PATHWAYS TO NET-ZERO: OPPORTUNITIES FOR CANADA IN A CHANGING ENERGY SECTOR

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The climate is changing, and Canada is changing with it. Canada has committed to reducing its greenhouse gas emissions. Initiatives have been taken, but more work is needed. Private enterprise is key to the invention, improvement, and proliferation of sustainable energy sources. The extent to which the Canadian economy can be decarbonized hinges in part on how effectively regulatory schemes facilitate and incentivize commercial endeavours to exploit low-carbon energy sources. This article accordingly evaluates foreseeable regulatory frameworks for three new lower-carbon energy sources: hydrogen, geothermal energy, and biofuels. The thread running throughout this article is that, while there are many challenges ahead, there is also opportunity: regulatory schemes are evolving and adapting to support business ventures that monetize these three renewable energy sources.

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I. INTRODUCTION

A. CLIMATE AND THE DYNAMICS OF DEVELOPING A LOWER-CARBON ECONOMY

The climate is changing and Canada is endeavouring to change with it.[1] One of the primary contributors to climate change is the emission of greenhouse gases (GHGs), including carbon dioxide (CO_2), the most common GHG.[2] Although the global warming potential of many of the other GHGs is greater, CO_2 remains the primary target of most emissions reduction strategies because it is generated in large volumes mostly "by the combustion of fuels, whether for residential, industrial, transportation or electric power generation purposes"[3] — the everyday activities that characterize Canadian lives. Because CO_2 emissions are embedded throughout the Canadian economy, they are unlikely to decline without government intervention, and the imposition of rules that discourage the consumption of fuels with higher CO_2 emissions and incentivize alternatives and substitutes that, on a cradle-to-grave basis, have fewer associated emissions. Due to the significant role of CO_2 emissions in the climate change equation, the societal changes necessary to mitigate climate change risks are frequently referred to as transitioning to a lower-carbon economy. Despite the system-wide challenges that decarbonization presents and the fact that anthropogenic GHG emissions have a wide variety of sources, this article focuses primarily on efforts to reduce hydrocarbon use and the resultant CO_2 emissions,[4] though many of the policies and technologies discussed in this article are intended to reduce — and will likely have the effect of reducing — GHG emissions more generally.

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1 See generally United Nations Intergovernmental Panel on Climate Change, *Global Warming of 1.5°C: An IPCC Special Report on the Impacts of Global Warming of 1.5°C Above Pre-industrial Levels and Related Global Greenhouse Gas Emission Pathways, in the Context of Strengthening the Global Response to the Threat of Climate Change, Sustainable Development, and Efforts to Eradicate Poverty* (2019) at 4–23, online: <www.ipcc.ch/site/assets/uploads/sites/2/2019/06/SR15_Full_Report_High_Res.pdf>. For a concise overview of the challenges — and risks — that Canada faces as a result of a changing climate, see *References re* Greenhouse Gas Pollution Pricing Act, 2021 SCC 11 at paras 7–12 [*References re GGPPA*]. In this passage, the Supreme Court of Canada has arguably taken judicial notice of the reality, scale, and severity of climate change. See further regarding our efforts to address climate change: *United Nations Framework Convention on Climate Change*, 12 June 1992, 1771 UNTS 107, Preamble (entered into force 21 March 1994) [*UNFCCC*]. "The ultimate objective of this Convention and any related legal instruments that the Conference of the Parties may adopt is to achieve, in accordance with the relevant provisions of the Convention, stabilization of greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system" (*ibid*, art 2). *Kyoto Protocol to the United Nations Framework Convention on Climate Change*, 11 December 1997, 2303 UNTS 162 (entered into force 16 February 2005) [*Kyoto Protocol*]; *Paris Agreement*, 12 December 2015, UN.DocFCC/CP/2015/10/Add.1, 55 ILM 740 (entered into force 4 November 2016); Government of Canada, *Pan-Canadian Framework on Clean Growth and Climate Change: Canada's Plan to Address Climate Change and Grow the Economy*, Catalogue No En4-294/2016E-PDF [*Pan-Canadian Framework*].

2 National Aeronautics and Space Administration, "The Causes of Climate Change," online: *Global Climate Change: Vital Signs of the Planet* <climate.nasa.gov/causes/>. In Schedule 3 of the *Greenhouse Gas Pollution Pricing Act*, SC 2018, c 12, s 186 [*GGPPA*], the Government of Canada targets 33 different GHGs for reduction, including CO_2.

3 Natural Resources Canada, "Environmental Impacts of Combustion," online: <www.nrcan.gc.ca/ energy /publications/efficiency/industrial/cipec/6695>.

4 It is for this reason that this article does not, for example, address the regulations intended to reduce methane emissions.

While international bodies have attempted on multiple occasions to establish a road map to a lower-carbon future, they have not been particularly successful.[5] But despite these historical failures, the world may have reached an inflection point in 2015 when, at the twenty-first Conference of the Parties, the parties to the *United Nations Framework Convention on Climate Change* reached an agreement (the *Paris Agreement*) to work towards limiting global temperature increases to 1.5–2.0 degrees Celsius above pre-industrial levels.[6] As part of the *Paris Agreement*, each signatory state agreed to establish ambitious nationally determined emissions reduction contributions (NDCs) that would, in the aggregate, represent an important first step in limiting humanity's collective contributions to climate change.[7]

As one of the original signatories, Canada ratified the *Paris Agreement* in 2016 and, shortly thereafter, set an NDC of reducing its domestic GHG emissions by 30 percent below 2005 levels by 2030.[8] In connection with the federal government's actions, Canada's first ministers (the prime minister and the provincial premiers) announced a domestic commitment — the Vancouver Declaration on Clean Growth and Climate Change[9] — to collaborate in the development of "a pan-Canadian framework for clean growth and climate change."[10] In December 2016, the federal and provincial governments followed up on this commitment by agreeing to the *Pan-Canadian Framework*,[11] a document that sets out a number of strategies to help Canada achieve its international commitments and, ultimately, reduce the carbon intensity of its economy.

More recently, climate change initiatives in Canada and around the world have accelerated as a result of the stimulus opportunity that the economic recovery following the COVID-19 pandemic presented. In April 2021, for example, the federal government twice revised its 2030 NDC emissions reduction target, first establishing a 36 percent reduction "floor"[12] in the federal budget before announcing a commitment to reducing emissions by 40–45 percent below 2005 levels by 2030 at the Leaders Summit on Climate on 22 April 2021.[13]

5 See e.g. the failure of the parties to the *UNFCCC* to abide by the targets established in the *Kyoto Protocol*, *supra* note 1; Colin Hunt, "Kyoto Protocol Fails: Get Ready for a Hotter World" (15 November 2012), online: <theconversation.com/kyoto-protocol-fails-get-ready-for-a-hotter-world-10742>.

6 *UNFCCC*, *supra* note 1; *Paris Agreement*, *supra* note 1.

7 *Paris Agreement*, *ibid*, arts 3, 4.2.

8 United Nations NDC Registry, "Canada's INDC Submission to the UNFCCC," online: <www4.unfccc.int/sites/ndcstaging/PublishedDocuments/Canada%20First/INDC%20-%20Canada%20-%20English.pdf>; United Nations NDC Registry, "Canada's 2017 Nationally Determined Contribution Submission to the United Nations Framework Convention on Climate Change," online: <www.unfcc.int/sites/ndcstaging/PublishedDocuments/Canada%20First/Canada%20First%20NDC-Revised%20submission%202017-05-11.pdf>. See also *References re GGPPA*, *supra* note 1 at para 13.

9 British Columbia, Intergovernmental Relations Secretariat, "Vancouver Declaration on Clean Growth and Climate Change" (3 March 2016), online: <news.gov.bc.ca/stories/vancouver-declaration-on-clean-growth-and-climate-change>.

10 *Ibid*.

11 *Supra* note 1.

12 Ryan Patrick Jones, "Budget Goes Big on Green Spending as Environmentalists Criticize Tax Credits for Carbon Capture," *CBC News* (19 April 2021), online: <www.cbc.ca/news/politics/liberal-federal budget-2021-reaction-1.5991419>.

13 John Paul Tasker & Aaron Wherry, "Trudeau Pledges to Slash Greenhouse Gas Emissions by At Least 40% by 2030," *CBC News* (22 April 2021), online: <www.cbc.ca/news/politics/trudeau-climate emissions-40-per-cent-1.5997613>.

B. ENERGY SYSTEM TRANSITION AND CANADA'S CHALLENGING ROAD AHEAD

Despite much of the rhetoric and political messaging surrounding Canada's efforts to foster a lower-carbon economy and the opportunities that it may, or may not, present, achieving or exceeding Canada's goal of reducing GHG emissions by 40–45 percent below 2005 levels by 2030 will prove difficult.[14] While there has been some degree of economic "decoupling" in recent years, carbon-based energy consumption has historically driven industrialization and development, and any transition will have profound consequences, whether driven by near-to-medium term cost increases or the possible displacement of incumbent industries and supply chains and the resultant upheaval in certain parts of the economy.[15] The Canadian economy is particularly exposed to the risks that accompany an energy transition in part because of its reliance on carbon intensive industries like oil and gas, mining, and heavy industry.[16] This is exacerbated by the colder climate and vast geographical distances that separate the country's population centres.[17] In fact, approximately 7 percent of Canada's GDP is directly tied to the energy sector and many others, such as heavy industry and transportation, which rely on inputs derived from the products that Canada's oil and gas sector provides.[18]

Developing a lower-carbon economy and achieving Canada's emissions reduction commitments will clearly require significant shifts in the way Canadians do business, the way we move ourselves around, and the way we power our cities and industrial activities. Such changes are likely to prove challenging, and given the impact of these policies on energy production and the hoped-for displacement of fossil fuel consumption, there is expected to be a disproportionate impact on oil and gas producing provinces.[19] This process will also require the development, adoption, and implementation of new technologies and

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14 Environment and Climate Change Canada, "A Healthy Environment and a Healthy Economy," online: <www.canada.ca/en/services/environment/weather/climatechange/climate-plan/climate-plan-overview/healthy-environment-healthy-economy.html>.

15 Michael Grubb, Benito Müller & Lucy Butler, "The Relationship Between Carbon Dioxide Emissions and Economic Growth: Oxbridge Study on CO2-GDP Relationships, Phase 1 Results," online: <www.oxfordenergy.org/wpcms/wp-content/uploads/2011/02/Presentation19-The-RelationshipBetweenCarbonDioxideEmissionsandEconomicGrowth-MGrubbBMullerLButler-2004.pdf>.

16 Canada Energy Regulator, "Market Snapshot: The Value of Canadian Energy Exports Has Been Growing Since 2016, But Is Still Lower than the Highs Seen in 2014" (26 February 2020), online: <www.cer-rec.gc.ca/en/data-analysis/energy-markets/market-snapshots/2020/market-snapshot-value-canadian-energy-exports-has-been-growing-since-2016-but-is-still-lower-than-highs-seen-in-2014.html?=undefined&wbdisable=true>. See also Canada Energy Regulator, "Market Snapshot: Crude Oil – One of Canada's Top Exports Is Also One of the Most Globally Traded Commodities" (12 June 2019), online: <www.cer-rec.gc.ca/en/data-analysis/energy-markets/market-snapshots/2019/market-snapshot-crude-oil-one-canadas-top-exports-is-also-one-most-globally-traded-commodities.html>. See also Environment and Climate Change Canada, "Greenhouse Gas Sources and Sinks: Executive Summary 2021" (see Table ES-3), online: <www.canada.ca/en/environment-climate-change/services/climate-change/greenhouse-gas-emissions/sources-sinks-executive-summary-2021.html> [ECC, "Greenhouse Gas Sources"].

17 Cynthia A Williams, "Disclosure of Information Concerning Climate Change: Liability Risks and Opportunities" (2018) at 3, online: <digitalcommons.osgoode.yorku.ca/reports/206>.

18 Natural Resources Canada, "10 Key Facts on Canada's Natural Resources," online: <www.nrcan.gc.ca/science-and-data/data-and-analysis/key-facts-and-figures-on-the-natural-resources-sector/16013>. See also Williams, *ibid* at 3. Canada is the fourth largest producer and the third largest exporter of oil in the world and the fourth largest producer and the sixth largest exporter of natural gas: Natural Resources Canada, "Crude Oil Facts," online: <www.nrcan.gc.ca/science-data/data-analysis/energy-data-analysis/energy-facts/crude-oil-facts/20064>; Natural Resources Canada,"Natural Gas Facts," online: <www.nrcan.gc.ca/science-and-data/data-and-analysis/energy-facts/natural-gas-facts/20067>.

19 Williams, *ibid* at 3.

a consideration of how the existing energy industry can apply its competencies in new ways. While it is difficult to forecast what the process will look like or how quickly it will happen, rapidly changing government policy suggests that this transition could happen more quickly than Canada and the other *Paris Agreement* signatories anticipated: "[T]he global mindset as it pertains to fighting climate change has largely and quickly changed from emissions mitigation to a goal of a net zero future with an ever growing focus on renewable energy sources."[20] However, absent rapid technological advancement and substantial government support, net-zero targets may remain aspirational.

Fortunately for Canada, companies and individuals participating in the oil and gas sector possess many of the skills needed for the development of a lower-carbon economy. And while a top-down policy imperative will, in large, part drive the commercial imperative to adapt and respond to such policy, the speed and efficiency with which new technologies can be developed and deployed will depend on the fit between such policy and the existing, or revised or new, legal and regulatory frameworks.

This article focuses on several of the new initiatives and strategies that the governments of Canada, British Columbia, Alberta, and Saskatchewan have announced to facilitate the decarbonization of the Canadian oil and gas, industrial, transportation, and electricity sectors. These four sectors taken together are uniquely exposed to emissions-reduction efforts, whether through direct emissions-reduction mandates or indirect cost increases and market diminishment and are also closely connected to the energy sector.[21] Specifically, this article considers the road ahead for a possible hydrogen industry, a geothermal industry, and a renewable or clean fuel industry. And in particular, how these "new energy" industries are or will be regulated. This article also offers views on the effectiveness or coherence of these legal and regulatory regimes and proposes ways in which they can be improved.

II. COMMERCIALIZATION FRAMEWORK

Regulatory uncertainty and various other challenges, including higher costs, will inevitably challenge the successful development of Canada's "new energy" industries. To help organize the discussion that follows, this article draws a conceptual distinction between "commercialization frameworks" and "regulatory frameworks." At a high level, commercialization frameworks consist of the policies, financial incentives and disincentives, and the new standards and requirements that governments have, or will, put in place to encourage growth and increase the competitiveness of these industries.[22] Regulatory frameworks, on the other hand, are comprised of the various laws and regulations that apply to the operation of each of the "new energy" industries discussed in this article. In the early stages of these industries' growth trajectories, both frameworks are necessary to ensure that they can play a part in helping Canada develop a lower-carbon economy.

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20 Paul Wells quoting Sara Hastings-Simon, "Canadian Oil Gas Sector's Role in Energy Transition Quickly Changing, Says FGL Forum Panelist" (30 March 2021), online: <www.dailyoilbulletin.com/article/2021/3/30/canadas-oil-gas-sectors-role-in-energy-transition-/> [internal quotation marks omitted].

21 ECC, "Greenhouse Gas Sources," *supra* note 16.

22 Many Canadian governments also offer financial support for commercialization initiatives, including preferential tax treatment and various other direct funding programs, but due to the constraints of this article, they are not addressed.

