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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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EDITORIAL

Managing Editors

Rowland Harrison K.C. and Gordon E. Kaiser

This issue of the *Energy Regulation Quarterly* (*ERQ*) comes at a time when Canada is facing a real prospect that the country will not meet its carbon reduction goals. Canada is not unique. Most counties are behind.

To meet the carbon goals most countries face a significant upgrade and expansion of their electricity grid. That leads to two major problems. First, there will be a significant increase in spending on new generation, distribution and transmission assets. Second, many of those assets involve new and untested technology. If they fail there will be further cost implications and delays.

To meet this challenge the federal government in Canada is making new and significant regulatory changes This issue of the *ERQ* looks at four of these: new tax credits, new clean energy regulations and new investment in small nuclear and offshore wind.

NEW FEDERAL ENERGY POLICY

New Tax Credits

On August 4, 2023 draft legislation with respect to a new Clean Technology Investment Tax Credit was announced by the federal government. It is reviewed in detail in an article in this issue of the *ERQ* by Colena Der, Jake Sadikman and Edward Rowe of the Osler law firm.

The 30 per cent tax credit applies to certain types of eligible property including zero emission electricity generation technologies like solar, wind, small hydro, small nuclear reactors and electric storage systems that do not use fossil fuels in their operations.

To be eligible the property must be new equipment situated in Canada and intended for use exclusively in Canada. The credit is available for eligible property acquired on or after March 28, 2023. The property is considered to be "acquired" when it is available for use. The credit will be available for ten years.

New Clean Electricity Regulations

On August 10, 2023, less than a week after the federal government announced the draft legislation on the new tax credits, the government issued draft new Clean Electricity Regulations. The proposed Regulations are reviewed in this issue of the *ERQ* by Dufferin Harper of the Blakes law firm in Toronto.

The Regulations establish strict GHG emission performance standards that will apply to electricity generated by fossil fuel within Canada. As of January 1, 2025 the Regulations will apply to any electrical generating unit or EGU that meets the following three conditions:

1. The EGU has an electricity generation capacity of 25 MW or greater.

2. The EGU generates electricity using fossil fuel.

3. The EGU is connected to an electricity system that is subject to the North American Electricity Reliability Corporation or NERC standard.

An EGU that exports more electricity onto an electricity system, subject to NERC, than it imports from a system, subject to NERC, during a calendar year is subject to an average annual emissions intensity performance standard of 30 tonnes of CO_2 per GWh. As of January 1, 2035 the Performance Standard will apply to:

1. An EGU that burns coal or petroleum coke.

2. An EGU commissioned after January 1, 2025.

3. An EGU that has increased its electricity generation capacity by 10 per cent or more since the registration of the EGU.

The article by Dufferin Harper considers the terms and conditions of the new legislation in greater detail but it is safe to say there will be mixed reactions. The Regulations are open for comments until November 2, 2023.

Small Nuclear

The next article that considers the scope of federal efforts to develop renewable energy in Canada is the article by John Richards and Christopher Mabry of Simon Fraser University in British Columbia. It is called "Power When You Need It: The Case for Small Nuclear Reactors."

Small nuclear reactors are nuclear reactors to produce less than 30 MW of electricity. They are much smaller than traditional nuclear plants which generally produce more than 800 MW. They are also cheaper to build and scalable which means they can target specific industrial requirements as well the requirements of remote communities.

Three Provinces, Ontario, Saskatchewan, and New Brunswick have been active in this initiative since 2019. Alberta joined the development process in April 2021. SMRs will qualify for the tax credits mentioned above in the future but over the last three years federal funding has been key.

The first project to go online is the project located at Darlington, Ontario where the federal Infrastructure Bank is investing $970 million. That facility is expected be in service by 2028. The next project will be the Saskatchewan project which is being backed by $74 million in federal government funding. Following that is another SMR design being developed at the New Brunswick Power nuclear plant located at Point Lapreau, NB. That facility is forecasted to be operational by 2030.

Nuclear technology is complex but Canada has a long-standing highly regarded skill in the technology. To date only the provinces of Ontario and New Brunswick have relied on nuclear to produce electricity. That is about to change as pointed out in the Richards Mabry article. That article which is based on a larger study by the CD Howe institute in Toronto offers a detailed analysis of the costs and benefits of this important new technology.

Offshore Wind

The last of the four areas where the federal government has recently taken strides to develop renewable energy involves offshore wind in the Atlantic Ocean. Canada has been slow to develop offshore wind. Ontario started a project to develop offshore wind in Lake Ontario ten years ago but shut it down after two years only to face a multimillion-dollar claim under NAFTA.

The Atlantic coast is more complicated than Lake Ontario because there is international, national, and provincial jurisdiction. The solution to this problem was less dependent on money then it was on changing the regulatory framework.

On May 30, 2023 the Canadian government introduced Bill C-49 to amend the Canada Newfoundland and Labrador Atlantic Accord and the Canada-Nova Scotia Offshore Petroleum Resources Accord. The amended legislation established a framework for the development and regulation of offshore projects that expands regulation of current petroleum projects and clarifies jurisdictional rules regarding domestic boundaries.

Under Bill C-49 regulatory authority for offshore wind power is granted to two existing jointly managed offshore boards that are currently exclusively responsible for regulating offshore oil and gas projects. Two new boards have been created, the Canada Nova Scotia Offshore Energy Regulator and the Canada Newfoundland and Labrador Offshore Energy Regulator. These two regulators have the power to govern all aspects of renewable energy activities including safety, environmental protection, decommissioning and royalties. The regulators can also conduct environmental assessments, public hearings and dispute resolution programs.

Bill C-49 also includes a series of broader changes to environmental jurisdictional and the enforcement aspects of the existing legislation. While Bill C-49 has yet to be adopted, Nova Scotia has already set a target of issuing 5 GW of licenses for offshore wind by 2030 with the stated aim to encourage green hydrogen production. Leasing under this scheme is expected to commence in 2025.

In connection with this initiative the Nova Scotia government on June 14, 2023 issued the first version of the Nova Scotia onshore roadmap which outlines the province's vision for the offshore wind industry.

The article in this issue of the *ERQ* that addresses these offshore wind projects is written by five authors from the McCarthy law firm in Montreal: Dominique Amyot-Bilodeau, Louis-Nicolas Boulanger, Elena Sophie Drouin, Kimberly Howard, and Jacob Stone. It is worth careful reading. This could become a very important industry in Canada.

THE PROVINCES

Ontario and British Columbia have recently been active in promoting renewable energy.

Ontario teamed up with the federal government and spent millions of dollars developing two plants to produce lithium batteries that would underwrite the province's plans to develop electric vehicles.

More recently, Ontario teamed up with Québec in a very innovative agreement to swap energy that will reduce the demand on both of their systems. The provinces electricity operators, the Independent Electricity System Operator in Ontario and Hydro-Québec have agreed to trade up to 600 MW of energy each year.

The agreement makes sense because the majority of electricity from both provinces comes from renewable energy — nuclear in the case of Ontario and hydroelectric power in case of Québec. The trade also works because Ontario and Québec have different energy peaks. The Ontario energy demand peaks in the summer driven by air conditioning while Québec energy demand peaks in the winter driven by electric heating on cold days. The deal will last 10 years with reviews taking place throughout that period to modify the amounts traded if necessary.

British Columbia has a long history of leading the charge when it comes to renewable energy driven by the province's aggressive energy goals and the ability to use the market power and technology of the province-owned British Columbia Electric Hydro & Power Authority.

British Columbia has recently taken steps to refine and develop a new regulatory regime for energy regulation which also involves new liabilities and wider jurisdiction. This is set out in an article in this issue of the *ERQ* by Sasa Jarvis, Ralph Cuervo-Lorens, Sean Ralph, and Jordan Ghag of the McMillan law firm.

On November 24, 2022 the British Columbia *Energy Statutes Amendment Act* was enacted by the provincial government to establish a comprehensive regulatory regime beyond oil and gas to "energy resources" which include hydrogen, petroleum, natural gas, methanol, and ammonia. The legislation expands the scope of the regulatory regime of the Oil and Gas Commission, changes its name to the British Columbia Energy Regulator and introduces new potential liability for responsible persons.

One key amendment is the purpose of the *Energy Resource Activities Act*. The purpose will be revised to expand the regulator's mandate to regulate energy resource activities in a manner that protects public safety and the environment, supports reconciliation with Indigenous Peoples and the transition to low-carbon energy, conserves energy resources, fosters a sound economy and social well-being.

It is worth noting the Ontario government is currently reviewing the objectives of its energy legislation that defines the role of the Ontario Energy Board. In the energy regulation world, the objects or purpose set out in the legislation defines the tribunals jurisdiction. It will not be surprising if the Ontario amendments resemble those that have recently been enacted in British Columbia.

The new British Columbia legislation also sets out in some detail new liabilities for principles and/or responsible persons engaged in oil and gas or storage activities and prescribed energy resource activities.

As explained in the article by Sasa Jarvis *et al.*, these amendments will impose significant new liabilities on the board of directors of energy corporations operating in the province.

INTERNATIONAL POLICY DEVELOPMENTS

The last article in this issue of the *ERQ* addresses an important international policy known as the carbon border adjustment. In particular it deals with the European Union's new carbon border adjustment mechanism which was signed into law on May 10, 2023 which is substantially the same as the EU's original draft published in July 2021. The article is by Neil Campbell, Talia Gordner, Lisa Page, and Adelaide Egan of the McMillan law firm in Toronto.

As countries around the world come closer to the deadline for net zero greater attention will turn to carbon border adjustments. The world can not achieve the net zero goal without some form of international regulation that creates the necessary incentives to make sure that all countries are aligned in this commitment. Sooner or later the Canadian government will have to face this issue. The article presents a very careful and helpful analysis of a complicated policy issue.

THE CHAIRS INTERVIEW

This issue of the *ERQ* also includes an interview with the Chair of the British Columbia Utilities Commission, David Morton and the Vice Chair, Anna Fung. This interview was in fact carried out by the Ivey Energy Policy and Management Centre at the University of Western Ontario. It was originally published by the Centre two years ago. It is important today because of the growing interest in defining the role of the Utility Regulator in the massive energy transition that all Canadian provinces are facing.

The Iver Report notes that energy policy usually tries to balance three imperatives, affordability for consumers, reliability and security of supply. The Ivey Institute asked how an economic regulator like the BCUC deals with these three pillars of energy policy. The response in the article is worth reading. ■

CANADA ISSUES DRAFT LEGISLATION ON TAX CREDITS FOR CLEAN ENERGY [1]

*Colena Der, Jake Sadikman, and Edward Rowe**

INTRODUCTION

On August 4, 2023, the Canadian federal government released a significant package of draft legislation to implement various tax measures, update certain previously released draft legislation and make certain technical changes. Included in this package is draft legislation for the Clean Technology Investment Tax Credit (Clean Technology ITC) first announced in the 2022 Fall Economic Statement,[2] the labour requirements applicable to various clean energy investment tax credits, legislative amendments to the Carbon Capture, Utilization and Storage Investment Tax Credit (CCUS ITC) announced in the 2023 Federal Budget and various other tax supports for the clean energy sector announced in the 2023 Federal Budget or earlier (Proposals).[3]

The news release that accompanied the Proposals invites interested parties to make submissions with respect to the Proposals by September 8, 2023.

Notably, the legislative package does not include draft legislation for the Clean Hydrogen, the Clean Electricity or the Clean Technology Manufacturing ITCs. The news release indicated that draft legislation for the Clean Hydrogen ITC would be released soon, and noted that the cleanest forms of blue hydrogen (hydrogen produced from natural gas where emissions are abated using CCUS) would be eligible for the investment tax credit, which would include hydrogen produced using clean-powered autothermal reforming with a high rate of carbon capture. The government did not provide any timing commitment on the other ITCs.

CLEAN TECHNOLOGY INVESTMENT TAX CREDIT

The Clean Technology ITC is aimed at supporting investment in low-emitting energy generation and storage equipment. This 30 per cent refundable ITC was first announced in the 2022 Fall Economic Statement, with an update in the 2023 Federal Budget that the ITC would also be available for geothermal energy equipment.

The draft legislation released last week largely aligns with the prior announcements on the Clean Technology ITC. The proposed

[1] An earlier version of this article appeared in an Osler Update bulletin published by the firm, see online: <www.osler.com/en/resources/regulations/2023/canada-releases-long-awaited-draft-legislation-for-tax-credits-supporting-the-clean-energy-sector>.

* Colena Der, Jake Sadikman and Edward Rowe, Osler, Hoskin & Harcourt LLP. Colena Der and Edward Rowe are partners in Osler's Tax group. Jacob Sadikman is a partner in Osler's Energy and Infrastructure group.

[2] "Tax Measures: Supplementary Information – Business Income Tax Measure" *2022 Fall Economic Statement* (3 November 2022), online: *Government of Canada* <www.budget.canada.ca/fes-eea/2022/report-rapport/tm-mf-en.html#business-income-tax>.

[3] "Tax Measures: Supplementary Information – Business Income Tax Measures" *2023 Federal Budget* (28 March 2023), online: *Government of Canada* <www.budget.canada.ca/2023/report-rapport/tm-mf-en.html#a29>.

mechanics for the credit also largely follow the existing ITC framework in the *Income Tax Act* (Canada) (*Tax Act*) and adopts certain elements of that framework, in particular those for the Scientific Research and Experimental Development (SRED) investment tax credit. The remainder of this section summarizes the key elements of the Clean Technology ITC draft legislation.

Eligible property

The Clean Technology ITC is only available in respect of the cost of eligible property. The types of eligible property include the following:

- zero-emission electricity generation technologies, like solar, wind, small hydro, concentrated solar energy and small modular nuclear reactors;

- electricity storage systems that do not use fossil fuels in their operations, like batteries, flywheels, compressed air energy storage, pumped hydroelectric energy storage, gravity energy storage and thermal energy storage;

- certain active solar heating equipment, air-source heat pumps and ground-source heat pumps;

- equipment used exclusively for generating electrical energy or heat (or a combination) solely from geothermal energy, but excluding any equipment that is part of a system that extracts both heat from geothermal fluid and fossil fuel for sale or use; and

- non-road zero-emission vehicles that are fully electric or powered by hydrogen, and charging or refuelling equipment primarily used to support such vehicles.

There are a few aspects concerning the scope and definition of eligible property that project proponents should note.

First, the eligible property must be new equipment, situated in Canada and intended for use exclusively in Canada.

Second, the draft legislation clearly states that electricity storage equipment is eligible if the equipment does not use fossil fuels in its system. However, the explanatory notes refer to storage equipment "for zero-emission energy," which could be interpreted to restrict eligible storage equipment to those that only store electricity produced from zero-emission sources. Grid-connected electricity storage projects in Canada in the foreseeable future will not be in a position to control the percentage of non-emitting electricity that they are charged with. The disconnect between the legislative text and the explanatory notes appears to be inadvertent as the latter does not align with the legislation, nor prior statements from the government.

Lastly, there are specific provisions defining eligible "concentrated solar energy equipment" and "small modular nuclear reactors" (SMNRs), with specific components of these systems being excluded from the credit:

- In the case of concentrated solar energy equipment, auxiliary heating and electrical generating equipment that use any fossil fuels and distribution equipment are excluded.

- In the case of SMNRs, eligibility is limited to a reactor that (a) is part of a system that has gross rated generating capacity not exceeding 300 megawatts electric, or an energy balance equivalent gross rated generating capacity of electricity or heat equivalent of 1,000 megawatts thermal and (b) is part of a system all or substantially all of which is comprised of modules that are factory-assembled and transported prebuilt to the installation site. Eligible SMNR equipment expressly excludes nuclear waste disposal equipment, transmission equipment and distribution equipment.

Credit available for 10 years

The credit is available for eligible property acquired on or after March 28, 2023 (Budget Day).

Generally, a taxpayer is not considered to have "acquired" the eligible property until such time as the property becomes "available for use" (AFU), as determined for purposes of the capital cost allowance rules in subsection 13 of the *Tax Act* (without reference to the rules that accelerate AFU status on disposition of the property or, in the case of a building, on completion of construction). However, property acquired prior to Budget Day is not eligible for the credit regardless of whether such property becomes AFU before or after Budget Day.

The credit will be phased out after 2034, with the credit rate reduced to 15 per cent for 2034 and nil thereafter.

