

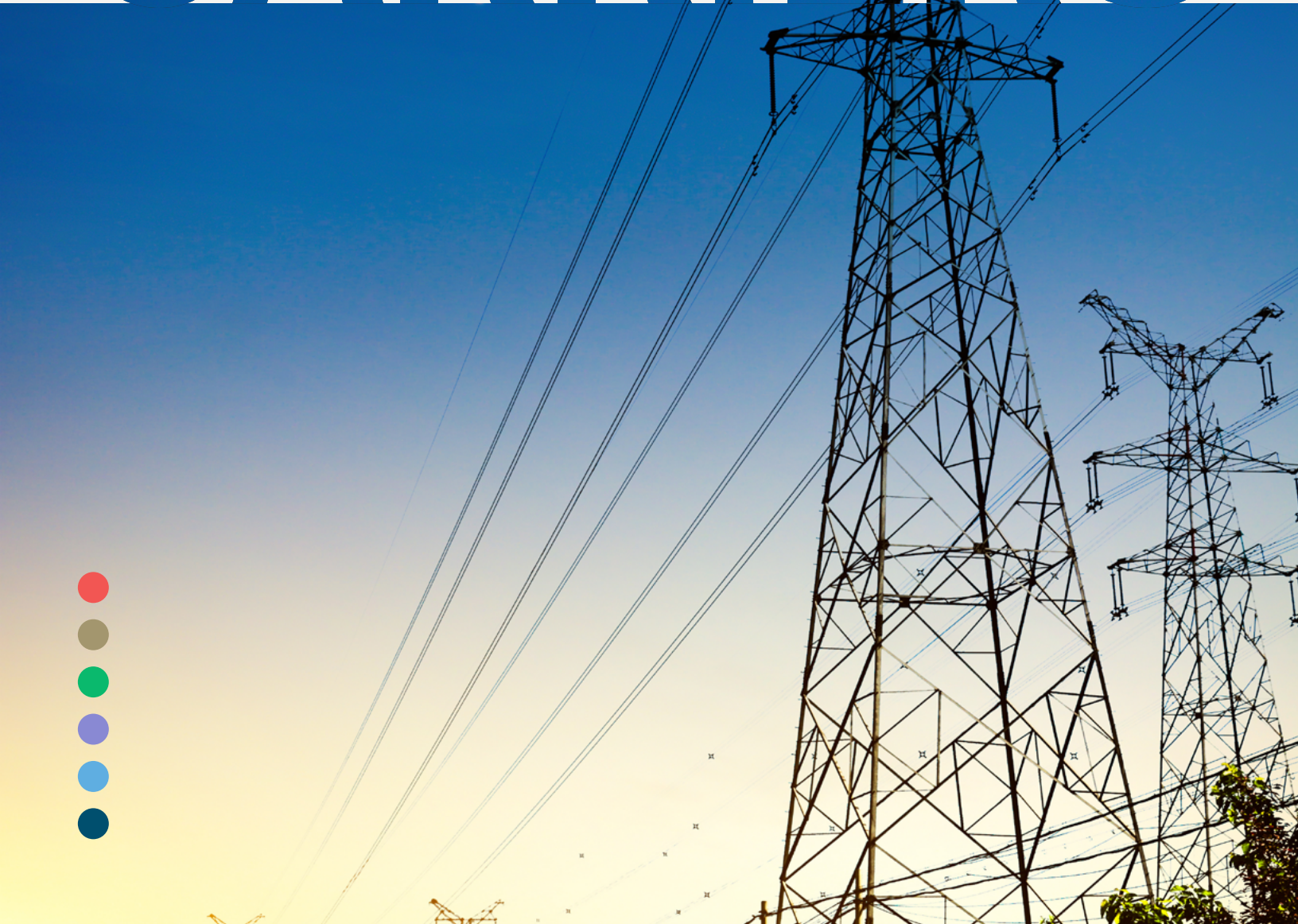
The Transition
Accelerator



L'Accélérateur
de transition

Canada's Opportunity Playbook:
Pathways to Strategic Decarbonization

ENERGY CARRIERS





The transition to net zero requires a dramatic transformation of this mix, with decarbonized electricity emerging as the main energy carrier.

7. Energy Carriers

Energy carriers link primary energy sources to end uses that provide the energy services we value. In Canada today the dominant energy carriers are fossil fuels. Petroleum moves people and goods. Natural gas heats buildings, meets the needs of industry, and contributes to electricity generation, while coal is now used primarily for industrial processes.

The transition to net zero requires a dramatic transformation of this mix, with decarbonized electricity emerging as the main energy carrier. Low-carbon hydrogen and alternative fuels will serve a complementary role, filling gaps in heavy industry and transport where direct electrification is not technically or economically viable. And to the extent that fossil fuels continue to serve as energy carriers in a net-zero world, their production and use will involve emissions abatement and carbon removals.

The technical and institutional systems for exploiting these four energy carriers are at different stages of maturity. Yet their future evolution is deeply interdependent. The pace at which electricity scales will influence the extent to which low-carbon hydrogen is economically viable, how long alternative fuels remain necessary, and how quickly fossil fuel demand contracts.

The four sections that follow examine the potential of each carrier as the world moves towards net zero. The electricity section focuses on decarbonizing the remaining fossil-dependent provincial grids and expanding generation across the country to meet demand that is expected to double by mid-century.[78,79]¹ The section on hydrogen explores its possible movement from an industrial feedstock to a carrier providing energy for high-temperature industrial heat, heavy transport, or seasonal energy storage. The section on alternative fuels examines which non-fossil liquid and gaseous fuels are most

¹ This estimate does not fully account for emerging electricity demand from AI data centres.

likely to serve residual demand given finite feedstocks and competition across applications. Finally, the section on oil and gas considers both the potential for near-term production emission reductions as well as the longer-term trajectory of a sector that currently contributes roughly 7% of national GDP and supports 200,000 direct jobs.[80]²

The assessments that follow do not assume we can fully anticipate the energy carrier mix multiple decades in the future or define the pace at which change will take place. They do indicate the direction of probable advance, and are intended to help decision-makers

distinguish among the options that appear most promising, those that confront unresolved barriers, and those that are unlikely to deliver at the scale some anticipate. Readers should expect to encounter challenges and trade-offs without simple solutions, including how to build out the electricity system without driving up prices, whether hydrogen hubs can achieve the scale needed to break through current infrastructure and cost barriers, where finite biofuel feedstocks are best deployed, or how producing regions can prepare for an eventual weakening of fossil fuel demand.

² All noted references can be found in the full Playbook document.



7.1 ELECTRICITY

Function	Provides lighting, heating, cooling, and mobility, and powers motors, other machinery, and devices that underpin modern society; enables industrial processes.
GHG emissions	7.6% of national emissions in 2024, 49.6 Mt CO₂e.[61]
Options for decarbonization	Decarbonization Pathways: Wind power, utility-scale solar PV, hydro (reservoir), nuclear (conventional reactors) Bridge Pathways: Gas with CCS Niche Pathways: Building-integrated solar PV, hydro (run-of-river), geothermal power, biomass combustion Enabling Pathways: Grid improvements, interprovincial and international interties, power storage, demand-side management, energy efficiency
Stage of transition	Emerging: Gas with CCS, geothermal power, small modular reactors Diffusion: Wind power, utility-scale solar PV, building-integrated solar PV, hydro (reservoir and run-of-river), nuclear (conventional reactors), biomass combustion, grid improvements, interprovincial and international interties, power storage, demand-side management, energy efficiency
Nature of the problem today	Some provinces remain heavily reliant on fossil energy due to ageing infrastructure, slow permitting processes, lack of carbon-neutral-optimized utility structures, slow uptake of technology, rising cost concerns, and a reluctance to engage fully with the energy transition
Other systemic issues	Energy reliability/security; electricity costs and efficiency losses; centralized versus distributed control
Opportunities and concerns	Reduction in air pollution; clean electricity exports; economic opportunities
Priorities for action	Phaseout of coal; interprovincial transmission ties between carbon-intensive and clean provincial grids; support for renewables deployment; buildout and modernization of grid infrastructure; measures to manage electricity demand
Longer-term issues	Increased electricity supply and storage capabilities to reliably electrify transportation, buildings, and industry; integrating a large proportion of intermittent/variable renewables (wind, solar) on electricity grids; accommodating more distributed generation where appropriate
Indicators of progress	Percentage of electricity demand supplied by non-emitting sources. Percentage of final energy demand supplied by electricity; approximately 18% (1,990 petajoules) of Canada's final energy end-use is currently provided by electricity.[81].

7.1.1 Current Status

The electricity system provides power for lighting, heating and cooling, mobility, and the operation of machinery and electronic devices. Its energy services are vital to the health and welfare of Canadians, as well as to economic productivity and growth. In 2024 Canada generated 625.2 terawatt-hours of electricity (about 2% of the world total) and the country was the seventh-largest global producer. In 2023 the sector employed over 110,000 people[82] and contributed \$51 billion to Canada's GDP.[80] Net electricity exports to the United States in 2024 were about 2.6% of Canadian production.[83]

Canada's electricity sector is currently among the cleanest in the world, with more than 83% of power coming from emission-free sources (60% hydro, 6% wind, 14% nuclear, and 3% from other renewables). Most of the remainder comes from coal (5%) and natural gas (12%) (Figure 7). The generation mix varies widely from province to province (see Figure 9).

Provinces can today be divided into three groups: hydro provinces with more than 90% of the generation from hydro (Quebec, 94%; Manitoba, 96%; Newfoundland, 97%; and British Columbia, 89%); fossil provinces where two-thirds or more of power is derived from fossil fuels (Alberta, 85%; Saskatchewan, 85%; and Nova Scotia, 73%); and mixed-supply provinces (Ontario with 55% nuclear, 24% hydro, and 13% wind/solar; and New Brunswick with 40% nuclear, 23% hydro and 11% wind/other renewables). The remaining jurisdictions of Prince Edward Island (PEI), the Yukon and Northwest Territories, and Nunavut together account for less than 0.5% of Canadian production.

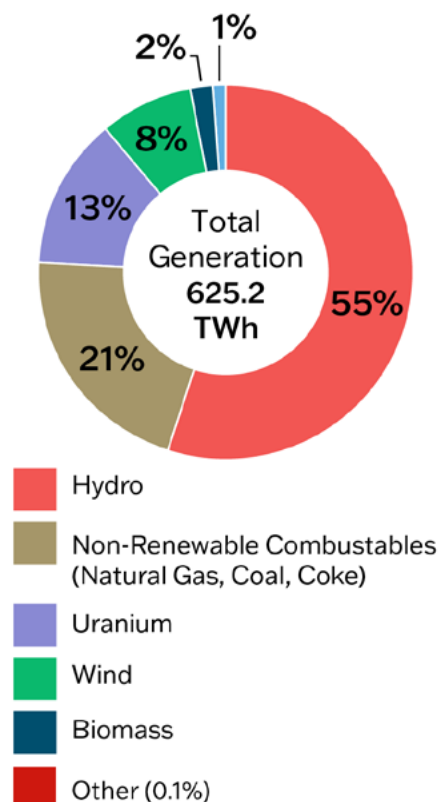


Figure 7. Canada, electricity generation by fuel type (2025)

Source: Statistics Canada Table: 25-10-0015-01, 2025

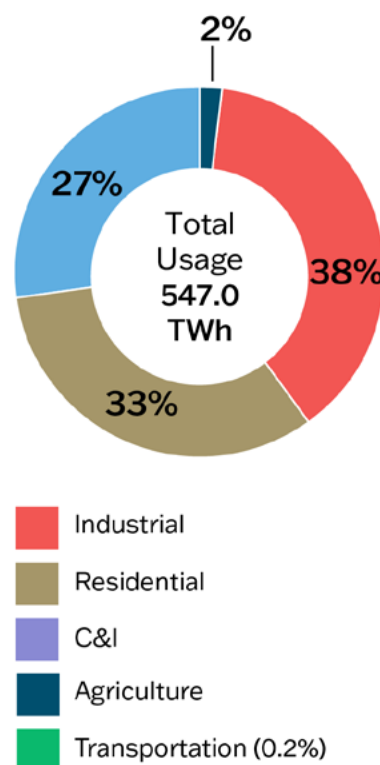


Figure 8. Canada, electricity usage by major sector (2023)

Source: NRCAN, 2023 Comprehensive Energy Use Database.

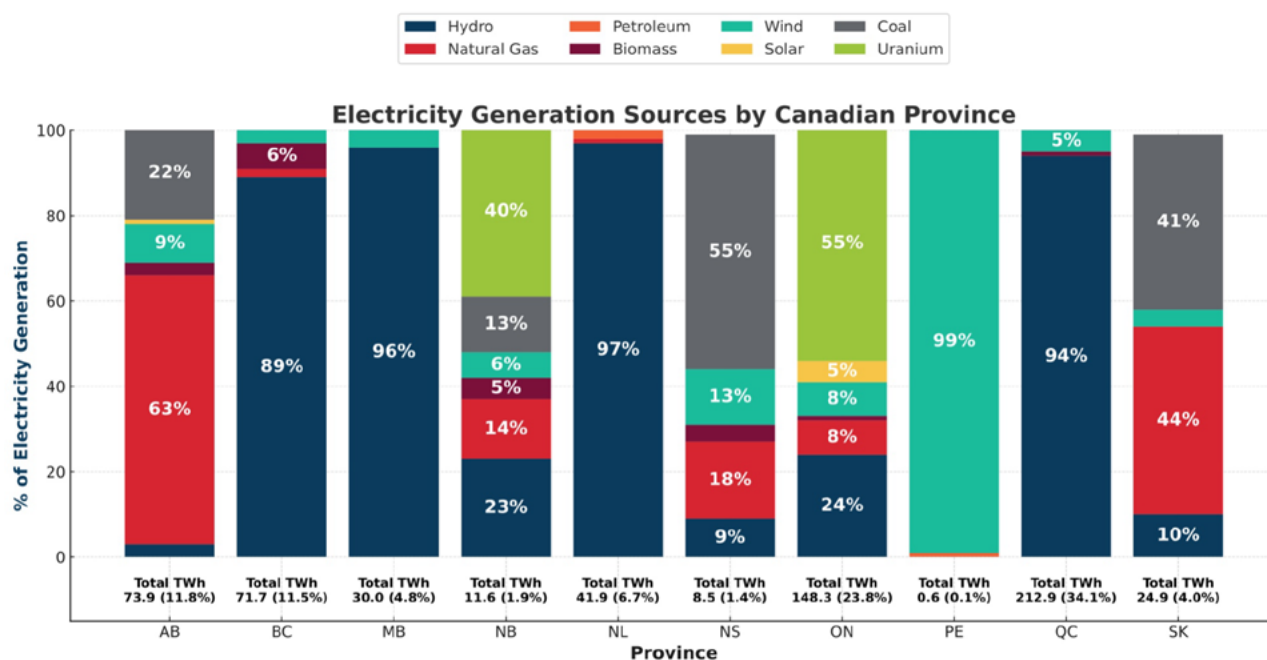


Figure 9. Electricity generation sources by Canadian province, 2021*

Source: Canadian Energy Regulator (CER), 2022

*The sum of individual percentages may not equal exactly 100% due to rounding by the CER.

The division of powers under Canada's constitution means that electricity systems are essentially under provincial control. However, the federal government retains regulatory oversight in several areas, including the nuclear industry, electricity exports, national and international environmental pollutants, inter-provincial transmission, and electricity metering, as explicitly provided for by the *Electricity and Gas Inspection Act*.^[84] Provinces have always viewed electricity policy as a critical lever for economic development, and jealously guard control over generation and transmission. North-south grid interties with U.S. markets are more developed than east-west interprovincial grid connections.^[55] The eight mainland Canadian provinces are integrated into the grid balancing areas of the North American Electric Reliability Corporation (NERC).

In most provinces, electrical utilities are vertically integrated Crown corporations. Deregulated wholesale electricity markets exist in Alberta and to some extent in Ontario. Industry accounts for the largest share of domestic consumption (39%), followed by residential buildings (32%), the commercial and institutional sectors (27%), agriculture (2%), and transport (0.2%), with variation across provinces (Figure 8).

Canadian electricity prices are among the lowest in the OECD but differ from province to province. There are arguments over how best to compare rates (at what level of monthly consumption, before or after taxes, and so on) but the basic pattern of variation is captured in Figure 10. Industrial bulk users receive significant discounts, and hydro provinces typically have the cheapest rates.^[85]

Average Large Industrial and Residential Electricity Prices* (as of April 2023) in cents/kWh

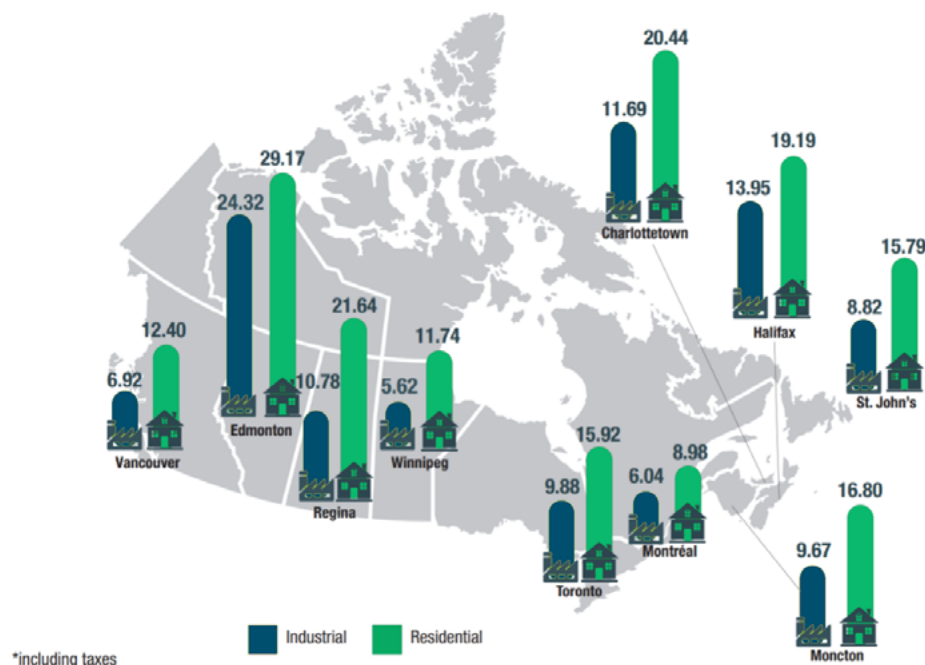


Figure 10. Average large industrial and residential electricity prices, April 2023

Source: NRCAN, 2023. Electricity Facts.

Climate change–related drought conditions in recent years have measurably strained Canada’s hydroelectric generation capacity. Hydropower typically provides around 60% of the nation’s electricity, so prolonged low precipitation and high temperatures can significantly constrain overall supply.[86] In 2021, Manitoba Hydro incurred an estimated \$248 million³ revenue loss due to drought-driven hydropower shortfalls.[87] After a brief recovery in 2022, widespread drought returned by 2023, driving an 8.4% year-over-year drop in hydroelectric and pushing total generation to its lowest level since at least 2016.[86] This hydro shortfall has persisted into 2024, with national hydropower production remaining about 3.5% below the recent five-year average as drought conditions continued in parts of central and eastern Canada.[88]

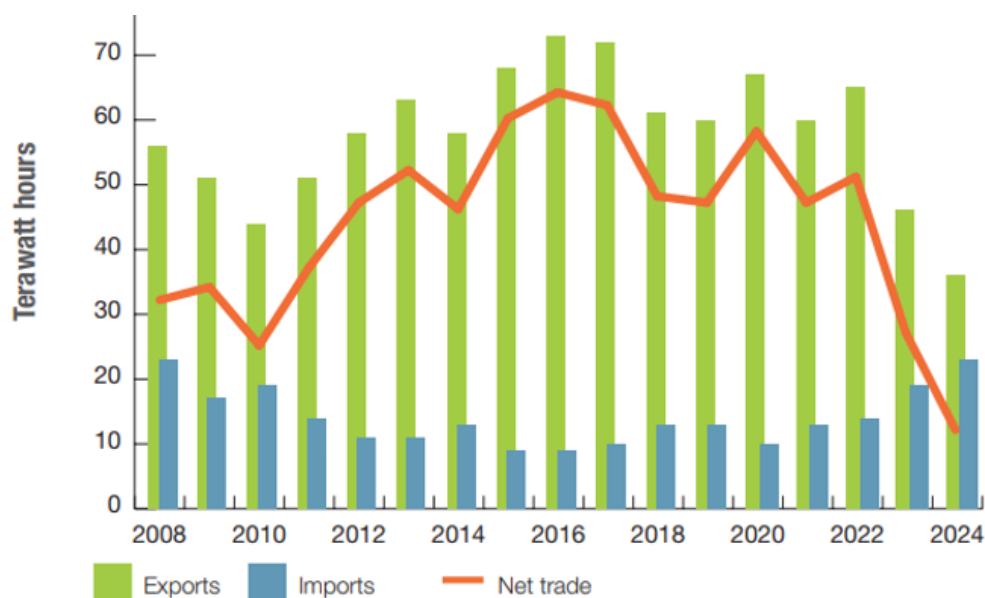
These climate-driven deficits have also disrupted electricity trade and grid operations. With reduced water inflows, Canada’s exports

of electricity to the United States fell by roughly one-quarter in 2023—the lowest export volume in years—as utilities dialed back cross-border sales to preserve reservoir levels.[80] To maintain reliability, other sources were leveraged: domestic thermal generation was ramped up, and electricity imports from the U.S. surged by over 50% year-on-year.[89] Such drought-related stresses on the grid are expected to recur; federal climate assessments project that summer droughts will become more frequent and intense in key hydropower regions of southern Canada under warming scenarios.[90]

The recent hydroelectric shortfalls and trade imbalances of 2020–2024 are therefore seen as a preview of the challenges climate change poses to Canada’s electricity system, underscoring the need for adaptive measures to safeguard grid resilience.

³ In 2021 Canadian dollars

Canada's Electricity Trade with the U.S.*



* includes only electricity traded under purchased contracts; excludes electricity transferred under non-financial agreements (e.g. under treaty obligations)

Figure 11. Canada's electricity trade with the United States, 2008-2024

Source: Natural Resources Canada, 2026. *Energy Fact Book 2025-2026*[91]

7.1.2 Nature of the Problem

Electricity systems have a pivotal role to play in decarbonization, as power can displace fossil fuel end-uses in transport, buildings and industry. At a global scale, the shift to low carbon electricity is well underway, with dramatic falls in the price of wind and solar generation encouraging ever wider deployment (see Figure 12).[92]

In this context, Canada enjoys three distinct advantages. First, our electricity supply is already substantially decarbonized.[93] Second, we have generous renewable resource endowments (including wind and

solar, but also tidal and geothermal), often located in areas where fossil energy dependence is highest today. Third, our abundant legacy hydro (the third largest installed capacity in the world[80]) can provide an energy storage solution to help balance grids and facilitate the large-scale integration of intermittent renewables.[94] Canada's ready access to low-carbon energy and potential to rapidly complete the decarbonization of electric supply is a competitive advantage to attract businesses seeking cheap net-zero emission power (for battery or EV manufacture, minerals processing, etc.).