A. POLICIES

Part I, above, briefly summarized some of the policy positions that Canadian governments have taken in respect of climate change and their emissions-reduction ambitions. Though there will be some overlap between that introductory discussion and this part of the article, it is important to understand the various policy goals and commitments that inform the governments' actions in greater detail because these goals and commitments are, in many ways, signposts that can help reveal the future direction of legislative and regulatory action.

1. INTERNATIONAL OBLIGATIONS: THE *UNFCCC* AND THE *PARIS AGREEMENT*

As mentioned, Canada has been a party to the *UNFCCC* since 1992. One of the stated objectives of the *UNFCCC* is to stabilize GHG concentrations at a level that prevents "dangerous anthropogenic interference with the climate system."[23] Over the past 30 years, the *UNFCCC* has inspired numerous international agreements and policy changes with respect to climate governance. However, the *UNFCCC* does not itself create any binding targets or mandate any specific actions the parties must undertake to reduce their emissions. Instead, it is a principles-based framework for co-operative action that relies on countries taking the initiative to act in ways that are tailored to their domestic circumstances and accounting for their strategic advantages and disadvantages. But it is against the backdrop of the *UNFCCC* that the *Paris Agreement* was developed, which implements an accountability mechanism that relies on transparency and common but differentiated responsibilities to create a hybrid regime requiring signatories to develop and achieve their NDCs in a way that makes sense for their respective economies and societies.[24] Consistent with the aims of the *UNFCCC*, the *Paris Agreement* arguably requires developed countries with diverse economies to lead the way in international emissions-reduction efforts because they tend to have the economic strength to withstand the short-to-medium term economic impacts of system-wide change.

2. THE *PAN-CANADIAN FRAMEWORK* AND FEDERAL AND PROVINCIAL STRATEGIES

a. Federal

While Canada, as a developed economy, is one of the countries that should lead the way in striving to achieve the aims of the *UNFCCC*,[25] its national economy — and that of many of its provinces — relies strongly on heavy industry and the oil and gas sector. This fact was acknowledged in the *Pan-Canadian Framework*[26] and may explain why the governments that

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23 *Supra* note 1, art 2.

24 A hybrid regime in this context is one that includes binding and non-binding elements: Harro van Asselt et al, "Maximizing the Potential of the Paris Agreement: Effective Review in a Hybrid Regime" (2016) at 1–2, online: <mediamanager.sei.org/documents/Publications/Climate/SE1-OB-2016-Mazimizing-potential-Paris-Agreement.pdf?>.

25 *Supra* note 1. "The Parties should protect the climate system for the benefit of present and future generations of humankind, on the basis of equity and in accordance with their common but differentiated responsibilities and respective capabilities. Accordingly, the developed country Parties should take the lead in combating climate change and the adverse effects thereof" (*ibid*, art 3(1)).

26 *Supra* note 1 at 20.

endorsed the *Pan-Canadian Framework* centred their agreed-upon strategy on market mechanisms, such as emissions pricing.[27] These mechanisms create an environment of "creative transition" that relies on price signals to encourage emission reductions and help make alternative technologies economically competitive: whether by raising the cost of higher-emitting technologies, and theoretically attributing a price to environmental externalities, or creating secondary markets, which can help monetize emerging technologies with low or negative emissions attributes.

In addition to its revised 2030 emissions-reduction target, the federal government has, in the space of seven months, announced plans to (1) join more than 110 other countries in a shared commitment to achieve net-zero emissions by 2050;[28] (2) commit funds to, among other things, make zero-emissions vehicles, including hydrogen fuel cell vehicles, more affordable, attract increased investments in the development of zero-emissions technology, and develop a Clean Power Fund that will in part help regions transition to cleaner sources of power generation;[29] (3) introduce tax incentives for businesses involved in the manufacturing of wind turbines, electric vehicles, and geothermal systems;[30] (4) create an $8 billion "Net Zero Accelerator" that will help accelerate the industrial low-carbon transformation;[31] (5) create a $1.5 billion Clean Fuels Fund to "support the production and distribution of low-carbon and zero-emission fuels, including hydrogen and biomass, across Canada";[32] and (6) provide financial support to the advancement of carbon capture and sequestration.[33] Many of these steps were outlined in the *Pan-Canadian Framework*, but others are new initiatives. Taken together, these announcements not only establish ambitious reduction targets but describe a number of government-supported mechanisms that are intended to help backfill the investment gap and accelerate the commercialization timelines.

b. British Columbia

At the provincial level, British Columbia has been one of the most active provinces with respect to climate policy. In 2007, the British Columbia government enacted the *Greenhouse Gas Reduction Targets Act*, a statute that has since been renamed the *Climate Change Accountability Act*[34] and amended to reflect a target of reducing the province's GHG emissions by 40 percent below 2007 levels by 2030 and by 80 percent below 2007 levels by

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27 *Ibid* at 2. "Pricing carbon pollution is an efficient way to reduce emissions, drive innovation, and encourage people and businesses to pollute less. However, relying on a carbon price alone to achieve Canada's international target would require a very high price" (*ibid).*

28 *Canadian Net-Zero Emissions Accountability Act*, SC 2021, c 22; UN News, "The Race to Zero Emissions, and Why the World Depends on It" (2 December 2020), online: <news.un.org/en/story/2020/12/1078612>. There is some uncertainty regarding the number of countries that have made this commitment, with some sources citing 73 parties to the *UNFCCC*: International Institute for Sustainable Development, "73 Countries Commit to Net Zero CO2 Emissions by 2050" (17 December 2019), online: <sdg.iisd.org/news/73-countries-commit-to-net-zero-co2-emissions-by-2050/>.

29 Canada, Governor General, *A Stronger and More Resilient Canada: Speech from the Throne to Open the Second Session of the Forty-Third Parliament of Canada*, Catalogue No SO1-1 (23 September 2020).

30 Alex Ballingall, "Budget Bolsters Federal Climate Plan with $17.6B in New Spending," *The Star* (19 April 2021), online: <www.thestar.com/politics/federal/2021/04/19/budget-bolsters-federal-climate-plan-with-17b-in-new-spending.html>.

31 Department of Finance Canada, *Budget 2021: A Recovery Plan for Jobs, Growth, and Resilience*, Catalogue No F1-23/3E-PDF (19 April 2021) at 147.

32 *Ibid* at 170.

33 *Ibid* at 169.

34 SBC 2007, c 42.

2050.[35] At a policy level, the enactment of the *Climate Change Accountability Act* was followed by a Climate Action Plan in 2008 and an updated Climate Leadership Plan in 2016.[36] To complement its Climate Leadership Plan and legislated emissions-reduction targets, the government also released its "CleanBC" plan,[37] which proposes a development strategy that will, based on the policies outlined therein, help British Columbia achieve 75 percent of its 2030 emissions-reduction target[38] and includes an interim target of reducing emissions by 16 percent below 2007 levels by 2025.[39] To meet these goals, the CleanBC plan focuses mostly on the industrial and transportation sectors of the British Columbia economy, setting out initiatives to (1) ramp up clean electricity generation, (2) impose a renewable content requirement on natural gas combustion by 2030, (3) require that fuel suppliers reduce the carbon intensity of diesel and gasoline by 20 percent by 2030, and (4) incentivize the adoption of zero-emissions vehicles, including battery and hydrogen powered vehicles.[40] Finally, the Government of British Columbia has also announced that it will impose sector-specific emissions reduction targets, requiring the transportation, heavy industry, and oil and gas sectors to reduce their emissions by 27–32 percent, 38–43 percent, and 33–38 percent, respectively, below 2007 levels by 2030.[41]

c. Alberta

In 2003, Alberta implemented the *Climate Change and Emissions Management Act.*[42] Under this *Act*, the province committed to reducing its GHG emissions "relative to Gross Domestic Product to an amount that is equal to or less than 50% of 1990 levels."[43] The *Act* was renamed in late 2019 to the *Emissions Management and Climate Resilience Act*,[44] but the reductions target was not updated to reflect the new national and international policy environments. As part of the *Pan-Canadian Framework*, Alberta also agreed to decarbonize its electricity sector by phasing out coal generation[45] and to implement an emissions cap on its oil sands industry.[46] Alberta has acted on both commitments, including by negotiating with coal-fired power producers to retire coal-powered generation facilities before the end of their useful lives and legislating a 100 megatonne cap on aggregate oil sands emissions in the *Oil Sands Emissions Limit Act*.[47] Despite the legislated cap, the regulations required to make it enforceable have not yet been developed.

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35 *Ibid*, ss 2(1)(a.1), 2(1)(b).

36 Government of British Columbia, *Climate Leadership Plan* (August 2016), online: <www.toolkit.bc.ca/resource/climate-action-plan>.

37 British Columbia, *CleanBC: Our Nature, Our Power, Our Future* at 5, online: <blog.gov.bc.ca/app/uploads/sites/436/2019/02/CleanBC_Full_Report_Updated_Mar2019>.

38 *Ibid*.

39 British Columbia, Ministry of Environment and Climate Change Strategy, News Release, "B.C. Sets New 2025 Emission Target, Details Climate Action in CleanBC Report" (16 December 2020), online: <news.gov.bc.ca/releases/2020ENV0061-002075>.

40 *Supra* note 37 at 8–9.

41 Government of British Columbia, Ministry of Environment and Climate Strategy, News Release, 2021EVN0022-000561 "B.C. Sets Sectoral Targets, Supports for Industry and Clean Tech" (26 March 2021), online: <archive.news.gov.bc.ca/releases/news_releases_2020-2024/2021ENV0022-000561.htm>.

42 SA 2003, c C-16.7.

43 *Ibid*, s 3(1).

44 SA 2003, c E-7.8.

45 *Supra* note 1 at 12. See also Government of Alberta, "Phasing Out Emissions from Coal," online: <www.alberta.ca/climate-coal-electricity.aspx>.

46 *Pan-Canadian Framework*, *ibid* at 20.

47 SA 2016, c O-7.5.

d. Saskatchewan

Unlike the other Canadian provinces, Saskatchewan did not sign on to the *Pan-Canadian Framework* when it was released. In December 2017, however, the Saskatchewan government released its own emissions-reduction strategy document, *Prairie Resilience: A Made-in-Saskatchewan Climate Change Strategy*,[48] setting out a strategy to reduce GHG emissions by 12 million tonnes by 2030. To help achieve this goal, *Prairie Resilience* outlines commitments to reduce emissions from electricity generation,[49] extend the use of carbon capture use and storage, and address the emissions intensity of vehicular fuel use.[50] In connection with its commitment to reduce emissions from electricity generation, the Saskatchewan government entered an agreement with the federal government regarding GHG emissions in the electricity sector in which Saskatchewan committed to increasing the percentage of non-emitting sources of electricity generation in its electricity sector to 40–50 percent by 2030.

From the foregoing, it is evident that of the four jurisdictions considered in this article, the governments of Canada and British Columbia have taken the lead on aggressively outlining and implementing policy to achieve the aims of the *Pan-Canadian Framework* and meet Canada's 2030 NDC. In some ways, this is not entirely surprising given the key role that oil and gas play in the economies and employment markets in Alberta and Saskatchewan and the reality that overly ambitious targets, even if well-intentioned, may prove practically and politically impossible to achieve without a more considered approach. However, one common theme is the focus on pairing emissions-reduction mandates with downstream market creation incentives, such as policies intended to increase the role that electricity and hydrogen play in personal transportation.

It is also worth noting that the federal government and each of the provincial governments have shared and overlapping jurisdiction over environmental matters.[51] Thus, to the extent that any province fails to act, the federal government has some authority to step in and either impose its own policy goals or require the provincial legislatures to enact their own.[52] An example here is the nation-wide emission pricing regime the federal government has put in place. However, this dynamic, if relied on too heavily to enforce a singular vision of emissions-reduction strategies, could lead to continued jurisdictional wrangling and constitutional and regulatory uncertainty as governments with divergent economic interests try to control the direction of future development.[53]

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48 Government of Saskatchewan, *Prairie Resilience: A Made-in-Saskatchewan Climate Change Strategy*, online (pdf): <www.saskatchewan.ca/business/environmental-protection-and-sustainability/a-made-in-saskatchewan-climate-change-strategy/saskatchewans-climate-change-strategy> [Government of Saskatchewan, *Prairie Resilience*].

49 For more information, see Government of Canada, *Canada-Saskatchewan Equivalency Agreement Regarding Greenhouse Gas Emissions from Electricity Producers*, s 4.4, online: <www.canada.ca/en/environment-climate-change/services/canadian-environmental-protection-act-registry/agreements/equivalency/canada-saskatchewan-greenhouse-gas-electricity-producers.html#toc4>.

50 Government of Saskatchewan, *Prairie Resilience*, *supra* note 48 at 5–7.

51 *Friends of the Oldman River Society v Canada (Minister of Transport)*, [1992] 1 SCR 3 at 63–64.

52 Brendan Downey et al, "Federalism in the Patch: Canada's Energy Industry and the Constitutional Division of Powers" (2020) 58:2 Alta L Rev 273 at 275, 279, 312. See also *References re GGPPA*, *supra* note 1.

53 See generally Downey et al, *ibid*.

B. EMISSIONS PRICING

1. FEDERAL

The central component of the *Pan-Canadian Framework* — and, indeed, Canada's approach to meeting its 2030 NDC — is emissions pricing.[54] To that end, Parliament has enacted the *Greenhouse Gas Pollution Pricing Act* in June 2018.[55] This regime has two parts: (1) a fuel charge, enabled by the *Fuel Charge Regulations*[56] and (2) an output-based emissions pricing system (OBPS) for large industry, enabled by the *Output-Based Pricing System Regulations*.[57] Both parts impose a minimum price on GHG emissions, which is determined with reference to their CO_2 equivalent (CO_2e). The federal OBPS also relies on a form of emissions trading to help facilities covered by that system achieve their compliance targets, incentivize emissions reduction efforts, and commercialize other emissions-reduction technologies.[58] The federal pricing system applies in provinces and territories that request it and in those that do not have their own equivalent emissions-pricing systems to ensure that there is a minimum price on emissions across the country.

Under current federal plans, the minimum price for GHG emissions is currently $40 per tonne of CO_2e and will increase to $50 per tonne in April 2022. This was initially the ceiling for pricing increases, but on 11 December 2020, the federal government announced that, commencing in 2023, the minimum price will increase by $15 per year until it reaches $170 per tonne in 2030.[59]

2. BRITISH COLUMBIA

The British Columbia government implemented a tax on CO_2e emissions in 2008.[60] To date, the value of the tax has exceeded the minimum pricing benchmark that the *GGPPA* requires, and given British Columbia's recent track record on climate policy, it is likely that it will continue to escalate in step with the federal government's projected increases out to 2030. In addition to its emissions-pricing scheme, the Government of British Columbia has enacted the *Greenhouse Gas Industrial Reporting and Control Act*[61] and the following associated regulations: the *Greenhouse Gas Emission Reporting Regulation*,[62] the *Greenhouse Gas Emission Administrative Penalties and Appeals Regulation*,[63] and the *Greenhouse Gas Emission Control Regulation*.[64] Together, this statutory framework creates emissions-reduction performance standards for large facilities, including emissions

54 *Supra* note 1 at 50.
55 *Supra* note 2.
56 *Ibid*, s 187.
57 SOR/2019-266.
58 For an explanation of this approach, see Government of Canada, "Review of the Federal Output-Based Pricing System Regulations," online: <www.canada.ca/en/environment-climate-change/services/climate-change/pricing-pollution-how-it-will-work/output-based-pricing-system/review.html>.
59 John Paul Tasker, "Ottawa to Hike Federal Carbon Tax to $170 a Tonne by 2030," *CBC News* (11 December 2020), online: <www.cbc.ca/news/politics/carbon-tax-hike-new-climate-plan-1.5837709>; Canada Revenue Agency, "Fuel Charge Rates," online: <www.canada.ca/en/revenue-agency/services/forms-publications/publications/fcrates/fuel-charge-rates.html>.
60 *Carbon Tax Act*, SBC 2008, c 40.
61 SBC 2014, c 29.
62 BC Reg 249/2015.
63 BC Reg 248/2015.
64 BC Reg 250/2015.

benchmarks for coal and liquefied natural gas facilities and imposes reporting requirements on facilities that emit more than 10,000 tonnes of CO_2e per year.

