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Admitted in: MA, ME, NH

March 25, 2019

James R. Beyer
Maine Dept. of Environmental Protection
106 Hogan Road, Suite 6
Bangor, ME 04401

RE: NECEC – Comments of Central Maine Power Company Regarding Greenhouse Gas Emissions Reductions

Dear Jim:

Enclosed are CMP's Comments Regarding Greenhouse Gas Emissions Reductions.

Sincerely,

Matthew D. Manahan

Enclosure
cc: Bill Hinkel, LUPC
Service Lists

STATE OF MAINE
DEPARTMENT OF ENVIRONMENTAL PROTECTION

IN THE MATTER OF

CENTRAL MAINE POWER COMPANY)
NEW ENGLAND CLEAN ENERGY CONNECT)
#L-27625-26-A-N/#L-27625-TG-B-N/)
#L-27625-2C-C-N/#L-27625-VP-D-N/)
#L-27625-IW-E-N)

COMMENTS OF CENTRAL MAINE POWER COMPANY REGARDING GREENHOUSE GAS EMISSIONS REDUCTIONS

Pursuant to the Maine Department of Environmental Protection's (DEP's) Third Procedural Order,[1] CMP provides these comments in support of its September 2017 Site Location of Development Act (Site Law) application and Natural Resources Protection Act (NRPA) application (collectively, applications) statements that the New England Clean Energy Connect (NECEC) Project is expected to reduce regional greenhouse gas (GHG) emissions. *See* Site Law Application at § 1.4;[2] NRPA Application at § 2.2.[3]

[1] DEP stated, "CMP stated in its application that the reduction of greenhouse gas emissions will be a benefit of the project and CMP presents such a reduction as a rationale for the construction of the project. The parties and the general public will be allowed to submit evidence with regard to these statements in the application, which may include, for example, comments, data, and reports, until the close of the record." DEP Third Procedural Order ¶ 8.a. The Maine Land Use Planning Commission determined that the Project's impact on greenhouse gas levels "does not relate to the Commission's role or review criteria." LUPC Third Procedural Order § II.B.

[2] "The use of the NECEC for delivery of up to 8,500,000 MWh of Clean Energy Generation will provide many significant benefits to Maine and all of New England. In particular, the delivery of Quebec-sourced Clean Energy Generation is expected to reduce greenhouse gas emissions from fossil-fuel fired thermal generation in New England, enhance electric reliability (particularly during winter months when natural gas supply constraints have occurred in recent years), and reduce the wholesale cost of electricity for the benefit of retail customers across the region." The NECEC Site Law Application stated that the NECEC would deliver up to 8,500,000 MWh of Clean Energy Generation because at the time the Application was submitted to the DEP in September 2017, Massachusetts had not yet selected the winning bid in the Section 83D RFP and

GHG emissions are not directly relevant to DEP's approval criteria, as stated in CMP's January 29, 2019 letter to Presiding Officer Miller (incorporated herein by reference). Nevertheless, to the extent the parties are allowed to rebut in written submissions CMP's application statements about GHG emissions benefits, or to the extent DEP determines that GHG benefits should be considered in determining the reasonableness of the Project's impact (if any) on certain resources, CMP submits these comments to supplement the record with evidence that supports its application statements.

I. The Project Will Reduce Regional GHG Emissions.

A. The Clean Hydropower Delivered by the NECEC Will Reduce Carbon Dioxide Emissions in Maine, New England, and Beyond, Consistent with Maine's Long-Term GHG Emissions Reductions Goals.

Once the NECEC Project goes into service in late 2022, it will significantly advance Maine's progress toward meeting the long-term GHG reduction goals set forth in 38 M.R.S. § 576 by substantially reducing the emissions of carbon dioxide (CO2), a greenhouse gas, across Maine and New England, through the delivery of clean energy into the ISO-NE Control Area, that will displace fossil-fuel-fired generation.

In the Certificate of Public Convenience and Necessity (CPCN) proceeding before the Maine Public Utilities Commission (PUC), Docket No. 2017-00232, three different studies of the NECEC's impact on CO2 emissions were submitted by three different production cost modeling

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8,500,000 MWh was the minimum amount of Clean Energy Generation that the NECEC proposed to supply to Massachusetts. Ultimately, on March 28, 2018, the NECEC's 100% hydro proposal to supply 9,450,000 MWh (9.45 TWh) was selected as the winning bid in the 83D RFP process. *See* https://macleanenergy.com/83d/.

[3] "The NECEC project is expected to reduce regional CO2 (greenhouse gas) emissions by over one million metric tons per year in Massachusetts, which is a direct benefit to neighboring states, including Maine. This amount would help achieve the stated goals of the Regional Greenhouse Gas Initiative (RGGI) by reducing the total amount of CO2 emissions from the power sector of the six New England states, and Delaware, Maryland, and New York."

experts. The first study was conducted by CMP's expert Daymark Energy Advisors; the second study was conducted by Energyzt Energy Advisors (Energyzt) on behalf of the Generator Intervenors[4] using modeling conducted by Calpine and overseen by Energyzt (hereinafter Energyzt/Calpine modeling); and the third study was conducted by the PUC's own independent consultant, London Economics International (LEI). These experts all modeled how generators would be dispatched with and without the NECEC in service and calculated the GHG emissions reductions that would result from the NECEC's injection of 9.45 TWh of clean hydroelectric energy into ISO-NE. While the precise levels of GHG emissions reductions from the Project varied, all of these expert studies found that the NECEC will drive significant GHG emissions reductions in Maine, Massachusetts, and the entire New England region.

Specifically, in the Daymark Report attached hereto as **Attachment I,** Daymark concluded that adding the NECEC-delivered hydropower to the supply mix in New England will induce CO2 emission reductions of approximately 3.1 million metric tons across New England each year, and the net emissions from the portion of regional generation serving Maine load will be reduced by approximately 264,000 metric tons annually.[5] This is roughly equivalent to taking 56,051 passenger vehicles off the road in Maine each year.[6]

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[4] The existing thermal generator intervenors collectively referred to as the Generator Intervenors consist of Calpine Corporation (Calpine), Bucksport Generation LLC, and Vistra Energy Corporation. NextEra Energy Resources, LLC (NextEra) is also an existing thermal generator, but NextEra intervened separately in the PUC proceeding and thus was referred to separately.

[5] Rebuttal Testimony of Daymark Energy Advisors, PUC Docket No. 2017-00232, at 40:18-41:2 (July 13, 2018) (Daymark Rebuttal) (citing CMP PUC Exhibit NECEC-5, Daymark Energy Advisors, NECEC Transmission Project: Benefits To Maine Ratepayers: Quantitative and Qualitative Benefits (Sept. 27, 2017) (Daymark Report) at 4 of 98), attached hereto as **Attachment II**.

[6] GHG metric ton reduction equivalencies calculated using the U.S. Environmental Protection Agency Greenhouse Gas Equivalencies Calculator (updated Dec. 2018), *available at* https://www.epa.gov/energy/greenhouse-gas-equivalencies-calculator.

The Energyzt study, attached hereto as **Attachment III**, was based on the Calpine/Energyzt modeling and likewise found that the NECEC-delivered clean energy will result in an annual reduction of 3 million metric tons of CO2 emissions in New England.[7] Finally, LEI, the Commission staff's independent expert, found even greater emissions reductions from the NECEC-delivered clean energy, stating that the Project could reduce CO2 emissions in New England by approximately 3.6 million metric tons per year.[8] LEI's analysis is attached hereto as **Attachment IV**.

Neither LEI's analysis nor Energyzt's analysis included a specific finding as to the GHG reductions in Maine, but using Daymark's approach of calculating the Maine GHG reductions based on a ratio of Maine load to New England load (no party objected to this methodology in the PUC proceeding),[9] the NECEC would result in approximately 255,000 metric tons of GHG reductions per year in Maine using the results of Energyzt's analysis, and approximately 306,000 metric tons of GHG reductions per year in Maine using the results of LEI's analysis.[10] This is roughly equivalent to taking between 54,140 to 64,968 passenger vehicles off the road in Maine each year.[11] Accordingly, the evidence in the record of the PUC proceeding establishes that the NECEC will significantly reduce CO2 emissions in all of New England, including Maine.

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[7] Attachment II (Prepared Direct Testimony of James M. Speyer, PUC Docket No. 2017-00232 (Speyer Direct), Exhibit JMS-4 (Energyzt Advisors, LLC, Technical Report: New England Clean Energy Connect (NECEC) Regional Carbon Emissions Impacts) (Apr. 30, 2018)) at 3.

[8] Attachment III (London Economics International, LLC, Independent Analysis of Electricity Market and Macroeconomic Benefits of the New England Clean Energy Connect Project, PUC Docket No. 2017-00232 (May 21, 2018) (LEI Report)) at 12 of 85.

[9] Attachment I (Daymark Report) at 21 of 98.

[10] CMP Post-Hearing Brief at 104, PUC Docket No. 2017-00232 (Feb. 1, 2019), attached hereto as **Attachment V**.

[11] U.S. Environmental Protection Agency Greenhouse Gas Equivalencies Calculator (updated Dec. 2018), *available at* https://www.epa.gov/energy/greenhouse-gas-equivalencies-calculator.

Notably, even Calpine's Director of Government and Regulatory Affairs, John Flumerfelt, whose company vigorously opposed the NECEC during the PUC proceeding, testified in the hearing on the February 21, 2019 settlement between certain parties in the PUC Proceeding (Stipulation)[12] that the NECEC will reduce carbon emissions in Maine and New England.[13]

B. Hydro-Québec has Sufficient Clean Energy Available for Export to Meet its Obligations to New England without Shifting Exports Away from other Regions.

Setting aside the Generator Intervenors' findings of NECEC's facilitation of GHG emission reductions in New England, the NECEC opponents in the PUC proceeding argued that the NECEC will result in increased total carbon emissions across the Northeast region, because, they claimed, Hydro-Québec will have to divert exports to other energy markets such as New York or Ontario to supply to New England over the NECEC transmission line 9,450,000 megawatt hours (MWh) (9.45 terawatt hours (TWh)) of clean hydropower energy. As discussed below, this claim is unfounded and contradicted by information provided directly by Hydro-

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[12] On February 21, 2019, the following parties entered into a Stipulation to achieve an agreed upon resolution of CMP's Petition for a CPCN for the NECEC: Central Maine Power Company, the Maine Office of the Public Advocate, the Governor's Energy Office, Industrial Energy Consumer Group, Conservation Law Foundation, Acadia Center, Western Mountains & Rivers Corporation, City of Lewiston, Maine State Chamber of Commerce, and International Brotherhood of Electrical Workers.

[13] 3/7/19 PUC Docket No. 2017-00232 Hearing Tr. at 75:18-22, attached hereto as **Attachment VI**. Specifically, Mr. Flumerfelt testified at the Stipulation hearing that the NECEC would have the effect of reducing carbon emissions in Maine and in New England, softening the demand for RGGI allowances, thereby reducing the State's RGGI revenues and the ability of Efficiency Maine Trust to continue to fund its programs at the same level. 3/7/19 PUC Docket No. 2017-00232 Hearing Tr. at 74:21-75:3. In response to Mr. Flumerfelt's statements, PUC Hearing Examiner Mitchell Tannenbaum asked Mr. Flumerfelt the following question:

> MR. TANNENBAUM: But would that mean that the NECEC will reduce carbon emissions?
>
> MR. FLUMERFELT: NECEC will certainly reduce carbon emissions in New England by displacing existing fossil fuel generation both in Maine and across New England.

3/7/19 PUC Docket No. 2017-00232 Hearing Tr. at 75:18-22.

Québec in the PUC proceeding that demonstrates that Hydro-Québec has more than enough clean hydropower energy to supply the 9.45 TWh of energy via the NECEC without diverting energy from other regions.

Hydro-Québec has been pursuing a long-range plan of investment in clean energy generation to increase its existing hydropower capacity, including the addition of the 395 MW Romaine 3 unit that went into service in 2017.[14] With its existing hydroelectric generation capacity, Hydro-Québec has sufficient excess generation capacity to generate energy for the NECEC without diverting electricity from other markets. In fact, in a letter from Hydro-Québec submitted by CMP in the PUC proceeding, Hydro-Québec stated that in 2017 and 2018 it spilled substantial amounts of water due to lack of economic transmission.[15] Specifically, Hydro-Québec stated that it spilled 4.5 TWh of energy in 2017 due to lack of economic transmission and that in 2018 it spilled water equaling approximately 10.4 TWh of energy for that same reason.[16] Hydro-Québec also stated in the letter that it expects that, without additional transmission export capability, the quantity of spilled water in future years will be comparable to the quantity of spilled water in 2018 under comparable market and operational conditions.[17]

The 10.4 TWh worth of energy that Hydro-Québec did not generate due to lack of economic transmission is more energy than the 9.45 TWh of energy required to supply the NECEC. This additional clean energy, currently being wasted, could be used to serve New

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[14] Rebuttal Testimony of Thorn Dickinson, Eric Stinneford and Bernardo Escudero, PUC Docket No. 2017-00232 (July 13, 2018) (Dickinson, Stinneford and Escudero Rebuttal) at 30-31, attached hereto as **Attachment VII**.

[15] PUC Data Response Kelly-004-001, Attachment 1 (December 14, 2018 Hydro-Québec Letter submitted to the PUC in response to data requests from Dot Kelly, citizen intervenor), attached hereto as **Attachment VIII**.

[16] *Id.*

[17] *Id.*

England load through deliveries over the NECEC, as purchased by the Massachusetts Electric Distribution Companies, thereby displacing fossil-fuel-fired generation in New England without the need for the construction of any additional generation resources in Quebec.

Furthermore, Hydro-Québec is installing additional capacity in the near future. Specifically, Hydro-Québec is constructing a new 245 MW hydropower generation facility, the Romaine 4 unit, that is expected to be in service in 2020, and it is adding 500 MW of capacity upgrades at existing hydro facilities (such as the replacement of aging turbines with more efficient, new equipment) that are expected to be in service by 2025.[18] This 745 MW of additional Hydro-Québec generation capacity will be capable of generating 3.8 TWh of additional energy per year on top of the 10.4 TWh of energy that Hydro-Québec expects to continue to have to waste, through spilled water, unless additional transmission capacity to New England, like the NECEC, is developed. This is a driving reason for Hydro-Québec's long-standing interest and efforts to support the development of an additional transmission link to New England.[19]

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[18] Dickinson, Stinneford and Escudero Rebuttal at 30-31; *see also* Corrected Supplemental Testimony of William S. Fowler and Tanya L. Bodell, PUC Docket No. 2017-00232 (Dec. 10, 2018) (Fowler and Bodell Supplemental) at 27:1-9 (referencing Romaine-4 coming online in 2020 and Hydro-Québec Production's anticipated upgrades of 500 MW in 2025); Speyer Direct Testimony, Exhibit JMS-3 (Technical Report, Hydro-Québec Exports) at 10, Figure 8 ("Romaine-4 would add another 245 MW of capacity and 1.3 TWh of energy.") (Apr. 2018). All of footnote 18 is attached hereto as **Attachment IX**.

[19] In fact, Hydro-Québec President and CEO Eric Martel in a television interview by the Journal de Québec stated (as translated from French) "we are in surplus. It takes U.S. lines to export that. I don't want to throw ten terawatt-hours of water away every year and not monetize it. It's the lack of lines." See Le Journal de Quebec, Video Interview With Eric Martel (in French), "Hydro-Québec donne la priorité à l'exportation" [Hydro-Québec gives priority to exportation] (Nov. 21, 2018), available at https://www.journaldequebec.com/2018/11/21/entrevue-avec-eric-martel--hydro-quebec-donne-la-priorite-a-lexportation, with translated English transcript, attached hereto as **Attachment X**.

The opponents have suggested that Hydro-Québec's spillage in 2017 was due to a high water year. The evidence shows, however, that there has been a trend of increased precipitation in Québec in recent years.[20] Additionally, further precipitation increases in the coming years are forecast due to the impacts of climate change on Canada.[21] These expected increases mean that Hydro-Québec will likely have even more water to produce more hydroelectric energy in the future. Thus, it is reasonable to conclude that, without additional transmission capacity such as the NECEC, Hydro-Québec will be forced to increase spillage of water in the future. Accordingly, Hydro-Québec has enough incremental energy to export to New England via the NECEC without diverting energy exports from other markets.

In light of the fact that the energy that Hydro-Québec will export to New England will be additional incremental energy and not just exports that are diverted from other markets, the energy that flows over the NECEC will result in GHG reductions not only in New England, but also in export markets in the Northeast and in Canada.[22] As Daymark explained in their July 2018 Rebuttal Testimony in the PUC proceeding, the Generator Intervenors' own Energyzt analysis, buried in the analyses that Energyzt provided in response to a data request, shows that if you assume that the NECEC energy is incremental, the NECEC will result in GHG reductions

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[20] PUC Docket No. 2017-00232 Exhibit CLF-11 (Vincent, *et al. Observed Trends in Canada's Climate and Influence of Low-Frequency Variability Modes*) at 4550 (June 2015) (finding that annual precipitation in all seasons in northern Québec has increased over the period 1948-2012, as well as throughout northern Canada and in some areas of southern Canada, including portions of Ontario and Atlantic Canada), attached hereto as **Attachment XI**.

[21] PUC Docket No. 2017-00232 Exhibit NECEC-97 (Climate Risks & Adaptation Practices for the Canadian Transportation Sector 2016, Ottawa, ON: Government of Canada (Palko, K. and Lemmon, D.S.) (2017)) at 205-206 of 320; PUC Docket No. 2017-00232 Exhibit NECEC-98 (2013-2020 Government Strategy for Climate Change Adaptation, Québec in Action Greener by 2020, Government of Québec) at 11 of 50. All of footnote 21 is attached hereto as **Attachment XII**.

[22] Daymark Rebuttal at pages 42-43.

not only in New England, but also in other markets such as the New York ISO, PJM, and Ontario.[23] Thus, the net impact of the NECEC's injection of 9.45 TWh of clean hydroelectric energy into New England is a substantial reduction in CO2 emissions, not only throughout New England, but also in the larger Northeast region, including Ontario.

II. The NECEC-Enabled Hydropower Generation Will Provide Many of the Same Benefits as Hydropower that Satisfies Maine's Definition of a Renewable Resource, at No Cost to Maine Customers.

The NECEC-enabled hydropower generation does not fall within the definition of a renewable resource or a new renewable capacity resource under Title 35-A because the NECEC energy will come primarily from dams with more than 100 MW of production capacity.[24] Accordingly, the NECEC generation will not be eligible to meet Maine's renewable generation goals as set forth in Maine's renewable portfolio standard (RPS).[25]

Nevertheless, the NECEC-enabled generation provides many of the same benefits as hydropower resources that fall within Maine's definition of a renewable resource. For example, in Maine's 2015 Comprehensive Energy Plan Update the Governor's Energy Office stated that "Maine's hydropower provides clean baseload generation" and included a policy

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[23] *Id.*

[24] See 35-A M.R.S. § 3210(2)(C) (defining a "Renewable resource" as "a source of electric generation . . . [w]hose total power production capacity does not exceed 100 megawatts" and that relies on one or more specified generation sources, including "[h]ydroelectric generators"); 35-A M.R.S. § 3210(2)(B-3) (defining a "Renewable capacity resource" as "a source of electric generation . . . [w]hose total power production capacity does not exceed 100 megawatts" and that relies on one or more specified generation sources, including "[h]ydroelectric generators that meet all state and federal fish passage requirements applicable to the generator").

[25] *See* 35-A M.R.S. § 3210(3) (setting forth the Class II renewable portfolio standard for eligible resources (Class II), which are either a renewable resource or an efficient resource (a qualifying cogeneration facility that meets the statutory efficiency standard)) and 35-A M.R.S. § 3210 (3-A) (setting forth the Class I renewable portfolio standard for new renewable capacity resources).

recommendation that the State "encourage hydropower."[26] Although the NECEC energy does not come from generation facilities located in Maine, the Project will deliver at least 1,090 MW of hydropower energy from Québec into New England in all hours of the year for at least the next twenty years, backed by the HQ Production[27] system of reservoirs.

Additionally, in enacting the Maine Waterway Development and Conservation Act,[28] the Maine Legislature found that in-state hydropower makes a "significant contribution to the general welfare of the citizens of the State" because hydropower "is the state's only economically feasible, large-scale energy resource which does not rely on combustion of a fuel, thereby avoiding air pollution, solid waste disposal problems and hazards to human health from emissions, wastes and by-products."[29] As set forth above, the NECEC will avoid air pollution from fossil-fuel based generation sources and significantly reduce GHG emissions levels in Maine, New England, and the Northeast region. Accordingly, although the NECEC is not a "renewable resource" under Maine law, it provides many of the same benefits as in-state hydropower under the 100 MW cap, which is considered a renewable resource.

