

BORDERLESS

*How an integrated US-Canada natural gas market keeps energy
affordable, reliable, and competitive across North America*

ENERGY

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Executive summary

Energy policy has consequences that extend well beyond producers and pipelines to impact household and business costs. In North America, a key factor keeping energy affordable is the flow of Canadian natural gas into US markets. When gas moves freely across the border, households and businesses save billions of dollars. When gas trade is disrupted, those additional costs are passed on to consumers through higher heating bills, higher electricity prices, and higher costs for goods and services.

This makes an integrated Canada–US natural gas market a major competitive advantage for both countries. It lowers energy costs, strengthens electricity reliability, supports manufacturing, and helps meet rapidly growing demand from data centers and other energy-intensive industries. Preserving and strengthening this integration should be a priority for policymakers on both sides of the border.

The benefits are substantial:

- American households save approximately US\$2.2 billion annually on natural gas bills under continued market integration – roughly US\$40 per year for the average household that uses natural gas and US\$45 for households that rely on gas as their primary heating source.
- American households could face an additional US\$4.2 billion in annual natural gas costs under a sustained trade disruption. This represents the largest and most direct consumer cost of weakening North American energy integration.
- American electricity consumers save approximately US\$3.5 billion annually through lower residential power prices. Under stronger integration and rising demand, those savings could increase to more than US\$6 billion per year.
- American manufacturers benefit from roughly US\$660 million annually in lower input costs. Industries such as fertilizer

production, petrochemicals, and refining are particularly sensitive to natural gas prices and depend on affordable, reliable supply.

- The rapidly growing US data center sector has billions of dollars at stake. With electricity demand on pace to reach 580 terawatt-hours by 2028, the difference between continued integration and a major disruption is roughly US\$8 billion annually in electricity costs.
- Canada also benefits significantly. Natural gas exports support jobs, investment, government revenues, and economic growth across the country. In 2024, the oil and gas sector generated C\$76 billion in real value-added output, equivalent to 3.3 percent of Canadian GDP.

The costs of disrupting this relationship would be significant. Regions that depend on Canadian natural gas – including the Midwest, Pacific Northwest, Northern Plains, and parts of the Northeast – would face higher energy costs and increased pressure on electricity systems. Canadian producers would receive lower prices, reducing incentives to invest in production and infrastructure. The result would weaken affordability, reduce competitiveness, and lower economic growth on both sides of the border.

These findings point to a clear policy agenda. The 2026 review of the United States–Mexico–Canada Agreement (USMCA) should be used to:

- Preserve tariff-free energy trade between Canada and the United States.
- Maintain and strengthen the agreement’s energy-related provisions.
- Improve cross-border infrastructure coordination and regulatory cooperation.
- Reduce barriers that limit the efficient movement of natural gas across North America.
- Recognize energy integration as a critical component of affordability, reliability, and economic competitiveness.

The case for action is urgent. Electricity demand is rising, artificial intelligence and data center investments are accelerating, and manufacturers are seeking reliable sources of affordable energy. Integrated Canada–US natural gas markets help meet those challenges while lowering costs for households and businesses.

For Canada, the stakes are also high. Nearly all Canadian pipeline natural gas exports – 99.5 percent in 2025 – were destined for the United States. This is a foundational economic relationship that cannot be replaced in the near term through alternative markets.

The choice facing policymakers is straightforward: strengthen a North American energy partnership that saves consumers and businesses billions of dollars each year, or accept higher costs, weaker competitiveness, and reduced energy security. The 2026 USMCA review is an opportunity to reinforce the policies that keep energy affordable and reliable for millions of Canadians and Americans. ★

Motivation

Canada and the United States share the most deeply integrated natural gas market in the world. Over the next 18 months, several policy decisions will determine whether that system continues to operate as one market or begins to fragment. The most important decision is the joint review of the USMCA, which is required under Article 34 of the Agreement to take place no later than July 1, 2026.

USMCA, together with its Canada–US side letter on energy, is the legal scaffolding that keeps the cross-border gas trade tariff-free, predictable, and rules-based. The terms on which the review concludes – or in a more adverse scenario, fails to conclude – will shape investment in upstream production, pipelines, electricity infrastructure, and the industrial capacity that depends on affordable gas as a feedstock. Provincial decisions on West Coast LNG development and federal decisions on cross-border pipeline permitting will jointly influence the future direction of North American natural gas integration.

This report evaluates the economic effects of those decisions. We pose a relatively narrow question: What is the measurable economic value of integrated Canada–US natural gas trade for households and industry on both sides of the border, and what could Canadians and Americans lose if that integration were disrupted? The answer, explained in detail in the sections that follow, is that the stakes are large and quantifiable. Under continued integration, Canadian pipeline gas can save US households roughly US\$2.2 billion a year on their gas bills, support another US\$3.5 billion a year in lower electricity bills, and underwrite a price advantage for US fertilizer, petrochemical, and manufacturing producers that competes globally on gas costs. If trade were to be disrupted for a sustained period, those savings would reverse: US households would face roughly US\$4.2 billion in

additional gas costs with knock-on effects on electricity bills, industrial competitiveness, and the cost of powering the US data center buildout.

Scope of the report

It is worth stating clearly up front what this report is not arguing. Most participants in the Canadian energy debate are not calling for Canada to stop selling natural gas to the United States. The federal government’s “energy superpower” framing, echoed by most provincial governments and most industry observers, focuses on growing Canadian production and broadening the customer base. The US is currently – and on any realistic timeline, will remain – the largest single customer for Canadian gas.

The critical policy questions are about terms, scale, and complementary diversification. On what terms should Canada and the United States preserve and extend their gas trading relationship through the USMCA review? At what scale should Canada build out West Coast LNG capacity to reach Asian and, indirectly, European buyers? And how should provincial and federal regulators balance affordability, reliability, emissions, Indigenous consultation and participation, and infrastructure approvals as the system grows? This report speaks to the first question and provides the economic context for the second and third questions.

Continental integration and overseas diversification are complements, not substitutes

The case for deeper Canada–US integration is not a case against diversification to Asia. The two strategies affect different parts of the Canadian gas system and serve different policy goals.

Pipeline gas to the United States is – and for at least the next decade will remain – Canada’s anchor export. Backing away from this trade would impose real losses on Canadian producers and Canadian provincial revenues, and would also raise prices for tens of millions of American households who have no near-term substitute supply.

West Coast LNG, by contrast, opens a genuinely new export channel. LNG Canada’s first phase began shipping from Kitimat in 2025; Woodfibre LNG and Cedar LNG are under construction; and

additional capacity, including a potential LNG Canada Phase 2, is in active development. These projects monetize gas from the Montney and Duvernay basins in northern British Columbia and Alberta that would otherwise face transportation constraints and steep discounts relative to US benchmarks. They give Canada a foothold in Asian gas markets and, through the arbitrage mechanics of the global LNG market, indirect exposure to European buyers seeking alternatives to Russian supply.

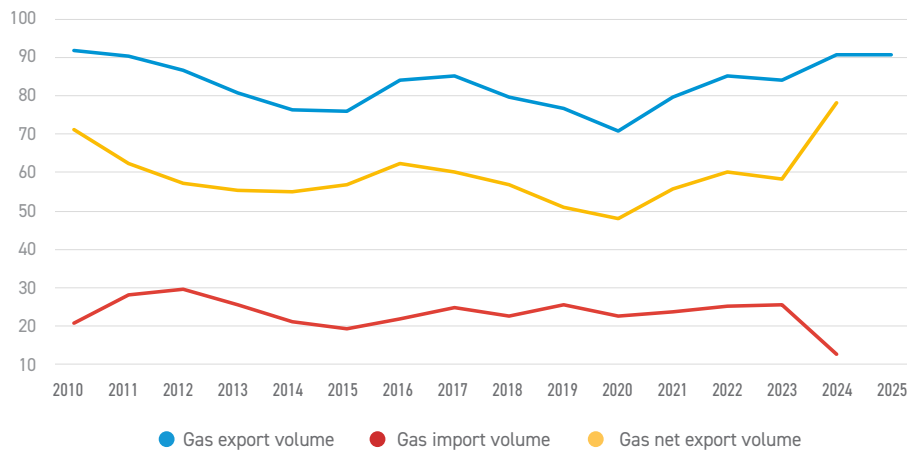
Underpinning both channels is the depth of Canada's underlying resource base. Canada holds substantial undeveloped natural gas reserves; contingent resources in the Western Canadian Sedimentary Basin are more than sufficient to meet rising domestic demand and sustain elevated export volumes through the mid-century (CER 2023; 2024). This vast potential is central to the analysis that follows.

Economic significance of Canadian natural gas and natural gas liquids exports

Export volumes and dollar value

Canadian natural gas exports to the United States remain one of the clearest indicators of Canada's importance to North American energy security and affordability. **Figure 1** shows that export volumes have remained at robust levels over the past five years, rising from 70 billion cubic meters in 2020 to 91 billion cubic meters in 2024. Natural gas imports, by contrast, are much smaller, leaving Canada as a major net exporter across the period. This asymmetry also matters from the US perspective. In 2025, Canadian pipeline gas accounted for 99.5 percent of total US natural gas imports. Canada's natural gas exports to the US account for 47 percent of Canada's production. About 96 percent of Canada's gas imports come from the US, accounting for 17 percent of consumption.

FIGURE 1: Annual natural gas trade volumes from Canada to the United States (in billions of cubic meters)



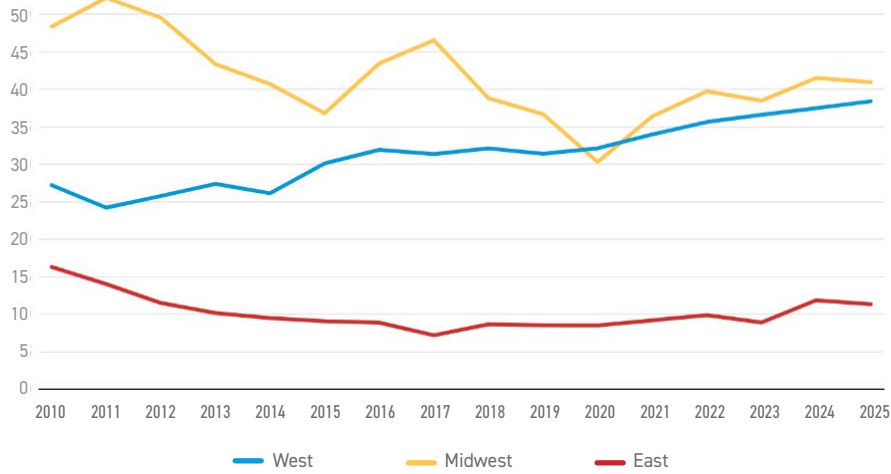
Source: CER (2025a).

The regional breakdown of exports to the United States demonstrates the strategic depth of that relationship. The US Midwest remains the single largest destination for Canadian gas, receiving more than 40 billion cubic meters annually in 2025 – roughly 45 percent of total Canadian pipeline exports to the United States. At the same time, exports to the US West have trended steadily upward and now sit close to the volumes going to the Midwest.

Exports to the East are smaller, but still economically meaningful, particularly for regions such as New England where winter heating demand and limited alternative supply options can amplify the value of reliable Canadian flows. The temporary dip in Midwest-bound volumes visible in 2020 and 2021 (**Figure 2**) reflects a drop in pandemic-era demand together with growing competition from Appalachian shale gas reaching Midwest markets via expanded US pipeline capacity. However, flows recovered as industrial demand normalized and as winter heating loads returned to trend.

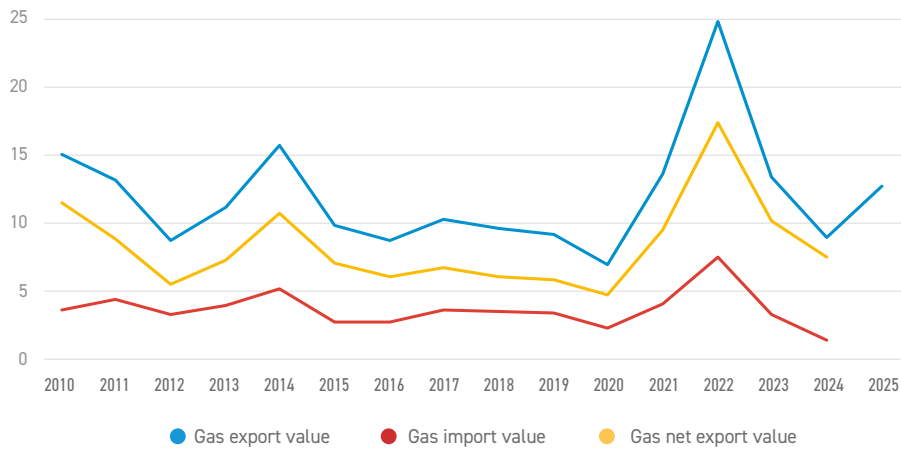
As **Figure 3** shows, Canadian natural gas export values rose from C\$7 billion in 2020 to nearly C\$25 billion in 2022, before easing when global prices normalized after the initial shock that year associated with the war in Ukraine and the broader European supply realignment. Even after the pullback, export receipts remained well above import values, preserving a substantial net trade surplus in gas.