3. ALBERTA

Alberta's approach to emissions pricing has changed over time, which of late can be partly attributed to the change in provincial governments in 2015 and 2019. While Alberta initially undertook to implement a fuel charge as part of its commitments under the *Pan-Canadian Framework*,[65] an undertaking it followed through on when it imposed an escalating fuel charge administered under the *Climate Leadership Act*[66] and the accompanying *Climate Leadership Regulation*,[67] that charge was repealed in May 2019. As a result, the federal fuel charge under the *GGPPA* has filled the gap and currently applies in Alberta.

Alberta has been more active on pricing emissions from large industrial facilities. In 2007, the *Specified Gas Emitters Regulation*[68] came into effect under the authority of the formerly called *Climate Change and Emissions Management Act*. Principally, the *SGER*: (1) established an emissions reporting framework,[69] (2) required regulated facilities to meet facility-specific emissions reduction targets (initially set at a 12 percent reduction of emissions intensity, but later increased to a 20 percent reduction),[70] and (3) imposed a price of $15 per tonne of CO_2e emitted in excess of the reduction target. This price increased to $20 per tonne in 2016 and $30 per tonne in 2017.[71] On 1 January 2018, the *Carbon Competitiveness Incentive Regulation* replaced the *SGER*, holding the price on emissions at $30 per tonne of CO_2e throughout 2018.[72] But the changes did not stop there. In 2019, the Alberta government enacted the *Technology Innovation and Emissions Reduction Regulation*, which replaced the *CCIR* on 1 January 2020 and imposed facility-specific emissions intensity reduction targets on large facilities operating in Alberta.[73] At the time of its enactment, the *TIER Regulation* satisfied the federal government's minimum pricing requirements, initially imposing a price of $30 per tonne of CO_2e emitted in excess of each regulated facility's emission reduction target.[74]

The *TIER Regulation* is Alberta's version of the federal OBPS and applies to emitters that emitted more than 100,000 tonnes of CO_2e per year in 2016 or any subsequent year. To encourage compliance with the emissions intensity reduction targets, *TIER Regulation*-regulated facilities must provide annual compliance reports. And facilities that are unable to achieve their targets may either purchase credits from other facilities that have exceeded their targets, purchase carbon offsets, or pay a levy to the "TIER Fund": a fund that supports low-

65 *Supra* note 1 at 56.
66 SA 2016, c C-16.9.
67 Alta Reg 175/2016.
68 Alta Reg 139/2007 [*SGER*].
69 *Ibid*, ss 11–19.
70 *Ibid*, s 4(3).
71 See Robson Fletcher, "How Alberta Will Keep its $30-Per-Tonne Carbon Tax but Make It Easier for Some Big Emitters to Avoid Paying," *CBC News* (29 October 2019), online: <www.cbc.ca/news/canada/calgary/alberta-carbon-tax-tier-sger-ccir-large-emitters-1.5339464>.
72 Alta Reg 255/2017 [*CCIR*].
73 Alta Reg 133/2019 [*TIER Regulation*].
74 Fletcher, *supra* note 71.

emissions technology in the province[75] and seeks to encourage private investment in potentially marginal projects that may not have otherwise been built.

4. SASKATCHEWAN

As mentioned above, Saskatchewan has not signed onto the *Pan-Canadian Framework*. Like Alberta, Saskatchewan also does not have a provincially administered fuel charge and therefore the federal fuel charge applies within the province.

Regarding its approach to regulating emissions, the Saskatchewan government has enacted *The Management and Reduction of Greenhouse Gases Act*[76] to regulate GHG emissions in the province. However, the *MRGGA* only partially satisfies federal requirements. The federal OBPS applies to certain electrical generation and natural gas pipelines, and the federal fuel charge is also in place, imposing a price on emissions associated with fuel consumption.[77] That said, facilities that have annual GHG emissions in excess of 50,000 tonnes, other than those mentioned above, are regulated by the province. The following regulations, each of which complements the operation of the *MRGGA*, are currently in place in Saskatchewan: *The Management and Reduction of Greenhouse Gases (General and Electricity Producer) Regulations*,[78] *The Management and Reduction of Greenhouse Gases (Reporting and General) Regulations*,[79] and *The Management and Reduction of Greenhouse Gases (Standards and Compliance) Regulations*.[80] These Regulations collectively establish reporting requirements and impose various emissions limits for emitters that fall within the provincial program.

C. CLEAN FUEL STANDARDS

1. FEDERAL

As part of its commitments under the *Pan-Canadian Framework*, the federal government agreed that it would develop a "Clean Fuel Standard" to implement across the country.[81] To that end, the federal government's principal policy initiative to encourage the integration of clean fuels to reduce GHG emissions in fuel production and consumption is the Clean Fuel Standard, set out in the *Clean Fuel Regulations*, which is currently published in draft form

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75 *TIER Regulation*, *supra* note 73, ss 15–21. See also Government of Alberta "Technology Innovation and Emissions Reduction Engagement" (2019), online: <www.alberta.ca/technology-innovation-and-emissions-reduction-engagement.aspx>.

76 SS 2010, c M-2.01 [*MRGGA*].

77 Government of Canada, "Output-Based Pricing System," online: <www.canada.ca/en/environment-climate-change/services/climate-change/pricing-pollution-how-it-will-work/output-based-pricing-system.html>; Government of Canada, "Carbon Pollution Pricing Systems Across Canada," online: <www.canada.ca/en/environment-climate-change/services/climate-change/pricing-pollution-how-it-will-work.html>.

78 RRS c M-2.01 Reg 1.

79 RRS c M-2.01 Reg 2.

80 RRS c M-2.01 Reg 3.

81 *Pan-Canadian Framework*, *supra* note 1 at 19.

and was developed under the *Canadian Environmental Protection Act, 1999*[82] and the *Environmental Violations Administrative Monetary Penalties Act.*[83]

The Clean Fuel Standard creates obligations primarily for liquid fuel (gasoline, diesel, and home heating oil) producers, importers, and refiners, which will require such primary suppliers of liquid fuels that are to be consumed in Canada to reduce the carbon intensity of their liquid fossil fuels starting in 2022.[84] The carbon intensity of a fuel is a measure of the GHG emissions from the fuel's entire life cycle: from extraction, refining, distribution, and use of the fuel.[85] The targeted reduction is approximately 13 percent below 2016 levels in the carbon intensity of liquid fuels used in Canada by 2030.[86] This does not apply to liquid fuels that are exported.

The Clean Fuel Standard will establish a credit market, giving suppliers the option to comply by reducing their own emissions associated with the production of fuels or purchasing credits created by other parties who reduce the lifecycle emissions of their fuel production.[87] The Government of Canada suggests that a broad range of compliance strategies exist that give suppliers the flexibility to choose the lowest cost compliance actions available. These options include (1) undertaking projects that reduce the lifecycle carbon intensity of fossil fuels (for example, carbon sequestration and renewable electricity), (2) supplying lower carbon fuels by blending biofuels into conventional fuel supplies, and (3) switching from fossil fuels to lower carbon fuels or energy like electricity or hydrogen in vehicles.[88]

The Clean Fuel Standard is not expected to come into force until the end of 2022, but in the interim, this article considers the implications of this policy as it exists in its current form.

Initially, the Government of Canada proposed that the Clean Fuel Standard would apply to liquid, solid, and gaseous fuel sources, including natural gas. However, with the release of Canada's enhanced climate plan in December 2020, the federal government opted to scale back coverage of the Clean Fuel Standard, excluding solid and gaseous fuels, in favour of a long-term increase to the national carbon price.[89] Though this may not necessarily incentivize emissions reductions in sectors of the economy that do not rely on liquid fuels, it will likely increase costs in the transportation sector and encourage the adoption of lower-emitting vehicles, such as electric and hydrogen fuel cell vehicles, both of which could help establish markets for the geothermal and hydrogen industries. The omission of gaseous fuel sources from the Clean Fuel Standard was welcomed by natural gas producers; however, it

82 SC 1999, c 33 [*CEPA*].
83 SC 2009, c 14, s 126. See also Government of Canada, "Clean Fuel Standard: Discussion Paper" at 1, online (pdf): <www.canada.ca/en/environment-climate-change/services/canadian-environmental-protection-act-registry/clean-fuel-standard-discussion-paper.html> [Government of Canada, "Discussion Paper"].
84 Government of Canada, "What is the Clean Fuel Standard?," online: <www.canada.ca/en/environment-climate-change/services/managing-pollution/energy-production/fuel-regulations/clean-fuel-standard/about.html> [Government of Canada, "Clean Fuel Standard"].
85 Government of Canada, "Discussion Paper," *supra* note 83 at 9.
86 Government of Canada,"Clean Fuel Standard," *supra* note 84.
87 *Ibid*.
88 *Ibid*.
89 *Ibid*.

is likely that upstream fuel producers and consumers alike will be affected by the introduction of the Clean Fuel Standard.

Provincially, clean fuels regulations tend to be two-pronged and include (1) carbon-intensity reduction requirements and (2) renewable content requirements for conventional fuel sources. British Columbia has the most stringent provincial requirements and Saskatchewan does not have an intensity reduction requirement.

2. BRITISH COLUMBIA

Parties who manufacture fuel in British Columbia, as well as those who import fuel into this province, are categorized as "fuel suppliers" pursuant to the *Renewable and Low Carbon Fuel Requirements Regulation*.[90] Fuel suppliers in British Columbia are subject to two sets of requirements: annual carbon-intensity reduction targets and minimum renewable content in the fuels supplied to end users.[91] The carbon-intensity reduction targets came into force in 2020, with a 9.1 percent carbon-intensity reduction requirement for that year. These targets increase by 1.09 percent annually up to 20 percent by 2030.[92] Fuel suppliers also have an obligation to include 5 percent renewable content in gasoline and 4 percent renewable content in diesel, calculated as an average of the renewable content in the fuel supplied on an annual basis.[93]

Smaller-scale fuel suppliers in British Columbia may be exempt from these requirements. Companies supplying less than 75 million litres of fuel in 2020 may apply for exemption from the renewable or the low carbon fuel requirements. The threshold for eligibility for an exemption is reduced to suppliers producing 25 million litres for the 2021 annual compliance period, and to 200,000 litres starting in 2022.[94]

3. ALBERTA

Alberta has had carbon reduction requirements for fuel producers in place since 2010. The *Renewable Fuels Standard Regulation*[95] requires a minimum annual average of 5 percent renewable alcohol in gasoline and 2 percent renewable diesel in diesel fuel sold in Alberta by fuel suppliers. To meet the Renewable Fuels Standard, renewable fuels must demonstrate at least 25 percent fewer GHG emissions than the equivalent petroleum fuel.[96]

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90 BC Reg 394/2008 [*BC Carbon Regulation*].
91 Government of British Columbia, "BC-LCFS Requirements," online: <www2.gov.bc.ca/gov/content/industry/electricity-alternative-energy/transportation-energies/renewable-low-carbon-fuels/requirements>.
92 *Ibid*; *BC Carbon Regulation*, *supra* note 90, ss 7–11.11.
93 *BC Carbon Regulation*, *ibid*, s 7.
94 Government of British Columbia, "BC-LCFS Requirements," *supra* note 91.
95 Alta Reg 29/2010.
96 Government of Canada, "Clean Fuel Standard," *supra* note 84.

4. SASKATCHEWAN

Saskatchewan's *Renewable Diesel Act* has been in place since 2012 and requires fuel distributors to include 2 percent renewable diesel content. The province also requires that fuel blends include at least 7.5 percent ethanol.[97]

5. JURISDICTIONAL ISSUES

Section 140 of the *CEPA* sets out the federal power to make regulations in respect of the composition and content of fuels but does not empower the federal government to authorize equivalency agreements.[98] This means that all clean fuels' requirements in force, "both provincially and federally, must be met even if they are duplicative."[99] Competing carbon-cutting policies between the federal and provincial governments in Canada are in a familiar situation. Hopefully, this will be addressed before the Clean Fuel Standard comes into force.

D. EVOLVING INVESTING PRACTICES AND RISK MANAGEMENT

As part of the commercialization framework, it is also important to observe that government-led international and domestic commitments and policies are not the only forces steering us towards a low-emissions future. Indeed, investors and banks increasingly rely on environmental and social criteria to help guide their investment decisions, including environmental and climate performance. For example, the CEOs of eight Canadian pension funds,[100] with approximately $1.6 trillion in assets under management, recently called for companies and investors to place a larger emphasis on the role of sustainability in their management and reporting practices and requested improved disclosure in respect of material, industry-relevant, and environmental factors, specifically targeting climate change.[101] More recently, a Mark Carney-led group of 160 "[b]anks, insurers and fund managers that control US$70-trillion of assets have banded together to use their financial might in efforts to speed up the global transition to a net-zero emissions economy with the aim of preventing the worst effects of climate change."[102]

For reporting issuers in the energy and industrial sectors, investors are increasingly expecting disclosure concerning climate change as a material environmental and economic sustainability risk factor. For example, Institutional Shareholder Services (ISS), a major

97 *Ibid.*
98 *Supra* note 82, s 140.
99 Canadian Association of Petroleum Producers, "The Federal Clean Fuel Standard: Risks to Economic Recovery and Barriers to Environmental Innovation" (August 2020) at 2, online: <www.capp.ca/wp-content/uploads/2020/09/The-Federal-Clean-Fuel-Standard-Risks-to-Economic-Recovery-and-Barriers-to-Environmental-Innovation-375521.pdf>.
100 AIMCo, BCI, CDPQ, CPP Investments, HOOPP, OMERS, OTPP, and PSP.
101 British Columbia Investment Management Corporation, "CEOs of Eight Leading Canadian Pension Plan Investment Managers Call on Companies and Investors to Help Drive Sustainable and Inclusive Economic Growth" (25 November 2020), online: *Cision* <www.newswire.ca/news-releases/ceos-of-eight-leading-canadian-pension-plan-investment-managers-call-on-companies-and-investors-to-help-drive-sustainable-and-inclusive-economic-growth-844608554.html>.
102 Jeffrey Jones, "Major Banks, Insurers Team up with Carney, Vowing to Mobilize Trillions of Dollars Toward Net-Zero Goals," *The Globe and Mail* (21 April 2021), online: <www.theglobeandmail.com/business/article-major-banks-insurers-team-up-with-carney-vowing-to-mobilize-trillions/>.

international proxy advisory firm, recently updated its Canadian proxy voting guidelines for its subscribers in late-2020. Including "poor risk oversight of environmental … issues" as a factor in its list of considerations to help shareholders evaluate management performance regarding corporate risk management.[103]

Relatedly, and reflecting a similar perspective, 116 financial institutions[104] — including seven Canadian institutions — have incorporated the Equator Principles[105] into their risk-management protocols for project finance. With respect to climate risk in particular, the 2020 edition of the Equator Principles explains that "negative impacts on Project-affected ecosystems, communities, and the climate should be avoided where possible."[106] The institutions that use the Equator Principles (the EPFIs) also expressly "support the objectives of the … *Paris Agreement*" and recognize that institutional lenders have a role to play in achieving its goals.[107]

While the actions of the large institutional shareholders such as the ISS and the EPFIs that follow the Equator Principles may be described as primarily self-interested (they are, after all, designed to mitigate risks facing investors and lenders), the trend towards incorporating "climate transition risks"[108] into corporate governance, investment, and lending decision-making is a signal to the market that the "money" is starting to prepare itself for a transition to a lower-carbon economy. Though not a direct commercialization framework, this shift in thinking will inevitably impact the availability of both debt and equity financing for major project developments and for proponents who do not consider these risks in their strategic planning or actively seek to mitigate these risks, including, for example, by incorporating lower-emitting technologies into their corporate strategies, there may be a struggle to secure external financing.

