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Governance, Trade and Finance of a National Electricity Grid

Rules Before Wires

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Rules Before Wires

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In Brief

Three interlocking arguments have stalled every proposal for a Canadian electricity grid that binds the country together: the Constitution will not allow it, the country cannot finance it, and the provinces cannot agree on how to trade across it. The pages that follow take up all three. The first two are not credible impediments; the third is real, and it will yield only to agreement.

The country already has the three connective tissues a national grid needs: its constitution, its markets and its capital. Six findings follow, each developed in the Part named beside it.

1. **The governance question is answered.** Parliament has held authority over lines that cross a provincial boundary since 1867, legislated the machinery in 1990 and again in 2019, and has never used it. Exercising it leaves every provincial grid in provincial hands. The federal fast-track statutes enacted since 2025 stop, by their own terms, where provincial jurisdiction begins, and they make the designation power more valuable to use. (Part 1)
2. **A national market can be stitched together without dismantling anything.** Provinces join a trading layer by agreement, on top of the systems they already run, beginning with a clearinghouse on the cooperative model the Supreme Court upheld in 2018. What remains is the stitching. (Part 2)
3. **The financing capacity is in place.** The Canada Strong Fund, the Canada Infrastructure Bank and Canada's pension funds can carry the corridor through existing structures, once the allocation of risk is written down in advance. (Part 3)
4. **The corridor pays as reliability.** For the full set of benefits, the two most-studied western expansions return benefit-to-cost ratios near four, and a megawatt hour that fails to arrive is worth roughly 100 to more than 800 times a megawatt hour that is traded. (Section 3.5)
5. **Indigenous ownership is a condition of durability.** Equity belongs in the capital structure from day one, held in an entity separate from either provincial utility. (Part 4)
6. **The vehicle exists.** Advanced as a national commitment through the Major Projects Office, on a statutory clock Parliament has already set, the corridor needs a decision. (Part 5)

* The authors used artificial intelligence tools in preparing this paper. A Note on Method at the end of the paper names the tools and describes how they were used. The authors take full responsibility for the paper.

Executive Summary

This paper answers an argument. Canada cannot build an east-west electricity grid, the argument runs, because electricity belongs to the provinces and section 92A settles it. Section 92A settles a different question, and it settles the one an electricity transmission corridor most needs settled. The Supreme Court has held that paragraph 92A(1)(c) exists to stop a province's generating stations being drawn into federal jurisdiction by their connection to an interprovincial line. Parliament reaches the line itself, and built the machinery to do so in 1990, rebuilding it in 2019. That machinery has never been used, and Bill C-39, introduced on September 21, 2026, would sharpen it further. The provinces regulate interties today because Parliament has never legislated. When the Supreme Court considered the Alberta to British Columbia intertie in 1981, it upheld provincial regulation on exactly that ground, and the Attorney General of Canada argued for that result.

The wires already exist and are used in a pattern no engineering constraint explains. Between 2022 and 2024 most western and central interties carried, on average, less than 40 per cent of what they could, while the Quebec to Atlantic connections ran at 90 to 100 per cent. The same interties are close to fully committed when the system is stressed: east-west utilization averages 72 per cent at annual peak demand, and the Alberta to British Columbia and Manitoba to Saskatchewan paths run at or above their rated transfer capability in those hours. Idle across the year and saturated in the hours that matter is the signature of capacity rationed by scarcity, not traded on rules. The difference is commercial, not physical. The converter outage described in Part 2 showed what it costs to have no rulebook, clearinghouse or forum for a derated intertie.

The case for the corridor is a reliability case, and it should be measured as one. Across the full set of benefits, the peer-reviewed modelling of the two most-studied western expansions returns benefit-to-cost ratios of 3.69 and 4.08. Production cost is one of seven benefits the American planning rule requires a transmission planner to measure, not the test of the investment. The asymmetry behind that is large: in Alberta a megawatt hour that is not delivered is valued at roughly one hundred to more than eight hundred times a megawatt hour that is traded. Part 3 sets out what the absence of a corridor costs.

The trading layer cannot be legislated into existence. It has to be agreed, on the cooperative template the Court upheld in 2018. The capital is already in the room. What has never been written down is who carries which risk, and five guardrails answer that, each an instrument with a named risk-bearer.

The argument runs in three steps. Existing law can permit the line without federalizing provincial generation. A cooperative trading layer can make existing and new interties usable without replacing provincial market designs. A staged financing model can allocate costs and risks to the parties that receive the reliability, adequacy and commercial benefits. The recommendation is rules before wires: write the institutional framework first, then build only the capacity that the rules and the evidence justify.

What is asked for is an order in council, a statutory clock, a clearinghouse, a costed converter and a risk allocation in writing. The order sets the rules once, and the Regulator then decides applications on the evidence. None of it needs a constitutional amendment or a reference case, and no province is asked to surrender anything section 92A gives it.

Recommended Actions

Ten things. They are set out in the order a government would take them. Not one requires a new federal statute, and the argument for each is in the Parts that follow, every one of which closes with the recommendations it has earned.

1. Sign a designation order under the power Parliament first granted in 1990 and no government has used, covering a priority corridor. List the corridor under the *Building Canada Act* as well, so that its federal authorizations run through a single conditions document.
2. Specify in that order the cost-allocation principles, the standards for Indigenous participation, and the phase triggers with their off-ramps, and require that benefits be measured across the full benefit set, including avoided unserved energy, and not on trade margin alone. Carry the same principles into a policy direction to the Regulator under section 13(1) of the *Canadian Energy Regulator Act*, a second federal power that has never been exercised.
3. Start the statutory clock, and publish every excluded period and extension as the Act requires.
4. Cost the seam at trading scale. The owner has put the end-of-life replacement of the Alberta and Saskatchewan converter at about \$1 billion. What remains unpriced is the cost of building the seam to the scale a trading framework would justify, and nothing else can be sequenced until that number is known.
5. Stand up a voluntary clearinghouse for bilateral contracts, beginning with reserve sharing and balancing, and publish available transfer capability, loss factors and seam prices.
6. Design the trading layer to be non-discriminatory from the outset, which answers the only live exposure under Chapter 22 of the *Canada-United States-Mexico Agreement* and costs nothing, because it is what the compact requires in any event.
7. Enact the model interprovincial trading statute province by province, on the 2018 template, with opt-in and withdrawal on notice.
8. Put the risk allocation in writing, and in the order, before asking pension capital to price it. A host province should receive compensation for the risk it carries by rule, not by a negotiation between first ministers for each project.
9. Build indexation and a scheduled review into every long-dated contract underpinning the corridor, arbitrated by the Regulator, because the Supreme Court has held that no court will supply the review afterwards.
10. Set the Indigenous equity floor at market-clearing levels, where the evidence shows the market will clear, not where a proponent says it can just bear, and treat that equity as a preferred form of the capital the guardrails exist to attract. Hold each designated line in an entity distinct from either provincial utility, which keeps the provincial grids provincial and is the natural vehicle for that equity. Make the agreement of the Indigenous governments whose lands a designated line crosses a condition of designation, giving them at least the standing the *Building Canada Act* gives provinces.

Introduction: The Grid, Not the Pipe

For close to a year, from November 2024 to October 2025, the only link between Canada's two electrical interconnections was out of service, and the country had no other route. A single converter station near Medicine Hat, commissioned in 1989, had failed, and no institution was responsible for having an alternative. That is the problem this paper addresses. The answer it builds on is the TransCanada Power Corridor, an east-west transmission backbone capable of moving Canadian electricity to Canadian markets instead of routing it, as the existing system mostly does, north and south into the United States. The original report answered the engineering half of that proposal in exhaustive detail.¹ What that report proposed should be stated in its own terms, because the recommendations in this paper sit inside its architecture. Instead of a single line drawn across the country, the corridor emerges as three regional grids, West, Central and East, joined at key nodal points so that power can move for trade while the system stays secure. It is to be sited along existing rail and highway rights-of-way where practical, to hold down land-use conflict and shorten permitting. And it is sized against a target: electricity rising from roughly a quarter of final energy consumption today to half by 2035 and four fifths by 2050. On the report's figures, that means annual electricity supply rising about fivefold, from roughly 700 terawatt hours to 3,550, and interprovincial electricity trade rising to ten or twenty times its present level. The federal regulator's own net-zero scenario is more conservative and points the same way: installed generating capacity rising from about 160 gigawatts in 2023 to about 400 by 2050, generation more than doubling, and interprovincial flows rising from 55 to 140 terawatt hours a year.²

What that report left as an agenda for future work is the subject here. Governance and regulation, electricity trade as a national strategic asset, and aligning capital with national purpose are the three headings under which that report set out its recommendations. The Parts that follow take those three headings in turn, with the question of Indigenous consent running through all of them.

Why this is not a pipeline argument

A paper about wires opens on pipe, and the reason should be stated, not assumed, because the comparison is easy to overwork.

What transfers between a pipeline and a transmission corridor is not the economics. Emissions regulation differs. Export markets differ, because oil and gas can be stored and shipped to overseas counterparties while Canadian electricity cannot be stored at scale and has one foreign buyer. Ownership and system operation differ, because most Canadian transmission is owned

¹ Jatin Nathwani, Kam Mofid and Georgia Goodwin, *TransCanada Power Corridor: A National Grid Uniting Canada*, BSIA Special Report (Waterloo: Balsillie School of International Affairs, November 20, 2025).

² Nathwani, Mofid and Goodwin, *supra* note 1 at 11 (Table 1), 16 and 46, giving annual electricity supply of about 700 terawatt hours in 2025, 1,950 in 2035 and 3,550 in 2050. The report's Table 1 also expresses the trajectory as installed capacity of 80, 220 and 400 gigawatts; those figures correspond to the energy figures divided by the 8,760 hours in a year, that is, to average load, and this paper therefore uses the energy figures. For installed capacity and interprovincial flows, Canada Energy Regulator, *Canada's Energy Future 2026: Energy Supply and Demand Projections to 2050* (Calgary: CER, March 17, 2026), Canada Net-Zero Scenario fact sheet, reporting capacity of around 160 gigawatts in 2023 rising to 400 gigawatts by 2050, generation of 621 terawatt hours in 2023 rising by over 700 terawatt hours, and annual interprovincial flows rising from 55 to 140 terawatt hours. For current generation, Statistics Canada, "Electricity supply and disposition, 2024 (preliminary)," *The Daily*, October 22, 2025, reporting 622.2 million megawatt hours in 2024.

by provincial Crown corporations and dispatched by provincial system operators, not by private firms under contract. A reader who pushes the analogy beyond this will reach wrong conclusions; the argument here stops where the analogy does.

What does transfer is the political structure of a nation-building project in a federation. A vision arrives first, usually stated in language grand enough to embarrass the engineers who have to build the thing. Then comes the argument about money, about which province pays and which one benefits, and about who gets a seat at the table. The railway had that argument in the 1870s. The Trans-Canada pipeline had it in 1956. The highway had it through the 1949 Act and the decade of provincial friction that followed. Electricity is having a quieter version of the same argument now. The financing precedent and its limits are set out in Part 3.

The argument is also running in public and in fast motion. In July 2026 the Prime Minister and Alberta's premier announced an oil pipeline to the British Columbia coast as an equal Canada-Alberta partnership, with a reserved Indigenous equity stake built into the announcement instead of negotiated afterward. British Columbia's premier told reporters his province lacked the legal authority to stop it. Four days later the premiers of Ontario and Alberta announced Northern Shield, a proposed 3,300 kilometre oil line from Hardisty to Sarnia.³ Electricity has not had its equivalent moment. The constitutional, trade and financing tools required for one are on the shelf, tested on other projects, in the same country, inside the same year. What electricity lacks is the set of rules that would make a line worth building once the instrument is used, which is the subject of this paper.

What has moved since the original report

The policy environment has changed faster than most companion papers get the chance to track. On March 4, 2026 Ontario announced the National Energy Corridor Agreement, a non-binding memorandum of understanding signed by Ontario, British Columbia, Alberta, Saskatchewan, Manitoba, New Brunswick, Prince Edward Island, Nova Scotia, Yukon and the Northwest Territories. Quebec has agreed provisionally, on the condition that the collaboration remain within exclusive provincial jurisdiction. Newfoundland and Labrador and Nunavut are not parties.⁴

On April 27, 2026 the federal government launched the Canada Strong Fund. On May 14, 2026 it released *Powering Canada Strong*, a national electricity strategy issued for consultation and built around four pillars: building and financing the infrastructure, connecting grids east, west and north, training and attracting the workforce, and expanding domestic manufacturing of grid components. The first two are addressed here. Workforce and manufacturing are left to a future companion instead of being treated thinly. In the same window the Major Projects Office moved from launch to a portfolio of 27 nation-building initiatives, which it accounts for at more than \$192 billion in investment and more than 330,000 jobs.⁵

³ Prime Minister of Canada, "Canada and Alberta advance west coast pipeline project proposal and Pathways Project Carbon Capture Initiative," news release, July 2, 2026; Kyle Bakx, "Ford, Smith unveil plan for new 'Northern Shield' oil pipeline between Alberta and Ontario," CBC News, July 6, 2026; Reuters, "B.C. Signals It Won't Fight New Oil Pipeline Under Federal Deal," reprinted in *Pipeline & Gas Journal* (July 2026), quoting Premier David Eby: "we do not have the authority to stop a new pipeline."

⁴ Ontario, Ministry of Energy and Mines, "Ontario Secures Groundbreaking National Energy Corridor Agreement," news release, March 4, 2026; Government of New Brunswick, "Province signs memorandum of understanding on electricity transmission," news release, March 4, 2026.

⁵ Department of Finance Canada, Canada Strong Fund backgrounder, April 27, 2026; Government of Canada, *Powering Canada Strong: A National Strategy for an Electrified Canadian Economy*, May 14, 2026, which sets out eight areas for action for consultation and projects that interprovincial transmission could grow by up to 27 per cent by 2035 and 70 per cent by 2050; Major Projects Office, "Projects and

The pace has not slowed since. On June 26, 2026, following the Energy and Mines Ministers' Conference in Yellowknife, the federal government named five transmission projects for priority financial and regulatory support. They are the British Columbia to Yukon grid connection, restoration of the Alberta to British Columbia intertie, replacement and enhancement of the McNeill converter at the Alberta-Saskatchewan seam, a scalable expansion between Saskatchewan and Manitoba along the Regina to Winnipeg corridor, and the Prince Edward Island to New Brunswick interconnection. It referred a Transmission InterConnect Investment Strategy to the Major Projects Office, and secured ministers' support for a federal, provincial and territorial framework on interties. Eleven weeks later Ottawa convened the first Canada Investment Summit in Toronto. There the Prime Minister announced immediate expensing for most new capital investment, a review standard of one project, one review and one year, and close to half a trillion dollars in investment commitments against a five-year target of one trillion.⁶ A paper written a year earlier would have had to argue that this was worth Ottawa's attention. That argument is over.

As this paper was being finished, Ottawa moved twice on the very machinery Part 1 relies on. The first move was quiet. On September 3, 2026, new regulations took international power lines, and interprovincial lines designated under federal law, off the list of projects that need a federal impact assessment.⁷ Those lines now answer to the Canada Energy Regulator alone.

The second move was not quiet. On September 21, 2026, the day Parliament returned, the government introduced Bill C-39, the *Building Canada Strong Act*.⁸ The bill would require the Regulator to decide on pipelines, designated power lines and offshore renewable projects within a year of receiving the information it needs. It would bring the Crown's consultation with Indigenous peoples and the other federal approvals into one coordinated process, with the Commission as the only assessor. And it would let Cabinet declare whole regions to be in the national interest.

The pattern is hard to miss. The government is sharpening the very tool it is being urged to pick up, while it still sits unused. The timelines described in Part 1 may be shorter by the time this paper is read, and the case for finally using the power grows stronger with each change.

On October 1, 2026, the government used the listing power for the first time. The Governor in Council added the West Coast Oil Pipeline, now called Pacific Link, to Schedule 1 of the *Building Canada Act* as a project of national interest, and the Major Projects Office, supported by the Canada Energy Regulator, is to settle the project's conditions document by September 1, 2027. The first project listed under the Act is a pipeline. No power line has yet been listed.⁹

transformative strategies," Privy Council Office, and Government of Canada, Canada Investment Summit 2026, for the portfolio figures.

⁶ Natural Resources Canada, "Canada takes action to advance a stronger grid and increase reliable, affordable energy," news release, June 26, 2026; Prime Minister of Canada, remarks and opening remarks at the 2026 Canada Investment Summit, September 15, 2026. The Summit was held in Toronto on September 14 and 15, 2026, hosted with CPP Investments and PSP Investments.

⁷ *Regulations Amending the Physical Activities Regulations*, SOR/2026-185, (2026) C Gaz II, vol 160, no 18 (September 9, 2026), in force September 3, 2026.

⁸ Bill C-39, *Building Canada Strong Act*, 1st Sess, 45th Parl, 2026 (first reading September 21, 2026), Part 1, Division 3, amending the *Canadian Energy Regulator Act* to require decisions on pipelines, designated power lines and offshore renewable projects within one year of receipt of the required information and studies, to coordinate Crown consultation and federal authorizations, and to make the Commission the sole assessor; and permitting the Governor in Council to add a region to a new schedule where its designation is in the national interest.

⁹ *Order Amending Schedule 1 to the Building Canada Act*, PC 2026-0925 (October 1, 2026), made under subsection 5(1) of the Act, with the accompanying Explanatory Note; Prime Minister of Canada, "Prime

How the argument runs

Part 1 asks what section 92A protects, what it does not supply, what federal power reaches the line, how the new federal fast-track statutes relate to it, and what happens to provincial grids when that power is used. Part 2 asks why wires that already exist are idle for most of the year and fully committed in the hours that matter, and what would have to be agreed to change that. Part 3 asks who carries which risk, how a line that benefits a country gets paid for by a province, and what the absence of a corridor costs when supply fails. Part 4 makes the commercial case for Indigenous ownership, separate from the constitutional one, and points the same way. Part 5 sets out what a government is actually being asked to do.

The order matters. Getting the governance model right is what makes the trade and financing arguments credible and not merely aspirational, and each part inherits a constraint from the one before it. The recommendation those five parts arrive at reduces to three words. Rules before wires.

Minister Carney lists the West Coast Oil Pipeline, now known as Pacific Link, as a project of national interest to unlock Canada's full potential as a global energy superpower," news release (Fort McMurray, October 1, 2026), stating that the Major Projects Office, supported by the Canada Energy Regulator, will work to finalize the project's conditions by September 1, 2027; Major Projects Office, "West Coast Oil Pipeline" (Ottawa: Privy Council Office, 2026); *Canada Gazette*, Part I, vol 160, no 31 (August 1, 2026), Supplement, "Notice: West Coast Oil Pipeline"; Peter Zimonjic, "West Coast oil pipeline becomes 1st project designated in national interest," *CBC News* (October 1, 2026).

Part 1: The Constitutional Foundation

Every argument for a national electricity grid arrives sooner or later at the same objection, and the objection is always constitutional. Ottawa cannot build a power line across the provinces, it runs, because electricity belongs to the provinces, and section 92A says so. The objection is made confidently, it is rarely examined, and it has closed this file for forty years.

Section 92A does not say so. It settles a different question, and the question it settles is the one a corridor most needs settled. Canada's problem in building an east-west grid has never been that Parliament lacks the power. It is that Parliament has never once used the power it already has, and no province has ever been given a reason to want it used.

This Part takes the questions in the order a government would meet them. What section 92A protects. What it does not supply. What federal power reaches the line, and what happens to the provincial systems when that power is exercised. And where the trading arrangements that make the line worth building would have to come from, given that the constitutional text which protects provincial generation declines, deliberately, to build a market.

1.1 What section 92A was written to do

Section 92A was added to the *Constitution Act, 1867* in 1982. Paragraph (1)(c) gives each provincial legislature exclusive authority over the development, conservation and management of sites and facilities in the province for the generation and production of electrical energy.¹⁰ On its face the paragraph adds nothing. Every activity it names was almost certainly provincial before 1982, and the commentators writing at the time said as much.¹¹ The Supreme Court has explained why it was put in anyway, and the explanation is about grids.

In *Ontario Hydro*, decided in 1993, La Forest J set out the danger the paragraph was drafted to meet, and it was not the danger most people assume. The fear was that the stations would be transformed into purely federal undertakings by reason of their connection or extension beyond the province. In most provinces generation and distribution are carried on by the same undertaking, as an integrated system running from the plant to the customer. There was also authority suggesting that even an emergency interprovincial grid connection might be enough to make the whole of it a work connecting the province with another.¹² On that state of the authorities, a province connecting its grid to a neighbour's risked converting its entire supply system, and conceivably the whole undertaking from production to export, into a federal work.

Section 92A answered that danger. La Forest J held that the paragraph ensures the province the management of the sites and facilities for the generation and production of electrical energy that "might otherwise be threatened by section 92(10)(a)." The express grant in paragraph (1)(c),

¹⁰ *Constitution Act, 1982*, s 50, enacting s 92A of the *Constitution Act, 1867*. Paragraph (1)(a) covers exploration for non-renewable natural resources; paragraph (1)(b) covers development, conservation and management of non-renewable natural resources and forestry resources, including the rate of primary production.

¹¹ Nigel Bankes and Andrew Leach, "Preparing for a Mid-Life Crisis: Section 92A at 40" (2023) 60:4 *Alberta Law Review* 853, reviewing the contemporaneous literature, in particular Robert Cairns, Marsha Chandler and William Moull, "The Resource Amendment (Section 92A) and the Political Economy of Canadian Federalism" (1985) 23:2 *Osgoode Hall LJ* 253.

¹² *Ontario Hydro v Ontario (Labour Relations Board)*, [1993] 3 SCR 327, per La Forest J at 376 to 378, citing *British Columbia Power Corp v Attorney-General of British Columbia* (1963), 44 WWR 65 (BCSC), and G V La Forest and Associates, *Water Law in Canada* (1973) at 46 and following. His Lordship noted that a number of commentators, himself among them, had not shared that view of the law, but that the result on the authorities was by no means certain.

read with the export power in subsection (2), offers at least comfort for the position that, other heads of power aside, the development, conservation and management of generating facilities fall exclusively within provincial competence.¹³

The passage states the objection a premier raises today, and the Court answered it thirty-three years ago. The fear that connecting a provincial grid to an interprovincial line will end in federal control of the province's generating fleet is not a modern political worry. It is the precise mischief a judge of the Supreme Court of Canada identified as the reason paragraph (1)(c) exists. The answer to the objection is in the constitutional text, and the Court has said what the text is for.

