ENERGY REGULATION QUARTERLY

VOLUME 6, ISSUE 3 2018

Ms. Kimberly J. Howard, BA, LLB, MA, Associate, McCarthy Tétrault, Calgary

Ms. Rachel Hutton, LLB, BA, Partner, Stikeman Elliott, Vancouver

Mr. Martin Ignasiak, BComm, LLB, Partner, Osler Hoskin & Harcourt LLP, Calgary

Mr. Mark A. Jamison, BSc, MSc, PhD, Director, Public Utility Research Center, University of Florida

Ms. Michelle S. Jones, BSoc Sc, LLB, Associate, Lawson Lundell LLP, Vancouver

Ms. Jessica Kennedy, BSc, MBA, JD, Associate, Osler Hoskin & Harcourt LLP, Calgary

Mr. William Lahey, BA, LLM, Professor, Schulich School of Law, Dalhousie University

Mr. Dennis Mahony, BA, LLB, Partner, Torys LLP, Toronto

Mr. Jonathan McGillivray, BA, MA, LLB, BCL, Associate, Demarco Allan LLP, Toronto

Mr. Peter Miles, Retired Economist

Ms. Caitlin Milne, BSc, BA, Articling Student, Torys LLP, Toronto

Mr. William A. Mogel, BA, LLB, Partner, Mogel & Sweet LLP, Washington DC

Ms. Caitlin Morin, BA, BCL, LLB, Associate, Torys LLP, Toronto

Mr. David J. Mullan, LLM, Professor Emeritus, Faculty of Law, Queens University

Mr. Gordon M. Nettleton, BComm, LLB, Partner, McCarthy Tetrault, Calgary

Dr. Dwight Newman, BA, LLB, BCL, M Phil, PhD, Professor, Canada Research Chair in Indigenous Rights, in Constitutional and International Law, University of Saskatchewan

Martin Olszynski, BS, LLB, LLM, Associate Professor, University of Calgary

Mr. Peter Ostergaard, BA, MA, Former Chair, BC Utilities Commission, Vancouver

Mr. Johannes P. Pfeifenberger, MS, MA, Principal, The Brattle Group, Cambridge

Ms. Jessalyn Pryciak, BA, Analyst, Concentric Energy Advisors, Marlborough

Mr. André Plourde, BA, MA, PhD, Professor, Dean, Faculty of Public Affairs, Carleton University

Mr. Henry Ren, BSc, JD, Associate, Torys LLP, Toronto

Ms. Molly Reynolds, LLB, Senior Associate, Torys LLP, Toronto

Ms. Cassie Richards, BA, JD, Articling Student, Osler Hoskin & Harcourt LLP, Calgary

Mr. Erik Richer La Flèche, BCL, LLB, Partner, Stikeman Elliott

Mr. Mark Rodger, BA, LLB, Senior Partner, Borden Ladner Gervais LLP, Toronto

Mr. Chris Sanderson, Q.C., BA, LLB, Senior Counsel, Lawson Lundell LLP, Vancouver

Dr. Sanem Sergici, BS, PhD, Principal, The Brattle Group, Cambridge

Ms. Katie Slipp, BComm, LLB, Partner, Blakes, Calgary

Dr. Kathleen Spees, BS, MS, PhD, Principal, The Brattle Group, Cambridge

Mr. Lawrence E. Smith, Q.C., BA, LLB, MA, Partner, Bennett Jones, Calgary

Mr. David Stevens, BA, LLB, Partner, Aird & Berlis, Toronto

Ms. Charlotte Teal, Articling Student, Bennett Jones, Vancouver

Mr. John Vellone, BA Sc, LLB, MBA, Partner, Borden Ladner Gervais LLP, Toronto

Mr. Ron Wallace, Retired as Permanent Member, National Energy Board

Mr. Daniel Watt, BA, LLB, Partner, McInnes Cooper, Halifax

Mr. Adam White, BA, CEO, Powerconsumer Inc

Dr. Moin A. Yahya, BA, MA, JD, PhD, Associate Professor, Faculty of Law, University of Alberta

Dr. Adonis Yatchew, BA, MA, PhD, Professor, Department of Economics, University of Toronto

Mr. C. Kemm Yates, Q.C., BA, JD, Partner, Blakes, Calgary

Mr. Glenn Zacher, BA, LLB, Partner, Stikeman Elliott, Toronto

Mr. Ryan Zahara, BA, LLB, Partner, Blakes, Calgary

MISSION STATEMENT

The mission of the Energy Regulation Quarterly 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 Quarterly is intended to be balanced in its treatment of the issues. Authors are drawn principally from a roster of individuals with diverse backgrounds who are acknowledged leaders in the field of the regulated energy industries and whose contributions to the Quarterly will express their independent views on the issues.

EDITORIAL POLICY

The Quarterly is published by the Canadian Gas Association 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 Quarterly will maintain a "roster" of contributors 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. From time to time other individuals may also be invited to author articles. Some contributors may have been representing or otherwise associated with parties to a case on which they are providing comment. Where that is the case, notification to that effect will be provided by the editors in a footnote to the comment. The managing editors reserve to themselves responsibility for selecting items for publication.

The substantive content of individual articles is the sole responsibility of the contributors.

In the spirit of the intention to provide a forum for debate and discussion the Quarterly invites readers to offer commentary on published articles and invites contributors to offer rebuttals where appropriate. Commentaries and rebuttals will be posted on the Energy Regulation Quarterly website.

ENERGY REGULATION QUARTERLY

TABLE OF CONTENTS

EDITORIAL

Rowland J. Harrison, Q.C. and Gordon E. Kaiser
Managing Editors

The Canadian energy regulatory framework continues to develop, increasingly characterized by unpredictability. The articles in this issue of *Energy Regulation Quarterly* include reviews of several significant recent and current developments at both the federal and provincial levels.

The issue at the core of many of these developments is of course climate change and the concomitant response of greenhouse gas emission pricing. The current Canadian scene on the subject may be best described as one of turmoil, with the federal government enacting legislation (*Greenhouse Gas Pollution Pricing Act*[1]) imposing a "carbon tax backstop" on emitters in provincial jurisdictions that have not implemented a pricing system by 2019, while at the same time, Ontario moved to cancel the province's further participation in the California-Quebec-Ontario Cap and Trade system. Ontario has also announced a reference to challenge the constitutionality of the federal government's initiative and that it will join Saskatchewan in its constitutional challenge.

In their comprehensive review of these developments in "Canadian Carbon Pricing: Where is it Going?", Lisa DeMarco and Jonathan McGill describe the Ontario initiative as "carbon pricing whiplash", in the midst of which legal issues abound.

The newly-elected Ontario government also announced the cancellation wind and solar contracts that had been at the forefront of the province's efforts to transition towards a low carbon economy and directed the Independent Electricity System Operator to wind down the Feed-In Tariff (FIT) program that had been introduced in 2009. Gordon Kaiser discusses the development in "Ontario Cancels Wind and Solar Contracts."

Meanwhile, the Parliament of Canada continues its consideration of Bill C-69[2] (*An Act to enact the Impact Assessment Act and the Canadian Energy Regulator Act, to amend the Navigation Protection Act and to make consequential amendments to other Acts*). As described in the last issue of *ERQ*, Bill C-69 is "the most significant federal initiative in energy regulation since at least the 1980 National Energy Program". The far-reaching changes proposed by Bill C-69 include impacts on timelines for reviewing federal projects. Jonathan Drance *et al.*, in "Federal Energy Project Reviews: Timelines in Practice", offer valuable empirical research that should inform the debate as Bill C-69 proceeds. The authors conclude that proponents are "likely to take only cold comfort from the 'legislative timelines' in Bill C-69."

While much public attention is currently focused on pipelines, the implications of Bill C-69 for regulation of energy projects are far broader. In his article on "The role of the CNSC under the proposed *Impact Assessment Act*", Andrew Dusevic describes how the responsibility of the Canadian Nuclear Safety Commission to perform environmental assessments would not only be eliminated, but the Commission would have no meaningful participation in the process, notwithstanding that it "is the only government agency with the requisite technical expertise to effectively evaluate the full scope of the nuclear activities."

The consequences of policy and legislative initiatives directed at climate change can reach beyond their immediate goals. Implementation of the Alberta government's 2015 Climate Leadership Plan, for example, had the potential

1 *Greenhouse Gas Pollution Pricing Act*, being Part 5 of Bill C-74, *Act to implement certain provisions of the budget tabled in Parliament on February 27, 2018 and other measures,* 1st Sess, 42nd Parl, 2018 (assented to 21 June 2018), SC 2018.
2 Bill C-69, *An Act to enact the Impact Assessment Act and the Canadian Energy Regulator Act, to amend the Navigation Protection Act and to make consequential amendments to other Acts*, 1st Sess, 42nd Parl, 2018.

to materially impact market dynamics in Alberta's energy-only market. As discussed by Martin Ignasiak *et al*. in "The New Alberta Electricity Legislation", this has led to the proposed shift under Bill 13, *An Act to Secure Alberta's Electricity Future*[3] to a capacity market.

Discussion of the challenges faced by energy policy-makers and regulators frequently focuses on processes for reviewing proposed new development projects, due to the public controversy that they often generate in today's environment. However, dynamic developments within the energy industries, particularly developments resulting from technological innovation, also raise significant policy/regulatory issues. A recent report commissioned by the Canadian Gas Association and the Canadian Electricity Association on "Ratepayer Funded Innovation" discusses the case for utility-led and ratepayer-funded innovation. Adonis Yatchew comments on the report that the authors "have provided us with a valuable and cogent review of innovation models in electricity and natural gas industries", focused on jurisdictions where ratepayers (or taxpayers) contribute to funding innovation initiatives.

As is apparent from the foregoing outline of the contents of this issue of *ERQ*, the interface between "policy" and "regulation" is frequently central to addressing "energy regulation" issues and the proper role of regulators. Stephen Bird discusses the challenge in his article "Addressing the Policy Regulatory Nexus in Canada's Energy Decision-Making". Dr. Bird's article is the most recent of a series of articles to be published by *ERQ* emanating from the Positive Energy project at the University of Ottawa. ■

3 Bill 13, *An Act to Secure Alberta's Electricity Future*, 4th Sess, 29th Leg, Alberta, 2018.

CANADIAN CARBON PRICING: WHERE IS IT GOING?

Lisa (Elisabeth) DeMarco and Jonathan McGillivray[1]

On June 15, 2018, then Premier-designate Doug Ford announced that Ontario would not participate in the quarterly cap and trade allowance auction as part of the linked California-Quebec-Ontario Cap and Trade system (**WCI System**),[2] and thereby triggered the rapid repeal and demise of Ontario's cap and trade, carbon pricing system (**CT System**) 18 months after it began. The announcement was followed by directions to the Independent Electricity System Operator (**IESO**) to dismantle the GreenON website and cancel funding for all green projects that were slated for funding from the $2.8 billion in dedicated funds from all cap and trade allowance auctions to date, with the exception of certain home retrofit projects. Each of these actions took place swiftly after the Ontario election wherein the Ford-led Progressive Conservatives won a 76-seat majority government and having run on a surgically-focused policy platform that included repealing Ontario's cap and trade system. That same election saw the New Democrat Party become the official opposition, with 40 seats; the Green Party win its first seat in Ontario; and the Liberals, after governing for a 15-year period, reduced to seven seats and without official party status.[3] All of these actions took place before the new government was sworn in on June 29, 2018.

The dismantling of Ontario's CT System continued with the California Air Resources Board (**CARB**) suspending all WCI System trading in cap and trade compliance units from Ontario registered accounts on June 15, 2018.[4] The Ford government then introduced Ontario Regulation 386/18 on July 3, 2018, to repeal Ontario Regulation 144/16 (the **CT Regulation**) and prohibit registered participants from acting to "purchase, sell, trade or otherwise deal with emission allowances and credits."[5] Then, on July 25, 2018, the Ford government introduced Bill 4, *Cap and Trade Cancellation Act, 2018*. Bill 4, if passed, will repeal the *Climate Change Mitigation and Low-carbon Economy Act, 2016* (the **CT Act**) and formally end the province's cap and trade program.[6] The legislation provides for the (i) retirement and (ii) cancellation of Ontario emission allowances, Ontario credits, and Quebec and California emission allowances, offset credits, and early reduction credits (**Cap and Trade Instruments**)[7] in the following manner:

i. Cap and Trade Instruments that were held in the cap and trade accounts of an Ontario participant on July 3, 2018 — the date on which Ontario Regulation 386/18 entered into force — and that are not classified with or assigned a vintage year of 2021 are eligible for retirement.[8] The number of eligible Cap

1 Lisa (Elisabeth) DeMarco is a lawyer with over two decades of experience in law, regulation, policy and advocacy relating to energy and climate change and the Senior Partner of DeMarco Allan LLP. Jonathan McGillivray is an associate at the firm.
2 Office of the Premier-designate, Government of Ontario, News Release, "Premier-Designate Doug Ford Announced an End to Ontario's Cap-and-Trade Carbon Tax" (15 June 2018), online: <https://news.ontario.ca/opd/en/2018/06/premier-designate-doug-ford-announces-an-end-to-ontarios-cap-and-trade-carbon-tax.html>.
3 Justin Giovannetti, "Ontario PCs romp to comfortable majority as NDP forms the official opposition", *The Globe and Mail* (7 June 2018), online: <https://www.theglobeandmail.com/canada/article-ontario-pcs-romp-to-comfortable-majority-as-ndp-forms-the-official/>.
4 California Air Resources Board, Market Notice, "New Functionality in CITSS" (15 June 2018), online: <https://arb.ca.gov/cc/capandtrade/auction/marketnoticejune2018.pdf>.
5 O Reg 386/18.
6 Bill 4, *Cap and Trade Cancellation Act, 2018*, 1st Sess, 42nd Leg, Ontario, 2018 (first reading July 25, 2018).
7 *Ibid,* s 1(2).

and Trade Instruments actually retired will be that number that is equal to, or, as applicable, less than, the aggregate amount of all greenhouse gas emissions attributed to a participant in respect of a time period to be prescribed by regulation.[9] Cap and Trade Instruments held by a participant that are in excess of the aggregate amount of all greenhouse gas emissions attributed to a participant in respect of a time period to be prescribed by regulation will not be retired.[10]

ii. All Cap and Trade Instruments held in the cap and trade accounts of an Ontario participant on July 3, 2018 — other than those Cap and Trade Instruments that are retired (see above) — will be cancelled.[11] All Cap and Trade Instruments created under the CT Act and never distributed will also be cancelled.[12]

The government will pay compensation to an Ontario participant for the number of Cap and Trade Instruments that is equal to the number of Cap and Trade Instruments held in the participant's cap and trade accounts that are cancelled (see above), less the number of emission allowances that were distributed free of charge to the participant, and less the number of Cap and Trade Instruments held in the participant's cap and trade accounts that are classified with or assigned a vintage year of 2021.[13]

The amount of compensation payable will be determined in accordance with forthcoming regulations, which may prescribe certain criteria that must be met or circumstances that must apply in order for compensation to be paid.[14]

No compensation will be paid to the following participants (unless otherwise provided for by regulation):

Market participants;

- Participants registered with respect to the importation of electricity into Ontario for consumption in Ontario;
- Participants registered with respect to the distribution of natural gas in Ontario;
- Participants registered with respect to operation of equipment related to the transmission, storage, and transportation of natural gas;
- Participants registered with respect to the supply of petroleum products for consumption in Ontario; and
- Participants registered with respect to the operation of equipment for a transmission system within the meaning of subsection 2 (1) of the Electricity Act, 1998 and that has been issued an order under subsection 78 (1) of the Ontario Energy Board Act, 1998.[15]

The draft legislation seeks to bar causes of action and proceedings arising out of the cancellation of Ontario's cap and trade program.[16]

The draft legislation also requires that the government establish targets for the reduction of greenhouse gas emissions in Ontario and allows the government to revise those targets from time to time.[17] Additionally, the Minister of Environment, Conservation and Parks (the **Minister**) is required to prepare a climate change plan, to be accompanied by regular progress reports.[18] The legislation provides the Minister with the option of appointing an advisory panel for the purpose of preparing the climate change plan.[19]

During this tumultuous period, the federal government passed its *Greenhouse Gas Pollution Pricing Act* imposing a carbon tax backstop on emitters in provincial jurisdictions — now

8 *Ibid*, s 6(1).
9 *Ibid*, s 6(2).
10 *Ibid*.
11 *Ibid*, s 7, para 1.
12 *Ibid*, s 7, para 2.
13 *Ibid*, s 8(1).
14 *Ibid*, ss 8(2)-8(3).
15 *Ibid*, s 8(4).
16 *Ibid*, s 10.
17 *Ibid*, s 3(1).
18 *Ibid*, ss 4(1) and 5(1).
19 *Ibid*, s 4(2).

ostensibly including Ontario — that have not implemented a carbon pricing system by 2019.[20] Federal Minister of Environment and Climate Change Catherine McKenna confirmed that, in the absence of an equivalent carbon pricing scheme, the federal backstop will apply in Ontario.[21] However, on July 19, 2018, at the summer meeting of the Council of the Federation, Ontario announced that it will intervene and join Saskatchewan in its constitutional reference, challenging the federal government's ability to impose a carbon tax in the provinces.[22] Minister of Environment, Conservation and Parks Rod Phillips and Attorney General Caroline Mulroney further announced, on August 2, 2018, that the Government of Ontario will take steps to challenge the constitutionality of the federal backstop by commencing a reference to the Ontario Court of Appeal.[23] The government indicated that Ontario's position in court will be that the federal backstop imposes an unconstitutional tax on Ontarians.[24] An independent legal opinion commissioned by the Government of Manitoba and released on October 11, 2017, concluded that the federal government does have the authority to implement the federal backstop and stated that there was a "strong likelihood that the Supreme Court of Canada would uphold the proposed carbon tax/levy."[25]

Other provinces and prudent industry appear to be considering these developments very carefully, particularly Alberta's NDP government that will fight a 2019 election against the Unified Conservative Party (**UCP**) where energy pipelines and carbon pricing are anticipated to be central election issues. Specifically, UCP Leader Jason Kenney has vowed to repeal Alberta's long standing carbon pricing system,[26] which was recently made more stringent through the Alberta *Climate Change Incentive Regulation* (**CCIR**).

Legal issues abound in the midst of this carbon pricing policy whiplash, and responsible corporate entities and small energy customers appear to bear the greatest risks from the resulting uncertainties. Specifically:

- Responsible emitters have already invested $2.8 billion in Ontario-auctioned emission allowances and now face the possibility that such investment could be stranded, absent a reasonable transition from the new Minister. Emitters with value at risk of being stranded are also likely to have enhanced pressures from their shareholders.
- Many responsible corporate entities have invested in emissions-reducing technologies and programs as a prudent business response to mandatory carbon pricing and the market value of surplus emission allowances and lower emissions resulting from such clean technology. Their institutional investors have embraced the Task Force on Climate-related Financial Disclosures[27] and are demanding greater transparency and information on climate strategy and management actions to facilitate a smooth business transition to a lower-carbon economy and take advantage of climate-related opportunities. Responsible management and boards of directors are therefore faced with contrasting government and stakeholder demands and are therefore likely to re-examine the changing business case and all related implications.

---

20 See Bill C-74, *An Act to implement certain provisions of the budget tabled in Parliament on February 27, 2018 and other measures*, 1st Sess, 42nd Parl, 2018, (assented to 21 June 2018).
21 CBC Radio, "They don't have a climate plan': Catherine McKenna calls out new Ontario government", *CBC Radio* (19 July 2018), online: <https://www.cbc.ca/radio/asithappens/as-it-happens-wednesday-edition-1.4751691/they-don-t-have-a-climate-plan-catherine-mckenna-calls-out-new-ontario-government-1.4751696>.
22 Janyce McGregor, "Ontario joins Saskatchewan in opposing federal carbon tax plan", *CBC News* (19 July 2018), online: <https://www.cbc.ca/news/politics/carbon-tax-premiers-thursday-1.4752747>.
23 Ministry of the Attorney General, Government of Ontario, News Release, "Ontario Announces Constitutional Challenge to Federal Government's Punishing Carbon Tax Scheme" (2 August 2018), online: <https://news.ontario.ca/mag/en/2018/08/ontario-announces-constitutional-challenge-to-federal-governments-punishing-carbon-tax-scheme.html>.
24 *Ibid.*
25 Government of Manitoba, News Release, "Province Releases Expert Legal Opinion on Carbon Pricing" (11 October 2017), online: <https://news.gov.mb.ca/news/index.html?item=42320>.
26 Robson Fletcher, "Jason Kenney says he supports a carbon tax — but only on major industrial emitters in Alberta" *CBC News* (7 May 2018), online: <https://www.cbc.ca/news/canada/calgary/ucp-kenney-carbon-tax-power-politics-large-emitters-1.4652145>.
27 See *Task Force on Climate Related Financial Disclosures*, online: <https://www.fsb-tcfd.org/>.

- Other registered participants in the Ontario cap and trade market, including offset companies and energy trading companies, have invested in primary allowances and secondary emission allowance instruments, which are also estimated to be of material, but now potentially stranded, value.

- Natural gas utilities and their customers are in the midst of at least two regulatory proceedings[28] before the Ontario Energy Board, wherein the cost and value of Ontario cap and trade compliance instruments, related renewable natural gas and geothermal programs, additional low carbon fuel standards (federal and provincial), and the final amounts charged to customers are at issue. All of the regulated gas utilities, natural gas consumer groups, and the regulator itself await further policy determinations in order to assess the potential impacts of repealing Ontario's CT System. Quebec has similar renewable natural gas proceedings pending before the Régie de l'énergie.[29]

- Environmental groups, including the Canadian Environmental Law Association (**CELA**), have launched legal application for review of the repeal of Ontario's CT System to the Environmental Commissioner of Ontario on the basis of the Ford government's failure to provide the required notice and/or consultation on the repeal pursuant to section 67 of the *Environmental Bill of Rights, 1993*.[30]

- California and Quebec emitters holding material quantities of Ontario allowances will prudently be required to consider what, if any, legal or other relief is available to compensate them for the value of the potentially stranded Ontario allowances that they hold. California and Quebec regulators, CARB and Ministère du Développement durable, de l'Environnement et de la Lutte contre les changements climatiques (**MDDELCC**), respectively will similarly be required to prudently consider what legal or other relief, if any, they can obtain and/or should provide to affected entities. California has assessed that Ontario allowances represent less than 1 per cent of its current cap and trade market,[31] however both jurisdictions will no doubt monitor their August 14, 2018, joint allowance auction to assess the impacts of Ontario's withdrawal from the WCI System.

- Provinces and other entities will also need to assess what role, if any, they will play in the Saskatchewan constitutional reference, and the legal, constitutional, and shareholder implications of any decisions not to participate.

