Regulatory and policy issues of interest to the Muskrat Falls Inquiry

prepared for the Commission of Inquiry Respecting the Muskrat Falls Project by London Economics International LLC ("LEI")

July 11th, 2019

LEI was asked by the Commission of Inquiry ("the Commission") to address five regulatory and policy questions related to electricity, energy, and environmental policies in Newfoundland and Labrador ("NL"). LEI's review was high level and focused on selected relevant public documents; it was not intended to be an exhaustive review of all documents submitted to the Commission or related to the questions at hand. LEI's observations include the following:

- *while NL's system of electricity regulation shares many characteristics with other Canadian provinces, some aspects may need to be updated to adequately address sale of electricity to those who are not ratepayers;*
- *issues arising due to interconnection, including reliability standards, open access, and energy marketing, require additional consideration, particularly with regards to aspects such as risk management;*
- *environmental considerations should be incorporated into the Province's energy policy, and supported through an ongoing inter-ministerial working group;*
- *NL should explore moving beyond cost of service ratemaking to address both performance expectations and the role of non-utility distributed energy resources; and*
- *there is a limited role for renewable energy generation expansion in the coming decades, particularly for export; the primary focus for renewables should be on combining them with storage for isolated systems.*

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List of acronyms

AESO	Alberta Electric System Operator
AUC	Alberta Utilities Commission
BC	British Columbia
BCUC	British Columbia Utilities Commission
BP	Balancing Pool
Capex	Capital Expenditures
CIC	Crown Investments Corporation
COMFIT	Community Feed-In Tariff
COS	Cost of Service
CPI	Consumer Price Index
DER	Distributed Energy Resource
DNR	Newfoundland and Labrador Department of Natural Resources
DSO	Distribution System Operator
DSPP	Distribution Services Platform Provider
DUoS	Distribution Use of System
EIM	Energy Imbalance Market
ESM	Earnings Sharing Mechanism
EUB	New Brunswick Energy and Utilities Board
EV	Electric Vehicle
FERC	Federal Energy Regulatory Commission
FIT	Feed-In Tariff
FTE	Full Time Equivalent
GHG	Greenhouse Gas
GRA	General Rate Application
GWh	Gigawatt Hour
HVDC	High-Voltage Direct Current
IESO	Independent Electricity System Operator
IIS	Island Interconnected System
IPP	Independent Power Producer
IRP	Integrated Resource Plan
ISO	Independent System Operator
ISO-NE	New England Independent System Operator
km	Kilometers
kW	Kilowatt
kWh	Kilowatt Hour
LCOE	Levelized Cost of Energy
LEI	London Economics International LLC
LIS	Labrador Interconnected System
MB PUB	Manitoba Public Utilities Board
MSA	Market Surveillance Administrator

MWh	Megawatt
MWh	Megawatt Hour
NB	New Brunswick
NERC	North American Electric Reliability Corporation
NFAT	Need for and Alternatives to
NL	Newfoundland and Labrador
NL PUB	Newfoundland and Labrador Board of Commissioners of Public Utilities
NLH	Newfoundland and Labrador Hydro
NLSO	Newfoundland and Labrador System Operator
NP	Newfoundland Power
NSPI	Nova Scotia Power Incorporated
NUG	Non-Utility Generator
NYISO	New York Independent System Operator
NYSERDA	New York State Energy Research and Development Authority
O&M	Operations and Maintenance
OATT	Open Access Transmission Tariff
OEB	Ontario Energy Board
OPG	Ontario Power Generation
PBR	Performance-Based Regulation
PPA	Power Purchase Agreement
PPI	Producer Price Index
PSC	New York Public Service Commission
PUB	Public Utilities Board
PV	Photovoltaic
REC	Renewable Energy Credit
REV	Reforming the Energy Vision
RFP	Request for Proposal
RIIO	Revenue set to deliver strong Incentives, Innovation, and Outputs
ROE	Return on Equity
RSP	Rate Stabilization Plan
SRRP	Saskatchewan Rate Review Panel
TOU	Time of Use
TRR	Transmission Revenue Requirement
TWh	Terawatt hour
UARB	Nova Scotia Utility and Review Board
UK	United Kingdom
VAR	Value at Risk

1 Background

1.1 Client mandate

The Commission of Inquiry Respecting the Muskrat Falls Project ("the Commission") was established on November 20th, 2017 under the Public Inquiries Act, 2006. Justice Richard D. LeBlanc was appointed as Commissioner and is tasked, as stated in Section 4 of the Commission's Terms of Reference, with inquiring into the following matters:

a) "the consideration by Nalcor of options to address the electricity needs of Newfoundland and Labrador's Island interconnected system customers that informed Nalcor's decision to recommend that the government sanction the Muskrat Falls Project;"
b) "why there are significant differences between the estimated costs of the Muskrat Falls Project at the time of sanction and the costs by Nalcor during project execution, to the time of this inquiry together with reliable estimates of the costs to the conclusion of the project;"
c) "whether the determination that the Muskrat Falls Project should be exempt from oversight by the Board of Commissioners of Public Utilities was justified and reasonable and what was the effect of this exemption, if any, on the development, costs and operation of the Muskrat Falls Project;" and
d) "whether the government was fully informed and was made aware of any risks or problems anticipated with the Muskrat Falls Project, so that the government had sufficient and accurate information upon which to appropriately decide to sanction the project and whether the government employed appropriate measures to oversee the project particularly as it relates to the matters set out in paragraphs (a) to (c), focusing on governance arrangements and decision-making processes associated with the project."[1]

1.2 LEI's scope of work

LEI was engaged by the Commission to provide a report addressing the following five questions relating to electricity regulation in Newfoundland and Labrador ("NL"):

1. How does NL's electricity regulation system compare to other comparable systems? Does NL's system of legislation and regulations adequately cover both sale of electricity to NL ratepayers and to others?
2. Is NL's system of regulation adequate to deal with the new challenges that arise after interconnection, including energy marketing? Does it meet the needs of current players in our electrical system including ratepayers, and if not, what changes should be made?
3. Should environmental considerations be made part of the Province's energy policy?
4. At a high level, how effective is the current electricity pricing model, and should any changes to it be considered? Is it appropriate to continue to set rates for consumers of electricity on a cost of service basis or is there another more appropriate basis to set rates?
5. Is there likely to be any role for renewable energy generation expansion in the coming decades, either for internal use or for export?

[1] Government of NL. *Commission of Inquiry Respecting the Muskrat Falls Project Order.* November 20, 2017.

1.3 High level nature of work product

LEI was engaged on May 29th, 2019. Each of the five questions raised by the Commission could be a topic for a separate multi-month investigation. While LEI's work product in this matter is based on its over two decades experience in the sector, both across Canada and around the world, as well as a review of key documents, our opinion is not intended to address every detail related to each of the topics. Additional relevant materials may exist which would impact LEI's views.

1.4 Background on the NL electricity sector

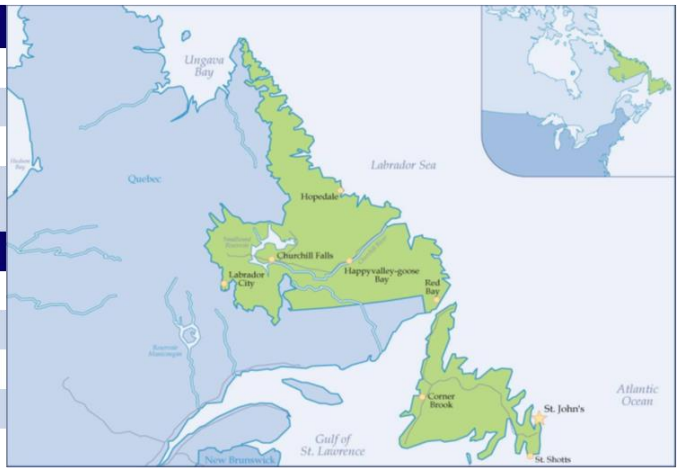
The province of NL is primarily served by two utilities, Newfoundland and Labrador Hydro ("NLH") and Newfoundland Power ("NP"). NLH is wholly owned by the provincial crown corporation Nalcor Energy (established in 2007 by the provincial government),[2] while NP is an investor-owned utility and subsidiary of Fortis, a publicly owned holding company.

Both NLH and NP operate as vertically integrated utilities, although NLH's operations are weighted heavily towards generation and transmission, while NP's operations are weighted towards the delivery side. Currently, NP purchases around 93% of its energy requirements from NLH and generates the remaining 7% within its own facilities.[3] There are also several non-utility generators ("NUGs") who serve the market indirectly by supplying energy to these two utilities.

Figure 1 below highlights key indicators relating to the Province's economy and electricity sector.

Figure 1. Electricity market indicators

Macroeconomic Indicators (2017)	
Population	528,817
GDP per capita	$62,543
Population density	1.41/km^2
GDP growth (nominal)	4.3% (2016-2017) 0.5% (2008-2017)
Electricity Sector Statistics (2017) *	
Installed capacity	1,902 MW
Peak demand (IIS)	1,714 MW
Peak demand growth (IIS)	1.3% (2008 – 2017)
Number of customers	306,600
Total load (IIS)	8,416 GWh

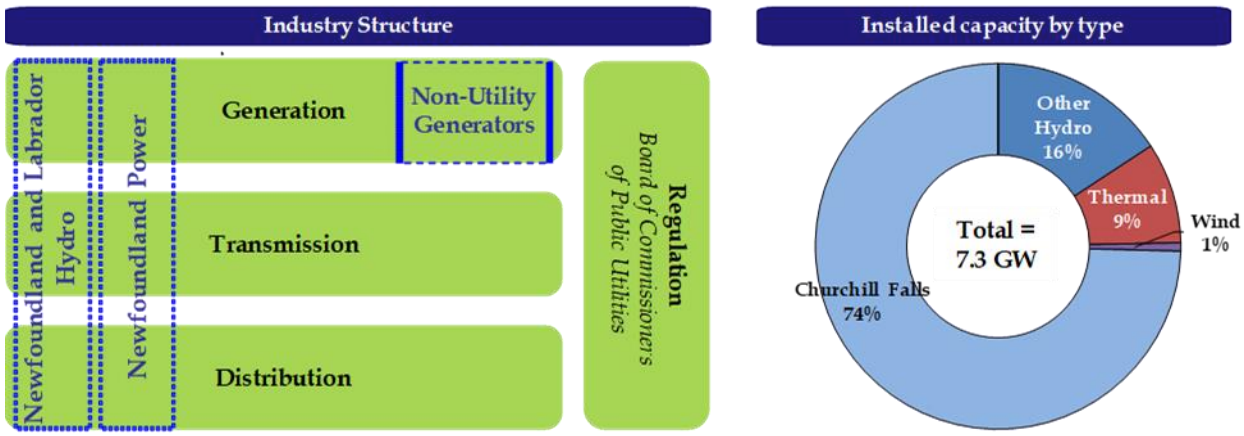


Sources: Statistics Canada tables 17-10-0005-01, 36-10-0222-01; Nalcor Energy information publications; Government of NL; NLH and NP annual reports.
* Installed capacity is for NLH and NP, excluding Churchill Falls; demand data is for the Island Interconnected System.

[2] NL Department of Natural Resources. "Electricity." Last accessed on June 4, 2019. Available at: <https://www.nr.gov.nl.ca/nr/energy/electricity/index.html>
[3] Fortis Inc. *Annual Information Form.* February 14, 2019.

Figure 2 below provides an overview of NL's electricity industry structure.

Figure 2. Electricity market overview



Sources: Government of NL; NLH and NP annual reports.

1.4.1 Generation

Installed generating capacity in the province is around 7.3 GW.[4] The single largest facility is the 5,428 MW Churchill Falls Generating Station, owned and operated by Churchill Falls (Labrador) Corporation, which in turn is jointly owned by NLH (66%) and Hydro Quebec (34%).[5] Most of the output from Churchill Falls is sold to Hydro Quebec under a long-term fixed price contract up to 2041, while a small amount serves customers on the Labrador Interconnected System ("LIS"). Once completed, the Muskrat Falls project will add another 824 MW to the Province's generating capacity, for both local use and export.

To serve the Province's load, NLH has a generation portfolio with an installed capacity of 1,763 MW (as of 2018), with over 1,696 MW of these being regulated.[6] NP's generation portfolio has an installed capacity of 139 MW (as of 2018), of which approximately 70% is hydro, and the remaining 30% is thermal.[7]

1.4.2 Transmission

NLH is the main entity tasked with transmitting electricity in the Province, owning over 4,400 km of transmission lines.[8]

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[4] Based on nameplate capacity information from third party commercial database.
[5] Churchill Falls (Labrador) Corporation Limited. *Financial Statements. December 31st, 2016.* March 1, 2017.
[6] Around 56% of this capacity is hydro and the remaining 44% is thermal. Thermal supply includes around 25 smaller isolated diesel systems (total of 66 MW) used to meet electricity demand, especially in more isolated areas. Source: NLH. "Corporate Overview." Last accessed on June 4, 2019. Available at: <https://nlhydro.com/about-hydro/corporate-overview/>
[7] Fortis Inc. *Annual Information Form.* February 14, 2019.
[8] NLH. *2017 Annual Performance Report Transparency and Accountability.* June 2018.

Prior to 2018, NL operated an isolated bulk electric system, comprising the Island Interconnected System ("IIS"), which was isolated from North America, and the LIS, which shares an interconnection with Quebec with a total transfer capacity of 5,200 MW.[9] In February 2018, the IIS joined the North American electricity grid via the Maritime Transmission Link, an HVDC line with a long underwater segment, running from southwestern Newfoundland to Nova Scotia, across the Cabot Strait.[10] Additionally, in June 2018, the Labrador Island Transmission Link came into service, a 1,100 km long HVDC transmission system, connecting Labrador to Newfoundland.[11] The interconnection of Newfoundland through these two links significantly changes the electricity sector planning process for the Province going forward.

1.4.3 Distribution

The distribution and supply of electricity across the province is carried out by both NLH and NP. NLH owns over 2,700 km of distribution lines, reaching 38,600 direct residential and commercial customers in rural NL.[12] NP operates in Newfoundland only and is the main distributor by both kilometers of distribution lines owned and number of customers, totaling around 12,600 km and 268,000 customers respectively.[13]

[9] Natural Resources Canada. "Newfoundland and Labrador's Electric Reliability Framework." Last accessed on June 4, 2019. Available at: <https://www.nrcan.gc.ca/energy/electricity-infrastructure/18834>

[10] National Energy Board. "Market Snapshot: Newfoundland joins the interconnected North American electricity grid." Last accessed on June 4, 2019. Available at: <http://www.neb-one.gc.ca/nrg/ntgrtd/mrkt/snpsht/2018/06-04nwfndlnd-eng.html>

[11] Nalcor Energy. *Historic Flow of Power from Churchill Falls to the Island*. June 27, 2018.

[12] NLH. *2017 Annual Performance Report Transparency and Accountability*. June 2018.

[13] Fortis Inc. "Our Companies." Last accessed on June 4, 2019. Available at: <https://www.fortisinc.com/our-companies/newfoundland-power>

2 Electricity regulation system and adequacy for sales to ratepayers and others

Question: ***How does NL's electricity regulation system compare to other comparable systems? Does NL's system of legislation and regulations adequately cover both sale of electricity to NL ratepayers and to others?***

2.1 How do you define an "electricity regulation system"?

An electricity regulation system consists of a set of laws, institutions, and regulations which govern the production, transmission, distribution, and sale of electricity, including both monopoly and competitive aspects of the electricity value chain. Institutions include both policy setting bodies, such as ministries, and rate and standard setting bodies, such as regulators.

2.2 What are the components of the electricity regulation system in NL?

2.2.1 Laws

Policymakers and regulators require a legal framework in which to operate. The NL Department of Natural Resources ("DNR") sets policy for energy, including electricity; it operates under the following legislation: the Canada-Newfoundland and Labrador Atlantic Accord Implementation Act, which sets out the mechanism for managing the Province's offshore area; the Churchill Falls (Labrador) Corporation Limited (Lease) Act; the Electrical Power Control Act; the Energy Corporation Act; the Energy Corporation of Newfoundland and Labrador Water Rights Act; the Hydro Corporation Act; the Lower Churchill Development Act; and the Petroleum and Natural Gas Act.[14]

The NL Board of Commissioners of Public Utilities ("PUB") is an independent, "quasi-judicial" regulatory body. Two pieces of legislation provide the PUB its regulatory authority and are discussed in more detail below.[15]

Public Utilities Act, 1990: Defined the operational authority the PUB would have over public utilities in NL. The Act defined a public utility as any person or institution in the fields of energy, electricity, water, heat and sewage, that either owns, operates or manages facilities which provide generation, transmission or delivery services for compensation. The Act provides the PUB general supervisory powers over all public utilities, including regulatory oversight as well as approving rates charged by electricity providers. The Board is also charged with ensuring public access to information, hearing public complaints, and taking action against violations if they occur.[16]

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[14] NL Department of Natural Resources. "Legislation." Last accessed on June 27, 2019. Available at: <https://www.nr.gov.nl.ca/nr/department/legislation.html#energy>

[15] NL Department of Natural Resources. "Electricity Overview." Last accessed on June 5, 2019. <http://www.nr.gov.nl.ca/nr/energy/electricity/index.html>

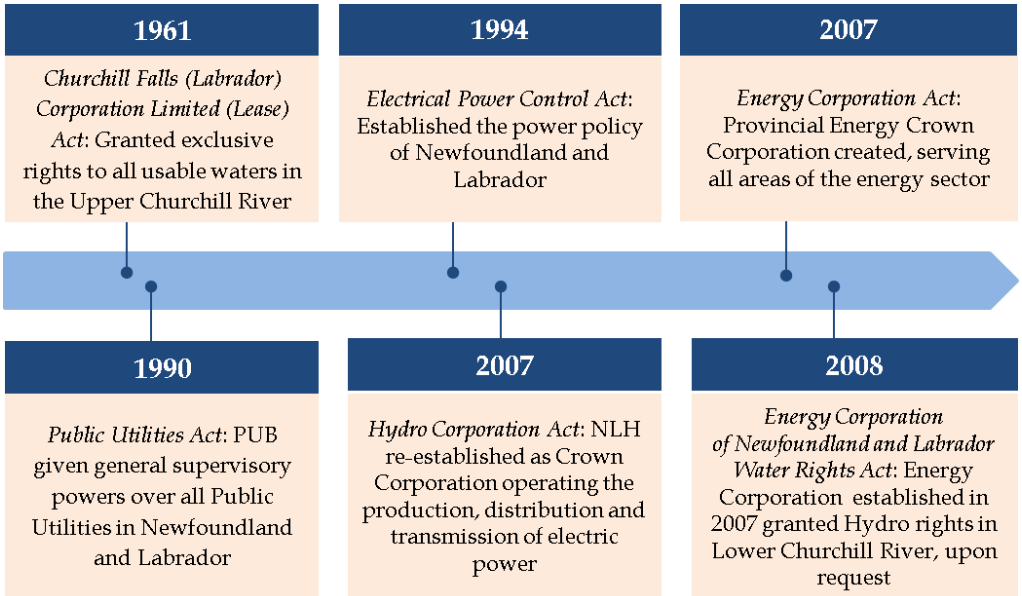
[16] NL House of Assembly. "Public Utilities Act (1990)." Last accessed on June 5, 2019. <http://www.assembly.nl.ca/legislation/sr/statutes/p47.htm#78_>

Electrical Power Control Act, 1994: Enacted to regulate the electric power sector in NL. The Act directs the PUB to enforce government policy in relation to the electricity industry. It declares that rates charged to consumers in the province should be reasonable, while also allowing producers and sellers of electricity to be able to make reasonable revenues from their operations. It also declared that the generation, transmission and distribution of electricity in the province should be done efficiently and equitably, and carried out in a manner that allows all consumers to have adequate access at a fair cost.[17]

Following these key power sector laws, one major regulatory decision ensued. In 2012, amendments were made to the Electrical Power Control Act, 1994 to facilitate financing for the Muskrat Falls project. The legislative amendments provided NLH with the exclusive right to supply and sell electricity to retailers and industrial customers in the IIS, and also required retailers in the IIS, such as NP, to buy electricity exclusively from NLH.[18]

Figure 3 below highlights the key legislation in the Province's electricity sector.

Figure 3. Key power sector legislation in NL



Source: NL House of Assembly.