E. SUMMARY

In discussing the commercialization framework that is currently in place to incentivize investment in, and the development of, "new energy" industries and technologies, this article discussed international and domestic agreements, top-down emissions-reduction policies, emissions pricing, clean fuel standards, direct funding initiatives, and evolving investment and lending practices. Though these various pieces of the commercialization framework

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103 Institutional Shareholder Services, "Canada: Proxy Voting Guidelines for TSX-Listed Companies Benchmark Policy Recommendations" (19 November 2020) at 16, online: <www.issgovernance.com/file/policy/active/americas/Canada-TSX-Voting-Guidelines.pdf>.

104 Equator Principles, "Members & Reporting," online: <equator-principles.com/members-reporting/>.

105 Equator Principles, "About the Equator Principles," online: <equator-principles.com/about/>.

106 Equator Principles, "The Equator Principles: July 2020" at 3, online: <equator-principles.com/wp-content/uploads/2021/02/The-Equator-Principles-July-2020.pdf>.

107 *Ibid.*

108 *Ibid* at 23–24. "Climate transition risks" is defined in the Equator Principles to mean

> are risks which can arise from the process of adjusting to a lower-carbon economy. These include: policy and legal risks, such as policy constraints on emissions, imposition of carbon tax and other applicable policies, water or land use restrictions or incentives; shifts in demand and supply due to technology and market changes; reputation risks reflecting changing customer or community perceptions of an organisation's impact on the transition to a low carbon and climate-resilient economy.

In a companion document, the EPFIs identify the following as climate transition risks as (1) policy and legal risks, (2) technology risks, (3) market risks, and (4) reputation risks. See Equator Principles, "Guidance Note on Climate Change Risk Assessment" (September 2020) at 5–6, online: <equator-principles.com/wp-content/uploads/2020/09/CCRA_Guidance_Note_Ext_Sept_2020.pdf>.

come at the problem of emissions reduction from different angles, they all share one thing in common: a focus on driving down emissions and enabling alternatives through fiscal policy. Whether they go about doing this through the imposition of legal or regulatory imperatives, primary or secondary market creation, ratcheting up the cost of emitting GHGs, supporting currently economically uncompetitive technologies, steering corporate decision-making and governance practices, or re-allocating the deployment of funds, they all add up to a significant amount of pressure on consumers and producers to change their practices. The extent to which these aspirational policy goals and emissions reduction mechanisms succeed, when they inevitably run up against the very real obstacles that decarbonization poses, remains to be seen. But, notwithstanding the outcome of these challenges, the commercialization framework described above is in place and it is within this framework that "new energy" industries are starting to emerge.

III. THE "NEW ENERGY" INDUSTRIES

A. HYDROGEN

1. THE HYDROGEN INDUSTRY: WHAT IS IT?

While electrification and the deployment of renewable electrical generation such as wind or solar is the focus of much of the conversation concerning the transition to a low-carbon economy, hydrogen is another alternative to CO_2-emitting fossil fuels. At least in theory, hydrogen is well-suited to assist in the energy transformation. It is a versatile and clean-burning energy "carrier"[109] that can be used for energy storage, transportation, heating, and as a fuel source.[110] According to David Layzell,

> The global shift to net-zero emission energy systems will require replacement of fossil carbon energy carriers (i.e. gasoline, diesel, jet fuel, natural gas), the combustion of which generates the majority of the world's energy-based greenhouse gas (GHG) emissions. Electricity made from zero/low emission sources is likely to become the dominant energy carrier. However, electricity is not a viable solution for all sectors (heavy transport, heavy industry, space heating in cold climates); zero emission chemical fuels will also be required.
>
> The potential of biobased fuels is limited by resource availability and concerns about adverse impacts on biodiversity and food production. Hydrogen … is rapidly becoming the global, zero-emission fuel of choice.[111]

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109 US Energy Information Administration, "Hydrogen Explained," online: <www.eia.gov/energyexplained/hydrogen/>: "Energy carriers allow the transport of energy … from one place to another. Hydrogen, like electricity, is an energy carrier that must be produced from another substance.… Hydrogen has the highest energy content of any common fuel by weight (about three times more than gasoline), but it has the lowest energy content by volume (about four times less than gasoline)."

110 International Renewable Energy Agency, "Hydrogen: A Renewable Energy Perspective" (September 2019) at 7, online: <www.irena.org/-/media/Files/IRENA/Agency/Publication/2019/Sep/IRENA_Hydrogen_2019.pdf>. See also David B Layzell et al, "Towards Net-Zero Energy Systems in Canada: A Key Role for Hydrogen" (September 2020) at 9, online: <transitionaccelerator.ca/towards-net-zero-energy-systems-in-canada-a-key-role-for-hydrogen/> [Layzell et al, "Accelerator White Paper"]; International Energy Agency, "The Future of Hydrogen: Seizing Today's Opportunities" (June 2019) at 13, online: <www.iea.org/reports/the-future-of-hydrogen> [International Energy Agency, "IEA Report"].

111 David B Layzell et al, "Building a Transition Pathway to a Vibrant Hydrogen Economy in the Alberta Industrial Heartland" (November 2020) at 1, online: <transitionaccelerator.ca/wp-conent/uploads/2020/11/Building-a-Tradition-Pathway-to-a-Vibrant-Hydrogen-Economy-in-the-Alberta-Industrial-Heartland-November-2020-4.pdf> [Layzell et al, "Alberta Hydrogen Report"].

However, the "hydrogen economy" that proponents of this technology envision remains in its early stages of development and faces a number of challenges that it will need to overcome before it can achieve widespread adoption. These challenges include cost, infrastructure build-out, and market development.

Hydrogen is a relatively mature technology where its potential as an energy carrier has been known for decades, but it has not yet managed to overcome the hurdles it faces. That said, there now appears to be some appetite for its inclusion in global energy transition and a reinvigorated policy imperative to integrate it into future energy systems is starting to take shape.[112] Across the world, including in Canada, governments increasingly view hydrogen as a viable way to decarbonize their energy, industrial, and transportation sectors.[113]

This is a good example of how commercialization frameworks can help shape transition pathways. In the case of hydrogen, for example, one of the primary obstacles is cost.[114] However, as Layzell notes, assuming that natural gas and hydrogen are both simply combusted for heat, a price of $160 per tonne of CO_2e on GHG emissions will increase the price of natural gas enough to eliminate the cost differential between these potentially competing fuels.[115] In Canada, the gradually increasing price on emissions will reach $170 per tonne CO_2e by 2030, which should help hydrogen compete with natural gas on cost by the end of the decade and other incentives, including direct funding, emissions credit trading under the federal OBPS or its provincial equivalents, such as the *TIER Regulation*, and top-down emissions reduction mandates which could either reduce the price of hydrogen or increase the price of natural gas sooner. While Layzell's analysis does not provide an illustration of the impact that this price increase will have on consumer prices, it is clear that without technological improvements and related cost decreases, the substitution of hydrogen for natural gas in Canada will come with a cost.

112 Layzell et al, "Accelerator White Paper," *supra* note 110 at 19, 48.

113 *Ibid*. Internationally, Germany, South Korea, and Japan have all announced hydrogen strategies that include importing hydrogen. By 2040, these countries could require as much as 22.2 kilotonnes of hydrogen per day. Watson Farley & Williams LLP, "The German Hydrogen Strategy" (17 February 2021), online: <www.wfw.com/articles/the-german-hydrogen-strategy/>; International Energy Agency, "Korea Hydrogen Economy Roadmap 2040," online: <www.iea.org/policies/6566-Korea-hydrogen-economy-roadmap-2040>; Japan, Ministry of Economy, Trade and Industry, *Basic Hydogen Strategy (Key Points)*, online: <www.meti.go.jp/english/press/2017/pdf/1226_003a.pdf>. See also Canada, Department of Natural Resources, *Hydrogen Strategy for Canada: Seizing the Opportunities for Hydrogen*, Catalogue No M134-65/2020E-PDF (December 2020) [Department of Natural Resources, *Canada Hydrogen Strategy*].

114 Layzell et al, "Alberta Hydrogen Report," *supra* note 111 at 13.

115 *Ibid* at 13–14.

2. THE HYDROGEN RAINBOW: BLUE IS THE NEW GREY

Although hydrogen is the most abundant element in the universe, there is not enough naturally occurring pure hydrogen on Earth to support demand.[116] As a result, hydrogen must be produced from other elements. Once produced, hydrogen is relatively clean burning,[117] but its production process is not always so clean. If not pursued carefully, carbon-intensive hydrogen production may simply displace emissions from the point of combustion to the point of production, increasing the cost of energy without a corresponding drop in emissions. If hydrogen is going to play a key role in the transformation to a less carbon-intensive energy system, it will be important to decarbonize production methods and ensure that verification standards are in place to enhance the marketability of Canadian-produced hydrogen.[118]

Hydrogen is currently classified with reference to its production method. Grey and blue hydrogen are produced from fossil fuels through steam methane reforming or autothermal reforming. However, the emissions profile of blue hydrogen is reduced through the use of carbon capture or utilization, either sequestering the associated emissions deep underground or diverting them toward some other commercial use or method of long-term storage. Because it lacks this second step, grey hydrogen production is less expensive than blue hydrogen production but creates more GHG emissions. Green hydrogen, on the other hand, is produced by breaking water molecules down into their constituent elements — oxygen and hydrogen — through a process of electrolysis that is entirely emissions free. While any source of electricity can be used for this process, the resulting hydrogen is only considered green if the electricity source is also considered to be green (for example, solar, wind, hydro, and arguably, nuclear). The colour coding of hydrogen based on its origin is not particularly helpful and the industry should work with regulators to develop a certification protocol based on verified lifecycle emissions-intensity thresholds instead of the process of production, which should, in turn, be used to inform the domestic commercialization and regulatory frameworks.

Approximately 98 percent of global hydrogen production is currently grey hydrogen.[119] If hydrogen demand continues to grow and the international pressure to reduce emissions intensifies, there will be a significant role for both blue and green hydrogen in Canada's future energy systems. And Canada, with its ample natural gas reserves and technological expertise, could become an important player in this industry. To illustrate this, the Alberta Transition Accelerator projects that hydrogen *could* be the energy carrier for 27 percent of Canada's energy demand by 2050.[120] The power needed to meet this demand with green hydrogen would require the construction of 66,000 wind turbines, 30 large nuclear plants equivalent to Ontario's Bruce Station, or 195 new hydro reservoirs which would be the size of British Columbia's planned Site C.[121] The scale of this infrastructure in terms of both cost and CO_2e emissions for materials and construction is immense. If recent experience in the

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116 Department of Natural Resources, *Canada Hydrogen Strategy*, *supra* note 113 at 13–14.

117 Richard Derwent et al, "Global Environmental Impacts of the Hydrogen Economy" at 1, online: <www.geos.ed.ac.uk/~dstevens/Presentations/Papers/derwent_ijhr06.pdf>.

118 See e.g. the CertifHy verification standard.

119 Ruven Fleming, "Clean or Renewable — Hydrogen and Power-to-Gas in EU Energy Law" (2021) 39:1 J Energy & Natural Resources L 43 at 44.

120 Layzell et al, "Accelerator White Paper," *supra* note 110 at 10, 43.

121 *Ibid* at 10, 44.

major infrastructure space is any guide, the logistical and regulatory hurdles associated with such an undertaking would be challenging, to say the least. Blue hydrogen produced in Canada, on the other hand, would face fewer obstacles because it does not require the same investment in new green electricity generation facilities. It would require natural gas volumes equal to approximately 72 percent of Canada's total natural gas production in 2018 to produce enough blue hydrogen to meet the 27 percent market share referenced by the Alberta Transition Accelerator[122] and a commensurate build out of carbon sequestration capacity. As an aside, the development of hydrogen as a mainstream source of energy represents a commercialization opportunity for carbon capture and sequestration, increasing demand for the use of the technology and creating a market in which it could be profitable.

3. FEDERAL AND PROVINCIAL HYDROGEN ROADMAPS

One of the keys to integrating a new industry across various sectors and jurisdictions is first developing a coherent roadmap to organize the collective efforts of government and industry.[123] Recognizing this, a number of Canadian jurisdictions, including the governments of Canada, British Columbia, and Alberta have prepared reports intended to assess the feasibility of developing a domestic hydrogen industry and to provide a path for such development. This article briefly outlines these strategy documents here, each of which is, in some ways, another piece of the commercialization framework that will be crucial for the development of a Canadian hydrogen industry.

a. Federal

In December 2020, the Government of Canada released a "Hydrogen Strategy for Canada."[124] Because it is focused on the development of a national hydrogen strategy, the Canada Hydrogen Strategy provides a helpful reference point for the integration challenges that need to be navigated as the hydrogen industry expands beyond a regional node structure.[125]

Regarding production potential, the Canada Hydrogen Strategy singles out British Columbia as possessing the natural characteristics necessary to support both a green hydrogen industry, driven primarily by hydroelectricity, and a blue hydrogen industry, supported by its substantial natural gas reserves in the Montney Formation.[126] Alberta and Saskatchewan, on the other hand, are best positioned to use their natural gas reserves to support a blue hydrogen industry.[127]

In terms of uses, the Canada Hydrogen Strategy envisions a national "hydrogen economy" that uses hydrogen for: (1) transportation, including hydrogen fuel cell vehicles and compressed natural gas vehicles;[128] (2) power generation;[129] (3) heat for use in the industrial

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122 *Ibid* at 44.
123 See e.g. Layzell et al, "Alberta Hydrogen Report," *supra* note 111 at 2.
124 Department of Natural Resources, *Canada Hydrogen Strategy*, *supra* note 113.
125 *Ibid* at 69–70.
126 *Ibid* at 33.
127 *Ibid* at 74–75.
128 *Ibid* at 45.
129 *Ibid* at 57.

sector;[130] and (4) as a feedstock for industry, including in the oil and gas sector.[131] Notably, these correspond to the sectors identified above as being most exposed to a low-carbon transition and, consistent with the federal policies highlighted in Part II.A.2, emphasize the importance of market creation to support innovation and growth.

