FINAL

HYDRO IMPORTS ANALYSIS

B&V PROJECT NO. 180696

PREPARED FOR

New England States Committee on Electricity

1 NOVEMBER 2013

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1.0 Executive Summary

The New England States Committee on Electricity (NESCOE) retained Black & Veatch Corporation (Black & Veatch) to analyze electricity market and emissions implications of adding 3,600 megawatts (MW) of hydroelectric (hydro) imports from eastern Canadian Provinces into the New England region.

The analysis initially examined existing and planned hydro capacity and transmission infrastructure in eastern Canada. Black & Veatch then analyzed assumed *incremental* imports enabled by three (3) new hypothetical 1,200 MW transmission lines from different points in Canada into different areas of the New England power grid together with two different supply level resource assumptions in Quebec, Newfoundland and Labrador. Using computer simulations of the eastern North American electricity market, the analysis estimated the impact that increased imports of hydro power may have on electricity consumer costs and electric sector emissions. Black & Veatch also developed cost of service-based transmission cost estimates for the hypothetical transmission configurations in each scenario. Given the uncertainty of the capital costs for such hypothetical transmission configurations and in the absence of a competitive solicitation and/or negotiations to confirm costs, the annual carrying costs for the transmission configurations are not reflected in the economic comparisons presented herein.

The average annual economic benefits associated with reduced electricity market prices ranged from $103 to $471 Million. The cumulative reduction in New England electricity customer costs resulting from the three hypothetical transmission configurations ranged from $3.325 Billion in the Base Case Supply to $5.652 Billion in the Alternative Hydro Supply Case. The difference between the Base Case Supply scenarios and the Alternative Hydro Supply Case scenarios was the assumed addition of 5,000 MW of hydro supply in eastern Canada, currently in the permitted and proposed stage - primarily the assumed introduction of the 824 MW Muskrat Falls and the 2,250 MW Gull Island hydro facilities in 2018 and 2022, respectively.

The hypothetical transmission configuration with the greatest incremental impact on electricity prices and emissions is a 1,200 MW HVDC cable from New Brunswick to Massachusetts plus a 1,200 MW HVDC cable from Quebec through New York to Connecticut. This infrastructure build-out is detailed below as Transmission Configuration #2. The average annual incremental price reduction benefit enabled by this transmission configuration is $125 Million in the Base Case Supply and $190 Million in the Alternative Hydro Supply Case.

The average annual emission reductions associated with incremental hydro imports ranged from 1.3 to 8.0 million tons per year. The cumulative electric sector carbon emissions reduction in the Base Case Supply scenarios resulting from the imports enabled by the three hypothetical transmission configurations is approximately 57.7 million tons. For the Alternative Hydro Supply Case scenarios, the cumulative electric sector carbon emissions reduction resulting from the imports enabled by the three hypothetical transmission configurations is approximately 96.9 million tons.

Separately, NESCOE also requested Black & Veatch to provide a summary of the various means to develop incremental transmission to enable increased hydroelectric imports and to provide its professional judgment about the preferred means to facilitate such transmission development, should the New England states elect to do so. In sum, Black & Veatch prefers a cost-based participant funded commercial approach to transmission development designed to increase hydro imports.

2.0 Introduction

NESCOE retained Black & Veatch to analyze the market and address specific questions related to hydro power and the New England region.

NESCOE presented the following questions to Black & Veatch in this study:

- Are 3,000 to 5,000 MW of incremental hydroelectric capacity reasonably available to export from Canada to New England over the next 20 years?
- What incremental transmission investment is required to transport such power to the New England market?
- What are the electricity market and emissions-related impacts on New England from this incremental capacity?

This report outlines Black & Veatch's approach to performing the analyses necessary to address the questions stated above and the methodology used, and presents the findings of the analyses.

Black & Veatch analyzed the electricity market and emissions implications of adding 3,600 MW of hydroelectric imports from eastern Canadian Provinces into the New England region. The analysis assumed *incremental* imports enabled by three (3) new 1,200 MW transmission lines from different points in Canada into different areas of the New England power grid. Working with the New England states, Black & Veatch identified the following three hypothetical new transmission lines for purposes of this analysis: 1) a 1,200 MW transmission line from New Brunswick to Massachusetts, 2) a 1,200 MW transmission line from Quebec through New York to Connecticut, and 3) a 1,200 MW transmission line from Quebec to Vermont. These illustrative transmission configurations are for study purposes and do not indicate preferred or recommended geographic locations for potential projects. Black & Veatch analyzed imports enabled by these incremental transmission lines together with two different hydro supply level resource assumptions in Quebec, Newfoundland and Labrador: 1) a base Canadian supply case and 2) a Canadian supply case that assumes 5,000 MW of additional hydro supply.

Further, Black & Veatch developed cost of service-based transmission cost estimates for the transmission configurations in each scenario. The costs in the study are, however, illustrative and based on assumptions. The actual costs of incremental hydroelectric imports cannot be identified with certainty absent a competitive process to identify a fixed bid price, a negotiated price, or an actual project advancing to operation. Moreover, the actual cost of hydroelectric imports may be influenced by New England's electricity market prices. Those prices may be influenced by a number of factors not assessed in this study, such as, for example, natural gas supply and prices.

In addition, NESCOE requested Black & Veatch to provide a summary of the various means to develop incremental transmission to enable increased hydroelectric imports and to provide its professional judgment about the preferred means to facilitate such transmission development, should the New England states elect to do so. That summary and recommendation is presented in Section 6.0.

2.1 STUDY APPROACH AND METHODOLOGY

To address the questions above, Black & Veatch coordinated the following individual tasks, each of which are described in more detail below.

- Black & Veatch performed research to gather information on existing and planned hydro capacity in eastern Canada (consisting of Ontario, Quebec, the Maritimes, and Newfoundland and Labrador) capable of reaching the New England market over the 2014 through 2029 period (the Study Period).
- Black & Veatch researched existing and planned transmission infrastructure located in Canada that would be required to transport incremental hydro power to the New England market.
- Black & Veatch took into account existing and planned hydro capacity in eastern Canada and projected the eastern Canadian provinces' own demand for the hydropower. With that information, Black & Veatch analyzed the Canadian native load and resource balance for each year of the Study Period. This process enables a view on the approximate amount of power available for export to the United States, which may be viewed as indicative of the amount of hydro power available for export given the proportion of hydro power as compared to other types of power generation in eastern Canada (as illustrated in Figures 3-2 and 3-3 of this report).
- Black & Veatch simulated the market using PROMOD™ (a computer-based production cost model licensed for use by Black & Veatch from Ventyx, an ABB company) under a number of incremental import scenarios identified by NESCOE. Using PROMOD™, Black & Veatch performed a number of simulations to assess various supply and transmission alternatives. This allowed Black & Veatch to analyze the impact on New England market power prices and electric sector carbon dioxide emissions associated with various assumed levels of incremental hydro capacity imports into New England enabled by hypothetical transmission and supply investments. The difference in the costs to serve New England's electricity customers between scenarios serves as a proxy for the economic benefits associated with incremental imported hydro power. Similarly, the difference in electric sector carbon dioxide emissions between scenarios serves as a proxy for emission reduction benefits associated with incremental imports.
- Separately, Black & Veatch identified and evaluated a range of commercial and pricing options for development of new transmission alternatives. As part of the evaluation of transmission development alternatives, Black & Veatch addressed policy objectives that New England policymakers may take into consideration.

2.2 STUDY LIMITATIONS

This high-level analysis of incremental imported hydro is intended to provide policymakers with directionally indicative analysis. It is not a plan and should not be interpreted as such. The scope was limited to the electric sector and relies upon simplistic representations of the electric transmission system. The results are therefore directionally indicative, not predictive, exhaustive or precise.

The analysis is based on hypothetical assumptions, any one or more of which history may prove wrong in the near term or at any time during the Study Period. Indeed, the Base Case Supply, which is based on NESCOE's *Gas-Electric Study*, did not assume the late August 2013 announced shutdown of the Vermont Yankee nuclear reactor by the end of 2014. Assumptions in this analysis are based on NESCOE's judgment at one point in time and Black & Veatch's industry knowledge and project experience.

The costs in the study are illustrative and based on assumptions. The actual costs of incremental hydroelectric imports cannot be identified with certainty absent a competitive process to identify a fixed bid price or an actual project advancing to operation. Moreover, the actual cost of hydroelectric imports may be influenced by New England's market prices, which may be influenced by a number of factors not assessed in this study, such as, for example, natural gas supply and prices.

Further, the model used to produce this analysis optimizes the economic efficiency of electric capacity utilization. It does not examine the need for ancillary services or maintaining electric reliability. Capacity market concepts and financing new electric generation are beyond the scope of the analysis.

The carbon dioxide emissions estimated by the model only include hypothetical smoke stack emissions from electric power generators. The life-cycle emissions issues associated with natural resource extraction, fuel transportation and delivery, decaying organic matter, and aquatic and terrestrial sequestration are beyond the scope of this analysis.

Finally, as discussed in the *Gas-Electric Study*, it is reasonable to expect that with the full amount of incremental hydro assumed in this study imported into the New England system, the demand for natural gas would decline, and potentially put downward pressure on gas prices. This in turn would drive the production costs savings higher and show added benefit from incremental hydro imports into the region.

3.0 Existing and Planned Hydro Capacity in Canada

3.1 HYDRO RESOURCES

The analysis of existing and planned hydro capacity in Canada focused on eastern Canada and specifically on power that could be imported to the New England market. Black & Veatch's hydro power capacity findings in terms of ownership, location, and winter capacity ratings are summarized in Table 3-1, below. [1] Black & Veatch also reviewed the proportion of hydroelectric power resources in eastern Canada. Given the economics of the various supply resources and the magnitude of hydro capacity, Black & Veatch estimates that hydro power accounts for in excess of 90 percent of the energy generated in eastern Canada.

Black & Veatch examined hydro resource capacity in each province during each year between 2013 and 2029, inclusive.[2] Figure 3-1, below, illustrates the hydro capacity, by province, that is summarized in Table 3-1. In 2014, for example, the eastern Canadian provinces' total existing and planned capacity is 53,756 MW. (This consists of 965 MW in New Brunswick, 5,429 MW in Newfoundland and Labrador, 421 MW in Nova Scotia, 9,023 MW in Ontario, and 38,602 MW in Quebec.) Looking out to the year 2024, for example, the total available existing and planned capacity increases to 59,634 MW. As seen in Table 3-1, in some years, eastern Canadian hydro capacity increases compared to the previous year. Such increases indicate a new hydro power resource is projected to begin commercial operation. Black & Veatch did not find information that allows it to classify all of the existing and planned capacity in terms of the type of hydro resource (i.e. run of river, reservoir, or pumped storage).

Black & Veatch offers the following general observations about Canadian hydro power:

- In general, most run of river hydro capacity is located in western Canada. Most reservoir hydro capacity is located in eastern Canada.
- Run of river hydro power facilities tend to be relatively smaller in size than reservoir hydro power facilities.
- Approximately 28 percent (by capacity) of hydro power in Quebec is run of river. Approximately 72 percent (by capacity) of hydro power in Quebec is reservoir.
- The majority of the new hydro projects reflected in Table 3-1 is reservoir capacity.

[1] A more detailed presentation of this information is included as Appendix A to this report.

[2] The analysis focuses on available capacity, rather than energy, to provide high-level information regarding the availability of imported hydro power during the entire year.

Table 3-1 Summary of Hydro Resources (MW)

PROVINCE	2013 - 2014	2015	2016	2017	2018	2019 – 2020	2021 – 2022	2023	2024 - 2026	2027 - 2029
New Brunswick	965	965	965	965	965	965	965	965	965	965
Newfoundland & Labrador	5,429	5,429	5,429	5,429	5,429	6,253	6,253	8,503	8,503	8,503
Nova Scotia	421	421	421	421	421	421	421	421	421	421
Ontario	8,979	9,023	9,023	9,039	9,039	9,039	9,039	9,039	9,039	9,039
Quebec	37,962	38,602	38,669	38,939	39,334	39,466	40,106	40,106	40,706	41,306
Total	**53,756**	**54,440**	**54,507**	**54,793**	**55,188**	**56,144**	**56,784**	**59,034**	**59,634**	**60,234**

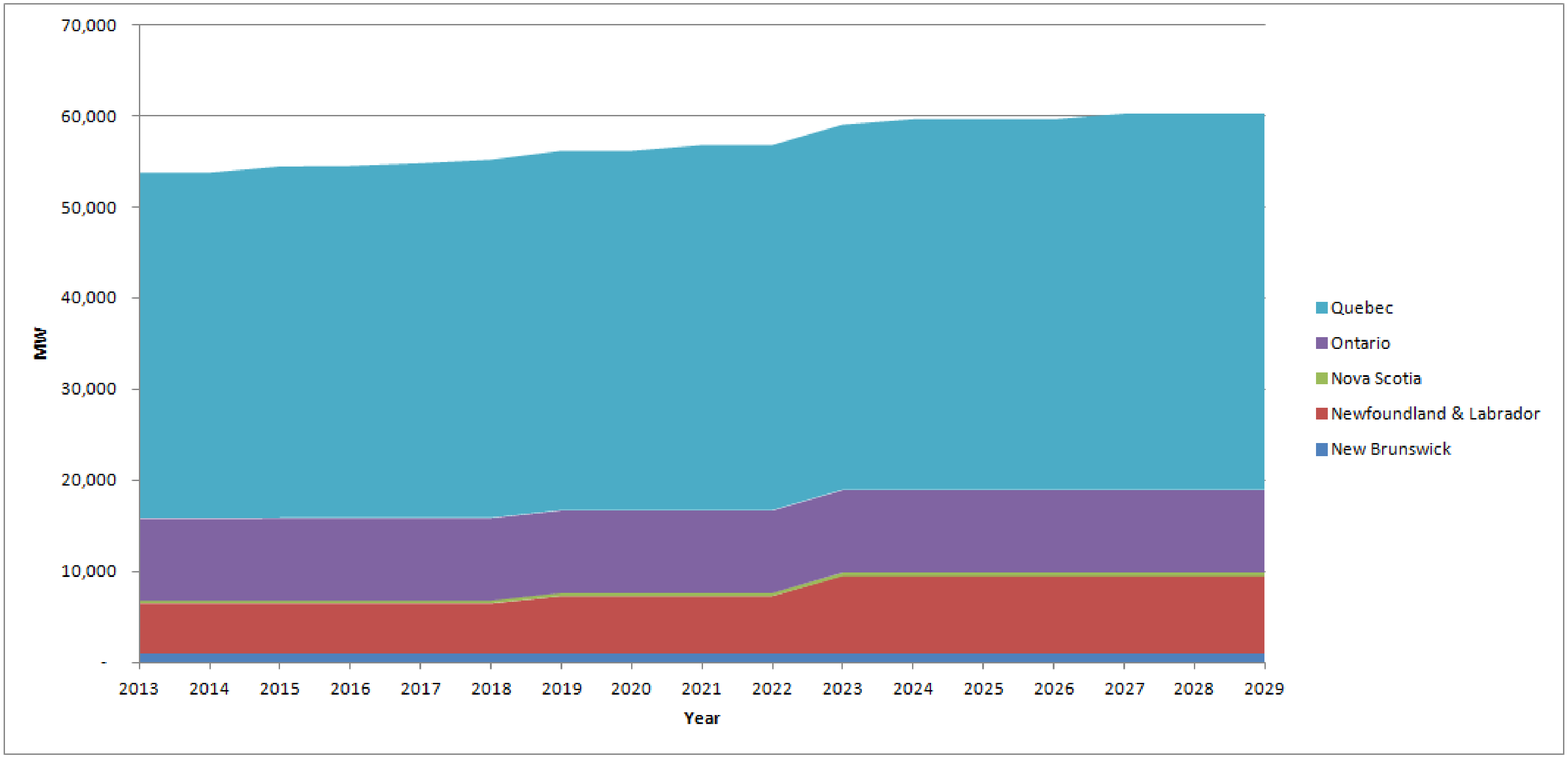

Figure 3-1 Hydro Capacity, by Province, 2013 through 2029

Black & Veatch investigated the estimated capital costs for the larger new hydro projects reflected in Table 3-1. This includes Hydro Quebec's La Romaine 1, 2, and 3 and 4; Muskrat Falls; Gull Island; and Petit Mecatina projects. The basis for the capital cost estimates for different projects may not be consistent (i.e. different basis years, consideration of interest during construction, treatment of all project costs). Therefore, the estimated capital costs are indicative. Such estimates are inherently imprecise and actual costs may differ.[3] The following are conclusions related to estimated capital costs for the projects for which Black & Veatch found information:[4]

