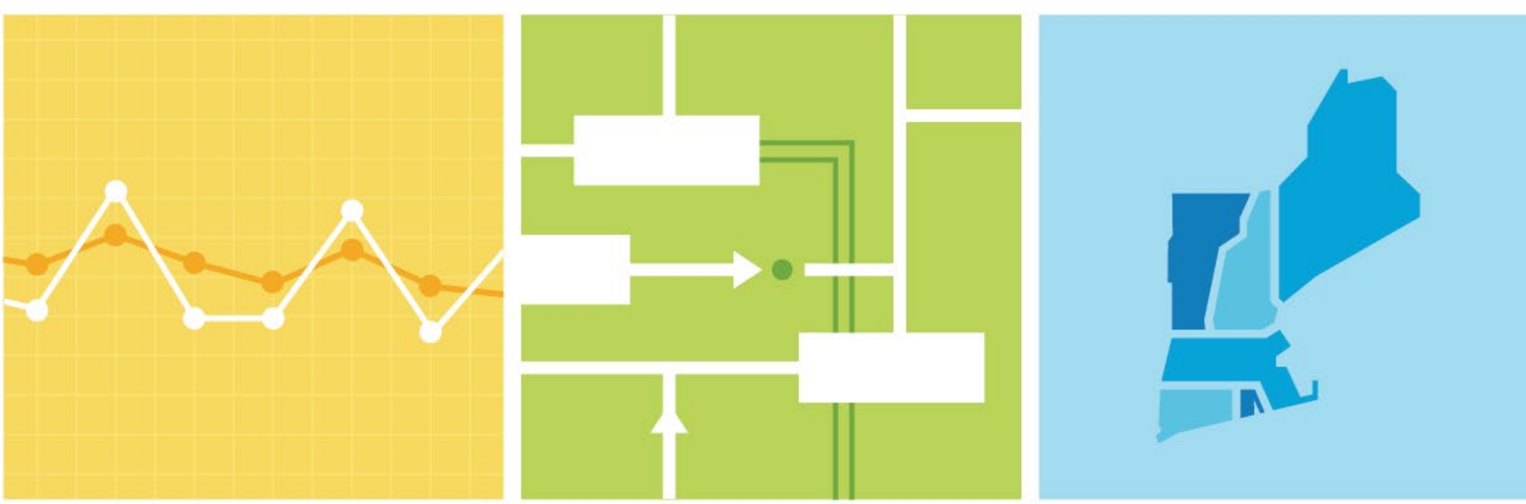
2020 Economic Study: Interregional Storage's Capability to Facilitate the Effective Use of Clean Energy Resources

Revision 1 – June 10, 2022



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Section 1
Executive Summary

This report documents ISO New England's (ISO-NE, the ISO) 2020 Economic Study, also known as the *Interregional Storage's Capability to Facilitate Use of the Clean Energy Resources*. National Grid requested this study under Attachment K Section 4.1(b) of the ISO Open Access Transmission Tariff (OATT). The goal of this study, as with many recent future-looking studies in this field, was to explore various challenges the power grid faces, as it is decarbonized and then explore possible solutions. The move to decarbonize the power grid presents new challenges to power system operations with high variable energy resource penetrations (e.g., wind and solar) and fossil-fueled resource retirements. These changes have the potential to impact wholesale electricity market prices, consumer costs, and system operability. This study's results provide additional information in two main areas: the utilization of long- and short-term storage and the impacts of further fossil-fuel resource retirements.

One of the focuses of this study was to model the use of the existing and new tie-lines to neighboring regions as bi-directional lines.[1] National Grid sought to define how varied use of the tie-lines and long-duration storage in Québec might facilitate a cost-effective achievement of New England's clean energy goals for the year 2035. Bi-directional tie-lines could optimize renewable resource production, minimize curtailment, and reduce the reliance on fossil-fueled resources during peak load hours and/or low renewable resource availability.

Additional sensitivity[2] scenarios explored the impact of select base assumptions changes on the metrics. In these sensitivity scenarios, the balance of supply and demand was changed to give storage more opportunities to reduce production costs. Additional changes included prioritizing New England renewables over imports, prioritizing imports over New England renewables, and prioritizing storage in Québec over local storage by reducing the amounts of assumed New England battery energy storage systems (BESSs).

For the bi-directional scenarios,[3] results revealed that the introduction of bi-directional transfers across existing interregional tie-lines caused reductions in the curtailment of variable energy resources. These reductions occurred during conditions in which there were low loads coupled with high variable energy resource production. The study revealed locational marginal prices (LMPs) decreased when banked energy reimported from Canada displaced energy produced by gas-fired resources. In all the scenarios examined, electric sector CO_2 emissions met the states' goals for 2035.

Banked energy in Québec largely consisted of deferred imports. However, a portion of this banked energy went unutilized in New England because there was insufficient energy demand or insufficient import

[1] Bi-directionality refers to using the existing and new tie-lines to lower renewable build-out curtailments by utilizing "energy banking." Energy banking was discussed in detail at the February 17, 2021 PAC meeting (slides 10-14). The intent was to use bi-directional external tie-lines with negative threshold prices to simulate incentives of renewable energy credits (RECs). The study explored the addition of two new tie-lines & seasonal storage with Québec.

[2] All sensitivities assumed no internal transmission constraints (e.g., unconstrained transmission).

[3] Included modeling of a constrained and unconstrained transmission system. The ISO modeled the unconstrained transmission system as a single zone. In a constrained model, the New England system is represented by 13 Regional System Plan (RSP) zones connected by "pipes" representing the interfaces between the RSP zones (a collection of one or more transmission lines between zones).

capacity.[4] The results of the sensitives with varying amounts of BESSs indicated the presence of BESSs led to increased New England renewable production (i.e., reduced curtailments) and decreased production by gas-fired resources.

The other focus of the study was built off the work done for the 2019 Economic Study requested by New England States Committee on Electricity (NESCOE) to understand the impact of additional resource retirements. For the incremental retirement scenarios, here on referred to as the incremental scenarios, an increasing number of resources were retired across the scenarios. Retirements included Millstone 2 nuclear facility, Mystic 8&9 combined-cycle liquefied natural gas (LNG) facilities, all coal and oil resources, and large amounts of natural-gas resources.

In these scenarios, National Grid also requested a different threshold price order than those assumed in the 2019 Economic Studies. During periods when supply exceeds demand, imports were curtailed after renewables in New England under this threshold price order sensitivity. This threshold price order first curtailed offshore wind, followed by onshore wind, utility scale photovoltaics, imports from New Brunswick, imports from Québec, imports over the new transmission tie-lines with Quebec (i.e., the New England Clean Energy Connect [NECEC]), and then finally behind-the-meter solar photovoltaics. The goal of this threshold price order sensitivity was to identify whether the proposed build out of wind and solar resources was too large. If substantial amounts of curtailment of these resources was occurring, that may imply that the proposed amounts were too large.

Highlights of the results include that the retirement of coal and oil resources with these assumptions was not impactful, as these resources were not needed to meet load even if they were in-service. The case that added natural-gas resource retirements was found to not meet reliability criterion and resources including a new import transmission line were added to the case. Finding that this case was short is itself noteworthy – that even with the addition of large amounts of wind, solar PV, and battery storage there were not sufficient resources. The new zero-cost resources then reduced emissions and production costs and offset the loss of the fossil-fueled resources.

The 2020 Economic Study provided significant information on how the balance of supply and demand can impact the results. The incremental retirement scenarios found that retirement of dual-fuel gas-fired resources on top of oil, coal, and nuclear unit retirements cannot be compensated solely by the renewables mix National Grid envisioned. The bi-directional cases and sensitivities found that energy banking under certain conditions could reduce carbon dioxide emissions and production costs. However, when supply and demand are relatively balanced, minimal opportunities exist for energy banking.

[4] Only 1,200 MW could be exported via the new tie-line during oversupply conditions. A maximum of 9,530 MW of New England renewables were curtailed and 3,003 MW of imports were deferred/curtailed/banked for importing at a future time.

Section 2
Background and Purpose

A key objective of this study was to investigate using Québec's hydroelectric reservoir system to better optimize New England's renewable resources by reducing curtailment. National Grid recognized that the 2019 Economic Studies did not include representation for exports to Québec and identified significant curtailment of renewable energy resources. They suggested this indicated "under-utilization" of New England investments in renewables. A 2020 MIT Study investigated a coordinated northeast dispatch. This study showed large bi-directional transfers between New England and Québec could be beneficial and could better utilize renewable energy across a wider regional footprint.[5]

National Grid, intrigued by the use of tie-lines to avoid curtailments of renewable resources such as solar and wind, submitted a 2020 Economic Study request to explore these concepts further. Key assumptions for the Economic Study included: 8,000 MW of offshore wind in the SEMA/RI region, 1,330 MW of additional onshore wind in northern New England, 2,000 MW / 8,000 MWh of batteries, 1,817 MW of peak electric vehicle charging (equates to 2.2 million vehicles), 5,214 MW of heating electrification at the winter peak, and a bi-directional tie-line model between Québec and New England.

The National Grid Economic Study request was submitted to the ISO on April 1, 2020 and presented to the Planning Advisory Committee (PAC) on April 23, 2020.

As a part of the regional system planning effort, and as specified in Attachment K Section 4.1(b) of the ISO *Open Access Transmission Tariff* (OATT), the ISO may conduct Economic Studies each year. The ISO posts all past study reports on the Economic Studies webpage. Using scenario analysis, the Economic Studies provide information on system performance, such as estimated production costs, load-serving entity energy expenses, transmission congestion, and electric sector emission levels.[6] Scenario analyses also inform stakeholders about different visions of the future grid. These hypothetical scenarios do not reflect the ISO's vision of future development, projections, and preferences or precise physically realizable interconnection plans. Study scenarios include assumptions that may not satisfy laws or policies that will be in effect for the study year, but they can assist the public by identifying key regional issues.

The ISO conducts Economic Studies under the auspices of the PAC. The role of the PAC in the Economic Study process is to discuss, identify, and assist the ISO by advising on the proposed studies. For this study, stakeholders and the study proponent, National Grid, helped to shape the scope of work. The ISO provided guidance to narrow the scope of National Grid's request (ancillary services analysis was removed) and modified some assumptions (e.g., capping of the new tie-line interface limit). These modifications of the study scope allowed the prioritization of work on the 2021 Economic Study (Future Grid Reliability Study [FGRS] – Phase 1) which included analysis that was, in part, a next iteration of the 2020 Economic Study.

The goal of the study was to inform developers, consumer interest groups, advocates, policymakers, and regulators as they develop strategies to meet the region's renewable energy goals. The ISO encourages

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[5] The 2020 MIT study refers to the paper "Two-Way Trade in Green Electrons: Deep Decarbonization of the Northeastern U.S. and the Role of Canadian Hydropower" by Emily Dimanchev, Joshua Jodge, and John Parsons that can be viewed here: https://dspace.mit.edu/handle/1721.1/130577.

[6] *Load-serving entity (LSE) energy expenses (LSEEE)* are the costs the LSEs pay for the energy at the receipt point's calculated locational marginal price (LMP). They equal the total electric energy revenues that resources and imports from neighboring systems would receive for supplying electric energy to the wholesale market plus the cost of congestion.

interested parties to compare the results for the different scenarios and to reach their own conclusions about the possible implications.

The ISO completed the 2020 Economic Study through the PAC stakeholder process involving discussions of modeling assumptions and simulation results. Table 2-1 below summarizes the presentations made to the PAC.

Table 2-1: History of 2020 Economic Study PAC Presentations

Presentation	Date (Link)
High-level draft scope of work and assumptions (1/3)	May 20, 2020
High-level draft scope of work and assumptions (2/3)	June 17, 2020
High-level draft scope of work and assumptions (3/3)	July 22, 2020
Preliminary Results	November 19, 2020
Modeling of Battery Storage in Economic Studies	December 16, 2020
Feedback on Preliminary Results & Proposed Sensitivities	December 16, 2020
Sensitivity Results	February 17, 2021

Section 3
Scenarios

The ISO considered seven scenarios and eight sensitives, based on the National Grid study request and further scope development with stakeholders.

3.1 Bi-directional and Incremental Scenarios

The seven scenarios included four bi-directional scenarios that modeled imports across the New England tie-lines with Hydro Québec (HQ) and New Brunswick (NB) and three incremental retirement scenarios. Profiled imports that could not be utilized during times of high renewable output and/or lower loads were deferred/curtailed/banked in HQ for use later in the year when they could be imported during times of low renewable output and/or higher loads to displace fossil-fueled generation.

Variable energy resources and other profiled resources used threshold pricing to provide the software a method to curtail resources in a specified order during times of oversupply. The bi-directional scenarios used negative threshold prices to reflect revenue streams outside of the energy market arising from renewable energy credits (RECs). The offsetting compensation garnered via RECs was assumed to enable a resource to bid negative offers in the energy market, while still receiving a positive combined revenue stream. Negative offers may also stem from a resource having contractual obligations for energy production with penalties for under-performance. Table 3-1 summarizes the key assumptions for the seven scenarios studied.

