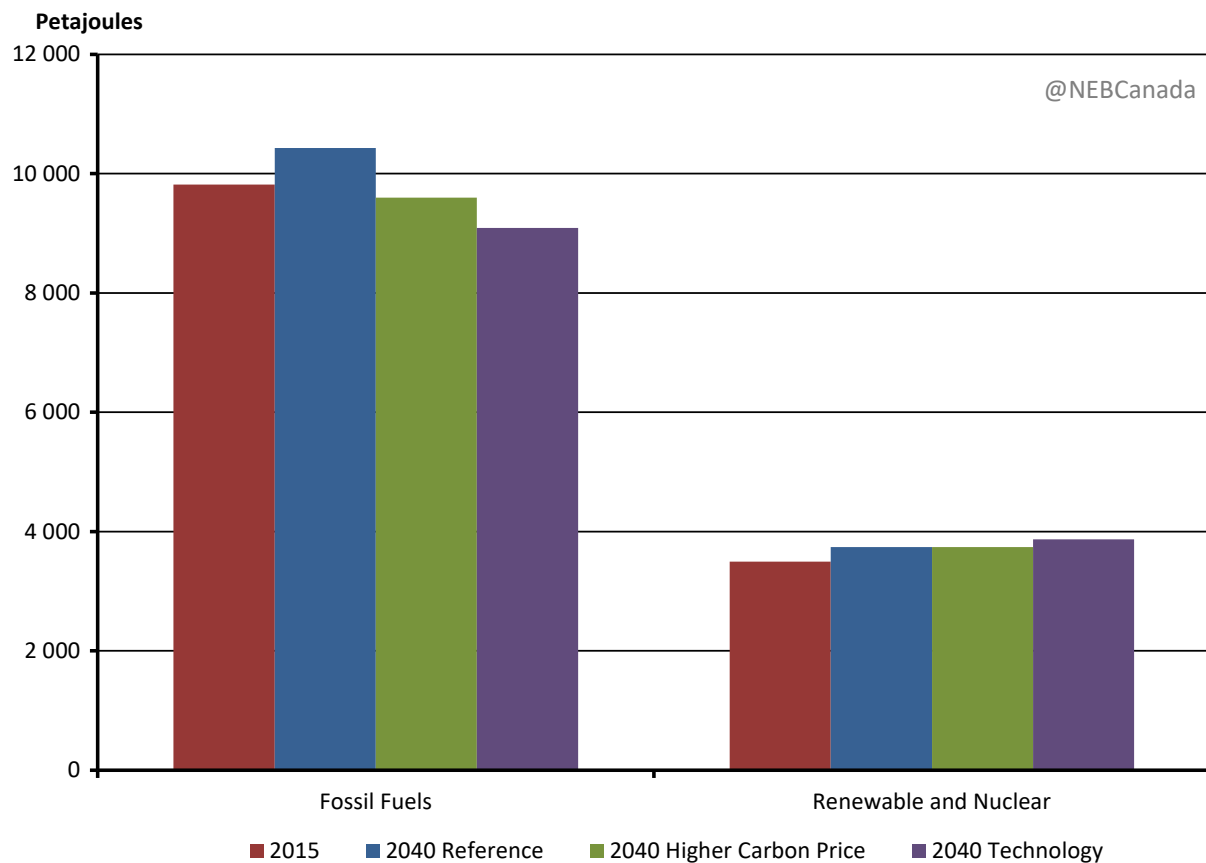


Key Finding 5: Future policies and technology trends, both domestically and globally, will shape Canada's sustainable energy future.

In the Higher Carbon Price and Technology cases, fossil fuel use and GHG emissions in 2040 are less than current levels, while the share of renewable and other non-emitting fuels increases. These cases illustrate the ability of policies and technologies to bend the energy use trajectory. The analysis in Energy Futures 2017 presents projections of future energy demand and supply under various assumptions, and is not a pathway to meet specific climate goals or targets. While the results suggest more action will be needed to meet Canada's GHG emission targets, the cases in Energy Futures 2017 do not represent a ceiling on Canada's potential for GHG emission reductions. Rather, the cases illustrate the impact climate policy and technology can have on Canada's energy system.

FIGURE ES.5

Energy Use, All Cases



About the NEB

The [National Energy Board](#) (NEB or Board) is an independent national energy regulator. Its role is to regulate, among other things, the construction, operation and abandonment of pipelines that cross provincial or international borders, international power lines and designated interprovincial power lines, imports of natural gas and exports of crude oil, natural gas liquids, natural gas, refined petroleum products, and electricity, and oil and gas exploration and production activities in certain areas. The NEB is also charged with providing timely, accurate and objective information and advice on energy matters.

The NEB's strategic outcome states: The Regulation of pipelines, power lines, energy development and energy trade contributes to the safety of Canadians, the protection of the environment and efficient energy infrastructure and markets, while respecting the rights and interests of those affected by NEB decisions and recommendations.

The Board's main responsibilities include regulating:

- the construction, operation, and abandonment of pipelines that cross international borders or provincial/territorial boundaries;
- associated pipeline tolls and tariffs;
- the construction and operation of international power lines and designated interprovincial power lines;
- imports of natural gas and exports of crude oil, natural gas, natural gas liquids, refined petroleum products, and electricity; and
- oil and gas exploration and production activities in specified northern and offshore areas.

About this Report

The Board monitors energy markets and assesses Canadian energy requirements and trends to support its regulatory responsibilities. This report, *Canada's Energy Future 2017: Energy Supply and Demand Projections to 2040*, is the continuation of the *Energy Futures* series, and projects long-term Canadian energy supply and demand trends.

EF 2017 was prepared by National Energy Board technical staff under the Direction of Abha Bhargava (abha.bhargava@neb-one.gc.ca), Director, Energy Integration, Bryce van Sluys (bryce.vansluys@neb-one.gc.ca), Andrea Oslanski (andrea.oslanski@neb-one.gc.ca) Project Managers – Energy Futures. Specific questions about the information in this report may be directed to: General Questions energyfutures@neb-one.gc.ca Key Drivers and Macroeconomics: Bryce van Sluys (bryce.vansluys@neb-one.gc.ca) Chris Doleman (chris.doleman@neb-one.gc.ca). Energy Demand: Chris Doleman (chris.doleman@neb-one.gc.ca), Matthew Hansen (matthew.hansen@neb-one.gc.ca), Ken Newel (ken.newel@neb-one.gc.ca), Lukas Hansen (Lukas.hansen@neb-one.gc.ca). Crude Oil: Peter Budgell (peter.budgell@neb-one.gc.ca). Refinery Balances: Jesus Rios (jesus.rios@neb-one.gc.ca). Natural Gas: Melanie Stogran (melanie.stogran@neb-one.gc.ca). Natural Gas Liquids: Jesus Rios (jesus.rios@neb-one.gc.ca). Electricity: Michael Nadew (michael.nadew@neb-one.gc.ca), Mantaj Hundal (mantaj.hundal@neb-one.gc.ca), Ryan Safton (ryan.safton@neb-one.gc.ca). Coal: Lukas Hansen (lukas.hansen@neb-one.gc.ca).

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INTRODUCTION

- The National Energy Board's *Energy Futures* series explores how possible energy futures might unfold for Canadians over the long term. This analysis is not a prediction of what will take place, nor does it aim to show how certain goals like Canada's climate targets will be achieved. Rather, *Energy Futures* employs economic and energy models to make projections based on a certain set of assumptions given what we know today about technology, energy and climate policies, human behaviour and the structure of the economy.
- This report, *Canada's Energy Future 2017: Energy Supply and Demand Projections to 2040* (EF2017), is the latest edition of this series.
- EF2017 considers three cases:
 - The Reference Case is based on a current economic outlook, a moderate view of energy prices, and climate and energy policies announced at the time of analysis.
 - The Higher Carbon Price (HCP) Case considers the impact on the Canadian energy system of higher carbon pricing than in the Reference Case.
 - The Technology Case considers the impact on the Canadian energy system of greater adoption of select emerging energy production and consumption technologies.
- In developing this report the NEB engaged various energy experts and stakeholders to gather input and feedback on the assumptions and preliminary projections. The NEB would like to thank all participants for their contributions to EF2017.
- Over the projection period, it is likely that developments beyond the realm of normal expectations, such as geopolitical events or technological breakthroughs, will occur. Likewise, new information will become available and trends, policies, and technologies will evolve. In particular, EF 2017 makes several simplifying assumptions on future carbon pricing in Canada. The actual implementation of the pan-Canadian approach to carbon pricing could lead to different impacts on Canada's energy system than shown here. This report should not be taken as an official or definitive impact analysis of this initiative. Readers of this analysis should consider the projections a baseline for discussing Canada's energy future today, not a prediction of what will take place in the future.

KEY ASSUMPTIONS

This chapter describes the key assumptions underpinning this analysis.

Key Assumptions

- Three key assumptions underpin the analysis in EF2017:
 - Over the long term, all energy production will find markets and infrastructure will be built as needed.
 - Environmental and socio-economic considerations beyond the included policies and programs are outside the scope of the analysis.
 - EF2017 includes many recently announced climate policies. The following criteria were applied to determine whether a certain policy was included in EF2017:
 - The policy was publically announced prior to 1 January 2017.
 - Sufficient detail exists to credibly model a policy, or reasonable assumptions can be made about the details of a policy.
 - Goals and targets, including Canada's international climate targets, are not explicitly modelled. Rather, policies that are announced, and in place, to address those targets are included in the modeling.
- Table A.1, found at the end of this document, describes many recent climate policy developments and indicates whether that policy is included in the EF2017 analysis.

Carbon Price Assumptions

Climate Policy Developments

- Climate policy in Canada has evolved rapidly since late 2015. The federal government and many provincial governments made major policy announcements throughout 2016.
- Several climate policies were announced by the federal government in the fall of 2016, including:
 - [The Pan-Canadian approach to pricing carbon pollution](#)
 - [An initiative to green the federal government](#)
 - [Amendments of federal regulations to phase out traditional coal-fired generation by 2030](#)
 - [A plan to develop a clean fuel standard](#)

- Many provincial governments across Canada also [announced policies and action plans](#) related to climate change since late 2015.
- Federal and provincial climate policies and action plans are at various stages of development and implementation. Some announced policies, such as Alberta’s carbon levy on end-use emissions and Ontario’s cap-and-trade system, had already been implemented at the time of analysis. In other cases, legislation and regulations are being drafted, or proposals are in the development and consultation phase.

Carbon Pricing as a Climate Policy Tool

- In December 2016, the federal government released the [Pan-Canadian Framework on Clean Growth and Climate Change](#) (Pan-Canadian Framework). This outlines Canada’s actions that will contribute to meeting or exceeding its 2030 climate change target of a 30% reduction below 2005 [greenhouse gas](#) (GHG) emission levels. The implementation of [carbon pricing](#) is a key pillar of the Pan-Canadian Framework.
- Several provinces have already implemented carbon pricing: Alberta introduced an intensity-based carbon price for large emitters in 2007, British Columbia (B.C.) began taxing carbon in 2008 and Quebec’s cap-and-trade program came into effect in 2013. Alberta, through a carbon levy, and Ontario, through a cap-and-trade program, began widespread pricing of carbon in January 2017.
- In general, carbon pricing mechanisms add a per-unit-fee to fuels that release GHG emissions when consumed. The fee is proportional to the GHG emissions released by that fuel. Table 2.1 demonstrates how different carbon prices impact the price of different fuels.

T A B L E 2 . 1

Example Carbon Prices of Various Fuels in Energy Equivalent and Volumetric Terms

Carbon Price	\$30/tonne		\$50/tonne		\$90/tonne		\$140/tonne	
	Energy	Volume	Energy	Volume	Energy	Volume	Energy	Volume
Natural Gas	1.50 \$/GJ	\$1.58/Mcf	2.49 \$/GJ	\$2.63/Mcf	4.49 \$/GJ	\$4.74/Mcf	6.98 \$/GJ	\$7.38/Mcf
Gasoline	2.06 \$/GJ	7.1¢/L	3.43 \$/GJ	11.9¢/L	6.17 \$/GJ	21.4¢/L	9.59 \$/GJ	33.2¢/L
Diesel	2.22 \$/GJ	8.6¢/L	3.70 \$/GJ	14.3¢/L	6.67 \$/GJ	25.8¢/L	10.37 \$/GJ	40.1¢/L

- Carbon pricing can have several outcomes:
 - o Pricing carbon raises the price of fuels that emit GHGs, causing a decrease in the use of those fuels. When carbon is priced, energy users more accurately account for the cost of releasing GHGs into the atmosphere in their decision making.
 - o Pricing carbon alters the relative prices of various fuels to better reflect their GHG content. As a result, low or no emitting fuels become more attractive when carbon is priced than if it were not. For example, the carbon price per unit of energy for natural gas is lower than for gasoline, reflecting the lower carbon content of natural gas, as shown in Table 2.1.

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- o A price on carbon can be a driver of innovation and investment in GHG-emission reducing technologies. Creating an economic incentive for consumers and businesses to reduce their carbon costs strengthens the market for products and services that help reduce GHG emissions.
 - o Carbon pricing can be a source of revenue for governments. Revenues can be used for program spending, including support for the development of carbon-reducing technologies, or rebates to consumers. Carbon pricing revenue can also be used to offset other types of taxes, such as personal or corporate income taxes.
 - Economists generally consider carbon pricing to be an [economically efficient means of reducing GHG emissions](#). Economic theory suggests that energy producers, transporters, and consumers who can reduce their GHG emissions at a cost less than the carbon tax will choose to do so.

Carbon Pricing Mechanisms

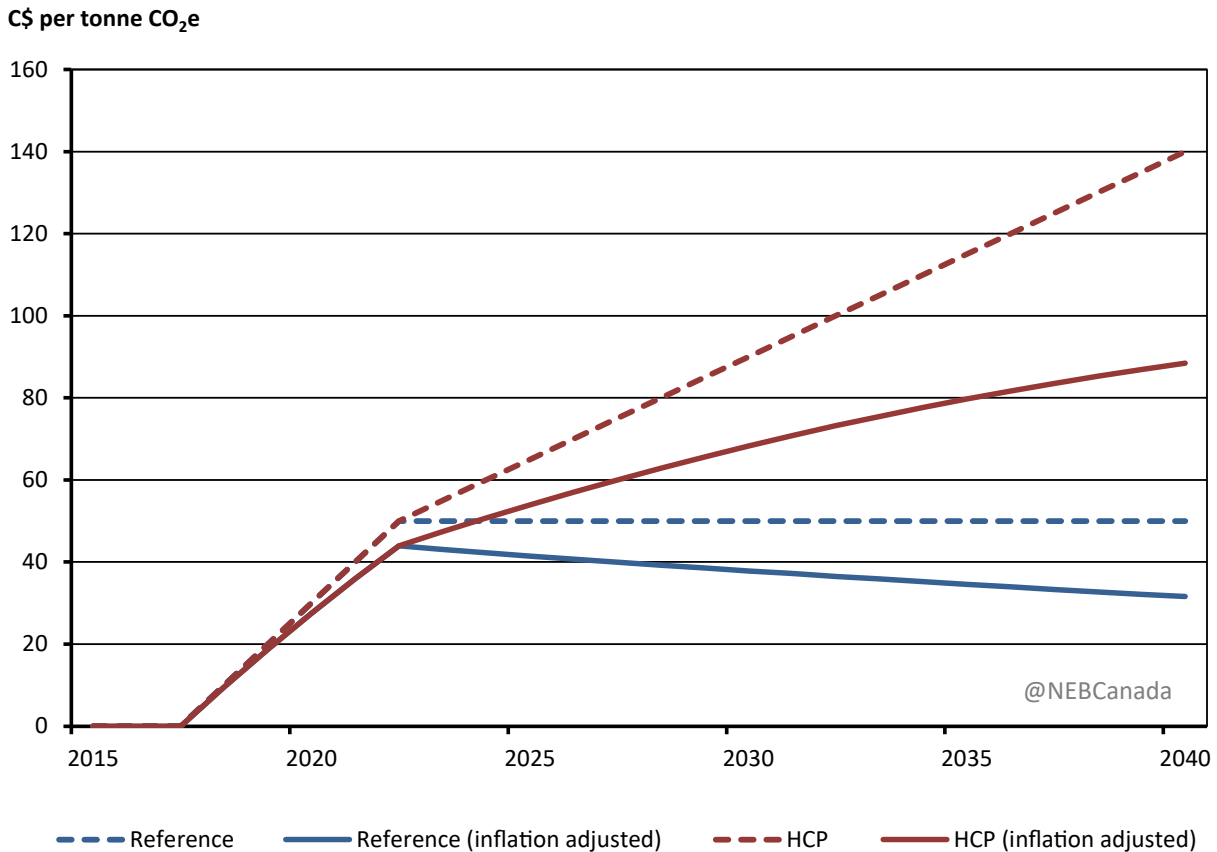
- Carbon pricing schemes usually fall into two main categories: a carbon tax or a cap-and-trade system:
 - o Under a carbon tax, a jurisdiction sets a price on carbon emissions consistent with its policy objectives, with a higher price translating into greater expected emission reductions.
 - o In a cap-and-trade system, a government sets a cap on the maximum allowable GHG emissions and then sets the number of emission permits available equal to that cap. Market participants must hold permits equal to the amount of GHGs they emit over a given period. Through trading between many participants, market forces determine an economy-wide price for GHG emissions.
- Carbon pricing policies can have drawbacks, some of which can be dealt with through effective policy design:
 - o Carbon pricing can have economic impacts, [especially for industrial sectors that are emissions-intensive and face competition in other jurisdictions](#). If one jurisdiction introduces a carbon price, trade-exposed industries may shift their operations to a region with less stringent carbon policies, resulting in no net reduction in global GHG emissions. This is often referred to as “carbon leakage” and is usually addressed by offering free emission permits to these types of industries. Wider adoption of climate policies around the world could also reduce this effect by removing the option for industries to move to another region in order to reduce carbon costs.
 - o [A price on carbon can be regressive](#), meaning it could have a disproportionately negative impact on lower income individuals. The use of carbon price revenues to provide targeted rebates or other tax cuts can offset this impact.
 - o Some types of GHG emissions, such as methane emissions from agriculture or oil and natural gas operations, are difficult to measure, making them difficult to price. [Other policy tools such as technology standards are often a more effective tool](#) to address these types of emissions.
- For an in-depth discussion of carbon pricing in a Canadian context, the Working Group on Carbon Pricing Mechanisms established by Canada’s First Ministers in the Vancouver Declaration [released a detailed final report on carbon pricing mechanisms](#) in the fall of 2016.

The Federal Carbon Pricing Plan in EF2017

- The Government of Canada announced [the pan-Canadian carbon pollution pricing benchmark](#) in October 2016 to ensure that carbon pricing applies to a broad set of emission sources throughout Canada in 2018 with increasing stringency over time. The benchmark provides provinces and territories with flexibility to implement their own carbon pollution pricing systems—either an explicit price-based system (a carbon tax such as the one in British Columbia, or a carbon levy and an output-based pricing system, such as in Alberta) or a cap-and-trade system (such as those in Quebec and Ontario). In the benchmark, the federal government also committed to implement a federal carbon pricing backstop system that will apply in any province or territory that does not have a carbon pricing system in place by 2018 that aligns with the benchmark. [The Government of Canada released a discussion paper in May 2017 outlining the proposed federal carbon pollution pricing backstop system](#). It is composed of two key elements:
 - A carbon levy applied to fossil fuels starting at \$10 per tonne of GHG emissions in 2018, rising \$10 per year to \$50 per tonne in 2022, and
 - An output-based pricing system for industrial facilities that emit above a certain threshold, with an opt-in capability for smaller facilities with emissions below the threshold. By pricing a portion of emissions and enabling emissions trading, this component incents innovation and emissions reductions but mitigates adverse impacts on competitiveness.
- EF 2017 makes several simplifying assumptions on future carbon pricing in Canada. The actual implementation of the pan-Canadian approach could lead to different impacts on Canada's energy system than shown here. This report should not be taken as an official or definitive impact analysis of this initiative. All cases in EF 2017 assume that the minimum price for carbon pollution in Canada varies from \$10/tonne of CO₂ equivalent (CO₂e) starting in 2018 to \$50/tonne in 2022. In the Reference Case, the price for carbon is held at \$50/tonne in nominal terms from 2022 to 2040.
- The Federal Government [stated that the Pan-Canadian approach for pricing carbon pollution will be reviewed in 2022 to confirm the path forward](#). Following this review, the minimum price for carbon could change, particularly if other jurisdictions around the world take similar actions. The HCP Case explores the impact on the Canadian energy system of higher carbon pricing than in the Reference Case over the long term. **This sensitivity analysis is not a recommendation or endorsement by the NEB of a certain policy direction.**
- The HCP Case assumes that the price for carbon increases steadily after 2022. As shown in Figure 2.1, the minimum price continues to increase at \$5/tonne per year after 2022, reaching \$90/tonne in 2030 and \$140/tonne by 2040 in nominal terms. In constant 2016 dollar terms, the carbon price in the HCP Case reaches \$68/tonne in 2030 and \$88/tonne by 2040.

FIGURE 2.1

Federal Carbon Price Floor, Reference and HCP Cases



- Some provinces already are part of, or may join, cap-and-trade systems for carbon pricing. In these systems the future price of carbon will be determined by the supply and demand for emission permits. The outlook for this market price will be uncertain, similar to other market prices such as crude oil and natural gas. Like crude oil and natural gas prices, EF 2017 makes simplifying assumptions for the future outlook of carbon pricing. The Reference and HCP cases assume that the price for carbon is equal across all jurisdictions after 2022, including those with cap-and-trade systems.
- Implementing a carbon price that is significantly higher than in other countries can impact the competitiveness of some Canadian industries. Carbon pricing policies can be designed to offset this to an extent. Existing carbon pricing plans in various provinces have some measures in place to mitigate carbon leakage. However, carbon prices well above those in other countries could still have competitiveness impacts.

-
- The [proposed approach for the federal carbon pricing 'backstop' system](#) also includes an element to minimize competitiveness and carbon leakage risks, particularly for emissions intensive and trade exposed industries. This system provides an allowable level of emissions for large emitters, and facilities pay for the emissions above that level or receive credits for their emissions below it. This system reduces the average carbon cost for these facilities, but maintains the incentive for emission reductions. In this analysis, emitters face the full carbon price at an end-user level to capture the price incentive effect, while the impact of the output based allocations in reducing the income effects of the carbon prices is captured in the industrial macroeconomic projections.
 - The HCP Case assumes that other countries also increase the strength of their climate policies over time. Given the competitiveness impacts of higher carbon pricing, it is more likely that Canada would increase its carbon price if other nations do so as well. Action on climate in developed countries increases at a similar pace as in Canada. Developing nations increase the strength of their climate policies more gradually over the projection period. This assumption also simplifies the analysis by eliminating concerns related to carbon leakage.
 - This sensitivity case is not meant to replicate scenario analysis that explores the global energy transition required to keep a global temperature rise to below 2 degrees Celsius, such as the International Energy Agency's [World Energy Outlook 450 Scenario](#). Nor is it a scenario designed with Canada's international climate targets as the ultimate objective.
 - The energy supply and demand results of the Reference and HCP cases are discussed in Chapter 3: Reference and HCP Case Results.

Technology Case Assumptions

- Technology's influence on the energy system can be substantial. Which emerging technologies achieve widespread use is often difficult to predict. Likewise, the nature of future breakthroughs is unknown. The adoption rate of emerging technologies is a key uncertainty to the projections in EF2017.
- Governments in Canada and around the world have emphasized technological innovation as a key component to their plans to reduce GHG emissions. A pillar of the Pan-Canadian Framework is [Clean Technology, Innovation and Jobs](#). In addition, Canada is participating in [Mission Innovation](#), a global initiative, including 22 countries and the European Union, to accelerate global clean energy innovation. Through its participation in Mission Innovation, Canada aims to, among other things, double federal investment in clean energy research and development from 2015 to 2020.
- Several provincial governments have programs to encourage innovation in energy technology. Examples include [SaskPower](#), [Institut de recherche d'Hydro-Québec](#), [Ontario Centres of Excellence](#), and [Emissions Reduction Alberta](#). Some of these programs are funded from revenue generated by carbon pricing initiatives.
- Adoption of new technologies can be encouraged by climate policies, such as carbon pricing or other options, which improve the competitiveness of low or non-emitting technologies. Alternatively, a technology can sometimes become more popular when public or private sector research and development results in a lower emission technology that is equivalent, or better, than existing technology for reasons such as cost, convenience, quality, or societal factors.

-
- The Technology Case considers the impact of greater use of a selection of emerging energy technologies on the energy system. It builds upon the underlying assumptions of the HCP Case, including the long-term increases in carbon pricing shown in Figure 2.1.
 - The Technology Case assumes:
 - o Greater cost decreases for solar and wind electricity generating technology over the projection period.
 - o Greater interprovincial electricity trade and modest penetration of grid-scale battery storage technologies.
 - o Faster uptake of electric vehicles (EVs) in the passenger transportation sector.
 - o Adoption of steam-solvent technology in the oil sands sector.
 - o Greater electrification of space and water heating in the residential and commercial sectors.
 - o Increasing use of carbon capture and storage (CCS) technology for coal-fired electricity generation.
 - These technologies are a selection of the wide array of emerging technologies that have the potential to increase their market share over the projection period. They are chosen to illustrate how technological development may impact energy supply and demand trends in various sectors of the economy. It is unclear which technologies will gain wider adoption in the future; these technologies provide an example among many potential outcomes. **This sensitivity analysis is not a prediction or recommendation of certain technologies.**
 - The energy supply and demand results of the Technology Case are discussed in Chapter 4: Technology Case Results.

Crude Oil and Natural Gas Prices

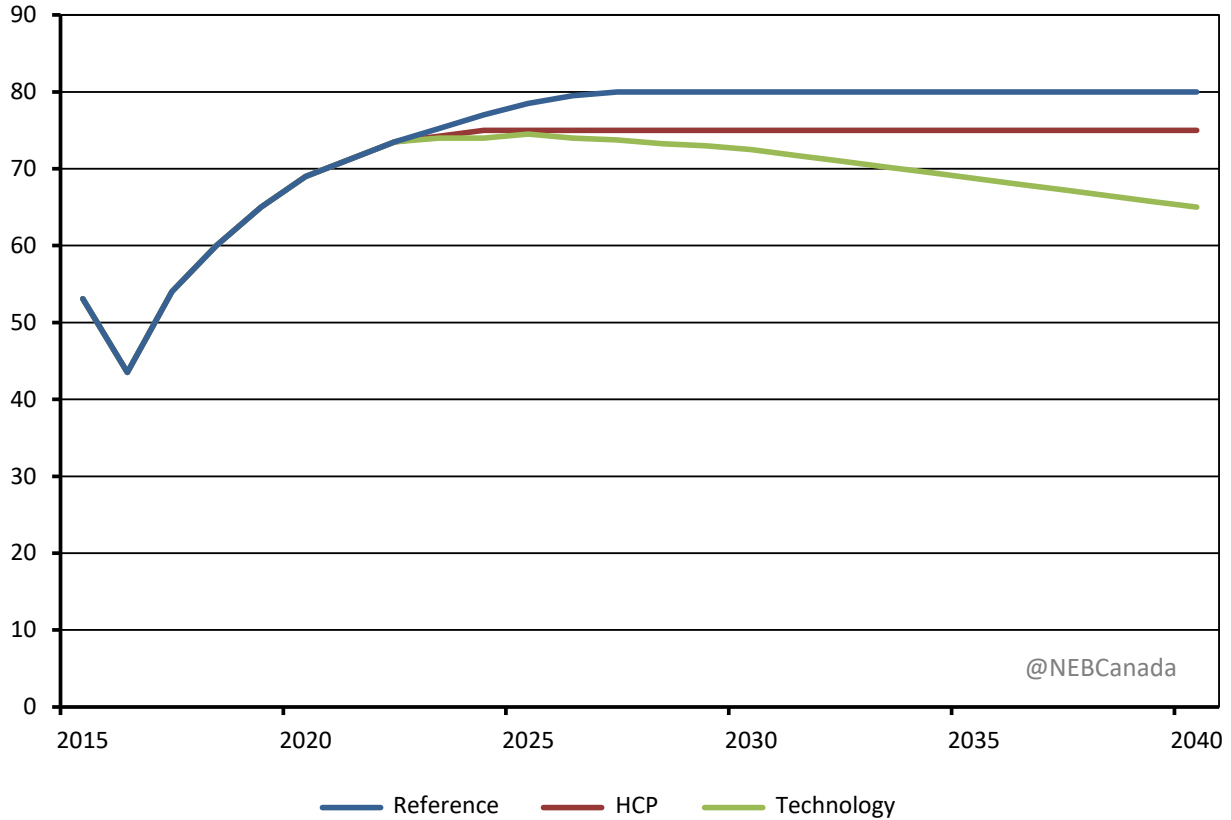
Crude Oil

- Crude oil prices are a key driver of the Canadian energy system and are determined by global supply and demand factors. Canada is a major [crude oil](#) producer and prices are an important driver of future production growth. The prices of [refined petroleum products](#) (RPPs), such as gasoline and diesel, are closely related to crude oil prices and can influence energy use trends.
- From 2011 to mid-2014, global crude oil prices were stable near US\$100 per barrel (bbl). Prices dropped steadily starting in mid-2014, with the [Brent](#) crude oil price falling to less than US\$30/bbl in January 2016. The price increased through the spring of 2016 and stabilized near US\$50/bbl through the rest of 2016 and into 2017.
- Figure 2.2 depicts the Brent crude oil price assumptions in EF2017. The Reference Case price, in constant 2016 dollar terms, reaches US\$80/bbl by 2027, and stays at that level through the remainder of the projection period. Investment in new crude oil production capacity has declined in recent years due to low oil prices. As a result, prices increase early in the projection period as higher prices help to bring on additional production to balance supply and demand. After 2027, the Brent crude oil price stays at US\$80/bbl reflecting the potential for crude oil demand growth to flatten or begin declining.

FIGURE 2.2

Brent Crude Oil Price, All Cases

2016US\$ per barrel



- As shown in Figure 2.2, the Brent crude oil price is lower in the HCP and Technology cases. In both cases, the Brent crude oil price follows the trajectory of the Reference Case until 2022. Thereafter, the prices diverge, with prices in the HCP Case reaching US\$75/bbl in constant 2016 dollar terms. The Technology Case assumes that the Brent price begins to slowly decline, reaching US\$65/bbl in 2040, US\$15/bbl lower than in the Reference Case.
- The HCP Case assumes greater global climate action relative to the Reference Case. This implies lower demand for GHG emission-intensive goods, including RPPs, and crude oil. Similarly, in the Technology Case, greater global adoption of technologies like EVs implies lower demand for crude oil compared to the Reference Case.
- Lower price assumptions in the HCP and Technology cases highlights that stronger global climate action or greater adoption of low carbon technologies could reduce the market for crude oil compared to the Reference Case. For energy consumers, lower crude oil prices would reduce the costs for RPPs like gasoline and diesel but higher carbon prices more than offset this, resulting in higher end-use prices for those fuels.
- The ultimate impact of greater global climate action, or greater technology adoption, on crude oil prices is highly uncertain. The differences in crude oil prices between the cases could depend on future climate policies, the evolution of crude oil supply costs around the world, and the availability of alternative technologies.

- The difference between the cases in EF2017 is not an assessment of the impact of greater climate action on crude oil prices but is an assumption with which to build broad and plausible scenarios.