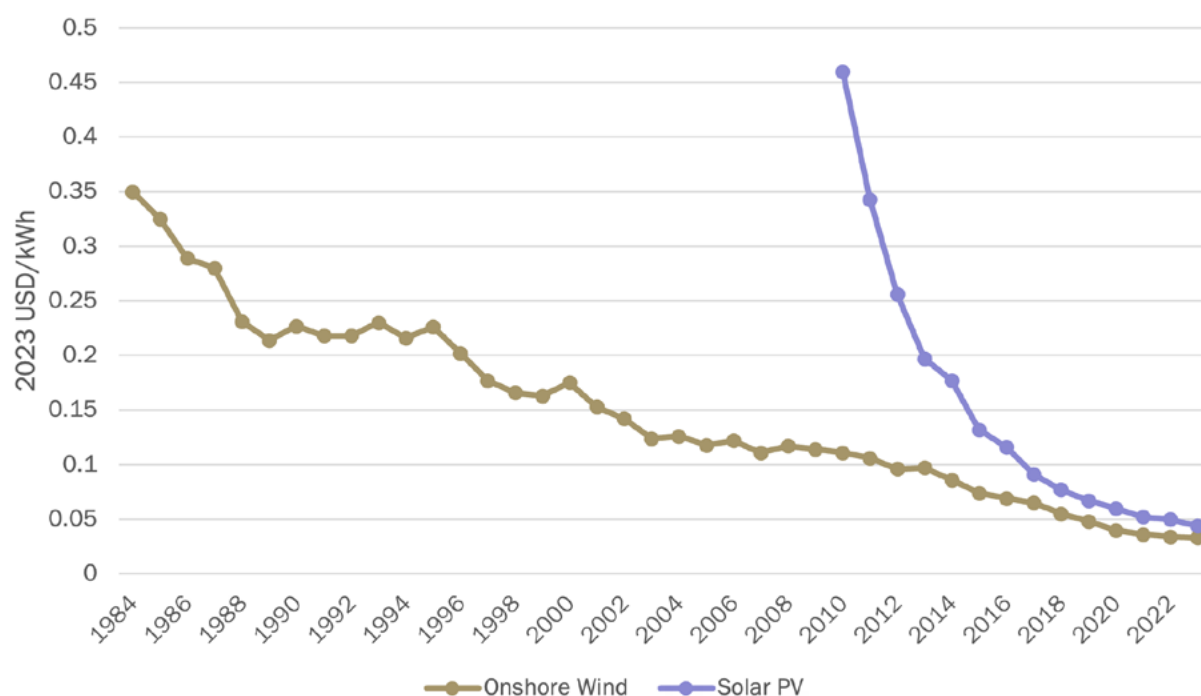


Figure 12. Global weighted average of levelized cost for onshore wind and solar PV, 1984-2023

Source: IRENA, 2023[95]

Nevertheless, the current split between low- and high-carbon provincial electricity systems poses challenges. The financial and political effort required to transform the fossil-dependent systems will be significant, requiring the construction of new generating capacity, retirement of fossil assets before their anticipated lifetime, and movement away from coal or gas produced within the province.

Most models suggest the cost of fully decarbonizing Canadian electricity systems could be lowered by closer inter-provincial coordination. While this flows against the tradition of provincial independence,[55,96] the federal government appears interested in encouraging such linkages.[97–99] More recently, eight provinces and territories signed a memorandum of understanding to build better-connected country-wide electrical transmission infrastructure.[100] In 2023, the federal government introduced Clean Electricity Regulations (CER) to establish a national framework for achieving a

net-zero electricity grid by 2035, signaling a stronger federal role in shaping long-term power system planning and emissions performance across provinces.

Other current challenges relate to public sensitivity over rising electricity costs, aging electricity infrastructure, electricity rate structures not aligned with the shift to net zero, and potential opposition to large scale energy projects (generating facilities, transmission lines). Over the past decade, average electricity costs in Canada have increased more rapidly than inflation.[101] The largest increase has been in Ontario, where prices rose by two thirds between 2007 and 2016. Although household energy spending averages only 2.6% of domestic budgets, increases hit lower-income families particularly hard. And electricity price increases are always politically salient. Drivers of this rise in Ontario included the costs of moving off coal, refurbishment of aging nuclear plants, grid modernization, and

decades of artificially suppressed prices and lack of investment. Although price rises in Alberta have been modest (because of exceptionally low natural gas prices), managing cost pressures will be an important consideration in advancing electricity decarbonization. Much of Canada's electricity infrastructure dates from the post-war period, requiring projected investments of nearly \$1.7 trillion⁴ by 2050, to meet clean electricity demands.[102] Public opposition to large energy infrastructure projects is not confined to pipelines, and resistance to the construction of generation assets (power plants, wind or solar developments) and transmission could raise costs, introduce delays or forestall potential projects.

7.1.3 Net-Zero Pathways

Moving Canada's electricity systems towards net zero involves two interrelated tasks: decarbonizing the existing electricity supply and expanding electricity systems so they can power sectors currently dependent on end-use fossil fuels. Both involve (a) building net-zero electricity generation; (b) adjusting electricity grids to make them more flexible, smart, and resilient; and (c) managing demand and encouraging energy efficiency to limit the need for additional generation. This will require a combination of centralized and decentralized energy solutions. Ultimately a net-zero electricity system may be integrated more closely with other parts of the energy system: for example, with hydrogen produced through electrolysis (or from fossil resources with CCS), which can serve as an electricity storage medium and meet demand in other sectors.

The first challenge—decarbonizing existing electricity supply—is most acute in fossil dominated provinces (Alberta, Saskatchewan,

Nova Scotia), but there is work to be done in New Brunswick and Ontario. The second challenge—expanding capacity to meet increased demand—is often assumed to be gradual, yet industrial demand can spike abruptly, particularly from sectors such as data centres, which require substantial capacity additions within short time frames. This rapid growth places pressure on electricity systems even in provinces like Alberta, Quebec, and Newfoundland, which currently have power surpluses.

Modelling suggests that electricity demand might double or more by mid-century in a decarbonized economy.[78,79] However, this estimate does not fully account for the recent emergence of AI data centres, whose significant electricity consumption could further accelerate the need for grid expansion. Increasing power production and distribution on this scale over coming decades represents an enormous task—especially in a context where energy projects today can stir substantial public opposition.

There are many ways to make relatively inexpensive net-zero emission electricity, but each approach has costs as well as benefits.[94] Hydro forms the backbone of most Canadian electricity systems, providing cheap and reliable legacy power. But sites close to demand centres have already been exploited, environmental impacts are substantial, capital costs and cost overruns (such as those at Muskrat Falls in Labrador and the Site C dam in British Columbia) are a significant concern, and there has been opposition from Indigenous communities. It is generally assumed that while new hydro generation will continue, most future capacity additions will come from other generation sources. Tremendous wind resources and falling prices mean that wind often represents the cheapest incremental addition to grids.

4 In 2011 Canadian dollars

Wind is intermittent in the short term, and its energy output varies by season, so a backup and/or storage is required when it does not blow. In the near to medium term, some jurisdictions may continue to rely on limited amounts of dispatchable thermal capacity (primarily natural gas-fired plants) to manage this intermittency. In these contexts, natural gas generation functions primarily as a system reliability and affordability backstop rather than a growth pathway for electricity supply, with utilization expected to decline with the expansion of wind energy storage, interties, and demand-side flexibility.

In some Canadian jurisdictions there is public opposition to further wind development. Offshore wind is attracting significant global investment and holds considerable promise for Canada's coastal provinces, including Ontario on the Great Lakes, as well as Nova Scotia, which is actively exploring major offshore wind projects. The costs of solar photovoltaic continue to fall.[103] Canada has substantial solar potential, but daily and seasonal variability pose significant challenges. Specifically, the mismatch between peak energy demand—driven primarily by electric heating and heat pumps during cold winter nights—and the lowest

availability periods for wind and solar generation highlights a critical obstacle. Addressing this seasonal imbalance will be central to integrating renewable energy successfully into Canada's electricity grid.

Other renewables (tidal, wave, geothermal) have promise but remain further from market and are limited geographically. Nuclear provides reliable, GHG-emission-free baseload power in Ontario and New Brunswick. Disadvantages include high capital costs, inflexibility (plants cannot be ramped up or down to follow intermittent renewables), security, waste disposal, and substantial public opposition to new build.[104] Small modular reactors (SMRs) are a possibility for the future, with Canada's first project underway in Ontario and expected to be operational by around 2030. However, the technology remains to be proven, and widespread deployment may be several decades away.[105] Fossil combustion with CCS (with removals to handle residual emissions) is possible. But coal with CCS appears expensive compared to renewables and emits many hazardous pollutants.[106,107] Gas with CCS could serve to back up variable renewables.



For now, wind presents the cost point for other technologies to beat, but solar continues to decline rapidly. Least-cost models of decarbonization in Canada currently suggest massive wind power additions even in hydro provinces.[96] Energy storage is an important consideration in building low-carbon generation capacity. Batteries continue to decline in price, and electricity/hydrogen linkages (where hydrogen serves as storage and a complementary energy carrier) could increase the overall flexibility of the energy system.

But it is not possible today to anticipate exactly how the low-carbon supply will develop. Choices in each province will be influenced by specific system attributes (sunk investments), capacities and decisions of neighboring jurisdictions, the evolution of technologies and comparative costs, public attitudes, market design, and political calculus.

Reliable and flexible grids will be essential to deliver decarbonized supply and expanded end-use electrification. Grids will accommodate variable and more widely distributed generation (e.g. wind and solar), support larger power flows (delivering more energy to end users), connect over longer distances (to balance loads), service more diverse end uses (electric vehicle charging) and allow more sophisticated demand management (to reduce peak usage). Investment in interprovincial and/or international interties, storage (battery, pumped hydro, compressed air, hydrogen, etc.), enhanced communications, and control systems (smart grids) will be important. So too will be adjustments to market design and regulatory mandates to accelerate needed investment.[79,108–111]

Energy efficiency and demand management can reduce the generation and transmission capacity required to deliver expanded energy services. Efficiencies can be sought on the supply side to enhance generator

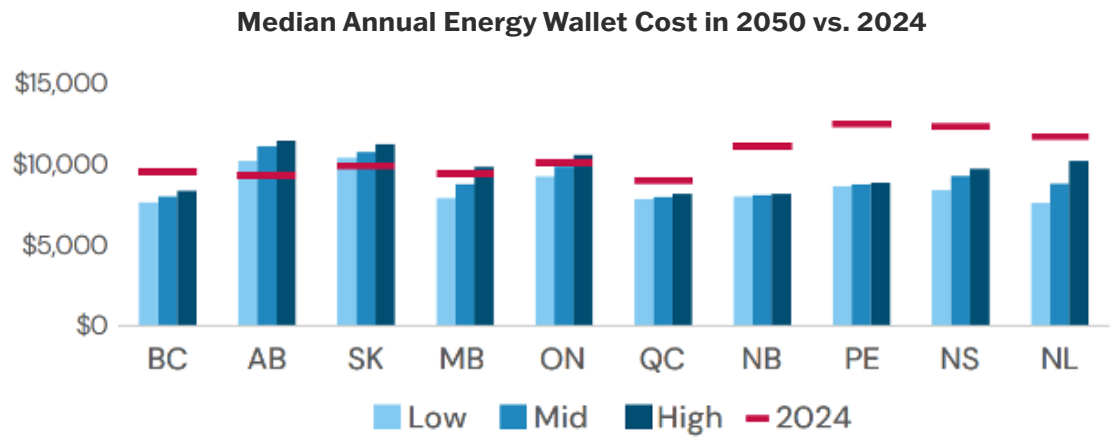
performance and reduce transmission and distribution losses, but more significantly on the demand side through improvements in technologies providing energy services (for example, space conditioning for buildings). Demand management programs that displace use over time (to off-peak hours) or allow customer loads to be curtailed during extreme weather events or other crises can reduce the need for peaking plants and transmission upgrades and contain costs.[112] These programs can involve new technologies, program designs, and institutions (energy efficiency utilities, “behind the meter” energy management companies). While efficiency gains and demand reduction strategies can contribute to managing electricity needs, investment in new generation and transmission capacity should be prioritized. The risks associated with inadequate electricity supply are substantial, whereas the downside of slightly overbuilding capacity is negligible. Moreover, prioritizing efficiency before expansion may hinder progress and limit the availability of essential new energy sources required to support growing industries and economic development.

An important but open question for long-term decarbonization is the extent to which the supply and management of power is centralized with the electrical utilities or decentralized to the customer level. Very different visions of net-zero energy systems co-exist today. On the one hand, there are highly centralized designs where power is produced in areas with maximal renewable resources and then moved across continents to load centres.[113] While existing long-distance transfers predominantly run north-south, emerging renewable energy emphasizes east-west transfers to align with solar availability across time zones. And on the other, highly decentralized models where electricity is produced and consumed locally (perhaps involving microgrids, or tens of millions of “prosumers” producing and

consuming their own power), with traditional grids serving backup and balancing functions.[114] Choices that would generate one or another alternative are political as well as being related to economics, technologies and resource availability. Yet there are many reasons for believing that real-world systems will involve a complex and nuanced mix of centralized and decentralized elements. There are advantages to local power production at the building or community level, such as reducing the need for large-scale projects, avoiding transmission losses and grid congestion, and promoting increased local control and resilience. And yet economies of scale and linkages between regions with different resources and load profiles are also attractive. So it makes sense to take a

pragmatic approach that combines centralized and decentralized elements to optimize overall benefits as net-zero-emission power systems are built out.

The two interrelated tasks of decarbonizing electricity supply and expanding systems must be done with affordability in mind. If done well, they will leave most Canadian households better off. In nearly every province, median energy wallet costs in 2050—defined as the total direct expenditure a household spends on energy—are expected to remain stable or fall compared to today, even under ambitious transition scenarios[115]. Clean electricity paired with smart grid investments and better efficiency isn't just good to reduce emissions; it's a cost-saving strategy for households across the country.



Note: All monetary values are expressed in 2024 Canadian dollars (CAD).

Figure 13. Median Annual Energy Wallet Cost between 2024 and 2050, according to three growth rates for electricity grids (low, mid, high).
Source: The Transition Accelerator, Household Energy Affordability in a Net-Zero Future, 2024

7.1.4 Provincial Initiatives

Critical decisions about the future of Canadian electricity systems will be made at the provincial level.

In making choices, the provinces face distinct geographic circumstances and resource endowments, legacy generation and transmission infrastructure, regulatory structures, and political economic realities.

Ontario

Ontario has a hybrid market design with substantial public ownership, complex lines of authority, and 60 local distribution companies. On May 1st, 2025, the province launched a major update to its electricity market to modernize the system and improve the way the market is scheduled and priced.[116] Electricity policy is highly politicized, with recent arguments about the roll out of renewables and the rise in energy prices. After the coal phase-out, Ontario has had a comparatively clean grid, dominated by nuclear power. But as nuclear units are taken out of service for refurbishment over the coming decade, increased emissions from natural gas plants are likely. To bolster supply and address these pressures, the province is undertaking major procurements of new electricity generation[117] and has completed its largest battery storage procurement to add grid flexibility.[118]

At present the province is firmly committed to a reinvestment in nuclear power. The stakes for the province and Canada's nuclear industry are high. Ontario's first Integrated Resource Plan (IRP) includes major nuclear investments in refurbishments and expansions including both conventional reactors and SMRs. Whether or not longer-term plans for nuclear expansion survive cost overruns and project delays which have often plagued earlier investment rounds, the province will eventually require additional wind and solar

capacity. Enhanced transmission interties with Quebec and aggressive energy efficiency programs could keep costs down and slow the speed at which new generation capacity must be built out.[119]

Alberta

Alberta completed its coal phase-out in 2024, marking a major milestone for decarbonizing its grid. Nevertheless, the province faces major challenges balancing continued decarbonization with affordability and reliability. Its deregulated electricity market remains heavily reliant on natural gas, raising concerns about locking in emissions-intensive infrastructure.

Wind and solar have grown quickly since 2019 but new policy restrictions on siting and reclamation have created regulatory uncertainty.[120] Still, given their cost advantages, renewables remain central to Alberta's energy future. Opportunities to expand grid interties with British Columbia and to develop geothermal and hydrogen offer further pathways to diversify supply.

A key uncertainty is the potential electrification of oil sands operations, which could drive major new electricity demand. Managing this shift while maintaining grid stability will require integrated long-term planning and coordination with federal infrastructure efforts.

Saskatchewan

Saskatchewan's electricity system is vertically integrated and primarily operated by a single public utility, SaskPower, with the exception of Saskatoon, which has an independent distribution utility. The system remains heavily reliant on coal and natural gas generation. Unlike provinces with large hydroelectric or nuclear fleets, the province has minimal non-emitting baseload capacity, giving it one of the longest decarbonization pathways in Canada. The province still

operates multiple coal-fired power units, including one with CCS (Boundary Dam 3), as well as gas-fired plants. The dependence on fossil fuels means that the province requires major new investments in generation and transmission infrastructure to transition to a low-carbon supply.

In 2023, the province signaled plans to extend the life of its coal-fired plants (which run on locally mined coal) even as current federal regulations mandate phasing out unabated coal by 2030. Saskatchewan has set a goal of net zero by 2050 and has asserted provincial jurisdiction over power generation.[121–123] In the meantime, SaskPower is pursuing a diversified transition strategy by expanding renewables, with plans to add up to 3,000 MW of wind and solar capacity by 2035, maximizing imports of hydroelectric power from Manitoba, and exploring nuclear energy.[121]

Manitoba

In Manitoba, hydroelectric dams produce most the province's power, and this hydro dominance keeps Manitoba's grid emissions among the lowest in Canada—though drought years can pose challenges.

The province's surplus of hydroelectricity is sold via interconnections, with export sales contributing to over one-fifth of Manitoba's electricity revenue. However, politically, the province has begun prioritizing domestic use of its hydro resources. In 2025, it declined the renewal of 500 MW of U.S. export contracts to reserve more power for regional economic development.[124] A major initiative in this regard is the proposed Kivalliq Hydro-Fibre Link, which is a combined transmission and broadband corridor that will send Manitoba's surplus power to Nunavut's Kivalliq region to displace diesel.[125]

Nova Scotia

Nova Scotia has long depended on coal-fired power, with coal generating over half of the province's electricity in 2021. In recent years, however, provincial law has mandated phasing out coal and reaching 80% renewable electricity by 2030.[126]

In 2024, the province enacted major reforms to modernize electricity regulation and drive its clean energy transition. The *Energy Reform Act* created a new Nova Scotia Energy Board and established an independent system operator to take over grid operations and planning from Nova Scotia Power to ensure more transparent, climate-aligned decision-making.[127] Nova Scotia also intends to add roughly 1,500 MW of onshore wind capacity by 2030[128] (including Indigenous-led projects like the 94 MW Mi'kmaq-owned Weavers Mountain wind farm[129]) and increasing imports of hydroelectricity via the Maritime Link from Labrador. As of 2025, the province has brought renewables to 43% while cutting coal's share down to 36%.[128]

New Brunswick

New Brunswick's generation is a mix of major hydroelectric facilities and the Point Lepreau nuclear station, which together provide almost two-thirds of the province's electricity.[130] The remaining third is sourced from emitting sources, such as coal, oil, and gas.[131] The province is now positioning its grid for decarbonization in line with current federal CER target of net zero by 2035. The province has committed to phase out coal by 2030 and is planning major clean energy investments. This includes a nearly fivefold expansion of wind power by 2035 (adding 1,400 MW of new wind power) and solar power (adding 200 MW)[130]. NB Power is also planning to build SMRs at Point Lepreau by 2035 (adding 600 MW), with a 100 MW unit scheduled for 2029.[130]

In 2024 the federal and provincial governments reached an understanding to allow flexibility under the new clean electricity rules, recognizing New Brunswick's need to balance decarbonization with affordability and reliability. Recent developments have focused on NB Power's financial health. The utility has faced rising rates (20% in two years) and \$5 billion⁵ in debt.[132]

British Columbia

A vertically integrated Crown corporation (BC Hydro) serves more than 90% of customers in B.C. Electricity demand is forecast to grow strongly over the coming decades. Further hydro development is politically contentious, as is the development of wind and run-of-the-river projects by independent power producers (under contract to BC Hydro). The completed Site C project on the Peace River attracted significant opposition from Indigenous communities and environmental groups. But the province has enormous wind potential. BC Hydro is beginning to harness this through regular calls for power: the utility launched its first competitive power procurement in 15 years in 2024 and is set to add about 5,000 GWh per year of new wind-based generation from that call.[133] Going forward, BC Hydro plans to hold such calls bi-annually to continuously bring new renewable energy online, primarily tapping the province's abundant wind resources.

Key areas of focus in the future include efficiency and demand management, continuing modernization and upgrades of transmission and existing hydro facilities, and incremental addition of renewables, especially wind. BC Hydro's expanded demand management programs emphasize energy efficiency and peak shaving, even piloting "virtual power plants" that aggregate distributed energy resources. For example, in 2025 the utility debuted a Peak Saver pilot project, installing 200 coordinated residential

batteries in two communities to improve grid resilience.[134] They are also investing in grid infrastructure by working to expand the transmission system in the northwestern part of the province to support electrification and economic development in that region.[135] British Columbia's ambition to become a major LNG exporter remains a critical issue, as does a commitment to electrify future liquefaction and associated upstream natural gas production infrastructure (compressors, pumps, etc.), with clean electricity, with obvious implications for electricity supply.[136]

Quebec

Quebec's electricity system is dominated by Hydro-Quebec, a publicly owned, vertically integrated utility known for its vast hydroelectric resources. This network ensures that Quebec has amongst the lowest grid emissions in North America, with over 99% of electricity generated from renewable sources. Nevertheless, anticipated growth in domestic electricity demand due to electrification goals, including transportation and industrial expansion, has prompted significant new infrastructure and generation investment. In 2024, Hydro-Quebec launched its 2035 Action Plan, aiming to meet rising demand through significant grid modernization and diversification of generation sources, notably investments in new wind generation capacity of over 10,000 MW.[137] In early 2024, the utility accepted eight bids from five developers to build 1,550 MW of new onshore wind under a call for tenders launched in 2023.[138]

The province is also ramping up solar generation by setting a target of 3,000 MW by 2035.[139] This marks a major shift for a province almost exclusively reliant on hydro power. Further, there has been a renegotiation of the utility's longstanding power agreement with Newfoundland and Labrador over Churchill Falls. Following a

5 In 2025 Canadian dollars

change of government in Newfoundland and Labrador, the 2024 agreement-in-principle was replaced by an enhanced agreement signed in August 2026 that guarantees supply from Churchill Falls until 2077. It also gives Hydro-Québec access to a total potential of more than 10,000 MW from Labrador, of which 6,915 MW is firm and 3,850 MW is tied to potential future projects, such as a Labrador wind farm and an additional hydroelectric facility at Churchill Falls.[140-142]

In all cases, provincial politics plays a significant role in the structure and design of electricity markets. If Canada is to meet long term decarbonization goals in a cost-effective manner there will need to be a concerted effort to break through parochial electricity market rules that prevent access and flexibility, and to enhance the potential for inter-jurisdictional coordination.

Competitiveness Implications

Canada's hydro provinces can make an offer most jurisdictions cannot: legacy reservoirs provide dispatchable clean electricity and the grid flexibility to integrate large volumes of wind without the dedicated storage costs that raise system prices elsewhere. The real competitive asset is hydro-wind complementarity, not clean generation on its own, and it functions as an industrial siting advantage at a moment when data centres, battery plants, and minerals processors are competing globally for firm, affordable, low-carbon power. Manitoba's 2025 decision to redirect 500 MW of export capacity toward domestic economic development suggests provinces are beginning to treat clean electricity as an economic development tool rather than an exportable surplus. But the window narrows as other jurisdictions build out their own clean supply. Whether Canada captures that investment depends less on generation endowment than on how fast provinces can connect strategic industrial loads to firm clean power.

