INCREMENTAL HYDROPOWER IMPORTS WHITEPAPER

Fall 2013

New England States Committee on Electricity

CONSIDERATIONS, OPTIONS, AND MARKET OVERVIEW REGARDING THE POTENTIAL TO INCREASE HYDROPOWER IMPORTS FROM EASTERN CANADIAN PROVINCES TO NEW ENGLAND

This whitepaper is provided solely as a source of information for New England state policymakers. The information provided is largely drawn from publicly available reports and other documents and should be independently verified before it is relied upon.

Any views that may be expressed in or inferred from this whitepaper should not be construed as representing those of NESCOE, any NESCOE Manager, or any state agency or official.

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INTRODUCTION

The six New England states are assessing opportunities and implications associated with the potential to increase the relative level of hydroelectric imports from Canadian provinces into New England.[1] Over the last several years, hydroelectric power has accounted for approximately 6% of the resources serving New England customers.[2] Hydroelectric power is considered to be a low-carbon resource and is thus one potential way to achieve state objectives and/or statutory requirements to reduce carbon emissions.[3]

This whitepaper describes the current New England and eastern Canadian Provinces' power systems, including both supply and transmission, and summarizes relevant market rules and issues to provide a context for the analysis of hydroelectric imports. The whitepaper observes some potential risks and benefits associated with increasing hydroelectric imports into the New England region. For example, while increased imports of Canadian power have the potential to help New England states achieve carbon reduction requirements or goals, to satisfy these statutory mandates and objectives, imports must be from low-carbon resource generating units and validated as such, in the same way New England today validates clean energy attributes of generating units. This whitepaper also identifies a range of potential approaches for policymakers' consideration, together with potential illustrative advantages and disadvantages of each.

More specifically, this whitepaper is structured as follows:

- **Section I** – Overview of New England's Competitive Wholesale Energy Markets and Mechanisms to Achieve Public Policy Objectives
- **Section II** – Description of the Eastern Canadian Provinces' Generation Resource Mix

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[1] There are three studies in process that may inform policymakers' consideration of incremental hydro imports. NESCOE commissioned Black & Veatch to conduct an *Analysis of Hydroelectric Power Imports* to study various incremental levels of imports and provide an associated cost-benefit analysis. NESCOE also retained Black & Veatch to perform an analysis of the natural gas-electric power system challenges in New England arising from the region's increasing reliance on natural gas. The 2013 *Gas-Electric Study* provides cost-benefit analysis of a variety of solutions to such challenges, including the development of electric transmission to increase the level of hydroelectric imports into New England. Materials related to these Black & Veatch studies will be available at www.nescoe.com. In addition, ISO-NE is currently conducting an Economic Study to evaluate the impact of increasing MW levels of imports through HQ Phase II on regional production costs, consumer costs (including energy and reserve market Locational Marginal Prices) and other metrics. ISO-NE has indicated that a draft of the study results will be available in December 2013, with the final study to be issued in early 2014.

[2] ISO New England Inc., *2012 Annual Markets Report*, at 90 (Table 4-5), available at www.iso-ne.com/markets/mkt_anlys_rpts/annl_mkt_rpts/2012/index.html.

[3] The degree to which Canadian hydropower is ultimately a low carbon resource is the subject of debate in some quarters. It is beyond the scope of this whitepaper to evaluate any studies that question or present life-cycle emissions analysis regarding hydropower.

- **Section III** – Power System Synergies Between the Eastern Canadian Provinces and New England
- **Section IV** – Identification of Potential Benefits and Risks Associated with Increasing Hydroelectric Imports and the Need for a Resource Tracking System
- **Section V** – Options for Increasing Hydroelectric Imports and Implications for Further Consideration

I. NEW ENGLAND'S COMPETITIVE WHOLESALE ELECTRICITY MARKETS, MECHANISMS TO SATISFY POLICY OBJECTIVES, AND CHALLENGES TO INTEGRATING STATE POLICIES IN THE WHOLESALE MARKETS

A. Electric Industry Restructuring and Generation Divestiture

In the 1990s, five of the six New England states restructured the electric utilities operating within their respective jurisdictions. Through restructuring, these states directed electric utilities to divest their generation assets, transforming these entities into transmission and distribution companies.[4] Unregulated merchant power companies took ownership of most of the region's generation resources, and New England transitioned to competitive wholesale energy markets that ISO New England Inc. (ISO-NE) administers and that the Federal Energy Regulatory Commission (FERC) regulates.

A primary reason for moving from the vertically integrated utility model, characterized by resource decisions being made in the context of central planning, to a competitive wholesale generation structure, where competition would identify what resources would deliver service most efficiently, was to shift the risk of investment decisions from ratepayers to shareholders.

Among other principles that guided the states' approach to restructuring the electric industry were:

1) Market mechanisms are preferred over regulation to set price where viable markets exist.

2) Risks of business decisions should fall on investors rather than consumers.

3) Consumers' needs and preferences should be met with lowest costs.

[4] The State of New Hampshire did not require Public Service Company of New Hampshire to divest all generating assets.

4) Electric industry restructuring should not diminish environmental quality, compromise energy efficiency, or jeopardize energy security.[5]

B. Identifying Least-Cost Resources to Serve Customers and Examples of Existing Mechanisms to Achieve Public Policy Objectives

In New England, ISO-NE identifies the level of resources needed to meet the region's electricity requirements and administers the competitive wholesale markets. Through competitive processes, the market selects generating units and other resources that are able to meet those needs at the lowest cost to consumers. The *energy* market identifies least-cost resources to provide energy on a daily basis. The *capacity* market, commonly referred to as the Forward Capacity Market (FCM), identifies through an annual auction least-cost resources that will have an obligation to offer energy into the energy market three years forward in exchange for capacity payments. In general, the New England markets were designed to provide an income stream to encourage generation investment and maintain existing resources.

Historically, a primary driver of renewable resource development in New England has been states' Renewable Portfolio Standard (RPS) requirements, which create a separate market for environmental attributes through renewable energy certificates (RECs). In New England, five of the six states have RPS requirements that mandate electric distribution utilities to purchase an increasing number of RECs each year. While most of these states established RPS programs before the FCM, the market-based approach reflected in these policies works within the structure of the competitive wholesale markets.

Under RPS programs, one REC is generated for each megawatt hour (MWhr) of renewable energy produced by resources that, pursuant to a state's RPS law, are eligible to participate. None of the New England states define RPS-eligible resources to include large hydroelectric resources.[6] Energy production from qualifying renewable energy generators is tracked according to each state's RPS policy with REC pricing determined

[5] Maine Public Utilities Commission, Electric Utility Industry Restructuring, Docket No. 95-462, Report and Recommended Plan, Dec. 31, 1996, at 1.

[6] In 2013, Connecticut enacted Public Act 13-303, which made certain modifications to the state's RPS. Under the Act, large-scale hydropower is not eligible as a Class I resource. The Act provides, however, that any large hydroelectric resources procured by the state may satisfy up to one percentage point per year of the state's Class I RPS requirements, in the event of a sustained material shortage of Class I supply that is verified through a multi-step "trigger" mechanism. *See* Connecticut Public Act 13-303, An Act Concerning Connecticut's Clean Energy Goals, Sections 4, 7, and 9. Although Vermont does not have an RPS, it does have voluntary renewable goals; as of 2012, large hydroelectric resources may be counted toward these renewable goals in Vermont. *See* Act 159, An act relating to renewable energy (2010 Vt., Adj. Sess.) § 13; 30 V.S.A. § 8005.

by supply and demand factors.[7] Revenues from selling RECs are used to provide revenue to support the development and continued viability of renewable resources.[8]

States generally do not require distribution companies to buy RECs to satisfy RPS requirements at any cost. In general, most state RPS requirements include a provision to allow distribution companies to make Alternative Compliance Payments (ACP), which is a capped amount, if the company does not fulfill its RPS requirement with REC purchases. Proceeds from ACPs are often required by law to fund qualified renewable energy initiatives and projects.[9]

Some states have established additional mechanisms to encourage renewable energy development by providing revenue streams beyond those available through the REC markets, seeking to facilitate the financing of new renewable resources. For example, in Massachusetts, distribution companies are required to solicit proposals from renewable energy developers and, if reasonable proposals are submitted, enter into cost-effective long-term contracts, subject to regulatory authority approval, to facilitate financing of renewable generation resources.[10] Similarly, Connecticut's Department of Energy and Environmental Protection (DEEP) was authorized in 2013 by *An Act Concerning Connecticut's Clean Energy Goals* to solicit proposals for Class I renewable power and large scale hydropower under certain circumstances for up to 200 MW, representing five percent of the state's electric load, and to direct electric distribution companies to enter long-term agreements with these resources subject to state regulatory review and approval.[11]

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7 In New England, the New England Power Pool (NEPOOL) Generation Information System (GIS) is the platform for tracking and trading RECs among buyers and sellers. Additional information on the GIS is available at www.nepoolgis.com.

8 Clean Energy States Alliance, *The State of State Renewable Portfolio Standards,* June 2013, at 13, available at www.cleanenergystates.org/assets/2013-Files/RPS/State-of-State-RPSs-Report-Final-June-2013.pdf.

9 *See, e.g.,* Conn. Gen. Stat. §§ 16-244c(j) and 16-245(k); 225 Code of Mass. Regs. § 14.08(3)(c).

10 *See* An Act Relative to Competitively Priced Electricity in the Commonwealth, St. 2012, c. 209, §§ 35 and 36 (Section 83A); Green Communities Act, St. 2008, c. 169, § 83 (Section 83). Pursuant to Section 83, Massachusetts electric distribution companies (EDCs) issued a request for proposal that ultimately resulted in the execution of five power purchase agreements for the development of 150 MW of new renewable generating resources. Peregrine Energy Group, *Study on Long-Term Contracting Under Section 83 of the Green Communities Act*, Dec. 31, 2012, at 2, available at www.mass.gov/eea/docs/doer/pub-info/long-term-contracting-section-83-green-communitiesa-act.pdf. In addition, National Grid and NStar executed respective power purchase agreements with Cape Wind Associates, LLC under Section 83. *See id.* at 2, 4, 21. In accordance with Section 83A, earlier this year, Massachusetts EDCs initiated a joint solicitation for additional long-term contracts for new renewable energy projects. The solicitation timetable calls for executed PPAs to be filed for approval with the Massachusetts Department of Public Utilities in the fourth quarter of 2013. *See* Joint Petition of Fitchburg Gas and Electric Co. d/b/a Unitil, Massachusetts Electric Co. and Nantucket Electric Co. d/b/a National Grid, NSTAR Electric Co., and Western Massachusetts Electric Co. for approval of a proposed timetable and method for the solicitation and execution of long-term contracts for renewable energy, pursuant to St. 2012, c. 209, § 36, D.P.U. 13-57 (2013).

11 Connecticut Public Act No. 13-303, Sections 6-7. On July 8, 2013, pursuant to Section 6, DEEP issued a request for proposals for long-term contracts for Class I renewable energy projects. Other New England states have also enacted laws relative to power-purchase agreements that may enable the financing of

New England appears positioned to meet its collective renewable energy goals at least over the near-term. ISO-NE's *2012 Regional System Plan* (RSP) compared New England's potential for renewable resource development to the total GWhrs[12] required by the New England states' collective renewable energy goals in 2021. The 2012 RSP indicated that there are enough renewable resources in the ISO-NE interconnection queue to meet all of New England's RPS requirements through 2018.[13] ISO-NE's generation interconnection queue includes those generators that have submitted requests to interconnect to the ISO-NE transmission system.[14]

Additionally, most renewable resources have lead-times of only a few years. For that reason, many resources do not need to enter the interconnection queue until they are in the later stages of development. It is reasonable to assume that there are likely additional renewable energy resources in New England that could satisfy state requirements beyond 2018 that are not in the interconnection queue today. Nevertheless, whether resources currently in the interconnection queue or those that may enter the queue will in fact satisfy the states' collective RPS requirements is unknown until they become operational. Also, it is possible that low-carbon resources, incremental to those needed to satisfy RPS requirements, may be necessary to satisfy some states' carbon reduction requirements or goals.[15]

C. Treatment of State-Supported Renewable Resources in the FCM

Due to recent rule changes in New England's FCM, it is unlikely that new state-supported resources will be accounted for in the region's wholesale capacity market. Specifically, pursuant to ISO-NE's Minimum Offer Price Rule (MOPR), each resource is assigned a "reference" or "benchmark" price, known as "Offer Review Trigger Prices" (ORTP). Offers at or above such prices are deemed competitive, while offers below such prices will be evaluated for competitiveness. In the latter case, the resource must justify its cost to ISO-NE's Internal Market Monitor, and out-of-market revenue sources (e.g., state approved or sponsored long-term contracts, but not RECs) will cause an offer to be mitigated up to a price as high as the ORTP. The intent of the MOPR is to prevent resources from offering supply into the market that is below actual cost (i.e., uneconomic), thereby deterring those with buyer-side market power from suppressing capacity market prices.[16] If the level of hydro imports in the resource mix were increased through a long-term, out-of-market power contract, the way in which ISO-NE's Internal Market Monitor would view the resource's offer into the capacity market would be important.

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new renewable generation. *See, e.g.,* Rhode Island Gen. Laws §§ 39-26.1 and 39.26.2 et seq.; 30 V.S.A. § 8005(d).

[12] 1,000 MWhrs.

[13] ISO-NE, 2012 Regional System Plan, at 138, available at www.iso-ne.com/trans/rsp/2012/index.html.

[14] *Id.* at 2.

[15] *See, e.g.,* Global Warming Solutions Act of 2008, St. 2008, c. 298, codified at M.G.L. c. 21N (requiring greenhouse gas emissions reductions in Massachusetts).

[16] *See ISO New England Inc. and New England Power Pool Participants Committee*, 135 FERC ¶ 61,029 (2011), at paragraph 166, *order on reh'g and clarification*, 138 FERC ¶ 61,027 (2012).

In December 2012, NESCOE filed a complaint with FERC pursuant to Section 206 of the Federal Power Act regarding the ability of certain state-supported renewable resources to participate in the region's FCM.[17] NESCOE argued that the MOPR would have the effect of largely foreclosing renewable resources from clearing in the FCM. Further, NESCOE asserted that the MOPR would be unlawful absent a narrowly tailored categorical exemption for up to 225 MW of Class I renewable resources per FCM auction to meet the states' collective renewable energy statutory requirements.[18] NESCOE argued that without this exemption, renewable resources that enable states to meet renewable energy requirements would likely be priced out of the market, undermining state clean energy policies codified in statutes and regulations. At this time, the proposed exemption only includes hydro facilities with a generating capacity not exceeding 30 MW and, thus, an exemption, if granted by FERC, would not apply universally to large hydro resources.

NESCOE also contended that, without this limited exemption, consumers will be forced to purchase more capacity in the FCM than is needed because new renewable resources developed in furtherance of state laws—but effectively excluded under the MOPR—will be commercially available and providing capacity to the region. NESCOE urged FERC to strike a balance between FERC's and the states' shared interest in promoting competitive outcomes in wholesale markets and accommodating public policies.

New England generators and ISO-NE opposed NESCOE's proposed renewable resource exemption on a number of grounds, including that the allowance of an exemption for higher priced renewables would suppress prices for New England's capacity market resources. They argued that an exemption for state-sponsored resources to offer prices into the market that were below their actual costs, and therefore uneconomic, would lead to artificially lower capacity payments to all other market participants.

In a split decision, FERC rejected NESCOE's complaint.[19] Among other reasons, the majority concluded that even a proposed capped exemption was unacceptable because of the potential price-suppressing effect it would have on the capacity market. Commissioner Cheryl LaFleur added in her concurrence: "Given the importance of reliability of service to customers, particularly in New England where challenging issues such as gas-electric coordination are presently acute, it is more important than ever that such market prices are accurate. . . . [A]bsent a fundamental revision to the overall design of the FCM, particularly the vertical demand curve, blanket exemptions to the MOPR are

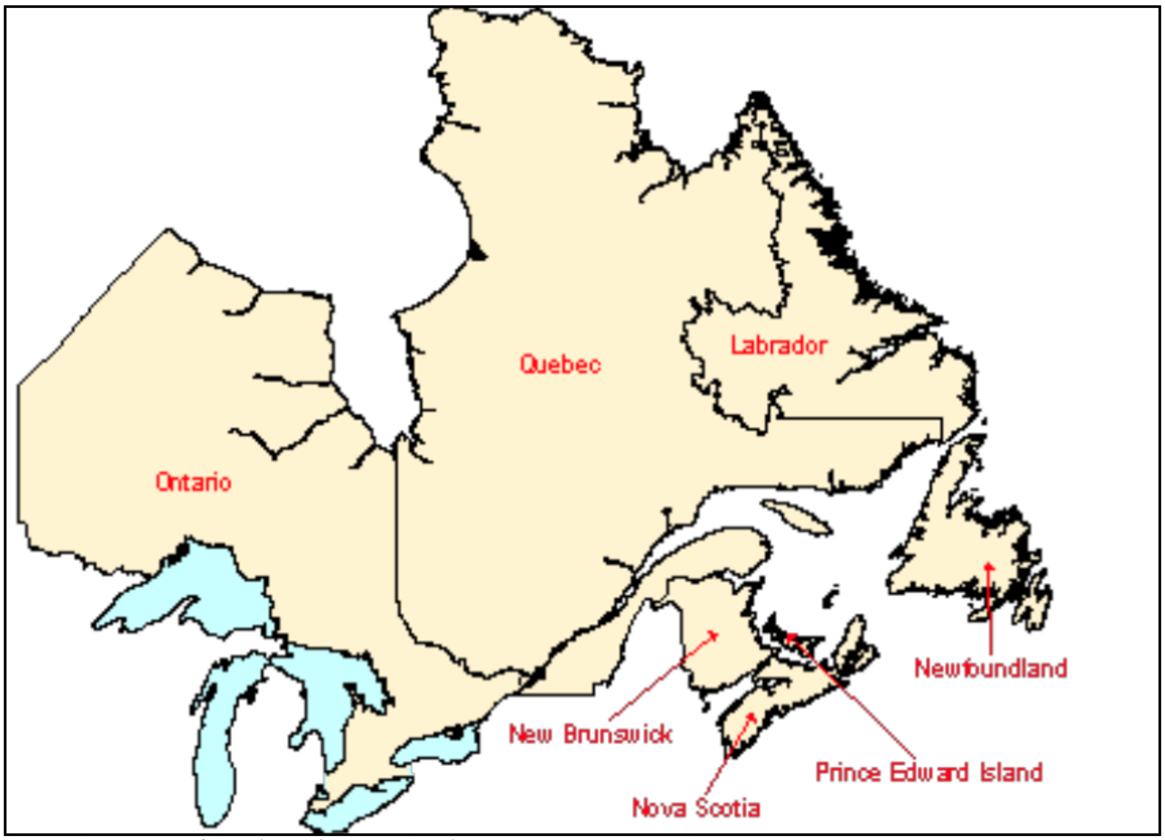
[17] New England States Committee on Electricity v. ISO New England Inc., Complaint, Docket No. EL13-34-000 (filed Dec. 28, 2012).
[18] To provide a sense of scale for the requested exemption, New England is a roughly 32,000 MW system, with a $1-2 billion per year wholesale capacity market.
[19] *New England States Committee on Electricity v. ISO New England Inc.*, 142 FERC ¶ 61,108 (2013).

on balance harmful to the long-term integrity and sustainability of this market and its ability to fulfill its fundamental purpose."[20]

NESCOE subsequently filed with FERC a request for rehearing, which is pending as of the date of this whitepaper. The FERC order also leaves open the possibility of case-specific exemption requests for resources seeking to offer at prices that the MOPR deems uncompetitive.