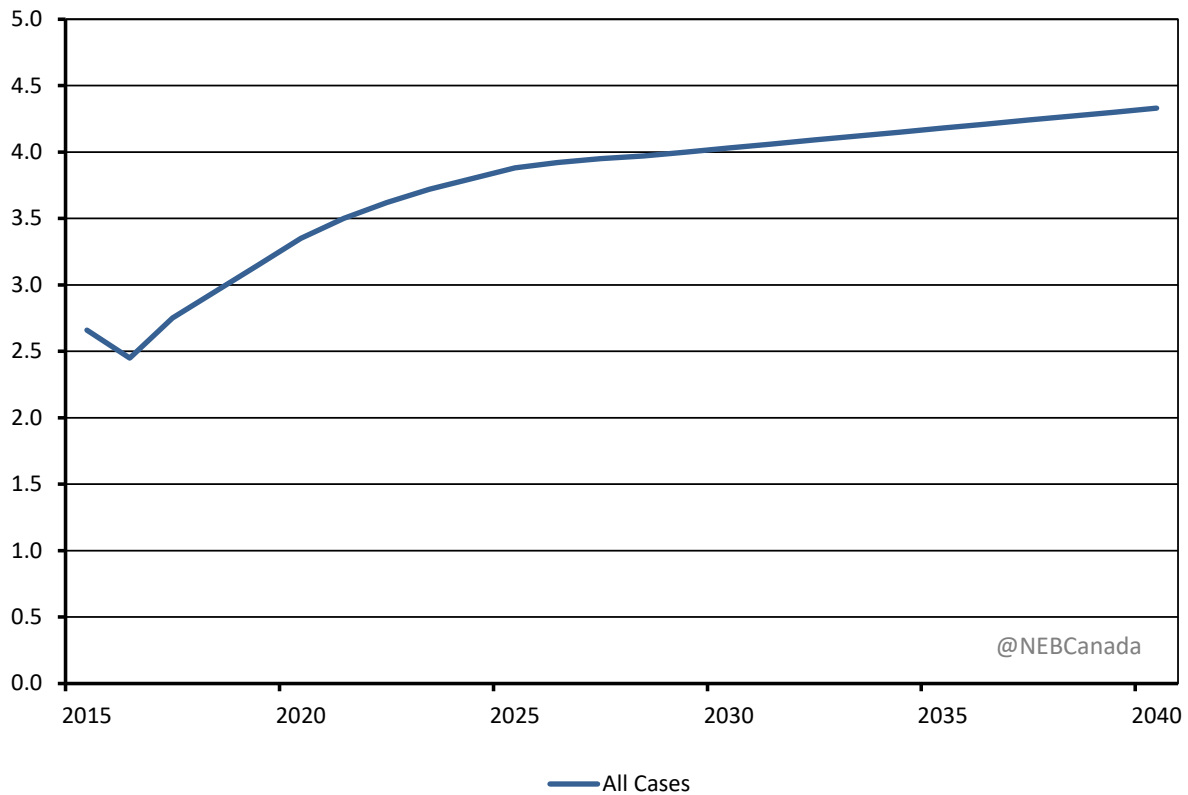
Natural Gas

- Natural gas prices have declined considerably over the past decade. [Henry Hub](#) prices fell from the US\$6-9 per million British thermal units (MMBtu) range between 2006 and 2008 to less than US\$4/MMBtu for the majority of the last five years. In the first half of 2016, Henry Hub prices were as low as US\$2/MMBtu and averaged closer to US\$3/MMBtu in the second half of 2016 and into 2017.
- Figure 2.3 shows the Henry Hub natural gas price assumptions of EF2017. The price in all three cases, in constant 2016 dollar terms, increases from US\$2.45/MMBtu in 2016 to US\$4.30/MMBtu in 2040.

FIGURE 2.3

Henry Hub Natural Gas Price, All Cases

2016US\$ per MMBtu



-
- Natural gas is less GHG-intensive than other [fossil fuels](#). Under the assumptions of the HCP and Technology Cases, it is unclear whether natural gas demand would increase or decrease in response to the assumptions in those cases. Power producers in North America may choose to replace coal-fired generation with natural gas to reduce emissions and service higher electricity demand. Similarly, a global shift towards natural gas could increase demand for LNG exports from North America, which could increase natural gas prices. On the other hand, stronger climate policy and technology adoption could reduce demand for all fossil fuels, including natural gas. Given this uncertainty, the Henry Hub price assumptions in all three cases are the same.

REFERENCE AND HCP CASE RESULTS

Overview

- This chapter focuses on the results of the Reference and HCP cases. Chapter 4 describes the outcomes of the Technology Case.
- Detailed data tables supporting the discussion in this Chapter are available in the online Data Appendices. Historical data is sourced primarily from [Statistics Canada’s Report on Energy Supply and Demand in Canada](#). That data is supplemented with additional details from various federal and provincial data sources. Please contact energyfutures@neb-one.gc.ca with any questions regarding the historical energy data.

Macroeconomic Drivers

- The economy is a key driver of the energy system. Economic growth, industrial output, inflation, exchange rates, and population growth all influence energy supply and demand trends.
- Macroeconomic projections for each of the scenarios were provided by The Centre for Spatial Economics (C4SE). [C4SE](#) developed unique projections of key macroeconomic indicators such as gross domestic product, exchange rate, and industry gross output for each of the scenarios, based on the price assumptions and output of the NEB’s supply and demand models.
- Key economic variables are shown in Table 3.1. Economic growth averages 1.73% per year over the projection period in the Reference Case.

TABLE 3.1

Economic indicators, Reference and HCP Cases

Economic Indicator	Compound Average Annual Growth Rate (unless otherwise noted)		
	1990-2015	Reference Case (2016-2040)	HCP Case (2016-2040)
Real Gross Domestic Product	2.3%	1.73%	1.72%
Population	1.0%	0.76%	0.76%
Inflation	1.9%	1.93%	1.93%
Exchange Rate (average)	81.3 US/C\$	83.7US/C\$	83.4 US/C\$

- Compared to the past 25 years, the pace of economic growth is slower in both the Reference and HCP cases.

-
- Economic growth in the HCP Case is slightly lower than in the Reference Case, largely due to somewhat lower global demand for the fossil fuels and fossil fuel-intensive goods that Canada exports. This includes crude oil, petrochemicals, and some manufactured products. In addition, higher prices for fossil fuel energy increases costs for consumers and businesses, increases inflation and slows economic growth relative to the Reference Case.
 - Despite this, the impact on economic growth is small, with economic activity 0.2% lower in the HCP Case compared to the Reference Case in 2040. Two key effects offset the negative economic impacts of higher carbon pricing:
 - The analysis assumes that, in the longer term, revenue from higher carbon pricing is returned to consumers and business through personal and corporate income tax reductions. This shift in taxation has positive economic impacts relative to the Reference Case.
 - The higher price for fossil fuel energy in the HCP Case encourages businesses to rely less on energy and more on labour and machinery when it is possible to substitute between production inputs. For example, a manufacturer may choose to replace their low efficiency boiler sooner than they would have without higher carbon pricing. This increases investment and enhances productivity, resulting in greater economic growth in the long term.

Key Uncertainties

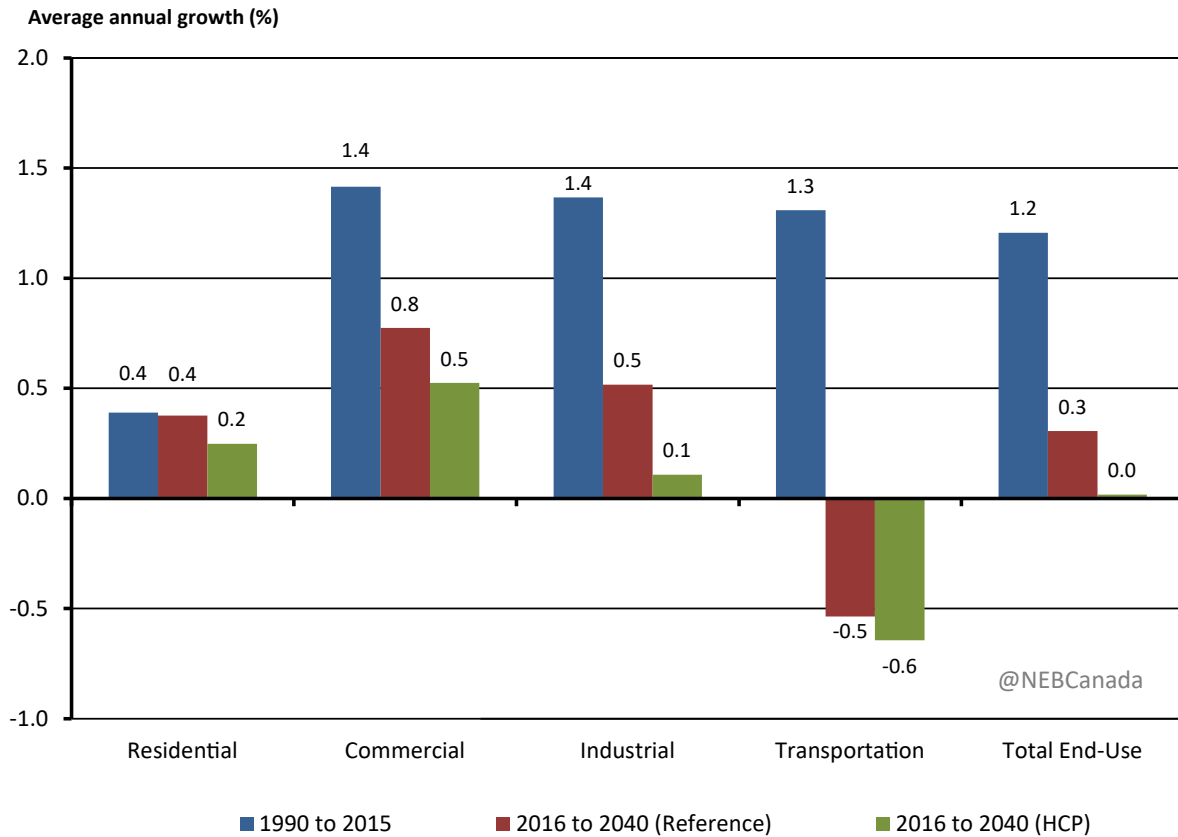
- International demand for Canadian goods, the production of which can be energy-intensive, will influence export-oriented industries. Faster or slower economic growth in the United States (U.S.), Canada's largest trading partner, would affect the economic and energy demand projections. The impact of greater global climate action on demand for GHG-intensive goods is highly uncertain and could impact growth of heavy industry in Canada.
- Large projects in the mining, oil, natural gas, and electricity sectors affect the macroeconomic projections in a number of provinces. The pace of these developments is uncertain and could lead to higher or lower economic growth.
- As noted in Chapter 2, a price on carbon can be a driver of innovation and investment in technologies that would reduce GHG emissions. It is difficult to predict the innovations and accompanying economic activity that may develop due to a greater economic incentive to reduce GHG emissions.

Energy Demand

- This section focuses mainly on end-use, or [secondary energy demand](#). Secondary demand excludes energy used to generate electricity, which is accounted for in [primary demand](#).
- Figure 3.1 shows annual average growth rates of energy use by sector over the past 25 years and from 2016 to 2040 in the Reference and HCP cases. Compared to the 1990-2015 period, when demand grew by an average of 1.2% per year, end-use energy demand in the Reference Case grows considerably more slowly over the outlook period, averaging growth of 0.3% per year.

FIGURE 3.1

Historical and Projected Average Annual Growth in End-Use Energy Demand by Sector, Reference and HCP Cases



- Unlike previous *Energy Futures* Reference Case outlooks, end-use demand eventually begins to decline near the end of the projection period. Total end-use energy demand peaks in 2037 at nearly 12 155 petajoules (PJ). Energy consumption slowly declines for the remainder of the projection period.
- There are many reasons why energy use grows more slowly than history, and eventually starts to decline near the end of the projection period. Some key factors include:
 - Economic and population growth influence energy use and, as shown in Table 3.1, both grow at slower rates in the projection period compared to history. Canada also has a long trend of declining energy use per dollar of economic activity, which is typical of developed countries. This trend continues in the projection period.
 - Energy efficiency has improved in many areas in the past, and continues to improve in the projection period. This reduces energy demand growth because less energy is required for new devices and equipment. For example, since 1990, [lower efficiency natural gas furnaces have nearly been entirely replaced](#) by medium and high efficiency units that are 30% to 50% more efficient. In recent years, the stock of medium efficiency furnaces has declined, while high efficiency units continue to grow.

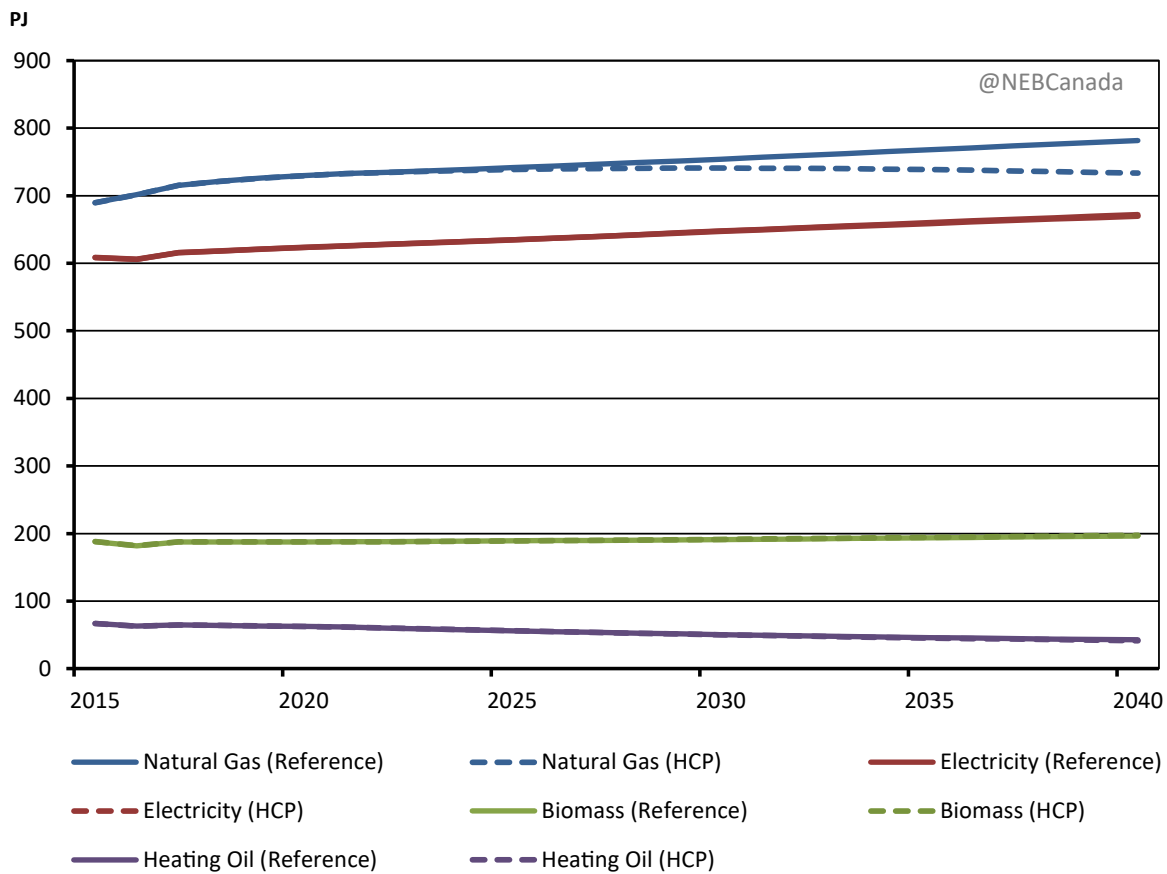
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- o Although oil and natural gas prices are currently lower than their recent peaks, Figures 2.2 and 2.3 show that both prices are assumed to increase from current levels over the projection period. This will further slow demand growth.
 - o The pan-Canadian approach for pricing carbon pollution is included in the Reference Case. An economy-wide carbon price will have a downward impact on energy use trends. [A recent review of a variety of studies on B.C.'s carbon price](#) finds that the policy reduced demand and GHG emissions between 5 and 15% compared to what would have occurred without carbon pricing.
 - o Several other policies, programs and regulations affect energy use in the projection period. For example, light and heavy duty vehicle emission standards will improve the efficiency of new vehicles in both the passenger and freight sectors over the projection period.
- Compared to the Reference Case, total end-use demand growth is lower in the HCP Case. Demand grows until peaking in 2022, more than a decade earlier than in the Reference Case. After 2022, demand declines at an average annual rate of 0.3%, and is nearly 800 PJ lower than the Reference Case by 2040.

Residential and Commercial

- Residential energy use is the energy consumed by Canadian households. This includes energy used for space and water heating, air conditioning, lighting, large appliances, and other devices like televisions and computers. The residential sector made up 14% of total end-use demand in 2015.
- In the Reference Case, energy use in the residential sector increases from 1 570 PJ in 2016 to 1 717 PJ in 2040, or 9%. Population growth, a key driver in residential energy use, grows by 20% over that period, implying that residential energy use per person declines. This continues the [historical trend of energy use per household declining](#), and is influenced by many factors including energy prices and energy efficiency improvements.
- In the HCP Case, energy use grows slightly slower and in 2040 total energy use is 50 PJ less than in the Reference Case. Figure 3.2 shows energy use by fuel in the Reference and HCP cases.

FIGURE 3.2

Residential Energy Demand by Major Fuel, Reference and HCP Cases



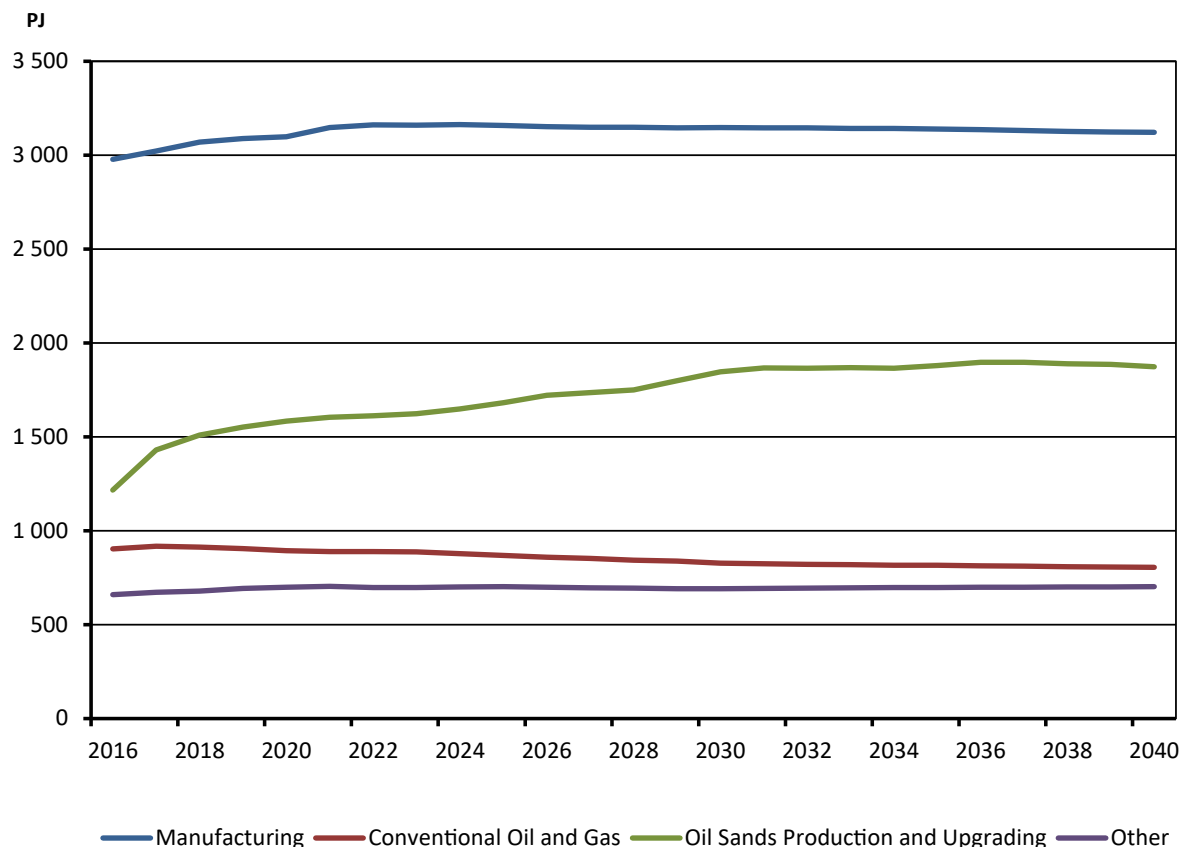
- In the HCP Case, residential natural gas demand in 2040 is 6% lower than in the Reference Case as consumers invest in more efficient natural gas furnaces and water heaters and other energy saving measures. Higher carbon pricing also makes lower emission fuels more attractive, resulting in similar electricity and biomass consumption in the HCP Case. Biomass is used most frequently in Quebec and Atlantic Canada, where wood and wood pellet consumption makes up over 20% of residential energy use.
- The commercial sector is a broad category that includes offices, stores, warehouses, government and institutional buildings, utilities, communications, and other service industries. It also includes energy consumed by street lighting and pipelines. The commercial sector made up 12% of total end-use demand in 2015.
- In the Reference Case, commercial demand increases by 0.8% per year over the projection period, slower than the 1.4% growth over the past 25 years. In the HCP Case, demand grows by 0.5% per year and is 6%, or 93 PJ, lower than in the Reference Case by 2040.
- [Energy use per square foot for buildings in the commercial sector has decreased by 15% from 1990](#), despite increased energy use by equipment such as computers in buildings. Continued efficiency improvements, and fewer additions of new equipment, contribute to the slower demand growth in the projection period.

Industrial

- The industrial sector includes manufacturing, forestry, fisheries, agriculture, construction, mining, and oil and natural gas extraction. The industrial sector made up slightly more than half the end-use demand in 2015.
- The industrial energy demand projections are largely driven by the economic growth projections of various industries. In many cases, industrial growth is linked to demand for goods consumed domestically but also those exported internationally due to Canada's trade-oriented economy.
- In the Reference Case, industrial demand grows steadily in the first decade of the projection period largely due to growth in the oil sands. Industrial demand increases from 5 739 PJ in 2016 to 6 495 PJ in 2026, a 13% increase. After 2023, industrial demand stays relatively constant, a result of steady efficiency improvements and slowing output growth in industries such as paper and metal manufacturing.
- Figure 3.3 shows energy use trends by various industrial sectors in the Reference Case. The oil sands sector grows over the projection period, driven largely by increasing in situ bitumen production. Natural gas is the primary fuel for in situ production, and demand in that sector increases from 610 PJ in 2016 to 1 025 PJ in 2040, a 68% increase. While total demand increases, the energy intensity of in situ production continues to decline throughout the projection period.

FIGURE 3.3

Industrial Energy Demand by Category, Reference Case



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- Industrial energy demand in the HCP Case is 9%, or 595 PJ, lower than in the Reference Case by 2040. This lower demand is largely due to two factors:
 - o As in other sectors, higher carbon pricing encourages greater investments in more energy efficient devices and processes than in the Reference Case.
 - o As described in the Macroeconomic Drivers section of this chapter, the HCP Case assumes that global demand for more carbon-intensive products, including crude oil, is somewhat lower. This translates into slightly lower production from these industries, resulting in less energy use.

Transportation

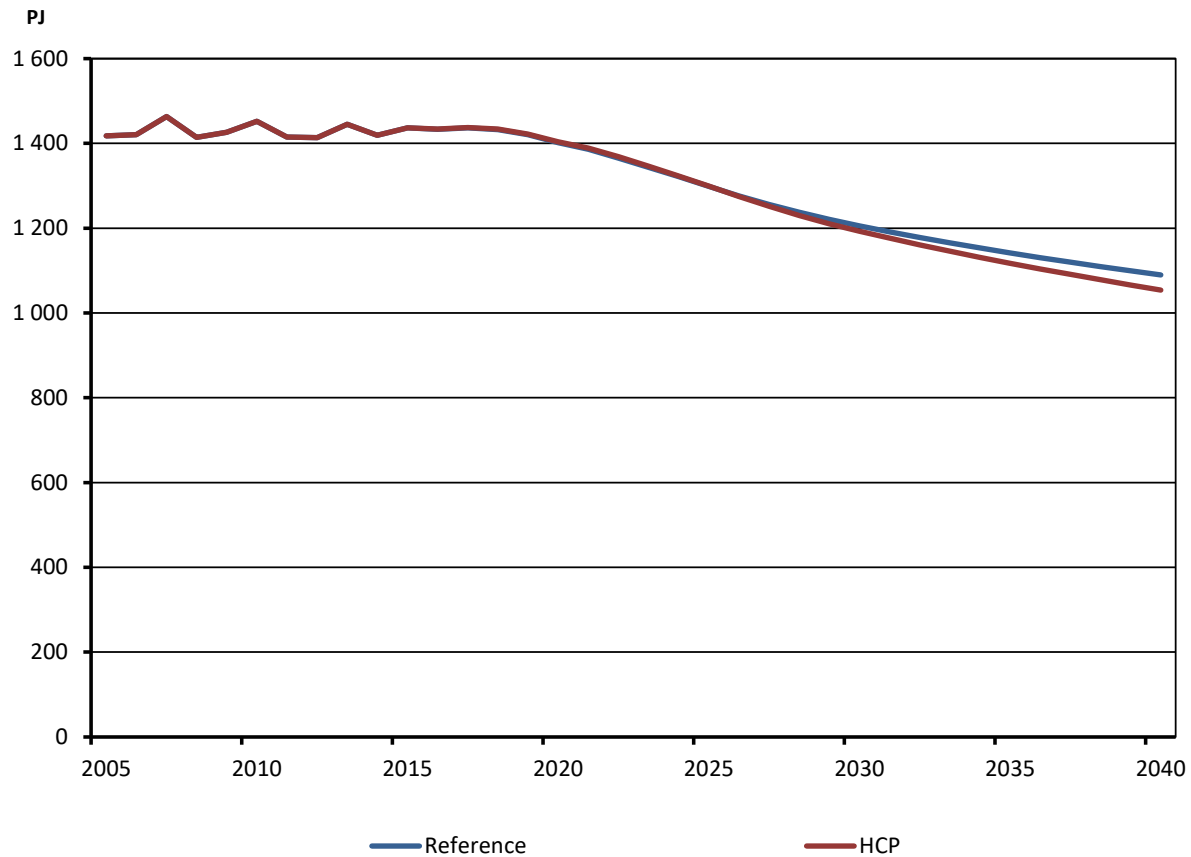
- The transportation sector includes passenger and freight on-road transportation, as well as air, rail, marine, and non-industrial off-road travel, such as recreational all-terrain vehicles and snowmobiles. The transportation sector made up 23% of total end-use demand in 2015.
- After increasing steadily for the past 25 years, total transportation demand declines slowly over the projection period, averaging a 0.5% decrease per year from 2016 to 2040. On-road passenger transportation, which was 42% of total transportation demand in 2015, falls steadily, while freight transportation increases slightly over the projection period.

Passenger Transportation

- On-road passenger transportation energy use has been relatively constant in Canada; consumption in 2015 was close to 2002 levels. Early in the projection period, consumption begins to decline, falling to 720 PJ in 2040, a third less than in 2016. This is driven by several factors:
 - o Alongside the U.S., [Canada enacted GHG emission standards that extend from 2012 to 2025](#). The standards target GHG emissions per kilometer (km) driven. The average emissions of new passenger vehicles bought in Canada fell from 158 grams CO₂e per km in 2011 to 142 grams for those sold in 2015. This decrease is, in part, due to fuel economy improvements resulting from greater use of technologies such turbochargers, cylinder deactivation, and continuous variable transmissions.
 - o The Reference Case assumes modest adoption of EVs over the projection period. The displacement of some traditional passenger automobiles with EVs contributes to lower energy consumption. The Technology Case, discussed in Chapter 4, provides an analysis of greater EV adoption.
 - o Canada's population grows more slowly in the projection period than in the past, resulting in less transportation demand growth. Canada's population grew by 1.0% per year from 1990 to 2015, compared to 0.8% from 2016 to 2040 in the Reference Case.
- Total Canadian gasoline demand in all sectors falls to 1 090 PJ in 2040 In the Reference Case, 26% lower than when gasoline consumption peaked in 2007. Figure 3.4 shows gasoline consumption in the Reference and HCP cases.

FIGURE 3.4

Gasoline Demand, Reference and HCP Cases



- In the HCP Case, gasoline demand declines more quickly, and is 3% lower than in the Reference Case by 2040. Higher carbon pricing translates to higher gasoline prices, encouraging purchases of more fuel efficient vehicles and less driving in general.

Freight Transportation

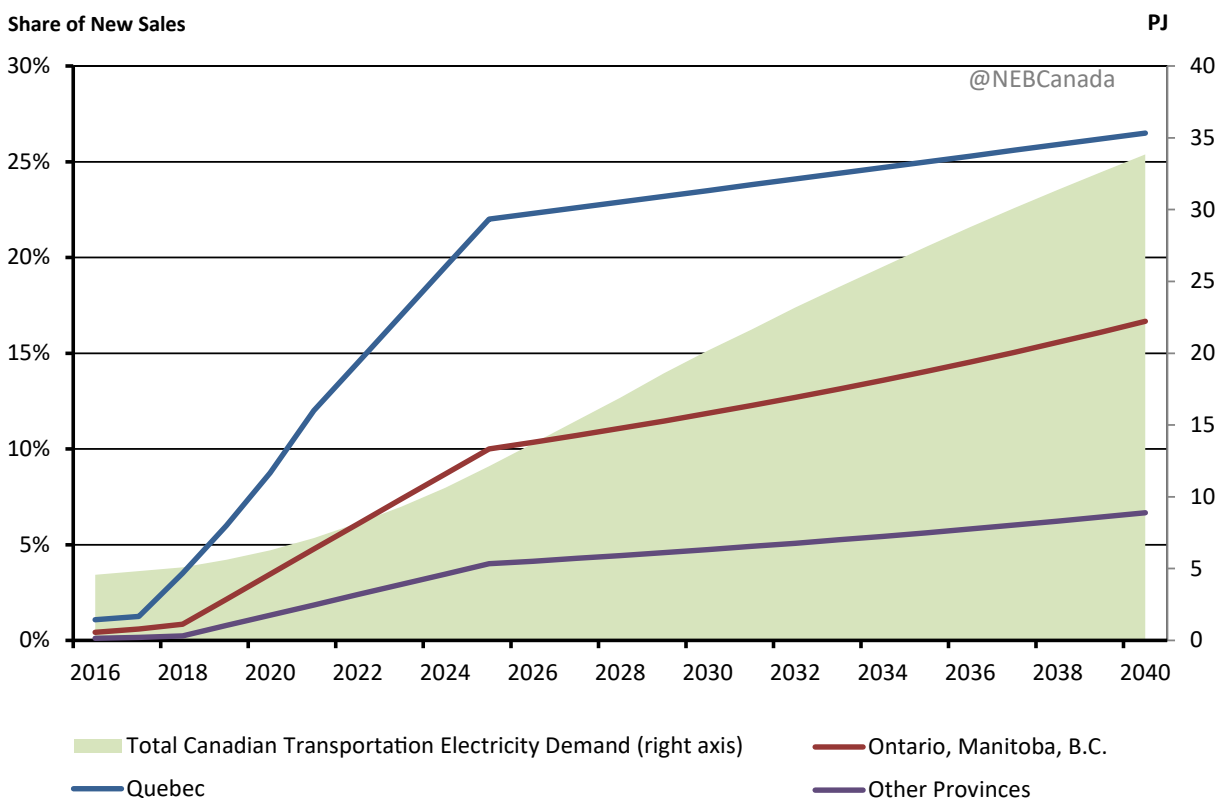
- Freight transportation energy use, which includes demand from medium and heavy trucks, air, railways and marine vessels, made up 44% of total transportation demand in 2015. Freight demand is linked to growth in goods-producing industries and increased steadily at an annual average rate of 2.4% from 1990 to 2015, nearly doubling over that period.
- Compared to the past 25 years, freight energy use grows much slower, averaging 0.7% per year from 2016 to 2040. Similar to passenger transportation, policies like the GHG emission standards for medium and heavy duty vehicles result in slower energy demand growth than in previous years. Economic growth, a key driver of freight activity, is also somewhat slower than in the past. In particular, freight energy demand growth in Alberta and Saskatchewan slows following several years of rapid growth. This is similar to the experience in Ontario and Quebec, where growth slowed following rapid growth in the 1990s and early 2000s. Total freight energy use peaks in 2022 at 1 210 PJ.
- In the HCP Case, freight energy use is 5% lower than in the Reference Case by 2040.

Electric Vehicles (EVs)

- Gasoline and diesel are the primary fuels in the transportation sector. However, [some market observers](#) suggest that a transformation of the transportation sector may be underway, with EVs poised to quickly replace traditional passenger vehicles. It is always difficult to predict whether the momentum behind a new phenomenon, such as the recent surge of interest in EVs, will translate into a transformational change.
- The Reference and HCP cases take a conservative approach to new technology and assume modest adoption of EVs. However, incentives for purchases in some provinces, as well as an EV mandate in Quebec, contribute to a steadily increasing market share for EVs in both cases.
- Figure 3.5 shows the proportion of new passenger vehicle purchases that are EVs as well as total electricity demand in the transportation sector. The Reference Case assumes EV sales are highest in Quebec due to its EV mandate policy, purchase incentives, and low electricity prices. Ontario, B.C. and Manitoba also have higher EV sales due to their low-emitting electricity grids and vehicle purchase incentives. Sales increase steadily from 2016 to 2025 as a result of various programs to support EV purchases. After 2025, the share of new sales increases more gradually as those programs are phased out. In 2040, total Canadian electricity demand from EVs is 34 PJ, less than 1.5% of total electricity consumption in Canada.