In the near term, the Government of Canada envisions that establishing a coherent regulatory environment and relying on commercialization initiatives such as zero-emissions vehicle fuel mandates, emissions pricing, the Clean Fuel Standard, and renewable gas targets for natural gas utilities will help provide the stability that a potential hydrogen industry requires to grow.[132] This growth will initially be driven by regional development and the Canada Hydrogen Strategy specifically targets the Alberta Industrial Heartland and coastal ports in British Columbia as nodes that can support regional development.[133] In the long term, the Canada Hydrogen Strategy expects that hydrogen will expand beyond these regional-use cases and become more broadly integrated throughout the Canadian economy.[134] Ultimately, hydrogen may end up satisfying the need for utility-based high power demand applications, while battery development will target lower-power demand applications.[135]

The Canada Hydrogen Strategy concludes by outlining eight strategic pillars that will help support the industry's future growth, including: creating strategic partnerships; introducing funding initiatives to de-risk investments; modernizing codes and standards to support commercial deployment; ensuring that hydrogen is integrated in clean energy roadmaps, policies and strategies and is supported by enabling regulation; and implementing regional blueprints that identify specific opportunities and plans for hydrogen production and end use.[136]

These pillars are generally consistent with the various recommendations provided in British Columbia and Alberta's hydrogen strategies. Though there is some divergence, it is encouraging to see that all three governments recognize the need to update the regulations and policies that would govern a hydrogen industry in a manner that ensures coherence and predictability. Such updates would necessarily include hydrogen-specific commercialization and regulatory frameworks, none of which presently exist, though various pieces are beginning to emerge.

b. British Columbia

British Columbia was the first of the jurisdictions considered in this article to prepare a study on the feasibility of developing a provincial hydrogen industry and the role it can play in decarbonization by releasing the "British Columbia Hydrogen Strategy" in September 2019.[137] Like the Canada Hydrogen Strategy, the BC Hydrogen Strategy focuses on the

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130 *Ibid* at 59.
131 *Ibid* at 64–66.
132 *Ibid* at 72–73.
133 *Ibid*.
134 *Ibid* at 73–74, 101–102.
135 *Ibid* at 73–74, 102.
136 *Ibid* at 104–105.
137 Zen and the Art of Clean Energy Solutions, "British Columbia Hydrogen Study," online: <www2.gov.bc.ca/assets/gov/government/ministries-organizations/Zen-bcbn-hydrogen-study-final-v6.pdf> [Zen and the Art of Clean Energy Solutions, "BC Hydrogen Strategy"].

attributes and specific advantages that British Columbia possesses that would make a hydrogen industry viable. For example, the BC Hydrogen Strategy notes that blue hydrogen, produced from the province's natural gas reserves, represents the lowest cost path forward. In addition, the BC Hydrogen Strategy identifies the following opportunities for hydrogen to help decarbonize British Columbia's economy: (1) injecting hydrogen into the natural gas grid for power and heat generation and other industrial uses; (2) as a transportation fuel; and (3) for "low carbon synthetic fuels" that would ultimately align with the aims of the Clean Fuel Standard and British Columbia's clean fuel content requirements.[138] The BC Hydrogen Strategy ultimately makes ten high-level recommendations to support the development of a provincial hydrogen sector. The most notable of which include: adopting policies to encourage the use of low carbon-intensity hydrogen and, relatedly, updating the definition of renewable natural gas in the *Greenhouse Gas Reduction Regulation* to include low carbon intensity hydrogen; setting targets for a transition to renewable hydrogen supplies by establishing thresholds of required renewable content over time; and adopting policies and a regulatory framework for light and heavy-duty hydrogen fuel cell electric vehicles to support the build out of hydrogen refueling infrastructure.[139]

Given the inward focus of the BC Hydrogen Strategy, it is less prescriptive as to how British Columbia can collaborate with other provinces or the federal government to develop its hydrogen industry. But in light of the multi-jurisdictional interest in this emerging sector, it is likely that strategic partnerships with Governments of Alberta, Saskatchewan, and Canada will emerge.

c. Alberta

In October 2020, the Government of Alberta released its Natural Gas Vision and Strategy,[140] which includes an 11-point plan that the government intends to follow to facilitate the development of a blue hydrogen economy built around the province's extensive natural gas reserves.[141] Alberta's hydrogen strategy is not as detailed as British Columbia's or Canada's; however, there are many ways in which the three complement each other and it is reasonable to expect that all three will inform each other as they continue to evolve.

In the short term, the Alberta government will begin building partnerships with key stakeholders to determine deployment pathways and commercial, technological, and policy gaps.[142] Looking ahead to 2023, the Alberta Gas Strategy outlines a number of more concrete steps, including developing a "Hydrogen Roadmap," working to align policy across the western provinces, ensuring an efficient regulatory and legislative framework that accommodates hydrogen deployment, and exploring joint federal and provincial funding initiatives to advance pilot projects.[143] In the long term, the Alberta government has indicated

138 *Ibid* at iv (executive summary).
139 *Ibid* at ix (executive summary).
140 Government of Alberta, "Getting Alberta Back to Work: Natural Gas Vision and Strategy" (October 2020), online: <open.alberta.ca/dataset/988ed6c1-1f17-40b4-ac15-ce5460ba19e2/resource/a7846ac0-a43b-465a-99a5-a5db172286ae/download/energy-getting-alberta-back-to-work-natural-gas-vision-and-strategy-2020.pdf> [Government of Alberta, "Alberta Gas Strategy"].
141 *Ibid* at 23–25.
142 *Ibid* at 25.
143 *Ibid*.

that it will work with other Canadian governments to ensure a country-wide hydrogen transmission network and will try to attract a "hydrogen for energy export project to Alberta."[144]

In some ways, Alberta's hydrogen strategy is a plan to make a plan. But, despite the temptation to act quickly, prudence suggests that this more deliberate approach is the correct path forward, especially given the emphasis on jurisdictional harmonization in the other Canadian hydrogen plans. In addition, a number of important pieces to the hydrogen puzzle already exist in Alberta, and if the government and industry can work together effectively and in an organized manner to establish and leverage the necessary commercialization and regulatory frameworks, the puzzle can be put together.

To begin, carbon sequestration or reuse is a necessary component for blue hydrogen production.[145] And Alberta already has a regulatory regime for carbon capture that is well understood.[146] Alberta also has an extensive gas pipeline network that could facilitate the growth of local demand in the short-to-medium term, which may be repurposed in the future.[147] In connection with the repurposing of existing infrastructure, limited amounts of hydrogen can be mixed with natural gas and transported via existing pipelines.[148] The development of a limited local transportation network using existing infrastructure could help support the growth of a local industry in the short-to-medium term. In addition, Alberta's *TIER Regulation* and the forthcoming federal Clean Fuel Standard, particularly with regard to the commercialization of hydrogen fuel cell vehicles, may provide part of the commercialization framework needed to help hydrogen overcome the fact that, currently, it costs more to produce and transport than other fuels. Finally, Alberta's electricity sector is deregulated and is therefore uniquely well suited among the provinces to accommodate privately funded pilot projects for hydrogen-fuelled electricity generation projects. Indeed, ATCO's hydrogen blending project in Fort Saskatchewan, ACTO's recently announced partnership with Suncor to develop a large hydrogen production facility near Edmonton, and the Alberta Zero Emissions Track Electrification Collaboration (AZETEC) project may be early signals that the commercialization framework in Alberta is sufficient to help get some pilot projects off the ground.[149]

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144 *Ibid*.

145 Department of Natural Resources, *Canada Hydrogen Strategy*, *supra* note 113 at 30.

146 See *Carbon Capture and Storage Statutes Amendment Act, 2010*, SA 2010, c 14; *Carbon Sequestration Tenure Regulation*, Alta Reg 68/2011.

147 See e.g. International Energy Agency, "IEA Report," *supra* note 110 at 15. See also Enagás et al, "European Hydrogen Backbone: How a Dedicated Hydrogen Infrastructure Can Be Created" (July 2020) at 16, online (pdf): <gasforclimate2050.eu/sdm_downloads/european-hydrogen-backbone/>.

148 Department of Natural Resources, *Canada Hydrogen Strategy*, *supra* note 113 at 61–62.

149 See ATCO, "ATCO to Build Alberta's First Hydrogen Blending Project with ERA Support" (21 July 2020), online: <www.atco.com/en-ca/about-us/news/2020/122900-atco-to-build-alberta-s-first-hydrogen-blending-project-with-era.html>; Emissions Reduction Alberta, "Alberta Zero Emissions Truck Electrification Collaboration (AZETEC)," online: <eralberta.ca/projects/details/alberta-zero-emissions-truck-electrification-collaboration-azetec/>; Dan Healing, "Suncor and Atco Working Together on Potential Hydrogen Project Near Edmonton," *Global News* (11 May 2021), online: <globalnews.ca/news/7850878/suncor-energy-atco-hydrogen-project/>.

4. THE REGULATORY FRAMEWORK FOR A HYDROGEN INDUSTRY

Canada has a long history of regulating natural resource development, including oil and gas infrastructure, that is similar to what a hydrogen industry will require: pipelines, production facilities, wells for natural gas extraction or carbon sequestration, and among other things. Despite this regulatory familiarity, the regulatory frameworks in place do not directly address hydrogen projects, though various parts of these projects may fall under existing regulations. Indeed, hydrogen projects already exist so there is regulatory precedent,[150] but their development and ongoing regulation is in some ways akin to wearing a shoe on the wrong foot — it works, but not as well as it could. Unfortunately, the absence of hydrogen-specific regulations may delay investment and growth in the short-to-medium term. But it is clear that federal and provincial legislators are aware of this, given the emphasis on developing codes, standards, policies, and regulations in the various plans that have been put forward and the timelines they have established.

This section outlines and assesses the regulatory frameworks in place federally and provincially in the Western Provinces. Given the aims of this article, there will not be an exhaustive accounting of these frameworks. That said, it is important to understand the rules as they exist now in order to anticipate how they can or should evolve such that they can work in tandem with the commercialization framework described in Part II of this article and incentivize the growth of a new hydrogen industry.

a. Hydrogen and the Constitutional Division of Powers

Despite the federal government's clearly stated intention to foster the development of Canada's "hydrogen economy,"[151] it will likely play a limited role in the day-to-day regulation of most future hydrogen projects built in Canada. This is primarily due to the constitutional division of powers set out in the *Constitution Act, 1867*.[152] Historically, the provinces have borne most of the responsibility for regulating resources and industrial development.[153] And arm's-length provincial regulators such as the British Columbia Oil and Gas Commission (the BCOGC) and the Alberta Energy Regulator (the AER) lead the way in developing and implementing comprehensive regulatory schemes.[154] Due to the local nature of hydrogen production facilities and their associated infrastructure or, for that matter, geothermal and clean fuels operations, this is not expected to change. In addition, blue hydrogen is derived from natural gas and its development is subject to the exclusive legislative jurisdiction of the provinces.[155] Arguably, the federal government's most important role will be developing and administering the commercialization framework

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150 See e.g. the Scotford Chemical Manufacturing Plant and the Edmonton Hydrogen Plant.

151 Department of Natural Resources, *Canada Hydrogen Strategy*, *supra* note 113 at IX.

152 *Constitution Act, 1867* (UK), 30 & 31 Vict, c 3, ss 91–92, reprinted in RSC 1985, Appendix II, No 5.

153 Relevant heads of power in this respect include: exploring, developing, and managing non-renewable natural resources contained within the province (*ibid*, s 92A); the management of public property owned by the provincial government in right of the Crown (*ibid*, s 92(5)); matters pertaining to property and civil rights within the province (*ibid*, s 92(13)); and, more generally, all matters of a local or private nature within the province (*ibid*, s 92(16)).

154 In Saskatchewan, the regulation of the oil and gas industry has primarily been undertaken by a government ministry.

155 *Constitution Act, 1867*, *supra* note 152, s 92A(1).

necessary to support the growth of these nascent industries. That said, the federal government may play a more active role in carrying out federal environmental impact assessments[156] and regulating the uniquely federal aspects of projects, such as interprovincial transportation, export, and projects on federal lands.[157]

b. Federal

The growth of an integrated Canadian and export-based hydrogen industry will ultimately require hydrogen to be moved from its point of production to its point of use. While shipping by truck or rail can accomplish this, pipelines are likely the most cost-effective and logistically straightforward means of transportation. The Canada Energy Regulator (the CER) has regulatory authority over interprovincial and international pipelines, referred to as "federal pipelines," that are used for the transmission of oil, gas, or any other commodity.[158] For the purposes of the *CERA*, "gas" means "any hydrocarbon or mixture of hydrocarbons … in a gaseous state" or any substance designated by regulation to be a gas product[159] if it results from the processing or refining of hydrocarbons or coal and is "a source of energy by itself or when it is combined or used in association with something else."[160] Based on this definition and the scope of the CER's designating power, green hydrogen is not a gas, and the designation of blue hydrogen as a gas will depend on whether the CER concludes that it results from the processing or refining of hydrocarbons.[161] Despite this apparent legislative gap, it seems exceptionally unlikely that the CER would decline to regulate a federal pipeline transporting blue or green hydrogen, and even if the definitions are not updated, it is likely that any interprovincial or international pipeline built to transport hydrogen as a primary product could be regulated as a commodity pipeline.

Before any person can construct or operate a federal pipeline, they must first apply to the CER for a certificate or exemption that permits them to do so.[162] Similar approval

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156 *Impact Assessment Act*, SC 2019, c 28, s 1 [*IAA*]. Currently, hydrogen facilities are not included in the *Physical Activities Regulations*, SOR/2019-285 [*PAR*] and therefore do not trigger the impact screening and assessment process required under the *IAA*.

157 *Constitution Act, 1867*, *supra* note 152, ss 91(2), 92(10)(a). See also National Energy Board, *Jurisdiction over the Coastal GasLink Pipeline Project MH-053-2018* (26 July 2019), File Of-Fac-PipeGen-T211 04 at 5, 26–28, online: NEB <docs2.cer-rec.gc.ca/ll-eng/llisapi.dll/fetch/2000/90464/90550/90715/3615343/3715570/3809973/C00715-1_%20NEB_–_Letter_Decision_–_Coastal_GasLink_–_MH-053-2018_-_A6W4A5.%20pdf?nodeid=3809655&vernum=-2>. This decision relies on *Consolidated Fastfrate Inc v Western Canada Council of Teamsters*, 2009 SCC 53.

158 *Constitution Act, 1867*, *ibid*, s 92(10)(a). See also *Canadian Energy Regulator Act*, SC 2019, c 28, ss 10, 179–81 [*CERA*]. Pipelines over which the CER exercises its regulatory authority are defined in section 2 of the *CERA*, as follows:

> pipeline means a line — including all branches, extensions, tanks, reservoirs, storage or loading facilities, pumps, racks, compressors, interstation communication systems, real or personal property, or immovable or movable, and any connected works — that connects at least two provinces or extends beyond the limits of a province, Sable Island or an area referred to in paragraph (c) of the definition designated area in section 368 and that is used or is to be used for the transmission of oil, gas or any other commodity. It does not however include a sewer or water pipeline that is used or is to be used solely for municipal purposes.

Pursuant to National Energy Board Order MO-CO-3-96, commodities pipelines are regulated on a slightly different basis than are oil and gas pipelines. The National Energy Board gave a helpful background discussion to the regulation of such pipelines in National Energy Board, *Reasons for Decision: Souris Valley Pipeline Limited MH-1-98*, Catalogue No NE22-1/1988-7E (October 1998) at 1–3.

159 *CERA*, *ibid*, s 2.

160 *Ibid*, s 390(1)(a).

161 *Ibid*.

162 *Ibid*, ss 180, 182, 214.

requirements are required for the variation of an existing certificate[163] and could, for example, apply to the retrofitting of currently operating natural gas pipelines. This approval requirement engages a public review process pursuant to which the CER will consider a number of factors to decide whether a pipeline can be built and operated, including the following: the environmental effects of the pipeline; any health, social, and economic effects; the existence of actual or potential markets that the pipeline will serve as well as its economic feasibility; and the extent to which the effects of the pipeline hinder or contribute to the Government of Canada's ability to meet its environmental obligations and its commitments in respect of climate change,[164] including the NDC established under the *Paris Agreement*.

