ENERGY REGULATION QUARTERLY

VOLUME 13, ISSUE 2 2025

CONTRIBUTORS 2025

Nigel Bankes, LLM, Emeritus Professor of Law at the University of Calgary

Sam Brothwell, BSc, Vice President of Strategic and Financial Advisory, MCR Performance Solutions

Daliana Coban, BA, JD, Counsel, Torys, Toronto

Paul Daly, LLM, PhD, Professor, Chair in Administrative Law and Governance, University of Ottawa, Ottawa

Carl R. Danner, BA Econ and Political Science, MPP, PhD

Daniel Gralnick, JD, LLL, Senior Associate, Troys LLP

Mark Kolesar, BA, MBA, Emeritus Chair of the Alberta Utilities Commission

Joe McKinnon, BA, MA, Electricity Canada

David Morton, BSc, PEng., former Chair and CEO, British Columbia Utilities Commission

Martin Olszynski, BSc, LLB, LLM, Associate Professor and Chair in Energy, Resources and Sustainability, Faculty of Law, University of Calgary

Philip Quadrini, BA Econ, MBA, Senior Regulatory Analyst, Pacific Gas and Electric Company

Edgardo Sepulveda, BA, MA, Consultant, Sepulveda Consulting

Ian Thomson, BSc, BA, MPP, JD, Incoming Associate, Torys

MISSION STATEMENT

The mission of Energy Regulation Quarterly (ERQ) is to provide a forum for debate and discussion on issues surrounding the regulated energy industries in Canada, including decisions of regulatory tribunals, related legislative and policy actions and initiatives and actions by regulated companies and stakeholders. The role of the ERQ is to provide analysis and context that go beyond day-to-day developments. It strives to be balanced in its treatment of issues.

Authors are drawn from a roster of individuals with diverse backgrounds who are acknowledged leaders in the field of energy regulation. Other authors are invited by the managing editors to submit contributions from time to time.

EDITORIAL POLICY

The ERQ is published online by the Canadian Gas Association (CGA) to create a better understanding of energy regulatory issues and trends in Canada.

The managing editors will work with CGA in the identification of themes and topics for each issue. They will author editorial opinions, select contributors, and edit contributions to ensure consistency of style and quality. The managing editors have exclusive responsibility for selecting items for publication.

The ERQ will maintain a "roster" of contributors and supporters who have been invited by the managing editors to lend their names and their contributions to the publication. Individuals on the roster may be invited by the managing editors to author articles on particular topics or they may propose contributions at their own initiative. Other individuals may also be invited by the managing editors to author articles on particular topics.

The substantive content of individual articles is the sole responsibility of the respective contributors. Where contributors have represented or otherwise been associated with parties to a case that is the subject of their contribution to ERQ, notification to that effect will be included in a footnote.

In addition to the regular quarterly publication of Issues of ERQ, comments or links to current developments may be posted to the website from time to time, particularly where timeliness is a consideration.

The ERQ invites readers to offer commentary on published articles and invites contributors to offer rebuttals where appropriate. Commentaries and rebuttals will be posted on the ERQ website (www.energyregulationquarterly.ca).

ENERGY REGULATION QUARTERLY

TABLE OF CONTENTS

EDITORIAL

Managing Co-Editors

*Karen J. Taylor and Moin A. Yahya**

This is our first edition as managing co-editors of *Energy Regulation Quarterly* ("*ERQ*"). We would like to thank the Canadian Gas Association ("CGA") for trusting us to build on the already established reputation of this important journal and continuing its excellent scholarship — exploring matters relating to energy regulation, economics, and the interplay between law and policy.

We would also like to thank Rowland Harrison for his leadership and guidance, not only over our transition period, but for his years curating content from a broad group of supportive contributors, making *ERQ* a must-read journal for those interested in the energy regulation space. Rowland leaves a significant legacy, and we have, in short, large shoes to fill.

The global macro economic and political conditions, so dominant in the 2024 Year in Review in the first *ERQ* issue for 2025 continued unabated in the months leading up to the publication of this second issue. The trade and economic policies of the Trump Administration in the U.S.,[1] have upended Canada's historical trading and economic relationships with the U.S., with Prime Minister Carney stating that Canada's old relationship with the United States "based on deepening integration of our economies and tight security and military cooperation, is over."[2]

Canada is not alone in this regard — actions by the Trump Administration threaten to end the multi-lateral global trading regime in place since the end of the second world war, jeopardizing the status of the U.S. dollar as the world's reserve currency,[3] and potentially ending the role of U.S. treasury bonds as the go-to asset class during times of turmoil, as the U.S. may no longer be viewed as a reliable partner.[4] Public musings by President Trump about firing the Chair of the U.S. Federal Reserve,[5] undermining the Federal Reserve's vaunted independence and political neutrality, have resulted in additional financial market volatility.

President Trump's Liberation Day[6] tariffs prompted former U.S. Treasury Secretary Janet Yellen to declare "this is the worst

---

* Karen J. Taylor is an independent energy consultant, with deep experience in capital markets, regulatory policy and infrastructure investing. She is Vice Chair of the Council for Clean & Reliable Energy, a non-profit organization that provides a platform for public dialogue and analysis on subjects related to energy policy and governance. She also served as the Executive Advisor to the Chair of the Ontario Energy Board and was a Member of the Ontario Energy Board.

Moin A. Yahya is a professor of law at the University of Alberta. He was a member and acting member of the Alberta Utilities Commission from 2009–2018. He teaches and researches various areas of law.

[1] Zvi Halpern-Shavim & Elena Balkos, "U.S. – Canada Tariffs: Timeline of Key Dates and Documents" (last visited 9 April 2025), online: <blakes.com/insights/us-canada-tariffs-timeline-of-key-dates-and-documents>.

[2] Jessica Murphy, Ali Abbas Ahmadi & Bernd Debusmann, "Canada PM Mark Carney says old relationship with US 'is over'" (last visited 27 March 2025) BBC, online: <bbc.com/news/articles/c5y41z4351qo>.

[3] Edward Fishman, Gautam Jain, & Richard Nephew, "How Trump Could Dethrone the Dollar"" (ast visited 8 April 2025) Foreign Affairs, online: <foreignaffairs.com/united-states/how-trump-could-dethrone-dollar>.

[4] Lee Ying Shan, "Trump tariffs drove a Treasury sell-off – who sold the safe-haven asset?" (ast modified 16 April 2025) CNBC, online: <cnbc.com/2025/04/15/us-treasurys-selloff-what-happened-and-why.html>.

[5] Aamer Madhani, Christopher Rugaber & Josh Boak, "Trump suggests he can remove Fed Chair Powell and says he's 'not happy' with him over interest rates" (last modified 17 April 2025) Associated Press, online: <apnews.com/article/trump-powell-federal-reserve-fed-termination-b6148c8048dda538a6ca3b5a270fd09e>.

[6] Which refer to April 2nd, 2025.

self-inflicted policy wound I've ever seen in my career inflicted on our economy"[7] and led J.P. Morgan Research to raise its assessment of the probability of a "U.S. recession occurring in 2025 to 60% — up from 40%."[8]Against this backdrop, Canadians voted to return the Liberal Party to power for a fourth term, led by former Bank of Canada Governor Mark Carney. Election night analysis suggested that Carney is perceived to be better positioned to steer Canada through rough waters over the duration of the Trump presidency.

Canada's new federal government must, among various pressing concerns, address the nation's over-dependence on the U.S. — the largest destination for Canadian raw materials, products, and energy, by deepening existing trading relationships, finding new ones, working with provincial and aboriginal leaders to reduce internal trade barriers, and building export infrastructure. A further immediate concern is the need to address Western alienation and Alberta Premier Danielle Smith's list of demands that would, without resolution in the first six months of a new term, touch off "an unprecedented national unity crisis."[9]

These demands are not insignificant and include[10]: guaranteeing Alberta full access to unfettered oil and gas corridors to the north, east, and west; repealing Bill C-69 (or the "no new pipelines act"); lifting the tanker ban off the B.C. coast; eliminating the oil and gas emissions cap (which is a production cap); scrapping the so-called Clean Electricity Regulations; ending the prohibition on single use plastics; abandoning the net-zero car mandate; returning oversight of the industrial carbon tax to the provinces; and halting the federal censorship of energy companies.

Whether these demands can be met over the course of a single federal electoral term, let alone in six months, remains to be seen.

The first article in this issue of *ERQ* "Federal legislative authority in relation to oil and gas development in Canada: An overview"[11] by Martin Olszynski, Associate Professor and Chair of Energy, Resources, and Sustainability at the University of Calgary Faculty of Law, is a timely review of when and how Canada's federal government can regulate oil and gas development. Olszynski writes that provincial legislatures do not have exclusive domain over oil and gas development and federal heads of power as set out in Canada's constitution may be engaged. While federal regulation of oil and gas may have incidental effects on matters within provincial jurisdiction, the primary purpose of federal regulation must be about matters that fall within federal heads of power, and not, in pith and substance, be an attempt to regulate a provincial matter of concern. Olszynski also discusses how federal criminal law can be used to regulate electricity production and potentially, oil and gas, and how broad federal powers relating to spending and taxation can be used to shape industrial and economic policy.

Canadian and U.S. economic, infrastructure and environmental interdependencies are illustrated in articles by Nigel Bankes, Emeritus Professor at the University of Calgary Faculty of Law and David Morton, former Chair of the British Columbia Utilities Commission and Member of the Advisory Board of the Canadian Reliability Council.

In his article "The modernization of the Columbia River Treaty: Interim arrangements to implement the Agreement-in-Principle,"[12] Bankes describes the interim measures put in

[7] Steff Danielle Thomas, "Yellen slams Trump tariff agenda as 'worst self-inflicted policy wound'"(last visited 12 April 2025) The Hill, online: <thehill.com/business/5245945-janet-yellen-donald-trump-tariff-agenda>.

[8] J.P.Morgan, "The probability of a recession has now fallen below 50%" (last visited 15 April 2025) J.P.Morgan, online: <jpmorgan.com/insights/global-research/economy/recession-probability>.

[9] Cory Knutt, "Premier Smith shares concerns with Prime Minister Mark Carney" (last visited 21 March 2025) Central Alberta, online: <centralalbertaonline.com/articles/premier-smith-shares-concerns-with-pm-mark-carney>.

[10] *Ibid*.

[11] Martin Z. Olszynski, *Federal Legislative Authority in Relation to Oil and Gas Development in Canada,* (International Institute for Sustainable Development, 2025) online (pdf): <iisd.org/system/files/2025-02/canada-federal-authority-oil-gas-development.pdf>.

[12] Nigel Bankes, "The Modernization of the Columbia River Treaty: Interim Arrangements to Implement the Agreement-in-Principle" (last visited 6 February 2025) ABlawg, online (blog): <ablawg.ca/2025/02/06/the-modernization-of-the-columbia-river-treaty-interim-arrangements-to-implement-the-agreement-in-principle>.

place to bridge the gap between the execution of an Agreement-in-Principle in mid-2024 and the completion and ratification of a final, modernized treaty at some time in the future. The implications relating to the changed relationship between Canada and the United States are also briefly discussed.

The threats to Canadian energy reliability are discussed in the article "Top reliability challenges to Canada's energy system" by David Morton. What energy reliability is, the context of reliability in the broader energy system, and Canada's reliability challenges are examined in the article. In his conclusion, Morton argues that it is important to understand the interdependencies in the energy system and not take a siloed approach. He also suggests threats that are currently unidentified may be the greatest challenges to energy system reliability and that there is currently little consensus on an approach that balances reliability with other key energy system goals.

Former Chair of the Alberta Utilities Commission, Mark Kolesar, discusses in his article "Repricing the grid: Should it be regulated as a common carrier?" the challenges facing the modern electricity grid. Gone are the days where the electricity system is one integrated natural monopoly, and all services are priced using average costs. Today, customers can bypass the grid using new technologies, such as increasingly cheaper solar, which leads to a new set of challenges. Kolesar describes these challenges and proposes treating the grid as a common carrier to overcome some of these challenges.

Joe McKinnon, the Manager of Economic Regulations & Standards at *Electricity Canada*, provides a pithy thought piece "Regulatory solutions to reduce investment risk in the electricity sector." McKinnon provides five-pointed policy recommendations to overcome emerging supply chain challenges to federal regulations affecting electricity supply and affordability.

In an article titled "Connecting data centres in Ontario: Key considerations and challenges," Daliana Coban, Daniel Gralnick, and Ian T. D. Thomson (all of the Tory's law firm) tackle the seemingly ever-present data centres. The question of how to regulate data centre's access is one that seems to have perplexed regulators and legislators in various jurisdictions. Coban, Gralnick, and Thomson guide the reader with a step-by-step analysis of what is involved in setting up a data centre all the way to mechanics of how such centres access the electricity grid and what regulatory challenges await.

All in all, this issue will provide our readers with articles that will tackle the challenging issues that face our country from both sides of the border. Undoubtedly the upcoming year or two will be unlike any we have seen in the past. We hope, as the two new managing co-editors of the *ERQ*, to continue the fine tradition that our predecessors have set in providing timely and quality articles that will keep your interest piqued and that will also keep you informed. ■

FEDERAL LEGISLATIVE AUTHORITY IN RELATION TO OIL AND GAS DEVELOPMENT IN CANADA: AN OVERVIEW

*Martin Z. Olszynski**

INTRODUCTION

There is in Canada today considerable public debate and uncertainty regarding both the wisdom and validity of federal laws and regulations that affect oil and gas development. This brief article, which borrows from a longer report prepared for the International Institute for Sustainable Development ("IISD"),[1] outlines when and how Canada's federal government can regulate such development. As further set out below, while provincial legislatures have broad legislative authority over oil and gas development within their territorial limit, Parliament — and through it the federal government of the day — can also make laws and regulations in relation to those aspects of oil and gas development that engage federal jurisdiction. Indeed, oil and gas development can engage over a dozen classes of federal legislative authority, both directly and indirectly. Oil and gas development on federal lands, in the offshore, and on Indigenous reserves, as well as its interprovincial and international transport and export, all fall directly under federal legislative authority. Indirectly, such development engages federal jurisdiction over navigation, fisheries, Indigenous Peoples and their interests in land (including but also beyond reserves), transboundary water pollution, migratory birds, and certain aspects of climate change. Oil and gas development is also affected by the exercise of federal jurisdiction over taxation, spending, patents, and bankruptcy and insolvency.

This article proceeds as follows. Part I discusses the general principle of federalism within the Canadian state, while Part II sets out the rules that Canadian courts apply when assessing the constitutional validity of a given law or regulation (whether federal or provincial). Part III summarizes the rules and principles surrounding nine relevant sources of federal legislative authority. Part IV concludes.

PART I: GENERAL PRINCIPLES OF FEDERALISM

Canada is a federal state. This means that the jurisdiction to make laws (also called legislative power or legislative authority) is divided between the federal and provincial legislatures. This "division of powers" is primarily set out in Sections 91 (federal) and 92 and 92A (provincial) of the *Constitution Act, 1867*.[2] These sections each set out a list

* Martin Z. Olszynski, Associate Professor, Chair in Energy, Resources and Sustainability, University of Calgary Faculty of Law.

[1] See Martin Z. Olszynski, *General Rules and Principles of Federal Legislative Authority in Relation to Oil and Gas Development in Canada*, (Winnipeg: International Institute for Sustainable Development, 2025), online (pdf): <iisd.org/system/files/2025-02/canada-federal-authority-oil-gas-development.pdf>.

[2] *Constitution Act, 1867* (UK), 30 & 31 Vic, c 3, s 91, reprinted in RSC 1985, Appendix II, No 5.

of over twenty "classes of subjects," also called "heads of power" assigned to the federal and provincial legislatures, respectively. The relationship between the federal and provincial legislatures is one of equal partners, not of subordination. When making laws each level of government is autonomous; neither level is under any obligation to accommodate the policy preferences of the other.

Legislative authority does not amount to, or confer, a *right* to anything — including a right to develop natural resources.[3] Rather, it simply enables the relevant government to pass laws in relation to "matters coming within the classes of subjects" listed in Sections 91, 92, and 92A. For example, the protection of fish habitat has been deemed a "matter" that falls within the scope of 91.12. (Sea Coast and Inland Fisheries) and is therefore something that Parliament may pass laws in relation to — and indeed has. As another example, the development, conservation and management of non-renewable natural resources are "matters" found in 92A(1) that provincial legislatures may pass laws in relation to — and this includes oil and gas development. Again, however, it does not follow that the provinces or private proponents have some unfettered *right* to such development: such development can be subject to, and constrained by, valid laws by both levels of government.

Two other types of federal authority or power merit a brief mention here. They are mentioned here because their use is primarily limited by political, rather than legal, constraints. The first is the authority to spend money, or the spending power: "[t]he federal (and provincial) spending power is that of a natural person."[4] Both levels of government have the ability to spend money — and to attach conditions for such spending, including conditions on the receipt of such spending. In the oil and gas context, the most conspicuous examples might be the relatively recent purchase of the Trans Mountain pipeline[5] and the provision of over $1 billion in COVID relief funding to the provinces to address the oil and gas sector's significant closure liabilities.[6]

The second authority is the "declaratory power" in Section 92(10)(c), pursuant to which Parliament may declare a "work" wholly situated in one province to be "for the general Advantage of Canada or for the Advantage of Two or more of the Provinces." This power has been used "no less than 472 times, the majority of which have been in respect of local railways."[7] That being said, this power is regarded as generally inconsistent with Canada's federal structure: "[i]t has been used very rarely in recent times."[8]

PART II: CHARACTERIZATION, CATEGORIZATION, DOUBLE ASPECTS, AND INCIDENTAL EFFECTS

The general framework that Canadian courts apply when assessing whether a given law or regulation is constitutional (i.e., whether it falls within the legislative authority of the government that passed it) is referred to as the division of powers analysis. This analysis consists of (i) characterization and (ii) categorization.[9] Two additional and relevant doctrines are the "double aspect" doctrine and the "incidental effects" doctrine. These doctrines enable the concurrent application of federal and provincial laws and regulations in various contexts, provided always that those laws and regulations respect the rules of the head of

[3] Bankes, Nigel & Andrew Leach, "The Word 'Exclusive' Does Not Confer a Constitutional Monopoly, Nor a Right to Develop Provincial Resource Projects" (1 November 2023), online (blog): <ablawg.ca/2023/11/01/the-word-exclusive-does-not-confer-a-constitutional-monopoly-nor-a-right-to-develop-provincial-resource-projects>.

[4] Peter W. Hogg, *Constitutional Law of Canada*, 5th ed §57:4 and §6:8 (Scarborough: Osgoode Hall Law School of York University, 2007).

[5] Thomas Gunton, *Assessment of fossil fuel subsidies in Canada: A case study of the Trans Mountain Pipeline*. (Winnipeg: International Institute for Sustainable Development, 2024), online (pdf): <iisd.org/system/files/2024-09/fossil-fuel-subsidies-trans-mountain-pipeline.pdf>.

[6] For a discussion regarding this funding, see Bankes, Nigel et al, "Governance and Accountability: Preconditions for Committing Public Funds to Orphan Wells and Facilities and Inactive Wells" (24 April 2020), online: <ablawg.ca/2020/04/24/governance-and-accountability-preconditions-for-committing-public-funds-to-orphan-wells-and-facilities-and-inactive-wells>.

[7] *Supra* note 4 at §22.10.

[8] *Ibid*.

[9] *Reference re Impact Assessment Act*, 2023 SCC 23 [*Reference re: IAA*].

power pursuant to which they were passed. In the event of a conflict or inconsistency between such federal and provincial laws, the federal law will prevail on the basis of the doctrine of federal paramountcy.[10]

(i) Characterization

At the first step, a court examines the relevant law or regulation (or relevant portions thereof)[11] and seeks to identify its essence — what the case law refers to as its "pith and substance."[12] This, then, is the "matter" (sometimes also referred to as the subject matter) that is subsequently categorized as falling within one of the potentially relevant heads of power in Sections 91, 92, or 92A. To determine pith and substance, "two aspects of the law must be examined: the purpose of the enacting body and the legal effect of the law."[13]

As a recent example, in *References re: Greenhouse Gas Pollution Pricing Act*[14] and after assessing its legal and practical effects, a majority of the Supreme Court of Canada concluded that the "true subject matter" of the *Greenhouse Gas Pollution Pricing Act* SC 2018, c. 12, s. 186 ("*GGPPA*") was "establishing minimum national standards of GHG price stringency to reduce GHG emissions."[15] This was the "matter" or "subject matter" that the Court subsequently classified as falling within Parliament's residual POGG power. Importantly, the majority rejected other characterizations, such as the regulation of GHGs, generally, and even national standards for GHGs, generally, as overly broad characterizations of the *GGPPA*, favouring instead the "most precise" characterization of the subject matter of the legislation.[16]

(ii) Categorization

Once a law has been characterized as above (i.e., its matter has been identified), the courts then determine the head(s) of power into which the matter falls: "If the matter of the law is 'properly classified [i.e., categorized] as falling under a head of power assigned to the adopting level of government, the legislation is [constitutional] and valid.'"[17] It is at this stage that some awareness and understanding of provincial heads of power becomes critical to the analysis: a federal law or regulation that purports to regulate some aspect of oil and gas production, processing, or transportation will not be categorized with a view only to potential federal heads of power but rather with awareness of, and sensitivity to, relevant provincial heads of power: "Classes of subjects [i.e., heads of power] should be construed in relation to one another… In cases where federal and provincial classes of subjects contemplate overlapping concepts, meaning may be given to both through the process of 'mutual modification.'"[18]

(iii) Double aspect

While there was once a time that Canadian courts applied a "watertight compartments" approach to the division of powers, whereby overlap between federal and provincial heads of power was strenuously avoided, this has long since given way to a more flexible approach that recognizes that the same fact situation can have both a federal and provincial aspect pursuant to what is called the "double aspect doctrine."[19] The "double aspect doctrine" allows the same set of facts to be regulated from different perspectives or aspects, with the federal government employing heads of power falling within Section 91 and provincial governments using heads of power within Sections 92 or 92A.

[10] *References re Greenhouse Gas Pollution Pricing Act*, 2021 SCC 11 at paras 129–30 [*References re: GGPPA*]. A detailed discussion of the paramountcy doctrine is beyond the scope of this article.

[11] *Canadian Western Bank v Alberta*, 2007 SCC 22 at para 25 [*Canadian Western Bank*].

[12] *Reference re: IAA*, *supra* note 9 at para 61.

[13] *Western Canada Bank*, *supra* note 11 at para 27.

[14] *References re: GGPPA*, *supra* note 10.

[15] *Ibid* at para 80.

[16] *Ibid* at paras 57, 80.

[17] *Reference re: IAA*, *supra* note 9 at para 110.

[18] *Ward v Canada (Attorney General)*, 2002 SCC 17 at para 30 [*Ward*].

[19] *Reference re: IAA*, *supra* note 9 at paras 117, 119.