- Ontario will also need to determine, what, if any, meaningful climate policy it will implement in lieu of the CT System and work with energy, environment, and financial regulators in attempt to effect a smooth transition.

In summary, governments and stakeholders are being called upon respond to an increasing number of *policy* issues and challenges that will result from the Ontario decision to repeal cap and trade on very tight timelines.

In addition, Ontario's repeal of the CT System presents a number of *political* challenges that the federal government and its climate policy allies[32] will need to navigate in a very ambitious

28 See EB-2017-0319, "Renewable Natural Gas Enabling and Geothermal Energy Service Programs", Enbridge Gas Distribution Inc., *Ontario Energy Board*, online: <https://www.oeb.ca/participate/applications/current-major-applications/eb-2017-0319> and EB-2017-0224, EB-2017-0255, EB-2017-0275, "Application for Approval to Recover the Costs Associated with 2018 Cap and Trade Compliance Plans", Enbridge Gas Distribution Inc., Union Gas Limited, EPCOR Natural Gas Limited Partnership, *Ontario Energy Board*, online: <https://www.oeb.ca/participate/applications/current-major-applications/eb-2017-0224>.

29 See R-4008-2017, " Énergir - Demande concernant la mise en place de mesures relatives à l'achat et la vente de gaz naturel renouvelable", Société en commandite Gaz Métro, *Régie de l'énergie*, online: <http://publicsde.regie-energie.qc.ca/_layouts/publicsite/ProjectPhaseDetail.aspx?ProjectID=411&phase=1&Provenance=A&generate=true>.

30 Canadian Environmental Law Association, *Application for Review re Ontario Regulation 386/18*, filed 18 July 2018, online: <https://www.cela.ca/sites/cela.ca/files/EBR-Application-for-Review_cap-and-trade.pdf>.

31 California Air Resources Board, Compliance Instrument Report, "Linked California and Quebec Cap-and-Trade Programs Carbon Market Compliance Instrument Report" (9 July 2018), online: <https://www.arb.ca.gov/cc/capandtrade/complianceinstrumentreport.xlsx>.

32 These include, among others, New Zealand, Japan, Australia, and Norway.

Fall 2018 policy season and 2019 election year. The California Global Climate Action Summit and New York Climate week may necessitate nuanced Canadian policy developments leading into the negotiation of the United Nations Paris Rulebook at COP 24 in Katowice, Poland in December, 2018. But the real challenges for the federal government are likely to arise in and around elections. With Quebec going to the polls on October 1, 2018, Alberta on May 31, 2019, and the federal election on October 21, 2019, further extreme partisan positioning on carbon pricing may reasonably be anticipated over the next year. Soon after pipelines appear to have hit their zenith, carbon pricing may, in fact, be Canada's next existential energy crisis that requires concerted policy and political attention. ■

ONTARIO CANCELS WIND AND SOLAR CONTRACTS

*Gordon E. Kaiser**

Over the last decade governments around the world have increased their efforts to transition towards a low carbon economy. A major initiative in this effort has been the introduction of feed in tariffs or FIT contracts to promote renewable energy. Wind and solar have been at the forefront.

Ten countries and five US states led this initiative. Ontario was the first in North America and invested more capital than any other jurisdiction with the possible exception of Spain. All that came to a crashing halt on July 13 when the new Ontario government, elected on June 7, cancelled 559 wind and solar contracts.

On July 13, 2018, Greg Rickford, Minister of Energy, directed the Independent Electricity System Operator (IESO) pursuant to subsections 25.32(5) and (11) of the *Electricity Act*, 1998[1], to wind down the Feed-In Tariff (FIT) programs, undertaken by the IESO stating:

> *Since the introduction of the Feed-in Tariff (FIT) program in 2009 and the Large Renewable Procurement (LRP) initiative in 2014, the IESO has entered into a significant number of renewable energy contracts. These procurement initiatives have contributed to the cost pressures facing electricity consumers across all sectors of the economy, including residential, farming, small business and industrial consumers.*
>
> *The IESO's recent system planning work indicates that Ontario's current contracted and rate regulated electricity resources are sufficient to satisfy or exceed forecasted provincial needs for the near term and that there are other means of meeting future energy supply and capacity needs at materially lower costs than long-term contracts that lock in the prices paid for these resources.*
>
> *The IESO's system planning analysis indicates that the adequacy and reliability of supply can be maintained while winding down certain FIT and LRP contracts and that it would be in the best economic interests of Ontario's electricity ratepayers, in respect of the FIT program, to wind down contracts where the IESO has not issued Notice to Proceed and, in respect of the LRP program, to wind down contracts where the IESO has not notified the contract counterparty that all Key Development Milestones have been met.*[2]

The Directive stated:

> *In accordance with the authority I have pursuant to subsections 25.32(5) and (11) of the Act, I hereby direct the IESO to take all necessary steps in respect of the*

*Gordon Kaiser is an Arbitrator and Mediator practicing in Toronto and Washington DC. He is a former Vice Chair of the Ontario Energy Board.

1 *Electricity Act, 1998*, SO 1998, c 15, schedule A, s 25.32(5), (11).

2 *Minister's Directive To: The Independent Electricity System Operator*, OIC 1003/2018, (2018 O Gaz), online: < https://www.orec.ca/wp-content/uploads/2018/07/directive-20180713-wind-down-FIT-and-LRP.pdf>.

> *Initiative, as follows:*
>
> *1. To immediately take all steps necessary to wind down all FIT 2, 3, 4 and 5 contracts where the IESO has not issued Notice to Proceed.*
>
> *2. To immediately take all steps necessary to wind down all LRP I contracts where the IESO has not notified the LRP I contract counterparty that all Key Development Milestones have been met.*
>
> *3. To take all other steps which are necessary or desirable in order to facilitate the full and complete implementation of this Directive, as soon as is practicable.*[3]

Background

Feed in tariffs were first developed in Europe starting with Germany in 2004 and followed by the Czech Republic in 2005, Italy in 2007, Spain in 2008, and the UK in 2010.

In North America, Ontario was the leader when it first introduced Feed in Tariffs in 2006 followed by a substantial revision in 2009 through the *Green Energy Act*.[4] Ontario was followed by California in 2008, Vermont and Maine in 2009 and New York in 2012. The federal government in the United States relied mainly on tax credits, which proved to be a very effective tool without some of the liabilities of feed in tariffs.

The concept behind feed in tariffs was the same in all jurisdictions. These were long-term contracts for renewable energy at attractive prices. In some jurisdictions the contracts guarded against future changes with price adjustment clauses or amendments to volume commitments. Some like Ontario had few adjustments except for price increases.

In most jurisdictions a common problem developed. Governments for different reasons changed the incentive programs either by reducing the incentives or eliminating them entirely. Most countries discovered that this new renewable energy was very expensive power. The cost often exceeded what utilities could charge for it. In Spain this “electricity tariff deficit” as it came to be known, reached €26 billion. No estimate is made of the Ontario deficit but it was significant. And customers objected. It turned out that wind in particular was expensive power. It was often located in remote locations with significant transmission costs to bring it to market.

There may have been good reasons for the amendments but investors were not amused. When that happens, investors seek damages in local courts or through arbitration under international investment treaties.

There are two reasons why investors often choose arbitration. First, as the Ontario Court found in *Trillium Wind*,[5] there is often no remedy under domestic law. There, the plaintiff sought $2 billion in damages when the Ontario government cancelled the offshore wind FIT program. The company claimed breach of contract, unjust enrichment, negligent misrepresentation, misfeasance in public office and intentional infliction of economic harm. The court threw out all but one of the claims on the ground that the government’s decision to stop financing windfarms was a policy decision and immune from suit. The Court of Appeal agreed but admitted that there was one claim that could proceed – the claim for misfeasance in public office – not the easiest claim to prove.

The claims available in international arbitration, whether under NAFTA or the Energy Charter Treaty under which many of the European cases are brought, include direct and indirect expropriation of the investment, discrimination against a specific investor, denial of fair and equal treatment and denial of legitimate expectations – all claims not available under domestic law.

The second reason investors prefer arbitration is that many of the investors are foreigners and they prefer an arbitration panel to the domestic courts particularly where the claim is against the government of that country.

In both the UK and Canada investors challenged

3 *Ibid,* at 4.
4 *Green Energy and Green Economy Act, 2009,* SO 2009, c 12, schedule A.
5 *Trillium Wind Power Corp. v. Ontario*, 2013 ONCA 6083.

changes to renewable incentive programs in the local courts. In the UK that has been successful[6] but not in Canada.[7] In Canada, investors have also challenged reductions in incentive programs in two NAFTA arbitrations. One of those, *Windstream*[8], resulted in very substantial victory for the investors. In the other, *Mesa Power*[9], the investor lost.

More extensive litigation has occurred in Europe, particularly in Spain, where 30 investment treaty arbitrations have been filed, along with 7 cases against the Czech Republic and 9 cases against Italy. Virtually all of those have been filed under the *Energy Charter Treaty*.[10]

The first three international arbitration awards dealing with government decisions to cut back incentive programs in renewable energy were handed down in 2016. The first was *Charanne*[11] in January 2016, a claim against Spain under the ECT. This was followed by *Mesa Power* in May of 2016 and *Windstream Energy* in December 2016. In both *Charanne* and *Mesa Power,* the complainants were unsuccessful. In *Windstream Energy* the complainant was successful and received an award of C$25 million, the largest Canadian NAFTA award to date.

The second decision dealing with the Spanish reforms was *Eiser Infrastructure*[12]. There, an ICSID panel in May 2017 ruled that Spain must pay €128 million to British-based Eiser Infrastructure Limited and its affiliates. Spain defeated a third ECT claim in *Isolux*[13] the following year. There have been 9 arbitrations filed against changes to the Italian renewable programs to date. In the first, *Blusun*[14], a €187 million claim, Italy was successful in its defense.

If we try to determine the general principles established by the four European and two Canadian cases it would be this: These decisions are about "incentive" programs. That is the magic word.

Government incentive programs create legitimate expectations on the part of investors.

Legitimate expectations are a key component of fair and equitable treatment, a concept that runs throughout most international investment treaties.

The general rule is that governments can introduce new legislation that changes incentive programs provided they do not target or discriminate against a specific investor, contravene a promise to a specific investor, or introduce retroactive measures. These principles do not always apply but they are the red flags.

The strange twist to some is that if the investor is foreign and protected by an investment treaty they will have a cause of action. If the investor is domestic they are out of luck.

The Impact

The new government canceled 758 solar and wind contracts claiming that the savings would yield $790 M in savings to Ontario taxpayers. Two of those contracts were wind contracts. The first was Otter Creek, a 15 MW wind project near Wallaceburg. The second was the Strong Breeze project, a 57 MW project south of Belleville. The rest of the contracts were smaller solar contracts with the result that wind account for about 25 per cent of the cancellation capacity.

All of these contracts were contracts where the government had not issued an NTP or Notice to Proceed. That meant that on cancellation, the amount of compensation payable by the government could be calculated by the formulas set out in the contracts without additional penalties.

However, there was a third wind contract. This was the White Pines wind project, an 18.5 MW project in Prince Edward County. Unlike the other wind contracts, this was a FIT 1 contract which had already received its NTP.

6 *Secretary of State for Energy and Climate Change v. Friends of the Earth et al,* 2011 EWHC 3575.
7 *SkyPower v. Ministry of Energy, 2012* OJ No. 4458 at para 84; 2013 ONCA 683, 117, OR (3d) 721.
8 *Windstream Energy LLC v. Government of Canada,* PCA Case No. 2103-22, 27 September 2016.
9 *Mesa Power Group LLC v. Government of Canada,* PCA Case No. 2002-17, 24 March 2016.
10 *The Energy Charter Treaty,* 17 December 1994, EECH/A1/X.
11 *Charanne v. Kingdom of Spain,* Case No. 062/2012, ECT, January 2016.
12 *Eiser Infrastructure Limited and Energia Solar Luxembourg Sari v. Kingdom of Spain,* ICSID Case No. ARB /13/36.
13 *Isolux Netherlands,BV v. Kingdomof Spain,* SCC Case V2013/153 (Spain) [*Isolux*].
14 *Blusun SA, Jean-Paul Lecorcier and Michael Stein v. Italy,* ICSID Case No. ARB./14/3.

The only way this contract could be cancelled was to create special legislation designed to do that. That is exactly what the new government did when they enacted the *White Pines Project Termination Act*.

All of the wind contracts cancelled had one thing in common – they were strongly opposed by the community in which they were located. However, White Pines had a special feature. The NTP had been granted by the previous government during the writ period. The new government argued that this was exceptional and unauthorized. The standard practice was that during the writ period, the existing government should not enter into new contracts or make significant regulatory decisions which could bind the conduct of a future government.

While there has been a great deal of publicity regarding these cancellations it is evident that they represent a small percentage of the capacity that the IESO has contracted for under the FIT program. Today the total wind capacity contracted for by the IESO is 4500 MW. The cancelled wind only amounts to 29 MW less than 1 per cent of the total. In the case of solar, the total megawatts contracted for by the IESO by the end of 2017 was 1659 MW. The cancelled solar was only 333 MW or 20 per cent. The number of contracts was large but the volume was small.

The Compensation

The next question is what compensation are parties entitled to when the government cancels a long term contract? There is no doubt that the legislature has the power to cancel contracts subject to constitutional limitations. In the case of renewable energy contracts those contracts are clearly within the constitutional jurisdiction of the provincial government. A very helpful Report[15] on this topic was recently prepared by Bruce Pardy, of the Queens University Faculty of Law. It is worth reading.

These principles apply to actions in the local courts. However, where the projects are owned by foreigners, those investor may have rights under investment treaties with Canada. That is a different situation. We saw this in *Windstream Energy,* where the Complaint was successful in a NAFTA arbitration held in Toronto and received an award of $25 million. That claim resulted from the Province of Ontario's decision to terminate the offshore wind program. In the case of White Pines, the owner is German not American, and would not qualify for NAFTA protection. However, there may be protection for that investor under the recently agreed to CETA trade agreement with the European Union.[16] However, the legislation Ontario enacted to deal with White Pines has enough flexibility to allow the province to strike the appropriate agreement with the White Pine project.

In Ontario all FIT contracts contain a mutual "termination for convenience" provision in section 2.4. This can only be exercised before the IESO issues a Notice to Proceed. Where the IESO exercises this right it is required to pay the Supplier's Preconstruction Development Costs. Those must be substantiated by the supplier and are subject to the Preconstruction Liability Limits contained in the contract. These limits are based on a fixed lump sum plus an amount per kilowatt of contract capacity.

Later, FIT contracts such as FIT 4 and FIT 5 and the LRP contracts also have a pre-NTP termination right called a Keystone Development Milestone or KDM. This right is also mutual. In addition, they have a post NTP termination for convenience right, which the IESO calls an Optional Termination. The IESO, however, cannot exercise this right after the Commercial Operation Date or COD. Section 9.6 of the LRP contract contains a detailed formula to calculate the termination compensation. FIT 4 and FIT 5 contracts which were launched after LRP contain a similar formula. The one good thing that can be said about the Ontario FIT contracts is that they contain well thought out provisions for termination at different construction stages and detailed formulas to calculate the compensation. This is something that most European contracts missed.

The White Pines contract is a special case.

15 Bruce Pardy, "Fit to be Untied: How a new provincial government can unravel Feed-In Tariff electricity contracts", Commentary, CCRE Commentary, April 2018, online: <https://www.thinkingpower.ca/PDFs/Commentary/CCRE%20Commentary%20-%20FIT%20to%20be%20Untied%20by%20Bruce%20Pardy%20-%20April%202018.pdf>.

16 The Comprehensive Economic and Trade Agreement (CETA) between the European Union and Canada was signed October 20 2016 but the Investment Court System (ICS) is still not in force.

White Pines was a FIT 1 contract. In those contracts there is no section 2.4 provision. There was originally, but on August 2, 2011, just before the fall election of that year, the OPA was directed by the government to waive its section 2.4 termination rights in those contracts. As a result, the government was forced to introduce special legislation called the *White Pines Wind Project Termination Act*[17] to deal with this project.

The special legislation terminated the FIT contract dated May 4, 2010, that had been awarded to White Pines. Section 5 of the Act also extinguished any cause of action White Pines might have against the Crown, current or former members of the Executive Council, or any current or former employee agent of the Crown. No proceeding under any statute may be brought against those persons even if the proceeding was commenced before the Act comes into force.[18]

In terms of compensation the Act provides that no person is entitled to any compensation except that provided under section 6 of the Act. Section 6 sets out the formula to determine compensation and provides that White Pines can only recover its expenses incurred to date to develop the project. No recovery is allowed for lost profits. The Act expenses cannot exceed fair market value. The Act also provides that any dispute under this legislation must be determined by arbitration under the *Ontario Arbitration Act.*[19]

This is very comprehensive legislation and allows the government complete flexibility in determining a settlement including the ability to pass further legislation establishing the maximum amounts payable and/or the method of determining that maximum amount.

Lessons Learned

The contracts established by the previous administration in Ontario had a number of deficiencies. First in the early days the government placed no limitations on the total quantity of power to be purchased under the program. The situation the province faces today is that it has committed to purchase power that it cannot use. The contracted supply far exceeds the demand.

There are only three solutions to this problem. First, the IESO can direct the suppliers to reduce the output from the contracted level. This happens regularly with respect to wind which blows at night when the power is not needed. Generally speaking wind generators are only generating approximately 35 per cent of their capacity. However, the FIT contracts force the government to purchase nearly 100 per cent of the capacity. These are essentially 'take or pay' contracts. This in effect increases the costs per MW to customers significantly. If you purchase 35 per cent but pay for 100 per cent your cost per MW is three times what you thought it was going to be

This lack of a capacity adjustment clause is a real problem. The IESO can either pay for power not transmitted or pay US customers to take the excess power off the grid. The IESO has also been forced to do this. Excess power has to be removed from the grid. That means selling the power at negative prices. In recent years the cost of negative price sales has been significant.

Annual price adjustments could have been considered. The German program from the beginning used annual rate reductions. The Ontario Energy Board for years has established five-year rate plans with rebasing at the end of five years, if rebasing the utility was over earning the prices were reset to bring the rates back in line with allowed rate of return and windfall gains from prior periods were shared equally between customers and the utility. A long-term 20 year contract with guaranteed volumes and prices with a price escalator is pretty close to a natural monopoly. In short, greater consumer protection could have been easily introduced.

Second, the contracts provided no adjustment for increased efficiency. The contract prices were set on the costs prior to the date the contracts were signed. However, the industry has encountered significant cost reductions in both wind and solar technology. These cost reductions fall directly to the suppliers bottom line increasing the contract rate of return significantly. If we assume that a fair rate of return is the return the OEB sets for Ontario

17 *White Pines Wind Project Termination Act, 2018,* SO 2018, c 10, schedule 2.
18 *Ibid,* s 5.
19 *Ibid,* s 6.

electricity distributors twice a year, the excess profits on most FIT contracts are substantial.

The contract terms can be criticized, but the real problem may have been the contracting process. The contracts were standard offer contracts awarded on a first-come-first-served basis. When the contract windows opened, the applications rolled in fast. It was first come first served. Most were accepted.

The early FIT contracting process in Ontario also discouraged community involvement. The contracts required only basic feasibility evidence. Developers competed with each other for leases. This meant that they signed leases on a confidential basis without the community knowing. The rules also allowed developers to flip leases and contracts with few restrictions. It was the wild west. Ultimately greater community involvement was mandated but in many cases it was too late.

A much more prudent process would have involved competitive bidding as the province of Alberta recently chose to do. The prices that Alberta obtained in its most recent bid were a fraction of the Ontario prices. It is true that costs. have fallen significantly since the first Ontario contracts were awarded but the lack of a competitive process did promote excessive costs The Alberta priced are half of the most recent Ontario contracts.

Conclusion

The new government did a good job of dealing with a difficult situation. Two things were very clear. First the power was very expensive. Second the Province did not need the power.

Some very reasoned analysis went into the solution. The new government decided to leave the FIT 1 contracts alone. It is true that this was where most of the capacity was; certainly in the case of wind which was the biggest problem. But that was also where the greatest litigation risk was.

Many of the FIT 1 contracts were owned by Americans and cancellation could lead to a NAFTA claim. Given the experience in Windstream that could be an expensive process with a costly result. The ability to deal with the FIT 1 contracts was also compromised by the former government's decision before the last election to remove the section 2.4 termination rights.

In theory the government could have passed special legislation to deal with other FIT 1 contracts like they did with White Pines. White Pines, however, was a special case. The NTP had been granted in the final days of the last government. Most of the other contracts were long past the NTP stage in any event. Some are already connected to the grid and others were close. Investors had sunk large amounts of money into the projects. Henvey Inlet for example which is 300 MW had raised $1 billion from foreign investors in early 2018.

Cancelling before NTP is entirely permissible under the contact and the damages were set out in the contract. Investors understood that when they invested. In the end the concern that the cancellations by the new government will compromise foreign investment in Ontario energy projects is likely overstated. ■

FEDERAL ENERGY PROJECT REVIEWS: TIMELINES IN PRACTICE

*Jonathan Drance, Glenn Cameron and Rachel Hutton**

(A) Recent Developments and Proposals

In recent years the timeline to complete Canadian regulatory reviews of proposed major projects – and particularly environmental assessments which are the key part of the project review process – has become a major political issue. Over the last decade or so, project proponents have consistently raised concerns about the speed and unpredictability of project review processes –principally at the federal level. Complaints have also been made, and lawsuits have been commenced, by opponents of those projects including environmental groups, First Nations bands, and other interested parties alleging procedural and other flaws in the project review process – again principally at the federal level.

Motivated by many of the same concerns, we undertook a survey of the timelines to review major energy projects – those with estimated CAPEX of $1 billion or more (the "Project Survey") for a presentation to the Canadian Energy Law Foundation in 2016.[1]

Also, in response to these concerns and complaints, and given the significant impact of these projects on the economy, the Canadian federal government, in June 2016, directed the Minister of the Environment and Climate Change to "immediately review Canada's environmental assessment processes to regain public trust and help get resources to market".

In February 2018 the federal government introduced Bill C-69[2] to create an Impact Assessment Agency of Canada (the "Agency") which would replace the existing Canadian Environmental Assessment Agency ("CRAA"). Bill C-69 would also reform and rename the National Energy Board to create the Canadian Energy Regulator and would amend certain provisions of related federal project review legislation.

In its Consultation Paper on Information Requirements and Time Management[3] (the "Consultation Paper"), released contemporaneously with Bill C-69, the federal government envisages two principal types of project review. In the ordinary course the Consultation Paper articulates an objective that most reviews would be conducted by the Agency with a rough timeline of 510 days.[4] For projects governed under the proposed Canadian Energy Regulator legislation (such as interprovincial or international pipelines and transmission lines) or the *Nuclear Facilities Control Act*[5] (such as nuclear power

* Jonathan Drance was a senior partner and in January 2014 he transitioned to being a consultant to Stikeman Elliott. He has specialized expertise in project development and financing, including undertaking various activities in M&A and the capital markets relating to capital projects and infrastructure. From 2008 to 2010 Jonathan served on the Board of BC Hydro and, at various times, served as Chair of each of its Corporate Governance Committee and its Capital Projects Committee.