FIGURE 3.5

EV Share of New Passenger Vehicle Purchases and Transportation Electricity Demand, Reference Case

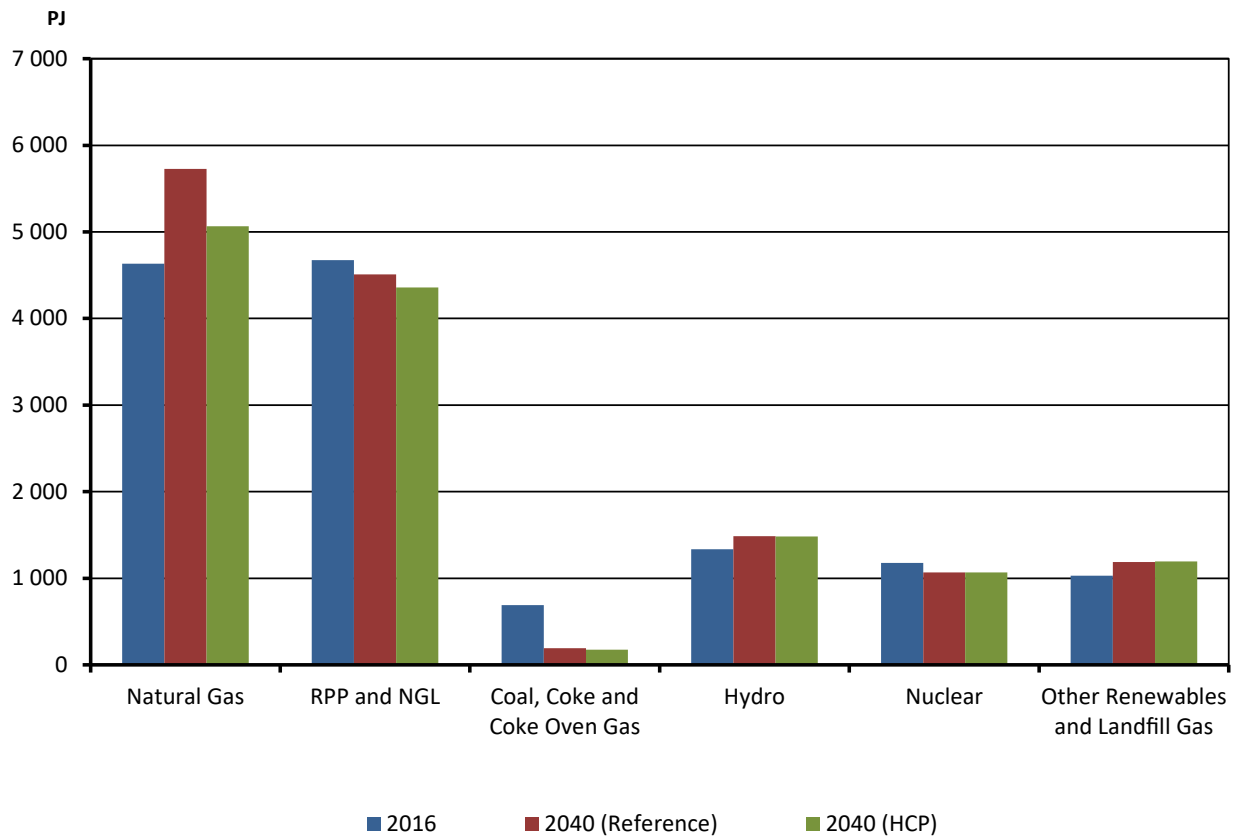


Primary Demand

- In this analysis, primary demand is the total amount of energy used in Canada. In addition to end-use demand, it includes the energy required to generate electricity.
- Primary demand is calculated by adding the energy used to generate electricity to total end-use (or secondary) demand, and then subtracting the end-use demand for electricity.
- In the Reference Case, primary energy demand increases at an average annual rate of 0.2% over the projection period, reaching 14 170 PJ in 2040—an increase of 854 PJ. Primary demand grows slowly until 2036, at which point it begins to decline. As shown in Figure 3.6, the share of natural gas increases the most, driven by power generation and the oil sands. Coal’s share of primary demand falls considerably due to declining coal-fired power generation.

FIGURE 3.6

Primary Energy Demand, Reference and HCP Cases



-
- Primary energy demand peaks earlier in the HCP Case, reaching 14 049 PJ in 2019 before declining throughout the remainder of the projection period. Demand for most fuels is lower relative to the Reference Case. Natural gas demand in 2040 is 12% lower compared to the Reference Case while consumption of RPPs and natural gas liquids (NGLs) is 3% lower.
 - Energy intensity, measured as energy use per unit of economic activity, declines steadily in both the Reference and HCP cases. Energy intensity declines at an average 1.5% per year in the Reference Case and 1.8% in the HCP Case. Energy use per dollar of gross domestic product falls from 7.5 megajoules (MJ) per dollar in 2016 to 5.2 MJ/\$ in 2040 in the Reference Case and 4.9 MJ/\$ in the HCP Case.

Key Uncertainties

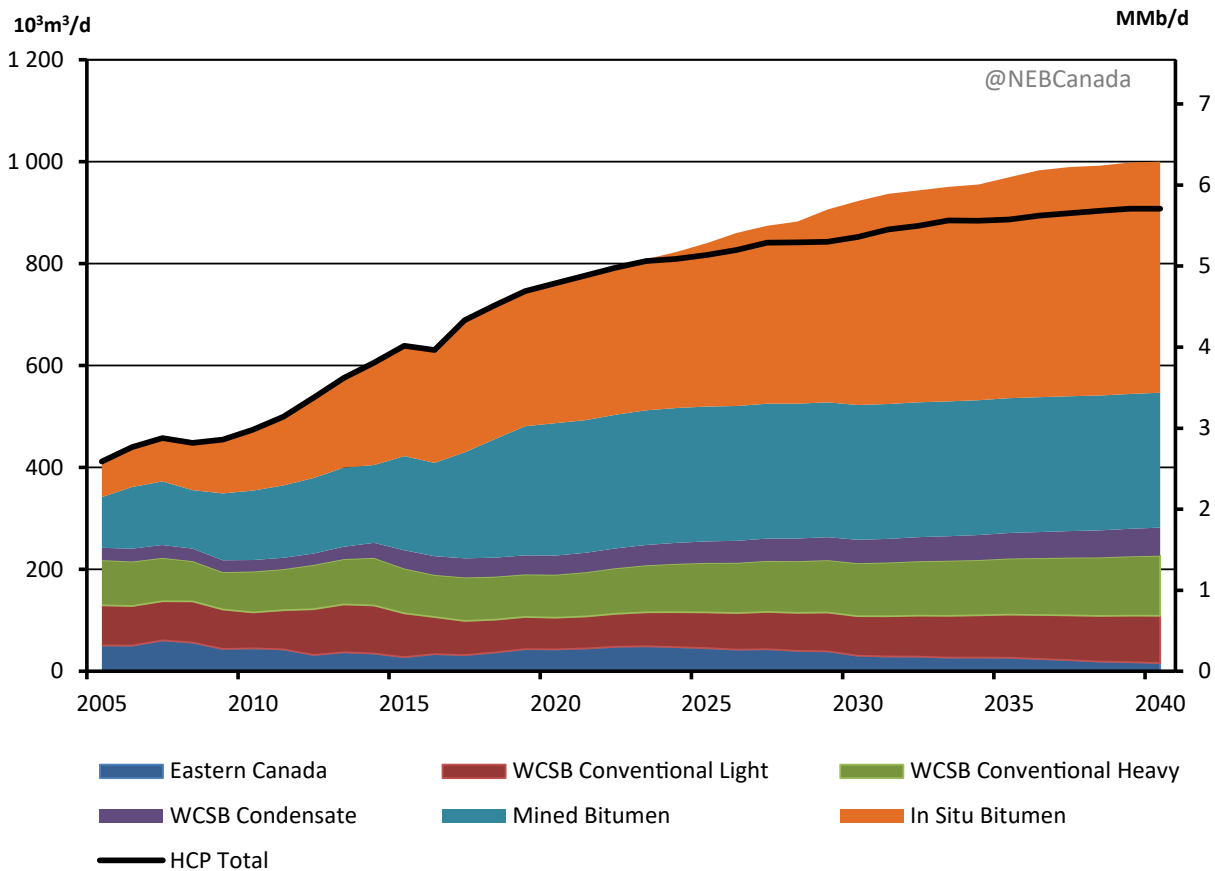
- EF2017 assumes modest growth of emerging technologies. However, technology's influence on the energy system can be substantial and often difficult to predict. Chapter 4 explores this uncertainty by analyzing the impact of greater uptake of a selection of emerging technologies on the energy system.
- The HCP Case examines the impact of higher carbon prices in the long term. The energy use impact in this case is based on the energy demand forecasting model and assumptions employed for this analysis. Other energy models or assumptions could produce different impacts of carbon pricing.
- The HCP Case examines one element of future climate policy uncertainty: carbon pricing. Policies, programs, and regulations are continually under development at federal, provincial, territorial, and municipal levels. These may have significant implications for energy demand trends. The suite of climate policies that will be in place in the long term is unknown.

Crude Oil

- By 2040 Canadian crude oil production in the Reference Case is 1 000 thousand cubic metres per day ($10^3\text{m}^3/\text{d}$) or 6.3 million barrels per day (MMb/d). This is 59% higher than 2016 levels of 631 $10^3\text{m}^3/\text{d}$ (4.0 MMb/d). Figure 3.7 shows crude oil production by type in the Reference Case and total production in the HCP Case.

FIGURE 3.7

Total Canadian Crude Oil and Equivalent Production, Reference and HCP Cases



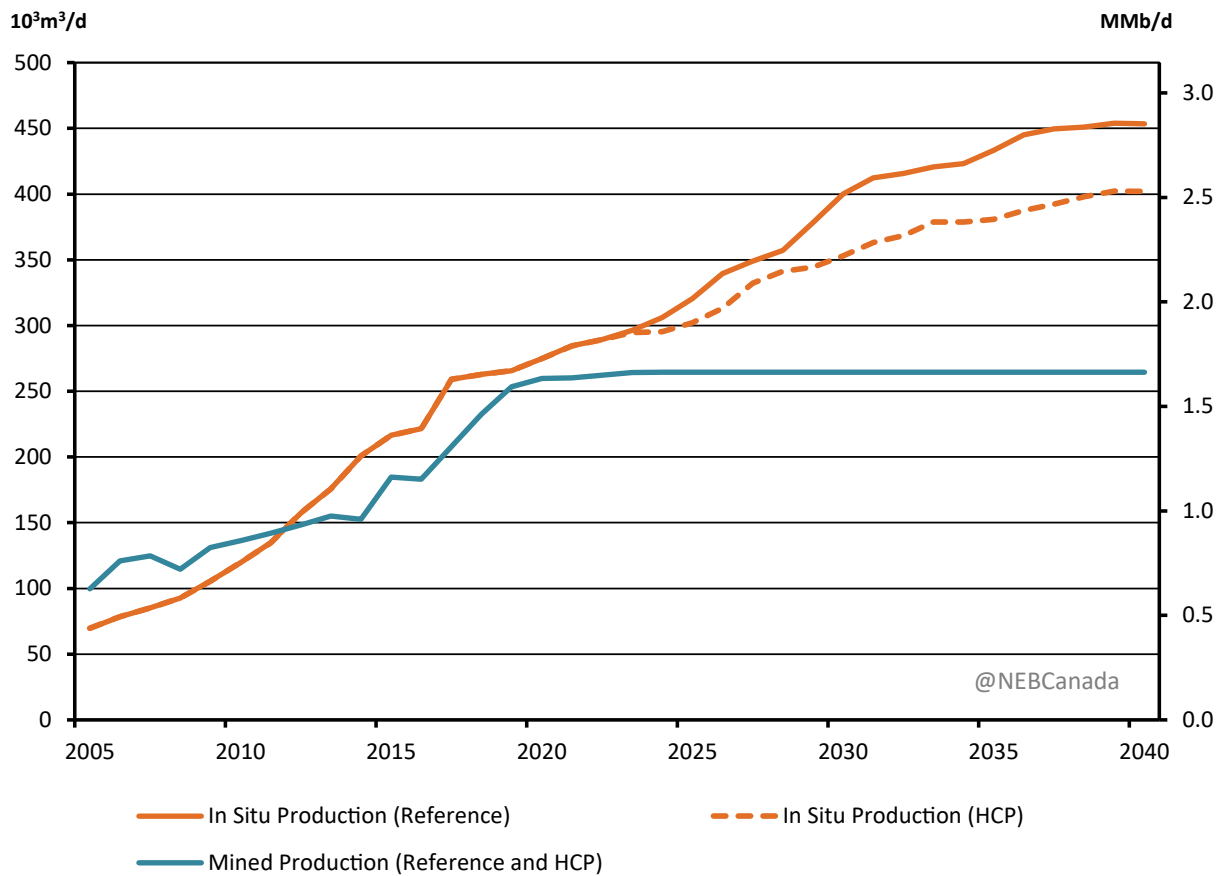
- Total oil production in the HCP Case reaches 908 $10^3\text{m}^3/\text{d}$ (5.7 MMb/d) by 2040, 9% lower than in the Reference Case.

Oil Sands

- Oil sands production in 2016 was 405 $10^3\text{m}^3/\text{d}$ (2.5 MMb/d). At nearly two-thirds of total Canadian oil production in 2016, oil sands make up most of the production growth over the projection period. As shown in Figure 3.8, oil sands production in the Reference Case increases by 77% from 2016 to 2040, reaching 718 $10^3\text{m}^3/\text{d}$ (4.5 MMb/d). The Reference and HCP Cases assume no major use of solvent-based technologies, which involves injecting propane or butane into in situ reservoirs to improve bitumen recovery and reduce energy use. The impact of greater use of this technology is explored in the Technology Case, discussed in Chapter 4.

FIGURE 3.8

Oil Sands Production, Reference and HCP Cases

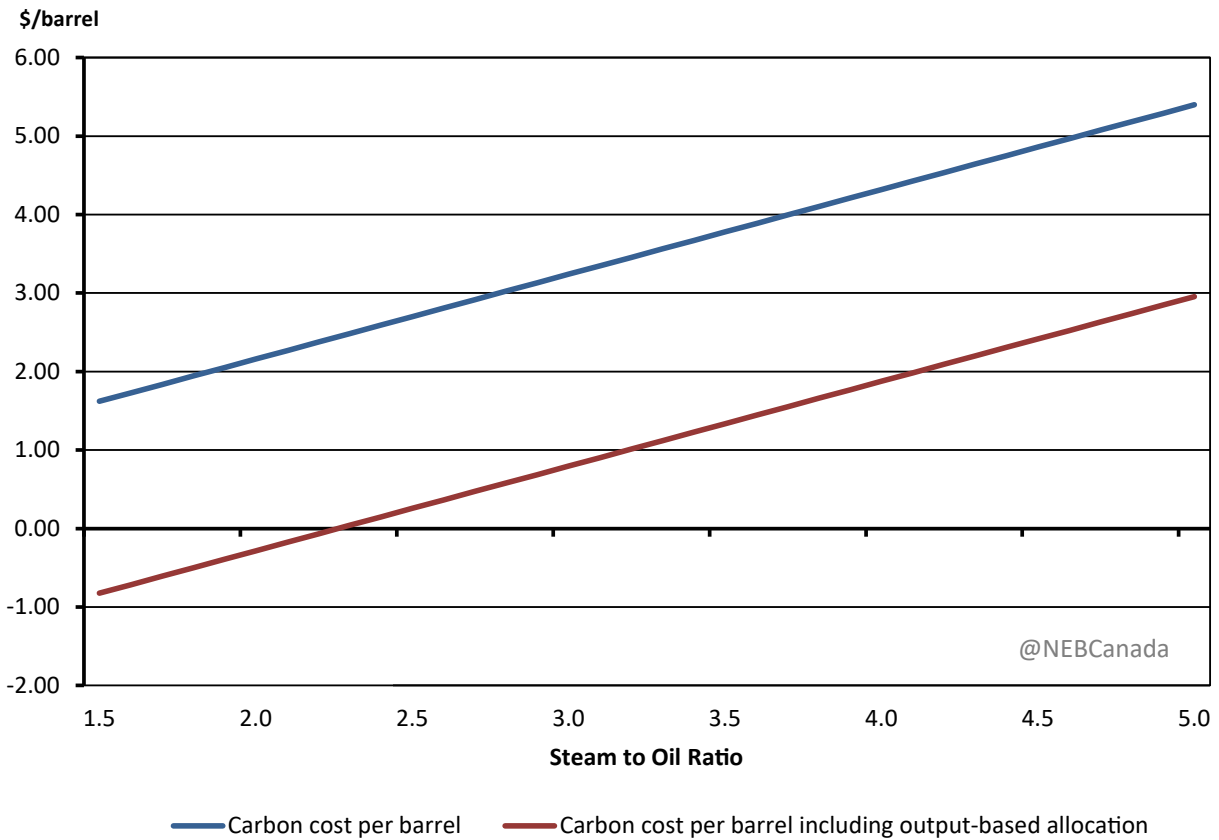


- In the Reference and HCP cases, production of [mined](#) and [in situ](#) bitumen grows steadily early in the projection period. This growth is from recently completed oil sands projects that are ramping up production and those currently under construction. From 2018 to 2021, annual oil sands production growth averages $19\ 10^3\text{m}^3/\text{d}$ (122 Mb/d) per year, slightly slower than growth in the past decade but quicker than the 2022 to 2040 period in both the Reference and HCP cases.
- After mining projects currently under construction are completed and their production is brought up to capacity, no additional mining capacity is added over the projection period. In both cases, crude oil prices do not reach high enough levels to encourage new investment. After 2024, mined bitumen production in the Reference and HCP cases stay constant at $265\ 10^3\text{m}^3/\text{d}$ (1.7 MMb/d).
- In the Reference Case, in situ bitumen production more than doubles from 2016 to 2040, reaching $453\ 10^3\text{m}^3/\text{d}$ (2.9 MMb/d) in 2040, up from $222\ 10^3\text{m}^3/\text{d}$ (1.4 MMb/d) in 2016. The crude oil price assumptions in the Reference Case encourage sufficient investment to grow production, particularly by experienced producers with high quality deposits.

-
- In the HCP Case, in situ production continues to grow but more slowly than in the Reference Case. This is driven by:
 - o The assumption of lower global crude oil prices in the HCP Case.
 - o Higher carbon prices than in the Reference Case.
 - The crude oil prices in the two cases slowly diverge starting in 2023 and by 2040 the Brent crude oil price is US\$5/bbl lower in the HCP Case. This lower price reduces the incentive to invest in more costly projects and is a driver of lower in situ production in the HCP Case.
 - In both cases, the carbon pricing scheme for industrial emissions described in the [Alberta Climate Leadership Panel's report](#) is applied to the oil sands sector. A key element of this scheme is sector-specific output-based allocations that aim to mitigate the competitiveness and employment impacts of applying carbon pricing to trade-exposed industries.
 - For oil sands producers the structure of the industrial carbon pricing scheme means that, in a given year, each producer receives the same allocation of free emission permits per barrel of output. However, each producer's net per barrel carbon costs will vary based on how GHG-intensive they are compared to other producers.
 - A common metric of the energy intensity of in situ oil sands projects is their [steam to oil ratio](#) (SOR). Figure 3.9 shows the estimated per barrel carbon cost of in situ oil sands projects with different SORs. The figure shows the carbon costs associated with natural gas consumption for oil sands projects in the year 2022, when the carbon price is \$50/tonne in both Reference and HCP cases. Most in situ oil sands projects have SORs ranging from 2 to 3 barrels of steam per barrel of oil produced.

FIGURE 3.9

Estimated per Barrel In Situ Oil Sands Carbon Costs at \$50/tonne in 2022



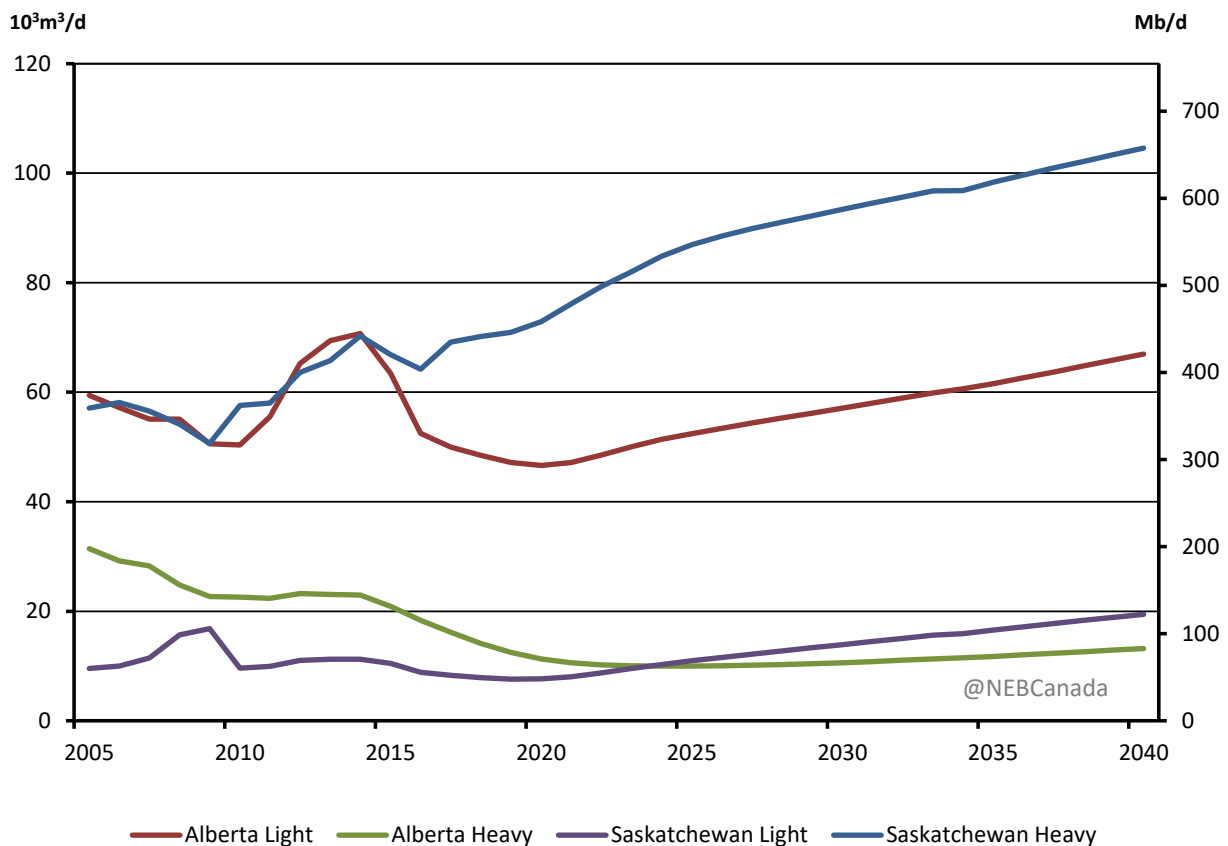
- As shown in Figure 3.9, the per barrel cost increases as the SORs of in situ projects increase. It also shows the impact of the output-based allocations, which reduce the average per barrel carbon cost for all producers by roughly \$2.40 per barrel. Producers performing better than the 25th percentile receive allocations in excess of their carbon costs, resulting in a net credit for producers with SORs lower than 2.3.
- In the HCP Case, the carbon price, and hence the carbon cost per barrel, continues to increase over the projection period. The HCP Case assumes greater global climate action. Accordingly, mechanisms addressing competitiveness concerns, like output-based allocations, are less necessary. The size of the output-based allocations is gradually reduced over the projection period in the HCP Case.
- Together, higher carbon costs and lower crude oil prices in the HCP Case cause in situ production to grow slower, reaching 402 10³m³/d (2.5 MMb/d) in 2040, or 11% lower than in the Reference Case. Some more costly and emission-intensive projects that are included in the Reference Case are excluded from the HCP Case.

Western Canadian Conventional Crude Oil

- Total conventional crude oil production from western Canada accounted for nearly 30% of total Canadian production in 2016 at 192 10³m³/d (1.2 MMb/d). Conventional production is classified as [light](#) or [heavy](#) depending on the [API gravity](#) of the oil. In 2016, 43% of western Canadian conventional production was heavy and 57% was light (including [condensate](#) production). Over 90% of conventional production came from Alberta and Saskatchewan in 2016, with smaller amounts from Manitoba, B.C., and Northwest Territories (NWT). Figure 3.10 shows total conventional production over the projection period in Saskatchewan and Alberta.

FIGURE 3.10

Conventional Oil Production by Type, Saskatchewan and Alberta, Reference Case

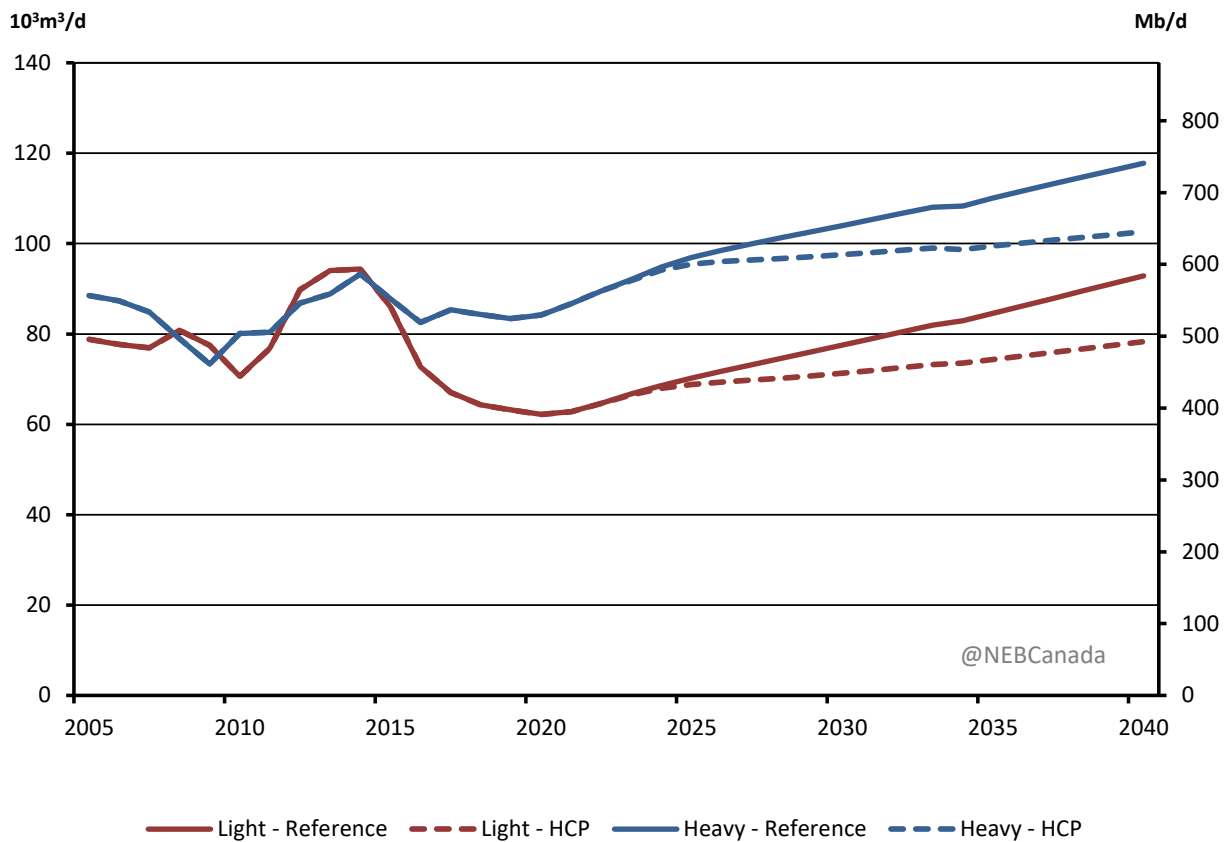


- In Saskatchewan, heavy oil production increases by over 60% from 2016 levels, increasing from 64 10³m³/d (404 Mb/d) to 105 10³m³/d (658 Mb/d) in 2040 in the Reference Case. Heavy oil production in Alberta declines early in the projection period and then grows moderately to 2040.

- Heavy oil production growth in Saskatchewan is a result of the application of [steam assisted gravity drainage recovery](#) (SAGD) methods — a technology often deployed in the oil sands — to heavy oil fields. By early 2017, 15 thermal heavy oil projects were operating in Saskatchewan, a nearly 3-fold increase from 2012. Similar to the oil sands, production from these thermal projects does not exhibit the steep decline rates typical of traditional heavy oil wells. This contributes to the attractiveness of this type of production, leading to steady growth over the projection period.
- Production of light conventional oil declines in the first 4 years of the projection period in the Reference Case as oil prices are insufficient to encourage enough new drilling to offset declines from existing wells. After 2020, production begins to increase as higher prices encourage greater investment. By 2040, light conventional oil production, which includes [tight oil](#), is 28% higher than in 2016, reaching 93 10³m³/d (584 Mb/d).
- In the HCP Case, higher carbon costs and lower crude oil prices result in conventional production growing slower, as shown in Figure 3.11. Total conventional production in western Canada reaches 181 10³m³/d (1.1 MMb/d) in 2040, or 13% lower than in the Reference Case.

FIGURE 3.11

Western Canada Conventional Oil Production by Type, Reference and HCP Cases



Newfoundland Offshore

- In the Reference Case, Newfoundland and Labrador offshore oil production increases steadily over the next five years as the Hebron project begins production and additional wells are brought online at existing facilities. After peaking at 49 10³m³/d (309 Mb/d) by 2023, production begins to decline as shown in Figure 3.12. The Reference Case assumes two generic offshore discoveries add new production starting in 2027 and 2033. As a result of lower oil price assumptions, the HCP Case assumes only one new discovery, which adds production starting in 2030.

FIGURE 3.12

Newfoundland Oil Production, Reference and HCP Cases



Key Uncertainties

- Future oil prices are a key driver of future Canadian oil production and a key uncertainty to the projections in EF2017. Crude oil prices could be higher or lower depending on demand trends, technological developments, geopolitical events, and the pace at which nations enact policies to reduce GHG emissions. The previous edition of *Energy Futures, Canada's Energy Future 2016: Update*, provides additional sensitivity cases that explore the impact of higher or lower oil prices.