The three incremental scenarios revisited the New England States Committee on Electricity (NESCOE) 2019 Economic Study assumptions by revising the threshold price priority order of renewables vis-à-vis imports from Canada. These scenarios did not have bi-directional flows on the tie-lines. Instead, fixed profiles based on historical imports represented flows from Canada into New England. The 2019 Economic Study assumptions carried forward included: continued growth of energy efficiency, air source heat pump adoption, electric vehicle adoption, and PV deployment (behind-the-meter and utility-scale). Additional assumptions carried forward included 2,000 MW / 8,000 MWh of battery energy storage systems (BESSs) and 8,000 MW of offshore wind in the Bureau of Ocean and Energy Management (BOEM) lease area south of the Martha's Vineyard and Nantucket Islands.

All seven scenarios were studied with and without internal transmission constraints (constrained and unconstrained, respectively). Section 4 provides additional details regarding the assumptions used in the study.

Table 3-1: Summary of Bi-directional and Incremental Scenarios

Scenarios	Threshold Prices Used	Retirements	Must Run Units	Wind Additions (Nameplate)	Peak Demand from Heat Pumps	Peak Demand from Electric Vehicles	Nameplate Storage Additions	Bi-Directional External Tie(s)
Bi-Directional Reference (B)	REC-Inspired	FCA 14, Mystic 8&9, Millstone 2, NE Coal, + 75% of conventional NE oil including dual-fuel based on age	Nuclear, Municipal Solid Waste, Landfill Gas, Wood	1,330 MW Onshore 8,000 MW Offshore	5,214 MW	1,817 MW (2.2 million vehicles)	2,000 MW / 8,000 MWh Battery and Utilizing HQ as Virtual Storage	None
Bi-Directional Legacy (B_HQNB)								HQ PHII and NB
Bi-Directional New Transmission 1 (B_HQNB_1T)								HQ PHII, NB, HG, one new 1,200 MW tie
Bi-Directional New Transmission 2 (B_HQNB_2T)								HQ PHII,HQ HG, NB, two new 1,200 MW ties
Incremental_8000 (I)	Positive Threshold Prices	FCA 14, Mystic 8&9, Millstone 2, NE Coal					2,000 MW / 8,000 MWh Battery	None
Incremental_8000 with Oil retirements (I_Oil)		Same as (I) plus all of the oil resources						
Incremental_8000 Oil and NG Retirements (I_Oil_NG)		Same as (I_Oil) plus 50% of the remaining NG units including dual-fuel units						Two new 1,200 MW import only ties

The key differences between the bi-directional and incremental scenarios were:

<u>Bi-directional Scenarios:</u>

- Scenario B: Only imports into New England across ties with HQ and NB were permitted and negative threshold pricing was used to reflect RECs
- Scenario B_HQNB: Same as B, but with exports to Canada permitted across tie-lines with HQ and NB
- Scenario B_HQNB_1T: Same as B_HQNB, but with the addition of one new bi-directional 1,200 MW tie-line from HQ to CMA/NEMA
- Scenario B_HQNB_2T: Same as B_HQNB, but with the addition of two new bi-directional tie-lines (1,200 MW each, 2,400 MW total) from HQ to CMA/NEMA

<u>Incremental Scenarios:</u>

- Scenario I_8000: Used positive threshold pricing that prioritized imported energy from Canada over the installation of new renewable resources in New England
- Scenario I_8000_Oil: Same as I_8000, but with all oil resources retired
- Scenario I_8000_Oil_NG: Same as I_8000_Oil, but with 50% of remaining gas-fired resources retired and two new tie-lines added from HQ to CMA/NEMA

3.2 Sensitivity Scenarios

Following discussion with the PAC after sharing preliminary results of the scenarios, the ISO performed several sensitivities. Table 3-2 summarizes the key assumptions for the sensitivity scenarios studied.

In the first four sensitivities, the ISO investigated two variations of threshold prices:

- “REC Inspired” threshold prices applied REC valuation to only solar and wind resources in New England
- “Import Priority” threshold prices reflected greater REC-like attributes for imported energy from Québec’s existing hydro system than renewable resources in New England

All sensitivities assumed lower loads previously used for the year 2030 and put Millstone 2 (which had been retired in the scenarios) back in-service. These assumptions changes were made to increase the gap between supply and demand to explore the operation of storage. The remaining sensitivities explored the effect of removing BESSs on the use of the new tie-lines for energy banking. Section 4 provides additional details regarding the assumptions used in the study.

The key differences between the four main sensitivity scenarios are:

- B_Redispatch_0: Iterative case that curtails imports before New England renewables (“REC inspired” threshold prices)
- B_Track_0: Iterative case that curtails New England renewables before imports (“import priority” threshold prices)
- B_Redispatch_1T: Same as sensitivity B_Redispatch_0, except this sensitivity includes one new 1,200 MW bi-directional tie-line for energy banking
- B_Track_1T: Same as sensitivity B_Track_0, except this sensitivity includes one new 1,200 MW bi-directional tie-line for energy banking

The ISO examined the removal of BESSs for all sensitivities.

Table 3-2: Summary of Sensitivity Scenarios

	Scenarios	Threshold Prices Used	Retirements	Must Run Units	Wind Additions (Nameplate)	New England System Load (Incl. EE)	EVs, Heat Pumps, Load Profiles	Number of Iterations	Nameplate Storage Additions	Bi-Directional External Tie(s)
Preliminary Scenarios	Bi-Directional Reference (B)	REC-Inspired	FCA 14, Mystic 8&9, Millstone 2, NE Coal, +75% of conventional NE oil including dual-fuel based on age	Nuclear, Municipal Solid Waste, Landfill Gas, Wood	1,330 MW Onshore 8,000 MW Offshore	2035 load extrapolated from 2020 CELT Report (unchanged from Preliminary results)	Unchanged from National Grid 2020 Preliminary Results	One	2,000 MW / 8,000 MWh Battery and Utilizing HQ as Virtual Storage	None
	Bi-Directional Legacy (B_HQNB)									HG, PHII NECEC, and NB
Sensitivity Scenarios	Bi-Directional Redispatch Reference (B_Redispatch_0)		Same as above except Millstone 2 in-service			2030 load extrapolated from 2019 CELT Report (From the NESCOE 2019 Economic Study)	NESCOE 2019 Economic Study			None
	Bi-Directional Track & Iterate Reference (B_Track_0)	Import Priority		Nuclear, Municipal Solid Waste, Landfill Gas, Wood, Imports						
	Bi-Directional Redispatch 1T (B_Redispatch_1T)	REC-Inspired		Nuclear, Municipal Solid Waste, Landfill Gas, Wood				Two		One New 1,200 MW tie to facilitate energy banking, existing ties and NECEC only import
	Bi-Directional Track & Iterate 1T (B_Track_1T)	Import Priority		Nuclear, Municipal Solid Waste, Landfill Gas, Wood, Imports						

Section 4
Methodology and Assumptions

Economic Studies aim to simulate the complex interactions of the physical transmission system and the electricity markets for a given set of assumed resources. To enable those simulations, many assumptions factor into the studies that can significantly influence results. Some assumptions have a greater impact on the results than others (e.g., threshold prices for various resource types). As noted earlier in Table 2-1, the ISO discussed the 2020 Economic Study assumptions in detail at the May, June, and July 2020 PAC meetings. This section highlights the importance of certain assumptions and how the ISO modelled them in the 2020 Economic Study. The Economic Studies Reference Guide[7] provides more details on generic assumptions.

4.1 Modeling Tools and Methodology

The ISO conducted the 2020 Economic Study analyses in Hitachi Energy's GridView[8] economic dispatch program. The program is a complex simulation tool that calculates least-cost, transmission-security-constrained resource commitment and economic dispatch under differing sets of assumptions and minimized production costs for a given set of resource characteristics. While the simulation model used in this analysis explicitly represents the full transmission network, New England was modeled as either a single area for unit commitment (unconstrained scenarios) or regionally constrained subareas (constrained scenarios) to decrease simulation time and focus on the optimal economic dispatch of a given set of resources.[9] This approach allows the study to focus on the broader high-level impact of the scenarios under investigation.

While GridView is based on a nodal load-flow program, this study was configured to neglect detailed system issues that may arise within system planning subareas (Regional System Plan [RSP] subareas or bubbles). Rather, the ISO system was represented as a "pipe-and-bubble" model (see Section 4.2.1) that primarily identifies system transfer issues between RSP subareas. Therefore, it did not identify transmission system upgrades needed to move energy within subareas.

4.1.1 Energy Banking Methodology

The ISO developed a bi-directional transmission model that represented opportunities to export ("bank") excess renewable energy within New England to Canada (which would have otherwise been curtailed) and defer profiled import energy from Canada for later use during times of low renewable energy production and/or high system loads. This bi-directional model allowed imports from Canada into New England when LMPs were above $2/MWh (the NECEC threshold price). Then, imports remained at zero until the LMPs in New England reached $-25/MWh, when exports would commence. Under this model, simultaneous imports and exports were *not* allowed to occur. Additionally, Highgate imports were essentially "must run" given how far down they were in the threshold price order.

In the sensitivity scenarios, when energy banking with Québec occurred, iterative simulation runs were used to identify the most economic times to deliver banked/deferred energy from Canada and thus optimize the use of the returned energy. This banking method applied only in the sensitivity scenarios: B_Redispatch and B_Track.

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[7] The Economic Study Reference Guide is located on the Economic Studies webpage on the ISO website.

[8] GridView was formerly developed by ABB. However, Hitachi acquired ABB since the start of the 2020 Economic Study.

[9] GridView is not configured by ISO New England to replicate a power-flow model; refer to Section 4.2.1 for more details.

A multi-step iterative process was used for banking and utilizing energy in HQ via one to two 1,200 MW tie-lines. The iterative process followed these steps.

(1) Only exports to Canada were allowed on the new tie-line(s) in the first step.

(2) The total banked energy from the first iteration was the sum of curtailed imports on the existing ties plus surplus renewable energy exported from New England to Québec on the new tie-lines at $-25/MWh.

(3) A profile was created to return the total banked energy on the new 1,200 MW tie(s) during times of higher LMPs.

(4) A second iteration was run using this profile to deliver banked energy to New England. Similar to other profiled resources, a threshold price of $ 5/MWh (in B_Redispatch) or $-5/MWh (in B_Track) was used to curtail this new profile if the energy could still not be economically consumed in New England.

The return of exported energy assumed a 12% round trip transmission loss factor.

Following the process outlined above, all banked energy was returned to New England. At times of higher LMPs, the full 1,200 MW capability of the line was used to import the banked energy. Figure 4-1, below highlights key assumptions of this iterative process.

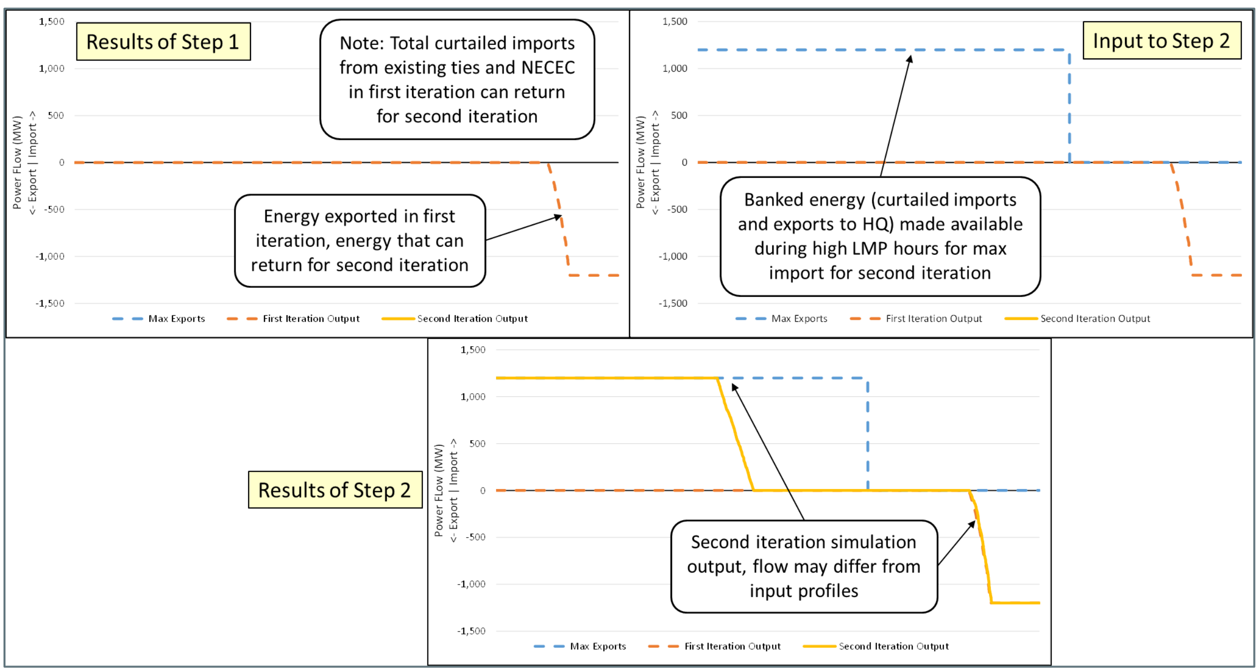

Figure 4-1: Multi-Step Process for Returning Banked Energy

4.2 Assumptions

This section summarizes the key assumptions made for the following parameters:

- Transmission constraints
- Interchanges with neighboring systems
- Weather year

- Load forecast, including electrification
- Energy storage
- Resource threshold prices
- Resource retirements
- Electric Sector emission allowances

The Economic Studies Reference Guide provides more details on generic assumptions.

