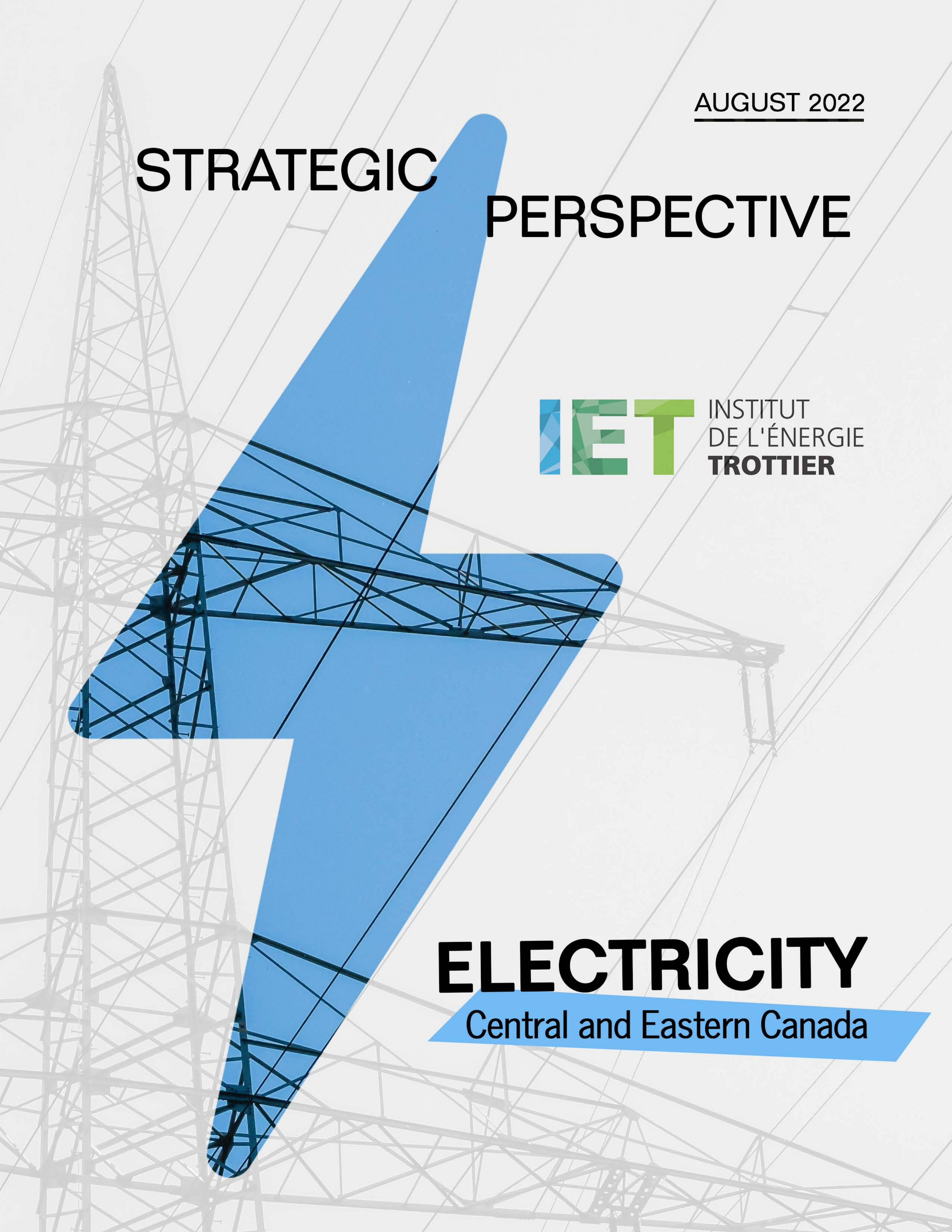

AUGUST 2022

STRATEGIC PERSPECTIVE

INSTITUT DE L'ÉNERGIE TROTTIER

ELECTRICITY

Central and Eastern Canada

A Strategic Perspective on Electricity in Central and Eastern Canada

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About the Institut de l'énergie Trottier (IET)

The IET was created in 2013 thanks to a generous donation from the Trottier Family Foundation. Its mission is to train a new generation of engineers and scientists with a systemic and trans-disciplinary understanding of energy issues, to support the search for sustainable solutions to help achieve the necessary transition, to disseminate knowledge, and to contribute to discussions of energy issues. Based at Polytechnique Montréal, the IET team includes professor-researchers from HEC, Polytechnique and Université de Montréal. This diversity of expertise allows IET to assemble work teams that are trans-disciplinary, an aspect that is vital to a systemic understanding of energy issues in the context of combating climate change.

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Context

Achieving climate goals in Canada requires a major electrification of the economy. This electrification will be accompanied by the opening of new markets, an increase and diversification of domestic demand, and a transformation of electricity generation and storage technologies. These transformations are in addition to Canada's objective to make its electricity sector carbon neutral by 2035. In the face of these profound and rapid disruptions, which could have a significant impact on tariffs and the nature of the country's economic development, demand forecasting and production planning at the provincial level are too often limited to traditional, technical concerns.

It thus seems appropriate to **explore the nature of the interactions between these various transformations in a regional context, that is, in Central and Eastern Canada, and the effects of various choices available to the provinces in terms of energy access, decarbonization and the development of local and regional economies.**

Achieving this goal will require a significant amount of effort. This white paper represents a preliminary step to take stock of the situation, to present an initial analysis of the challenges inherent in the widespread electrification of Central and Eastern Canada, and to propose a path forward for the next steps.

This document is an expanded version of a discussion paper, enriched with inputs from stakeholders consulted since January 2022 (see annex). However, the analysis and conclusions are those of the authors.

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1 Introduction

Achieving greenhouse gas (GHG) emission reduction objectives across Canada will require the massive electrification of its energy services. This transition will take place amidst an opening of new electricity markets, a rising and diversifying domestic demand, and a transformation in dominant technologies for electricity generation and storage. These profound and rapid disruptions may have a major impact on rates and rate structures, as well as on the nature of economic development across the country. Demand and production planning, which is still mainly developed at the provincial level, is too often limited to the technical aspects that are traditionally emphasized by the sector.

This white paper identifies a number of challenges and the possible implications of choices made about the electricity sector at the provincial level in Central and Eastern Canada. It is intended to provide background information on these challenges and offer choices to stakeholders considering avenues for improving the sector from a regional perspective by reflecting on the interactions among the different transformations to expect in light of these challenges.

This document was enriched by the results from workshops with stakeholders held since January 2022.[1] It is part of a broader reflection on the future of the electricity sector in North America, where other contributions have highlighted the costs associated with the lack of grid integration across neighbouring provinces and US states (Pineau and Langlois-Bertrand 2020); the opportunities and challenges of implementing such integration (Pineau and Ba 2021; Rodriguez-Sarasty et al. 2020); and the potential role(s) for the Government of Canada in securing provincial grids (Kanduth & Dion, 2022). To add to these contributions, particular emphasis is placed here on the mismatch between the challenges of implementing solutions for ongoing and future changes in electricity demand and the current planning of the various entities with jurisdiction over the electricity systems in Central and Eastern Canada.

The white paper also provides an overview of the electricity sector in each of the six provinces considered: Ontario, Quebec, New Brunswick, Nova Scotia, Prince Edward Island, and Newfoundland and Labrador; summarizing the structure of their electricity sectors and the current state of planning.[2] Using the projections from the Canadian

[1] See the annex *Annex – Description of* the workshops for more information.

[2] For more detailed portraits, see Bouchet and Pineau (2022) and Pineau (2021).

Energy Outlook 2021 (CEO2021, Langlois-Bertrand et al., 2021), which modeled different scenarios to reach net-zero emissions at the national level, as a reference, it then identifies some of the key challenges the sector is facing given expected trends and transformations.

2 Electricity systems in Central and Eastern Canada: a general overview

This section of the white paper provides an overview of some of the characteristics of the electricity sectors in the provinces in the study region, that is, Ontario, Quebec, New Brunswick, Nova Scotia, Prince Edward Island, and Newfoundland and Labrador. First, it describes the Canadian context by recalling the federal commitments to decarbonize the country. It then presents the carbon intensity of electricity generation in each of the provinces, the installed capacity and generation mix, the annual demand profiles, and the intertie capacities between the provinces and the U.S. regions, including New York state and New England. The section concludes with a paragraph on the diversity of rates found in the study area. A more detailed description of the electricity sectors in each province is provided in Section 3 of this paper.

Key facts

- Various studies predict that new demands (particularly building heating) will significantly increase peak demand or shift peak demand from summer to winter (e.g., Ontario)
- The difference between minimum and maximum demand can be significant in some provinces. For example, in Quebec, the maximum demand is almost three times the minimum demand.
- Prices charged to customers can vary considerably between provinces, with a difference of up to 17¢ per kilowatt-hour for the same category of customers.
- A significant increase in the carbon intensity of electricity generation in some provinces, such as Ontario (+600% by 2040), is anticipated, as the province plans to add significant amounts of natural gas to its electricity mix in the coming years.

2.1 Electrification across Canada

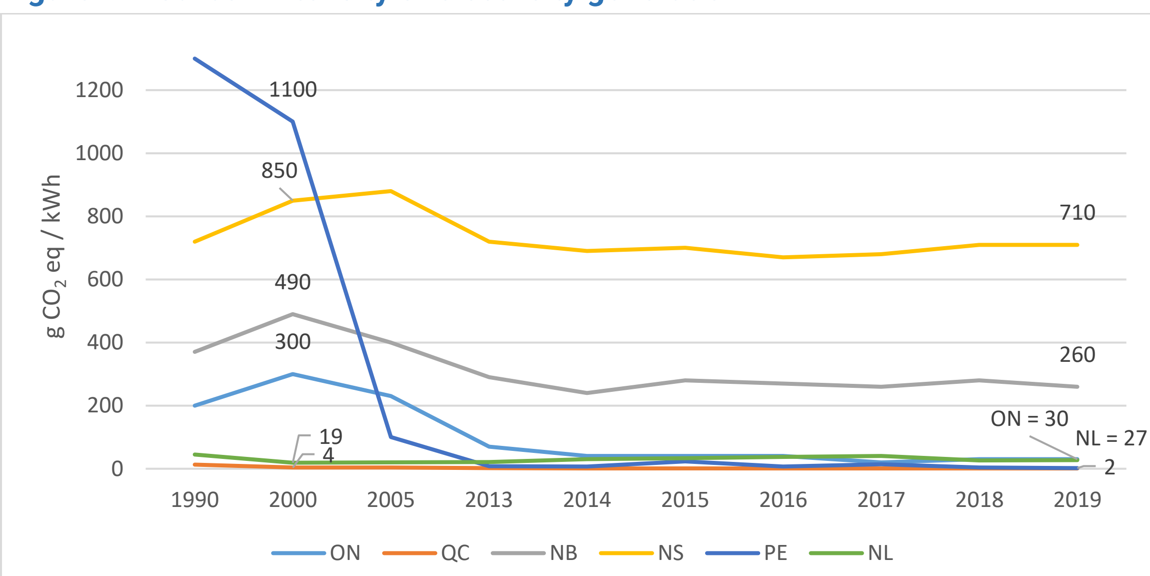
Electricity in Canada is produced primarily from non-emitting sources. In 2019, these sources represented nearly 80% of the electricity mix: more than 59% came from hydroelectricity, 15.1% from nuclear and 5.1% from wind. In this context of availability of non-emitting sources for electricity production, **massive electrification is one of the main paths Canada has chosen to decarbonize its economy**. In April of 2021, the federal government set a more ambitious GHG emission reduction target for 2030, aiming for 40-45% with respect to 2005 (instead of the previous target of 30%). The government also announced a net-zero emission target for 2050. In its efforts towards decarbonization, Canada has introduced various measures concerning the electricity sector such as a target for non-emitting energy sources in electricity production (90% by 2030), low-emission vehicles incentives with cash rebates, and the elimination of conventional coal in electricity generation by 2030. More recently, the federal government announced its objective to make the electricity sector carbon neutral by 2035. However, non-emitting electricity sources are not evenly distributed across the provinces: while some provinces have an electricity mix that is largely decarbonized, others still rely on coal. Thus, **each province will have to face its own unique challenges as well as those they have in common. An integrated vision would greatly help to overcome these challenges in the most cost-optimal way**.