- The estimated capital cost for La Romaine is approximately $4,200 per kilowatt (kW)[5].
- The estimated capital cost for Muskrat Falls is approximately $4,975 per kW.[6]
- Black & Veatch did not find recent capital cost estimates for Gull Island; however, based on earlier capital cost estimates, Black & Veatch estimates the cost per kW for Gull Island to be approximately 71 percent of the capital cost of Muskrat Falls.[7] Applying that ratio to the current capital cost estimate for Muskrat Falls shown above yields an estimated capital cost for Gull Island of approximately $3,530 per kW.
- Estimated capital costs for the Petit Mecatina projects were not available for review.

3.2 TRANSMISSION

To provide a relative sense of transmission costs, Black & Veatch identified the transmission projects for which cost information was available and that could transport hydro power from eastern Canada to the vicinity of, or into, the United States. These are summarized in Table 3-2, below. These transmission projects include two projects designed to transport power within eastern Canada and one transmission project that allows for transport of power to the United States through a project that terminates in New York. The transmission projects and their costs are as follows:

1) the (Labrador to Newfoundland) Labrador-Island Transmission Link, a 683 mile transmission line with a 900 MW capacity rating. Projected Cost: $2,824,000,000.
2) the (Newfoundland to Nova Scotia) Maritime Link, a 251 mile transmission line with a 500 MW capacity rating . Projected cost: $1,580,000,000.

[3] Further, as previously mentioned, the capital cost estimates associated with these new hydro capacity resources may not accurately reflect the actual costs of incremental imported hydro supply into New England, which are influenced by electricity market prices and underlying economic fundamentals.

[4] For comparison, see U.S. Energy Information Administration, *Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants* (April 2013), Table 1, available at: http://www.eia.gov/forecasts/capitalcost/pdf/updated_capcost.pdf and *Levelized Cost of New Generation Resources in the Annual Energy Outlook 2013* (January 2013), Table 1, available at: http://www.eia.gov/forecasts/aeo/electricity_generation.cfm.

[5] http://www.aecom.com/Where+We+Are/Americas/Energy/_projectsList/Le+complexe+hydroélectrique+de+La+Romaine+–+un+projet+d'énergie+renouvelable. Calculated as $6.5 Billion divided by 1,550 MW.

[6] http://www.powerinourhands.ca/qa1.asp. Calculated as $6.2 Billion, less $2.1 Billion of Labrador-Island Transmission Link (see http://www.gov.nl.ca/lowerchurchillproject/backgrounder_7.htm), divided by 824 MW.

[7] Ratio of Gull Island to Muskrat Falls per earlier estimates (http://bondpapers.blogspot.com/2010/10/williams-announces-political-exit-plan.html). Apply ratio to Muskrat Falls cost estimate above.

3) the (Quebec to New York) Champlain Hudson Power Express project, a 330 mile transmission line with a 1,000 MW capacity rating. Projected cost: $2,200,000,000.

The information on project costs in Table 3-2 is indicative and not actual. These costs provide information about the scale of investment necessary to bring incremental imported hydro power to the New England region. Transmission cost estimates associated with the hypothetical transmission configurations assumed to enable the imports in the Black & Veatch analysis are presented later in this report.

Table 3-2 Summary of Transmission Projects

PROJECT DESCRIPTION	ESTIMATED PROJECT COST ($MILLION)	ESTIMATED PROJECT LENGTH (MILES)	ESTIMATED COST PER MILE ($MILLION/ MILE)	LOCATION	OWNER	TYPE	VOLTAGE RATING	CAPACITY RATING	IN-SERVICE DATE	NOTES/ COMMENTS
Transmission Projects – Termination in eastern Canada										
Labrador-Island Transmission Link	2,100 (See Note 1)	683.6	4.13	From new plant (Muskrat Falls) to St. John's, NL	Nalcor and Emera	HVDC	350 kV	900 MW	2018	Includes underwater segment of about 700 km (435 miles)
Maritime Transmission Link	1,580 (See Note 2)	251	6.29	From Granite Canal, NL to Cape Breton, NS	Emera	HVDC	250 kV	500 MW	2018	Includes underwater segment of about 30 km (19 miles)
Transmission Projects – Termination in United States										
Champlain Hudson Power Express	2,200 (See Note 3)	330	6.67	Between the Canada–United States border and New York City	CHPE	HVDC	320 kV	1,000 MW	2018	Entire line is underground or underwater

(1). http://www.gov.nl.ca/lowerchurchillproject/backgrounder_7.htm

(2). http://www.businesswire.com/news/home/20130128006240/en/NSP-Maritime-Link-Requests-UARB-Approval-Maritime. Includes $60 Million for variance as stated in source.

(3). http://www.chpexpress.com/economics.php

Black & Veatch's analysis of existing and planned hydro capacity in eastern Canada also included a review of general relevant announcements and industry news. The summary-level conclusions of this review are not specific to any one project or eastern Canada, but rather are representative of the hydro power industry in Canada.

- The Canadian Hydropower Association indicates that there is approximately 62,000 MW of technical potential for new hydro power in eastern Canada. This technical potential does not take into account economics or other factors that allow for a direct correlation to the magnitude of incremental hydro capacity that may ultimately be developed or the ability to transport the power to the Northeast U.S. Nevertheless, it is a data point in assessing future hydro potential in eastern Canada.
- New hydro capacity projects in Canada are projected to be approximately equally split between eastern and western Canada. About one third of the projects are upgrades or restorations expected to be located mainly in eastern Canada.
- Of the new hydro projects in Canada that may materialize over the next 20 years, more than 80 percent of new construction is projected to be run-of-river and mostly located in western Canada. Most reservoir hydro projects are anticipated to be located in eastern Canada.
- Costs for construction of new hydro capacity are expected to be highest in the central region of Canada (where there is relatively little new hydro construction), and lowest in the western region. Cost estimates in eastern Canada are towards the low side of the cost range across Canada. This general trend in estimated capital costs is not consistent with the estimated capital costs for the specific new hydro projects discussed previously, which underscores the illustrative nature of cost estimates and the inherent uncertainty in quantifying estimated capital costs for new project development.
- Imported hydro power from Canada represents less than 1 percent of US electricity consumption, and opportunities to increase penetration in the US are being actively sought out.

3.3 DISCUSSION OF RESOURCES AND LOAD BALANCE

To analyze the export capability of eastern Canadian hydro into New England, it is important to characterize the amount of potential hydro resources within the eastern Canadian province region. Black & Veatch developed two different supply outlooks for this analysis, which consist of the following generation resource portfolios:

- **Base Case Supply** – Consists of all existing hydro, all hydro under construction, in testing, and in site preparation in eastern Canada.
- **Alternative Hydro Supply Case** – Consists of the Base Case Supply, plus any supply that is permitted and proposed, but does not otherwise conform to the definition of the Base Case Supply. The Alternative Hydro Supply Case assumes 5,000 MW more hydro than exists in the Base Case Supply.

Most of the planned hydro coming into eastern Canada is in Quebec, Newfoundland, and Labrador (collectively referred to below as QNL). Accordingly, the supply and demand balance analysis, below, reflects information for QNL only.[8] The supply and demand balance for Maritimes and Ontario are provided separately in Appendix A to this report.

The balance of supply and demand considers supply expected to be available to meet projected demand. It is evaluated on a capacity, or MW, basis. The energy requirements, expressed as megawatt-hours (MWh), are typically satisfied in the most economical manner possible based on the relative costs of generation for each supply resource. As noted above, given the magnitude of hydro capacity as illustrated in Figure 3-2 and Figure 3-3, the majority of energy is likely to be generated by hydro resources.

Black & Veatch presents the balance of Canadian resource supply and demand for the Base Case Supply in Figure 3-2. Black & Veatch uses a 15 percent reserve margin as a target for maintaining resource adequacy in the QNL control area. The balance of resource supply and demand provides a comparison of the amount of supply (MW) expected to be available to meet the projected demand (MW), plus the 15 percent reserve margin. If the peak demand plus reserve margin (MW) cannot be met, additional supply (MW) must be added.

Under Base Case Supply assumptions, the balance of supply and demand indicates that the QNL cannot maintain a 15 percent reserve margin beginning in 2021. Therefore, for purposes of the analysis, Black & Veatch adds new capacity in the QNL electric systems in 2022 through 2029 to maintain reserve margin requirements. This new additional capacity is assumed to be combustion turbines. This is because QNL has plenty of energy resources and only needs peaking capacity to maintain reserve margins. In sum, under the Base Case Supply, QNL is not assumed to need new resources to meet their own demand until 2021, and at that time, need only peaking units.

[8] For reference, the PROMOD™ analysis examines the entire Eastern Interconnection.

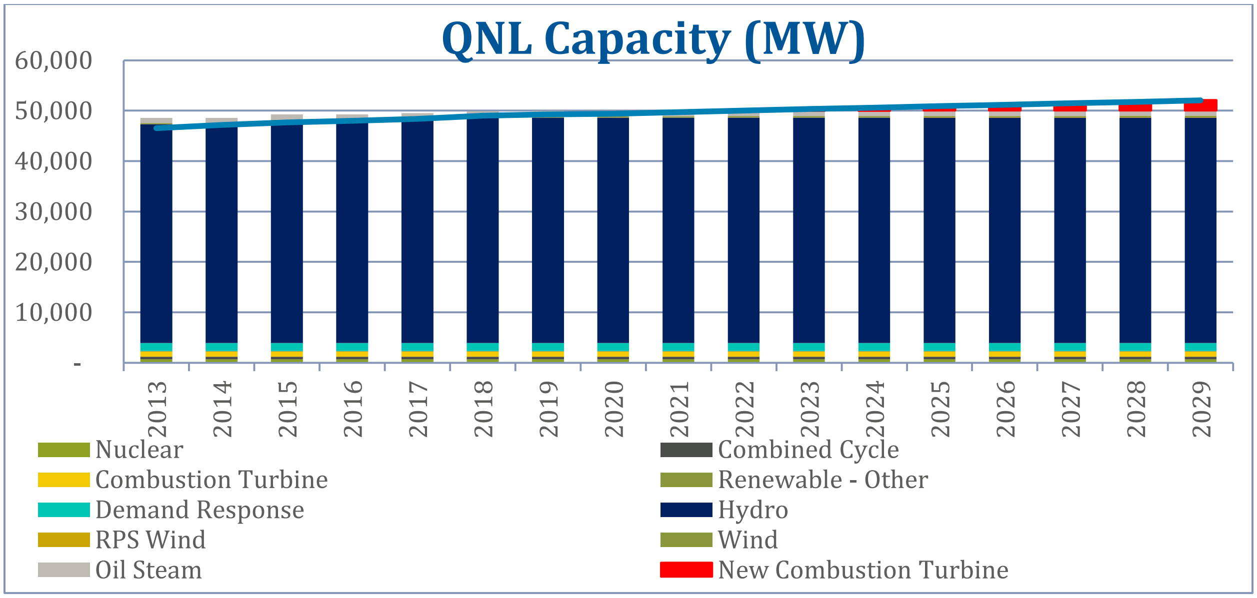

Figure 3-2 Base Case Supply – Balance of Loads and Resources

Black & Veatch also developed an Alternative Hydro Supply Case. It is illustrated in Figure 3-3. This Alternative Hydro Supply Case shows more than a 5,000 MW increase in hydro capacity in QNL throughout the Study Period as compared to the Base Case Supply. Given this increase in hydro capacity, Black & Veatch did not need to assume added capacity for purposes of this analysis in order to maintain QNL's 15 percent reserve margin. The increased hydro capacity in the Alternative Hydro Supply Case is primarily driven by the introduction of the 824 MW Muskrat Falls facility in 2018 and the 2,250 MW Gull Island hydro facility in 2022.