Eligible claimants – taxable Canadian corporations and partnerships

The Clean Technology ITC may be claimed by taxable Canadian corporations which acquire eligible property or by taxable Canadian corporations which are partners in partnerships that acquire eligible property. Individuals (including trusts) and tax-exempt entities are not eligible.

The ITC is also not available where the eligible property, or an interest in a person or partnership that has an interest in that property, is a tax shelter investment.

In the case of eligible properties acquired by a partnership, the Clean Technology ITC is computed as if the partnership were a taxable Canadian corporation and then is allocated to the partners. The allocation of the ITC amongst the partners must be reasonable (and section 103 is modified to apply to the allocation of this credit).

In the case of limited partnerships, the draft legislation adopts the existing provisions in subsections 127(8.1) and (8.2) that impose further limitations on the amount of ITC that may be allocated to limited partners. Under these restrictions, the amount of the partnership's ITC for a fiscal year that can be allocated to a limited partner is limited to the lesser of the limited partner's "at risk amount" and "expenditure base" (as determined at the end of that fiscal period):

- The at-risk amount is computed under subsection 96(2.2) and is, very generally, equal to the tax cost of the partner's partnership interest plus (or minus) the partner's share of the partnership's income (or losses) for the fiscal period.

- The expenditure base is defined in subsection 127(8.2) and, very generally, limits the amount of ITCs allocated to a limited partner to an amount that is attributable to eligible expenditures funded by contributions from that partner.

The computation of a limited partner's "at-risk amount" and "expenditure base" are both highly technical. Any amounts that cannot be allocated to the limited partners by virtue of these limitations can be allocated to non-limited partners.

Labour requirement

The credit is subject to the Labour Requirements, which are discussed in more detail below.

Claiming the Clean Technology ITC

The Clean Technology ITC is claimed by filing a prescribed form with the claimant's income tax return for the year in which the eligible property is acquired. Upon claiming the Clean Technology ITC, the taxpayer is deemed to have made a payment against its tax liability for that year equal to the amount of the ITC. The draft legislation does not give the taxpayer discretion, as with other ITCs, to roll forward and defer claiming the ITC.

A late filing is permitted up to one year from the claimant's filing due date for the year. The Minister does not have discretion to accept a late filing beyond that date.

Reduction to eligible expenditures

The cost of eligible property, and therefore the expenditure base used to compute the ITC, is adjusted in certain circumstances, including:

- *Assistance*: The cost of eligible property is reduced by any governmental or non-governmental assistance that can reasonably be considered to be in respect of the property that, at the time of filing the tax return for the year in which the property is acquired, the taxpayer has received, is entitled to receive or can reasonably be expected to receive. Given this broad language, assistance can reduce the ITC expenditure base even before it is actually received. There is a mechanism for restoring the ITC expenditure base in the event the taxpayer repays the assistance or is no longer entitled to the assistance.

- *Acquisition from non-arm's length persons*: Where the eligible property is acquired from a non-arm's length person, the cost of the property is limited to the lesser of the cost to the purchaser and the cost to the vendor. In essence, the purchaser's ITC will not capture any increase in the value of the eligible property between the time the vendor acquired the property and the time it was sold to the non-arm's length purchaser.

- *Unpaid amounts*: If the cost for eligible property is unpaid 180 days after the end of the taxation year in which the ITC would otherwise be available, that cost is excluded from the expenditure base until it is paid.

Recapture

Similar to the existing SRED ITC regime, the Clean Technology ITC is subject to recapture if, within 20 calendar years of the acquisition of the eligible property, the property is converted to a non-clean technology use, exported from Canada or otherwise disposed of by the taxpayer.

The recapture amount is equal to the ITCs claimed multiplied by a fraction with the numerator equal to the fair market value proceeds and the denominator equal to the taxpayer's cost in the property. On a sale of the property to an arm's length person, the numerator, and therefore the recapture amount, will be based on the taxpayer's proceeds of disposition. On a disposition of the property to a non-arm's length person, or the conversion or export of the property, the numerator will be based on the fair market value of the property at the time of the disposition, conversion or export. The recapture amount is capped at the amount of the ITC claimed in respect of the property.

In the case of a taxable Canadian corporation, the recapture amount is added to the corporation's tax liability for the year in which the disposition, conversion or export occurs.

In the case of a partnership, the recapture amount is first applied to reduce the partnership's Clean Technology ITC (before allocation to its partners) and any excess is allocated to its partners and included in the partners' Part I tax liability. In the circumstances where the membership of the partnership changes between the time the ITC is claimed and the recapture event occurs, it is possible that partners receiving the benefit of the ITC and the party bearing the cost of the recapture could be different. This latent recapture liability will need to be considered in negotiating the commercial terms for partner withdrawals and partner admissions.

The recapture rules do not apply where the disposition is between *related persons* and the property would be eligible property to the acquirer (without regard to the new property requirement). The scope of this limited exception is unclear:

- The parallel exception in the SRED ITC recapture rules excludes transfers between *non-arm's length persons*, which includes related persons and factually non-arm's length persons. In contrast, the Clean Technology ITC adopts the more restrictive "related persons" concept.

- Subsection 251(2), which defines persons who are considered related for purposes of the *Tax Act*, does not address partnerships. As a result, how this exception in the Clean Technology ITC would apply to transfers involving a partnership is uncertain.

The recapture rules will be particularly important (and may be problematic as currently drafted) in the context of commercial real estate sales, where rooftop solar generating facilities may be integrated into a building that is sold as an asset transfer to the purchaser. As currently drafted, neither the existing building owner that accesses the ITC to build the solar project, nor the purchaser of the building with the solar project included, would appear to realize the full benefit of the ITC.

Other consequential amendments

The draft legislation also sets out a list of consequential amendments to other provisions of the *Tax Act* to reflect the introduction of the Clean Technology ITC. These include an amendment to provide for a reduction in the capital cost of eligible property (for capital cost allowance purposes) in respect of the ITC claim and adjustments to a taxpayer's cost in a partnership interest to reflect the allocation and recapture of ITCs from the partnership.

Still outstanding

The announcement and draft legislation do not provide insight into how the Clean Technology ITC will interact with the overlapping Clean Electricity ITC. Further clarity on this interaction is particularly important where a partnership acquires property that is eligible for both the Clean Technology and Clean Electricity ITCs and has both taxable corporations and tax-exempt entities as partners.

LABOUR REQUIREMENTS

The 2023 Federal Budget set out the basic parameters of the prevailing wage and apprenticeship conditions comprising the Labour Requirements, as well as the government's intention to apply those requirements to the proposed Clean Technology, Clean Hydrogen, Clean Electricity and CCUS ITCs.[4]

Overview of the requirements

While draft legislation setting out the Labour Requirements largely aligns with what was announced in the 2023 Federal Budget, it clarifies the prior announcements and introduces certain additional requirements:

- Under the prevailing wage component, covered workers must be paid in accordance with an "eligible collective agreement" or in an amount at least equal to the amount of wages and benefits in the "eligible collective agreement" most closely aligned with the covered worker's experience level, tasks and location. In provinces other than Québec, the "eligible collective agreement" is generally a collective agreement for the relevant industry and type of work performed which aligns with the worker's duties and location. In Québec, the eligible collective agreements are those negotiated under relevant provincial law.

- With respect to the apprenticeship component, registered apprentices must work at least 10 per cent of the total labour hours that would be performed by a worker in a Red Seal trade.

- Responsibility for satisfying the Labour Requirement falls on the "incentive claimant," which is defined to be the person claiming the credit or a partnership where at least one partner is claiming the credit.

- The incentive claimant elects into the Labour Requirements, and therefore elects into claiming the higher ITC rate. If this election is not made, the available ITC is reduced by 10 percentage points.

- The Labour Requirements only apply to "covered workers" at a "designated work site" of the incentive claimant.

  - "Covered workers" is defined to mean workers who are engaged in the preparation or installation of property that is eligible for a specified tax credit and whose work is primarily manual or physical in nature. Covered workers include employees of the incentive claimant or those of any other person or partnership (contractors or subcontractors) who are engaged in the preparation or installation of eligible property.

  - A "designated work site" means a work site where eligible property of the incentive claimant is located during the year. This definition does not require that the work site belong to the incentive claimant or be under its control.

- The Labour Requirements must be complied with during each taxation year where preparation or installation work is completed with respect to an eligible property. Since the requirement only refers to preparation and installation, the manufacturing of the eligible property appears to be excluded from the Labour Requirements. However, additional clarity may be required as to the exact meaning of "preparation" in this context to ensure that the "designated work site" does not apply to each portion of the supply chain for eligible property.

- Even though, as currently drafted, the Labour Requirements only apply in respect of a "specified tax credit" (which is defined to mean the CCUS tax credit and the Clean Technology ITC), the Explanatory Notes confirm that the intention is still for the Labour Requirements to apply in

[4] "Tax Measures: Supplementary Information – Labour Requirements Related to Certain Investment Tax Credits" *2023 Federal Budget* (28 March 2023), online: *Government of Canada* <www.budget.canada.ca/2023/report-rapport/tm-mf-en.html#a46>.

respect of the Clean Hydrogen and Clean Electricity ITCs. The Labour Requirements do not apply to the 15 per cent CCUS Refurbishment ITC or the Clean Technology ITC claimed for the acquisition of off-road zero-emission vehicles or for the acquisition or installation of low-carbon heat equipment.

Attestation and other compliance obligations

With respect to the prevailing wage requirements, the incentive claimant is required to attest that its own employees who are covered workers for purposes of the Labour Requirements are being compensated in accordance with the requirements. The claimant will also need to attest that it has taken reasonable steps to ensure that any covered workers who are employed by any other persons or partnerships (contractors or subcontractors) are being compensated in accordance with the requirements. Furthermore, the incentive claimant must communicate in a manner readily visible and accessible by covered workers, either at the work site or by electronic means, that the work site is subject to prevailing wage requirements, including a plain language explanation of what that means and information regarding how to report non-compliance.

With respect to the apprenticeship requirements, the draft legislation specifies that where the 10 per cent apprenticeship labour hours requirement cannot be met because of restrictions under applicable labour laws or a collective agreement, the incentive claimant must make reasonable efforts to ensure that the highest possible percentage of the total labour hours performed during the year by Red Seal workers on the preparation and installation of eligible property is performed by apprentices registered in a Red Seal trade while respecting the applicable labour laws or collective agreement. The incentive claimant must then attest that the apprenticeship requirements have been met in respect of covered workers at a work site.

The draft legislation does not provide any guidance on what would constitute “reasonable steps” or “reasonable efforts,” as required in the drafting legislation, to ensure compliance with the Labour Requirements.

Consequences of non-compliance

The draft legislation also sets out the penalties for not complying with the labour requirements where the incentive claimant has elected into those requirements and claimed the regular (higher) credit rate:

- *Per diem penalty for prevailing wages*: If a covered worker was not compensated in accordance with the specified wage requirements for one or more days in a taxation year in respect of which a specified tax credit is being claimed at the regular rate, the incentive claimant is liable to pay an additional tax of $20 per day for each day in that taxation year that the covered worker was not paid the prevailing wage.

- *Top-up for prevailing wages*: An incentive claimant may, within one year after receipt of notification from the Minister (or such longer period as is acceptable to the Minister) of its non-compliance with the prevailing wage requirement, cause each covered worker to be paid a top-up amount to resolve the non-compliance.

    - The top-up amount is generally equal to the difference between the prevailing wages that were required to have been paid and the amount the covered worker was actually paid.

    - The top-up amount will be deemed to be salary and wages to the worker in the year received and will be deductible by the incentive claimant in computing income for the year in which it is paid. However, it will not constitute an expenditure that qualifies for any specified tax credit.

    - If the top-up amount is not paid, the incentive claimant will be liable to pay a penalty equal to 120 per cent of the top-up amount in respect of each worker that was not paid the top-up amount. Paying the top-up does not appear to eliminate the $20 per diem penalty.

- *Penalty for apprenticeship*: If the apprenticeship hours requirement is not met at a particular work site during a taxation year in respect of which a specified tax credit is being claimed at the regular rate, the incentive claimant is liable to pay an additional tax equal to $100 multiplied by the difference between the number of hours that were required to have been performed by apprentices and the number of hours of labour that were actually performed by apprentices.

- *Misconduct or gross negligence*: If an incentive claimant's failure to meet any of the labour requirements was done knowingly or in circumstances amounting to gross negligence, the incentive claimant is (a) disentitled to the regular tax credit rate and is entitled only to the reduced tax credit rate; and (b) liable to pay a penalty equal to 50 per cent of the difference between the amount of the specified tax credit claimed and the amount that the incentive claimant would have been entitled to under the reduced rate. In such cases, the *per diem* prevailing wage and apprenticeship penalties (described above) are not applicable and the claimant is not entitled to make a top-up payment in respect of the prevailing wage requirement. It is not clear whether the claimant would otherwise be subject to the 120 per cent penalty on the top-up amount.

Effective date

Consistent with the 2023 Federal Budget announcement, the Labour Requirements are proposed to be effective in respect of specified property prepared or installed after September 30, 2023.

Notably, the application of the Labour Requirements to a particular property is not based on when the property is acquired (as is the case for determining *when* the associated ITC may be claimed). As the application of the Labour Requirements is based on the date when property is prepared or installed, property that is prepared and installed on or after October 1, 2023, would appear to be subject to the Labour Requirements even if the property was acquired before that effective date.

CARBON CAPTURE, UTILIZATION AND STORAGE INVESTMENT TAX CREDIT

The CCUS ITC was first announced in the 2022 Federal Budget, with draft legislation released in mid-2022. The 2023 Federal Budget proposed additional design changes to the CCUS Credit.[5] The draft legislation released on August 4, 2023, largely reflects the 2023 Federal Budget announcement. The draft legislation for the CCUS ITC will be addressed in a separate update.

If enacted, the CCUS ITC will be deemed to have come into force on January 1, 2022, and apply to eligible expenses incurred from that day to December 31, 2040.

FLOW-THROUGH SHARES AND CRITICAL MINERAL EXPLORATION TAX CREDIT FOR LITHIUM FROM BRINES

The draft legislation implements changes announced in the 2023 Federal Budget to allow for certain expenses relating to mining lithium from brines to be treated as Canadian exploration expenses (CEE) and Canadian development expenses (CDE) eligible for flow-through treatment and to expand eligibility for the Critical Mineral Exploration Tax Credit.

The proposed draft legislation makes several amendments to the CEE and CDE regime to implement the announced changes, including:

- The definition of "principal business corporation" in subsection 66(15) is amended to include corporations whose principal business includes the production or marketing of lithium and the manufacturing of products, where the manufacturing involves processing of lithium. Only "principal business corporations" can issue flow-through shares to renounce CEE and CDE to subscribers.

- Paragraphs (c.2) and (d) of the definition of CDE in subsection 66.2(5) are

[5] "Tax Measures: Supplementary Information – Investment Tax Credit for Carbon Capture, Utilization, and Storage" *2023 Federal Budget* (28 March 2023), online: *Government of Canada* <www.budget.canada.ca/2023/report-rapport/tm-mf-en.html#a63>.

amended to include expenses related to the drilling of a well for the extraction of lithium from brines.

- The definition of "mineral resource" in subsection 248(1) is amended to include lithium as a mineral resource. The "mineral resource" definition is relevant to determining a taxpayer's eligibility to claim CEE and CDE.

- A new provision is added (subsection 66(21)) to ensure that projects for the exploration and development of lithium from brines are treated similarly to traditional mineral resource mines. Specifically:

  - a well for the extraction of material from lithium brine deposits is deemed to be a mine for the purposes of the definitions of CEE and CDE;

  - all wells of a taxpayer are deemed to be from the same mine if the materials extracted are sent to the same plant for processing; and

  - wells can be deemed to be one mine if the Minister, in consultation with the Minister of Natural Resources, determines the wells to constitute one project.

- As a consequence of the above changes, an individual (other than a trust) who invests in flow-through shares may also be eligible to claim the Critical Mineral Exploration Tax Credit or the Mineral Exploration Tax Credit under subsection 127(5) in respect of certain CEE related to mining lithium from brines.

The above amendments are deemed to come into force on March 28, 2023, but do not apply in respect of expenses incurred before March 28, 2023.