2.2 Characteristics of the systems

2.2.1 Electricity carbon intensity

Canada's provinces are unequal in terms of renewable resources available for electricity generation. While Quebec and Newfoundland and Labrador rely mainly on hydroelectric resources, other provinces like New Brunswick and Nova Scotia still rely heavily on non-renewable combustible fuels.

Figure 1 – Carbon intensity of electricity generation



Source: ECCC 2021

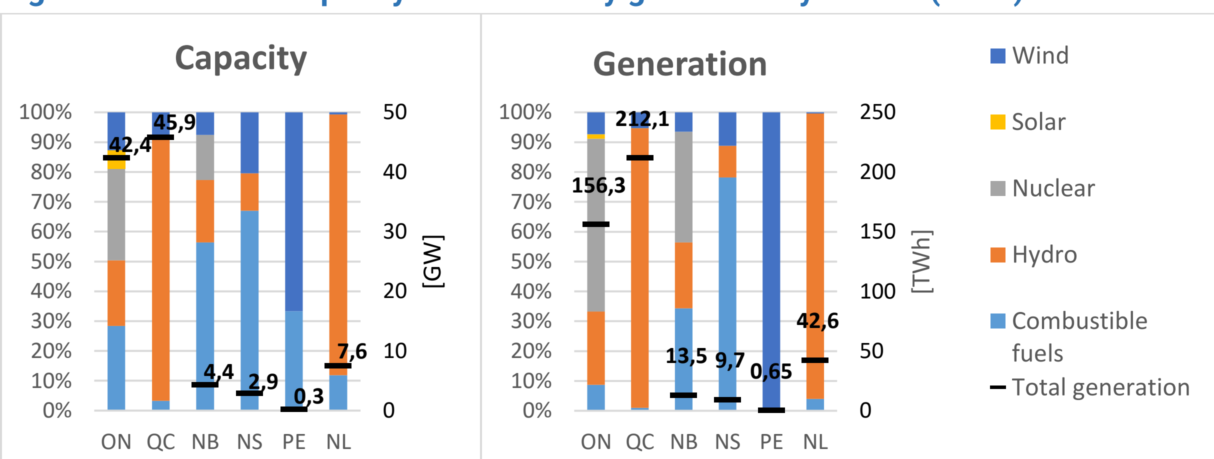
While this carbon intensity evolved in most provinces over the years, it has been more or less stable for almost a decade. However, significant changes are anticipated in

Ontario as the province plans to increase its natural gas-fired generation over the next few years, increasing the carbon intensity of the system by more than 375% by 2030 and 600% by 2040, compared to 2017, according to IESO projections[3].

2.2.2 Installed capacity and power production

Figure 2 shows how different the electricity mixes are among the provinces, with Ontario having the greatest diversity in energy sources. In fact, in addition to its hydro and combustible fuel power plants, Ontario is the country's leader in nuclear, wind and solar power in terms not only of installed capacity but also of electricity produced. Because of capacity factors, large increases in the installed capacity of variable renewable energy such as wind and solar do not always translate into the same proportion in the generation mix. For example, although 20.4% of the installed capacity in Nova Scotia is wind power, this percentage represents only 11.2% of the generation mix. Furthermore, **the proportion of installed capacity for combustible fuels is much higher than in the generation mix of other central and eastern provinces as well**. This is partly due to the presence of gas-fired power plants and/or diesel power plants used almost exclusively to meet annual peak demand.

Figure 2 – Installed capacity and electricity generated by source (2019)



[3] Values calculated from the IESO Annual Planning Outlook tables, published in December 2021. Similar values were published in Winfield & Kaiser, 2022.

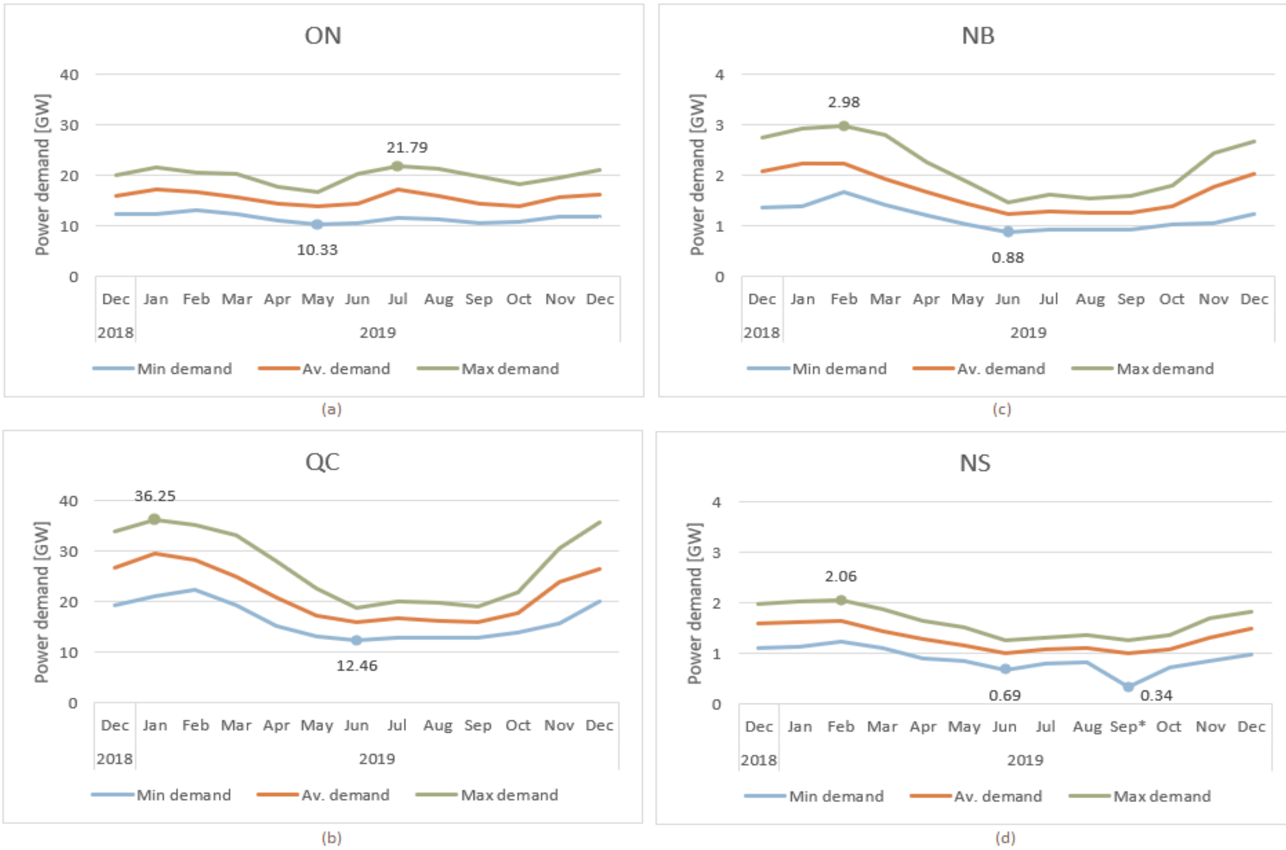
Source: Statistics Canada 2021
Note: Combustible fuels include biomass

The annual peak demand in is generally reached for a few hours during the winter (usually in January or February), with the exception of Ontario where it occurs during the summer (Figure 3).

With the **electrification of the economy**, in particular space heating electrification and EV market penetration, annual demand profiles tend to change. Various studies predict that these **new demands will significantly increase the annual peak or shift it from summer to winter in regions with cold climates like Ontario** (Electric Power Research Institute, 2021; Waite & Modi, 2020). It is interesting to note that while the difference between summer and winter peaks is slight in Ontario (less than 0.3 GW), the gap between minimum and maximum demand can be significant in some provinces. For example, the minimum power demand in Quebec is 12.5 GW in June, compared to the maximum demand of 36.3 GW in January, which is almost three times as high as the minimum demand.

Currently, there is no integrated approach to the massive electrification of our societies, which would temper the significant challenge, both technical and economical, to meeting the new demand. The various strategies employed to meet peak demand include using demand side management and demand response, relying on imports, and deploying large and costly infrastructures.

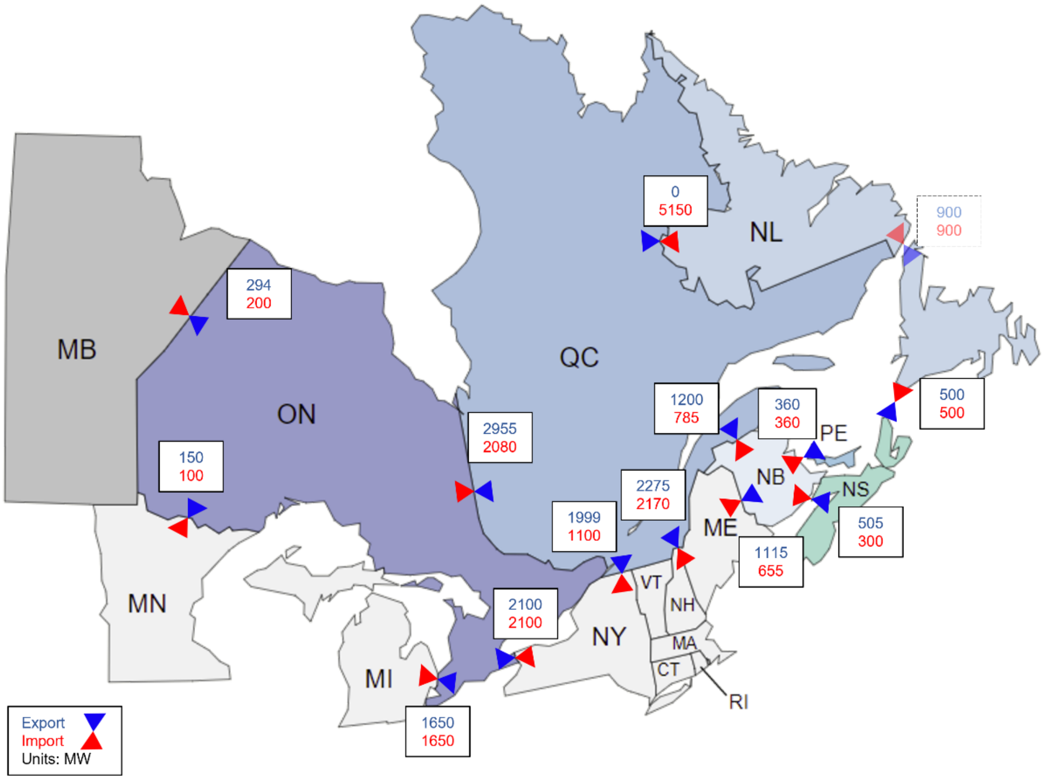
Figure 3 – Annual demand profiles (2019)



Note: *Typically, minimal power demand is in May or June; The minimal observed in September for NS is related to power outages caused by hurricane Dorian.*

In addition to the challenge of direct electrification, it is important to keep in mind the substantial decarbonization efforts that some provinces will need to make to achieve net-zero, including Nova Scotia, New-Brunswick and, to a lesser extent, Ontario and Newfoundland and Labrador. Several studies support the development of collaborative strategies involving increased interconnection of the grids of central and eastern Canadian provinces and northeastern US states in order to efficiently (technically, economically and environmentally) meet electricity needs in the context of decarbonizing economies (Rodriguez-Sarasty et al., 2021; Brinkman et al., 2021; Gorski et al., 2021; Pineau and Langlois-Bertrand, 2020). These studies support increased electricity export and import capabilities over the current system (see Figure 4). However, this approach raises several technical and non-technical issues (regulatory, political tensions, social acceptance, etc.) (Pineau and Langlois-Bertrand, 2020; Rodriguez et al. 2021).

