Electricity Systems Across Western Canada

A Landscape Analysis

Brendan Cooke & Marla Orenstein | July 2023

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Canada West Foundation
110 – 134 11th Avenue SE, Calgary, Alberta T2G 0X5
Phone: 403-264-9535 Email: cwf@cwf.ca

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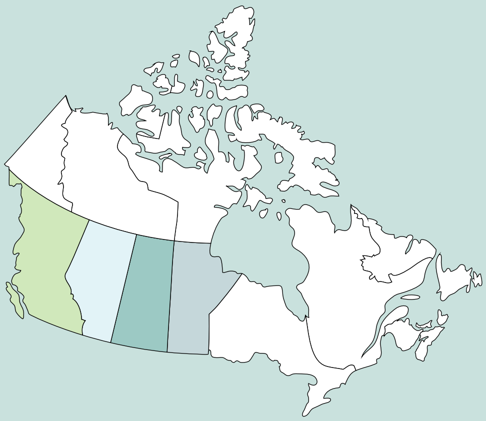


When it comes to electricity, the four western provinces share a common goal. All four aim to:

- Increase electricity supply to meet future demand
- Reduce greenhouse gas emissions from electricity production
- Maintain affordability while doing so.

However, each province faces unique challenges and appropriate solutions will look different for each jurisdiction. This is because there are key differences across the provinces in terms of current conditions, the energy resources available in each location and the way each province's electricity sector is structured. These factors act as boundaries that circumscribe what is possible, what is effective and what may be affordable.

PART 01

The way the system is organized affects everything else

KEY FACTS

- The electricity sector comprises:
  - Utilities regulators, which set rules, ensure compliance and protect consumers
  - System operators, which manage and operate the grid and plan for future expansion
  - Utilities, which generate electricity, transmit it, distribute it and sell it to customers
- B.C., Saskatchewan and Manitoba all have government-owned, vertically integrated utilities. They are also fully regulated, meaning the government regulates electricity generation, transmission, distribution and selling to consumers.
- Alberta, in contrast, is de-regulated. It has no government ownership of assets, allows competition for some functions, and has private sector electricity providers.

IMPLICATIONS

- The way each province's electricity sector is organized and regulated influences everything from the power resource mix to emissions to end-user prices.
- In addition, it impacts investment. In B.C., Saskatchewan and Manitoba, investment in power generation facilities is normally limited to the monopolies that operate in each province. In Alberta, all power generation facilities are privately owned and electricity is sold through a competitive bidding process. Alberta's deregulated market also allows for corporate Power Purchase Agreements (PPAs) with renewable electricity producers. This has led to major investments from companies such as RBC, Budweiser Canada, Amazon and Microsoft that have spurred rapid growth of wind and solar in Alberta.

PART 02

Where power comes from, what it does to emissions and how much we need (now and in the future)

KEY FACTS

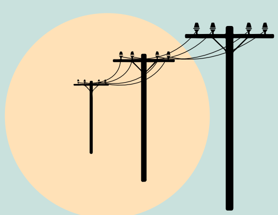
- The four provinces have very different power resource mixes that stem from both policy decisions and the hard facts of geography.
- B.C. and Manitoba get almost all their power from hydro. As a result, GHG emissions are very low—both total emissions and emissions intensity.
- Alberta and Saskatchewan get most of their power from fossil fuels. As a result, their emissions are much higher than B.C. and Manitoba. However, both have had a substantial decline in emissions intensity—particularly Alberta, where it decreased 45% between 2015 and 2021.
- Alberta uses primarily natural gas and will decommission its last remaining coal-fired plant in 2023. It has also become the leading developer of wind and solar projects in the country, making up 26% of installed capacity in 2022. Saskatchewan is on a path to eliminate unabated coal from its power resource mix by 2030 and has also seen a surge in wind and solar development.
- Over the coming decades, demand for electricity is expected to increase: Canada will require between 62% and 210% more electricity by 2050.
- Electricity is traded among the four western provinces, and between each province and the U.S. Manitoba and B.C. are by far the largest electricity exporters, and the majority of their exports go south of the border. These electricity exports are a major source of revenue. B.C. also engages in power price arbitrage—importing power when prices are low and exporting it when prices are high.

IMPLICATIONS

- All four western provinces will need to grow their electricity supply to meet a future demand that is substantially higher than today. This growth will require careful planning and many trade-offs—and is made more difficult because current forecasts of future demand are highly uncertain.
- The provinces are at different starting points in terms of their ability to reduce emissions, both in terms of how much they need to reduce and what options are available to them. This leads to distinct challenges, costs and opportunities for each—and may clash with the federal government's proposed Clean Electricity Regulations.
- The vast hydro resources of B.C. and Manitoba offer both provinces flexibility when planning the future of their electrical systems. Alberta and Saskatchewan face a substantial challenge in maintaining reliability as they move to more intermittent power sources such as wind and solar.
- As energy exporters, B.C. and Manitoba must decide whether to develop additional capacity sufficient to continue exporting large volumes of electricity; or to use their existing surplus to meet demand increases and reduce the need for new investment—a strategy that would reduce revenue and increase electricity prices within the province. The decisions made by B.C. will have knock-on effects for Alberta as it relies on power from its neighbouring province to satisfy a portion of its own domestic demand.

62%–210%

Canada will require between 62% and 210% more electricity by 2050.



45%

Alberta and Saskatchewan have had a substantial decline in emissions intensity—particularly Alberta, where it decreased 45% between 2015 and 2021.

Exports

Manitoba and B.C. are the largest electricity exporters among the four provinces, and the majority of their exports go south of the border. These electricity exports are a major source of revenue.

PART 03

Moving to the grid of tomorrow… And paying for it

KEY FACTS

- To prepare for changes in future electricity demand, utilities and governments must implement a variety of grid modernization policies and programs. These include advanced metering infrastructure (AMI), demand side management and distributed energy resources. All four western provinces are examining grid modernization programs, but implementation is patchy.
- Meeting future electricity demand—whether building new generation facilities, powerlines, interties or rolling out grid modernization programs—is expensive.
- Each province places different constraints on the ways companies are allowed to earn a return on their investments. In all four provinces, regulated utilities are only allowed to earn a return on capital investments—with the exception of demand-side management in B.C.

IMPLICATIONS

- Grid modernization programs will dictate each province's ability to respond to future demand in an efficient and cost-effective manner.
- However, different approaches to regulation affect the extent to which utilities are motivated to invest in innovation. The current regimes strongly incentivize large capital investments and disincentivize investments in non-infrastructure solutions such as software development, pilot or research projects, efficiency programs and public education. This bias towards large capital projects makes it more difficult to foster rapid innovation under current cost-of-service models. Without policy and regulatory changes to incentivize innovation and risk-taking, grid transformation is likely to be slower.
- A deregulated market is ultimately the best environment for innovation, as changes can occur organically as companies react to market conditions and look for new competitive advantages.

PART 04

Cost to consumers – the price of electricity

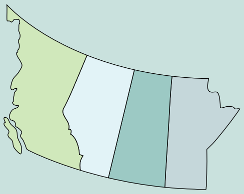
KEY FACTS

- In the fully-regulated provinces of B.C., Saskatchewan, and Manitoba, electricity rates are fixed by the provincial regulator. As a result, prices are relatively consistent over the long term.
- In Alberta, supply and demand determine price within the deregulated competitive wholesale electricity generation market; and only distribution and transmission rates are regulated. As a result, the price of electricity in Alberta is far more volatile—although the province sets a price cap of $999/MWh. Most customers reduce exposure to volatility by purchasing electricity on fixed price contracts.
- B.C. and Manitoba's power prices are much lower than the prairie provinces. Much of this is due to their low-cost hydro resources. Both provinces also have large exports of power to the U.S., which earns revenue and reduces the returns required from domestic customers.

IMPLICATIONS

- Canadians have access to some of the lowest cost electricity in the world—a competitive advantage for large electricity consumers such as heavy industry and manufacturing. However, the competitive advantage is not equal across all provinces. B.C. and Manitoba's lower electricity prices favour them.
- The costs of grid expansion, modernization and emissions reduction may further increase the price disparity between provinces and reduce the investment attractiveness of certain regions—a concern that has been raised by the premiers of Alberta and Saskatchewan.
- Electricity prices also impact trade between the provinces. B.C. and Manitoba prefer international rather than interprovincial trade because power prices are higher in the U.S. than in Alberta and Saskatchewan. As long as this is the case, it will be difficult to encourage greater grid coordination between the provinces despite other potential benefits.
- Finally, low-income households in Alberta and Saskatchewan are likely to be the hardest hit by increased electricity rates.

Key challenges facing each province



British Columbia

Historically, B.C. has been able to rely on its substantial hydro assets to supply low-cost, reliable, low-emissions electricity. However, B.C. faces hard decisions around how to meet future demand. Additional major dams are unlikely, especially after the uncertainty and cost increases that plagued the Site C hydro project. Instead, B.C. will have to rely on a combination of run-of-river hydro; zero-emissions sources like solar and wind; and energy efficiency/demand-side measures. Because B.C. has a unique legislated requirement to produce enough electricity to be self-sufficient, it can't rely on imports to cover shortfalls in annual generation. B.C. could use some or all of its lucrative energy exports—the majority of which currently go to the U.S.—to satisfy increased domestic demand. This would lessen the need to build new generation capacity, but would decrease provincial revenue and increase electricity costs for B.C. consumers. The final question hanging in the air for B.C. is exactly how much future demand there will be—the scale of demand will be highly influenced by whether or not an electrified LNG industry is built in the province.

Alberta

Alberta has capitalized on its access to low-cost fossil fuels to develop a reliable and affordable grid. But now the province faces a triple challenge. First, electricity supply must increase substantially to meet a large growth in future demand. Second, this new supply must be low- or zero-emissions. And third, the province must at the same time figure out a way to bring existing generation to net-zero. Alberta has committed to reaching net-zero by 2050 but has raised concerns about the federal government's proposed Clean Electricity Regulations—stating that the 2035 target is not technologically feasible. The scale of the transition needed is enormous, and is likely to have massive cost implications for utilities and their customers. The context in which these developments take place is also different than the other western provinces. Alberta's privatized generation market isn't backed by the government; but it is flexible and able to rapidly incorporate innovation. This has resulted in corporate power purchase agreements (PPAs) that have made Alberta the leading developer of wind and solar projects in Canada. But the replacement of fossil fuel with intermittent renewables will require additional measures to ensure reliability—and there are no easy solutions. The only certainty is that Alberta's electricity future will look substantially different than its past.

Saskatchewan

Like Alberta, Saskatchewan provides baseload and dispatchable electricity through fossil fuels—in Saskatchewan's case, a mix of natural gas and coal. Although the province has seen a recent surge in wind and solar development, future growth will eventually bump up against reliability issues. The province has also taken measures to reduce emissions through investment in carbon capture technology for the Boundary Dam coal-fired power facility, which captured over five million tonnes of CO_2 between operational start-up in 2014 and the end of 2022. Saskatchewan has stated that it will reach net-zero on its own terms (by 2050) and will run fossil fuel sources until their end of life. This puts Saskatchewan on a collision course with the proposed Clean Electricity Regulations and sets the stage for an upcoming battle over what order of government has authority to decide how to reduce provincial emissions from the sector and at what pace.

Manitoba

Manitoba is in a good position in terms of both supply and emissions. The province's massive, low-emissions hydro resources provide 96% of its current power generation; and on average Manitoba produces 30% more electricity than it needs. This excess electricity is exported to interprovincial and international markets, which provides substantial revenue to the province and keeps domestic electricity costs lower than the other western provinces. To meet increased future demand, Manitoba plans to use some of its export capacity for use in province. This would result in reduced export revenue and increased costs for local customers. In addition, not all of its export capacity is available to divert to Manitoba customers: only the portion that is surplus to long-term contracts. This may not be enough, and all future scenarios being explored by Manitoba Hydro include the addition of new thermal capacity by 2042. Diversified electricity generation sources will also increase the province's robustness, as its reliance on hydro makes it susceptible to the impacts of drought and flooding. This was seen in 2021 when low water levels resulted in historically low power production and lost export revenue.

Introduction

Electricity systems throughout Canada and the world are undergoing a period of enormous transformation. Mass electrification of industry, transportation, buildings and homes is driving demand both for increasing amounts of electricity and for different ways electricity can be produced and delivered.

Experts have estimated that by 2050 Canada will require an increase in electricity supply between 62% and 210%.[1,2] And to meet Canadian GHG emissions reduction targets, that electricity will need to be low- or zero-emissions, safe, reliable—and affordable. The integration of more renewable energy sources, smart grid technology and distributed generation and storage offers new opportunities, but at the same time introduces new problems to be solved.

The BIG question is: are Canadian electricity systems ready?