1 Kurtis Reed, Bradley Grant, Cameron Anderson and Jonathan Drance, "Timing of Canadian Project Approvals: A Survey of Major Projects" (2016) 54:2 Alberta L Rev 311; And see our updates to the Project Survey on SE Energy: Jonathan Drance, Glenn Cameron and Rachel Hutton, "The Timing of Major Energy Project Reviews" (11 May 2017) and "A Tale of Two Models: the Timing of Major Energy Project Reviews" (8 June 2017).

2 Bill C-69, *An Act to enact the Impact Assessment Act and the Canadian Energy Regulator Act, to amend the Navigation Protection Act and to make consequential amendments to other Acts*, 1st Sess, 42nd Parl, 2018, (first reading 8 February 2018).

3 Government of Canada, "Consultation Paper on Information Requirement and Time Management Regulations", (Ottawa: Government of Canada, February 2018) [Consultation Paper].

4 *Ibid,* at 6.

5 *Nuclear Facilities Control Act,* SC 1997, c 9.

plants) or which are likely to generate significant controversy and public concern, project reviews would be carried out by specifically appointed panels ("Review Panels") with a rough timeline of 870 days.[6]

These timelines – falling roughly 18 to 30 months after the filing of an initial Project Description by a proponent – would, if actually implemented and adhered to, be in line with other project review processes currently employed by various Canadian provinces and by similar jurisdictions in other countries. They are however ambitious in relation to the actual prior experience and practice of the federal government.

In this piece we look at recent actual experience with federal project review timelines to give some context for assessing the timeline proposals in Bill C-69.

(B) The Project Survey

The Project Survey covered the actual timelines for major energy project reviews at the federal and/or provincial levels which were completed from and after January 1, 2010 or which were substantially underway as of the effective date of the Project Survey, in June 2016. The Project Survey measured the time between the filing of a project description or equivalent and the issuance of a final decision to authorize a project – usually an environmental assessment certificate or equivalent approval. Our detailed results, together with applicable qualifications and disclaimers, are set out in the Project Survey itself.

We would note at the outset that our Project Survey necessarily involved a relatively small number of projects; that there are judgement calls about which projects should be included and how to measure both the starting and end points and directional; as well as the effective duration, of specific project reviews. The Project Survey provides a set of useful data points to help analyze the timelines for conducting reviews of major energy projects – but at the end of the day it is suggestive and illustrative, not definitive.

Table 1 - List of Federal Projects Covered in Survey

Project	Project Category	Timeline (months)	
Northern Gateway	Pipeline	104	
Mackenzie Gas	Pipeline	77	
Jackpine Expansion	Oil Sands	77	
Joslyn North Mine	Oil Sands	70	
Darlington New Nuclear	Generation	68	
Muskrat Falls	Generation	64	
Labrador-Island Link	Transmission	57	
Energy East	Pipeline	54[7]	1
Trans-Mountain Expansion	Pipeline	43[8]	2
Pacific NW LNG	LNG	42[9]	3
Site C	Generation	41	
Darlington Refurbishment	Generation	36	
Keeyask Hydro	Generation	35	
Maritime Link	Transmission	19	

6 Consultation Paper, *supra* note 3 at 6.
7 Calculations of applicable timelines were all current as of the date of the Project Survey, in June 2016. The timelines for cerain specified projects, including Trans-Mountain Expansion, Energy East and Pacific Northwest LNG were estimated and where the project review process was not complete those results are shown as set out in the Project Survey. Since the Project Survey, the Trans-Mountain Expansion and Pacific Northwest LNG project reviews have each been completed substantially, as estimated in the Project Survey; the Energy East application has been withdrawn.
8 *Ibid.*
9 *Ibid.*

1. Federal Timelines in Practice

The federal projects covered in our Project Survey were noted in table 1.

Broken down by Project Category, federal timelines for major energy project reviews included in the Project Survey are noted in table 2.

Overall, the time for conducting federal project reviews of major energy projects ranged from 19 to 104 months and averaged 56 months.

These federal timelines in practice are much longer than under applicable federal declaratory policy. Over time the federal government has adopted various methods to try to complete project reviews over a roughly 24 to 36 month period. Specific examples of attempts to devise approaches to deliver final project review decisions within this general time frame include:

- in 2007, a Cabinet Directive to improve regulatory performance;[10]
- from 2007 through 2010, service standards governing timelines for federal project reviews;[11]
- in 2011, regulations establish specific timelines for completion of Comprehensive Studies undertaken by CEAA;[12]
- in 2012, the adoption of generally applicable legislated timelines in CEAA 2012;[13]
- In 2018, Bill C-69 with revised timeline provisions for federal project reviews.[14]

The existing federal practice – at least for major energy projects – hasn't come close to meeting any of these declaratory ideals or objectives.

The federal timelines for project reviews appear to be materially longer than provincial timelines for reviews of roughly equivalent projects. Provincial project reviews in our Project Survey included pipelines, transmission

Table 2 - Project Categories and Timelines

Project Category	Timeline (months)	
	Range	Average
Pipelines (4)	43-104	70
Oil Sands (2)	70-77	74
LNG (1)	42	42
Generation (5)	35-68	49
Transmission (2)	19-57	38

10 See Canada, Major Projects Management Office, *Cabinet Directive on Improving the Performance of the Regulatory System for Major Resource Projects*, (Ottawa: Government of Canada, 2007). The Cabinet Directive's key goal was (in section 5.3 of a related memorandum of understanding) "to achieve the commitments in Budget 2007 to cut in half the average regulatory review period for large natural resource projects, from four years to about two years . . ."

11 See Natural Resources Canada, *Audit of the Major Projects Management Office,* Project AU 1017, (Ottawa: NRCan, 2010). The Audit Report describes (on p 5) existing service standards providing for a 24-28 month project review process, depending upon the type of review required. For Comprehensive Studies this would include a 4 month Project Agreement Phase following the filing of a Project Description followed by a 24 month period to complete the Comprehensive Study and issue any related federal permits.

12 *Establishing Timelines for Comprehensive Studies Regulation*, SOR/2011-139. Provided for a 90 day review period following the filing of a Project Description to determine if a Comprehensive Study was required (section 3.1) and thereafter a 365 day period to complete the Study (section 5.1).

13 *Canadian Environmental Assessment Act,* SC 2012, c 19, s 52 [CEAA 2012]. CEAA 2012 provided for a 45 day initial screening process (CEAA 2012, s 10). Thereafter project reviews had to be conducted within a period of 12 to 24 months, depending on the nature of the review and subject to specified exemptions or exceptions (section 27(2) and 38(3)); See also Sandy Carpenter, "Fix the Energy Approval Process in Canada: An Early Assessment of Bill C-38 and Other Thoughts" (2012) 50:2 Alta L Rev 229 at 239.

14 Bill C-69 provides for an initial 180 day period following the filing of a Project Description to review and consult about the project (section 12). Any subsequent review by the Agency must be completed within 300 days (section 28(2)) and any review by a Review Panel must be completed within 600 days (section 37(1)). Final decisions by political authorities must be completed within a period of 30-90 days, depending on whether the decision is by the Minister or by the Governor in Council (section 65). All timelines are subject to specified exemptions and exceptions.

Table 3 - Comparison Between Federal and Provincial Timelines

Project Category	**Average (months)**	
	Federal	**Provincial**
Pipelines	70	21
Oil Sands	74	33
LNG	42	28
Generation	49	22
Transmission	38	18

lines, electrical generation facilities, oil sands plants and LNG terminals – all in excess of the billion-dollar threshold. The provincial project reviews in our Project Survey averaged 26.5 months to complete and virtually all were completed in less than 36 months. Broken down by project category the comparison between federal and provincial timelines was as shown in table 3.

Independent estimates[15] confirm a generalized expectation that the time to complete a provincial project review is generally in the range of 18-24 months – and certainly within a band of 24 months (+/- 6).

Finally, though sample sizes of this were small, there is no clear evidence that the various timeline limits adopted either before or after CEAA 2012 have had any material effect. Several major projects undergoing project review subsequent to the adoption of CEAA 2012 faced material delays beyond the "mandatory" maximum legislated timelines. Project reviews were either late in starting or had the "clock stopped" for various reasons including compliance with new rules,[16] responding to requests for fresh information from federal regulators[17] or dealing with various federal legal or procedural mis-steps.[18]

The submission by Enbridge to the Expert Panel reviewing CEAA 2012 is well worth quoting on this point of the CEAA 2012 timelines:

> "The 2012 changes to CEAA and the *National Energy Board Act* included the establishment of mandatory timelines. However, legislated timelines have not resulted in predictability and consistency as expected. This is primarily because the 2012 amendments introduced multiple opportunities for time extensions and time outs, for instance:
>
> - Regulator deems application to be incomplete (clock does not start);
> - Regulator issues information requests or requires additional studies (clock stops running);
> - Minister and/or GIC may extend the time limit (more than one extension possible);
> - GIC may refer the report back … for reconsideration."[19]

15 Worley Parsons, *Environmental Regulation: An International Comparison of Leading Oil and Gas Producing Regions,* report produced by Worley Parsons and commissioned by the Canadian Association of Petroleum Producers (WorleyParsons, 2014). See page 13, where the project review process of the province of Alberta was found to generally take up to 18 months to complete – roughly comparable to jurisdictions such as Queensland, Australia; Norway and the UK and somewhat shorter than US federal project reviews in North Dakota and the Gulf Coast.

16 For example, to comply with new analytical and disclosure obligations on upstream carbon emissions introduced in January 2016. See Major Projects Management Office, MPMO Tracker – Pacific Northwest LNG Project and Major Projects Management Office, MPMO Tracker – Trans Mountain Oil Pipeline Expansion.

17 Review of the Pacific Northwest LNG Project was formally paused five times for an aggregate period of over 15 months as the proponent was required to provide additional information. See Major Projects Management Office, MPMO Tracker – Pacific Northwest LNG Project.

18 Review of the Trans Mountain Oil Pipeline Expansion Project was paused for **[5]** months to resolve a conflict and evidentiary issue when the federal government appointed an expert witness for the proponent to the National Energy Board. See Allison Sears, "Over the First Hurdle and into the Sharks: The NEB Recommends Approval of the Trans Mountain Pipeline Expansion Project" (30 May 2016), *Stikeman Elliott*, online: < https://www.stikeman.com/en-ca/kh/canadian-energy-law/over-the-first-hurdle-and-into-the-sharks-the-neb-recommends-approval-of-the-trans-mountain-pipeline-expansion-project> at note 1.

19 Enbridge, *Submission to the Expert Panel Review of Environmental Assessment Processes* (December 2016) at 7 [Enbridge Submission].

Indeed, said Enbridge, their own experience was that review periods were actually increasing since the passage of CEAA 2012 even with its regime of legislated timelines.[20]

Though the evidence is necessarily patchy and less than fully reliable, the timelines for project reviews in foreign jurisdictions with roughly comparable economic and environmental standards, and similar commitments to the rule of law, suggest that timelines for major project reviews are shorter than the Canadian federal project review process in practice and are much more consistent with the provincial ones. Consider:

- in the United States:
    - the Congressional Research Service recently found that the project reviews by FERC of natural gas facilities took on average 18 months and none had taken longer than 30 months;[21]
    - a DoE survey of over two decade's worth of NEPA reviews indicated that the median review process took 21 months when the proponent was a third party applicant;[22]
    - Congress has considered, and in some cases passed, various timeline limits for project reviews under US federal laws; virtually all timeline limits were in the 12-24 month range; none was longer than 36 months;[23]
- In Australia, timelines for project reviews of major LNG facilities were generally within the range of 24 months (+/- 6).[24]

2. Extended Federal Timelines

While it is commonplace to note that federal project review timelines are long, some have been particularly extended on any scale and by

Table 4 - Project Timelines and Review Process

Project	**Timeline** (months)		**Review Process**
Northern Gateway	104		Federal (Review Panel)
Mackenzie Gas	77		Federal (Review Panel)
Jackpine Expansion	77		Joint (Review Panel)
Joslyn North Mine	70		Joint (Review Panel)
Darlington New Nuclear	68		Federal (Review Panel)
Muskrat Falls	64		Federal (CEAA)
Labrador-Island Link	57		Federal (CEAA)
Energy East	54[25]	4	Federal (NEB)
Trans-Mountain Expansion	43[26]	5	Federal (NEB)

20 *Ibid*, at 7 at footnote 10.
21 US, Congressional Research Service, Paul W. Parformak, *Interstate National Gas Pipelines: Process and Timing of Project Application Review,* (R43138) (Washington: US Government Printing Office, 16 January 2013) at note 12 (average length of review) and at note 16 (longest citied review period).
22 US Department of Energy, *Measuring DOE's EIS Process*, (2017) 92 NEPA: Lessons Learned Quarterly Report 1. Environmental Impact Statements issued by DoE from 1994 to 2016 in response to applications by third parties for approvals, permits or financial assistance, the median time for conducting a project review was roughly 21 months. The median time to complete project reviews for DoE – sponsored programs and projects was roughly 31 months.
23 Paul Parformak, Congressional Research Service, *supra* note 21 at 13 and 14. See also US, *Presidential Office, Presidential Executive Order to establish discipline and accountability in the US federal project review process*, (15 August 2017) s 4(a)(i)(B) [Executive Order] – including a directive to complete reviews of major new infrastructure projects not more than an average of 2 years, measured from the date of publication of a Notice of Intent to prepare any environmental impact statement.
24 For example see the review process for Australia Pacific LNG Project by Queensland, Australia. From initial filing until final approval, total elapsed time was roughly 23 months. See Queensland Government, Department of State Development, Manufacturing, Infrastructure and Planning, "Assessments and Approvals" (2011), online: <http://statedevelopment.qld.gov.au/assessments-and-approvals/>. From interviews/discussions with Australian counsel, common expectations for timelines to review LNG projects were generally consistent with experience in Australia Pacific LNG.
25 *Supra* note 7.
26 *Ibid.*

comparison to any jurisdiction in the world. As we reviewed various projects for purposes of the Project Survey, we noted some key common procedural characteristics shared by many of the very longest and most controversial federal project review processes. See table 4.

The lengthiest federal processes have tended to be before Review Panels or the NEB. Each Review Panel has tended to adopt its own practices and procedures depending on its terms of reference and the composition of the particular Panel, which offers little opportunity for consistent adoption of best or most effective practices. In its own internal evaluation, Natural Resources Canada noted that the variations between the terms of reference for Review Panels as well as the variations in their process and procedures had resulted in a relatively less predictable project review process.[27]

Moreover, Review Panels and the NEB tend to conduct their project review process in a more or less fully quasi-judicial fashion – replete with formal public hearings and oral testimony. Historically the NEB and many Review Panels often permitted full cross-examination and/or extensive written information requests designed to test evidence as well as entertaining various interim motions to determine process and procedural issues.

It may not be a case of pure cause and effect, but there is a noticeable correlation between the very longest of review processes and their degree of judicialization and formality.

On the role that overly judicialized processes played in causing delays in the federal project review process, the Expert Panels were surprisingly direct.

The CEAA Panel noted in its final report that:

> "Current quasi-judicial assessment policies are in most circumstances more formal, adversarial and intimidating than is needed."[28]

The CEAA Panel went on to recommend the adoption of looser and less judicialized processes by federal project review authorities, with greater emphasis on more informal working groups, collaborative and consultative processes rather than maintaining the current federal reliance on more formal public hearings and trial-type procedures.[29]

For its part, the NEB Panel may have been sharper in their criticism of the formality and level of judcialization of the federal project review process. In their final report, the NEB Panel noted:

> "We heard that today's [NEB] hearings are overly rigid and legalistic to a degree that limits the depth and quality of the engagement with the public and Indigenous peoples. The broad perception . . . was that hearing proceedings are designed for lawyers and specialists and that average citizens are not on a level playing field. Canadians told us that the design and conduct of hearings made them feel as though they were out of their depth."[30]

The NEB Panel went on to recommend a greater degree of flexibility in choice of procedures – there could well be some role for the formal hearings and trial-type discovery processes followed by the NEB to date. But the emphasis should clearly shift to more creative, innovative and collaborative processes and should not be frozen in a particular form of quasi-judicial processes that is "rigid and inhuman".[31]

The longest of the federal review processes have tended to follow and adopt the most deeply quasi-judicial procedures. And other

27 See Natural Resources Canada, "Evaluation of the Major Projects Management Office Initiative", (Ottawa: NRCan, 2012) at 55 and 56.

28 Canada, Minister of Environment and Climate Change, *Building Common Ground: A New Vision for Impact Assessment in Canada,* by the Expert Panel for the Review of Environmental Assessment Processes, (Ottawa: Canada Environmental Assessment Agency, 2017), online: <https://www.canada.ca/en/services/environment/conservation/assessments/environmental-reviews/environmental-assessment-processes/building-common-ground.html> at 39 [*Building Common Ground*].

29 *Ibid* at 58.

30 Natural Resources Canada, *Forward, Together: Enabling Canada's Clean, Safe and Secure Energy Future*, by the Expert Panel on the Modernization of the National Energy Board, (Ottawa: NRCan, 2017), online: <https://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/pdf/NEB-Modernization-Report-EN-WebReady.pdf> at 70 [*Forward, Together*].

31 *Ibid* at 72.

jurisdictions, such as Canadian provinces as well as FERC and the DoE in the United States or state-led project reviews in Australia have been significantly shorter and less judicialized than at least the longest and most controversial Canadian federal project reviews.

3. A Tale of Two Models

On further review of the results of the Project Survey, we have noted there is a particularly pronounced contrast between the usual project review process of the federal government and that of the province of British Columbia, both in terms of the time required to complete the process and the nature of their respective and usual public consultation process.

The BC timelines for reviewing major energy projects included in our Project Survey were as shown in table 5.

The time that it took BC to conduct these project reviews ranged from 17 to 28 months and took an average of 24 months – markedly shorter than then timelines for federal project reviews.

The BC model for conducting project reviews has generally followed a timeline consistent with traditional expectations and with key international comparables – and overall has taken only about half the time as have the federal project review process to deliver reasonably acceptable and defensible project decisions.

Several key contrasts between the federal and BC processes are evident right on the face of the record. The province of BC conducts its project review process principally if not exclusively through a single agency, the British Columbia Environmental Assessment Office ("BCEAO"), which has evolved a relatively consistent and predictable approach to public consultation and engagement.

The BCEAO favours a public consultation process involving notice and comment procedures rather than more fulsome quasi-judicial or trial-type procedures. The BCEAO describes its public consultation process as one that encourages participation in public meetings, open houses and other forums, and that encourages the public to review the record and make comments, generally through various in-person and electronic submissions. The BCEAO process also encourages the formation of informal working groups to convene key participants to review and understand core issues and concerns.

For each project review, the BCEAO issues a relatively consistent and detailed procedural order specifying the scope, procedures and methods by which the review must be conducted – both during any pre-filing and any formal review stage.[32] These orders specify how public consultation must be carried out at all stages with an emphasis on various informal procedures that do not involve formal testimony in lengthy public hearings or the systematic delivery of extensive information requests to the proponent.

The available evidence suggests that these

Table 5 - B.C. Timelines for Reviewing Major Energy Projects

Project	Project Category	Timeline (months)
Woodfibre LNG	LNG	28
LNG Canada	LNG	27
Westcoast Connector	Pipeline	24
Mica 5 + 6	Generation	24
Coastal Gaslink	Pipeline	22
PRGT	Pipeline	17

32 See for example the Section 11 Order, dated June 6, 2013, issued by the BCEAO in its review of LNG Canada's proposed LNG Export Terminal. See in particular Part F (Working Groups), Part G (Consultation with Aboriginal Groups) and Part J (Public Consultation). The Section 11 Orders issued for the other major energy projects included in the Project Survey were substantially similar.

relatively more informal public consultation processes tend to be more expedited and more predictable than the quasi-judicial processes more widely employed at the federal level.[33] It is obviously harder to measure the respective qualities of these two models, but it is worth noting these most recent high-profile judicial cases involving the adequacy of particular project review processes have tended to strike down aspects of the federal project review process relatively more frequently than those conducted by the BCEAO.

4. Survey Conclusions

The data from the Project Survey was at least consistent with the following conclusions:

1. Federal timelines for major energy project reviews have generally been longer than 36 months and many have been substantially longer.

2. The mandatory timelines introduced in the Canadian Environmental Assessment Act, 2012 have not yet materially reduced federal timelines for major energy project reviews, at least not consistently down to a 24 month (+/-6) range – though the sample size for these types of project reviews is so far extremely limited.

3. Provincial timelines for major energy project reviews appear both materially shorter and more predictable than federal timelines and fall generally within a 24 month (+/-6) range.

4. There is a substantial correlation between the length of the review process and its level of judicialization, in terms of the nature and intensity of hearings and the procedureal complexity of the review process.

These general conclusions found support in Submissions filed by the proponent community during the recent federal review of its projects review process.[34]

It was palpably and powerfully felt by members of the proponent community that federal project reviews were too long and were uncompetitive,[35] that the legislated timelines in CEAA 2012 were ineffective but that much more strictly enforced timelines could play a useful role;[36] and that various provincial project review processes were generally more efficiently administered.[37]

(C) Prospects for Reform

Bill C-69 contemplates a project review process divided into three segments: a planning phase, an assessment phase and a decision phase.[38] In the ordinary course both initial planning and the assessment of a proposed project would be done by the Agency and a final decision would be made by the Minister. For certain designated projects such as interprovincial or international pipelines and transmission lines, nuclear facilities or other high-

33 The BCEAO process tends to resemble the project reviews conducted by the Federal Energy Regulatory Commission ("FERC"), at least for interstate pipelines and other major gas facilities under its jurisdiction. For these project reviews, FERC tends to use a relatively informal public consultation process including a range of 'notice and comment' procedures, open houses and public meetings. FERC has the power and authority to conduct quasi-judicial 'trial type' hearings in connection with project reviews, but does so infrequently. See FERC, Pre-Filing Environmental Review Process at www.ferc.gov/resources/processes/flow/lng-1-text.asp and Paul Parformak, Congressional Research Service at 5.

34 The public consultation portion of the federal review was effectively delegated to two Expert Panels: the Expert Panel for the Review of Environmental Assessment Processes (the "CEAA Panel") and the Expert Panel on the Modernization of the National Board (the "NEB Panel").