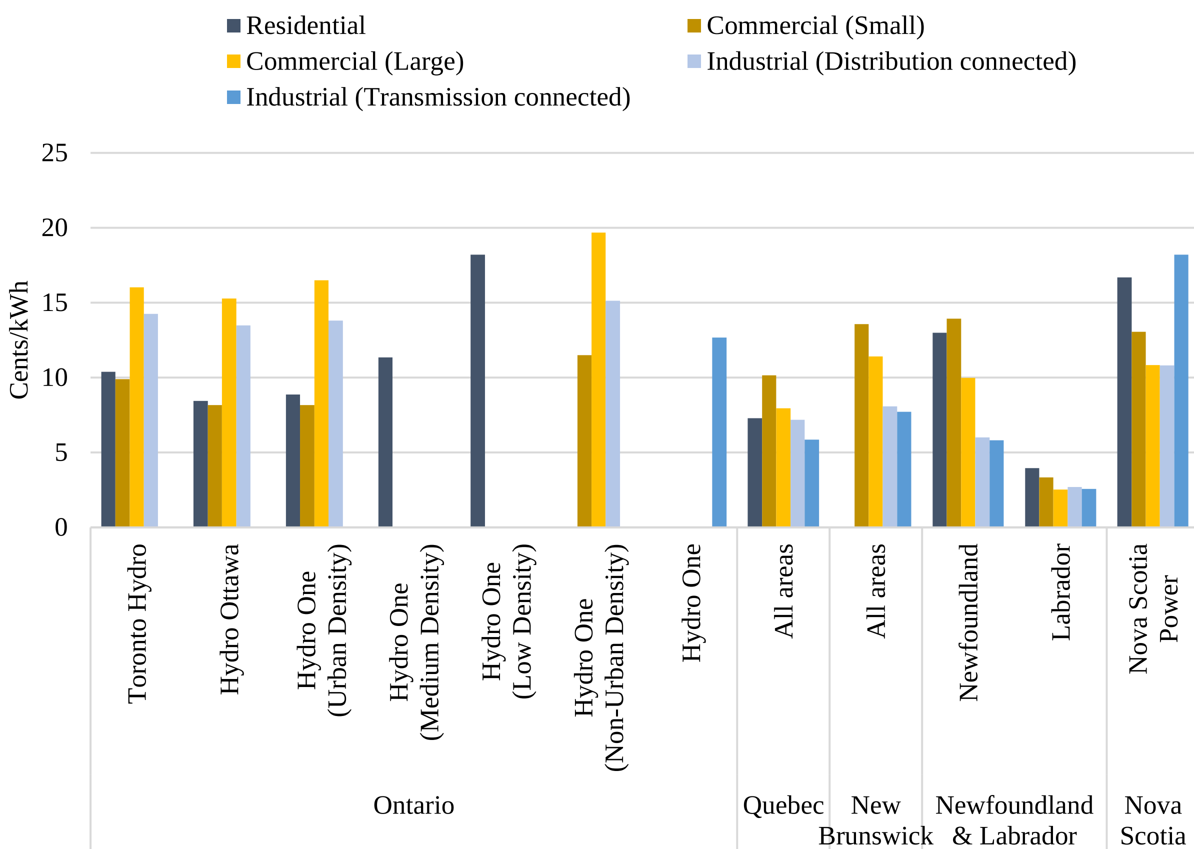
Figure 4 – Interties in 2019



2.2.3 Cost structures

System costs vary across provinces based on system characteristics: for instance, provinces with a higher share of hydropower baseload typically bear lower overall system costs. However, the prices charged to customers vary significantly, mainly according to customer class. Some provinces charge higher unit power costs to their residential and small business customers, while others charge higher rates to industrial customers (Figure 5).

Figure 5 – Estimated average power costs (¢/kWh) for various consumer classes



Source: Bishop, Ragab, & Shaffer, 2020

Furthermore, electricity rates have increased over the past few years at a higher rate in Ontario than in the other provinces covered in this document. These **increases do not have the same key drivers: fixed costs associated with infrastructure maintenance, refurbishment or upgrades are typically an important source of these escalations, but peak demand management efforts may also lead to higher overall costs and, by extension, prices charged to customers**. Some of these drivers are very likely to persist in the near future, adding to the list of challenges presented in Chapter 4.

3 Detailed description of electrical systems and planning

This section of the white paper provides a profile of the electricity sectors in each of the provinces studied. It begins with a review of recent developments in the electricity sector. It then describes some of the characteristics of each of the electricity systems, before concluding with a discussion of the planning guidance provided by the responsible agencies (e.g., the IESO). The context and planning elements presented identify several challenges facing the provinces, which are discussed in more detail in Part 4 of this document.

Key facts

- The provinces have very different market structures (partial privatization, quasi-monopoly Crown corporation, quasi-monopoly private company)
- The topology of the Ontario system, separated into several areas connected by interfaces, is an atypical configuration for a provincial transmission system in Central and Eastern Canada. This configuration creates funnels that bring more challenges in terms of generation location, reliability and interface equipment capacity. Added to this is the problem of modernizing the distribution system, which is common to all provinces.
- The provinces also face common demand growth drivers, including transportation, building heating, greenhouse, and industrial needs, although in varying proportions.

3.1 Ontario

3.1.1 Recent developments

After 15 years of successive Liberal governments marked by several major transformations to the electricity sector, the Ford government elected in the spring of 2018 announced several changes to policies in the electricity sector, many of which were enacted out of a concern for the impact on electricity costs.

The Green Energy and Green Economy Act, which had been the flagship policy aimed at spurring the deployment of renewable electricity generation since 2009, was repealed in 2018. After the closing of coal-fired powerplants in 2014, nuclear refurbishment had become more pressing. Work at the Darlington nuclear powerplant began first and is expected to be completed by the end of 2026. Work at the Bruce nuclear powerplant, which formally began in 2020, is expected to continue until 2033. Given that nuclear energy supplies the bulk of baseload power in the province, the overlapping of refurbishments starting in 2020 raised concerns that led to extending the end of life at the Pickering nuclear station, originally scheduled to be permanently closed before 2020 but extended until 2024. In addition, the government-owned Ontario Power Generation (OPG) subsidiary Atura Power purchased three natural gas-fired plants previously owned by TC Energy.

In the transport sector, the province also cancelled its Electric and Hydrogen Vehicle Incentive Program, which offered rebates for the purchase of low-emission vehicles. The financial incentives to install charging stations for home or business use and the Electric Vehicle Chargers Ontario grant program that developed a network of charging stations across the province were also cancelled.

3.1.2 Electricity market structure and infrastructure

Since the partial privatization that broke up the Ontario Hydro public monopoly at the turn of the 21st century, the electricity sector in Ontario has been a mix of private and public actors, with the latter still playing a large role. Ontario Power Generation, a crown corporation, generates about half the electricity produced in the province, including most hydroelectric facilities and all nuclear power generation stations. Private actors are particularly present in wind and solar generation and natural gas-fired generation. However, transmission is almost wholly managed by the Hydro One crown corporation. Distribution and retail are mainly conducted by local utilities, although options are available to buy from private retailers, an option that is used by a minority of customers at the present time.

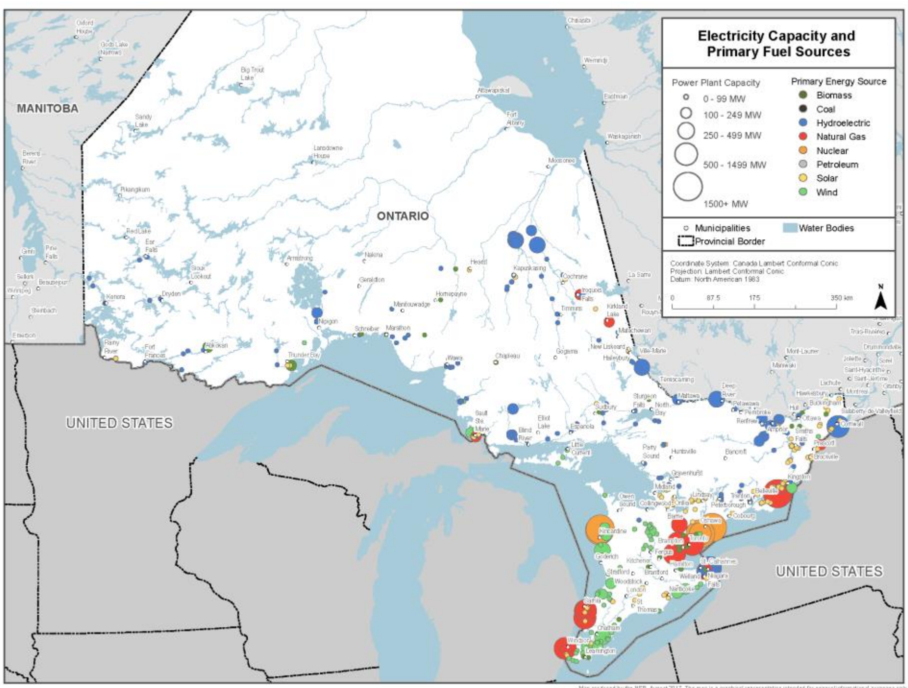
While transmission is operated by both Hydro One and private companies, the Independent Electricity System Operator (IESO), another crown corporation, is responsible for its reliability. The bulk system planning is led by the IESO, in coordination with Hydro One. The IESO last published its Annual Planning Outlook in late 2021, outlining the electricity needs for the province for 2023 to 2042. Finally, the Ontario Energy Board serves as the regulating entity for the province's system.

Ontario's electricity rates and costs also differ from those in the other provinces considered here. While in most other provinces, industrial customers are typically charged lower prices for power consumption, in Ontario, it is residential and small business customers who benefit from lower rates owing to various rebates. The province is also unique in its application of a Global Adjustment Mechanism to cover the gap between contract costs and market rates. Industrial customers pay the highest rate for this mechanism, although some may benefit from the Industrial Conservation Initiative by closely managing their demand and avoiding the year's five highest peak demand periods.

3.1.3 Production and demand

Total electricity production in Ontario was 156.3 TWh in 2019. Nuclear energy provides the largest share of Ontario's electricity with three nuclear powerplants combining 13 GW of installed capacity and supplying around 58% of the electricity. Hydroelectric production comes second, with facilities producing 25% of the total. Most of the remaining generation comes from low-emission sources, wind (7%) and solar (2%) in particular. This combines to make up 92% of electricity generated from low-emission sources, the last source being natural gas, which highlights the significant differences with the importance of gas in installed capacity vs. supply. Most of the generation facilities are located in the southeast region of the province and along the Quebec border.

Figure 6 – Electricity generation in Ontario



Source: CER, Natural Resources Canada

The province is also divided into 10 IESO electrical zones, connected by bulk transmission interfaces. This bulk transmission system is also used for imports and exports with jurisdictions outside the provinces. Transmission capacity to other provinces and northern US states includes Manitoba to the west, Quebec to the east, and Minnesota, Michigan and New York (which connects with two links, the Niagara and the St Lawrence regions) to the south.

Several transmission reinforcement projects are already planned or underway for the 2020-2025 period for the West of Chatham Area, the Hawthorne-Merivale, and the East-West Tie. However, transfer capacity along three major interfaces (FETT, FIO and BLIP) is facing major constraints.

3.1.4 Trade

The capacity to trade electricity with Manitoba, Quebec, Minnesota, Michigan and New York resulted in 19.8 TWh of electricity being exported from the province and 6.6 TWh being imported in 2019. While New York and Michigan are principally export markets, trade with Manitoba and Minnesota is more balanced, with slightly more exports to than imports from these markets. As concerns Quebec, although 2.6 TWh is exported annually, more than twice as much is imported (5.9 TWh).

3.1.5 Planned GHG reduction objectives and strategies

Ontario aims to reduce its GHG emissions by 30% by 2030 (compared to 2005). Its electricity sector has already significantly cut back its emissions from 14.4 Mt in 2011 to 4.4 Mt in 2019, largely through a phase-out of conventional coal completed in 2014. Today, the electrification of the economy brings new challenges in the short, medium and long term.