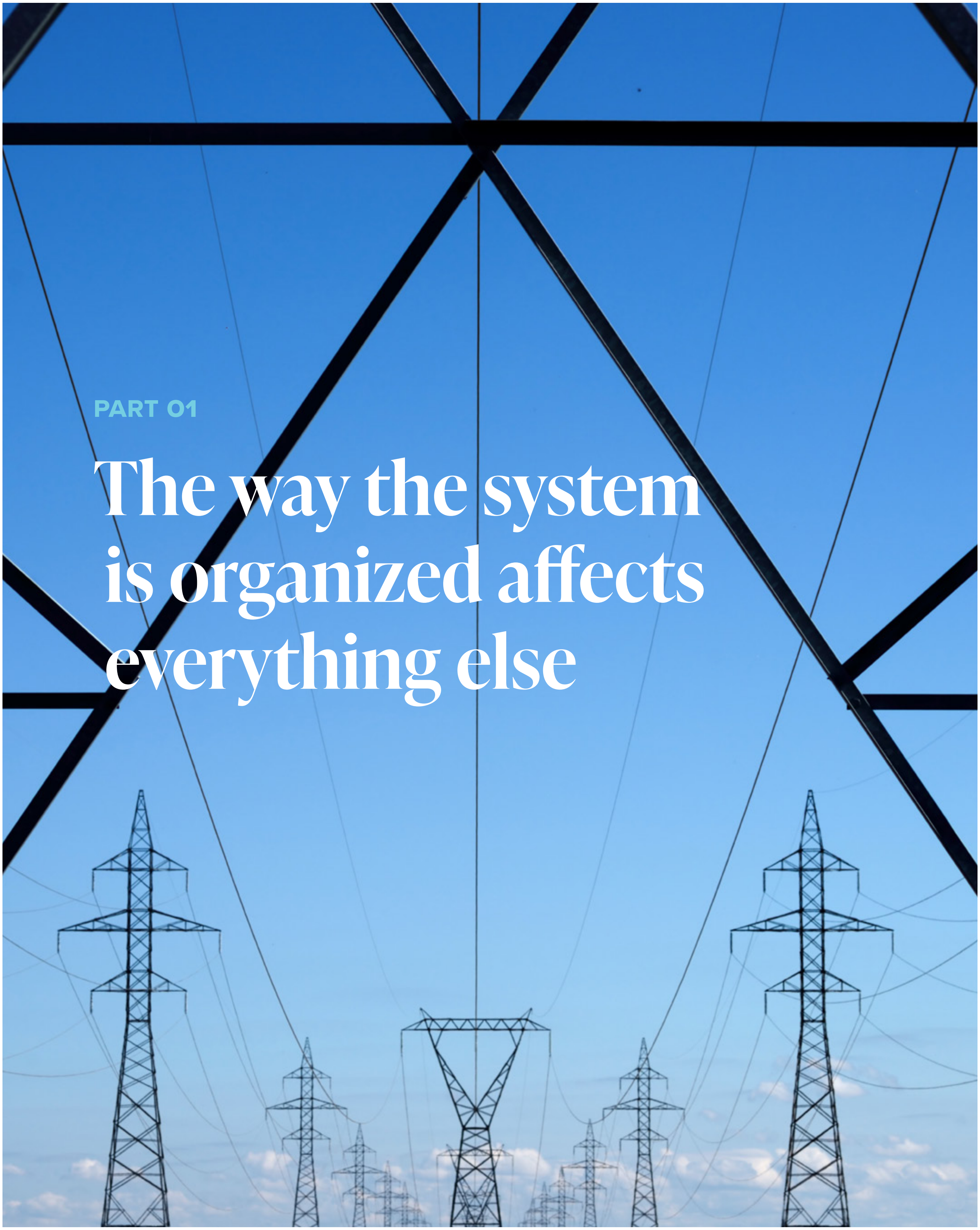
Canada's four western provinces have electricity systems that are different from one another in striking ways—including how the system is organized, the energy resources available in each location, and the policy context in which it operates.

This means that each province faces a distinct set of challenges on its journey to modernize, reduce emissions and satisfy rapidly growing demand for electricity—and the solutions for one jurisdiction aren't necessarily the best fit for another.

This report describes key features of the electricity systems in B.C., Alberta, Saskatchewan and Manitoba, including system organization, ownership structures, power generation sources, emissions profiles, integration of innovative technologies, demand and supply, system costs and how prices are set. **For each of these elements, this report describes what it means, why it is relevant, how it differs across provinces and what the implications are as each province grows and modernizes.**

1 Canada Energy Regulator. *Canada's Energy Future 2023: Energy Supply and Demand Projections to 2050*. 2023.

2 Dion J, Lee C, Kanduth A, Guertin C, Beugin D. *The Big Switch: Powering Canada's Net Zero Future*. Canadian Climate Institute. May 2022.



PART 01

The way the system is organized affects everything else

Electricity sector composition and structure

In every jurisdiction, the electricity sector is composed of a set of organizations that work together to provide safe, reliable and affordable electricity to end-users. These electricity sector "actors" include:

- Utilities regulators, which set rules, ensure compliance and protect consumers
- System operators, which manage and operate the grid and plan for future expansion
- Utilities, which generate electricity, transmit it, distribute it and sell it to customers

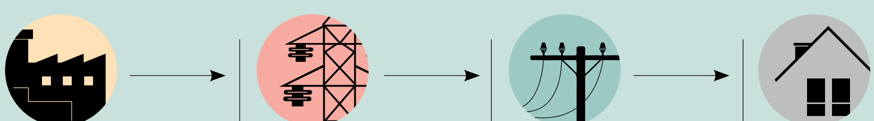
Box 1 provides additional detail on each of these organization types.

Box 1: Electricity sector actors, explained

UTILITIES REGULATORS are government agencies responsible for ensuring end-users across the province have access to reliable, safe and affordable electricity. A large part of the regulator's role is the economic regulation of the electricity market. This means that the regulator is responsible for approving the rates charged for electricity generation, transmission and distribution. Regulators may also be responsible for approving the construction of new assets—decisions that they would make based on the proposed asset's fit within the existing grid to ensure reliability and affordability for customers.

SYSTEM OPERATORS ensure electricity gets to where it is needed when it is needed. They do this through two key responsibilities. The first is the 24/7 real-time coordination of all market participants to balance supply with demand. The second is the long-term planning of a province's electrical grid. As demand grows and consumer needs change, the system operator makes sure there are sufficient power generating assets, and that the right transmission infrastructure is developed to efficiently transport electricity throughout the province.

UTILITIES produce energy and provide it to customers. This comprises four distinct functions. Any given utility company may engage in all four, or only a subset.



Generation
Producing electricity

Transmission
Long distance, high voltage transport of electricity

Distribution
Shorter distances, lower voltage transportation of electricity

Retail
Selling electricity to the consumer

Across the provinces, there are differences in the degree of competition and regulation allowed under each of these functions. Jurisdictions in which all four functions are regulated are referred to as *fully regulated*.

Provincial differences

When it comes to the structure of Western Canada's provincial power sectors, no two provinces are exactly the same. However, there is a large degree of similarity among B.C., Saskatchewan and Manitoba. All are served primarily by government-owned, vertically integrated utilities and are fully regulated. Alberta, in contrast, has no government ownership of assets, allows competition for some functions and has private sector electricity providers (see *Table 1*).

B.C.

British Columbia's government-owned corporation BC Hydro operates as the primary utility as well as the provincial system operator. However, British Columbia stands out from the other fully regulated provinces due to the presence of another major utility—FortisBC—for generation, transmission, distribution and retail. In addition to FortisBC and BC Hydro, independent power producers (IPPs) exist within the generation market, but their participation is limited as new IPP facilities can only be constructed when a request has been issued by BC Hydro. BC Hydro's first call for power in 15 years is expected to be issued in Spring 2024.

SK

Saskatchewan differs from the other fully-regulated provinces in that it does not have a dedicated utilities regulator. Instead, the Saskatchewan electricity sector is regulated directly by the Saskatchewan government and several independent organizations including the Saskatchewan Rate Review Panel. Saskatchewan's primary utility and system operator is the Crown corporation SaskPower. Much like BC Hydro, SaskPower operates in a near monopoly with the exception of a growing number of IPPs in the generation market who must sell their electricity to SaskPower. Outside of SaskPower the only other utilities are Saskatoon Light and Power and Swift Current Electricity Services which provide distribution and retail services in their respective cities.

MB

Among the three fully regulated provinces, **Manitoba** is the closest to a complete monopoly. Manitoba Hydro, the province's government-owned utility and system operator, controls 100% of all market functions with the exception of three wind projects owned by IPPs.

AB

Alberta has a mix of regulated and deregulated functions. The Alberta Utilities Commission (AUC) regulates prices for wire services (transmission and distribution) but competition determines prices for the power generation and retail markets. Power generation and selling to customers is provided by a wide range of commercial organizations that choose to enter this competitive market. Unlike the other three provinces, prices for wholesale electricity are controlled by market competition—although a market cap of $999.99/MWh has been set by the Alberta Electric System Operator (AESO).

It is important to note that although power generation is deregulated in Alberta, this doesn't mean that there are no regulatory requirements—all projects require permitting and environmental approvals.

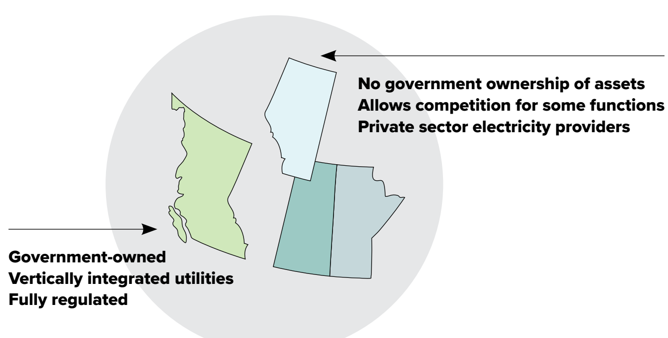
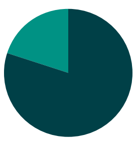
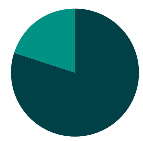
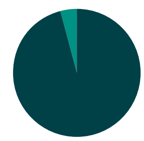
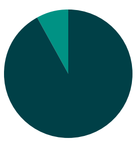
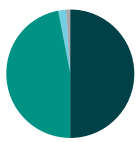
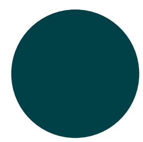
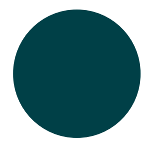


Table 1: Cross-province comparison of electricity industry composition

	B.C.	**AB**	**SK**	**MB**
UTILITIES REGULATOR	British Columbia Utilities Commission (BCUC)	Alberta Utilities Commission (AUC)	Government of Saskatchewan	Public Utilities Board (PUB)
WHAT IS REGULATED	Generation **YES** Transmission **YES** Distribution **YES** Retail **YES**	Generation **NO** Transmission **YES** Distribution **YES** Retail **PARTIAL**	Generation **YES** Transmission **YES** Distribution **YES** Retail **YES**	Generation **YES** Transmission **YES** Distribution **YES** Retail **YES**
SYSTEM OPERATOR	BC Hydro (Crown corporation)	Alberta Electric System Operator – AESO (Independent)	SaskPower (Crown corporation)	Manitoba Hydro (Crown corporation)
MARKET STRUCTURE	Vertically integrated government- and privately-owned monopolies	Private enterprises	Vertically integrated government-owned monopoly	Vertically integrated government-owned monopoly
UTILITIES				
GENERATION	**BC Hydro** 80% **Fortis BC and IPPs** 20% 	**Competitive market with many participants** 	**SaskPower** 80% **IPPs** 20% 	**Manitoba Hydro** 96% **IPPs** 4% 
TRANSMISSION (Long-distance high-voltage)	**BC Hydro** 92% **FortisBC** 8% 	**AltaLink** 50% **ATCO Electric** 47% **ENMAX Power Corp** 2% **EPCOR Utilities** 1% 	**SaskPower** 100% 	**Manitoba Hydro** 100% 
DISTRIBUTION (Local lower-voltage)	BC Hydro FortisBC Municipalities	ATCO Electric ENMAX Power Corp Fortis Alberta EPCOR Utilities Municipalities	SaskPower Municipalities	Manitoba Hydro
RETAIL (Sales to final customer)	BC Hydro FortisBC Municipalities	Wide range of regulated and competitive rate providers	SaskPower Municipalities	Manitoba Hydro

Implications

Differences in how each province's electricity sector is organized and regulated influences everything from the power resource mix to emissions to end-user prices. These features are examined in the following chapters of this report.

The differences also affect how investment is attracted to electricity generation opportunities in each province.

Within the regulated markets of B.C., Saskatchewan and Manitoba, new investment in power generation plants is normally limited to the large monopolies that operate in each province. If/when there are opportunities for independent power producers to participate in a regulated market, they are generally facilitated through a call for project proposals that provides strict criteria regarding location, size and energy source. And the price paid to the IPPs for electricity produced is often fixed through long-term power purchase agreements (PPAs) with the regulated utility.

Conversely, in Alberta's deregulated market, private investment in power plants is the norm and wholesale electricity is priced on an hourly basis through a competitive bidding process managed by the AESO. The deregulated market also allows for corporate Power Purchase Agreements (PPAs)—both physical and virtual—with renewable electricity producers.* In addition to low-emissions electricity for the purchaser, PPAs also provide price certainty to the buyer and seller through long-term contracts (something not normally afforded by competitive hourly prices in Alberta's deregulated market), making it easier to finance and develop renewable projects. Corporate PPAs have been growing in popularity in recent years and investments from companies with large electricity needs looking to reduce emissions—such as RBC, Budweiser Canada, Amazon and Microsoft—have played a considerable role in the rapid growth of wind and solar resources in Alberta, with deals announced to support over 2,700 MW in renewables capacity.[3]

Investment in transmission and distribution (wireline) assets is not available to new entrants in any of the four western provinces due to regulated regional monopolies. Although private companies participate in Alberta's transmission and distribution functions, they are common carriers for all generated electricity, each responsible for a specific geographical region and new development is awarded accordingly. This structure reduces the risk of unnecessary development of what are ultimately shared assets and higher costs that would be associated with overbuilding.

* *A physical PPA results in the direct delivery of electricity to the buyer; virtual PPAs allow customers to reduce their carbon footprint by purchasing the renewable attributes of the electricity produced at a wind or solar farm without purchasing actual electrons directly.*

3 Business Renewables Centre. *Alberta's Corporate Renewables Procurement Advantage*. No date. Accessed May 23, 2023.

PART 02

Where power comes from, what it does to emissions and how much we need (now and in the future)

Power resource mix

Power resource mix refers to the combination of energy sources a jurisdiction uses for electricity production. Within Canada, the dominant power sources are hydro (dams and run-of-river), natural gas, coal, wind, solar and nuclear.