TEMPORARY RATE REDUCTION FOR ZERO-EMISSION TECHNOLOGY MANUFACTURERS

The 2023 Federal Budget announced two changes to the temporary 50 per cent rate reduction for zero-emission technology manufacturers that was first introduced in the 2021 Federal Budget.[6] First, the rate reduction will be expanded, for taxation years beginning after 2023, to include manufacturers of nuclear energy equipment, processing or recycling of nuclear fuels and heavy water, and manufacturing of nuclear fuel rods. Second, the rate reduction, originally planned to be fully phased out in 2032, will now be fully phased out three years later in 2035. The newly released draft legislation implements these two changes. ■

[6] "Tax Measures – Supplementary Information: Rate Reduction for Zero-Emission Technology Manufacturers" *2021 Federal Budget* (19 April 2021), online: *Government of Canada* <www.budget.canada.ca/2021/report-rapport/anx6-en.html#rate-reduction-for-zero-emission-technology-manufacturers>.

CANADA SEEKS INPUT ON NEW DRAFT CLEAN ELECTRICITY REGULATIONS

*Dufferin Harper**

On August 10, 2023, Canada released draft *Clean Electricity Regulations*[1] (Regulations), which are intended to form an essential part of Canada's approach to achieving economy-wide net-zero greenhouse gas (GHG) emissions by 2050. The Regulations establish strict GHG emissions intensity performance standards that will apply to electricity generated from fossil fuel within Canada. As noted in the Regulatory Impact Analysis Statement that accompanied the Regulations, the Regulations were chosen as the most effective and appropriate instrument to address the issue. More specifically, the Regulatory Impact Analysis Statement stated:

> Considering the urgency to address climate change and Canada's climate change goals towards becoming a net-zero GHG emissions economy by 2050, a transformational change will be required in every sector of the Canadian economy including the electricity-generating sector.

In the government notice advising of the Regulations, it was noted that the Regulations were developed around three core principles:

- Maximizing GHG reductions to achieve net-zero emissions from the electricity grid by 2035;
- Maintaining electricity affordability for Canadians and Canadian businesses; and
- Maintaining grid reliability to support a strong economy and meet Canada's growing energy needs.

TIMING AND APPLICATION OF REGULATIONS

As of January 1, 2025, the Regulations will apply to any electrical generation unit (EGU) that:

- has an electricity generation capacity of 25 megawatts (MW) or greater;
- generates electricity using fossil fuel (which is defined to include hydrogen gas); and
- is connected to an electricity system that is subject to North American Electric Reliability Corporation (NERC) standards.

An EGU that meets the applicability criteria as of January 1, 2025, must be registered with the federal Minister of Environment by the end of 2025. Any EGU commissioned after January 1, 2025, must be registered within 60 days of being commissioned.

By requiring an EGU to be connected to an electricity system subject to NERC standards before the Regulations apply, stand-alone and isolated EGUs will be exempt. This effectively means the Regulations and the imposition of the Performance Standard as discussed below will not apply to many northern Canadian communities currently relying on diesel generators and localized electricity transmission systems for their electricity.

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[1] "Clean Electricity Regulations" (Unofficial Version, 10 August 2023), online: *Government of Canada* <www.canada.ca/en/services/environment/weather/climatechange/climate-plan/clean-electricity-regulation.html> [RIAS] [CER], s 3.

EMISSIONS INTENSITY PERFORMANCE STANDARD

An EGU that exports more electricity onto an electricity system subject to NERC than it imports from an electricity system subject to NERC (i.e., its net exports are greater than zero gigawatt hours) during a calendar year is subject to an average annual emissions intensity performance standard of 30 tonnes of CO_2e per gigawatt hour (GWh) of electricity production (Performance Standard).

The Performance Standard applies to various EGUs based on a phased approach. As of January 1, 2035, the Performance Standard will apply to:

- an EGU that burns coal or petroleum coke;
- an EGU commissioned on or after January 1, 2025; and
- an EGU that has increased its electricity generation capacity by 10 percent or more since the registration of the EGU.

Because a pre-existing EGU may have to undergo extensive modifications to comply with the Performance Standard, the Regulations provide additional time for the imposition of the Performance Standard on EGUs commissioned prior to January 1, 2025. For any such EGU that was previously a coal burning unit and was converted to a natural gas burning unit, the application of the Performance Standard is delayed until the latter of January 1, 2035 or January 1 of the calendar year in which subsection 4(2) of the *Regulations Limiting Carbon Dioxide Emissions from Natural Gas-Fired Generation of Electricity* begin to apply to it. For all other EGUs, the Performance Standard is not imposed until the latter of January 1, 2035 or 20 years after the commissioning date of the EGU.

EXCEPTIONS TO THE PERFORMANCE STANDARD

The Regulations include three exceptions to the Performance Standard:

1. An EGU that uses carbon capture and storage (CCS). The Performance Standard is calculated based upon the quantity of overall CO_2e emissions during the calendar year from the combustion of fossil fuel in an EGU. However, the quantity of CO_2e emissions that are permanently captured and stored in a carbon capture and storage project (CCS Project) can be subtracted from the overall CO_2e emissions. Approved CCS Projects include: (i) injection into a deep saline aquifer for the sole purpose of CO_2 storage; and (ii) injection into a depleted oil reservoir for the purpose of enhanced oil recovery. Eligible CCS Projects can be situated in either Canada or the United States. An EGU that uses CCS as part of its compliance strategy is allowed to have an average emissions intensity of up to 40 tonnes of CO_2e per GWh, provided it can demonstrate it is capable of operating at 30 tonnes of CO_2e per GWh based on actual emissions data. The CCS exception is only available until the earlier of seven years following the commissioning of the CCS system or December 31, 2039.
2. Operation of an EGU during peak periods of energy demand. An EGU that does not combust coal can emit up to 150 kilotonnes of CO_2e in a calendar year provided it operates for no more than 450 hours per calendar year.
3. Operation during emergency circumstances. An EGU can apply for an exemption from the Performance Standard from the Minister of Environment during two types of emergency circumstances. The first circumstance includes an emergency that arises due to "an extraordinary, unforeseen and irresistible event." It is unclear what constitutes an "irresistible event" or what is meant by that term. The second circumstance includes scenarios where the government issues an emergency proclamation or order or declares an emergency based on the anticipated shortage of fuel, or in situations where there is an actual or anticipated shortage of fuel, but fuel is required to protect Canada's national security, participate in military activities or support humanitarian relief efforts.

ADDITIONAL SECTIONS

The Regulations also contain additional sections pertaining to emissions intensity calculations, sampling frequency, record retention and the submission of annual reports.

COMMENT PERIOD

The Regulations are open for comments until November 2, 2023. Final Regulations are anticipated to be published in 2024. ■

POWER WHEN YOU NEED IT: THE CASE FOR SMALL NUCLEAR REACTORS[1]

*John Richards and Christopher Mabry**

EDITOR'S INTRODUCTION

Provinces across Canada are facing a number of technical challenges as they race to meet the carbon reduction goals established by the federal government. Each of the provinces is making serious investments in new technology. That technology differs from province to province but a number of provinces are now backing what is called small nuclear or SMRs.

SMRs are nuclear reactors that produce less than 300 MW of electricity. They are smaller than traditional nuclear power plants that generally produce 800 MW or more. They are cheaper to build, scalable and able to meet specific industrial and remote community needs. Ontario, Saskatchewan and New Brunswick have worked together to develop SMR's in Canada since 2019. Alberta joined the party in April 2021.

SMRs are now beginning to look like a reality. The first of the SMR projects to come online will be the facility located in Darlington in Ontario where the federal Infrastructure Bank is investing $970 million . It will be the first grid scale SMR project in Canada with a size of 300 MW, enough to power 300,000 homes. It is expected to be in service by 2028.

The Darlington project will be followed by four similar units in Saskatchewan with the first to be in service by 2032. The Saskatchewan project is also backed by the federal government which will invest $74 million. An advanced SMR design is also being developed in New Brunswick where a demonstration unit will be operating at the existing Point Lepreau nuclear site by 2030.

A new class of micro SMRs is also being developed to replace diesel use in remote communities. These are 5 MW gas cooled reactor projects to be located at the Chalk River nuclear site in Ontario. These are expected to be in service by 2026.

The article that follows this introduction is based on a very careful analysis of SMR technology first set out in an important study by the CD Howe Institute in Toronto.

THE STUDY IN BRIEF

- The 2021 *Canadian Net-Zero Emissions Accountability Act* requires Canada to achieve "net zero" greenhouse gas emissions (GHGs) by 2050. An important component of the goal is that the power sector realize "net zero" by 2050.

- The Canada Energy Regulator (CER) has developed a net-zero projection for the power sector, emphasizing renewables (hydro, wind, solar). Wind and solar comprise 60 per cent of projected increase in generation between 2019 and 2050.

[1] This article was originally published by the CD Howe Institute (15 November 2022), online: <www.cdhowe.org/public-policy-research/power-when-you-need-it-case-small-nuclear-reactors>. The authors thank Charles DeLand, Benjamin Dachis, Alexandre Laurin, Chris Benedetti, Dave Collyer, Laurie Pushor, Gary Rose and anonymous reviewers for comments on an earlier draft. The authors retain responsibility for any errors and the views expressed. The C.D. Howe Institute does not take corporate positions on policy matters.

* John Richards is an emeritus professor, Simon Fraser University and fellow-in-residence, C.D. Howe Institute.

Christopher Mabry, Master's of Public Policy, Simon Fraser University, is a policy analyst with the Government of Canada.

- While wind and solar provide low-GHG power, these technologies require "storage" of power not needed in the middle of the day. Whatever the form, storage requirements increase the system cost of wind and solar.

- Several power utilities (notably California) have faced system instabilities due to inadequate capacity of readily "dispatchable" sources (hydro, fossil-fuel, and nuclear) able to meet demand when the sun is not shining and/or the wind is not blowing.

- The CER envisions refurbishing some existing reactors, but no expansion of Canadian nuclear capacity. By contrast, the UN's International Panel on Climate Change and the International Energy Agency conclude that more nuclear power is necessary for elimination of GHGs in the power sector.

- In order to meet net-zero targets, many countries (e.g., China, Russia, and France) are investing heavily in small modular reactors (SMRs), which may realize shorter construction time, as well as simpler and safer designs than conventional reactors. Canada is well placed to promote SMRs, given our history of nuclear development and domestic sources of uranium.

INTRODUCTION

In a 2018 report targeting policymakers, the UN's International Panel on Climate Change (IPCC) discussed four strategies to contain the world temperature increase to 1.5 degrees Celsius, relative to pre-industrial levels (see Box 1). All four require an increase in nuclear power. Relative to world nuclear power capacity in 2010, the minimum estimated requirement by 2050 is a doubling of nuclear power capacity (pathway two); the maximum requirement (pathway three) is a five-fold increase.[2]

The International Energy Agency (IEA) comes to a similar conclusion in its annual *World Energy Outlook*:

> In the [net zero emissions by 2050] scenario, electricity becomes the new linchpin of the global energy system, providing more than half of total final consumption and two-thirds of useful energy by 2050. Total electricity generation grows by 3.3 per cent per year to 2050, which is faster than the global rate of economic growth across the period. Annual capacity additions of all renewables [wind, solar, hydro] quadruple from 290 GW in 2021 to around 1 200 GW in 2030. With renewables reaching over 60 per cent of total generation in 2030, no new unabated coal fired plants are needed. Annual nuclear capacity additions to 2050 are nearly four times their recent historical average.[3]

Canada has committed itself by law to realize "net zero" power in terms of greenhouse gas (GHG) emissions by 2050.[4] The intent of this E-Brief is to assess the potential for nuclear power as a major component in realizing net zero in electricity generation. In particular, we emphasize the potential role of small modular reactors (SMRs).

Canada is uniquely positioned as a country with a track record of relying on nuclear. Though unknown by most Canadians, Canada has been successfully operating nuclear reactors for over 70 years. Currently, we operate 19 nuclear reactors located in Ontario and New Brunswick. We are the second-largest producer of uranium globally, attributable to mining operations in Saskatchewan, and it is estimated that we could support in Canada 70–80 per cent of a nuclear supply chain, from fuel production to parts manufacturing.[5]

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[2] We thank anonymous reviewers for many thoughtful comments on earlier drafts. In addition, we thank Esam Hussein for advice throughout preparation of the manuscript.

[3] "World Energy Outlook" (last accessed 27 October 2022) at 121, online (pdf): *International Energy Agency* <iea.blob.core.windows.net/assets/830fe099-5530-48f2-a7c1-11f35d510983/WorldEnergyOutlook2022.pdf>; "Net Zero by 2050: A Roadmap for the Global Energy Sector" (last accessed 27 October 2022), online (pdf): <iea.blob.core.windows.net/assets/deebef5d-0c34-4539-9d0c-10b13d840027/NetZeroby2050-ARoadmapfortheGlobalEnergySector_CORR.pdf>.

[4] Parliament approved the *Canadian Net-Zero Emissions Accountability Act* in 2021.

[5] "OPG advances clean energy generation project" (2 December 2021), online: *OPG* <www.opg.com/media_releases/opg-advances-clean-energy-generation-project/>.

Since the Canada Energy Regulator (CER) is a federal government agency, we examine its 2050 net-zero projection, a projection that relies heavily on expansion of renewable power sources (wind, solar, and hydro), envisions no increase in nuclear capacity, and assumes only a modest increase in total electrical consumption from 2019 to 2050. For reasons we discuss below, the very heavy reliance on wind and solar raises potential problems concerning the instability of power utilities. The Achilles heel of wind and solar is provision of adequate storage, at reasonable cost, of power not needed in the middle of the day, but needed when the sun is not shining and/or the wind is not blowing.

THE CANADA ENERGY REGULATOR

The CER informally defines its role as follows: "We work to keep energy moving safely across the country. We review energy development projects and share energy information, all while enforcing some of the strictest safety and environmental standards in the world."[6] There exist other projections enabling Canada to achieve net zero greenhouse emissions by 2050 in the electrical power generation sector.[7] While we are skeptical of several CER assumptions, the CER provides a credible foil.[8]

Box 1: IPCC's Potential Pathways to Limit Increase in Temperature to 1.5 degrees Celsius[9]

Seventy-five academics, representing many countries and disciplines, co-signed this report. The report defined four potential strategies. The sectors to change dramatically differ by pathway. All four strategies entail major, inevitably controversial, policy changes. IPCC describes them as:

Pathway one (lower energy demand, renewables, afforestation)
A scenario in which social, business and technological innovations result in lower energy demand up to 2050 while living standards rise, especially in the global South. A downsized energy system enables rapid decarbonization of energy supply. Afforestation is the only carbon dioxide removal option considered; neither fossil fuels with carbon capture and storage (CCS) nor bioenergy with carbon capture and storage (BECCS) are used.

Pathway two (sustainability, renewables, healthy diet)
A scenario with a broad focus on sustainability, including energy intensity, human development, economic convergence and international cooperation, as well as shifts towards sustainable and healthy consumption patterns, low-carbon technology innovation, and well-managed land systems with limited societal acceptability for BECCS.

Pathway three (renewables, nuclear, lower energy demand)
A middle-of-the-road scenario in which societal as well as technological development follows historical patterns. Emissions reductions are mainly achieved by changing the way in which energy and products are produced, and to a lesser degree by reductions in demand.

Pathway four (energy-intensive, renewables, nuclear, BECCS)
A resource- and energy-intensive scenario in which economic growth and globalization lead to widespread adoption of greenhouse-gas-intensive lifestyles, including high demand for transportation fuels and livestock products. Emissions reductions are mainly achieved through technological means, making strong use of CDR through the deployment of BECCS.[10]

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[6] Canada Energy Regulator – About Us, online: <www.cer-rec.gc.ca/en/about/>.

[7] Relative to present Canadian electricity generation, Environment and Climate Change Canada (ECCC) projects at least a doubling by 2050; see "A Healthy Environment and a Healthy Economy" (2021), online: *ECCC* <www.canada.ca/en/services/environment/weather/climatechange/climate-plan/climate-plan-overview/healthy-environment-healthy-economy.html>.

[8] "Canada's Energy Futures 2021 Fact Sheet: Electricity – Total Generation by Energy Source – Evolving Policies Scenario" (last accessed 25 June 2022), online: *CER* <www.cer-rec.gc.ca/en/data-analysis/canada-energy-future/2021electricity/2021electricity.pdf>.

[9] International Panel on Climate Change, "Summary for Policymakers" (2018) in Global Warming of 1.5°C, online: <www.ipcc.ch/sr15/chapter/spm/>. IPCC Special Report on the impacts of global warming of 1.5°C above pre-industrial levels and related global greenhouse gas emission pathways, in the context of strengthening the global response to the threat of climate change, sustainable development, and efforts to eradicate poverty.