With this in mind, electricity sector planning in Ontario emphasizes the following:

- The IESO Annual Outlook expects an average annual increase in overall demand of almost 2% until 2040, a significant increase from projections in the previous year's Outlook, given the inclusion of the federal target of 100% new sales of vehicles being electric by 2035. Other than this, several drivers combine to continuously increase electricity demand over the next two decades. This includes a 0.9% average annual growth for the residential sector (increased suburban and exurban migration which increases single-family homes with higher energy intensity rates, growth in work-from-home arrangements, increased adoption of electronics) and the commercial sector (decreased demand in offices but increase in warehouses), 7% for agriculture (greenhouse expansion and proliferation of artificial lighting in greenhouses), and growth in electric vehicle sales. In the industrial sector, demand is expected to plateau for most of the 2020s after recovering and then to increase by a 1% average annual growth for the industrial sector;

- The Outlook also points to transmission infrastructure constraints leading to capacity needs emerging in the mid-2020s (mainly in the GTA and Eastern Ontario regions at first), with the capacity retirement of the Pickering Nuclear Generation Station, the temporary withdrawal for refurbishment of the Bruce and Darlington nuclear generating stations, and the expiration of several supply contracts from the mid-2020s (mostly for natural gas-fired electricity);

- There are also other transmission issues, especially in relation to regional interfaces, notably the Flow East Towards Toronto (FETT), the Flow Into Ottawa (FIO), and the Buchanan Longwood Input (BLIP). Since a large portion of the retiring capacity is located east of the FETT interface, new generation capacity must be located to the east because of constraints to this interface.

The IESO plans to continue meeting Ontario's needs through "continued use of existing resources, the expansion of transmission, imports, the growing use of DERs, storage, and incremental energy-efficiency savings" (IESO, 2020).

3.2 Quebec

3.2.1 Recent developments

Because its electricity is already largely decarbonized, Quebec is able to focus directly on electrifying its economy to achieve its GHG emission reduction objectives. In 2018, the province adopted the zero-emission vehicle standard. Two years later, in 2020, a new chapter in the building code focusing on energy efficiency came into effect to replace the previous regulation that dated back to 1983 (Régie du bâtiment du Québec, 2020). In November of the same year, Quebec released its 2030 Plan for a Green Economy in which it presents the framework of its policy to combat climate change at the 2030 horizon. The following month, the Minister of the Environment and the Fight Against Climate Change announced that Quebec had missed its target of a 20% reduction in GHG emissions for 2020.

For the past few years, Hydro-Québec (HQ) has sought to position itself as a key player in energy transition in the northeast of the continent. In this context, it has obtained supply contracts with New Brunswick and several US states. In addition, a number of its transmission line projects to connect Quebec and New England states received all the necessary regulatory approvals, thus increasing Quebec's export capacity in the short and medium term. Moreover, in 2021, HQ won a tender from the state of New York to supply about 10 TWh/year for 25 years starting in 2025. This adds to the 9.45 TWh/year supply agreement signed with Massachusetts in 2019. To deliver this electricity, HQ and its partners plan to build a transmission line that will cross the state of Maine. However, despite having obtained the necessary government approvals, this project (also known as NECEC) is facing strong public opposition.

At the end of 2020, HQ Distribution (HQD) released its 2020-2029 supply plan in which it identified emerging and fast-growing sources of energy demand such as data centres, cryptocurrency mining centers, greenhouses, and electric vehicles. According to this plan, new sources of supply will be needed from 2026. To meet these needs, the announcement of a call for projects was launched in early 2022 for an additional 780 MW of supply. Section 3.2.5 sets out more details about this plan.

3.2.2 Electricity market structure and infrastructure

The Régie de l'énergie regulates the electricity transmission and distribution markets, for which Hydro-Québec, a state-owned enterprise, holds a quasi-monopoly. TransÉnergie, a Hydro-Québec group (HQT), operates the electricity transmission network, which is the largest in North America with more than 34,500 km of lines and over 520 substations. The electricity distribution network, managed by HQD, is made up of more than 119,300 km of medium voltage lines and 107,400 km of low voltage lines. In addition to the main electricity distribution network, there are nine municipal networks and one cooperative network, which together purchase approximately 4.5 TWh of electric energy from HQD annually. While the electricity production for domestic consumption and export are dominated by Hydro-Québec's production group (HQP), the province also has many independent producers, in particular for wind farms, cogeneration (biomass and biogas) plants, and small hydropower plants. Most of the independent producers have contracts with Hydro-Québec's distribution group.

From 2017 to 2020, investments made for distribution infrastructures grew continuously, climbing from $650 to $773 million between 2017 and 2020. About 90% of these investments are intended to accommodate customer growth and maintain infrastructures, some 2% to improve the management of the grid, and the rest is used to comply with regulatory requirements. In its 2020-2024 strategic plan, HQ recognizes that significant investments are needed to modernize the electrical grid.

The electricity from the heritage pool is bought by HQD from HQP at about 3¢/kWh, while electricity costs in long-term contracts average 10.9¢/kWh. The electricity from short-term markets is bought at an average price of 4.4¢/kWh. This results in annual electric power supply costs of approximately $6.69 billion in 2021[4].

According to Hydro-Québec's 2021 survey, Quebec offers the lowest price for the residential sector in North America and the top three lowest prices for all other categories of consumers (small power, medium power, and large power). Prices have been stable in Quebec over the last six years (2016-2021).

3.2.3 Production and demand

Quebec is the largest electricity producer in Canada. In 2019, the province's total electricity production was 212.1 TWh, 94% of which came from hydropower. Other sources of electric power generation include wind (5.3%), biomass (0.7%), other thermal sources (0.3%), and solar photovoltaic (0.001%). The province's total installed capacity is over 42 500 MW and, as reflected in its power generation, is largely dominated by hydropower. The most recent hydroelectric project is the La Romaine complex, composed of four power plants for a total of 1,550 MW. The first three power plants were commissioned between 2014 and 2017; the last (245 MW) is expected to be completed in 2022.

In 2019, HQD sold 174.6 TWh of electricity within the province, 40.5% of which went to the residential sector; 27.4% to the commercial, institutional and small industry sectors; and 32.1% to the large industry and other sectors. About 92% of the demand is met by the heritage pool, a block of electricity provided at low price by "heritage" power plants[5], the remainder being met by long-term supply contracts (7.2%) and the purchase of energy in short-term markets (0.8%). Long-term procurement contracts are managed by HQD, except for Labrador's Churchill Falls. The electricity provided by this hydropower complex, representing 30 to 35 TWh per year, is managed by HQP. In 2019, there were more than 60 active long-term contracts between HDQ and private electricity producers. Table 1 presents the number of contracts by energy source.

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[4] (176.9 -17.2) TWh * 10^9 * 0.03 $/kWh ÷ 10^9 + 1.9 G$ = 6.69 G$

[5] Heritage plants refer to hydropower plants that were built in the last century. They include, among others, the La Grande complex and generating stations on Rivière Manicouagan, the Ottawa River, and the Saint Lawrence River.

Table 1 – Electricity procurement contracts

Sources	Number of contracts	Installed Capacity (MW)	Annual energy contribution (TWh)	Procurement costs (¢/kWh)
Hydro (Churchill Falls)[6]	1	5 428	30-35	0.2
Wind	39	3 882	11.4	6.9 to 15.2
Small hydro	7	144	0.6	≈ 9.4
Biomass and biogas cogeneration	23	345	2.5	≈ 12
Other suppliers	-	968	-	-

3.2.4 Trade

Quebec has interties with three Canadian provinces, New Brunswick (NB), Newfoundland and Labrador (NL) and Ontario (ON), as well as two American regions, the State of New York (NY) and New England (NE). Interprovincial and international transmission capacities are generally quite similar for imports and exports, except for the intertie with Newfoundland and Labrador, which is entirely dedicated to the import of the electricity generated by Churchill Falls.

Table 2 – Total interties capacity

	Export (MW)	Import (MW)
QC - NB	1200	785
QC - NL	0	5150
QC - ON	2955	2080
QC - NE	2275	2170
QC - NY	1999	1100

Quebec is a net exporter of electricity. In 2019, it imported a total of 34.2 TWh, mainly from Newfoundland and Labrador (92%), and exported about 37 TWh, more than 70% of which went to New England and New York.

[6] Contract managed by HQP, not HQD.

The price of a MWh differs from one wholesale market to another. Over the last three years, due to the strong presence of natural gas in the energy mix in New England and New York, electricity prices in these wholesale markets were generally low at about $40/MWh, with higher prices during a few hours at peak demand during winter and summer ($50-$65 per MWh). The same trend can be observed in the Ontario market.

3.2.5 GHG reduction objectives and planned strategies

Quebec has ambitious GHG reduction targets. It aims to reduce its GHG emissions by 37.5% from 1990 levels by 2030 and to become carbon neutral by 2050.

The 2030 Plan for a Green Economy sets out the provincial government's policy framework to achieve its 2030 objectives, which include:

- achieving 70% of renewable energy in HQ's autonomous networks;
- increasing 22% of new zero-emission vehicles by 2025, reaching 1.5 million electric vehicles by 2030, and ceasing to sell gasoline-powered vehicles as of 2035;
- improving energy efficiency, especially for space heating; et
- developing the hydrogen industry.

In early 2022, Hydro-Québec released its 2022-2026 strategic plan, which focuses on electrifying the province's economy, and sales growth within Quebec. It also aims to improve the efficiency of operations in the electricity system by relying on digital technology and taking into account the impacts of climate change in planning. **It projects an increase in annual electricity demand of over 100 TWh by 2050.**

Furthermore, Hydro-Québec released its 2020-2029 procurement plan at about the same time as the provincial government released its 2030 decarbonization plan. About two years later, HQ issued a second progress report on its procurement plan. Some key elements of this planning include demand projections: the utility expects a growth of 20 TWh (12%) by 2029 driven by "natural" growth and the development of key markets (greenhouse – 1.1TWh/year in 2029; data centers – 4.2TWh/year in 2029; cryptocurrency mining centres; and the accelerated development of EVs based on the government's 2030 plan). The procurement plan also points to the need for additional supplies as of 2026-2027. To meet this upcoming need, Hydro-Quebec has issued two calls for tenders in early 2022, for a total of 780 MW, including 300 MW reserved specifically for wind power. It also focuses on decarbonizing its 22 autonomous electrical grids.

Throughout these plans, Hydro-Québec outlines the following specific strategies:

- Optimize available supplies.
- Implement energy efficiency measures, specifically power demand management solutions (Hilo, GDP Affaires program, interruptible electricity for industrial customers).
- Plan new long-term supplies.
- Achieve an energy transition in its autonomous power networks by reducing demand and/or replacing diesel by renewable energy sources.
- Develop export markets.

3.3 New Brunswick

3.3.1 Recent developments

New Brunswick's Climate Change Act of 2018 set out targets for GHG emissions and regulation under the Electricity Act mandates that 40% of the electricity sold within the province come from renewable sources. As part of the Climate Change Action Plan (updated in 2017), the province has also committed to phasing out coal by 2030. It is worth noting that since the minority Progressive Conservative government that came to power in 2018 did not reject the 2016 plan or its 2017 update, GHG emissions reduction targets still apply.

Over the past decade, the province has made substantial progress towards its decarbonization objectives, most of which are tied to the electricity sector. Changes in the electricity generation mix in the last 10 years have been the main reason New Brunswick was able to achieve a 30% reduction in GHG emissions between 2005 and 2019. This also contributed to reducing electricity generation's share of total emissions from the province from 40% in 2005 to 26% in 2019. While this change is substantial, New Brunswick remains the home to thermal generation from natural gas, coal and petroleum, which points to the fact that more can be done to reduce emissions from this sector. In November 2021, the federal government has decided not to pursue the equivalency agreement proposed by the province to keep the Belledune coal station in operation until 2040.

3.3.2 Electricity market structure and infrastructure

Electricity generation, transmission and distribution in New Brunswick is mainly handled by New Brunswick Power Corporation (NB Power), a vertically integrated crown corporation. NB Power owns all but one of the province's fossils fuels powerplants, as well as the Point Lepreau Nuclear Generating Station. Ownership of hydroelectric facilities is more mixed, although NB Power is the dominant actor. The utility does not own any wind farm. NB Power sells electricity to customers in all regions of the province, except for Saint John, Edmunston and Perth-Andover where local utilities take care of distribution to customers. Transmission and operation are managed by Transmission and System Operator (T&SO) within the vertically integrated NB Power. The electricity sector in the province is regulated by the New Brunswick energy and Utilities Board (EUB).