That being said, in the recent *Reference re: the Impact Assessment Act*, a majority of the Supreme Court cautioned that while the application of the double aspect doctrine allowed concurrent operation of federal and provincial laws, this did not amount to concurrent jurisdiction: "If a fact situation can be regulated from both a federal perspective and a provincial perspective, it follows that each level of government can only enact laws which, in pith and substance, fall under its respective jurisdiction."[20]

As is further discussed in Part III, some heads of power, e.g., the criminal law power, have rules about both the substance and form of such laws.[21] Other heads of power have been described as being in relation to a resource (e.g., the fishery resource) or an activity (e.g., interprovincial railways), which can also have implications for their scope and breadth.

(iv) Incidental effects

Finally, Canadian courts have also recognized that valid legislation may, to some degree, touch on matters beyond the legislature's jurisdiction *without* becoming unconstitutional:

> [A law's] secondary objectives and effects have no impact on its constitutionality: "merely incidental effects will not disturb the constitutionality of an otherwise [constitutional] law"… By "incidental" is meant (*sic*) effects that may be of significant practical importance but are collateral and secondary to the mandate of the enacting legislature… Such incidental intrusions into matters subject to the other level of government's authority are proper and to be expected.[22]

The "incidental effects" doctrine recognizes that "it is in practice impossible for a legislature to exercise its jurisdiction over a matter effectively without incidentally affecting matters within the jurisdiction of another level of government. For example…it would be impossible for Parliament to make effective laws in relation to copyright without affecting property and civil rights."[23] Thus, federal laws and regulations in relation to fisheries, navigation, or Indigenous Peoples may incidentally affect the development of oil and gas without being rendered unconstitutional. For example, the need to obtain authorization under the federal *Fisheries Act* RSC 1985 c. F-14 (*Fisheries Act*) to destroy fish habitat can affect — and indeed has affected — the timing of the construction of an oil sands mine.[24]

PART III: FEDERAL HEADS OF POWER RELEVANT TO OIL AND GAS

As noted above, when construing the scope of federal legislative authority and whether a given law or regulation falls within the scope of that authority, Canadian courts are cognizant of provincial legislative authority and seek to maintain the balance of federalism reflected in those sections and the policy choices underpinning them: "Each head of power was assigned to the level of government best placed to exercise the power."[25]

Provincial legislative authority in relation to oil and gas development is both broad and deep. In many respects, the provinces' legislative jurisdiction over "property and civil rights" (92.13) is itself sufficient to ground the vast majority of resource-related laws and regulations. As noted by the Supreme Court, "the regulation of trade and industry within the province generally (with certain exceptions) falls within the province's jurisdiction over property and civil rights."[26] Provisions with respect to public lands (92.5), local works and undertakings (92.10), and matters of a local nature (92.15) provide any required supplementation in this context. Indeed, provincial legislative authority under Section 92 is so broad that

[20] *Ibid* at paras 120–21.

[21] *Desgagnés Transport Inc. v Wärtsilä Canada Inc.*, 2019 SCC 58 at para 41 [*Desgagnés Transport*].

[22] *Canadian Western Bank*, *supra* note 11 at para 28.

[23] *Ibid* at para 29.

[24] See *Imperial Oil Resources Ventures Limited v Canada (Fisheries and Oceans)*, 2008 CanLII 382 (FC).

[25] *Canadian Western Bank*, *supra* note 11 at para 22.

[26] *Ward*, *supra* note 18 at para 42.

it has led commentators to question whether subsection 92A(1), which explicitly refers to the development of non-renewable resources and electricity generation, actually added anything to provincial powers: "[Section 92A] seems to cover a lot of the ground already covered by section 92…since the activities it mentions…were almost certainly within provincial legislative jurisdiction before the adoption of the resources amendment."[27]

With provincial legislative authority briefly set out, this section now turns to an examination of nine federal heads of power (all federal heads of power noted in the introduction are discussed in the longer report mentioned at the outset of this article).

91.1A. The public debt and property

Parliament has legislative authority over public debt and property. Federal public property, in this context, includes "national parks, military bases and the sea that lies beyond the geographic boundaries of any province or territory."[28] While geographically limited, this authority is important, especially in relation to offshore oil and gas development off Canada's coasts.[29] Where federal lands are concerned, the federal government has essentially the same broad authority over oil and gas development as the provinces do with respect to development on their own lands.

91.2. The regulation of trade and commerce

Parliament has legislative authority over the regulation of trade and commerce but, out of concern for preserving provincial authority over "property and civil rights" (s 92.13), this head of power has been interpreted relatively narrowly.[30] It consists of two branches: a general trade and commerce power, and power over international and interprovincial trade and commerce. With respect to the first branch, authority is restricted to matters that are "qualitatively different from anything that could practically or constitutionally be enacted by the individual provinces either separately or in combination."[31] The Supreme Court of Canada relies on five principal criteria in making this determination.[32]

With respect to the second branch, international and interprovincial trade and commerce, most of the case law considers the question of interprovincial, rather than international, trade. Consequently, the latter space appears governed by political convention rather than clear doctrine developed through litigation. The Canada Energy Regulator ("CER") has been delegated the authority to regulate the export of oil and gas, which it does pursuant to Part 7 of the *Canada Energy Regulator Act* SC 2019, c. 28, s. 10 ("*CERA*"). The question that arises is when the exercise of this authority might transgress incidentally affecting provincial policies and preferences in relation to resource development to encroaching on provincial authority in relation to such development. This question has taken on increased urgency as a result of recent developments in the United States and the current trade dispute in particular. Decisions made about exports in this context would seem to fall squarely within federal jurisdiction over international trade.

Outside of that context (i.e., outside of an international trade dispute), the federal government has banned the export of some

[27] Nigel Bankes & Andrew Leach, "Preparing for a mid-life crisis: Section 92A at 40" (2023) 60:4 *Alberta L Rev* 853 at 863.

[28] Isabelle Brideau et al., *The Distribution of Legislative Powers: An Overview,* (Ottawa: Library of Parliament, 2022), Publication No. 2019-35-E, online (pdf): <lop.parl.ca/staticfiles/PublicWebsite/Home/ResearchPublications/HillStudies/PDF/2019-35-E.pdf>.

[29] For an overview of relevant legislation and agreements, see Government of Canada, "Legislation and Regulations - Offshore Oil and Gas" (last modified 7 January 2025), online: <natural-resources.canada.ca/energy-sources/fossil-fuels/legislation-regulations-offshore-oil-gas>.

[30] *Reference re PanCanadian Securities Regulation*, 2018 SCC 48 at para 100. See also Peter W. Hogg, Constitutional law of Canada, 5th ed., (Scarborough: Thomson Carswell, 2019) § 20:3.

[31] *Attorney General of Canada v Canadian National Transportation, Ltd.*, 1983 2 SCR 206 at p 267.

[32] *Reference re: Pan-Canadian Securities*, *supra* note 30 at para 103: "(1) Is the law part of a general regulatory scheme? (2) Is the scheme under the oversight of a regulatory agency? (3) Is the law concerned with trade as a whole rather than with a particular industry? (4) Is the scheme of such a nature that the provinces, acting alone or in concert, would be constitutionally incapable of enacting it? (5) Would a failure to include one or more provinces or localities in the scheme jeopardize its successful operation in other parts of the country?".

products, such as asbestos. This ban, however, is also anchored in a prior listing of asbestos as a "toxic substance" under the *Canadian Environmental Protection Act*, 1999 SC 1999 c. 33 ("*CEPA, 1999*").[33] Conversely, when controversy over potential bulk freshwater exports from Canada to the United States hit a highwater mark at the turn of the 21st century, the federal government insisted that only the provinces were constitutionally capable of enacting bans on such exports.[34] The latter position seems most directly analogous to the oil and gas context; while CO_2 and other GHGs have also been listed as toxic substances, neither oil nor natural gas have been listed as such.

91.3. The raising of money by any mode or system of taxation

The federal government has broad authority to make laws in relation to taxation, both direct and indirect.[35] In a legal opinion prepared for the government of Manitoba and publicly released in the run-up to the Supreme Court's hearing in *References re: GGPPA*, this power was described as "extremely broad and generally subject to restriction only on the grounds that the measure in question can be classified as something other than a tax."[36] (As a reminder, the *GGPPA* was ultimately classified as a regulatory charge and a matter of "national concern", *i.e.*, something other than a tax.)

While this power is constrained in a few other ways as well (e.g., Section 125 of the Constitution prohibits the taxation of lands and property belonging to either the federal or provincial governments), its relevance to oil and gas development should be plain. At the turn of the 21st century, the *Income Tax Act* RSC 1985 c. 1 (5th Supp.) and, more specifically, amendments to the *Income Tax Act* and its regulations were used to promote oil and gas development, especially oil sands development (e.g., through accelerated capital cost allowances).[37] More recently, the oil and gas sector received generous tax credits to facilitate the deployment of carbon capture, utilization, and storage ("CCUS") facilities.[38] The extent to which this power is used to incentivize any economic activity is entirely within the federal government's discretion.

91.10. Navigation and shipping

The federal government has legislative authority over navigation and shipping, which has been interpreted broadly: "Courts have interpreted the federal power generously in recognition of the national importance of the maritime industry, thereby permitting the development of uniform legal rules that apply across Canada."[39] To understand the scope of this power, it is necessary to understand the scope of the public right of navigation in Canada. A common law public right of navigation exists wherever a water body is navigable.[40] Only Parliament is competent to legislate in relation to this common law right, including authorizing its interference as a result of a work such as a dam or bridge. In the oil and gas context, Transport Canada relies on various permits pursuant to the *Canada Navigable Waters Act* RSC 1985, c. N-22 ("*CNWA*") to authorize interferences with navigation in relation to various forms of infrastructure, e.g., a bridge, pipeline crossing, or water intake. A recent search of the federal Common Project Registry lists over 100 *CNWA* authorizations issued to the oil and gas sector in British Columbia, Alberta, and

[33] See *Export of Substances on the Export Control List Regulations*, SOR/2013-88 and *Prohibition of Asbestos and Products Containing Asbestos Regulations*, SOR/2018-196.

[34] Martin Z.P. Olszynski, "The commodification of Canadian water: Exploring international trade implications" (2006) 69 Sask L Rev, 221.

[35] *Supra* note 30, § 31.1.

[36] Bryan P. Schwartz, "Legal Opinion on the Constitutionality of the Federal Carbon Pricing Benchmark & Backstop Proposals" (6 October 2017), Prepared for the Government of Manitoba, online (pdf): <gov.mb.ca/asset_library/en/climatechange/federal_carbon_pricing_benchmark_backstop_proposals.pdf>; See also *Reference re: GGPPA*, *supra* note 10 at para 219.

[37] Ketchum, Ken, Robert Lavigne, & Reg Plummer, "Oils Sands Tax Expenditures" (2001) Department of Finance Canada, Working Paper 2001-17, online (pdf): <publications.gc.ca/collections/collection_2008/fin/F21-8-2001-17E.pdf>.

[38] Bill C-69, *An Act to implement certain provisions of the budget tabled in Parliament on April 16, 2024*, 1st Sess, 44th Parl, 2024, online: <parl.ca/documentviewer/en/44-1/bill/C-69/royal-assent>.

[39] *Desgagnés*, *supra* note 21 at para 45.

[40] *Friends of the Oldman River Society v Canada (Minister of Transport)*, 1992 CanLII 110 SCC, [1992] 1 SCR 3.

Saskatchewan (completed or in progress).[41] The federal government also regulates all shipping, including of oil and liquefied natural gas ("LNG"), under the *Canada Shipping Act* S.C. 2001, c. 26, which jurisdiction proved relevant in the litigation surrounding the Trans Mountain pipeline expansion project.[42]

91.12. Sea coast and inland fisheries

The federal government has broad jurisdiction over sea coast and inland fisheries. The fisheries power "includes *not only conservation and protection*, but also the general 'regulation' of the fisheries, including *their management and control*. They recognize that "fisheries" under s. 91(12)…refers to the fisheries as a resource; "a source of national or provincial wealth"…a "common property resource" to be *managed* for the good of all Canadians."[43]

This legislative authority provides the basis for the federal *Fisheries Act*, RSC 1985 c. F-14. While the *Fisheries Act* is primarily concerned with fisheries management, there is an entire part — "Fish and Fish Habitat Protection and Pollution Prevention" (Sections 34–43) — that is concerned with impacts to fish, fish habitat, and pollution prevention, and that has come to represent the *de facto* national water quality regime in Canada. Of particular importance to oil and gas, Section 36 prohibits the deposit of deleterious substances in waters frequented by fish, which is virtually all waters in Canada, unless authorized by regulations. Pursuant to this regime, the federal government has enacted numerous effluent regulations for most sectors, including metal and diamond mining, pulp and paper, and municipal wastewater, and is currently developing regulations for oil sands processed water.

Other relevant provisions of the *Fisheries Act* include Section 34.2, which provides the federal Minister of Fisheries and Oceans with the authority to direct flows (relevant to water withdrawals for oil sands processing, fracking, as well as to future remediation and reclamation planning), and Section 35, which prohibits the harmful alteration, disruption or destruction ("HADD") of fish habitat unless authorized by the Minister or by regulations. Every oil sands mine has required a Section 35 authorization, often requiring the destruction of several thousand hectares of fish habitat. HADD authorizations are also generally required for infrastructure in water, including bridges, pipeline crossings, and water intakes. A recent search of the federal Common Project Registry yielded 17 *Fisheries Act* authorizations issued to the oil and gas sector in Western Canada since 2018.

91.21. Bankruptcy and insolvency

Parliament has the authority to legislate matters relating to bankruptcy and insolvency. In the exercise of this jurisdiction, Parliament enacted the *Bankruptcy and Insolvency Act* RSC, 1985, c. B-3 ("*BIA*"). The *BIA* "outlines, among other things, the powers, duties and functions of receivers and trustees responsible for administering bankrupt or insolvent estates and the scope of claims that fall within the bankruptcy process."[44] More fundamentally, and as recently explained by the Supreme Court, "subject to reasonable conditions, the *BIA* permits an honest but unfortunate debtor to be freed from the burdens of indebtedness and to reintegrate into economic life."[45]

Parliament's authority to set the rules of bankruptcy and insolvency is directly relevant to the oil and gas sectors' significant and presently unfunded and unsecured environmental liabilities (i.e., the costs of closing, remediating, and reclaiming sites and facilities). Adjusted for inflation, these have been estimated to be as high as $320 billion

---

[41] See Government of Canada, "Common Project Search: Registry Results" (last modified 19 February 2025), online: <common-project-search.canada.ca/search-recherche?view=map>.

[42] *Tsleil-Waututh Nation v. Canada (Attorney General)* 2018 FCA 153. See Martin Z. Olszynski and David V. Wright, "*Tsleil-Waututh Nation v. Canada (Attorney General)*: Clarifying the (F)Laws in Canada's Pipeline Approval Process" (2019) 22:4 Can Envtl L Reports 8.

[43] *Ward*, *supra* note 18 at para 41.

[44] *Orphan Well Association v Grant Thornton Ltd.*, 2019 SCC 5 at para 178.

[45] *Poonian v British Columbia (Securities Commission)*, 2024 SCC 28 at para 1.

in Alberta alone (both conventional and non-conventional).[46] At present, in the absence of robust liability management regimes at the provincial level,[47] the *BIA* appears to invite oil and gas companies to neglect or ignore their environmental liabilities for as long as possible, and to then try to walk away from them through a combination of a "brisk trade in junk assets" and the bankruptcy process[48] — an approach that appears far removed from the honest but unfortunate debtor. This was the subtext to the relatively recent and high-profile *Redwater* litigation in Alberta (known formally as *Orphan Well Association v. Grant Thornton Ltd.*).[49] There is also no shortage of abandoned industrial sites throughout Canada, including the Giant Mine in the Northwest Territories, whose remediation and reclamation — in the billions of dollars — now weigh on the public purse.[50] Needless to say, Parliament's jurisdiction over bankruptcy and insolvency could be recalibrated to try to prevent the externalization (directing the costs onto the public) of what should be private costs, rather than to facilitate it.

91.27. The criminal law

A law or regulation will be valid criminal law if "in pith and substance: (1) it consists of a prohibition (2) accompanied by a penalty and (3) backed by a criminal law purpose."[51] These requirements have been interpreted flexibly by Canadian courts in upholding various important federal regimes: "Parliament's criminal law power is broad and plenary… The criminal law must be able to respond to new and emerging matters, and the Court 'has been careful not to freeze the definition [of the criminal law power] in time or confine it to a fixed domain of activity.'"[52]

CEPA, 1999's "toxic substance" regime, upheld as a valid exercise of the criminal law power,[53] is particularly relevant to oil and gas development. In 2005, the federal government designated six kinds of GHGs as "toxic substances" pursuant to the Act, unlocking its machinery and its regulation-making powers to be applied to the problem of climate change. Since then, the federal government has enacted several important regulations under the Act.

In *Syncrude v Canada*, which involved a challenge by Syncrude to the constitutionality of the *Renewable Fuels Regulations* (SOR/2010-189) ("*RFR*"), passed pursuant to *CEPA, 1999*, the Federal Court of Appeal had no difficulty concluding that fighting climate change was a valid criminal law purpose: "It is uncontroverted that GHGs are harmful to both health and the environment and as such, constitute an evil that justifies the exercise of the criminal law power."[54] The *RFR* also did not contravene the criminal law power's form requirements (a prohibition backed by a penalty) even though they incorporated market-based compliance mechanisms to increase their flexibility. In prior challenges to federal laws passed under the criminal law power, some provinces have argued that the existence of a relatively complex regulatory scheme is contrary to the form requirement. A critical question in this context is whether the relevant prohibition is "confined to ensuring compliance with the [legislative] scheme," which would make it impermissibly

[46] De Souza, Mike et al, "Cleaning up Alberta's oil patch could cost $260 billion, internal documents warn" (last modified 21 November 2018), online: <globalnews.ca/news/4617664/cleaning-up-albertas-oilpatch-could-cost-260-billion-regulatory-documents-warn>.

[47] See Martin, Olszynski, Leach Andrew, & Yewchuk Drew, "Not fit for purpose: Alberta's oil sands and the mine financial security program" (2023) 16:36 University of Calgary School of Public Policy Research Paper; Drew, Yewchuk, Fluker Shaun, & Olszynski Martin, "A made-in-Alberta failure: Unfunded oil and gas closure liability" (2023) 16:36 University of Calgary School of Public Policy Research Paper.

[48] Jeef, Lewis et al, "Hustle in the oil patch: Inside a looming financial and environmental crisis" (last modified 22 October 2020), online: <theglobeandmail.com/canada/article-hustle-in-the-oil-patch-inside-a-looming-financial-and-environmental>.

[49] *Supra* note 43.

[50] Federally, see Auditor General of Canada, *Contaminated Sites in the North*, (Commissioner of the Environment and Sustainable Development to the Parliament of Canada, 2024), online (pdf): <oag-bvg.gc.ca/internet/docs/parl_cesd_202404_01_e.pdf>.

[51] *Reference re: Genetic Non-Discrimination Act*, 2020 SCC 17 at para 67.

[52] *Ibid* at para 69.

[53] *R. v Hydro-Québec*, 1997 CanLII 318 (SCC).

[54] *Syncrude Canada Ltd. v Canada (Attorney General)*, 2016 CanLII 160 (FCA) at para 62 [*Syncrude*].

regulatory in nature, or whether it would "stand on [its] own, independently serving the purpose" of the law or regulation in question.[55] The *RFR* meets this requirement because the effect of its prohibition "on a yearly, Canada-wide, basis" is that "2% less fossil fuel is consumed."[56]

The federal government recently enacted the *Clean Electricity Regulations* ("*CER*"),[57] which will limit the GHG emissions from power plants (including natural gas power plants, beginning in 2035) and has been developing regulations to establish a GHG emissions cap on the oil and gas sector.[58] Both the *CER* and the proposed oil and gas GHG emissions cap contain a prohibition against emitting a certain level of GHGs, subject to conditions. Like the *RFR*, then, such prohibitions would appear to "stand on their own, independently serving the purpose" of combatting the "evil" (or apprehended harm) of anthropogenic climate change by reducing overall GHG emissions and are not merely about ensuring compliance with these regimes. While prohibitions on GHGs are bound to affect the generation of electricity or the production of oil and gas, such impacts would be incidental and therefore constitutional.[59]

92.10(a) Interprovincial Works and Undertakings

The federal government has legislative authority over interprovincial works and undertakings. This includes interprovincial railways and pipelines. The nature of this jurisdiction can be gleaned from its history, and specifically its explicit carving out from provincial jurisdiction over local works and undertakings: "While the preference in s. 92(10) was for local regulation of works and undertakings, some works and undertakings were of sufficient national importance that they required centralized control."[60] Parliament's legislative authority in relation to interprovincial works and undertakings, including interprovincial oil or gas pipelines, can be described as comprehensive, encompassing all relevant social, economic and environmental considerations.[61]

91. Residual power: Peace, order, and good government

On its face, the opening paragraph of Section 91 broadly authorizes the federal government to "make Laws for the Peace, Order, and good Government of Canada." Read literally, the list of federal "classes of subjects" (heads of power) that follows is intended to *clarify* ("for greater certainty") this broad legislative authority "but not so as to restrict the Generality of the foregoing Terms." The only *explicit* limit on the general POGG power is the explicit exclusion of those "classes of subjects" (heads of power) assigned to the provinces in Section 92. Nevertheless, over the past several decades the POGG power has received a restrictive interpretation. Presently, it consists of two branches: the emergency branch and the national concern branch. The emergency branch provides a broad constitutional basis for addressing national emergencies, but any legislation so passed must be temporary in nature (until the emergency passes).[62] The contours of, and test for, the "national concern" branch were recently revised in *References re: GGPPA*,[63] where a majority of the Supreme Court of Canada upheld the *GGPPA* on the basis that

[55] *Reference re Firearms Act (Can.)*, 2000 CanLII 31 (SCC), [2000] 1 SCR 783 at para 38.

[56] *Syncrude*, *supra* note 54 at para 79. See also Nathalie J. Chalifour, "Canadian climate federalism: Parliament's ample constitutional authority to legislate GHG emissions through regulations, a national cap and trade program, or a national carbon tax" (2016) 36 NJCL, 331 at 357; Stewart Elgie, "Kyoto, the Constitution, and carbon trading: Waking a sleeping *BNA* bear (or two)" (2007) 13:1 Rev Const Stud at 108.

[57] Environment and natural resources, "Canada's clean electricity future" (last modified 14 mars 2025), online: <canada.ca/en/services/environment/weather/climatechange/climate-plan/clean-electricity.html>.

[58] For a description of these proposed regulations, see Environment and natural resources, "Oil and gas sector greenhouse gas pollution cap" (last modified 14 mars 2025), online: <canada.ca/en/services/environment/weather/climatechange/climate-plan/oil-gas-emissions-cap.html>.

[59] *Syncrude*, *supra* note 54 at pp 506–7.