Each source has advantages and disadvantages in terms of cost, reliability, availability, safety and environmental impact. Coal, for example, is highly reliable and relatively low cost but comes with high GHG emissions; solar and wind have low emissions but also low reliability, especially during periods of extreme weather; hydro is reliable, can be easily adjusted to match demand and has low emissions but is not available in all locations. System operators in each province balance these factors to achieve a system that is as reliable, affordable, and low-impact as possible.

Imports from neighbouring provinces and the U.S. also play a role in supplying electricity. These imports can be based on spot market trades or long-term contracts, and the generation source of the electricity is not always specified. Imports and exports are covered in more detail under the topic of Demand and Supply and are not included in the values discussed in this section.

Box 2: Capacity vs. generation: what's the difference?

There are two different ways of measuring a region's power resource mix: through capacity or through generation. Both are useful but provide very different types of information.

INSTALLED CAPACITY represents maximum possible performance. It measures the potential instantaneous energy output a power plant could in theory produce under optimal conditions. Capacity is measured in Watts (W).

ELECTRICITY GENERATION is the total amount of electricity actually generated over a period of time. Generation is measured in Watt hours (Wh). Under perfect conditions, a 1W power plant would produce 8,760 Wh of electricity per year. However, in practice the amount generated may be less, due to factors such as maintenance downtime, the availability of sun, wind or other energy inputs, or low demand for that particular plant's output.

Provincial differences

B.C.

British Columbia's rivers have provided the vast majority (around 90%[4]) of the province's electricity since the early 1900s. Historically, the province supplemented its energy mix with natural gas and biomass-powered facilities. However, since 2015 63% of the province's natural gas capacity has been decommissioned and investment has focused instead on renewables development—in particular, wind and biomass. Hydro still plays the largest role in meeting growing demand within the province; between 2010 and 2021, hydro capacity grew by nearly 2,800 MW (21%) and is expected to add an additional 1,100 MW with the completion of the Site C Clean Energy Project.

AB

Throughout its history, **Alberta** has relied on fossil fuels as its primary source of generation. Prior to 2012, coal was the dominant fuel. Since then natural gas has overtaken coal. The transition from coal to natural gas was driven by factors that included the low cost of natural gas, the implementation of carbon pricing, and policy changes at the federal and provincial levels. In 2015, the Alberta government took measures to eliminate all coal-fired generation by 2030 (followed by similar federal legislation three years later). Alberta's measures included transition payments made to owners of coal-fired power plants ($1.1 billion) and working with the federal government to establish regulation favourable to coal-to-gas conversions.[5] The province is set to decommission its last remaining coal-fired plant in 2023, seven years ahead of schedule.

In addition to fossil fuels, Alberta has a rapidly growing renewables industry and has quickly become the leading developer of wind and solar projects in the country, with a nearly seven-fold increase in capacity since 2010. However, while wind and solar made up 26% of Alberta's total installed capacity in 2022, they made up only 14% of generation.[6] This difference highlights the lower capacity factor of wind and solar compared to resources such as natural gas or large hydro—intermittent renewables produce less energy per unit of installed capacity over the course of a year.

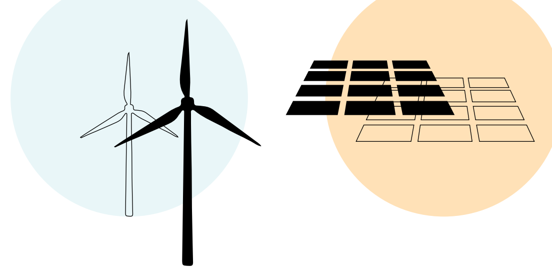
SK

Like Alberta, **Saskatchewan** has a long history of fossil fuel generation in its electricity industry. Coal was the primary fuel used until 2015 when, much like in Alberta, natural gas became the largest contributor to electricity generation. Saskatchewan is also on a path to eliminate unabated coal (in other words, coal burning that releases GHG emissions) from its power resource mix; however, it likely will not achieve this goal until 2030.[7] While the province will have decommissioned all unabated coal plants by this time, it may not remove coal from its resource mix completely. This is because Saskatchewan is home to the world's only coal-fired power plant equipped with carbon capture and sequestration (CCS) technology—the Boundary Dam Power Station.

Saskatchewan has also seen a surge in wind and solar development in recent years—predominantly wind. Between 2010 and 2022, wind and solar grew from just 4% of total installed capacity to 14%.

MB

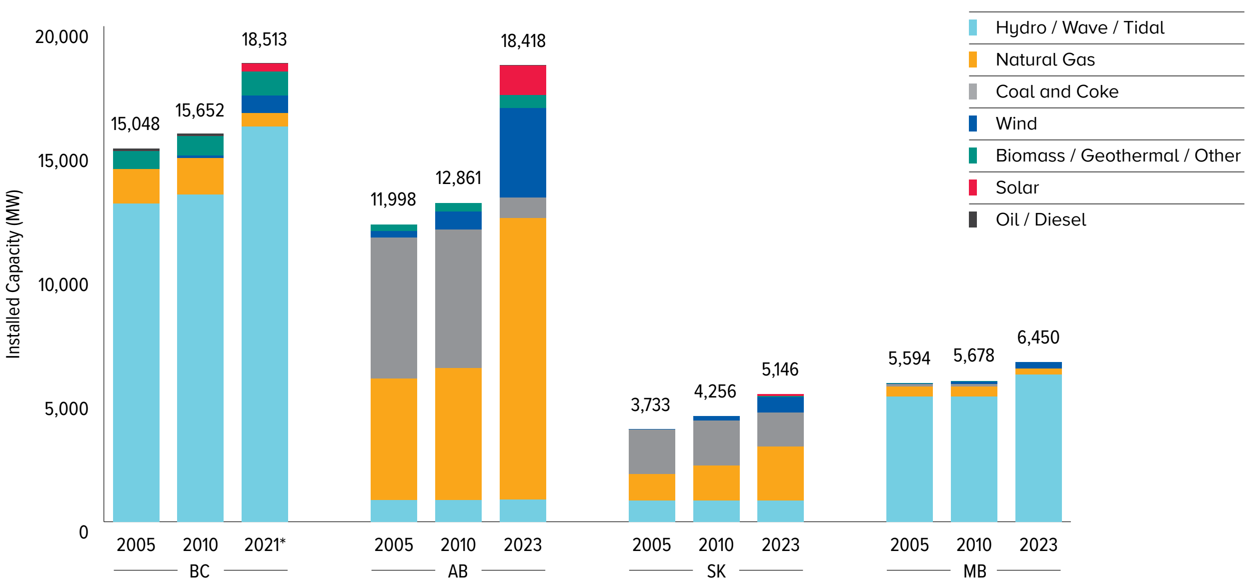
Manitoba, like British Columbia, has abundant hydropower resources that have been used by the province for decades. In Manitoba, hydropower makes up 92% of installed capacity; the remaining 8% is split equally between wind and natural gas. In the past two decades, the province has almost completely eliminated its use of fossil fuels for power production. In 2021, fossil fuels supplied less than 1% of total electricity generated despite accounting for 4% of installed capacity. However, future growth of the province's electricity sector may not be able to rely on hydro power as it has in the past. In fact, all four scenarios being explored in Manitoba Hydro's ongoing strategic planning include the addition of new thermal capacity by 2042.[8]



4 Statistics Canada. *Table 25-10-0015-01, Electric power generation, monthly generation by type of electricity*. 2023.
5 Vriens L. *The End of Coal: Alberta's Coal Phase-out*. International Institute for Sustainable Development. 2018.
6 Alberta Energy System Operator. *Alberta's Power System in Transition*. No date. Accessed May 15, 2023.
7 SaskPower. *Why We're Changing How We Power the Province*. Accessed April 25, 2023.
8 Manitoba Hydro. *Completed Modelling and Analysis – 2023 Integrated Resource Plan*. April, 2023.

Figure 1 shows differences in capacity mix; these stem from both policy decisions and the hard facts of geography. *Figure 2* shows differences in generation, a result of how efficiently the resources produce power.

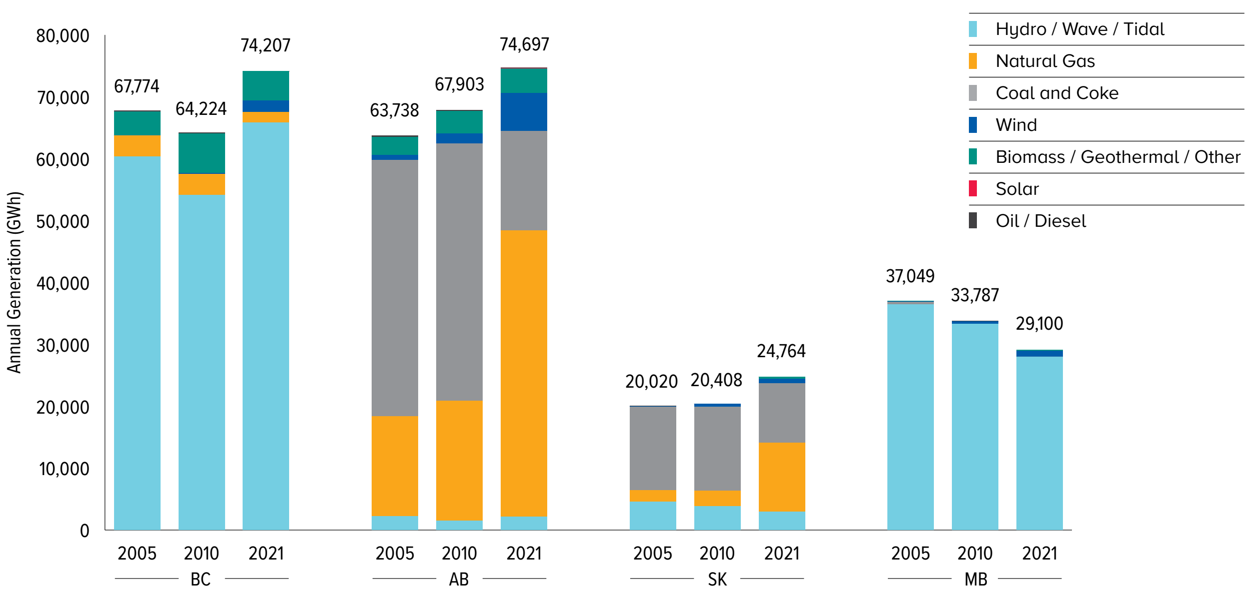
Figure 1: Provincial installed capacity 2005-2023



* 2023 data not available for British Columbia—no significant changes in mix since 2019

Sources: See footnote 9

Figure 2: Provincial annual electricity generation 2005-2021



Sources: See footnote 10

[9] Canada Energy Regulator. *Canada's Energy Future Data Appendices*. No Date. Accessed June 20, 2023.
Alberta Electric System Operator. *Current Supply Demand Report.* No Date. Accessed May 6, 2023.
SaskPower. *Third Quarter Financial Report*. December 31, 2022.
Manitoba Hydro. *Generating Stations*. No Date. Accessed May 9, 2023.
Algonquin. *Operational Assets*. No Date. Accessed May 9, 2023.
Pattern Energy. *St. Joseph Wind*. No Date. Accessed May 9, 2023.

[10] Statistics Canada. *Table: 25-10-0020-01, Electric power, annual generation by class of producer*. November 16, 2022.
Statistics Canada. *Table 25-10-0028-01, Electricity generated from fossil fuels, annual.* December 6, 2022.

Implications

For an electricity system to run smoothly, the balance of resources must be able to provide reliable baseload power as well as dispatchable resources that can quickly respond to changes in demand.

The vast hydro resources of British Columbia and Manitoba are ideal in this sense; they can provide both reliable baseload power and dispatchable resources. Hydro dams also bring an additional benefit: the ability to provide long-term energy storage. This offers both provinces flexibility when planning the future of their electrical systems. First, because nearly all their power is already renewable, they do not face societal or governmental pressure to decommission existing plants and replace them with different energy types. Second, additional solar and wind resources can be integrated with less concern about their intermittency, reliability and dispatchability. (However, as noted above, Manitoba has plans to add additional thermal capacity.)

In Alberta and Saskatchewan, reliable baseload and dispatchable power are available through the existing mix of natural gas and coal. However, both provinces face a substantial challenge in maintaining reliability as they move to more non-emitting power sources. While they have good wind and solar potential, the reliability of these resources is low due to their intermittent nature. This means that they need to be complemented by other energy sources (or storage) that can quickly respond to spikes in demand. Currently, this need is met by natural gas. Non-emitting but still sufficiently responsive sources include hydrogen, biomass, or natural gas with CCS. While all of these technologies are promising, none have been integrated at scale into Alberta or Saskatchewan's grids to date.

The power resource mix also has implications for affordability (discussed in *Part 4*) and emissions (discussed below).

GHG emissions

Reducing the greenhouse gas (GHG) emissions associated with electricity production has become a top priority of both provincial and federal governments in recent years.