II. CURRENT AND PROPOSED GENERATION RESOURCES IN THE EASTERN CANADIAN PROVINCES

Map 1: The Eastern Canadian Provinces



Source: Government of Canada, Environment Canada, at www.ec.gc.ca.

A. Structure, Ownership and Current Resource Mix of Eastern Canadian Generation Assets

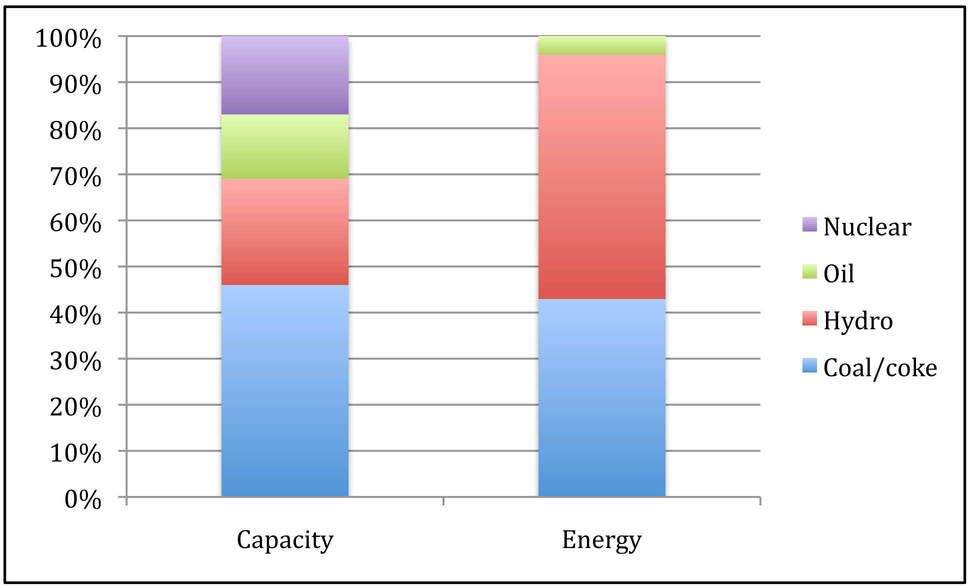
NB Power is a Crown Corporation wholly owned by the ***Government of New Brunswick***. It is composed of a holding company and four sub-companies: NB Power Distribution and Customer Service, NB Power Generation, NB Power Nuclear, and NB Power Transmission. The New Brunswick System Operator is a not-for-profit

[20] *Id.*, Concurring Opinion of Commissioner LaFleur, at 2.

independent corporation whose primary responsibilities are to ensure the reliability of the electrical system and to facilitate the development and operation of a competitive electricity market in New Brunswick. It is not part of NB Power.

Resource Mix: NB Power has 3,787 MW of in-province generating capacity consisting of 17% nuclear, 46% coal/coke, 23% hydro, and 14% fuel oil. New Brunswick's energy production in 2011/2012 consisted of 53% hydro, 43% coal and petroleum coke, and 4% heavy fuel oil. This production was sufficient to serve just 46% of New Brunswick's load. A New Brunswick nuclear facility with a capacity of over 600 MW, Point Lepreau, had been out of service from early 2008 through late 2012.[21] Due to this outage, in 2011/2012, 54% of New Brunswick's energy needs were supplied by power imported from outside the province.[22]

Chart 1: New Brunswick Resource Mix



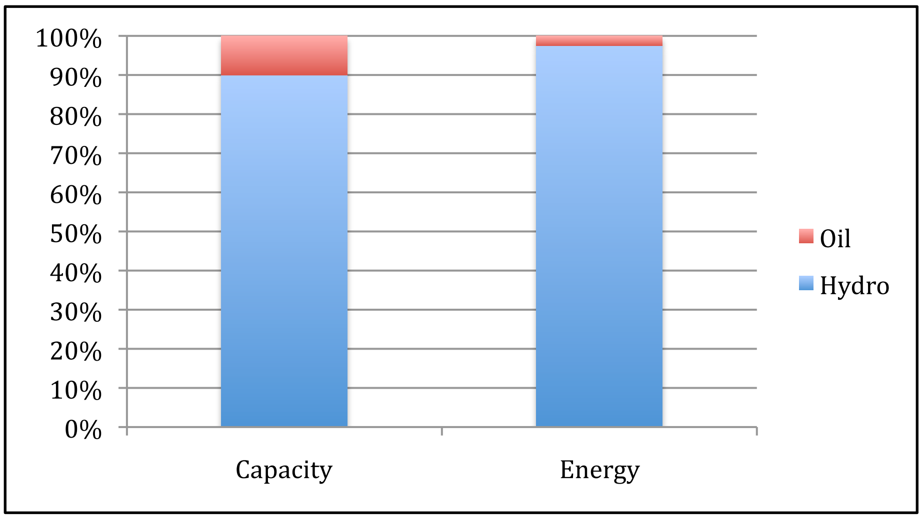
Nalcor Energy (Nalcor) is a provincial Crown Corporation under the ***Government of Newfoundland and Labrador***. Nalcor Energy was created in 2007 to manage the province's energy resources. Nalcor generates and delivers electricity and, to certain customers, voice and data, holds and manages oil and gas interests in onshore and offshore oil developments, and owns the Bull Arm Fabrication site (Atlantic Canada's largest industrial fabrication site).

[21] *See* NB Power, *2011/2012 Annual Report*, at 15, available at www.nbpower.com/html/en/about/publications/annual/Annual-rep-2012-en.pdf; NB Power, Nov. 23, 2012 Press Release, available at www.nbpower.com/html/en/about/media/media_release/pdfs/ENPLSGNovember232012.pdf. Point Lepreau is licensed to operate through June 2017. *See* Canadian Nuclear Safety Commission, Point Lepreau Generating Station, at http://nuclearsafety.gc.ca/eng/mycommunity/facilities/pointlepreau/.

[22] *See* NB Power, *2011/2012 Annual Report*, at 65. Power has been imported from New England, Quebec, Prince Edward Island and Nova Scotia.

Resource Mix: Nalcor owns 7,298 MW of generating capacity, 90% of which is hydro, with the balance being primarily thermal units fueled by Number 6 fuel oil. Nalcor produces a large quantity of power for export. In 2011, 74% of all power produced was exported. This consisted almost entirely of Churchill Falls power being exported to Hydro-Quebec, and hydroelectricity represented approximately 97.5% of the power produced in the province. The balance was a mix of Number 6 fuel oil and diesel.[23]

Chart 2: Nalcor Resource Mix



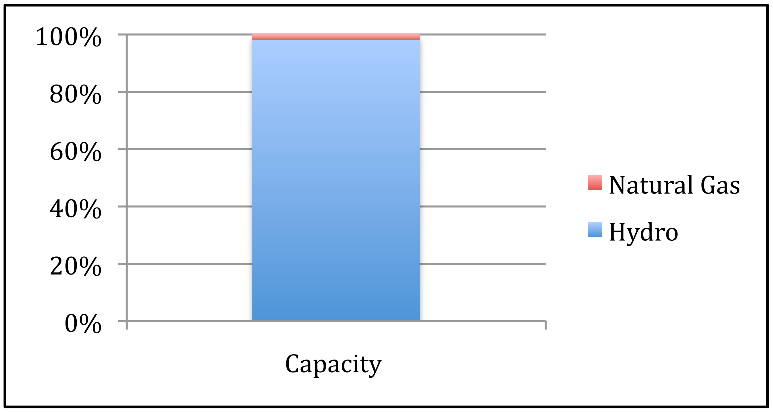
Hydro-Quebec (HQ) is a government-owned public utility established in 1944 by the ***Government of Quebec***. Based in Montreal, the company oversees generation, transmission and distribution of electricity for all of Quebec.

Resource Mix: In 2012, ***Hydro-Quebec*** owned 35,829 MW of generation, 98% of which was hydro. The balance consisted of two gas turbine plants and several small diesels. In addition, HQ contracted for approximately 5,400 MW of Churchill Falls from Nalcor, and also purchased the output of fifteen wind farms, seven biomass facilities, and three small independently owned hydro plants.[24]

[23] Nalcor, *2011 Business and Financial Report*, at 90, available at http://www.nalcorenergy.com/uploads/file/2011%20Nalcor%20Energy%20Business%20and%20Financial%20Report.pdf.

[24] Hydro-Quebec, *2012 Annual Report*, at 100, available at www.hydroquebec.com/publications/en/annual_report/pdf/annual-report-2012.pdf.

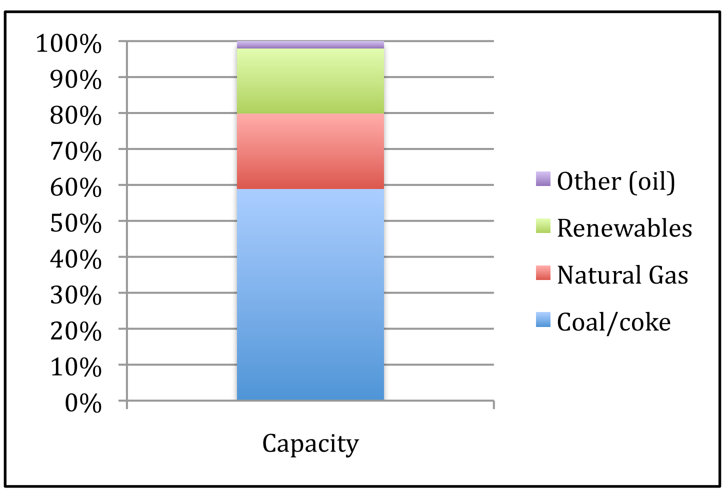
Chart 3: Hydro-Quebec Capacity Mix



Nova Scotia Power is a power generating and delivery company in Nova Scotia. It is ***privately owned by Emera*** and regulated by the provincial government through the Nova Scotia Utility and Review Board. The provincial government formerly owned Nova Scotia Power. In 1992, it was privatized in what was then the largest private equity transaction in Canadian history. This privatization created Nova Scotia Power Incorporated. In 1999, the company was reorganized to create a holding company structure. The following year, the name of the holding company was changed to Emera.

Resource Mix: Nova Scotia Power owns 2,374 MW of generating capacity. In 2012, Nova Scotia Power's energy mix consisted of 59% coal and petroleum coke, 21% natural gas, 18% renewables (wind, tidal, hydro, biomass) and 2% other (imported and oil).[25]

Chart 4: Nova Scotia Power Company Capacity Mix

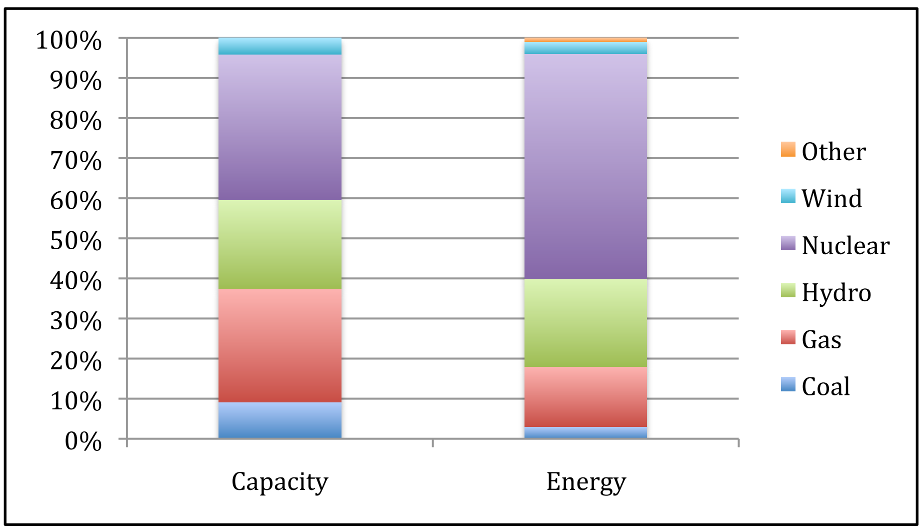


[25] Nova Scotia Power, How We Make Electricity, at www.nspower.ca/en/home/aboutnspower/makingelectricity/default.print.aspx.

In April 1999, ***Ontario Hydro*** was reorganized into five companies: Ontario Power Generation (OPG), the Ontario Hydro Services Company (later renamed Hydro One), the Independent Electricity Market Operator (later renamed the Independent Electricity System Operator and abbreviated IESO), the Electrical Safety Authority, and Ontario Electricity Financial Corporation. The two commercial companies, Ontario Power Generation and Hydro One, were intended to eventually operate as private businesses rather than as Crown Corporations. Both are still fully owned by the ***Government of Ontario***.

Resource Mix: Ontario has 35,858 MW of installed capacity. Ontario's generating capacity in 2012 consisted of 36% nuclear, 28% gas, 22% hydro, 9% coal, and 4% wind. In 2012, energy production was 56% nuclear, 22% hydro, 15% gas, 3% coal, 3% wind, and 1% other.[26]

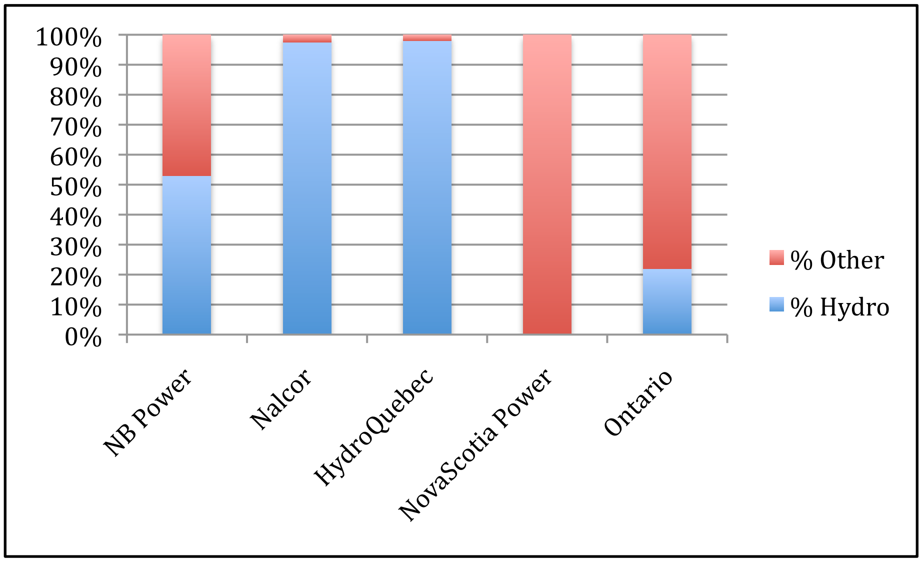
Chart 5: Ontario Resource Mix



The following chart summarizes eastern Canadian energy production by region and, where information was available, delineates between hydroelectricity and other resources. As stated above, Novia Scotia Power includes hydroelectricity in a "renewables" category and, therefore, the percentage of hydropower that Novia Scotia Power produces is not reflected below.

[26] IESO, Supply Overview, at www.ieso.ca/imoweb/media/md_supply.asp.

Chart 6: Eastern Canadian Province Resource Mix



B. Current and Anticipated Large-Scale Hydro Projects in the Eastern Canadian Provinces

1. Large Scale Hydro Projects in Labrador

There is currently one large-scale hydro project in Labrador, Churchill Falls, which is rated at 5,428 MW. It is located on the western side of Labrador with its primary output interconnections into the Hydro-Quebec system. According to the *2011 Nalcor Energy Business and Financial Report*: "[A] significant portion of that electricity is being sold to Hydro-Quebec through a long-term power purchase agreement with additional sales" to Labrador's residential and industrial customers.[27] Nalcor's contract with Hydro-Quebec runs through 2016, although Hydro-Quebec has stated that it intends to exercise an option to extend this contract until 2041.

The contract gives Nalcor the ability to sell up to 300 MW from Churchill Falls to other entities. Hydro-Quebec has filed a lawsuit against Churchill Falls that asserts its existing contract with Nalcor for Churchill Falls gives Hydro-Quebec operational flexibility. Nalcor claims that Hydro-Quebec is only entitled to "fixed monthly energy blocks."[28] Through this operational flexibility, Hydro-Quebec can "coordinate the operation of Churchill Falls with its entire generating fleet, and to do so both on a seasonal and a multi-year basis."[29] In addition, Hydro-Quebec claims that Nalcor has

[27] Nalcor, *2011 Business and Financial Report*, at 4-5, available at www.nalcorenergy.com/uploads/file/2011%20Nalcor%20Energy%20Business%20and%20Financial%20Report.pdf.

[28] *See* Hydro-Quebec, July 22, 2013 Press Release, available at http://news.hydroquebec.com/en/press-releases/389/hydro-quebec-petitions-the-quebec-superior-court-to-confirm-certain-of-its-contract-rights/#.UhOp-Rbkbwx.

