WHO PAYS FOR THE ENERGY TRANSITION?

MATTHEW KEEN, MICHAEL MANHAS,
AND EMMA RUSSELL*

The global shift towards decarbonization-driven energy technologies is reshaping existing energy systems and driving demand for clean energy. Governments, utilities, and private capital are embracing various technologies like wind, solar, nuclear, and hydrogen. However, the challenge lies in determining who bears the costs, risks, and rewards of this transition — governments, ratepayers, or investors — with lasting consequences. Taxpayers, utility ratepayers, and private investors each have unique interests that can create tensions. Despite diverse approaches across Canada, the ultimate aim is reducing emissions to net zero. This article explores the multifaceted funding scenarios and offers insights into efficient and equitable decision-making for a successful energy transition. It examines the roles of stakeholders, analyzes approaches, and recommends ways to navigate trade-offs.

TABLE OF CONTENTS

I. INTRODUCTION

A. OVERVIEW

Decarbonization objectives are driving a transition toward new and developing energy technologies across the globe. These new technologies will affect existing energy systems, both directly by shifting the infrastructure needs and modes of utility-scale energy supply, and indirectly by enabling the electrification of commercial and industrial processes

---

* The authors are lawyers at the law firm Norton Rose Fulbright Canada LLP and practice energy and environmental law across Western Canada. The views in this article are those of the authors, and should not be understood to reflect positions of either the firm or any of its clients. The authors appreciate the assistance of Ali Kamalipour, Alyna Campbell, and Kyle Havart-Crans, and have particular gratitude for the efforts of Alexander Baer, Jonathan Tomm, and Emily Chan.

historically powered by fossil fuels, which in turn are projected to massively increase the demand for clean energy.

Governments, utilities, and other private capital have already realized or considered a broad suite of new technologies, including competitively priced wind and solar generation, electric vehicles (EVs), liquefied natural gas (LNG), coal-to-gas conversions, small modular nuclear reactors, and green and blue hydrogen-powered applications. But "old" technologies and systems are also primed to change as, for instance, the electric transmission grid evolves from its historical model, with centralized generation being transmitted to (sometimes very distant) load sites, to one that must incorporate distributed generation, energy storage, and different load curves.

This transition will not come cheaply. Though it is impossible to estimate the cost with precision, McKinsey Global Institute has estimated the global cost of the energy transition to be 7.5 percent of GDP on average between 2021 and 2050, or some US$275 trillion.[1] Although this figure has been the subject of some criticism for failing to account for the cost of business as usual,[2] another recent study pegged the incremental cost of switching to renewables in 145 countries at a much lower, but still substantial, US$62 trillion.[3] In Canada, the cost has been estimated at up to CDN$43.3 billion annually until reaching net zero (with potential fuel savings of up to CDN$78 billion to follow).[4]

All of this gives rise to critical questions: who will pay for this new infrastructure? Who will take the financial risk associated with the (often very large) investments necessary to turn plans for EV networks powered by fields of wind turbines complemented by energy storage into a reality? And who will reap the rewards if and when such investments pay off in the future?

Broadly speaking, the funds for such projects may come from taxpayers, gas and electricity utility ratepayers, or private investment (in other words, shareholders of utilities or other companies) — groups whose sometimes differing interests may create tension. Governments pull many of the levers that dictate the focus and pace of decarbonization efforts — including carbon taxes, carbon credits, industry-based output limits, and direct subsidies — allowing them to allocate costs across multiple stakeholders. But private environmental, social and corporate governance (ESG)-related objectives, and social enterprise are driving additional change on their own, and government intervention may, in some cases, displace rather than enhance these private efforts. Added to this mix are public utilities, some of which have used ratepayer (and sometimes taxpayer) dollars to not only invest capital in their traditional natural monopoly domains, but to also expand their services into markets that private competitors are seeking to develop. And these efforts in Canada are

---

1 "The Net-Zero Transition: What It Would Cost, What It Could Bring," online: *McKinsey & Company* [perma.cc/9KZN-YSS4].

2 Karl Burkart, "Will the Path to Net Zero Really Cost $275 Trillion?," *Greenbiz* (31 March 2022), online: [perma.cc/Y56B-HJTX].

3 Mark Z Jacobson et al, "Low-Cost Solutions to Global Warming, Air Pollution, and Energy Insecurity for 145 Countries" (2022) 15 Energy & Environmental Science 3343 at 3350; Steve Hanley, "Switching the World to Renewable Energy Will Cost $62 Trillion, But the Payback Would Take Just 6 Years," *CleanTechnica* (6 September 2022), online: [perma.cc/84T8-4DEL].

4 Thomas Stringer & Marcelin Joanis, "Assessing Energy Transition Costs: Sub-National Challenges in Canada" (2022) 164 Energy Policy 1 at 1.

not occurring in a vacuum; new technologies and infrastructure are being developed globally, and successes and failures elsewhere will impact Canada's path too.

These complexities have led to a hodgepodge of different approaches across Canada, which differ across jurisdictions and technologies.

Yet fundamentally the overarching goal is the same: reducing greenhouse gas emissions to ultimately achieve net zero. The urgency of climate change demands efficient energy and climate choices, including deciding where limited capital and resources should be deployed. Viewed through this common lens, initiatives should seek to achieve policy objectives in as efficient a manner as possible, maximizing climate benefits while minimizing costs to ratepayers and taxpayers. At the same time, options may also have different distributional effects (that is, funding through progressive rather than regressive measures) that policy-makers must also take into account to ensure fairness. To weigh these trade-offs, policy-makers, regulators, and the public need good information.

This article examines how recent developments in energy transition-related matters have been addressed by stakeholders and provides guidance on how related trade-offs can be assessed more coherently going forward. It does so by:

1. reviewing the roles that government, regulators, and investors have played in the energy transition to date, including specific examples of programs they have undertaken;

2. analyzing specific approaches to elements of energy generation, transmission, and distribution systems across Canada, including the adoption of new technologies; and

3. recommending how the allocation of costs and benefits associated with the energy transition should be considered by governments, regulators, and the public.

B. RECENT DEVELOPMENTS IN CANADA TO ADDRESS THE ENERGY TRANSITION

Governments, regulators, and investors across Canada have each invested substantial time and money to establish frameworks for the energy transition and to move it forward. The sections that follow summarize the role played by each to date.

1. GOVERNMENT

Greenhouse gas emissions are generally recognized to be environmental externalities that are overproduced in private markets due to collective action and tragedy of the commons issues. As such, governments, including those in Canada, have taken it upon their shoulders to make achieving net zero emissions a social and political objective, achieved through a number of direct and indirect measures.[5]

In some instances, governments have invested in order to support research and development into new energy technologies:

- In April 2022, Alberta invested $50 million to establish the "Hydrogen Centre of Excellence," which "supports research, development and demonstration that helps companies and entrepreneurs that are building hydrogen technologies."[6]

- In February 2023, Ontario announced the establishment of a Hydrogen Innovation Fund, to be administered by the Ontario Independent Electricity System Operator (IESO). The Fund will invest $15 million over three years to promote hydrogen (including hydrogen electricity storage), and can be used towards existing facilities, new hydrogen facilities, and relevant research studies.[7]

In other instances, governments have invested directly into the development of new infrastructure:

- The Alberta government is supporting Air Products' new natural gas to hydrogen production facility, which is eligible for $161.5 million in grants spread across three years once the facility is running, and an additional $15 million provided through Emissions Reduction Alberta.[8] The Government of Canada also announced a federal contribution of $300 million through the Strategic Innovation Fund's Net Zero Accelerator Initiative to support the project.[9]

- In April 2022, the Government of Canada announced $300 million in funding to support northern and Indigenous communities launching clean energy projects such as wind, solar, geothermal, hydro, and biomass, along with a new, streamlined service model for communities seeking to access resources and clean energy funding.[10]

- In May 2022, the Government of Canada announced a further nearly $50 million for the Burchill Wind Limited partnership to deploy renewable energy and grid modernization technologies to support clean energy in Saint John, New Brunswick.[11]

---

5 Brett Dolter & Jennifer Winter, "Electricity Affordability and Equity in Canada's Energy Transition" (12 September 2022) at 29, online (pdf): *Canadian Climate Institute* [perma.cc/3WQF-LVNB].

6 Government of Alberta, News Release, "Supporting Innovation in Hydrogen Production" (20 July 2022), online: [perma.cc/5QUB-AAHS].

7 Government of Ontario, News Release, "Ontario Launches Hydrogen Innovation Fund" (6 February 2023), online: [perma.cc/6P3T-96F7].

8 Government of Alberta, News Release, "Major Investment Moves Alberta's Hydrogen Sector Forward" (8 November 2022), online: [perma.cc/Q22Q-6K29].

9 "Net Zero Accelerator Initiative" (29 May 2023), online: *Innovation, Science and Economic Development Canada* [perma.cc/8CS5-CQQ4].

10 Canada, "Northern REACHE Program" (13 February 2023), online: [perma.cc/C736-MLAA].

11 Natural Resources Canada, News Release, "Canada Invests in Indigenous Wind Energy Project in Saint John, New Brunswick" (17 May 2022), online: [perma.cc/KL8B-DWT2].

- In October 2022, the Government of Canada and the Canada Infrastructure Bank (CIB) announced a further $50 million in funding and project development support for the 250-megawatt Oneida Energy Storage project, developed in partnership with the Six Nations of the Grand River Development Corporation, Northland Power, NRStor, and the AECON Group.[12]

- The 2023 Federal Budget includes a commitment to invest at least $20 billion in "clean power" and "green infrastructure" through the Canada Infrastructure Bank.[13]

Governments have also provided tax incentives for the adoption of green technology.[14] The 2023 Federal Budget includes a 15 percent refundable tax credit for eligible investments in non-emitting electricity generation (for example, wind, solar, hydro, and nuclear), abated natural gas-fired electricity generation, energy storage, and transmission projects that connect provinces and territories. The budget also includes an investment tax credit of between 15 and 40 percent for investments made in clean hydrogen production, an expansion of the clean technology investment tax credit to include geothermal energy systems, and an expansion of tax incentives for carbon capture, utilization, and storage.

These investments and tax incentives can generate technological breakthroughs, promote and increase uptake of certain technologies and projects, and encourage private investment. They may also fairly socialize the costs of pursuing objectives that benefit broader society, rather than placing those costs on specific groups (for example, utility customers) who may otherwise bear an inordinate share of the cost relative to their means. But subsidies can also obscure the true cost of particular measures, and may be economically inefficient (for example, by crowding out or incenting inefficient private investment, or diverting capital and resources to trendy projects rather than those most likely to contribute to achieving net zero).

In parallel, governments have also implemented statutory measures, such as carbon taxes, which have the effect of imposing costs on higher-carbon sources of energy. The implementation of these programs varies to some extent across jurisdictions and industries (for example, output-based pricing, cap and trade), but the underlying idea is the same: to efficiently incentivize private investment to shift to lower-carbon alternatives.[15]

Other legislative measures implemented by governments create carbon credits and markets for them. In addition to a longstanding, broadly applicable carbon tax, British Columbia also has a series of industry-specific protocols to generate carbon credits directly.[16] Other laws allow parties that invest in lower carbon energy production and clean technology to commercialize the carbon reductions resulting from their investments. These measures include the federal *Clean Fuel Regulations*,[17] the *Technology Innovation and Emissions*

---

12 Natural Resources Canada, News Release, "Governments of Canada and Ontario Working Together to Build Largest Electricity Battery Storage Project in Canada" (10 February 2023), online: [perma.cc/6GUP-NXVX].

