New England Can Import Canadian Hydropower to Meet Environmental Goals

David O'Connor

Canadian hydropower has often been suggested as a potentially valuable addition to the portfolio of generation sources that supply electricity to consumers in New England.

Imports of hydropower have recently increased, but they have never been a large contributor to the region's power supply portfolio. Instead, as the region's aging coal and oil plants have retired, most new generating capacity has been fueled with natural gas. This trend has caused problems for the region, especially in the winter when large amounts of natural gas are always needed for space heating. Gas and electricity prices have spiked, and oil plants, with their harmful emissions, have had to operate to maintain electric system reliability. These short-term problems are clear warning signs of more serious trouble on the horizon.

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The region's governors, and others, have argued that imports of Canadian hydropower would be a logical and desirable way to address these problems. This article describes the problems that burden the region's wholesale electricity market, the potential for hydropower imports to solve those problems, and the regulatory changes needed to accomplish it.

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SURGING USE OF NATURAL GAS

Across the New England region, discussion of electricity markets and policies is dominated by concerns about an ever-expanding reliance on natural gas to produce power. Deregulation of the generation market, which began in 1998, has caused the retirement of old, inefficient coal and oil plants. Most of that lost capacity has been replaced by natural gas-fired plants, with about 12,000 megawatts added since 2004.[1] Over the last 15 years, using natural gas to generate electricity has tripled. As **Exhibit 1** demonstrates, it was a mere 15 percent of the region's fuel used to generate electricity in 2000. By 2014, natural gas had jumped to over 45 percent.

New England's reliance on natural gas-fired generation is the consequence of simple economic and environmental realities. In a deregulated generation market, as New England has had since the late 1990s, private investors minimize risk by investing in generation that requires the least capital commitment per megawatt installed. In New England, that means natural gas-fired plants.

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In addition, natural gas plants emit pollution at rates over 50 percent below the coal and oil plants they are replacing. This feature makes obtaining the environmental permits relatively simple, inexpensive, and predictable. The

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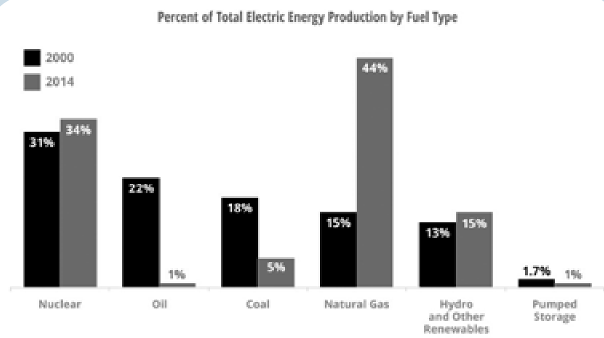
Exhibit 1. Electricity Production in New England by Fuel Type



Source: ISO-NE.

discovery and extraction of plentiful amounts of shale gas in the nearby Marcellus and Utica regions of Pennsylvania and Ohio have reduced natural gas prices, at least during portions of the year when it is not needed for heating or cooling.

Plant operators can run when the price of natural gas favors electricity production, and avoid running when it does not.

GENERATING CAPACITY RETIREMENTS

The practical advantages of natural gas mean that the natural gas-fired electric generation is likely to replace retiring plants in the foreseeable future. As **Exhibit 2** indicates, 3,500 megawatts of mostly coal- and oil-fired generation sources are slated to retire by 2018. Retirements of nuclear stations have occurred and will occur in the foreseeable future.[2] By 2020, over 25 percent of the region's current power resources will have retired, plan to retire, or are highly likely to retire.[3]

The ISO-NE list of proposed projects indicates the degree to which natural gas-fired plants are likely to dominate new capacity additions. By June 2015, over 12,000 megawatts of new generating plant proposals had submitted formal applications to join the region's portfolio of generation assets. As **Exhibit 3** indicates, of these, almost 8,000 megawatts, or 66 percent, are for plants fired by natural gas.[4]

State policies and incentive programs aimed at boosting renewable generation have not resulted in a substantial increase in non-hydro renewable energy generation. According to ISO-NE, in the year 2000, non-hydro renewables made up 8 percent of New England's energy generation mix. Fifteen years later, in 2014, the net contribution from non-hydro renewable sources, mostly wind generation, had only increased to 9 percent.[5]