[29] *Id.*

sold power from Churchill Falls in excess of the 300 MW limits allowed under its contract.[30] If there were excess power available for sale to New England, given its geographic location and the existing transmission system, the path to New England would run through Quebec.

The following map of Labrador shows Churchill Falls and the major transmission lines connecting south to Hydro-Quebec:

Map 2: Churchill Falls area of Labrador

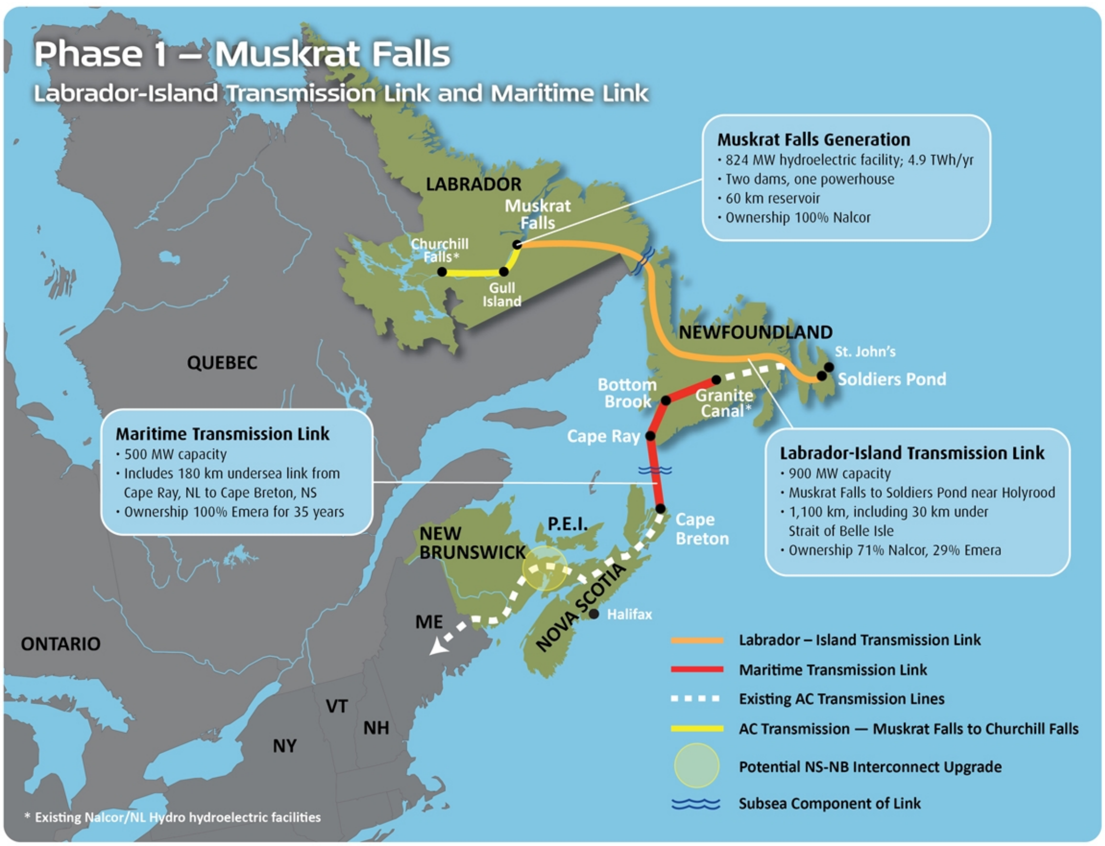
Source: Nalcor Energy, Labrador-Island Transmission Link, Environmental Assessment Registration and Project Description, Jan. 29, 2009, available at www.env.gov.nl.ca/env/env_assessment/projects/Y2010/1407/1407_registration.pdf.

Nalcor is planning to expand this hydro capability and associated transmission lines in several phases. The first phase of the Lower Churchill Project, Muskrat Falls, is under construction and scheduled for completion in 2017.[31] The Muskrat Falls project

[30] *Id.*
[31] Additional information about Muskrat Falls is available at https://muskratfalls.nalcorenergy.com/.

includes: (i) an 824 MW hydroelectric generation facility consisting of two dams and a powerhouse at Muskrat Falls; (ii) a High Voltage Direct Current (HVDC) transmission line from Muskrat Falls in Labrador to Soldiers Pond on the Avalon Peninsula; (iii) a High Voltage Alternate Current (HVAC) transmission line between Muskrat Falls and Churchill Falls; and (iv) a 35 km subsea cable crossing from Forteau Point, Labrador across the Strait of Belle Isle to Shoal Cove, on the Island of Newfoundland. In addition, a 480 km HVDC Maritime Transmission Link between the Island of Newfoundland and Nova Scotia is planned and will be financed and constructed by Emera, the parent company of Nova Scotia Power. This link will allow power to flow to the existing AC system in New Brunswick and, ultimately, reach New England. There is no reference to contracts for power from the Muskrat facility on the Nalcor website or in its Annual Report. The following map illustrates the proposed project:

Map 3: Muskrat Falls area of Labrador



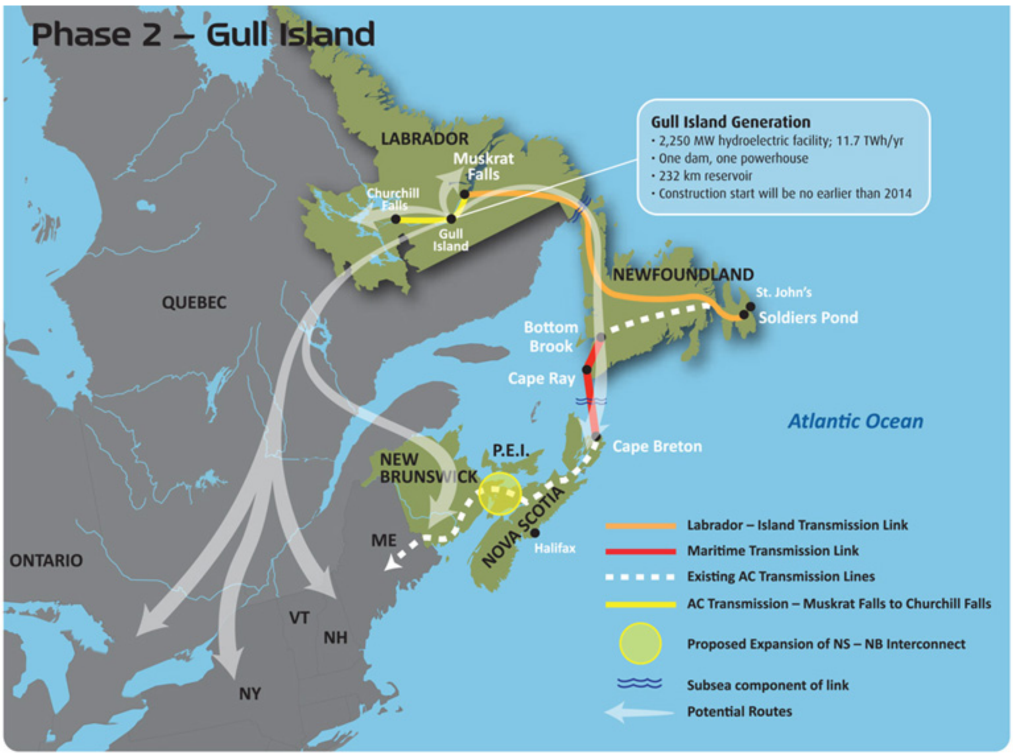
Source: Nalcor Energy, at www.nalcorenergy.com/lower-churchill-project.asp.

As noted above, Hydro-Quebec filed a lawsuit against Churchill Falls that puts the Muskrat Falls project in jeopardy. Muskrat Falls uses the same river system as Churchill Falls. The Newfoundland and Labrador government made changes to its Electrical Power Control Act in 2007 to create a water management agreement, allowing Nalcor to integrate Churchill Falls and Muskrat Falls. Nalcor's intention is "to draw back Churchill Falls during peak power usage months in the winter and compensate for this energy when generation levels spike during the spring thaw. Also, because Churchill

Falls is upstream, Nalcor needs that facility to run at full bore or Muskrat Falls will not be able to run at full capacity."[32] Hydro-Quebec has asserted that it has the rights to flexibly schedule Churchill Falls.[33]

Nalcor is also proposing a second phase of development to follow Phase One. Phase Two of the Lower Churchill Project will consist of a 2,250 MW Gull Island generation facility and associated transmission. The proposed development of Gull Island would begin at least three years after Muskrat Falls is completed. The project is expected to take approximately eight years to fully develop. The following map illustrates the proposed Phase Two project:

Map 4: Gull Island area of Labrador[34]



Source: Nalcor Energy, at www.nalcorenergy.com/lower-churchill-project.asp.

2. Large Scale Hydro in Quebec

Hydro-Quebec has significant large hydro resources. Table 1 below lists existing HQ hydro resources greater than 100 MW, for a total of 33,655 MW system-wide:[35]

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[32] Paul McLeod, *Hydro-Quebec challenge could endanger Muskrat Falls project*, Chronicle Herald, available at http://thechronicleherald.ca/novascotia/1143721-hydro-quebec-challenge-could-endanger-muskrat-falls-project.

[33] *See* Hydro-Quebec, July 22, 2013 Press Release.

[34] Primary sources for the above section and graphics: Nalcor website, Nalcor Environmental Assessment.

[35] Hydro-Quebec, Hydroelectric Generating Stations (2012), at www.hydroquebec.com/generation/centrale-hydroelectrique.html.

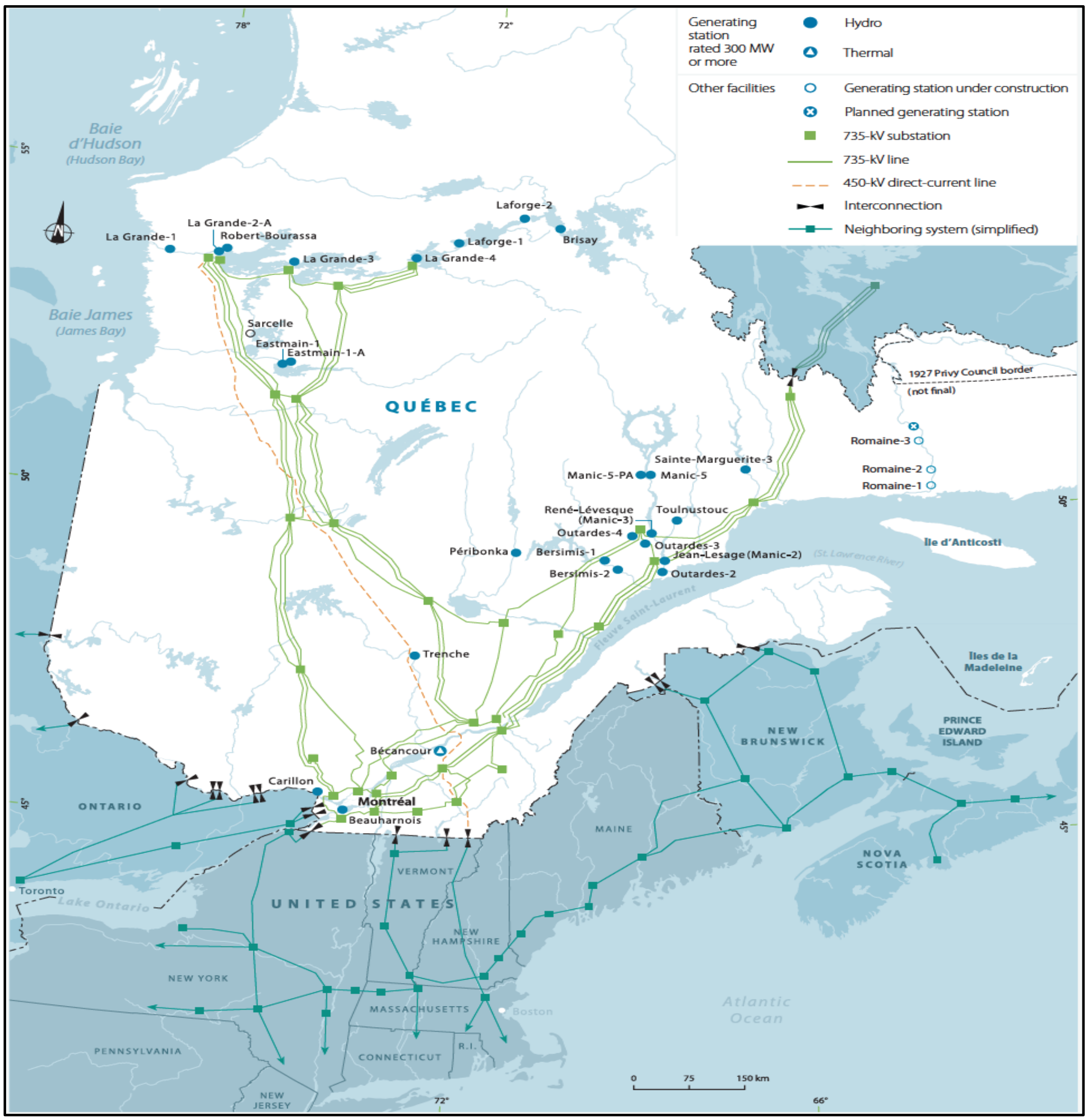
Table 1: HQ Hydro Resources larger than 100 MW

Name	River or other watercourse	Type	MW	Number of units	Commissioning date
Robert-Bourassa	Grande Rivière	Reservoir	5,616	16	1979–1981
La Grande-4	Grande Rivière	Reservoir	2,779	9	1984–1986
La Grande-3	Grande Rivière	Reservoir	2,417	12	1982–1984
La Grande-2-A	Grande Rivière	Reservoir	2,106	6	1991–1992
Beauharnois	Lac Saint-François and canal de Beauharnois	Run-of-river	1,911	38	1932–1961
Manic-5	Manicouagan	Reservoir	1,596	8	1970–1971
La Grande-1	Grande Rivière	Run-of-river	1,436	12	1994–1995
René-Lévesque (Manic-3)	Manicouagan	Run-of-river	1,244	6	1975–1976
Bersimis-1	Betsiamites	Reservoir	1,178	8	1956–1959
Jean-Lesage (Manic-2)	Manicouagan	Run-of-river	1,145	8	1965–1967
Manic-5-PA	Manicouagan	Reservoir	1,064	4	1989–1990
Outardes-3	Aux Outardes	Run-of-river	1,026	4	1969
Sainte-Marguerite-3	Sainte-Marguerite	Reservoir	884	2	2003
Laforge-1	Laforge	Reservoir	878	6	1993–1994
Bersimis-2	Betsiamites	Run-of-river	869	5	1959–1960
Outardes-4	Aux Outardes	Reservoir	785	4	1969
Carillon	Outaouais	Run-of-river	753	14	1962–1964
Toulnustouc	Toulnustouc	Reservoir	526	2	2005
Outardes-2	Aux Outardes	Run-of-river	523	3	1978
Eastmain-1	Rivière Eastmain	Reservoir	507	3	2006
Brisay	Caniapiscau	Reservoir	469	2	1993
Péribonka	Péribonka	Run-of-river	405	3	2007–2008
Laforge-2	Laforge	Run-of-river	319	2	1996
Trenche	Saint-Maurice	Run-of-river	302	6	1950–1955
La Tuque	Saint-Maurice	Run-of-river	294	6	1940–1955
Beaumont	Saint-Maurice	Run-of-river	270	6	1958–1959
McCormick4	Manicouagan	Reservoir	235	7	1952
Rocher-de-Grand-Mère	Saint-Maurice	Run-of-river	230	3	2004
Paugan	Gatineau	Run-of-river	206	8	1928–1956
Rapide-Blanc	Saint-Maurice	Reservoir	204	6	1934–1955
Shawinigan-2	Saint-Maurice	Run-of-river	200	8	1911–1929
Shawinigan-3	Saint-Maurice	Run-of-river	194	3	1948–1949
Manic-1	Manicouagan	Run-of-river	184	3	1966–1967
Rapides-des-Îles	Outaouais	Run-of-river	176	4	1966–1973
Chelsea	Gatineau	Run-of-river	152	5	1927–1939
La Gabelle	Saint-Maurice	Run-of-river	131	5	1924–1931
Première-	Outaouais	Run-of-river	131	4	1968–1975

Chute					
Rapides-Farmer	Gatineau	Run-of-river	104	5	1927–1947
Les Cèdres	Saint-Laurent	Run-of-river	103	11	1914–1924
Rapides-des-Quinze	Outaouais	Run-of-river	103	6	1923–1955

The *Hydro-Quebec 2012 Annual Report* provides a map, reproduced below, reflecting the scale of these resources on the HQ power system, illustrating major facilities and their interconnections with neighboring systems:

Map 5: Generation and Transmission in Quebec



Source: Hydro-Quebec 2012 Annual Report.

There are two new large-scale hydro projects under construction in Quebec, shown on the map above as open circles. The first project, Eastman-1-A/Sarcelle/Rupert, would divert flow from the Rupert River in western Quebec through two new generating stations, Eastman-1-A and Sarcelle. Eventually, the river flow would empty into the Robert-Bourassa reservoir, which feeds other existing hydro facilities. Almost 900 MW of total new generation will be created from this project, which began construction in 2007. It is expected to be complete this year.