4.2.1 Transmission Constraints

The simulations analyzed unconstrained and constrained conditions. For unconstrained transmission, the New England transmission system was modeled as a single-zone system ignoring all internal transmission limits. For constrained transmission scenarios, the system was modeled using the "pipe and bubble" configuration. "Pipes" represented transmission lines that connect the RSP subarea "bubbles."[10]

The transfer limits for internal and external transmission interfaces for 2035 used the last year of values (2029) presented for the fifteenth Forward Capacity Auction (FCA 15). Regional resources were economically dispatched in the transmission-constrained simulations to respect the assumed transmission system N-1 transfer limits.[11]

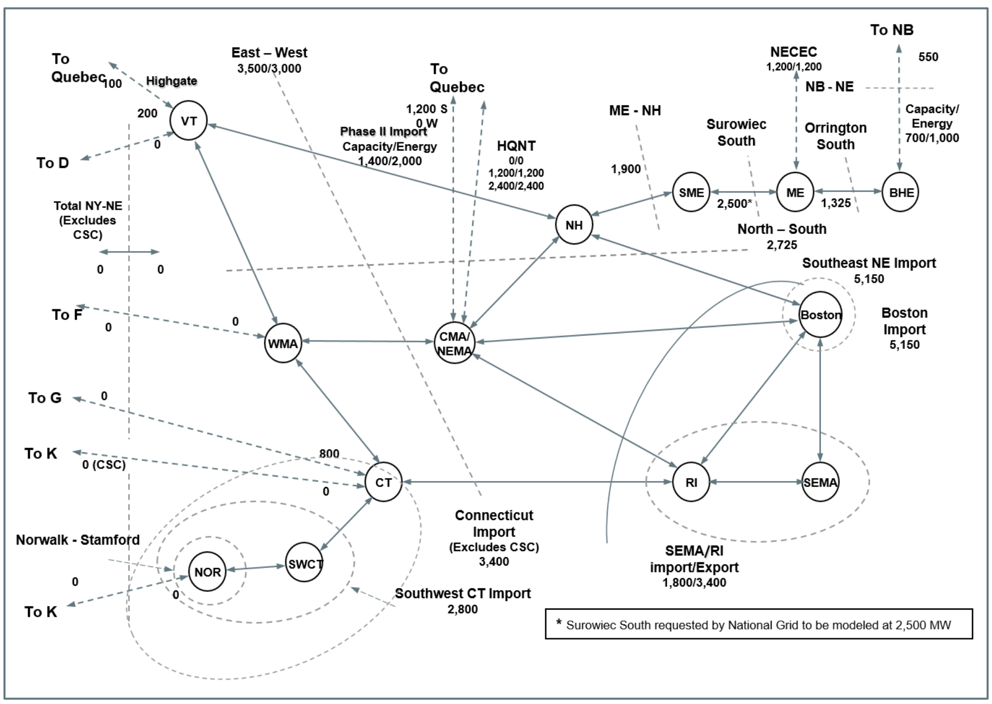

Figure 4-2: New England Pipe and Bubble Representation (MW) Assumed Transmission Interfaces 2035

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[10] For more information on RSP areas, refer to the System Planning Subareas map at this ISO website link: https://www.iso-ne.com/about/key-stats/maps-and-diagrams/#system-planning-subareas. Also, refer to the ISO's Regional System Plan webpage at: https://www.iso-ne.com/rsp.

[11] Normal transmission system transfer limits account for transmission system security constraints, which consider expected transmission facilities in service and first-contingency (N-1) criteria. A *first contingency* is the loss of the power system element (facility) with the largest impact on system reliability. A *second contingency* (N-1-1) occurs after a first contingency when the facility that, at that time, has the largest impact on the system is lost. N-1-1 also can refer to a constraint met by maintaining an operating reserve that can increase output when the first contingency occurs.

4.2.2 Interchange with Neighboring Systems

Table 4-1 shows the assumed 2035 interchange with neighboring systems, including the new state-contracted transmission line with Québec (i.e., NECEC). The same internal and external interface capabilities were assumed for all scenarios. The New Brunswick import profile used historical hourly energy profiles that reflected a combination of both FCM capacity imports and opportunity-based energy imports that respected the import-transfer capability of the ties.

Table 4-1: Interchange with Neighboring Systems

Interconnection	Import-Transfer Capability (MW)[(a)]	Interchange Modeling
Highgate	217	Historical diurnal profile averaged over 2016 through 2018
Phase II	2,000	Historical diurnal profile averaged over 2016 through 2018
NECEC	1,200	Assumed firm energy delivery of 1,090 MW across all hours
New Brunswick	1,000	Historical diurnal profile averaged over 2016 through 2018
New York AC	1,400	Assumed no interchange[(b)]
CSC	330	Assumed no interchange[(b)]

(a) These values represent import capability for energy.

(b) Assuming no interchange is a conservative assumption to avoid relying on New York to serve New England loads as New York interchange is less predictable than Canada to New England Flows.

The export capabilities of tie-lines in the bi-directional scenarios are described in Table 4-2.

Table 4-2: Export Capability in Bi-directional Cases

	Scenario			
Export Capability (MW)	**B**	**B_HQNB**	**B_HQNB_1T**	**B_HQNB_2T**
Highgate	100	100	100	100
Phase II	1,000	1,000	1,000	1,000
NB	550	550	550	550
First New Tie-line to Québec	0	0	1,200	1,200
Second New Tie-line to Québec	0	0	0	1,200

4.2.3 Weather Year

For all scenarios, the 2015 weather year was used for wind, solar, and load profiles.[12] The study used 2015 in part because of the availability of one-minute data for the initially proposed ancillary services analysis. The use of different weather year profiles can result in different magnitudes for the study metrics, but trends in results between scenarios would be similar.

4.2.4 Load Forecast

For all scenarios, the ISO's 2020 Capacity, Energy, Loads, and Transmission (CELT) Report was the basis for gross demand and electrification load assumptions. Projected loads for the last year of the CELT period (2029) were scaled to represent 2035 using the growth rate from 2028 to 2029. Between the 2019 and 2020 Economic Studies, there was a significant increase in the modeled annual energy from 159 TWh up to 187 TWh. This change was due to the new method the ISO used to create the 8760 profile for EE that better matched both annual energy and peak supply of EE. The net load profile reflects adjustments to account for all energy efficiency, solar photovoltaic (both behind-the-meter [BTM] and non-BTM), transportation electrification (e.g., electric vehicles [EVs]), and heating electrification (e.g., air source heat pumps). Profiled

[12] Wind data is from the ISO's wind and power time series model developed by DNV (available on the ISO-NE website).

resources such as wind energy, hydro (excluding pumped storage), existing imports, and new imports also decrease the load served by dispatchable resources.

Transportation and heating electrification loads were modeled based on assumptions provided by National Grid. Compared to the 2019 Economic Study, the 2020 Economic Study had significantly more EVs and heat pumps. There were approximately 16 TWh of EVs and heat pumps as compared to 5 TWh in the 2019 Economic Study. A total of 2.2 million EVs, equivalent to 2.51 TWh of load, were modeled in the scenarios. EV locations were distributed by state, utilizing the same distribution that was used in the 2016 Economic Study (see Table 4-3). Hourly load shapes were created for each subarea based on their share of system-wide peak load.

Table 4-3: Distribution of Electric Vehicles

State	Percent of Load	Number of Vehicles
Massachusetts	43%	946,000
Connecticut	23%	506,000
Main	12%	264,000
New Hampshire	11%	242,000
Rhode Island	6%	132,000
Vermont	5%	110,000
New England	**100%**	**2,200,000**

4.2.5 Energy Storage

Conceptually, energy storage (i.e., pumped storage and BESSs) resources store lower-priced energy for use to replace higher-priced energy. Across all scenarios, existing pumped storage resources were dispatched to minimize the price range of daily high and low net loads while respecting the physical and economic constraints (i.e., reservoir size and resource efficiency). Pumped storage resources were assumed to have approximately a 74% round-trip efficiency.

For the 2020 Economic Study, the ISO used GridView's storage functionality, which seeks to dispatch storage to minimize production cost over the next 7 days. BESSs were assumed to have enough storage to discharge at full output for four hours and have approximately an 86% efficiency. For the sensitivity scenarios, the ISO assessed scenarios with no BESSs.[13]

4.2.6 Resource Threshold Prices

Threshold prices were assigned to profile-based resources (e.g., wind, solar, imports, etc.) in this study. Threshold prices facilitated the analysis of times when supplies of energy exceeded demand by setting an order to curtail "zero-cost" energy and imports. Threshold prices are not indicative of the "true" cost, expected bidding behavior, or a preference for one type of resource over another. Use of different threshold prices would produce different outcomes, particularly in amounts of curtailment by resource type.

GridView is driven by a cost-minimization objective function. Generally, production cost, emissions, and curtailment results are not affected by negative threshold prices. Production cost results are not impacted by threshold prices because production costs are calculated by fuel costs and heat rates rather than LMPs. Total curtailment is a reflection of supply and demand balance, not of threshold prices, so the negative threshold prices will not impact curtailment results. Since threshold prices only come into play to decide which "zero-

[13] Removing BESSs allowed for comparison to scenarios that had BESSs to understand what level of impact they would have on the energy banking results.

emission" resource[14] to curtail, emissions results were not impacted by the negative threshold prices. However, LMPs, LSEEE, and energy market revenues are affected by threshold prices and their order.

The bi-directional scenarios used a threshold price order that reflected RECs and led the bi-directional model to export when LMPs were negative. Negative threshold prices reflect that some resources may be able to make a profit using revenues from outside the energy markets (such as RECs), even when energy prices are negative. In the bi-directional model, it was also assumed that when energy prices reached a chosen negative threshold, energy would be exported to Québec rather than curtailed (within the abilities of the export transmission lines capacity to transport the energy). As described in Table 4-4 below, curtailment of BTM PV was the last energy source to be curtailed at an LMP of $-100/MWh. The balance of supply and demand in these simulations did not result in the curtailment of BTM PV. Imports from Canada (except Highgate) were curtailed at positive LMPs. Exports were triggered at $-25/MWh. Wind and PV were only curtailed when the export capability was exhausted.

Table 4-4: REC-Inspired Threshold Price Order

Price-Taking Resource	Threshold Price ($/MWh)
Imports from NB	10.00
Imports from Québec (Including New Ties)	5.00
NECEC	2.00
Trigger for Exports	-25.00
Onshore Wind	-30.00
Offshore Wind	-40.00
FCM and Energy-only PV	-50.00
Highgate Imports	-99.00
Behind-the-Meter PV	-100.00

As described in Table 4-5, the positive threshold price order reflected positive threshold prices only and curtailed offshore wind first, followed by onshore wind, utility scale PV, imports from NB, imports from HQ, NECEC, and then finally BTM-PV. These threshold prices were requested by National Grid to provide additional sensitivities that could give insights into the cases analyzed in past Economic Studies. This threshold price order was intended to curtail renewables resources first in part to help determine whether the right quantity of these resources were in a given scenario.

Table 4-5: Positive Threshold Price Order

Price-Taking Resource	Threshold Price ($/MWh)
Offshore Wind	13.00
Onshore Wind	12.00
Utility Scale PV	11.00
Import from NB	10.00
Imports from Québec	5.00
NECEC	2.00
Behind-the-Meter PV	1.00

Table 4-6 shows the import priority threshold price order used in some of the sensitives cases. This threshold price mixes the intentions of both the positive and REC-inspired threshold price orders while also adding other prices needed for the bi-directional model.

[14] For the purposes of this study, imports are assumed to have zero emissions. Calculating emissions for imports can be very complex and was outside the scope of this study.

Table 4-6: Import Priority Threshold Price Order

Price-Taking Resource	Threshold Price ($/MWh)
Imports on New Tie Line	-5.00
Trigger for Exports on New Line	-25.00
Offshore Wind	-35.00
Onshore Wind	-40.00
Utility Scale PV	-45.00
Imports from Canada over Existing Lines	-50.00
NECEC	-99.00
Behind-the-Meter PV	-100.00

As discussed earlier, if the study modeled other threshold prices or orders, different outcomes in LMPs and amounts of curtailment by resource type would occur (total curtailment will be consistent).

4.2.7 Resource Retirements

The study removed all resource retirements cleared through FCA 14 from the model. At the request of the study proponent (National Grid), the Mystic 8 & 9 combined-cycle liquefied natural gas facility, all coal resources, and the Millstone 2 nuclear facility were retired. An additional scenario also retired 75% of the remaining New England oil resources (including dual-fueled) in order of oldest to newest. Another scenario also included the retirement of 50% of the remaining New England gas-fired resources based on age in addition to the other retirements.