13 Department of Finance Canada, *Budget 2023: A Made-in-Canada Plan*, Catalogue No 1719-7740 (Ottawa: Department of Finance Canada, 28 March 2023) at 69, 81, online: [perma.cc/3MNM-A96U].

14 *Ibid* at 79, 88, 91, 93.

15 Canada, "How Carbon Pricing Works" (7 July 2023), online: [perma.cc/Y37F-5G47].

16 Ministry of Environment and Climate Change Strategy, *British Columbia Offset Program: Offset Protocol Policy* (1 June 2022), online: [perma.cc/JMZ8-ND5P].

17 SOR/2022-140 [*CFR*].

Reduction Regulation[18] in Alberta, and the low carbon fuel standard (LCFS) regime in British Columbia, as reflected in the *Greenhouse Gas Reduction (Renewable and Low Carbon Fuel Requirements) Act*[19] and the *Renewable and Low Carbon Fuel Requirements Regulation*[20] (and the new British Columbia LCFS regime reflected in the *Low Carbon Fuels Act*,[21] not yet in force[22]).

Carbon taxes (and cap-and-trade) are widely recognized as an, if not the most, economically efficient way to achieve greenhouse gas emissions reductions. They incent businesses to decarbonize, while leaving organizations with the flexibility to choose measures that are cost-efficient and make sense in their industry and for their particular business. Organizations that decide, in the face of the price signals imposed by these measures, to continue with higher-carbon activities contribute additional tax revenue, which can then be used for other purposes (and such funds may be earmarked for climate-related programs or used to reduce other taxes to encourage economic growth).

A challenge with carbon taxes, however, is getting the price right to achieve desired greenhouse gas reduction objectives, due both to estimation uncertainties and the practical political challenges that can arise in their implementation. Cap and trade poses additional challenges, including administrative burden and complexity, price transparency for market participants, and ensuring that offsets reflect truly incremental emissions reductions.

Finally, though not yet widespread, some proposed government measures may directly cap emissions by sector or industry.[23] Although these types of inflexible regulations are generally recognized to be inefficient, they may be preferred in some instances for regulatory simplicity or to achieve other social or political objectives.

2. PUBLIC UTILITIES AND THEIR REGULATORS

Historically, energy utilities have been textbook "natural monopolies"[24] subject to economic regulation by public utility regulators. These regulators have generally exerted significant control over the investments made by utilities, both into infrastructure and new technologies, though this has lessened in certain jurisdictions that have deregulated parts of

---

18 Alta Reg 133/2019 [*TIER*]. As noted by the Alberta government: "The TIER system implements Alberta's industrial carbon pricing and emissions trading system. TIER helps industrial facilities find innovative ways to reduce emissions and invest in clean technology to stay competitive and save money" (Alberta, "Technology Innovation and Emissions Reduction Regulation," online: [perma.cc/M6N9-WQU6]).

19 SBC 2008, c 16 [*GGRA*].

20 BC Reg 394/2008 [*RLCFRR*].

21 Bill 15, *Low Carbon Fuels Act*, 3rd Sess, 42nd Leg, British Columbia, 2022 (first reading 9 May 2022) [*LCFA*].

22 British Columbia, "Renewable & Low Carbon Fuel Requirements Regulation," online: [perma.cc/GWW5-KA52].

23 Environment and Climate Change Canada, *Options to Cap and Cut Oil and Gas Sector Greenhouse Gas Emissions to Achieve 2030 Goals and Net-Zero by 2050: Discussion Document*, (3 August 2022), online: [perma.cc/R7D4-44EQ].

24 As explained by the Supreme Court of Canada, a natural monopoly exists when "technology and demand are such that fixed costs are lower for a single firm to supply the market than would be the case where there is duplication of services by different companies in a competitive environment": *ATCO Gas & Pipelines Ltd v Alberta (Energy & Utilities Board)*, 2006 SCC 4 at para 3 [citations omitted].

their energy systems. In all models, however, ratepayer interests and the provision of low cost, safe, and reliable energy are central.

Utility regulators now face novel questions raised by the need to achieve greenhouse gas (GHG) emissions targets. Early stage energy transition-related technologies are not necessarily the most cost-effective way to supply power, and traditionally utilities played no or limited role in innovation. In some cases, new technologies undermine the economic case for traditional regulation.[25] And new statutory regimes that adjust or constrain regulators' ability to apply otherwise standard rate-making principles have led to shifting legal paradigms.

Public utility commissions therefore also have a central role to play in enabling the energy transition. Most Canadian regulators do not have a legislative mandate to address climate change, and have either had to defer (to varying degrees) to government policy, or to address climate change through flexible interpretations of their mandates. These regulators often face an inherent tension in their dual role of adapting their approaches to match public policy objectives while also ensuring ratepayer interests remain protected. On one hand, they can be creative, facilitating utilities' investment of money towards innovation and innovative products, and broadening age-old regulatory principles to the new world. On the other hand, they must be careful in doing so, to avoid greatly increasing the cost to supply from the grid, risking grid defection, or, even more seriously, undermining the economic case for electrification altogether. At the same time, large increases in electricity rates may be disproportionately borne by lower-income households as a percentage of household income[26] — those often most impacted by climate change, and least able to afford the steps necessary to avert it.

Regulators across Canada have taken different approaches to these issues.

Alberta has adopted an approach intended to minimize red tape to encourage innovation in the private sector. In 2020, the Alberta Utilities Commission (AUC) launched an independent "Procedures and Processes Review Committee" to look for ways to improve efficiencies and streamline adjudicative procedures,[27] with almost all of the recommendations having since been adopted.[28] Improvements in efficiency should serve to reduce the burden on the private sector, while also enabling the AUC to more nimbly respond to changing energy markets.

Other regulators have become more directly involved in funding innovation for low-carbon energy solutions. In Ontario, for example, the IESO Grid Innovation Fund and the Ontario Energy Board (OEB) have coordinated to promote distributed energy resource (DER) projects. In March 2022, the OEB announced four pilot projects involving testing

25 For instance, the British Columbia Utilities Commission has observed, in the context of both the EV charging market and hydrogen services market in British Columbia, that to the extent aspects of these markets are competitive, full-scale economic regulation is not necessary: see notes 137–39.

26 Dolter & Winter, *supra* note 5 at 35.

27 Alberta Utilities Commission, *Bulletin 2020-17: AUC Creates Independent, Expert Committee to Assist in Improving Efficiency of Rates Proceedings* (8 May 2020), online (pdf): [perma.cc/8U2P-BRB8].

28 Alberta Utilities Commission, *Bulletin 2020-33: Process Improvements to AUC Rate Proceedings* (22 October 2020), online (pdf): [perma.cc/K9WU-YYYX].

models for using DERs — including wind, solar, and battery storage.[29] The four projects total $37 million in investment, with $10.6 million coming from the IESO's Grid Innovation Fund and the remaining funding coming from proponents and other government and industry partners.[30]

The British Columbia Utilities Commission (BCUC), meanwhile, has grappled with innovation associated with the energy transition within the standard rate setting paradigm — an approach which has resulted in disparate, but principled, outcomes. As one example, the BCUC considered "innovation fund" requests made by related natural gas and electric utilities, FortisBC Energy Inc. and FortisBC Inc. The BCUC approved a $24.5 million ratepayer-funded innovation fund for the natural gas utility,[31] but refused the electric utility's similar request for a $2.5 million innovation fund, largely on the basis that that the natural gas utility must strive to reduce or eliminate GHG-emitting fuel sources (which requires innovation), while the electrical utility did not face the same pressures.[32]

3. INVESTORS

Private investment in green technologies has been substantial in recent years, driven by several factors.

As described above, government "carrots" for investment in clean energy abound — including the opportunity for public-private partnerships, the availability of grants and subsidies, and access to desirable financing, and tax breaks — as do "sticks" like carbon taxes. Some investors simply respond to the economic incentives created by these policies.

At the same time, there is a growing private market for green finance, making clean energy investment more accessible. Some organizations may wish to invest in the energy transition as part of their sustainability or ESG commitments, or to improve stakeholder relations and maintain their social licence. Investment in clean energy can also be part of a strategic plan for existing emitters to maintain or even expand their market share in future, as well as for newer players to obtain a competitive advantage. Investment may be prompted by shareholder activism. Yet others still simply get involved for the sake of social enterprise, such as recent Corporate Power Purchase Agreements (PPAs) by Amazon and Microsoft to purchase solar and wind power in Alberta (as well as elsewhere in North America).[33]

While not the focus of this article, it is also worth noting that Canada has seen a significant uptick in Indigenous equity participation (by First Nations, Indigenous groups,

---

29 Ontario Energy Board, News Release, "Unlocking the Electricity Potential in Ontario's Communities: IESO, OEB and Local Organizations Collaborate on Local Energy Projects Totalling $37 Million" (30 March 2022), online: *Independent Electricity System Operator* [perma.cc/RJ7J-8B57].

30 *Ibid.*

31 Alberta Utilities Commission, *supra* note 27.

32 *FortisBC Energy Inc. and FortisBC Inc. Application for Approval of a Multi-Year Rate Plan for the Years 2020 through 2024* (22 June 2020), Decision and Orders G-165-20 & G-166-20 at 125-126, online (pdf): *British Columbia Utilities Commission* [perma.cc/J5K3-5DM8].

33 Gabriel Friedman, "Amazon's Solar Farm Offtake Deal to Accelerate Alberta's Renewable Energy Transformation," *Financial Post* (23 June 2021), online: [perma.cc/M2QD-MFPY]; ATCO, News Release, "ATCO Closes Major Canadian Renewables Acquisition and Enters into a Long-Term Renewable Energy Purchase Agreement with Microsoft" (6 January 2023), online: *ATCO* [perma.cc/4WNC-RFVE].

and Indigenous-owned businesses) in energy projects in recent years.[34] This trend is partially attributable to new sources of funding aimed at addressing barriers to funding created by the federal *Indian Act*.[35] Several of the projects discussed below have some degree of Indigenous equity participation. The perspectives and values of Indigenous participants in these major projects may also help drive private capital into technologies that support the energy transition.

II. SPECIFIC CHALLENGES RELATING TO GENERATION, TRANSMISSION, AND ENERGY CONSUMPTION

Although each of these parties have different mandates and interests, there is inevitable overlap and friction between the steps they are taking toward the energy transition, with resulting consequences for the efficiency of spending and allocation of costs. Broadly speaking, these frictions manifest differently for (1) new generation and energy sources; (2) necessary changes to transmission and distribution infrastructure; and (3) developments in the consumption of energy. This section considers each of these areas of concern in turn.

A. WHO PAYS FOR THE NEW GENERATION AND NEW ENERGY SOURCES NEEDED FOR THE ENERGY TRANSITION?

Decarbonizing electricity generation has generally been recognized as critical to achieving greenhouse gas emissions reduction targets.

In Canada, there are limited interconnections between provincial utility grids, creating disparate emissions profiles across provinces. Hydroelectric rich jurisdictions like British Columbia and Manitoba already have relatively low emissions intensity grids, but must still contend with building new generation to address anticipated load growth arising from fuel switching and electrification. Provinces without comparable hydroelectric capabilities like Alberta and Ontario have even more demanding paths, needing to not only address future demand but to also take significant steps to decarbonize their existing generation mix.