The second project, the Romaine Project, consists of four units in eastern Quebec. Total installed capacity of all four facilities will be 1,550 MW. Three of the four units are under construction. The first, Romaine–2, is 640 MW and is expected to come on-line in 2014, followed by Romaine-1 at 270 MW in 2016, then Romaine-3 at 414 MW in 2018. Romaine-4 is proposed at 226 MW, with an in-service date of 2020. That unit is listed as proposed.[36]

III. TRANSMISSION INTERCONNECTIONS AND SYSTEM SYNERGIES BETWEEN THE EASTERN CANADIAN PROVINCES AND THE NEW ENGLAND POWER SYSTEM

A. Transmission Ties Between New England and Eastern Canada

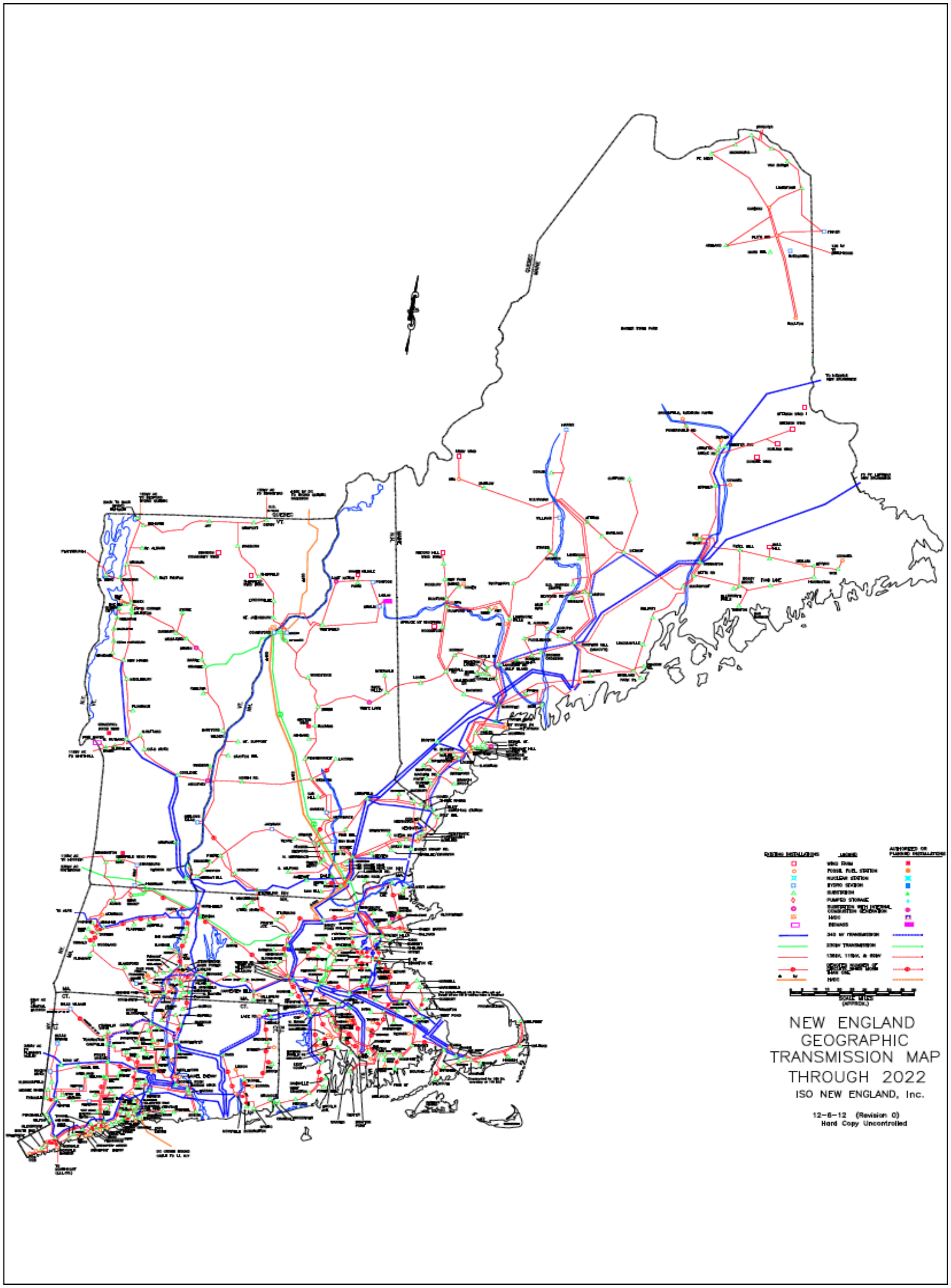
1. Current transmission ties between New England and eastern Canada and their operational limits

There are four major active transmission grid connections, often referred to as "ties," between New England and eastern Canada.[37] Each is described below, including information about their operational limits. Further below is related analysis about what additional capacity may exist on each transmission grid connection in the form of load duration curves, a common indicator of the use of existing infrastructure over the course of a given year. A map of the current New England transmission system, including ties to eastern Canada, is below:

[36] Primary sources for the above section and graphics: Hydro-Quebec website, 2012 Hydro-Quebec Annual Report, Hydro-Quebec Sustainability Report 2011.

[37] Another tie between Quebec and Vermont is the Derby Line. It has a very small transfer capability and is operated in a state referred to as "Normally Open," which means that its typical operating status does not allow the systems to flow energy. Derby Line is an alternating current (AC) tie that was designed to allow a portion of Vermont's load to be served directly from Quebec. Since it is an AC tie, breakers in New England must be opened to allow this section of the system to disconnect from New England prior to connecting to Quebec. This line cannot be used to import power further south beyond the directly connected section.

Map 6: New England Geographic Transmission System



Source: ISO-NE, available at www.iso-ne.com/nwsiss/grid_mkts/key_facts/iso-geo-diagram-2012-final-non-ceii.pdf.

a. Highgate. Built in 1985, a 200 MW Direct Current (DC)[38] tie known as Highgate is one of the connections with Quebec. It was constructed to bring power into Vermont during an extended Vermont Yankee outage. Highgate is named for the Vermont town close in proximity to where the transmission line crosses the New England-Canadian border.

Highgate was built by a group of public and private utilities called the Highgate Joint Owners.[39] Highgate was originally constructed as a cost-of-service transmission project that was included in the rate base of each of its owners and paid for by their respective ratepayers. In November 2000, Highgate was classified as Pool Transmission Facilities (PTF)[40] at the request of the joint owners, and has been rolled into the Regional Network Service (RNS)[41] rate since that time.

b. Quebec/Phase II. New England's major interconnection with Quebec was built in two phases. Phase I went into operation in 1986. It consisted of a DC transmission line from Des Cantons substation in Sherbrooke, Quebec to Comerford Station in Monroe, New Hampshire with converter terminals at each end. Phase II of the project, built to bring power from Hydro-Quebec's large-scale hydro facilities to New England, consisted of two elements. In Canada, TransEnergie (HQ's transmission division) built a line from Sherbrooke, Quebec north to Radisson in the James Bay region of Quebec where large hydro facilities are located. In the United States, New England Hydro-Transmission Electric Company and New England Hydro-Transmission Company (both National Grid subsidiaries) extended the line from Monroe, New Hampshire down to a HVDC converter station in Sandy Pond, Massachusetts. Phase II entered operation in 1991. Construction costs for the HQ tie were over $600 million.[42]

When constructed, the electrical rating of Phase I was 690 MW and Phase II was 2,000 MW. Phase I and II were designed to operate simultaneously. However, technical issues arose that prevented the two smaller terminals from being operated in parallel with the large terminals. Due to these limitations, the converter terminals at Comerford and

[38] There are two ways that electric lines operate: AC and DC. The transmission system in New England is almost entirely AC. AC systems allow power to flow more or less freely from generators to load, using the most efficient paths available. Flows on AC systems are not controlled and power flow can reverse as system conditions change. Conversely, DC lines flow power in one direction at a time, at a controlled level, to a single delivery point. There is a convertor station at each end where it connects to the AC system to control flow in and out of the DC line. Highgate was constructed as a DC line because of the technical difficulties in electrically synchronizing the New England and Quebec Systems.

[39] These include: Burlington Electric Department, Central Vermont Public Service Corporation, Vermont Electric Cooperative, Green Mountain Power, Vermont Public Power Supply Authority and Village of Johnson Electric Light Department.

[40] In general, PTF are looped transmission facilites rated at 69kv and above. They are considered part of the regional transmission network as opposed to local distribution facilities.

[41] RNS is the mechanism that recovers the revenue requirements for most PTF in New England. It is charged out to all New England electricity customers monthly on a load ratio share basis. This is referred to as network load.

[42] *PJM Interconnection, LLC, New York Independent System Operator, Inc., and ISO New England Inc.*, 118 FERC ¶ 61, 017 (2007), at paragraph 5.

Des Canton have been dismantled. The transmission line between the two Phases is still in service; however, it is not possible to import power over Phase I.

The HQ Phase II DC tie has maintained its equipment rating of 2,000 MW. However, "[d]ue to the need to protect for the loss of this line at full import level in the PJM and New York Control Areas' systems, ISO-NE has assumed its transfer capability for capacity and reliability calculation purposes to be 1,400 MW."[43]

The HQ Phase I and Phase II tie lines were developed as participant funded transmission projects, which are paid for by specific entities rather than rolled into transmission rates that, in the case of projects needed for reliability, are charged to electricity customers across New England. The construction and operation of the facilities were funded through a complex series of contracts among lenders, project sponsors, and the ultimate users of the line. In other words, ratepayers did not pay for this line through regional tariff rates. Utilities throughout New England were offered the opportunity to obtain rights to use the transmission capacity to transmit power to and from Quebec in exchange for commitments to pay the costs of building, maintaining, and operating the project. Those utilities that agreed to financially support the projects entered into Support Agreements and became the Interconnection Rights Holders (IRH).[44]

Under "Support Agreements," the IRH have a firm, irrevocable obligation to pay all of the support costs of the facilities. In exchange for accepting this obligation, the IRH were granted exclusive rights to the transmission capacity of the lines. Each IRH holds a share of the transmission capacity in the Phase I and/or Phase II lines equal to its share of the support cost obligation under the Support Agreements.

Under FERC open access policies, all IRH that are transmission providers are required to offer their rights to other potential transmission customers if they are not using the rights themselves. Transmission owning utilities that are under FERC's jurisdiction hold about 95% of the rights over the interconnection. There is no publicly available information about whether and how such rights have been sold, or for what time periods. However, large quantities of power are flowing over the Phase II line, which indicates that this market is functioning adequately. The other 5% of rights are held by public power entities, such as municipal utilities, that are not subject to this resale requirement.

The support agreements between the financing entities and the IRH terminate in 2020. Two years before this expiration, there is a mutual option to extend the agreements for twenty years. National Grid, the parent of the financing entities, can elect not to extend if a certain threshold level of participation is not achieved. To date, there is no readily accessible publicly available document that indicates whether parties intend to extend or not.

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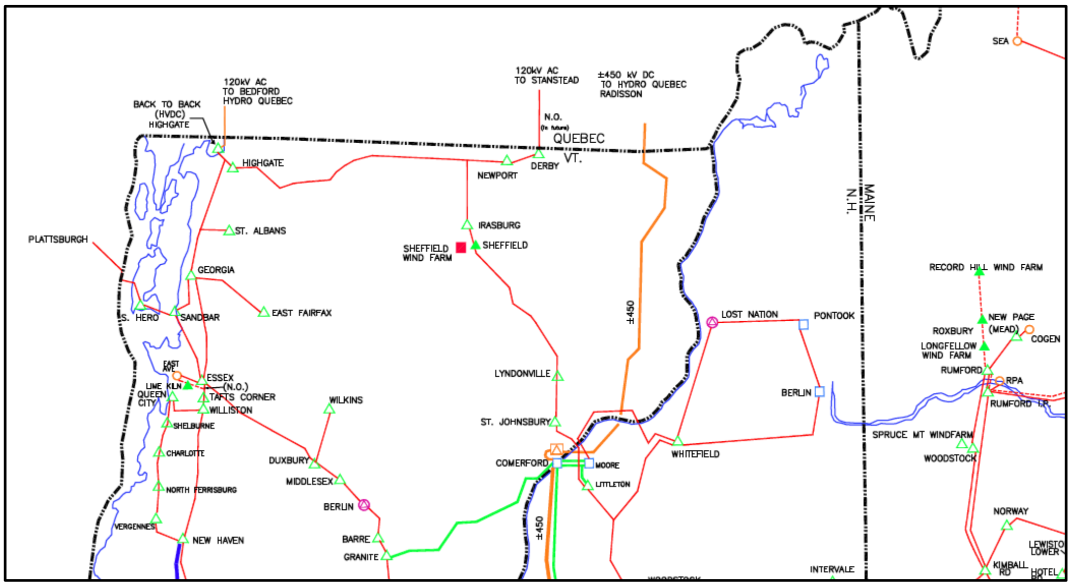
[43] ISO-NE, Transmission Transfer Capabilities for Transportation Models: 2013 Regional System Plan Assumptions, June 3, 2013, available at www.iso-ne.com/committees/comm_wkgrps/relblty_comm/pwrsuppln_comm/mtrls/2013/jun32013/index.html.

[44] The full listing of IRH is available at www.oatioasis.com/ISNE/ISNEdocs/Phase-I-II-percentages.htm.

The map below shows the Vermont- and New Hampshire-based grid connections with the Quebec system.

Map 7: Northern Vermont and New Hampshire area of New England Geographic Transmission System



Source: ISO-NE

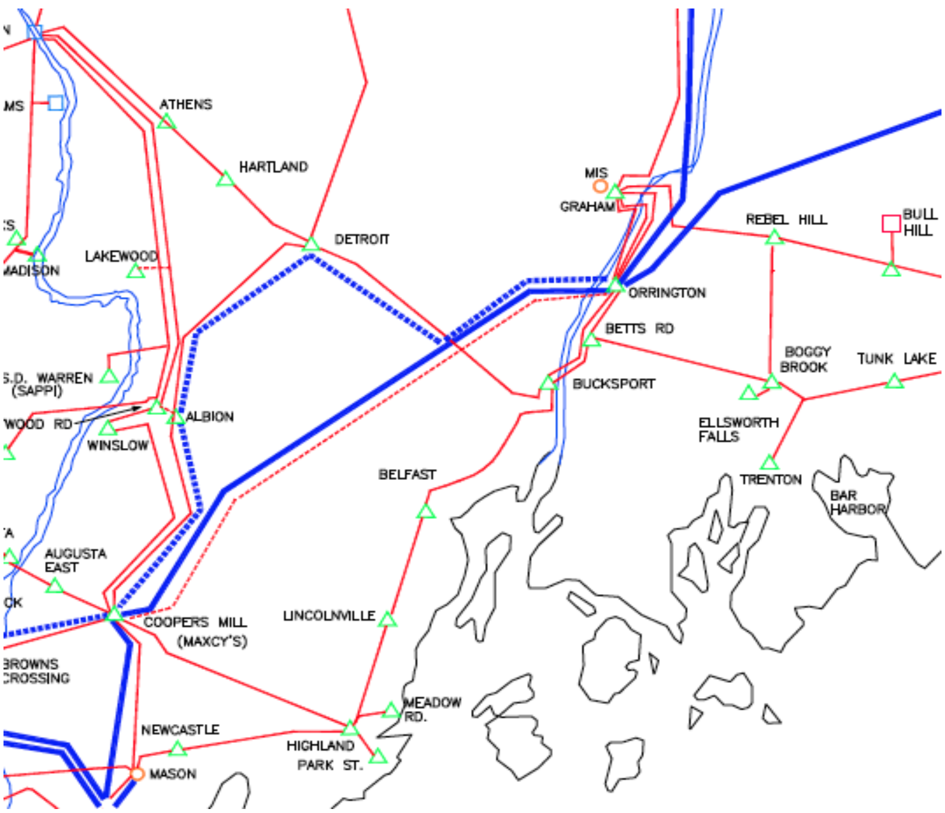
c. MEPCO. There are two interconnections with New Brunswick with a total transfer capability of 1,000 MW. The first tie line, commonly referred to as the MEPCO line, was built in 1969 and is rated at 700 MW. The three Maine utilities, Central Maine Power (CMP), Bangor Hydro-Electric Company (BHE) and Maine Public Service Company (MPS), formed a company called Maine Electric Power Company (MEPCO) as a vehicle to build and pay for the line jointly. The MEPCO tie is a 345 kV transmission line connected to CMP at the Maine Yankee substation in Wiscasset, Maine, and at the Maxcy's substation in Windsor, Maine to BHE at Orrington, Maine and at its northern end, at the Canadian border at Orient, Maine, to a similar 345 kV transmission line owned by New Brunswick Power.

Originally, MEPCO was operated and administered by CMP on behalf of the three owners. However, eventually, the MEPCO owners, ISO-NE and NEPOOL negotiated to reclassify the MEPCO line as PTF. Costs associated with the line are now included in the RNS rate.

d. NRI. In 2007, BHE constructed a new tie line. This line, the Northeast Reliability Interconnect (NRI), is commonly referred to as the "second New Brunswick tie." The NRI project primarily consists of a 345 kV AC transmission facility connecting the Orrington Substation in Maine with New Brunswick at the Point Lepreau Substation. The line is rated at an additional 300 MW of interconnection capability. However, when adjusted for the ability to deliver capacity to the greater New England Control area, the total New Brunswick-New England transfer capability for both MEPCO and NRI combined is considered to be 700 MW for New England's system planning purposes. As detailed below, the reason for the limited transfer capability is the downstream transmission constraints in Maine and in particular at the Orrington South interface.

In this context, constraint means "[a]ny transmission facility or facilities that operate at or over its limit (e.g., thermal limit, stability limit, or voltage limit)."[45] According to ISO-NE, "the northern portion of the Maine transmission system continues to present challenges to reliable system planning and operations."[46] CMP is constructing a project known as Maine Power Reliability Program (MPRP). While the main purpose of this project is to increase delivery to load within the state of Maine, it will slightly increase the transfer capability across several constrained interfaces allowing more power to flow south. This project is expected to be completed in 2015.

