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HEAT EXCHANGE

How today's policies will drive or delay Canada's transition to clean, reliable **heat for buildings**

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INTRODUCTION

Affordable, reliable heating and cooling for Canadian buildings is a necessity, not an option, on the road to net zero. Delivering on that goal requires some big shifts from provincial governments, energy regulators, utilities, and Canadians. The stakes are high: a passive, reactive policy approach is a recipe for higher emissions, higher costs, or both.

The economy-wide goal of net zero by 2050 is increasingly the frame for policy conversations in Canada and around the world (*see Box 1*). For the buildings sector, reaching net zero means that Canadian policy must incentivize a gradual and steady shift toward clean heat.

Governments, utilities, and regulators are just starting to contend with the impact this transition will have on the vast network of gas pipelines buried beneath large parts of the country, as well as on Canada's electricity infrastructure.

Today, fossil fuels—primarily gas and, to a lesser extent, heating oil—feed the furnaces and boilers that heat nearly half of this country's homes (*NRCan 2020*) and an equivalent share of its commercial and institutional buildings (*NRCan 2023a*; *NRCan 2023b*). Transitioning to clean sources of heat will mean widespread changes at the scale of individual buildings and neighbourhoods: more efficient new buildings, energy retrofits on old buildings, and rising consumer uptake of efficient electric heat pumps, displacing the use of gas and oil.

Alongside these building-by-building changes, the clean energy transition will require transformative change at the scale of provincial energy systems. Governments, utilities, and regulators are just starting to contend with the impact this transition will have on the vast network of gas pipelines buried beneath large parts of the country, as well as the impact on Canada's electricity infrastructure.

This report focuses on that system scale: the energy systems that Canadians rely on to keep their homes and businesses warm. We explore how those systems, and the regulatory frameworks that govern them, must adapt for Canada to reach net zero in a way that minimizes costs for ratepayers, governments, and the economy as a whole.

Box 1

Aligning building heat with net zero

The drive to reach net zero in order to limit the damage from accelerating climate change increasingly drives policy and markets across Canada and around the world.

Canada has a legislated commitment to reach net zero by 2050 through the *Canadian Net-Zero Emissions Accountability Act*, which came into force in June 2021. Seven provinces and territories have Climate Accountability Acts that require the government to set emissions targets, establish a plan, and report on progress (*Linden-Fraser 2024*). Of these, Prince Edward Island (*Net Zero Carbon Act*), Nova Scotia (*Environmental Goals and Climate Change Reduction Act*), Yukon (*Clean Energy Act*), and British Columbia (*Climate Change Accountability Act*) have directly legislated their 2050 climate targets.[1] Quebec, New Brunswick, and Manitoba have a publicly stated goal of a carbon-neutral economy by 2050 (*Government of Québec 2023a; Government of New Brunswick 2022; Government of Manitoba n.d.*), and Alberta's emission reduction and energy development plan notes the province's aspiration of carbon neutrality by 2050 (*Government of Alberta 2023*).

Globally, too, net zero commitments are increasingly the norm, setting the context of the global economy. Countries committed to reaching net zero by mid-century generate 90 per cent of global GDP (*IEA 2023a*), including over 93 countries and the European Union. More than a third of the world's largest publicly traded companies now have net zero targets, including two thirds of Canada's largest businesses (*Net Zero Tracker 2022*). Industry associations from dairy farming to cement production have action plans to make their products carbon neutral, with interim milestones along the way (*Dairy Farmers of Canada n.d.*; *Cement Association of Canada n.d.*). The clean energy transition is a global transition, setting the conditions for success for Canada's economy, with major competitiveness risks and opportunity costs if Canada falls behind. (*Samson et al. 2021*).

For Canada to meet both the threat of accelerating climate change and the opportunity of the global clean energy transition, net zero is non-negotiable. Policymakers now face important choices about the pathway Canada takes to net zero, to navigate the clean energy transition while protecting affordability and seizing economic opportunities.

1. *British Columbia has committed to updating its target, but the legislation currently is set at 80 per cent emissions reduction below 2007 levels by 2050; the other provinces with legislated targets specify net zero by 2050.*

In most of the country, regulated utilities deliver the gas and electricity used to produce building heat and other critical energy services, such as hot water. These utilities are highly regulated in part because they provide essential services. Canada's energy regulators and the provincial policymakers that set the rules for those regulators will be central actors in the clean energy transition for building heat.

What looks like a promising option for a utility's bottom line may not always be in the best interest of ratepayers and the energy system overall, nor the most cost-effective path to net zero for the broader economy.

Energy utilities, however, are only beginning to map out what the clean energy transition means for their systems and customers. Some gas utilities are seeking to pivot to biomethane; others are starting to blend small amounts of hydrogen into their pipes.[2]

In some cases, both electricity and gas utilities are working together. For example, as electric heat pumps become increasingly efficient and cost-effective, utilities are exploring opportunities to pair them with gas heating backup to form hybrid systems that capture the benefits of heat pumps while keeping gas available for the very coldest days and nights of the year.

But what looks like a promising option for a utility's bottom line may not always be in the best interest of ratepayers and the energy system overall, nor the most cost-effective path to net zero for the broader economy. Furthermore, policymakers, utilities, and regulators may not yet fully understand or agree on the best pathways from the perspective of total system costs. Ambiguity and uncertainty can delay action, risking higher costs to reverse course later, or more pollution and missed climate targets.

This report seeks to advise policymakers—especially provincial and territorial governments—about how to facilitate the shift toward net zero buildings while protecting affordability, now and in the future.

2. ***FortisBC (BC)*** *has committed to 15 per cent biomethane blending in its networks by 2030, although it will achieve some of that percentage by purchasing credits from biomethane produced and used outside of British Columbia (Labbé 2023).* ***ATCO (AB)*** *is blending 5 per cent hydrogen in a small pilot project in Fort Saskatchewan (ATCO 2021).* ***Enbridge (ON)*** *is blending 2 per cent hydrogen in Markham, and has several biomethane projects, including blending biomethane from solid waste facilities in Toronto and from agricultural residues in Stratford, as well as a partnership to develop a new biomethane facility in Niagara Falls (Enbridge 2022).* ***Énergir (QC)*** *is aiming for 10 per cent biomethane by 2030; it is currently regulated to blend 1 per cent, a ratio scheduled to increase to 5 per cent in 2025. New gas customers in Quebec will be connected to 100 per cent biomethane (Sokic 2023).*

This report is structured as follows.

SECTION 1 brings clarity about least-cost pathways to net zero for buildings in Canada. It draws from new, original modelling analysis, literature review, and expert consultation. We identify some consistent patterns in what a cost-optimal pathway to net zero means for the buildings sector across the country, as well as important differences between provinces.

SECTION 2 assesses the extent to which space heating in Canada is currently on track to meeting net zero in a cost-effective way. We find that greenhouse gas emissions from the sector are still growing, and that investment in costly gas utility infrastructure continues apace despite a diminishing role for gas networks under net zero.

SECTION 3 assesses the sufficiency of existing provincial, territorial, and federal policies. Though more needs to be done, current climate policies—including carbon pricing, consumer incentives, and building codes—are influencing consumer choices. But to have an impact at the scale of electricity and gas utility systems, policy attention must also focus on the role utility regulators play in the clean energy transition.

SECTION 4 explores additional policy options, many of which aren't yet getting enough attention. Utility regulators have tools they can use now to align energy systems with net zero while protecting affordability for ratepayers. But stronger policy and clearer direction from provincial and territorial governments can enable utility regulators to do more to ensure prudent investments and to protect ratepayers over the long term. Without such clarity, continued investment in dead-end pathways risks compromising affordability for ratepayers, raising economy-wide costs, missing climate targets, or all of the above.

SECTION 5 presents a set of recommendations for policymakers to start putting Canada's buildings—and the gas and electricity networks that provide the energy to heat them—on track to cost-effectively meet the nation's climate commitments.

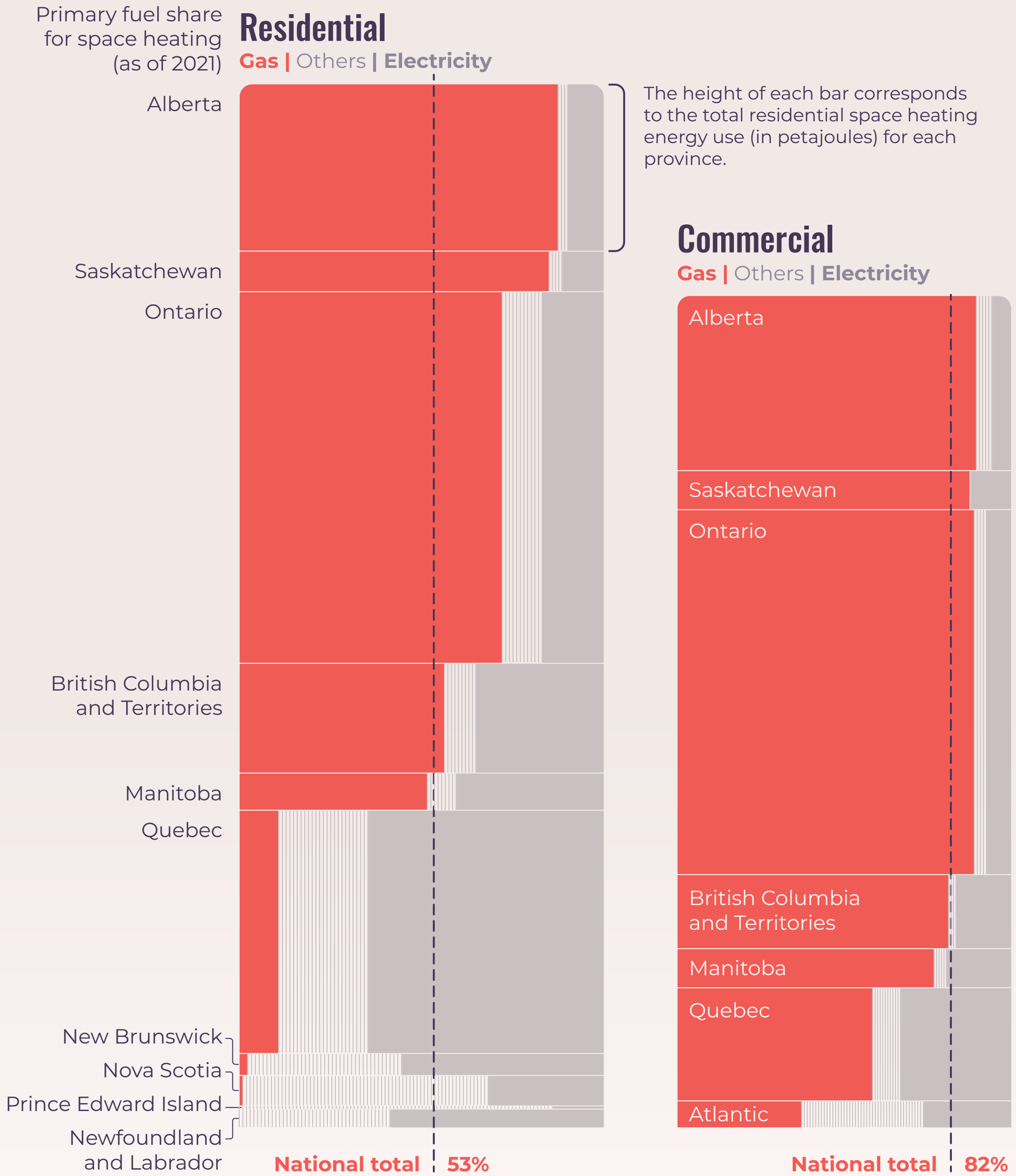
This report doesn't provide a complete policy roadmap for aligning building heat with net zero. The current fuel mix for space heating varies widely across the country (*see Figure A*). The cost-optimal pathway to net zero will be different in different places. Much of the policy work and transformative change in energy systems must be done province by province and even municipality by municipality, based on the specifics of each electricity and gas network.

And that work must start now. While a widespread shift in how Canadians heat their buildings will take place over decades, policymakers and regulators are making decisions today that will set the groundwork out to 2050 and beyond. Gas utility infrastructure, for example, is typically paid for by ratepayers over 40 to 50 years (or longer for some assets), so investment decisions have long-run consequences for consumer bills as well as potential liabilities if costly infrastructure goes unused or underused before it is paid off.

Protecting energy affordability throughout the energy transition requires that governments, utilities, and regulators think ahead and plan accordingly. By making forward-looking decisions today, policy makers can enable a successful and fair energy transition in which every home and business can access the clean, reliable heat they need.

Figure A

Gas furnaces and boilers currently provide space heating for more than half of Canada's buildings, but provinces vary significantly



SECTION 01

Net zero and **the future** of building heat

To explore the implications of a net-zero-aligned buildings sector for Canada's energy systems, we employed a techno-economic cost optimization model: the North American TIMES Energy Model (NATEM). This modelling analysis doesn't seek to prescribe a particular pathway to net zero, but instead identifies ways to reach net zero while minimizing costs to the whole system.

NATEM's cost optimization is economy-wide and covers a broad scope of costs, including energy commodity prices; consumer capital and operating costs; supply-side costs like infrastructure, operation, and maintenance; costs of energy efficiency investments; capacity expansion costs; and costs of early retirements. Minimizing overall costs helps to protect long-term affordability for households and businesses. This techno-economic cost optimization model is well-equipped to provide insights about consistent patterns in the cost-optimization findings in different regions, and across sensitivity analyses, and to investigate differences between building types and between regions.

The modelling analysis accounts for all energy demands in the buildings sector, including space heating and cooling, water heating, and cooking. We focus the analysis on space heating, rather than all energy usage in buildings, because space heating drives most of the energy demand in the buildings sector (58 per cent as of 2021), and because it underpins demand peaks—important considerations for ensuring energy system reliability. Due to data limitations and the particular opportunities and constraints of energy systems in the territories, the regionally specific analysis is focused on Canada's provinces.

WHY FOCUS ON PEAK DEMAND?

Peak demand is the period of time when electricity demand is at its highest. The height of the peak affects the size and cost of the electricity system. That's because it determines the amount of generation, transmission, and distribution capacity that must be available to meet the demand at its highest point. Peak demand can also be lowered by **load shifting** (moving demand from peak hours to non-peak hours), **peak shaving** (reducing demand at peak times) and overall demand reduction through improved energy efficiency. Most Canadian jurisdictions are winter peaking, which means that electricity demand is highest on the coldest days of the year, when the need for heating is highest. Currently, only Ontario is summer peaking, where demand for air conditioning on hot, humid days determines the time of highest electricity usage.

*In NATEM, the buildings sector includes **residential buildings** (single detached, single attached, apartments, and mobile homes) as well as **commercial buildings** such as offices, shops, and restaurants. Institutional buildings such as hospitals, schools, and universities are bundled with commercial buildings in this analysis. Residential buildings are more numerous—there were about 29 times more residential buildings than commercial and institutional buildings in 2020—but because commercial and institutional buildings are larger, space heating demand in the residential sector is estimated to be only 1.3 times greater than commercial and institutional demand in 2020.*

The modelling results help to clarify implications for the buildings sector of a cost-optimal path to achieving net zero economy-wide, as well as the potential trade-offs of pursuing alternative routes. We also tested the robustness of the modelling results with sensitivity analyses that were selected based on input from experts and industry stakeholders regarding key sources of uncertainty for future planning. (For additional detail on our modelling approach, including a list of sensitivity analyses, see Appendix 1.)

In this section, we describe and discuss the lead insights that our analysis surfaced. The major takeaways—that a cost-optimal pathway to net zero for Canada means increasing electrification, decreasing gas demand, and the need for investments in electricity capacity and energy efficiency—align with the findings of similar recent Canadian and international studies. (For a summary, see Appendix 2).

1.1 Overarching insights for Canada's energy systems

Overall, the model's cost optimization consistently shows a significant increase in the use of electricity for building heat, and a declining use of gas. This pattern is robust across the sensitivity analyses we ran, and consistent with other, similar net zero studies. We unpack these findings in more detail below.

Electrifying almost all building heat is the most cost-effective path to net zero

In all provinces and across all sensitivities, a cost-optimal pathway to net zero for the economy results in electricity becoming the dominant energy supply for building heat. Nationally, electricity's share of annual space heating energy demand rises from 21 per cent today to between 55 and 60 per cent by 2040 and between 78 and 91 per cent by 2050.

Electrification uptake varies by region, by sector, and by building type, but in almost all scenarios, getting to net zero means that electric technologies—led by heat pumps—heat most of Canada's residential buildings by 2050. Electric end-use technologies play a major role in commercial buildings as well—including in hybrid systems where heat pumps provide the bulk of heating needs. (For a description of end-use technologies for building heat, *see Table 1*).

In all regions, the model results show significant heat pump uptake in the residential buildings sector, including heat pumps deployed as part of a hybrid system (*see Figure B*). Heat pumps and electric resistance heating are the cost-optimal technologies for the system in the vast majority of homes by 2050. Widespread electrification of heat on a cost-optimal pathway occurs in part because heat pumps are so much more energy efficient than gas furnaces. When considering the broader economic impacts of the energy system, the alternative of using hydrogen or biomethane in buildings leaves less of those low-emission fuels available for other uses where they are highly needed, such as in heavy industry.

Table 1 Space heating technologies

HEAT PUMPS

Use electricity to move heat between locations. During the winter, a heat pump gathers heat from the outside air, ground, or a water source, and pumps it into a building, heating it. In the summer, the process works in reverse: heat pumps move heat from inside to outside, cooling a building. Heat pumps can work with ducts, similar to a forced-air furnace, or be ductless (mini-splits). Heat pumps are typically two to three times more efficient than electric-resistance heating.

Air-source heat pumps

Contain liquid refrigerant that absorbs heat from outdoor air. The refrigerant then boils to become a low-temperature vapour, which is in turn compressed, causing it to further heat up. The heat from the gas is then transferred into the indoor air, and the cycle repeats itself. The reverse cycle occurs in the summer, cooling the indoor air (*NRCan 2022*).

Cold-climate air-source heat pumps

Can operate at temperatures as low as –30° C.

Ground-source heat pumps

Circulate a liquid through underground or underwater piping, which absorbs heat. The liquid then passes through a heat exchanger, transferring its heat to the refrigerant in the heat pump. The heat pump can then transfer the heat to the indoor air. When cooling, the process works in reverse (*Efficiency Manitoba 2021*).

ELECTRIC RESISTANCE HEATING SYSTEMS

Electric furnaces

Use fans to pull air across electrically heated elements and then distribute it through a building via ductwork.

Electric boilers

Pass electricity through a resistive conductor, which heats water. A circulating pump moves the heated water around the home through radiators or underfloor heating pipes, distributing heat.

Table 1 (continued)

Electric baseboards

Operate as individually controlled units around a building. They generate heat from an element, which then radiates into the room.

HYBRID HEATING SYSTEMS

Combine the installation of an electric heat pump with a gas furnace. The heat pump provides heating and cooling most of the time, but the furnace is available at very low temperatures when heat pumps can lose efficiency and effectiveness.

CONVENTIONAL FURNACES AND BOILERS

Furnaces

Burn gas, oil, or propane to generate heat, which passes through a heat exchanger. Fans blow air across the heat exchangers, then circulate the heated air through the building via ductwork.

Boilers

Burn gas, oil, or propane to heat water. The equipment then distributes hot water or steam through pipes to radiators.

All gas-fired furnaces and boilers can also burn biomethane without modification.

HYDROGEN FURNACES AND BOILERS

Similar to their conventional gas counterparts, but instead burn hydrogen. Boilers and furnaces that use 100 per cent hydrogen are not yet commercially available.

THERMAL ENERGY NETWORKS

Generate or recover, then distribute heat through a connected pipe network, instead of distributing gas. The heat can be generated directly with fossil fuels or with renewable sources such as bioenergy, solar thermal, geothermal, or air-source, water-source, or ground-source heat pumps. Thermal energy networks can also be a component of cogeneration (combined heat and power) systems or systems that make use of waste heat, for example from wastewater or industrial operations. Some thermal energy networks can also provide space cooling by circulating chilled water.

BIOMASS STOVES

Use biomass fuels (for example, wood pellets) for heating.

Figure B

On a cost-optimal path to net zero, electricity overwhelmingly powers space heating by 2050, even in provinces that rely heavily on gas today

Primary space heating mix in the **residential sector**, % market share by technology

Heat pump | Electric baseboards | Hybrid (electric heat pump with gas backup)

Today, 34% of HOMES in Canada heat with electricity, mostly baseboards.

To meet net zero, nearly all home heating in 2050 is entirely or mostly powered by electricity, including heat pumps backed up by gas in a hybrid system.