Consistent with each province facing different generation-related challenges, there has also been a wide-range of approaches to this issue across provinces.

1. RATEPAYERS

In many cases, ratepayers have been asked to absorb the costs of building new generation and infrastructure needed to support lower-carbon fuel sources.

---

34 R Max Collett et al, "Project Development Partnerships with Indigenous Groups" (10 November 2022), online (blog): *Lexpert* [perma.cc/9VFZ-CL89].

35 RSC 1985, c I-5. See e.g. Canada, "Indigenous Business and Federal Procurement" (17 August 2023), online: [perma.cc/37A4-AE2B]; "About the FNFA," online: *First Nations Finance Authority* [perma.cc/23CM-DJQH]; "Indigenous Community Infrastructure Initiative" (2023), online: *Canada Infrastructure Bank* [perma.cc/RA3W-FUJ3]; Alberta Indigenous Opportunities Corporation, *Mandate and Roles Document* (8 March 2022), online (pdf): [perma.cc/GT3E-XHM5]; "Overview of the Aboriginal Loan Guarantee Program," online: *Ontario Financing Authority* [perma.cc/9QC9-E6M9]; British Columbia, "First Nations Clean Energy Business Fund," online: [perma.cc/F6D7-8UMR].

For example, in British Columbia, a number of government-directed efforts to shift to low-carbon sources have been reflected in electricity and gas rates.

Historically, the British Columbia government has generally left decisions about the construction of electricity generation to the province's utilities — including the Crown-owned BC Hydro, which provides electricity to the bulk of the province, the privately-owned FortisBC Inc. and smaller municipal power utilities — with independent power producers playing a much smaller role. Over the past two decades, however, successive provincial governments have focused the activities of utilities, through legislation like the *Clean Energy Act*[36] and the *Greenhouse Gas Reduction (Clean Energy) Regulation*,[37] toward low-carbon investments exempt from review by the BCUC, including notably the Site C dam. BC Hydro's 2002–2010 green or clean power calls greatly expanded BC Hydro's reliance on independent producers to meet its energy needs.

These legislative measures have promoted the development of clean technology and infrastructure regardless of whether it would qualify for recovery from ratepayers under traditional rate-setting methodologies, but nonetheless requires ratepayers to pay the costs. It is unlikely that all of this spending would have been approved to be recovered from ratepayers under the traditional rate-setting model.

Gas utility ratepayers have similarly paid for efforts at developing LNG in British Columbia. The history of FortisBC Energy Inc.'s efforts to expand its LNG facilities at Tilbury highlights the potential tension between low-carbon technologies and traditional rate-making principles.

Phase 1 of FortisBC Energy Inc.'s Tilbury expansion involved constructing additional facilities for LNG production, storage, and transportation,[38] used to balance FortisBC's system and to allow some exports. In 2013, the British Columbia government directed the BCUC[39] to allow FortisBC Energy Inc. to construct Phase 1, and specifically permitted FortisBC to recover the costs for the Phase 1 expansion (up to a maximum of $825 million) from the majority of its customer base without BCUC review.[40] Whether doing so was within ratepayers interests was therefore not considered publicly.

Yet when FortisBC Energy Inc. subsequently applied to the BCUC in 2020 for approval to construct a further extension to its Tilbury facilities — beyond the expansion exempted by the earlier government direction — it hit a roadblock. The proposed expansion was intended to increase the "resiliency" of FortisBC Energy Inc.'s natural gas system through

36 SBC 2010, c 22, s 7 [*CEA*].
37 BC Reg 102/2012 [*GGRR*].
38 Todd Smith et al, "Tilbury Phase 2 LNG Expansion Project: Initial Project Description" (10 February 2020) at I-7, online (pdf): *FortisBC* [perma.cc/S2T3-M7MN]; "Tilbury Phase 1 LNG Expansion Project" (2023), online: *FortisBC* [perma.cc/35NB-PCXS]; The British Columbia government directed the BCUC to allow FortisBC Energy Inc. to construct the Phase 1 expansion through *Direction No 5 to the British Columbia Utilities Commission*, BC Reg 245/2013, s 4 [*Direction No 5*].
39 The British Columbia government has the authority to direct the BCUC how to exercise its powers: *Utilities Commission Act*, RSBC 1996, c 473, s 3 [*UCA*].
40 *Direction No 5*, *supra* note 38, ss 1, 4: see definition of "applicable customers."

the construction of a new storage tank and liquefaction unit.[41] But the BCUC recently exercised the discretion it retained for this new expansion request and adjourned the proceeding to invite FortisBC Energy Inc. to file additional information to support its application,[42] because it had not provided sufficient information about future domestic natural gas demand to allow the BCUC to make an informed decision about whether the project was in the public interest.[43]

In Ontario, meanwhile, the OEB has focused on providing the regulatory flexibility necessary to allow innovations in utility service offerings (including in the clean energy sphere). The OEB established an "Innovation Sandbox" in 2019, the purpose of which was stated to be to "[p]rovide a venue for proponents to engage in candid conversations with OEB staff about innovative ideas," "allow proponents to request temporary relief by way of a streamlined, simplified application process," "[r]educe regulatory uncertainty and risk," and give the OEB "insight into sector challenges and innovations."[44]

Although the Sandbox handled numerous inquiries in its first few years of existence, there were also limitations: there was no funding source attached to the Sandbox, meaning there were no monies available to provide seed funding to pilot innovation; for some of the proposals, the requested regulatory relief was not within the OEB's jurisdiction; and some stakeholders expressed concerns that efforts to protect commercial confidentiality for proponents hampered transparency.

After two years, the OEB conducted a consultation on the Sandbox, producing a report entitled *Innovation Sandbox 2.0* in January of 2022. The report details changes to the Sandbox, including strategies to enhance Sandbox awareness and transparency, enhancements to the Sandbox website, improved annual reporting, and increased outreach.[45] In a further recent report on the progress of the Sandbox, from April 2023, the OEB has described various projects that the Sandbox has facilitated to date, and flagged upcoming initiatives in 2023, including the "Innovation Sandbox Challenge, a one-time funding opportunity of $1.5 million to support innovative projects in the energy sector."[46]

2. TAXPAYERS AND INVESTORS

In other cases, taxpayers and investors have footed the bill of shifting generation.

---

41 "Application for a Certificate of Public Convenience and Necessity for the Tilbury Liquefied Natural Gas Storage Expansion Project" (29 December 2020), online (pdf): *FortisBC* [perma.cc/ Z5S2-26LW] [*Application for Certificate*]. "Tilbury Phase 2 LNG Expansion Project" (2023), online: *FortisBC* [perma.cc/7QP9-FX4G].

42 *Application for Certificate*, *ibid* at i-ii.s.

43 *Application for a Certificate of Public Convenience and Necessity for the Tilbury Liquefied Natural Gas Storage Expansion Project* (23 March 2023), Decision and Order G-62-23 at i–ii, online (pdf): *British Columbia Utilities Commission* [perma.cc/2LFG-92CM].

44 Ontario Energy Board, *OEB Innovation Sandbox: Overview, November 2020* (27 November 2020) at 4, online (pdf): [perma.cc/3KQG-F9Y3].

45 Ontario Energy Board, *OEB Innovation Sandbox 2.0* (January 2022) at 4, online (pdf): [perma.cc/92W8-GSV9].

46 Ontario Energy Board, *Innovation Sandbox 2.0 Report: April 2023* (21 April 2023) at 16, online (pdf): [perma.cc/4XTC-KWL5].

Alberta's coal-to-gas conversion stands as one prominent example. For Alberta, the transition from coal-fired generation to other energy sources (particularly natural gas) is crucial for decarbonization.[47] Since 2015, Alberta's emissions have fallen thanks to a rapid phase-out of coal fired electricity generation, and they are projected to continue on a downward trajectory in the coming years as natural gas displaces coal in the supply mix and renewable energy generation continues to grow.[48] In 2023, Alberta's final coal-fired generation capacity is anticipated to be converted to natural gas.[49]

These developments reflect purposeful government policy. In the mid-2010s, Alberta launched a public engagement and policy advisory process on climate change, led by the Climate Leadership Panel.[50] In November 2015, the Climate Leadership Panel recommended five major climate change measures, including the phase-out of coal-fired power by 2030.[51]

Both investors and Alberta taxpayers have largely paid the cost of implementing these recommendations. In November 2016, the Alberta government announced transition agreements providing for annual payments to companies operating coal-fired generation until 2030, totalling $1.1 billion.[52] The issuance of new federal regulations also enabled the extended use of existing coal generation assets through modest investments to convert them to natural gas use.[53] These taxpayer-funded initiatives did not insulate owners of coal-fired facilities; academic commentary notes that investors bore losses through the reduction in coal plant asset value by environmental policies (mitigated somewhat by the potential for the conversion of these assets to natural gas use), while taxpayers covered compensation costs, estimated to be smaller than the erosion of asset value borne by investors.[54]

Conversely, direct renewable investments made by the Alberta government elsewhere have been profitable. As discussed in Part II.A.4 below, Alberta's Renewable Electricity Program (REP) helped to kick start a wave of private renewable investment that continued even after the program was cancelled. Alberta has seen a significant amount of private investment in solar and wind projects in recent years, including, for example, the recently completed 465MW Travers Solar Project[55] and forthcoming 465MW Midnight Solar Project.[56]

---

47 Although the fourth largest province by population in Canada, Alberta has the highest GHG emissions in the country, and has among the highest per-capita emissions globally: Benjamin J Thibault, Tim Weis & Andrew Leach, "Alberta's Quiet but Resilient Electricity Transition" in Mark S Winfeld, Stephen Hill & James Gaede, eds, *Sustainable Energy Transitions in Canada; Challenges and Opportunities* (Vancouver: UBC Press, 2023) at 2, online: [perma.cc/8FDJ-6AVD].

48 *Ibid.*

49 Alberta Electric System Operator, *AESO Net-Zero Emissions Pathways Report* (27 June 2022), online (pdf): [perma.cc/FK9B-X2TG] [AESO Report].

50 Alberta, *Climate Leadership Discussions: Technical Engagement Summary*, (20 November 2015), online: [perma.cc/AK5E-6SS6].

51 Alberta Climate Leadership Panel, *Climate Leadership: Report to Minister,* by Andrew Leach et al (20 November 2015) at 5–6, online: [perma.cc/T7CY-MDYQ].

52 Alberta, News Release, "Revised: Alberta Announces Coal Transition Action" (24 November 2016), online: [perma.cc/GTX9-SDH5].

53 Canada, "Technical Backgrounder: Federal Regulations for Electricity Sector" (12 December 2018), online: [perma.cc/E3VU-PQ98].

54 Thibault, Weis & Leach, *supra* note 47 at 21.

55 Alberta, "Travers Solar Project," online: [perma.cc/V6Q2-D4SY].

56 Alberta, "Midnight Solar and Battery Storage Project," online: [perma.cc/X5Y8-PDYE].

In another example of taxpayer investment, Ontario Power Generation (wholly owned by the province of Ontario) broke ground on Canada's first grid-scale small modular reactor in December 2022.[57] The current Phase 1 — consisting of all preparation prior to nuclear construction — is being funded by CIB, which committed $970 million (the CIB's largest single investment in clean power).[58] The cost to ratepayers is not yet clear; Ontario Power Generation (OPG) has indicated that it is expecting to know overall project costs and make a final construction design by the end of 2024.[59] In the meantime, federal funds are pushing the project forward.