The limits travel with it, and they should be stated plainly now, before a reader discovers them later. *Ontario Hydro* held that paragraph (1)(c) could not displace federal jurisdiction over the nuclear stations in issue, which came within Parliament's reach through the declaratory power and through peace, order and good government.¹⁴ Six of the seven members of the Court held that paragraph (1)(c) did not alter the declaratory power. Five years later, in *Westcoast Energy*, the majority declined to carry La Forest J's reading across to natural gas, holding his comments on section 92(10)(a) to be obiter. The ground of distinction matters, and it runs in this paper's favour: paragraph (1)(c) deals specifically with sites and facilities, and paragraph (1)(b), which was the provision in issue, does not. McLachlin J would have gone further, in dissent.¹⁵ Section 92A(1) fortifies provincial authority. It does not immunize provincial activity from otherwise valid federal law, and every time that argument has been put to the Supreme Court it has lost.¹⁶

For a corridor this is the right answer in both directions. The province keeps its stations. Parliament keeps what it held in 1982. Nothing in this paper asks a province to surrender the first, and nothing in it requires Ottawa to reach for the second in its crudest form.

1.2 The bargain, in the words of the men who made it

Section 92A was drafted by governments that had just lost in court, and what those governments thought they were getting is on the public record in the transcripts of the Special Joint Committee on the Constitution.

Saskatchewan drove it. Two decisions of the Supreme Court had gone against the province inside eighteen months. In *CIGOL* the Court struck down the royalty surcharge Saskatchewan had imposed to capture the windfall when oil prices tripled after 1973, holding the charge an indirect tax beyond provincial competence. In *Central Canada Potash* the Court struck down a prorationing scheme that had kept the province's potash mines and the towns around them alive through a market collapse, holding that it reached extra-provincial trade.¹⁷

¹³ *Ontario Hydro*, *supra* note 12 at 378. His Lordship also observed that s 92A(1) does not at first sight appear to add much to the catalogue of provincial powers, and concluded that it at a minimum fortifies the powers already there.

¹⁴ *Ontario Hydro*, *supra* note 12, per Lamer CJ at 355 to 356 and per Iacobucci J at 409 to 410. Neither the declaratory power nor the residuary power was surrendered when s 92A was enacted.

¹⁵ *Westcoast Energy Inc v Canada (National Energy Board)*, [1998] 1 SCR 322 at paras 81 to 84, per Iacobucci and Major JJ; and per McLachlin J, dissenting, at para 166. The Court confirmed at para 84 that s 92A does not derogate from Parliament's jurisdiction under s 92(10)(a), while distinguishing paragraph (1)(c) on the basis that it alone refers to sites and facilities.

¹⁶ Bankes and Leach, *supra* note 11, concluding that in both *Ontario Hydro* and *Westcoast Energy* the majority rejected the suggestion that s 92A(1) limits federal powers, and that an argument for immunity would have to be built on interjurisdictional immunity, which the current jurisprudence discourages.

¹⁷ *Canadian Industrial Gas & Oil Ltd v Government of Saskatchewan*, [1978] 2 SCR 545; *Central Canada Potash Co Ltd v Government of Saskatchewan*, [1979] 1 SCR 42. Both schemes were Saskatchewan's and

Premier Allan Blakeney appeared before the Joint Committee on December 19, 1980 and put the purpose of the amendment in one sentence. Saskatchewan wanted confirmation of rights it believed it already held and that recent decisions of the Supreme Court had called into question. It wanted them confirmed, he said, not so that the province could do new and different things, but so that it could “continue to do with certainty what we are now doing with great uncertainty.”¹⁸ That is the whole of it. Section 92A is a certainty provision, and the government that demanded it said so before Parliament while it was being drafted.

What Blakeney conceded is more useful to a corridor than what he asked for. Almost all of Saskatchewan’s resources were sold into world markets, and the province wanted room to regulate production inside its borders even where that regulation touched trade beyond them. It asked for that room subject to unqualified federal paramountcy, and Blakeney put the concession in plain words: if Parliament thought the province was off base, it need only pass a law and the provincial law is inoperative.¹⁹

The province that drove the resources amendment told a committee of Parliament that federal law would prevail over anything it did in this field. A premier arguing today that section 92A shields a provincial electricity system from a federal interprovincial line is arguing against the government that wrote the provision.

The negotiators were equally clear about what they had failed to obtain. Romanow, Leeson and Whyte, writing from inside the room, record that Alberta’s own draft had sought to immunize provincial resource laws from virtually all federal powers, that this did not survive into the Best Efforts draft, and that the residual federal authority under peace, order and good government remained “a serious and unresolved threat to provincial ownership and jurisdictional authority.”²⁰ Nobody who negotiated section 92A believed they were building a wall.

One caution belongs with this material and is stated here, not left for a reader to find. In *Ontario Hydro* the Court warned against leaning too heavily on the Minutes of the Special Joint Committee when construing section 92A, and specifically against using them to conclude that the amendment had cut down the federal declaratory power.²¹ The warning is a good one and it does not touch the use made of the record here. The Minutes are used in this paper for what the provinces said they were asking for and for what they accepted, not to read down a federal head

both were struck down at the instance of the producing companies rather than at the instance of the federal government.

¹⁸ Canada, Parliament, Minutes of Proceedings and Evidence of the Special Joint Committee of the Senate and of the House of Commons on the Constitution of Canada, 32nd Parl, 1st Sess, No 30 (December 19, 1980) at 9 to 10 (Hon Allan E Blakeney, QC, Premier of Saskatchewan). Issue No 30 is the sitting of December 19, 1980; No 29 is the sitting of December 18, 1980. Blakeney was the sole witness that day, and the brief tabled with his statement, *The Patriation and Amendment of the Constitution of Canada*, was circulated to the Committee and is reproduced with the proceedings. He told the Committee that resources then provided more than a quarter of Saskatchewan’s provincial revenues.

¹⁹ *Ibid* at 24 to 25. Saskatchewan’s own draft, reproduced at Appendix F of its brief, had struck out the compelling national interest test contained in the 1979 Best Efforts draft and replaced it with unqualified federal paramountcy over both interprovincial and international trade, which Blakeney described to the Committee as a compromise and not the province’s first choice.

²⁰ Roy Romanow, Howard Leeson and John Whyte, *Canada Notwithstanding: The Making of the Constitution 1976 to 1982* (Toronto: Thomson Carswell, 2007) at 27, 52 and 273. Romanow was Saskatchewan’s Attorney General and one of the three drafters of the November 1981 accord; Whyte was among the province’s constitutional advisers.

²¹ *Ontario Hydro*, *supra* note 12, per Iacobucci J at 409 to 410, holding that the Ontario Court of Appeal should not have relied so heavily on the Minutes in reaching that conclusion.

of power. On that question the Court's holding and Saskatchewan's own concession point in the same direction.

1.3 What section 92A does not supply

Section 92A(2) lets a province legislate the export of its electricity to another part of Canada. Not to the United States. The subsection carries a proviso: such laws may not authorize or provide for discrimination in prices or in supplies exported to another part of Canada. Subsection (3) preserves Parliament's authority over the same subject and makes federal law paramount where the two collide.²²

The proviso is often read as doing most of the work a national trading platform requires. It does not, and the point has to be made carefully, because it drives the recommendation in Part 2. The proviso constrains provincial export legislation. It says nothing about open access. Nothing about dispatch. Nothing about scheduling, settlement or how a price is formed. It may not engage at all where a Crown utility trades by commercial contract and not under a statute. And it has never been construed by any court, because no law has ever been challenged under it.²³

Why is the constitutional text silent on these functions? Electricity cannot be stored at scale. A constitutional provision governing a non-storable commodity cannot supply a market by text alone, because a market for such a commodity requires continuous institutional coordination at the instant of flow, coordination that constitutional text can authorize but cannot perform. Section 92A(2)'s proviso against discrimination is a constraint on static legislative output. It cannot substitute for the dynamic institutional functions that a non-storable commodity requires at every instant. The silence is a consequence of the commodity's physical nature: a market for electricity is an institutional operation, not a legal text.

One open question cuts against the corridor and belongs in the text, not in a footnote. Whether a province may prefer itself, in price or in supply, has never been decided. The proviso is drafted against discrimination in what is exported to another part of Canada, and the parallel construction of the price and supply limbs inside a single clause suggests a province keeps the ability to favour its own load.²⁴ If that is right, section 92A(2) is a floor against a province playing its neighbours off against one another. It is not a promise that any province will sell into a national market on the terms it sells at home. A trading layer resting on the assumption that the proviso requires open access would rest on a provision that has never in forty years been asked to do anything at all.

The open-access discipline Canadian utilities actually observe was not written in Canada. A utility selling into the United States must follow the open access transmission tariff of the Federal Energy Regulatory Commission, and so cannot discriminate between transmission customers even inside its own province. Ian Blue, writing in the *Dalhousie Law Journal* in 2009 in an article discussed further in section 1.4, traced how that happened. In 1995 the Commission refused market-based rate authority to a marketer partly owned by a Hydro-Québec subsidiary,

²² *Constitution Act, 1867*, ss 92A(2) and (3). The Best Efforts draft of February 1979 would have extended provincial authority to international exports and reversed the ordinary paramountcy rule in the province's favour. Neither feature survived into the enacted text: Bankes and Leach, *supra* note 11.

²³ *Alberta (Attorney General) v British Columbia (Attorney General)*, 2021 FCA 84 at para 166. The Federal Court of Appeal held British Columbia's challenge to Alberta's *Preserving Canada's Economic Prosperity Act* premature in the absence of implementing regulations, observing that the concept of discrimination in s 92A(2) was difficult to interpret without them. At first instance Grammond J had found a serious issue to be tried: *British Columbia (Attorney General) v Alberta (Attorney General)*, 2019 FC 1195 at paras 115 to 131.

²⁴ Bankes and Leach, *supra* note 11, Part 3, "Interprovincial trade in natural resources: subsections (2) and (3)," on a province's preference for itself and the parallel construction of the proviso.

because of how Hydro-Québec was organized in Canada, and in 1997 it refused the same authority to Powerex, Ontario Hydro and a Hydro-Québec subsidiary, citing their market power. Hydro-Québec ceded control of its transmission and adopted the Commission's form of tariff, Ontario restructured its system in 1998, and every other Canadian utility followed. Van de Biezenbos draws the inference: most Canadian transmission owners already comply with a working template for interprovincial tariffs. The rule a national trading layer needs is foreign only to Canadian law; Canadian utilities have lived under it for thirty years.²⁵

Section 92A(4) completes the picture. It broadens provincial taxation authority over resources and over generating sites and facilities, subject to a parallel rule against taxation that differentiates between production exported to another part of Canada and production that stays home.²⁶

Read together, the operative subsections give a province secure control of its generating stations, a narrow and untested power over interprovincial export, and a wider power to tax. They do not give anyone a market. That silence is the bargain that was struck: provincial control over generation, in exchange for a guarantee that provincial control would not be turned into a weapon against a neighbouring province. Nobody in the room in 1981 was trying to build a trading platform, and the text they produced does not contain one.

1.4 The power Parliament has never used

Section 92(10)(a) excepts from provincial jurisdiction works and undertakings connecting one province with another. Parliament has legislated under it for electricity, and the machinery is on the statute book. The *Canadian Energy Regulator Act* provides that the Governor in Council may designate an interprovincial power line as one to be constructed and operated under a certificate, and may specify the considerations the Commission must apply in deciding whether to issue it.²⁷

That power has never been exercised. Not once. In the entire life of the *Canadian Energy Regulator Act*, and of the *National Energy Board Act* before it, no order has ever issued designating an interprovincial power line. The absence is a policy choice, made by one government and renewed by every government since, each of which held the power and declined to use it.

Two features of the machinery have gone unremarked in the current debate, and both matter. The first is that the fixed timetable recommended here exists in statute. As the Act stands, the Commission must decide within a limit set by the Lead Commissioner and no longer than 300 days after a complete application, with any excluded period and any extension made public. The

²⁵ Ian Blue, "Off the Grid: Federal Jurisdiction and the Canadian Electricity Sector" (2009) 32:2 *Dal LJ* 339 at 343 to 347, tracing the Federal Energy Regulatory Commission's decisions from *Energy Alliance Partnership* (1995) through the 1997 market-based rate refusals; Kristen van de Biezenbos, "Lost in Transmission: A Constitutional Approach to Achieving a Nationwide Net Zero Electricity System" (2022) 59:3 *Osgoode Hall LJ* 629.

²⁶ *Constitution Act, 1867*, s 92A(4). The subsection reversed, prospectively, the principal holding in *Canadian Industrial Gas & Oil Ltd v Government of Saskatchewan*, *supra* note 17, that a producer-level charge of that kind was an indirect tax beyond provincial competence.

²⁷ *Constitution Act, 1867*, s 92(10)(a); *Canadian Energy Regulator Act*, SC 2019, c 28, s 10, ss 261 and 262. Section 261(1)(a) provides for the designation; s 261(1)(b) for the specification of considerations.

Governor in Council then has 90 days to approve or refuse. The certificate must issue within seven days of approval.²⁸ Ottawa is being asked to start a clock Parliament wound in 2019.

The second is section 261(1)(b), which is the instrument for attaching conditions. Cost-allocation principles, standards for Indigenous participation, and the phase triggers Part 3 describes can all be specified in the designation order itself. No new legislation. No new agency. An order in council, signed by a Cabinet that has decided to sign it.

The gap was identified at the framing, and by a province that wanted the power used. On November 20, 1980 the Newfoundland branch of the Canadian Bar Association appeared before the same Joint Committee and made a submission that reads today like a description of this paper. It accepted that constitutional authority to regulate interprovincial transfers of electricity rested with the federal government. Its complaint was that “there is no available mechanism to compel the federal government to exercise its jurisdiction.” It asked for a regime for interprovincial and international power transfers modelled on the *National Energy Board Act* provisions for pipelines, including the expropriation of a power corridor where the public interest and economic feasibility could be demonstrated.²⁹

Newfoundland was arguing its own case against a neighbour, and the circumstances were particular. The structural observation was correct and has aged better than almost anything else said about electricity during patriation. Forty-six years later the mechanism it asked for exists, in sections 261 and 262 of the *Canadian Energy Regulator Act*. There is still no way to compel a government to use it. The highway, whose financing Part 3 sets out, was built through a decade of the same friction, and nobody now proposes undoing it.

The Supreme Court has already explained why the provinces regulate interties today, and the explanation is not the Constitution. In *Fulton v Energy Resources Conservation Board*, decided in 1981, Calgary Power sought provincial approval for a 500 kilovolt line to the British Columbia border, to meet a British Columbia Hydro line at a dead-end tower. The purposes set out in the agreed facts were generation capacity reserve, mutual assistance in emergencies, operating economies through exchange of capacity and energy, sale of surplus power, mutual support for reserve and reliability requirements when new plant is delayed, and backup transmission. The utilities that built the line had stated the multi-value case for an intertie forty-five years ago.

Chief Justice Laskin held that an electrical system could come within section 92(10)(a), relying on *Hewson*. He upheld the provincial board’s jurisdiction for one reason: no federal legislation occupied the field. Unexercised federal authority, he wrote, may give leeway to the exercise of provincial authority. Calgary Power did not dispute Parliament’s power at the point of interconnection should Parliament choose to act, and the Court answered the constitutional question subject to the prescription of federal legislation. The most telling detail is procedural. The Attorney General of Canada intervened in support of the provincial board. Provincial regulation of interties rests on federal silence rather than on constitutional entitlement, and in 1981 Ottawa appeared in the Supreme Court to argue for its own silence.³⁰

The argument was made again in 2009, in the *Dalhousie Law Journal*, by Ian Blue, a senior commercial litigator and energy lawyer. He proposed two amendments to the *National Energy Board Act*. The first would have extended the provisions for international power lines to

²⁸ *Canadian Energy Regulator Act*, *supra* note 27, s 262. The Commission must also have regard to the interests and concerns of the Indigenous peoples of Canada, including their current use of lands and resources, and to effects on rights recognized and affirmed by s 35 of the *Constitution Act, 1982*.

²⁹ Special Joint Committee, *supra* note 18, No 9 (November 20, 1980) at 81 (Edward M Hearn, Newfoundland Branch, Canadian Bar Association). The submission was made in the context of Newfoundland’s inability to move Labrador power to market across Quebec.

³⁰ *Fulton v Energy Resources Conservation Board*, [1981] 1 SCR 153 at 161 to 166.

interprovincial ones, so that the regulator could approve new interconnections. The second would have extended its tolls and tariffs Part to interprovincial lines, so that it could set interprovincial transmission tariffs, resolve access disputes, order a provincial utility to build new facilities and apportion their cost. That authority would have superseded provincial jurisdiction over interprovincial access and rates, and Blue was explicit that it would not otherwise diminish provincial control of utilities or transmission systems. The proposal in this paper differs in method, not in object. It relies on a designation Parliament has legislated, a trading layer provinces join by agreement and an arbitral role for the regulator, and it needs no statutory power to compel construction. The diagnosis has now been made by the Newfoundland branch of the Canadian Bar Association in 1980, by a practitioner in 2009, by a former chief executive of the Ontario Power Authority in 2010, and by a legal scholar in 2022. Blue also records that section 58.4 of the *National Energy Board Act*, the predecessor of the present designation provisions, was enacted in 1990.³¹

A second federal instrument now sits beside the designation power, and the relationship between them has to be stated, not assumed. The *Building Canada Act* creates a national interest designation and a Major Projects Office to carry projects through it, on a standard of one project, one review, with projects able to proceed within two years. The stated purpose is to move the question from whether a project of national interest should be built to how.³² The two are complementary, and both are recommended here. The *Building Canada Act* accelerates a project that somebody has proposed. It does not create a proponent where none exists, allocate costs between two Crown utilities in two provinces, or tell a regulator which considerations to apply. Section 261(1)(b) does the last of those, and Part 3 explains why the first two are the binding constraint on an interprovincial line.

The Act's mechanics make the relationship precise. Once the Governor in Council lists a project, the federal findings it requires are deemed made in its favour, and a single conditions document stands in for its federal authorizations.³³ For a power line, the authorization that listing reaches is the certificate under section 262 of the *Canadian Energy Regulator Act*. Listing does not relieve the proponent of applying to the Regulator, and the Act confines the Regulator's confirmation to the safety and security of persons and regulated facilities.³⁴ Parliament also wrote the division of powers into the Act. Before listing, the Governor in Council must consult the province in which the project will be carried out and obtain its written consent where the project falls within areas of exclusive provincial jurisdiction.³⁵ Bill C-39 would carry the same

³¹ Blue, *supra* note 25 at 342, 365 to 366.

³² *Building Canada Act*, enacted as Part 2 of the *One Canadian Economy Act*, SC 2025, c 2, assented to and in force June 26, 2025; Major Projects Office, Privy Council Office. The Office reports a portfolio of 27 nation-building initiatives. Major Projects Office, "Projects of national interest: The process" (Ottawa: Privy Council Office, 2026), stating that the single conditions document allows a listed project to proceed within two years.

³³ *Building Canada Act*, SC 2025, c 2, s 4, ss 5(1), 6(1), 7(1); Avalon Jennings, Alexandre Lafrenière and Adriane Yong, *Legislative Summary of Bill C-5: An Act to enact the Free Trade and Labour Mobility in Canada Act and the Building Canada Act*, Publication No 45-1-C5-E (Ottawa: Library of Parliament, June 18, 2025) at ss 2.2.2 to 2.2.3, summarizing the Bill as introduced.

³⁴ George Vegh and Kate Koplovich, *Clear the Way: Does the Building Canada Act Help Canada Build?*, Commentary No 728 (Toronto: C.D. Howe Institute, September 2026) at 21 to 23, explaining that under the *Canadian Energy Regulator Act* the authorizations affected by listing are those under ss 186(1) and 262(1), that listing does not relieve a proponent of applying to the Regulator, and that s 17 of the *Building Canada Act* confines the Regulator's confirmation to the safety and security of persons and regulated facilities.

³⁵ *Building Canada Act*, *supra* note 33, s 5(1.1); David V Wright and Martin Z Olszynski, "Building Canada Act: Move fast and make things, or move fast and break things?" (2025) 13:3 *Energy Regulation*

model from single projects to whole regions, which the government says could include energy corridors and transmission systems.³⁶

These instruments accelerate every federal step, and by their own terms they stop where provincial jurisdiction begins. The department responsible for electricity told the House of Commons Standing Committee on Natural Resources as much in 2024: provinces set electricity policy, market structures and prices, and interties across different market structures raise the question of who absorbs the risk and who pays.³⁷ The first listing came on October 1, 2026, when the Governor in Council added the West Coast Oil Pipeline to Schedule 1. The government had said it intended to list four projects by the fall, and the one transmission line referred to the Major Projects Office was proceeding through British Columbia's own regulatory process.³⁸ The new toolkit makes the designation recommended here more valuable to use, and it leaves the trading rules where Part 2 places them: with the provinces, to be agreed.

The most careful independent assessment of the Act, by a former chair of the Canada Energy Regulator and a colleague, presses an objection this Part should meet. Its authors argue that political approval of individual projects is the root cause of regulatory uncertainty in Canada, and a designation made by the Governor in Council could be read as more of the same.³⁹ The designation recommended here is different in kind. An order under section 261 decides which regime governs a class of line and approves nothing. The conditions this Part asks the order to carry work the way the same authors recommend for cabinet's power under section 13(1) of the *Canadian Energy Regulator Act* to give the Regulator binding policy directions, a power no federal government has used: government sets the rules once, and the Regulator decides applications on the evidence.⁴⁰

1.5 The power Parliament could use, and should not

There is a second federal power over works, and any honest treatment of a national grid has to name it. Section 92(10)(c) lets Parliament declare a work wholly situated within a province to be for the general advantage of Canada, and a declared work passes into federal jurisdiction.

Quarterly (online), Part II, recording that the requirement was added on amendments introduced in the House of Commons Standing Committee on Transport, Infrastructure and Communities and adopted at third reading, and observing that the Constitution confers exclusive authority over matters, not over projects.

³⁶ Bill C-39, *supra* note 8, Part 1, Division 2; Government of Canada, "Bill C-39 Introduction" (September 2026), stating that regions of national interest could include transportation or energy corridors and energy production and transmission systems.