[10] *Ibid* at 14

Relative to 2019 (pre-COVID), the CER projects by 2050 a net increase in electricity generation of 186 terawatt hours (**TWh**)[11] (819 TWh in 2050 – 633 TWh in 2019. See Table 1 and Figure 1.). The projection eliminates all coal-based power. In total, natural gas-based power does not change, but half of gas-based power will emit zero GHGs due to CO_2 capture and storage (**CCS**). Implicit in the CER projection is that Canada has exploited most large-scale hydro sites; hence, the hydro contribution to the increase will be modest. There will be some refurbishment of existing nuclear plants but no increase in nuclear-based power capacity.

The CER projection eliminates 79 TWh of power currently generated by fossil fuels. After elimination of most fossil fuel power generation, realizing the projected 2050 generation requires an increase by 2050 from low-GHG emission technologies of 266 TWh (187 TWh net increase + 79 TWh fossil fuel replacement). The CER assumes wind and solar increase their annual production by 159 TWh, 60 per cent of the 266 TWh increase.

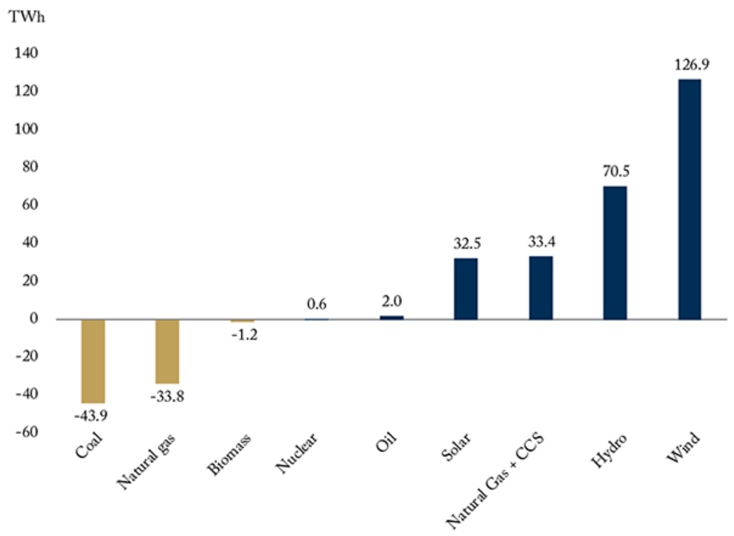
Table 1: CER Electricity Generation Projection, by Technology and Ability to Dispatch, 2019–50 (TWh)

	2019	2050	Change 2019–50	Decrease 2019–50	Increase 2019–50	Decrease 2019–50	Increase 2019–50
	(TWh)					*(present)*	
Technology							
Coal	44.0	0.1	-43.9	-43.9		55.6	
Natural gas	69.6	35.8	-33.8	-33.8		42.8	
Biomass	8.9	7.7	-1.2	-1.2		1.5	
Nuclear	95.5	96.1	0.6		0.6		0.2
Oil	3.7	5.7	2.0		2.0		0.8
Solar	2.2	34.7	32.5		32.5		12.2
Natural gas + CCS	0.0	33.4	33.4		33.4		12.6
Hydro	376.0	446.5	70.5		70.5		26.5
Wind	32.2	159.2	126.9		126.9		47.7
Total	632.2	819.2	187	-78.9	265.9	100.0	100.0
Ability to dispatch							
Dispatchable	597.7	625.3	27.6	-78.9	106.5	100.0	40.1
Non-dispatchable	34.5	193.9	159.4	0.0	159.4	0.0	59.9
Total	632.2	819.2	187.0	-78.9	265.9	100.0	100.0

Source: Author's calculations from CER (2021).

[11] Appendix 1 defines several concepts common to engineering policy discussions. The first time a term, defined in Appendix 1, appears in the text it is bolded.

Figure 1: CER Projected Change, by Technology, 2019-50 (TWh)



Source: Authors' calculations from CER (2021).

COST ESTIMATES

Estimating unit costs of alternate technologies is obviously relevant, but the estimates are inevitably surrounded with large confidence intervals. In the case of SMRs, our cost estimates per megawatt hour (MWh) come from the white paper published by the Canadian Small Modular Reactor Roadmap Steering Committee,[12] a coalition of four provincial governments (New Brunswick, Ontario, Saskatchewan, Alberta) and their respective utilities, plus several other agencies (see Table 2). The cost estimates of other technologies (including both cost of generation and cost of storage) are from a joint IEA/OECD publication.[13] For nuclear and renewables (hydro, wind, solar), the cost range of generating a MWh of electricity is similar. The highest unit cost estimate of generating a low-GHG MWh of electricity is coal supplemented with CCS.

There is an important distinction to introduce: **dispatchable** versus **non-dispatchable** power sources. Dispatchable sources, such as hydro, fossil-fuel, and nuclear, enable a utility to adjust the power supplied to the utility's grid to meet demand; in the case of non-dispatchable sources the utility cannot do so. To incorporate non-dispatchable sources, such as wind and solar, requires some form of **storage** of power generated.

[12] Canadian Small Modular Reactor Roadmap Steering Committee, "A Call to Action: A Canadian Roadmap for Small Modular Reactors" (November 2018), online (pdf): <smrroadmap.ca/wp-content/uploads/2018/11/SMRroadmap_EN_nov6_Web-1.pdf>.

[13] IEA and OECD Nuclear Energy Agency, "Projected Costs of Generating Electricity" (2020), online (pdf): <iea.blob.core.windows.net/assets/ae17da3d-e8a5-4163-a3ec-2e6fb0b5677d/Projected-Costs-of-Generating-Electricity-2020.pdf>.

Table 2: Estimated Levelized Costs By Power Source, per MWh (Canadian dollars)				
	Levelized Cost of Generating Electricity (LCOE)	Levelized Cost of storage (LCOS)	Total (LCOE + LCOS)	Total, Point Estimate (LCOE + LCOS) (range average)
Dispatchable				
New Nuclear (SMR)[14]	55–85		55–85	70
Coal-based with CCUS[15]	140		140	140
Gas-based with CCUS[16]	100–125		100–125	113
Hydro with reservoir[17]	63–130		63–130	97
Non-dispatchable				
On-shore wind[18]	50–80	40–75	90–155	123
Commercial photo-voltraic solar[19]	55–95	40–75	95–170	133

The most widely used metric to compare costs of generating electricity from different technologies is **levelized cost of electricity** (LCOE), a measure of average cost per unit of electricity over the lifetime of a typical power plant, subject to its **capacity** and **capacity factor**. The total cost of non-dispatchable sources is the LCOE plus the **levelized cost of storage** (LCOS), calculated in a manner similar to LCOE.

Wind and solar are valuable sources of low-GHG emission electricity, but they are non-dispatchable. The power they generate is typically supplied instantaneously to the grid when available. In order to match supply to demand, the utility adjusts dispatchable sources. For example, BC's hydro-dependent system can, in general, readily adjust hydro generation. However, if the utility relies heavily on non-dispatchable wind and solar power, it will probably generate hydro output below optimum during the day.

The overwhelming majority of hydro generation costs is fixed capital costs of the dam and reservoir. Using dispatchable hydro below optimum system capacity increases hydro LCOE. The utility may be able to offset some of the decrease in hydro output by sales to a utility outside BC. However, the need to store non-dispatchable power will typically create a higher system-wide LCOE. In effect, the increase in system-wide LCOE is the LCOS attributable to the non-dispatchable power.[20] Storage costs for renewables obviously vary, depending on the environment of the utility — but they are never zero.

France generates 70 per cent of its power by nuclear, which has enabled it to generate the lowest GHG emissions per MWh among all large industrial countries. Given the prevalence of nuclear, France cannot limit the use of nuclear to **baseload power**; it has evolved techniques to enable variation in nuclear power output. Admittedly, adjusting nuclear power output is subject to many more constraints than hydro or fossil-fuel power generation (see Appendix 1 for more detail).

At present, mechanical storage of potential energy is the overwhelmingly most important

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[14] *Supra* note 12 at 33. LCOE at 6% discount rate. The steering committee used 2018 data, whereas the IEA data are for 2020. The Canadian machinery and equipment price index was stable over the two years 2018 to 2020 (June 2018 91.4, June 2020 88.3).

[15] *Supra* note 13 at 14. Levelized costs at 7% discount rate.

[16] *Ibid*.

[17] *Ibid*.

[18] *Ibid* at 14, 103. Levelized costs at 7% discount rate.

[19] *Ibid*.

[20] The same argument of increase in LCOE due to below-optimum output applies to nuclear. For a new reactor, the estimates its LCOE to be in the range C$65 – C$90 per MWh if the reactor operates at 90 per cent of capacity. The LCOE range rises to C$90 – C$125 if it operates at 60 per cent. *Ibid* at 16.

form of storage. There are other potential means to store non-dispatchable power:[21]

- *hydro reservoirs*: An important example is reservoirs of a hydro-based utility, as in BC. Provincial hydro capacity is designed above the estimated optimum capacity based on water flow. Installing excess capacity enables hydro plants to store renewable power in the middle of the day by reducing water flow through turbines. At times of peak dispatchable source demand (typically in the morning and evening) the utility can allow water flow above the deemed equilibrium level.[22]

- *pumped water*: If the utility lacks hydro reservoirs, it may be able to use wind/solar power to pump river water into a lake at a higher altitude and, when needed, supply the power to the grid by run-of-the-river turbines.

- *chemical storage*: An example is to transform a non-dispatchable electricity source into hydrogen, which can, later, be transformed into electricity. Canada has entered into an agreement with Germany to export "green" hydrogen generated by means of hydro power.[23] While this example is not intended as storage for non-dispatchable power, hydrogen is a potential means of storing non-dispatchable power.

- *electro-chemical*: e.g., batteries.

- *electric storage*: Super-capacitors.

- *thermal storage*: Molten salt thermal storage.

At present, storage of non-dispatchable sources is usually costly. Utilities providing electricity to a large number of consumers (such as residents in a province) require adequate dispatchable power that can be adjusted according to variation in system demand, over a 24-hour period or seasonal variations. In Canada, as opposed to France, large nuclear reactors are restricted to baseload power; output is not intended to vary. Including nuclear, the basic sources of dispatchable power (hydro, fossil fuels [coal, gas, oil], and nuclear), currently comprise 95 per cent of Canadian power generated (see Table 1). The CER projects wind and solar to be 60 per cent of incremental low-GHG emission power in 2050 relative to 2019. This increases the non-dispatchable share of power generation from 5 per cent in 2019 to 24 per cent in 2050.

Over the last decade, power utilities highly dependent on wind and solar have faced problems of lost system flexibility, informally labeled the "duck curve" problem. Figure 2 illustrates electricity demand over 24 hours on a recent day in California, and the distribution of supply between dispatchable and non-dispatchable sources. The hourly dispatchable demand corresponds (more-or-less) to the back of a duck, viewed in profile. The duck's head is peak dispatchable demand in the evening, a time of maximum power demand and low available renewable power.

The duck problem has afflicted power systems, notably in California and Germany, two jurisdictions with substantial renewable capacity.[24] The German case is illustrative of what can happen with insufficient dispatchable power. In the 2010s, Germany decided to shut down its nuclear plants and heavily subsidize renewable power sources. To provide adequate dispatchable power, Germany has been obliged to re-open coal-based plants and, until summer 2022, had committed itself to large imports of Russian gas.

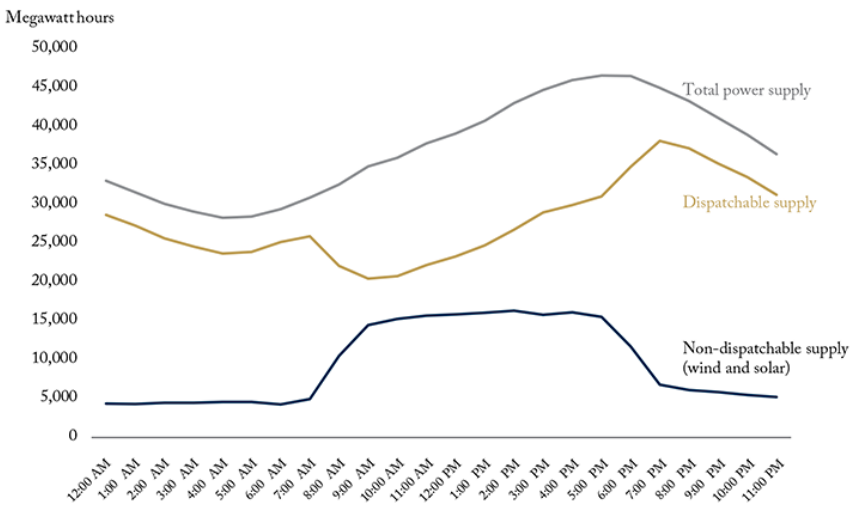
[21] *Ibid* at ch 6.

[22] One benefit in BC Hydro's cost-benefit analysis of the Site C dam is the increase in storage for expected expansion of renewables over the next three decades.

[23] "Joint declaration of intent between the Government of Canada and the Government of the Federal Republic of Germany on establishing a Canada-Germany Hydrogen Alliance" (2022), online: *NRCan* <www.nrcan.gc.ca/climate-change-adapting-impacts-and-reducing-emissions/canadas-green-future/the-hydrogen-strategy/joint-declaration-intent-between-the-government-canada-and-the-government-the-federal/24607>.

[24] "Can Europe go green without nuclear power" (15 August 2021), online: *The Economist* <www.economist.com/graphic-detail/2021/08/15/can-europe-go-green without-nuclear-power>; "Why Germans remain so jittery about nuclear power" (8 January 2022), online: *The Economist* <www.economist.com/europe/2022/01/08/why-germans-remain-so-jittery-about nuclear-power>; "Europe reconsiders its energy future" (5 March 2022), online: *The Economist* <www.economist.com/business/2022/03/05/europe-reconsiders-its-energy-future>; Patrick Wintour, "'We were all wrong': How Germany got hooked on Russian energy" (2 June 2022), online: *The Guardian* <www.theguardian.com/world/2022/jun/02/germany dependence-russian-energy-gas-oil-nord-stream>.

Figure 2: California Energy Demand "Duck Curve", 2 September 2022 (MWh)



Source: https://www.caiso.com/todaysoutlook/Pages/supply.html.

SMALL REACTOR DESIGNS

The International Atomic Energy Association (IAEA) defines small nuclear reactors as having capacity under 300 MW.[25] There are several expected benefits of small reactors over larger conventional nuclear plants (with capacity over 1,000 MW):

- *economies of standardized construction*: SMRs may generate economies in standardized construction of multiple reactors of a particular design.[26] These economies may more than offset scale economies of large reactors.[27] SMRs are simpler in design than large reactors, which may reduce regulation and reduce regulatory delays.

- *safety of new designs*: Whether large or small capacity, new (Generations III+ and IV) reactor designs are safer than early generation designs. In the event of a meltdown, modern designs incorporate passive features that shut down the reactor even if operators do nothing — safety-by-physics rather than safety-by-engineering.[28]

- *potential for generating heat*: Some SMR designs provide high-temperature steam, which can be used, for example, in oil sands extraction or desalination of water.

- *location near consumer location*: SMRS can be located near the intended customer load. This may reduce need for large investments in long-distance high-voltage power transmission.

- *displacing diesel generators in remote communities*: Micro-SMRs (< 25 MW) may be cost-efficient as means to eliminate diesel generators in remote communities.

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[25] Joanne Liou, "What are Small Nuclear Reactors (SMRs)?" (4 November 2021), online: *International Atomic Energy Association* <www.iaea.org/newscenter/news/what-are-small-modular-reactors-smrs>.

[26] The BWRX-300 reactor, which Ontario Power Generation (OPG) intends to deploy next to its Darlington nuclear station, is simpler than larger reactors. There are fewer components, less concrete, steel, etc. per MW of generation capacity. Key components, like the reactor pressure vessel and turbine systems, can be procured from more suppliers than is the case for large reactors.

[27] Esam M.A. Hussein, "Emerging small modular nuclear power reactors: A critical review" (December 2020), online: <www.sciencedirect.com/science/article/pii/S2666032620300259>; Giorgio Locatelli, Chris Bingham, and Mauro Mancini, "Small modular reactors: A comprehensive overview of their economics and strategic aspects" (May 2014), online: <www.sciencedirect.com/science/article/abs/pii/S0149197014000122>.