3. THE CREATION OF OFFSET SCHEMES

Where emissions cannot be sufficiently reduced or eliminated, organizations may engage in offsetting to reduce their carbon footprint. At a high level, offsetting involves investing in projects that will reduce greenhouse gas emissions to compensate for emissions generated elsewhere that may be more difficult to reduce. Offsets, which have been used since the 1970s, may be sold in private markets by private entities, or created by statute (as discussed at Part II.C.1).

Despite the fact that offsets are a longstanding voluntary and involuntary carbon emissions mitigation mechanism, regulators have had to grapple with offsets' role in achieving government policy. For example, in its Phase 1 Report in the Inquiry into the Acquisition of Renewable Natural Gas by Public Utilities in British Columbia, the BCUC considered the role of offsets in British Columbia's renewable natural gas scheme, discussing whether they can be paired with natural gas to create "renewable natural gas."[60] In the ongoing second phase of the Inquiry, the BCUC is considering what *types* of environmental attributes can be paired with natural gas to create renewable natural gas (RNG) — and, in particular, whether such environmental attributes must be derived from the production of biomethane, or could be from other, unrelated sources.[61]

Offsets have also been considered in Alberta, where the transition from coal generation to natural gas will not, on its own, enable the province to meet its climate goals. For instance, in June 2022, the Alberta Electric System Operator (AESO) issued its "Net-Zero Emissions Pathway Report," analyzing the potential for Alberta to reach net zero emissions.[62] Although the AESO found that, by 2035, the Alberta electricity system could in theory approach zero emissions, it anticipated that a small volume of emissions would necessarily remain due to the continued operation of some carbon-producing assets.[63] In the main, the AESO does not

---

57 Ontario, Office of the Premier, News Release, "Ontario Breaks Ground on World-Leading Small Modular Reactor" (2 December 2022), online: [perma.cc/L2N9-8K7G].

58 Canada Infrastructure Bank, News Release "CIB Commits $970 Million Towards Canada's First Small Modular Reactor" (25 October 2022), online: [perma.cc/9YGB-AXP8].

59 Ontario Power Generation, Media Release, "Darlington New Nuclear: Ontario is Leading North America's Clean Energy Future" online: [perma.cc/4SYZ-W2GP].

60 British Columbia Utilities Commission, *Inquiry into the Acquisition of Renewable Natural Gas by Public Utilities in British Columbia: Phase 1 Report* (28 July 2022) at 19, online (pdf): [perma.cc/6GLZ-Z59D].

61 *Ibid*.

62 AESO Report, *supra* note 49 at 1.

63 *Ibid* at 72.

anticipate that zero physical emissions will be achieved by 2035, and points to the significant role for offsets in achieving net zero.[64]

Many industry stakeholders have also recognized the importance of offsets in achieving net zero emissions. For example, the Pathways Alliance, a group made up of Canada's six largest oil sands producers[65] (facilities that account for 95 percent of oil sands production), reported in 2022 that it plans to achieve net zero GHG emissions by 2050 through offsets and carbon capture utilization systems connecting oil sands developments to a carbon storage facility hub near Cold Lake.[66] Similarly, Shell has announced its tiered approach to addressing emissions and goal of achieving net zero, which includes using offsets when, in Shell's view, reducing physical emissions is not possible.[67]

Offsetting schemes have attracted some criticism, however; several independent studies assert that many credits sold by leading offset programs likely do not represent valid greenhouse gas reductions.[68] Similarly, earlier this year, an investigation reported that more than 90 percent of the rainforest offset credits certified by the world's leading carbon credit certifier did not represent genuine carbon reductions,[69] though the validity of these results has been disputed.[70] In any case, although these criticisms take issue with whether specific offsetting programs achieve their intended ends, they do not undermine the underlying rationale for offsetting and the role it will likely have to play if net zero is to be achieved.

4. ATTEMPTS TO SHAPE OR CREATE MARKETS

One alternative approach that policy-makers have employed in place of the standard utility model is to attempt to create or influence markets in power generation with the goal of incentivizing a private-sector response. As historical experience has taught some provinces, however, these measures must be carefully tailored to avoid undesired market responses to invitations to increase renewable generation. A properly designed government measure may, however, lead to an efficient and effective increase in low carbon generation. Three representative examples include:

---

64 *Ibid*.

65 Cenovus Energy, News Release, "Cenovus and Pathways Alliance Advance Initiatives to Achieve Net Zero GHG Emissions by 2050" (March 2022), online: [perma.cc/T2AF-B9B3].

66 "The Pathways Alliance Vision" (17 October 2022) at 4, online (pdf): *Pathways Alliance* [perma.cc/SWN5-PYPW].

67 Susannah Pierce, "Net-Zero Commitments: Getting from Here to There" (8 April 2021), online: *Shell Canada* [perma.cc/73L8-Z7L7].

68 Anja Kollmuss, Lambert Schneider & Vladyslav Zhezherin, "Has Joint Implementation Reduced GHG Emissions? Lessons Learned for the Design of Carbon Market Mechanisms" (2015) Stockholm Environment Institute Working Paper 2015-07, online: [perma.cc/89BN-DTDK]; Martin Cames et al, "How Additional is the Clean Development Mechanism? Analysis of the Application of Current Tools and Proposed Alternatives" (March 2016), online (pdf): *Öko-Institut e.V.* [perma.cc/Q5W4-58PJ].

69 Patrick Greenfield, "Revealed: More Than 90% of Rainforest Carbon Offsets by Biggest Certifier Are Worthless, Analysis Shows," *The Guardian* (18 January 2023), online: [perma.cc/FFB6-RY8V]. See also Alejandro Guizar-Coutiño et al, "A Global Evaluation of the Effectiveness of Voluntary REDD+ Projects at Reducing Deforestation and Degradation in the Moist Tropics" 36: e13970 Conservation Biology; Thales AP West et al, "Overstated Carbon Emission Reductions from Voluntary REDD+ Projects in the Brazilian Amazon" (14 September 2020) 117:39 Proceedings of the National Academy of Sciences 24188; Sebastien Desbureaux et al, "The 'Virtual Economy' of REDD+ Projects: Does Private Certification of REDD+ Projects Ensure their Environmental Integrity?" (2016) 18:2 Intl Forestry Rev 231.

70 Verra, News Release, "Verra Response to Guardian Article on Carbon Offsets" (18 January 2023), online: [perma.cc/DCF6-3QJN].

a. BC Hydro's Green or Clean Power Calls

As part of a move towards green or clean power, in 2002 the British Columbia government began procuring "green," "bioenergy," and "clean" power from independent producers through a series of calls. In 2007, government established two requirements for BC Hydro that drove significant growth in Independent Power Producers (IPPs) for a decade: that at least 90 percent of all electricity generated in British Columbia must originate from clean sustainable sources; and, that BC Hydro must become self sufficient (that is, not rely on imports to meet forecast domestic demand).[71] The related Standing Offer Program in 2008 facilitated small projects to bid into BC Hydro power calls.[72] A shift to a new two-tier industrial rate structure, with marginal cost exposure and "retail access," was also introduced to create a competitive IPP power market.

In this case, the British Columbia government direction led BC Hydro to procure a significant volume of renewable energy from independent power producers — energy that BC Hydro ultimately did not need. An independent report commissioned by the British Columbia government concluded that under the program BC Hydro bought surplus energy at too high a price,[73] which BC Hydro then sold to ratepayers at rates less than it was buying from IPPs, resulting in BC Hydro having no alternative but to, structurally, buy high and sell low.[74] The impact to ratepayers was conservatively estimated to be at least $16.2 billion over 20 years for the acquisition of the surplus energy, with an additional $6.8 billion of losses arising from the energy sales.[75] BC Hydro suspended the Standing Offer Program in 2019, following a government review of BC Hydro's operations.[76]

b. Ontario's Feed-In Tariff Program

Starting in 2009, the Ontario government instituted the Feed-in Tariff (FIT) program, which aimed to promote the development of renewable energy projects, such as wind, solar, and biomass, in the province. Under the FIT program, renewable energy developers were offered long-term contracts and guaranteed prices for the electricity they produced, which were to be funded by a non-market surcharge on electricity called the Global Adjustment.[77] A 2015 report by the Auditor General of Ontario concluded that the guaranteed-price contracts under the FIT program would cost electricity consumers $9.2 billion over what would have been incurred under the province's previous renewable procurement program,

71 British Columbia, "Zapped: A Review of BC Hydro's Purchase of Power from Independent Power Producers Conducted for the Minister of Energy, Mines, and Petroleum Resources," by Ken Davidson (2019), online (pdf): [perma.cc/SMF5-6NXL].
72 *Ibid*.
73 *Ibid* at 1.
74 *Ibid*.
75 *Ibid*.
76 "Standing Offer Program," online: *BC Hydro* [perma.cc/8AG7-CVGY].
77 Ben Eisen, "Creating Policy Calling Cards to Attract Business to Ontario" (12 September 2018) at 38, online (pdf): *Fraser Institute* [perma.cc/M9HA-D3Z8].

and that the guaranteed prices in the FIT contracts were double or triple market price.[78] The Ontario government ultimately cancelled the FIT program.[79]

c. Alberta's Renewable Energy Program

Alberta's experience with the REP demonstrated a different, and more sustainable, approach to encouraging investment while reducing potential burden on both ratepayers and taxpayers. The REP was a competitive procurement process, administered by the AESO, to build renewable generation, with the provincial government guaranteeing a per-MWh price for power through contracts for difference.[80] The REP led to the addition of approximately 1,360 MW of renewable capacity[81] and helped to kick off a larger influx of private investment in wind and solar generation.[82] Looking forward, efforts by the AESO to enable the integration of more energy storage into Alberta's transmission system may also help to foster further private investment by mitigating the "wind discount" — the fact that wind generation tends to occur at times when wholesale power prices are relatively low.[83] Encouragingly, the REP did not raise the bill for taxpayers, as the contracts for difference ultimately favoured the government.

B. WHO PAYS FOR THE EXPANDED TRANSMISSION AND DISTRIBUTION INFRASTRUCTURE NEEDED FOR THE ENERGY TRANSITION?

Energy transmission and distribution infrastructure also require expensive upgrades to accommodate the changes wrought by the energy transition. For instance, the electric transmission grid will need to change and evolve as Canada moves from the past model, with centralized generation being transmitted to (sometimes very distant) load sites, to a new model that includes distributed generation and load curves with different characteristics.

In transmission and distribution, where regulated utilities are ubiquitous, the burden of the energy transition by default falls on ratepayers. But regulators are alive to the fact that traditional rate-making principles and legislative frameworks may be strained by the scale and novelty of the coming changes.

1. WHICH RATEPAYERS SHOULD PAY?

While ratepayers are the default payers when it comes to transmission and distribution infrastructure, how the burden is distributed among ratepayers has been a central concern.

---

78 *Ibid*. See also Office of the Auditor General of Ontario, *Annual Report 2015* (19 November 2015) at 214–15, online (pdf): [perma.cc/4MTY-W2L7].