Transmission capacity beyond the province's territory includes direct interties to Quebec, Prince Edward Island, and Nova Scotia. These interties provide many opportunities for balancing needs through increased imports when needed. Interties also exist with neighbouring US states. New Brunswick's intertie with Northern Maine plays a critical role for this latter region, as it is not connected to any other system, and variable energy sources account for a large portion of the total installed capacity at just over 42% (primarily wind).

3.3.3 Production and demand

In 2019, 13.5 TWh of electricity was generated in the province. New Brunswick is home to the only nuclear powerplant outside of Ontario, the Point Lepreau Nuclear Generating Station, which produces 37% of the province's electricity. Around 30% of electricity comes from fossil fuels (natural gas, coal, and petroleum), while the rest is provided by hydroelectricity (21%), wind (7%) and biomass (3%).

This mix has changed substantially over the past 20 years, with the closure of two major fossil fuel-fired powerplants and the deployment of wind energy. The refurbishment of the nuclear powerplant, completed in 2012, also helped cement its role in this mix.

3.3.4 Trade

New Brunswick imports and exports relatively similar total quantities every year, with total exports of around 3.4 TWh and imports of around 4 TWh. Despite interties with New England states, this trade is overwhelmingly with neighbouring provinces.

New Brunswick provides over 70% of the electricity consumed in Prince Edward Island, even though this share has decreased substantially over the past decade after the island began to deploy wind energy.

3.3.5 GHG reduction objectives and planned strategies

New Brunswick has a GHG reduction objective of 35% by 2030 and 80% by 2050, both with respect to 1990 levels.

In terms of planning, the latest Integrated Resources Plan highlights the following issues:

- Load forecasts include a continuous increase until 2040. The residential sector constitutes 44% of total demand, with industry at 33%. Most of the rest of the demand comes from general services, and virtually none from agriculture.

However, only 2019 is included in the IRP, making it unclear what drives this and how specific uses are forecast to evolve.

- The New Brunswick government was seeking an equivalency agreement on the Belledune coal station. To avoid building a new plant, it was proposing to reduce generation from Belledune to only peak periods in winter months until 2040, which would not represent any increase in total GHGs emitted over emissions from normal operations until 2030 but the federal government rejected this proposition forcing the province to find another solution.
- The province is also looking to extend the life of natural gas at the Bayside generating station.
- According to its planning, NB Power is considering: "adding transmission infrastructure; targeted demand reductions (smart grid technology / DSM programs); and strategically locating any new generation."
- In recent years, NB Power has also shifted its focus to include demand management (Energy Smart NB), which will be a large part of the IRP for the next decade. This includes the Smart Grid component aimed at building and operating a smarter, cleaner, more reliable and efficient power grid.

3.4 Nova Scotia

3.4.1 Recent developments

Although Nova Scotia reduced its GHG emissions by 26% between 2005 and 2018, its electricity sector still relies heavily on fossil fuels. Owing to its dependence on coal, the province has negotiated an Equivalency Agreement with the federal government to extend the time required under the federal Coal-Fired Electricity Regulations (no more coal after 2030) to phase out its coal power plants. In return, the province must reduce its GHG emissions from other sources. The first agreement, which was signed in 2014, was valid until 2019. This agreement was then renewed for another five-year period.

In its efforts to reduce its GHG emissions, Nova Scotia launched a cap-and-trade program in 2019 and organized the first auction in June 2020. In 2010, it adopted a Renewable Electricity Standard requiring 40% of the electricity supply in the province to be derived from renewable sources by 2020. This share climbs to 80% by 2030. The Maritime Link, which allows Nova Scotia to import electricity from Muskrat Falls in Newfoundland and Labrador, plays a key role in achieving the Renewable Electricity Standard goal.

3.4.2 Electricity market structure and infrastructure

Most of the electricity in Nova Scotia is generated, transmitted and distributed by the vertically integrated electric utility, Nova Scotia Power Inc. (NSPI), owned by Emera, a private company. The province also has five municipal electric utilities that purchase their electricity primarily from NPSI, as well as many wind power plants owned by independent power producers. All the electric utilities, both private and municipal, are regulated by the Nova Scotia Utility and Review Board (NSUARB), which oversees rate setting, the approval of large capital expenditures and many other tasks to ensure safe and reliable service to customers. Until 2019, the province had a sixth municipal electric utility, the Canso Electric Light Commission, which was sold to NSPI for $1.

With regard to the distribution grid, the average investment per year for distribution infrastructures between 2012 and 2016 was $63.3M, which increased to $114.2M between 2016 and 2020. It is projected to fall to $70-72M per year from 2022 to 2025 due to a continued growth in distribution system investments from 2015 to 2019, which now seem to be decreasing.

3.4.3 Production and demand

In 2019, 9.74 TWh of electricity were generated in Nova Scotia, 78.1% of which were produced from combustible fuels, mainly coal, coke, natural gas, petroleum and roughly 1%-2% biomass. The remaining 21.9% derived from hydropower (10.7%), wind power (11.2%) and a very small amount of tidal power. In 2019, the province's total consumption of electricity was about 11.1 TWh.

The total capacity installed in 2020 was 2992 MW, with more than 64.4% being provided by non-renewable combustible fuels power plants. While NSPI plans to retire several coal-fired power plants (around 320 MW) by 2030, its current retirement plan does not foresee eliminating 100% of coal-fired power plants by 2030, which means that 900 MW will remain. In addition, even though the Annapolis tidal power plant will be closed in 2021, tidal power will still be part of the energy mix because of several ongoing tidal power plant projects (usually small capacities of 0.6MW to 5MW).

3.4.4 Trade

In 2019, Nova Scotia's exports were 132.6 GWh and imports were 825.7 GWh. The electricity is mainly purchased from New Brunswick and Newfoundland and Labrador.

The export capacity from NB to NS is 300 MW, while the export capacity from NS to NB is 505 MW. The Maritime Link Project, in service since January 2018, connects NS with the Muskrat Falls hydropower plant in NL. Energy began to flow in December 2020 but has not yet reached the planned capacity. The agreement guarantees that Nova Scotia will receive 20% of Muskrat Falls production for 35 years in return for paying 20% of the costs. This 20% took the form of the construction of the Maritime Link, which has a transmission capacity of 500MW. According to current plans, NS will receive a firm block of 153 MW from Muskrat Falls, representing at least 900 GWh annually. It is anticipated that up to an additional 2000 GWh per year will become available. This intertie is owned and operated by a subsidiary of Emera, NSP Maritime Link. Thanks to this intertie, NS is integrated into the Northeast Power Coordinating Council (NPCC) bulk power system. Although this link is part of the Atlantic loop project supported by the current government, little information is publicly available on this project.

3.4.5 GHG reduction objectives and planned strategies

Nova Scotia's GHG emissions reduction objectives are to ensure a 53% reduction by 2030 for all sectors combined and to be carbon neutral by 2050 (Sustainable Development Goals Act, 2019). The province signed an equivalency agreement with the federal government respecting coal-fired power plants, which includes a 55% reduction in GHG emissions by 2030 for the electricity sector rather than retiring all the coal-fired power plants. Nova Scotia also has Renewable Electricity Standards, which targeted having 25% of electricity sales in 2015 and 40% of electricity sales in 2020 come from renewable power. Given delays in the Muskrat Fall project, the latter objective was adapted to 40% over the 2020-2022 period. The province's objective for 2030 is for 80% of electricity sales to come from renewable power.

NSPI released its Integrated Resource Plan in November 2020, followed by its 10-year System Outlook in June 2021. Highlights from these documents include an emphasis on the following:

- More imports (Maritime Link) will be needed in the future, which translates into a need to strengthen transmission structures within the province (2025-2035 or even earlier if possible and viable).
- Electrification is to be a key element in NS decarbonization efforts, but it must be done while decarbonizing the electric mix. The focus for electrification will initially be on the transportation and building sectors.
- Thermal plants will be retired and replaced, with the preparation of a plan with a first withdrawal scheduled for 2023.

NSPI also identifies two drivers of demand growth: electric heating in the residential sector and industrial growth until 2024. According to its forecast, the demand is subsequently expected to stagnate around 11 TWh thanks to demand side management, improvements in energy efficiency and increases in the number of behind-the-meter installations, especially residential PV.

3.5 Prince Edward Island

3.5.1 Recent developments

The government of Prince Edward Island released its 10-year energy strategy in 2017. It also established a Climate Change Secretariat in its 2018-2023 Climate Change Action Plan, which initially reiterated the 30% GHG emissions reduction target (by 2030). However, it revised this target to 40% in 2018. In December 2020, the province went further, passing the Net Zero Carbon Act, committing to reduce net emissions to zero by 2040. Legislation also requires the government to publish a yearly report on the progress made toward achieving the targets.

Government measures pay special attention to transportation since the sector accounts for almost half of the province's GHG emissions. The 2018-2023 Climate Change Plan committed to designing and installing a province-wide electric vehicle charging network. This plan was followed by the release of the Sustainable Transportation Strategy in late 2019, which proposes measures such as different rate structures for electric vehicles registration.

3.5.2 Electricity market structure and infrastructure

Electricity generation, transmission and distribution in Prince Edward Island is handled by Maritime Electric, a public utility and subsidiary of Fortis. Maritime Electric owns and operates two generating stations, the Charlottetown Thermal Generating Station (to be decommissioned in 2022) and the Borden Generating Station, both operating on diesel and used only during peak demand. In addition, the Summerside municipal utility is responsible for about 10% of the island's load. The rest of all the electricity generated within the province is provided by a small number of wind energy producers, including a crown corporation – the PEI Energy Corporation – and independent producers. An intertie with New Brunswick provides the rest of the supply to the province.

3.5.3 Production and demand

Wind-generated electricity constitutes a little over a quarter of the province's consumption, while the rest comes from neighbouring New Brunswick, including from the Point Lepreau nuclear station, meeting a total demand of 1.5 TWh in 2019. This intertie makes Prince Edward Island part of the northeastern grid. Although this level of dependence on imports is high compared with other provinces, rapid wind development over the past decade has reduced the province's dependence on New Brunswick production. Peak demand, which occurs during winter months, is met by thermal generation.

3.5.4 Trade

Electricity exchanges are exclusively with New Brunswick. In 2019, 0.3 TWh was exported from Prince Edward Island and 1.3 TWh was imported.

3.5.5 GHG reduction objectives and planned strategies

GHG emissions in Prince Edward Island come overwhelmingly from transport (47%) and agriculture (23%), although public electricity and heat production still amount to 21% of total emissions, despite a very small share of electricity generated on the island from fossil fuel sources.

In its Integrated System Plan 2020, Maritime Electric highlights the following elements:

- Based on demand profiles and cross-country trends for transport and space heating, demand for electricity should significantly and continuously expand over the coming two decades.
- The province aims to reduce its dependence on New Brunswick and its GHG emissions by increasing installed wind capacity and demand-side management programs on the island. The role of storage in tempering the baseload issues is unclear and solar energy is still considered uneconomic.
- The current capacity of the link to New Brunswick (300 MW) was almost reached during PEI's system peak in January 2020 (287 MW).

3.6 Newfoundland and Labrador

3.6.1 Recent developments

The province's carbon pricing system, which came into effect in January 2019, is based on a performance standard system applying, among others, to large industrial facilities and large-scale electricity generation.

The final report of the Commission of Inquiry Respecting the Muskrat Falls Project was released in March 2020. The purpose of this commission was to analyze the elements that led to the significant problems associated with the Muskrat Falls project. In December of the same year, the first hydro turbine at Muskrat Falls was commissioned about four years later than originally planned. The projected impact of the Muskrat Falls project on rates is an increase from 13.06¢/kWh on average in 2020 to 22.89¢/kWh (a 75% increase) when the project is fully in service if no mitigation measures are implemented.

A feasibility study, published in March 2021 and commissioned by the Offshore Energy Research Association (OERA), examined the potential for hydrogen to aid decarbonization and grow the province's economy. It was found that while Newfoundland and Labrador has great potential for producing green hydrogen, local demand potential is low.