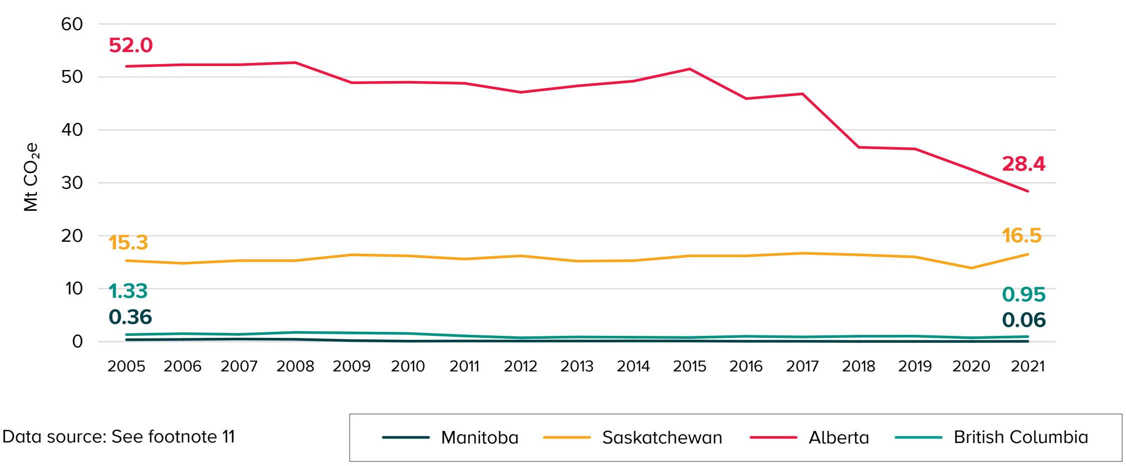
There are two ways to look at GHG emissions: total emissions and emissions intensity. Total emissions describes the total volume of emissions and is strongly tied to how much electricity is produced. If nothing else changes, as the amount of electricity produced increases, total emissions will also rise. Emissions intensity measures emissions per unit of electricity produced. Emissions intensity decreases as a province shifts to lower-emitting sources, and is a better indicator of changes in resource mix (e.g., coal to gas), process improvements (e.g., CCUS and reducing methane leakage) and overall progress towards decarbonization. Both total emissions and emissions intensity are relevant to the challenges each province will face in meeting net zero goals.

Provincial differences

Emissions

GHG emissions are tied to power resource mix. The two provinces that use hydropower (B.C. and Manitoba) have lower emissions and the two provinces that use fossil fuels (Alberta and Saskatchewan) have higher emissions. Total emissions are shown in *Figure 3*, and emissions intensity in *Figure 4*.

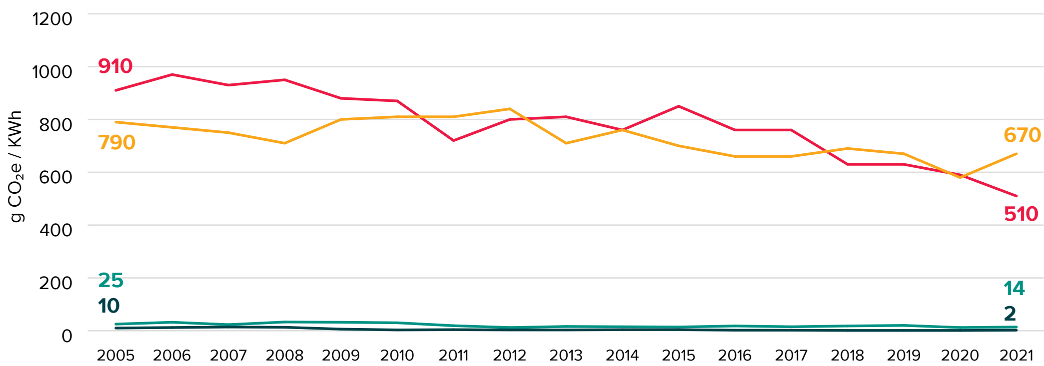
Figure 3: Total GHG emissions over time from the electricity sector in each province



Data source: See footnote 11

[11] *Environment and Climate Change Canada. Canada's Official Greenhouse Gas Inventory, A-Tables.* April 14, 2023.

Figure 4: GHG emissions intensity over time from the electricity sector in each province



Data source: See footnote 12

Change in emissions 2005-2021

	Total emissions (Mt CO_2e)		Emission Intensity (g CO_2e/KWh)	
B.C.	↓ 0.4 Mt	↓ 29%	↓ 11 Mt	↓ 44%
AB	↓ 23.6 Mt	↓ 45%	↓ 400 Mt	↓ 44%
SK	↑ 1.2 Mt	↑ 8%	↓ 120 Mt	↓ 15%
MB	↓ 0.3 Mt	↓ 84%	↓ 8 Mt	↓ 80%

B.C.

Due to its use of hydropower as the predominant power source, **British Columbia's** overall electricity sector emissions are low (0.95Mt CO_2e), as is its emissions intensity (14g CO_2e/KWh). Since 2007, the baseline date for B.C.'s reduction target, the province's electricity sector emissions have dropped by 39%. These reductions were largely driven by decommissioning several natural gas-fired power plants. Although these facilities did not emit a large quantity of GHGs, they were the source of most of the sector's emissions.

AB

Although **Alberta** and British Columbia produce a similar quantity of electricity annually, Alberta's use of fossil fuels for power generation results in far higher total emissions (28.4Mt CO_2e) and higher emissions intensity (510g CO_2e/KWh). However, a rapid increase in renewable electricity projects and the transition from coal to natural gas resulted in a substantial decline in both carbon intensity and overall emissions during a time of market growth. Between 2015, when the Climate Leadership Plan was introduced, and 2021 emissions intensity decreased by 45%. While more current data are not yet available, the decommissioning of additional coal-fired power plants and increased renewable generation since 2021 will have further reduced the province's emissions intensity.

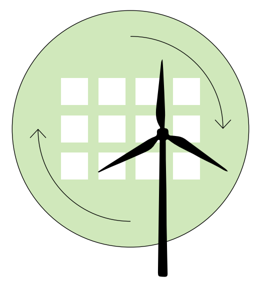
SK

Saskatchewan's emissions intensity (670g CO_2e/KWh) is the highest among the four provinces, due to its reliance on coal and natural gas for 84% of the power produced in the province. The province reduced emissions intensity by 15% between 2005 (the baseline year for emissions reduction targets) and 2021; and 20% between 2012 (the peak of electricity emissions) and 2021. This resulted in part from the province's large investment in the Boundary Dam CCS facility, which captured over five million tonnes of CO_2 between operational start-up in 2014 and the end of 2022.[12] The emissions intensity decrease was also strongly influenced by an increased reliance on natural gas. And, finally, the integration of additional wind and solar resources also played a role. However, due to market growth, the province's overall emissions (16.5Mt CO_2e) have increased over the past decade.

MB

Because **Manitoba** generates 99% of its electricity from renewable sources, its emissions intensity (2g CO_2e/KWh) and overall emissions (0.06Mt CO_2e) are by far the lowest among the four western provinces.

MANITOBA generates 99% of its electricity from renewable sources



Emissions policy

Much of the pressure to decarbonize has come in the form of government policy and regulation, some from the federal government and some at the provincial level.

Although all these policies move the electricity sector in the same direction—towards lower emissions—the provinces and federal government have in some cases chosen different policy approaches. This is particularly the case for the federal government's proposed Clean Electricity Regulations (CER – see *Box 3*). The CER clashes with the approach to electricity sector emissions reduction chosen by some provinces—most notably, Saskatchewan and Alberta—and sets the stage for an upcoming battle over what order of government has authority to decide how to reduce provincial emissions from the sector and at what pace.

[12] SaskPower. *BD3 Status Update: Q4 2022*, 2023

British Columbia

B.C. has established firm commitments to reducing emissions in its *Climate Change Accountability Act* (2007) and a net-zero target established in the CleanBC Plan (2018). However, these commitments are economy-wide and are not broken out by sector. BC Hydro has set its own target of reducing emissions by 71% by 2030 compared to a 2007 baseline.

The policies with the most direct impact on the electricity sector are the province's carbon tax, which applies to natural gas fuel inputs, and a target of 100% renewable electricity by 2030.

Policy Approach	Provincial Response
Emissions reduction commitments for electricity sector	No sector-specific target 71% by 2030 compared to 2007 levels – BC Hydro only
Coal phase-out	Not applicable – no coal-fired power plants
Renewable resources target	100% by 2030 – *CleanBC Roadmap to 2030 (2021)*
Carbon pricing for the electricity sector	Yes – *Carbon Tax Act and Regulation (2008)*

Alberta

Like B.C., Alberta has an economy-wide goal of net-zero for 2050[13] but no commitment specific to the electricity sector. However, the implementation of climate policies, including the Climate Leadership Plan in 2015—which mandated a transition from coal to gas—and carbon pricing through the TIER regulations, played a major role in the decline of both carbon intensity and overall emissions. The province has seen a 45% reduction in emissions intensity from the electricity sector since 2015. In addition, provincial legislation requires that 30% of power production come from renewable sources by 2030. However, the provincial government has stated that the Clean Electricity Regulations will be unreasonably harmful and are not technologically feasible by 2035.[14]

Policy Approach	Provincial Response
Emissions reduction commitments for electricity sector	No sector specific target
Coal phase-out	Yes – coal-generated electricity to be phased out by 2030. *Climate Leadership Plan (2015)* Note: In practice, all coal will be eliminated by the end of 2023
Renewable resources target	30% of electricity supplied by renewables by 2030 – *Renewable Electricity Act (2020)*
Carbon pricing for the electricity sector	Yes – *Technology Innovation Emission Reduction Regulation (TIER) (2019)*

13 Government of Alberta. *Alberta Emissions Reduction and Energy Development Plan*. 2023.

14 Ibid.

Saskatchewan

Saskatchewan has established an emissions cap that will result in a 40% reduction of electricity sector emissions by 2030 compared to 2005 and has also set a goal of net-zero electricity by 2050. In addition, the province recently implemented its own carbon pricing regulations, replacing the federal Output-Based Pricing System Regulations. SaskPower had previously committed to removing unabated coal by 2030[15] but the province has more recently indicated that it intends to run existing fossil fuel assets (coal and natural gas) until end-of-life.[16] In addition, the Premier announced that the province will not comply with federal government's 2035 target under the proposed Clean Electricity Regulations.[17]

Policy Approach	Provincial Response
Emissions reduction commitments for electricity sector	40% by 2030 compared to 2005 levels – *Management and Reduction of Greenhouse Gases (General and Electricity Producer) Regulations (2018)* Net zero by 2050 – *Saskatchewan's Power Future: Looking to 2035 and Beyond (2023)*
Coal phase-out	Until end-of-life
Renewable resources target	None
Carbon pricing for the electricity sector	Yes – *Management and Reduction of Greenhouse Gases (Standards and Compliance) Regulations (2023)*

Manitoba

Manitoba has no provincial policies that apply to the electricity sector and does not have a specific emissions reduction target for its power sector or for the province as a whole. The only emissions regulation that applies to power production in Manitoba is the federal *Greenhouse Gas Pollution Pricing Act*—which only applies to the province's two remaining gas-fired power plants.

Policy Approach	Provincial Response
Emissions reduction commitments for electricity sector	None
Coal phase-out	Not applicable – no coal-fired power plants
Renewable resources target	None
Carbon pricing for the electricity sector	None – only federal

15 SaskPower. *Why We're Changing How We Power the Province*. No date. Accessed June 15, 2023.

16 Government of Saskatchewan. *Premier Outlines Plans For Affordable, Reliable Power Production*. May 16, 2023.

17 Ibid

Federal

Although the electricity sector falls under provincial jurisdiction, the Canadian federal government has established policies and regulations that impact the electricity sector in all provinces and territories. In most cases existing regulations act as backstops to those in place at the provincial level, including regulations regarding coal phase-out and carbon pricing. The federal government has also proposed legislation—the Clean Electricity Regulations—that would require all provincial electricity grids to be essentially emissions-free by 2035 (see *Box 3*).

Policy Approach	Federal Regulations
Emissions reduction commitments for electricity sector	Net zero by 2035 – *Clean Electricity Regulations (Proposed)*
Coal phase-out	Conventional coal phased out by 2030 – *Reduction of Carbon Dioxide Emissions from Coal-Fired Generation of Electricity Regulations (2018)*
Renewable resource target	Nothing for renewables specifically; 90% from non-emitting sources by 2030 – *2030 Emissions Reduction Plan (2022)*
Carbon pricing for the electricity sector	Yes – *Output-Based Pricing System Regulations (2019)*
Other	Emissions standards for natural gas power generation – *Regulations Limiting Carbon Dioxide Emissions from Natural Gas-fired Generation of Electricity (2018)*

Box 3: Proposed Federal Clean Electricity Regulations

The Clean Electricity Regulations are proposed regulations under the federal *Environmental Protection Act, 1999* that will affect the electricity industry across the country. The regulations will require electricity production across all of Canada to be net zero by 2035. The frame for the regulations, released by Environment and Climate Change Canada (ECCC) in August of 2022, describes the mechanisms through which this objective will be achieved. This includes an emissions intensity standard that will prohibit the operation of power plants with emissions over a near-zero threshold and a financial compliance mechanism that will require plants operating with emissions between zero and the threshold to either offset their remaining emissions through compliance offset credits or by paying an amount that corresponds to the federal carbon price for that year.

Some exemptions have been proposed:

- Any facility commissioned prior to 2025 would not be subject to the regulation's emissions intensity standard until its prescribed end of life (although the definition of "prescribed end of life" has not yet been determined)
- Facilities not connected to a regulated grid
- Small capacity facilities (although the definition of "small" has not yet been determined).
- Facilities required to supply electricity during emergency circumstances

Concerns about implementation of the Clean Electricity Regulations have been raised by many parties, and Saskatchewan and Alberta have indicated that achieving the net zero objectives of the CER by 2035 will not be possible.

Implications

As is evident from *Figures 3* and *4*, the provinces are at different starting points in terms of their ability to reduce emissions–both in terms of how much they need to reduce and what options are available to them. This leads to distinct challenges, costs and opportunities for each.