79 Government of Ontario, News Release, "Ontario Scraps the Green Energy Act" (7 December 2018), online: [perma.cc/TZB8-BGX3]; The Canadian Press, "Ontario Government Cancels 758 Renewable Energy Contracts, Says It Will Save Millions," *CBC News* (13 July 2018), online: [perma.cc/ZQM2-479L].

80 "About the Program," online: *Alberta Electric System Operator* [perma.cc/V7W6-MFPF].

81 "REP Results," online: *Alberta Electric System Operator* [perma.cc/U447-A878].

82 Thibault, Weis & Leach, *supra* note 47 at 21.

83 David Eeles et al, "Energy Storage: The Regulatory Landscape in Alberta" (2021) 59:2 Alta L Rev 355 at 369–70.

Two recent examples from British Columbia, both representing significant investment in transmission infrastructure in northern British Columbia, show divergent approaches through the application of government policy:

1. With the Northwest Transmission Line, the costs were ultimately borne by users of the line. The Northwest Transmission Line was intended to provide electricity to industrial developments and a connection point for clean power generation projects in the northwestern part of British Columbia, and was completed in 2014 at a cost of roughly $746 million.[84] The federal government contributed approximately $130 million through the Green Infrastructure Fund and AltaGas (the anchor tenant) provided $180 million in capital contributions, with the balance of roughly $436 million recovered from users of the line (largely mining projects in northwestern British Columbia) via a special tariff.[85] In considering the approval of BC Hydro's proposed tariff for the line, the BCUC noted that the *CEA* specifically required the BCUC to approve the rate proposed by BC Hydro in relation to the line, thus removing the BCUC's general discretion under the *UCA* to assess the rate.[86]

2. In contrast, the Peace Region Electricity Supply (PRES) project was paid for by ratepayers more generally. The PRES, completed in 2021, consisted of new power lines, substation upgrades, and new and upgraded roads intended to increase the capacity of the transmission system that supplies the South Peace Region in northwestern British Columbia and improve service reliability.[87] When this $290 million project was announced, the federal government committed up to $83.6 million through the Investing in Canada Plan, with BC Hydro (in other words, ratepayers) providing the remaining $205.4 million.[88] The PRES project is a "prescribed undertaking" under the *CEA*, for the purpose of reducing greenhouse gas emissions (by displacing more carbon intensive generation), which requires the BCUC to allow BC Hydro to recover its costs in rates without the same scrutiny that would typically be required for utility projects.[89]

In Alberta, an inquiry by the AUC emphasized the importance of rate-making principles to ensure that inter-customer subsidies do not create incentives for inefficient investment in new, sometimes green technologies. The February 2021 *Distribution System Inquiry Final Report* completed a two-year process of inquiry focused primarily on the likely effects of

---

84 BC Hydro, News Release, "New Transmission Line Ready to Power Northwest BC" (13 August 2014), online: [perma.cc/4GJ5-G26Q].

85 *Northwest Transmission Line Application: Tariff Supplement No. 37 to BC Hydro Electric Tariff* (April 2013), Order G-52-13, online (pdf): *British Columbia Utilities Commission* [perma.cc/K4JB-ZX66] [Order G-52-13], as amended by *Tariff Supplement No. 37 Amendments Application: Northwest Transmission Line Supplemental Charge* (May 2017), Order G-68-17, online (pdf): *British Columbia Utilities Commission* [perma.cc/SQ3Z-PCAY]. The tariff was rescinded in 2021: *Application for Consent to Rescind Tariff Supplement No. 37 and Approval of Rate Schedules 1894 and 1895* (5 February 2021), Order G-38-21, online (pdf): *British Columbia Utilities Commission* [perma.cc/H5SJ-XRHR].

86 Order G-52-13, *ibid* at 6 (see Reasons for Decision).

87 "2021/22 Annual Service Plan Report" (August 2022), online: *BC Hydro* [perma.cc/9B6Z-FSUD].

88 Infrastructure Canada, News Release, "Canada and BC to Bring Clean Energy to the Peace Region" (18 April 2019), online: [perma.cc/N3S7-PD2J].

89 *British Columbia Hydro and Power Authority F2020 to F2021 Revenue Requirements Application* (2 October 2020), Decision and Order G-246-20, online (pdf): *British Columbia Utilities Commission* [perma.cc/97Q2-DKT3].

future increases in the use of DERs. DERs are broadly understood as any technology connected to the distribution system that affects electricity supply or demand.[90] This includes a number of technologies that are likely to play an important role in the energy transition, including EV charging, solar and wind generation, demand response technologies, and energy storage.

A primary challenge identified by the AUC was the potential for DERs to shift utility costs among ratepayers. The AUC described "uneconomic bypass" as when DERs reduce the transmission or distribution portion of a customer's energy bill without reducing the costs of the electric system.[91] As those avoided costs do not disappear, they must be recovered, through higher rates, from other ratepayers. The result may be a spiral of increasingly inefficient investment.[92]

The AUC found that the principles of economic efficiency, competition, and customer choice embedded in Alberta's statutory framework provided the necessary flexibility to address this potential challenge.[93] The AUC also emphasized the centrality of the "vital and centuries-old principle" that utility rates must be just, reasonable, and not unduly discriminatory.[94] That meant ensuring that customers who install DERs continue to pay an appropriate share of utility system costs.[95]

More recently, the AUC grappled again with the challenge of applying rate-making principles and legislative frameworks to the new circumstances of the energy transition, in its decision on the AESO's proposal to significantly overhaul the design of Alberta's transmission tariff, in part to accommodate shifts in the generation fleet (including an increase in renewables and a phase-out of coal).[96] In the end, the AUC denied the AESO's proposal — in large part due to the implications of Alberta's legislated requirement for "postage-stamp" rates that do not vary by location, and the fact that the cost of serving demand varied widely across the province, relative to designing a rate that "provid[ed] efficient consumption signals."[97] The decision reflects a tension between the earlier bypass concern, the need for tariffs to respond to the energy transition, and potentially the need to revisit legislation to remove unintended consequences that have emerged within a more complex system. It also raises questions about how best to foster economically efficient investments and manage transmission cost impacts even as demands on the transmission system are likely to rise as the economy shifts toward increasing electrification.

---

90 Alberta Utilities Commission, *Distribution System Inquiry Final Report* (2021) at 4, online (pdf): [perma.cc/U8DK-PGCW]
91 *Ibid* at paras 93–97.
92 *Ibid* at paras 5, 102.
93 *Ibid* at para 268.
94 *Ibid* at para 269.
95 *Ibid* at paras 281–90.
96 Alberta Utilities Commission, *Alberta Electric System Operator Bulk: Regional and Modernized Demand Opportunity Service Rate Design Application* (10 November 2022), online (pdf): [perma.cc/P74V-V5U8].
97 *Ibid* at paras 55, 107.

2. BALANCING THE INTERESTS OF RATEPAYERS AND UTILITY INVESTORS

Another important concern is the distribution of costs between utility investors and ratepayers. The OEB recently addressed this issue in its January 2023 *Framework for Energy Innovation* report (*FEI Report*). The *FEI Report* sets out the OEB's policies and plans to integrate DERs into distribution grid planning and operations, as well as the use of DERs as non-wire alternatives.[98]

The OEB identified utility investor incentives as a key problem to address. DERs may be important "non-wires alternatives" to meet the demands placed on electric distribution systems by the energy transition. But the interests of distribution utilities and their investors are not necessarily aligned with those of their ratepayers. Distributors who adopt third party DER solutions instead of building out their own capital "wires" investments may forgo the opportunity to add a capital asset to rate base and earn a return from ratepayers.[99] The resulting misalignment of interests may slow down otherwise beneficial (efficient) DER deployment:

> This misalignment between utilities' interests (to earn profits by building assets) and customer interests (to have the most cost-effective delivery of reliable energy services) may be a barrier to DER solutions.[100]

While stakeholders agreed that disincentives for DER adoption should be mitigated, they disagreed about whether positive incentives would be appropriate.[101] The OEB acknowledged that providing incentives to distributors to deploy third party owned DERs may be necessary to overcome the near-term problem of encouraging sufficient DER adoption to facilitate the energy transition. The OEB invited distributors to propose incentives in their rate applications, including options that would see savings from DERs shared between utility investors and their ratepayers.[102] The OEB also recognized that in some cases, utility-owned, rate-funded DERs are appropriate.[103]

3. RATEPAYERS OR TAXPAYERS

Finally, there is also the important question of who should pay when upgrades are made for reasons beyond traditional ratepayer service — such as to incent new load rather than being necessary to service current and anticipated load.

Lack of transmission infrastructure has long been a choke point for industrial electrification. Recently in British Columbia, LNG Canada announced it would be proceeding on its proposed second phase with natural gas rather than electricity due to lack

---

98 Ontario Energy Board, *Framework for Energy Innovation: Setting a Path Forward for DER Integration*, (Toronto: Ontario Energy Board, 2023).
99 *Ibid* at 25.
100 *Ibid* at 24.
101 *Ibid* at 5.
102 *Ibid* at 29–30.
103 *Ibid* at 15, where the OEB noted its 2019 approval of Toronto Hydro's proposal to build in-front-of-the-meter storage to meet distribution system needs and to include those expenditures in rate base.

of transmission lines (which, even where funding exists, take many years to build).[104] In response, British Columbia Premier David Eby acknowledged the need to fast-track clean power expansion and distribution, and indicated that his government wants "to shift to a model where we are creating the generation capacity upfront, and then recruiting and retaining businesses."[105] To this end, BC Hydro recently completed an Expression of Interest process with respect to expanded transmission infrastructure in the North Coast of British Columbia, inviting industry to signify their interest in taking electricity from BC Hydro with regard to proposed new transmission lines and associated infrastructure.[106]

However, creating excess transmission infrastructure upfront — and trusting that businesses can be recruited — has not always been successful in the province. For instance, in the late 1980s, BC Hydro built an additional transmission line to Gold River on Vancouver Island, prompted by the then-premier's commitment to have sufficient power for a second pulp mill and newspaper mill. Growth stalled shortly thereafter, and Gold River continues to have excess power available.[107] Standard regulatory practice would disallow recovering imprudent expenditures (albeit, importantly, without using a hindsight lens) and would not allow recovery of the costs associated with assets that are not "used and useful" for utility service.

Should "pioneer" type energy transition funding be a risk for ratepayers, to be locked in early by politically savvy governments? Or left for taxpayers by "meat and potatoes" regulators? Or is the question one of better matching ratepayer benefits to utility spending? We suggest that the urgency of climate change calls for transparent discussion of risk sharing to facilitate faster and better investments and decisions.

In 2022, the AUC considered similar issues raised by another technology of the energy transition: the blending of hydrogen into natural gas distribution systems. While hydrogen blending may play an important role in reducing carbon emissions, the costs incurred by distribution systems to integrate hydrogen are likely to outstrip savings from carbon taxes in the near term.[108] The resulting cost to ratepayers may be difficult to justify.[109] As a result, the AUC suggested that credits, tax rebates, or subsidies may be appropriate — in effect shifting some of the cost burden from ratepayers to taxpayers.[110] The AUC also emphasized that only prudently incurred costs should be borne by ratepayers.[111] Thus, prudence review remains an important tool to discipline utility spending and balancing the competing interests of utility investors and ratepayers. In considering how the distribution system might adjust to changing technologies, the AUC has continued to affirm that traditional ratemaking principles remain important.