7.1.5 Priorities for Action

Priorities for action differ by province. For the fossil-dependent jurisdictions, increasing energy efficiency, investing in renewable generation, building interties with neighboring hydro provinces, and phasing out coal are the most urgent tasks. Current federal regulations set 2030 as the deadline to end unmitigated coal generation, but decommissioning plants earlier will lower carbon intensity and secure immediate air quality gains. Simply replacing coal plants with new gas plants should be avoided. With the continuing fall in wind and solar costs, it makes more sense to build renewable resources steadily, particularly

since the fossil-based systems are well buffered with gas. As it is quite possible that emission abatement targets will be further tightened over coming decades, even "CCS ready" plants will pose a risk, so a straight switch to renewables is more prudent to prevent the further stranding of fossil assets.

For the hydro-rich provinces, incremental buildout of wind or solar can be timed to provide additional supply as needed. Large hydro facilities provide opportunities for storage to meet peak demand and balance intermittent resources. Active exploration of interties with neighboring provinces offers the possibility of more flexible and resilient

grids, and additional revenues or reduced power costs, through power transactions. At some point all jurisdictions should:

- Put greater effort into long-term power system planning by starting from the target of meeting anticipated needs while achieving net-zero GHG emissions by mid-century and modelling backwards. This involves first estimating the total electricity demand required to support full electrification of end uses at net-zero emissions. Once this endpoint is established, provinces can then work backwards to determine annual increments of generation, transmission, and distribution infrastructure needed. Scenarios should focus on system transformation, including radical shifts in supply and demand configurations, rather than incremental market-induced adjustments alone. Further, the planning should explore the implications of continued radical cost reductions in clean technologies, demand response, and efficiency measures, as well as collaboration with other jurisdictions.
- Introduce regulatory and/or market reforms to make system decarbonization and expansion a central preoccupation of all system entrants. Most provincial electricity markets are designed to limit access, limit flexible market participation, limit imports and exports, and facilitate central control. This historic approach to electricity system planning needs to shift to one of open access, flexibility, policy certainty, competition, and opportunities for market participants to operate in demand, response, efficiency, supply, storage, and financing. Governments must direct regulatory bodies to create regulated return models that incentivize achieving net zero and phase out rate structures based on sales volumes and capital expenditures.
- Ramp up incremental investments in transmission infrastructure (modernization, smart grids, distribution, renewables access, etc.) and storage to build flexible and resilient grids that can be adapted to shifting demand, and technological innovation.
- Involve electricity companies and regulators more directly in electrification of GHG emitting energy end-uses (such as transportation, space heating and cooling buildings, and industrial processes) to permit utilities to offer behind-the-meter load management systems and financial incentives to push load off peak.
- Support Indigenous power initiatives across the system, including northern and off-grid community supply projects, building efficiency, and building replacement, geothermal, skills training, and Indigenous-led finance mechanisms.
- Accelerate development and investment in new technologies, including geothermal, small modular reactors, hydrogen linkages, energy storage, and smart grid technologies.

Criteria Status

-
- Fails to meet criteria
-
- Meets in some respect
-
- Not promising
-
- Potentially meets criteria
-
- Meets criteria

7.1.6 Electricity Pathways Table

Not promising Potentially meets criteria Meets criteria			ALIGNMENT WITH CARBON NEUTRALITY	Economic		Technical			Social		
PATHWAY ELEMENTS	ROLE IN NET-ZERO SYSTEM	SIGNAL TO DECISION-MAKERS		ECONOMIC VIABILITY	ECONOMIC DEVELOPMENT OPPORTUNITY	MATURITY	OPERATIONAL FIT	INFRA-STRUCTURE AND SUPPLY CHAIN SUITABILITY	SOCIAL ACCEPTABILITY	RELEVANCE TO STAKEHOLDERS	RELATED BENEFITS AND COSTS
 Electricity Generation											
Wind (Onshore & Offshore)	<i>Priority</i> Decarbonization Pathway Expected to provide significant portion of power in a net-zero future. Canada has a vast wind resource on land and coastlines.	Deploy Support deployment with permissive regulatory environments. Educate public to reduce safety and environmental misconceptions.	 Clean power but needs storage to handle intermittent generation.	 One of the cheapest sources of new electricity, with low operating costs. Offshore wind costs remain higher. Intermittency may add costs.	 Drives jobs in manufacturing, construction, and maintenance. Boosts rural incomes through land leases and taxes. Positions Canada for export opportunities.	 Fully commercial — mature technology deployed widely. Offshore wind is less mature in Canada but proven in Europe.	 Integrates well with modern grids but challenges remain with regard to balancing and storage.	 Typically requires new transmission from wind areas to demand centres.	 Generally accepted but local opposition can be significant. Community involvement can improve acceptance. Offshore has higher acceptance.	 Aligned with federal and most provincial clean energy goals. Backed by utilities, provincial plans, the wind industry, and some landowners.	 No air pollution or water use during operation. Some issues with noise, migratory bird or bat deaths, and landscape impacts.
Utility-Scale Solar PV	<i>Priority</i> Decarbonization Pathway Costs now rival or beat new gas, and suitable land/rooftop area is ample.	Deploy Support deployment with permissive regulatory environments and R&D in cold-climate regions.	 Clean power (assuming panel lifecycle emissions are managed) but needs storage to handle intermittent generation.	 Cost-competitive with or cheaper than new natural gas generation in certain provinces. Intermittency may add costs.	 Construction and maintenance jobs. Draws private investment, boosts local tax revenues, and supports innovation and exports.	 Technology is proven. Multiple large solar farms operate in Canada. Performance in cold climates being demonstrated.	 Easy to connect at various scales, but high adoption needs better grid management.	 Most useful when paired with storage or hydro, but output varies seasonally.	 Strong support. Local concerns about land use can arise.	 Utilities for grid planning. Governments and regulators for meeting clean energy targets. Industry and communities through deployment.	 No direct emissions and improves air quality and health. Recycling of panels is immature.
Small-Scale & Residential Solar PV	<i>Potential</i> Niche Pathway Constrained by roof space and economics but still material.	Engage Upgrade local grid infrastructure to allow for smart metering. Provide financing options to assist in managing upfront costs.	 Clean power (assuming panel lifecycle emissions are managed).	 Costly without incentives but offers savings and local grid benefits. Costs are gradually declining.	 Local job creation in installation, sales, and manufacturing. Widespread adoption spurs investment within communities.	 Mature with numerous installations in Canada.	 Requires sunny, grid-connected areas or remote areas paired with batteries. Can require backup through winter.	 Integrates easily on rooftops with little land or new infrastructure needed. Some smart meters and local grid upgrades needed.	 Generally very high public acceptability with no notable opposition.	 Consumers and municipalities for cost savings and energy independence. Mixed views from utilities for grid impacts and revenue concerns.	 Clean, quiet energy source with reduced grid strain during peak times. Minimized land impact. Recycling of panels is immature.

PATHWAY ELEMENTS	ROLE IN NET-ZERO SYSTEM	SIGNAL TO DECISION-MAKERS	ALIGNMENT WITH CARBON NEUTRALITY	Economic		Technical			Social		
				ECONOMIC VIABILITY	ECONOMIC DEVELOPMENT OPPORTUNITY	MATURITY	OPERATIONAL FIT	INFRA-STRUCTURE AND SUPPLY CHAIN SUITABILITY	SOCIAL ACCEPTABILITY	RELEVANCE TO STAKEHOLDERS	RELATED BENEFITS AND COSTS
Building-Integrated Solar PV	Niche Pathway Typically only used in showcase buildings.	Deploy Encourage interest from developers and building owners with financing mechanisms. Provide workforce training for installation. Work to integrate micro generation with the larger electricity grid.	 Clean power (assuming panel lifecycle emissions are managed).	 Costs have dramatically declined over time. Economics can depend on regional incentives. Return on investment occurs in solar panel lifespan.	 Industry is well established. Some opportunities for local installers and domestic material production.	 Commercially Mature.	 Best on sun-exposed surfaces in space-limited urban buildings. Must be integrated into building design and meet codes.	 Supply chain is early commercial.	 Widely accepted and non-disruptive.	 Niche interest among innovation-focused stakeholders, with limited utility impact due to small scale.	 When paired with storage they provide resilience in power outages and reduce peak demand. Can sell energy back to the grid. Immaturity of recycling panels and differing lifespan from building materials.
Hydro (Reservoir)	Decarbonization Pathway Forms the backbone of Canada's decarbonized baseload power. In the future, new generation will be challenging.	Deploy Support new builds where site conditions are economical and expansions where feasible. Collaborate with Indigenous communities. Expand and improve transmission infrastructure.	 Achieves net zero. Some GHG emissions associated with initial flooding and land changes, but these can be mitigated over time.	 New generation is likely to be capital-intensive, with long payback but low operating cost. Competes well on cost per MWh if sites are appropriate.	 Large projects spur employment. Limited new dam opportunities, but exporting hydro power can generate revenue.	 Mature technology with decades of operation.	 Compatible with grid needs. Some concerns about impact of changing climate on reservoir levels.	 Large dams require extensive transmission build-out to deliver power. New projects still face logistical challenges.	 Historically mixed — strong opposition from Indigenous groups and environmentalists for new large dams. Shared equity or co-governance with Indigenous communities can improve acceptability.	 Provincial utilities for reliable baseload and storage capacity. Relevant to Indigenous communities where there are equity stakes, co-governance, and early engagement.	 Delivers clean energy balancing other intermittent renewables (water reservoir storage). However, can lead to flooding of ecosystems and Indigenous lands.
Hydro (Run-of-River)	Niche Pathway Strong fit where geography allows, yet cannot scale to a large national share.	Deploy Support buildout where site conditions are favourable. Collaborate with Indigenous communities.	 Can supplement big hydro reservoirs.	 Cost per kWh can be competitive in favourable sites.	 Regional construction and contracting opportunities for smaller firms. In Indigenous or rural areas, can spur local economic activity.	 Proven technology and mature. Deployments in Canada are ongoing but site-specific.	 Particularly suitable for remote or smaller grids.	 Integration is simple, but remote projects need new transmission lines on a smaller scale.	 Generally more accepted than large dams. Local opposition still possible from environmental groups and Indigenous communities.	 Local and Indigenous communities looking for development. Provincial utilities looking for incremental additions to the grid.	 Avoids large reservoir flooding and has a lower ecological footprint. Can have a negative impact on river health.

PATHWAY ELEMENTS	ROLE IN NET-ZERO SYSTEM	SIGNAL TO DECISION-MAKERS	ALIGNMENT WITH CARBON NEUTRALITY	Economic		Technical			Social		
				ECONOMIC VIABILITY	ECONOMIC DEVELOPMENT OPPORTUNITY	MATURITY	OPERATIONAL FIT	INFRA-STRUCTURE AND SUPPLY CHAIN SUITABILITY	SOCIAL ACCEPTABILITY	RELEVANCE TO STAKEHOLDERS	RELATED BENEFITS AND COSTS
Nuclear (Conventional Reactors)	Decarbonization Pathway Makes up a large share of non-emitting baseload. Development beyond current assets is limited.	Deploy Future support may be relevant in provinces with uranium supply chains or long-standing operational experience.	Zero-emission, steady power. Requires decarbonized mining and waste management to handle upstream and downstream emissions.	Costly and have a history of significant cost overruns and schedule delays. Interest where nuclear supply chains are being built out.	Supports high-skilled jobs via refurbishments. Limited new builds constrain broader economic growth potential.	Mature and reliable. Large reactors remain complex with limited recent innovation.	Fits well but requires major scale, long timelines, and is less flexible for variable renewables.	Strong nuclear supply chains and fuel security, but new builds require major infrastructure and could strain current capacity.	Mixed and region-dependent. Strong backing in some areas (e.g., ON) but persistent concerns over safety and waste in others (e.g., BC, NS).	Ontario and industry group interest. National momentum is building. Investment shifting away from large new builds.	Waste product difficult to manage and some security and safety concerns. Waste heat can have negative impacts on water quality.
Nuclear (Small Modular Reactors)	Potential Decarbonization Pathway Successful deployment has not yet occurred in Canada. Cost and schedule overruns may pose significant barriers.	Incubate Support R&D, pilots, and demonstrations. Build out supply chains capable of manufacturing SMR fuel sources and modular parts.	Zero-emission, steady power. Requires decarbonized mining and waste management to handle upstream and downstream emissions.	Unclear — still in development. Capital costs per kW are not well established.	Could drive major job creation, exports, and domestic industry growth.	Research & prototype stage. No SMR is commercially deployed in Canada yet. Proven in small test reactors.	Some SMR designs well-suited to smaller grids, industrial sites, and remote areas. More flexibility for grid operators.	Strong nuclear supply chain foundations but suitability varies by reactor design. Some SMRs require new fuel sources, modular manufacturing capacity, and upfront supply-chain investment.	Cautious but growing - strong near existing plants, mixed in remote areas, limited nationally.	Backing from federal and some provincial governments, utilities, and heavy industry. Align with decarbonization and energy reliability goals.	Waste product is difficult to manage and some security and safety concerns. Waste heat can have negative impacts on water quality.
Geothermal Power (Closed Loop, Conventional, and Deep)	Potential Decarbonization Pathway Geothermal has potential for generating net-zero electricity and heat.	Enable Support closed loop R&D as well as pilot and demonstration projects. Support longer-term development of deep geothermal.	Conventional geothermal releases some carbon dioxide. Closed loop and deep geothermal are more promising for net zero.	Not currently cost-competitive in Canada currently due to high drilling and capital costs. Potentially viable in remote areas.	Potential dependent on cost-effectiveness. Can create jobs in drilling and operations, reduced fuel imports in remote communities, and exportable tech.	Demonstration stage with one closed loop project under construction in Canada. Deep geothermal in early research.	Site-dependent and best suited to regions with accessible heat at depth. Deep geothermal has wider geographical applicability.	Can leverage oil & gas infrastructure and expertise with standard equipment and a ready supply chain.	Significant concerns of seismic activity for conventional geothermal. Support from off-grid Indigenous communities with closed-loop systems.	Western provinces, oilfield service firms, and federal innovation programs as a transition opportunity. Utilities are cautious.	Small land footprint and co-benefits (usable heat, grid stability, consistent performance, etc.). Can affect water quality if conventional geothermal is used.

PATHWAY ELEMENTS	ROLE IN NET-ZERO SYSTEM	SIGNAL TO DECISION-MAKERS	ALIGNMENT WITH CARBON NEUTRALITY	Economic		Technical			Social		
				ECONOMIC VIABILITY	ECONOMIC DEVELOPMENT OPPORTUNITY	MATURITY	OPERATIONAL FIT	INFRA-STRUCTURE AND SUPPLY CHAIN SUITABILITY	SOCIAL ACCEPTABILITY	RELEVANCE TO STAKEHOLDERS	RELATED BENEFITS AND COSTS
Biomass Power (Combustion)	Niche Pathway Feedstock supply is limited. Likely only economical and net-zero in very niche circumstances such as on-site power generation.	Don't Prioritize Unlikely to have a role in mainstream power generation. Watch for niche opportunities to support local or on-site power generation.	 Dependent on biomass carbon intensity, land change, and transport emissions. Likely requires CCS to achieve net zero.	 Costlier per kWh than wind or solar. Can be viable at small scale near cheap waste feedstock.	 Opportunities in rural and Indigenous communities through local jobs and valorization of forestry residues. Limited growth potential.	 Mature, proven technology widely used in Canada, especially at pulp mills.	 Baseload or on-demand power in biomass-rich regions. Requires developed fuel supply chains and consistent feedstock.	 Challenges around feedstock availability and industry competition.	 Mixed — higher when using waste feedstocks at small, clean facilities. Concerns of sustainability, traffic, and air pollution.	 Minimal interest from utilities, urban planners, and energy developers due to supply risks and higher costs.	 Total lifecycle emissions are variable. Air quality pollutants can be worse than burning natural gas. Land use changes can be negative.
Gas with CCS	Bridge Pathway Can be used as a backup power source while renewables are built out or marginal balancing in a net-zero system.	Don't Prioritize Watch for local or regional power reliability issues. Could be useful as backup power.	 Difficult to capture all emissions with CCS. Requires negative emissions to offset lifecycle emissions (extraction, transport, and combustion).	 Costly due to CCS. Needs subsidies but may become moderately competitive for baseload power.	 Protects existing energy jobs and supports regional CCS industries. Development depends on CCS demand and innovation.	 Demonstration stage. Technology for post-combustion capture from gas turbines is being tested.	 Best for steady-output roles. Can support flexible power with efficiency trade-offs in peaking or cycling applications.	 Benefits from existing infrastructure but requires new CO ₂ pipelines and strong methane management.	 Generally accepted if seen as a climate solution. Opposition remains over continued fossil fuel reliance and CO ₂ storage concerns.	 Relevant to gas producers and suppliers, Alberta, and industries needing firm power.	 Aids grid stability. Air quality and health issues with conventional combustion.
Coal with CCS	Dead-End Pathway Not required in Canada to reach net-zero.	Dismiss Difficult to fit with existing operations and infrastructure.	 Requires carbon offsets which can be limited. Perpetuates use of materials that will have little functionality in a net-zero economy.	 Very high cost and poor economics. can double the cost of electricity. More costly than renewables or gas + CCS.	 Apart from CCS, which has limited growth prospects, there are better opportunities in other clean energy sectors.	 Coal power plants are mature, but CCS is demonstration stage at scale, with one project in Saskatchewan.	 Frequent maintenance outages observed and requires suitable geology to store CO ₂ nearby. Coal phase-out makes this operationally irrelevant.	 Uses existing coal infrastructure with added capture units and CO ₂ pipelines. Coal fleet is being phased out.	 Negative due to coal but moderate CCS acceptability.	 Policies and utilities move to phase out coal entirely.	 Issues with air quality and health from exhaust. Water demand and upstream emissions (associated with mining) are high.

			ALIGNMENT WITH CARBON NEUTRALITY	Economic		Technical			Social		
PATHWAY ELEMENTS	ROLE IN NET-ZERO SYSTEM	SIGNAL TO DECISION-MAKERS		ECONOMIC VIABILITY	ECONOMIC DEVELOPMENT OPPORTUNITY	MATURITY	OPERATIONAL FIT	INFRA-STRUCTURE AND SUPPLY CHAIN SUITABILITY	SOCIAL ACCEPTABILITY	RELEVANCE TO STAKEHOLDERS	RELATED BENEFITS AND COSTS
 Grid Infrastructure and Electricity System Expansion and Improvements											
Inter-provincial Interties	Enabling Pathway Can reduce costs for decarbonization and increase grid resilience.	Deploy Encourage provincial collaboration and support interties that improve power reliability and security.	 Ensures reliability with renewable generation. Clean power can be available when local supply is limited.	 Economics can be positive depending on the projects. Funding is available but requires collaboration between parties.	 Reduces reliance on the U.S. and creates domestic jobs through infrastructure construction and maintenance. Generates domestic demand for electrical equipment manufacturing.	 Transmission technology is mature, but autarchical approach historically hampered progress.	 Provinces operate and plan resources individually. Some connections are geographically difficult with long timelines.	 New or larger transmission lines are required.	 Transmission lines often face local opposition. Shared ownership with Indigenous communities can help build support.	 Greater flexibility and reliability for users. Complexity with provincial collaboration and planning.	 Enhances power reliability in Canada and lowers decarbonization costs but requires new or expanded transmission corridors, leading to potential land disruptions.
International (U.S.) Interties	Enabling Pathway Not a priority for decarbonizing Canada. With political tensions and tariffs, economics have some risk.	Don't Prioritize Most connections and exports already established. Monitor for new export opportunities. Prioritize provincial interties.	 Offers an export opportunity for Canada's excess renewable power.	 Economics depend on the project and power demand within U.S. regions.	 Already a mature industry. Exports could grow with excess domestic power and increasing decarbonization requirements in the U.S.	 Already occurs in every province bordering the U.S.	 Requires strong collaboration between provinces and states, which can be difficult due to misalignment on goals, planning or regulations.	 Requires upgrades to existing transmission lines.	 Transmission lines often face opposition, as they require support across multiple jurisdictions. Additionally, international political tensions may heighten public scrutiny.	 Strong political tensions due to tariffs. Requires many parties to collaborate.	 Both countries benefit from increased reliability in the power grid and cleaner electricity. Some land use changes.
Grid Improvements	Priority Enabling Pathway Necessary to accommodate increased power demand. Raises grid efficiency, reliability, and resilience.	Deploy Support with stable financing. Support testing and piloting of new technologies and build out regulatory environment to include these.	 Integral to the net-zero future and its associated electrical demand across Canada.	 Cost structures vary by the type of improvement. Funding is available for some options.	 Installation and construction jobs in areas completing improvements.	 Depending on the technology, some are established (underground transmission lines) and some are emerging (smart grids).	 Proven technologies can integrate seamlessly whereas newer technologies can be complex with slow regulatory processes.	 Capacity and transmission will need to expand so that location specific needs are met.	 Improved grid reliability is seen positively but increased visible power lines may have opposition.	 Highly important to power companies for improving grid reliability, but viability depends on payment structures and government support to make business cases feasible.	 Improved reliability of electricity delivered to customers.

PATHWAY ELEMENTS	ROLE IN NET-ZERO SYSTEM	SIGNAL TO DECISION-MAKERS	ALIGNMENT WITH CARBON NEUTRALITY	Economic		Technical			Social		
				ECONOMIC VIABILITY	ECONOMIC DEVELOPMENT OPPORTUNITY	MATURITY	OPERATIONAL FIT	INFRA-STRUCTURE AND SUPPLY CHAIN SUITABILITY	SOCIAL ACCEPTABILITY	RELEVANCE TO STAKEHOLDERS	RELATED BENEFITS AND COSTS
Power Storage	Enabling Pathway Necessary to reach net zero where power supply is primarily supported by intermittent renewables.	Enable Support R&D so economics improve and demonstration or deployment where contexts are economically positive. Reduce regulatory hurdles for new technologies.	Prevents excess generation going to waste and mitigates issues related to the intermittency of renewable energy sources.	Costs vary by technology but are falling. Currently and only cost-competitive in certain contexts (remote locations or peak shaving).	Vary by technology but opportunities and projects are emerging associated with domestic jobs.	Some technologies (hydro reservoirs) well developed where others (grid batteries or pumped storage hydropower) at varying levels of commercialization and deployment.	Improved grid operations, Can help with diurnal peaks. Seasonal battery storage not yet feasible or economic.	Will require some changes to connect to the grid but should reduce the burden on infrastructure.	Depends on technology, location and size of projects not widely implemented yet.	Aligns with objectives to improve grid reliability, counteract peaking, and work with intermittent renewable generation.	Counteracts the intermittency of renewable generation.
Demand Side Management	Enabling Pathway Required to reduce and manage overall power demand.	Deploy Support regional and local testing and piloting to determine the best methods and subsequent deployment.	Reduces need for new power generation.	Often cheaper for governments than adding additional electrical infrastructure.	Frees electricity for industry, export, and trade.	Implemented in some locations in Canada with mild success compared to other locations.	Is mainly implemented through policy and regulations which may have downstream effects on operations.	Functions with existing infrastructure and can reduce burden on the existing system.	Resistance to utility-controlled demand. Programs need to be communicated clearly to the public.	Can offer large savings. Seen as very favourable to utilities and large electricity users.	Reduces environmental burden through avoided power generation and grid peak loads. Lowers energy costs.
Energy Efficiency	Enabling Pathway Required to reduce end demand for power.	Deploy Provide education to manufacturers, installers, retrofitters, and purchasers on the benefits of high-efficiency assets. Offer financing mechanisms to help with up-front costs where relevant (i.e. low-income and cold-climates).	Reduces need for new power generation.	Often cheaper than adding additional electrical infrastructure. Funding can vary widely by application and region.	Job growth in many end-use sectors with retrofits and technology installations or upgrades.	Maturity of high efficiency technologies vary by sector and application.	Typically requires purchase of new assets.	Can require import of new end-use technologies. Reduces burden on existing infrastructure.	Understanding and perceptions of efficient equipment can vary widely. Higher-efficiency appliances may also carry higher up-front costs, raising equity concerns.	Inconsistent information leads to limited understanding, causing many stakeholders to undervalue the effectiveness and deprioritize adoption.	Cost savings for consumers and providers. Reduces environmental burden through avoided power generation and grid peak loads. Lowers energy costs.