[28] International Atomic Energy Agency, "Advances in small modular reactor technology developments" (2018), online (pdf): <aris.iaea.org/Publications/SMR-Book_2018.pdf>; Esam M.A. Hussein, "Design features of small reactors for distributed energy production" (2022) 41st annual conference of the Canadian Nuclear Society and 46th Annual CNS/CNA. Manuscript available from author.

Many SMR designs keep the size sufficiently small to allow the reactor to be transported on a truck bed, in shipping crates, and on railway cars. The IAEA[29] definition of modularity includes both the reactor and components that regularly need replacing. The buyer receives a fully assembled product that fits into the designated site or comes in several pieces to be assembled on-site. SMRs can be used in tandem. Small towns might use one unit, while metropolitan areas use four or five. The ability to add more SMRs at a later date enables a nuclear power plant to build capacity incrementally. This enables a smaller initial upfront capital investment.[30]

Table 3 is indicative of significant international interest in SMRs. The country making the largest commitment to SMRs is China. It has one SMR online and a second scheduled to come online in 2022. It is expected to build approximately 200 SMRs over the next decade, at a cost over C$500 billion.[31]

Table 3: Comparing National On-Shore SMR First-of-a-Kind Development Timelines

Country/ Province	Firm	SMR Type	Mwe	Completion Date
China	China Huaneng	HTGR	200	2022[32]
Canada/Ontario	Global First Power	HTGR	5/15Mwt	2026[33]
USA	X-Energy	HTGR	200	2027[34]
Russia	Rosatom	PWR	200	2028[35]
Canada/Ontario	GE Hitachi	LWR	300	2028[36]
USA	NuScale	LWR	60	2029[37]
Canada/New Brunswick	Arc Energy	SFR	100	Early 2030s[38]
Canada/New Brunswick	Moltex	SSR-W	300	Early 2030s[39]
France	Electricité de France	PWR	300–400	2033[40]
South Korea	Korea Atomic Energy Research Institute	LWR	100	~
UK	Rolls Royce	PWR	470	Early 2030s[41]

[29] International Atomic Energy Agency, *ibid.*

[30] Hussein, *supra* note 27.

[31] "China is Home to World's First Small Modular Nuclear Reactor" (20 December 2021), online: *Bloomberg* <www.bloomberg.com/news/articles/2021-12-21/new-reactor-spotlights-china-s-push-to-lead-way-in-nuclear-power>.

[32] "Demonstration HTR-PM connected to grid" (December 2021), online: *World Nuclear News* <www.world-nuclear-news.org/Articles/Demonstration-HTR-PM-connected-to-grid>.

[33] Bhavini, "Global First Power plans to deploy a small modular reactor in Canada by 2026" (November 2021), online: *Prospero Events Group* <www.prosperoevents.com/global-first-power-plans-to-deploy-a-small-modular-reactor-in-canada-by-2026>.

[34] "Advanced Reactor Demonstration Program" (November 2021), online: *X-Energy* <x-energy.com/ardp>.

[35] "Deal signed for nuclear to power Russian gold mine" (January 2022), online: *World Nuclear News* <www.world-nuclear-news.org/Articles/Deal-signed-for-nuclear-to-power-Russian-gold-mine>.

[36] "OPG advances clean energy generation project" (December 2021), online: *Ontario Power Generation* <www.opg.com/media_releases/opg-advances-clean-energy-generation-project>.

[37] "Projects", online: *NuScale Power* <www.nuscalepower.com/en/projects>.

[38] "Interprovincial Strategic Plan for Deployment of Small Modular Reactors in Canada" (8 April 2022), online: *ARC Clean Technology* <www.arc-cleantech.com/news/59/39/Interprovincial-Strategic-Plan-for-Deployment-of-Small-Modular-Reactors-in-Canada>.

[39] "Moltex receives $50.5M from Government of Canada for small modular reactor" (18 March 2021), online: *Moltex Energy* <www.moltexenergy.com/moltex-receives-50-5m-from-government-of-canada-for-small-modular-reactor/>.

[40] "French-developed SMR design unveiled" (17 September 2019), online: *World Nuclear New*<world-nuclear-news.org/Articles/French-developed-SMR-design-unveiled>.

[41] "UK SMR to start regulatory process this autumn" (17 May 2021), online: *World Nuclear News* <world-nuclear-news.org/Articles/UK-SMR-to-start-regulatory-process-this-autumn>.

PROBLEMS POSED BY NUCLEAR POWER

Nuclear poses four inherent problems, including complexity of design, potential accidents, and storage of spent fuel and other waste products. The fourth is public skepticism, based on Chernobyl and Fukushima, and the threat of channeling nuclear power technology toward nuclear arms.

Complexity of Design

Historically, many large nuclear power plants have overrun initial cost estimates and have experienced delays in completion. A partial explanation is over-regulation; another is the complexity of large nuclear plants relative to most other power generation technologies. The expectation among advocates of SMRs is that their smaller size will reduce complexity of design, and construction of many SMRs will enable experimentation in optimal reactor design. Relative to large reactors, Ontario Power Generation (OPG) expects its SMR to require less steel, concrete, and other components per MW of capacity. Admittedly, there is little to no practical experience yet to warrant claims of simpler designs and fewer regulatory delays.

Nuclear Accidents

Nuclear accidents involving mortality, morbidity, and environmental impacts have occurred, but all power generation technologies have some degree of negative impact on society and the environment. We emphasize the results of studies employing, as a measure, the deaths attributable to various technologies, normalized per TWh of electricity generated. Deaths may arise from extraction of fuel (e.g., coal mining and transportation), construction and maintenance of power plants (e.g., SMRs, wind mills, hydro dams), nuclear contamination from meltdown. Since 1950, two major meltdowns of nuclear power plants have taken place: Chernobyl in Ukraine in 1986, and Fukushima in Japan in 2011. Ritchie[42] has estimated deaths attributed to radiation emanating from Chernobyl as 433. From Fukushima only one death has been attributed to radiation, though about 19,000 were killed by the 2011 earthquake and tsunami.[43] Overall, the deaths per TWh of wind, solar, and nuclear are less than 0.1 death per TWh. Deaths due to fossil fuel power generation are two orders of magnitude higher: 25 per TWh for coal-based power, 18 for oil, 3 for gas.

Nuclear Waste Storage

The Canadian Nuclear Safety Commission (CNSC) shares the international professional consensus that deep rock formations are the preferred deposit for long-run storage. Writing in the Encyclopedia of Physical Science and Technology, emphasize the need for "broad public acceptance":

> While the technical and scientific communities may agree that deep geologic disposal is safe and ethical, the public seems much more skeptical. The main hurdle now is gaining public and political confidence in the safety of a deep geological disposal program and of the sites selected by that program.
>
> The waste management community needs to communicate to the general public in simple yet precise terms how it obtains scientific and technical consensus that safe disposal can be achieved. If this communication is to be effective, it requires the involvement of the public in all aspects of the program. There must be recognition within the technical and scientific community that implementing any form of nuclear waste disposal is determined not only by technical or regulatory processes but also by broad public acceptance.[44]

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[42] Hannah Ritchie, "What was the death toll from Chernobyl and Fukushima?" (24 July 2017), online: *Our World in Data* <ourworldindata.org/what-was-the-death-toll-from-chernobyl-and-fukushima>; and "What are the safest and cleanest sources of energy?" (10 February 2020), online: *Our World in Data* <ourworldindata.org/safest-sources-of-energy>.

[43] "Fukushima Daiichi Accident" (updated August 2023), online: *World Nuclear Association* <world-nuclear.org/information-library/safety-and-security/safety-of-plants/fukushima-daiichi-accident.aspx>.

[44] Saeid Saeb and Stanley J. Patchet, "Radioactive Waste Disposal (Geology)" (2003) Radioactive Waste Disposal in Encyclopedia of Physical Science and Technology (third edition) at 633–41, online: <www.sciencedirect.com/topics/engineering/deep-geological-disposal>.

While the authors emphasize public confidence, they don't discuss details. The prerequisites in realizing more deep disposal sites will probably be a government white paper, parliamentary committee hearings, and consistent support by senior politicians.

Public Attitudes

Recent public surveys of Canadian public attitude to nuclear power are ambiguous. Upon election of Doug Ford as Premier in 2018, the Ontario government refused to extend renewable power access to the grid, on grounds it was potentially destabilizing the provincial power system. In January 2020, Friends of the Earth, an environmental organization opposed to expansion of nuclear power, published a national survey on small nuclear reactors (n=2094). The survey began with the following statement to participants: "*Ontario has recently paid $237 million to shut down 758 renewable energy projects, while Saskatchewan is refusing to allow any more homeowners to install solar panels. Recently, Ontario, Saskatchewan and the New Brunswick Premiers announced support for a $27 billion plan to produce hundreds of uranium fueled Small Modular Nuclear Reactors*." The survey continued with the following question: "*Do you think these governments are on the right path or wrong path with respect to energy production and dealing with climate change?*" The share responding "wrong path" was 62 per cent, "right path" 31 per cent, "unsure" 7 per cent. The lowest "right path" responses were in BC and Quebec (below 30 per cent), two provinces with no history of nuclear power generation and large-scale hydroelectric generation. The highest "right path" responses were in Ontario and the Prairie provinces (above 35 per cent).

In a second survey, Common Ground, an institute associated with the University of Alberta, conducted a two-stage survey (sample size 1,659) in Saskatchewan, in 2020 and 2021. The survey invited respondents to respond to the following statement: "*Saskatchewan should use small modular reactors to replace coal energy generation on the provincial electrical grid*." The survey allowed five responses with the following results: strongly disagree (7.5 per cent), somewhat disagree (7.5 per cent), neutral (32.2 per cent), somewhat agree (32.9 per cent), and strongly agree (19.9 per cent).

According to the first survey, the majority oppose nuclear expansion via SMRs; in the second, the majority (at least in Saskatchewan) support investment in SMRs. Arguably, the first survey employed a biased introduction. It implied that Ontario's refusal of further renewable energy connections to the grid and agreement to large-scale investment in SMRs was driven by ideological bias, as opposed to concerns over system instability.

Saskatchewan should not be interpreted as representative of national opinion.[45]Arguably, respondents were influenced by the prospect of economic benefits from expansion of the provincial uranium sector. Clearly, survey responses vary with the context presented. If Canada is to accept the logic of nuclear expansion, political leaders will have to organize extensive public consultation.

DON'T PUT ALL OUR EGGS IN THE WIND AND SOLAR BASKET

Honouring the Paris Accord agreement (limiting temperature rise to 1.5C degrees) requires ambitious international co-operation — which to date has been absent. All feasible strategies (see Box 1) require high-income countries to invest heavily in several technologies — acknowledging the many uncertainties in each. Wind and solar pose problems in the form of potentially high cost of storage and public resistance to many on-shore wind mills and large solar farms. After a century of expanding hydro capacity, increased hydro power in Canada requires building dams in less productive sites. Nuclear poses problems in terms of accidents, spent fuel storage, and adverse public opinion.

The CER projection implies that, by 2050, a quarter of power generation derives from wind and solar. At that level of non-dispatchable power, the "duck" problem may well be serious. A potential scenario for nuclear expansion via SMRs is to maintain, in 2050, the dispatchable share of power generation in 2019. After shutting down most fossil fuel power and realizing CER's projected increase in hydro power, construction of 47 300 MW

[45] Saskatchewan is the province whose respondents were the most sympathetic to SMRs in the first survey. The provincial response in the first survey was 40 per cent "right way", the highest share among provinces.

SMR plants would reduce reliance on wind and solar, and maintain non-dispatchable power at 5 per cent of the CER projected portfolio of power sources.[46] This scenario is one of many. Perhaps, after constructing a few SMRs, their LCOE will turn out to be much higher than our estimates, maybe not. Perhaps, the LCOS of wind and solar declines substantially, maybe not.

Realizing a "net zero" power sector by 2050 requires a massive reconfiguration, one that Canadians have only begun to undertake. In October 2022, Ottawa made a modest down payment in diversifying its green energy financial support: Canada Investment Bank is investing $970 million in Canada's first SMR.[47] In addition, the *Fall Economic Statement*[48] introduced a refundable tax credit of up to 30 per cent for investments in clean technologies, including SMRs. These are welcome actions from Ottawa, however nuclear energy is still excluded from some major federal clean energy funding programs such as the Green Bond Framework. Much more funding will be needed to ensure we don't put all our eggs in the wind and solar basket.

APPENDIX 1: TERMS FREQUENTLY USED IN DISCUSSION OF POWER UTILITY POLICY

Dispatchable / non-dispatchable power[49]

A dispatchable source of electricity refers to an electrical generating source that can adjust its power output supplied to the electrical grid on demand. In Canada, we have three dispatchable sources: hydro, fossil-powered plants (coal, gas, oil), and nuclear. Most renewable sources, such as wind and solar, are non-dispatchable. They can only generate electricity when their energy source (wind or sunlight) is available. They can be considered as dispatchable if they enjoy adequate storage of the power generated.

Dispatchable sources must be able to ramp up to maximum capacity or shut down relatively quickly, depending on the demand for electricity. Different types of power plant have different speed of output adjustment:

- Hydroelectric turbines are able to adjust output very quickly, in under a minute.
- Natural gas turbines can generally be ramped up or down in a few minutes.
- Nuclear power plants are primarily intended to deliver stable baseload power at the capacity designed. However, in France, 70 per cent of power derives from nuclear, which requires the ability to adjust output (for example, adjustment to time-of-day use).

Why is dispatchable power important?

- **Load matching**: Typically, peak demand is in early morning and evening. Much less electricity is needed at night than during the day. Dispatchable capacity must be sufficient to accommodate peak demand.
- **Cover lead-in times**: A lead-in time is time a power plant takes to achieve desired output.
- **Cover intermittent power sources**: Non-dispatchable sources provide valuable electricity, but they do not provide guaranteed electricity, unless the power sector can provide adequate storage.

[46] Based on projections of the CER, the dispatchable share of power generated declines from 94.5 per cent in 2019 to 76.3 per cent in 2050. Assume the CER 2050 projection of dispatchable power, 625 TWh (including expensive gas with CCS). Second, assume wind and solar power in 2050 to be 45 TWh. This maintains 5.5 per cent non-dispatchable. Third, assume SMRs supply the residual dispatchable power to maintain the 2019 dispatchable share in 2050. Under these assumptions, Canada would require 47 SMRs (each with 300 MW capacity and 85 per cent capacity factor).

[47] "CIB commits $970 million towards Canada's first Small Modular Reactor" (25 October 2022), online: *Canada Infrastructure Bank* <cib-bic.ca/en/medias/articles/cib-commits-970-million-towards-canadas-first-small-modular-reactor/>.

[48] "Fall Economic Statement 2022" (2022) at 30, online: *Government of Canada* <www.budget.canada.ca/fes-eea/2022/home-accueil-en.html>.

[49] In several glossary items, we have adapted the description from publicly available text prepared by the University of Calgary.

Capacity and capacity factor

A power plant is designed with a generating capacity, designated by the electricity generated in one hour under optimum conditions. The International Atomic Energy Association defines small nuclear reactors as those with capacity under 300 MW (i.e., able to generate a maximum of 300 MWh in an hour).

The capacity factor refers to the expected power generated over, say, a year relative to the plant generating power throughout the year at the designed capacity. Wind and solar have a capacity factor of about 30 per cent, nuclear plants about 90 per cent.

Baseload power / peaking power

Baseload power is the minimum capacity needed for the electrical grid over a given time period, such as a 24-hour day. Baseload power plants are intended to operate at their optimum capacity. In other words, they have a high capacity factor. The three important baseload power sources in Canada (hydro, fossil fuel, and nuclear) are also dispatchable, with variable dispatch potential. Demand fluctuates throughout a typical day, so baseload power is not enough. The grid requires peaking power for spikes in power demand. The utility may supply peaking power from a high-cost plant not usually used; the utility may purchase peaking power from another utility.

Levelized cost of electricity (LCOE) and levelized cost of storage (LCOS)

The most frequently used metric to compare the cost of electricity arising from alternate technologies is levelized cost. Typically, LCOE is measured as dollars per megawatt hour (MWh) of electricity generated by a particular power plant. The intuition behind levelized costing is to define a constant price per MWh of power generated by a particular power plant over its estimated life span such that the present value of revenue generated equals the present value of projected lifetime costs incurred by a plant (capital + operating costs).