FIGURE 2: Annual natural gas export volumes to various regions in the US (billions of cubic meters)



Source: CER (2025a).

FIGURE 3: Annual natural gas trade values, (current Canadian dollars, billions)



Source: CER (2025a).

This matters economically for two reasons. First, it confirms that natural gas exports are a major source of Canadian foreign exchange earnings and income generation. Second, it shows that any policy or infrastructure shock affecting access to the US market would feed quickly into producer revenues, royalty flows, and provincial and federal fiscal balances.

Appendix A further discusses the provincial patterns of natural gas exports as well as the trends in LNG trade between Canada and the United States.

Economic contribution

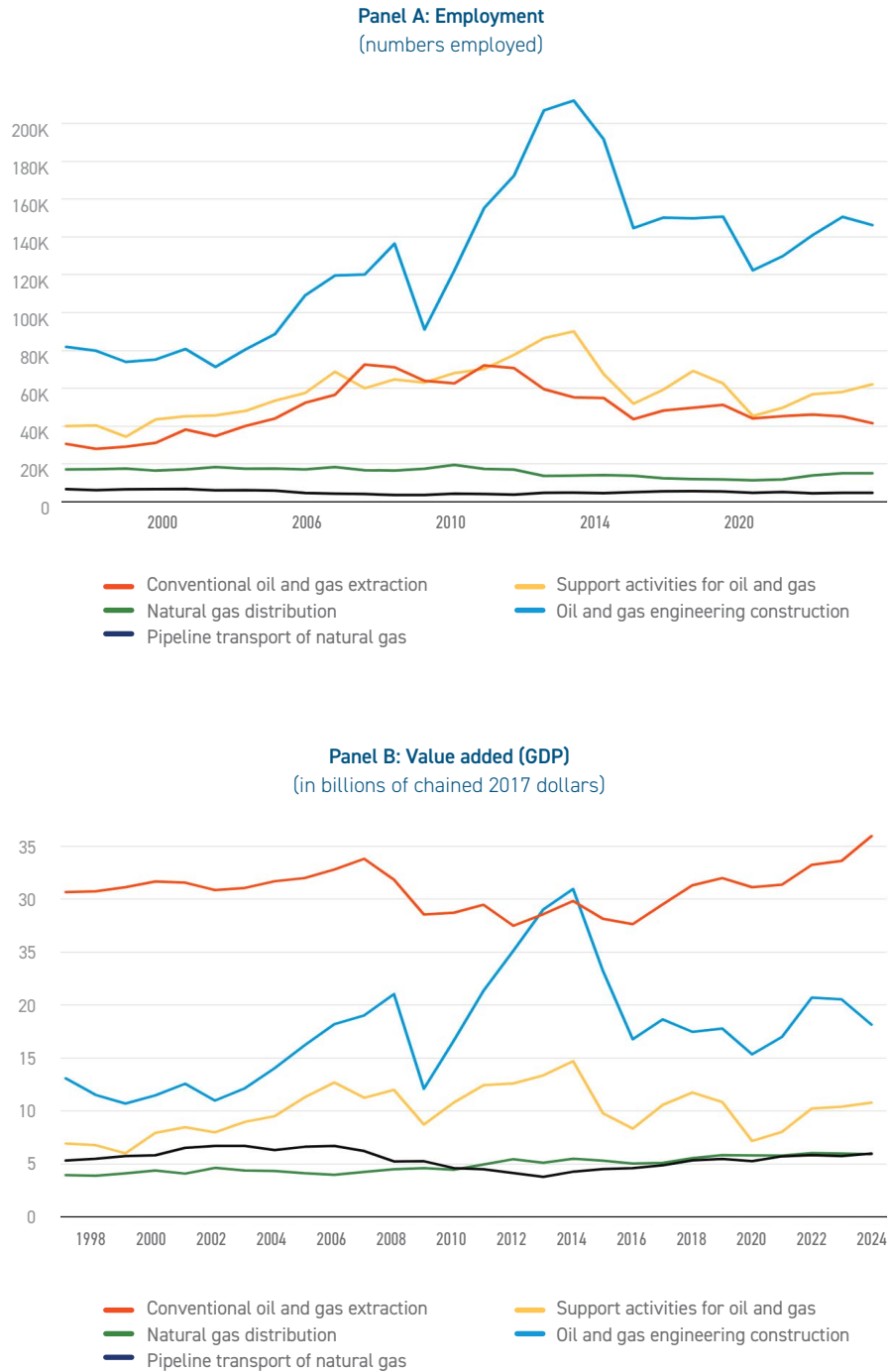
The natural gas and oil extraction sector is one of the most productive industries in the Canadian economy. In 2024, oil and gas extraction (NAICS 211 — the standard North American industry classification for the sector) contributed C\$75.5 billion in real value-added output (measured in chained 2017 dollars) which is equivalent to 3.3 percent of total Canadian gross domestic product (GDP) at basic prices.

Canadian natural gas exports and related industries support a much broader domestic economy than these headline figures alone suggest. **Figure 4, Panel A** shows that the greatest proportion of people employed in the sector had jobs in oil and gas engineering construction, where the numbers employed rose from 80,000 workers in the late 1990s to a peak of over 200,000 in the mid-2010s, before settling back to 145,000 to 150,000 in recent years. Conventional oil and gas extraction employment also grew materially in the same period, as did support activities for oil and gas. By comparison, the number of workers in natural gas distribution remained relatively stable at around 15,000, while those employed in pipeline transportation remained at between 4,000 and 6,000 workers.

Figure 4, Panel B shows the story in value-added terms. Conventional oil and gas extraction remained the sector's largest economic contributor, holding steady at near \$30 billion for much of the period and rising to \$36 billion by 2024. Oil and gas engineering construction was more cyclical, climbing from \$13 billion in value-added in the late 1990s to over \$30 billion around 2014, then easing back to \$18 billion by 2024. Support activities also fluctuated sharply, peaking near \$15 billion before falling and partially recovering.

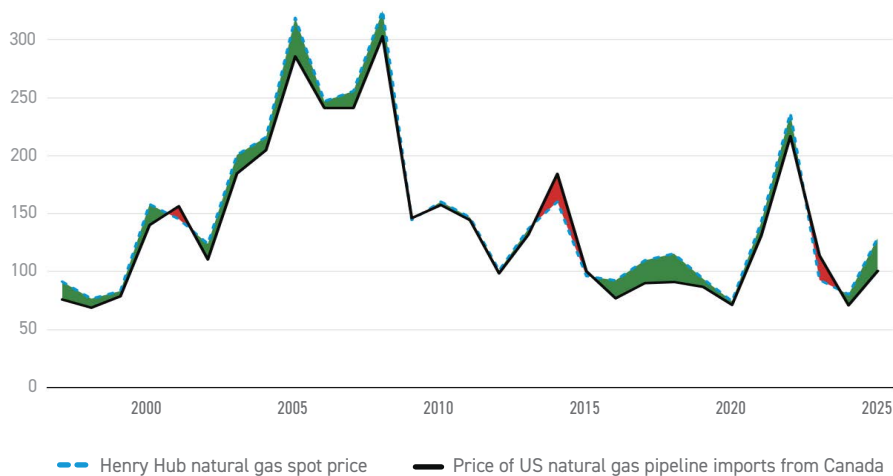
The United States relies overwhelmingly on Canadian pipeline gas for its foreign natural gas supply. In 2025, the US imported 89 billion cubic meters (bcm) of pipeline natural gas from Canada, accounting for 99.5 percent of total US natural gas imports, virtually all US pipeline gas imports, and 10 percent of total US natural gas consumption.¹

FIGURE 4: Natural gas related economic impacts in Canada, 1997–2024



Source: Statistics Canada (2026c).

FIGURE 5: US natural gas spot price versus the price of gas imported from Canada



Note: Green shading marks years in which Canadian imports entered the US market at a discount to Henry Hub; red shading marks the reverse.

Source: EIA (2026b, 2026e).

At 2024 volumes and a border price² of US\$71 per thousand cubic meters, the annual value of Canadian gas entering the US market was US\$6.4 billion. In higher-price years such as 2021 and 2022, the same flows were worth US\$10.5 billion and US\$18.8 billion respectively.

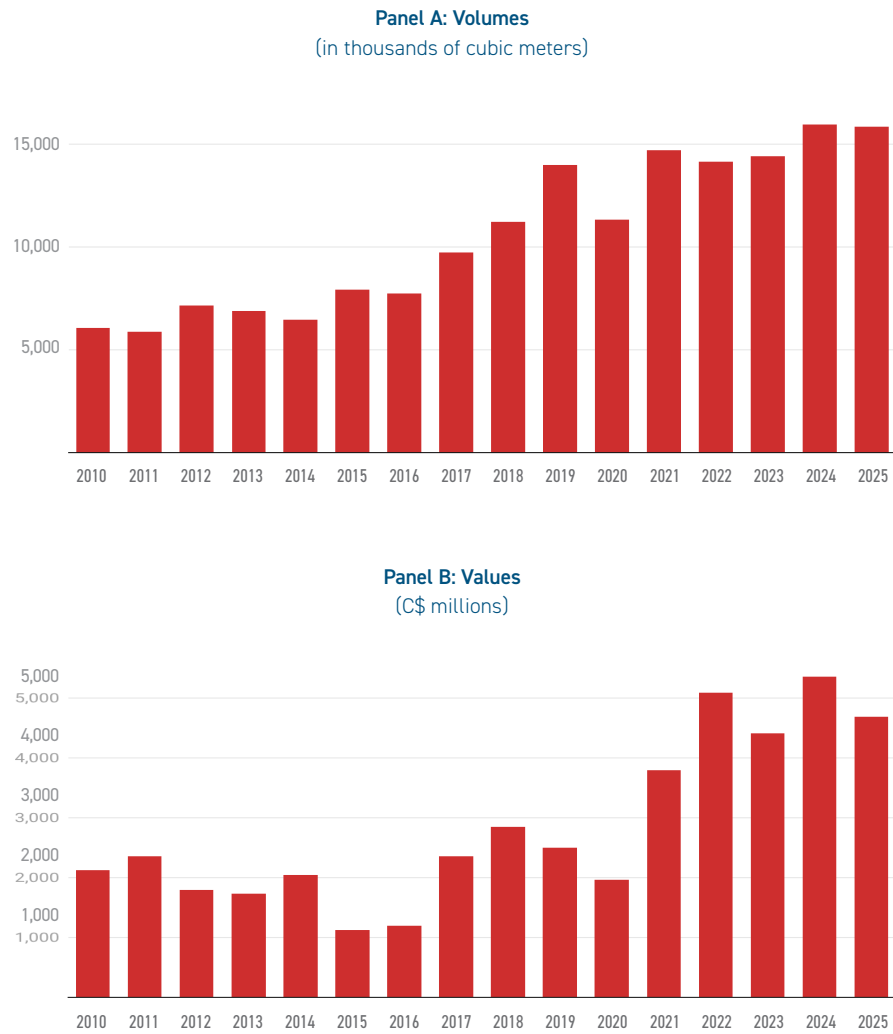
Canadian gas has also provided US consumers with a structural price advantage relative to the domestic US benchmark.³ **Figure 5** plots the Henry Hub natural gas spot price from 1997 to 2025, expressed in dollars per thousand cubic meters.⁴ For most of the period, and in all years of materially elevated prices, Canadian gas has traded below the US benchmark at the border.

Taking these spillover benefits into account, the economic case for maintaining and deepening the Canada–US natural gas trading relationship rests as much on US consumer interests as on Canadian producer interests.