---

104 Rod Nickel & Nia Williams, "Natural Gas, Not Electricity, to Power Canada's First LNG Plant, Increasing Carbon Footprint," *CBC News*, online: [perma.cc/34K5-6CLP].

105 Justine Hunter, "BC Hydro to Ask Heavy Emitters How it Can Help Them Meet Climate Targets," *The Globe and Mail* (6 February 2023), online: [perma.cc/Q5HL-TETD].

106 "North Coast Electrification: Transmission-Service Load Customer Expression of Interest" (15 February 2023), online (pdf): *BC Hydro* [perma.cc/34EG-J3RF].

107 Hunter, *supra* note 105.

108 Alberta Utilities Commission, *Hydrogen Inquiry Report,* Proceeding 27256 (Calgary: Alberta Utilities Commission, 2022) at para 226, online: [perma.cc/E4UD-87TD].

109 *Ibid* at para 235.

110 *Ibid*.

111 *Ibid* at para 256.

C. WHO PAYS FOR THE NEW METHODS OF ENERGY CONSUMPTION BEING ADOPTED FOR THE ENERGY TRANSITION?

Finally, the energy transition will also involve large-scale changes in how customers, ranging from residential consumers to large industrial operations, consume energy. These changes will result in significant costs to taxpayers, ratepayers, and investors.

1. TAXPAYERS

As with the other aspects of the energy transition considered in the prior sections, the shift toward lower-carbon products and manufacturing will be paid for in part by taxpayers. At the federal level, for instance, the 2023 Budget includes investment tax credits for clean technology manufacturing (including investment in mining or processing minerals for batteries, EVs, nuclear technology, and energy storage) projected to cost approximately $10.1 billion by 2035.[112] The government also announced additional funding for a Strategic Innovation Fund devoted to supporting "clean technologies, critical minerals, and industrial transformation."[113]

There are also other initiatives at all levels of government to encourage consumers to switch from carbon-emitting forms of energy consumption to cleaner options (for example, shifting from internal combustion engines to EVs). These initiatives may make the use of higher-carbon technologies more expensive, provide direct financial incentives for the use of lower-carbon technologies, or create private markets for the environmental benefits that lower-carbon technologies provide, to encourage investment in these sectors.

The clearest example of governments passing legislation to financially incent private consumers to make the switch to goods and services with a smaller carbon footprint has been the enactment of carbon taxes. The federal carbon tax legislation — the *Greenhouse Gas Pollution Pricing Act*[114] — only applies where provincial or territorial governments have not enacted their own carbon pricing scheme that meets or exceeds federal minimum standards. In this way, the federal system is often referred to as a "backstop." At the time of writing, Yukon, Nunavut, and Manitoba are fully under the federal backstop, while Alberta, Saskatchewan, Ontario, and Prince Edward Island are partially under the federal backstop.[115]

Funds generated through the federal backstop are returned to the province or territory where they were generated. For jurisdictions that opted in to the federal system when it was implemented (Nunavut, Prince Edward Island, and Yukon), the funds are remitted directly to the provincial or territorial government. For jurisdictions where the federal system was imposed (Alberta, Manitoba, Ontario, and Saskatchewan), approximately 90 percent of the funds are returned directly to residents via quarterly Climate Action Incentive payments, with

---

112 Department of Finance Canada, *supra* note 13 at 83–84.
113 *Ibid* at 90.
114 *Greenhouse Gas Pollution Pricing Act*, SC 2018, c 12, s 186.
115 Canada, "Carbon Pollution Pricing Systems Across Canada" (4 November 2021), online: [perma.cc/4JJE-83JD].

the remaining 10 percent distributed to support small businesses, farmers, and Indigenous groups.[116]

Implementing and administering a coordinated carbon tax scheme is made more challenging in Canada due to the overlapping jurisdiction of the federal and provincial governments. The federal regime was the subject of high-profile litigation, and was ultimately found to be constitutional in 2021[117] — though there may yet be further challenges as the scheme continues to be expanded and amended.

Despite carbon taxes, governments at all levels rely on additional prescriptive measures to require specific clean technology choices, such as British Columbia's policy goals of 92 percent (now 100 percent) carbon-free power, Alberta and federal coal phase-outs, and project-specific emissions caps for LNG projects. In addition to making higher-carbon activities more expensive, in recent years governments across Canada have provided generous offers of taxpayer dollars to incent consumers to adopt lower-carbon alternatives. For instance, six provinces (British Columbia,[118] Quebec,[119] New Brunswick,[120] Newfoundland and Labrador,[121] Nova Scotia,[122] and Prince Edward Island[123]) and Yukon[124] offer rebates on the purchase of EVs, and these provincial and territorial rebates can be stacked on top of the federal EV rebate.[125] Many provinces and the federal government also provide incentives for the installation of EV charging infrastructure.[126]

However, these programs are not without controversy and some jurisdictions have pursued policies which may discourage EV use. For example, Saskatchewan has implemented a road use fee for EV owners, apparently to account for their lack of contribution to highway maintenance (otherwise collected from drivers through a provincial fuel tax).[127] Moreover, only higher income households can generally afford currently available EVs, so these subsidies can be regressive.

---

116 Department of Finance Canada, News Release, "Climate Action Incentive Payment Amounts for 2022–23" (14 October 2022), online: [perma.cc/74ZA-HLQK].

117 *References re Greenhouse Gas Pollution Pricing Act*, 2021 SCC 11. Three provinces (Ontario, Saskatchewan, and Alberta) challenged the constitutionality of the *Act* in their Courts of Appeal, with the Courts of Appeal in Ontario and Saskatchewan finding the *Act* constitutional and Alberta's Court of Appeal finding the *Act* unconstitutional. At the Supreme Court of Canada, the decision was split 6–3. Dissents from Justices Brown, Côté, and Rowe focused on the breadth of the application of the *Act* and the majority's application of the national concern test.

118 British Columbia, "Passenger Vehicle Rebates," online: [perma.cc/BY5Y-BQND].

119 Quebec, "Aide financière pour un véhicule électrique" (2023), online: [perma.cc/TR9C-GP4U].

120 "Electric Vehicle Rebates," online: *Énergie NB Power* [perma.cc/SC96-V6WP].

121 "Electric Vehicle Rebate Program" (2023), online: *Newfoundland Labrador Hydro* [perma.cc/2V6K-Y2XC].

122 "Rebates" (2022), online: *EV Assist Nova Scotia* [perma.cc/Q9JT-RA36].

123 Prince Edward Island, "Electric Vehicle Incentive" (8 May 2023), online: [perma.cc/ 583N-T2PS].

124 Yukon, "Apply for a Rebate for a New Zero-Emission Vehicle" (2023), online: [perma.cc/ 8ZAP-K9AP].

125 Transport Canada, "Incentives for Purchasing Zero-Emissions Vehicles" (26 June 2023), online: [perma.cc/5LV8-3EF7].

126 See e.g. Natural Resources Canada, "Zero Emission Vehicle Infrastructure Program" (9 May 2023), online: [perma.cc/EXK6-SRVN]; "EV Charger Rebate Program for Single-Family Homes" (2023), online: *BC Hydro* [perma.cc/3VUE-R8P8]; Quebe, "Financial Assistance for a Home Charging Station" (2023), online: [perma.cc/3LV9-NCSX]. "Commercial EV Charger Rebate" (2023), online: *Newfoundland Labrador Hydro* [perma.cc/WY5V-YNRF]; Prince Edward Island, "PEI Electric Vehicle Charging Funding Program (PEI EVCF Program)" (2023), online: [perma.cc/PX56-G58A]; Yukon, "For the Road" (2023), online: [perma.cc/CCR2-H978].

127 Saskatchewan, News Release, "New Annual Fee of $150 on Electric Vehicles" (20 April 2021), online: [perma.cc/GU2K-DLPQ].

2. RATEPAYERS

Regulators have also been considering the appropriate regulatory framework to apply to new low-carbon technologies, with implications on ratepayer funds. The BCUC has been particularly active in recent years, with numerous decisions grappling with the appropriate regulatory approach to the energy transition (and the associated innovations in technology). Although British Columbia legislation exempts certain "prescribed undertakings" relating to decarbonization investments from "needs" reviews and requires the BCUC to allow utilities to recover costs incurred in pursuing these undertakings from ratepayers,[128] the BCUC retains the discretion to oversee how those undertakings are implemented and how costs are recovered. And this discretion has teeth: in line with a long sequence of decisions stretching back decades, the BCUC has frequently applied traditional economic regulation principles to this shifting landscape, often to the benefit of ratepayers.[129]

As one example, last year, the BCUC considered BC Hydro's proposed rates for EV charging services at stations it owns and operates.[130] Under the *CEA* and *GGRR*, these services are "prescribed undertakings" for which BC Hydro is entitled to full cost recovery. Nonetheless, the BCUC rejected BC Hydro's proposed charging rate on the basis it was not just and reasonable, because it failed to recover BC Hydro's cost of service and would therefore create an uneven playing field for other (non-utility) charging service providers and potentially distort the competitive EV charging market.[131] In other words, the BCUC refused to permit BC Hydro to distort a nascent market by cross-subsidizing its EV charging operations with funds generated from other ratepayers.

In contrast, the BCUC approved the EV charging rates applied for by another British Columbia electric utility (FortisBC Inc.).[132] In doing so, the BCUC noted that: (1) a rate that supports the development of a competitive market for EV charging would be just and reasonable, and accordingly the playing field between the utility and other competitive EV charging service providers should be as level as possible;[133] (2) the EV charging rate should aim to minimize any recovery of EV charging costs from the utility's other ratepayers (in other words, cross-subsidization should be minimized);[134] (3) a comparison to market EV charging rates would be helpful as a check on the utility's proposed EV rates;[135] and (4) the

---

128 *CEA*, *supra* note 36; *GGRR*, *supra* note 37.

129 *An Inquiry into FortisBC Energy Inc.'s Offering of Products and Services in Alternative Energy Solutions and Other New Initiatives* (27 December 2012), Order G-201-12, online (pdf): *British Columbia Utilities Commission* [perma.cc/Y6BL-TWAH] [AES Report] which set out a framework to assess the entry of "traditional" utilities such as FortisBC Energy Inc., which provides natural gas service in British Columbia, into new business activities outside of the traditional utility business. The AES Report built on the BCUC's 1997 Retail Markets Downstream of the Utility Meter Guidelines, which similarly set out guidelines for the conduct of regulated utilities in non-traditional or unregulated spheres.

130 *British Columbia Hydro and Power Authority Public Electric Vehicle Fast Charging Service Rates Application* (26 January 2022), Order G-18-22, online (pdf): *British Columbia Utilities Commission* [perma.cc/9JWH-99SM].

131 *Ibid* at i.

132 *FortisBC Inc. Application for Approval of Rate Design and Rates for Electric Vehicle Direct Current Fast Charging Service* (24 November 2021), Order G-341-21, online (pdf): *British Columbia Utilities Commission* [perma.cc/P2TW-5UZL].

133 *Ibid* at 15–16.

134 *Ibid* at 16.

135 *Ibid* at 17.

ongoing uncertainties relating to the EV charging market required periodic monitoring and evaluation of the utility's rates by the BCUC.[136]

These different decisions by the BCUC on EV charging rates demonstrate that, even when governments require regulators to allow the recovery of costs related to the energy transition from ratepayers, regulators still have a role to play in ensuring that the mechanism for this recovery is fair to those ratepayers, and does not unduly impede the development of private investment outside of the utility's domain.

