CRA Charles River Associates

Prepared For:

Northern Pass Transmission

LMP and Congestion impacts of Northern Pass Transmission Project

FINAL REPORT

Prepared By:

Charles River Associates

200 Clarendon Street

Boston Massachusetts 02116

Date:

CRA Project No.

Page intentionally left blank

Table of contents

1. INTRODUCTION AND SUMMARY

1.1. Purpose and Overview of analysis

Northeast Utilities ("NU") and NSTAR subsidiaries have entered into a joint venture, Northern Pass Transmission LLC ("NPT"), to develop the Northern Pass Transmission Line ("NPT Line" or the "NPT Project"). On October 4, 2010, NPT entered into a forty year transmission service agreement with H.Q. Hydro Renewable Energy, Inc. ("HQHRE"), to facilitate delivery of power generated in Québec to the New England transmission system. The NPT Line will provide capacity to deliver up to 1,200 MW of power to New Hampshire, allowing a significant amount of power generated by plants burning fossil fuels to be replaced with imported power generated predominantly by hydroelectric facilities in Québec. The additional deliveries of power from Québec to New England will supplement imports on the current ties between the systems, which are fully utilized in most peak hours throughout the year. The capacity provided by the NPT Line will therefore relieve congestion on the transmission interface between Québec and ISO New England Inc. ("ISO-NE") by allowing more competitively priced power from low incremental cost resources in Québec to be delivered in the hours when New England prices are highest but existing transfer capacity is exhausted.

At the request of NPT, CRA has prepared an assessment of the congestion mitigation impacts of the NPT Line and resulting price reductions in New England. This report summarizes CRA's analysis of the ISO-NE electricity market and power system under scenarios with and without the NPT Line in service. Specifically, CRA has estimated the hourly operations of the ISO-NE system for each scenario and compared electricity prices, wholesale power costs, and power plant operations between the two scenarios to quantify the impact of the congestion mitigation and increased supply provided by the NPT Line.

Section 1.2 provides a summary of the principal results of CRA's study. Section 2 follows with background information about the NPT Project, the Hydro Québec system, the ISO-NE market, and the expected impact of the Line. Section 3 describes the analytical methodology and key assumptions utilized in the study. Section 4 presents the quantitative results regarding the impact of the NPT Line and Section 5 provides a summary of key conclusions.

1.2. Principal Results

The principal results of CRA's analysis include:

- The NPT Line will reduce congestion between Québec and ISO-NE by:

  (i) allowing more competitively priced energy to be imported in ISO-NE, displacing higher cost generation on the ISO-NE system, and

  (ii) allowing more of the energy imported from Québec to be delivered during peak hours when marginal generation costs and prices in New England are highest.

  This reduced congestion will lower New England power prices and reduce costs for wholesale load customers. CRA's base case estimate of the cost reduction to wholesale load customers is $1.58/MWh, or $206 million in 2015 and $2.30/MWh, or $327 million in 2024. These wholesale cost savings should be passed on to retail customers through lower electricity rates driven by lower prices in standard offer procurements and lower costs to competitive retail suppliers.

- Without the NPT Line, existing ties are expected to be fully utilized in 99.8 percent of peak hours. The capacity of the NPT Line allows energy delivered in other, lower-priced hours, or delivered to lower-priced locations in New York and Ontario, to be reallocated to deliveries in New England during these peak hours, when (and where) the power is most valuable.
- Based on the quantity of energy expected to be available for Hydro Québec (referred to as either "Hydro Québec" or "HQ" herein), the parent company of HQHRE, to export from Québec to neighboring markets, CRA's analysis shows that as much as 7.7 TWh of energy would be delivered to ISO-NE via the NPT Line in 2015, the first year the Line is expected to be operational. By 2024, imports on the Line are expected to grow to 8.9 TWh, with the increased utilization driven by expansion of the hydroelectric generating capacity in Québec. Accounting for reductions in the net imports of power into ISO-NE on other AC and DC ties with neighboring markets, the analysis shows that total net imports to New England will increase by 5.3 TWh in 2015 and 6.4 TWh in 2024. This modeled level of exports from Québec is based on projected export capability for the Hydro Québec system. Under open access provisions in the TSA, other competitive power marketers may also have access to unused transmission capability on the Line from time-to-time, potentially allowing for additional utilization.
- In order to provide a conservative estimate of the reduction in congestion and wholesale power costs in New England, CRA's analysis has examined a base case with assumptions that represent conservative expectations for market conditions. The likely range of actual market conditions also includes scenarios under which the reduction in congestion, displacement of thermal generation, and wholesale cost reductions would be greater. In particular, higher natural gas prices, more limited renewable capacity additions, and unit retirements would all tend to increase the benefits of the project. Moreover, CRA has conservatively assumed that currently projected growth in exports from Québec will occur whether or not the NPT Line is built. However, absent the NPT Line, these additional exports would be delivered during lower value periods with lower net revenues to Hydro Québec, which could result in delaying the development of the resources that will allow growth in total exports. If more projects supporting exports were developed as a result of the NPT Line, the impact of the line on imports, reduction in fossil-fueled generation in New England, and wholesale cost reductions would be greater.
- Under the base case scenario modeled, the increased net imports to New England would lead to the displacement of generation from fossil-fueled generators totaling 5.3 TWh in 2015, most of which will be from gas-fired generating units. If, as a result of their ongoing build of new hydro-electric facilities, Hydro Québec has more surplus energy than modeled, exports could increase to a level that would support additional deliveries on the NPT line, up to 10.5 TWh. For every additional TWh of imports that displaces gas-fired generation, carbon emissions would be reduced by approximately 0.44 million tons, up to 5 million tons total.

- The NPT Line will also provide reliability and fuel diversity benefits. The 1,200 MW of firm capacity that can be imported over the Line will add to the ISO-NE reserve margin for several years and, based on the current ISO-NE demand forecast, delay the need for constructing new capacity within ISO-NE by 4 to 5 years. Additionally, the Project will enhance reliability by reducing the region's dependence on natural gas, particularly during high gas demand periods in the winter months. Under CRA's 2015 base case the power transfers across the NPT Line are expected to displace 24.7 Tcf of natural gas in New England.

2. BACKGROUND

2.1. THE NORTHERN PASS TRANSMISSION PROJECT

The NPT Line will consist of (i) a 1,200 MW high voltage direct current ("HVDC") transmission line from the United States-Canadian border to a converter station to be constructed in the City of Franklin, New Hampshire, and (ii) a radial 345 kV alternating current ("AC") transmission line between the Franklin converter station and the Deerfield substation owned by NU subsidiary, Public Service Company of New Hampshire, where it will interconnect with the ISO-NE transmission system. On the Canadian side of the border, the NPT Line will connect with a new HVDC transmission line to be constructed by Trans-Energie, a transmission division of Hydro-Quebec, into the Des Cantons substation in Québec. The NPT Line will be constructed to have the capability to transmit up to 1,200 MW of power, supplementing the existing ties between Québec and New England, which includes an interconnection to Sandy Pond in central Massachusetts and an interconnection to Highgate in Vermont. Major construction is expected to begin in 2013, with a target in service date in 2015.

The NPT Line will support sales of surplus energy and capacity available in Québec. The energy from the Québec system is generated almost entirely from hydroelectric power stations, which will be supplemented with the output from new hydro projects under construction or currently under development. The variable operating costs for these generating facilities is extremely low. By contrast, natural gas is the predominant fuel for electric generation in New England, leading to significantly higher operating costs and market prices. Given the large differential between the low power costs in Québec and the high electricity prices in the ISO-NE market, the existing ties between the two systems are very highly utilized, especially during peak periods. The NPT Line will provide additional delivery capacity during many on-peak hours when the existing ties are fully utilized, but a large differential between the system marginal cost in Québec and the market price in ISO-NE remains. The additional capacity provided by NPT will therefore mitigate transmission congestion between the two systems.

2.2. HYDRO QUÉBEC SYSTEM

2.2.1. Existing Resources and Load Responsibilities

A division of Hydro Québec, Hydro-Québec Production ("HQP"), owns and operates one of the largest fleets of zero-carbon generation in the world. HQP's current fleet of generating facilities consists of 36,810 MW of installed capacity:

Source	*Number of Units*	*Installed Capacity*
Hydroelectric generating stations	60	34,499 MW
Nuclear generating station	1	675 MW
Thermal generating stations	27	1,634 MW
Wind farm	1	2 MW

Source: Hydro-Québec, http://www.hydroquebec.com/generation/index.html

Expected annual production from the hydroelectric facilities is 166.7 TWh, depending upon water availability. The Gentilly-2 nuclear station produces 5.2 TWh annually when at normal availability. The thermal generation plants, principally the 600 MW Tracy steam plant, are lightly utilized and contribute only 0.2 TWh of electricity annually, on average.[1]

Additionally, Hydro-Québec has contracts to purchase the output from all, or substantially all, of the output from an additional 7,382 MW of installed capacity:

Source	*Number of Units*	*Installed Capacity*
Churchill Falls generating station	1	5,428 MW
Privately owned wind farms	8	657 MW
Other independent power producers		1,297 MW

Source: Hydro-Québec, http://www.hydroquebec.com/generation/index.html

Long-term purchase arrangements contribute an expected 35.4 TWh to the Hydro-Québec system annually; additional purchases from independent power producers are expected to add a further 0.5 TWh annually.

As the franchise utility for the province, Hydro-Québec also has substantial load-serving responsibility. Hydro-Québec expects to deliver 188 TWh of power (including associated delivery losses) within Québec in 2010, plus an additional 2.9 TWh for contractual deliveries outside of Québec. This leaves the system with approximately a 15 TWh margin of flexibility for managing low runoff risk and for short-term sales.

[1] See HQ's Environmental Impact Assessment Study - Romaine Complex - Volume I, December 2007, table 2-8, page 2-10, available in French at: http://www.hydroquebec.com/romaine/pdf/ei_volume01.pdf .

In terms of peak energy, the Hydro-Québec system has an expected capacity requirement of 39,519 MW for the 2010–2011 power year, of which 482 MW are for short- and long-term contracts outside of the province. After accounting for purchases and operating considerations, Hydro-Québec has sufficient capacity to support an expected minimum of 1,249 MW of sales in 2010–2011, with significantly more capacity available to support exports in most hours. It is particularly noteworthy that Québec is a winter-peaking system, so additional capacity is available for sale during the summer to meet New England's peak loads. As a result, annual energy limits are a more relevant constraint to exports than are capacity constraints.

2.2.2. Plans for Expansion in Québec

Québec has substantial amounts of untapped renewable energy resources from further large-scale hydroelectric development. HQP has brought several new hydro-electric facilities into service recently. Its Mercier, Peribonka, Rapide-des-Coeurs, and Chute-Allard facilities have been in full-scale commercial operation since 2007, which, together with various upgrades to existing facilities, has added 621 MW of capacity and 9.4 TWh of energy to the Hydro-Québec system.

Going forward, HQP has three major hydroelectric projects under construction:

1. The Eastmain-1-A facility, with 768 MW of capacity and 2.3 TWh of energy;
2. The Sarcelle facility, with 125 MW of capacity and 0.9 TWh of energy.
3. The Romaine Complex, which will add 640 MW of capacity (3.0 TWh) in 2015, potentially ramping up to 1,550 MW of capacity (8.0 TWh) by 2021.

Collectively, these projects and related upgrades to existing resources will add 2,506 MW of capacity and 16.7 TWh of energy on the Hydro-Québec system.[2]

Looking into the future, Hydro-Québec has a strategy to add a further 3,000 MW of hydroelectric capacity. The timing of these projects "will take into account power market conditions here in Québec and in neighboring provinces and states."[3] An additional block of 3,000 MW of hydroelectric power is also contemplated for the northern area of the province.

2.2.3. Interconnections to the U.S. and Other Canadian Provinces

Although Hydro-Québec's TransÉnergie transmission system is not synchronized with the Eastern Interconnection, it is well interconnected to all of the neighboring markets, as shown in Table 1.

[2] Hydro-Québec, "Strategic Plan 2009–2013", p.20.

[3] Id., at 22.