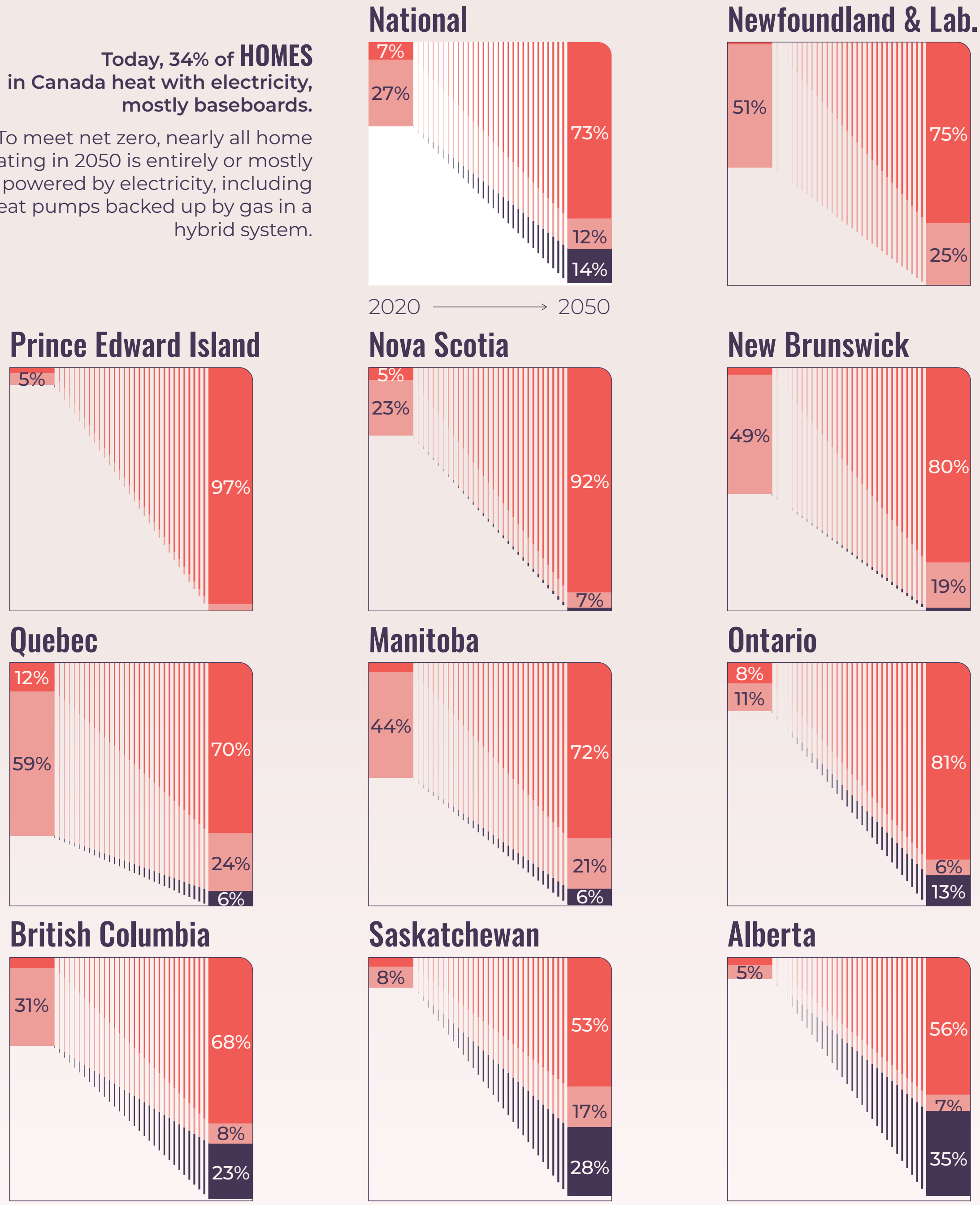


Figure B (continued)

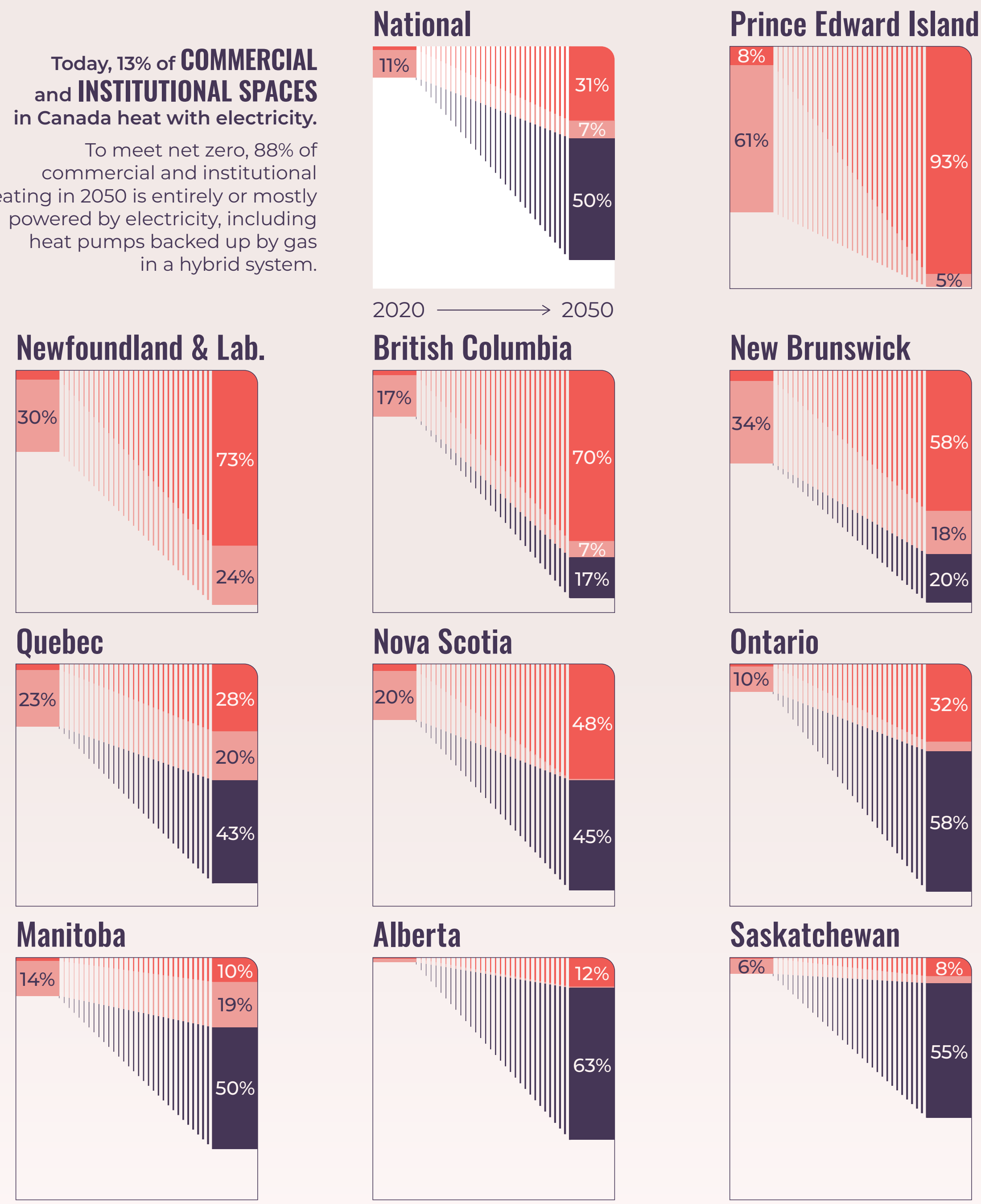
On a cost-optimal path to net zero, electricity overwhelmingly powers space heating by 2050, even in provinces that rely heavily on gas today

Primary space heating mix in the **commercial and institutional sector**, % market share by technology

Heat pump · Electric baseboards, furnaces, and boilers · Hybrid (electric heat pump with gas backup)

Today, 13% of COMMERCIAL and INSTITUTIONAL SPACES in Canada heat with electricity.

To meet net zero, 88% of commercial and institutional heating in 2050 is entirely or mostly powered by electricity, including heat pumps backed up by gas in a hybrid system.



Electric end-use technologies gain significant market share in residential space heating by 2050, even in provinces that mostly heat with gas now, such as Alberta, Saskatchewan, and Manitoba. Under the cost-optimal pathway, some of these regions deploy hybrid heating systems that pair electric heat pumps with a back-up gas furnace. Alberta sees the highest uptake of hybrid systems at 35 per cent of market share in 2050, compared to an average of 14 per cent across Canada. We discuss hybrid systems in greater detail in *Section 1.2*.

Provinces with little to no existing gas infrastructure, including Nova Scotia, New Brunswick, Prince Edward Island, and Newfoundland and Labrador, see all-electric end-use technologies (heat pumps and electric resistance heating) grow to make up nearly all of their residential market share by 2050.

The electrification of space heating in commercial and institutional buildings is more varied across provinces compared to the residential sector. Commercial and institutional buildings use a greater range of technologies, such as geothermal heat pumps, thermal energy networks, and hydrogen boilers, but only in some provinces. They also see a higher uptake of hybrid heating systems.

This finding of high rates of electrification is robust across sensitivity analyses. Under a sensitivity analysis that tests a lower range of efficiency improvements for heat pumps, the results show slightly lower overall electrification levels, but electricity still meets 78 per cent of annual space heating energy demand by 2050. Even under sensitivity analyses that combine lower costs and greater availability of low-emission gases with higher costs for electric end-use technologies, a widespread shift to electric building heat still tends to be more cost-effective than significant use of low-emission gases in the buildings sector.

Similarly, sensitivity analyses testing the possibility of higher biomethane feedstock availability and lower costs of biomethane production do not decrease the proportion of building heat provided by electricity.

As for hydrogen, we find that even assuming lower supply and end-use technology costs and setting blending rates to 20 per cent does not materially impact the rate of electrification of building heat. Adjusting assumptions on the costs of end-use hydrogen technologies to 50 per cent lower than baseline assumptions only shows an effect in the commercial sector: a 12 per cent increase in the market share of hydrogen technologies, and a corresponding decline in the market share of hybrid systems. The market share of full-electric technologies is unaffected. Reducing the costs of production by 30 per cent from the baseline assumption also shows no impact on the share of hydrogen technology uptake.

This persistent finding of electrification as the cost-optimal pathway for buildings comes in part because, from a whole-economy perspective, it is more cost-effective for scarce low-emission gases to go toward decarbonizing other sectors. Sectors such as heavy industry and hydrogen production consistently consume the majority of biomethane in the model.

It is more cost-effective for scarce low-emission gases to go toward decarbonizing other sectors.

This finding on the importance of electrification is broadly consistent with other major Canadian and global studies that have investigated the same topic (*IEA 2021*; *Mahone et al. 2018*; *Williams et al. 2021*; *Langevin et al. 2023*; *European Climate Foundation and European Alliance to Save Energy (EU-ASE) 2022*; *Guidehouse 2022*). For example, in EPRI's Canadian National Electrification Assessment's net zero scenario, electric heating share increased in both residential and commercial buildings to 76 per cent and 73 per cent respectively by 2050 (*EPRI 2021*). Similarly, the Trottier Energy Institute's Canadian Energy Outlook reported that across their net zero scenarios, electricity would account for more than 95 per cent of total consumption in the buildings sector by 2050 (*Langlois-Bertrand et al, 2021*).

In all provinces, gas use in buildings declines steeply as Canada decarbonizes

On a cost-optimal path to net zero, total gas consumption in buildings falls in every province, including in the major gas-consuming provinces of Alberta, Ontario, Saskatchewan, British Columbia, and Manitoba (*see Figure C*).

As overall gas consumption declines, the use of biomethane and hydrogen in the buildings sector increases, but only slightly. Because electrification is so much more cost-competitive and because there is competition for their use from other sectors, even by 2050, these fuels would replace only a small fraction of current gas demand (*see Figure D*). Across all sensitivity analyses, by 2050, the extent of hydrogen and biomethane demand in the buildings sector overall (including space heating, water heating, and cooking applications) only makes up between 5.1 and 12.7 per cent of 2020's total gas demand. These modelling results illustrate the very limited role of any kind of gas in the buildings sector in 2050 on a cost-optimal pathway to net zero.

Figure C

On the path to net zero, buildings sector gas use declines in all provinces

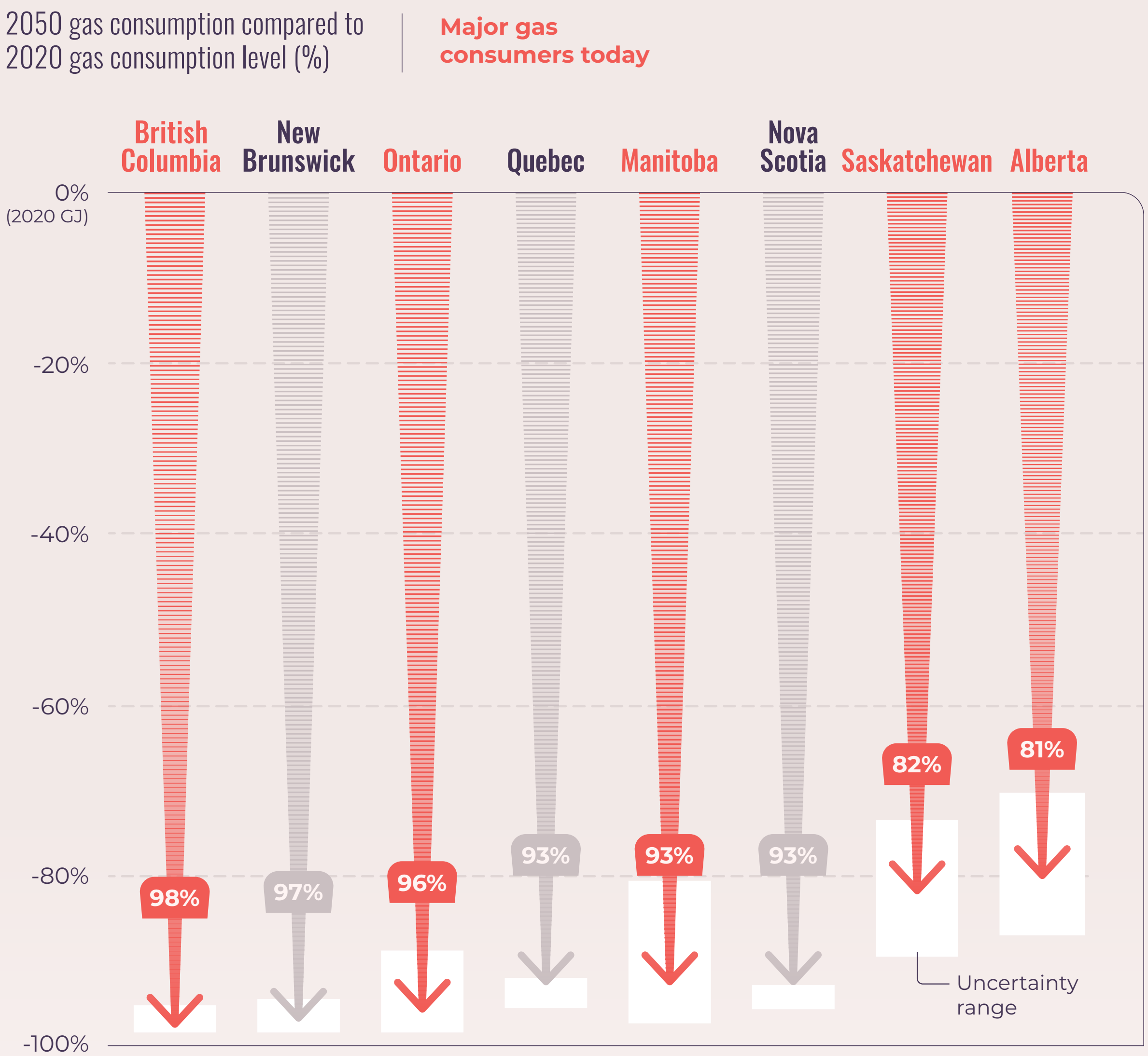
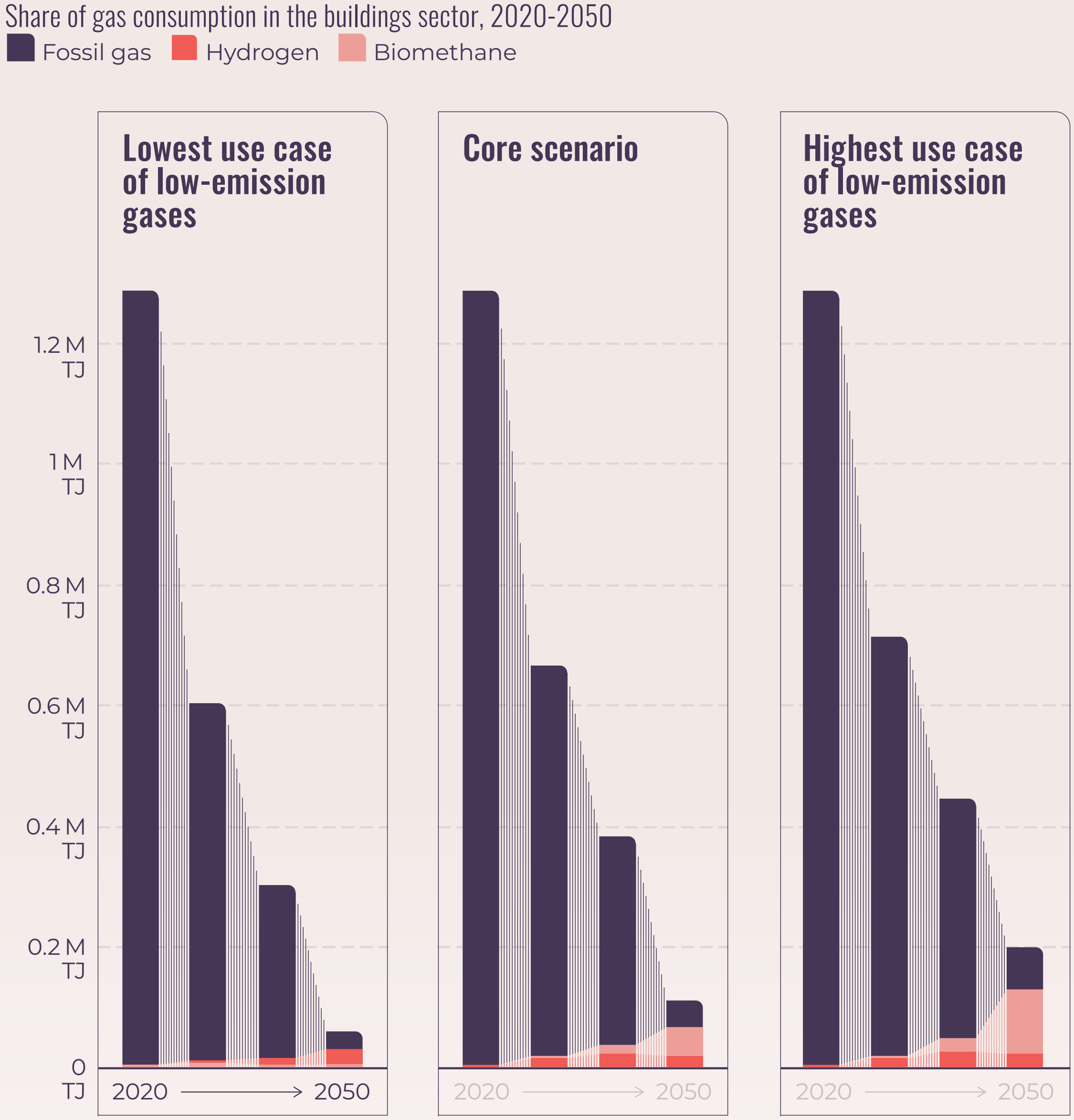


Figure D

On a cost-optimal pathway, biomethane and hydrogen only replace a small fraction of today's gas use in buildings



HYDROGEN AND BIOMETHANE

Hydrogen and **biomethane** are two alternative gases that could be used for building heat. **Hydrogen** can be produced with fossil fuels or electricity, with lower greenhouse gas intensity if it is coupled with carbon capture technology or produced using renewable electricity (*IEA 2023b*). Hydrogen can be used in fuel cells, or burned to produce energy. It is not, however, a full substitute for methane gas—at any pressure, the volumetric energy density of hydrogen is about one third that of methane. To date, Canadian gas utilities have only tested low-percentage blends of hydrogen in existing gas infrastructure.

Biomethane, also called renewable natural gas or RNG, is a form of biogas that is produced from anaerobic digestion or direct gasification of organic feedstocks such as wood and crop residues, manure, corn silage, or pulp mill sludge. Once it is refined, biomethane can be injected directly into existing gas distribution infrastructure and burned in any existing gas space heating equipment.

The decline in gas use on a cost-optimal pathway to net zero is consistent across various sensitivities, including those that test lower cost and higher availability assumptions for low-emission gases. Under low-cost assumptions for hydrogen, more hydrogen furnaces and boilers are deployed in commercial buildings in Alberta, Saskatchewan, and Manitoba. However, total gas consumption from the buildings sector in these provinces still drops by 70 per cent in Alberta, 73 per cent in Saskatchewan, and 80 per cent in Manitoba. Under a sensitivity analysis that tests higher assumptions for the availability of biomethane feedstocks, the results show similar levels of biomethane use in buildings; the additional feedstocks are more cost-optimally used elsewhere.

This finding of declining gas demand for space heating is consistent with other net zero studies. For example, the Canadian Energy Outlook report shows that gas use in the buildings sector falls in all net zero scenarios; gas consumption is projected to decline and be only 4 to 8 per cent of 2016 demand by 2050 (*Langlois-Bertrand et al. 2021*). Studies in other countries have reached similar conclusions; for example, Guidehouse's Decarbonisation Pathways for the European Building Sector shows that, in a highly electrified pathway, gas is no longer used in buildings by 2050, and even in a pathway that deploys more hybrid systems and low-emission gases, gas demand still declines by 70 per cent by 2050 (*Guidehouse 2022*).

The levels of gas decline estimated by the NATEM model may even be an underestimate, due to limitations in how it captures the potential dynamics of gas-demand decline. The model can identify where it is most cost-effective to switch from gas to electricity to meet emissions targets, but it does not account for how falling gas demand could raise costs for remaining customers—leading to further customer defection. This can create a negative feedback loop, in which customer defection from the gas network increases costs for remaining customers as a shrinking customer base must pay for gas network maintenance. Those higher costs for remaining customers drive additional defections, and so on.[3]

While the model optimizes for system-wide costs (how much it costs overall), it does not optimize for potential distributional concerns (who pays those costs). Higher costs for remaining customers represents not only a potential accelerant of gas demand decline. It also represents an important equity challenge for policymakers, which we discuss further in *Section 3*.