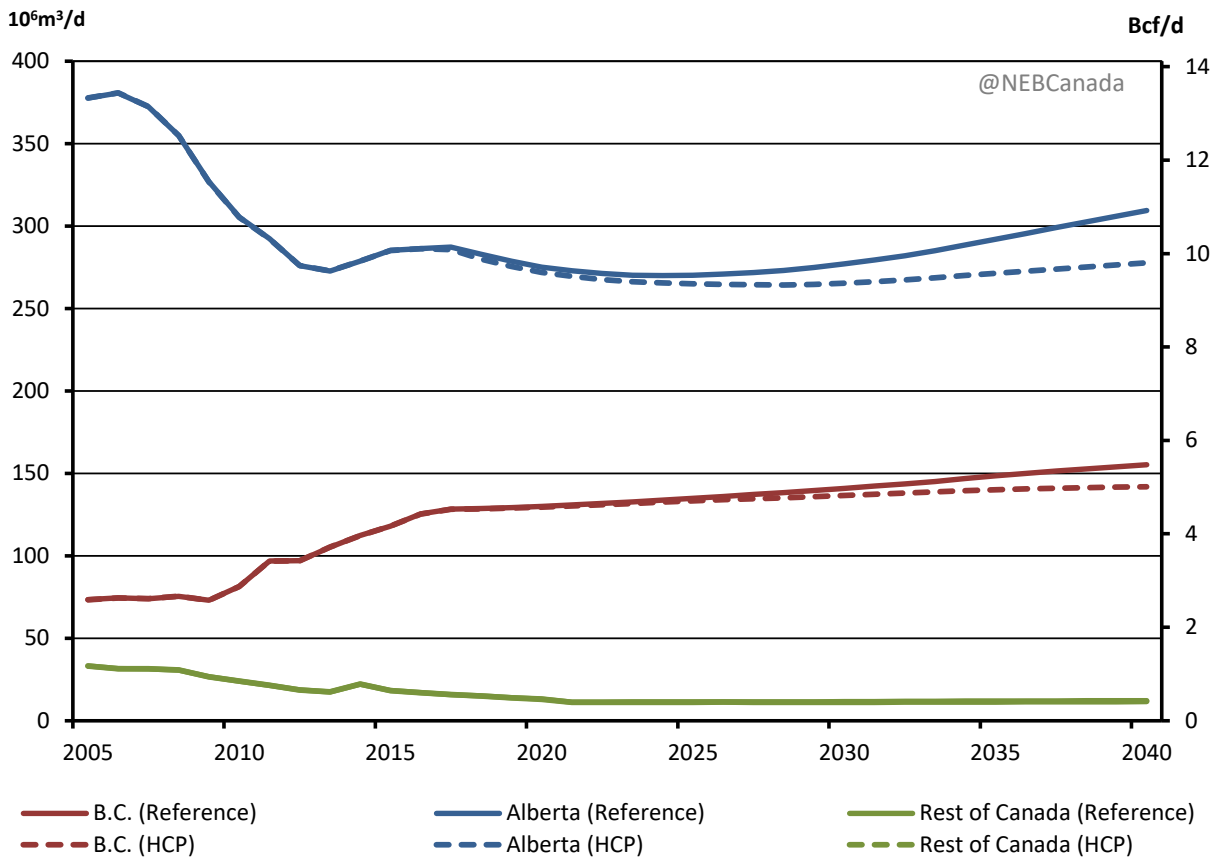
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- The HCP Case assumes that global crude oil prices are lower compared to the Reference Case. This price impact is uncertain and depends on the robustness of concerted global climate action, the responsiveness of oil demand to higher carbon costs, and the availability of alternatives to existing technologies.
 - The pace of technological developments in the oil sands is a key uncertainty. EF2017 assumes gradual technological improvement in the sector and more or less rapid technology development could impact the oil sands production projections. Potential advances that could change the supply projections include solvent-based processes, electrification, and CCS technology.
 - The application of SAGD recovery techniques to Saskatchewan's heavy oil resources is a recent trend and future production growth is uncertain.
 - This analysis assumes that over the long term, all energy production will find markets and infrastructure will be built as needed. However, projects to increase oil transportation capacity in North America have proven controversial. Whether sufficient pipeline infrastructure is in place will impact pricing of Canadian crude oil and the economics of production. Chapter 10 of [Canada's Energy Future 2016](#) provides additional analysis on this key uncertainty to the Canadian energy outlook.

Natural Gas

- Natural gas production in the Reference Case declines early in the projection period, reaching a low of 414 million cubic metres per day ($10^6\text{m}^3/\text{d}$) or 14.6 billion cubic feet per day (Bcf/d) in 2023. After 2023, production begins to increase as gradually higher prices encourage enough drilling to offset production declines from older wells. By 2040, production increases to $477\ 10^6\text{m}^3/\text{d}$ (16.8 Bcf/d), its highest level since 2007. Figure 3.13 shows natural gas production in Alberta, B.C., and the rest of Canada in the Reference and HCP cases.

FIGURE 3.13

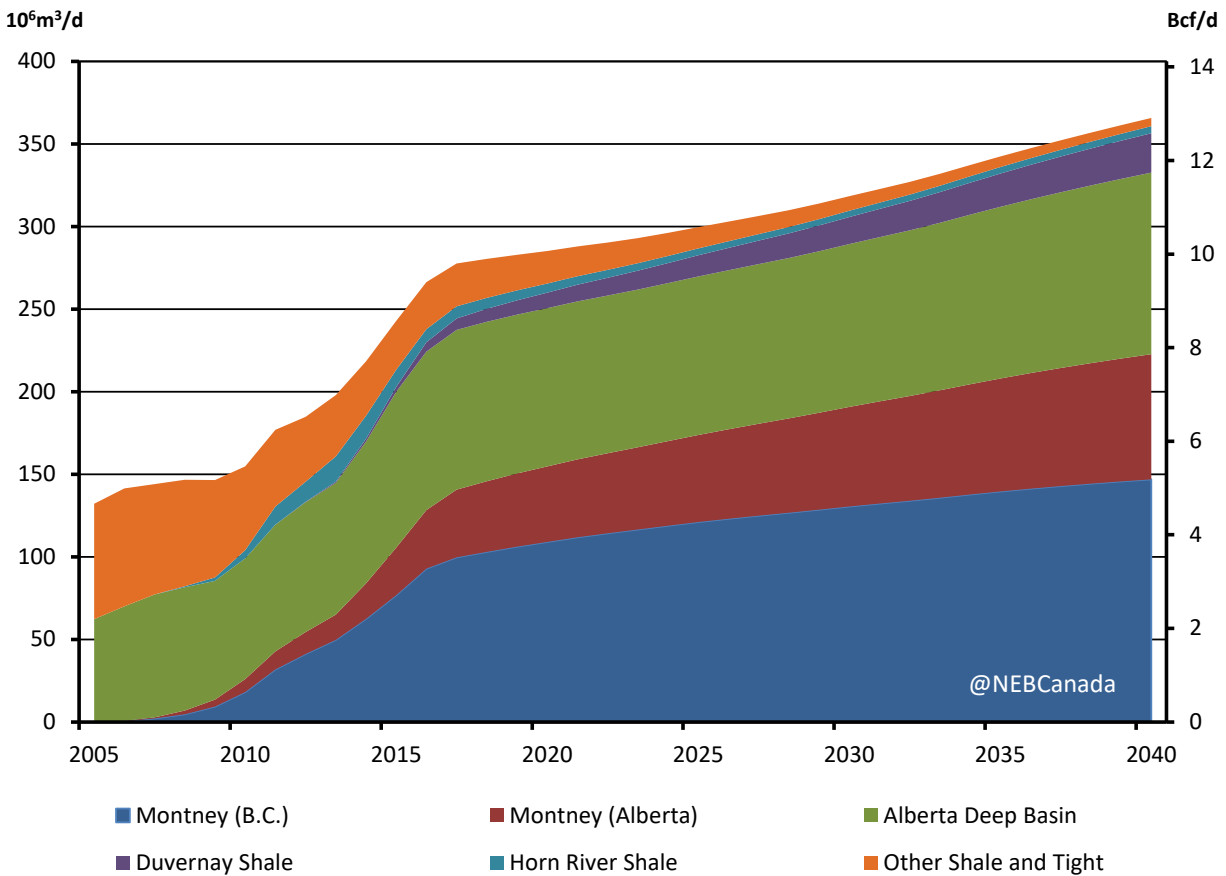
Natural Gas Production, Reference and HCP Cases



- Figure 3.14 shows tight and shale gas production by play in the Reference Case. Production from the Montney formation, a large resource located in northeast B.C. that extends into northwest Alberta, has grown significantly over the past five years. Production of [tight gas](#) from the Montney increased from no production prior to 2006 to almost 128 $10^6 \text{m}^3/\text{d}$ (4.5 Bcf/d) in 2016, or 30% of total Canadian natural gas production in 2016. The majority of production growth over the projection period comes from the Montney, with production reaching 223 $10^6 \text{m}^3/\text{d}$ (7.9 Bcf/d) in 2040, a 74% increase from 2016. In the HCP Case, production from the Montney grows at a slightly slower pace and is 8% lower than the Reference Case by 2040.

FIGURE 3.14

Tight and Shale Natural Gas Production by Play, Reference Case



- The Alberta Deep Basin — a liquids rich tight gas play which runs along the Alberta foothills — produced 96 10⁶m³/d (3.4 Bcf/d) in 2016. Production grows modestly as natural gas and natural gas liquids prices increase, reaching 110 10⁶m³/d (3.8 Bcf/d) by 2040 in the Reference Case and 105 10⁶m³/d (3.7 Bcf/d) in the HCP Case.
- The Duvernay and Horn River shale gas plays currently produce small amounts of natural gas and production from both grows modestly over the projection period. The Duvernay is an emerging shale play in Alberta that contains natural gas, natural gas liquids and crude oil. The Horn River play lacks natural gas liquids, reducing its attractiveness compared to other areas. Combined, production from the two plays increases from 14 10⁶m³/d (0.5 Bcf/d) in 2016 to 28 10⁶m³/d (1.0 Bcf/d) in the Reference Case by 2040.
- Production from [conventional](#) and [coalbed methane](#) natural gas resources — which do not rely on horizontal drilling and [multi-stage hydraulic fracturing](#) techniques — declines steadily over the projection period as new drilling targeting these resources is not economic given the natural gas price assumptions in EF2017. Western Canadian [conventional non-tight production](#), which made up 65% of total production in 2006 and 37% in 2016, falls to 23% in 2040.

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- Natural gas production in eastern Canada continues to decline over the projection period. Onshore natural gas production in New Brunswick falls to near zero in both the Reference and HCP Case by 2040. Offshore natural gas production in Nova Scotia declines steadily over the projection period. Production ceases in 2021 when the costs of offshore operations exceed the revenue generated by the natural gas produced.
 - Previous *Energy Futures* Reference Case projections have assumed some volumes of LNG exports within the projection period. The global LNG market is becoming increasingly competitive as more facilities are built around the world. [Some LNG projects are still being considered by developers on Canada's east and west coasts](#). However, given recent low global LNG prices and the relatively higher cost of commissioning a new LNG facility along with pipelines needed to supply gas to it, EF2017 makes an assumption that no LNG exports from Canada will take place over the projection period.

Key Uncertainties

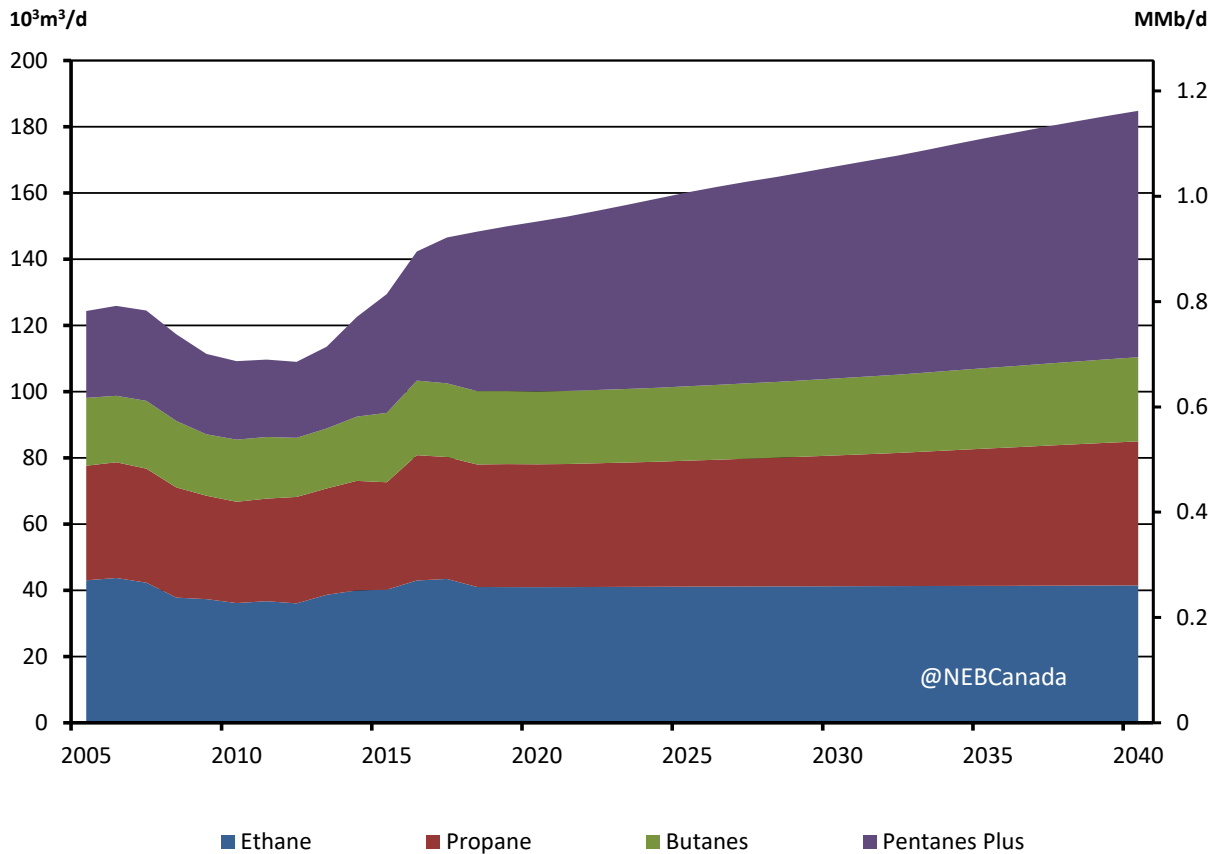
- Future natural gas prices are a key uncertainty in the projections. The previous edition of *Energy Futures*, [Canada's Energy Future 2016: Update](#), provides additional sensitivity cases that explore the impact of higher or lower natural gas prices.
- This analysis assumes that over the long term, all energy production will find markets and infrastructure will be built as needed. However, lack of markets for Canadian natural gas production could reduce the prices Canadian producers receive relative to the Henry Hub price and impact gas production trends.
- The timing and volume of LNG exports from Canada is uncertain. Canadian LNG exports have several advantages over competitors such as its proximity to Asian markets, the low cost of natural gas feedstocks, and the benefits of cooler Canadian weather. It is possible that market conditions and the costs of commissioning a new LNG export facility may change in the future, influencing the future prospects of LNG in Canada. Uncertainty related to LNG exports is explored further in two sensitivity cases in Chapter 11 of [Canada's Energy Future 2016](#).
- The HCP Case assumes the same natural gas prices as in the Reference Case. As noted in Chapter 2, this is based on uncertainty related to the impact that stronger global action on climate could have on North American and global natural gas demand, and hence natural gas prices. Stronger carbon action may affect fuel choices, the competitiveness of renewables in the power generation sector, and the pace of technological developments.

Natural Gas Liquids

- Raw natural gas recovered at a wellhead is comprised primarily of methane, but often contains other hydrocarbons and some contaminants. These other hydrocarbons consist of ethane, propane, butanes and pentanes plus, which are collectively referred to as [NGLs](#). The majority of NGLs are recovered from natural gas but some are also produced as a by-product of oil refining or bitumen upgrading.
- Total natural gas liquid production increases steadily throughout the projections, as natural gas producers increasingly target areas rich with NGLs. Combined NGL production increases by 30% over the projection period, from 142 10³m³/d (0.9 MMb/d) in 2016 to 185 10³m³/d (1.2 MMb/d) in 2040. Figure 3.15 shows total NGL production in the Reference Case.

FIGURE 3.15

Natural Gas Liquids Production, Reference Case



- Ethane, the majority of which is extracted at [large natural gas processing facilities](#) located on major natural gas pipelines in Alberta and B.C., made up 30% of NGL production in 2016 at 43 10³m³/d (270 Mb/d). Ethane production in the Reference Case is relatively stable at 41 10³m³/d (261 Mb/d) over the projection period as its production is limited to the capacity of petrochemical facilities in Alberta which use it as a feedstock.
- Propane production in the Reference Case declines until the end of the decade, following overall natural gas production trends. As natural gas production begins to increase, propane production begins to increase steadily, and reaches 43 10³m³/d (273 Mb/d) by 2040, 15% higher than 2016 levels of 38 10³m³/d (238 Mb/d).
- Butanes production follows a similar pattern to propane production, declining early and then increasing steadily through the remainder of the projection period. Butane production is 13% higher than 2016 levels by 2040, increasing from 23 10³m³/d (142 Mb/d) to 25 10³m³/d (160 Mb/d).
- Production of pentanes plus, also referred to as condensate, increased over 50% from 2013 to 2016, as producers targeted pentanes plus rich areas, such as the Montney and Duvernay plays. Of the NGLs, pentanes plus increases the most over the projection period, increasing by 91%, from 39 10³m³/d (245 Mb/d) in 2016 to 74 10³m³/d (468 Mb/d) in 2040. Production growth in the oil sands provides a growing market for pentanes plus, where it is used as [diluent](#).

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- In the HCP Case, NGL production is slightly lower due to somewhat lower natural production projections. Total NGL production reaches 172 10³m³/d (1.1 MMb/d) in 2040, 7% lower than in the Reference Case.

Key Uncertainties

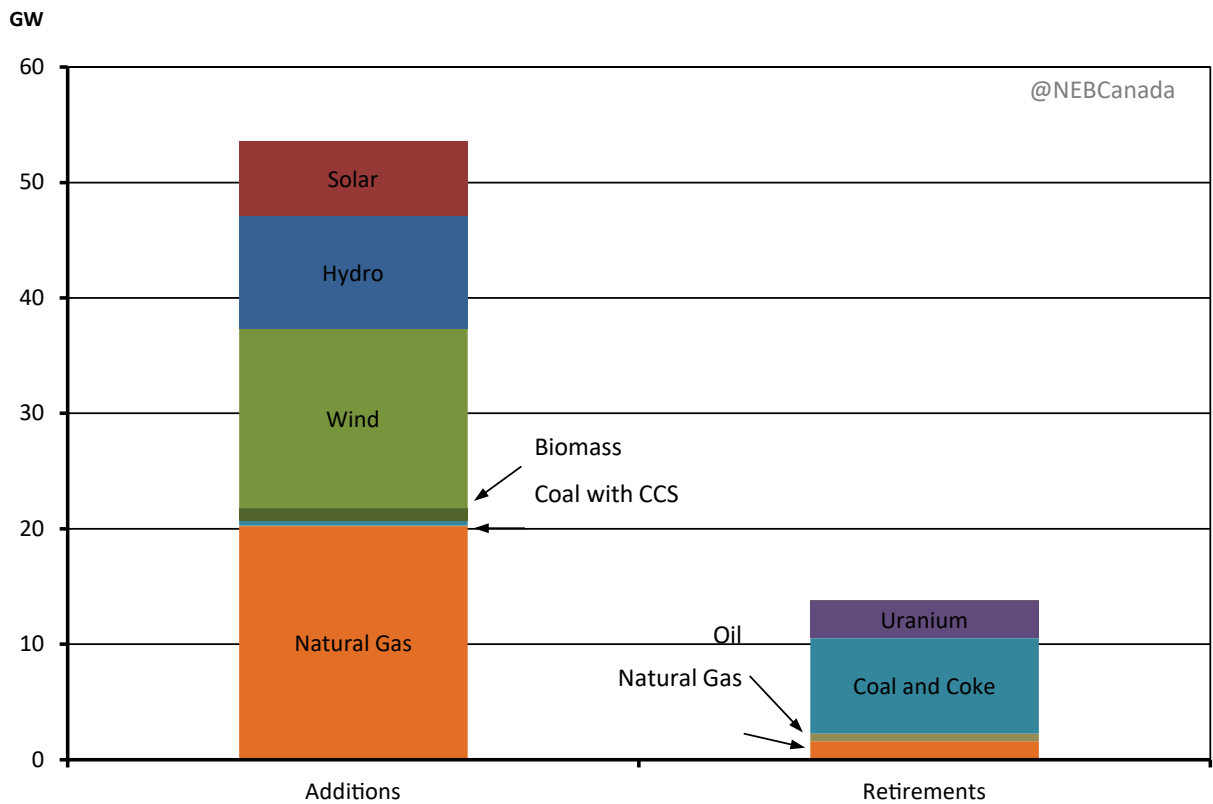
- NGLs are a by-product of natural gas production, and the uncertainties identified in the Natural Gas section are uncertainties to the NGL projections.
- The rate of oil sands production growth, and proportion of bitumen that is upgraded, will affect the demand for pentanes plus required for diluent. Likewise, greater use of solvent technologies in the oil sands could increase the market for propane and butanes, which could impact those production projections.

Electricity

- In 2015, installed electricity generation capacity in Canada reached 145 gigawatts (GW). Hydroelectricity remains the primary source of electric power, accounting for 55% of total capacity and 58% of generation. Natural gas, coal, nuclear and non-hydro renewables, including wind, solar, and biomass, provide most of the remaining supply.
- The electricity supply mix varies significantly among the provinces and territories, reflecting the types of energy available, economic considerations, and policy choices in each region. Quebec, B.C., Manitoba, Newfoundland and Labrador, and Yukon have significant hydroelectric resources which are used to supply most of their electricity needs. Saskatchewan and Alberta have historically relied on locally abundant coal resources but have recently expanded their natural gas-fired fleet. Nuclear power plants make up approximately one-third of Ontario's capacity, with natural gas and hydro providing much of the remaining power. The Maritime provinces rely on a combination of hydro, various fossil fuels, nuclear, and non-hydro renewable resources. Diesel-fueled plants account for most of the capacity in Nunavut and NWT.
- In 2015, Canadian electricity demand was 522 terawatt-hours (TW.h) and accounted for 17% of total Canadian end-use energy demand. From 1990 to 2015, Canadian electricity demand increased by an average of 1.0% per year. In the Reference Case, electricity demand increases at an average annual rate of 0.9% over the projection period.
- Figure 3.16 shows additions and retirements of generating capacity over the projection period. The majority of additions to capacity in the Reference Case are natural gas, wind, and hydro facilities, accounting for 85% of the 54 GW added from 2016 to 2040. The remaining additions include 6.4 GW of solar, 1.1 GW of biomass and 0.4 GW of coal equipped with CCS technology. Coal, nuclear and oil-fired facilities, along with some older natural gas-fired facilities, make up the bulk of retirements.

FIGURE 3.16

Capacity Additions and Retirements by 2040, Reference Case



*not visible in Figure 3.16 is the addition of 78 MW of oil-fired generating capacity

- Electricity supply is often be discussed in terms of capacity and generation. Capacity is the maximum electric output a facility can produce while generation refers to the amount of power actually produced. These concepts are discussed in detail in the Board’s recent report “[Canada’s Renewable Power Landscape](#)”. Table 3.2 shows capacity and generation by fuel in 2016 and 2040 in the Reference Case.

T A B L E 3 . 2

Electric Capacity and Generation in 2016 and 2040, Reference Case

Energy Source	Capacity in GW and %		Generation in TW.h and %	
	2016	2040	2016	2040
Hydro	80.4	89.2	376.7	413.0
	54.8%	48.0%	58.3%	56.4%
Wind	11.9	26.6	28.4	69.4
	8.1%	14.3%	4.4%	9.5%
Solar	2.3	8.6	3.6	13.0
	1.6%	4.6%	0.6%	1.8%
Biomass	2.7	3.5	13.2	15.3
	1.8%	1.9%	2.0%	2.1%
Nuclear	14.3	11.1	96.3	87.0
	9.7%	6.0%	14.9%	11.9%
Coal	9.7	1.8	61.9	4.1
	6.6%	1.0%	9.6%	0.6%
Natural Gas	21.5	41.7	62.9	128.0
	14.7%	22.5%	9.7%	17.5%
Oil	3.8	3.3	3.3	2.0
	2.6%	1.8%	0.5%	0.3%
All Sources	146.6	185.8	646.3	731.9

Outlook by Fuel

Hydro

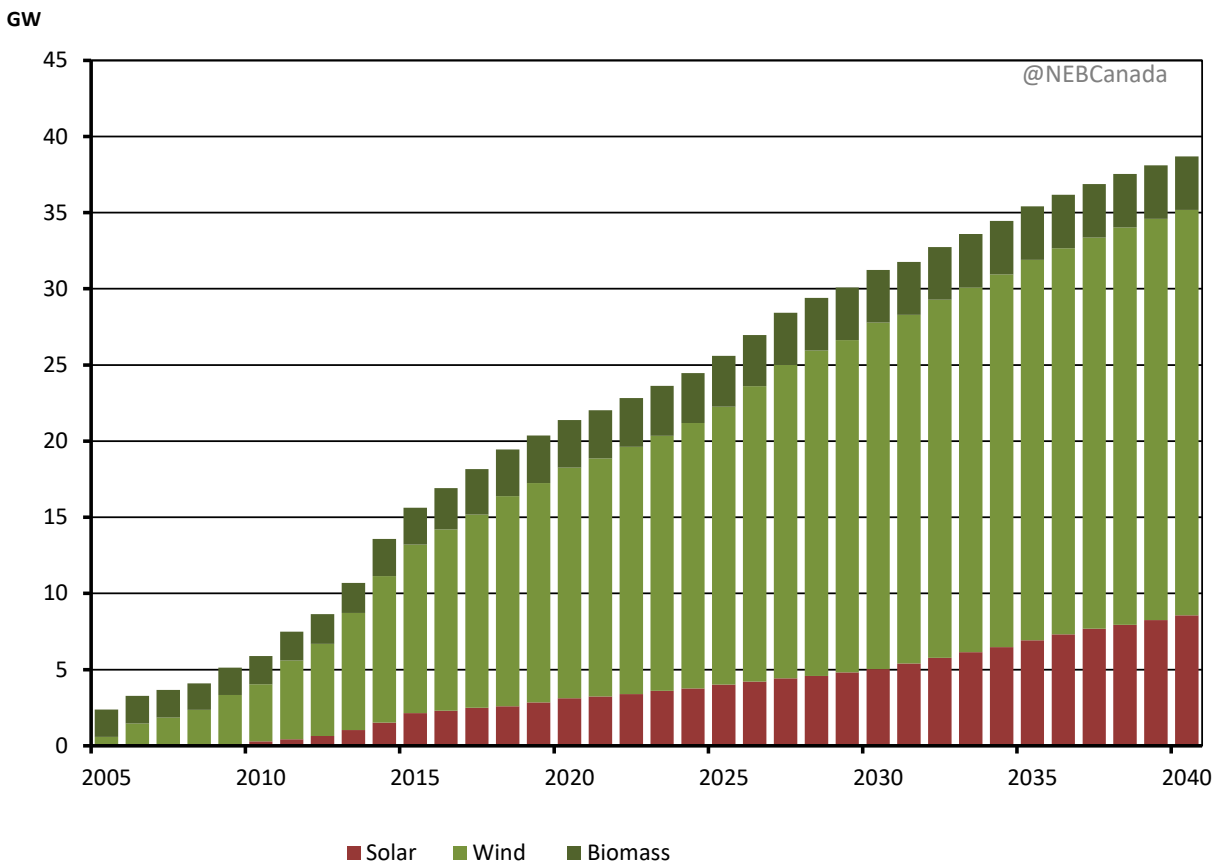
- Hydroelectricity remains the dominant source of electricity supply in Canada over the projection period. Hydro power has numerous advantages, including flexibility, relative affordability, lack of GHG emissions at the operation stage, and cost-stability. With its capability to store water and to change output as needed, Canada's hydro capacity also facilitates the development of intermittent renewable resources such as wind and solar.
- Hydro-based capacity, including small hydro and run-of-river facilities, increases from 80 GW in 2016 to 89 GW in 2040. This capacity expansion reflects a number of large hydro projects currently under construction or in the planning and development phases.
- As a result of hydro-based capacity expansions, annual hydroelectricity production increases from 377 TW.h in 2016 to 413 TW.h in 2040 in the Reference Case. Due to faster growth in other forms of generation, such as wind and natural gas, the share of hydroelectricity declines slightly over the projection period from 58% in 2016 to 56% in 2040.

Non-hydro Renewables

- Canada has considerable non-hydro renewable resource potential including wind, biomass, solar, tidal, wave, and geothermal. Over the past 5 years, policy incentives and declining costs have spurred significant growth in the use of some of these technologies. In 2015, Canada had 16 GW of wind, solar, and [biomass](#) capacity, nearly triple 2010 levels. Most wind power capacity is in Ontario, Quebec, and Alberta, while the majority of solar capacity is in Ontario.
- As shown in Figure 3.17, non-hydro renewable capacity continues to grow in the Reference Case, more than doubling to 39 GW by 2040. Wind capacity increases from 12 GW in 2016 to 27 GW in 2040, with nearly 60% of that increase in Alberta. Solar capacity more than triples, increasing from 2.3 GW in 2016 to 8.6 GW in 2040, with the majority of growth in Ontario, Quebec, and Alberta. Biomass generation capacity grows steadily, from 2.7 GW in 2016 to 3.5 GW by the end of the projection period.

FIGURE 3.17

Non-Hydro Renewable Capacity, Reference Case



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- Recent cost declines, particularly for solar, play a role in increasing renewable capacity as do various government plans and policies. This includes Alberta's Renewable Energy Program, which adds 5 GW of renewable capacity by 2030, and Saskatchewan's goal of increasing its renewable capacity to 50% of total capacity by 2030. Generation from these sources increases from 45 TW.h in 2016 to 98 TW.h in 2040 in the Reference Case, accounting for 13% of all electricity generated.

Nuclear

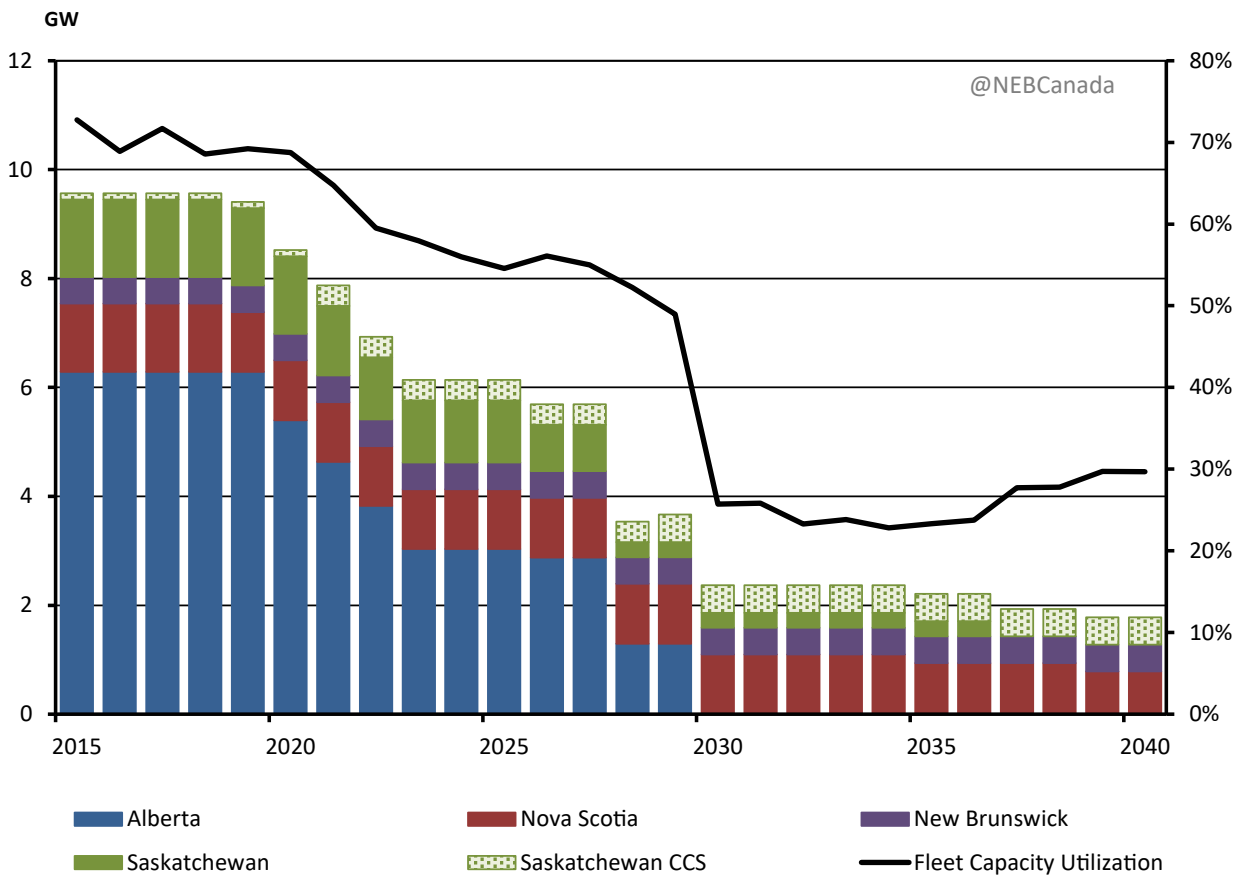
- Nuclear energy accounted for 15% of total electricity generation in Canada in 2015. Ontario's three nuclear facilities had a combined capacity of nearly 14 GW in 2015 and generated 58% of the province's electricity. New Brunswick's single nuclear facility generated a third of the province's power in 2015.
- Annual nuclear generation declines from 92 TW.h in 2016 to 82 TW.h in 2040 in the Reference Case due to the shutdown of Ontario's Pickering Nuclear facility in 2024. Through much of the projection period, nuclear generation is somewhat lower than current levels due to outages of several nuclear units in Ontario that are scheduled for refurbishment. No new nuclear units are built during the projection period.
- Non-emitting generation sources: hydro, renewables and nuclear, contribute 82% of generation by 2040 in the Reference Case. Despite considerable additions of non-hydro renewables, this is only up slightly from 80% in 2016 as natural gas-fired generation is also added over the projection period to meet increasing load growth.