Table 1: Hydro Québec External Ties

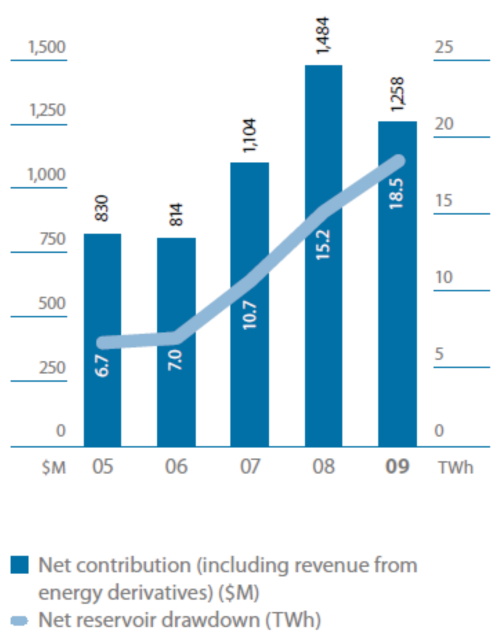
Neighboring System	*Import Mode (MW)*	*Export Mode (MW)*
New York	1,100	2,000
Ontario – Existing	695	1,455
Ontario – New	1,250	1,250
New England – Existing	1,870	2,275
New Brunswick	785	1,080
Newfoundland and Labrador	5,150	0

Source: Hydro-Québec, http://www.hydroquebec.com/transenergie/en/reseau/bref.html

The above table does not include the additional transfers of up to 1,200 MW that the NPT Project would allow between Québec and New England.

Since markets were deregulated in 1999, HQP, through its U.S.-based marketing affiliate HQ Energy Services Inc. ("HQUS"), has engaged in energy trading in the U.S. Northeast: sales of electricity produced in Québec, purchase/resale operations and price arbitraging. Since the early 2000s, HQP has also exported electricity to Ontario at market prices. As Figure 1 shows, HQP's exports have risen substantially over the last decade, nearly tripling from 6.7 TWh in 2005 to 18.5 TWh in 2009.

Figure 1: Hydro Québec Exports



Source: HQ Annual Report, 2009

2.2.4. Expected Future Export Potential

The combination of increased production capability in Québec resulting from the addition of new hydroelectric will allow Hydro-Québec to continue to increase its exports going forward. Hydro-Québec projects that the *installed capacity* available for long-term sales will more than double from 1,249 MW in the 2010–2011 power year to 2,862 MW in the 2020–2021 power year, even taking into account increased demand in the province. In parallel, Hydro-Québec forecasts that the amount of *energy* available for long-term sales will increase to nearly 24 TWh by 2013.[4] By 2021, potential export capacity is expect to grow to approximately 30 TWh.[5] The ability to *deliver* these incremental volumes during periods when cost in the destination markets are highest, however, is dependent upon increasing the interconnection links between Québec and potential export markets, including, for example, the NPT Project into New England. This modeled level of exports from Québec is based on projected export capability projected for the Hydro Québec system. Other competitive power marketers will also have access to released transmission capability on the NPT Line, potentially allowing for additional utilization.

2.3. ISO New England Market

2.3.1. Overview

ISO-NE was formed in 1997 to operate the power markets in the New England region, and became the regional transmission organization (“RTO”) in 2005. ISO-NE serves as the independent system and market operator for the members of the legacy New England Power Pool (“NEPOOL”) organization, a voluntary association of market participants that now serves as the primary stakeholder advisory group to ISO-NE.

ISO-NE operates the Day-Ahead and Real-Time Energy Markets, along with markets for installed capacity and ancillary services. Figure 2 show the ISO-NE footprint, which includes eight major load zones covering all of the New England states, with the exception of the far northern part of Maine. Over 500 generating units are interconnected within the ISO-NE system, almost 33 GW of supply to meet peak summer demand, along with an additional 2,300 MW of Demand Response capacity.[6] The all-time record peak demand of 28,130 MW was reached in August 2006 during very hot conditions. The 2009 peak demand of 25,081 MW was significantly lower, reflecting milder weather and the effects of the current economic downturn. The weather-normalized peak for 2009 was estimated to be 27,460 MW, demonstrating the significant impact of the mild summer weather on demand. The summer peak for 2010 was 27,100 MW.

---

[4] See HQ’s Strategic Plan 2009-2013, page 25, available at: http://www.hydroquebec.com/publications/en/strategic_plan/index.html.

[5] See HQ’s Environmental Impact Assessment Study - Romaine Complex - Volume I, December 2007, table 2-8, page 2-10, available in French at: http://www.hydroquebec.com/romaine/pdf/ei_volume01.pdf

[6] System capacity is based on summer capacity from ISO-NE Seasonal Claimed Capacity Report; October 1, 2010. Demand response capacity is cleared demand response from the FCM Forward Capacity Auction for the 2010/11 Commitment Period.

Figure 2 New England (ISO-NE) Electric Regions

ISO-NE currently has ample supply. The projected reserve margin for the summer of 2010 is 33 percent with a capacity reserve of 7,519 MW, which exceeds the required amount by 2,404 MW. ISO-NE administers a Forward Capacity Market ("FCM") in order to secure sufficient resources three years in advance of each planning year. Excluding resources that do not have a firm capacity obligation from the Forward Capacity Auction ("FCA") for the 2010/11 FCM Commitment Period, the surplus is 1,774 MW. Based on the Installed Capacity Requirement ("ICR") applied in the most recent FCM auction (for the 2012/13 FCM Commitment Period), the target minimum reserve margin for ISO-NE is approximately 15 percent; in the longer-term, the market should trend toward this reserve margin level.

2.3.2. Energy Market

In 2003, ISO-NE implemented a Standard Market Design ("SMD") framework with a two-settlement spot energy market consisting of a Day-Ahead Market ("DAM") and a Real-Time Market ("RTM"). The DAM enables market participants to purchase and sell energy at binding Day-Ahead prices. This market is cleared based on submitted supply offers and demand bids using a least-cost security-constrained unit commitment algorithm. The DAM produces financially binding obligations and schedules for demand and generation. The ISO-NE dispatch and market clearing process determines Locational Marginal Prices (LMPs) for energy at over 900 nodes throughout the region. These prices are the sum of a reference energy cost, plus local loss and congestion terms. Through the DAM, ISO-NE produces hourly LMP pricing, and it also schedules commitments for generation and external transactions for the next day.

Load obligations are settled at zonal prices, which are determined as load-weighted average of nodal prices within each of eight load zones within ISO-NE (three in Massachusetts plus one for each of the other five states). The “Mass Hub” price is the unweighted average of 32 nodal prices in central Massachusetts; this hub was created to facilitate bilateral trading and is traded on the New York Mercantile Exchange (“NYMEX”).

Projected spot prices for power in these ISO-NE administered competitive wholesale markets provides a very good indicator of the ultimate cost of wholesale power that will be passed on to retail customers. As a result of industry restructuring, New England’s electric distribution utilities and other load serving entities own and operate only a small percentage of the region’s generating capacity, but rather serve their customers’ demand through wholesale purchases from the competitive market, the costs of which are ultimately recovered through retail rates charged to end-use customers. Numerous New England customers pay a retail rate tied to prices set in periodic Standard Offer Service auctions, which in turn closely ties to expected wholesale power costs. Wholesale power costs are therefore a good measure of electricity costs for consumers in the New England Region.

2.3.3. Capacity and Generation Mix

ISO-NE currently has generation resources that together provide Summer Claimed Capability of 30,146 MW.[7] Demand-side resources (DR) and Emergency Generation provide an additional 1,679 MW and 600 MW, respectively, of capacity resources, along with 934 MW of capacity from imports (excluding the HQICC[8]). Together, these resources provided a reserve margin of nearly 33 percent against the 2010 peak load forecast.

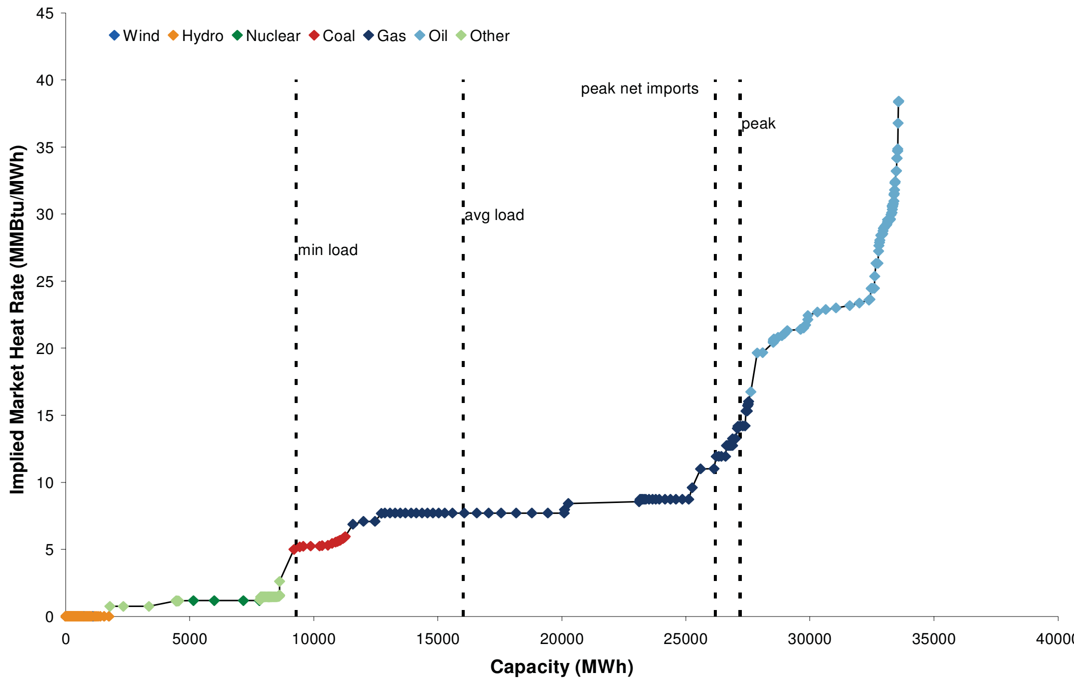
Figure 3 shows the Summer 2010 generation supply curve for ISO-NE. The installed capacity base in New England is dominated by gas- and oil-fired generation, as shown by the long, flat portion of the supply curve, consisting of combined cycle capacity, and the gas- and oil-fired steam and peaking capacity at the right end of the curve. Approximately 50 percent of ISO-NE capacity is either gas-fired (26%) or gas/oil dual-fueled (24%). Oil-fired generators (without dual-fuel capability) contribute another 15 percent, with hydro, nuclear, and coal capacity making up most of the rest of the New England fleet. Gas- and oil-fired generation set market prices a large percentage of the time in New England. Over the last few years, these generators were on the margin in more that 60 percent of the ISO-NE dispatch intervals.[9]

[7] ISO-NE Summer Claimed Capability Report, November 1, 2010.

[8] Hydro Québec Interconnection Capacity Credits (HQICC) are capacity credits that the holders of transmission rights across the Phase I/II interconnection (“Interconnection Rights Holders” or IRH) can use to satisfy their capacity obligations under the New England Forward Capacity Auction (FCA). And therefore lower the total quantity procured in the FCA.

[9] 2009 ISO-NE Annual Markets Report

Figure 3: ISO-NE Supply Curve, Summer 2010



Planned New Capacity

Existing New England generating capacity, along with expected imports and DR resources, is expected to be sufficient to meet system needs several years into the future. As a result of new resources that are planned to come on-line in the next several years, all near-term needs and capacity requirements will be met for several additional years. These generating resources represent capacity secured in the first four FCAs. Additionally, significant new DR resources have been secured in the auctions.

New resources totaling 626 MW that were secured through the first FCA have either recently come on-line or are scheduled to enter commercial operation before the end of 2010. In addition, several additional new units have capacity supply obligations from the second and third FCAs and should enter service over the next two years, along with a small amount of new capacity that cleared in the fourth FCA.

Another important source of capacity resources for New England is demand response. Existing DR sources totaling 1,367 MW (1,092 MW after prorating for joint feasibility) cleared in the first FCA and 1,187 MW of new DR cleared, for a total of 2,279 MW counting toward the regional capacity requirement. Additional resources secured through the second and third FCA have brought the total DR for the 2012/13 FCM Capacity Commitment Period up to 2,867 MW. Hence, DR totaling about 10 percent of the ISO-NE forecast peak will be available as capacity resources.

The generation mix in New England creates attractive export opportunities for a supplier such as HQ. With gas- or oil-fired generation on the margin and setting the price in most peak hours, New England prices are very closely tied to the price of natural gas. These gas-driven prices are higher in many hours than those in markets with significant coal-fired generation.

Additionally, as much of the current capacity surplus was created by the addition of DR. New England currently has commitments from demand-side resources totaling approximately 10% of the forecasted peak load for the region. Meeting such a substantial portion of the region's requirement for reserve capacity with curtailment of demand rather than generation supply means that, under conditions of unusually high demand or unexpected loss of supply, the system operators will have to rely on emergency procedures that allow the DR to be called.

2.3.4. Transmission System and Interconnections

The ISO-NE transmission network includes over 8,000 miles of transmission lines, with twelve interconnections to Canada and New York. The transmission system includes a higher voltage (345 kV) regional backbone, as well as lower level lines connected to load and generation in the local areas within the regional network. The external ties are a combination of DC ties (two with Québec, one with Long Island) and AC lines.