³⁷ House of Commons, Standing Committee on Natural Resources, *Evidence*, 44th Parl, 1st Sess, No 98 (May 9, 2024) (Debbie Scharf, Assistant Deputy Minister, Energy Systems Sector, Natural Resources Canada), in the Committee's study of Canada's electricity grid and network.

³⁸ Vegh and Koplovich, *supra* note 34 at 24, reporting that no project had been added to Schedule 1 and that 18 had been referred to the Major Projects Office; Major Projects Office, "West Coast Oil Pipeline," *supra* note 9, describing the project's referral and its listing on October 1, 2026; Graeme Gordon, "Building Canada Act's purpose questioned as Carney government marks 1 year without a single project designated," *The Hub* (June 17, 2026); MLT Aikins LLP, "Second round of nation-building projects announced for Major Projects Office" (December 2025), on the North Coast Transmission Line. See also "Inside the agency advancing Carney's major projects agenda," *Globe and Mail* (August 2026), reporting that none had yet been listed and that the government intended to list four by the fall.

³⁹ Vegh and Koplovich, *supra* note 34 at 12 to 14, 26 to 27.

⁴⁰ *Ibid* at 19; *Canadian Energy Regulator Act*, *supra* note 27, s 13(1).

Ontario Hydro confirms that Parliament did not surrender the declaratory power when section 92A was enacted.⁴¹

The drafting history is sharper than the provision. The Best Efforts draft of February 1979 would have barred any declaration touching the generation of electrical energy without the concurrence of the affected province. That limitation did not make it into section 92A.⁴² The provinces asked for a lock on this particular door. They were refused, and the refusal is in the constitution the country actually lives under. The declaratory power over electricity works is intact, unqualified by the resources amendment, available today.

Using it is not recommended here, and the reason is practical, not legal. A corridor built on a declaration would be resented by the province whose works were taken, litigated for years on immunity grounds that would probably fail but would freeze the project while they ran, and financed by nobody in the meantime. Naming the power is useful precisely because we are declining to use it. It disposes of the notion that the constitutional question is close.

The constitutional question is not close. Canada's difficulty in building an east-west grid has never been a shortage of federal authority. It has been the absence of any reason for a province to welcome the exercise of the authority that exists. Everything that follows in this paper is about supplying that reason.

1.6 Why designation does not swallow the provincial grids

The objection that has kept this file closed is the fear that federal permitting of an interprovincial line would pull the systems at either end into federal jurisdiction with it. Three decisions answer it, and the test they set is demanding.

Central Western requires that a provincial work be part of, or integral to, a federal work, and holds that something more than physical connection and a mutually beneficial commercial relationship is needed.⁴³ *Westcoast Energy* makes the primary question whether the operations are functionally integrated and subject to common management, control and direction, and treats common ownership as relevant but not determinative.⁴⁴ *Tessier* requires that the provincial undertaking lose its distinct character, and confirms that a province regulates transportation inside its boundaries while Parliament's authority runs to what crosses them.⁴⁵ A

⁴¹ *Constitution Act, 1867*, s 92(10)(c), read with s 91(29); *Ontario Hydro*, *supra* note 12, per Iacobucci J at 409 to 410 and per La Forest J at 378. The power has been used for the grain trade, among other subjects.

⁴² Bankes and Leach, *supra* note 11, citing Romanow, Leeson and Whyte, *supra* note 20 at 47. In several respects the enacted text is less favourable to the provinces than the Best Efforts draft, and this is one of them.

⁴³ *United Transportation Union v Central Western Railway Corp*, [1990] 3 SCR 1112; *Consolidated Fastfrate Inc v Western Canada Council of Teamsters*, 2009 SCC 53. The decision confirms the physical-crossing distinction from the converse direction. A 6-3 majority held that a nationally integrated freight forwarder remained subject to provincial labour jurisdiction because its own employees and equipment did not cross provincial boundaries; interprovincial carriage was performed by third-party carriers. Section 92(10)(a) captures works and undertakings that physically connect provinces through transportation, not undertakings connected only notionally through contracts. A transmission line that physically crosses a provincial boundary is squarely within s 92(10)(a), which is the corridor's position. A provincial grid that remains separately owned and operated on each side of the boundary is the *Fastfrate* of this analysis: connected to the interprovincial work but not itself crossing the line.

⁴⁴ *Westcoast Energy*, *supra* note 15 at paras 49 to 53. The absence of functional integration and common management, control and direction will in all likelihood determine that the operations are not part of the same interprovincial undertaking.

⁴⁵ *Tessier Ltée v Quebec (Commission de la santé et de la sécurité du travail)*, 2012 SCC 23. A provincial undertaking becomes federal derivatively only where its relationship to the federal work is so integral that

provincial grid that remains separately owned, separately dispatched and separately regulated meets none of those conditions. Certifying a line does not make the systems at either end into one enterprise. That conclusion depends on one condition, and it should be stated openly. Blue reads *Westcoast* as strongly suggesting that a provincial utility's own transmission would fall under federal jurisdiction if it were under common management, direction and control with an interprovincial line. *Fulton* turned in part on the finding that no single promoter was in a position to effect the interprovincial connection on its own: each utility built to a dead-end tower at the border and retained unfettered control of its side. The design consequence is straightforward. A designated line should be owned and operated by an entity distinct from either provincial utility, not folded into the system of the province at either end. That structure keeps the grids provincial, and it is also the natural home for the Indigenous equity described in Part 4.

Section 92A(1)(c) stands behind that conclusion rather than in front of it. The functional integration cases establish that a federal work does not absorb what it touches. *Ontario Hydro* establishes that the provincial legislature holds exclusive authority over the generating stations themselves, and that preventing exactly this absorption was the purpose of the paragraph. The line is federal. The grids are not. A premier asking for that assurance can take it from the Court and from the text.

A province resisting designation might reach for a second argument: interjurisdictional immunity, the doctrine that one level of government may not impair the core of the other's jurisdiction. The argument would be that federal designation of an interprovincial line, and the conditions written into the designation order, impair the core of provincial jurisdiction over the generation and management of electricity under section 92A(1)(c).

The argument faces a doctrinal barrier that has grown higher in recent years. In *Canadian Western Bank v Alberta*, 2007 SCC 22, the Supreme Court held that interjurisdictional immunity should be applied with restraint, limited to situations already covered by precedent, and that courts should favour the complementary doctrines of paramountcy and cooperative federalism. In *Rogers Communications Inc v Chateauguay (City)*, 2016 SCC 23, the Court confirmed that the doctrine applies only where a federal or provincial measure impairs, rather than merely affects, the core of the other level's exclusive jurisdiction. The doctrine has since been reaffirmed, not narrowed, most recently in *Opsis*, discussed below. The answer to a province invoking the doctrine against a designation order cannot therefore be that the doctrine is moribund. It is that the impairment threshold is not met. Designation of an interprovincial line under section 92(10)(a) does not impair the core of section 92A(1)(c). It reaches the line, which is a federal work, and leaves the generating stations exactly where *Ontario Hydro* and the functional integration cases place them. A province whose grid remains separately owned, separately dispatched, and separately regulated has not had the core of its jurisdiction impaired. The conditions the designation order attaches, cost allocation, phase triggers, publication of transfer capability, run to the interprovincial work, not to the provincial generating fleet. The interjurisdictional immunity argument would require a court to find that conditions on a federal work impair the core of provincial jurisdiction over an entirely separate class of facilities, which is a reach the current jurisprudence does not support.

Opsis Airport Services Inc v Quebec (Attorney General), 2025 SCC 17 is the most recent authoritative statement of interjurisdictional immunity. A unanimous Court applied the "final say" formulation of the impairment test. Aspects of Quebec's private-security licensing scheme gave a provincial body the final say over security activities falling within the core of exclusive

it loses its distinct character. *Tessier's* stevedoring was not a discrete unit of its business, and the company, considered as a whole, remained a local undertaking.

federal powers over aeronautics and navigation and shipping, and the Court held that to be impairment, not a mere effect. The distinction reinforces the narrowness of this proposal. The cooperative model preserves provincial operational control over dispatch, generation adequacy and retail pricing; no federal body acquires the final say over any function within the core of section 92A(1)(c). The designation order's conditions run to the interprovincial work, the line, its transfer capability and the terms governing the corridor, and not to provincial generating stations. That satisfies the *Opsis* threshold: the order affects provincial jurisdiction at the seam without impairing its core.⁴⁶

1.7 The market cannot be legislated

Part 2 argues that the binding constraint on interprovincial electricity trade is the absence of common commercial arrangements rather than a shortage of wire. That argument carries an obligation with it, which is to say where Parliament would find the authority to create those arrangements. The obvious candidate does not survive examination, and it is better to find that out here than in a reference case.

The general branch of the trade and commerce power is governed by the five indicia Dickson CJ set out in *General Motors*. A national electricity trading regime would satisfy the first two. It would be a regulatory scheme, and it would be overseen by a regulator. It fails on the third, which excludes federal regulation of a single commodity or industry from the general branch. Electricity is a single commodity. It struggles on the fourth and fifth, which require that the provinces be constitutionally incapable of enacting the scheme jointly or severally.⁴⁷ The provinces are entirely capable. What they lack is a reason. The gap is one of incentive, and the Court has been explicit that how well a policy would work does not answer a division-of-powers question.

The third indicium is a threshold, not a factor to be weighed. If the subject matter is a single commodity or industry, the general branch is unavailable however important that commodity is to the national economy, and that answers the most natural objection to the cooperative model, which is that electricity is too important to be left to voluntary provincial enactment. The *Securities Reference* shows why. The Court accepted that capital markets are systemically important and still held that the federal statute's pith and substance was the day-to-day regulation of a single industry, characterizing the legislation by its operation, the regulation of securities participants, and not by its purpose, the prevention of systemic contagion. A grid failure reaches every sector of the economy, as section 3.5 records, but systemic importance does not convert the regulation of a single industry into the regulation of trade as a whole. For electricity the general branch is excluded, and economic importance, however real, cannot change that classification.

The 2011 reference adds a second difficulty. A unanimous Court advised against federal securities legislation under the general branch, in part because a federal regime would have displaced provincial schemes that were functioning.⁴⁸ A national trading statute imposed over

⁴⁶ *Ibid.*

⁴⁷ *General Motors of Canada Ltd v City National Leasing*, [1989] 1 SCR 641 at 661 to 663. On the third indicium in particular, federal regulation of individual commodities or industries cannot be sustained under the general branch.

⁴⁸ *Reference re Securities Act*, 2011 SCC 66, in particular at paras 114 to 116; *References re Greenhouse Gas Pollution Pricing Act*, 2021 SCC 11. The leading post-2018 POGG decision. A 6-3 majority upheld the federal *Greenhouse Gas Pollution Pricing Act* under the national concern branch of POGG, characterizing it as establishing minimum national standards of GHG price stringency rather than regulating provincial resource sectors. Brown J, dissenting, warned that the majority's approach risked expanding federal authority at the expense of provincial jurisdiction and argued that cooperative federalism should be

Alberta's energy-only market, Ontario's hybrid market and eight vertically integrated systems would meet that objection in a sharper form. Any province could defeat it by pointing at its own working arrangements and asking why Ottawa needed to replace them. Alberta would ask first, and Alberta would be right.

What remains is more than enough, and it is the recommendation here. The interprovincial branch of the trade and commerce power is broad and uncontroversial, and it supports rules for the transactions that cross a boundary: scheduling, settlement, clearing, and the publication of transfer capability. The works and undertakings power supports the line itself and, through section 261(1)(b), the conditions written into its designation. Everything beyond that has to be agreed. It cannot be imposed. The trading layer must be built the way a trading layer can actually be built in this federation: by consent.

The cooperative model is the only model that can produce what the corridor needs. Precision is needed here, because the claim is practical, not constitutional. The Constitution does not, in terms, require cooperation. What the Constitution does is close the general branch to a single commodity, leaving Parliament with the interprovincial branch and the works and undertakings power, which together support the line and the transactions that cross it but cannot support a comprehensive national trading regime. A federal statute that designated the physical line without securing provincial cooperation on the trading layer would designate a physical substrate without the institutional partner that gives it value. The trading layer's continuous, real-time operational character, scheduling, dispatch and settlement at the instant of flow, requires the active, ongoing participation of provincial system operators who cannot be conscripted by a federal designation order. They must agree. The constitutional architecture leaves no unilateral path to a functioning trading layer, and a line without a trading layer is inert. Appendix II sets out when the boundary between two provincial systems is structural, so that the clearinghouse must mediate between them, and how that classification changes as provinces harmonize.

1.8 The template the Court has already approved

The Supreme Court refused to uphold a unilateral federal regulatory scheme in 2011 and upheld a cooperative one in 2018. The difference between those two decisions is the architecture a corridor needs, and it is available off the shelf.

The Court described cooperative federalism in the *Pan-Canadian Securities* reference as an interpretive principle. It disposes courts to read the heads of power harmoniously, and it discourages judicial interference with cooperative schemes operating inside constitutional boundaries. Governments acting in tandem may put in place a regime that neither of them could establish acting alone. The limits appear in the same passage. The principle cannot override or modify the division of powers, and it cannot make otherwise ultra vires legislation valid.⁴⁹ Both halves belong to the Court. The claim made here is narrow by design, and it cannot be knocked over by citing the limits, because the limits are set out here as well.

What the Court upheld in 2018 was a structure, not an aspiration, and the structure transfers. A model provincial statute had no force in a province until that province's legislature enacted it. The federal statute was confined to systemic matters. A joint regulator administered both instruments. A council of ministers sat above the regulator, with every participating government

preferred where provinces can act. The majority's deliberately constrained characterization technique parallels the subject-matter proportionality approach this paper applies to the electricity clearinghouse: federal authority confined to what is genuinely systemic, with day-to-day regulation remaining provincial.

⁴⁹ *Reference re Pan-Canadian Securities Regulation*, 2018 SCC 48 at paras 17 to 19. The formulation concerning governments acting in tandem is adopted there from *R v Comeau*, 2018 SCC 15.

represented. No government surrendered jurisdiction, and each could join and withdraw on notice. Two limits travel with the design: a legislature may not delegate its primary legislative authority, and an executive agreement may not fetter a legislature in exercising it.⁵⁰

Translated into electricity, the elements are these. A model interprovincial electricity trading statute, with no force in any province until that province enacts it. Federal legislation confined to what is genuinely systemic, being the line, the transactions that run across it, and the publication of capability data. A joint body administering the trading rules, with every participating system operator at the table. A council of energy ministers above it. Opt-in, with withdrawal on notice, which is both what the Court required and what makes the arrangement tolerable to a province holding a profitable export book it has no intention of surrendering. The National Energy Corridor Agreement is a voluntary compact of roughly this shape. The task is to give it statutory form, not to invent something new.

The companion report to this paper proposes a National Energy Infrastructure Council, convened under the Major Projects Office or the Canada Energy Regulator and chaired by the Prime Minister, as a single forum bringing together premiers, Indigenous leadership and industry.⁵¹ The instinct is right, and it needs one piece of constitutional engineering to work. A council of first ministers cannot itself take decisions that bind, for the two reasons just given. What such a council can do is settle the content of the instruments that do bind: the designation order on the federal side, and the model statute enacted province by province on the other. The Council is where the agreement is reached. The order and the statute are where it takes effect.

The Pan-Canadian Securities reference also shows that three of those features operate as constraints on the cooperative model. The federal statute stays confined to systemic matters, provincial legislative authority is preserved in full, and the right to withdraw on notice keeps federal governance from entrenching itself against provincial consent. Appendix II sets out what those constraints require of the joint governing body, function by function, and why the arrangement survives a challenge whatever the clearinghouse's operating mix.

The independent assessment noted in section 1.4 reaches the same distinction from the other side. It distinguishes cooperative federalism of the kind the Court upheld in 2018, in which legislatures empower a shared regime, from executive federalism, in which first ministers strike bilateral bargains outside legislative oversight, and it places the *Building Canada Act* in the second category.⁵² The trading layer proposed here belongs to the first. Independent work on grid integration has reached the same institutional answer: McPherson and Fairley propose a Power Exchange to handle trades across the provinces' disparate market structures, alongside a national planning council and a forum to coordinate regulation.⁵³

1.9 Consent is not the fourth item

No corridor of this length crosses Canada without crossing land subject to Aboriginal title, treaty rights, or both. The duty to consult that follows is part of the same analysis, and no permitting formality bolted onto it. The duty arises from the assertion of Crown sovereignty itself, it

⁵⁰ *Pan-Canadian Securities Regulation*, *supra* note 49 at paras 21 to 27 and at paras 66 to 78.

⁵¹ Nathwani, Mofid and Goodwin, *supra* note 1.

⁵² Vegh and Koplovich, *supra* note 34 at 17 to 18, relying on *Reference re Pan-Canadian Securities Regulation*, *supra* note 49 at para 19.

⁵³ Madeleine McPherson and Peter Fairley, "Jump-starting a Canadian power grid" (Toronto: C.D. Howe Institute, December 10, 2025); Madeleine McPherson and Peter Fairley, *It's Long Past Time for a National Transmission Grid*, Intelligence Memo (Toronto: C.D. Howe Institute, December 19, 2025).

attaches before any underlying claim is proven, and it is engaged by high-level strategic decisions including corridor route planning, long before a shovel is near the ground.⁵⁴

Precision matters here, because the doctrine is routinely described more strongly in conversation than it operates in law. The duty is not a veto. *Haida Nation* is explicit that it guarantees a genuine process calibrated to the strength of the claim and the seriousness of the impact, not a particular result. At the shallow end, notice and an opportunity to respond may be enough. Where a corridor crosses established treaty land and the impact is significant and hard to reverse, the process demands real accommodation and not a consultation calendar. A line of this length sits, for most of the communities whose territory it crosses, at the deep end of that spectrum.

That is the legal floor, and the designation process supplies the means of building above it without new legislation. The certificate provisions require the Commission to weigh Indigenous interests and concerns, current use of lands and resources, and effects on section 35 rights. Section 261(1)(b) lets the Governor in Council specify more. Indigenous governments are a jurisdictional actor inside the same analysis, and the statute contains the instrument for seating them at the table where the route is decided.

1.10 What this Part asks for

Establish, under the Canada Energy Regulator, a single designation process for priority corridors. Advance the first designations as a national commitment through the Major Projects Office, which holds the Transmission InterConnect Investment Strategy, and run the process on the clock Parliament enacted in 2019, which Bill C-39 would shorten, not on an open-ended negotiation. Use the designation order under section 261(1)(b) to specify the considerations the Commission must apply, including cost allocation, Indigenous participation, and the phase triggers Part 3 sets out. Leave generation where section 92A(1)(c) puts it, and say so in the order. Hold the designated line in an entity distinct from either provincial utility, so that neither provincial system can be treated as integrated with it. Build the trading layer as a cooperative compact on the 2018 model, with a model provincial statute, a joint administrator, a council of ministers and withdrawal on notice. Do not attempt to legislate a national market under a head of power that will not carry one. Once a corridor is designated, list it under the *Building Canada Act* so that its federal authorizations run through one conditions document, and carry the order's principles into a policy direction to the Regulator under section 13(1) of the *Canadian Energy Regulator Act*. The designation carries the rules; the listing and the direction speed and steady their application.

The proposal stays within the existing constitutional settlement and asks only for the political decisions that settlement leaves to governments. It requires a Cabinet willing to sign an order under a power Parliament first granted in 1990 and no government has ever used, and provincial and territorial legislatures willing to give statutory form to the cooperation their governments committed to in the National Energy Corridor Agreement.

⁵⁴ *Haida Nation v British Columbia (Minister of Forests)*, 2004 SCC 73; *Rio Tinto Alcan Inc v Carrier Sekani Tribal Council*, 2010 SCC 43, confirming that strategic or structural decisions can trigger the duty.

Part 2: Trade. The Wires Exist. The Market Does Not.

Part 1 ends with a conclusion that constrains everything after it. Parliament can permit the line. Parliament cannot legislate the market that would make the line worth permitting. The trading layer has to be agreed. This Part is about what would have to be agreed, why nobody has agreed it, and what the country has been paying in the meantime.

The argument runs against the intuition that a national grid is a construction problem. It is not, or not yet. Canada already owns wires between its provinces that carry little for most of the year and are fully committed at peak. The second pattern is what scarcity looks like. The first is not explained by their size at all.

2.1 What the wires actually did

Between 2022 and 2024, most east-bound and west-bound flows across the western and central Canadian interties ran at average capacity factors below 40 per cent. The interties between Quebec and Atlantic Canada, meaning Quebec to New Brunswick and New Brunswick to Nova Scotia, averaged roughly 90 to 100 per cent utilization in their dominant direction of flow.⁵⁵ The figures come from a critic of this corridor, not from its advocates, and they are accepted here without qualification. They are not, however, the whole picture, and the other half comes from the industry. Measured at annual peak demand instead of across the year, Canadian east-west interties average 72 per cent utilization, the Alberta to British Columbia and Manitoba to southern Saskatchewan paths run at 101 per cent of rated transfer capability, and Alberta to Saskatchewan runs at 88 per cent. East-west transfer capability totals roughly 17 gigawatts against 28 gigawatts north-south. Both measurements are correct, and the critic anticipated the reconciliation, observing that one would expect usage to be focused on peak needs. Read together they describe capacity that is idle across the year and fully committed in the hours a province has no alternative, which is rationing by scarcity rather than trading under rules. They remain the most important numbers in this paper.

Across the year, two connections in the country run flat out and the rest run at about a third of what they could carry. The difference between them is not engineering. Quebec and the Maritimes have long-term bilateral contracts and a settled commercial relationship. The western and central interties have neither, and a wire with nothing to carry across it carries nothing.

The trade data since has moved in one direction. Canadian electricity exports fell from 49.4 terawatt hours in 2023 to 35.6 in 2024, the lowest total since 2004, and to roughly 32.7 in 2025.

⁵⁵ AJ Goulding, “Beyond ‘Energy Superpower’: Market-Friendly Planning for Canada’s Power Sector,” E-Brief 380 (Toronto: C.D. Howe Institute, January 20, 2026), note 7, using data from AESO, IESO, Hydro-Québec and Nova Scotia Power. On an alternative metric dividing flows in a given direction by the product of capacity and the number of hours with flows in that direction, the same interties show utilization frequently below 60 per cent. Goulding anticipates the reconciliation with peak-hour measurement, noting that one would expect usage to be focused on peak needs. For that measurement see Deloitte, *Intertie Study* (Ottawa: Electricity Canada, December 2025) at 7 to 9, reporting average peak-demand utilization of 72 per cent on east-west interties and 79 per cent north-south, 101 per cent on the Alberta to British Columbia and Manitoba to southern Saskatchewan paths and 88 per cent on Alberta to Saskatchewan, and combined transfer capability of roughly 17 gigawatts east-west against 28 gigawatts north-south. The study draws on three years of member-validated data covering drought years in the hydro provinces, a period in which the Alberta to Saskatchewan intertie was out of service for over a year and the Ontario to Manitoba intertie was capacity-limited by an equipment failure, and it states that detailed cost-benefit analysis was beyond its scope.