2.2.2 Institutions

Policy setting: The Province's DNR, through the Mines and Energy Branches, is responsible for the "supervision, control and direction of all matters relating to the promotion, exploration and

[17] NL House of Assembly. "Electrical Power Control Act, 1994." Last accessed on June 5, 2019. Available at: <http://www.assembly.nl.ca/legislation/sr/statutes/e05-1.htm>

[18] NL House of Assembly. "Bill 61: An Act to Amend the Electrical Power Control Act, 1994, the Energy Corporation Act and the Hydro Corporation Act, 2007." Last accessed on June 5, 2019. Available at: <https://www.assembly.nl.ca/business/bills/Bill1261.htm>

development of mineral and energy resources."[19] The Energy Branch within the Department is divided into three main sections: (1) the Petroleum Development Section, (2) the Royalties and Benefits Section, and (3) the Energy Policy Section. The Energy Policy Section's mandate includes legislative, regulatory, and policy functions related to the Province's energy sector, comprising electricity, as well as oil and gas.[20]

Regulatory: The PUB is responsible for ensuring that the rates charged to customers are "just and reasonable" and that the service provided is "safe and reliable."[21] Both NLH and NP are regulated by the PUB.

2.2.3 Regulations

Regulators establish a body of regulations which provide the framework under which entities under their jurisdiction operate. Some regulations can be exhaustive and applicable to the industry as a whole, while others may be specific to a particular stakeholder. Figure 4 below provides a sample of key electricity-related PUB regulations in the province.

Figure 4. Electricity-related regulations in NL

Regulation	Description
Regulation 39/96, Board of Commissioners of Public Utilities Regulations, 1996	Sets out procedures for the Board, including form of the application, public notice, submission by intervenors, information requests, document exchange along with rules and protocol surrounding public hearings.
Regulation 92/00, Labrador Hydro Exemption Order	Exempts NLH from the Electrical Power Control Act and the Public Utilities Act for activities pertaining to the Labrador Hydro Project (Churchill Falls, Gull Island, Muskrat Falls).
Regulation 11/14, Labrador West Transmission Exemption Order	Newfoundland and Labrador Hydro is exempt from the Electrical Power Control Act, 1994 and the Public Utilities Act for all planning, design, construction and contribution activities pertaining to the Labrador West Transmission Project.
Regulation 119/13, Maritime Link Exemption Order	Essentially duplicates Regulation 92/00 in general impact, but is more detailed and specific with respect to what is exempt.
Regulation 120/13, Muskrat Falls Project Exemption Order	Again, essentially duplicates Regulation 92/00 in general impact, but is more detailed and specific with respect to what is exempt.
Regulation 47/15, Net Metering Exemption Order	Enables net metering by exempting net metering purchases by NP from the restrictions contained in Section 14.1 of the Electrical Power Control Act (which prohibits NP from purchasing energy from any entity other than NLH).
Regulation 42/18, Open Access Transmission Regulations	Essentially sets out the code of conduct, or the policies and procedures, applicable to the operation and provision of transmission service on the integrated electric system. Also designates NLSO as the system operator.
Regulation 4/09, Water Management Regulations	The water management agreement shall be the coordination of the power generation and energy production in the aggregate for all production facilities on a body of water to satisfy the delivery schedules for all suppliers on the body of water, in a manner that provides for the maximization of the long term energy-generating potential of a body of water.

Source: NL Board of Commissioners of Public Utilities. "Legislation." Last accessed on July 3, 2019. Available at: <http://www.pub.nf.ca/laws.htm>

[19] NL Department of Natural Resources. *Annual Report 2017-18*. 2018.
[20] NL Department of Natural Resources. "Energy Policy Section." Last accessed on June 13, 2019. Available at: <https://www.nr.gov.nl.ca/nr/department/branches/energy/policy/index.html>
[21] Natural Resources Canada. "Newfoundland and Labrador's Electric Reliability Framework." Last accessed on June 4, 2019. Available at: <https://www.nrcan.gc.ca/energy/electricity-infrastructure/18834>

In addition to the above, there are several exemption orders related to specific companies and projects.

2.3 How do you define "comparable" systems?

For the purpose of exploring regulatory systems, LEI has defined "comparable" systems as being Canadian provinces with a total number of customers equal to or greater than those in NL. Figure 5 below provides a snapshot of the electricity sector for each of the provinces chosen for this comparison.

Figure 5. Electricity sector overview for selected Canadian provinces

	Customers (as of 2015)	Population (as of 2018)	Electricity Sales (MWh, 2017)	Wholesale Price Setting	Institutions	Industry Structure
Newfoundland and Labrador	300,150	525,355	9,444,068	Regulated	Department of Natural Resources; PUB	Provincially owned monopoly (mainly generation) and privately owned monopoly (mainly distribution)
Alberta	1,750,000	4,307,110	54,953,964	Market	Alberta Energy; AESO; AUC; BP; MSA	Investor-owned generators and wires companies (some muni investment)
British Columbia	2,100,000	4,991,687	55,452,603	Regulated	Ministry of Energy, Mines and Petroleum Resources; BCUC	Main operator is a vertically integrated monopoly, provincially-owned
Manitoba	561,900	1,352,154	22,241,046	Regulated	Department of Growth, Enterprise and Trade; PUB	Vertically integrated monopoly, provincially-owned
New Brunswick	398,000	770,633	11,858,046	Regulated	Ministry of Energy and Resource Development; EUB	Vertically integrated monopoly, provincially-owned
Nova Scotia	506,000	959,942	10,291,497	Regulated	Department of Energy and Mines; UARB	Vertically integrated monopoly, privately owned
Ontario	4,900,000	14,322,757	129,663,873	Market; majority of generation contracted/ under rate regulation	Ministry of Energy, Northern Development and Mines; IESO; OEB	Hybrid semi-competitive, includes both privately, provincially, and muni owned
Quebec	4,200,000	8,390,499	170,309,902	Regulated	ministère de l'Énergie et des Ressources naturelles; Régie	Vertically integrated monopoly, provincially-owned
Saskatchewan	580,000	1,162,062	22,852,226	Regulated	CIC; SRRP	Vertically integrated monopoly, provincially-owned

Although this selection results in a heterogeneous mix with regards to area, customer numbers, dominant generation technologies, and ownership structures, the eight provinces share common legal frameworks which shape institutions and regulations. Distinctions in population size among the provinces impact the size of the regulator and its duties, but do not mean that the regulatory system is substantially different. While Canadian provinces share some characteristics with US states, the Canadian parliamentary system leads to different approaches with regards to institutional independence and generally much longer procedural histories which makes them less useful as comparators.

2.3.1 Alberta

Institutions: The Alberta power market has evolved into a competitive wholesale electricity market. Alberta managed its restructuring process gradually, beginning in 1996 and transitioning from a system dominated by a few large, vertically integrated utilities from both the public and private sector. Alberta's gradual restructuring utilized power purchasing arrangements ("PPAs") to ensure competition in the market. The PPAs resulted in a virtual divestiture in which plant owners retained ownership of the plant and were ensured cost recovery, but were not allowed to bid into the competitive power market. That right was purchased by the PPA owner. As such, it was the right of the PPA owner to determine the amount of energy to bid into energy markets.[22]

Currently, the Province's competitive electricity market structure is based on four core policy tenets: (1) open access transmission, (2) energy-only market design, (3) customer choice, and (4) fair, efficient, and openly competitive markets for electricity and ancillary services.[23] The province is undergoing a transition to an energy and capacity market design, with the first obligation period expected at the end of 2021. However, the recently elected government is reviewing whether to proceed with the capacity market.

In terms of key institutions in the market, Alberta Energy, a Ministry of the Government of Alberta, serves as the Province's policy making arm with regards to the energy sector.[24] Its stated objective is to "sustain the interests of Albertans through the stewardship and responsible development of energy and mineral resource systems."[25]

The Alberta Electric System Operator ("AESO") is the Province's Independent System Operator ("ISO").[26] The AESO is a not-for-profit entity that is independent of any industry affiliations, in the sense that it does not own any transmission or market assets.[27] The AESO's key responsibilities include: administering the hourly wholesale market, overseeing the development

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[22] Retail Market Review Committee. *Power for the People. Report and Recommendations for the Minister of Energy, Government of Alberta.* September 2012. p. 221.
[23] Natural Resources Canada. "Alberta's Electric Reliability Framework." Last accessed on June 18, 2019. Available at: <https://www.nrcan.gc.ca/energy/electricity-infrastructure/18826>
[24] Alberta Energy. "Energy." Last accessed on June 18, 2019. Available at: <https://www.alberta.ca/energy.aspx>
[25] Ibid.
[26] Alberta Electric System Operator. "About the AESO." Last accessed on June 18, 2019. Available at: <https://www.aeso.ca/aeso/about-the-aeso/>
[27] Natural Resources Canada. "Alberta's Electric Reliability Framework." Last accessed on June 18, 2019. Available at: <https://www.nrcan.gc.ca/energy/electricity-infrastructure/18826>

of new transmission facilities, and developing and administering transmission tariffs through applications to the Alberta Utilities Commission ("AUC") for approval.[28]

The AUC is an independent, quasi-judicial agency responsible for regulating the investor-owned utilities in the province.[29] One of the AUC's key responsibilities is to set Alberta's transmission and distribution rates, to "ensure that customers receive safe and reliable service at just and reasonable rates."[30]

In terms of utilities, the generation side of the market includes the following key players: TransAlta Corporation, ATCO Power, Capital Power, TransCanada and ENMAX. Major transmission owners are ATCO Electric Ltd., AltaLink Management Ltd., EPCOR Energy Services and ENMAX Power Corp. The Province's key distributors are FortisAlberta Inc., ATCO Electric Ltd., EPCOR Distribution Inc. and ENMAX Power Corp.

Alberta's competitive market structure comprises two additional key institutions, the Market Surveillance Administrator ("MSA") and the Balancing Pool ("BP"). The MSA is responsible for competition monitoring in the province. The BP serves two essential functions in the Province's marketplace. First, it serves as the institutional backstop to PPAs between incumbent generators and PPA buyers.[31] Second, the BP manages customer benefits from the transition to wholesale electricity market competition in Alberta.[32]

Laws: The provision of electricity service in Alberta is mainly governed by the Electric Utilities Act and the Hydro and Electric Energy Act.[33] The former relates to the AESO, providing the entity with its responsibilities of reliability monitoring and operating on a real-time, zonal basis.[34] The latter relates to the construction and operation of the physical assets used to deliver electricity in the province. Additionally, the AUC operates mainly under the umbrella of the Alberta Utilities Commission Act.[35]

Regulations: Since 2009 for ENMAX, and 2013 for the rest of the distribution sector, the AUC sets rates on a performance-based ratemaking ("PBR") basis for five-year terms.[36] All electric distribution utilities in the province, including ENMAX's distribution business, are regulated under a price cap, while ENMAX's transmission business is regulated under a revenue cap.[37]

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[28] Government of Alberta. *Electricity Agencies and the Utilities Consumer Advocate.*
[29] Alberta Utilities Commission. "Mission Statement." Last accessed on June 18, 2019. Available at: <http://www.auc.ab.ca/pages/mission-statement.aspx>
[30] Alberta Utilities Commission. "Who We Regulate." Last accessed on June 18, 2019. Available at: <http://www.auc.ab.ca/pages/who-we-regulate.aspx>
[31] Government of Alberta. *Electricity Agencies and the Utilities Consumer Advocate.*
[32] Ibid.
[33] Alberta Utilities Commission. *Decision 2012-059.* February 27, 2012.
[34] Alberta Electric System Operator. "About the AESO." Last accessed on June 18, 2019. Available at: <https://www.aeso.ca/aeso/about-the-aeso/>
[35] Alberta Utilities Commission. "Acts and Regulations." Last accessed on July 3, 2019. Available at: <http://www.auc.ab.ca/pages/acts-and-regulations.aspx>
[36] Alberta Utilities Commission. "Distribution Rates." Last accessed on June 18, 2019. Available at: <http://www.auc.ab.ca/pages/distribution-rates.aspx>
[37] Alberta Utilities Commission. *Decision 2009-035, ENMAX Power Corporation 2007-2016 Formula Based Ratemaking.* March 25, 2009.

Alberta regulations also take a unique approach to transmission, as the so-called "T-reg" or transmission regulation encourages construction of transmission to a level that is intended to eliminate congestion; in some cases, this level of transmission development may be more costly than the congestion it is intended to address.

2.3.2 British Columbia

Institutions: British Columbia's Ministry of Energy, Mines and Petroleum Resources is tasked with developing comprehensive policies for the energy sector in British Columbia, as well as governing the Province's vertically integrated electric utility, British Columbia Hydro and Power Authority ("BC Hydro").[38] BC Hydro also operates as the Province's Balancing Authority, working alongside Balancing Authorities in Alberta and the US.[39] Moreover, BC Hydro's wholly owned energy trading subsidiary, Powerex, is responsible for selling BC Hydro's surplus energy destined for export markets.[40]

In addition to BC Hydro, the province is also served by FortisBC, a large investor-owned, integrated utility, which supplies energy to the southern interior portion of British Columbia.[41] Both BC Hydro and FortisBC are regulated by the BC Utilities Commission ("BCUC"), a quasi-judicial entity tasked with setting fair rates for customers.[42]

Laws: British Columbia's Ministry of Energy, Mines and Petroleum Resources is governed by the Ministry of Energy and Mines Act.[43] BC Hydro is directed by the Hydro and Power Authority Act, which provides the Crown corporation its mandate to generate, manufacture, conserve, and supply power in the province.[44] Finally, the BCUC is governed by the Utilities Commission Act, which requires public utilities to service the province in an adequate, safe, efficient, just and reasonable manner, and provides the BCUC with its rate setting duties.[45]

Regulations: In terms of rate setting, BC Hydro's rates are set on a cost of service ("COS") basis, while FortisBC's rates are set within a framework that combines cost of service and performance-based regulation ("PBR").[46,47] FortisBC's PBR Plan, which is set to run from 2014 to 2019, incorporates an incentive mechanism to improve the utility's operating and capital expenditure efficiencies, and sets out the requirements for an annual review process, which provides

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[38] Ministry of Energy, Mines and Petroleum Resources. *2017/18 Annual Service Plan Report.* June 21, 2018.
[39] BC Hydro. "Balancing Authority Load Data." Last accessed on June 14, 2019. Available at: <https://www.bchydro.com/energy-in-bc/operations/transmission/transmission-system/balancing-authority-load-data.html>
[40] British Columbia Hydro and Power Authority. *2017/18 Annual Service Plan Report.* July 2018.
[41] FortisBC. *Annual Information Form 2018.* March 15, 2019.
[42] British Columbia Utilities Commission. "Our Role." Last accessed on June 14, 2019. Available at: <https://www.bcuc.com/about/our-role.html>
[43] BC Laws. "Ministry of Energy and Mines Act." Last accessed on June 14, 2019. Available at: <http://www.bclaws.ca/EPLibraries/bclaws_new/document/ID/freeside/00_96298_01>
[44] British Columbia Hydro and Power Authority. *2017/18 Annual Service Plan Report.* July 2018.
[45] BC Laws. "Utilities Commission Act." Last accessed on June 14, 2019. Available at: <http://www.bclaws.ca/civix/document/id/complete/statreg/96473_01>
[46] British Columbia Hydro and Power Authority. *2017/18 Annual Service Plan Report.* July 2018.
[47] FortisBC. "Regulatory Affairs." Last accessed on June 14, 2019. Available at: <https://www.fortisbc.com/about-us/regulatory-affairs>

stakeholders a venue to meet and discuss the utility's current performance and future activities.[48,49]

As for BC Hydro, the utility is required to file integrated resource plans ("IRPs"), although the regulatory body with which it files has been subject to change. In 2010, the Clean Energy Act stripped the BCUC of its oversight of BC Hydro's IRP, and moved this function to the Cabinet.[50] However, following a 2018 Comprehensive Review of BC Hydro, the government has since stated its intention to introduce legislation to restore the BCUC's authority.[51] BC Hydro's next IRP is set to be submitted to the BCUC by February 2021.[52]

Through the 2018 Comprehensive Review of BC Hydro, the province repealed several other regulations restricting BCUC's oversight and decision-making authority. Legislation will enable the BCUC to "review and make decisions on BC Hydro's costs, proposed rate increases and almost all regulatory accounts, programs and capital projects."[53]

2.3.3 Manitoba

Institutions: Manitoba's Department of Growth, Enterprise and Trade, and the Energy Division that lies within, is responsible for developing the Province's energy policy, as well as seeking economic development opportunities related to energy development and energy efficiency activities.[54] The Province's vertically integrated electric power and natural gas utility is Manitoba Hydro, a Crown corporation and the Province's sole energy distributor.[55] Manitoba's regulatory body is the Manitoba Public Utilities Board ("PUB"), an independent, quasi-judicial administrative tribunal with broad oversight and supervisory powers over Manitoba's public utilities and designated monopolies.[56]

Laws: Manitoba Hydro is governed by the Manitoba Hydro-Electric Board and the Manitoba Hydro Act, which calls on the utility to provide an adequate supply of power to meet the needs of the province, and to promote "economy and efficiency" in the development, generation, transmission, distribution, supply, and end-use of power.[57] The PUB operates under the Public Utilities Board Act, which outlines the regulator's role in rate setting, establishing just and reasonable rates under a COS methodology for the provision of electricity by Manitoba Hydro, as well as other public utilities.[58,59] Under the Manitoba Crown Corporations Public Review and

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[48] FortisBC. *Annual Information Form 2018.* March 15, 2019.
[49] Ibid.
[50] Government of British Columbia. *Clean Energy Production in BC.* April 2016.
[51] Ministry of Energy, Mines and Petroleum Resources. *Comprehensive Review of BC Hydro: Phase 1 Final Report.* 2018.
[52] Ibid.
[53] Ibid.
[54] Natural Resources Canada. "Manitoba's Electric Reliability Framework." Last accessed on June 14, 2019. Available at: <https://www.nrcan.gc.ca/energy/electricity-infrastructure/18830>
[55] Ibid.
[56] The Public Utilities Board. "About the PUB." Last accessed on June 14, 2019. Available at: <http://www.pubmanitoba.ca/v1/about-pub/index.html>
[57] Manitoba Hydro-Electric Board. *Building a Strong Energy Future: Annual Report 2016-2017.* July 28, 2017.
[58] Manitoba Public Utilities Board. *Strategic Plan 2017-2020.*
[59] The Public Utilities Board. "Regulatory Principles." Last accessed on June 14, 2019. Available at: <http://www.pubmanitoba.ca/v1/about-pub/regulatoryprinciples.html>

Accountability and Consequential Amendments Act, "no change in rates for services shall be made and no new rates for services shall be introduced without the approval of the PUB."[60]

Regulations: In terms of Manitoba Hydro's investment decisions, the PUB does not have any oversight with regards to the utility's capital expenditures, including dams, transmission lines, and export contracts.[61] There is also no requirement for Manitoba Hydro to develop an IRP. However, the PUB may be called upon by the provincial government to provide recommendations about Manitoba Hydro's capital development plans, as was the case in the 2014 Need For and Alternatives To ("NFAT") Review.[62]

2.3.4 New Brunswick

Institutions: New Brunswick's Ministry of Energy and Resource Development, and more specifically the Department of Energy and Mines, develops and manages the Province's energy and mineral resources.[63] The Energy Branch within the Department provides policy, regulatory and legislative support on matters relating to the Province's energy sector.[64]

New Brunswick Power Corporation ("NB Power"), a Crown corporation, is New Brunswick's vertically integrated electric utility. NB Power also has a wholly owned subsidiary, New Brunswick Energy Marketing Corporation ("NB Energy Marketing"), which conducts energy trading activities outside of the province.[65] NB Power is regulated by the New Brunswick Energy and Utilities Board ("EUB"), an independent crown agency.