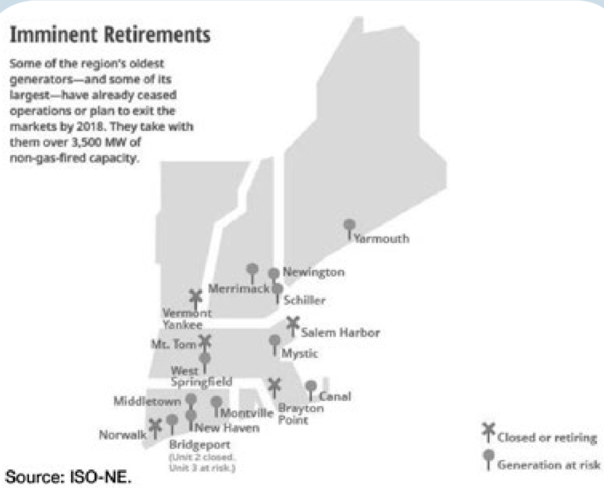
In the region's southern tier, consuming states, which depend heavily on natural gas-fired generation, the contribution from non-hydro renewable generation was even lower. In 2013, Massachusetts generated only 6 percent of its electricity from non-hydro renewable sources.[6]

VOLATILE ELECTRICITY PRICES

Amidst the proliferation of gas-fired generation, however, the region has seen no substantial expansion of the capacity of major interstate gas pipelines. These pipelines must serve local gas distribution companies, which deliver gas to homes and businesses for heating during the winter, before any of its capacity can be devoted to providing fuel for the production of electricity. New England has experienced large increases in the price of natural gas in the winter-time, which has caused spikes in the price of electricity. In the winter of 2013–14, electricity prices shot up, tracking the cost of natural gas closely. This cost ratepayers more than $6 billion, an increase over previous winters of almost 100 percent.

By themselves, hydropower imports will not solve the region's winter-time price volatility. That is likely to require expansion of both pipeline capacity and storage capacity for liquefied natural

Exhibit 2. Imminent Power Plant Retirements in New England



Source: ISO-NE.

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gas. But Canadian hydropower is sufficiently plentiful that it can be guaranteed to reach New England throughout the year, even on the coldest days of the winter. If so, such imports would add considerable electricity to the region's wintertime supply at a predictable and stable price, helping to moderate the volatility of electricity prices.

REDUCING CARBON EMISSIONS

One notable benefit of replacing coal and oil generation with cleaner-burning natural gas has been a dramatic reduction in the emission of pollutants by power plants. From 2001 through 2012, emissions of sulfur dioxide fell by 92 percent, nitrous oxides fell by 66 percent, and "greenhouse gas" (GHG) emissions fell by 21 percent.[7] This trend has been accelerated by the establishment of new programs to reduce carbon emissions from power plants and to foster the development of renewable energy.[8]

However, future reductions in GHG emissions will be much harder to come by and will cost more to achieve than those to date. All six New England states have set targets for reductions over the coming decades that are far more aggressive than those required under the EPA's plan. In Massachusetts, the Global Warming Solutions Act (GWSA) requires a 25 percent reduction in the state's economywide greenhouse gas emissions by 2020 and an 80 percent reduction by 2050. Interestingly, the plan for meeting the GWSA requirements calls for a dramatic reduction in fossil fuel electricity generation. As **Exhibit 4** demonstrates, hydropower imports are expected to provide the majority of the emission reductions needed to achieve the GWSA goals.

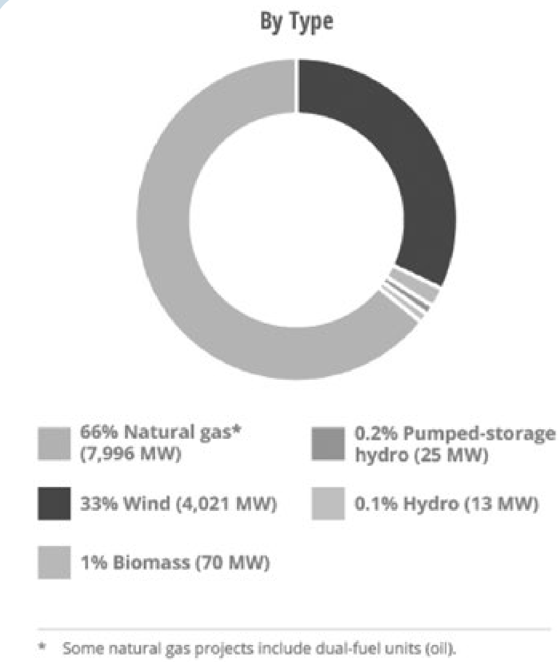
Current circumstances and foreseeable trends suggest that New England cannot avoid increased dependency on natural gas or meet its 2050 requirements for GHG reductions without a major infusion of clean and reliable electricity. This need could be fulfilled by Canadian hydropower.