The contribution and value of natural gas liquids

Natural gas liquids (NGLs)⁵ add an important second layer of value to Canada’s gas sector because they generate export earnings beyond dry natural gas alone. **Figure 6, Panel A** shows that the export volumes

FIGURE 6: Annual exports of natural gas liquids

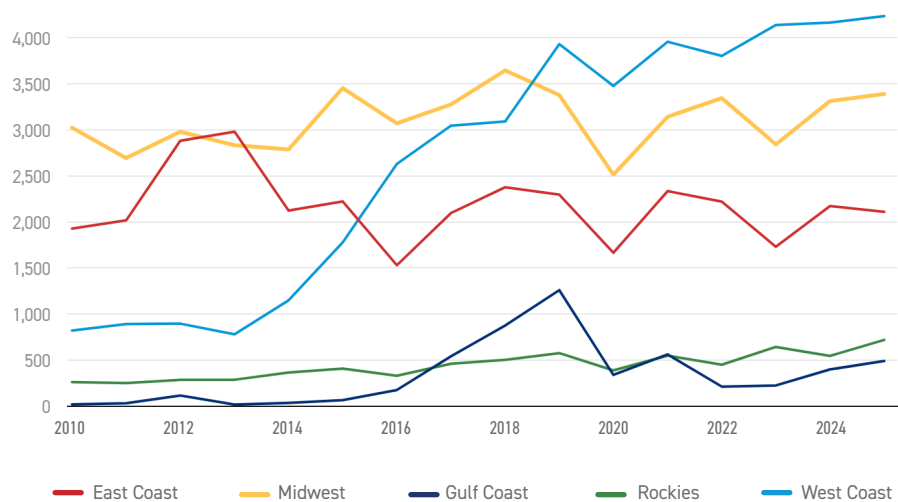


Note: The export data shown here cover propane and butanes only; ethane and pentanes+ are discussed qualitatively unless separately sourced.

Source: Statistics Canada (2026a, 2026b).

of NGLs, covering only propane and butanes, rose from 6.0 million cubic meters in 2010 to 16.0 million cubic meters in 2024 and 2025, representing a near tripling over 15 years. **Figure 6, Panel B** shows that export values were more volatile but also moved much higher over time, rising from C\$2.1 billion in 2010 to a peak of C\$5.3 billion in 2024, before easing to C\$4.7 billion in 2025.

FIGURE 7: Annual exports of natural gas liquids from Canada to various US regions (thousand cubic meters)



Note: The export data shown here cover propane and butanes only; ethane and pentanes+ are discussed qualitatively unless separately sourced.

Source: Statistics Canada (2026a, 2026b).

Figure 7 shows that the trade in natural gas liquids has become increasingly regionally concentrated around key US markets. The US West Coast was the fastest-growing destination, rising from 0.8 million cubic meters in 2010 to more than 4.2 million cubic meters by 2025, making it the largest regional market.

The Midwest remained a major destination throughout, ending up at near 3.4 million cubic meters, while the East Coast remained an important market but stayed broadly flat at around 2.1 million cubic meters in 2025. By contrast, the Gulf Coast and Rockies remained much smaller markets, even though both saw intermittent gains. The main point is that exports of NGLs are growing in both scale and strategic relevance, with western US demand becoming increasingly important to Canada’s liquids trade. **Appendix Figures A1** and **A2** present provincial breakdowns of the volume and value of NGLs exports.

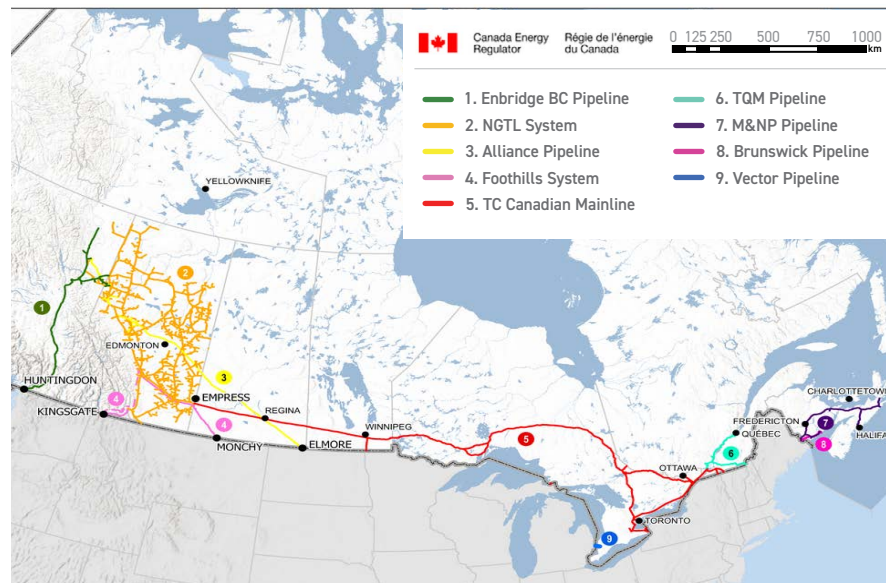
Trade and infrastructure scenarios affecting cross-border energy flows

Current pipeline infrastructure and use

If a pipeline extends across provincial or international borders, it falls under the federal oversight of the Canada Energy Regulator (CER).⁶ This report concentrates on transmission pipelines, as these typically cross such boundaries.⁷ Overall, the CER oversees 68,000 kilometers of active pipelines, including 48,338 kilometers dedicated to natural gas transmission. **Figure 8** highlights the major natural gas pipelines under CER jurisdiction.

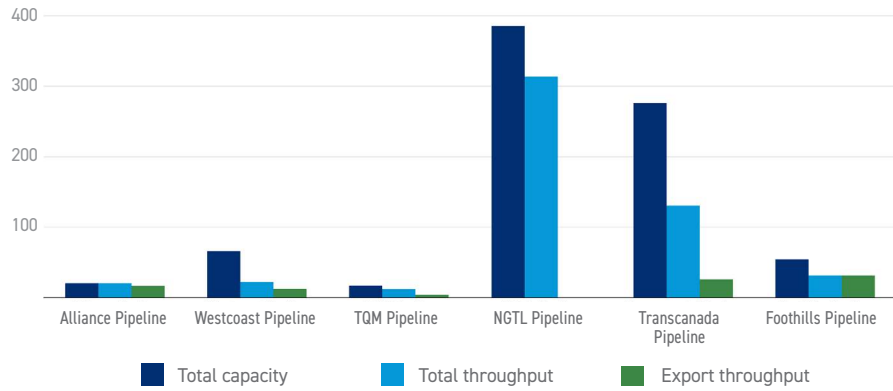
In 2025, the six major Canadian systems shown in **Figure 9** had a combined capacity of 818 billion cubic meters and total throughput of 529 billion cubic meters, implying an aggregate use of 65 percent. NOVA Gas Transmission Limited (NGTL) was by far the largest system, with 385 billion cubic meters of capacity and 314 billion

FIGURE 8: Major natural gas pipelines regulated by the Canada Energy Regulator



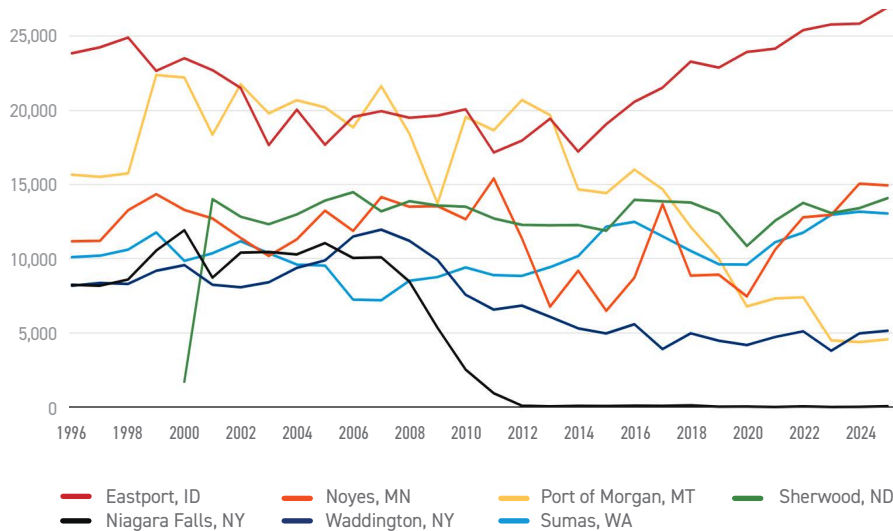
Source: CER (2026b).

FIGURE 9: Major natural gas pipeline capacity and throughput, 2025
(in billions of cubic meters)



Source: CER (2026c).

FIGURE 10: US natural gas imports by major points of entry, 1996–2025
(in millions of cubic meters)



Note: These are the historically seven largest points of entry for natural gas imports from Canada.

Source: EIA (2026f).

cubic meters of throughput, reflecting its role as the gathering and transmission backbone for Western Canadian supply rather than a direct export pipe. By contrast, smaller export corridors are critical to US supply: Foothills carried 31.0 billion cubic meters of throughput, all of it exported; Alliance carried 20.7 billion cubic meters, including

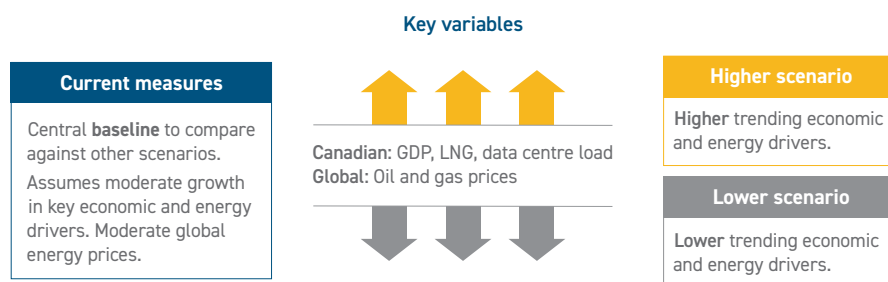
16.5 billion cubic meters of export throughput; and TransCanada carried 25.7 billion cubic meters for export.

Figure 10 reinforces this corridor logic from the American side. In 2025, Eastport, Idaho, was the largest single-entry point at 26.9 billion cubic meters, followed by Noyes, Minnesota, at 14.9 billion cubic meters, Sherwood, North Dakota, at 14.1 billion cubic meters, and Sumas, Washington at 13.1 billion cubic meters. Together, these four points accounted for 77 percent of Canadian natural gas pipeline imports to the United States. Eastern entry points such as Niagara Falls and Waddington are now much smaller than they were in the late 1990s, indicating the declining role of traditional eastern import routes and the rising importance of Western Canadian supply into the Midwest, Northern Plains, and Pacific Northwest.

Scenario description

The scenario analysis in this report uses the Canada Energy Regulator’s *Canada’s Energy Future 2026* as the quantitative anchor for three Canada–US natural gas trade and infrastructure cases shown in **Figure 11**. The CER scenarios are presented as structured modeling exercises that test how Canadian energy supply and demand could evolve under different assumptions. This report therefore uses CER’s projections for production, prices, LNG exports, demand, and macroeconomic conditions as empirical bounds for assessing three policy-relevant scenarios: a baseline integration case, an enhanced market-access case, and a constrained market-access case (**Figure 12**).

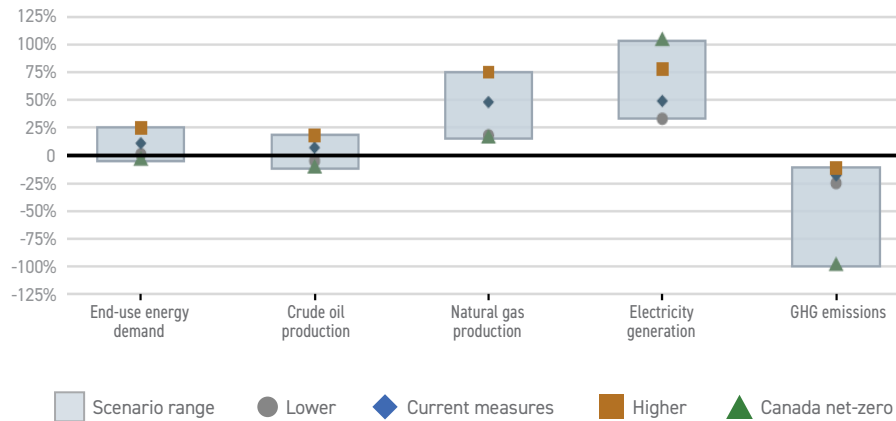
FIGURE 11: Illustration of the scenarios in Canada’s energy future as of 2026



Excludes policies after November 2025.

Source: EIA (2026f).