In addition to NB Power, there are also three municipal distribution utilities: (1) Edmundston Energy, (2) Perth Andover Electric Light Commission, and (3) Saint John Energy.[66]

Laws: NB Power operates under the Electricity Act.[67] Through the Act, NB Power agrees to maintain rates as low as possible, whereby any changes in rates should be stable and predictable from year to year.[68]

Regulations: The Electricity Act guides NB Power's general rate application ("GRA") and IRP processes. Under the Act, NB Power must submit a GRA on an annual basis, regardless of whether or not it proposes an increase in rates for that year.[69] NB Power is also required to file an

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[60] Legislature of Manitoba. *The Crown Corporations Public Review and Accountability and Consequential Amendments Act.* 1988.
[61] The Public Utilities Board. "What We Don't Do." Last accessed on June 14, 2019. Available at: <http://www.pubmanitoba.ca/v1/about-pub/what-we-dont-do.html>
[62] The Public Utilities Board. "Utility Rates." Last accessed on June 14, 2019. Available at: <http://www.pubmanitoba.ca/v1/about-pub/regulatory-principles.html>
[63] Natural Resources Canada. "New Brunswick's Electric Reliability Framework." Last accessed on June 14, 2019. Available at: <https://www.nrcan.gc.ca/energy/electricity-infrastructure/18832>
[64] Ministry of Energy and Resource Development. *Annual Report 2017-2018.* November 2018.
[65] New Brunswick Power Corporation. *2017/18 Annual Report*. July 2018.
[66] Natural Resources Canada. "New Brunswick's Electric Reliability Framework." Last accessed on June 14, 2019. Available at: <https://www.nrcan.gc.ca/energy/electricity-infrastructure/18832>
[67] New Brunswick Power Corporation. *2017/18 Annual Report*. July 2018.
[68] Ibid.
[69] New Brunswick Energy and Utilities Board. *Decision: Matter No. 375*. July 20, 2018.

IRP with the EUB every three years, covering a planning period of not less than 20 years.[70] Although the EUB does not review the IRP directly, the document is used as a point of reference for other efforts, such as rate setting and approving capital projects over $50 million.

Additionally, the Act requires NB Power to file its capital expenditure projections with the EUB every year, as part of its 10 Year Strategic, Financial and Capital Investment Plan.[71] This document is utilized for information purposes only, except for capital expenditures above the $50 million threshold, which require EUB approval.

2.3.5 Nova Scotia

Institutions: The Nova Scotia Department of Energy and Mines manages and promotes energy resources in the province to achieve "optimum economic, social and environment value."[72] Specifically, the Department is responsible for setting the policy and legislative framework for Nova Scotia's electricity system.[73] The Province's main utility, Nova Scotia Power Incorporated ("NSPI"), is vertically integrated and investor owned, responsible for providing 95% of the generation, transmission, and distribution of electricity in Nova Scotia.[74] NSPI is also the principal subsidiary of Emera Inc.[75] The Nova Scotia Utility and Review Board ("UARB"), is an independent quasi-judicial tribunal that regulates all public utilities in the province, including NSPI.[76]

Laws: The Department of Energy and Mines is governed by the Public Service Act.[77] NSPI was established following the privatization of the Province's Crown corporation, Nova Scotia Power Corporation – a process that was enabled through the Nova Scotia Companies Act.[78] The UARB operates under the Public Utilities Act, with a jurisdiction covering matters including rate setting, which is determined on a COS basis, as well as oversight with regards to capital expenditures in excess of $250,000.[79]

Regulations: On an annual basis, NSPI submits an Annual Capital Expenditure Plan to the UARB for approval.[80] The UARB also directs NSPI to develop IRPs with a 25-year outlook in order to plan for and meet future emissions and energy requirements in a cost-effective, safe, and reliable

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[70] NB Power. *NB Power's 10-Year Plan: Fiscal Years 2020 to 2029.* December 2018.
[71] Ibid.
[72] Nova Scotia Department of Energy. *Statement of Mandate 2015-2016.* March 2015.
[73] Ibid.
[74] Nova Scotia Power. "Who We Are." Last accessed on June 17, 2019. Available at: <https://www.nspower.ca/en/home/about-us/who-we-are/default.aspx>
[75] Emera. "Nova Scotia Power." Last accessed on June 17, 2019. Available at: <http://www.emera.com/en/home/affiliates/nspower.aspx>
[76] Nova Scotia Utility and Review Board. "Electricity." Last accessed on June 17, 2019. Available at: <https://nsuarb.novascotia.ca/mandates/electricity/>
[77] Nova Scotia Department of Energy. *Statement of Mandate 2015-2016.* March 2015.
[78] Nova Scotia Power. "Our History." Last accessed on June 17, 2019. Available at: <https://www.nspower.ca/en/home/about-us/who-we-are/our-history.aspx>
[79] Nova Scotia Utility and Review Board. "Electricity." Last accessed on June 17, 2019. Available at: <https://nsuarb.novascotia.ca/mandates/electricity/>
[80] Nova Scotia Utility and Review Board. *Electricity Mandate – Annual Capital Expenditure Plan.*

manner.[81] Since 2007, NSPI has filed three IRPs with the Board: (1) in 2007, with a forecast horizon of 2007 to 2029; (2) in 2009, which provided an update to ensure changing conditions were properly addressed; and (3) again in 2014.[82]

The province also operates two feed-in tariff ("FIT") programs. The first is the Nova Scotia Community Feed-in Tariff ("COMFIT") Program, which was launched in 2011 to encourage community-based renewable energy projects. COMFIT ended in 2015, although many projects are still active in the province. The second is the Developmental Tidal FIT Program, which is designed to "incent tidal energy developers to test and deploy their large-scale in-stream tidal energy projects" and was approved by the UARB in 2015.[83,84]

2.3.6 Ontario

Institutions: Ontario has operated an energy-only wholesale electricity market since 2002, following the restructuring of the vertically integrated Ontario Hydro. The generation side of the market comprises Ontario Power Generation ("OPG") and Bruce Power, with a number of independent power producers ("IPPs", also known as NUGs) supplying the remainder of the Province's needs. Transmission in the province is owned almost entirely by Hydro One, while distribution is more fragmented – with approximately 60 distribution utilities operating in the province (the largest of these being Hydro One, Alectra, and Toronto Hydro).

In terms of key institutions, the Ontario Ministry of Energy, Northern Development and Mines ("the Ministry") is responsible for setting policy for the province's electricity system.[85] Additionally, the Ministry interacts with the Independent Electricity System Operator ("IESO") and the Ontario Energy Board ("OEB").[86]

The IESO, a not-for-profit corporation, is the Province's ISO. Its key responsibilities include operating and settling the wholesale electricity markets, ensuring the reliability of the Province's power system, promoting energy-efficiency and demand-management programs, and planning for Ontario's future electricity needs alongside stakeholders and communities across the province.[87]

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[81] Nova Scotia Power. "Integrated Resource Plans (IRP)." Last accessed on June 17, 2019. Available at: <https://www.nspower.ca/en/home/about-us/electricity-rates-and-regulations/regulatory-initiatives/archive/irp.aspx>

[82] Nova Scotia Utility and Review Board. "Electricity." Last accessed on June 17, 2019. Available at: <https://nsuarb.novascotia.ca/mandates/electricity/>

[83] Government of Nova Scotia. "COMFIT." Last accessed on July 4, 2019. Available at: <https://energy.novascotia.ca/renewables/programs-and-projects/comfit>

[84] Government of Nova Scotia. "Developmental Tidal Feed-in Tariff Program." Last accessed on July 4, 2019. Available at: <https://energy.novascotia.ca/renewables/programs-and-projects/tidal-fit>

[85] Government of Ontario. "Ministry of Energy, Northern Development and Mines." Last accessed on June 18, 2019. Available at: <https://www.ontario.ca/page/ministry-energy-northern-development-and-mines>

[86] Natural Resources Canada. "Ontario's Electric Reliability Framework." Last accessed on June 18, 2019. Available at: <https://www.nrcan.gc.ca/energy/electricity-infrastructure/18842>

[87] IESO. "What We Do." Last accessed on June 18, 2019. Available at: <http://www.ieso.ca/Learn/About-the-IESO/What-We-Do>

The OEB, an independent government agency, regulates the Province's electricity sector and is responsible for: overseeing the IESO, which includes approving the IESO's budget and fees; and setting transmission and distribution rates, as well as the contracted rates for OPG's regulated hydroelectric and nuclear fleet.[88] Currently, the OEB follows a quasi-judicial process that is open to public participation when setting rates. To ensure clarity in the rate setting process, the OEB developed its Handbook to Utility Rate Applications in 2016 to provide "guidance to utilities and stakeholders on applications to the OEB for approval of rates."[89]

Laws: The Ministry's responsibilities are outlined in the Ministry of Energy Act, 2011. The Ministry also administers the legislation governing the major institutions in Ontario's electricity market, such as the Electricity Act, 1998, which governs the IESO, as well as the Ontario Energy Board Act, 1998, which dictates the authority of the OEB.[90] Other legislation worth noting include: the Green Energy Act, 2009 – which established the Province's FIT and microFIT programs and was repealed on January 1, 2019; and Bill 87, Fixing the Hydro Mess Act, 2019 – which includes uploading responsibility for the Province's conservation programs from local distribution companies to the IESO, overhauling the OEB and ending the Fair Hydro Plan (which was enacted by the previous Liberal government to provide temporary rate relief for certain customers, mostly residential and small commercial customers).[91,92,93]

Regulations: For Ontario's electricity distributors, three alternative PBR methodologies are available in terms of rate-setting, as established under the Renewed Regulatory Framework for Electricity Distributors: (1) price cap incentive rate-setting ("Price Cap IR"), (2) custom incentive rate-setting ("Custom IR"), and (3) an annual incentive rate-setting index ("Annual IR Index").[94] Under the Price Cap IR methodology, base rates are set through a COS process for the first year and the rates for the following four years are adjusted using a formula specific to each year.[95] Under the Custom IR methodology, rates are set considering a multi-year (minimum five-years) forecast of a distributor's revenue requirements and sales volumes.[96] Under the Annual IR Index methodology, rates are subject to the same annual adjustment formula as under Price Cap IR, but instead of using a COS process to set base rates, distribution utilities are required to apply the highest stretch factor.[97]

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[88] Natural Resources Canada. "Ontario's Electric Reliability Framework." Last accessed on June 18, 2019. Available at: <https://www.nrcan.gc.ca/energy/electricity-infrastructure/18842>
[89] Ontario Energy Board. *Handbook for Utility Rate Applications.* October 13, 2016.
[90] Government of Ontario. "Ministry of Energy, Northern Development and Mines." Last accessed on July 4, 2019. Available at: <https://www.ontario.ca/page/ministry-energy-northern-development-and-mines>
[91] Government of Ontario. "Green Energy Act, 2009." Last accessed on July 4, 2019. Available at: <https://www.ontario.ca/laws/statute/09g12>
[92] Legislative Assembly of Ontario. "Bill 87, Fixing the Hydro Mess Act, 2019." Last accessed on July 4, 2019. Available at: <https://www.ola.org/en/legislative-business/bills/parliament-42/session-1/bill-87>
[93] Government of Ontario. "Ford Government Taking Bold Action to Fix Hydro Mess." Last accessed on July 4, 2019. Available at: <https://news.ontario.ca/mndmf/en/2019/03/ford-government-taking-bold-action-to-fix-hydro-mess.html>
[94] Ontario Energy Board. "2019 Electricity Distribution Rate Applications." Last accessed on June 18, 2019. Available at: <https://www.oeb.ca/industry/applications-oeb/electricity-distribution-rates/2019-electricity-distribution-rate>
[95] Ontario Energy Board. *Handbook for Utility Rate Applications.* October 13, 2016.
[96] Ibid.
[97] Ibid.

As for the Province's electricity transmitters, rate-setting alternatives include Custom IR or Revenue Cap IR, which is similar to the Price Cap IR option available to electricity distributors.[98]

In terms of Ontario's generators, OPG's nuclear assets, as well as most of its hydroelectric assets, are rate-regulated by the OEB. OPG's nuclear business uses a Custom IR approach, while its regulated hydroelectric business sets rates based on the Price Cap IR approach.[99]

2.3.7 Quebec

Institutions: Quebec's ministère de l'Énergie et des Ressources naturelles manages the development of land, energy and mineral resources in the province, and is responsible for setting the policy and legislative framework for Quebec's electricity system.[100]

Hydro Quebec, the Province's wholly government-owned public utility, comprises four primary divisions: (1) Hydro Quebec Production, an unregulated generation entity; (2) Hydro Quebec Distribution, a regulated load serving entity; (3) Hydro Quebec TransÉnergie, the Province's regulated transmission system operator; and (4) Hydro Quebec Equipment and Innovation.[101] Additionally, Hydro Quebec's wholly owned US subsidiary, HQ Energy Services, engages in energy marketing.[102]

The Régie de l'énergie ("the Régie"), is an independent, economic regulatory agency, charged with balancing the public interest, consumer protection, and the fair treatment of the electricity carrier and distributors.[103]

Laws: Hydro Quebec is governed under the Hydro-Québec Act, while the Régie operates under the Act respecting the Régie de l'énergie.[104,105] Under the Act, the Régie has the authority to fix the rates and conditions for the transmission of electric power by Hydro-Québec TransÉnergie, as well as the distribution of electric power by Hydro-Québec Distribution. However, the Régie has no regulatory oversight over Hydro-Québec Production with regards to its costs or rates.[106]

Regulations: Future regulations may need to account for Bill 34, tabled in June 2019. The bill provides for the following changes with regards to rate setting for Hydro-Québec Distribution: (1) in 2020 there will be a freeze on rates; (2) from 2021 to 2024, rate adjustments will be pegged to inflation (which can be viewed as a form of PBR); (3) in 2025, rates will be established by the

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[98] Ibid.
[99] Ibid.
[100] Government of Quebec. "The Organization and its Commitments." Last accessed on June 14, 2019. Available at: <https://www.quebec.ca/en/government/ministere/energie-ressources-naturelles/mission-mandate/>
[101] Hydro Quebec. "Our Mission and Activities." Last accessed on June 14, 2019. Available at: <http://www.hydroquebec.com/about/mission-activities.html>
[102] Bloomberg. "Company Overview of HQ Energy Services (US) Inc." Last accessed on June 14, 2019. <https://www.bloomberg.com/research/stocks/private/snapshot.asp?privcapid=106628687>
[103] Régie de l'énergie. *2013-2014: Annual Report.* 2014.
[104] Publications Quebec. "Hydro-Quebec Act." Last accessed on June 14, 2019. Available at: <http://legisquebec.gouv.qc.ca/en/ShowDoc/cs/H-5>
[105] Régie de l'énergie. *2013-2014: Annual Report.* 2014.
[106] Ibid.

Régie; and (4) from 2026 onwards, rate adjustments will be pegged to inflation for a four-year cycle, with mandatory GRA filings to the Régie in the fifth year.[107] As this legislation does not apply to Hydro-Québec TransÉnergie, this division of the utility will continue to be regulated according to current Régie regulations.[108]

2.3.8 Saskatchewan

Institutions: The Government of Saskatchewan manages the province's main utility, Saskatchewan Power Corporation ("SaskPower"), through the Crown Investments Corporation ("CIC"), a holding company for the Province's commercial crown corporations.[109] SaskPower, the Province's vertically integrated utility, has an exclusive franchise over Saskatchewan's transmission and distribution (except for distribution in the cities of Saskatoon and Swift Current, which are serviced by municipal franchises).[110] SaskPower is regulated by the Saskatchewan Rate Review Panel ("SRRP"), which reviews rate proposals by the utility and provides recommendations to the government with regards to electricity rate changes.[111]

Laws: Under the Crown Corporations Act, the CIC is mandated to exercise supervisory powers, including approving rate changes and major investment decisions for SaskPower.[112,113] SaskPower was established through the Power Corporation Act.

Regulations: SaskPower is also responsible for developing IRPs, which it uses as a decision support tool, examining potential pathways to meet the Province's future generation needs while also complying with regulatory requirements.[114] The utility's 2017 IRP comprised a 20-year plan evaluating resource options for meeting forecast demand under a range of potential future conditions.[115] While IRPs provide general guidance as to the utility's long-term strategy, each investment decision requires the preparation of an independent business case.[116]

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[107] Hydro Quebec. "Electricity Rates: Adoption of a Simplified Approach that will Guarantee Low Rates." Last accessed on June 17, 2019. Available at: <https://news.hydroquebec.com/press-releases/1510/electricity-rates-adoption-of-a-simplified-approach-that-will-guarantee-low-rates/>

[108] Ibid.

[109] Natural Resources Canada. "Saskatchewan's Electric Reliability Framework." Last accessed on June 17, 2019. Available at: <https://www.nrcan.gc.ca/energy/electricity-infrastructure/18849>

[110] SaskPower. *Maintaining a Powerful Commitment: 2017-18 Annual Report.* July 2018.

[111] Crown Investments Corporation of Saskatchewan. "Saskatchewan Rate Review Panel." Last accessed on June 17, 2019. Available at: <https://www.cicorp.sk.ca/saskatchewan_rate_review_panel>

[112] Crown Investments Corporation of Saskatchewan. "Who We Are." Last accessed on June 17, 2019. Available at: <https://www.cicorp.sk.ca/about_us/who_we_are>

[113] Natural Resources Canada. "Saskatchewan's Electric Reliability Framework." Last accessed on June 17, 2019. Available at: <https://www.nrcan.gc.ca/energy/electricity-infrastructure/18849>

[114] SaskPower. *Maintaining a Powerful Commitment: 2017-18 Annual Report.* July 2018.

[115] Saskatchewan Rate Review Panel. *Regarding the SaskPower 2017 Rate Application.* January 10, 2018.

[116] Ibid.

2.4 How does NL's electricity regulation system compare to these comparable systems?

Figure 6. Electricity regulation system for selected Canadian provinces

	Regulator approval for IRPs	Where the consumer advocate resides	Regulator approval for capital projects	Presence of FIT	Whether retail competition is allowed
Newfoundland and Labrador	Not Exercised	Department of Justice and Public Safety	No	No	No
Alberta	No	Office of the Utilities Consumer Advocate	Wires	No	Yes
British Columbia	Proposed	None	No	No	No
Manitoba	No	None	No	No	No
New Brunswick	Considered	Office of the Public Energy Advocate	Yes	No	No
Nova Scotia	Yes	Nova Scotia Utility and Review Board	Yes	Yes	Yes
Ontario	No	None	Wires	No	Yes
Quebec	Distributor	None	No	No	No
Saskatchewan	Considered	Proposed	No	No	No

NL's electricity regulation system shares many elements of the comparable systems. Policy and regulatory bodies are separate; laws establish the role for each; provincially owned entities are corporatized and professionally managed. Processes for establishing rates are set forth in regulations.

Where the provinces differ, however, is in the role of the market, the extent of alternatives for customers, whether IRPs are encouraged, and whether there is an established consumer advocate. Figure 6 above shows how the selected provinces compare in these areas.

NL mirrors many of the conventional elements in law and institutions with other provinces. However, other provinces appear to be reverting authority back to the regulator to approve large projects and IRPs. Some regulators, particularly those in Ontario and Alberta, have begun tackling issues associated with new technologies, such as storage, microgeneration, and microgrids; a larger number have also begun investigating the implications of electric vehicles ("EVs"). In some ways, the time required to address the issues associated with Muskrat Falls may have prevented regulators and policymakers from exploring some of these advanced regulatory topics in greater detail.

2.5 Does NL's regulatory system adequately cover sales to ratepayers?

2.5.1 Have previously identified shortcomings been addressed?

In 2015, Power Advisory LLC produced a report entitled "Review of the Newfoundland and Labrador Electricity System," prepared for NL's DNR.[117] The report identified several areas which the authors felt deviated from best practice. These included:

- defining a public interest test to set rates and review proposed projects (the authors suggested common regulatory concepts such as "just and reasonable" or "not unduly discriminatory");
- employing outcome-based policy direction;
- assessing need for new facilities and cost-effectiveness of alternatives (the authors allowed for exclusion of large capital projects – LEI would not);
- requiring IRPs of all utilities;
- increasing budget filing thresholds from $50,000 for capital expenditures and $5,000 for capital leases;
- addressing the Rural Deficit Subsidy; and
- establishing a timely rate review process, including establishing a requirement to issue decisions with a specified timeframe.

LEI's review of the record since 2015 suggests that little progress has been made on most of the above recommendations, all of which are generally sensible and with which LEI concurs. While the Rural Deficit Subsidy had fallen by 2018 relative to where it was in 2015, price signals in isolated communities remain suppressed. While the budget filing threshold issue is a constraint set in the Public Utilities Act, the Act should be modernized to grant the PUB the authority to set these thresholds as it sees fit. NL is not unique among Canadian provinces in having issues with timely proceedings; however, this is not a reason to avoid addressing the issue. Development of a rate handbook similar to Ontario's would be helpful.

2.5.2 Are there other aspects which should be considered?

LEI believes that the issues of inclusion of capital expenditure in ratebase and of customer choice need to be more fully addressed as NL evolves its electricity regulatory system. LEI does not believe that **any** expenditure that is included in ratebase should be excluded from regulatory review. LEI does not share Power Advisory's view that public policy objectives override the need for regulatory review. If governments wish to pursue a project for public policy reasons, they are free to do so using taxpayer funds. If they want to fund such projects through electricity rates, the project must be subject to full regulatory review.