Map 8: Orrington, Maine

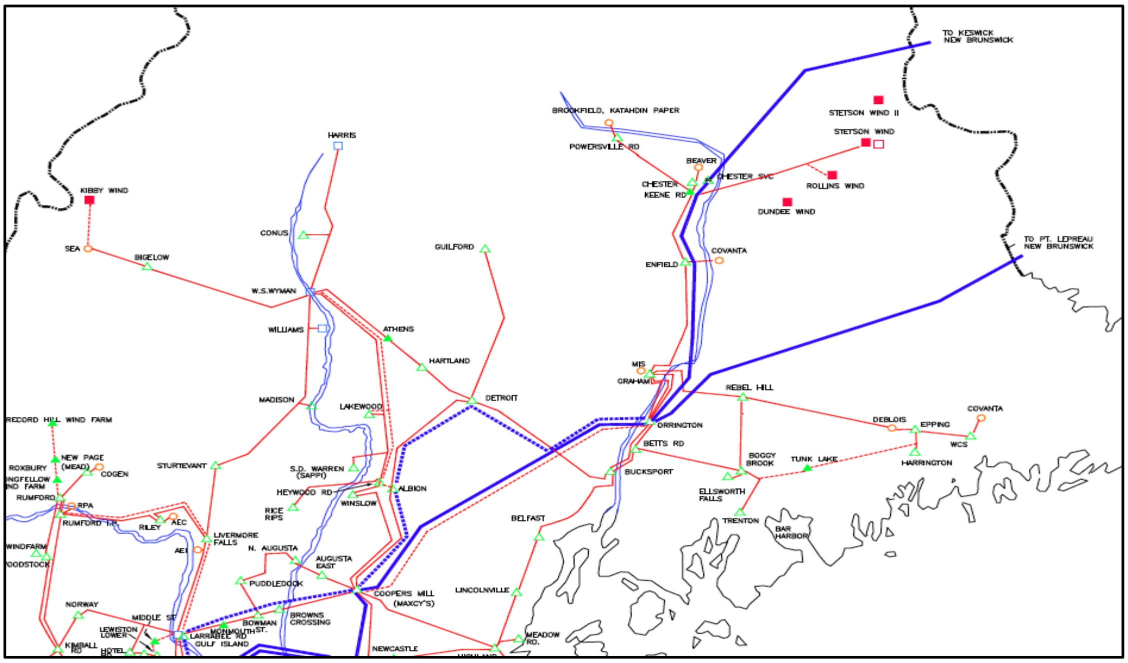


Source: ISO-NE

[45] ISO-NE, Glossary & Acronyms, at www.iso-ne.com/support/training/glossary/index-p1.html.
[46] ISO-NE, 2012 Regional System Plan, at 76.

The map below shows the Maine-based grid connections with the New Brunswick system:

Map 9: Central Maine area of New England Geographic Transmission System



Source: ISO-NE

2. Representative Proposals for New Transmission Ties Between New England and Eastern Canada

In recent years, entities have proposed new transmission lines between eastern Canada and New England to enable increased power flows between the two regions.[47] Several proposed projects are described below for illustrative purposes.

Not all proposed projects are ultimately built and put into service. The summary of proposed projects below does not indicate any judgment or expectation about whether any one or more will eventually be constructed. Proposed projects are subject to a range of risks, including, for example, financing, land acquisition or the emergence of unforeseen environmental issues. Proposed transmission projects also face close scrutiny in the context of siting proceedings. Local property owners typically express valid concerns and/or questions about, among other things, equity, prudence and impacts associated with the proposed project. In many cases, there is organized opposition by environmental advocacy groups that may prefer other resources or projects. Also, in

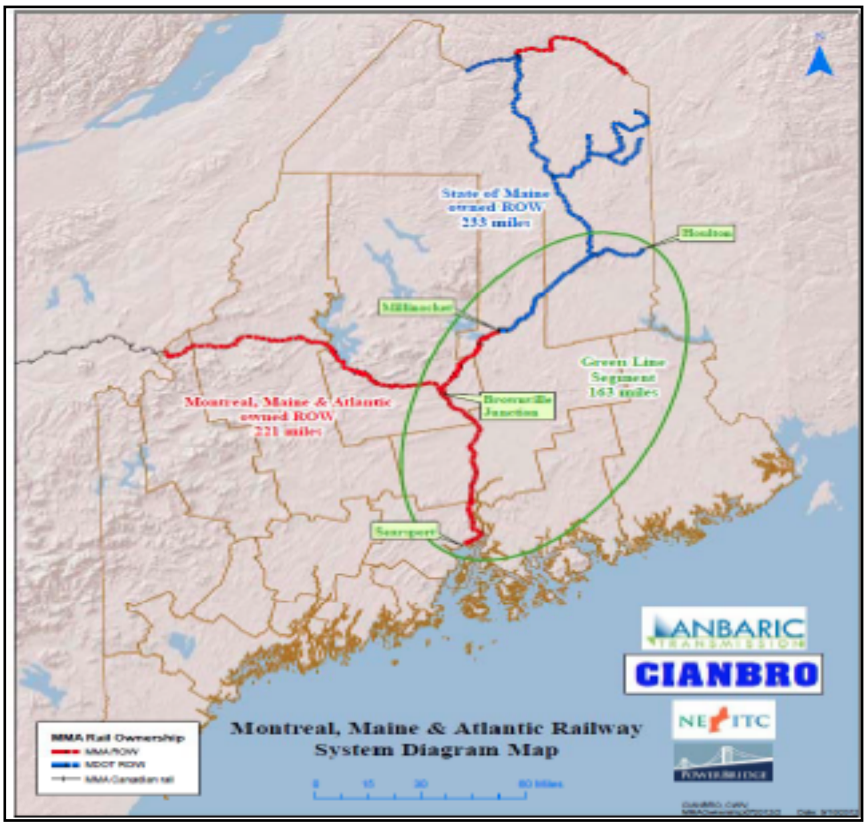
[47] The total amount of new transfer capability being proposed from eastern Canada to New England from the Northern Pass and Green Line projects described below is approximately 2,200 MW. Also, a separate project detailed below, the Northeast Energy Link, could increase flow across existing tie lines by reducing internal constraints.

some cases, elected officials advance legislation to address concerns that emerge in public forums and elsewhere.

Thus, the proposed projects described below do not signify judgment about whether any proposed project may or may not move forward, or an endorsement of any project by any one or more states. Similarly, the absence of any potential project does not signify lack of any state support for such project.

a. The Green Line by New England Independent Transmission Company

Map 10: Proposed Green Line



Source: NEITC, used with permission

New England Independent Transmission Company's (NEITC) Green Line proposal contemplates a 1,000 MW to 1,200 MW HVDC system to connect wind-generated energy in Aroostook County, Maine to electric markets in southern New England. The system consists of an HVDC converter station in southern Aroostook County connected via a 350-mile DC transmission line to an HVDC converter station in greater Boston. The DC line includes approximately 160 miles of terrestrial line in Maine and 190 miles of submarine cable. According to NEITC, the project's terrestrial segment will run primarily along an existing railroad right of way in Maine over which NEITC has acquired exclusive rights to transmit electricity.[48]

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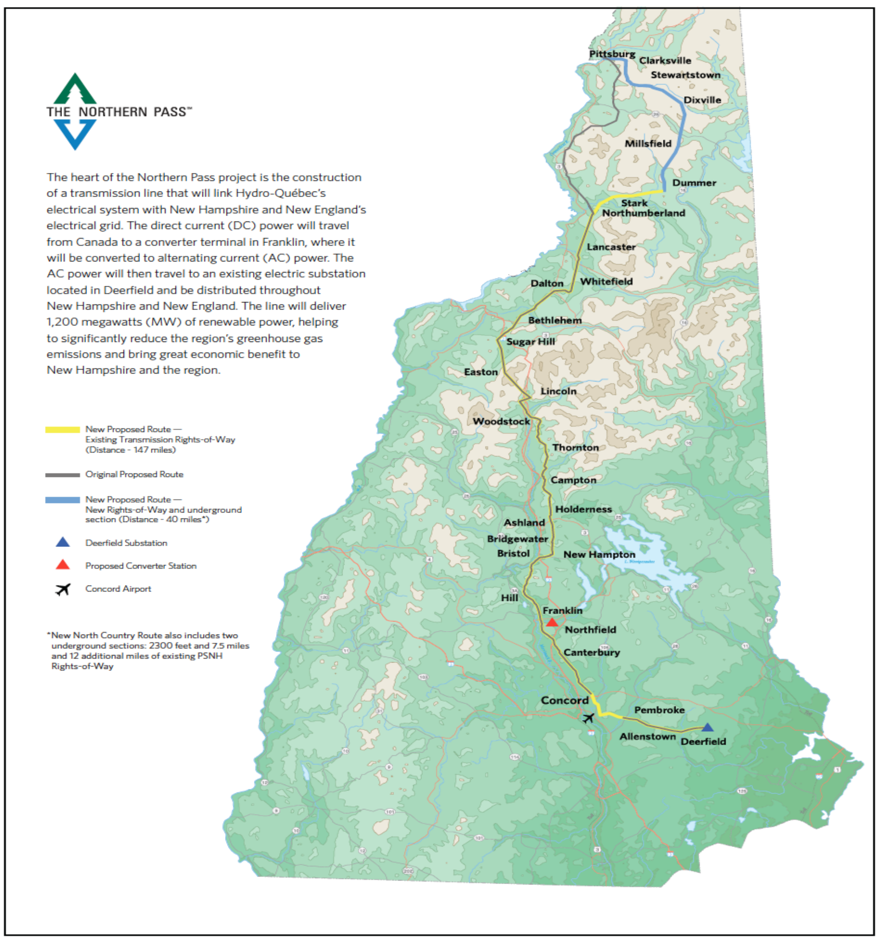
[48] New England Transmission Co., LLC, Greenline, at http://greenlineproject.com/sites/.

The project also includes a 345kV AC link from the converter station in Aroostook County to the 345kV AC grid in New Brunswick. In addition to New Brunswick, Quebec, Nova Scotia and Newfoundland would have a commercial opportunity to fill the Green Line when the Maine wind units are not operational. The Green Line would only connect to the ISO-NE grid from the converter station in the greater Boston area.

NEITC markets the Green Line as transmitting exclusively renewable or low carbon energy and designed to enable firm energy flow. Also, NEITC states that the typical intermittency of renewable energy, such as wind, could be largely mitigated at the northern end of the Green Line project with complementary energy flows from neighboring systems that may be primarily hydro-based.[49]

b. Northern Pass by Hydro-Quebec and Northeast Utilities

Map 11: Revised Proposed Route of Northern Pass



The Northern Pass • PO Box 330 • 780 North Commercial Street • Manchester, NH 03105-0330 • 800-286-7305 • www.northernpass.us

Source: The Northern Pass, Route Info/Route Map, at http://northernpass.us/route-info.htm.

[49] *See* http://greenlineproject.com for additional information regarding the project.

Northern Pass[50] was proposed in 2008 as a joint project by Northeast Utilities (NU) and NStar, which have since merged, and Hydro-Quebec. Northern Pass is a proposed 1,200 MW HVDC line connecting the Des Canton Substation in Quebec (where Phase I interconnected) to a converter terminal in Franklin, New Hampshire (NPT line).[51] The NPT line would then continue on as a new AC line to an existing substation in Deerfield, New Hampshire, where it would interconnect with the New England grid.

Northern Pass is proposed as a participant funded project.[52] Under the arrangement, Hydro-Quebec has committed to pay the full cost of the line and, in return, will be granted all rights across it. Hydro-Quebec had initially proposed that one of its subsidiaries would enter into one or more long-term power purchase agreements with New England load-serving entities. However, Hydro-Quebec subsequently proposed a change to the structure of the power sale arrangement. Pursuant to the terms of a transmission service agreement (TSA) between Northern Pass and HQ Hydro Renewable Inc. (HQ Hydro), a Hydro-Quebec U.S. affiliate, and accepted by FERC:

- Northern Pass would develop, site, finance, construct, own, and maintain the NPT Line;
- Northern Pass would then sell 1,200 MW of firm transmission service over the NPT Line to HQ Hydro over a 40-year term;
- HQ Hydro would be responsible for providing approximately $1.1 billion in initial construction costs and return on such costs, necessary additional capital expenditures and return, and other expenses associated with the line over the 40-year operating term of the TSA; and
- HQ Hydro planned to recover these costs through competitive sales of wholesale power in the New England market rather than through power purchase agreements.[53]

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[50] Additional project detail is available at www.northernpass.us/.

[51] New Hampshire public officials note that the Northern Pass proposal faces significant hurdles to its implementation in its current form. Organized grass-roots opposition by citizens, advocacy groups and state and local elected officials, has led to apparent bipartisan opposition to the project in the New Hampshire Legislature. As of August 2013, proposed bills designed to modify the features of (or prevent the building of) Northern Pass have been introduced in the New Hampshire Legislature. If these efforts are not successful, litigation against the project is likely to follow. Objections against the project center around the potential visual impact of transmission towers on scenic areas of northern New Hampshire, the associated impacts on property values and tourism in the communities along the proposed route, and the belief that the power provided is not needed by New Hampshire, and would be sent to southern New England.

[52] New England generators challenged this proposed contract and funding structure at FERC. These generators expressed a number of concerns, including that the structure was not truly a participant funded project, but rather a mechanism to have NU and NStar ratepayers fund transmission construction indirectly through a bundled energy contract. FERC approved the participant funded structure. *See Northeast Utilities Co. and NSTAR Electric Co.*, 127 FERC ¶ 61,179 (2009), *reh'g denied*, 129 FERC ¶ 61,279 (2009).

[53] *Northern Pass LLC*, 136 FERC ¶ 61,090 (2011) at paragraphs 1, 3. However, HQ Hydro may seek to enter into a power purchase agreement with Public Service Company of New Hampshire (an NU subsidiary), subject to state commission approval, "for a small portion of the power delivered over the" NPT line. *Northern Pass Transmission LLC*, 134 FERC ¶ 61,095 (2011) at n. 11.

The Northern Pass project developers describe the changed sales arrangement in greater detail in their TSA filing, stating that HQ Hydro:

> intends to sell most of the power transmitted over the NPT Line into the ISO-NE markets, and will thus bear the full risk of selling its generation, inclusive of transmission costs associated with the NPT Line, at prevailing market prices. This change from the power sale arrangement originally described in the [FERC] Petition for Declaratory Order ensures that [HQ Hydro] will bear the entire risk of cost recovery for the NPT Line through competitive power sales into the ISO-NE energy market and that no New England customers will be compelled to purchase Hydro-Quebec power delivered over the NPT Line at an above-market price.[54]

In July 2013, company officials announced a new route for Northern Pass, proposing that some elements of the project be placed underground.[55] Table 2 below shows the planned investment activity by HQ from its 2009-2013 Strategic Plan, including $406 million in connection with a 1,200 MW interconnection with New England:

Table 2: Investment Activity: HQ Plan to Invest $406M in Interconnection to New England

Growth – Native load and interconnections

Main projects	
Construction of 1,250-MW interconnection with Ontario	$251 M
Construction of 1,200-MW interconnection with New England	$406 M
Connection of large industrial customers	$141 M
Construction of Charlesbourg substation (230/25 kV)	$79 M
Construction of Anne-Hébert substation (315/25 kV)	$75 M
Construction of Bout-de-l'Île substation (735/315 kV)	$70 M
Construction of Saint-Janvier substation (315/25 kV)	$66 M
Construction of Mont-Tremblant substation (120/25 kV)	$36 M

Source: HQ Strategic Plan 2009-2013, available at http://www.hydroquebec.com/publications/en/strategic_plan/.

[54] Northern Pass Transmission LLC, Submission of Transmission Service Agreement (Dec. 15, 2010), Docket No. ER11-2377-000, at 8-9 (footnotes omitted), available at http://northernpass.us/assets/permits-and-approvals/FERCTransmissionServiceAgreementFiling.pdf.

[55] Additional information is available at www.northernpass.us/presskit.htm.

c. Champlain Hudson Power Express by TDI and Hydro Quebec

Champlain Hudson Power Express (CHPE)[56] is not proposed for New England, but is an additional example of a project designed to increase Canadian imports into the United States. The CHPE is a proposed 1,000 MW HVDC line from Quebec to New York City. The proposed route will start at the U.S.-Canadian border, travel south through Lake Champlain and along railroad rights of way (purporting to avoid environmentally sensitive areas), and then enter the Hudson River south of Albany, New York. The power will be delivered to a converter station in Astoria, Queens. The CHPE project will connect to the Quebec transmission system by continuing to run the HVDC cables past the New York-Canadian border to a converter station that is expected to be located at or near the Hertel HVAC substation near Montreal.

TDI is developing the project in the United States. According to the project website, TDI plans to use a mix of private equity, shippers and contractor support to finance this project. TDI's lead investor is the Blackstone Group, a large and well-known investment firm.

In April 2013, the New York State Public Service Commission (NY PSC) granted the project developer the right to construct and operate the project. The NY PSC stated that "the transmission line, estimated by the developer to cost $2 billion, would be built either underwater or underground along the entire length of the route, avoiding or minimizing visual and other potential environmental impacts."[57] The NY PSC also stated that a critical factor in its decision to approve the project was that the financial risk to ratepayers is minimized since customers will not be required to assume the financial risks to build and operate the project.

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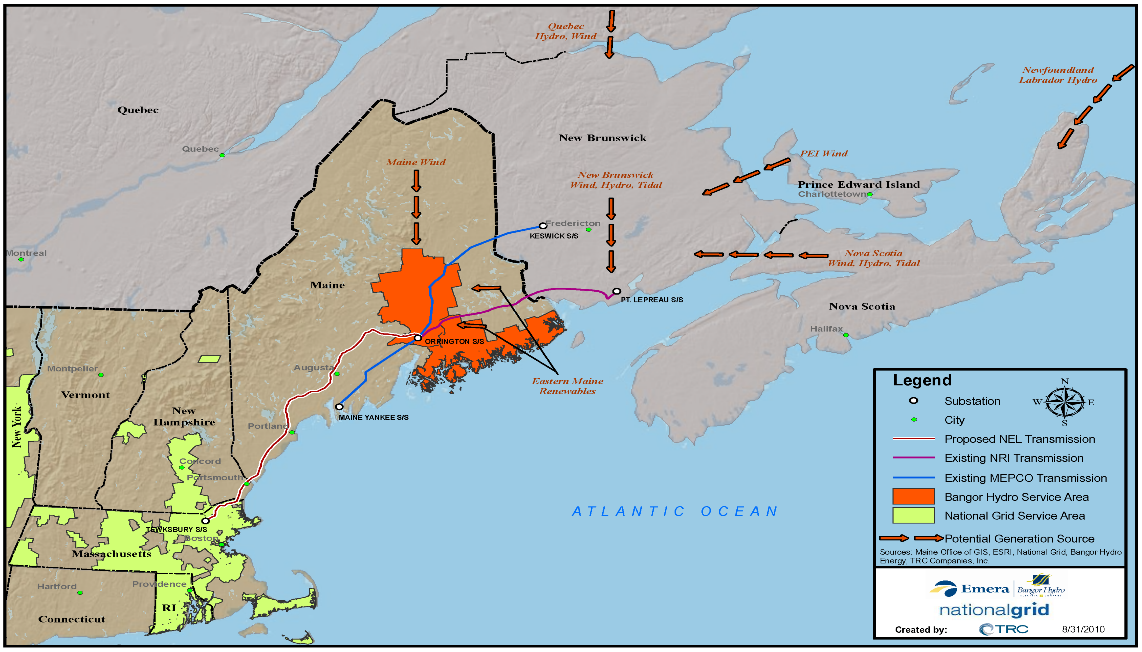
[56] Additional detail on CHPE is available at www.chpexpress.com/.