Coal

- Coal-fired generation facilities accounted for 6% of installed capacity in 2015, and generated 9% of all electricity. Currently four provinces operate coal-fired power plants: Alberta, Saskatchewan, New Brunswick and Nova Scotia.
- Federal regulations apply a strict emission performance standard to units that have reached the end of their useful lives, essentially requiring them to be shut down or retrofitted with CCS technology. In 2015, Alberta announced plans to accelerate the phase out of its coal fleet, requiring traditional coal plants to be phased out by 2030. In autumn 2016, the federal government announced its intention to amend its existing coal regulations to phase out traditional coal-fired facilities by 2030 rather than at the end of their economic lives.
- As a result of these initiatives, coal capacity declines considerably over the projection period. EF2017 assumes equivalency agreements are reached in Saskatchewan, New Brunswick and Nova Scotia, allowing those provinces to keep some traditional coal capacity in place after 2030. That capacity is used sparingly in the 2030 to 2040 timeframe. Figure 3.18 shows coal capacity by province over the projection period, as well as the capacity utilization of the existing plants.

FIGURE 3.18

Coal-fired Generating Capacity by Province, Reference Case



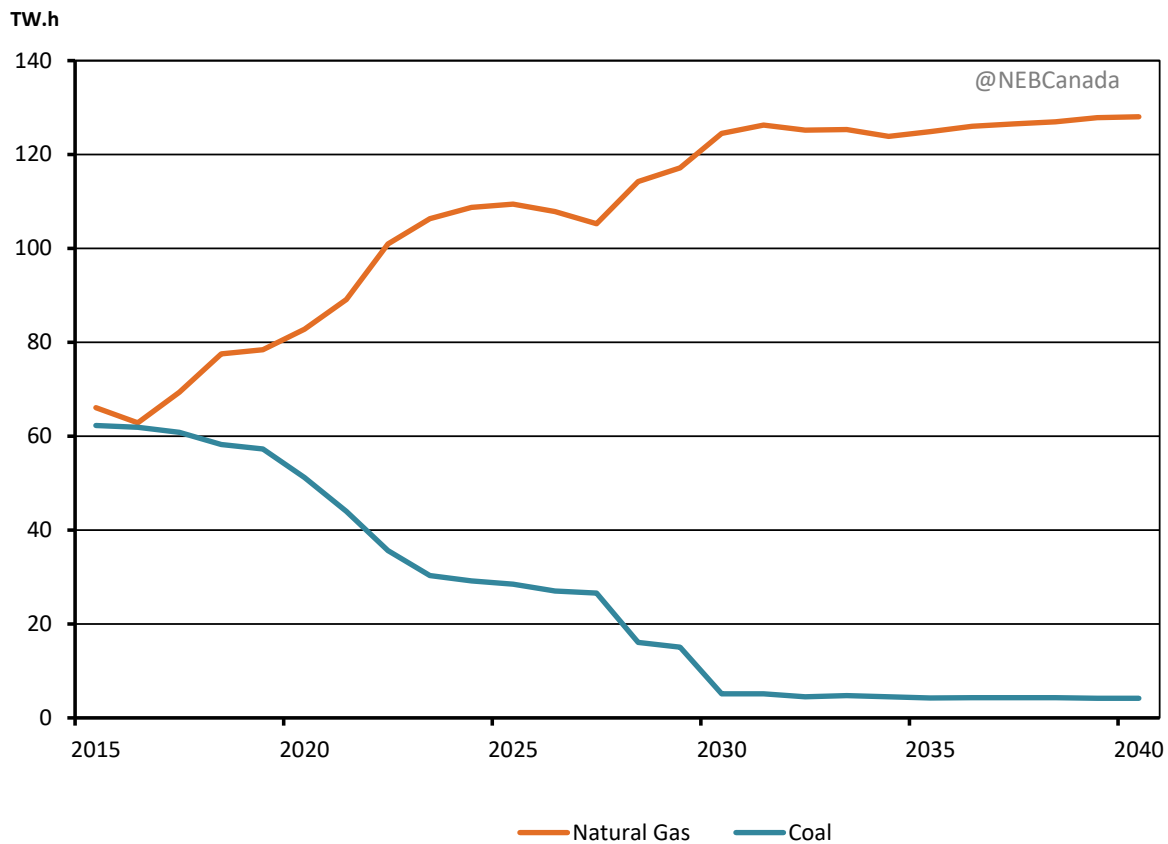
- Saskatchewan currently has one coal-fired generation station that is equipped with CCS technology. The Boundary Dam facility was put into operation in autumn 2014 and as of May 2017, it has captured 1.6 MT of CO₂. Over the projection period, three additional Saskatchewan coal units are retrofitted with CCS technology, providing 0.4 GW of capacity.

Natural Gas

- Natural gas-fired capacity accounted for 15% of total capacity in 2015, with 22 GW installed. All regions in Canada other than Prince Edward Island and Nunavut use natural gas to generate some electricity, although its share is most significant in Alberta and Saskatchewan.
- Natural gas-fired capacity increases steadily over the projection period. As a result of relatively low fuel prices and upfront capital costs, natural-gas fired capacity replaces much of the coal capacity that is retired over the projection period. In the Reference Case, natural gas capacity nearly doubles from 21.5 GW in 2016 to 41.7 GW in 2040. Figure 3.19 shows generation from natural gas and coal over the projection period.

FIGURE 3.19

Generation by Natural Gas and Coal Plants, Reference Case



- Natural gas capacity also increases as a result of increasing use of intermittent renewable resources such as wind and solar. Greater production from intermittent generation sources requires grid operators to be able to accommodate fluctuations in both electricity consumption and production. This makes natural gas plants' ability to increase or decrease generation quickly an attractive quality, especially in provinces without large scale hydro resources. Chapter 4: Technology Case Results, discusses some of the options available to integrate intermittent renewables.

Oil

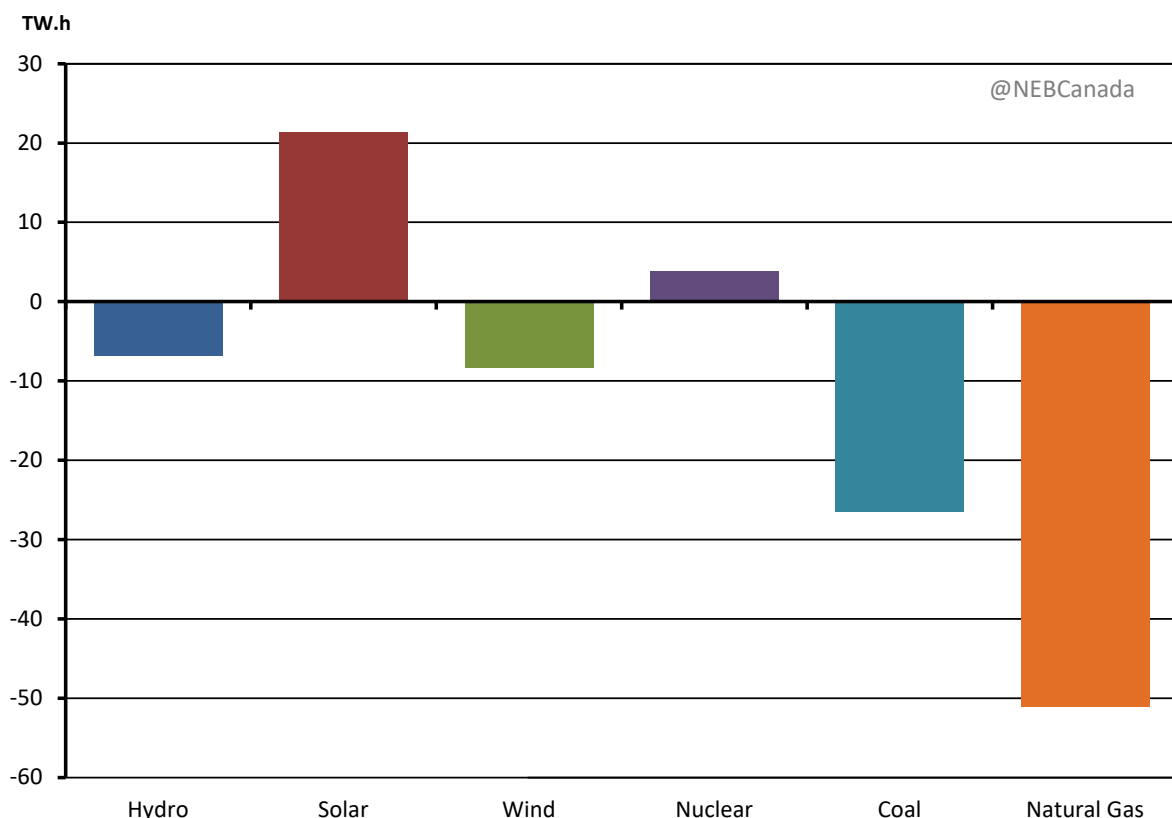
- Oil-fired power plants accounted for only 2.5% of total Canadian installed capacity in 2015 but are an important part of the electricity supply mix in some smaller provinces and territories. Oil-fired power plants, which mostly run on diesel, are used to generate electricity during peak demand periods or in areas where other generation options are not widely available.
- Total oil-fired capacity declines from 3.8 GW in 2016 to 3.3 GW in 2040. This reflects the retirements of aging units, which are being replaced by renewable power, natural gas or LNG-fired units when possible.

HCP Case Electricity Results

- Higher carbon pricing has a modest overall impact on Canada’s electricity sector. Reasons for this include:
 - Canada already has a low emitting electricity sector, with hydro, renewables, and nuclear making up the majority of generation. Carbon pricing more directly impacts emitting resources which make up a smaller portion of Canada’s electricity supply.
 - Numerous climate policies already target the electricity sector, particularly the phase out of traditional coal-fired generation. As a result, the impact of higher carbon pricing is muted compared to scenarios in which those policies are not in place.
 - Many types of generating facilities have high upfront capital costs and long economic lives. As a result, the electricity mix can be slow to change in response to changing fuel prices.
- In the HCP Case, higher fuel prices, and hence higher electricity prices, result in somewhat lower electricity consumption over the projection period. By 2040, electricity use is 1.1% lower compared to the Reference Case. This results in slightly lower generation by most generation types over the projection period, although the biggest reduction is for coal and natural gas. Figure 3.20 shows cumulative generation from 2022 to 2040, by fuel type, in the HCP Case compared to the Reference Case. Solar capacity grows somewhat more quickly in the HCP Case due to higher carbon pricing, resulting in greater solar generation compared to the Reference Case.

FIGURE 3.20

Cumulative Generation from 2022 to 2040 by Fuel, HCP Case Compared to the Reference Case



Key Uncertainties

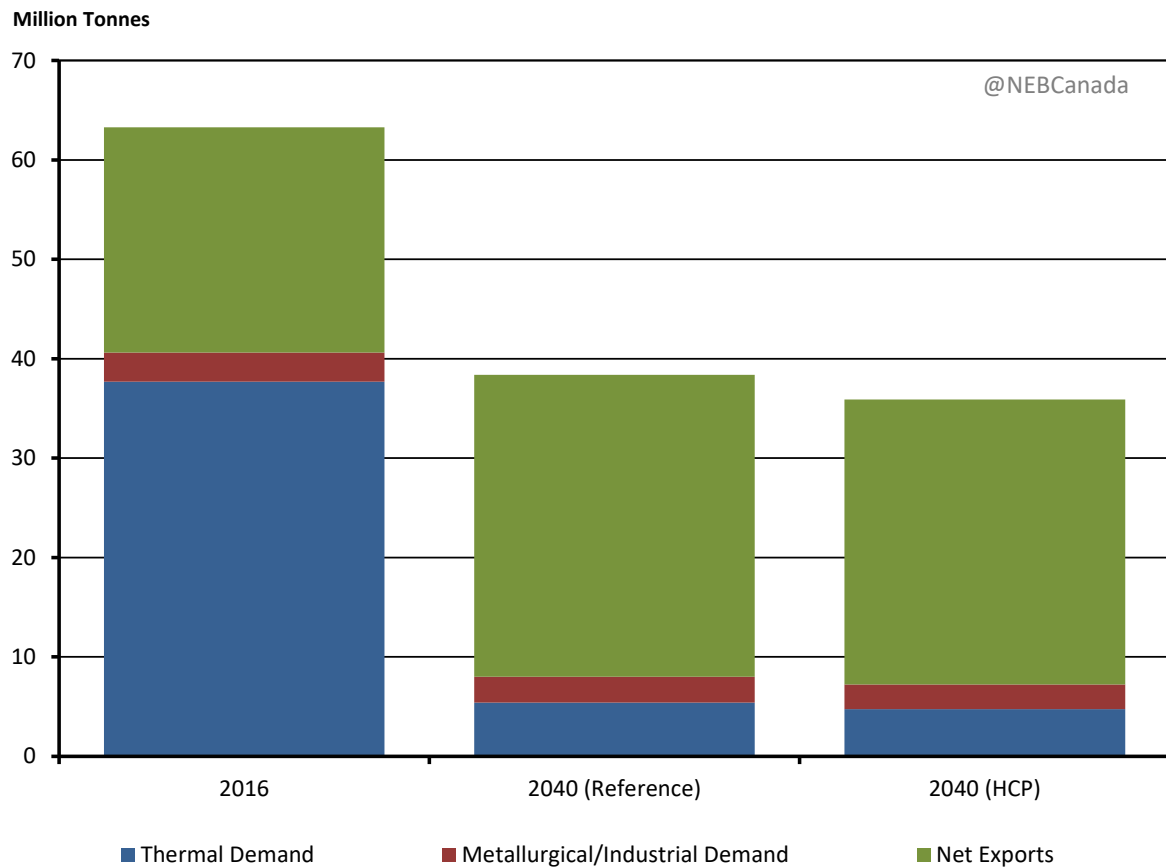
- The capital costs associated with building different generating technologies is an important factor in determining what type of facilities are built. Future costs for technologies can be uncertain, particularly for less mature technologies such as wind, solar, and CCS. Chapter 4 explores the uncertainty associated with lower cost assumptions for these types of technologies compared to the Reference Case.
- Strong growth in both utility-scale and rooftop solar capacity in some southwestern U.S. states is [creating new challenges for grid operators](#). High levels of solar generation during sunny hours results in steep drops in non-solar generation in the morning and rapid increases in the evening once the sun begins to set. This pattern is impacting non-solar generation in those regions, favouring generators with the ability to increase or decrease generation quickly. While most regions in Canada do not get as much solar radiation as the U.S. southwest, the implications of much faster growth in solar than projected in EF2017 is a key uncertainty.
- Electricity demand growth is an important factor in determining future electricity supply. As a result, the uncertainties identified in the “Energy Demand” section are uncertainties to the electricity supply projections.

Coal

- Total Canadian coal production in 2015 was 61.9 million tonnes. There are two main types of coal produced in Canada, [thermal](#) and [metallurgical](#) coal. As the fuel for coal-fired power generation, Canadian thermal coal production is linked to the use of coal in the electricity sector, particularly in Alberta and Saskatchewan. Metallurgical coal is primarily used for steel manufacturing domestically and internationally. Much of Canada’s metallurgical coal production is exported and future production trends are linked to global coal demand and prices.
- Thermal coal, mostly used for power generation, accounted for 93% of total coal consumption in 2015 in Canada. In the Reference Case, demand for thermal coal declines by 86% over the projection period, falling from 37.7 million tonnes in 2016 to 5.4 million tonnes in 2040. Most of the thermal coal consumed in 2040 is used in coal-fired generation facilities equipped with CCS technology.
- This declining trend is driven primarily by retirements of coal-fired generation capacity resulting from regulations to phase out traditional coal-fired power plants by 2030. In response to declining domestic demand, production of thermal coal in Canada falls from 36.3 million tonnes in 2016 to 7.9 million tonnes by 2040.
- Domestic demand for metallurgical coal used in steel manufacturing is stable over the projection period at 3.0 million tonnes. Global demand for metallurgical coal grows moderately over the projection period, resulting in steady growth in net exports from Canada. Total metallurgical coal production in Canada increases from 26.9 million tonnes in 2016 to 30.5 million tonnes in 2040.
- Figure 3.21 shows Canadian production and consumption of coal in Canada in 2016 and 2040 in the Reference and High Carbon Price Cases.

FIGURE 3.21

Canadian Coal Production and Disposition, Reference and High Carbon Price Cases



- In the HCP Case, coal production is 6% lower by 2040 compared to the Reference Case. Coal is a GHG-intensive fuel meaning that the carbon costs per unit of energy are higher compared to other fossil fuels when carbon is priced. As a result, utilization of coal-fired generation in the HCP Case is lower compared to the Reference Case. In addition, the HCP Case assumes greater global climate action than in the Reference Case, resulting in somewhat lower global demand for metallurgical coal and lower exports of Canadian coal.

Key Uncertainties

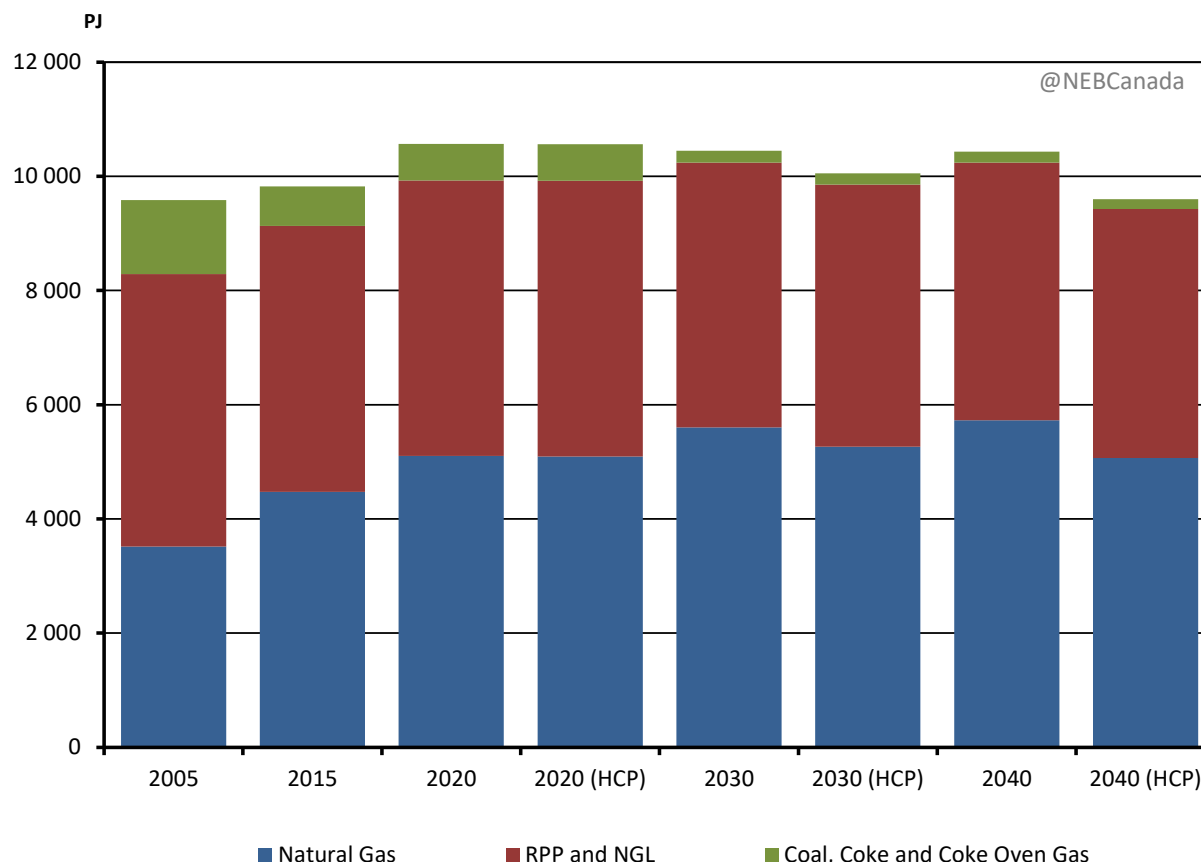
- Global coal markets and price trends are a key uncertainty for Canadian coal exports. If coal importing countries shift further away from using coal, it is also possible that demand and prices could decrease. It is also possible that global coal demand for steel and electricity generation could be higher than anticipated and lead to greater exports as well.

GHG Emissions

- Currently, energy use and GHG emissions in Canada are closely related. The majority of GHGs emitted in Canada are a result of fossil fuel combustion. Fossil fuels provide the vast majority of energy used to heat homes and businesses, transport goods and people, and power industrial equipment. Emissions from fossil fuels, including those used for the production of energy, accounted for 81% of Canadian GHG emissions in 2015. The remaining emissions are from non-energy sources such as agricultural and industrial processes, and waste handling.
- Environment and Climate Change Canada (ECCC) publishes Canada’s official GHG projections in its [Canada’s Emission Trends](#) report and in Canada’s [Biennial Report to the United Nations Framework Convention on Climate Change](#).
- In the Reference Case, fossil fuel consumption increases early in the projection period. By 2019 consumption peaks and is relatively flat through the remainder of the projection period and is slightly lower than 2019 levels by 2040. Fossil fuel consumption in 2040 is 4.3% higher than in 2016, and nearly 9% higher than in 2005.
- In the HCP Case, fossil fuel consumption also peaks in 2019 and declines more quickly compared to the Reference Case. Fossil fuel consumption in 2040 is 4% lower than in 2016, and is nearly the same as in 2005. Figure 3.22 shows fossil fuel consumption by fuel in the Reference and HCP cases.

FIGURE 3.22

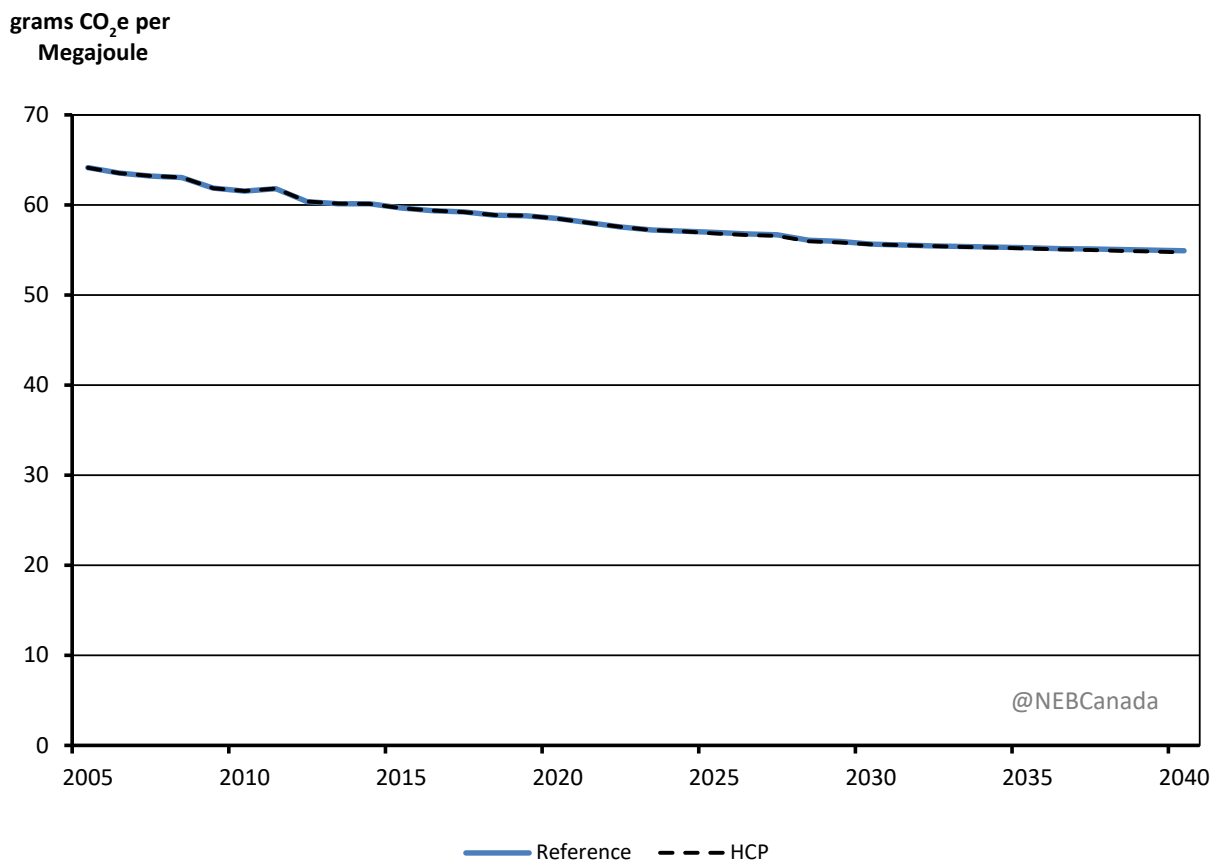
Total Demand for Fossil Fuels, Reference and HCP Cases



- While total fossil fuel consumption grows in the Reference Case, a changing fuel mix leads to declining GHGs per unit of fossil fuel energy used, as shown in Figure 3.23. Growth in natural gas, coupled with a steep drop in coal, results in GHG intensity declining by 7.5% from 2016 to 2040, or 14% from 2005 to 2040. Capturing carbon from facilities that employ CCS technology also reduces the GHG intensity of fossil fuel use. The GHG intensity of the fuel mix in the HCP Case is similar to the Reference Case. Accounting for reductions in non-combustion emissions, such as reducing methane leaks, as well as including emission credits purchased through international trading mechanisms (such as Ontario and Quebec’s emission trading with California) could further decrease emissions intensity.

FIGURE 3.23

Estimated Weighted-Average GHG Emission Intensity of Fossil Fuel Consumption, Reference and HCP Cases



Key Uncertainties

- The uncertainties identified in the Energy Demand section of this chapter, such as future climate policies and technology development, are also key uncertainties to the fossil fuel combustion-related GHG emission results.

TECHNOLOGY CASE RESULTS

- The Technology Case considers the impact of greater use of a selection of emerging energy technologies on the energy system. It builds upon the underlying assumptions of the HCP Case and the carbon price increases steadily throughout the projection period.
- The Technology Case assumes:
 - o Greater cost decreases for solar and wind electricity generating technology over the projection period.
 - o Greater interprovincial electricity trade and modest penetration of grid-scale battery storage technologies.
 - o Faster uptake of EVs in the passenger transportation sector.
 - o Adoption of steam-solvent technology in the oil sands sector.
 - o Greater electrification of space and water heating in the residential and commercial sectors.
 - o Increasing use of CCS technology for coal-fired electricity generation.
- These technologies are a selection of the wide array of emerging technologies that have the potential to increase their market share over the projection period. They are chosen to illustrate how technological development may impact energy supply and demand trends in various sectors of the economy. It is unclear which technologies will gain wider adoption in the future; these technologies provide an example among many potential outcomes. **This sensitivity analysis is not a prediction or recommendation of certain technologies.**

Technology Developments

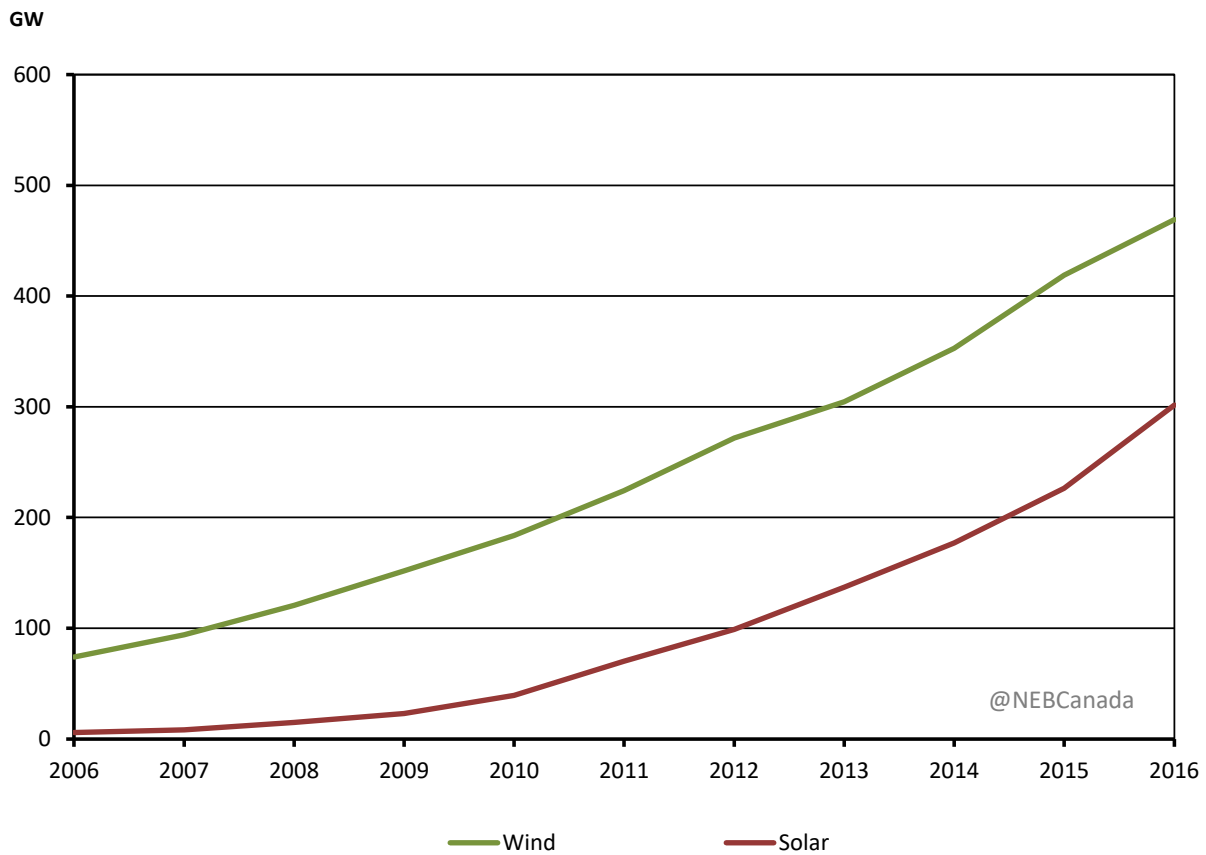
- Over the past decade, technological changes have impacted the energy system in many ways. The widespread application of horizontal drilling and multistage hydraulic fracturing in tight and shale oil and natural gas resources was among the most impactful; significantly increasing production of crude oil and natural gas in North America.
- Other technological developments over the past decade have also influenced energy trends and have the potential to alter the long-term energy outlook in both Canada and globally. The following section discusses the specific technologies included in the Technology Case and is followed by a discussion of the energy supply and demand results.

Renewable Electricity Generation

- Installations of renewable electricity generation technologies, particularly photovoltaic solar and wind, have increased significantly around the world over the past decade. Figure 4.1 shows cumulative global installations of solar photovoltaic and wind capacity.