3.6.2 Electricity market structure and infrastructure

NL has two major electrical systems: the Island Interconnected System (IIS) and the Labrador Interconnected system (LIS). In addition to these systems, there are also several isolated systems supplied by diesel. The province's two electric utilities are regulated by the Newfoundland and Labrador Board of Commissioners of Public Utilities. Newfoundland Power, an investor-owned utility, focuses on distributing electricity, while the crown-owned utility Newfoundland and Labrador Hydro (NLH) concentrates more on generation and transmission. While serving 87% of all customers in the province, Newfoundland Power purchases about 93% of its electricity needs from NLH. More than 80% of the electricity consumed in the province is generated by NLH.

The budget for the distribution grid infrastructure has continuously increased between 2019 and 2021, rising from $40 M to $45.9M. These amounts represent between 40% and 46% of Newfoundland Power's total capital budget.

3.6.3 Production and demand

The province's total installed capacity in 2019 was slightly more than 7550 MW, 87.3% of which came from hydropower, 12% from thermal resources (heavy oil, gas, and diesel) and 0.7% from wind power plants. The Churchill Falls complex represents 82.3% of the installed hydroelectric capacity.

Late in 2020, the first hydro turbine of the Muskrat Falls project was completed, adding 206 MW to the installed capacity. When the Muskrat Falls project is completed, it will add a total of 824 MW to the installed capacity, producing about 5 TWh per year.

In 2019, a total of 42.6 TWh was generated in the province, most of which was produced by hydroelectric power plants (40.7 TWh). The remainder was generated by thermal power plants, mainly fired by oil and gas. The province has a small number of wind turbines: about 54 MW that produced roughly 0.2 TWh. The forecasted demand for 2019 was approximately 8.6 TWh for the IIS and 2.9 TWh for the LIS. The electricity demand on the island is almost three times the demand in Labrador. For both systems, the peak demand occurs during winter.

3.6.4 Trade

Almost all the electricity produced by Churchill Falls generation station is sold to Hydro-Québec, except for two blocks totalling 525 MW. In 2019, NL exported about 31.3 TWh of electricity and imported 0.25 TWh.

NL has a 5150 MW intertie with Quebec exclusively for export, as well as the Maritime Link, a 500 MW interconnexion with NS. Labrador and Newfoundland are connected by the Labrador Island Link (LIL), a 1100 km 900-MW high voltage direct current transmission line that has a submarine section.

3.6.5 GHG reduction objectives and planned strategies

Newfoundland and Labrador GHG reduction objectives target 30% under 2005 levels by 2030 and 75-85% under 2001 levels by 2050.

In terms of planning, demand drivers were identified mainly as follows for the next 20 years:

- Data centers, with a cumulative total of +2.3 TWh (300MW).

- The Scully iron ore mine in Wabush, which re-started operation in 2019, with a total of +0.5 TWh (±60 MW) per year.
- Load from newly electrified end uses (heating systems and transportation sectors), with 166-605 GWh by 2030 and more than 95% of this load growth occurring on the Island Interconnected System.
- Conversion of the central heating plant of the Department of National Defence, with 50-80 GWh per year.

Planning emphasizes the retirement of three steam generating units at the Holyrood thermal power plant, which has a total capacity of 490 MW, once Muskrat Falls is fully operational, with only one 123 MW unit in operation.

3.7 Additional elements: the northeastern US markets

The electricity grids of the Central and Eastern provinces, New York and the New England states (Maine, Massachusetts, New Hampshire, Vermont, Rhode Island and Connecticut) are interconnected. This implies that the policies that will be implemented by the states south of the border will have a marked impact on the Canadian electricity sector. There is more north-south traffic (from Canada to US states) than in the other direction. In 2019, Canada's exports amounted to about 60 TWh, more than 75% of which came from the Central and Eastern provinces, in contrast to some 13 TWh in imports, less than 4% of which went to these same provinces. The governors of the New England states have also expressed a clear desire to increase interstate and neighbouring collaboration with respect to electricity and other sectors (NESCOE[7] and CONEG[8] are two examples of these initiatives).

The following table presents the characteristics of the electricity sector in the states interconnected with Central and Eastern Canadian provinces.

[7] New England States Committee on Electricity
[8] Coalition of Northeastern Governors

Table 3 – Characteristics of the Northeastern US states (2019)

	Primary energy source for electricity	Generation	Demand	Average retail price	Net imp. or Net exp.	Carbon Intensity of electricity prod.
		TWh	TWh	¢/kWh		g / kWh
New York	Natural gas	131.60	145.6	14.34	Importer	188
New England	Natural gas	99.99	114.46	-	Importer	-
Maine	Hydro	10.49	11.73	14.04	Importer	173
Massachusetts	Natural gas	21.51	51.34	18.40	Importer	395
New Hampshire	Nuclear	18.03	10.71	17.15	Exporter	108
Vermont	Hydro	2.29	5.43	15.36	Importer	3
Rhode Island	Natural gas	7.62	7.35	18.49	Exporter	392
Connecticut	Natural gas	40.05	27.9	18.66	Exporter	237

The current US federal government outlined a blueprint for decarbonization of the electricity sector with the announcement of several aggressive targets to accelerate this transition, which include:

- reaching 100 percent carbon emission-free electricity by 2035;
- making half of all new vehicles sold in 2030 zero-emissions vehicles; and
- increasing solar power to 40% of electricity generation by 2035 and 45% by 2050 (In 2020, solar power represented less than 4% of the US electricity mix).

These targets could lead individual states to amend their own objectives. New York and all the New England states currently have various forms of regulation to increase the share of renewable energies in the electricity mix. However, there is little to no regulation for EVs and even though 2050 targets generally aim for substantial GHG emission reductions, there are no net-zero targets.

Furthermore, the place of natural gas in electricity mixes in the Northeastern US states could have an impact on the potential to export electricity from Central and Eastern Canada to these states. Based on the US Energy Information Administration's Annual Energy Outlook 2021, natural gas is projected to represent 40% of cumulative capacity additions through 2050.

4 An analysis of provinces' choices and strategies

As a reference point for this analysis, we use results from the Canadian Energy Outlook 2021 (CEO2021), which modelled different net-zero scenarios over different time horizons, including Canada's current target for 2050. These modelling results are useful to illustrate what we can expect in terms of electricity production and consumption, both in net-zero trajectories and in a business-as-usual scenario.

4.1 Results from the CEO2021 and general trends

The model used for the CEO2021 is ESMIA Consultants' NATEM (North America TIMES Energy Model), a technology-rich techno-economic optimization model that finds least cost energy system evolutions under given constraints – in our case, GHG emission limits.

Table 4 shows the electricity demand forecast by the utilities for each province covered by this document and the projections from the CEO2021 for the reference scenario – aligned with demand projections from the reference scenario of the Canadian Energy Regulator's Energy Future 2020 – and NZ50, which constrained emissions in order to reach the country-wide net-zero objective by 2050.

Two points should be highlighted about the demand growth projections for the CN50 scenario presented in the table below:

- The NATEM model applies cost-effective energy efficiency measures (e.g., improved building insulation and the replacement of heating systems with heat pumps). Nevertheless, it is possible that some measures that are considered uneconomic over the time horizon studied (2016-2060) may in fact become so. In addition, energy efficiency or energy conservation measures resulting from changes in individual behaviour are not supported by the model.
- Unlike the utility forecasts, the CEO2021 electricity demand forecasts do not include new industrial demand sectors such as greenhouse heating.

Table 4 – Electricity demand growth by province in REF and NZ50 scenarios (with regard to 2016)

	Share of fossil fuel-based generation in total (2016)	Projected demand									Notes on key difference between REF and NZ50
		Forecast by utilities			CEO2021 REF scenario			CEO2021 NZ50 scenario			
		2030	2040	2050	2030	2040	2050	2030	2040	2050	
ON	8.2%	17%[9]	46%[9]	-	43%	72%	98%	23%	97%	202%	Lower increase in NZ50 by 2030 occurs because of increases in energy productivity.
QC	0.2%	12%[10]	-	55%	8%	18%	27%	2%	25%	54%	The main difference is a faster and deeper electrification of sectors in NZ50; growth is also slower in NZ50 before 2030 because of an increase in energy productivity.
NB	42%	19%	26%	-	-3%	5%	5%	7%	44%	62%	Electrification of sectors is slow before 2030 and accelerates substantially thereafter in NZ50.
NS	74.8%	1%[9]	-	-	24%	33%	38%	39%	102%	155%	In contrast to REF, growth in CN50 after 2030 is supported by transport electrification.
PEI	1.2%	39%	-	-	15%	28%	41%	30%	76%	118%	Imports increase by 40% by 2050 to support demand; NZ50 sees significant electrification of the residential and transportation sectors after 2030.
NL	2.7%	17%	-	-	13%	13%	3%	67%	126%	82%	Part of the increased demand in NZ50 comes from hydrogen production.

Notes:

- *Lower increases by 2030 in the NZ50 scenario compared to the REF scenario are mainly because of improved energy productivity*
- *Sources:*
    - *IESO. (2021). Annual Planning Outlook – Ontario's electricity system needs: 2023-2042. Independent Electricity System Operator (IESO).*
    - *Hydro-Québec Distribution. (2021). État d'avancement 2021 du Plan d'approvisionnement 2020-2029.*
    - *NB Power. (2020). Integrated Resource Plan. New Brunswick Power Corporation.*
    - *Nova Scotia Power Inc. (2021). 2021 10-Year System Outlook, for Nova Scotia Utility and Review Board*
    - *Maritime Electric Company. (2020). Integrated System Plan*
    - *Newfoundland and Labrador, Board of commissioners of public utilities. (2020). Rate mitigation options and impacts – Muskrat Falls – Final Report.*

[9] Forecasts include the effects of demand management programs

[10] The forecast for Québec is for 2029.

The CEO2021 results show that:

- **Electricity demand sees very large and rapid increases in Ontario, Nova Scotia and Prince Edward Island in both REF and NZ50 scenarios** (in other words, increases are projected to be sizeable even without further efforts to reduce GHG emissions);
- **Electricity demand increases much more rapidly in the net-zero scenario after 2030** in all provinces.

In comparison with the utilities' forecasts, the following conclusions can be drawn:

- **Overall, the provinces appear to be underestimating the growth in electricity demand implied by the carbon neutrality targets.** In Ontario and Nova Scotia, even when the potential impact of demand side management programs put forward by the utilities is considered, demand growth forecasts appear to be inconsistent with Canada's carbon neutrality goals for 2050. The other provinces' forecasts may seem to better capture the efforts required by the energy transition, at least for the 2030 milestone, but these forecasts include new sources of demand, such as industrial growth, which are not considered in the CEO2021 projected demand.
- **Ontario and New Brunswick are the only two provinces that have forecasts for 2040, while Quebec is the only province that has one for 2050.** Although there is considerable uncertainty in such long-term forecasts, the exercise can still provide relevant indications for strategic planning given the time required to develop infrastructure like hydroelectric and nuclear power plants, which can take from one to several decades to build.

The overarching takeaway from these results is that electricity demand increases are not to be taken lightly for the short to medium term for all provinces, even though there are differences in degree. More importantly, this growth is multiplied in scenarios where efforts to reduce GHG emissions to reach net-zero are intensified. This is the result of the significant role that the electrification of many energy services plays in net-zero pathways, including in the short term, with such drivers as the required sweeping expansion of electric vehicles, heat pumps for space heating, increased use of electricity for industrial and commercial heat needs, the multiplication of greenhouses, and the electrification of machinery in agriculture.

These general trends do not change the fact that the provinces face different challenges in terms of the current state of their electricity system and related planning.

4.2 Challenges

Despite the challenges facing the electricity sector being largely dependent on the specificities of each province's situation, there are also commonalities to keep in mind, starting with those identified in the CEO2021 findings outlined above. Table 5 summarizes both the overarching and the province-specific challenges that are described in the following sections.

The common challenges are ranked according to the degree of influence that the electric utilities have on these challenges (see Section 4.2.1), rather than being prioritized or ranked in chronological order of actions to take. Province-specific challenges have not been classified. The numberings in Table 5 are provided only for the purpose of simplifying the references to these challenges in the rest of the report.