Scale of transition

The largest challenge in lowering emissions—and the largest distinguishing factor among provinces—is the scale of transition needed. Manitoba and British Columbia have the simplest path forward. In Manitoba, there are only 250 MW of emitting sources—of which 244 MW comes from a single natural gas power plant. British Columbia's 1,600 MW of emitting assets still comprises only 8% of its total fleet. The transition of the existing asset fleet in Alberta and Saskatchewan, on the other hand, will be an enormous effort. With 12,200 MW and 3,500 MW of emitting thermal assets in each province respectively—representing ~70% of the total generating capacity in each—eliminating the emissions from these plants will be a massive undertaking.

In addition to the sheer scale of transition, Alberta and Saskatchewan also have fewer options for how to reduce emissions than their hydro neighbours. For baseload electricity supply, thermal assets cannot be replaced with intermittent renewables like wind and solar without also adding substantial storage capacity.

A related challenge is the timeline. Major facilities take a long time to plan and build and the regulatory process for approving construction of new transmission and generation assets (as well as CCUS facilities) is also lengthy. These long timelines undercut the potential for rapid sector transformation.

And finally, the best opportunity today may not be the best opportunity over the longer term. For example, many utilities see nuclear (in the form of small modular reactors) as a promising, zero-emissions option for electricity production. However, given the long timelines for technology development and regulatory approval, few SMRs are likely to be ready by 2035. Similarly, solar panel technology continues to improve substantially year over year. This poses a conundrum for provincial governments to make sure that investments today don't hinder future opportunities to implement better performing technologies.

Costs

While the cost of transition will be felt in all provinces, it will have a disproportionate impact on Alberta and Saskatchewan, due to the scale of transition required. The AESO has estimated that a net-zero pathway will cost Alberta an additional $44.1 billion to $52.1 billion by 2041 (a 30-36% increase in spending) compared to a baseline scenario.[18] Although AESO's analysis has been criticized for using overly high cost estimates for renewables, its analysis is still useful in identifying that the costs of a rapid transition are likely to be very high, in the tens of billions of dollars.

There are several different compliance mechanisms that electricity producers can use to reach net zero, including a switch to non-emitting sources, using CCUS to capture emissions, or purchasing carbon offsets. These different approaches will incur different costs over the short or long term. However, the ability to use the lowest-cost approaches will be determined both by what is suitable for a specific energy production context as well as by what is allowed under provincial and federal regulations (such as the proposed Canadian Electricity Regulations).

Opportunities

There may be cascading benefits for provinces that are successful in lowering GHG emissions while maintaining low-cost electricity. As corporations become more concerned with ESG performance and lowering their own emissions, low-emissions low-cost electricity may become a competitive advantage that enables a jurisdiction to attract new business.

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[18] Alberta Electric System Operator. *AESO Net Zero Emissions Pathways Report*. June 2022.

Demand and supply

Over the coming decades, demand for electricity is expected to increase everywhere; some experts have estimated that Canada will require between 62%[19] and 210%[20] more electricity by 2050. Much of this increase is driven by the growth of electrification for heating, transportation and industry. The pace and volume of change will be influenced by changes in energy and climate policy, regional population size, changes in industrial activity, electrification of specific industrial operations and electric vehicle charging.[21] At the same time, demand management, energy efficiency programs and smart grids provide opportunities to reduce overall demand and shift consumption away from peak periods (see *Part 3* for more details).

Annual demand (shown as annual electricity consumption in *Table 2*) is a good indication of the size of a given market. However, demand fluctuates hour-by-hour, day-to-day and seasonally. These fluctuations can be more pronounced in certain sectors. For example, industrial demand tends to fluctuate the least due to steady operations and minimal seasonal impacts; commercial demand is typically consistent throughout working hours but peaks during heating and cooling seasons; and residential demand can vary significantly by the hour, day and season depending on when people are at home as well as heating, cooling and vehicle charging needs.

Supply also fluctuates. Wind and solar are the most variable resources, but even hydro is subject to seasonal low water conditions or events such as drought or floods. These variations in supply and demand must be balanced by the system operator in real time to avoid power outages. A mismatch between the power produced at any given time and the amount required means there are opportunities to export excess power, but even those provinces that are net exporters of electricity sometimes require electricity imports from their neighbours. Over the longer term, supply is also affected by resource endowments, emissions policy and public attitudes toward the development of new infrastructure.

[19] Canada Energy Regulator. *Canada's Energy Future 2023: Energy Supply and Demand Projections to 2050*. 2023.

[20] Dion J, Lee C, Kanduth A, Guertin C, Beugin D. *The Big Switch: Powering Canada's Net Zero Future*. Canadian Climate Institute. May 2022.

[21] Some innovative charging solutions are described in the Canada West Foundation's *Energy Innovation Brief* special issue on EV charging.

Provincial differences

B.C.

While **British Columbia** currently produces more power than it needs, the province's demand for electricity is expected to grow 20-55% by 2050. This growth will be driven by electrification of transport in the province, electrification of the natural gas and LNG industries and other changes driven by the province's climate policy.[22,23] The estimates show "net" growth and include plans by the province to manage demand in order to reduce the need for additional generation capacity.

B.C. is unique among the four provinces in having a legislated requirement to be energy self-sufficient. Several projects have been initiated to keep up with growing demand, including upgrades to modernize turbines at existing hydro facilities, as well as the development of new generation including the Site C Clean Energy Project (hydro) which is expected to be fully operational by late 2025.[24, 25] With these additions, as well as planned demand side measures and renewals with existing independent power producers (IPPs), BC Hydro estimates the province will have sufficient electricity generation to meet domestic demand until 2029.[26] The need for additional generation after this point prompted BC Hydro's announcement of a 2024 call for power from IPPs.

B.C. is the largest trader of electricity among the four western provinces, with import and export volumes well above the other three. The use of electricity imports doesn't undermine B.C.'s mandated requirement for energy self-sufficiency. Rather, the province uses trading to take advantage of power price arbitrage opportunities—producing excess power for export when prices are high, and importing power when prices are low. In 2022, B.C. reported international electricity exports of $1.76 billion – 2.7% of total provincial exports (higher even than seafood exports).[27] British Columbia has interties with Alberta, to which it exports six times as much as it imports, and Washington state, which permits trade with other states—primarily California which values B.C.'s zero emissions electricity.[28] Trade with the U.S. makes up the majority of the province's activity (75% on average since 2010).[29]

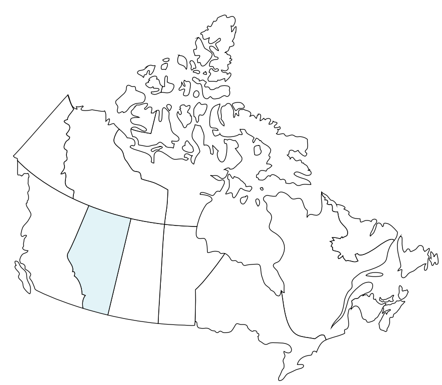
AB

Alberta has the largest electricity demand in Western Canada due primarily to the large power requirements of its oil and gas industry. According to the AESO's latest demand forecast, Alberta could see up to a 25% increase in power demand by 2041.[30] However, electricity demand within the province is highly dependent on oil sands activity—both due to the oilsands' direct energy consumption and to its relationship with overall economic activity within the province. Given that 63% of Alberta's electricity goes to industrial users, the growth or decline of oil and gas projects will have major impacts on future electricity demand.

Alberta is also the largest producer of electricity in Western Canada. This electricity is sourced not only from dedicated power producers but also from industrial players. In many cases electricity is a byproduct of the heat required for their operations (co-generation). Nearly 37% of the power produced in Alberta in 2021 (19,657 GWh) came from industry rather than utilities, of which nearly 99% was sourced from fossil fuels.[31] The treatment of these industrial facilities under future climate regulations will play a major role in the province's energy transition.

Even with the large amount of electricity generated in the province each year, Alberta still relies on trade to satisfy some of its demand. It has interties with B.C., Saskatchewan and Montana. The intertie with B.C. is by far the largest and accounts for the majority of its electricity trade each year. Revenue for electricity exports is dispersed among generating companies.

ALBERTA is also the largest producer of electricity in Western Canada. This electricity is sourced not only from dedicated power producers but also from industrial players.



22 BC Hydro. *BC Hydro and Power Authority 2021 Integrated Resource Plan*. 2021.

23 Wolinetz M. *British Columbia Electrification Impacts Study*. Navius Research. 2020.

24 BC Hydro. *Projects*. No date. Accessed May 15, 2023.

25 BC Hydro. *About Site C.* No date. Accessed May 15, 2023.

26 BC Hydro. *BC Hydro and Power Authority 2021 Integrated Resource Plan (2023 Update)*. June 15, 2023.

27 BCStats. *Annual BC Origin Exports*. May 4, 2023.

28 BC Hydro. *Importing and exporting power*. No date. Accessed May 15, 2023.

29 Statistics Canada. *Table 25-10-0021-01, Electric power, electric utilities and industry, annual supply and disposition*. November 16, 2022.

30 Alberta Electric System Operator. *AESO 2021 Long Term Outlook*. June 2021.

31 Statistics Canada. *Table: 25-10-0020-01, Electric power, annual generation by class of producer*. November 16, 2022.

SK

Saskatchewan is the smallest electricity market in Western Canada, both in terms of power production and consumption. While no long-term demand forecast is currently available for Saskatchewan, it can be assumed that the province's electricity needs will continue to grow as more of its economy electrifies. How future demand will be met is still unclear, although SaskPower is in the process of developing a long-term supply plan which will be released in spring 2024.[32]

Saskatchewan is also the province least engaged in electricity trade. Although it has connections with Manitoba, Alberta and North Dakota, the province's imports and exports are minimal and are often quite balanced, making it difficult to classify Saskatchewan as either an importer or exporter. While data beyond 2021 was not available at the time of writing this report, electricity trade is expected to increase with the operation of the Birtle Transmission Project between Saskatchewan and Manitoba completed in March 2021 and increased capacity with North Dakota expected to come online in 2027.[33, 34]

SASKATCHEWAN is the province least engaged in electricity trade, and it is difficult to classify the province as either an importer or an exporter.

MB

According to Manitoba Hydro's latest rate application, electricity demand is expected to grow by roughly 30% by 2042.[35] However, **Manitoba** is unique among the four western provinces, in that demand will be driven by population increases and the electrification of transportation and buildings, rather than industry. This is because Manitoba's residential sector makes up the largest portion of its demand and its industrial sector the least, whereas in all three of the other provinces industry is the primary consumer.

In an average year, Manitoba's electricity production far exceeds its demand. Although the province's 2021 electricity production was just 3,700 GWh above its consumption (see *Table 2*), this is uncharacteristically low, and was caused by low water levels—something that is a risk for provinces almost completely dependent on hydropower.

Historically, Manitoba has produced on average 30% more electricity than it needs. This excess electricity is exported to domestic and international markets through its interties with Saskatchewan, Ontario, North Dakota and Minnesota. Much like B.C., Manitoba conducts most of its trade with the U.S.—over 90% on average since 2010. However, unlike B.C., Manitoba generally exports 30 times the amount of power it imports. For example, in 2020, it exported 11.6 GWh and imported only 0.2 GWh.[36] These electricity exports are a major source of revenue for Manitoba Hydro, accounting for more than 20% of total revenue on average.[37]

MANITOBA is unique among the four western provinces, in that demand will be driven by population increases and the electrification of transportation and buildings, rather than industry.

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32 SaskPower. *Future Supply Plan – 2030 and Beyond*. No date. Accessed April 25, 2023.

33 Manitoba Hydro. *New Birtle Transmission Line Starts Sending Power to Saskatchewan*. May 1, 2021. Accessed May 15, 2023.

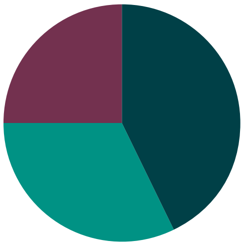
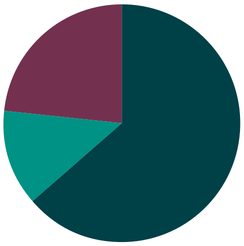
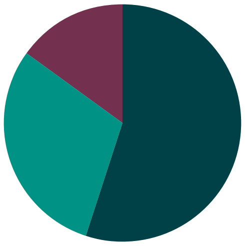
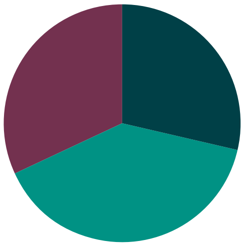
34 Martell C. *SaskPower announces deal with U.S. power pool to increase transmission capacity by 2027*. *Regina Leader-Post*, August 10, 2022.

35 Manitoba Hydro. *2023/24 & 2024/25 General Rate Application*. November 15, 2022.

36 Statistics Canada. *Table 25-10-0021-01, Electric power, electric utilities and industry, annual supply and disposition*. November 16, 2022.

