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MISSION STATEMENT

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

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

EDITORIAL POLICY

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

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

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

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

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

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

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Managing Editors

Rowland J. Harrison Q.C. and Gordon E. Kaiser

From time-to-time the Editors of *Energy Regulation Quarterly* invite law firms and others to address certain topics of particular importance to energy regulators.[1] Two articles on hydrogen in this Issue of *ERQ* continue the series. They concern an important new technology that will undoubtedly have a major impact on energy regulators and the companies they regulate.

In the past year, most countries have significantly increased their commitments to carbon reductions and the amount of funding they are prepared to invest in reaching that goal. As a result, there is a mad rush to develop new technologies that will lead the decarbonization process.

At the top of the list is hydrogen. Most countries now have a hydrogen program. In Canada, there is a federal hydrogen program as well as existing or proposed programs in most provinces. We invited the Gowlings law firm to review these initiatives and explain where they currently stand and how they are likely to unfold. Its review is found in the lead article in this Issue of *ERQ* under the title "Is Hydrogen the Silver Bullet?" We also invited the Stikeman Elliott law firm to address the unique hydrogen program that British Columbia recently announced. Finally, in something of a departure, we also asked a leading developer of this technology, Siemens, to provide commentary on where it thought the technology was going and what the regulatory barriers to entry might be. Siemens' report is included in the first of these two articles.

The expanding role of hydrogen is of course a means of pursuing the overarching goal of reducing greenhouse gas emissions. In parallel with the adoption of emerging technologies, various policy, legislative and regulatory initiatives continue to pursue that goal with measures aimed directly at reducing the use of carbon. In "Carbon Tariffs – The Next Challenge in Canadian Climate Law and Policy?", Dr. A. Neil Campbell *et al*. examine one such initiative, namely Carbon Tariffs or Border Carbon Adjustments (BCAs), which "adjust the import prices of carbon-intensive goods to match the cost of locally produced goods impacted by carbon pricing regimes." Canada announced in the 2021 Budget that it plans to develop BCAs as an element of its Climate Plan.

Meanwhile, expanding the role of Québec's "green" hydro-electricity in the North American energy supply mix continues to face significant obstacles in the form of "forceful and effective opposition abroad" to proposed new export transmission lines. In "Hydro-Québec and Its U.S. Transmission Projects," Erik Richer La Flèche examines the history of Québec's five largest export projects of the last three decades and discuss how such projects may be configured in the future to increase their chances of success. Interestingly, the author notes that the arguments against Québec's exports "often overlap with those used against pipelines and, to the surprise of much of Québec's political class, the 'green' credentials of Québec's hydropower are insufficient to ensure the success of export projects."

In "The Cause of the Ontario Electricity Price Increases," Benjamin Dachis and Joel Balyk suggest that the crux of the problem of rising system costs in Ontario's electricity sector for more than a decade is "increases in the cost of supply from high-cost contracts spread over

[1] See: Paul Kraske et al, "Electricity Storage in North America" (2019) 7:1 Energy Regulation Q 55; KPMG, "Capitalizing the Cloud: The Regulatory Challenges" (2020) 8:1 Energy Regulation Q; Ron Clark, "The Ontario Generation Contract Review Report" (2020) 8:4 Energy Regulation Q 54.

less electricity consumption than forecast when the contracts were struck." They suggest that Ontario should replace the current industrial electricity pricing system for large customers with "a market-based 'interruptible rate' that rewards them for agreeing to interruptions of supply during extreme peak demand hours." They conclude that the government should end its "hands-on approach" to system planning and procurement and, instead, provide high-level policy direction that empowers the Ontario Energy Board to regulate and that ensures the independence of the Independent Electricity System Operator (IESO) "to avoid repeating past mistakes."

In November 2020, the report of a judicial inquiry into the 2012 sale by the Town of Collingwood of 50 per cent of its interest in Collus Power Corporation, the local electricity distribution company, was released. The inquiry was called to investigate allegations of conflicts of interest, unfair advantages alleged to have been given to the purchaser and alleged malfeasance by certain parties. In "The Collingwood Judicial Inquiry: Lessons for Ontario's Electric Utilities," Ron Clark discusses the relevance of the inquiry's recommendations to LDCs and the insights to be drawn from its report.

Jurisprudence on Indigenous rights continues to evolve, most recently in a significant decision of the British Columbia Supreme Court ruling that the rights of First Nations under Treaty 8 in the northeast of B.C. had been infringed by the cumulative impacts of industrial developments within the Nations' traditional territory. The decision is analyzed by Sander Duncanson *et al*. in "British Columbia Supreme Court Significantly Expands Indigenous Rights."

This Issue of *ERQ* concludes with a book review by Adam Chisholm of the latest edition of the indispensable *The Guide to Energy Arbitrations*. ■

IS HYDROGEN THE SILVER BULLET?

*Jay Lalach, Adriana Da Silva Bellini, Jimmy Burg, Emma Hobbs and Gabrielle Matheson**

Comments by: Chris Norris

INTRODUCTION

Hydrogen is the most abundant chemical element in the universe. It can serve as a low or no-emission fuel alternative and has a number of other applications in energy storage, transportation, power production, and heating. When blended with fossil fuels, hydrogen plays an important role in decreasing their carbon emissions. In short, this element makes a compelling case as a self-contained solution to the clean energy transition.

Across the globe, countries are committing to achieve carbon neutrality with some aiming to reach this milestone as soon as 2050. As a result, the focus is shifting to hydrogen as the key to the diversification of the planet's energy sources and a resulting cleaner and greener economy. However, hydrogen does not exist in a natural state that may be incorporated into commercial applications, and must be converted from other raw materials like water or natural gas. Further, the conversion process is expensive and energy intensive.

So, *is* hydrogen the silver bullet? While political and societal will is increasing, can technology keep up with the pace? This article provides an overview of hydrogen's role in the clean energy transition beginning with a general introduction to hydrogen production, usage, transportation and storage, followed by a look at government commitments to date in Canada and around the globe and potential regulatory challenges, and concluding with the perspective of an industry player.

THE TECHNOLOGY

Hydrogen Basics

Recent interest in hydrogen revolves around its ability to act as a fuel or energy carrier, and therefore serve as an alternative to fossil fuels. Hydrogen carries roughly three times more energy per mass than gasoline, produces only water when consumed, and has a lower lifecycle carbon intensity than fossil fuels.[1] On this basis, hydrogen represents an excellent fuel alternative in a range of applications including transportation, power production and heating, including both process heating (industrial) and space heating (residential and commercial). The primary drawback is that hydrogen is currently more expensive to produce than fossil fuels. While hydrogen may be derived from several feed stocks (e.g., natural gas, agricultural waste, forest products, water) and chemical processes, the price differential between hydrogen and fossil fuels largely depends on the method of hydrogen production.

Today, most hydrogen production across the globe is derived from natural gas. This "grey" hydrogen is produced through the steam reforming of methane or natural gas, generating carbon emissions when measured over the

* Jay Lalach is a partner at Gowling WLG. Adriana Da Silva Bellini, Jimmy Burg, and Emma Hobbs are associates and Gabrielle Matheson is a law student at the firm.

[1] US Department of Energy, "Increase your H2IQ!" (September 2019) at Presenter's Notes 5, online (pdf): *Office of Energy Efficiency and Renewable Energy* <www.energy.gov/sites/prod/files/2019/09/f67/fcto-increase-your-h2iq-training-resource-2019-update.pdf>. The lifecycle approach measures the total carbon emissions over time, from the extraction of the product until its ultimate consumption.

lifecycle of the product from extraction to consumption. However, as hydrogen has no emissions at the point of consumption, the lifecycle carbon intensity of grey hydrogen is lower than traditional fossil fuels.

When paired with carbon capture and storage technology, grey hydrogen is characterized as "blue" hydrogen. It has even lower lifecycle carbon emissions than grey hydrogen, but at a greater production cost given the added requirement of carbon capture.

Hydrogen can also be produced by splitting water molecules into hydrogen and oxygen with electric currents through the process of electrolysis. When the electricity used to power the electrolyzers comes from a non-emitting source (i.e., hydroelectric, nuclear, solar, wind), the entire process is emission-free. This hydrogen is called "green" hydrogen and is the most expensive to produce.

Currently, the largest use for hydrogen, both in Canada and globally, is as feedstock in emission-intensive industrial sectors. The most common uses of hydrogen today are in oil refining, and the production of ammonia, methanol and steel.[2]

Transportation and Storage of Hydrogen

Due to its lower volumetric density, transport and storage of hydrogen can be challenging and costly, impacting its competitiveness when compared to other fuels. More specifically, the volume of hydrogen needed to supply the same amount of energy as natural gas is threefold, increasing the costs and infrastructure required for transmission and storage of hydrogen across the network. This is particularly challenging for long distance transportation of hydrogen, as the primary means of transporting hydrogen in Canada, both gaseous and liquid, is by tanker truck.[3]

Because of this, hydrogen is primarily utilized at the site of production. However, a number of different options exist to increase the storability and transportability of hydrogen, such as compression, liquefaction or chemical process involving the incorporation of hydrogen into larger molecules (chemical carriers) that are more readily transported and stored as liquids in natural gas transmission and distribution pipelines.[4]

While a number of dedicated hydrogen pipelines are already in operation, the existing gas network has a significant inherent storage capacity.[5] By carrying a blend of hydrogen and natural gas, Canada's existing natural gas transmission and distribution pipelines can be repurposed to expedite the growth of hydrogen use in Canada. This blend can also be directly used in a number of end-use applications instead of natural gas, as discussed below.

Other storage options include fuel cells, which are expected to play a significant role in a variety of applications including transportation, fuel for power generation, heat, and feedstock for industry. Geological means of storage also exist, as hydrogen in its gaseous form can be stored underground in salt caverns, depleted natural gas or oil reservoirs and saline aquifers.[6]

Hydrogen Blending

As a fuel source, hydrogen and natural gas have a number of similarities, particularly with regard to their safety considerations, transportability and versatility. With increasing interest in hydrogen as a fuel source, blending hydrogen with natural gas or even with propane, provides an opportunity to increase hydrogen demand while lowering carbon emissions and optimizing the use of existing fuel delivery infrastructure as the hydrogen market develops. This blended fuel can be used in many applications in place of pure natural gas. Currently, blend ratios of up to 20 per cent hydrogen are being tested

[2] Government of Canada, "Hydrogen Strategy for Canada: Seizing the Opportunities for Hydrogen" (December 2020) at 64, online (pdf): *Natural Resources Canada* <www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/environment/hydrogen/NRCan_Hydrogen-Strategy-Canada-na-en-v3.pdf> [Hydrogen Strategy for Canada].

[3] *Ibid* at 40.

[4] International Energy Agency, "The Future of Hydrogen: Seizing today's opportunities" (June 2019) at 70, online (pdf): <iea.blob.core.windows.net/assets/9e3a3493-b9a6-4b7d-b499-7ca48e357561/The_Future_of_Hydrogen.pdf> [IEA Hydrogen]; Hydrogen Strategy for Canada, *supra* note 2 at 40.

[5] *Ibid* at 152; Hydrogen Strategy for Canada, *supra* note 2 at 41.

[6] *Ibid* at 69; Hydrogen Strategy for Canada, *supra* note 2 at 39.

with limited impact on delivery infrastructure and end-use appliances.[7]

Blending relatively small amounts of hydrogen into the existing natural gas pipeline networks would at most require minor changes to fuel delivery infrastructure and end-user appliances while providing a boost to hydrogen supply technologies. This has the advantage of minimizing the high upfront capital costs and associated risks related to the development of dedicated hydrogen transmission and distribution infrastructure.[8]

While hydrogen blending will be an important contributor to the development of the hydrogen economy, a number of challenges remain, namely with regard to pipeline compatibility, tolerance of end-use equipment, as well as considerations related to the density and volume variability of hydrogen. As noted above, at room temperature, hydrogen has roughly one-third the volumetric energy density of natural gas, which in turn reduces the energy content of blended gas. As hydrogen blending increases, the average calorific content of the blended gas falls, and thus an increased volume of blended gas must be consumed to meet the same energy needs. This is but one factor that must be taken into account for transportation, in light of pipeline capacity, as well as for end-use applications.

Further, depending on the composition and operating conditions of a given pipeline, exposure to hydrogen can lead to embrittlement and degradation over time. Newer steel and polyethylene used in natural gas distribution systems are not typically subject to embrittlement concerns, however, the steel used in older distribution infrastructure and natural gas transmission pipelines may be susceptible to such issues when exposed to higher concentrations of hydrogen and higher pressures over an extended period of time.[9]

Hydrogen blend ratios intended for distribution can only be as high as the capacity and tolerance of the end-use equipment connected to the grid. As such, the tolerance of the overall grid is limited by the end-use component with the lowest tolerance. This may be particularly challenging for finely tuned industrial processes that utilize natural gas as a feedstock. Evaluation of more conventional (residential and commercial) end-use appliances is ongoing.

Electricity Generation and Storage

Hydrogen has a number of uses in the electricity industry. While it can be used directly (and/or as a blend) in combustion turbines, its use in stationary fuel cell power plants has been rapidly increasing.[10] Fuel cells convert hydrogen into electricity and heat, producing water and no direct emissions.

Another role for hydrogen in the power sector is through the provision of load management capabilities. Hydrogen can be employed as a back-up power and storage option to support variable renewable energy, providing for additional flexibility, stability, and a means to address seasonal variations and intermittency in both the demand and generation capabilities of renewable electricity.[11]

Excess electricity generated from wind and solar during off-peak hours can be used to produce hydrogen via electrolysis (such facilities are referred to as 'power-to-gas' or P2G), which in turn can be stored and used to produce electricity at a later time, either through combustion turbines or stationary fuel cells.

Pursuant to an energy storage contract with Ontario's Independent Electricity System Operator, the first P2G facility in Canada was established to provide regulation services to balance and manage real-time electricity supply and demand, and ensure reliable operation of Ontario's electricity grid by converting surplus renewable electricity into hydrogen. The hydrogen is stored for conversion back into electricity through hydrogen fuel cells when needed by the grid. Recently, Enbridge Gas and Cummins announced a new project that will blend this renewable hydrogen into a segregated

[7] Hydrogen Strategy for Canada, *supra* note 2 at 41.

[8] IEA Hydrogen, *supra* note 4 at 182–83.

[9] Hydrogen Strategy for Canada, *supra* note 2 at 60.

[10] *Ibid* at 57.

[11] *Ibid*; IEA Hydrogen, *supra* note 4 at 150.

loop of the existing Enbridge Gas natural gas distribution network.[12]

The efficiency of such conversion and storage methods remains a challenge, as a significant amount of the original electricity is lost in the process, especially when compared to the storage cycle losses of lithium-ion batteries, for example.[13] That said, hydrogen can contribute to improving "the economics of variable renewables by providing large-scale energy storage that optimizes the utilization of these power generation assets."[14]

Beyond supporting variable renewable electricity, fuel cells can also facilitate access to reliable electricity in remote locations. Currently, off-grid and back-up power generation remains largely fueled by diesel, which can be costly to transport to remote and Indigenous communities. Hydrogen can be integrated into renewable energy systems and produced locally through electrolysis. It can also be stored through fuel cells to provide back-up power, supply a microgrid system, and be distributed with cogeneration of heat and power. Fuel cells offer an interesting alternative that would not only reduce reliance on imported diesel and other fossil fuels, but also provides a much cleaner and healthier alternative by reducing emissions and improving local air quality.[15] Another important consideration in the context of vehicles used in remote areas is that fuel cells perform better than batteries in colder temperatures.[16]

Transportation Industry

As noted throughout, hydrogen fuel cells have a number of applications and are expected to play a significant role in a variety of industries including power generation, heat, feedstock for industry, and in particular, transportation. New markets are emerging for transportation powered by hydrogen fuel cells, including passenger vehicles, freight trucks, coach buses, city transit systems, trains, marine vessels, and even aircrafts.[17]

As with battery electric vehicles, fuel cell electric vehicles (or FCEVs) produce zero tailpipe or exhaust emissions and could improve local air quality and reduce pollution.[18] However, passenger vehicle emissions comprise only a small portion of the emissions from the transportation sector, with most coming from the other modes of transportation mentioned above. Hydrogen fuel cells have the potential to power all of these vehicles. However, the large vehicle fuel cell industry is still in the nascent stages due to low adoption rates, lack of widespread hydrogen refueling infrastructure and high costs when compared to fossil fuel and battery electric vehicles.

Light-duty passenger FCEVs and transit buses are commercially available in certain countries,[19] and a number of major automakers have fuel cell vehicles either on the market or in development.[20] While battery electric vehicles are currently expected to comprise the lion's share of the Canadian market for light-duty vehicles[21], FCEVs perform better in long-haul, heavy-duty commercial trucking

[12] See Cummins Inc., "In its Second Year, North America's First Multi-Megawatt Power-to-Gas Facility Shows Hydrogen's Potential" (12 November 2020), online: <www.cummins.com/news/2020/11/12/its-second-year-north-americas-first-multi-megawatt-power-gas-facility-shows>; see also Enbridge Gas Inc., "Groundbreaking $5.2m Hydrogen Blending Project Aims to green Ontario's Natural Gas Grid" (18 November 2020), online: <www.enbridge.com/stories/2020/november/enbridge-gas-and-hydrogenics-groundbreaking-hydrogen-blending-project-ontario>.

[13] "Hydrogen-based storage options suffer from low round-trip efficiency: in the process of converting electricity through electrolysis into hydrogen and then hydrogen back into electricity, around 60% of the original electricity is lost, whereas for a lithium-ion battery the losses of a storage cycle are around 15%." (IEA Hydrogen, *supra* note 4 at 158)

[14] Hydrogen Strategy for Canada, *supra* note 2 at 23.

[15] *Ibid* at 58; IEA Hydrogen, *supra* note 4 at 154.

[16] *Ibid* at 45.

[17] See Ballard, "The Future of Clean Transit is Electric" (last visited 18 August 2021), online: <www.ballard.com/markets/transit-bus>.

[18] IEA Hydrogen, *supra* note 4 at 124.

[19] Hydrogen Strategy for Canada, *supra* note 2 at 45.

[20] Such as Hyundai, Toyota, Honda, GM, Mercedes, Ford, Nissan, and Volkswagen.

[21] Hydrogen Strategy for Canada, *supra* note 2 at 46.

and transportation applications, and have the benefit of providing extended range, faster refueling, and more reliable performance in colder climates.[22] That said, FCEVs' competitiveness will largely depend on the costs of fuel cell technologies and the availability of refuelling stations.[23]

As governments explore the use of hydrogen to assist in meeting their emissions reduction targets, they are rolling out a number of direct and indirect legislative and policy measures. In the next section, we discuss measures in Canada, the United States, Europe, the United Kingdom, as well as several international partnerships, all of which will aid in the energy transition.