As in any discounting exercise, the calculated LCOE varies with the discount rate. The present values of initial capital costs do not much vary with the discount rate. On the other hand, varying the discount rate has a sizeable impact on present value of revenue generated over many decades. Hence, the higher the discount rate, the higher the LCOE. The levelized cost of storage (LCOS) for a utility depends on the available storage options. The LCOS is an average calculated in a manner similar to LCOE.

Carbon capture and storage (CCS)

Continued reliance on fossil-based dispatchable power is consistent with elimination of GHG emissions in the power system — but only if carbon is extracted from the exhaust gases of the power plant and buried. Extraction is feasible but, currently, it is expensive.

Megawatt hour (MWh), terawatt hour (TWh), kilowatt hour (KWh)

Watt is a unit of energy. An incandescent 100-watt bulb lit for an hour consumes 100 watt hours. If lit for ten hours, the bulb consumes 1,000 watt hours, or one kilowatt hour, of electricity. One megawatt hour of electricity is one million watts in an hour; one terawatt hour is one trillion watts in an hour.

Renewable power sources. Sources of power that are not exhausted by use. They include bioenergy, geothermal, hydropower, solar photovoltaics, concentrating solar power, wind and marine (tide and wave) energy.

APPENDIX 2: GLOSSARY OF NUCLEAR REACTOR DESIGNS

LWR – Light Water Reactor. This is the most common reactor type, used around the globe. It uses normal water, as opposed to heavy water, as both its coolant and neutron moderator. Reactor fuel is used as a solid form of fissile elements. SMR designs typically take this old reactor concept and simplify it through removal of unnecessary components. These reactors tend to be simpler and cheaper to build than other types of reactors.

PWR – Pressurized Water Reactor. This is the most common type of light water reactor. In a PWR, the primary coolant is water, which is pumped under high pressure to the reactor core where it is heated by the fission of atoms. The heated, high-pressure water then flows to a steam generator, where it generates steam to turn a turbine.

SFR – Sodium-Cooled Fast Reactor. This advanced (Gen 4) reactor uses liquid metal (sodium) as a coolant instead of water, which is used in most reactors operating today. Using liquid metal allows for the coolant to operate at higher temperatures and lower pressure than current reactors. This improves the efficiency and safety of the system. The SFR uses a fast neutron spectrum, meaning that neutrons can cause fission without having to be slowed down first as in current reactors. Fast reactors have significantly reduced waste streams in comparison to our current reactors.

SSR-W – Stable Salt Reactor – Wasteburner. This advanced (Gen 4) type is a hybrid between light water reactor fuel types and traditional molten salt reactor approaches. In the SSR-W, the liquid molten salt fuel mixture is contained within fuel assemblies that are very similar to current light water reactor technology and are submerged in a pool of pure liquid salt coolant. This is also a fast reactor that could use recycled existing Canadian nuclear waste as fuel. ■

CANADA INTRODUCES NEW LEGISLATION TO REGULATE OFFSHORE WIND PROJECTS[1]

*Dominique Amyot-Bilodeau, Louis-Nicolas Boulanger, Elena Sophie Drouin, Kimberly J. Howard, and Jacob Stone**

INTRODUCTION

The Minister of Natural Resources of Canada, Jonathan Wilkinson introduced on May 30, 2023 legislation to allow for offshore wind energy development for the first time in Atlantic Canada. Bill C-49, *An Act to amend the Canada-Newfoundland and Labrador Atlantic Accord Implementation Act and the Canada-Nova Scotia Offshore Petroleum Resources Accord Implementation Act*[2] will amend the *Canada-Newfoundland and Labrador Atlantic Accord Implementation Act*[3] and the *Canada-Nova Scotia Offshore Petroleum Resources Accord Implementation Act*[4] which do not, in their present form, permit the approvals of offshore wind energy projects.

Currently the Atlantic Accords Acts implement agreements between Canada and the respective provinces on the joint management of offshore petroleum resources. Bill C-49 would modernize the Atlantic Accord Acts by notably establishing a framework for the development and regulation of offshore renewable energy projects in both provinces and their offshore areas. Bill C-49 also expands regulation of current petroleum projects and clarifies jurisdictional rules regarding domestic and internal sea boundaries.

THE NEW REGULATORY FRAMEWORK

The expansive amendments introduced by Bill C-49 are expected to streamline applications for seabed rights approvals by introducing a single "submerged land" licence to carry out offshore renewable energy projects. This system would replace this existing tenure system whereby multiple licenses are issued in the context of petroleum project development.

Under Bill C-49, regulatory authority for offshore wind power would be granted to the two existing jointly managed offshore boards that are currently exclusively responsible for regulating offshore oil and gas projects: the Canada-Nova Scotia Offshore Petroleum Board[5] and the Canada-Newfoundland and Labrador

[1] This article was originally published by McCarthy Tétrault LLP (27 June 2023), online: <www.mccarthy.ca/en/insights/blogs/canadian-energy-perspectives/prepare-offshore-winds-canada-introduces-bill-c-49-amending-atlantic-accords-acts-regulate-offshore-wind-energy-projects-atlantic-canada>.

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[2] Bill C-49, *An Act to amend the Canada-Newfoundland and Labrador Atlantic Accord Implementation Act and the Canada-Nova Scotia Offshore Petroleum Resources Accord Implementation Act and to make consequential amendments to other Acts*, 1st Sess, 44th Parl, 2023 (first reading 30 May 2023).

[3] Justice Laws Website, "*Canada-Newfoundland and Labrador Atlantic Accord Implementation Act* (S,C, 1987, c. 3)" (18 august 2023), online: *Government of Canada* <laws.justice.gc.ca/eng/acts/c-7.5/>.

[4] Justice Laws Website, "*Canada-Nova Scotia Offshore Petroleum Resources Accord Implementation Act* (S.C. 1988, c. 28)" (18 august 2023), online: *Government of Canada* <laws-lois.justice.gc.ca/eng/acts/C-7.8/index.html>.

[5] Canada-Nova Scotia Offshore Petroleum Board (CNSOPB), online: <www.cnsopb.ns.ca/>.

Offshore Petroleum Board.[6] As part of the amendments, these boards will be renamed the Canada-Nova Scotia Offshore Energy Regulator and Canada-Newfoundland and Labrador Offshore Energy Regulator, (the "**Regulators**").

The Regulators would have the power to govern various aspects of offshore renewable energy activities, such as safety, environmental protection, decommissioning, and royalties. The Regulators would also have the authority to conduct environmental assessments, public hearings, and dispute resolution processes related to offshore renewable energy projects.

Exploration, development, and production of offshore renewable energy resources, such as wind, tidal, or wave energy would be authorized by way of an application to the Regulators, but the decision to issue calls for bids would be subject to the approvals of both the federal and provincial ministers.

CHANGES TO EXISTING REGULATIONS

Bill C-49 proposes amendments to the existing regulation of offshore petroleum activities, to align them with the new provisions on offshore renewable energy. Some of the amendments include:

- new or amended consultation requirements with the provincial governments, Indigenous peoples, and others before issuing authorizations or making regulations on offshore petroleum activities;

- expanded powers for the Regulators to act and regulate offshore petroleum activities, such as safety, environmental protection, decommissioning, and royalties; and

- additional measures on environmental assessments, public hearings, and dispute resolution processes related to offshore petroleum projects.

NEW REGULATION AND ENVIRONMENTAL STANDARDS

Bill C-49 also includes a series of broader changes to environmental, jurisdictional and enforcement aspects of the existing legislation. Key changes to the management rules for transboundary offshore pools and fields are expected ensure consistency and cooperation among the relevant jurisdictions.

In keeping with other recent federal bills, Bill C-49 would expand existing enforcement and compliance tools, such as inspections, audits, orders, administrative monetary penalties, and offences, to ensure the safety and environmental protection of offshore activities.

Procedurally, Bill C-49 also contemplates additional protection of confidential information and new rules on the disclosure of information in the public interest, subject to certain exceptions and procedures.

From an environmental perspective, Bill C-49 would have Marine Protected Areas[7] standards apply to all offshore areas governed by the regulations. Offshore wind farms should be permitted within Marine Protected Areas. Bill C-49 also clarifies that offshore renewable energy activities would not be considered key industrial activities, but related activities which conflict with conservation objectives set out by the federal government may nevertheless be prohibited.

The new federal impact assessment process will be applicable to offshore energy development. For petroleum projects, future significant discovery licenses will be limited to 25 years, replacing the indefinite term currently in place. Existing significant discovery licenses, however, would remain exempt from the 25-year limit.

COMPENSATION FOR EXISTING RIGHTS

Before initiating a call for bids, Bill C-49 will require designated government authorities, namely the federal or provincial ministries, or the Regulators, to identify suitable areas for

[6] Canada-Newfoundland and Labrador Offshore Petroleum Board (C-NLOPB), online: <www.cnlopb.ca/about/board/>.

[7] "Marine Protected Areas" (8 February 2023), online: *Government of Canada* <www.dfo-mpo.gc.ca/oceans/mpa-zpm-aoi-si-eng.html>.

development, conservation, or fishing. The proposed legislation does not, however provide details on potential compensation for members of the fishing industry who may be excluded from offshore areas due to renewable energy project approvals.

The chair of the Canada Nova Scotia Offshore Petroleum Board has stated that the terms and conditions associated with seabed licenses and compensation schemes are still being determined by the governments. There are no indications in Bill C-49 that the compensation process would involve third-parties, such as wind farm developers.

NEXT STEPS

Overall, Bill C-49 represents an ambitious effort to modernize the regulation of offshore energy resources. By establishing a unified federal-provincial regulatory framework and introducing new environmental safeguards, the bill aims to promote sustainable development, enhance cooperation, and ensure the responsible and efficient management of resources. Both the Newfoundland and Labrador and the Nova Scotia governments are expected to introduce similar legislation to complete the framework proposed in Bill C-49.

While Bill C-49 has yet to be adopted, Nova Scotia has already set a target of issuing five gigawatts of licences for offshore wind by 2030[8] under the *Marine Renewable-energy Act*, with a stated aim[9] to encourage green hydrogen production. Leasing under this scheme would be expected to commence as of 2025.

In connection with this initiative, the Nova Scotia government released, on June 14, 2023,[10] Module 1[11] of the Nova Scotia Offshore Wind Roadmap,[12] which details the province's vision for the offshore wind industry, regulation and investment possibilities. This module outlines remaining work required to complete the legislative and regulatory regime for offshore wind projects. The other two modules, to be published later this year, will provide guidance on infrastructure, supply chain, public consultation and environmental issues. ■

[8] Nova Scotia Premier's Office, "Province Sets Offshore Wind Target" (September 2022), online: *Province of Nova Scotia* <novascotia.ca/news/release/?id=20220920003>.

[9] Keith Doucette, "Nova Scotia sets five-gigawatt target for offshore wind power by 2030" (20 September 2022), online: *Atlantic* <atlantic.ctvnews.ca/nova-scotia-sets-five-gigawatt-target-for-offshore-wind-power-by-2030-1.6076109>.

[10] Natural Resources and Renewables (Nova Scotia), "Province Releases Offshore Wind Road Map" (14 June 2023), online: *Province of Nova Scotia* <novascotia.ca/news/release/?id=20230614004>.

[11] Natural Resources and Renewables (Nova Scotia), "Nova Scotia Offshore Wind Roadmap, Module 1" (May 2023), online (pdf): *Province of Nova Scotia* <cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/demand-side-management/acc-models-latest-version/2022-acc-documentation-v1a.pdf>.

[12] "Offshore Wind", online: *Province of Nova Scotia* <novascotia.ca/offshore-wind/>.

THE *ENERGY STATUTES AMENDMENT ACT* – BRITISH COLUMBIA'S NEW REGULATORY REGIME AND NEW LIABILITIES FOR THE ENERGY INDUSTRY[1]

*Sasa Jarvis, Ralph Cuervo-Lorens, Sean Ralph, and Jordan Ghag**

INTRODUCTION

On November 24, 2022, British Columbia's *Energy Statutes Amendment Act* (the "***ESAA***") received Royal Assent. The *ESAA* makes sweeping changes to the regulation of energy in British Columbia, and will rename the "*Oil and Gas Activities Act*" the "*Energy Resource Activities Act*".[2] Similarly, it replaces the "*Oil and Gas Commission*" with the "*British Columbia Energy Regulator*" (the "**Regulator**").[3] The amendments made by the ESAA will broaden the scope of the regulatory regime beyond oil and gas to contemplate "energy resources" which include hydrogen, petroleum, natural gas, methanol, and ammonia.[4] Additionally, the revised *Energy Resource Activities Act* will expand the potential liabilities for oil and gas or storage activities and for prescribed energy resource activities beyond just the applicable permit holder.[5] Each of these categories of changes will be discussed in turn, along with potential Court challenges and defences related to the expansion of liability under this new regulatory regime.

PART I – THE NEW REGULATORY REGIME

By expanding the scope of the *Energy Resource Activities Act* to include additional energy

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[1] This article is an updated version originally published by McMillan (1 February 2023), online: <mcmillan.ca/insights/the-energy-statutes-amendment-act-british-columbia-welcomes-the-hydrogen-industry/>.

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[2] *Energy Statutes Amendment Act*, SBC 2022, c 42, s 1 [*ESAA*] (the name change will occur once section 1 of *ESAA* is in force).

[3] *Ibid*, s 5.

[4] *Ibid*, s 2(d) (see new defined term "energy resource").

[5] *Ibid*, s 14; *Oil and Gas Activities Act*, SBC 2008, c 36, s 21, as amended by *ESAA*, *supra* note 2, s 43.01 [*OGAA*].

resources, the provincial government will establish a comprehensive regulatory regime with a single regulator throughout British Columbia. The *ESAA* will do this by repealing the definition and references to "oil and gas activity" and replacing it with "energy resource activity," which explicitly includes the "*construction or operation of… a facility for manufacturing hydrogen, ammonia or methanol from petroleum, natural gas, water or another substance*."[6]

Following the amendments, a person must acquire a permit prior to constructing or operating a facility for manufacturing hydrogen.[7] In order to acquire a permit, a person must apply to the Regulator and provide, among other things, a description of the proposed site of the activity and a written report regarding consultations with the owner of the land on which the person intends to carry out the activity.[8] Further, the *Energy Resource Activities Act* also delineates the process to transfer a permit related to a hydrogen project, the environmental measures that must be complied with, what must be done in the event of spillage, and when an official may enter land or a premises being used as a hydrogen facility.[9] In relation to environmental protection, the interplay between provisions in the *Energy Resource Activities Act* and those already in the *Environmental Management Act* and the regulations under it remains unclear.

Other Amendments

In addition to expanding the scope of the regulatory regime and potential liability for principals and responsible persons, other noteworthy amendments include:

- The purpose of the *Energy Resource Activities Act* will be revised to expand the Regulator's mandate to "regulate energy resources activities in a manner that protects public safety and the environment, supports reconciliation with Indigenous peoples and the transition to low-carbon energy, conserves energy resources and fosters a sound economy and social well-being."[10]
- The renamed British Columbia Energy Regulator's board now must consist of between five and seven directors (opposed to three), consisting of at least one deputy minister and one Indigenous person.[11]
- The revised *Energy Resource Activities Act* provides that the Regulator will have to publish a list of orphan sites and that if the Regulator disposes of property abandoned at an orphan site, the proceeds of the disposition must be paid into the fund used to help pay for the cost of restoration of orphan sites and related purposes.[12]

PART II – LIABILITIES AND CHALLENGES

Expansion of Potential Liabilities

Pursuant to the revised *Energy Resource Activities Act*, "principals" and "responsible persons," in addition to the applicable permit holder, can be found liable for oil and gas or storage activities and for prescribed energy resource activities.[13] The *Energy Resource Activities Act* will define "principal" to include directors and officers of a corporation as well as individuals who control, directly or indirectly, the corporation.[14]

The term "responsible person" will be defined exceptionally broadly to include people who (i) hold, or have a legal or beneficial interest in, the petroleum or natural gas rights, or the location for the applicable permit, and/or (ii) have a legal or beneficial interest in production or profits resulting from an energy resource activity authorized by the applicable permit.[15]

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[6] *ESAA*, *supra* note 2, s 2(f) (see new defined term "energy resource activity").