3. *A recent study from the Brattle Group identified this dynamic as a major energy transition risk for gas utilities in the United States. They find that by 2040, given existing policies, electricity could replace 60 per cent of the heating demand currently being served by the gas sector in New York, increasing gas bills for remaining customers by 71 per cent (Graves et al. 2021). In the United Kingdom, their regulator noted a similar concern about the potential for spiralling network charges, with residual asset value (currently C$45 billion) paid for by fewer and fewer customers over time (Ofgem 2023). In February 2024, the energy regulator in France announced that gas rates will increase by 5.5 to 10.4 per cent in July 2024 to cover fixed costs amid declining gas consumption (franceinfo 2024).*

1.2 Implications for the electricity system

The widespread electrification of building heat—alongside electrification of other energy end uses on a pathway to net zero—has major implications for electricity system investments.

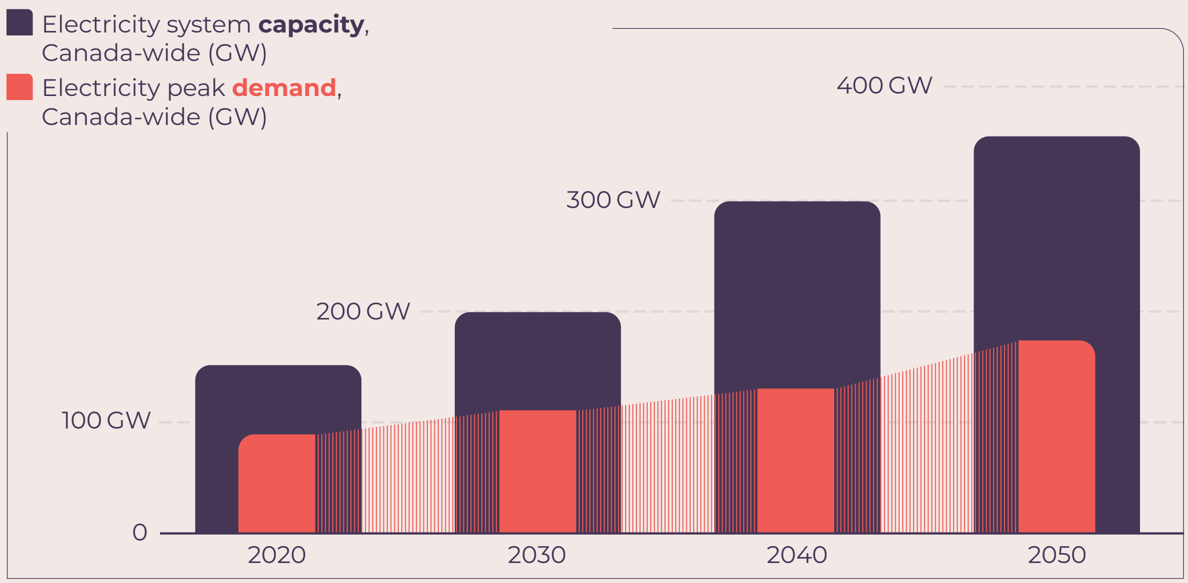
A significant investment in electricity system capacity, reliability, and resilience will be required to reach net zero by mid-century

Increased electricity demand from all sectors necessitates significant additional electricity generation capacity. To meet net zero on the cost-optimal pathway, the model projects an electricity capacity build-out to a national average of 2.6 to 2.9 times the amount in place today, across all of the sensitivity analyses (*see Figure E*). This expansion of electricity systems is broadly consistent with other net zero modelling studies. Our previous research found that installed electricity capacity must grow between 2.2 and 3.4 times by 2050, compared with 2020, in order to reach net zero (*Lee et al. 2022*).

This scale of electricity capacity expansion is the result of higher demand from electrifying activities across the whole economy, not just buildings, but also from the addition of more intermittent renewables to the generation mix. Peak electricity demand from the buildings sector rises. But as other sectors such as transportation and industry also electrify and new electrified technologies such as direct air capture emerge, the percentage of total peak demand due to usage in the buildings sector declines. In 2020, electricity use in buildings drove 69 per cent of peak demand nationally, whereas our modelling finds that in 2050, when most of the buildings sector is electrified, buildings would only be responsible for 48 per cent of winter peak electricity load.

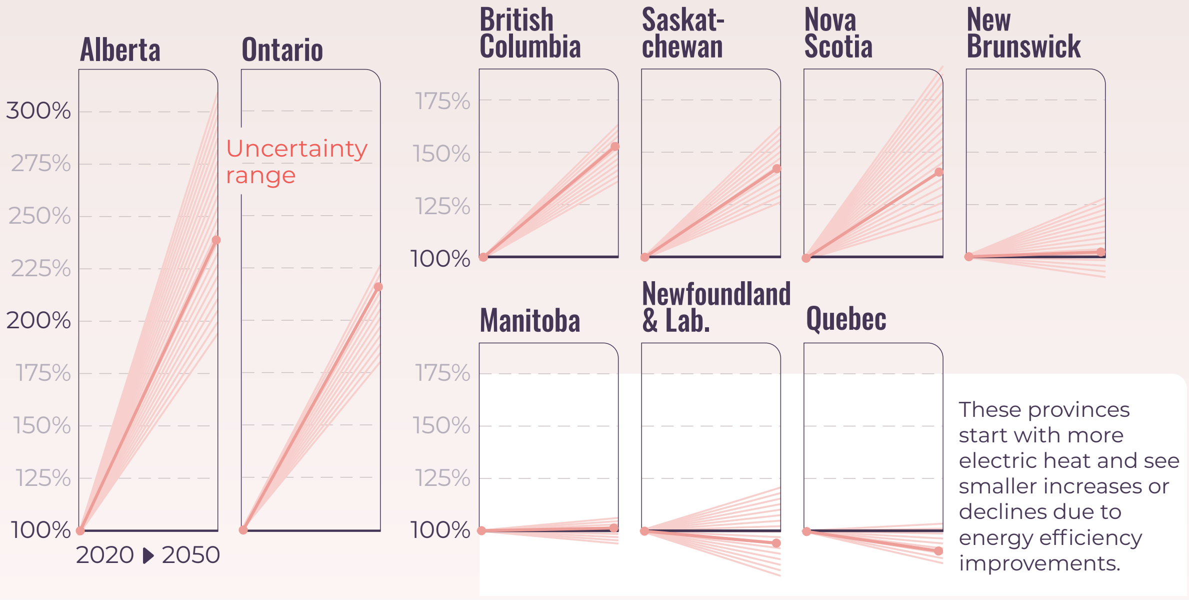
Figure E

Overall electricity capacity needs to increase. Electrification in all sectors, not only buildings, drives growth in peak demand



Peak demand from the buildings sector will climb in some provinces and decline in others

Peak demand change compared to 2020 (%)



Even though electricity demand increases, total energy demand decreases dramatically. On a cost-optimal pathway to net zero, from 2020 to 2050, the total square footage of buildings increases as the population and economy grows. But due to significant improvements in energy efficiency over time, total energy demand from the buildings sector declines on a cost-optimal path to net zero.

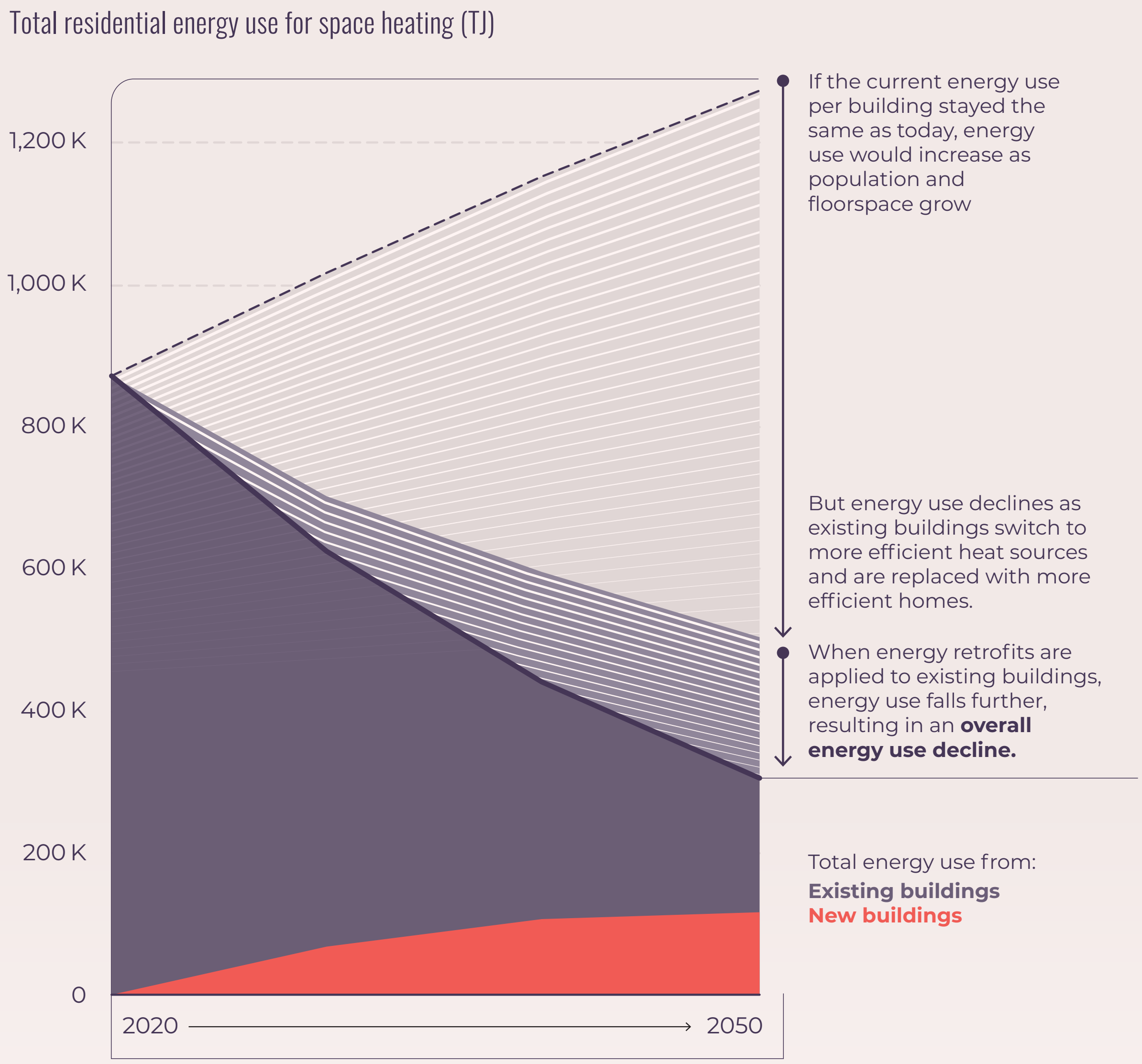
Historically, total energy demand for space heating residential buildings in Canada has remained fairly flat, even as floorspace increases, as existing buildings are retrofitted and newer, more efficient buildings replace older buildings (*NRCan n.d.*). In our modelling results, efficiency improvements result in lower total energy demand from the buildings sector in 2050 compared to 2020 (*see Figure F*). Fuel switching to heat pumps is responsible for much of those energy savings, as heat pumps are typically 1.4 to 3.7 times more efficient than gas furnaces at converting energy into useful heat (*Ferguson and Sager 2022*). Energy efficiency retrofits of existing buildings and the replacement of older buildings with more efficient new buildings drive further energy savings. Altogether, total space heating energy demand from the buildings sector falls by more than half between 2020 and 2050.

In Quebec, New Brunswick, and Newfoundland and Labrador, which currently rely more on electric baseboards for heat, the switch from less efficient electric resistance heating to heat pumps results in sufficient energy savings to decrease overall electricity demand from building heat. For example, in Newfoundland and Labrador, which currently relies on electric baseboards for 41 per cent of its residential and commercial heating, efficiency improvements are sufficient to cause electricity demand from space heating in buildings to fall 31 per cent between 2020 and 2050 as customers switch to heat pumps and benefit from better building envelopes. The energy savings more than offset other factors, such as population growth, which push up demand.

In provinces that currently rely more heavily on gas heat, the widespread uptake of heat pumps, alongside other ongoing electrification (for example, of personal transport), does significantly increase electricity demand, necessitating electricity system investments to meet winter peak demand in ways that maintain reliability. Moreover, increasing Canada's reliance on electricity in a changing climate—with more frequent and more intense threats to electricity infrastructure from extreme weather—heightens the imperative to invest in system resilience.

Figure F

Buildings' total energy use declines on the path to net zero due to improving efficiency



Investments to reliably meet peak winter electricity demand also yield benefits for summer peaks. The electricity system supports peak cooling demand in summer (when gas systems play a very small role), and cooling demand has increased over the past century. Some provinces, such as Ontario, are already summer-peaking systems, while some others may see the gap between winter and summer demand narrow or even have summer peaks surpass their winter peaks as the climate warms (*CER 2021*; *Mertz 2021*; *Government of British Columbia 2015*).

Managing demand peaks is crucial to any cost-optimal net zero pathway

Energy efficiency measures can reduce energy demand in general, including at peak times. Energy retrofits and switching to more efficient technologies like heat pumps require significant effort and investment. But the extent of their deployment on a cost-optimal pathway speaks to how cost-effective energy efficiency is at minimizing total system costs.

Lower levels of energy efficiency and fewer building retrofits would require more electricity generation capacity, resulting in higher overall costs. A sensitivity analysis in which we assume 80 per cent fewer energy retrofits and reduced efficiency of heat pumps results in higher winter and summer demand peaks. This, in turn, requires more installed electricity capacity: 5 per cent more in 2040 and 3 per cent more in 2050. These higher peaks also translate into higher total electricity system costs—up 12 per cent in 2040 and up 9 per cent in 2050.

In addition to broader energy efficiency measures, measures to specifically reduce electricity demand at peak times (known as peak shaving) and shift demand to non-peak times (load shifting) can mitigate costs associated with demand peaks. Many tools are available to do so, and utilities can and should deploy them as a portfolio, rather than in isolation (*See Figure G*).

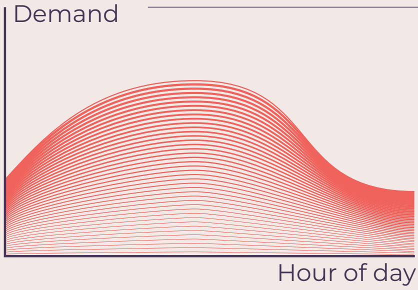
The range of potential peak management tools outlined in *Table 2* is broader than the energy efficiency retrofits we model. Distributed storage technologies, for instance—including thermal storage and batteries at multiple scales, from the utility level down to neighbourhoods, electric vehicle fleets, and in buildings—are multiplying the options available to shift demand to non-peak hours while storing electricity to meet demand spikes. These options are relatively new, but experience with them is growing. For example, a Vermont utility is providing utility-owned batteries to customers to bolster grid resilience and promote energy decentralization (*DiGangi 2023*). As part of a new pilot program, Nova Scotia Power is offering customers home battery systems, which can be used by homeowners in case of outages, and could be deployed by the utility to feed energy back to the grid in times of peak demand (*Nova Scotia Power n.d.*).

NATEM and similar models do not yet capture most of these newer measures and technologies. It is therefore difficult to characterize their potential contributions, although evidence from other studies suggests that they could be considerable—both on limiting costs and improving system reliability (*Nadel 2017*; *EIA 2019*; *Gattaciecca et al. 2020*; *Specian 2021*; *Bronski et al. 2015*; *Fitzgerald et al. 2015*; *Martin and Brehm 2023*; *Srivastav et al. 2024*). For example, in 2015, the ACEEE looked at potential demand response savings from 28 utilities, finding that on average these energy savings could be 10 per cent or more of system peak (*Nadel 2017*). A study from the Rocky Mountain Institute found that residential demand flexibility measures could result in $13 billion per year of avoided grid costs in the United States, and reduce total peak demand by 8 per cent (*Bronski et al. 2015*).

Demand-side measures, including deep retrofits and newer types of demand-side management and response, reduce costs for the entire system, not just the customers who implement them. Some regulators and utilities include energy efficiency investments as a resource for meeting energy needs, and evaluate the relative cost-effectiveness of those investments compared to supply-side alternatives. Such demand-management tools can play a key role in meeting energy needs while minimizing the costs associated with achieving economy-wide electrification.

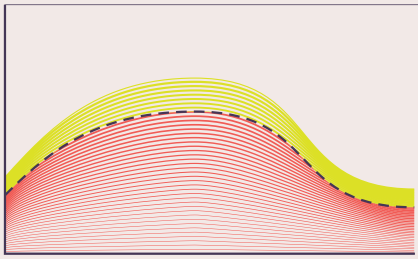
Figure G

Various tools can help manage electricity demand peaks and lower system-wide costs



Baseline demand

Baseline consumer demand for electricity has peaks and valleys depending on the time of year and the time of day

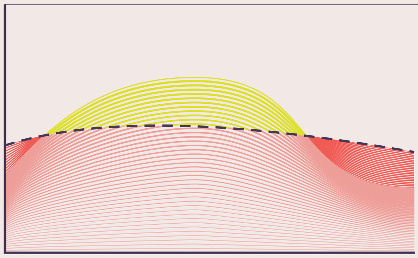


Energy efficiency

Lowers overall energy demand, including peak demand

Building envelope improvements

Higher efficiency appliances



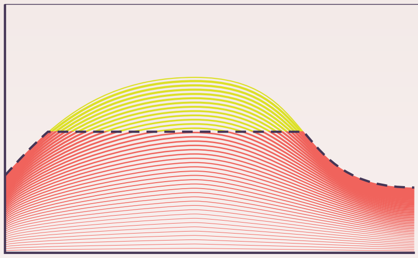
Load shifting

Moves electricity demand to off-peak times

Smart technologies and energy management systems

Distributed energy storage

Off-peak incentive rates



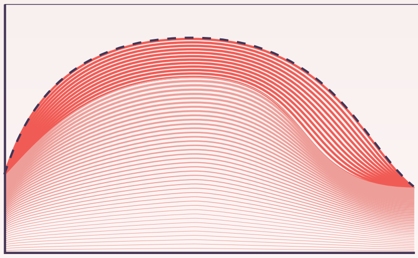
Peak shaving

Lowers electricity demand at peak times

Interruptible supply rates for large loads

Consumer peak reduction incentives

Smart technologies and appliances



Supply-side flexibility

Can dispatch clean electricity when demand is unusually high (e.g., cold snap, heat wave)

Grid interties for trade

Utility-scale storage

1.3 Implications for the gas system

The flipside of growing electricity demand and growing investments in the electricity system in the clean energy transition is falling gas demand. Gas demand from buildings declines on a cost-optimal pathway even with the availability of options such as biomethane, hydrogen, and hybrid heating systems. We consider implications for those decarbonization strategies below, as well as what declining gas demand means for the gas network.

Building heat is not a cost-effective use of low-emission gases

Biomethane and hydrogen are relatively scarce and expensive, and supplies are projected to remain limited.[4] Yet some sectors, such as heavy industry, will struggle to decarbonize without using them. In contrast, electricity is a simple and cost-effective option for building heating—meaning that it is more cost-effective for the economy as a whole to reserve their use for sectors where they provide the best value.

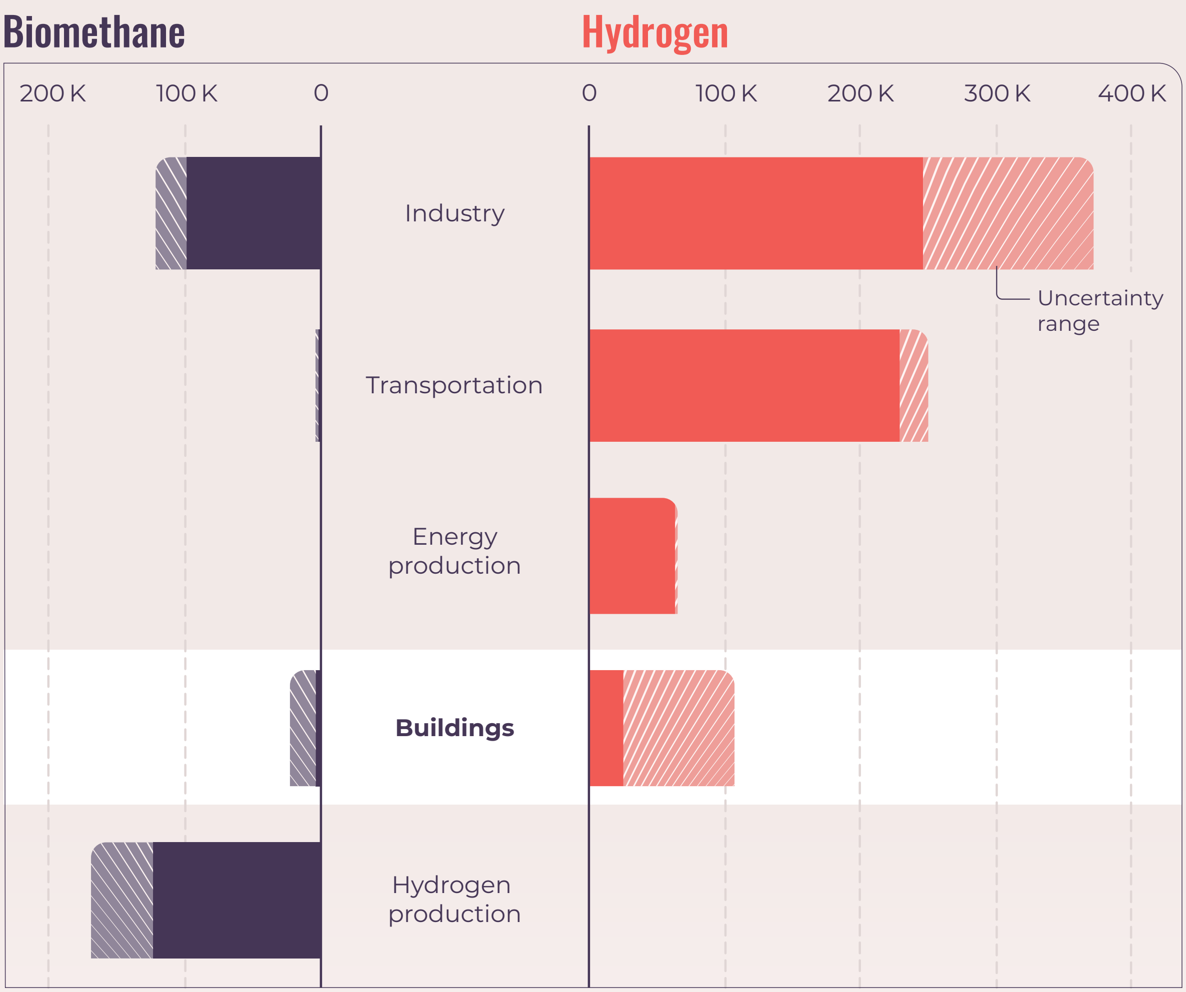
When cost-optimizing for the entire economy, the modelling results show biomethane and hydrogen are primarily used in other sectors, not for building heat. By 2050, Canada's buildings sector is using only 6 per cent of available hydrogen and 6 per cent of available biomethane. The rest is taken up in the industry, transportation, and energy production sectors (*see Figure H*).