[57] New York Public Service Commission, Press Release, Case No. 10-T-0139, Apr. 18, 2013. More information is available at http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=10-T-0139.

d. The Northeast Energy Link by National Grid and Bangor Hydro

Map 12: Northeast Energy Link Concept Plan



Source: National Grid, used with permission

The Northeast Energy Link (NEL)[58] is a joint project of National Grid and Bangor Hydro. As NESCOE understands the proposed project, it would be located entirely within New England and consist of an approximately 230 mile HVDC transmission line running from Orrington, Maine to Tewksbury, Massachusetts with up to 1,100 MW of capacity. The NEL is intended to "deliver cost-effective renewable and low carbon resources from northern New England and the Canadian Maritime to southern New England customers, providing energy to meet state [RPS] requirements."[59] Emera owns Bangor Hydro, in Maine, as well as Nova Scotia Power. Emera is also developing the HVDC Maritime Transmission Link between the Island of Newfoundland and Nova Scotia (described above).

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[58] Additional information on the NEL is available at www.northeastenergylink.com/.

[59] Edison Electric Institute, *Transmission Projects: At A Glance*, March 2013, at 73, available at www.eei.org/issuesandpolicy/transmission/Documents/Trans_Project_lowres.pdf.

Map 13: Snapshot of Certain Existing and Proposed Generation and Transmission Projects in Eastern Canada and the Northeast United States

Source: National Grid, used with permission

3. Issues and Complexities Associated with Pairing Wind and Hydro Power on Transmission Infrastructure

As a threshold matter, the difference between AC and DC transmission line technology is important with regard to a transmission project's ability to transmit hydropower over long distances and to collect, or pick up wind-generated power along the way. A 2003 report prepared by the Connecticut Office of Legislative Research explaining key differences between the two technologies still appears to hold true today:

> The overwhelming majority of the electric transmission system in the U. S. uses [AC] technologies in which the current changes direction 60 times per second. On the other hand, DC transmission

> technologies, in which the current flows in one direction, have been used in certain applications. For example, an above ground DC line that has been in operation for decades connects the New England and Quebec power grids. The recently built Cross Sound cable, which links Connecticut with Long Island under the Long Island Sound seabed, also uses DC. The developer of this line considered using AC, but determined that DC would provide operational benefits and be less expensive. . . .
>
> DC lines have several advantages over AC lines that make them preferable in certain circumstances. DC lines are controllable and can function as the equivalent of power plants, while power on an AC line automatically follows the path of least resistance. DC lines require two cables, while AC requires three. Partially for this reason the DC lines, in and of themselves, can be less expensive per mile than AC lines. In addition, the ability to move power at high voltages for long distances on underground AC lines is limited by engineering constraints, which is less of an issue for underground DC lines. Also, most underground AC lines carrying 230 kilovolts or more have used fluids to dissipate the heat produced by the transmission cables, raising concerns about possible leaks and damage to aquifers. In contrast, most DC cables have used non-draining paper for insulation.
>
> On the other hand, DC systems are subject to several limitations. They are primarily designed for point-to-point transmission of power, and it is expensive to build the converter stations needed to connect a DC line to a power plant or substation, as well as to the AC transmission grid. Each converter station costs up to $50 million and can use up to three or four acres of land. In addition, the unavailability of DC circuit breakers restricts the feasibility of using DC in a grid. All of the connected DC lines in the grid must be taken out of service when an outage occurs or when a segment needs to be turned off for repairs or modifications. Unlike AC lines, power does not automatically reroute itself to avoid blackouts when there is a fault on a DC line.[60]

At a conceptual level, using controllable hydro resources to "firm up" wind[61] and therefore fully utilize transmission infrastructure appears attractive. While technically feasible, the benefits associated with combining intermittent renewable resource output with hydro power depend on several factors. The respective locations of the wind

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[60] Kevin McCarthy, Connecticut Office of Legislative Research, *Feasibility of DC Transmission Line*, Report No. 2003-R-0530, July 28, 2003, available at www.cga.ct.gov/2003/olrdata/et/rpt/2003-R-0530.htm.

[61] In other words, since wind does not blow constantly, adding hydro energy to the system when wind speeds wane and backing it off when wind picks up.

resource, the hydro resource, the existing transmission grid, and the new interconnecting transmission all significantly affect the economics of pairing wind and hydro. The notion of pairing intermittent wind output with hydro power for firm delivery becomes complicated when the resources are in separate transmission grids, cross international boundaries, and/or require conversion from DC to AC.

While balancing is a control area function,[62] NERC reliability standards do not preclude the use of imported resources to balance. Doing so presents complexities, however, and New England would need to work out protocols, procedures and so forth with the control area on the other end of the transmission line.

For intermittent wind output and hydro power to be successfully paired in conjunction with DC transmission technology,[63] the resources may need to be balanced on an AC system before being converted to DC. If the resources are not balanced before being converted to DC, a multi-terminal transmission configuration is necessary. Converter stations at each terminal are relatively expensive, such that DC is primarily considered for long-distance applications. It may not be cost effective to design a DC line with multiple terminals along the route to accommodate the collection of intermittent resource output.

Finally, there are environmental and economic considerations associated with the potential to pair wind and hydro resources. If an objective of increasing the relative percentage of hydro and wind power in the region's resource mix is to maximize emissions reductions, it may be preferable to use natural gas-fired resources to balance intermittent wind resources and allow a transmission line carrying hydro to run at its full level. Also, if hydropower resources are less expensive than natural gas-fired resources, and if an objective is to obtain an economic impact from hydro imports, it would take significant levels of hydro imports to displace gas-fired generation as the marginal unit in most hours.[64] Low-cost hydro imports would influence the hourly energy clearing prices by displacing the highest cost resources that would have otherwise been operated; however, that value may be small in most hours.

[62] ISO-NE defines a Balancing Authority Area as follows: "For compliance with NERC reliability standards, an area comprising a collection of generation, transmission, and loads within metered boundaries for which a responsible entity (defined by NERC to be a balancing authority) integrates resource plans for that area ahead of time, maintains the area's load-resource balance, and supports the area's interconnection frequency in real time. This term is used interchangeably with control area." ISO-NE, Glossary and Acronyms, at www.iso-ne.com/support/training/glossary/.

[63] To import power directly from the Hydro Quebec system, DC transmission technology is necessary. For other hydro resources requiring long-distance transmission to enable imports into New England, for the reasons described above, DC technology may be less expensive than similarly-sized AC configurations.

[64] A marginal resource is the "last generator to be dispatched at any point in time . . . and typically sets the market price for that market period. Power system operators dispatch generators based on cost (sequentially from lowest to highest cost) and physical capabilities." National Renewable Energy Laboratory, Glossary of Transmission Grid Integration Terms, at http://www.nrel.gov/electricity/transmission/glossary.html.

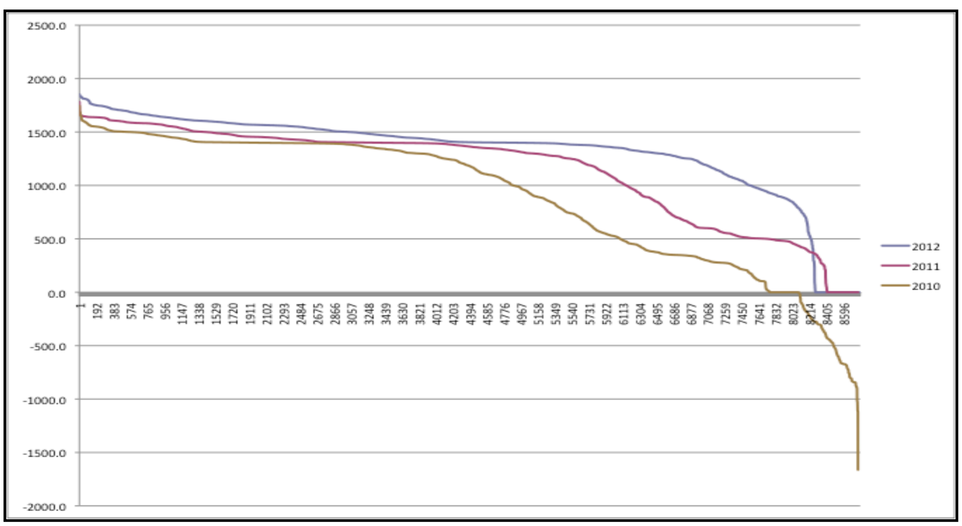
4. Power export and import levels by and between New England and Eastern Canada

With limited exception, most transmission ties between New England and Canada are full or close to full most of the time, and generally do not present a scalable opportunity to incrementally increase flows of power. The graphs below illustrate the extent to which ties have been used in recent years.

These so-called "load duration curves" sort a transmission line's energy flows from greatest to least. The resulting shape of the curve provides an indication of the direction, magnitude, and time that a transmission line is used in a given time period—a calendar year in the graph below. Load duration curves for each of the four New England-Canadian interfaces discussed above appear below. A positive number (the portion of the curve above the horizontal line) indicates imports from Canada to New England. A negative number indicates exports from New England to Canada.

Graph I illustrates power flows across HQ Phase II from 2010 through 2012, inclusive, with each year having a different color. For HQ Phase II, flow is generally in the form of imports from Canada into New England at about 1,400 MW; however, flow has been as high as 1,836 MW. As described above, the technical limit of Phase II is 2,000 MW, although it is most often limited to 1,400 MW in operations due to conditions in NYISO and PJM. HQ Phase II is full or close to full most of the time (again, due to operating limitations, not total technical capability) and does not have appreciable excess capacity for more flow.

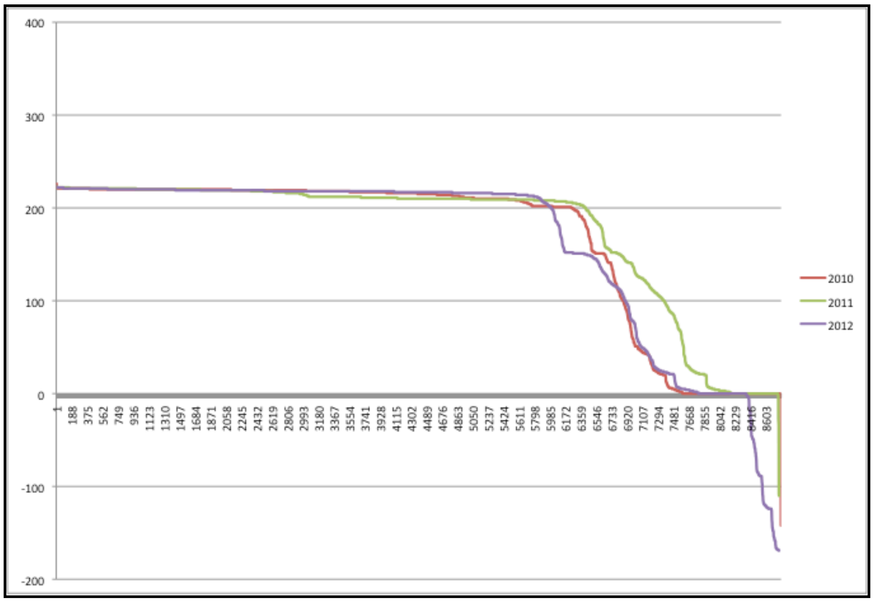
Graph 1: HQ Phase II Load Duration Curves 2010-2012



Data source: ISO-NE, Historical Interchanges Data, at http://www.iso-ne.com/markets/hstdata/dtld_net_intrchng/index.html.

Graph 2, below, is the load duration curve for Highgate. Highgate has operated just above its 200 MW rating for most hours of the year. There is limited opportunity for more imports across the Highgate tie.

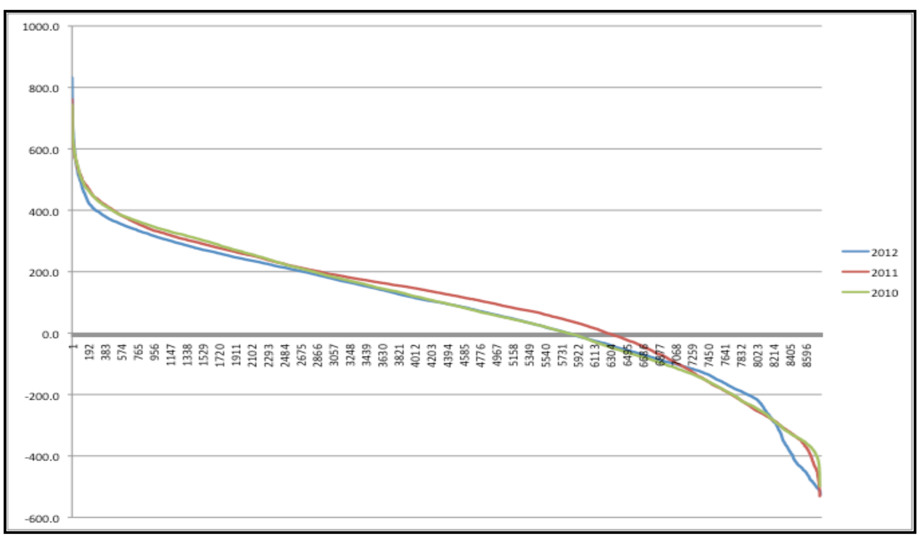
Graph 2: Highgate Load Duration Curves 2010-2012



Data source: ISO-NE, Historical Interchanges Data, at http://www.iso-ne.com/markets/hstdata/dtld_net_intrchng/index.html.

Graph 3 is the load duration curve for the New Brunswick interface. The two transmission lines that make up this interface are scheduled together for operational purposes. Accordingly, there is a single set of data available for the two ties. The New Brunswick interface has excess capacity and could accommodate increased power flows. It is possible that the low level of imports for this period is connected with the recent extended outage of Point Lepreau. That outage caused New Brunswick to import a high level of power to serve its native load. Point Lepreau has since returned to service.

Graph 3: New Brunswick Load Duration Curves 2010-2012



Data source: ISO-NE, Historical Interchanges Data, at http://www.iso-ne.com/markets/hstdata/dtld_net_intrchng/index.html.

Finally, historical import and export data in connection with the level of Canadian imports coming into New England during cold winter periods indicate whether New England and Canada experience cold weather at the same time and, therefore, whether import levels decline due to Canada's need to meet its own demand. The table below illustrates the actual average hourly flow from Canada into New England for each month in 2012. A positive number is an import, and a negative number is an export. While total flow is higher on average in the summer than the winter, this data, albeit one snapshot in time, does not support the assumption that there is no excess power available from Canada in the winter.

Table 3: Average hourly flows from Canada into New England, Monthly 2012

Month	HQ Phase II	Highgate	New Brunswick	Total
Base Interface Limits	1400	200	700	2300
January	1313.6	201.3	-78.1	1436.8
February	1288.4	194.4	-244.5	1238.3
March	1388.3	187.6	33.1	1609.0
April	1349.3	216.9	272.3	1838.5
May	1141.0	157.8	145.9	1444.7
June	1300.2	180.7	102.6	1583.5
July	1521.3	193.3	71.4	1786.0
August	1380.8	183.5	67.2	1631.5
September	1131.9	164.9	54.1	1350.9
October	1453.9	33.1	197.1	1684.1
November	1151.7	94.7	165.9	1412.3
December	1422.5	201.9	81.2	1705.6

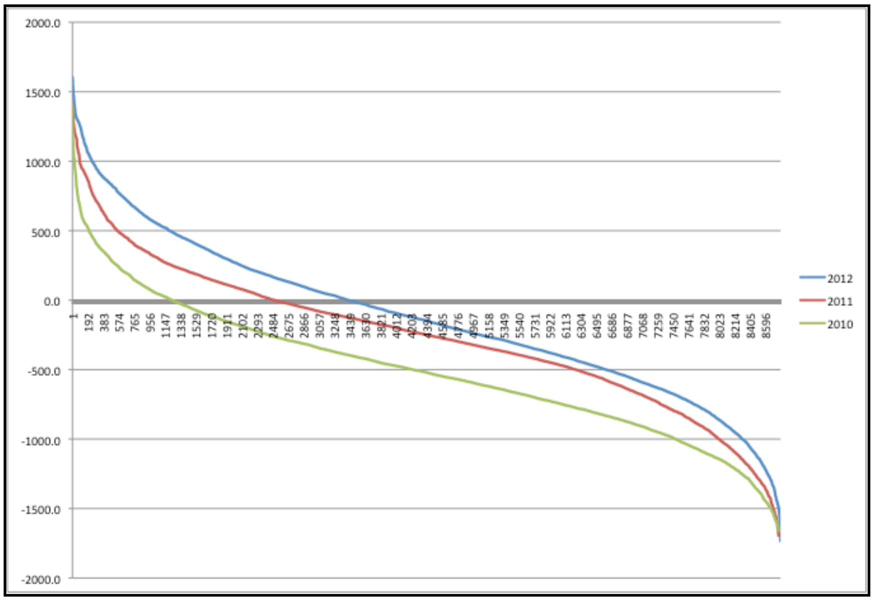
Data source: ISO-NE, Historical Interchanges Data, at http://www.iso-ne.com/markets/hstdata/dtld_net_intrchng/index.html.

5. New England and New York: Current and Historic Import and Export Levels

Graph 4, below, illustrates power flows between New York and New England, not including the cables to Long Island, during 2010-2012, inclusive. Like the load duration curves for Canadian ties, positive numbers indicate imports from New York into New England. For about forty percent of the time, or approximately 3,600 hours of the year, power flowed from New York into New England. For the remainder of the hours, or about sixty percent of the time, New England exported power to New York.