GOVERNMENT COMMITMENTS

Canada

Federal

In 2016, the same year Canada ratified the Paris Agreement, the Canadian federal government released a national climate plan designed to help Canada reach its 2030 goal of reducing greenhouse gas emissions by 30 per cent below 2005 levels.[24] Four years later, in December 2020, the Government of Canada followed up with an updated and strengthened climate plan: *A Healthy Environment and a Healthy Economy* (the "**Climate Plan**"). The Climate Plan includes 64 federal policies and programs that target the transition to clean energy and aim to put the country on track to exceed its 2030 Paris Agreement emission reduction goals. The Climate Plan not only supports a new federal target of net-zero emissions by 2050, but also aligns with the accelerated interim targets set out by the *Canadian Net-Zero Emissions Accountability Act*, legislation that, once passed, will make these targets legally binding.

On December 16, 2020, the Government of Canada released its Hydrogen Strategy for Canada (the "**Canada Strategy**").[25] The Canada Strategy positions hydrogen as a crucial component to meeting Canada's 2050 net-zero targets, projecting that hydrogen could account for 30 per cent of Canada's end-use energy by 2050. The Canada Strategy sets out short, medium, and long-term timelines. Canada's short-term focus, from present to 2025, will be on creating a foundation for hydrogen production and use in Canada by developing new hydrogen supply and distribution infrastructure. The mid-term focus (from 2025 to 2030) will be on growth and diversification of the hydrogen sector, specifically deploying and connecting regional hydrogen hubs. Canada's long-term focus from 2030 to 2050 will be on rapid market expansion, as dedicated hydrogen pipelines become a feasible and cost-competitive alternative to natural gas.

The Canadian Government has recognized that all blue and green low-emission hydrogen production pathways are required to meet the targets set out in the Canada Strategy.[26] To jumpstart planning and production, the Government is prioritizing strategic coordination and investment across the entire value chain. To this end, the federal government has launched a number of funding programs designed to support investments in the production of low or zero carbon infrastructure.

Of particular note is the Government of Canada's proposed *Clean Fuel Standard* regulation that aims to drive the adoption of clean fuels by requiring fuel suppliers to gradually reduce the carbon intensity of their fuels.[27] Canada's $1.5 billion Clean Fuels Fund ("**CFF**"), introduced as part of the Climate Plan and reaffirmed in its 2021 Budget, supports the objectives of the *Clean Fuel Standard* and the Canada Strategy by providing funding

[22] *Ibid* at 45–46.

[23] IEA Hydrogen, *supra* note 4 at 123.

[24] In 2021, an enhanced target was submitted to the United Nations of 40–45 per cent below 2005 levels by 2030. See Government of Canada, News Release, "Government of Canada confirms ambitious new greenhouse gas emissions reduction target", online: <www.canada.ca/en/environment-climate-change/news/2021/07/government-of-canada-confirms-ambitious-new-greenhouse-gas-emissions-reduction-target.html>.

[25] Hydrogen Strategy for Canada, *supra* note 2.

[26] Environment and Climate Change Canada, "A Healthy Environment and a Healthy Economy", (2020) at 40–41, online (pdf): *Government of Canada* <www.canada.ca/content/dam/eccc/documents/pdf/climate-change/climate-plan/healthy_environment_healthy_economy_plan.pdf>.

[27] Government of Canada, "Clean Fuel Standard" (last modified 26 July 2021), online: <www.canada.ca/en/environment-climate-change/services/managing-pollution/energy-production/fuel-regulations/clean-fuel-standard.html>.

to projects designed to build out clean fuel production, including hydrogen, ethanol, renewable diesel, and renewable natural gas. The CFF helps tackle the upfront costs that would otherwise present a barrier to growth in the domestic clean fuels market. Natural Resources Canada will provide funding through conditionally repayable contribution agreements of up to 30 per cent of the total eligible project costs to a maximum of $150 million per project.[28] Together, the *Clean Fuel Standard* and the CFF operate as a carrot-and-stick approach, where the CFF incentivizes, and the *Clean Fuel Standard* mandates Canadians to reduce the carbon intensity of their fuels.

The federal government has also rolled out a host of other funding programs aimed at accelerating the transition to low carbon fuel through the development of clean energy technology and infrastructure. These include a pledge of $150 million to support the deployment of infrastructure for zero-emission vehicles,[29] and through programs such as the Canadian Emission Reduction Innovation Network (CERIN), Clean Growth Program (CGP), Green Infrastructure Program and Indigenous Off-Diesel Initiative.

Provincial

Governments at the provincial level are also exploring opportunities to deploy hydrogen to meet climate goals.

In BC, hydrogen is a focal point for the Province in its efforts to attain ambitious greenhouse gas reduction targets. On July 6, 2021, the Province released the BC Hydrogen Strategy (“**BC Strategy**”), breaking ground as the first province in Canada to release a comprehensive provincial hydrogen strategy.[30] The BC Strategy, designed to spur investments in hydrogen in the province, outlines a series of policy commitments and long and short-term strategies to scale up hydrogen in the province. The BC Strategy sees hydrogen as the most practical solution to decrease emissions in hard to decarbonize sectors like medium and heavy-duty transportation. As at the federal level, many provincial regulations align with the Hydrogen Strategy to support clean energy transition. BC’s *Renewable and Low Carbon Fuel Requirements Regulation* prescribes both a renewable content requirement for diesel and gasoline and a general decrease in the carbon intensity of liquid fuels. The regulation, which offers credits to fuel suppliers looking to transition to low carbon fuels, recently enabled a fleet of 65 heavy-duty trucks to switch from diesel to hydrogen in northeastern BC.[31] The Province also recently amended the *Greenhouse Gas Reduction (Clean Energy) Regulations* to increase the production and use of renewable gas and green and waste hydrogen in BC. The changes will provide natural gas utilities with more flexibility, stimulate investments in renewable energy and accelerate growth of hydrogen and renewable gas supply in their systems.[32]

In October 2020, Alberta released, “Getting Alberta Back to Work – Natural Gas Vision and Strategy” (the “**Alberta Strategy**”) which sets out the provincial government’s plan for Alberta’s economic future.[33] The Alberta Strategy identifies hydrogen as one of the key growth areas in Alberta’s natural gas sector. The Alberta Strategy plans to achieve large-scale blue hydrogen production across Alberta, to deploy hydrogen in various province-wide commercial applications, and to export hydrogen and

[28] Natural Resources Canada, “Clean Fuels Fund” (last modified 16 July 2021), online: <www.nrcan.gc.ca/climate-change/canadas-green-future/clean-fuels-fund/23734>.

[29] Infrastructure Canada, “Zero Emission Transit Fund” (last modified 10 August 2021), online: <www.infrastructure.gc.ca/zero-emissions-trans-zero-emissions/index-eng.html>.

[30] Ministry of Energy, Mines and Low Carbon Innovation, “B.C. Hydrogen Strategy – A sustainable pathway for B.C.’s energy transition” (6 July 2021), online (pdf): <www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/electricity-alternative-energy/electricity/bc-hydro-review/bc_hydrogen_strategy_final.pdf>.

[31] Ministry of Energy, Mines and Low Carbon Innovation, “Heavy-duty hydrogen fuelling station powers clean energy transition” (28 June 2021), online: *Government of British Columbia* <news.gov.bc.ca/releases/2021EMLI0044-001213>.

[32] Ministry of Energy, Mines and Low Carbon Innovation, News Release, “Province enables increased investments in renewable gas, hydrogen” (2 July 2021), online: *Government of British Columbia* <archive.news.gov.bc.ca/releases/news_releases_2020-2024/2021EMLI0046-001286.htm>.

[33] Government of Alberta, “Getting Alberta Back to Work – Natural Gas Vision and Strategy” (6 October 2020), online (pdf): <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>.

hydrogen-derived products to domestic and global markets by 2040.[34]

Also in 2020, Quebec released its Plan for a Green Economy, a plan designed to help the province achieve its self-imposed 2030 GHG emissions reductions targets.[35] The plan identifies various areas of application for green hydrogen, including industrial processes, intensive and heavy transportation, green chemistry, massive energy storage and heat production. The Government of Quebec intends the Plan for a Green Economy to help establish the province as a leader in the production of green hydrogen and other bioenergies.

Forthcoming hydrogen strategies are also expected from the government of Ontario, as well as Newfoundland and Labrador.

United States

In January 2021, the Biden-Harris Administration officially rejoined the Paris Agreement, putting the country on track to meet a goal of net-zero carbon emissions no later than 2050.[36] The commitment finds support from legislation such as the *CLEAN Futures Act*, which was introduced to the House in March 2021. If passed into law, the *CLEAN Futures Act* would set decarbonisation standards for the power, building, and transportation sectors to achieve net-zero by 2050.The *CLEAN Futures Act* will also establish a Clean Energy and Sustainability Accelerator which, with $100 billion in funding, will mobilize public and private investments to provide financing for low and zero emissions energy technologies.[37]

To achieve the country's emissions targets, the US plans to decarbonize the energy sector by scaling up hydrogen use and production. In particular, the Biden-Harris administration has identified a use for hydrogen in power production and as a zero-emissions alternative fuel.[38]

The US Department of Energy's ("**DOE**") Hydrogen and Fuel Cell Technologies Office ("**HFTO**") provides competitive grants to conduct research and development in hydrogen production, delivery, infrastructure, storage, fuel cells, and end uses.[39] The Office's H2@Scale initiative, launched in 2016, focuses on bringing together stakeholders to develop projects for the advancement of affordable hydrogen production, storage, transport and utilization.[40] HFTO has provided funding for projects devoted to fuel cell technology and manufacturing of heavy-duty fuel cell trucks, large-scale hydrogen use at ports and data centres, academic research on the application of hydrogen for the production of "green steel" and training programs for a hydrogen and fuel cell work force.[41] Congress allocated $150 million to HFTO for 2021.

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[34] Paule Hamelin et al, "The Frontier Comes Into View: Canadian Governments' Hydrogen Strategies" (8 June 2021), online: *Gowling WLG* <gowlingwlg.com/en/insights-resources/articles/2021/canadian-governments-hydrogen-strategies/>.

[35] Government of Québec, "Plan pour une économie verte 2030 – Politique-cadre d'électrification et de lutte contre les changements climatiques" (2020), online (pdf) : <cdn-contenu.quebec.ca/cdn-contenu/adm/min/environnement/publications-adm/plan-economie-verte/plan-economie-verte-2030.pdf?1605549736>.

[36] The White House, Press Release, "FACT SHEET: President Biden Sets 2030 Greenhouse Gas Pollution Reduction Target Aimed at Creating Good-Paying Union Jobs and Securing U.S. Leadership on Clean Energy Technologies" (22 April 2021), online: <www.whitehouse.gov/briefing-room/statements-releases/2021/04/22/fact-sheet-president-biden-sets-2030-greenhouse-gas-pollution-reduction-target-aimed-at-creating-good-paying-union-jobs-and-securing-u-s-leadership-on-clean-energy-technologies/">.

[37] House Committee on Energy & Commerce, Press Release, "E&C Leaders Introduce the Clean Future Act, Comprehensive Legislation to Combat the Climate Crisis" (2 Mars 2021), online: <energycommerce.house.gov/newsroom/press-releases/ec-leaders-introduce-the-clean-future-act-comprehensive-legislation-to>.

[38] Molly Wood, "President Biden says green hydrogen is key to a lower emissions future. So, what is it?" (29 April 2021), online: *Market Place* <www.marketplace.org/shows/marketplace-tech/president-biden-says-green-hydrogen-is-key-to-a-lower-emissions-future-so-what-is-it/>.

[39] See Office of Energy Efficiency & Renewable Energy, "Hydrogen and Fuel Cell Technologies Office" (last visited 18 August 2021), online: <www.energy.gov/eere/fuelcells/hydrogen-and-fuel-cell-technologies-office>.

[40] Office of Energy Efficiency & Renewable Energy, "H2@Scale" (last visited 18 August 2021), online: <www.energy.gov/eere/fuelcells/h2scale>.

[41] Alan Mammoser, "How to build the foundation for a hydrogen economy in the US", *GreenBiz* (15 September 2020), online: <www.greenbiz.com/article/how-build-foundation-hydrogen-economy-us>.

The DOE's Loans Program Office ("**LPO**") also provides funding for American manufacturers to develop and deploy innovative energy technologies. There is $4.5 billion in remaining Title XVII Innovative Clean Energy Loan Guarantee authority to support green and blue hydrogen production and infrastructure through the open Renewable Energy and Efficient Energy Projects solicitation, and more than $10 billion in the Advanced Technology Vehicles Manufacturing Loan Program to support the manufacture of fuel-cell electric passenger vehicles and components.

On June 7, 2021, Secretary of Energy Jennifer M. Granholm launched the US Department of Energy's Energy Hydrogen Shot initiative. The initiative seeks to reduce the cost of clean hydrogen by 80 per cent to $1 per kilogram within the next decade. As part of the launch, the DOE's Hydrogen Program issued a Request for Information on viable hydrogen demonstrations that can help lower the cost of hydrogen.[42] The DOE's overall fiscal year 2022 budget request seeks roughly $400 million for various hydrogen related efforts, a significant boost from current funding.[43]

Europe

The EU committed to net-zero by 2050 in March 2020. On July 8, 2020, the European Commission set out much more ambitious targets with the release of the EU's Hydrogen Strategy for a Climate-Neutral Europe ("**EU Hydrogen Strategy**"). In it, the EU has also committed to a low-carbon hydrogen target of 40GW of installed electrolyser capacity by 2030 with at least 6GW of green hydrogen electrolysers by 2024.[44] These are ambitious targets given current electrolyser production capacity in Europe is under 1GW per year.

The EU Hydrogen Strategy makes clear that the European Commission expects hydrogen will play an indispensable role in the transition to a new low-carbon energy system in Europe. While the EU's Hydrogen Strategy focuses heavily on green hydrogen, in the short term, the EU Hydrogen Strategy plans to replace existing grey hydrogen production with blue hydrogen to leverage the capacity of existing production facilities.[45] To support the development of a market for green and blue hydrogen, the EU has also committed to creating a standard classification system of types of hydrogen and a certification system to support its trade.[46] Ultimately, the EU aims to create a large regional hydrogen market encompassing Eastern Europe and North Africa.

The European Commission has created the European Clean Hydrogen Alliance to help implement the hydrogen strategy. The alliance coordinates scaling up the hydrogen value chain across Europe by identifying hydrogen projects and support for necessary investments.[47] The Alliance brings together industry, civil society, national, regional, and local government authorities to provide a forum for coordinating investments by all stakeholders.[48]

To finance the massive scale up the EU Hydrogen Strategy envisions, the European Commission is deploying EU funds and European Investment Bank financing. Phase 1 of the EU Hydrogen Strategy requires between €24 billion and €42 billion invested in electrolysers, with a further €220 to 340 billion to scale up and connect 80 to 120GW of solar and wind capacity to the electrolysers.

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[42] Department of Energy, Press Release, "Secretary Granholm Launches Hydrogen Energy Earthshot to Accelerate Breakthroughs Toward a Net-Zero Economy" (7 June 2021), online: <www.energy.gov/articles/secretary-granholm-launches-hydrogen-energy-earthshot-accelerate-breakthroughs-toward-net>.

[43] Andrew Freedman & Ben Geman, "Exclusive: DOE launches push to meet hydrogen "Earthshot" goal", *Axios* (7 June 2021), online: <www.axios.com/biden-hydrogen-climate-change-f79de0f9-e240-4b4d-a8f2-0de2826d1d63.html>.

[44] European Commission, "A Hydrogen Strategy for a Climate-Neutral Europe" (8 July 2020), online (pdf): <ec.europa.eu/energy/sites/ener/files/hydrogen_strategy.pdf> [EU Hydrogen Strategy].

[45] Dan O'Donnell, Gareth Baker & Gus Wood, "Sustainable Hydrogen: Green and Blue and the EU/UK Policy Overview" (2 June 2021), online: *Gowling WLG* <gowlingwlg.com/en/insights-resources/articles/2021/sustainable-hydrogen-green-and-blue-and-the-eu-uk/>.

[46] Alan Mammoser, "Europe Looks To Become The Global Leader In Hydrogen", *Oil Price* (29 July 2020), online: <oilprice.com/Alternative-Energy/Fuel-Cells/Europe-Looks-To-Become-The-Global-Leader-In-Hydrogen.html>.

[47] European Commission, "European Clean Hydrogen Alliance" (last visited 18 August 2021), online: <ec.europa.eu/growth/industry/policy/european-clean-hydrogen-alliance_en>.

[48] EU Hydrogen Strategy, *supra* note 44.

Retrofitting half of the existing hydrogen production plants is estimated to cost around €11 billion. A further €65 billion will be required for hydrogen infrastructure.[49]

Several EU member states have also published their own hydrogen strategies in recent years with independent targets and financing plans, most notably Germany (published June 2020), France, the Netherlands and Spain.[50]

The UK

The UK committed to achieving net-zero by 2050 in June 2019, and recently went a step further by increasing its emissions reduction target from 68 per cent by 2035 (compared to 1990 levels) to 78 per cent. The Government's "Ten Point Plan for a Green Industrial Revolution" sets out a framework for achieving net-zero, with hydrogen identified as a prominent contributor in achieving net-zero, and establishes a target of 5GW of low-carbon hydrogen production capacity by 2030. The 5GW production target assumes a mix of blue and green hydrogen, a key difference from other European markets. For a deeper analysis of the UK and the EU's Hydrogen Strategy see Sustainable Hydrogen: Green and Blue and the EU/UK Policy Overview, *supra* note 45.

International Partnerships

The momentum behind hydrogen is taking hold on an international scale. In the private sector, one of the biggest international initiatives currently building steam is the Hydrogen Council, a CEO-led initiative that unites member companies behind a coherent global strategy to deploy hydrogen solutions at scale. At the state level, a number of countries are working collaboratively through international organizations and global governmental partnerships to deploy a collective hydrogen strategy.

Mission Innovation is a global initiative designed to advance action and investment in the research and development of clean energy in this decade.[51] The initiative works in conjunction with member states' Paris Agreement goals to accelerate progress on pathways to net zero. One of the initiative's three key missions, launched at the June 2021 Mission Innovation ministerial, is the Clean Hydrogen Mission that aims to increase the cost-competitiveness of clean hydrogen by reducing end-to-end costs to $2 USD per kilogram by 2030.[52]

Some countries are also seeking to strategize through bilateral agreements. These agreements are designed to leverage signatories' combined comparative strengths to efficiently scale up hydrogen use and production. On May 16, 2021, Germany and Canada signed an agreement that provides a framework for the two countries to collaborate on the deployment of hydrogen in the clean energy transition. Germany has identified hydrogen as a central component to its clean energy transition, and, amongst other things, the agreement names Canada as Germany's main hydrogen supplier moving forward.[53] The agreement also establishes a mutually beneficial framework for the two countries to cooperate on the development of innovative hydrogen technologies.

REGULATORY CHALLENGES

Surging interest in hydrogen by governments, businesses, and consumers across the globe will present a myriad of regulatory challenges as this

[49] *Ibid* at 7.