Imports rose from 16.7 terawatt hours to 23.2 and then 22.1. The Canada Energy Regulator attributes the change to sustained drought affecting hydroelectric production, growing domestic demand and increased American generation.⁵⁶ Quebec exported 25.9 terawatt hours in 2019 and 13.3 in 2023. British Columbia imported 11.2 terawatt hours in 2019 and 16.8 in 2023. The provinces that were selling surplus are now buying it, and buying it from a single counterparty during their own shortfalls.

2.2 The year Canada had no working link

Canada's two electrical interconnections meet at one place. The McNeill back-to-back converter station near Medicine Hat is rated at 150 megawatts and was commissioned in 1989. It is the only facility joining the Western Interconnection to the Eastern.⁵⁷

After a component failure in November 2024 the Alberta system operator posted available transfer capability at zero in both directions. It stayed at zero until the station returned to normal operations on October 30, 2025. For close to a year the two halves of the Canadian grid were not connected to each other at all, and there was no alternative route, because there is no alternative route to build one against.

In September 2025, while the converter was still out of service, during an early-autumn heat wave, Alberta could import nothing on any of its interties, to British Columbia, to Saskatchewan or to Montana, for about ten days. Market data attribute the episode to a planned outage on the British Columbia and Montana path that coincided with the converter repairs, which left the province an electrical island.⁵⁸ A province facing near-record demand had no neighbour it could call on, no enforceable claim on anyone else's power and no forum to take a dispute to. That is the problem.

Neither episode is an argument for more wire. Both are arguments about what happens when a country owns interprovincial infrastructure and no institution responsible for it.

The economic cost is an order of magnitude, not a precise figure, but it should be stated. A 150 megawatt converter running at even a modest 40 per cent capacity factor delivers roughly 526 gigawatt hours a year. Priced at \$58.87 per megawatt hour, the 2024 average price of Canadian electricity exported to the United States East and the most conservative published proxy available, that is roughly \$31 million a year in foregone transfer value. At the western export price of \$125.40 it is closer to \$66 million. The true cost sits above both, because the value of a link is greatest during the stress hours when a province has no alternative, and those are precisely the hours the converter was not available. The figure is small against the scale of the investments this paper discusses. That is the point. Canada's only east-west electrical connection

⁵⁶ Canada Energy Regulator, "Market Snapshot: Annual Trade Summary, Electricity," June 25, 2025; and "Market Snapshot: Electricity trade trends affected by recent low precipitation," August 7, 2024. The 2025 volumes are taken from the Regulator's commodity statistics for electricity.

⁵⁷ Alberta Electric System Operator, available transfer capability postings and market updates for the Alberta to Saskatchewan intertie, November 2024 to October 30, 2025; ATCO, McNeill back-to-back converter station, giving a rating of 150 megawatts and a commissioning date of 1989.

⁵⁸ David Morton, "Interprovincial cooperation and energy reliability" (2026) 14:1 *Energy Regulation Quarterly*, attributing the September 2025 episode to reliability deratings. Market Surveillance Administrator data, as reported in later commentary, attribute the September 19 to 28 window to a planned outage on the British Columbia and Montana intertie coinciding with the McNeill converter repairs. Under normal conditions the Alberta to British Columbia path, part of WECC Path 1, carries roughly 1,200 megawatts west to east and 1,000 megawatts east to west; the 230 kilovolt Montana-Alberta Tie Line adds about 300 megawatts; and the two links to Saskatchewan supply roughly 150 megawatts combined.

was worth tens of millions of dollars a year, it was out of service for close to a year, and nobody was responsible for the loss.

Electricity cannot be stored at scale. More than a point of contrast with pipelines, that is the physical fact that determines where the corridor's value resides. Because electricity must be consumed at the instant it is produced, a transmission line produces value only at the moment of flow. No flow, no value. What is lost is lost outright.

Whether flow occurs depends on whether institutional coordination, scheduling, dispatch, transfer-capability determination and settlement, has been completed at or before that instant. The institutional functions and the physical flow must therefore be temporally simultaneous. The line cannot create value first and wait for the rules to catch up; by then the megawatt-hour has passed.

That temporal simultaneity makes the institutional framework and the physical infrastructure non-separable. Neither produces any output alone. The wire without the trading layer is an inert object, as the western interties demonstrate. The trading layer without the wire is an abstraction. Together they produce interprovincial electricity trade, and neither produces it alone.

A highway carries a commodity, vehicles and goods, that can wait. A truck delayed at a provincial border loses time, but the cargo does not vanish. A pipeline carries oil that can be stored at either end. Electricity cannot wait and cannot be stored. When institutional coordination fails, when the McNeill converter posts zero transfer capability, when Alberta's interties fall to zero, the electricity that would have flowed does not accumulate somewhere waiting. It ceases to exist as an interprovincial flow. There is no backlog to clear when coordination resumes. Every megawatt-hour lost is permanently lost. This is why the paper's sequencing recommendation, rules before wires, is a claim about what the corridor fundamentally is. The rules are the asset. The wires are the delivery mechanism.

2.3 What the reliability study found, including the part that cuts against us

The North American Electric Reliability Corporation published a Canadian analysis of interregional transfer capability in April 2025. Applying twelve past weather years to projected 2033 conditions, it found the potential for energy deficiency in every one of the twelve, across six provinces, and identified roughly 14 gigawatts of additional transfer capability that would improve energy adequacy under extreme conditions. Quebec showed the largest deficiency, at 10 gigawatts under extreme winter conditions. Nova Scotia showed shortages in all twelve years.⁵⁹

The constraint that must govern the design is this: Building transfer capability between systems that are simultaneously resource-deficient does not improve energy adequacy, and increasing transfer capability without surplus energy available to move would be inefficient.⁶⁰ A corridor that connects two provinces short of power in the same hour has connected two problems. No technical objection to an east-west grid is stronger, and it is set out here because it is true.

It also tells us what the corridor is for. The value is in diversity, not in aggregate capacity. Distance is the asset. A system 3,000 kilometres away is unlikely to be short in the same hour,

⁵⁹ North American Electric Reliability Corporation, *Interregional Transfer Capability Study: Canadian Analysis* (April 2025). The study also finds that expanded transfer capability with New Brunswick would address the Nova Scotia deficits.

⁶⁰ NERC, *ibid*. The study also records that geographic distance makes adverse conditions in one province less likely to affect its neighbours, and that provinces and northern states with cross-border ties rely on one another during extreme weather.

which is the entire reason an east-west line is worth more than another parallel line between neighbours who already fail together.

That geographic diversity is also a climate-adaptation value, and it is the adaptation side of the paper's net-zero case. The Clean Electricity Regulations, as proposed, make reliability on a largely non-emitting grid a system-wide constraint; reaching Canada's net-zero electricity targets is not only a matter of adding generation but of moving clean power across regions when drought, heat or cold stresses a local system. The corridor is adaptation infrastructure in that narrower sense: it turns geographic diversity into an operating resource and reduces the pressure to duplicate fossil or behind-the-fence capacity solely to survive the hardest hours.⁶¹

2.4 The seam has a price, and only part of it is public

Alberta sits in the Western Interconnection. Saskatchewan sits in the Eastern. The two systems are not synchronized and cannot be, so any corridor crossing that seam requires high-voltage direct current conversion, with converter stations at both ends and capital costs that scale with the capacity being converted. It is the single largest engineering cost in the whole proposal, and it is almost always left out of the discussion.

The facility that performs that conversion today is old. Its owner has put a like-for-like end-of-life replacement at about \$1 billion. No public estimate exists of what it would cost to expand conversion capacity to the scale a national corridor would need.

That missing number is the first task for feasibility work, ahead of any decision on route, scale or financing. A paper that proposed a corridor without saying so would be proposing a project whose largest single cost, at the scale that matters, is unknown to everyone including its authors. It is stated here plainly, and Part 3 ties the first phase of the guardrails to it.

Two things have changed since, and neither of them closes that gap. On June 26, 2026 the federal government named the replacement of the McNeill converter station among five transmission projects it will prioritize for financial and regulatory support, describing the work as installing updated technology to raise the intertie's trade capacity by roughly 250 megawatts and to extend its life.⁶² The announcement carried no cost. The owner's preliminary estimate, given to investors earlier in the year, prices the replacement, not the scale.

The load on the eastern side of the seam grew at the same time. In September 2026 Bell Canada and the Government of Saskatchewan announced a 1.2 gigawatt artificial intelligence infrastructure hub in that province, a commitment of more than \$50 billion and the largest in Saskatchewan's history.⁶³ Set the two announcements beside each other. A province preparing to host 1.2 gigawatts of new demand is joined to the Western Interconnection through a converter whose replacement is federally prioritized and proposed to reach roughly 400 megawatts.

The largest new loads in the country are already voting on the state of the grid, and they are voting with their own capital. The artificial intelligence campuses under development in Alberta

⁶¹ Madeleine Seale and Madeleine McPherson, "Mitigation and adaptation: Assessing the multi-value benefits of transmission expansion" (2025) 207 *Energy Policy* 114821.

⁶² Natural Resources Canada, *supra* note 6. The five are the British Columbia to Yukon Grid Connect, restoration of capability on the Alberta to British Columbia intertie, upgrade of the Alberta to Saskatchewan intertie through replacement of the McNeill converter station, expansion of the Saskatchewan to Manitoba intertie by up to two gigawatts along the Regina to Winnipeg corridor, and expansion of the Prince Edward Island to New Brunswick interconnection.

⁶³ Prime Minister of Canada, remarks to media at the 2026 Canada Investment Summit, September 15, 2026, describing the project as generating more than 4,500 jobs.

are being built with dedicated generation behind the meter instead of with grid connections. One campus near Medicine Hat pairs 884 megawatts of its own generation with a 650 megawatt computing load on a site designed to exceed 1.2 gigawatts. A group of three campuses in northern Alberta opens at 220 megawatts of critical capacity with substantial expansion potential, on behind-the-fence natural gas. A third project in central Alberta plans to scale from 300 megawatts to a gigawatt. The proponents give the reason without embarrassment: assured power and delivery timelines independent of grid constraints.⁶⁴ A developer who builds a power plant instead of waiting for a connection has priced the Canadian transmission system and found it wanting. The developer has made a market judgment with billions of dollars at risk, and it carries more weight than any figure in this paper.

Those choices quantify an implied reliability premium. They are paying a capital premium, building power plants they would not need if the grid were institutionally reliable, to avoid dependence on a transmission system without enforceable delivery commitments. That capital premium is the market's revealed price for the absence of rules. It carries that weight because it is denominated in actual capital deployed by parties bearing their own risk.

Alberta did not leave that to inference. The province set out to become North America's destination of choice for AI-enabled data centre investment, and the applications arrived.⁶⁵ By late 2025 the system operator held 37 large-load applications which, if all were connected, would have drawn a combined 19 gigawatts, against a provincial peak demand of roughly 12. It capped the first tranche of available capacity at 1,200 megawatts, allocated the whole of it to three projects near Edmonton, and left the remainder of the queue to bring their own generation or wait for the grid to catch up. The province then introduced legislation directing the operator to give priority to applicants who supply their own power.⁶⁶

Two readings of that are available and both are true. One is a judgment about transmission. The other is a judgment about rates, because a gigawatt of new load on a shared system raises costs for everyone else on it, and a province competing for the investment has reason to prefer generation that sits behind the fence and outside the rate base. Neither reading describes a grid that a gigawatt-scale customer expects to be able to rely on.

Hold the two numbers together. Nineteen gigawatts of demand queued in one province. A federally prioritized converter is proposed to carry only a fraction of that new load across the national seam.

One further comparison belongs here. Of the five interties the federal government named in June, one reached the investment market with a number attached. The Prince Edward Island to New Brunswick expansion was presented in September at roughly US\$215 million for new submarine cables and associated grid work.⁶⁷ The converter at the Alberta and Saskatchewan

⁶⁴ Government of Canada, Canada Investment Summit Prospectus (September 2026), Digital Technology. The campuses described are the Redcliff AI Data Center Campus near Medicine Hat, the Alto Northern Alberta projects and the AHI AI Hub of Innovation in central Alberta.

⁶⁵ Government of Alberta, Technology and Innovation, *Powering the Future of Artificial Intelligence: Alberta's AI Data Centre Strategy* (December 2024), which states that Alberta is driven to be North America's destination of choice for AI-enabled data centre investment and identifies power capacity, sustainable cooling and economic diversification as its three pillars.

⁶⁶ Alberta Electric System Operator, allocation of a first 1,200 megawatt tranche of large-load capacity, November 2025, the Chief Executive Officer stating that connecting all 37 applications then in the queue would require a combined 19 gigawatts; *Utilities Statutes Amendment Act, 2025* (Bill 8), assented to December 11, 2025, amending the *Electric Utilities Act* to prioritize and accelerate approval for data centres that bring their own generation and to place the cost of the transmission upgrades their connection requires on the developer rather than on ratepayers.

⁶⁷ Canada Investment Summit Prospectus, *supra* note 64, Power and Utilities.

seam, named in the same list eleven weeks earlier, has only its owner's preliminary estimate for a like-for-like replacement and no public number for the scale a trading framework would require.

2.5 First movers: who goes first, and why

Saskatchewan-Manitoba is the first plausible pair. The Canadian modelling supports the pairing. Dolter and Rivers, co-optimizing generation, storage and transmission across every province at hourly resolution, find that new interprovincial connections combined with wind expansion in southern Saskatchewan and Alberta are the lowest-cost path to decarbonizing the Canadian system, and that hydropower and interprovincial trade supply the balancing that makes that wind usable.⁶⁸ Saskatchewan's 1.2 gigawatt Bell Canada AI hub creates an immediate demand-side incentive. Manitoba's existing participation in the Midcontinent Independent System Operator gives it experience in organized markets. The Saskatchewan-to-Manitoba intertie expansion, up to two gigawatts along the Regina-to-Winnipeg corridor, is among the five federally named priorities. Saskatchewan sits at the seam between the Western and Eastern Interconnections, making it the natural point at which the coordination failure is most acute.

Saskatchewan's own utility made the case to Parliament nine years ago, when SaskPower told the House of Commons Standing Committee on Natural Resources that it supported further study of interties between provinces, especially between Manitoba and Saskatchewan.⁶⁹

British Columbia-Alberta is the other obvious first mover. It is the most-modelled pair, with \$1.7 billion in net benefits to 2050 for a 2.4 gigawatt expansion. British Columbia already participates in the Western imbalance and day-ahead markets. Alberta has 19 gigawatts of large-load applications in its queue and has allocated only 1,200 megawatts of the first tranche, creating a clear need for reliable external supply without requiring a redesign of its energy-only market.

Ontario and Quebec belong on the list too, and they belong on it carefully. No pair in the country has more wire in place: Ontario operates eleven interties with Quebec, and in 2025 it exported 8.8 terawatt hours to its neighbour. Quebec, however, has joined the National Energy Corridor Agreement only provisionally, for reasons that are commercial as much as constitutional, as section 3.10 explains. That makes Ontario and Quebec the natural second wave: the pair with the most to gain from common trading rules, and the one whose participation has to be earned on terms Quebec accepts.⁷⁰

These pairs have the strongest incentive to move first because each combines an immediate reliability or load problem with a partner that knows how to transact across a market boundary. The designation order would identify the priority corridor under section 261(1)(a) and specify the cost-allocation, Indigenous-participation, phase-trigger and revenue protections under section 261(1)(b). For Saskatchewan-Manitoba, the first trigger should test the seam, the converter and the new demand together. For British Columbia-Alberta, it should test the existing market interface and the external supply needed by Alberta's queued loads. In both cases the cooperative trading statute would preserve each province's domestic design while the order supplies the common guardrails.

⁶⁸ Brett Dolter and Nicholas Rivers, "The cost of decarbonizing the Canadian electricity system" (2018) 113 *Energy Policy* 135.

⁶⁹ House of Commons, Standing Committee on Natural Resources, *Strategic Electricity Interties: Report of the Standing Committee on Natural Resources*, 42nd Parl, 1st Sess (December 2017), recording the evidence of Mike Marsh of SaskPower.

⁷⁰ Ontario, Ministry of Energy and Mines, *supra* note 4, reporting fourteen Ontario interties, eleven of them with Quebec, and 8.8 terawatt hours exported to Quebec in 2025.

The Atlantic provinces may not wait for the west. On September 25, 2026, the Atlantic Economic Panel, appointed by the federal minister responsible for the Atlantic Canada Opportunities Agency, recommended that the four Atlantic provinces function as a single economy and build an integrated electricity system under a region-wide independent system operator. A regional operator goes further than the trading layer proposed here, because it would take over dispatch. The clearinghouse is the step that lets a proposal of that kind be tested before any province hands over control of its system, and the Atlantic region is where it could be tested first.⁷¹

2.6 Calling this a market failure, carefully

The absence of a common trading platform is routinely described as a market failure. The description is loose, and the looseness matters, because market failure is a term of art and the corridor debate has been using it as a slogan.

In its technical sense the term describes a situation in which private actors, responding rationally to the incentives in front of them, invest less than is socially optimal, usually because of an externality, a public good, or market power. Used that way, Goulding is right that it is not evident one exists in east-west transmission. Close to the full cost of electricity infrastructure is recovered through rates. Where an intertie is mutually beneficial, mechanisms already exist to fund it through rate base, and provincial utilities and system operators are better placed than the federal government to assess the need and allocate the cost against the benefit.⁷² Nothing in the Canadian record contradicts him, and this paper does not try to.

The claim being made here is a different one, and stating it precisely makes it stronger. The failure sits one level up, in the market for the institutions that would let electricity be traded.

A common trading platform has the structure of a public good. It returns nothing to the first province that builds it and a great deal to every province once several have joined. Each province facing that arithmetic reaches the same answer, which is to wait, and so none builds. The result is a coordination failure, and coordination failure is a category both economists and Canadian courts recognize.⁷³ National competition rules, national trademark protection and the national management of systemic risk in securities markets have all been upheld on the same structural ground: a benefit no single actor can secure alone.⁷⁴

This matters for more than vocabulary. If the problem were a shortage of wire, the answer would be capital and the argument would be about how much. Because the problem is an absent institution, the answer is an agreement, and the argument is about who signs it. That is a different paper from the one the corridor debate has been having.

2.7 Answering Goulding on his own test

A. J. Goulding, writing for the C.D. Howe Institute in January 2026, argues that the concept of an east-west grid is ill-defined and may pose economic risks to Canadians if overbuilt. He adds

⁷¹ Atlantic Canada Opportunities Agency, “Atlantic Economic Panel unveils blueprint for Atlantic Canada’s future,” news release (September 2026); The Canadian Press, “Eastern Canada business leaders call for ‘single economy’ between Atlantic provinces” (September 25, 2026).

⁷² Goulding, *supra* note 55, setting out the definition of market failure used here and concluding that it is not evident that market failure exists in the case of east-west transmission.

⁷³ On market failure as the test for public intervention, Goulding, *supra* note 55; on the courts’ recognition of the same structure, see the authorities *infra* note 74.

⁷⁴ *General Motors of Canada Ltd v City National Leasing*, *supra* note 47; *Kirkbi AG v Ritvik Holdings Inc*, 2005 SCC 65; *Reference re Pan-Canadian Securities Regulation*, *supra* note 49; Cairns, Chandler and Moull, *supra* note 11; *Seattle and McPherson*, *supra* note 61; van de Biezenbos, *supra* note 25.

that a new east-west transmission grid, leaving aside the shelved Atlantic Loop, is a solution in search of a problem, and that it is not evident that market failure exists in this case. Building generation or transmission for export, whether interprovincial or international, poses significant economic risks in his view unless underpinned by firm, long-term contracts.⁷⁵ He is not a fringe voice and the argument deserves an answer, not a footnote.

On the first objection, this paper agrees with him and adopts his discipline. Investment decisions driven by public policy goals rather than by the mutually recognized needs of neighbouring provinces are exactly what the cooperative structure in Part 1 is built to prevent. A compact that no province is obliged to join cannot be used to build a line into a province that does not want one.

On the second, underuse does not prove the wires need to multiply. He is right, and nothing here argues otherwise. Adding capacity to a corridor nobody can trade across efficiently would spend money on towers when the constraint sits upstream of the towers. The sequencing recommended here follows from his point; it does not route around it. Fix the commercial arrangements first. Let the existing interties show how much unmet demand was there all along. Then decide whether new capacity is warranted, and how much. Rules before wires. That order costs little, risks less, and answers his overbuilding concern on his own terms.

On the third, his contracting objection is the objection the guardrails in Part 3 exist to meet, and each of those guardrails now names the party that carries the risk, which is the form his objection takes and the form an answer to it has to take.

There is a fourth point he makes himself, in an Intelligence Memo of February 24, 2026, and it cuts in this paper's favour. His published framework for judging which major projects deserve federal support requires that a project address a genuine market failure, that it benefit more than one province, and that it involve First Nations from the outset. He lists electricity and telecommunications connections to the north among the project types that might qualify, which is not the same as endorsing an east-west corridor. He is equally explicit that the framework must be capable of saying no, that projects benefiting a single province should be paid for by that province, and that wrapping an initiative in a maple leaf and calling it nation-building is insufficient.⁷⁶ A corridor built on a fixed statutory timetable, a coordination failure honestly identified, benefits distributed across at least two provinces by construction, and Indigenous equity embedded from the first order in council is close to the test he is asking Ottawa to apply. It is a fair test to be judged by.

2.8 Answering Sepulveda: this is his second model

Edgardo Sepulveda's July 2026 report for the Macdonald-Laurier Institute compiles seven decades of trade data and finds that Quebec, British Columbia and Manitoba have held positive export-import spreads for decades, built through deliberate public investment, and apply the proceeds to hold domestic rates down. Ontario's spread turned negative after the 2002 restructuring, because its export prices track its own wholesale price.⁷⁷ That evidence is accepted here without argument. Those margins are the return on provincial public capital, and a proposal that would convert them into a common clearing price would be refused, and refused rationally.