FIGURE 4.1

Cumulative Global Installed Solar Photovoltaic and Wind Generation Capacity



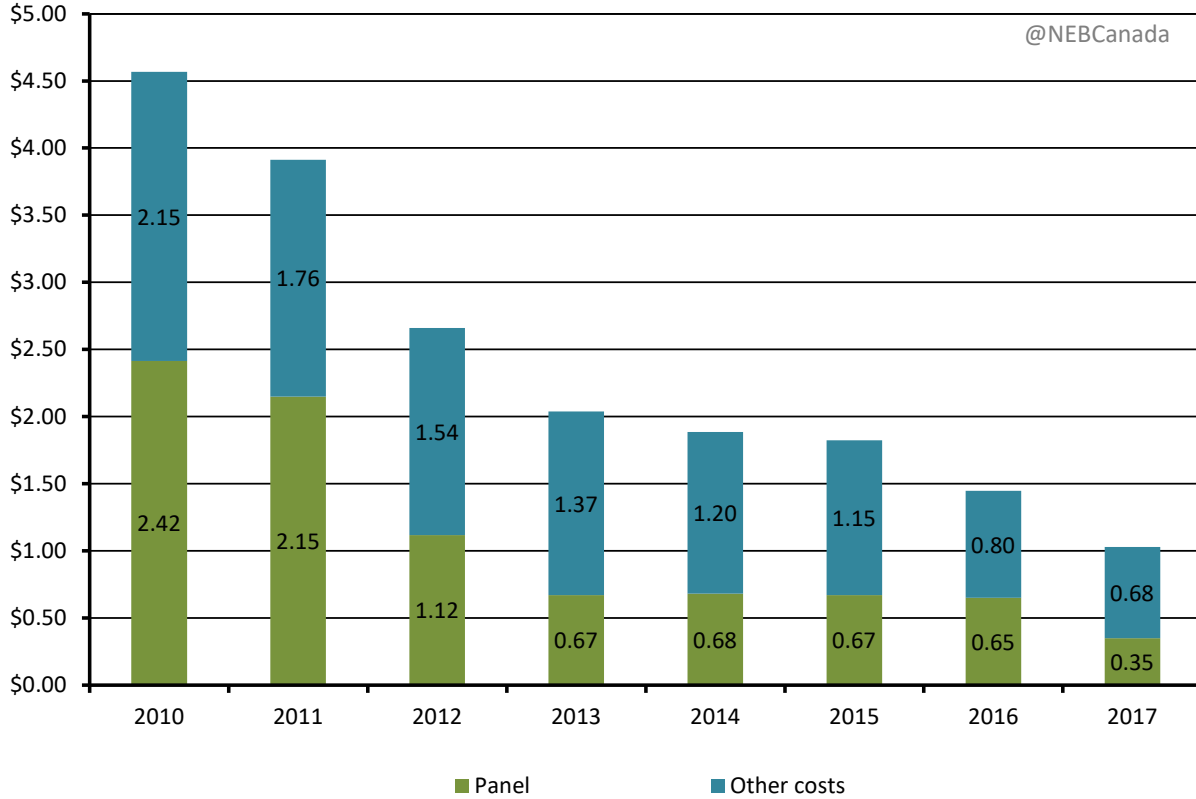
Source: [BP 2017 Statistical Review of World Energy](#)

- A total of 1.5 GW of solar was installed globally during 2006 compared to more than [75 GW in 2016](#). China installed the most solar in 2016, followed by the U.S. and Japan. A total of 11 GW of wind was installed in 2006, compared to 55 GW in 2016.
- Accompanying the increasing use of these technologies has been a decline in costs, particularly for solar photovoltaic installations. Figure 4.2 shows the estimated costs associated with a utility-scale solar installation in the U.S. from 2010 to 2017. Total installed costs [fell from nearly US\\$4.5 per watt in 2010 to nearly US\\$1 per watt in 2016](#).

FIGURE 4.2

U.S. Solar Photovoltaic Utility-Scale Solar System Cost Benchmark

2017US\$/W (direct current)



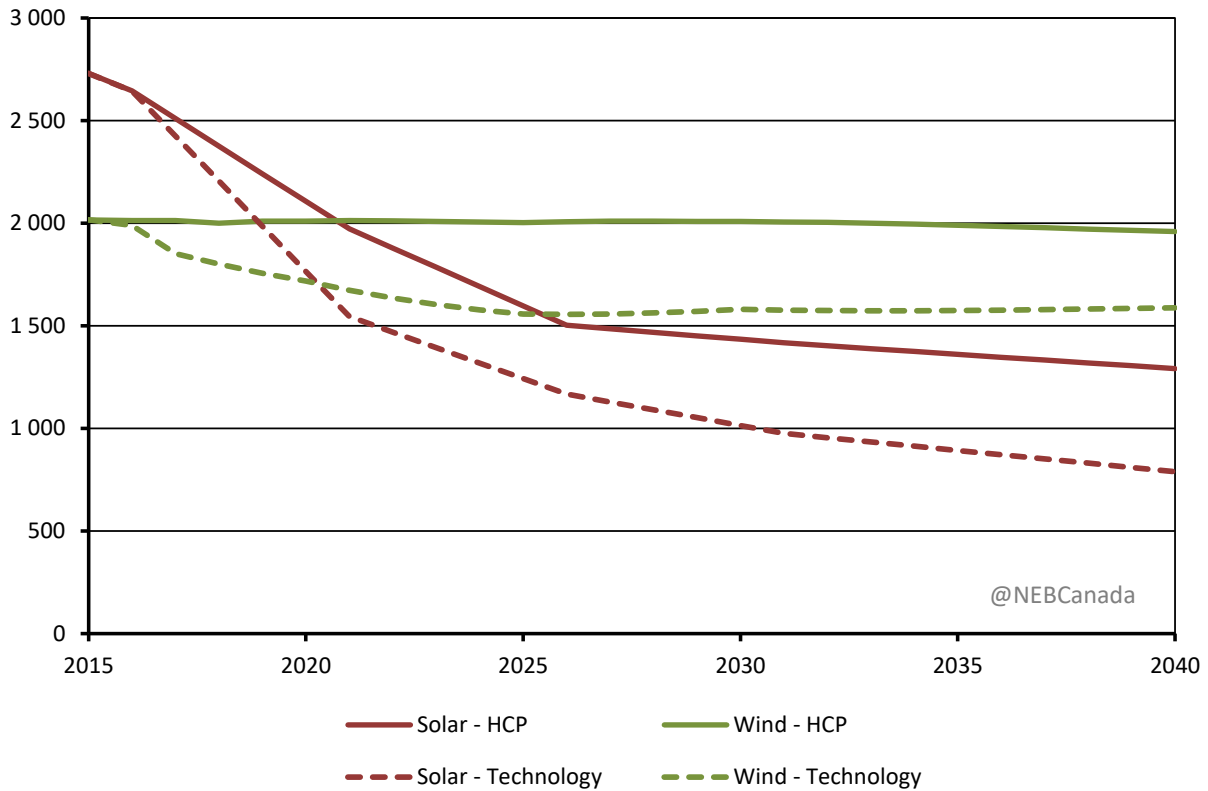
Source: [National Renewable Energy Laboratory \(NREL\)](#)

- Most industry observers expect the [costs for solar and wind generation to continue to decline](#). The Technology Case assumes that these costs decline more steeply than in the Reference or HCP cases. Figure 4.3 shows the cost assumptions for solar (alternating current) and wind in the HCP and Technology cases.

FIGURE 4.3

Capital Costs for Onshore Wind and Utility-Scale Solar Photovoltaic, HCP and Technology Cases

2016 US\$/kW



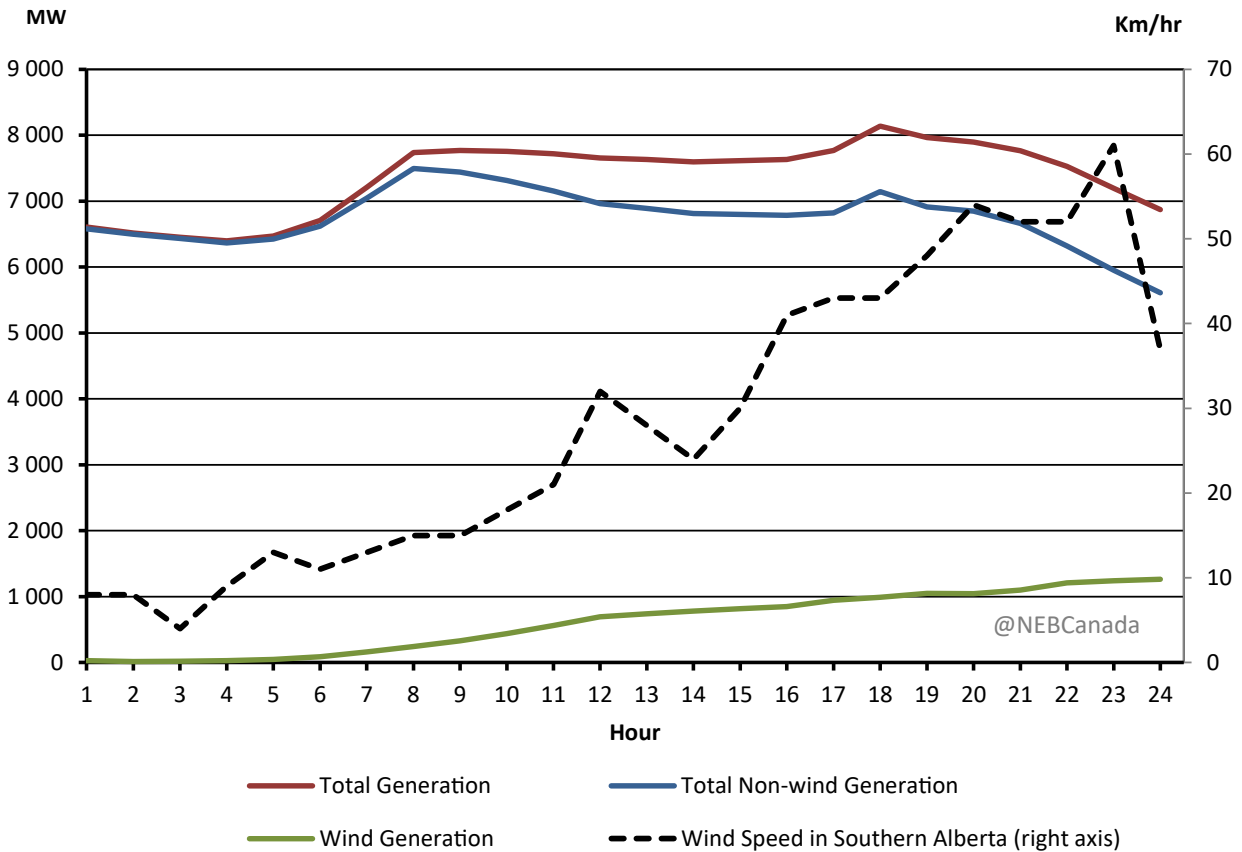
Source: NREL, Energy Information Administration (EIA)

Improving the Integration of Intermittent Renewables

- Electricity grid operators must constantly keep electricity production and consumption in balance to ensure the system is stable and reliable. Energy consumption changes continuously as demand from homes, businesses, and industry vary constantly. Electricity system operators' main tool to keep the system in balance is to increase or decrease electricity generation to meet demand. Flexible generation resources, such as some hydroelectric and natural gas-fired facilities, are most often used to balance supply and demand for electricity.
- Unlike traditional generation sources, wind and solar are intermittent. They generate power when the wind is blowing or sun is shining. This can add to the challenge of balancing supply and demand because, in addition to fluctuations in electricity consumption, grid operators also need to accommodate variations in supply from these resources.
- Figure 4.4 shows an example of hourly generation in Alberta for a day in autumn 2015, a day with a large swing in wind generation. In the early hours of the day, almost all generation was from non-wind sources, primarily coal. Generation increased from 5:00 am to 8:00 am as homes and businesses increased their electricity use. Throughout the day wind speeds steadily increased, resulting in higher wind generation and lower non-wind generation. Later in the evening, total demand decreased while wind generation continued to increase. Wind was less than 1% of total generation in the morning and over 18% by midnight. This variability was accommodated by changes in output from other supply sources.

FIGURE 4.4

Alberta Hourly Net to Grid Electricity Generation and Wind Speed, November 10, 2015



Source: [Alberta Electric System Operator](#), [Environment and Climate Change Canada](#)

- When the share of intermittent resources is small, or if a grid has large levels of flexible generation available, fluctuations in supply are relatively easy to accommodate. However, as the shares of these resources increases, additional measures to accommodate increasing variability may be needed. These measures include:
 - Building additional flexible generating capacity, such as natural gas-fired facilities, that can increase or decrease generation quickly.
 - Various options to manage electricity demand, such as grid operators coordinating with large electricity users to increase or decrease their electricity use.
 - Increasing transmission interconnections between electricity grids to allow greater electricity trade to manage variability.
 - Building grid-scale electricity storage facilities that would charge and discharge to help balance the electricity system. Grid-scale storage includes many technologies such as pumped hydro, batteries, compressed air and flywheels.
- Compared to the Reference and HCP cases, the Technology Case assumes lower costs and modest penetration of grid-scale lithium ion batteries, greater use of demand management, and the expansion of the existing electricity interconnection between Alberta and B.C. by 500 MW.

Electric Vehicles

- The vast majority of vehicles on the road today utilize internal combustion engines (ICE) which are powered by fossil fuels, usually gasoline or diesel. EVs are powered by electricity stored in a battery and use an electric motor to propel the vehicle.
- EVs can include pure electric or hybrid vehicles. Pure electric EVs are only powered by an electric motor and the battery pack is charged by plugging into the electricity grid. Hybrids are vehicles that combine EV and ICE technologies. Plug-in hybrids have a battery that can be charged via the electricity grid but when the battery is depleted a small onboard ICE charges the battery to extend the vehicle's range.
- As a passenger transportation vehicle, EVs have benefits and drawbacks compared to ICE vehicles. EVs have no tailpipe emissions, meaning they do not directly emit GHGs. However, if the electricity used to charge an EV is produced with fossil fuels, there would be GHG emissions associated with operating the vehicle. In some jurisdictions where coal is the dominant electricity source, charging an EV may result in more GHGs per kilometre driven compared to a similar sized ICE vehicle.
- Currently, the selection of EVs is growing but limited compared to ICE vehicles. EVs are also generally more expensive to purchase, largely as a result of battery pack costs. However, EVs are usually less expensive to drive per kilometre. This is partly due to higher efficiency of electric motors compared to ICEs and typically lower costs of electricity relative to gasoline or diesel in many provinces.
- One challenge with EVs can be the range of the vehicle, which can impact their usefulness for taking longer trips. The range of EVs are generally less than ICE vehicles although some with larger battery packs have comparable ranges. However, ICE vehicles have access to a well-established infrastructure of service stations to quickly refuel, accommodating trips further afield. EVs can take longer to charge, ranging from 30 minutes to many hours depending on the type of charger. Publically available charging stations are less common than refueling stations but their numbers are growing quickly. Table 4.2 compares some key characteristics of various electric vehicles and a typical ICE vehicle (Toyota Corolla).

T A B L E 4 . 1

Select Light Duty Vehicle Characteristics, 2017 Models

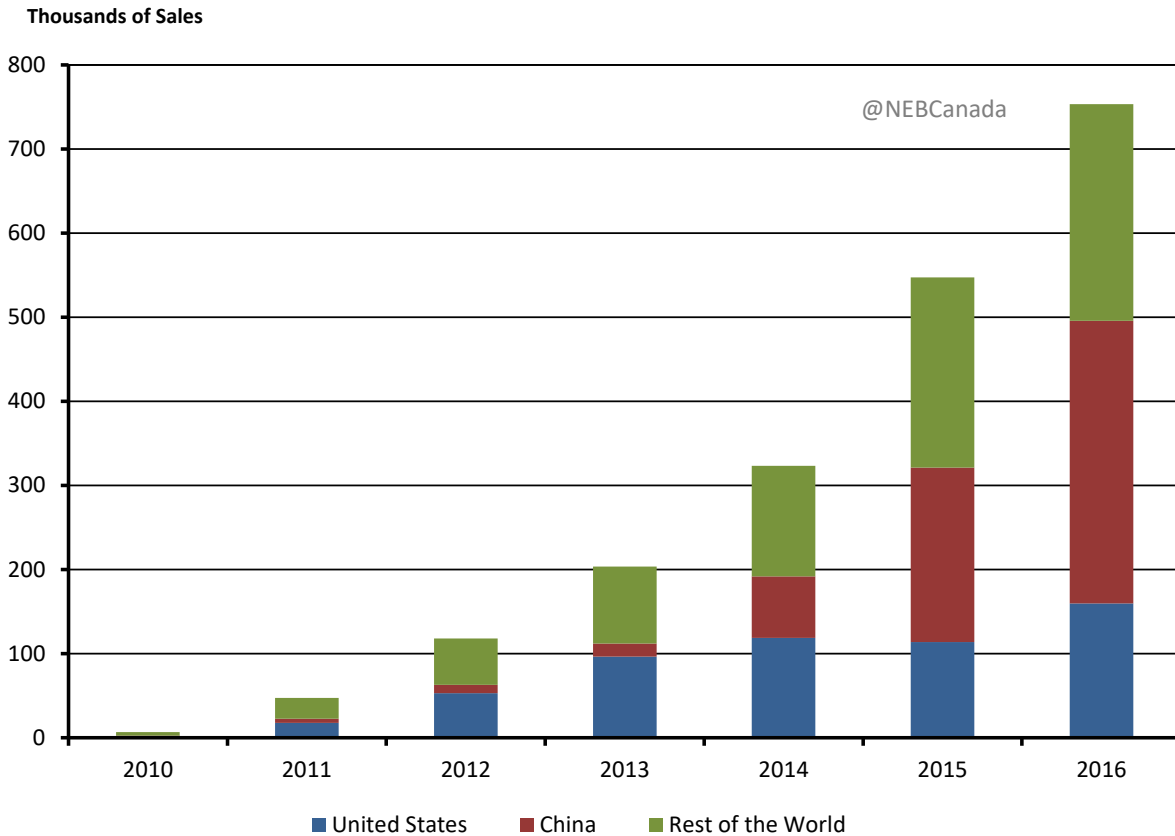
Model	Range (km)	Purchase Price (US\$)	KW.h/100 km	L/100km
Nissan Leaf	172	33 735	30	2.1
Ford Focus Electric	185	29 120	31	2.2
Hyundai Ioniq Electric	200	31 000	25	1.7
Volkswagen e-Golf	201	32 295	28	2.0
Chevrolet Bolt EV	383	38 763	28	2.0
Tesla Model X2	397	108 440	37	2.6
Tesla Model S2	433	83 863	34	2.3
Toyota Corolla (ICE)	658	20 590	-	7.6

Source: [Environmental Protection Agency](#)

- Sales of EVs have increased in recent years due to a wider selection of vehicles, declining purchase costs and government policies aimed at increasing EV ownership. Figure 4.5 shows global annual sales of EVs, including plug-in hybrids. [Total EVs on the road globally reached 2 million in 2016.](#)

FIGURE 4.5

Annual EV Sales, Pure and Plug-in Hybrid EVs



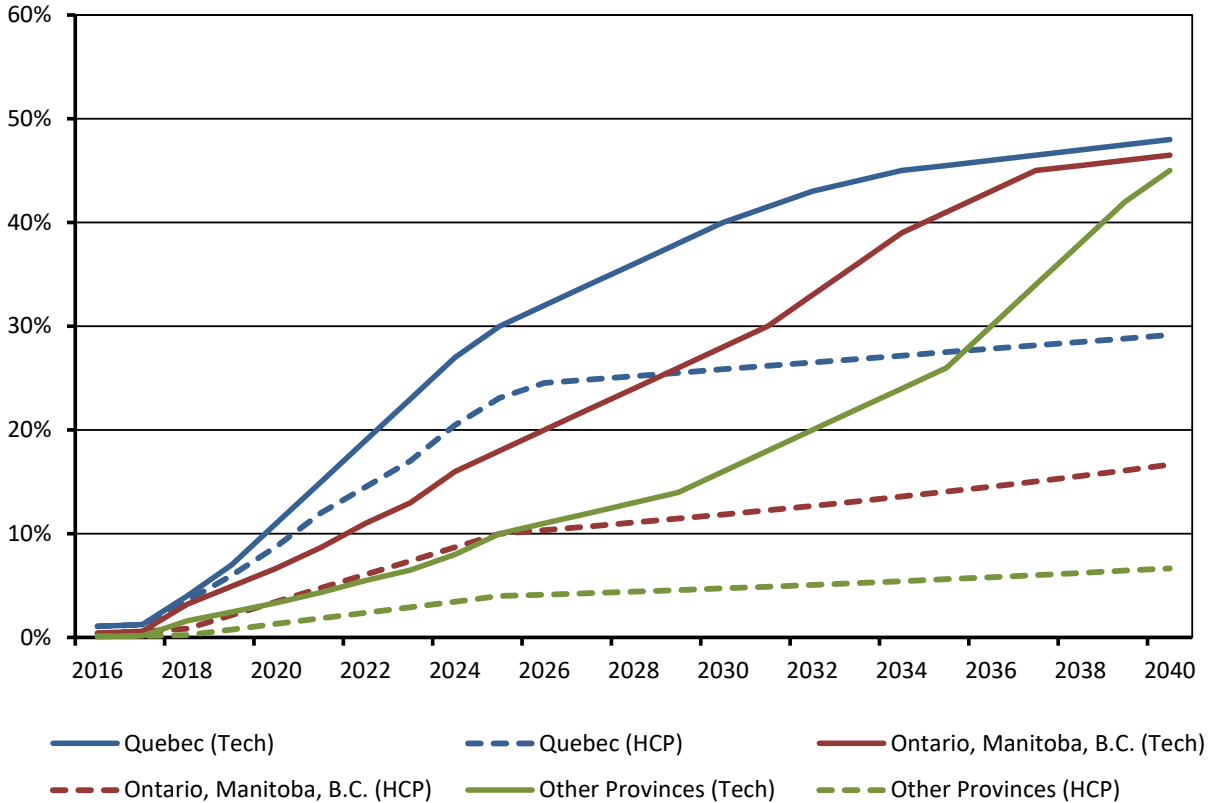
Source: [International Energy Agency](#)

- EV sales in Canada, including plug-in hybrids, were 11 500 in 2016. This was 0.6% of all passenger vehicle sales in Canada in 2016.
- The Reference and HCP cases assume moderate market penetration of EVs, with the share of light duty vehicle annual sales reaching 3% in 2020 and 16% in 2040. Sales are stronger in regions of Canada that produce a large amount of their electricity from non-emitting sources and have EV policies. Sales grow quickest in Quebec as a result of the province's EV mandate.
- The Technology Case assumes that recent growth in EV sales continue to accelerate, with lower battery costs and longer ranges encouraging greater adoption both globally and in Canada. The Technology Case assumes annual EV sales of 6% of total sales in 2020, and 47% in 2040. EVs gain a larger share in the passenger car market initially but also gain some share of the utility vehicle, light truck, and bus market later in the projection period. The Technology Case does not assume widespread adoption of autonomous driving technologies. Figure 4.6 shows the EV sales assumptions in the HCP and Technology cases.

FIGURE 4.6

EV Share of New Passenger Vehicle Purchases, HCP and Technology Cases

Share of New Sales



- In the HCP Case, roughly 16% the passenger vehicles on the road in 2040 are EVs, or about 3 million vehicles. In the Technology Case, there are approximately 8 million EVs on the road in 2040, or about 34% of all passenger vehicles.

Steam-Solvent Technology in the Oil Sands

- Extracting bitumen from the oil sands can be energy intensive, particularly for in situ operations. In situ oil sands production involves burning natural gas to create steam, which is then injected into reservoirs to reduce the viscosity of the bitumen, allowing it to be pumped to the surface. In recent years, technology and process improvements have reduced the amount of steam, and hence natural gas, used per barrel. Further discussion of this trend is available in the “Energy Use in the Oil Sands” section in Chapter 2 of [Canada’s Energy Future 2016](#).
- The decline in crude oil prices since mid-2014 — along with the implementation of carbon pricing and a 100 MT cap on oil sands emissions — creates an incentive for oil sands producers to continue to reduce costs and GHG emissions. [Many different technologies are being proposed and tested](#) in the oil sands. Steam-solvent processes are one technology that has potential to reduce in situ supply costs, natural gas consumption, and GHG emissions.

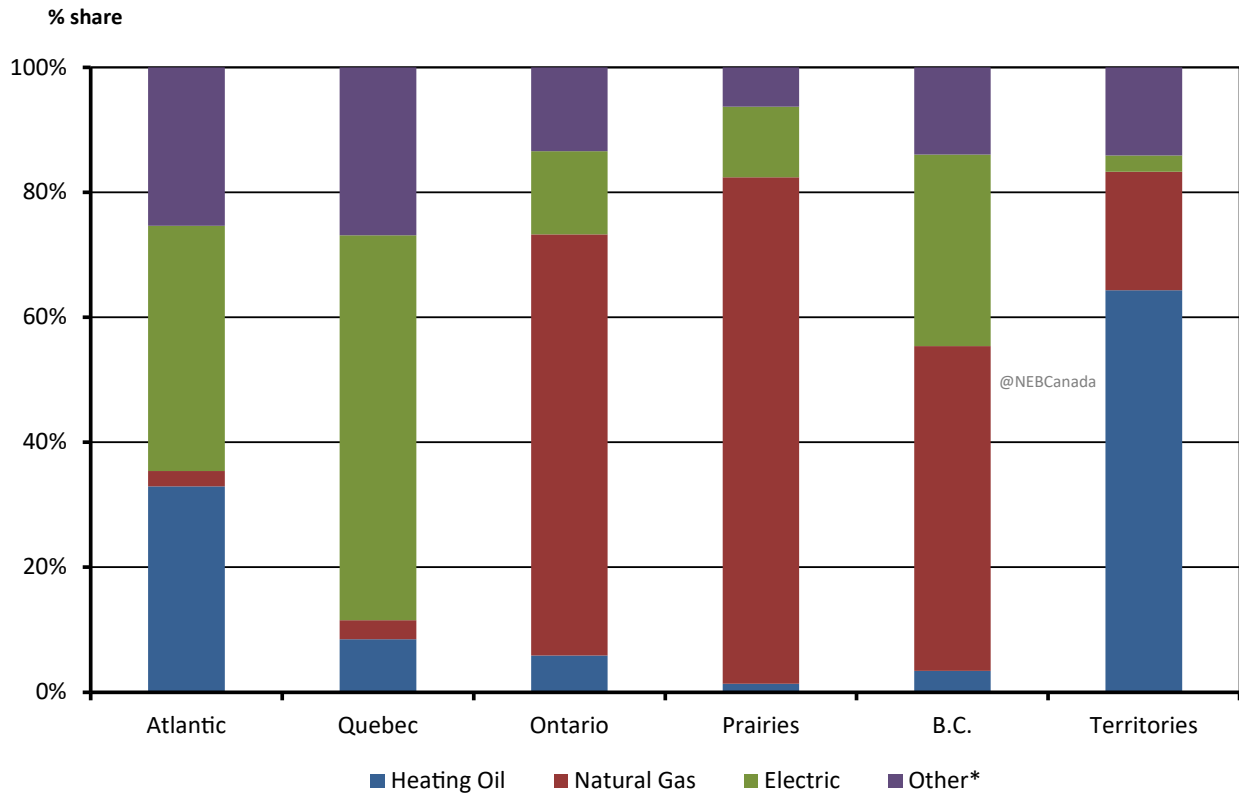
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- Steam-solvent processes involve combining solvents, such as propane or butane, with the steam being injected into in situ reservoirs. Solvent concentrations in the steam can range from 10% to 20%. The addition of solvents aids in reducing the viscosity of the bitumen in the reservoir and has shown to improve recovery rates from wells by 10% to 30% compared to steam alone. The technology also has potential to reduce the energy intensity of production considerably. Steam-solvent processes differ from [pure solvent processes](#), which involve using only solvents to extract bitumen.
 - An in situ project using steam-solvent technology can have higher upfront costs than a traditional in situ project as a result of additional facilities to store, treat, and recover solvents. Greater bitumen recovery rates and lower steam requirements can offset those costs to varying extents depending on individual project characteristics. The economics of steam-solvent processes are influenced by the cost of the propane or butane to be injected. In recent years the price of these commodities, particularly propane, have been quite low due to increasing production of liquids-rich tight and shale gas in western Canada. Another factor in the cost effectiveness of steam-solvent processes is the extent to which the injected solvents can be recovered from the reservoir. Typical recovery rates are around 70% but can vary widely.
 - Several pilot projects have successfully implemented steam-solvent technology and some commercial scale projects are under consideration. Cenovus stated that its [Narrows Lake project](#), which was recently deferred due to low oil prices, would employ steam-solvent technology on a commercial scale. [Imperial Oil's Aspen and Cold Lake](#) expansion projects both propose to apply steam-solvent processes and are currently under regulatory review.
 - The Technology Case assumes that oil sands producers increasingly use steam-solvent processes. Early in the projection period, the technology is applied at select expansion projects and is gradually implemented at existing facilities later in the projection period. Higher oil recovery rates and lower steam requirements reduce the cost per barrel of building new or expanding in situ facilities by roughly 30%. For existing facilities, bitumen recovery rates increase and natural gas consumption declines as a result of the use of steam-solvent processes.

Greater Electrification of Space and Water Heating

- Several different technologies are used to heat homes and businesses in Canada. Most are heated using natural gas or oil furnaces, electric baseboard heating or with wood. The predominant type of heating in a region is usually determined by the relative costs of fuels and the infrastructure to deliver those fuels. For example, low electricity prices in Quebec encourages more electric baseboard heating. In Atlantic Canada, oil furnaces and electric heat are more common, in part due to limited natural gas distribution infrastructure. Figure 4.7 demonstrates the heating system types across Canada.

FIGURE 4.7

Share of Residential Heating System Type by Region, 2014



*Other includes wood, heat pumps and dual fuel systems such as wood combined with electric

Source: [Natural Resources Canada](#)

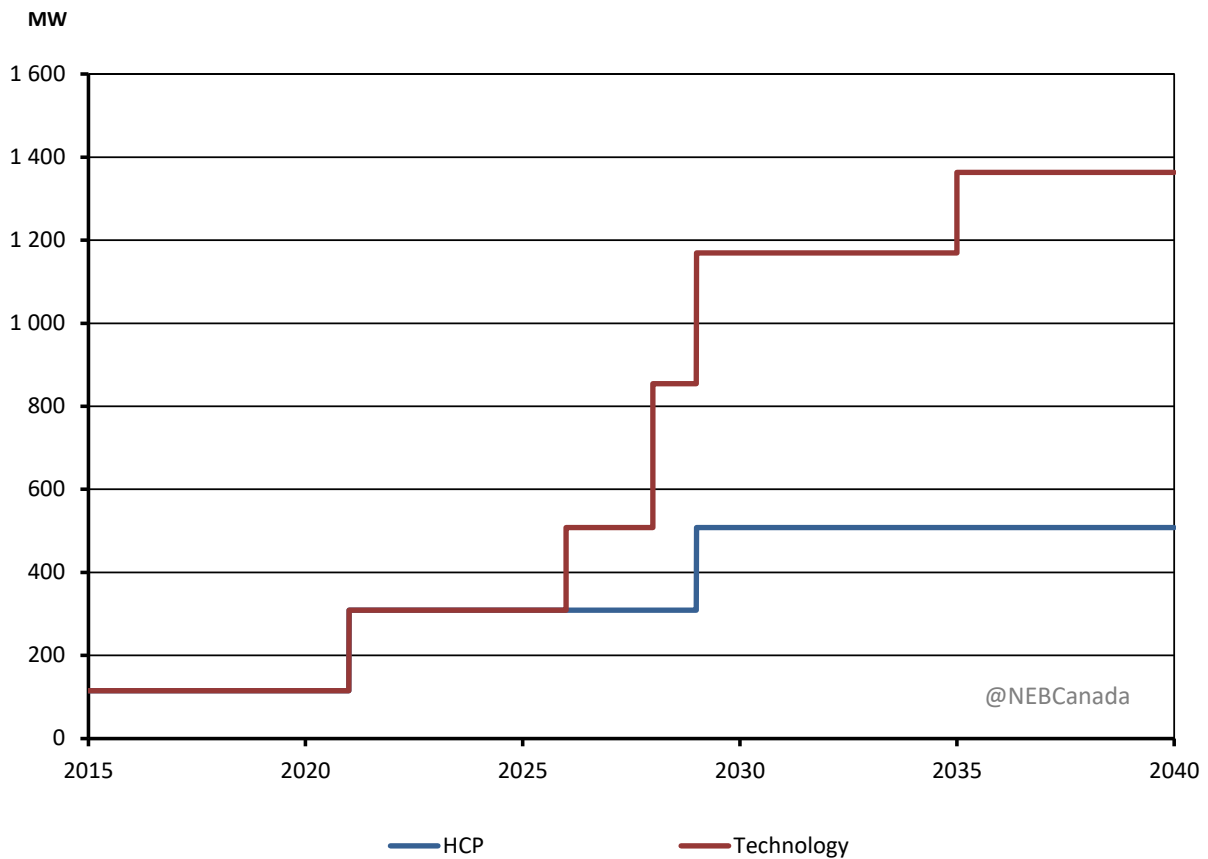
- The energy efficiency and GHG intensity of space and water heating depends on a variety of factors, including heating system type, the quality of a building’s insulation and weather sealing, type of heating fuel, and local climate conditions.
- Heat pumps operated with electricity are an alternative technology that can be used for space and water heating. Heat pumps use similar processes as freezers or air conditioners but can heat a space rather than cool it. Most heat pumps can both heat and cool as needed.
- The advantage of heat pumps is that rather than directly creating heat, they exchange energy, extracting heat from an outside source and pumping it into a space. As a result, a heat pump uses two to five times less electricity compared to baseboard heating to generate the same amount of heat. The efficiency of a heat pump depends on the temperature of the medium it is extracting heat from — the lower the temperature, the more energy it takes to extract the heat.
- There are two main types of heat pumps: air and ground source. Air source heat pumps extract heat from the air outside. Ground source heat pumps are typically part of a geo-exchange system, where the heat is extracted from a liquid that is pumped through underground pipes which either absorb or dissipate heat to and from the ground.
- The Technology Case assumes heat pumps installations increase to 15% of new heating device purchases in 2025, for both new buildings and retrofits in existing buildings. The share of installations increase to 30% by 2040.