4.2.8 Electric Sector Emission Allowances

The study modeled electric sector emission allowance prices for carbon dioxide (CO_2), nitrous oxides (NO_X), and sulfur dioxide (SO_2). Table 4-7 lists the assumed environmental air emission allowances prices for 2035. Electric Sector CO_2 emissions for Massachusetts fossil-fueled generators were monitored exogenously to confirm that they meet the Massachusetts Global Warming Solutions Act (GWSA) cap allowances.

Table 4-7: Assumed 2035 Emission Allowance Prices

Emission Type	Modeled Price ($/ton)
NO_X	4.00
SO_2	2.00
CO_2	33.52

Section 5
Key Results and Observations

The objective of the 2020 Economic Study submitted by National Grid was to provide stakeholders analyses of interregional storage's capability to facilitate the use of clean energy resources to meet New England state goals. The study investigated leveraging bi-directional transmission capabilities with neighboring control areas to utilize their significant hydro storage capabilities and interregional load diversity. A complimentary investigation gave priority to imports of Canadian energy over New England wind and PV resources. The ISO also evaluated the use of existing and new tie-lines with adjacent control areas to lower curtailments of variable energy resources by utilizing "energy banking" with a hypothetical proposed 2035 topology. Only the most relevant simulation results are included in this report.[15]

5.1 Bi-directional Scenarios

The introduction of bi-directional tie-lines caused a reduction in supply-side resource curtailments during situations in which there was low demand or high variable energy resource production. For days when there was significant renewable production, the addition of one new tie-line reduced curtailment significantly, and the addition of two new tie-lines eliminated all New England resource curtailment. Total system-wide curtailment was relatively low compared to the 8,000 MW scenario[16] from the 2019 Economic Study. This was primarily due to assumptions of higher loads and the retirement of a nuclear resource in the 2020 Economic Study. The 2020 Economic Study assumed 187 TWh of total energy compared to 159 TWh in the 2019 Economic Study. In other words, since the balance of demand to supply was more even in 2020 than in 2019, there was less curtailment. With the addition of new tie-lines to return the banked energy from Québec, New England gas-fired resource production was displaced.

Table 5-1 and Table 5-2 summarize the outputs for selected bi-directional scenarios studied with constrained and unconstrained transmission, respectively.

Table 5-1: Summary of Constrained Bi-directional Scenario Metrics

Metric	Scenario			
	B	B_HQNB	B_HQNB_1T	B_HQNB_2T
Avg. Annual LMP ($/MWh)	12.64	12.99	9.62	7.00
Production Costs ($ million)	1,094	1,094	889	745
LSEEE + Uplift ($ million)	3,298	3,365	2,783	2,157
Curtailment of Imports (TWh)	8.108	8.108	12.974	18.217
Curtailment of New England Renewables (TWh)	0.949	0.181	0.074	0.036
CO_2 emissions (million short tons)	19.685	19.685	17.372	15.693

15 PAC presentations outlined in Table 2-1 provide additional results.

16 The 2019 NESCOE Economic Study report is available at: https://www.iso-ne.com/static-assets/documents/2020/06/2019_nescoe_economic_study_final.docx

Table 5-2: Summary of Unconstrained Bi-directional Scenario Metrics

Metric	Scenario			
	B	B_HQNB	B_HQNB_1T	B_HQNB_2T
Avg. Annual LMP ($/MWh)	12.64	12.99	9.62	7.00
Production Costs ($ million)	1,094	1,094	889	745
LSEEE + Uplift ($ million)	2,962	3,043	2,417	1,745
Curtailment of Imports (TWh)	7.821	7.821	12.725	19.105
Curtailment of New England Renewables (TWh)	0.934	0.173	0.071	0.035
CO_2 emissions (million short tons)	19.582	19.583	17.299	15.609

The following sections detail the key observations from the simulation results.

5.1.1 Curtailment and Congestion Impacts

Variable energy resource curtailment occurred when production exceeded the system's ability to consume the power, whether it occurred to respect transmission constraints in a local area or due to the lack of system-wide demand for the power when produced. The large-scale development of resources in areas not originally designed for significant exports, such as offshore wind off the southern coast of Massachusetts or onshore wind in northern Maine, may require additional transmission to relieve constraints and avoid transmission-related curtailment. Conversely, the development of resources connected closer to population centers in southern New England and Boston helped avoid transmission-related curtailment of renewable energy. In sum, internal constraints had a negligible impact. Curtailment in the constrained cases increased only 1.0-3.5% from the unconstrained cases.

Overall, import curtailments increased in B_HQNB_1T and B_HQNB_2T (as shown in Tables 5-2 and 5-3) in large part because the new 1,200 MW of imports across each of the new ties increased the total amount of supply available in the cases while demand remained constant. The new tie-lines may be used for exporting when their imports are curtailed, depending on the balance of supply and demand.

For all bi-directional scenarios studied, the 2020 Economic Study confirmed that adding bi-directionality to existing tie-lines nearly eliminated curtailment of offshore and onshore wind as depicted in Figure 5-1. It should be noted that there were not significant curtailments of onshore and offshore wind in the base scenario. Wind curtailments accounted for 0.934 TWh (10.3%) of curtailments in scenario B.

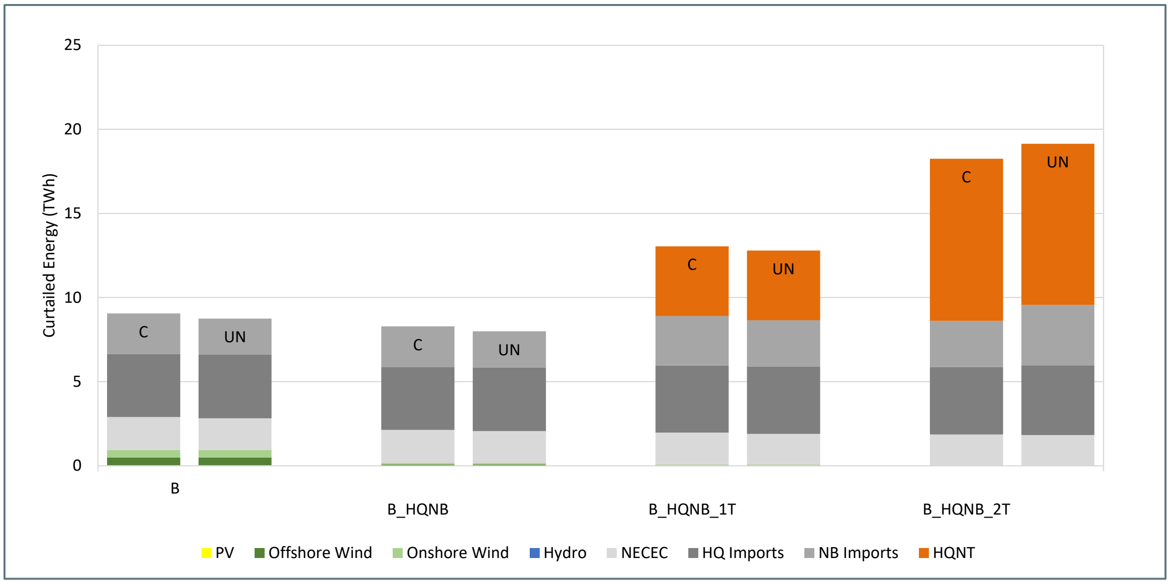

Figure 5-1: Bi-directional Scenarios – System-wide Curtailments

Exports to adjacent control areas were not consistent from month to month. As depicted in Figure 5-2, for the bi-directional scenarios studied, exports were concentrated in the shoulder seasons due increased production from offshore wind and lower loads. In this study, the export transfer capability limited how much energy could be exported during times of high renewable energy production.

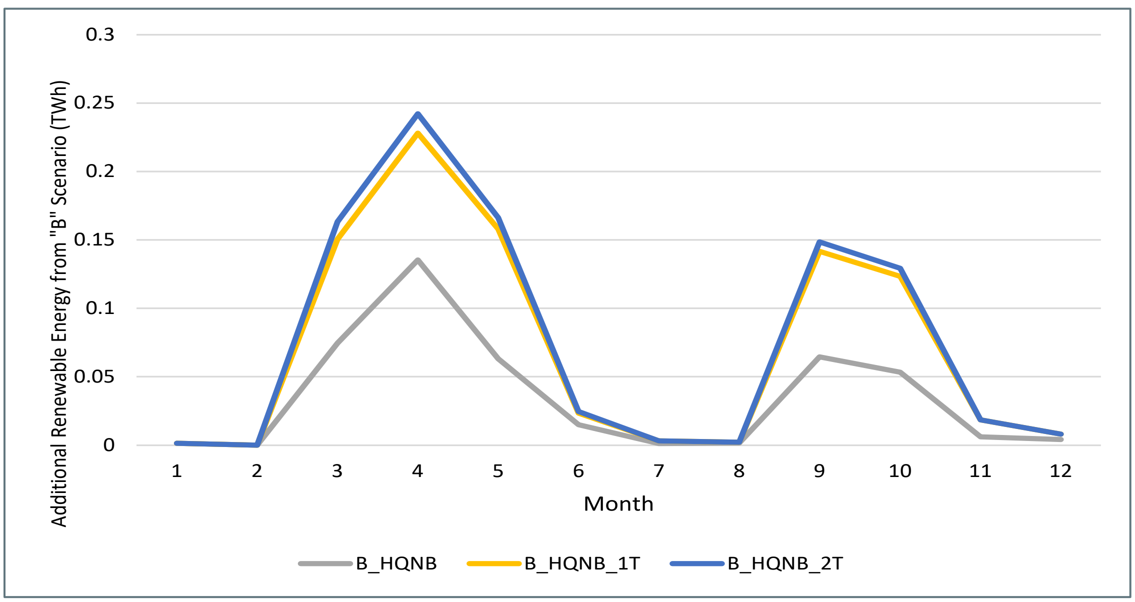

Figure 5-2: Bi-directional Scenarios – Monthly Renewable Exports

Annual power flow duration curves shown in Figure 5-3 highlight when excess renewable energy was exported to Canada instead of being curtailed. There were fewer opportunities for exporting energy to Canada in the 2020 Economic Study than the 2019 Economic Study because of higher New England loads and the assumed retirement of a nuclear resource.

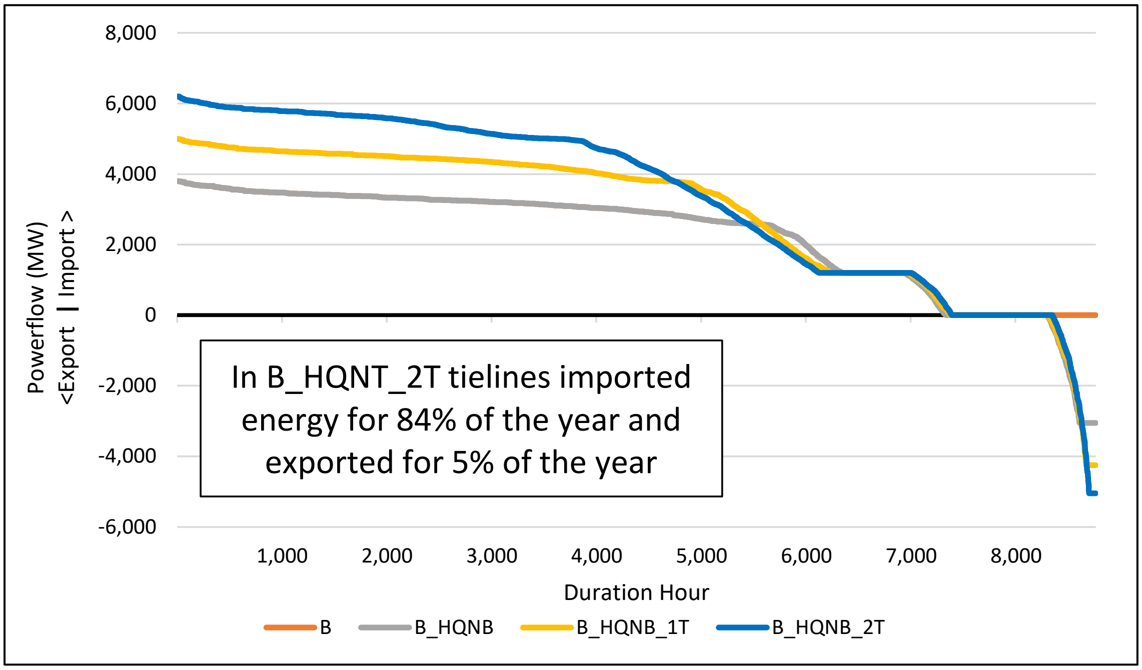

Figure 5-3: Bi-directional Constrained Scenarios – Annual External Tie-Line Power Flows

The addition of new tie-lines reduced congestion internal to New England on the Orrington-South, Surowiec-South, Maine-New Hampshire, and North-South interfaces as the energy from the tie-lines reduced the need for resources in Maine including New Brunswick imports. As illustrated in scenario B_HQNB_2T, East-West congestion becomes an issue when the new tie-lines interconnect to the CMA/NEMA zone. See Figure 5-4 for the congestion of interfaces across the scenarios.