[50] O'Donnell, *supra* note 45; See German Federal Government, "Die Nationale Wasserstoffstrategie" (June 2020), online (pdf): <www.bmwi.de/Redaktion/DE/Publikationen/Energie/die-nationale-wasserstoffstrategie.pdf?__blob=publicationFile&v=20>; Ministry of the Ecological and Social Transition, "Stratégie française pour l'énergie et le climat" (21 April 2020), online (pdf): <www.ecologie.gouv.fr/sites/default/files/20200422%20Programmation%20pluriannuelle%20de%20l%27e%CC%81nergie.pdf>; Government of the Netherlands, "Government Strategy on Hydrogen" (6 April 2020), online (pdf): <www.government.nl/documents/publications/2020/04/06/government-strategy-on-hydrogen>; Government of Spain, "Hoja de ruta del hidrógeno: Una apuesta por el hidrógeno renovable" (Octobre 2020), online (pdf): <www.miteco.gob.es/images/es/hojarutahidrogenorenovable_tcm30-525000.PDF>.

[51] See Mission Innovation, "Overview" (last visited 18 August 2021), online: <mission-innovation.net/about-mi/overview/>.

[52] Mission Innovation, "Clean Hydrogen Mission" (last visited 18 August 2021), online: <mission-innovation.net/missions/hydrogen/>.

[53] FuelCellsWorks, "Canada, Germany Sign Hydrogen Cooperation Deal" (16 March 2021), online: <fuelcellsworks.com/news/canada-germany-sign-hydrogen-cooperation-deal/>

emerging sector develops. These challenges may require a rethinking of current regulatory frameworks. For example:

Hydrogen Blending

There is currently no industry consensus on how much hydrogen can be safely blended into natural gas (current ongoing trials around the world range from 1% to 22%) in order to reduce the carbon emissions for residential and commercial heating. This blending discussion implicates both the physical vessel distributing the gas as well as the end-use appliance of the gas. Resolving these questions and setting clear standards will provide much-needed certainty to the industry to reduce regulatory risks and encourage investment. For more information on blending hydrogen with natural gas, see our article: How About Some Clean, Green Hydrogen With that Natural Gas?[54]

Accounting and Guarantees of Origin

Tracking the volume of hydrogen injected into the grid and its carbon intensity of the overall mix will be an important regulatory consideration. Such an accounting method — sometimes called a "guarantee of origin" — is essential if operators are to be paid a premium for supplying lower-carbon gas.

Transmission and Distribution

As jurisdictions race to develop regional and national hydrogen economies, storage and distribution will become a key issue. The search for the most techno-economically optimal way to distribute hydrogen (i.e. road, rail, pipeline, etc.) is still ongoing. Standardization of certain parameters like compression, storage, and distribution will play a role in driving this analysis. Each method will require unique regulatory considerations to achieve a safe and economically efficient solution in the coming months and years. For more information on the transmission and distribution of hydrogen, see our article: Hydrogen: The Next Clean Energy Frontier.[55]

Alternative Clean Energy Rate Designs

Energy regulators are showing an increasing willingness to fund innovative clean energy technology through innovative rate structures. Previously, these types of mechanisms were rejected, viewed as unfair to require rate-payers to fund experimental technology.[56] Such hesitancy is now giving way to the pursuit of clean energy objectives by a growing body of jurisdictions around the world. Accordingly, we might expect to see an increase in approvals of novel hydrogen-related projects that are funded by rate-payers. However, this may not be without controversy: the cost premiums on clean hydrogen remain stubbornly high as compared to the incumbent fossil fuels, and are projected to remain so throughout the next decade. It is unclear whether such cost disparity is a price that rate-payers will be willing to accept in the near-term. Either way, these market forces are likely to result in a host of new regulatory procedures.

Regulatory Jurisdiction, Codes and Standards

Most jurisdictions currently rely on their natural gas frameworks to regulate hydrogen. However, the differences between natural gas and hydrogen (e.g. chemical, thermodynamic, volumetric) may warrant a new regulatory approach. Provincial, federal, and international codes, standards, and regulations for hydrogen production will have to be reviewed in order to establish a compatible and enabling framework.

Part of this approach should consider whether the current energy and natural gas regulators are appropriate for hydrogen, or whether new regulatory bodies should be designed. The vast range of applications for hydrogen (e.g. transportation, energy generation, and heating, to name a few) will make this especially challenging given the number of

[54] Jay Lalach & Adriana Da Silva Bellini, "How About Some Clean, Green Hydrogen With that Natural Gas?" (8 June 2021), online: *Gowling WLG* <gowlingwlg.com/en/insights-resources/articles/2021/clean-green-hydrogen-with-that-natural-gas/>.

[55] Jimmy Burg et al, "Hydrogen: The Next Clean Energy Frontier" (2 February 2021), online: *Gowling WLG* <gowlingwlg.com/en/insights-resources/articles/2021/hydrogen-the-next-clean-energy-frontier/>.

[56] See Gordon E. Kaiser, "Canadian Energy Regulators and New Technology: The Transition to a Low Carbon Economy" (2021) 9:2 Energy Regulation Q 7.

regulators that will be engaged. Reflecting this range, hydrogen projects may need to be regulated in accordance with the specific end use or production pathway. For example, there may be parallels in the treatment of hydrogen produced from fossil fuel sources with oil and gas activities. Ultimately, whatever approach is taken should support the industry by reducing unnecessary red tape and barriers to entry for both demand-side and supply-side participants.

A TECHNOLOGY PROVIDER'S PERSPECTIVE[57]

Green Hydrogen – Catalyst for the Energy Transition[58]

Hydrogen generated with renewables could play a key role in accelerating the transition to a low carbon economy by facilitating long-term storage of renewables and balancing out grid fluctuations caused by non-dispatchable sources. Experts believe this flexibility will have to double by 2040. At the same time, power-to-gas — the technology of using electricity, especially surplus green power, to produce gas fuel by way of electrolysis — makes it possible to electrify those sectors that are currently still reliant on hydrocarbons and to make that power usable to transport goods and people, for making steel and cement, or as feedstock for the chemical industry. Establishing such an energetic link between previously separated sectors by way of renewables — also known as "sector coupling" — can reduce primary fossil energy consumption by 50 per cent despite growing power demand. Generally, a more diversified fuel supply would also help to improve energy security, and some countries with cheap and abundant renewable power could dedicate that capacity entirely to making green hydrogen for local consumption and export.

Large-scale integration of hydrogen and related commodities would also further foster the demand for renewable power generation, creating a self-sustaining incentive towards an economically viable and ecologically sustainable energy system.

In order to harness the full potential of green hydrogen, it will be necessary to find the most effective projects today and close the cost gap with grey hydrogen as the application is scaled up. Just as important, however, is the need for close collaboration between various stakeholders. Power producers, for instance, will have to exchange know-how and coordinate with mobility service providers, and all market players will have to be clear about their own role and those of their companies in what promises to be a highly disruptive industry. Finally, bringing about a breakthrough for the hydrogen economy will also necessarily involve more support from governments and regulators, since they have the authority to change regulatory frameworks and drive decarbonization targets.

As more governments, municipalities, and the industry become involved, manufacturers will have an order pipeline that justifies further investments in technology and production processes, which will trigger scale effects and ultimately bring down costs. This dynamic, which was effective in bringing about the break-through of solar power, can also foster green hydrogen and make this sustainable energy carrier a success story.

CONCLUSION

So, *is* hydrogen the silver bullet?

Although hydrogen represents a viable solution in the pursuit of carbon neutrality, it currently comes with a number of drawbacks, most notably production costs and transportation challenges. Governments around the world are actively investing and passing legislation aimed at supporting the growth of the hydrogen industry, but it is still early days. Much work remains on both the technology and regulatory fronts before hydrogen can truly be considered a key component of the clean energy transition. ■

[57] Chris Norris, Research Director, Siemens Inc.

[58] Siemens Energy, White Paper, "Green Hydrogen: Cornerstone of a Sustainable Energy Future" (2021), online: <www.siemens-energy.com/mea/en/company/megaprojects/dewa-green-hydrogen-project.html#Download>.

BRITISH COLUMBIA REDUCES REGULATORY BARRIERS TO HYDROGEN INVESTMENT

*Eric Bremermann, Glenn Zacher and Daniel Gralnick**

On May 25th, 2021, British Columbia amended its Greenhouse Gas Reduction Regulation (made under BC's *Clean Energy Act*) to authorize regulated gas utilities to produce, purchase and distribute specified types of hydrogen (the "Amendments"). The Amendments represent one of many strategies that legislators and regulators have adopted to facilitate the introduction of cleaner forms of technology to the highly regulated energy sector. The reduction of existing regulatory hurdles, coupled with increased legislative prescriptions to reduce greenhouse gas (GHG) emissions, are creating an environment that is conducive to investment and mergers & acquisitions (M&A) in the hydrogen sector.

BACKGROUND

In December 2020, the federal government published a policy document entitled *A Healthy Environment and a Healthy Economy* which provided aggressive targets for Canada to reduce its greenhouse gas emissions and to ultimately become carbon neutral by 2050. Subsequent developments are further transitioning Canada's GHG reductions policy to a binding legal regime. Notably,

- the Supreme Court of Canada approved the constitutional validity of the *Greenhouse Gas Pollution Pricing Act* earlier this year[1]; and
- Bill C-12: *An Act Respecting Transparency and Accountability in Canada's Efforts to Achieve Net-Zero Greenhouse Gas Emissions by the Year 2050* received royal assent on June 29, 2021.

Hydrogen is widely viewed as an emerging technology that will assist Canadians to achieve GHG reductions targets as it is a zero-carbon emission fuel source when combusted. The federal government published a Hydrogen Strategy for Canada (the "Hydrogen Strategy") in December 2020 that provides a framework to harness hydrogen's potential as a tool to achieve the transition to cleaner sources of energy and achieve GHG reduction targets. Furthermore, various provincial governments have published similar policy documents, including Ontario's Strategy Discussion Paper, and more recently, the B.C. Hydrogen Strategy.

The Hydrogen Strategy states that regulatory incentives to drive hydrogen adoption are an important step to unlocking hydrogen's potential to enable Canada to become carbon neutral by 2050. The Amendments further this objective.

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[1] P. Jason Kroft & Victor MacDiarmid, "The Supreme Court of Canada Upholds the Constitutionality of the Greenhouse Gas Pollution Pricing Act" (19 April 2021), online: *Stikeman Elliott* <www.stikeman.com/en-ca/kh/canadian-energy-law/the-supreme-court-of-canada-upholds-the-constitutionality-of-the-greenhouse-gas-pollution-pricing>.

THE AMENDMENTS

The Amendments add the production, purchase and distribution of specified types of hydrogen as a new "prescribed undertaking" under section 18 of the *Clean Energy Act*.

Section 18 of the BC *Clean Energy Act* provides gas utilities with the regulatory authorization and rate recovery to participate in prescribed projects, programs, contracts or expenditures that are aimed to reduce GHG emissions in the province, and to recover the costs up to a prescribed amount that are incurred from such undertakings.

Notably, the Amendments allow public gas utilities to participate in the following activities for eligible types of hydrogen:

- the production or purchase, and distribution of hydrogen through the natural gas distribution system to the customers of that public utility or of another public utility; and

- the purchase and provision of hydrogen outside the natural gas system to the customers of that public utility if it is to be used to replace, at least in part, natural gas derived from fossil fuels.

The relevant undertaking is limited to the following types of hydrogen:

- that is primarily derived from water using electricity that is generated primarily from clean or renewable resources (often known as green hydrogen); and

- that is waste hydrogen purchased by the public utility, as will be defined by regulation.

THE BROADER REGULATORY CONTEXT

Due to the highly regulated nature of Canada's power sector, the capacity to unlock the commercial potential for hydrogen in Canada will be substantially influenced by commercial entities' abilities to clear existing regulatory hurdles. In this respect, the Amendments represent one of the many policy tools that different jurisdictions are introducing to facilitate innovation and the introduction of greener technologies such as hydrogen.

A prevailing view is that hydrogen will be best positioned for commercial viability by creating local hydrogen hubs where a full hydrogen value chain is developed in suitable locations. Commercial entities will be largely dependent on public utilities to purchase, transport and deliver the commodity to customers. However, public utilities are inherently risk averse and operate in regulated environments where innovation is challenging, as they are typically only able to recover the costs of activities that are proven to be prudently incurred.

In a recently published article "Canadian Energy Regulators and New Technology: The Transition to a Low Carbon Economy"[2], Gordon Kaiser discusses how Canadian energy regulators have historically been reluctant to fund new technology through rates, which has served as an obstacle to innovation in the energy sector. Kaiser identifies measures that have been adopted by various energy regulators in response to this challenge, which include:

- pilot programs to introduce new technologies for test periods, for example, the pilot program approved by the Ontario Energy Board to study the effects of hydrogen blending in the natural gas distribution system;

- collaborative platforms between industry actors and regulators such as the Ontario Energy Board's Innovation Sandbox initiative;

- rate-payer funded innovation funds; and

- amendments to the regulators' statutory objectives "to facilitate innovation in the electricity sector."[3]

While many of the above measures provide regulators and public utilities with tools to facilitate the introduction of greener technologies within their respective regulatory environments,

[2] Gordon E. Kaiser, "Canadian Energy Regulators and New Technology: The Transition to a Low Carbon Economy" (2021) 9:2 Energy Regulation Quarterly 7.

[3] *Ontario Energy Board Act, 1998*, SO 1998, c 15, Sched B, s 1(1)(4).

the Amendments go a step further in providing regulatory certainty: the Amendments constitute explicit legislative directions that permit gas utilities to acquire and supply specific types of hydrogen, and to recover specified costs of such undertakings. It will be interesting to see if other provinces introduce similar legislative changes.

CONCLUSION: INCREASED INVESTMENT AND M&A

Legislative directions and social incentives for industry to reduce their GHG emissions, coupled with the regulatory treatment that is adapting to facilitate the introduction of greener technologies, are creating conditions favourable to increased investment in the Canadian hydrogen sector. Furthermore, international cooperation — such as the memorandum of understanding signed between Canada and Germany to establish an energy partnership that supports the production, usage and trade of clean hydrogen — is signaling government support for developing a robust hydrogen industry, and is also laying the framework for Canadian hydrogen to reach foreign markets. As such, we expect Canada to follow global trends of increased M&A activity in the hydrogen sector. ■

CARBON TARIFFS – THE NEXT CHALLENGE IN CANADIAN CLIMATE LAW AND POLICY?

*Dr. A. Neil Campbell, Lisa Page, Talia Gordner and Adelaide Egan**

Carbon Tariffs or Border Carbon Adjustments (BCAs) are being explored by various countries to support climate change initiatives.[1] BCAs adjust the import prices of carbon-intensive goods to match the cost of locally produced goods impacted by carbon pricing regimes.

The Government of Canada announced in the 2021 Budget that it plans to develop BCAs as an element of Canada's Climate Plan:

> Border carbon adjustments make sure that regulations on a price on carbon pollution apply fairly between trading partners. If a different price on pollution is levied at source, the difference is accordingly applied on imports and exports between countries. This levels the playing field, ensures competitiveness, and protects our shared environment. An important part of advancing this work is ensuring a common understanding of border carbon adjustments and hearing views from interested Canadians, as well as working with Canada's international partners.[2]

Canada's Climate Plan includes reducing greenhouse gas (GHG) emissions 30 per cent by 2030 and reaching net-zero emissions by 2050.[3] The Government anticipates that BCAs will help protect the competitiveness of key Canadian industries such as oil and gas, mineral production and chemicals while advancing Canada's Climate Plan.[4]

The Role of Border Carbon Adjustments

A BCA is a tariff on imported goods based on their carbon content. BCAs would be applied to imports of products from exporting countries that either do not have their own domestic carbon pricing regimes or have weaker domestic

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[1] Canada, the United States, the European Union, and the United Kingdom are among the jurisdictions considering the use of BCAs in the future.

[2] Government of Canada Department of Finance, *Budget 2021: A recovery Plan for Jobs, Growth, and Resilience* (Ottawa: Department of Finance, 2021) at 176 [*Budget 2021*].

[3] For more information about Canada's net-zero emissions initiative, please refer to McMillan's bulletin: Donia Hashem et al, "Canada Legally Commits to Net-Zero Emissions by 2050" (December 2020), online: <mcmillan.ca/insights/canada-legally-commits-to-net-zero-emissions-by-2050/>.

[4] Government of Canada, "Progress towards Canada's greenhouse gas emissions reduction target" (last modified 3 March 2021), online: <www.canada.ca/en/environment-climate-change/services/environmental-indicators/progress-towards-canada-greenhouse-gas-emissions-reduction-target.html>

carbon pricing regimes than the importing country.[5] In effect, BCAs are intended to "level the playing field" between the costs of producing carbon-intensive goods in domestic and foreign markets. BCAs also reinforce domestic efforts to incentivize production of "environmentally friendlier" goods.[6]

BCAs have a critical role in deterring the "carbon leakage" that occurs when firms relocate production to countries without, or with weak, carbon pricing schemes. Relocation allows firms to avoid the added costs associated from compliance with stricter emissions regulations.[7] Carbon leakage results in global carbon emissions being redistributed to other countries rather than being reduced. In addition, domestic production and employment may decline from the relocation of manufacturing activities to foreign countries.

BCAs aim to equalize the basis of competition between foreign and domestically produced goods manufactured under different carbon compliance regimes. By raising the costs of imported products that are not fully carbon-priced in the exporting country, BCAs attempt to reflect the cost of producing similar goods at the carbon pricing level in the domestic market. BCAs also indirectly incentivize other countries to develop and meet more rigorous emission targets to avoid their exports being subject to BCAs.

Integrating BCAs within Canada's Carbon Pricing Regime

The Supreme Court of Canada (SCC) recently upheld Canada's domestic carbon pricing regime as set out in the *Greenhouse Gas Pollution Pricing Act* (GGPPA).[8] The GGPPA establishes a minimum national standard for carbon pricing emissions that all Canadian provinces and territories must meet.

The SCC stated that climate change was a threat to human life and Canada should approach the issue through national and international efforts.[9] The GGPPA decision appears to pave the way for a broad range of climate measures that could include BCAs.

Canada's federal carbon pricing system under the GGPPA is known as the Output-Based Pricing System (OBPS). The OBPS allows the provinces and territories to design and implement their own carbon-pricing regimes, as long as the programs meet the minimum federal requirements. For provinces and territories that do not do so, the federal OBPS functions as a backstop to ensure they are subject to carbon pricing at the federal level.[10]

The CO_2 emissions limit for each facility regulated under the OBPS is calculated using a formula in the *Output-Based Pricing System Regulations*.[11] A facility is required to pay for each tonne of carbon emitted above its limit for a year. The minimum price under the OBPS is currently C$40 per tonne of CO_2, and will progressively increase to C$170 per tonne of CO_2 by 2030.

An increase from C$40 to C$50 per tonne of CO_2 under the OBPS has been estimated to result in a 1-5 per cent increase in production costs for Canadian manufacturers of goods in the iron, chemical, petroleum, and steel industries.[12] In the absence of BCAs, carbon-intensive imported goods produced in

[5] Aaron Cosbey et al, "Developing Guidance for Implementing Border Carbon Adjustments: Lessons, Cautions, and Research Needs from the Literature" (2019) 13:1 Review of Environmental Economics and Policy 3.