Certainly, regardless of whether the NECEC clean energy generation is renewable under Maine's statutory definition of a renewable resource, the NECEC will combat climate change by

[26] Maine Comprehensive Energy Plan Update, State of Maine, Governor's Energy Office at 46 (Feb. 2015) (Policy Recommendations: "Encourage hydropower. Maine's hydropower provides clean, baseload generation."), *available at* https://www.maine.gov/energy/publications_information/index.html.

[27] The hydropower that will be delivered on the NECEC will be generated by Hydro-Québec Production (HQ Production), the business unit within Hydro-Québec that operates Hydro-Québec's hydro generation units and markets the energy and capacity produced by those units within Québec and regionally.

[28] P.L. 1983, ch. 458, § 18 *et seq.* The Maine Waterway Development and Conservation Act sets forth the permitting requirements for constructing or reconstructing a hydropower project or structurally altering a hydropower project in ways that change water levels or flows. 38 M.R.S. § 633.

[29] 38 M.R.S. § 631(1).

reducing GHG emissions across New England and the entire northeastern United States and Canada from fossil-fuel fired generation, through greater reliance on clean hydropower generated in Québec.

Dated this 25th day of March, 2019.

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Lisa A. Gilbreath

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Attachments:

Attachment I: CMP PUC Exhibit NECEC-5, Daymark Energy Advisors, NECEC Transmission Project: Benefits To Maine Ratepayers: Quantitative and Qualitative Benefits (Sept. 27, 2017).

Attachment II: Rebuttal Testimony of Daymark Energy Advisors, PUC Docket No. 2017-00232, at 40:18-41:2 (July 13, 2018) (Daymark Rebuttal) (citing CMP PUC Exhibit NECEC-5, Daymark Energy Advisors, NECEC Transmission Project: Benefits To Maine Ratepayers: Quantitative and Qualitative Benefits (Sept. 27, 2017) (Daymark Report) at 4 of 98).

Attachment III: Prepared Direct Testimony of James M. Speyer, PUC Docket No. 2017-00232, Exhibit JMS-4 (Energyzt Advisors, LLC, Technical Report: New England Clean Energy Connect (NECEC) Regional Carbon Emissions Impacts) (Apr. 30, 2018).

Attachment IV: London Economics International, LLC, Independent Analysis of Electricity Market and Macroeconomic Benefits of the New England Clean Energy Connect Project, PUC Docket No. 2017-00232 (May 21, 2018).

Attachment V: CMP Post-Hearing Brief at 104, PUC Docket No. 2017-00232 (Feb. 1, 2019).

Attachment VI: PUC Docket No. 2017-00232 Hearing Tr. at 75:18-22 (Mar. 7, 2019).

Attachment VII: Rebuttal Testimony of Thorn Dickinson, Eric Stinneford and Bernardo Escudero, PUC Docket No. 2017-00232 (July 13, 2018) (Dickinson, Stinneford and Escudero Rebuttal) at 30-31.

Attachment VIII: December 14, 2018 Hydro-Québec Letter submitted to the PUC in response to data request Kelly-004-001.

Attachment IX: Dickinson, Stinneford and Escudero Rebuttal at 30-31; Corrected Supplemental Testimony of William S. Fowler and Tanya L. Bodell, PUC Docket No. 2017-00232 (Dec. 10, 2018) (Fowler and Bodell Supplemental) at 27:1-9 (referencing Romaine-4 coming online in 2020 and Hydro-Québec Production's anticipated upgrades of 500 MW in 2025); Speyer Direct Testimony, Exhibit JMS-3 (Technical Report, Hydro-Québec Exports) at 10, Figure 8 ("Romaine-4 would add another 245 MW of capacity and 1.3 TWh of energy.") (Apr. 2018)

Attachment X: Translated English transcript of Le Journal de Quebec, Video Interview With Eric Martel (in French), "Hydro-Québec donne la priorité à l'exportation" [Hydro-Québec gives priority to exportation] (Nov. 21, 2018), video interview available at https://www.journaldequebec.com/2018/11/21/entrevue-avec-eric-martel--hydro-quebec-donne-la-priorite-a-lexportation.

Attachment XI: PUC Docket No. 2017-00232 Exhibit CLF-11 (Vincent, *et al. Observed Trends in Canada's Climate and Influence of Low-Frequency Variability Modes*) at 4550 (June 2015) (finding that annual precipitation in all seasons in northern Québec has increased over the period 1948-2012, as well as throughout northern Canada and in some areas of southern Canada, including portions of Ontario and Atlantic Canada).

Attachment XII: PUC Docket No. 2017-00232 Exhibit NECEC-97 (Climate Risks & Adaptation Practices for the Canadian Transportation Sector 2016, Ottawa, ON: Government of Canada (Palko, K. and Lemmon, D.S.) (2017)) at 205-206 of 320; PUC Docket No. 2017-00232 Exhibit NECEC-98 (2013-2020 Government Strategy for Climate Change Adaptation, Québec in Action Greener by 2020, Government of Québec) at 11 of 50.

NECEC TRANSMISSION PROJECT: BENEFITS TO MAINE RATEPAYERS

Quantitative & Qualitative Benefits

SEPTEMBER 27, 2017

PREPARED FOR

Central Maine Power

PREPARED BY

- Daniel E. Peaco, Principal Consultant
- Douglas A. Smith, Managing Consultant
- Jeffrey D. Bower, Senior Consultant

EXECUTIVE SUMMARY

Central Maine Power (CMP or the Transmission Sponsor) has proposed to build the New England Clean Energy Connect Transmission Project (NECEC Transmission Project) as part of an offering of two project bids (NECEC Project Bids) in response to the "*Request for Proposals for Long-Term Contracts for Clean Energy Projects*" (Massachusetts RFP) issued jointly by the Massachusetts Department of Energy Resources (MA DOER) and the Distribution Companies of the Commonwealth of Massachusetts[1], collectively referred to herein as the Soliciting Parties.

Each bid requires the construction of the NECEC Transmission Project in order to deliver clean energy to Massachusetts via the CMP transmission system from the point of delivery in Lewiston, Maine. At no cost to Maine ratepayers, each bid will, as a consequence of providing clean energy to Massachusetts, result in significant benefits to Maine ratepayers, as well. The significant benefits to Maine ratepayers are the focus of this report.

A. NECEC Transmission Project

The NECEC Transmission Project provides for the reliable delivery of up to 1,200 megawatts (MW) of energy per hour into the New England grid. The total cost of the project will be paid for in two ways. The NECEC Project Proponents[2] have included the cost of [redacted] MW of the transmission capacity from the NECEC Transmission Project as part of their bid. This represents the portion of the transmission capacity needed to deliver the clean energy included in their bid. Hydro Renewable Energy, Inc., an affiliate of Hydro-Québec, has agreed to be financially responsible for the remaining [redacted] MW of transmission capacity on the line. None of the cost of the NECEC Transmission Project will be borne by Maine ratepayers.

B. NECEC Project Bids to Massachusetts

The two NECEC Project Bids (collectively referred to as Bids, individually as Bid 1 and Bid 2) have been offered as separate and exclusive offers to deliver a minimum of [redacted] gigawatt-hours (GWh) and up to [redacted] GWh of clean energy generation per year, each to be delivered via the NECEC Transmission Project to a delivery point at the existing Larrabee Road substation in Lewiston, Maine.

Bid 1 includes firm delivery of incremental hydroelectric generation, and Bid 2 includes Class I RPS eligible energy from [redacted] MW of new wind generation, firmed by incremental hydroelectric generation.

[1] Per Section 1.1 of the Massachusetts RFP, the Distribution Companies are: Fitchburg Gas & Electric Light Company d/b/a Unitil, Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid, NSTAR Electric Company and Western Massachusetts Electric Company d/b/a Eversource.

[2] The NECEC Project Proponents includes CMP, Hydro Renewable Energy, Inc., and SBx, a joint venture of Gaz Metro Limited partnership (Gaz Metro) and Boralex Inc. (Boralex).

C. NECEC Benefits to Maine Ratepayers

The Transmission Sponsor retained Daymark Energy Advisors (Daymark) to evaluate the NECEC Project and provide an analysis of the benefits of the project to Maine ratepayers associated with the public benefits determination required for a Certificate of Public Convenience and Necessity (CPCN) from the Maine Public Utilities Commission (the Commission). This report and its associated appendices provide Daymark's estimation of these benefits, as well as our methodology and assumptions used to derive the benefit values.

The benefits analyzed are:

- Energy and Capacity price impacts;
- Greenhouse gas (GHG) reductions;
- Additional hedging benefits;
- Impacts on Ancillary Services; and
- Other benefits.

Price Impacts

In consideration of a CPCN petition, the Commission may consider many factors, including the economics associated with the proposed project.[3] In addition, Maine has a long-established goal of reducing energy prices and volatility for ratepayers in Maine.[4] The delivery of low-cost, firm power will exert downward pressure on both energy and capacity market clearing prices throughout New England. While Massachusetts Distribution Companies are contracting for the energy, all New England ratepayers will see lower energy prices with the NECEC Project in place due to the reduction in locational marginal prices (LMPs) system-wide.

Depending on the amount of energy ultimately delivered by the NECEC Project, Maine ratepayers will benefit from between $40 million and $44 million annually in levelized LMP savings. The LMP reduction and cumulative NPV benefits of both the minimum contract and the additional clean energy potential can be seen in Figure 1.[5]

Considering only the assumed additional energy associated with the RFP contract, Maine ratepayers will yield levelized benefits of $40 million per year (present value $454 million) resulting from LMP reductions averaging $3.38/MWh. When including energy from the full capacity of the line, the additional energy that may be imported on a market price basis will increase total benefits to Maine ratepayers $44 million per year (present value $496 million) resulting from LMP reductions averaging $3.70/MWh.

3 35-A M.R.S. § 3132(6).

4 CPCN Petition, Section IV.B.3. provides a detailed discussion of Maine policy regarding energy prices and volatility.

5 Present value savings are provided in 2023 dollars, the first full year the project is expected in service.

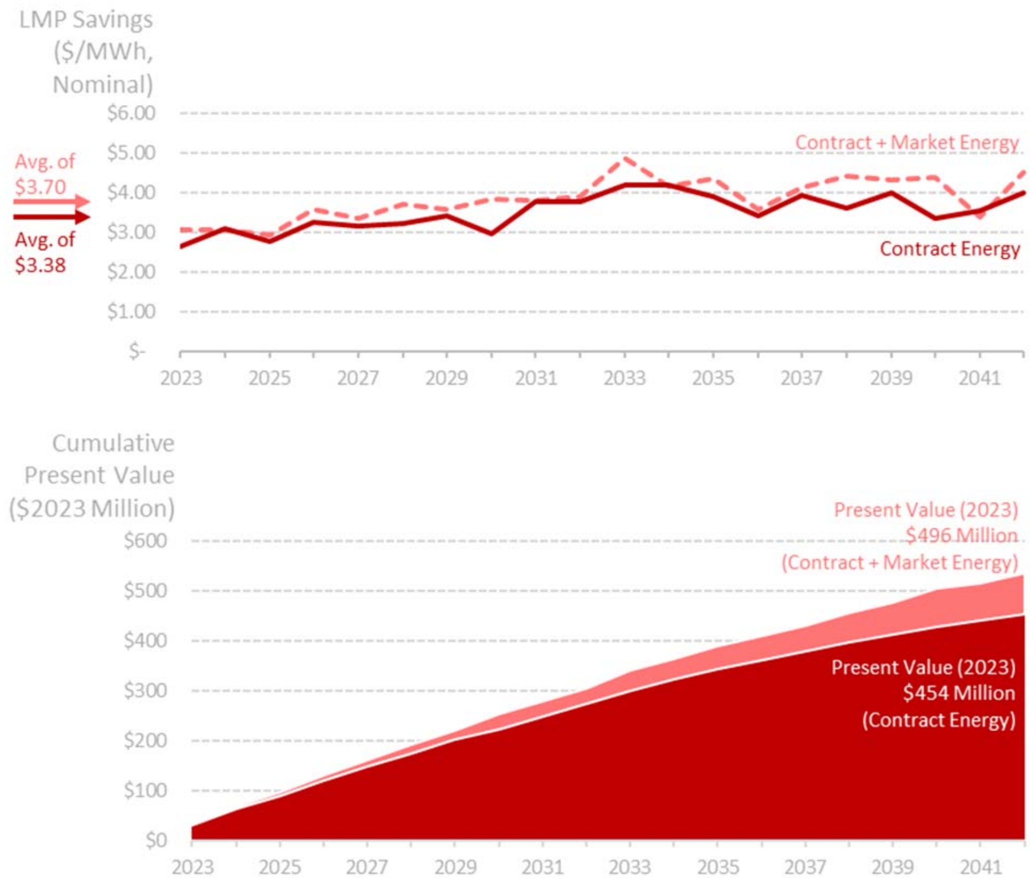

Figure 1. LMP Savings Benefit ($/MWh) and Present Value of Cumulative Benefit to ME Ratepayers ($2023 Millions).

Greenhouse Gas Reductions

Maine has established public policies and actions to mitigate climate change by reducing greenhouse gas (GHG) emissions.[6] As a large source of non-emitting generation, the NECEC Project will help contribute to Maine's efforts to achieve its policy goals.

The NECEC Project will provide clean, inframarginal energy, displacing significant generation from primarily GHG-emitting resources in the ISO New England (ISO-NE) system. Our analysis concludes that the NECEC Project will induce annual CO_2 emission reductions of approximately 3.1 million metric tons across New England. As a result, the net emissions from the portion of regional generation serving Maine load is reduced by approximately 264,000 metric tons per year.

[6] CPCN Petition, Section IV.B.2. provides a detailed discussion of Maine GHG reduction policy.

Additional Hedging Benefits

The generation portfolio in ISO-NE has become dominated by natural gas in recent years. Natural gas provides nearly half of the total electric energy produced in New England and is the marginal fuel setting electric market prices in more than three-fourths of the year.[7] As a result, volatility in the cost of fuel has exposed ratepayers in Maine and across the region to higher electric energy prices when the natural gas prices are high. The addition of a large source of firm, unconstrained, low-cost renewable energy and capacity provides a valuable hedge against natural gas price swings.

Energy from the NECEC Project reduces the portion of the resource mix that is subject to fluctuating fuel prices, allowing greater market flexibility under high gas prices that can drastically impact energy prices. As natural gas prices impact energy prices system-wide, the hedging benefits will be shared by Maine ratepayers, as well as ratepayers throughout the region.

On the capacity side, the ISO-NE capacity market may be experiencing thermal and nuclear resource retirements in the coming years, potentially exposing ratepayers to capacity price escalation. The NECEC Project also represents incremental clean, low-cost capacity that provides hedging benefits in the capacity market.

Impacts on Ancillary Services

Backed by Hydro-Québec's significant hydroelectric facilities, the resources available to provide the clean energy under the NECEC contract will be available in all hours. This firmness provides several benefits to the New England Ancillary Services markets. Firm power will provide strong value by being available when it is most needed, such as in stress conditions due to high load or outages. The firm power of the NECEC Project may also free up other resources to provide more reserve or other ramping capabilities, ensuring a more robust grid.

Ancillary services are centrally coordinated and procured by ISO New England, with load in each state paying for its proportional share of the costs. By providing firm energy, the NECEC Project will likely reduce the cost of providing ancillary services to the grid. Maine ratepayers will benefit proportionally from the consequent reduction in ISO-NE ancillary services costs.

[7] *2016 Annual Markets Report, ISO New England's Independent Market Monitor*, May 30, 2017. The IMM reports that, in 2016, 49% of total generation was fired by natural gas (page 14) and was the marginal fuel 77% of the time (page 91).

Other Benefits

The NECEC Project provides several other benefits to Maine ratepayers, including the following:

Reduction in Natural Gas Consumption

The NECEC Project will help displace some natural gas consumption. This is particularly impactful in winter months, when gas pipeline constraints can have severe impacts on pricing for electricity generation.

Congestion

The NECEC Transmission Project includes system upgrades sufficient to ensure deliverability of the energy and capacity to southern New England. The project creates virtually no congestion and allows the full delivery of the energy and capacity.

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ACRONYMS AND DEFINED TERMS

AEO	Annual Energy Outlook
AURORA	AURORAxmp®
CMP	Central Maine Power
CPCN	Certificate of Public Convenience and Necessity
Daymark	Daymark Energy Advisors
Distribution Companies	Distribution Companies of the Commonwealth of Massachusetts
EIA	U.S. Energy Information Administration
ETU	Electric transmission upgrade
FCA	Forward Capacity Auction
FCM	Forward Capacity Market
GHG	Greenhouse gas
GWh	Gigawatt hours
GWSA	Global Warming Solutions Act
HRE	Hydro Renewable Energy
HVDC	High Voltage Direct Current
IMM	Internal Market Monitor
Incremental Transmission Capacity	Remaining [redacted] MW of transmission capacity on the line
LCOE	Levelized cost of energy
LDCs	Local Distribution Companies
LMP	Locational Marginal Price
MA DOER	Massachusetts Department of Energy Resources
MassDEP	Massachusetts Department of Environmental Protection
MMBtu	Millions of British Thermal Units
MW	Megawatts
MWh	Megawatt hours
NECEC Project	New England Clean Energy Connect
NECEC Wind Developer	A Joint venture of Gaz Metro Limited Partnership and Boralex Inc.
Net CONE	Net Cost of New Entry
NPV	Net present value
REC	Renewable energy credit
Solar PV	Solar photovoltaic
Soliciting Parties	MA DOER and Distribution Companies
Transmission Sponsor	Central Maine Power

I. INTRODUCTION

A. The NECEC Transmission Project

The Transmission Sponsor is proposing, as part of the NECEC Project Bids discussed below, to develop the NECEC Transmission Project designed to reliably deliver the clean energy from either Bid to Massachusetts and the region.

The NECEC Transmission Project consists of a high voltage direct current (HVDC) transmission line that runs from the Québec-Maine border in Beattie Township to a substation in the Lewiston area, a new HVDC converter station and related alternating current (AC) interconnection facilities in Lewiston, and all related transmission network upgrades on the U.S. side of the border. The NECEC Transmission Project includes upgrades to the AC transmission system in Maine that will increase the transfer capability at the Surowiec-South interface by approximately 1,000 MW and provide a pathway for up to 1,200 MW of new clean energy resources from Québec via the proposed HVDC transmission line.[8]

B. The NECEC Projects Bids to Massachusetts

Each Bid offers a minimum of [redacted] GWh and up to [redacted] GWh of firm service clean energy to be delivered to Massachusetts.

In Bid 1, Hydro Renewable Energy LLC (HRE)[9] provides the energy being delivered to Massachusetts ratepayers from incremental hydroelectric resources at a fixed price for energy and transmission.

In Bid 2, SBx, a joint venture of Gaz Metro Limited Partnership and Boralex Inc. (collectively, the "NECEC Wind Developer") provides [redacted] MW of Class I qualifying wind generation, producing 1,100 GWh of clean energy generation and 1.1 million renewable energy credits (RECs) backed by firm service hydroelectric generation. The remaining clean energy generation is hydroelectric energy offered by HRE. Bid 2 is also a fixed price to Massachusetts for energy, RECs and transmission.

The NECEC Project Bids include the use of and the cost for sufficient NECEC Transmission Project transfer capability to deliver the contracted energy without constraint. HRE has agreed to pay for any remaining MW of the Transmission Project capacity, which will be available to HRE to deliver additional energy and capacity to the New England. This could include additional deliveries of clean energy to the Soliciting Parties or to others in the New England market. Thus, all the transmission cost will be borne by Massachusetts or HRE and none of the cost will be borne by Maine ratepayers.

[8] For a full description of the NECEC Transmission Project attributes, refer to the NECEC CPCN Petition, Section V.

[9] HRE is an affiliate of Hydro-Québec.

C. Evaluation of NECEC Project Benefits to Maine Ratepayers

This report presents the results of our evaluations of the economic and environmental benefits that will accrue to Maine ratepayers from the development of the NECEC Project and is presented for consideration by the Commission in the evaluation of the NECEC CPCN submission.

Our quantitative analysis simulates the regional electric market operations, comparing market price and environmental performance changes in cases with and without the NECEC Project. This analysis uses a current Reference Case analysis in a zonal model of the regional markets using the AURORAxmp® (AURORA) software. Using this model, we provide quantitative analysis to assess the impact of the NECEC Project Bids on regional market prices, production cost, GHG emissions, and congestion at key interfaces in the region.

