ENERGY REGULATION QUARTERLY

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MISSION STATEMENT

The mission of Energy Regulation Quarterly (ERQ) is to provide a forum for debate and discussion on issues surrounding the regulated energy industries in Canada, including decisions of regulatory tribunals, related legislative and policy actions and initiatives and actions by regulated companies and stakeholders. The ERQ 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 ERQ will express their independent views on the issues.

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

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

The ERQ will maintain a "roster" of contributors and supporters who have been invited by the managing editors to lend their names and their contributions to the publication. Individuals on the roster may be invited by the managing editors to author articles on particular topics or they may propose contributions at their own initiative. 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 ERQ invites readers to offer commentary on published articles and invites contributors to offer rebuttals where appropriate. Commentaries and rebuttals will be posted on the Energy Regulation Quarterly website (www.energyregulationquarterly.ca).

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EDITORIAL

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

Restructuring of the Alberta electrical power market, which began in the late 1990s, continues to evolve. In the lead article in this issue of *Energy Regulation Quarterly*, "A Tale of Two Market Designs: What's New in Alberta", Bob Heggie discusses the current initiative to reshape the role of market forces in the wholesale electricity market through the introduction of an administered capacity market, while the Alberta Utilities Commission is examining whether and how market forces can be brought to bear in the, traditionally monopolistic, distribution infrastructure function. Central to the exercise is the perennial question in economic regulation: which functional elements of the system can be turned over to competitive markets and which should be regarded as monopoly functions? Heggie concludes that, somewhat paradoxically, "the evolution in Alberta is moving to introduce more central control in what was once an inherently competitive function, while potentially introducing competitive forces into what was an inherently monopoly function."

The challenge of getting government's role right in the governance of the electricity sector is also the subject of Robert Warren's article on "The Avista and East-West Tie Cases, and Their Implications for the Governance of the Electricity Sector in Ontario." Warren suggests these two cases[1] "have highlighted a serious weakness in the governance of the electricity sector in Ontario [and] illustrate not just the immediate adverse effects of Government interference in specific matters but the deeper damage the Government's role does to governance of the sector as a whole."

Meanwhile, the day-to-day regulation of the electricity sector continues. In "OEB Takes Steps Towards Implementing 'Activity and Program Based Benchmarking", David Stevens reviews the Ontario Energy Board's recently-released Discussion Paper. He notes that, while the Discussion Paper itself is confined to the application of the APB approach to electricity distributors, the OEB plans to implement APB for all regulated utilities, including gas distributors.

In "Inconsistent with the Public Interest: FERC's Three Decades of Deference to Electricity Consolidation", Scott Hempling questions the Federal Energy Regulatory Commission's approach to the approval of mergers and acquisitions of retail electric utilities in the U.S., noting that the number of independent retail electric utilities has been cut by more than half since the mid-1980s. While the FERC is required by statute to find consolidating transactions to be "consistent with the public interest", FERC's orders in fact require only "no harm". Hempling questions whether this is the correct standard, suggesting that, consistent with the public interest standard, perhaps more emphasis should be placed on whether the relevant markets resulting from consolidating transactions are "effectively competitive markets."

Ever since the closing decades of the last century, energy markets have been characterized by fundamental structural changes, technical innovation and other dynamic changes. In his article on "How Scalability is Transforming Energy Industries", Adonis Yathcew observes that, for much of the 20th century, the dominant force shaping the structure of the energy industries was "increasing scale economies". In the 21st century, the trend has been reversed, towards "scalability". For example, in Yatchew's view, OPEC's ability to influence prices has been undermined, not so much because fracking has opened up new supplies, but because reductions

[1] The Avista case was analyzed from a U.S. perspective by Scott Hempling in the last issue of *Energy Regulation Quarterly*, "Merger Rejected: Common Sense from Washingtom", (March 2019) 7:1 Energy Reg Q, online: <http://www.energyregulationquarterly.ca/articles/merger-rejected-common-sense-from-washington#sthash.ZAZASioQ.dpbs>.

in supply by OPEC members are met with reciprocal increases from shale sources – shale production can be scaled to offset reductions in supply from other sources. "In electricity industries, *highly scalable* distributed energy resources, such as wind, solar and storage continue to experience rapid declines in costs." Yatchew identifies the regulatory, institutional and legal issues that arise, such as "the potential for impaired or stranded assets, supply reliability (e.g., through capacity markets), tariff evolution, and cost challenges."

The significant shortfall in Canadian oil pipeline capacity continues to have immediate, serious and identifiable repercussions – for industry, government revenues and investor confidence, with implications for the longer term growth of the domestic oil industry. The obvious solution – adding capacity – will not be available in the short-term, as each of three major oil pipeline projects (Trans Mountain Expansion, Enbridge Line 3 Replacement and KXL) continue to face various legal, regulatory and permitting delays. In November, 2018 the Minister of Natural Resources asked the National Energy Board for advice on what might be done in the meantime to optimize the use of current pipeline capacity. In its report in March, titled "Optimizing Oil Pipeline and Rail Capacity out of Western Canada", the Board noted that pipelines are currently operating "at full capacity [and that any] notable increase in throughput would have to come from new capacity additions." The Board did, however, offer some suggestions for non-regulatory steps that might be taken in the meantime to improve the process for nominating for capacity. Rowland Harrison, one of our Co-Managing Editors comments.

The current constraints on oil pipeline capacity, and the direct implications for the current and future development of the Alberta oil sands, are of course the subject of almost daily news reports and commentary. Three books have resulted, the most recent of which, *THE PATCH: The People, Pipelines, and Politics of the Oil Sands* by Chris Turner, is reviewed by Rowland Harrison.[2] Harrison concludes that *THE PATCH*, which won the 2018 National Business Book Award, "is an extremely valuable contribution to the existential debate that will almost certainly continue in Canada for the foreseeable future." ■

[2] See also McConaghy, "Dysfunction: Canada after Keystone XL", reviewed (June 2017) 5:2 Energy Reg Q, online: <http://www.energyregulationquarterly.ca/book-reviews/dysfunction-canada-after-keystone-xl-dennis-mcconaghy-dundurn-toronto-2017#sthash.qzPJLaF0.dpbs>; and Poitras, "Pipe Dreams: The Fight for Canada's Energy Future", reviewed (December 2018) 6:4 Energy Reg Q, online: < http://www.energyregulationquarterly.ca/book-reviews/pipe-dreams-the-fight-for-canadas-energy-future#sthash.l0mQg50f.dpbs>.

A TALE OF TWO MARKET DESIGNS: WHAT'S NEW IN ALBERTA

Bob Heggie

INTRODUCTION

Alberta was the first Canadian jurisdiction to implement a restructured electrical power market. Structuring the electricity sector for competition led to policy determinations and reforms that unbundled generation and retailing functions and turned them over to competitive markets. Other aspects of the sector were kept as monopoly functions, particularly the transmission and distribution systems.

For a variety of reasons that will be discussed below, Alberta is reshaping the role of market forces in the wholesale electricity market through the introduction of an administered capacity market, while the Alberta Utilities Commission (AUC) is examining whether and how market forces can be brought to bear in the, traditionally monopolistic, distribution infrastructure function.

CONTEXT

Electricity involves many complex functions that can theoretically be kept as monopolies or turned over to competitive forces. Virtually any of the functions, even those with clear monopoly characteristics, could be turned over to competition.

Forcing competition in a natural monopoly function however can be costly as the economies of scale and scope that define reasonably efficient infrastructure monopolies could be lost and replaced by duplicative and inefficient competitors.

The promise of turning functions over to competitive markets is that, by having private investors, rather than governments or regulators, determine investment and resource decisions and take the associated commercial risk, efficiencies will be gained and consumer costs reduced. While planning, including technology choice, is left to the market, key inputs to those decisions are still required from the regulator, such as the value of reliability (the energy price cap) or the amount of reliability needed (the capacity procurement volume).

Non-market structures operate differently. All of the complexity of operating, planning and coordinating the electric system is left with monopoly providers. Investors are insulated from investment revenue risk through durable, frequent rate reviews and return awards.

INTRODUCTION OF A CAPACITY MARKET

Since the mid 90's, Alberta has stood alone in consistently pursuing a competitive wholesale market through an "energy only" market design. In energy only markets, generators are only paid for the actual electricity sold in the wholesale or ancillary services markets. There is no payment for having their capacity available to supply electricity.

Although there have been some refinements, the energy only market design has remained relatively stable with the consensus view that investors were financially willing and able to build new generation capacity. Simply put, the energy only market design provided sufficient revenue certainty or upside potential to attract investment.

Similarly, the transmission and distribution functions, with limited exceptions, have largely remained as natural monopolies. The Alberta Electric System Operator (AESO) has, on a limited basis, introduced competitive forces through the use of competitive procurement for transmission projects.

With the election of the NDP government in 2015, a new policy objective for the electricity sector emerged. Achieving a lower-carbon sustainable electricity system is now policy.

Specific measures to achieve this objective were included in the Climate Leadership Plan (CLP), announced in November 2015. The CLP contains policy measures that will have a substantial impact on Alberta's mix of generation supply by 2030, as emissions from coal units are eliminated and significant amounts of renewable generation are added.

This changing supply mix will materially impact electricity market dynamics and, in turn, the ability of the energy only market structure to continue to deliver on the objectives of reliability and reasonable cost, in the long run.

As a result, in 2016 the AESO recommended to government that Alberta would be best served by the addition of a capacity market. A capacity market was determined to be the change required to ensure objectives were met, in particular because the market design will ensure reliability and specifically compensate investors for firm generation through a more stable revenue stream.

The evolved market design will include three markets: capacity, energy and ancillary services. In this new system the AESO, a government appointed entity, will determine and procure the capacity required to meet expected demand. By purchasing capacity ahead of delivery, consumers take on short term forecast risk. By paying suppliers for capacity to ensure they are in place if needed, rather than only when needed, for equivalent levels of reliability, consumers pay and suppliers receive a more stable revenue stream that potentially reduces risk premiums and thus consumer cost. The nature of the capacity arrangements can also be leveraged to address market power concerns.

Various legislative and regulatory changes were enacted to enable this market transition, including Bill 13 which amended the *Electric Utilities Act*[1] and the *Capacity Market Regulation*[2], passed in December 2018.

In this new regulatory process, the AESO applies to the AUC for provisional approval of the rules required to implement and operate the capacity market. The capacity market rules will be developed in two stages. First, a set of provisional rules essential for the AESO to implement and operate the first capacity market auction will be reviewed by the AUC, with a decision due by July 31, 2019. The goal is to have the preparation for first auction beginning in late 2019 and a subsequent auction in mid-2020.

Additionally, the AUC must consider and decide on the first set of rules under its normal process no later than 18 months from July 31, 2019.

The two stage process will allow for a complete examination of the capacity market rules that might not have been afforded due to time constraints in the initial provisional rule proceeding.

The AUC's public hearing to consider the provisional rules is scheduled to commence April 22 and conclude on June 7.

On April 16 the United Conservative Party led by Jason Kenny won a majority government, resulting in a change from the previous New Democratic Party government led by Premier Notley. The UCP is expected to advance a number of changes to the energy sector and power market and, in particular, intends to consult on whether Alberta should return to an energy only market or create a capacity market – reporting back to Albertans within 90 days.

The movement to directly procure the amount of capacity needed in a capacity market reduces reliance on competitive forces to guide the timing of market entry. The decision to introduce a capacity market design in conjunction with the "low carbon policy" structure was driven by the uncertainty that the pure "energy-only market "approach would deliver sufficient revenue certainty and supply adequacy at reasonable cost while accommodating climate change objectives.

COMPETITION IN A MONOPOLY FUNCTION?

While the Alberta government moves to regain some control in the wholesale generation sector, the potential introduction of market forces in the monopoly distribution system function is being contemplated by the AUC.

Spurred by advancements in technology, including advances in energy efficiency, demand

[1] *Electric Utilities Act,* SA 2003, c E-5.1.

[2] *Capacity Market Regulation,* Alta Reg 260/2018.

response, distributed energy resources and energy storage, among others, the AUC has spearheaded a proceeding to comprehensively assess the implications this modernization march will have for the Alberta distribution grid.

The regulator is interested in understanding how the potential changes to the distribution system could impact rate and market structures.

Historically, the AUC has seen new technology introduced, but it has been largely reviewed on a piecemeal basis through various one off applications. Rather than reviewing technologies on a siloed basis, the inquiry will assess the potential for new technologies, whether and how competitive markets could deliver those technologies to consumers and whether current rate structures will need to evolve to support the technology transition.

The AUC inquiry announced late last year, and further delineated and scoped on March 29, 2019, is intended to better understand and seek advice on how these potential new investments and operating changes will impact the traditional regulatory approach, including, grid planning, rate structures, cost recovery mechanisms and incentives, among others.

Interestingly, the Commission has expanded the original scope of the inquiry from an examination of the electric distribution grid alone to include an examination of impacts on the natural gas distribution grid.

The inquiry has been divided into three modules: an examination of technology, an examination of delivery models and market structures and lastly, implications for rate structures. The AUC will complete the first module in the fall of 2019, and expects to issue its inquiry report in early 2020.

Importantly, the Commission will not be making any final determinations in this process. Rather, the work will lead to a series of future proceedings to consider changes to the utilities' rate structures, rate designs and terms of service.

CONCLUSION

The electricity system in Alberta is evolving. Key to the evolution is understanding which functional elements of the system can be turned over to competitive markets and which should be regarded as monopoly functions. Somewhat paradoxically, the evolution in Alberta is moving to introduce more central control in what was once an inherently competitive function, while potentially introducing competitive forces into what was an inherently monopoly function. ■

THE AVISTA AND EAST-WEST TIE CASES, AND THEIR IMPLICATIONS FOR THE GOVERNANCE OF THE ELECTRICITY SECTOR IN ONTARIO

*Robert B. Warren**

INTRODUCTION

Two recent cases have highlighted a serious weakness in the governance of the electricity sector in Ontario. The cases illustrate not just the immediate adverse effects of Government interference in specific matters but the deeper damage the Government's role does to governance of the sector as a whole.

The first case involves the denial by state regulatory authorities in the United States of the attempt by Hydro One Limited ("Hydro One") to acquire the shares of Avista Corporation ("Avista"), (referred to hereinafter as the "Avista Case"). The second case is the Province's intervention in the applications to the Ontario Energy Board ("OEB") for approval of leave-to-construct ("LTC") a transmission line in northwestern Ontario (referred to hereinafter as the "East-West Tie" or "EWT" case).

The two cases differ superficially but are similar in one critical respect. In the Avista case, the Province did not intervene directly to affect the outcome of the state's regulatory process; rather, it imposed the governance arrangements on Hydro One, arrangements which led the State of Washington's Washington Utilities and Transportation Commission ("WUTC") to deny approval of the proposed acquisition. In the EWT case, the Province intervened directly to dictate the result of the OEB's regulatory process.

What the two cases have in common is the provincial Government's interference in the governance of the electricity sector, in one case as a shareholder of Hydro One and in the other case as a Government exercising directive power. In both cases, the Government interference had adverse financial impacts. In the Avista case, Hydro One must pay a break-up fee of $103 million as a result of the denial of approval of the acquisition. In the EWT case, the result may be an increase in the range of at least $100 to $125 million to the cost of the transmission line.

But the adverse financial implications of the Government's actions, while important, may be less significant in the long run than the implications of those actions for the governance of the electricity sector in Ontario and for the protection of ratepayer interests. By its actions in the Avista case, the Government has affected shareholder rights and interests in ways which bring the reputation of the Province as a secure place in which to invest into disrepute and so may have long-term implications for investment in the electricity sector. By interfering in the EWT case, the Government has, among other things, undermined the independence of the Ontario Energy Board ("OEB") and the integrity of the regulatory system. That, in turn, may have adverse implications for investment in the sector.