[6] *Budget 2021*, *supra* note 2 at 176.

[7] European Commission, "Carbon leakage" (last accessed 12 July 2021), online: <ec.europa.eu/clima/policies/ets/allowances/leakage_en>.

[8] *References re Greenhouse Gas Pollution Pricing Act*, 2021 SCC 11.

[9] For more information, please refer to McMillan's bulletin: Holly Sherlock et al, "Supreme Court of Canada Upholds Federal Carbon Pricing Regime" (29 March 2021), online: <mcmillan.ca/insights/supreme-court-of-canada-upholds-federal-carbon-pricing-regime/>.

[10] Ontario, New Brunswick, Manitoba, Prince Edward Island, Saskatchewan, Yukon, and Nunavut rely on the federal OBPS, although New Brunswick and Ontario are currently in the process of transitioning from the federal OBPS to their own provincial carbon pricing programs.

[11] *Output-Based Pricing System Regulations*, SOR/2019-266, ss 36–43.

[12] International Monetary Fund, "Four Charts on Canada's Carbon Pollution Pricing System" (18 March 2021), online: <www.imf.org/en/News/Articles/2021/03/17/na031821-four-charts-on-canadas-carbon-pollution-pricing-system>.

countries that have carbon pricing at lower levels, or no carbon price at all, will have a cost advantage over Canadian goods.

It is expected that Canadian BCAs would be developed for imported products that compete with Canadian products affected by the OBPS. In practice, implementing BCAs in Canada may be a complex process. Some provinces use cap-and-trade systems, while others apply direct prices on carbon. Given the variance in carbon-pricing implementation across Canada, designing a Canadian BCA that equitably protects producers in all provinces and territories may prove challenging.

International Consideration of BCAs

The European Union is expected to announce its proposed "Carbon Border Adjustment Mechanism" (CBAM) regulations in July 2021, and they could enter into effect as early as 2023.[13] The European Parliament and member states will need to approve the CBAM proposal before it comes into force.[14]

At the June 2021 G7 Summit in the United Kingdom, leaders "acknowledge[d] the risk of carbon leakage" and committed to "work collaboratively to address this risk and to align our trading practices with our commitments under the Paris agreement."[15] However, no consensus was reached in support of BCAs. The strongest opposition to BCAs amongst the G7 countries currently comes from the United States and Japan,[16] the only G7 countries without national carbon-pricing regimes.[17] The U.S. has considered the use of BCAs but views them as a tool of "last resort."[18]

Designing BCAs that are World Trade Organization Compliant

BCAs will almost certainly be scrutinized under the World Trade Organization's dispute settlement regime. The *General Agreement on Tariffs and Trade* (GATT) provides that countries cannot use tariffs to discriminate in favour of domestic producers of goods.[19] A WTO-compliant BCA will need to be non-discriminatory, applying clear and consistent principles for all countries.[20] A WTO-compliant BCA will likely also need to account for carbon pricing already applied in the exporting country to avoid placing domestically produced goods at a market advantage relative to the imported goods.

Alternatively, if a BCA fails the non-discrimination requirements under the GATT, it may still be justified under one of the General Exceptions in Article XX of the GATT.[21] They allow a trade measure to be exempt from the GATT where necessary for the protection of human, animal or plant life, or where necessary for the conservation of exhaustible natural resources.[22] Clean air has been recognized as an exhaustible

[13] European Parliament, "Legislative Train Schedule: A European Green Deal" (last modified 24 June 2021), online: <www.europarl.europa.eu/legislative-train/theme-a-european-green-deal/file-carbon-border-adjustment-mechanism>.

[14] European Parliament, "Ordinary legislative procedure" (accessed 12 July 2021), online: <www.europarl.europa.eu/infographic/legislative-procedure/index_en.html>.

[15] The White House, Press Release, "Carbis Bay G7 Summit Communiqué" (13 June 2021), online: <www.whitehouse.gov/briefing-room/statements-releases/2021/06/13/carbis-bay-g7-summit-communique/>.

[16] Karl Mathiesen, Jakob Hanke Vela & Esther Webber, "The EU's carbon club of one", *Politico* (12 June 2021), online: <www.politico.eu/article/eu-carbon-border-tax-support-g7-us-japan/>; Leslie Hook, "John Kerry warns EU against carbon border tax", *Financial Times* (11 March 2021), online: <www.ft.com/content/3d00d3c8-202d-4765-b0ae-e2b212bbca98>.

[17] World Bank, "Pricing Carbon" (last accessed 11 July 2021), online: <www.worldbank.org/en/programs/pricing-carbon>.

[18] Hook, *supra* note 16.

[19] *General Agreement on Trade and Tariffs and Trade*, 30 October 1947, Article II and Article III, UNTS 187 (entered into force 1 January 1948) [*GATT*].

[20] Jennifer Hillman, Policy Paper, "Changing Climate for Carbon Taxes: Who's Afraid of the WTO?", *German Marshall Fund of the United States* (25 July 2013), online: <www.gmfus.org/publications/changing-climate-carbon-taxes-whos-afraid-wto>.

[21] *GATT*, *supra* note 19, Article XX.

[22] *Ibid*, Article XX (b), Article XX (g).

resource.[23] However, a trade measure cannot be used as an excuse for arbitrary or unjustified discrimination or to disguise a restriction on international trade.[24]

Canadian Government Consultation Process

The Government has announced that it will begin a BCA consultation process with exporters and importers of carbon-intensive goods in summer 2021. Broader public consultations are expected later in fall 2021.[25] Firms that produce and sell carbon-intensive products may want to participate in these consultations to ensure that level playing field, regulatory burden and other considerations are fully understood by the Government. ■

[23] World Trade Organization, "WTO rules and environmental policies: GATT exceptions" (last accessed 11 July 2021), online: <www.wto.org/english/tratop_e/envir_e/envt_rules_exceptions_e.htm>.

[24] *Ibid*.

[25] *Budget 2021*, *supra* note 2 at 176.

HYDRO-QUÉBEC AND ITS U.S. TRANSMISSION PROJECTS

*Erik Richer La Flèche**

Year in, year out, Quebec's vertically integrated state-owned power utility Hydro-Québec (HQ) exports approximately 33.5 TWh. In 2019, HQ exported 33.7 TWh — representing 16 per cent of all electricity sold by HQ but 22 per cent of its net income. Today, exports remain more profitable than domestic sales. About 75 per cent of HQ exports go to three American states: New York, Massachusetts, and Vermont. The rest is sold to Ontario and New Brunswick.

HQ and the Quebec government have been working for decades to increase electricity exports to the U.S., including by proposing new transmission lines. The electricity available for export is renewable and, thanks to HQ's large reservoirs, is a secure and stable source of power. In light of this, it would be reasonable to think that these exports would be welcomed and that opposition would be limited.

History shows that this is not the case. Just as Canada's oil industry has encountered difficulties with its pipelines, so have Quebec's transmission projects engendered forceful and effective opposition abroad. Moreover, the arguments used against Quebec's exports often overlap with those used against pipelines and, to the surprise of much of Quebec's political class, the "green" credentials of Quebec's hydropower are insufficient to ensure the success of export projects.

In this article, we examine Quebec's five largest export projects of the last three decades and summarize lessons learned as well as how export projects may be configured in the future to increase their chances of success.

GREAT WHALE

It is 1986. Quebec's newly elected premier, Robert Bourassa, has just announced his intention to build the Great Whale hydroelectric project in Quebec's north. The project would add 3,090 MW to the more than 10,000 MW already at the La Grande complex.

Electricity generated at Great Whale is to be exported to New York and New England. In 1988, the New York Power Authority (NYPA) conditionally signed a 21-year $17 billion power purchase contract with Hydro-Québec. This contract is essential to make Great Whale bankable and is great news for the province's economy.

By 1992, however, the contract with the NYPA is in tatters. Two years later, Great Whale is permanently beached.

So what went wrong? A crucial mistake made by the Quebec government was that it undertook the Great Whale project with little inclination to consult — and even less to involve — the Cree and Inuit most affected by the project. The Cree and Inuit pushed back, resulting in lengthy, acrimonious lawsuits and public debates that galvanized opposition to the project.

The Quebec government and HQ were caught flat-footed.

The Cree and Inuit advantageously used the courts and media. They accused Quebec of not only destroying a fragile environment but also

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of committing "cultural genocide" by flooding large swaths of their ancestral lands.

The high point of the Cree and Inuit campaign was the very telegenic arrival at New York City on Earth Day 1990 of a 24-foot craft carrying 60 Cree and Inuit paddling down the Hudson River at the end of a more than 1900 km, five-week journey. Advance notice ensured maximum media coverage. This in turn rallied American Non-Government Organizations and other pressure groups to gather behind the cause.

In 1991, the NYPA asked HQ for a one-year extension before confirming the previously signed power contract. A year later, the NYPA decided not to proceed. While economic factors were the main cause of the cancellation, environmental and other social considerations made the decision much easier to make and defend.

Great Whale was finally shelved by premier Jacques Parizeau in 1994 after a face-saving hiatus. Quebec had learned a valuable lesson from this episode: what happens at home resonates in export markets.

As a result, Quebec undertook to repair its relations with the Cree Nation. In 2002, premier Bernard Landry and Grand Chief Ted Moses of the Grand Council of the Crees signed the 50-year *Paix des Braves*. *Paix des Braves* is a comprehensive agreement providing, among other things, for joint jurisdiction over much of the territory occupied by the James Bay hydroelectric dams and reservoirs in northern Quebec.

Despite repeated demands from other First Nations, Quebec has refused to replicate the *Paix des Braves*, preferring to enter into more limited agreements.

NORTHERN PASS

In 2008, HQ and two American utilities, Northeast Utilities and NSTAR (these two companies later merged in 2012 to form Eversource Energy), agreed to develop the 1,200 MW Northern Pass project.

The project involved the U.S. project proponents financing, constructing, and operating approximately 290 km of new transmission line from the Quebec-New Hampshire border to Franklin, New Hampshire, where it would then connect to existing grid facilities. HQ was to be responsible for the Quebec portion of the project.

Very early on, the siting of the future transmission line worried tourism, recreation and environmental groups concerned about the project's impact on New Hampshire's environment, including its large protected forests. But that was not the only criticism levelled against the project.

Opponents highlighted that much of the power would be consumed in Massachusetts and not in New Hampshire (this was important as the project needed to invoke eminent domain along many sections of its route). Among other considerations, they also questioned whether the project would reduce electricity rates, challenged the green credentials of HQ's large reservoirs and Quebec's treatment of the Innu First Nation, and worried about the project's impact on local forestry practices and New Hampshire's own renewable power industry.

Although the project was modified to assuage some of these concerns, including by promising to bury part of the line, in early 2018 the New Hampshire Site Evaluation Committee voted unanimously to deny Northern Pass. The decision was appealed to the Supreme Court of New Hampshire. When the appeal was rejected in July 2019, Governor Sununu of New Hampshire issued this terse press release:

> "The Court has made it clear – it is time to move on. There are still many clean energy projects that lower electric rates to explore and develop for New Hampshire and the rest of New England."[1]

The press release is telling because it implies that large-scale power imports from Quebec are not indispensable to New England's environmental aspirations. In other words: what was orthodoxy in Quebec in the early 2000s might no longer be true in New England a decade

[1] New Hampshire Governor, Press Release, "Governor Sununu Statement on Northern Pass" (19 July 2019), online: <www.governor.nh.gov/news-and-media/governor-sununu-statement-northern-pass>.

later. Eversource Energy abandoned Northern Pass shortly after the Governor's press release.

NEW ENGLAND CLEAN ENERGY CONNECT

New England Clean Energy Connect (NECEC) is a 1,200 MW transmission project from Quebec to Massachusetts by way of Lewiston, Maine. The project is designed to transport electricity purchased from HQ pursuant to a 20-year 9.45 TWh per year power purchase agreement. Although most of the electricity will be consumed in Massachusetts, Maine is guaranteed 500,000 MWh per year for the same period as an inducement to allow the NECEC to traverse the state.

The project requires the construction of 233 km of high-voltage transmission lines mostly following existing power rights-of-way, with only about 85 km on a new right-of-way to be cut through working forest lands from Forks, Maine up to the Quebec border. Interestingly, the right-of-way is to be much narrower than what is usually provided, thus substantially reducing the environmental footprint of the line.

On January 15, 2021, NECEC's sponsors, including HQ, publicly confirmed that after a lengthy process lasting nearly three years, the NECEC had secured all major state and federal permits and was now "shovel-ready." Ordinarily, this milestone would mark the beginning of the project's construction.

Not in Maine, however.

On the same day the project proponents issued their press release, the Federal Court of Appeals in Boston issued an injunction suspending work on the Forks-to-Quebec section of the project in the Upper Kennebec region. Environmental groups were challenging whether one of the federal permits was properly issued.

A week later, on January 21, 2021, a coalition of groups opposed to the NECEC delivered a petition with approximately 100,000 signatures to the Maine Secretary of State. The petition asked that the Secretary place on the November ballot a citizen's initiative that would retroactively require state legislature approval for transmission lines over 50 miles and prohibit power line construction in the Upper Kennebec region. Thus, effectively preventing the NECEC from moving forward.

While the injunction was lifted on May 14, 2021, and construction can resume on the Fork-to-Quebec portion of the project, the Secretary of State has accepted the petition and placed the citizen's initiative on the November 2, 2021, ballot. Accordingly, political risk continues to imperil the project. The question that the voters will be asked to vote on is as follows:

> *"Do you want to ban the construction of high-impact electric transmission lines in the Upper Kennebec Region and to require the Legislature to approve all other such projects anywhere in Maine, both retroactively to 2020, and to require the Legislature, retroactively to 2014, to approve by a two-thirds vote such projects using public land?"*[2]

Opposition to the NECEC appears to have a wider base on the ground compared to the Northern Pass project. It also appears better funded. Depending on the opponent, opposition is grounded in one of the following:

> (i) The politics of rural resentment and grievance. The project traverses Maine's second congressional district, one of the most rural in the U.S. and a district that delivered an electoral vote for President Trump. Maine — like Nebraska — attributes some of its electors by congressional districts. Not everyone in northern Maine believes that allowing high-voltage power lines to cross their forests to serve the city of Boston is a good thing, per se.
>
> (ii) Dissatisfaction with, and distrust of, the local power company, Central Maine Power, a major proponent of the NECEC. Promises of lower rates

[2] Department of the Secretary of State – State of Maine, Press Release, "Secretary Bellows announces final wording of referendum question" (24 May 2021), online: <www.maine.gov/sos/news/2021/referendumquestionwording.html>.

and better service have not had the expected effect.

(iii) Competition with large incumbent electricity producers, including renewable electricity producers.

Some NECEC proponents have responded by attacking the bona fide intentions of their opponents and deep-pocketed backers. By doing so, however, they are attacking the way politics is played in the U.S. — a complaint that, when uttered by foreigners, usually falls on deaf ears. But, more importantly, by doing so the proponents are not directly addressing the concerns of their opponents, including voters in Maine's second congressional district.

Because of the stakes involved, it is unclear whether the outcome of this November's vote in Maine will settle the issue. The matter may continue to drag on for quite some time before the courts.

CHAMPLAIN-HUDSON POWER EXPRESS

New York State has ambitious plans to move to 70 per cent renewable electricity by 2030.

On October 15, 2020, the New York Department of Public Service confirmed that existing hydropower is eligible for renewable energy credits when it is delivered into New York City. This is a first in that state and allows HQ hydropower to be competitive.

In pursuit of the state's objective, in January 2021 New York launched a request for proposals for the supply of 1,500 MW of renewable electricity into New York City. HQ has responded with the U.S. proponent of the Champlain-Hudson Power Express (CHPE), namely Transmission Developers, a Blackstone portfolio company.

CHPE is a "shovel-ready" project to build a 1,250 MW transmission line from the Quebec-New York border all the way down to the New York City borough of Queens.

CHPE is structured so as to put into effect many of the lessons learned from previous proposals. Firstly, CHPE traverses a single jurisdiction, New York State, to reach its intended customers. This greatly diminishes opposition based on whether local benefits are sufficient. Secondly, CHPE will either be submerged under Lake Champlain and the Hudson and Harlem Rivers, or buried along existing rights of way. This will greatly reduce visual and other environmental impacts usually encountered with high-voltage transmission infrastructure. Thirdly, it was recently announced that the project's transmission line on the Quebec side of the border would be a joint venture between HQ and the Mohawk Council of Kahnawà:ke. HQ does not enter into transmission joint ventures in Quebec and this joint venture should increase the chances of First Nation support for CHPE and HQ electricity exports in general. Fourthly, CHPE has spent more than 8 years on an extensive communication effort with communities along the route and has considerable municipal support.

NEW ENGLAND CLEAN POWER LINK

This project is similar to the CHPE and has the same proponent, Transmission Developers. It involves building a 1,000 MW transmission line in Vermont. The line would start from the Quebec-Vermont border and proceed to Ludlow, Vermont where it would link up with existing transmission facilities. Like CHPE, the line is planned to be submerged under Lake Champlain or buried along existing rights of way. The project does not currently have an off-taker but could be used by HQ to pursue future opportunities in the New England market should NECEC be abandoned.

LESSONS LEARNED

There are numerous lessons that can be drawn from Hydro-Québec's travails in the U.S.

Local Communities: Consultations with local communities along the path of a project are now a given but they must be meaningful and, just as importantly, be seen as such. As Tip O'Neill, the influential Speaker of the House of Representatives from 1977 to 1987, was famous for saying: "All politics is local." Mobilized constituents can place a lot of pressure on their elected officials and derail projects, even ones whose benefits are advantageous in the long term.

"Get your house in order": Opponents will level all manner of criticism against a project and their search for arguments will extend far beyond their jurisdiction. It is therefore important for a proponent to control what it can control. The following recent example will illustrate this point. For decades, a number of Quebec First Nations have asked to negotiate an arrangement similar to the *Paix des Braves* with the Cree. Quebec has refused. On August 5, 2020, the Innu First Nation of Pessamit and the Atikamekw First Nation of Wemotaci issued a press release, asking among other things that Quebec and HQ compensate them for the hydroelectricity produced on their territory. HQ responded, by way of a spokesperson, that it was surprised and found the public statement unhelpful to the export of electricity to New England and New York State, i.e., the NECEC and CHPE projects. Shortly thereafter, the Penobscot Nation of Maine issued a press release opposing NECEC and supporting the Innu and Atikamekw First Nations, thereby increasing local public pressure against NECEC.

Demonstrable Short and Long-Term Economic Benefits: Northern Pass and NECEC have eloquently demonstrated how "not in my backyard" (NIMBY) sentiment is particularly strong when a transmission line project is primarily for out-of-state purposes. Projects must provide demonstrable direct benefits to the localities along their route.

Visibility: Transmission lines and their corridors are not without environmental impact. Unless buried or submerged, they are highly visible and can have a splintering effect on the landscape as well as adversely affect wildlife. To maximize success of future projects, it is preferable to use existing rights of way or be as visually discreet as possible.