FIGURE 12: Percentage change in energy demand, oil and natural gas production, electricity generation, and GHG emissions, 2024 to 2050, by scenario (percent change, 2024 to 2050)



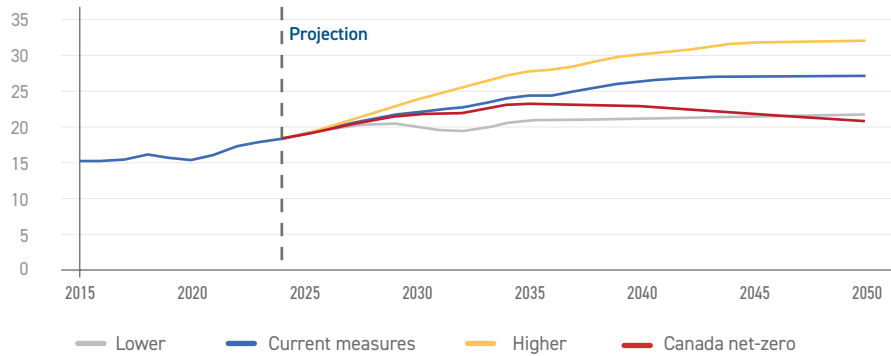
Source: CER (2026a), Figure ES.2

Scenario A: Baseline (current measures / status quo integration)

Scenario A is anchored in CER’s Current Measures scenario. It represents a continuation of the broadly integrated Canada–US natural gas markets under existing policy, regulatory, and infrastructure conditions and is the reference case against which the enhanced and constrained cases are compared. Under Current Measures, Canadian natural gas production continues to grow from recent record levels (**Figure 13**). CER reports that Canadian natural gas production reached 18.3 billion cubic feet per day (bcf/d) in 2024 and projects it to rise to 27 bcf/d by 2050 in the Current Measures scenario. This supports the baseline view that Canada remains a major gas supplier over the long term, even as domestic energy demand and electricity systems evolve.

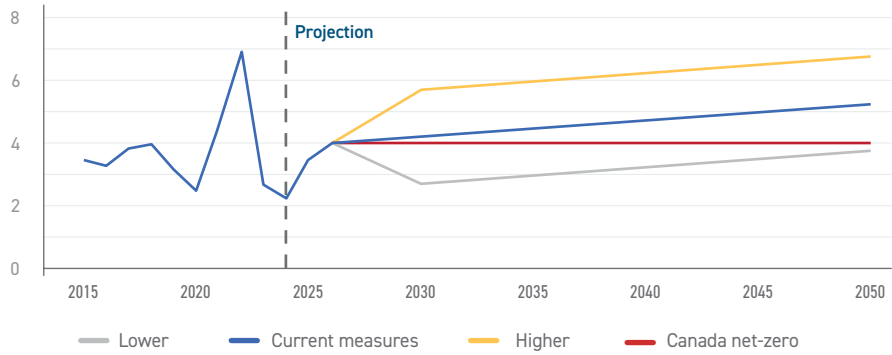
The most important driver of incremental production in this baseline is LNG. CER assumes that 6.1 bcf/d of natural gas goes to LNG exports by 2050 in Current Measures, equivalent to 48 million tonnes per annum (MTPA). Across each of its scenarios, CER notes that most incremental natural gas production goes to LNG exports, with LNG accounting for 20 to 25 percent of total Canadian production by 2050. **Figures 14** and **15** illustrate the various projections for all scenarios for natural gas prices and LNG exports.

FIGURE 13: Total natural gas production in all scenarios (billion cubic feet per day, BCF/d)



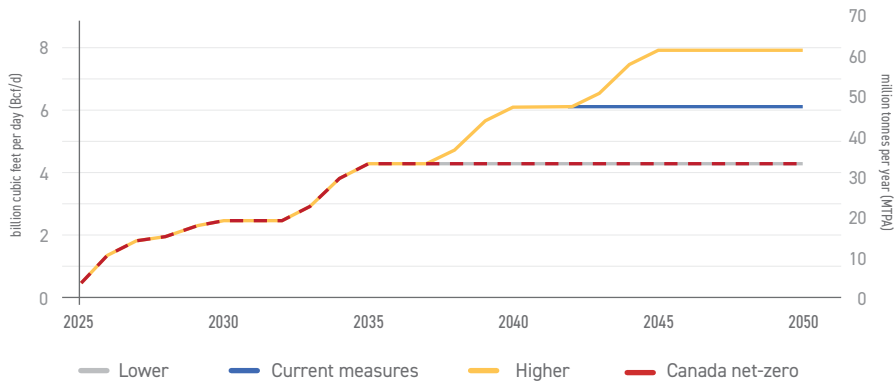
Source: CER (2026a), Figure R.13.

FIGURE 14: International natural gas price assumptions (Henry Hub), all scenarios (2025 US\$ per MMBtu)



Source: CER (2026a), Figure A.4.

FIGURE 15: Canadian LNG export volume assumptions, all scenarios



Source: CER (2026a), Figure A.5.

Scenario B: Enhanced cooperation (higher scenario)

Scenario B uses CER's Higher scenario as the quantitative anchor but interprets it through a Canada–US market-access lens. It assumes stronger economic and energy drivers than Current Measures, including higher GDP growth, higher LNG exports, stronger data center load growth, and higher global oil and natural gas prices. Those assumptions are consistent with, but do not themselves require, a policy environment in which Canada and the United States deepen energy cooperation and reduce infrastructure bottlenecks.

The production response under this case is materially greater than in the baseline. CER projects Canadian natural gas production reaching 32 bcf/d by 2050 in the Higher scenario, compared with 27 bcf/d in Current Measures. LNG is again central: CER assumes 7.9 bcf/d of natural gas goes to LNG exports by 2050 in the Higher scenario, or 62 MTPA. Under these conditions, upstream investment is stronger and the economic value of Canadian gas exports rises. Better infrastructure and market access would reduce transportation bottlenecks and increase the prices Canadian producers receive for their natural gas. At the same time, higher available supply and more stable natural gas prices would continue to reduce delivered energy costs in US regional markets. Therefore, the policy logic is that were Canada and the United States to preserve tariff-free gas trade, improve permitting timelines, and reduce infrastructure constraints, Canadian supply could continue to moderate US regional delivered prices while still providing adequate returns for Canadian producers.

Scenario C: Constrained trade (policy or infrastructure limits)

Scenario C uses CER's Lower scenario as the main quantitative boundary. This scenario reflects weaker economic and energy drivers than Current Measures, including lower GDP growth, lower LNG exports, lower data center load growth, and lower global oil and natural gas prices. Within those limits, the Lower scenario provides a useful benchmark for the scale of production and investment downside that could accompany weaker market access. Under this scenario, CER projects that natural gas production would still grow relative to 2024, but only to 21 bcf/d by 2050 in the Lower scenario, compared with 27

bcf/d in Current Measures and 32 bcf/d in the Higher scenario. LNG growth is also reduced: CER assumes 4.3 bcf/d of gas goes to LNG exports by 2050 in both the Lower and Canada Net-zero scenarios, compared with 6.1 bcf/d in Current Measures and 7.9 Bcf/d in the Higher scenario.

In practical terms, bilateral trade shocks – such as a sustained US tariff on Canadian pipeline gas, new regulatory barriers, or infrastructure restrictions – would operate through a different mechanism than CER’s Lower scenario. It would weaken demand for Canadian gas exports and widen the gap between Canadian benchmark prices and Henry Hub. In practice, that would compress Canadian producer netbacks, weaken upstream investment, and increase the risk that Canadian gas is stranded at a discount even while nearby US regions face higher delivered energy costs.⁸

Scenario analysis

This analysis uses the CER *Energy Future 2026* Henry Hub price assumptions as the commodity benchmark for each scenario: US\$4.21 per MMBtu (one million British thermal units, the standard pricing unit for natural gas; one MMBtu equals roughly one thousand cubic feet of gas) in 2030 for Current Measures, US\$5.71 for the Higher scenario, and US\$2.71 for the Lower scenario. We then separately calibrate the spread between Henry Hub and the Canada border price.⁹

Table 1 summarizes each scenario’s prices, spreads, and production trajectory. Two points open to interpretation sit alongside the numbers. First, the Scenario B widening of the delivered Canada-border discount to US\$1.25 per MMBtu is close to the Henry Hub minus AECO-C differential observed in 2023 at US\$1.29 per MMBtu; under stronger supply growth and improved use of the infrastructure, more Canadian gas would compete for US continental market share at the border even as the absolute benchmark price rises. Second, the delivered-price discount used here is conceptually distinct from the AECO/NIT producer netback discount, which would, all else equal, narrow under Scenario B as transportation bottlenecks ease. Scenario C2 is an authors’ stress case calibrated outside the CER 2026 framework; it assumes pipeline constraints or trade barriers sever Canadian supply

from US import-dependent markets, causing AECO to fall materially below Henry Hub while US regions short of domestic supply face localized scarcity premiums.

TABLE 1: Scenario summary – production, pricing, and policy framing

Indicator	Scenario A: Baseline (CER current measures)	Scenario B: Enhanced cooperation (CER higher)	Scenario C1: Constrained trade (CER lower)	Scenario C2: Trade disruption (stress case)
Henry Hub price, 2030 (US\$/MMBtu)	4.21	5.71	2.71	Elevated in import-dependent regions
Delivered Canada border discount vs. Henry Hub (US\$/MMBtu)	0.70	1.25	0.25	Negative; scarcity premium
Canadian gas production by 2050 (bcf/d)	27	32	21	Materially below baseline
Canadian LNG exports by 2050 (bcf/d/MTPA)	6.1 / 48	7.9 / 62	4.3 / 34	Reduced
Policy framing	Status quo continental integration	Tariff-free trade plus reduced bottlenecks	Weaker market access, lower investment	Severe bilateral trade disruption

Source: CER (2026a); authors' calibration of scenario spreads.

Affordability impacts for households and industry

Household affordability

The total annual US consumer savings that result from the Canadian price discount is calculated as:

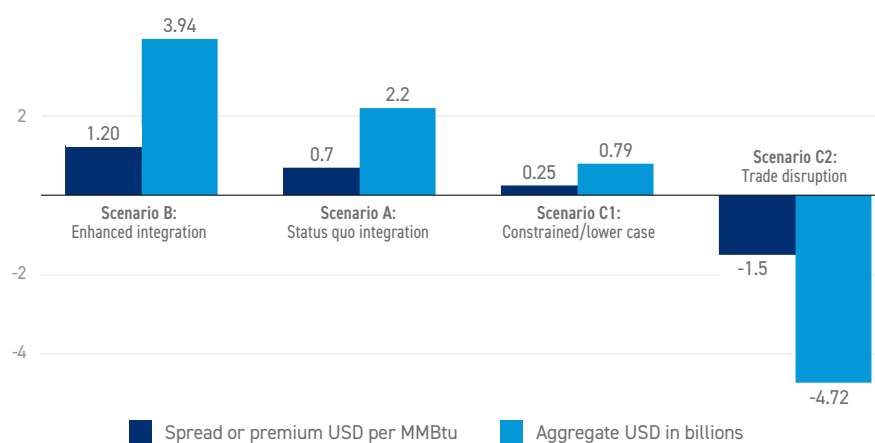
$$Savings = Spread \times Annual\ Import\ Volume$$

The model parameters used throughout this section are as follows: fixed charges of US\$150 per year (AGA 2024); distribution cost of US\$7.00 per MMBtu representing the average 2019–2023 residential-to-citygate price spread (EIA 2024a)¹⁰ and consumption from the EIA 2020 *Residential Energy Consumption Survey* (EIA 2024b). Based on the

spread assumptions described above, a US\$1.00 per MMBtu change in the commodity component changes the annual fuel bill by US\$52 for a national-average household (before fixed charges and distribution).

As **Figure 16** shows, and using the historical import volume of 89 billion cubic meters per year, the implied annual consumer savings are US\$3.94 billion under Scenario B, US\$2.20 billion under Scenario A, and US\$0.79 billion under Scenario C1. Scenario C2 produces an implicit annual cost of US\$4.72 billion, reflecting the premium US consumers would pay if Canadian supply were withdrawn from import-dependent markets.¹¹

FIGURE 16: Aggregate US commodity-cost savings or costs

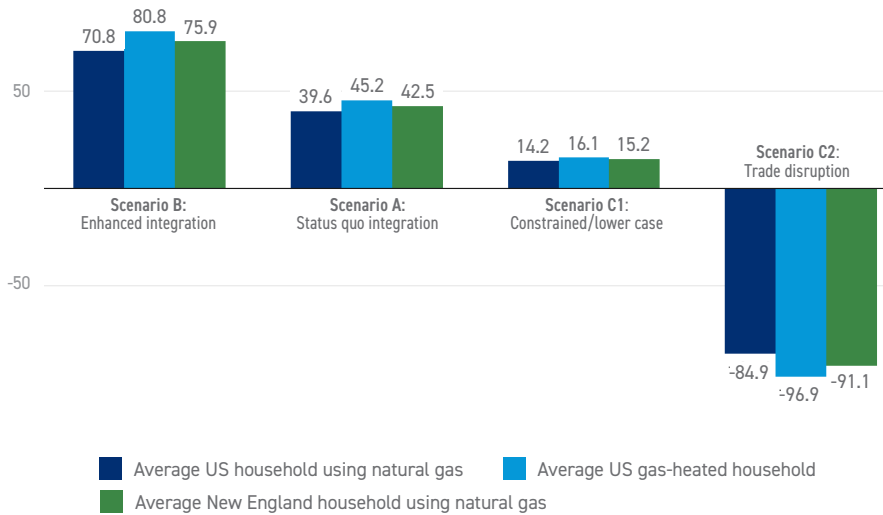


Note: Aggregate USD in billions = 2025 US pipeline imports from Canada in billion MMBtu × spread/premium.
EIA heat-content conversion is 1 Mcf = 1.038 MMBtu.