For purposes of this report, the amount of contracted energy was assumed to be 8,600 GWh, derived from a contracted capacity of [redacted] MW, operating at a [redacted] capacity factor. This was modeled as 981 MW of clean energy delivered over the NECEC Transmission Project in each hour. Except where noted, no additional energy from the last [redacted] MW of transmission reservation was included in the determination of benefits. There are additional benefits to Maine ratepayers that will likely result from this extra [redacted] MW of capacity.

D. Maine CPCN and Public Policy Objectives

This report supports the Transmission Sponsor's CPCN petition. In considering the petition, Maine's CPCN statute requires the Commission to consider a variety of factors, including economics, reliability, public health and safety, scenic, historic and recreational values, state renewable energy generation goals, the proximity of the proposed transmission line to inhabited dwellings, and alternatives to construction of the transmission line, including energy conservation, distributed generation or load management.[10]

In addition, Maine has established public policies of lowering electricity prices for the benefit of customers, as well as public policies to encourage development of renewable energy resources and to reduce greenhouse gas emissions to mitigate the effects of climate change.

This report demonstrates the value of the NECEC Project in the context of several of these CPCN factors and public policies, as described below.

Electric Energy Price Reductions

The Maine CPCN statute lists "economics" as a primary factor in considering a petition. In addition, Maine has a long-established goal of reducing energy prices and volatility for ratepayers in Maine.[11]

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[10] 35-A M.R.S. § 3132(6).

[11] See, e.g. Maine's capacity resource adequacy statute, 35-A M.R.S. § 3210-C(2). See also the 2013 Maine Energy Cost Reduction Act, P.L. 2013, Ch. 369, Part B (codified at 35-A M.R.S. § 1901 *et seq.*).

As our analysis shows, the provision of nearly 1,000 MW of low-cost, firm power will exert downward pressure on both energy and capacity market clearing prices throughout New England. Market prices in central Maine will be most directly affected, as the ISO New England energy market design is locational, causing reduced market prices at the delivery point and in Maine pricing zones. Analysis of the impact on energy and capacity market clearing prices is discussed in Section III.

GHG Reductions

In addition to the goal of reducing energy prices, Maine has established public policies to support of the reduction of GHG. In 2003, the Maine Legislature enacted the Act to Provide Leadership in Addressing the Threat of Climate Change (the "Climate Change Act"), which established GHG reduction goals for 2010, 2020, and beyond. As part of that Act, Maine set the following objectives:

- In the short term, by January 1, 2010 to 1990 levels;
- In the medium term, by January 1, 2020 to 10% below 1990 levels; and
- In the long term, reduction sufficient to eliminate any dangerous threat to the climate. To accomplish this goal, reduction to 75% to 80% below 2003 levels may be required.

In addition, Maine participates in the Regional Greenhouse Gas Initiative (RGGI) CO_2 Cap-and-Trade Program, which establishes multistate CO_2 budgets designed to reduce regional GHG emissions.

The NECEC Project contributes to these goals by inducing reductions in GHG emissions region-wide. Our analysis quantifies these benefits in Section IV.

Renewable Energy

Maine has a mandatory Renewable Portfolio Standard (RPS) requiring any competitive energy provider (CEP) serving load in Maine to procure Class I RECs at an increasing percentage of its portfolio over time. The required percentage currently tops out at 10% from "new" resources[12] in 2017. NECEC Bid 2 includes significant generation from Class I qualifying wind resources. While the RECs associated with the contracted energy would be committed to Massachusetts for the contract term, there may be the potential for additional Class I energy to be imported over any portion of the NECEC Transmission Project not contracted for under the Massachusetts RFP.

To the extent that load growth, changes in Maine RPS policy, or retirement of other REC producing resources lead to future needs for Maine CEPs, the addition of incremental REC supply to the regional REC markets also may produce a future beneficial effect for Maine ratepayers.

[12] 35-A M.R.S. § 3210(3-A)

II. EVALUATION METHODOLOGY

This section provides a description of the analysis methodology used to conduct our evaluation of the NECEC Transmission Project and associated clean energy Bids. We evaluated the broad range of benefits of the NECEC Project to Maine. The models, evaluation methodology, and key assumptions are described in this section.

A. Methodology & Tools Used

The quantification of benefits of the NECEC Project is derived from analysis using the AURORAxmp® zonal model for the Eastern Interconnect (AURORA), developed by EPIS, Inc. The results of the market simulation performed with AURORA provided the data upon which we relied to prepare estimates of the following benefits:

- Changes in LMPs and wholesale costs of energy for the ratepayers; and
- Reductions in greenhouse gas emissions in Maine.

Other benefits assessments were derived using our proprietary market modeling and spreadsheet models, including our New England Forward Capacity Market (FCM) model.

Appendices A, B, and C provide documentation of the models, methodologies, and assumptions used for the benefits evaluations presented in this report.

B. Key Assumptions

Our analysis relies on a set of Reference Case assumptions on future market conditions in New England. The analytical basis of our analysis reflects a reasonable set of reference assumptions, derived from public sources, including ISO-NE and the U.S. Energy Information Administration (EIA). The results of the modeling form the foundation of our analysis of the full range of benefits of the NECEC. This section provides summary-level descriptions of key assumptions and methods. Appendix A to this report provides a full description of our assumptions.

Natural Gas

Natural gas is the predominant marginal fuel in New England and is a significant factor in determining LMPs, wholesale energy costs, and production costs. Our analysis used natural gas price forecasts from the 2017 Annual Energy Outlook (AEO)[13] published by the EIA. The AEO forecasts used in this analysis include ISO-NE's Algonquin Citygates pricing index, the Henry Hub index, as well as the primary trading markets neighboring ISO-NE that are represented in our model.

For our Reference Case, we used the AEO's "Reference" forecasts. Figure 2 below depicts the key natural gas price assumptions.

[13] https://www.eia.gov/outlooks/aeo/

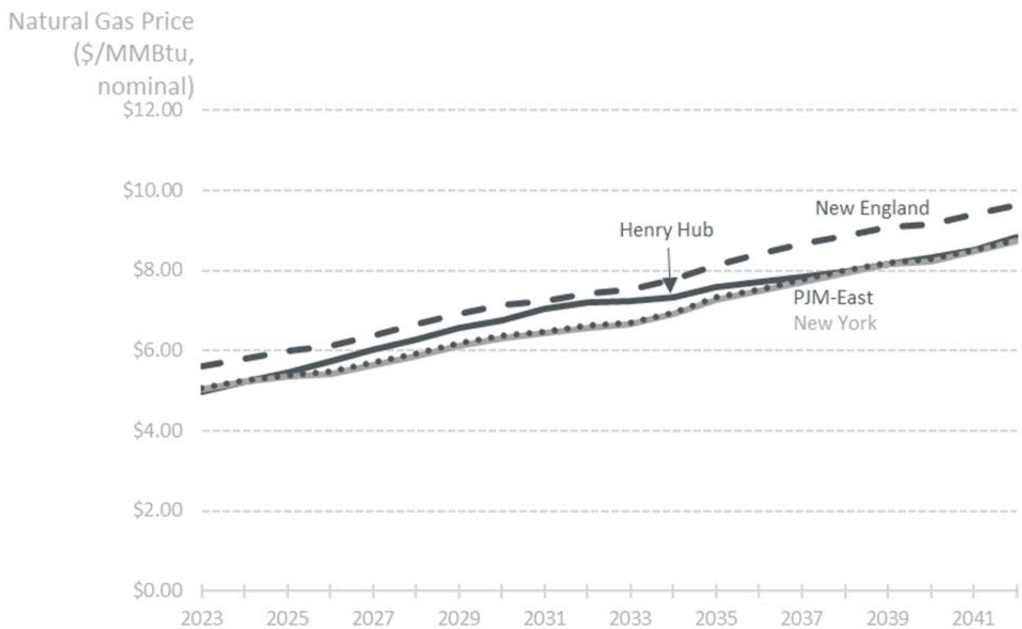

Figure 2. Natural Gas Price Assumptions ($/MMBtu, nominal)

Generator Additions and Retirements

Our analysis relies on assumptions of generator retirements and additions based on known and forecasted retirements and additions for generators in the ISO-NE market. The primary sources of the known resource designations are the results of the ISO-NE Forward Capacity Auctions (FCA), the most recent of which (FCA11) determined capacity obligations for the 2020-2021 commitment period. In addition to the generators that cleared in that most recent auction, further retirements and additions are based on results of analysis conducted with our New England FCM model. This model is described in Appendix C.

Renewable Resources

Our Reference Case assumptions of utility-scale renewable resources include all existing projects, projects currently under construction, and the approximately 460 MW of renewable projects selected under the 2015-16 Three State Clean Energy RFP jointly conducted by Massachusetts, Connecticut, and Rhode Island. These projects are all assumed to be in service by the beginning of the evaluation period. We have also assumed a total of 1,600 MW of new offshore wind capacity contracted under the upcoming Massachusetts Offshore Wind RFP[14], phased in as 400 MW tranches every other year beginning in 2024.

[14] For details on the MA Offshore Wind RFP see https://macleanenergy.com/83c/

In addition, we assumed a solar photovoltaic (solar PV) buildout that is consistent with the ISO-NE solar forecast conducted as part of the CELT report process, and a continued growth of distributed solar deployment for the years beyond the end of the ISO-NE forecast period.

III. PRICE IMPACTS

The NECEC Project includes the construction of a 1,200 MW HVDC line and the injection of firm clean energy into the New England markets. The addition of these firm, low-cost resources will have significant impacts on both the energy and capacity markets of ISO-NE.

A. Energy Market Impacts

Maine ratepayers will receive substantial energy market benefits from the NECEC Project. The cost of energy supply in Maine is based on the hourly ISO-NE Maine Load Zone LMP, which is derived from the more granular prices at dozens of load and generator nodes across the state. The addition of low marginal cost energy will deliver the greatest LMP reductions in nodal prices at and near the injection location (Larrabee Road in Lewiston, Maine), but will also reduce LMPs throughout the state and larger ISO-NE region.

We evaluated the energy market benefits of the NECEC Project Bids, and the potential additional energy, through market simulation with AURORA. As noted above, the NECEC Project Bids were simulated in the model as delivering 981 MW of clean energy each hour. For the analysis evaluating the potential benefits of the additional energy that could be delivered using the full capacity of the NECEC Transmission Project, the energy delivery was modeled as 1,086 MW of clean energy each hour.

By comparing simulations with and without the NECEC Project Bids in service, we quantified the change in LMPs that results from the incremental clean energy. This reduction in LMPs directly reduces the wholesale energy costs of serving New England customers. Figure 3 below depicts the cumulative NPV of LMP savings for each state in New England, corresponding to the lower estimate of delivered energy.

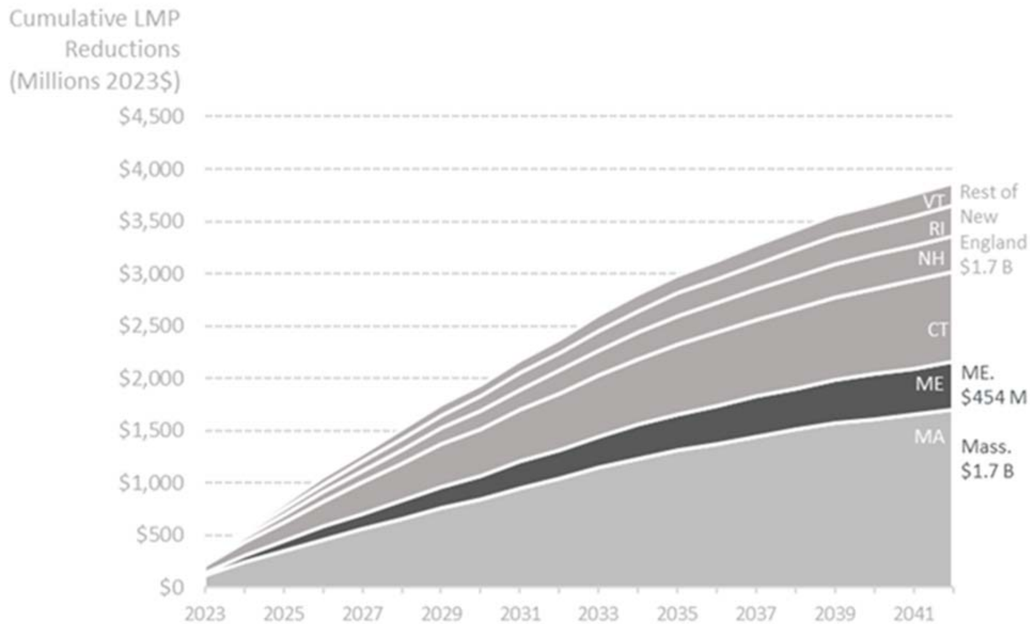

Figure 3. Cumulative LMP reductions by state, 981 MW Scenario

Figure 4 below depicts the reductions in Maine LMPs and the resulting cumulative NPV of the benefits resulting from the addition of the NECEC Project. The dark red corresponds to the benefits associated with the 981 MW portion of the project, whereas the light red corresponds to the additional benefits from the additional [redacted] MW portion of the project.

The injection of clean energy from the NECEC Project will yield significant price impacts to ISO-NE energy prices that will benefit ratepayers, with the impacts being most pronounced in Maine.

Considering only the assumed additional energy associated with the RFP contract, Maine ratepayers will yield levelized benefits of $40 million per year (present value $454 million) resulting from LMP reductions averaging $3.38/MWh. When including energy from the full capacity of the line, the additional energy that may be imported on a market price basis will increase total benefits to Maine ratepayers $44 million per year (present value $496 million) resulting from LMP reductions averaging $3.70/MWh.

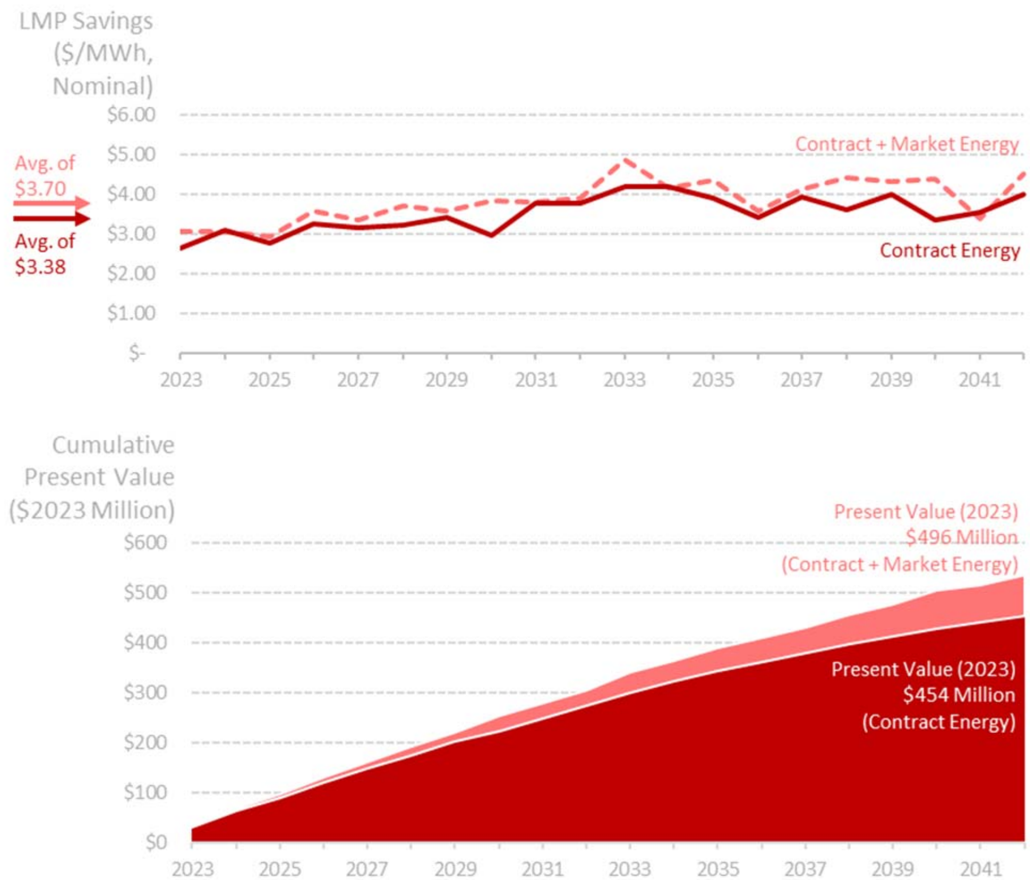

Figure 4. LMP Savings Benefit ($/MWh) and Present Value of Cumulative Benefit to ME Ratepayers ($2023 Millions)

B. Capacity Market Impacts

As a large source of clean, firm, low-cost generation, the NECEC Project Bids have the potential to provide significant benefits to the ISO-NE capacity market. The Massachusetts RFP requires that all proposed projects satisfy the Capacity Capability Interconnection Standard.[15] For capacity market purposes, either of the NECEC Project Bids would be considered an import resource associated with an elective transmission upgrade[16] and, given that the Bids are being offered in accordance with the appropriate interconnection standards, would be eligible to offer incremental capacity into the ISO-NE FCM. The offer price for the capacity would be subject to review and potential mitigation by the ISO-NE Internal Market Monitor (IMM).[17]

We analyzed the potential impact of the NECEC Project Bids on the ISO-NE capacity market and the resulting benefits to Maine ratepayers. Each year, ISO-NE procures capacity through the Forward Capacity Auction (FCA) and allocates the cost of that capacity – determined primarily by clearing price and amount procured – based on the load-ratio share of the system's coincident peak.[18]

For the purposes of this analysis, we assumed that the NECEC Project Bids result in [redacted] MW of incremental qualified capacity starting in FCA14, with a capacity delivery period of June 2023 – May 2024. The NECEC Project will be subject to several tests in order to qualify to participate in the market, and then must offer its capacity at a competitive price in order to clear the market. To assess the potential impact of the capacity for this analysis, we assumed that the capacity qualifies and offers at a price that clears the market in every year. We used our New England FCM model to determine the changes in the types and timing of capacity supply (imports, resource retirements, new generation additions) and changes in market clearing prices due to the addition of [redacted] MW from the NECEC Project Bids.

Our New England FCM model is a standalone tool used to simulate future FCAs. The model incorporates several generator-specific cost and revenue components, including energy revenue data from the AURORA production cost modeling, to compile resource going-forward costs (also known as "delist bids"). The model incorporates these delist bids along with forecasts of Cost of New Entry (CONE) to clear or retire resources using the ISO-NE demand curve.[19]

Our analysis found that the addition of the new low-cost capacity initially displaces other price-sensitive import resources. The impact of the additional capacity supply also advances the retirement of a small amount of capacity in the region that was dependent on capacity revenue for viability.

[15] The Capacity Capability Interconnection Standard (CCIS) ensures that a new resource can interconnect into the New England transmission system and fully deliver its capacity without compromising the reliability, stability, and operability of the larger grid.

[16] An elective transmission upgrade (ETU) is generally comprised of a transmission element with interconnection points within the New England Control Area tied to one or more generation resources.

[17] Appendix C discusses these interconnection, qualification, and offer pricing issues in more detail.

[18] The ISO-NE CELT report forecasts Maine's portion of system coincident peak to average 7.5%.

[19] Appendix C provides additional detail on the FCM model.

The addition of either NECEC Project Bid yields benefits due to reduced capacity clearing prices for the first 8 years of the project. After this point, the market approaches equilibrium, with the cost of new incremental capacity (also known as the Net Cost of New Entry, or "Net CONE") setting the market clearing prices. Once the market reaches this point and new supply is clearing the market, the NECEC Project Bids no longer yield benefits over a market future without the NECEC Project Bids.

Based on the results of this analysis, we calculated the FCM-related benefits of the NECEC Project Bids on Maine ratepayers by comparing the Maine allocations of ISO-NE capacity costs between the two cases (with and without NECEC Project Bids).

During the first 8 years of the project, assuming it clears in each year, the NECEC Project Bids produce an average of $50 million per year in benefits to Maine ratepayers, and a total NPV of $312 million (2023$) over the study period.

Since the FCA clearing price determines capacity costs across the ISO-NE region, there are even broader benefits to New England as a whole. The NPV of benefits to the region total $4.17 billion over 8 years.

This analysis is subject to key uncertainties including inherent market uncertainty. While we have assumed that the NECEC Project Bids will clear [redacted] MW beginning in 2023, this assumption depends on factors such as the ISO-NE IMM review of bid prices, the amount of qualified capacity that can be sold in the market, and the price and amount that clears in the market. Furthermore, potential ISO-NE Market Rule changes in the qualification and capacity auction clearing process – such as the proposed two-tiered auction – can change how an import resource associated with an ETU will participate in the market and its likelihood of obtaining a capacity supply obligation. Nevertheless, our analysis indicates that under plausible assumptions, the benefits of reduced capacity costs of the NECEC Project Bids to Maine and New England ratepayers could be substantial.