⁷⁵ Goulding, *supra* note 55. He defines an east-west transmission grid, for his purposes, as one in which investment decisions are based on broader public policy goals rather than on the mutually recognized needs of neighbouring provinces.

⁷⁶ A.J. Goulding, "Why Boring is Best for Nation-Building," Intelligence Memo (Toronto: C.D. Howe Institute, February 24, 2026).

⁷⁷ Edgardo Sepulveda, *The Integration Illusion* (Ottawa: Macdonald-Laurier Institute, July 2026).

The disagreement is narrower than it looks. Sepulveda sets out three models: regulated without restructuring, some markets without restructuring, and full market restructuring. His case is against the third. This paper proposes the second, and says so plainly. No province is asked to unbundle, to price its home supply at a common clearing price, or to give up the decision whether and at what price to trade.

The middle model already operates in Canada, which is the part of the argument that should settle it. British Columbia participates in the western imbalance and day-ahead markets while its home supply stays regulated. Manitoba has participated in the Midcontinent Independent System Operator since 2001. Both provinces trade this way with American markets and have done for years. What they have never done is trade this way with each other.

2.9 The trade-off the case has to survive

Canadian electricity trade is overwhelmingly north-south, and it is profitable. Any honest case for reorienting east-west has to account for what is given up.

The opportunity cost is real and it is measurable. An hour of surplus sold east is an hour not sold south, and the southern price is often the better one. In 2024 the average price of Canadian electricity exported to the United States West was \$125.40 per megawatt hour. To the United States East it was \$58.87. The American market is larger than any adjacent provincial market, and southbound transfer capability comfortably exceeds what is available between provinces: Goulding puts it at roughly three times, and the industry's own figures at roughly 28 gigawatts against 17.⁷⁸ A province asked to sell into a national market at a lower price than it can obtain from a New York or Minnesota counterparty is being asked to accept less money, and it will want to know why.

The answer is that nothing here proposes redirecting flows. It proposes creating an option where the country currently has one, and the value of an option does not depend on exercising it every hour. It depends on being able to exercise it in the hours that matter. Canada has just spent a year discovering which hours those are.

The modelling says the same thing, and the way it says it is instructive. The peer-reviewed analysis behind the figures in Part 3 finds that on production cost alone the benefit-to-cost ratios for the two most-studied intertie expansions are 0.21 and 0.46. Adding emissions and generation capital savings brings them to 1.04 and 1.49. The full framework, counting resource adequacy and resilience, produces ratios of 3.69 and 4.08. The spread between those numbers is not a weakness in the case. It measures what single-metric screening misses, and production cost is the metric by which Canadian interties have historically been judged. The American planning rule now requires transmission planners to measure at least seven benefits, of which production cost savings is one, alongside avoided reliability facilities, reduced loss of load probability and mitigation of extreme weather. A project assessed on production cost alone is assessed by a method the regulator next door has abandoned, and the visible result of that method in Canada is a single converter station from 1989 at the country's only asynchronous seam. The modelling is driven by the Clean Electricity Regulations as proposed, which will differ from the final regulations, and it prices interprovincial trade at zero, a simplifying assumption the authors acknowledge is not indicative of real-world behaviour.⁷⁹

⁷⁸ Canada Energy Regulator, "Market Snapshot: Annual Trade Summary, Electricity," *supra* note 56, for the 2024 average export prices. On relative capacity, Goulding, *supra* note 55. For the industry's figures, Deloitte, *Intertie Study*, *supra* note 55 at 7 to 9.

⁷⁹ Seattle and McPherson, *supra* note 61, Tables 7 and 9. On the treatment of production cost as one benefit among several, Federal Energy Regulatory Commission, Order No. 1920, *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation* (May 2024), requiring

On the metrics a sceptic would reach for first, the corridor does not pay for itself. It pays as resource adequacy and as adaptation, which is what the authors of the modelling themselves conclude. A reader who wants this corridor justified as cheaper electricity should stop here. A reader who accepts that reliability and optionality have value, and who has watched the country spend a year with no working link between its two grids, has the rest of the argument in front of them.

There is a second element of the trade-off that is harder to price and easier to observe. Canada currently sells its surplus electricity to one country. Across 2026 that country replaced a balance-of-payments surcharge with an open-ended tariff action. It imposed duties on Canadian goods under a statute requiring nothing more than a presidential finding of fact and carrying no exclusion process, and it has issued proclamations converting part of that action from an additional duty into a prohibition on entry.⁸⁰ Electricity has not been the target. The point is not that it will be. The point is that the instrument now reaching Canadian goods requires no investigation, no agency finding and no comment period, offers no process for asking to be let out, and has been used not merely to price a category of Canadian trade but to prohibit it outright. A country with one buyer has no answer available if that instrument is ever pointed at its electricity, and building the answer takes a decade while signing a proclamation takes an afternoon.

The Section 338 sequence is now concrete. Section 122 of the *Trade Act of 1974* was invoked on February 24, 2026 and expired by operation of law on July 24 at the end of its 150-day period. A Section 301 action carrying no statutory sunset took effect as that measure lapsed. Three proclamations issued on July 20 under section 338 of the *Tariff Act of 1930* imposed an additional ad valorem duty of up to 50 per cent on specified Canadian motor vehicle, dairy and alcoholic beverage goods. An August 18 proclamation suspended that measure for three days, moving the effective date to August 22. Five further section 338 proclamations issued on September 8 adjusted the scope of the duties and, for specified alcoholic beverages, whey and molasses products and motorcycles over 800cc, replaced the duty with a prohibition on importation that took effect on September 29. Canada's responding surtaxes, on roughly US\$20 billion of imports, took effect on September 8. Section 338 contains no exclusion process. The dates and instruments described are those issued as at September 30, 2026.

The revenue at stake is not hypothetical. Canada exported 49.4 terawatt hours of electricity in 2023 and an estimated 32.7 terawatt hours in 2025. Priced at \$58.87 per megawatt hour, the lower of the two observed 2024 regional averages, the 2025 volume alone is worth about \$1.9 billion. At the western price of \$125.40 the same volume is worth about \$4.1 billion. The Regulator does not publish the split between the two regions, so the floor is stated here, not a blended figure. The floor is enough for the argument. A trade of that size rests on a single counterparty, and Canada has no second route to offer a seller if that counterparty becomes unreliable.⁸¹

transmission providers to measure and use at least seven benefits, including avoided or deferred reliability facilities and aging infrastructure replacement, reduced loss of load probability or reduced planning reserve margin, production cost savings, reduced transmission energy losses, reduced congestion due to transmission outages and mitigation of extreme weather events, and permitting selection criteria applying a minimum benefit-to-cost ratio no lower than 1.25 to 1.

⁸⁰ *Trade Act of 1974*, ss 122 and 301; *Tariff Act of 1930*, s 338; the 2026 proclamations and Canadian surtaxes described in the text.

⁸¹ Canada Energy Regulator, *supra* note 56, for the 2024 volumes and average export prices.

2.10 What the *Canadian Free Trade Agreement* does not contain

It is occasionally suggested that Canada already has an internal energy market and needs only to enforce it. It does not. The *Canadian Free Trade Agreement* contains no energy chapter. Chapter Eight is the general exceptions chapter, and nothing in the agreement creates an open access obligation or a mechanism for interprovincial dispatch.⁸² There is no rulebook. There is no Canadian equivalent of the American PJM Interconnection that would let a Manitoba generator with surplus hydro bid that surplus into Ontario on the same footing as an Ontario generator. The gap is not being under-enforced. It has never been filled.

2.11 The critique that deserves an answer

The most serious objection to an east-west grid does not come from economists who doubt the trade case. It comes from people who think transmission will crowd out what could be built faster. Brendan Haley argues that Canada has a recurrent pattern of large infrastructure pushes launched in reaction to a crisis that fail to develop the complementary technologies around them. His example is the transcontinental railway, which secured the territorial integrity it was built for and did not produce the industrial diversification that might have grown up around it. The criticism is of what a country does alongside its infrastructure, not of the decision to build it.⁸³

His Canadian example is close to home for a paper written this year. The political drive to build Muskrat Falls and its undersea link foreclosed an independent assessment of alternatives, the dam ran significant cost overruns, and Nova Scotia spent a decade dependent on a single megaproject at the expense of efficiency and community-scale renewables. Only when the Atlantic Loop was shelved did attention turn to demand management, storage and domestic generation. Transmission takes years or decades to build. Demand-side measures can be deployed in months.⁸⁴

That objection is answered by the sequencing Part 1 recommends and by what the corridor is for. Haley's own constructive proposal is complementarity: local systems balancing hourly and daily variation, and interprovincial transmission managing seasonal differences so that reservoirs refill ahead of the winter heating season. Haley's proposal is the reliability study's geographic diversity argument arriving from the opposite direction, and it states the case for a corridor in its narrowest and most defensible form. A line built for seasonal and adequacy value does not compete with a heat pump. A line built because a corridor sounds like nation-building does.

2.12 What CUSMA requires, and what it no longer does

Canada does not trade electricity as a single counterparty. Provincial utilities and system operators conduct the trade under provincial authority, and they act in their own interest when it suits them. Ontario demonstrated the point in March 2025 with a surcharge on exports to New York, Michigan and Minnesota, imposed by provincial regulation and a ministerial direction to the system operator, and suspended the day after it took effect. The federal dimension lies elsewhere. Every export line crossing into the United States requires a federal

⁸² *Canadian Free Trade Agreement*, 2017, Chapter Eight (General Exceptions). The agreement is sometimes described as gesturing at an internal energy market. It does no such thing. Energy appears instead in the parties' exceptions: Ontario's schedule, for example, reserves measures on natural gas and electrical energy from the non-discrimination and market access obligations in articles 201, 307 and 312.

⁸³ Brendan Haley, "A national grid should accelerate, not stifle, the energy transition," *Policy Options* (Institute for Research on Public Policy, May 29, 2025).

⁸⁴ *Ibid.*

certificate under the *Canadian Energy Regulator Act* international power line regime, a licensing authority with no provincial equivalent and no provincial veto.⁸⁵

The agreement adds a second federal layer and removes an older one. Chapter 2 imposes ordinary national treatment and market access discipline, so Canada cannot restrict electricity exports in a manner that discriminates against American buyers relative to Canadian ones. Unlike its NAFTA predecessor, CUSMA carries forward no energy proportionality obligation between Canada and the United States. That was a deliberate result of the renegotiation, not an oversight.⁸⁶ A grid designed to move Canadian electricity west to east, and not exclusively north to south, is compatible with CUSMA precisely because the proportionality lock is gone. Ottawa is exercising a trade authority that has more room in it than at any point in three decades.

One question has to be answered, not left open, because most Canadian transmission owners are provincial Crown corporations. The state-owned enterprise disciplines in Chapter 22 reach them only in part. Annex 22-D suspends, for Canada, most of the chapter as it applies to an enterprise owned or controlled by a sub-central level of government. Gone for a provincial Crown utility are the commercial considerations obligation, the non-discrimination rule on purchases, the non-discrimination rule on sales to enterprises of another Party, the non-commercial assistance prohibitions and the annual listing requirement.⁸⁷

What survives is narrower, and it should be named. In selling a service, a provincial Crown utility must still accord to an enterprise that is a covered investment in Canada treatment no less favourable than it accords to comparable domestic investments. Three further limits narrow even that. The disciplines do not reach a service supplied in the exercise of governmental authority. They do not reach an enterprise below the revenue threshold. And the definition itself reaches only an enterprise principally engaged in commercial activities, which excludes one operating on a cost-recovery basis, as a rate-regulated transmission utility ordinarily does.⁸⁸

The corridor can therefore be built through provincial Crown utilities without colliding with Chapter 22. The only live exposure runs to the terms on which service is sold to covered investments, and it is answered by designing the trading layer to be non-discriminatory from the start, which is what this Part recommends for its own reasons. One caution goes with that conclusion and it belongs on the review agenda, not on this one. Annex 22-C obliges the Parties to negotiate an extension of these disciplines to sub-central enterprises, and no outcome of those negotiations has been published.⁸⁹

2.13 Why a province hesitates before signing a long contract

There is a reason provincial utilities approach long-dated interprovincial power contracts with more caution than the engineering warrants, and it is not constitutional. In 1969 Churchill Falls

⁸⁵ *Canadian Energy Regulator Act*, *supra* note 27, ss 247 to 262, governing permits and certificates for international power lines. The regime traces to the former *National Energy Board Act* and operates independently of provincial authority over in-province generation under s 92A(1)(c).

⁸⁶ *Canada-United States-Mexico Agreement*, ch 2 (National Treatment and Market Access for Goods). Chapter 6 of the North American Free Trade Agreement contained a proportionality obligation; CUSMA does not carry it forward.

⁸⁷ *CUSMA*, *supra* note 86, ch 22, art 22.9.2 and Annex 22-D; footnote 29 to that Annex defines sub-central level of government as the regional and local levels.

⁸⁸ *Ibid*, arts 22.1, 22.2.6, 22.4.1(c)(ii) and 22.13.5, read with Annex 22-A. Footnote 1 to art 22.1 provides that activities undertaken on a not-for-profit or cost-recovery basis are not commercial activities. The threshold was set at 175 million Special Drawing Rights on entry into force and is adjusted at three-year intervals.

⁸⁹ *Ibid*, art 22.14 and Annex 22-C, requiring the Parties to begin further negotiations within six months of entry into force and to endeavour to conclude them within three years.

(Labrador) Corporation and Hydro-Québec signed a 65-year take-or-pay contract at fixed prices, with Hydro-Québec carrying most of the construction risk. Prices then moved, and the contract became a source of windfall profit on one side of a provincial boundary and the deepest grievance in Canadian energy federalism on the other.⁹⁰

The Supreme Court closed the judicial route in 2018. Seven judges to one, it held that Hydro-Québec had no duty to renegotiate. The duty to cooperate that flows from good faith does not extend to requiring a party to sacrifice its own interests. The contract was neither a joint venture nor a relational contract, the parties had intentionally allocated the risk between them, and the doctrine of unforeseeability forms no part of Quebec civil law.⁹¹ A court will not rebalance an interprovincial power contract that time has made lopsided. That is settled, and every provincial utility in the country knows it.

The consequence here is specific. A trading layer built on bilateral contracts, which is what this Part recommends and what Quebec and the Maritimes operate, has to carry its own indexation and its own scheduled review, because no external body will supply either afterwards. Part 3 treats that as the fifth guardrail.

2.14 The instrument

What Canada needs first is smaller than the debate assumes, and it is already designed. A voluntary clearinghouse for bilateral contracts, registering existing arrangements, clearing trades and publishing available transfer capability, loss factors, seam flows and prices, would put on the record the information that no province currently has about its neighbours. It would begin with the transactions that are least threatening and most obviously mutual, being reserve sharing and balancing, and it would leave real-time dispatch authority exactly where it is now.⁹²

The clearinghouse manages the structural boundaries between provincial systems described in Appendix II without replacing them. It must be able to bridge and to net from the outset, because provinces will harmonize at different speeds, if at all.

This is also the *Payment Clearing and Settlement Act* (PCSA) model arriving from a different direction. The Act regulates the clearing system itself, its rules, its risk management and its operational continuity, rather than the participants defined by sector membership. The Bank of Canada's oversight powers run to the system operator and system rules, not to individual banks or dealers. The Act supplies the legislative template for the electricity clearinghouse: regulate the infrastructure that sits between provincial systems, not the provincial systems themselves.

Nord Pool began with a deliberately modest encounter: a Norway-Sweden bilateral link between Norway's regulated hydro system and Sweden's liberalized market. The first step was a neutral day-ahead interface while each transmission system operator kept real-time control. The interface exposed schedules and price signals without requiring either country to restructure its domestic market.

The sequence then widened by experience rather than decree. Denmark joined after the Norway-Sweden arrangement, Finland followed, and the Baltic states were added in later stages. Governance mattered as much as sequencing: the participating transmission system operators owned the market institution, but the market operator was independent in administering the

⁹⁰ *Churchill Falls (Labrador) Corp v Hydro-Québec*, 2018 SCC 46, [2018] 3 SCR 101, describing the terms of the 1969 power contract and the allocation of risk under it.

⁹¹ *Ibid*, per Gascon J, Rowe J dissenting.

⁹² Madeleine McPherson, *Powering the Federation: A Blueprint for National Electricity Integration in Canada*, Commentary 696 (Toronto: C.D. Howe Institute, October 2025).

rules and clearing trades, while operational control remained with the TSOs. That division let the market deepen without turning the market operator into a national dispatch authority.

The benefits were demonstrated, not promised. Where interconnection capacity was available, prices converged more closely across borders; shared balancing and reserve resources improved reliability; and systems needed to carry less isolated reserve against the same contingencies. Nord Pool therefore supplies more than an analogy. It shows that a TSO-owned, independently operated market can begin with a narrow interface, earn trust through settlement and balancing, and reduce both price dispersion and duplicated reserve requirements as coupling expands. The relevance to Canada is direct. Canada is also a federation of systems with different market designs. Alberta's energy-only market, Ontario's hybrid market and the vertically integrated provincial systems need not be made uniform before they can trade. They need a neutral interface through which the differences can be managed. The key lesson is not simply that gradualism is prudent. A voluntary, phased sequence, clearinghouse before exchange and reserve sharing before restructuring, is the only approach that has produced durable cross-border electricity trade between systems with different market designs. Canada should copy the sequence, not pretend the institutional differences do not exist. The continental modelling points the same way. The North American Renewable Integration Study, whose Canadian analysis was prepared with Natural Resources Canada, values interregional transmission expansion across North America at \$70 billion to \$180 billion in 2018 United States dollars over the period to 2050. It finds that the flexibility of hydropower reduces system costs by more than \$2 billion a year, and that under coordinated transmission less than 10 per cent of potential wind and solar output is curtailed.⁹³ Those are continental figures, not Canadian ones, and they are cited for the direction and the order of magnitude. The value at stake once such an interface exists is not speculative. Modelling of increased transfer capability across the American east-west seam, the closest physical analogue to the Alberta-Saskatchewan boundary, returns benefit-to-cost ratios between 1.2 and 2.9 against the 1.25 threshold the industry applies to justify transmission investment. A separate peer-reviewed analysis finds that inter-regional coordination with transmission expansion reduces system cost by 46 per cent against a state-by-state approach in a fully renewable United States system. Neither study is Canadian. Both measure the same physical problem at the seam at issue here.⁹⁴

Three instruments complete it, and Part 1 has already established where each of them comes from. A contracts-for-differences framework, so that a generator in one province can hedge its exposure to another province's spot price without becoming a licensed participant in every market it touches. Minimum non-discrimination standards for the transactions that cross a boundary, resting on the interprovincial branch of the trade and commerce power and not on section 92A(2), which will not carry them. And a Canada Energy Regulator mandate to arbitrate disputes about the interprovincial rules, leaving each province's domestic market design untouched.

None of this asks Alberta to stop running an energy-only market, Ontario to stop running a hybrid one, or Quebec to stop selling into New England on long-term contracts at prices it negotiated itself. Any proposal has to pass that test in this federation, and the restructuring proposals of the last two decades failed it.

⁹³ National Renewable Energy Laboratory, *The North American Renewable Integration Study: A Canadian Perspective* (Golden, CO: NREL, 2021), prepared with Natural Resources Canada; the value range is stated in 2018 United States dollars.

⁹⁴ *McPherson*, *supra* note 92.

2.15 Provincial incentives: why the provinces move differently

Alberta has deliberately chosen behind-the-fence generation and an energy-only market, so a designation order could be perceived as complicating the model it has built. But the behind-the-fence trend is not merely a policy preference. Developers are building generation because they cannot obtain a firm grid connection on the timetable their loads require, and they are paying for capacity the grid would otherwise supply. The cooperative framework would not ask Alberta to restructure; it would give Alberta an instrument to make that isolation less commercially costly: enforceable access to reserve sharing, balancing and scheduled external supply through the clearinghouse.

The September 2025 stress event makes the point. As section 2.2 records, for about ten days during an early-autumn heatwave Alberta could import nothing on any of its interties, to British Columbia, Saskatchewan or Montana, while the converter at its eastern seam was already out of service. No neighbour owed it power, and the episode showed that isolation is commercially costly precisely when the system and the loads it is trying to attract are under stress. A province competing for data-centre investment cannot indefinitely answer reliability risk by requiring every developer to build its own plant.

Alberta's 19 gigawatts of queued large-load applications represent the largest concentration of new electricity demand in the country, against a provincial peak of roughly 12 gigawatts.⁹⁵ As section 2.4 describes, most of that queue has been told to bring its own generation or wait. A cooperative trading layer gives those queued loads a credible path to grid-connected service without requiring Alberta to build all replacement capacity itself: imports during stress, exports during surplus, and a clearinghouse that turns access from an informal hope into a priced commercial right. The value to Alberta is the difference between a project that can finance on a grid connection and one that must carry a second power plant behind the fence.

Ontario's incentive is different and just as concrete. It is the province that initiated the National Energy Corridor Agreement,⁹⁶ and its winter peak reliability problem makes access to Manitoba hydro and Quebec surplus valuable even when Ontario's domestic market remains hybrid and its internal decisions remain provincial. Imports from both directions would give Ontario an option during cold-weather stress, reduce the need to overbuild reserve capacity solely for the sharpest peaks, and create an outlet when neighbouring systems have surplus. The cooperative framework gives Ontario those options without requiring it to replace its domestic market or surrender control over the terms on which it trades.

Quebec's calculation is different again, and it is not the calculation of a holdout. Its interties toward Atlantic Canada already run near capacity in their dominant direction, so it has no spare route east.⁹⁷ A clearinghouse would give it a priced and enforceable route to Ontario and the Prairies that it does not now have, oblige it to sell nothing, and leave untouched the long-term contracts it negotiated with New York and New England. Section 3.10 sets out why its caution is rational. The point here is narrower: an opt-in compact does not need Quebec to move first, and it works as well if Quebec moves last.

2.16 What this Part asks for

Stand up a voluntary clearinghouse for bilateral contracts, and begin with the transactions that threaten nobody, which are reserve sharing and balancing. Publish available transfer capability, loss factors, seam flows and prices, so that each province can see what its neighbours have.

⁹⁵ Alberta Electric System Operator, *supra* note 66.

⁹⁶ Ontario, Ministry of Energy and Mines, *supra* note 4.

⁹⁷ Goulding, *supra* note 55, note 7, reporting utilization of roughly 90 to 100 per cent in the dominant direction of flow on the Quebec to New Brunswick and New Brunswick to Nova Scotia interties.