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* Robert Warren is a partner in the law firm of WeirFoulds LLP. He was counsel to Hydro One Networks Inc. in the East-West Tie case discussed in this paper. The views expressed in this paper are entirely his own.

This paper is divided into the following sections:

1. In the first, I describe the Avista and EWT cases;

2. In the second, I set out the principles which I suggest should apply to governance in the electricity sector and why adherence to those principles is important;

3. In the third, I discuss the governance of the electricity sector and what the Avista and EWT cases say about the present state of governance in the sector; and

4. In the final section I discuss the changes in the governance of the electricity sector required to protect the interests of ratepayers and the reputation of both the Province and the electricity sector as places in which to invest.

I. THE AVISTA AND EWT CASES

(A) The Avista Case

Before considering the Avista transaction and its regulatory treatment, it is necessary to provide background to the ownership structure and governance arrangements for Hydro One.

i. The Governance Structure of Hydro One

Hydro One is a corporation formed under the *Ontario Business Corporations Act* whose sole shareholder used to be the Ontario Government. In 2015 the then-Liberal Government decided to sell a portion of its interest in Hydro One. The stated reasons for doing so were, first, to use the revenue generated from the sale to finance infrastructure improvements and, second, to in the words of the Governance Agreement between Hydro One and the Government, "strengthen the long-term performance of Hydro One".[1]

The decision by the Government to sell a portion of its interest in Hydro One was controversial. There were two main lines of criticism, offered by the then opposition parties, among others. The first was that the sale would deprive the Province of an ongoing stream of revenue, a stream that would in the long-term be more valuable that the immediate capital gain. This criticism, simply put, was that the sale made no economic sense: a government that could borrow money at less than 3 per cent should not sell an asset that consistently earned more than 10 per cent in order to invest in new infrastructure. In proceeding with the sale, the government in effect ignored this line of criticism. I will return to this point below.

The second line of criticism was that the loss of Government control over Hydro One would subject ratepayers to the risk of rate increases.[2] The Government asserted, correctly in my view, that this latter line of argument had no factual foundation as Hydro One's rates were set by the OEB, notionally an independent regulator.[3]

In an attempt to mitigate the criticism that owning less than 100 per cent of the shares of Hydro One would somehow put Ontario ratepayers at risk, the Government put in place a mechanism by which it would retain a measure of control over Hydro One after the sale.

The mechanism chosen by the Government was the Governance Agreement between Hydro One and the Government. While the Government owned only approximately 47 per cent of the shares of Hydro One, and had the right to appoint only 40 per cent of the members of the board of directors, the Governance Agreement permitted the Government to require that the entire board be replaced.[4]

The Governance Agreement served two, fundamentally contradictory, purposes. On the one hand, it was to provide the public with assurance that, even though the Government owned only 47 per cent of Hydro One shares, it

[1] Governance Agreement between Hydro One Limited and her Majesty the Queen in Right of Ontario, 5 November 2015, Recitals, Section A ["Governance Agreement"].

[2] See, for example, article by Andrea Horwath, the leader of the *Ontario New Democratic Party*, Toronto Star, April 15, 2015.

[3] See, for example, Canadian Press article dated April 20, 2015, citing Premier Kathleen Wynne.

[4] *Supra* note 1, Governance Agreement, s 4.7.1.

could exercise a measure of control over Hydro One's actions through the power to affect a change in the board of directors. On the other hand, the Governance Agreement was intended to assure investors that Hydro One was, as the WUTC was itself assured, "fully in charge of its own affairs".[5]

Three sections of the Governance Agreement serve to illustrate these contradictory purposes. Section 2.1 of the Governance Agreement set out the "Governance Principles" which included the following:

> "2.1.3 The Province shall, with respect to its ownership interest in Hydro One, engage in the business and affairs of Hydro One and the Hydro One Entities as an investor and not as a manager."[6]

Section 2.3 of the Governance Agreement provides that included in the matters for which the Board of Hydro One is responsible and in respect of which it has full authority are:

> the appointment, termination, supervision and compensation of the CEO, the Chief Financial Officer and the other senior officers of Hydro One" and the "remuneration of directors.[7]

In contrast, section 4.7.1 permitted the Government to require Hydro One to hold a shareholders' meeting for the purpose of removing all of the directors.[8] This power is at odds with the concept, set out in the sections cited above, that the Government is a mere shareholder and that Hydro One is an independent, privately-owned Corporation not managed or directed by the Province.

ii. The Proposed Acquisition of Avista

The proposed transaction between Avista and Hydro One would have had Hydro One, acting through a wholly-owned subsidiary, Olympus Equity LLC, enter into an agreement to acquire all of the outstanding common stock of Avista. Had the transaction gone through, Avista would become an indirect, wholly-owned subsidiary of Hydro One.

The WUTC, relying on the evidence provided to it by Hydro One, stated that:

> Throughout this proceeding, we received repeated assurances from Hydro One's witnesses that despite the province's large ownership share, Hydro One is a private, publicly traded corporation, fully in charge of its own affairs with the direction of an independent board of directors. We received assurances that the Province of Ontario would not interfere in the direction and management of Hydro One.[9]

Those assurances were based, in substantial measure, on the provisions of the Governance Agreement.

The transaction required approval of the state regulators in the states where Avista operated.[10] As noted above, for the purpose of this analysis I focus on the regulatory decision in only one of those states, Washington.

In determining whether to approve the transaction, the WUTC applied two tests. The first was whether the transaction provided a net benefit to Avista's customers. The second was whether the transaction was consistent with the public interest.[11]

As noted above, Hydro One provided evidence to the WUTC to mitigate the perception that the Province's 47 per cent ownership of Hydro One's shares posed a risk to Avista and its customers. The core of that evidence was that Hydro One was protected from political interference by the terms of the Governance Agreement.

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[5] US, *Final Order Denying Joint Application for Transfer of Property,* Docket U-170970 Washington Utilities and Transportation Commission, Wash, 5 December 2018, at 17 ["WUTC Decision"].

[6] *Supra* note 1, s 2.1.3.

[7] *Ibid*, s 2.3.

[8] *Ibid*, s 4.7.1.

[9] *Supra* note 5, WUTC Decision, at 17.

[10] Avista operates in the states of Washington, Idaho, Montana, Oregon, and Alaska.

[11] *Supra* note 5, WUTC Decision, at 6.

Notwithstanding the assurances of the Ontario Government and the provisions of the Governance Agreement, the WUTC learned, through press reports and after the hearing for approval of the transaction had ended but before a decision had been rendered, of the decision of the new Conservative Government to interfere in the governance of Hydro One. The WUTC referred to a letter agreement, dated July 11, 2018[12], between Hydro One and the Ontario Government whereby the CEO of Hydro One would be removed immediately and the entire Hydro One board removed and replaced on August 15, 2018. The WUTC also referred to press reports about the Conservative party's promise that, if elected, it would reduce Hydro One's rates by 12 per cent.[13] Finally, the WUTC referred to Bill 2, the legislation that, among other things, allowed the Government to set the compensation for Hydro One executives.[14]

The WUTC described these "developing facts" as having "undermined more or less completely assurances we had been given earlier concerning the potential risks associated with the large ownership interest in Hydro One retained by the Province of Ontario".[15]

Based on this information about the actions and proposed actions of the new Government, the WUTC reopened the record to receive additional evidence. Hydro One provided additional evidence in an attempt to persuade the WUTC that, notwithstanding the actions of the new provincial Government, the ratepayers of Avista would be protected from the impact of political interference in Hydro One.

The WUTC rejected Hydro One's evidence about the risk of political interference. The WUTC made the following findings:

1. Hydro One remains subject to management control by the Province, and that the Province may not limit itself, or allow itself to be limited, to the role of "shareholder" as had been represented to the Commission.[16]

2. Hydro One's directors cannot be considered independent and the Province's role is not limited to that of a minority shareholder in a publicly traded corporation.[17]

3. The Governance Agreement between Hydro One and the Province cannot be considered protective of Hydro One's status as a publicly traded corporation.[18]

4. Hydro One's board acted without a due diligence review of the potential adverse impacts of the precipitous changes in direction and executive management to which it agreed. These changes, in fact, caused harm to Hydro One and its shareholders, and to Avista and its shareholders.[19]

5. Bill 2[20] gave the Province a direct and active role in setting, and continuing oversight of, executive compensation at Hydro One. There appeared to be nothing that would prevent this level of interference from occurring again if the Government leadership became dissatisfied in some respect with decisions by the new board of directors or with the new CEO, or simply due to political considerations without regard to sound business practices. The WUTC further noted that additional legislation might be forthcoming to effectuate a 12 per cent rate reduction promised by the new Government. In the words of the WUTC, "Hydro One continues to be subject fully to the provincial Government and the political will of its leadership".[21]

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[12] *Ibid* at II.
[13] *Ibid* at III.
[14] *Ibid*.
[15] *Ibid* at 4.
[16] *Ibid* at II.
[17] *Ibid*.
[18] *Ibid*.
[19] *Ibid* at III.
[20] Bill 2, *Urgent Priorities Act, 2018*, SO 2018, c 10 (assented to 25 July 2018).
[21] *Supra* note 5, WUTC Decision, at III.

The WUTC concluded that:

> …the evidence demonstrates that Hydro One lacks sufficient independence from its former owner and now largest shareholder, the Province of Ontario, to be a reasonable and appropriate merger partner for Avista. The events following the provincial election in June 2018 demonstrate the material and significant risk of the proposed transaction to Avista's customers that results from the Province of Ontario's dominant ownership interest in Hydro One and the willingness of the provincial Government to exert its dominance in ways that are **contrary to the best interests of Hydro One** and, by extension, Avista, were it to be owned by Hydro One. The financial and other benefits for Avista customers and the broader public promised by the transaction, including rate credits, are inadequate to compensate for the risks of harm Avista's customers would face were we to approve this transaction.[22] [Emphasis added]

To fully understand the implications of the Avista decision for Hydro One and the governance of the electricity sector in Ontario, it is useful to cite a number of the WUTC's findings, as follows:

i. The provincial Government also promises to lower Hydro One's rates by a specific percentage, apparently without having first considered the impact this could have on the safety and reliability of services Hydro One provides.[23]

ii. It no longer is clear that Hydro One can be regarded as a private, publicly-traded corporation. While not legally a Crown Corporation, Hydro One manifestly is subject to being controlled by the Province's legislative power.[24]

iii. It appears that Hydro One's corporate identity as a private, publicly-traded corporation depends significantly on the identity of the ruling party in Ontario or even on the leadership of that party.[25]

iv. Soon after the change in majority leadership resulting from the June 7, 2018 Ontario general election, it became apparent that the force of the Governance Agreement as an enforceable contract that would protect Hydro One's independence and freedom from political insurance depended less on its language than on the identity of the governing party in power and the willingness of the board to enforce its terms in court, if necessary.[26]

v. Considering events that have already transpired, we cannot trust that the Province will not take additional actions without regard to the harmful consequences they may have for Hydro One and Avista.[27]

vi. The character of Hydro One as a publicly traded corporation is seriously impaired by virtue of the Province's interference in the company's affairs.[28]

vii. It [Hydro One] simply cannot be considered an independent, publicly traded company with a board of directors possessed of sufficient independence and power to protect Hydro One from political interference likely to cause harm to the company, much less to protect Avista from the consequences of bad decisions that Hydro One driven by the political whims of a controlling party in Ontario.[29]

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[22] *Ibid*,at III – IV.
[23] *Ibid* at 5.
[24] *Ibid* at 17.
[25] *Ibid*.
[26] *Ibid* at 25-26.
[27] *Ibid* at 18-19.
[28] *Ibid* at 29.
[29] *Ibid* at 34.

Reduced to their essence, these findings are that the Province cannot be trusted to honour its contracts. That is, in my view, devastating for the reputation of the Province as a secure place in which to invest.

The WUTC also commented on the effects of the Province's action on the protection of shareholder interest. The WUTC first observed that the "spirit and intent" of certain provisions of the governance agreement was to "protect the rights of all shareholders and to prevent a removal and replacement process for the board that elevated the interests of a single shareholder, the Province, above that of all other shareholders".[30] Having made that observation, the WUTC then commented as follows:

> The point is that all shareholders in a private corporation have equal rights and their rights should be acknowledged in all processes that call for their participation. In this case, their rights were ignored; they were given no opportunity to air any concerns they may have had in connection with the removal of the CEO and the entire board of directors. In addition, waiving these provisions of the governance agreement in a singular effort to effect as quickly as possible the results the new provincial Government had promised in the run up to the June 7, 2018 election, shows that Hydro One remains very much subject to the Province's authority, and, as a practical matter in the Province's control. It simply can't be considered an independent publicly-traded company with a board of directors possessed of sufficient independence and power to protect Hydro One from political interference likely to cause harm to the company, much less to protect Avista from the consequences of bad decisions at Hydro One driven by the political whims of the controlling party in Ontario.[31]

These comments seem, at first glance, to be outside the scope of the WUTC's interest. It was not a regulatory proceeding dealing with shareholder rights. The comments may also be unfair to Hydro One's senior management, faced as it was with the threat of legislation if it did not comply with the Government's will. The important point is that the evident willingness of the Province to override shareholder interests suggests that the nature of the corporate governance of Hydro One, the largest distribution and transmission utility in the Province, is now a matter of interest to the governance of the electricity sector as a whole. The implications of this point are explored below.

Hydro One sought to have the WUTC's decision reversed. It was unsuccessful in doing so.[32]

(B) The East-West Tie Case

In 2010, the Government's Long Term Energy Plan identified the need for an enhanced transmission line between Wawa and Thunder Bay. What is now the Independent Electricity System Operator ("IESO") had originally said that the EWT should be in service by 2018. It subsequently changed the needed in-service date to 2020. As discussed below, the date when the line could be in service was a central issue in the hearing of the applications for LTC under section 92 of the *Ontario Energy Board Act 1998* ("OEBA").

The development of the required transmission line (hereinafter referred to as the "EWT") into northwestern Ontario was to be subject to the OEB's new transmission development policy. That policy, set out in the report entitled "Board Policy: Framework for Transmission Development Plans", set out the OEB's conclusion that "economic efficiency will be best pursued by introducing competition in transmission service".[33] In that Policy, the OEB also noted that included in the principles it uses in fulfilling its transmission policy was "regulatory predictability".[34] That Policy, in turn, reflected the Government's policy on developing transmission through competitive processes.[35]

[30] *Ibid*.
[31] *Ibid*.
[32] *Ibid* Order 6.
[33] OEB, EB-2010-0059, "Board Policy: Framework for Transmission Development Plans", 26 August 2010, at 3 ["Policy"].
[34] *Ibid* at 3.
[35] Letter from the Minister of Energy to the Chair of the Ontario Energy Board (29 March 2011).

The EWT required upgrades to the existing Hydro One Networks Inc. ("HONI") feeding stations. These upgrades were to be evaluated as part of an application filed by HONI with the OEB (the "stations application"). The stations application was a process at once separate from but directly related to the competition for the construction of the EWT. Indeed, delays in the completion of the stations upgrade, caused by environmental assessment issues, meant that the transmission line could not be in service before the end of 2021, regardless of the result of the competitive process implemented by the OEB for the EWT.

In 2012, the OEB convened a process whereby it divided the work on the EWT into two phases. The first phase, referred to the "Designation Phase", contemplated the receipt of bids for the development of work. The actual construction of the EWT required the approval, by the OEB, of an application LTC. The second phase, which I refer to as the "Construction Phase", was to commence with the filing of that application.