CANADIAN HYDROPOWER POTENTIAL

Canada possesses large, untapped hydropower potential, despite already deriving 63 percent of its electricity from hydroelectric sources.[9] In recent years, New England has increased the amount of hydroelectric power it imports from Canada's eastern provinces threefold, from 5 terawatt-hours in 2004 to almost 17 terawatt-hours in 2013. These imports now represent approximately 8 percent of all electricity consumed by New England.

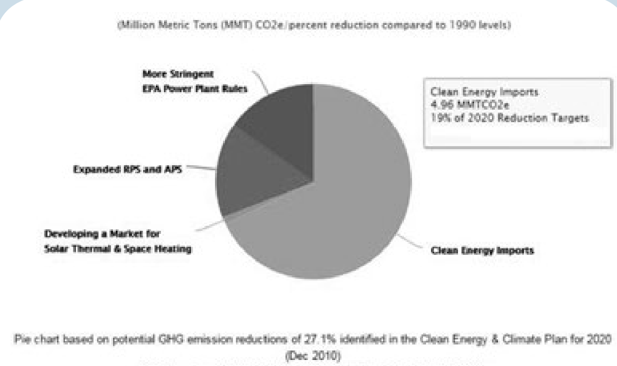
As **Exhibit 5** illustrates, the majority have come from generating assets owned and operated

Exhibit 3. ISO-NE Generator Interconnection Queue as of June 2015



Source: ISO-NE.

Exhibit 4. MA 2020 GHG Emission Reduction Targets for Electricity Generation



Source: MA Executive Office of Energy and Environmental Affairs.

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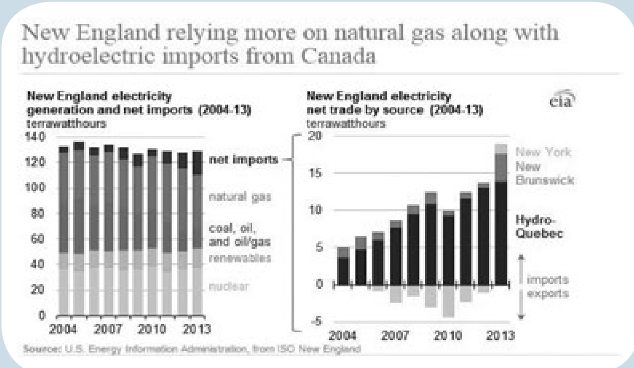
Exhibit 5. New England Electricity Generation by Source, 2004–13



by Hydro-Quebec (HQ). The company boasts a massive hydropower portfolio of around 38,000 megawatts. The Romaine project now under construction would add 1,550 megawatts of capacity by 2020.[10] As for its US presence, HQ has recently signed a contract with Vermont utilities to deliver power there at market prices for 20 years.[11] The Canadian Hydropower Association reports that HQ has an additional 5,500 megawatts of new generation planned or on the way, with an astounding 44,100 megawatts of capacity beyond that considered "technically achievable."[12]

But Quebec is not the only potential source hydropower for New England. The eastern Canadian provinces of New Brunswick and Newfoundland and Labrador each have the potential to develop and deliver large amounts of hydropower, far beyond what is needed to serve their indigenous demands. Additionally, current installed hydro capacity in New Brunswick is around 908 megawatts, and the province sees the potential to develop more. In 2012, a report commissioned by the government of New Brunswick concluded that the province has resources that could produce an additional 352 megawatts of power from almost 700 sites.

In Newfoundland and Labrador, Nalcor Energy can export significant electrical energy to New England. The company already owns and operates the hydro facility at the Churchill Falls dam, which has over 5,400 megawatts of capacity. (Most of that power is sold to HQ, and a large portion of it may already find its way to New England as exports by HQ.)

Further down the Churchill River, Nalcor will soon complete construction of the Muskrat Falls project. When complete, this 832-megawatt hydro facility will deliver most of its power within the province, but several hundred megawatts will be available for export. The company is ready to develop a third huge hydropower facility on the Churchill River at a location known as Gull Island with the potential to generate up to 2,250 megawatts.

TRANSMITTING WIND AND HYDRO

Existing transmission lines from Canada to New England are fully utilized. Delivery of new supplies of Canadian hydropower will require construction of hundreds of miles of new transmission lines.