CCS Technology

- CCS technology involves capturing and storing CO₂ emissions that would have otherwise been released into the atmosphere. The carbon is usually stored underground in geological formations. CCS projects are usually designed to capture CO₂ from large sources of emissions, such as power plants or natural gas processing plants, to take advantage of concentrated streams of GHG emissions. Global large scale CCS capacity was [34 MT in 2016](#), which is equivalent to about 5% of Canada's GHG emissions.
- Carbon can be captured using a variety of processes. Pre-combustion processes convert fossil fuels to hydrogen and CO₂. The hydrogen can then be used for energy or other processes and the CO₂ stored. Post-combustion processes involve separating CO₂ from the exhaust from an industrial facility or power plant using a variety of techniques. There are also oxy-fuel processes involving combusting fossil fuels in an oxygen-rich environment, resulting in an exhaust stream of mostly water and CO₂, making it easier to recover a concentrated CO₂ stream suitable for storage.
- In many cases, the CO₂ stream resulting from CCS is used for other purposes. One common use is for enhanced oil recovery (EOR), where CO₂ is injected into oil-bearing reservoirs to increase the amount of oil that can be extracted.
- The [Boundary Dam power station](#) in Saskatchewan began operations in 2014. The 115 MW coal-fired power plant is capable of capturing 1.3 MT of CO₂ per year. Most of the CO₂ from the facility is transported to nearby oil fields and used for EOR while some is also stored underground in geological formations near the plant. In addition, Saskatchewan has also been [importing CO₂ by pipeline](#) for EOR from a coal gasification plant in North Dakota.
- In Alberta, the [Quest Project](#) captures CO₂ from Shell's Scotford upgrader and transports it by pipeline for permanent storage underground. The project is designed to capture up to 1.1 MT of CO₂ per year or roughly 35% of the upgrader's emissions. Under development is the [Alberta Carbon Trunk Line](#), a 240 km pipeline that will transport CO₂ from an industrial area north of Edmonton to EOR projects in central Alberta. Starting in 2018 the project will transport 1.7 MT CO₂ per year captured from two facilities: the [Sturgeon Refinery](#) (currently under construction) and an Agrium fertilizer plant. The pipeline has a capacity of nearly 15 MT per year to allow for future CCS projects.
- The Reference and HCP cases include some additional CCS projects over the projection period. This includes the retrofitting of the additional coal units at Boundary Dam in Saskatchewan, with units 4 and 5 coming online in 2021 and unit 6 coming online in 2029. The Technology Case assumes that ongoing research and development in CCS technology results in lower costs and encourages more CCS capacity to be added over the projection period. This includes retrofitting Boundary Dam unit 6 with CCS earlier and additional retrofits of the existing coal-fired generation facilities in Saskatchewan and Alberta. Figure 4.8 shows total installed capacity of coal-fired generation with CCS technology installed.

FIGURE 4.8

Installed Coal-Fired Generation Capacity with CCS, HCP and Technology Cases



Technology Case Results

- The Technology Case builds upon the underlying assumptions of the HCP Case, meaning the carbon price increases steadily throughout the projection period. As noted in Chapter 2, the Technology Case assumes that greater adoption of technologies like electric vehicles has an impact on global crude oil demand. As a result, the crude oil price is lower than in Technology Case compared to the HCP or Reference cases, reaching US\$65/bbl in 2040.

Macroeconomic Drivers

- Key economic variables are shown in Table 4.1. Economic growth averages 1.74% per year over the projection period in the Technology Case, slightly higher than in the Reference Case.

T A B L E 4 . 2

Economic indicators, Reference, HCP and Technology Cases, 2016-2040

Economic Indicator	Compound Average Annual Growth Rate (unless otherwise noted)		
	Reference Case	HCP Case	Technology Case
Real Gross Domestic Product	1.73%	1.72%	1.74%
Population	0.76%	0.76%	0.76%
Exchange Rate (average)	83.7 US/C\$	83.4 US/C\$	82.0 US/C\$

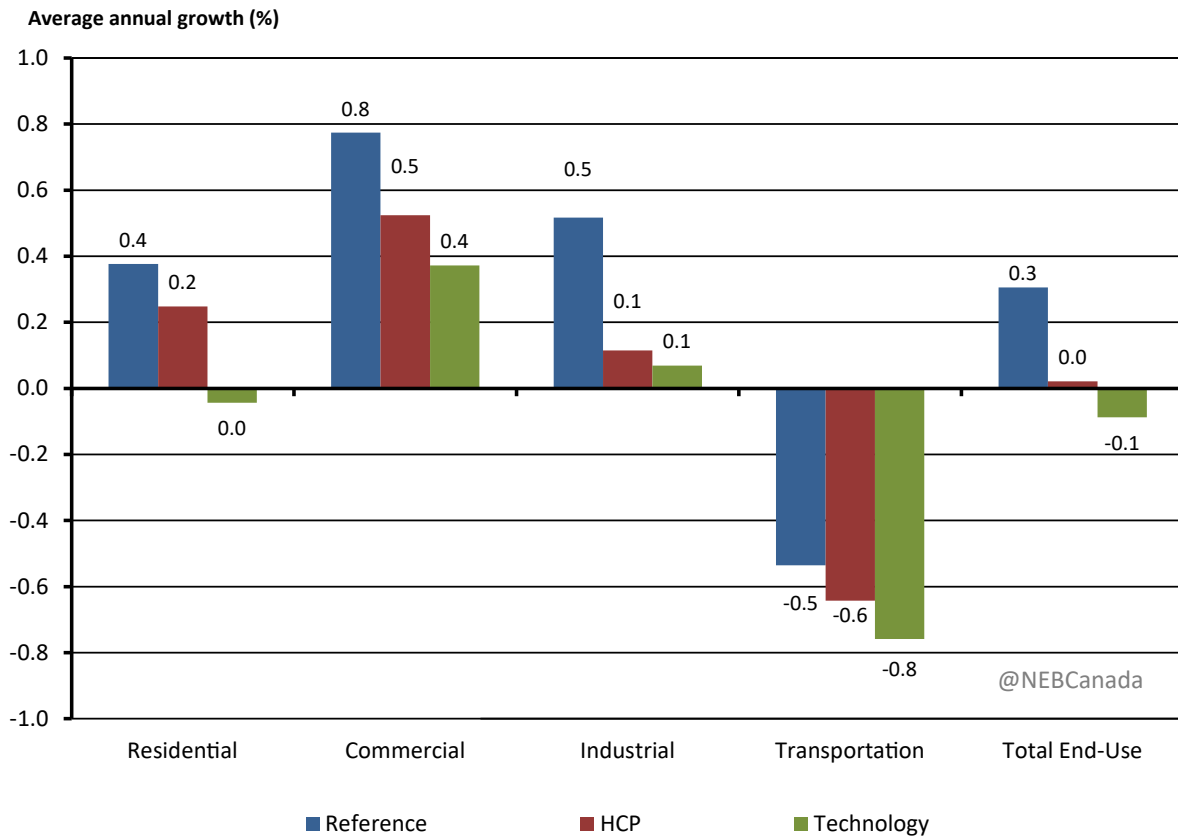
- Lower crude oil prices and production in the Technology Case depreciate the Canadian-US exchange rate relative to the other cases. This, along with reduced energy costs due to the various technologies in the Technology Case, leads to faster economic growth. However, the overall economic outcomes in all three cases are similar, despite shifts in the energy system. By 2040, gross domestic product is 0.2% lower in the Higher Carbon Price Case than in the Reference Case, and 0.1% higher in the Technology Case.

Residential, Commercial, and Transportation Energy Demand

- The technologies considered in the Technology Case impact energy use in a variety of ways, and result in a decrease in end-use energy demand. Total end-use demand in 2040 in the Technology Case is 11 045 PJ, or 2.6% lower than in the HCP Case and 9% lower than in the Reference Case.
- Figure 4.9 shows average annual growth rates for total end-use demand as well as the four sectors. Energy use grows more slowly or declines faster than the HCP Case. These trends are a result of the specific technology assumptions in the Technology Case, as well as the impacts of lower crude oil prices and changing macroeconomic drivers.

FIGURE 4.9

Projected Annual Average Growth in End-Use Energy Demand by Sector, 2016 to 2040, All Cases

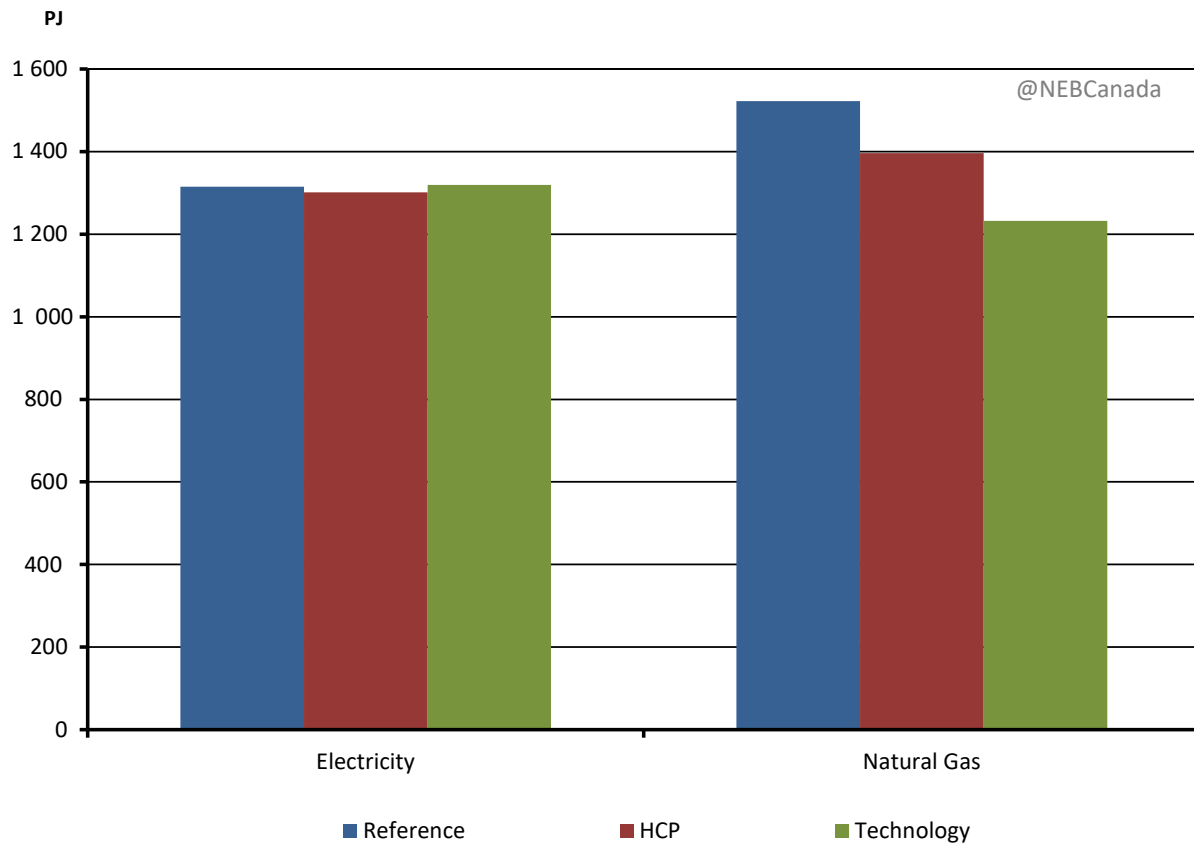


Residential and Commercial

- The higher penetration of heat pumps for heating and cooling in buildings leads to lower energy use in the residential and commercial sector because that technology heats and cools more efficiently than conventional natural gas, electric, or oil systems.
- Figure 4.10 compares residential and commercial electric and natural gas demand in 2040 across the cases. Electricity demand increases slightly in the Technology Case. Greater electrification of heating is partially offset by improving the energy efficiency of heating in jurisdictions such as Quebec that have a high share of electric baseboard heating. Greater electrification reduces natural gas demand in buildings, which is 12% lower in the Technology Case compared to HCP Case.

FIGURE 4.10

Residential and Commercial Electricity and Natural Gas Demands in 2040, All Cases

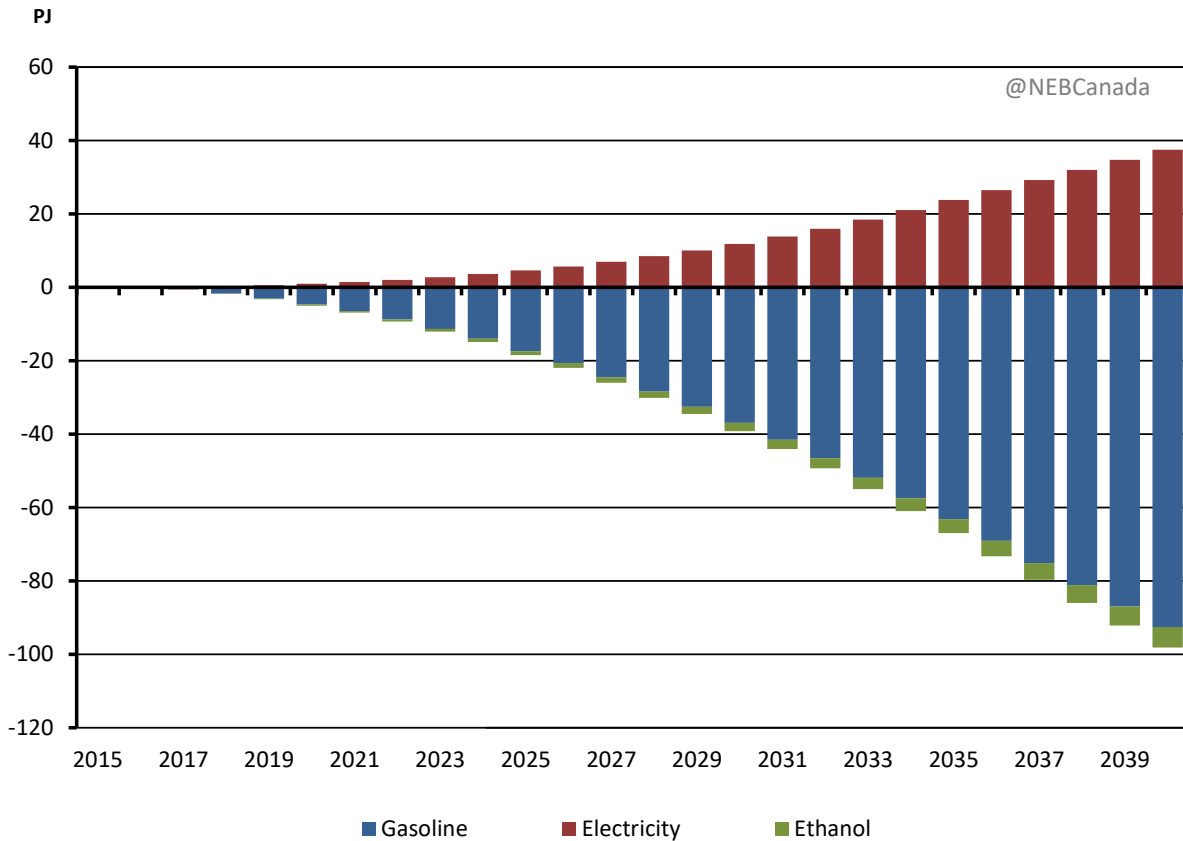


Transportation

- An increased share of electric vehicles reduces transportation energy demand in the Technology Case. Total transportation energy demand in the Technology Case is 3% lower than HCP and over 5% lower than the Reference Case in 2040. Demand is lower because electric vehicles typically use less energy per km travelled compared to conventional vehicles. This impact is muted however due to the lower oil price assumption in the Technology Case. The resulting lower gasoline and diesel prices encourage more driving by the remaining conventional gasoline and diesel vehicles.
- Figure 4.11 shows the difference in demand between the Technology and HCP cases for electricity, gasoline, and ethanol, which is blended with gasoline. As the share of electric vehicles in transportation grows, electricity demand increases, offsetting use of gasoline and blended ethanol. In 2040, electricity demand is 37 PJ higher than in the HCP case, and gasoline demand is reduced by 98 PJ.

FIGURE 4.11

Difference in Electricity, Gasoline and Ethanol Use between the Technology and HCP Cases



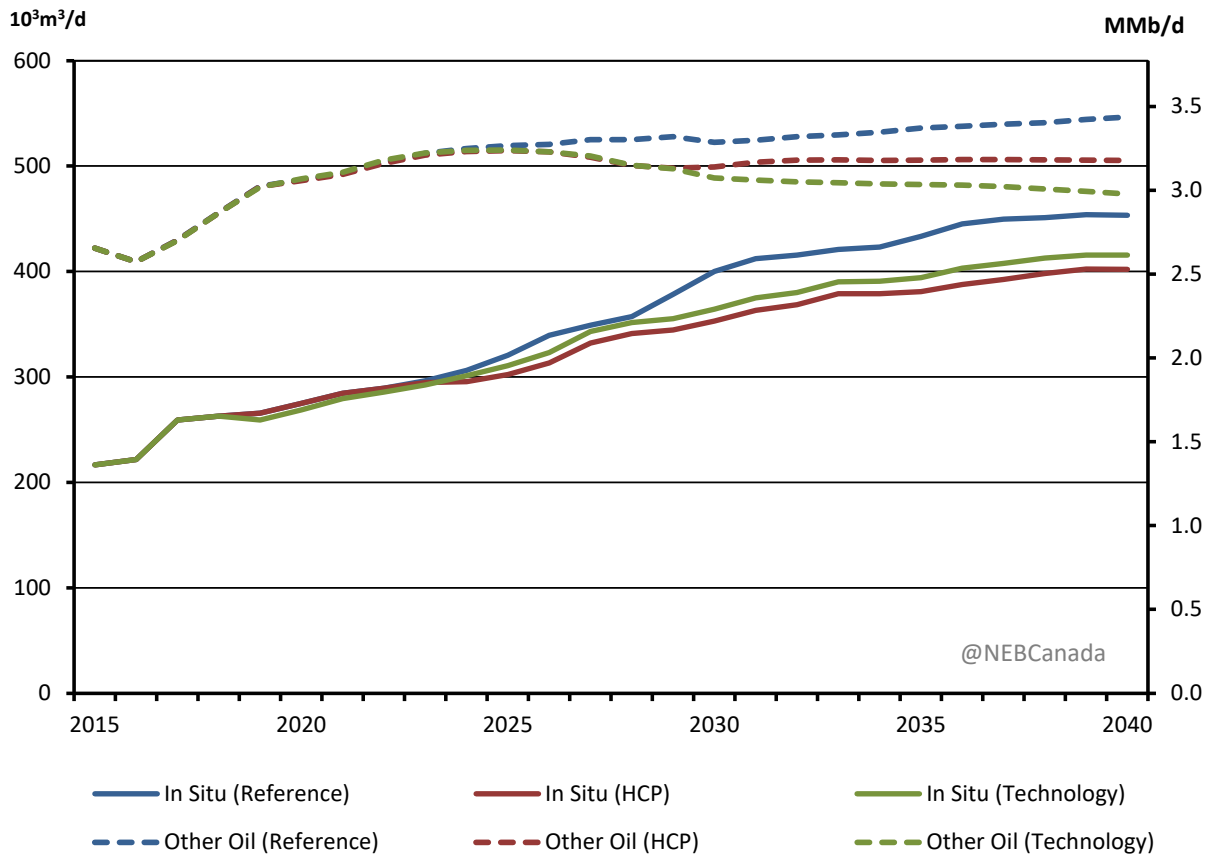
- In the Technology Case, ethanol is blended with gasoline according to minimum federal and provincial blending requirements. As a result of lower gasoline use, ethanol use is 5.5 PJ lower in 2040 in the Technology Case compared to the HCP Case.

Crude Oil Production and Industrial Energy Demand

- In the Technology Case, oil sands producers increasingly use steam-solvent technologies for in situ projects. This reduces the per barrel costs for new projects and expansions of existing projects. However, the Technology Case also assumes that greater technological adoption occurs globally, reducing crude oil consumption overall. As a result, crude oil prices in the Technology Case are lower, reaching US\$65/bbl in 2040 compared to US\$75/bbl in the HCP Case and US\$80/bbl in the Reference Case. Lower supply costs are partially offset by the lower price assumptions in the Technology Case and production reaches 416 10³m³/d (2.6 MMb/d) by 2040, 3% higher than in the HCP Case.
- The costs of production for conventional and mined oil sands resources do not decrease significantly in the Technology Case. Mined oil sands production is the same as no new production is added beyond those facilities currently under construction in all three cases. Conventional oil production, including offshore Newfoundland and Labrador production, is lower in the Technology Case as result of lower price assumptions. Figure 4.12 shows in situ oil sands and all other crude oil production in all three cases.

FIGURE 4.12

In Situ and Other Crude Oil and Equivalent Production, All Cases

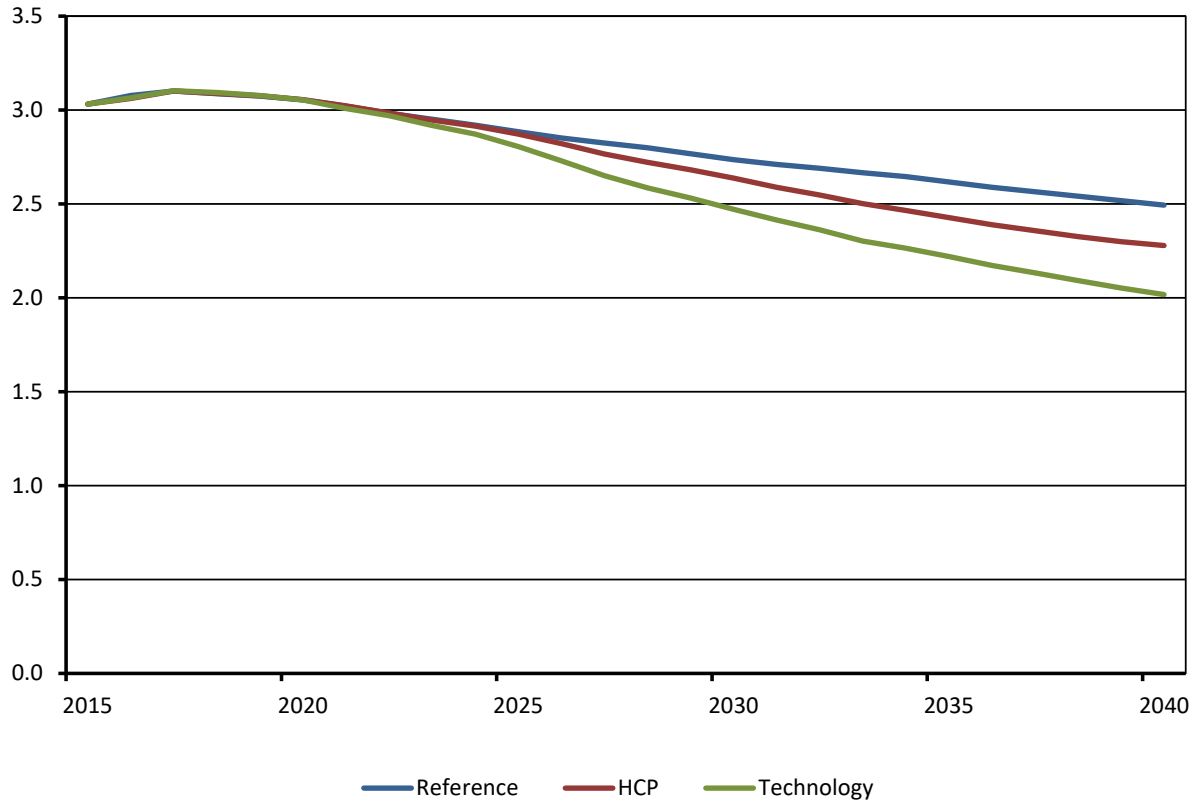


- The use of steam-solvent technology in the Technology Case reduces the amount of steam, and hence natural gas, used per barrel of production. Figure 4.13 shows production-weighted SOR in all three cases. Higher in situ production in the Technology Case is more than offset by lower SORs, and in situ oil sands energy demand is 6.5% lower than the HCP Case in 2040.

FIGURE 4.13

Annual Average Production-Weighted Steam Oil Ratio of Thermal Oil Sands Production, All Cases

PW SOR



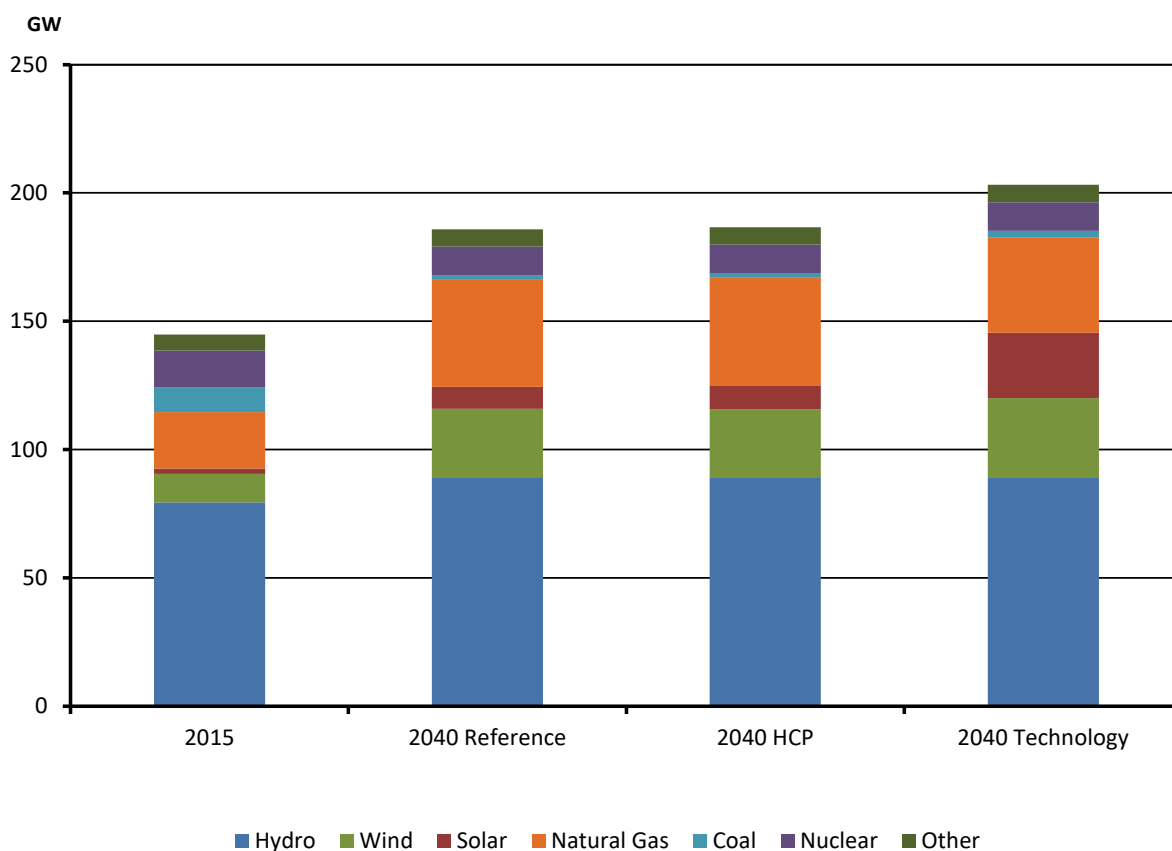
- Natural gas production is 3% lower in the Technology Case compared to the HCP Case in 2040. This is primarily because lower crude oil production results in lower production of solution gas, the natural gas produced along with oil from oil wells.
- Overall industrial energy use in the Technology Case is 1% lower than the HCP Case in 2040. Lower oil sands energy use in the Technology Case is offset by slightly higher energy use in other sectors. This is largely a result of higher economic growth in some export-oriented industries and lower energy price assumptions relative to the HCP Case, which decrease end-use energy prices and increase demand.

Electricity

- Although total end-use demand is lower in the Technology Case, a shift towards electricity in buildings and transportation causes electricity demand in the Technology Case to be 2.7% higher than the HCP Case in 2040. This, combined with lower renewable costs, increased CCS, and improved integration of renewable sources leads to a shift in the electricity mix in the Technology Case.
- By 2040, total capacity in the Technology Case is 8.8% higher than the HCP Case, and 40% higher than 2015 levels. Due to lower costs and measures to improve the integration of renewables, solar capacity in 2040 is 16 GW higher in the Technology Case relative to HCP Case, and wind capacity is 4.4 GW higher. In the Technology Case, wind and solar make up 27% of Canada's capacity mix in 2040, compared to 19% in the Reference and HCP cases, and 9% in 2015. Figure 4.14 shows total electric capacity by fuel in 2015 and 2040 in all three cases.

FIGURE 4.14

Generating Capacity by Fuel, 2015 and 2040, All Cases

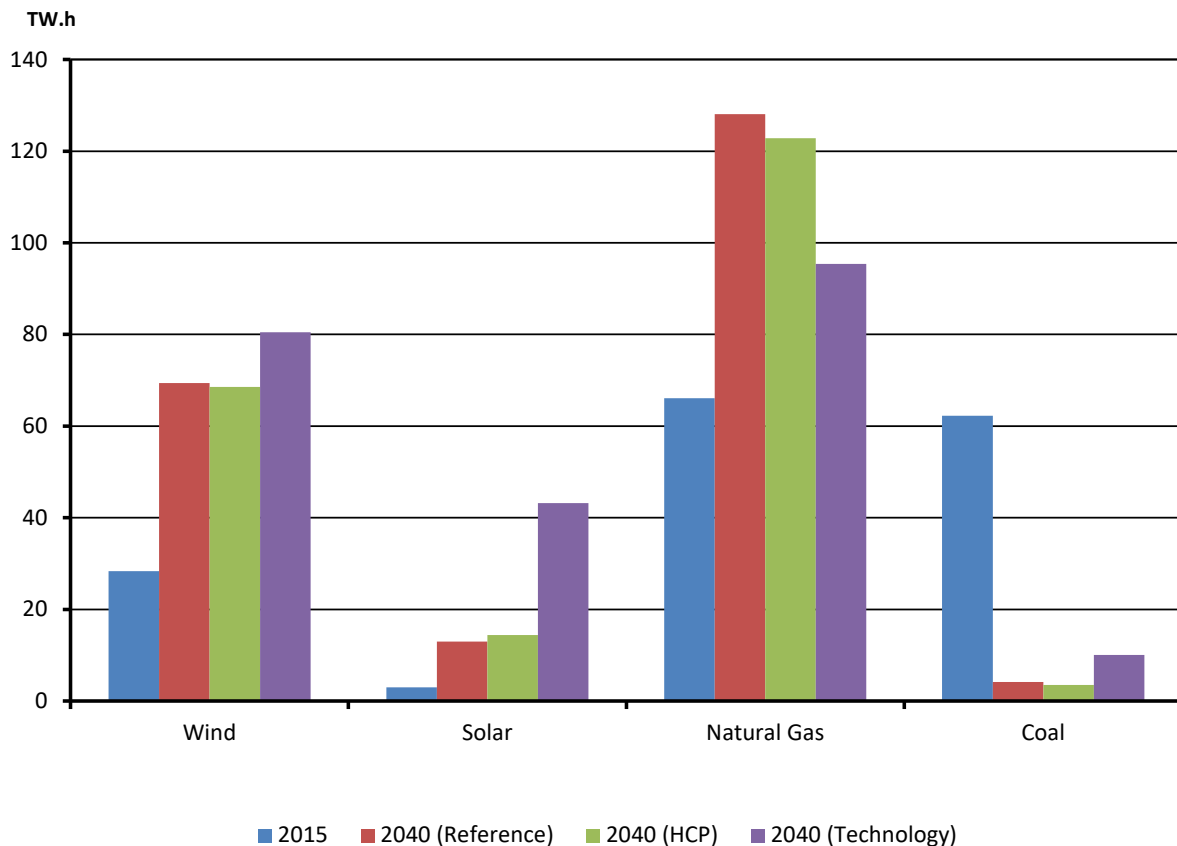


- Natural gas capacity does not grow as fast in the Technology Case, but still increases relative to current levels. In 2040, natural gas capacity in the Technology Case is nearly 70% higher than in 2015, as it continues to play an important role in replacing retired coal capacity and balancing intermittent renewables. Additional CCS capacity in Alberta and Saskatchewan increases the share of coal-fired capacity compared to the Reference and HCP cases.