[60] *Consolidated Fastfrate Inc. v Western Canada Council of Teamsters* [2009] 3 SCR 407 at paras 36–37.

[61] *Reference re: IAA*, *supra* note 9 at para 176. See also Martin Olszynski, "Testing the jurisdictional waters: The provincial regulation of interprovincial pipelines" (2018) 23:1 Rev Const Stud at 91.

[62] *R. v Crown Zellerbach Canada Ltd.*, [1988] 1 SCR 401 at pp 431–32.

[63] *Reference re: GGPPA*, *supra* note 10.

"establishing minimum national standards of GHG price stringency to reduce GHG emissions" was a matter of national concern.[64]

Previously recognized matters of national concern include marine pollution[65] and interprovincial river pollution.[66] In *Reference re: IAA*, the Supreme Court held that the federal government could not rely on the matter of national concern identified in *Reference re: GGPPA* to constitutionally anchor the *IAA*'s application to the GHG emissions of major projects.[67] Consequently, any subsequent reliance on the POGG power in relation to climate change, whether under the *IAA* or elsewhere, requires establishing a new matter of national concern by satisfying the revised three-part test:

i. Threshold question: Is there an evidentiary basis for asserting that a given matter is of national importance?

ii. Singleness, distinctiveness, and indivisibility: Can the matter be distinguished from matters falling within provincial jurisdiction, with a view towards provincial inability to address the matter in particular; and

iii. Scale of impact: balancing provincial and federal interests at stake.

PART IV: CONCLUSION

While oil and gas development clearly falls within provincial legislative authority, the foregoing discussion makes clear that numerous federal legislative authorities may also be implicated, both directly and indirectly. Oil and gas development on federal lands, in the offshore, and on Indigenous reserves, as well as its interprovincial and international transport and export, all fall directly under federal legislative authority. Indirectly, oil and gas development implicates and engages federal jurisdiction over navigation, fisheries, Indigenous Peoples and lands reserved for them, transboundary river pollution, migratory birds, and federal aspects of climate change. The discussion above and the examples provided also shows that, with some exceptions, over the past two decades federal legislative authority has been used to facilitate and promote natural resource development, including oil and gas development. ■

---

[64] *Ibid* at para 80.

[65] *R. v Crown Zellerbach Canada Ltd.*, *supra* note 61.

[66] *Interprovincial Co-operatives Ltd. v The Queen*, [1976] 1 SCR 477.

[67] *Reference re: IAA*, *supra* note 9 at paras 182–89.

THE MODERNIZATION OF THE COLUMBIA RIVER TREATY: INTERIM ARRANGEMENTS TO IMPLEMENT THE AGREEMENT-IN-PRINCIPLE

*Nigel Bankes**

This comment examines the interim arrangements that the United States and Canada ("the Parties") have adopted to address the temporal gap (the "Interim Period" between the Agreement-in-Principle[1] ("AiP") on a "modernized" Columbia River Treaty[2] ("CRT" or "Treaty") adopted in mid-2024 and the conclusion and ratification of final modernized treaty text at some future time. The interim arrangements consist of three sets of documents: (1) a Canada/U.S. Exchange of Notes[3] re Columbia River Treaty Assured Operating Plan for 2024–25, (September 18 and 20, 2024) and re an Entity Agreement on the Interim Period Determination of Downstream Power Benefits (September 13, 16 and 17 September, 2024),[4] (2) a Canada/U.S. Exchange of Notes Regarding Interim Pre-Planned Flood Risk Management Arrangements (November 18 and 22, 2024),[5] and (3) an Entity Agreement[6] regarding Pre-Planned Flood Risk Management Arrangements (November 14 & 15, 2024).

---

* Nigel Bankes is an Emeritus Professor at the Faculty of Law, University of Calgary. This article was previously published in a different format as Nigel Bankes, "The Modernization of the Columbia River Treaty: Interim Arrangements to Implement the Agreement-in-Principle" (6 February 2025), online (pdf): <ablawg.ca/2025/02/06/the-modernization-of-the-columbia-river-treaty-interim-arrangements-to-implement-the-agreement-in-principle>.

Thanks to Barbara Cosens, University Distinguished Professor Emerita, University of Idaho, College of Law for helpful comments on an earlier draft of this post.

[1] Government of British Columbia, "Columbia River Treaty: An Agreement-in-Principle has been reached to modernize the Treaty" (last visited 17 April 2025), online: <engage.gov.bc.ca/columbiarivertreaty/agreement-in-principle>.

[2] *The Columbia River Treaty*, Canada and US, 17 January 1961, online (pdf): <engage.gov.bc.ca/app/uploads/sites/6/2012/04/Columbia-River-Treaty-Protocol-and-Documents.pdf>.

[3] Exchange of Notes between Mr. Brian A. Nichols and Mr. Glen Linder (18 September 2024), online (pdf): <engage.gov.bc.ca/app/uploads/sites/6/2024/12/20240920_AOP25_DDPB_EON_Executed.pdf>.

[4] *Ibid*.

[5] Exchange of Notes between Mrs. Shalini Anand and Mr. Brian A. Nichols (15 November 2024), online (pdf): <engage.gov.bc.ca/app/uploads/sites/6/2024/12/20241122_FRM_EON_CAN_US.pdf> [*Exchange of Notes, September 18 & 20*].

[6] "Columbia River Treaty Entity Agreement Regarding Pre-Planned Flood Risk Management Arrangements During the Interim FRM Period" (6 December 2024), online (pdf): <engage.gov.bc.ca/app/uploads/sites/6/2024/12/20241115_FRM_EA_Executed.pdf>.

In practice, the Parties and their operating Entities[7] are using the operational capability offered by the Treaty[8] to selectively implement some of the terms of the non-binding AiP. The Parties and their Entities have chosen to prioritize the early implementation of the changed flood control and power provisions of the AiP but have not extended that same priority to other elements of the AiP, including ecosystem considerations, and the creation of the Joint Ecosystem and Indigenous and Tribal Cultural Values Body ("JEB"). Neither do the interim arrangements address two groups of provisions in the AiP that were clearly intended to confer an advantage on Canada; first an additional annual compensation payment to Canada for "additional benefits"[9] brought about by coordinated operations, and second, certain flexibility rules designed to allow Canada (British Columbia) to "undertake Treaty operations for domestic priorities, such as environmental, Indigenous cultural values and socioeconomic purposes."[10]

The post first explains why the Parties might think that interim arrangements would be necessary. It then provides a brief description of the rules and practice pertaining to an exchange of diplomatic notes and Entity Agreements. It then turns to examine first the interim arrangements on flood control or flood risk management, and then the power operation and the downstream power benefits. In each case, the analysis begins with a summary of the applicable Treaty provisions, then the relevant AiP provisions, and then the interim measures that the Parties and their operating entities have adopted to deal with each main subject (flood and power).

THE AGREEMENT-IN-PRINCIPLE AND THE NEED FOR INTERIM MEASURES

On July 8, 2024 Canada and the United States announced that they had reached an Agreement-in-Principle[11] on a "modernized" Columbia River Treaty. I posted on that important development twice.[12] The Parties have not released the actual text of the AiP but have instead released a "public document"[13] summarizing the AiP. This is problematic in the present context since at least some of the documents that are the subject of this post expressly refer to AiP text.

The Parties continued to negotiate following the AiP but have yet to agree on the text of the required amendments — amendments which would then be subject to the domestic processes of ratification in each state before the modernized Treaty could enter into force. For many treaties this would not be problematic; the existing treaty would simply continue in force until the new arrangements could be finalized. And in most circumstances, one might expect this to occur reasonably expeditiously. But neither seems likely to work right now for the Columbia River Treaty for two reasons; one reason is internal to the Treaty, the other is external.

The problem internal to the CRT is that while the CRT as a whole has no particular end date (indeed it can only be terminated — and then only in part — on ten years notice[14]) the Treaty's flood control regime changed automatically on midnight of September 15, 2024, the eve of the sixtieth anniversary of the entry into force of the Treaty. More specifically, the Treaty's flood control regime changed from the assured

---

[7] See discussion of the term "Entities" below.

[8] See especially *supra* note 2 art XIV(4).

[9] British Columbia Government, *Negotiations to Modernize the Columbia River Treaty Agreement-in-Principle Content*, (30 August 2024), at 4, online (pdf): <engage.gov.bc.ca/app/uploads/sites/6/2024/09/CRT-AIP-Canada-public-description-Final_2024Aug30.pdf>.

[10] *Ibid* at 3.

[11] *Supra* note 1.

[12] See Nigel Bankes, "Agreement in Principle on a Revised Columbia River Treaty" (18 July 2024), online (blog): <ablawg.ca/wp-content/uploads/2024/07/Blog_NB_Revised_CRT.pdf>; see also Nigel Bankes, "New "Public Document" on the Agreement in Principle to Modernize the Columbia River Treaty" (12 September 2024), online (blog): <ablawg.ca/2024/09/13/new-public-document-on-the-agreement-in-principle-to-modernize-the-columbia-river-treaty>.

[13] *Supra* note 9.

[14] *Supra* note 2 art XIX(2).

operation contemplated by Article IV(2) of the treaty to what is known as the "called-upon" operation specified in Article IV(3) and qualified by the terms of the 1964 Protocol to the Treaty. Assured flood control was operationalized through the terms of paragraph 5 of Annex A (Principles of Operation) of the Treaty and Flood Control Operation Plans ("FCOP"). The current FCOP adopted in May 2003[15] is effectively superceded by the expiration of Article IV(2) of the Treaty.

But there are considerable uncertainties as to how to operationalize "called-upon", and this has been perhaps the most significant driver behind the AiP negotiations. The loss to the U.S. of an assured flood control operation afforded Canada one of its most significant negotiating levers since it allowed Canada to seek concessions in return for acceding to U.S. efforts to secure greater certainty through a more planned flood control operation. The AiP addressed this concern, but the AiP does not create legal obligations for either Party and is not self-implementing

The external challenge results from the U.S. elections in November 2024 and the consequential presidential transition in January 2025. Despite optimistic statements from Secretary Blinken and Minister Joly in November 2024,[16] it never seemed likely that the Parties would be able to develop and gain approval for final treaty text prior to the presidential transition, and this too therefore called out for transitional arrangements to address not only flood control but also power operations and downstream power benefits. That said, the case for interim arrangements for downstream power benefits is (legally) much weaker than the case for planned flood control. This is simply because the Treaty itself does not envisage any change in the power operation on the Treaty's sixtieth anniversary. Nevertheless, there was clearly pressure from U.S. interests to implement the changes contemplated by the AiP sooner rather than later. But perhaps the principal issue for both Parties now, but most especially Canada, is how long we can expect this interim period to last. In the scenario of a continued Democratic presidency, it might have been reasonable to anticipate a reasonably short interim period (depending upon U.S. domestic measures for implementing any treaty amendments), but under a Trump presidency it seems naïve to anticipate either the speedy or predictable finalization of treaty text, or the speedy conclusion of domestic ratification procedures. Of course, we shouldn't be too one-sided about all of this. Given the current prorogation of parliament and a likely federal election sometime this year, perhaps sooner rather than later, it will also be difficult for Canada (if not British Columbia) to finalize text and proceed to ratification — which in Canada's case will involve, at a minimum, tabling proposed treaty amendments in the House of Commons.[17] But at least the path to certainty on this side of the border seems more predictable and achievable within a shorter timeframe than what we see to the south.

In summary, the U.S. and Canada have reached an agreement-in-principle on how to amend the Treaty but have been unable to finalize text and comply with domestic ratification procedures to meet the internal deadline imposed by the flood control provisions of the Treaty, or the external deadline imposed by the transfer of executive power in the United States. Given that, the two states have fallen back on a series of *ad hoc* measures to implement now some, but only some, of the agreed (in principle) changes, pending finalization and domestic ratification of formal treaty text. The Parties have chosen to do this through a combination of diplomatic notes and agreements between the operating Entities. The next step therefore is to examine how the CRT deals with such instruments.

---

[15] Corps of Engineers, Northwestern Division, North Pacific Region for the United States Entity, "Columbia River Treaty: Flood control operating plan" (Portland: 2003), online (pdf): <nwd-wc.usace.army.mil/cafe/forecast/FCOP/FCOP2003.pdf>.

[16] Ashley Joannou and Kelly Geraldine Malone, "Joly, Blinken push to get B.C. River treaty through Congress before Trump government", *The Canadian Press* (15 November 2024), online: <thecanadianpressnews.ca/politics/joly-blinken-push-to-get-b-c-river-treaty-through-congress-before-trump-government/article_40c46ddb-3faf-5494-a4f5-bf5cb0f886cb.html>.

[17] See Government of Canada, "Policy on Tabling Treaties in Parliament" (last visited 17 April 2025), online: <treaty-accord.gc.ca/procedures.aspx?lang=eng>; See also Nigel Bankes and Barbara Cosens, *The Future of the Columbia River Treaty*, (Toronto: University of Toronto, 2012), online (pdf): <ablawg.ca/wp-content/uploads/2024/07/The-Future-of-the-CRT-October-2-Final-Document.pdf>.

DIPLOMATIC NOTES AND ENTITY AGREEMENTS

States frequently record agreements between them in the form of an exchange of diplomatic notes. Such agreements typically take the form of a letter from a senior official or diplomat (e.g. an ambassador) expressing State A's understanding of the agreement that has been reached with State B. A person of similar rank in State B responds with a letter couched in parallel terms acknowledging that same understanding. Unlike an agreement-in-principle, an exchange of diplomatic notes is a treaty for the purposes of international law in the sense that it is "an international agreement concluded between States in written form and governed by international law, whether embodied in a single instrument or in two or more related instruments and whatever its particular designation."[18] The CRT itself expressly contemplates that the Parties may use an exchange of notes to confirm or vary the application of the Treaty in a number of ways. Here are some relevant examples from the Treaty text:

- Article IV(1) requires an exchange of notes to confirm the adoption of the first operating plan for Canadian storage and again "if in the view of either Canada or the United States of America [a new operating plan] departs substantially from the immediately preceding operating plan [the new plan] must, in order to be effective, be confirmed by an exchange of notes…"[19]

- Article VIII(1) provides that with the approval of both Parties, evidenced by an exchange of notes, "portions of the downstream power benefits to which Canada is entitled may be disposed of within the United States of America…"[20]

- Article XV(4) requires the Permanent Engineering Board, the Treaty's supervisory body, to "comply with directions, relating to its administration and procedures, agreed upon by Canada and the United States of America as evidenced by an exchange of notes."[21]

- Article XIV(4) — most importantly for present purposes — provides that "Canada and the United States of America may by an exchange of notes empower or charge the entities with any other matter coming within the scope of the Treaty."[22]

And this last example brings us to the question of "the Entities" and agreements between the Entities. The CRT pragmatically recognizes that while the Treaty itself is between the two governments, the responsibility for the construction, operation and coordination of storage, generation and related transmission facilities and general treaty implementation must necessarily fall to others — the designated Entities as prescribed by Article XIV(1) of the Treaty. The designated Entities for the operational purposes of the CRT are BC Hydro for Canada and the Northwestern Division, U.S. Army Corps of Engineers ("USACE") and the Bonneville Power Administration for the United States. Entity Agreements are not treaties and are not governed by international law. It should also be noted that each Party may change its designation of an Entity from time to time.

THE INTERIM FLOOD CONTROL/ FLOOD RISK MANAGEMENT ARRANGEMENTS

Before examining the Interim Flood Control/ Flood Risk Management Arrangements that the Parties have adopted it is useful to recall the Treaty provisions on flood control as well as what the Parties have publicly said about their AiP on this topic.

[18] Vienna Convention on the Law of Treaties, 23 May 1969, 1155 UNTS 331, s 2(1)(a). For confirmation that Canadian practice recognizes that an exchange of notes may constitute a treaty see Government of Canada, "Policy on Tabling Treaties in Parliament", s 5.1, (last visited 17 April 2025), online: <treaty-accord.gc.ca/procedures.aspx?lang=eng>.

[19] *Supra* note 2 art IV(1).

[20] *Ibid* art VIII(1).

[21] *Ibid* art XV(4).

[22] *Ibid* art XIV(4).

The Treaty and flood control

Flood control was one of the two main objectives of the Treaty (the other being power) when the Treaty was first negotiated. In order to achieve these objectives, Canada agreed to build the three treaty dams Keenleyside (Arrow), Duncan and Mica and to devote 15.5 million acre feet (MAF) of that storage for "flow improvement."[23] As it happens, Canada, built additional storage (especially behind Mica) giving rise to what is known as non-treaty storage. On the flood control side of things, Canada agreed to dedicate 8.45 MAF of the treaty storage to flood control.[24] Most of this (7.1 MAF) was originally allocated to Arrow, but a series of agreements between the Entities (concluding in 1995) has redistributed the flood control obligation as follows: Arrow, 3.6 MAF, Mica, 4.08 MAF and Duncan, 1.27 MAF (no change) for a total 8.95 MAF (BC Hydro agreed to increase total flood control space by 0.5 MAF in return moving the flood control space from Arrow upstream to Mica).[25] This storage was subject to the assured flood control operation discussed in the introduction until 2024. In return for the commitments associated with construction and operation, Canada received a one-time payment totalling US$64.4 million.[26]

Paragraphs 4 and 5 of Article IV[27] stipulate how Canada will be paid when it provides post-2024 called-upon flood control operations: the U.S. is to pay Canada "(a) the operating cost incurred by Canada in providing the flood control, and (b) compensation for the economic loss to Canada arising directly from Canada foregoing alternative uses of the storage used to provide the flood control."[28] The called-upon operation requires Canada to operate available storage (treaty and non-treaty) "to meet flood control needs for the duration of the flood period for which the call is made."[29]

What did the AiP say about flood risk management?

The AiP frames the flood provisions in the more modern language of flood risk management ("FRM") rather than flood control. The August 2024 "Public Document"[30] is rather brief. It begins by acknowledging the automatic change in the flood control rules of the Treaty which took effect in September 2024 and then goes on to provide that:

> Canada and the United States plan to update the pre-planned (also known as "assured") flood risk management operations with Canada, providing the U.S. with 3.6 MAF of pre-planned FRM for the Arrow Reservoir through to Operating Year 2044.
>
> Implementation of the pre-planned 3.6 MAF operation at Arrow would be accomplished by the Entities in the same manner as the current storage:
>
> - this volume would be evacuated according to an agreed *Storage Reservation Diagram* ("SRD");
> - *coordinated refill* of Canadian projects for U.S. FRM purposes would continue in the same manner as today, with *proportional* refill to manage downstream flows. The U.S. Entity is expected to submit an updated *Flood Control Operating Plan* corresponding to the 3.6 MAF FRM. In coordinating the operation of all Treaty storage for all purposes, every effort would be made to minimize flood damage in the United States and Canada.[31]

[23] See *ibid* art 2.

[24] See *ibid* art IV(2) and Annex A at para 5.

[25] All as detailed in the current Flood Control Operating Plan. See *supra* note 15 at 14, 24–26.

[26] As and when flood control became available at the three treaty dams (*supra* note 2 s VI(1)).

[27] *Supra* note 2 arts IV(4), IV(5).

[28] *Ibid* arts VI(4)(a) & (b).

[29] *Ibid* art IV(3) and the Protocol, art I (2) & (3).

[30] *Supra* note 9.

[31] *Ibid* at 1–2.

It will be observed that while the AiP relieves Mica and Duncan from assured flood control operations, Arrow will continue to be subject to the same 3.6 MAF that it has assumed since 1995. The Public Document[32] does not define the term "proportional refill" and this requires clarification.

As for compensation for the pre-planned FRM, the Public Document states that:

> The United States is expected to compensate Canada for preplanned FRM by providing US$ 37.6 million per year, indexed to inflation (based on the US Consumer Price Index or equivalent). Such compensation is expected to begin the first year in which Canada provides the pre-planned FRM, which can be as early as this operating year. Such compensation is expected to end after Operating Year 2044. Delivery of the pre-planned FRM operation will end when compensation ends.[33]

The Public Document also acknowledges that the assured FRM operation will be in addition to, rather than in substitution for, the post 2024 called-upon flood control operation described in Article IV(3) of the Treaty[34] and paragraphs 1 and 2 of the Protocol.[35] This appears from the Parties' commitment to "develop a process to enhance the understanding of each other's positions regarding *Called-Upon* flood control."[36] I examined the position of the Parties on this issue, particularly with respect to the trigger for a Called-Upon operation more than a decade ago[37] and the Parties themselves through their respective Entities have articulated their preliminary (and conflicting) positions on these issues in two important publications.[38]

Finally, the Public Document[39] also refers to a mutual interest in managing the flood risk on Kootenay Lake which implicates the operation of the Libby Dam (and perhaps also Duncan) as well as a "levels" order for Kootenay Lake established by the International Joint Commission (and referenced in Article XII(6) of the CRT).

We can now turn to the question of how the Parties have operationalized (or not) these provisions of the AiP within the interim arrangements for FRM.

HOW DO THE INTERIM FRM ARRANGEMENTS IMPLEMENT THE AiP?

To address the interim FRM arrangement, there are both (in chronological order) an Entity Agreement on pre-planned FRM (November 14 and 15, 2024) and an exchange of notes (November 18 and 22) between the Parties. While that may be the chronological order it is important to stress that insofar as a continuing pre-planned operation is inconsistent with the terms of the existing Treaty, we must locate the source of the authority to vary these terms. This requires a hierarchical rather than a chronological analysis since the Entities themselves clearly lack the authority to vary the terms of the Treaty. This suggests that our inquiry should begin with the exchange of notes but in practice it is easier to examine the two documents (Entity Agreement and exchange of notes) in parallel.

[32] *Ibid*.

[33] *Ibid* at 4.

[34] *Supra* note 2.

[35] *Ibid*.

[36] *Supra* note 9 at 2.

[37] Nigel Bankes, "The Flood Control Regime of the Columbia River Treaty: Before and after 2024" (2012) 2:1 Wash J Envtl L & Pol'y 1 at 1.

[38] For the U.S. see U.S. Army Corps of Engineers, *Columbia River Post-2024: Flood Risk Management Procedure*, Northwestern Division (2011), online (pdf): <critfc.org/wp-content/uploads/2019/07/Post-2024-White-Paper-09-11_FINAL.pdf>. For Canada see BC Hydro, *Canadian Entity's Preliminary View of Columbia River Treaty Post-2024 Called Upon Procedures*, BC Hydro and Power Authority (2013), online (pdf): <engage.gov.bc.ca/app/uploads/sites/6/2012/07/130214-CanadianEntity_View_CRT_Post-2024_CU-FINAL4.pdf>.

[39] See *supra* note 9 at 3.