Historically, the most frequently binding transmission constraints in ISO-NE have been major interfaces between zones. Figure 4 shows the major interfaces throughout the ISO-NE system. Over the last several years, the most frequently congested interfaces have been the Boston/NEMA Import Limit, the Southwest Connecticut Import Limit, the Maine-New Hampshire Interface, and the New England East-West Interface. As reflected by the relatively low price separation among the zones in Figure 5, congestion on these interfaces has diminished in both frequency and magnitude. Rather, price separation among ISO-NE regions has been attributable more to the pricing of marginal losses.

Figure 4: Major ISO-NE Interfaces

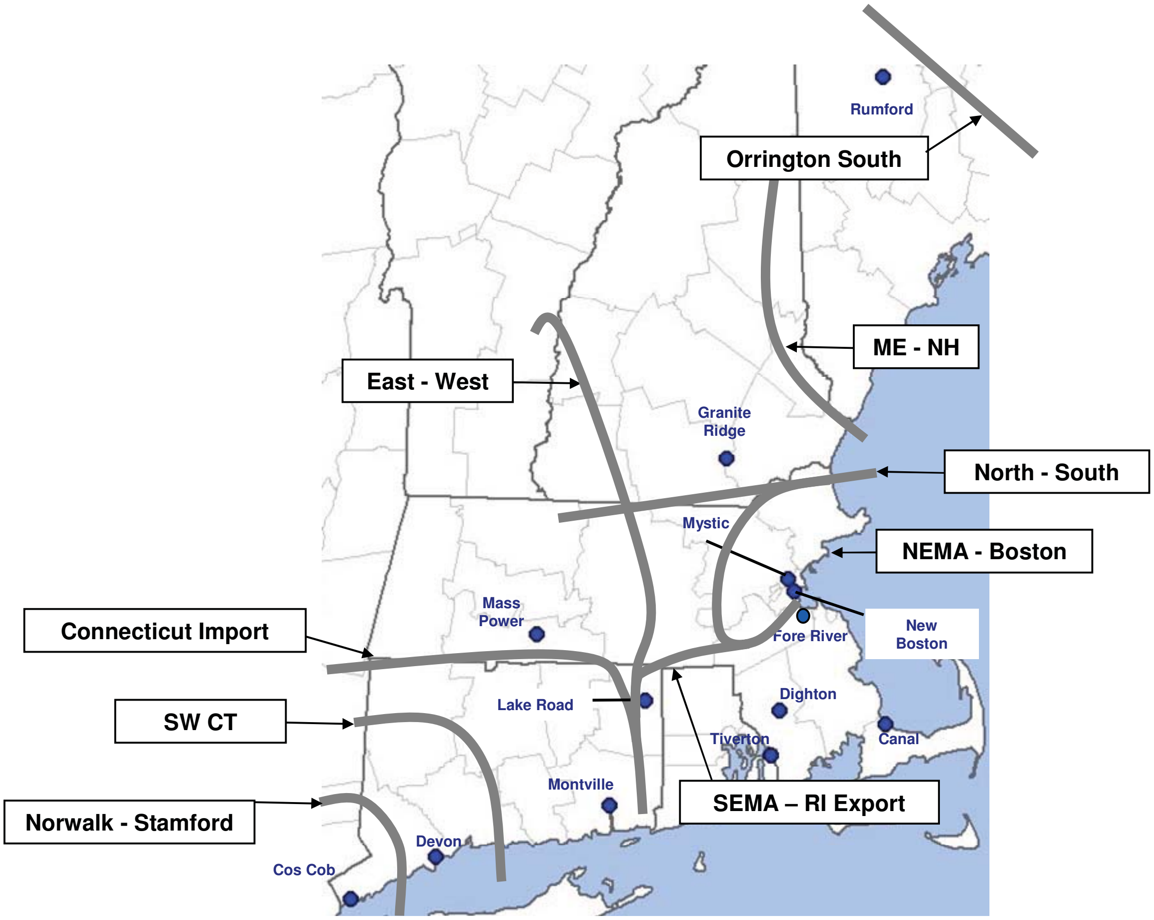
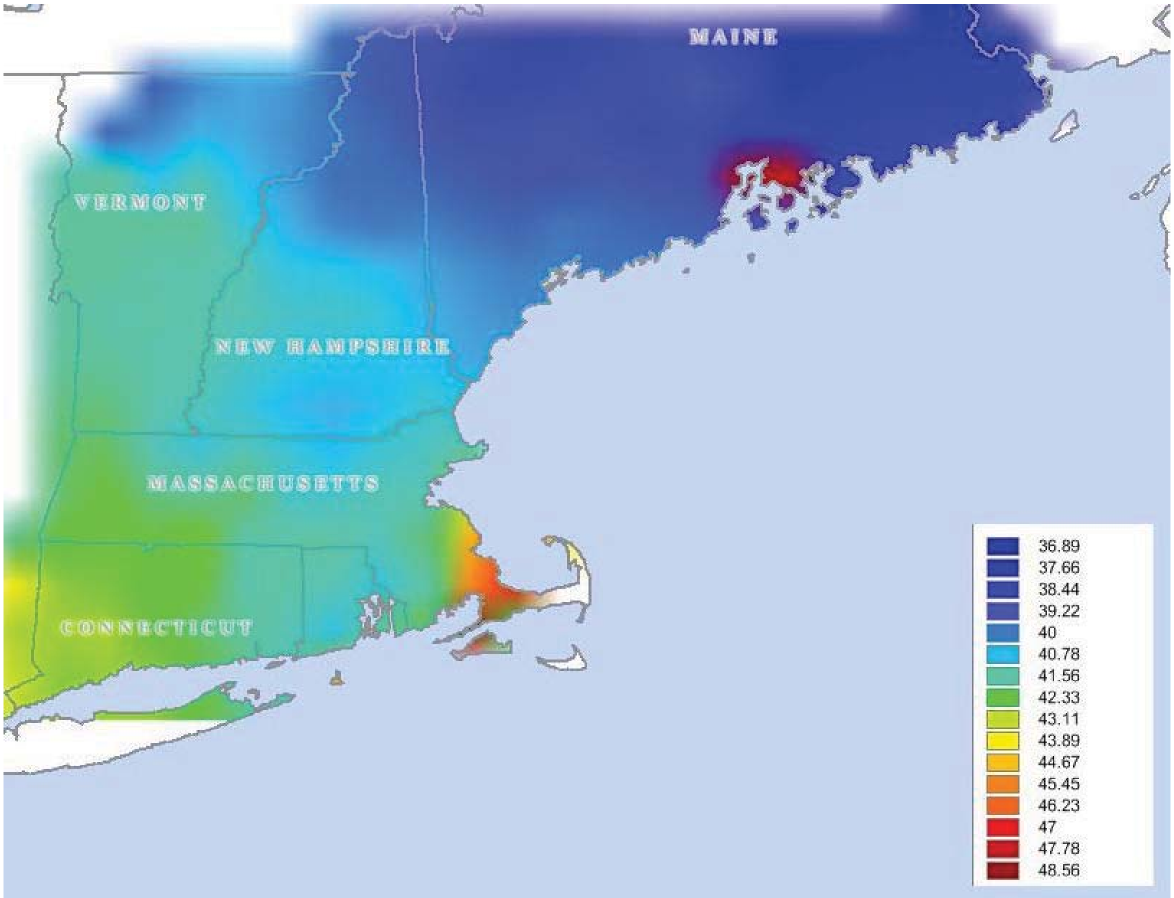


Figure 5: ISO-New England LMP Day-Ahead Patterns, 2009



The reduced level of congestion across these major interfaces is attributable to recent transmission upgrades within ISO-NE. First, upgrades to the 345 kV system in and around Boston have significantly reduced congestion for the NEMA zone, while supporting higher prices in SEMA as separation between the two zones has declined. Similarly, upgrades to the Connecticut transmission system through the Southwest Connecticut Reliability Project, which includes 345 kV upgrades, allows more power to flow into the Norwalk-Stamford and Southwest Connecticut load pockets.

With these internal transmission upgrades in place, congestion has not been completely eliminated, however. Additional congestion has occurred on the New England East-West and Connecticut Import Interfaces, essentially reflecting a shift in the bottleneck from Southwest Connecticut back to the Connecticut border. Several potential transmission upgrades have been proposed to help mitigate this congestion and prevent additional congestion on the interfaces as loads increase. The planned upgrades are part of the New England East-West Solution (NEEWS) project, consisting of four projects designed to reduce this congestion and provide other reliability benefits. The projects are proposed for completion in the 2013 – 2016 time frame. The other major transmission upgrade recently completed in New England is the Maine to New Brunswick Interconnector, which significantly increases the ability for Maine to import power from the Maritimes region.

In addition to NPT, other major transmission projects currently under review in ISO-NE include:

- A proposed line from Scobie (in NH) to Tewksbury (in MA), which would facilitate additional flows from Maine and New Hampshire south to NEMA.
- The Green Line project, which would bring power from Maine into Southern New England.

All of these projects are still under development without a definitive timetable for construction or commitment to move forward. Although the Scobie-Tewksbury line is not yet part of the regional system plan, ISO-NE has identified either this line or an equivalent overhead transmission upgrade that is needed to help solve reliability problems in the greater Boston area and relieve a significant bottleneck at the North-South interface. Therefore, CRA has included the Scobie-Tewksbury line in the analysis.

2.3.5. Historical Pricing

Two major trends become apparent when looking at historical power prices in New England:

1. The close relationship between power prices and natural gas prices, particularly during peak hours
2. The decrease in price separation across New England

New England's generation fleet is dominated by gas-fired combined cycle capacity, tying power prices tightly to the natural gas market during most peak hours. As shown in Table 2 and Table 3, power prices across New England have followed the trends in the natural gas markets over the past five years. New England power prices reflect the run up in gas prices in 2008 and the subsequent decline. These trends can be observed in both on-peak and off-peak markets[10]. The latter suggesting a limited supply of base load generation, that allows intermediate generating resources, e.g. combined cycle generating plants, to set prices during hours that were traditionally covered by coal and nuclear generation.

Transmission upgrades, such as the NSTAR 345 kV cables into the Boston area and the two phases of the 345 kV Southwest Connecticut Reliability project increased the transfer capability between transmission zones and greatly reduced the congestion potential across New England.

[10] The on-peak period in New England is defined as a 16-hour period between 7 a.m. and 11 p.m. on weekdays. The remaining night time hours on weekdays and all hours on both Saturday and Sunday are defined as off-peak periods.

Table 2: Zonal Congestion and Losses for ISO-NE, Peak Hours ($/MWh)

On-Peak		Mass Hub	CT	ME	NEMA-Boston	NH	RI	SEMA	VT	WCMA
2005	LMP	88.81	96.62	78.87	91.96	84.52	85.50	85.45	89.02	89.00
	Congestion	-	7.15	(4.37)	4.56	(2.22)	(1.34)	(1.20)	(0.47)	(0.06)
	Losses	-	10.94	(17.26)	3.62	(7.36)	(4.85)	(5.03)	0.27	0.40
2006	LMP	69.56	79.75	64.66	69.56	67.30	67.00	67.58	70.15	69.97
	Congestion	-	9.84	(1.78)	1.06	(0.95)	(1.12)	(0.66)	0.43	0.17
	Losses	-	15.97	(8.26)	(0.46)	(3.69)	(3.91)	(2.94)	0.67	0.71
2007	LMP	77.00	82.94	72.07	75.01	75.45	74.47	76.98	78.91	77.79
	Congestion	-	4.63	(2.19)	(1.02)	(0.80)	(1.33)	1.01	1.00	0.32
	Losses	-	8.51	(7.74)	(2.76)	(2.54)	(3.94)	0.74	3.02	1.23
2008	LMP	90.94	97.41	84.78	90.04	89.25	89.36	93.68	91.60	91.87
	Congestion	-	4.63	(1.78)	(0.33)	(0.40)	(0.55)	3.42	0.33	0.46
	Losses	-	9.96	(8.66)	(1.39)	(2.70)	(2.43)	6.09	1.01	1.33
2009	LMP	46.37	48.28	43.96	46.41	45.56	45.91	46.67	46.44	46.85
	Congestion	-	1.19	(0.34)	0.31	(0.14)	(0.04)	0.39	0.00	0.20
	Losses	-	2.54	(3.79)	(0.14)	(1.38)	(0.79)	0.47	0.08	0.78
2010 YTD	LMP	55.75	58.67	52.94	54.84	54.75	54.58	54.84	56.82	56.49
	Congestion	-	1.48	(0.43)	(0.32)	(0.34)	(0.45)	(0.45)	0.38	0.25
	Losses	-	4.59	(4.80)	(1.66)	(2.09)	(1.98)	(1.57)	1.53	1.53

Table 3: Zonal Congestion and Losses for ISO-NE, Off-Peak Hours ($/MWh)