If a federal pipeline is a designated project under the *IAA* and the *PAR*,[165] the regulatory review will be carried out by a review panel established under the *IAA*,[166] which is comprised of members of the Impact Assessment Agency and at least one commissioner of the CER.[167] An impact assessment carried out under the *IAA* is more expansive than the CER's regulatory review[168] and currently applies to new pipelines that require a total of 75 kilometres or more of new right of way.[169] However, this could change if a future government amends the designated project list or the Minister determines an impact assessment is nevertheless required.[170]

Ultimately, however, the approval of any new major federal pipeline is a decision reserved to the federal Cabinet that is made on the basis of whatever report and recommendation the applicable reviewing body provides.[171] While the desired ameliorative environmental and climate effects of integrating hydrogen throughout Canada's energy system and the broad support that hydrogen has garnered from the federal and provincial governments suggest hydrogen pipelines will be less politically contentious than the regulatory reviews of hydrocarbon pipelines that have taken place over the past decade, it is likely that there will continue to be regulatory uncertainty surrounding their construction, particularly, in the case of pipelines intended to carry blue hydrogen or blends of hydrogen and natural gas.

Regarding exports, the CER currently regulates the export of crude oil, natural gas, and natural gas liquids from Canada under the authority of the *CERA* and in accordance with the regulations.[172] Pursuant to this authority, the CER may issue short-term orders or long-term licences of up to 40 years for the export of natural gas.[173] While the definitions of gas and natural gas for the purposes of the regulations do not capture hydrogen,[174] the federal

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163 *Ibid*, s 190.
164 *Ibid*, s 183(2).
165 *Supra* note 156.
166 *CERA*, *supra* note 158, s 185(a); *IAA*, *ibid*, s 47.
167 *IAA*, *ibid*, ss 47(3), 50(1)(c).
168 See e.g. the factors for consideration set out in the *IAA*, *ibid*, s 22.
169 *PAR*, *supra* note 156, s 41 (under Schedule).
170 *IAA*, *supra* note 156, s 9(1).
171 *CERA*, *supra* note 158, s 186; *IAA*, *ibid*, ss 51(3), 61(1).
172 *Ibid*, ss 343–44; *National Energy Board Act Part VI (Oil and Gas) Regulations*, SOR/96-244 [*Part VI Regulations*]. See also Canada Energy Regulator, "Frequently Asked Questions – Regulations," online: <www.cer-rec.gc.ca/en/about/acts-regulations/frequently-asked-questions-regulations.html#s8> (look under the heading of *National Energy Board Act* Part VI (Oil and Gas Regulations)).
173 *CERA*, *ibid*, s 353(2).
174 *Ibid*, s 2; *Part VI Regulations*, *supra* note 172, s 10.1.

government may seek to exercise some control over its export through the CER, particularly if it eventually becomes a strategic resource for Canada.

c. British Columbia

British Columbia does not have a clearly defined regulatory framework for hydrogen facilities. Under the *Environmental Assessment Act*,[175] a proponent must obtain an environmental assessment certificate before commencing to "undertake or carry on any activity that is a reviewable project."[176] A catalogue of "reviewable projects" is set out in the *Reviewable Projects Regulation*;[177] however, these projects are either of a particular size or satisfy certain effects thresholds.[178] On review, there are few that clearly capture hydrogen projects, although blue hydrogen facilities may, depending on their size and notwithstanding the use of carbon capture or utilization, be viewed as facilities that emit GHGs at a rate sufficient to bring them above the specified emissions threshold that requires an environmental assessment.[179] In addition, hydrogen facilities may be viewed as chemical manufacturing facilities that, depending on their size, would be classified as reviewable projects. Nevertheless, projects that are not reviewable can also be designated under section 11 of the *BCEAA*, which would then subject them to an environmental assessment.

Regarding permitting requirements, the *Oil and Gas Activities Act* could apply to the production of blue hydrogen as an "oil and gas activity" to the extent that the operation of a hydrogen facility constitutes the processing of natural gas or, alternatively, the "operation of a manufacturing plant designed to convert natural gas into other organic compounds."[180] While the latter is an imperfect fit, the two activities considered together arguably capture hydrogen production and could apply to hydrogen facilities until a more hydrogen-specific activity is identified in statute. Assuming this view is correct, a proponent cannot construct or operate a hydrogen facility until the BCOGC has issued a permit in respect of that activity.[181] Natural gas pipelines are subject to the same permitting requirements as the ones described above.[182] Given that blue hydrogen facilities will be tied into pipelines for their natural gas supply, it seems unlikely that a facility could or would escape regulatory scrutiny and permitting requirements. That said, more clarity in this respect would be helpful for project proponents to better understand their regulatory obligations.

British Columbia's *PNGA* applies to underground storage, including for purposes of sequestration,[183] such that the government may designate land as a storage area on application.[184] As is the case for processing facilities and pipelines, "the operation or use of a storage reservoir" is an "oil and gas activity" that requires a permit under the *OGAA*.[185]

175 SBC 2018, c 51 [*BCEAA*].
176 *Ibid*, s 6(1).
177 BC Reg 243/2019.
178 *Ibid*, ss 3–5(1), 7–8, 11–12.
179 *Ibid*, s 4(1)(a).
180 SBC 2008, c 36, s (1) [*OGAA*].
181 *Ibid*, s 21.
182 *Ibid*, ss 1(1)– (2); *Petroleum and Natural Gas Act*, RSBC 1996, c 361, s 1 [*PNGA*]: natural gas is "all fluid hydrocarbons, before and after processing, that are not defined as petroleum, and includes hydrogen sulphide, carbon dioxide and helium produced from a well."
183 *PNGA*, *ibid*, ss 126–32.
184 *Ibid*, ss 127–28.
185 *OGAA*, *supra* note 180, ss 1, 21.

Finally, water is a critical component of blue hydrogen production. In British Columbia, a person must not divert water or use diverted water without a licence issued under the *Water Sustainability Act*.[186] However, licences issued under section 9 of the *Act* are only available for specified "water use purposes" such as industrial, as defined by regulation, mining, oil and gas, primarily related to the development of wells or the production of oil or natural gas resources, and power or waterworks purposes, but none of which readily apply to hydrogen production.[187] At a stretch, one could argue that the use of water in hydrogen production is a "subset" of one of the foregoing water use purposes, such as a power purpose,[188] but again, this is not a precise fit.

d. Alberta

Despite several hydrogen facilities currently operating in the province, Alberta, like British Columbia, does not have a dedicated regulatory regime for hydrogen. Instead, the provincial regulatory framework for hydrogen is an amalgam of existing environmental and oil and gas statutes and regulations that do not always apply perfectly. For example, proposed industrial facilities and other activities often require environmental assessments and authorizations under the *Environmental Protection and Enhancement Act*.[189] Currently, an approval under section 60 of the *EPEA* is required for gas processing plants[190] and chemical manufacturing plants,[191] both of which are somewhat analogous to blue hydrogen production facilities. However, the Scotford Chemical Manufacturing Plant and the Edmonton Hydrogen Plant were both approved as chemical manufacturing plants,[192] which are defined in the *Activities Designation Regulation* as plants that manufacture organic or inorganic chemicals, other than gas processing and petrochemical plants.[193]

Though past practice suggests that hydrogen facilities can be regulated as chemical manufacturing facilities, they also bear some similarities to "sweet gas processing plants."[194] Given the integration of blue hydrogen facilities with other components of Alberta's natural gas industry, proponents may prefer to maintain a single window regulatory relationship with the AER for cradle-to-grave lifecycle regulation,[195] which may see those proponents advancing applications for hydrogen facilities on the basis that they are gas processing facilities rather than chemical manufacturing facilities. Practically speaking, this may be preferable to having multiple regulatory bodies involved across the hydrogen production

186 SBC 2014, c 15, ss 6, 10 [*WSA*].

187 *Ibid*, s 2. See also *Water Sustainability Regulation*, BC Reg 36/2016 (see Schedule A).

188 *WSA*, *ibid*, ss 1–2.

189 RSA 2000, c E-12, ss 41, 43, 47, 60, 63 [*EPEA*]; *Activities Designated Regulation*, Alta Reg 276/2003.

190 *Activities Designated Regulation*, *ibid*, s 5, Part 8 of Schedule 1.

191 *Ibid*, s 5, Part 2 of Schedule 1.

192 Alberta Environment and Sustainable Resource Development, EPEA Approval No 264422-00-00 (6 June 2014), online: <avw.alberta.ca/pdf/00264422-00-00.pdf>; Alberta Environment and Parks, EPEA Approval No 206969-01-00 (31 May 2016), online: <avw.alberta.ca/pdf/00206969-01-00.pdf>.

193 *Supra* note 189, s 2(2)(g).

194 Defined in the *Activities Designated Regulation, ibid*, s 2(2)(nnn): "means a plant that (i) processes raw gas, (ii) does not separate any sulphur compounds from the raw gas stream, and (iii) releases industrial wastewater to the environment other than by evaporation, by injection into an approved deep well facility, or by directing the industrial wastewater to a wastewater treatment plant."

195 See e.g. the regulatory process outlined by the Alberta Energy Regulation, "Integrated Applications for Major Projects," online: <www.aer.ca/regulating-development/project-application/integrated-decision-approach/major-projects>.

chain, though other refining facilities operate successfully under a split regime.[196] However, if the Alberta government wishes to create a more efficient regulatory process for new hydrogen facilities and thereby encourage investment, one improvement it could make to the existing regulatory regime is to designate a single regulatory authority such as the AER.

Indeed, even if blue hydrogen facilities are not sweet gas processing facilities under the *EPEA*, they arguably fit within the definition of "processing plant" for licensing purposes under the *Oil and Gas Conservation Act*,[197] which illustrates some of the internal inconsistency present in even sophisticated regulatory schemes. Processing plants under the *OGCA* are plants "for the *extraction from gas* of hydrogen sulphide, helium, ethane, natural gas liquids or *other substances*, but [this definition] does not include a well head separator, treater or dehydrator"[198] and require approval from the AER.[199] It is not clear that the process of steam methane reforming to produce hydrogen is equivalent to extracting substances from a natural gas stream, but there are conceptual similarities.

The AER also regulates pipelines under the *Pipeline Act*,[200] which requires that pipeline proponents first obtain approval from the AER before constructing or operating a pipeline for the transportation of "natural gas both before and after it has been subjected to any processing" and "any substance recovered from natural gas … for transmission in a gaseous state."[201] Thus, any pipeline that delivers natural gas to a hydrogen facility or that carries hydrogen or natural gas from a hydrogen facility will likely be subject to AER regulation.

Another piece of the blue hydrogen production puzzle in Alberta is carbon capture and sequestration or reuse. About a decade ago, Alberta undertook a number of legislative changes intended to provide regulatory clarity for carbon sequestration.[202] One of the most important changes to emerge from this legislative overhaul was the clarification of ownership of pore space, which was declared to have vested in the Crown in right of Alberta unless located within federal lands.[203] Thus, the disposition of rights for the use of pore space, like the disposition of rights for other fossil fuel development projects, falls within the purview of Alberta Energy.[204]

Under Part 9 of the *Mines and Minerals Act*,[205] the Minister may enter agreements with proponents to explore and evaluate pore space and agreements for the right to inject CO_2 into a subsurface reservoir for sequestration.[206] In either case, however, a proponent must also

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196 Alberta Energy Regulator, "How Does the AER Regulate Energy Development in Alberta?," online: <www.aer.ca/protecting-what-matters/holding-industry-accountable/how-does-the-AER-regulate-energy-development-in-alberta>.

197 RSA 2000, c O-6, ss 1(1)(y), 1(1)(pp), 39(1) [*OGCA*].

198 *Ibid*, s 1(1)(pp) [emphasis added].

199 See also *Oil and gas Conservation Rules*, Alta Reg 151/1971, ss 9.010–9.070.

200 RSA 2000, c P-15.

201 *Ibid*, s 1(i).

202 For a thorough discussion of these changes and the regulation of carbon sequestration more generally, see Nigel Bankes, Jenette Poschwatta & E Mitchell Shier, "The Legal Framework for Carbon Capture and Storage in Alberta" (2008) 45:3 Alta L Rev 585; Michael G Massicotte, Alan L Ross & Chidinma B Thompson, "The Changing Legislation and Regulation of Carbon Capture and Storage: Impacts on Purpose, Policy, and Projects" (2011) 49:2 Alta L Rev 305.

203 Massicotte et al, *ibid* at 315. See also *Mines and Minerals Act*, RSA 2000, c M-17, s 15.1 [*MMA*].

204 Massicotte et al, *ibid* at 316; *MMA*, *ibid*, s 2(a).

205 *Ibid*.

206 *Ibid*, ss 115–116.

obtain a licence and various other approvals from the AER before commencing the relevant operations.[207]

Finally, and in addition to the facility and infrastructure approvals and licences that a hydrogen proponent will require, proponents also need to obtain a licence under the *Water Act* to commence a diversion of water for any purpose.[208] The availability of a licence may depend on the needs of the project when balanced against any water management plan in effect in the area where the facility will be located and various other environmental effects.[209]

e. Saskatchewan

Like British Columbia and Alberta, there is no single regulatory framework for hydrogen in Saskatchewan though the existing oil and gas legislative framework captures most elements of a blue hydrogen project. At the first stage of project development, *The Environmental Assessment Act* prohibits project proponents from proceeding with a "development" until it has received ministerial approval.[210] The question then is whether a blue hydrogen facility is a "development" that attracts this environmental assessment requirement. Under the *SKEEA*, a development means, among other things, any undertaking that is likely to do the following: (1) "have an effect on any unique, rare or endangered feature of the environment" or, more generally, have a significant impact on the environment; (2) substantially utilize a provincial resource such as natural gas in a manner that pre-empts its use for other purposes; (3) causes public concern regarding potential environmental changes; or (4) involves a new technology concerned with resource utilization, which may induce significant environmental change.[211] Though not certain, it seems reasonably likely that a blue hydrogen "development," depending on its size and water consumption, would require an environmental assessment under the *SKEEA*.

In addition to the environmental assessment regime, Saskatchewan's regulatory framework appears to apply to blue hydrogen facilities as "facilities" for which a person must first obtain a licence prior to commencing construction or operation under *The Oil and Gas Conservation Act*.[212] Though not defined in Saskatchewan's *SKOGCA*, "facility" is defined in *The Oil and Gas Conservation Regulations, 2012* to mean

> any building, structure, installation, equipment or appurtenance that is connected to or associated with the *recovery*, development, production, storage, handling, *processing*, treatment or disposal of oil, gas, water, *products or other substances*, that are produced from or injected into a well, but does not include a pipeline.[213]

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207 *Ibid*. See also *OGCA*, *supra* note 197, s 39(1.1); Alberta Energy Regulator, "Directive 065: Resources Applications for Oil and Gas Reservoirs" (9 April 2021), online: <static.aer.ca/prd/documents/directives/DirectiveO65.pdf> (see under unit 4).

208 RSA 2000, c W-3, s 49(1)(a).

209 *Ibid*, ss 51(4)(a), 51(4)(b), 51(4)(c)(iii).

210 SS 1979-80, c E-10.1, ss 8(1), 15 [*SKEAA*].

211 *Ibid*, s 2(d).

212 RSS 1978, c O-2, s 8.01(1) [*SKOGCA*].

213 *The Oil and Gas Conservation Regulations, 2012*, RRS c O-2, Reg 6, s 2(1)(m) [emphasis added].