Source: EIA (2026e); CER (2026a); authors' calculations.

At the household level, the per-household discount equals the spread multiplied by annual natural gas consumption. The EIA (2024b) reports that the average US household using natural gas consumed 56.6 MMBtu of natural gas per year, while the average New England household using natural gas consumed 60.7 MMBtu. Using those values, the annual fuel-cost discount from Canadian supply is US\$71 under Scenario B, US\$40 under Scenario A, and US\$14 under Scenario C1 for the national-average natural-gas-using household. For New England, the comparable figures are US\$76, US\$42, and US\$15 (**Figure 17**).

FIGURE 17: Per-household fuel-cost discount from Canadian gas (in current dollars)



Note: Household value = spread or premium (\$/MMBtu) × annual natural gas consumption (MMBtu/year). Data come from EIA (2024b) Table CE2.1 and equate to: 56.6 MMBtu for average US household using natural gas; 64.6 MMBtu for household whose main heating fuel is natural gas; 60.7 MMBtu for New England household using natural gas.

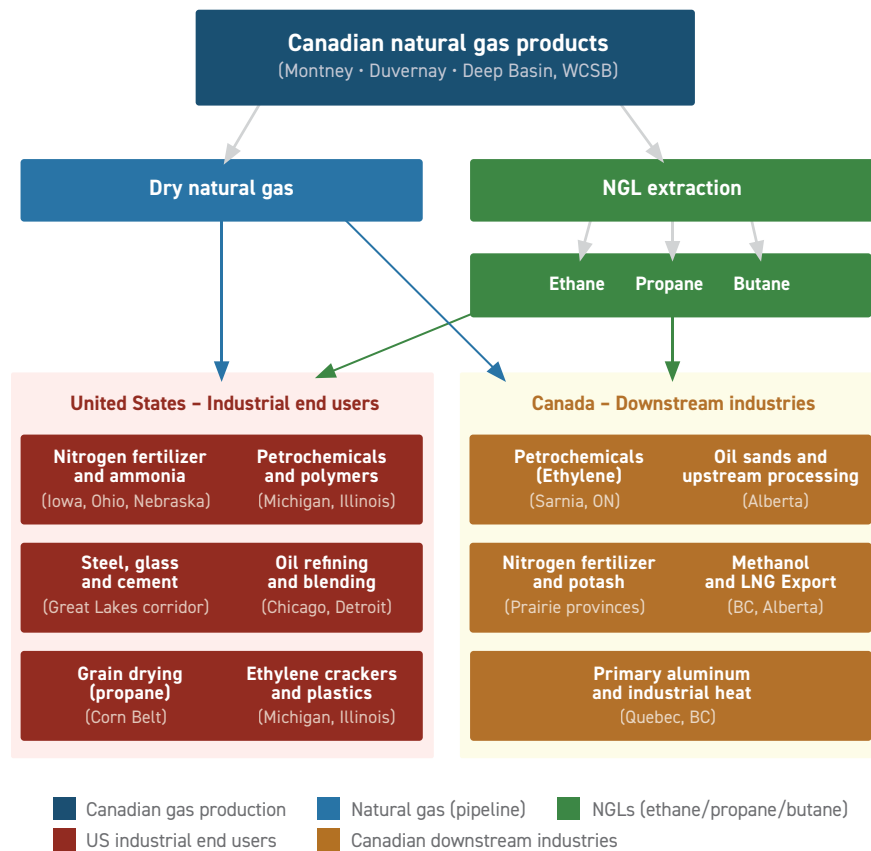
Source: EIA (2024b); CER (2026a); authors' calculations.

Propane and NGL markets follow the same integration logic through a separate supply chain. Better market access under Scenario B supports Canadian propane availability for US off-grid and rural households, including the 6.6 million US households that used propane as a primary space-heating fuel in 2024, and for agricultural users that rely on propane for crop drying, heating, and other farm operations. The 2023 retail propane data from the Propane Education and Research Council (PERC) show that US agricultural propane sales were 826 million gallons, with grain drying representing an important seasonal source of demand. Under Scenario C1 or C2, if Canadian NGLs were constrained it would reduce supply flexibility and could place upward pressure on regional propane prices, especially in rural and agricultural markets with fewer short-run substitution options.

Industrial impacts

Industrial affordability can be calculated using the same pricing mechanism described in Section 3, but it affects business margins rather than household bills. Natural gas and natural gas liquids are feedstocks for fertilizer, petrochemicals, refining, plastics, grain drying, glass, steel, and other energy-intensive activities (**Figure 18**). The relevant metric is therefore the spread: the difference between Henry Hub and the delivered price of Canadian gas or gas-linked liquids entering US markets. When that spread is favorable, Canadian supply lowers US input costs. When the spread narrows, the industrial advantage falls. When trade is disrupted, the discount can turn into a scarcity premium in import-dependent regions.

FIGURE 18: The value of Canadian natural gas and NGL to industry – sources and end uses



Source: Authors' illustration; CER (2026a); NRCan (2022a, 2022b); ACC (2023).

For industrial users, the basic calculation is:

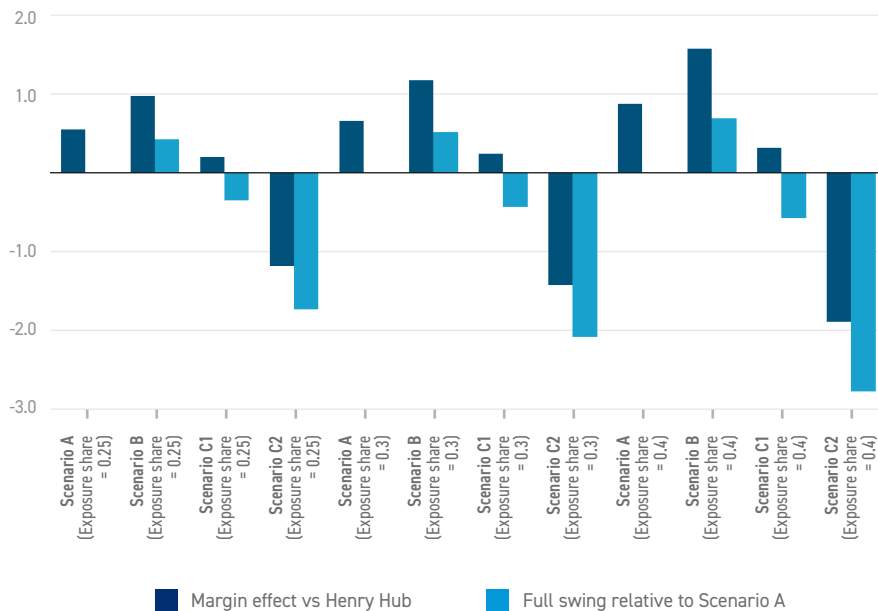
$$\text{Industrial margin effect} = \text{spread} \times \text{industrially exposed Canadian gas volume}$$

EIA’s 2024 *Natural Gas Annual* reports total US natural gas deliveries to consumers of 81.5 bcf/d, including 23.44 bcf/d delivered to industrial consumers. Industrial deliveries therefore accounted for 29 percent of delivered US gas consumption in 2024. This report uses a 30 percent exposure assumption as the central case, with 25 percent and 40 percent shown as sensitivities in **Figure 19**.

Using the same 89 billion cubic meter Canadian import-volume base as in Section 3, a 30 percent industrial exposure share implies 0.94 billion MMBtu of industrially exposed Canadian gas.

At a 30 percent industrial exposure share, the baseline competitiveness margin from the integrated Canada–US gas trade is US\$0.66 billion per year under Scenario A, rising to US\$1.18 billion under Scenario B. Under Scenario C1 the margin falls to US\$0.24 billion, Under Scenario C2 the margin falls to US\$0.24 billion,

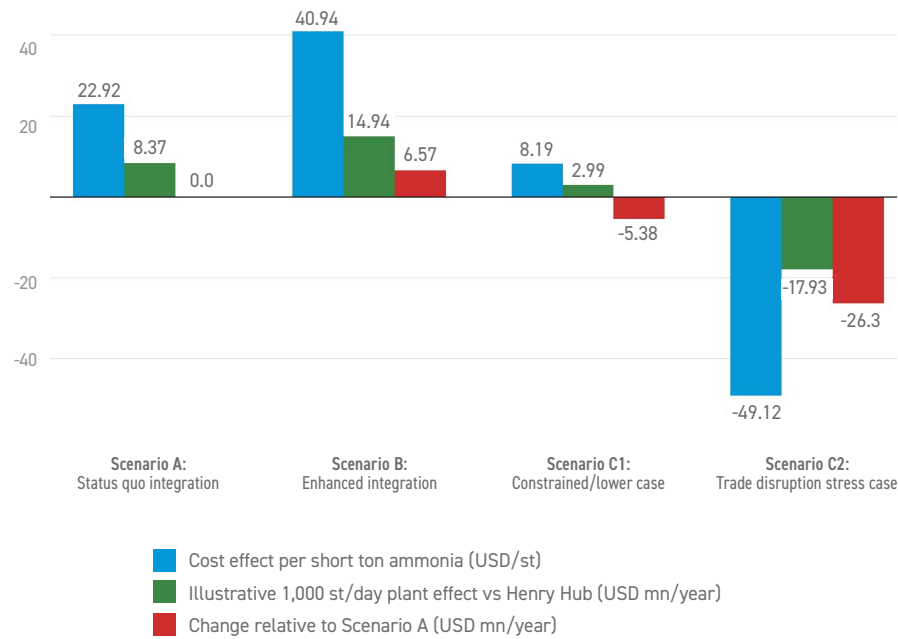
FIGURE 19: Industrial margin sensitivity by exposure share (in US\$bn/year)



Note: "Full swing relative to Scenario A" is larger than the penalty vs Henry Hub because it includes the loss of the Scenario A discount.

Source: Authors' calculations.

FIGURE 20: Ammonia/fertilizer margin exposure



Source: Huang (2007); authors' calculations.

and under the Scenario C2 trade-disruption stress case it inverts into a US\$1.41 billion industrial input-cost penalty relative to Henry Hub.

Nitrogen fertilizer provides the most direct plant-level example. Natural gas is the primary raw material used to produce ammonia; 33 MMBtu of natural gas are required to produce one ton of ammonia, and that natural gas accounts for 72 to 85 percent of the production cost of ammonia (Huang 2007; IEA 2021). This means that every US\$1.00/MMBtu change in natural gas cost changes ammonia production cost by US\$33 per short ton. **Figure 20** shows the scenario effect in two ways: dollars per short ton of ammonia and the effect on the annual cost for an illustrative 1,000-short-ton-per-day ammonia plant. Under Scenario A, the US\$0.70/MMBtu Canadian discount is worth US\$23 per short ton. Under Scenario B, the US\$1.25/MMBtu discount is worth US\$41 per short ton. Under Scenario C1, the benefit falls to US\$8 per short ton. Under Scenario C2, the disruption premium raises feedstock cost by US\$50 per short ton relative to Henry Hub. For an illustrative

1,000-short-ton-per-day ammonia plant, each US\$1.00/MMBtu shift in feedstock cost is worth US\$12 million per year.

The same economic mechanism applies to petrochemicals and refining through natural gas liquids. EIA identifies ethane, propane, butanes, and natural gasoline as hydrocarbon gas liquids with distinct industrial uses.