With respect to the Designation Phase, the OEB's proposal was that a successful bidder would be allowed to do the development phase work (for example, engineering design, Indigenous consultation, environmental assessment, and so forth) and be allowed to recover the costs of that development work from ratepayers.

Six bidders submitted proposals in the Designation Phase. The proposals included a forecast cost for the development work as well as for the construction work that was to take place in the Construction Phase.

Upper Canada Transmission Inc., operating as NextBridge Infrastructure LP ("NB"), was awarded the development phase work, and was allowed to recover $22.2 million in development costs. NB had estimated its construction costs in the range of $450 million. In designating NB to do the development work, the OEB stated that the construction phase of the work would be open to competition.[36]

In its December 20, 2018 Decision and Order, discussed in detail below, the OEB made the following observation:

> In accordance with the Transmission Policy Framework, the Designation Decision clarified the designation did not carry with it the exclusive right to build the new line between Wawa and Thunder Bay or the exclusive right to apply for leave to construct. The designated transmitter was only assured of recovery of the budgeted amount for project development. As a result, a non-designated transmitter would be able to apply for a leave to construct the line between Wawa and Thunder Bay as there were no specific criteria set out in the Transmission Policy Framework to prevent this situation. This would enable an application by a non-designated transmitter that would require, presumably, a comparison of the leave to construct applications using the consideration set out in the act.[37]

As stated above, the Construction Phase of the process commenced with an application for LTC the EWT. NB filed an application, pursuant to section 92 of the OEBA for LTC. In its Designation Phase bid, NB had forecast a construction cost of $450 million. In its LTC application it forecast a cost of $737 million, an increase of approximately 80 per cent.

Hydro One Networks Inc. ("HONI") filed its own application to construct the line, at a forecast cost of approximately $642 million.

NB filed a motion asking the OEB to dismiss HONI's application for LTC, a motion that was, after a hearing, dismissed.[38]

[36] OEB, EB-2011-0140, "East-West Tie Line Designation, Phase 2 Decision and Order", 7 August 2013, at 4.

[37] OEB, EB-2017-0182, EB-2017-0194, EB-2017-0364, Decision and Order, 20 December 2018, at 65, the ["First Leave-to- Construct Decision"].

[38] OEB, EB-2017-0364, "Decision and Order", 19 July 2018.

The OEB combined the two LTC applications and the stations application into one proceeding, and a hearing was held in October of 2018. The evidence at the hearing was that NB's costs would be in the range of $737 to $810 million, while Hydro One's costs would be in the range of $642 to $681 million.[39]

The criteria which the OEB must apply, in determining whether to approve an application for LTC a transmission line are set out in subsection 96(2) of the OEBA. That subsection provides:

> (2) In an application under section 92, the Board shall only consider the following when, under subsection (1), it considers whether the construction, expansion or reinforcement of the electricity transmission line or electricity distribution line, or the making of the interconnection, is in the public interest:
>
> 1. The interests of consumers with respect to prices and the reliability and quality of electricity service.
>
> 2. Where applicable and in a manner consistent with the policies of the Government of Ontario, the promotion of the use of renewable energy sources.[40]

Since renewable energy resources were not a relevant consideration in the circumstances of the NB and HONI applications, the OEB was limited to only one consideration, namely the interests of consumers with respect to prices and the reliability and quality of electricity services.

Notwithstanding that narrow jurisdiction, the parties to the hearing of the applications supporting NB focused on three issues that were unrelated to the price of electricity services. One was the question of which of the applicants could have the line in service by 2020. The second was which of the applicants conferred greater benefits on, and reflected more thorough consultation with, Indigenous groups. The third was the status of Environmental Assessment ("EA") approvals that were required to build the line.

The OEB issued a decision in the applications, on December 20, 2018.[41] I will refer to this as the "First Leave-To-Construct Decision". Critically, this decision did not award the right to construct the EWT.

In the First Leave-To-Construct Decision, the OEB dealt first with the duty to consult and the environmental assessment issues. With respect to the former, the OEB relied on the decision of the Supreme Court of Canada in *Carrier Sekani*[42] to hold that its role in relation to consultation was limited by the wording of sections 92 and 96 of the OEBA. The OEB held that it was required to "follow the Legislature's intent and confine its review to the issues set out in Section 96(2) of the Act".[43] As noted above, those issues were, in the circumstances of the two applications, the impact of the proposals on the price of electricity and the reliability and quality of service.

The OEB also held that its jurisdiction to consider environmental matters was likewise limited to the impact, if any, on the issues of price, reliability and quality of electricity where they can impact the costs of and schedule for a project.[44]

In considering the criteria in subsection 96(2) the OEB found that "both projects are acceptable from a reliability and quality of electricity service perspective. As a result, prices will determine which Applicant is granted leave to construct the new transmission line."[45]

With respect to the in-service date, the OEB concluded that, because of the timing of required environmental approvals on the stations project, the in-service date of 2020 was no longer relevant and that both projects were capable of being in-service by the end of 2021.[46]

[39] *Supra* note 37, First Leave-to-Construct Decision, at 46-47.
[40] *Ontario Energy Board Act 1998*, SO 1998, c 15, s B, s 96 ["OEBA"].
[41] *Supra* note 37, First Leave-to-Construct Decision.
[42] *Ibid* at 12.
[43] *Ibid*.
[44] *Ibid* at 13.
[45] *Ibid* at 42.
[46] *Ibid* at 60.

With respect to the issue of consultation with and economic benefits for Indigenous communities, the OEB found that both applicants were capable of reaching satisfactory arrangements with these communities.[47]

On the determinative issue of price, the OEB took the unusual step of offering the parties the opportunity to submit a not-to-exceed ("NTE") price, and to do so by January 31, 2019. The OEB stated that the successful applicant was to agree not to seek recovery in rates for amounts beyond the NTE price specified.[48] That NTE price was, in other words, to be a cap on the cost of constructing the line.

On January 30, 2019, an Order in Council (OIC) was issued directing the OEB to amend NB's transmission licence to permit it to construct the EWT.[49] The OIC was issued pursuant to the authority contained in section 28.6.1 of the OEBA,[50] an authority authorizing the Minister of Energy to issue directives to the OEB related to, among other things, the construction of transmission lines.

Section 97.1, added to the OEBA in 2016, limits the authority of the OEB to grant leave-to-construct applications pursuant to section 92 of the OEBA in circumstances where a directive has been issued pursuant to section 28.6.1.[51] So while the OIC could not use section 28.6.1 to grant LTC, that is its practical effect. The OEB must grant LTC but its doing so is purely a formality.

The OIC made the filing NTE prices at the OEB moot. Because of that, ratepayers were precluded from knowing how much lower the cost might have been had NB and HONI filed NTE prices.

The OEB subsequently issued a Decision and Order, dated February 11, 2019, pursuant to section 92 of the OEBA, granting NB LTC as effectively required by the OIC.[52] I will refer to this as the "Final Leave-to-Construct Decision".

In the Final Leave-to-Construct Decision, the OEB expressed its concern with the construction costs put forward by NB. It noted that the costs had increased from $409 million at the time of the designation proceeding to $737 million at the time NB filed its LTC application.[53] The OEB also noted that NB had not filed an updated construction cost since the application had been filed, some 18 months earlier.[54] This was important because the evidence in the hearing was that NB's construction costs were pegged to a 2020 in-service date and that delays in the construction schedule would likely cause the cost of construction to increase.

The practical result of the OIC, thus, was that the OEB was forced to approve NB's application for LTC without knowing the impact of NB's proposal on the cost to build the EWT. As the cost of construction would be recovered from ratepayers, the impact on ratepayers could not be known. Put another way, ratepayers were precluded from knowing how much lower the cost might have been had NB and HONI filed NTE prices. The OEB put this result bluntly when it stated, in the Final Leave to Construct Decision and that "Given the Directive, mitigation of ratepayer risk through a comparative analysis of two competing applications based on costs is no longer an optio".[55] The OEB was, thus, compelled to issue an LTC decision without being able to fulfill its obligation, set out in subsection 96(2) of the OEBA, to consider the interests of consumers with respect to prices when deciding whether to approve an application for LTC.

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[47] *Ibid* at 62.

[48] *Ibid* at 66.

[49] BC, Executive Council Chambers, *Order In Council*, 52/2019 (30 January 2019), ["OIC"].

[50] *Supra* note 40, OEBA, s 28.6.1.

[51] *Ibid*, s 97.1.

[52] OEB, EB-2017-0182, EB-2017-0194, EB-2017-0364, Decision and Order (11 February 2019) ["Final Leave-to-Construct Decision"].

[53] *Supra* note 37, First Leave-to-Construct Decision, at 7.

[54] *Ibid*.

[55] *Ibid*.

The ostensible reasons for the issuance of the OIC were, first, that it would "provide an increased level of regulatory certainty to the processes currently being undertaken by the Ontario Energy Board".[56] That is a puzzling rationale, given that the OEB's regulatory processes were within days of being completed, with the only uncertainty being which of the two competitors would offer the lowest not-to-exceed price.

The second reason offered for the OIC was that the "economic participation of Indigenous communities is a policy objective of the Ontario Government and an increased level of regulatory certainty would support partnerships entered into in respect of the East West Tie Line Project".[57] That too is a puzzling rationale in that both NB and HONI had offered economic participation to Indigenous communities and neither could begin construction until the required environmental approvals were in place. As noted above, the OEB, having heard the evidence of both parties, concluded, in its First Leave-to-Construct Decision that both parties were capable of offering economic benefits to Indigenous communities.

Neither of those reasons set out in the OIC were supported by the evidence that had been examined by the OEB during the hearing of the competing LTC applications. The OEB's finding, noted above, was that, because of the requirements of environmental assessment approvals for the stations upgrade, neither Hydro One nor NB could have the line in service before the end of 2021. As a result of that, the economic benefits to Indigenous communities could not be provided any faster by NB than they could by Hydro One. The evidence was that Hydro One was offering Indigenous communities economic benefits equal to, or in one case superior to[58], the economic benefits offered by NB. Finally, since the OEB's decision on the LTC applications would, presumably, have been issued within days of the filing of the NTE prices, the regulatory delay could be measured in, at most, days if not hours.

The OIC made no reference to the cost of constructing the EWT. As a result NB had accomplished something that it could never have accomplished in its LTC application, namely having no limits on the cost to construct the EWT.

Although not reflected in the OIC, it would appear that the Government made the decision to intervene based on submissions, written or oral, to it from NB. NB had, as early as August of 2018, written to two Ministers asking that they grant NB the right to build the line, thus by-passing the OEB while its hearing process was about to begin. NB wrote to the Minister of Energy on January 21, 2019, again asking for that relief. That letter refers to a letter of January 8, 2019, a copy of which has not been disclosed.

In the letters NB wrote to the Government that have been disclosed, NB provided information about its proposal and that of HONI. The information included in these letters was in some cases inaccurate. For example, in its January 21, 2019 letter to the Minister of Energy, Northern Development and Mines NB stated that "Hydro One's project would be completed much later than the Next Bridge-BLP One causing delays and corresponding losses in economic development and risks to the electrical reliability".[59] As reflected in its December 20, 2018 Decision and Order, OEB had found that neither NB nor HONI would have the line in service before the end of 2021 and had found that neither project caused a risk to electrical reliability.

In that same letter, NB included what it described as a "comparison of net project cost".[60] That comparison included assumptions about HONI's costs, for example, additional costs to follow an alternate route, which were not correct.

The important point was that neither NB nor the Government disclosed the fact of or the contents of the letters at the time they were sent to the Government and in circumstances where they could be examined in a public proceeding and where stakeholders could respond.

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[56] *Supra* note 49, OIC, at 1.

[57] *Ibid* at 2.

[58] The evidence in the hearing was that Hydro One was offering the Indigenous community most directly affected by the EWT a 34 per cent equity interest, as opposed to the 20% equity interest offered to the same community by NextBridge.

[59] Letter from Jennifer Tidmarsh of NextBridge Infrastructure to the Minister of Energy, Northern Development and Mines (21 January 2019).

[60] *Ibid.*

The point of these observations is not to argue that Hydro One's application was superior to that of NB. The evidence in the OEB proceedings can be evaluated on its merits. The findings of the OEB with respect to construction costs are set out in the First Leave-to-Construct Decision and in the Final Leave-to-Construct Decision.

It is arguable that the regulatory process originally created by the OEB for the development of the EWT was flawed from the outset. The Designation Decision created substantial competitive advantages for the party awarded the right to do the development work. To give effect to the policy of having competition to construct the EWT, any party other than NB would have to overcome those competitive advantages. That, in turn, would require the OEB to allow a competing party the full opportunity to make its case in an LTC application. That, in turn, would involve some regulatory delay. To its credit, the OEB, at least implicitly, recognized the problems in the original regulatory process it had created and gave NB and HONI the opportunity to make their cases. That meant there was a transparent process whereby the competing proposals could be thoroughly examined. To put the matter another way, the OEB had given effect to its policy, and to the Government's policy, of having transmission lines developed through a competitive process. It was the Government's intervention that nullified the process, and reversed the policy.

The effects of the Government's decision to effectively grant NB the right to construct the EWT are the following:

1. The right to construct the line was granted in violation of the statutory obligation in the OEBA to consider in the interests of consumers with respect to prices;

2. Beyond that, given the evidence in the hearing, the right to construct was granted by the Government knowing, based on the findings of the OEB, that it almost certainly would cost more than the alternative proposal, ensuring that ratepayers would pay more than they would otherwise have had to;

3. The Government's decision was based on considerations that were, again based on the findings of the OEB, demonstrably incorrect, namely that it would end regulatory delay and uncertainty and result in economic benefits flowing more quickly to Indigenous groups;

4. The Government undermined the OEB's regulatory process, which included nullifying the open and transparent consideration of competing evidence and the opportunity for affected stakeholders to express their concerns.

5. By acting on untested information submitted by NB, the Government violated the rules of natural justice which are supposed to govern decisions in the electricity sector affecting the interests of ratepayers; and

6. The Government abandoned the policy of having transmission lines developed through competitive processes, but did so without acknowledging that it had done so.

II. GOVERNANCE IN THE PUBLIC SECTOR

In this section I consider the principles of governance in the public sector, and why adherence to those principles is important.

The OECD describes governance in the public sector as follows:

> Public governance refers to the formal and informal arrangements that determine how public decisions are made and how public actions are carried out, from the perspective of maintaining a country's constitutional values when facing changing problems and environments.[61]

The OECD has commented on the importance of good governance for regulators as follows:

How a regulator is set up, directed, controlled, resourced and held to account – including

[61] OECD, Division of the OECD Directorate for Financial and Enterprise Affairs, *Principles of the Government of Regulators : Public Consultation Draft*, (Paris OECD EDITIONS, 2011), Chapter 10, at 2.

the nature of the relationships between the regulatory decision-maker, political actors, the legislature, the executive administration, judicial processes and regulatory entities – builds trust in the regulator and is crucial to the overall effectiveness of regulation. Improving governance arrangements can benefit the community by enhancing the effectiveness of regulators and, ultimately, the achievement of important public policy goals.[62]

The OECD, among others, has identified the following characteristics of effective regulatory systems:

1. Independence;
2. Accountability;
3. Certainty;
4. Effectiveness;
5. Efficiency.[63]

The OECD also noted the importance of the relationship between regulatory integrity and independence as follows:

> Establishing the regulator with a degree of independence (both from those it regulates and from Government) can provide greater confidence and trust that regulatory decisions are made with integrity. A high level of integrity improves outcomes of the regulatory decisions.[64]

Considerations of the proper governance of regulatory agencies necessarily require a consideration of the relationship between the Government and those agencies. For that reason, the OECD's principles of good governance can be applied in considering the governance arrangements for the electricity sector as a whole, and for the impact of the Avista and EWT cases on that governance.