[117] Power Advisory LLC. *Review of the Newfoundland and Labrador Electricity System.* October 26, 2015.

In the US, regulators have used their authority to address cost overruns in various ways, the textbox below provides one such example. They have disallowed expenditures that they regarded as imprudent. In other cases, they have allowed recovery without a return. Regulators have also used deferral accounts and contingent recovery mechanisms to manage the impact of overruns. NL should consider granting authority to the PUB prospectively with regards to large projects to examine what portion of costs is appropriate for ratepayers to bear, and what portion should be borne by the shareholder.

Regulatory treatment of Kemper in Mississippi

The 582 MW Kemper Power Plant in Kemper County, Mississippi, was touted to be the world's largest coal carbon capture plant. Developed by Mississippi Power Co., a subsidiary of the Southern Co., the project was designed to be the first of its kind in using clean coal, generating power by burning soft lignite coal and removing carbon dioxide and other pollutants in the process. Construction on the plant began in 2010 with a planned budget of approximately $2.4 billion and a targeted commercial operation date of May 2014.

However, by 2017, Southern Co. announced it would be abandoning construction of the plant, after extensive cost overruns and missed construction deadlines. At the time of abandonment, the project cost had ballooned to $7.5 billion, amounting to nearly $5.1 billion in cost overruns.

In 2018, the Mississippi Public Service Commission, the state's utility commission, approved a settlement to "relieve customers of paying for the project's multibillion coal gasification technology." Instead, Southern Co. will be absorbing the vast majority of the project costs. It wrote off $6.4 billion in costs billed to Mississippi Power Co. related to the coal's gasifier technology. As for Mississippi Power Co. customers, they will be charged for the natural gas portion of Kemper, which has been generating power for them since 2014. This portion of the plant amounts to a charge of $99.3 million annually over a payment period of eight years. This payment plan "assures Mississippi Power customers do not pay anything out-of-pocket for Kemper."

Sources: Amy, Jeff. "Utility Faces Federal Investigation Over Failed $7.5 Billion Kemper Power Plant." *Clarion Ledger* May 1, 2019; Kelly, Sharon. "How America's Clean Coal Dream Unraveled." *The Guardian* March 2, 2018; Ablaza, Kendra. "Regulators Settle 'Emotionally Intense' Kemper Power Plant Case." *Mississippi Today* February 6, 2018.

As rates increase, NL will find it more difficult to avoid the question of customer choice. NL arrangements regarding attaining supply from third parties are highly restrictive. Rising rates will make self-generation more economic for more customers if they are allowed to do so; eventually these customers will seek to pool their resources, or suppliers will develop innovative ways to evade the restrictions on non-utility supply. NL will need to be proactive in addressing these challenges.

2.6 Does NL's regulatory system adequately cover sales to others?

The regulatory system only needs to touch upon sales to others when those sales have an adverse impact on ratepayers. Power Advisory takes a similar view, suggesting legislative changes to enable oversight and approval of long-term contracts by the PUB, but only where the risks are

borne by ratepayers.[118] Otherwise, normal commercial relations apply – corporate boards should provide oversight, and courts interpret disputes.

However, one key area where additional clarity is required relates to allocation of system costs associated with transmitting exports to the Province's borders. For exports to be appropriately priced, these costs need to be considered. However, in the event that the exports do not occur, ratepayers are left paying the full cost of the transmission system. Other provinces with significant exports have oscillated between charging exports for system costs with profits retained by the trading arm, and charging all system costs to ratepayers with ratepayers sharing in the profits. Below, we briefly describe practice in other provinces before considering the approach NL should consider.

2.6.1 British Columbia

The use of BC Hydro's transmission system for export related to surplus sales is referred to by the utility as Domestic Transmission – Export ("export"). According to BC Hydro's 2020-2021 Revenue Requirements Application, export costs are included in BC Hydro's Transmission Revenue Requirement ("TRR") and are recovered under the open access transmission tariff ("OATT"). These export costs represent BC Hydro's use of point-to-point transmission service for domestic exports. In the TRR, export costs are allocated to the utility's cost of energy via intersegment revenues. This allocation of intersegment revenues ensures that costs are only recovered from domestic customers once.[119]

In terms of export costs relating to generation, the province utilizes the concept of "expenditure for export," which it defines as "the amount of an expenditure for the construction or extension of a plant or system or for an acquisition of electricity that is in addition to the amount the authority would have had to spend to achieve electricity self-sufficiency."[120] Under the Clean Energy Act, specifically Direction No. 7, the BCUC is directed to refrain from calculating expenditures for export and recovering these costs in BC Hydro's rates. As a result, any expenditure associated with exports is not included in domestic rates, meaning that ratepayers are not responsible for subsidizing export power sales.[121]

However, in a Comprehensive Review of BC Hydro, commissioned by the provincial government and conducted collaboratively by the Ministry of Energy, Mines and Petroleum Resources, the Ministry of Finance and BC Hydro in 2018, it was decided that Direction No. 7 will be repealed. Specifically, the Review states the government's intention to introduce legislation in Spring 2019 to amend the Clean Energy Act and repeal the concept of expenditures for export. In the interim,

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[118] Power Advisory LLC. *Review of the Newfoundland and Labrador Electricity System.* October 26, 2015.
[119] British Columbia Hydro. *British Columbia Hydro and Power Authority F2020-F2021 Revenue Requirements Application.* February 25, 2019.
[120] British Columbia Utilities Commission. *British Columbia Hydro and Power Authority F2020-F2021 Revenue Requirements Application.* April 23, 2019.
[121] BC Hydro. *Backgrounder: Pursuing Export Opportunities.* 2010.

the government will "continue to direct the BCUC to refrain from considering expenditures for export when determining BC Hydro's rates."[122]

2.6.2 Manitoba

In a 1988 report, Manitoba's PUB recommended the creation of a separate export customer class to allow for the segregation of revenues and costs related to export sales by Manitoba Hydro.[123] The PUB argued this separate customer class would demonstrate that domestic customers are not subsidizing export sales. However, in its Order in respect of the 2016 Cost of Service Study Methodology Review, the PUB found that a separate export customer class should no longer be used, to clearly establish that domestic customers, and not export customers, are ultimately responsible for all of Manitoba Hydro's costs.[124]

In the same Methodology Review, the PUB found that export revenues should be credited to domestic classes based on their share of generation and transmission costs. The export revenues deduct costs related to water rentals, variable hydraulic operating and maintenance costs associated with exports, as well as the Affordable Energy Fund (which provides support for energy efficiency and alternative energy programs). Prior to this decision, net export revenues were allocated on the basis of total costs instead, which at the time was thought to result in "an improvement in the equitable sharing of export revenue between customer classes."[125] Total costs comprise generation, transmission, sub transmission, distribution, and customer services costs.

2.6.3 Approach to system cost allocation for exports in NL

LEI believes that the appropriate approach for NL would be to charge exports an appropriate allocation of system costs using its OATT. LEI believes that such an approach is more transparent, enables better accounting and economic decision-making, and avoids having NL ratepayers subsidize export customers.

2.7 Consolidated response – regulatory system adequacy

While NL's electricity regulation system contains elements similar to those of comparable systems, shortcomings identified in the 2015 Power Advisory report remain to be addressed. LEI believes that for NL's system of legislation and regulations to adequately cover sales to NL ratepayers, it must further empower the regulator, particularly with regards to large capital project approvals. With regards to sales to others, NL needs to assure that the regulator has the authority to approve or deny any export sales contract which has an adverse impact on ratepayers, and that transmission costs are appropriately allocated between exports and domestic ratepayers.

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[122] British Columbia Ministry of Energy, Mines and Petroleum Resources. *Comprehensive Review of BC Hydro: Phase 1 Final Report.* 2018.
[123] Manitoba Public Utilities Board. *Board Report to the Minister of Energy and Mines.* March 31, 1988.
[124] Manitoba Public Utilities Board. *Order No. 164/16.* December 20, 2016.
[125] Manitoba Hydro. *Cost of Service Methodology Review.* December 4, 2015.

3 Addressing potential challenges from interconnection

Question: ***Is NL's system of regulation adequate to deal with the new challenges that arise after interconnection, including energy marketing? Does it meet the needs of current players in our electrical system including ratepayers, and if not, what changes should be made?***

3.1 What criteria should be used to assess adequacy of regulation related to interconnection?

With regards to addressing interconnection challenges, we assess the adequacy of regulation based on the extent to which it reflects the minimum institutional framework in place in other jurisdictions, taking into account NL's size and unique position at the far Northeast end of the North American electric power grid.

3.2 What new challenges are likely to arise as a consequence of interconnection?

There are a number of challenges which arise as a consequence of interconnection. As one of the smallest jurisdictions integrated into the North American grid, NL has limited influence over a wide range of regulations to which it must adhere, and must participate in a larger number of institutions. This participation needs to be funded and resourced. Simply monitoring developments at the US Federal Energy Regulatory Commission ("FERC"), the North American Electric Reliability Corporation ("NERC") and New England's Independent System Operator ("ISO-NE") takes one or more full time equivalents ("FTEs"); similar attention must be paid to regulatory and policy developments in the other Atlantic provinces.

Aside from the challenges of power marketing, discussed separately below, interconnection requires greater participation in regional planning and exposure to US Federal and ISO rules and NERC standards, even extending to issues like cybersecurity. NL must also continue steps already underway to assure an open access regime that is deemed sufficiently reciprocal to allow continued access to US markets. None of these challenges are necessarily problematic for NL, in that the bulk of FERC rules are developed to protect consumers, and NERC regulations to assure reliability. However, there may be cases where the rules, regulations, and standards prescribe thresholds that are more difficult or costly for NL to achieve, potentially requiring NL to seek waivers.

3.3 What are some specific challenges that energy marketing poses?

Energy marketing is a distinct activity which requires a dedicated subsidiary. As have major exporting utilities in Quebec, New Brunswick, and British Columbia, Nalcor has established an energy marketing subsidiary, Nalcor Energy Marketing. However, setting up the subsidiary is only the first step. Key to ongoing operations is having strong risk management and compliance functions in place. Energy marketing also requires the ability to post credit, both with counterparties and with ISOs. Inability to post credit can impede the ability to hedge, leading to

a downward spiral in which risk increases, credit becomes less available, and even fewer hedges are possible.

Comparative size of potential excess generation available for sale

Muskrat Falls has an expected annual generation of around 4.9 TWh. Of this, 0.98 TWh would be provided to Emera. Per the PPA signed between NLH and the Muskrat Falls Corporation (dated November 29, 2013), the implied delivery to NLH could average around 2.28 TWh over the course of the first 10 full years of Muskrat Falls' in-service date, and 2.74 TWh over the course of the first 20 years. Under the assumption that all the remaining generation is available for export, on average around 1.64 TWh would be available for export over the first 10 years, and 1.16 TWh would be available for export over the first 20 years.

Other Canadian jurisdictions with energy marketing arms include BC Hydro, New Brunswick Power, and Hydro Quebec. The smallest of these three, New Brunswick Power, exported 3.5 TWh in 2017/18, with revenues of $265 million. BC Hydro and Hydro Quebec's export-based revenues for 2018 were $710 million and $1.7 billion respectively. Excess generation for export from Muskrat Falls, compared to other power marketers not just in Canada but also in the United States, is therefore relatively small.

Sources: Based on information contained in: PPA between NLH and Muskrat Falls Corporation (date November 29, 2013); New Brunswick Power's 2017/18 Annual Report; BC Hydro's 2017/18 Annual Service Plan Report; and Hydro Quebec's 2018 Annual Report.

Risk management policies must be clearly stated, staffed independently of the trading function, and require clear and consistent reporting. Risk management staff must have sufficient authority to unwind trades that violate policy and to "bench" traders who fail to follow reporting procedures. Risk management must be a focus of the Board; policies should be approved and monitored at the Board level. Concepts like ability to calculate value at risk ("VAR"), avoid credit concentration, and adequately assess counter-party credit risk are essential.

Compliance is equally critical. Canadian entities trading into US markets have been subject to significant scrutiny; Powerex faced large settlement costs related to the 2001 California power crisis, for example. Trading entities need to maintain market-based rate authority with FERC, and follow FERC requirements for periodic reporting. The more complex the trading patterns, the more likely they are to draw scrutiny. Nalcor's relatively small size means that it is unlikely to attract significant attention from either FERC or ISO market monitors, but complying with all the relevant regulations and reporting requirements can be time consuming. Although being small means Nalcor may seldom face accusations of abuse of market power, it also means that the fixed costs of risk management and compliance are spread over a smaller base.

3.4 What are the needs of current players?

Current players include ratepayers, utilities, IPPs, industrial consumers (who of course also fall into the ratepayer category), and policymakers. Stakeholders in the NL electric power system need to know that the complexities of interconnection are being managed, that the consequences are well understood, that interconnections are being operated on a least cost and nondiscriminatory basis, and that information regarding interconnection-related issues is publicly available.

3.5 Which of these needs are not met by the current regulatory system?

The needs of ratepayers and needs of shareholders are different, and respond to different regulatory systems. Provided ratepayers are not exposed to energy trading losses, risk management and compliance at Nalcor Energy Marketing is a matter for the board of its parent, not the regulator. Many other issues related to the interconnection are the responsibility of the newly established Newfoundland and Labrador System Operator ("NLSO"). Given its nascent state, it may not be fair to suggest that it is not meeting the needs of stakeholders. However, NLSO will require PUB oversight. This is consistent with the PUB's role relative to NLSO as established in law. That oversight will extend to areas with which the PUB has less familiarity. Both parties need to recognize that there is a learning curve, and to invest resources to assure that NLSO is operating effectively, particularly given that it may not be perceived as independent given its current institutional home within an owner of transmission and generation.

3.6 What changes should be made?

It is premature to suggest changes to an institution which has been in existence for less than a year and a half. Over the near term, one test will be the extent of stakeholder engagement as rules change and needs evolve. Over the longer term, NLSO and policymakers will need to consider the implications of open access with regards to domestic power sector monopolies. Would new IPPs be allowed to export over the interconnection? Should export prices influence domestic charges? Is a market monitor necessary, to critique proposed NLSO rules and propose enforcement actions if participants behave in anticompetitive ways? Should NLSO control extend to the distribution level to enable trading among distributed energy resources ("DERs")?

From a regional perspective, does it make sense for each of the Atlantic provinces to have their own system operators, given that they are now better integrated? Combining system operators from Newfoundland and Labrador, Nova Scotia, and New Brunswick would improve independence, allow for economies of scale, and facilitate regional planning. If such a consolidation is initially challenging, the respective system operators may want to explore setting up an Energy Imbalance Market ("EIM") which would allow coordination without requiring consolidation. US ISOs have been able to reduce costs for members by focusing on so-called "seams issues" which serve as barriers to regional trade; Atlantic province system operators could do the same.

3.7 Consolidated response – interconnection challenges

NL's system of regulation is evolving to meet the challenges arising from interconnection. Both the PUB and NLSO will need to further develop their capabilities, and engage in frequent stakeholder consultation, to assure that open access is properly implemented. Nalcor Energy Marketing's risk management policies need to be reviewed at least annually, and both it and NLSO need to be mindful of the challenges of US compliance.

4 Role of environmental considerations in energy policy

Question: ***Should environmental considerations be made part of the Province's energy policy? If so, how?***

4.1 What is the Province's energy policy?

The DNR released the Province's first comprehensive Energy Plan, "Focusing Our Energy," in 2007.[126] As the plan was released by the previous government, these expressions of policy are dated and may not represent current political realities. Nonetheless, the plan was intended to guide both the short- and long-term energy policies of NL up to and beyond the expiration of the Upper Churchill contract in 2041. The Energy Plan was created through a comprehensive development process, including a discussion paper on NL's energy resources, province-wide consultations, written submissions, research and analysis, as well as the engagement of external non-governmental energy advisors.[127]

In 2015, the Department released a follow-up report outlining the Province's progress towards the goals and policy actions identified in the 2007 Energy Plan.[128] The progress report identifies 94 policy actions out of the original 107 that were completed or operational.

Both the 2007 Plan and 2015 Follow-up Report outline the following as energy goals for the province:

- demonstrate environmental leadership through the development of renewable energy resources, including hydroelectric and wind generation, as well as investing in energy efficiency and conservation programs;
- ensure energy security through a reliable and competitively priced supply;
- sustainable economic development;
- maximize electricity export value;
- maximize the long-term value of oil and gas; and
- ensure an effective and efficient regulatory and governance structure to manage the development of the province's energy resources.[129]

The following is a list of some current energy policies relating to the electricity and oil and gas sectors:

- the Energy Corporation of Newfoundland and Labrador Water Rights Act, enacted in 2008, granting water rights on the Lower Churchill River to Nalcor Energy for the purpose of generation;

[126] NL Department of Natural Resources. "Energy Plan." Last accessed on June 26, 2019. Available at: <https://www.nr.gov.nl.ca/nr/energy/plan/index.html>
[127] Ibid.
[128] NL Department of Natural Resources. *Focusing Our Energy: Energy Plan Progress Report.* 2015.
[129] NL Department of Natural Resources. *Focusing Our Energy.* 2007.

- the Electrical Power Control Act, amended in 2012 to grant NLH exclusive rights to supply, transmit, distribute, and sell future electrical power to retailers and industrial customers on the island;
- the Labrador Industrial Electricity Rate Policy, introduced in 2012, which sets one rate for all LIS industrial customers;
- a net metering policy, launched in 2015, to provide customers an opportunity to offset their electricity requirements with their own renewable energy sources;
- maintaining least-cost power as the primary objective in electricity rate setting in the province, through the Electrical Power Control Act, 1994.[130]

4.2 What is the Province's environmental policy?

The NL Department of Municipal Affairs and Environment supports environmental protection and enhancement in the province through "implementing water resource and pollution prevention regulations and policies, and coordination of environmental impact assessments".[131] The Department comprises four Branches: (1) Municipal Infrastructure and Support, (2) Fire, Emergency and Corporate Services, (3) Environment, and (4) Climate Change.[132]

The Environment Branch within the Department is responsible for the Divisions of: Water Resources Management, Pollution Prevention, and Environmental Assessment and Sustainable Development. These three Divisions operate under the Environmental Protection Act, as well as the Water Resources Act, the Air Pollution Control Regulations, and the Environmental Assessment Regulations, among others.[133] The Environmental Assessment and Sustainable Development Division requires anyone who plans a project that could have a significant impact on the natural, social or economic environment of the province to present the project for examination.[134] Projects can range from large hydroelectric developments, to smaller waste management projects.[135]

The Climate Change Branch, previously the Office of Climate Change, merged with the Department in 2017-18.[136] The Branch's mandate is to develop strategies and policies on climate change adaptation and mitigation and energy efficiency, including integrating climate change considerations throughout the provincial level of government.[137]

As with many jurisdictions, much of NL's environmental policy can be found within its climate change plans. In December 2016, NL joined the federal government and other provinces in

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[130] NL Department of Natural Resources. *Focusing Our Energy: Energy Plan Progress Report.* 2015.
[131] Government of NL. "Municipal Affairs and Environment." Last accessed on June 26, 2019. Available at: <https://www.mae.gov.nl.ca/>
[132] NL Department of Municipal Affairs and Environment. *Annual Report 2017-18.*
[133] NL Department of Municipal Affairs and Environment. "Legislation." Last accessed on June 27, 2019. Available at: <https://www.mae.gov.nl.ca/department/legislation.html>
[134] NL Department of Municipal Affairs and Environment. "Environmental Assessment Division." Last accessed on June 11, 2019. Available at: <https://www.mae.gov.nl.ca/department/branches/divisions/envassessment.html>
[135] EngageNL. "Environmental Assessment Legislation Review." Last accessed on June 11, 2019. Available at: <https://www.engagenl.ca/engagement-initiatives/environmental-assessment-legislation-review>
[136] NL Department of Municipal Affairs and Environment. *Annual Report 2017-18.*
[137] Ibid.

adopting the Pan-Canadian Framework on Clean Growth and Climate Change. The framework commits the province to reduce greenhouse gas ("GHG") emissions, stimulate clean innovation and growth, build resilience to a changing climate, and develop a carbon program to meet the unique circumstances of the province.[138]

NL's main entity tasked with leading policy and strategy development with regards to climate change and energy efficiency is the Climate Change Branch, residing within the Department of Municipal Affairs and Environment.[139] In March 2019, the Department released "The Way Forward on Climate Change," the Province's collaborative five-year Climate Change Action Plan.[140] The plan's development was informed by a three-month consultation process, taking place from mid-June to mid-September in 2016, which engaged stakeholders across the province through public consultation sessions, written submissions, as well as meetings with stakeholder groups.[141] These groups included advocacy organizations, businesses, industry associations, and representatives from Aboriginal governments and organizations.[142]

At a high level, the plan's stated policy actions address how the province will:

- increase energy efficiency in homes and buildings;
- implement a carbon pricing program, which takes a made-in NL approach to pricing;
- increase the penetration of EVs;
- decrease reliance on diesel electricity generation in off-grid isolated communities;
- support the Province's agriculture, aquaculture, and forestry sectors;
- build climate change resilient infrastructure;
- address climate change related health issues; and
- pursue education and community outreach.[143]

The plan is intended to guide provincial action and support implementation of the Pan-Canadian Framework.[144] According to the plan, stated policy actions will be led by departments and agencies across the provincial government, in collaboration with partners. The Department of Municipal Affairs and Environment has also committed to reporting on the action plan's progress halfway through the five-year timeframe, and again at the end of the plan's duration.[145]

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[138] NL Department of Municipal Affairs and Environment. *The Way Forward on Climate Change.* March 1, 2019.
[139] NL Climate Change Branch. "About the Branch." Last accessed on June 26, 2019. Available at: <https://www.exec.gov.nl.ca/exec/occ/office/index.html>
[140] NL Department of Municipal Affairs and Environment. "Provincial Government Launches Climate Change Action Plan." Last accessed on June 26, 2019. Available at: <https://www.releases.gov.nl.ca/releases/2019/mae/0301n01.aspx>
[141] NL Climate Change Branch. "Climate Change Consultations." Last accessed on June 26, 2019. Available at: <https://www.exec.gov.nl.ca/exec/occ/consultations.html>
[142] NL Climate Change Branch. *What We Heard.* January 11, 2019.
[143] NL Department of Municipal Affairs and Environment. "Provincial Government Launches Climate Change Action Plan." Last accessed on June 26, 2019. Available at: <https://www.releases.gov.nl.ca/releases/2019/mae/0301n01.aspx>
[144] NL Department of Municipal Affairs and Environment. *The Way Forward on Climate Change.* March 1, 2019.
[145] Ibid.