7.2 HYDROGEN

Function	Today: Used as a feedstock for the chemical industry, fertilizer production, bitumen upgrading, and oil refining. Future: Could play an expanded role as a clean energy carrier in transportation, and industrial heating, alongside emerging roles in energy storage, grid balancing, and in the production of biofuels and steel.
GHG emissions	Currently, Canada lacks a hydrogen-specific national accounting system for production volumes, pathways, and associated emissions. Production methods vary in carbon intensity, and most hydrogen produced today is higher-emission “grey” hydrogen, with only limited low- or net-zero-emissions hydrogen deployed. A rough estimate suggests emissions from Canadian hydrogen production could be 38 Mt of CO₂e in 2024 (already reflected in our inventory, largely under oil and gas and refining categories—not additional to reported totals).¹
Options for decarbonization	Decarbonization Pathways: Autothermal reforming with carbon capture and storage, electrolysis with low-emission electricity. As an emerging but highly uncertain opportunity, some companies are exploring natural hydrogen, which should have very low carbon intensity. Bridge Pathways: Steam methane reforming with carbon capture storage. Niche Pathways: Methane pyrolysis, biowaste gasification, byproduct of industrial processes.
Stage of transition	Emerging: Methane autothermal reforming and pyrolysis, hydrogen derived from carriers (i.e., ammonia, methanol, liquid organic hydrogen carriers, etc.) Early Diffusion: CCS applied to methane reforming and electrolysis supported by low-emission electricity.
Nature of the problem today	There is currently limited demand and production for hydrogen as a fuel, and very limited distribution infrastructure. Very little low-carbon-emission hydrogen is now being produced. Substantial investment risk with the uncertainty in infrastructure development and downstream demand. High production, storage, and delivery costs.
Other systemic issues	Fugitive emissions from natural gas extraction. Requirements of high volumes of decarbonized electricity and water availability for electrolysis. Hydrogen leaks could elevate levels in the atmosphere and increase the half-life of atmospheric methane. In this way, hydrogen is an indirect greenhouse gas, so leaks must be managed.
Strategic opportunities and concerns	Opportunities: Hydrogen is a decarbonization energy option for hard-to-abate sectors. Potential for societal and economic benefits from development of a new industry. Co-located demand and production hubs offer high economic potential. Concerns: Infrastructure/demand feedback loop stalls investment and growth. Decarbonization of existing production methods requires expensive retrofits or new market demand. Hydrogen leakage across production, storage, and transport infrastructure could undermine climate benefits if not effectively managed.
Priorities for action	Use policy to encourage production and demand and co-location of production with demand. Establish carbon intensity thresholds and reduction schedules to ensure a clear pathway to zero emissions. Additional research and demonstration for compatibility with existing infrastructure, equipment, and safety requirements.

¹ National production: 4 Mt of hydrogen
 Energy density: 120 GJ/t
 Carbon intensity of grey hydrogen: ~80 kg CO₂e/GJ
 $4,000,000 \text{ t} * 120 \text{ GJ/t} * 0.08 \text{ t CO}_2\text{e/GJ} = 38,400,000 \text{ t CO}_2\text{e} = 38.4 \text{ Mt CO}_2\text{e}$

Longer-term issues	Buildout of infrastructure to meet broader applications. Address fugitive methane and hydrogen emissions and data gaps. Demand on water.
Indicators of progress	Total emissions from hydrogen production, carbon intensity of hydrogen, production and retail costs, deployment of fuel cell vehicles and other technologies that efficiently convert hydrogen into energy services, proportion of energy use for which low-carbon hydrogen, ammonia or methanol displace fossil fuels in end-use sector.

7.2.1 Current Status

Hydrogen is light, abundant, and highly reactive, and bonds with elements like oxygen to form water or carbon to form hydrocarbons. Releasing hydrogen from oxygen bonds (as in water) requires significant energy input; releasing it from hydrocarbon bonds generates energy. Some industries, like the chlor-alkali sector, produce hydrogen as a byproduct.

Hydrogen is currently used mostly as a chemical feedstock for hydrocarbon refining, ammonia and methanol production, and fertilizer production. Additionally, it can be used as an energy carrier that can generate electricity in a fuel cell, be combusted to generate heat, added to improve the energy density of carbon in biomass, or leveraged to reduce iron oxide in the production of green steel.

Several factors make hydrogen attractive:

- **Zero-emissions Potential:** Hydrogen combustion or electrochemical conversion in a fuel cell emits no greenhouse gases. It is technically feasible to produce hydrogen with zero emissions.⁶
- **Flexibility:** Hydrogen is a versatile molecule that can be stored or transported as a gas or cryogenic liquid. It can be used to make energy-rich chemicals (e.g. ammonia) for transportation or heating, generate electricity, make steel, or produce drop-in biofuels.

- **Complementarity to Electricity:** Hydrogen can fill gaps where electrification is difficult, such as with rail and heavy-duty vehicle transport, and can store renewable electricity as chemical energy. A hydrogen “grid” of pipelines and salt cavern storage could improve the economic viability of large-scale, low-carbon electricity deployment (wind, solar, nuclear), since the production of hydrogen would add value to surplus electricity generation while creating a zero-emission fuel that can be stored for long periods. As a northern country, Canada’s surplus power generation in the summer could be stored as hydrogen for use as a zero-emission heat source in the winter.
- **Regional Benefits:** Hydrogen could support regional transitions away from fossil fuels. Areas with abundant natural gas or renewable energy could have a future role as hydrogen producers. Some argue the Canadian Shield is a promising geology for the discovery of natural hydrogen sources.

Canada has many advantages when it comes to hydrogen production. There are abundant feedstocks, including natural gas, clean electricity, fresh water, as well as space for geological carbon storage. Canada is already established in the hydrogen fuel cell sector with more than 100 companies and 2,400 employees in the value chain.[143,144] Today, Canada produces roughly 4 Mt of hydrogen annually, ranking among the top 10 global producers.[145]

6 Although hydrogen combustion does not produce direct greenhouse gas emissions, it does produce NOx as the air is heated to high temperatures during the combustion process. NOx is not considered a direct greenhouse gas, but it does contribute indirectly to greenhouse gas emissions through the formation of ozone. Additionally, NOx leads to local air quality concerns and is associated with human health impacts.

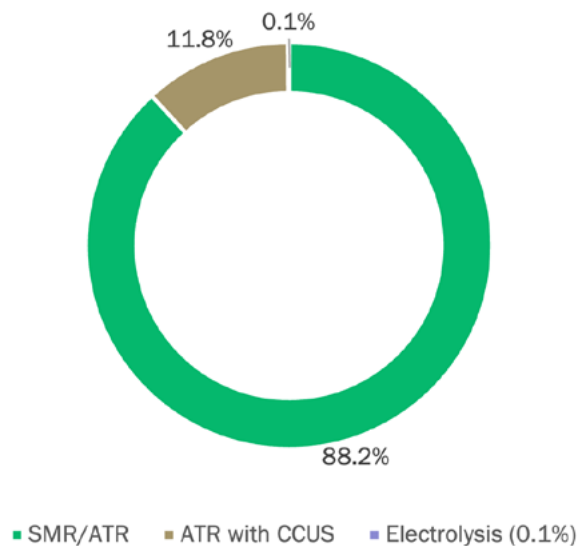


Figure 14. Canadian hydrogen production by method (2024)

Source: CER and AER[146–148]

Virtually all the hydrogen produced in Canada in 2020 was consumed by industrial processes, chiefly oil upgrading and refining, ammonia, and methanol production. Western Canada produces and consumes Canada's hydrogen. Alberta consumes the largest share of hydrogen produced in Canada, about 61%.[149] Alberta also produces 65% of the hydrogen in Canada.[146] Hydrogen-based steelmaking remains a future pathway rather than a current source of demand, with existing direct reduction of iron (DRI) facilities operating on natural gas and only limited pilot-scale hydrogen-use tests conducted to date.

There is consensus that hydrogen will be required to reach net zero, but uncertainty in the required quantities and its use cases. Canada's hydrogen strategy, updated in 2024, envisions hydrogen providing between 3% and 18% of the country's end-use energy by 2050.[148]

7.2.2 Nature of the Problem

The hydrogen economy is confronted with a “chicken and egg” dilemma: infrastructure depends on demand, and demand depends on infrastructure. This mutual dependency fuels market instability and deters investment. Hydrogen has potential as a net-zero fuel, but low-emission hydrogen supply in Canada is extremely limited, distribution networks are fragmented and mostly reliant on trucking, and end-use equipment is only available in niche, early-market applications.

Currently, around 3.5 Mt of hydrogen is generated from unabated natural gas, while only 0.5 Mt is confirmed to employ low-carbon methods.[146–148] According to Canada's updated hydrogen strategy, between 6 Mt and 20 Mt of low-carbon hydrogen will be needed for net zero in 2050.[148] This highlights the need to scale production and shift to lower-emitting methods. However, widespread adoption of hydrogen is constrained by several infrastructure-related barriers.

Infrastructure

Production: Hydrogen's emerging role as an energy carrier requires significant investment in production infrastructure. Achieving low-carbon hydrogen at scale requires retrofitting existing facilities with CCS and building new facilities with either natural gas and CCS or electrolysis. Both options are associated with significant costs and planning. Natural or geological hydrogen is an additional longer-term alternative that, if proven at scale, could bypass some of these production costs entirely.

Transport: Governments and natural gas utilities are exploring repurposing natural gas networks for hydrogen transport, as this minimizes the need for new infrastructure and enables the continued use of gas networks. The picture varies by network type: lower-pressure distribution pipelines are generally more

compatible with hydrogen, while high-pressure transmission pipelines made of high-carbon steel are prone to hydrogen embrittlement and would likely need to be replaced for pure hydrogen service. End-use equipment such as meters, appliances, and industrial burners would also require modification or replacement in either case.⁷ Only newer polyethylene (PE) networks might accommodate pure hydrogen, but such a transition would likely still require the replacement of end-use equipment. Where pipelines are not available, hydrogen must be compressed or liquefied for transport on trucks or trains. This can be expensive, energy-intensive and safety-sensitive.[150]

Storage: Unlike electricity, hydrogen can be stored as a physical fuel, making it a valuable complement to variable renewable generation. However, hydrogen is challenging to store due to its low density and small molecular size. It can be compressed at moderate pressure (i.e., 350 bar) or high pressure (i.e., 700 bar), or liquefied to reduce volume, but these options involve trade-offs in cost, energy use, and safety similar to those in transport. Hydrogen can also be converted into ammonia for easier handling, but this has not yet proven to be cost-effective at scale. Storing hydrogen underground in geological formations shows promise as a low-cost option. Salt cavern storage in particular has been demonstrated commercially, though it is only economical at large scale, reinforcing the need for substantial demand before this alternative is viable.[150]

Distribution: Canada currently has only a handful of accessible hydrogen fuelling stations, leaving most of the country without refuelling options for hydrogen vehicles.[151] High capital costs per station, low utilization, and no self-reinforcing demand cycle yet in

place create a financing gap that private operators are unlikely to bridge without targeted government support.

In all cases infrastructure safety remains a foundational concern. Hydrogen is non-toxic and disperses quickly, reducing some risks. However, its high flammability and low ignition-point demand specialized safety protocols that are currently limited to a few industrial settings. To the extent that hydrogen expands into sectors like transport, the need for broader expertise, standardized guidelines, and public education will grow significantly.

Market size and cost competitiveness

Infrastructure challenges contribute directly to uncertainty in market size and cost competitiveness. Without clear infrastructure pathways, the scale of hydrogen adoption in Canada remains unclear. Hydrogen will continue to serve as an essential feedstock for the chemical and fertilizer sectors and may support difficult-to-electrify applications. However, its potential beyond this, including its role in building heating and transportation, remains less certain. Until infrastructure policies, funding, and plans are in place, investment at scale will remain a challenge.

Hydrogen is currently expensive, largely due to high capital and operating costs and limited end uses. Today it is not cost-competitive with most other fuel types. Cost would go down with infrastructure buildout and greater demand. Ongoing development of multiple technologies will influence its evolving cost competitiveness. While natural gas-based hydrogen is generally cheaper today, electrolysis is expected to become cheaper as technology improves and scales.

⁷ The specific threshold will vary according to the characteristics of the system in question, but 20% hydrogen by volume is often cited as an upper limit for typical natural gas networks. Hydrogen is less energy dense per unit volume than methane, meaning a 20% blend of hydrogen could be expected to reduce emissions by approximately 6-7% over natural gas alone.

7.2.3 Net-Zero Pathways

Hydrogen can be produced by steam methane reformation, autothermal reforming or pyrolysis using natural gas as a feedstock, or electrolysis using water as a feedstock. This section explores decarbonizing these technological pathways. Hydrogen can in principle also be derived from alternative sources, such as biomass. However, due to the limited availability of biomass feedstocks and their likely small role in the market, this is not explored further in this report. Hydrogen generated as a byproduct from industrial processes, like chlor-alkali processes, was also excluded as the supply is limited.

Steam Methane Reforming (SMR)

SMR is the most common method of hydrogen production by reacting methane with steam and air, generating both hydrogen and CO₂. To reach net zero, CO₂ must be captured. Current capture systems typically address only about 60% of process emissions. The remaining emissions are found in flue gas, and there is currently no commercial-scale capture of these. While 90% capture rates have been demonstrated in pilots, no commercial plants exist. It is, however, very difficult to achieve net zero with SMR and carbon capture, as flue gas is very dilute.

Autothermal Reforming (ATR)

ATR is a commercial methane reforming process similar to SMR except that it uses pure oxygen in place of air and carries out the reaction in a closed vessel. This produces a concentrated CO₂ stream, making carbon capture more efficient. There are ATR's commissioned in the United States and facilities planned for Canada; all have target capture rates of 95%.^[152–154] The absence of flue gas simplifies capture, making ATR a more viable near-term pathway for low-carbon hydrogen compared to SMR.

Methane Pyrolysis

Pyrolysis is less developed than SMR and ATR, and has a higher natural gas consumption rate, but recent commercial projects have been announced in Canada.^[155] This method decomposes methane without oxygen to yield hydrogen and solid carbon (carbon black), eliminating the need for carbon capture from process emissions. While carbon black is a valuable product, the development of supply chains would be necessary as its market potential is believed to be limited.⁸

To fully meet net-zero requirements, methane-based hydrogen production pathways (SMR, ATR and pyrolysis) might require negative-emissions technologies to negate fugitive methane emissions, while those involving carbon capture would require such technologies to account for the residual carbon emissions.

Electrolysis

Electrolysis is a process that uses electricity to split water into hydrogen and oxygen. This method produces no direct emissions and does not require carbon capture. The emissions associated with electrolysis are from the source of electricity. Electrolyzers can be found in various sizes, enabling both small-scale distributed units and larger centralized facilities to be deployed as needed. Electrolysis projects are planned in British Columbia, and Canadian Pacific Kansas City has deployed a retrofitted hydrogen-electric locomotive, complete with on-site electrolysis-based hydrogen refuelling facilities, that is reported to be cost-competitive with purchasing a new Tier 4 diesel-electric locomotive.^[144,156,157]

Energy decarbonization across pathways

Regardless of production method, hydrogen pathways rely heavily on energy inputs for heat, processing, or other facility operations. SMR,

⁸ Carbon black is manufactured today for use in various industries such as the production of pigments, and manufacture of tires and other rubber goods.

ATR, and pyrolysis require industrial-scale heat either directly or in the form of steam, while electrolysis requires substantial electricity for processing. To achieve net zero, these energy-related emissions must also be addressed through electrified heating, clean electricity sources, or the use of low-emission fuels.

Hydrogen production methods may be more viable in some regions than others. Alberta's abundant natural gas may favour thermal methods, while British Columbia's clean electricity makes electrolysis more suitable. This highlights the need for location-specific strategies.

Storage and transportation

Storage and transport methods are critical in determining hydrogen's carbon intensity and net-zero compatibility. The most suitable option depends on transport distance, volume, and infrastructure availability. Compressed gas trucks are typically used for short hauls and small volumes, while liquefied hydrogen

becomes more cost-effective at longer distances and larger loads. Pipelines are the lowest-cost option for high-volume regional transport once demand is established, though they require the highest upfront investment. For overseas transport, conversion to ammonia, methanol or liquid organic hydrogen carriers is only economical at large scale due to higher capital requirements. In some cases, it may be more cost-effective to produce hydrogen at the point of use where local natural gas or clean electricity is available, though this should be weighed against the economics of dedicated hydrogen infrastructure, which can be significantly cheaper per unit of energy at scale. Techno-economic analyses that compare capital and operating costs, alongside existing infrastructure and location-specific energy prices, are needed to evaluate trade-offs between these options. Table 3 outlines the main hydrogen transport methods and the distance and volume ranges where each becomes economically viable.

Table 3. Hydrogen transport method distance and amount requirements for economic viability

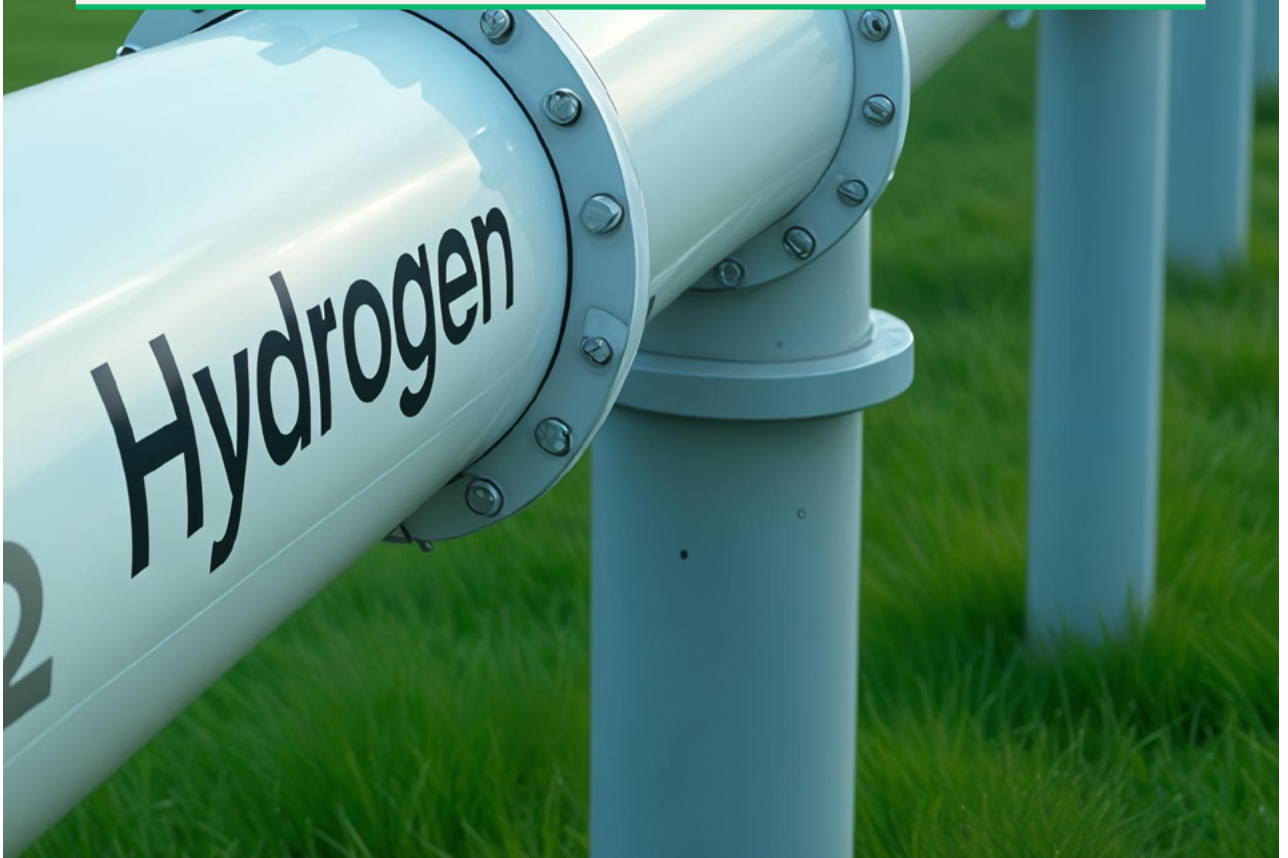
Transport Method	Distances	Amount
Compressed Gas Truck	<320 km	500 kg
Liquefied Hydrogen (Truck/Train)	320 km – 960 km	4 tonnes
Transmission Pipeline	Regional (inter-city or province)	1-2 tonnes/day per km of pipeline
Ammonia (Marine)	>4000 km	Substantial demand required for economy

Competitiveness Implications

The harder problem in Canada's hydrogen export ambitions is market-formation timing. The architecture of international hydrogen trade (carbon-intensity certification thresholds, bilateral offtake commitments, port and carrier infrastructure) is being built now by jurisdictions furthest ahead in deploying certified supply. Producers who lock in these frameworks will set the terms of access others must accept.

Canada has not yet resolved a prior question: whether its export value lies in the hydrogen molecule itself, in derived carriers like ammonia, or in production technology and equipment. These are three different strategies requiring different infrastructure, different partnerships, and different certification pathways.

This is compounded by the divergence between Canada's two regional production tracks: western natural-gas-based hydrogen must demonstrate verified CCS capture rates sufficient to meet emerging carbon-intensity thresholds; eastern electrolytic hydrogen must demonstrate additionality of clean electricity supply. Neither certification pathway is resolved. The risk is not production capability; it is that bilateral offtake relationships and carbon-intensity benchmarks may be substantially set before Canada's export proposition is defined.



7.2.4 Priorities for Action

Identifying viable, no-regrets applications

To accelerate hydrogen deployment and reduce investment risk, decision-makers should start by identifying the most viable and impactful use cases in their jurisdictions—applications where hydrogen is already close to being cost-effective, technically compatible, and operationally necessary. These “no-regrets” opportunities are typically found in sectors where hydrogen has few substitutes, such as heavy industry, refining, and long-haul or high-utilization transport fleets. In regions with clean electricity and surplus grid capacity, electrolytic hydrogen may also be viable for local energy storage or the displacement of high-emissions fuels.

Once these priority applications are identified, policy frameworks can be structured to support them. Focusing early investment and policy effort on these foundational use cases enables capacity building across the value chain, reduces uncertainty for infrastructure development, and establishes the institutional expertise needed to scale hydrogen more broadly in the future. These early steps are not just about technology readiness; they are about creating credible pathways for growth that align with local strengths and decarbonization needs.