Table 2 summarizes the most important uses for NGLs. PERC’s 2023 *Annual Retail Propane Sales Report* indicates total US retail propane sales of 8.995 billion gallons, including 826 million gallons in the agriculture sector. The same source explains that main uses of agricultural propane are for grain drying, harvesting, weed control, radiant heating, crop irrigation engines, and related applications. PERC also reports that 3.946 billion gallons of non-odorized propane sales went to the US petrochemical sector in 2023, including 2.922 billion gallons to ethylene plants and 1.024 billion gallons to propane dehydrogenation feedstock.¹²

TABLE 2: Greatest uses for US propane/NGLs

Sector	2023 propane sold (million gallons)	Share of total sales (%)
Residential	4,854	54
Commercial	2,013	23
Industrial, non-forklift	288	3
Agriculture	826	9
Cylinder market	312	3
Internal combustion	702	8
Total retail propane	8,995	100
Petrochemical propane, non-odorized	3,940	43.8
Propane to ethylene plants	2,922	

Note: PERC also reports non-odorized petrochemical propane sales of 3.94bn gallons and ethylene plant sales of 2.922bn gallons, which support the NGLs industrial feedstock channel.

Source: PERC (2023).

Electricity demand, AI infrastructure, and grid reliability

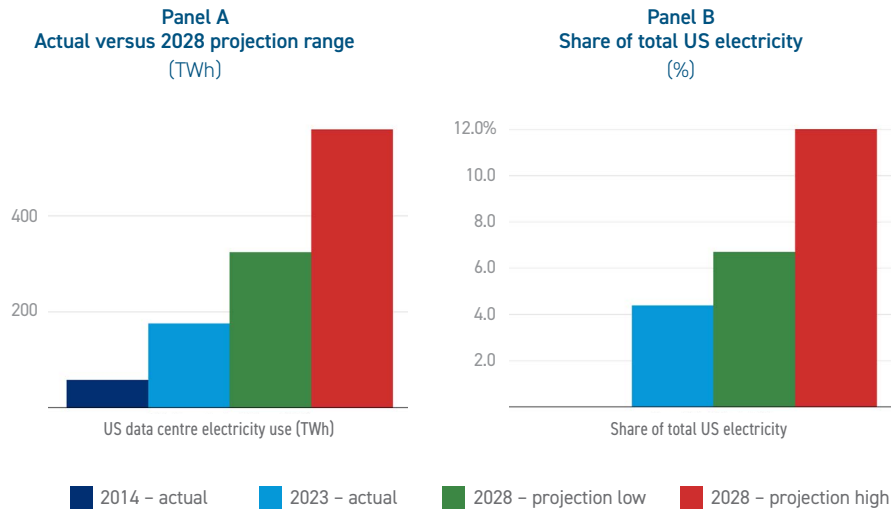
After roughly two decades during which generation remained flat, US electricity demand is rising again. Net generation reached a record 4,430 TWh in 2025, 2.8 percent above 2024 levels (EIA 2026d), and EIA (2026a) projects further growth of 1.2 percent in 2026 and 3.3 percent in 2027, with commercial-sector demand, which includes data centers, growing faster than the residential or industrial categories. The dynamic is continental, not strictly American. Canada's recently announced Powering Strong Energy Strategy commits to roughly doubling national electricity-generation capacity by 2050 to support electrification, industrial growth, and AI-related load (Canada 2025). Because natural gas remains the marginal fuel for providing back-up power and meeting peak electricity demand on both sides of the border, the sustained growth in fuel demand across the continent points toward higher gas demand in the integrated North American market over the coming decades, with corresponding implications for prices, pipeline use, and investment in cross-border infrastructure.

AI and data centers are now a major electricity-demand driver

According to the US Department of Energy's summary of the 2024 Lawrence Berkeley National Laboratory (LBNL) data center report, US data center electricity use increased from 58 TWh in 2014 to 176 TWh in 2023 (DOE 2024). The same report estimates that data center electricity use could rise to anywhere from 325 to 580 TWh by 2028. The DOE also reports that data centers consumed 4.4 percent of total US electricity in 2023, but that demand could reach 6.7 to 12.0 percent by 2028.

Figure 21 summarizes that shift. It shows that US data center load roughly tripled between 2014 and 2023 and could double or triple again by 2028. This is not a marginal load category. At the high end of the range predicted by the LBNL and DOE, US data centers would consume more electricity than many national power systems.

FIGURE 21: US data center electricity use



Source: DOE (2024).

The International Energy Agency (2025) reaches the same broad conclusion globally. It projects that electricity demand from data centers worldwide will more than double by 2030 to around 945 TWh, slightly more than Japan’s current electricity consumption. It identifies AI as the most significant driver of the increase and projects that electricity demand from AI-optimized data centers will more than quadruple by 2030. In the United States, the IEA projects data centers to account for almost half of the growth in electricity demand between now and 2030.

Electricity bill impacts under the various scenarios

The natural gas price scenarios outlined in earlier in this paper also extend to electricity markets. The effect is not one-for-one because natural gas is only one of the inputs in electricity systems. Retail electricity bills also include transmission, distribution, taxes, utility riders, procurement contracts, hedging, and regulatory lag. Still, gas prices matter because gas-fired generation remains a major dispatchable resource, especially during peak demand, when renewable output is low, during winter cold events, and in transmission-constrained periods.

This section uses a transparent generation-cost pass-through proxy rather than assuming a fixed retail pass-through. The proxy is calculated as:

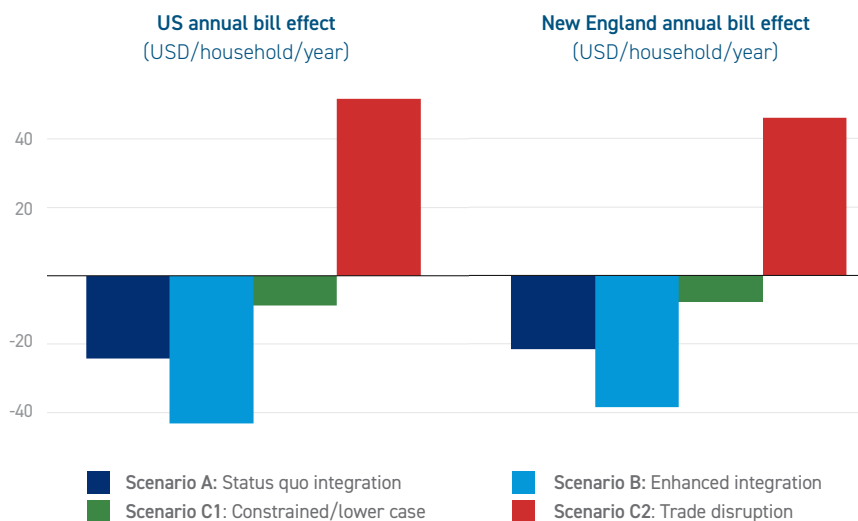
$$\begin{aligned} \text{Electricity pass-through proxy} &= \text{natural gas heat rate} \\ &\times \text{natural gas share of generation} \end{aligned}$$

EIA (2025a) reports an average operating heat rate for natural gas generation of 7,754 Btu/kWh, equivalent to 7.754 MMBtu/MWh. Natural gas also accounted for 43 percent of US electricity generation in 2024. Together, these values imply a national electricity-cost pass-through proxy of approximately US\$3.33/MWh for every US\$1.00/MMBtu change in natural gas prices. In New England, ISO New England (2026) reports that natural gas generated 60,447 GWh in 2025, or 55 percent of total regional generation. Applying the same heat-rate method gives a New England pass-through proxy of US\$4.26/MWh. These values provide indicative generation-cost measures that we can use to compare scenarios on a consistent basis. **Appendix Table A1** reports the model inputs and sources.

The residential bill inputs are based on data from EIA's 2024 average monthly residential electricity bills. The average US residential customer consumed 863 kWh per month, or 10.36 MWh per year, and paid an average monthly electricity bill of US\$142.26, equivalent to US\$1,707 per year. In New England, the average residential customer consumed less electricity, 601 kWh per month, or 7.21 MWh per year, but paid a higher average price and bill: 27.68 cents/kWh and US\$166.48 per month, or US\$1,998 per year.

Appendix Table A2 shows the scenario gas-price assumptions. **Figure 22** isolates the Canadian gas discount or premium itself. Under Scenario A, the Canadian supply discount lowers the average annual electricity bill by US\$24 per household nationally and US\$22 per household in New England, relative to a no-discount gas supply baseline. Under Scenario B, the discount increases the electricity saving to US\$43 nationally and US\$38 in New England. Under Scenario C1, the electricity saving falls to US\$9 nationally and US\$8 in New England. Under Scenario C2, the discount becomes a scarcity premium,

FIGURE 22: The effects on electricity bills of Canadian natural gas exports to the United States



Note: Positive values are savings from a Canadian gas discount relative to a no-discount baseline. Negative values are premiums under a trade-disruption scenario.

Source: EIA 2024 monthly bill – residential, EIA Electric Annual 2024 and ISO-NE Resource Mix for pass-through proxy inputs.

increasing annual electricity costs by US\$52 nationally and US\$46 in New England relative to the no-discount baseline.

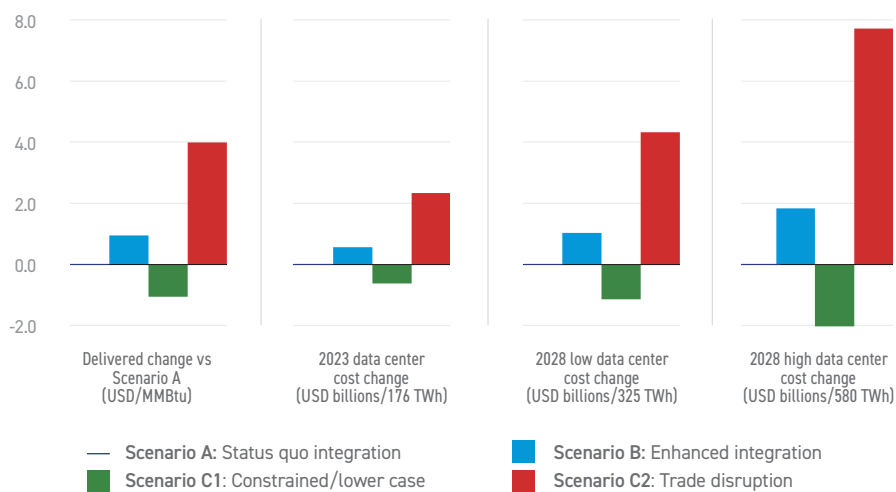
The aggregate residential numbers are also material. Using EIA (2024c) customer counts, the Canadian discount under Scenario B is worth US\$6.2 billion per year across US residential electricity customers, compared with US\$3.5 billion under Scenario A. Under Scenario C2, the effect becomes an aggregate residential electricity cost premium of US\$7.4 billion per year.

Figure 23 extends the same pass-through model to US data center electricity demand. The DOE (2024) estimates that US data center electricity use rose from 58 TWh in 2014 to 176 TWh in 2023 and could reach 325 to 580 TWh by 2028. The International Energy Agency similarly projects that global data center electricity demand will more than double by 2030, with AI as the primary driver of growth (IEA 2025).

Using the national pass-through proxy, the data center electricity-cost exposure is substantial. In the 2028 low case of 325 TWh, Scenario B lowers data center electricity costs by US\$1.0 billion per year relative to Scenario A, while Scenario C2 raises them by US\$4.3 billion. In the

2028 high case of 580 TWh, the corresponding estimates are a US\$1.8 billion reduction under Scenario B and a US\$7.7 billion increase under Scenario C2.

FIGURE 23: Data center electricity costs relative to Scenario A



Note: Uses the national central pass-through proxy and the LBNL and DOE data center electricity demand range. Positive values are electricity-cost increases relative to Scenario A; negative values are decreases.

Source: DOE (2024); IEA (2025)

Conclusion and USMCA recommendations

Integrated Canada–US natural gas and natural gas liquids markets generate measurable economic and affordability benefits on both sides of the border. For Canada, these exports support foreign exchange earnings, upstream investment, provincial revenues, and employment in energy-producing regions. For the United States, Canadian supply helps moderate regional natural gas prices, support industrial competitiveness, strengthen propane and NGL supply chains, and improve electricity-system reliability during periods of rising demand. These benefits are especially important in import-dependent regions

where pipeline access and infrastructure constraints determine whether households and businesses face a price discount, benchmark pricing, or a scarcity premium.

Table 3 summarizes the scenarios in this report and their associated affordability and policy implications, while **Box 1** outlines the principal limitations and caveats of the analysis. Canada should therefore enter the 2026 USMCA discussions with three clear policy priorities:

- Preserve tariff-free treatment for natural gas, NGLs, electricity, and related energy goods, while avoiding measures that create new price wedges in integrated energy markets.
- Improve Canada–US permitting and regulatory coordination for cross-border pipeline and electricity infrastructure, particularly projects that reduce bottlenecks and improve reliability.
- Strengthen bilateral energy-security coordination by identifying import-dependent regions, clarifying emergency-response protocols, and supporting shared infrastructure planning.