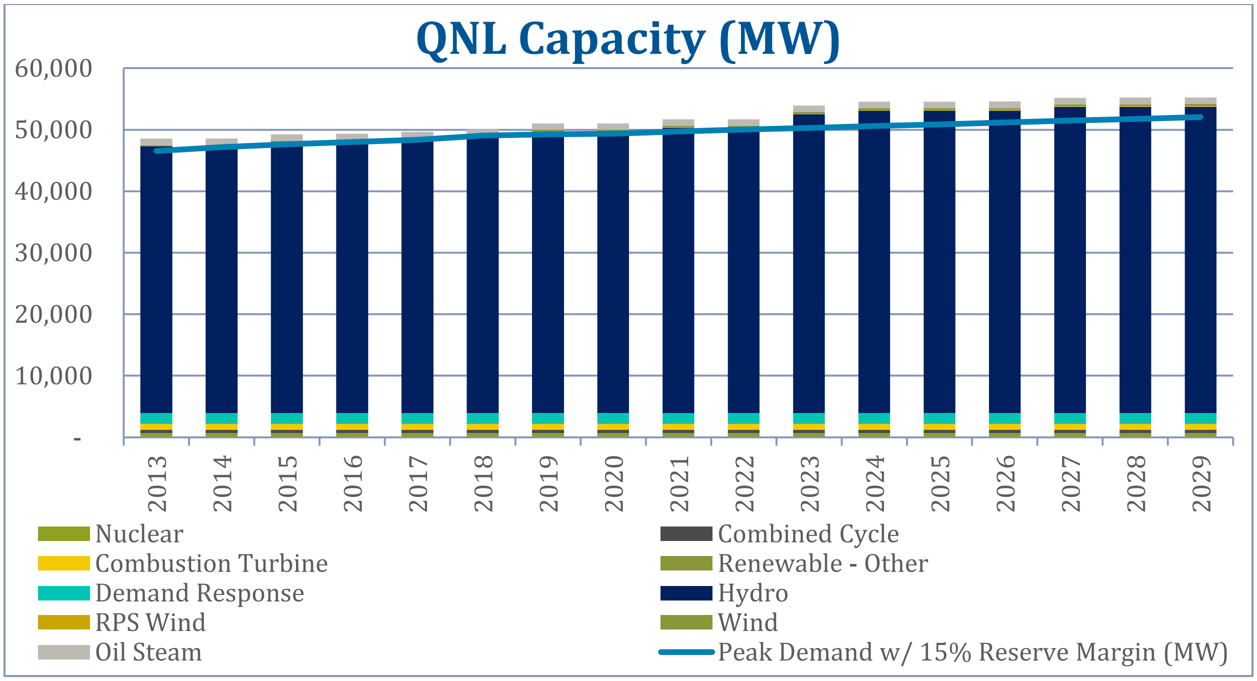

Figure 3-3 Alternative Hydro Supply Case – Balance of Loads and Resources

As illustrated in Figures 3-2 and 3-2, QNL is heavily weighted toward hydro resources. QNL has no coal generation. Additions of new low-cost capacity, such as wind, would not affect the ability of QNL to export hydro power to New England given the large quantity of hydro power available and its low operating cost.

4.0 Price and Emission Reduction Estimates

Black & Veatch simulated the effects on the New England electricity market likely to result from increased availability of hydro resources from eastern Canada. Assuming incremental levels of imported Canadian power capability into New England, Black & Veatch estimated the reduction in electricity prices New England consumers may experience and electric sector carbon dioxide emission reduction. This section provides an overview of the simulation modeling approach and input assumptions. It then presents the price and emission reduction results. In sum, the analysis indicates that increased imports of hydro power would likely result in decreased electricity prices and electric sector emissions reductions.

4.1 MODELING OVERVIEW

Using the NESCOE *Gas-Electric Study* Base Case as a starting point,[9] discussed further below, and the commercially available PROMOD™ market simulation model, Black & Veatch developed and simulated eight supply and transmission scenarios. These eight scenarios reflect various combinations of generation (i.e. "supply") and transmission alternatives. The eight scenarios are outlined in Table 4-1.

The two supply cases, described above, are as follows:

- **Base Case Supply** – Consists of all existing hydro, all hydro under construction, in testing, and in site preparation generation in eastern Canada.
- **Alternative Hydro Supply Case** – Consists of the Base Case Supply, plus any supply that is permitted and proposed, but does not otherwise conform to the generation categories listed in the Base Case Supply.

The three incremental 1,200 MW transmission configurations are as follows:

- **Transmission Configuration #1 -** 1,200 MW HVDC cable from New Brunswick to Massachusetts (NB to MA). Total Incremental Transmission: 1,200 MW
- **Transmission Configuration #2** – Transmission Configuration #1 (NB to MA) *plus* a 1,200 MW HVDC cable from Quebec through New York to Connecticut (Q via NY to CT) Total Incremental Transmission: 2,400 MW
- **Transmission Configuration #3** – Transmission Configuration #2 (NB to MA *and* Q via NY to CT) *plus* a 1,200 MW HVDC cable from Quebec to Vermont. Total Incremental Transmission: 3,600 MW

To evaluate the resource adequacy benefits associated with investments in incremental transmission infrastructure, the imported power is assumed to be "deliverable." This assumption is consistent with fully utilizing the incremental transmission infrastructure toward the reserve margin during all hours of the Study Period.

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[9] The Quebec to New York City component of the Champlain Hudson Power Express, the Labrador-Island Transmission Link, and the Maritime Transmission Link were added to *Gas-Electric Study* Base Case Scenario.

Table 4-1 Supply and Transmission Scenarios

SCENARIO	SUPPLY OPTION	TRANSMISSION CONFIGURATION
1	Base Case Supply	Base Case Transmission
2	Base Case Supply	Transmission Configuration #1 (1,200 MW - NB to MA.)
3	Base Case Supply	Transmission Configuration #2 (2400 MW - NB to MA + Q via NY to CT)
4	Base Case Supply	Transmission Configuration #3 (3600 MW - NB to MA + Q via NY to CT + Q to VT)
5	Alternative Hydro Supply	Base Case Transmission
6	Alternative Hydro Supply	Transmission Configuration #1 (1200 MW - NB to MA)
7	Alternative Hydro Supply	Transmission Configuration #2 (2400 MW - NB to MA + Q via NY to CT)
8	Alternative Hydro Supply	Transmission Configuration #3 (3600 MW - NB to MA + Q via NY to CT + Q to VT)

The transmission projects listed in Table 3-2 are included in all eight of the scenarios listed above in Table 4-1. The Maritime Transmission Link allows an additional 500 MW of supply to come into New Brunswick. That additional supply would then be able to utilize the hypothetical New Brunswick to Massachusetts transmission line.

4.1.1 Gas-Electric Study Input Assumptions

In the fall of 2012, NESCOE commenced a three-phase study of the New England natural gas and electricity market interactions conducted by Black & Veatch (*Gas-Electric Study*). Phase II of the *Gas-Electric Study* included, among other things, the development of a Base Case scenario and associated input assumptions. Black & Veatch developed assumptions in consultation with NESCOE and the New England states. The assumptions include: electricity and natural gas demand forecasts; assumptions for electric generator retirement and reasonably certain new entry, environmental and carbon emission regulations, and electric transmission and natural gas infrastructure; and other economic parameters. To take advantage of the *Gas-Electric Study's* assumption and input development process, to leverage existing modeling set-up, and to expedite this analysis, the *Gas-Electric Study's* Base Case input assumptions were used as a starting point.[10]

[10] For more information on the Gas-Electric Study, see: http://www.nescoe.com/Gas_Supply_Study.html.

4.2 GENERAL OBSERVATIONS

This study assesses the economic and electric sector emissions[11] impacts on the New England electricity market likely to result from the import of additional hydro power from eastern Canada. To fully assess the economic impact of any electricity customer cost savings, it is important to understand the change in dispatch and operations, and any transmission and generation that affected the operations. Black & Veatch identifies trends that exist across all eight scenarios. These trends are as follows:

- Black & Veatch assumed that the transmission for all projects would enter operation in 2018. As a result, all of the values for 2013 through 2017 are the same for each of the supply scenarios.
- For this analysis Black & Veatch has assumed the RGGI program stays in place through 2019, and then converts to a Federal program in 2020. The costs to serve electricity customers include a larger increase in 2020, as carbon prices move from $8.54 per ton in 2019 to $13 per ton in 2020 (in constant 2013 dollars), an increase of about 52 percent.
- In 2020, the existing coal generation (approximately 2,300 MW) increases and therefore produces more CO_2 emissions. Nationwide, the increase in the carbon tax produces more gas demand (less coal generation) and drives the price of natural gas higher in 2020. In this study, in 2020, the gas prices rise by $0.72 per MMBtu, while the price of coal actually declines slightly. While this may seem counter-intuitive, the average coal and gas heat rates combined with the increase in gas prices and carbon prices actually make coal move lower in the dispatch stack in 2020 versus the years prior to 2020.
- Leading up to the 2023-2024 timeframe, several fossil fuel-fired steam units are expected to retire, and this generation is replaced by hydro, primarily from QNL.
- After 2020, CO_2 emissions continue to decline throughout the Study Period as existing coal- and oil-fired generation is retired and more hydro displaces coal and natural gas.

4.3 PRICE REDUCTION ESTIMATES

Black & Veatch presents below the marginal costs to serve New England electricity customers for each of the eight scenarios. As discussed in the Study Approach and Methodology section above, the difference between the costs of each scenario serve as a proxy for economic benefits, in the form of customer savings, associated with incremental hydro power imports.

Wholesale power costs in New England are set by the marginal unit(s). This means that the cost at any location within the system is the cost to serve the next MW of load at that particular location. It is appropriately named the locational marginal price (LMP). For this economic analysis, Black & Veatch used the product of the LMP ($/MWh) and the demand (MW) for each of the areas for each hour to arrive at a cost ($) to serve customer load. For each scenario, Black &

[11] The life cycle emissions issues associated with hydroelectric power generation are beyond the scope of this study.

Veatch focused on electricity customer costs across the years 2018 through 2029, since 2018 is when new transmission entered the system. As previously described, Black & Veatch calculated electricity customer cost savings by comparing the Base Case Supply and the Alternative Hydro Supply Case (no new transmission) to scenarios with new transmission (Scenarios 2 through 4 and 6 through 8).

Tables 4-2 and 4-3 (presented below) illustrate the price reduction estimates for the Base Case Supply, and Tables 4-4 and 4-5 (presented later in this section) illustrate the price reduction estimates for the Alternative Hydro Supply Case.

4.3.1 Base Case Supply – Price Results

Table 4-2 Cumulative Price Reduction Benefits – Base Case Supply Scenarios (Millions, 2013$)

SCENARIO	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	TOTAL	AVERAGE
Scenario 2 (1,200 MW: NB to MA Transmission)	74	102	130	109	126	126	151	101	139	13	81	79	1,231	103
Scenario 3 (2,400 MW: NB to MA + Q via NY to CT Transmission)	165	195	254	239	249	284	276	200	264	158	235	207	2,725	227
Scenario 4 (3,600 MW:NB to MA + Q via NY to CT + Q to VT Transmission)	204	231	302	295	303	320	320	264	306	217	283	281	3,325	277

Table 4-3 Incremental Price Reduction Benefits – Base Case Supply Scenarios (Millions, 2013$)

SCENARIO	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	TOTAL	AVERAGE
Scenario 2 (1,200 MW: NB to MA Transmission)	74	102	130	109	126	126	151	101	139	13	81	79	1,231	103
Scenario 3 (2,400 MW: NB to MA + Q via NY to CT Transmission)	91	93	124	129	123	158	125	99	126	145	154	128	1,494	125
Scenario 4 (3,600 MW:NB to MA + Q via NY to CT + Q to VT Transmission)	39	36	48	56	54	36	44	64	42	59	48	74	600	50

As shown in Figure 4-1, the long-term trend of increasing costs to serve New England electricity customers is due to demand growth and fuel price forecasts. Beginning in 2018, the incremental imported hydro begins to affect electricity market prices, leading to customer savings over the Study Period. The amount of incremental imported hydro power in each scenario has a corresponding effect on market prices. See Scenario 4, which assumes 3,600 MWs of incremental hydro imports and has the largest cumulative customer savings effect.

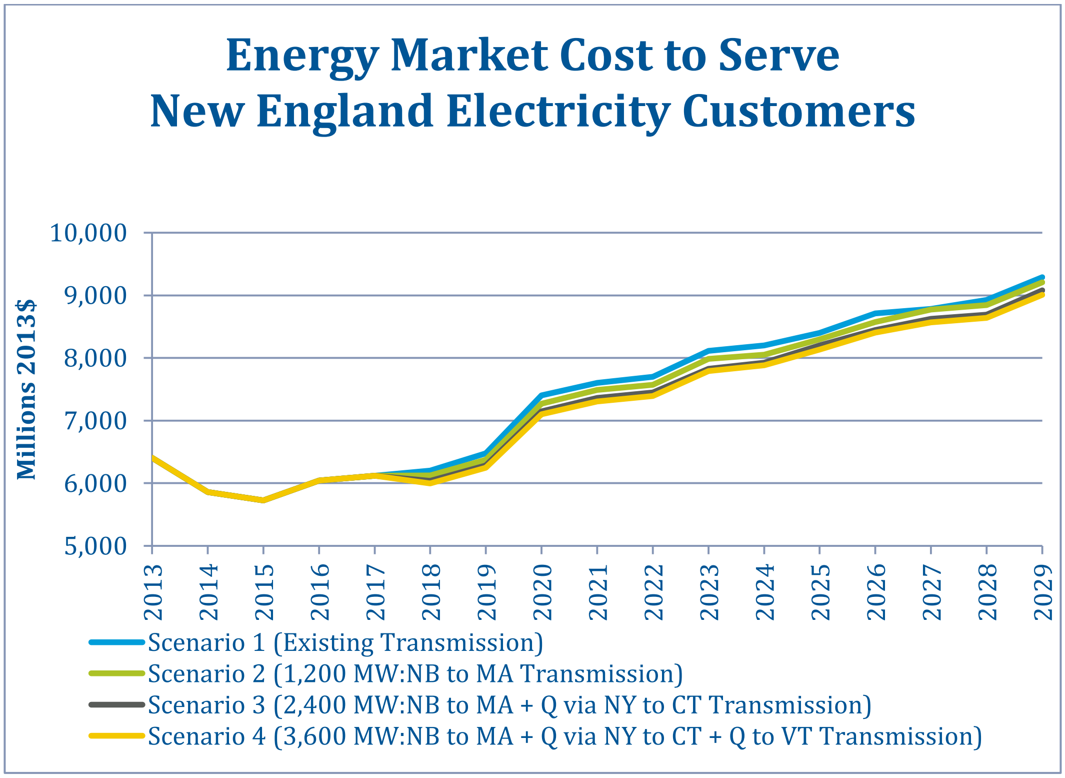

Figure 4-1 **Analysis of Energy Market Costs – Base Case Supply**

- **Scenario 1 (Base Case Supply and Transmission):** This scenario is the benchmark to which the other incremental imported hydro power cases (Base Case Supply Scenarios 2-4) are compared. Its cost to serve electricity customers and electric sector carbon dioxide emissions is the baseline for the analysis of the Base Case Supply scenarios.
- **Scenario 2 (a new 1,200 MW line from NB to MA):** This 1,200 MW transmission scenario allows the use of the Maritime Link that imports power into NB. The cost to serve customers in Scenario 2 is $1.231 billion *lower* across the Study Period than the costs in Scenario 1. Hydro power coming into NB from the Maritime Transmission Link, and then using the NB to MA line reduces system costs by displacing high cost generation in New England's relatively higher cost load centers, such as Boston.
- **Scenario 3 (2,400MW - new 1,200 MW line from NB to MA *plus* a new 1,200 MW line from Q via NY to CT)**: This 2,400 MW scenario had the largest downward

incremental impact on marginal costs of any of the scenarios in the Base Case Supply. In this scenario, customer costs were cumulatively reduced by $2.725 billion from Scenario 1. Prices in New England are typically higher closer to New York City. This new 1,200 MW additional import provides a lower cost generation alternative to the gas- and oil-fired generation located in this general area of New England. In Scenario 3, low cost generation is being delivered directly to some of the largest load centers in New England (Boston and Southwest CT) that contain some of the highest costs generation. It should be noted here that the flow on the existing transmission line between Quebec and Massachusetts (Phase II) decreases under this scenario as more hydro flow is sent to CT where locational marginal prices are typically higher.