35 On the length of federal project review processes adversely affecting Canada's competitiveness, see various submissions to the several Expert Panels, including the Enbridge Submissions, *supra* note 19 at 1; and submissions by Canadian Association of Petroleum Producers (CAPP) December 2016 at 2-9; Canadian Energy Pipeline Association (CEPA) (March 2012) at 1; Syncrude at 2; BC Business Council (December 2016) at 3. A survey by Worley Parsons for CAPP, "International Review of Environmental Assessment Processes" (December 2016 – 307074-02W-ENREP-0001) concluded that Canada's project review and general licensing and permitting processes were among the best in the world for inclusiveness and thoroughness but did not fully implement best practices employed in jurisdictions such as the US, Australia and Norway to improve timeliness. While supporting key elements of the Canadian federal project review process, the Worley Parsons survey concluded (page 23) that "Canada currently has one of the most expensive, time and resource-consuming [project review] processes in the world".

36 See, in particular, Enbridge Submissions, *supra* note 19 at 7; *Forward, Together, supra* note 30, at 5, 6 and 20.

37 Submissions from the proponent community were generally supportive and not critical of province project review processes – and there was widespread support for substitution or deviation or similar arrangements to effectively leave project reviews to affected provinces rather than the federal government. See submissions by CAPP, *supra* note 35*; BC Business Council, supra* note 35 at p.4.

38 Consultation Paper, *supra* note 3 at 6.

profile and controversial projects any assessment would be carried out by a specially appointed Review Panel with the final decision likely taken by Cabinet.

The proposed timelines (in days) for each of these alternative processes would ideally be as follows:[39]

	Agency	Review Panel
Planning	180	180
Assessment	300	600
Decision	30	90
	510	870

For several reasons, these time frames are likely more aspirational than realistic, particularly for the largest and more controversial projects. First, these timelines ignore some of the actual procedural periods that would apply, for example to govern referrals to a Review Panel. And they ignore the timing of the detailed procedural steps that must be taken to move from phase to phase under Bill C-69. More importantly though each of the timelines in Bill C-69 is accompanied by a Praetorian guard of exceptions.[40] Any timeline can be extended by the Minister for 90 days and by the Cabinet for virtually any amount of time. Moreover, for projects referred to a Review Panel at the end of the early planning phase, the Minister can, right from the very outset, vary the timeline governing the Review Panel to assess and report on the proposed project.

The mechanics of the project review process in Bill C-69 place a great deal of emphasis on the early planning phase as a means to try to establish early consensus and allow meaningful dialogue about projects early enough so that they can be changed to reflect public concerns before too many expensive and irrevocable steps have been taken and commitments made.

As described in the Consultation Paper, proponents would initiate the project review process by filing a bare-bones initial Project Description.[41] This would be used by the Agency as the basis for consulting with affected stakeholders, particularly Indigenous peoples. Following a process of initial consultation, analysis by the Agency and feedback to the proponent, a more detailed Project Description would be filed with the Agency to allow a determination to be made about whether a formal project review is required and, if so, whether by the Agency or a Review Panel.[42]

This may be realistic for smaller or even mid-size projects, but for larger and more controversial energy projects with CAPEX likely in the $5-$10 billion range and up, this seems like a very ambitious (likely unachievable) schedule.

Moreover, for the largest and most controversial projects the whole notion that this will materially improve dialogue and understanding could well be more wishful thinking than realistic.

Indeed, particularly for large and environmentally impactful energy projects, the real dynamics affecting the project have to be looked at in a broader context than just the formal project review process. The internal planning process for a major energy project can easily take 18 to 36 months. Before any meaningful Project Description is filed, a further 18 to 36 months can be required for analytical work, preliminary engineering and design and environmental field studies. By the time any material initial filing is made, the proponents may have spent up to 5 years or more in investigating and analyzing the project. Expenditures for projects of this scale and significance can be material before any single document is filed to trigger any form of project review. At the point of filing of even an Initial Project Description as anticipated in the Consultation Paper, much planning by

39 *Ibid.*
40 See Bill C-69, *supra* note 2.
41 Consultation Paper, *supra* note 3 at 3.
42 *Ibid* at 4.

the proponent will already have occurred – modifications can be expensive to make and can challenge assumptions that may already be deeply embedded in the proponent's analysis. The essential point is that what the Consultation Paper assumes is an early planning stage may in fact be early only for regulatory purposes – not in reality.

Proponents are also likely to take only cold comfort from the "legislative timelines" in Bill C-69. Legislative timelines were embedded in CEAA 2012 but in a number of controversial and high profile energy projects they were not a meaningful constraint on a prolonged federal project review process.

The Consultation Paper invites comments on when the federal time clock can be stopped – a major complaint and concern of project proponents. There will be a natural limit however to the impact that even an enhanced code of conduct can have on starting or stopping the clock for purposes of effectively controlling timelines. Virtually all jurisdictions which have accepted timelines or limits on project reviews permit stoppages where supplemental information is required by regulators or where new laws or regulations require fresh or enhanced disclosure or analysis. At the end of the day, regulatory and political attitudes and the application of a common sense "rule of reason" in the conduct and administration of the project review process is just as important as, and maybe even more important than, any formal timeline rules.

The proposals in Bill C-69 and the prospects for realistic reform in the timing of federal project reviews need to be considered in light of history.

There have been 25 years of virtually continuous complaints from the proponent community about the speed of federal project reviews – or more precisely about the lack of speed. There have been more than a decade's worth of federal directives, policies, service standards and even legislated timelines, all attempting – so far, unsuccessfully – to speed the federal project review process along.

At some point, one cannot sensibly either continue to blame, or attach too much hope to, any specific timeline legislation or regulation. It may just be that the political realities and incentives facing the federal government are insufficient to make it a priority to push project reviews to completion in a timely fashion. If so, formal rules will continue to be insufficient and ineffective to induce greater federal efficiency in project reviews. We have most likely reached the point where major project proponents will have to lobby for or campaign to bring about a political change in priorities at the federal level that are more conductive to economic growth and project approvals. Either that, or they may just choose to invest in other, more pro-growth, jurisdictions. ■

THE ROLE OF THE *CNSC* UNDER THE PROPOSED *IMPACT ASSESSMENT ACT*

Andrew Dusevic[1]

1. Introduction

On June 20th 2018, Bill C-69 received its introduction and first reading in Canada's Senate. Bill C-69 aims to enact the *Impact Assessment Act (the "IAA").*[2] The *IAA* repeals the current *Canadian Environmental Assessment Act (the "CEAA"),*[3] and implements broad changes to the Canadian environmental assessment process. One significant change that has received little exposure is the removal of the *Canadian Nuclear Safety Commission's (the "CNSC")* authority to conduct environmental impact assessments of nuclear activities. Under the *IAA,* impact assessments of nuclear activities are referred to a review panel composed of members appointed by the Minister of the Environment (the "Minister").[4]

The *CNSC* is established by the *Nuclear Safety and Control Act (the "NSCA")* to develop regulations and oversee nuclear activities within Canada.[5] The *CNSC* maintains unique expertise and knowledge of the nuclear field to effectively regulate in accordance with the environmental and safety objectives of the *NSCA*. The following discussion demonstrates how the *CNSC*'s limited participation in impact assessments interferes with their ability to carry out these objectives and impairs their ability to impart important knowledge conducive to the impact assessments of nuclear activities. These limitations will have significant impacts on Canada's nuclear industry and will pose unique challenges for the progression of industry and the consideration of novel and innovative nuclear technologies such as small modular reactors and other advanced reactors.

2. Appointment of Review Panels

The *IAA* eliminates the responsibility of the *CNSC* to perform impact assessments of nuclear activities previously held under the *CEAA* and prescribes that those assessments be delegated to a review panel made up of members appointed by the Minister. The *IAA* attempts to balance this shift by compelling the *Impact Assessment Agency of Canada (the "Agency"*) and the Minister to offer consultation with the *CNSC*. However, the success of this consultation is precarious as the scope and effectiveness of the measures are placed at the discretion of the Agency and Minister.

The establishment of a review panel to perform impact assessments of nuclear activities occurs as follows. Section 43(a) of the *IAA* requires the Minister to refer the impact assessment of physical activities regulated under the *NSCA* to a review panel.[6] When referring assessments to

---

1 Andrew Dusevic is an LL.M. student at the University of Saskatchewan College of Law. He is grateful to the Sylvia Fedoruk Canadian Centre for Nuclear Innovation for providing funding for his graduate studies which allow him to write articles like this.

2 Canada, Bill C-69, *An Act to enact the Impact Assessment Act and the Canadian Energy Regulator Act, to amend the Navigation Protection Act and to make consequential amendments to other Acts,* 1st Sess, 42nd Parl, 2018 [*Bill C-69*].

3 *Canadian Environmental Assessment Act, 2012*, SC 2012, c 19, s 52 [*CEAA*].

4 Jamie Kneen, "Bill C-69: New Federal Environmental Reviewa Laws Fall Short of Promises" (9 February 2018), *Mining Watch Canada (blog),* online: <https://miningwatch.ca/blog/2018/2/9/bill-c-69-new-federal-environmental-review-laws-fall-short-promises> [*Kneen*]; See *Bill C-69, supra* note 2 at cl 52.

5 *Nuclear Safety and Control Act*, SC 1997, c 19, s 8(1) [NSCA].

6 *Bill C-69, supra* note 2 at cl 43.

a review panel, the Minister must establish the terms of reference of the panel, and appoint a chairperson and at least two other members to form the panel.[7] When appointing members, the Minister is to choose at least one person from a roster consisting of members of the *CNSC*.[8] This change is in response to the public concern that government agencies such as the *CNSC* lack competency and consistency in their application of the law during impact assessments.[9] Notwithstanding the validity of these concerns, this approach neglects the importance and significance of the *CNSC*'s expertise and knowledge for the performance of impact assessments.

The *IAA* attempts to fulfill the need of expert knowledge in the process by providing the *CNSC* the opportunity to be consulted by the Agency and the Minister, but falls short as the act fails to provide scope and meaningful influence within those measures. Prior to the performance of the impact assessment, the Agency is required to offer consultation with the *CNSC* when preparing for a possible impact assessment under s. 12 of the *IAA*.[10] This consultation, in part, is to be used by the Agency to determine and inform the proponent of a summary of issues that it finds relevant to the project.[11] However, any meaningful influence the *CNSC* derives from this measure is limited by the discretion of the Agency. Section 14(1) obligates the Agency to relay to the proponent, at their discretion, "a summary of issues with respect to that project that it considers relevant, including issues that are raised by … [the *CNSC*]."[12] Additionally, the *IAA* is silent as to the exact content and scope of this consultation, thus placing such aspects within the responsibility of the Agency. As a result, consultation with the Agency provides the *CNSC* with a precarious influence in the pre-assessment steps of defining and raising important issues for impact assessments.

The *IAA* obligates the Minister to offer consultation with the *CNSC* to determine factors to be addressed by prospective impact assessments, but fails to provide the *CNSC* with any actual meaningful participation. Section 21(a) of the *IAA* provides that the Minister must offer to consult and cooperate with the *CNSC* with respect to impact assessments.[13] This consultation may include determining the scope of factors that must be considered.[14] However, like the pre-assessment consultation discussed above, the content of the consultation between the *CNSC* and the Minster is ambiguous. The *IAA* does not directly define what the *CNSC* can or must be consulted on. Thus, the utility and influence of this consultation is at the discretion of the Minister. Again, this requirement to offer consultation provides the *CNSC* with a precarious and limited participatory role in the impact assessment process.

The *IAA* has replaced the responsibility of the *CNSC* to perform environmental assessments with an uncertain consultative role within the impact assessment process. By failing to address the scope and content of the Minister and Agency's obligation to consult with the *CNSC,* the *IAA* entrusts the utility of these obligations to the discretion of the Agency and the Minister. Not only does this limit the *CNSC's* influence and expertise within impact assessments, but there is a danger that this obligation may become perfunctory as requirements of these consultations are minimal. Insignificant consultation with the *CNSC* may impair impact assessments as the *CNSC* is the only government agency with the requisite technical expertise to effectively evaluate the full scope of the nuclear activities.

7 *Ibid* at cl 44(1).
8 *Ibid* at cl 44(3).
9 Canada, Minister of Environment and Climate Change, *Building Common Ground: A New Vision for Impact Assessment in Canada*, by the Expert Panel for the Review of Environmental Assessment Processes, (Ottawa: Canada Environmental Assessment Agency, 2017), online: <https://www.canada.ca/en/services/environment/conservation/assessments/environmental-reviews/environmental-assessment-processes/building-common-ground.html> [*Building Common Ground*] (the public criticized government agencies such as the CNSC for lacking competency and consistency in their application of the law during impact assessments at 49); See also Kneen, *supra* note 4.
10 *Ibid* at cl 12.
11 *Ibid* at cl 14(1).
12 *Ibid.*
13 *Ibid* (the Minister must offer to consult and cooperate with any jurisdiction with respect to impact assessments if that jurisdiction has powers, duties or functions in relation to an assessment of the environmental effects of a designated project) at cl 21(1)(a).
14 See *Ibid* at cl 22(2)(b).

3. Powers of the Review Panel and the Minister

The *IAA* charges the review panel and the Minister with a broad set of powers that eliminates the necessity for *CNSC* participation and impacts the issuance of nuclear licenses. The *IAA* charges the review panel with the powers granted to the *CNSC* under the *NSCA* and provides the Minister with the power to ascribe conditions to the licenses issued by the *CNSC*. This conveyance of powers removes any reliance on the *CNSC* for performing impact assessments, while maintaining the responsibility of the *CNSC* to monitor and enforce licensing conditions ascribed by the Minister. As a result, impact assessments may be carried out autonomously of the *CNSC* and diminishes any need to include them within impact assessments.

Review panels are embodied with the powers of the *CNSC* so long as those powers are exercised in accordance with their duties in conducting impact assessments.[15] The duties of the review panel are dictated by the Minister's terms of reference[16] and by the duties listed within s. 51 of the *IAA.*[17] The *IAA* does not limit the scope of the powers conveyed to the review panel and thus confer the full suite of powers given to the *CSNC* under the *NSCA*. This broad set of powers include the holding of meetings of the *CNSC,*[18] operating as a court of record,[19] calling and examining witnesses,[20] and more. The *IAA* therefore establishes review panels as a complete analog of the *CNSC* in the context of impact assessments, thus eliminating any operational need for the *CNSC* in performing the assessment.

The *IAA* empowers the Minister with ability to ascribe the conditions contained in his or her decision statement to the licenses issued by the *CNSC* under s. 24 of the *NSCA.*[21] A decision statement informs the proponent of the determinations resulting from the assessment, and may include licensing conditions.[22] This is in contrast with the approach taken by the *CEAA,* which does not provide the Minister with such abilities. This has three important implications for the *CNSC* and licensed nuclear activities. First, the Minister may impose conditions on the licenses issued, renewed or amended by the *CNSC*. Second, the *CNSC* is responsible for ensuring that those conditions are being maintained by the proponent. Third, any contravention of those conditions is a breach punishable under the *NSCA*. This is significant as the *NSCA* provides a larger fine for licensing breaches than does the *IAA* and provides the possibility of imprisonment for the licensee.[23] The ability of the Minister to ascribe environmental conditions to nuclear licenses thereby removes any reliance on the *CNSC* for such operation while maintaining the responsibility of the *CNSC* to enforce those conditions under the *NSCA.*

The *IAA* equips the Minister and the review panel with the necessary tools to perform impact assessments and effectively removes any operational need for the *CNSC* within the process. The powers conferred to the review panel allow them to carry out impact assessments autonomously and completely independent of the *CNSC*. Additionally, the Minister's ability to dictate licensing conditions for nuclear activities exploits the *CNSC's* license enforcement duties under the *NSCA* while affording them no authoritative or influential role within the process. The conveyance of these powers to the review panel and the Minister assures their autonomy and effectively eliminates any need to include the *CNSC* in impact assessments.

4. Conflict with the safety objectives of the CNSC

The exclusion of the *CNSC* from impact assessments frustrates their ability to discharge their objective to prevent unreasonable risk to the environment as prescribed by the *NSCA.*[24] The environmental safety objective is developed

15 *Bill C-69, supra* note 2 at cl 46.
16 *Ibid,* cl 41(1).
17 *Ibid*, cl 51.
18 *NSCA, supra* note 5, s 14(2).
19 *Ibid* at cl 20(1).
20 *Ibid* at cl 20(2).
21 *Ibid* at cl 67(1).
22 *Ibid* at s 64(1), s 65(1).
23 *NSCA, supra* note 5, s 51(3)(a) – (b).
24 *NSCA, supra* note 5, s 9(a(1).

within the regulations established by the *CNSC* and acts complementary to their primary objective of preventing unreasonable risk.[25] The exclusion of the *CNSC* from impact assessments forces the regulator to rely on potentially incomplete, inaccurate, misguided or otherwise inadequate assessments and determinations made by the review panel and the Minister for the assurance that their environmental safety objective is met. This frustrates the *CNSC*'s ability to discharge their environmental safety objective and ultimately impacts their primary objective of ensuring that the risks of the activity are reasonable.

The environmental protection safety objective requires two things. First, that reactor facilities be "designed to ensure that during normal operation, anticipated operational occurrences and design basis accidents, there are no detrimental significant adverse effects on the environment as required by the *Canadian Environmental Assessment Act.*"[26] Second, that "[t]he design shall also provide for the mitigation of the environmental consequences of beyond design basis accidents, to the extent practicable." Historically, these two criteria are met by the performance of an impact assessment by the *CNSC* in accordance with the *CEAA*. Though the prevention of detrimental significant adverse effects and the mitigation of consequences are continued within the *IAA,* the satisfaction of this criteria is no longer at the discretion of the *CNSC.*[27] The question arises as to whether the *CNSC* has sufficient input in impact assessments to effectively ensure their safety objectives are met and whether they may rely on the assessments of the review panel for the satisfaction of this safety objective.

As discussed earlier, the measures taken by the *IAA* to include the consultation of the *CNSC* in the assessment process are insufficient to ensure any meaningful participation, influence or conveyance of expertise within the impact assessment process. In their role as a nuclear regulator, it is the ultimate responsibility of the *CNSC* to ensure that the objectives of the *NSCA* are met. Therefore, to satisfy this objective, the *CNSC* require adequate participation in the process to ensure that the full scope of their environmental protection safety objective is satisfied. This cannot be done within the prescribed regime of the *IAA*.

Moving forward, the *CNSC* has few options other than to rely on the determinations and assessments made by the Minister and the review panel. However, concerns arise as to the adequacy of such assessments without meaningful consultation with the *CNSC*. Another option may be for the *CNSC* to review the report prepared by the review panel and the decision statement of the Minister to determine whether their environmental protection safety objective is met. This option will allow the *CNSC* to ensure that their regulatory objectives are satisfied. However, it may be uneconomical for the *CNSC* to provide an in-depth analysis for every assessment. Additionally, it may increase costs, licensing times and redundancy, while also being frustrating for the proponent. Thus, the *CNSC* must rely on the determinations made by the review panel and Minister.

In sum, the *IAA* has frustrated the *CNSC*'s ability to discharge their environmental protection safety objective and, ultimately, their primary objective of preventing unreasonable risk, in accordance with the mandate of the *NSCA.* The *IAA* forces the *CNSC* to rely on the assessment performed by the review panel and the determinations made by the Minister for the fulfillment of their regulatory objectives, which may be ill-advised for areas that require expertise unique to the *CNSC*. This concern has been raised by members of industry who question the review panel's lack of experience regarding radiation exposure and Canada's international obligations.

5. Expertise and International agreements

At the Standing Committee on Environment and Sustainable Development (ENVI) concern was raised regarding radiation exposures and the international commitments that Canada has made.[28] It was argued that a review panel does not have the adequate expertise to ensure the protection from radiation exposure and

25 Canada, Canadian Nuclear Safety Commission, "Design of small reactor facilities", (Ottawa: CNSC, 2011), online: <http://www.nuclearsafety.gc.ca/pubs_catalogue/uploads/RD-367-Design-of-Small-Reactor-Facilities_e.pdf> at 4.
26 *Ibid.*
27 See *Bill C-69, supra* note 2 at cl 6(1)(a) – (n), cl 22(b).
28 Canada, House of Commons, Standing Committee on Environment and Sustainable Development, *Committee Meeting: Evidence*, 42nd Parl, 1st Sess, Meeting No 102, online: <https://www.ourcommons.ca/DocumentViewer/en/42-1/ENVI/meeting-102/evidence> [*ENVI*].

that Canada's international commitments on safeguards and non-proliferation will be maintained.[29] The *CNSC* is the only agency with the requisite expertise and position to perform an assessment that satisfies these criteria efficiently and effectively. Not only do these two criteria require technical and scientific expertise, but they are woven throughout the regulatory framework developed by the *CNSC*.

The *CNSC* has developed their regulations regarding radiation protection and acceptance safety objectives to be in accordance with the objectives mandated within the *NSCA* and Canada's international commitments. These regulations provide that the exposure of radiation within the reactor facility during anticipated operational occurrences, or any planned release of radiation, be kept as low as reasonably achievable *(ALARA)*.[30] The satisfaction of this objective is achieved through different control processes and planning.[31] *ALARA* is an aspirational goal common to nuclear regulation that is revealed through experience and practice over several years.[32] Thus, the *CNSC* is in the best position to ensure that nuclear activities have sufficient measures to ensure that radiation is *ALARA* when performing impact assessments.

Canada's international obligations provide imperative regulatory requirements for the applicant. Canada has ratified many treaties and conventions, most of them arising out of agreements of safeguards and measures entered into with the International Atomic Energy Association (the "IAEA") and the Nuclear Energy Agency (the "NEA"). These agreements and other international commitments are expressed and developed within the regulations created by the *CNSC*. Thus, the *CNSC* has in-depth experience in the administration of these objectives.

A review panel does not have the requisite experience to assess radiation protection measures and to ensure that Canada's international commitments are maintained. The *CNSC* has years of practice and experience with the administration of these requirements. Radiation exposure objectives employ a qualitative goal that requires referential experience to evaluate. Not only would a review panel not have this requisite experience, but the establishment of a new panel for each assessment prohibits the accumulation of such requisite experience for the accurate evaluation of this safety objective and others.

6. Conclusion

The impact assessment regime proposed under the *IAA* removes the *CNSC* from regulating nuclear activities mandated to them under the *NSCA*. Drafters of the *IAA* attempt to balance their removal by creating opportunities for them to be consulted at two stages within the assessment process. However, the effectiveness of this approach is hindered by the lack of direction and scope of the consultation, and, instead, the *IAA* entrusts the utility of the consultation to the discretion of the Agency or the Minister. Not only does this change frustrate the *CNSC*'s responsibility to ensure the safety of the environment and maintain Canada's international obligations, but it also places the impact assessment of technical and complex nuclear activities at the discretion of a review panel that lack experience and expertise. This change has broad impacts for Canadians and the nuclear industry.