The eastern Canadian provinces have enough potential excess hydropower to fill at least two 1,200-megawatt lines.[13] Such lines would be costly to build and operate. That cost would be made manageable by using wind generation to complement the hydro resource. Dispatching wind generation whenever the wind permits (typically up to 40 percent of the time) and dispatching hydropower whenever the wind dies down (typically up to 60 percent of the time) would allow for a transmission line that serves them both to operate at capacity over 90 percent of the time.

The prospect of increasing wind generation in combination with hydropower development boosts the already promising clean energy potential of Canadian hydropower.[14]

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LONG-TERM CONTRACTS FOR HYDROPOWER

Construction of new dams and hydropower-generating facilities is a capital-intensive undertaking.

A new dam and transmission lines will cost billions. But once built, they will produce many billions of megawatt-hours of electricity over many decades, and over time, these facilities will more than recover the cost of construction. The problem to resolve is who will shoulder the initial risk of financing their construction.

Electricity consumers in Canada cannot be expected to do so. These facilities will be built and operated primarily to export power to other regions. In all fairness, the financial risks associated with their construction should be borne by the beneficiaries in those regions. The risk is that, over the initial term of construction financing, the sale price of the power produced will not be sufficient to fully recover the cost of that financing. This is the financial risk that must be borne by the rate-paying consumers of the electricity in New England.

The only effective way to allocate that risk to those ratepayers is for their electric distribution utilities to contract with the developers of the hydro, wind, and transmission resources that will provide guaranteed purchase of the power over several decades. This revenue stream will allow the developers to obtain financing for these developments. Without the security provided by such contracts, hydropower, wind, and transmission assets cannot and will not be developed.

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The benefits from such contracts—stable prices, reliable and continuous delivery of power created with minimal GHG emissions—can only be obtained by having New England ratepayers shoulder that financial risk. Long-term purchased-power agreements with creditworthy counterparties in New England are absolutely necessary for developing new Canadian energy resources that will deliver clean, affordable electricity to New England.

STATE LEGISLATION NEEDED

To develop and secure such contracts, the states must enact legislation that directs their electric distribution utilities to enter long-term contracts for the delivery of clean energy. These contracts would enable those distribution utilities to purchase delivered energy, transmission service to get the power to the New England border, and renewable energy credits from the portion of the power generated by wind capacity over an extended term of 20, 30, or even more years. These contracts would be chosen through a competitive solicitation process open to any eligible "clean energy" resource, mainly hydropower and wind generation. The result would be a sizeable amount of new, clean electricity delivered into the region at a stable low cost.

The New England states have enacted several statutes that authorize public utility commissions to approve such contracts. Connecticut has authorized its Department of Energy and Environmental Planning to solicit and execute contracts for electricity from large-scale hydropower developments for up to 15–20 years in duration.[15] Rhode Island allows utility companies to file competitive proposals with the Public Utility Commission (PUC) for long-term renewable projects.[16] In Maine, the PUC may direct investor-owned transmission and distribution utilities to enter long-term agreements for renewable capacity.[17] New Hampshire authorizes the PUC to negotiate with Canadian suppliers of power.[18] Under its Green Communities Act, Massachusetts directs the Department of Public Utilities to adopt regulations regarding competitively solicited long-term contracts for renewable energy.[19] Finally, recently enacted Vermont legislation encourages retail electricity providers to secure long-term contracts for renewables and may create a competitive bid process to select a portion of those contracts.[20]

Additionally, the states of Massachusetts, Rhode Island, and Connecticut will soon issue a so-called Three-State Request for Proposals for the procurement of significant electricity generated by clean energy resources.[21] In Massachusetts, the legislature is considering legislation that would authorize Massachusetts' electric distribution utilities to contract to purchase up to one-third of the state's annual electricity consumption from Canadian hydropower and wind generation.

LONG-TERM THINKING

New England policymakers can no longer hope that merely allowing competitive

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electricity markets to work as they are structured will solve the region's growing cost and risky dependence on natural gas or achieve the dramatic reductions in GHG emissions needed by 2050. The investment incentives of a deregulated marketplace demand a return in a time frame too short to address those challenges. While remarkably efficient at allocating risk and reward in the short run, those incentives are not capable of providing the security needed to facilitate investments in infrastructure that pays off only eventually. Those incentives cannot account for the long-run costs of depending too heavily on one fuel, natural gas, to meet the region's electricity and environmental needs.

Canadian hydropower, coupled with new wind generation and highly efficient transmission, can meet those needs. But to secure the benefits provided by these long-lived assets, they will have to be purchased under long-term contracts that allocate a proper share of the risk they entail to the ratepayers who benefit from them. Only long-term contracts to purchase the combined output of hydro, wind, and transmission assets will enable developers to secure the financing to construct them.