Treaty authority for the interim FRM arrangements

The Entity Agreement claims that the arrangements between the Parties and the Entities are based on Article XIV(2)(k) of the Treaty. This is the paragraph that allows the Entities to prepare and implement detailed operating plans that may produce operations that are more advantageous to both countries than the operations that would be required under the terms of Annexes A and B of the Treaty.[40] By contrast, the exchange of notes regards the arrangements as effective under the broader terms of Article XIV(4) quoted above. In my view, this is a more convincing explanation of the authority for the arrangements. Indeed it is notable how the exchange of notes adopts the precise language of Article XIV(4) when the Parties recite that "the scope of the Treaty,"[41] which remains in force, includes "cooperative measures for hydroelectric power generation and flood control"[42] taken from the Preamble of the Treaty and so encompasses the Interim FRM Period Entity Agreement ; later the parties adopt the language of "empower or charge" and expressly reference Article XIV(4).

Duration

Both the Entity Agreement and the exchange of notes contemplate that the interim arrangements will run from this operating year (August 2024 – July 31, 2025) until July 31, 2027 (i.e. a three-year term) unless earlier superceded "on the first July 31st after the entry into force of the Modernized Treaty."[43] However, the Entity Agreement adds a coda to the effect that:

> If it appears to the Entities that the Modernized Treaty will not enter into force before July 1, 2027, the Entities will make good faith efforts to negotiate a new agreement between them in relation to pre-planned FRM operations that continues to reflect the July 8, 2024 agreement in principle.[44]

This commitment is not carried through into the exchange of notes but its inclusion in the Entity agreements suggests that the Entities themselves are none too sanguine about the early completion of formal Treaty Modernization.

Pre-planned or an option in favour of the United States?

Both the Entity Agreement and the exchange of notes refer to the arrangements as pre-planned, but the assurance of these pre-planned operations only runs in favour of the United States; there is no mutuality to the assurance. Instead, both arrangements offer the United States the *option* to require Canada to evacuate storage as required by the terms of the agreements; and it is only if and when the United States exercises that option that the U.S. is required to make the payment of US$37.6 million for the benefits conferred by the pre-planned or assured operation in the operating year to follow. While this might offer the U.S. the opportunity to game the election (and thus its liability) based on available information of snowpack etc., this seems unlikely in the ordinary course since the Entity Agreement requires that the U.S. make its election by September 30 of the preceding year. It is only in this first year (2024–25) that the U.S. was allowed to delay making an election until December 31, 2024. That said, this is not a firm rule since it allows the Entities to agree upon a different date. The election is made by the U.S. Entity making the prescribed payment. I have no information as to whether or not the payment was made for this year.

Both the Entity Agreement[45] and the exchange of notes remain faithful to the idea that nothing in these arrangements with respect to pre-planned FRM prejudices the U.S.

[40] *Supra* note 2.

[41] *Supra* note 5 at 2.

[42] *Ibid*.

[43] *Ibid*.

[44] *Supra* note 6 s 1 "Term".

[45] *Ibid* s 4 "Savings and Effect of Agreement".

entitlement to a called-upon operation. The exchange of notes puts it this way:

> The Government of the United States of America shares the understanding expressed by the Government of Canada in its note that the provision of and compensation for pre-planned FRM operations under the Interim FRM Period Entity Agreement would be distinct from and in no way related to the provision of and compensation for called-upon FRM operations under Article IV(3) of the Treaty.[46]

A new Flood Risk Operating Plan

As noted above, the existing Flood Control Operating Plan ("FCOP") (2003) effectively expired with the expiration of the assured operation required by Article 4(2) of the Treaty. The full implementation of the pre-planned FRM therefore requires a new Flood Risk Operating Plan ("FROP"). The Entity Agreement (confirmed in this regard by the exchange of notes) contemplates that the Parties will follow current FCOP practice such that the FROP will be developed in the first instance by the U.S. Army Corps of Engineers ("USACE"). The Entity Agreement also confirms that the FROP (including any updates) "will not be applicable in relation to the operation of Canadian. Treaty storage unless it has been accepted by the Canadian Entity."[47]

The Entity Agreement anticipates that the new FROP will be in place by March 31, 2025. Failing that, the Agreement stipulates that the Entities will apply current operating rules (i.e. the rules in effect under the FCOP for 2023–2024) with appropriate adjustments to reflect FRM storage of 3.6 MAF at Arrow (as contemplated by the AiP) during the "flood control refill period" defined in the FCOP as the "Reservoir regulation period that begins 20 days prior to the date the unregulated mean daily discharge is forecast to exceed 450,000 cfs at The Dalles, Oregon. The end of the Flood Control Refill Period will be when no further flood potential exists at any of the damage areas in Canada and the United States…"[48]

It appears that in the future the terms of the FROP will be reflected in the successive assured operating plans ("AOPs") or detailed operating plans ("DOPs") adopted by the Entities on an annual basis. But what happens in any year where the U.S. fails to make its payment and exercise its option for pre-planned FRM? The Entity Agreement suggests that in such a case "none" of the FRM provisions reflected in such AOPs or DOPs "will be applicable."[49] That sounds simple, but I suspect that it will be difficult to disentangle FRM operations in any particular case without the risk of disagreement.

Without prejudice

In addition to confirming their understanding that pre-planned FRM is supplemental to, and not in substitution for, the called-upon provisions of the Treaty (see above), the Parties also emphasise in their exchange of notes "that the empowerment and charge provided through this exchange of notes does not waive any options that may be available to either Party to resolve any difference arising under the Treaty, as provided in its Article XVI, and is without prejudice to the rights and obligations of the Parties under the Treaty."[50] The reference to Article XVI is a reference to the "settlement of differences" provision of the Treaty. This is significant insofar as the called-upon provisions do pose significant interpretive challenges which may ultimately require authoritative settlement by a third party.[51]

Other flood risk management issues in the AiP

There is nothing in the interim flood risk management arrangements to address other flood-related issues referenced in the AiP including the operation of Libby and flood issues on Kootenay Lake, or the need for clarity

[46] *Supra* note 5 at 4–5.
[47] *Supra* note 6 s 2, Pre-Planned FRM Operations.
[48] See *supra* note 15 at Appendix B. For the FCOP's treatment of damage areas in Canada see *supra* note 15 at 16–17.
[49] *Supra* note 6 s 2, Pre-Planned FRM Operations.
[50] *Supra* note 5 at 3, 5.
[51] See *supra* note 38 for the position papers of both Entities.

about the rules for the called-upon operation including the triggers for such an operation. Furthermore, while FCOP (2003) references Libby and the duty of coordination of Libby operations under Article XII (5) and (6), there is no reference to Libby in either the Entity Agreement or the exchange of notes and the existing Libby Coordination Agreement also expired in September 2024 along with the assured flood control provisions. The emphasis on Arrow in these documents suggests that we can expect the FROP to be silent on the coordinated operation of Libby. That said, I acknowledge that the Entity Agreement provides that "The scope of the FROP necessarily includes re-fill operations by the Canadian Entity, but may include other pre-planned operations in Canada or the United States of America."[52]

Finally, it is worth noting that the current FCOP also addresses the possible need for flood operations during the fall and winter where a combination of rain and low-elevation snowmelt can cause flood flows in the lower Columbia.[53] The FCOP requires both Arrow and Mica to operate within the range of natural flows "insofar as possible"[54] to address this risk. It is not clear whether these requirements (which might for example reduce energy otherwise available from Mica and Revelstoke) will be brought forward into the FROP.

POWER ARRANGEMENTS AND THE DOWNSTREAM POWER BENEFIT

It will be recalled that the CRT required Canada to construct 15.5 MAF of treaty storage that could be used for power purposes when not dedicated to flood control. This storage provided Canada with generation potential at Mica and subsequently at Revelstoke (a non-treaty run of the river dam immediately downstream of Mica) as well as a small amount of generation installed at Arrow/Keenleyside (185 MW)[55]. There is no generation at Duncan. In addition, and most importantly from a Treaty perspective, agreed operation of this Canadian storage in accordance with assured and detailed plans of operations (AOPs & DOPs) permitted U.S. mainstream dams to make more efficient use of the flow of the river. Accordingly, it was agreed that Canada would be entitled to 50 per cent of the incremental capacity and energy benefits at those mainstem facilities. This is known as the downstream power benefit and the calculation of the benefit is prescribed by Articles III – V and Annexes A and B of the Treaty. The mode of assessing the benefit and the size of the benefit became increasingly contested over time[56] and therefore, while there was no automatic sunsetting or change in the power provisions of the Treaty in 2024 as there was (as we have seen) for flood control, the scale of the downstream power benefit became an important part of the mix in the negotiations to modernize the CRT.

What did the AiP say about the power operation and the downstream power benefits?

The "Public Document"[57] describing the AiP contains two groups of provisions addressing the power side of the operation of Canada's Treaty dams. The first group of provisions (in the order in which they appear in the document) seeks to provide Canada additional flexibility in the operation of Treaty dams in order to address domestic priorities such as "environmental, Indigenous cultural values and socioeconomic purposes."[58] However, the AiP itself makes it clear that these rules only become operational *after* entry into force of the modernized Treaty. Accordingly, it is hardly surprising (albeit likely disappointing to some) that the interim arrangements do not integrate these flexibility provisions into Treaty operations during the interim period.

[52] *Supra* note 6 s 2, Pre-Planned FRM Operations.

[53] See *supra* note 17 at 9.

[54] *Ibid* at 26, 28.

[55] Columbia Power, "Arrow Lakes Generating Station" (last visited 24 April 2025), online: <columbiapower.org/facilities/arrow-lakes-generating-station>.

[56] For more discussion see Nigel Bankes, "The Columbia Basin and the Columbia River Treaty: Canadian Perspectives in the 1990s" (2001) Northwest Water Law & Policy Project, PO95-4, online (pdf): <ablawg.ca/wp-content/uploads/2025/02/Bankes_Lewis-and-Clark-Columbia-Paper_1996.pdf>.

[57] *Supra* note 9.

[58] *Ibid* at 3.

The second group of provisions deals with the downstream power benefits and simply prescribes a declining schedule of capacity and energy benefits without any supporting rationale or argumentation. The changes in the AiP cover the period commencing August 1, 2024 (the new operating year) through to July 31st, 2044. While the AiP does not expressly provide that this will be addressed in any interim arrangements, the Parties have chosen to do so by means of another exchange of notes[59] and two Entity Agreements (although one of these Agreements is the adoption of an assured operating plan ("AOP") for the current operating year, which, as I have already noted is relevant for both the flood control and power operations under the Treaty).[60]

Authority for the Downstream Power Benefit changes

In my opinion, any change to the manner in which the downstream power benefits to Canada are determined is a significant amendment to one of the most fundamental elements of the Treaty. Indeed, the entirety of Annex B of the Treaty is concerned with the "Determination of the Downstream Power Benefits"[61]. How then did the Parties finesse this issue in the interim arrangements? Once again, the key document is the exchange of diplomatic notes; the Entities don't get to amend the treaty by way of an Entity Agreement. And once again, Article XIV(4) is central to the argumentation. Here's that text again:

4. Canada and the United States of America may by an exchange of notes empower or charge the entities with any other matter coming within the scope of the Treaty.[62]

But the chain of reasoning in the exchange of notes is extremely thin. The notes again recognize that the scope of Treaty includes cooperative measures for hydroelectric power generation and then concludes that this extends to the Entity Agreement on the Interim Period Determination of Downstream Power Benefits.[63] There are at least two problems with this approach. First, the notes do not explain how a general treaty provision like Article XIV(4) can possibly override a whole series of specific provisions in the CRT dealing with the determination of downstream benefits. The first rule of treaty interpretation, much like the first rule of statutory interpretation, is the duty to read specific provisions in the context of the entire instrument. Article 31(1) of the Vienna Convention on the Law of Treaties puts it this way:

1. A treaty shall be interpreted in good faith in accordance with the ordinary meaning to be given to the terms of the treaty in their context and in the light of its object and purpose.

2. The context for the purpose of the interpretation of a treaty shall comprise, in addition to the text, including its preamble and annexes:

   (a) any agreement relating to the treaty which was made between all the parties in connection with the conclusion of the treaty;

   (b) any instrument which was made by one or more parties in connection with the conclusion of the treaty and accepted by the other parties as an instrument related to the treaty.[64]

But of course, in the case of a bilateral treaty, the Parties can agree on pretty much any interpretation of the treaty that suits their

[59] *Exchange of Notes, September 18 & 20*, *supra* note 5.

[60] *Supra* note 6.

[61] *Supra* note 2 Annex B (title).

[62] *Ibid* art XIV(4).

[63] *Exchange of Notes, September 18 & 20*, *supra* note 5.

[64] *Supra* note 18 art 31.

interests.[65] At least they can freely do so unless there is a person with standing (and a motivating interest) in a domestic court to make the argument that Article XIV(4), broad as it is, cannot be used to allow an Entity Agreement to significantly amend one of the foundational concepts of the Treaty. And in this case, the persons most affected (the owners of mainstem dams in the U.S. and their ratepayers), will have zero interest in contesting any reduction in the Canadian entitlement to downstream power benefits. (That said, the owners of those mainstem dams are questioning whether the U.S. Entities have been too generous to Canada in determining ongoing downstream power benefits[66]). And neither can we expect the Treaty's supervisory body, the Permanent Engineering Board ("PEB") established by Article XV of the Treaty to take any issue with this "amendment"; after all Article XV(4) instructs that the PEB:

> …shall comply with directions, relating to its administration and procedures, agreed upon by Canada and the United States of America as evidenced by an exchange of notes.[67]

The second problem however is that the Entity Agreement, while couched (through its title) as an agreement relating to the Interim Period, reproduces the *entirety* of the schedule from the AiP of Canada's declining benefits from this operating year through to 2044. And the exchange of notes appears to endorse this approach.

There is a second source of authority recited in the diplomatic notes for the Entity AOP arrangements[68] but to me this is secondary and not specifically relevant to the reduction in the downstream power benefits. I refer to the references to Article IV(1) of the Treaty (quoted above) which requires an exchange of notes whenever a new AOP departs substantially from its predecessor.

Finally, much like the FRM arrangements both the exchange of notes and the Entity Agreement on the downstream power contain broadly drafted without prejudice clauses confirming the applicability of the dispute settlement provisions of the Treaty.

CONCLUSION: WHEN IS AN AGREEMENT-IN-PRINCIPLE NOT AN AGREEMENT-IN-PRINCIPLE?

The answer to the above riddle must be that an agreement-in-principle is no longer a mere agreement-in-principle when the parties to the AiP have agreed to binding implementation of the AiP — or at least selected parts of that AiP. And while the AiP itself seems like a balanced agreement between the Parties, I think that there at least two ways in which these interim arrangements are somewhat one-sided.

The first way in which the interim arrangements are one-sided is that the U.S. gets what it wanted most out of the Treaty Modernization process *now*. It doesn't have to wait until the entry into force of a Modernized Treaty in order to get both pre-planned flood risk management operations and the immediate reduction of downstream power benefits. By contrast, Canada has to wait for both the "additional benefits" compensation and the flexibility to operate for values other than power and flood control. Neither do I see much assurance in these arrangements for Canada as to the future (and interim) coordinated operation of Libby, although that may become clearer when we see the new FROP.

The second way in which the interim arrangements are one-sided is that they clearly prioritize the traditional Treaty values of power and flood control and the traditional Treaty

[65] See the extended discussion of U.S./Canada treaty practice in Nigel Bankes & Barbara Cosens, "Protocols for Adaptive Water Governance: The Future of the Columbia River Treaty" (2014) Munk School of Global Affairs for the Program on Water Issues, online (pdf): <gordonfoundation.ca/wp-content/uploads/2018/05/2014_POWI_Protocols-for-Adaptive-Water-Governance-Final.pdf>.

[66] See press filings K.C. Mehaffey, "Mid-C PUDs Sue BPA, Corps for Failing to Develop Post-Treaty Plans" (28 June 2024), online: <newsdata.com/clearing_up/courts_and_commissions/mid-c-puds-sue-bpa-corps-for-failing-to-develop-post-treaty-plans/article_d4924d3c-34e9-11ef-9163-278f0736bc0b.html>; Matthew T. Richards, "Amid Ongoing Lawsuit, Mid-C PUDs Halt Energy Allotments to Canada" (29 October 2024), online: <kpq.com/amid-ongoing-lawsuit-mid-c-puds-halt-energy-allotments-to-canada>.

[67] *Supra* note 2 art XV(4).

[68] *Exchange of Notes, September 18 and 20, 2024*, *supra* note 3 at 2 (Canada) and at 4 (US).

players — the Entities. And so, while much has been made by all concerned, including the Parties, of the elevation of ecological values and the involvement of Indigenous peoples, all of that is pushed to one side by these interim arrangements. As Charles Wilkinson might have observed, the "Lords of Yesterday" are still with us today.[69] The Parties could have offered some further endorsements of these new directions for a Modernized Treaty. For example, they might have announced new or additional Entity designations or appointments to the PEB that would reflect the importance of ecosystem function in future operations under the Treaty.[70]

Perhaps no real damage will be done if these prove to be short-lived interim arrangements. But I think that there is at least some risk that the political instability south of the border, combined with the anti-Canada rhetoric and tariff talk emerging from the White House, along with anticipated changes in the federal government in Canada, will lead to these interim arrangements taking on a life of their own. And if that happens, it will become increasingly difficult to raise up the other values highlighted in the AiP, as well the enhanced involvement of Indigenous peoples and civil society. I hope that I am wrong.

And finally, there is one other aspect of these interim arrangements that I find troubling and that is that they do little to address the democratic deficit associated with the executive act of treaty making. I think I have demonstrated above that these interim arrangements are actually Treaty amendments dressed up as "empowerment" of the Entities. And yet these amendments have not been subject to the public scrutiny and debate typically devoted to significant treaty amendments. They have simply been adopted by diplomatic notes and Entity Agreements. It is of course true that there was *some* public debate on the AiP from mid-July 2024 onwards, but I don't recall anybody telling us, for example, that the Parties and Entities had already signed off on the exchange of notes authorizing a changed Assured Operating Plan and the Interim Period Entity Agreement on the Determination of Downstream Power Benefits as early as mid-September 2024. Furthermore, if these arrangements (and I refer here to the exchanges of notes) are in reality Treaty amendments, there is the question (at least on this side of the border) of why they were not tabled in parliament (I can find no record that they were) as required by the Federal Policy on the Tabling of Treaties in Parliament[71] a policy that was adopted to address the democratic deficit associated with treaty making by the executive branch. ■

[69] Charles Wilkinson, *Crossing the Next Meridian: Land, Water, and the Future of the West*, Island Press (1992).

[70] See e.g. for example the recommendations of the Universities Consortium on Columbia River Governance to the U.S. Negotiating Team for the Columbia River Treaty (2024), online (pdf): <ablawg.ca/wp-content/uploads/2025/02/UCCRG-comments-on-AiP-following-Nov-2024-Symposium_Final_US-Submission.pdf>.

[71] See *supra* note 17.

TOP RELIABILITY CHALLENGES TO CANADA'S ENERGY SYSTEM

*David Morton**

1. INTRODUCTION

The Canadian Energy Reliability Council ("CERC") was formed in 2024. Its goal is to focus on energy reliability as Canada navigates the ever-changing domestic and global energy marketplace and policy landscape. It will do so by facilitating collaboration between its members, stakeholders and government.

This article outlines the key energy reliability threats facing Canada's energy system. It is difficult to rank these threats; any ranking it may be possible to make can change abruptly. Further these threats are often coupled together for various reasons.

Threats to energy reliability originate from a number of different places, including the physical environment and changes in economic and trade patterns. However, a major driver of reliability risk arises from government and public policy, particularly with respect to net-zero.

As this article was being finalized a timely example of public policy risk emerged as a smoldering trade war between the U.S. and Canada broke out. It is impossible to predict the implications of this on energy reliability, on both sides of the border, but it is nevertheless important to understand what they may be.

2. WHAT IS ENERGY RELIABILITY?

For most of the past 150 or so years the energy system we enjoy in Canada has provided reliable energy to Canadians. But what is reliability and what do people mean by that term?

Most people have an intuitive sense of energy reliability: Can I find somewhere reasonably close to refuel my car and is that facility open when I need it? When I come home and turn on the switch, does the light go on? And when winter comes and the temperature drops, does the heating system in my home provide me with the warmth I need?

A reliable energy system answers yes to all these questions. Perhaps not every time — it is difficult for any system to deliver anything 24 hours a day by 7 days per week for 365 days of the year, each and every year. These difficulties arise for a number of reasons, including the unpredictability of the reliability of individual components of the system and therefore the difficulty of ensuring the efficacy of preventative maintenance programs and the speed with which the operator can adapt to new threats. Further, there is an inherent trade-off between reliability and cost. The more one spends the more reliable the system is likely to be. However, as more money is spent, the system becomes less affordable to those who use it.

However, as with many cost-benefit calculations, the low-hanging fruit is cheaper to pluck and the more reliable the system is, the higher the cost to improve it. That said, although reliability can, to some extent, be quantified, it has very different value to different consumers of energy, but as long as the times when energy isn't available are brief and infrequent most people are satisfied.

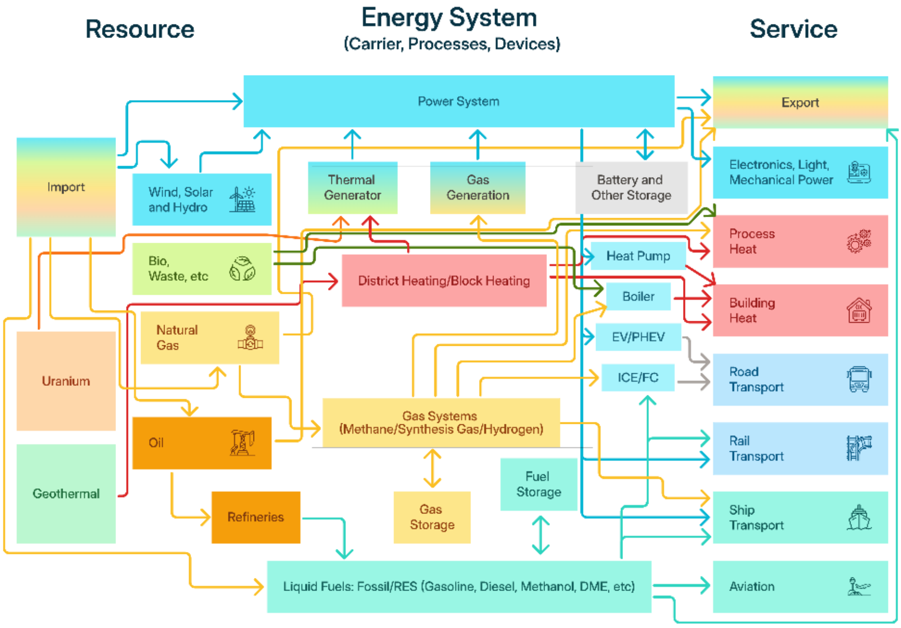
* David Morton is a professional engineer with over 45 years of experience, specializing in utility regulation and energy policy. He led the British Columbia Utilities Commission (BCUC) and conducted several significant inquiries for the British Columbia government. Currently, he is involved in international energy regulatory associations and frequently participates in global conferences and training sessions.