Removal of the *CNSC* from impact assessments may result in inadequate impact assessments which jeopardize the safety of Canadians and the welfare of Canada's nuclear industry. Inadequate assessments of nuclear activities put the safety of the environment and Canadians at risk as the review panel may neglect or inadequately assess important factors or considerations. Furthermore, this regime may negatively impact the nuclear industry as proponents may be dissuaded by the regulatory uncertainties created by the lack of expertise of the review panel and variation of impact assessments caused by the review panel's impermanency. This is particularly pertinent for proponents of advanced nuclear reactors and small modular reactors who attempt to deploy first of a kind technology and thus face

29 *Ibid.*
30 *Radiation Protection Regulations*, SOR/2000-203, s 4(a); See also *Packaging and Transport of Nuclear Substances Regulations, 2015,* SOR/2015-145 ("keep the amount of exposure to radon progeny and the effective dose and equivalent does received by and committed to a person as low as reasonably achievable, social and economic factors being taken into account"), s 18(1).
31 *Ibid.*
32 "Nuclear Regulatory Decision Making" (Paris: Organisation for Economic Co-Operation And Development, 2005) at 17.

critical economic hurdles.

Impact assessments are most efficiently conducted by the *CNSC* because of their position as Canada's nuclear regulator and their expertise in the area.[33] Providing the *CNSC* with a more meaningful role in the process would abate the majority of the issues raised within this article. An effective solution may be to re-assign the *CNSC* as the responsible authority for the impact assessment of nuclear activities. To encourage consistent and competent application of Canadian law and assessment requirements, an oversight structure may be implemented. Such a structure may require the *CNSC* to consult with another impact assessment body, such as the Agency, on the performance of their assessment throughout the process. Alternatively, another approach may be for the *CNSC* to conduct assessments with one or more members being appointed by the Minister. These two recommendations would encourage public trust within the process while maintaining adequate expertise. ■

33 *ENVI, supra* note 8 at 3.

THE NEW ALBERTA ELECTRICITY LEGISLATION

Martin Ignasiak, Jessica Kennedy, Danielle Chu and Cassie Richards[1]

On June 11, 2018, the Alberta Legislature passed Bill 13, *An Act to Secure Alberta's Electricity Future*.[2] Bill 13 amends several existing statutes and provides the necessary legal framework for the establishment of an electrical generation capacity market – which marks a significant change to Alberta's power generation regime. In so doing, it makes noteworthy changes to how system rules are established and approved in Alberta, as further discussed in this article. Opportunities for stakeholders to get involved in these rule-making processes are outlined below.

The early versions of the Bill included some long-anticipated legislative changes to address current issues with how extraordinary asset dispositions in the utility sector are managed in Alberta, an issue that arises from the Supreme Court of Canada's 2006 ruling in *Stores Block*.[3] However, those provisions failed to make it through the legislative process, as further discussed herein.

The shift from "energy only" to "energy + capacity"

Currently, Alberta operates under an "energy-only" market where electricity generators are paid solely for the electricity they supply to the market. The only exception for some is the ancillary services market, where companies can be paid for supplying resources necessary to support the operation of the transmission system. Bill 13 will introduce a third market – a capacity market – that will have significant implications on the overall market structure for generators.

The shift to a capacity market was driven by the Alberta Government's 2015 Climate Leadership Plan,[4] which sought to accelerate the phase out of coal-fired electricity production and replace that generation with renewable sources of power. This shift, including the Alberta Electric System Operator's (AESO) Renewable Energy Program that followed, had the potential to materially impact market dynamics in the energy-only market, which was designed to promote sufficient generation at the lowest cost – regardless of technology used. The AESO found that the new priorities established under the Climate Leadership Plan had the potential to jeopardize the market's ability to ensure reliability and reasonably priced power in the long run.

In a capacity market, generators are paid for their ability to supply energy in the future. In principle, the more reliable the supply source, the higher the capacity payment will be. Therefore, to ensure that a reliable supply of electricity remained available in the future and to facilitate the Alberta government's climate policy goals, the AESO recommended that Alberta transition to a capacity market.[5]

The last significant change to Alberta's electricity market (deregulation) was a multi-year process that involved input and expertise from a

1 The authors are partners and associates at Osler, Hoskin and Harcourt LLP in Calgary. An earlier version of this article was published by the authors in the Osler Law Bulletin.
2 Bill 13, *An Act to Secure Alberta's Electricity Future*, 4th Sess, 29th Leg, Alberta, 2010 [Bill 13].
3 *ATCO Gas & Pipelines Ltd. v Alberta (Energy and Utilities Board)*, 2006 SCC 4 [*Stores Block*].
4 Lorne Carson et al, "Alberta's New Climate Change Leadership Plan", (23 November 2015), *Osler*, online: < https://www.osler.com/en/resources/regulations/2015/alberta-s-new-climate-change-leadership-plan>.
5 Alberta Electric System Operator, "Alberta's Wholesale Electricity Market Transition Recommendation", (Alberta: AESO, 3 October 2016), online: <https://www.alberta.ca/documents/Electricity-market-transition-report.PDF >.

wide range of stakeholders and international experts. In contrast, the Alberta government first introduced Bill 13 in April 2018 and is expecting that the first capacity auction will occur in November 2019, with the transition being complete by 2021.[6] This emphasis on a quick switch is evident in Bill 13, which sets tight timelines for the establishment of new market rules and limits the rights of parties to file complaints or appeals of the initial rules, discussed below.

Capacity market rules

Participants in the capacity market will be subject to the same general obligation to conduct themselves in a manner that supports the fair, efficient and openly competitive (FEOC) operation of the market as they are under the energy-only market. However, specific rules are needed to provide clarity on how the market will operate and what behaviour will be rewarded vs. penalized. Some of those rules are created by the AESO, which rules must support the FEOC operation of the capacity market.

Bill 13 introduces several specific rule-making obligations, including changes to the typical AESO rule-making process. Of note:

- Bill 13 places an obligation on the AESO to make rules, as soon as practicable, for the establishment and operation of the capacity market. This may include rules regarding capacity auctions, capacity market participants, and the calculation of capacity payments.[7]

- Currently, rules made by the AESO are deemed approved unless a market participant objects.[8] However, under the new legislative regime the AESO will be required to obtain approval from the Alberta Utilities Commission (AUC) for all market rules.[9]

- Bill 13 establishes a provisional AUC review process for new rules proposed by the AESO that are deemed "essential" to establish and operate the capacity market. The AUC must "provisionally" approve those AESO rules within six months of their filing.

  - After a rule is provisionally approved, it must undergo a full review by the AUC within 24 months of its filing. This means the rules that are provisionally approved will not be subject to a full review before they are put into place and before the first capacity auction.

  - It is unclear how changes that occur following the full review process or a separate AESO rule application will impact parties that are already participating in the capacity market. As a result of Bill 13, the AUC can implement rule changes retroactively, which introduces risk to market participants.

  - According to the Ministry of Energy, the first set of rules for the capacity market will be filed with the AUC in January 2019.[10] The provisional review process will therefore be complete by July 2019, allowing the provisionally approved rules to be in place prior to the initial capacity market auction scheduled to occur in November 2019. The full review will not be complete until 2021.

  - It does not appear that Bill 13 contemplates a scenario where the AUC denies some or all of the AESO's provisional rules, or if the AUC requires the AESO to make certain amendments or conduct further work before granting provisional approval. These

6 Government of Alberta, "Electricity capacity market", online: <https://www.alberta.ca/electricity-capacity-market.aspxhttps://www.alberta.ca/electricity-capacity-market.asp>.
7 Bill 13, *supra* note 2, cl 2(29).
8 *Electric Utilities Act*, SA 2003 c E-5.1, s 20.3 [*Electric Utilities Act*].
9 Bill 13, *supra* note 2, cl 2(13).
10 Alberta, Ministry of Energy, "An Act to Secure Alberta's Electricity Future Technical Information Session" (Presentation, April 2018), online: <https://www.energy.alberta.ca/AU/electricity/AboutElec/Documents/StakeholderAgencyBill%2013%20Presentation.pdf>.

outcomes could trigger a process that extends beyond the first auction date, which could impact overall implementation timelines.

- The provisional review process sets a lower bar for AUC approval as the AUC may provisionally approve an AESO rule "if it appears" that the rule satisfies certain criteria.[11] In contrast, under the regular review process the AUC must "be satisfied" that the criteria have been met.[12]

- Typically, any market participant can file a complaint with the AUC regarding AESO conduct or rules that are in effect.[13] Bill 13 precludes the making of complaints to the AUC regarding provisionally approved rules.[14]

- Under section 29 of the *Alberta Utilities Commission Act*[15], any decision or order of the AUC is appealable to the Alberta Court of Appeal on questions of law or jurisdiction. Bill 13 attempts to shield provisional rule approvals from this review process by precluding appeals of any AUC decision in relation to a provisional AESO rule until after the two-year "regular consideration" process is complete.[16]

In addition to market rules under development by the AESO, Alberta Energy is in the process of developing regulations regarding the capacity market. These regulations are expected to focus on:

- dispute resolution and complaints in advance of capacity auctions;
- resource adequacy;
- cost allocation; and
- fair, efficient and open competition.

Consultation and rules about making rules

Although Bill 13 removes many opportunities for stakeholders to challenge provisional rules, there will be a greater obligation on the AESO to consult when developing the rules. Pursuant to Bill 13, the AUC must make rules requiring the AESO to consult with the Market Surveillance Administrator, market participants and other interested parties in developing its rules.[17] In light of this, the AUC has released Draft Rule 017: *Procedures and Process for Development of ISO Rules and Filing of ISO Rules with the Alberta Utilities Commission*, which is intended to address the requirements and criteria set out in Bill 13 regarding the procedures and process for the development of AESO rules.

Consultations regarding Draft Rule 017 are ongoing, and many stakeholders have expressed concerns with the current version. The finalized Rule 017 is expected to be released on August 1, 2018.[18] At this time, it is not clear what process the AUC will follow for the approval of AESO rules, including provisional rules.

Ongoing engagement opportunities

The AESO will continue to engage with stakeholders regarding the implementation of the capacity market. Currently, four engagement streams are planned:

- **Capacity Market Rules** (July 26 – October 31, 2018): Drafting and consultation on the AESO's rules that will set out market participant and AESO obligations for the capacity, energy and ancillary markets. The Capacity Market Rules developed by the

11 Bill 13, *supra* note 2, cl 2(14).
12 *Ibid*, cl 2(14).
13 *Electric Utilities Act*, *supra* note 8, s 25
14 Bill 13, *supra* note 2, cl 2(14).
15 *Alberta Utilities Commission Act*, SA 2007 c A-37.2.
16 Bill 13, *supra* note 2, cl 2(14).
17 *Ibid*, cl 2(18).
18 Alberta Utilities Commission, "AUC Rule 017: Consultation Meeting", (Presentation, 26 June 2018), online: <http://www.auc.ab.ca/regulatory_documents/Consultations/2018-06-26-Rule017-PresentationSlides.pdf>.

AESO are expected to largely concord with the Comprehensive Market Design Final proposal,[19] and the engagement process will be influenced by the new AUC Rule 017. The AESO expects to develop approximately 18 new rules, which will include 16 capacity market rules and 2 new energy market rules regarding energy market monitoring and mitigation and demand capacity asset outage reporting and coordination. All of these rules will be put forward for provisional approval by the AUC.[20]

- **Demand Curve** (August 16 – October 2018): Working group engagement on development of the demand curve and filing language for demand curve (to include rule-like language and follow the provisional rule approval process). Engagement regarding the demand curve will occur parallel to the Capacity Market Rule engagement.[21]

- **Cost Allocation Tariff Design** (August 2018 – Late 2019): Advisory group and working groups to assist with tariff design to allocate the costs arising from the operation of the capacity market.

- **Market Roadmap** (October 2018 – November 2019 and beyond): Consultation on items identified for introduction into market structure beyond the 2021/2022 obligation year.[22]

Alberta Energy has also commenced a stakeholder engagement process for the development of capacity market regulations, which will purportedly give stakeholders the opportunity to provide detailed input and feedback on proposed regulations. Alberta intends to distribute a discussion paper to stakeholders on July 23, 2018 to commence this process, which will also include a webinar on July 25, 2018.

Stores Block: a bridge too far

In addition to facilitating the electricity market shift, we note that early versions of the Bill included provisions meant to address what many perceive to be a regulatory gap left by the *Stores Block* line of cases. Those proposed provisions did not survive the committee process and were removed through an amendment put forward by the Minister of Energy.

By way of background, in 2006, the Supreme Court of Canada issued its decision in *Stores Block*: *ATCO Gas & Pipelines Ltd. v Alberta (Energy & Utilities Board)*.[23] *Stores Block* examined whether Alberta's utility regulator (then the Alberta Energy and Utilities Board (AEUB), now AUC) had the power to direct surplus value realized on a utility asset sale. The Court decided that the regulator had no power to distribute any gains to utility customers, and that the gains resulting from the disposition of utility assets accrued only to the utility owner's shareholders.[24] The fact that the asset was used for utility purposes was immaterial – the utility asset owner would have sole claim to the gains.[25]

Stores Block was applied in various regulatory decisions to the converse situation of losses, where utility owners were forced to bear the burden of unexpected losses caused by asset stranding or destruction.[26] This approach was confirmed by the Alberta Court of Appeal in *FortisAlberta Inc v Alberta (Utilities Commission)*.[27] Applying the logic of *Stores Block*, where gains would accrue solely to the utility owner and not customers, then losses that occur as a result of stranded assets or

19 Alberta Electric System Operator, "Comprehensive Market Design Final Proposal" (Alberta: AESO, 29 June 2018), online: <https://www.aeso.ca/assets/Uploads/Consolidated-proposal.pdf>.
20 Alberta Electric System Operator, "Market Transition Industry Stakeholder Session" (Presentation, 10 July 2018), oline: <https://www.aeso.ca/assets/Uploads/July-10-Market-Transition-Industry-Session-FINAL2.pdf>.
21 *Ibid.*
22 *Ibid.*
23 *Stores Block, supra* note 3; For a succinct overview of the *Stores Block/Fortis Alberta* issue, see Nigel Banks, "Overturning Stores Block and Implementing the Capacity Market", (25 April 2018) *ABlawg* (blog), online: < https://ablawg.ca/wp-content/uploads/2018/04/Blog_NB_Bill_13.pdf>.
24 *Stores Block*, *supra* note 3 at para 78.
25 *Ibid* at para 87.
26 See *FortisAlberta Inc v Alberta (Utilities Commission)*, 2015 ABCA 295 at paras 59-62 [*FortisAlberta*].
27 *Ibid.*

where assets are no longer required for utility purposes, should accrue solely to the utility owner as well.[28] The Court in *FortisAlberta* opined that the principle established in *Stores Block* is good law in Alberta.[29] In doing so, the Court suggested that *Stores Block* and its subsequent case law could only be overturned by a legislative act.

Specifically in regards to the Climate Leadership Plan, this issue has arisen in relation to technological updates necessary to promote and accommodate increased renewable generation. For example, as a result of the AUC's approach to allocating stranded asset costs following *Stores Block*, EPCOR declined to pursue a "smart" meter infrastructure program because the existing meters were not fully depreciated and the consequent "stranding" of the assets would result in a loss to utility shareholders.[30] Utility companies have recently stated that this approach represents a barrier to the future development of renewable generation, as distribution companies may be reluctant to invest in the assets and technology that may be necessary to help achieve the government's renewable energy goals if doing so results in stranded assets and financial loss. They suggested that legislative revisions or other government policy clarity would be required before such investments are made to further the objectives of the Climate Leadership Plan.[31]

Bill 13 at first reading proposed to amend the *Alberta Utilities Commission Act* by adding s. 17.1, which empowered the AUC to allocate amongst both the utility owner and the utility customers, the costs and benefits arising out of:

(a) a sale, lease or mortgage of a property owned by a utility;

(b) a removal or withdrawal of property from service to the public by the owner of a utility;

(c) a removal of property from rate base.[32]

These provisions are a clear response to address the *Stores Block/FortisAlberta* decisions that have loomed over Alberta's utility sector since 2006. However, the proposed amendments were criticized by certain stakeholders for failing to provide clarity on when the costs of stranded assets would be borne by a utility's shareholders vs. ratepayers.

These provisions were ultimately struck at the committee stage. On May 30, 2018, the Minister of Energy moved to amend Bill 13 to strike the provisions in Bill 13 addressing the *Stores Block* gap.[33] In moving for the strike, the Minister cited a need for further discussion, and a desire for additional collaboration with industry, consumer groups and the relevant government agencies to "develop the best possible policy for Albertans."[34] The amendment was passed and the provisions were struck.

Therefore, while legislative change to correct the *Stores Block* gap appears forthcoming, we will have to wait to see what approach the government will take to address it. The Minister's reference to further consultation suggests a potential opportunity for market participants to provide input before the next proposal is put before the Legislature.

That these provisions were proposed and then struck citing the need for further consultation is an indication that the process of changing Alberta's electricity regime deserves careful consideration to ensure the consequent regimes are workable and beneficial for Alberta.

Coming into force

The majority of Bill 13, including the provisions discussed herein, will be fully in force on August 1, 2018.[35] A handful of clauses

28 *Ibid* at para 62.
29 *Ibid* at paras 160-161.
30 *EPCOR Distribution & Transmission Inc – 2013 PBR Capital Tracker True-up and 2014-2015 PBR Capital Tracker Forecast* (25 January 2015), 3100-D01-2015, online: AUC <http://www.auc.ab.ca/regulatory_documents/ProceedingDocuments/2015/3100-D01-2015.pdf>, at para 705.
31 Alberta Utilities Commission, "Alberta Electric Distribution System-Connected Generation Inquiry: Final Report", (Alberta: AU, 29 December 2017) at paras 294-297.
32 Bill 13, *supra* note 2, cl 1(2) (first reading 19 April 2018).
33 Bill 13 A1, *Amendments to Bill 13 An Act to Secure Alberta's Electricity Future Act*, 29th Leg, 4th Sess, Alberta, 2018, cl A (as passed by the Legislative Assembly of Alberta May 30, 2018).
34 Alberta, Legislative Assembly, *Hansard*, 29th Leg, 4th Sess, (May 30, 2018) at 1322.
35 OC 2018-208 (June 14, 2018).

came into force on Royal Assent on June 11, 2018,[36] while the rest of the clauses come into force on Proclamation.[37] Most clauses have been Proclaimed in force as of August 1, 2018, with the exception of clauses 2(24), 2(25) and 37(a)(ii) related to the *Electric Utilities Act*. There is not yet a Proclamation date for these remaining clauses. ■

36 Bill 13, *supra* note 2, cls 1(1), (3), (10), (11) and (12), 2(1), (2)(a)(viii), (3), (6), (18), (26), (30), (31), (32), (33), (36), (37)(a)(i) and (39) and 3(1) and (2).
37 See *Ibid*, cl 5(1).

SHOULD RATEPAYERS FUND INNOVATION?

*James M. Coyne, Robert C. Yardley and Jessalyn Pryciak. Comments by Adonis Yatchew.**

Editors Introduction

The authors of this article, James M. Coyne, Robert C. Yardley and Jessalyn Pryciak are consultants with Concentric Energy Advisors Inc. This article is based on a longer research report supported by the Canadian Gas Association and the Canadian Electricity Association. Where articles are funded by a particular organization it is the policy of this journal to invite a Commentator to provide a neutral perspective. In this case the Commentator is Professor Adonis Yatchew of the University of Toronto, a well-known writer in energy economics and Editor -in- Chief of the Journal of Energy. His comments follow the conclusion at the end of the article.

Introduction

The case for utility-led, ratepayer-funded innovation has strengthened over the past decade and is being driven by a series of interconnected energy realities. These include the need to employ technology to integrate significant quantities of customer-sited distributed energy resources, the emergence of new natural gas end-use technologies, and a recognition by governments that utilities can play a central role in the achievement of energy and environmental public policy goals that require innovative solutions. These factors have taken hold among global economic regulators and this report concludes that the trend is spreading beyond some of the early movers. The responsibility for ensuring that innovation prepares the energy industry to realize the potential for reliable, affordable, and clean energy with greater customer choices among products and services is shared by the utilities, regulators and other policy makers.

In an earlier report,[1] we described the significant benefits that energy innovation provides to customers and society with benefit-to-cost ratios in the 2 to 5:1 range across several programs. The report provided a framework for evaluation of alternative funding mechanisms, focusing primarily on government (taxpayer) and utility (customer) funding options. Government funding is most appropriate in the high-risk early research and development phase or where there are significant spillover benefits that discourage risk-taking. Utility customer funding is most appropriate where the benefits largely accrue to utility customers and where they are in a unique position to test new technologies and business models. The report identified potential obstacles to utility innovation and recommended a utility customer-funding model that maintains active regulatory oversight.

---

*Adonis Yatchew's research focuses on econometrics, energy and regulatory economics. Since completing his Ph.D. at Harvard University, he has taught at the University of Toronto. He has also held visiting appointments at Trinity College, Cambridge University and the University of Chicago, among others. He has written a graduate level text on semiparametric regression techniques published by Cambridge University Press. He has served in various editorial capacities at The Energy Journal since 1995 and is currently the Editor-in-Chief. He has advised public and private sector companies on energy, regulatory and other matters for over 30 years and has provided testimony in numerous regulatory and litigation procedures. Currently he teaches undergraduate and graduate courses in energy economics, graduate courses in econometrics and 'Big Ideas' courses on energy and the environment with colleagues in physics and classics. In June 2018 the International Association for Energy Economics presented him with its Award for Outstanding Contributions to the Profession.

1 Stephen Caldwell, Robert Yardley, Jr., & James Coyne, "Stimulating Innovation on Behalf of Canada's Electricity and Natural Gas Customers" (2014) Concentric Energy Advisors discussion paper prepared for the Canadian Gas Association and the Canadian Electricity Association, online : <http://44f0gi3luy7z39sz523bbcjn.wpengine.netdna-cdn.com/wp-content/uploads/2015/10/CGA_CEA-Report.pdf>.

Two subsequent updates (2015 and 2016) provided updates on trends in utility-sponsored innovation along with examples of recent projects. This 2018 report focuses on customer-funded innovation programs with a deeper dive into the reasons why regulators in eight jurisdictions support customer-funded innovation. These include four leading United States jurisdictions (California, New York, Minnesota, and Massachusetts), two Canadian provinces (Ontario and British Columbia), and two international jurisdictions (Great Britain and Australia). We supplemented regulatory research with regulatory and policy interviews in these jurisdictions to obtain perspective on whether the programs were working, and indications of results achieved to date.