Companies considering taking on long-term investments in natural gas infrastructure raise legitimate concerns about the risks associated with emissions policies and asset longevity. However, if governments on both sides of the border can preserve integrated North American gas infrastructure, energy can still be affordable and reliable while remaining flexible about lower-emissions fuels, methane mitigation, and carbon-capture deployment over time.

As the growth in the demand for electricity accelerates and geopolitical uncertainty increases, the economic value of integrated North American energy systems is likely to rise rather than diminish. The 2026 USMCA review is therefore not only a trade-policy exercise, but also a broader test of North American affordability, reliability, and industrial competitiveness.

Through its tariff-free energy trade, regulatory coordination, and cross-border infrastructure cooperation USMCA already provides an institutional framework for preserving this integration. The agreement, together with the Canada–US side letter on energy, supports market access, regulatory transparency, and broader North American energy-

TABLE 3: Scenario matrix – Canada–US natural gas trade and affordability outcomes

Attribute	Scenario A: Status quo	Scenario B: Enhanced cooperation	Scenario C1: Constrained	Scenario C: Trade Disruption
CER anchor	Current measures	Higher	Lower (with Canada net-zero as secondary reference)	Authors' stress case (not a CER scenario)
Canadian gas production by 2050	~27 Bcf/d	~32 Bcf/d	~21 Bcf/d	Bounded below Lower
LNG export assumption by 2050	6.1 Bcf/d (~48 MTPA)	7.9 Bcf/d (~62 MTPA)	4.3 Bcf/d	Constrained; pipeline access to U.S. severed
Spread vs. Henry Hub (USD/MMBtu)	+ 0.70 (status quo discount)	+1.25 (wider delivered discount)	+0.25 (narrower discount)	-1.50 (scarcity premium in U.S.; AECO falls below HH)
Household gas bill effect (per natural-gas household, USD/year)	-\$40 national; -\$42 New England	-\$71 national; -\$76 New England	-\$14 national; -\$15 New England	+\$50-plus national; comparable in NE
Aggregate U.S. consumer commodity savings/cost (USD bn/year)	-\$2.20 bn (savings)	-\$3.94 bn (savings)	-\$0.79 bn (savings)	+\$4.72 bn (cost)
Industrial input-cost effect (USD bn/year, 30% exposure)	-\$0.66 bn (margin gain)	-\$1.18 bn (margin gain)	-\$0.24 bn (margin gain)	+\$1.41 bn (margin loss vs. HH); -\$2.08 bn swing vs. A
Residential electricity bill effect (per household, USD/year)	-\$24 national; -\$22 NE	-\$43 national; -\$38 NE	-\$9 national; -\$8 NE	+\$52 national; +\$46 NE
Aggregate residential electricity effect (USD bn/year)	-\$3.5 bn (savings)	-\$6.2 bn (savings)	Smaller savings	+\$7.4 bn (cost)
Policy implication	Maintain status quo integration; modest baseline affordability and reliability benefit	Reinforce tariff-free trade, accelerate permitting, expand corridor capacity to capture larger affordability and reliability gains	Affordability discount largely lost; Canadian netbacks weakened; investment slows	Highest economic and reliability risk; affordability turns into scarcity premium; producer netbacks compressed

Note: Negative dollar values denote savings to US consumers/industry; positive values denote costs. Spreads are stated as Henry Hub minus delivered Canadian border price; Scenario C2 is an authors' stress case calibrated outside CER's Canada's Energy Future 2026 framework.

Source: CER (2026a); EIA (2024a, 2024c, 2025a, 2026e); ISO New England (2026); authors' calculations.

security coordination (Global Affairs Canada 2020a, 2020b, 2020c, 2020d; USTR 2018). The 2026 review of USMCA will therefore have implications that extending beyond trade policy. USMCA will influence investment certainty in energy infrastructure, industrial production, electricity reliability, and the broader competitiveness of integrated North American energy markets. ★

BOX 1: Limitations and caveats

The affordability and industrial-margin estimates are high-level pass-through calculations rather than full general-equilibrium forecasts; they isolate the commodity-cost channel and do not capture all behavioral, substitution, or capital-stock adjustments. Scenario C2 (Trade Disruption) is an authors' stress case calibrated outside CER's Canada's Energy Future 2026 framework; it is not a CER scenario and its scarcity-premium assumption reflects an analytical bound rather than a forecast. CER scenario values reported beyond the latest year of historical data are projections under stylized assumptions, not historical observations. Readers should interpret the numerical results as illustrative orders of magnitude consistent with the empirical anchors cited and the framework presented. ★

About the author



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Endnotes

- 1 Total US natural gas consumption was 33.5 trillion cubic feet in 2025 (EIA 2025b).
- 2 Throughout this analysis, the border price is the delivered import price into the United States as reported by EIA, which already embeds the cost of pipeline transportation from the Canadian production basin to the US point of entry. The Henry Hub–border spread therefore reflects the net price advantage available to US buyers after Canadian transportation costs have been incurred, rather than a wellhead comparison.
- 3 Readers wanting an illustration that explains how prices are formed from the wellhead through the AECO-C hub to the US border and on to Henry Hub can consult publicly available pricing diagrams from the Canada Energy Regulator and the Alberta Energy Regulator. They trace the flow of gas and the formation of prices across the North American system.
- 4 Henry Hub is the Louisiana pipeline interchange that serves as the standard US spot reference price for natural gas against the average US border price for Canadian pipeline imports.
- 5 Natural Gas Liquids (NGLs) are hydrocarbons that are found in natural gas and are separated out during processing. They are not the same as methane (the main component of natural gas) but are valuable by-products. NGLs typically include: Ethane (C_2H_6) – used mainly to produce ethylene (plastics); Propane (C_3H_8) – used as fuel for heating and cooking (LPG); Butanes (C_4H_{10}) – used in gasoline blending and as fuel; Isobutane – used in refining and as a refrigerant; Natural gasoline (pentanes+) – used as a blending component in fuels.
- 6 The Canada Energy Regulator is an independent federal agency working in the Canadian public interest. It is responsible for

regulating interprovincial and international pipelines, energy development, and trade.

- 7 In contrast, pipelines that operate entirely within a single province are usually regulated by provincial authorities, unless they are designated as federal undertakings.
- 8 AECO-C is the primary natural gas spot trading hub for Western Canada and the benchmark price reference for Alberta and British Columbia producers. See Appendix C for a fuller explanation of AECO-C, its relationship with NIT (Nova Inventory Transfer), and the distinction between the AECO/NIT netback discount and the delivered Canada-border discount that this report uses.
- 9 This is US\$0.3 per MMBtu lower than the AECO-C and Henry Hub price differential for 2025 to 2034 under lowered US-Canada tariffs projected at US\$1 per MMBtu and to account for delivery costs.
- 10 The citygate is the point at which a local utility takes physical delivery from the long-haul pipeline system.
- 11 The US\$2.20 billion figure for Scenario A aligns closely with Section 1's estimate of US\$1.1 billion per year over the eight years between 2015 and 2024 when the Canadian border price was below Henry Hub; the difference reflects the inclusion of years when the spread was narrower or negative in the Section 1 calculation.
- 12 This distinction matters for the policy argument. Agricultural propane is used seasonally and is concentrated in rural markets, especially when needed for crop drying and winter heating. Petrochemical propane exposure is larger by volume and tied directly to US ethylene, propylene, plastics, and resin supply chains. Ethane exposure is different again: it depends heavily on dedicated pipelines and cracker capacity (facilities that convert ethane into ethylene, a key feedstock for plastics). Butane is used primarily by refineries, in gasoline blending, and for alkylation. These should not be conflated with methane, which is dry natural gas rather than an NGL.

Appendices

APPENDIX A

Natural gas export by province

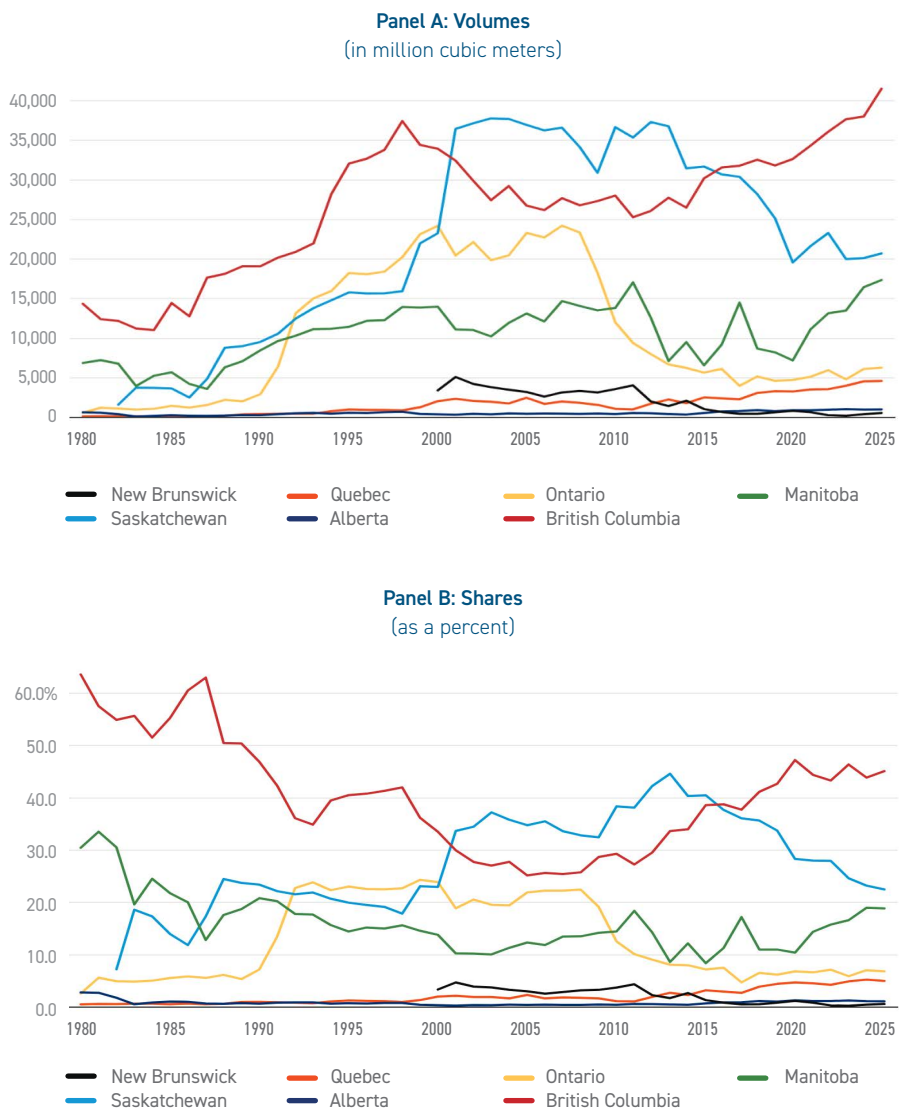
The provincial data included Panel A and Panel B of Figure A1 add a useful long-run perspective on the geography of natural gas export activity, with the caveat that Statistics Canada’s monthly natural-gas transmission data reports flows from the province in which the gas was exiting rather than by the province of production. Provinces with major export-routing infrastructure can therefore appear as large “exporters” even when most of the gas they ship was produced in Alberta or northeastern British Columbia. With that caveat, in routed-volume terms, British Columbia was the dominant exit province between 1980 and 2000. Saskatchewan became the leading routing point through much of the 2000s and early 2010s, and British Columbia then regained the lead over the last decade.

Ontario also played a substantial routing role in the 1990s and 2000s, but its routed export volumes fell sharply after the late 2000s. Manitoba remained a meaningful mid-tier exit point and strengthened that position again post-2020, while Quebec rose from a negligible base to a still modest but growing position. Alberta and New Brunswick appear as comparatively small exit-point exporters in these data even though Alberta is by far the largest gas-producing province; this reflects the fact that most Alberta-produced gas is routed to US markets through pipelines that leave Canada through British Columbia or Saskatchewan rather than directly across the Alberta-Montana border. The export shares data in Panel B reinforce the same routing pattern: British Columbia’s share fell from a dominant position in the early 1980s, recovered strongly after the mid-2010s, and now accounts for the largest exit-point share, while Saskatchewan’s share rose significantly and then moderated. These figures describe the shifting geography of export routing rather than of production origin, but they reinforce the broader point that western provinces continue to anchor Canada’s export capacity.