Off-Peak		Mass Hub	CT	ME	NEMA-Boston	NH	RI	SEMA	VT	WCMA
2005	LMP	69.60	71.41	63.81	69.29	67.27	68.08	67.94	69.87	69.80
	Congestion	-	1.31	(1.53)	0.78	(0.73)	(0.03)	(0.01)	(0.21)	0.02
	Losses	-	1.81	(5.79)	(0.31)	(2.33)	(1.52)	(1.66)	0.28	0.20
2006	LMP	53.46	56.48	50.62	52.83	52.24	52.26	52.49	53.54	53.70
	Congestion	-	2.77	(0.52)	0.18	(0.20)	(0.14)	0.01	0.00	0.06
	Losses	-	3.02	(2.85)	(0.64)	(1.22)	(1.20)	(0.97)	0.08	0.24
2007	LMP	60.10	61.89	57.62	59.33	59.31	58.93	60.07	61.00	60.50
	Congestion	-	0.77	(0.33)	(0.00)	(0.21)	(0.23)	0.77	0.20	0.03
	Losses	-	1.79	(2.48)	(0.76)	(0.78)	(1.17)	(0.02)	0.91	0.40
2008	LMP	71.25	73.71	68.30	70.78	70.24	70.43	72.67	71.56	71.63
	Congestion	-	1.04	0.46	(0.02)	(0.00)	(0.03)	1.93	0.05	0.01
	Losses	-	2.46	(2.95)	(0.47)	(1.01)	(0.82)	1.42	0.31	0.38
2009	LMP	37.31	37.90	35.79	37.11	36.75	36.97	37.36	37.34	37.57
	Congestion	-	0.03	0.13	0.02	(0.02)	(0.00)	0.12	(0.02)	0.04
	Losses	-	0.59	(1.51)	(0.20)	(0.55)	(0.33)	0.05	0.03	0.26
2010 YTD	LMP	41.46	42.69	39.65	40.89	40.64	40.83	40.97	41.95	42.03
	Congestion	-	0.46	(0.18)	(0.17)	(0.26)	(0.17)	(0.16)	(0.03)	0.24
	Losses	-	1.22	(1.82)	(0.58)	(0.83)	(0.63)	(0.49)	0.49	0.56

Going forward, the prevalence of combined cycle generators will remain important for pricing in the New England market, as these units will remain the marginal source of generation in many hours. However, as reserve margins tighten, prices will be set by higher cost generators more frequently. Additionally, in many peak hours DR will play an important role in market pricing, since dependence on DR to meet a large portion of reserve margin requirements is likely to lead to more periods when emergency conditions are triggered, allowing DR to be called. These conditions often lead to very high spot prices in the hourly markets for electricity, which can increase substantially the value of incremental supply, such as the import capacity provided by the NPT Line.

2.4. EXPECTED IMPACT OF THE NPT LINE

The additional import capacity provided by the NPT Line is expected to affect the ISO-NE market in several important ways. First, the Line will provide congestion relief on the tie lines connecting Québec to ISO-NE. Currently, the existing HVDC ties between the two markets are fully utilized during most peak hours. In these hours, the gas-driven New England prices are often substantially above the hydro-driven marginal generation cost in Québec, which is near zero. Allowing additional imports to New England during these hours will lower the price differential between the markets, reducing congestion.

Québec has ample hydro storage capacity, allowing Québec to export power during the hours when prices in the destination markets are highest. However, as a result of the congestion on these tie lines between Québec and New England during many of the peak hours when exports to New England would have the highest value, the energy in Québec that is available for export is instead sold in lower-demand periods, or to other markets with lower prices than New England. Hence, the additional capacity that will be provided by NPT will reduce congestion by allowing more power to be delivered during the hours when prices are highest and to the market where the power is valued most. The result of the congestion relief will be lower ISO-NE prices, lower fossil-fueled generation in New England, reduced production costs, and lower costs of wholesale power purchased through the New England market in order to serve load customers.

The NPT Line will also have benefits in terms of enhanced reliability and resource adequacy. The capacity provided by the Line will contribute to the ISO-NE reserve margin and delay the need for new capacity. Additionally, allowing more imports will help contribute to a diversified fuel mix and reduced dependence on natural gas within New England. Deliveries of power from the hydro-rich Québec system will displace gas-fired generation in New England and lower not only the total amount of gas used through the year, but also the dependence on potentially constrained gas delivery capacity during peak winter periods when gas demand is highest.

3. ANALYTICAL METHODOLOGY

3.1. Overview of Modeling Approach

CRA's projections of the market impacts of the NPT Line were derived by simulating this competitive market dispatch and market clearing process for ISO-NE and neighboring markets. CRA used the General Electric Multi-Area Production Simulation Model ("GE MAPS"), a chronological production cost model licensed by GE Power Systems. The GE MAPS model was used to estimate the market clearing prices and the associated dispatch of generating units throughout the system under scenarios both with and without the NPT Line. The results of the two cases were then compared in order to estimate the impact of the NPT Line. CRA simulated 5 years (2015, 2016, 2018, 2021, and 2024) to cover the 10-year time frame between 2015 and 2024.

The analysis was conducted using a model that covers the Northeast portion of the Eastern Interconnection, including ISO-NE, NYISO, PJM, and Ontario IESO. Because the HQ power system is not operated synchronously with the Eastern Interconnection, but rather connected to neighboring markets via DC ties, Québec generation and load are not explicitly represented in the model. Rather, each individual HVDC intertie between HQ and its neighbors is modeled[11]. As will be discussed in more detail in Section 3.3, the total quantity of energy expected to be available for export from Hydro Québec was allocated among the DC ties based on expected prices in each potential export market. The objective of the allocation was to maximize the value of the exported energy by scheduling flows on each tie in the hours and locations with the highest realized prices. Including the NPT Line allowed additional energy to be allocated for delivery to New England during hours with relatively higher clearing prices.

3.2. GE MAPS model

CRA used the GE MAPS fundamental electricity market model to estimate electricity prices and unit operations. Fundamental electricity market models simulate the dispatch and market clearing process using detailed data about demand for electricity and the power plants available to supply that demand. A fundamental model accounts for the significant market factors that drive electricity prices, such as electricity demand and fuel prices, and allows the effects of long-term changes in those factors over time to be reflected accurately. The model also accounts for hour-to-hour fluctuations in demand and unit availability.

GE-MAPS is a detailed economic dispatch and production-costing model for electricity networks. It was originally developed by General Electric (GE) and is currently used by over twenty major utilities and RTOs in the U.S. CRA has worked closely with GE and market participants to ensure that the model's data structures and dispatch logic accurately reflect the conditions and outcomes of the competitive markets being modeled.

---

[11] The Maritimes power system was not explicitly modeled, but imports to New England from New Brunswick were modeled to capture the impact on the New England market. Much of the flow across this interface captures exports from Québec that are wheeled through New Brunswick and ultimately delivered to the ISO-NE market.

GE MAPS calculates prices based on market supply and demand, as well as the physical properties of the electrical system. The GE MAPS model is what is referred to as a security-constrained dispatch model. It simulates the hourly chronological operation of an electricity market, accounting for limits on the flow of power across transmission lines throughout the system. Based on unit-level marginal cost bids, the model calculates a least-cost dispatch subject to thermal and contingency constraints and computes hourly, locational-based marginal prices for electricity. Zonal load prices are calculated as load-weighted averages of the relevant nodes with each zone, which is the same approach used by ISO-NE for calculating the load zone prices used to compute wholesale costs to load customers.

The model captures important details about the transmission system and other operational details that affect market pricing in ISO-NE and other neighboring markets. The GE MAPS model calculates Locational Marginal Prices (LMPs), consistent with the pricing methodology used by ISO-NE in the actual market clearing. Under an LMP scheme, a separate price is calculated for each node on the system. The locational prices reflect the relative impact of generation at each node on the level of transmission congestion and transmission line losses throughout the system, in order to capture the incremental impact of additional supply at that node on the overall system cost of meeting demand. Because the economics of energy imports on the NPT Line may be affected by transmission congestion within the ISO-NE market, capturing the details of LMP pricing is important for correctly assessing its market impacts.

3.3. Key Input Assumptions

3.3.1. Demand and Peak Load

ISO-NE demand (MWh) and peak load (MW) for GE MAPS simulations are based on the 2010 ISO-NE CELT forecast, adjusted for passive demand response (PDR). The level of PDR through 2013 is based on cleared resources from the Forward Capacity Market; thereafter it is assumed to grow proportional with energy demand. Demand and peak load for NYSIO and PJM are based on the 2010 “Gold Book” and the 2010 PJM Load Forecast, respectively. IESO demand and peak load assumptions are based on the December 2009 Ontario Reliability Outlook. The Northeast ISOs provide peak load and energy demand forecasts through 2019. Beyond 2019, CRA extrapolated the energy forecasts for each region based on the five-year compound annual growth rate. Table 4 shows the annual aggregate ISO-NE demand and peak load, before adjustments for PDR. Zonal loads for each region, along with projected levels of PDR, are shown in Appendix A.

Table 4: ISO-NE Demand and Peak Load, 2011-2024

Year	Demand (GWh)	Peak Load (MW)
2011	128,083	26,876
2012	128,110	27,092
2013	127,959	27,482
2014	129,262	27,919
2015	130,379	28,328
2016	131,511	28,650
2017	132,743	28,963
2018	134,032	29,271
2019	135,305	29,559
2020	136,565	29,875
2021	137,837	30,195
2022	139,121	30,518
2023	140,417	30,844
2024	141,725	31,174

3.3.2. Planned ISO-NE Capacity Additions and Retirements

The planned capacity additions and retirements in New England included in the study are based on actual cleared resources in the ISO-NE Forward Capacity Market. Table 5 shows the generating capacity additions assumed to enter commercial service in 2010 and beyond.

Table 5: Planned Capacity Additions in New England

Capacity Market Auction Clearings

Unit	Type	Summer Capacity (MW)	Online Date
Swanton Gas Turbine 1	Natural Gas	20	Feb-2010
Swanton Gas Turbine 2	Natural Gas	20	May-2010
Devon 15-18	Natural Gas	188	Jun-2010
Sheffield Wind Farm **	Wind	40	Nov-2010
Concord Steam	Wood Waste Solids	14	Jun-2011
Granite Reliable Power **	Wind	99	Jun-2011
Kimberly-Clark Corp Energy Independence Project	Natural Gas	14	Jun-2011
Longfellow Wind Project **	Wind	40	Jun-2011
Middletown 12-15	Natural Gas	186	Jun-2011
Other Small Renewables *	Renewable	8	Jun-2011
Record Hill Wind **	Wind	51	Jun-2011
Rhode Island LFG Genco, LLC - ST	Landfill Gas	26	Jun-2011
Rhode Island LFG Genco, LLC - ST #2	Landfill Gas	11	Jun-2011
Ansonia Generating Facility	Natural Gas	60	Jun-2012
Dartmouth Power Expansion	Natural Gas	21	Jun-2012
New Haven Harbor Units 2, 3, & 4	Natural Gas	130	Jun-2012
Other Small Renewables *	Renewable	10	Jun-2012
Plainfield Renewable Energy	Wood Waste Solids.	38	Jun-2012
BFCP Fuel Cell	Natural Gas	13	Jun-2013
Highland Wind **	Wind	129	Jun-2013
Laidlaw Berlin Biopower	Wood Waste Solids.	59	Jun-2013
Northfield Mountain ***	Pump Storage	30	Jun-2013
Other Small Renewables *	Renewable	13	Jun-2013
Kleen Energy	Natural Gas	620	Jun-2014

* Includes wind, biomass, landfill gas, and photovoltaic
** Nameplate capacity reported
*** Uprate in capacity (units 2 - 4)

In addition to planned capacity additions per FCM, CRA modeled the construction of additional generic renewable resources that will be required to meet state specific RPS requirements. Table 6 shows the generic capacity additions. CRA forecasted renewable capacity additions based on current RPS levels for each state within the ISO-NE market as well as any projected revisions of the RPS levels. In identifying locations for the capacity, consideration was given to projects identified within the ISO-NE interconnection queue, noting that, based on historical data, only a fraction of projects currently in the queue have high probability of being completed. While the generic renewable capacity additions do not represent specific projects, the mix of technology types and locations is influenced by the mix of projects under development. Specifically, the new renewable capacity mix includes 700 MW of offshore wind, including the Cape Wind project and other offshore resources under development for Southern New England. Because there is significant uncertainty about whether sufficient renewable resources can be added in the timeframe required to meet RPS targets and whether all targets will remain at their current levels, the assumed build out is a conservative assumption[12]. If fewer resources are added, the potential price impact of the NPT Line should be greater.