"Time Is Not a Friend": High-voltage transmission lines are long gestation projects that can take a decade or more to be commissioned. During that time their economic and technological advantages may erode. During the last decade, costs associated with renewable energy from wind and solar have dramatically fallen and reliability has increased. As a result, new means of production are competitive, even in the crowded Northeast United States. The May 2021, U.S. federal approval of the country's first offshore wind farm, the 800 MW Vineyard Wind 1 offshore wind power project off the coast of Massachusetts, eloquently illustrates this point.

Two-Way Trade: Power transmission projects such as NECEC are mercantilist by nature and the time for traditional one-way export projects may be drawing to an end.

A February 2020 working paper from the MIT Center for Energy and Environmental Policy Research titled "*Two-Way Trade in Green Electrons: Deep Decarbonization of the Northeastern U.S. and the role of Canadian Hydropower*" concluded that the best use of HQ's hydro-electrical facilities and reservoirs is when they are used to balance intermittent renewable electricity producers. Under this scheme, HQ sells electricity to a state when the wind or solar resources of that state are insufficient and in turn purchase electricity when there is surplus renewable electricity. By conserving water in its reservoirs, HQ would in practice "store" energy for later use and become the battery for the Northeastern United States.

This complementary way of doing business not only reduces utility costs but also has the advantage of being an easier political sell, as "two-way electrical flows" do not displace local renewable energy producers nor the jobs and investments they engender.

Interestingly, two-way trade is specifically mentioned as a future opportunity in the CHPE proposal.

ATLANTIC LOOP

In its September 24, 2020 Throne Speech, the Government of Canada announced its support for the Atlantic Loop, a project which aims to "connect surplus clean power to regions transitioning away from coal."

Simply stated, the Atlantic Loop as currently envisaged would interconnect the electrical systems of New Brunswick and Nova Scotia with those of Quebec and Newfoundland and Labrador. This would enable New Brunswick and Nova Scotia to transition to cleaner sources of electricity while at the same time furthering their local renewable energy sectors, with Quebec and Newfoundland and Labrador acting in two capacities: base-load power suppliers as well as providers of "battery" services when local wind or solar resources are insufficient.

The Atlantic Loop could of course be extended to the U.S. Northeast to form an even larger integrated grid. Perhaps Quebec's best export opportunities lie in the east rather than to the south.

Greater grid integration in Eastern Canada — and hopefully in the Northeastern U.S. — would also serve as a model for Manitoba and British Columbia, two provinces with considerable hydro capacity and fossil fuel consuming neighbours. ■

THE CAUSE OF THE ONTARIO ELECTRICITY PRICE INCREASES

*Benjamin Dachis and Joel Balyk**

SUMMARY

Ontario's electricity sector has struggled with rising system costs for more than a decade. Why? The crux of the problem are increases in the cost of supply from high-cost contracts spread over less electricity consumption than forecast when the contracts were struck. The result has been upward pressure on prices that has only been mitigated by government rebates that have shifted costs to taxpayers.

How can Ontario fix this? To help businesses, it should replace the current industrial electricity pricing system for large customers with a market-based "interruptible rate" that rewards them for agreeing to interruptions of supply during extreme peak demand hours. For medium-sized customers, set the full cost of energy prices on an hourly basis. For residential customers and small businesses who pay regulated energy rates, we propose giving consumers the option of a lower price than otherwise most of the time, but with an incentive to reduce use at extreme peak demand hours.

The Ontario government should provide sound policy direction that focuses on empowering and resourcing the regulator, the Ontario Energy Board (OEB), to oversee decisions on procuring electricity, moving electricity procurement decisions to local buying groups.

Policymakers should recognize the cost containment in the distribution and transmission side of the system led by Hydro One since its 2015 partial sale. Since privatization, Hydro One has lowered its overall cost per customer by $90, mostly by reducing administrative costs. To help other local distribution companies emulate those savings, which we estimate would save customers of other LDCs $61 per year, the province should implement tax changes that allow cities to find outside investors while simultaneously unlocking value for municipal taxpayers.

Lastly, the province should reduce rate subsidies, which have climbed to $6.5 billion in the 2021/22 fiscal year. For comparison, this is $700 million more than what the province plans to spend on long-term care. They are not sustainable.

Rising costs have burdened Ontario's electricity system for well over a decade and yet there remains no end in sight. Ontario had the highest system costs among the provinces in 2018.[1]

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* Joel Balyk is a Research Associate and Benjamin Dachis is the Director of Public Affairs at the C.D. Howe Institute. An earlier version of this article was previously published by the Institute. See Benjamin Dachis & Joel Balyk, "Power Surge: The Causes of (and Solutions to) Ontario's Electricity Price Rise Since 2006" (15 June 2021), online (pdf): *C.D. Howe Institute* <www.cdhowe.org/sites/default/files/attachments/research_papers/mixed/e-brief_316_0.pdf>.

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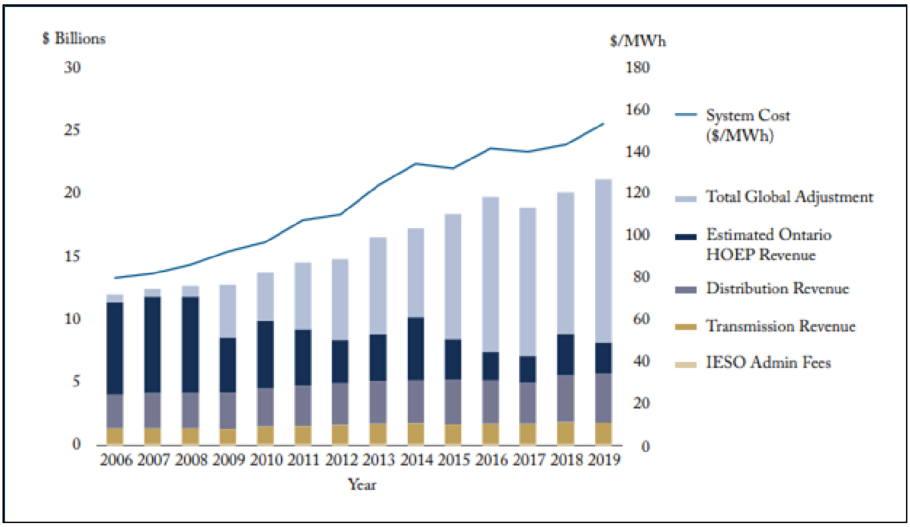
[1] Grant Bishop, Mariam Ragab & Blake Shaffer, "The Price of Power: Comparative Electricity Costs across Provinces" (October 2020), online (pdf): *C.D. Howe Institute* <www.cdhowe.org/sites/default/files/attachments/research_papers/mixed/Commentary%20582.pdf>.

Figure 1: System Cost by Component



Sources: Ontario Independent Electricity System Operator (IESO), Ontario Energy Board, Hydro One.

Ontario's electricity system is separated into generation, transmission, distribution, and (a relatively minor cost) market operation by the Independent Electricity System Operator (IESO). The system's total cost reflects the revenues raised by each component. Total system cost has increased from $12 billion in 2006 up to $21 billion in 2019 (Figure 1). Over the same period, Ontario demand has fallen by approximately 10 per cent, well below the originally forecast levels from 2007.[2]

Generating facilities, whether for hydro, natural gas, nuclear, or other energy, in Ontario collect revenue through a mix of payments from (i) long-term power contracts (the net amounts paid under these contracts are aggregated into the "Global Adjustment" or "GA") and (ii) payments from the real-time wholesale market ("the Hourly Ontario Energy Price" or "HOEP"). These revenues combined represent the cost of energy and comprise the largest portion of the system cost in Ontario as expressed in Figure 1 and Figure 2. While revenues from the HOEP have fallen from $7.4 billion in 2006 to $2.5 billion in 2019, revenues from the GA have soared from $700 million to $13 billion over the same period. The long-term power contracts covered by the GA are designed such that if the revenues from the HOEP are insufficient to cover the returns as specified in the energy contracts or regulated rates, the compensating payments from the GA make up the difference.[3] With energy costs set by contracts, if the HOEP is lower, the GA is higher. The GA is now the single largest component of the total system cost at over 60 per cent in 2019.

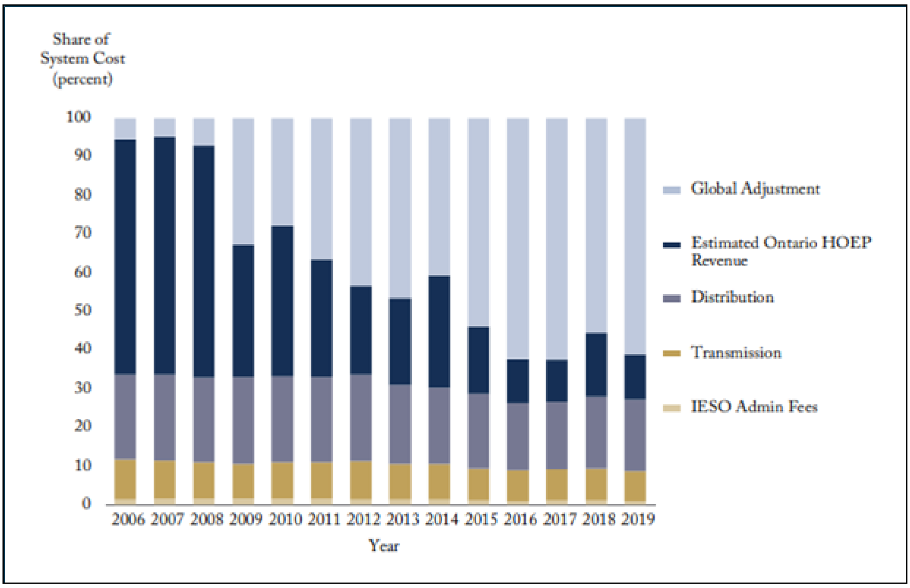
Transmission in Ontario is almost entirely provided by Hydro One. The revenues accrued by Hydro One through transmission have increased from $1.2 billion in 2006 to $1.7 billion in 2019 as shown in Figure 1, however, transmission's share of the total system cost has declined slightly as illustrated in Figure 2.

Numerous local distribution companies (LDCs) provide services in Ontario, with a total of

[2] Independent Electricity System Operator, "Hourly Demand Report" (last modified 25 May 2018), online: <reports.ieso.ca/public/Demand/> (We use 2006 for the aggregate system cost data analysis as our base year as that is the first year in which we have consistent data for all parts of the system).

[3] Independent Electricity System Operator, "Global Adjustment (GA)" (last visited 15 June 2021), online: <www.ieso.ca/en/%20power-data/price-overview/global-adjustment>.

Figure 2: Share of System Cost by Component



Sources: Ontario Independent Electricity System Operator (IESO), Ontario Energy Board, Hydro One.

59 LDCs operating in 2019, including Hydro One.[4] Distribution represents a larger cost than transmission, with costs climbing from $2.7 billion in 2006 up to $3.9 billion in 2019. Despite this, distribution's share of system costs has similarly fallen over the years as expressed in Figure 2. Transmission and distribution's combined share of the total system cost in 2019 was slightly more than 25 per cent compared to 33 per cent in 2006.

TRANSMISSION & DISTRIBUTION

To explore transmission and distribution revenues further, we segregate Hydro One into its transmission and local distribution companies operating in Ontario, as well as LDCs that eventually became acquired by Hydro One, and all remaining LDCs.[5] Total distribution revenues for Hydro One have increased from $900 million in 2006 up to $1.6 billion in 2019, while distribution revenues for other LDCs have increased from $1.7 billion to $2.3 billion over the same duration, as illustrated in Figure 3 (which we explore further, controlling for customer density, below). In 2015, the previous government began its first phase of privatization of Hydro One, and Ontario now owns slightly less than half of shares.[6]

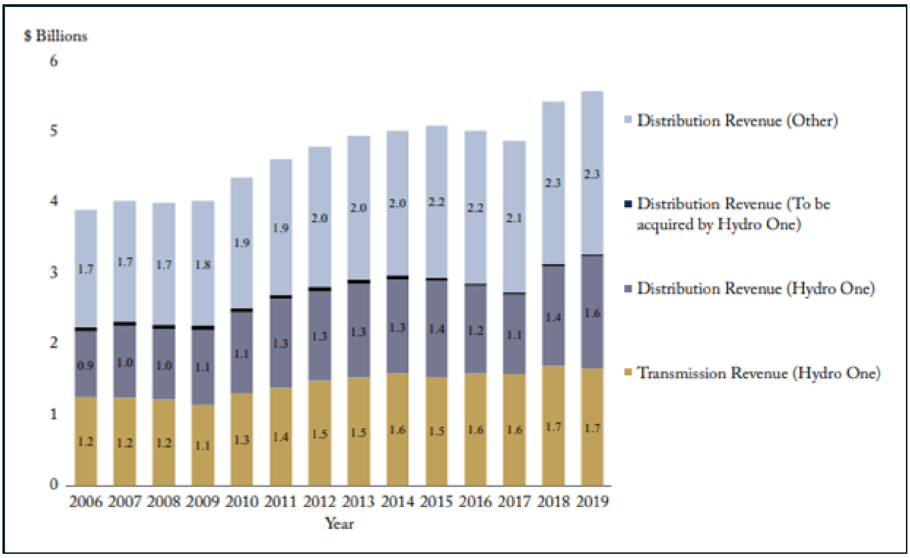
Of the major categories of distribution expenses, which include depreciation/amortization, financing, operating, maintenance, and administrative, the latter is

[4] Ontario Energy Board, "Yearbook of Electricity Distributors 2019/20" (13 August 2020), online (pdf): <www.oeb.ca/oeb/_Documents/RRR/2019_Yearbook_of_Electricity_Distributors.pdf?v=20201116>.

[5] Between 2006 and 2019, Hydro One acquired Woodstock Hydro Services, Haldimand Country Hydro, Norfolk Power Distribution, and Terrace Bay Superior Wires. In 2020, Hydro One acquired Orillia Power Distribution and Peterborough Distribution. We do not include Hydro One Brampton as part of Hydro One in historical analysis here or in subsequent analysis, as it operated as a separate company until it was merged into Alectra. These purchased utilities represent a small share of total sector costs and are not a material part of the analysis. Hence we do not distinguish these acquired LDCs in our later analysis.

[6] Hydro One, "2019 Annual Report" (2020), online (pdf): <www.hydroone.com/investorrelations/Documents/AR2019/Hydro%20One%20Limited%20Annual%20Report%202019%20Financial%20Statements.pdf>.

Figure 3: Grid Costs Expressed by Transmission and Distribution Revenues



Sources: Ontario Independent Electricity, System Operator (IESO), Ontario Energy Board, Hydro One.

where LDCs have the most leeway to create efficiencies.[7] Between 2006 and 2014, before its privatization, Hydro One's administrative expenses increased 82 per cent from $134 per customer up to $244 per customer, while those of other LDCs increased 36 per cent from $116 per customer to $158 per customer over the same duration. Even excluding its final year as a wholly owned Crown corporation, in which administrative costs rose the most, Hydro One's pre-privatization administrative cost increases were faster than the rest of the sector. The situation changed after 2014. While other LDCs saw their average administrative expense per customer rise 5 per cent from $158 per customer in 2014 to $166 per customer in 2019, Hydro One's fell by 36 per cent from $244 per customer to $155 per customer over the same period as illustrated in Figure 4.[8]

THE ROLE OF TAXPAYER SUPPORT

Successive governments in Ontario have increasingly relied on taxpayer-funded support to manage electricity rates. Subsidy programs of various kinds arose and then changed, with the first major change occurring with the Fair Hydro Plan in 2017, which then developed into the Ontario Electricity Rebate of 33.2 per cent in 2020.[9] In response to the pandemic, the government implemented additional programs as well as suspending time-of-use pricing — thus increasing the rate subsidies further.[10] In the November 2020 budget, the province again shifted how taxpayers provide support by covering 85 per cent of the green energy component of the GA through the Comprehensive Electricity Plan, lowering costs for businesses and meeting its policy commitment to having residential costs rise in line with inflation.

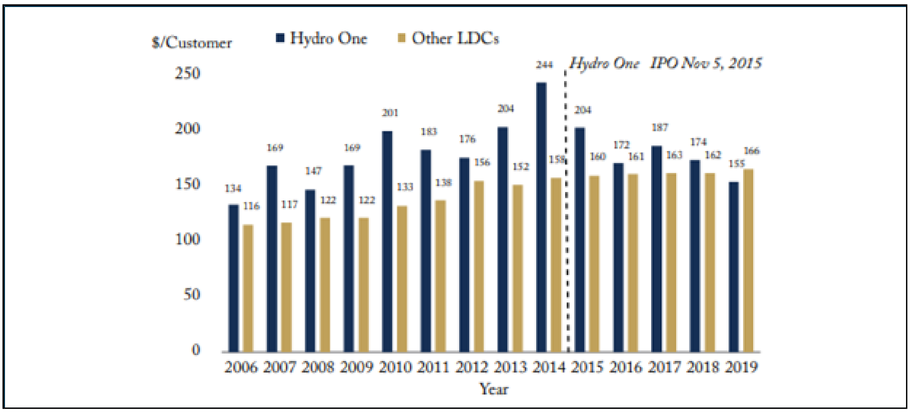
[7] Between 2006 and 2019, administrative costs for Hydro One have been about 22 to 25 per cent of total costs. For the rest of Ontario LDCs, administrative costs are approximately 28 to 33 per cent of total expenses.

[8] In its 2020 Annual Report, Hydro One points to $738 million in productivity savings since 2015, pointing to initiatives such as supply chain and fleet optimization, IT contract savings, and changes to customer call centres as examples of savings.

[9] Ontario Energy Board, News Release, "Ontario Energy Board sets new electricity prices for households and small businesses" (13 October 2020), online: <www.oeb.ca/newsroom/2020/ontario-energy-board-sets-new-electricity-prices-households-and-small-businesses>.

[10] Ontario Energy Board, News Release, "Time-of-Use and Tiered Pricing Resumes" (22 February 2021), online: <www.oeb.ca/newsroom/2021/time-use-and-tiered-pricing-resumes>.

Figure 4: Distribution Administrative Expenses for Hydro One vs Other LDCs



Note: These administrative expenses are only from distribution, and do not include expenses from transmission.
Sources: Ontario Energy Board and author's calculations.

The inception of the Fair Hydro Plan on July 1, 2017 coincided with both the initial increase in subsidies and the substantial drop in the Ontario residential electricity price index (Figure 5).[11] However, rising energy costs coupled with a political desire to keep rates low have caused the rate subsidies to soar to levels far higher than in previous years. At the start of the 2021/22 fiscal year, with the introduction of the Comprehensive Electricity Plan, the province allocated $6.5 billion to consumer subsidies.[12] The result is that residential ratepayers have enjoyed rates in 2020 as low as they were in the 2013/14 fiscal year whereas the cost to taxpayers has never been bigger.