III. THE GOVERNANCE OF THE ELECTRICITY SECTOR

The governance of regulatory agencies can be defined as follows:

> For regulatory agencies, governance may be defined, broadly, as the mechanisms or instruments, processes, and relations by which a regulator is controlled and directed, and by which its decisions and actions are measured and held to account. The mechanisms or instruments would include the governing legislation, any regulations made under that legislation, and the rules governing the regulatory agency's relations with the Government, the legislature, and the courts. It would also include the regulatory agency's own structures, rules, and practices.[65]

Electricity is, along with food and shelter, essential to the wellbeing of citizens. Governments must ensure that there is a sufficient supply of electricity at prices every citizen can afford. To accomplish those objectives, provincial Governments have created a governance structure for the electricity sector. The structure, created by legislation and regulation, sets out the respective roles of the Government and its two regulatory agencies, the OEB and IESO.

As originally conceived, the core of the governance structure for the electricity sector was a system by which an independent regulator, the OEB, approves rates based on evidence filed in public proceedings and which is available to be tested by ratepayers.

Again as originally conceived, the governance structure of the electricity sector had the following major components:

1. The OEB was given the authority, by statute, to approve the rates charged

[62] OECD, *Principles for the Government of Regulators: Public Consultation Draft*, 21 June 2013 (Paris: OECD Publishing, 2013), ["OECD Principles"].

[63] *Report of the Ontario Energy Board Modernization Review Panel*, October 2018.

[64] *Supra* note 62, OECD Principles, at 47.

[65] Robert Warren, "The Governance of Regulatory Agencies: A Case Study of the Ontario Energy Board", Council for Clean and Reliable Energy, January 2015, at 5.

for the transmission and distribution of electricity, and for the construction of transmission lines. The statute sets out the tests which the OEB must apply. It also specifies how it is to make those decisions, namely by a hearing. The fact that it is required to make its decisions by a hearing means that it has an obligation to follow the rules of natural justice.

2. Decisions of the OEB may be appealed to courts on issues of law.

It is an accepted fact of governance in the electricity sector and indeed in the governance of regulatory agencies in all sectors, that the Government may establish policies which the OEB is required to follow. It is essential, in a democratic society, that regulatory agencies be responsive to the policies of the Government. There may be circumstances where government intervention is necessary, for example to ensure adherence to a policy. However, such intervention should be done in a manner that is transparent.

There is always a tension between the obligation to be responsive, and indeed to implement policies, and the need for independence. However, absent specific statutory direction, how the OEB interprets and applies those policies lies within its discretion. Put another way, how the OEB interprets those policies in light of its statutory obligation to set, for example, just and reasonable transmission and distribution rates, lies within the discretion of the OEB. It is essential that, in striking the balance between the obligation to interpret policies and exercising its discretion, the OEB do so in an open and transparent way.

In this context, section 1 of the OEBA is an illustration of how the balance between Government policies and regulatory independence may be struck.[66] That section sets out the objectives by which the OEB, in carrying out its responsibilities under the OEBA, is to be guided. The Government's objectives are clearly stated, but the discretion as to how those objectives are to be achieved in keeping with its statutory obligations is left to the OEB.

The relationship between the Government and the OEB is formally prescribed in the "Memorandum of Understanding between the Minister of Energy and the Chair of the Ontario Energy Board" (hereinafter referred to as the MOU).[67] Section 1 of the MOU sets out the "Purposes of this Memorandum". Section 1.2 provides as follows:

> This Memorandum does not affect, modify or limit the powers or responsibilities of the Ontario Energy Board or the powers or responsibilities of individuals or entities that are derived from the Ontario Energy Board, set out in applicable legislation, or otherwise established by law.[68]

Section 4 of the MOU sets out the "Guiding Principles". Section 4.1 reads as follows:

> The Minister recognizes that the Board is a statutory corporation and that the Board, the Chair and the Management Committee each exercise powers and perform duties in accordance with the Act and other applicable Legislation. The Minister also recognizes that as a statutory entity, the exercise of the Board's powers and duties is subject to limitations, constraints and conditions that flow from applicable Legislation, from the Board's status as an independent quasi-judicial tribunal or both. The Minister acknowledges that the Board's adjudicative and regulatory decisions must be made, and be seen by the public to be made, independently and impartially. The Parties agree that this Memorandum and all obligations contained in it shall be interpreted and applied in a manner that is compatible with the foregoing.[69]

This basic structure for the governance of the electricity sector began to change with the

[66] *Supra* note 40, OEBA, s 1.
[67] *Memorandum of Understanding Between the Minister of Energy and the Chair of the Ontario Energy Board*, s 1.2.
[68] *Ibid*, s 1.2.
[69] *Ibid*, s 4.

introduction, in 1998, of the first amendment to the OEBA allowing the Government to issue directives to the OEB. What is now section 27 of the OEBA provides that the Government may issue policy directives "concerning general policy and the objectives to be pursued by the Board. The section provides that when the directives are issued, the Board is required to implement them.[70]

What is now section 27 of the OEBA has served, with one exception, as a template for the subsequent amendments in the OEBA granting the Government the power to issue directives. The wording of what is now section 27 contemplates that directives will be issued by the Government and then applied by the OEB. The practical result is that the application of the directives would, in most cases, be considered in hearings. While the effect of the directives would be to limit the OEB's discretion, the relationship between what was required by the directive and the exercise of the Board's discretion would be subject to stakeholder input in a transparent process. That process was not followed in the EWT case, a distinguishing feature of the case and of the Government's use of the directive power.

In the following 15 years, the OEBA was amended by adding ten (10) sections authorizing the issuance of directives. Many of those directives were intended to allow the Government to direct how its renewable energy and energy conservation initiatives were to be implemented.

The directive power used by the Government in the EWT case was added to the OEBA by amendments in 2016. This directive is an exception to the other directives in the OEBA in that, by virtue of section 97 of the OEBA, exercising it strips the OEB of its discretion to approve the construction of transmission lines. That amendment was not subject to any discussion in either legislative committee or the legislature itself.

The new provincial Government has arguably taken the power to issue directives to new lengths. The *Hydro One Accountability Act, 2018*,[71] gave the Government the power to issue directives to among other things, set the compensation of the CEO of Hydro One. On February 1st of this year the Government issued a directive allowing just that.[72]

The *Electricity Act, 1998* has also been amended to give the Government control over the content of and the implementation of the long-term energy plan.[73] Where originally the IESO and the OEB were principally responsible for the content and application of the long-term energy plan, the decisions about the content and application of the plan now lie with the Government.

While making these amendments, successive Governments have, with the one exception of sections 28.0.1 and 97 of the OEBA, left intact the discretion of the OEB to exercise its core function of approving just and reasonable rates. The effect of these amendments arguably has been to change the governance arrangements for the electricity sector in a material way by inserting the Government into the decision-making process and constraining the discretion of the OEB. However, the OEB retained a measure of independence in that it had some discretion in how the directives were to be applied. In addition, in cases where the directives did not apply, the discretion of the OEB was unchanged. The EWT and Avista cases have in my view changed that.

I use the OECD criteria to examine what are the governance arrangements for the electricity sector. I suggest that these arrangements, as originally conceived, created by statute and regulation, specify discrete roles for the Government and the OEB, and ensure the appropriate measure of independence for the OEB. In addition, the arrangements require that decisions affecting ratepayers, and in particular the costs which ratepayers must pay for electricity service, are to be made in open and transparent processes, with the evidence on which decisions are made available for public scrutiny and the OEB accountable for those decisions.

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[70] *Supra* note 40, OEBA, s 27.
[71] *Hydro One Accountability Act, 2018*, SO 2018, c 10, s 1.
[72] Directive dated 21 February 2019.
[73] *Electricity Act, 1998*, SO 1998, c 15, s A, s 25.29 and 25.30.

Ontario Governments, of all parties, have a long, and largely unhappy, history of intervening in the electricity sector.[74] Governments have frozen, and then unfrozen, electricity prices. Governments have reduced electricity prices. The auditor general, in his 2011 Report, observed, of the Government's *Green Energy and Green Economy Act, 2009*, that "the Government created a process to expedite the development of renewable energy by providing the Minister with the authority to supersede many of the Government's usual planning and regulatory oversight processes".[75] That observation could stand as a useful summary of the effect of the Government's legislation in the electricity sector from 1998 on.

The power to issue directives has constrained the ability of the OEB to act as an independent, quasi-judicial decision-maker. But its use of the directive power in the EWT case has done something fundamentally different, namely overriding the OEB processes, and making a decision on the basis of information that has not been tested or, indeed, on information that had been tested in a hearing and found to be incorrect.

What the Avista case discloses is that the Government can use its power, as the largest shareholder in Hydro One, to affect the governance over the sector. There is some irony in this in that, prior to the partial privatization, the Ontario Government was the sole shareholder of Hydro One, and so had complete control. However, as noted elsewhere in this paper, the Government entered into the Governance Agreement to signify that it would limit its control over Hydro One to corporate and business, rather than political, considerations.

Against that background, two questions arise. The first is whether, and if so to what extent, the principles of good governance, particularly those expressed by the OECD, can continue to apply in the electricity sector. The second is whether the Avista and EWT cases represent a material change in the governance of the electricity sector or are simply the logical culmination of the changes in the governance structure of the electricity sector that have taken place over the past 15 years.

IV. THE AVISTA AND EWT CASES AND THE GOVERNANCE OF THE ELECTRICITY SECTOR

The role of the provincial Government in both the Avista and EWT cases has had, as noted above, adverse economic effects. In the case of the Avista, the WUTC's denial of approval of the Avista transaction meant that Hydro One has to pay a breakup fee of some $103 million. In the case of the EWT, the Government intervention means that the transmission line may cost at least $100 to $120 million dollars more than would have otherwise been the case. In the case of the breakup fee, the cost may not be borne by ratepayers but by taxpayers. In the EWT case, the construction cost will be borne by ratepayers. Since there is, for all intents and purposes, no

[74] Examples of Government interference are legion. The following examples are indicative.

1. The *Energy Competition Act, 1998*, created a competitive market in the electricity sector. One of the objectives was to have ratepayers pay the true cost of power;
2. The *Electricity Pricing, Conservation and Supply Act, 2002*. This legislation capped electricity prices for two years. It also froze transmission and distribution rates until 2006. The effect of the legislation was to undue the experiment in market pricing as established by the 1998 legislation;
3. The E*lectricity Restructuring Act, 2004*. That legislation reorganized the institutional structure of the electricity sector. Among other things, the legislation granted the Ontario Power Authority, the predecessor to the IESO, the power to develop what is now called the Long Term Energy Plan. As noted in the text, that power now lies with the Minister;
4. The *Green Energy Act and Green Economy Act, 2009*. This legislation reflected the Government's embrace of renewable energy generation, and substantially enhanced the Government's power to issue directives;
5. *Ontario Clean Energy Benefit, 2011*. This legislation introduced a 10 per cent discount on ratepayers' electricity bills;
6. The *Ontario Rebate for Electricity Consumers Act, 2016*, lowered hydro rates by 8 per cent starting on January 1, 2017;
7. The *Fair Hydro Act, 2017*, reduced hydro rates by a further 17 per cent, for a total reduction of 25 per cent.

[75] Ontario, Office of the Auditor General of Ontario, *2011 Annual Report*, (Toronto: Queen's Printer for Ontario, 2011), at 89.

distinction between taxpayers and ratepayers, it may be a distinction without a difference.

For purposes of this analysis, it is the indirect effects that, in my view, are more troubling. That the provincial Government owns the largest, and arguably the most important, transmission and distribution utilities means that how it exercises its ownership power will have a material impact on the governance of the electricity sector. This was implicitly recognized when, in the context of the sale of shares in Hydro One, the Government entered into the Governance Agreement.

As noted above, the Governance Agreement was intended to accomplish contradictory objectives. On the one hand, it was intended to reassure the public that the Government retained sufficient control to be able to protect ratepayers from rate increases, a form of protection, as I have noted, that was unnecessary because of the role of the OEB in approving rates. On the other hand, and as Hydro One argued in the Avista case, it was intended to reassure regulators and investors that the Government could not control Hydro One.

As the WUTC found, the Governance Agreement provided no protection for the independence of Hydro One. Hydro One's board waived the protection of the agreement and gave in to the desire of the Government to fire the CEO and the board. It did so, it would appear, under threat of legislation. In addition, the Government simply overrode the Governance Agreement to introduce legislation giving it the power to set the compensation levels for the executive and the board of Hydro One.

What the WUTC recognized, by necessary implication, is that the corporate governance arrangements for Hydro One, and in particular the role of the Government as shareholder in those arrangements, now play a significant role in the governance of the electricity sector as a whole.

In the EWT case, the Government used its power to by-pass the OEB's hearing process and negate the protection of ratepayer interests required by the OEBA.

As noted above, Ontario Governments of all parties have interfered in the electricity sector, often with adverse consequences. In addition, and again as noted above, the governance structure of the electricity sector has, over the course of the past 15 years, been changed to alter the relationship between the Government and its regulatory agencies. Given those things, it may be argued that the Avista and EWT cases do not represent anything new or different in the nature of the effects of the Government's interference in the governance structure of the electricity sector. I think they do, however, in three particular ways:

1. For the first time, the Government has used the power to issue directives to effectively dictate an OEB decision, using that power to nullify a process that had been undertaken following the rules of natural justice;

2. For the first time, the Government's interference in the corporate governance arrangements of Hydro One has made those arrangements a factor in the governance of the electricity sector as a whole;

3. For the first time, the Government has used the threat of legislation to coerce the making of decisions in the sector.

The shift in the governance structures in the electricity sector, and in particular the enhanced role of the Government, are, in and of themselves, causes for concern about political interference in the electricity sector and therefore its security as a place to invest. In my view, the EWT and Avista cases have highlighted those concerns in dramatic ways, and in the process damaged the reputation of the Province and the electricity sector as places to invest.

Measured against the OECD's principles of good governance, the Government's actions in the Avista and EWT cases fail in the following respects:

1. Particularly in the EWT case, the Government's actions were not transparent. The OEB process that was the essence of transparency, by contrast the Government's interference was the opposite of transparency;

2. Again, particularly in the EWT case, the Government's actions nullified the operation of the rules of natural justice that were at the centre of the governance arrangements for the electricity sector. That the Government was legally authorized to do what it did is not the point. The governance structure of the electricity sector was designed so that decisions affecting the price of electricity paid by consumers would be determined

in processes governed by the rules of natural justice. The Government's interference nullified the protection provided by those rules;

3. The Government's interference in both cases was not effective, if measured by the impact on prices paid by ratepayers for electricity and, indirectly, by taxpayers. In the case of Avista, the interference led to the termination of a commercial agreement at a cost of $103 million. In the EWT case, the Government intervention will cost ratepayers more to build the transmission line;

4. The Government's interference in both cases was based on considerations that were demonstrably incorrect. In the Avista case, firing both the CEO of Hydro One and the board of directors would not have a material, if any, effect on rates. In the EWT case, the intervention would not speed up the regulatory process and would confer no material benefit on Indigenous communities. The Government's intervention was not based on facts;

5. The Government's intervention in both bases affected two costly regulatory proceedings. It resulted, in other words, in a waste of money, time, and effort. The Government's intervention was, in other words, the antithesis of efficient; and

6. The Government's interference in the EWT case robbed the regulator and its processes of accountability and certainty.

As noted above, the OECD noted the links between good public governance, investment, and development. The findings of the WUTC would make troubling reading for anyone considering investing in the electricity sector in Ontario. The Government's intervention in the EWT case means investors can have no confidence in the decisions of the OEB, or in the processes by which those decisions are made. The Government's intervention is an invitation to by-pass those processes. Potential investors can have no confidence that the Government of the day will not intervene to act in a way which diminishes the value of those investments. Confidence in the independence and integrity of the regulatory process is particularly important at a time of fundamental change in the electricity sector and when investment in new technologies will be essential.