[7] *OGAA*, *supra* note 5, s 21, as amended by *ESAA*, *supra* note 2, s 64.

[8] *Ibid*, ss 22, 24, as amended by *ESAA*, *supra* note 2, s 64.

[9] *Ibid*, ss 21, 29, 36, 37, as amended by *ESAA*, *supra* note 2, s 57.

[10] *ESAA*, *supra* note 2, s 6.

[11] *Ibid*, s 5.

[12] *Ibid*, s 19.

[13] *Ibid*, s 14; *OGAA*, *supra* note 5, s 21, as amended by *ESAA*, *supra* note 2, s 43.01.

[14] *ESAA*, *supra* note 2, s 14; *OGAA*, *supra* note 5, s 21, as amended by *ESAA*, *supra* note 2, s 43.01.

[15] *ESAA*, *supra* note 2, s 14; *OGAA*, *supra* note 5, s 21, as amended by *ESAA*, *supra* note 2, s 43.02.

Additionally, if a person has ceased to be a responsible person for a permit, the *Energy Resources Activities Act* will give the Regulator the power to designate the person as still being a responsible person if the Regulator is satisfied that the person intended to evade responsibility.[16]

Further, the Regulator will be able to establish a responsible persons register and any people listed in such register will be "conclusively deemed" to be a responsible person.[17] If a responsible person is listed in the Regulator's register and wants to be removed, they will have to satisfy the Regulator that they are not a responsible person, and they may also be required to provide the Regulator information or records to assist with identifying other responsible persons for the permit.[18] The grounds on which individuals will be placed on the register remain unclear and may well be open to challenge if not sufficiently related to the fundamental purpose of the legislation. Concerns may also be raised with respect to the reverse onus placed on an individual seeking to challenge inclusion in the register as it goes firmly against well-established jurisprudence placing the onus of proof upon the state actor seeking to: (i) impose legal obligations on an individual or entity; or (ii) circumscribe their range of permissible activity.

Following the enactment of the *ESAA*, the Regulator will be given increased power and will have the authority to take action in various instances including, but not limited to, the following:

- if the permit holder or former permit holder has ceased to exist or fails to comply with a specified provision, the Regulator can make an order compelling a responsible person or principal to (i) provide security to the Regulator to ensure performance of an obligation, (ii) carry out actions for the restoration or protection of public safety, and (iii) reimburse the Regulator for costs and expenses incurred in certain circumstances;[19]

- in relation to an orphan site for which the permit is cancelled or expired, the Regulator can make an order requiring a principal or responsible person to (i) perform each obligation imposed under the *Energy Resource Activities Act* or applicable permit, (ii) comply with prescribed requirements; and (iii) carry out actions for restoration or protection of public safety;[20]

- the Regulator can transfer a permit in relation to an orphan site to a responsible person or a principal of the current or former permit holder;[21] and

- in certain instances, the Regulator can transfer an authorization to conduct activities related to an energy resource activity to a third person, including a principal or related person.[22]

The revised *Energy Resource Activities Act*, however, will provide some minimal safeguards for principals and responsible persons. For instance, the Regulator will have to give a principal an opportunity to be heard prior to making an order against the principal, and upon application by a responsible person who has restored an orphan site, the Regulator may compensate the responsible person for a portion of their costs.[23] It should be noted though, that legislators have made an effort to protect orders made by the Regulator against persons other than principals, even when the burden imposed is disproportionate to that person's interest in, control over, or benefit from the relevant energy resource activity, by including a statutory protection against such orders from being considered unreasonable, and therefore vulnerable to court challenge.[24] As a bold attempt on the part of the legislature to limit

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[16] *ESAA*, *supra* note 2, s 14; *OGAA*, *supra* note 5, s 21, as amended by *ESAA*, *supra* note 2, s 43.06.

[17] *ESAA*, *supra* note 2, s 14; *OGAA*, *supra* note 5, s 21, as amended by *ESAA*, *supra* note 2, s 43.05(1).

[18] *ESAA*, *supra* note 2, s 14; *OGAA*, *supra* note 5, s 21, as amended by *ESAA*, *supra* note 2, s 43.05(2).

[19] *ESAA*, *supra* note 2, s 14; *OGAA*, *supra* note 5, s 21, as amended by *ESAA*, *supra* note 2, s 43.07.

[20] *ESAA*, *supra* note 2, s 14; *OGAA*, *supra* note 5, s 21, as amended by *ESAA*, *supra* note 2, s 43.08.

[21] *ESAA*, *supra* note 2, s 14; *OGAA*, *supra* note 5, s 21, as amended by *ESAA*, *supra* note 2, s 43.09.

[22] *ESAA*, *supra* note 2, s 14; *OGAA*, *supra* note 5, s 21, as amended by *ESAA*, *supra* note 2, s 43.10.

[23] *ESAA*, *supra* note 2, s 14; *OGAA*, *supra* note 5, s 21, as amended by *ESAA*, *supra* note 2, ss 43.11(2), 43.12.

[24] *ESAA*, *supra* note 2, s 14; *OGAA*, *supra* note 5, s 21, as amended by *ESAA*, *supra* note 2, s 43.11(3).

the traditional supervisory role of the courts in relation to exercises of a statutory power we would expect this provision to be tested on constitutional grounds in the right case.

The *Energy Resource Activities Act* is also noteworthy for its reference to supporting reconciliation with Indigenous peoples in the "purpose" provision of the Regulator.[25] Any exercise of a statutory power that may impact Indigenous interests must take into account those interests in keeping with the constitutional duty to consult and, where appropriate, accommodate Indigenous interests. Including this reference in the context of the function of the Regulator represents another aspect of the expanding approach to reconciliation with Indigenous peoples, one requiring that those interests be taken into account as part of the regulatory function over energy resource activities. Query what the remedy would be in the event that the Regulator in a given exercise of its statutory powers acts or decides in a manner that fails to support reconciliation.

Failure to comply could lead to prosecution of the company or its directors or officers with potentially quasi-criminal sanctions. The *Energy Resource Activities Act* as before is to be enforced through the imposition of administrative penalties and/or quasi-criminal prosecution for the more serious violations.[26] In the case of the latter, a fine of up to $1,500,000 or imprisonment for not more than 3 years or both can be imposed in the event of a conviction. In a prosecution for an offence, it is sufficient proof of the offence to establish that it was committed by the defendant's contractor, employee, or agent even if the contractor, employee or agent has not been identified or prosecuted.

Similarly, if a corporation commits an offence, a director or officer of the corporation who authorized, permitted or acquiesced in the offence also commits the offence, as does any other person who: (a) is directly or indirectly responsible for the act or omission that constitutes the offence, and (b) is a contractor, employee or agent of the person or of an other person described in (a), whether the corporation is also prosecuted or not.

Anyone facing an investigation or an allegation of non-compliance under the *Energy Resource Activities Act* will want to ensure from the outset that the full panoply of procedural rights afforded to targets of a regulatory investigation under the *Charter of Rights* and the common law (such as the right to counsel, the right to silence, the right to know the allegations faced) are properly assessed and if appropriate asserted. In the event that the investigation results in charges being laid, there are substantive defences that can be raised to this type of offence such as the defence of due diligence, mistake of fact or law, officially induced error and the defence of necessity.

CONCLUSION

The passing of the *ESAA* brings with it significant changes to the regulation of energy in British Columbia. Notably, the *ESAA* will widen the scope of the application of the revised *Energy Resource Activities Act* to capture natural resources including include hydrogen, petroleum, natural gas, methanol, and ammonia. The *ESAA* will also update the goal of the revised *Energy Resource Activities Act* to include the preservation of the environment and the protection of public safety while supporting Indigenous reconciliation efforts to help foster a sound economy and social well-being.

The revised *Energy Resource Activities Act* will provide that certain persons, including directors and officers of a corporation, can be found liable for activities conducted by the applicable permit holder. Further, following the amendments, several aspects of the revised *Energy Resource Activities Act* remain uncertain, including how the goals of supporting Indigenous reconciliation and environmental preservation will be advanced in practical terms. With other sections of the *ESAA* coming into force in the future, it is important to be mindful that failure to properly abide by the provisions of the revised *Energy Resource Activities Act* may result in penalties of varying degrees, some of which may be as severe as quasi-criminal prosecution. ■

[25] *ESAA*, *supra* note 2, s 6; *OGAA*, *supra* note 5, s 4, as amended by *ESAA*, *supra* note 2, s 6.

[26] *OGAA*, *supra* note 5, ss 62, 86.

THE EU'S NEW CARBON BORDER ADJUSTMENT MECHANISM IN ACTION: IMPACTS ON CANADA AND BEYOND[1]

Neil Campbell, Talia Gordner, Lisa Page, and Adelaide Egan[*]

INTRODUCTION

As part of its plan to reduce greenhouse gas emissions by 55 per cent by 2030, the European Union ("**EU**") signed into law a new Carbon Border Adjustment Mechanism ("**CBAM**") Regulation on May 10, 2023.[2] The Regulation is substantially similar to the EU's original CBAM proposal published in July 2021.[3]

Border carbon adjustments are a trade tool designed to level the playing field for tradable products affected by global climate regulation.[4] The CBAM will impose a charge on certain imports of carbon-intensive goods from countries with less stringent emissions requirements. The mechanism is part of the EU's broader effort to achieve its ambitious climate targets and to ensure a fair transition to a low-carbon economy. A transitional phase will begin on October 1, 2023 with full implementation scheduled for January 2026.[5] The new measures will have important consequences for Canadian exporters of carbon-intensive goods to the EU.

COVERAGE AND REQUIREMENTS

The Regulation covers the same industries and will function with the same certificate system as originally planned. It will implement the following key measures for EU importers and foreign exporters:

- A carbon price will be imposed on carbon-intensive goods entering the EU in the following sectors that are currently

[1] This article was originally published by McMillan LLP (5 June 2023), online: <mcmillan.ca/insights/publications/the-eus-new-carbon-border-adjustment-mechanism-in-action-impacts-on-canada-and-beyond>.

* Neil Campbell and Talia Gordner are partners in the Toronto office and Lisa Page and Adelaide Egan are associates in the Ottawa office of McMillan LLP. This article only provides an overview and does not constitute legal advice.

[2] European Council, "EU climate action: provisional agreement reached on Carbon Border adjustment Mechanism (CBAM)" (13 December 2022), online: <www.consilium.europa.eu/en/press/press-releases/2022/12/13/eu-climate-action-provisional-agreement-reached-on-carbon-border-adjustment-mechanism-cbam>.

[3] For an assessment of the EU's original CBAM proposal, see Neil Campbell, Talia Gordner, Lisa Page and Adelaide Egan, "Leveling the Playing Field: EU First Out of the Gate with Proposed Carbon Border Adjustment Mechanism" (11 August 2021), online:<mcmillan.ca/insights/leveling-the-playing-field-eu-first-out-of-the-gate-with-proposed-carbon-border-adjustment-mechanism>.

[4] Neil Campbell, Talia Gordner, Lisa Page and Adelaide Egan, "Carbon Tariffs – The Next Challenge in Canadian Climate Law and Policy?" (October 2021) 9:3 Energy Regulation Q, online: *ERQ* <energyregulationquarterly.ca/articles/carbon-tariffs-the-next-challenge-in-canadian-climate-law-and-policy>.

[5] European Commission, "Carbon Border Adjustment Mechanism" (last accessed 18 May 2023), online: <taxation-customs.ec.europa.eu/carbon-border-adjustment-mechanism_en>.

covered by the EU's "Emissions Trading System" ("**ETS**"):

- iron and steel;
- cement;
- fertilizer;
- aluminum; and
- electricity and hydrogen.[6]

- Importers must purchase CBAM certificates to offset the carbon content of their goods. The price for CBAM certificates will be based on the prices for intra-EU ETS allowances. The price of ETS allowances fluctuates based on market demand and the EU's climate targets. The ETS price in May 2023 hovered around € 85/tonne (approximately CAD $123/tonne),[7] which is significantly higher than the 2023 Canadian minimum Carbon Pollution Price of CAD $65/tonne.[8]

- Importers must report their annual CBAM obligations based on the carbon content embedded in the products they import into the EU. A third-party verifier will confirm the accuracy of these reports.[9]

- Products exported from countries that have established domestic carbon pricing schemes, including Canada, will be eligible to receive rebates on the value of CBAM certificates that would otherwise be required, based on the amounts already paid through their own domestic carbon pricing. The EU will establish a framework to assess the equivalency of other countries' carbon pricing policies, and rebates will be provided if the domestic carbon pricing is deemed equivalent or partially equivalent to the EU ETS.[10]

- The EU will phase-out its free allowances system which allows EU domestic producers to compensate for indirect emissions incurred from greenhouse gas emissions. The phase out will occur in parallel with the phasing-in of the CBAM.[11] The new CBAM is designed to ensure that the phase-out of free allowances should "in no case result in more favourable treatment for Union goods compared to goods imported into the customs territory of the Union."[12]

PHASE-IN TIMELINE

Starting from October 1, 2023 until December 31, 2025, EU importers will need to comply with a "simplified" CBAM consisting only of reporting obligations regarding the carbon content of imported goods. This initial phase is designed to allow the EU to gather data to inform the operation of the program before the full CBAM is implemented.[13] The transitional phase will also allow importers, and the foreign exporters who supply them, to gain experience working with the new system and in meeting the administrative requirements. In particular, the determination of the embedded carbon content in products and the amounts of

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[6] Council of the European Union, "Regulation of the Parliament and of the Council establishing a carbon border adjustment mechanism" ANNEX I (December 2022), online: <eur-lex.europa.eu/legal-content/EN/TXT/?uri=uriserv:OJ.L_.2023.130.01.0052.01.ENG&toc=OJ:L:2023:130:TOC>.

[7] Official Journal of the European Union "Regulation (EU) 2023/955 of the European Parliament and the Council of 10 May 2023 establishing a carbon border adjustment mechanism" (May 2023) [2023] OJ, L 130/66 at 56, online (pdf): <eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=OJ:L:2023:130:FULL>.

[8] Canada's carbon price will progressively increase to CAD $170 by 2030, see Government of Canada, "Update to the Pan-Canadian Approach to Carbon Pollution Pricing 2023-2030" (last accessed 18 May 2023), online: <www.canada.ca/en/environment-climate-change/services/climate-change/pricing-pollution-how-it-will-work/carbon-pollution-pricing-federal-benchmark-information/federal-benchmark-2023-2030.html>.

[9] Council of the European Union, "Regulation of the Parliament and of the Council establishing a carbon border adjustment mechanism (CBAM)", 2021/0214 (COD) (14 December 2022) ss 18, 20, online (pdf): <data.consilium.europa.eu/doc/document/ST-16060-2022-INIT/en/pdf>.

[10] Council of the European Union, "Regulation of the Parliament and of the Council establishing a carbon border adjustment mechanism (CBAM)", 2021/0214 (COD) (14 December 2022) ss12, 14, online (pdf): <data.consilium.europa.eu/doc/document/ST-16060-2022-INIT/en/pdf>.

[11] *Supra* note 5.

[12] *Supra* note 7.

[13] *Supra* note 2.

any price reductions based on domestic carbon pricing in the country of export will involve complex calculations.

The permanent phase will begin on January 1, 2026. At that time, EU importers will be required to report the quantity and the embedded CO_2 content of all goods covered by the CBAM, as well as purchase and surrender the requisite number of CBAM certificates for such imports.[14]

CBAM'S IMPLICATIONS FOR GLOBAL TRADE

The CBAM will impact goods entering the EU from countries with less stringent carbon pricing policies.[15] To adapt to the new CBAM, some countries may choose to enter into bilateral agreements with the EU. Canada would be an obvious candidate for such an agreement, which could assist Canadian exporters by clarifying and standardizing how Canada's federal carbon pricing regime (and provincial variations) would interface with the CBAM - particularly in relation to reductions of the value of certificates to be surrendered based on carbon pricing charges levied in Canada.