Table 6: Generic Capacity Additions to Meet RPS in New England (Name Plate MW)

Technology Type	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Wind	-	208	257	202	140	200	200	200	200	200	200
Offshore Wind	-	-	-	-	28	500	260	100	-	-	-
Biomass	-	-	150	125	47	-	-	-	-	-	-
Landfill Gas	-	2	20	-	-	-	-	-	-	-	-
PV	17	33	45	41	41	41	40	40	40	40	40
Hydro	-	-	7	1	-	1	-	1	-	1	-
Market Total	17	242	479	369	256	742	500	341	240	241	240

The capacity retirements assumed to take place in 2010 and beyond, based on accepted delist bids in the Forward Capacity Auctions include:

- Somerset 6
- Salem Harbor 1-2

This limited set of retirements is again a conservative assumption. Additional delist bids have been rejected based on reliability concerns. If those concerns are resolved, additional unit retirements are likely. Specifically, permanent delist bids have been filed for Salem Harbor 3 and 4 for FCA 5, and a delist request of Vermont Yankee, for which the Vermont legislature has voted to deny extension of an operating license, was rejected in FCA 4.

3.3.3. Fuel Prices

Long-term natural gas prices at Henry Hub were based on the Energy Information Administration's Annual Energy Outlook 2010 ("AEO 2010") forecast. Basis differentials to regional trading hubs were estimated based on NYMEX futures and historical data. Plant level delivered gas prices were forecasted based on the historic relationships of local prices to hub prices. Prices were forecasted monthly, accounting for the pricing impacts of seasonal differences in supply and demand.

Monthly fuel oil prices were derived from forecasted crude oil prices and historical relationships between crude oil prices and refined products. Crude oil prices were based on the AEO 2010 forecast.

Annual average fuel prices are shown in Table 7.

[12] See, for example, ISO-NE's 2010 Regional System Plan (RPS), section 8.5.2.2, page 130 for a discussion on the attrition of wind projects from the ISO-NE's interconnection queue and the level of available wind projects necessary to meet RPS across New England.

Table 7: Fuel Price Assumptions for the Northeast ($/MMBtu, 2009 dollars)

Year	Henry Hub	Algonquin	Transco Zone 6 NY	NYC 1% FO6	NYC 0.3% FO6	NYC FO2
2015	6.30	6.97	6.96	11.50	14.01	20.14
2016	6.40	7.08	7.07	11.97	14.58	20.94
2017	6.41	7.09	7.08	12.34	15.05	21.59
2018	6.46	7.14	7.13	12.75	15.54	22.28
2019	6.53	7.21	7.21	13.01	15.86	22.73
2020	6.66	7.35	7.36	13.24	16.15	23.12
2021	6.76	7.46	7.47	13.40	16.35	23.40
2022	6.95	7.66	7.68	13.58	16.57	23.70
2023	6.98	7.69	7.71	13.77	16.79	24.01
2024	6.93	7.64	7.66	13.94	17.00	24.30

3.3.4. Transmission Topology and Planned Transmission Projects

The transmission topology used for CRA's analysis is based on a power system model developed by the Eastern Interconnection Reliability Assessment Group (ERAG). CRA used ERAG's 2009 series representation of 2013 summer conditions as a starting point. The case was modified to include expected transmission upgrades, including the NEEWS, MPRP, and the Scobie-Tewksbury line in New England, as well as major transmission projects in New York (M29 project) and PJM (TrAIL, PATH, Branchburg-Hudson, and Susquehanna-Roseland). CRA modeled the Scobie-Tewksbury line to reflect the reliability need for North-to-South transmission upgrades in New England noted in ISO-NE's long-term planning studies. Specifically, ISO New England's 2010 RSP lists the Scobie-Tewksbury line and the Seabrook-Ward Hill line as transmission alternatives to address reliability issues in the Greater Boston area. Both projects are expected to have a comparable impact on the transfer capabilities across the New England power system.

The NPT project includes an HVDC converter station in Franklin, NH and a 345 kV radial AC line to the existing Deerfield substation. For modeling purposes CRA assumed a power delivery directly at Deerfield.

3.3.5. Transmission Interface Limits

Based on ISO-NE's recent Regional System Plans (2009 RSP and 2010 RSP) and the MPRP study in support of the proposed plan application[13], CRA used the following limitations

[13] For N-1 limits see ISO New England's 2009 Regional System Plan, table 9-1 on page 112; available at: http://www.iso-ne.com/trans/rsp/2009/rsp09_final.pdf. For N-1-1 limits see ISO New England's 2010 Regional System Plan, explanations to Table 5-1 on page 54; available at: http://www.iso-ne.com/trans/rsp/index.html. The Northern New England-Scobie interface limit is based on the limitations stated in CRP's Maine Power Reliability Program, Proposed Plan Application, Analyses, Final Draft Report, Revision 3, June 9, 2008, table 5-11, page 78; available at: http://www.iso-ne.com/committees/comm_wkgrps/relblty_comm/relblty/mtrls/2008/jun172008/a2_3_mprp_final_draft_report_6_9_08.pdf

for major transmission interfaces in New England for the year 2015 and beyond. Except for Boston Import, CT Import, and SWCT Import, these limitations reflect single contingency ("N-1") planning limits. Reflecting ISO-NE operations, CRA assumed operational limitations ("N-1-1" limits) for Boston Import, CT Import, and SWCT Import interfaces. The maintenance of adequate operating reserves is critical in these transmission zones and allowable power transfers into these zones reflect the scenario that a first contingency could potentially be followed by a second contingency, increasing the amount of local generation that needs to be available to ensure reliable system operations.

Based on NPT engineering estimates the Scobie-Tewksbury 345 kV line is expected to increase the North-South interface capacity by an additional 700 MW, increasing the limit to 3,400 MW.

Table 8: New England Transmission Interface Limits

Interface	Limit (MW)
Orrington-South	1,200
Surowiec-South	1,150
Maine-NH	1,475
Northern New England-Scobie	3,080
North-South	3,400
Boston Import	3,700
East-West	3,500
CT Import	2,500
SWCT Import	2,300
NOR Import	1,650

3.3.6. Environmental Policy Assumptions

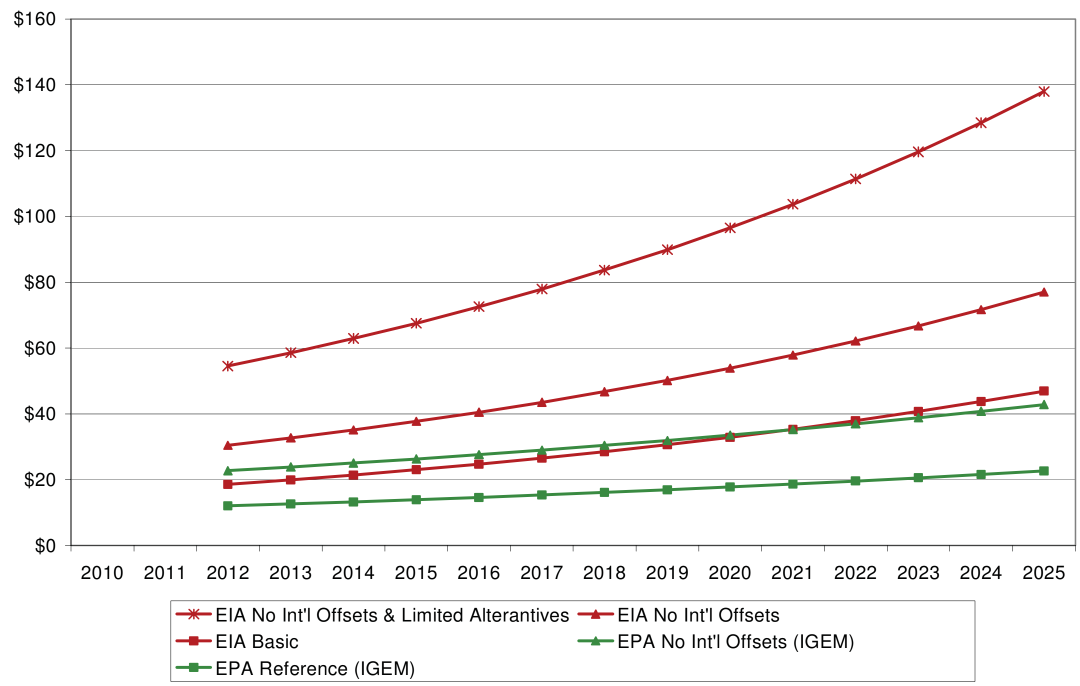
Due to the large degree of uncertainty in form and timing of future environmental policy under draft EPA rules, CRA has modeled the Clean Air Interstate Rule (CAIR) currently in effect, including scheduled tightening of the emissions restrictions, but no additional changes to the policies governing release of airborne emissions. In terms of the impact of NPT project, this assumption is likely conservative, as EPA is currently in the process of drafting environmental regulations that will ultimately replace CAIR with what are likely to be more stringent regulations. Estimated allowance prices are based on the results of CRA's North American Electricity and Environment Model (NEEM) for CAIR and are shown in Table 9.

Table 9: Emission Price Assumptions ($/ton, 2009 dollars)

Year	CO_2	NO_x	SO_2
2014	10.00	1,027	374
2016	10.00	1,132	288
2018	10.00	1,248	318
2020	10.00	1,376	350
2022	10.00	1,517	386
2024	10.00	1,673	426

With regard to CO2 regulation CRA assumed a national carbon policy, starting in 2015 at $10/ton and remaining at that price level throughout the study horizon. This level reflects a moderate increase in the cost of carbon emissions over what is expected under the RGGI program currently in place for New England and other states in the Northeast, but a smaller increase than the prices expected under most potential federal carbon legislation. Figure 6 provides the CO_2 price projections by EPA and EIA under different scenarios. Given the time horizon of this study, some form of federal policy is reasonably likely to be in place before the end of the analysis period, creating the potential for costs well above $10/ton. Hence, $10/ton provides a reasonable assumption, likely falling in the lower end of the range of potential long-term outcomes.

Figure 6: EPA and EIA Projections of CO_2 Prices under Various Scenarios (2009 dollars)



3.4. Modeling Approach for Québec Exports

Table 10 shows the assumed transfer capacities between the HQ system and neighboring control areas, including New England[14]. Based on the maximum transfer capabilities and initial GE MAPS simulation results, CRA developed monthly energy targets for each HQ intertie that correspond to reported annual net export targets of HQ.[15] The targets were developed by considering the range of potential export opportunities among all hours and destination markets and choosing the set of hours/destinations that would maximize net revenue for Hydro Québec. The resulting hourly delivery quantities were then summed for each intertie on a monthly basis, providing a monthly target energy level for each intertie and each month. Given these monthly energy allocation and maximum flow levels for each tie, the hourly schedules were develop with the GE MAPS model in order to allow the model to optimize the resulting hourly utilization for each intertie. A schedule was developed separately for the baseline scenario and the scenario with the NPT Line in service. Flows across HQ's ties with Vermont and New Brunswick were modeled based on historical flow data. Table 11 shows CRA's modeling results for the annual net export targets for all HQ interties, while Table 12 and Table 13 provide a breakdown by individual intertie for the base line and the NPT case, respectively.

Table 10: Assumed Transfer Capacities across HQ interties (MW)

	Ontario	New York	New England Phase II	New England NPT
Export Capacity from HQ	2,800	1,500	1,400	1,200
Import Capacity to HQ	1,850	1,000	1,400	1,200

Table 11: Annual Net Export Targets (TWh)

	2015	2016	2018	2021	2024
HQ net exports	24.0	25.0	28.0	30.0	30.0

14 Assumed transfer capacities reflect expected operating limitations under normal system conditions. Operating limitations were derived from observed historical tie line operations, and tend to be lower than the thermal limitation of the interties.

15 The 2015 export target was taken from HQ's Strategic Plan 2009-2013, page 25, available at: http://www.hydroquebec.com/publications/en/strategic_plan/index.html. Export targets for subsequent years were derived from HQ's Environmental Impact Assessment Study - Romaine Complex - Volume I, December 2007, table 2-8, page 2-10, available in French at: http://www.hydroquebec.com/romaine/pdf/ei_volume01.pdf

Table 12: Annual Energy Targets for HQ Interties – Baseline Case without NPT Line (GWh)

	Ontario	New York	New Brunswick	New England Phase II	New England NPT	New England Highgate	Total HQ
2015	3,445	6,787	1,752	10,436	0	1,577	23,996
2016	3,902	7,044	1,752	10,724	0	1,577	24,999
2018	5,624	7,648	1,752	11,399	0	1,577	27,999
2021	6,613	8,387	1,752	11,670	0	1,577	29,999
2024	6,613	8,387	1,752	11,670	0	1,577	29,999

Table 13: Annual Energy Targets for Individual HQ Interties – with NPT Line (GWh)

	Ontario	New York	New Brunswick	New England Phase II	New England NPT	New England Highgate	Total HQ
2015	-120	4,170	1,752	8,967	7,654	1,577	23,999
2016	-99	4,539	1,752	9,278	7,954	1,577	25,001
2018	381	6,219	1,752	9,797	8,272	1,577	27,998
2021	1,641	5,853	1,752	10,326	8,851	1,577	30,000
2024	1,641	5,853	1,752	10,326	8,851	1,577	30,000

Note that a key assumption of this allocation approach for exports from Québec as well as CRA's analysis of congestion and LMP impacts is that total exports from Québec would remain constant between scenarios with and without the NPT Line in service. In reality, the additional transmission capacity provided by the NPT Line could lead to additional development of resources to support exports from Québec, leading to higher total exports in the case with NPT in service. With those additional resources, the reduction in congestion and LMPs would be greater, and additional fossil-fueled generation would be displaced, resulting in a larger reduction in gas demand and CO_2 emissions.