37 Manitoba Hydro. *Electricity Exports*. No date. Accessed May 15, 2023.

Table 2: Electricity production and use

	B.C.	AB	SK	MB
ANNUAL ELECTRICITY PRODUCTION (2021)	74,207 GWh	74,697 GWh	24,764 GWh	29,100 GWh*
ANNUAL ELECTRICITY CONSUMPTION (2021)	67,054 GWh	79,531 GWh	24,975 GWh	25,412 GWh
ELECTRICITY DEMAND BY SECTOR (2019)	Industrial (43%) Residential (32%) Commercial (25%) 	Industrial (63%) Residential (13%) Commercial (23%) 	Industrial (55%) Residential (30%) Commercial (15%) 	Industrial (29%) Residential (40%) Commercial (32%) 
IMPORTS (2021)	8,937 GWh	6,451 GWh	673 GWh	3,081 GWh*
EXPORTS (2021)	16,090 GWh	995 GWh	462 GWh	6,769 GWh*
INTERTIES	Alberta Washington	British Columbia Saskatchewan Montana	Alberta Manitoba North Dakota	Ontario Saskatchewan North Dakota Minnesota
FORECAST FUTURE DEMAND	81,000-109,000 GWh (2050)	85,000-101,000 GWh (2041)	SaskPower forecast expected spring 2024	33,261 GWh (2042)

*Manitoba's power generation, imports, and exports were all impacted by low water levels in 2021; numbers are not representative of annual averages for the province.
Data sources: See footnote 38

[38] Manitoba Hydro. *2023/24 & 2024/25 General Rate Application, Appendix 5.6: 2022 Supply/Demand Scenario Tables*. November 15, 2022.
Statistics Canada. *Table 25-10-0021-01, Electric power, electric utilities and industry, annual supply and disposition*. November 16, 2022.
Wolinetz M. *British Columbia Electrification Impacts Study*. Navius Research. 2020.
Canada Energy Regulator. *Provincial and Territorial Energy Profiles.* Published March 10, 2023. Accessed April 25, 2023.
Alberta Electric System Operator. *AESO 2021 Long Term Outlook*. June 2021.
SaskPower. *Future Supply Plan – 2030 and Beyond*. No date. Accessed April 25, 2023.

Implications

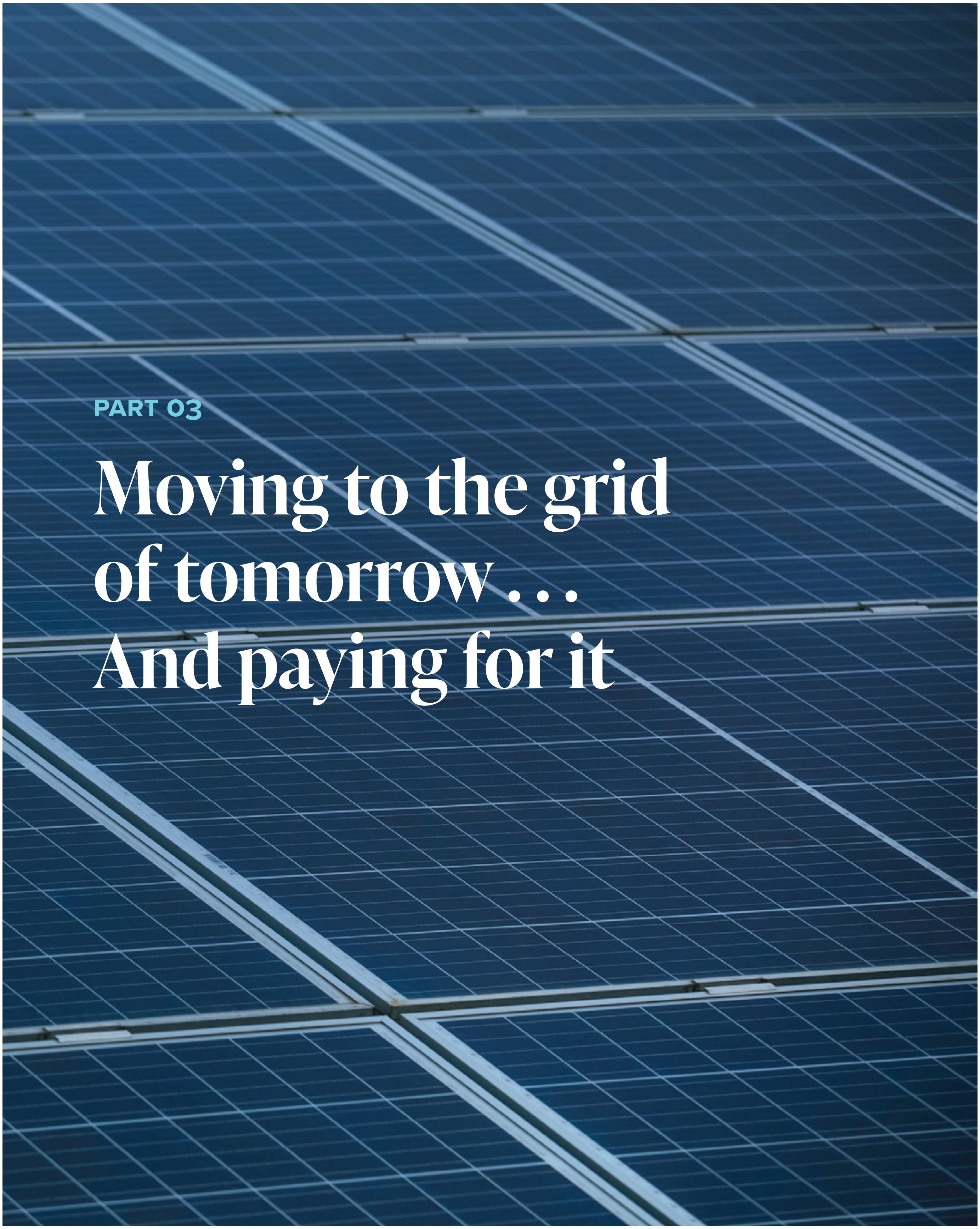
All four western provinces will need to grow their electricity supply to meet a future demand that is substantially higher than today. However, how this demand takes shape is largely dependant on the impacts of proposed climate and energy policies and the addition of large sources of demand not historically seen in the electricity sector. Adapting to these changes will require careful planning and many trade-offs—and will be made more difficult by the high levels of uncertainty they introduce to forecasts of future demand.

As they prepare for the future, provincial electricity systems must grapple with:

- Identifying where, when and how to develop new assets for generation, transmission and distribution. The scale and timing of demand growth will impact what generation resources are developed and which need to be replaced, as well as when and where investments in new transmission and distribution infrastructure are required to avoid bottlenecks in the system. The challenge may be more pronounced in Alberta and Saskatchewan, as these provinces not only need to account for new capacity to meet increased demand but also the need to replace or modernize existing fossil fuel generation facilities. And, as described in *Part 2*, their options for low-emissions generation are more limited.
- Mitigating against overbuilding or underbuilding. Underbuilding of generation, transmission or distribution assets will result in insufficient supply of electricity to customers—a huge problem. But overbuilding also has risks: unnecessarily high costs for customers and under-utilization of built resources.
- Deciding whether to export electricity or to keep it for use within the province. As demand grows, provinces that rely heavily on export revenues—such as B.C. and Manitoba—must decide whether to develop additional capacity sufficient to continue exporting large volumes of electricity or to use existing surpluses to meet demand increase and reduce the need for new investment. Lower export volumes are likely to decrease revenue and increase domestic prices as a result.
- And where a province relies on imports from its neighbour to meet current or future demand, the growth and export decisions made by that neighbour will have knock-on effects.

The umbrella implication is that provincial system planning and coordination will be more important as demand increases and supply options are considered.[39]

[39] These issues are further explored in the Canada West Foundation paper: Martin N. *Power Without Borders: Moving towards an Integrated Western Grid*. Canada West Foundation. 2018.



PART 03

Moving to the grid of tomorrow . . . And paying for it

Grid modernization policy and initiatives

The grid of the future is one that provides sufficient electricity to meet future demand, while also offering more flexibility, efficiency, resiliency and environmental benefits than the grid of today—all while maintaining safety, reliability and, hopefully, affordability.

To adapt to future demand, electricity delivery will need to support increased penetration of renewables, distributed energy resources (DERs) and changes in electricity demand profiles—the result of electric vehicle charging, smart homes, home electricity generation and storage, and electrification of industry. To prepare for these changes, utilities and governments across the western provinces have implemented a variety of grid modernization policies and programs (see *Table 3*).

Table 3: Grid modernization policy and initiatives

	B.C.	AB	SK	MB
ADVANCED METERING INFRASTRUCTURE (AMI) PROGRAMS	Yes – 99% of customers	Yes – some	Yes – some	No
DEMAND SIDE MANAGEMENT (DSM)				
Energy efficiency programs	Yes	Yes	Yes	Yes
Time-of-use rate programs	No	No	No	No
Demand response programs	Residential only	Industrial only	Industrial only	Industrial only
DISTRIBUTED ENERGY RESOURCES (DERS)				
Commercial DER programs	No	Yes	No	No
Self-generation programs	Yes	Yes	Yes	Yes
Owner compensation	Net metering	Net billing / Market participation	Net billing	Net billing

Provincial differences

Advanced metering infrastructure programs

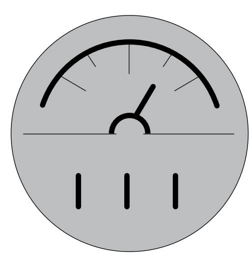
Advanced Metering Infrastructure (AMI) is a broad term that refers to the use of smart meters and other infrastructure to enable two-way communication between customers and utilities and to remotely control electricity distribution. AMI forms the foundation for many other grid modernization services including self-generation, net-metering, power-outage monitoring, time-specific rate structures and utility-led demand-side management initiatives. It also removes the need for manual meter reading by utilities, ultimately reducing the costs and emissions associated with sending out trucks to read meters.

In 2018, over 82% of all meters in Canada were already smart meters; however, Western Canada has not yet seen the same level of uptake.[40]

- In **British Columbia**, AMI rollout started over a decade ago—in 2011 for BC Hydro customers[41] and 2014 for FortisBC customers.[42] As of 2023, 99% of customers in B.C. have been equipped with an advanced meter.
- In **Alberta**, AMI programs are less established. All major utilities in the province (EPCOR, EQUS, Fortis AB, ATCO and ENMAX) have stated that they will provide advanced meters to customers participating in self-generation programs and have AMI initiatives underway. However, each utility is at a different stage of implementation, and few Alberta municipalities have complete coverage at this time.[43]
- In **Saskatchewan**, SaskPower has successfully installed over 45,000 smart meters for its commercial and industrial customers.[44] A residential smart meter pilot program was started in 2021 with mass deployment starting in January 2022, although the mass rollout has been paused due to meter shortages.[45]
- **Manitoba** is the only province with no plans to deploy AMI technology. In 2009, Manitoba Hydro ran a pilot program that deemed advanced meters not viable for the province based on a cost-benefit analysis. While the company states that it may need to revisit the implementation of AMI at some point, no plans to do so have been announced.[46]

Demand side management programs

Demand side management (DSM) is an all-encompassing term for measures taken to change how electricity is consumed by end-users so that system operators can better align supply and demand at any given point. DSM measures can work either by reducing overall demand or by shifting the times when consumers use the electricity. DSM measures benefit the grid by reducing the need for additional generation capacity, reducing transmission and distribution congestion during peak hours and improving reliability.



40 McLean S, Wadhera A, Wong S, Roy M, *Smart Grid in Canada 2020-21*. Natural Resources Canada, April 2022..
41 BC Hydro. *BC Hydro Confirms Benefits of Smart Metering Program*. January 16, 2016. Accessed April 25, 2023.
42 Fortis BC. *FortisBC to Begin Advanced Meter Exchanges in Trail.* July 3, 2014. Accessed April 25, 2023.
43 Natural Resources Canada. *Smart Grids*. July 4, 2017. Accessed April 25, 2023.
44 SaskPower. *Residential Smart Meter Program Launching in Saskatchewan*. Nov. 22, 2021. Accessed April 25, 2023.
45 SaskPower. *Smart Meters*. April 2022. No date. Accessed April 25, 2023.
46 Manitoba Hydro. *Advanced Metering Infrastructure*. April 19, 2022. Accessed April 25, 2023.

Energy efficiency programs are a common type of DSM. They use education, financial incentives and regulatory requirements to encourage customers to consume less electricity. Programs in Western Canada include performance standards for various electrical loads such as household appliances, heating and cooling systems and some industrial equipment; incentives and grants for energy efficient retrofits; and educational resources to learn about energy conservation.

- **All four western provinces** have implemented energy efficiency programs.

Time-of-use rate programs are another form of DSM that can help utilities manage growing demand without increasing electricity capacity. These programs incentivize customers to consume electricity during periods of low demand (such as at night) or high supply (such as during peak solar production) and avoid consumption during peak demand (such as in the early evening) by offering lower rates for electricity for those times. This helps utilities to achieve peak-shaving and load-shifting objectives.

- **British Columbia** does not currently have a time-of-use rate design. However, BC Hydro has submitted a request to the B.C. Utilities Commission for approval of new time-of-use rates for residential customers.[47]
- In **Alberta,** no utilities have fully implemented time-of-use rates. However, ATCO has announced a pilot project to test time-of-use rates in specific communities, starting with Grande Prairie in 2023.[48]
- In **Saskatchewan,** SaskPower has implemented time-of-use rates for limited customer bases including large commercial, farm, and industrial loads served via customer-owned transformers.[49]
- **Manitoba** is currently in the midst of a consultation process on time-of-use rate options.[50]

Demand response programs are another type of DSM that incentivizes customers to reduce electricity use during periods of peak demand. These programs reward customers for their ability to reduce electricity consumption in response to short-term events such as heat waves, cold spells or shortages in supply due to power plant outages. In these programs, customers are either instructed by the grid operator to reduce their load voluntarily or customers hand over control to the operator so the load can be reduced remotely. While these programs have historically focused on large commercial and industrial customers, advances in AMI are making the management of smaller dispersed loads more efficient.