4.2.1 Carbon pricing

The Province's "made-in Newfoundland and Labrador" carbon program was approved by the Federal government on October 23, 2018 and was implemented by the province on January 1, 2019.[146] The Province's carbon pricing program is a hybrid system comprising of both a carbon tax commencing at $20 per tonne, on transportation, building fuels, electricity generation, and other fuels combusted in the province and a performance standard system for large industrial facilities and large-scale electricity generation that emit more than 25,000 tonnes of GHG emissions per year.[147]

The program operates through amendments to the Revenue Administration Act and the Management of Greenhouse Gas Act, which were passed by the House of Assembly in December 2018.[148] Further, amendments to the Newfoundland and Labrador Atlantic Accord Implementation Act, also passed in December 2018, ensure the provincial carbon program applies to offshore areas.[149]

4.2.2 Electric vehicles

As stated in the Province's Climate Change Action Plan, renewable electricity from Muskrat Falls presents new opportunities to reduce GHG emissions through vehicle electrification.[150] Although NL has yet to enact policies with regards to EVs, the plan states its intention to "develop a comprehensive long-term strategy to increase EV penetration in consultation with the electric utilities, municipalities and industry."[151]

In terms of policy progress to date, a comprehensive study was published in November 2015 by the Province's former Office of Climate Change and Energy Efficiency, which assessed the state of EV technology, as well as infrastructure requirements and market developments.[152] According to the report, NL's current electricity infrastructure is equipped to handle lower levels of EV penetration. However, the report cautions that at higher levels of penetration, a more detailed review of electricity distribution infrastructure may be required.

As for legislative and regulatory considerations, NL's current legislations governing the sale of electricity in the province, the Electrical Power Control Act and the Public Utilities Act, do not cover EV charging stations, as they neither supply power for compensation, nor are classified as a public utility or retailer.[153]

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[146] NL Departments of Municipal Affairs and Environment, Finance, and Natural Resources. "Provincial Government Releases Federally-Approved Made-in Newfoundland and Labrador Approach to Carbon Pricing." Last accessed on June 26, 2019. Available at: <https://www.releases.gov.nl.ca/releases/2018/mae/1023n01.aspx>
[147] Government of NL. *Made-in-Newfoundland and Labrador Carbon Pricing Plan*. 2018.
[148] NL Department of Municipal Affairs and Environment. *The Way Forward on Climate Change*. March 1, 2019.
[149] Ibid.
[150] Ibid.
[151] Ibid.
[152] NL Office of Climate Change and Energy Efficiency. *An Examination of Electric Vehicle Technology, Infrastructure Requirements and Market Developments*. November 2015.
[153] Ibid.

4.2.3 Energy efficiency in homes and buildings

Currently, there are three active programs in NL designed to improve energy efficiency in homes and electrify heating. These are the Energy Efficiency in Oil Heated Homes Program, the Home Energy Savings Program, and the Energy Efficiency and Fuel Switching Program. These programs are jointly funded by the Federal government's Low Carbon Economy Leadership Fund and the provincial government's matched contributions.[154]

The Energy Efficiency in Oil Heated Homes Program is implemented through takeCharge, a joint energy efficiency initiative of NP and NLH.[155] The program provides households reliant on fuel-oil for space heating with rebates to install insulation, programmable thermostats, and electronic thermostats.

The Home Energy Savings Program is delivered through the NL Housing Corporation.[156] The program assists low-income households in making energy efficiency upgrades to their home through grants of up to $5,000. The program applies to both households that are electrically heated, as well as households reliant on fuel-oil for space heating.

Finally, the Energy Efficiency and Fuel Switching Program is implemented by the Department of Transportation and Works.[157] The program supports energy efficiency and fuel switching retrofits in existing public sector buildings currently reliant on fossil fuels for space heating, including post-secondary institutions and medical clinics.

4.3 In what ways are the policies complementary and in what ways are they in conflict?

The Province's Energy Plan already includes explicit references to environmental goals. "Focusing Our Energy" was created with two guiding objectives in mind, developing the Province's energy resources to achieve (1) economic self-reliance and (2) environmental sustainability. The plan "builds on the initiatives outlined in the Province's 2005 Climate Change Action Plan and introduces new actions to ensure that growth in the energy sector and in the economy as a whole, does not come at the expense of [the] environment."[158]

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[154] NL Climate Change Branch. "Low Carbon Economy Leadership Fund." Last accessed on June 26, 2019. Available at: <https://www.exec.gov.nl.ca/exec/occ/low_carbon_economy_fund.html>

[155] NL Climate Change Branch. "Energy Efficiency in Oil Heated Homes Program." Last accessed on June 26, 2019. Available at: <https://www.exec.gov.nl.ca/exec/occ/low_carbon_economy_programs/oilheatedhomes.html>

[156] NL Climate Change Branch. "Expansion of the Home Energy Savings Program (HESP)." Last accessed on June 26, 2019. Available at: <https://www.exec.gov.nl.ca/exec/occ/low_carbon_economy_programs/homeenergysavings.html>

[157] NL Climate Change Branch. "Energy Efficiency and Fuel Switching in Public Buildings." Last accessed on June 26, 2019. Available at: <https://www.exec.gov.nl.ca/exec/occ/low_carbon_economy_programs/publicbuildingsfuelswitching.html>

[158] NL Department of Natural Resources. *Focusing Our Energy*. 2007.

Figure 7. Matrix of NL's energy and environmental goals

Energy Goals \ Environmental Goals	Increase energy efficiency in homes and buildings	Implement a carbon pricing program	Increase penetration of EVs	Decrease reliance on diesel electricity generation in off-grid communities	Support the agriculture, aquaculture, and forestry sectors	Build climate change resilient infrastructure	Address climate change related health issues	Pursue education and community outreach
Develop clean energy resources and invest in energy efficiency and conservation	Complementary	Complementary	Complementary	Complementary		Complementary		
Ensure a secure, reliable, competitively-priced supply to meet current and future needs	Complementary		Complementary	Complementary				
Ensuring energy developments capitalize on competitive advantages				Complementary				
Maximize electricity export value								
Maximize long-term value of oil and gas		Conflicting	Conflicting					
Ensure effective governance structure to develop energy resources	Complementary	Complementary	Complementary	Complementary				

Complementary goals Conflicting goals Not directly relevant goals

Figure 7 above compares the province's six energy goals, as stated in the DNR's 2007 Energy Plan, with its eight environmental goals, as laid out in the Department of Municipal Affairs and Environment's 2019 Climate Change Action Plan. As shown in the matrix, many of the goals are independent of one another, which is not surprising. However, the energy goals thought to align with the Province's climate change goals include: developing clean energy resources, including, but not limited to, hydroelectric and wind generation, as well as investing in programs relating to energy efficiency and conservation; ensuring energy security through a reliable supply designed to meet the Province's current and future needs; and ensuring an effective and efficient regulatory and governance structure to manage the development of NL's energy resources.

While developing NL's oil and gas resources has climate change implications, assuring that such development is conducted in a manner which is mindful of minimizing emissions, effluents, and water usage is a necessary part of environmental compliance. Furthermore, carbon pricing initiatives make industries more conscious of their carbon footprint, internalizing the costs of negative externalities.

4.4 How should they be better integrated?

Co-development of energy and environmental policies can lead to more effective results. Given that the Climate Change Action Plan was released in 2019 while the energy policy dates back to 2015, it may be necessary to now update the energy policy to account for recent environmental policy statements. 2020 would mark five years since the last energy plan update; regularly updating the energy plan a year after regularly scheduled environmental plan updates would be reasonable.

Coordination of policies should extend to coordination of implementation. If environmental policies are driving towards vehicle electrification, for example, future supply planning will have to take additional load from EVs into account, while the PUB will also need to address rates for EV charging, whether only utilities can provide charging services, and the need for greater application of time-of-use ("TOU") rates. Similar dynamics exist for energy efficiency or policies encouraging electric heating; for these policies to be implemented, they need to be integrated with electricity system planning and regulation.

Creation of ongoing inter-ministerial working groups can help with this integration process; indeed, such entities likely already exist, at least on an informal basis. Where appropriate, this integration of environmental and energy policy in the province should also extend to PUB authority, including potential use of IRPs.

4.5 Consolidated response – environmental considerations in energy policy

Environmental considerations should be made part of the Province's energy policy. Energy policy is an exercise in constrained optimization; one of the elements which impacts how this optimization occurs is environmental policy. Environmental policies must be clearly stated, and ideally allow for multiple pathways to compliance. As such policies are updated, the corresponding energy policy must be updated as well. When the energy policy is updated, it should explicitly reference areas of intersection with environmental policy, along with an implementation plan. The implantation plans should be monitored quarterly by the aforementioned inter-ministerial working group.

5 Effectiveness of current electricity pricing model

Question: ***At a high level, how effective is the current electricity pricing model, and should any changes to it be considered? Is it appropriate to continue to set rates for consumers of electricity on a cost of service basis or is there another more appropriate basis to set rates?***

5.1 What is the current electricity pricing model in NL?

The PUB provides regulatory oversight of electricity rates in NL by presiding over a GRA process. Both NLH and NP are required to submit a GRA whenever they seek an adjustment to their rates. In terms of rate setting, legislation directs the PUB to use a COS methodology, a traditional form of utility regulation whereby changes in rates approved by regulators are linked to an evolution in underlying costs. The COS methodology allows utilities an appropriate rate of return, which the PUB determines according to financial market conditions, on a ratebase of allowed costs.[159] For example, from 2016 to 2018, NP's rates reflected an allowed ROE of 8.5% on a capital structure of 45% common equity.[160]

There is no formal schedule for the submission of GRAs by public utilities in NL. In practice, GRAs have been filed every two to three years by NP, while NLH last filed in 2017 and 2013 before that.[161] However, the PUB has the discretion to order a public utility to file a GRA. For example, NP was ordered by the PUB to file a GRA by June 1, 2018, after not filing an application since 2016.[162] Historically, NP has submitted a GRA on a two to three year cycle to recover capital expenditures, increases in costs and any changes to general economic conditions that would affect the company's cost of capital and funding capabilities.

In between applications, rates are adjusted for variations in fuel costs (with the pass-through effective July of each year) and changes in appropriate ROE (rate change effective January of each year). Apart from these components, rates remain constant until the subsequent rate application and regulatory hearing. As part of its Rate Stabilization Plan ("RSP"), NLH adjusts rates on July 1st every year based on the price of oil used to generate electricity at its 490 MW Holyrood Thermal Generating Station, the amount of electricity used by customers, and the annual amount of water used for hydroelectric generation. The RSP is designed to ensure that customer's rates reflect the actual cost of electricity generation from year to year.[163]

Additionally, an asymmetrical earnings sharing mechanism ("ESM") is deployed in NL. An ESM shares a specified portion of a utility's profits in excess of the approved ROE with customers; in symmetrical arrangements, profits below the specified ROE are topped up by ratepayers. In the case of utilities in NL, if the utility performs below the allowed ROE, it is required to absorb the

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[159] NL Department of Natural Resources. "Electricity." Last accessed on June 4, 2019. Available at: <https://www.nr.gov.nl.ca/nr/energy/electricity/index.html>

[160] Fortis Inc. 2018 Annual Report.

[161] NL Board of Commissioners of Public Utilities. "Hearing Documentation." Last accessed on June 24, 2019. Available at: <http://www.pub.nf.ca/document.htm>

[162] NP. *Media Release.* November 14, 2018.

[163] NLH. "Hydro Adjusting Rates for Customers on July 1, 2018." Last accessed on June 5, 2019. Available at: <https://nlhydro.com/hydro-adjusting-rates-for-customers-on-july-1-2018/>

losses, but if the utility exceeds the allowed return on rate base (of which the ROE is only one component) by more than 20 basis points, the surplus is placed in an "excess earnings account."[164] The disposition of this account is then to be determined by the PUB.

In NL, rate structures vary according to customer group, as well as the customer's location. For customers on the IIS there are rates for domestic service (residential), general service (very small, small, medium and large commercial), street and area lighting, and industrial customers. NP also has a curtailable service option for the two largest commercial service customer groups. On the LIS there is a similar rate structure.[165] There is also a separate rate structure for isolated communities, which are powered through diesel generation. These customers receive a first block of power at the same rates as island interconnected consumers.[166]

In 2015, after eight years of development, the province launched its Net Metering Program, which allows residential and commercial customers to develop their own small scale electricity generators up to 100 kW, with credit or cash paid for any excess generation, and province wide participation capped at 5 MW.[167,168]

5.2 How do you assess effectiveness?

We assess effectiveness based on multiple criteria. We distinguish effectiveness from appropriateness in that effectiveness focuses on impacts whereas appropriateness considers alternative methods of achieving the same goal. We discuss appropriateness later in Section 5.4. Factors to consider when assessing effectiveness include whether rates recover prudent costs; whether rate increases are consistent with or below general levels of inflation in the economy on a longer term basis;[169] that utilities and customers have a common understanding of desired performance; and that rates are affordable given the level of performance desired and alternatives available.

NL faces challenges across all of these measures of effectiveness. Rates in future may be recovering not only prudent costs but cost overruns which would normally be shared with equity; rate increases are likely to exceed inflation; customers and utilities have distinct views regarding performance; and rates are becoming less affordable. Such issues merit consideration of whether changes in the current electricity pricing model are worthwhile.

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[164] NL Board of Commissioners of Public Utilities. *Newfoundland and Labrador Hydro General Rate Application for 2018 and 2019 Test Years: Order No. P.U. 16(2019).* 2019.

[165] NL Department of Natural Resources. "Electricity." Last accessed on June 4, 2019. Available at: <https://www.nr.gov.nl.ca/nr/energy/electricity/index.html>

[166] Ibid.

[167] NL Department of Natural Resources. *Net Metering Policy Framework.* July 2015.

[168] As of May 2018, net metering applications in the province included 11 residential applications (of which 9 were approved) and 5 commercial applications (of which 3 were approved). Source: The Telegram. "Use of Net Metering Minimal in Newfoundland and Labrador to Date." Last accessed on July 2, 2019. Available at: <https://www.thetelegram.com/business/use-of-net-metering-minimal-in-newfoundland-and-labrador-to-date-207064/>

[169] Over the short term, rate increases can be expected to diverge from inflation in periods with substantial capital expenditure or elevated fuel costs.

5.3 What are some alternatives to cost of service for setting electricity rates?

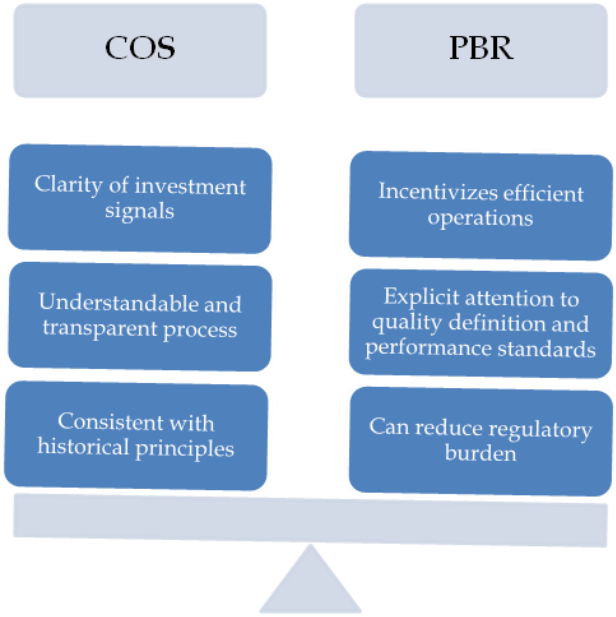
The primary alternative to COS for natural monopoly activities of the value chain is PBR. PBR can come in many flavors, depending on how performance is defined and the intensity of the incentive mechanisms. Below, we describe a range of PBR approaches, next generation PBR, and new ways of approaching sector regulation.

5.3.1 Types of PBR

PBR is a regulatory approach that aims to provide incentives for regulated utilities to improve efficiency. Generally, the main goal of PBR is to rectify what have come to be understood as the two foundational problems with traditional COS, alternatively referred to as "rate base rate of return regulation:" (1) incentives for cost-efficiency are weak, and (2) the associated administrative process is intensive. These two objectives are pursued by minimizing the direct linkage between costs and rates and by shifting the balance of the ratemaking process away from one that investigates costs to one that sets a partly pre-determined (formulaic) path for rate growth.

As a result, PBR has several perceived advantages, which are depicted below in Figure 8, along with the benefits associated with a COS regime. First, application of PBR is expected to motivate larger efficiency improvements amongst utilities than traditional COS. Second, if properly designed, PBR should create lower rates for customers than a COS regime in the long run, while also bringing commercial success to those utilities where management is willing to strive for and exceed industry expectations on productivity. Third, PBR is typically described as a regulatory framework that can, in principle, reduce the regulatory burden on both utilities and regulators by decreasing the need for frequent regulatory hearings.

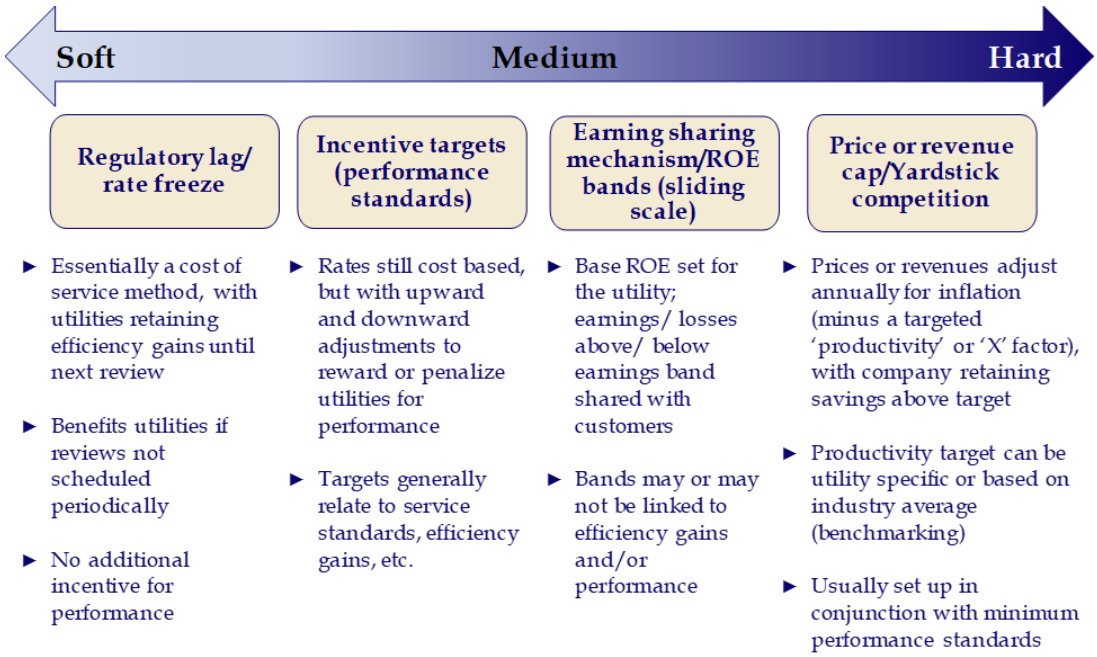
Figure 8. Comparison of COS and PBR benefits



5.3.1.1 Hard versus soft mechanisms

PBR regulation is best thought of as a continuum ranging from "soft" to "hard" mechanisms, rather than as a single type of regulatory regime. "Soft" mechanisms include adaptations to the traditional COS, such as regulatory lags where rates may be fixed for a period of time. Price caps and revenue caps lie at the "hard" end of the continuum, with performance standards and ESMs lying between the two. This continuum of mechanisms is depicted in Figure 9 below.