Developing viable hydrogen hubs and corridors

A key solution to hydrogen infrastructure challenges is co-locating hydrogen production and demand in a hub, where production, storage, distribution, and end-use are all in one place. These hubs reduce the need to transport hydrogen over long distances and allow the sharing of costs. Offtake agreements, which commit buyers to purchase goods from suppliers in advance of their production, can provide producers with demand certainty and can help to diversify end-use applications. Even

so, it's expected that governments will need to support the initial buildout of infrastructure to get the hubs started. That support should be focused on a limited number of hubs where potential exists to reach commercial scale, delivering hydrogen to end users at a reasonable price for multiple years.

Hydrogen hub development is already underway in Alberta, where strong industrial demand aligns with production potential. Both Edmonton and Calgary host active coordination hubs that focus on connecting hydrogen producers with demand centres and facilitating project development. While these early ventures serve coordination and development functions, fully integrated physical infrastructure hubs with co-located production, storage, distribution, and end-use facilities are still in development. Future clusters are likely to emerge near existing hydrogen demand centres (e.g., refineries, chemical plants), emerging demand (e.g., steelmaking), or transportation nodes (e.g., ports, railyards).

Demand-side support

Demand-side support is vital to the development of the hydrogen ecosystem. Measures that encourage hydrogen demand could include:

- Market development tools and projects for potential key end users, with piloting, testing, and awareness-building around hydrogen technologies.
- Clean fuel standards (such as Canada's Clean Fuel Regulations) to create demand-pull for hydrogen by allowing it to generate compliance credits when substituted for higher-carbon fuels.
- Offtake agreements and contracts of difference to de-risk investment by securing long-term prices and demand.

- End-use incentives to reduce upfront costs for fuel switching and equipment adoption.
- Carbon pricing to increase the cost-competitiveness of hydrogen as fossil fuel costs rise. The exact carbon price needed to make hydrogen cost-effective varies by end use and industry.
- Mandates and procurement requirements for low-carbon fuels like hydrogen in key sectors (e.g., transport, industry).
- Supply chain coordination, including OEM engagement to ensure equipment availability.
- Targeted subsidies or production incentives for electrolytic hydrogen producers.
- Tax credits and financial incentives to offset capital investment and support the whole value chain including transport and storage.
- Carbon intensity thresholds and reduction schedules to ensure hydrogen decarbonizes over time.
- Streamlined regulations and standards to ensure safe deployment and industry clarity.
- Continued decarbonization of electricity grids.

Supply-side support

In addition to co-locating production and demand, coordinated supply-side and demand-side policies are required. Supply side policies to encourage hydrogen production can include:

- Government investment in enabling infrastructure including storage and distribution systems.
- Support for pilot and demonstration projects that improve production technologies and reduce costs, as well as validate the technical compatibility of hydrogen with various end uses.

Canada's hydrogen strategy envisions Canada becoming an exporter of hydrogen and hydrogen-related technologies. However, the specifics of where and how this export will happen are not clear, nor is Canada's comparative advantage as compared to production in other jurisdictions evident.[158] Based on current potential, it is anticipated that eastern Canada will primarily produce hydrogen from electricity, while western Canada will focus on hydrogen from natural gas. Further analysis is required to determine the size of the opportunity and the specifics regarding the return on investment that can be expected for Canadians.

Criteria Status

- Fails to meet criteria
- Meets in some respect
- Not promising
- Potentially meets criteria
- Meets criteria

7.2.5 Hydrogen Pathways Table

PATHWAY ELEMENTS	ROLE IN NET-ZERO SYSTEM	SIGNAL TO DECISION-MAKERS	ALIGNMENT WITH CARBON NEUTRALITY	Economic		Technical			Social		
				ECONOMIC VIABILITY	ECONOMIC DEVELOPMENT OPPORTUNITY	MATURITY	OPERATIONAL FIT	INFRA-STRUCTURE AND SUPPLY CHAIN SUITABILITY	SOCIAL ACCEPTABILITY	RELEVANCE TO STAKEHOLDERS	RELATED BENEFITS AND COSTS
Autothermal Reformation with Carbon Capture and Storage (ATR & CCS)	Potential Decarbonization Pathway Provides significant GHG reductions in hydrogen production.	Enable Invest in oxygen production, and CO ₂ supply in regions with natural gas and geological storage. Support demonstration and prioritize regulatory and infrastructure frameworks.	 Significant GHG reductions. Very high capture feasible via pure O ₂ feed. May require removals for residual emissions. Requires upstream methane capture.	 Moderate premiums from incumbent. More efficient capture process than steam methane reformation + CCS.	 Drives oxygen and CCS services. Regional job growth.	 Demonstration phase.	 High capture efficiency with simplified CO ₂ capture. Requires oxygen production and integration.	 Requires hydrogen pipelines and storage or nearby industrial users. Needs O ₂ supply, CO ₂ compression hubs and storage.	 Generally accepted but public concern over hydrogen safety and CCS leakage.	 Hydrogen producers and natural gas industry as a longer-term net-zero hydrogen production strategy.	 Some concerns about CO ₂ and hydrogen leakage and continued upstream methane emissions.
Steam Methane Reformation with Carbon Capture and Storage (SMR & CCS)	Bridge Pathway Cannot eliminate emissions. Use as an opportunity to codevelop CCS.	Don't Prioritize Do not lead with new investment in CCS retrofits for SMR. Focus investments on ATR and CCS. Allow existing assets to run through their lifespans.	 Offers moderate emissions reduction but cannot reach net zero without combination with negative emissions due to dilute flue gas.	 Moderate premiums from incumbent. High capital costs for retrofit with CCS infrastructure and ongoing operational complexity.	 Maintains existing industrial base and jobs in regions with natural gas resources. Drives CCS services.	 Mature and deployed in Canada.	 Compatible with existing SMR plants, but flue gas capture retrofit is complex.	 Requires hydrogen pipelines and storage or nearby industrial users. Needs CO ₂ compression hubs and storage.	 Generally accepted but public concern over hydrogen safety and CCS leakage.	 Hydrogen producers and natural gas industry as near-term emissions reduction strategy.	 Air pollution concerns. Some concerns about CO ₂ and hydrogen leakage and continued upstream methane emissions.
Pyrolysis of Natural Gas	Potential Niche Pathway Beneficial in regions with natural gas supply and with technical maturity. Provides significant GHG reductions in production.	Incubate Fund R&D and pilot projects to prove commercial viability. Develop markets for carbon black.	 Enables net-zero hydrogen with solid carbon byproduct. May require removals for residual emissions. Requires upstream methane capture.	 Moderate premiums from incumbent. Higher gas consumption. Emerging tech with pilot costs.	 Potential market for carbon black. New manufacturing opportunities.	 Pilot/ demonstration stage.	 Operates similarly to SMR but yields solid carbon. Requires reactor modifications.	 Requires solid carbon- handling supply chain. Nascent support. Requires hydrogen transport and storage or nearby users.	 No particular concerns. Public is unfamiliar with carbon black products.	 Hydrogen producers. Maturity and markets for products limiting uptake.	 Avoids flue gas emissions. Produces marketable carbon black product. Risk of continued upstream methane emissions.

PATHWAY ELEMENTS	ROLE IN NET-ZERO SYSTEM	SIGNAL TO DECISION-MAKERS	ALIGNMENT WITH CARBON NEUTRALITY	Economic		Technical			Social		
				ECONOMIC VIABILITY	ECONOMIC DEVELOPMENT OPPORTUNITY	MATURITY	OPERATIONAL FIT	INFRA-STRUCTURE AND SUPPLY CHAIN SUITABILITY	SOCIAL ACCEPTABILITY	RELEVANCE TO STAKEHOLDERS	RELATED BENEFITS AND COSTS
Electrolysis with Clean Power	Decarbonization Pathway Can produce net-zero hydrogen.	Enable Invest in electrolyzer supply chains and grid interconnections. Support deployment in regions with surplus clean electricity.	 Fully decarbonizes when powered by clean electricity.	 High premiums compared to SMR. Cost declines with renewables.	 Stimulates electrolyzer manufacturing and grid integration.	 Mature but limited commercialization.	 Compatible with existing water and power infrastructures with minor adjustments. Flexible scaling.	 Requires grid upgrades, high-voltage interconnects, electrolyzer supply chain. Requires hydrogen transport and storage or nearby users.	 Highly favourable where clean power exists.	 Hydrogen producers and utilities have begun developing some commercial projects.	 Complements renewable electricity generation. Integration as storage and transportation option. Supports grid balancing.
Biowaste Gasification	<i>Potential Niche Pathway</i> Likely only economical and net-zero in very niche circumstances.	Don't Prioritize Watch for improvements in feedstock costs and conversion efficiency. Prioritize investments if site-specific conditions demonstrate viability.	 Moderate GHG reduction. Dependent on sustainable feedstock availability.	 High operation, maintenance, and feedstock costs.	 Creates rural jobs. Supports waste management and circular economy.	 Demonstration stage.	 Requires biomass pre-processing. Fits waste-to-energy sites.	 Needs certified biomass supply chains. Limited scalability. Requires hydrogen transport and storage or nearby users.	 Waste management supportive. Public views mixed.	 Waste operators and municipalities.	 Reduces landfill emissions. Provides local feedstock management. Competition with other sectors for feedstocks.
Byproduct of Industrial Processes	Niche Pathway Only available from limited chemical production pathways.	Deploy Support capture and utilization of existing byproduct hydrogen streams where economical.	 Moderate GHG reduction. Leverages concentrated process streams.	 Highly viable where hydrogen concentrated. Minimal incremental cost depending on purity of hydrogen byproduct.	 Very limited opportunity to expand as hydrogen supply is dependent on other industries and finite.	 Fully commercial.	 Direct integration into existing process off-gas capture systems.	 Uses on-site infrastructure.	 Broadly accepted as efficient waste valorization.	 Supported by chlor-alkali and petrochemical industries.	 Cost-effective hydrogen supply. Reduces flaring. Improves overall plant efficiency.

PATHWAY ELEMENTS	ROLE IN NET-ZERO SYSTEM	SIGNAL TO DECISION-MAKERS	ALIGNMENT WITH CARBON NEUTRALITY	Economic		Technical			Social		
				ECONOMIC VIABILITY	ECONOMIC DEVELOPMENT OPPORTUNITY	MATURITY	OPERATIONAL FIT	INFRA-STRUCTURE AND SUPPLY CHAIN SUITABILITY	SOCIAL ACCEPTABILITY	RELEVANCE TO STAKEHOLDERS	RELATED BENEFITS AND COSTS
Natural or Geological Hydrogen	Potential Decarbonization Pathway Potential for large GHG reductions but maturity is currently too low to determine overall role.	Don't Prioritize Track geological exploration results and early research. Commit capital when resource potential and extraction methods are clear.	 Fully decarbonized hydrogen.	 Potential to be very low cost, but still speculative.	 Opportunity to develop hydrogen production in regions that find geological potential.	 Research phase; no real-world applications.	 Some geological hydrogen production methods fit with existing utility systems; others would require modification.	 Requires build out and supply of new facilities and technologies.	 Similar concerns to other resource extraction operations	 Some research and early geological exploration are occurring in Canada.	 Some concerns with water pollution depending on the method of production.

7.3 ALTERNATIVE FUELS

Function	Low-carbon substitutes for conventional fossil fuels ideal for hard-to-abate sectors (aviation, heavy freight, and industrial applications). Alternative fuels include blended fuels that require mixing with conventional fuels at specific ratios and drop-in fuels that can directly replace petroleum fuels without engine or infrastructure modifications.
GHG emissions	Production of alternative fuels currently contributes relatively small greenhouse gas emissions with no formal, comprehensive system to track these emissions separately. Canada's National Inventory Report appears to under-represent the growth of clean fuels mandated under federal regulations, with recent analysis suggesting renewable fuel consumption is undercounted by a factor of more than two at the national level compared with compliance-program data.
Options for decarbonization	Decarbonization Pathways: Sustainable Aviation Fuel (SAF). Niche Pathways: Hydroprocessed Esters and Fatty Acids (HEFA) SAF, renewable diesel, renewable natural gas (RNG), advanced biofuel, bio-synthetic and synthetic fuels (e-fuels). Dead-End Pathways: Biodiesel, ethanol (as transport fuels).
Stage of transition	Mature: Biodiesel, ethanol. Emergence: Renewable diesel, sustainable aviation fuel, renewable natural gas. Early emergence (R&D): Synthetic e-fuels
Nature of the problem today	Limited domestic production of biofuels, feedstock constraints, and higher production costs compared to fossil fuels.
Other systemic issues	Sustainability and land-use concerns, dependence on imports, infrastructure limitations, and competition with electrification strategies.
Strategic opportunities and concerns	Canada has abundant biomass resources, renewable electricity, and innovation capacity, but faces competition from international incentives and sustainability challenges.
Priorities for action	Scale domestic advanced biofuel production for selected applications, strengthen policy mandates, ensure sustainable feedstock, support infrastructure upgrades, and incentivize innovation.
Longer-term issues	Long-term feedstock and technology constraints require balancing hydroprocessed esters and fatty acids deployment with scaling advanced residue-based biofuels, while carefully assessing the role of higher-cost synthetic e-fuels (likely focused on export) and coordinating this transition with the managed decline of fossil fuel infrastructure and evolving global market conditions
Indicators of progress	Blending rates, production capacity, greenhouse gas intensity, sustainability metrics, market signals, and investment/cost trends.

7.3.1 Current Status

Canada’s alternative fuels encompass several non-fossil energy carriers that can be used in place of conventional petroleum fuels and natural gas, including bio-based liquids (ethanol, biodiesel, renewable diesel, biocrude oils), synthetic liquids (power-to-liquid e-fuels), renewable gaseous fuels like biomethane/RNG, and others. Renewable propane, produced from non-fossil feedstocks and commonly emerging as a byproduct of renewable diesel and sustainable aviation fuel refining, is also beginning to enter the Canadian market as a low-carbon drop-in fuel.[159] Deploying these fuels is a strategy to cut emissions in sectors that cannot be easily electrified. Transportation is a prime example with an estimated contribution of 22% of Canada’s GHG emissions.[160] While electrification will reduce emissions from light- and medium-duty vehicles, many heavier or long-range transport applications and some industrial heating will likely continue to need high-density liquid or some form of gaseous fuel. Alternative fuels offer a way to decarbonize these fuel demands through drop-in low-carbon alternatives with lower lifecycle carbon intensities.

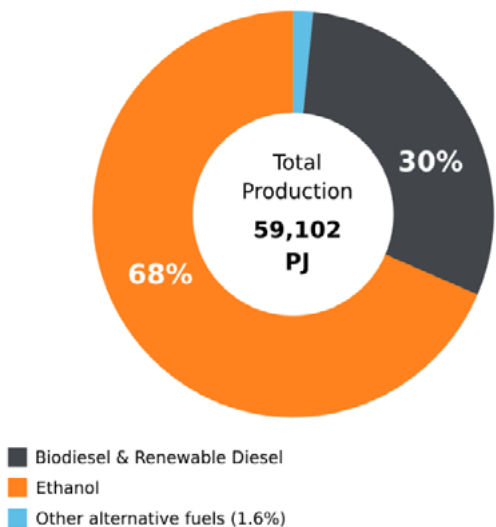


Figure 15. Canada, Alternative fuel production (2023)

Source: Statistics Canada, 2025. Renewable fuel plant statistics, supply and disposition, monthly.[161]

Source: Natural Resources Canada, 2025. Energy Fact Book 2025-26.[162]

Energy density of “Other alternative fuels” was assumed to be 36.67 MJ/L, an average of fossil diesel and gasoline. In 2023, all co-processed fuels were produced in Burnaby refinery and Tidewater Renewables and were primarily a blend of gasoline or diesel.

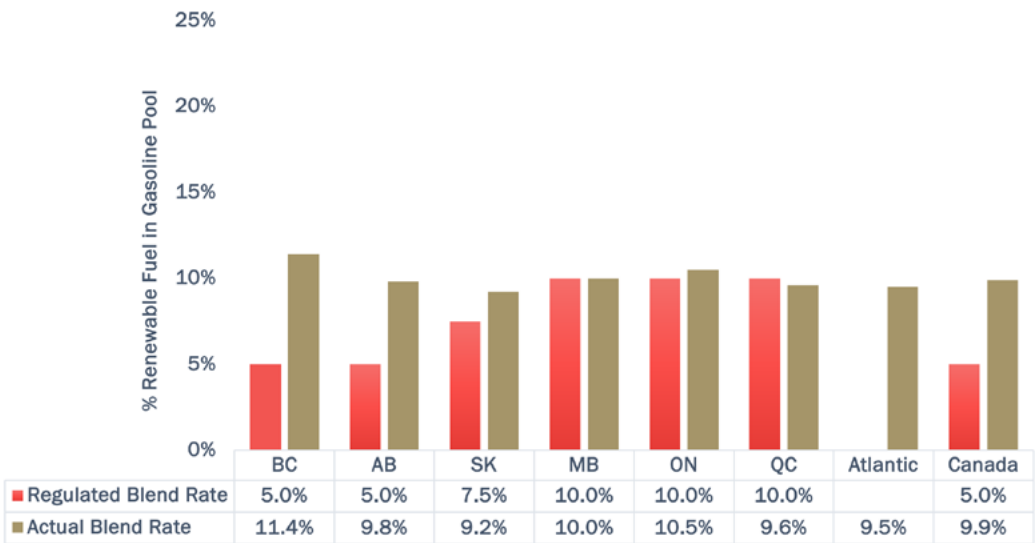


Figure 16. Renewable fuel content in gasoline by province (2024)

Source: Advanced Biofuels Canada & Navius Research, 2025[163]

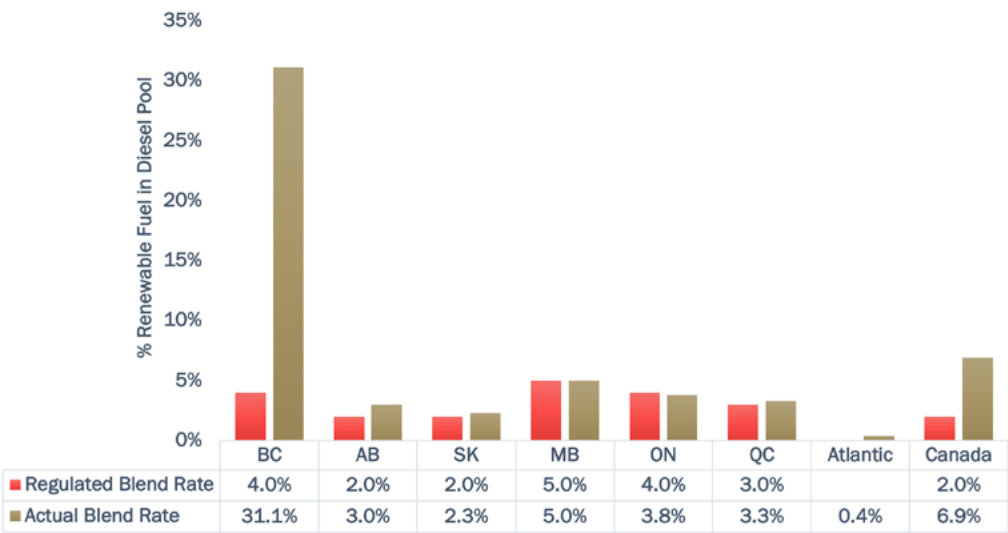


Figure 17. Renewable fuel content in diesel by province (2024)
Source: Advanced Biofuels Canada & Navius Research, 2025[163]

7.3.2 Nature of the Problem

Ethanol

Ethanol represents Canada’s most established alternative fuel, with a history of blending into gasoline dating back decades. Federal renewable fuel regulations have set baseline requirements of 5% ethanol in gasoline, while several provinces have mandated their own standards—Ontario and Manitoba require 10% ethanol, Saskatchewan 7.5%, and all provinces have met or exceeded their standards.[160,164] In 2023, ethanol consumption reached four billion litres, representing 9.44% of the gasoline pool, while production of 1,756 ML fell short of domestic demand of 4,072 ML in 2024 (Figure 18).

Despite its maturity, the niche for ethanol is increasingly narrow. While ethanol can reduce emissions, demonstrating 55% lower carbon emissions than gasoline in 2023 (or about 5% emissions reduction for a 10% ethanol/90% gasoline blend), its application faces fundamental limitations that make it unsuitable as a long-term solution for achieving net zero. [163] Ethanol suffers from inherent technical constraints, including higher oxygen content, corrosivity, and lower energy density, that prevent it from being transported in existing

pipelines and limit conventional vehicles to blend levels of 10–20%.[165] Higher blends like E85 require flex-fuel vehicles and dedicated fuelling infrastructure, which are costly and limited in Canada.

More critically, ethanol’s reliance on food-grade commodities raises sustainability concerns and intensifies the food versus fuel debate. Currently, approximately 400,000 tonnes of corn and wheat are used monthly for ethanol production, creating direct competition with food supply and contributing to potential land-use changes that can result in higher emissions than fossil fuels.[166]

For light-duty vehicles specifically, ethanol presents a dead-end pathway. As electrification becomes more viable for passenger cars and light trucks, ethanol makes an increasingly poor investment compared to BEV infrastructure. The modest but persistent 3% energy loss in E10 blends, infrastructure and blend-wall limitations that prevent higher concentrations, together with competition from other uses for bio-based feedstocks positions ethanol as fundamentally incompatible with deep decarbonization goals for LDVs.[167]

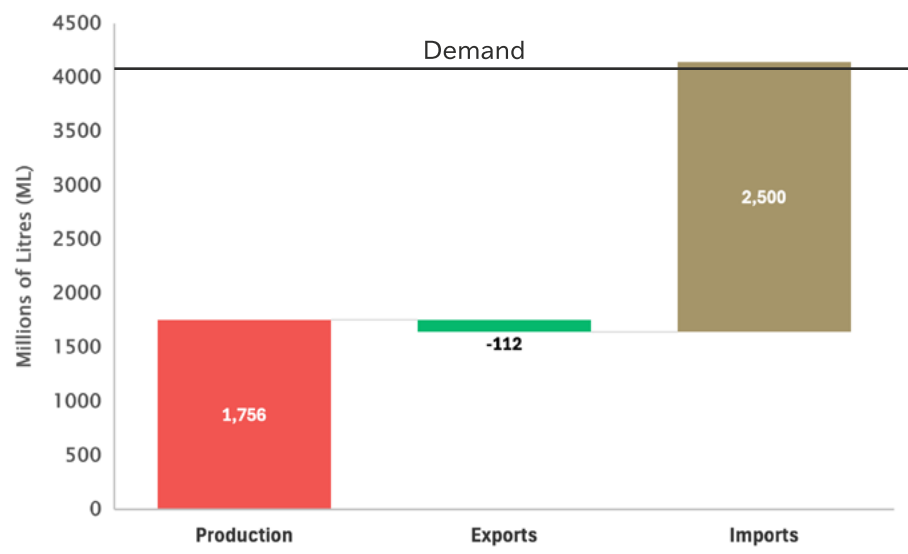


Figure 18. Canada's ethanol supply balance, 2024: Domestic production, trade, and total demand (ML)

Source: NRCan, 2024. Energy Fact Book 2025-26.[162]

Biodiesel and Renewable Diesel

Biodiesel and renewable diesel present a more promising pathway than ethanol, though they carry their own challenges and occupy different market niches. Canada's production of biodiesel and renewable diesel totalled 1,119 ML in 2024, while demand reached 1,005 ML, the first time Canada has filled the substantial supply gap previously filled by imports primarily from the U.S (Figure 19). Renewable diesel consumption more than doubled to 1.2 billion litres in 2023 relative to previous years—surpassing biodiesel for the first time in 2019—and was 2.2 times greater than biodiesel consumption (530 ML, up 14%).[163] Renewable diesel's compatibility with existing diesel infrastructure gives it a logistical advantage. Biodiesel and renewable diesel differ fundamentally in their production processes. Biodiesel is produced through transesterification of vegetable oils and fats, creating a blend-limited product (typically 5–20% with petroleum diesel), while renewable diesel undergoes hydrotreating to become almost chemically identical to conventional petroleum diesel, enabling 100% replacement without blend limits. Although renewable diesel's additional processing can

result in a higher carbon intensity than biodiesel, the chemical similarity of renewable diesel to conventional diesel provides better cold-flow properties and storage stability, enabling higher deployment volumes. The unrestricted blend limits allow renewable diesel to be deployed to meet overall carbon-intensity requirements set by the Canadian Clean Fuel Standard (CFS).