- In **British Columbia,** BC Hydro proposed demand response programs for residential, commercial and industrial customers in their 2021 Integrated Resource Plan. The residential program, Peak Rewards, is active; the commercial and industrial programs are not. FortisBC is also piloting a residential demand response program.
- In **Alberta,** the AESO's Operating Reserves program allows it to curtail electricity use by large industrial operators in exchange for financial compensation. No demand response programs exist for commercial or residential customers.
- In **Saskatchewan,** SaskPower offers a demand response program to large industrial customers who are able to reduce their load by a minimum of 5 MW within a specific time frame.
- In **Manitoba**, compensation is provided to industrial customers who are able to reduce their load by a minimum of 5 MW within a specific time frame. Expanded demand response programs are being explored through Manitoba Hydro's resource planning process.

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47 B.C. Utilities Commission. *BC Hydro Optional Residential Time-of-Use Rate*. No date. Accessed June 7, 2023.

48 ATCO. *Time of Use Rates*. No date. Accessed April 25, 2023.

49 SaskPower. *Power Supply Rates*. No date. Accessed May 16, 2023.

50 Manitoba Hydro. *2023/24 & 2024/25 General Rate Application*. December 21, 2022.

DERs, self-generation and owner compensation

In the traditional power system model, electricity is produced at large power plants and transported over long distances to customers who need it. Distributed energy resources (DERs) offer an alternative. Most DERs comprise small-scale power generation and/or storage systems that are located near the site where the electricity will be consumed. They are most commonly owned by the business, community or residence that is the primary consumer of the electricity produced (self-generation). They can also be operated as commercial assets, with excess energy sold to other users or to the grid. While DERs offer many benefits for their owners, they introduce new challenges for utilities which must coordinate a growing number of smaller-scale resources whose market participation often differs from large generators.

There are two main ways that owners of DERs are compensated for the electricity they provide to the grid.

The first is through net-metering or net-billing programs. These are specific to DERs used for self-generation where the owner is also the primary consumer of the electricity produced. While both net-metering and net-billing serve the same purpose, the two methods differ slightly (see *Box 4*).

Box 4: Net metering vs. net billing

Under a **net billing** system, customers are paid a predetermined wholesale price for the electricity they provide to the grid (a value that is usually less than the retail rate). Customers pay for the power they consume from the grid as per the standard retail rates and their bill is determined based on the difference between the value earned and the value paid. In some cases, the value earned can only be applied against the cost of electricity consumed, not against other services such as transmission or administration fees.

Under a **net metering** system, customers earn a credit for each unit of electricity supplied to the grid which is then used to offset the units of energy consumed from the grid. The customer is then charged based on their net consumption at the retail rate. The ability to carry over units or be paid out for them differs between utilities.

The second is through power purchase agreements (PPAs) or market participation (depending on the jurisdiction). These options typically only apply to large DER projects and those that are operated as commercial assets, as they treat DERs the same as full-scale power plants, both in terms of compensation and obligations to the grid.

- In **B.C.,** current options for DERs are limited. BC Hydro previously had several options for DER integration including a Standing Offer Program (SOP), a Micro-SOP tailored to First Nations and communities, and a net-metering program; however, the SOP and Micro-SOP programs were cancelled in 2019.[51, 52] Net metering is still available to any customer in B.C., whether residential or commercial, so long as they meet several program conditions. First, the electricity generated must come from a "clean" or renewable source. Second, generating capacity must be below 100 kW for BC Hydro[53] or 50 kW for FortisBC.[54] And finally, generating capacity cannot be outsized compared to the energy requirements of the home or business (i.e., systems should not be built to routinely run a surplus).

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51 BC Hydro. *Our Distributed Generation Programs*. No date. Accessed April 25, 2023.

52 BC Hydro. *Standing Offer Program*. March 20, 2019. Accessed April 25, 2023.

53 BC Hydro. *Generate Your Own Electricity*. No date. Accessed April 25, 2023.

54 FortisBC. *Net Metering Program*. No date. Accessed April 25, 2023.

- **Alberta** has two options for small DER participation in the grid. The first is established under the Micro-Generation Regulation and applies only to owners focused on self-supply of electricity. Under this regulation, projects must be grid-connected, have systems under 5,000 kW, use renewable or alternative energy sources and not produce more energy than the home or business requires on an annual basis.[55] DERs not focused on self-supply fall under the Small Scale Generation Regulation.[56] Under this regulation, owners must use low-emissions resources and there is no size limit for projects so long as they are within the capacity constraints of the distribution system.

  In Alberta, micro-generation projects are compensated through net-billing (projects below 150kW receive the retail rate while projects over 150kW are paid based on the pool price). Projects with a capacity above 5MW are required to actively participate in the electricity market and are treated the same as larger transmission-connected power plants.

- In **Saskatchewan**, the only current option for DERs is through what it calls a "net-metering program" (although it operates as net-billing). The program is available to all SaskPower customers with projects that have a nameplate capacity under 100kW with a zero-emissions power source. SaskPower previously had a Power Generation Partner Program which allowed project proponents to apply to supply the utility with renewable or carbon-neutral electricity from projects ranging from 100 kW to 5 MW. The program ended in 2020 and no replacement has been announced.[57]

- In **Manitoba**, all DERs fall under Manitoba Hydro's non-utility generation program and access is generally limited to projects focused on self-supply where only excess power is provided to the grid. Projects must use a renewable source and while there are no specific capacity limitations for projects, the method of compensation varies based on their size.

  Net-billing is available to Manitoba Hydro customers who have a generating asset with a capacity below 100kW. Generators with a capacity of >100kW can still provide power to the grid. Their sale price is determined on a case-by-case basis and generally requires a PPA.

Implications

The grid modernization programs in each province influence their ability to respond to future demand requirements in an efficient and cost-effective manner.

New generation capacity and transmission infrastructure will be required to meet growing demand. However, "non-wires" alternatives such as DER integration and demand-side management can reduce the level of utility investment needed. Energy Efficiency Alberta's "Non-Wires Alternatives Study" found that non-wires alternatives were 2.5 to 24 times more cost-effective at managing the increased load from EV charging than investments in new transmission and distribution (depending on the size of the load offset).[58]

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55 Alberta Utilities Commission. *Generate Your Own Electricity*. January 7, 2022. Accessed April 25, 2023.

56 Government of Alberta. *Electric Utilities Act: Small Scale Generation Regulation*. January 1, 2020.

57 SaskPower. *SaskPower Announces Successful Applicants for Third and Final Intake of Power Generation Partner Program*. January 29, 2021. Accessed May 12, 2023.

58 Efficiency Alberta. *Non-Wires Alternatives Study: How Energy Efficiency, Demand Response and Managed Charging Can Cost-Effectively Offset Electric Vehicle Load Growth in Alberta.* 2020.

Incentivizing utilities to invest in modernization and change

Electricity generators and transmission and distribution utilities, like all companies, need to earn a return on their investments. This is true regardless of whether they are government-owned Crown corporations (like BC Hydro or SaskPower) or privately-held companies (like ATCO, ENMAX or Fortis). How they make money and how much money they make is largely a function of the regulatory environment in which they operate.

How utilities earn a return isn't just a financial issue. It also has implications for how utilities are able to modernize, decarbonize and support electrification efforts among their customers—and also influences the price paid by end-users.

Here's how it works.

In a deregulated competitive market, returns are dictated by the ability of a company to outperform its competition—both profits and losses are limitless. In a regulated market, the regulator limits utilities' monopoly power by regulating "allowed earnings" to ensure affordable electricity for end-users in the province. Rules dictate which investments the utility can earn a rate of return on, and what that rate of return should be. Exactly what those rules look like depends on the jurisdiction and the type of regulation employed. Within the four western provinces, these rules appear in three distinct forms.

> **COST-OF-SERVICE REGULATION (COSR).** Cost-of-service regulation directly links a utility's allowed earnings to its capital investments. The regulator ensures that a utility's revenue allows it to cover its operating costs and earn a fair rate of return on eligible investments—but no more than that. This fair rate of return is typically established by the regulator as a return on equity (ROE) and can often only be earned on capital investments, not operating expenses (although exceptions do exist: see B.C., below). Once the utility's revenue requirement—the sum of costs and a fair return on eligible investments—has been determined, a pricing structure is established based on the cost to serve each of the utility's various customer classes (e.g. industrial and residential).
>
> **PERFORMANCE-BASED REGULATION (PBR).** Performance-based regulation provides financial incentives for high performance against specific metrics. These metrics usually relate to operational efficiency and cost reduction, although they could in theory include other desirable performance outcomes such as energy efficiency, DER integration or GHG emissions targets.
>
> **DEREGULATED COMPETITIVE MARKET.** In a competitive market, regulators do not place any restrictions on how companies earn revenue.

Provincial differences

Provincial differences in allowed returns mirror the differences in regulatory structure discussed in *Part 1*. This leads to strong similarities among the three fully regulated provinces, with Alberta as the outlier once again. B.C., Saskatchewan and Manitoba use cost-of-service regulations to set rates and allowed earnings whereas Alberta uses a mix of cost-of-service, performance-based and deregulation. However, while B.C., Saskatchewan and Manitoba are consistent in the type of regulations they use, important differences exist in how they are applied.

B.C.

Under **B.C.'s** cost-of-service regulations, allowed earnings are typically established based on an ROE calculation on the company's deemed equity (both ROE and deemed equity per cent are set by the regulator).[59] BC Hydro, following direction from the provincial government, has moved towards a PBR and COSR hybrid model with a fixed return of $712M until 2025. British Columbia's COSR is also unique in that it allows for a return to be made on demand-side management investments so long as the program is deemed to be in the public interest.[60, 61]

AB

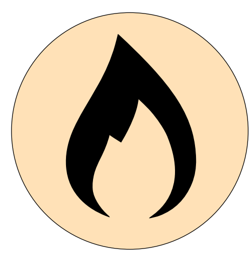
Alberta has different rate regulations for each market function. For transmission, rates are set based on cost-of-service regulation that allows for an ROE of 8.5%.[62] For distribution, performance-based regulation is used, where higher rates of return can be earned by utilities that operate more efficiently and successfully reduce operating costs. Finally, wholesale power prices in Alberta's deregulated generation market are not subject to rate regulations.

SK

Among the four provinces, **Saskatchewan**'s COSR is the most textbook example. The province has set a target of 8.5% allowable ROE with only capital investments included in the equation—however, actual returns have trended below target for several years.

MB

While **Manitoba** also uses a COSR to establish rates, the regulator has not established any rules regarding allowed earnings. This is because Manitoba Hydro operates as a closed loop; its owner, the government of Manitoba, does not require any dividend to be paid but also offers no further investment to the utility. Any surplus revenue serves only to reduce/stabilize rates in the future, so return on investments is less of a concern than in other provinces.



59 FortisBC. *Management Discussion & Analysis for the Quarter Ended March 31, 2022*. May 3, 2022.
60 Government of B.C. *Clean Energy Act*. Current to May 10, 2023. Accessed May 12, 2023.
61 Government of B.C. *Utilities Commission Act Section 44.2.* Current to March 29, 2023. Accessed May 12, 2023.
62 Alberta Utilities Commission. *Rate of Return: Determining a Fair Rate of Return for Regulated Utilities*. No date. Accessed May 12, 2023.

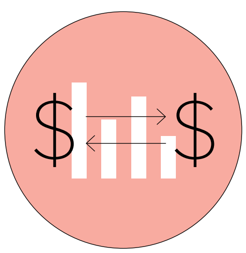
Implications

The different methods of rate regulation affect the extent to which market participants are incentivized to invest in innovation, as each approach places different constraints on how companies are allowed to earn a return on their investments.

Under the COSRs found in all four provinces, utilities are only allowed to earn a return on capital investments—with the exception of demand-side management in B.C. This establishes a strong incentive for large capital investments and a disincentive for investments in non-infrastructure solutions such as software development, small pilot or research projects, efficiency programs, public education and third-party services, which are not considered in the ROE calculation. Many of the cutting-edge innovations that will be required to operate the grid in the future will require an increase in operational costs, not capital. As a result, because of its bias towards large capital projects, it will be more difficult to foster rapid innovation under current cost-of-service models. Manitoba may be an exception to this rule as its regulations do not encourage earning a return on any investments, so incentives towards all investments, capital or otherwise, could be seen as equal.

While PBRs could theoretically encourage innovation by establishing incentives for better performance in target areas related to grid modernization or decarbonization, their use in the western provinces are currently limited to encouraging operational efficiency and cost reduction.[63]

A deregulated market is ultimately the best environment to attract investment for innovation, as changes can occur organically as companies react to market conditions and look for new competitive advantages. This can be seen in the rapid evolution of Alberta's power generation market. However, massive amounts of innovation will be required in transmission and distribution as well as grid modernization approaches such as those discussed in the section above. Without policy and regulatory changes to incentivize innovation and risk-taking, grid transformation is likely to be slower.



[63] Guidehouse Canada Ltd. *Navigating Barriers to Utility Investment in Grid Modernization*. 2020.

PART 04

Cost to consumers – the price of electricity

Price of electricity

The price of electricity paid by the consumer or end-user is impacted by nearly everything that has been discussed so far in this report—market structure, government policy, power resource mix, emissions reduction efforts, import and export activity, and investments in innovation and grid modernization.

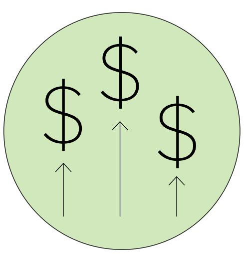
Provincial differences

How prices are set

The manner in which electricity prices are set in the western provinces is driven by the differences in sector structure discussed in *Part 1* and the differences in return on investment discussed in *Part 3*.