In addition, the BCUC has been active in considering the appropriate regulatory framework for new technologies associated with decarbonization. Recent proceedings have considered the regulation of EVs,[137] renewable natural gas,[138] and hydrogen.[139] These generic proceedings allow the Commission to holistically evaluate the regulatory issues raised for these technologies, rather than on a one-off basis in individual rate applications, and can provide industry participants with certainty as to how their operations will be rate-regulated, if at all.

3. INVESTORS

Private investment in the manufacture and distribution of consumer-facing energy products has also been on the rise. One recent example is Volkswagen's announcement in March 2023 that would establish an EV battery manufacturing facility in St. Thomas, Ontario — part of more than $17 billion in investment by global automakers and suppliers of EV batteries and battery materials that Canada and Ontario have attracted since 2020.[140] This

136 *Ibid* at 17.

137 *An Inquiry into the Regulation of Electric Vehicle Charging Service: Report Phase 1* (26 November 2018), Order G-10-18, online (pdf): *British Columbia Utilities Commission* [perma.cc/4D3B-6HP3] where the BCUC held that persons providing EV charging services were "public utilities" under the *UCA* (*supra* note 39), but that an exemption from utility regulation should be granted to EV service providers that were not otherwise public utilities because the EV charging market was not a monopoly in need of economic regulation.The BCUC ultimately issued an exemption (*An Inquiry into the Regulation of Electric Vehicle Charging Service* (22 March 2019), Order G-66-19, online (pdf): *British Columbia Utilities Commission* [perma.cc/YQK4-TJLJ]).

138 Supplying natural gas is a "prescribed undertaking" under the *CEA* and *GGRR* when certain criteria are met: *CEA, supra* note 36; *GGRR*, *supra* note 37. Historically, the BCUC has considered RNG energy supply contracts on an ad hoc basis to ensure they meet the legislated requirements, but the BCUC is now undertaking an inquiry into RNG that is expected to establish a framework for assessing RNG contracts (*Inquiry into the Acquisition of Renewable Natural Gas by Public Utilities in British Columbia: Phase 1 Report* (28 July 2022), Order E-14-21, online (pdf): *British Columbia Utilities Commission* [perma.cc/UCZ7-2AY6]). The first phase of the BCUC's RNG inquiry concluded in July 2022, and provided additional clarity on what constitutes RNG under British Columbia's legislative scheme. The second phase of the inquiry is ongoing, and is expected to further clarify the scope of natural gas products that qualify as RNG, as well as the BCUC's role in assessment and enforcement of RNG-related issues.

139 *An Inquiry into the Regulation of Hydrogen Energy Services* (21 November 2022), Order G-330-22 at Exhibit A-2, online (pdf): *British Columbia Utilities Commission* [perma.cc/D8DH-8CLB] where the BCUC considered the appropriate regulatory framework for hydrogen energy services in British Columbia, including its production and storage, distribution, and sale to end-use customers, and whether the hydrogen industry is anticipated to constitute a competitive market. See also *An Inquiry into the Regulation of Hydrogen Energy Services: Hydrogen Workshop Draft Report* (26 April 2023), Order G-95-23, online (pdf): *British Columbia Utilities Commission* [perma.cc/F8Z9-EJXS] in which the BCUC recommended several exemptions from regulation for participants in the hydrogen industry, on the basis of the principles set out in the BCUC's earlier AES Report (*supra* note 129), including that the BCUC generally prefers not to regulate in the face of competitive markets.

140 Innovation, Science and Economic Development Canada, "Canada and Ontario Welcome Historic Investment from Volkswagen," online: [perma.cc/S8FR-G8AX].

follows up on Umicore's announcement in 2022 that it plans to invest $1.5 billion to build an industrial scale cathode and precursor materials manufacturing plant in eastern Ontario, which would also assist in the production of EV batteries.[141] Across the country, private investors (often supported by or in partnership with public bodies) are expending significant capital on the technologies and infrastructure necessary for the energy transition.

Further, various jurisdictions have passed legislation to create markets for carbon credits, whereby investors in lower carbon energy production and clean technology can commercialize the carbon reductions resulting from their investments. As specific examples:

1. At the federal level, the *CFR* will provide economic incentives for the development and adoption of clean fuels, technologies, and processes, and will also require producers and suppliers of liquid fossil fuels (gasoline and diesel) to reduce the carbon intensity of these fuels.[142] The *CFR* also establishes a credit market through which fuel producers and suppliers can create, purchase, or sell carbon credits for use in their own operations in future years or those of other parties, who may purchase credits to comply with the reduction requirements imposed by the *CFR*.[143]

   The *CFR* are, for the most part, already in force, and the annual reduction requirements take effect on 1 July 2023.[144] Credits can be created in three ways under the *CFR*: by undertaking projects that reduce the lifecycle carbon intensity of liquid fossil fuels (for example, carbon capture and storage, on-site renewable electricity, or co-processing); supplying low carbon fuels (for example, ethanol or biodiesel); or supplying fuel or energy to advanced vehicle technology (for example, electricity or hydrogen in vehicles). The last category, in particular, will help promote the uptake of EVs, by providing a way for charging network operators and charging site hosts to commercialize the environmental benefits of EV adoption.[145]

2. In Alberta, the *TIER* requires facilities that emit more than 100,000 tonnes of GHGs per year to reduce their emissions intensity by a specified percentage.[146] Facilities to which *TIER* applies can achieve compliance by implementing processes and technologies to reduce on-site emissions; purchasing emission offset credits from other producers or utilizing emission performance credits, if obtained in previous years; or purchasing credits by paying into the TIER Fund at prescribed prices.[147]

   Facilities in Alberta can generate emission offset credits by voluntarily reducing their greenhouse gas emissions through offset projects meeting the requirements of *TIER*, and the resulting offsets are quantified using Alberta-approved

---

141 Ontario, News Release, "Eastern Ontario Joins Province's EV Revolution with Game-Changing Battery Materials Manufacturing Investment" (13 July 2022), online: [perma.cc/K2AS-SVFX].

142 Canada, "What Are the Clean Fuel Regulations?" online: [perma.cc/Z3VL-LSKB].

143 *Ibid*.

144 *CFR*, *supra* note 17, s 176. See also Canada, Department of the Environment, *Regulatory Impact Analysis Statement*, Canada Gazette, Part I, vol 154: 51 Clean Fuel Regulations (19 December 2020), online: [perma.cc/527S-V5G7] [*Clean Fuel Regulations*].

145 Canada, "Compliance with Clean Fuel Regulations," online: [perma.cc/7ZB9-YVNA].

146 *TIER*, *supra* note 18, s 3.

147 *Ibid* at "Compliance obligations."

methodologies called quantification protocols.[148] These credits can then be used to offset future emissions or sold through the carbon credit market.

3. In British Columbia, the LCFS regime, reflected in the *GGRA* and *RLCFRR*, sets carbon intensity targets for certain fuels (broadly, gasoline and diesel), with fuel suppliers generating credits for supplying fuels with a carbon intensity below the targets and receiving debits for supplying fuels with a carbon intensity above the targets.[149] In effect, those who supply lower-carbon fuel are provided with a commodifiable asset (credits) that they can sell to other, higher-carbon fuel suppliers.

   The *GGRA* and *RLCFRR* are expected to be replaced by the new *LCFA* in 2024.[150] Although many key aspects of the *LCFA* remain to be set out in forthcoming regulations, the British Columbia Government has stated that the intent of the *LCFA* is to expand the scope of the LCFS to include more fuels, such as aviation and marine fuels, and to enable the Province to issue credits to projects that capture carbon dioxide directly from the air, thus widening the pool of potential proponents eligible to earn LCFS compliance credits.[151]

III. WHY WHO PAYS MATTERS

Does it matter who provides the funding necessary to reach net zero goals, as long as the effect of this spending is to reduce greenhouse gas emissions — especially when it appears there will be plenty of funding for such efforts from governments, ratepayers, and investors?

The answer is "yes," because there is ultimately a finite amount of capital and resources available to finance the energy transition, and a decision to pursue one path may foreclose another. For example, when governments pick technological winners and losers, they may divert resources away from better options. Similarly, placing the burden of increased utility investment on ratepayers may in fact undermine electrification by sending inefficient price signals. Finally, taxes or regulation that increase costs for trade-exposed industries — particularly those that are likely to play a critical role in supporting the energy transition — can sometimes simply push emissions into other jurisdictions, while eroding government revenue and potentially creating a vicious cycle that reduces the resources available to pay for energy transition investments.

Choices must therefore be made between different spending options (for example, different tax incentives, investments in different forms of technology, or investments in different pieces of infrastructure), which may have vastly different practical outcomes and distributional effects. These trade-offs cannot be made with eyes closed; it is critical that those controlling policy understand the effects of their policies and approaches, and balance

---

148 Alberta, "Alberta Emission Offset System," online: [perma.cc/X23A-E6Y5].

149 British Columbia, "Renewable & Low Carbon Fuel Requirements Regulation," online: [perma.cc/SS9N-KP38].

150 *Ibid*.

151 British Columbia, News Release, "Low-carbon Fuel Expansion Cuts Emissions, Creates Jobs" (9 May 2022), online: [perma.cc/A2BM-ZRTE].

the development of private markets against the management of market inefficiencies (and, in some cases, failures).

It should never be lost that the ultimate goal of the energy transition is to meet greenhouse gas emissions reduction targets. Accordingly, initiatives should focus on accomplishing this goal efficiently. That is, ensuring that each dollar is spent purposefully, with the aim of lowering overall emissions at the least possible cost, and appreciating potential economic interactions at provincial, national, and international scales. The review above highlights that many of the questions of how this should be accomplished (namely, who should pay) are being answered in different ways in different places, sometimes on an ad hoc basis.

We therefore conclude by proposing five principles to assist policy-makers and regulators in assessing these trade-offs.

First, private markets and private investment should be leveraged where possible. Market forces offer scale and technological advantages to help achieve the speed energy transition policy objectives need, provided private capital has sufficient "skin in the game" to pursue promising solutions. Investors have invested, and will continue to invest, huge sums for a few, potentially overlapping reasons: the profits to be made in the energy transition; the desire to avoid costs imposed by regulatory changes; the drive to remain relevant in a shifting economy; and a sense of social responsibility.

And, of course, market forces operate no matter what — the question is how.

Done right, government intervention can facilitate markets that tap into vast stores of private capital and profit-driven innovation. Alberta's REP program is an example in which government sponsored "de-risking" facilitated investment and contributed to price discovery, leading to significant investment in green generation without public subsidies.[152] Carbon pricing and flexible regulation also help enable markets to find efficient solutions.[153]

Utility regulators face concerns with utility investments into markets where private competition may naturally arise. Economic regulation of "natural monopolies" has always attempted to approximate competitive markets, in recognition that competitive markets are preferable and should be allowed develop where possible, all else equal.

Regulators should conduct careful cost-benefit testing of utility innovation spending where utilities seek to have their ratepayers, rather than their shareholders, pay for that spending. Utilities' role in innovation has historically been limited, so they often do not have competitive advantages in that regard. Utilities' ability to pass on research and development costs to ratepayers also means they do not have the same incentive to spend that money efficiently as (non-utility) private capital does.