Table 5 – Overview of overarching and province-specific challenges

<table>
<tr><th>Overarching</th><th colspan="2">Province-specific</th></tr>
<tr><td rowspan="3">1. Integration of large amounts of variable generation
2. Replacement of aging transmission and distribution infrastructure and upgrades to accommodate changes in demand distribution
3. Adaptation of PUCs to the privatization of production
4. Adaptation of tariff structures to the evolution of costs structures
5. Clarification of the role of emerging technologies
6. Deciding on the potential future role for hydrogen
7. Planning for the overall increase in society's reliance on electricity
8. Meeting demand projections implied by GHG reduction efforts
9. Adaptation to new demand drivers
10. Adaptation to new patterns of consumption
11. Meeting increased cybersecurity threats arising from the use of some technologies
12. Adaptation of electricity systems to the impacts of climate change</td><td>Ontario
ON.1. Capacity shortages due to nuclear refurbishment
ON.2. Incompatibility of new natural gas generation and GHG targets
ON.3. Transmission infrastructure upgrade needs inside the province</td><td>Quebec
QC.1. Cost of new supply + expiration of long-term procurement contracts
QC.2. Profitability of exports and transmission line projects (given natural gas prices)
QC.3. Potential role of HQ's large dams with regard to variable generation in the northeast grid
QC.4. Electrifying transport and industry</td></tr>
<tr><td>Nova Scotia
NS.1. Replacement of coal-fired baseload without resorting to natural gas
NS.2. Capacity deficit</td><td>Prince Edward Island
PE.1. Meeting expanding demand</td></tr>
<tr><td>New Brunswick
NB.1. Replacement of coal-fired baseload without resorting to natural gas
NB.2. Upgrade of transmission infrastructure</td><td>Newfoundland and Labrador
NL.1. Muskrat Falls cost mitigation
NL.2. Deployment of electrification infrastructure (heating and transportation – EVs)
NL.3. Improvements to electricity transmission infrastructure
NL.4. Development of exports</td></tr>
</table>

4.2.1 Overarching

Before providing details on each province's situation, this section summarizes these common considerations, breaking these challenges down into three categories. As a reminder, these are listed neither in order of priority nor in chronological order of intervention.

The first category includes challenges internal to the electricity system or related to production:

1. The **integration of large amounts of variable generation** requires a different management, including the question of how to meet peak demand with declining baseload production from natural gas and coal powerplants (especially important for Ontario, Nova Scotia, New Brunswick and also Prince Edward Island owing to its imports from New Brunswick).
2. **Enhancing grid capacity** – Because aging transmission and distribution infrastructure and accommodating demand increases are sporadically managed by provinces and transmission operators, there is no clear direction on how to optimize this planning from a regional perspective (i.e., where to expand transmission capacity apart from urgent needs). Efforts such as the Atlantic Loop may be the beginning of this type of initiative but have not yet produced many concrete results. New demand points to a densification of needs rather than an expansion of the grid, which may require different distribution equipment than that customarily used.
3. Although electricity production has traditionally been overwhelmingly in the public sector in the past 100 years, new producers are increasingly private actors in areas such as wind and solar energy, natural gas-fired generation, and decentralized electricity production, which in many cases augments the overall cost of electricity. As this trend continues throughout the expansion of electricity production over the next decades, **regulating agencies will be required to adapt** their approach. In addition, because of the impact of revenue distribution in the sector, a different set of actors capture value throughout electricity systems (not only private utility producers but also groups who are behind the meter).
4. Across most of North America, tariff structures have been largely developed and regulated for situations where variable costs are higher than fixed costs. A number of new factors make this type of **tariff structure inadequate to ensure sufficient revenues for the actors involved**, particularly large utilities owning and operating transmission and/or distribution networks. New demand drivers, demand profiles and a higher share of fixed costs in overall costs combine to require changes to common practices in this area, which in turn requires regulatory agencies to adapt as well.
5. Most provincial planning struggles to **make specific decisions about emerging technologies**, resulting in no clear direction for the role of various options for storage in particular. These include technologies pertaining to centralized generation and storage (e.g., thermal or chemical storage, nuclear SMRs, bioenergy with CCS, or hydrogen), distributed generation and storage (e.g., solar

thermal or battery storage), and consumption (e.g., smart appliances and HVAC systems). The situation is somewhat different for SMRs, which are an important part of New Brunswick's planning after 2035.

6. The federal government has clearly indicated its desire to develop the hydrogen industry and several studies on its potential in the Central and Eastern provinces have been conducted (Hoornweg, et al., 2021; Zen and the Art of Clean Energy Solutions et al., 2020; Zen and the Art of Clean Energy Solutions et al., 2021). However, **little provincial planning has attempted to forecast its use in terms of providing grid resilience, flexibility through chemical storage, flexibility in avoiding electricity waste, and so on.**
7. While electrification is projected to be a key strategy to reduce GHG emissions and increase energy productivity in the future, the massive electrification of services across sectors implies a **greater reliance of the economy on electricity networks**, making their resilience and reliability crucial to planning infrastructure developments and upgrades.

The second category addresses challenges external to the electricity system with the partial influence of utilities, that is, challenges where the utilities or key stakeholders can alter the main drivers or causes through strategic actions:

8. As Table 4 shows, many services must quickly be electrified to maintain the provinces on a path to net-zero emission by 2050. At the provincial level, the highest projections show demand increasing by 26% by 2040, a figure considerably lower than in the CEO2021 projections. This is true for both the business-as-usual and the net-zero scenarios, but especially for the latter, underscoring the **gap between demand planning and needs for net-zero pathways**. The increase in demand also leads to concerns about capacity for peak demand, as well as declining export revenues if more internal production is used for local demand rather than for exports. Although some provinces plan for aggressive energy efficiency improvements to compensate for the overall increase in demand, it is unlikely that this trend would be eliminated by such measures.
9. **New demand drivers change load profiles**, including for peak demand. This challenge is somewhat different across the provinces, with electricity use increases in agriculture (e.g., greenhouses), the commercial sector (e.g., cryptocurrencies), industry (e.g., electric manufacturing processes) and space heating in buildings being of unequal importance given current energy consumption profiles. In contrast, the electrification of transport has many similarities across the provinces.

10. **Consumption patterns will change**, partly because of new demand drivers (see above). For example, as batteries are less efficient during the winter, both transport and building heating will see their demand increase, which could exacerbate peak management challenges.

The last category addresses the challenges external to the electricity system where utilities or stakeholders have little to no control over the main drivers or causes:

11. Technological innovations like smart meters, sensors and other control tools make networks much more flexible and able to respond to the needs generated by the electrification of Central and Eastern Canada's economies. However, this flexibility comes at the price of an **increased risk of cyber attacks.**
12. Climate change leads to more frequent extreme weather events (extreme heat and cold, storms, etc.), which pose physical risks to infrastructure. The resilience of electricity networks is therefore essential, but **climate change also affects the demand**, increasing the need for space cooling or heating services during extreme summer or winter conditions. To meet this challenge, NRCan and Public Safety Canada are coordinating efforts for a national strategy.

The next sections focus on challenges more specific to each province.

4.2.2 Ontario

Ontario faces the following main challenges:

ON.1.

- The IESO Annual Outlook's demand increase forecast leads to capacity shortages starting in the mid-2020s (especially due to the closure of the Pickering nuclear station and the refurbishment of the Bruce and Darlington nuclear generating stations, along with the expiration of several supply contracts, mainly for natural gas-fired electricity, from the mid-2020s). However, these **forecasts are already much lower than the electricity demand increases needed to meet both ongoing trends in electrification and the additional demand to come if GHG reduction efforts are to intensify this electrification.**

ON.2.

- Moreover, **the renewal of the expiring contracts under consideration will come in direct conflict with GHG reduction objectives** or may be affected by carbon pricing increases as these contracts are primarily for natural gas-fired generation. The same can be said of generation from the natural gas-fired stations recently acquired by Ontario Power Generation.

ON.3.

- Given the particular structure of transmission zones in Ontario, **work that has begun on improving interface transmission capacity needs to be revised to accommodate the challenges inherent in the preceding point**. Moreover, limited attention seems to be paid to import-export transmission capacity, which is likely to be essential to meeting this increased demand.

Crucially, although the IESO planning document commits to considering the application of several solutions to these challenges, it makes few clear choices.

4.2.3 Quebec

The main challenges confronting Quebec are as follows:

QC.1.

- For the 2019-2021 period, the average cost of long-term supply is more than three times higher than the heritage pool electricity. Thus, **an increase of non-heritage electricity in the procurement may have an impact on consumers' bills**. In addition, although HQP shares ownership of the Churchill Falls power plant (with a 34.2% share) with Nalcor (which holds the other 65.8%), the sales contract from Churchill Falls to HQP (for some 30 TWh/year ≈ 15% of total HQ sales) at 0.2¢/kWh ends in 2041. It is not clear what will happen after this contract expires.
- **The expiry of long-term procurement contracts** will be almost continuous from 2026 onwards (for wind and small hydro).

QC.2.

- The high proportion of natural gas in the electricity mix of New England (NE) and New York pulls down wholesale market prices in the short and medium term (average under $50/MWh for the last five years in NE markets). **This raises questions about the profitability of exports and transmission line projects (with the New England states and New York) and the impact on local electricity prices.** It is difficult to clearly define what the long-term future of natural gas will be in these states, and the impact it will have on electricity markets.
- **While Ontario may be an interesting export destination during the refurbishment of its nuclear plants**, at present neither Ontario nor Quebec has proposed this option.

QC.3.

- Given the crucial role that Hydro-Québec's dams can play in the context of very high penetration of variable energy sources in northeastern electricity grids, notably by providing grid balancing services and long-term storage services (seasonal, annual or multi-year), **the utility must determine how to position the province's facilities regionally and how to manage these reservoirs if they are to play such a role.**

QC.4.

- **The need to modernize the distribution system as part of the electrification of services** is already known, but the costs and implementation challenges associated with this modernization are currently poorly documented, making it impossible to properly assess the scope of the task.
- **Decarbonization issues in Quebec are mainly tied to transport and industry.** These two sectors will contribute to the increase in electricity demand in addition to other emerging markets (Greenhouses, data centres, etc.).

4.2.4 New Brunswick

New Brunswick faces the following main challenges:

NB.1.

- **Replacing the coal-fired generation from the Belledune station after 2030, especially for the winter months**, remains a key issue. Since 2030 is too soon to hope for the SMRs to be in place (which seems to be the longer-term plan), the government argues that if it cannot keep the Belledune station open, then it will need to build a gas-fired powerplant.

NB.2.

- **Future transmission constraints and needs are unclear as they will largely depend on the strategy the province develops for expanding trade**. The Integrated Resource Plan provides mainly for transmission upgrades and replacements rather than expansions. Opportunities also exist to increase transmission capacity with neighbouring jurisdictions. This would enable increased energy imports into New Brunswick from Quebec and potentially into Nova Scotia from New Brunswick. NB Power recently entered into an agreement with Hydro-Québec under which the two utilities will consider building new interties between Quebec and New Brunswick.

4.2.5 Nova Scotia

Nova Scotia faces the following main planning challenges:

NS.1.

- With little hydroelectric potential and, at present, no nuclear facilities, **the province is likely to experience base-load power supply problems over the years as coal-fired plants are retired (by 2040) and hydroelectric plants are refurbished.** Some options to address this problem are the implementation of demand side management programs, the increase of electricity imports, the implementation of energy storage (centralized and/or distributed), and the use of combustible fuel-fired power plants coupled with carbon capture technologies.
- NSPI's plan provides for the addition of two natural gas power plants, one in 2026 (150MW) and one in 2030 (100MW). **Since this type of gas-fired plant has a lifespan of 30 to 40 years, it is difficult to reconcile this strategy with the goal of carbon neutrality in 2050.**

NS.2.

- **There is an identified capacity deficit of about 73-80 MW between 2022 and 2024.**
- To partially fill the projected capacity gap, NSPI is considering adding natural gas-fired generation facilities, but since 2018, Nova Scotia no longer produces natural gas. **Increased demand for natural gas raises cost and gas transmission/distribution infrastructure issues.**

4.2.6 Prince Edward Island

The main planning challenges for Prince Edward Island are:

PEI.1.