- Electricity generation is 3% higher in the Technology Case compared to the HCP Case in 2040. This is less than the 8% increase in capacity because most of the additions are wind and solar. These resources are variable depending on wind speeds and sun intensity, and over the course of a year tend to generate less per megawatt of capacity compared to other sources of electricity. While wind and solar make up 27% of the capacity mix in 2040, these resources account for 16.5% of generation. Figure 4.15 shows generation by select fuel in 2015 and 2040 in all cases.

FIGURE 4.15

Generation by Select Fuels, 2015 and 2040, All Cases



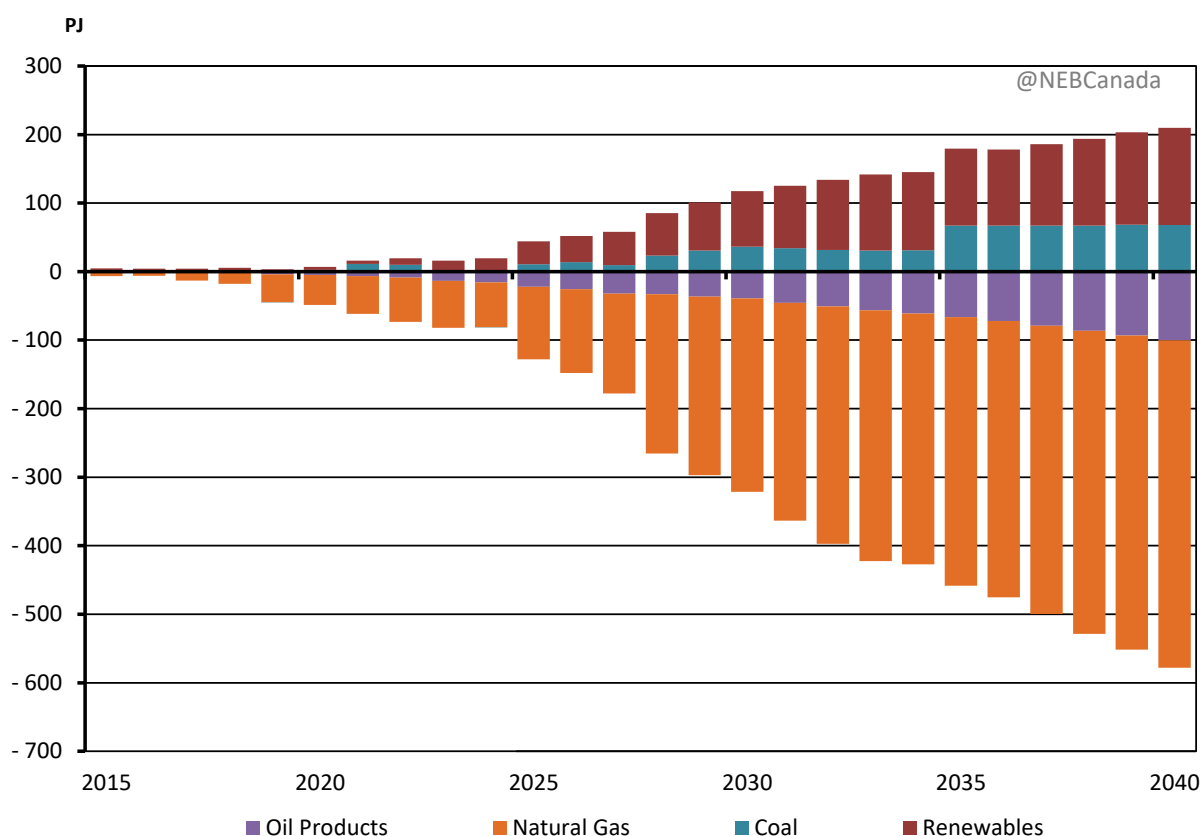
- The shift towards wind, solar, and coal with CCS causes Canada's already low emitting electricity sector to become even greener. The share of non-emitting resources increases to 86% in the Technology Case in 2040, compared to 82% in the Reference and HCP cases, and 80% in 2015.

GHG Emissions

- The Technology Case has implications for primary energy demand because of the shift towards more electricity and reduced overall demand in the end-use sector, and more renewable generation in the electricity sector. These changes further reduce Canada's GHG emission trajectory, as less fossil fuels are combusted and more carbon is captured and sequestered.
- The Technology Case adds renewable and coal demand due to the shift in the electricity mix.
- Oil product demand declines primarily because of reduced consumption in the transportation sector. Natural gas demand declines relative to the HCP Case in the residential, commercial, and industrial end use sectors, as well as in electric generation.

FIGURE 4.16

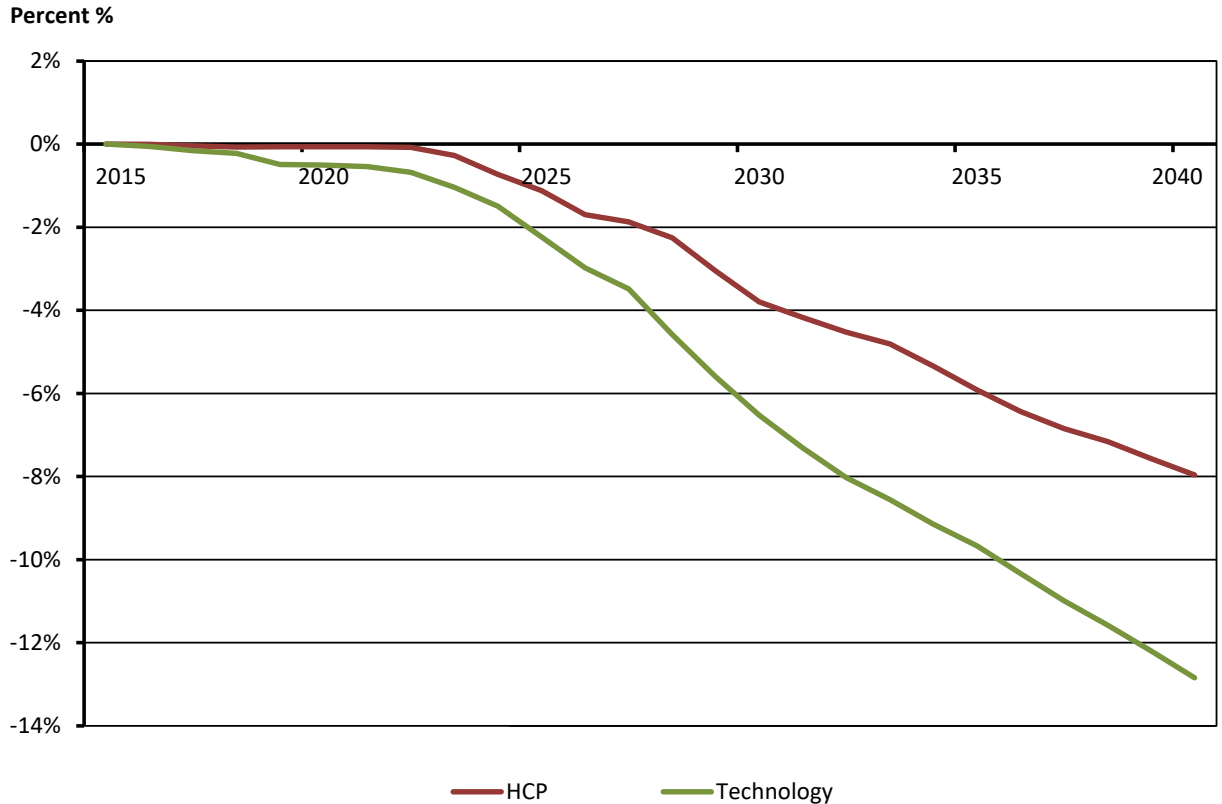
Change in Primary Energy Demand by Fuel Type, Technology Case vs HCP



- The impact of these changes causes total primary demand to decline in the Technology Case, both relative to the Reference and HCP projections, as well as 2015 values. By 2040, total primary demand in the Technology Case is 2.7% less than 2015 levels, 8.5% less than the Reference Case in 2040, and 2.9% less than the HCP Case in 2040.
- Total fossil fuel demand in the Technology Case declines faster than total primary demand. By 2040, total fossil fuel use in the Technology Case is 7.4% less than 2015 values, 13% less than the Reference Case in 2040, and 5% less than the HCP Case in 2040. Figure 4.17 shows the difference in fossil fuel use from the Reference Case for both the HCP and Technology cases.

FIGURE 4.17

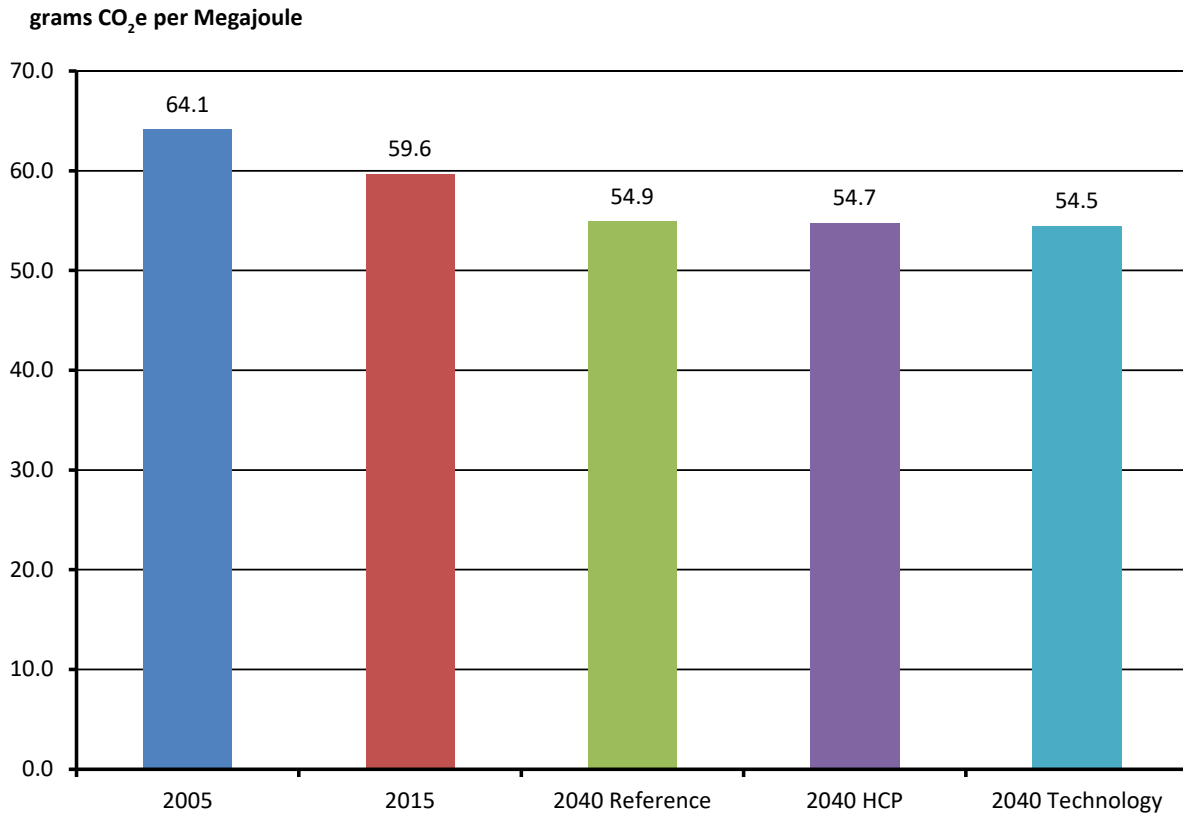
Total Fossil Fuel Use - Percentage Difference in the HCP and Technology Cases from the Reference Case,



- The GHG emission intensity of the fossil fuel mix in the Technology Case is similar to the Reference and HCP cases (Figure 4.18). Natural gas decreases more than other fuels in the Technology Case relative to the HCP Case, and because natural gas is less emissions-intensive than other fuels, this will increase the average CO₂ per megajoule intensity. However, increases in carbon sequestration from CCS units in the Technology Case offset this effect and lead to lower emissions intensity. By 2040, emission intensity of the fossil fuel mix in the Technology Case is just 0.5% less than the HCP Case.

FIGURE 4.18

Estimated Weighted-Average GHG Emission Intensity of Fossil Fuel Consumption, Reference, HCP and Technology Cases



- The analysis in Energy Futures 2017 presents projections of future energy demand and supply under various assumptions, and is not a pathway to meet specific climate goals or targets. As in the Reference and HCP cases, accounting for reductions in non-combustion emissions, such as reducing methane leaks, as well as including emission credits purchased through international trading mechanisms (such as Ontario and Quebec’s emission trading with California) could further decrease Canada’s emissions trajectory.
- The pace and magnitude of technological change is a key uncertainty in these projections, and the Technology Case explores this uncertainty by illustrating the impact of select technologies on the energy system. Numerous other technologies could be employed to further decarbonize Canada’s energy system. Likewise, the market response to the increased carbon price in the HCP and Technology cases could be higher or lower than what is projected.
- The HCP and Technology cases do not represent a ceiling on Canada’s potential for GHG emission reductions. Rather, the cases illustrate the impact climate policy and technology can have on Canada’s energy system. EF 2017 shows that both factors can bend Canada’s fossil fuel use trajectory in a meaningful way, and will influence the way Canadians produce and consume energy over the next several decades.

Key Uncertainties

- The Technology Case examines the impact of higher carbon prices as well as the increased adoption of select technologies in the long term. The impacts in this case are based on the suite of models and assumptions employed for this analysis. Other energy models or assumptions could produce different impacts of carbon pricing and technology trends.
- Numerous other emerging technologies could affect Canada's energy system in the future. If the technologies explored here gain a significant market share in the future, the speed at which they are adopted could be faster or slower than assumed in the Technology Case. Energy transitions have happened many different ways in history, and the eventual path of future transitions could be much different than shown here.
- The impact of a global shift to greater climate policy action and broader adoption of low carbon technologies on global energy markets is highly uncertain. The HCP and Technology Cases assume that crude oil prices are lower than the Reference Case, but this impact could be smaller or larger. Natural gas, coal, and electricity markets could all be affected by changing global dynamics, as could the supply and demand for energy intensive goods. These changes will have implications for Canadian macroeconomic, energy and emission trends.
- The Technology Case shows a higher penetration of wind and solar electricity generation due to lower cost and improved integration. Both of these factors are important for the future of solar and wind in Canada. Costs could fall more or less than assumed in the Technology Case. Even with lower costs, challenges in integrating these intermittent resources could limit their uptake. Alternatively, advances in integrating wind and solar resources could lead to them making up an even higher share of Canada's electricity mix than shown in the Technology Case.

APPENDIX: RECENT CLIMATE POLICY DEVELOPMENTS

- Table A.1 describes many recent climate policy developments and whether that policy is included in the analysis of EF2017. Policies already implemented as of summer 2015, such as Quebec’s cap-and-trade system and B.C.’s carbon tax, are not included in the table but are still incorporated in the projections.
- EF2017 includes many recently announced climate policies. The following criteria were applied to determine whether a certain policy was included in EF2017:
 - o The policy was publically announced prior to January 2017.
 - o Sufficient detail exists to credibly model a policy, or reasonable assumptions can be made about the details of a policy.
 - o Goals and targets, including Canada’s international climate targets, are not explicitly modelled. Rather, the policies currently in place to address those targets are included.

T A B L E A . 1

Recent Major Climate Policy Announcements

Description	Details	EF2017
Pan-Canadian Framework on Clean Growth and Climate Change	<p>In December 2016, Canada’s First Ministers released the Pan-Canadian Framework on Clean Growth and Climate Change (Pan-Canadian Framework), which outlined the actions that will contribute to meeting or exceeding Canada’s 2030 climate change target of a 30% reduction below 2005 GHG emission levels. Pillars of the Pan-Canadian Framework include: 1) pricing carbon pollution, 2) complementary actions to reduce emissions, 3) adaptation and climate resilience, 4) and clean technology, innovation, and jobs.</p> <p>The framework describes many new actions associated with the four pillars. Elements of the framework which were announced prior to December 2016 are discussed in the following rows.</p>	Some elements of the Pan-Canadian Framework are included in EF2017, as described in the following seven rows.
Emission standards for heavy-duty vehicles (for post-2018 and beyond model years)	<p>In October 2014, the federal government provided notice of its plan to develop regulations to reduce GHG emissions from on-road heavy-duty vehicles and engines for post-2018 model years. ECCC recently stated it expects to bring forward these regulations in the near future.</p> <p>The regulation would aim to reduce GHG emissions from on-road heavy-duty vehicles through emission standards applicable to manufacturers and importers of new heavy-duty vehicles, engines and trailers.</p>	Post-2018 model year emission standards for heavy-duty vehicles are included in EF2017 and are modeled similarly to the existing U.S. heavy-duty vehicle standards.
Canada-U.S. joint action to reduce methane emissions from the oil and gas sector	<p>In March 2016, Canada and the U.S. announced joint action to reduce methane emissions from the oil and gas sector by 40 to 45% below 2012 levels by 2025.</p> <p>In May 2017, the federal government released a technical backgrounder detailing the proposed regulations to deliver on this commitment. The regulations will apply to oil and gas facilities responsible for the extraction, production and processing, and transportation of crude oil and natural gas, including pipelines. The first federal requirements come into force in 2020, with the rest of the requirements coming into force in 2023.</p>	Regulation of methane emissions is included in EF2017.

<p>Pan-Canadian Approach to Pricing Carbon Pollution</p>	<p>The federal government outlined its proposed approach to carbon pricing in Canada in October 2016. Jurisdictions have the flexibility to implement:</p> <p>(i) an explicit price-based system (a carbon tax like British Columbia's or a carbon levy and performance-based emissions system like in Alberta), or</p> <p>(ii) a cap-and-trade system (e.g. Ontario and Quebec). Revenues from carbon pricing remain in the jurisdiction of origin.</p> <p>In May 2017, the federal government released a technical paper on the implementation of a federal carbon pricing backstop. It provides details on how carbon will be priced in jurisdictions that do not have a carbon pricing system in place.</p>	<p>A national carbon price is included in EF2017. Key assumptions regarding the inclusion of this policy are described in Chapter 2, Key Assumptions.</p> <p>In all cases, the minimum carbon price starts at \$10/tonne in 2018 and increases by \$10/tonne per year to reach \$50/tonne in 2022. This is consistent with the minimum carbon price for jurisdictions with an explicit price-based system in the Pan-Canadian approach to carbon pricing.</p> <p>In the Reference Case, the carbon price is held at \$50/tonne from 2022 to 2040. In the HCP and Technology Cases, the price continues to increase, reaching \$90/tonne in 2030 and \$140/tonne in 2040. The same carbon price is applied to all provinces and territories regardless of existing carbon pricing intentions as a simplifying assumption.</p>
<p>Initiative to green the federal government</p>	<p>The federal government announced in November 2016 that it would act to reduce its own GHG emissions. This includes initiatives to reduce energy consumption in government buildings through repairs and retrofits, and investments to shift the government vehicle fleet to electric and hybrid vehicles.</p>	<p>This initiative is included in EF2017.</p>
<p>Federal phase-out of traditional coal-fired generation by 2030</p>	<p>In November 2016, the federal government announced it is amending the regulations applicable to coal-fired electricity generation to ensure that all traditional coal-fired units are phased out by no later than 2030. Alberta, Saskatchewan, New Brunswick, and Nova Scotia have coal-fired power plants that would be impacted by these regulations. Prior to this announcement, Alberta had already committed to phasing out pollution from coal-fired plants by 2030.</p>	<p>The phase-out of coal-fired generation is included in EF2017. Equivalency agreements with Saskatchewan and Nova Scotia were announced and are discussed later in this table.</p>

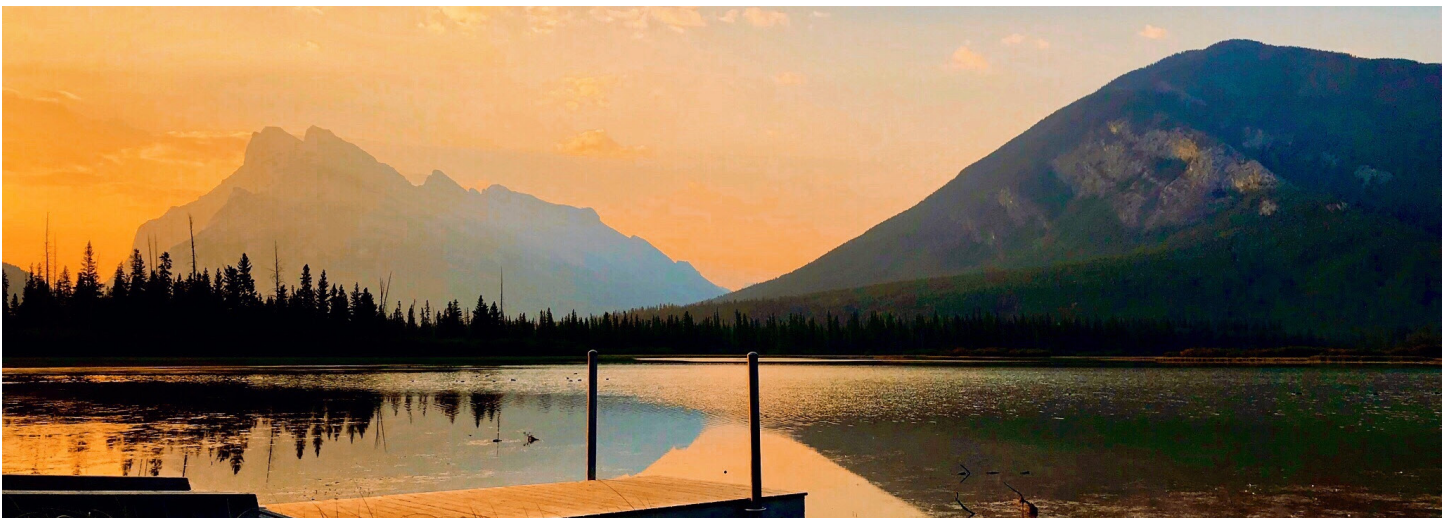
Federal clean fuel standard	<p>The federal government announced a plan in November 2016 to work with provinces, territories, and stakeholders to develop a clean fuel standard. A clean fuel standard requires the lifecycle carbon footprint of fuels supplied to decline over time.</p> <p>The proposed standard would be broadly applied to many sectors of the economy, flexible for fuel suppliers and complementary to carbon pricing.</p>	The clean fuel standard was under development at the time of analysis and is not included in EF2017.
Federal regulations to reduce hydrofluorocarbon (HFC) consumption	In November 2016, the federal government proposed regulatory measures to reduce HFCs . HFCs are powerful GHGs and are increasingly used in commercial, industrial, and residential applications such as refrigeration, air-conditioning, foam insulation, and aerosols.	These regulations aim to reduce HFCs, a potent GHG, and will impact GHG emission trends. They are unlikely to demonstrably impact the energy system and are not included in EF2017.
B.C. - Climate Leadership Plan	The B.C. government released its Climate Leadership Plan in August 2016. The plan highlights 21 action items to reduce GHG emissions in key areas such as transportation, industry and utilities, and natural gas.	<p>Some elements of the B.C.'s Climate Leadership Plan are incorporated into EF2017. This includes extending B.C.'s low carbon fuel standard to reducing the carbon intensity of transportation fuels by 15% by 2030 and incentives for zero emission vehicles.</p> <p>Many other actions described in the B.C. Climate Leadership Plan were still under development at the time of analysis and are not included in EF2017.</p>
Alberta - Climate Leadership Plan	In spring 2016, the Alberta government unveiled a climate change and emissions strategy based on recommendations put forth by the Climate Leadership Panel in fall 2015. The main elements of the Alberta Climate Leadership Plan, including recent announcements related to the plan, are discussed below.	Elements of the Alberta Climate Leadership Plan are described in the following five rows.
Alberta - carbon pricing: end-use emissions	In January 2017, an economy-wide carbon levy on GHG-emitting fuels came into effect in Alberta . The levy is set at \$20/tonne in 2017 and will increase to \$30/tonne in 2018. The funds generated by the levy will be recycled back into the Alberta economy through direct payments to low- and middle-income families, small business tax reductions and investments in energy efficiency, technology and infrastructure.	The carbon levy is included in EF2017. In the Reference and HCP cases, the levy increases to \$40/tonne in 2021 and \$50/tonne in 2022 in alignment with the federal government's plan to price carbon pollution.

<p>Alberta - carbon pricing: large industrial emitters</p>	<p>Alberta announced plans to replace its existing carbon pricing program for large industrial emitters, the Specified Gas Emitters Regulation, with a new program referred to as the Carbon Competitiveness Regulation by the Climate Leadership Panel. Large emitters would pay a carbon levy of \$30/tonne starting in 2018 on their combustion emissions.</p> <p>The Climate Leadership Panel proposes a sector-specific output-based performance standard as a method to mitigate competitiveness impacts of carbon pricing on trade-exposed industrial sectors. Under the performance standard Alberta firms would receive allocations, essentially free emission permits, on a per-unit-of-output basis. The allocations would equal the emissions per-unit-of-output of the top quartile in terms of emission intensity in a given industry. This approach provides firms with an incentive to reduce their emission intensity and a measure of protection for emission-intensive and trade-exposed industries.</p>	<p>Pricing of industrial GHG emissions is included in EF2017. In the Reference and HCP cases, the price for industrial emissions increases to \$40/tonne in 2021 and \$50/tonne in 2022 in alignment with the federal government's plan to price carbon pollution.</p>
<p>Alberta - accelerated coal phase-out</p>	<p>The Alberta government has stated its plan to phase out pollution from coal-fired electricity generation by 2030.</p> <p>Under existing federal regulations, 12 of Alberta's 18 remaining coal-fired plants will be retired prior to 2030; the six remaining plants will also be phased out under the Alberta plan.</p>	<p>The accelerated phase-out of coal-fired generation in Alberta is included EF2017.</p>
<p>Alberta - Renewable Electricity Program</p>	<p>As part of the Climate Leadership Plan, Alberta established the Renewable Electricity Plan. The Plan calls for the development of 5 000 MW of renewable electricity between 2017 and 2030. The target of the program is to have at least 30% of the electric energy produced in Alberta produced from renewable energy resources.</p> <p>Through a competitive process managed by Alberta Electricity System Operator, auctions will be held starting in 2017. The auctions will identify the lowest cost qualified renewable electricity projects, which will receive support through a renewable energy credit payment mechanism. Support will be funded through a portion of carbon pricing revenues from large industrial emitters.</p>	<p>The Renewable Electricity Program is included in EF2017.</p>

<p>Alberta - 100 MT limit on oil sands GHG emissions</p>	<p>In the fall of 2016, the Alberta government passed legislation that limits oil sands GHG emissions to an annual maximum of 100 MT.</p> <p>The legislation exempts certain oil sands emissions from the cap, including cogeneration emissions attributable to electric generation and up to 10 MT of emissions related to new or expanded upgrading capacity.</p>	<p>The MT limit on oil sands GHG emissions is included in EF2017.</p>
<p>Saskatchewan - 50% renewable target</p>	<p>Saskatchewan's provincial utility, SaskPower, set a target of increasing renewable generating capacity up to 50% of total capacity by 2030. Currently about 25% of generating capacity in Saskatchewan is renewable.</p>	<p>As a target, this initiative is not explicitly modelled.</p>
<p>Saskatchewan - equivalency agreement on coal phase-out</p>	<p>The Saskatchewan government announced in November 2016 that it and the federal government reached an agreement in principle to finalize an equivalency agreement related to the federal government's plan to phase-out traditional coal-fired electric generation by 2030. Through the agreement, Saskatchewan would be allowed to run its traditional coal-fired plants beyond 2030 on the condition that it meets or improves upon federal emission requirements over time on an electricity system-wide basis.</p>	<p>The equivalency agreement between Saskatchewan and the federal government is included in EF2017.</p>
<p>Ontario - cap-and-trade program</p>	<p>Ontario's cap-and-trade program came into effect in January 2017. The cap will be set at 142 MT for the first year of the program and will decline to 125 MT by 2020.</p> <p>The program will be phased in and provide temporary allowances to trade-exposed industries. Revenues from the plan will be invested in GHG-reducing initiatives for homes and businesses, such as electric vehicle purchase incentives and energy retrofits.</p>	<p>The Ontario cap-and-trade program is included in EF2017. The analysis assumes the permit price increases to \$20/tonne in 2019 and to \$50/tonne by 2022 in the Reference and HCP Case. This is a simplifying assumption as the future price of GHG emissions under a cap-and-trade system is uncertain and will be determined by the supply and demand for emission permits.</p> <p>In the Reference Case, the permit remains at \$50/tonne through the remainder of the projection period. In the High Carbon Price Case, the permit price continues to increase at \$5/tonne per year after 2022, reaching \$90/tonne in 2030 and \$140/tonne by 2040.</p>

<p>Ontario - Climate Change Action Plan</p>	<p>In June 2016, the Ontario government released its Climate Change Action Plan. The five year plan introduces key actions Ontario will take towards meeting its emissions reduction targets. It also defines how revenues from the province's cap-and-trade program will be spent.</p> <p>The plan lists key actions to be taken in nine areas, such as transportation, land-use planning, and research and development. The Ontario government will consult with stakeholders regarding the design and implementation of many of these actions.</p>	<p>Some elements of Ontario's Climate Action Plan are incorporated into EF2017. This includes the implementation of a renewable fuels standard for gasoline and incentives for electric vehicles.</p> <p>Other actions described in the Ontario Climate Action Plan were still under development at the time of analysis and are not included in EF2017.</p>
<p>Quebec - The 2030 Energy Policy</p>	<p>In spring 2016, Quebec released an energy policy document that aims to guide the province's energy transition to 2030. The document outlines the government's plans to establish a cohesive governance structure to manage the transition, promote a low-carbon economy, diversify Quebec's energy supply, and take a new approach to fossil fuel energy. It also sets out targets to be achieved by 2030 for improving energy efficiency, reducing petroleum consumption and increasing renewable energy production.</p> <p>Legislation enabling the implementation of the 2030 Energy Policy was passed in December 2016. A series of action plans describing the measures that will be taken to implement the Policy will be forthcoming.</p>	<p>Measures to implement the Quebec 2030 Energy Policy were still under development at the time of analysis and are not included in EF2017. The Quebec cap-and-trade system is included in EF2017.</p> <p>The Quebec zero emission vehicle mandate mentioned in the 2030 Energy Policy is discussed in the following row.</p>
<p>Quebec - zero-emission vehicle standard</p>	<p>In October 2016, the Quebec government passed legislation establishing a zero-emission vehicle (ZEV) standard for the province. The standard requires car manufacturers to sell a minimum percentage of zero-emission ZEVs, starting with 2018 models.</p> <p>Currently, 10 U.S. states, including California and several northeastern states, have adopted ZEV standards.</p>	<p>The ZEV standard is included in EF2017. The implementation of the mandate is modelled after ZEV standards in several states.</p>
<p>New Brunswick - Climate Change Action Plan</p>	<p>New Brunswick released a climate change action plan in December 2016 that outlines the province's response to climate change. The plan includes over 100 action items related to climate change.</p>	<p>Actions described in the New Brunswick Climate Change Action Plan were still under development at the time of analysis and are not included in EF2017.</p>

<p>Nova Scotia – federal agreement on carbon pricing and equivalency agreement</p>	<p>In November 2016, Nova Scotia and the federal government announced an agreement in principle on Clean Growth and Climate Change. Nova Scotia stated it would implement its own cap-and-trade program. Nova Scotia also announced it would establish a new equivalency agreement to allow Nova Scotia’s coal-fired plants to operate at some capacity beyond 2030.</p>	<p>Aligning with the assumptions related to the federal carbon pricing plan, carbon pricing via a cap-and-trade program in Nova Scotia is included in EF2017.</p> <p>The equivalency agreement between Nova Scotia and the federal government is included in EF2017.</p>
<p>Newfoundland and Labrador - Management of Greenhouse Gas Act</p>	<p>The Newfoundland and Labrador government passed legislation in June 2016 that enables the regulation of GHG emissions from industrial facilities in the province. The plan will include a form of carbon pricing for industrial emitters, the revenues of which will support funding of emission-reducing technology.</p>	<p>Regulations to enact the plan were still under development at the time of analysis and are not included in Update 2016.</p>



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