Figure 9. Overview of possible PBR approaches



In terms of "soft" mechanisms, options available to regulators include either a regulatory lag or a rate freeze. A regulatory lag essentially allows for a delay in introducing new rates. The lag provides a utility a longer horizon to plan, operate and keep the benefits of the incentives provided in PBR. Likewise, through a rate freeze, a utility's rates are held constant during the PBR term. A rate case moratorium is similar to a rate freeze, in that it represents a commitment not to initiate a rate case. Such mechanisms give strong incentives to reduce or control operating costs. Rate freezes are also commonly used to protect consumers during transition (i.e. transition to retail competition). However, without inflation adjustments, lengthy terms can impose risks on the regulated firm, particularly if substantial capital expenditure is required.

As for "medium" mechanisms, options include performance standards, as well as ESMs. The former, a COS approach with performance standards, ensures that any cost reductions implemented by the utility do not lead to deterioration of service quality. With performance standards, payments to utilities are adjusted upwards or downwards in correspondence to their level of performance. In contrast, ESMs allow customers to share in a company's earnings in excess of a pre-determined threshold ROE through lower rates in subsequent years. Some ESMs

also require customers to bear a portion of any shortfall of earnings below a certain ROE threshold.

Finally, in terms of "hard" mechanisms, options include either a price cap or a revenue cap. Under a price cap, the PBR formula adjusts rates for each year during the regulatory period, taking into account changes in inflation and changes in productivity. Typically, price caps apply to a basket of services over which it is averaged, giving the utility a degree of flexibility in how to optimize specific customer rates and consider cost allocations. Under a price cap regime, the utility bears the volumetric risk, but is rewarded during periods of high demand growth.

In contrast, under a revenue cap regime, the PBR formula adjusts revenues according to a predetermined formula, taking into account changes in inflation and productivity, and rates are recalibrated automatically. Under a revenue cap, there is no incentive for utilities to maximize sales, but there is still an incentive to minimize overall costs, making it arguably more compatible with utilities that are facing substantial demand response programs or energy efficiency reductions in consumer demand. Revenue cap regimes provide more pricing flexibility and are preferable when costs do not vary significantly with sales volumes.

As Figure 10 below shows, several Canadian provinces have a form of PBR and/or some form of performance standards.

Figure 10. Presence of PBR and performance standards across Canadian provinces

Province	PBR?	Performance Standards?
Alberta	Yes	Yes
British Columbia	Yes	Yes
Manitoba	No	Yes
New Brunswick	No	No
Newfoundland and Labrador	No	Yes
Nova Scotia	No	Yes
Ontario	Yes	Yes
Prince Edward Island	No	Yes
Quebec	No	Yes
Saskatchewan	No	Yes

Note: NB Power reports on SAIDI and SAIFI as part of its set of Key Performance Indicators but does not submit this to the EUB.

Further details of elements of PBR mechanisms can be found in Appendix A.

5.3.2 Next generation PBR

Some jurisdictions, including the United Kingdom ("UK") and Ontario, have moved beyond traditional PBR to develop broad categories of expected outcomes for their regulated utilities. In addition to meeting efficiency and service quality standards, utilities are required to submit plans

to meet a broad array of social goals. While the cost of meeting these goals is incorporated in approved financial plans, failure to meet specified targets can result in a loss of revenue.

The UK has also introduced new features associated with capital expenditure and innovation. Through the so-called "totex" regime, the UK has attempted to eliminate a perceived bias towards capital expenditure among utilities. The regulator calculates allowed annual capital recovery in a fashion which creates a deemed allocation between so called "slow" and "fast" money, but does not vary the recovery based on the utility's actual allocation between capital and operating expenditure. This allows utilities greater flexibility in pursuing outsourcing and cloud-based solutions, for example. Another regulatory evolution in the UK and elsewhere has been utilization of a so-called "regulatory sandbox" to allow for short term exemptions from regulatory procedures to enable testing of innovative approaches to utility challenges.

The UK's RIIO model

The UK's Outcomes-based PBR regime, the RIIO model, stands for **R**evenue set to deliver strong **I**ncentives, **I**nnovation, and **O**utputs. Under the RIIO model, transmission and distribution utilities in the UK are encouraged to "*play a full role in the delivery of a sustainable energy sector and deliver value for money network services for existing and future consumers.*" The model requires utilities to submit robust business plans that demonstrate they are proposing the best option in terms of meeting the goals of the RIIO model. The business plans include data such as the utilities' forecasts for network replacement and capacity additions.

Under RIIO's totex approach, utilities are incentivized to consider whole life costs, rather than being driven to choose between capex and opex. A capitalization ratio is set between opex and capex that would be applied in the regulatory period. This ratio sets how much revenue will be expensed ("fast money") or added to the regulatory asset base ("slow money") at the onset of the regulatory period. Through this, utilities are indifferent as to whether to use opex or capex, knowing that their decisions do not impact how the allowed revenue is determined.

Through the totex approach, utilities are incentivized to submit reasonable forecasts and to spend the allowance prudently. Utilities that submit forecasts that are closer to Ofgem's view of efficient costs receive a higher totex incentive rate. This means that the utilities receive more of the underspend. Ofgem expects that efficient spending leads to better returns for the investors and lower rates for customers.

Utilities need to report their actual totex to the regulator annually, explaining the actual performance compared to the allowed totex. According to the 2017-2018 Annual Report, the distribution utilities in UK have underspent their totex allowance by 5% or £1.2 billion for the 2017-2018 period. According to Ofgem, a proportion of the underspend is due to efficiencies, which have the effect of driving down costs.

Sources: Ofgem. RIIO-ED1 Annual Report 2017-18 and Ofgem. RIIO Handbook.

5.3.3 New forms of sector regulation

Regulators are increasingly grappling with the integration of new technologies and DERs. One approach is known as the distribution services platform provider ("DSPP") model; it is meant to

compensate utilities for facilitating connection and coordination of distribution resources. The New York Public Service Commission's ("PSC") ongoing Reforming the Energy Vision ("REV") proceeding has advanced conceptualization of the DSPP model and the supporting tariff design structures required. REV became a multi-pronged strategy to develop a clean, resilient, and affordable energy system. It prioritizes energy efficiency and clean locally-produced power and encourages deeper penetration of DER. REV engages end-users through the creation of a more local, distribution network-oriented market structure facilitated by utility as a DSPP. The idea is to reform the traditional utility business model so that integrating DERs from third party providers is a standard business practice and to ensure that utilities are incentivized to consider DER solutions as an alternative to traditional grid investments.

The DSPP model can contain several elements, including: the concept of distribution level open access; the creation of a distribution use of system ("DUoS") charge paid by those wishing to wheel power from DERs across the low voltage system to final customers; technology and ownership neutral provision of new investment in the distribution system; and development of a default alternative for those customers who wish to purchase traditional centralized supply.

The DUoS charge could be differentiated depending on customer needs, ranging from full requirements service to back up power, along with gradations of reliability or outage protection in between. The methods for setting the DUoS charge could follow a number of approaches, and could remain a regulated rate determined using costs and incentives. However, the way in which the distribution system is used would fundamentally change; utilities would need to be prepared for more bi-directional flows; their cost base would need to explicitly include costs associated with a distribution system operator ("DSO") role; and utilities would likely seek greater flexibility to set rates to minimize the impact of grid defection.

Under the DSPP model, however, there would be no net metering programs; DERs would have direct access to customers, and need to shape their value propositions on true costs of system usage and customer tastes and preferences. Utilities in their DSO role would be required to engage in technology and ownership neutral procurements; DERs would only be compensated for offsetting distribution utility costs if they were successful in a utility procurement round.

5.3.4 Unbundling and export referent pricing

Some academic commentators, such as Feehan, suggest unbundling bills and removing wholesale supply from COS treatment.[170] Feehan suggests using referent prices for generation based on the opportunity costs of foregone sales into export markets. While theoretically sound, this approach faces several challenges. Would customers be allowed to purchase from third parties? Or import themselves? In order to hedge, would customers need to use ISO-NE futures markets? How would stranded costs be dealt with? While LEI supports unbundling and use of markets in general, LEI believes that over the near term such an arrangement would be difficult to

[170] Feehan, James. "Connecting to the North American Grid: Time for Newfoundland to Discontinue Inefficient Price Regulation." *Canadian Public Policy*. December 2016.

implement, and consideration may best be deferred until Muskrat Falls is operating and NLSO has been in place for several years.

5.4 How do you assess appropriateness?

Eight principles should be considered when assessing the appropriateness of a particular regulatory framework. These include:

- transparency,
- administrative simplicity,
- incentives compatibility,
- consistency with cap ex cycle,
- provides opportunity for a fair return on prudent investment,
- reflects technological evolution,
- provides value to ratepayers, and
- reflects local conditions.

These principles are mostly long held touchstones of regulatory economics, mitigated by the view that regulators should be cautious about adopting a "one size fits all" mentality. The principles are meant to be applied in concert rather than individually, which means that some trade-offs are required to achieve a reasonable balance.

5.5 Based on the criteria described, what do you believe would be the most appropriate approach for NL?

LEI assessed the four electricity pricing models against the above criteria for appropriateness. The COS model was assumed to be a basic COS regime with annual GRAs. Traditional PBR incorporates all of the elements of Appendix A, with rates set to change based on inflation minus an efficiency target over a five-year regulatory term. Next generation PBR includes all of the traditional PBR elements, but with additional outcomes targets layered on top along with totex and a regulatory sandbox. Finally, under the DUoS approach, utilities become DSPPs and bills are fully unbundled and retail competition is introduced, with open access extended to the distribution system.

Figure 11 below provides a high level indication of how the four models compare in terms of appropriateness. Note that this is not intended to be detailed exploration of all aspects of a potential new regulatory model for NL; instead, it is intended as an initial screening exercise which can be used to further explore regulatory framework designs. Outcomes may vary depending on the weight placed on the various evaluative criteria. The models are not mutually exclusive; for example, DUoS rates can be set using either COS or PBR principles. Furthermore, over time, one model can gradually evolve into another. Traditional PBR can be augmented with totex, for example.

Figure 11. Electricity pricing models evaluated against appropriateness criteria

Criteria	Electricity pricing model			
	Cost of service	Traditional PBR	Next generation PBR	DUoS
Transparency	High	Medium	Medium	Low
Administrative simplicity	High	Medium	Low	Low
Incentives compatibility	Low	High	Medium	High
Consistency with cap ex cycle	High	Medium	Low	High
Opportunitiy for fair return on prudent investment	High	Medium	Low	Medium
Reflects technological evolution	Low	Medium	High	High
Provides value to ratepayers	Low	High	Medium	High
Reflects local conditions	Medium	Medium	Low	Low

The current system of electricity pricing has some incentive characteristics; the ESM and the fact that GRAs are not necessarily performed annually provide some financial incentive for utilities to improve productivity. The presence of these elements may facilitate a transition into a traditional PBR approach. Among the models explored, we find that DUOS is not consistent with current conditions in NL, and so believe it should not be considered at the present time; we do not believe that a vibrant marketplace for DERs is imminent, and could result in significant stranded costs. Next generation PBR implies experience with PBR to begin with; this body of knowledge has yet to be built up within NL.

However, LEI believes that the current COS model in NL can be enhanced. Doing so will take time; PBR cannot be implemented overnight. However, by improving incentives for productivity, changing approaches to capital expenditure planning, and linking performance standards to consequences, LEI believes that some of the potential rate increases can be mitigated. It is important to caution that although rate increases can be reduced, a transition to PBR will yield only incremental change, orders of magnitude will be small, and PBR cannot make preexisting costs disappear.

5.6 Consolidated response: current electricity pricing model effectiveness

The current electricity pricing model is not as effective as it could be. Changes should be considered. NL should consider evolving to a PBR framework, as this is a more appropriate basis to set rates than COS.

6 Role for renewable energy expansion in the future

Question: ***Is there likely to be any role for renewable energy generation expansion in the coming decades, either for internal use or for export?***

6.1 How do you define renewable for the purposes of your opinion and why?

For the purposes of generation, renewable resources are those that are not depleted in the production of electricity. Renewable resources include wind, solar, hydroelectric, biomass, tidal, wave, and geothermal. These resources are present in varying quantities throughout the province. As covered in Section 6.4, untapped potential for some of these resources, particularly wind and hydro, is significant from a technical perspective.

> ***Renewable Resources:*** *"Sources of energy which are inherently self–renewing, such as water power, solar energy, wind energy, tidal energy and geothermal energy. Wood, garbage and waste burned as fuel are also considered renewable."*
>
> Newfoundland and Labrador Department of Natural Resources. "Focusing Our Energy: Energy Plan Progress Report." 2015.

6.2 What time horizon are you considering?

LEI utilized a 20-year ahead time horizon (2019 – 2038). This time horizon is consistent with the upper bound of what system operators in some Canadian jurisdictions, such as Ontario and Alberta, consider in their longer-term outlooks. Shorter 10-year ahead outlooks were used in NLH's 2018 Reliability and Resource Adequacy study, New Brunswick Power's 10-year plan, and Nova Scotia Power's 10-year system outlook.

6.3 What are the criteria you are using to assess the role for renewable energy generation expansion?

Our approach to determining whether there is a role for renewable energy generation is to first assess whether there is further technical potential for renewables generation in the province. If the technical potential exists, the role of renewable energy generation expansion will depend on internal and external demand going forward, as well as the comparative costs associated with supply from any new renewable development.

At a high level, expansion of renewable generation for **internal** use could be justified if it could provide reliable and cost-competitive supply for:

- incremental grid capacity additions, if a longer-term net capacity need emerges;
- replacement of aging non-hydro units that serve the grid; or
- as an alternative, replacement, or complement to existing diesel plants that serve isolated communities.

Expansion of renewable generation for export purposes would depend on **external** demand for renewable power. For the export-based development of renewable generation to make sense, consideration would need to be given not just to the cost of building the facility, but also to the cost of building additional transmission, the reliability of the power source (e.g. hydro versus

wind), the interest from export markets in procuring supply from outside jurisdictions, and competing power supply options.

6.4 Is new renewable energy generation expansion technically feasible?

In assessing the theoretical potential for renewable expansion, LEI first reviewed third-party studies that focused on this topic. Renewable resources considered were the following: tidal, wave, hydroelectric, wind (on- and off-shore), geothermal, solar, and biomass resources. Based on these studies, the potential for certain resource types, particularly wind and hydro, are significant. A summary of these numbers are provided below for illustrative purposes.

According to a study conducted for the Canadian Hydro Association, the province has technical potential for 8,500 MW of new **hydro**.[171] Future large hydroelectric projects such as the 2,250 MW Gull Island facility represent significant sources of renewable development for the province, and could output approximately 11.9 TWh of energy per year.[172] Additionally, the potential remains for smaller, run-of-river developments, due in part to the Province's geography and precipitation; one study estimated Newfoundland's small hydro potential at 940 MW across 190 projects located throughout the island.[173]

Similar to hydro, **wind** supply is abundant in the province, but unlike hydro it is significantly underutilized compared to its theoretical potential.[174] Leaving cost considerations aside, wind is therefore the most promising renewable resource for future development in the province. In terms of onshore wind potential, regions of interest include the Northeast coast, the Burin Peninsula, the Northern Peninsula and parts of central Newfoundland.[175] These high potential areas are characterized by high wind speeds, exceeding 7 meters per second at a height of 80 meters above ground, and are located nearby existing transmission lines but at least 5 kilometers ("km") away from population centers.[176] One study estimated that, assuming 25% of these high potential areas are utilized, NL could generate approximately 530 TWh of wind power per year,[177] enough to supply *all* of Canada's annual power needs.[178]

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[171] Canadian Hydropower Association. *Report of Activities, 2014 – 2015.*

[172] Newfoundland and Labrador Department of Natural Resources. *Gull Island: Why Not Develop Gull Island First*? November 2012.

[173] Fisher, Iqbal and Fisher. "Small Scale Renewable Energy Resources Assessment for Newfoundland." *The Harris Centre Memorial University,* 2009.

[174] There are only two currently operational wind projects in Newfoundland, totaling 54 MW. NLH holds power purchase agreements ("PPAs") for both, namely the 27 MW project in St. Lawrence with NeWind Group Inc., as well as the 27 MW project in Fermeuse with SkyPower Corporation. Source: Newfoundland and Labrador Hydro. "Corporate Overview." Last accessed on June 6, 2019. Available at: <https://nlhydro.com/about-hydro/corporate-overview/>

[175] Fisher, Iqbal and Fisher. "Small Scale Renewable Energy Resources Assessment for Newfoundland." *The Harris Centre Memorial University,* 2009.

[176] Barrington-Leigh, Christopher and Ouliaris, Mark. "The Renewable Energy Landscape in Canada: A Spatial Analysis." *Renewable and Sustainable Energy Reviews,* vol. 75, 2017, pp. 809-819.

[177] Ibid.

[178] Based on Statistics Canada data on total sales of electricity to ultimate customers [Table 25-10-0021-01]. For reference, total sales ranged from 480 to 490 TWh between 2013 and 2017.

As for the Province's offshore wind potential, the Gulf of St. Lawrence (located west of Newfoundland) has been identified as another high potential area.[179] Although offshore wind projects benefit from higher wind speeds than those on land, they are currently constrained by higher costs relating to construction, maintenance, and transmission.[180] Nevertheless, given potential capacity factors of 50%, projects on the Gulf of St. Lawrence could produce an additional 13 TWh of wind energy per year.[181]

Tidal and wave resources could also theoretically be made available in the future. For **tidal** supply, under the assumption that only 15% of the Province's identified tidal potential can be realistically harnessed, NL could produce 0.56 TWh of tidal energy per year through tidal stream generators.[182] The Province's wave potential is estimated at 5.7 TWh per year, assuming 125 km of coastline is utilized for wave energy development at a 10% wave-to-electrical conversion efficiency.[183]

The remaining renewable sources (geothermal, solar, and biomass) are either not naturally abundant or have a poor comparative advantage. This is not to say they should not be considered in the future, but rather they would not contribute significantly to the theoretical renewable potential for the province.[184] For **geothermal**, high temperature sources most viable for electricity generation are not easily accessible, as they are buried deep underground under impermeable rock.[185] Geothermal energy was not included as an untapped potential resource in the Province's Energy Plan (2007), which set out NL's vision for energy resource development.