New England's distribution utilities must enter those contracts on behalf of their customers. They will require legislative mandates and regulatory assurance of cost recovery before entering them. To enable such contracts, state legislation must assure their distribution utilities that properly structured and competitively procured contracts will allow them to recover the costs of the power they supply and the environmental benefits they deliver.

NOTES

1. ISO-NE. (2014, April 4). *The state of energy in the Commonwealth, Appendix I, 4/14/2015*. Retrieved from http://www.iso-ne.com/static-assets/documents/2015/04/final_used_ma_tue_iso_george_april14_2015.pdf.
2. Last year, the Vermont Yankee nuclear plant, a 604-megawatt facility, was shut down after 42 years of service. Recently, Entergy Corporation announced that it will close its 680-megawatt Pilgrim nuclear plant by June of 2019, citing low electricity prices, reduced revenues, and increased operating costs. See Abel, D. (2105, October 15). Pilgrim Nuclear Power Plant to close in Plymouth. *The Boston Globe*. Retrieved from *http://www.bostonglobe.com/metro/2015/10/13/entergy-close-pilgrim-nuclear-power-station-nuclear-power-plant-that-opened/fNeR4RT1BowMrFApb7DqQO/story.html*.
3. See ISO-NE. (2015). *Today's challenges*. Retrieved from http://www.iso-ne.com/about/what-we-do/todays-challenges.
4. See ISO-NE. (2015). *Resource mix*. Retrieved from http://www.iso-ne.com/about/what-we-do/key-stats/resource-mix.
5. See ISO-NE. (2015, January). *2015 Regional Energy Outlook*. Retrieved from *http://www.iso-ne.com/static-assets/documents/2015/02/2015_reo.pdf*.
6. See EIA. (2013). *Renewable energy in Massachusetts*. Retrieved from http://www.acore.org/files/pdfs/states/Massachusetts.pdf.
7. See ISO-NE. (2014, May 14). *Overview of carbon emission trends from New England generators*. Retrieved from http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/eag/mtrls/2014/may282014/iso_ne_regional_carbon_trends_neca_2014.pdf.
8. The New England states have joined with New York, Delaware and Maryland to form the Regional Greenhouse Gas Initiative (RGGI), a compact to that relies on state environmental permitting authority to reduce GHG emissions from the power-generation sector. The New England states have already achieved the 2020 emission reductions required of them under the Clean Power Plan and will meet the 2030 reductions well ahead of that schedule. See Silverman, G. B. (2015, August 14). Most RGGI states on track to meet power plan targets. *BNA Energy and Climate Report*. Retrieved from http://www.bna.com/rggi-states-track-n17179934724.
9. Canadian Electricity Association. (2015). *Canada's electricity supply*. Retrieved from http://powerforthefuture.ca/electricity-411/electricity-generation-choices/canadas-electricity-supply.
10. Sullivan, C. (2014, January 31). Canadian hydro gambles big on US export market—but at what cost? *Energywire*. Retrieved from http://www.eenews.net/stories/1059993773.
11. Remsen. N. (2011 April 18). Board approves power deal with Hydro Quebec. *Burlington Free Press*. Retrieved from http://archive.burlingtonfreepress.com/article/20110418/NEWS03/110418018/Board-approves-power-deal-Hydro-Quebec.
12. See Note 10.
13. Due to requirements imposed by the region's independent transmission system operator, ISO-NE, any new line entering the region will be limited to a capacity of 1,200 megawatts. This limit is imposed so that, if the line were to suddenly fail, the system operator could replace the lost power almost instantly from other sources.
14. A transmission line that runs from hydropower resources in Canada to the US border and connects to a transmission line inside New England will require approval by national regulatory agencies in both countries.
15. Connecticut Public Act 13-303, Sections 6 and 7.
16. The General Laws of Rhode Island, Chapter 31 of Title 39.
17. The Maine Revised Statues Annotated, Title 35-A, Section 3210-C.
18. The New Hampshire Revised Statutes Annotated, Title 34, Chapter 363, Section 18.
19. The Massachusetts Green Communities Act, Section 83A.
20. Vermont Statutes Annotated § 8005 (b)(3), Sec. 4. 30.
21. The RFP would allow large-scale hydropower to be used in combination with renewable resources up to a ceiling of 2.75 million megawatt-hours. The RFP is expected to be finalized this fall.