Resilience is closely related to reliability and the intuitive sense of energy reliability people have also includes the notion of resiliency. Resilience relates to reliability and includes how people perceive energy reliability. Reliability refers to normal operations, while resilience is about adapting to disruptions. Resilience also has a time component; the quicker an energy system adapts to disruptions; the higher perceived resilience. Both terms are often used interchangeably in contexts like power grids and pipelines.

3. CANADA'S ENERGY SYSTEM

Canada's energy system differs from province to province, with different mixes of energy types, fuels and delivery systems. The diagram below illustrates the interdependencies between segments of Canada's energy system. It isn't intended to be an accurate representation of the energy system in any province or territory, but an approximation of Canada as a whole.

Figure 1: Simulated energy flow in Canada[1]



[1] Antje, Orths et al., "Flexibility From Energy Systems Integration: Supporting Synergies Among Sectors", (2019) 17:6 *IEEE Power and Energy Mazazine*, at 1, online (pdf): <esig.energy/wp-content/uploads/2020/01/PRE-PRINT-Orths-Flexibility-from-Energy-Systems-Integration-.pdf>.

Canada's energy system is often talked about in terms of different sectors — the gas sector, the electricity sector, fuels, pipelines, etc. While in some cases, an individual company may operate in more than one segment, it is generally the case that the segments operate quite independently. However, as the diagram demonstrates, there are many touchpoints between sectors in the system.

The diagram does not display the many interconnections between the systems that, while not directly involved in energy production or transportation, remain essential. For example, electricity to provide power to refineries and pipelines and gasoline to power trucks to build and maintain the electricity network.

It is fair to say that Canada has one of the most reliable energy systems in the world. It has contributed substantially to the well-being of Canadians and the growth of one of the most successful economies in the world. Producers and providers of energy, whether regulated or not, take steps to ensure they can deliver energy to their customers — motivated both by competitive forces and/or a regulatory regime.

If we were to draw the same diagram for, say, 2050, it may look quite different, due in part to technology changes, but largely because of policy driving a lower carbon emitting system. Pathways that evolved relatively slowly over the past hundred years or so are now being redrawn. How will these changes impact the reliability of the energy system? Understanding these interdependencies is important when planning any changes. We will talk a bit about these changes, particularly those driven by energy policy, later in this article.

4. CAN ENERGY RELIABILITY BE MEASURED?

Most people don't use a measure for reliability, in the same way, for example, they measure how much energy they use or track how much it costs. However, the industries that produce, supply and sell energy do measure and track the reliability of their systems.

Canada's energy system consists of an economically regulated component (delivery of electricity and natural gas) and all the rest.[2] Economic regulation in Canada's energy system was originally introduced to remedy the market failures caused by monopolistic suppliers of energy services. The delivery of natural gas and electricity were considered "natural monopolies" which arose due to the enormous economies of scale inherent in their delivery system. However, monopoly suppliers can potentially control prices and quantities, leading to economic inefficiencies. Regulation attempts to mitigate any such inefficiencies by setting prices and other conditions of sale. Economic regulation is often referred to as price regulation.

In the portions of the energy system that are subject to economic regulation, the bedrock of economic regulation is a "regulatory compact" that attempts to balance the provision of "safe and reliable service" at rates that are "just and reasonable" and that provide the utility the opportunity to earn a "fair return". In the portion of the energy system that is market-based, competition works to set prices which a buyer and a seller are willing to transact — competition incents providers to continue producing and delivering reliable energy.

The companies that deliver our electricity and natural gas and the bodies that regulate them use various metrics to measure and track reliability. These include System Average Interruption Duration Index ("SAIDI") and System Average Interruption Frequency Index ("SAIFI").

5. HOW DO WE MAKE OUR ENERGY SYSTEM RELIABLE?

Organizations such as the Institute of Electrical and Electronics Engineers, the American Society of Mechanical Engineers, and the Canadian Standards Association develop and maintain standards to support the design, manufacture, deployment and testing of safe and reliable components of our energy infrastructure. These standards are followed by engineers, technicians and managers that build and maintain our energy system.

[2] In the Atlantic provinces and Nunavut, gasoline and diesel prices are set, either at the wholesale or retail level. In Quebec the "Régie de l'Énergie" establishes a minimum price under which retailers cannot sell.

However, energy reliability is "more than just a technical matter. It is also dependent upon the organizational structure that enables and constrains entities in their management of operations."[3] Management structures are very important and must be in place to ensure that infrastructure continues to be reliable throughout its operating life and that the necessary elements are in place to ensure operation as designed.

An example of a body that supports a systemic approach to reliability is the North American Electricity Reliability Corporation ("NERC"). NERC provides cooperative oversight of the high voltage grid in three countries: the U.S., Canada and Mexico.

It was constituted in its present form in response to a wide-spread loss of electricity in 2003, in the eastern U.S. and Ontario, caused by a tree falling on a powerline. This event caused an unexpected cascade of equipment tripping off,[4] thereby illustrating the vulnerability of an important component of energy infrastructure upon which people depend — not only for their livelihood, but to support human life.

Currently NERC imposes more than 100 mandatory reliability standards in areas of resource and demand balancing, critical infrastructure protection, communications, emergency operations, facilities design and maintenance, interconnection reliability operations, modeling, data and analysis, personnel performance, training and certification, and transmission operations.

6. WHAT ARE CANADA'S CURRENT ENERGY RELIABILITY CHALLENGES?

Threats to reliability challenge almost every step in the energy production and delivery process. These threats include environmental (e.g., fire, wind, flood, earthquakes), aging infrastructure, supply chain issues, cyber and physical threats, and electricity resource adequacy. The latter arises from changes to the electricity system undertaken to reduce GHG intensive generation with generation from renewable resources, while electricity demand is rising at a pace not seen for a long time. Most of us are aware of these threats — and some of us may have experienced the reliability impacts of them first-hand.

Reliability challenges often defy strict categorization. For example, upgrading infrastructure can make it more resilient to some of the environmental threats described below. Aging or improperly maintained infrastructure can be more vulnerable to environmental threats.

Further, as discussed earlier in this article, Canada's energy system has many interdependencies — for example, natural gas is critical for some electricity generation; without electricity, oil and gas flow in pipelines could be impacted. It is important to understand the interdependencies and their impact on reliable energy delivery.

6.1 Environmental threats

Environmental threats include wind, extreme heat and cold, wildfires, flooding, drought, tsunamis and earthquakes, amongst others. Because exposed energy infrastructure is particularly vulnerable to these threats, the electricity system is often the first and most visibly impacted. However, pipeline, road and rail infrastructure are not immune, especially to flooding and earthquakes. Wildfires and tsunamis can impact access to all energy infrastructure. Hydroelectric generation is particularly vulnerable to drought.

We have seen many such incidents in Canada. Notable examples are the wildfires in Fort McMurray that significantly impacted oil and gas extraction operations in Northern Alberta and floods in the Fraser Valley that exposed portions of the main north-south natural gas transportation pipeline.

Hardening infrastructure requires capital investment. Investment in the regulated sector — which includes pipelines and electricity transmission and distribution lines and other related infrastructure — typically require regulatory approval. Do regulators

[3] Daniel Scholten, *Keeping an Eye on Reliability: The Organizational Requirements of Future Renewable Energy Systems*, (Academic Publishers, 2012).

[4] Tripping off refers to a circuit breaker or other protective device opening, thereby cutting off power to prevent damage, overheating, or fire.

understand the need to ensure the energy system continues to be reliable in the face of these multiple threats?

Regulators are usually very conservative in their approach to spending approvals. They need to see a direct line between the need and the spend. Can they approve these investments, which could be characterized as "speculative" in that they may not be needed if an event doesn't happen or isn't reasonably expected to happen or is a high impact low probability event?

A better understanding of the threats themselves would help both regulators and utility companies. Earthquakes are difficult to predict, but a probabilistic assessment is possible and from that a risk analysis can provide the necessary evidentiary basis for a decision. Weather data upon which we rely for forecasting demand for energy and for driving codes and standards for construction of infrastructure only goes back, at best, a few hundred years — which is clearly proving to be too short a time-series for what we need. The same is true for sea, lake and river level data. Better data and a more effective approach to that data would help greatly.

Better data and ways to view the data we have can also be helpful for actors in other areas of the energy system that do not have to make a case to an economic regulator.

6.1.1 Increased demand during heat and cold waves

Extreme heat and extreme cold events cause a sharp spike in electricity and natural gas usage due to increased heating and air conditioning needs. While electricity and natural gas utilities typically design their systems to meet these peak days, the latter can still exceed available capacity for any number of reasons, including unexpected unavailability of supply of gas or electricity due to damage to infrastructure that is often related to the cause of the extreme heat/cold event. There is evidence that the frequency and duration of extreme weather events may be increasing. However, there appears to be no consensus on whether both are increasing and by how much they may be increasing. The recent fires in the Los Angeles area potentially point to another development: extreme weather occurring outside its expected season.[5]

6.1.2 Physical damage to infrastructure

Ice storms and strong winds can damage power lines, transformers, and poles, causing widespread disruptions to electricity supply.

Since extreme weather impacts reliability both through the potential to damage infrastructure and through the increase in demand described above, it is important to understand the quantitative aspects of any changes to weather-related parameters that are used to forecast load and to design infrastructure.

6.1.3 Rural and remote communities

Rural and particularly remote communities can be more vulnerable to many environmental threats. In addition, they are often off-grid and served by less reliable energy systems. Maintenance personnel may not be on site and therefore response times to an interruption can be longer. Access to replacement parts can be more challenging than in less remote areas.

6.2 Aging and under capacity infrastructure

Aging equipment and facilities directly threaten reliability. In some cases, they can also be a safety risk. Energy infrastructure requires long term "patient" capital investment. The ongoing energy system evolution and the desire to transform or abandon existing energy infrastructure is creating increased regulatory uncertainty. This impacts investors' willingness and ability to fund capital expenditure on existing energy infrastructure and maintain aging infrastructure — with serious implications for energy reliability.

Additionally, as the need to build more infrastructure increases, the approval and permitting process has become more complex. This is a well documented phenomena and it has serious implications for energy reliability going forward. Investment in energy projects in Canada may be perceived as riskier than in other jurisdictions leading to higher costs and difficulty financing projects.

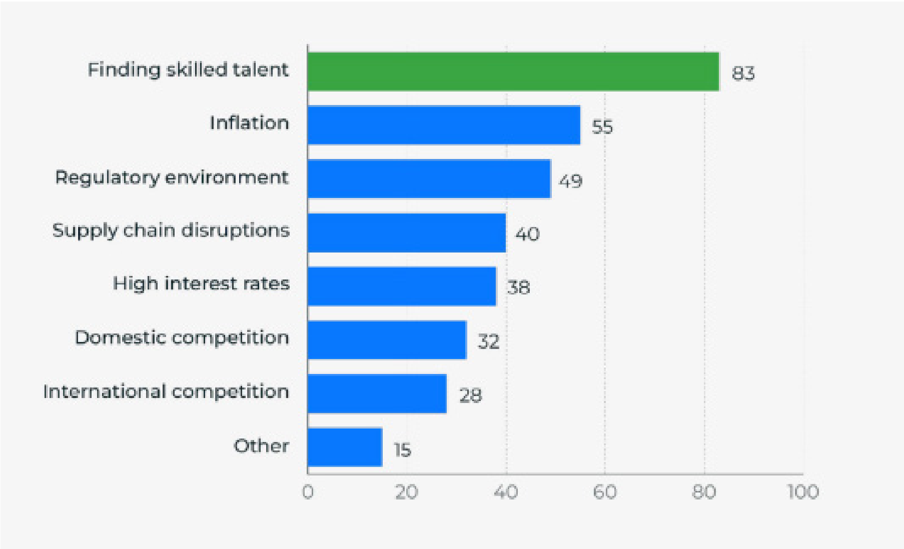
[5] Richard Vanderford, "Natural Disasters Cost $417 Billion Worldwide in 2024" (22 January 2025), online: <wsj.com/articles/natural-disasters-cost-417-billion-worldwide-in-2024-1bf513f3?msockid=2ef09c59de7f6a360bf988a1dfc76b32>.

6.3 Supply chain issues including skilled labour

The transition to low or zero-GHG emission electricity generation sources, the introduction of renewable natural gas ("RNG") and hydrogen into the fuel mix, new technologies such as Capture Carbon, Utilization and Storage ("CCUS") and electric vehicles — all such developments create new supply chain needs and changes in the skills required by workforces.

A new report projects Canada's energy industry could add up to 116,000 jobs by 2035.[6] Approximately 28,000 of those jobs are expected to be in the electricity sector by 2028.[7] Clearly this weighs heavily on the mind of management in the electricity sector as this recent survey indicates:

Figure 2: Most pressing issues constraining your outlook over the next 5 years (% of employers), 2023[8]



[6] Careers in Energy, *Canada's Energy Workforce: National Labour Market Outlook to 2035*, (Calgary: Careers in Energy, 2024) at 30, online (pdf): <careersinenergy.ca/wp-content/uploads/2024/03/FINAL_CIE-National-Outlook_Mar-19.pdf>.

[7] Electricity Human Resources Canada, *Electricity in Demand: Labour Market Insights 2023 – 2028*, (Ottawa: Electricity Human Resources Canada, 2023) at 12, online (pdf): <ehrc.ca/wp-content/uploads/2024/05/Electricity-in-Demand-Labour-Market-Insights.pdf>.

[8] *Ibid* at 88.

Is the pace and scale of the changes to our energy system achievable without risking shortages in any area that is essential to energy reliability? Importantly, we need to look beyond any part of that system. Constraints on skills and materials may also be felt by end users whether undertaking residential retrofits or repowering an industrial plant to use electricity or hydrogen.

6.4 Cyber and physical threats

Canada's energy system faces significant cyber and physical security threats that can disrupt operations, endanger public safety, and undermine economic and national security. These threats are increasing — and becoming increasingly sophisticated — as operators adopt digital technologies and artificial intelligence for management and control of their systems and infrastructure becomes more interconnected.

Suncor Energy, a leading company in the oil sands industry, experienced a significant cybersecurity incident in mid-2023. This attack, reportedly carried out by a sophisticated hacker group, led to a temporary halt in Suncor's operations, costing the company not only millions of dollars but also damaging its reputation.

The attackers targeted Suncor's operational technology ("OT") network, which controls physical processes and devices within the company's industrial systems. The attackers successfully infiltrated Suncor's corporate network and then moved laterally into the OT network, exploiting the interconnections between them. Once there, they deployed a ransomware attack, which locked up critical systems and demanded a ransom to restore access.

Suncor, for the most part, experienced no disruptions in the supply and delivery of fuels, although parts of its payment system at gas stations and convenience stores were affected. However, this incident raises important questions about how such events can be prevented.[9]

6.5 Electricity resource adequacy

After many years of almost stagnant growth in electricity demand, forecasters now predict significant increases in the need for electricity. For example, BC Hydro recently stated that in BC, electricity demand is expected to increase by 15 per cent between now and 2030. The Ontario IESO predicts increases of approximately 24 per cent by 2030, 37 per cent by 2035 and 75 per cent by 2050.

What is driving this increase in demand? There are a number of causes. One of the biggest reasons for stagnant demand in recent years is demand side measures taken by utilities to increase electricity efficiencies. These demand-side savings offset the increase in electricity demand driven by population and GDP growth, leaving electricity demand relatively flat. However, with measures such as the replacement of incandescent light bulbs with LEDs and significantly improved building insulation widely in place, a lot of that "low hanging fruit" has been picked. Coupled with this, population growth rate is on an upward trajectory. The substantial 3 per cent increase in Canada's population in 2023 marks the highest annual population growth rate in recent history, although that number moderated somewhat to 2.4 per cent in 2024.[10]

The increase in the number of data centers, particularly to fuel an AI boom also significantly drives electricity demand. Data centers are expected to represent 13 per cent of new electricity demand and 4 per cent of total anticipated Ontario demand in 2035.[11] Very recent developments in AI research and development may result in significantly lower power consumption, although AI is only one component of data centre demand growth. As a result, it is unclear what the impact of data centre demand growth will be.

[9] TeckPath, "A Deep Dive into the Suncor Cybersecurity Incident" (18 September 2023), online: <teckpath.com/a-deep-dive-into-the-suncor-cybersecurity-incident>.

[10] Statistics Canada, *Population estimates, quarterly*, Table 17-10-0009-01, (Ottawa: Statistics Canada, last modified 30 April 2025), online: <150.statcan.gc.ca/t1/tbl1/en/tv.action?pid=1710000901&cubeTimeFrame.startMonth=10&cubeTimeFrame.startYear=2013&cubeTimeFrame.endMonth=10&cubeTimeFrame.endYear=2024&referencePeriods=20131001%2C20241001>.

[11] Independent Electricity System Operator, *2025 Annual Planning Outlook: Demand Forecast Information Session*, Resource Planning: Demand and Conservation Planning (Independent Electricity System Operator, 2024), online (pdf): <ieso.ca/-/media/Files/IESO/Document-Library/engage/apo/APO-20241016-presentation-demand-forecast.pdf>. At the time this article was being finalized, recent development suggest that AI electricity use may be significantly lower than at first expected.

Forecast increased load for electric vehicles, electric heat pumps to replace natural gas furnaces and electric compression for LNG export facilities also contribute to increased electric load.

Is supply keeping up with this surge in demand? According to NERC, not everywhere:[12]

Capacity and energy risk assessment area summary			
Area	**Risk level**	**Years**	**Risk summary**
Midcontinent Independent System Operator (MISO)	High	2025	Resource additions are not keeping up with generator retirements and demand growth. Reserve margins fall below Reference Margin Levels (“RML”) in winter and summer.
Manitoba	Elevated	2028	Potential resource shortfalls in low-hydro conditions, driven by rising demand.
SaskPower	Elevated	2026	Risk of insufficient generation during fall and spring when more generators are off-line for maintenance.
Southwest Power Pool (SPP)	Elevated	2025	Potential energy shortfalls during peak summer and winter conditions arise from low wind conditions and natural gas fuel risk.
New England	Elevated	2026	Strong demand growth and persistent winter natural gas infrastructure limitations pose risks of supply shortfalls in extreme winter conditions.
Ontario	Elevated	2027	Reserve margins fall below RMLs as nuclear units undergo refurbishment and some current resource contracts expire. Demand growth is also adding to resource procurement needs.
PJM	Elevated	2026	Resource additions are not keeping up with generator retirements and demand growth. Winter seasons replace summer as the higher-risk periods due to generator performance and fuel supply issues.
SERC East	Elevated	2028	Demand growth and planned generator retirements contribute to growing energy risks. Load is at risk in extreme winter conditions that cause demand to soar while supplies are threatened by generator performance, fuel issues, and inability to obtain emergency transfers.
Electricity Reliability Council of Texas (ERCOT)	Elevated	2026	Surging load growth is driving resource adequacy concerns as the share of dispatchable resources in the mix struggles to keep pace. Extreme winter weather has the potential to cause the most severe load-loss events.
California-Mexico	Elevated	2028	Demand growth and planned generator retirements can result in supply shortfalls during wide-area heat events that limit the supply of energy available for import.
British Columbia	Elevated	2027	Drought and extreme cold temperatures in winter can result in periods of insufficient operating reserves when neighbouring areas are unable to provide excess energy.

[12] North American Electric Reliability Corporation: *2024 Summer Reliability Assessment, May 2024*, (North American Electric Reliability Corporation, 2024), online (pdf): <nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2024.pdf>.

In some regions, the integration of large amounts of intermittent renewable energy sources, particularly wind and solar, into the electricity grid poses challenges primarily due to their variability and unpredictability. These sources depend on weather conditions — solar power generates energy only during daylight hours and is affected by cloud cover, while wind energy depends on wind speeds, which can fluctuate.

This intermittency can lead to mismatches between energy supply and demand, particularly during peak usage periods when renewable generation may be insufficient. Without adequate energy storage solutions or backup generation, the grid risks instability and/or blackouts. We will look a bit further at this in the following sub-section. Addressing these challenges requires investments in grid infrastructure, large-scale energy storage, demand-response technologies, and diversified energy sources to ensure a stable and reliable electricity supply.

The need for reliable back-up generation is increasingly being met by natural gas. However, generally speaking, natural gas generation tends to rely on a just in time delivery system for its fuel. This raises issues around the reliability of the gas supply and the follow-on impact on the reliability of the electric system. NERC is taking an active role in this area and has published a number of analyses on this issue.[13]

Other reliability issues related to the deployment of intermittent renewables include:

- Inverter based resources — Solar and wind generate DC current and require power for electronic devices to convert DC to AC current. The maturity of this technology presents challenges to maintaining grid reliability, stability, and operational efficiency.

- Increasing amounts of generation on a distribution system that doesn't have the same level of reliability oversight as the high voltage grid. This also poses a challenge to high voltage grid operations as there is limited "visibility" into these generation resources.

6.5.1 Intermittent renewables

Around the world and in Canada, increasingly more electricity is generated by intermittent renewables. California leads the U.S. in the amount of electricity generated by wind and solar. According to the Solar Industries Association, the end of 2023 California had a total of 46,874 MW which provided for 28 per cent of the state's electricity generation. Wind accounted for 6.9 per cent as of 2022.

How does the electricity grid handle one third of its electricity generated by intermittent sources? According to the California's Independent System Operator ("CAISO"), one way is

> [r]otating outages, or controlled load reductions, which are relatively short power disruptions that alternate throughout communities to reduce demand to match supply and maintain grid reliability. Planned outages help stretch available energy when supplies are short and ensure the grid doesn't collapse into uncontrolled and unplanned power failures, while limiting outages to the smallest group of customers in a more contained area for shorter periods of time.[14]

Not all rotating outages are caused by a shortage of electricity from intermittent sources, As the CAISO points out, in addition to cloud cover and a lack of wind reducing solar and wind generation and affecting available supplies, adequate energy supply can also be impacted in several ways, primarily by high temperatures which causes increased air conditioning use and drives up electricity demand and unexpected power plant or transmission line outages caused by mechanical failure, wildfire, or constraint on transmission lines.

---

[13] See e.g. North American Electric Reliability Corporation: *Reliability Guideline: Fuel Assurance and Fuel-Related Reliability Risk Analysis for the Bulk Power System*, (Atlanta: North American Electric Reliability Corporation, 2023), online (pdf): <nerc.com/comm/RSTC_Reliability_Guidelines/Fuel_Assurance_and_Fuel-Related_Reliability_Risk_Analysis_for_the_Bulk_Power_System.pdf>.

[14] California Independent System Operator, *Fact Sheet: Rotating power outages*, (2023), online (pdf): <caiso.com/Documents/Rotating-Power-Outages-Fact-Sheet.pdf>.

The CAISO initiated rotating outages on August 14 and15, 2020. Before that, it had been almost two decades since outages were imposed due to energy shortages. What triggered this rotating outage? According to the Root Cause Analysis ordered by the Governor after that event, three factors necessitated rotating outages:

- An extreme heat wave across the western United States resulting in demand for electricity exceeding existing electricity resource adequacy and planning targets,
- In the late afternoon, solar generation declines at a faster rate than demand decreases, and
- Some practices in the day-ahead energy market exacerbated the supply challenges.