I noted above that the partial privatization of Hydro One was criticized on economic grounds. There is an argument that a new government has the right to reverse a decision of a previous government that it regards as wrong. However, that is not what happened in the Avista case. The new Government did not reverse the privatization; indeed, it offered evidence to the WUTC of its continuing support of the acquisition. It intervened to affect one outcome of the privatization, namely the ability to fix executive remuneration, and in the process penalized Hydro One and all of its shareholders by causing Hydro One to have to pay a breakup fee.

There is also an argument that investors should be wary of dealing with Canadian governments given the explicit lack of a constitutional guarantee of private property and the primacy of legislative decisions. In the case of Avista, the existence of the Governance Agreement suggests that the Government wanted to neutralize those concerns.

In the case of the EWT, the authority of the OEB has been fundamentally undermined. Neither investors nor ratepayers can have confidence in the independence of the OEB as a quasi-judicial decision maker. The regulatory process is supposed to ensure that decisions are made in a transparent way, with evidence fully tested. The Government's interference in the EWT case meant that a decision was taken to undermine that process, and was based on information that was not subject to public review.

The protection of ratepayer interests requires that the integrity of the regulatory process be respected. Government interference in the governance of the sector, whether indirectly in the case of Avista or directly in the case of the EWT, destroys that integrity. The only way to ensure that the integrity is preserved would be to structure, and constrain, the ability of the Government to intervene, in at least two ways.

As I have stated, electricity is an essential commodity and the regulatory structure was designed not simply to ensure its availability but to give ratepayers a say in how it was transmitted and delivered and at what cost. The Avista and EWT cases illustrate how Government interference can nullify that by by-passing both the arrangements for, and the principles of, good governance.

I acknowledge that it may be naïve to believe that the Government would stay out of the governance of the electricity sector, and limit its role to setting broad, policy guidelines. It may be easier to find a cure for malaria than to get the Government out of the electricity sector. However, what the Avista and EWT cases make clear is that the Government ought to do that. The starting point is an acknowledgement of the importance of good governance, and the principles through which it should operate and a frank recognition of the adverse effect of violating those principles. In an ideal world, the Government would amend the OEBA to delete the authority to issue directives, and would either sell its interest in Hydro One or do what it said it was doing in the Governance Agreement, namely allow Hydro One to operate as a publicly traded, private corporation. It should also adhere to the spirit and intent of the MOU.

On the assumption that Ontario governments will never get out of the electricity sector, I suggest that three measures are required. The first is to respect the integrity of the regulatory process by allowing the OEB to make decisions based only on evidence that has been tested in open and transparent processes. The second is that policy direction from the government be presented in open and transparent processes. The third is that communications between the Minister and the regulator be disclosed.

The Ontario Energy Board's Modernization Review Panel's Report,[76] though dated October, 2018, has recently been released. In that Report, the Panel makes a number of recommendations on measures it believes are essential to making the operations of the OEB consistent with, among other things, OECD principles. The recommendations deal primarily with structural changes to the OEB. Those changes, while salutary, would be ineffective without a change in the Government's approach to the governance of the electricity sector. To put the matter another way, the Government's attitude to the governance of the electricity sector, as evidenced by the Avista and EWT cases, largely nullify the benefits of the changes the Panel recommends. ■

[76] *Report of the Ontario Energy Board Modernization Review Panel*, October 2018.

OEB TAKES STEPS TOWARDS IMPLEMENTING “ACTIVITY AND PROGRAM BASED BENCHMARKING”[1]

*David Stevens**

On February 25, 2019, the *Ontario Energy Board* (OEB) staff released their Discussion Paper on Activity and Program Based Benchmarking (APB) For Electricity Distributors.[2] The stated objective of APB is “to establish a framework to enable the comparison of utility cost performance in specific capital and OM&A activities/programs, thereby further helping OEB assess utility efficacy at delivering value to customers.”[3] OEB staff states that APB “will allow identification of best practices in key programs, peer cost comparisons and assessment of year-over-year continuous improvement based on key activities and programs.”[4]

As set out in the cover letter[5] accompanying the Discussion Paper, APB is intended to be used as a tool for assessing the performance of regulated utilities, beginning with electricity distributors. According to the Discussion Paper, the OEB plans to use APB results to, among other things, evaluate/identify areas that may require detailed review in rate applications, support proportionate reviews of applications and inform other regulatory investigations. The Discussion Paper suggests that APB can also “guide individual distributors to seek increased cost efficiencies through adoption of best practices exhibited by the best performing distributors.”[6]

The Discussion Paper outlines the research and consultation process that has been undertaken to date, and then explains what OEB staff believe should be included in an APB framework. Key items to be taken into account include what activities/programs should be benchmarked, what methods should be used for benchmarking, what data is available and how should it be used.

It is the identification and assessment of particular activities that is said to make APB more useful than “Total Cost Benchmarking”. OEB staff indicates that the plan is to benchmark only those programs/activities that contribute significantly to distributors’ operations and customer service. In identifying the appropriate programs/activities, the OEB will consider the significance of the program/activity, materiality of the expense(s)/capital investment(s), the ease of data collection and comparability of the results between distributors.

Based on review of existing data and recommendations from experts and stakeholders,

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[1] The following article is a reprint (updated) with permission of the one that appeared in the *Energy Insider* published by Aird & Berlis LLP see online: <https://www.airdberlis.com/insights/blogs/energyinsider/post/ei-item/oeb-takes-steps-towards-implementing-activity-and-program-based-benchmarking>.

[2] OEB, *Staff Discussion Paper: Activity and Program Based Benchmarking (APB) For Electricity Distributors,* (February 25, 2019), EB-2018-0278, online: <https://www.oeb.ca/sites/default/files/APB-OEB-Staff-Discussion-Paper-20190225-v3.pdf>.

[3] *Ibid* at 4.

[4] *Ibid* at 7.

[5] Cover letter for *Activity and Program Based Benchmarking (ABP) Initiative* (February 25 2019), online: <https://www.oeb.ca/sites/default/files/OEB-CovLtr-APB-Discussion-Paper-20190225-v2.pdf>.

[6] *Supra* note 3 at 12.

OEB staff have identified a preliminary short list of ten activities/programs for APB (six operating activities and four capital programs). The proposed items are set out in the table below, reproduced from the Discussion Paper.

As set out in the Discussion Paper, OEB staff proposes that APB be implemented incrementally with benchmarking, starting with some or all of the programs/activities listed above. OEB staff is proposing the use of both unit cost (including cost/volume) analysis and econometric modeling for benchmarking the selected activity/program candidates, with the emphasis on the unit cost method. The initial benchmarking will rely on existing RRRs and reported data. Additional data requirements and sources will be identified over time.

The Discussion Paper indicates that the OEB wants to move quickly with the implementation of the APB framework "given the benefits of this type of benchmarking to the regulatory process, the opportunities it presents to incent continuous performance improvement within the distribution sector, and the value it can deliver to utility customers."[8] Therefore, it can be expected that there further steps will quickly follow, indicating how the OEB plans to move forward. Notable in this regard is the comment in the cover letter[9] that the OEB plans to implement APB for all regulated entities (including transmitters, OPG and gas distributors), using the framework developed for electricity distributors as the base. No mention is made as to how benchmarking will be undertaken where there are fewer participants for these other regulated activities.

OEB staff held a meeting/webcast on March 5, 2019 to give stakeholders the opportunity to ask questions about the APB initiative and the Discussion Paper.[10] Following the meeting, nine interested parties, including distributors and ratepayer groups, provided their comments on the Discussion Paper, including comments on the specific questions set out at Appendix A to the Discussion Paper.[11] The OEB has indicated that these comments will assist in the development of the APB framework, but has not provided any indicative timing of when this will be completed. ■

OM&A	Group 1 Average Costs – OM&A ($M)	Capital	Group 1 Average Costs – Gross Capital ($M)
Vegetation Management (Right of Way)	161	Poles, towers and fixtures	4,713
Billing	124	Transformers (excludes station transformers)	3,898
Metre Expense	81	Distribution station equipment	1,919
Line Operation and Maintenance	190	Metres	1,326
Distribution Station Equipment	50	–	–
Maintenance Poles, Towers and Fixtures	29	–	–

OM&A Benchmarking & Capital Benchmarking – Gross Asset dollar value per USoA category[7]

[7] *Ibid* at 18-19.

[8] *Ibid* at 49.

[9] *Supra* note 5.

[10] OEB: *Activity and Program based Benchmarking – Stakeholder Information Meeting, OEB Staff Presentation,* March 5, 2019 online: <https://www.oeb.ca/sites/default/files/OEB-Staff-Presentation-Stakeholder-Information-Meeting-20190305.pdf>.

[11] Submissions are published to the OEB site; online: <http://www.rds.oeb.ca/HPECMWebDrawer/Record?q=CaseNumber=EB-2018-0278&sortBy=recRegisteredOn-&pageSize=400>.

INCONSISTENT WITH THE PUBLIC INTEREST: FERC'S THREE DECADES OF DEFERENCE TO ELECTRICITY CONSOLIDATION

*Scott Hempling**

Since the mid-1980s, mergers and acquisitions approved by the *Federal Energy Regulatory Commission* (FERC) have cut the number of independent retail electric utilities by more than half. These transactions have taken every possible form: horizontal, vertical, convergence, and conglomerate; operationally integrated and remote; domestic and international; publicly traded and going-private; debt-financed and stock-for-stock.

Accompanying this consolidation has been a complication. The conventional pre-1980s utility – local, pure play, conservatively financed – is being replaced by multistate and multinational holding company systems: corporate structures housing multiple, and sometimes conflicting, business ventures – structures that owe their financeability and viability to their utility affiliates' monthly cash flow.

Under Section 203 of the *Federal Power Act*,[1] the FERC must find these consolidating and complicating transactions "consistent with the public interest".[2] Despite multiple policy statements, rules, and 70-plus transaction approvals, the FERC has never defined a "public interest" in terms of the industry's performance. Though the 1996 *Merger Policy Statement*[3] states a purpose of "encouraging greater wholesale competition", that purpose rarely appears in the FERC's actual merger orders.[4] These orders require only "no harm", and no harm only to pre-merger competition – regardless of whether that pre-merger competition is effective or ineffective. Effective competition exists when a market's structure, and its sellers' conduct, pressure all rivals to perform at their best. By requiring only "no harm", and by applying that standard only to pre-merger competition, the FERC has invited and approved transactions whose contributions to performance are necessarily suboptimal. For 30 years, the Commission's merger decisions have disconnected the "public interest" from performance.[5]

That disconnection has produced, and continues to produce, consolidated asset ownership and complicated business structures. Today's

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[1] *Federal Power Act,* 16 USC § 824b [hereinafter cited as Section 203].

[2] *Ibid*, § 203(a)(4).

[3] See *Inquiry Concerning the Commission's Merger Policy under the Federal Power Act: Policy Statement,* 61 Fed Reg 68 (1996) § 595.

[4] Scott Hempling, "Inconsistent with the public interest: FERC's three decades of deference to electricity consolidation" (2018) 39:233 Energy LJ at 233, online : <https://www.eba-net.org/felj/energy-law-journal/current-issue>.

[5] *Ibid* at 282.

electricity industry resembles nothing any prior FERC intended, because no prior FERC ever stated what it intended – not only in terms of industry performance, but also in terms of the key influences on performance, such as the appropriate number of utility systems in a region, the appropriate mix of businesses and business structures within those systems, the types of owners and the financing they use, and those owners' strategies for subsequent expansion. The main influence on the FERC's merger decisions – the main force determining these industry features – is not any public interest vision, but rather the merger applicants' strategic aims.

The Commission's deference to applicants' strategies is logical, and lawful, when the relevant markets giving birth to these transactions are effectively competitive markets. But when mergers involve retail monopolies, the relevant markets are not effectively competitive. Deference to transactions undisciplined by effective competition cannot be consistent with the public interest.

This absence of a public interest vision, and the resulting deference to private interest transactions, are the big-picture errors. They lead to five main policy errors.[6] The FERC (1) looks only at wholesale competition, ignoring retail competition; (2) views each merger in isolation from the others, ignoring their cumulative effects; (3) ignores the relationship of purchase price to real transaction value, thereby approving transactions whose benefit-cost relationship is suboptimal; (4) allows the transacting parties to allocate nearly all their transaction's value to themselves, disregarding the contributions to that value made by the target's ratepayers; and (5) assumes without inquiry that regulators will be capable and willing to handle the post-consummation complexity.

Supporters of the FERC's merger policy might make two main arguments.[7] First, the Commission's near-universal merger approvals have produced no obvious performance backslide. Second, no studies exist to test whether today's consolidated industry performs less efficiently than had the FERC done things differently. But neither factor proves the policy correct. The mere absence of backslide is the wrong standard to apply to a multi-trillion-dollar, infrastructural industry on which lives depend; the absence of useful studies is a reason to conduct them, not to continue a policy unquestioned.

The Commission should re-examine its policy's premises[8]: that "no harm" is the correct standard; that the market structure to which no harm should apply is the pre-merger market structure regardless of its competitive defects; and that the strategies that drive merger proposals are necessarily disciplined by forces aligned with the public interest. That re-examination should take the form of a notice of inquiry, led by a task force with expertise and hierarchical prominence comparable to the Commission's offices on reliability and enforcement. Fact-gathering and analysis, instead of continuous approvals, will help us ensure that future mergers are, as Section 203 requires, consistent with the public interest. ■

[6] *Ibid* at 286-287.

[7] *Ibid* at 270.

[8] *Ibid* at 308.

HOW SCALABILITY IS TRANSFORMING ENERGY INDUSTRIES

*Adonis Yatchew**

ABSTRACT

Fracking, a combination of hydraulic fracturing and horizontal drilling, has upturned oil markets, not so much because it has opened up new supplies, but because it is *scalable*. OPEC's ability to influence prices has been undermined because reductions in supply by its members are met with reciprocal increases from shale sources. The technology has also produced a surfeit of natural gas in North America which is driving globalization of natural gas markets.

In electricity industries, *scalable* distributed energy resources (how could they be distributed if they were not available at small scales?) such as wind, solar and storage continue to experience rapid declines in costs. They are poised to fundamentally alter the structure and regulation of electricity industries, particularly as they place competitive pressures on incumbent utilities. These changes spawn a host of regulatory, institutional and legal issues. Among them, the potential for impaired or stranded utility assets, supply reliability, tariff evolution, and cost allocation challenges.

INTRODUCTION[1]

For much of the 20th century increasing scale economies were the dominant force shaping the structure of energy industries. In electricity, generating units became ever larger to take advantage of improving scale efficiencies. In oil extraction, a small number of firms with global reach, capable of developing multi-billion dollar projects, dominated world oil markets. Natural gas industries, while continental in nature, were also dominated in most places by a small number of firms. Transmission and distribution, whether of molecules or electrons, were for the most part natural monopolies. Efficiency and profitability imperatives drove energy companies to become ever larger. These centripetal forces led to industries marked by a high degree of concentration and market power, but also having increased political and regulatory influence.