IV. GHG REDUCTIONS

As discussed in Section I.D., Maine has established goals for long term GHG reductions. The NECEC Project will contribute to the state's efforts to achieve those goals through the guaranteed delivery of emission-free energy.

Maine is part the New England Control Area, an integrated system where generation from units in Maine may be needed to serve load outside of Maine. Likewise, Maine electricity demand can be served by units located outside Maine.

Therefore, to determine Maine's share of the New England emissions reductions caused by the NECEC Project, we first derived New England-wide emissions reductions and then allocated to Maine based on the ratio of Maine load to total New England load. Compared to a case without the NECEC Project, New England-wide CO_2 emissions are reduced by approximately 3.1 million metric tons of carbon emissions annually. Since Maine represents just over 8.5% of New England load, the NECEC Project would lead to approximately 264,000 fewer metric tons of carbon emissions annually from electric load in Maine as compared to a status quo case. This is roughly a 10% reduction in carbon emissions related to Maine electric load.

V. ADDITIONAL PRICE BENEFITS FROM A REGIONAL CLEAN ENERGY HEDGE

As the ISO-NE market has become more reliant on natural gas as the primary marginal fuel, Maine customers have been impacted by volatile fuel prices in recent years. This impact has been felt both on a short-term basis (daily or weekly price spikes typically experienced in winter months) and a medium-term basis (months or years with higher prices). There have been several state and regional efforts to increase supply of natural gas to the region, but many have so far been delayed. The NECEC Project's delivery of firm, unconstrainted, clean energy into New England reduces reliance on energy from natural gas generators, allowing greater market flexibility under high gas prices that can drastically impact energy market prices, such as have occurred in the recent past in New England. While a firm price contract serves as a hedge for Massachusetts load, the NECEC Project will also serve as a hedge for the rest of New England load through the delivery of firm, all hours inframarginal clean energy. This delivery will help protect Maine customers from multiple high gas price scenarios, as described below.

A. Sustained High Gas Price Scenario

To calculate the potential for the NECEC Project to hedge against high gas prices, we first analyzed a scenario with systematic high natural gas prices persisting throughout the contract period. For this scenario, we utilized the highest gas price scenario included in U.S. EIA's 2017 AEO.[20] The figure below compares the Reference and High prices for gas delivered to New England.

[20] The AEO's highest gas price scenario is termed "Low Oil and Gas Resource and Technology", and represents a future in which oil and gas supply is low, and technological advancement in recovery techniques is delayed, causing high prices.

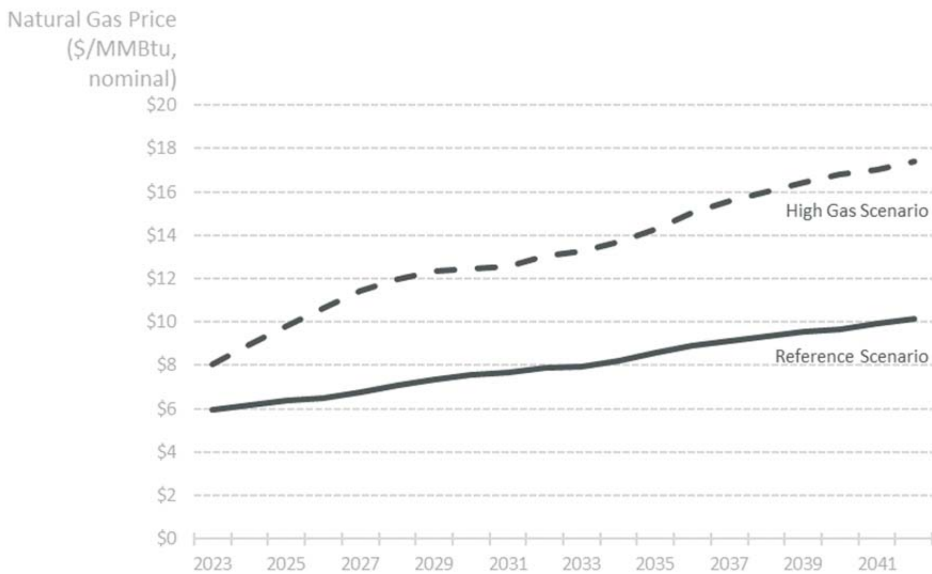

Figure 5. Algonquin Citygates, Reference and High Gas Scenarios

In a high gas future, the value of low-cost firm energy increases. We calculated the incremental LMP-related savings to Maine ratepayers in this kind of future; the additional savings totaled $83 million (2023$ NPV) over the study period. These additional savings illustrate the benefit that Maine ratepayers receive even without being the purchaser of the clean energy low-cost clean energy.

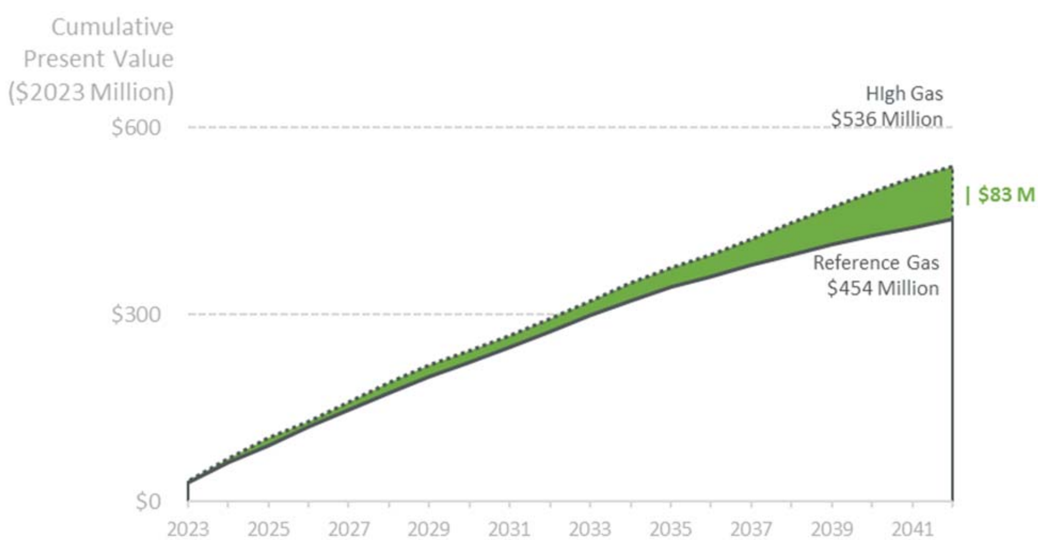

Figure 6. Present Value of Cumulative Benefit to ME Ratepayers, Reference and High Gas Price Scenarios ($2023 Millions)

B. Temporary High Gas Price Scenario (i.e., Polar Vortex)

The second scenario analyzed relates to recent winter price spikes experienced in the region. The ISO-NE market has been subject to severe winter electricity price spikes in several recent years. In many cases these price spikes have been temporary and episodic, but have exposed Maine ratepayers to extreme volatility and high wholesale energy prices.

This condition arises most frequently during cold winter periods when the natural gas pipeline capacity is being used by the natural gas Local Distribution Companies (LDCs) for space heating purposes, resulting in a lack of available supply for natural gas generators in the region. With insufficient supply, natural gas prices spike and less-efficient and normally higher-priced oil units are dispatched to meet demand. This ultimately results in an escalation in electricity market clearing prices.

This market condition is distinct from the persistent high natural gas price scenario described in the context of firmness benefits in Section V.A. above. Long-term high natural gas prices are the result of broader market conditions impacting supply and demand. These short-term spikes, by contrast, are the result of acute system conditions, but can have severe customer impacts in only a small number of days or hours.

We evaluated the benefits that the NECEC Project Bids would provide under these high winter price spike conditions. For the Reference Case analysis, the monthly natural gas price shape modeled reflects average conditions, with no extreme price conditions. For the analysis of the impact of NECEC Project Bids on winter electricity price spikes, we modeled the 2024-2025 winter period assuming that natural gas prices mimicked the daily price shape for the 2013-2014 winter period, when "polar vortex" conditions caused extreme natural gas and electricity prices in New England.

The figure below compares the winter natural gas basis (difference between the Henry Hub and Algonquin Citygates prices) used in the Reference Case analysis with the daily basis used to replicate the conditions of the 2013-2014 winter. No other changes were made to the model assumptions.

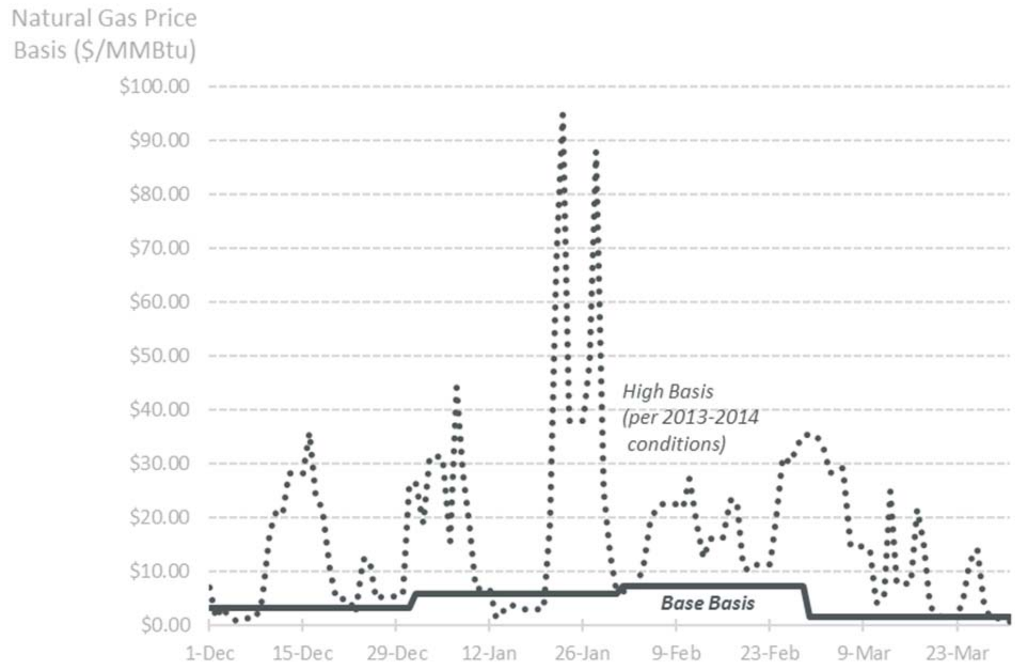

Figure 7. Natural Gas Price Basis from Henry Hub to Algonquin Citygates ($/MMBtu)

We evaluated the NECEC Project under both conditions for the 2024-2025 winter to assess the value of the project under these extreme conditions. The results show that in the high winter price spike scenario, the NECEC Project Bids produce LMP-related savings to Maine ratepayers of $51 million (nominal) for the period from December through March, as compared to $9 million in the Reference Case for the same period. The figure below depicts the Maine LMPs for the modeled futures, each with and without the NECEC Project.

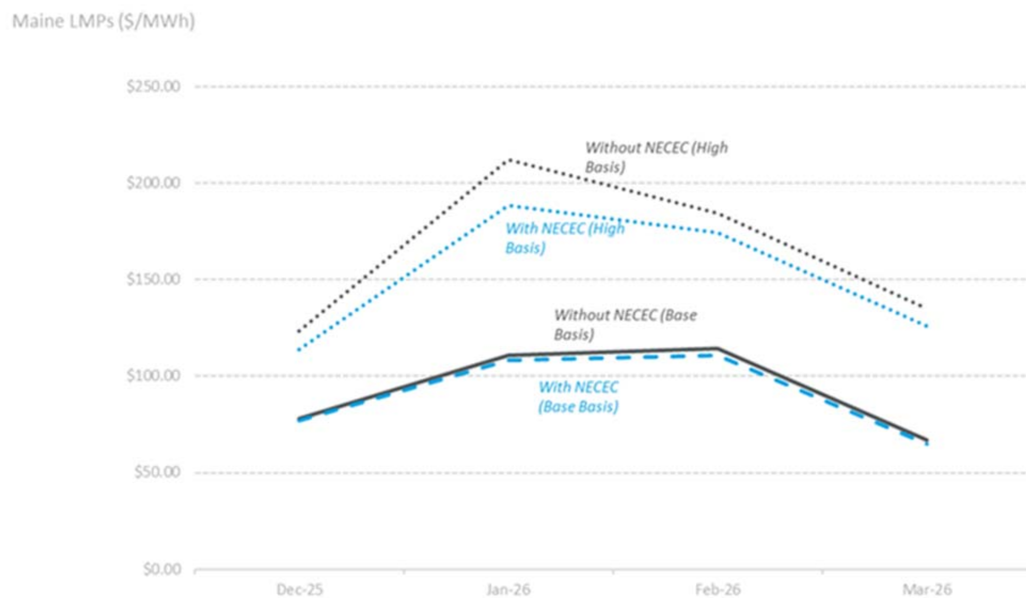

Figure 8. Maine Locational Marginal Prices under Base and High Basis Assumptions ($/MWh)

Because it is unlikely that the conditions of the winter of 2013-14 will be precisely replicated, these results should be viewed as directional and indicative of the possible scale of savings. These indicative results demonstrate, however, the value of the NECEC Project Bids as a hedge against extreme gas price conditions. When gas prices spike and LMPs escalate, the NECEC Project's value in reducing LMPs also increases. Spread across all load in Maine, these LMP reductions can generate large benefits over a short period of time.

The beneficial impact on ratepayers of the hedge provided by the NECEC Project Bids could be very substantial for Maine load in the short run and, as noted above, reduce the long-term costs for ratepayers by reducing the impact of price volatility.

C. Hedging Value Against Thermal Generation Retirements

The NECEC Project provides additional hedging value as a large source of clean, firm capacity that is not subject to volatile fuel prices, and therefore can mitigate the impact of potential future thermal generation retirements.

Maine and New England customers are exposed to ongoing electricity supply cost risk due to the potential for conventional thermal and nuclear resources in the region to retire in coming years. The regional supply of dispatchable thermal resources predominantly consist of natural gas resources. There are just a small number of coal units remaining online in New England and a larger number of oil-fired generators, though many of these resources are older.

Several of the non-gas generators are potentially at risk of retirement in the near future due to increasing operating and maintenance costs and a potential decline in energy and capacity revenues. As these units retire, the further dependence of the ISO-NE market on natural gas generators exposes Maine and New England customers to increased risk of the high gas price scenarios discussed above.

The NECEC Project serves as a hedge against the market effects of these potential resource retirements by adding a large source of firm capacity while enhancing the fuel diversity of the ISO-NE supply mix.

Additionally, retirements put upward pressure on the ISO-NE FCM. The addition of [redacted] MW of low-cost firm power that, by the requirements of the Massachusetts RFP, must pass the necessary tests for deliverability into the capacity market will act a hedge against increases in capacity costs to ratepayers.

VI. IMPACT ON ANCILLARY SERVICES

One of the issues frequently discussed in relation to renewable energy is the impact on ancillary services. Intermittent resources can, depending on circumstances, place extra burden on a system's ability to ramp up or down, leading to the need for more fast start resources to provide regulation and operating reserves. The NECEC Project avoids this potential issue by providing firm power to the grid based on an agreed upon schedule that will be part of the contracts with the Massachusetts electric Distribution Companies. Backed by Hydro-Québec's significant hydroelectric facilities, the resources available to provide the clean energy under the NECEC contract will be available in all hours.

As ancillary services are centrally coordinated and procured by ISO-NE, system-wide costs for these services are allocated to the system on a load-ratio share basis. As a large source of firm energy with a predictable schedule, the NECEC Project will likely reduce the cost of providing ancillary services to the grid. Maine ratepayers will therefore benefit proportionally from the reduction in ISO-NE ancillary services costs.

We have not quantified these benefits for this report, but have described the impacts below.

A. Operating Reserves

Units that provide operating reserves in New England are generally unavailable to provide energy, as they are required to bid at a level well above their cost, therefore ensuring they only dispatch rarely. This means that the operating reserve and energy markets compete for resources. Providing a large block of firm, low-cost power will move higher-cost units further up the supply stack, leading some to seek revenue by providing operating reserves instead of energy. The provision of firm energy will therefore exert downward pressure on the various operating reserve markets in New England by increasing supply.

Highly reliable power such as is provided by the NECEC Project, will also assist ISO-NE operations with non-performance issues when the system is under stress. ISO-NE has experienced high system stress instances in the past, where resources fail to respond to instructions due to various reasons such as gas limitations, weather induced derates, or other issues. By having roughly 1,000 MW of highly reliable power, the impact of these non-performing assets will be reduced because ISO-NE may be able to rely on them less.

B. Ramping

In addition to pushing units up the supply stack and out of the energy market, the NECEC Project will also allow some units to operate at levels that will allow for more ramping capability in New England. This is a significant benefit, as more ramping capability in any given hour means that it is easier to absorb more intermittent resources. So not only will the NECEC Project provide a large block of firm clean energy, but it will assist the system in absorbing even more clean energy over time.

VII. OTHER BENEFITS

In addition to the benefits discussed in Sections III. through VI. above, we studied the following additional benefits and issues that the Commission may wish to consider as it evaluates the NECEC Project:

- Regional and Maine reductions in electric sector natural gas consumption; and,
- Energy congestion mitigation considerations.

A. Energy Sector Reductions in Consumption of Natural Gas

In addition to the impacts on energy, capacity, and REC prices, plus the reductions in Maine and New England CO_2 emissions, the NECEC Project Bids will help reduce the electric sector demand for natural gas. This reduction in natural gas demand will provide downward pressure on the spot market for natural gas. Because New England marginal wholesale electric costs are based almost exclusively on natural gas, this will also provide an additional benefit in the form of further lowering LMPs. In addition, lower regional natural gas prices will benefit all natural gas consumers, including those that use natural gas for heating or other residential, commercial, or industrial purposes.

While we do not attempt to quantify these additional benefits in this report, we did quantify the reduction in natural gas burn in Maine and in the region resulting from the addition of the NECEC Project. The NECEC Project induced an average annual reduction of 54.2 million MMBtu of natural gas burn in the ISO-NE region, and an average of nearly 8 million MMBtu annually in Maine.

Figure 9 provides the monthly natural gas burn in ISO-NE in 2023 to illustrate the shape of the impact of the NECEC Project.

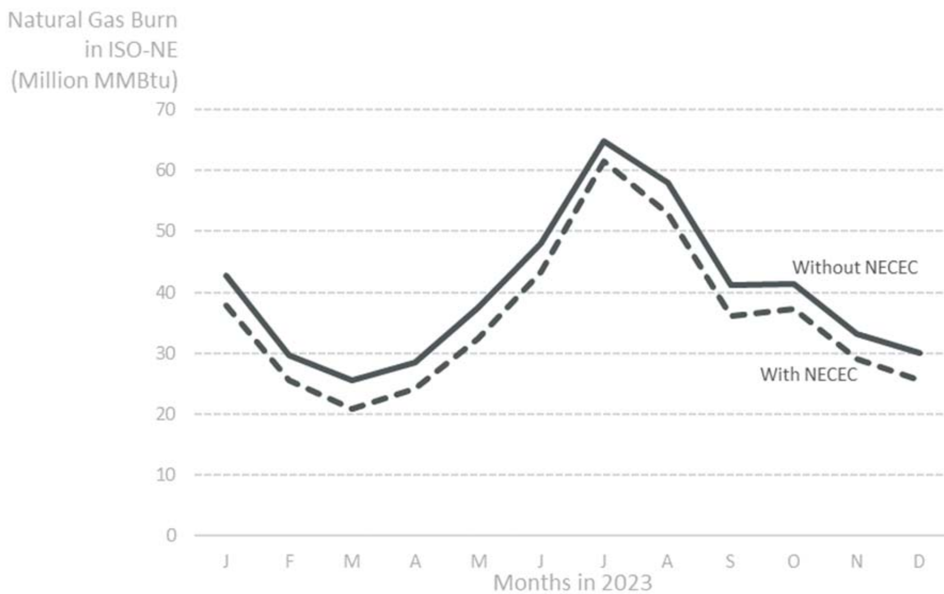

Figure 9. ISO-NE Natural Gas Consumption, 2023 (Million MMBtu)

As can be seen in Figure 10 below, the impact, on a percentage basis, is greatest in the winter. This is beneficial, as the supply of natural gas to electric generators is tightest in the winter months, making a larger reduction in those months desirable.