4. *Hydrogen production cost assumptions in the NATEM model are derived from a range of studies, including IEA's* ***The Future of Hydrogen*** *report, Element Energy* ***Hydrogen Supply Chain Evidence Base, Data and Assumptions****, and various NREL datasets. Biomethane production cost assumptions were derived from IEA's* ***Outlook for biogas and biomethane report****, other literature, and consultations with stakeholder groups in this space.*

Figure H

On a cost-optimal path to net zero, the buildings sector only accounts for a small amount of low-carbon gas use

Low-emission gas use by sector in 2050 (TJ)



Feedstock constraints are an important limiting factor for biomethane production. Recent studies estimate that, given current feedstock availability and existing production technologies, Canada could feasibly produce between 90 and 218 petajoules of biomethane per year (*Abboud et al. 2010*; *Kelleher Environmental 2013*; *Stephen et al. 2020*). This is equivalent to only 2 to 5 per cent of Canada's total 2021 gas demand (*CER 2023*).

Early-stage technologies that produce synthetic gas from solid biomass could enable Canada to access forestry industry residues as feedstock; doing so would increase biomethane production potential by 150 petajoules, or 4 per cent of gas demand as of 2020. If active forest management techniques such as thinning are applied on Crown timberlands, this estimate could increase by several hundred petajoules (*Stephen et al. 2020*).

Even if the higher ranges of biomethane availability forecasts are realized, supplies available to the buildings sector will likely still be limited due to competing uses, such as heavy industry (*see Figure F*). Indeed, in the sensitivity analyses, tripling available biomethane feedstocks and reducing the cost of biomethane production by 30 per cent does not lead to an increased uptake of biomethane in the buildings sector. Instead, other sectors that are more difficult or more expensive to electrify use more biomethane.

The modelling results also suggest that biomethane feedstocks may be more efficiently used as direct fuel sources rather than converted into biomethane. When available biomethane feedstocks are tripled in the model, some of the additional feedstock is used to meet end-use energy demands directly; in particular, the buildings sector shows more than a fivefold increase in wood and wood-pellet fuel use in this scenario.

Global supply constraints make it unlikely that international trade will significantly increase Canada's domestic biomethane supply. The International Energy Agency estimates that if all current sustainable feedstocks for biomethane were used, they could serve just 20 per cent of current global gas demand (*IEA 2020*).

The use of hydrogen for building heat is constrained by cost and competition with other sectors.

In our modelling results, the vast majority of hydrogen is more cost-optimally used in sectors other than the buildings sector, such as heavy industry. On a cost-optimal pathway, we only see hydrogen boilers deployed in commercial buildings in Alberta, Manitoba, and Saskatchewan, at market shares of 15 per cent, 6 per cent, and 22 per cent, respectively. When we assume a halving of the costs of hydrogen-compatible end-use technologies in a sensitivity analysis, we find a notable increase in their deployment in Alberta, Manitoba, and Saskatchewan, to 53 per cent, 42 per cent, and 57 per cent of the commercial market share, respectively. However, even with low-cost assumptions, hydrogen end-use technologies are not deployed in residential buildings anywhere.

Generally in the modelling results, we see some uptake in the use of biomethane and hydrogen in the buildings sector along a cost-optimal pathway to net zero, but nowhere near enough to replace the sector's current gas consumption.

Hybrid systems play a role in some contexts, but use very little gas by 2050

Hybrid space heating systems that pair heat pumps with gas furnaces—predominantly replacing stand-alone furnaces in existing buildings—grow in market share along a cost-optimal pathway to net zero, particularly in some contexts.

Targeted use of hybrid heat can help some regions deal with winter peak electrical demand, particularly when deployed in older, less efficient buildings that tend to have higher heating needs.

In provinces such as Alberta and Saskatchewan that have cold climates, well-established gas distribution networks, and high levels of gas consumption for heating, hybrid systems reach a residential market share of 35 per cent and 28 per cent, respectively, in 2050, under a cost-optimal pathway, compared to 14 per cent nationwide.

Pulling back to the national scale and shifting to the commercial sector, the modelling results indicate much higher deployment of hybrid systems in commercial buildings compared to residential—such hybrid heating systems rise to capture 37 per cent of the national share of the commercial buildings market by 2040, and 50 per cent by 2050. This is in part because commercial and institutional buildings are generally larger and more complex, which translates into greater heating loads. Switching them from gas equipment to electric heat pumps often requires more significant upgrades, raising project costs.

From a system perspective, hybrid heating systems in commercial buildings can offer more peak-shaving value, with larger loads and operations that often coincide with daytime peak hours, which increases the value of gas availability to mitigate peak demand. However, the importance of hybrid systems for managing peak demand may be overestimated, as NATEM and other models don't fully capture alternative strategies to mitigate the cost of peak demand, such as distributed energy resources and interprovincial trade.

By 2050, in our modelling results, hybrid heating systems burning low-emission gases are nearly the only context in which Canada's buildings are consuming gas—they make up the entirety of gas demand in the existing distribution system. Under a cost-optimal net zero pathway, all exclusively fossil-gas space heating is phased out by 2050.

Other approaches to peak shaving and load shifting could lower electricity capacity needs with less risk of locking in costly gas infrastructure.

So while hybrid heating systems maintain a role for gas networks, those networks are delivering very low volumes of fuel. The quantity of gas used for space heating in residential buildings still drops by 96 per cent, from an average of 4.7 GJ per month in 2020 to an average of 0.2 GJ per month in 2050. In commercial buildings, consumption drops 88 per cent, from an average of 122 GJ per month in 2020 to 15 GJ per month in 2050.

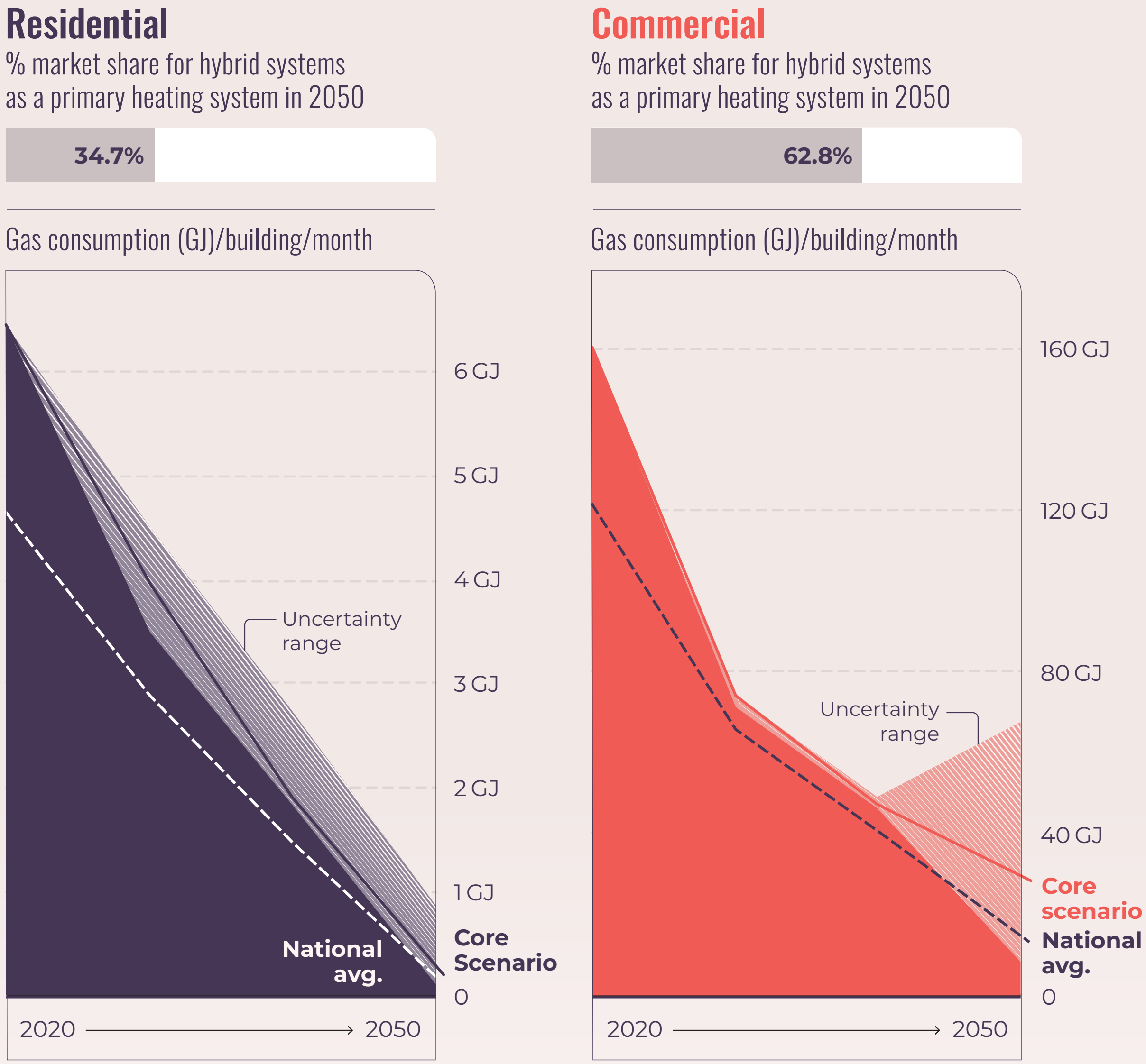
In Alberta, which sees the highest uptake of hybrid systems in 2050 (35 per cent of residential market share by 2050), residential gas consumption nonetheless plunges by 83 per cent over the same period (*see Figure I*). Even where buildings retain a gas furnace, heat pumps are covering most of the heating load.

As for commercial buildings, while hybrid systems rise to make up 50 per cent of national market share by 2050, gas consumption from commercial buildings still declines, falling by 91 per cent nationally by 2050.

All of this points to a future of profound upheaval for Canada's gas systems—even in regions where hybrid heat may play a significant role. Some buildings may still use gas for space heating in a net zero future, but only during the coldest days or weeks of the year. Gas utilities will find it complex and challenging to recover ongoing network maintenance costs from a customer base that is smaller and uses less gas.

Figure 1

Even in Alberta, the province with the highest projected share of hybrid fuel systems by 2050, gas consumption is projected to fall



Uncertainty in the extent of gas use in the commercial sector widens between 2040 and 2050, but the particular shape of the distribution between 2040 and 2050 is a function of the model's mechanics. GHG reduction requirements in the model tighten over time and the model works in five-year timesteps. In one of the sensitivity analyses, 2040 is the point when cost assumptions result in a shift to more gas use.

Hybrid systems may appear optimal in some regions or contexts, but given the high costs of maintaining gas systems just to service peak demand, other approaches to peak shaving and load shifting could lower electricity capacity needs, with less risk of locking in costly gas infrastructure. As we discuss above, our modelling has limited representation of some of the newer peak shaving and load shifting options, so its findings for the cost-optimal levels of hybrid heating may be overestimated. In areas where hybrid systems could play a larger role, more granular modelling of regional pathways would help to better understand its costs and benefits compared to non-gas alternatives.

A larger role for hydrogen and biomethane comes with the risk of higher costs and reliance on less certain technologies

A cost-optimal pathway to net zero includes a modest role for some hydrogen and biomethane in building heat. A much larger role for low-emission gases in buildings is likely more expensive overall but could broaden the possibility of keeping existing gas infrastructure (furnaces in homes and pipelines in the ground) in use for longer. However, pushing for a bigger role for hydrogen and biomethane risks raising overall costs, and depends more on less-certain decarbonization technologies, while doing little to mitigate the need to invest in electricity capacity expansion.

To date, Canada's biomethane supply is fairly limited and expensive. In British Columbia, for example, ratepayers can elect to pay a premium of $7 per gigajoule for biomethane—about 30 per cent more than the price of fossil gas as of January 2024—to offset the emissions from their gas consumption. This price is below the actual additional cost to the gas utility, according to records provided to the regulator (*BCUC 2024*). Energir in Quebec also charges customers more for biomethane: as of October 2023, biomethane cost $19 per gigajoule compared to less than $3 per gigajoule for fossil gas.

Increased production capacity and importation are possible, at least in the near term. But given the feedstock constraints and competing uses we discuss above, a reliance on significant levels of biomethane for building heat could prove costly or difficult to deliver, which risks locking in higher costs to ratepayers, higher emissions, or both.

Blending hydrogen into existing gas supply systems risks under-delivering on greenhouse gas emissions reductions, unless utilities achieve much higher blending rates. Blends of five to 20 per cent by volume may require utilities to only slightly modify their existing networks. A 2022 National Research Council study concluded that, in general, up to 5 per cent blending can be tolerated anywhere, and up to 20 per cent in distribution or regional transmission pipelines with no critical downstream appliances (*Yoo et al. 2022*). However, such blending rates mean that the end product is still predominantly methane gas, not hydrogen, driving only marginal greenhouse gas savings. Moreover, when hydrogen displaces methane in a gas network, it also reduces overall energy content (hydrogen has only about one third the volumetric energy density of methane gas), such that a 20 per cent hydrogen blend only reduces greenhouse gas emissions by 6 to 7 per cent. Blending at low levels is therefore not a viable long-term pathway.

A strategy for building decarbonization that relies on yet-unproven technologies risks failure if the technologies' potential is not realized.

Higher-ratio blends or pure hydrogen would likely require more substantial modifications and new pipes, and homeowners would also need to upgrade or switch to hydrogen-compatible appliances (*Baldwin et al, 2022*; *Topolski et al. 2022*). Pure hydrogen boilers for homes are not yet commercially available. Pilots of pure hydrogen for heating have started in some places, but the idea is in the early stages. Two pilot projects in England for 100 per cent hydrogen heating, for example, were recently cancelled due to community opposition to the trials and inadequate local hydrogen supply. A similar pilot in Scotland is still in the planning phases (*Ambrose 2023*).

Committing to a pathway that involves the future use of pure hydrogen for heating would mean relying on end-use technologies that have not yet been deployed at commercial scale, and building new gas distribution networks or retrofitting existing ones. The extent to which existing pipes can tolerate pure hydrogen without embrittlement and excessive leakage is uncertain. And regardless of equipment costs, the costs of hydrogen itself—especially given that other sectors will be competing for it—may be enough to make hydrogen heating an uncompetitive pathway relative to alternatives.

A strategy for building decarbonization that relies on yet-unproven technologies risks failure if the technologies' potential is not realized. Provinces would then need to pivot to other options despite sunk costs and additional costs of delay, or risk missing climate targets.

Implementation uncertainty exists, of course, for all decarbonization strategies. For example, the extent to which energy retrofits can be completed, or the number of heat pumps that can be installed, depends on the corresponding investment and effort. But low-emission gases are at an earlier stage of their development, and their potential is less clear.

In any case, a larger role for low-emission gases in the buildings sector doesn't avoid the need to extensively build out electricity system capacity. Our modelling finds that using more of Canada's scarce supply of low-emission gases in the buildings sector requires greater electrification in other sectors, such as heavy transportation and industry, to meet emission targets. The required scale of the electricity system build-out ends up being similar.

Continued growth of the gas network is inconsistent with cost-effectively reaching net zero

Given the rapid shift away from gas consumption in buildings along a cost-optimal pathway to net zero (*see Figure H*), provinces that continue to expand their gas distribution networks could jeopardize Canada's climate goals or raise the cost of meeting them.

This conclusion is consistent with numerous other studies, including the following:

- In its report *Net Zero by 2050: A Roadmap for the Global Energy Sector*, the International Energy Agency concludes that, while gas pipelines will still have a role to play, additional investment in new gas pipelines is not indicated given the projected decline in fossil fuel demand (*IEA 2021*).
- In a 2022 analysis, the International Institute for Sustainable Development (IISD) found that declining fossil fuel demand may lead to stranded assets if utilities are unable to recover infrastructure expansion costs— leaving ratepayers or governments on the hook (*Cameron et al. 2022*).
- In a 2021 presentation, global research and consulting firm The Brattle Group asserted that accelerating electrification will increasingly disrupt conventional gas utility business models, and that companies will face increasing risks to recovering the capital investments they need to expand their networks (*Graves et al. 2021*).

- A recent study in the journal Nature Energy concludes that a continued expansion of gas infrastructure that has a decades-long service life will hinder the transition to renewables, while resulting in "carbon lock-in" (*Kemfert et al. 2022*).

- After three years of evidence and consultation, Massachusetts' future of gas regulatory proceeding came to a close in 2023. The regulator's final decision includes direction to "minimize investments in the gas pipeline system that may be stranded costs in the future as decarbonization measures are implemented," beginning by considering non-pipeline alternatives (*Massachusetts DPU 2023*; *Energy and Environmental Economics Inc. and ScottMadden Inc. 2022*).

The potential economic viability of hybrid heat in some regions of Canada does not justify the costs of expanding the gas system in those areas. Adoption of hybrid heat can be particularly valuable in existing buildings as a stepping stone to electrification, particularly because older buildings tend to be less efficient and their larger energy needs contribute more to peak heating demand. But this is not necessarily true for new buildings, and extending gas networks to them carries risks with less potential benefit to the system as a whole.

The potential economic viability of hybrid heat in some regions of Canada does not justify the costs of expanding the gas system in those areas.

At the consumer level as well, in many contexts in Canada and the United States, all-electric new buildings are already a more cost-effective option (*Miller et al. 2023*, *Billimoria et al 2018*; *McDiarmid 2022a*).

As we discuss in the next section, further growth of the gas network presents serious risks, both for gas ratepayers and Canada's climate goals. Cost-effectively meeting net zero means that new gas infrastructure could be unused or underused before it is fully depreciated—typically over 40 to 50 years—resulting in a stranded asset that someone will be left to pay for. That someone could be a steadily contracting base of ratepayers, but it could also include utility shareholders, governments, or a combination of the above.

SECTION 02

The current trajectory of building heat compared to a **cost-optimal net zero pathway**

A cost-optimal path to net zero consistently includes extensive electrification, contracting gas demand, limited long-term use of hybrid systems, and significant investments in electricity capacity and energy efficiency. Each of those elements has important implications for Canada's policymakers, regulators, and utilities. This is particularly the case because, despite some recent progress, Canada's buildings sector and its electricity and gas systems are not yet on that cost-optimal net zero path.

In this section, we unpack the implications of this misalignment for the buildings sector, for energy utilities and regulators, and for Canada's clean energy transition.

2.1 The status of building heat in the clean energy transition

Getting closer to the cost-optimal pathway to net zero described in *Section 1* would require a major shift in direction from where the buildings sector and gas and electricity systems have been trending over the past 10 to 15 years.

Canada's emissions from building heat continue to rise

Greenhouse gas emissions from Canada's buildings sector grew 8.8 per cent between 2005 and 2022, and existing climate policy has proven insufficient to reverse the sector's rising emissions. Nearly every other sector is successfully reducing emissions, yet rising emissions from only three sectors—buildings and upstream oil and gas—undercut the other sectors' progress to date (*Stiebert and Sawyer 2023*).

Greenhouse gas emissions from Canada's buildings sector grew 8.8 per cent between 2005 and 2022.

Previous research from the Canadian Climate Institute has found that the buildings sector's emission trajectory is not on track to meet Canada's 2030 target—let alone the 2050 net zero target (*Sawyer et al. 2023*). That's even after accounting for all existing policies that could lower emissions from buildings, such as carbon pricing and government programs supporting energy retrofits and clean technologies. To meet the 2030 goal, buildings-sector emissions would need to decline to between 26 to 31 megatonnes of carbon dioxide equivalent below 2005 levels. Our analysis found that existing legislated policies would barely yield half (13 megatonnes) of the required reductions.

If Canada cannot rein in emissions from buildings, it risks either missing its climate targets or requiring a disproportionate effort from other sectors, raising the energy transition's overall costs.