4. Results

4.1. Wholesale Energy Pricing Impact

Table 14 shows CRA's projections of the impact of the NPT Line on wholesale power prices at the Mass Hub. Over the simulated 10-year period, the NPT Line is expected to decrease the average Mass Hub price by $1.22-1.86/MWh. The overall decrease in power prices is largely driven by lower on-peak prices, as most of power sales between HQ and ISO-NE were scheduled during peak hours.[16] The decline in off-peak prices is less pronounced. In 2015, lower power imports across the existing Phase II connection during summer off-peak hours are projected to offset the price effect of power imports across NPT, leading to a slight increase in average off-peak power prices.

Table 14: Energy Price Impact, Mass Hub ($/MWh, 2009 dollars)

		2015	2016	2018	2021	2024
Base Case	**Peak (5x16)**	72.36	73.73	74.89	77.34	78.97
	Off-Peak	58.27	59.00	59.41	60.96	61.93
	All Hours	64.99	66.00	66.79	68.77	70.06
NPT	**Peak (5x16)**	69.76	70.92	71.67	74.37	75.92
	Off-Peak	58.30	58.42	58.88	60.27	61.14
	All Hours	63.76	64.36	64.97	66.99	68.20
Delta	**Peak (5x16)**	(2.60)	(2.80)	(3.22)	(2.98)	(3.05)
	Off-Peak	0.03	(0.58)	(0.54)	(0.69)	(0.78)
	All Hours	(1.22)	(1.64)	(1.82)	(1.78)	(1.86)

Table 15 shows estimates of the average price impact of the NPT Line across New England RSP zones on a time-weighted basis that is indicative of the impact on locational marginal prices. Power prices in northern New England (BHE, ME, SME, NH, and VT) are expected to decline more sharply than power prices in southern New England. This is due to congestion across the New England North-South interface that occurs in some hours. The power that is delivered across the NPT Line into northern New England, along with generation from local sources, is sufficient in some hours to fully utilize capacity on the North-South transmission interface, resulting in lower prices in northern New England.

[16] Peak hours are defined as the periods from 7 AM through 11 PM, Monday through Friday. The remaining hours are classified as off-peak.

Table 15: Energy Price Impact, Simple Average by RSP Zone ($/MWh, 2009 dollars)[17]

	2015	2016	2018	2021	2024
BHE	(1.65)	(1.97)	(2.25)	(2.26)	(2.31)
ME	(1.70)	(2.04)	(2.31)	(2.35)	(2.47)
SME	(1.85)	(2.22)	(2.47)	(2.56)	(2.65)
NH	(1.88)	(2.25)	(2.49)	(2.58)	(2.68)
VT	(1.56)	(1.96)	(2.18)	(2.24)	(2.32)
BOS	(1.40)	(1.80)	(1.99)	(1.99)	(2.07)
NECMA	(1.34)	(1.75)	(1.94)	(1.90)	(2.00)
WMA	(1.11)	(1.52)	(1.70)	(1.62)	(1.71)
RI	(1.06)	(1.47)	(1.65)	(1.59)	(1.68)
SEMA	(1.15)	(1.55)	(1.73)	(1.70)	(1.78)
CT	(0.95)	(1.34)	(1.49)	(1.42)	(1.50)
SWCT	(0.85)	(1.23)	(1.37)	(1.28)	(1.36)
NOR	(0.82)	(1.19)	(1.33)	(1.23)	(1.31)
Total	(1.33)	(1.71)	(1.91)	(1.90)	(1.99)

4.2. WHOLESALE ENERGY COSTS FOR CUSTOMERS

Table 16 shows average decrease in wholesale power costs for customers in each RSP zone on a $/MWh basis. These load-weighted prices are representative of the average cost to load, as they account for the regional distribution and seasonality of the annual load shape.

[17] The ISO-NE RSP zones are defined as follows:

BHE	Northeastern Maine
ME	Western and central Maine/Saco Valley, New Hampshire
SME	Southeastern Maine
NH	Northern, eastern, and central New Hampshire/eastern Vermont and southwestern Maine
VT	Vermont/southwestern New Hampshire
BOS	Greater Boston, including the North Shore
NECMA	Northeastern Massachusetts/central Massachusetts
WMA	Western Massachusetts
RI	Rhode Island/bordering Massachusetts
SEMA	Southeastern Massachusetts/Newport, Rhode Island
CT	Northern and eastern Connecticut
SWCT	Southwestern Connecticut
NOR	Norwalk/Stamford, Connecticut

Table 16: Energy Price Impact, Load-Weighted Average by RSP Zone ($/MWh, 2009 dollars)

	2015	2016	2018	2021	2024
BHE	(2.00)	(2.27)	(2.60)	(2.65)	(2.71)
ME	(2.05)	(2.35)	(2.70)	(2.77)	(2.92)
SME	(2.31)	(2.64)	(2.98)	(3.10)	(3.23)
NH	(2.32)	(2.64)	(2.98)	(3.11)	(3.23)
VT	(1.94)	(2.28)	(2.62)	(2.68)	(2.77)
BOS	(1.72)	(2.08)	(2.35)	(2.37)	(2.45)
NECMA	(1.68)	(2.04)	(2.33)	(2.31)	(2.40)
WMA	(1.37)	(1.74)	(2.03)	(1.95)	(2.03)
RI	(1.32)	(1.68)	(1.96)	(1.92)	(2.01)
SEMA	(1.40)	(1.75)	(2.02)	(2.02)	(2.10)
CT	(1.23)	(1.59)	(1.85)	(1.80)	(1.85)
SWCT	(1.10)	(1.47)	(1.70)	(1.64)	(1.69)
NOR	(1.10)	(1.47)	(1.71)	(1.63)	(1.68)
Total	(1.58)	(1.93)	(2.22)	(2.22)	(2.30)

Table 17 shows the corresponding projected energy cost savings for New England customers that are associated with the expected decline in energy prices. The wholesale costs to New England customers are expected to decrease by $206 million in 2015 and $327 million by 2024.

Table 17: Impact on Wholesale Energy Costs, by RSP Zone ($million, 2009 dollars)

	2015	2016	2018	2021	2024
BHE	(4)	(4)	(5)	(5)	(6)
ME	(14)	(16)	(19)	(20)	(21)
SME	(7)	(9)	(10)	(10)	(11)
NH	(23)	(27)	(31)	(34)	(36)
VT	(14)	(16)	(19)	(20)	(21)
BOS	(45)	(55)	(63)	(66)	(70)
NECMA	(15)	(18)	(21)	(21)	(23)
WMA	(14)	(18)	(22)	(21)	(23)
RI	(15)	(19)	(23)	(23)	(25)
SEMA	(19)	(24)	(28)	(29)	(31)
CT	(19)	(24)	(29)	(29)	(30)
SWCT	(12)	(16)	(18)	(18)	(19)
NOR	(6)	(8)	(10)	(9)	(10)
Total	(206)	(254)	(297)	(306)	(327)

4.3. ISO-NE GENERATION MIX

The impact of the NPT Line on the 2015 New England generation mix is illustrated in Figure 7. The details for the remaining study years are given in Table 18. The power transfers across the NPT Line are expected to primarily displace generation of combined-cycle power plants. Generation from gas/oil-fired steam generators and peaking plants is also displaced. By lowering primarily the on-peak prices across New England, the NPT Line is expected to narrow the on-peak vs. off-peak spread, which leads to lower utilization of pumped storage hydro facilities. Additionally, a portion of the additional net power imports from HQ are expected to be wheeled through to the NYISO control area.

Figure 7: Change in New England generation due to NPT Line, 2015

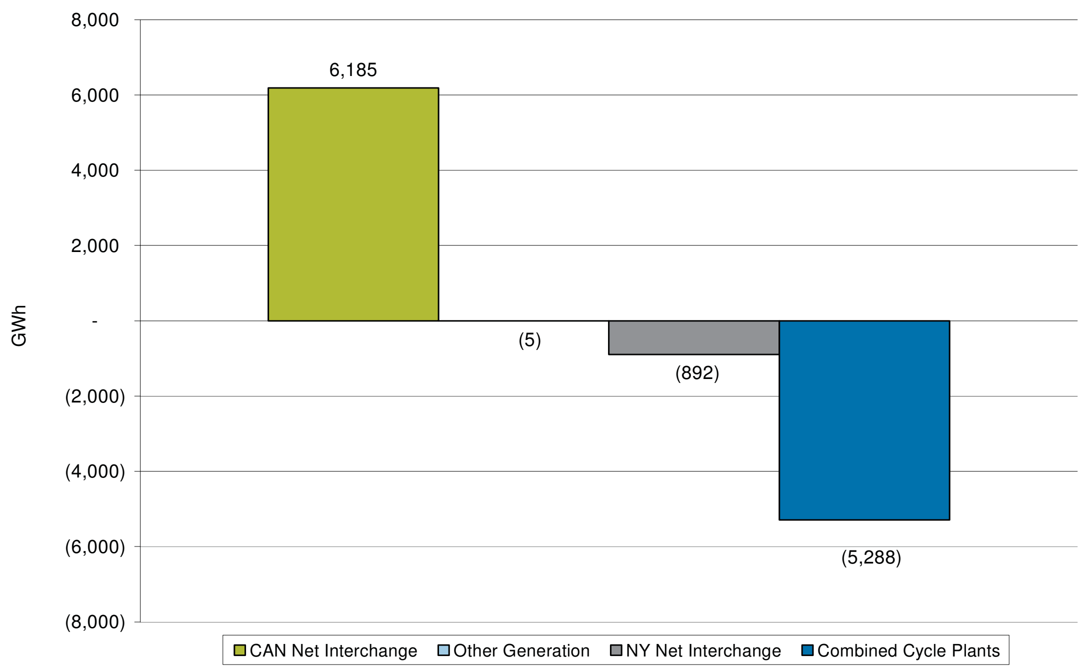


Table 18: Generation Impact by Generation Type (GWh)

(Negative values reflect a reduction in generation)

	2015	2016	2018	2021	2024
CAN Net Interchange	6,185	6,507	6,670	7,507	7,507
Combined Cycle	-5,288	-5,901	-6,157	-5,989	-5,925
NY Net Interchange	-892	-896	-1,038	-1,166	-1,072
Other Generation*	-5	289	525	-352	-510
Total	0	0	0	0	0

* includes changes in transmission losses and pumped storage losses

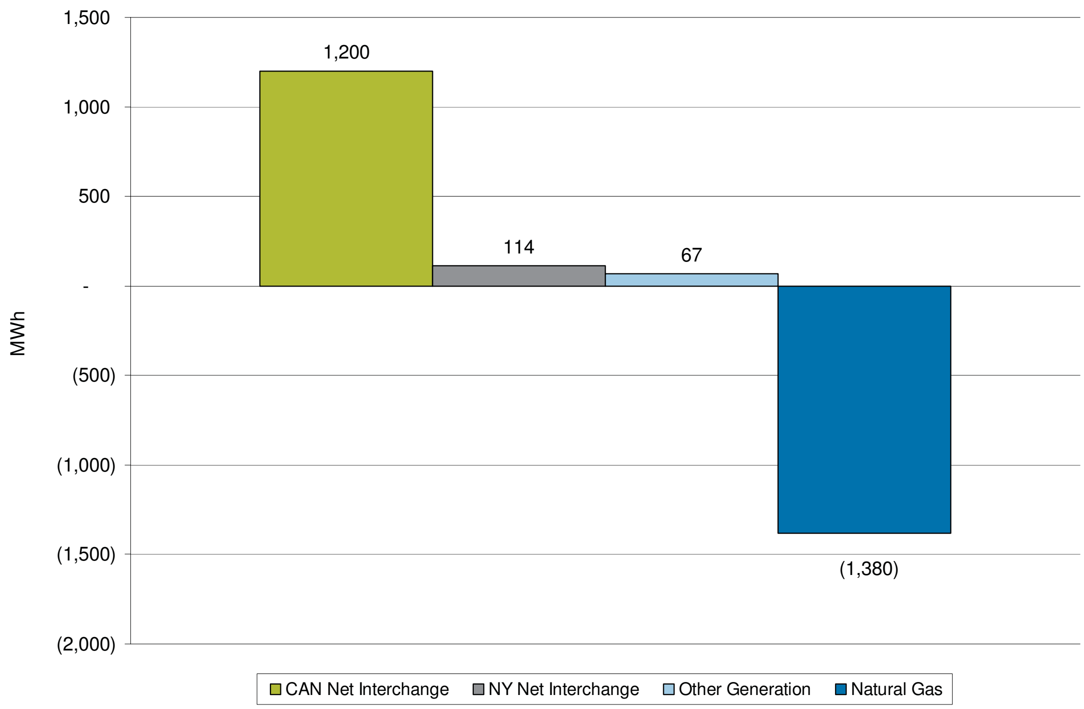
As shown in Table 19, the hydro-backed net imports from HQ across the NPT Line are expected to displace significant amounts of natural gas as a fuel for generating plants.