- **Scenario 4 (3,600 MW- new 1,200 MW line from NB to MA, *plus* a new 1,200 MW line from Q via NY to CT *plus* a new 1,200 MW line from Q to VT):** This 3,600 MW scenario continued to drive down customer costs, but did not have as much of an incremental impact as Scenario 3. In this scenario, costs were cumulatively reduced by $3.325 billion from Scenario 1. Vermont is located to the north of the North-South Interface and west of the East-West Interface. This may influence the incremental price reduction impact of hypothetical additional imports. This increase in transmission allows more of the low cost generation from Quebec to move toward the load centers further to the south and southeast of Vermont.

4.3.2 Alternative Hydro Supply Case - Price Results

Table 4-4 Cumulative Price Reduction Benefits – Alternative Hydro Supply Case Scenarios (Millions, 2013$)

SCENARIO	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	TOTAL	AVERAGE
Scenario 6 (1,200 MW:NB to MA Transmission)	115	126	188	178	160	254	167	125	243	111	161	135	1,962	164
Scenario 7 (2,400 MW:NB to MA + Q via NY to CT Transmission)	245	259	349	356	327	478	402	301	434	310	390	394	4,244	354
Scenario 8 (3,600 MW:NB to MA + Q via NY to CT + Q to VT Transmission)	303	300	399	410	459	553	568	450	574	493	545	599	5,652	471

Table 4-5 Incremental Price Reduction Benefits – Alternative Hydro Supply Case Scenarios (Millions, 2013$)

SCENARIO	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	TOTAL	AVERAGE
Scenario 6 (1,200 MW:NB to MA Transmission)	115	126	188	178	160	254	167	125	243	111	161	135	1,962	164
Scenario 7 (2,400 MW:NB to MA + Q via NY to CT Transmission)	129	133	161	178	168	224	234	176	191	199	229	259	2,281	190
Scenario 8 (3,600 MW:NB to MA + Q via NY to CT + Q to VT Transmission)	58	41	50	54	131	75	166	149	140	183	156	205	1,409	117

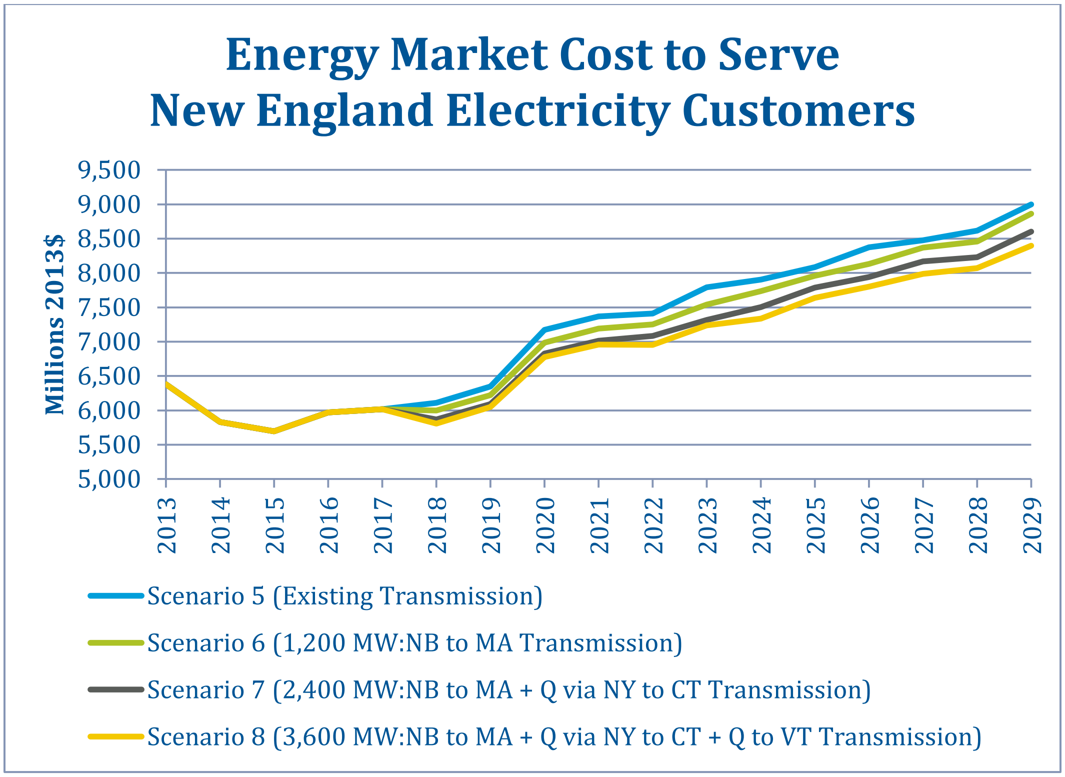

Figure 4-2 Analysis of Energy Market Costs – Alternative Hydro Supply Case

- **Scenario 5 (Alternative Hydro Supply Case with Base Case Transmission):** This scenario is the benchmark to which the other incremental imported hydro power cases (Scenarios 6-8) will be compared. Its cost to serve electricity customers and electric sector carbon dioxide emissions serve as the baseline for the analysis of the Alternative Hydro Supply scenarios. This Alternative Hydro Supply Case reduced electricity costs for New England customers by $3.353 billion compared to the Base Case Supply. Due to the structure of the scenarios, this savings is driven by the increased hydro energy imported into New England.
- **Scenario 6 (a new 1,200 MW transmission line from NB to MA):** This 1,200 MW transmission scenario allows assumed use of the Maritime Link that imports power into NB. The cost to serve customers in Scenario 6 is $1.962 billion lower across the Study Period than Scenario 5. Hydro power theoretically coming into NB from the Maritime Transmission Link, and then utilizing the NB to MA line, reduces system costs by displacing high costs generation in the New England's relatively higher cost load centers. Scenario 6 is approximately $731 million lower than Scenario 2, reflecting additional hydro imports. The higher marginal costs in Northeast MA provide an incentive for additional low cost power in QNL to be utilized even further.
- **Scenario 7 (2,400 MW - a new 1,200 MW transmission line from NB to MA *plus* a new 1,200 MW transmission line from Q via NY to CT):** This 2,400 MW scenario had the largest downward incremental impact on marginal costs of any of the scenarios in

the Alternate Supply case. In this scenario, customer costs were cumulatively reduced by $4.244 billion from Scenario 5. This new 1,200 MW hydro power addition provides a less expensive generation alternative to the gas and oil-fired generation located in this general area. Scenario 7 is approximately $1.519 billion lower than Scenario 3. With power prices higher toward southern New England versus much of the rest of the power system, low price hydro power is utilized at a higher rate in the locations where power prices are at a premium.

Scenario 8 (3,600 MW – a new 1,200 MW transmission line from NB to MA *plus* a new 1,200 MW transmission line from Q via NY to CT *plus* a new 1,200 MW transmission line from Q to VT). This 3,600 MW scenario continued to drive down customer costs, but did not have as much of an incremental impact as Scenario 7. In this scenario costs were cumulatively reduced by $5.652 billion from Scenario 5. Vermont is located to the north of the North-South Interface and west of the East-West Interface, which may influence the incremental price reduction impact of hypothetical additional imports injected into northern New England. The North-South Interface has a 2,700 MW limit and remains constant throughout the study. In contrast, the East-West Interface has a current limit of 2,800 MW, which increases to 3,500 MW in 2017 to reflect actual planned transmission system enhancements. Scenario 8 is approximately $2.327 billion lower than Scenario 4, driving the energy market cost in New England even lower. This reduction provides further evidence that the low cost hydro power in QNL can continue to be used in New England to displace higher priced gas and oil resources.

4.3.3 Price Reduction Benefits Observations

The difference between the Base Case Supply scenarios and the Alternative Hydro Supply Case scenarios is the assumed addition of 5,000 MW of hydro supply in eastern Canada, specifically the QNL regions. As noted, these additional resources are currently in the permitted and proposed stage, rather than the under construction, in testing, or site preparation stage. The assumed additional 5,000 MW of hydro resources in the Alternative Hydro Supply Case allows QNL to meet its resource adequacy requirements without building additional peaking capacity. Further, under the Alternative Hydro Supply Case, the three hypothetical transmission configurations are loaded to an average capacity factor of 88 percent, indicating that the Alternative Hydro Supply Case resource additions are reasonably available to export from Canada to New England over the study period. The increased hydro capacity in the Alternative Hydro Supply Case is primarily driven by the assumed introduction of the 824 MW Muskrat Falls in 2018 and the 2,250 MW Gull Island hydro facilities in 2022.

In this analysis, the additional 5,000 MW of hydro resources lowered New England electricity customer costs by approximately $3.353 Billion for the 2014-2029 Study Period (the difference in total Study Period customer costs between Scenario 1 and Scenario 5).[12] In addition, the incremental price reductions, and therefore consumer cost impacts, associated with the hypothetical transmission configurations were greater in the Alternative Hydro Supply Case scenarios compared to the Base Case Supply scenarios. The cumulative price *reduction* benefits resulting from the three hypothetical transmission configurations increased from $3.325 Billion in the Base Case Supply (Scenario 4) to $5.652 Billion in the Alternative Hydro Supply Case (Scenario 8).

The hypothetical transmission configuration with the greatest incremental impact was Transmission Configuration #2, a 1,200 MW HVDC cable from New Brunswick to Massachusetts *plus* a 1,200 MW HVDC cable from Quebec through New York to Connecticut (Scenarios 3 and 7).[13] The average annual incremental price reduction benefit for this transmission configuration (NB to MA + Q via NY to CT) was $125 Million in the Base Case Supply (Scenario 3) and $190 Million in the Alternative Hydro Supply Case (Scenario 7). The second largest incremental price reduction benefits resulted from Transmission Configuration #1 (MA to NB only, Scenarios 2 and 6), and the smallest incremental price reduction benefits resulted from Transmission Configuration #3 (MA to NB + Q via NY to CT, + Q to VT).

4.4 EMISSION REDUCTION ESTIMATES

In this analysis, Black & Veatch also evaluated electric sector emissions impacts associated with incremental imports of hydro power. For the purposes of this relatively simple analysis, the carbon emissions associated with imported power enabled by the hypothetical transmission configurations is assumed to have zero carbon emissions.[14] The difference between the New England electric sector carbon emissions in each scenario is a proxy for emissions reductions resulting from imported hydro power. In sum, in this analysis, increased imports of hydro power from eastern Canada reduce electric sector carbon dioxide emissions in New England. Tables 4-6 through 4-9 illustrate the emissions reductions for the Base Case Supply and Alternative Hydro Supply Case.

[12] This analysis assumes the transmission facilities discussed in Section 3.2 are placed in service for all scenarios.

[13] Further analysis would be required to analyze why Transmission Configuration #2 has the highest incremental price reduction benefits. It is unclear whether the primary cause is the import injection location in Connecticut or the particular resources displaced by 2,400 MW of imported hydro power (relative to 1,200 MW or 3,600 MW).

[14] As mentioned previously, life-cycle emissions issues are beyond the scope of the analysis. Further, imported power from neighboring electrical systems may have various emissions attributes. To accurately track the emissions attributes of imported power, a measurement and verification system is necessary. Analyzing the emissions attributes of system power in the Quebec and New Brunswick also requires further study.

4.4.1 Base Case Supply - Emissions Results

Table 4-6 Cumulative Base Case Supply Emission Reduction (1,000s of Short Tons)

SCENARIO	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	TOTAL	AVERAGE
Scenario 2 (1,200 MW: NB to MA Transmission)	1,617	1,696	1,460	1,343	1,388	1,009	1,398	1,269	1,007	1,069	1,254	1,053	15,563	1,297
Scenario 3 (2,400 MW: NB to MA + Q via NY to CT Transmission)	3,790	3,865	3,820	3,706	3,628	3,467	3,622	3,481	3,179	3,249	3,202	3,025	42,034	3,503
Scenario 4 (3,600 MW:NB to MA + Q via NY to CT + Q to VT Transmission)	5,355	5,155	4,936	4,945	4,919	4,791	4,779	4,713	4,493	4,649	4,507	4,446	57,687	4,807

Table 4-7 Incremental Base Case Supply Emission Reduction (1,000s of Short Tons)

SCENARIO	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	TOTAL	AVERAGE
Scenario 2 (1,200 MW: NB to MA Transmission)	1,617	1,696	1,460	1,343	1,388	1,009	1,398	1,269	1,007	1,069	1,254	1,053	15,563	1,297
Scenario 3 (2,400 MW: NB to MA + Q via NY to CT Transmission)	2,173	2,168	2,360	2,363	2,240	2,459	2,225	2,213	2,172	2,180	1,948	1,971	26,471	2,206
Scenario 4 (3,600 MW:NB to MA + Q via NY to CT + Q to VT Transmission)	1,565	1,290	1,116	1,240	1,291	1,323	1,156	1,232	1,314	1,400	1,305	1,421	15,653	1,304

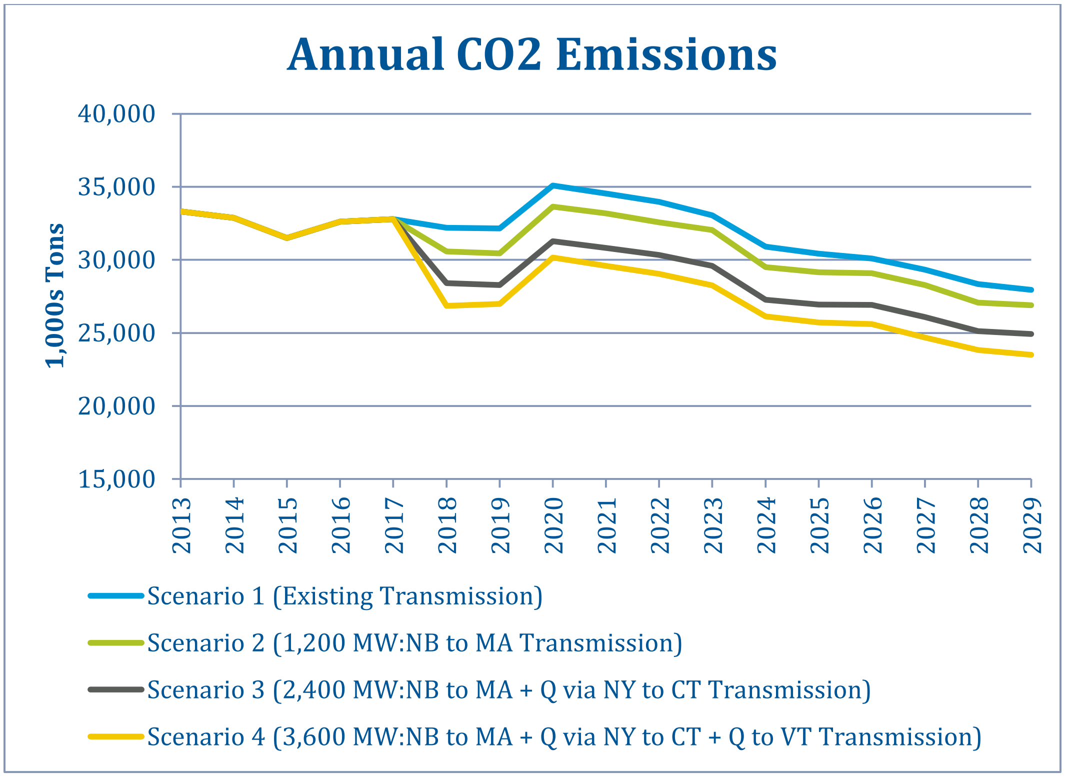

Figure 4-3 Analysis of CO_2 Emissions – Base Case Supply

The trends in New England's generation mix drive carbon emission reductions, as illustrated in Figure 4-3. In New England, gas-fired generation is on the margin (e.g., sets the market clearing price) more than any other resource type. As more carbon emissions-reducing hydro energy enters the system, it pushes higher priced gas-fired generation off the margin and reduces the amount of carbon being emitted. However, because gas–fired generation is so abundant in New England, it continues to be the marginal resource and sets the market clearing price. This explains why emissions are reduced with the addition of incremental hydro power, but the costs to produce energy continue to rise throughout the Study Period.[15]

[15] Over the long-term, gas supply prices are projected to increase and, therefore, long-term electricity prices are also expected to increase.