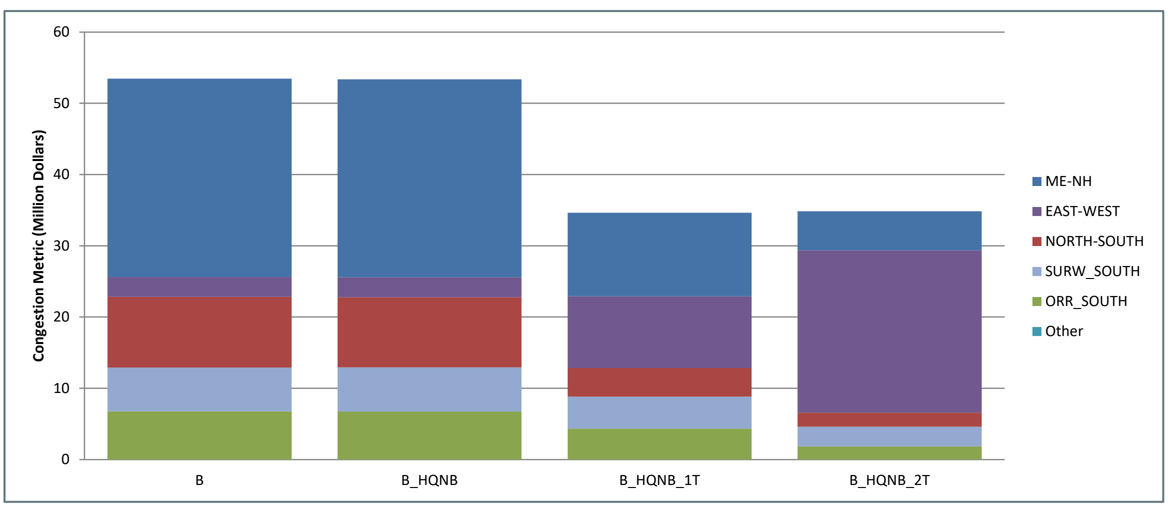

Figure 5-4: Bi-directional Scenarios – Congestion by Interface

5.1.2 Electric Sector Emissions

The 2020 Economic Study assessed the environmental impacts of the scenarios to current state policies and regional goals related to electric sector emissions. No emissions were assumed with imports from neighboring systems because detailed models for our neighbors were not included and the energy was assumed to come from hydro resources in Canada or excess renewable energy banked from New England.

NO_x and SO_2 emissions were part of this study, but the results from all scenarios were negligible.

As seen in Figure 5-5, the addition of two new tie-lines with HQ (scenario B_HQNB_2T) reduced electric sector CO_2 emission by approximately one-fifth of the region's total electric sector emissions as compared with scenario B.

In all scenarios, municipal solid waste (MSW), landfill gas (LFG), and wood resources contributed a significant amount of electric sector carbon emissions. It is worthwhile to note state emission goals exclude emissions from these resources. They assume the resources to be effectively carbon neutral because of their avoided emissions from their fuel stocks. However, this study reports out emissions from direct electricity production only and does not explore avoided emissions from electric vehicles, heating electrification, or MSW, LFG, and wood resources.

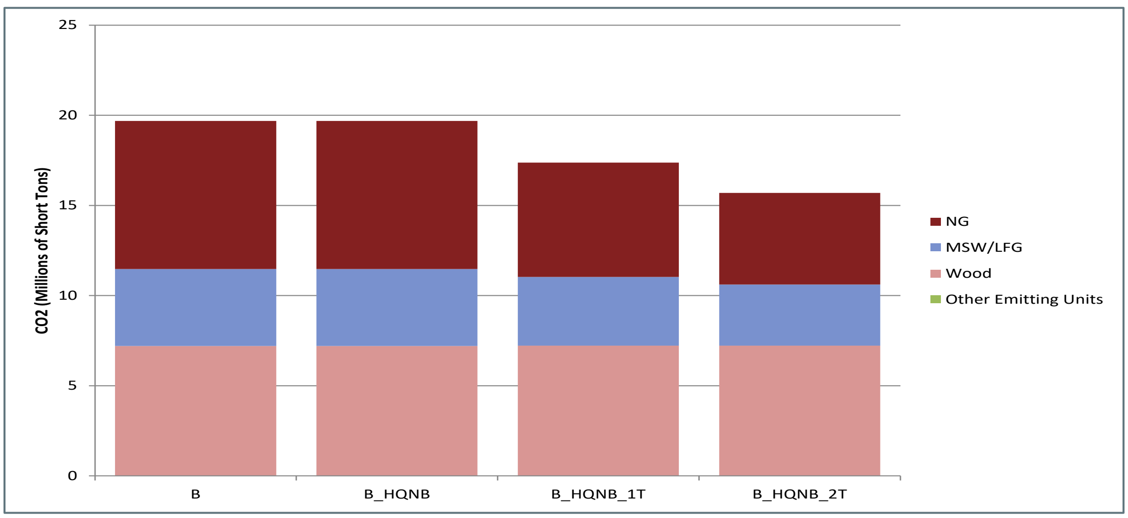

Figure 5-5: Bi-directional Scenarios – Electric Sector CO_2 Emissions by Fuel Type

Considering each state individually, all bi-directional scenarios studied have total electric sector emissions lower than their respective state goals as shown in Figure 5-6. Note that MSW/LFG/wood resource emissions are not counted towards the state emissions goals and as such were not included in the figure.

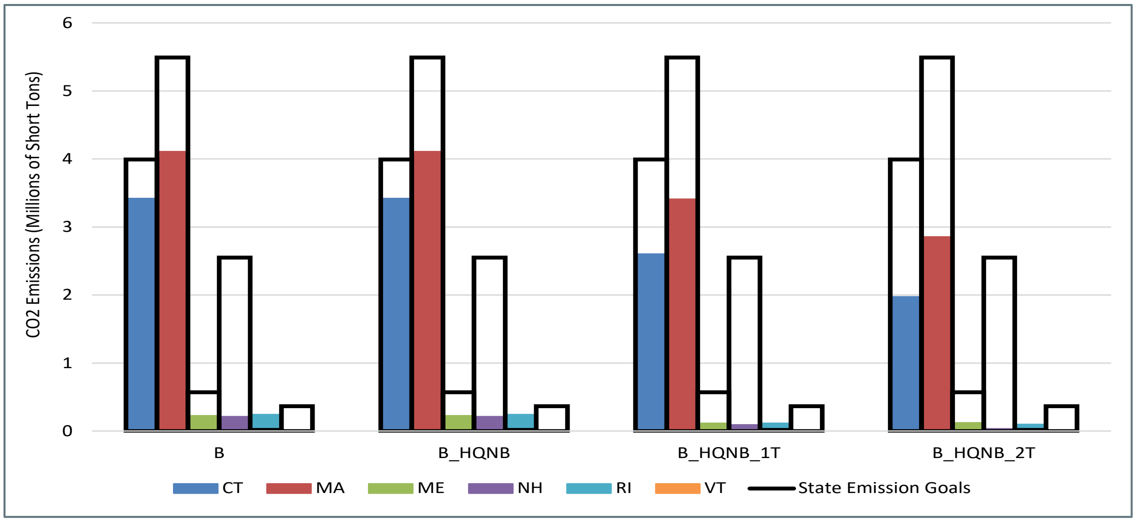

Figure 5-6: Bi-directional Scenarios – Electric Sector CO_2 Emissions by State vs 2035 State Goals

5.1.3 System-wide Production Costs

Production costs reflect operating expenses, which include fuel, dispatch, resource commitment, and emission allowances. Natural gas consumption, and to a lesser extent other fossil fuels, drive overall system-wide production costs.

In general, the addition of "zero-cost" 1,200 MW tie-lines drove down system-wide energy production costs significantly as shown in Figure 5-7.

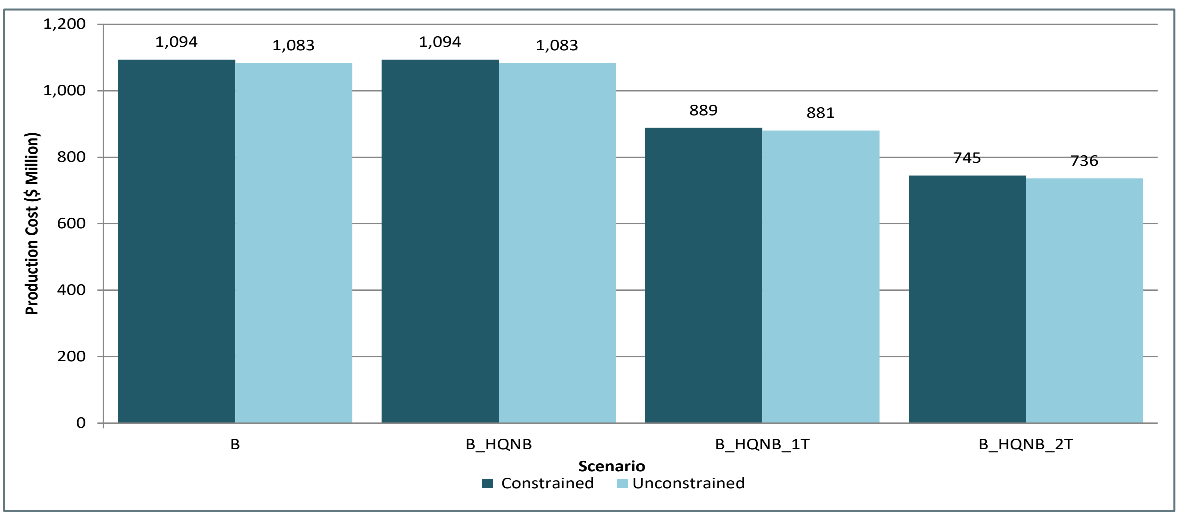

Figure 5-7: Bi-directional Scenarios – System-wide Energy Production Costs

When examining specific resource types, it is worth noting that even with increased renewable energy production, the system needs significant amounts of gas-fired resources to serve the load as shown in Figure 5-8. Additionally, as a fleet, these resources have negative net revenues in the production cost simulations as shown in Figure 5-9. Note that these production costs simulations only considered energy revenues. The negative net revenues were greatest when two tie-lines were added. Uplift, capacity payments, or other out-of-market revenues would likely be required for gas-fired and nuclear resources to make them whole.

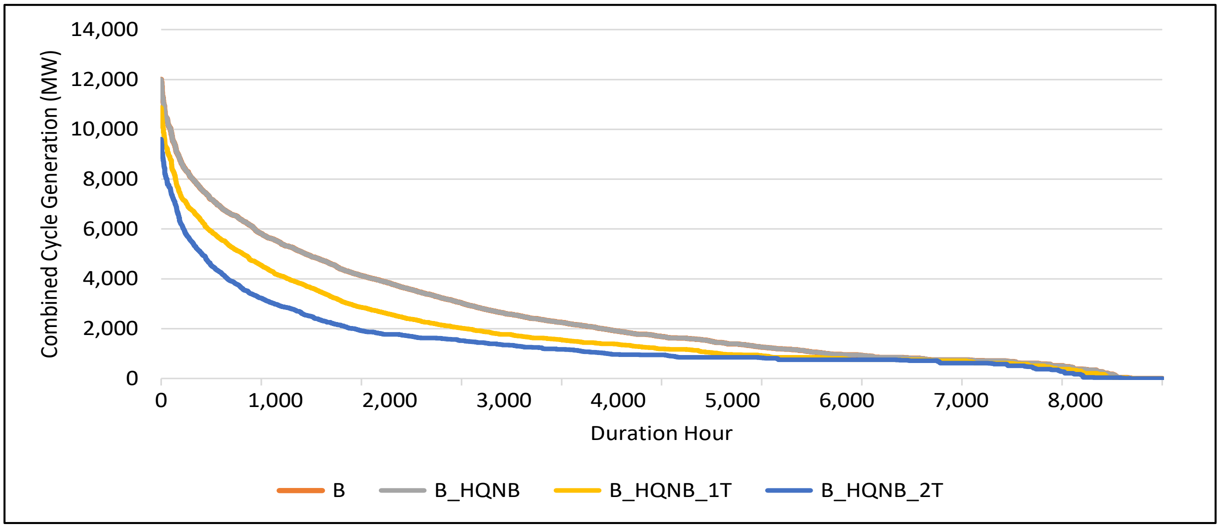

Figure 5-8: Bi-directional Scenarios – Combined-Cycle Generation Duration Curves

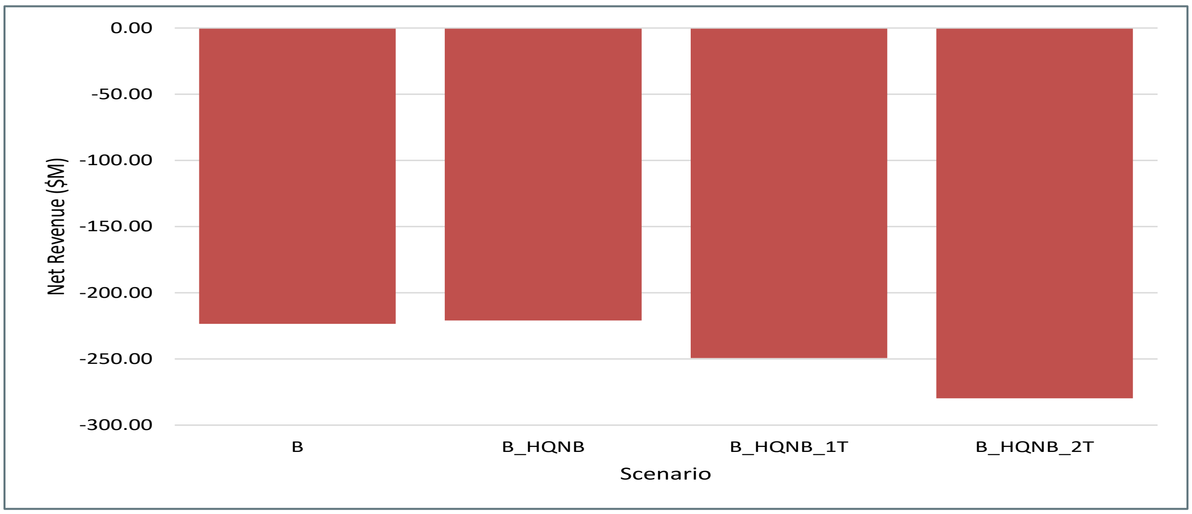

Figure 5-9: Bi-directional Scenarios – Negative Net Revenues for Gas-fired Generators

5.2 Incremental Scenarios

For the incremental scenarios, the ISO evaluated increasing amounts of retirements. These mimicked the 2019 Economic Study ('8,000_1' scenarios from 2019[17]) but with updated input assumptions and positive threshold price order, as described in Table 4-6.