Table 19: Impact on Natural Gas Consumption in New England (Tcf)

	2015	2016	2018	2021	2024
Natural Gas Consumption (Tcf)	-24.7	-29.7	-25.0	-23.5	-21.8

New England's generation fleet relies heavily on natural gas for fuel. During the winter months – depending on weather – gas supply to New England may be tight, as gas demand for generation competes with demand for heating purposes. Gas supply disruptions during this period may jeopardize energy security. Figure 8 illustrates the impact of the NPT project on New England's generation dispatch during the 2015 winter peak hour. The 1,200 MWh of additional imports from HQ are projected to result in the displacement of 1,380 MWh of gas-fired generation, primarily combined-cycle generation, a reduction in exports to NYISO by about 115 MW, and a slight increase in other generation, largely related to pumped storage facilities. In effect, NPT is expected to provide a net 1,265 MW of additional security against gas disruptions in New England during the 2015 winter peak hour.

Figure 8: Generation Impact by Fuel, winter peak hour (MWh)



5. Conclusions

As detailed above, the addition of the NPT Project has a pronounced and continuing effect on the New England power market. The addition of 1,200 MW of transfer capability between Québec and southern New Hampshire creates several benefits, including:

- Reducing congestion between Québec and New England. At present, transmission limitations between these two systems limit the ability of Hydro-Québec to export its available energy to New England at times of greatest system need. Increasing the available transmission with the NPT Project allows Hydro-Québec to match deliveries with times of highest prices more closely, thereby having a greater benefit to New England consumers. This effect is best seen by the much greater reduction in wholesale electricity prices during peak periods (averaging $2.93/MWh over the modeled years) compared to the reduction in off-peak periods (averaging $0.51/MWh). This reduced congestion will allow imports from Québec to displace higher-cost fossil-fired generation in New England, resulting in wholesale savings for New England consumers of $206 million in 2015 to $327 million in 2024.
- Enhancing total imports of low-cost, zero-emissions energy to New England. Although the Hydro-Québec system today has a limited amount of energy available for export, projects in construction and in earlier development phases will allow Hydro-Québec to export substantial amounts of additional energy to New England. Without the NPT Project, however, the full amount of this additional power cannot be delivered directly to the New England market. The NPT Project allows an additional 5.3 TWh of Canadian imports into the New England market in 2015, rising to 6.4 TWh in 2024. CRA has conservatively assumed that currently projected growth in exports from Québec will occur whether or not the NPT Line is built. However, absent the NPT Line, these additional exports would be delivered during lower value periods with lower net revenues to Hydro Québec, which could result in delaying the development of the resources that will allow growth in total exports. If more projects supporting exports were developed as a result of the NPT Line, the impact of the line on imports, reduction in fossil-fueled generation in New England, and wholesale cost reductions would be greater.
- Improved fuel diversity resulting in greater system reliability. New England relies very heavily on natural gas for its electricity supply: 32 percent of annual generation.[18] More importantly, natural gas is on the margin during more than 60 percent of the pricing intervals.[19] New England has little gas storage, and New Englanders also rely heavily on natural gas as a heating fuel, so there is a potentially serious risk to the available fuel supply to the electric generation fleet on very cold winter days. The NPT Project would reduce the reliance on natural gas and so reduce the risk of service interruption to either heating or electric customers. Annually, the NPT is

[18] ISO New England Inc., *2009 Annual Markets Report*, p. 75.

[19] *Id.*, p. 80.

expected to free up 24.7 TCF on natural gas to the New England market which will increase reliability in both the power and natural gas markets.

APPENDIX A: DETAILED MODEL DESCRIPTION

An overview of the GE MAPS model was provided in Section 3.2 of this report. This appendix provides more detail about how the model combines its inputs to project hourly locational prices and unit generation, and discusses additional key input assumptions used in the model. The first section describes some assumptions implicit in the GE MAPS modeling approach (*e.g.*, how maintenance is scheduled, how operating reserve requirements are imposed), while the second details some of the fundamental input assumptions not discussed in the body of the report.

A.1 BASIC MODEL REPRESENTATION

The GE MAPS model is a security-constrained dispatch model that simulates the hourly chronological operation of an electricity market. Based on unit-level marginal cost bids, the model performs a least-cost dispatch subject to thermal and contingency constraints and calculates hourly, locational-based marginal prices for electricity. Nodal prices and unit level generation data can be aggregated to whatever level is desired (utility, region, state, *etc.*). Zonal load prices can be calculated either as load-weighted averages or as simple averages of locational prices. The GE MAPS simulation is consistent with the congestion management scheme currently utilized in ISO-NE and the other Northeast ISOs. The model's locational spot price calculation algorithm has been successfully benchmarked against the market price algorithm used in the New England market.[20]

CRA used a MAPS model footprint covering New England and neighboring regions for our analysis.[21] The model commits and dispatches generation to meet load in each of four market areas: NYISO, ISO-NE Ontario IMO, and PJM. In order to capture limitations in the coordination among these markets, economic imports from one area to another were only implemented if the resulting savings exceeded an economic hurdle.

A.1.1 Operating Reserves

MAPS accounts for spinning and non-spinning reserve requirements in its commitment and dispatch. The spinning reserve market affects energy market prices because the units that provide spinning reserve cannot produce electricity under normal conditions.[22] As a result, energy prices in MAPS are higher when reserve markets are modeled. Operating reserve requirements were modeled individually for each market area.

Only a limited portion of a generating unit's capacity can provide spinning reserves due to ramp-up constraints that prevent units from reaching their full capacity for delivering energy

20 The actual ISO-NE transmission representation for an individual hour was input into MAPS, along with actual loads, imports and exports and generator bids. The locational prices calculated by the GE MAPS program matched those produced by the ISO-NE LMP system for those conditions.

21 Specifically, the footprint includes the NPCC, MAAC, and ECAR NERC regions.

22 Non-spinning reserve requirements rarely influence MAPS energy prices in areas like the eastern U.S., with a reasonably large supply of quick-starting gas turbines.

within the ten minute period required for operating reserves. Within the model, CRA specified a ramp rate for each unit and allowed it to hold operating reserves equal to the amount the unit can ramp in ten minutes.

A.1.2 Maintenance Scheduling for Thermal Generation Units

The GE MAPS model schedules maintenance of thermal generating units with the objective of levelizing the reserve margin across the weeks of each year.[23] CRA assumed that maintenance within each market area is scheduled such that reserves within the pool are levelized on an annual basis. For example, if a region's load peaks only in the summer, it will schedule little or no maintenance in that season; similarly, if a region's load peaks in both the summer and winter, it will schedule no maintenance in these two seasons.

A.1.3 Generation from Conventional Hydro and Pumped Storage Units

Hourly generation levels for each hydro unit were determined by the GE MAPS model for each of the scenarios and years modeled. The GE MAPS model takes monthly generation totals for each hydro unit together with limits on their maximum and minimum generation levels and schedules hydro generation against the load shape for the market area in which the unit is located. The GE MAPS model generally does not dispatch hydro generation to relieve transmission congestion. However, if the locational price at a hydro station bus is very low (less than $5/MWh), then MAPS backs down generation from that unit to relieve congestion; under these circumstances, backing down the hydro unit is the most economic and may be the only alternative to relieving congestion. Also, GE MAPS does not increase generation from hydro resources to relieve congestion, meaning that only thermal units are used for congestion management.

GE MAPS dispatches pumped storage units based on load and committed thermal generation in the surrounding region. The model approximates the price elasticity for each hour over the course of a week using the stack of available generating units in the surrounding region and finds the corresponding operating pattern for pumped storage units that minimize total production cost. The model honors the physical characteristics of each unit, including pumping and generating capacities, pumping efficiency and reservoir storage limits. When developing the schedule, the model does not directly account for transmission limits, but rather restricts the set of generators it considers to be available to ramp up for pumping or ramp down when the pumped storage units generate to those in the local region of each unit. Once the pumping and generating pattern has been developed, the model does honor all transmission constraints when meeting the schedule as part of the dispatch process.

A.2 KEY INPUT ASSUMPTIONS

CRA's analysis utilized our proprietary GE MAPS database, which has been compiled from the best available public data sources. The following is a list of the major components of the model. The list is followed by a description of the data sources for each component not discussed in the body of this report.

---

23 The weekly reserve margin is capacity available during that week minus the week's peak load.

(1) Load Inputs

(2) Thermal Unit Characteristics

(3) Planned Additions and Retirements

(4) Fuel Price Forecasts

(5) Transmission System Representation

(6) Environmental Regulations

(7) Hydro Unit Output

A.2.1 Load Inputs

Peak loads and annual energy demands were based on forecasts reported by NYISO, PJM and ISO-NE. Since published data do not extend beyond 2019, forecasts were extended based on the projected growth over the reported forecast period. For New England peak load and annual energy demand, CRA relied on the 2010 ISO-NE CELT report, published in April 2010. The demand assumptions are shown in Table 4 in the body of this report. CRA adjusted the 2010 CELT forecast to allow passive demand response (PDR) to grow proportional to peak load. Tables A-1 and A-2 show CRA's PDR adjustments and the resulting peak load and energy forecasts.

Table A-1: ISO-NE Peak Load Reflecting Growth in PDR (MW)

Year	CELT Summer 50/50 Peak	CELT Summer Peak PDR	CRA Summer Peak PDR	CELT Summer 50/50 Peak Net PDR	CRA Summer 50/50 Peak Net PDR*
2011	27,660	784	784	26,876	26,876
2012	28,165	1,073	1,073	27,092	27,092
2013	28,570	1,073	1,088	27,497	27,482
2014	29,025	1,073	1,106	27,952	27,919
2015	29,450	1,073	1,122	28,377	28,328
2016	29,785	1,073	1,135	28,712	28,650
2017	30,110	1,073	1,147	29,037	28,963
2018	30,430	1,073	1,159	29,357	29,271
2019	30,730	1,073	1,171	29,657	29,559

* Peak loads after 2019 were assumed to grow by the 5-year CAGR

Table A-2: ISO-NE Demand Reflecting Growth in PDR (GWh)

Year	CELT Annual Energy	CELT Energy PDR	CRA Energy PDR	CELT Annual Energy Net PDR	CRA Annual Energy Net PDR*
2011	132,370	4,287	4,287	128,083	128,083
2012	134,005	5,895	5,895	128,110	128,110
2013	134,655	6,659	6,696	127,996	127,959
2014	136,060	6,659	6,798	129,401	129,262
2015	137,280	6,659	6,901	130,621	130,379
2016	138,500	6,678	6,989	131,822	131,511
2017	139,810	6,659	7,067	133,151	132,743
2018	141,175	6,659	7,143	134,516	134,032
2019	142,520	6,659	7,215	135,861	135,305

* Demand after 2019 was assumed to grow by the 5-year CAGR

Individual regional load shapes are based on actual 2006 zonal hourly load data as reported by the ISOs or utilities. The GE MAPS model adjusts each area's historical hourly load shape to fit the peak and annual energy numbers specified for that area for the year being modeled. The hourly load data created by that process for each area is then used as an input for the GE MAPS hourly simulation. Tables A-3 and A-4 show the peak load and annual energy assumptions for each zone in New England.