The Case for Utility Funded Innovation

It is becoming increasingly accepted that new business models need to be developed, enabled by energy and data system technologies that require development and testing before they can be deployed at scale. Network infrastructure (pipeline and wire) modernization is an explicit goal for utilities and regulators, for both gas and electric utilities. Future investments in the networks are being designed to support an unfolding market characterized by engagement of both customers and third parties in the utility business model and the implementation of new consumer products and services. Utilities can support this evolving market via rate-funded demonstration projects that test new technologies and business models. Generally, while innovation in energy technologies and less expensive ways of performing traditional utility activities continue to grow, there has been more focus in the past few years on integration of demand energy resources, new business models, and the security of "big data" that enables this transformation. These programs de-risk investments for both customers and shareholders and help establish the business case for full-scale technology development and market adoption. Utility-led technology deployment and demonstration activities will have important direct benefits for customers by improving the way their customers use energy, control their energy use and derive benefit from it. Further, we are seeing many national and subnational governments developing large technology and funding programs. Utility ratepayer funding offers an opportunity to leverage these funds.

Regulators have another important objective with innovation: to spur a transformation of utility cultures to become learning and innovative organizations. Electricity and natural gas "utilities of the future" will be required to leverage advancements in energy technology, big data, and the desire of consumers to be evermore involved in their energy use patterns. Regulators also cite a desire to increase the reliability and resiliency of utility service and improve environmental performance.

The United Kingdom regulator concluded that its earliest efforts at innovation, the Low Carbon Network Fund (LCNF), which aimed to achieve aggressively low carbon goals, demonstrated that regulation has a critical role in promoting utility innovation and removing existing barriers for utilities. California has long been a supporter of customer-funded demonstration projects and continues this effort. New York's policy makers have implemented longer-term research and development programs, and requested that the regulator adopt a longer-term perspective when evaluating ten-year business plans that can be reprioritized during the plan as experience is gained. Minnesota has engaged a stakeholder process to contribute to the design of demonstration projects before they are submitted for review by the regulatory commission, thereby improving the opportunities for learning by all parties. AVANGRID, for example, is developing a demonstration "Energy Smart Community" that will test new customer engagement and business models after it installs Advanced Metering capabilities for over 10,000 customers in Ithaca, New York. Australia has supported customer-funded innovation that aims to reduce peak demand as growth is threatening reliability and will require expensive infrastructure investments. Ontario currently funds innovation through a combination of customer, utility shareholder, and vendor funding. The Ministry of Energy recently published a 2017 Long Term Energy Plan that focuses more intently on the role of innovation, and the potential barriers presented by existing regulation. The Massachusetts Commission has recently signaled its willingness to fund demonstration projects, indicating a willingness to follow through with a policy that was established in 2014 by a prior Commission. In British Columbia, an ambitious provincial clean energy policy has provided flexibility for utilities to propose - and the regulator to approve - customer-funded innovation projects in areas such as renewable natural gas and natural gas for transportation. These projects are seen as precursors to kick-starting new technologies and new applications of those technologies that may ultimately lead to scaled-up competitive markets.

Table 1 identifies programs in each of these jurisdictions where regulators have made an explicit determination that they meet specific innovation or demonstration project requirements to merit customer funding.

Funding levels for innovation vary across the jurisdictions we have examined. The most recent data are summarized below in Figure 1. These programs span a range from $0.72 to $14.12 per customer, or an average of $6.55. While virtually all policymakers and regulators express concern for costs, they also recognize the potential benefits. Ratepayer advocates have expressed concern that demonstration projects should be sufficiently defined with quantifiable benefits to support such investments.[2] The potential gains from adaptation of new technologies and business approaches to a "mature" industry are large, and studies indicate the potential consumer benefits from RD&D outweigh the costs by up to 5:1 multiples.[3]

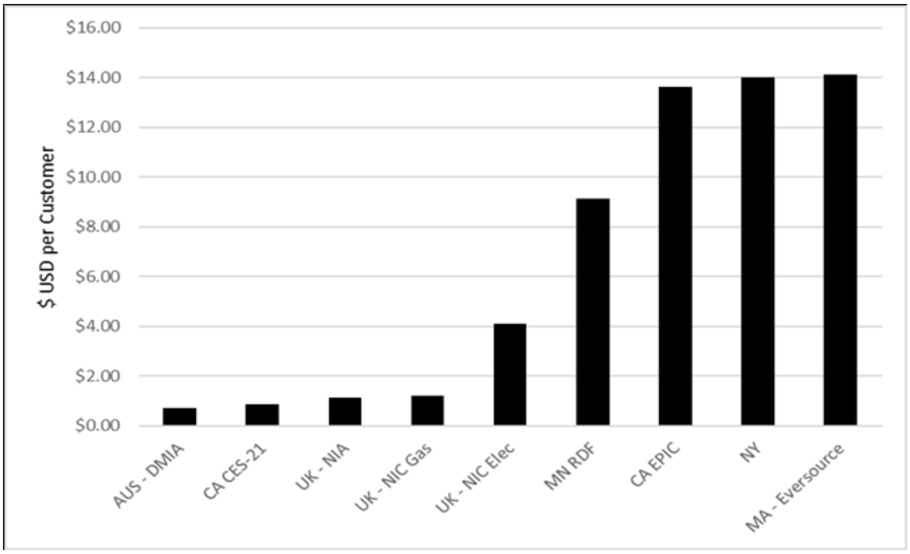
Table 1: Summary of Innovation Programs

Regulator/ Government	Program/ Directive	Link to Program	Start Date	Funding Level (annually per customer, $USD)
Ofgem	RIIO framework: Network Innovation Allowance (NIA) & Network Innovation Competition (NIC)	https://www.ofgem.gov.uk/network-regulation-riio-model https://www.ofgem.gov.uk/network-regulation-riio-model/current-network-price-controls-riio-1/network-innovation	2013-2015*	NIA: $1.13 NIC: $4.11 Electricity, $1.23 Gas
California PUC	California Energy Systems for the 21st Century (CES-21)	https://www.llnl.gov/sites/default/files/field/file/CES21.pdf	December 2012	$0.87
California PUC	Electric Program Investment Charge (EPIC)	http://www.energy.ca.gov/research/epic/	May 2012	$13.61
New York PSC and NYSERDA	Reforming the Energy Vision (REV)	https://rev.ny.gov/ http://www.dps.ny.gov/REV/	April 2014	NYSERDA funding: $4.69 ConEd REV project: $9.33
Minnesota PUC	Renewable Development Fund	https://www.xcelenergy.com/energy_portfolio/renewable_energy/renewable_development_fund	1994	$9.12
Australian Energy Regulator	Demand management incentive scheme and innovation allowance mechanism	https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/demand-management-incentive-scheme-and-innovation-allowance-mechanism	December 2017	DMIA: $0.72 *(hypothetical)*
Massachusetts DPU	Order requiring Grid Modernization Plan	http://www.raabassociates.org/Articles/MA%20DPU%2012-76-B.pdf	June 2014	Eversource demo projects: $14.12
IESO (Ontario)	Conservation Fund	http://www.ieso.ca/get-involved/funding-programs/conservation-fund/cf-overview	2005	*Insufficient data*

*Start dates vary by gas vs. electricity, and transmission vs. distribution.

2 US, Office of Ratepayer Advocate, *Policy Position on CES-21*, online: <http://www.ora.ca.gov/general.aspx?id=2422>.
3 Caldwell, Yardley, Coyne, *supra* note 1 at 2.

Figure 1: Examples of Utility Funding Levels, in Annual USD Per Customer[4]



Notes:
AUS – DMIA: Australia Demand Management Innovation Allowance
CA CES-21: California Energy Systems for the 21st Century
UK – NIA: Ofgem Network Innovation Allowance
UK – NIC Gas/Electric: Ofgem Gas/Electric Network Innovation Competition
MN RDF: Minnesota Renewable Development Fund
CA EPIC: California Electric Program Investment Charge
NY: New York State Energy Research & Development Authority and Con Edison
MA – Eversource: Eversource Grid Modernization Plan projects

In considering these funding levels, policymakers and regulators might ask: what is the optimal level of funding, which programs are most successful, and what factors determine whether funding should be increased or decreased? These are important questions without easy answers, but our research In considering these funding levels, policymakers and regulators might ask: what is the optimal level of funding, which programs are most successful, and what factors determine whether funding should be increased (or decreased)? These are important questions without easy answers, but our research sheds light on them. Where energy policy dictates a shift in the status quo, funding levels would be expected to be higher to facilitate the transition, and targets comparable to the CA-NY-MA range may be appropriate. Given the relatively new nature of utility funded innovation, it is difficult to measure success, but Ofgem programs appear at the forefront, with benefits for certain programs estimated in the 4.5-6.5 times funding level range. Capital investment theory stipulates that any investment with a positive return should be undertaken with risk and capital costs factored in. This suggests that program funding up to a return ratio of 1:1 is warranted. Even with current budgets, California has estimated its RD&D funding gap is as much as $670 million

4 Massachusetts - Eversource spending represents costs of recently approved electric vehicle and energy storage projects. The UK NIC Electric is decreasing funding from £90 million to £70 million – this decrease is not reflected in the chart. UK NIA funding uses SGN Scotland and SGN Southern NIA expenditure as an example. New York data represents NYSERDA funding for the most recent year (significantly lower than the previous year as a result of a funding mechanism logistical change), plus ConEd funding for REV Demo projects. Australia DMIA funding is based on an average of hypothetical allowance of selected companies. Sources: AER Determinations Attachments 1 – annual revenue requirements; CES-21 Annual Report 2016; Ofgem, RIIO-GD1 Annual Report 2015-16; Ofgem, The Network Innovation Review: Our Policy Decision, March 2017; Xcel Energy, RDF Annual Report 2017; CA IOU websites; NYSERDA Financial Statements March 2017; New York DPS Order in Case 16-E-0060; Massachusetts DPU 17-05 Order.

per year. As long as estimated benefits continue to exceed funding levels, policymakers and regulators are serving the public interest.

Overall, this report documents the trend toward increased customer funding of innovation projects in both the natural gas and electricity industries and cites the rationale relied upon by policy makers and regulators. In some jurisdictions, the changes are implemented through a combination of legislation and regulation. The potential returns from innovation are significant. Whether avoiding costly investments in infrastructure, or helping customers save money on their bills by utilizing technology to manage their energy use, regulators are concluding that the short- and long-term benefits clearly justify the costs of demonstration projects.

The following sections describe the approaches taken in each jurisdiction and insights gained from evaluation of these programs.

Customer-Funded Innovation from Around the Globe

1. United Kingdom

The United Kingdom's energy regulator, the Office of Gas and Electricity Markets ("Ofgem"), has been an international leader in regulatory reform since its predecessor agencies were established when natural gas and electricity markets were privatized in the 1980s. Notably, it was an earlier adopter of performance-based regulation ("PBR"). The most recent version of this multi-year utility revenue model is "RIIO", representing the equation, "Revenue = Incentives + Innovation + Outputs", which was applied to natural gas and electricity distributors in 2013 and 2015, respectively. This new model was the result of a "RPI-X@20" review of PBR as applied in the UK. During this same era, Ofgem and the U.K. utilities gained experience with the Low Carbon Network Fund (LCNF).

The concept of compensating utilities for how well they perform as innovators grew from the recognition that the energy sector was about to experience significant change and that utilities needed to be able to innovate in order to respond to evolving customer demands and policy drivers.[5] Ofgem recognized that even within the new incentive-based ratemaking framework, "research, development, trials and demonstration projects - the earlier stages of the innovation cycle - are speculative in nature and yield uncertain commercial returns."[6] Ofgem recognized that even "failures" in terms of innovation attempts could provide useful information.[7]

Ofgem established two distinct innovation funding programs to implement the innovation component of RIIO: the Network Innovation Allowance (NIA) and the Network Innovation Competition (NIC). These two programs fund research by the Distribution Network Operators (DNOs) that will facilitate the transition to a low carbon economy, while providing cost savings to customers. Customers will pay for these activities through their energy bills. The NIA is for funding smaller innovation projects and is a set annual allowance available to each network operator. The NIC is an annual competition to fund selected innovation projects, and is focused on larger, more complex projects that require approval.

Funding Levels

For electricity distribution, Ofgem required utilities to define innovation strategies based on NIA funding of between 0.5 and 1 per cent of their base revenues. NIA projects do not require individual project approvals. While funding caps are company-specific, they have generally been between 0.5 and 0.7 per cent for both electric and natural gas DNOs. £61 million is available for the NIA annually. In 2016, Ofgem provided £44.6 million in funding to six projects through the NIC. This funding is combined with the companies' contributions and external funding, creating a total of £53.9 million (approximately $75 and $90 billion Canadian dollars, respectively). In 2016, funding for the NIC was approximately £3.05 per electric customer and £0.91 per gas customer ($4.11 and $1.23 USD, respectively).

5 UK, Ofgem, *RIIO: A New Way to Regulate Energy Networks: Final Decision*, (London: Office of Gas and Electricity Markets, October 2010), online: <https://www.ofgem.gov.uk/ofgem-publications/51870/decision-docpdf>.

6 UK, Ofgem, *Decision and Further Consultation on the Design of the Network Innovation Competition*, (London: Office of Gas and Electricity Markets, 2 September 2011) at 4, online: <https://www.ofgem.gov.uk/sites/default/files/docs/2011/09/nic-consultation.pdf>.

7 UK, Ofgem, *Innovation in Energy Networks: Is More Needed and How Can This Be Stimulated?* (Working Paper No 2) (2009) at 11, online: <https://www.ofgem.gov.uk/sites/default/files/docs/2009/07/rpi-x20-innovation-working-paper_final-draft_0.pdf>.

With the reduction of £90 million to £70 million in electric NIC funding, future funding will be approximately £2.37 per electric customer ($3.20 USD).[8]

Regulatory Rationale and Program Insights

Ofgem noted that the innovation stimulus is intended to "kick start" a cultural change at utilities.[9] Innovation funding is provided by customers since they will benefit from innovations.[10]

The UK's focus on innovation is intended to produce a low-carbon future, while also driving down costs for network customers. Ofgem has significant authority and has not required legislation to implement its innovation agenda. The LCNF experience, supported by a survey from an independent evaluation report prepared by the consultancy Pöyry in October 2016, demonstrated that regulation has a critical role to serve in promoting utility innovation and removing existing barriers for DNOs.[11] The NIA and NIC programs continued the goal to foster a more innovative culture within network companies. Policy makers are hopeful that the innovative culture will be applied to resolving industry challenges as they arise and provide value to customers. Ofgem has made tweaks to governance over the past few years, providing more flexibility to DNOs based on satisfactory performance to date.[12]

The UK government, through Ofgem, has made utility innovation a key objective of its regulatory framework. The regulator wants to drive cultural change at utilities in order to create a smarter, distributed, renewable, sustainable, efficient, and diversified electric and gas grid for the benefit of customers. Utility customer funding is utilized along with co-funding from third party vendors. The goals and scope of the UK program are among the most ambitious examined.

2. California

California has two large programs that fund RD&D in the energy sector. The CES-21 program is a collaborative effort among the three large investor-owned utilities and Lawrence Livermore National Laboratories (LLNL) that funds investments in several specified areas, focusing most recently on cybersecurity and grid integration projects. The Electric Program Investment Charge (EPIC) Program funds investments that promote the adoption of clean technologies. Both programs are reviewed and approved by the California Public Utilities Commission (CPUC) and rely on customer funding.

Funding Levels

CES-21 funding in 2016 was $10.3 million, divided among the approximately 11.9 million customers of the three IOUs, results in a funding level of $0.87 per customer. EPIC's annual budget of $162 million translates to funding of approximately $13.61 per customer.

Regulatory Rationale and Program Insights

The statute provides the CPUC with the clear authority to approve RD&D funding by utilities and establishes a set of guidelines to consider. In the absence of clearly expressed legislative intent, the CPUC could have relied on more general "public interest" statutory provisions that are common in utility statutes. The Commission cited a Staff position suggesting that the California RD&D funding gap was as much as $670 million per year.[13]

California is a leader in customer-funded innovation. The California CES-21 program demonstrates that enabling legislation can achieve two objectives: 1) clarifying the authority of a regulatory agency to approve RD&D expenditures by utilities and 2) establishing

8 UK, Ofgem, *Infographic: The energy network, 28 September 2017*, online: <https://www.ofgem.gov.uk/publications-and-updates/infographic-energy-network>.

9 UK, Ofgem, *Electricity Network Innovation Competition Governance Document*, (London: Office of Gas and Electricity Markets, 1 February 2013) at 5, online: <https://www.ofgem.gov.uk/ofgem-publications/53526/spnic-pdf>.

10 *Decision and Further Consultation on the Design of the Network Innovation Competition*, *supra* note 6 at 2.

11 UK, Pöyry, *An Independent Evaluation of the LCNF*, October 2016.

12 Based on a discussion with Jonathan Morris and Neil Copeland of Ofgem.

13 *Electric Program Investment Charge, Staff Proposal*, 10 February 2012, Rulemaking 11-10-003 at 9- 10, 17; D.12-05-037, *Phase 2 Decision Establishing Purposes and Governance for Electric Program Investment Charge and Establishing Funding Collections for 2013-2020*, 24 May 2012 at 6, online: <http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/167664.pdf>.

guidelines that a regulatory agency can apply in approving specific proposals. However, it also demonstrates that legislatures can subsequently modify their perspectives with respect to the amount and focus of RD&D. In this instance, the decision to reduce funding of the CES-21 program appears to have been caused by concerns about the proportion of the funding that was being used to fund administrative costs.

3. New York

New York supports customer-funded RD&D projects in both the natural gas and electric industries. There are several categories of funding. The seminal order establishing competition in New York's electric and natural gas industries (Order 96-12) established a non-bypassable systems benefits charge (SBC) from customers to fund research and development as well as energy efficiency investments, low-income programs, and environmental monitoring. The New York State Energy and Research Development Authority (NYSERDA) was designated in 1998 to administer the SBC funds. Prior to that time, utilities performed research and development activities that were approved by the New York Public Service Commission (NYPSC) and funded through customers' utility bills. New York's utilities continue to request and receive authorization to perform R&D activities that are approved in their rate cases.

In 2000, the NYPSC approved a surcharge intended to fund medium-to-long-term R&D by New York's investor-owned natural gas local distribution companies (LDCs) in response to a decision by the Federal Energy Regulatory Commission to phase out support for the Gas Research Institute through a surcharge on interstate pipeline deliveries.[14] New York's LDCs pledged to work collaboratively to address common needs and avoid duplication of research activities. The NYPSC relied on a Staff recommendation to have funds directed to distribution activities, and not to upstream activities (i.e., supply and storage) or to improving end-use appliances that were considered competitive activities. An appendix to the recommendation provides a list of qualifying distribution activities that includes pipe installation, pipe repair and maintenance, modeling of pipe flows, and improvements that would address environmental impacts related to the distribution function. This effort came to be known as the Millennium Fund. An industry trade group estimated that the benefit-to-cost ratio of gas R&D projects was approximately 3:1. The Millennium Fund remains in place today.

Millennium Fund programs are supplemented by utility-specific natural gas R&D programs that are approved in individual LDC rate cases. For example, Consolidated Edison proposed the deployment of trenchless technologies that allow the companies to repair gas distribution lines without digging a trench. Central Hudson has proposed to test a "non-pipes alternatives" concept as a way to meet growing peak demand on constrained parts of their system.

New York's support for innovation experienced a renaissance with its "Reforming the Energy Vision" (REV) proceeding that began in 2014. Customer-funded RD&D occurs through two mechanisms: (1) REV demonstration projects proposed pursuant to the Track 1 Order in the REV proceeding, and (2) RD&D efforts organized and managed by NYSERDA and funded by the SBC.

REV demonstration projects were filed pursuant to guidelines established in the REV Track 1 Order issued on February 26, 2015. The REV proceeding is New York's broad-based initiative to leverage technology and business model innovation in order to integrate substantial amounts of "Distributed Energy Resources" and thereby enhance reliability and resiliency while lowering carbon emissions.

Funding Levels

Cap on REV demonstration project cost recovery of 0.5 per cent of total revenue requirements, or $10 million per year.

Regulatory Rationale and Program Insights

The NYPSC expressed its support for innovation with its opening paragraph of the Track 1 Order:

> *The electric industry is in a period of momentous change. The innovative potential of the digital economy has not yet been accommodated within the electric distribution system. Information technology, electronic*

14 New York Public Service Commission Staff Recommendation in Case 99-G-1369, 31 January 2000.

> *controls, distributed generation, and energy storage are advancing faster than the ability of utilities and regulators to adopt them, or to adapt to them. At the same time, electricity demands of the digital economy are increasingly expressed in terms of reliability, choice, value, and security.*

Policy makers were particularly interested in demonstrating that the industry could transition to a new business model without having an adverse impact on reliability. NYSERDA recognizes that utility participation in RD&D is critical to the ultimate goal of new technologies and business models being deployed for the benefit of customers who are funding the research through the SBC. There is a tension between the uncertainty and risk associated with RD&D and the cost-benefit analysis that regulators typically apply to more traditional utility investments. The longer timeframe associated with returns to RD&D also present a challenge as regulators are generally looking for some measurable customer or environmental benefit (e.g., a specified carbon reduction quantity) within the first five years. Although NYSERDA is a state agency, its budget and activities are subject to review and approval by the NYPSC. As part of the Clean Energy Fund review, NYSERDA has received approval to apply a ten-year business planning horizon to its portfolio of programs. NYSERDA will file annual, rolling updates to its portfolio, adjusting priorities in response to technology and market developments, and defunding programs that no longer appear promising. This longer horizon is more aligned with the risk associated with RD&D, and also provides greater certainty and continuity as the NYSPC grows more comfortable with NYSERDA's portfolio approach.

The New York approach to innovation requires that the NYPSC apply a different perspective to its review and oversight of RD&D than it takes to its more traditional approval actions. The Commission is being asked to adopt a higher risk tolerance on behalf of customers based on the belief that customers will benefit in the long run from innovation and that, absent customer-funding, a suboptimal level of RD&D will occur in the regulated utility segment.

New York has promoted utility innovation through multiple programs targeting both the gas and electric industries. While New York policy makers are pressuring the utilities to be innovative, they are also keeping utilities firmly within a cost-of-service regulatory environment. The introduction of potentially disruptive market and regulatory models is a concern among utilities as DERs continue to be integrated throughout the state. The issue may be brought to a head with NYSERDA taking a more active policy role in an effort to sustain the momentum toward increasing innovation.

4. Minnesota

Minnesota has two initiatives that provide customer-funded RD&D projects: a Renewable Development Fund established in 1994, and a more recent effort to develop demonstration projects through extensive stakeholder participation as part of Minnesota's e21 initiative. This initiative is addressing the future of energy market more comprehensively by examining changes to business models and regulatory frameworks necessary to leverage new technologies to promote a sustainable future with greater reliance on customer-sited and other renewable energy supplies.

Funding Levels

For the RDF, there is a $25.6 million annual contribution to the fund. In 2017 the RDF charge for a typical customer was $0.76 per month, equaling $9.12 per year.

Regulatory Rationale and Program Insights

The RDF's objective is to remove barriers to entry for renewable energy technologies, including economic barriers from competing against conventional energy sources.