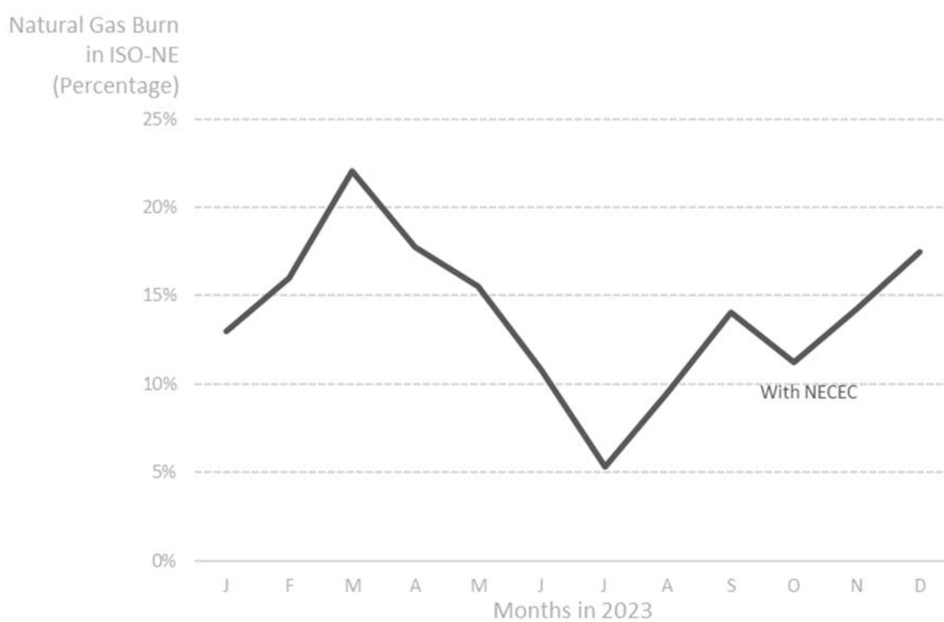

Figure 10. Monthly Natural Gas Consumption by ISO-NE Generators, Percent Reduction With NECEC Project, 2023

B. Energy Congestion

We performed two analyses designed to review the impact of the NECEC Project on regional and Maine-specific congestion. First, we reviewed the annual results for the 20-year Reference Case at two key interfaces:

- Surowiec South Interface; and
- Maine-New Hampshire Interface.

The results of the long-term analysis shows that the NECEC Project Bids do not create material congestion at Maine interfaces, with results showing: (1) uncongested deliveries on the Surowiec South interface more than 99.9% of all hours; and (2) uncongested deliveries on the Maine-New Hampshire interface more than 99.2% of all hours.

In addition to the zonal analysis, we reviewed the hourly data for key interfaces that could represent bottlenecks for new renewable energy deliveries from western Maine to southern New England. The interfaces reviewed in this detailed manner included:

- Surowiec South Interface;
- Maine-New Hampshire Interface;
- NNE-Scobie+394 Interface; and
- New England North-South Interface.

These interfaces were evaluated using a nodal representation of the New England grid, modeling an "all lines in" condition for one year (2025). In all cases, following the construction of the NECEC Project, the key interfaces were unconstrained a minimum of 99% of the hours in the year.[21] To provide a conservative estimate of potential congestion, the DC line was assumed to be running at its full 1,200 MW capability all hours of the year for this test. No congestion resulted at Surowiec South. Figure 11 through Figure 14**Error! Reference source not found.** below depict duration curves of the hourly flow over each of the four tested interfaces for 2025, with and without the NECEC Project in place.

[21] See Technical Appendix A, Section V for discussion of these calculations.

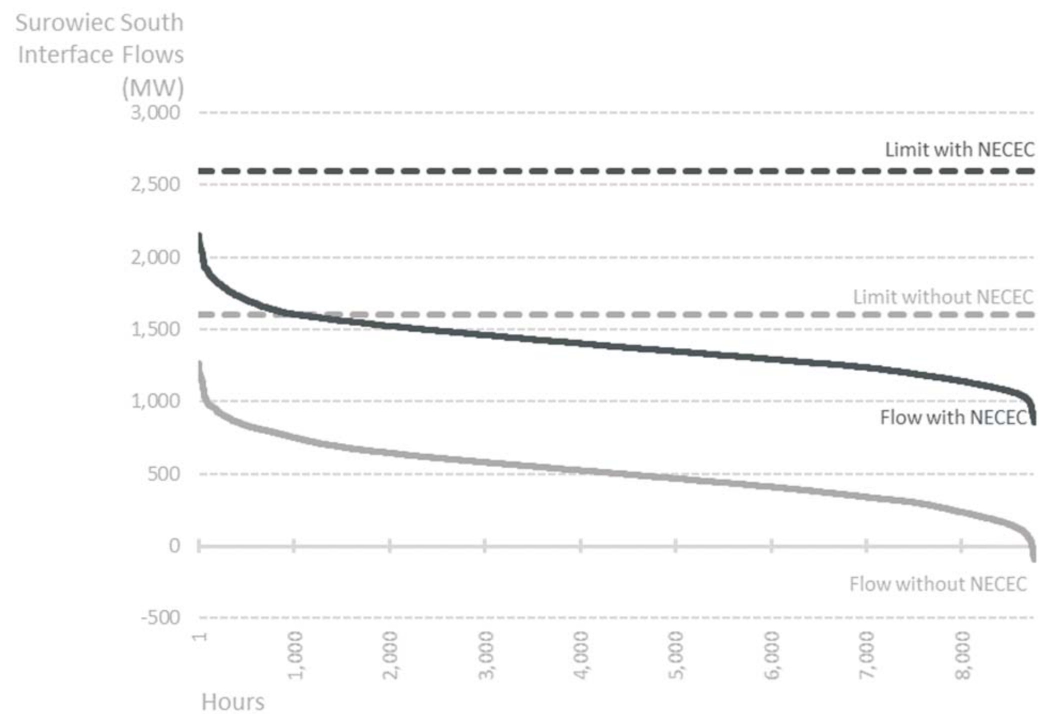

Figure 11. Surowiec South Interface Hourly Flow Duration Curve (2025)

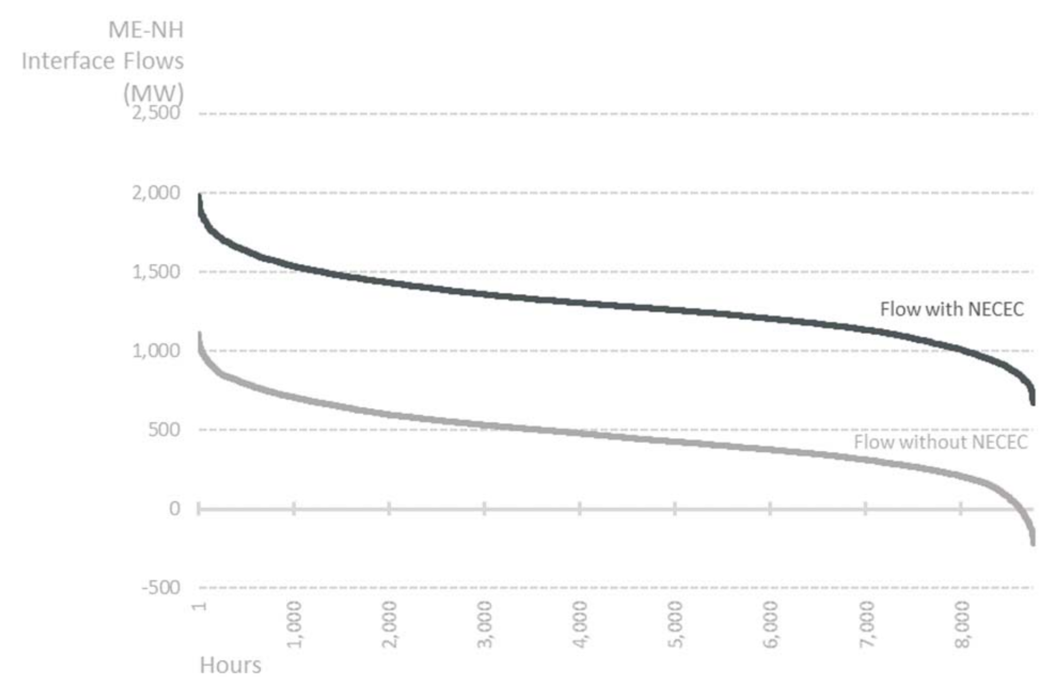

Figure 12. Maine-New Hampshire Interface Hourly Flow Duration Curve (2025)

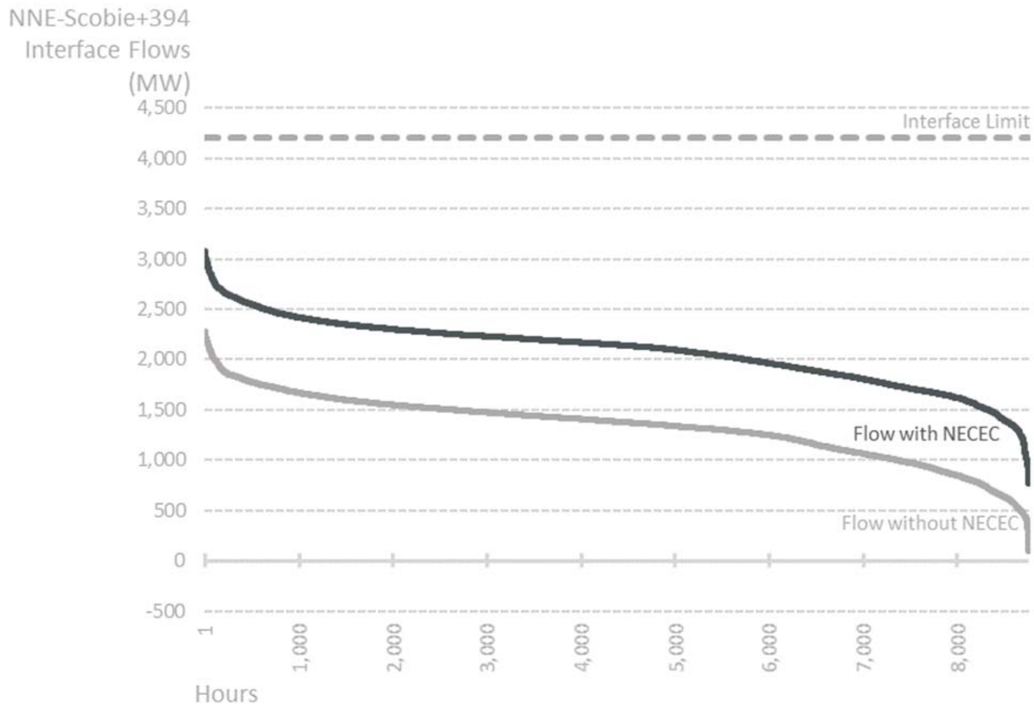

Figure 13. NNE-Scobie+394 Interface Hourly Flow Duration Curve (2025)

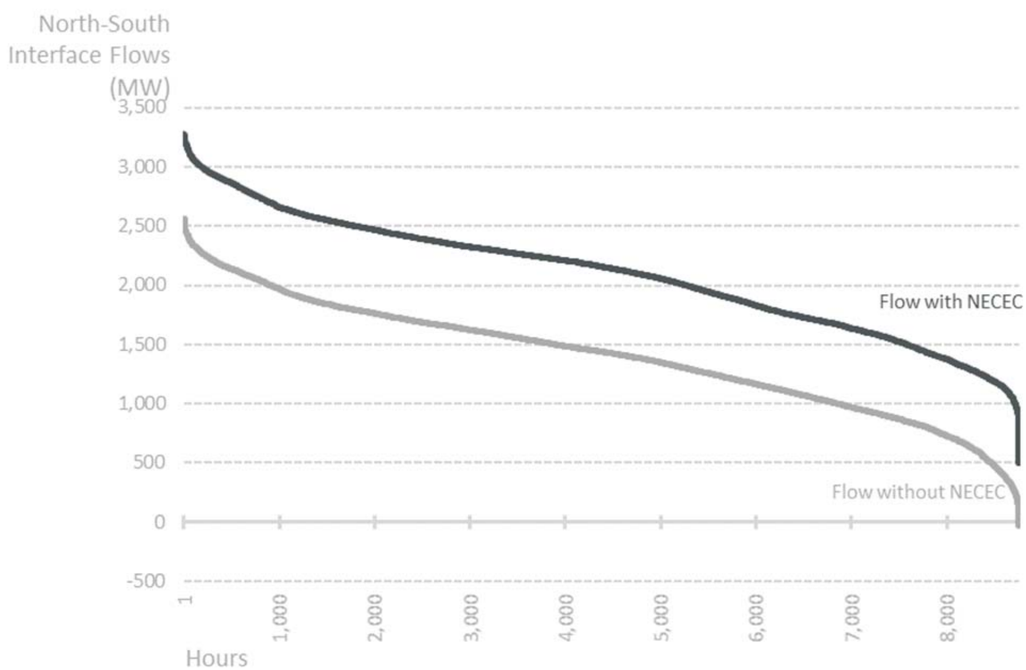

Figure 14. North-South Interface Hourly Flow Duration Curve (2025)

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APPENDIX A: ENERGY MARKET MODELING DETAILS AND METHODOLOGY

SEPTEMBER 27, 2017

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I. INTRODUCTION

Daymark Energy Advisors performed energy market analysis in support of the New England Clean Energy Connect (NECEC) Project Bids. The analysis utilizes production cost modeling to examine the benefits of the proposed transmission upgrades and incremental hydroelectric and wind generation capacity.

The two NECEC Project Bids (collectively referred to as the Bids, individually as Bid 1 and Bid 2) are being offered as separate and exclusive offers of Clean Energy Generation, each to be delivered via the NECEC Transmission Project. Each Bid includes a combination of Clean Energy Generation and the NECEC Transmission Project.

In Bid 1, Hydro Renewable Energy LLC (HRE)[1] is sponsoring firm service hydroelectric generation. Bid 1 includes [redacted] megawatts (MW) of hydroelectric energy, offered at a [redacted] capacity factor, providing approximately 8,600 gigawatt hours (GWh) of firm service clean energy being delivered to the Commonwealth's ratepayers at a fixed price for energy and transmission.

In Bid 2, HRE is joined by a joint venture of Gaz Metro Limited Partnership and Boralex Inc. (collectively, the "NECEC Wind Developer") to offer a combined bid of wind energy and renewable energy credits (RECs) and firm service hydroelectric generation. Bid 2 includes [redacted] MW of wind energy backed by firm service hydroelectricity, collectively offered at a [redacted] capacity factor by the NECEC Wind Developer and [redacted] MW of hydroelectric energy, offered at a [redacted] capacity factor by HRE. The combination of these two elements of Bid 2 provide approximately 8,600 GWh of firm clean energy plus the delivery of approximately [redacted] million Massachusetts Class 1 renewable energy credits (RECs).

Central Maine Power (CMP or the Transmission Sponsor) joins each bid offering the NECEC Transmission Project to deliver the Clean Energy Generation[2]. The NECEC Transmission Project provides for the reliable delivery of up to 1,200 MW of Clean Energy per hour into the New England grid. The NECEC Project Proponents include the costs for the [redacted] MW of transmission capacity from the NECEC Transmission Project needed to deliver the Clean Energy Generation proposed in Bids 1 and 2. HRE has agreed to be financially responsible for the remaining [redacted] MW of transmission capacity on the line.

Daymark's NECEC Project Benefits report (the "Daymark Report") provides a discussion of the results of our analysis. This appendix to the Daymark Report provides additional detail on the evaluation and describes the energy market modeling methodology and analysis which informed our conclusions. The analysis described in this appendix yielded the following results and conclusions in the Daymark Report:

1 HRE is an affiliate of Hydro Québec.

2 CMP proposes to develop, construct and own the NECEC transmission facilities on the U.S. side of the border. The transmission facilities located on the Canadian side of the border will be developed, constructed and owned by Hydro Québec TransEnergie, Inc. (HQT), an affiliate of Hydro Québec and HRE, in accordance with HQT's Open Access Transmission Tariff.

- Direct Contract Benefits – RFP Section 2.3.1.1
- Other Costs and Benefits to Retail Customers
    - LMP impact – RFP Section 2.3.1.2(i)
    - Production cost impact – RFP Section 2.3.1.2(i)
    - GWSA impacts – RFP Section 2.3.1.2(iii)
    - Resource firmness benefits – RFP Section 2.3.1.2(iv)
- Qualitative Benefits of Reliability – RFP Section 2.3.2(iv)
    - Contribution to reducing winter electricity price spikes
- Other Benefits and Considerations
    - LMP reductions in other states in region
    - Reduced natural gas consumption

This appendix describes the energy market analytical methodology and provides details on key assumptions.

II. ANALYTICAL FRAMEWORK

Daymark was retained, in part, to conduct an evaluation of the NECEC Project Bids using the quantitative and qualitative criteria and methodologies specified in the RFP, and using methods and assumptions that are representative of those that are likely to be used by the Soliciting Parties in evaluation of the proposals. To evaluate the impacts on the New England energy markets and fully account for the combined benefits of the NECEC Transmission Project and a combination of incremental clean energy projects proposed in conjunction with the NECEC Transmission Project, we performed production cost modeling using our in-house zonal energy model, the Daymark Energy Advisors Northeast Market Model (NMM). We have also conducted nodal modeling to assess the deliverability of the Bids.

To evaluate the benefits of the NECEC Bids, we analyzed multiple scenarios, each featuring a "Without NECEC Case" and "With NECEC Case". Each Without NECEC Case includes a set of our "status quo" assumptions (described below). Each With NECEC Case makes two changes to the associated Without NECEC Case. First, the Surowiec South interface limit is increased to 2,600 MW, attributable to the upgrades from the NECEC Transmission Project. Second, each With NECEC Case includes delivery of incremental clean energy generation via the NECEC Transmission Project, delivered into the Central Maine Zone.

By comparing the results of each pair of runs – LMPs, production cost, emissions, fuel burn, etc. – we calculate the economic benefits of the NECEC Bids.

The following sections describe the NMM and provide details on our key modeling assumptions.

A. NMM Overview

The Daymark Energy Advisors NMM uses an hourly chronologic electric energy market simulation model on the AURORAxmp® software platform ("AURORA"). The model provides a zonal representation of the electrical system of New England, New York and the neighboring regions.

The underlying technology, AURORA, is a well-established, industry-standard simulation model that uses and captures the effects of multi-area, transmission-constrained dispatch logic to simulate real market conditions. AURORA captures the dynamics and economics of electricity markets.

AURORA realistically approximates the formation of hourly energy market clearing prices on a zonal basis using all key market drivers, including fuel and emissions prices, loads, demand-side management (DSM), generation unit operating characteristics, unit additions and retirements, and transmission congestion and losses.

The NMM utilizes a comprehensive database representing the entire Eastern Interconnect (the North American interconnected power system east of the Rocky Mountains), including representations of power generation units, zonal electrical demand and transmission configurations. Daymark constructed this database from a number of established sources of information, including:

1. A comprehensive database issued by EPIS, Inc., the developer of AURORA.
2. The U.S. Department of Energy's Energy Information Administration (EIA).
3. The Independent System Operator of New England (ISO-NE).
4. The New York Independent System Operator (NYISO).
5. The New York Mercantile Exchange (NYMEX).

Daymark supplements the EPIS database with custom updates and revisions of key inputs for the New England and New York markets, as well as more limited updates to neighboring control areas.

III. SYSTEM TOPOLOGY

The NMM is a zonal model, where each defined zone represents a "bubble" of load and generation. Transmission is represented as single composite links between zones with constraints on certain combinations of links to represent interfaces. Key attributes that can be defined for each individual link are wheeling costs, transfer losses and transfer capability. The topology of ISO-NE and contiguous areas used to model the NECEC Project is shown in Figure III-1 below.

The zones modeled in Maine include:

- Southern Maine (SME): Generation and load between New Hampshire and the Surowiec South interface.
- Central Maine (CME): Generation and load bounded by the Surowiec South interface to the south and Orrington South to the northeast. The NECEC Clean Energy is delivered to this zone.
- Bangor Hydro Electric (BHE): All ISO-NE generation and load north and east of the Orrington South interface. This zone is also interconnected to the New Brunswick zone.
- Northern Maine Independent System Administrator (NMISA): Primarily the Emera territory known as the Maine Public District, this zone includes all Maine load not interconnected with ISO-NE. This zone is only connected to the New Brunswick zone.

The zonal topology remains the same in both the Without NECEC and With NECEC model runs. As noted above, the only change in the With NECEC cases is an increase in the Surowiec South transfer limit due to the upgrades associated with the NECEC Transmission Project.