Across all of Canada, electricity production by intermittent renewables is much lower, at 6.6 per cent:

- Wind Energy: Increased from 1.5 per cent in 2013 to 5.8 per cent in 2022.
- Solar Energy: Grew from 0.1 per cent in 2013 to 0.8 per cent in 2022.

However, solar and wind generation isn't uniformly distributed across the country. As of 2021, PEI leads the provincial pack with 99 per cent of its electricity generated by wind. Next are Alberta with 20 per cent wind, 6 per cent solar and Ontario with 10 per cent wind 2.5 per cent solar.[15]

Even at these lower penetrations, intermittent renewables can still be impactful if the wind doesn't blow, or the sun doesn't shine. For example, on April 5, 2024 the Alberta Electric System Operator ("AESO") shed firm load for the first time since 2013. Although electricity demand was relatively low on April 5 as prevailing temperatures were close to 0°C across Alberta, there was a high amount of thermal generator outages and low wind generation, which reduced supply.[16]

Prior to the load-shed event, a period of exceptionally cold weather drove high demand, prompting the AESO to declared Emergency Energy Alerts ("EEA") events on four consecutive days, from January 12 through January 15, 2024. EEAs indicate that the province's electricity grid is under stress and facing a potential supply shortfall and the need for grid stability measures. The AESO stated that "extreme cold resulting in high power demand has placed the Alberta grid at a high risk of rotating power outages. As a result, it asked Albertans to immediately limit their electricity use to essential needs only."[17]

The report on the outages attributed the EEAs to a combination of existing generator outages and very low wind generation throughout the day. The report also noted that the wind forecast started to anticipate low wind production around January 11, 2024.

6.6 Public policy and decarbonizing Canada's energy system?

Many of the changes to Canada's energy system that we are experiencing, and we will likely continue to experience are driven not principally by organic, bottom-up demand, but by top-down policy. This policy sets various targets and goals for 2030, 2035, 2040, and by 2050 a goal of net-zero GHG emissions economy wide.

What consideration does this policy give to energy reliability? Is the pace and scale of the proposed changes achievable without risking shortages in any area that is essential to energy reliability? Importantly, we also need to look beyond any particular part of the energy system. Some of the biggest reliability impacts may be felt by end users, as the way they use different types of energy is likely to change, whether as the result of residential retrofits or repowering an industrial plant to use electricity or hydrogen.

[15] Canada Energy Regulator, "Provincial and Territorial Energy Profiles" (last modified 6 September 2024), online: <cer-rec.gc.ca/en/data-analysis/energy-markets/provincial-territorial-energy-profiles>.

[16] Alberta Market Surveillance Administrator, Alberta electricity system events on January 13 and April 5, 2024: MSA review and recommendations, (Alberta Market Surveillance Administrator, 2024), online (pdf): <albertamsa.ca/assets/Documents/January-and-April-2024-Event-Report.pdf>.

[17] *Ibid* at 6.

Increasingly, energy policy is driving the replacement of liquid and gaseous fossil fuels with electricity — replacing molecules with electrons that must be produced or generated using energy. However, as we discussed above, concerns about electricity resource adequacy are already emerging. Where will the electricity to power a net-zero policy that relies on electricity come from?

Already steps are being taken to accelerate the move to electricity — including municipal gas bans. A number of Canadian municipalities have prohibited or curtailed the use of natural gas in new building construction, including the Metropolitan Community of Montreal, City of Vancouver, City of Richmond BC, Nanaimo BC and Prévost, Quebec.

Additionally, two recent regulatory decisions found that demand for natural gas will significantly decline in the face of increased electrification and in one case, denied a capital project to upgrade a pipeline and in the other disallowed any amortization period for certain natural gas infrastructure investments.[18]

These actions may be well intentioned, but do they consider whether there will be enough electricity in place at a price that is affordable to average Canadians to replace the natural gas needed to heat homes and businesses and power industry? If there isn't sufficient electricity, where it will come from?

A recent *Energy Regulation Quarterly* article discussed these decisions at greater length.[19] That article concluded that

> for regulators to make informed decisions requires a holistic view of an energy transition that is not always amenable to such views. It also requires policy makers to provide clear policy direction when at all possible and when not possible to ensure that they encourage and support the regulator to take steps to consider all the aspects of the energy system when making decisions about the energy transition.[20]

While federal and provincial energy policy may increasingly lean more heavily towards electrification as 'the' pathway to achieve net-zero by 2050, there could be other viable pathways as well. Other options include, but may not be limited to:

- CCUS used in industrial processes and from fossil fuel use to enable net-zero operations without full electrification.
- Increased utilization of mini and micro energy grids, including district thermal systems using Combined Heat and Power ("CHP").
- Green or low carbon hydrogen to replace fossil fuels in industries and transportation.
- Biofuels and synfuels to decarbonize aviation, shipping and other hard-to-decarbonize sectors.
- Biomass used for heating.
- Nuclear energy with advanced nuclear reactors and small modular reactors ("SMRs") providing high-temperature heat for industry, reducing reliance on fossil fuels. This could be in conjunction with CHP district energy systems.
- Geothermal and renewable/waste heat to replace fossil-fuel based heating in buildings and industrial processes, including CHP systems.

It is important to look at these alternatives not only from a cost perspective, but to consider the reliability implications of adopting — or not adopting — these energy pathways.

---

[18] *Phase 1 Enbridge Gas Inc: 2024-2028 Rates Proceeding* (21 December 2023), EB-2022-0200, at 2, online (pdf): OEB <rds.oeb.ca/CMWebDrawer/Record/827754/File/document>. See also *FortisBC Energy Inc: Application for Certificate of Public Convenience and Necessity for the Okanagan Capacity Upgrade Project* (22 December 2023), G-361-23, online: BCUC <ordersdecisions.bcuc.com/bcuc/decisions/en/522057/1/document.do>.

[19] David Morton, "The Energy Transition and Natural Gas: Two Regulators Speak Out" (2024) 12:4 Energy Regulation Q, online: <energyregulationquarterly.ca/articles/the-energy-transition-and-natural-gas-two-regulators-speak-out >.

[20] *Ibid*.

7. SUMMARY

This article has looked at some of the challenges to the continued delivery of reliable energy to Canadians. In assessing and responding to these challenges it is important to understand the interdependencies in the system and not taking a siloed approach to viewing it. It is also important to acknowledge the greatest threat may be one that has not been identified — the unknown unknowns. Even so, so called known unknowns also sometimes come back to bite quite ferociously, demonstrating a significant shortcoming in preparation of such usually infrequent events. Some examples are the Colonial Pipeline shutdown[21] and the 2021 incident of gas wells freezing in Texas[22] — although as we learn more about threats generally, we can improve preparations for future adverse events.

Hardening infrastructure improves reliability and resilience in the face of many threats but requires a thoughtful approach. Investments are expensive and energy infrastructure is long lasting. As a result, return periods for investors are long. Further, the diminishing returns on reliability investments discussed earlier must be considered.

Public policy towards net-zero pathways is increasingly impacting energy system reliability and this impact may well increase. At the time of writing, there is little consensus on an approach that balances reliability and resiliency with other key goals — affordability and GHG emissions — and little understanding of how that consensus can be reached. This lack of a consensus puts us all at risk of reduced access to reliable energy. ■

---

[21] Colonial Pipeline, a major U.S. fuel pipeline, experienced a significant ransomware attack by the DarkSide group. This attack resulted in the temporary shutdown of the pipeline, causing widespread fuel shortages and panic buying along the East Coast. Colonial Pipeline ultimately paid a ransom to the attackers, but the attack highlighted the vulnerability of critical infrastructure to cyber threats. See generally Shariq Khan, "Colonial Pipeline's main US gasoline artery likely shut Friday" (last modified 15 January 2025), online: <reuters.com/business/energy/colonial-pipelines-main-us-gasoline-artery-likely-shut-until-friday-2025-01-15>.

[22] During severe winter storms in Texas, freezing temperatures can disrupt natural gas production by causing "freeze-offs" at wellheads and in pipelines, leading to reduced gas supply. This phenomenon, where ice or hydrates form and block gas flow, can shut down power plants and impact overall energy supply.

REPRICING THE GRID: SHOULD IT BE REGULATED AS A COMMON CARRIER?[1]

*Mark Kolesar**

THE PROBLEM WITH AVERAGE COST-BASED PRICING

Bonbright's principles of public utility rates assumed vertically integrated electricity monopolies and proposed that ratemaking balance the interests of utility capital attraction with those of ratepayers. Bonbright's approach focused on establishing a reasonable utility revenue requirement that allows the company to recover prudently incurred costs and earn a fair return, fair apportionment of costs among customer classes, and optimal consumption efficiency, all at the discretion of the regulator.[2] Implementation of these principles was, and generally still is, in the form of average cost-based pricing. The key assumption is that the provision of electricity is a natural monopoly characterized by decreasing average cost throughout the full range of (kWh) production.

These principles formed the foundation of utility rate setting that is largely practiced today. However, consumers are increasingly presented with alternatives to grid-supplied electricity, which has led to many changes in the monopoly aspects of the utility. This creates new issues such as tariff bypass, bill shock and potentially a worsening of energy poverty.[3]

The advent of distributed energy resources is also producing new customer segments: the prosumers and flexumers[4] among others, such as competitive retailers, who are competing with distribution utilities at the edge of the grid. Although many of these market entrants continue to take delivery of energy when needed, they also engage the grid for purposes other than passively receiving grid-supplied energy. Currently, along with policies to incentivize the adoption of photovoltaic generation, including rebates and other

[1] This article is based on the author's previous writing. An earlier and longer version of this article can be found here: Mark Kolesar, *Rethinking, repackaging and repricing the grid and retail electricity*, Fereidon Sioshansi in The Future of Decentralized Electricity Distribution Networks (London UK: Elsevier, 2023).

* Mark Kolesar is a researcher, author and consultant in utility regulation and policy development, and a frequent participant in webinars and conferences in Canada and the U.S. He was a member of the Alberta Utilities Commission for twelve years, including six years as Vice Chair and two years as Chair. Mark is now managing principal at Kolesar Buchanan & Associates Ltd., where he advises on utility regulation matters. Mark is grateful to Bruce Chapman of Christensen Associates Energy Consulting for his contributions to this article.

[2] Karl R. Rábago & Radina Valova, "Revisiting Bonbright's principles of public utility rates in a DER world" (2018) 31:8 at 9. Bonbright's revision in Principles of Public Utility Rates (1988) referred to marginal cost pricing, however the technology to implement it was not yet available.

[3] Tariff bypass is the act of connecting an end-use customer directly to an electric delivery system other than the customer's utility distribution system. Bill shock refers to a rapid increase in a customer's utility bill, generally assumed to be an increase of more than 10 per cent. Energy poverty refers a situation where a household lacks adequate access to energy, in this context because the cost of energy is too high so that other basic needs are forgone.

[4] A prosumer is a utility customer who both consumes and produces energy, either for self-consumption or for others. A flexumer combines consumption, generation, and storage and provides market flexibility in the demand for and provision of energy on the grid.

financial inducement, the major reason consumers make investments in distributed generation and storage that reduce their demand for grid-supplied electricity is because of the incentives provided by average cost-based pricing of retail electricity.

In many jurisdictions throughout North America and elsewhere, the average retail price is significantly above the annual average marginal cost of supplying the last kWh. This market distortion encourages poor utility decision making and incentivizes consumers to reduce their electricity bills by at least partially exiting the grid supplied energy system, or engaging it in new ways to offset the cost of grid supplied energy.[5] Using California as an example, the average marginal cost per kWh withdrawn from the grid by a residential consumer is less than five cents, but the consumer is charged an average price of 22 cents to recover the sunk costs of the transmission and distribution grid as well as other often policy driven costs. Under net energy metering, a rooftop solar system, at an estimated cost of $3.50 per Watt, allows the consumer to avoid much of the 22 cents/kWh average price of grid-supplied electricity.[6] Although this makes it economical for consumers who invest in rooftop solar, these costs must now be recovered from a smaller number of utility-generated kWh. More than 15 per cent of residential electricity consumption in California, for example, is behind-the-meter solar, which has shifted cost recovery onto non-solar customers.[7] Accordingly, the total cost of utility-provided electricity increases for all consumers.

As sunk costs are recovered from a shrinking base of energy consumers, those consumers who still rely on utility-provided electricity for all their load are increasingly burdened with the cost of recovering a disproportionate share of distribution grid costs. And, as the price of utility-provided energy increases in response, those who can avail themselves of alternatives to utility-provided electricity will have a greater incentive to do so. This problem is exacerbated by commercial and industrial customers who can engage in 'behind the meter' generation as the cost of self-supply comes down. As a result, providing ubiquitous service at affordable rates will pose challenges to regulators and government policymakers.

The bypass of utility tariffs will lead to potential rate shock for the remaining but shrinking, base of energy customers. This creates another issue, namely energy poverty. Energy poverty is already a significant issue for 27 per cent of U.S. households who forego food and medical care to pay for energy as of 2020.[8] In Canda, two million people report energy poverty, predominately among seniors, renters, newcomers, and single-parent families.[9]

The conventional economic wisdom calls for tariff reform and the adoption of marginal cost pricing. However, few utilities have rushed to adopt marginal cost pricing, because of barriers including inadequate metering infrastructure, regulator resistance, and utility indifference. As non-utility alternatives proliferate, a shift to marginal cost pricing will eventually become more attractive as a means of dealing with consumer abandonment in the face of price escalation and potential earnings attrition for utilities.

Unfortunately, many jurisdictions have a significant sunk cost recovery challenge, often exacerbated by the imposition of costs related to climate policy. With so much fixed cost to recover, the conventional approach to marginal cost pricing of utility services may not be sufficient. A new more expansive approach to pricing use of the grid may be necessary.

---

[5] Ruchard J. McCann, *Leveraging the rise of the prosumer to promote electrification* Fereidon Sioshansi in The Future of Decentralized Electricity Distribution Networks (London UK: Elsevier, 2023).

[6] Frank A. Wolak & Ian H. Hardman, *The Future of Electricity Retailing and How We Get There SpringerLink* volume 41 (Switzerland: Springer Nature, 2022), online (pdf): <link.springer.com/content/pdf/10.1007/978-3-030-85005-0.pdf>.

[7] Next 10, *Designing Electricity Rates for An Equitable Energy Transition*, (The Energy Institute at UC Berkeley's Haas School of Business, 2021).

[8] U.S. Energy Information Administration, "Residential Energy Consumption Survey", online: <eia.gov/consumption/residential>.

[9] Efficiency Canada, "Energy Poverty in Canada" (last visited 2 May 2025), online: <efficiencycanada.org/energy-poverty-in-canada>.

THE GROWTH IN NON-UTILITY ALTERNATIVES

Decarbonization of electricity generation is gradually replacing traditional base load dispatchable supply from fossil fuels with intermittent renewables. The U.S. alone is projected to require 1200 GW of additional renewables to achieve the decarbonatization policy goals set for 2035.[10] Much of the renewable capacity will be utility scale solar and wind, which will be augmented by smaller scale localized distributed resources. A significant portion of these latter resources will be in the form of non-utility small scale renewables. In Canada, the adoption of non-utility small scale renewables has been significantly slower than in the U.S. However, with policy changes and as the installed cost of small-scale roof top solar continues to decline, the current adoption rate of one in 200 homes can be expected to reach one in three homes by 2050.[11]

In addition, community-based energy initiatives promoting local engagement and sustainability are developing in Canada with an increasing interest in community solar projects and local energy co-ops.[12] There is also an increased interest in the adoption of microgrids in North America, in industrial parks, on college campuses and in residential communities. For example, in Edmonton, Alberta, Blatchford's district energy sharing provides centralized energy to all the buildings within the community, tying in renewable energy sources like geo-exchange, sewer heat recovery and solar panels.[13]

Transactive energy projects are also being developed. In 2016, a $16.4 million Canadian project was launched to link three widely dispersed microgrids in Toronto, Nova Scotia, and upstate Maine into a 'transactive energy' framework.[14] Companies like ConsenSys are now developing peer to peer trading platforms, such as Grid+, which give consumers direct access to wholesale energy markets.[15] The Rocky Mountain Institute and Grid Singularity have joined forces to launch Energy Web Foundation and create open source applications for energy trading that allow "any energy asset owned by any customer to participate in any energy market."[16] Virtual Power Plants[17] are also gaining acceptance. In 2022, the VPP market was valued at $1.08 billion. The VPP market is expected to grow annually at a compound annual growth rate of 12.75 per cent to 2030.[18]

THE NEED FOR TARIFF REFORM

As the growth in non-utility alternatives accelerates, tariff reform will become increasingly urgent. Retail tariff reform is necessary to ensure that customers making investments that reduce their consumption of grid-supplied energy are doing so, not only to reduce their own costs, but because that investment reduces the overall cost of supplying

[10] GrildLAB, Goldman School of Public Policy, University of California Berkeley, "Home - 2035 The Report" (last visited 15 April 2021), online: <2035report.com>.

[11] Dunsky Energy + Climate Advisors, *BTM Solar: Canadian Market Outlook: How Behind-the-Meter (BTM) solar can contribute to Canada's net-zero future*, (Canadian Renewable Energy Association, 2023), online (pdf): <renewablesassociation.ca/wp-content/uploads/2023/12/BTMSolar_CdnMarketOutlook_Oct2023_CanREA_Dunsky-ExecSummary.pdf>.

[12] Statista, "Energy - Canada" (last visited 2 May 2025), online: <statista.com/outlook/io/energy/canada>.

[13] City of Edmonton, "Blatchford Renewable Energy" (last visited 7 May 2025), online: <edmonton.ca/city_government/utilities/blatchford-renewable-energy.aspx>.

[14] Jeff St. John, "A 3-Part Microgrid Launches in Canada, With Transactive Energy as the Goal" (20 September 2016), online: <greentechmedia.com/articles/read/a-three-part-microgrid-launches-in-canada-with-transactive-energy-as-the-go>.

[15] Grid+, "Grid+ ICO Review - Blockchain Lowering Energy Costs? Grid PLUS" (25 October 2017), online (video): <youtube.com/watch?v=P9FOSLl_3p0>.

[16] Nonetheless, small scale peer to peer trading is still slow to develop. See Jason Deign, "Peer-to-Peer Energy Trading Still Looks Like a Distant Prospect" (23 December 2019), online: <greentechmedia.com/articles/read/peer-to-peer-energy-trading-still-looks-like-distant-prospect>; See also Energy Web, "Build Connect Transform" (last visited 7 April 2025), online: <energyweb.org>.

[17] A virtual power plant (VPP) is an integrated set of power resources that provide power to a micro-grid and usually sells excess power on demand to an interconnected utility grid.

[18] Renée Müller, "VPP explained: What is a Virutal Power Plant?" (23 Octobre 2024), online: <tibo.energy/blog/virtual-power-plant-vpp>. See also Evans, "The Emerging Trend of Virtual Power Plants in Electric Utilities" (last visited 7 May 2025), online: <evansonline.com/blog/the-emerging-trend-of-virtual-power-plants-in-electric-utilities>.

all consumers with electricity and does not simply shift sunk costs on to other consumers.

In the emerging market environment, the proliferation of intermittent renewables coupled with average cost-based pricing leads to significant problems including balancing supply and demand and efficient network utilization, tariff bypass, and the threat of rate shock and energy poverty.

Low-output, intermittent generation, particularly at the consumer level, is being distributed rapidly throughout the grid, particularly in California and other southern states with ample sunshine. With the proliferation of non-utility intermittent distributed generation, balancing supply and demand in real time becomes more challenging for grid operators. The topology, composition, and management of electrical grids will have to adapt, adding more costs to managing the grid.

Tariff reform in the form of spatially and temporally varying pricing of distribution network services can provide incentives for investments in load-flexibility technologies that can benefit all customers. The declining cost of network monitoring and metering equipment and automated response technologies can allow significantly more efficient use of existing distribution networks and the development of new services. Transitioning to marginal cost-based pricing of retail electricity and repricing use of the grid can avoid the issues of bypass and needless price escalation and abate the threat of energy poverty.

However, regulators are often challenged to bring about change either because they are actively blocked by those with an interest in maintaining the status quo, or passively blocked by regulatory inertia or a lack of knowledge. Regulators may exhibit a status quo bias that keeps traditional rate structures in place to avoid perceived problems such as bill impacts. In addition, rate complexity and price risk may present challenges to regulatory acceptance of alternative rate designs. There may also be legislative and other jurisdictional barriers that constrain regulators from implementing regulatory renewal.

Despite the growing adoption of interval metering and grid technology improvements, and the back-office infrastructure required make data available to facilitate the adoption of marginal-cost based pricing, adoption has been slow. Although there are economies of scale and scope in the installation of modern technologies, the question of who should bear the burden of additional cost recovery over the immediate term presents a challenge to regulators, as do issues of intergenerational equity, allocation of risk, and recovery of stranded capital, among others.

Regulators have often included explicit subsidies in rate designs to support affordability for specific customer classes or to promote innovation, usually by manipulating revenue to cost ratios among costumer classes or by adopting rate riders. These subsidies will be unsustainable as bypass erodes utility revenues, either because volumetric energy rates collect the subsidy shortfall from certain classes of customer or because the rate riders that collect the shortfall are also volumetric; all of which invites tariff avoidance.

In addition, as alternatives to utility-delivered electricity expand, the rates that would prevail under a regulated monopolist will be vulnerable to entry by cream skimming[19] competitors, in the absence of marginal cost-pricing. Services that support subsidies for policy objectives such as keeping rates affordable for certain customer classes or promoting the introduction of innovative technology are likely to be targeted by competitors. Competitive alternatives will likely be priced below utility-delivered energy and gradually move pricing toward their own marginal cost as utilities respond until market equilibrium is achieved. Predictably, selective cream skimming can undermine the broader goal of affordability, as well as posing financial difficulties for a regulated utility required to provide ubiquitous availability throughout its territory.

Abandoning average cost-based pricing in favor of marginal cost-based pricing allows the utility to disaggregate its bundled delivered electricity tariffs into tariffs based on the marginal cost of the components required for the delivery of the service. This allows for a new

[19] Cream skimming refers to a market entry pricing practice to attract only high value or low-cost customers while leaving lower value or higher cost customers to the incumbent provider.

approach to pricing, akin to pricing models in competitive markets that recognize the cost of delivering services as well as the relative value to customers, including those who use the grid for the delivery of services that compete with the utility.

More efficient pricing of services provided on the distribution network will allow customers with distributed generation and storage to realize economic benefits without shifting the cost burden of legacy networks or necessary network reinforcement onto other customers. Transitioning to marginal cost-based pricing of retail electricity would help to eliminate the incentive to make uneconomic investments, provide incentives for investments in load-flexibility technologies that can benefit all customers, support policies to encourage further electrification and help distribution utilities compete with alternatives to grid-supplied energy. Transitioning to marginal cost-based pricing of retail electricity would also support policies to encourage further electrification. However, the transition will bring challenges.