Although there are signs of progress, the push to build bigger electricity systems remains nascent and uneven

The electricity sector is Canada's emissions-reduction poster child. The sector's greenhouse gas emissions have plunged 56 per cent since 2005, driven in large part by efforts to phase out coal power. Provinces such as Ontario, Alberta, Saskatchewan, Nova Scotia, and New Brunswick still have further to go, and each is facing unique challenges, but the collective progress and momentum on clean electricity is undeniable.

That said, when it comes to expanding systems to meet the steep load growth associated with broad electrification, policy in many regions is still in its infancy. In some, it is absent. While as recently as 2021, almost no Canadian utilities had plans for significant expansion, a string of announcements this past year signalled more ambitious plans for growth:

- The Province of Ontario released *Powering Ontario's Growth*, a guidance document that directs the Independent Electricity System Operator to procure numerous types of new supply to meet growing industrial demand for clean power and demand from household electrification (*Government of Ontario 2023*).

- Hydro-Quebec committed to an historic spending and capital investment plan of between $155 and $185 billion, similarly aimed to prepare its system for the demand that is coming, and to enable the province to continue to be an exporter of power (*Hydro Québec 2023*).

- In 2024, BC Hydro announced a $36-billion capital expenditure plan (*BC Hydro 2024*) in its own infrastructure and issued the first new call for power from independent producers in 15 years as part of a series of calls, each anticipated to drive $2.3 to $3.6 billion of private investment in generation capacity (*Government of British Columbia 2024*). The Government of British Columbia is also examining how it can prepare its power system for accelerated electrification via initiatives such as its climate-aligned energy action framework and BC Hydro Task Force.

Some provinces are including planning scenarios that consider high rates of electrification (British Columbia, Nova Scotia, Ontario, Alberta). Some are exploring significant expansion of offshore renewables (Nova Scotia, Newfoundland and Labrador). Some are introducing or considering electricity planning and governance reforms (Ontario, Nova Scotia), or intending to produce net zero energy roadmaps that can inform and guide electricity system expansions (Manitoba, New Brunswick).

This progress is encouraging. But if Canada is to prepare its electricity systems for growing demand, governments, utilities, and regulators must expand the scope of this work and accelerate its implementation.

Meeting climate goals in a cost-effective way requires that gas networks stop growing, yet gas utilities continue to lay pipe and add customers

The clean energy transition challenges Canada to take a sober and systematic approach to the switch from gas to electricity in building heating, while ensuring reliable and affordable heating for consumers. As we discuss above, taking the lowest-cost path to achieve Canada's 2050 climate target means it will be necessary to stop expanding gas distribution networks.

The clean energy transition challenges Canada to take a sober and systematic approach to the switch from gas to electricity in building heating.

And yet, across the country, gas utilities are continuing to expand (*see Figure J*).

Regulatory filings that disclose gas utility assets offer a window into the scale of ongoing investment in Canada's gas distribution systems. A gas utility recoups the costs of its regulator-approved assets plus a defined rate of return on these assets from customers. The recouping of costs is spread over the financial lifetime of the assets. For pipelines, for example, this is typically 40 to 50 years. After this time, infrastructure may still be used as long as it is safe to do so, but it has been fully paid off by ratepayers.

The rate base for Canadian gas customers, meaning the assets still to be paid off, reached approximately $29.5 billion in 2022. A growing rate base is one indicator of the extent of ongoing investment in gas utility networks. It includes undepreciated property, plant, and equipment assets, as well as some financial assets.

Over the last decade of available data, the total reported rate base of Canadian gas utilities grew by about $8.5 billion (inflation-adjusted)—a 40 per cent increase[5]. Most of that increase occurred in provinces with large established gas networks, such as Ontario, British Columbia, Alberta, and Saskatchewan (*see Figure J*).

Some of those new assets are pipeline extensions. For example, FortisBC, SaskEnergy, and CentraGas (Manitoba) have collectively added more than 10,000 kilometres of pipeline to their networks since 2013.

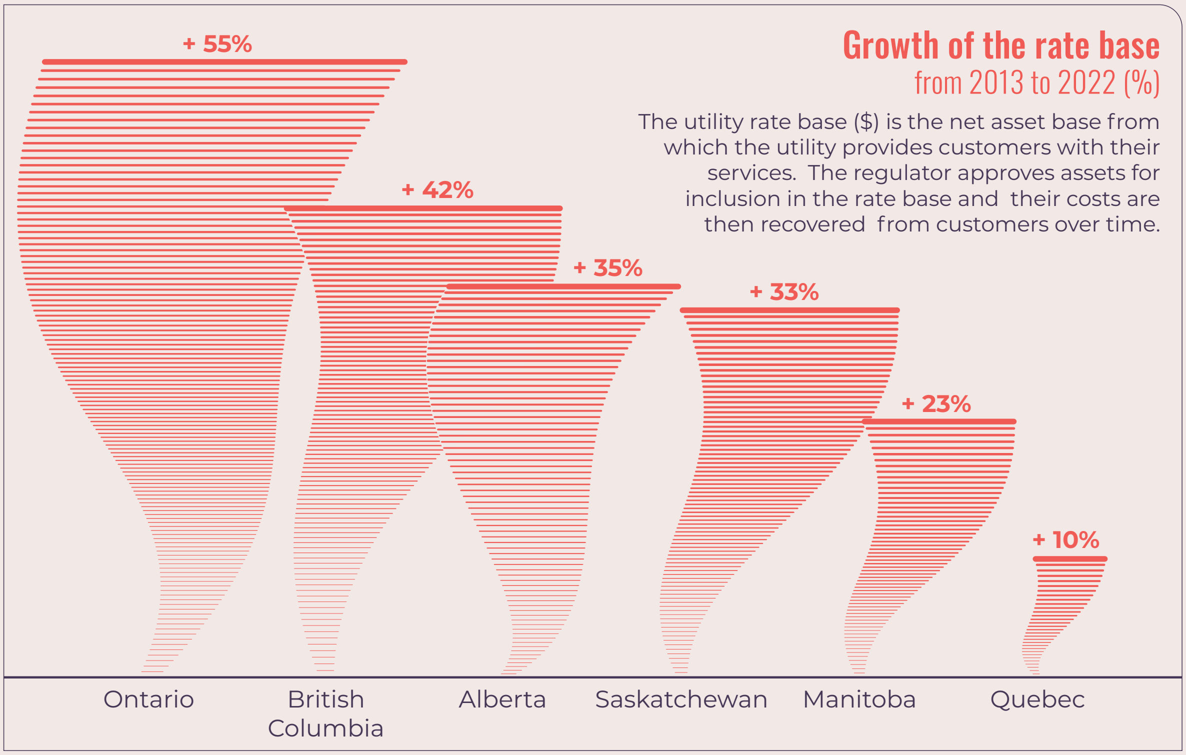
Gas utilities are also steadily growing their customer base. Gas companies across Canada added about 778,000 new customer accounts to their networks between 2013 and 2022, representing 12 per cent growth over that ten-year period.[6]

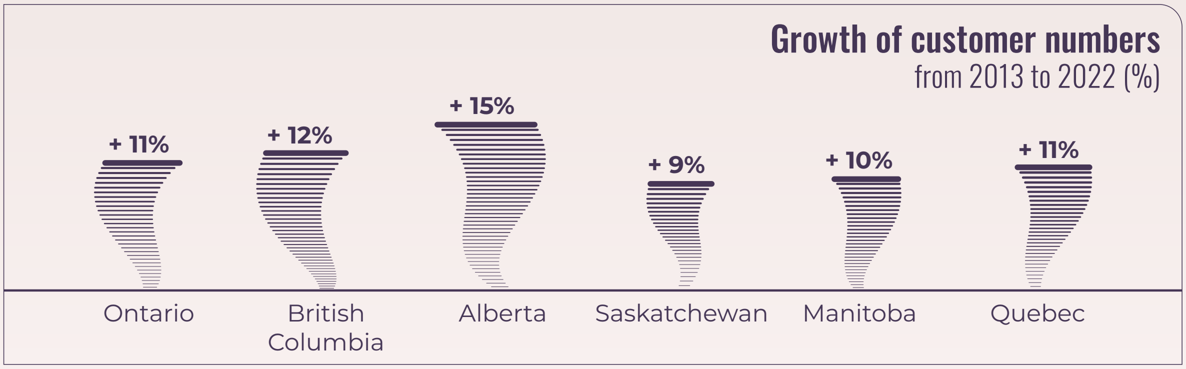
Between 2013 and 2022, FortisBC, British Columbia's largest gas utility, grew by an average of over 13,000 customer accounts each year. And Ontario's gas providers together added an average of 43,600 additional customer accounts per year between 2013 and 2022.

5. *We arrived at our calculations regarding the size and growth over time of rate base assets by consulting regulatory filings with eight regulators and the financial statements of 11 utilities for the years 2013–2020. Information on rate base assets was available for all jurisdictions and years except for 2021–2022 in Manitoba, and 2013–2015 and 2020 in Nova Scotia. For those years, we calculated the average annual growth rate and linearly extrapolated for the missing data points.*
6. *We calculated the growth in customer numbers by consulting the regulatory filings with eight regulators and the sustainability reports and websites of 11 utilities for the years 2013–2022.*

Figure J

Gas networks are growing, increasing costs that must be paid for and maintained by the customer base





2.2 The stakes of being off-track

This trend of continued expansion of gas systems while underinvesting in electricity systems presents risks for both ratepayer affordability and system reliability. If electricity systems do not grow fast enough, and gas networks continue to grow despite uncertainty about their long-term use, Canadian rate-payers face the risk of higher rates, reliability concerns, or both.

Continued gas network growth is creating risk by adding liabilities that must ultimately be paid for

Even as the clean energy transition continues apace, gas utilities are still laying pipelines and growing their distribution networks, despite the looming risk of a declining customer base as more consumers switch to electric heating technologies.

Gas utilities are still laying pipelines and growing their distribution networks, despite the looming risk of a declining customer base as more consumers switch to electric heating technologies.

Because companies amortize their infrastructure investments over decades, infrastructure decisions taken today will affect affordability for consumers now and for decades to come. The broad base of gas customers typically subsidizes new connections to existing gas networks, assuming existing customers will benefit from sharing the fixed costs of the gas network across a larger base. But this only benefits all gas customers so long as the gas customer base keeps growing and new customers continue to use gas for decades after connecting.

For many new connections, the cost is covered by gas ratepayers if the anticipated revenue from the new customer over a given time period (typically, 40 years) is equal to or greater than the cost of connecting them to the gas network and serving them over that time. The cost accounting typically assumes the new customer will stay connected to the system for the full time period. When gas utilities extend their networks into rural regions, however, projected new customer revenue—even when assumed to last over 40 years—will only cover a small part of costs. Direct government support for network expansion has enabled rural expansion in some provinces (for example, Ontario, Alberta, Saskatchewan), where otherwise connections would be uneconomic.

Under these arrangements, there is little incentive for a developer to choose electrification, even where the electric option would be cheaper for the eventual building occupants, since the cost of gas connection is free to the developer and the energy bills are paid by the occupants. But this choice exacerbates risks for gas customers. Should these new customers use less gas than anticipated (for example, by installing a hybrid system down the road) or leave the network before the end of the 40 years' anticipated revenue from their bills, the remaining customer base could be left covering the remaining cost of connecting them to the network through higher rates.

Ongoing network expansion presents significant risk to all provinces with gas systems.

As our analysis in *Section 1* shows, falling gas demand is part of a cost-optimal net zero pathway across all sensitivity analyses. A declining number of gas customers will strain a given gas utility's ability to recover the costs of its historical and ongoing infrastructure investment. This risk of stranded assets is most acute for new investments in infrastructure, such as pipeline replacements and expansions. Newer infrastructure has less accumulated depreciation. Its higher remaining asset values relative to older infrastructure represent higher liabilities for current and future customers to bear, should the assets become stranded due to disuse or underuse before the end of their expected lifetime.

Ongoing network expansion presents significant risk to all provinces with gas systems. However, the extent and age of infrastructure, like the prevalence of gas heating, is highly variable by region. Provinces with newer or recently replaced or expanded systems face higher risks to customer bills as more infrastructure has yet to be paid off. And those provinces with a small user base face an elevated risk that these liabilities will land heavily on remaining customers if and when assets end up stranded. Risks can therefore be especially pronounced for provinces with smaller and newer gas networks, such as New Brunswick and Nova Scotia.

Underinvesting in electricity systems compromises Canada's climate targets, energy reliability, and economic opportunities

Canadian electricity systems that do not prepare for their customers' evolving energy needs—including improving their resilience to intensifying climate-related impacts—could be prone to service disruptions and additional costs to ratepayers while pushing Canada's climate targets out of reach.

Faster-than-expected electrification has already driven some Canadian electricity utilities—for example, BC Hydro and Newfoundland and Labrador Hydro—to update their forecasts and undertake new planning ahead of schedule (*Butler 2024*). Demand for and competition over new electricity supply has never been stronger, and provincial governments are already having to make choices about who gets access. In 2023, Quebec moved to a selective process for industrial connection requests above five megawatts (*Government of Québec 2023b*; *The Canadian Press 2023*) while British Columbia recently suspended connection requests from cryptocurrency miners (*Government of British Columbia 2022*).

Prompt, clear, and decisive policy, coupled with strong future-proofing of grid investments, can unlock opportunities, reduce overall costs, and smooth the energy transition.

If demand outpaces system growth, then these tensions will only grow. They could also lead to lost economic opportunities. Less clean electricity available for new industrial demand could drive investment abroad, as industries increasingly make access to reliable and affordable clean power a condition of their investment in Canada (*Beugin and Gullo 2022*).

Prompt, clear, and decisive policy, coupled with strong future-proofing of grid investments, can unlock opportunities, reduce overall costs, and smooth the energy transition—avoiding a more abrupt shift further down the road (*Bataille et al. 2015*). Absent these proactive moves, Canadian electricity systems' ability to continue to support Canada's clean energy transition while continuing to deliver reliable, affordable service will be strained.

An incremental approach to the transition risks elevating costs, introducing reliability issues, and locking in dead-end pathways

Some actions that are being implemented or piloted today—such as more energy-efficient gas furnaces and blending modest percentages of biomethane or hydrogen—may reduce emissions somewhat in the short-to-medium term. But not every action that reduces greenhouse gas emissions in the near term is necessarily compatible with the long-term goal of reaching net zero in a cost-effective way.

Not every action that reduces greenhouse gas emissions in the near term is necessarily compatible with the long-term goal.

Strategies that only reduce emissions incrementally can be a dead-end pathway (*Net-Zero Advisory Body 2020*). If the choice of pathway does not drive the necessary transformations of the electric and gas systems nor sufficiently increase adoption of needed end-use technologies, it can deepen the commitment to a system that does not meet the need for deep emissions reductions and is incompatible with Canada's clean energy transition.

Continued inertia and a lack of bold action carries significant risk. Either Canada fails to deliver on its international commitment to reduce greenhouse gas emissions, or Canadians effectively pay twice: once for incremental and insufficient solutions, and again to eventually correct course and build out the necessary infrastructure.

SECTION 03

Limitations of existing policy and institutions

This section explores why the trends we discuss in Section 2 are unlikely to change under current policy and regulatory approaches, and elaborates the risks that continued inertia poses to Canada's climate goals and the success of its energy transition.

The bulk of the policy discussion in this report is focused on provincial governments. Reaching net zero for building heat in the territories has particular opportunities and challenges that are not covered here in detail.[7]

3.1 Limitations of current climate policy

Climate policy is making a difference in the buildings sector. Without it, greenhouse gas emissions from building heat would be even higher, and fewer Canadians would have access to the cost savings and other benefits of energy retrofits and cleaner technologies. But to date, climate policy has not been sufficient to get the buildings sector on track to meet Canada's climate goals.

Existing climate policies are insufficient to address rising emissions from the buildings sector

A suite of federal, provincial, and territorial policies encourage Canadians to heat their homes and businesses more efficiently and switch from fossil fuels to electricity. But gaps remain, and implementation is fragmented and slow. Economy-wide climate targets, plans, and policies are in place in some places and not others, and often lack consistency and specificity.

7. *The implications of the clean energy transition on Indigenous communities, particularly in remote settings, is also not addressed in detail in this report. Forthcoming work from the Institute, in partnership with Indigenous Clean Energy, will address some elements of this issue. Healthy Energy Homes will explore ways to improve housing stock in Indigenous communities in order to address poor Indigenous health outcomes, reduce emissions, and support reconciliation (Canadian Climate Institute n.d.).*

In the context of a cost-effective pathway to net zero, existing policies fall short in four main ways:

1. **Limited adoption and implementation of climate targets.** While the federal government has legislated its commitment to net zero by 2050 (*see Box 1*), only a handful of provinces have followed suit (*Linden-Fraser 2024*). Notable examples include Prince Edward Island, Nova Scotia, and British Columbia; however, British Columbia's legislation currently only requires the province to reduce greenhouse gas emissions 80 per cent by 2050 (*Government of Prince Edward Island 2024*; *Environmental Goals and Climate Change Reduction Act, Nova Scotia 2021, c.20.*, *Climate Change Accountability Act, Statutes of British Columbia 2007, c.42*). Where provincial and territorial targets exist, they aren't necessarily connected to clear plans, and provincial and territorial climate plans often lack detail on the necessary changes in energy use.

2. **Policy inconsistency.** Demand-side policies focused on building electrification are a patchwork, and rebates for energy retrofits and heat pumps vary significantly by province and by municipality. Policies that support energy efficiency and electrification in buildings, such as net zero building codes, building performance standards, and supports for heat pumps, are common in provinces with strong climate commitments (for example, British Columbia's Zero Carbon Step Code, and strong heat pump incentive program uptake in the Maritimes) (*Glave and Wark 2019, Turner 2023*). But overall, policy implementation is a mixed bag across much of Canada, with gaps in access.

3. **Policy uncertainty.** Existing programs, such as rebates for energy retrofits, are often funded for short terms. The stop-start pattern of incentive programs makes it difficult to maintain momentum in consumer demand and to maintain the ability of heating, ventilation, air conditioning, and retrofit industries to respond (*Miller et al. 2023*). Broader policies such as carbon pricing, which would drive increased electrification, rarely look further than a decade down the road, whereas purchases of energy-using equipment and the planning of gas and electricity systems routinely carry implications well beyond that time horizon.

4. **Limited attention to gas system infrastructure.** Little to no policy focuses directly on limiting the build-out of gas supply infrastructure to avoid stranded assets and protect future ratepayers. Some municipalities (for example, the municipalities of Greater Montreal and the City of Prévost) have started to prohibit gas hookups to new builds, but progress is slow and

can be contested by gas utilities (*Communauté métropolitaine de Montréal 2024*; *Le Devoir 2023*). In some cases, policy is even pushing in the opposite direction, encouraging more and continued gas use. For example, some governments continue to subsidize gas network expansion. Since 1973, the Government of Alberta has funded the Rural Gas Grant program, which offsets the cost of providing new rural agricultural and domestic gas service (*Federation of Alberta Gas Co-ops Ltd. 2022*). In 2021, the Government of Ontario announced a $234 million expenditure on expanding the gas distribution system, connecting 43 communities to the gas network at a cost of $26,700 per connected household (*Government of Ontario 2019*; *Government of Ontario 2021*).

Climate policies alone are likely not enough to drive change in regulated energy systems

In less regulated markets, government climate targets and policies would send a strong market signal, influencing investment decisions and shifting businesses and households onto a lower-carbon path. But the business of providing gas and electricity is tightly enabled and constrained by utility regulation.

Energy utilities provide essential services. Recognizing that they are natural monopolies, regulatory oversight is in place to ensure their services are delivered reliably and at a fair cost. This means that the regulators that oversee energy utilities, and the rules that enable and constrain those regulators, play an important role in either amplifying or constraining the market signals from climate policies.

Even with stronger demand-side climate policies, action focused only on end-use consumers is unlikely to transform the electricity and gas systems to the extent needed to align the provision of building heat with net zero. Demand-side policies and falling clean-technology costs may accelerate building electrification, but on the supply side, traditional regulatory approaches risk the continuing growth of gas networks and the insufficient growth of electricity grids.

3.2 Limitations of current utility regulation

Utility regulation will play an important role in determining the pace and cost of the clean energy transition for building heat. But provincial and territorial governments haven't fully prepared their utility regulators for that task. The extent of change required to switch building heat from fossil fuels to clean energy, combined with the fact that regulator mandates and practices predate the age of climate action, mean that the laws, regulations, and policies that determine energy utility oversight can be ill-suited to the needs of the energy transition, and even act as a barrier to it.

The long life of energy equipment and infrastructure means that decisions made today have long-lasting repercussions.

While the energy transition will play out over decades, the decisions that regulators are making today will have long-lived significance. Consider that the average Canadian household will purchase a new vehicle every eight years. That same family's furnace or heat pump could last for 20 to 30 years. The lifetime of a gas pipeline is even longer: a new or replaced pipe is paid off over 40 or 50 years and can often keep functioning past that time. The long life of energy equipment and infrastructure means that decisions made today, particularly in gas systems, have long-lasting repercussions.

Slow and steady growth in demand for gas and electricity has been a foundational expectation of energy utilities for decades, but that assumption does not hold for the clean energy transition

Canada's ability to meet its climate goals rests not only on climate policy that is focused on energy consumers, but also on provincial regulatory policy that is focused on the utilities that supply those consumers. Both energy utilities and the regulators that oversee them wield significant influence over the kinds of energy supplied and the way Canadians pay for it. (*See Box 2*: Energy utility regulation in Canada.)