Adopt a contracts-for-differences framework so a generator can hedge exposure to another province's spot price without becoming a licensed participant in every market it touches. Impose minimum non-discrimination standards on the transactions that cross a boundary, resting on the interprovincial branch of the trade and commerce power and not on section 92A(2). And give the Canada Energy Regulator a mandate to arbitrate disputes about the interprovincial rules, leaving each province's domestic market design alone.

Price the converter at the Alberta and Saskatchewan seam before anything else. It is the first item on the list because nothing downstream can be sequenced until it is known.

2.17 Why this is worth doing before a single new tower goes up

Fix the commercial arrangements and the underused interties start earning before anyone pours concrete. This is the financing argument's first proof point. No pension fund evaluating a fifty-year transmission asset wants to be told that the commercial framework governing its revenue is still being negotiated province by province, and no province wants to explain to its ratepayers why it spent capital on a line whose value depends on agreements nobody has signed.

Canada has two connections running at full capacity and the rest running at a third. It has the converter outage described above, and no published cost for a seam built to trading scale. It has a reliability study finding potential energy deficiency in twelve weather years out of twelve. And it has no rulebook, no clearinghouse, no common definition of available capacity and no forum in which a lost intertie can be argued about.

The wires exist. The market does not. Building more of the first without any of the second would be the most expensive way of learning what the country already knows.

Part 3: Finance. The Capital Is Already in the Room

This paper's predecessor treated national financing architecture as a proposal for future work. That was correct when it was written and it is no longer true. The instruments a corridor would need now exist, most of them announced within the last year, and none of them were created for this project. The financing question has stopped being where the money comes from. It is who carries which risk, and nobody has written that down.

3.1 What Ottawa built while the debate was elsewhere

On April 27, 2026 the federal government launched the Canada Strong Fund, the country's first national sovereign wealth fund, with an initial endowment of \$25 billion over three years. It is structured as an arm's-length Crown corporation with a mandate to co-invest alongside private and institutional capital in nation-building infrastructure, and it names energy corridors among its targets. The companion report to this paper called for a Canada Clean Infrastructure Sovereign Fund, capitalized federally and co-invested with the large pension funds. One now exists.⁹⁸ On May 14, 2026 *Powering Canada Strong*, the federal electricity strategy, proposed a Transmission InterConnect Investment Strategy and floated extending Clean Electricity Investment Tax Credit eligibility to major high-voltage transmission, a category previously excluded.⁹⁹ A conversation the predecessor report deferred became federal policy inside a year.

One design feature of the Fund needs careful statement, because it is often overstated. The government has said it intends to let individual Canadians hold a direct stake through a retail investment product. The design of that product is not settled. It remains the subject of consultation run by the Fund's transition office.¹⁰⁰ The feature matters even as an intention, because a citizen who owns a piece of a corridor has a harder time treating it as somebody else's project, and because a retail instrument is the one part of the architecture that cannot be reversed quietly by a future Cabinet.

Canada's large pension funds sit alongside the sovereign fund; they do not compete with it. They manage exactly the long-dated liabilities that match the forty and fifty year asset life of transmission, and they have shown consistent appetite for regulated utility assets with stable, legally secured cash flows. Nothing about the Canada Strong Fund's mandate displaces that appetite. International capital, sovereign funds from allied jurisdictions with their own long-dated liabilities and their own interest in secure low-carbon supply, is a further pool worth designing for deliberately, before construction begins, instead of discovering by accident.

The capital is not the constraint. Part 1 established that the constitutional authority is not the constraint either. What is missing sits between them.

3.2 Five guardrails, each with a named risk-bearer

Guardrails are usually described as properties of a well-structured project. Described that way they are useless, because the questions that decide whether capital moves are who bears risk,

⁹⁸ Department of Finance Canada, Canada Strong Fund backgrounder, *supra* note 5; Prime Minister of Canada, "Prime Minister Carney announces the Canada Strong Fund: Canada's first sovereign wealth fund," news release, April 27, 2026, announcing an initial federal contribution of \$25 billion.

⁹⁹ *Powering Canada Strong*, *supra* note 5.

¹⁰⁰ Department of Finance Canada, *supra* note 5, which states the intention to offer Canadians the opportunity to participate directly in the Fund through a new retail investment product, and confirms that the design will be determined through consultation.

how costs are allocated, and how staged approval is governed. A guardrail that does not name the party carrying the risk is a wish. Each of those below is an instrument, with the party who carries the risk identified, and with the place in the designation order where it would be written down.

A revenue floor for an initial period carries the risk that demand growth disappoints. The floor is funded by the beneficiaries identified in the cost-allocation analysis, because those are the parties to whom the modelling attributes the reliability and adequacy gains. Early-stage capital is not asked to bear a forecasting risk better carried by the parties who benefit if the forecast is met. The floor has a term, and it expires.

An allowed return tied to certified in-service milestones carries delivery risk, and the builder carries it. The return steps up as each milestone is certified and is withheld where it is not. Ratepayers do not pay for delay, and a builder who delivers on time is rewarded for doing so and not merely permitted to keep what it was promised.

Phase triggers published in the designation order carry the risk that uptake is slower than forecast. The order names the body that determines whether a trigger has been met, and the Regulator arbitrates disputes about the determination. It also names the consequence of a trigger not being met, which is the element most often left out: the next phase does not proceed, the capital committed to it is released, and the project continues at its existing scale without stopping altogether. An off-ramp that nobody has defined is a renegotiation under pressure, conducted by whoever has the most to lose. The authority for all of this is section 261(1) (b) of the *Canadian Energy Regulator Act*, which lets the Governor in Council specify the considerations the Commission must apply.¹⁰¹

A regulatory deferral account with a defined amortization period and a stated recovery test carries the mismatch between when money is spent and when the asset earns. The rate base carries the deferred amount across the amortization period and not in the year of spending, and the recovery test states the utilization level at which the deferred amount becomes recoverable. Early-year ratepayers do not carry costs that a fully used corridor will not generate for another decade.

A fifth guardrail belongs with those four, and the reason is the decision set out in Part 2. Every long-dated contract underpinning the corridor carries a price formula with a scheduled review and an indexation mechanism agreed at the outset, and a dispute about either is arbitrated by the Regulator. The parties carry that risk between them, which is the only place it can sit, because the Supreme Court has held that a court will not supply the review afterwards.¹⁰² A contract that cannot be adjusted inside its own terms will eventually be adjusted outside them, and the Canadian record on how that goes is not encouraging.

The first phase is converter capacity across the Alberta and Saskatchewan seam, for the reason Part 2 gives. At the scale a trading framework would require, it is the largest unpriced item in the project, and no sensible phase two exists until somebody has costed phase one.

3.3 What a calibrated guardrail looks like

A guardrail with a named risk-bearer and no numbers in it is still half an instrument. A regulator cannot apply it and a lender cannot price it. What follows is a worked illustration on a single intertie pair, using the one expansion for which published modelling exists, being the 2.4 gigawatt British Columbia to Alberta path. The figures are illustrative and are not a

¹⁰¹ *Canadian Energy Regulator Act*, *supra* note 27, s 261(1)(b). The provision permits the specification of considerations by order, without new legislation.

¹⁰² *Churchill Falls (Labrador) Corp v Hydro-Québec*, *supra* note 90.

recommendation. They show the shape a calibrated instrument takes. A regulator would set the values on the evidence in front of it.

The revenue floor is expressed as a percentage of forecast first-year interprovincial transfer revenue, illustratively 70 per cent, and runs for a fixed term of five years from commercial operation. It is funded by the two provincial rate bases in the proportions the benefit study assigns to each, not equally, and not by the host province alone. If transfers meet forecast, nothing is drawn. If they fall short, the shortfall is met from the fund and every drawdown is published.

The allowed return begins at the regulator's approved base rate with a stated number of basis points held back, on the order of 75, released in thirds against three certified milestones: energization of the converter, confirmation of the path rating uplift, and commercial operation on schedule. A missed milestone forfeits that third; it is not deferred. The builder carries the risk and can see the arithmetic before it bids.

The phase trigger is an observed figure, not a forecast one, which is what makes it a trigger rather than an intention. Phase two proceeds when scheduled interprovincial transfers across the existing path exceed a stated capacity factor, in the range of 55 per cent, sustained across four consecutive quarters. The body named in the designation order makes the determination and the Regulator arbitrates any dispute about it. If the trigger is not met inside a stated window, the committed phase two capital is released and the project holds at phase one.

The deferral account carries construction-period costs across an amortization period tied to asset life and not to the rate year, which for transmission means something closer to forty years than to five. Below the utilization level set by the recovery test, the balance accrues and is not charged.

Four numbers, four instruments, and a fifth guardrail that is a drafting instruction, not a figure. A document a provincial regulator could apply on the evidence in front of it. None of this arithmetic is difficult. It has simply never been written down for an interprovincial line, because no interprovincial line has ever been designated.

3.4 What the corridor is worth, honestly

The companion report models the destination. The first step is priced here. That division is deliberate, and it explains why the figures in this Part are so much smaller than the ones in that one. None of them add up to a single number for the whole corridor, and none will be manufactured here. A rigorous whole-corridor cost-benefit model does not exist in public. Inventing a headline figure to fill that gap would repeat the error the arithmetic elsewhere in these pages has discredited.

What can be said is that the verified pieces compound rather than merely add. A national grid is ten pairs whose value to one another rises as the trading layer matures, because each new connection increases the value of every connection built before it. That is the ordinary arithmetic of a network,¹⁰³ and it is the reason the individual pair studies understate the whole.

The individual pairs have been modelled, and the figures should be stated with the conditions their authors attach. Expanding the British Columbia and Alberta intertie by 2.4 gigawatts yields \$1.7 billion in net benefits to 2050. Adding 1.5 gigawatts between Manitoba and Saskatchewan yields \$2.3 billion. The multi-value ratios are 3.69 and 4.08, counting resource adequacy, resilience and emissions, and resource adequacy is the largest single benefit in both. The production-cost-only ratios for the same expansions are 0.21 and 0.46, and they answer a

¹⁰³ National Renewable Energy Laboratory, *supra* note 93, on the value of interregional coordination across the continental system.

narrower question: whether the corridor pays as cheaper power in ordinary hours. It does not, and transmission of this kind is not built on that expectation. Under the American planning rule production cost savings is one of seven benefits a planner must measure, and selection may apply a minimum benefit-to-cost ratio of 1.25 to 1 across the full set. On that basis both expansions clear comfortably. Part 2 sets out what those ratios rest on.¹⁰⁴

As Part 2 put it, the corridor pays as reliability and adaptation, not as cheaper power. The value of resource adequacy is the cost avoided when the system does not fail. That cost is difficult to model, but the converter outage described in Part 2 and the ten days in which Alberta could import nothing show what its absence looks like. It is also revealed by the capital choices of developers building behind the fence: a developer spending hundreds of millions of dollars on dedicated generation instead of relying on the grid has put a price on the absence of resource adequacy, and that price exceeds anything in the modelling. Saying so plainly is the condition of being believed on anything else.

An illustrative reliability-value frame is available even before the seam is priced at trading scale. The McNeill station's 150 megawatts, at the modest 40 per cent capacity factor used in Part 2, represents roughly 526 gigawatt hours a year. The paper's conservative proxy put the 2024 to 2025 outage year's foregone transfer value at roughly \$31 million at the eastern export price and roughly \$66 million at the western price, before any separate allowance for emergency procurement, lost trade revenue in stress hours or deferred investment.¹⁰⁵ That is a floor, and it is a floor of the wrong kind. Foregone transfer value measures revenue the system did not earn. It does not measure the cost to an economy of power that does not arrive, which is the benefit an intertie delivers and which is valued on unserved energy rather than on trade margin. The reliability value of the same asset is larger than the trade proxy by a wide margin, and the smaller number is stated because it can be sourced. Against it must be set the converter's replacement cost, now publicly estimated at approximately \$1 billion. So must the capital premium revealed by developers building 884 megawatts of dedicated generation for a 650 megawatt computing load, and 220 megawatts of initial behind-the-fence capacity with substantial expansion planned, none of it waiting for a grid connection.¹⁰⁶ Those choices imply a

¹⁰⁴ Seattle and McPherson, *supra* note 61. On the comparative seam evidence, Aaron Bloom et al., "The Value of Increased HVDC Capacity Between Eastern and Western U.S. Grids: The Interconnections Seam Study," National Renewable Energy Laboratory, NREL/JA-6A20-76850 (October 2020), reporting benefit-to-cost ratios between 1.2 and 2.9 against a 1.25 threshold and modelling the 150 megawatt Alberta facility without considering it for expansion; and Patrick R Brown and Audun Botterud, "The Value of Inter-Regional Coordination and Transmission in Decarbonizing the US Electricity System" (2021) 5:1 *Joule* 115, reporting a 46 per cent reduction in system cost, from \$135 to \$73 per megawatt hour, for a 100 per cent renewable United States system.

¹⁰⁵ Alberta Electric System Operator, *supra* note 57. On replacement cost, Canadian Utilities Limited, fourth quarter 2025 results call, management stating that system-operator-led work is under way for an end-of-life replacement of the McNeill converter, that preliminary cost estimates are approximately \$1 billion, and that the majority of those costs are expected to fall outside the company's current five-year capital plan; and Natural Resources Canada, *supra* note 6, describing the project as replacing and enhancing the McNeill converter station to increase the intertie's trade capacity by approximately 250 megawatts, and naming the other four priority projects as the British Columbia to Yukon grid connection, restoration of approximately 150 megawatts on the Alberta to British Columbia intertie, a scalable Saskatchewan to Manitoba expansion of up to two gigawatts along the Regina to Winnipeg corridor, and the Prince Edward Island to New Brunswick interconnection. On the valuation, 150 megawatts at a 40 per cent capacity factor is 525.6 gigawatt hours a year, valued at the 2024 average export price to the United States East of \$58.87 per megawatt hour and to the United States West of \$125.40 per megawatt hour, giving a band of roughly \$31 million to \$66 million.

¹⁰⁶ Natural Resources Canada, *supra* note 6; Canada Investment Summit Prospectus, *supra* note 64, Digital Technology; and Alberta Electric System Operator, *supra* note 66.

reliability premium paid in real capital: generation that would not be built if the grid offered a firm, timely connection. The figures are estimates, and without a costed design for the seam at trading scale no final comparison is possible; the point is to establish the scale of the value that a replacement converter would have to recover, not to manufacture a ratio.

3.5 The cost of not having it

The asymmetry at the centre of this argument is not a matter of temperament. Surplus capacity costs money. Absent capacity costs an economy far more, and the Canadian evidence is unusually well documented. On August 14, 2003 a cascading failure across the Eastern Interconnection removed power from an area holding roughly 50 million people and 61,800 megawatts of load, including about 10 million Ontarians, with rolling blackouts in parts of Ontario for more than a week. Canadian gross domestic product fell 0.7 per cent that month. The economy lost 18.9 million work hours, and Ontario manufacturing shipments fell by \$2.3 billion. Estimates of total cost in the United States alone ranged from \$4 billion to \$10 billion.¹⁰⁷

The 2003 event was a failure of reliability coordination, not a shortage of interties, and nothing in this paper suggests that more transmission would by itself have prevented it. Its relevance is narrower and more useful. It is the best-measured Canadian answer to the question of what a week without power costs, and that figure is the denominator against which reliability investment is judged. Set beside it, an annual foregone transfer value of \$31 million to \$66 million at a single converter marks only the visible edge of the exposure. Ontario, for its part, absorbed both kinds of failure inside twelve months. The 2002 crisis followed the opening of its restructured market and was an economic and policy failure; the 2003 blackout was a failure of reliability. The design in this paper is built to avoid repeating either: it asks no province to restructure its market, and it proposes no corridor without the reliability rules to operate it.

The failure also taught its own lesson, and the industry acted on it. The blackout investigation found that operators could not see the disturbance spreading across the wider system in time to contain it, and inadequate situational awareness became the cause the industry set out to fix. The instrument of the fix is the phasor measurement unit, which records grid conditions many times a second and time-stamps each reading, so that conditions across an entire interconnection can be seen at once. About 200 such units were networked across North America in 2009; synchrophasor technology is now in use in every NERC region, a footprint that includes Ontario. The objection that more interconnection means more exposure to a spreading failure was the right lesson in 2003. The wide-area monitoring built since answers much of it, and a corridor built now would operate inside that monitoring from its first day.

Canadian system experience makes the same point in less dramatic form. When a large part of Ontario's nuclear fleet was removed from service in 1997, and again during the ice storm of 1998, interconnection with neighbouring systems absorbed shortfalls that would otherwise have

¹⁰⁷ U.S.-Canada Power System Outage Task Force, *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations* (April 2004), drawing on Statistics Canada's Labour Force Survey and Monthly Survey of Manufacturing for August 2003. On the lesson of 2003 and the deployment of phasor measurement units since, see North American Electric Reliability Corporation, *Real-Time Application of Synchrophasors for Improving Reliability* (Princeton, NJ: NERC, October 2010), finding that the lack of wide-area visibility prevented early identification of the August 14, 2003 blackout; North American SynchroPhasor Initiative, *Synchrophasor Technology Fact Sheet*, recording about 200 research-grade units networked across North America in 2009; and United States Department of Energy, Office of Electricity, *Advancement of Synchrophasor Technology in Projects Funded by the American Recovery and Reinvestment Act of 2009* (March 2016), identifying inadequate situational awareness as a major cause of the 2003 blackout and reporting synchrophasor technology in use in every NERC region.

reached customers. The structural gap is equally measurable: Denmark holds interconnection capacity with its neighbours equal to roughly 80 per cent of its own generating capacity, and Ontario roughly 20 per cent.¹⁰⁸

Canada has a recent example of its own. During Alberta's grid emergency in the extreme cold of the 2023 to 2024 winter, it was the interties to British Columbia and Saskatchewan that let the province import power and balance its system, as a senior Natural Resources Canada official later told Parliament.¹⁰⁹

This is why the benefit framework matters more than the rhetoric. Reduced loss of load probability and mitigation of extreme weather are two of the seven benefits the American planning rule requires a transmission planner to measure, and they are the categories in which the corridor's value is concentrated. The reliability regulator has found the potential for energy deficiency in each of the twelve weather years it modelled, across six provinces. A framework that prices those exposures at zero, and then reports that the corridor fails on production cost, has not found the corridor uneconomic. It has declined to measure what the corridor is for.

The asymmetry can be stated as a ratio. In 2024 the Alberta system operator published an estimate, prepared by the Brattle Group, placing the value of lost load in Alberta at roughly \$12,000 to \$50,000 per megawatt hour. Other North American markets use administrative values in the same range: Texas used an administrative value of US\$9,000 in 2020, before lowering its offer cap after the 2021 winter storm, and the market monitor for the Midcontinent system has recommended that scarcity prices be able to reach US\$12,000.¹¹⁰ Set against the export prices used elsewhere in this paper, \$58.87 to \$125.40 per megawatt hour, a megawatt hour that is not delivered in Alberta is valued at roughly one hundred to more than eight hundred times a megawatt hour that is traded.

One caution governs how that ratio can be used. Value of lost load applies only to energy that is actually unserved. It cannot be multiplied against the 525.6 gigawatt hours the McNeill outage kept from being traded, because most of that energy was replaced from other sources, not lost. The defensible use is the per-unit comparison, which explains why reliability benefits dominate a properly constructed benefit-cost framework without claiming a loss the evidence does not show.

The same Alberta document supplies a second point, and it strengthens the argument of Part 2. Alberta's energy market price has been capped at \$1,000 per megawatt hour for two decades, a small fraction of the value its own consultant places on lost load, and the system operator has itself tied the level of the cap to Alberta's ability to attract imports when supply is scarce.¹¹¹ A market that suppresses its scarcity price mutes the very signal that would draw power across an intertie in the hours it is most needed. That is a rule, not a wire.

The underlying argument about regulation is not new, and one of this paper's authors made it in the peer-reviewed literature more than a decade ago. Lara and Nathwani argued that

¹⁰⁸ Jatin Nathwani, "Canada's Low Carbon Electricity Advantage: Unlocking the Potential of Inter-Regional Trade" in R Marceau, ed, *Canada: Becoming a Sustainable Energy Superpower* (Ottawa: Canadian Academy of Engineering, 2014) ch 6 at 93 to 118.

¹⁰⁹ Standing Committee on Natural Resources, *Evidence*, No 98, *supra* note 37 (Debbie Scharf).

¹¹⁰ Alberta Electric System Operator, *Pricing and Reserve Market Options Paper* (Calgary: AESO, August 16, 2024), reporting the Brattle Group's value of lost load estimate for Alberta; The Brattle Group, *Energy-Market Payment Options for Demand Response in Ontario*, prepared for the Independent Electricity System Operator (2020), reporting the Texas administrative value and the Midcontinent market monitor's recommendation; Public Utility Commission of Texas, decision lowering the high system-wide offer cap from \$9,000 to \$5,000 per megawatt hour, effective January 1, 2022.

¹¹¹ Alberta Electric System Operator, *supra* note 110.

ratemaking has treated the customer's interest as the minimum cost of supply, even where that works against customers exposed to long interruptions. They found that regulators have given no signal that closing the gap between the value and the cost of electricity service is a legitimate objective, and they argued that investment in resilience should be evaluated against the economic losses it prevents, measured through customer damage functions.¹¹² The corridor is that argument applied at the scale of the federation.

The discipline of sections 3.2 and 3.3 survives that observation, and depends on it. Asymmetric risk is the reason to size the system for the hours when supply fails. The phase triggers, the off-ramps and the utilization thresholds are what govern how fast and how far that system is built, so that the argument for reliability does not become a warrant for open-ended construction. No forecaster can say what Ontario's peak demand will be on a summer afternoon in 2036, and an interconnected system does not need one to: a province that is short imports, and a province that is long exports. Interconnection is how a power system insures itself against the forecast it cannot make. Plan for the hours that hurt; build in stages that can be stopped.

The next step is the modelling exercise the blueprint proposes: a Canadian grid planning body, built for national-scale analysis, which no single province and no single study has the mandate to produce alone. Until that body exists, the aggregate case rests on the verified weight of its parts. That is a smaller claim than a headline number. It is also the only claim that survives checking, and someone will check.