THE GLOBAL ADJUSTMENT CONTINUES TO GROW FOR ALL TYPES OF ENERGY

The GA represents the difference between the revenues generators receive through long-term fixed power contracts and the revenues they collect in the wholesale market. It now accounts for the largest share of system cost growth since 2006. The GA has increased from $700 million in 2006 to $14 billion in 2020 — representing a 1,900 per cent increase (Figure 6).

All generation in Ontario receives out-of-market payments through the GA, with nuclear and hydro making up the largest share as shown in Figure 6. In 2020, Ontario Power Generation's (OPG) share of the GA revenues for its nuclear and hydro energy amounted to $4.6 billion; non-OPG nuclear represented $2.8 billion; wind was $2 billion; solar was $1.7 billion; natural gas generation was $1.3 billion; non-OPG hydro was $800 million; and the remainder of the GA categorized as "other" was $600 million.[13]

POLICY SOLUTIONS

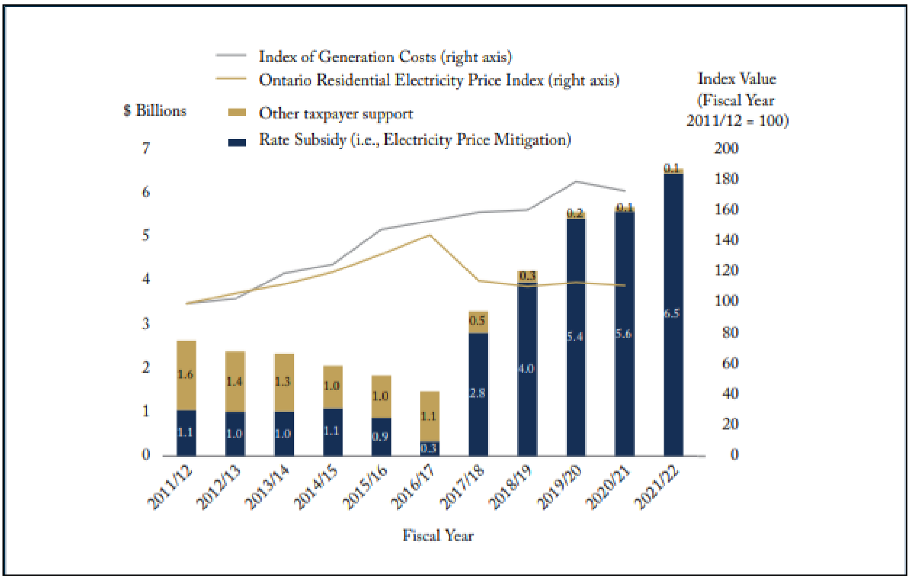
The government should look to find savings in the cost of energy and look to find further savings across the electricity distribution system, thus building on the savings Hydro One found after its privatization.

[11] In 2017, the Ontario government introduced a refinancing program without an apparent fiscal cost that, after partly causing the Auditor General to question the accuracy of the financial statements of the province, the subsequent government converted into an explicit taxpayer-financed subsidy.

[12] Government of Ontario, "Expenditure Estimates for the Ministry of Energy, Northern Development and Mines (2021-22)" (21 April 2021) online: <www.ontario.ca/page/expenditure-estimates-ministry-energy-northern-development-and-mines-2021-22>.

[13] Unfortunately, comparable data on production and generation capacity are not readily available to produce measures of the unit cost of GA components.

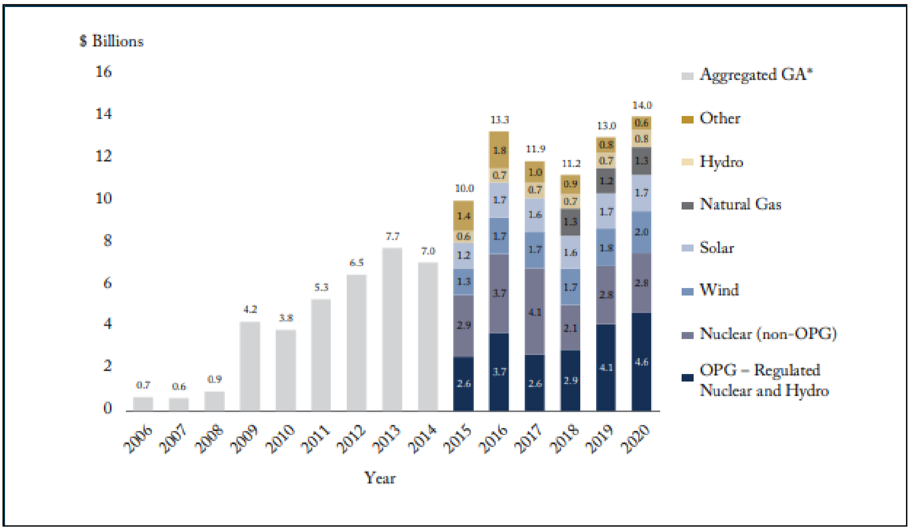
Figure 5: Ontario Electricity Prices and Taxpayer Support



Note: Hourly Ontario Energy Price (HOEP) and Global Adjustment (GA) converted to Ontario fiscal year (March 31 year-end) from monthly costs reported by IESO and the converted to annual index.

Sources: Ontario government public accounts and expenditure estimates; Ontario Independent Electricity System Operator (IESO).

Figure 6: Global Adjustment by Components



* Global adjustment data by components are only available from 2015 onwards. The aggregated total global adjustment is shown from 2006 to 2014.

Source: IESO, Global Adjustment Report.

ASSIGNING GLOBAL ADJUSTMENT COSTS EFFICIENTLY

By creating the right price signals for consumers to reduce electricity consumption during the periods of highest costs, the province can reduce the need for costly peak-period production when extra supply must be provided to meet demand. Aggregate system costs can also fall if consumers increase their demand during periods of low cost.

Residential and small business consumers are subject to prices set by the OEB based on an estimate of the cost of supply for such regulated consumers. These regulated prices, broken into blocks of time during the day, roughly correspond to the system cost in given hours.

There are more accurate ways of assigning costs, therefore reducing consumption during high-cost hours and overall system costs.[14] One option is to set a price that reaches very high levels only during times of market stress, known as critical peak pricing. Another option, increasingly viable with the rise of smart home heating systems and electric vehicles, is to allow grid operators to reduce consumption by these kinds of uses during periods of high system costs. In both cases, the result would be lower costs overall for residential and small business consumers and lower system costs. These steps would reduce consumption when capacity is most costly to procure. Adding either price option for consumers could lower system costs.

There are two groups of industrial and large commercial consumers. Large consumers (so-called Class A consumers) that are part of the Industrial Conservation Initiative (ICI) can reduce the annual GA component of their electricity bill by reducing or eliminating their electricity consumption during the year's five hours of peak demand. Smaller industrial and commercial customers (Class B consumers) have their hourly GA component set at the end of the month. That end-of-month $/MWh amount applies to all consumption of electricity, regardless of the system costs in any given hour.

The industrial electricity pricing system does not lead to the efficient or fair allocation of costs in the system. Class A consumers face an overly high cost for power during peak hours and aren't sufficiently rewarded for reducing their electricity usage during the top five demand hours of the year. The ICI allows an industrial facility to avoid the GA portion of its bill based on reducing its share of power during the five hours with the greatest demand during a given year, which are not known in advance. If a customer used power during those peak hours, the cost was approximately $110,000/MWh in 2019. This is far above the cost of installing added capacity.[15] With such excessive costs around peaks, the ICI contributes to increased volatility for directly connected industrial loads as certain consumers reduce their consumption in far more hours than those that end up being the top five consumption peaks.

The IESO should instead create, initially as a pilot to test market interest, a demand response auction into which ICI customers would make offers for the price in return for curtailing their power consumption when the system is at capacity. This would create a market-based "interruptible rate" for ICI-eligible customers.[16]

ICI-eligible customers could get a lower fixed rate based on the amount of the demand they offer into the demand response market. Such a system would better align the prices industrial consumers pay with the system costs, while also preserving industrial competitiveness. Such a system would create a market-based signal for consumers to invest in electricity storage systems rather than the current arbitrary administrative rules in the ICI.

For smaller industrial and commercial consumers, the immediate solution is to have the IESO set the GA on an hourly basis. Without such time varying charges many industrial and commercial consumers lack

[14] Bishop, Ragab & Shaffer, *supra* note 1.

[15] Grant Bishop & Benjamin Dachis, "Ontario Industrial Power Prices are Set to Spike: A Four-part Reform" (5 May 2021), online (pdf): *C.D. Howe Institute* <www.cdhowe.org/sites/default/files/IM-Bishop-2020-0505.pdf>.

[16] Hydro-Québec, for its part, offers large customers credits in exchange for curtailing electricity consumption at its request. See Hydro-Québec, "Interruptible Electricity Options for Rate L customers" (last visited 15 June 2021), online: <www.hydroquebec.com/business/customer-space/rates/interruptible-electricity-options-large-power-customers.html>.

incentive to smooth their power consumption. Smoothing load saves costs for the system by reducing the need for additional capacity to meet peak demand. An hourly GA rate would encourage price-sensitive manufacturers to push production to early mornings to avoid high-use, high-system-price afternoons and evenings. The OEB is examining such a system and should introduce a pilot pricing program for willing customers.[17]

REGULATORY EMPOWERMENT

The Ontario government's hands-on approach to energy procurement with little restraint has long been the center of controversy. The OEB does not have sufficient regulatory review powers to provide a check on government direction of the sector.[18]

In 2004, the province established the Ontario Power Authority (OPA), which had a broad mandate under which it was responsible for forecasting supply and demand, assessing long-term adequacy, procuring capacity for the province, and overseeing conservation programs. The OPA signed contracts mostly with natural gas generators at first then renewables that led to the high cost of these generating facilities today, albeit with a few versions of procurement having a competitive process.

The trend towards increasing ministerial powers continued with the enactment of the *Green Energy Act, 2009*[19] in 2009, which granted additional powers to the Ministry of Energy. The Act is most well-known for the introduction of the feed-in-tariff that allowed all renewable power the right — up to a fixed total capacity — to connect to the grid and receive a generous fixed rate for their power.[20] This led to an influx of renewables, with commensurately high costs, while system planning and regulatory oversight took a back seat.

By the time the OPA merged into the IESO in 2015, it had over 33,000 contracts for generation with most contracts containing 20-year terms. The bulk of these contracts were for renewables, but also included other sources of power such as natural gas generation. Between 2005 and 2015, the Ministry of Energy issued more than 100 directives to the IESO (and previously the OPA) to procure energy without regulatory review.[21]

SHIFTING THE DECISION-MAKING POWERS

The *Green Energy Act, 2009* was repealed in 2019, but the Ontario government's top-down approach to energy procurement has allowed ministerial directives to shape the grid while largely being devoid of regulatory oversight. Renewable energy is not to blame for the cost increases, but rather it is the framework used to procure the energy. Unfortunately, the burden of these short-sighted decisions falls on future ratepayers and taxpayers (Alberta has shown a better way to reduce renewable costs through better design of long-term contracts — see Box 1). One remedy to mitigate costly policy errors going forward is to limit political interference from system planning and energy procurement. Governments often make choices based on a broad set of criteria in their overall policy goals. Legislation is the right forum for socio-economic goals. Implementation should then be left to independent agencies. That should leave regulators with the sole priority of seeking economic efficiency.[22]

[17] Ontario Energy Board, "Staff Research Paper: Examination of Alternative Price Designs for the Recovery of Global Adjustment Costs from Class B Consumers in Ontario" (28 February 2019), online (pdf): <www.oeb.ca/sites/default/files/rpp-roadmap-staff-research-paper-20190228.pdf>.

[18] Office of the Auditor General of Ontario, "2011 Annual Report" (Fall 2011) at 87–120, online (pdf): <www.auditor.on.ca/en/content/annualreports/arreports/en11/2011ar_en.pdf>.

[19] SO 2009, c 12, Schedule A.

[20] George Vegh, "Electricity Procurements in Ontario: Time for a New Approach" (27 February 2020), online (pdf): *Ontario 360* <on360.ca/wp-content/uploads/2020/02/Electricity-Procurements-in-Ontario-Time-for-a-New-ApproachFINAL-1.pdf>.

[21] Michael Trebilcock, "Ontario's Green Energy Experience: Sobering Lessons for Sustainable Climate Change Policies" (15 August 2017), online (pdf): *C.D. Howe Institute* <www.cdhowe.org/sites/default/files/attachments/research_papers/mixed/e-brief_263.pdf>.

[22] Jeffery Church, "Defining the Public Interest in Regulatory Decisions: The Case for Economic Efficiency" (9 May 2017), online (pdf): *C.D. Howe Institute* <www.cdhowe.org/sites/default/files/attachments/research_papers/mixed/Commentary_478.pdf>.

Box 1: A Better Way to Procure Green Energy

The Alberta government launched the Renewable Electricity Program (REP) in 2017 with the goal of bringing additional renewable electricity online. Unlike Ontario's feed-in tariff program, the REP utilized competition as a driving force in procurement. Three competitive auctions for a fixed amount of capacity were held between 2017 and 2018 in which the lowest cost offers won. This not only incents the lowest- cost generation to be built first, but has the added benefit of price discovery. The average price for wind contracts was $37/MWh.[23] These 20-year contracts were "contracts for differences" meaning when market prices are higher than $37/MWh the government receives the difference, and if prices are below the government pays it. To date, the government has earned money as the generation-weighted price since inception is slightly over $38/MWh. In addition to this, the contracts awarded through the REP auctions stipulated that wind farms surrender their right to receive carbon offsets — thus translating to additional cost savings.

The IESO, if subject to appropriate regulatory review by the OEB, is far better equipped than the government for making decisions on the most economical means of procuring electricity. However, the OEB does not currently have the power to review the IESO procurement process or government decisions. Such review powers could reduce the risk of Ontario repeating past mistakes in procurement and could provide the same benefit to other provinces, as exemplified by Site C in B.C. or Muskrat Falls in Newfoundland and Labrador where regulators were sidelined.[24] The Ontario government can also mitigate risk to ratepayers by creating a competitive group of buyers of electricity, not just relying on the IESO.[25] In such a system, LDCs would take part in buying groups that each forecast demand in areas they serve. Such load-serving entities would reduce the aggregate risk of contracting and supply on ratepayers. Risks would be shared with the shareholders of companies serving customers. These load-serving entities could take part in an IESO-operated, and OEB-regulated, contract market as recommended by Shaffer.[26]

REDUCING DISTRIBUTION COSTS

One solution for reducing distribution system costs is for the province to enact tax changes that allow cities to find outside investors who can reduce costs while also unlocking value for municipal taxpayers. Another solution is to find other ways to encourage LDCs to find savings through scale economies.

SEEKING SCALE ECONOMIES FROM THE SMALLEST LDCs

Figure 7 plots each LDC's adjusted administrative costs per customer against the number of customers of that LDC from 2014 to 2019. There are scale economies in LDCs — to a point. The very smallest LDCs have administrative costs per customer that are $300 or more than the average LDC over this period.[27] If these smallest LDCs merged to take advantage of scale economies, they might find significant per-customer savings. However, these small LDCs have few customers. Thus, the savings would not be material system wide.

[23] Sara Hastings-Simon & Blake Shaffer, "Valuing Alberta's Renewable Electricity Program (March 2021), online (pdf): *University of Calgary, The School of Public Policy* <www.policyschool.ca/wp-content/uploads/2021/03/EEP-trends-Shaffer.pdf>.

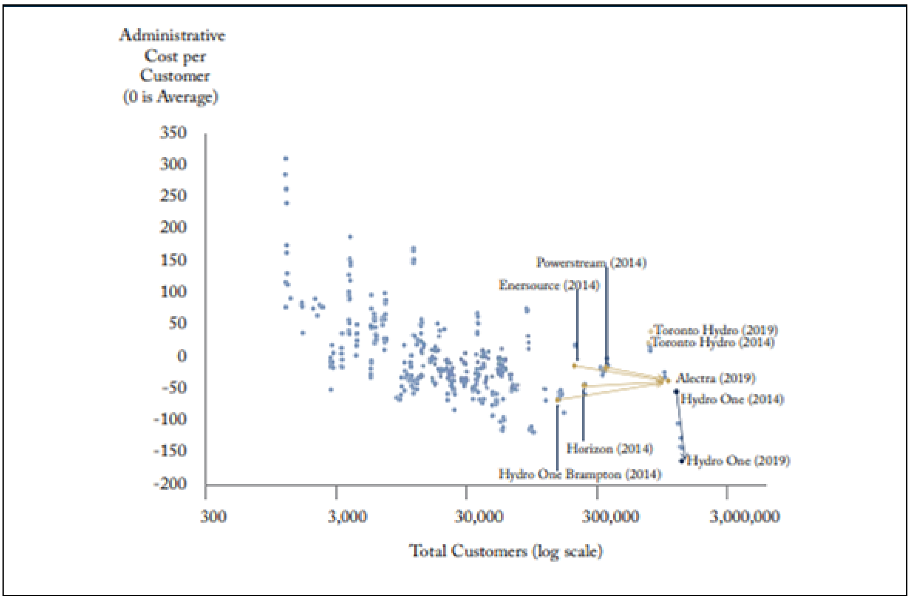
[24] A.J. Goulding, "Dammed If You Do: How Sunk Costs Are Dragging Canadian Electricity Ratepayers Underwater" (17 January 2019), online (pdf): *C.D. Howe Institute* <www.cdhowe.org/sites/default/files/attachments/research_papers/mixed/Commentary_528.pdf>.

[25] A.J. Goulding, "A New Blueprint for Ontario's Electricity Market" (18 September 2013), online (pdf): *C.D. Howe Institute* <www.cdhowe.org/sites/default/files/attachments/research_papers/mixed/Commentary_389_0.pdf>.

[26] See Blake Shaffer, "Using Forward Contracts to Deliver Reliable and Affordable Power" (18 October 2019), online (pdf): *C.D. Howe Institute* <www.cdhowe.org/sites/default/files/IM-Shaffer-2019-10-18.pdf>.

[27] Administrative costs are adjusted to control for the higher costs of LDCs that cover a wide area. An LDC's administrative costs per customer are positive if they have higher costs than an LDC of average customer density, and negative if costs are below average. This methodology follows that laid out in Stephen Fyfe, Mark Garner & George Vegh, "Mergers by Choice, Not Edict: Reforming Ontario's Electricity Distribution Policy" (25 March 2013), online (pdf): *C.D. Howe Institute* <www.cdhowe.org/sites/default/files/attachments/research_papers/mixed/Commentary_376_0.pdf>.

Figure 7: Relative Administrative Cost By Size of Customer Base, 2014–2019



Note: Relative administrative costs is calculated from regression analysis that controls for year-specific effects and the density of customers per square km of service. Methodology is the same as in Garner, Fyfe, and Vegh.[28] By regressing out the relationship between customer density and administrative costs per customer, this leaves a residual that, by definition, is unexplained by customer density.

Sources: Ontario Energy Board electric utility yearbooks; author's calculations.