The Regulations further define "gas" to mean natural gas, including "all liquid hydrocarbons other than oil and condensate."[214] Clearly, this does not capture hydrogen. However, "product," as underlined in the definition of "facility" above, is broadly defined in the *SKOGCA* to mean "*a commodity made from* oil or *gas* and includes … by-products derived from oil or gas and blends or mixtures of two or more liquid products or by-products derived from oil or gas, *whether or not mentioned herein*."[215] This likely captures blue hydrogen, but not green hydrogen, and suggests that blue hydrogen facilities could be regulated as gas processing plants under the *SKOGCA*.[216]

The Pipelines Act, 1998 also requires that a proponent obtain a licence before constructing or operating a pipeline.[217] However, the definition of "pipeline" for the purposes of the *Act* does not obviously apply to hydrogen pipelines. Per the definition, the *Act* only applies to the following: pipelines for the transportation of liquid or gaseous hydrocarbons, including natural gas, and "water, steam, or any other substance where" such substance "is incidental to or used in the production of" crude oil, natural gas, or carbon dioxide.[218] Hydrogen produced through steam methane reforming is not incidental to or used in the production of crude oil or natural gas nor is it a gaseous hydrocarbon. While hydrogen mixed with natural gas probably falls within the meaning of "natural gas," there does not appear to be any provision for hydrogen-specific pipelines.

As for carbon sequestration in Saskatchewan, the pore space left behind by the production of Crown minerals in Saskatchewan remains vested in the Crown and the Crown may lease such pore space for the purposes of storing captured carbon dioxide,[219] but there is no statutory guidance for pore space on Crown lands. Facilities for the injection of CO_2 into a subsurface reservoir will also require licences under the *SKOGCA*.[220]

Finally, the Water Security Agency manages the use of water resources in Saskatchewan.[221] As part of its mandate, the Water Security Agency may issue water rights licences for the right to the use of any water.[222]

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214 *Ibid*, s 2(1)(q).
215 *SKOGCA*, *supra* note 212, s 2(1)(n) [emphasis added].
216 Government of Saskatchewan, Ministry of Energy and Resources, *Facility License Requirements: Directive PNG001* (June 2020) at 5–6, online: <pubsaskdev.blob.core.windows.net/pubsask-prod/85482/Directive%252BPNG001-Facility%252BLicence%252BRequirements%252Bv.1.1.pdf>.
217 SS 1998, c P-12.1, s 5(2).
218 *Ibid*, s 2(j).
219 *The Crown Minerals Act*, SS 1984-85-86, c C-50.2, s 27.2(2).
220 *Supra* note 212, s 8.01.
221 Saskatchewan, Water Security Agency, "Overview," online: <www.wsask.ca/about/overview>.
222 *The Water Security Agency Act*, SS 2005, c W-8.1, ss 50(1)–51. The construction and operation of infrastructure required to divert water also requires a written approval (*ibid*, s 59(1)).

B. GEOTHERMAL

1. GEOTHERMAL POWER IN CANADA

Geothermal energy has been used for direct heating and electricity generation around the world for decades but is only recently starting to see increased investment and adoption in Canada. A variety of geothermal projects are in development, including direct heat production, co-production with oil and gas, and various means of electricity generation.

The traditional energy industry itself is also beginning to embrace geothermal along with a range of other renewable and sustainable energy sources. This has been notably demonstrated in the US$40 million investment in Calgary-based Eavor Technologies Inc. by BP Ventures, Chevron Technology Ventures, Temasek, BDC Capital, Eversource, and Vickers Venture Partners.[223]

Geothermal power generation offers a package of benefits rarely found together in renewable energy technologies. Geothermal can act as both deployable and baseload power, meaning that it can be run steadily to provide foundational power to the grid and also easily ramped up to keep pace with market demand. As a baseload power source, geothermal does not suffer intermittency issues associated with wind and solar power, boasting a nearly 98 percent capacity factor.[224]

Geothermal also has the potential for advantages specific to Western Canada. The Western Provinces have significant experience in drilling and completing the deep wells necessary for geothermal power generation projects. The technology has been advocated by the Government of Alberta as a way to take advantage of this expertise to develop a new industry.[225] Possible synergies between oil and gas production and geothermal power generation are being pursued by Razor Energy Corp. in its Alberta co-production facility. The project intends to recover geothermal waste heat produced in concert with oil and gas and use that heat to generate between 3–5 MW of electricity.[226]

Despite the inherent advantages of geothermal as a renewable power generation option, its commercial usefulness in Canada may be limited. High costs of production compared with alternative electricity generation options mean that the cost of geothermal must be brought down through subsidies or technological innovation. Alternatively, the cost of competing energy sources must be increased through taxes or cap-and-trade programs. Further, although heavily publicized by the Government of Alberta, repurposing of oil and

223 Eavor, "Global Energy Majors Lead Pivot to Eavor's Geothermal Solution with USD$40 Million Investment" (16 February 2021), online: <press/global-energy-majors-lead-pivot-to-eavors-geothermal-solution-with-usd40-million-investment/>.

224 Clean Energy BC, "Geothermal," online: <www.cleanenergybc.org/sectors/geothermal>.

225 Government of Alberta, "Clearing a Path for Geothermal Resource Development," online: <www.alberta.ca/clearing-a-path-for-geothermal-resource-development.aspk> [Government of Alberta, "Clearing a Path"].

226 Razor Energy Corp, "Razor Energy Receives Funding for Geothermal Power Project" (27 June 2019), online: <www.globenewswire.com/news-release/2019/06/27/1875064/0/en/Razor-Energy-Receives-Funding-for-Geothermal-Power-Project.html>.

gas wells for geothermal will be very challenging and the actual potential of this endeavour is limited.[227]

It will be critical for geothermal project proponents to understand the legislative and regulatory process required to move projects from conception to active power generation and eventually to reclamation and abandonment. This section of the article will discuss the steps required for a geothermal project proponent in western Canada to move through the licensing and permitting process, the obligations that will be placed on the proponent, and where the legislation leaves unanswered questions.

2. THE REGULATORY FRAMEWORK FOR GEOTHERMAL POWER

a. British Columbia

Geothermal project development in British Columbia is governed by the *Geothermal Resources Act*.[228] The *GRA* became law in British Columbia in 1996 and governs the development and use of geothermal resources at and above 80 degrees Celsius.[229]

The *GRA* defines "geothermal resource" as

> the natural heat of the earth and all substances that derive an added value from it, including steam, water and water vapour heated by the natural heat of the earth and all substances dissolved in the steam, water or water vapour obtained from a well, but does not include
>
> (a) water that has a temperature less than 80°C at the point where it reaches the surface, or
>
> (b) hydrocarbons.[230]

This definition is broad, including the thermal energy itself along with the medium in which that energy is transported, provided in the case of water that the temperature is greater than 80 degrees Celsius). Unlike Alberta's legislation, the *GRA*'s definition includes any dissolved substances aside from hydrocarbons. This may provide an additional revenue stream for geothermal companies, as valuable substances such as lithium may be produced with geothermal fluids.[231]

Ownership of geothermal resources is vested under the *GRA* in the Government of British Columbia. Vesting the right to geothermal resources with the Crown has the potential to avoid many of the issues that may occur when geothermal rights are vested with the mineral rights holder, as is the case in Alberta. Geothermal project proponents in British Columbia

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227 Dan Goldbeck, "A Look at How Geothermal Fits in the Renewable Energy Puzzle" (2 March 2020), online: <www.americanactionforum.org/insight/a-look-at-how-geothermal-fits-in-the-renewable-energy-puzzle/>.

228 RSBC 1996, c 171 [*GRA*].

229 Government of British Columbia, "Geothermal Regulations," online: <www2.gov.bc.ca/gov/content/industry/electricity-alternative-energy/renewable-energy/geothermal-energy/regulatory-information>.

230 *Supra* note 228, s 1(1).

231 *Ibid*, s 2; Alexander Richter, "Geothermal Lithium, Its Extraction and Impact on Clean Energy" (13 February 2021), online: <www.thinkgeoenergy.com/geothermal-lithium-its-extraction-and-impact-on-clean-energy/>.

do not need to reach agreements with a variety of mineral rights holders and individual mineral rights holders cannot exercise an effective veto right on a project.

The *GRA* explicitly establishes the Government of British Columbia's right to collect a royalty from the production of geothermal resources.[232] In a 2018 proposal, the British Columbia Ministry of Energy, Mines, and Petroleum Resources announced its intention to implement a royalty regulation for geothermal resources, but there are currently no prescribed royalties.[233] The proposal reviews precedent royalty rates from the United States, Australia, and Kenya, which range from 1–10 percent and concludes by announcing the intention to implement a 3 percent royalty on geothermal resource production following a ten-year royalty holiday.[234] Though the proposal states that the regulation will be introduced in 2019, it has yet to be brought into law in the province.[235]

b. Alberta

The Government of Alberta introduced Bill 36, *Geothermal Resources Development Act*, on 20 October 2020.[236] The bill received royal assent on 9 December 2020 and will take effect on proclamation. The introduction of the *GRDA* has signaled the Government of Alberta's intention to build more transparency and consistency into the licensing and permitting process. However, the *GRDA* also provokes several questions as to how the legislation will be applied in practice, how these new rules will interact with the roles of Alberta's regulators, and what obligations will be placed on geothermal project proponents throughout the process.

Bill 36 regulates geothermal development "below the base of groundwater protection."[237] The base of groundwater protection is the approximate point at which underground water turns from fresh water to salt water, "the best estimate of the elevation of the base of the formation in which non-saline groundwater occurs at that location."[238] Any geothermal projects above this point are regulated by Alberta Environment and Parks.[239] The temperatures necessary to produce geothermal electricity can only be found below the base of groundwater protection, so the *GRDA* will be responsible for regulating all geothermal projects in the province with the potential to generate electricity.[240]

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232 *Ibid*, s 17.

233 British Columbia Ministry of Energy Mines and Petroleum Resources, *Intentions Paper Geothermal Royalty Policy Proposal*, online: <www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/electricity-alternative-energy/geothermal/geothermal_resouces_act_proposed_royalty_policy.pdf>.

234 *Ibid* at 3–4.

235 *Ibid* at 7.

236 2nd Sess, 30th Leg, Alberta 2020 (assented to 9 December 2020), SA 2020, c G-5.5 [*GRDA*]; Phil Heidenreich, "Alberta Government Introduces Legislation to Promote Geothermal Energy Development," *Global News* (20 October 2020), online: <www.globalnews.ca/news/7409356/alberta-government-geothermal-resource-development-act-ucp>.

237 *Ibid*, s 1(1)(d).

238 Government of Alberta, *Water Wells and Ground Source Heat Exchange Systems Directive* (11 December 2018), s 1.2(2)(c), online: <open.alberta.ca/dataset/5bc817ba-3d6d-45cd-a403-2e727abe665e/resource/508b38c0-0ca7-4fbe-8a90-cfeb5139e122/download/directivewaterwellsgroundsourceheatexchange-dec11-2018.pdf>.

239 Government of Alberta, *Laying the Groundwork for Geothermal Development*, (Government News), (20 October 2020), online: <www.alberta.ca/release.cfm?xID=74510CC59C290-04AA-1364-7265D9C846EC9548>.

240 To the contrary, see Charlotte Helston, "Low-Temperature Geothermal Power" (May 2012), online: <www.energybc.ca/lowtempgeo.html>.

The *GRDA* is modeled after Alberta's *Oil and Gas Conservation Act* and puts the AER in charge of regulating geothermal development.[241] Bill 36 also amends several other legislation, including the *MMA*.[242] The amendments to the *MMA* primarily do one important thing: vest the "right to explore for, develop, recover and manage the geothermal resources" with the owner of the mineral title.[243]

The decision to vest geothermal rights with the mineral rights holder is a major point of contention with industry stakeholders. Development of a geothermal project for heat or power generation requires a significant capital investment. Acquisition of mineral rights in addition to the various required capital expenditures may render otherwise commercially viable projects uneconomic.

Geothermal project proponents will have to acquire a licence from the AER to commence or continue to drill any well or to construct or operate any geothermal well or facility.[244] Where the Crown holds all of the mineral rights associated with a given project, this will be done through agreement with the Minister or possibly through a tenure regime should one be established in the future. It is expected that acquiring a geothermal licence on land in which the Crown holds the mineral rights will be simpler than when mineral rights are freehold rights held by individuals or where some of the Crown's mineral rights have been leased for the purposes of oil and gas production.

The acquisition of a licence may be more difficult in the case of freehold land where ownership of mineral rights has been split by product. Because the revised *MMA* vests the right to explore for, develop, recover, and manage geothermal resources with the owner of mineral title, geothermal project proponents may need to negotiate separately with the mineral rights holder for each product, petroleum and natural gas, coal, and so on. If ownership rights have been subdivided, this may drastically increase the cost and effort required to obtain the necessary geothermal rights for development with each holder of such rights having the ability to effectively veto the project. This has the potential to be a significant sticking point for future projects and this is expected to be addressed in some manner in the AER's forthcoming rules on geothermal development.

As stated previously, any additional costs to a geothermal project proponent at the outset of the project may be prohibitive. If the Government of Alberta wishes to support geothermal development in the province, the cost of acquiring a licence should be carefully considered.

Vesting geothermal rights with the mineral rights holder, which in Alberta is the Crown in most cases, also empowers the Crown to charge royalties on production of geothermal heat directly or on power generated from geothermal heat. The Government of Alberta has not released any detail on whether it intends to charge a royalty on geothermal projects and, if this is intended, what possible form that royalty may take.

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241 *GRDA*, *supra* note 236, ss 1(1)(g), 4.
242 *Ibid*, s 31(1)
243 *Ibid*, s 31(b).
244 *Ibid*, s 7.

c. Saskatchewan

Saskatchewan does not have a specific legislative framework in place for geothermal projects. Geothermal project proponents in Saskatchewan must navigate existing regulatory systems to receive project rights and approvals. The recent success of the DEEP Corp. in receiving permitting for and drilling Canada's first geothermal production and injection test well demonstrates that Saskatchewan's system can support geothermal development, but it must be approached on a one-off basis.[245]

Although there is no legislation dealing specifically with geothermal projects in Saskatchewan, geothermal project applications have been processed through the Integrated Resources Information System (IRIS).[246] IRIS is "an online business system that supports the development and regulation of Saskatchewan's energy and resources industry."[247] IRIS processes geothermal projects as "storage operations," defining a geothermal project as "a development where geothermal energy is recovered through deep well(s). There are two main types of geothermal project; open-loop and closed-loop."[248]

As Saskatchewan has no dedicated legislative or regulatory framework for geothermal, there is no statutory definition of geothermal resources and no definitive statement on the ownership of geothermal resources in the province.

3. ROYALTIES ON GEOTHERMAL POWER PROJECTS

Geothermal project developers traditionally resist royalties of all kinds levied on their projects. Depending on the level of royalty charges contemplated, and how those royalties may be structured, the imposition of royalties on geothermal projects may have a chilling effect on development. Industry stakeholders have advocated for a royalty holiday, whereby royalties are not collected by the Crown until the project has achieved payback on its initial capital investment.[249]

Two of the world's leading geothermal nations, New Zealand and Iceland, do not charge royalties for the use of geothermal resources. In New Zealand, the *Resource Management Act 1991 (NZ)*,[250] which governs geothermal power production, reserves the right for regional authorities to collect royalties on geothermal power generation. These clauses have "never

245 Deep Corp, "Our Latest News," online: <deepcorp.ca/publications/>.

246 Brenda Heelan Powell, "Gaining Steam: A Regulatory and Policy Framework for Geothermal Energy Development in Alberta: Module 4: The Regulation of Geothermal Energy in Other Jurisdictions" (October 2020) at 8, online: <elc.ab.ca/wp-content/uploads/2020/10/Geothermal-Energy-Module-4-Regulation-of-Geothermal-Energy-in-Other-Jurisdictions.pdf>.