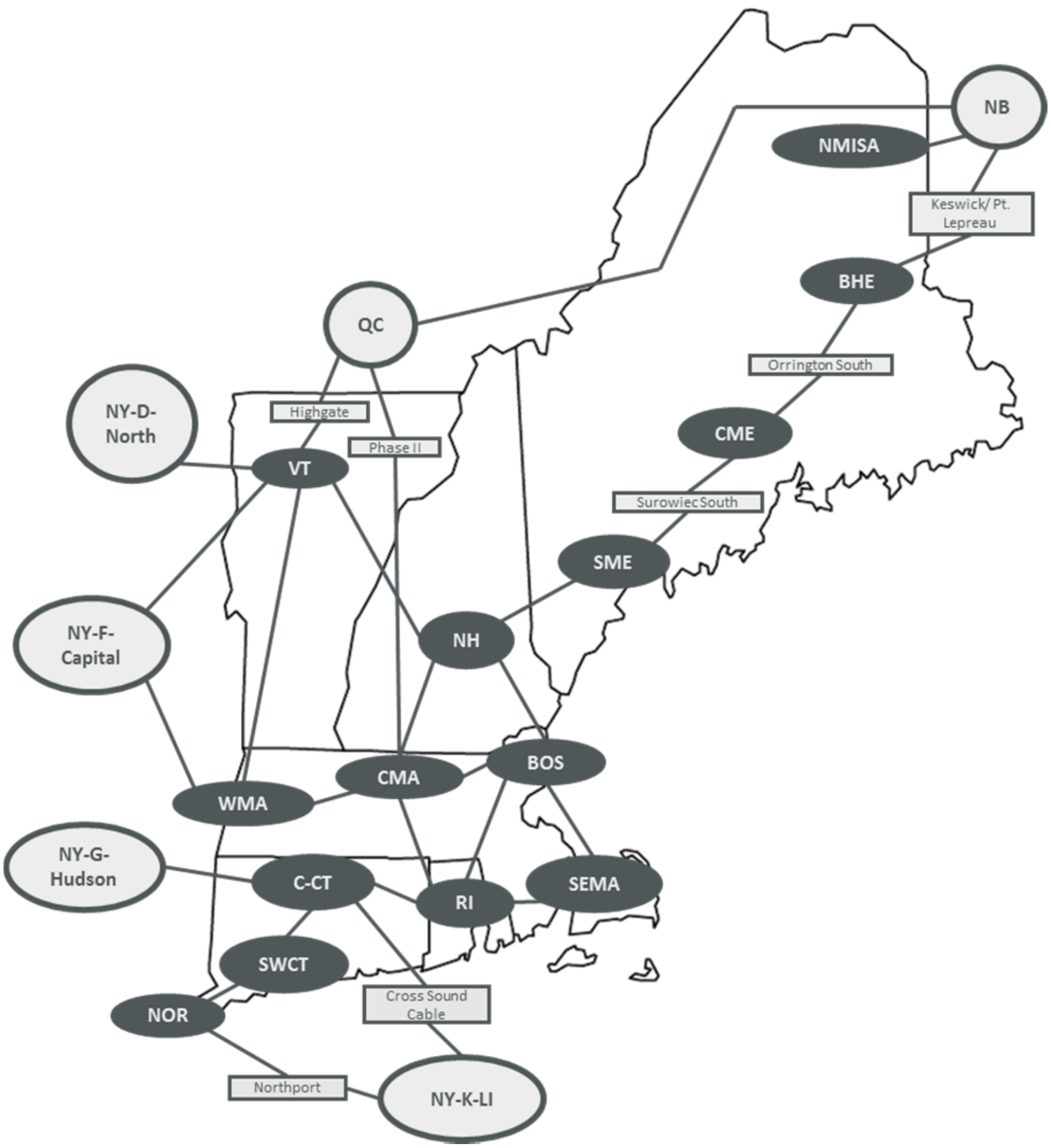

Figure III-1. NMM Model Topology: ISO-NE and regional interconnections

IV. KEY INPUTS

As discussed in the Daymark Report, Section II.C., the goal of Daymark's analysis is to conduct an evaluation of the NECEC Project using the quantitative and qualitative criteria and methodologies specified in the RFP, using methods and assumptions that are representative of those that are likely to be used by the Soliciting Parties in evaluation of the proposals.

This section provides details on the key modeling inputs and assumptions used in the NMM energy market analysis.

A. Load

Section 2.3.1.2 of the RFP notes that "[t]he reference case system topology will be based on the 2016 ISO New England Capacity, Energy, Load and Transmission (CELT) report."

Therefore, the load forecast used in the NMM for New England is based on the 2016 CELT report. Since the zones modeled in the NMM align with the RSP zones, we used the forecast values directly from the CELT report.

For the forecast years through 2025, the 2016 CELT report provided gross peak and energy load and peak and energy load net of energy efficiency (EE).[3] ISO-NE's EE forecast in the CELT report includes estimates based both on the resources cleared in the ISO-NE FCM and the load reduction projected due to state-sponsored EE programs. For extrapolation in modeled years after 2025, gross load is assumed to grow at the compound annual growth rate from 2020-2025. EE reductions are extrapolated such that EE's percent of gross load, both peak and energy, in 2025 remains constant through the rest of the study period. These extrapolations are done separately for each zone in the system.

Figure IV-1 below shows the 2016 CELT forecasts of gross and net coincident peak load and Figure IV-2 shows the gross and net energy demand for the New England Control Area.

[3] ISO-NE refers to EE as "passive demand resources" (PDR).

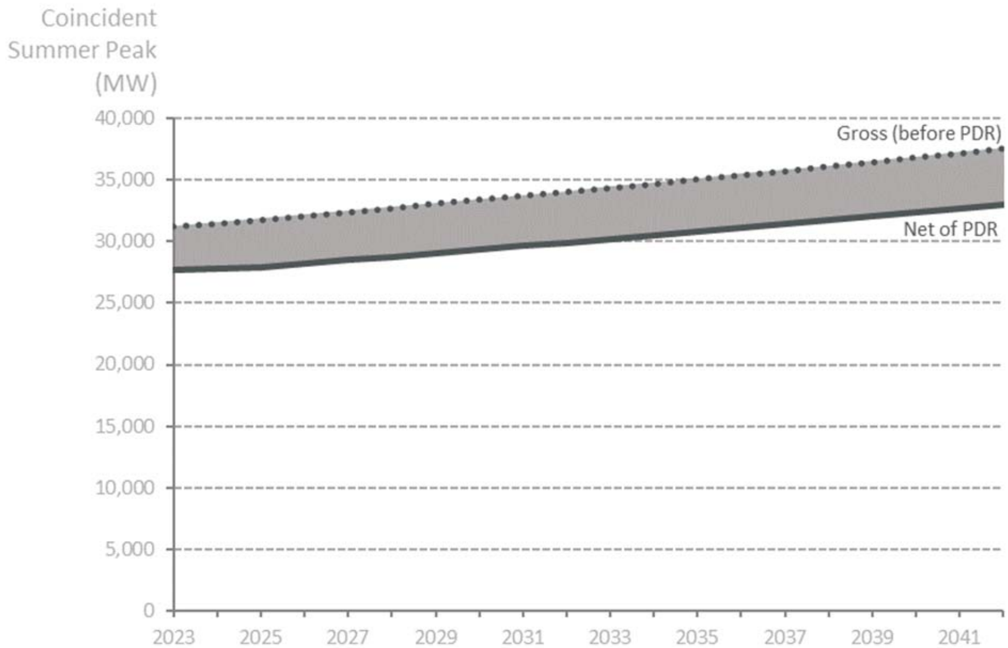

Figure IV-1: New England Coincident Peak Load, Gross and Net of Energy Efficiency

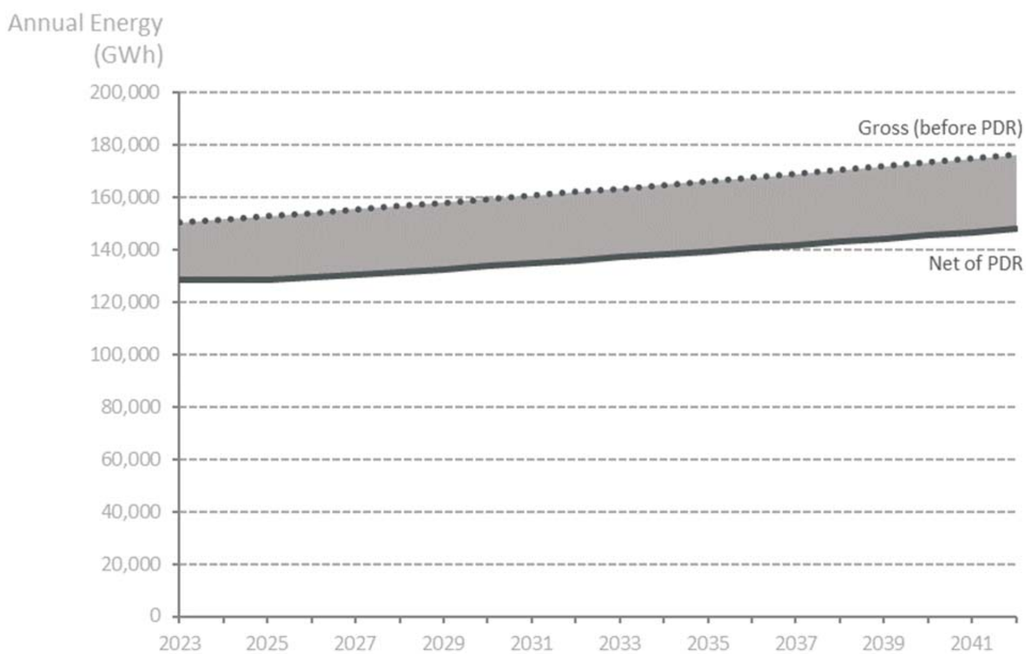

Figure IV-2: New England Energy Load, Gross and Net of Energy Efficiency

Dispatchable Demand Response (DR) units are added to New England in the NMM based upon the level of DR that has cleared in the ISO-NE Forward Capacity Market (FCM). In the market's Forward Capacity Auction (FCA) 7, the level of DR dropped precipitously from the level that had been clearing previously, and continued to decline in FCA 9 and FCA 10. Total cleared DR has declined from approximately 1,000 MW in FCA 8 to only 378 MW in FCA 10. DR capacity (in MW) for years beyond the last FCA period is assumed to remain constant at the level of the last FCA. Therefore, for the NECEC modeling, the assumption is that this lower level of 378 MW of DR persists through the end of the study period. These units are modeled as "load control" units in the NMM, and therefore when dispatched they act to reduce load instead of providing generation.

B. Fuel Prices

Fuel prices are key assumptions for the NMM, and are subject to a large amount of uncertainty. As a key component of dispatch cost, fuel prices are an important to price formation and regional market dynamics. In the NMM production cost model, each generator is assigned a fuel price based on the type of fuel, unit type, and plant location.

The following sections describe how fuel price assumptions are developed.

Natural Gas Index Prices

The ISO-NE market is currently dominated by natural gas generation and will likely remain so throughout the study period. Therefore, the natural gas price assumptions are a critical driver to our modeling and results.

For this analysis, Daymark utilized the U.S. EIA's 2017 Annual Energy Outlook (AEO) Reference Case assumptions of natural gas price indices. The AEO is a publicly available long-term forecast that is commonly used in the energy industry.

Daymark used the AEO forecast for the Henry Hub Index, as well as region-specific indices for New England, New York, and the PJM RTO (Figure IV-3 below).

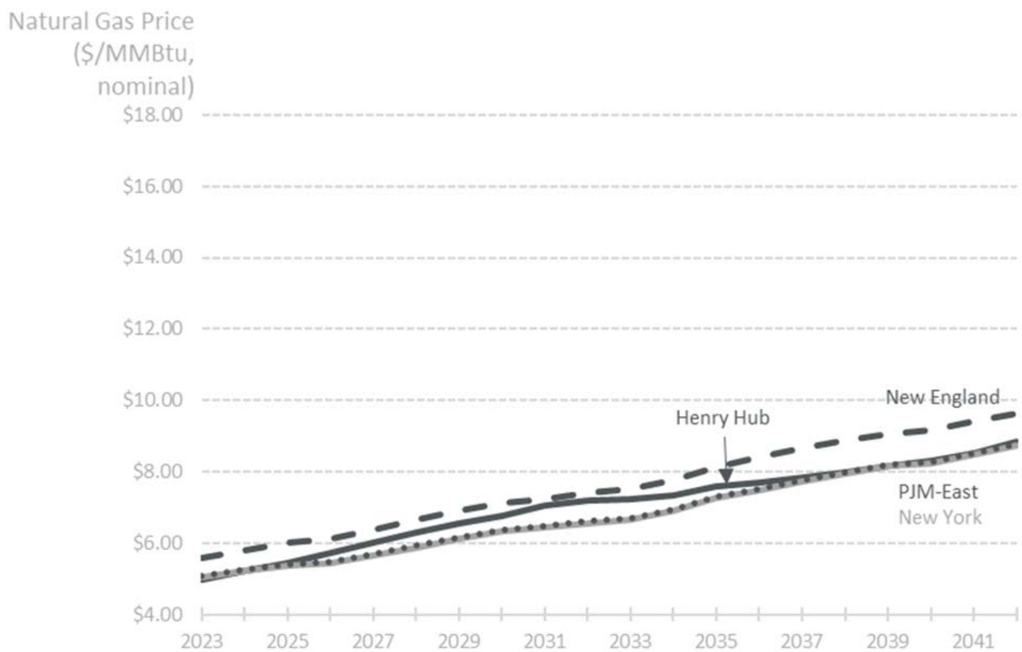

Figure IV-3. Natural Gas Price Assumptions ($/MMBtu, nominal)

In addition to the AEO Reference Case, Daymark also used AEO's high gas forecast[4] for the analysis of the value of firmness (see Section IV.D. of the Daymark Report). Figure IV-4 below depicts the price assumptions for the four indexes.

[4] The highest natural gas scenario in the 2017 AEO is the "Low Oil and Gas Resource and Technology". This scenario represents a future in which there are low physical reserves available for recovery, and the speed of technological advancement in recovery techniques is slow, resulting in low supply and high prices.

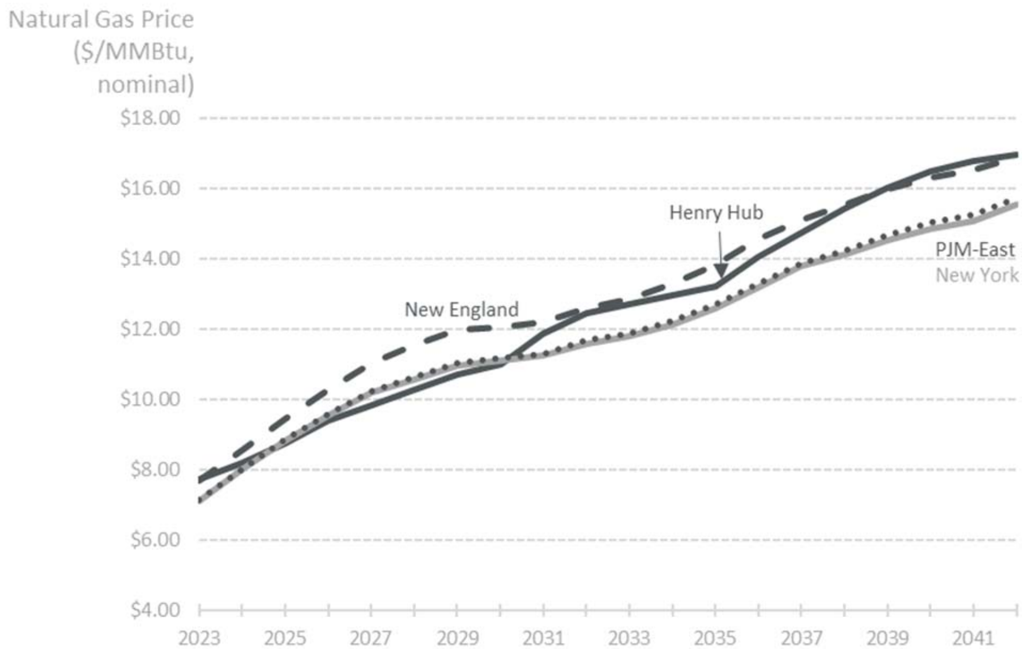

Figure IV-4. High Natural Gas Price Assumptions ($/MMBtu, nominal)

Figure IV-5 below compares the Reference Case assumption with the High Case natural gas price assumption.

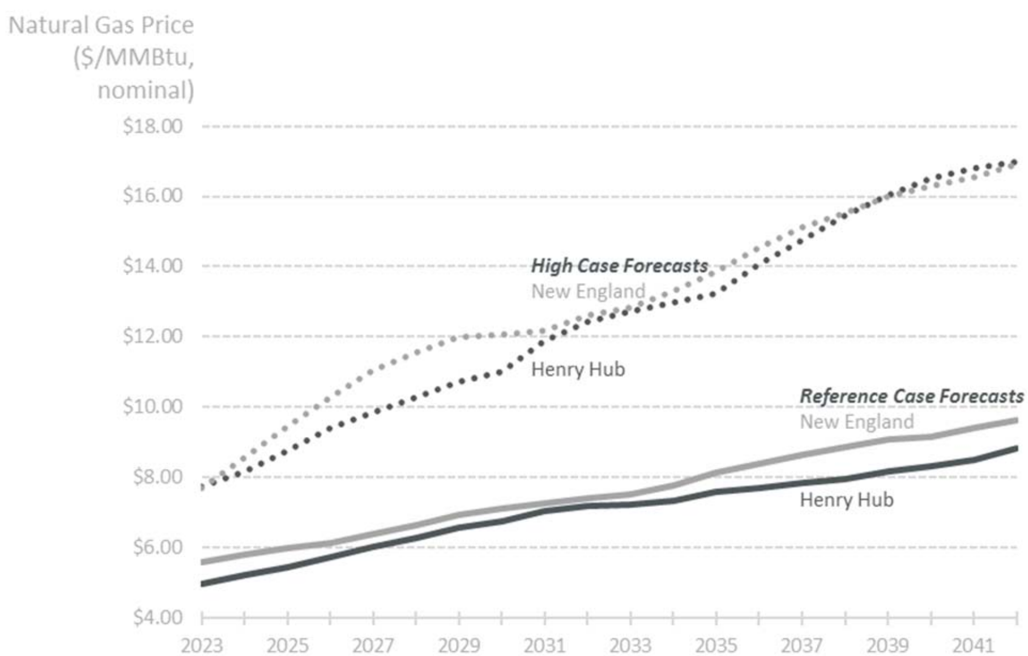

Figure IV-5. Comparison of Reference and High Natural Gas Cases

The index prices represent one component of the actual gas price used by the production cost model in each hour to determine economic dispatch of resources. For example, the price of natural gas for each New England generator is constructed according to the following basic formula for year *y*, month *m*:

$$\mathbf{DP_{y,m} = (IP_y * MS_m) + R_m + p}$$

Where:

DP	=	Delivered price to generator
IP	=	Index price, annual average
MS	=	Monthly shape factor for index price
R	=	Regional adder, if any
p	=	Peaking unit adder

The index price is sourced from the AEO as described. The derivation of each of the remaining components of the equation above is explained in the sections below.

Monthly Shape Factor for Index Prices

Annual average natural gas prices are shaped monthly to reflect seasonal trends and variation in The monthly shape vector for the index prices is based on analysis of historical trends. These values are applied to the annual index prices to yield monthly values. Figure IV-6 below displays the monthly shapes for the four primary indexes used in this analysis.