4.4.2 Alternative Hydro Supply Case - Emissions Results

Table 4-8 Cumulative Alternative Hydro Supply Case Emission Reduction (1,000s of Short Tons)

SCENARIO	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	TOTAL	AVERAGE
Scenario 6 (1,200 MW: NB to MA Transmission)	2,036	1,986	2,164	2,403	2,492	2,360	2,883	1,949	2,320	2,177	2,043	1,839	26,653	2,221
Scenario 7 (2,400 MW: NB to MA + Q via NY to CT Transmission)	4,552	4,654	5,078	5,344	6,045	6,057	6,229	5,295	5,825	5,614	5,150	5,071	64,916	5,410
Scenario 8 (3,600 MW:NB to MA + Q via NY to CT + Q to VT Transmission)	6,539	6,610	7,187	7,604	8,759	9,573	9,096	8,117	8,887	8,533	8,044	8,029	96,980	8,082

Table 4-9 Incremental Alternative Hydro Supply Case Emission Reduction (1,000s of Short Tons)

SCENARIO	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	TOTAL	AVERAGE
Scenario 6 (1,200 MW: NB to MA Transmission)	2,036	1,986	2,164	2,403	2,492	2,360	2,883	1,949	2,320	2,177	2,043	1,839	26,653	2,221
Scenario 7 (2,400 MW: NB to MA + Q via NY to CT Transmission)	2,517	2,667	2,914	2,942	3,554	3,696	3,345	3,346	3,505	3,437	3,107	3,232	38,262	3,189
Scenario 8 (3,600 MW:NB to MA + Q via NY to CT + Q to VT Transmission)	1,987	1,957	2,109	2,259	2,714	3,516	2,868	2,822	3,062	2,919	2,894	2,958	32,065	2,672

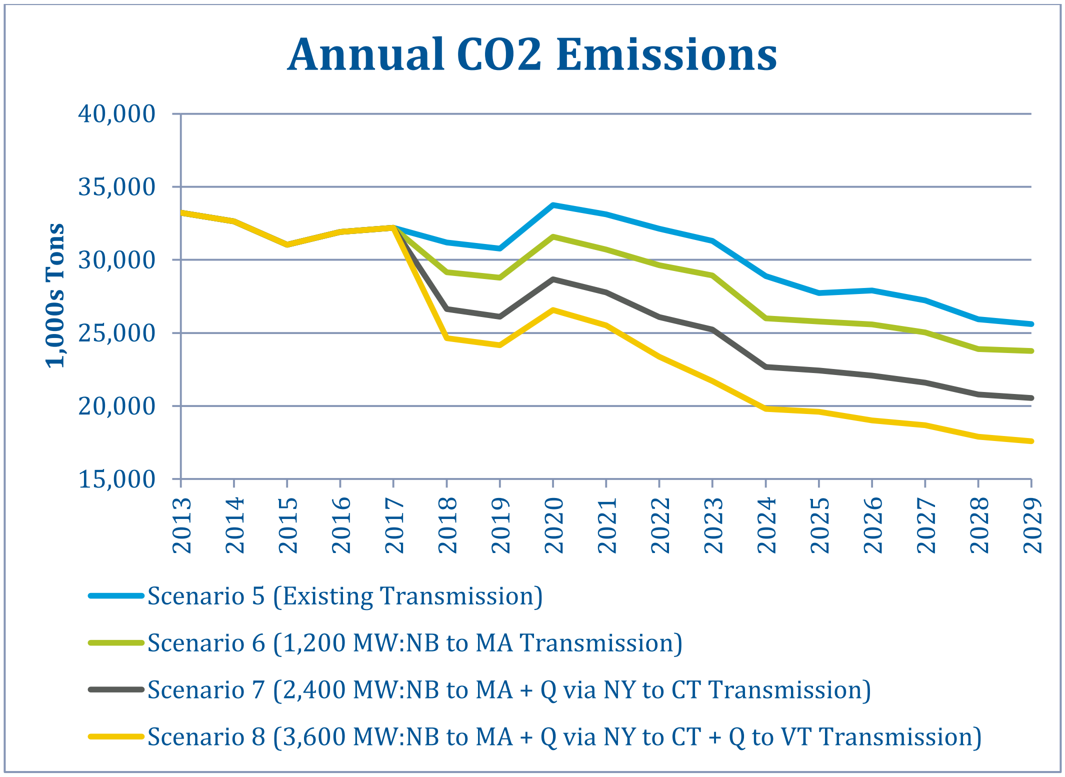

Figure 4-4 Analysis of CO_2 Emissions – Alternative Hydro Supply Case

4.4.3 Emissions Reductions Benefits Observations

Due to New England's electric generation resource mix, incremental imports of hydro power have varying impacts on electric sector emissions over the Study Period. Initially, electric sector emissions decrease as hydro power imports displace some of the gas-fired resources from the margin. However, in the medium term, electric sector CO_2 emissions increase as coal-fired resources are dispatched to an increasing degree to serve customer demand. In the later years of the study, fossil-fueled resource retirements, increasing carbon regulation prices, and imported hydro power significantly reduce electric sector carbon dioxide emissions.

The additional 5,000 MW of hydro resources in the Alternative Hydro Supply Case scenario (Scenario 5) delivers more CO_2 emissions reductions benefits than the Base Case Supply scenario (Scenario 1). The difference in New England electric sector carbon dioxide emission between these two scenarios is approximately 24.5 million short tons over the Study Period (2014-2029).

In the Base Case Supply scenarios, the cumulative electric sector carbon emissions reduction resulting from the imports enabled by all three hypothetical transmission configurations (Scenario 4) is approximately 57.7 million short tons. For the Alternative Hydro Supply Case scenarios, the cumulative electric sector carbon emissions reduction resulting from the imports enabled by all three hypothetical transmission configurations is approximately 97 million short tons.

The Alternative Hydro Supply Case scenarios (Scenarios 5-8) produce greater emissions reductions compared to the Base Case Supply scenarios (Scenarios 1-4). Also, Transmission Configuration #2 (2,400 MW: MA to NB + Q via NY to CT) delivers the largest incremental emissions reductions (Scenarios 3 and 7), compared to the other transmission configurations in both the Base Case Supply scenarios (Scenarios 2 and 4) and the Alternative Hydro Supply Case scenarios (Scenarios 6 and 8). Notably, Transmission Configurations #1 (MA to NB) and #3 (MA to NB + Q via NY to CT + Q to VT) result in the same average annual incremental emission reductions in the Base Case (Scenarios 2 and 4). In contrast, Transmission Configuration #3 (Scenario 8) delivers greater average annual incremental emission reductions than Transmission Configuration #1 in the Alternative Hydro Supply Case (Scenario 6).

5.0 Hypothetical Transmission Configurations

After Black & Veatch determined the hydro resources in the Base Case Supply and Alternative Hydro Supply Case, Black & Veatch evaluated the transmission needed to move this new generation from eastern Canada to the New England region. As noted, for purposes of this study, Black & Veatch evaluated three hypothetical transmission projects. Each one is a 1,200 MW high-voltage direct current (HVDC) transmission line, and each would deliver hydro imports from different points in eastern Canada into different part of the New England power system.[16] HVDC technology is necessary to interconnect the New England electric grid with Quebec due to asynchronous operation of the two systems.[17] Further, HVDC technology is considered to be most appropriate economically for long-distance transmission. Black & Veatch evaluated the capital cost of each line separately.

The three hypothetical transmission configurations to enable incremental hydro power imports and their cost estimates are as follows:

- **Transmission Configuration #1, New Brunswick to Boston/Northeast Massachusetts (NB to MA)** – This is a 1,200 MW line that extends from New Brunswick to the Boston area. It is mostly a submarine cable, and is designed to bring renewable energy from New Brunswick and Northern Maine,[18] as well as imported power from QNL.
  - **Cost Estimate**: **$2,117,000,000**
  - **Cost Estimate (ME terminal)[19]:** **$300,000,000**
- **Transmission Configuration #2, New England Portion of the Champlain Hudson Power Express (Q via NY to CT)** – This is a 1,200 MW line. It is mostly submarine cable that extends from Quebec down the Hudson River and terminates in Connecticut.
  - **Cost Estimate:** **$2,120,000,000**
- **Transmission Configuration #3, Quebec to Vermont (Q to VT)** – This is a 1,200 MW line extending from Quebec into Vermont. It is the shortest of the three lines assumed in the analysis. Its cost estimate is presented in two formats, overhead and underground.
  - **Cost Estimate Overhead**: **$710,000,000**
  - **Cost Estimate Underground**: **$1,000,000,000**

Cost estimates for each of these transmission configurations are provided in Table 5-1.

[16] The assumed location of the lines does not reflect preferred or recommended locations or routes.
[17] Due to the physics of alternating current, two separate systems that wish to share power must be electrically synchronized. Otherwise, a direct current connection can be used to connect two asynchronous electric grids.
[18] To effectively pair intermittent renewable resource output and hydro power imported via HVDC technology, one approach is to inject the renewable resource output into the HVDC transmission line. For the purposes of this high-level analysis, an additional terminal was added to this hypothetical transmission configuration to enable such injection. The cost estimate associated with the additional terminal is shown above. Additional transmission investments necessary to connect the renewable resources to the HVDC terminal are not included in this estimate.
[19] Represents estimated cost for terminal discussed in previous note.

Table 5-1 Transmission Configurations

TRANSMISSION CONFIGURATION	COST (MILLIONS)
#1 NB to MA	2,117
#1 NB to MA (Additional Terminal in ME)	300
#2 Q via NY to CT	2,120
#3 (Overhead) Q to VT	710
#3 (Underground) Q to VT	1,000

6.0 Approaches to Develop Incremental Transmission and Recommendation

Black & Veatch provides in this section a detailed description of each principal transmission development commercial model present in current transmission markets across the United States. The section also provides Black & Veatch's recommended commercial model approach for a transmission project that imports hydroelectric supply ("hydro") into New England that may best satisfy New England policymakers' objectives if policymakers determine to facilitate such development.[20] The review considers only transmission in the United States and does not address any Canadian transmission. Depending on the specific hydro resource locations in Canada, transmission may be necessary on the Canadian side as well, which will have its own attendant costs and development processes.

Black & Veatch summarizes at a high-level commercial options for new transmission development below.[21] Other alternatives include adding capacity to existing or planned lines. Each of these options has a specific set of tradeoffs from a development and cost recovery perspective.

- **Merchant Model** – developer takes on 100 percent of the development risk and seeks participants to purchase firm capacity at market-based or negotiated rates. Costs are allocated to participants.
- **Cost Based Participant Funded Model** – developer sells firm capacity to a participant(s) in exchange for funding (can be developed by incumbent or non-incumbent transmission developer).[22] Costs are allocated to participants.
- **Regional Funded Model** - project is developed pursuant to regional transmission expansion planning processes approved by the Federal Energy Regulatory Commission (FERC) (outlined by Open Access Transmission Tariff, or OATT) and in which costs of approved projects are typically borne by captive ratepayers in the region. Following implementation of FERC's Order 1000,[23] it is anticipated that this model will be available to both incumbent and non-incumbent transmission owners with certain limited exceptions. Costs are allocated regionally using various allocation methods; in

[20] Following the recommendations portion of this section, information on two alternative approaches for transmission funding is presented

[21] The following general description is not intended as an exhaustive discussion of each model and does not, for example, attempt to capture all of the similarities and differences between merchant and participant funded projects and regional projects.

[22] Note – See FERC final policy statement, "Allocation of Capacity on New Merchant Transmission Projects and New Cost-based, Participant-funded Transmission Projects," AD12-9-000 and AD11-11-0000, January 17, 2013. This statement among other things clarified that pursuant to certain conditions that developers of new merchant and non-incumbent participant funded projects may subscribe up to 100% of firm transmission capacity to an anchor customer.

[23] FERC Order 1000, 136 FERC ¶ 61,051, Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, July 21, 2011

New England for instance, costs of Pool Transmission Facilities (PTF) are allocated regionally on a load ratio basis.

6.1 APPROACHES FOR DEVELOPING TRANSMISSION

6.1.1 Merchant Model

Merchant projects are projects in which the transmission developer assumes all or a major portion of up-front development risks. In effect, many merchant projects are planned and designed before any participants are identified. Merchant developers must undertake a process to solicit participation ("capacity subscription"). FERC has recently enacted a set of new standards that merchant and other non-incumbent transmission developers must adhere to in their capacity subscription process.[24] In its Final Policy Statement in Docket AD11-11,[25] FERC articulated that a merchant (and non-incumbent cost-based participant funded transmission developers) may now subscribe up to 100 percent of a project's firm capacity to a single "anchor customer" with certain requirements and restrictions the developer must meet as part of that process. Specifically, developers that follow this subscription approach must demonstrate adherence to four factors (known as the "Chinook Four Factors" – in reference to a prior proceeding in which FERC established these factors) that FERC reviews as part of its approval for the developer's negotiated rate authority. These factors are that the process will result in: 1) rates that are just and reasonable, 2) no undue discrimination, 3) provide for no undue preference to affiliates, and 4) preserve regional reliability and efficiency. In its evaluation of factors 2 and 3, FERC will review whether the developer has broadly solicited interest in the project and demonstrated that the process meets specific solicitation, selection, and negotiation criteria. This FERC ruling permits merchant developers to engage in active bi-lateral discussions with potential participants and presumably to permit more effective commercial term discussions with a single participant, thereby helping to expedite participant sign-on.