247 Government of Saskatchewan, "Integrated Resource Information System (IRIS)," online: <www.saskatchewan.ca/business/agriculture-natural-resources-and-industry/oil-and-gas/oil-and-gas-licensing-operations-and-requirements/integrated-resource-information-system-iris>.

248 Government of Saskatchewan, "Storage Project Application," online: <www.saskatchewan.ca/business/agriculture-natural-resources-and-industry/oil-and-gas/oil-and-gas-licensing-operations-and-requirements/oil-and-gas-drilling-and-operations/gas-storage-and-cavern-storage-disposal>.

249 Letter from Canadian Geothermal Energy Association to Warren Walsh (Electricity and Alternative Energy Division BC Ministry of Energy and Mines), "Re: Support and Comments on the Proposed Geothermal Royalty Policy" (16 July 2018), online: <www.cangea.ca/uploads/3/0/9/7/30973335/rr_-_final_signed6790[6800].pdf>.

250 1991/69.

been used and implementation would be expected to be contentious."[251] Likewise, in Iceland, "there is no official tariff for land or resources owned by the state."[252]

The theoretical or moral right of the Crown to collect royalties on production of geothermal heat is also worthy of discussion. Production of petroleum products deprives future generations of the ability to produce and use those products, as those products are not renewable. As such, the Crown has an argument that it may impose a charge on those producing petroleum products on behalf of the present and future citizens of the province. That same argument cannot be used to support the charging of royalties on geothermal heat. As geothermal heat is a renewable resource which can be sustained for thousands of years with proper management, future generations are not prejudiced by its present use. In fact, future generations actually *benefit* from the establishment of geothermal power generation facilities. These facilities will not only reduce carbon emissions but also have a very long productive life. An investment in a geothermal energy or heat generation facility today will likely continue to pay dividends for many decades in the future. As with wind and solar electricity generation, a geothermal power project is not taking anything but rather using a renewable resource productively that might otherwise go to waste.

If a provincial government did want to charge royalties on the use of geothermal resources, perhaps a more justifiable method would be to measure the impact that a geothermal well will have on the heat reservoir below the surface. If geothermal heat is removed in a sustainable way, allowing the resource to regenerate, no royalties would be charged. However, if a project depletes geothermal resources faster than they can be replenished, a royalty may be levied on the amount by which the reservoir is depleted beyond the rate at which it can replenish itself. This would motivate geothermal project developers to be good stewards of the resource while not hampering capital intensive projects with unnecessary start-up costs. Such conservation of geothermal resources is built into the legislation of leading geothermal nations such as New Zealand with a mandate that the present use of the resource must preserve the resource for future generations.[253]

Simpler yet, royalties could be charged based on a rental principle. Royalties could be charged at a flat rate and derived from use of the land at the surface. This rental-based royalty may be assessed in a similar manner to royalties charged across the Canadian provinces for hydroelectric power plants. While some provinces charge royalties based on the annual power output of a hydroelectric facility, British Columbia also charges a flat fee for occupied land, both dammed and flooded.[254] Though royalties based on power production are likely not suitable in the geothermal context, moderate charges based on land use may be a justifiable way to garner revenues from geothermal projects.

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251 Bart van Campen & Harpa Petursdottir, "Geothermal Sustainability Regulation in Iceland and New Zealand" (September 2016) at 2, online (pdf): <www.researchgate.net/publication/304019622_Geothermal_Sustainability_Regulation_in_Iceland_and_New_Zealand>.

252 *Ibid* at 6.

253 *Ibid* at 3.

254 Pierre-Olivier Pineau, Lucile Tranchecoste & Yenny Vega-Cárdenas, "Hydropower Royalties: A Comparative Analysis of Major Producing Countries (China, Brazil, Canada and the United States)" (2017) 9:4 Water Economics & Policy 287 at 9, online: <www.mdpi.com/2073-4441/9/4/287/pdf>.

Finally, is there a possibility that a royalty may be taken in kind? The answer to this question will depend on the use of the geothermal resource. If the resource is being used to generate electricity, it is reasonable to suppose that a portion of that electricity could be directed to the Crown or to a freehold owner in the form of a royalty. However, if the geothermal well is being used for direct heating, this becomes more difficult. Heat is nearly impossible to transport efficiently over large distances, so the royalty owner, be it the Crown or a freehold owner, would need to have a delivery point in close proximity to the well for the "heat royalty" to be viable. It is unlikely that this would be the case except in rare circumstances.

C. BIO AND CLEAN FUELS

The pursuit of reduced carbon intensity of liquid fuels is a goal in which technology and policy converge. For nearly as long as combustion engines have existed, users have been aware that fuel derived from non-hydrocarbon fuel sources, known as "biodiesel" or "biofuels," could power machines.[255] It was not until the early 2000s that biofuels gained attention for emitting fewer GHGs than conventional fuels.[256] The production of biodiesel as an alternative to hydrocarbon-based products is the foundation of "clean fuel": a foundational term in the language of climate change prevention.

The description of biodiesels as clean fuels implies fossil fuels are "dirty," but perhaps "cleaner" would be a more accurate description. There are different ways to evaluate the carbon footprint of energy sources — with or without regard to other societal impacts — and the designation only implies an effort to reduce emissions as compared to traditional fuels.

As is common for new technologies, the development of clean fuels has evolved in distinct "generations." The first generation of biofuels derived ethanol fuel "from sugar and starch-based crops such as corn, wheat, and sugarcane," and biodiesel "from oil-based crops such as canola and soybeans."[257] A critical downside of the production of biofuels in this manner is that the plants used as feedstock for first generation biofuels were also food sources. Food resources being used for fuel feedstock raised concerns about food pricing and security making first generation biofuels a problematic solution to climate change.[258]

The second generation of biofuels, also referred to as advanced biofuels, are intended to address the food pricing and scarcity concerns associated with first-generation biofuels. The second generation of biofuels use non-food biomasses to produce fuel. Ethanol can be produced from crop residues, woody biomass, and municipal waste.[259] Innovation in both feedstock and technology are improving the integration of second-generation biofuels into commercial and consumer fuel supplies. The majority of policies discussed in this article relate to second-generation biofuels.

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255 eXtension Farm Energy, "History of Biodiesel" (3 April 2019), online: <farm-energy.extension.org/history-of-biodiesel/>.

256 *Ibid*.

257 Canadian Energy and Emissions Data Centre, "Biofuels and Solid Biomass Data," online: <www.sfu.ca/ceedc/databases/Biofuels.html>.

258 Many thanks to Alanna Wiercinski for her assistance with research on the history of clean fuels in Canada.

259 eXtension Farm Energy, "History of Biodiesel," *supra* note 255.

1. REGULATING CLEAN FUELS

Unlike geothermal and hydrogen power, which are newer entrants to the energy market, efforts to change the sources of liquid fuels are already underway through the biofuel blending and ethanol requirements that exist at the provincial level. Moreover, innovation around second-generation biofuels is not contingent on the development of a new regulatory framework in the same way that applies to the geothermal and hydrogen strategies discussed in this article.

The compliance framework that applies to participants in the clean fuels market depends on (1) jurisdiction and (2) the stage of fuel production they contribute to. Provincial clean fuels requirements will apply in addition to any applicable rules around fuel refining or biofuel feedstocks. For example, downstream fuel production in Alberta is subject to regulation under the *Responsible Energy Development Act*,[260] the *OGCA*, the AER's Directives that apply to refining facilities, the *Emissions Management and Climate Resilience Act*,[261] and the *Renewable Fuels Standard Regulation*.[262] The *Renewable Fuels Standard Regulation* provides the technical requirements for clean fuels, as well as a process by which a designated validator issues a validation that affirms refiners' compliance with the *Renewable Fuels Greenhouse Gas Emissions Eligibility Standard*.[263] In this way, clean fuels legislation is "layered" over the existing industrial fuel production regulations to help further lower the carbon intensity of the industry.

The same principle applies for suppliers of biofuel feedstock. The disposal of municipal and industrial organic waste is monitored by industry-specific regulations in each jurisdiction. The conversion of waste products into biofuels is regulated by the statutes and regulations applicable to the facilities needed to process the waste with verification and quality control effected through provincial environmental management and clean fuels regulations. In Alberta, regulations under the *EPEA* govern the handling of organic waste.[264] In British Columbia, regulations under the *Environmental Management Act* set the rules for managing organic waste and producing cleaner fuel.[265] And, in Saskatchewan, *The Environmental Management and Protection Act, 2010* and its regulations manage secondary uses for waste.[266]

To the extent that the market for clean fuels is stimulated by the implementation of the Clean Fuel Standard, the regulatory framework for reducing the carbon impact of Canada's fuel supply may have to adapt and expand if regulatory barriers arise. Action by provinces and territories will complement the federal Clean Fuel Standard. The success of this action will depend on the interplay between existing provincial regimes and the federal Clean Fuel Standard, on Canada's ability to commercialize biofuel production, and on Canadian

260 SA 2012 c R-17.3
261 *Supra* note 44.
262 *Supra* note 95.
263 *Ibid*, ss 2(1)(i), 4(1).
264 *Supra* note 189.
265 SBC 2003 c 53. See particularly the *Cleaner Gasoline Regulation*, BC Reg 498/95; *Organic Matter Recycling Regulation*, BC Reg 18/2002; *Code of Practice for Agricultural Environmental Management*, BC Reg 8/2019; *Code of Practice for Industrial Non-Hazardous Waste Landfills Incidental to the Wood Processing Industry*, BC Reg 263/2010.
266 SS 2010, c E-10.22.

enterprises and people's ability to adopt less carbon-intensive alternatives to their current fuel sources.

2. COMMERCIALIZATION: CHALLENGE OR OPPORTUNITY?

The Clean Fuel Standard may present a significant opportunity for growth in Canada's biofuels industry — up to $4.9 billion in new economic activity is expected in this sector by 2030. This includes up to $1.4 billion in "new investment a year out to 2030, largely to build and expand ethanol, biodiesel, renewable diesel and renewable natural gas facilities."[267] However, the realization of these prospects for growth depend, among myriad of other factors, on fuel producers opting for those compliance options that support innovation over purchasing compliance credits.

As of 2019, Canada did not produce enough biofuels to meet the provincial blending requirements and imported 1.4 billion litres.[268] With abundant corn, wheat, canola and other organic feedstock supplies on the prairies, the barrier to producing more biofuels domestically may be at the production stage. To the extent that the Clean Fuel Standard imposes greater blending requirements and fuel suppliers demand more biodiesel, there is an opportunity for Canadian enterprises to take on the relatively simple production of biofuels. Ultimately, increased domestic biofuel production will depend on demand and pricing, as well as the availability of a skilled workforce.

Provincial clean fuels regulations have fostered innovation and created opportunities for enterprises to produce fuels that meet the existing standards. In particular, enterprises that can successfully develop waste-to-energy solutions will see the demand for their solutions and services increase. For example, Enerkem Inc., a Quebec-based company has, established a full-scale commercial waste-to-biofuels plant near Edmonton where waste destined for landfills is converted into ethanol.[269] The plant has annual capacity to convert 115,000 tonnes of waste to 38 million litres of bioethanol when blended with gasoline at 5 percent to meet the provincial requirements can fuel 400,000 cars per year.[270] Industrial waste is also proving to be a potential feedstock for ethanol. For example, LanzaTech Inc. has developed a process to produce ethanol from the off-gas of forestry-residue pyrolysis in Alberta with extended benefits for converting other resources such as industrial waste gases and agricultural residues using a gas fermentation platform.[271]

However, one immediate and personal cost of the introduction of the Clean Fuel Standard is the anticipated increase in the cost of fuel. The Canadian Energy Research Institute estimates that, as a result of the Clean Fuel Standard, the cost of a litre of gasoline may

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267 Clean Energy Canada "What a Clean Fuel Standard Can Do for Canada: A Road to Cleaner Fuels, More Jobs and Less Carbon Pollution" (November 2017) at 7, online: <cleanenergycanada.org/wp-content/uploads/2018/03/CleanFuelStandardReport-FINAL.pdf>.

268 USDA Foreign Agricultural Service, *Canada: Biofuels Annual*, by Harvey Bradford (17 July 2019), online: *USDA Foreign Agricultural Service* <apps.fas.usda.gov/newgainapi/api/report/downloadreportbyfilename?filename=Biofuels%20Annual_Ottawa_Canada_8-9-2019.pdf>.

269 Government of Alberta, "Bioenergy Programs," online: <www.alberta.ca/bioenergy-programs.aspx#stories> (see under heading of Bioenergy Success Stories: Enerkem).

270 *Ibid*.

271 Emissions Reduction Alberta, "ERA's Best Challenge Projects" (12 March 2019), online: <eralberta.ca/archive-stories/eras-best-challenge/>.

increase by up to 11 cents over the next decade.[272] The knock-on effects of any price increase will be felt universally. Directly, Canadians will see rising gasoline prices at the pump and indirectly on every good and service that relies on liquid fuels for production, transportation, or delivery. Industries that rely heavily on liquid fuels for operations such as shipping, aviation, and forestry will likely be forced to pass on these higher fuel costs, or the costs of technology and fuel switching, in their products and services. Absent off-setting government fiscal policies, it will be low-income Canadians who are impacted the hardest by any associated rising cost of living and not those who can afford higher fuel prices or take advantage of policies that encourage buying new electric or hybrid vehicles.

IV. CONCLUDING COMMENTS

If the commercialization framework briefly outlined in this article is any indication, multilateral efforts to move toward a lower-carbon economy are well underway.[273] While there will be costs associated with any "transition," the changes that are required should not be viewed solely as compliance obligations. Instead, these obligations should be viewed as mechanisms to open pathways to new commercial opportunities that Canada is well-positioned to exploit.

Whether Canadians reduce our emissions by (1) incorporating geothermal energy into our electrical grids, (2) replacing natural gas with hydrogen, or (3) reducing the emissions associated with liquid fuels by either reducing their emissions intensity with cleaner burning feedstock or replacing gasoline-powered vehicles with electric and hydrogen fuel cell vehicles, there are a number of opportunities for Canada's energy industry to be involved. Hurdles certainly exist, and it would be a mistake to believe that overcoming them will be easy, but federal and policy imperatives can both reveal Canada's lower-carbon destination and clear the path of obstacles.

This article has discussed three "new energy" industries that can help Canada achieve its ambitious emissions-reduction targets and has also assessed some of the challenges these industries will face. The discussion was not exhaustive, and there are other pieces to the commercialization and regulatory frameworks not directly addressed that will prove important. However, it seems reasonably clear that, while much of the necessary framework is or will soon be in place, Canadian legislative bodies have some work to do to better facilitate the development of these industries. Regarding the regulatory framework in particular, at least in the case of hydrogen and geothermal, it is adequate if not optimized. Canadian legislatures should work together to establish harmonized regulatory schemes that will both ease the growing pains of new business ventures and limit future conflict and uncertainty. The opportunities are there and the capital appears to be willing. Each of these new energy technologies could have a role to play in any transition pathway that Canada follows and it is encouraging to see that Canadian governments are beginning to take the steps required to support and facilitate their expanded role in Canada's future energy economy.

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272 Hossein Hosseini, Andrei Romaniuk & Dinara Millington, "Economic and Emissions Impacts of Fuel Decarbonization" (May 2019) at 74, online: *Canadian Energy Research Institute* <ceri.ca/assets/files/Study_179_Full_Report.pdf>.

273 These multilateral efforts encompass domestic and foreign efforts as well as private and public.

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