The structure of that trade also remains overwhelmingly pipeline based. Although LNG is beginning to emerge as a meaningful export,

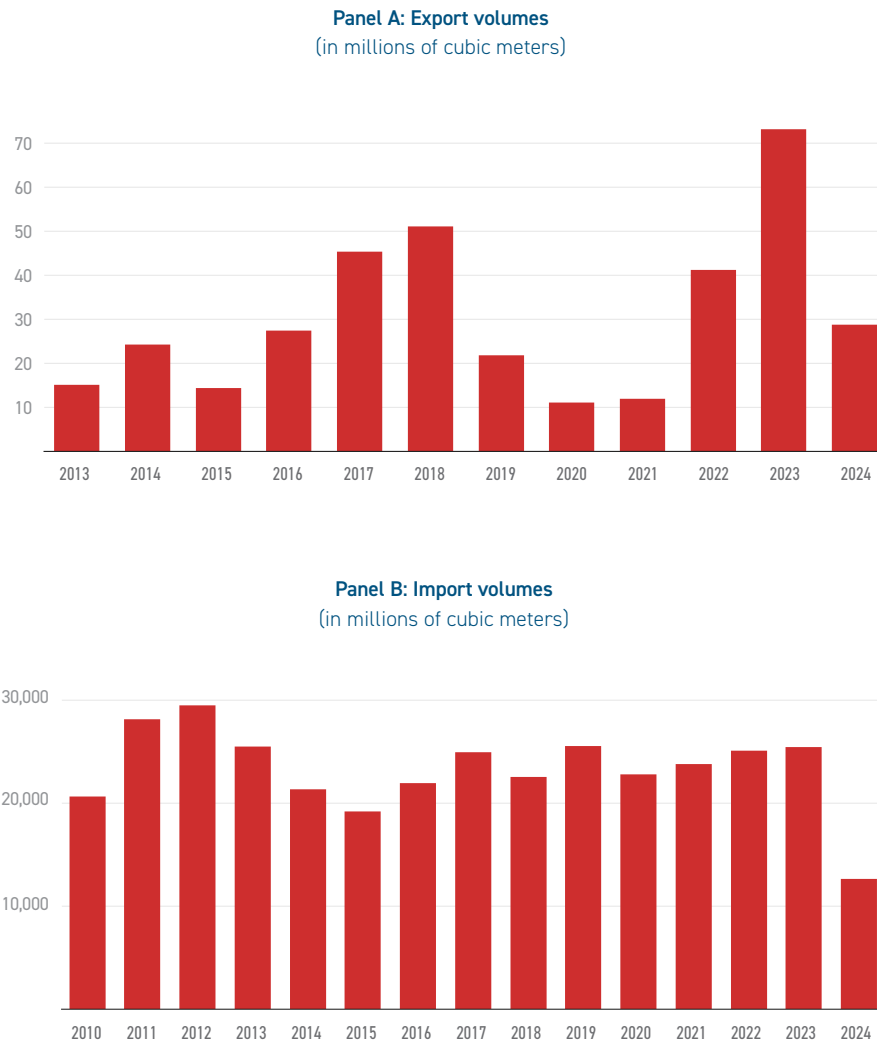
especially with the start of LNG Canada, Figure A2 indicates that LNG export volumes are still negligible compared with pipeline exports. Panel A shows that Canadian LNG exports remained very small through the period shown, although they picked up somewhat in the most recent years. Panel B shows that LNG imports were historically much larger than LNG exports, though they fluctuated and appear to have declined by 2024.

FIGURE A1: Natural gas export by province (export points)



Source: Statistics Canada (2026a, 2026b).

FIGURE A2: Annual LNG trade



Note: The amount of exports in 2025 was 3,142 million cubic meters.

Source: CER (2025a).

APPENDIX B

Natural gas liquids – industrial feedstock channels

US demand for Canadian natural gas liquids comes from several distinct industries, each with its own feedstock chemistry and end-use profile. These are summarized below to support the household and industrial affordability discussion in Section 4.

Ethane (C₂H₆).

Used primarily as feedstock for ethylene and polyethylene production through steam cracking. Demand depends on dedicated ethane pipelines and US cracker capacity. The principal US cracker clusters are in Texas, Louisiana, and the Marcellus/Utica region in the eastern United States.

Propane (C₃H₈).

Propane has three main end uses: (i) Rural and off-grid residential heating: 6.6 million US households used propane as a primary space-heating fuel in 2024; (ii) Agricultural applications, including grain drying, crop irrigation engines, weed control, and radiant heating in livestock barns: PERC reports US agricultural propane sales of 826 million gallons in 2023; and (iii) Petrochemical feedstock: PERC reports 3.946 billion gallons of non-odorized propane sold to US petrochemical markets in 2023, including 2.922 billion gallons to ethylene plants and 1.024 billion gallons to propane dehydrogenation feedstock.

Butanes (C₄H₁₀, including isobutane).

Used principally in refinery gasoline blending, alkylation units, and as a petrochemical and refrigerant feedstock.

Dry natural gas (methane).

Not an NGL, but worth distinguishing alongside them because the industrial-margin discussion in Section 4 turns on methane being the feedstock for ammonia and urea production via steam methane reforming.

Sources: EIA (2023); PERC (2023).

APPENDIX C

AECO-C and the Western Canadian Gas Pricing Hub

AECO-C (Alberta Energy Company C-meter station) is the primary natural gas spot trading hub for Western Canada. Located near Suffield, Alberta, and operated by TC Energy, AECO-C is the delivery point for the NOVA Gas Transmission Ltd. (NGTL) system and serves as the benchmark price reference for Alberta and British Columbia producers. AECO prices are quoted in Canadian dollars per gigajoule.

Because most Canadian natural gas producers receive netback prices linked to AECO-C, the AECO-to-Henry-Hub spread directly determines the economics of Canadian gas exports to the United States and the revenue available to producers for upstream reinvestment. When the spread is wide and favorable to US buyers (when AECO is below Henry Hub), US consumers have access to Canadian gas at a meaningful discount. When the spread narrows or inverts (when AECO is above Henry Hub, as occurred briefly in 2023), Canadian producers capture higher netbacks but the competitive pricing advantage for US buyers is reduced.

NIT (Nova Inventory Transfer) is the closely related AECO transfer price used in physical market settlements. This report refers to NIT and AECO-C interchangeably. The distinction between the delivered Canada-border discount used in Section 3 and the AECO/NIT producer netback discount is important: the delivered discount reflects what a US buyer pays at the border, while the netback discount reflects what a Canadian producer receives after transportation costs. Improved infrastructure use narrows the producer netback discount even as it can widen the delivered discount available to US buyers.

FIGURE C1: Annual exports of NGLs by province (in thousands of cubic meters)

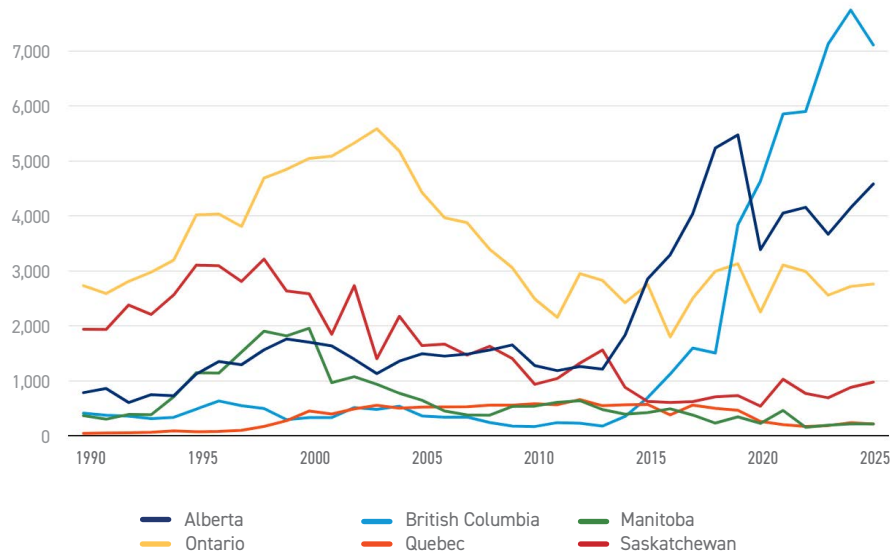
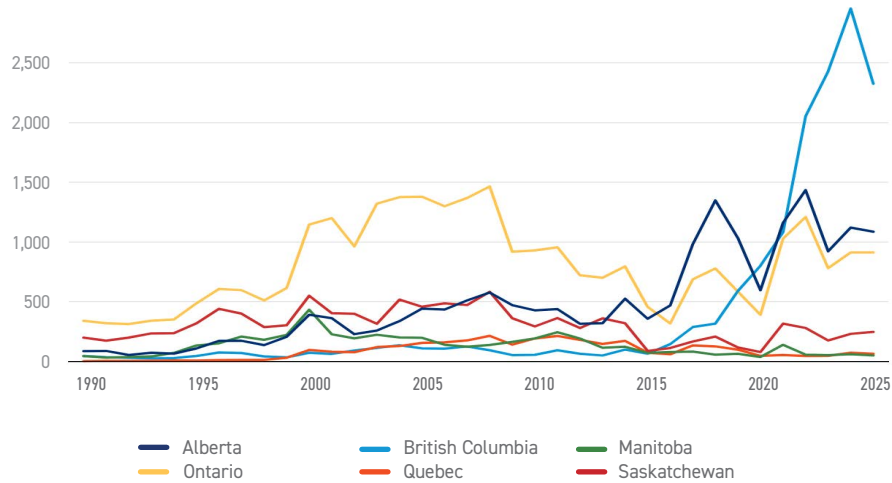


FIGURE C2: Annual values of NGLs by province (in CA\$ millions)



Note: Exports include propane and butanes only; Newfoundland & Labrador, Prince Edward Island, Nova Scotia, New Brunswick, Yukon, and Northwest Territories are excluded due to insignificant values.

Source: Canada Energy Regulator (2025b).

TABLE C1: Electricity bill pass-through model inputs

Input	Value	Units	Use in model
Natural gas average operating heat rate	7.754	MMBtu/MWh	Central pass-through heat rate
Natural gas combined-cycle tested heat rate	7.548	MMBtu/MWh	Lower heat-rate sensitivity
US natural gas generation share	0.43	Share	National pass-through proxy
ISO-NE natural gas generation share	0.55	Share	New England pass-through proxy
US residential monthly consumption	863	kWh/month	Annual household electricity consumption
New England residential monthly consumption	601	kWh/month	Annual household electricity consumption
US residential customers	143144185	Customers	Aggregate residential bill impact
New England residential customers	6653781	Customers	Aggregate regional residential bill impact
US average monthly residential bill	142.26	USD/month	Baseline annual bill context
New England average monthly residential bill	166.48	USD/month	Baseline annual bill context
US data center electricity use, 2023	176	TWh/year	Data center exposure context
US data center electricity use, 2028 low	325	TWh/year	Data center exposure low case
US data center electricity use, 2028 high	580	TWh/year	Data center exposure high case

Pass-through proxy equals heat rate multiplied by gas share of generation. Central national pass-through = 3.33 USD/MWh per USD/MMBtu gas-price change. Central New England pass-through = 4.26 USD/MWh per USD/MMBtu gas-price change.

Source: EIA Electric Power Annual 2024, EIA Generation Mix/Energy Explained, ISO New England Resource Mix 2025, Energy 2024 Average Monthly Bill – Residential, DOE/LBNL 2024 US Data Center.

Note: The employment and GDP figures discussed in Section 1 capture direct contributions from the natural gas industry only. Indirect impacts – through inputs supplied to the gas sector and induced effects from re-spending of wages – are not enumerated here but are typically estimated to add a further multiple on the order of 1.5 to 2 times the direct contribution to both jobs and GDP, based on standard input-output multipliers for the Canadian energy sector (Statistics Canada Supply and Use Tables).

TABLE C2: Scenario gas-price assumptions

Scenario	Canadian Discount/ Premium (USD/MMBtu)	Delivered Gas-Price Proxy (USD/MMBtu)	Change vs Scenario A (USD/MMBtu)
Scenario A: Status quo integration	0.7	3.51	0
Scenario B: Enhanced integration	1.25	4.46	0.95
Scenario C1: Lower / constrained case	0.25	2.46	-1.05
Scenario C2: Trade disruption stress	-1.5	7.5	3.99

Note: Delivered gas-price proxy = Henry Hub minus Canadian discount. Negative discount means scarcity premium and is added to Henry Hub. Scenario C2 is a stress case, not a CER EF2026 scenario; Henry Hub at USD 6.00/MMBtu is retained from the draft's disruption case framing.

Source: CER EF2026 scenario framing for A/B/C1 Henry Hub assumptions; C2 is author stress test. Scenario spreads are author assumptions calibrated to the post-shale Canada-border/Henry Hub spread distribution used in Section 3.1.



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