In Canada, gas and electricity utilities are governed by business models and decision-making processes that have for decades operated under conditions of assumed slow, steady, and predictable demand growth. Decarbonizing building heat upends this foundational assumption. It challenges an approach to utility regulation and gas network investment cost recovery that assumes that gas demand will continue to increase indefinitely. And it presents significant challenges related to the need to rapidly build out the electricity system to meet rising demand.

Regulators are not adequately equipped to guide utilities through the clean energy transition

Since the 1960s, utility regulators have relied on the Bonbright Principles—named after economist James C. Bonbright—to guide their high-level decision making. The principles focus on cost-based pricing, avoiding a socially undesirable expansion of the rate base, ensuring infrastructure will be used and useful, providing a fair return for utilities (with stability and predictability of business), ensuring just and reasonable rates for consumers, and avoiding undue discrimination between different classes and types of consumers (*Bonbright 1960*).

These long-standing tenets remain relevant today, even as regulators may need to reinterpret some elements to guide decision making in the context of Canada's energy transition (*Utilis Consulting 2023*). For example, regulators have long considered what is fair—not only to current customers, but also to future ratepayers. Re-interpretation of this principle for the clean energy transition requires regulators to consider fairness over timescales of multiple decades, recognizing the potential impacts of today's decision on evolving risk for future ratepayers.

However, while the Bonbright Principles can be consistent with the needs of the energy transition, their application in this context starts to raise difficult questions that require policy guidance from governments. For example, regulators determine whether proposed asset investments are prudent or unwise, and approve calculations, such as depreciation schedules, based on the expected used and useful lifetime of those assets. But the energy transition raises fundamental questions about these assumed lifetimes.

Box 2

Energy utility regulation in Canada

In much of the country, gas and electricity—and, in some provinces, energy efficiency services—are provided by regulated utilities. Though the provinces differ in their approach to utility regulation, regulator mandates and responsibilities tend to include some common elements.

Regulators are responsible for ensuring energy utilities provide safe and reliable energy at a just and reasonable cost to the ratepayer. Because utilities holding regional monopolies generally operate electric and gas grids, regulators act as a proxy for the competitive market. (One notable exception to this is Alberta, which has a competitive electricity-generation market. Ontario also has some elements of a competitive market for generation). Regulators' focus is primarily economic, ensuring both a fair rate of return for utilities and reasonable rates and reliable service for the customers they serve.

In the regulated aspects of their business (for example, the delivery of electricity and/or gas to customers), utilities earn a predetermined return on investments that the regulator agrees are prudent. Under this structure, regulators play a crucial role in determining what investments utilities are approved to make in the energy system.

Regulators are mostly independent agencies, but cannot exceed their legislated mandate.[8] A provincial or territorial government establishes a regulator's authority through legislation, as well as orders and directives; these can be, and have been, amended over time. A regulator can exercise discretion, but only within its prescribed mandate. If a utility perceives that the regulator has overstepped or failed to fulfill its mandate, it has the right to appeal.

Regulators deliver on their mandate through a quasi-judicial process that considers and balances the parties' competing needs. Proceedings are typically case-by-case and utility-by-utility, but can also involve more general lines of inquiry.

8. *Saskatchewan is an exception. The province has two Crown corporations—SaskPower for electricity and SaskEnergy for gas. An appointed Rate Review Panel makes rate change recommendations for both utilities to the provincial Cabinet, which issues final decisions. The system does not have the same hearings and processes as other Canadian regulators.*

Shortening them pulls costs forward in time, increasing costs today but limiting the risk that a smaller pool of future ratepayers are left paying high costs for infrastructure they no longer use. In the absence of clear direction from government on these questions, regulators have to date proceeded with caution.

In at least three key respects, the limitations of existing regulatory frameworks and the lack of guidance from governments constrain both energy utilities and regulators from enacting plans and making decisions consistent with a cost-optimal net zero pathway:

1. **Policy uncertainty:** While regulatory best practices prioritize consideration of future ratepayers, a lack of clear policy direction is contributing to inertia. Provincial and territorial economy-wide climate plans and targets often lack the clarity that regulators need to guide decision making. And even where climate targets exist, uncertainty with respect to their implications for future demand for electricity and gas infrastructure (for example, when gas utilities propose use of biomethane or hydrogen in the pipelines) can leave regulators without a sufficient evidence base to make decisions consistent with climate targets. A core component of this policy uncertainty is the inherent uncertainty of the energy transition itself. Even with a net zero mandate, regulators may not have sufficient basis to change their approach without guidance from the provincial government on available pathways and energy system priorities.

2. **Limited mandate:** Regulators tend to have mandates that focus primarily on safety, reliability, and economic efficiency. Climate objectives, which did not exist when these mandates were set, are typically interpreted as being out of scope, unless a government clearly specifies them in policy, legislation, or other guidance. This scenario leads regulators to exercise caution when evaluating future infrastructure needs that involve a significant departure from the status quo in service of climate goals. Yet, in the energy transition, innovation and a departure from status quo approaches are likely necessary to protect long-term energy affordability for ratepayers.

3. **Fragmented decision making:** Regulatory proceedings typically consider individual cases regarding specific utilities. A broader assessment of system-level dynamics would require regulators to consider a future where electric and gas energy systems follow opposite trajectories, with demand for the former growing and the latter declining. The lack of an integrated perspective constraints regulators' capacity to manage an energy transition with deep implications for both systems. And existing practices can

also exacerbate this fragmented decision making. For example, the legal requirement to connect gas customers upon request—often included as part of the obligation to serve—presumes and perpetuates the ongoing expansion of the gas network. Requirements are often linked to distance from existing infrastructure, but can snowball as each connection or reconnection expands the area of obligation.[9]

Current regulatory processes can leave promising solutions unconsidered

Under current frameworks, energy utilities generally bring solutions to their regulators for review, and propose initiatives and investments that focus on their operations. This approach can fail to surface alternative services delivered by the competitive market, and more distributed, customer-oriented solutions such as household energy storage and thermal energy networks.

Managing peak demand mitigates costs for the whole system, but under current regulatory systems, clean-energy approaches to peak shaving and load shifting risk falling through the cracks. Some of these solutions—particularly those that depend on access to distributed energy resources such as demand-response programs and virtual power plants—may be provided by non-utility actors, such as aggregators.[10] These parties may have limited avenues to propose their solutions, or their solutions may rely on innovations and support from utilities that are not currently incentivized to provide them.

If regulators are only ruling on utility-proposed solutions, the outcomes may not always be cost-optimal. For example, under current incentives low-emission gases and hybrid heat solutions are sure to be more attractive to gas utilities than full electrification and alternative approaches to peak management—but may not always be in the best interests of ratepayers or the energy system writ large.

9. *An example of an obligation to serve in British Columbia: "On being requested by the owner or occupier of the premises to do so, a public utility must supply its service to premises that are located within 200 metres of its supply line or any lesser distance that the commission prescribes suitable for that purpose" (Utilities Commission Act, British Columbia 1996, c.473 , Part 28).*

10. *Aggregators bundle together resources from many smaller distributed energy resources (such as residential solar panels or batteries) to act as a virtual power plant, and then sell either the electricity or a service (such as energy storage, or ability to deliver during peak time) to a utility (IRENA 2019, Brehm et al. 2023).*

3.3 Why status quo inertia puts the energy transition at risk

The limitations of climate policy and utility regulation discussed above interact to sustain a status quo trajectory for building heat that does not align with a cost-optimal path to net zero. It points instead to rising greenhouse gas emissions, growing gas networks, and electricity systems that aren't growing fast enough.

Gas utility business models are predicated on network expansion

Gas utilities' existing business models and current regulatory structures mean that their incentives can be at odds with maintaining future bill affordability for consumers in the context of the energy transition. Because gas utilities realize returns based on the infrastructure they install rather than the fuel they sell, they have a direct economic incentive to pursue continued growth of gas infrastructure and new customers—even if the long-term usage case is uncertain.

In the regulated segments of their business, gas utilities are largely insulated from most market signals—including the prospect of declining gas demand. A gas utility will pass some of its costs—including the cost of the gas itself, and carbon price costs—straight through to its customers. The gas utility's profits do not depend directly on gas sales volumes. As long as a gas utility's distribution networks remain in place, customers remain connected to them, and the gas utility can still recover its fixed costs through rates, a decline in sold gas volume—for example, from some customers converting to hybrid heat—is not an immediate threat to the underlying business model.

A gas utility earns its profits via a predetermined rate of return on its infrastructure investments as approved by the regulator. To secure approval, utilities must convince the regulator that new infrastructure will be necessary and useful. But once infrastructure is approved, utilities can be reasonably assured they will earn a return on it even if that usage case does not bear out.

The regulator can serve as a check against the accrual of excessive liabilities in the form of infrastructure that does not prove sufficiently used and useful over its lifetime. But regulators are not only required to protect customers from rate increases; they must also protect utilities' ability to maintain an adequate business and support the level of investment that is required for continued provision of energy services. They must also provide the opportunity for gas utilities to earn a reasonable rate of return, and can only stop or delay adding new investment to customer bills if such investment is shown to be imprudent—for example, if it will be underused or is more expensive than an alternative. As we discuss above, regulators are often constrained in their ability to make these kinds of assessments in the context of the energy transition.

In a less regulated sector, market signals would reduce the incentive that companies would have to pursue a strategy of continued network expansion in the face of potential demand declines.

In a less regulated sector, market signals would reduce the incentive that companies would have to pursue a strategy of continued network expansion in the face of potential demand declines. But gas utilities are partially insulated from these kinds of signals. They therefore have a strong incentive to advocate for pathways that require ongoing system maintenance or expansion—such as hybrid heating or a shift towards low-emission gases.

Fewer new customers and a declining customer base in the future is the primary concern for gas utilities under their current business model, but falling gas demand in terms of total volume does create some challenges under existing gas rate design. Historically, fixed costs have been partly included in variable consumer charges for reasons of consumer preference and to avoid a regressive pricing model that disproportionately affects lower-income consumers. With declining gas usage, however, gas utilities will eventually need to seek approval to modify their rate structures or seek public subsidies to recover the costs of increasingly underutilized assets.

Gas utilities will likely continue to focus on expanding their networks because regulatory models limit their ability to diversify

Legislation typically limits the activities of regulated gas utilities to building and operating gas infrastructure and certain associated demand-side management initiatives. This restricts their ability to diversify in the face of declining gas demand.[11]

Gas utility companies can conduct other business under separate competitive arms. But the stable, regulated rates of return are reserved only for the regulated parts of the utility's business to ensure continued capital investment in the utility's core mandate of reliable service delivery.[12]

Regulators in different jurisdictions have variously interpreted gas utility attempts to establish new lines of business. For example:

- In the past, citing competition, regulators such as the British Columbia Utilities Commission excluded alternate energy services, such as thermal energy networks, from the gas utility's regulated business (*BCUC 2012: page 60*). The regulatory framework guidelines for thermal energy networks, are however currently under review in British Columbia (*BCUC n.d.*).

- In some regions, gas utilities can generate revenue by delivering demand-side management and energy efficiency programs through performance-based incentives. However, in other regions (Nova Scotia, New Brunswick, Manitoba), distinct entities or utilities deliver those programs.

- In British Columbia, the province's gas utility includes various biomethane investments in the regulated part of its business, enabling a return for the utility on their investment (*Fortis 2023*). But Ontario's regulator already considers biomethane a competitive space—thus excluding it from gas utilities' regulated business (*OEB 2009*).

11. *Some gas utilities in the United States have started to explore diversification options to better position themselves in the clean energy transition. For example, Philadelphia Gas Works, a municipally owned gas utility, commissioned a study on their potential to diversify (Energy + Environmental Economics et al. 2021); Eversource in Massachusetts is piloting networked geothermal systems; and Vermont Gas has started to lease electric heat pumps and hot water heaters to customers as part of their business.*

12. *Regulators also ensure the unregulated business does not receive any undue advantage from the regulated business; operations, financing and resourcing must be kept separate.*

— In Ontario, Enbridge tried to increase their role in electrification by including heat pumps in their rate base, but was denied by the regulator (*OEB 2021*). Traditionally, gas utilities must focus on savings to their own customer base. The system is not designed to consider broader cost savings from fuel-switching for the consumer (who is now no longer a gas customer), for the overall energy system, or for other parts of the economy.

Each jurisdiction is exploring and interpreting how these potential new regulated activities interact with current lines of business, and what they mean for protecting ratepayer interests. While there is likely a case to be made for a departure from the status quo, policymakers and regulators will need to carefully consider what changes are in the public interest and which add cost and unnecessarily crowd out private sector efforts.

Electric utilities lack incentives to support electrification and expand systems to meet growing demand

While the regulatory framework for the electricity system is more closely aligned with achieving net zero than it is for gas, there is still room to improve, for example by increasing flexibility for electric utilities to make innovative proposals for investments and rate design, and by enabling electric utility planning to be more responsive to evolving conditions (*Utilis Consulting 2023*).

Policymakers and regulators have not yet fully directed, empowered, or incentivized electric utilities to prepare for the increasing demand for power that electrification will drive.

An electric utility interested in enabling electrification must justify any associated expenditure to its regulator based on the benefit the investment will provide to its own customers and electricity system. Investment in new capacity can put upward pressure on electricity rates, and detailed project-by-project oversight for new electricity capacity is in place to protect ratepayers from imprudent investments. But because current regulatory structures limit electric utilities' ability to include progress toward climate goals and savings for gas consumers as benefits of proposed investments, these utilities can only play a limited role in directly supporting or enabling electrification.

As electricity utilities enter a new era in which they are widely understood to be lead actors in the energy transition, the growth imperative to handle widespread electrification can clash with an investment approach that has grown to prioritize caution to pass regulatory approval. Historically, some Canadian electric utilities have faced public scrutiny for building or planning to build capacity in anticipation of load that did not materialize. For example, in 2013, Manitoba Hydro's Conawapa hydro project was cancelled after a panel review concluded that their long-term projections were too uncertain (*McClearn 2022*).

Finally, the energy transition stands to shift the dynamic between gas and electricity utilities, which are both governed by the same energy regulator. After years of operating in parallel in contexts where they provide mostly distinct services, in certain regions and in some respects, they are now competing for market share. The best example of this may be the rivalry brewing between heat pumps and gas furnaces, and the implications each has for gas versus electric utilities. Challengingly, the energy transition also opens up other areas that may require more explicit collaboration, such as load forecasting or planning for hybrid systems.

Under declining gas demand, regulators' ability to protect ratepayers will face unprecedented challenges

The energy transition presents new challenges to regulators' longstanding mandates to make sure utilities provide Canadians with safe and reliable energy at just and reasonable rates.

A first challenge comes from falling gas demand, resulting in fewer customers on the gas system and increased rates for those who remain.

Under current policies and market conditions, consumer uptake of heat pumps is on the rise (*Turner 2023*; *Kanduth 2023*). And in many housing types and regions across Canada, heat pumps already save consumers money over their lifetimes compared to gas or oil furnaces and air conditioning (*Miller et al. 2023*; *McDiarmid 2022b*). Where efficient electric technologies, driven by climate policies and market forces, outcompete gas on a cost basis, households and businesses will increasingly switch to electric options. And, where they can, they may increasingly defect from the gas network altogether to avoid paying connection fees. If gas consumption continues to contract, the smaller number of customers that still rely on gas will shoulder the fixed costs of maintaining the network. And if the exodus from gas heat accelerates, absent policy intervention, the customers with the fewest financial resources or wherewithal to switch will find themselves stuck on the system and bearing escalating gas rates.

A scenario of falling gas demand and customer numbers also creates financial and competitiveness risks for gas-consuming businesses. For technical or financial reasons, some industrial customers, such as steel, cement, and chemical plants, may not be able to electrify as readily or as quickly as others. As residential and commercial demand declines, remaining industrial customers may need to pay more of the fixed costs to maintain the gas network.

Left unchecked, customer defection could significantly accelerate a rise in gas rates, and financial markets may contribute to it. Some lenders are starting to consider the potential risks associated with a long-term reduction in gas use. In reviewing the capital structure of Enbridge Gas, for example, a recent Ontario Energy Utility Board-commissioned assessment flagged that the utility's investors and credit rating agencies are "widely recognizing the potential long term reduction in natural gas use" (*LEI 2023*). That perception of increased risk could translate to higher debt costs for gas utilities, resulting in rate increases and the potential for further customer defection.

The second challenge relates to stranded assets. Where assets are no longer used, any number of actors could be left with their stranded costs, including:

- Future customers, if regulators and governments allow gas utilities to leave stranded costs in the rate base—even though they are no longer used.
- Current customers, if regulators accelerate depreciation of these assets.
- Shareholders, if regulators remove these costs from the rate base.
- Canadians, if governments compensate shareholders for the early retirement of otherwise useful assets, either as a proactive measure or a consequence of litigation.

However the costs are distributed across these groups, the prospect of stranded assets raises complex issues of incentives and fairness. To protect system reliability for remaining gas customers while shielding them from costly rate increases, regulators may need new approaches.

As we discuss in *Box 3*, even options such as hybrid heat systems that could maintain a significant customer base in the gas system raise difficult questions for regulators.

Box 3

For hybrid systems to play a larger role, regulators and utilities face a difficult balancing act

Hybrid systems could play a role in the clean energy transition in some contexts, particularly as a stepping stone to electrification. But implementation is not straightforward.

A regulator or government would likely need to introduce a subsidy of some kind to sustain interest in hybrid systems at scale, since customers would need an ongoing incentive to stay connected to the gas network even while they are using very low volumes of fuel. (An alternative approach would be to use delivered bottled fuel for gas backup.)

Rate design to support hybrid system uptake is a balancing act. It typically must incorporate subsidies to recover gas network costs in a context where gas customers are using minimal gas, while still discouraging customers from using it as their primary heating fuel. Gas service bills include both fixed costs (for example, recovering the cost of building and maintaining gas pipelines) and variable costs (for example, the cost of the gas sold). In most regions, a bill's variable charges partially cover fixed costs. Risk of consumer disconnection from the gas network grows as fixed costs increase (which is to be expected under a widespread shift to hybrid heat), as customers will likely prove reluctant to pay high fixed costs for minimal service, particularly during the warm-weather seasons when their heating system is off (*RMI 2022*).

Several Canadian utilities are testing strategies to incentivize and accommodate consumer adoption of hybrid heating. Hybrid heat initiatives to date include a collaboration between Hydro Québec and Énergir (*Séguin and Bigouret 2023*), and a pilot by Fortis BC in a region where they supply both electricity and gas (*FortisBC 2024*). In Quebec, Hydro Quebec led the way by agreeing to pay Energir $2.4 billion to convert customers to hybrid systems, in compensation for lost gas-ratepayer revenue. They sought regulator approval to reclaim costs from electricity ratepayers on the basis that keeping gas systems for back up during cold periods can reduce pressure on Hydro Quebec's grid.

Box 3 (continued)

In the pilot programs designed to date, electricity rates essentially cross-subsidize gas rates to help cover peak service demand.

However, several issues arise:

REGULATORY UNCERTAINTY

This use of cross-subsidization is a new approach, which comes with uncertainty over whether the regulator will allow costs that are outside of typical electricity distribution service expenses to be reclaimed from electricity customers (*Baril 2023*).

COST OPTIMIZATION

It is not guaranteed that such arrangements are cost-optimal from an integrated energy system perspective. Regulators could, and should, require the value of investments in hybrid heat to be demonstrated compared to other peak management alternatives, and regulators in different jurisdictions, or considering different situations, could make different decisions.

DISTORTED INCENTIVES

Allocating more costs to electricity rates can disincentivize business and household electrification.

EQUITY IMPACTS

On average, cross-subsidies may benefit higher-income households more than lower-income households. The type of heating system used in Canadian homes correlates with income, and with ownership status. On average, higher-income, home-owning Canadian households are more likely to heat with gas, and lower-income and renting households are more likely to heat with electricity. Only 28 per cent of Canadians in the lowest income quintile heat their homes with gas, compared to 56 per cent of homeowners in the highest bracket. This split is also similar between renters (27 per cent gas) and homeowners (52 per cent gas) (*Statistics Canada 2023*).

3.4 Continuing with business-as-usual utility regulation in the energy transition is risky

Current approaches to utility regulation are not well-equipped for the needs of the energy transition. Continuing with the status quo despite its limitations risks raising long-term costs for ratepayers and jeopardizes a cost-effective clean energy transition in Canada.

Ultimately, someone must pay for the costs of maintaining gas networks and stranded assets within them.

On the electricity side, delayed action on needed investments raises risk for Canadian households and businesses. Should increasing consumer demand for electric technologies outpace changes to the electricity system, it could strain reliability, significantly exacerbate costs, or both. These risks exist for both generation capacity build-out as well as the necessary investments to manage peaks and improve reliability, including infrastructure upgrades, energy and heat storage, energy efficiency, and demand management.

On the gas side, status quo utility regulation and the inertia in gas system expansion that it drives also carries significant risk. Ultimately, someone must pay for the costs of maintaining gas networks and stranded assets within them. Without policy intervention, ongoing investment in an increasingly underutilized gas system will yield higher costs for remaining gas consumers.

And this new context where gas and electricity utilities potentially find themselves in competition and/or collaboration may challenge regulators' ability to protect the public interest.

Letting competition play out between gas and electricity utilities will not necessarily yield favourable outcomes for ratepayers under status quo approaches. For example, a transition in which gas network defection occurs organically rather than being steered through novel rate designs and conscientious system planning could lead to electricity demand peaks that the system is poorly prepared for, to gas networks with wide distribution that only serve sporadic customers at high costs, or both.