Further, there do not appear to be scale economies in administration for municipally owned LDCs beyond 300,000 customers. For example, Toronto Hydro, with about 780,000 customers as of 2019, has higher administrative costs than average and has seen rising administrative costs per customer since 2014. The merger to create Alectra (announced in 2015) also shows this. Compared to the 2014 weighted administrative costs per customers of its constituent companies (Powerstream, Horizon, Enersource, and Hydro One Brampton) of $138, administrative costs per customer of the new company went up to $143 by 2019.

SEEKING PRIVATE INVESTMENT IN MUNICIPALLY OWNED LDCs

There was one major LDC that saw private investment over this period: the distribution arm of Hydro One. It saw the largest administrative cost savings per customer over this period of $90 per customer. That amounted to a 37 per cent savings on each Hydro One customer's $244 share of 2014 administrative cost. Private investors, beginning in 2015, have likely brought in cost discipline to Hydro One, something the merger to form Alectra did not see.

What if all the rest of Ontario's LDCs followed this route and saw similar 37 per cent administrative savings per customer? Using 2019 data, administrative costs now at about $650 million would fall by $239 million, saving customers $61 per year in LDC administrative costs. Total system-wide, municipal-owned LDC costs were about $2 billion, so private investment could shave about 10 per cent of these costs.

For the province to enable local governments to find similar administrative savings through

[28] *Ibid.*

private investment, it should eliminate a series of LDC-specific taxes.[29] It should eliminate the payments-in-lieu-of corporate-taxes (PILs), which collect the equivalent of both federal and provincial corporate income tax for the province. It should also eliminate a departure tax akin to a capital gains tax on leaving the PILs regime. The province should also eliminate a transfer tax it levies of 22 per cent on the value of the assets sold. These taxes were intended to ensure the province had a financial backstop for provincial stranded debt from the 1990s in case electricity assets left public ownership. Now that the debt has been whittled down with PILs collected for decades from LDCs, Hydro One and Ontario Power Generation, there is no reason for a tax on these grounds.

What is the argument for keeping LDCs in public ownership? There should be a clear policy objective such as correcting a market failure or filling a void in the market.[30] In the context of an electricity system, the most obvious market failure are the natural monopolies for distribution and transmission. Correcting these market failures requires strong rate regulation — not government ownership. Private investment alleviates risk that taxpayers would otherwise face and brings a stronger incentive to reduce controllable costs.

Cities too would see a windfall benefit, with estimates of municipal equity value of between $11 and $14 billion.[31] Cities could turn equity stranded in LDCs into needed infrastructure such as transit, roads, or sewers.

REDUCING RELIANCE ON TAXPAYER SUPPORT

As system costs — particularly in energy generation — have continued to rise, the Ontario government has increasingly turned towards taxpayers to keep total bills down. The most recent estimates from the Ministry of Finance show the cost of subsides rising to a staggering $6.5 billion for the 2021/22 fiscal year — or nearly 3.5 per cent of total government expenditures. To put this number in context, that same budget proposed to spend $5.8 billion in taxpayer dollars on long-term care. The total budget for transportation is less as well, at $6.2 billion. This approach is unsustainable in the long term and may further increase costs. The effect of taxpayers subsidizing costs is that consumers are responding by using more electricity than they otherwise would have. Total system costs will increase as a result of price mitigation.[32]

Starting in 2021, a large share of the taxpayer support will go towards reducing the GA. Residential and small business consumers will see a commensurate reduction in their taxpayer subsidy provided through on-bill rebates. However, they will still enjoy a considerable amount of on-bill taxpayer subsidy. The policy rationale for taxpayers financing the green energy component of the GA is that policy decisions made for non-market energy reasons should be financed outside of the energy system. This partly justifies the subsidy amount announced in the 2020 Ontario budget. It is economically justified because Ontario businesses that compete globally with companies that pay market-set prices do not need to shoulder politically motivated decisions on energy procurement. On-bill subsidies over and above this amount have little justification, and should be phased out.

Residential subsidies are more politically motivated. There are various ways to reduce this subsidy in a politically palatable way, such as by as making it means-tested or applicable only up to a certain amount of consumption.

CONCLUSION

Ontario's system cost grew from $12 billion in 2006 to $21 billion in 2019 while demand has fallen by 10 per cent over the same period. The cost of energy has been the largest driver of system cost growth. As costs continue to mount, the Ontario government increasingly relies on taxpayers to help foot the bill likely contributing to the rise in system costs.

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[29] *Ibid*.

[30] Many jurisdictions across North America (including Ontario) have shown that private investors are willing to invest in these segments of the market indicating no void in the market.

[31] Steven Robins, "Surge Capacity: Selling City-owned Electricity Distributors to Meet Broader Municipal Infrastructure Needs" (19 April 2017), online (pdf): *C.D. Howe Institute* <www.cdhowe.org/sites/default/files/attachments/research_papers/mixed/e-brief_257.pdf>.

[32] Exploring the effect of the electricity price mitigation on electricity consumption is beyond the scope of this paper.

The Global Adjustment has grown dramatically and high energy costs are the cause of recent price spikes. The short-term solution to this problem is to focus on better price signals and risk allocation for all kinds of customers to keep costs down. Long-term solutions to reduce energy costs require systemic change. The Ontario government should end its hands-on approach to system planning and procurement. Instead, the Ontario government should provide high- level policy direction that focuses on both empowering the OEB to regulate and ensuring the independence of the IESO to avoid repeating past mistakes.

To encourage further system cost reductions, the province should encourage LDCs to find savings. One solution is for the province to enact tax changes that allow cities to find outside investors who can reduce costs while also unlocking value for municipal taxpayers. Lastly, the province should eliminate subsidies over and above what covers the green energy component. ■

THE COLLINGWOOD JUDICIAL INQUIRY: LESSONS FOR ONTARIO'S ELECTRIC UTILITIES

*Ron Clark**

THE TRANSACTION AND INQUIRY

In a transaction closing on July 31, 2012, the Town of Collingwood sold 50 per cent of its interest in Collus Power Corporation, the local electricity distribution company (LDC) serving the Collingwood service area, to PowerStream Incorporated.

However, after a new municipal council was elected in Collingwood in 2014, questions arose about the transaction. A judicial inquiry was eventually launched, led by Associate Chief Justice Frank N. Marrocco, to investigate allegations of conflicts of interest, unfair advantages given to PowerStream throughout the procurement process, and potential malfeasance by certain parties.

THE REPORT

The Collingwood judicial inquiry published its report, entitled "Transparency and the Public Trust: Report of the Collingwood Judicial Inquiry" on November 2, 2020.[1] It contains 306 recommendations relating to best practices in corporate governance and municipal governance. A number of these recommendations are relevant to LDCs, and there are some important insights to be drawn from these recommendations.

The Report details the history of the Collus share sale, as well as the history of a separate transaction in which the proceeds of the Collus share sale were used to fund construction of certain structures at Collingwood's arena and pool facilities. This article deals with lessons arising out of the share sale.

The Report focuses in large part on the roles of the then-Mayor of Collingwood and the then-President and CEO of Collus who, at various times, was also Executive Director, Engineering and Public Works, and interim Chief Administrative Officer of Collingwood.

The Report found that the CEO was the driving force behind the transaction, and that he believed that a merger or strategic transaction with another utility could provide greater resources for Collus' future activities. The Report found this objective (of obtaining more resources for Collus so that it could pursue opportunities for growth) was at odds with Collingwood's goals at that time, which were focused on debt reduction and greater efficiencies.

Collingwood Council approved the creation of a Strategic Partnership Task Team and moved forward with a request for proposal (RFP) process based on the identification of a strategic

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[1] The Honourable Frank N. Marrocco, "Transparency and the Public Trust: Report of the Collingwood Judicial Inquiry" (2 November 2020), online (pdf): <www.collingwoodinquiry.ca/report/pdf/CJI-Complete_Report-2-web.pdf> [Marrocco Report].

partner to purchase 50 per cent of the shares of Collus. However, the Report describes this step as causing the Task Team to "unwittingly [move] forward with a plan that resulted in prioritizing Collus' interests over those of the Town: the pursuit of a strategic partner."

PowerStream was ultimately selected as the strategic partner and would acquire 50 per cent of the shares of Collus. It was selected over competing higher bids based on non-financial factors. Legal counsel to Collus was only obtained after PowerStream was selected as the strategic partner. The Mayor declined to heed advice to obtain independent counsel for the Town.

CONFLICTS OF INTEREST AND DUTIES OF DIRECTORS AND COUNCILLORS

Overview

Often, a mayor or municipal councillor of a municipal shareholder of an LDC will also sit on the board of the LDC or its holding corporation. When an individual has these dual roles with respect to an LDC, each of the LDC, the individual and the municipal shareholder should be mindful of the differing obligations and duties imposed on that individual by virtue of their roles — and be aware of whether that individual is wearing their "director hat" or their "councillor hat" when making any particular decision.

Fiduciary Duty and Duty of Care

Section 134(1) of the Ontario *Business Corporations Act*[2] (*OBCA*) requires directors and officers of a corporation to "act honestly and in good faith with a view to the best interests of the corporation", and to "exercise the care, diligence and skill that a reasonably prudent person would exercise in comparable circumstances".

Interpretation of the Fiduciary Duty

Courts have interpreted this as a fiduciary duty, and subsection 134(3) specifies that, subject to restrictions contained in any unanimous shareholders' agreement (or shareholder declaration, in the case of a single shareholder), "no provision in a contract, the articles, the by-laws or a resolution relieves a director or officer from [the duties mentioned above]". As described by the Supreme Court of Canada in *Peoples Department Stores*[3]:

> The statutory fiduciary duty requires directors and officers to act honestly and in good faith vis-à-vis the corporation. They must respect the trust and confidence that have been reposed in them to manage the assets of the corporation in pursuit of the realization of the objects of the corporation. They must avoid conflicts of interest with the corporation. They must avoid abusing their position to gain personal benefit. They must maintain the confidentiality of information they acquire by virtue of their position. Directors and officers must serve the corporation selflessly, honestly and loyally.

May not Favour Individual Shareholders

In fulfilling this duty to act in the best interests of the corporation, a director must consider the interests of the corporation as a whole and not favour any particular shareholder. This means that the director cannot be biased in favour of the shareholder that nominated them, even if they are also a municipal councillor or mayor of that shareholder. As discussed in *820099 Ontario Inc. v Harold E. Ballard Ltd.*[4]:

> It may well be that the corporate life of a nominee director who votes against the interest of his "appointing" shareholder will be neither happy nor long. However, the role that any director must play (whether or not a nominee director) is that he must act in the best interests of the corporation… The nominee director's obligation to his "appointing" shareholder would seem to me to include the duty to tell the appointer that his requested course of action is wrong if the director in fact feels

[2] RSO 1990, c B.16.

[3] *Peoples Department Stores Inc. (Trustee of) v Wise*, 2004 SCC 68 at para 35.

[4] *820099 Ontario Inc. v Harold E. Ballard Ltd.*, [1991] OJ No 266 (Ont Gen Div), 25 ACWS (3d) 853.

> this way. Such advice, although likely initially unwelcome, may well be valuable to the appointer in the long run. The nominee director cannot be a "Yes man"; he must be an analytical person who can say "Yes" or "No" as the occasion requires (or to put it another way, as the corporation requires).

Confidentiality

Part of this fiduciary duty is a duty of confidentiality. Directors must be careful to observe this duty of confidentiality at all times, and in particular, municipal councillors who act as directors of an LDC or its holding corporation should take care not to disclose confidential information to the municipality that is obtained as a result of the councillor's position as a director of the corporation.

Conflicts of Interest for Directors

A director is obliged to avoid conflicts of interest with the corporation. This is not simply limited to personal interests of the director conflicting with the interests of the corporation — conflicts can also arise in situations in which the director may not have an explicitly personal stake, including if the interests of the municipality of which the director is a councillor conflict with the interests of the corporation.

Conflicts of Interest for Councillors

It is instructive to compare conflicts of interest in the corporate context, which are interpreted broadly, with the rules relating to conflicts of interest applied to municipal councillors under the *Municipal Conflict of Interest Act*[5] (*MCIA*). While municipal councillors are trustees of the public interest, the *MCIA* defines conflicts of interest relatively narrowly, focusing on pecuniary (i.e. monetary) interests.

However, the Report also warns against considering "pecuniary interest" as the sole criterion in assessing whether a councillor is subject to a conflict of interest:

> …it is far too easy to misconstrue the *Municipal Conflict of Interest Act* as addressing all the kinds of conflict of interest that Council members must confront. Despite its name, the *Municipal Conflict of Interest Act* does not provide a complete conflict of interest code for municipal actors. It addresses the pecuniary interests of a narrowly defined group of family members related to a Council member which are by virtue of the *Act* deemed to be pecuniary interests of the Council member. Council members are obligated to avoid all forms of conflicts of interest or, where that is not possible, to appropriately disclose and otherwise address those conflicts.[6]

ROLE OF THE MUNICIPAL SHAREHOLDER AND REPORTING/ CONTROL MECHANISMS

Often, the impetus for an LDC amalgamation or sale comes from the LDC itself, since the LDC's officers and directors have experience, expertise and connections within the industry and are the first to become aware of an opportunity. Officers and directors of the LDC can provide valuable insight when a strategic transaction or sale is being considered, and they play an important role in addressing operational and transitional matters while the transaction is being finalized. Ultimately, though, the municipal shareholder is the owner of the LDC, and municipal council must take charge of evaluating the merits of any transaction that affects the municipality's shares of the LDC.

There are a number of ways for a municipal shareholder or shareholders to exert control over a subsidiary LDC. As a first step, a unanimous shareholders' agreement (or shareholder declaration, in the case of a single shareholder) will require that before taking certain major actions, approval of the municipal shareholder(s) must be obtained for those actions. The scope of what is subject to approval can vary, depending on the level of control that the shareholders wish to exert and the level of strategic autonomy that they wish to give to the LDC to pursue opportunities for growth. Nevertheless, major transactions such as amalgamations or sales of the entire business

[5] RSO 1990, c M.50.

[6] Marrocco Report, *supra* note 1, vol 1 at 21.

will inevitably require shareholder approval (though perhaps at a threshold of less than 100 per cent of shareholder votes).

When a potential transaction arises that will require shareholder approval, the municipal councils should be informed at an early stage so that councillors can make fully informed decisions and delegate certain tasks as appropriate. Functionally, once municipal council gives a tentative approval to proceed with exploring a transaction, a smaller task force or team usually performs due diligence, assesses the merits of the transaction, and reports back to municipal council. Reporting structures should be thoughtfully structured to ensure that councillors have all necessary information to be able to properly evaluate the transaction, and municipal shareholders should retain separate counsel to provide them with independent legal advice on the transaction.

In particular, LDCs and their municipal shareholders should be careful when one individual might have a monopoly of access to the council and thus be able to control and filter the information that council receives. This concern often arises when one individual holds multiple roles (e.g. a municipal councillor who also sits on the board of the LDC or its holding corporation), and is therefore naturally placed to be a liaison between the LDC and municipal council.

It is crucial that municipal shareholders obtain independent legal counsel when evaluating a merger or sale transaction involving an LDC, since as was seen in the Collus transaction, the incentives of the LDC and the incentives of the municipal shareholder are not always aligned.

PROCUREMENT PROCESSES

LDCs and their shareholders should strive for fairness and transparency in procurement processes, including situations like the Collus transaction where bids are solicited from third parties for the sale of shares of the LDC. All parties should consider the nature of the proposed transaction in determining whether a sole-source procurement is appropriate or if multiple bidders should be solicited. Once a bidding process is underway, care should be taken to act in good faith, to be even-handed among all bidders, and to follow the rules and processes set out in the procurement documents (e.g. the RFP document and its accompanying rules/procedures). The tendering party in the procurement should avoid any asymmetric information sharing among the bidders.

LDCs and their shareholders should be careful not to allow procurements to functionally be run as if they are a sole source procurement, while masquerading as a multiple source procurement. If one bidder is heavily favoured over another (including before the RFP is announced), then it skews the process and may result in less favourable outcomes for the tendering party. The tendering party should ensure that it acts in good faith and in an even-handed manner among all parties when sharing information about an upcoming or ongoing procurement, when preparing the procurement documents, and when soliciting and evaluating bids.

In particular, once an RFP or other tender is issued, the common law requires that the tendering party follow the rules and procedures set out in the tender. The "Contract A, Contract B" principle was first set out by the Supreme Court of Canada in the case of *Ron Engineering*[7], and was further built upon in *M.J.B. Enterprises*[8] and *Martel Building*[9]. It establishes that there are two different types of contracts formed with bidders. "Contract A" is established between a procurer and a bidder upon the bidder's submission of a compliant bid in response to a tender. Contract A governs the terms of the procurement process, while "Contract B" is the subsequent contract for goods and services. Procurement law requires procurers to act fairly and consistently in the evaluation of bids, and the principles of fairness and good faith are implied terms of the Contract A that is formed when a bidder submits its compliant bid. Contract A can be thought of as a contract between the procurer and each bidder that the rules and processes set out in the procurement documents will be followed, and that the procurer will act fairly, consistently and in good faith while doing so. If the procurer deviates from the evaluation

[7] *The Queen (Ont.) v Ron Engineering*, [1981] 1 SCR 111, 119 DLR (3d) 267.

[8] *M.J.B. Enterprises Ltd. v Defence Construction (1951) Ltd.*, [1999] 1 SCR 619, 170 DLR (4th) 577.

[9] *Martel Building Ltd. v Canada*, 2000 SCC 60.

criteria set out in the original tender, then a disappointed bidder could argue that Contract A was breached and therefore sue for breach of contract.

KEY LESSONS FOR LDCs

There are three main lessons for LDCs to be drawn from Justice Marrocco's conclusions in the Report:

1. LDCs, their affiliates and their directors should understand and be mindful of the obligations and duties of individuals playing multiple roles at the LDC and its affiliates, particularly when they are both a director of the LDC or its affiliate and a municipal councillor of a shareholder. While municipal conflict of interest legislation applicable to municipal councillors focuses on conflicts where the councillor may have a pecuniary (i.e. monetary) interest, the duties of a director of a corporation go much further. The Ontario *Business Corporations Act*[10] imposes a fiduciary duty on directors to act in the best interests of the corporation, a duty that is not altered or diminished by the method by which the director was elected (e.g. if they were a nominee of a particular municipal shareholder). In acting in the best interests of the corporation, the director must be even-handed among all shareholders and not favour the shareholder that nominated them, or the shareholder of which they are a municipal councillor.

2. While the officers and directors of an LDC have expertise and knowledge of the electricity distribution sector and can provide valuable insight when considering a strategic transaction involving the LDC, the municipality (in particular, municipal council) must take responsibility for decision-making on such major transactions. The LDC, as the asset owned by the municipal shareholder(s), should not be "in charge of selling itself," as Justice Marrocco describes the Collus transaction in the Report. Instead, the municipal shareholder(s), as owner of the asset, should take an active role in managing the asset and ensuring that the proposed transaction provides optimal value to shareholders. In doing so, they should be mindful of the potential for misaligned incentives, and also keep in mind that after the transaction is complete, management of the LDC (and its board) will be obliged to act in the interests of all shareholders. Municipal shareholders should retain separate counsel from the LDC and receive independent legal advice in respect of potential transactions, since their interests will not always be aligned with those of the LDC.