B.C., SK & MB

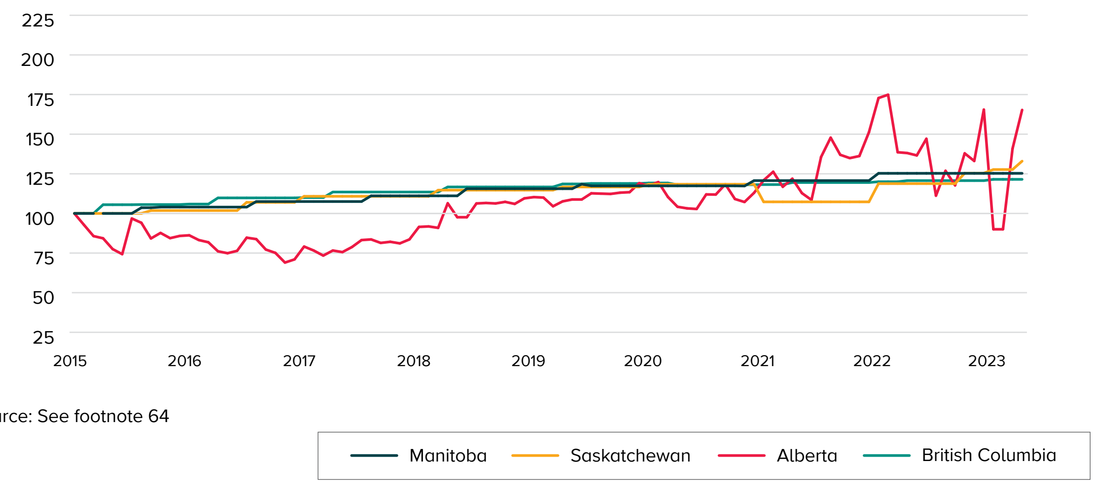
In the fully-regulated provinces of **B.C., Saskatchewan** and **Manitoba**, electricity rates are fixed by the provincial regulator. Due to the monopoly held by the Crown corporations, rates set in these provinces apply to the full suite of services offered by the utilities—including power generation, transmission, distribution and administrative activities—and are based on the revenue requirements /cost of operation for the major utilities. The result can be seen in *Figure 5*: prices that are consistent over the long term and increase at a predictable rate.



AB

In **Alberta**, supply and demand determine price within the deregulated competitive wholesale electricity generation market and only distribution and transmission rates are regulated. Wholesale electricity prices can fluctuate between $0/MWh and the price cap of $999/MWh, with prices set on an hourly basis. (Utilities may offer their customers fixed-rate prices to reduce their exposure to volatility, but this is competitive positioning, not a regulatory requirement.) Changes in price are driven by bidding behaviours that respond to changes in market conditions such as high levels of generation by low-cost renewables, facility outages, peak-demand periods, and cost of inputs such as natural gas. As a result, the price of electricity in Alberta is far more volatile than the other three western provinces, as can be seen in *Figure 5*.

Figure 5: Indexed change in residential electricity price

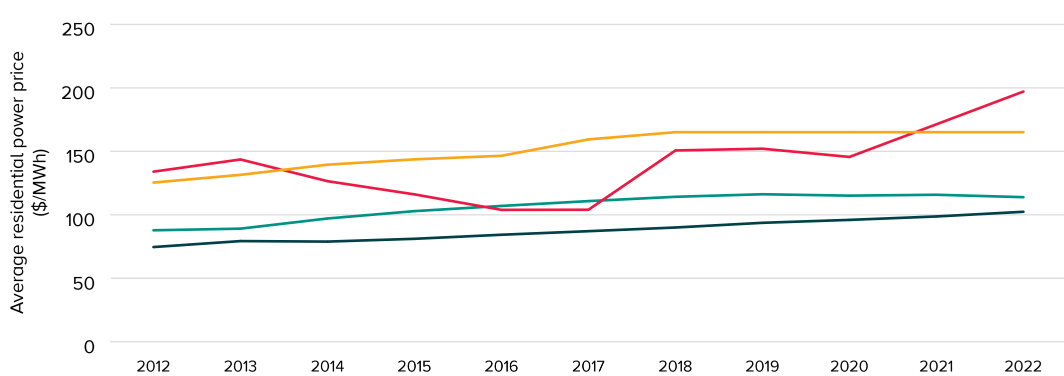


Source: See footnote 64

Final price

As shown in *Table 4* and *Figure 6*, electricity prices differ widely across the western provinces, and different fixed rates apply to specific customer classes (residential, commercial or industrial). As above, the inter-provincial differences are driven by the ways in each province's sector is structured and regulated. Final prices are also affected by the import and export capabilities and resource mix of each province.

Figure 6: Average residential energy price



Note: Alberta reflects an average of EPCOR and ENMAX prices.
Source: See footnote 65

[64] Statistics Canada. *Table 18-10-0004-01 Consumer Price Index, monthly, not seasonally adjusted.* No date. Accessed June 5, 2023

[65] Hydro Quebec. *2022 Comparison of Electricity Prices in Major North American Cities*. April 2022. Previous years from equivalent annual reports.

B.C. & MB

B.C. and **Manitoba's** power prices are much lower than the prairie provinces. Both provinces are dominated by large-scale hydro resources which, despite high upfront capital costs, enable low-cost electricity due to low operating and maintenance costs, near-zero variable costs and long economic life (sometimes over 100 years).[66] B.C. and Manitoba also benefit from having a large government-owned utility. The returns required by Crown corporations are lower than those that are expected by the shareholders of private organizations and the utilities have access to government-backed (or government-held) debt which offers a lower cost of borrowing than would be available otherwise.[67] In addition, as noted in *Part 2*, these provinces earn revenue through power exports, which allows them to offset their in-province expenses and further reduces the returns required from domestic customers—on average, export revenue represents 20-25% of total revenue for BC Hydro and Manitoba Hydro, compared to 2% for SaskPower.

AB

Alberta has the highest electricity prices of all the western provinces. Perhaps unsurprisingly, it also lacks all the elements that enable low-cost electricity for B.C. and Manitoba. The natural gas power plants that Alberta relies on have a much higher levelized cost of electricity than hydro. Operating costs at these facilities are also impacted by the price of natural gas, which has been volatile over the past few years. The private companies operating within the Alberta market do not have access to government-backed borrowing. And finally, the province's status as a net importer of electricity means it is unable to offset costs to customers through export revenue—although due to the private and distributed nature of the Alberta market and the competitive bidding process, it is unlikely larger export volumes would have the same cost-lowering effect as in monopoly provinces. Moving into the future, emissions reduction measures including carbon pricing and infrastructure development to support low-emissions generation will also impact price.

All these factors impact the marginal cost of wholesale electricity in the province. But it is ultimately the behaviour of companies within Alberta's competitive generation market that decides the final price. Of the 120% increase in peak hour prices that occurred between 2020 and 2021, over half can be attributed to firms exercising market power and selling well above marginal prices.[68]

SK

While **Saskatchewan's system** is operated by a large government-owned utility, it is otherwise closer to Alberta than its fellow regulated provinces. Much like Alberta, Saskatchewan also relies on natural gas as its primary electricity source and operates as a net importer, giving it the same price disadvantages as Alberta.

[66] International Renewable Energy Agency. *Renewable Energy Technologies: Cost Analysis Series. Hydropower*. June, 2012.

[67] KPMG. *Manitoba Hydro Financial Targets Review*. May, 2015.

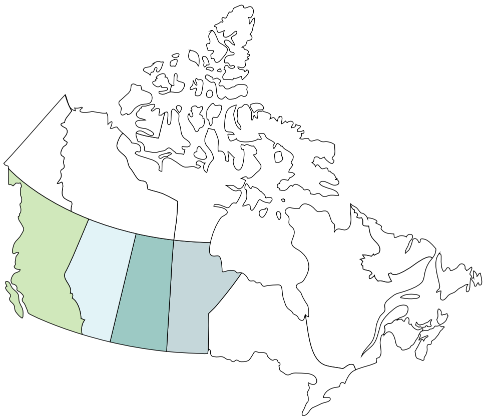
[68] Brown DP, Eckert A, Shaffer B. *Evaluating the impact of divestitures on competition: Evidence from Alberta's wholesale electricity market.* *Int J Ind Organ*. 2023;89:102953.

Table 4: Cross-province comparison of electricity prices in 2022

($/MWh)	B.C.		AB		SK		MB	
RESIDENTIAL 1000 kWh/month	BC Hydro	$114	ENMAX EPCOR	$199 $195	SaskPower	$165	Manitoba Hydro	$102
SMALL CUSTOMER 40 kW 10,000 kWh/month	BC Hydro	$117	ENMAX EPCOR	$183 $193	SaskPower	$140	Manitoba Hydro	$97
MEDIUM CUSTOMER 1,000 kW 400,000 kWh/month	BC Hydro	$90	ENMAX EPCOR	$150 $173	SaskPower	$120	Manitoba Hydro	$78
LARGE CUSTOMER 5,000 kW 3,060,000 kWh/month	BC Hydro	$78	ENMAX EPCOR	$132 $141	SaskPower	$90	Manitoba Hydro	$59

Source: See footnote 69

THE COST OF ELECTRICITY in the four western provinces plays a major role in their ability to attract and retain investment in industry, provide affordable living conditions for their citizens and engage in mutually beneficial interprovincial trade.



[69] Hydro Quebec, *2022 Comparison of Electricity Prices in Major North American Cities.* 2022.

Implications

The cost of electricity in the four western provinces plays a major role in their ability to attract and retain investment in industry, provide affordable living conditions for their citizens and engage in mutually beneficial interprovincial trade. As more of the economy electrifies, customers of all kinds will become increasingly sensitive to increases in price.

Canadians have access to some of the lowest cost electricity in the world—an attribute that has been recognized as a competitive advantage for large electricity consumers such as companies operating in heavy industry and manufacturing. However, as the data presented in this section shows, this competitive advantage is not equal across all provinces. Grid expansion, decarbonization and modernization will require investments in all regions, but greater investment is likely to be required in Alberta and Saskatchewan where existing fossil fuel plants will need to be abated or replaced. This increased investment has the potential to further increase the price disparity between provinces and reduce the investment attractiveness of certain regions—a concern that has already been raised by the premiers of Alberta and Saskatchewan. B.C. and Manitoba have their own price risks, though. Because both provinces use revenue from exports to subsidize domestic rates, any reduction in exports to help satisfy growing domestic demand could result in higher power prices for in-province customers.

Changes to electricity prices will impact residents of the four provinces differently. Research suggests that while power prices will increase on the path to net-zero, spending on energy as a whole may be reduced for some.[70] However, low-income households in Alberta and Saskatchewan are likely to be the hardest hit by increased electricity rates as they may have the least flexibility to implement changes to reduce costs.

Electricity prices also impact trade between the provinces. One of the primary reasons for B.C. and Manitoba's focus on international rather than interprovincial trade is higher prices for power in the U.S. So long as prices in Alberta and Saskatchewan remain lower than in neighbouring U.S. states, it will be difficult to encourage greater coordination between the provinces despite the potential benefits it could bring.

[70] Dion J, Lee C, Kanduth A, Guertin C, Beugin D. *The Big Switch: Powering Canada's Net Zero Future*. Canadian Climate Institute. May 2022.

Conclusion

The Challenge Ahead

This report highlights numerous areas of difference among the electricity sectors of the four western provinces. These differences determine the unique challenges each province will face as it grows to meet additional future demand, while also providing a low-emission, reliable and affordable grid.

British Columbia

- B.C. faces hard decisions around how to meet future demand. Additional major dams are unlikely; instead, B.C. will have to rely on a combination of run-of-river hydro; zero-emissions sources like solar and wind; and energy efficiency/demand-side measures.
- Because B.C. has a unique legislated requirement to produce enough electricity to be self-sufficient, it can't rely on imports to cover shortfalls in annual generation.
- B.C. could use some or all of its lucrative energy exports to satisfy increased domestic demand. This would lessen the need to build new generation capacity, but would decrease provincial revenue and increase electricity costs for B.C. consumers.
- Future demand in B.C. is largely uncertain and will be highly influenced by whether or not an electrified LNG industry is built in the province.

Alberta

- Alberta faces a triple challenge. First, electricity supply must increase substantially to meet a large growth in future demand. Second, this new supply must be low- or zero-emissions. And third, the province must at the same time figure out a way to bring existing generation to net zero.
- Wind and solar have grown enormously in Alberta but if they are used to replace baseload power, additional measures will be needed to ensure reliability—and there are no easy solutions.
- The scale of the transition for Alberta is enormous, and is likely to have massive cost implications for utilities and their customers.

Saskatchewan

- Saskatchewan faces similar challenges to Alberta: rapid growth, emissions reduction and a need to find reliable sources of baseload power to replace fossil fuel generation.
- However, Saskatchewan relies more heavily on coal than Alberta. Its Boundary Dam coal-fired power facility is outfitted with carbon capture technology. In addition, the province has two unabated coal facilities that the province plans to use until their end of life.
- This puts Saskatchewan on a collision course with the federal government over what order of government has authority to decide how to reduce provincial emissions from the sector and at what pace.

Manitoba

- Manitoba is in a good position to meet future challenges in terms of both supply and emissions.
- To meet increased future demand, Manitoba plans to use some of its export capacity to meet demand in province. However, its surplus may not be enough, and additional generation may therefore be required.
- Diversification of electricity generation sources may be needed to increase the province's robustness to drought and flooding, which impact hydro production.
- In addition, electricity exports provide substantial revenue to Manitoba. Exports diverted to local use may create budget shortfalls and increase costs to Manitoba consumers.

HOW AND WHEN these challenges are addressed by policy and investment decisions will make the difference between reaching net-zero and not; between maintaining affordability and not; and between having an electricity future that is reliable and sufficient and not. As provincial electrical grids expand and evolve to meet future needs, good public policy should consider these differences and remain flexible. Such a diverse set of challenges will require a diverse range of solutions. There is no one-size-fits-all approach.

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