In the 21st century, these trends are being reversed. Natural gas and oil can be profitably extracted by small entities employing hydraulic fracturing and horizontal drilling technologies (fracking) – the minimum efficient scale has dropped by *three orders of magnitude*. This has fundamentally undermined the OPEC oil cartel, as is explained further below. In electricity, generating units were historically 500 MW or more in size. Today, distributed energy resources (DERs) can, in an increasing number of locations, be effectively and competitively deployed at scales that are *also three or more orders of magnitude smaller*. The continued declines in costs of DERs (such as wind, solar and batteries) may, in the not too distant future, lead to a tipping point where even low volume 'prosumers' may seek to untether themselves from the incumbent utility.[2]

Scale economies are not only a critical determinant of industry structure, in particular, the number of firms, but also of its regulation. Rate regulation of

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[1] This paper draws liberally on past papers, presentations and materials from undergraduate and graduate courses taught by the author, online: <https://www.economics.utoronto.ca/yatchew>.

[2] The term 'prosumer' (producer-*cum*-consumer), was coined in the 1980s by futurist Alvin Toffler. It is not clear that Toffler anticipated either small scale self-generation of electricity, or 3-d printing. The latter is paving the way to a 'self-manufacturing' revolution.

natural monopolies has long since been recognized as a necessary but second-best alternative to competition. Industries where market power can be exercised relatively easily even if multiple firms are present (think electricity) have also been subject to regulatory intervention.

For purposes of this paper, scalability will mean that the activity can be undertaken at much smaller scales than previously. For example, distributed energy resources, of necessity, embody the notion that they can be deployed at small scales, else how would one distribute them?[3] The main thesis of this paper is that scalability is transforming not only the structure of energy industries, but also their regulation.

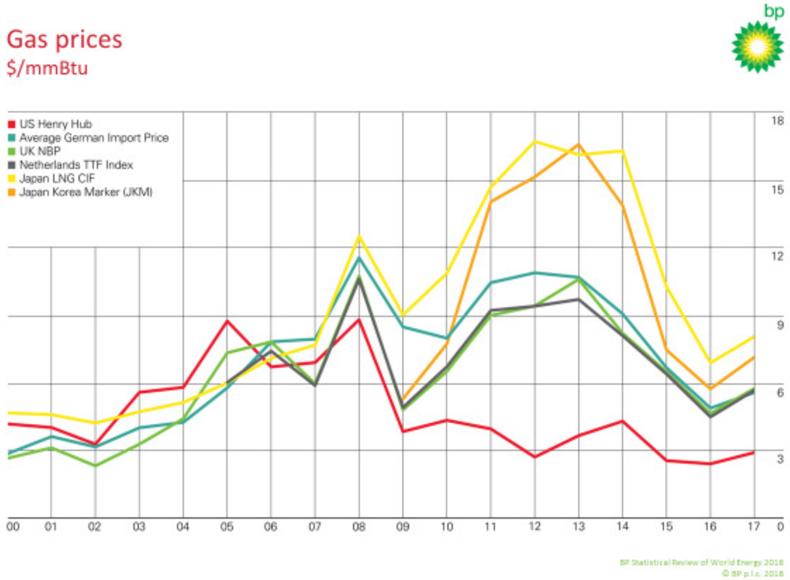
HYDROCARBONS

Shale Gas

At the beginning of this century, there were significant concerns that the U.S. would begin to run out of natural gas. By 2005, prices at Henry Hub, the reference price for U.S. natural gas, were the highest in the world at $9 USD per million BTUs (see Figure 1). Prospects for increasing sales from Canada to the U.S. were promising. Plans to build liquid natural gas (LNG) *import* terminals on the Gulf of Mexico were in progress. Shale gas constituted a negligible portion of total U.S. production (see Figure 2). Beginning around 2006, shale supplies began to ramp up steadily, increasing to 90 billion cubic feet (bcf) per day by 2018. With average daily U.S. consumption levels presently around 75 bcf per day, U.S. LNG exports are on the rise.

The impacts of this growing supply are clearly evident in natural gas prices. In 2009, in the midst of the financial crisis, reference natural gas prices – in Europe, Japan and the U.S. – plummeted. Then a recovery began – everywhere except in the U.S. – where they have been at about one third to a half of European prices.[4]

Figure 1: Natural Gas Benchmarks[5]



[3] But, one can also ask the obverse question – whether a technology can be scaled up. The proliferation of intermittent or non-dispatchable resources has led to concerns about the impacts on the electricity system when the *share* of such resources increases and crosses certain thresholds. Furthermore, a technology such as solar may be difficult to scale up in countries with high population density, such as China and India.

[4] The very high LNG prices in Japan from 2011 to 2014 were a consequence of the Fukushima disaster which forced Japan to increase its imports of natural gas.

[5] "BP Statistical Review of World Energy 2018" (2018) 67 BP Statistical Review of World Energy, online: <https://www.bp.com/en/global/corporate/energy-economics/statistical-review-of-world-energy/downloads.html>.

The consequences for Canada were major. Natural gas exports to the U.S. declined and volumes on the TransCanada Mainline deteriorated to the point that the National Energy Board (NEB) held a lengthy proceeding to try to remedy the impacts on Mainline tariffs. Thus, fracking technology had not only a supply and price impact, but regulatory repercussions, requiring a delicate decision on the part of the NEB.[6] Eventually, flows on certain eastern portions of the Mainline system were *reversed* to allow the import of U.S. natural gas into Canada.[7]

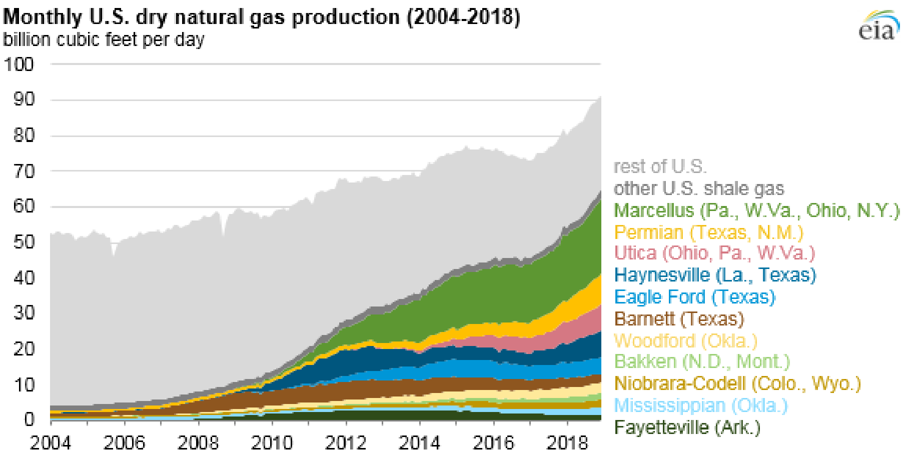
Low U.S. natural gas prices have also impacted Canadian *electricity* export markets. For example, Manitoba Hydro has made substantial investments on the expectation of export opportunities. However, low priced natural gas electricity generation has impacted its competitiveness in U.S. markets.[8]

Fracking has provided a vast new source of natural gas in North America – about 70 per cent of U.S. production of natural gas in the U.S. is from shale, and supply now exceeds demand. Historically, natural gas markets have been continental. And, although the process of supplying LNG to other continents (liquefaction, transportation and regasification) is still expensive, LNG prices at least provide an upper bound to natural gas delivered by pipeline (e.g., in Europe) particularly as LNG import terminals proliferate. As Qatar, Australia and the U.S. compete in LNG markets, along with other smaller providers, natural gas spot price differentials are beginning to narrow.

Shale Oil

The tectonic shift in oil markets followed the shift in natural gas markets by about 5 years. In 2014, prices plummeted from previous highs of well over $120 USD per barrel, to levels below $30. Multiple factors contributed to this drop, but it is arguable it was to a significant degree a consequence of the scalability of fracking because it led to fundamental changes in strategic behaviour by OPEC.

Figure 2: U.S. Natural Gas Production[9]



[6] For an early analysis of this decision, see Gordon Kaiser, "The TransCanada Mainline Decision: Toward Hybrid Regulation" (2013) 1 Energy Regulation Quarterly, online: <http://www.energyregulationquarterly.ca/case-comments/the-transcanada-mainline-decision-toward-hybrid-regulation#sthash.Xr66T926.dpbs>.

[7] Efforts to convert come of TransCanada's underutilized natural gas pipelines to oil – the 'Energy East' proposal – were unsuccessful and subsequently abandoned.

[8] See, e.g., Adonis Yachew, *Before the Public Utilities Board of Manitoba, Manitoba Hydro General Rate Application, 2017/18 and 2018/19, Expert Testimony of Adonis Yatchew, November 15, 2017* (2017), online: <http://www.pubmanitoba.ca/v1/proceedings-decisions/appl-current/pubs/2017per cent 20mhper cent 20gra/iecper cent 20reports/yatchewper cent 20report.pdf>.

[9] Jack Perrin & Emily Geary, "EIA adds new play production data to shale gas and tight oil reports" *U.S. Energy Information Administration* (19 February 2019), online: <https://www.eia.gov/todayinenergy/detail.php?id=38372>.

"Whereas in the past OPEC might have coordinated a supply reduction to sustain prices, its ability to do so became far more limited because shale producers (and others) could fill the gap. OPEC's strategy was to retain market share rather than sustain higher prices. Thus, the peculiar features of the shale revolution have altered the nature of supply in critical ways. Not only are entirely new sources now technologically viable, they can be brought online in tiny increments – as noted above, the cost of a productive shale well is three orders of magnitude smaller than conventional mega-projects."[10]

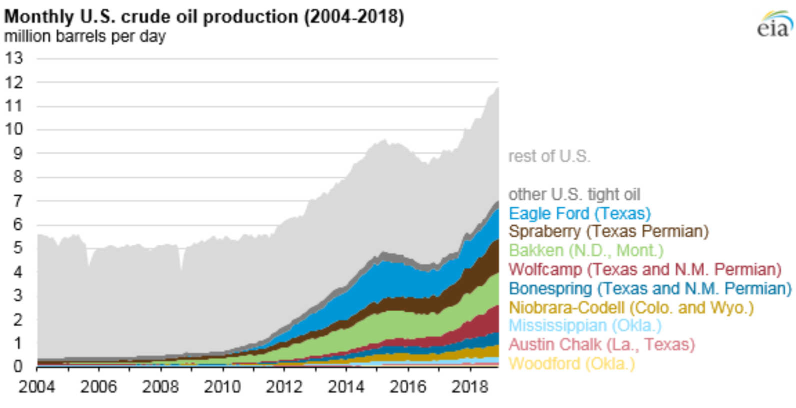
The initial speculation in 2014 was that well-endowed conventional suppliers would be able to drive out U.S. shale. That would not be the case. The drop in oil prices in 2014[12] was followed by a reduction in U.S. oil production in 2015 and 2016 (see Figure 3). But shale producers found ways to reduce costs, and as prices began to increase, their production rebounded. It continues to grow.[13]

The Effects of Scalability

Fracking for natural gas and oil has provided for a scalable response by many producers as market conditions change. Scalability of shale also reduces risks – wells do not last long – usually about two years – but capital requirements are low and lead-times short. Producers do not need to rely on long-term predictions of prices to inform their investment decisions. Furthermore, equipment used in extraction can be used in both oil and natural gas production.

More importantly, in oil markets, scalability has further limited unilateral or cartelized market power. Indeed, OPEC has over the last few years sought agreements with Russia, which is not a member, to reduce production in order to support prices. This in turn may restore a degree of market power to OPEC.[14] With increases in the price of oil during the first quarter of 2019, shale production is ramping up.

Figure 3: U.S. Oil Production[11]



[10] D. Dimitropoulos & A. Yatchew, "Discerning Trends in Commodity Prices" (paper delivered at a workshop on "Commodity Super-Cycles" at the Bank of Canada, (April 2015), "Discerning Trends in Commodity Prices" (2017) 22:3 Macroeconomic Dynamics 683-701.

[11] Source: see *supra* note 9.

[12] In a remarkably prescient observation, at least two years prior to the 2014 decline when prices for WTI were about $120 USD, a physics professor at Berkeley, asked "How high can the price of oil go? In the long term, it should not be able to stay above the synfuel price of $60 per barrel…There is another upcoming source of liquid fuel that could drive the price of oil lower, and that could even challenge the profitability of synfuel. It's called shale oil." Richard A. Mueller, *Energy for Future Presidents: The Science Behind the Headlines* (New York: W. W. Norton & Company, 2012) at 108.

[13] See, e.g., Emily Geary, "U.S. crude oil production grew 17 per cent in 2018, surpassing the previous record in 1970", *U.S. Energy Information Administration* (9 April 2019), online: <https://www.eia.gov/todayinenergy/detail.php?id=38992&src=email>.

[14] In addition to undermining the market power of OPEC, there have been other major geopolitical consequences, for example, on Russia and Venezuela. The potential for increased LNG exports to Europe may, in time, reduce the influence of Russian gas on European natural gas prices. Future geopolitical ramifications are subject to wide speculation. Suffice it to say that non-democracies have produced the dominant share of world oil production, receiving trillions of dollars of oil revenues in excess of the costs of production.

For Canadian oil producers, heavily invested in large long-term projects requiring long periods to recover capital outlays, the collapse in oil prices combined with pipeline constraints, have been devastating, emanating throughout the Alberta economy, a circumstance from which the Province has yet to recover. Efforts are being made to mitigate the pipeline bottlenecks by expanding the use of *another scalable technology – rail transportation of oil*. The Canadian dollar – which is highly correlated with world oil prices – has also been strongly impacted by the shale revolution (see Figure 5).

Figure 4: Crude Oil Prices[15] (Constant 2017 USD)

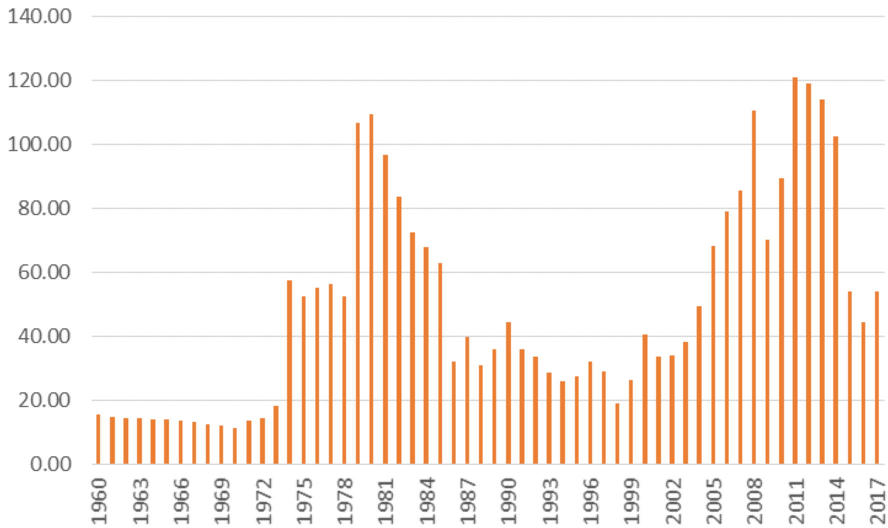
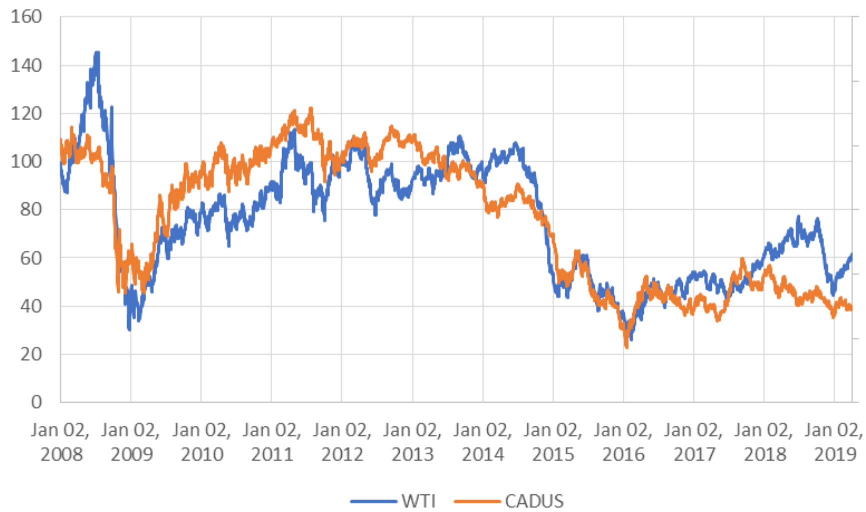


Figure 5: Oil Prices in USD (blue) vs CAD/US Exchange Rate (orange)[16]



[15] *Supra* note 5. The major increases in oil prices in the 1970s were a consequence of OPEC actions. The opening of the North Sea fields drove prices down, beginning in the mid-1980s. Prices again rose in the 21st century, with a major plunge as a result of the 2008-2009 financial crisis.