On the other hand, explicit cooperation between gas and electric utilities might not necessarily prove optimal for ratepayers. For example, companies may negotiate cross-subsidies that allow them to maintain their current business models and infrastructure, but that may ultimately result in higher overall costs to ratepayers when compared with a future of growing electricity networks and shrinking gas networks. Utilities may also work to protect their regulated markets and limit opportunities for new actors, such as energy service companies, which risks raising costs for consumers.

If utility regulators are to continue delivering on their mandate of providing safe and reliable energy at just and reasonable rates, provincial governments must equip them to face the new challenges of the energy transition head-on. Regulators have a great deal of power to shape the future of Canada's energy system, including addressing the question of who will pay for it. If provincial governments do not enable regulators to exercise their influence in the service of meeting Canada's climate goals, they risk costlier pathways, worsening affordability, and failure to achieve our climate commitments.

SECTION 04

Opportunities for policy to drive change

Despite the significant barriers laid out in the last section, regulators and governments have tools at their disposal to align Canada's gas and electricity systems with a cost-effective pathway to net zero. This section outlines ways that regulatory action and government policy, particularly from provincial and territorial governments, can counteract the prevailing inertia.

4.1 Existing options and recent developments

Regulators and policymakers in Canada have policy tools they could use today to start planning more proactively for a clean energy transition for building heat. In just the past year, we note examples of regulators and policymakers in Canada starting to change the status quo using their existing tools, and even more examples of regulators and policymakers in the United States contending with the same issues.

Regulators have tools under existing authority to navigate the energy transition

Though the specifics vary by jurisdiction, broadly speaking, provinces and territories have endowed regulators with powers and responsibilities to oversee energy system planning that will be valuable through the clean energy transition. With current mandates, energy utility regulators may be able to:

- Initiate consultations, inquiries, or even general proceedings on the future of the gas network in their province. No Canadian regulator has done so yet, but in the United States, at least 10 regulators have opened such proceedings since 2020 (*Bagdanov 2022*). Massachusetts' regulator was the first to issue a decision in 2023 (*See Box 3*).

- When evaluating rate filings and decision processes for utilities' capital plans, request more detailed risk assessments on the potential for, and implications of, a declining gas customer base, a significant drop in demand per customer, and increasing electricity demand.

- Increase information sharing and insights on the implications of the energy transition, emerging technologies, and changing consumer behaviours for regulators' core responsibilities to ensure fairness and protect ratepayers, for example through the Canadian association of energy and utility regulators (CAMPUT).

- Consider new business and remuneration models and rate designs that reflect the needs of the evolving energy system and the implications of overlap in the energy services supplied by gas and electric utilities (*Seguin & Bigouret 2023*).

Under declining gas demand, regulators can also limit future liabilities from the gas network and better align its scale with the future customer base. Where prudent, regulators can act to prevent or constrain new gas infrastructure construction by:

- Denying approvals for new gas pipelines, and capacity expansions for existing lines, based on the expected fall in gas demand over the infrastructure's lifespan. For example, in December 2023, the British Columbia Utilities Commission (BCUC) denied a gas utility's request to invest in gas capacity expansion in the Okanagan on the basis that increasing gas demand could not be assured. The BCUC directed the utility to respond by July 2024, and show consideration of alternatives (*BCUC 2023*). The Ontario Energy Board had previously signalled concern around the risk of stranded assets when it denied a replacement pipeline in Ottawa in 2022 (*Beer 2023*).

- Extending the useful life of the existing network as far as safe and practical, to restrain growth in the remaining value of assets that still need to be paid for. For example, in a December 2023 decision, the Ontario Energy Board directed the gas utility to emphasize monitoring, repairing, and, in general, extending the life of its system, and ensure that it only pursues the most critical replacement projects (*OEB 2023*).

- Requiring cost-benefit comparison of new gas pipelines against packages of non-pipeline alternatives, such as targeted fuel switching and energy efficiency, thermal energy networks, and temporary supply-side measures such as bottled gas. For example, the Colorado Public Utilities Commission requires utilities with a customer base greater than 500,000 households to analyze at least five non-pipeline alternatives (*Sullivan and Murphy 2024*; *Nelson et al. 2023*).

Box 4 The future of gas in Massachusetts

In 2023, Massachusetts' Public Utilities Commission became the first American regulator to issue a ruling on their Future of Gas Proceeding (*Massachusetts Department of Public Utilities 2023*). After a three-year-long process, the gas regulator ruled that gas utilities must:

- file climate compliance plans with performance metrics every five years;
- study the feasibility of targeted electrification in the state; and
- demonstrate consideration of non-gas alternatives when proposing to replace or expand gas infrastructure

The regulator also ruled that gas utilities cannot use ratepayer money to promote gas use.

The regulator ruled out a significant role for biomethane due to cost and availability concerns. It also ruled out the use of hydrogen as a primary fuel source for home heating due to uncertainty and competition for use with other sectors. The regulator was not convinced that a broad hybrid heating strategy, funded by ratepayers, was viable, but hybrid heat was not explicitly disallowed.

Similar proceedings are currently underway in Oregon, Washington, Nevada, Colorado, Minnesota, Rhode Island, New York, and California (*Advanced Energy United 2023*; *Eversource n.d.*; *Gridworks 2021*; *California Public Utilities Commission 2022*; *California Public Utilities Commission 2023*; *Mihaly 2023*; *NYSERDA 2022*; *Colorado Public Utilities Commission 2022*; *Colorado General Assembly 2021*; *Vermont Public Utility Commission 2023*; *Cosgrove 2022*).

When approving new gas infrastructure, regulators can reduce risk and improve incentives by adopting accounting practices that assume lower usage and shorter potential lifetimes, and clarify who will pay the bill for the proposed project. For example, regulators could:

- Require builders and developers to pay for new gas connections that would serve their projects, rather than subsidizing the work from future ratepayers on anticipated 40-year revenues. For example, in December 2023, the Ontario Energy Board effectively reversed the long-standing norm that all gas ratepayers must bear the upfront cost of new gas connections. The regulator noted that anticipating 40 or more years of income from these new customers may no longer be a reasonable assumption under a clean energy transition and given increasingly affordable alternatives to gas (*OEB 2023*). The Board's decision follows similar actions in other jurisdictions, including California and Colorado.

- Shorten time horizons for necessary new infrastructure. When a utility must replace a pipeline for safety or reliability reasons, the regulator can require the company to adjust its anticipated useful lifetime. This limits the risk that future ratepayers will be left paying for infrastructure they no longer use.

- Consider introducing accelerated asset depreciation schedules and other accounting practices that more accurately reflect and apportion infrastructure costs and risks (*Bilich 2019*). For example, New York State's regulator now requires gas utilities to submit depreciation studies assessing the impact of accelerated depreciation schedules on both ratepayers and costs (*Bagdanov 2022*).

Without clear government direction and support, regulators would likely be hesitant to change long-standing practices.

Many of these tools are within regulators' existing powers, and could be exercised starting today. Still, without clear government direction and support, regulators would likely be hesitant to change long-standing practices, out of concern that a court may overturn their decision based on a utility's appeal.

Some energy regulators and policymakers are taking steps to consider the clean energy transition in their decision making

Though the work is nascent and uneven, regulators across the country are starting to ask electric utilities to explain how they will decarbonize their systems, and have begun approving updated plans based on rising projected electricity demand. In early 2024, for example, the regulator in British Columbia accepted an updated 2021 IRP from BC Hydro that highlighted the need to obtain additional clean power to meet its customers' future electricity needs cost-effectively (*BCUC 2024*).

Utility regulators, most recently in British Columbia and Ontario, are also starting to ask gas utilities to more seriously consider the clean energy transition, directing them to better manage risk and ensure that proposed new infrastructure will be used and useful in the future (*Harland 2024*).

Regulators are also starting to scrutinize gas utility proposals for clean-fuel blending for their economic viability and to call for greater clarity on the role of the gas network in the future and how to protect customers along the way (*BCUC 2024*).

But while these new initiatives could reduce greenhouse gas emissions and mitigate customer rate impacts, regulators are having to decide on their deployment without a clear picture of where they fit in each province's long-term net zero pathway, and how they will ensure long-term energy affordability for all Canadians.

4.2 The importance of provincial leadership

Without provincial initiative, the path to Canada's climate targets is likely to be slow, costly, and ineffective (*Linden-Fraser 2023*).

Strong climate policy—from legislated targets, to broad-based economy-wide measures, to utility- and consumer-scale policies—will be critical to Canada's success. Not only does policy help influence consumer and business decision-making, it also sends a clear signal to regulators, utilities, and other energy-system actors, informing their planning. The federal government can certainly help, but provinces can significantly strengthen the policy environment by adopting each others' successful policies and tailoring approaches to their specific challenges and opportunities.

But even with strengthened climate policy, unless provinces also address the regulatory framework for energy utilities, regulators may lack the clarity and resources they need to contend with the energy transition on their own.

Many voices are calling for provincial policy clarity

Without provincial initiative, the path to Canada's climate targets is likely to be slow, costly, and ineffective.

Even as some Canadian regulators express concern about the looming risks of the clean energy transition and the importance of coordinating responses, they are also calling for provincial leadership.

In a March 2024 decision on BC Hydro's Integrated Resource Plan, for example, the British Columbia Utilities Commission encouraged BC Hydro and FortisBC to improve their communication and coordination, but noted that it "cannot force the utilities to agree upon any given view of the future, and [does] not wish to be overly prescriptive on provincial planning issues that may be more appropriately in the domain of the government" (*BCUC 2024*).

Similarly, in a September 2023 decision, the Nova Scotia Utilities and Review Board approved the gas utility's rate application, but questioned if its growth plan was in line with the province's net zero goals. The Board noted that, while the clean energy transition raised pertinent questions for the continued viability of the gas utility, clarity on the role of gas in the transition was more appropriately the purview of the provincial government (*NSUARB 2023*).

In the past year, various independent task forces and expert panels have similarly called for more provincial government direction to facilitate improved long-term planning. Ontario's Energy Transition and Electrification Plan, for example, invited the government to produce an economy-wide vision for the clean energy transition, as well as provide "policy direction on the role of natural gas in Ontario's future energy system as part of [the government's] next integrated long-term energy plan" (*Electrification and Energy Transition Panel 2023*).

While energy regulators will grapple with the many challenges of the energy transition at the ground level, the levers of change are mostly in the hands of provincial governments. Their inaction or continued inertia will only make the problem worse.

Provincial direction to regulators is the missing piece

Some provincial governments are beginning to recognize the need to direct and empower their energy regulators, at least with respect to the electricity system.

For example, in early 2024, the Province of Nova Scotia announced plans to significantly restructure its utility regulation regime. The province would spin out a new Nova Scotia Energy Board from the original Utilities and Review Board, establish a new independent System Operator, and include in the new Energy Board's mandate the goals and targets in the *Environmental Goals and Climate Change Reduction Act*, including its 2030 and 2050 climate goals (*Government of Nova Scotia 2024*).

Also in 2024, British Columbia amended the Clean Energy Act to direct the British Columbia Utilities Commission to ensure the procurement of sufficient electricity to meet climate targets while also limiting electricity rate increases to the rate of inflation. The amendments are an important step, even as further work is needed on energy system planning to support the interpretation and implementation of the new directives (*Fransen et al. 2024*).

No province, however, has yet issued a long-term direction on what the clean energy transition means for the future of gas for building heat in their jurisdiction, or how gas and electricity systems both must transform to get on a cost-effective path to net zero.

This lack of direction carries significant consequences. For example, ongoing ambiguity around potential new lines of regulated business for gas utilities is contributing to inertia. Both significant expansion of their regulated lines of business and restriction to their current ones have pros and cons: expansion allows them to find a new path forward, but restricts the roles that electric utilities and other actors will get to play; restriction allows new players to enter, but leaves gas utilities as forceful advocates for the status quo of continued system expansion. A lack of clarity around these questions leaves both utilities and their regulators at a crossroads, and is contributing to inertia.

The limits of current climate policy, on the one hand, mean that existing market signals are not strong enough or consistent enough to drive gas demand down fast enough. The limits of current utility regulation, on the other hand, mean that regulators are not adequately equipped to prepare for the energy transition and the risk it could pose to ratepayers. And these two policy problems interact to keep energy systems on the wrong track.

Provinces risk ending up with underdeveloped or unbalanced energy systems that are not ready for what's coming.

Absent policy leadership, provinces risk ending up with underdeveloped or unbalanced energy systems that are not ready for what's coming, straining affordability and reliability. The continued expansion of gas networks exacerbates the risk of stranded assets and elevated costs for ratepayers, as well as costly emissions lock-in that either puts an unfair burden on other sectors or puts Canada's climate targets out of reach. And without careful attention from policy makers and regulators, the risk of exacerbating equity impacts will remain unresolved: low-income Canadians and renters will continue to face barriers to access energy savings for efficiency and clean technology, and the last customers on the gas system will likely be those with the least capacity to bear its costs.

To provide better policy leadership and needed guidance to energy sector actors, provincial governments are starting to commission independent pathway assessments and produce net zero energy roadmaps. Box 4 discusses these tools and their critical features.

Box 5

The role of pathway assessments and energy roadmaps

A **pathway assessment** is a study of the available and credible pathways to achieving a net zero economy by 2050. It is a valuable tool for ensuring an orderly energy transition, as it helps to evaluate choices and tradeoffs, identify priority actions, and bring key stakeholders together for evidence-based discussions. The insights gained from an independent pathway assessment—particularly one that includes a degree of regional assessment—can help drive a cost-effective transition.

Properly designed, a pathway assessment helps build consensus among stakeholders regarding these choices, and will help set a clear direction for the decarbonization of a province's heating system. Ideally, a pathway assessment is re-commissioned on a regular basis, and is not a replacement for the more detailed energy system planning that system operators and utilities undertake, instead acting as a clear input to that work, and a signal regarding where investments should be going.

To be useful to governments, regulators, utilities, and other actors, pathway assessments should be:

EXHAUSTIVE

A pathway assessment should consider all credible net zero pathways, regardless of established technology or pathway preferences, accounting for the inherent uncertainty of the transition. This could be accomplished by commissioning a pathway assessment from independent experts or by ensuring project scope is inclusive of all potential scenarios, considering uncertainties such as technology costs and availability as well as global climate action and oil prices.

COMPREHENSIVE

The assessment's modelling should include an evaluation of the greenhouse gas emissions associated with all aspects of the economy, the interactions with all types of energy sources (not exclusive to electricity), and regional differences within the province or territory.

Box 5 (continued)

TRANSPARENT

Model selection, scenario design, and the selection of inputs and assumptions should be done transparently, with the outputs from all considered scenarios available for public scrutiny.

CONSULTATIVE

It is critical to be thoughtful about the data inputs, scenario design, and assumptions employed in a modelling exercise. Many assumptions are highly subjective and should be determined in consultation with local subject matter experts and stakeholders (including electricity system regulators, energy utilities, government officials, labour and civil society organizations, consumer interest organizations, and municipal and external policy experts), as well as Indigenous rights holders.

HIGH-LEVEL

A pathway assessment should not seek to replace more detailed electricity system planning and modelling conducted by system operators and utilities, but instead provide credible scenarios as an input. A pathway assessment can use more detailed modelling, specific to a given power system, region, or sector, to enhance the inputs and assumptions it makes when considering different scenarios.

RECURRING

In order to ensure a jurisdiction's energy strategy remains relevant, a pathway assessment should be recommissioned on a regular schedule (perhaps every five years). This allows for the inclusion of new scenarios, consideration of changes in technology costs and availability, macroeconomic changes, and insights from more detailed modelling that looks at specific sectors, technologies and regions.

Box 5 (continued)

Provincial governments can develop **energy roadmaps** to guide their transition to a net zero energy system. The roadmap serves as a comprehensive strategy or high-level plan—it clearly articulates the government's overall vision and objectives, while focusing on near-term priority actions.

Such system-level energy strategies must be produced by an elected government, as energy sector actors, like regulators, do not have the authority or mandate to make the wide-reaching policy decisions that meaningful energy roadmaps provide.

Energy roadmaps are seeing increasing use in a variety of jurisdictions across North America, helping energy system actors to navigate the policy priorities of governments, and plan the necessary investments accordingly.

To help navigate the decarbonization of building heat systems, energy roadmaps should:

CENTRE NET ZERO BY CLEARLY ARTICULATING A 2050 NET ZERO OBJECTIVE IN THE ENERGY ROADMAP

This objective should also be reflected in the legislation that articulates the mandate for regulators, system operators, permitting and approvals authorities, and Crown utilities (see first recommendation, below).

CLEARLY ARTICULATE THE GOVERNMENT'S VISION, OBJECTIVES, AND ACTIONS

Set out a clear picture of outcomes that the roadmap is trying to achieve in 2050, five-year milestones along the way, the objectives that inform the roadmap, and the near-term actions that can achieve these objectives and the long-term vision.

PROVIDE REGULAR UPDATES

Ensure the roadmap, and the priorities it sets out, are updated at least every five years. This will be critical to ensure roadmaps stay action oriented, drive specific changes, and remain relevant to the evolution of the energy system.

Box 5 (continued)

ENSURE ALIGNMENT ACROSS ENERGY SYSTEM ACTORS

Require responsible entities or agencies to publicly report no less than biannually to the provincial or territorial government to outline how they are supporting the jurisdiction's net zero energy vision and to identify both progress and barriers.

MODERNIZE ENERGY GOVERNANCE AND REGULATION

Identify and provide direction on key reforms necessary to update existing energy governance and regulatory frameworks to align with the achievement of a net zero energy system.

SCOPE TO INCLUDE ALL ENERGY SYSTEMS

Provide direction on the necessary action and reforms for the full energy system (both electricity and gas systems), promoting integrated planning and resource deployment and tackling the full domestic energy mix that will be required in 2050. Energy exports can be considered out of scope for a roadmap.

DEVELOP A PARTICIPATORY ENGAGEMENT PROCESS

Ensure that Indigenous rights holders, key stakeholders, and the broader public have the support and resources to meaningfully participate in developing the energy roadmap, and the opportunity to inform the regular updates that take place.

CONDUCT REGULAR EVALUATIONS OF ACTIONS

In addition to five-year milestones and periodic updates to the roadmap, the government should commit to transparently reporting back no less than biannually, to transparently review the actions outlined and provide updates on progress.

For more information on best practices in pathway assessments and energy roadmaps, see the appendix of the Canada Electricity Advisory Council's report *Powering Canada: A Blueprint for Success* (Dunsky et. al 2024).

SECTION 05

Aligning building heat with net zero

As we've seen throughout this analysis, the clean energy transition has profound implications for the energy systems that provide gas and electricity to heat Canada's buildings. In this section, we step back to summarize the top-line conclusions this analysis yields, and then present a series of recommendations designed to help regulators and provincial governments navigate this transition in a way that protects long-term energy affordability and reliability for Canadians.

5.1 Conclusions

Canada's clean energy transition will fundamentally change how Canadians heat buildings, and transform gas and electric systems. Four overarching conclusions emerge from our analysis.

Electricity powers most space heating as Canada approaches net zero

Managing peak demand to keep electricity affordable and reliable will likely emerge as the central challenge facing electric utilities in this transition.

Across all regions and in all sensitivity scenarios, the story is the same: On a cost-effective pathway to net zero, most homes and businesses switch from fossil fuels to electricity to heat their spaces. The details vary province to province, but the pattern of substantial electrification is consistent everywhere.

Many provinces are making progress in cleaning up their electricity grid. But to support economy-wide decarbonization, all provincial electricity systems must get cleaner, bigger, and smarter—and quickly.

Indeed, managing peak demand to keep electricity affordable and reliable will likely emerge as the central challenge facing electric utilities in this transition.

Even with hybrid heat, biomethane, and hydrogen, a cost-optimal clean energy transition means contracting gas networks in Canada

Our modelling results and the results of similar studies see gas volume declining in all regions and across all sensitivities in the transition to net zero. Low-emission gases don't come close to making up the difference. Scarce supplies of biomethane and hydrogen are more optimally used to decarbonize other sectors, such as heavy industry.

Hybrid heat can be a stepping stone in many places, and part of a long-term pathway in some contexts. But those opportunities are limited, and even in cases where hybrid heat plays a larger long-term role, the gas network must likely still contract to keep costs manageable for ratepayers.

A business-as-usual approach increases the risk of higher costs, jeopardizes Canada's climate goals, or both

The longer that policymakers and regulators delay action, the greater the risk that Canadians will end up on the hook.

Under status quo utility regulation and current climate policy, greenhouse gas emissions from the buildings sector are rising, gas utilities are continuing to expand their networks, and electricity utilities are only just starting to get serious about growth.

Delayed action on the gas system will result in continued growth, adding costs that would take decades to recover. Ongoing and increasing investment in the gas system leaves remaining gas ratepayers at risk of rising gas rates, as larger numbers of gas ratepayers switch to electricity to heat their homes and businesses. It also increases the undepreciated value of assets, which can make contraction of the gas system more expensive, causing further delay.

Delayed action on the electricity side, meanwhile, risks a mismatch between growing electricity demand and supply. This can inhibit the momentum of consumers switching to electricity, which means that consumers lose out on the advantages of electrification while hampering Canada's progress to net zero.

The longer that policymakers and regulators delay action, the greater the risk that Canadians will end up on the hook for an overbuilt and underused gas system, an overburdened electrical grid, or both.

Provincial and territorial policy is the missing piece for achieving climate goals while protecting reliability and affordability

Provinces and territories oversee electric and gas utility regulation. Their policy leadership is needed to make sure Canada's energy systems and their regulators are driving the clean energy transition while protecting reliability and affordability.