The niche for these fuels lies primarily in heavy-duty applications where their high energy density and compatibility with existing diesel infrastructure provide current advantages over electrification. In 2023, biomass-based diesel demonstrated 87% lower lifecycle carbon intensity than conventional diesel, making it valuable to sectors like long-haul trucking, marine shipping, and industrial heating where today battery electric alternatives remain technically and/or economically challenging.[163]

However, significant obstacles constrain their expansion. Biodiesel faces poor cold-weather performance challenges—blends above 5% have shown persistent gelling unless treated for cold flow and can cause engine challenges

unless properly tuned. Feedstock constraints represent another limitation with volatile prices and competition between food and fuel leading to price instability. Renewable diesel offers better characteristics compared to biodiesel by eliminating cold-weather and engine compatibility problems, but Canada's first standalone renewable diesel facility, owned by Tidewater Midstream, has encountered difficulties. While renewable diesel can be produced from various feedstocks, Tidewater relies on canola oil, tallow from meat processing, and tall oil from pulp and paper production—feedstocks chosen to leverage Canada's agricultural and forestry byproduct streams. But their limited availability constrains overall production capacity and increases processing costs. A second Canadian facility, Braya Renewable

Fuels in Come by Chance, Newfoundland and Labrador, was forced to shut down in January 2025 citing inability to compete with U.S. production tax credits and loss of blender's tax credits, but has since reopened under improved market conditions.[168] Meanwhile, provincial policy is tightening with B.C.'s updated LCFS now requiring renewable diesel and biodiesel be produced in Canada as of April 2025, with a similar requirement for ethanol as of January 2026.[169] At the same time, Imperial Oil's Strathcona Renewable Diesel facility in Alberta is now online and expected to produce up to 1 billion litres per year at full capacity, making it the largest renewable diesel facility in Canada and a major new source of low-carbon diesel for western Canadian markets.

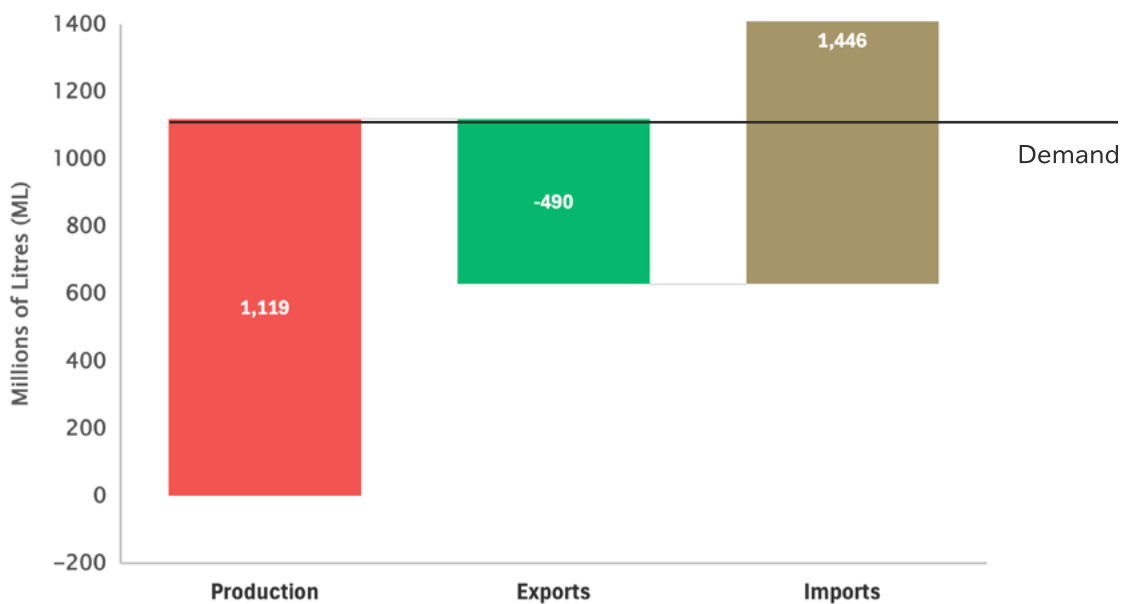


Figure 19. Production, imports, exports, and total demand of biodiesel and renewable diesel, Canada, 2024
Source: NRCan, 2024. Energy Fact Book 2025-26.[162]

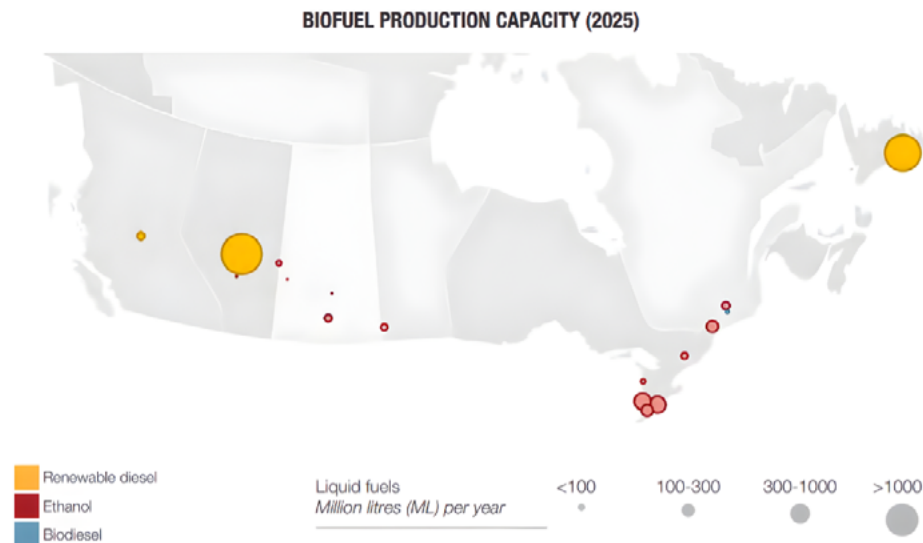


Figure 20. Biofuels production facilities and capacities in Canada, 2025

Source: NRCan, 2024. Energy Fact Book 2025-26.[162]

Sustainable Aviation Fuels (SAF)

Sustainable aviation fuels represent the most critical alternative fuel for achieving net-zero emissions given aviation's unique requirements.

The niche for SAF is clear: commercial aviation currently has no reasonable alternative for long-haul flights. Unlike light-duty transport, which can transition to electrification, or short-haul shipping, which may use hydrogen, aviation's energy density requirements and safety considerations make liquid fuels indispensable for the foreseeable future.

However, SAF faces economic and production constraints. SAF is in the emerging phase of transition with current production representing less than 1% of aviation fuel demand globally and remaining virtually absent commercially in Canada, where volumes are still limited to imported SAF and pilot-scale projects and assessments.[170,171] Air Canada's recent purchase of approximately 78 million litres of unblended SAF from Neste constitutes the airline's first commercial import of SAF into Canada and highlights the country's current reliance on overseas production.[172] Economic barriers are also

present with costs two to seven times more than conventional jet fuel.[171]

Most SAF today relies on the Hydroprocessed Esters and Fatty Acids (HEFA) process, accounting for 86% of global SAF production. [171] HEFA draws on waste oils, animal fats, and used cooking oil, as well as virgin vegetable oils — principally canola in the Canadian context — the same feedstocks competing with biodiesel and renewable diesel production.[173] Concerns about indirect land-use change have historically weighed on the carbon credentials of crop-oil HEFA, but emerging evidence suggests those impacts may be overstated for Canadian canola with a stable cropland base. Additionally, Canadian canola is already exported for overseas crushing – so redirecting supply to domestic fuel production largely replaces an existing commodity flow rather than creating new demand. Even with a more favourable outlook, sustainable feedstock supply limits HEFA to a minority of Canadian SAF demand, positioning it as a viable near-term niche pathway within its feedstock scope rather than a full-system solution. As SAF demand scales toward the estimated 24 million tonnes (30 billion litres)

globally required by 2030, feedstock availability will become further constrained,[174] making Fischer-Tropsch routes based on residues and waste—covered below under Advanced Biofuels—essential to meet the balance of aviation fuel demand.

Canada's SAF ecosystem is at an early but pivotal stage. According to a roadmap produced by the Canadian Council for Sustainable Aviation Fuels (C-SAF), the Transition Accelerator, and the Energy Futures Lab, Canada could produce up to 1.2 billion litres annually by 2030, meeting the 10% target.[175] However, unlocking this potential requires mobilizing sustainable feedstocks, investing in at least 10 commercial-scale plants, and putting in place strong policy incentives and offtake agreements.

In Europe, regulatory measures are driving uptake with the EU's ReFuelEU Aviation regulation legally mandating escalation of SAF and e-SAF (synthetic aviation fuel produced from renewable electricity and captured CO₂) shares in fuel pools through 2050. Canada, as a participant in the Carbon Offsetting and Reduction Scheme for International Aviation (CORSIA), is pursuing a federal target of 10% SAF in domestic jet fuel by 2030, while British Columbia has introduced its own 2030 requirement of 3% SAF and a 10% reduction in carbon intensity.

Renewable Natural Gas (RNG)

RNG is produced by upgrading biogas from organic waste sources—including landfills, wastewater treatment plants, agricultural operations, and municipal solid waste—to pipeline-quality gas with a methane content of 90% or greater.[176]

The niche for RNG lies in applications where existing natural gas infrastructure provides distribution advantages and where direct electrification faces technical or economic barriers. This includes industrial heating

processes and residential heating in regions with established gas networks. RNG can be injected directly into existing natural gas pipelines without infrastructure modifications, making it immediately compatible with current systems. However, RNG remains in early stages of deployment, comprising only 0.36% of gas delivered by Canadian utilities in 2021. Moreover, Canada's full realistic biomethane potential (estimated at 91-160 PJ/year) represents only 2-4% of national gas demand, limiting RNG's role to a supplementary blending strategy.[177] Some provinces are also exploring RNG as a tool for peak demand management. In Quebec, dual-energy heating systems are being deployed to manage winter grid peaks, while gas distributors are being pushed to reduce fossil gas use and increase renewable gas within a broader plan to reach 100% renewable energy in buildings by 2040.[178]

The obstacles to RNG expansion include limited feedstock availability relative to total natural gas demand, collection and processing costs, and competition with direct electrification strategies. Production requires either anaerobic digestion systems for wet organic waste or gasification systems for dry biomass, both requiring significant capital investment. The Canadian gas industry has so far failed to meet its 2016 target of a 5% RNG blend nationally by 2025—national RNG capacity reached only about 17.1 PJ in 2025, against the roughly 184 PJ a 5% blend would require—while British Columbia's CleanBC strategy mandates 15% renewable gas content by 2030.[177,179,180]

Advanced bio- and synthetic fuels

Along with hydrogen (explored in section 7.2), advanced biofuels and synthetic fuels are widely viewed as the main scalable options for decarbonizing sectors that will remain difficult to electrify, particularly long-haul aviation and portions of marine shipping. Both advanced biofuels and synthetic fuels

are designed to produce drop-in, energy-dense fuels compatible with existing aircraft and fuel infrastructure, but they differ fundamentally in their primary inputs and near-term readiness.

Synthetic Fuels (Power-to-Liquids / Power-to-X)

Synthetic fuels (often called e-fuels) are produced by combining electrolytic hydrogen (from water electrolysis powered by low-carbon electricity) with captured CO₂ to synthesize hydrocarbons or other energy carriers through Power-to-Liquids (PtL) or broader Power-to-X (PtX) routes. In principle, these fuels can approach very low lifecycle emissions when electricity is near-zero carbon and the carbon feedstock is sourced from the atmosphere (i.e., direct air capture) or other eligible non-fossil streams.

The primary strategic niche for synthetic fuels is hard-to-abate demand where liquid fuels remain indispensable, long-haul aviation, some marine applications, select industrial uses, and, in some systems, as a form of long-duration or seasonal energy storage when clean electricity is abundant.

However, the dominant constraints are electricity intensity and thermodynamic efficiency. Current PtL pathways convert only a fraction of input electricity into usable liquid fuel energy, making costs highly sensitive to the availability of abundant, ultra-low-cost clean power. Synthetic fuel production is also tightly coupled to the cost and performance of enabling technologies (green hydrogen production, CO₂ capture including Direct Air Capture, and advanced fuel synthesis systems) which remain capital-intensive and complex. As a result, synthetic fuels are unlikely to contribute at large scale in the near term but may become important by mid-century for residual emissions in sectors with limited alternatives.

Advanced Biofuels (Biomass-to-Liquids /FT Fuels)

Advanced biofuels provide a nearer-term pathway to drop-in fuels by converting sustainably sourced biomass residues, such as forest or agricultural residues, into liquid hydrocarbons. A key route is Biomass-to-Liquids (BtL), in which biomass is gasified into syngas and upgraded through Fischer-Tropsch (FT) synthesis to produce renewable diesel and SAF. Relative to first-generation biofuels derived from crop oils, residue-based pathways can reduce food-versus-fuel concerns and may leverage established forestry and agricultural supply chains, though they remain constrained by sustainable feedstock availability, transport logistics and costs, and project economics.

Canada has emerging examples of this approach. Expander Energy's Carseland Bio-Synfuels facility (25 ML/y) is positioned as a first-of-a-kind bio-synthetic diesel and SAF project with stated ambitions for near-zero carbon intensity fuel performance with the addition of carbon capture and storage (CCS) for the concentrated bio-CO₂ produced in the gasification-plus-FT process. Highbury Energy's Fort Frances planned biorefinery (20 ML/y) is expected to produce drop-in SAF and renewable diesel with an explicit longer-term objective of reaching near-zero fuel carbon intensity through CCS as well.[181]

Overall, advanced biofuels represent the more credible near-term route to scaling next-generation drop-in fuels from residues, while synthetic fuels are the longer-term option that becomes compelling primarily under conditions of very low-cost, near-zero-carbon electricity and scalable, low-cost CO₂ capture and hydrogen supply.

7.3.3 Net-Zero Pathways

Achieving Canada's net-zero emissions target by 2050 requires a fundamental reorientation of alternative fuel strategy away from the current piecemeal approach toward a comprehensive, technology-specific deployment framework. Strategic prioritization and resource allocation are essential to advancing beyond the Clean Fuel Regulations and provincial policies. To reach net zero by mid-century requires transition of all applications to fully zero- or near-zero-carbon fuels.

Several key pathways can be identified, each with distinct sectoral roles and uncertainty about ultimate market shares. Given deep uncertainty about technology costs, fuel availability, and adoption rates—for example, how rapidly electrification could overtake slower hydrogen and renewable diesel development—the information should be treated as a portfolio of pathways.

Sustainable biofuels from non-food feedstocks

The pathway requires expanding sustainable biofuels produced from non-food feedstocks and waste streams. Second-generation biofuels derived from cellulosic materials (agricultural residues, wood waste, and forest biomass) can avoid food competition challenges while leveraging Canada's significant biomass potential. Advanced processing facilities that convert cellulose and waste into fuels through gasification and Fischer-Tropsch and other thermochemical pathways must be developed, coupled with carbon capture and storage systems to achieve net-negative-emission fuels.[160,182] That said, sustainable biofuels should be prioritized for applications where high energy density and drop-in compatibility with existing infrastructure provide the greatest value.

Synthetic hydrocarbon E-fuels

Synthetic hydrocarbon production using clean electricity and recycled carbon represents a longer-term and potentially necessary complement to advanced biofuels, particularly for aviation applications where bio-feedstock availability will prove insufficient. E-fuel development should focus on applications where electrification is technically infeasible and where the energy storage characteristics of liquid fuels provide system value. However, realistic deployment timelines place e-fuels as post-2035 solutions requiring sustained research and development investment and early deployment in niche, high-value markets, notably aviation and potentially long-distance marine shipping.

Sectoral fuel allocation and primacy of electrification

Strategic fuel allocation becomes critical given finite resources. Light-duty transport should transition primarily to electrification, reserving liquid biofuels—including renewable diesel and other advanced fuels—for heavy-duty trucking, aviation, marine shipping, and industrial heating where alternatives are limited. This requires explicit policy frameworks that prevent alternative fuels from competing with electrification in sectors where batteries provide greater solutions, while acknowledging that the eventual balance between electrification, hydrogen, and renewable fuels in freight and off-road applications continues to be uncertain. Economically, capital for alternative liquid and gaseous fuels is best directed toward long-haul freight, aviation, marine, and industrial heat markets, rather than light-duty road transport.

Renewable Natural Gas as a targeted bridge

Renewable natural gas expansion should focus on waste methane capture and industrial applications where gas provides processing advantages, while recognizing its bridging role rather than permanent solution status. The development of regional biomethane networks can provide near-term emissions reductions while supporting agricultural waste management. In a systematic view, RNG plays a time-limited, niche role: targeting high-leverage waste streams and specific industrial users rather than broad, system-wide gas substitution.

Cross-cutting CCUS and infrastructure integration

The integration of carbon capture utilization and storage technologies across fuel production pathways offers potential for bio-CO₂ as feedstock and net-negative emissions. This will be particularly important for offsetting residual emissions in sectors where complete decarbonization is elusive. The coordinated development of CO₂ transport and storage infrastructure alongside fuel production facilities will be critical.

Taken together, these pathways represent a systematic map of uses based on alternative fuel type. Policy design and investment strategy should therefore emphasize flexibility and periodic review, scaling up those pathways that prove most compatible with rapid electrification and cost-effective emissions reductions.

Competitiveness Implications

When Braya Renewable Fuels shut its Newfoundland facility in early 2025, it cited a specific cause: inability to compete with U.S. production tax credits. When Air Canada made its first commercial SAF purchase (78 million litres from Finland's Neste), it did so because no Canadian producer could supply the volume. Canada's SAF production is virtually zero at commercial scale. The pattern is consistent: feedstock leaves, refined product returns, and the conversion-stage value where margin and industrial capability concentrate accrues elsewhere. Imperial Oil's Strathcona renewable diesel facility and B.C.'s new domestic production mandate show this can be reversed when investment or regulation intervenes. But the gap that matters most now is fiscal: absent a federal framework competitive with U.S. and EU regimes, refining capital will keep flowing to jurisdictions that offer producers greater certainty, and offtake relationships will form around non-Canadian supply. Canada continues to be the only G7 nation without a federal bioeconomy strategy.

7.3.4 Priorities for Action

Secure and stabilize feedstock through regional bio-hubs

A key priority must be establishing regional bio-hubs—sub-provincial clusters organized around an anchor conversion facility—that aggregate and preprocess feedstocks such as wood residues, agricultural wastes, and CO₂ streams before conversion. In this context, regional refers to feedstock catchment areas rather than entire provinces or single cities. Each hub may focus on a subset of compatible feedstocks and products, with modular expansion around the anchor facility rather than attempting to integrate all possible streams from the outset. While more complex than single-molecule hubs (i.e., hydrogen hubs), this can reduce risk by diversifying feedstocks and end-markets within a defined geography.

These hubs ensure reliable, stable supplies and lower costs by co-locating:

- Feedstock collection and preprocessing facilities;
- An anchor biorefinery (either dedicated biorefineries or retrofit support for existing petroleum refineries) to handle bio-crude, bio-oils, and Fischer-Tropsch (FT) intermediates, with capacity that can be expanded as additional feedstock becomes available;
- Logistics coordination and shared infrastructure (including storage and CO₂ handling) to minimize transport emissions and costs.
- Federal incentives for refitting existing refinery infrastructure or deploying new biorefineries will catalyze early adoption and unlock domestic value addition.

Build integrated regional fuel hubs

Once feedstock security is in place from bio-hubs, develop integrated regional fuel hubs that co-locate conversion technologies (i.e., pyrolysis, gasification, electrolysis) alongside end-users. This approach captures value domestically while minimizing transport costs and embedded emissions from larger feedstocks. Strategic positioning near biomass or CO₂ sources can dramatically reduce the cost and logistical barriers that constrain deployment.

Align alternative fuels with hard-to-electrify sectors

Given the finite sustainable feedstock resources, alternative fuels should be prioritized where the most value is added and directed toward sectors where electrification is currently not possible and may remain out of reach, including some heavy-duty trucking, aviation, marine shipping, and certain types of industrial heating.

Accelerate commercial-scale RD&D and demonstration

Accelerated RD&D should move beyond pilot projects toward first-of-a-kind (FOAK) commercial facilities demonstrating scalability and economic viability. Priority should focus on cellulosic pathways for SAFs, advanced biomass conversion technologies, and integration of CCS to achieve net-negative emissions.

Develop early-stage hydrogen and CO₂ infrastructure

The development of hydrogen and CO₂ supply hubs underpins both e-fuel production and broader decarbonization of hard-to-abate sectors. There should be a focus on early infrastructure development to break investment chicken-and-egg cycles while supporting multiple industrial applications concurrently.

Strengthen policy, procurement, and strategic coordination

Policy frameworks require strengthening and refinement to create predictable demand signals supporting long-term investment. While Canada's Clean Fuel Regulations provide a foundation, achieving net zero may need more aggressive carbon intensity requirements. Public and private procurement by government fleets, military operations, and crown corporations can provide necessary early demand signals. Canada remains the only G7 nation without a federal bioeconomy strategy tying biomass use to emission-reduction targets. A national policy framework should:

- Link climate goals explicitly to sustainable biomass deployment;
- Tighten carbon intensity requirements under the Clean Fuel Regulations;
- Leverage government, military, and crown-corporation procurement to provide early, predictable demand signals.

Standardize carbon accounting and life-cycle assessment

Common emissions accounting standards and verification systems should also address the fundamental gap undermining investor confidence. Current LCA methodologies create uncertainty—both from absent indirect land use change accounting, which can overstate benefits, and from reliance on legal global economic models whose indirect land-use change assumptions may overstate impacts for feedstocks like Canadian canola. Standardized systems provide credibility needed for large-scale investment.

Incentivize domestic value-add production

Finally, policy frameworks should incentivize value-added processing within Canada to create economic benefit while reducing costs through shorter supply chains. Fostering domestic capabilities must address Canada's position as a raw material exporter importing refined products.