Table A-3: ISO-NE Peak Load by Zone, 2011-2024 (MW)

Annual Peak (MW)	BHE_AR	SME_AR	ME_AR	NH_AR	VT_AR	BOS_AR	NECMA_AR	SEMA_AR	WMA_AR	RI_AR	CT_AR	NOR_AR	SWCT_AR
2011	326	579	1,137	1,984	1,214	5,516	1,804	2,852	2,010	2,472	3,364	1,307	2,321
2012	325	578	1,142	2,019	1,216	5,530	1,847	2,876	2,036	2,493	3,377	1,308	2,345
2013	330	593	1,161	2,053	1,230	5,597	1,895	2,915	2,065	2,527	3,420	1,322	2,378
2014	335	607	1,181	2,102	1,254	5,670	1,944	2,953	2,099	2,565	3,467	1,337	2,412
2015	340	612	1,200	2,136	1,273	5,752	1,973	3,002	2,128	2,599	3,515	1,356	2,445
2016	340	622	1,215	2,170	1,287	5,819	1,997	3,036	2,157	2,628	3,548	1,370	2,469
2017	344	627	1,229	2,204	1,301	5,882	2,017	3,075	2,181	2,657	3,577	1,379	2,492
2018	344	636	1,244	2,233	1,315	5,939	2,036	3,108	2,205	2,691	3,610	1,394	2,511
2019	349	641	1,259	2,262	1,324	5,997	2,055	3,147	2,229	2,715	3,639	1,403	2,535
2020	352	649	1,274	2,295	1,338	6,060	2,077	3,185	2,256	2,745	3,670	1,415	2,558
2021	354	656	1,289	2,328	1,351	6,124	2,098	3,222	2,282	2,775	3,702	1,428	2,582
2022	357	664	1,304	2,362	1,365	6,188	2,120	3,261	2,309	2,805	3,734	1,440	2,605
2023	359	672	1,320	2,396	1,378	6,253	2,141	3,299	2,336	2,836	3,767	1,452	2,629
2024	362	680	1,336	2,431	1,392	6,319	2,163	3,339	2,363	2,867	3,799	1,465	2,653

Table A-4: ISO-NE Demand by Zone, 2011-2024 (GWh)

Annual Target Energy (GWh)	BHE_AR	SME_AR	ME_AR	NH_AR	VT_AR	BOS_AR	NECMA_AR	SEMA_AR	WMA_AR	RI_AR	CT_AR	NOR_AR	SWCT_AR
2011	1,870	3,149	6,617	9,604	6,937	25,842	8,365	13,157	10,060	11,179	15,222	5,584	10,502
2012	1,872	3,157	6,634	9,680	6,925	25,788	8,461	13,194	10,103	11,190	15,113	5,532	10,457
2013	1,865	3,147	6,611	9,723	6,902	25,691	8,536	13,201	10,122	11,190	15,055	5,490	10,424
2014	1,884	3,184	6,677	9,875	6,984	25,920	8,671	13,318	10,225	11,307	15,176	5,526	10,514
2015	1,899	3,207	6,728	9,988	7,046	26,167	8,754	13,444	10,324	11,409	15,276	5,561	10,578
2016	1,913	3,231	6,780	10,112	7,104	26,410	8,839	13,566	10,427	11,502	15,378	5,601	10,649
2017	1,928	3,255	6,837	10,247	7,179	26,659	8,930	13,699	10,532	11,626	15,489	5,643	10,727
2018	1,947	3,288	6,904	10,391	7,248	26,920	9,022	13,832	10,637	11,754	15,604	5,684	10,810
2019	1,962	3,317	6,966	10,526	7,323	27,187	9,113	13,970	10,746	11,857	15,724	5,726	10,888
2020	1,978	3,345	7,027	10,665	7,394	27,448	9,205	14,104	10,855	11,972	15,838	5,767	10,967
2021	1,994	3,373	7,089	10,806	7,466	27,712	9,298	14,240	10,964	12,088	15,953	5,810	11,047
2022	2,010	3,402	7,151	10,948	7,539	27,978	9,392	14,377	11,075	12,205	16,069	5,852	11,127
2023	2,027	3,430	7,213	11,093	7,612	28,247	9,486	14,515	11,186	12,323	16,186	5,895	11,208
2024	2,043	3,459	7,276	11,239	7,686	28,518	9,582	14,655	11,299	12,443	16,303	5,938	11,289

A.2.2 Thermal Unit Characteristics

GE MAPS models generation units in detail, in order to accurately simulate their operational patterns and thereby project realistic hourly prices. The following characteristics are modeled:

- Unit type (steam, combined-cycle, combustion turbine, etc.)
- Full load heat rates and heat rate curves.
- Summer and winter capacities.
- Operation and maintenance costs.
- Forced and planned outage rates.
- Minimum up and down times.
- Quick start and spinning reserve capabilities.
- Startup costs.

Sources for thermal unit data include the EIA-411, EIA-867, and EIA-412 forms, the FERC Form 1, and the REA-12 forms. When unit-specific data were unavailable, we developed generic heat rate curves for different unit types based on available data for similar units. CRA specified unit forced and planned outage rates for each type based on an analysis of NERC's "Generating Availability Data System" data set.

A.2.3 Planned Additions and Retirements

Planned additions and retirements impact the fuel mix of installed capacity and the composition of plants on the margin. In the near-term, CRA added new non-renewable capacity to the model based only on existing projects that are currently under construction or have an obligation to provide capacity under the FCM.[24] As discussed in the body of this report, new renewable capacity was added to capture the impacts of renewable portfolio standards. Additional generic new capacity was added in the longer term if needed to meet regional reserve requirements in each case.

A.2.4 Fuel Price Forecasts

The opportunity cost of fuel consumed for generation (i.e., or the current spot price of fuel) is generally the largest component of a unit's marginal cost bid. To project these variable fuel costs, we used forecasts of spot fuel prices at regional hubs, and further refined these based on historical differentials between price points around each hub. For oil and gas, we used estimates of the price of delivered fuel to generators on a regional basis, while for coal we used plant specific price forecasts. The derivation of fuel price forecasts is described in the body of this report.

A.2.5 Transmission System Representation

The GE MAPS commitment and dispatch accounts for the impact of designated transmission constraints. CRA implemented a set of transmission constraints for the model regions based on publicly available regional studies and specific transmission constraints listed in ISO documents. Specifically, the modeled constraints included:

- NERC flowgates throughout the model footprint.
- All major interfaces in New England, NYISO and PJM.
- Most frequently binding constraints in the ISO-NE, NYISO, and PJM markets, as determined by CRA based on data published on the ISO websites.

[24] As reported in Ventyx Energy Velocity Database.

APPENDIX B: DETAILED MODEL RESULTS

Table B-1: Simple Average LMP by RSP Zone – Base Case ($/MWh, 2009 dollars)

	2015	2016	2018	2021	2024
BHE	64.62	65.44	66.15	67.78	68.97
ME	65.06	66.04	66.81	68.58	69.86
SME	64.86	65.88	66.73	68.67	69.93
NH	64.28	65.30	66.16	68.13	69.44
VT	64.46	65.43	66.20	68.06	69.13
BOS	64.96	65.99	66.82	68.87	70.23
NECMA	65.21	66.25	67.08	69.12	70.50
WMA	65.23	66.23	67.00	68.94	70.20
RI	65.09	66.11	66.91	68.92	70.23
SEMA	65.27	66.31	67.14	69.21	70.63
CT	64.98	66.02	66.86	68.89	70.14
SWCT	65.14	66.20	67.06	69.16	70.41
NOR	65.29	66.37	67.24	69.35	70.55
Total	64.96	65.97	66.78	68.74	70.02

Table B-2: Simple Average LMP by RSP Zone – NPT Case ($/MWh, 2009 dollars)

	2015	2016	2018	2021	2024
BHE	62.97	63.48	63.90	65.51	66.67
ME	63.36	64.00	64.51	66.23	67.39
SME	63.01	63.66	64.26	66.10	67.28
NH	62.40	63.05	63.68	65.55	66.76
VT	62.90	63.47	64.01	65.82	66.81
BOS	63.56	64.18	64.83	66.88	68.16
NECMA	63.87	64.50	65.14	67.22	68.50
WMA	64.11	64.71	65.31	67.32	68.49
RI	64.03	64.64	65.26	67.32	68.54
SEMA	64.11	64.77	65.41	67.52	68.85
CT	64.03	64.68	65.36	67.47	68.64
SWCT	64.29	64.97	65.69	67.88	69.05
NOR	64.47	65.17	65.91	68.12	69.23
Total	63.62	64.25	64.87	66.84	68.03

Table B-3: Load-Weighted Average LMP by RSP Zone – Base Case ($/MWh, 2009 dollars)

	2015	2016	2018	2021	2024
BHE	66.39	67.22	67.96	69.77	71.05
ME	66.85	67.92	68.81	70.80	72.26
SME	67.11	68.27	69.26	71.43	72.90
NH	66.48	67.58	68.54	70.78	72.21
VT	66.43	67.45	68.30	70.32	71.46
BOS	66.92	68.02	68.96	71.23	72.72
NECMA	67.33	68.44	69.36	71.64	73.13
WMA	67.12	68.17	69.03	71.18	72.56
RI	66.99	68.06	68.96	71.22	72.64
SEMA	67.05	68.14	69.05	71.41	72.95
CT	67.53	68.64	69.58	71.93	73.32
SWCT	67.82	68.96	69.91	72.38	73.78
NOR	68.44	69.62	70.60	73.08	74.42
Total	67.13	68.22	69.14	71.40	72.82

Table B-4: Load-Weighted Average LMP by RSP Zone – NPT Case ($/MWh, 2009 dollars)

	2015	2016	2018	2021	2024
BHE	64.39	64.95	65.35	67.12	68.34
ME	64.80	65.57	66.11	68.03	69.34
SME	64.80	65.63	66.28	68.33	69.67
NH	64.16	64.93	65.56	67.67	68.98
VT	64.49	65.17	65.68	67.63	68.70
BOS	65.21	65.94	66.60	68.87	70.26
NECMA	65.66	66.40	67.04	69.33	70.73
WMA	65.75	66.43	67.00	69.23	70.52
RI	65.68	66.37	67.00	69.30	70.63
SEMA	65.65	66.39	67.03	69.39	70.85
CT	66.30	67.05	67.73	70.13	71.46
SWCT	66.72	67.49	68.21	70.74	72.08
NOR	67.34	68.15	68.90	71.45	72.74
Total	65.55	66.28	66.92	69.18	70.52

Table B-5: Wholesale Cost of Serving Load in RSP Zones – Base Case ($million, 2009 dollars)

	2015	2016	2018	2021	2024
BHE	126	129	132	139	145
ME	450	461	475	502	526
SME	215	221	228	241	252
NH	664	683	712	765	812
VT	468	479	495	525	549
BOS	1,751	1,796	1,856	1,974	2,074
NECMA	589	605	626	666	701
WMA	693	711	734	780	820
RI	764	783	810	861	904
SEMA	901	924	955	1,017	1,069
CT	1,032	1,056	1,086	1,147	1,195
SWCT	717	734	756	800	833
NOR	381	390	401	425	442
Total	8,752	8,971	9,267	9,842	10,321

Table B-6: Wholesale Cost of Serving Load in RSP Zones – NPT Case ($million, 2009 dollars)

	2015	2016	2018	2021	2024
BHE	122	124	127	134	140
ME	436	445	456	482	505
SME	208	212	218	230	241
NH	641	657	681	731	775
VT	454	463	476	505	528
BOS	1,706	1,741	1,793	1,908	2,004
NECMA	575	587	605	645	678
WMA	679	693	713	759	797
RI	749	763	787	838	879
SEMA	883	901	927	988	1,038
CT	1,013	1,031	1,057	1,119	1,165
SWCT	706	719	737	781	814
NOR	374	382	392	415	432
Total	8,546	8,717	8,970	9,536	9,995

Table B-7: Generation by Type – Base Case (GWh)

	2015	2016	2018	2021	2024
Peakers	389	383	429	451	491
Steam (Gas/Oil)	171	143	214	248	308
Combined Cycle	43,543	43,267	44,609	45,019	44,635
Pumped Storage	955	1,241	1,425	1,904	2,114
Steam (Coal)	18,836	18,709	18,583	19,081	19,137
Nuclear	36,455	36,899	36,541	37,330	37,507
Renewables	19,500	20,525	21,737	24,112	27,928
Hydro	5,290	5,290	5,290	5,290	5,290
CAN Net Interchange	13,281	13,567	14,256	14,508	14,533
NY Net Interchange	-216	66	245	65	-637
Total	138,203	140,091	143,328	148,008	151,308

Table B-8: Generation by Type – NPT Case (GWh)

	2015	2016	2018	2021	2024
Peakers	310	316	341	356	387
Steam (Gas/Oil)	108	82	131	150	204
Combined Cycle	38,255	37,366	38,452	39,030	38,710
Pumped Storage	847	1,106	1,448	1,804	1,971
Steam (Coal)	18,914	18,725	18,660	19,176	19,242
Nuclear	36,455	36,899	36,541	37,330	37,507
Renewables	19,500	20,524	21,737	24,112	27,928
Hydro	5,290	5,290	5,290	5,290	5,290
CAN Net Interchange	19,466	20,075	20,926	22,015	22,041
NY Net Interchange	-1,064	-871	-713	-975	-1,672
Total	138,081	139,512	142,813	148,289	151,608