THE SHIFT TO MARGINAL COST PRICING

Electric utilities exhibit characteristics common to other service industries: inseparability of production and consumption,[20] and perishability.[21] As a result, utility pricing strives to charge customers not only for total consumption but for peak usage when the cost of metering makes such an approach cost effective.

Consumer surplus refers to the amount consumers are willing to pay for a good or service relative to its market price. A consumer surplus happens when the price that consumers pay is less than the price they are willing to pay. It is a measure of the additional benefit that consumers receive because they are paying less than they are willing to pay. Put another way, a surplus is created when one is willing to spend more than the market price for a good or service. Consumer surplus is a function of marginal utility. Competitive alternatives to utility-delivered energy will either offer lower prices where the utility service is priced above the entrant's marginal cost or provide greater utility to consumers to pull consumers away for the utility-provided service, until a market equilibrium price is established that eliminates any consumer surplus.

Traditional average-cost pricing and rate class discrimination has disregarded consumer surplus. It assumes that because electricity is an essential service, consumers are willing to spend above the regulated tariff price for electricity; hence the need for regulated tariffs. The purpose of regulation has long been to prevent unregulated monopolists from profiting by charging monopoly rents to exploit consumer surplus. This remains a significant objective of regulation.

However, in a market where consumers can avail themselves of alternatives to grid-supplied electricity, the relative marginal utility of consumer alternatives and consumers' willingness to pay for utility services rather than competitive alternatives becomes a consideration in utility rate design. The value that consumers ascribe to the delivery of grid-supplied energy relative to other alternatives must now be considered in utility rate design. Also, the value that other users of the grid (e.g., prosumers and flexumers) ascribe to the utility of the grid must also be considered in utility rate design. The role of the regulator is, by necessity, expanding to now include the advancement of efficient market entry for both the utility and new entrants.

Price discrimination[22] in electric utilities has been implemented by creating rate classes that designate who is eligible for a tariff plan (e.g., residential, commercial, industrial). However, alternative rates designs are being developed to further discriminate within rate classes based on time of day, volume, and location to provide price signals that minimize consumer surplus, maximize the number of customers, and manage capacity utilization while reducing the costs of production and delivery within rate classes. These rate designs are often priced

[20] Electricity is produced and consumed simultaneously.

[21] Utility scale electricity cannot be saved, although the advent of large-scale storage is gradually modifying this characteristic to some extent.

[22] Price discrimination in this context refers to a marketing strategy that charges consumers different prices for the identical service, the delivery of energy.

at marginal cost, however it is possible to unbundle pricing without adopting marginal cost pricing. For example, a combination fixed/variable rate design may include customer, energy, and demand elements at the embedded cost-based unit costs established in a cost-of-service study. However, transitioning to marginal cost-based pricing of retail electricity sends price signals that consumers will respond to and that emulate pricing in a competitive market resulting in more efficient utility capacity investments and a better response to competitive alternatives to grid-supplied energy.

The availability of sufficiently granular marginal cost data and the ability to capture consumer usage patterns for data collection and billing purposes frequently dictate the degree to which a utility can devise marginal cost-based rates. Utilities usually adopt a tariff approach that aligns with their current technology and capabilities, recognizing the cost to upgrade technologies (e.g., smart meters) may be prohibitive and may not be accepted by their regulator.

The marginal cost of grid-supplied electricity is composed of the marginal cost of energy, the marginal cost of system (grid) operations and the marginal cost of capacity constraints associated with an increase in load. Economic efficiency is best achieved when rates are based on short-run marginal costs because the cost consequences of a decision whether to consume another kW/h of electricity are communicated to the consumer.

A marginal cost-based energy charge would include the following elements:

- A volumetric energy charge ($/MWh) reflects short-run marginal costs by time of use and location, and incorporates marginal transmission and distribution line losses, or other cost drivers.

- A distribution facility charge recovers the costs associated with substations and distribution lines, based on peak demand; and

- An additional charge recovers connection costs and any other specific customer-related costs.

Unfortunately, a marginal cost-based energy charge alone that includes all these elements may not generate the revenues necessary to align with accounting costs because fixed charges are recovered through a volumetric rate. When there is unused capacity, revenues may not recover costs. Periodic over-recovery can occur as well, but a rate designed to average these puts and takes blunts the effectiveness of marginal-cost pricing. When accounting costs are not fully recoverable, the marginal cost-based energy rate must be augmented.

However, sometimes the unrecovered costs are significant and onerous. Using California again as an extreme example, 66 to 77 per cent of ratepayer bills are associated with the fixed costs of operation.[23] Arguably, the fixed cost quandary in California resulted from utility and regulator expectations that demand would continue to rise, requiring additional generation and grid enhancements. Instead, loads and peak demands have stagnated as Californians responded to opportunities to adopt solar options, storage and demand side management to reduce their demand for grid supplied energy.[24] Nonetheless, where utility investments have been prudently made with a defensible expectation that the investments were required, and those investments were approved by a regulator, the utility should have a reasonable expectation of recovery. When those good faith investments become stranded the challenge for the regulator is how to recover their costs in rates.

The problem of unrecovered accounting costs can be dealt with in several ways. For example, for large industrial customers these costs can be recovered with multi-part tariffs that include a demand charge, which is facilitated by more sophisticated metering when the cost of more expensive metering is recoverable. For some rate classes, an alternative is to modify the volumetric energy charge proportional to the relative time of use, location, or other cost

[23] Next10, *Designing Electricity Rates for An Equitable Energy Transition*, (The Energy Institute at UC Berkeley's Haas School of Business, 2021), online (pdf): <next10.org/sites/default/files/2024-05/Next10-electricity-rates-v2.pdf>.

[24] See Ahmad Faruqui, Jim Lazar & Richard McCann, "New electricity rate reform in California: A rejoinder to Meredith Fowlie" (2023) 11:4 *Energy Regulation Q*, online: <energyregulationquarterly.ca/articles/new-electricity-rate-reform-in-california-a-rejoinder-to-meredith-fowlie>.

drivers to generate additional revenue. Another alternative is block (tiered) pricing with the marginal costs reflected in the tail block. Most utilities use a form of demand charge ($/kW) coupled with a marginal cost-based volumetric energy charge to recover capacity-related costs, usually based on coincident system peak demand. However, adopting a demand charge for residential consumer rates can result in rate shock if the unrecovered fixed costs are significant. In California, the Income Graduated Fixed Charge[25] proposal, which is intended to blunt the effect of high fixed costs recovery for lower income consumers, has been met with significant controversy. There appear to be no easy answers.

If better rate design options are not available to utilities, they may be reluctant to make the capital investments required to support the emerging industry evolution brought on by a melange of decarbonization policies, changing consumer expectation and technological upheaval. Uncertainty about how, or even whether, they will be able to recover these costs in current rates as the market evolves, or if investments that are ultimately stranded will be recoverable at all, will have a chilling effect on utility investment.

As the market evolves, it will become advantageous to unbundle the pricing of generation, transmission, and distribution from bundled tariff rates. Where there is an independent system operator ("ISO"), the cost of wholesale energy and transmission is already disaggregated in the calculation and billing of utility rates. And, in jurisdictions with retail competition, distribution charges are billed separately from volumetric energy charges, usually as a separate charge established to recover the wire-related revenue requirement of the distribution utility. But more will need to be done.

Further unbundling and pricing of grid services at the distribution level is the logical next step in the evolution of price signals to incentivize more efficient use of the grid, facilitate cost recovery and develop new grid services. This will also allow for a more precise allocation of grid costs to both customers who rely on grid-supplied energy and to customers who use the grid for other purposes, such as self-supply and export, peer to peer trading, power purchase agreements, standby power, interconnection of microgrids and alike. Management of the transfer of electrons on the grid can be theoretically priced based on marginal cost and allocated to users of the grid based on cost causation and value received, thereby facilitating efficient market entry and avoiding consumer defection. As pricing for use of the grid is unbundled, new approaches to rate design will be required. In the end, it may require that the grid itself be regulated as a common carrier.

SHOULD THE GRID BE REGULATED AS A COMMON CARRIER

A common carrier is one engaged in common callings that have a duty to serve as originally established in early English courts. This required private enterprises to provide essential public services to the public, to do so without discrimination, and to charge a reasonable rate. The first carriers to which this principle was applied were ferries. In the American context, public works such as roads, bridges, and canals were determined to be necessary for the defense of society and for administering justice, but chiefly for facilitating commerce.[26] Eventually, common carrier obligations were imposed on railways in North America and other network industries including airlines and telecommunications carriers that were assumed to be affected with the public interest. The regulation of common carriers formed the basis of public utility regulation of network industries, including electric distribution, as it is now practiced.

The distribution grid, when disaggregated from the other functions of an electric utility (generation, transmission, energy retailing) and engaged in managing the efficient transfer of energy between metering points is arguably 'affected with the public interest.' There should not be much debate that in this context, the

[25] Ruthie Lazenby, Highly Charged: An Explainer on California's Income-Graduated Fixed Charge Debate, (Emmett Institute on Climate Change & the Environment), 2024), online (pdf): <law.ucla.edu/sites/default/files/PDFs/Publications/Emmett%20Institute/PritzkerPaper_18-1dd%20NEW.pdf>.

[26] See Adam Smith, *An inquiry into the nature and causes of the wealth of nations*, Boston Public Library (London: University of Glasgow, 1776).

distribution utility has common carrier obligations when the energy is not generated by the distribution utility itself.

Admittedly the distribution grid functions differently from other networks that offer specific point to point routing of freight, passengers, and data bits. In simple terms, the distribution grid manages energy flows and congestion, maintains voltage levels, and keeps load and generation in balance. All of which means the grid is a natural monopoly and will remain so. However, use of the grid at different points, depending on where metered energy enters and leaves, results in costs that vary relative to the distance between generation and load, the effect of line losses, and congestion points on the grid. Locational marginal pricing of the distribution grid based on points of metered entry and egress, points of congestion, capacity costs, and other cost drivers can be calculated.

The term 'essential facilities' derives from telecommunications regulation where it refers to an electronic communications network facility or combination of an electronic communications network facility and other associated facilities that is exclusively or predominantly provided by a single or limited number of operators and cannot feasibly (whether economically, environmentally, or technically) be substituted or duplicated to provide a service. An essential facilities doctrine specifies the owner(s) of an 'essential' or 'bottleneck' facility must provide access to that facility, at a reasonable price.[27] The distribution grid is an essential facility when used for the transfer of energy on behalf of customers who use the grid for purposes other than passively receiving the distribution utility's grid-supplied energy.

Users of the grid for purposes other than passively receiving the distribution utility's grid-supplied energy are engaging the grid to achieve their own commercial objectives and should be provided with this essential monopoly service without discrimination at a reasonable price. This may best be achieved by regulating the distribution grid as a common carrier and unbundling the pricing of grid access and energy transfers for different purposes. Such an approach would facilitate the development of grid-specific services and pricing of the distribution grid separate from the costs of the energy that is delivered at the egress metering point.

In regions with the potential to develop solar resources, for example, pricing use of the distribution network as a service has the potential to create an entirely new paradigm for utility pricing. Dynamic pricing of distribution network services can significantly improve the efficiency of distributed solar resources and storage facilities deployment. Dynamic pricing will also provide economic signals for where to locate these resources, and how and when to operate them.

Under such a regime, the regulator may require mandatory access to the grid as an essential monopoly-provided facility and establish distribution tariffs for users of the grid. This is already done when a competitive retail energy market is developed. The distribution tariffs are charged separately from the costs of energy and the utility recovers its wires costs separately from energy costs. Competitive retailers usually collect the distribution tariff and remit to the distribution utility. Once tariffs for access to essential grid facilities are in place, the regulator ensures that the utility imputes these wholesale tariffs into its own retail prices to avoid allegations of a price squeeze.[28]

Regulating the grid as a common carrier and further unbundling the pricing of wires services to develop marginal cost-based tariffs for use of the distribution grid may better serve the needs of consumers, micro-grids, energy exporters and other emerging users of the grid, while ensuring a better allocation of grid costs to all users. It will go some way to solving the problems created by bypass and the resulting effect on utility rates by more equitably allocating the fixed and variable costs of the grid among all users of the grid. ■

---

[27] Frédéric Marty, *Essential Facilities Doctrine*, Encyclopedia of Law and Economics (New York: Springer, 2023), online: <link.springer.com/referenceworkentry/10.1007/978-1-4614-7883-6_659-2>.

[28] A price squeeze occurs when a vertically integrated firm provides an input that is required to compete and is uneconomical for a competitor to duplicate and raises the price of that input (sometimes while simultaneously lowering retail prices) so that its rivals are not able to profitably compete. Where the vertically integrated firm is a regulated entity, regulatory rules are often put in place to guard against such behaviour.

REGULATORY SOLUTIONS TO REDUCE INVESTMENT RISK IN THE ELECTRICITY SECTOR

*Joe McKinnon**

Investing to meet the needs of our energy future entails many challenges. Important variables like government policy, consumer preferences, technology adoption, and market volatility resulting from strained U.S. relations impact investment risk for utilities. Uncertainty in capital access, revenue, and regulation are all compounding factors that shape the investment landscape for our domestic energy sector. Electricity demand growth is a trend across the country. Both national and provincial forecasts suggest a near doubling of electricity demand over the next 25 years. To secure our energy independence, it is estimated that Canada will need to invest over $1.5 trillion[1] in the electricity sector. However, challenges at the international, federal, and provincial levels create barriers to investment, leading to heightened investment risk and uncertainty for the sector. The approach Canada should take to enable the investment sector is multifaceted, but an often overlooked aspect is the more granular reforms at the level of provincial regulation. In a recent Electricity Canada report *Regulation and risk: Overcoming uncertainty*[2] we outline some practical reforms for the sector. Of course, major challenges in our trade relationships, federal funding, and provincial legislation should be addressed, but the further the policy dialogue is removed from the day-to-day activities of the sector, the harder it is to assess the impact of those macro reforms.

While we need to acknowledge the policy opportunities that exist at all levels to promote investment, we should pay particular attention to those reforms that are most attainable. Changes to economic regulation are an option, that in many cases, do not require legislative changes or major government policy, and can mitigate investment risk.

CHALLENGE: SUPPLY CHAINS

Electricity sector participants have found it increasingly difficult to source key equipment, impacting supply chain security and the ability of utilities to invest to meet load growth. This is due to increased international competition, scarcity, and longer procurement lead times. Across-the-board tariffs imposed by the U.S. and Canadian counter-measures will significantly exacerbate existing issues, impacting the electricity industry's ability to source critical equipment necessary for operation and long-term build-out. Disruptions to supply chains in the short term will impact long-term investment decisions and project timelines, harming the sector's ability to meet the demand growth for electricity over the coming decades.

* Joe McKinnon is Manager of Economic Regulation & Standards at Electricity Canada.

[1] Electricity Canada, "Barriers to Building Infrastructure" (last visited 26 May 2025), online: <electricity.ca/knowledge-centre/the-grid/regulatory/barriers-to-building-infrastructure>.

[2] Electricity Canada, Regulation and risk: Overcoming uncertainty, (Electricity Canada, 2025), online: <issuu.com/canadianelectricityassociation/docs/regulation_and_risk_overcoming_uncertainty>.

CHALLENGE: FEDERAL REGULATION

Policy at the federal level is also a challenge for the sector. While provincial regulators are limited in terms of their scope and mandate, they should understand these policy pressures and introduce risk reduction measures to mitigate the challenges that federal policy pose.

The Clean Electricity Regulations ("CERs") will also create reliability and affordability challenges across Canada, particularly in provinces such as Alberta, Saskatchewan, Nova Scotia and New Brunswick. CERs will drive up system costs as existing infrastructure may need to be retired early, leading to sub-optimal economic pathways for the sector. These added costs will ultimately be paid for by Canadian families and businesses. While future federal policy may impact the longevity of these specific regulations, they still set a precedent for sector restrictions that challenge adequate investment. The sector needs a regulatory environment that promotes investment and building projects faster.

CERs create even greater regulatory misalignment with the U.S. undermining our competitiveness and ability to attract global capital. The CERs are an unnecessary regulatory burden, driving up system costs and undermining this competitive advantage.

CHALLENGE: AFFORDABILITY

Utilities are facing immense policy pressure regarding affordability concerns yet simultaneously are encouraged to make major investments in the grid. This balancing of investment and affordability is a serious concern for utilities, as they are faced with a changing energy landscape. Regulators must support long-term utility investments in areas such as capacity additions, grid modernization and hardening against severe weather much more rapidly to reduce the cost of inaction and delay. While the urgent need to invest in a modern expanded grid will inevitably cost customers more, this can be mitigated through targeted programs, measures and incentives for low-income Canadians at or below the poverty line who cannot pay more for energy. A more balanced approach with tailored support for consumers must be prioritized in the ratemaking process.

ECONOMIC REGULATION AS A SOLUTION

When regulators do not sufficiently account for the impacts that government policy, broader industry trends, and key issues like energy security have on utility investment requirements, the utility cannot effectively manage costs and risks. Regulatory reforms that help reduce investment uncertainty and align priorities between utilities, customers, and regulators can have a positive effect on promoting investment and reducing a utility's exposure to commercial risk resulting from challenges at the international, federal, and provincial levels. By considering the broader policy landscape in rate-setting, regulators can provide utilities with clearer guidelines on expected returns for investments that align with the totality of investment pressures. This reduces risk by ensuring utilities are adequately compensated for the cost of meeting evolving policy demands and are less likely to have proposed investments rejected.

There are practical and technical reforms that can be made at the regulatory level without major policy direction, which can mitigate the impact of these overarching policy issues and help reduce investment risk:

- **Allowing for the increased use of mid-project cost recovery mechanisms** helps manage investment pressures by allowing partial returns before project completion, improving cash flow and attracting private investors. These recovery mechanisms can also help utilities improve credit metrics, which benefit ratepayers through reduced utility borrowing costs. Mid-project recovery has a natural smoothing effect, further reducing financing costs otherwise paid by ratepayers over time.

- **Encouraging a stable economically regulated environment through an increased return on equity** reduces financial risk, lowering borrowing costs and improving credit ratings. Equity Risk Premium ("ERP") incentivizes long-term investment, making utility stocks more attractive. A higher approved CoC is essential for financing to meet load growth. Without competitive returns, utilities may struggle to attract investment, delaying critical infrastructure upgrades.

- **Using tailored accounts to reduce financial uncertainty** can reduce short-term financial strain, as new projects to manage load growth can be lengthy. Having access to accounts, like innovation and variance accounts, reduces the impact of uncertainty and unplanned costs.

- **Increasing assessment thresholds for cost recovery supports regulatory efficiency.** Accounting for inflation and changing investment requirements supports regulatory efficiency and creates greater certainty for moderate capital allocation.

- **Using more non-adjudicative tools** can provide greater certainty to utilities, allowing service providers to direct internal efforts towards projects that they believe have a high likelihood of being included in the rate base, promoting regulatory efficiency. By adopting more non-adjudicative frameworks, regulators can provide utilities with greater flexibility to implement innovative solutions and reduce investment risk.

Regulatory changes that are broadly applicable across Canada provide opportunities for the sector to reduce investment risk and continue to orient investment towards customer value, despite overarching market and policy uncertainties. Regulation can serve as a risk reduction tool at a granular level, allowing the sector to manage its own needs and challenges despite exogenous factors. Overall, these regulatory innovations can create a more adaptable and financially sustainable system for utilities navigating Canada's evolving energy landscape. ■

CONNECTING DATA CENTRES IN ONTARIO: KEY CONSIDERATIONS AND CHALLENGES

*Daliana Coban, Daniel Gralnick, and Ian T. D. Thomson**

Data centres are the backbone of modern technology infrastructure and digital security. Their development is crucial for protecting national interests, increasing productivity and providing Canada a competitive edge in key industries such as health care and manufacturing.[1] Despite offering many potential benefits, data centres also present significant challenges for the energy sector as meeting their power demands and reliability requirements may involve significant investment in grid expansion and reinforcement.

In Canada, Ontario leads the data centre market with over 80 facilities already built. The province is anticipating and planning for increased data centre demand. In the most recent 2025 outlook by the Independent Electricity System Operator ("IESO"), data centres were one of the top new drivers for electricity demand in the province.[2] In the next ten years, Ontario expects 16 more data centres to connect to its grid, representing 13 per cent of new electricity demand and 4 per cent of total anticipated demand.[3] While the IESO states this is "an uncertain area of electricity demand growth"[4], the IESO is

* Daliana Coban is counsel at Torys LLP in its energy regulatory practice. Before joining Torys, Daliana was the Director of Regulatory Applications and Business Support at Toronto Hydro. While there, she was also a member of the Adjudicative Modernization Committee, which was formed in 2021 to provide early advice, input and feedback on enhancing adjudication processes and policies at the Ontario Energy Board. With over a decade of experience in the regulated electricity industry, Daliana offers practical counsel on a wide range of complex regulatory matters, including in public and administrative law, economic regulation, and regulatory compliance.

Daniel Gralnick is a senior associate at Torys LLP in its energy regulatory practice. His experience includes advising public and private sector energy sector participants on matters relating to electricity markets, regulatory proceedings, including rate applications, energy procurements, and regulatory and commercial issues arising from energy transactions and project development.

Ian T. D. Thomson is an incoming associate at Torys LLP with a focus in its energy and infrastructure practice areas. He previously worked as a public policy consultant providing research, analysis and strategic advice to governments, media outlets and research institutes on energy policy matters. The views expressed in this article are those of the authors alone, and do not necessarily reflect that of Torys nor any other person or entity.

[1] Shaz Merwat, "Power Struggle: How AI is challenging Canada's electricity grid" (4 December 2024) RBC Climate Action Institute, online: <rbc.com/en/thought-leadership/climate-action-institute/power-struggle-how-ai-is-challenging-canadas-electricity-grid>.

[2] Independent Electricity System Operator, *Annual Planning Outlook: Ontario's electricity system needs: 2026-2050*, (Independent Electricity System Operator, 2025), online (pdf): <ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/apo/2025/2025-Annual-Planning-Outlook.pdf> at 13–15.

[3] Independent Electricity System Operator, "Electricity Demand in Ontario to Grow by 75 per cent by 2050" (16 October 2024), online: <ieso.ca/Corporate-IESO/Media/News-Releases/2024/10/Electricity-Demand-in-Ontario-to-Grow-by-75-per-cent-by-2050>; Rob Ferguson, "'Ontario needs more power:' Ford government wants to boost electricity expansion to meet surging demand" (last modified 27 November 2024) The Toronto Star, online: <thestar.com/politics/provincial/ontario-needs-more-power-ford-government-wants-to-boost-electricity-expansion-to-meet-surging-demand/article_a161dc1c-8bd2-11ef-b036-c76557a2975e.html>.