Evaluation of the incremental scenarios revealed there was virtually no difference between the I_8000 and I_8000_Oil scenario. This was because oil resources were not committed in the I_8000 scenario. However, for the I_8000_Oil_NG scenario, results were noticeably different due to assumed additional retirement of 50% of the remaining gas-fired resources and addition of new tie-lines. Specifically, there was a larger amount of

[17] The 2019 Economic Study 8,000_1 scenarios included offshore wind at the following quantities and locations: 800 MW at the Montville (CT) substation, 1,000 MW at the Kent County (RI) substation, 1,600 MW at the Brayton Point (SEMA) substation, 2,400 MW at the Barnstable (SEMA) substation, and 2,200 MW at the Mystic (Boston) substation.

wind and solar resource curtailments due to the change in resource mix and a different threshold price order favoring imports over larger renewables. Additionally, there was a reduction of LMPs and production costs as the two new 1,200 MW tie-lines replaced an equivalent amount of price-setting gas-fired resources for much of the year. Total gas-fired resource production was reduced due to the new tie-lines modeled in I_8000_Oil_NG. For a given hour in I_8000_Oil_NG, the most expensive 2,400 MW of resources that were previously on the margin in I_8000 and I_8000_Oil were not dispatched. See Figure 5-10 and Figure 5-11 respectively.

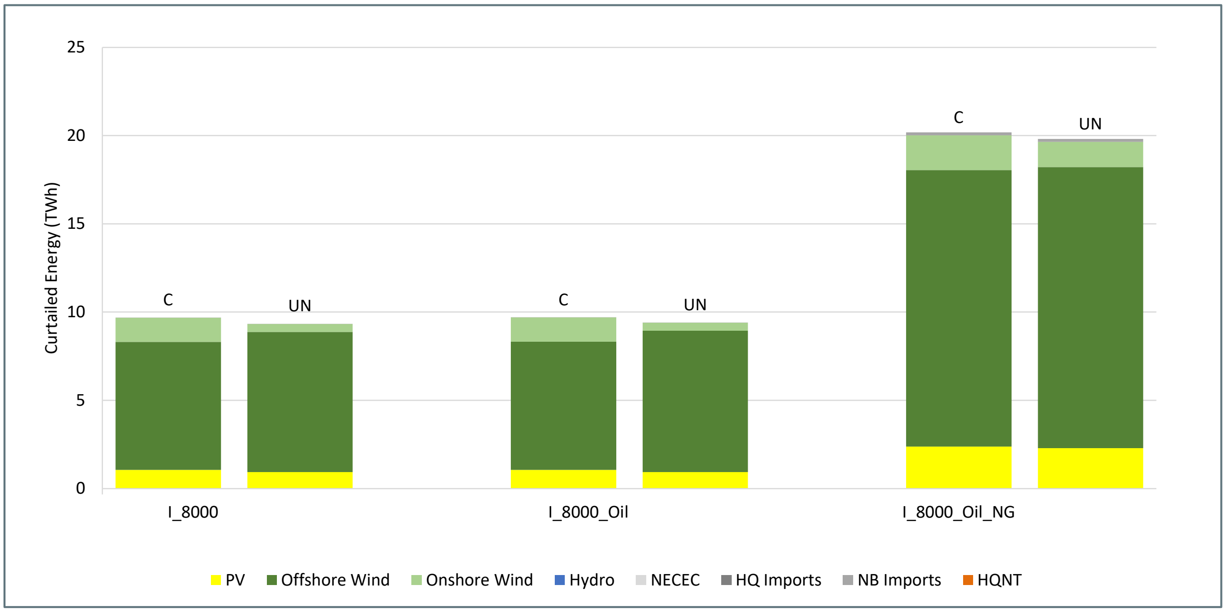

Figure 5-10: Incremental Scenarios – System-wide Curtailments by Subtype

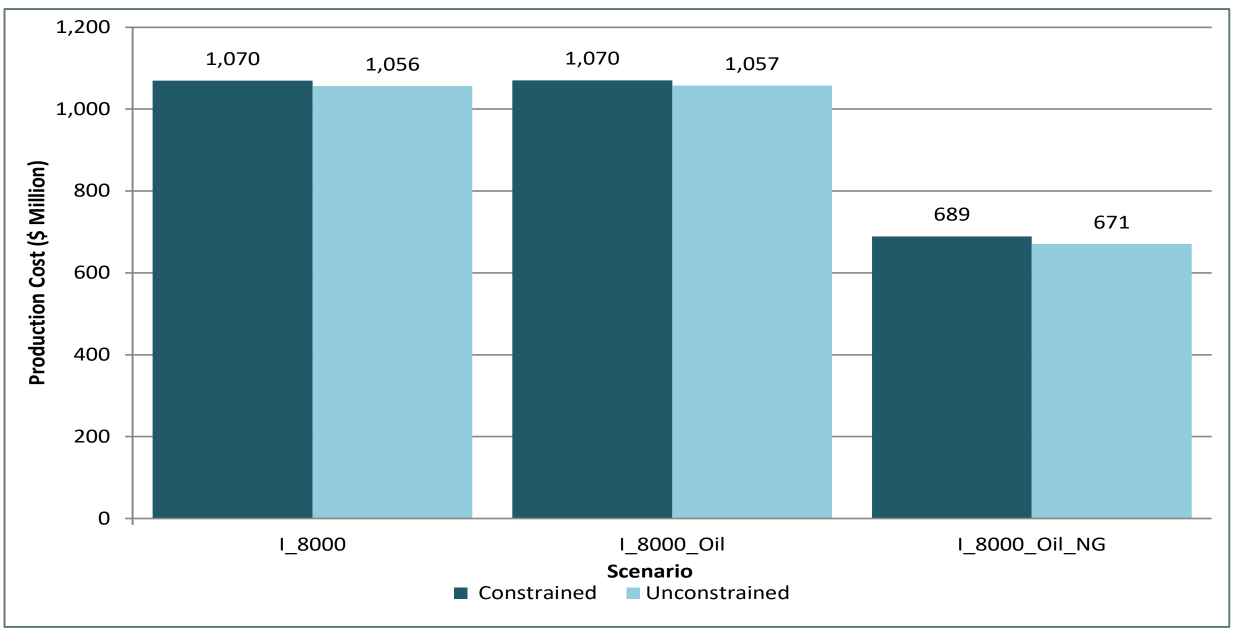

Figure 5-11: Incremental Scenarios – System-wide Energy Production Costs

The incremental scenario assessment revealed no difference in electric sector CO_2 emissions between the I_8000 and I_8000_Oil scenario results, since oil resources were not committed in the I_8000 scenario. However, the I_8000_Oil_NG scenario, where some gas-fired resources were replaced with zero-carbon imports from Québec, had a reduction of electric sector CO_2 emissions within New England as shown in Figure 5-12.

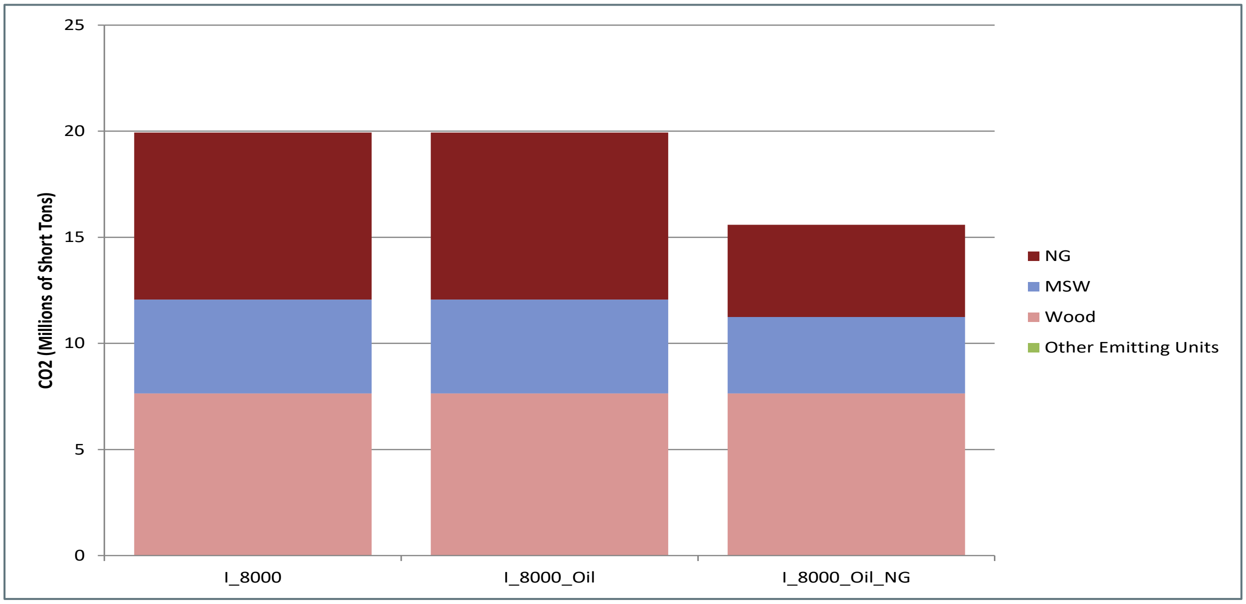

Figure 5-12: Incremental Scenarios – Electric Sector CO_2 Emissions by Fuel Type

5.3 Sensitivity Scenarios

At the request of stakeholders, after presentation of the previous scenarios the ISO considered four additional scenarios (see Table 3-2) beyond the original National Grid 2020 Economic Study request. Stakeholders were interested in revisiting assumptions of the bi-directional model that included the following:

- Shift the balance of supply and demand[18]
- Increase the opportunities for export to Canada and evaluate energy banking
- Explore the impact of bi-directionality rather than additional imports over new tie-lines
- Impact of removing BESSs

5.3.1 Shift the Balance of Supply and Demand

One of the sensitivities requested to use the 2019 Economic Study load levels and resource retirement assumptions to illustrate the differences caused by those key assumptions. The LMPs were significantly lower as shown in Figure 5-13 due to the lower loads for the study from 2030 and the retention of Millstone 2. Figure 5-14 shows less energy imported and increased exports to Canada.

[18] To gain insight into the impact that changing load and resources could have on the amount of energy exported, the sensitivity assumption changes included: keeping Millstone 2 in-service and the use of the 2019 Economic Study base loads, transportation electrification, and heating electrification loads.