It is not yet clear whether the EU's leadership on border carbon adjustments will be followed by other countries that export significant amounts of carbon-intensive products. The Canadian Government announced plans to create a border carbon adjustment regime in its 2021 Budget and held a public consultation on the issue in the Fall of 2021.[16] However, it has not yet brought forward a proposed regime. The United States has lagged on climate regulation and is not well placed to implement a CBAM-style regime because of the absence of a domestic carbon pricing regulatory framework. However, there are indicators of interest in the subject matter. The United States is currently negotiating a "Green Steel" deal with the EU. The agreement, once finalized, will impose higher tariffs on carbon-intensive steel, and will be open to any other interested countries who wish to join and benefit from the agreement.[17] More recently, a group of legislators put forward a "Clean Competition Act" which includes proposals for a border tax on carbon-intensive imports.[18]

KEY TAKEAWAYS

The EU's newly adopted CBAM will have significant implications for the global trade of carbon-intensive goods. Canadian businesses in the affected sectors will need to adapt to these changes and develop systems to comply with this regulatory regime to maintain exports to the EU market. As a starting point, Canadian exporters should consider the products they are currently selling to the EU and determine their CO_2 content and carbon-intensity to better understand how the CBAM will specifically impact their sales, costs and prices. This may also help to identify competitive advantages and growth opportunities relative to other countries exporting to the EU that impose no or lower domestic carbon pricing charges than Canada (e.g. the US and China, among many others). For Canadian policy-makers, the to-do list may include development of a bilateral agreement with the EU related to its CBAM and decisions about whether and how to proceed with a Canadian border carbon adjustment regime. ■

[14] *Supra* note 5.

[15] As more countries consider implementing similar measures it remains an open question as to how these new developments will fit into the WTO legal framework including the *General Agreement on Tariffs and Trade*. For a fuller analysis on how border carbon adjustments may face scrutiny under WTO rules, please see Neil Campbell, William Pellerin and Tayler Farrell, "A Roadmap for Trade Law Compliant Border Carbon Adjustments" (10 July 2022), online: <www.cdhowe.org/intelligence-memos/campbell-pellerin-farrell-roadmap-trade-law-compliant-border-carbon-adjustments>.

[16] "Consultation on border carbon adjustments" (last modified 1 February 2022), online: *Government of Canada* <www.canada.ca/en/department-finance/programs/consultations/2021/border-carbon-adjustments.html>.

[17] The White House, "FACT SHEET: The United States and European Union to Negotiate World's First Carbon-Based Sectoral Arrangement on Steel and Aluminum Trade" (31 October 2021), online: <www.whitehouse.gov/briefing-room/statements-releases/2021/10/31/fact-sheet-the-united-states-and-european-union-to-negotiate-worlds-first-carbon-based-sectoral-arrangement-on-steel-and-aluminum-trade/>.

[18] Sheldon Whitehouse, United States Senator for Rhode Island "Whitehouse and Colleagues Introduce Clean Competition Act to Boost Domestic Manufacturers And Tackle Climate Change" (8 June 2022), online: <www.whitehouse.senate.gov/news/release/whitehouse-and-colleagues-introduce-clean-competition-act-to-boost-domestic-manufacturers-and-tackle-climate-change>.

BUILDING AND GOVERNING THE CANADIAN ENERGY SECTOR: LEARNING FROM CANADA'S ENERGY LEADERS. AN INTERVIEW WITH DAVID MORTON AND ANNA FUNG OF THE BRITISH COLUMBIA UTILITIES COMMISSION

Rowland J. Harrison, K.C. and Gordon E. Kaiser

INTRODUCTION

In the September 2019 issue of *Energy Regulation Quarterly* (*ERQ*), we introduced a series of interviews with the chairs of Canada's public utility tribunals. In this issue of *ERQ*, the Series continues with the publication of an interview with the Chair and the Deputy Chair of the British Columbia Utilities Commission. The interview was conducted by associates of the Ivey Energy Policy and Management Centre. It was originally published by the Centre (July 2022), online (pdf): <www.ivey.uwo.ca/media/ovwd0tty/iveyenergycentre_interview_bcuc_july2022_v2.pdf>.

David M. Morton, Chair and Chief Executive Officer

David was appointed Chair and CEO of the BCUC in December 2015. His responsibility is to deliver on the Vision of the BCUC — to be a trusted and respected regulator that contributes to the well-being and long-term interests of British Columbians. He is also a Commissioner, a role he has had since 2010, and he continues to participate in many proceedings. David also has over 25 years of experience as a consultant in the information technology sector. He is a Professional Engineer in BC, has a Licentiate in Accounting from the Society of Management Accountants Canada, was certified with the ICD.D designation in 2013 by the Institute of Corporate Directors, and holds a Bachelor of Applied Science from the University of Toronto. David also serves as President of the West Vancouver Community Arts Council. Appointed by OIC 490/19.

Anna Fung K.C., Deputy Chair, Commissioner

Anna was appointed as a BCUC Commissioner in December 2017 and as Deputy Chair in 2019, after serving as Vice President, Legal and General Counsel for TimberWest Forest Corp., where she also served as its inaugural Chief Ethics Officer. She was previously Corporate Counsel at Intrawest ULC and Senior Counsel at BC Gas Inc. Anna holds a Bachelor of Laws and Bachelor of Arts (English and French) from the University of British Columbia. She earned her Certified Corporate Counsel designation in 2015. She has served as President of the Law Society of British Columbia, Canadian Corporate Counsel Association, People's Law

School, Association of Chinese Canadian Professionals and BC Autism Association. She is the Chair of the BC Unclaimed Property Society and a past director for the Vancouver Airport Authority, Vancouver Foundation, Law Foundation of British Columbia and Arts Club Theatre Company. Appointed by OIC 491/19.

Energy policy usually tries to balance three imperatives: affordability for consumers, reliability and security of supply, and environmental impacts. How does an economic regulator like the BCUC think about these three pillars of energy policy?

Morton: We are an economic regulator. As an economic regulator, we have a different focus than a policymaker.

Regulators set rates to provide safe and reliable service. They also have to provide the utility the opportunity to earn a reasonable financial return. Rates, therefore, aren't too high and they aren't too low. They either achieve their goal or they don't.

This doesn't mean that there aren't affordability issues. Certainly, on a personal level, that's a major concern for me but traditionally economic regulators don't focus on affordability. If someone can't afford to pay their electricity bill, that's an issue for policymakers. That's a huge problem. But it's not what the regulator is empowered or legislated to do.

A similar argument applies to greenhouse gas reduction. If government places a cap on utility emissions, that would fit within our economic framework, we would move towards finding the least cost methods of providing energy given that target. If we don't have that legislative target to work towards, then we don't have the authority to require this of regulated entities — or of customers.

Fung: I agree. I would add that it's important for us as an economic regulator to understand what our role is not to formulate policy or substitute our own views or opinions for what government establishes as policy. We are a creature of statute. That means our powers come strictly from governing legislation. We don't get to make up the rules when we review applications. Nor do we get to substitute our own opinions for the Government's. We have to follow policy mandated in legislation, not formulate policy of our own.

Do you think that the mandate of regulators could evolve to incorporate additional pillars in the future? When there are trade-offs, for example, between environmental impacts and affordability, regulators possess substantial expertise and may be well-positioned to evaluate multiple objectives.

Fung: That's a great question and I have to say that there's certainly an argument for that. As parties with expertise, we are well-placed to understand the various competing considerations. We can provide input to government on whether we think that our mandate should include these factors. But I'm always conscious of the fact that I'm not elected by ratepayers to make those decisions. Politicians are elected to carry out the wishes of the electorate. If I wanted to set policy, I should run as a politician. I shouldn't be a regulator.

Morton: I think a regulator is well-positioned to make certain decisions, but only within a fairly narrow mandate. As Anna says, we're not elected and decisions about broader societal trade-offs should be made by politicians.

With that being said, I do think that we can help in making those decisions. We have transparent public processes. We are effective at gathering and testing evidence. We often have inquiries to gather information and make recommendations to government. So a Commission could be helpful in that context.

How do you manage regulatory hearings? And how do you ensure BCUC decisions are made independently?

Morton: We adhere to principles of natural justice and administrative law. Everyone potentially affected by a decision has a right to be heard and everyone has a right of reply. A panel will never consider evidence where parties to a proceeding haven't had an opportunity to comment.

We ensure that our hearings are open and transparent, but this doesn't mean that every decision needs hundreds of people weighing in. You scale the process to meet the circumstances. Everything is done publicly and everybody knows what we're doing. If you think we've made a wrong decision, then you can appeal to the BC Court of Appeal and convince the judge of your case. I can't guarantee that we didn't miss something or that we should have adjusted a utility's budget a little more over here or a little more over there. But we do make our decisions in an open and transparent process.

Fung: We've managed hearings to ensure that there is transparency and accountability. You don't assign panel members to a hearing if you know that they have agendas or specific views on the issue. Panel members are supposed to keep an open mind and not allow their personal views to influence outcomes. Decisions are based on the evidence that was brought forward in the proceeding.

We're also very careful to ensure that any given panel is totally independent of the rest of the Commission. There's no interference by other Commissioners with respect to the decision. Decisions are by the panel that heard the evidence. Further, every Commissioner is fully aware that, while staff assist tremendously in a proceeding and analyze the evidence, it is the panel that's responsible. There is no crossing the line when it comes to who is making the decisions.

Morton: I would add that our Commissioners are appointed by the Cabinet for specified terms. Any party that appears before us could attempt to persuade a Commissioner on an ex parte basis, but influence could also come from government. Certainly, some people think that we do whatever government tells us — especially as the Government owns the biggest electricity company in the province. But there is no phone call in the night telling us what to decide. Our terms are respected and I'm actually impressed with the level of independence that we have.

How are market forces and new technologies changing the scope of regulation? For example, regulators need to deal with traditional networks of transmission and distribution while at the same time storage is becoming more important and customers are becoming more demanding. How does the BCUC think about areas where it may regulate more or regulate less?

Morton: If you look at the evolution of energy over the last few years, one of the themes is greater input from customers. If you want electricity at your house, you rely on the wires that run down your street. There isn't much choice in whichever electricity company happens to be in your neighbourhood.

One of the important practices that we adopted at the BCUC is the perspective that we should only regulate where market conditions made it necessary. That might sound like a no-brainer — the whole reason for utility regulation is natural monopoly — but, if you actually read our *Utilities Commission Act*, the definition of a utility is anybody that sells energy in British Columbia. The word monopoly doesn't appear.

Thinking of new technologies, an issue that has arisen with electric vehicle charging is billing. If you charge your electric car outside the home, you can be billed on a perminute basis. Charging at home is billed on a per kilowatt-hour basis. Is this a regulatory matter for organizations such as the BCUC?

Morton: This issue has come up in BC. Measurement Canada is the regulator of all electric meters in the country. Measurement Canada has yet to approve a standard for volumetric delivery of EV charging.

Currently, it only has a time-based standard. We asked whether a utility could use an EV meter that is not approved by Measurement Canada and it seems that they can't. So, we ordered our two biggest electric utilities to ask for a dispensation from Measurement Canada. In plain speak, they are asking for an exemption from Measurement Canada rules, which say that you can't use volumetric meter for out-of- home EV charging.

More generally, EV charging is not part of a monopolistic utility. Anybody can set up an EV charging station and sell you electricity for your electric car. An important principle is that the BCUC deals with monopolies. As a result, we recommended to government that technologies such as EV charging not be regulated by us, because it is not monopolistic.

Fung: This is a perfect illustration of how some regulatory processes have not kept up with the pace of change in technology. Regulation and technology have to go hand-in-hand for regulation to be effective. This one is such an easy fix. Surely, it is possible to have a standard that can measure volumetric charging. Everyone understands the inequities of charging by time when you have different vehicles capable of different charging speeds, different battery sizes and at different temperatures, all of which influence the amount of time it takes you to get a full charge. Our direction to

BC's utilities arises because we're not waiting for Measurement Canada. It's unclear how long it will be before we see an approved measurement device.

BC is at the forefront of renewable natural gas. FortisBC, as an example, recently submitted an application on incorporating more renewable gas into their services. How do you see renewable natural gas fitting into the BC system?

Morton: We're in the early stages of FortisBC's submission. Since I'm on the panel, I can't say much. What I can do is offer some historical context.

Fortis first came to the BCUC with a proposal for a voluntary program. They wanted to enter into contracts with BC-based producers to buy upgraded, pipeline-quality biogas. They would then inject this into the system and deliver it to customers on a voluntary basis.

Initially, there was a big price differential between biogas and conventional natural gas. This differential has eroded as natural gas prices and the carbon tax have increased, but there's still a gap. The BCUC was okay with the pilot proposal as long as it was on a voluntary basis. Our concern as a regulator was imposing — on the entire customer base — the cost of a specific energy that they don't, from a statutory perspective, have to purchase and that is not required under law. This is why making the initial program voluntary was important.

Currently, the pace of decarbonization in the province has picked up. The Government stepped in with a regulation that allowed Fortis to buy and be compensated for a certain amount of biogas. The motivation was to backstop the risk for Fortis. The greenhouse gas reduction regulations have evolved to allow Fortis to buy up to a certain percentage of its total gas supply as renewable natural gas, and cost recovery is guaranteed.

Fung: Biogas is not a silver bullet that is going to solve the energy crisis and resolve climate change. It's one of the many tools that we have to deploy. In order to meet the greenhouse gas reduction targets that have been set, we need a range of technologies. Most new and emerging alternative energy sources don't come cheap. Our job at the BCUC is to do whatever we can to make them affordable.

British Columbia has experienced the severe effects of climate change. We had the Heat Dome, floods and fires in Abbotsford, Merit and Lytton. We need to seriously explore all opportunities. Renewable natural gas is one of the many that we should look at seriously. Other technologies include carbon capture and hydrogen. We will likely need all of these and more.

Economists typically recommend that consumers face time-varying prices for electricity. Yet, many jurisdictions are reluctant to implement these types of pricing schemes. How important do you think it is to update pricing structures? What do you think would be feasible from a consumer perspective?

Fung: Time-of-use rates are still relatively rare. It's not an approach that we've used to date in British Columbia. We understand the value of encouraging electric vehicle charging at night, but we prefer an approach that doesn't involve adding costs to the rate base.

Morton: Mandatory time-of-use rates are becoming less popular. Voluntary time-of-use rates are certainly more politically palatable. That said, I do think that time-of-use rates, and rate structures more generally, are important tools going forward.

Time-of-use rates are particularly useful for managing capacity issues. Anything that can smooth out demand is helpful because we build infrastructure for peak demand. We don't build for average demand. This means that much of what we build is not used most of the time. Regulations and practices that help us become more efficient help with affordability.

BC has used other rate structures like demand charges and residential increasing block rates. They were quite controversial when they first came in and remain so in some areas. In fact, we're moving away from block rates. We also had industrial declining block rates, but those are likewise becoming less common.

Rate design is important, but we need to do it in a thoughtful way. It can't be about forcing people to do their laundry at night and eating dinner in the middle of the day. It is critical to provide affordable electricity to people when they need it.

Fung: Energy policy and solutions, including rate design, have to be considered as a whole.

Morton: Further, as regulators, we need to be careful. We're technical people. We're analysts, engineers, accountants and economists. For us, there's no structure that is too complicated. But most people don't like complicated. Anything other than a straightforward per kilowatt-hour charge is a complicated rate structure. Simplicity and public accessibility is something that we sometimes forget, but it is important.

BC is in the fortunate position of having an abundance of clean hydro resources. Many jurisdictions are less fortunate. Building greater connections across Canada, so that provinces such as BC can supply provinces with clean electricity, could help achieve Canada's net zero targets. What are the prospects for developing new transmission infrastructure?

Morton: Virtually all of our transmission infrastructure runs North-South. This is not unique to British Columbia. There is very little East-West transmission and there's a lot of inertia in our existing transmission system.

I don't currently see much impetus to build transmission between BC and Alberta. BC has a market for all the power we generate. We have connections to California and other US states. Canada would like to encourage East-West transmission, but I don't think there's a business case for it right now. Moreover, unlike in the US, Canada does not have a national regulator that's promoting interprovincial transmission projects.

How do you see BCUC's role in improving energy literacy among the public?

Fung: I learned English as a second language and then proceeded to teach English. This experience taught me that it is very important to communicate in a manner that's easy for people to understand. Since I've been at the Commission, we've made a concerted effort to make our processes more accessible, less complicated and less mysterious to a wider range of people. In addition to our website, we post YouTube videos that explain to the public what we do and, more importantly, what we don't do. We use language that everyone can understand as opposed to acronyms. As an example, consider the term ratepayers. Why can't we just say customers?

We now have a practice of ensuring that every decision includes a short executive summary that tells people what this decision is about, rather than forcing them to read pages of acronyms and difficult concepts. As David pointed out, nothing is too technical for energy wonks at the Commission. But not everybody wants to be an energy wonk. ■