[4] *Supra* note 2 at 22.

projecting an increase in 13 TWh in net annual energy demand between 2016 to 2050 for new data centre load connect to its grid. This represents more than a five-fold increase between 2016 and 2050, with a compound annual growth rate of 7.1 per cent.[5]

This article explores the various regulatory requirements and considerations for developing and connecting data centres in Ontario. Section One outlines the regulatory approvals and processes that data centre proponents need to navigate to connect their facilities to Ontario's grid. Section Two discusses public interest and ratepayer risk protection considerations related to data centre-driven grid expansions. Section Three considers the regulatory requirement for generating electricity for direct supply. Section Four identifies ongoing energy policy and regulatory changes that may affect data centre development projects in Ontario. Section Five examines the implication of the IESO's recent Market Renewal Program.

SECTION ONE: CONNECTING A DATA CENTRE TO THE GRID

In Ontario, the electricity markets are administered by the IESO and electricity grid connection requirements are set out in Transmission System and Distribution System Codes ("TSC" and "DSC", respectively)[6] which are overseen by the Ontario Energy Board ("OEB"). Across these two regimes, regulatory approvals related to data centre connections generally fall into four categories:

- A data centre proponent will **need to register as a market participant** and be authorized by the IESO to participate in the electricity market or program offered as part of that market. This process takes about three weeks, but it may require other regulatory approvals, such obtaining an OEB license to operate in the province. Proponents should also know about the applicable changes under the IESO's Market Renewal Program ("MRP") (discussed further in Section 5).
- The IESO conducts **a System Impact Assessment ("SIA")** for projects greater than 10MW to evaluate the effect of the connection on system reliability.[7] The IESO also oversees regional planning processes which consider how to address system requirements in a cost-effective way. Data centre proponents are encouraged to monitor and participate in regional planning consultations that may impact their projects.
- **Leave to construct approval** may be required from the OEB to build or reinforce transmission facilities to enable the connection.[8] This process has many requirements, and may be subject to a public hearing, which can take anywhere from 6 to more than 12 months to complete.
- **Rate approvals from the OEB may be required** for the utility facilitating the connection to secure the funding necessary to construct a grid expansion. This could be a standalone application for the project or could be done as part of a rate application filed in the normal course (every 4-5 years) to get rates approved by the OEB.

GRID INTERCONNECTION REQUIREMENTS

Connection rules are complex and circumstance specific, and connection cost responsibility requirements are evolving (this is discussed more in Section Four). Data centre proponents need to undertake thorough due diligence to understand the regulatory landscape and connection cost responsibility requirements for their projects.

---

[5] *Ibid.*

[6] *Distribution System Code*, (Ontario Energy Board), 2024, online (pdf): <oeb.ca/sites/default/files/uploads/documents/regulatorycodes/2025-04/Distribution_System_Code.pdf> [*DSC*]; *Transmission System Code*, (Ontario Energy Board), 2025, online (pdf): <oeb.ca/sites/default/files/uploads/documents/regulatorycodes/2025-04/Distribution_System_Code.pdf>.

[7] Independent Electricity System Operator, "Connecting to Ontario's power system" (last visited 28 May 2025), online: <ieso.ca/Sector-Participants/Connection-Process/Overview>.

[8] Ontario Energy Board, *Filing Requirements for Electricity Transmission Applications*, Chapter 4: Leave to Construct and Related Matters under Part VI of the Ontario Energy Board Act (Ontario: Ontario Energy Board, 2023), online (pdf): <oeb.ca/sites/default/files/OEB-Electricity-Leave-to-Construct-Filing-Requirements-20230316.pdf>.

Broadly, there are two types of infrastructure that a data centre will have to pay for to connect to the grid in Ontario:

1. **Connection assets** are dedicated to serving a particular customer. At the distribution level, these assets are paid by the customer upfront and in full, if the cost goes beyond a basic connection allowance that the utility may already be approved to recover through rates. At the transmission level, these assets are paid for through connection rates, and an economic evaluation is done to determine whether the cost will be fully funded through rates, or if some shortfall needs to be paid upfront by the customer through a capital contribution.

2. **Upstream grid assets** that serve multiple customers may also need to be expanded or reinforced to facilitate the connection. At the distribution level, these investments are paid for through rates, and an economic evaluation is performed at the outset of the connection process to determine whether the cost will be fully funded through rates, or whether there is a shortfall that needs to paid upfront by the customer through a capital contribution. At the transmission level, the costs of upstream network investments are socialized among all ratepayers in the province through the uniform transmission rate. In exceptional circumstances, a portion of these costs may be attributed to the connecting customer in which case a capital contribution would be required.

NON-WIRES SOLUTIONS (NWS)

Non-Wires Solutions ("NWSs") are alternative non-capital investments, such as procuring demand response or flexible capacity, intended to defer or replace the need for constructing new or modified physical grid infrastructure like poles and wires.[9] The OEB's Non-Wires Solutions Guidelines encourage distributors to consider NWSs as an alternative to grid expansion when connecting customers.[10] Although NWSs are unlikely to eliminate the need for grid upgrades, these alternatives may assist in facilitating a faster connection or reducing the upfront cost burden for the connecting customer. Data centre proponents with behind-the-meter generation or energy storage resources, or demand flexibility may be able to leverage the NWS Guidelines to manage their projects' connection costs or expedite the timelines.

SECTION TWO: PUBLIC INTEREST AND RATEPAYER RISK PROTECTIONS

Attracting data centre investment is becoming an increasingly important objective for the federal and provincial governments.[11] In developing these policies, it is important for the government to consider the potential ratepayer implications of accommodating increased data centre demand on the grid. These risks arise from the possibility that data centre load might decrease over time due to improved energy efficiency or changes in business conditions that may cause data centre demand to drop or relocate to other jurisdictions. If this happens before the connection costs have been fully recovered, ratepayers may be on the hook for the costs associated with expanding the grid to facilitate the connection.[12]

[9] Examples of NWS for addressing system needs include energy efficiency programs, demand response programs, energy storage (in front or behind the meter), generation (in front or behind the meter) managed charging of electric vehicle (Ontario Energy Board, "Non-Wires Solutions Guidelines for Electricity Distributors" (2024) EB-2024-0118, online (pdf): <oeb.ca/sites/default/files/uploads/documents/regulatorycodes/2024-04/OEB_2024%20NWS%20Guidelines_20240328.pdf>.

[10] *Ibid* at 8–10. Distributors are required to document their consideration of NWSs when making an investment on system needs when there is an expected capital cost of $2M or more (excluding general plant investments). Distributors are also encouraged to consider NWSs for system needs that "are driven by specific customers and funded by customer capital contributions, where there is a reasonable expectation that an NWS may reduce the total cost and required customer capital contribution." (*Ibid* at 9).

[11] For example, see Innovation, Science and Economic Development Canada, "Canadian Sovereign AI Compute Strategy" (last modified 6 May 2025) Government of Canada, online: <ised-isde.canada.ca/site/ised/en/canadian-sovereign-ai-compute-strategy>.

[12] Margarita Patria, Chris Nagle & Oliver Stover, "How do we power AI" (28 November 2024), online: <datacentrereview.com/2024/11/how-do-we-power-ai>.

Ontario's TSC protects ratepayers by categorizing connections into high-risk, medium-high risk, medium-low risk, and low risk, which dictates the economic evaluation period. High-risk connections undergo a five-year evaluation, while low-risk connections have a 25-year period. Shorter evaluations yield smaller revenue streams, necessitating higher upfront capital contributions to cover the expansion costs. Obtaining a larger upfront contribution for high-risk connections protects ratepayers from potentially having to bear the costs of the expansion if the expected load does not materialize or decreases beyond the five-year revenue window.[13] Data centre proponents should review the transmitter's risk classification policies and assess the connection cost implications for their projects.

In the DSC, the risk is addressed through expansion deposit requirements.[14] In the context of a system expansion, the customer must provide the distributor an expansion deposit that covers both the forecast risk (i.e. risk that project revenue will materialize as forecast) as well as the asset risk (i.e. risk that expansion is constructed, completed to specifications and operates when energized). Once the facilities are energized, the customer receives an annual refund of the expansion deposit in proportion to the actual demand that has materialized in that year. However, if at the end of the connection horizon (typically five-years but could be longer) the forecasted demand has not materialized, the distributor retains the remaining portion of the expansion deposit.[15]

Data centre proponents should consider the different ways in which revenue risk is addressed in the DSC and TSC, and the cost implications of connecting their project to the distribution versus the transmission grid.

SECTION THREE: GENERATING ELECTRICITY FOR DIRECT POWER SUPPLY

Data centres can also opt for direct or self-supplied power. Microsoft selected this option in 2024, signing a 20-year power purchase agreement to restart the Three Mile Island Unit 1 nuclear facility to power its data centres.[16]

There are several regulatory requirements that must be met to secure direct power supply in a compliant manner. Property ownership must be considered given that the generation facility and the wires delivering the power to the load facility typically need to be located on the same or contiguous parcels of land. Generation facilities may need a license to operate and to sell electricity to specific consumers. These licenses come with a host of conditions and compliance requirements that must be maintained. Common license conditions include restricting the licensee from acquiring an interest in a transmission or distribution system in Ontario, and notifying the OEB within 20 days of any material change that has had (or is likely to have) an adverse effect on the licensee's business, operations or assets.[17]

A data centre contemplating on-site generation should consider the type of electricity that will be generated to power the facility. With gas generation, the proponent may want to consider carbon capture or renewable energy credits to meet climate targets, and the infrastructure needed to get a reliable supply of gas. For other forms of generation, like wind and solar, the proponent will have to consider reliability requirements. This will likely entail remaining connected to the grid in some way unless the renewable generation facility is paired with an energy storage system to manage intermittency.

---

[13] Ontario Energy Board, *Appendix 4: Customer Financial Risk Classification*, Transmission System Code, online (pdf): <oeb.ca/documents/cases/RP-2004-0220/appendix4_clean.pdf>; PHB Hagler Bailly, "Risk Assessment Methodology Options" Ontario Energy Board, online (pdf): <oeb.ca/documents/cases/RP-2004-0220/report_riskassessmentmethodology.pdf>.

[14] *DSC*, *supra* note 6 ss 3.2.30, 3.2.21.

[15] *Ibid* at s 3.2.23.

[16] Constellation, "Constellation to Launch Crane Clean Energy Center, Restoring Jobs and Carbon-Free Power to The Grid" (10 September 2024), online: <constellationenergy.com/newsroom/2024/Constellation-to-Launch-Crane-Clean-Energy-Center-Restoring-Jobs-and-Carbon-Free-Power-to-The-Grid.html>.

[17] Ontario Energy Board, "Electricity Generation Licence EG-2022-0215: Algonquin Power (Long Sault) Partnership and N-R- Power Partnership" (2022) Ontario Energy Board, EG-2022-0215, online (pdf): <rds.oeb.ca/CMWebDrawer/Record/756637/File/document> at ss 6.1, 7.2.

If the data centre intends to connect a generation facility to a constrained part of the grid, "flexible hosting" can also be considered. The DSC was recently amended to allow distributors to offer a flexible hosting arrangement "that will require the output or operation of the proposed embedded generation facility to be varied".[18] The UK has been offering such flexibility for years allowing customers to connect more expediently and cost-effectively in constrained areas.[19] For instance, Electricity North West, a UK distribution network operator, offers "Curtailed Connection Offers".[20] When connection reinforcement is necessary, the Offers help curtail connection import/exports to manage constraints until the reinforcement is finished.[21]

Further, the UK's National Grid Electricity Distribution provides a variety of flexible connection options.[22] Examples include:

- timed connections: curtailing based on the time of day, day or week or season;
- export limitation schemes: measuring power at the exit point of installation and using that information to restrict the generation out or balance customer demand to prevent capacity from being exceeded; or
- load managed connection: using real time data monitoring to determine the network's ability to accommodate a customer's load. If the full load cannot be accommodated a constraint signal is sent out.

Flexible load or generation connections for data centres may involve reliability trade-offs, if flexibility is achieved by curtailing the data centre's supply of consistent energy. These innovative solutions are particularly suitable for data centres with variable load profiles, behind-the-meter generation or storage assets, or excess capacity that can be utilized for flexibility until full load requirements are met. When considering these arrangements, project proponents should also assess the trade-offs related to participation in other market programs, such as the Industrial Conservation Initiative ("ICI"), which allow customers to shift electricity consumption from peak hours—when demand is highest—to off-peak hours to manage their cost of power.[23]

SECTION FOUR: ENERGY POLICY AND REGULATORY CHANGES AFFECTING DATA CENTRE DEVELOPMENTS

Data centre proponents should monitor ongoing regulatory changes that may impact project development and grid connection requirements in Ontario. Specifically, the *Affordable Energy Act, 2024*[24] (the *Act*) introduced through Bill 214 in October of 2024 sets the groundwork for substantive changes to Ontario's electricity sector to implement the government's Energy Vision for the province. [25]

---

[18] *DSC*, *supra* note 6 s 6.2.4.1.A.; Ontario Energy Board, "Notice of Amendments to the Distribution System Code: Amendments to Enable Flexible Hosting Capacity Arrangements" (2024), EB-2019-0207, online (pdf): <rds.oeb.ca/CMWebDrawer/Record/846008/File/document>.

[19] In 2022, Ofgem reviewed the rules surrounding flexible connections, given criticism that the previous rules were "poorly-defined" and provided "no commonly defined limit on the extent to which their network access can be curtailed". 2022 reforms outlined explicit curtailment limits, and end dates for the connection to not be curtailed, among other changes. (See *Access and Forward-Looking Charges Significant Code Review: Final Decision* (3 May 2023), online: Office of Gas and Electricity Markets <ofgem.gov.uk/sites/default/files/2022-05/Access%20SCR%20-%20Final%20Decision.pdf>.

[20] Electricity North West, "Curtailed Connected Offers" (last visited 28 May 2025), online: <enwl.co.uk/get-connected/apply-for-a-new-connection/curtailed-connection-offers>.

[21] Small Customer is defined as "either a domestic or non-domestic customer who are whole current metered ie up to 20kVA for 1ph and 60kVA for 3ph. A "small customer" generally excludes those who do not have a current transformer ("CT") meter" (*ibid*).

[22] Nation Grid Electricity Distribution, "Flexible Connection Options", online (pdf): <nationalgrid.co.uk/downloads-view-reciteme/540250>.

[23] Independent Electricity System Operator, "Global Adjustment Class A Eligibility" (last visited 29 May 2025), online: <ieso.ca/en/Sector-Participants/Settlements/Global-Adjustment-Class-A-Eligibility>.

[24] *Affordable Energy Act*, 2024, SO 2024, c 26 [*Affordable Energy Act*].

[25] *Ibid*.

The *Act* grants the Minister of Energy and Electrification regulation-making authority to amend the cost allocation and cost recovery rules in the DSC and TSC.[26] The Minister has already announced plans to enact a regulation that aims to reduce the cost and financial burden on first-mover connection customers[27] as well as enhance grid readiness at strategically significant locations where future load is highly likely to materialize.[28]

The *Act* also articulates the government's process and responsibility for developing an Integrated Resource Plan ("IRP").[29] Following a consultation process that was initiated in December 2024, the IRP is expected to be released in the spring of 2025 and may contain policy guidance and directives that are impactful to large loads such as data centres.

Proponents should remain vigilant to future energy policy and regulatory changes which could affect the economics and timelines of connecting date centre projects to Ontario's grid.

SECTION FIVE: *IESO MARKET RENEWAL PROGRAM* ("*MRP*")

The MRP, which is in effect as of May 2025, was initiated in 2016 to modernize Ontario's electricity markets and implement fundamental design changes to the IESO-administered markets.[30] While Ontario has had a wholesale electricity market since 2002, the design has remained largely unchanged since its conception, which has resulted in market inefficiencies, including the uneconomic dispatch of resources.[31] The MRP aims to provide new mechanisms to address these deficiencies. The core changes include:

1. Replacing Ontario's two-schedule market with a single schedule market ("SSM") to help align market prices and system dispatch. The SSM will introduce local marginal pricing ("LMP") to account for transmission congestion and losses, with the pricing varying by location to reflect electricity production cost at the given time and place.[32] This will replace the Hourly Ontario Zonal Price ("HOEP"), which will no longer be published by the IESO.

2. Establishing a day ahead market ("DAM") to "provide financially binding schedules for participating resources a day ahead of operation"[33].

3. Introducing the Enhanced Real-Time Unit Commitment Process ("ERUC") initiative designed to reduce scheduling costs and resource dispatch inefficiencies when changes in system needs arise in the pre-dispatch time frame.[34]

While it is outside the scope of this article to explain the full extent of changes to the IESO-administered market introduced of the MRP, we consider three ways in which the IESO's MRP might affect data centres.

First, if a data centre is connecting on the transmission side, it typically would be registered as a "non-dispatchable load"

---

[26] *Ibid*, Schedule 2, s 70.4(1).

[27] See e.g., the first customers that want to connect in an area where energy infrastructure is not sufficient to meet the new demand. (Environmental Registry of Ontario, "Proposal to create a regulation under the *Ontario Energy Board Act*, 1998 to change cost responsibility rules for certain electricity system connection infrastructure for high-growth areas where load growth materializing in the future is very likely" (23 October 2024) ERO 019-9300, online: <ero.ontario.ca/notice/019-9300>.

[28] *Ibid*.

[29] *Affordable Energy Act*, *supra* note 24 Schedule 1.

[30] *IESO Market Rule Description Evidence in Response to Procedural Order No. 2* (11 December 2024), EB-2024-0331, at 2, online: Ontario Energy Board <rds.oeb.ca/CMWebDrawer/Record/875538/File/document>.

[31] *Ibid* at 2.

[32] *Ibid* at 4.

[33] Independent Electricity System Operator, *Market Renewal Program: Energy Stream Business Case*, BC-165, (2019), at 25, online (pdf): <ieso.ca/-/media/Files/IESO/Document-Library/market-renewal/MRP-Energy-Stream-Business-Case-2019.pdf>.

[34] *Ibid*.

("NDL") in the market.[35] An NDL does not respond to market prices and draws power for their operations regardless of price or system conditions.[36] A material change applicable to NDLs resulting from MRP is that they will now pay for energy based on the sum a the DAM Ontario Zonal Price ("OZP") plus a load forecast deviation adjustment calculated by the IESO. The OZP is calculated as a weighted average of the DAM LMPs adjusted to reflect differences between day ahead demand forecast and actual demand in real time.[37] This calculation replaces the previous market's Hourly Ontario Energy Price ("HOEP"). Compared to the LMP, the HOEP did not vary based on location or reflect actual cost of electricity at a given time and place. The IESO has noted that it expects the load forecast deviation adjustment to be a small component of the price paid for NDLs, and that the DAM OZP will be a good predictor of the final price.[38]

Second, for data centres connecting on the distribution side, the MRP affects the financial price of energy paid by these customers. The OEB's *Standard Supply Service Code* and *Retail Settlement Code* provide the settlement of distributed connected load customers.[39] Calculating settlement costs were previously based on the HOEP. To achieve alignment with the MRP, the OEB amended the *Retail Settlement Code* and the definition of "Spot Market Price" in the *Standard Supply Service Code*, replacing references to the HOEP with the new DAM OZP and the load forecast deviation adjustment.[40] As non-regulated price plan customers, connecting data centres will pay for power through this new pricing approach.

Finally, if the data centre is connecting to the transmission grid as a wholesale consumer, the facility will have the new opportunity to participate as a Price Responsive Load, a new resource type which participates in the market by receiving an hourly LMP and day-ahead schedule to manage in the DAM.[41] The Price Responsive Load resource-type, which can be understood as a combination of a dispatchable load and NDL, could provide a data centre greater operationality and financial certainty than participating in IESO-administered markets as an NDL.[42]

The MRP changes how data centres are charged for the cost of power and provides new opportunities for data centre customers to participate in the IESO-administered markets.

SECTION FIVE: CONCLUSION

Data centres are essential to Canada's digital infrastructure. Yet to realize their full potential, data centre proponents, governments and other interested stakeholders must consider both the challenges and opportunities in connecting these mega-loads to the electricity grid. Proponents must recognize the variety of regulatory processes and approvals required to connect, as well as system expansion costs that a data centre will have to pay to connect to the grid. This includes considering

---

[35] Independent Electricity System Operator, *Market Renewal Program: Day-In-The-Life for Non-Dispatchable Loads*, BC-165, (2023), at 5, online (pdf): <ieso.ca/-/media/Files/IESO/Document-Library/engage/imrm/ditl/imrm-ditl-non-dispatchable-loads.pdf>.

[36] Energy Education, "Non-dispatchable source of electricity" (last visited 29 May 2025) University of Calgary, online: <energyeducation.ca/encyclopedia/Non-dispatchable_source_of_electricity#:~:text=A%20non-dispatchable%20source%20of,Solar%20power%20and%20wind%20power>.

[37] Independent Electricity System Operator, *Guide to the Renewed Market for Local Distribution Companies* (*LDCs*), (2025), at 7, online (pdf): <ieso.ca/-/media/Files/IESO/Document-Library/training/mrp/Guide-to-the-Renewed-Market-for-LDCs.pdf>.

[38] Independent Electricity System Operator, *Overview of the Transition to the Renewed Market*, (2025), at 16, online (pdf): <ieso.ca/-/media/Files/IESO/Document-Library/engage/imrm/imrm-20250416-presentation-overview-of-the-transition-to-the-renewed-market.pdf>.

[39] Ontario Energy Board. *Retail Settlement Code*, (2025), at Appendix A, ss.3.3.1(a), ss 3.3.2(a), online (pdf): <oeb.ca/sites/default/files/uploads/documents/regulatorycodes/2025-03/Retail%20Settlement%20Code_MRP%20Implementation_20250327_Final.pdf>. Ontario Energy Board, *Appendix 4: Customer Financial Risk Classification*, Transmission System Code, online (pdf): <oeb.ca/documents/cases/RP-2004-0220/appendix4_clean.pdf>.

[40] Ontario Energy Board, "Notice of Amendments to Codes: Amendments to the Retail Settlement Code and the Standard Supply Service Code to Facilitate Implementation of the IESO Market Renewal Program" (2025) Ontario Energy Board, EB-2024-0300, online (pdf): <rds.oeb.ca/CMWebDrawer/Record/893579/File/document>.

[41] *Supra* note 35 at 5.

[42] *Ibid*.

demand flexibility as an alternative to building traditional grid infrastructure. Additionally, interested parties must understand the impacts of accommodating data centre demand on the grid, and how risk is factored into the DSC and TSC. A proponent should also consider whether to bring their own power to their site and the implications that this route brings.

Last, interested parties should stay vigilant to regulatory and legislative changes impacting connection processes and cost responsibility, and understanding the role of data centres as market participants under the IESO's MRP. Ontario's regulatory regime is complex and evolving with wide-ranging rules and policies affecting how the grid functions. Connecting data centres will require higher level of due diligence to navigate the complexity and support prudent decision-making. ■