The e21 approach to innovation tests the value of including stakeholders in the design and development of demonstration projects, particularly when the objective is to test a new business model or a new way for utilities to work with third-parties, or when the demonstration project is testing the engagement and responsiveness of customers to new products and services. Although specific demonstration projects still need to be reviewed and approved by the MPUC, the stakeholder experience improves the design of the projects and increases their eventual likelihood of success. Stakeholders engage directly with the utility throughout this facilitated process and are in a position to support regulatory approval, including ratepayer support. The benefits of improved stakeholder relationships can carry over to more controversial utility regulatory matters that employ stakeholder engagement, including integrated resource planning efforts. This type of engagement has the potential to reduce regulatory risk and regulatory lag that is exacerbated by lengthy litigation.

One byproduct of the e21 Initiative is legislation that codifies the authority of MPUC to approve multi-year rate plans, extending the maximum from 3 to 5 years, and requires any such plan to include a distribution system plan.[15] This legislation, the 2015 Jobs and Energy Bill, also provides the MPUC with the authority to develop performance metrics for utilities.[16] The identification of measures, specific metric definitions, and targets all benefit from stakeholder engagement outside of a more rigid litigation process. Thus, the e21 Initiative has effectively created a role for itself that complements rather than competes with the more traditional relationship among the regulator, utilities, and stakeholder intervenors. The issues faced by utilities and their regulators are expected to become increasingly complex as energy business models continue to evolve in response to technology and market developments.

Minnesota, with the e21 initiative, is increasing the likelihood that regulators will be willing to approve customer-funded innovation by increasing the degree of collaboration between the utilities and stakeholders, and by beginning the collaboration while the demonstration projects are still in the design phase.

5. Australia

The Australian Energy Regulator (AER) is beginning to respond to changes in the energy industry and the role of behind-the-meter resources as it faces rising peak demands. The AER proposed a demand management incentive scheme (DMIS) and demand management innovation allowance (DMIA) to encourage utilities to manage demand more proactively. The AER released a draft decision on the DMIS and DMIA in August of 2017 and finalized the decision that December.[17]

Funding Levels

DMIA funding is AU$200,000 plus 0.75 per cent of annual revenue requirements (ARR). DMIS funding is up to 1 per cent of ARR.

Regulatory Rationale and Program Insights

Despite these incentives, the AER has found it challenging to move utilities beyond a perceived focus on capital investments, and prior incentives have not been sufficient to overcome that hurdle. There is a cultural resistance. The AER is attempting to promote innovation through the DMIA and also wants to distinguish between services that should remain under regulation, and those that should be competitive, as described in its ring-fencing guidelines.

The driving forces impacting utility regulatory policy in Australia are consumer concerns regarding energy prices, reliability concerns, pending retirements of coal-fired plants and the growing penetration of renewables. The existing regulatory model is a multi-year incentive program. Companies come in every five years with forecasts for the next five years. The regulator, with technical advisors, determines if the forecast reflects "efficient costs," and then sets revenue for five years. The underlying rationale is if the utility can improve on costs, they retain the difference, and if there is a non-network alternative that's more cost-effective, the utility has the incentive to look at that alternative.

The AER is seeing more partnering between the networks and different innovators, and the networks are becoming more open to innovation. The AER sees its role as setting up a framework, and the industry is responding. The AER is also emphasizing a movement away from an adversarial relationship to a more collaborative model. Pilot projects are beginning to illustrate

15 US, HF 1437, *2015 Jobs and Energy Bill*, 89th Leg, 4th Engr, Minn, 2015, at 66, online: <https://www.revisor.mn.gov/bills/text.php?number=HF1437&version=4&session=ls89&session_year=2015&session_number=0> [*2015 Jobs and Energy Bill*].

16 *Ibid* at 67.

17 Australian Energy Regulator, "Regulation that supports innovation, demand and consumers" (Presentation delivered at the Disruption & Energy Industry Conference, 7 September 2017), online: <https://www.aer.gov.au/news/regulation-that-supports-innovation-demand-and-consumers-presentation-to-disruption-the-energy-industry-conference-sydney-7-september-2017>.

scalability. Tesla, for example, is building a 129-MWh battery with French energy company Neoen in South Australia, characterized as the world's largest battery.

Australia also funds RD&D projects as a result of the ARENA Act 2011, which targeted $2 billion (Australian dollars, equal to approximately $1.97 billion Canadian dollars) to invest in renewable energy and the Australian renewable technology sector. Funding has been modified by the Clean Energy Legislation (Carbon Tax Repeal) Bill 2013 and Budget Savings (Omnibus) Bill 2016.

Australia is poised to implement customer-funded innovation mechanism at a meaningful level. This proposal is broadly supported by stakeholders who recognize that utility innovation is part of the solution to adapt to a changing environment. This includes targeting a combination of energy costs, reliability, and the integration of renewable energy resources. A combination of government-funded, customer-funded and industry-led mechanisms are being utilized.

6. Ontario

Ontario currently funds innovation through a combination of ratepayer, utility investor, and third-party vendor resources. Ratepayer-funded projects are financed through the IESO's Conservation Fund and are included as a component of the Global Adjustment charge that appears as a separate line item on electric bills for all customers.

More recently, the provincial government of Ontario and its energy regulator have increased their attention on the role that innovation needs to serve in the energy sector. The Ministry of Energy's 2017 Long Term Energy Plan (2017 LTEP), released in October 2017, devotes an entire chapter to innovation.

Funding Levels

Ontario funds innovation through a combination of ratepayer, utility investor, and third-party vendor resources. Ratepayer-funded projects are financed through the IESO's Conservation Fund and are included as a component of the Global Adjustment charge that appears as a separate line item on electric bills for all customers. Recent demonstration projects that have been funded through this mechanism include several pilot programs that test TOU and other pricing mechanisms (often combined with energy management system technologies). They also include testing new energy technologies such as energy storage and the potential for solar power to defer infrastructure investments.

Regulatory Rationale and Program Insights

Ontario is focused on maintaining affordable energy for residential and business customers. Innovation in the delivery of electricity and natural gas, greater customer choice, and expanded access to natural gas, are viewed as major contributors to realizing this goal. The emphasis on innovation responds to stakeholder input that "electricity costs are too high," the Ministry should "consider new technologies and methods to manage energy use," and there is a need to "expand access to natural gas." The Ontario Energy Board's (OEB) 2017-2020 Business Plan identifies "technological innovation that presents new choices for consumers and challenges traditional business and regulatory models" as one of four key trends that define the current environment.

Stakeholders involved generally understand the goals: be cost effective, make the customer's voice heard, and meet environmental policy goals. An outcomes approach to regulation is compatible with these objectives. The OEB perceives a hangover of existing habits and approaches to distribution planning, and some prior regulatory features that do not provide adequate incentives for least cost systems. Incentives that align customer and utility objectives will drive down system costs. The OEB has also relied on moving more distribution charges to the fixed customer charge to remove barriers to innovation.

Governance for pilot projects includes the OEB establishing guidelines, followed by interim reports showing results based on the sample (e.g., how effective is it at demand response and consumer elasticity), followed by a mandatory final report. Monthly monitoring reports are sometimes utilized in the first period, followed by bimonthly reports.

Ontario is supporting customer-funded innovation through a broad-based customer-funded mechanism collected through the ISO. The strong positioning of the role of innovation in addressing energy costs in Ontario by the Ministry is important in reaching alignment with the OEB to provide support for innovation. The 2017 LTEP and OEB business plan recognize that regulatory barriers need to be addressed. The regulator is seeking to better align utility and customer interests and the regulatory model through demonstration projects and incentives that will ultimately deliver lower energy costs.

7. Massachusetts

In 2014, the Massachusetts Department of Public Utilities (DPU) issued an order on electric grid modernization, requiring each utility to file a Grid Modernization Plan (GMP). The order supports utility innovation and directs each of the Commonwealth's three investor-owned utilities (National Grid, Eversource, and Fitchburg Gas & Electric) to propose a list of projects that focus on testing, piloting, and deploying RD&D projects that modernize the grid and employ new technologies. The DPU invited the utilities to propose funding mechanisms as part of their GMP filings, clearly inviting customer-funded proposals. However, the DPU also directs utilities to leverage outside funding and pursue collaboration to the extent possible.[18]

Funding Levels

As an example, the recent approval of Eversource's storage and EV projects includes approved capital investments of $100 million. The annual revenue requirements associated with these investments will be recovered from Eversource's 1.4 million electric customers in Massachusetts. The Department considered bill impacts, net of customer benefits, when approving these spending levels.

Regulatory Rationale and Program Insights

Notably, the DPU indicated that it would not deny cost recovery "merely because of lack of success," responding directly to one of the major barriers to utility innovation, noting further that the DPU had not been supportive of RD&D projects in the past, and signaling an intent to reverse existing precedent. Grid modernization would result in lower energy costs by contributing to a less expensive electric system (investments, operations and maintenance expenses), reducing peak demands, and by providing customers with tools that they could employ to reduce their electricity usage.

Although the DPU has not yet issued orders in the grid modernization cases filed over two years ago, the Eversource order signals its intention to apply the policies from the prior Commission and its willingness to fund demonstration projects that advance the public interest. Most importantly, this qualifies as customer-funded innovation. It will be a few years before these recently approved projects will produce results that can be evaluated. The funding for Eversource's storage and EV projects coincided with approval of its PBR plan, indicating innovation and PBR can be pursued simultaneously.

8. British Columba

The 2007 Greenhouse Gas Reduction Targets Act set initial targets for reductions in greenhouse gas ("GHG") emissions at a 33 per cent reduction by 2020 and 80 per cent by 2050, and established a carbon tax. The 2010 Clean Energy Act (CEA) set goals with respect to electricity self-sufficiency, including reducing the expected increase in electricity demand by at least 66 per cent by 2020, generating at least 93 per cent of electricity from clean or renewable resources, supporting the development of innovative technologies that support the conservation and clean energy goals, and reducing GHG emissions dramatically by 2050.

The CEA directs the British Columbia Utilities Commission to set rates as necessary to allow utilities, including British Columbia's largest electric utility, provincial-owned BC Hydro, to recover the costs they incur to achieve these goals. The Greenhouse Gas Reduction Regulation ("GGRR"), authorized under the CEA, allows for utilities' prescribed undertakings that work towards GHG reductions, while still allowing them to recover their costs through utility rates. The GGRR allows utilities to implement prescribed undertakings without seeking the prior approval of the BC Utilities Commission, although the Commission still has the ability to rule on the prudency of expenditures. British Columbia's utilities have provided incentive funding to customers to support development of CNG and LNG fueling stations, vehicle and marine vessel conversions, and the use of renewable natural gas.

18 Caldwell, Yardley, Coyne, *supra* note 1 at 32.

One fund that is instrumental in achieving British Columbia's goals is the Innovative Clean Energy (ICE) Fund administered by the Province's Ministry of Energy, Mines and Petroleum Resources. The ICE Fund is a legislated Special Account designed to support the Province's energy, economic, environmental and greenhouse gas reduction priorities, and to advance B.C.'s clean energy sector.

Funding Levels

The ICE Fund was initially funded by a 0.4 per cent levy on the final sales of electricity, natural gas, fuel oil and grid-delivered propane. The electricity levy has since been removed with the reinstatement of the Provincial Sales Tax on April 1, 2013.

Regulatory Rationale and Program Insights

British Columbia, through a series of legislative actions, has established aggressive goals for its energy sector that depend on investments in clean energy production and infrastructure as well as technologies that support energy management activities. Many of these programs are funded through surcharges on energy usage.

A series of legislative and policy initiatives led to the establishment of the Clean Energy Act in 2010, and the subsequent GGRR in 2012. Under this legislation, utilities have the option to implement prescribed undertakings without seeking the prior approval of the BC Utilities Commission, although the Commission still has the ability to rule on the prudency of expenditures. The Province does not contribute any funding. The programs are fully funded by natural gas utilities and paid for by natural gas customers.

The GGRR has been amended over time to allow utilities to implement specific undertakings. In November 2013, amendments were made to allow utilities to expand their incentives to include trains and mine-haul trucks, and to provide tanker-truck delivery services to trucking, mining and marine-transportation customers. In May 2015, the Government further amended the GGRR to allow for shifts in the allocation of incentives and investments within the previously-approved total spending cap in order to better respond to changes in the marine market place. Amendments made in early 2017 enabled utilities to increase natural gas distribution to the marine transportation sector. Amendments also increased incentives for using RNG in transportation and established a Renewable Portfolio Allowance to increase the supply of RNG. Utilities provide comprehensive reports on these initiatives to the provincial government and the commission.

Concerns in BC have been expressed that these services might be offered by unregulated industry in a competitive market (e.g., LNG and CNG), and should not be supported by innovation funding because this would provide the utility with an "unfair advantage." Amendments to the legislation have been justified on the basis that utilities are serving a market that would likely not be served by competitive service providers. Utilities may also ask for incentives to execute innovative programs, particularly where a competitive procurement process is employed and overseen by an independent third-party "fairness advisor."

In British Columbia, an ambitious clean energy policy has provided flexibility for utilities to propose - and the regulator to allow - cost recovery for customer-funded innovation investments. These projects are seen as precursors to kick-starting new technologies and new applications of those technologies that may ultimately lead to scaled-up competitive markets.

Conclusions

Regulatory Rationale

Several policymakers, including utility regulators, have recognized the need for utilities to actively contribute to innovation in the electricity and natural gas sectors of the economy and the value this provides to customers. This report focuses on jurisdictions that provide customer funding for innovation and the reasons that regulators have cited in approving this funding. They have approved funding for demonstration projects that explore new business models, pilot technologies that result in delivery efficiencies, test new products and services, and support scalable investments. All of these investments help accelerate the pace of change in the sector.

Goals for these programs vary by jurisdiction, but common themes include: greenhouse gas reductions, lower energy prices, demand reduction or load shifting, accelerated deployment of renewable and distributed resources, improved system reliability, and the introduction of new utility technologies. Rationales also vary according to specific circumstances and preferences of regulators and policymakers. Ofgem sees innovation funding as a vehicle for driving cultural change at utilities, and necessary to achieve these objectives. California and BC see innovation as a mechanism for economic development. BC and Australia see innovation as a path for stimulating competitive service offerings. Ontario and Massachusetts emphasize new choices for consumers.

There is a growing recognition that customers are long-term beneficiaries from innovation in the utility business model, so investments on their behalf are justified and in the public interest. Customer funding for innovation-related projects is often applied in conjunction with funds that are contributed by government and third-party vendors.

Measuring the Benefits

The history of utility customer-funded innovation funding is relatively recent, so data on the benefits of these programs can be difficult to quantify. Successful deployment requires regulatory flexibility and appropriate governance to ensure the trade-offs between costs and impacts on rates are justified. Given the global nature of these policy objectives, the opportunity exists for lessons learned to be shared among regulators and industry stakeholders.

While not all demonstration projects successfully prove out a new technology or business model, these investments frequently prove to be gateways to new utility models, short-term accelerators to competitive service offerings, or some combination of quantitative and qualitative benefits. The potential gains from adaptation of new technologies and business approaches to a "mature" industry are large, and studies indicate the potential consumer benefits from RD&D outweigh the costs by up to 5:1 multiples. Whether avoiding costly investments in infrastructure, or helping customers save money on their bills by utilizing technology to manage their energy use, regulators are concluding that the short- and long-term benefits of customer-funded innovation justify the costs.

Commentary

James Coyne, Robert Yardley and Jessalyn Pryciak have provided us with a valuable and cogent review of innovation models in electricity and natural gas industries in various parts of the world. The primary focus is on jurisdictions where ratepayers (or taxpayers) contribute to funding innovation initiatives. The paper concludes that "The case for utility-led, ratepayer funded innovation has strengthened over the past decade and … that the trend is spreading." There are at least two distinct embedded contentions here – one is that innovation should be ratepayer funded, the other that it should be utility-led. That the "trend is spreading" is an empirical observation, which, in and of itself, does not constitute evidence that this is the right direction, it could be "herd behaviour" rather than *independent* judgements by policymakers and regulators.[19]

Ratepayer Funding of Innovation

So what is the foundational argument that can rationalize ratepayer funding models? An initial, if admittedly crude partitioning would go something like this:

- Innovation research that can be monetized, through intellectual property and ultimately profits, is best funded through utility and/or private sector risk taking.

- Innovations that do not produce intellectual property, such as is often the case with basic research, require broader support, often through government (or in this case ratepayer) funding.

This latter is much like a public goods problem whereby the marketplace does not produce sufficient quantities of a good because the full benefits cannot be internalized by the company engaging in the investment. There are unaccounted (yes, in the accounting sense) spillover effects as well as other externalities.

In fact, a good deal of innovation expenditure has both features, leading to some intellectual property, but also to deeper and broader knowledge – theoretical and practical – that

19 History is peppered with detrimental 'trends', such as the monetary stimulation by many central banks that contributed to the stagflation of the 1970s and was ultimately reversed at considerable costs. The present forces towards 'illiberal democracy' (an oxymoron in and of itself) represent a trend for which we may pay dearly.

entails much broader benefits. These gray and overlapping zones exist in part because of the unpredictability of innovation itself. Many innovations that brought about the enormous growth in productivity during the course of the 20th century, were the result of a delicate interplay between privately and publicly funded R&D.

Electricity industries are in the midst of technological [r]evolutions, driven by the ongoing innovations in distributed energy resources (DERs) including in storage and micro-grids. These are scale phenomena (else how could they be distributed). That such resources can be successfully integrated into grids is itself a product of another revolution, the information revolution, one that benefited very considerably from public funding.

Contrast innovation in electricity to two other game-changing revolutions – the multi-faceted and ongoing IT and telecom revolution; the other in hydrocarbon extraction, namely fracking.

- The IT/telecom revolutions were facilitated by public spending, e.g., on university research and on military technology. These technologies were adapted and evolved for commercial purposes by private companies. Declining unit costs and new, and very attractive features (mobility and data availability) made regulation less politically challenging. The question was how to stage deregulation in a way that would not create power vacuums and consolidation of disproportionate market power.

- The fracking revolution which first upturned North American natural gas markets, and more recently oil markets, was very much a consequence of private investment in innovation, driven by increasing prices. The potential (i.e., *ex ante*) private benefits to being able to capture cost-effectively these hydrocarbon molecules were enormous. Even after world prices collapsed in 2014 innovation continued, pounding down (and horizontally) shale oil extraction costs.

Electricity markets on the other hand are likely to remain heavily regulated for the foreseeable future, existing assets are long-lived and cost pressures are increasing.[20] This certainly creates a challenge for policy makers and for regulators seeking to support ratepayer funded innovation, especially if the benefits are likely to be spread over multiple years and may not be immediately visible.

Nevertheless, the enormous potential for broader benefits and spill-over effects, even at the geopolitical level (*sic*), as well as the environmental policy imperatives, make a strong case for publicly funded research. In this connection, I do not quibble between ratepayer vs. taxpayer funded support, though this distinction merits a discussion of its own. If anything, we are *under*-investing in electricity-related innovation, and I intend this to include electrification of the transportation sector, by far the hardest 'nut to crack'. Indeed, since the era of deregulation, research expenditures as a share of total revenues of electricity utilities has declined in many jurisdictions.

Utility Led Innovation

The second contention made by the authors is that innovation should be "utility-led". One of the important features of recent developments in electricity industries is the increasing interrelationship between DERs and the grid itself. Efforts to deregulate electricity industries were premised on the proposition that wires were natural monopolies and that generation was amenable to competition. This in turn led to their separation.[21] Whatever economies of scope may have been present in vertical integrations were foregone.

In today's world, there appear to be increasing economies of scope between DERs and the grid because of complex and evolving integration issues. Consider for example storage which can supplant traditional grid investments, provide backup power, reduce the need for capacity investments, improve reliability, facilitate the integration of renewables, and so forth. These

20 See, e.g., D. Dimitropoulos and A. Yatchew, "Is Productivity Growth in Electricity Distribution Negative?" (2017) 38:2 The Energy J 175.

21 A similar separation of pipes and gas supply had proved critical in promoting competition in the natural gas industry.

'multi-product' features of storage imply a very close relationship with the grid, in turn strengthening the argument for utility-led innovation. Arguably, these economies of scope provide an important part of the conceptual basis for the rhetorical question 'who is better positioned than utilities to promote integration and adoption of storage technologies'.

Concluding Comments

A sensible regulatory model applies the principles of incentive regulation to induce innovation itself (such regulatory models exhibit what economists call dynamic efficiency). Historically, the objective was to drive productivity growth. In a world of disruptive technological change, multi-product output and the potential for significant economies of scope, the regulatory tasks of detailed oversight of investment trade-offs, and rates and charges for the various kinds of outputs and services can be overwhelming. Conventional incentive regulation (such as price-caps) needs significant adaptation to accommodate these new realities. Critical to its success is allowing utilities to engage in innovative investments and to be rewarded by the retention of their share of the financial benefits arising therefrom.

The authors of this paper have produced an admirable piece of work, arguing the case for utility-led and ratepayer funded innovation. The fruits of such investments of course need to be shared with ratepayers; this would normally be the case whether the utility is privately or publicly owned, and whether the regulatory model is rate or return, or incentive regulation. An argument could also be made that contributions by taxpayers can be justified on the basis of the broader societal benefits of these innovations. Finally, and in future work, the analysis could be further illuminated by incorporating discussion of other jurisdictions where policy makers seek different mechanisms for promoting innovation. ■

ADDRESSING THE POLICY REGULATORY NEXUS IN CANADA'S ENERGY DECISION-MAKING

*Stephen Bird**

Canada faces serious challenges and crucial decisions when it comes to governing a twenty first century energy system. They are seen in ongoing controversy over siting of wind farms, pipelines, new hydro, and transmission lines; tensions between movement on climate change and other energy objectives like oil sands development, competitiveness and consumer affordability, fracking implementation, and the reform of the National Energy Board, to name but a few. Most industrialized democracies face similar kinds of controversies but Canada's unique energy profile arguably makes these difficulties more challenging.

One of the linchpins of a modern energy system is the relationship between policy-makers and regulators when it comes to public decision-making. This paper broadly assesses the challenges that Canada faces in this area – within, and between, provincial/territorial and federal levels – and explores options for existing systems. It also addresses critical issues that affect and are affected by this relationship, including Indigenous and public involvement, and collaborative processes. It builds on the idea that restructuring our policy and regulatory systems requires *informed reform,* so that Canada can maintain aspects of the system that are effective, while improving areas that need it. The analysis builds on the results of a two-day workshop held in June 2017 at the University of Ottawa which featured a diverse range of senior participants from government, Indigenous organizations, industry, ENGOs, and academia.

This study focuses primarily on the relationships between and roles of policymakers and regulators. In this discussion, policymakers are defined as elected officials from the executive branch and legislature who enact policy, design regulatory agencies, and appoint regulators. They do so with the support of the public service, mainly through government departments.