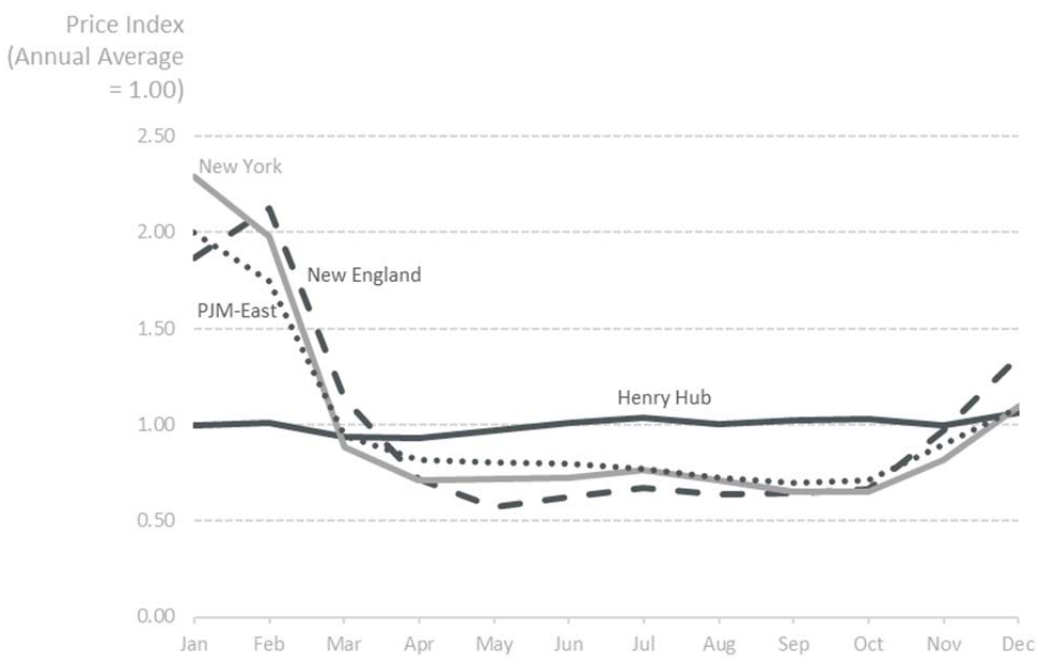

Figure IV-6. Natural Gas Index Monthly Shapes

Regional Adder

The Algonquin Citygates price provides a reasonable proxy for delivered natural gas prices for generators in southern New England. However, natural gas-fired generators in northern New England (Maine, New Hampshire, and Vermont) face additional expense due to the additional distance from gas supplies to the southwest. The NMM forecast of this additional basis is $0.59/MMBtu on an annual average basis, with seasonal range of $0.35 - $0.88/MMBtu (see Figure IV-7). The forecast is based on backhaul usage rates on the Maritimes and Northeast Pipeline and Portland Natural Gas Transmission System short term reservation rates.

Figure IV-7. Northern New England Basis Differential to Rest of New England (Algonquin Citygates)

Peaking Unit Adder

Some units are assumed to pay for fuel at prices above the monthly average price for delivered natural gas because they tend to only be dispatched on peak days when the daily gas price is likely higher. Our assumptions are summarized in the table below.

Natural Gas Delivery Class	Fuel Adder (2017$/MMBtu)	Resources in Class
Peaking	$0.89	New Haven Harbor Units 2-4 (151MW); Androscoggin Energy Center CT03 (51MW); Swanton Peaking Generation Project #10 (40MW); Algonquin Windsor Locks (38MW); Lowell Cogeneration #GEN1-2 (32MW); Capital District Energy Center STG (29MW); Waters River #1 (20MW); Pawtucket Power #1 (20MW); 15 smaller units totaling 33MW.
Super Peaking	$1.74	Devon 11-14 (161MW); Cleary Flood #9a (106MW).
Standard (Non-Peaking)	$0.00	All Remaining units.

Table IV-1. NMM Peaking Unit Fuel Price Adder Assumptions

C. Emission Prices

The NMM incorporates emission prices into the production cost and commitment/dispatch of units in the model. We incorporate prices for CO_2, NOx, and SO_2 into the NMM.

All New England states currently participate in Regional Greenhouse Gas Initiative (RGGI) program, a cap-and-trade program aimed at reducing CO_2 emissions from the power sector. Pricing carbon emissions affects New England electric energy prices by increasing the variable costs of fossil fuel-fired generators that are almost always on the margin. RGGI allowance prices have been minimal since the program began in 2009 because actual CO_2 emission levels have fallen well below the initial program caps. On February 7, 2013, the RGGI states announced their commitment to an Updated Model Rule that tightened caps significantly in 2014.

Daymark assumes that the New England states will continue to be subject to CO_2 emission prices through the study period, either through the RGGI program or a national CO_2 emissions program. Consistent with industry estimates, we assume a price for carbon emissions of $15/ton in 2022, escalating to $30/ton at the end of the study period in 2042 (values in 2016$).[5]

NOx and SO_2 emission prices are a relatively minor component of LMPs in New England because of the low emission rates of marginal generators (mostly gas units). We have assumed that NOx and SO_2 emission prices decline to $0 by 2020, the start of the study period.

[5] Source: Synapse Energy Economics, Inc. *Spring 2016 National Carbon Dioxide Price Forecast*. March 16, 2016. Available at: http://www.synapse-energy.com/sites/default/files/2016-Synapse-CO2-Price-Forecast-66-008.pdf

D. Retirements and Thermal Capacity Additions

Daymark's modeling analysis relies on assumptions of generator retirements and additions. These resource changes impact the efficiency of marginal units and can impact pricing, emissions, and net imports to the region, among other factors.

Our assumptions on retirements are based on known and forecasted retirements the ISO-NE market. The primary source of the known resource designations is the results of the ISO-NE Forward Capacity Auctions (FCA), the most recent of which (FCA11) determined capacity obligations for the 2020-2021 commitment period. In addition to these resources, further retirements and resource additions are based on results of analysis conducted with Daymark's ISO-NE FCM model.

Daymark's ISO-NE FCM model forecasts the economics of existing generators in New England, incorporating revenues from energy and capacity sales, and netting out resource costs including fuel, operation and maintenance (O&M), emission allowance costs, etc. The model determines relative economics of over 12,000 MW of generation in ISO-NE to determine the timing of resource retirements and construction of new plants.

Appendix C provides a full description of the FCM model methodology.

Figure IV-8 details the cumulative capacity additions and resource retirements assumed in the NMM.

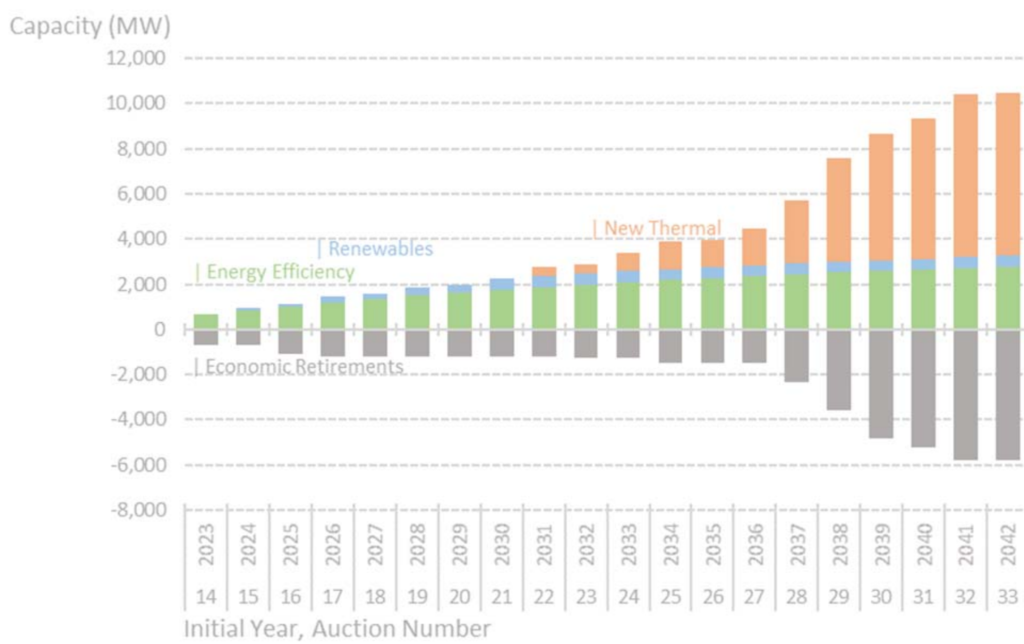

Figure IV-8. Cumulative Capacity Additions and Retirements

E. Renewable Additions

As noted above, our assumptions on renewable resources follow a "status quo" approach. Renewable projects modeled include:

- Existing and operational projects.
- Projects currently under construction.
- Projects with contracts resulting from the 2015-16 Clean Energy RFP issued by Massachusetts, Connecticut, and Rhode Island.
- New offshore wind assumed to be contracted as a results of Massachusetts Section 83C procurements.

With the exception of the offshore wind, we assume that all projects that fall under the preceding categories will be online at the start of the study period. Offshore wind is assumed to be added in 400 MW tranches every two years beginning in 2024. We also assume that all existing renewable projects will remain online through the end of the study period.

Distributed Solar Assumptions

The NMM includes a forecast of distributed, behind-the-meter solar. Our forecast is based on the ISO-NE distributed solar forecast, conducted as part of the annual load forecast and CELT report process.

The figure below summarizes our assumptions of distributed solar buildout by state.

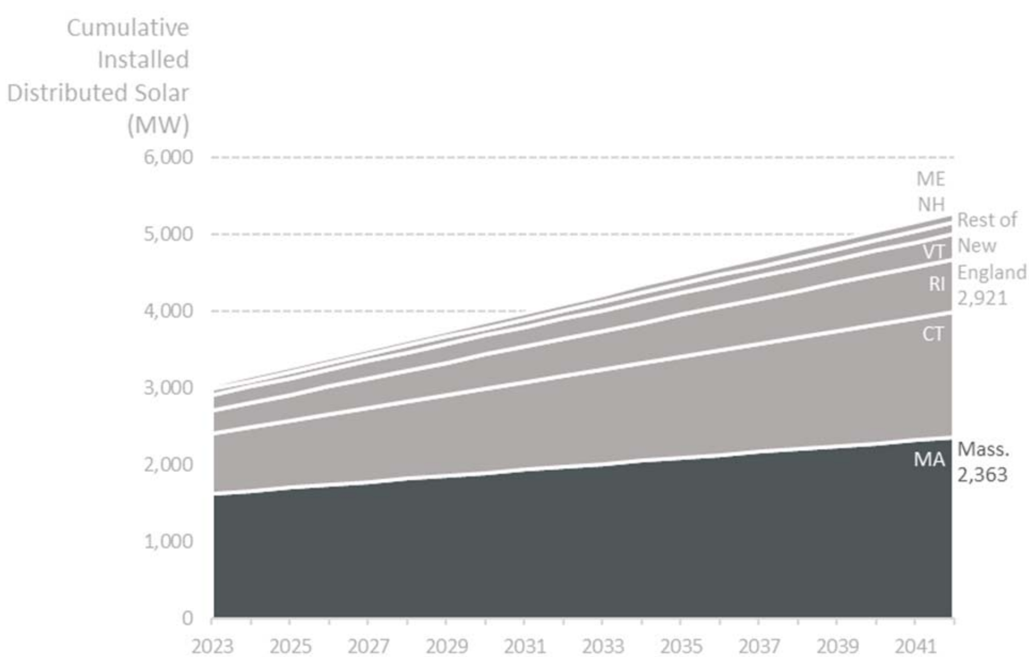

Figure IV-9. Distributed Solar Buildout (Cumulative MW)

DAYMARK ENERGY ADVISORS

APPENDIX B: RENEWABLE ENERGY CERTIFICATE MARKET ANALYSIS DETAILS AND METHODOLOGY

SEPTEMBER 27, 2017

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I. INTRODUCTION

Daymark Energy Advisors (Daymark) performed extensive benefits analysis in support of the New England Clean Energy Connect (NECEC) Project Bids. One component of our analysis is the mark-to-market analysis of the value of the renewable energy credits (RECs), as described in Section 2.3.1.1 of the RFP. Daymark's NECEC Project Benefits report (the "Daymark Report") provides a discussion of the results of our analysis. This appendix provides the details and analytical methodology supporting our analysis.

The two NECEC Project Bids (collectively "Bids", individually Bid 1 and Bid 2) are being offered as separate and exclusive offers of Clean Energy Generation, each to be delivered via the NECEC Transmission Project. Each Bid includes a combination of Clean Energy Generation and the NECEC Transmission Project. Bid 1 includes [redacted] megawatts (MW) of hydroelectric energy, offered at a [redacted] capacity factor, providing approximately 8,600 gigawatt hours (GWh) of energy. Bid 2 provides the same total quantity of clean energy, but instead of all hydro generation, it includes the output of [redacted] MW of new wind capacity, firmed up by the hydro to provide the same energy shape. The energy provided by the wind energy will generate approximately [redacted] million RECs that will be sold to the Distribution Companies at a fixed price.

Section II of this appendix provides an assessment and forecast of REC demand in New England. Section III provides Daymark's evaluation of existing and potential future REC supply in the region. Finally, Section IV of this appendix provides a review of historical pricing and describes Daymark's methodology for developing a REC price forecast.

II. NEW ENGLAND RENEWABLE ENERGY DEMAND FOR CLASS I RESOURCES

This section summarizes Daymark's forecast of demand for Premium Class I RECs in the New England region.

As used in this report, "Premium Class I RECs" refers to RECs eligible for compliance with Massachusetts (MA) Class I, Connecticut (CT) Class I, Rhode Island (RI) New, and New Hampshire (NH) Class I and II.[1] There are different eligibility requirements across each class and each state. Though some significant eligibility differences exist (particularly CT Class I), the markets sufficiently overlap to be thought of generally as a single market. While Maine and Vermont also have mandatory RPS standards, prices in these states are generally lower. Maine has made allowances for some existing biomass to qualify for Class I that does not qualify elsewhere, resulting in a significantly lower REC price than the other New England Class I markets. Vermont's new RPS is less stringent in its requirements than the other states as it has a low Alternative Compliance Payment (ACP) and allows large hydropower to fulfill requirements.

These premium REC classes generally contain more restrictions for eligibility and should carry higher prices due to the smaller pool of resource types that are eligible.[2] At the current time (and over the foreseeable future), Premium Class I RECs are the highest priced RECs in New England, but supply/demand dynamics for each of the REC classes ultimately determines prices. Not all classes permit participation by imported power as some classes require in-state locations (e.g., CT Class III) and have older vintage requirements (e.g., MA Class II) that reduce the applicability of the class to potential imports. Table II-1 summarizes the relevant definitions of the eligible resources for the premium classes, which are most relevant to import of certificates from outside of New England.

[1] Maine Class I was previously considered as a "premium" market but recent loosening of eligibility requirements has reduced the value of these RECs.

[2] Another factor is that the Alternative Compliance Payment, which is effectively a statutory or regulatory ceiling on prices for RECs, is generally set higher for Class I compared to other RPS classes.

RPS Class	Definition
CT Class 1[3]	Includes “energy derived from solar power, wind power, a fuel cell, methane gas from landfills, ocean thermal power, wave or tidal power, low emission advanced renewable energy conversion technologies, small (<5MW) run-of-the-river hydropower facility provided such facility has a generating capacity of not more than five megawatts, does not cause an appreciable change in the river flow, and began operation after July 1, 2003, or a sustainable biomass facility with an average emission rate of equal to or less than .075 pounds of nitrogen oxides per million BTU of heat input for the previous calendar quarter”
MA Class 1	New Renewable Generation Units are facilities that began commercial operation after 1997 and generate electricity using any of the following technologies: Solar photovoltaic, Solar thermal electric, Wind energy, Small hydropower, Landfill methane and anaerobic digester gas, Marine or hydrokinetic energy, Geothermal energy, Eligible biomass fuel
NH Class 1	Class I resources include generation facilities that began operation after January 1, 2006 and produce electricity from: wind energy; geothermal energy; hydrogen derived from biomass fuel or methane gas; ocean thermal, wave, current, or tidal energy; methane gas; or biomass Displacement of electricity by end-use customers from solar hot water heating systems, incremental new production from Class III and IV sources, and existing hydropower and biomass facilities that began operation as a new facility through capital investment also qualify as class I sources.
NH Class 2	Includes production of electricity from solar technologies, provided the source began operation after January 1, 2006.
RI New	Eligible renewable resources initially placed into commercial operation after December 31, 1997 that use direct solar radiation, wind, movement or the latent heat of the ocean, or the earth's heat; hydroelectric facilities up to 30 megawatts (MW) in capacity, Biomass facilities using eligible biomass fuels and maintaining compliance with current air permits (eligible biomass fuels may be co-fired with fossil fuels, provided that only the renewable-energy portion of production from multi-fuel facilities will be considered eligible), Fuel cells using renewable resources

Table II-1. Premium RPS Classes in New England (Definition Excerpts)

Compliance entities must purchase class-eligible RECs equivalent to a certain percentage of obligated load by a certain date each year. All four states allow some form of REC “banking”, enabling compliance entities to apply a limited number of surplus RECs from one compliance year toward future obligations. The table below summarizes the minimum percentage requirements by class and by year for the 2020-2035 time period and beyond.

3 CT Class 1 now has some allowance for large hydro to offset RPS requirements under certain conditions.

Year	CT Class 1	MA Class 1	NH Class 1	NH Class 2	RI New
2020	20.0%	15.0%	10.5%	0.3%	14.0%
2021	20.0%	16.0%	11.4%	0.3%	15.5%
2022	20.0%	17.0%	12.3%	0.3%	17.0%
2023	20.0%	18.0%	13.2%	0.3%	18.5%
2024	20.0%	19.0%	14.1%	0.3%	20.0%
2025	20.0%	20.0%	15.0%	0.3%	21.5%
2026	20.0%	21.0%	15.0%	0.3%	23.0%
2027	20.0%	22.0%	15.0%	0.3%	24.5%
2028	20.0%	23.0%	15.0%	0.3%	26.0%
2029	20.0%	24.0%	15.0%	0.3%	27.5%
2030	20.0%	25.0%	15.0%	0.3%	29.0%
2031	20.0%	26.0%	15.0%	0.3%	30.5%
2032	20.0%	27.0%	15.0%	0.3%	32.0%
2033	20.0%	28.0%	15.0%	0.3%	33.5%
2034	20.0%	29.0%	15.0%	0.3%	35.0%
2035	20.0%	30.0%+[4]	15.0%	0.3%	36.5%

Table II-2. Premium RPS Class Minimum Percentage Requirements, 2020-2035+

RPS policies in most states escalate annual until a certain target percentage is reached, with percentage requirements remaining static thereafter. By contrast, the Massachusetts RPS policy requires 15% renewable supply by 2020, and an additional 1% each following year, with no statutory end to the escalation. Figure II-1 shows the demand levels for the 2020-2035 period. Region-wide demand is expected to increase from 16 million RECs to almost 27 million Premium Class I RECs in 2035.

[4] After 2020, an additional 1% per year with no stated expiration date. Percentages include in-state solar carve-out.

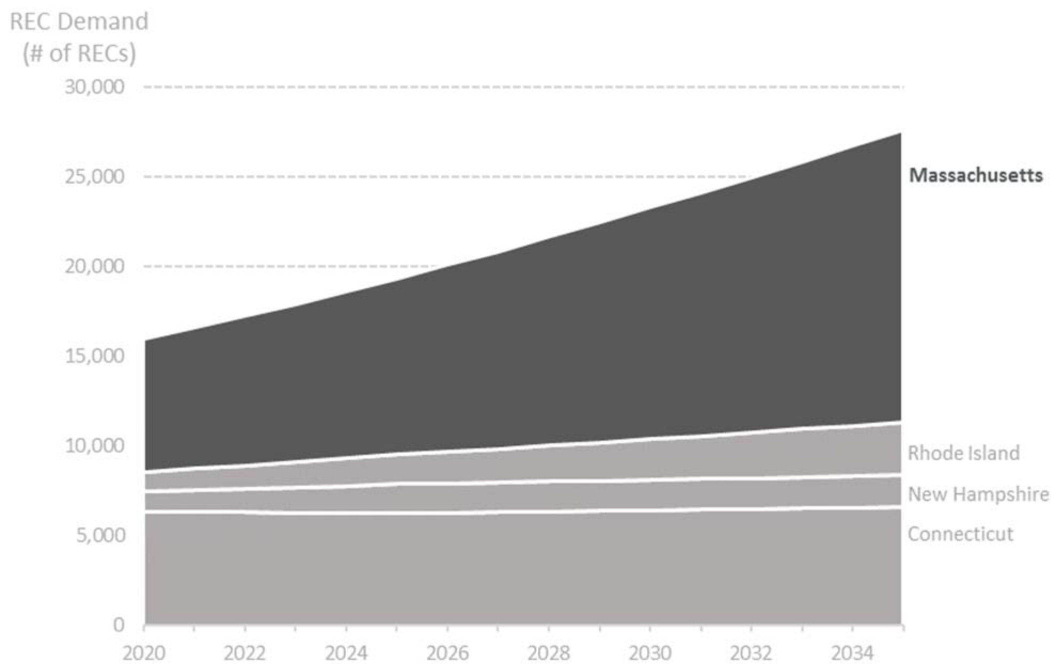

Figure II-1. Forecasted Premium Class I REC demand, 2020-2035

III. NEW ENGLAND REC SUPPLY

This section describes the existing and committed Premium Class I REC supply, the need for new supply to meet demand, and the potential impact of the NECEC project on that need.