Rates for merchant projects are typically set on a negotiated basis (as opposed to cost-based, discussed below) and FERC will review the reasonableness of rates and the capacity subscription process as part of its review in determining whether to grant the developer negotiated rate authority. Once the line is energized, the developer must establish service under an OATT. To date, this has been the predominate model used to develop much of the recent projects linking new renewable energy resources to load in other parts of the country.[26] This model has not been used

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[24] Non-incumbents are identified as project developers that do not currently own transmission and that does not currently operate pursuant to a FERC approved Open Access Transmission Tariff in the region where the transmission is being developed.

[25] See Footnote 22.

[26] Champlain Hudson Power Express is in advanced development Stage; this $2.2 billion project (1,000 MW/ 320 KV) is a merchant project being developed by Transmission Developers Inc., National Resources Energy, LLC, and Sithe Global TDI. It will deliver renewable power from Canada to US following a 333 mile route along the Hudson River to the New York City area. In April 2013, the New York PSC approved permitting and certification.

for renewable projects in New England- rather, elective upgrades and generator interconnections categorized as cost-based participant funded approaches have been used by renewable generation in New England.[27] The only example of a merchant transmission project in New England is the Cross Sound Cable.[28] The principal FERC regulatory approval steps in this model are for the developer to file for and receive negotiated rate authority – during this process FERC will also review any capacity allocation outcomes to ensure they comply with open access standards.

6.1.2 Cost Based Participant Funded Model

In this model, a transmission developer (incumbent or non-incumbent) will sell priority capacity rights on the transmission line to a discrete set of participants in exchange for cost-based funding.[29] In this way, participants fund a new transmission project. Alternatively, in New England, generators seeking to connect to existing transmission may request an elective transmission upgrade, and those costs are borne entirely by the generator. Although the approaches differ (cost-based participant versus generator interconnect), both result in participants bearing 100% of the transmission costs. Participants typically pay a FERC approved cost-based[30] formula rate (approved through a Federal Power Act Section 205 filing with FERC). In addition, like projects constructed for reliability, project developers may be able to earn certain FERC-approved rate incentives such as a return on equity (ROE) adder and 100 percent construction work in process (CWIP) treatment. Note, FERC practice related to approving incentives for electric transmission has been changing.[31] The participants (i.e., those funding the project) may be a single party or multiple parties. Additionally, in this commercial model, it is possible to commit transmission capacity rights to a set of discrete participants and to solicit any remaining capacity through an Open Season solicitation process.

In this commercial model, the capacity rights can be bundled with electric supply through a power sales agreement between the participant and the transmission owner, although this is not a requirement. Transmission owners under this model are obligated to expand capacity pursuant to the ISO-New England tariff. FERC typically only reviews capacity subscription of an incumbent project on a case-by-case basis. Non-incumbent transmission developers must follow a process

[27] See ISO New England OATT, Section II.47.5.

[28] A 330 MW 25-mile long HVDC underground cable connecting New Haven CT and Shoreham NY and has been in service since 2005.

[29] This model contrasts with the approach for identifying and planning for regional transmission project in which transmission needs are identified on a regional basis and projects are planned using specific reliability and system planning criteria; in these projects, the participants are in effect all customers in the region that benefits from the project's capacity (See Attachment K of the ISO-New England tariff for a description of the New England planning process).

[30] Rates that are set on the basis of embedded costs of the project. These costs typically include cost of equity and debt, operating and maintenance expenses, taxes, and depreciation.

[31] A recent Initial Decision has communicated, that FERC may be reconsidering the ROE levels currently in certain New England transmission rates. See FERC Docket EL11-66-001, Martha Coakley, Massachusetts Attorney et.al. vs. Bangor Hydro-Electric et.al.; Initial Decision filed August 6, 2013.

that meets specific criteria and procedures set forth in AD11-11[32] as explained above in the discussion of the Merchant Model. For incumbent developers, the principal regulatory step is to file with FERC and seek approval of the Transmission Service Agreement and to file and receive authorization for the cost-based rate and any requested incentives. Non-incumbent developers must follow these same procedures with FERC to establish a cost-based rate and any incentives; in addition, the FERC will review the capacity subscription process to ensure it complies with open access requirements—the "Chinook Four Factors"—outlined in AD11-11.

Under the New England OATT, elective upgrades and generator interconnections are categorized as cost-based participant funded projects. This is the method for most renewable generation interconnecting in New England.

6.1.3 Regional Funded Model (Incumbent and Non-Incumbent)

Regional funded projects are projects that are pursued through an established regional transmission expansion planning process codified within an OATT and which are qualified for regional funding through a cost allocation mechanism that FERC has already approved.[33] Attachment K of the ISO-New England tariff outlines the transmission planning process for New England. The procedures require ISO-New England to conduct a regional planning process, undertake needs assessment in consideration of particular reliability and other planning criteria for the system, evaluate alternatives, and to develop a Regional System Plan that addresses needs. These projects typically serve regional load needs including: reliability, economic (congestion), and public policy.[34] Considering transmission development reforms through Order 1000, new competitive processes for regional transmission projects are expected to be implemented next year, with new opportunities for qualified non-incumbents to compete with incumbent developers.[35] Costs for these projects are typically set using cost-based rates and may be eligible for FERC rate incentives.

FERC approved OATTs contain specific cost allocation procedures that define how costs of projects are allocated to load (costs can be allocated locally or regionally depending upon the nature of project and how benefits are assigned). These procedures generally follow a beneficiary pays approach, although specific cost allocation models differ by region and OATT. In New England for instance, the costs of Pool Transmission Facilities (PTF)[36] are allocated regionally using a load ratio basis and these procedures are codified in the ISO-New England FERC approved tariff (Schedule 12). In addition, the obligations and steps for transmission owners to process new

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[32] See Footnote 22, supra.

[33] See Order, ER13-193-000; ER13-196-000, ISO New England Order on Initial Compliance, May 17, 2013, P 342.

[34] Order 1000 requires planning processes to specifically consider public policy needs.

[35] To reflect policy shift per Order 1000 that removes with certain limited exceptions, incumbent Rights of First Refusal (ROFR) from OATT language.

[36] PTF projects are regional projects in New England historically defined as 69 kv and above; for upgrades to transmission since 2004, projects above 115kv or that otherwise meet non-voltage requirements are considered PTF – See Testimony David Boguslawski and Carol Sedewitz, filed with ISO-NE Order 1000 Compliance Filing, October 25, 2013, page 48 of testimony.

service requests are also specified in the OATT; and, in New England, these procedures and related items are outlined in the ISO-New England OATT at Section II (elective transmission upgrade), Schedules 11 and 12. FERC can review deviations from service request procedures on a case by case basis.[37]

Outside New England, the principal regulatory steps in this model are for the developer to file with FERC its proposed cost-based rates and, if the developer is seeking any rate incentives at that time, it will detail in this filing the reasons why the project is eligible to receive incentives. In addition, all developers pursing projects in this model will necessarily engage in the regional transmission expansion planning process with procedures outlined for this process in the region's OATT.[38]

6.2 COMPARISON OF DEVELOPMENT MODELS

NESCOE provided Black & Veatch with three primary preferred criteria for comparing the three development models identified above. The policy criteria are:

- Least Cost
- Greenhouse Gas Emissions Reduction
- Reliability

A development model can impact the following state-identified preferred criteria: least cost and reliability. A development model has less influence on greenhouse gas reductions. Accordingly, Black & Veatch included the criteria of least cost and reliability in the comparison of the alternative development models. The relative advantages and disadvantages of the alternative models are provided in Table 6-1 through Table 6-3.

[37] See FERC Final Policy Statement, P 42.

[38] Note- ISO-New England has proposed a process to address the regional evaluation and selection of regional projects that specifically support public policy objectives in its Order 1000 compliance filing with FERC (ER13-193-000; ER13-196-000), filed October 25 2012. This proposal is still in compliance phase.

Table 6-1 Merchant Model

MERCHANT MODEL	
Advantages	**Disadvantages**
Developer bears all risks	May not be experienced developer; higher risks
Benefits clearly identified as part of development process	May lack ISO-New England integration experience; higher risks
Focused purpose	May have to establish a new OATT[39]
Process can be streamlined with experienced developer; lower costs	Regulatory approval decided on case-by-case basis
Commercial pressures may be strong for merchants to contain costs	

Table 6-2 Cost Based Participant Funded Model

COST BASED PARTICIPANT FUNDED MODEL	
Advantages	**Disadvantages**
Developer bears all risks until participants committed	Some developers may have limited experience in identifying suitable participants and obtaining commitments
Benefits clearly identified as part of development process	May not have experience in ISO-New England interconnection process
Focused purpose	May not be experienced developer
Process can be streamlined with experienced developer	

[39] Note the Cross Sound Cable was incorporated in the ISO-NE's OATT.

Table 6-3 Regional Funded Model

REGIONAL FUNDED MODEL	
Advantages	**Disadvantages**
Uses FERC approved OATT and cost allocation method	Risk and cost borne by ratepayers
Serve multiple needs and needs established in regional participation process	Regional planning process can be cumbersome and slow
Processes well established	Capacity diluted to accommodate multiple benefits/constituents

6.3 BLACK & VEATCH RECOMMENDATION

Black & Veatch recommends that if New England policymakers elect to facilitate transmission development to import incremental hydro power, the New England states consider a cost-based participant funded commercial approach. Black & Veatch prefers a cost-based approach to a negotiated rate approach since Black & Veatch expects that FERC will review the cost basis and other terms and conditions more closely than it would under a negotiated rate approach. Black & Veatch would expect that FERC will review the project developer's proposed aspects such as return on equity, depreciation rates, tax recovery, and other critical cost aspects for rate recovery as part of the developer's Federal Power Act Section 205 rate filing and authorization process. The level of negotiated rates is difficult to predict for any transmission project because it depends on numerous market factors. As such, it is possible that a project in high market demand could support negotiated rate levels that are potentially somewhat higher than a cost-based one. Black & Veatch would expect that FERC will review the project developer's proposed negotiated rate levels in order to ensure that rates are just and reasonable. Negotiated rates can be influenced in part by competitive factors so that in some instances they could potentially exceed a cost-based level; however, FERC has authorized cost of service based rate ceilings for some negotiated rates in the past.[40]

For these reasons, Black & Veatch believes the cost-based commercial model is a better fit for state policymaker goals of achieving lower cost transmission results. Black & Veatch emphasizes however that any project pursued should be planned and executed in a prudent manner so as to avoid any cost over-runs that could seriously erode project net benefits. State policymakers that are concerned with potential costs of projects should participate vigorously in the Section 205 filing to help ensure costs recovered are prudent and reasonable.

[40] Order Granting Petition for Declaratory Order, FERC Docket EL09-20-000, May 22, 2009.

Black & Veatch believes that a participant based approach is also more suitable for a transmission project that will import hydro energy. To date, very few- if any- single purpose (e.g. renewables only) projects have been developed pursuant to the regional model. This may stem from the fact that pre-Order 1000, incumbent utilities operated with an incumbent right of first refusal for regional projects, and projects have been developed to address incumbent utilities' service obligations including reliability or economic (congestion) benefits. Order 1000 requires regional transmission plans to specifically consider public policies and, consequently, it is likely that some regional projects will, in a post-Order 1000 market, address some renewables needs. Yet, Order 1000 requires these projects to be pursued through a potentially lengthy regional planning process. NESCOE asserts that, depending on FERC's decisions in Order 1000 compliance filings and pending litigation in federal court, within this regional process, states may not have the opportunity to play a central role in the evaluation and selection of projects that advance their own state policies. Accordingly, Black & Veatch believes a participant funded approach that does not require a developer participating in an extensive regional planning process can be a more expedient way to develop this particular type of transmission project and need.

Black & Veatch believes that a cost-based participant funded model can be successfully developed by either an incumbent or non-incumbent owner/developer; and, the differences between each are modest at best. In evaluating an incumbent versus non-incumbent approach, Black & Veatch recommends policymakers consider the following:

- Developer's ability to attract capital and gain participant commitment;
- Developer's ability to prudently plan and execute transmission project and avoid cost over-runs;
- Anticipated regulatory approval processes and timing; and
- Ability of developer to provide innovative and cost effective solutions to an identified transmission need.

6.4 NOVEL APPROACHES FOR CONSIDERATION

6.4.1 Alternative Approach – Emissions Value Crediting

One way to provide additional incentive to pursue the transmission project could be to establish a cost treatment in which the value of some or all of the emissions credits associated with the participant power moving on the line is credited back to the developer. The credit could be completely reserved for the developer or split between the developer and participant (in this case the developer would receive the full cost-based rate and in addition, the value of any emissions credited to it). This approach may provide additional stimulus for initial development; however, the trade-off would be that participant(s) may have to forego some emissions value which could alter their economic rationale for participating. In addition, Black & Veatch believes FERC may be required to authorize this treatment as part of its review of cost-based rates and potentially the transmission service agreement. This approach would support state regulatory goals of Greenhouse Gas Reduction; however the cost impact to participants - and in turn end-consumers -

of this approach would require thorough review since emissions credits are typically of commercial value to participants and certain end customers (such as load serving entities) depending upon the implementation details of such an emissions policy.

6.4.2 Innovative Alternative Approach – Real Estate Investment Trust (REIT)

The need for expanding the U. S. transmission grid has been a strong driver for developing alternative and innovative ways to fund transmission development. One way is the use of Real Estate Investment Trusts (REITs). REITs offer a tax advantage to investors which can potentially increases the capital available to transmission developers. This may be of particular benefit to new entrants into the transmission business that lack the financial strength of established transmission owners. However, the use of REITs may offer advantages to any transmission owner/developer.

The REIT concept has been in existence for over 50 years and has been used as a tax incentive for investment in real estate. A time line history of REITs is provided in Figure 6-1 History of REITs. Recently, however, REITs have been used to fund electric transmission infrastructure and have been supported by IRS private letter rulings allowing REITs as alternative investment vehicles to the traditional partnership structure. Hunt Power, L.P. Marubeni Corp of Tokyo, John Hancock life Insurance (USA), TIAA-CREF, and Canadian-based pension provider OPTrust Private Markets have formed a REIT to invest primarily in transmission assets in Texas, the Great Plains and the Southwest states. One trade-off associated with REITs for funding new projects is that they need to distribute income annually; but, they can be useful to companies that own existing transmission assets to generate higher returns that can then be used for new development.