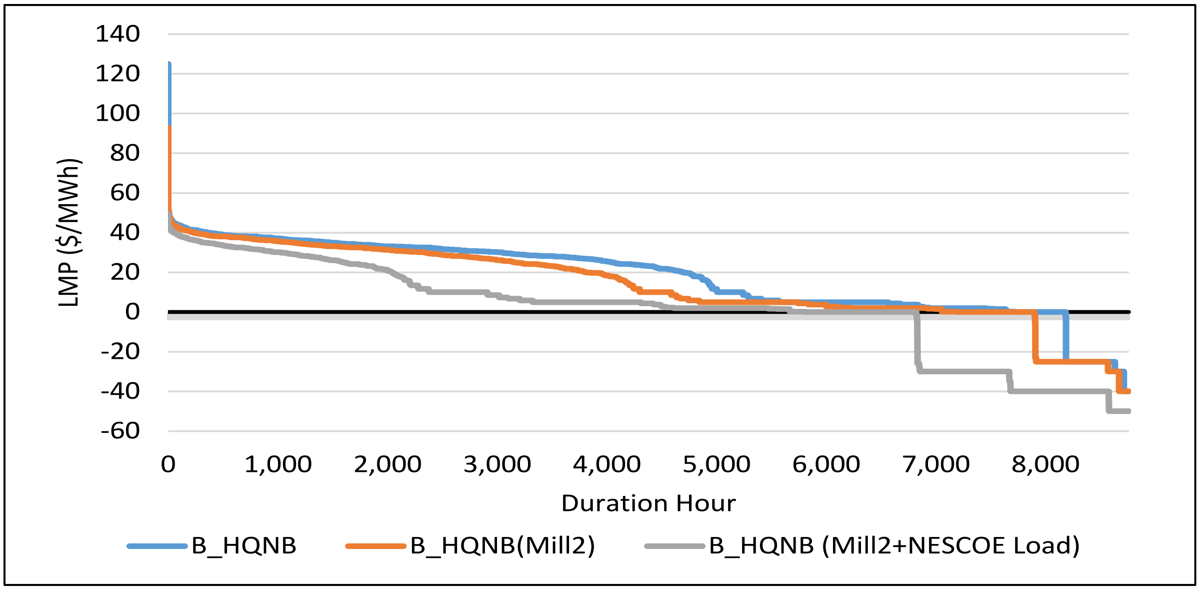

Figure 5-13: Sensitivity Scenarios – LMPs with 2019 Economic Study Assumptions

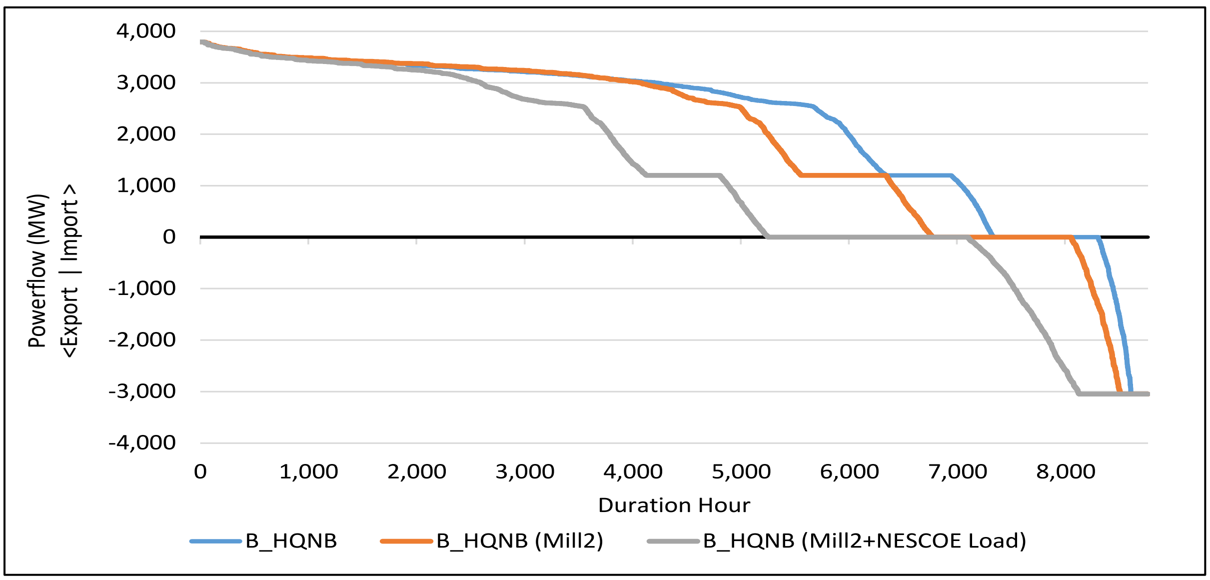

Figure 5-14: Sensitivity Scenarios – Canadian Flows with 2019 Economic Study Assumptions

5.3.2 Energy Banking Sensitivities

For the energy banking sensitivities, exports only occurred on the new 1,200 MW tie-lines to isolate the effects of energy banking. In the original scenarios, a constant 1,200 MW of import occurred on the new tie-line(s) except when curtailed or used for exports based on threshold prices. In the sensitivity scenarios, no import profile was assumed and the new tie-line(s) were used for energy banking only. By limiting which tie-line(s) were used for export, these scenarios help evaluate the incremental capability difference the tie-line would make rather than assessing a completely different operating method for all tie-lines.

Stakeholders requested two different methods of implementing the banked energy model, called 'redispatch' or 'track'. The two different methods also used different threshold prices. Comparing the generation of sensitivity B_Redispatch_0 (REC inspired threshold prices) with sensitivity B_Track_0 (import priority threshold prices), sensitivity B_Track_0's imports displaced more energy from New England's renewable resources. Because of the higher imports levels, there was a 4.7 TWh decrease in natural gas, LFG/MSW, wood, and hydro production in sensitivity B_Track_0 as opposed to sensitivity B_Redispatch_0. Sensitivity B_Track_0 also had a 6.5 TWh decrease in wind energy production.

With the new tie-line installed to facilitate energy banking, sensitivity B_Track_1T B_Track_0 showed that combined onshore and offshore wind production increased 3.0 TWh compared to sensitivity B_Track_0, while gas-fired production decreased by 2.4 TWh. Table 5-3 shows production for each sensitivity by fuel type.

Table 5-3: Comparison of Sensitivity Scenarios – System-wide Energy Production by Fuel Type

Fuel Type & Production (TWh)	B_Redispatch_0	B_Track_0	Delta	B_Redispatch_1T	B_Track_1T	Delta
Existing Imports + NECEC	16.3	28.4	12.1	15.4	28.4	13.0
Imported Deferred/Banked Energy	-	-	-	4.6	3.6	-1.0
Exports to Canada	-	-	-	-1.1	-3.9	-2.8
Offshore Wind	30.9	26.4	-4.5	31.4	28.6	-2.8
Onshore Wind	6.2	4.2	-2.0	6.6	5.0	-1.6
NG	11.8	10.2	-1.6	8.8	7.8	-1.0
Oil	0.0	0.0	0.0	0.0	0.0	0.0
Coal	0.0	0.0	0.0	0.0	0.0	0.0
LFG/MSW	2.8	2.6	-0.2	2.6	2.4	-0.2
PV	20.1	19.1	-1.0	20.2	19.6	-0.6
Wood	4.2	3.4	-0.8	4.2	3.2	-1.0
Nuclear	21.9	21.9	0.0	21.9	21.9	0.0
EE/DR	36.1	36.1	0.0	36.1	36.1	0.0
Hydro	6.4	4.3	-2.1	6.5	4.7	-1.8
Total	**156.7**	**156.7**	**0.0**	**157.3**	**157.3**	**0.0**

Since scenarios B_Track_0 and B_Track_1T did not curtail imports, banked energy was solely derived from excess output of New England renewables. With the ability to bank energy, New England wind, PV, and hydro generated 3.9 TWh more than they generated in scenario B_Track_0. Energy banking allowed for this 7% increase. Figure 5-15 shows available energy and the percent of wind, PV, and imported energy curtailed.

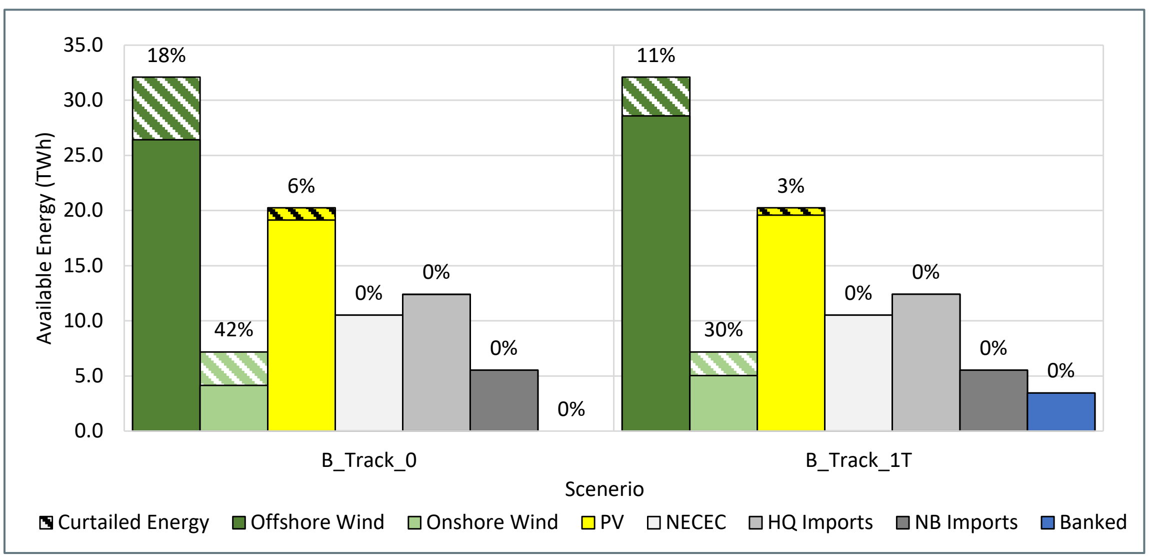

Figure 5-15: Comparison of Sensitivity Scenarios – System-wide Energy Production and Curtailments

Curtailments varied heavily over the year based on varying renewable production. While the ability to export lowered curtailments, there were times when New England renewables saturated the export capabilities of the 1,200 MW tie-line. At the hour of peak oversupply of New England renewable energy, the tie-line exported 1,200 MW, while 14,925 MW of renewable resources were curtailed. Figure 5-16 shows the monthly curtailments by resource type.

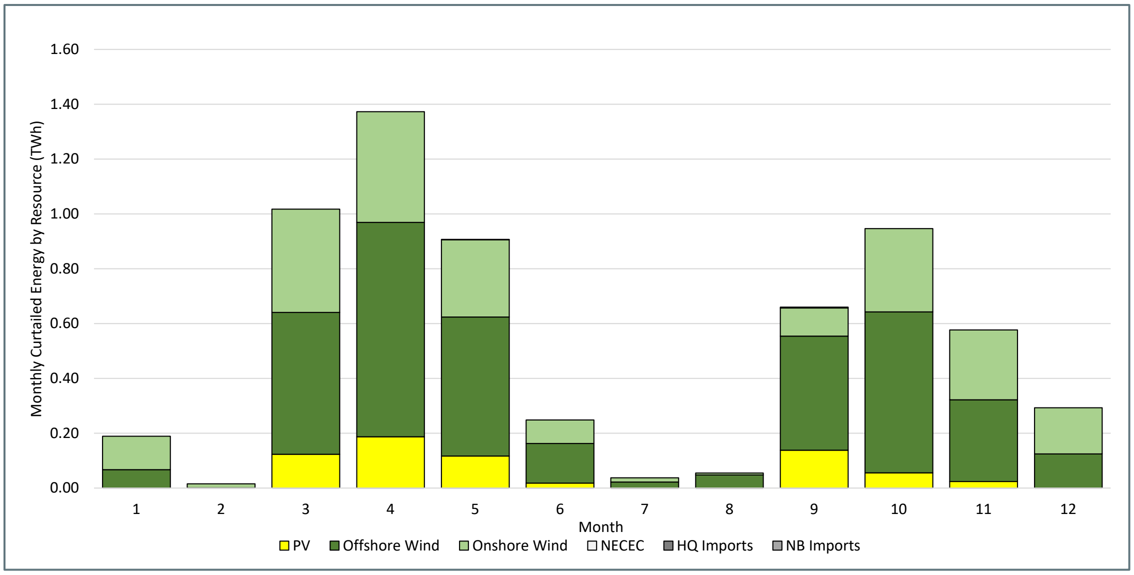

Figure 5-16: Sensitivity Scenario B_Track_1T – Monthly Curtailments

Looking more closely at the utilization of the new 1,200 MW tie-line, the flow duration curve (illustrated in Figure 5-17) showed the tie-line was importing for 2,888 hours (33.0% of the year) and exporting 3,653 hours (41.7% of the year). The tie-line was at maximum import for 2,839 hours (98.3% of importing hours) and maximum export for 2,905 hours (79.5% of exporting hours).