 Fails to meet criteria Meets in some respect
 Not promising Potentially meets criteria
 Meets criteria

ALIGNMENT WITH CARBON NEUTRALITY	Economic		Technical			Social		
	ECONOMIC VIABILITY	ECONOMIC DEVELOPMENT OPPORTUNITY	MATURITY	OPERATIONAL FIT	INFRA-STRUCTURE AND SUPPLY CHAIN SUITABILITY	SOCIAL ACCEPTABILITY	RELEVANCE TO STAKEHOLDERS	RELATED BENEFITS AND COSTS
Deep lifecycle emission reductions with forestry and other organic residues.	Higher direct production cost than HEFA but cheaper per tonne of CO₂ abated. Still requires policy support and offtake certainty.	Strong domestic potential. Integrated biorefineries, forest and agricultural residue value chains, and Canadian opportunities in gasification and FT.	Integrated FT-SAF at commercial scale is pilot/demo. Limited Canadian deployment.	Drop-in replacement for jet fuel. No aircraft or fuelling infrastructure changes required.	Biomass and residue supply chains emerging. FT synthesis and low-carbon H₂ infrastructure not yet at scale. Aviation blending infrastructure is in place.	Generally positive. Waste valorization and residue use are supported by communities.	Forest sector and waste managers for waste valorization. Federal government funding R&D.	Multiple co-benefits: waste diversion, forest management support, co-production of renewable diesel. No food competition or land use change concerns.
Moderate to deep lifecycle reductions depending on feedstock/crop chosen and associated land use changes. Crop-oil HEFA can exceed some fossil fuel intensities. Would require removals for net zero.	High costs relative to fossil jet fuel. Viability depends on policy support.	Moderate opportunity for domestic production in crop oil (i.e. canola) regions. Limited Canadian IP. Technology is imported.	Commercial globally. Canadian facilities are emerging.	Drop-in replacement for jet fuel. No aircraft or fuelling infrastructure changes required.	Compatible with existing blending and distribution infrastructure. Sustainable feedstock supply is the main constraint on domestic scale.	Virgin crop oils face growing food-vs-fuel and land-use concerns. Concerns less acute for Canadian canola given its stable cropland base.	Some airlines and airports actively purchasing fuel, limited by cost and supply. Federal regulations in progress; some provinces are further ahead.	Waste-oil and tallow feedstocks provide waste valorization option. Risks from indirect land-use change and pressure on food/feed markets.

			ALIGNMENT WITH CARBON NEUTRALITY	Economic		Technical			Social		
PATHWAY ELEMENTS	ROLE IN NET-ZERO SYSTEM	SIGNAL TO DECISION-MAKERS		ECONOMIC VIABILITY	ECONOMIC DEVELOPMENT OPPORTUNITY	MATURITY	OPERATIONAL FIT	INFRA-STRUCTURE AND SUPPLY CHAIN SUITABILITY	SOCIAL ACCEPTABILITY	RELEVANCE TO STAKEHOLDERS	RELATED BENEFITS AND COSTS
 Heavy Duty Diesel End Users											
Renewable Diesel	Niche Pathway Drop-in fuel compatibility and strong lifecycle reductions. Supports hard to electrify end users. Long term net-zero alignment requires sustainable feedstocks and removals.	Deploy Continue support to ensure cost parity. Provide education to end-users on drop-in capabilities.	 Drop-in fuel, delivering significant lifecycle CO ₂ cuts. Net zero requires sustainable feedstocks and complementary carbon removal.	 Currently requires support for price parity.	 Potential for domestic production and associated jobs.	 Commercial and rapidly scaling.	 Fits existing diesel engines and distribution networks without retrofit. Better cold-weather performance than some alternatives.	 Uses existing storage and pipelines but can be difficult to procure.	 Concerns of competition with food crops.	 Interest from hard hard-to-electrify industrial end users (i.e. trucking fleets). Developing interest from fuel producers to supply emerging markets, but confusion remains with properties of other alternative fuels.	 Improves air quality while retaining energy density. Risk of locking in diesel dependency for end users who could otherwise electrify.
Biodiesel	Potential Dead-End Pathway Provides near-term emission reductions using existing engines and infrastructure. Blending limits and feedstock availability limit uptake.	Don't Prioritize Not drop-in. Provide information on the quality differences between renewable diesel and biodiesel.	 Can cut tail-pipe CO ₂ significantly, but blending limitations exist with unmodified engines. Net zero requires sustainable feedstocks and complementary carbon removal.	 Costs greater than fossil fuel diesel.	 Creates domestic demand for used cooking oil and canola oil, boosting farm and refining sectors. Competes with food.	 Commercial, but climate-grade quality still improving.	 Compatible with diesel engines to B20. Cold weather performance and material sedimentation limit higher blends.	 Separate heated tanks are needed in winter. Logistics become complex above the B20 blend.	 Generally positive when made from wastes. Land-use change for virgin crops draws scrutiny.	 Can be less relevant than renewable diesel.	 Improves lubricity and reduces particulate matter. Offers a practical bridge until zero-emission drivetrains dominate.

			ALIGNMENT WITH CARBON NEUTRALITY	Economic		Technical			Social		
PATHWAY ELEMENTS	ROLE IN NET-ZERO SYSTEM	SIGNAL TO DECISION-MAKERS		ECONOMIC VIABILITY	ECONOMIC DEVELOPMENT OPPORTUNITY	MATURITY	OPERATIONAL FIT	INFRA-STRUCTURE AND SUPPLY CHAIN SUITABILITY	SOCIAL ACCEPTABILITY	RELEVANCE TO STAKEHOLDERS	RELATED BENEFITS AND COSTS
 Heat and Power Production											
Renewable Natural Gas (RNG)	<i>Potential Niche Pathway</i> Complements hard-to-electrify end uses and applications. Limited feedstocks constrain scale.	Enable Support projects that reduce methane emissions from waste. Focus funding on projects with secured long-term end users.	 Moderate GHG reduction. Methane capture benefits. Net-zero requires sustainable feedstocks and complementary carbon removal.	 Viable with support. Cost competitive under supportive policy environment.	 Creates jobs in waste management and valorizes agricultural residues.	 Emerging commercial.	 Compatible with existing pipelines and end-use equipment.	 Fully compatible with gas networks. Limited by feedstock availability and interconnection.	 Varying acceptance. Issues with increased traffic and odours. Seen as waste valorization.	 Seen as economic addition for agricultural and waste management. Gas utilities to leverage existing networks.	 Reduces fugitive methane. Potential for fertilizer production.
 Light Duty Vehicles											
Ethanol	Dead-End Pathway Limited lifecycle emissions reductions and sustainability concerns make ethanol unlikely to have a meaningful role in net zero.	Dismiss Not net-zero in its primary use of light duty vehicle decarbonization. Support transition to other pathways.	 Limited GHG reductions. Food-vs-fuel controversies over land use and feedstocks.	 Affordable and viable with support.	 Low value-add. Small rural jobs. Competes with food.	 Fully commercial.	 Compatible with gasoline blending up to E10. Higher blends need flex-fuel vehicles.	 Incompatible with existing pipelines beyond 10% blends. Requires new infrastructure.	 Mixed: accepted historically but declining due to sustainability concerns.	 Provincial regulators and oil refiners. Limited OEM engagement.	 Reduces gasoline emissions modestly. Supports legacy ethanol plants.

			ALIGNMENT WITH CARBON NEUTRALITY	Economic		Technical			Social		
PATHWAY ELEMENTS	ROLE IN NET-ZERO SYSTEM	SIGNAL TO DECISION-MAKERS		ECONOMIC VIABILITY	ECONOMIC DEVELOPMENT OPPORTUNITY	MATURITY	OPERATIONAL FIT	INFRA-STRUCTURE AND SUPPLY CHAIN SUITABILITY	SOCIAL ACCEPTABILITY	RELEVANCE TO STAKEHOLDERS	RELATED BENEFITS AND COSTS
 Advanced Bio and Synthetic Fuel Pathways											
Advanced Biofuel (Biomass-to-liquids)	Niche Pathway Delivers deep emissions reductions where sustainable feedstocks/ biogenic CO ₂ and low-carbon electricity exist, but restricted by localized and limited ability to obtain feedstocks.	Incubate Support R&D projects.	 Achieves high emissions reductions but requires substantial biomass feedstocks/biogenic CO ₂ and clean power. Feedstocks used must be decarbonized. May still require removals.	 High production costs due to complex multi-step conversion. Requires supportive policy environment.	 Creates integrated biorefineries and supports biogenic carbon capture build-out. Some provinces developing demonstration projects.	 Pilot/ demonstration.	 Drop-in compatibility with all diesel engines and aviation turbines.	 Requires biomass or biogenic carbon supply chains, gasification plants, and synthesis facilities. Forestry residue supply chain exists.	 No particular concern.	 Forest sector and waste managers for waste valorization. Federal government funding R&D.	 Multiple co-benefits: waste diversion, forest management support, co-production of renewable diesel and SAF. No food competition or land use change concerns.
Synthetic / E-Fuel	<i>Potential Niche Pathway</i> Potential for net-zero compatibility with offset or directly captured CO ₂ and low-carbon hydrogen.	Don't Prioritize Watch to see if economics or maturity improve; support if progress is made.	 Potential for deep lifecycle reductions. Carbon intensity depends directly on the H ₂ source and how CO ₂ is captured or offset.	 Not viable. High electricity input and low conversion efficiencies. Costs hinge on low-carbon H ₂ and CO ₂ capture/offset maturing at scale.	 Long-term manufacturing potential. Requires new industrial clusters.	 R&D/Concept.	 Drop-in compatibility with all diesel engines and aviation turbines.	 Requires low-carbon hydrogen, captured or offset CO ₂ (i.e. from direct air capture), and synthesis plants. No existing supply chain.	 Public awareness is low. Acceptance will depend on framing. Conceptually attractive as a “drop-in” net-zero fuel.	 Research institutions, energy ministries as a long-term feedstock-secure fuel production pathway.	 Unaffected by biomass supply chain instabilities.

7.4 OIL AND GAS

Function	Fuels for transportation, power generation, space heating, industrial processes, and feedstock for multiple industries including chemicals and fertilizers.
GHG emissions	190–200 Mt CO ₂ e annually, representing about 28–31% of Canada's emissions (208 Mt or 30% in 2024).[74] Emissions from the sector have increased over recent decades, driven by production growth, and are concentrated in upstream production and processing.
Options for decarbonization	Decarbonization Pathways: Methane abatement, electrification of upstream operations. Niche Pathways: Carbon Capture and Storage, blue hydrogen. Enabling Pathways: on-site clean power, lithium extraction from oilfield brines, geothermal power. Reduce production-related emissions to the lowest level possible through methane abatement, carbon capture, and efficiency improvements.
Stage of transition	Emerging: Blue hydrogen, lithium extraction from oilfield brines, geothermal power Diffusion: Methane abatement, electrification of upstream operations, carbon capture and storage, on-site clean power
Nature of the problem today	Emissions and emission intensity are high, and long-lived infrastructure and capital stock create transition complexity. Policy signals on decarbonization have strengthened since 2021 but remain subject to political uncertainty.
Other systemic issues	Deep economic dependence on oil and gas revenues in producing regions; environmental liabilities including abandoned wells and tailings ponds.
Opportunities and concerns	Leverage existing labour skills, industrial expertise, and infrastructure to support energy transitions; develop and export emissions-reducing technologies; avoid stranding assets prematurely through a managed and predictable transition.
Priorities for action	Reduce production emissions through methane abatement, efficiency improvements, and electrification of upstream operations. Strengthen industrial carbon pricing to provide a durable signal for carbon capture utilization and storage and other longer-term abatement investments.
Longer-term issues	Managing demand decline and macroeconomic impacts as electrification accelerates domestically and globally; reclamation liabilities; workforce and community transition in producing regions.
Indicators of progress	Sector production emissions and emissions intensity; upstream methane emissions.

7.4.1 Current Status

Canada's oil and gas sector is one of the country's most significant industries. Canada is the world's fourth-largest oil producer and fifth-largest natural gas producer. The sector directly contributed roughly 6% of national GDP in 2024, and supports approximately 200,000 direct jobs, with considerably more employment across supply chains and service industries.[154] In 2024, 93% of Canadian crude oil exports were directed to the United States, down from 97% the previous year due to the completion of the Trans Mountain Expansion Project.[183] The sector's economic weight is particularly concentrated in Alberta, Saskatchewan, British Columbia, and Newfoundland and Labrador, where it shapes provincial fiscal positions, investment patterns, and community livelihoods.

Since the 2021 edition of this report, the sector's operating context has shifted considerably. The collapse in global demand through 2020 and early 2021 caused widespread financial losses, asset write-downs, and accelerated consolidation across the industry.[184] Conditions reversed sharply with the post-pandemic recovery and the energy price shock following foreign conflicts, and Canadian producers recorded operating profits of \$66.6 billion in 2022.[185] Prices and

margins have since moderated from those highs, though oil sands production has continued to grow, supported in part by the Trans Mountain pipeline expansion. At the same time, global energy markets are being reshaped by accelerating electrification, tightening environmental standards in importing countries, and intensifying geopolitical competition over energy supply chains. The policy landscape in Canada has also evolved, with strengthened methane regulations, investment tax credits for carbon capture and clean hydrogen production and the introduction and subsequent withdrawal of a proposed federal oil and gas emissions cap in favour of a negotiated carbon pricing framework.

These developments underscore a fundamental reality: the oil and gas sector will continue to generate revenue and employment for Canada in the coming years, but the terms on which it does so are changing. How Canada manages this transition, which involves reducing production emissions, positioning for evolving global markets, and rolling out end-use alternatives (such as electric vehicles and heat pumps) that will ultimately reshape demand, will have significant consequences for national prosperity and regional economic stability.



7.4.2 Nature of the Problem

The oil and gas sector is Canada’s largest source of greenhouse gas emissions. According to the most recent national inventory data, the sector accounted for approximately 208 Mt CO₂e in 2024, representing roughly 30% of Canada’s total emissions.[61,186] Within the sector, oil sands production is the dominant source (approximately 44% of sector emissions), followed by natural gas production and processing, conventional oil production, and petroleum refining.[61,187]⁹ Production growth has been the primary driver of emissions increases: total crude oil output has roughly tripled since 1990, with oil sands production increasing more than eightfold over that period.[187]¹⁰

Of course, production-related emissions represent only a fraction of the total climate impact of oil and gas. When the end-use combustion of oil and gas products is included (in vehicles, furnaces, industrial equipment, and power generation), the full lifecycle emissions are roughly five times greater than production emissions alone.[188]

In a net-zero framework, this distinction matters. Reducing production emissions is necessary, but the larger prize, in emissions terms, lies in displacing the end-use combustion of fossil fuels through electrification and the deployment of alternative energy carriers. This is the central argument of this report: the most effective long-term strategy for reducing the emissions associated with oil and gas is to electrify demand.

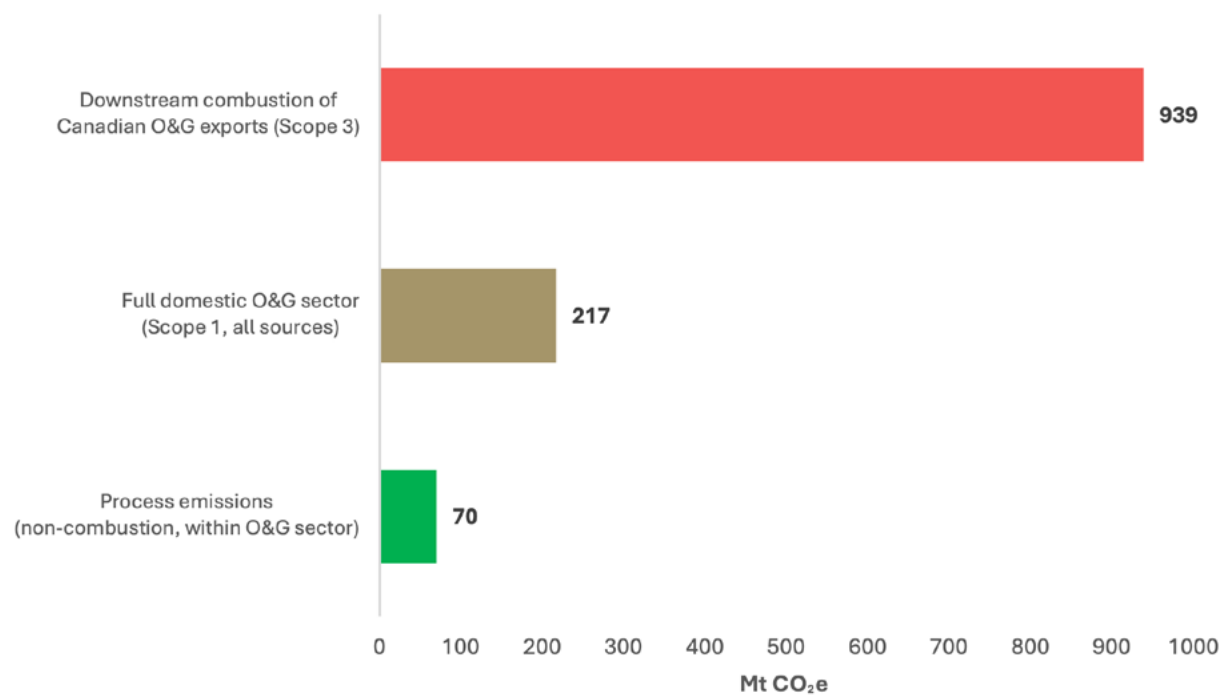


Figure 21. 2022 Process vs. Downstream Combustion (Mt CO₂e)
Source(s): Environment and Climate Change Canada, Greenhouse Gas Sources and Sinks in Canada: Executive Summary 2026 (2025)[46]. Climate Action Tracker, Canada’s Uncounted Emissions (2024).[189] International Energy Agency, Energy Balance (2024).[190]

9 ECCC, 2024 National Inventory Report (data for 2022). Oil sands: 87 Mt (40%); natural gas production and processing: 54.5 Mt; conventional oil: 39 Mt; petroleum refining: 17 Mt.
10 From 1990 to 2022, total crude oil production increased by 193%.

The scale of those downstream combustion emissions also reflects a structural feature of Canada's export position. The vast majority of Canadian crude oil exports flow to the United States, and the bulk of production- and transmission-related emissions from the sector are tied to supplying that single market. The United States is itself on an electrification trajectory, likely slower than Canada's, but directionally the same.[191] As U.S. end-use demand for oil and gas gradually contracts, Canadian producers will face pressure to redirect volumes. The obvious alternative is Asian markets, and Canada is positioning itself as a stable and reliable supplier to the Indo-Pacific. But those markets are simultaneously pursuing strategies to reduce their own hydrocarbon dependence, driven not primarily by climate policy but by energy security concerns: a lesson reinforced by recurring supply disruptions, price volatility, and the 2026 closure of the Strait of Hormuz.[192] The practical implication is that the long-run market environment for Canadian oil and gas is structurally more constrained and more competitive than near-term prices suggest, and that this dynamic compounds the challenge of justifying long-lived capital investment in conventional production.

Beyond greenhouse gas emissions, the sector carries significant environmental liabilities. These include multi-billion-dollar reclamation obligations from inactive and orphaned wells, unfunded liabilities associated with oil sands tailings ponds, and widespread landscape fragmentation.[193] These obligations represent fiscal and environmental risks that grow with the continued expansion of conventional operations and require proactive management regardless of the pace of the energy transition. In this sense, they are not simply legacy issues; ensuring adequate financial provisioning for these liabilities and not deferring costs to future taxpayers is a governance issue that grows more urgent with time.

The transition challenge is not only environmental or technological, but also economic and institutional. The most significant obstacle to the sector's transition is the gap between the long-term direction of the global energy system and the near-term economic incentives facing producers. Oil and gas remain highly profitable, and current commodity prices reward continued production expansion. In this context, investment in deep decarbonization competes directly with returns from conventional operations. While record profitability provides the financial capacity to invest in transition, the commercial pressure to deploy capital toward production growth is strong.

Infrastructure lock-in compounds this dynamic. Canada's oil and gas asset base (wells, pipelines, upgraders, processing plants) was built for a fossil-fuel economy and represents hundreds of billions of dollars in sunk capital. Retrofitting or repurposing this infrastructure for lower-emission operations requires significant additional investment, and in some cases is technically infeasible. Continued investment in conventional long-lived assets further strengthens this lock-in and raises the risk of future stranded assets.

Policy signals have become more directional, and federal-provincial friction has eased since the November 2025 Canada-Alberta MOU and its May 2026 Implementation Agreement, which replaced the contested emissions cap with a negotiated carbon pricing framework and streamlined project assessment processes. Whether these commitments prove durable remains to be seen, and international factors — including the evolving U.S. regulatory and trade landscape — add further uncertainty for long-term capital allocation decisions.

The political difficulty of imposing greater stringency on production emissions is real, but it will diminish as international markets increasingly differentiate on emissions

intensity. As carbon border mechanisms and importer standards take hold, the market case for low-intensity production aligns with the regulatory case. Over time, this could shift the balance of leverage between governments and industry, making stronger production-side requirements more politically and economically defensible.

In the long term, global demand for oil and gas is projected to plateau and eventually decline as electrification advances across major economies, though the pace and timing continue to be uncertain and are subject to geopolitical, technological, and policy variables. How quickly this demand contraction reaches Canadian producers will be shaped by the competitiveness of Canadian production, the success of carbon border mechanisms in importing countries, and the availability of lower-cost alternatives. This creates a difficult planning environment, whereby near-term market conditions still support expansion, even as the longer-term direction of travel points toward a more competitive and constrained market.

So long as domestic and international demand for oil and gas products remains robust, the economic case for supply-side transformation is harder to make. This reinforces the strategic priority of accelerating demand-side electrification while preparing for a more uncertain long-term market environment.

7.4.3 Net-Zero Pathways

In a net-zero world, fossil fuels will still have a role, but a significantly diminished and different one. Residual uses may include feedstock for petrochemicals, liquid fuels for aviation, specialty products such as lubricants, asphalt, and waxes that lack near-term substitutes, and fuel supply for remote and off-grid communities where infrastructure alternatives are uneconomical.

Beyond these residual uses, it is worth noting that even absent a global policy commitment to net zero, structural pressures on fossil fuel demand are already intensifying. The world's largest energy-importing regions—Europe and Asia—have powerful and durable incentives to electrify and reduce their dependence on imported hydrocarbons. Those incentives are not primarily climate-driven: they are strategic. Recurring supply disruptions, price volatility, and the concentration of critical transit routes in geopolitically unstable regions have consistently demonstrated the systemic vulnerabilities of fossil fuel import dependence. The 2026 closure of the Strait of Hormuz, which the IEA described as the largest oil supply disruption in the history of the global oil market, is only the most recent, and most dramatic, illustration of this dynamic.[194] For major importers, the energy security case for electrification is increasingly entangled with the climate case, and both are pointing in the same direction.

These pressures reinforce a central conclusion of this report: the trajectory of Canada's oil and gas sector toward net zero involves action on two distinct fronts: reducing emissions from production operations and managing the structural decline in fossil fuel demand as end-use sectors electrify. The following pathways describe the principal options available to the sector. They are not mutually exclusive; a realistic trajectory will combine elements of each, with the balance shifting over time as technologies mature and markets evolve.

Reduce production emissions while continuing to produce oil and gas.

This pathway focuses on driving production-related emissions toward the lowest achievable levels through a suite of technologies: methane abatement (leak detection and repair, elimination of routine venting and flaring), electrification of

upstream operations, carbon capture and storage at major facilities, process efficiency improvements, and the use of lower-emission extraction technologies. This is the pathway most directly aligned with the current industry trajectory, and it has received significant policy and investment attention.