---

152 *Supra* notes 80–81 and accompanying text.

153 Mark Jaccard, *The Citizen's Guide to Climate Success: Overcoming Myths that Hinder Progress* (Cambridge: Cambridge University Press, 2020) at ch 6.

At the same time, utilities seeking to enter markets without "natural monopoly" characteristics risk undermining the development of those markets for two reasons. The first is that utilities often have an unmatched geographic footprint arising from their exclusive monopoly, giving them a natural advantage over private competitors. The second, and perhaps more important, reason is that utilities have a captive ratepayer base from which they can often recover the costs of their investments in these new markets. Without careful oversight, utilities' ability to cross-subsidize these new ventures can allow pricing and investment that private competitors cannot match.[154] This risk must be zealously guarded against.

Despite these potential pitfalls, however, utilities also have great potential to assist in meeting climate goals. With effective regulatory oversight, utilities can offer the best of both worlds: the scale of private capital and innovation incentives with the efficiencies of scope and scale inherent in a natural monopoly that is under an obligation to serve.

Second, despite the importance of harnessing private markets and investments, the public will likely bear a large share of the cost of the energy transition, and policies should aim to spend that money efficiently and fairly. Policies designed to address the enormity of the challenge associated with climate change have come too late to allow for a gradual transition, and governments have generally not shown an appetite to impose the full costs of the transition on businesses and end users based on their emissions, through measures like large carbon taxes or low emissions caps. Although private-sector ESG initiatives and individual consumption decisions may bridge some of that gap, they are unlikely to be sufficient on their own. Since the challenge of climate change affects all of society, it very well may be appropriate that the public pay a share of the costs to combat it, even if public spending is generally less efficient than the deployment of private capital.

Yet government intervention in the form of subsidizing particular corporations or technologies can encourage "rent seeking" and provide limited public benefit. While multiple governments around the world are using subsidies as a central plank in their energy transition plans, these subsidies are not without controversy: subsidies can be zero-sum spending that displaces private capital that would have similarly been invested absent the subsidy, can lead to a "race to the bottom" as jurisdictions compete to attract industries, and can ultimately be wasteful if they plough capital into losing ventures that could have been more efficiently deployed elsewhere.

For example, the recently announced CDN$13 billion in government subsidies to be provided to Volkswagen to entice it to construct its EV battery plant in Southern Ontario involve a substantial amount of public money used to support what is fundamentally a profit-driven enterprise. The Volkswagen subsidies also illustrate that the energy transition in Canada is not happening in a vacuum — CDN$8 to $10 billion of these subsidies is intended

---

154 See e.g. *supra* notes 130–39, where the BCUC considered this issue in the context of BC Hydro's and Fortis Inc.'s respective applications for EV charging rates, and, in particular, the text accompanying notes 138–40.

to match benefits that Volkswagen would have received under the *Inflation Reduction Act* if it had put the factory in the United States.[155]

While the economics of government subsidies is beyond the scope of this article, we suggest five (non-exhaustive) guiding high-level considerations.

One consideration is that competing against other countries to subsidize specific energy transition-related initiatives may support other government strategic initiatives, and perhaps may even be justified on that basis, but is not advancing the energy transition beyond what would have occurred in any event.

Another consideration is that subsidies should target initiatives that create public, rather than private, benefits. Subsidies that merely increase the returns to private capital are not truly subsidizing the energy transition but instead are subsidizing investor profits. Where subsidies are flowing to specific projects with an aim to generate profits, the aim should be to ensure the public fairly shares in those profits to provide a continuing source of revenue for reinvestment into new, future initiatives. Inversely, where providing private benefits, more disperse, tailored approaches (for example, investment tax credits) that still require significant investment of private capital are more likely to be efficient than direct subsidization of specific private projects.

The next consideration is that direct spending on matters that are already within the government's control are more likely to generate public benefits. Governments are already directly and significantly involved in aspects of the economy that generate greenhouse gas emissions (transport, the built environment, Crown-owned utilities, and so on). Direct subsidies to facilitate emissions reductions in these areas are more likely to generate incremental greenhouse gas emissions reductions than others.

Another consideration still is that government's long time horizon means it can support riskier endeavours than the market can and that this may justify a preference for subsidies to fund basic research and early stage technology over established technologies that already have well-established project economics and markets.

A final consideration is that while end-user subsidies (for example, EV rebates, grants to encourage fuel switching or to install heat pumps) can avoid some of these issues, they can also create new ones, so care must be taken when establishing them. Depending on the nature of the market, the economic incidence of the subsidy may nonetheless allow suppliers to privatize the benefits rather than reducing prices for consumers. Subsidies can also cause consumers to shift their consumption patterns to offset the direct greenhouse gas emissions reductions associated with the subsidy. And even where effective, if subsidies support spending on products only affordable to higher income or wealthier individuals, they can be regressive in their effect and therefore unfair.

---

155 Ian Austen, "Canada Lands Volkswagen Battery Plant with Billions in Subsidies," *The New York Times* (21 April 2023), online: [perma.cc/64R8-SWQ9].

Third, not all "public" sources of funds are created equally. In some respects, utility ratepayers and taxpayers are often treated as akin, yet they often differ in important ways.

For instance, regulators who approve increases in energy costs are imposing a burden that is generally disproportionately borne by lower-income households, who can least afford it.[156] Accordingly, utility costs that increase electricity rates may, in effect, cause regressive impacts under traditional rate-setting models, doubly so where uptake of utility incentives and subsidies is skewed toward higher income utility customers. In contrast, taxes including income taxes and other climate change initiatives may have differing levels of progressivity.[157] Financing energy transition initiatives through taxation rather than utility costs may lead to more equitable outcomes, and particularly financing them through carbon taxes may be both equitable and a fair way to impose costs.

Creative rate-setting solutions (such as means-tested energy charges) may provide a partial solution to these concerns, but effectively mean that higher-income utility customers are subsidizing the rates of lower-income utility customers.[158] These solutions may also compound existing cross-subsidizations. For instance, in British Columbia, residential ratepayers are already cross-subsidized by other ratepayers, since the rates paid by residential customers are insufficient to cover their cost of service — with the difference made up by other customer classes (particularly commercial customers).[159] Distributional effects are even more complex where load is highly industrialized (for example, in Alberta, about 60 percent of electricity usage is industrial[160]). Cross-subsidies are not merely an academic unfairness. They can spark and justify political discontent, leading to the abandonment of otherwise successful initiatives, or the flight of capital into "fairer" jurisdictions. This is particularly a concern absent cross-border carbon adjustments to level the playing field for trade-exposed industries.

Higher energy costs potentially associated with large utility investments may also, unintentionally, inhibit electrification. Whereas carbon taxes provide an incentive to reduce emissions, high electricity prices can have the opposite effect, incenting emitters to continue emitting and paying carbon tax rather than electrifying. Accordingly, in some cases *taxpayer* infrastructure funding (hypothetically, the reallocation of carbon tax revenues) may provide more effective price signals.

Fourth, regulators should play a key role in providing policy makers and the public with a clear understanding of who is paying for what. Given the moving parts above, even if regulators may, in some instances, have limited discretion to impact the allocation of costs

---

156 Dolter & Winter, *supra* note 5 at 35.

157 Jennifer Winter, Brett Dolter & G Kent Fellows, "Carbon Pricing Costs for Households and the Progressivity of Revenue Recycling Options in Canada" (2023) 49:1 Can Pub Pol'y 13.

158 Dolter & Winter, *supra* note 5 at 22–28. See also California efforts to tie utility rates to income: Jeff St John, "Income-based Electric Bills: The Newest Utility Fight in California," *Canary Media* (9 May 2023), online: [perma.cc/Q27L-GT3Q].

159 British Columbia Ministry of Energy, Mines, and Petroleum Resources, *Comprehensive Review of BC Hydro: Phase 1 Final Report*, (Vancouver: February 2019) at 19, online: [perma.cc/4EQ2-CLTS]: "Currently, BC Hydro's residential customers are covering 90.8% of the cost of serving them. Commercial customers are paying as much as 123.5% of their cost of service and industrial customers are just over or under 100%."

160 Canada Energy Regulator, "Provincial and Territorial Energy Profiles – Alberta," online: [perma.cc/F2ZB-WKPL].

(due to government policy),[161] they should still ensure that the allocation of costs is made clear to the public, to ensure that all stakeholders in the energy transition (which, ultimately, includes all of us in one capacity or another) are able to make efficient choices, resulting in the best possible mix of energy and climate actions.

We have discussed examples above where government policies with the best of intentions have resulted in public funds being spent on green initiatives in inefficient and ineffective ways, while in other cases public actions in the energy transition have been a great success.[162] Public utility regulators have technical expertise and their ear to the ground and are therefore uniquely situated to speak both neutrally and with credibility about the issues surrounding the funding of the energy transition, so that government, industry, customers, and other stakeholders can make informed choices. As such, regulators should not be afraid to exercise their powers to provide the public with much-needed information, perspective, and credibility.[163] Regulators have a public-interest mandate and the expertise to provide valuable information, to government and the public, about the relative efficiency and effectiveness of decarbonization measures. Providing such advice should not be viewed as inappropriately entering the political realm.

Fifth, the perfect must not be the enemy of the good. Just as capital investment comes with trade-offs, so too do the choices of how to achieve greenhouse gas reduction targets. While some prefer to see net zero targets achieved through the adoption of green generation technologies rather than carbon capture or offsetting, there are ultimately human and environmental costs associated with every technological and infrastructure-based solution that need to be weighed in the balance. At the same time, hoping for technological breakthroughs to avoid moving away from greenhouse gas-emitting fuel sources places considerable weight on an unknowable breakthrough. Ultimately, all of these options will likely need to be invested in to some extent. Creating the proper incentives across governments, regulators, and private capital will, we hope, allow the energy transition to be undertaken efficiently and fairly.

---

161 *CEA*, *supra* note 36; *GGRR*, *supra* note 37 which together prescribe various undertakings for which the BCUC must allow a public utility to recover associated costs in rates, including undertakings related to the development of LNG (*GGRR*, s 2), electric transmission and distribution systems (*GGRR*, s 4) and hydrogen production and distribution (*GGRR*, s 6). BC Hydro's Standing Offer Program and the Ontario FIT, discussed in Part II.A.4, above, are other examples where regulators had curtailed ability to impact the allocation of costs.

162 As discussed in Part II.A.4, above, BC Hydro's 2002–2010 green or clean power calls and the Ontario FIT each led ratepayers in the respective jurisdictions to pay too much for the renewable energy obtained through the programs. In contrast, the REP in Alberta led to the acquisition of renewable electricity without raise the bill for taxpayers, as the contracts for difference acquired under the program ultimately favoured the government. The Gold River transmission line on Vancouver Island, discussed in Part II.B.3 above, is another example where, at the behest of government, a utility invested in a project that was not in ratepayers' interests (in that case, a transmission line that has to date not been used for its intended purpose, decades later).

163 Alberta Utilities Commission, *Report of the AUC Procedures and Processes Review Committee* (Calgary: Alberta Utilities Commission, 14 August 2020), online (pdf): [perma.cc/ZE4F-ZK6E] which encouraged the AUC to be more assertive in the exercise of its existing powers to ensure regulatory efficiency and the fulfilment of the Commission's mandate.

[*this page is intentionally blank*]