Application of REITs to transmission assets is still in its formative stages and details on how they functions are not available. Documentation at this stage appears to be limited to the opinions of legal and tax experts and the general information concerning the Hunt Power use of REITs for existing transmission structures. Expert opinions, however, indicate that the concept can be applied to both existing transmission assets as well as transmission assets in the development stage[41].

[41] "IRS Ruling Latest Development in String of Federal Energy Transmission and Distribution System Actions", http://www.pepperlaw.com/publications_update.aspx?ArticleKey=975

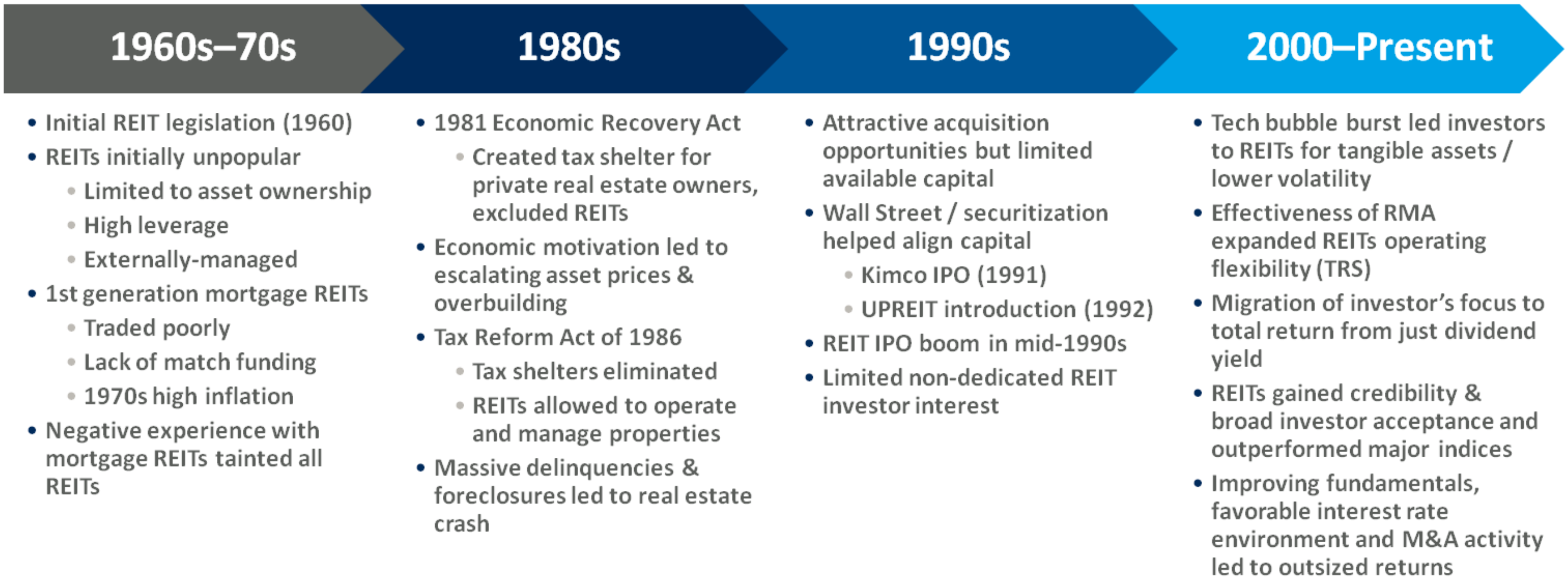

Figure 6-1 History of REITs

REITs own the assets and are paid a “rental” fee by the operator of the asset. The REIT then distributes income as dividends to the REIT shareholders. In the case of transmission, the “rent” are any fees transmission customers pay to use the facility. Income from the REIT is then distributed to the REIT investors as dividends under favorable tax treatment. The REIT receives a deduction for dividends paid which provides a benefit to investors. Additionally, many REITS trade on a national securities exchange, shares of traded REITS tend to be highly liquid which has the potential to offer projects equity capital with a lower cost[42]. The REIT vehicle may be appealing to investors in new system assets, as well as to corporations that are considering the transfer of existing systems to a more tax-advantaged structure. This ruling may be an integral piece in planning for investments in transmission and distribution infrastructure[43].

REITs offer both advantages and disadvantages over more traditional fund based models for raising and distributing capital. Some of the advantages and disadvantages are summarized in Table 6-4.

Proposed rules that are pending before the Federal Energy Regulatory Commission (FERC) would make it easier for smaller electric utilities to compete with larger utilities and form independent transmission companies. REITs may be an attractive option for such companies to access capital.[44] Companies such as InfraREIT specialize in REITs and provide potential developers with an experienced partner for using REITs. An expanded capital base could facilitate merchant developers who may not have balance sheets and access to capital of large utilities (incumbent and non-incumbent).

REITs have also been cited as favorable vehicles for Public Private Partnership (P3s). In those situations where public entities determined that investing in transmission is an appropriate an appropriate activity, the use of REITs provides access to private capital as a complement to traditional infrastructure financing using tax-exempt bonds[45].

It should be noted that the use of REITs for transmission assets is a relatively new occurrence in the industry and to date, little operational experience exists. But the current IRS support and willingness by some entities to use them could provide valuable experience in their application over the next few years.

[42] “Using REITS to Finance Solar Power Development, http://www.mortgageorb.com/e107_plugins/content/content.php?content.12821

[43] “IRS Ruling Latest Development in String of Federal Energy Transmission and Distribution System Actions”, http://www.pepperlaw.com/publications_update.aspx?ArticleKey=975

[44] “Could New Breed of REITs Help solve U.S. Infrastructure Crisis? ”http://www.costar.com/News/Article/Could-New-Breed-of-REITs-Help-Solve-US-Infrastructure-Crisis-/124885[7/16/2013 4:08:27 PM]

[45] “REITs and Infrastructure Projects The Next Investment Frontier?”, http://www.deloitte.com/assets/Dcom-UnitedStates/Local%20Assets/Documents/MA/us_ma_Infrastructure%20REITS_040210.pdf

Table 6-4 REIT Approach

REIT APPROACH	
Advantages	**Disadvantages**
Liquidity – Publically traded REITS can be bought and sold using traditional security trading mechanisms.	Loss of pass-through – tax losses do not pass through REIT shareholders and therefore cannot be used as they are in partnerships or other funding mechanism.
Scalable – Project size can be changed within the REIT structure and be reflected in additional offerings as the project grows.	Refinancing of projects – Distributions from refinancing are, in general, taxable to REIT shareholders even in case in which there are no earnings and profits
Access to capital markets – REIT shares are available to the full range of investors.	Income restrictions – REITs must derive at least 75 percent of their gross income from rents and mortgage interest payments as well as other related income restrictions.
Taxation – REITs have a number of tax advantages. Since REITs distribute income through dividends, the tax code allows the REIT to operate without tax as an entity as long as it distributes its taxable income annually. This has not only direct benefits but also a number of benefits for foreign ownership as well which increases the potential pool of investors.	Regulated utility environment – Because of the tax advantages associated with REITs, there may be limitations on how much rent can be charged within certain regulated utility environments.

Appendix A

Table A-1 presents more detailed components of the summary of hydro resources that is shown in Table 3-1.

Table A-1 Hydro Resources

Province/Operator	2013	2014	2015	2016	2017	2018	2019	2020
New Brunswick (MW)	**965**	**965**	**965**	**965**	**965**	**965**	**965**	**965**
Edmundston Energy	5	5	5	5	5	5	5	5
Energie NB Power	912	912	912	912	912	912	912	912
St George Pulp & Paper Co	15	15	15	15	15	15	15	15
WPS Energy Services of Canada Corp	34	34	34	34	34	34	34	34
Newfoundland & Labrador (MW)	**5,429**	**5,429**	**5,429**	**5,429**	**5,429**	**5,429**	**6,253**	**6,253**
Abitibi Consolidated Co of Canada								
Algonquin Power Systems Inc								
Chi Canada Inc								
Deer Lake Power Co								
Newfoundland & Labrador Hydro	5,429	5,429	5,429	5,429	5,429	5,429	6,253	6,253
Nova Scotia (MW)	**421**	**421**	**421**	**421**	**421**	**421**	**421**	**421**
Minas Basin Pulp & Paper Ltd	5	5	5	5	5	5	5	5
Nova Scotia Power	416	416	416	416	416	416	416	416
Ontario (MW)	**8,979**	**8,979**	**9,023**	**9,023**	**9,039**	**9,039**	**9,039**	**9,039**
Abitibi Consolidated Co of Canada	149	149	149	149	149	149	149	149
Algonquin Power Systems Inc	13	13	13	13	13	13	13	13
Beaver Power Corp	23	23	23	23	23	23	23	23
Begetekong Power Corp	23	23	23	23	23	23	23	23
Bracebridge Generation Ltd	2	2	2	2	2	2	2	2
Brookfield Renewable Energy Partners LP	409	409	409	409	409	409	409	409
Burks Falls Waterpower Corp	1	1	1	1	1	1	1	1
Canadian Hydro Developers Inc	11	11	11	11	11	11	11	11
Canadian Renewable Energy Corp	6	6	6	6	6	6	6	6
Clean Power Operating Trust	18	18	18	18	18	18	18	18
CVRD Inco Limited	32	32	32	32	32	32	32	32
Eastern Ontario Power	4	4	4	4	4	4	4	4
Elliot Falls Power Corp	2	2	2	2	2	2	2	2
FortisOntario Inc	95	95	95	95	95	95	95	95
Gemini SRF Power Corp	8	8	8	8	8	8	8	8
High Falls Energy Corp	1	1	1	1	1	1	1	1
Hydromega Services Inc	15	15	15	15	15	15	15	15
IESO (Ontario)	136	136	136	136	136	136	136	136
Innergex II Income Fund	8	8	8	8	8	8	8	8
Innergex Inc	5	5	5	5	5	5	5	5
Kagawong Power Inc	1	1	1	1	1	1	1	1
Long Sault Joint Venture	20	20	20	20	20	20	20	20
Mississagi Power	495	495	495	495	495	495	495	495
Mississippi River Power Corp	2	2	2	2	2	2	2	2
Ontario Power Generation Inc	7,445	7,440	7,484	7,468	7,484	7,484	7,484	7,484
Orillia Power Generation Corp	8	8	8	8	8	8	8	8
Peterborough Utilities Inc	4	4	4	4	4	4	4	4
Rankin Renewable Power Inc	6	6	6	6	6	6	6	6
Rideau Falls LP	2	2	2	2	2	2	2	2
Serpent River Power Corp	1	1	1	1	1	1	1	1
Shaman Power Corp	4	4	4	4	4	4	4	4
Spruce Falls Inc	3	3	3	3	3	3	3	3
St Catharines Hydro Inc		5	5	5	5	5	5	5
Synexus Global Inc	3	3	3	3	3	3	3	3
Trent Rapids Power Corp	8	8	8	8	8	8	8	8
Trout Creek Power	0	0	0	0	0	0	0	0
Twin Falls LP	6	6	6	6	6	6	6	6
Upper Thames River Conservation Authority	1	1	1	1	1	1	1	1
Valerie Falls LP	10	10	10	10	10	10	10	10
Yellow Falls Power LP				16	16	16	16	16
Quebec (MW)	**37,962**	**37,962**	**38,602**	**38,669**	**38,939**	**39,334**	**39,466**	**39,466**
Abitibi Consolidated Co of Canada	137	137	137	137	137	137	137	137
Algonquin Power Systems Inc	49	49	49	49	49	49	49	49
Boralex Inc	39	39	39	39	39	39	39	39
Brookfield Renewable Energy Partners LP	161	161	161	161	161	161	161	161
Gulf Power Co	18	18	18	18	18	18	18	18
Hydro Quebec	33,870	33,870	34,510	34,535	34,805	35,200	35,332	35,332
Hydro Sherbrooke	909	909	909	909	909	909	909	909
Hydromega Services Inc	41	41	41	41	41	41	41	41
Innergex Inc	26	26	26	26	26	26	26	26
Quebec Power Operations	2,687	2,687	2,687	2,687	2,687	2,687	2,687	2,687
Regional Power Development				42	42	42	42	42
Regional Power Inc	25	25	25	25	25	25	25	25
Total (MW)	**53,756**	**53,756**	**54,440**	**54,507**	**54,793**	**55,188**	**56,144**	**56,144**