Canada has made measurable progress on this front. Methane emissions from the oil and gas sector fell approximately 40% between 2014 and 2023, even as production continued to grow.[195] The federal government finalized enhanced methane regulations in December 2025, targeting a 72% reduction from 2012 levels by 2030.[196]

These developments have unfolded alongside a broader federal-provincial realignment. The November 2025 Canada-Alberta Memorandum of Understanding set aside the proposed federal emissions cap in exchange for Alberta's commitment to strengthen industrial carbon pricing and advance carbon capture investment. This led to an agreement-in-principle in March 2026 on methane equivalency,[197] an April Co-operation Agreement streamlining environmental and impact assessments for major projects,[198] and a May 2026 Implementation Agreement that formalized the MOU's commitments on carbon pricing and the Pathways CCS project.[199]

However, aside from methane abatement, the policy environment around decarbonizing production emissions is in flux. In late 2024, the Trudeau government published proposed regulations to cap upstream oil and gas emissions through a cap-and-trade system. [192] The proposal drew strong opposition from industry and producing provinces, and the November 2025 Canada-Alberta MOU effectively set it aside. The federal government agreed to forgo the cap in exchange for Alberta's commitment to

strengthen industrial carbon pricing and invest in carbon capture.[201]

With the emissions cap off the table, industrial carbon pricing is now the primary regulatory signal for decarbonization investment in the sector. But that signal is itself weakened. Alberta froze its Technology Innovation and Emissions Reduction (TIER) carbon price at \$95 per tonne in 2025,[202] and the market price collapsed to between \$17 and \$40 per tonne, due to a surplus of banked credits and weak demand.[203] The May 2026 Implementation Agreement attempts to address both problems, establishing a rising headline price schedule and a credit price floor reaching \$130 per tonne by 2040.[199], At these prices, there is little economic incentive for producers to invest in deep emissions reductions.

This matters directly for the viability of carbon capture at scale. The flagship initiative, the Pathways Project, a proposed \$16.5 billion CO₂ pipeline and storage hub in northern Alberta backed by the five major oil sands producers now organized as the Oil Sands Alliance,[204] depends on robust carbon credit revenue to close its business case. The May 2026 Implementation Agreement commits both governments to completing a trilateral MOU with the Oil Sands Alliance and extends the Alberta Carbon Capture Incentive Program to support it.[199] The project also faces structural cost challenges: CCS in remote oil sands operations is expensive relative to other abatement options, and independent analyses have raised doubts about whether it can break even under current cost trajectories.[205] Even at full scale, the project would address only a portion of production emissions.

The economic logic of this approach is straightforward: as global markets increasingly differentiate between higher- and

lower-emission sources of energy, Canadian producers with lower production-emission profiles will be better positioned to retain market access and command premium pricing. The EU's incoming methane intensity standards for imported fuels, and similar signals from Asian importers, reinforce this competitive case.[206]

Nevertheless, this faces real constraints. Reducing production emissions to near zero is technically demanding and capital intensive, particularly for in-situ oil sands operations. It would raise production costs, reducing economic competitiveness. And while the carbon intensity of barrels could theoretically be a market differentiator, this signal has not yet materialized into a market advantage, making long-term decarbonization investments harder to secure absent strong regulatory signals.

Develop net-zero energy products and alternative uses for hydrocarbon resources.

Rather than producing oil and gas exclusively for combustion, some segments of the industry could shift toward net-zero energy carriers, principally hydrogen produced from natural gas with carbon capture (so-called blue hydrogen), or potentially electricity generated from natural gas with CCS. Alberta's geological advantages for carbon storage, existing pipeline infrastructure, and established gas processing expertise give the province a cost advantage in blue hydrogen production.

Interest in hydrogen as an energy carrier has grown substantially since 2021, driven by industrial decarbonization needs in sectors like steel, cement, and heavy transport, as well as by emerging export opportunities. Canada's federal hydrogen strategy and provincial strategies in Alberta and British Columbia have established frameworks for development.[207] However, low-carbon hydrogen production at

scale remains in early stages, and the business case depends on sustained demand growth, infrastructure buildout, and continued cost reductions. More details about hydrogen's role in a net-zero energy system are available in the hydrogen section of this report.

Beyond energy carriers, hydrocarbon resources can serve as feedstock for non-combustion products: petrochemicals, carbon fibre, activated carbon, and other advanced materials. Bitumen-beyond-combustion concepts such as these have received research attention in Canada.[207] These applications could generate value from hydrocarbon resources without the associated combustion emissions, though most are at early commercial stages and none would match the economic scale of existing oil and gas operations.

Diversify into adjacent energy and resource sectors.

Some oil and gas companies are already diversifying into adjacent areas, such as renewable electricity generation, geothermal energy, critical minerals, and carbon management services. Lithium extraction from oilfield brines is being actively explored in Western Canada.[208] Alberta and Saskatchewan have significant solar and wind resources. CCUS is itself becoming a commercial service industry, with the sector's geological and engineering capabilities directly transferable.

Geothermal energy serves as an interesting example to repurpose existing expertise to support renewable energy development since it can leverage subsurface expertise, drilling technologies, and geological data from the oil and gas sector.[209,210] Emerging advanced geothermal systems including closed-loop technologies developed by Calgary-based Eavor, which require no fracking or water and can be deployed across a much wider range of geological settings than conventional

geothermal, are drawing international interest. [211] Canada's first co-produced geothermal power plant is already operating at Swan Hills, Alberta, using legacy oil and gas well infrastructure.[212] Alberta established a formal regulatory framework for geothermal development in 2022, including provisions for converting existing oil and gas wells to geothermal use.

This approach is best understood not as a direct replacement for oil and gas activity but as part of a portfolio strategy that builds resilience and captures emerging opportunities. Its relevance will grow as the energy transition progresses, global demand patterns shift, and new revenue streams mature.



Competitiveness Implications

Canada's methane abatement sector (over 130 firms, with a projected 34,000 jobs by 2040) is not simply a domestic compliance industry. It is an export capability being built under conditions few competing jurisdictions can match. Deploying across dispersed conventional wells, in-situ oil sands, offshore platforms, and northern gas processing facilities means these firms field-test their technologies under a wider range of operating conditions than any other major producing jurisdiction generates, a deployment credential with direct export value. The EU's methane regulation (2024/1787), which imposes intensity standards on imported energy, is the leading edge of an importer-side compliance market. The condition that sustains this capability is domestic regulatory consistency: Canada's own methane stringency maintains the commercial base these firms need to accumulate the operational track record that gives them their international edge. The risk is not that methane regulations cost too much; it is that inconsistency in the domestic regime erodes the proving ground before the export market fully materializes.

7.4.4 Priorities for Action

Focus on end-use electrification as the highest-impact use of limited government capital. As this report argues throughout, the most consequential reductions in emissions associated with oil and gas will come not from within the sector itself, but from displacing the combustion of fossil fuels in transportation, buildings, and industry. These end-use emissions represent roughly 80% of the lifecycle total.[213] Governments face real constraints on fiscal and political capital, and directing that capital toward grid buildout, EV adoption, heat pump deployment, and industrial electrification delivers the largest structural impact. As these transitions advance, they reduce domestic fossil fuel consumption and, over time, reshape global demand patterns, and provide a timeline for diversification strategies to develop.

Implement and maintain strong methane regulations. Methane abatement is the most cost-effective near-term emissions reduction available in the sector, with abatement costs estimated at \$48 per tonne CO₂e or less. Canada's enhanced methane regulations, finalized in December 2025, provide a clear framework, though a March 2026 Alberta-Ottawa agreement-in-principle on provincial implementation timelines has introduced some uncertainty of its consistent application.[197,214] Maintaining regulatory consistency and supporting the growth of Canada's methane abatement technology sector, which already includes over 130 firms and has the potential to create 34,000 jobs by 2040, strengthens both the climate and competitiveness case.[195]

Employ regulations and fiscal measures to encourage sector emission abatement through electrification, efficiency and CCUS approaches. If an industrial pricing regime is to be maintained, its architecture should be sufficiently robust to encourage incremental change from a business-as-usual scenario.

Support hydrogen development and net-zero fuels where the economics and demand warrant. Blue hydrogen production leverages Canada's natural gas resources, CCS expertise, and geological storage capacity. Federal and provincial hydrogen strategies should focus on building demand in hard-to-electrify sectors (e.g., industrial heat, heavy freight) and on the infrastructure needed to connect supply and demand.

Prepare for regional economic adjustment. As the energy transition progresses, producing regions will face adjustment pressures. Proactive investment in economic diversification, workforce development, and community transition planning done well in advance of acute economic disruption is essential. This includes supporting the development of new industries and value chains that can absorb the transferable skills concentrated in oil and gas regions, including engineering, project management, geosciences, and skilled trades. Because these capabilities and communities are geographically concentrated, transition planning must be place-based and proactive, rather than generic. It should be designed to ensure that producing regions participate in the economic upside of the energy transition rather than simply bearing its adjustment costs. This is both an economic and a political imperative.

Criteria Status

-
- Fails to meet criteria
-
- Meets in some respect
-
- Not promising
-
- Potentially meets criteria
-
- Meets criteria

7.4.5 Oil and Gas Pathways Table

			ALIGNMENT WITH CARBON NEUTRALITY	Economic		Technical			Social			
PATHWAY ELEMENTS	ROLE IN NET-ZERO SYSTEM	SIGNAL TO DECISION- MAKERS		ECONOMIC VIABILITY	ECONOMIC DEVELOPMENT OPPORTUNITY	MATURITY	OPERATIONAL FIT	INFRA- STRUCTURE AND SUPPLY CHAIN SUITABILITY	SOCIAL ACCEPTABILITY	RELEVANCE TO STAKEHOLDERS	RELATED BENEFITS AND COSTS	
Fails to meet criteria Potentially meets criteria Meets criteria												
 Oil and Gas Production												
Methane Leak Abatement Detection and repair, vapour recovery, and elimination of routine venting and flaring	Decarbonization Pathway Cost-effective near-term lever. Central to Canada's climate and trade strategies. Requires carbon removals for net zero.	Deploy Sustain and enforce finalized regulations. Support scale-up of Canadian methane abatement service sector.	 Targets one element of oil and gas production emissions. Reduces significant near-term GHG emissions. Would require complementary measures including carbon removals to get to net zero.	 Low cost compared to other direct GHG management measures. Potential to recover saleable gas, partially offsetting costs.	 Growing market for specialized oil and gas equipment. Canada has many technology firms and can export tech and expertise.	 Many technologies mature and used across Canada.	 Integrates with existing processes.	 Relies entirely on existing upstream infrastructure. Well-established domestic supply chain of equipment manufacturers, service companies, and measurement technology providers.	 Reduces pollution. Broadly accepted.	 Relevant to governments and producers as frequently lowest cost abatement option.	 Can improve air quality around operations.	
Carbon Capture and Storage (CCS)	Niche Pathway Effective where CO ₂ streams are concentrated and storage geology is favourable. Not a system-wide solution for all sector emissions.	Enable Support deployment at suitable point sources where pricing, geology, and hub infrastructure align. Develop policy to stimulate investment.	 Can eliminate meaningful share of emissions from specific facilities. Does not address very dilute upstream sources or end-use combustion. Will require additional removals.	 Adds operating cost without revenue generation. Requires strong policy signals.	 Potential for CCS expertise as an export.	 Mature for some applications. Used internationally and in Alberta.	 Retrofits feasible at large point sources. More complex at distributed upstream facilities.	 Requires CO ₂ pipelines and storage hubs. Alberta geology is well-characterized but transport network is limited.	 Public concern around long-term leakage and liability. Mixed Indigenous perspective.	 Strong industry interest. Weak regulatory signals.	 Co-benefits through CO ₂ feedstock for industrial uses. Continued environmental concerns from oil and gas production.	

PATHWAY ELEMENTS	ROLE IN NET-ZERO SYSTEM	SIGNAL TO DECISION-MAKERS	ALIGNMENT WITH CARBON NEUTRALITY	Economic		Technical			Social		
				ECONOMIC VIABILITY	ECONOMIC DEVELOPMENT OPPORTUNITY	MATURITY	OPERATIONAL FIT	INFRA-STRUCTURE AND SUPPLY CHAIN SUITABILITY	SOCIAL ACCEPTABILITY	RELEVANCE TO STAKEHOLDERS	RELATED BENEFITS AND COSTS
Electrification of upstream operations electric drives, grid-tied facilities, co-gen displacement, vehicle fleet and equipment electrification	Decarbonization Pathway Essential to decarbonizing the energy used in oil and gas production. Requires decarbonized electricity.	Deploy Prioritize transmission build-out into oil sands basins. Requires supportive policy environment.	Can decarbonize many upstream operations, equipment and process heat, but dependent on decarbonized electricity.	Economics currently challenged and would require significant policy intervention.	Stimulates demand for clean power, transmission, and electrical trades. Retains regional employment.	Deployed at Canadian sites, including some oil sands in-situ operations.	Requires facility redesign and reliable grid access or substantial decarbonized on-site generation.	Requires significant transmission build-out and generation capacity additions.	Generally supported. Transmission corridor siting can attract opposition.	Limited stakeholder engagement.	Reduces local air pollution and noise. Risk of stranding existing assets.
Hydrogen Fuel Switching Cogeneration and gas turbines, process boilers, compression drives, vehicles and equipment	<i>Potential Niche Pathway</i> Viable decarbonization lever for combustion assets where electrification is difficult. Dependent on low-carbon hydrogen supply.	Enable Advance where low-carbon hydrogen supply is credible and off-take is firm. Prioritize turbine hydrogen-readiness in new cogeneration builds.	Can achieve significant CO ₂ reductions. Net zero only achievable with near-zero upstream methane leakage and high-capture rate CCS and removals.	Economics currently challenged and would require significant policy intervention.	Leverages Alberta's existing gas processing expertise and CCS-ready geology for hydrogen production.	Maturity varies by technology.	Existing cogeneration units can blend hydrogen. Sole use of hydrogen will require substantial upgrades or equipment replacement and NOx control systems.	No dedicated hydrogen supply infrastructure exists at O&G production sites. Requires new production facilities, compression, pipelines or on-site storage.	Safety concerns around hydrogen flammability and storage.	Alignment with government hydrogen strategies. Active investment by some producers and OEMs in hydrogen-ready turbine upgrades.	Repurposes sector expertise. Produces NOx emissions but better overall air quality.
Low-Energy Extraction Technologies Solvent-assisted steam-assisted gravity drainage (SAGD), radio-frequency and electro-magnetic heating	<i>Potential Enabling Pathway</i> Could be part of a net-zero system provided decarbonized production. May reduce the energy intensity — and potentially emissions — of in-situ oil sands extraction.	Incubate Support R&D, field pilots, and transparent reporting of real-world performance data before commercial scaling.	Reduces energy intensity and associated emission but does not eliminate emissions. Requires decarbonized production.	Potential operational cost savings from lower steam and energy use. High capital costs.	Canadian-led R&D ecosystem with IP and service industry potential.	Pre-commercial. A few pilots and demonstrations exist with limited long-term field data.	Can retrofit some SAGD assets. Requires process changes and operator training.	Largely uses existing oil sands infrastructure and well pads.	Mixed perception. Performance claims are held primarily by industry. Limited independent verification.	Relevant to government and academia with pilots. Important to industry if cost savings occur.	Energy and water savings. Reduced steam-to-oil ratio. Land-use impacts persist.

PATHWAY ELEMENTS	ROLE IN NET-ZERO SYSTEM	SIGNAL TO DECISION-MAKERS	ALIGNMENT WITH CARBON NEUTRALITY	Economic		Technical			Social		
				ECONOMIC VIABILITY	ECONOMIC DEVELOPMENT OPPORTUNITY	MATURITY	OPERATIONAL FIT	INFRA-STRUCTURE AND SUPPLY CHAIN SUITABILITY	SOCIAL ACCEPTABILITY	RELEVANCE TO STAKEHOLDERS	RELATED BENEFITS AND COSTS
On-Site Clean Power Generation (Small modular reactors, solar and wind)	Enabling Pathway Provides low-carbon electricity and/or heat directly to remote upstream facilities where grid access is absent or unreliable. Enables electrification of operations.	Incubate Avoid scaling investment ahead of proven economics. With improvement continue R&D and pilot funding for SMRs and electrothermal storage. Advance regulatory frameworks for nuclear deployment in Alberta.	 Can fully decarbonize on-site power and heat when powered by zero-emission sources.	 Solar and wind cost-competitive in some contexts but intermittency requires storage investment. Small modular reactors uneconomic for oil sands applications under current conditions.	 Small modular reactor development would leverage Alberta's engineering and supply chain base and create high-skilled jobs.	 Solar and wind mature but limited application in remote northern sites. Small modular reactors are not commercially available in Canada and are not proven at remote sites.	 Small modular reactors co-location with SAGD facilities creates new regulatory and safety challenges. Solar/wind requires storage and backup to match continuous 24/7 steam demand.	 No nuclear supply chain established for remote locations. SMR components require new manufacturing pathways. Renewable on-site power supply chains more developed.	 Public awareness of nuclear energy in Alberta is low. Opposition exists from communities near proposed sites and some Indigenous groups. Renewable opposition also exists.	 Alberta and federal governments actively exploring small modular reactors. Some interest from producers but economics are the limiting factor. Renewables have a low-level of interest.	 Improved air quality from zero-emission power generation. Potential to export power surplus to the grid. Timelines may create significant stranded asset risk if oil sands demand declines faster than anticipated.
 Net-Zero Products from Hydrocarbon Resources											
Blue Hydrogen (Natural gas Reforming with CCS, methane pyrolysis, autothermal reformation with CCS)	Niche Pathway Leverages Canada's gas resources and geological storage to generate net-zero energy. Contingent on very low upstream methane leakage.	Enable Advance where end-use demand is firm. See hydrogen section for detail.	 Can approach net zero only at high capture rates and with near-zero upstream methane emissions. May require carbon removals for residual emissions.	 More cost-competitive than green hydrogen. Contingent on gas prices, capture costs, and durable policy signals.	 Leverages existing gas processing expertise and subsurface storage. Export potential through Western corridors.	 Steam methane reforming with CCS is commercial internationally. Other technologies are in demonstration and pre-commercial.	 Builds on existing gas-processing practices. Integrates with proposed CCS hubs.	 Requires hydrogen demand, new hydrogen distribution, storage, and CCS network build-out.	 Concerns of upstream methane leakage. Safety concerns related to hydrogen handling.	 Some investment by major producers. Interest from some provincial governments.	 Repositions gas assets for a decarbonized economy. Extends fossil fuel production.

PATHWAY ELEMENTS	ROLE IN NET-ZERO SYSTEM	SIGNAL TO DECISION-MAKERS	ALIGNMENT WITH CARBON NEUTRALITY	Economic		Technical			Social		
				ECONOMIC VIABILITY	ECONOMIC DEVELOPMENT OPPORTUNITY	MATURITY	OPERATIONAL FIT	INFRA-STRUCTURE AND SUPPLY CHAIN SUITABILITY	SOCIAL ACCEPTABILITY	RELEVANCE TO STAKEHOLDERS	RELATED BENEFITS AND COSTS
Electricity Production from Natural Gas with CCS	<i>Potential Niche Pathway</i> Can be used as a backup power source while renewables are built out or for marginal balancing in a net-zero system. Potential export opportunity.	Incubate Support R&D for carbon capture from existing natural gas assets. Watch for local or regional power reliability issues.	 Difficult to capture all emissions with CCS. Requires negative emissions, which can be limited, to offset lifecycle emissions.	 Costly due to CCS. Needs subsidies but may become moderately competitive for baseload power.	 Electricity export potential in limited regional circumstances.	 Demonstration stage. Technology for post-combustion capture from gas turbines is being tested.	 Best suited to baseload or steady-output roles, cycling and peaking operation reduces capture efficiency. Retrofitting existing plants is feasible but requires significant site engineering.	 Benefits from existing infrastructure but requires new CO ₂ pipelines and strong methane management.	 Opposition remains over continued fossil fuel reliance and CO ₂ storage concerns.	 Relevant to gas producers and suppliers, Alberta, and industries needing firm power.	 Offers reliable low-carbon power and aids grid stability. Air quality and health issues with conventional combustion.
Non-Combustion Uses for Bitumen (i.e. Carbon fibre, asphalt binder, energy storage devices)	<i>Potential Niche Pathway</i> Extracts value from bitumen, avoiding combustion emissions.	Incubate Continue targeted R&D and build market linkages into carbon-constrained value chains.	 Avoids combustion emissions from bitumen. Requires up-stream abatement of methane and CO ₂ . May require removals.	 Long-term outlook unclear and varies by product. Competition from cheaper feedstocks.	Diversification opportunity for Alberta. Demand for carbon materials is growing.	 Mostly laboratory and early pilot stage.	 Requires new processing facilities separate from conventional refining.	 Requires new supply chains, manufacturing capacity, and networks. Asphalt binder faces specific transportation difficulties.	 Concerns about tailings, land disturbance, and reclamation.	 Active government-funded ecosystem. Producers supportive as feedstock suppliers, end use commitments limited.	 New markets and reduced reliance on combustion revenue. Continued upstream environmental liabilities.

			ALIGNMENT WITH CARBON NEUTRALITY	Economic		Technical			Social		
PATHWAY ELEMENTS	ROLE IN NET-ZERO SYSTEM	SIGNAL TO DECISION-MAKERS		ECONOMIC VIABILITY	ECONOMIC DEVELOPMENT OPPORTUNITY	MATURITY	OPERATIONAL FIT	INFRA-STRUCTURE AND SUPPLY CHAIN SUITABILITY	SOCIAL ACCEPTABILITY	RELEVANCE TO STAKEHOLDERS	RELATED BENEFITS AND COSTS
Resource Diversification											
Lithium Extraction from Oilfield Brines (Direct Lithium Extraction)	Enabling Pathway Repurposes sector capital, infrastructure, and workforce to supply critical minerals for the broader energy transition. Does not directly reduce oil and gas emissions.	Incubate Support piloting, validation, and integration with existing oilfield infrastructure; align with federal and provincial critical minerals strategies.	 Supports the broader net-zero transition rather than abating sector emissions directly.	 High capital costs. Costs expected to fall as technology matures. Price exposed to global lithium markets.	 Diversification opportunity. Builds on subsurface and brine-handling expertise. Battery supply chain opportunities.	 Pilot and demonstration stage. Provincial projects advancing, but no commercial operations to date.	 Uses existing wells, brine handling, and operational know-how. Minimal disruption from operations.	 Leverages existing facilities and well pads. Downstream critical mineral supply chain is nascent in Alberta.	 No particular concerns.	 Strong alignment with federal critical minerals strategies. Active industry participation.	 Low land disturbance. Regional diversification. Workforce transition pathway for oilfield service firms.
Geothermal Power (Closed loop, Conventional, and Deep)	Enabling Pathway Geothermal has potential for generating net-zero electricity and heat. Can transition oil and gas expertise to a net-zero industry.	Enable Build up regulatory frameworks. Support transitioning expertise. Support closed loop R&D as well as pilot and demonstration projects.	 Conventional geothermal releases some carbon dioxide. Closed loop geothermal is more promising for net zero.	 Not cost-competitive in Canada due to high drilling and capital costs. Potentially viable in remote locations.	 Established Canadian leadership in advanced geothermal. Drilling and subsurface, expertise transferable from oil and gas. Strong technology export potential.	 Demonstration stage with one closed loop project under construction in Canada. Deep geothermal in early research. Conventional geothermal is mature.	 Drilling, subsurface knowledge, and brine management map directly from oil and gas operations. Alberta regulatory framework includes provisions for well conversion. Site-dependent and best suited to regions with accessible heat at depth.	 Can leverage oil & gas infrastructure and expertise with standard equipment and a ready supply chain. Closed-loop systems require specialized tools not yet in domestic supply chains.	 Significant concerns of seismic activity for conventional geothermal. Support from off-grid Indigenous communities with closed-loop systems.	 Western provinces, oilfield service firms, and federal innovation programs as a transition opportunity. Utilities are cautious. Active investment in Canadian technologies.	 Baseload zero-emissions power —addresses intermittency of other renewables. Low land and water footprint. Can affect water quality if conventional geothermal is used.