For **solar**, NL is plagued with low sunlight levels, receiving the lowest solar irradiation levels across all Canadian provinces.[186] As a result, according to a summary of information based on Natural Resource Canada data, a 1kW solar system installed in the province would only produce 949 kWh per year on average, as compared to a Canadian average of 1,133 kWh per year (i.e. a 10.8% capacity factor versus a 12.9% capacity factor).[187] Solar can still be developed on a small scale, particularly for rural and isolated areas, with one study estimating the Province's solar

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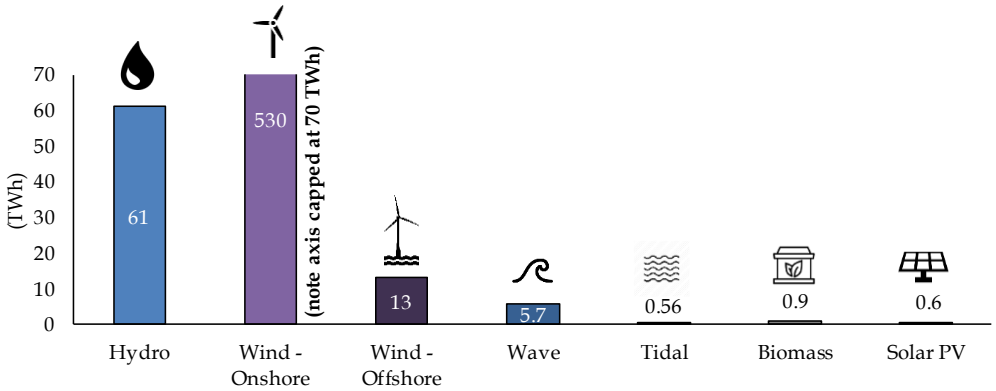
[179] Ibid.
[180] Ibid.
[181] Dowdell, Elizabeth and Patel, Sonak. "Newfoundland and Labrador Energy Market Profile." *University of Alberta Future Energy Systems.* August 23, 2018.
[182] Barrington-Leigh, Christopher and Ouliaris, Mark. "The Renewable Energy Landscape in Canada: A Spatial Analysis." *Renewable and Sustainable Energy Reviews,* vol. 75, 2017, pp. 809-819.
[183] Ibid.
[184] Both solar and biomass were included as eligible resource types in the province's 2015 Net Metering Program, which allowed residential and commercial customers to develop their own small scale electricity production and receive credits for excess generation (with individual participation limited to 100 kW, and total participation limited at 5 MW). The province also launched the Biogas Electricity Generation Pilot Program in 2014 to encourage the development of biogas power, with participation also capped at 5 MW. Solar and biomass have therefore been considered as part of the resource mix in the province, but on an aggregate level their theoretical potential is dwarfed by wind and hydro.
[185] Dowdell, Elizabeth and Patel, Sonak. "Newfoundland and Labrador Energy Market Profile." *University of Alberta Future Energy Systems.* August 23, 2018.
[186] Energy Hub. "Provincial Solar Guides." Last accessed on June 6, 2019. Available at: <https://energyhub.org/newfoundland-and-labrador/>
[187] Ibid.

photovoltaic ("PV") potential at 0.6 TWh per year, assuming 10 m² of installed PV panels per person located in rural areas.[188]

Figure 12 presents a summary of this theoretical generation potential for the resources discussed above based on one of the broadest third-party studies reviewed by LEI.

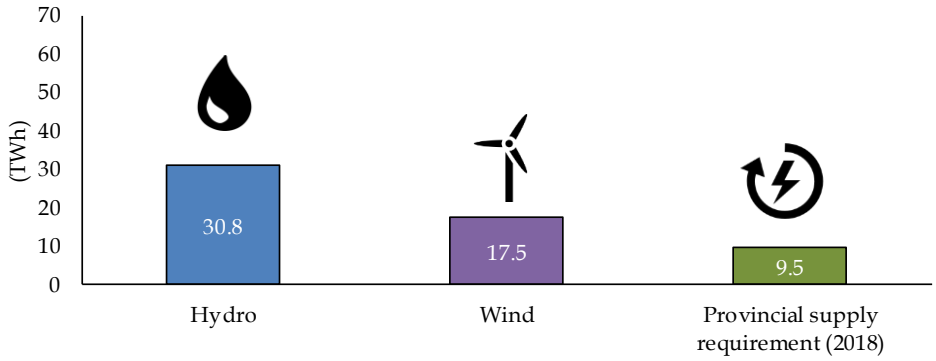
Figure 12. Illustrative potential for new renewable generation in the province (annual TWh)



Source: Based on information from Barrington-Leigh, Christopher and Ouliaris, Mark. "The Renewable Energy Landscape in Canada: A Spatial Analysis."

Estimates from NL's DNR have also put the potential undeveloped renewable capacity at significant levels, with over 5,000 MW of undeveloped wind potential and 6,000 MW of undeveloped hydro potential (including Muskrat Falls). Based on this capacity and assumptions around capacity factor, Figure 13 presents an estimate of potential additional generation from renewable resources.

Figure 13. New renewable potential in the province based on DNR data (annual TWh)



Note: Capacity data based on information from the DNR's website and 2007 Energy Plan. Wind generation based on assumption of 5,000 MW of undeveloped wind and a capacity factor of 40%. Hydro generation based on assumption of 5,176 MW of undeveloped hydro (6,000 MW of undeveloped hydro less Muskrat Falls capacity) and a capacity factor assumption of 68%. Provincial supply requirement based on information from NLH's 2018 Reliability and Resource Adequacy Study.

[188] Barrington-Leigh, Christopher and Ouliaris, Mark. "The Renewable Energy Landscape in Canada: A Spatial Analysis." *Renewable and Sustainable Energy Reviews,* vol. 75, 2017, pp. 809-819.

Regardless of what source is used, there is a substantial amount of renewable generation potential, and new renewable energy generation expansion is therefore technically feasible.

6.5 Based on current load growth projections, is there any need for new generation in NL over the next 20 years?

6.5.1 Capacity needs up to 2028

NLH's 2018 Reliability and Resource Adequacy Study, which covered an outlook horizon up to 2028, found there was almost no change in capacity and energy requirements and **no need for incremental capacity additions under its base case outlook**.[189]

Aside from the base case, NLH also examined 23 other cases centered around how the supply-demand balance could develop over the next decade. These cases varied based on four potential Island load scenarios, three potential Labrador load scenarios, and two planning criteria conditions (for a total of 24 cases).[190] Along with the base case, 16 of these cases projected no capacity shortfalls over the next decade (i.e. no additional resource needed). The remaining 7 cases mostly centered around Labrador load scenarios and the more extreme planning criteria scenario generally did not project capacity shortfalls until the mid to late 2020s.[191] New resource requirements across the 7 cases where capacity needs were identified range from 58.5 MW to 175.5 MW, while the remaining 17 cases had no resource requirements.

Conventional gas turbines were selected as the least cost option for resource additions, but as none of the 24 cases projected an energy shortfall, NLH stated they are looking at roles that conservation and demand management, rate structure, and alternative options such as battery storage could play in providing lower-cost solutions to a capacity need should it emerge at a later point in time.

6.5.2 Extending the outlook to 2038

Using information contained in NLH's 2018 Reliability and Resource Adequacy Study, we can infer a range for demand growth over the next decade, as well as an illustrative longer-term demand growth projection. As shown in Figure 14, the inferred illustrative demand by 2038 could grow to 2,175 MW in the medium demand case, 2,349 MW in the high demand case, and remain unchanged at 2,050 MW in the flat demand case. These three demand outlook projections

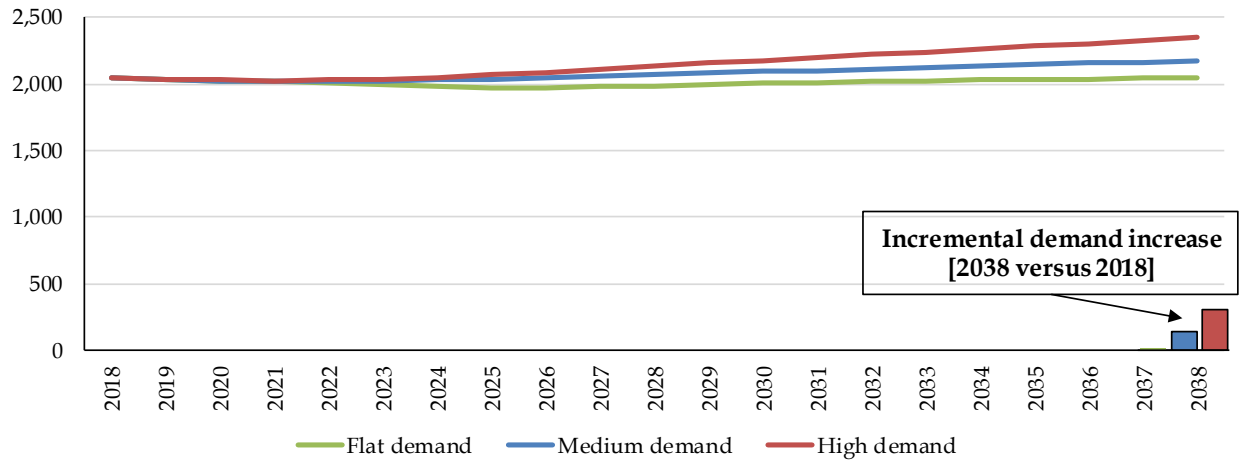
[189] The demand requirement outlook increased marginally from 2,047 MW in 2018 to 2,060 MW by 2028; energy requirements increased from 9,481 GWh to 9,495 GWh.

[190] Island load scenarios were low retail rate, medium retail rate, high retail rate, and high load growth; Labrador load scenarios were a base case outlook, a high industrial growth case, and a representative case where all recapture is consumed in Labrador; planning criteria conditions were P50 (where actual peak demand is expected to below forecasted peak 50% of the time, and above it 50% of the time), and P90 (actual peak below forecasted 90% of the time and above it 10% of the time).

[191] Three higher-case scenarios projected capacity needs in 2022, 2023, and 2025. However, these scenarios included the representative case for Labrador where all recapture was consumed in Labrador, and therefore load growth was assumed to grow to the level where all supply was consumed. Additionally, NLH noted that the two earliest capacity shortfall cases are "outside what utilities typically plan for."

represent a peak demand increase of around 302 MW, 128 MW, and 3 MW respectively over 2018 levels by 2038 (2018 demand requirement of 2,047 MW).

Figure 14. Illustrative provincial demand growth (MW)



Note: Based on information contained in NL Hydro's 2018 Reliability and Resource Adequacy Study, including Cases I, II, IV from "Island Interconnected System Forecast Annual Peak Demand Analysis" figure. Illustrative demand assumes Labrador demand grows at the same rate as island demand. Demand from 2030 to 2038 is assumed to follow the 5-year average demand growth rate from 2025 to 2029, at around 1% for the high case, 0.5% for the medium case, and 0.3% for the flat case.

Source: LEI analysis using information contained in NL Hydro's 2018 Reliability and Resource Adequacy Study.

6.5.3 Renewable development for internal supply needs

Given the tendency in the recent past for planners in North America to overestimate demand growth projections, the need for any net additions to resources over the next decade is not certain. Any incremental needs will depend on how the expected supply-demand balance plays out based on shorter term demand projections (three to five years out), which would provide adequate construction lead time. In the event this need does emerge, the decision to build any new capacity should be made on a technology-neutral and least-cost basis.

It is unlikely that new capacity will be needed to replace aging non-hydro units that serve the grid over the next two decades, based on their technical lifespans. Older thermal units include the 490 MW Holyrood plant, which is expected to retire in 2021. The 50 MW Stephenville and 50 MW Hardwoods Gas Turbine units are also considered for retirement in 2021 – and were assumed by NLH to retire in 2021 in their 2018 Reliability and Resource Adequacy Study. Output from these units will be replaced by supply from Muskrat Falls. The remaining non-hydro capacity in operation is relatively new. The St. Lawrence and Fermeuse wind projects were built around 2009, and wind projects can be expected to last for 30 years, with repowering options also available.[192] The largest remaining thermal unit would be the Holyrood Gas Turbine unit, which

[192] Based on the National Renewable Energy Laboratory's 2018 Annual Technology Baseline technical life assumptions. The PPA between NLH and Muskrat Falls dated November 29, 2013 included the assumption that these wind facilities

was built in 2015. The need for incremental capacity based on unit retirements is therefore unlikely.

Should an incremental capacity need emerge, assuming demand grows in line with the high case shown in Section 6.5.2, the options to meet this need on the renewable side would most likely be either hydro or a variable generation resource (most likely wind, but potentially solar). The benefit of **hydro** power is that it provides reliable clean power at high capacity factors. Potential new hydro developments were considered as part of NLH's 2018 Reliability and Resource Adequacy Study, with five potential new hydro projects identified with an average capacity factor of around 71%. However, initial cost estimates for these new developments were also substantial, averaging around $10,882/kW. Given this significant cost estimate, and the tendency for hydro projects to often go over schedule and over budget, development of new hydro for internal supply, should the need emerge, is likely cost prohibitive.

Variable generation resources such as **solar** and **wind** provide intermittent supply, with their outputs depending on real-time weather conditions. Because of this they also have limited flexibility, capable of curtailing production if there is excess system supply, but incapable of ramping up production in higher demand periods if weather conditions are not favourable. As previously discussed, solar capacity factors in the province are below the national average, and capability to provide power at system peak is poor.[193] In contrast, wind capacity factors are higher than the national average, but their capability to provide power at system peak is still uncertain.[194] Pairing a **wind option with storage** would provide enhanced reliability and flexibility, but this would come at a higher cost.

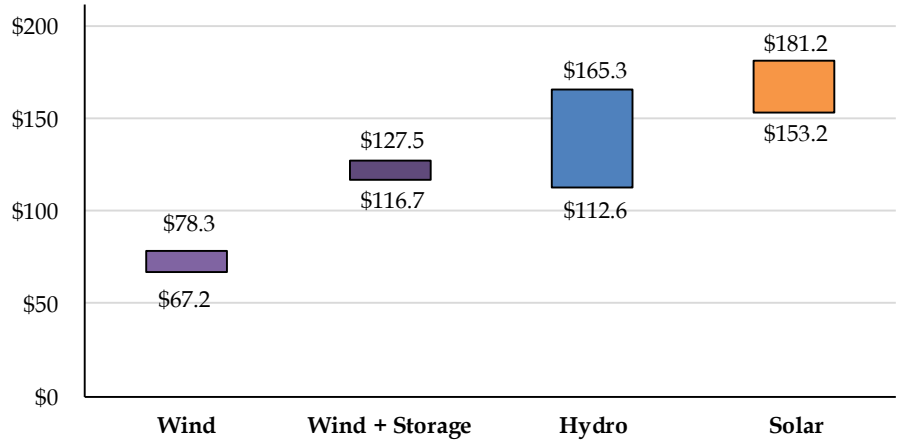
Figure 15 shows the illustrative Levelized Cost of Energy ("LCOE") for these options based on preliminary cost assessments from NLH's Reliability and Resource Adequacy Study. LCOEs are useful in comparing from a cost perspective the various potential options available to meet incremental needs, should they emerge. Based on these numbers, solar and hydro options are unlikely to be the source for incremental capacity due to their higher costs. Wind can provide energy at lower costs compared to other renewable options, but its supply is intermittent. Pairing a wind resource with storage enhances reliability, but at a higher cost. Still, based on the LCOEs this cost could be lower than developing new large-scale hydro, and the installations can be in more granular amounts. The competitiveness of storage will depend in large part on how rapidly its costs decline going forward.

would retire in mid-2028, however based on a review of currently operational wind facilities such a retirement date may be premature.

[193] NLH's Reliability and Resource Adequacy Study included two potential 10 MW solar projects, with capacity factors of 12.4% and 14.7%.

[194] Based on information from NLH's Reliability and Resource Adequacy Study, wind capacity factors could be around 40% and capability to provide power at system peak around 22%.

Figure 15. Illustrative LCOE for new renewable options in the province (2018 $/MWh)



Source: LEI analysis based on information contained in NLH's 2018 Reliability and Resource Adequacy Study and LEI assumptions. See Appendix B (Section 8) for assumptions.

The decision to build any new supply should only be made when the potential need emerges, not now. If the need does emerge, the resource decision should be made based on a technology-neutral and least-cost basis, which means considering non-renewable generation options (i.e. thermal) if consistent with then prevailing environmental laws, as well as non-generation options such as storage and conservation and demand-side management.[195]

6.6 Is there a role for renewable energy in NL remote communities or behind the meter?

The potential for development of renewable generation options in the Province's isolated communities have the same needs- and cost-based considerations as grid-connected development. However, as isolated communities are solely reliant on a small number of gensets (i.e. alternative grid supply options are not available), reliability concerns are an extremely important consideration.

The Province's 21 isolated electricity systems collectively serve around 4,400 customers with a total installed capacity of 42 MW. The potential for renewable development in these communities are in their early exploratory stages, with the DNR and NLH launching a Request for Expressions of Interest centered around the potential for renewable energy solutions in 14 of these isolated systems, and the Nunatsiavut Energy Security Working Group exploring the opportunities for renewable energy development in five Inuit communities.[196]

The potential for renewable additions to these isolated communities would depend on the outlook for longer-term demand growth, and in the short term, based on the potential for

[195] As the need that may emerge in higher demand outlooks is related to capacity and not energy, standalone storage may warrant consideration if this need emerges in future.
[196] Government of Newfoundland and Labrador's Department of Natural Resources and Newfoundland and Labrador Hydro. *Request for Expressions of Interest for Renewable Energy Solutions for Isolated Coastal Diesel-Powered Electricity Systems in Newfoundland and Labrador.* April 15, 2019.

displacement of diesel generation and enhanced reliability. Given the issues around renewable intermittency, any potential options would need to be able to operate in conjunction with existing diesel gensets, which would help alleviate intermittency and reliability concerns. As with the development of any option, cost-effectiveness is also an extremely important consideration.

Renewables may continue to play a role behind the meter on customer premises. To the extent allowed by law, this role may increase as NL's delivered rates increase, particularly if the costs of storage continue to fall.

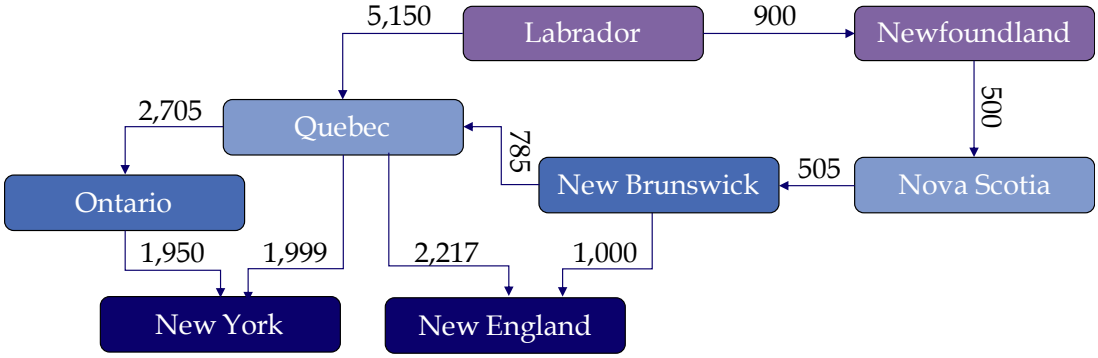
6.7 Which export markets did you consider?

The Northeastern US (New York and New England) is the largest potential market to export renewable power in the area from any large-scale development. Exports to other nearby Canadian jurisdictions made possible through the Maritime Link, notably Nova Scotia, are also technically feasible, but on a smaller scale. We do not view exports to Ontario as likely.

6.8 Is there sufficient transmission currently for additional supply to reach export markets?

Figure 16 presents the current export transmission constraints for nearby jurisdictions. Exports from any large new development would see constraints out of Newfoundland into Nova Scotia, Nova Scotia into New Brunswick, and New Brunswick into New England. New-build transmission will therefore likely be required to secure firm contracts. As transmission into Quebec was built to move power from Churchill Falls, exports from large new development out of Labrador would also likely need new transmission into Quebec, and from Quebec into the Northeastern US.

Figure 16. Transmission export capabilities in select jurisdictions (MW)



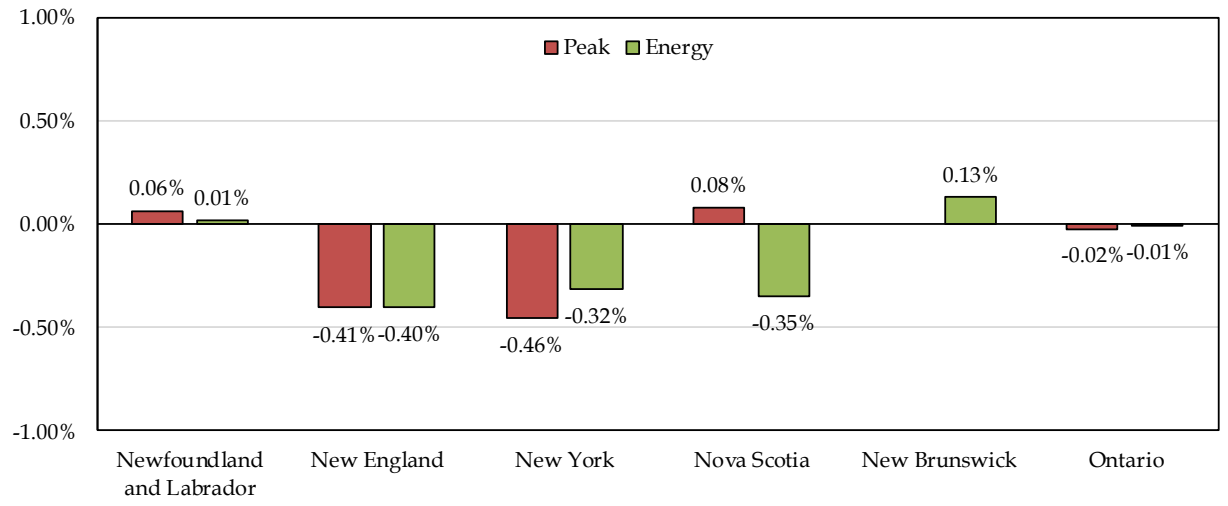
Note: According to NSPI's 10-year system outlook report, the NS-NB interconnection currently provides 350 MW of export transfer capability. However, the figure above presents the capability at 505 MW as NSPI's Q4 2017/2018 Nova Scotia Transmission System Operating Limits document mentioned that 'the Maritime Link Upgrades will increase export Total Transfer Capability up to 505 MW.'