3.6 Who pays, and on what principle

Cost allocation is where interprovincial infrastructure usually dies, and it dies for a reason that is easy to state. A line benefits a country and is paid for by a province. Manitoba Hydro put the problem to a House of Commons committee in 2017 more plainly than any policy paper has since. Manitoba's grid was already fully renewable and well connected to the United States, so a further half-billion or billion-dollar intertie to Saskatchewan did not bring Manitoba more value than it already had. Federal funding of Manitoba's portion of that line, the official added, would make it a much more viable project for Saskatchewan.¹¹³ Manitoba Hydro stated the cost-allocation problem nine years before this paper restated it as a general rule.

The principle that answers it is the federal spending power. Where a corridor's national benefit exceeds its host province's local benefit, Ottawa bridges the difference instead of asking that province's ratepayers to subsidize the rest of the country. The Trans-Canada Highway precedent set out in section 3.8 demonstrates the mechanism; it is not a novel intrusion into provincial finance and does not require a constitutional argument.¹¹⁴

Where a corridor's national benefit exceeds its host province's local benefit, Ottawa bridges the difference. That is the principle, and the federal spending power is its instrument.

British Columbia's agreement of July 2026 shows the cost of leaving that bargain unwritten. Having accepted that it could not stop a new oil pipeline, the province negotiated its terms instead: the North Coast tanker ban stays in place, and British Columbia receives an economic and revenue framework if the line proceeds. Compensation for the province that carries the risk

¹¹² José Daniel Lara and Jatin Nathwani, "Value of Electricity versus Cost: Resolving the Customer Benefit Dichotomy in Ratemaking" (2014) 27:6 *Electricity Journal* 86.

¹¹³ Van de Biezenbos, *supra* note 25, quoting testimony to the Standing Committee on Natural Resources reported in *Strategic Electricity Interties*, *supra* note 69.

¹¹⁴ Andrew Leach, "Constitutional Limits on the Design of Canadian Federal Climate Change Policy" (2026) 52:2 *Canadian Public Policy* 169.

was settled for one project, between first ministers. A designation order that states the cost-allocation principle settles the same bargain once, in advance, for every line it covers.¹¹⁵

Ottawa has named the template it means to borrow. *Powering Canada Strong* proposes building the corridor's cost-allocation mechanism on the European Union's Projects of Common Interest model, which co-finance cross-border transmission through the Connecting Europe Facility on a formula tied to each participant's share of the benefit rather than its share of the route.¹¹⁶

The PCI model comes with two decades of European operating experience. Its practical contribution is not only co-financing; it also supplies a method for settling the allocation formula once, instead of renegotiating who pays for every segment as a cross-border project is extended. That settlement discipline is what Canada will need when a corridor crosses several provincial rate bases and route jurisdictions.

The template now carries more weight than a policy reference. At the June 2026 Energy and Mines Ministers' Conference, ministers supported a federal, provincial and territorial framework on interties whose stated purpose includes developing a standard cost-allocation mechanism to guide and arbitrate costs among project participants, including the federal government.¹¹⁷ Ministers have therefore supported the framework in principle; the remaining step is to put the allocation rules in a designation order, where a regulator must apply them and a party can be held to them.

3.7 Four sources, four classes of beneficiary

A cost-allocation principle is not a funding plan. McPherson's blueprint names four sources, and each corresponds to a class of beneficiary, not to a level of government.¹¹⁸

The regulated rate base carries the share attributable to reliability, in both connected provinces, because customers in both of them gain from it. A stronger British Columbia to Alberta interconnection helps British Columbia manage increasingly variable seasonal water and helps Alberta ride through extreme weather in a wind-heavy future, and each provincial regulator can assess its own share against its own public interest test.

Bilateral agreements carry the share attributable to the users who gain most directly. Renewable developers facing long connection queues will co-finance access to high-quality resource areas, as they have in Australia and as Texas demonstrated by supporting \$6.9 billion of transmission to unlock competitive renewable energy zones. Large industrial loads will contribute where an expansion serves their operations directly, which is the practice in Alberta and in British Columbia's custom agreements with mining and liquefied natural gas projects.

¹¹⁵ Prime Minister of Canada, "Canada and British Columbia strike new cooperative prosperity partnership to build a stronger, more sustainable economy," news release (July 2, 2026); Andrew Kurjata, "North Coast oil tanker ban being upheld, Port of Vancouver expanding in multibillion-dollar B.C.-Ottawa deal," *CBC News* (July 2, 2026); "Alberta and Ottawa Advance West Coast Pipeline Partnership as B.C. Secures Tanker Ban Protection," *EnergyNow* (July 2026), on the economic and revenue framework. On British Columbia's acceptance that it could not stop the pipeline, see the Reuters report cited *supra* note 3.

¹¹⁶ Government of Canada, *Powering Canada Strong*, *supra* note 5; and see McMillan LLP, "Powering Up: Canada's New National Electricity Strategy," June 2026.

¹¹⁷ Natural Resources Canada, *supra* note 6, announcing the Federal-Provincial-Territorial Framework on Interties as supported by ministers at the 2026 Energy and Mines Ministers' Conference, to establish collaborative mechanisms for regional system planning and co-ordination and to develop the cost allocation mechanism described.

¹¹⁸ McPherson, *Powering the Federation*, *supra* note 92.

Congestion rents carry the share attributable to arbitrage. Revenues collected when a line reaches capacity and prices diverge across the seam would be directed into an interprovincial settlement and community benefit fund, which funds new infrastructure and shares benefit with the communities the corridor crosses. This is the source most often forgotten and the one that grows precisely when the corridor is most valuable.

Federal funding carries the national share, and it comes with conditions. Participation in minimum planning standards, data sharing, and engagement with the trading and coordination bodies Part 2 proposes are the conditions, and they are the conditions because they are what the country cannot obtain any other way.

Four sources, four classes of beneficiary, and no single ratepayer base asked to carry the whole. The allocation answers Manitoba Hydro's question, and a provincial regulator can apply it.

3.8 The same bargain, struck once already

Canada has built a national corridor on this financing model before. The *Trans-Canada Highway Act*, 1949 committed Ottawa to half the construction cost of a designated national route, with the provinces responsible for the remainder and for the construction itself. A 1956 amendment added a further 40 per cent federal contribution on one-tenth of each province's Trans-Canada mileage, and the federal ceiling moved from \$150 million to \$250 million in 1956, to \$350 million in 1959 and to \$400 million in 1960.¹¹⁹ Ottawa held no authority to build a highway across provincial land. Highways were, and remain, provincial. What Ottawa held was the spending power: build to a national standard, sign the agreement, and the cheque follows.

Every province took the offer within months except one. Quebec declined for a decade, judging the agreement an intrusion on provincial jurisdiction dressed as a construction grant. Ottawa did not force the issue. It funded the highway everywhere else and kept negotiating until Quebec signed on October 27, 1960. The National Energy Corridor Agreement, with Quebec participating on its own terms, begins from the same federal willingness to finance a national objective without taking provincial jurisdiction.

The friction did not stop when Quebec signed. British Columbia's premier boycotted the federal opening of the highway at Rogers Pass on September 3, 1962, in protest over the funding agreement, having held his own opening ceremony on the same highway five weeks earlier and having called the road British Columbia Highway 1.¹²⁰ A province that helped pay for a national corridor staged a rival opening and refused the national name. Federal-provincial friction is the normal condition of nation-building infrastructure. The highway was built anyway.

The analogy breaks down at the first technical step. The highway needed a construction standard: a common physical specification that allowed the road to join provincial roads. The corridor needs a trading layer, scheduling, settlement, clearing and price formation, because electricity cannot be stored at scale. A highway could be built before a national dispatch institution existed. An electricity corridor cannot produce value before those functions are operating at the instant of flow.

¹¹⁹ *An Act to Encourage and to Assist in the Construction of a Trans-Canada Highway*, assented to December 10, 1949; *Canada Year Book 1960* (Ottawa: Dominion Bureau of Statistics, 1960) at 829, setting out the route designation and construction standards required for a federal contribution, the 1956 amendment, and the movement of the ceiling.

¹²⁰ "Trans-Canada Highway," *The Canadian Encyclopedia*, recording that Premier W A C Bennett boycotted the federal opening of September 3, 1962 in protest over the funding agreement, that he had held an earlier official opening at the same location on July 30, 1962, and that he referred to the road as BC Highway 1. See also Parks Canada, "The Trans-Canada Highway," Glacier National Park, on the federal ceremony at Rogers Pass.

The second limit is political. Quebec's highway holdout was principally about constitutional principle and was resolved by money once the principle was respected. Quebec's electricity caution is about revenue and commercial advantage, including Hydro-Québec's export book. A province with a profitable set of long-term contracts may not be persuaded by money alone to place those contracts inside a new national trading arrangement.

The third limit is institutional. The highway required no post-construction coordination beyond maintaining a road to the agreed standard. The corridor requires perpetual institutional coordination, because every flow of electricity requires scheduling, settlement and dispatch at the instant it occurs. The highway's financing model transfers. Its institutional simplicity does not.

That is why rules before wires is a claim about where value resides. The highway's value was in the asphalt. The corridor's value is in the institutional framework, the clearinghouse, the contracts-for-differences framework, the published transfer-capability data, the dispute-resolution mandate and the risk allocation. The wire is the delivery mechanism for an asset that is institutional, not physical.

The distinction also explains why political momentum without institutional design produces Muskrat Falls rather than the highway. A national announcement and a federal cheque can overcome provincial friction; they cannot substitute for a trading layer, independent assessment and risk allocation. The highway is the precedent for financing through disagreement. Muskrat Falls is the warning against building through institutional vacancy.

3.9 What ten billion dollars did that a judgment could not

On August 17, 2026 the two provinces that had been arguing about Churchill Falls since 1969 signed a definitive agreement replacing both the original contract and the 2024 memorandum that preceded it. Newfoundland and Labrador Hydro, Hydro-Québec and Churchill Falls (Labrador) Corporation will upgrade and expand the existing station, develop Gull Island, build the associated transmission, and add a 2,000 megawatt onshore wind project in Labrador with Innu participation. The federal government committed \$10 billion in financing and investment support, including a loan guarantee for Gull Island and an equity stake of up to 40 per cent in the wind project, against a package the government puts at close to \$70 billion.¹²¹

Set that beside the 2018 judgment. Nothing in the division of powers changed between them. No court ordered the 1969 contract reopened and the Supreme Court had said plainly that none would. What changed is that a third government put capital on the table and made agreement worth more to both parties than holding out. The spending power did in one announcement what six decades of grievance and a trip to the Supreme Court of Canada could not.

Two qualifications keep that from proving more than it should. The agreement is bilateral, between parties with an existing physical connection and a fifty-seven year history, and it still took twenty months from the 2024 memorandum, a change of government in one province and an independent review to reach. A standing framework exists so that the next one does not

¹²¹ Prime Minister of Canada, "Prime Minister Carney announces the largest clean energy investment in North American history," news release, August 17, 2026; Government of Newfoundland and Labrador, Executive Council, "Newfoundland and Labrador Reaches Historic Deal with Government of Quebec and Government of Canada to Develop Churchill Falls and Gull Island," news release, August 17, 2026, recording that the province retains up to 2,350 megawatts against 1,990 megawatts under the 2024 memorandum, a guarantee that 85 per cent of person-hours in constructing Gull Island remain in the province with priority to qualified Labrador Innu, Canada's equity position of up to 40 per cent in the 2,000 megawatt wind project, and the referral of the projects to the Major Projects Office on conclusion of binding agreements.

require all of that. And the region has been here before. The warning in Part 2 about Muskrat Falls, where political momentum foreclosed an independent assessment of alternatives and the costs landed on ratepayers, applies to Gull Island with equal force. On the Labrador river system the guardrails in this Part are the difference between the two outcomes.

3.10 What Quebec's position is actually about

It would be a mistake to read Quebec's conditional participation as a rerun of 1960 with the names changed. The 1960 holdout was a constitutional argument. Quebec read federal conditional grants as an intrusion on provincial jurisdiction dressed as infrastructure funding, and it held out until the principle was respected, not until the money improved.

Quebec's caution in 2026 looks similar from a distance and is different up close. Hydro-Québec is one of the most successful exporters on the continent, its interties toward Atlantic Canada run near capacity, and it built that position through decades of long-term bilateral contracts with New York and New England. A shared national platform could complicate those contracts as easily as enhance them. A province holding the country's best export book has less obvious reason to trade that certainty for a seat at a table whose rules are still being written.

There is a newer reason that has nothing to do with 1960. Hydro-Québec has proposed roughly doubling the rate charged to large data centres, to an average of 13 cents a kilowatt hour, protecting headroom on its own system as demand accelerates across the continent.¹²² A province managing its own emerging capacity squeeze is a harder sell on sharing surplus nationally than a province defending constitutional turf. The answer to it is commercial, not constitutional, and the opt-in structure Part 1 describes is what makes a commercial answer possible.

Quebec's terms are on the record. It joined the National Energy Corridor Agreement only provisionally, on the jurisdictional condition recorded in the Introduction. It has answered the federal fast track with one of its own: in December 2025 its finance minister tabled Bill 5, to accelerate the authorizations required for priority projects of national scale under Quebec law, which the National Assembly's record shows had not been adopted.¹²³ The Churchill Falls framework announced in August 2026 remains to be ratified by March 2027, and Quebec's premier has said its future depends on the outcome of the province's general election.¹²⁴ A trading layer Quebec can join is one that leaves its jurisdiction and its utility's control intact.

3.11 The empty slot in Canada's own prospectus

In September 2026 the federal government convened global capital in Toronto and published a prospectus of investable projects: more than a hundred of them, across conventional energy, clean energy, minerals and metals, marine and port infrastructure, power and utilities, digital

¹²² Hydro-Québec, "A new rate for data centres and a rate adjustment for blockchains to reflect the value of renewable electricity," news release, February 19, 2026, proposing to the Régie de l'énergie a rate averaging 13 cents per kilowatt hour for data centres requiring more than 5 megawatts, approximately double the current large-power rate.

¹²³ Quebec, Bill 5, *Loi visant à accélérer l'octroi des autorisations requises pour la réalisation des projets prioritaires et d'envergure nationale*, 2nd Sess, 43rd Leg, 2025 (introduced December 9, 2025; reinstated in the 3rd Sess on May 6, 2026, after clause-by-clause study in the Committee on Public Finance; no record of adoption); Government of Quebec, "Le gouvernement agit pour accélérer la réalisation de projets prioritaires et d'envergure nationale," news release (December 9, 2025); "Québec veut s'arroger le pouvoir de modifier des lois pour favoriser des « projets d'envergure », " *Le Devoir* (December 9, 2025).

¹²⁴ Government of Newfoundland and Labrador, *supra* note 121; "L'avenir de l'entente sur Churchill Falls dépendra du résultat des élections, dit Fréchette," *Le Devoir* (August 2026), reporting that the parties have until March 2027 to ratify the framework.

technology, advanced manufacturing and transportation.¹²⁵ It is the most complete public statement Canada has made about what it believes it has to sell.

Eleven weeks earlier the same government had named five interties as priorities for financial and regulatory support. One of the five appears in the prospectus. The Prince Edward Island to New Brunswick expansion is there, carried by a provincial department. The Alberta to Saskatchewan upgrade is not. Neither is the Alberta to British Columbia restoration, nor the British Columbia to Yukon connection, nor the Saskatchewan to Manitoba expansion, which at up to two gigawatts is the largest of the five.

The transmission projects that did appear share one feature. Newfoundland and Labrador Hydro put forward a 735 kilovolt line from Churchill Falls to Labrador West at roughly \$2.5 billion, inside its own province. The Inuit-led Kivalliq Hydro-Fibre Link, a 1,200 kilometre corridor carrying up to 150 megawatts of hydroelectricity and fibre to Nunavut, appears at \$3.4 billion with a single dedicated corporation behind it. A private developer proposed two high-voltage direct current corridors linking Atlantic Canada to Quebec as part of a larger wind platform. Prince Edward Island's expansion has a provincial government standing behind it.¹²⁶ Every transmission entry in the book has one owner.

The four that are missing are the lines that join two separately owned provincial systems.

The pattern is neither a coincidence nor a failure of promotion. An investment prospectus asks three things of every entry: who the proponent is, what the capital cost is, and what the financing objective is. An intertie between two Crown utilities in two provinces has no single proponent, no agreed cost allocation, and therefore no revenue model. It cannot answer any of the three questions, so it cannot be put in front of an investor at all, no matter how much capital is sitting in the room looking for somewhere to go.

The capital was in the room. The interties were not. The distance between those two facts is what this Part is about, and it is not a funding gap.

3.12 What this Part asks for

None of this requires a second sovereign fund, a new Crown corporation, or a new tax. It requires the Canada Infrastructure Bank, the Department of Finance, the Canada Strong Fund's transition office and the provincial energy ministries to agree, in writing and in advance, how the five guardrails apply to the first tranche of priority projects, and to write the answer into the designation order where it binds. The same order should say how benefits are measured: across the full benefit set, including avoided unserved energy, rather than on trade margin, because a methodology that prices reliability at zero will always find the corridor uneconomic. Written in advance, the allocation also settles what British Columbia had to negotiate for a single pipeline in 2026: what a host province receives for the risk it carries.

That is a document, not a program. It can be drafted in a season. Until it exists, the pension and sovereign capital already circling this opportunity will keep circling, because the one thing long-dated capital will not underwrite is a risk allocation that has not been decided yet.

¹²⁵ Canada Investment Summit Prospectus, *supra* note 64.

¹²⁶ *Ibid*, Power and Utilities.

Part 4: Consent as Business, Not Only as Law

Part 1 placed Indigenous governments inside the constitutional analysis, not beside it. This Part makes the commercial case, which is separate, and which points the same way. The two arguments are usually run together and they should not be. One is about obligation. The other is about whether the corridor gets built at all.

4.1 What the transmission record actually shows

The defensible claim is a narrow one. In the recent Canadian transmission projects where Indigenous equity was structured in at the outset, the projects have proceeded. The litigation record in Canadian resource development runs the other way, and it runs that way most reliably where consent was treated as a permitting step and not as an ownership question.

The precedents that matter here are transmission precedents, not borrowed pipeline ones, because transmission has its own history and a shorter one. AltaLink's joint venture with the Piikani First Nation gave the Piikani an ownership stake in the transmission lines crossing their reserve. Seven First Nations and Métis communities together hold a 40 per cent stake in a major line running from Fort McMurray toward Edmonton.¹²⁷ Neither arrangement was a settlement negotiated after opposition. Both gave the communities along the route ownership of the line itself.

Hydro-Québec and the Mohawk Council of Kahnawà:ke hold a partnership in the 540 kilometre line expected to carry 1,250 megawatts toward New York. The Council has the right to become at least a 10 per cent partner, with an option to increase over time, and to earn dividends on that investment. It is Hydro-Québec's first shared ownership of transmission infrastructure with a First Nation.¹²⁸ A utility with the most successful export book in the country reached for a partnership on the line that carries it. The utility was judging what makes a line get built and stay built, and philanthropy had nothing to do with it.

The new federal instruments sharpen the point. The *Building Canada Act* requires a province's written consent before a project within exclusive provincial jurisdiction is listed, and it contains no equivalent requirement for Indigenous governments. British Columbia's First Nations Leadership Council called for the Act's withdrawal, and the Union of British Columbia Indian Chiefs has asked that no pipeline be listed without free, prior and informed consent.¹²⁹ Nine First Nations in Ontario have gone to court, asking the Ontario Superior Court of Justice to declare the Act's listing power unconstitutional and to enjoin its use.¹³⁰ In the North, the federal government has made the first listings it initiated contingent on the projects completing their

¹²⁷ Van de Biezenbos, *supra* note 25 at 657.

¹²⁸ Hydro-Québec, "Mohawk Council of Kahnawà:ke and Hydro-Québec sign Hertel-New York line agreements," news release, April 18, 2024, as reported in McPherson, *supra* note 92.

¹²⁹ Canadian Environmental Law Association, letter on the *Building Canada Act* (August 2025), noting that the Act requires provincial consent and contains no equivalent requirement of consent from Indigenous communities; First Nations Leadership Council, "Bill C-5: Overview and Discussion," communiqué (June 27, 2025); Union of British Columbia Indian Chiefs, Resolution 2026-34, "Opposition to Oil Pipeline Proposals to the Pacific Coast" (2026).

¹³⁰ "Nine First Nations in Ontario launch constitutional challenge against Bill 5 and Bill C-5," *Globe and Mail* (July 2025); and "9 Ontario First Nations ask for injunction against Bill 5, say law represents 'clear and present danger'," *CBC News* (July 2025), describing the application in the Ontario Superior Court of Justice, which seeks an injunction prohibiting the federal government from naming national interest projects under the *Building Canada Act*.

treaty-based impact assessments, deferring to the co-management regimes of modern treaties.¹³¹ Where a corridor crosses treaty and title lands, durability comes from equity and co-decision at the outset, and a consultation compressed at the end supplies neither.

4.2 A floor that the market cleared at double

The most instructive precedent in the country is a number that nobody predicted. When BC Hydro set a 25 per cent First Nations equity minimum in its 2024 call for power, eight of the nine selected wind projects exceeded the minimum. They came in at 51 per cent Indigenous ownership, supported by the Canada Infrastructure Bank's Indigenous Community Infrastructure Initiative and British Columbia's First Nations Equity Financing Framework.¹³²

Given a floor, the market cleared at roughly double it. The result inverts the assumption underneath most Canadian consultation practice. The assumption is that Indigenous ownership is a cost a proponent absorbs to obtain social licence, and that the regulator's job is to set the minimum a proponent can bear. British Columbia set the minimum, and the proponents went past it because a partner with a stake is worth more to a project than a consultee with a grievance.

A market that clears at double the floor is telling the regulator the floor was set too low.

4.3 Indigenous-led operation is not hypothetical

A standing objection to equity models says communities can hold shares but not run infrastructure of national significance. An operating counterexample answers the objection. The Arctic Gateway Group is owned through OneNorth by a partnership of 29 First Nations and 12 northern Manitoba communities. It owns and operates the Hudson Bay Railway, the Churchill Marine Tank Farm, and the Port of Churchill, which is Canada's only deep-water Arctic port connected to the North American Class 1 rail network.¹³³ An Indigenous and community-owned company operates the country's northern trade gateway. The question of capacity has been answered in the only way that counts: by operation.

One risk on the other side of the ledger belongs here, because it bears on every route a corridor could take. Aboriginal title, where established, carries the right to exclusive use and occupation of the land, and title claims across much of the country remain unresolved.¹³⁴ A transmission right of way is a long-lived interest in land, and it is no more secure than the title question underneath it. A right of way negotiated with a community holding an equity position in the line is a different legal object from one imposed over an unresolved claim. The title risk is another reason to structure ownership at the outset instead of treating consent as a permitting step.