3. LDCs and their shareholders should strive for fairness and transparency in procurement processes, including situations like the Collus transaction where bids are solicited from third parties for the sale of shares of the LDC. All parties should consider the nature of the proposed transaction in determining whether a sole-source procurement is appropriate or if multiple bidders should be solicited. Once a bidding process is underway, care should be taken to act in good faith, to be even-handed among all bidders, and to follow the rules and processes set out in the procurement documents (e.g. the Request for Proposals document and its accompanying rules/procedures). The tendering party in the procurement should avoid any asymmetric information sharing among the bidders. ■

[10] *Supra* note 2.

BRITISH COLUMBIA SUPREME COURT SIGNIFICANTLY EXPANDS INDIGENOUS RIGHTS

*Sander Duncanson, Martin Ignasiak, Tommy Gelbman, Olivia Dixon and Tyler Warchola**

On June 29, 2021, the British Columbia Supreme Court released its decision in *Yahey v British Columbia*[1], in which it ruled that the rights of the Blueberry River First Nations (BRFN) under Treaty 8 in northeast British Columbia had been infringed by the cumulative impacts of industrial developments within Blueberry's traditional territory, including forestry, oil and gas, renewable energy and agriculture. This decision marks a significant departure from past cases involving cumulative effects and treaty rights infringement. Depending on the outcome of any appeal, it could materially increase regulatory risks for new infrastructure projects in northeast British Columbia, and could extend to other areas in Canada where similar claims may be made.

BRFN is a relatively small First Nation in northeast British Columbia (B.C.), with a reserve located approximately 80 kilometres northwest of Fort St. John. BRFN has roughly 190 members living on-reserve and 295 members off-reserve.[2] BRFN's traditional territory is approximately 38,000 square kilometres, spanning from the Alberta-B.C. border in the east to the foothills of the Rocky Mountains in the west, south to the Peace River, and north and east to Pink Mountain, Sikanni Chief River, Lily Lake and Tommy Lakes. This area includes most of the Montney natural gas play in B.C., agricultural lands, various municipalities (including Fort St. John and Dawson Creek), active forestry areas, hydro-electric projects (including Site C), and several mines. BRFN's territory also falls within the area of Treaty 8, which BRFN's ancestors signed in 1900. BRFN's traditional territory also overlaps, to varying degrees, with the asserted territories of several other Indigenous groups who were not parties to the proceedings before the Court.

In 2015, BRFN filed a civil action seeking, among other things:

- a declaration that the B.C. government infringed BRFN's rights under Treaty 8, particularly the Crown's oral promises that Indigenous signatories would be as free to hunt, trap and fish after the Treaty as they would be had they never entered into it, and the Treaty would not lead to forced interference with their mode of life; and

* Sander Duncanson, Martin Ignasiak, Tommy Gelbman, and Olivia Dixon are partners at the Osler law firm in Calgary. Tyler Warchola is a summer student at the firm. An earlier version of this article appeared in the Osler Resource Bulletin. See online: <www.osler.com/en/resources/regulations/2021/british-columbia-supreme-court-issues-precedent-setting-cumulative-effects-decision>.

[1] 2021 BCSC 1287, online: <www.canlii.org/en/bc/bcsc/doc/2021/2021bcsc1287/2021bcsc1287.html>.

[2] British Columbia Assembly of First Nations, "Blueberry River First Nations" (last visited 16 July 2021), online: <www.bcafn.ca/first-nations-bc/northeast/blueberry-river-first-nations>.

- to enjoin B.C. from approving any further developments within its traditional territory.

After a series of unsuccessful pre-trial applications, including two applications by BRFN to enjoin certain Crown conduct pending the outcome of the trial and a judicial review petition, the B.C. Supreme Court held a full trial to consider BRFN's civil claim. The trial included roughly 70 days of expert and lay witness testimony, tens of thousands of pages of written submissions, and 25 days of oral argument.

SUMMARY OF DECISION

On June 29, 2021, the B.C. Supreme Court released its 511 page decision: *Yahey v British Columbia*. Justice Burke for the Court held that the cumulative effects from all types of industrial development in BRFN's territory have resulted in significant adverse impacts on the lands, water, fish and wildlife in the area, and to the exercise of BRFN's Treaty 8 rights. In particular, she found that BRFN's treaty rights to meaningfully hunt, fish and trap within the BRFN traditional territory have been significantly and meaningfully diminished, such that BRFN's rights under Treaty 8 have been infringed.[3]

In language reminiscent of the Alberta Court of Appeal's decision last year in Fort McKay[4], Justice Burke's conclusions were rooted in her view that B.C. had not acted honourably by allowing resource development to proceed "at an extensive scale" without assessing BRFN's concerns about cumulative effects of this development:

> I find that the Province has, for approximately two decades, been aware that the cumulative effects of development in the northeast portion of BC were leading to changes in wildlife habitat and water quality that posed serious concerns, and that by the late 1990s much of [BRFN's Traditional Territory] was being significantly impacted by industrial development. The Province has also, for at least a decade and likely more, had notice from Blueberry that it was concerned about the impacts of cumulative development in [BRFN's Traditional Territory], and on the exercise of their treaty rights. Despite having notice of Blueberry's concerns, I find that the Province has failed to respond in a manner that upholds the honour of the Crown and the obligation to implement treaty promises.[5]
>
> […]
>
> Acting with ordinary prudence in this case required that the Province investigate the concerns regarding cumulative impacts by developing processes to assess cumulative effects in [BRFN's Traditional Territory] and develop ways of managing and mitigating these effects. In the Court's view, ordinary prudence would have required that the Province pause some development in [BRFN's Traditional Territory], or key areas within [BRFN's Traditional Territory], pending the results of this work. Allowing development to proceed in the face of these substantial and well grounded concerns could not be said to be acting with good faith, loyalty, or ordinary prudence with a view to Blueberry's best interests. Ordinary prudence requires long-term planning, looking ahead and considering the likely future effects of current decisions, as opposed to simply stubbornly "staying the course."[6]

[3] *Supra* note 1 at paras 1116, 1132.

[4] *Fort McKay First Nation v Prosper Petroleum Ltd*, 2020 ABCA 163; For a discussion of the decision see Martin Ignasiak, Sander Duncanson & Jesse Baker, "Resource projects and the honour of the Crown: More than just consultation about a project's impacts" (14 May 2020), online: <www.osler.com/en/resources/regulations/2020/resource-projects-and-the-honour-of-the-crown-more-than-just-consultation-about-a-project-s-impacts>.

[5] *Supra* note 1 at para 1750.

[6] *Ibid* at para 1805.

Justice Burke granted the following declaratory relief:

1. In causing and/or permitting the cumulative impacts of industrial development on BRFN's treaty rights, B.C. has breached its obligation to BRFN under Treaty 8, including its honourable and fiduciary obligations. B.C.'s regulatory mechanisms for assessing and taking into account cumulative effects are lacking and have contributed to the breach of its obligations under Treaty 8.

2. B.C. has taken up lands to such an extent that there are not sufficient and appropriate lands in BRFN's traditional territory to allow for BRFN's meaningful exercise of their treaty rights. B.C. has therefore unjustifiably infringed BRFN's treaty rights in permitting the cumulative impacts of industrial development to meaningfully diminish BRFN's's exercise of its treaty rights in its traditional territory.

3. B.C. may not continue to authorize activities that breach the promises included in the Treaty, including B.C.'s honourable and fiduciary obligations associated with the Treaty, or that unjustifiably infringe BRFN's exercise of its treaty rights.

4. B.C. and BRFN must act with diligence to consult and negotiate for the purpose of establishing timely enforceable mechanisms to assess and manage the cumulative impact of industrial development on BRFN's treaty rights, and to ensure these constitutional rights are respected.[7]

Justice Burke suspended Declaration #3 for six months to give the parties the opportunity to negotiate changes to the regulatory regime that recognize and respect BRFN's treaty rights.

IMPLICATIONS

There are many aspects of *Yahey* that warrant comment, but for the purposes of this Update we focus on two key implications: Justice Burke's test for treaty infringement, and the decision's potential impacts on all types of infrastructure development in Canada.

TEST FOR TREATY INFRINGEMENT

Unlike prior Treaty rights jurisprudence, where allegations of infringement focused on a single piece of legislation or regulatory regime, BRFN's claim was based on the cumulative impacts of various activities, projects, and developments in northeast B.C. over the last 120 years, including municipal and agricultural development. Justice Burke considered this development in the context of the promises enshrined in Treaty 8 and found that, while the Crown has the power to take up lands from time to time, that power is not absolute or unrestricted and cannot be used to make the constitutional protection of Indigenous hunting, trapping and fishing rights meaningless.[8] Among other things, Justice Burke found that BRFN's Treaty 8 rights depend on healthy populations of moose and other wildlife so that the BRFN members have a chance at being successful on their hunts and do not need to travel far from or outside of their territory to find game.[9] She also noted that BRFN's way of life depends on a relatively stable environment, and that if forests are cut, or critical habitats are destroyed, it is not as simple as finding another place to hunt.[10]

According to Justice Burke, the test for determining whether treaty rights have been infringed is whether there has been a *significant or meaningful diminishment of the rights*.[11] Arguably, this modifies the Supreme Court of Canada's guidance in *Sparrow* and *Mikisew* that infringement occurs when there is "no meaningful exercise of the rights" — a test that Justice Burke concluded would upend the terms of the Treaty.[12] Justice Burke's test is

[7] *Ibid* at para1894.

[8] *Ibid* at para 275.

[9] *Ibid* at para 437.

[10] *Ibid* at para 433.

[11] *Ibid* at para 529.

[12] *Ibid* at para 514.

much easier to establish than the prior test in *Sparrow* and *Mikisew*, particularly when many parts of Canada (and Indigenous communities themselves) have changed materially over the last 120 years through, among other things, population growth, modernization and climate change. As Justice Burke acknowledged, "with more and more takings and development it becomes harder and harder for the Crown to fulfill its promise to Indigenous people that their modes of life would not be interfered with".[13]

Importantly, B.C. did not advance the defence that the infringement was justified. Justice Burke observed in obiter that "even if the Province had argued justification, it would have been difficult for the Province to justify the infringements of Blueberry's treaty rights".[14] As the justification defence was not advanced, there remains a gap in the law as to what could justify such infringement in the circumstances. For example, Justice Burke observed (also in *obiter*) that, while BRFN received $18 million from B.C. in benefits agreements from 2006 to 2013 (which could be viewed as accommodation for impacts to treaty rights), these payments are minimal relative to the annual revenue B.C. receives from resource royalties in the area.[15] While this reasoning does not follow any recognized legal test, this aspect of *Yahey* will likely be used to challenge attempts by provincial or federal governments in future litigation to argue that Treaty rights infringement has been justified by means of financial compensation.

IMPLICATIONS FOR INFRASTRUCTURE DEVELOPMENT

Obviously, *Yahey* has direct and serious implications for any future infrastructure development in BRFN's Traditional Territory. Declarations #3 and #4 in the decision may be construed as granting BRFN the right to veto any new development across its entire, expansive territory, without considering the potentially conflicting views of other Indigenous groups whose asserted traditional territories may overlap with BFRN's traditional territory. It is also possible that other Treaty 8 First Nations in northeast B.C. will rely on *Yahey* to assert that they are entitled to the same relief Justice Burke granted BRFN. Unless B.C. successfully appeals *Yahey* or reaches a settlement with BRFN that would allow development to proceed, the future of any new development in this part of B.C. (including, again, most of the Montney gas play in B.C.) may require BRFN's consent — thereby transferring control of a substantial portion of B.C.'s resource base to a community of less than 500 people. If B.C. does not seek to appeal *Yahey*, the appellate courts will not have an opportunity to weigh in on the trial decision.

The effects of *Yahey* will likely not be confined to northeast B.C. Many parts of Canada have seen material population growth, infrastructure and/or resource development since the time that historic treaties with Indigenous groups were entered into. We expect *Yahey* will lead to similar cumulative effects claims across Canada. Such claims could inject further uncertainty into Canada's regulatory approval processes, and, if successful, could significantly change the future of resource and infrastructure development in Canada. The deadline for B.C. to file a notice of appeal is July 29, 2021. ■

[13] *Ibid* at para 520.

[14] *Ibid* at para 1855.

[15] *Ibid* at para 1213.

THE GUIDE TO ENERGY ARBITRATIONS

*Adam Chisholm**

Those in the international arbitration and energy spaces have had the benefit of topical education in energy arbitration law since 2014 through the Global Arbitration Review's *The Guide to Energy Arbitrations*[1]. General Editor William Rowley's preface positions the latest offering, the Fourth Edition, as one published in the midst of energy and resource sector arbitrations being popular, but also in a world struck by the recent oil crash, the COVID-19 pandemic and Russian sanctions.

One could reasonably wonder about the need for the prolific generation of editions of *The Guide to Energy Arbitrations* — one less than every two years. The answer is implicit in recent developments: authoritative decisions from international and national courts alike and the passage of new international instruments. Rowley, Doak Bishop and Gordon Kaiser, having assembled the work, are clearly compelled to keep it relevant as the international landscape changes. An international cadre of contributing authors assists them in that goal.

The introduction to the work is one that rightfully spans editions. It provides an overview of the traditional energy sector and energy-related investment disputes. Co-editor Bishop identifies resources, markets, contracts and treaties elaborated on in other parts of the book. For those transitioning their skills into the area, the introduction is the right place to start. After this introduction, the work is decidedly more specialized and focused on specific topics rather than the general intersection of advocacy and energy.

The first section of the book focuses on "Investor-State Disputes in the Energy Sector." Owners of previous editions will find the foundational chapters in the first section topically updated. The chapter on the Energy Charter Treaty was already one of the longer pieces within the work, authored by Cyrus Benson et al. The Fourth Edition includes important additions about the use of the influential March 2018 decision of the Court of Justice of the European Union in *Slovak Republic v Achmea BV*[2] by EU Member States to object to the Energy Charter Treaty. Pages of analysis concerning related events (all taking place after publication of the Third Edition) review the impact of the decision.

The chapter on "Investment Disputes Involving the Renewable Energy Industry under the Energy Charter Treaty" has also been enhanced and lengthened from previous editions, with Igor Timofeyev et al now offering analysis of decisions from as recently as last year as part of the offering.

The second section of the book, covering "Commercial Disputes in the Energy Sector," includes a mixture of updated authorship and new topics. Chapters on "Construction Arbitrations Involving Energy Facilities" and "Offshore Vessel Construction Disputes" are freshly revised. New focuses include an enhanced and longer chapter on "Disputes Involving Regulated Activities," authored by Kaiser, which is centered on the availability of arbitration when regulators are involved. This chapter includes analysis and reference to recent decisions across

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[1] J William Rowley, Doak Bishop & Gordon E Kaiser, *The Guide to Energy Arbitration*, 4th ed (London, UK: Law Business Research Ltd, 2020), online: *Global Arbitration Review* <globalarbitrationreview.com/guide/the-guide-energy-arbitrations/4th-edition>.

[2] C-284/16, online: <curia.europa.eu/juris/liste.jsf?num=C-284/16&language=EN>.

North America, including considering the impact of a landmark domestic decision of the Supreme Court of Canada in 2019 on regulatory energy decisions[3].

A new chapter in the commercial disputes section, entitled "NAFTA Energy Arbitrations," speaks as much to the transition to the United States-Mexico-Canada Agreement as it does to the still-relevant (transitional) private action provisions under NAFTA. This section, also authored by Kaiser, postulates that new common law actions are promising tools to fill space formerly occupied by section 11 of NAFTA. It also addresses where investors in oil, gas and power generation qualify under the new Agreement.

Readers should not be concerned about an excessively North American focus. As noted above, there are material amendments to the work concerning the EU's Energy Charter Treaty. Furthermore, perhaps the most significant additions to the work focus on international liquefied natural gas (LNG) issues that arise around the world. The introduction to the chapter on "Gas Supply and LNG Arbitrations" demonstrates why LNG is so topical. Hagit Elul et al write:

> The natural gas and liquefied natural gas markets are in a state of flux. Even prior to the covid-19 pandemic, the evolution of the natural gas markets was sufficiently rapid as to disrupt existing long-term supply contracts and result in waves of gas price review arbitration predominantly in Europe. Since these initial arbitrations, attention has also turned to Asia, where the LNG market accounts for 68 per cent of global imports. Asia was spared Europe's arbitration wave, thanks in large part to the systemic differences between the Asian and European gas markets but that may be about to change.[4]

The next section in the Fourth Edition is on "Contractual Terms." This section, as if beckoned by the "Gas Supply and LNG Arbitrations" chapter that precedes it, contains three chapters focused on natural gas. The first chapter is a modestly updated, but foundational piece by authors Stephen Amway and George von Mehren on "The Evolution of Natural Gas Price Review Arbitrations."

Two new chapters focus on gas price review disputes and provide insights from two leading European-based practitioners. These new chapters come from experienced counsel, one contributing to *The Guide to Energy Arbitrations* for the first time, and the other providing a lengthier contribution than in the past. The first new chapter, from Devika Khanna, involves a focus on the process of gas price reviews, arising from the author's experiences as the LNG markets have developed.

The second new chapter seeks to identify "inflection points in the analyses of price review tribunals that drive the outcome of these extremely important cases."[5] Counsel to Edison SpA, Marco Lorefice, provides well-informed views given his role in developing the legal frameworks for both the Egyptian and Adriatic LNG Projects.

Collectively, the chapters on "Contractual Terms" and "Gas Supply and LNG Arbitrations" provide expertise about price review arbitrations and insights for possible success, but also reflect an increased emphasis on the Asian LNG market where "new price reviews sit at the crest of a new wave of arbitrations in Asia."[6]

Each edition of *The Guide to Energy Arbitrations* has included discussion of procedural issues in energy arbitrations. The Third Edition dealt with consolidation, compensation and expert evidence. This Fourth Edition focuses solely on an evolution of the first of those topics, as Pappas et al provide an expanded take on how to manage parallel proceedings when consolidation is not possible in "When Consolidation Fails: The Challenges of Parallel Arbitral Proceedings". The chapter provides useful measures to transactional lawyers to mitigate the risk of parallel arbitration and court proceedings and recommendations for arbitration practitioners once disputes have arisen.

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[3] See *Canada (Minister of Citizenship and Immigration) v Vavilov*, 2019 SCC 65.

[4] Rowley, Bishop & Kaiser, *supra* note 1 at 155.

[5] *Ibid* at 193.

[6] *Ibid* at 183.

Today's legal marketplace is defined more than ever by combining industry expertise with legal practice experience. To that end, *The Guide to Energy Arbitrations* provides information uniquely focused on the intersection of energy law and advocacy. The editors note that among the cases heard by the London Court of International Arbitration in 2019, the energy and resources sector accounted for the greatest number of parties. *The Guide to Energy Arbitrations* is a useful tool for those in this popular space, keeping up with a shifting international economic and legal landscape. ■