- Meeting the significant expansion in electricity demand while continuing to reduce GHG emission from the electricity sector requires not only increased wind (and later solar) capacity, but also potentially more low-carbon electricity imports from New Brunswick. This situation creates several challenges: first, **expanding wind and solar reduces import dependence but exacerbates the baseload issue**; second, **dependence on imports from New Brunswick also means dependence on issues facing New Brunswick**, with little influence over that province's decisions; and third, the role of storage remains undefined, which is key to both of the issues above.

- **A substantial share of emissions from space heating in buildings comes from fossil fuels, which if replaced by electricity would also increase demand**. The provincial government has initiated a program to replace these fuels with biomass in government buildings, although this will mean more remaining emissions.

4.2.7 Newfoundland and Labrador

The main planning challenges for Newfoundland and Labrador are:

NL.1.

- Once the Muskrat Falls project is fully in service, NL will have a surplus of electricity. Studies were conducted to **identify the best strategies to manage surplus electricity and mitigate the financial impacts of the Muskrat Falls complex** (see section 3.6.1).

NL.2.

- **The electrification of commercial and institutional space heating, as well as the transportation sector,** involves major implementation efforts as very little infrastructure, particularly charging stations for electric vehicles, has been currently installed.

NL.3.

- With the retirement of three generating units at Holyrood power plant, there will be hardly any generating capacity left on the Avalon peninsula even though that is where most of the customers of the Island Interconnected System reside. This raises concerns about the **reliability of the peninsula's electricity supply**. Furthermore, **the LIL (the only transmission line between Labrador and Newfoundland), and the Maritime Link are critical to enable the electricity to flow** from the mainland (Labrador and Nova Scotia) to the island of Newfoundland, and vice versa. Ensuring their reliability and resilience should be a priority.

NL.4.

- **The development of electricity exports**: First, with the eventual surpluses from the Muskrat Falls project, the export strategy that will be adopted for this surplus could maximize income to help mitigate the project's financial impact. At present, NL's only export contract is with NS for these facilities. There remains 2 to 3.5 TWh available annually for export. Second, thanks to the Maritime Link, NL is now connected (since 2018) to NS, thus completing the Energy Loop for Atlantic Canada. However, depending on the options chosen once the Churchill

Falls contract (with Quebec) has ended, electricity transmission capacity for export can become a major challenge.

5 Strategic planning priorities

The data presented in Table 4 shows the magnitude of the gulf that exists between the current planning of power utilities in Central and Eastern Canada and the efforts that must be provided to achieve the climate targets of the provincial and federal governments. Power utilities not only tend to underestimate the future growth of demand that will result from the electrification of the economy, but a lack of long-term vision is also noted concerning the possible trajectories it would be desirable to adopt to support the decarbonization efforts through electrification. Added to this lack of long-term vision is the fact that the deployment of electrical infrastructures (generation sites, transmission lines, transformer substations, distribution lines) necessitates a lapse of time possibly ranging from a few years to decades, which could lead to an impasse. Ontario is currently confronted with such a situation, because it projects that the carbon intensity of its power grid will have to grow 600% by 2040 to be able to respond to the growth of demand for electricity on its territory.

The analysis that was done, based on the planning documents of power utilities accessible to the public and the results of PEC2021, allowed the identification of 12 challenges that Central and Eastern Canada provinces have in common (see Table 5). These challenges concern the following points:

- the generation, transmission, and distribution infrastructure;
- the rate structures and regulations;
- the development of technologies associated with demand (including demand management); and
- the resilience and safety of the grids.

Added to these 12 common challenges are those specific to each province, particularly the decarbonization of electricity production for Ontario, Nova Scotia, New Brunswick and Prince Edward Island.

The challenges identified should be considered when planning the evolution of the power grids over the short, medium and long term. This would ensure that this planning is compatible with the achievement of the decarbonization objectives determined by the governments, which must be supported by electrification. **Unless the magnitude and speed of the necessary changes are properly understood, the electricity sector risks becoming a major factor slowing the deep decarbonization process of our societies.**

5.1 Consultations of Electricity Sector Actors

During the three workshops bringing together actors from the electricity sector in the provinces of Central and Eastern Canada[1], several problems were mentioned, particularly the following:

- **The question of the costs associated with the necessary conversions, and who will have to assume these costs.** Power utilities are subject to public utility commissions with the priority objective, among others, of ensuring that the cost of electricity is as low as possible. However, this approach is not always compatible with the objectives of reducing GHG emissions and is not conducive to accounting for these objectives in planning the power grids. Given that the decarbonization objectives are fixed and, in some cases, enshrined in the legislation, the question of costs, although it remains important, should not be an excuse to avoid planning the future of the power grids according to these objectives. Once the needs are identified, it is possible to develop solutions, while trying to reduce the impact of these investments on consumers as much as possible.

- **The lack of governance to carry out the decarbonization in the provinces and the various economic sectors.** In the absence of an authority that would have the role of coordinating the efforts of all stakeholders (the different levels of government, the private sector actors, etc.), planning tends to lack vision, implementation of the measures is delayed, and when they are implemented, they do not follow one or more of the common trajectories for achieving the decarbonization objectives.

- **The absence of a stable development and planning environment (public policies).** The instability of public policies in some provinces and the lack of long-term planning by governments make the exercise of planning power utilities more difficult. This also has the effect of slowing the dynamics of private investments in low carbon-emitting technologies.

5.2 Proposed Initiatives

Further to this analysis and the consultations that were conducted, several avenues were defined. Some are presented in the table below and could be examined by working groups. The objective of these groups would be to study the questions and the possible and desirable solutions, and then propose roadmaps to support the achievement of the solutions chosen.

Table 1 – Proposed Avenues to Support Central and Eastern Canada's Electrification Efforts

Theme	Questions that must be answered	Associated challenges
A. Regulation	The current regulations in the electricity sector are still very focused on seeking the lowest cost, which leads to decisions that are not always in accordance with achievement of the climate targets. **How can the mandate of the public utility commissions and power utilities be updated so that these authorities account for decarbonization issues more systematically?**	3, 8
B. Pricing	The potential impact of the transformations of the electricity system on the selling price per kWh to the customers generates debate. However, consumers are only indirectly interested in the price per kWh. They are more concerned about the possibility of heating and lighting their homes and using their household appliances at a reasonable cost. In most cases, they are interested in the services that energy can offer rather than energy itself. **Would it be relevant to adopt an overall pricing approach for the energy service instead of setting a price for customers per unit of energy consumed?**	4
C. Demand management	Some of the challenges enumerated in Table 5 could be largely overcome by having better demand management, better implementation of energy productivity criteria and more rigorous application of known measures that can improve energy efficiency. These strategies currently remain underused despite the fact that the available scientific literature allows the very clear	1, 2, 5, 7, 8, 9, 10

	identification of several of the obstacles encountered in their implementation. **How can demand management strategies best be integrated to be able to meet the challenges of managing peak demand and the current and future infrastructure development needs?**	
D. Resilience	Although our society's dependence on electricity is already very important, it will only increase with massive electrification of services in all sectors. Moreover, our infrastructure will be subject to a growing number of extreme weather events. **How can this growing need for resilience be more systematically taken into account in the planning and transformation of electrical infrastructure?**	7, 11, 12
E. Data	To be able to improve energy productivity, plan infrastructure (generation, storage, transmission, distribution) and innovate in regulation, business models and technology, a large quantity of data on current systems is required. **How can access to the data be facilitated sustainably? And how can the data be standardized so the actors in the field can use it more easily?**	9, 10, 12
F. Support for implementation	To develop and implement carbon neutrality trajectories that are credible, effective and convincing, it is necessary to rely on probative data and analyses. **How can the dissemination of knowledge and needs be improved among the different parties involved in the transformation of the electricity sector (governments, power utility companies,**	1, 2, 5, 6, 7, 8, 11, 12

	universities, etc.) so the implementation of this transformation is accelerated?	

6 Conclusion

In conclusion, it is recognized that a significant lag exists between the current planning of power utilities in Central and Eastern Canada and the efforts necessary to achieve the climate targets set by the provincial and federal governments.

There are several studies that emphasize the integration of the regional power grids of Central and Eastern Canada and the Northeastern United States and that propose an approach based on the optimization of the costs of the electrical system, which is necessary to meet the increased demand for electricity resulting from the decarbonization of our societies. Accounting for the magnitude of the necessary transformations, and especially the rhythm at which they would have to be implemented, the authors of this document have chosen to propose five initiatives focused on different themes. These initiatives thus would address regulation, pricing, demand management, data, support for implementation, and resilience. This work would contribute to provide the various actors with tools in the short and medium term, which would allow them to harmonize their planning by capitalizing on the achievement of the climate targets.

The actors to be assembled around each initiative should not come only from the electricity sector, but also from organizations that play a complementary role. Thus, the Canadian Centre for Energy Information[11] could contribute to the initiative on data (theme E), and the Energy Modelling Hub[12] could play a role in the initiative on support for implementation of the transformation of electrical infrastructure (theme F).

[11] https://energy-information.canada.ca/en

[12] https://emi-ime.ca/projects/modelling-projects-1/

Annex – Description of the workshops

In order to enrich the reflection in this white paper, three workshops were organized between January and May 2022. The objective of these meetings, held under Chatham House rules, was to discuss with key players the following two themes:

- Main issues and challenges related to the electrification of the economy, the effects of possible choices on the electric sector and the economic development across the Atlantic region;
- Strategic priorities, in a regional perspective, to align electrification initiatives with government expectation.

The content of this report engages only its authors and in no way the individuals and organizations who participated in the workshops and provided comments.

Atlantic provinces workshop

Date: January 27, 2022
Format: Virtual
Organizing partner: Net Zero Atlantic (formely Offshore Energy Research Association of Nova Scotia, OERA)
Participants:

Darren Clark	NB Power	NB
Heather Quinn	NB Government	NB
Michael Bourque	University of New Brunswick	NB
Tim Manning	NL Hydro / Nalcor	NL
Yousaf Khan	NL Government	NL
Mitch Downton	Atlantic Policy Congress of First Nations Chiefs	NS
John Esaiw	EfficiencyOne	NS
Larry Hughes	Dalhousie University	NS
Wayne Groszko	Nova Scotia Community College	NS
Nicole Godbot	NS Power	NS
Dan Roscoe	Roswall	NS
Keith Towse	Community Wind	NS
David Miller	NS Government	NS
Heather MacLeod	PEI Government	PEI
Evan Willemsen	Aspin Kemp	PEI

Ontario workshop

Date: March 01, 2022
Format: Virtual
Organizing partener: QUEST Canada
Participants:

Thomas Timmins	Gowling WLG
Ajay Garg	Hydro One
Nazila Mottagian	Hydro One
Kausar Ashraf	Independent Electricity System Operator (IESO)
George Vegh	McCarthy Tetrault
Adam White	Powerconsumer Inc.
Tonja Leach	QUEST Canada
Tarek Abdelgalil	SNC-Lavalin
Magdy Salama	University of Waterloo
Lorne Johnson	Ivey foundation
Richard Carlson	Pollution Probe
Tim Christie	Ontario Ministry of Energy
Bradley Little	NRCan - Renewable and Electrical Energy Division

Québec workshop

Date: May 04, 2022
Format: In person
Participants:

Réal Laporte	Hydro-Québec
Daniel Mongeon	Régie de l'énergie du Québec
Philippe Bourke	BAPE
Éric Léger	Ministère de l'énergie (MERN)
Alexandre Mignault	Hydro-Québec
François Bouffard	McGill
Mark Purdon	UQAM
Loïc Boulon	UQTR
Jonathan Théorêt	Ville de Montréal, BTER
Geneviève Gauthier	Econoler
Johanne Whitmore	HEC
Pierre Fréchet	Hydro-Sherbrooke
Jean-Pierre Finet	Regroupement des organismes environnementaux en énergie
Jacque Harvey	J. Harvey Consultant & Associés Inc
Jocelyn Millette	Canmet Energy

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