Alternately, regulation is carried out by regulators (appointed officials) and their agencies, with specialized professional staff. As a general rule they are focused on non-partisan evidentiary proceedings, generally with arm's length independence from the political level. There are wide varieties of regulatory entities across Canada and within jurisdictions in terms of scope, resources, structure, processes, independence, and responsibilities.

The paper is part of the broader *Public Authorities* research stream of the *Positive Energy* project, and is a detailed extension of the *System under Stress* paper released in early 2017. That paper outlines three crucial considerations in Canadian energy decision-making: 1. Who decides? The role of local authorities and how to balance local interests with broader regional, provincial and national interests;[1]

---

* Dr. Stephen Bird is Associate Professor of Political Science at Clarkson University (New York) and Senior Fellow at the Centre on Governance & Research Faculty Affiliate at Positive Energy at the University of Ottawa. Contact: sbird@clarkson.edu.
This paper has benefited from the input of the Positive Energy Research Group; many thanks to Marisa Beck, Mike Cleland, Stewart Fast, Monica Gattinger, Rafael Ponce, and Louis Simard. Thanks also to members of the Positive Energy Advisory Board for their review. I am also grateful to Patricia Larkin and Rafael Dezordi for extensive editing assistance. Finally, this paper is extensively derived from a broader research piece with a similar name available at https://www.uottawa.ca/positive-energy/research-publications. Any errors are the author's.

1 Stewart Fast, *Who Decides? Considering the Roles of Local and Indigenous Authorities in the Canadian Energy Decision-Making System*, System Under Stress, Interim Report #1 (Ottawa: University of Ottawa, 2017), online: <https://www.uottawa.ca/positive-energy/research-publications>.

2. The policy-regulatory nexus (this paper) 3. How to decide? Information, capacity and engagement in decision-making processes (forthcoming).

System under Stress outlines several tension areas when it comes to policy-regulatory relations. First, it identifies the dividing line between policy and regulation in substantive and procedural terms, including the tension between regulatory independence, and the need for communication and interaction between policymakers and regulators. Second, it delineates the governance of regulators by policymakers. Third, it demonstrates the planning challenges that are increasingly emerging between broad policy frameworks and detailed regulatory arrangements. Finally, it points out the lack of clarity on the role and place of Indigenous governments in the policy/regulatory nexus.

The paper is informed by an extensive array of *Positive Energy* engagement and research to date. This includes a major research study undertaken with the Canada West Foundation, a review of key literature, case study references, and expert interviews, and quantitative survey data from four case studies conducted in 2016. It also benefited from extensive input by the Positive Energy research team in consultation with senior leaders from government, industry, Indigenous interests, and ENGOs in review processes and during a two-day workshop in summer 2017. A specific set of eight ***recommendations*** derived from the broader analysis of the paper are embedded in the rest of the executive summary below.

New and Unique Challenges in Energy Governance

There are two critical underlying conditions that dramatically affect any discussion of underlying challenges in the policy-regulatory relationship. First, energy governance is more challenging now than in the past. There is extensive evidence that new challenges have emerged in energy governance. Social and technological changes have created new expectations for regulatory processes. There is greater distrust of government agencies and most institutions. Cumulative effects of different energy activities are increasing. And complex challenges like reconciliation with Indigenous peoples, "wicked problems" such as climate change, and increasing market complexities have come increasingly to the fore.

Studies undertaken by the Organization for Economic Co-operation and Development (OECD), International Monetary Fund (IMF), and World Bank, along with a plethora of scholarly work all attest to further challenges.[2] These include new economic and social concerns embedded in regulatory processes, and the challenge of conflicting mandates like being more responsive to regulated industry yet less vulnerable to external influences.[3] Complexity has also increased in markets, in the legal realm, and in technology. Public opinion data also shows greater distrust of regulators and increased dissatisfaction with decision-making processes. This has led to the beginnings of reform and assessment, including the current National Energy Board modernization process.[4]

Second, energy policymaking and regulation have unique characteristics that make them more politically challenging and complex than many other areas of regulation. Energy operates under a "triple" constraint of market and economic imperatives, environmental protection, and concerns for differing forms of security.[5] Energy markets, for example, vary in type and situation to an enormous degree. They include hybrids of monopoly regulation and pure market competition across the entire supply chain, and throughout all forms of energy supply and infrastructure. Complex and differing subsidies are at play, and some forms of energy (e.g., electricity) must be constantly balanced in real time. Finally, recent

2 Organisation for Economic Co-operation and Development (OECD), *Recommendation of the Council on Regulatory Policy and Governance*, (Paris: OECD, 2012), online: <http://www.oecd.org/governance/regulatory-policy/49990817.pdf>; Organisation for Economic Co-operation and Development (OECD), *'The Governance of Regulators:' OECD Best Practice Principles for Regulatory Policy*, (Paris: OECD, 2014), online: <http://www.keepeek.com/Digital-Asset-Management/oecd/governance/the-governance-of-regulators_9789264209015-en>; World Bank and University of Florida Public Utility Research Center (PURC), "Theories of Regulation" (2012), *Body of Knowledge on Infrastructure Regulation (BoKIR)*, online <http://regulationbodyofknowledge.org/general-concepts/theories-of-regulation/>.
3 Malcolm K Sparrow, *The Regulatory Craft: Controlling Risks, Solving Problems, and Managing Compliance* (Washington, D.C.: Brookings Institution Press, 2000).
4 Environment and Natural Resources Canada, "National Energy Board Modernization" (17 June 2016), *Government of Canada,* online : <https://www.canada.ca/en/services/environment/conservation/assessments/environmental-reviews/national-energy-board-modernization.html>.
5 Robert M. Lawrence and Norman I. Wengert, "The Energy Crisis: Reality or Myth: Preface" (1973) 410 The Annals of the American Academy of Political and Social Science ix–x; John M Deutch, *The Crisis in Energy Policy* (Cambridge, Mass.: Harvard University Press, 2011); Jason Bordoff, "America's Energy Policy - From Independence to Interdependence" (2016) 8 Horizons: J of Intl Relations and Sustainable Development 180.

scholarship and public responses have added a fourth imperative of social acceptance or equity to this complicated set of constraints.[6]

Best Practices

A variety of best practices gleaned from domestic and international practice should be considered in the Canadian context. Policymakers have to *create, design, and fund* strong regulatory agencies, including essential rules for operation.[7] Incorporated into regulatory design is the need to implement many of the best practices summarized below into those structures. Second, policymakers also must conduct oversight of regulators, and third, they must develop policies that guide the actions of regulators. Ideally, policy development is informed by interaction between policymakers and regulators; regulators in turn help inform the policy development process, particularly in areas where their expertise and knowledge of conditions on the ground is useful. Finally, much regulatory development and implementation, while the responsibility of the regulator, has the effect of producing *de facto* policy outcomes.

An important concern in the policy-regulatory relationship is regulatory independence, which is tied to the need for procedural integrity and the adjudication role that regulators perform.[8] While policymakers operate in the political system, responding to a variety of interests and values, regulators are intended to be sheltered from short term and partisan political interests and instead to make decisions in an independent manner using evidence established by technically informed, expert analysis, but following the broad mandates of policies under which they operate, the rule of law, and the public interest.

Concerns over procedural integrity arise when there is political interference during regulatory processes, or when policymakers alter regulatory decisions after the fact. There are parallel concerns for undue influence in regulatory decision-making by outside parties (industry, interest groups), or that lead to the perception or reality of regulatory capture (when a regulator is biased they are said to be captured by industry or interest groups). Objective and independent judgements and processes are critical to successful regulation. The Canadian experience has shown that there are lapses in these areas.[9] All of these concerns occur in a context in which regulators must regularly interact and communicate with government, regulated entities, interested parties, and the public. **R1. Enhance interaction and dialogue between policy-makers and regulators in relevant circumstances and jurisdictions while still maintaining appropriate regulatory independence.**

Governance and Accountability. An extensive scholarly and professional literature body describe the plethora of optimal expectations for governance and accountability that accompany the concern for regulatory independence. The OECD describes many (relatively obvious) best practices, and they are summarized immediately below.[10] Several aspects of these issues are discussed in greater detail later in the paper as well:

• Clear responsibilities for ministers • Clear articulation of policy goals • A national oversight body for regulation • Assessment of regulatory efficacy prior to implementation • Principles of open government: transparency, clarity, participation, public interest, plain language	• Regulatory coherence • Integration of regulatory approaches across jurisdictions, and across jurisdictional levels (national, provincial, regional, local) • Information sharing across agencies, and between all levels of government and regulators

6 Monica Gattinger, "Canada–United States Energy Relations: Making a MESS of Energy Policy " (2012) 42:4 American Review of Canadian Studies 460, online: <https://doi.org/10.1080/02722011.2012.732331>.
7 *OECD, Recommendation of the Council on Regulatory Policy and Governance, supra* note 2.
8 Geoff Edwards and Leonard Waverman, "The Effects of Public Ownership and Regulatory Independence on Regulatory Outcomes" (2006) 29:1 J of Regulatory Economics 23, online: <https://doi.org/10.1007/s11149-005-5125-x>; Louis Simard, "Effets et Évolution Des Instruments D'action Publique Participatifs: Le Cas de La Régie de L'énergie" (2014) 47:1 Canadian J of Political Science 159.
9 Michael Cleland et al, "A Matter of Trust: The Role of Communities in Energy Decision-Making" (2016) 4:4 Energy Regulation Q, online: <http://www.energyregulationquarterly.ca/articles/a-matter-of-trust-the-role-of-communities-in-energy-decision-making>.
10 *OECD, Recommendation of the Council on Regulatory Policy and Governance, supra* note 2.

Good governance requires clarity. Policymakers and ministries need clear and well-articulated responsibilities. Policy goals and policies need a degree of intelligibility and detail so that regulation is appropriately guided. This has been particularly problematic in terms of clear national energy policy. Even when energy policies exist in Canada (and similarly in the U.S.), they are notoriously limited in their scope (for example, provincial energy policies are often limited to electricity systems) and often suffer from lack of clarity or internal coherence. Second, detailed policy on controversial issues is often avoided by policymakers. Thus, detailed specifics on *how* Canada will balance climate obligations and other pivotal energy objectives such as fossil fuel development, sustainable development, energy affordability and consumer equity, are still vague. Similarly, little clarity exists on how national public benefits of energy development can be balanced against burdens on local communities. **R2. Integrate detailed policy goals (with market mechanisms) into the regulatory process**.

The OECD also suggests that a quasi-independent body designed to oversee, assess, and guide regulatory practices across the federal and sub-federal levels be put in place. Such an agency would presumably provide reports on regulatory effectiveness, best practices, and activities throughout a jurisdiction. It would also address regulatory coherence across jurisdictions, and across regulatory agencies.

The structure itself of regulatory agencies can be designed to strengthen impartiality. This can include guidelines for board representation, or threshold limits or requirements in terms of industry, environmental, consumer interests, diverse ideological representation, etc., to ensure balance, with an emphasis on scientific expertise. There is a compelling case for stronger coordination, sharing, and the development of guidelines that reflect Canadian circumstances; and for vigorous projection of those principles into the public debate in Canada. **R3. Implement ongoing ex ante and ex post assessment of regulations, regulatory design, institutional design, and regulatory effectiveness. The implementation of institutions or formal mechanisms to do so would strengthen this process.**[11]

The 6 c's: Communication, Coherence, Comprehensiveness, Cumulativeness, Capacity, Collaboration. Further best practices focus on *The 6 c's*. Two of these (Communication, Collaboration) have critical relevance for Canada.

One of the most critical components of the policy-regulatory relations is interaction and exchange of information. In the absence of strong communication, poor regulation can result, processes can become biased or incomplete, and the public can lose trust. Communication has many manifestations:

1) Policymakers must communicate clear policy goals to regulators.

2) Interaction between regulators and policymakers should occur on a regular basis.

3) Regulators need to correspond with other regulators.

4) Policymakers and regulators need to effectively exchange accessible and pertinent information with the public and all relevant stakeholders in their processes.

R4. Provide improved and effective information and communication of regulatory oversight, responsibility, and process to the public. Ensure this is occurring with (and between) policymakers, regulators, and developers.

The literature also argues for regulatory coherence: differing regulatory agencies and different jurisdictions (federal-provincial; province to province) should be governed by policies that achieve some level of integration, harmonization, or coordination. This is not the same as uniformity, which is neither possible nor desirable, especially in the context of federalism, but is an argument for the consideration of regulatory interactions across the context of different kinds of markets, and different provinces. **R5. Develop a stronger commitment to cross institutional and cross jurisdiction regulatory coherence**.

Both policymakers and regulators face a need

11 In Canada the Canadian Association of Members of Public Utility Tribunals (CAMPUT) does this to some degree, but it only addresses some forms of regulation, a broader approach is needed.

for policy direction and regulatory processes that are comprehensive and cumulative. Policies need to address all areas of concern, and must include regulatory oversight when it comes to the regulatory impact of a given policy or a specific form or area of development.[12] For example, in the context of siting major projects, these can include all aspects of environmental impacts (air, soil, health, toxics, viewshed, resource use, etc.), community impacts, safety, future risk, remediation, community and social cohesion or quality, economic benefits and impacts, including on competitiveness, investment and innovation, and cumulative impacts and risks from multiple projects.[13] **R6. Ensure regulatory oversight is both comprehensive and cumulative, while still balancing local impacts with a commitment to economic efficiency and public good outcomes.**

Finally, with respect to capacity, there is a need for an appropriate level of support for effective Regulation. This means that policymakers and government are effectively training, supporting, and funding regulatory institutions such that they can perform their work with expertise and in a timely way. **R7. Ensure regulatory institutions have appropriate capacity: funding, and access to high levels of human capital and expertise to regulate effectively.**

Unique Challenges and Next Practices

Canada faces a number of unique challenges in its energy decision-making:

1. linear projects
2. Indigenous authority
3. policy clarity
4. public understanding

Two of these concerns, linear projects and indigenous rights, are of particular concern to Canada. Canada's geographic size and the remote location of large scale hydro and fossil fuel projects mean that long run linear projects may occur more often in Canada, and are a cornerstone in the success of the energy system.

Second, indigenous rights have a unique place in Canada because of recent Court rulings affirming treaty obligations and higher levels of input and consideration. These rights are even more important given the hundreds of indigenous authorities in Canada and the fact that so many energy resources and infrastructure are found on or under, or traverse native lands. Several of the 'c's direct us to *next practices* that can help to address them (communication, clarity, and collaboration).

Linear projects such as transmission lines or pipelines are a challenge because they cover so many jurisdictions and communities, and because it is rare that benefits can accrue to every community whose land they cross.[14] Canada's specific geography and energy economy context mean that it has more than its share of these concerns. They require careful consideration of the balance between national need and local, regional, or provincial interests. A variety of innovative approaches have been used with some success and should be considered both in Canada (and abroad) for linear projects. These include the designation of transmission corridors, backstop siting authority, partnership approaches, and focused, early, comprehensive engagement. Clear guidelines from policymakers are needed for these forms of infrastructure.

Indigenous Authorities and rights in Canada are complex. They are far stronger than in the past, include unique legal protections and considerations, and to further challenge decision systems, are highly variable across

12 Riki Therivel and Bill Ross, "Cumulative Effects Assessment: Does Scale Matter?" (2007) 27:5 Environmental Impact Assessment Rev, Special issue on Data Scale Issues for SEA 365, online: <https://doi.org/10.1016/j.eiar.2007.02.001>; William A. Ross, "Cumulative Effects Assessment: Learning from Canadian Case Studies" (1998) 16:4 Impact Assessment and Project Appraisal 267, online: <https://doi.org/10.1080/14615517.1998.10600137>.

13 John Glasson, Riki Therivel, and Andrew Chadwick, *Introduction to Environmental Impact Assessment* (London; New York: Routledge, 2012); Bram F Noble, *Introduction to Environmental Impact Assessment: A Guide to Principles and Practice* (New York, NY: Oxford University Press, 2015).

14 Shalini P. Vajjhala and Paul S. Fischbeck, "Quantifying Siting Difficulty: A Case Study of US Transmission Line Siting" (2007) 35:1 Energy Policy 650, online: <https://doi.org/10.1016/jenpol.2005.12.026>; Christopher Groves, Max Munday, and Natalia Yakovleva, "Fighting the Pipe: Neoliberal Governance and Barriers to Effective Community Participation in Energy Infrastructure Planning" (2013) 31:2 Environment and Planning C: Government and Policy 340, online: <https://doi.org/10.1068/c11331r>.

the country.[15] In some cases, a communities' legal status creates tensions with traditional notions of the policy-regulatory relationship. Policymakers need to more explicitly consider Indigenous rights in regulatory design and operation, including *next practices* forms of regulatory governance (e.g., joint reviews, co-development and co-management, or partnerships).

Public Understanding and Trust. Public understanding of the regulatory process is poor, there are higher degrees of skepticism about its validity, and increased distrust of government. These create a toxic mix for the regulatory process. Public dissatisfaction can occur if regulatory processes are faulty, if it seems that decision-making occurs in the political arena, or if the public misunderstands where their concerns should be expressed. Findings from recent Positive Energy/Canada West Foundation case studies of community satisfaction with energy project decision-making show high levels of distrust and concern about the independence of regulatory processes.[16] Thus, there is an opportunity for regulators and policymakers to initiate *next practices* that more effectively communicate how and what they do, and to identify and strengthen practices to increase trust.

Collaborative Processes, with Limits. There is likely an important role for collaborative processes that veer from traditional regulator roles that simply arbitrate. Extensive evidence suggests that these processes can improve chances for more positive outcomes with a higher degree of stakeholder and public approval if well designed and managed.[17]

Examples of these processes include the co-development of regulations, co-management of monitoring, the encouragement of cooperative partnerships, impact benefit agreements, or community co-production with developers. These practices can be used in a variety of contexts, whether it be a project approval, electricity system planning, or ongoing monitoring of company operations. Importantly, they still require timelines, and though they may improve processes and satisfaction, they will not always satisfy all parties, or may still result in a "no" to a specific infrastructure development.

R8. Develop more fluid, interactive, and collaborative processes (that require more time, resources, and expertise) to address particularly challenging areas of energy governance: linear projects, indigenous jurisdictions, national policy clarity, and reduced public trust and understanding.[18]

Conclusion

Clearly Canada has an effective and robust system of energy governance, but there are areas of concern, particularly in an era of great challenge in the energy arena. In particular, Canada needs to focus on high quality

15 Joel Krupa, Lindsay Galbraith, and Sarah Burch, "Participatory and Multi-Level Governance: Applications to Aboriginal Renewable Energy Projects" (2015) 20:1 Local Environment 81, online: <https://doi.org/10.1080/13549839.2013.818956>; Alastair R. Lucas and Chidinma B. Thompson, "Infrastructure, Governance and Global Energy Futures: Regulating the Oil Sands Pipelines" (2016) 28:3 J of Environmental L & Practice; Scarborough 355; Holly L. Gardner, Denis Kirchhoff, and Leonard J. Tsuji, "The Streamlining of the Kabinakagami River Hydroelectric Project Environmental Assessment: What Is the' Duty to Consult' with Other Impacted Aboriginal Communities When the Co-Proponent of the Project Is an Aboriginal Community?" (2015) 6:3 Intl Indigenous Policy J, online: <http://search.proquest.com/openview/f7456276ae0438b2f9bb90881bf9b129/1?pq-origsite=gscholar&cbl=1996357>.

16 Michael Cleland et al, "A Matter of Trust: The Role of Communities in Energy Decision-Making" (Ottawa, Canada: University of Ottawa & Canada West Foundation, 2016), online: <https://www.uottawa.ca/positive-energy/research-publications>.

17 Laura Nourallah, "Communities in Perspective: Literature Review of the Dimensions of Social Acceptance for Energy Development and the Role of Trust" (Ottawa, Canada: University of Ottawa, April 2016), online: <http://www.uottawa.ca/positive-energy/sites/www.uottawa.ca.positive-energy/files/positive_energy-community_social_acceptance_literature_review_0.pdf>; Lawrence Susskind, Sarah McKearnan, and Jennifer Thomas-Larmer, *The Consensus-Building Handbook: A Comprehensive Guide to Reaching Agreement* (Thousand Oaks CA: Sage Publications, 1999); Margreet A. Frieling, Siegwart M. Lindenberg, and Frans N. Stokman, "Collaborative Communities Through Coproduction Two Case Studies," (2014) 44:1 The American Rev of Public Administration 35, online: <https://doi.org/10.1177/0275074012456897>; Liesbet Hooghe and Gary Marks, "Unraveling the Central State, but How? Types of Multi-Level Governance" (2003) 97:2 The American Political Science Rev 233; Michael Howlett, "Governance Modes, Policy Regimes and Operational Plans: A Multi-Level Nested Model of Policy Instrument Choice and Policy Design" (2009) 42:1 Policy Sciences 73.

18 Further discussion of the specifics of these processes are available in the third report from the Public Authorities research stream: "How to Decide? Engagement, Information, and Capacity, which is forthcoming from Positive Energy."

institutions across the regulatory policy nexus. The following recommendations demonstrate a series of actions that provinces and the federal government could take to improve on the policy and regulatory relationship, and the various contexts that are affected by it.

1. Enhance interaction and dialogue between policy-makers and regulators in relevant circumstances and jurisdictions while still maintaining appropriate regulatory independence.
2. Integrate detailed policy goals (with market mechanisms) into the regulatory process.
3. Implement ongoing ex ante and ex post assessment of regulations, regulatory design, institutional design, and regulatory effectiveness. The implementation of institutions or formal mechanisms to do so would strengthen this process.
4. Provide improved and effective information and communication of regulatory oversight, responsibility, and process to the public. Ensure this is occurring with (and between) policymakers, regulators, and developers.
5. Develop a stronger commitment to cross institutional and cross jurisdiction regulatory coherence.
6. Ensure regulatory oversight is both comprehensive and cumulative, while still balancing local impacts with a commitment to economic efficiency and public good outcomes.
7. Ensure regulatory institutions have appropriate capacity: funding, and access to high levels of human capital and expertise to regulate effectively.
8. Develop more fluid, interactive, and collaborative processes (that require more time, resources, and expertise) to address particularly challenging areas of energy governance: linear projects, indigenous jurisdictions, national policy clarity, and reduced public trust and understanding.

Canada has a strong tradition of sound policymaking and regulation, but recent stresses in energy decision-making systems point to the growing need for reform. This includes, importantly, the relationship between policymakers and regulators. The challenges in the Canadian context are extensive, but if sufficient investment is made in processes of "informed reform," the prospects for improving the energy decision-making landscape, particularly when it comes to the public authorities who oversee it, can bring extensive benefits to Canada along all energy imperatives: economic, environmental, security, and social acceptability. The recommendations are oriented in this direction. ■