Sources: Newfoundland and Labrador DNR's "Gull Island: Why not develop Gull Island first?" (November 2012); Hydro Quebec TransEnergie's Transmission System Overview; Emera's Maritime Link map; ISO-New England's "Forward Capacity Auction 14 Transmission Transfer Capabilities & Capacity Zone Development – Planning Advisory Committee" presentation (March 21, 2019).

6.9 Is load growing in export markets?

Peak load and energy outlooks for the export markets mentioned in nearby jurisdictions are flat to negative for the 2019 to 2028 period, as presented in Figure 17. Load outlooks only extended beyond the 2028 period for Ontario and New York, with longer-term peak load growing in both markets at a forecasted amount of around 0.5% per year and energy growing at a forecasted amount of around 0.6% per year (growth for Ontario is over the 2029 to 2035 timeframe, New York over the 2029 to 2038 timeframe).

Figure 17. Annual growth outlook for peak load and energy in selected jurisdictions, 2019 to 2028



Notes: Presents base case outlooks for jurisdictions where multiple outlooks are conducted; New England outlook is net of behind the meter PV and passive demand response; Newfoundland and Labrador's outlook covers the 2018 to 2028 period; New Brunswick Power did not have a capacity outlook.

Sources: NLH's 2018 Reliability and Resource Adequacy Study; ISO-NE's 2019 Forecast Data File; NYISO's 2019 Load and Capacity Data Report; NSPI's 2018 10-Year System Outlook Report; NB Power's 2017 10-Year Plan; IESO's 2016 Ontario Planning Outlook.

6.10 What alternative sources of new supply exist in export markets?

While load in most markets is not expected to grow substantially, new renewable resources have been in high demand in certain jurisdictions, particularly New York and New England, due to policy-driven efforts to reduce emissions and replace aging thermal generation. Clean supply imports from existing resources in Canadian jurisdictions have in some instances been procured; however, when procuring new-build resources, these potential export markets would have a preference for building them in their own jurisdictions.

> *By providing firm hydro back-up, the Maritime Link Project enables more renewable energy development, such as wind, **in Nova Scotia*** [emphasis added]
>
> Emera website

New York currently has significant policy-driven renewable energy procurement initiatives and goals. These include previous announcements targeting: 9,000 MW of off-shore wind by 2035;

3,000 MW of energy storage by 2030; and 6,000 MW of distributed solar by 2025. Recent renewable contract awards include a total of 1,650 MW of solar, wind, and storage (announced in January 2019);[197] and 1,380 MW of mostly wind and solar, procured at a weighted average REC ("renewable energy credit") price of US$21.71/MWh over 20-year contracts.[198] Importantly, **all of these resources were procured from within New York.**

Renewable procurement in **New England** is generally handled at the state level, with aggressive Renewable Portfolio Standards and Clean Energy Standards centered around procurement from non-emitting resources. Largely as a result of states pursuing aggressive renewable energy goals,[199] wind and solar energy have been expanding dramatically in New England. Recent large procurement examples include Massachusetts' 83C Request for Proposal ("RFP") specifically for offshore wind of around 1,600 MW by no later than 2027, with Vineyard Wind being selected to supply 800 MW of this.

It is important to note that renewables are not spread evenly in the New England region. For example, much of the wind generation is located in northern New England, which could be constrained in sending power to the load centers in southern New England. As such, the interconnection queue in areas such as Maine, northern New Hampshire, and northern Vermont has been constrained, resulting in physical constraints to build new resources and sending that power to the load centers. Leaving aside any preferences for building new resources in-state, as large new-build resources out of NL would need to pass through these jurisdictions to supply New England's load centers, this would present an additional hurdle.

6.11 Can supplies from NL compete in export markets?

As covered in Section 6.4, the theoretical potential for additional renewable development is significantly higher than what is needed for internal use. Using the DNR estimate, the province has over 6,000 MW of undeveloped hydro potential and 5,000 MW of undeveloped wind potential. However, for it to make sense to develop these resources, they would need to be cost-competitive compared to competing supply options in larger markets that have a need for renewable supply.

Recent PPAs signed in the Northeastern US for hydroelectric supply can provide some indication of an *upper-bound* willingness to pay for reliable cross-border supply. One example of this was the recent 20-year contract (regulatory approval pending) signed by Massachusetts distribution utilities for delivery of clean energy at a levelized 2017 price of US$59/MWh.[200] This followed a similar deal with Vermont utilities (including Green Mountain Power) for supply of clean energy over the course of a 26-year contract starting at US$58.07/MWh in 2012.[201] This contract

[197] NYSERDA. *NYSERDA Announces Details for $1.5 Billion for 20 Large-Scale Renewable Energy Projects to Combat Climate Change and Grow New York's Clean Energy Economy.* January 18, 2019.
[198] New York State Office of the Governor. *Governor Cuomo Announces Formal Request for New York Exclusion from Federal Offshore Drilling Program.* March 8, 2018.
[199] For Example, Massachusetts's Global Warming Solutions Act signed in August 2008 has very aggressive renewable energy goals to reduce greenhouse gas emissions of 25% below 1990 levels by 2020 and 80% by 2050.
[200] Massachusetts Department of Energy Resources. *RE: Petitions for Approval of Proposed Long-Term Contracts for Renewable Resources Pursuant to Section 83D of Chapter 188 of the Acts of 2016, DPU 18-64, 18-65, 18-66.* July 23, 2018.
[201] Vermont Department of Public Service. *Comprehensive Energy Plan 2011.* December 2011.

information suggests there can be demand for existing hydroelectric supply, but willingness to pay is unlikely to exceed an all-in cost of $80/MWh (2018 Canadian). As covered in Section 6.5.3, the estimates for smaller scale hydro developments put the illustrative LCOE range between $113 and $153/MWh.

Importantly, this LCOE range does not include the cost of transmission enhancements or additions, which would be required in the event larger scale development was being considered. Because of the distance resources from NL must travel to supply into larger export markets, NL resources must be significantly cheaper than local or more adjacent resources to cover the cost of transmission. Furthermore, resources with similar or better cost structures exist closer to the target markets. Finally, procurement initiatives in the Northeast US are often designed to favor (to the extent possible under US Federal law) in–state or in-market resources. Taken together, these factors suggest that new NL renewable resources are unlikely to be competitive in export markets.

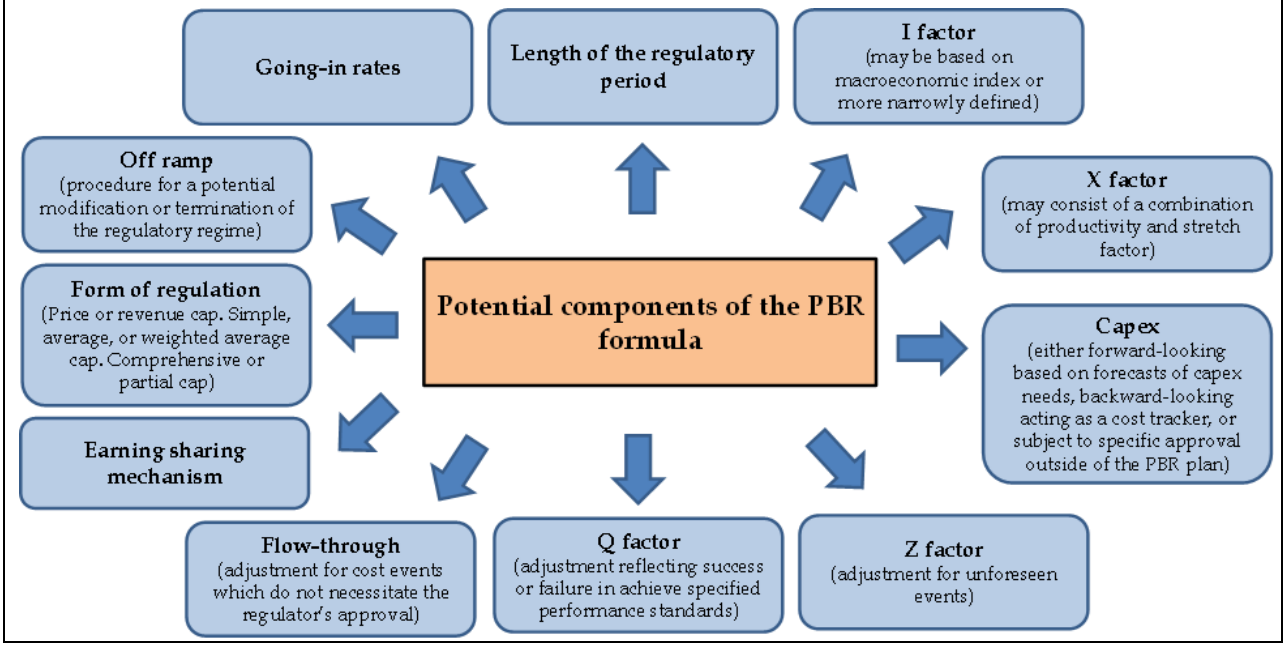
6.12 Consolidated response: future role for renewable energy expansion

There is a limited role for renewable energy generation expansion in NL in the coming decades. Such expansion is more likely to be justified for internal use, but given that load growth in NL is expected to be minimal and few additional retirements of existing generating stations are expected, renewables expansion will be small in scale and episodic. Initial opportunities are more likely in remote communities to reduce use of fossil resources where cost effective. Wind or wind plus storage installations are likely to be most cost-effective and can be installed in smaller unit sizes and more rapidly than hydro. Export markets are unlikely to provide justification for renewables development in NL given slowing demand, cost of transmission, and the existence of closer, cheaper resources.

7 Appendix A: Detailed design elements of PBR regimes

PBR mechanisms can include a range of components to address various objectives of the regulator. These include components for annual adjustments and for contingent adjustments, as well as additional mechanisms, all of which are shown in Figure 18 below.

Figure 18. Potential components of the PBR formula



In terms of annual adjustments, key components include: the inflation factor, or I factor, which adjusts for the level of inflation; the productivity improvement factor, or X factor, which adjusts rates to account for expected changes in a utility's productivity; and the capital expenditure factor, or K factor, which explicitly adjusts for capital expenditures.

As for contingent adjustments, these can include: the exogenous factor, or Z factor, which recovers extraordinary costs incurred outside of the company's control; the performance standards factor, or Q factor, which reflects the rewards or penalties resulting from the achievement or failure to reach specified performance targets; and the flow-through factor, or F factor, which reflects pre-approved costs that are passed through to customers as they arise.

Additional mechanisms that can be included in the PBR formula are: an earnings sharing mechanism ("ESM"), through which a specified portion of a utility's profits in excess of or below the approved return on equity is returned to customers; and the off-ramp mechanism, which allows utilities a way to revise the ratemaking mechanism before the end of the regulatory period or provide an exit out of the regulatory regime.

7.1 I factor

The inflation factor, or I factor, is an annual adjustment to the utility's revenue or rates reflecting the level of inflation, usually mirroring the actual inflation rate in the previous year. The purpose of the I factor is to pass on to customers increases in the utility's cost structure that, being driven by macroeconomic forces associated with the relative supplies of money and economic goods, are beyond the control of the utility's management.

Broadly, there are two types of inflation parameters: input-based and output-based measures. Input-based measures reflect the change in prices over a certain period for inputs into the utility 'production' process. The inflation rate is calculated by a weighted average, with the weights equal to the share of each input factor within the utility's cost structure. It is a direct measure of inflationary pressure faced by the company. An example of an input-based measure is the producer price index ("PPI") which estimates the average change over time in the selling prices received by domestic producers for their output.

On the other hand, output-based measures reflect the changes of prices for the final products produced by the utility, like the consumer price index ("CPI"). The advantage of this measure over the input-based measure is that it is readily available, comes from a reliable source, is not influenced by the regulated company itself, and is generally accepted by ratepayers due to its transparency and ease of understanding.

7.2 X factor

The productivity improvement factor, or X factor, represents an annual adjustment to revenue or rates reflecting expected changes in terms of productivity. There is a presumption that if the utility achieves the productivity equivalent to the X factor, then it will be able to earn its allowed rate of return. The X factor also serves as the mechanism by which customers reap the rewards of PBR (as it dictates the pace of real rate reductions). Therefore, there is a balance that needs to be preserved – the X factor needs to be feasible but also a challenging target, so that it can motivate cost reductions that are meaningful.

The X factor may be based on either the utility's historical performance or on an external benchmark. It may include a firm-specific target, or a stretch factor – which is a mechanism to adjust the utility's revenue or rates each year to reflect firm-specific expected productivity gains in comparison to the gains expected for the industry as a whole.

7.3 K factor

The capital expenditure factor, or K factor, is an annual adjustment in the rate index formula to address capital expenditures ("capex") explicitly. This K factor can either be forward-looking, based on forecasted capex needs, or backward looking, based on approved capex spending in the previous year.

7.4 Z factor

The exogenous factor, or Z factor, is a contingent adjustment to revenue or rates in order to recover extraordinary costs that are outside of the company's ability to control or predict. The Z factor allows for adjustment in case events occur that (i) are perceived as beyond the reasonable control of utility management; (ii) were neither foreseen nor foreseeable at the time a formula was set; and (iii) have a significant impact on company finances.

7.5 Q factor

The performance standards factor, or Q factor, is a contingent adjustment to revenue or rates for rewards or penalties linked to the achievement or failure to reach specified performance targets, usually in terms or service quality, as well as reliability and quality of supply. Performance standards are often used concurrently with efficiency incentives, to ensure any cost reductions implemented by the utility do not lead to deteriorating service quality.

7.6 F factor

The flow-through factor, or F factor, is a contingent adjustment to revenue or rates reflecting certain costs that are pre-approved during the regulatory review process and can be forecasted during the planning period. These costs are automatically passed through to customers as they arise.

7.7 Earnings sharing mechanism

An earning sharing mechanism ("ESM") is a mechanism through which a specified portion of a utility's profits in excess of or below the approved return on equity is returned to customers. These are designed so that if formulae-driven price adjustments result in too wide a divergence between prices and costs, the extra-normal earnings (or losses) are shared amongst the company and its customers rather than retained (or absorbed) entirely by the company.

7.8 Off-ramp option

The off-ramp mechanism provides utilities a way to revise the ratemaking mechanism before the end of the regulatory period or provide an exit out of the regulatory regime. Typically, there are circumstances defined before the start of the regulatory period that will trigger an off-ramp. These are usually events that are out of the management's control and would have to make the ratemaking regime in place unsustainable.

7.9 Going-in rates

Going-in rates are the starting point of the PBR regulatory term and are usually determined through a COS filing (or rebasing). The PBR annual adjustment (I – X) is subsequently applied to those rates during the regulatory period.

7.10 Length of the regulatory period

The length of the regulatory period is typically the time between a major review of underlying components of the determined rate regime (such as the allowed rate of return, the efficiency factor, performance standards, etc.) and the subsequent review. Separate regulatory periods can also be devised for the first "generation" of PBR, to account for timing to establish new institutions and to ease the transition to a new type of regulatory structure.

The length of the regulatory period needs to balance competing pressures. A longer period can increase the motivation for the utility to make cost reductions as it will be able to retain increased profits over the term (barring an ESM). On the other hand, longer periods between resets potentially increase the risk for regulators and utilities, due to an inability to act on changing circumstances in a timely fashion.

8 Appendix B: LCOE assumptions

Figure 19 presents the assumptions used to estimate the illustrative LCOEs in Section 6.5.3. Rows coloured in grey are based on information contained in NLH's 2018 Reliability and Resource Adequacy Study and associated supporting documentation. Weighted average cost of capital and leverage parameters were assumed by LEI to be the same across the different resources covered. Project life (for financing purposes) for wind and solar was assumed to be 20 years, based on the most common length contract terms for these resource types. As noted earlier, actual lives may be longer. Hydro was assumed to have a 60 year life, based on the higher end of long-term new hydro development contracts seen in other Canadian jurisdictions.

Figure 19. Assumptions used to estimate illustrative LCOEs for various resources

Parameter	Unit	Wind	Wind	Wind + Storage	Wind + Storage	Solar PV	Solar PV	Island Pond	Portland Creek	Round Pond	Badger Chute	Red Indian Falls
Capacity	MW	101	13	101	13	10	10	36	23	18	24	42
Capacity factor	%	40.0%	40.0%	40.0%	40.0%	14.7%	12.4%	59.0%	70.5%	88.2%	73.2%	72.8%
Capital cost	$ million	$ 189	$ 29	$ 365	$ 51	$ 19	$ 19	$ 405	$ 262	$ 248	$ 249	$ 393
Capital cost	$/kW	$ 1,878	$ 2,301	$ 3,624	$ 4,037	$ 1,928	$ 1,928	$ 11,256	$ 11,383	$ 13,772	$ 10,358	$ 9,348
Leverage	%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%
WACC	%	5.85%	5.85%	5.85%	5.85%	5.85%	5.85%	5.85%	5.85%	5.85%	5.85%	5.85%
Project life [financing]	years	20	20	20	20	20	20	60	60	60	60	60
Nominal variable O&M	$/MWh	1.0	1.0	1.0	1.0	1.0	1.0	5.7	5.7	5.7	5.7	5.7
Nominal fixed O&M	$/kW-year	$60.0	$60.0	$73.4	$73.4	$22.0	$22.0	$91.7	$117.4	$72.2	$83.3	$73.8
Levelized cost of energy	**$/MWh**	**$67.2**	**$78.3**	**$116.7**	**$127.5**	**$153.2**	**$181.2**	**$165.3**	**$144.7**	**$131.2**	**$123.8**	**$112.6**

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9 Appendix C: List of works cited

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10 Appendix D: Background on the firm and Mr. Goulding

10.1 Background on LEI

Figure 20. LEI's areas of expertise

LEI is a global economic, financial, and strategic advisory professional services firm with in-depth expertise in economic and financial issues related to the electricity, gas, and water sectors, such as asset valuation, procurement, regulatory economics, and market design, assessment and analysis. The firm has its roots in advising on the initial round of privatization of electricity, gas, and water companies in the UK. Since then, LEI has advised private sector clients, market institutions, and governments on privatization, asset valuation, deregulation, tariff design, market power, strategy, and strategy development in virtually all deregulated markets worldwide, including Canada, the United States, Europe, Asia, Latin America, Africa, and the Middle East.

LEI is active across the power sector value chain and has a comprehensive understanding of the issues faced by investors, utilities and regulators alike. LEI's areas of expertise are briefly described in Figure 20, and include:

- price forecasting and asset valuation;
- regulatory economics, performance-based ratemaking, and market design;
- expert testimony and litigation consulting;
- transmission and distribution;

- renewable energy; and
- procurement.

10.2 Background on A.J. Goulding

A.J. Goulding is president of London Economics International LLC. He has 27 years of experience advising on energy and infrastructure regulatory matters. Mr. Goulding has testified before regulatory bodies in Alberta, Manitoba, Ontario, and Nova Scotia, as well as in commercial litigation in a number of matters in the US and Canada. He recently served as a member of the Ontario Energy Board's Advisory Committee on Innovation, and led a two year study of regulatory and ownership arrangements in Hawaii. He is an adjunct associate professor teaching electricity markets and overseeing graduate workshops at Columbia University's School of International and Public Affairs, and is a fellow of the Columbia Center for Global Energy Policy. He has a master's degree in international business from Columbia and an undergraduate degree in economics.