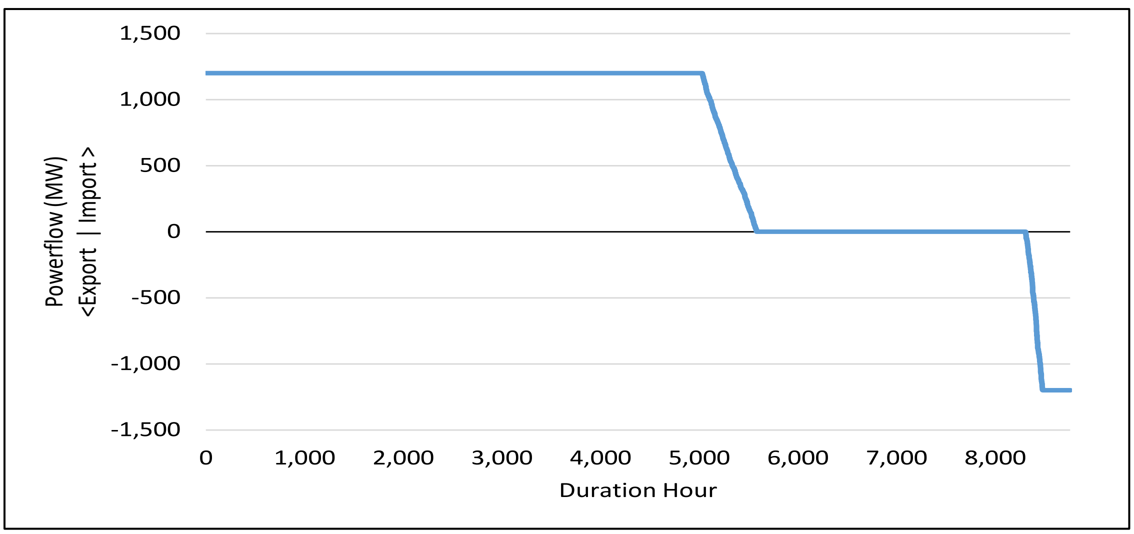

Figure 5-17: Sensitivity Scenario B_Track_1T – Flow on New 1,200 MW Tie-line

With the introduction of energy banking, there was greater utilization of New England renewables, which in turn displaced gas-fired energy production during times of high LMPs. This resulted in a 23% reduction in electric sector CO_2 emissions as shown in Figure 5-18. However, it is worth noting that for the B_Track_1T sensitivity, even during times of high renewable production or availability of banked energy, the gas-fired fleet production often exceeded the 812.5 MW spinning reserve requirement in the model. This result implies that the gas-fired resources were needed for more than just meeting the minimum reserve requirement.

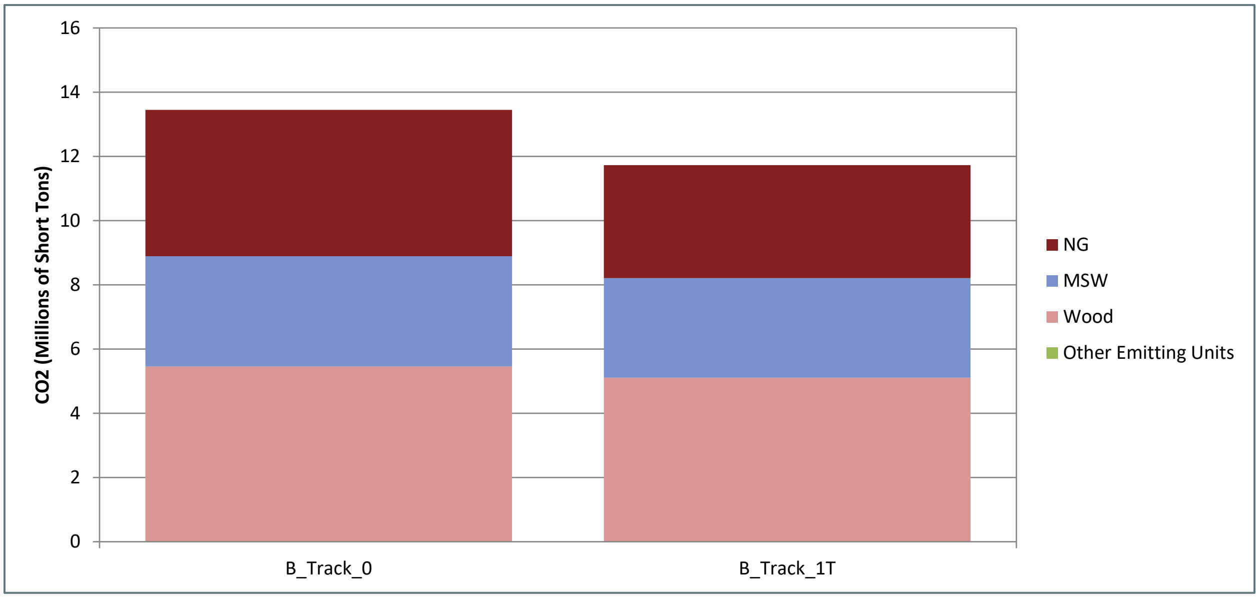

Figure 5-18: Sensitivity Scenario B_Track_1T – Electric Sector CO_2 Emissions by Fuel Type

5.3.3 Battery Storage Removal Sensitivities

The sensitivities that removed 2,000 MW / 8,000 MWh of BESSs led to a decrease in New England renewables production and increased production from gas-fired resources. Table 5-4 highlights the changes in resource energy production across the sensitivities studied. The BESSs removal also led to a higher utilization of pumped-hydro storage resources as shown in Figure 5-19. Cases ending with '_BESS' indicate the sensitivities where BESSs were removed.

Table 5-4: Total System-Wide Energy Production by Fuel Type

Fuel Type & Production (TWh)	B_Redispatch_0	B_Redispatch_0_BESS	B_Redispatch_1T	B_Redispatch_1T_BESS	B_Track_0	B_Track_0_BESS	B_Track_1T	B_Track_1T_BESS
Existing Imports + NECEC	16.3	16.7	15.4	16.0	28.4	28.4	28.4	28.4
Returned Banked	-	-	4.6	4.6	-	-	3.6	3.3
Exports	-	-	-1.1	-1.4	-	-	-3.9	-4.1
Offshore Wind	30.9	30.4	31.4	31.0	26.4	25.9	28.6	28.1
Onshore Wind	6.2	6.0	6.6	6.5	4.2	4.0	5.0	4.8
NG	11.8	12.2	8.8	9.1	10.2	11.0	7.8	8.6
Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LFG/MSW	2.8	2.8	2.6	2.6	2.6	2.6	2.4	2.5
PV	20.1	19.9	20.2	20.1	19.1	18.5	19.6	19.2
Wood	4.2	4.2	4.2	4.2	3.4	3.5	3.2	3.4
Nuclear	21.9	21.9	21.9	21.9	21.9	21.9	21.9	21.9
EE/DR	36.1	36.1	36.1	36.1	36.1	36.1	36.1	36.1
Hydro	6.4	6.3	6.5	6.4	4.3	4.3	4.7	4.7
Total	**156.7**	**156.5**	**157.3**	**157.2**	**156.7**	**156.4**	**157.3**	**157.0**

Red values denote fuel types with decreased production due to the removal of BESS

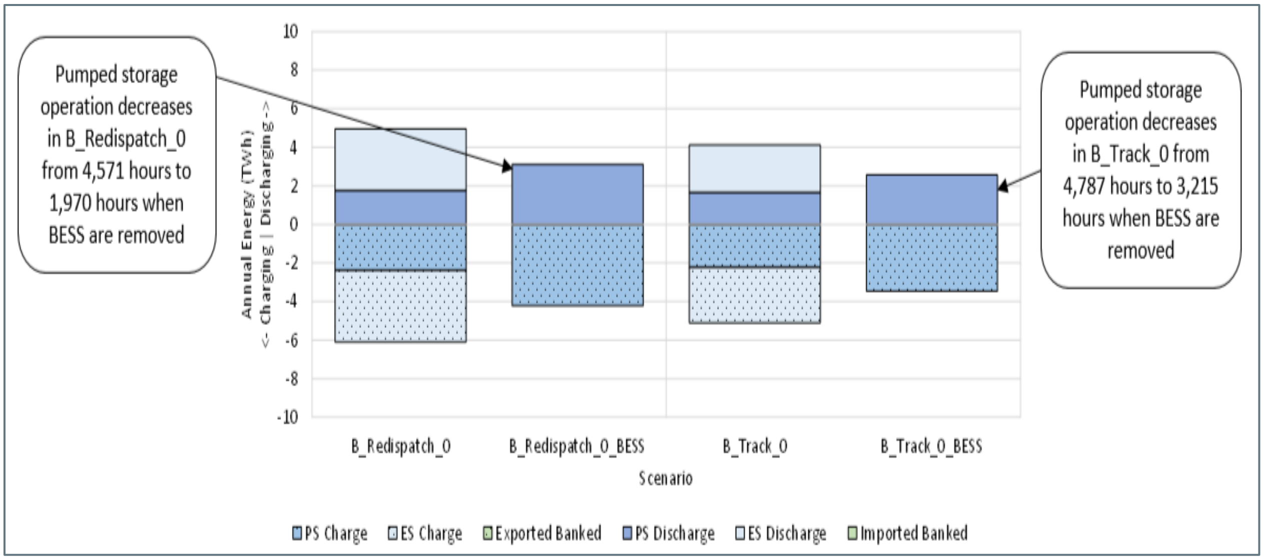

Figure 5-19: BESS Removal Sensitivities – Pumped Storage Utilization without Energy Banking

The introduction of energy banking did not have a significant effect on the operation of pumped-hydro storage and BESSs. This was because energy banking operated on a multi-month timeframe, whereas the pumped-hydro storage and BESS cycle operated within a 24-hour schedule. Additionally, the pumped-hydro and battery storage were dispatched in the simulation ahead of dispatching other resources. Exploring the utilization of BESSs for the B scenarios is depicted in Figure 5-20.

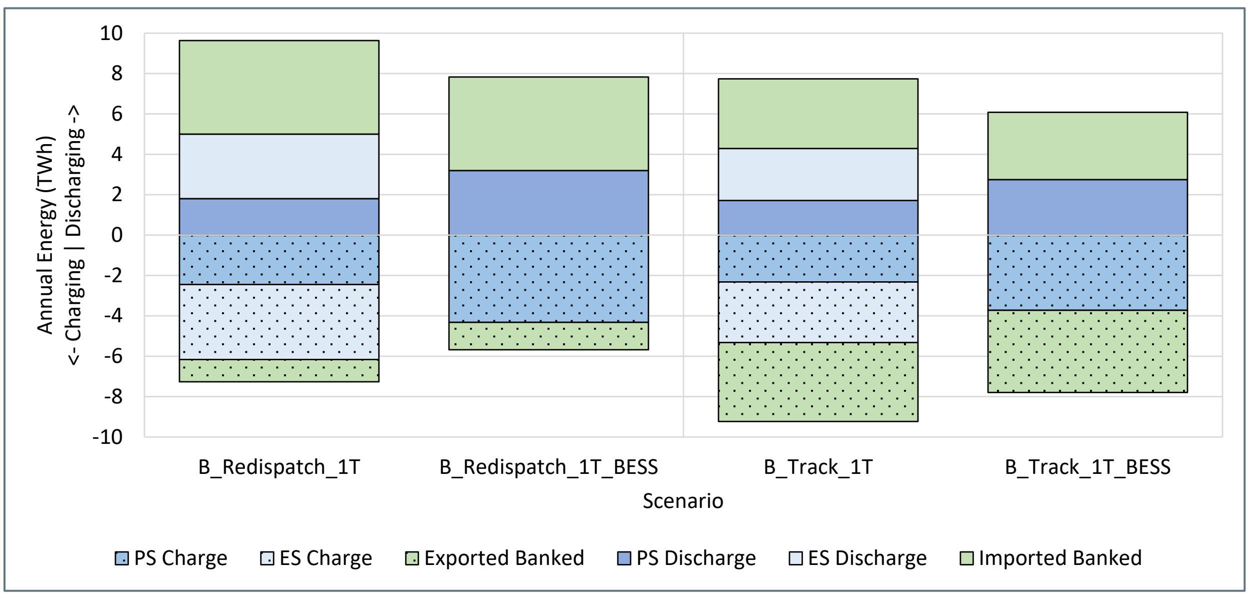

Figure 5-20: BESS Removal Sensitivities – Energy Storage Utilization in the Bi-directional Scenarios

Section 6
Summary

For this study, stakeholders and the study proponent, National Grid, helped shape the scope of work. The ISO provided guidance to narrow the scope of the request (ancillary services analysis was removed) and helped modified some assumptions (e.g., capping of the new tie-line interface limit). The study helped increase the understanding of tie-line utilization to facilitate interregional energy storage between New England and Québec.

Results of the 2020 Economic Study revealed that compared to the 2019 Economic Study, curtailments of renewables were significantly lower because of higher loads and additional transportation and heating electrification loads. The study also showed a reduction in renewable curtailments when tie-lines were operated in a bi-directional fashion to store excess energy in Canada and return the energy during times of higher LMPs and/or system demand. The results of this study show that the utility of energy banking in Canada will be minimal if either the overall supply and demand is fairly balanced, or demand generally exceeds supply. The sensitivities tilted the balance of supply and demand such that were more times of oversupply where energy could be banked. In general, this study found less utilization of Québec storage than the MIT study that inspired it. However, the scope and assumptions of the two studies were different. The inability of the long-term Québec storage to interact with short duration storage in the production cost model may have limited Québec storage's utilization.

Banking energy in Québec can be utilized to decrease overall system electric sector emissions and production costs. Given the large amount of renewable energy that is curtailed in future studies such as this one, mechanisms like long-duration storage in Québec have an opportunity to better utilize variable energy resources in the New England power system.

However, this study also shows that the region still needed significant amounts of local fossil-fueled generation capacity to serve loads during periods of high demand and low renewable resource output. Additionally, due to low and negative LMPs, these resources displayed negative net revenues and would need a significant amount of out-of-market compensation to continue operation. The reliance on fossil-fueled generation capacity was also apparent in the BESS removal sensitivities, where the removal of the BESSs led to a decrease in the production from New England renewables and an increase in the production from gas-fired resources.