¹³¹ Government of Canada, "Canada Initiates Process to List Major Projects under the *Building Canada Act*," news release (June 24, 2026); Major Projects Office, "Mackenzie Valley Highway" (Ottawa: Privy Council Office, 2026), recording the *Canada Gazette* notice of August 28, 2026. See also Wright and Olszynski, *supra* note 35, Part I, concluding that the Act does not and constitutionally cannot oust the assessment regimes established under modern treaties.

¹³² BC Hydro 2024 call for power, as reported in McPherson, *supra* note 92. Eight of the nine selected wind projects exceeded the 25 per cent minimum at 51 per cent Indigenous ownership. On the loan guarantee envelope see Natural Resources Canada, *supra* note 6.

¹³³ Arctic Gateway Group, "About Us," arcticgateway.com; Prairies Economic Development Canada, "Government of Canada launches market sounding study to strengthen growth at the Port of Churchill," news release, February 19, 2026.

¹³⁴ *Tsilhqot'in Nation v British Columbia*, 2014 SCC 44.

4.4 The condition nobody states

A condition undercuts all of this, and it takes the argument straight back to Part 2. Equity in a transmission line is worth holding only if the line is used and earns revenue.

Where there are no common rules, no consistent enforcement, and no transparent market, a community taking an ownership position assumes risks it has no instrument to manage. Capacity can be captured by a single counterparty. An intertie can lose its capacity, as every Alberta intertie did for about ten days in September 2025, with no forum in which to argue about it. The converter outage described in Part 2 can leave a line without revenue, with no contractual consequence to anyone.

A community that took equity in a line running through that year earned nothing from it and had nowhere to go. Indigenous equity depends on the trading layer exactly as pension and sovereign capital does, and for exactly the same reason. Offering a community a share of an asset that cannot reliably earn transfers a risk that the utility understands to a partner who has not been told about it.

If the corridor's value resides in the institutional framework rather than the physical wire, then equity in the corridor is equity in that institutional framework. A community offered a share of the wire alone is offered a share of a delivery mechanism. A community offered a share of the wire plus a seat at the table where the trading rules are written is offered a share of the asset that produces the return.

This is the sequencing point the rest of the paper has been making, arriving from a different direction. Fix the commercial arrangements, and every ownership position in the corridor becomes worth more. Leave them unfixed, and the equity offer is a promise secured against nothing.

4.5 What this Part asks for

Two things, and both use instruments that already exist.

Build Indigenous leadership into the designation process as a co-decision maker, not as a consultee informed once the route is fixed. The instrument is the designation order, which can specify considerations beyond those the certificate provisions already require.¹³⁵ Nothing further has to be enacted. The order has to be written. The *Building Canada Act* requires a province's written consent for a project within exclusive provincial jurisdiction and says nothing equivalent for Indigenous governments. The designation order can close that gap for the corridor by making the agreement of the Indigenous governments whose lands a designated line crosses a condition of designation.

Treat Indigenous equity as a preferred, and not merely permitted, form of the private capital the five guardrails exist to attract, and set the floor where the British Columbia evidence suggests the market will clear, not where a proponent says it can just bear. The financing tools to support it are in place, at the Canada Infrastructure Bank and in at least one provincial framework, and they have been used.

Both recommendations rest on one finding, which the transmission record supports and the litigation record confirms from the other side. Consent secured early costs less, in money and in years, than consent litigated late.

¹³⁵ *Canadian Energy Regulator Act*, *supra* note 27, ss 261(1)(b) and 262.

Limitations and Open Questions

The argument is deliberately narrower than a typical project prospectus. The following limitations are acknowledged because they define what the paper can responsibly claim; none is fatal because the recommendation is staged, cooperative and designed to make the missing information answerable before capital is committed.

Converter cost. A preliminary estimate of approximately \$1 billion is now public for the end-of-life replacement of the converter at the Alberta-Saskatchewan seam, the largest single capital cost in the proposal, for a replacement adding roughly 250 megawatts of trade capacity. That figure is an order-of-magnitude estimate offered by the owner, not a costed design, and it prices a replacement its owner is pursuing in any event. What remains unpriced is the incremental cost of building the seam to the scale a trading framework would justify, which is why the first phase still prices the converter before route, scale or financing is fixed.

Screening method. The peer-reviewed benefit-to-cost ratios are 0.21 and 0.46 on production cost alone, and 3.69 and 4.08 across the full benefit set. The corridor does not pay for itself as cheaper power, and the argument is reliability, resource adequacy and adaptation. Both figures are stated and neither is hidden, because the gap between them is the evidence that screening transmission on production cost alone understates it.

Model assumptions. As Part 2 records, the modelling rests on the proposed Clean Electricity Regulations and prices interprovincial trade at zero. The model is bounded evidence about the value of interconnection, not a substitute for final regulations or a whole-corridor investment decision; the rules-before-wires sequence leaves room to update it.

Simultaneous deficiency. Building transfer capability between systems that are simultaneously resource-deficient does not improve energy adequacy. The corridor is justified by geographic diversity and resource adequacy across different stress conditions, not by connecting two systems that fail together; phase triggers and the trading layer are designed to test whether surplus exists to move.

Whole-corridor modelling. A rigorous whole-corridor cost-benefit model does not exist in public. No invented aggregate claim is made; it proceeds from verified pair studies, staged development and a planning body that no single province can produce alone. The claim is smaller, and it is the only defensible one.

Section 92A(2). Whether a province may prefer itself in price or supply has never been decided. The uncertainty is real, but the proposed trading layer does not ask the proviso to do work it cannot do; it uses cooperative enactments, minimum non-discrimination standards and a regulator mandate to address the open question without assuming a judicial answer.

Annex 22-C. The negotiations on extending CUSMA state-owned-enterprise disciplines to sub-central enterprises have produced no published outcome. The present exposure is narrower and can be managed by designing the interprovincial trading layer to be non-discriminatory from the start; the negotiations remain a review item and no reason to leave the corridor institutionally vacant.

Retail investment product. The retail investment product contemplated for the Canada Strong Fund remains subject to consultation and is not settled. The financing architecture does not depend on that product; pension capital, the sovereign fund, federal spending and beneficiary rate bases can be structured without it.

Federal fast-track instruments. The *Building Canada Act* had been used once when this paper was finalized, to list a pipeline and not a power line; Bill C-39 remains before Parliament and may change; and the relationship between a listing and the Regulator's own process has not

been tested. The recommendations stand without either instrument: the designation power in section 261 carries them on its own, and the fast-track statutes are treated here as accelerants.

Political contingency and press sources. Quebec's participation and the Churchill Falls framework are subject to decisions that follow Quebec's 2026 general election. Several facts about the West Coast Oil Pipeline process, including the adequacy of consultation, rest on press reporting, which the notes identify as such.

Structural-boundary and proportionality analysis. The three-component test and the subject-matter proportionality analysis developed in Appendix II are inferences from existing jurisprudence, not formulations adopted directly by a court. A court applying them for the first time could reach a different formulation, even if it accepted the underlying division between structural and jurisdictional boundaries.

Part 5: An Institutional Vacancy, Not a Constitutional One

Canada already has the constitutional settlement this grid needs. What remains is to use it, in the order a federation permits.

The authority exists. Section 92A protects a province's generating stations, and the Supreme Court has said the paragraph was written to protect them from being swallowed by an interprovincial connection. Section 92(10)(a) reaches the line, and Parliament has had machinery to reach it since 1990, rebuilt in 2019 with a 300 day clock, which Bill C-39 would shorten, and a power to attach conditions by order. The functional integration cases mean that permitting the line does not federalize the systems at either end. A province that signs on keeps everything it has. The fast-track statutes Parliament has added since 2025 accelerate every federal step and stop, by their own terms, at the provincial boundary. They make the designation more valuable to use, and they leave the trading rules to be agreed.

What is missing is the market, and the market cannot be legislated. The general branch of the trade and commerce power will not carry a national platform for a single commodity, and a federal statute that displaced working provincial arrangements would meet the objection that sank federal securities legislation in 2011. The trading layer has to be agreed, on the cooperative template the Court upheld in 2018, beginning with a clearinghouse rather than an exchange and with reserve sharing rather than restructuring.

The capital exists too. A sovereign fund, the Maple Eight pension funds, allied sovereign capital and the federal spending power are all available. What has never been written down is who carries which risk, and long-dated capital will not underwrite a risk allocation that has not been decided.

5.1 The record is older than the debate

The argument this paper makes is not new, and the paper ends on how old it is.

In December 1980 the premier of Saskatchewan told a committee of Parliament that his province wanted the resources amendment so that it could continue to do with certainty what it was already doing with great uncertainty, and that it accepted unqualified federal paramountcy over interprovincial trade in those resources. One month earlier, in November 1980, the Newfoundland bar told the same committee that federal authority over interprovincial electricity transfers already existed and that the problem was the absence of any mechanism to compel Ottawa to use it. It asked for a regime for power corridors modelled on what already existed for pipelines.

The next year the question reached the Supreme Court. In *Fulton*, decided in 1981, the Court considered the Alberta to British Columbia intertie, a line whose stated purposes were capacity reserve, emergency assistance and reliability support, and held that the province could regulate it only because Parliament had not legislated. The Attorney General of Canada appeared to support that result. A senior energy lawyer made the case for federal action again in 2009, and a former chief executive of the Ontario Power Authority in 2010.

The mechanism the Newfoundland submission asked for has been on the statute book since 1990, and since 2019 in sections 261 and 262 of the *Canadian Energy Regulator Act*, and it is still waiting for a government to sign.

5.2 What is actually being asked

The ten steps at the front are the sequence, and the recommendations that close each Part are the substance. The argument in between supports each of them.

No constitutional amendment. No reference case. No province asked to surrender anything section 92A gives it.

Canada has spent forty years describing an east-west grid as a problem of jurisdiction, while the jurisdiction sat in the Constitution from 1867 and in the statute book from 1990. The year the McNeill converter was out exposed a country unable to say who was responsible when its only interconnection seam failed. That is an institutional vacancy, not a constitutional failure, and vacancies are filled by decision.

The authority has been there all along. What has been missing is the signature.

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Appendix I: Illustrative Designation Order under Sections 261 and 262 of the *Canadian Energy Regulator Act*

Illustrative only. This skeleton is not a recommendation and is not intended to prescribe the terms of any future order. The numerical thresholds are drawn from published practice rather than invented for the purpose: the utilization trigger sits above the level at which western and central interties have run since 2022 and below the 90 to 100 per cent at which the Quebec to Atlantic interties run in their dominant direction; the revenue floor and cap follow the regime Great Britain applies to electricity interconnectors, under which the floor is calibrated to the cost of debt and is forfeited in any year the availability standard is missed; and the 50 basis point holdback matches the order of magnitude of the return added the Federal Energy Regulatory Commission applies to transmission participation. The figures differ from the worked illustration in section 3.3, which uses a single pair over a shorter horizon; both are illustrations, and a regulator would set the values on the evidence.

Illustrative Order

Whereas paragraph 261(1)(a) of the *Canadian Energy Regulator Act* authorizes the Governor in Council to designate an interprovincial power line as one to be constructed and operated under a certificate;

Whereas paragraph 261(1)(b) of that Act authorizes the Governor in Council to specify the considerations that the Commission must apply in deciding whether to issue the certificate;

Whereas the Government of Canada considers that a staged, cooperative approach to an interprovincial power line should preserve provincial jurisdiction over generation, provide for meaningful Indigenous participation and allocate risk before capital is committed;

Therefore, the Governor in Council, on the recommendation of the Minister of Energy and Natural Resources, pursuant to section 261 of that Act, makes the following Order:

1. Designation

1.1 The Prairie Priority Interprovincial Power Line Corridor, being the Saskatchewan to Manitoba transmission expansion along the Regina to Winnipeg corridor together with the associated works at the Alberta and Saskatchewan seam (together, the “Corridor”) are each designated under paragraph 261(1)(a) of the Act as an interprovincial power line to be constructed and operated under a certificate.

1.2 The designation includes the associated converter stations, control facilities and other works necessary to transmit electricity between the connected provinces, but does not designate any provincial generating station or alter the ownership, operation or regulation of generation.

2. Considerations specified under paragraph 261(1)(b)

2.1 In deciding whether to issue a certificate for the Corridor and in recommending terms and conditions, the Commission shall apply the following considerations in addition to the matters required by section 262 of the Act.

(a) Cost Allocation. Costs shall be allocated between the connected provinces in proportion to the modelled benefits attributable to each province, using the best available reliability, adequacy, resilience and commercial evidence, including avoided unserved energy, and identifying separately any national benefit that is not captured by a provincial rate base. The federal contribution may bridge the difference between national benefit and local host-province

benefit so that a host province is not required to subsidize benefits received elsewhere. The allocation shall be stated before construction financing is closed and shall be reviewable only on the published evidence and method specified in the certificate.

(b) Indigenous Participation. The route-planning process shall require Indigenous leadership as co-decision makers, not merely as consultees after the route has been fixed. The certificate shall establish a minimum Indigenous equity floor at a level consistent with available market evidence and shall identify the financing support needed to make that floor investable. In applying this consideration, the Commission shall continue to weigh Indigenous interests and concerns, current use of lands and resources, and the effects of the Corridor on rights recognized and affirmed by section 35 of the *Constitution Act, 1982*. This Order shall not be read to limit the duty to consult and, where required, accommodate. The designation of any segment of the Corridor that crosses the lands of an Indigenous government has effect only upon that government's written agreement.

(c) Phase Triggers and Off-Ramps. The Corridor shall proceed in phases. A subsequent phase shall not proceed unless scheduled interprovincial transfers over the preceding phase have achieved an average capacity factor of 60 per cent sustained for four consecutive quarters. The joint administrator established under the cooperative trading compact shall determine whether the utilization trigger has been met and shall publish the data, method and determination. The Regulator shall arbitrate a dispute concerning the determination. If a trigger is not met within the period stated in the certificate, the next phase shall not proceed, capital committed solely to that phase shall be released, and the project shall continue at its existing scale unless the parties agree to a new application supported by updated evidence.

(d) Revenue Floor. For the first 25 years after commercial operation, the Corridor shall have a revenue floor equal to the amount required in each year to service the debt-financed portion of the efficient capital costs certified by the Commission, including a reasonable debt service cover ratio, and a corresponding cap above which revenues are shared with the beneficiary rate bases. Revenues shall be assessed against the floor and the cap annually, and the floor shall not be payable in any year in which the Corridor fails to meet the minimum availability standard set in the certificate. The floor shall be funded by the beneficiary rate bases in proportion to the modelled benefits allocated to them, and not by the host province alone. Every drawdown, the amount, the beneficiary share and the remaining commitment shall be published quarterly.

(e) Milestone-Tied Return. The allowed return on construction capital shall be calculated on the basis approved by the Commission, with 50 basis points of the allowed return held back until certified in-service milestones are achieved. The held-back return shall be released against certification of: (i) energization of the relevant converter or line segment; (ii) confirmation of the approved path-rating increase; and (iii) commercial operation in accordance with the approved schedule. A missed milestone shall forfeit the corresponding held-back amount unless the Commission determines that the delay arose from an event allocated to another risk bearer under the certificate.

(f) Contract Review. Every long-dated contract supporting the Corridor shall state a price formula, a scheduled review date and an indexation mechanism at the outset. The contract shall identify the events or data that activate the review and the consequences of applying the formula. A dispute about the formula, review or indexation shall be referred to the Regulator for arbitration under the procedure specified in the certificate. No party shall rely on a court or a later political negotiation to supply a review that the contract does not contain.

(g) Ownership. The certificate shall be held by an entity distinct from the provincial utilities of the connected provinces, in which the Indigenous governments whose lands the Corridor crosses may hold equity on the terms set under paragraph (b).

3. Provincial jurisdiction over generation

3.1 Nothing in this Order, the designation of the Corridor or a certificate issued in respect of it limits the authority of a provincial legislature under paragraph 92A(1)(c) of the *Constitution Act, 1867* over the development, conservation and management of sites and facilities in the province for the generation and production of electrical energy. The Commission shall construe and apply the certificate consistently with that reservation.

4. Statutory clock

4.1 The Commission shall conduct the certificate process within the period established by the Lead Commissioner, which shall not exceed 300 days after the application is complete, subject only to periods excluded or extensions permitted by the Act. Every excluded period and extension shall be published with the reason for it.

4.2 Following the Commission's decision, the Governor in Council shall approve or refuse the certificate within the 90-day period provided by the Act. If approval is given, the certificate shall issue within the period specified by the Act. The responsible departments shall publish the date on which each period begins and ends.

5. Publication and review

5.1 The Commission, the designated coordination body and each beneficiary rate base shall publish the data, determinations, drawdowns, milestone certifications and dispute outcomes required by this Order and the certificate. Nothing in this clause prevents the protection of confidential information where the Act requires it, but any protected information shall be described sufficiently to permit public understanding of the decision.

6. Coming into force

6.1 This Order comes into force on the day on which it is made.

Appendix II: Structural Boundaries and Subject-Matter Proportionality

This appendix sets out two pieces of analysis that support Part 1 and that a government drafting the designation order and the model statute would need: a test for when the boundary between two provincial electricity systems is structural, and the allocation of the trading layer's functions between federal and provincial subjects. Both are inferences from the jurisprudence, not formulations a court has adopted, as the limitations note.

A. Structural boundaries

The clearinghouse must bridge structural boundaries, not merely jurisdictional ones. At the transaction level, a boundary is structural when three conditions are met. First, there is protocol incompatibility: the two systems use different scheduling, settlement, pricing or dispatch protocols that cannot interoperate without mediation. Second, the incompatibility stems from law or institutional design, not commercial choice. Alberta's energy-only market and Ontario's hybrid market are products of provincial legislation, not private-sector preferences. Third, the mediation required is continuous and operationally embedded. A one-time contractual arrangement will not do, because electricity's non-storability means the protocols must be reconciled at or before every instant of flow.

All three conditions are met between Canadian provincial electricity systems. Alberta, Ontario, Quebec and the vertically integrated provinces operate under different legislative and regulatory frameworks, producing incompatible market protocols. That incompatibility was created by provincial law. Reconciling it requires continuous institutional mediation, scheduling, settlement, clearing and transfer-capability publication at every transaction; no one-time bridge will do. The clearinghouse therefore performs structural bridging: it manages boundaries that would otherwise prevent any transaction from occurring.

The classification is not static, because provincial protocols will evolve. Under the arrangement recommended here, each province enacts the model trading statute as an overlay on its existing market design: Alberta keeps its energy-only market, Ontario its hybrid, Quebec its regulated tariffs. The boundary stays structural for any pair whose domestic protocols still need mediation and becomes jurisdictional for pairs whose protocols have become compatible. Full convergence of market designs, which no province has been asked to accept, would leave the clearinghouse with efficiency netting alone, and it describes the end state the cooperative model deliberately does not require. The likeliest trajectory is partial harmonization, in which some provinces converge, others do not, and a province that has converged may temporarily diverge. The classification is therefore specific to each transaction and changes over time, and the designation order should say so: the clearinghouse must be able to perform structural bridging and efficiency netting at the same time, because the federation will never arrive at a uniform state.

B. Subject-matter proportionality

The features of the 2018 architecture described in section 1.8 produce a proportionality constraint, but it is subject-matter proportionality, not volume proportionality. The Court's architecture does not require federal governance authority to be proportionate to the federal share of transactions by volume. It requires federal governance authority to be confined to federal subjects, the interprovincial transactions, the systemic clearing function and the publication of transfer-capability data, while provincial subjects remain with provincial legislatures. Subject matter is the correct constitutional measure. The cooperative model

distributes governance by subject matter, tracking the division of powers, and not by transaction volume, which would require an empirical threshold the jurisprudence has never supplied.

The joint governing body, whether the council of energy ministers or the joint administrator, must therefore keep separate decision-making tracks that follow the division of powers, and each function of the trading layer can be placed on one of them. Dispatch, the real-time direction of generation to meet load, is securely provincial under section 92A(1)(c), and so are domestic price formation and open access on provincial systems under section 92(13). Open access on the designated line is federal under section 92(10)(a), because the line is a federal work. Scheduling and settlement are split: the decision to export or import, and bilateral contracts between provincial parties, are provincial under sections 92(13) and 92A(2), while coordinating schedules across the boundary and centralized clearing of interprovincial transactions rest on the interprovincial branch of section 91(2) and the works and undertakings power. Transfer capability is split in the same way: calculating it on a provincial system is provincial, and requiring that it be published to the clearinghouse is a condition of the interprovincial rules. The seam price emerges from the bilateral contracts and the clearinghouse under interprovincial rules, and no province is asked to adopt a common clearing price. A governing body that used federal-subject authority to reach provincial-subject decisions, or required provincial consent for genuinely interprovincial matters, would fail the subject-matter proportionality constraint. A government drafting the designation order and the model statute can use this allocation as its checklist.

This design prescription is what makes the cooperative model constitutionally durable. Each participating statute, federal and provincial, is validated by its own head of power. The clearinghouse operates under both. No single statute needs to carry the entire institution, and no court needs to determine what proportion of the clearinghouse's activity is 'federal enough' to sustain a unilateral federal statute. The volume-threshold question, what proportion of structural bridging sustains a system-wide infrastructure classification, does not arise, because the cooperative model does not require classifying the clearinghouse as a whole under a single head of power.

Two challenges could test the architecture. A province whose protocols have largely converged, or a small province that temporarily diverges, could argue that the clearinghouse's structural-bridging function has fallen below what federal jurisdiction requires. Neither argument is fatal. A pith and substance challenge targets the federal statute and not the institution, and a federal statute drafted narrowly to cover interprovincial transactions, systemic clearing and transfer-capability publication stands on its own head of power whatever the clearinghouse's operating mix at a given moment.

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A Note on Method

The authors used five artificial intelligence tools in preparing this paper: Claude (Anthropic), CoCounsel (Thomson Reuters Westlaw), Harvey AI, Microsoft Copilot and Grammarly. Under the authors' direction, the tools were used to locate and summarize sources, to draft and revise text, to test the argument against anticipated objections, to check citations and cross-references, to check grammar and style, and to format the manuscript. The research questions, the argument, the recommendations and the choice of authorities are the authors' own. The authors checked cited authorities against the original sources wherever those sources were available, and the notes identify the facts that rest on press reporting. The authors take full responsibility for the accuracy, originality and integrity of the paper, including content produced with the assistance of these tools. No artificial intelligence tool is an author of this paper.