There are periods of time during the year when the ties between New York and New England have been full in each direction. However, at most times, there is excess room on the ties for more power to flow in either direction.

Graph 4: New York/New England Load Duration Curve 2010-2012



Data source: ISO-NE, Historical Interchanges Data, at http://www.iso-ne.com/markets/hstdata/dtld_net_intrchng/index.html.

To the extent New England and New York import and export power to each other, the level and direction of such power flows, and generating resource types involved, may influence whether New England would reduce overall carbon emissions by importing increasing amounts of low-carbon hydropower from Canada. For example, if New England hypothetically imported an incremental 1,200 MW of low-carbon power from Canada and then exported 1,200 MW of power from New England carbon-producing resources to New York, New England may not have improved the overall region's carbon levels. If New England's objective in increasing the level of hydroelectric imports is primarily net carbon reduction, increasing imports may not necessarily, alone, achieve the objective.

6. New England and Canadian Power System Synergies

Based on the power system and generation resource mix described above, there are synergies between the New England and eastern Canadian power systems:

- New England has a summer peak and eastern Canada has a winter peak.[65] However, New England's power system has experienced particular operational challenges during cold winter periods such as winter 2012/2013. Absent a firm commitment to export power from Canada to New England

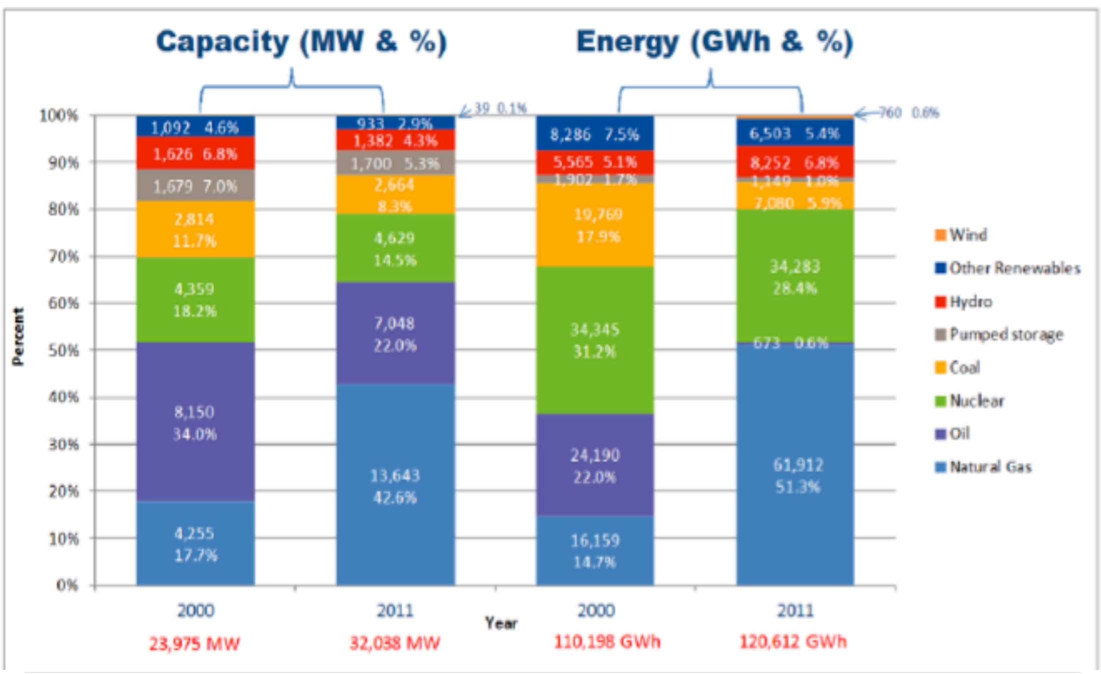
[65] The critical peak is when demand spikes and can occur in the winter season. For example, past critical peak dates/times on the Hydro-Quebec system are listed at www.hydroquebec.com/rates/heurejuste/pop-periode-critique.html. Also see www.hydroquebec.com/rates/heurejuste/pop-heure-juste.html for the critical peak calendar used in Hydro-Quebec's "Time it Right" pilot peak reduction program.

during cold winter periods, Canadian imports may not provide the certainty needed to ensure New England power system reliability based on economic dispatch.

- New England's current generation resource mix is largely natural gas and nuclear. Chart 7 illustrates New England's capacity and energy production in the years 2000 and 2011. Based on state RPS requirements, described above, as well as other renewable energy and carbon reduction goals, there is a general expectation that, on a going forward basis, wind power and other clean energy resources will be an increasing percentage of New England's generation fleet. Nalcor and HQ's generation resources are primarily hydropower; NB's is primarily coal and nuclear; Nova Scotia's is primarily coal; and Ontario's is mostly nuclear.

- Substations in Quebec may be close to certain Class I wind resources located in northern Maine. It is at least possible in theory that the Canadian power system could serve as a potential "battery" for northern New England-sited wind power generation, to be redelivered to New England along with incremental hydro resources during New England's peak demand.[66]

Chart 7: New England Capacity and Energy production within New England 2000 to 2011



Source: ISO-NE

[66] This concept is discussed further below in section V.F. *Consider Potential for Non-traditional System Synergy Scenario.* Subject to additional transmission engineering analysis that is beyond the scope of this whitepaper, this may be a technically feasible and lower cost approach for pursuing a bundled package of wind and hydro that fully utilizes the capacity enabled by a new transmission line.

IV. POTENTIAL BENEFITS AND RISKS ASSOCIATED WITH INCREASING HYDRO IMPORTS TO NEW ENGLAND

A. Some Potential Benefits

Increasing the level of hydroelectric imports in New England's resource mix presents an opportunity to reduce New England's reliance on natural gas-fired generation, which ISO-NE has identified as a risk and operational challenge to the New England power system. In a study commissioned by NESCOE, independent consultant Black & Veatch concluded that it believes New England's "natural gas infrastructure will become increasingly stressed as regional demand for natural gas grows, leading to infrastructure inadequacy at key locations."[67] Black & Veatch found that "increased usage of natural gas as an electric generation fuel potentially raises reliability concerns due to logistical issues that, if unaddressed, will pose reliability risks to the [New England] electric grid."[68]

Further, New England does not have local supplies of natural gas, and thus relies on natural gas imports, over which the region has no cost or other control. Since thousands of MW of in-region electric generators take service from individual pipelines, the potential exists for disruption of electricity supplies if a single pipeline is no longer available. A greater level of hydro imports would diversify New England's fuel supply sources. Black & Veatch also provided cost-benefit analysis of a range of potential solutions.[69] Since the supply and cost of natural gas influences the prices in New England's competitive wholesale market, it is important to assess implications of increasing any type of resource in the context of natural gas supply and price.

Increasing the level of hydro imports could also be important in future years, depending on circumstances as they unfold over time, in connection with the relative percentage of nuclear power in the region's resource mix. As noted in Chart 7 above, in 2011, nuclear power accounted for about 28% of the energy in New England. It is plausible that several of the nuclear units in the region could retire in the 2032-2035 timeframe, or sooner. Increasing the level of large hydroelectric resources may be valuable in terms of offsetting potential loss of major nuclear assets. In the last several years, two nuclear power stations in California and two in Florida have decided to shut down for reasons including increased operating costs. In addition, published news reports from South Carolina indicate that two new nuclear plants will be completed, but that the drop in cost of natural gas-fired facilities would make the new nuclear plants more expensive than new gas plants would have been. New England's aging nuclear power stations face cost pressure from natural gas plants, as has been demonstrated by the announced closing of the Vermont Yankee Nuclear Power Station. It is no longer

[67] Black & Veatch, *Natural Gas Infrastructure and Electric Generation: A Review of Issues Facing New England*, Dec. 14, 2012, at 2, available at www.nescoe.com/uploads/Phase_I_Report_12-17-2012_Final.pdf.
[68] *Id.*
[69] Black & Veatch, *Natural Gas Infrastructure and Electric Generation: Proposed Solutions for New England*, September 2013, available at www.nescoe.com.

possible to safely assume that nuclear power will continue to provide the same approximate percentage of the region's base load power for the next decades in the face of low natural gas prices. Whether by increasing hydro imports or some other means, New England will need to consider potential nuclear unit retirements in the coming decades.

Another primary benefit of increasing the level of hydro imports is its potential to reduce New England's carbon profile under certain circumstances, discussed further below. An open question is the relation of the all-in cost of increased hydro imports to current market prices—in other words, the relative cost to achieve any potential benefits.

Need to Validate Import Source To Confirm Carbon Benefits

Increased imports of Canadian power have the potential to help New England states achieve carbon reduction requirements or goals. However, to satisfy these statutory mandates and objectives, imports must be from low-carbon resource generating units and validated as such, in the same way New England today validates clean energy attributes of generating units. Such unit specific hydro validation requires system changes in New England, discussed below. Validation also requires eastern Canadian provinces to create and implement tracking and reporting systems.

The need for such tracking systems is straightforward. Once power is generated, it flows along the path of least resistance. Therefore, the point where specific physical energy is used may not be the same point where a contract required it to be delivered. Thus, to ensure that any imported power has the emissions and any other desired characteristic of hydropower, a system for measuring, verifying, and tracking the power's attributes is necessary. The strong storage capacities and interconnections between Canadian provinces with high levels of hydropower and others with higher-emitting resources underscore the need for such automatic verification. This is particularly important for New England states that may invest in hydro resources for the purpose of satisfying carbon reduction mandates.

Increased imports of Canadian hydropower have the potential to help New England states achieve carbon reduction requirements or goals. However, to satisfy these statutory mandates and objectives, imports must be from low-carbon resource generating units and validated as such, in the same way New England today validates clean energy attributes of generating units.

The question of how to track the emissions characteristics (or other attributes) associated with power generation has already been considered in several related contexts. For example and as discussed further below, the NEPOOL GIS directly tracks attributes associated with certain generation resources, primarily for renewable attributes and in some cases for environmental disclosure.[70]

[70] As an additional example, in California, rules have been developed to address so-called "resource shuffling," a form of "green-washing" imported power under the Assembly Bill 32 carbon dioxide emissions cap-and-trade program.

Separately, the Regulatory Assistance Project made a recommendation to the Regional Greenhouse Gas Initiative (RGGI) participating states to expand the use of the GIS system to improve tracking emissions associated with imported power generation.[71] This proposal, focused on "leakage" in the RGGI states, could be expanded to apply to specific Canadian hydropower resources, thereby enabling the measurement, verification, and tracking of emissions characteristics of imports into the New England region.

New England Generation Information System

NEPOOL created the GIS in 2001. The purpose of the GIS is to track MWhrs for various attributes, such as RECs. NEPOOL, rather than ISO-NE, owns and operates the GIS. It is administered by APX, a third party software firm. The GIS tracks each MWhr produced in New England according to an array of attributes, including fuel source, RPS qualifications, RECs, emissions, labor characteristics, and geographical location. In the case of energy imported from outside New England as system power,[72] the GIS assumes the imported power has the average characteristics of the control area from where it was imported. In other words, for imported power, the GIS does not account for the attributes of the specific generating unit from which power was produced, but rather assumes and tracks the average mix of the overall power system from where it was imported.

System power, as opposed to unit specific generator power, does not qualify for RECs under state laws in the New England states that have RPS requirements. Accordingly, the GIS does not issue RECs for system power. If, however, an import can be tracked to a specific generating unit, the GIS will recognize the unit specific attributes and the generating unit can receive RECs. Such tracking requires the importer, New England, and the adjacent control area (e.g., Canada) to have systems to support the tracking of unit sales to protect against double counting.

NEPOOL has modified the GIS many times since its creation in 2001.[73] Most changes have resulted from state actions, such as a state redefining what types of resources are eligible for RECs or changing other attributes that load serving entities are required to track. Historically, NEPOOL has consented to modifying the GIS to accommodate changes in state law. From time to time, market participants also request

[71] Regulatory Assistance Project and Center for Resource Solutions, *Tracking Emissions Associated with Energy Serving Load in the Regional Greenhouse Gas Initiative (RGGI) States: A Feasibility Study*, April 2013, available at www.raponline.org/document/download/id/6509.

[72] "System power" generally refers to large scale power imports that are not automatically tracked to a specific generating unit.

[73] There are two categories of changes to the GIS, Cardinal and Non-Cardinal. The difference between a change being considered Cardinal or Non-Cardinal is based on the degree of difficulty and expense of the programming required to implement the change. Under NEPOOL's GIS Agreement, Cardinal changes may only be requested if the NEPOOL Participants Committee approves the changes. Non-Cardinal changes may only be requested if the NEPOOL Markets Committee approves the changes. In the event the NEPOOL Markets Committee votes on and rejects a Non-Cardinal change, the NEOOL Participants Committee may consider the question and override the NEPOOL Markets Committee vote.

that NEPOOL modify the GIS to enable them to make certain representations in their marketing to customers or in anticipation of a change in state law.[74]

The cost of administering the GIS is allocated to all entities that own "GIS load assets" in the ISO-NE market system. A "GIS load asset" is an asset that is subject to its state's regulatory tracking requirements. All load assets are assumed to be GIS load assets unless the asset owners submit a form on an annual basis indicating that the load asset is exempt. Municipals utilities are an example of those entities that may be exempt. The GIS system is also able to track assets based on what entity is serving retail customers.

B. Some Potential Risks

A significant change to New England's resource mix is not without risk. One category of risk relates to the potential implications on New England's current generation fleet. Specifically, increasing in any substantial way the level of hydro imports could have the effect of displacing existing generation units that provide service in New England today and that are needed, whether by operating characteristic or geographic location, to reliably operate the regional power system. Increasing hydro imports has the potential to depress the current New England generating fleet's energy margins, placing the continued operation of those units at risk.

Another category of risk is energy security. Materially increasing the level of hydro imports as a relative percentage of New England's resource mix produces a greater dependence on resources over which New England has no direct control, either by way of future availability or cost over time. Hydro resources are subject to drought and flow restrictions on water use. Hydro projects also may be subject to relicensing efforts that limit operating flexibility because of the need to restrict water flows to address environmental or fish-passage concerns.[75] In addition, New England is, of course, not the only potential buyer of Canadian hydroelectric resources and it is reasonable to expect upward price pressure should other adjacent regions, such as New York and/or Ontario seek to contract for the same resources.

Further, increasing the extent to which New England relies on large quantities of power from distant resources over long transmission lines presents the risk of massive system failure and corresponding power loss, whether by a weather event, an act of terrorism, a technological failure or something as simple as a tree falling. Careful study of the technical implications of potential large-scale transmission expansions will enable evaluation of whether and how major new transmission facilities can be designed to preserve system reliability and avoid the potential for major disturbances in one area of the network from spreading to others. Risks associated with transporting power over

[74] Generally, NEPOOL has been less open to implementing changes based on requests that might benefit a subset of market participants, particularly in light of the costs associated with making system changes.
[75] Some of the relicensing proceedings for New England hydro projects have involved negotiations with regulators and other stakeholders regarding the retirement of some projects in exchange for increased energy production at other hydro units. ISO-NE, 2012 Regional System Plan, at 130.

very long distances, and associated costs, are minimized when generating resources are located close to load.[76]

The risk associated with transporting power long distances over transmission lines that are controlled by other entities is not theoretical. For example, on July 3, 2013, forest fires in northern Quebec caused four transmission lines to trip, which resulted in a reliability event.[77] The line tripping resulted in load and generation tripping within Quebec, and approximately 3,370 MW of exports to New England, New York, New Brunswick, and Ontario being tripped or reduced. When both Phase II and Highgate tripped, New England lost approximately 1,750 MW of imports from HQ over the span of a few minutes. New England recovered from the source loss in less than eleven minutes, which is within the NERC allowable timeframe of fifteen minutes. ISO-NE did not receive any notification from HQ of a possible problem before the lines tripped. NERC has initiated an investigation into the event.

An additional risk associated with significantly increasing hydroelectric imports is potential environmental impacts near the hydro source, such as re-routing of rivers or flooding.

V. SOME POTENTIAL MEANS TO INCREASE THE LEVEL OF CANADIAN HYDROPOWER IMPORTS INTO NEW ENGLAND

A. Allow Current Market Proposals, Described Above, to Increase Canadian Imports to Move Forward through Current Processes

Some illustrative Potential Advantages -

- Allow markets to efficiently allocate society's resources, identify economic opportunities, and satisfy consumer needs
- Avoid material distortions to New England's wholesale markets, which as ISO-NE cautions in other contexts, may present significant unintended consequences and reliability challenges
- Insulate New England's ratepayers from generation and transmission costs and risks that investors have indicated an intent to fund and undertake

Some illustrative Potential Disadvantages -

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[76] *See generally* U.S. Dep't of Energy, *Potential Benefits of Distributed Generation and Rate-Related Issues that May Impede Their Expansion, A Study Pursuant to Section 1817 of the Energy Policy Act of 2005*, June 2007, available at http://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/1817_Study_Sep_07.pdf.

[77] ISO-NE, Week of July 14-20, 2013 Operations; July 3, 2013 DCS Event, presented to the Reliability Committee, Aug. 15, 2013, available at http://www.iso-ne.com/committees/comm_wkgrps/relblty_comm/relblty/mtrls/2013/aug152013/index.html.

- The time it takes for project sponsors to move projects to markets may frustrate state interests if New England states determine that increased levels of hydropower are beneficial to New England consumers and achieve state requirements and objectives
- Market-based revenue streams may be too volatile for private-sector financing of new, capital-intensive, and long-lived assets like new transmission lines that would be required to substantially increase imports

B. Advocate to Increase and/or Maximize the Level of Power that Flows Over Current Transmission Infrastructure into New England

The Phase II HQ tie, as noted above, frequently operates near 1,400 MW or at about seventy percent (70%) of its rated capacity. HQ Phase II is capable of operating at higher levels. In conjunction with ISO-NE's 2013 Economic Study, described above, New England could further investigate the electric reliability and economic aspects associated with increasing the operational limits placed on the HQ Phase II tie. In theory, increasing the HQ Phase II operational limits could enable HQ to offer increased levels of hydro into the New England electricity market using existing infrastructure.