[16] West Texas Intermediate oil crude prices.

One is inclined to ask: why did the shale revolution take place, first in natural gas, then in oil? Several factors were critical – declining U.S. natural gas supplies and concomitant increasing prices, as well as high and increasing oil prices.[17] The development of the technology was incremental, with increasing efficiency and cost reductions occurring over time. But from a regulatory standpoint, it is unlikely that it would have occurred had it not been for the deregulatory trends that began in the late 1970s, and spread to natural gas markets.

ELECTRICITY INDUSTRIES

Economies – Past, Present and Future

In the past, electricity industries have been characterized by strong economies of scale in generation, and extreme economies of scale in 'wires' (natural monopolies in transmission and distribution). As deregulation spread to electricity industries, beginning in the 1990s, the wires segments (transmission and distribution) which remained fully regulated, were, in many jurisdictions, unbundled from generation in order to expose the latter to competition.[18]

Current electricity industry trends are characterized by decentralization, digitization and decarbonization (the "three d's"). Decarbonization policies are driving technological innovations that alter 'minimum efficient scale' in generation. (Think 800+ MW coal generator vs. 2 MW wind or 5 kW roof-top solar.) Digitization is facilitating integration of distributed energy resources and decentralization of wires (think microgrids).

Electricity industries have displayed other important 'economies':

- economies of density – distributors with a more densely distributed customer base usually enjoyed lower unit costs;[19]

- economies of contiguity – service of contiguous, or at least not too widely separated areas, also had beneficial impacts on costs;[20]

- vertical economies of scope which were sometimes used to justify vertical integration of generation, transmission and distribution;[21]

- horizontal economies of scope which underlie the multi-utility model (e.g., natural gas and electricity) contributed to lower administration costs.[22]

Decentralization and digitization are driving two 'new' economies:

- vertical scope economies at a much more granular level between 'wires' and DERs are growing, blurring the line between certain 'natural monopoly' segments of the industry, and those that are potentially competitive;

- the 'network effect' – the ability of individual participants on the grid to interact with others for purposes of coordination and exchange.

[17] Economists sometimes quip that the best cure for high prices is…high prices. This is a lesson also relevant in competitive electricity markets, such as energy-only markets.

[18] Incentive regulation also began to take hold, in an effort to drive productivity growth in regulated monopolies.

[19] Customer density is a common variable in estimation of the costs of distributing electricity. See, e.g., D. Dimitropoulos and A. Yatchew, "Is Productivity Growth in Electricity Distribution Negative? An Empirical Analysis Using Ontario Data", (2017) 38:2 The Energy Journal 175-200.

[20] For example, the Ontario Energy Board, in RP-2003-0044, concluded that the emergence of 'embedded distributors' within the boundaries of existing distributors, would lead to "diseconomies of contiguity", online: <https://www.oeb.ca/documents/cases/RP-2003-0044_Transcripts/decisionwithper cent 20reasons_270204.pdf>.

[21] Other industries were also often vertically integrated – for example, telephone companies provided both local and long-distance services, essentially due to economies of scope. Indeed, the legal and regulatory battles that ensued in the 1980s which eventually separated 'local loop' from long distance service revolved around economies of scope arguments.

[22] For example, Utilities Kingston provides electricity and natural gas to the city of Kingston, Ontario in addition to various other services.

Declining Costs of Key Scalable Technologies

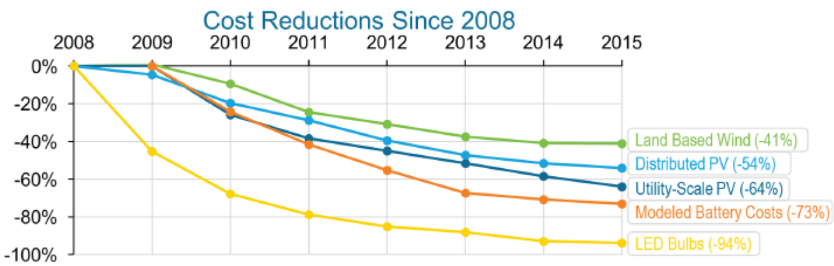
The costs of emerging technologies which are transforming electricity industries have been dropping at a rapid pace. Figure 6 provides an especially salient picture: over the period 2008 to 2015, costs of wind generation dropped by 41 per cent; photovoltaics dropped more than 50 per cent; and battery costs by 73 per cent.[23]

Non-dispatchable generation such as on-shore wind is priced at about 6 U.S. cents/kWh for new installations. Solar photovoltaic is also at 6 U.S. cents/kWh. Combined cycle natural gas electricity generation for new installations costs about 5 U.S. cents/kWh if used at high capacity, and conventional combustion turbine generation is at about 9 U.S. cents/kWh if used at low capacity, as is often the case.[25] Furthermore, in the U.S., over the period 2014 to 2018 costs of onshore wind have dropped in real terms by about 40 per cent, solar photovoltaic by 60 per cent and solar thermal by 40 per cent.[26] Capacity markets have been proliferating, driven by the need to maintain reliability as intermittent resources expand.

Storage

Storage is seen as the linchpin to overcoming two of the most pressing challenges: the intermittency of wind and solar generation, and decarbonization of the transportation sector. There are initiatives along multiple lines, but chemical battery storage that is scalable and cost effective would substantially overcome both hurdles. Although lithium-ion battery prices continue to drop dramatically, it may be that a very different technology will ultimately provide us with grid-scale storage because design parameters are much less restrictive than in transportation applications. Weight is not a factor for stationary batteries, and operating temperatures can be much higher. However, breakthrough technologies, especially from a cost point of view, are yet to be discovered.[27]

Figure 6: Cost Reductions in Key Technologies [24]



[23] LED bulb costs have declined by a stunning 94 per cent.

[24] Source: *Revolution…Now, The Future Arrives for Five Clean Energy Technologies – 2016 Update* (September 2016), online: <https://www.energy.gov/sites/prod/files/2017/05/f34/Revolution%20Now%202016%20Report_2.pdf>. "Notes: Land based wind costs are derived from levelized cost of energy from representative wind sites…Distributed PV cost is average residential installed cost...Utility-Scale PV cost is the median installed cost…Modeled battery costs are at high-volume production of battery systems, derived from DOE/UIS Advanced Battery Consortium PHEV Battery development projects. LED bulb costs are cost per lumen for A-type bulbs..."

[25] These are Levelized Cost of Energy (LCOE) numbers which embed assumptions about depreciation lifetimes, cost of fuel and, as indicated, utilization capacity factors. US, U.S. Energy Information Administration, *Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2019* (February 2019) Table 1b, at 8, online: <https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf>. Combined heat and power systems, because of their high efficiency, have the potential for increasing market penetration. See US, U.S. Department of Energy, *Combined Heat and Power Technical Potential in the United States* (March 2016), online: <https://www.energy.gov/sites/prod/files/2016/04/f30/CHPper cent 20Technicalper cent 20Potentialper cent 20Studyper cent 203-31-2016per cent 20Final.pdf>; also US, U.S. Energy Information Administration, *Many industries use combined heat and power to improve energy efficiency* (27 July 2016), online: <https://www.eia.gov/todayinenergy/detail.php?id=27252>.

[26] Author's calculations based on *ibid*, Table 1, at 6.

[27] A leading researcher in this area is Professor Donald Sadoway at MIT who focusses on liquid-metal batteries. The elements that he works with are much more abundant than those used in lithium-ion batteries, and therefore much cheaper. In his presentations, he often says "If you want batteries to be dirt-cheap, you need to make them out of dirt".

Distributed generation combined with storage creates the possibility of electricity self-sufficiency for small consuming units or groups of units, for example, on a microgrid.[28] At the same time, distributed resources can increase the resiliency of a system and ensure supply at institutions such as subways and hospitals where uninterrupted service is essential.[29]

Regulatory Challenges Associated With Storage

In electricity industries, assets are often used for multiple purposes, providing different types of services, or fulfilling different needs. This is yet another instance of the 'economies of scope' concept, where in this case, 'multi-products' can occur at various stages of production.

Electricity storage has this feature as it can be used for a variety of purposes, fulfilling various functions. This 'multi-product output' feature creates an ambiguity when attempting to allocate costs to the different uses. There is typically no formulaic approach leading to a unique allocation of costs based on 'cost causality'.

Grid-based energy storage has numerous applications and can confer a wide variety of benefits.

- In wholesale energy markets it can convey financial benefits to the facilities owner through energy arbitrage; it can produce system benefits through avoided or deferred investment in additional generation capacity; it can provide ancillary services.

- It can produce transmission benefits through avoided or deferred investment in transmission capacity or upgrades.

- At the distribution level, it can mitigate or relieve congestion; increase resiliency; delay or avoid investment in distribution capacity; and provide ancillary services.

- At the customer level, it can improve reliability and provide backup for critical loads (such as hospitals, transportation systems, communications and information systems).

- Energy storage becomes more important as intermittent renewables provide an increasing share of energy. It may also directly mitigate the carbon issue to the extent that it displaces gas-fired generation.

- In the transportation sector, storage is critical for electric vehicle charging given high load requirements, especially for rapid charging stations.

Given this wide range of activities and benefits cost allocation is a delicate matter. The relevant literature (which relies on cooperative game theory) leads to a range of cost allocations which are economically efficient, equitable and apprehensible within policy and regulatory settings. A common sense approach involves comparing the total costs of providing each output or service on a 'stand-alone' basis, to the costs of producing the outputs jointly. The savings achieved by the latter are then divided up.

When applied in settings where all firm outputs are sold in price-regulated markets, these cost allocation principles may be contested on grounds of equity. For example, cost allocation across customer groups is often a contentious matter in regulatory proceedings. However, if some outputs are sold in regulated markets, and others are not, there is an additional complication arising out of the risks that the utility might have the incentive to cross-subsidize competitive market activities by regulated activities. Misallocations can result in claims of anti-competitive behaviour, potentially undermining competition.

In some cases, the associated benefits can be quantified with a reasonable degree of accuracy,

[28] Though not a focal point in this paper, microgrids can contribute important resiliency benefits. In downtown Tokyo, there is an area called Ropponggi Hills, which provides its own electricity, heat, and cooling. Despite the devastating earthquake and tsunami in March 2011, and the Fukushima disaster, service in Ropponggi Hills was uninterrupted. The area also contributed to service restoration in other areas. Its Sendai microgrid was able to serve most of the nearby university campus as well as critical facilities such as a hospital. Distributed energy systems and microgrids also provided some advantages after Hurricane Sandy. Imagine what Puerto Rico would have looked like after Hurricane Maria had there been a significant number of micro-grids which could operate as islands, or link to neighbours or to the larger grid. See *Utility of the Future. An MIT Energy Initiative response to an industry in transition,* MIT Energy Initiative, December 2016 at 67, online: <http://energy.mit.edu/publication/utility-future-report>.

[29] Such facilities traditionally rely upon on-site backup generation, another type of distributed energy resource.

in others they are more difficult to calibrate, thereby complicating the allocation of costs to cost centers. But perhaps the most important benefits, and most difficult to quantify, are beneficial spillover effects and innovation that occurs as a result of 'learning by doing'.

Additional Considerations

Regulation of electricity industries has undergone considerable changes in recent decades. In many jurisdictions, incentive regulation replaced cost-of-service or rate-of-return regulation. Efforts to introduce competitive forces into the generation segment led to vertical separation or unbundling. Different implementations evolved into models with widely varying degrees of competition in generation, in some cases relying heavily on long-term supply contracts. Thus, e*ven in the absence of radical technological changes, effective regulation has been a constantly moving target*.

The rapidity with which costs of DERs are declining suggests that we are potentially on the cusp of disruptive changes, requiring the rethinking of utility business models and regulatory approaches. Disruptive innovation in regulated settings has precedent, most prominently in the telecom and information industries.

The increasing role of DERs creates new risks for incumbent utilities, as such resources can reduce sales. This, in turn may require revisiting allowable rates of return earned by utilities, and changes in rate design. For example, it may be that rates that are less dependent on volumetric measures would be more appropriate as sufficient wires capacity needs to be present to meet peak local demand even if total volume declines.

Ownership of storage by distributors and whether these costs can be included in rate base portends to be another contentious issue. Ownership by distributors reduces the incentives for distributors to build wires infrastructure[30] rather than relying on storage installations. On the other hand, 'level playing field' issues also arise.

Given environmental decarbonization objectives, the question arises how best to promote and fund innovation. A case can be made that innovation should be funded at least in part by ratepayers and/or taxpayers. The reasoning is that the spillover effects of innovation can vastly exceed the direct benefits arising from avoided T&D investment and arbitrage opportunities. Furthermore, innovation which does not lead to intellectual property, reduces the incentives for experimentation by utilities. In short, utilities that are responsible to their shareholders do not have the built-in incentives to produce socially optimal levels of expenditure on innovation.[31]

One of the complications which arises is the blurring of lines between DERs and grids. Distributing utilities are well positioned to take advantage of economies of scope which arise from operating the distribution wires and owning and dispatching storage units. They can identify, deploy and integrate storage in locations which best defer wires investments, reduce congestion and improve reliability. In addition, distributors have access to facilities that can site storage installations as well as to rights-of-way.

Furthermore, there can be considerable variation in outage rates and reliability within a distribution system. Some locations may experience especially high outage rates, for example, as a result of the relative age of facilities or a high incidence of congestion. This is arguably inequitable from a customer perspective. Battery storage can serve to mitigate such inequities.

CONCLUDING COMMENTS

Natural gas and oil industries have been profoundly transformed in little more than a decade by advances in fracking. This highly scalable technology has undermined OPEC market power and allowed the U.S. to become a leading world producer of hydrocarbons. 'Peak-oil' has been turned on its head: the question is no longer 'When will supply reach its peak?", but "When will world demand for oil begin to decline?"

[30] This is akin to the Averch-Johnson effect.

[31] See, e.g., James M. Coyne, Robert C. Yardley, Jessalyn Pryciak with comments by Adonis Yatchew, "Should Ratepayers Fund Innovation?" (2018) 6:3 Energy Regulation Quarterly, online: <http://www.energyregulationquarterly.ca/articles/should-ratepayers-fund-innovation#sthash.7MjneaUp.dpbs>.