Local details matter. Electricity grids and gas networks are provincially and territorially regulated; provincial economies differ; and each gas network has important spatial features. These spatial features include the extent and age of the network, and the number and type of customers connected. This challenge can therefore only be successfully navigated with detailed planning and policy leadership, province by province.

Provincial and territorial government policy attention is also required to ensure access to heating is affordable, reliable, and equitable. The clean energy transition offers opportunities to do just that. Energy efficiency, for example, can cut energy bills significantly and lastingly. But it also raises challenges. Those who would most benefit from energy efficiency and smart electrification are often the least able to afford the upfront investments required. Many households and businesses are already switching off fossil fuels, but asymmetrically across the country and across income levels. If this trend continues and only higher-income homeowners are able to retrofit homes and electrify with heat pumps, then the rising cost of maintaining the gas network could disproportionately fall on renters and lower-income Canadians.

5.2 Recommendations

While the clean energy transition will play out over several decades, the long-term implications of today's investment decisions mean that governments must start now to change the status quo and protect ratepayers from the costs of dead-end pathways. Based on our research and the conclusions above, we make the following policy recommendations.

1 Provincial governments should equip regulators, system operators, and utilities to make decisions consistent with net zero

A lack of policy clarity and alignment creates uncertainty for energy system actors. This uncertainty can delay the investments needed to deploy lower-cost and net-zero-aligned infrastructure, and risk further expansion of the gas system beyond what is cost-optimal.

In order to achieve an equitable and affordable transition, provincial governments need to clarify their policy objectives and make use of a suite of planning tools that are being deployed across a growing number of jurisdictions.

Provincial governments should:

- Legislate a target for net zero by 2050 and interim milestones, update the mandates of regulators to include achievement of these climate targets, and equip regulators with the financial and human resources needed to deliver. And in provinces where they exist, system operators and Crown utilities should receive similar mandates.

- Commission and regularly update independent, economy-wide pathway assessments, and/or leverage existing analyses that can inform development of an energy roadmap. These higher-level assessments should complement, and ideally integrate, more granular pathway assessments undertaken by utilities and/or system operators.

Produce energy roadmaps that present the government's vision for how the jurisdiction will meet its energy needs under net zero by 2050, lay out five-year milestones, and report annually on progress. In particular, roadmaps should specify the roles of the gas and electricity system through the transition and identify responsibilities for overall energy system coordination.[13]

Provincial governments can and should undertake these actions in parallel, since too much delay on any one component risks locking in dead-end pathways.

Pathway assessments and energy roadmaps should be consistent with best practices. In particular, provincial governments and regulators should consider gas and electricity systems together in related analysis and planning, so that efforts to right-size the gas system can be paired with electricity grid capital investment plans that protect energy system reliability and affordability for consumers. Such analysis and planning must be independent from any related analysis and planning by gas and electric utilities and other energy sector actors.

2 Provincial governments should stop treating gas system expansion as the default option, and equip regulators to consider alternatives

Across Canada, government policy should no longer treat the connection of new buildings to gas networks as a matter of course. In most contexts, and particularly for new developments, electric building heat should be the default, unless there is a specific local alternative such as a thermal network.

Process outcomes are currently biased in favour of gas connections in numerous and often complex ways.

13. *The organization responsible for managing this work may be an existing or new entity. Several jurisdictions have introduced new bodies to coordinate gas and electricity systems, such as the United Kingdom's Future System Operator and Massachusetts' Office of the Energy Transformation.*

To be successful, implementation of this recommendation may require provincial governments to take the following actions, many of them complementary to each other:

Provinces could immediately direct regulators to consider the risks of stranded gas assets, and compare them against alternatives to replacing and extending gas pipelines when reviewing gas utility submissions. Alternatives should be broadly defined to include electrification, efficiency measures, as well as options that could include pipes, such as thermal energy networks and waste heat recovery.

Provinces could also direct regulators to reform obligation-to-serve requirements for gas utilities, so they do not necessitate continued gas network expansion (*BDC 2024*).

Provinces could also mandate that new buildings be fully electric, except where a suitable net-zero alternative exists (such as a thermal energy network).

3 Provincial governments should require gas utilities to provide maps of their networks to facilitate a managed transition that protects ratepayers

Provincial governments, regulators, and gas utilities should start laying the groundwork for the gradual, managed contraction of gas networks.

Preparing for a smaller gas network will require balancing multiple interests, technical planning, and finding solutions to equity challenges. But the effort can pay off in savings for ratepayers.

Other jurisdictions have found that planning for declining gas demand can result in significant cost savings while better protecting the viability of remaining infrastructure (*Moore 2023*, *Energy + Environmental Economics, and ScottMadden Management Consultants 2022*). California, the Netherlands, and Germany, for example, have already begun selective, proactive gas network pruning based on detailed understanding of their gas grids. A German study found that orderly decommissioning within the country's gas grid could save up to $5 billion annually, compared to a similar pace of declining gas use, more interspersed throughout the gas network (*Herndorff et al. 2023*). Germany now mandates heat plans for all cities with more than 20,000 inhabitants (*Federal Ministry for Economic Affairs and Climate 2024*). The Netherlands has rolled out a gas-free-neighbourhood pilot in 66 communities (*OECD 2023*). In California, gas utilities are implementing targeted electrification—programs to switch customers from gas to electricity in locations that maximize benefits to the whole system—to avoid the expense and stranded asset risks of gas infrastructure replacement (*PG&E 2022*).

Mapping existing gas infrastructure is a foundational part of this proactive work. In particular, information on the age and condition of pipelines, and the anticipated timing and rate of gas pipeline replacement, is often unavailable. Requiring gas utilities to gather and share this information (in a way that protects confidentiality and security) would help provincial policymakers, regulators, and other energy utilities identify opportunities to gradually reduce the size of the gas system and address implications for rates and customer bills. Additionally, requiring utilities to share more detailed gas and electricity network information with municipalities and other utilities could help to proactively identify upcoming pipeline replacements and assess non-pipeline alternatives, such as thermal energy networks or targeted and neighbourhood-scale electrification.

4 All orders of government should strengthen policies to support building electrification, peak management, and energy efficiency

Energy efficiency and fuel switching policies differ significantly between provinces. Provinces with less experience can learn from those that have developed and implemented successful market transformation measures, such as the BC Energy Step Code.

Completing and strengthening the suite of consumer-focused policies includes:

- Regulatory certainty, including strengthened building codes for new buildings and retrofits, building performance standards, and equipment standards.

- Direct financial support for energy retrofits and smart electrification—with subsidies for low-income Canadians and financing tools for all to increase adoption rates.

- Implementation support for energy retrofits and smart electrification, such as labour market development, education and training, and community outreach initiatives.
- A broad-based, consistent, and rising price on greenhouse gas emissions.

Through their design and implementation, these policies should:

- Integrate equity objectives, including inclusion and co-design with underserved and equity-seeking groups and Indigenous communities.
- Prioritize energy efficiency and peak management. Governments and program administrators must pair electrification with efficiency to capture cost savings for the overall system and ratepayer.
- Steer investment away from dead-end pathways. An over-reliance on biomethane or hydrogen for decarbonizing buildings risks missed climate targets and high costs for ratepayers and for other sectors that must do more of the work of reducing emissions.
- Send a long-term signal to the market, via stable funding for incentive programs, clear long-term targets, and predictable improvements over time to performance-based building codes.

5 All orders of government should centre equity in policy design and provide targeted support to the most affected

Consumer-focused policy should centre equity and inclusion to ensure heating remains affordable in the clean energy transition, particularly for lower-income households.

As provincial and territorial governments and regulators take action to limit the overall size of infrastructure liabilities for all ratepayers, provincial and territorial policy must still determine who bears the remaining costs, and how. Policy choices affect how the cost of energy infrastructure is distributed within customer classes (for example, for residential ratepayers across the income spectrum), among customer classes (residential, commercial, and industrial) and across ratepayers, shareholders, and governments. Decreasing gas demand and a contracting customer base risks burdening remaining customers with high rates. Absent policy interventions, these remaining customers could be those who are least able to afford increased costs.

Governments and regulators presiding over energy system changes should anticipate equity impacts and design solutions to address them. Centring equity in policy making does not necessarily mean avoiding prudent climate and regulatory policies that could have adverse equity outcomes. Rather, it means carefully assessing the equity impacts of such policies and, where necessary, bringing in complementary, tailored policies, or supports that can address them, such as means-tested fixed charges (*Dolter and Winter 2022*) or low-income-targeted discounts on overall bills.

Regulators can play a supporting and even an implementing role in addressing equity, but need clear policy and guidance from governments to do so. It is governments that are ultimately accountable for addressing potential equity challenges.

APPENDIX 1 — THE NATEM MODEL

NATEM, a techno-economic optimization model run by ESMIA Consultants, can provide insight into the most cost-effective pathway to meet a given outcome. In this case, we set a net zero constraint for the whole economy to characterize how the buildings sector's technology mix and fuel use change over time and to evaluate how these changes may impact other sectors of the economy as they transition to net zero.

The constraint on emissions comes into effect in 2030 and increases linearly until reaching a limit of 10 megatonnes of carbon dioxide equivalent in 2050 (with an assumption that these remaining residual emissions would be offset by nature-based sources of negative emissions). The constraint is applied at a national level, requiring provinces and jurisdictions to reduce their emissions at a pace and scale that enables the country as a whole to decarbonize cost-effectively. Policies that were in effect or announced as of Spring 2023 must be met. Beyond this, no additional constraints are applied on the buildings sector, allowing the model to make technology and fuel choices that are consistent with achieving a cost-optimal pathway to net zero emissions economy-wide.

The NATEM model is well suited to this analysis because:

- **It can represent technologies in rich detail.** The model represents the Canadian economy in each region and sector, capturing the technologies and processes that enable the production (for example, refineries and power plants), transportation (for example, pipelines) and consumption (for example, furnaces and heat pumps) of energy. Each technology in the model is characterized by various parameters, including capital costs, operation and maintenance costs, efficiency, operational lifetime, and relevant operating constraints. Existing technologies can be replaced at the end of their lifetime or when cost-effective, with newer versions of the same technology (for example, replacing an old gas furnace with a new gas furnace) or swapped out for new technologies (for example, replacing an old gas furnace with a heat pump). The technological detail means we can analyze the energy transition from a bottom-up perspective and see the impacts of technology change on energy supply and demand, system-wide costs, and greenhouse gas emissions.

— **It can capture complex dynamics between sectors.** Because NATEM is a multi-sectoral model, containing all economic sectors, it can represent how change in one sector can affect other sectors. For example, it can characterize how electrification in sectors like buildings and transportation affects the full electricity supply chain in each province, from resource extraction to electricity delivery. This modelling approach means that NATEM is particularly well-suited to capturing the full dynamics of switching from one type of energy to another, for example, from fossil fuels to electricity.

— **It works to minimize cost across the economy, rather than in any single sector alone.** Optimizing costs across multiple sectors allows us to identify a pathway for building heat that does not merely externalize the costs of decarbonization to other sectors. To meet the net zero constraint, the model seeks to find the most efficient use of available clean energy resources across the whole economy.

We tested the robustness of the modelling results with sensitivity analyses and ground-truthing initial results with experts and stakeholders. We tested a variety of model input uncertainties (for example, technology costs and efficiencies, availability of fuel feedstocks) by configuring and running a series of sensitivity analyses (*see Table 2*). Throughout the modelling process, we engaged with stakeholders to collect feedback on modelling results and assumptions, and made adjustments to model inputs where possible.

Like all models, the NATEM model has limitations. NATEM's optimization does not account for the motivations of individual actors or how the dynamic responses of individual actors could influence the evolution of the energy system. NATEM captures some behavioural factors, for example by applying technological hurdle rates to account for consumer preferences for more familiar technology, but it is not an individual-agent-based model.

Also, even though NATEM uses the best data available and stakeholder-informed assumptions, significant uncertainty remains in particular around data points that rely on projections of the future, such as future technology and energy costs, energy demands, and resource availability. Sensitivity analyses can help to address but not fully eliminate this source of uncertainty. The pathways that we explore in this report should therefore be interpreted as possible ways that the energy system could, not will, cost-effectively transition under a certain set of assumptions.

Table 2 Description of sensitivity analyses run on the core modelled scenario

DESCRIPTION	MODEL PARAMETERS
Lower cost reductions, higher performance improvements of air-source and ground-source heat pumps	*Costs* Going down from 95% to 85% cost reduction in 2030 then from 75% to 65% in 2050. *Efficiency* Gradual increase of heat pump efficiency to reach a maximum of 130% by 2050.
Deep retrofits/rate of energy efficiency improvements and higher deployment of peak reduction measures	*Retrofits* Increase all retrofit-available capacities. Allow up to 30% of space heating by 2030 and 95% by 2060 for existing buildings.
Lower level of efficiency and higher peaks	*Efficiency* Immediate reduction of heat pump efficiency by 30% of calculated values, with no improvements over time. *Peak* All heat pumps winter peak efficiency set to 1 at all time. *Retrofit* Only allow 20% of the maximum potential for retrofit.
Lower clean electricity technology costs	*Costs* All costs aligned with CER assumptions since they are lower for solar, gas with carbon capture, and small modular reactors. However, for wind, our costs are already lower. Take 80% of the costs (same difference from NATEM and CER solar costs reduction).
Lower cost of H2 supply, distribution upgrades, and H2 appliances	*Costs* Supply costs: 30% cost reduction for green hydrogen technologies (biomass and electricity), 8% for autothermal reforming with carbon capture and 6% for other technologies. Appliance costs: 10% decrease in 2022 going to 50% decrease in 2050 for space heating, water heating and cooking appliances.
Higher availability of biomass feedstock supply; lower biomethane production cost	*Feedstock* 200% increase of biomass feedstock. *Costs* 30% reduced costs for biomethane production technologies by 2050.
Increase H2 blending	Increase H2 blending rate from 5% of energy content to 20% of energy content

APPENDIX 2 — REVIEW OF SIMILAR MODELLING STUDIES

Reference	Modelling approach	Key findings	Notes
Independent Canadian studies to determine optimal economy-wide pathways to net zero			
EPRI, 2021	***Model*** REGEN—a capacity expansion and dispatch optimization model integrated with end-use models of buildings, transportation, and industry sectors. ***Scenario*** A net zero constraint in 2050 is applied in each province. The federal carbon price is applied and is assumed to rise 10% per year after 2030.	— Electricity meets 76% and 73% of residential and commercial heating demand, respectively, in 2050. — Peak electricity demand increases by 51% between 2015 to 2050. — A significant amount of residual emissions remain in the buildings sector in 2050 due to continued use of gas. — Efficiency measures are critical to mitigating the increase in peak electricity demand.	Non-CO_2 greenhouse gas emissions are excluded from the analysis, meaning the solutions modelled address only 80% of Canada's greenhouse gas emissions. Low-emission fuels (biomethane and hydrogen) are excluded from the analysis so their potential role in decarbonizing sectors of the economy (including building heat) was not characterized. Thermal energy networks are excluded.
Langlois-Bertrand et al. 2021 (IET)	***Model*** NATEM—an economy-wide optimization model; includes electricity, buildings, transportation, industry, oil and gas, agriculture, and waste. ***Scenario*** Federal greenhouse gas targets are applied as constraints at a national level: 40% reduction from 2005 levels by 2030; Net zero by 2050.	— Electricity meets over 95% of residential and commercial total demand, in 2050. — Electricity generation increases around two-fold between 2016 and 2050. — Gas demand decreases by almost 100%. — Near zero emissions remain in the buildings sector in 2050. — Energy efficiency plays a significant role in a cost-optimal configuration of the buildings sector.	Hybrid systems are not included in the analysis.

Reference	Modelling approach	Key findings	Notes
Studies undertaken by Canadian gas utilities and associations to compare pathways to net zero			
Canadian Gas Association, 2021	**Model** Simulation; specific model or modelling framework is not described. **Scenarios** 1 Focus on adoption of gas heat pumps. 2 Focus on adoption of hybrid heating. 3 Focus on integrating hydrogen and biomethane into supply.	— Gas demand reduces by 30–56%. — Buildings sector emissions require offsets of 8–12 Mt CO_2 eq. in 2050 to meet net zero. — Require a combined volume of H2 and biomethane of approximately 500–850 petajoules in the buildings sector in 2050.	The modelling approach used here is designed to illustrate pathways and not to seek optimized solutions. Only the buildings sector is modelled; interactions with other sectors are not explored so the consequences of directing low-emission gases away from other sectors are not scoped in. Only the impact on emissions is modelled; the costs of the different pathways are not explored.
FortisBC, 2020	**Model** CanESS—a simulation model that accounts for energy supply and demand; includes electricity, buildings, transportation, and industry sectors. **Scenarios** 1 100% electrification economy-wide. 2 Moderate electrification economy-wide with a major role for low-emission gases.	— The 100% high electrification scenario results in a peak electricity demand in 2050 that is about 1.2x greater than the moderate electrification scenario. — Total energy system costs between 2020-2050 are 15% higher in the 100% high electrification scenario compared to the moderate electrification scenario. — Gas demand decreases by 60% in the high electrification scenario and stays constant in the moderate electrification scenario.	The modelling approach used here is designed to illustrate pathways and not to seek optimized solutions. The electricity required to produce low-emission gases is not accounted for.
Enbridge, 2023	**Model** Guidehouse's Low Carbon Pathways model—an integrated capacity expansion and dispatch optimization model that includes electricity, buildings, transportation, and industry sectors. **Scenarios** 1 High electrification economy-wide. 2 Moderate electrification economy-wide with a major role for low-emission gases.	— Electricity peak increases by 107% more in the high electrification scenario than in the scenario with moderate electrification/ more low-emission gas. — Total energy system costs between 2020 and 2050 are 6% higher in the high electrification scenario. — Annual energy demand for gas in buildings decreases by 88% and 49% respectively, in the high electrification and moderate electrification scenarios.	Though a cost-optimization model is used, the scenarios are very prescriptive and therefore limit the model from determining the cost-optimal technology and fuel mix in each sector. The high electrification scenario assumes higher carbon prices than the moderate electrification scenario. If the same carbon price was used, the moderate electrification scenario would cost more than the high electrification scenario (as was reported in the findings).

Reference	Modelling approach	Key findings	Notes
Independent International studies to determine optimal economy-wide pathways to net zero			
USA: An Open Energy Outlook: Decarbonization Pathways for the USA (*Venkatesh et al. 2022*)	***Model*** Temoa—an energy system optimization model used to analyze decarbonization pathways across the energy system. ***Scenario*** An economy-wide net zero by 2050 constraint is applied. Emissions are required to decline linearly starting in 2025.	— Electricity meets the majority of heating demand in the residential and commercial sectors in 2050. — Residential and commercial sectors see a shift to heat pumps for space heating. — By 2050 total electricity demand is more than double that in 2020. — Hydrogen is mainly used in the transportation and industrial sectors.	Due to computational limitations, the 50 states are aggregated into 9 regions. Many low-emission technology options for the industry sector are not included, so the potential pathways for decarbonizing this sector cannot be well characterized.
EU: Net-Zero Europe: Decarbonization pathways and socioeconomic implications (*D'Aprile et al. 2021*)	***Model*** The study uses two optimization tools: Decarbonization Pathway Optimizer (models combinations of technologies in the industry, transportation, buildings, and agriculture sectors), and the McKinsey Power model (models power and new fuels). Both tools optimize for the lowest system cost. ***Scenario*** EU greenhouse gas targets are applied as constraints: — 55% reduction from 1990 levels by 2030. — Net zero by 2050.	— The most cost-effective reductions can be achieved by retrofitting and replacing existing heating systems with more efficient technologies: in 2050, 40% of buildings use heat pumps, 33% use thermal energy networks, 15% use biomethane or hydrogen boilers, and 10% use solar thermal. — Low gas and oil prices can delay the adoption of renewable technologies if regulations do not exist to force fuel switching.	Fossil fuel prices were assumed to remain at current levels; the impact that falling oil and gas demand could have on prices in a net zero future was not considered. Due to computational complexity, EU-27 was modelled as 10 regions. The power and fuels model is only soft-linked to the end-use models of industry, transportation, buildings, and agriculture sectors. As a result, the modelling does cost-optimize across all economic sectors.
Australia: Pathways to Net Zero Emissions—An Australian Perspective on Rapid Decarbonization (*Brinsmead et al. 2023*)	***Model*** The study uses a combination of three models: GTEM which models global macroeconomic impacts, KPMG-EE which translates these impacts to the Australian economy, and AusTIMES which derives the least cost energy and emissions pathways. ***Scenario*** The carbon shadow price determined by GTEM to achieve net zero emissions is applied in AusTIMES.	— Electricity meets 85% of buildings sector energy demand in 2050. — By 2050, 70% of space heating and cooling in residential buildings is electrified. — Improving building thermal efficiency and replacing appliances with more efficient versions largely offsets the increase in electricity consumption associated with electrification.	

Reference	Modelling approach	Key findings	Notes
UK: The pathway to net zero heating in the UK (*Rosenow et al. 2020*)	***Model*** UK TIMES model—a bottom-up techno-economic cost optimization tool. Covers energy demand in the residential, industrial, service, transport and agricultural sectors. ***Scenario*** A net zero by 2050 constraint is applied to two scenarios: 1. a conservative approach to technology availability, 2. a progressive approach to technology availability that provides the model with more flexibility when making investment decisions in the buildings sector.	— Gas is almost completely phased out of the residential sector by 2050; no new homes should be connected to the gas grid after 2025. — By 2050, 58% of space heating will be met by heat pumps. The remaining demand is met largely by a mix of thermal energy networks and thermal storage. — Retrofits reduce total space heating demand in the residential sector by 10% in 2050. — Electrification of fossil fuel heating increases peak demand.	The UK is characterized as a single region in the model.

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