Province/Operator	2021	2022	2023	2024	2025	2026	2027	2028	2029
New Brunswick (MW)	**965**	**965**	**965**	**965**	**965**	**965**	**965**	**965**	**965**
Edmundston Energy	5	5	5	5	5	5	5	5	5
Energie NB Power	912	912	912	912	912	912	912	912	912
St George Pulp & Paper Co	15	15	15	15	15	15	15	15	15
WPS Energy Services of Canada Corp	34	34	34	34	34	34	34	34	34
Newfoundland & Labrador (MW)	**6,253**	**6,253**	**8,503**	**8,503**	**8,503**	**8,503**	**8,503**	**8,503**	**8,503**
Abitibi Consolidated Co of Canada									
Algonquin Power Systems Inc									
Chi Canada Inc									
Deer Lake Power Co									
Newfoundland & Labrador Hydro	6,253	6,253	8,503	8,503	8,503	8,503	8,503	8,503	8,503
Nova Scotia (MW)	**421**	**421**	**421**	**421**	**421**	**421**	**421**	**421**	**421**
Minas Basin Pulp & Paper Ltd	5	5	5	5	5	5	5	5	5
Nova Scotia Power	416	416	416	416	416	416	416	416	416
Ontario (MW)	**9,039**	**9,039**	**9,039**	**9,039**	**9,039**	**9,039**	**9,039**	**9,039**	**9,039**
Abitibi Consolidated Co of Canada	149	149	149	149	149	149	149	149	149
Algonquin Power Systems Inc	13	13	13	13	13	13	13	13	13
Beaver Power Corp	23	23	23	23	23	23	23	23	23
Begetekong Power Corp	23	23	23	23	23	23	23	23	23
Bracebridge Generation Ltd	2	2	2	2	2	2	2	2	2
Brookfield Renewable Energy Partners LP	409	409	409	409	409	409	409	409	409
Burks Falls Waterpower Corp	1	1	1	1	1	1	1	1	1
Canadian Hydro Developers Inc	11	11	11	11	11	11	11	11	11
Canadian Renewable Energy Corp	6	6	6	6	6	6	6	6	6
Clean Power Operating Trust	18	18	18	18	18	18	18	18	18
CVRD Inco Limited	32	32	32	32	32	32	32	32	32
Eastern Ontario Power	4	4	4	4	4	4	4	4	4
Elliot Falls Power Corp	2	2	2	2	2	2	2	2	2
FortisOntario Inc	95	95	95	95	95	95	95	95	95
Gemini SRF Power Corp	8	8	8	8	8	8	8	8	8
High Falls Energy Corp	1	1	1	1	1	1	1	1	1
Hydromega Services Inc	15	15	15	15	15	15	15	15	15
IESO (Ontario)	136	136	136	136	136	136	136	136	136
Innergex II Income Fund	8	8	8	8	8	8	8	8	8
Innergex Inc	5	5	5	5	5	5	5	5	5
Kagawong Power Inc	1	1	1	1	1	1	1	1	1
Long Sault Joint Venture	20	20	20	20	20	20	20	20	20
Mississagi Power	495	495	495	495	495	495	495	495	495
Mississippi River Power Corp	2	2	2	2	2	2	2	2	2
Ontario Power Generation Inc	7,484	7,484	7,484	7,484	7,484	7,484	7,484	7,484	7,484
Orillia Power Generation Corp	8	8	8	8	8	8	8	8	8
Peterborough Utilities Inc	4	4	4	4	4	4	4	4	4
Rankin Renewable Power Inc	6	6	6	6	6	6	6	6	6
Rideau Falls LP	2	2	2	2	2	2	2	2	2
Serpent River Power Corp	1	1	1	1	1	1	1	1	1
Shaman Power Corp	4	4	4	4	4	4	4	4	4
Spruce Falls Inc	3	3	3	3	3	3	3	3	3
St Catharines Hydro Inc	5	5	5	5	5	5	5	5	5
Synexus Global Inc	3	3	3	3	3	3	3	3	3
Trent Rapids Power Corp	8	8	8	8	8	8	8	8	8
Trout Creek Power	0	0	0	0	0	0	0	0	0
Twin Falls LP	6	6	6	6	6	6	6	6	6
Upper Thames River Conservation Authority	1	1	1	1	1	1	1	1	1
Valerie Falls LP	10	10	10	10	10	10	10	10	10
Yellow Falls Power LP	16	16	16	16	16	16	16	16	16
Quebec (MW)	**40,106**	**40,106**	**40,106**	**40,706**	**40,706**	**40,706**	**41,306**	**41,306**	**41,306**
Abitibi Consolidated Co of Canada	137	137	137	137	137	137	137	137	137
Algonquin Power Systems Inc	49	49	49	49	49	49	49	49	49
Boralex Inc	39	39	39	39	39	39	39	39	39
Brookfield Renewable Energy Partners LP	161	161	161	161	161	161	161	161	161
Gulf Power Co	18	18	18	18	18	18	18	18	18
Hydro Quebec	35,972	35,972	35,972	36,572	36,572	36,572	37,172	37,172	37,172
Hydro Sherbrooke	909	909	909	909	909	909	909	909	909
Hydromega Services Inc	41	41	41	41	41	41	41	41	41
Innergex Inc	26	26	26	26	26	26	26	26	26
Quebec Power Operations	2,687	2,687	2,687	2,687	2,687	2,687	2,687	2,687	2,687
Regional Power Development	42	42	42	42	42	42	42	42	42
Regional Power Inc	25	25	25	25	25	25	25	25	25
Total (MW)	**56,784**	**56,784**	**59,034**	**59,634**	**59,634**	**59,634**	**60,234**	**60,234**	**60,234**

Appendix B

Shown below are the supply and demand charts for the Maritimes and Ontario regions referenced in Section 3.0 of this report.

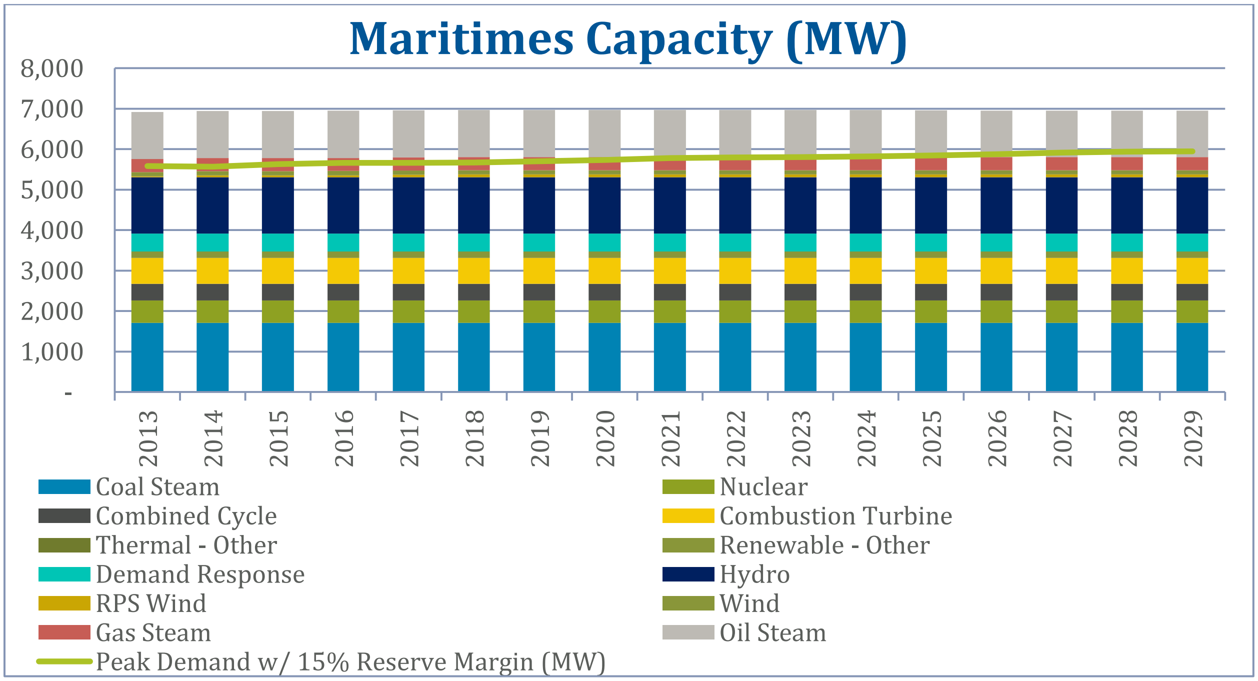

Figure B-1 Maritimes Supply & Demand - Base Case Supply

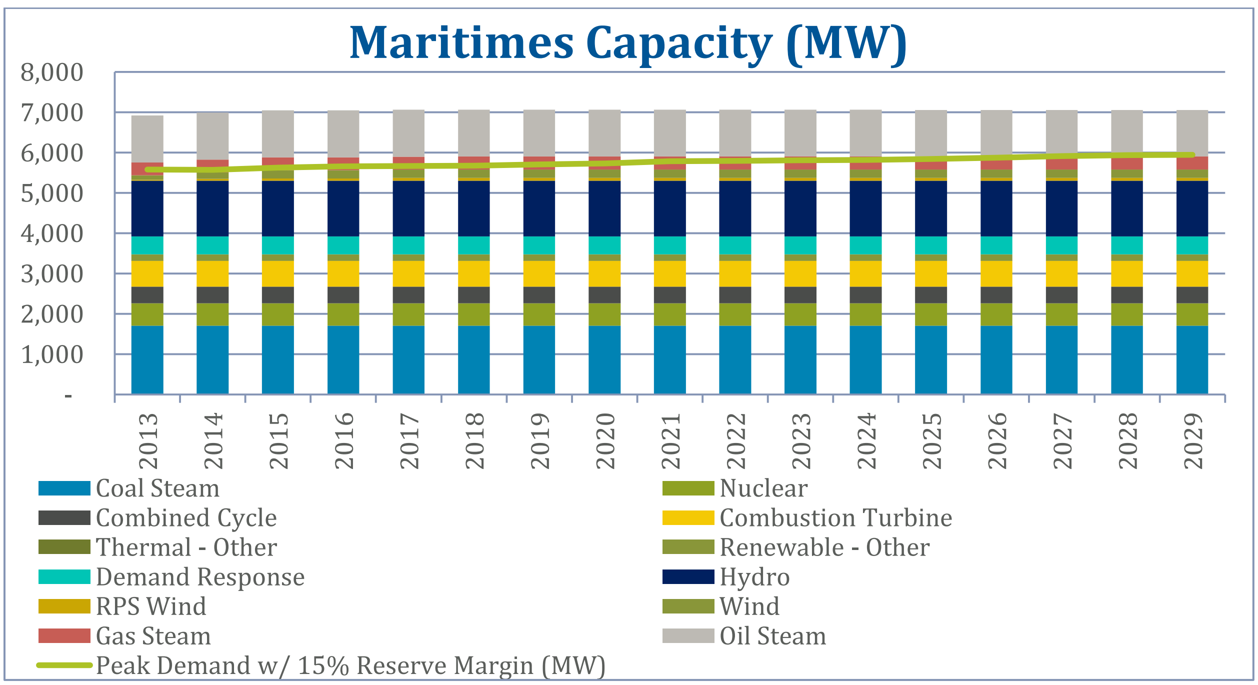

Figure B-2 Maritimes Supply & Demand - Alternative Hydro Supply Case

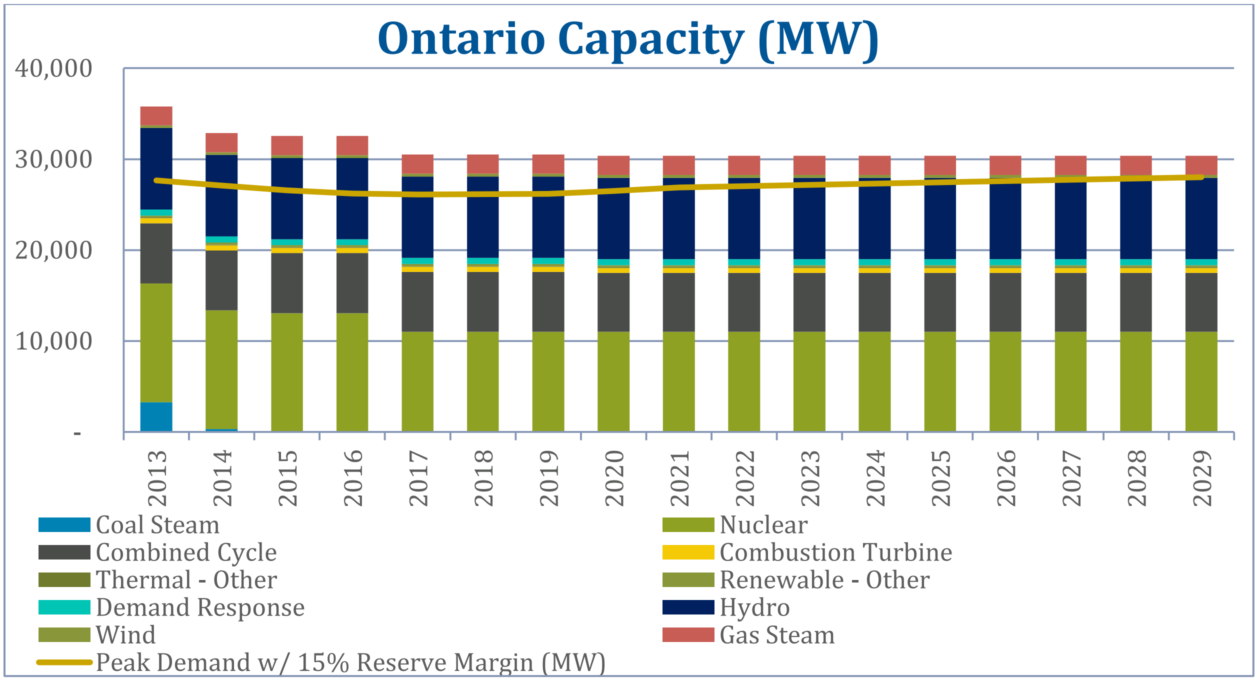

Figure B-3 **Ontario Supply & Demand - Base Case Supply**

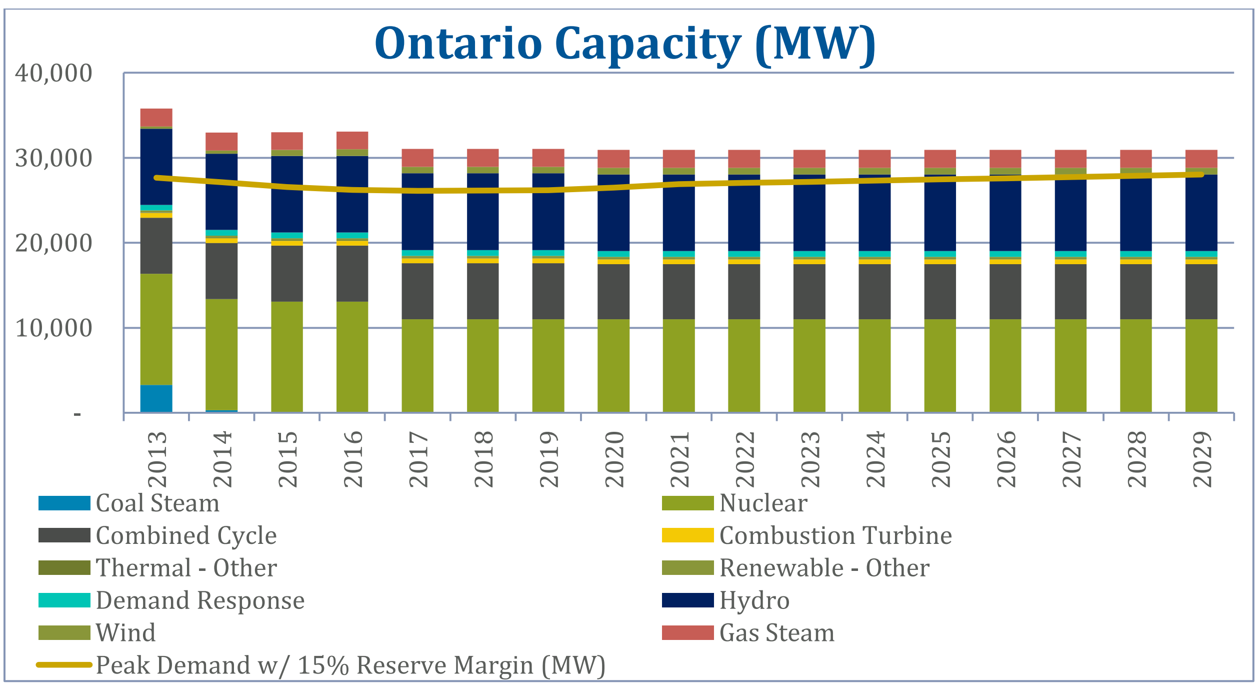

Figure B-4 **Ontario Supply & Demand – Alternative Hydro Supply Case**