The rapid decline in costs of scalable electricity technologies – DERs – is also transforming electricity industries. Along the way, DERs have spawned a host of challenges – regulatory, institutional and legal – among them:

- There are risks that some assets belonging to incumbent utilities will become impaired as a result of under-utilization, or even stranded.[32] These include generation and wires assets. Who should absorb the costs?

- Tariff redesign may be indicated as prosumer generation increases, but connection to the grid remains necessary. This may lead to greater emphasis on the fixed relative to the volumetric component of tariffs.

- Storage facilities, which we have focused on, raise a range of cost allocation issues given their multiple uses. These are further complicated as some activities are traditionally regulated (such as substitution of storage for wires investments), others presumably unregulated (such as energy arbitrage).

- The essentiality of reliability in the presence of intermittent supplies has contributed to the proliferation of capacity markets, which involve highly complex administrative processes and vigilant market oversight. Rule design can create risks of regulatory arbitrage, which may not be foreseen.

There is a continuing need for redesign and evolution of regulatory institutions and supporting legislation. One tends to worry about market failure, but regulatory failure is also a threat. Under-regulation can result in spectacular failures (think Enron, the 2008 financial crisis and Facebook privacy issues). Over-regulation can lead to failures that are more subtle but can have large and far-reaching implications, most importantly stifling innovation and productivity growth, but also unnecessarily increasing costs. ■

[32] Recall the impacts on the MainLine of U.S. shale gas.

NATIONAL ENERGY BOARD ADVICE TO THE MINISTER OF NATURAL RESOURCES ON *OPTIMIZING OIL PIPELINE AND RAIL CAPACITY OUT OF WESTERN CANADA*

*Rowland J. Harrison, Q.C.**

None of the additional facilities that are proposed to address the current shortfall in oil pipeline and rail capacity out of western Canada – pipeline expansions (Enbridge Line 3, TMX), a new pipeline (Keystone XL) and additional rail tanker cars – will be available in the short-term. Optimizing the use of existing capacity has, therefore, become all the more critical.

On 30 November 2018, the Minister of Natural Resources acted under the lightly-used Part II ADVISORY FUNCTIONS of the *National Energy Board Act*[1] to ask the Board's advice on three questions:

1. Is the current monthly nomination process to access available capacity on oil pipelines functioning appropriately, consistent with the "common carrier" provisions of the *National Energy Board Act* and efficient utilization of pipeline infrastructure (for example, by auctioning uncontracted export capacity to smaller producers)?
2. Are there any other impediments to the further optimization of pipeline capacity that could be addressed by the National Energy Board, governments or pipeline companies, in the short-term and long-term?
3. Are there short-term steps to further maximize rail capacity that could be addressed by governments to alleviate the current situation?[2]

The Board provided its advice in a March 2019 report under the title *Optimizing Oil Pipeline and Rail Capacity out of Western Canada.*[3]

The context for Question 1 is found in subsection 71(1) of the NEB Act, which, in effect, provides that oil pipeline companies shall act as common carriers. The general obligation is, however, subject to "such exemptions, conditions or regulations as the Board may prescribe…" In fact, several of the major pipelines out of Alberta operate under Board-approved contracted capacity, with limited uncommitted capacity available to satisfy common carrier obligations.[4]

* I wish to acknowledge helpful comments from Dennis McConaghy. Responsibility for the content, however, is entirely mine.

1 RSC, 1985, c N-7, as amended (NEB Act).

2 Canada, National Energy Board, *Optimizing Oil Pipeline and Rail Capacity out of Western Canada*, Advice to the Minister of Natural Resources by the NEB, (28 March 2019) at 2-3, online: <http://www.neb-one.gc.ca/nrg/sttstc/crdlndptrlmprdct/rprt/2019ptmzngcpct/2019ptmzngcpct-eng.pdf>, (referred to hereafter as the "NEB March Report"). In December 2018, the Board published a Background Report *Western Canadian Crude Oil Supply*, Markets, and Pipeline Capacity, (28 March 2019), <http://www.neb-one.gc.ca/nrg/sttstc/crdlndptrlmprdct/rprt/2018wstrncndncrd/2018wstrncndncrd-eng.pdf>, (referred to hereafter as the "NEB December Report").

3 *Ibid*, *NEB March Report*.

4 *Ibid*, *NEB December Report,* at 17.

The notable exception is the largest oil pipeline by far, the Enbridge Mainline, which has no contracted capacity, such that the availability of its whole capacity must satisfy the general requirement of subsection 71(1). Enbridge[5] does this by apportioning capacity. Apportionment is conducted in accordance with rules laid out in the pipeline's tariff and allegedly gives rise to opportunities to "game the system" by nominating and being allocated capacity that may not actually be used by the shipper, resulting in what are often referred to as "air barrels". The process also gives advantages to major players with upstream and downstream infrastructure that provides supply and takeaway capacity.

Against this background, the Board, in response to Question 1, reported that pipelines transporting crude oil out of western Canada are currently operating at full capacity. In the last quarter of 2018, the average utilization rate on the major export pipelines was 98 per cent. Any notable increase in throughput would have to come from new capacity additions.

The Board noted that integrated producers and shippers that own or have contracted crude oil storage and refinery capacity have a greater ability to acquire pipeline capacity.[6] The additional flexibility available to these parties to access pipeline capacity was the result of past investments and, furthermore, involved facilities beyond the jurisdiction of the NEB. The Board added that changes "would have significant effects on markets and stakeholders…but would not increase utilization further."[7]

The Board concluded that existing monthly nomination procedures do not appear to affect operational efficiency and do not raise compliance concerns. However, it added that there is scope to improve existing verification procedures, while noting that designing and establishing a new and integrated verification framework extended beyond the Board's oversight of federally-regulated pipelines. Without broad consultation with industry, governments, and regulatory bodies, "there is a significant risk of unintended consequences…"[8] A first step might be an interjurisdictional conference, in which the Board would participate.[9]

The obvious observation (although the Board refrained from making it) is that, with the advent of additional oil pipeline capacity, issues around nominations and verification would largely disappear. Furthermore, additional capacity would give greater leverage to unintegrated Alberta crude producers and other shippers, including the Alberta government.

In response to Question 2, the Board identified potential solutions to further optimizing capacity, such as building partial upgraders that would reduce the amount of diluent needed to ship bitumen. This would result in freeing up some capacity currently used to import diluent; this capacity could then be reversed and used to ship bitumen. Such solutions would, however, "require structural changes to the market, significant investments, and a long time horizon."[10] Furthermore, private investors may be "reluctant to make major investments in projects that may become uneconomic if new pipeline capacity is added."[11]

In responding to Question 3, the Board, in addition to noting the additional cost of moving oil by rail, reported that the timing and approval of additional pipeline capacity is hampering private investment in rail capacity. While there might be a role for governments, "any policy action has the potential to create unintended consequences given the complexity of the system."[12]

The NEB's overall conclusion – that the solution to Canada's current oil pipeline capacity challenges lies in adding new capacity – is of course not surprising. Two observations by the

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[5] *Ibid* at 17. And the other pipelines with available uncontracted capacity. In the *NEB December Report,* the capacity available for uncontracted transportation is estimated as follows: Trans Mountain 82 per cent; Keystone 6 per cent; and Express 10 per cent.

[6] *Ibid*, *NEB March Report*, at 13.

[7] *Ibid* at 1.

[8] *Ibid* at 14.

[9] *Ibid* at 15.

[10] *Ibid* at 2.

[11] *Ibid.*

[12] *Ibid.*

Board are, however, interesting. Firstly, the Board noted that certain structural advantages enjoyed by some market participants are the result of past investments by those participants. The implication is that those participants should not be penalized. Secondly, with respect to the possibility of government action, the Board cautions that "not all outcomes can be predicted"[13] and that "any policy action has the potential to create unintended consequences given the complexity of the system."[14] These two observations perhaps make it unlikely that any policy or regulatory change will follow from the Board's report.

However, other factors are likely to lead to significant changes in the Canadian oil pipeline capacity market over the next two to three years, such as the completion of any or all of the Enbridge Line 3, TMX or Keystone XL projects. Furthermore, Enbridge, which, as noted, currently does not offer contracted capacity and operates 100 per cent as a common carrier, is exploring with its shippers the possibility of offering contracted capacity on its Mainline system, to be implemented on the expiry of its current agreement with shippers in 2021.

Finally, it has sometimes been commented that Part II of the *NEB Act*[15] (ADVISORY FUNCTIONS) is somewhat anomalous in that it empowers the Minister to call on the Board for advice independently of the Board's quasi-judicial regulatory responsibilities. Historically, the explanation is found in the fact that at the time the Board was established in 1959 there really was no other federal department or agency with explicit responsibilities relating to energy. Apparently, it was thought that the newly-established Board would become the *locus* of the government's knowledge and expertise in the area. Interestingly, notwithstanding that there are now other government institutions with related mandates – Natural Resources Canada (as successor to Energy, Mines and Resources Canada) and Statistics Canada, for example – Part II of the *NEB Act*[16] is proposed to be carried forward under Bill C-69[17], which would replace the NEB with the *Canadian Energy Regulator*. ■

[13] *Ibid* at 21.

[14] *Ibid* at 2.

[15] *Supra* note 1.

[16] *Ibid*.

[17] 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, 2015.

THE PATCH: THE PEOPLE, PIPELINES, AND POLITICS OF THE OIL SANDS, CHRIS TURNER

Reviewed by Rowland J. Harrison, Q.C.

The rise of the Canadian oil sands is a remarkable story. In *THE PATCH: The People, Pipelines, and Politics of the Oil Sands*, Chris Turner recounts the many facets of that story, comprehensively and objectively. As the author himself describes it, the book is a record of the collision between competing world views: "…the first major battleground between the economic necessity of oil production and the ecological necessity of reducing greenhouse gas emissions…a defining story of the twenty-first-century energy business."[1] Not surprisingly, *THE PATCH* was the winner of the 2018 National Business Book Awards announced in October.

It has taken less than 10 years for the oil sands – and associated pipelines – to emerge as one of the most divisive subjects in Canadian politics. Yet the history of attempts to develop the resource extends as far back as the late 19th century. The first rudimentary extraction plants were constructed in the late 1920s and 30s but it was the commencement of Great Canadian Oil Sands'[2] mining operation in 1967 that was the catalyst for later developments, beginning with the startup of the Syncrude project in 1978.

By the mid-1990s, industry was forecasting capital expenditures on oil sands projects of $25 billion within 25 years. It took only five years to reach that figure. From 1999 to 2013, more than $200 billion was invested. In 2006, Statistics Canada reported that Alberta was in the midst of "the strongest period of economic growth ever recorded by any Canadian province", with annual GDP and population growth both above 10 per cent. In 2006, Calgary issued building permits for projects worth $4.7 billion, $1 billion more than the figure for Toronto.

It is surprising to realize now that there was little controversy surrounding this extraordinary growth until the early 2010s. Turner recounts that, as recently as 2008, Enbridge's Alberta Clipper project, a 36 inch line with a capacity of 450,000 barrels per day to move oil sands production from Hardisty, Alberta to Superior, Wisconsin, moved through *National Energy Board* (NEB) hearings without serious controversy. Turner quotes an Enbridge spokesman as telling the *Regina Leader-Post* in Saskatchewan that the pipeline was "the biggest project nobody knows about." Earlier in 2008, Trans Mountain completed its Anchor Loop project to twin its existing pipeline through parts of Jasper National Park and Mount Robson Provincial Park. The project had been approved by the NEB in 2004 without fanfare or rancor.

Yet by 2015, TransCanada's proposed Keystone XL project[3] had "turned oil sands pipelines into an international political issue and a proxy of the first resort for the much broader debate about climate and energy policy."[4]

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[1] Chris Turner, T*HE PATCH: The People, Pipelines, and Politics of the Oil Sands,* (Toronto: Simon & Shuster, 2017) at 13.

[2] Great Canadian Oil Sands (GCOS) evolved into the present day Suncor.

[3] The saga of the Keystone XL project is recounted in McConaghy, ''Dysfunction: Canada after Keystone XL" (June 2017) 5:2 Energy Regulation Quarterly.

[4] *Supra* note 1 at 119.

"Finally, there was a single villain, a focal point for action, a way to measure victory. And a pair of phrases – *the biggest carbon bomb, game over for the planet* – that reduced the staggering scope of the climate change problem to the scale of a campaign's concise slogans."[5] He later adds: "and so the proximate target became the enduring proxy for the wider debate, and the proxy became the vessel into which…the entire carbon economy's sins were stuffed."[6] Calgary's Mayor Naheed Nenshi is quoted by Turner as expressing the frustration of an industry and much of the Alberta population: "For some reason that one-metre pipe has been asked to bear all the sins of the carbon economy."[7] Turner does an excellent job of explaining the dynamics that led to such a dramatic change in just a few short years.

Somewhat surprisingly, and to his deep disappointment, Turner encountered widespread, not just reluctance, but complete unwillingness by many of the industry's key players and some of its most vocal critics to speak to him. His conclusion:

> On one hand I can understand the reticence to go on record about a story that neither boosters nor critics believe has ever been told fairly, but I would argue that no agenda is well served by refusing to allow more light in; it only amplifies the distortions. The Patch's story is an important one, and it is still being written, and it should be shared.[8]

"Amen" to that!

THE PATCH is, however, much more than a clinical review of the politics and economics of the oil sands, pipelines and climate change. Turner sprinkles his narrative liberally with human interest stories of the diverse workforce and individual lives. There is the lobsterman who, by shuttling back and forth between Prince Edward Island and Fort McMurray, is able to maintain his lobster fleet. A member of the Athabascan Chipewyan First Nation is a heavy equipment operator at Imperial Oil's Kearl Lake mine while maintaining his traditional trapline. The Pakistani community brings cricket to town!

THE PATCH is also the story of the rapid growth of Fort McMurray, a city that nevertheless instills intense loyalty and pride among its more than 80,000 permanent residents.[9] Turner recounts the story of a Toronto city girl who was "shocked how quickly she fell in love with Fort McMurray."[10] More than 18 years after she and her husband moved there, in the summer of 2016 the biggest wildfire in Alberta's history, known as "The Beast", destroyed their home. Less than three months later, they had begun rebuilding.

From afar, Fort McMurray frequently suffers from the stereotypical picture of the frontier boom town, with the usual negative images of drugs, alcohol abuse, gambling and prostitution; it has been the subject of high-profile international press reports "that lingered on the lurid details…"[11] Turner, however, reports a 2014 study commissioned by the Fort McMurray municipal government that painted a different, more complex story. That study found that the rate of cocaine-related arrests in Fort McMurray was four times the Canadian average. Vehicle thefts were nearly twice the national average. Otherwise, however, Fort McMurray was actually less prone to crime than the rest of Canada:

> Rates for sexual assault and robbery were well below average. Overall the crime rate in Fort McMurray *decreased* by 44 per cent from 2003 to 2012 (it declined nationally by 17 per cent over the same period)…[T]he image of felonious chaos was mostly invented.[12] Turner also reports that, in 2015, Fort McMurray led the nation in per capita donations to the United Way.

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[5] *Ibid* at 233.
[6] *Ibid* at 255.
[7] *Ibid* at 253.
[8] *Ibid* at 323.
[9] Plus a "shadow" population of approximately 40,000.
[10] *Supra* note 1 at 294.
[11] *Ibid* at 163.
[12] *Ibid* at 164.

THE PATCH is an extremely valuable contribution to the existential debate that will almost certainly continue in Canada for the foreseeable future. It is also an engaging and enjoyable read. ■