Some illustrative Potential Advantages –

- Increasing flows over existing lines may allow consumers to get maximum benefits from existing assets or rights
- Maximizing existing ties would ensure that investment in new infrastructure occurs only after full utilization of current infrastructure
- Potential to increase hydropower imports under the current market structure
- Eliminates the potential for disagreement over cost allocation related to new infrastructure

Some illustrative Potential Disadvantages –

- The ability to increase flows over the existing Phase II tie is limited by an agreement with other neighboring Regional Transmission Organizations (RTOs) and may require upgrades outside of New England to maximize use of the current infrastructure. Such upgrades in other regions have not been studied and their costs are unknown. In addition, such upgrades outside of New England are not within New England policymakers' control.
- Execution of complex, multi-regional contractual and operational changes are uncertain and even working towards them would take considerable time

C. Build (Site and/or Fund) New Transmission between New England and Canada

1. Background on Existing Funding Mechanisms for New Transmission

There are currently two mechanisms to fund new transmission infrastructure in New England: PTF eligible for regional cost allocation and participant funded projects.

Pool Transmission Facilities Eligible for Regional Network Service Treatment

Most transmission in New England is built pursuant to ISO-NE's Open Access Transmission Tariff (OATT) planning process and in response to an identified reliability need. ISO-NE includes transmission developed in this manner in its RSP. In such cases, transmission projects needed for reliability—called Reliability Transmission Upgrades or RTUs—are eligible to be rolled into regional transmission rates (i.e., RNS). To qualify to be included in the RNS, the transmission must be eligible, from a technical perspective, to be a PTF. ISO-NE has operational control of all PTF facilities that are 69 kV and above and are looped (i.e., not radial). In addition, to be eligible to be rolled into regional transmission rates, ISO-NE must review transmission project costs and find that they are not built to a standard above what is most cost effective, or that they include costs required by local zoning, such as undergrounding a line to satisfy local aesthetic preferences.

As noted above, the regional transmission rate is paid for by all load (customers) in New England on a monthly basis and is based on the percentage share of the system monthly coincident peak. This is referred to as network load.

All transmission lines that are included in the RNS rate are available for use by all participants to serve load in New England. Since the full cost of service of these facilities is paid for automatically through this monthly charge to network load, there is no need to charge for individual transactions executed to serve New England load. Accordingly, import transactions over these facilities are at no additional cost to the importer.

In addition to RTUs, the ISO-NE OATT currently includes one other category of projects eligible for regional cost allocation. Known as Market Efficiency Transmission Upgrades (METUs), these projects are designed primarily to reduce the total net production cost to supply the system load. A METU can exist when the net present value of the net reduction in total cost to supply system load is greater than the net present value of the carrying cost of the identified upgrade. In determining the net present value of power system resource costs, ISO-NE takes into account projected economic factors, such as energy, capacity, and fuel costs. If the New England power system resource costs are lower, after considering the costs of the prospective METU, then, assuming that the upgrade qualified as PTF, costs for the line would be socialized (i.e., rolled into RNS rates). No METU projects have been placed in service in New England.[78]

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[78] The absence of METU projects does not, however, mean that transmission upgrades put into service for reliability reasons have not also provided market efficiency benefits. As one report noted in citing the

Participant Funded Transmission

The second way that transmission can be paid for is referred to as participant funding. Under this method, a participant elects to construct transmission for its own purposes, agreeing to pay the cost of the upgrade and retaining the transfer rights over the line. Generator interconnections are the most common type of participant funded transmission.

Another type of participant funded project is an elective transmission upgrade. These upgrades are not needed for reliability and cannot be justified as a METU. Like generator interconnections, elective upgrades place the costs of the project on the sponsoring entity. Rights to the use of the transmission line are held by the entity that funds the line, subject to FERC's review that such rights are exercised consistent with its open access policies.

Transmission that is participant funded can be PTF, but it is not rolled into RNS. Those seeking to import over a participant funded line must pay the entity that holds the transmission rights.

2. Using Tariff Funding Mechanisms to Increase Hydro Imports

The New England states could agree to fund a transmission line to allow more Canadian resources to participate in the New England market directly. This new transmission line could conceptually fit within one of two categories detailed above: (1) a METU or (2) an elective upgrade. The significant difference between these two alternatives is the ownership of the rights to use the new transmission line and allocation of costs.

If, hypothetically, the states funded such a project, the rights to its use could be surrendered to the marketplace in the case of a METU. If an elective upgrade, the states could potentially enable priority access to an entity of the states' choosing. Any entity that has rights and does not use them must make them available for resale. Such rights can be sold bilaterally to a market entity if the rights holder wishes, or the rights can be posted for sale. If the rights are not sold, they are made available for use on a non-firm basis through ISO-NE's scheduling system. METUs are allocated to all load (customers) in New England on a load ratio share basis. Elective transmission upgrades are funded by whoever agrees to participate, whether one state or a group of states, and can be allocated in the manner agreed to by participating states.

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challenges of economic projects: "cost socialization for reliability upgrades can be more easily justified than for economic upgrades. This is because a failure at one point in a regional grid can potentially disrupt the entire system, while an economic upgrade may benefit only a subset of the region, making it harder to justify region-wide cost allocation." Stan Mark Kaplan and Adam Vann, *Electricity Transmission Cost Allocation*, Congressional Research Service, Apr. 19, 2010, at 8.

The New England states could agree to site and/or fund a transmission project and do nothing more, which could, in theory, enable incremental hydro resources to access and participate in the New England competitive market place.[79] Alternatively, the New England states could agree to fund a new transmission project and couple that with a solicitation for hydroelectric power (and/or renewable power, depending on the status of state definitions and preferences) to satisfy state policy objectives.

Some illustrative Potential Advantages -

- If transmission is the impediment to more hydro resources in the New England market, an investment in transmission could enable more hydro power to participate in the New England market
- Provided funding is through METU mechanism or agreement on cost allocation is reached for an elective project, potential for expedient action in furtherance of state policies

Some illustrative Potential Disadvantages -

- Potential to interrupt or adversely affect investors willing to fund new transmission
- The METU provision of the ISO-NE tariff has never been used and it is reasonable to anticipate considerable controversy if it is
- Potential to shift risk of investment from project sponsors to ratepayers
- New England states may prefer not to identify a transmission path for new resources absent a competitive process
- New England has long indicated an interest in evaluating all-in costs of transmission and generation combined
- Building and funding a transmission line provides no guarantee about ultimate costs to consumers (there is no basis to assume the costs of hydro to New England consumers will approximate the cost of hydro available to Canadian consumers)
- Potential to distort the competitive markets in favor of a resource that receives the benefits of the new transmission line, to the detriment of existing resources that incurred merchant risk

3. Potential Prospective Means: Order 1000

[79] Some areas of the country, for example, have pursued the notion of building transmission on the assumption it will be used to transport certain types of power to advance public policy objectives. *See, e.g.,* Public Utility Commission of Texas, Crez Transmission Program Information Center, Program Overview, at www.texascrezprojects.com/overview.aspx.

A third potential funding mechanism for transmission is through the FERC Order 1000 process. In 2011, FERC issued Order 1000, which required, among other things, that the transmission planning process consider public policy requirements and establish a method for allocating the costs of policy-driven transmission projects. As of the writing of this paper, no implementation date has been established for New England on the public policy component of Order 1000. In a May 17, 2013 order, FERC rejected key elements of ISO-NE's proposed process governing planning activities related to public policy projects and the associated cost allocation method. The region is currently developing new rules to be included in a further compliance filing with FERC.[80]

When ultimately approved by FERC and implemented, an additional mechanism will be in place in New England to fund transmission projects that advance state policy goals. The extent to which such a mechanism will be a viable option for states to achieve objectives cost-effectively will depend on the final structure of the process and the cost allocation method that is established. Finally, the timing associated with the ultimate Order 1000 process is unknown, and litigation risks exist depending on the final form of the process.[81]

D. Pursue Market-Based Approaches

The New England states could propose changes to the FCM to accommodate increasing levels of competitive participation by resources that satisfy state policy objectives, including low-carbon generation (a load following, low-carbon tranche, for example). Alternatively, the New England states could adopt the portfolio standard approach (e.g., RPS) to provide an incentive for the attributes of hydro power.

Some illustrative Potential Advantages -

- Reliance on market mechanisms to the maximum extent possible to solicit the most efficient resources to further state energy and environmental policy
- Meet policy objectives or state law requirements in the context of the current capacity market structure
- The portfolio standard approach for public policy resources is considered compatible with existing wholesale competitive markets

Some illustrative Potential Disadvantages -

- The New England states' ability to change the structure of the competitive wholesale electricity markets is limited (see, e.g., the description above of ISO-NE's Minimum Offer

[80] There also are pending rehearing requests before FERC, including from NESCOE, challenging the rejection of the proposed process for considering public policies in transmission planning and how projects driven by policy needs would be funded.

[81] Under one Transmission Owners' proposal of a new cost allocation rule, if adopted, each New England state could potentially be required to contribute to the recovery of transmission costs associated with importing incremental hydroelectricity, even states that do not identify a direct benefit from such imports.

Price Rule and states' efforts to include an exemption for renewable power, now a pending request for rehearing at FERC)

- The complexity and time associated with developing viable public-policy oriented mechanisms in the New England markets could be significant and ultimately not successful
- Potential to displace current generating resources needed for reliable system operations
- The complexity and time associated with developing a new portfolio standard in the New England states could be significant and ultimately not successful

E. Execute Competitive Procurement, Outside of Wholesale Marketplace, Resulting in Long-Term Contracts for Power

All or some subset of states could issue one or more Request for Proposals (RFPs) for hydropower (and/or power eligible to satisfy state RPS requirements) with the intent of signing out-of-market long-term contracts. Assuming an all-in (generation and transmission combined) solicitation, diverse resources such as wind and hydro could, in theory, submit proposals that use the same transmission line.

Long-term contracts for electrical output are commonly used to address price volatility in the wholesale markets. In New England's *energy* (rather than capacity) market, long-term contracts for energy are a permissible and useful means of hedging power costs. In New England's FCM, however, FERC and most New England market participants view out-of-market long-term power contracts entered into with state regulatory approval as an impermissible form of anti-competitive behavior. A common perspective among market participants is that if any resource has the opportunity for an out-of-market long-term contract, then all resources should be afforded the same opportunity and, absent such comparable treatment and opportunity, state approval of out-of-market contracts disrupts New England's competitive wholesale market and distorts price signals needed to attract new resources and maintain existing ones.

In fact, FERC has endorsed ISO-NE's MOPR that seeks to remove the price-suppressing effects of long-term contracts on competitive FCM prices. As a result, any capacity that states may procure through long-term contracts may not be counted towards the region's resource adequacy requirements. This means that, effectively, customers would pay for the resources under long-term contracts as approved by a state regulatory authority and then, when ISO-NE identifies the level of resources New England needs for system reliability, that regional requirement would be set as if the resources under long-term contract do not exist. As discussed above, FERC has rejected the New England states' request to exempt from the MOPR a relatively modest (225 MW/year) level of renewable resources correlated with state RPS requirements.

Some illustrative Potential Advantages -

- Reduce reliance on natural gas and diversify fuel supply sources
- Reduce reliance on oil to compensate for natural gas challenges
- Maximize use of infrastructure by importing incremental hydro to complement wind
- Increase levels of low carbon resources in energy mix.
- Identify lowest cost out-of-market resources via competitive procurement process

Some illustrative Potential Disadvantages -

- Ratepayer subsidy to some resources but not all, *vis a vis* long-term contracts, creates market distortions and allegations regarding government selecting, by virtue of RFP eligibility, winners and losers in a competitive market context
- Would also distort the competitive marketplace in favor of the resources that receive the benefits of using any new transmission that is not market participant funded, to the detriment of existing resources that incurred merchant risk
- Wholesale capacity market implications due to FERC orders protecting existing generation resources from economic harm associated with out-of-market subsidization of selected resources
- Shift costs of non-PTF transmission to ratepayers unless transmission is market participant funded
- Shift project risks from investors to ratepayers, including the risk of the contract, over its life, being above market (unless contract has market tracker that precludes prices from going some level above market)
- Potential to create power system reliability risks due to displacement of other resources from the market
- Would likely require state statutory changes in at least some states
- Benefits associated with reduced prices in the energy market may be given back through increased prices in the capacity market

F. Consider Potential for Non-Traditional System Synergy Scenario

Assuming there was incremental transmission available between northern New England and a Canadian province—a material assumption—the New England states could contract with RPS-eligible wind resources in northern New England to deliver, for example, 1,000 MW (35% capacity factor) to a Canadian Province. At another time of year, such as during New England's summer peak, Canada could "re-deliver" some portion of that amount of wind energy to New England when the New England system needs it most, plus some incremental hydro power. In this scenario, the wind produced in northern New England could, subject to applicable state law, satisfy state RPS requirements and contribute, through the arrangement with Canadian resources, to New England power system needs at peak periods when it would provide the highest value. New England could essentially pay a redelivery fee for a Canadian Province to export power that consists of, for example, 30% wind equal to the amount that Province received from Maine, and the balance of the block, or 70%, from hydropower for an annual total that could be, under such a scenario, two or three times the amount of wind that New England initially delivered to Canada. New England could not seek power delivery at periods when the power is most valuable to Canada, or during Canada's winter peak. Instead, New England could seek power delivery when it is both most valuable to the New England power system and least valuable to the Canadian system, which would likely be during summer peak periods. This emphasis on time of need would focus on how resources are used and maximize value of the power to each party to provide the fullest fuel diversity benefits.

Some illustrative Potential Advantages -

- Maximize synergies between systems
- Provides a focus on time of system needs.
- Support development of New England RPS-eligible resources and use that power when it is most needed and valuable to the system, not necessarily when produced
- Maximize use of existing and new transmission infrastructure
- Minimize reliance on current transmission system within Maine to move power directly to southern New England

Some illustrative Potential Disadvantages -

- Out of the ordinary power arrangement creates complexities and impediments may prove unfeasible
- Requires new transmission
- Uncertainty regarding whether Canadian systems would see benefit in taking and essentially parking wind power from New England outside of times Canada tends to need to imports

APPENDIX A

Background: Imports, Installed Capacity Requirement and PTF Effects

In New England, the Installed Capacity Requirement (ICR) is the amount of capacity that ISO-NE must purchase in the annual FCM auction to ensure that sufficient resource capability is contractually obligated to serve New England load reliably. ISO-NE determines the ICR level through a complex calculation that includes load levels, installed generation within New England, historic availability and performance of all resource types, and transmission line capabilities.

ISO-NE can secure resource adequacy over transmission interconnections with other control areas, such as Canadian provinces, through either (1) long-term contracts that are obligated in the capacity auction, or (2) "tie benefits." Tie benefits from neighboring control areas reflect the amount of emergency assistance that New England can rely on, without jeopardizing reliability in New England or the neighboring areas, in the event of a capacity shortage in New England. ISO-NE reduces the amount of ICR consumers purchase in each capacity auction by the level of tie benefits from neighboring control areas.

ISO-NE uses a probabilistic, multi-area reliability model to calculate total tie benefits from the New Brunswick, New York and Quebec control areas. Tie benefits from each individual control area are determined based on the results of individual probabilistic calculations performed for each of the three neighboring control areas. In the table below is the calculation methodology as described in ISO-NE's *Report on 2016-2017 ICR Values*:

Table 1. Tie Benefit Calculation Methodology[82]

- *Process 1.0*
  - Calculate the tie benefits values for all possible interconnection states using isolated New England system as the reference
- *Process 2.0*
  - Calculate initial total tie benefits for New England from all neighboring Balancing Authority Areas
- *Process 3.0*
  - Calculate initial tie benefits for each individual neighboring Balancing Authority Area
  - Pro-rate tie benefits values of individual Balancing Authority Areas based on the total tie benefits, if necessary
- *Process 4.0*
  - Calculate initial tie benefits for individual interconnection or group of interconnections
  - Pro-rate tie benefits values of individual interconnection or group of interconnections based on the individual Balancing Authority Area tie benefits, if necessary
- *Process 5.0*
  - Adjust tie benefits of individual interconnection or group of interconnections to account for capacity imports
- *Process 6.0*
  - Calculate the final tie benefits for each individual neighboring Balancing Authority Area
- *Process 7.0*
  - Calculate the final total tie benefits for New England

ISO-NE subtracts the tie benefits from PTF interconnections (i.e., New York and New Brunswick) when ISO-NE calculates the ICR. The theory is that, since the benefits of these ties are paid for by all load (i.e., customers), the benefits are shared by all load. Tie benefits associated with HQ Phase I are called Hydro-Quebec Interconnection Capability Credits (HQICCs). HQICCs are credited specifically to the IRH in proportion to their percentage interests in that project. ISO-NE calculates the tie benefits associated with HQ Phase II differently as well. HQ Phase II tie benefits are calculated simultaneously with the other tie benefits, but then ISO-NE subtracts them after ISO-NE establishes the total ICR.

Over time, questions have been raised regarding whether HQ Phase II should be treated as any other tie for purposes of tie benefit calculations, i.e., rolled into PTF and thereby into the RNS rate. For example, if HQ Phase II was rolled in to PTF and the RNS rate in the same way that MEPCO is, then the tie benefits associated with HQ Phase II would be treated the same as the other ties and there would be no separately calculated and credited HQICC. When questions about the treatment of ties have been brought to FERC over the years, FERC has ruled in favor of the IRHs to maintain the *status quo*.[83]

To illustrate how tie benefits interact with the ICR, considering the most recent calculations for the 2016/2017 Forward Capacity Auction. ISO-NE assumes total tie benefits of 1,870 MW for this period: 1,055 MW from Quebec over the HQ Phase II, 109 MW from Quebec over the Highgate interconnection, 392 MW total from New Brunswick and 314 MW from New York. There is no connection between the actual experienced level of flow and tie benefits.

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[82] ISO-NE, ISO New England Installed Capacity Requirement, Local Sourcing Requirements, and Maximum Capacity Limit for the 2016/17 Capability Year, Jan. 2013, at 29-33, available at www.iso-ne.com/genrtion_resrcs/reports/nepool_oc_review/2013/icr_2016_2017_report_final.pdf.

[83] *See, e.g., New England Power Pool and ISO New England, Inc.*, 111 FERC ¶ 61,132 (2005).