A. Existing and Committed Premium Class I REC Supply

The New England Premium Class I REC supply includes RECs generated in New England and those generated in neighboring states or provinces that are delivered into the ISO-NE Control Area. Currently there are over 9 million Premium Class I RECs produced in New England annually and more than 2 million Premium Class I RECs imported from neighboring regions, which is approximately equal to the region's demand. Our baseline assumption is that solar installations in New England will continue over the study period at the rate predicted by ISO New England's 2016 solar forecast. We have also assumed that New York and Canadian renewable resources currently under contract to New England buyers will continue to provide Premium Class I RECs through the study period. Finally, we have also assumed that resources procured during the 2015-16 Three State Clean Energy RFP will be constructed and have included those resources in the baseline.

Figure III-1 below shows the gap between the baseline level of class I REC supply and demand in the region between 2020 and 2035. This shows a deficit of about 2,000 GWh of renewable energy in 2020 growing to about 9,000 GWh of renewable energy in 2035.

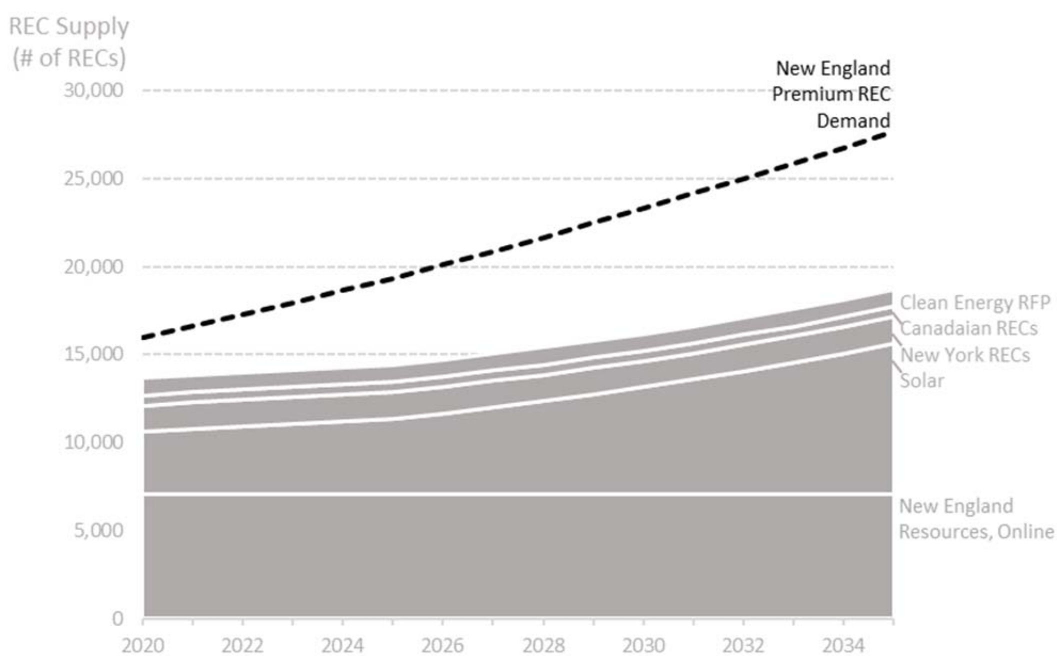

Figure III-1: Baseline REC Supply and Demand, 2020-2035

B. Potential Future Sources of Premium REC Supply

Beyond the baseline of projects currently online in New England and neighboring regions and forecasted solar, there are several categories of projects which could meet future growth in demand for Premium Class I RECs. These include:

- Additional imports from New York due to expiring NY REC contracts;
- Offshore wind projects procured by Massachusetts under Section 83C of the 2016 Energy Diversity Act; and
- Class I renewable energy procured by Massachusetts under Section 83D of the 2016 Energy Diversity Act.

We assessed the potential for RECs from each of the above categories individually and in combination. This analysis is described more fully below.

New York Imports

As part of the compliance with the New York RPS, the New York State Research and Development Authority (NYSERDA) conducted nine solicitations for renewable energy between 2005 and 2016. Each solicitation resulted in NYSERDA signing 10-year REC contracts with projects that will likely be in operation well beyond the contract period. As these contracts expire between 2016 and 2026, a significant potential new source of Premium Class I RECs for export from New York to New England may become available. The majority of the projects procured under the NYSERDA process would qualify for Premium Class I RECs in New England if they are successfully delivered to ISO New England and these would not meet the eligibility requirements for Tier 1 of New York's newly adopted Clean Energy Standard if they were online before January 1, 2015.[5] This means that there is a group of New York projects that could sell RECs to the New England market as their contracts with NYSERDA expire.

There is significant uncertainty regarding the likelihood of these Premium Class I RECs from New York resources entering the New England market. There is currently no path for these resources to continue to sell RECs to entities complying with the New York RPS, and some resources have already started selling RECs into New England. However, New York's aforementioned Clean Energy Standard has and aggressive target of a supply portfolio consisting of 50% renewable energy by 2030. It is possible that rules or regulations may be adopted to allow these older renewable projects to contribute to these goals, in which case they would not be able to sell Premium Class I RECs into New England.

Massachusetts 83C Offshore Wind

Section 83C of the Energy Diversity Act requires the distribution utilities in Massachusetts solicit proposals for 1,600 MW of offshore wind energy between 2017 and 2027. The first RFP was

[5] New York State Clean Energy Standard RES Tier 1 Certification: Application Instructions and Eligibility Guidelines, page 9. https://www.nyserda.ny.gov/All-Programs/Programs/Clean-Energy-Standard/Renewable-Generators-and-Developers/RES-Tier-One-Eligibility

issued on June 29, 2017[6] and states that the distribution utilities are looking to procure 400 MW of offshore wind energy, but would procure up to 800 MW if a larger project is likely to produce significantly greater benefits to ratepayers than a 400 MW project. For the purposes of future REC supply, we have assumed that 400 MW tranches of offshore wind will come online in 2024, 2026, 2028 and 2030.

Massachusetts 83D Clean Energy

The Section 83D RFP seeks bids for supplies of incremental Clean Energy, including resource eligible for Class I RECs. NECEC Bid 2 has the potential to contribute [redacted] million RECs to the regional market supply from the [redacted] MW of incremental wind capacity.

C. Summary of Premium Class I REC Supply and Demand

For this analysis, Daymark has assumed New England Premium Class I REC demand is met by a supply portfolio consisting of the baseline resources, new offshore wind under Section 83C, and New York resources described above. These resources are sufficient to meet regional RPS requirements in nearly all years, with a small shortage in the early years. The addition of the NECEC RECs reduces the need for NY RECs to comply with the RPS requirements. In this approach, the NECEC RECs represent the last Premium Class I RECs needed for the region to comply with RPS requirements. This approach is similar to the evaluation method used for the Three State Clean Energy RFP.

Figure III-2 below shows the New England Premium Class I REC supply and demand balance assumed for this analysis, including the 1.1 million Premium Class I RECs offered in NECEC Bid 2.

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6 https://macleanenergy.com/2017/06/29/section-83c-rfp-for-long-term-contracts-for-offshore-wind-energy-projects-issued/

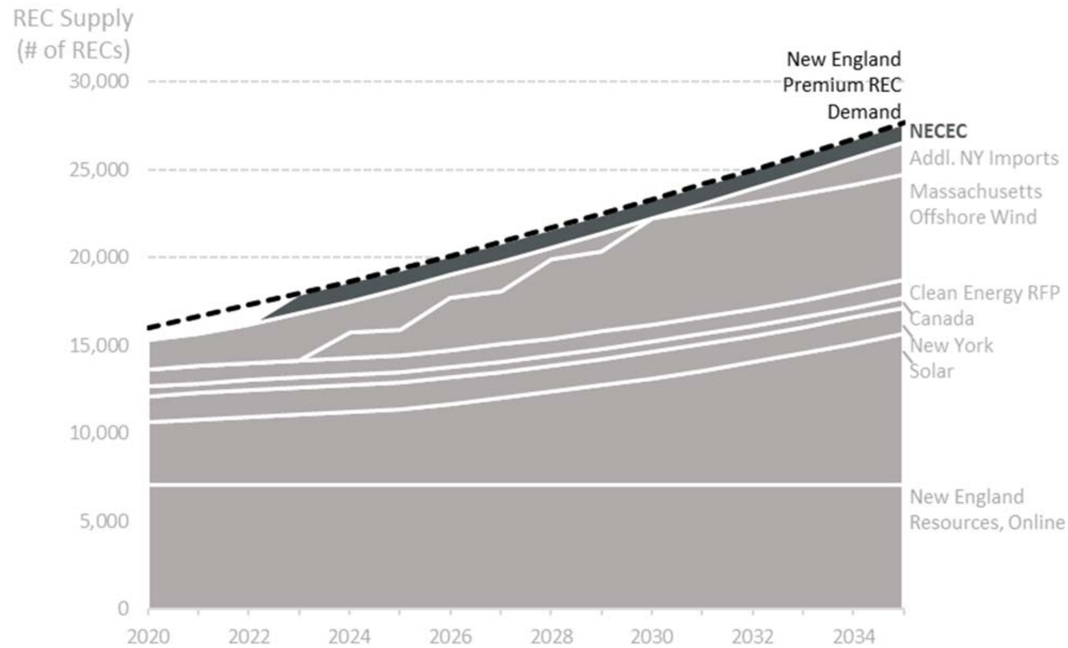

Figure III-2. New England Premium Class I REC Supply and Demand, with NECEC RECs

IV. REC PRICES

This section provides detail on market pricing for Premium Class I RECs and describes Daymark's methodology for determining prices used in the REC mark-to-market analysis in the Daymark Report.

The Premium Class I REC market is a bilateral market with trades generally occurring between two parties facilitated by a broker. Transactions on the bilateral market can be a onetime deal or longer term deals for RECs from a Class I facility. Pricing for these transactions is influenced by traditional market economics (supply and demand), as well as policy provisions, including the statutory ACP price.

A. Alternative Compliance Payments

ACPs provide a way for compliance entities to meet their requirement levels without the purchase of RECs and were instituted to provide a cap on the cost exposure of load-serving entities (LSEs) during shortage conditions. Use of ACP increases as conditions approach or are at shortage conditions. In most states, ACPs are set at a rate that increases with inflation; Connecticut is the exception, where the ACP is static at $55/MWh. Table IV-1shows ACP levels for 2017.

Premium RPS Class	2017
CT Class I	$55.00
MA Class I	$67.70
NH Class I	$56.02
NH Class II	$56.02
RI New	$67.71

Table IV-1. Premium RPS Class ACP rates ($/MWh)

B. Historical New England Short-Term Bilateral Market REC Prices

Historically the short term bilateral market REC prices in New England have hovered just below ACP in times of shortage and have dropped considerably below ACP in times of surplus. This is apparent in the graph of Massachusetts, Connecticut and Rhode Island Premium Class I REC prices included as Figure IV-1, below. REC prices were close to ACP in early 2008 and between 2011 and 2014 when there were shortages of RECs, and the price dropped as low as $12 per MWh between 2009 and 2010 when there was a surplus. Since the beginning of 2014, prices have trended lower, and currently the New England REC prices are between $20-$30/MWh.

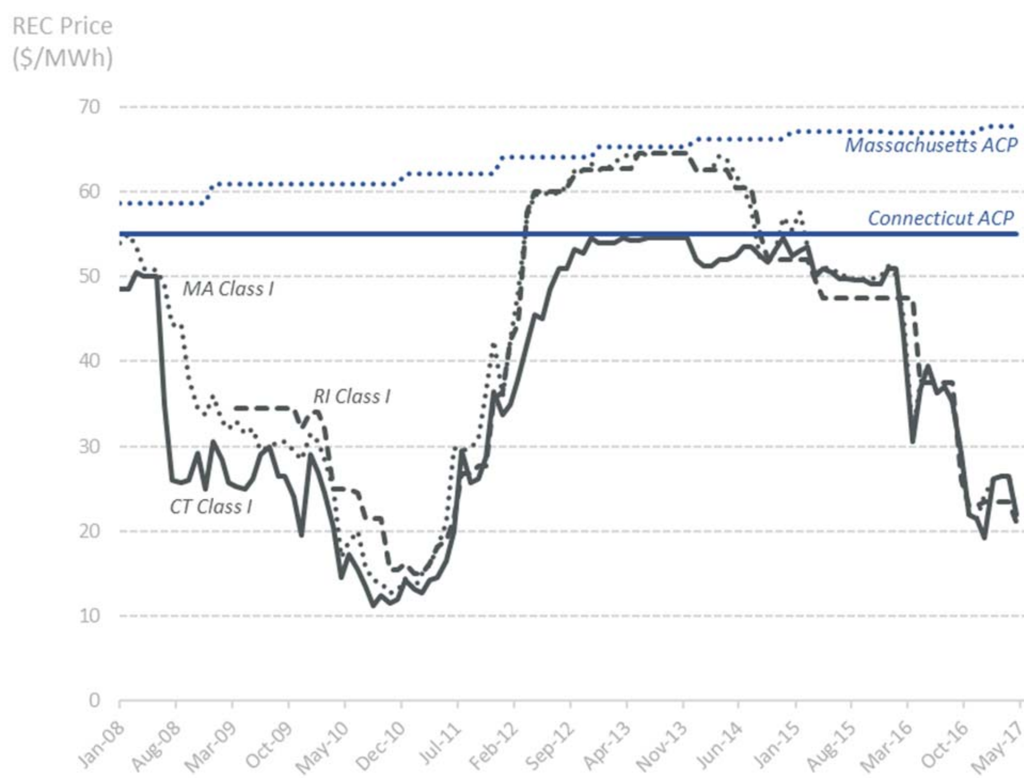

Figure IV-1: Historic Premium Class I REC Prices 2008-Present

C. Projected REC Prices During Study Period

The historical view of REC pricing in New England shows significant volatility over time. This volatility was generally caused by alternating periods of REC shortage and surplus. As the market matures, prices will tend towards a cost-based equilibrium price. In this future state, the REC market prices will reflect the revenue needed for a renewable project to be financially viable. Essentially, this will be the cost of the construction and ongoing operation of the project, net of the revenue the project will receive in the energy market.

Daymark developed a forecast of future REC market prices using this approach.[7] For the cost of the project, we used an estimate of levelized cost of energy (LCOE) for a new wind project published by the U.S. National Renewable Energy Lab (NREL).[8] This LCOE value is $73.20/MWh (2015$), assuming a cost premium for project in the northeast.

Using the results of Daymark's production cost modeling, we forecasted the energy revenue a wind project would receive. The difference between the LCOE and the energy revenue yield the forecasted cost-based REC price. The long-term decline in REC prices reflects the overall increase in energy revenue over time.

The resulting values are used in the REC mark-to-market analysis that is a component of the Direct Contract Benefits determination in Section V. of the Daymark Report.

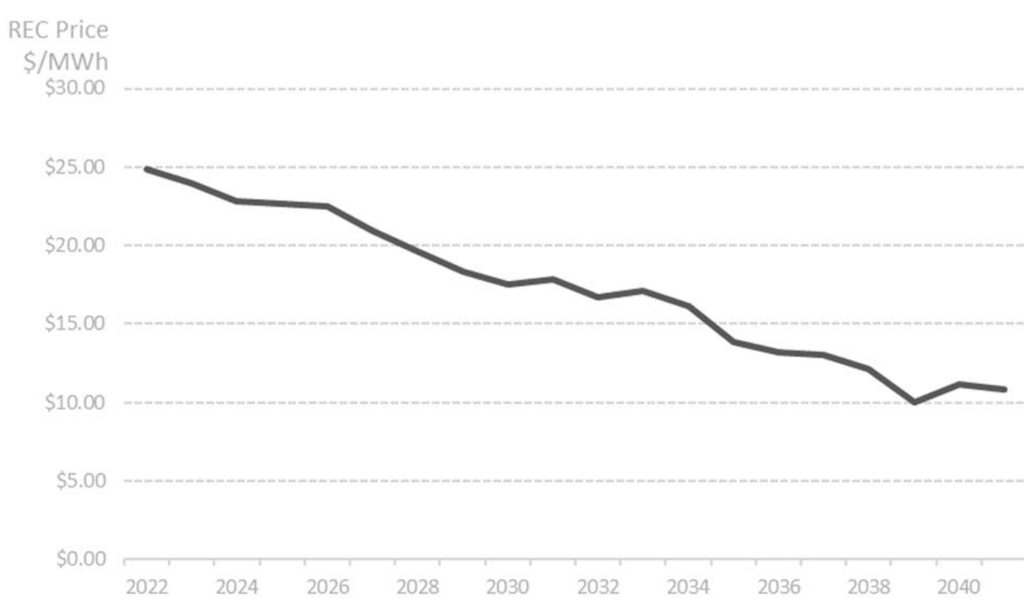

Figure IV-2. New England Premium REC price forecast

7 This approach is designed to mimic the approach used in the evaluation of the Three State Clean Energy RFP.

8 NREL. *2015 Cost of Wind Energy Review.* May 2017. http://www.nrel.gov/docs/fy17osti/66861.pdf

APPENDIX C: CAPACITY MARKET MODELING AND ANALYSIS

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I. INTRODUCTION

Daymark Energy Advisors performed comprehensive analysis of the benefits and potential impacts of the New England Clean Energy Connect Project Bids (NECEC Bids) on ISO-NE wholesale markets, including an evaluation of the potential impact of the NECEC Bids on the ISO-NE capacity market. Daymark's NECEC Project Benefits report (the "Daymark Report") provides a high-level discussion of the results of our analysis, and this appendix provides additional detail supporting the analysis.[1]

Section II of this appendix provides additional details on the relevant ISO-NE Forward Capacity Market (FCM) rules and procedures that pertain to the opportunities for the NECEC Project to participate in the market.

Section III of this appendix describes the modeling methodology used to prepare the capacity market analysis in the Daymark Report. Daymark has developed a proprietary capacity market model to simulate the ISO-NE Forward Capacity Auction (FCA) process and forecast the impact of various market conditions or new resources (such as NECEC) on FCA outcomes.

[1] See Section IV.E of the Daymark Report.

II. ISO-NE CAPACITY MARKET PROCEDURES

The NECEC Bids will provide a large source of clean, firm, low-cost capacity which will be eligible to be offered into the ISO-NE FCM. The NECEC Bids will be new capacity located outside the ISO-NE market that relies on an Elective Transmission Upgrade (ETU) to deliver capacity to New England, and are supported by long-term contracts for their energy output. The FCM rules have several special processes that apply to capacity resource offerings of this type and this section describes the FCM provisions that would apply to the NECEC Bids and the process of qualifying and clearing the capacity market.

A. Resource Qualification

The first key step for participation in the ISO-NE FCM is to qualify the resource capacity for the market. ISO-NE has established a multi-step qualification process. Each type of capacity resource (generation, demand or imports) has a distinctive qualification process designed to certify the reasonableness of the resource's availability at the beginning of the period and to determine the amount of qualified capacity it can supply after adhering to various ISO-NE requirements.

In 2015, ISO-NE updated it capacity market rules to incorporate the participation of ETUs. An ETU is generally comprised of a transmission element with interconnection points within the New England Control Area tied to one or more generation resources.

To qualify as an ETU, the entity that will provide capacity must demonstrate that there is either sufficient capacity across the entire exporting system or a dedicated resource to deliver capacity to New England up to the requested capacity supply obligation at any time throughout the year.

An ETU must also satisfy the reliability criteria mandated by the ISO-NE tariff. Schedule 25 of the ISO-NE Open Access Transmission Tariff describes the interconnection standards for ETUs: (i) the Network Capability Interconnection Standard (NCIS) and (ii) the Capacity Capability Interconnection Standard (CCIS). ISO-NE conducts transmission evaluation studies to assess compliance with each standard upon request from the owner of the facility. The studies for the NCIS – also known as Minimum Interconnection Standard – assess the impact to the New England Transmission system's reliability, stability, and operability from the construction of the ETU or ETU incremental upgrades. The studies for the CCIS assess the incremental impact of the new resource associated with an ETU on the New England Transmission system's reliability, stability, and operability under the assumption that all existing resources are operating without a need for redispatching and the capacity from this new resource is deliverable to the rest of the load zone. The results of these studies provide a list of network upgrades needed to meet the NCIS and/or the CCIS.

The NCIS is assessed in the Interconnection System Impact Study (SIS) while the CCIS is evaluated in the Capacity Network Resource Group Study (CNR Study). In order to participate in ISO-NE's FCM and eventually obtain a Capacity Supply Obligation, a facility must adhere to the CCIS in addition to meeting the NCIS requirements.

Once the resource and the ETU have been evaluated under the relevant standards and have demonstrated that the subject capacity is available to be delivered to New England, ISO-NE will qualify the import resource associated with an ETU.

B. Capacity Offer Pricing and Mitigation

As with all capacity bidding into the ISO-NE FCM, the import capacity associated with the ETU must submit an offer price for the capacity. After the completion of the qualification process, ISO-NE requires the submission of the ETU's capacity offer to be reviewed and possibly mitigated by ISO-NE's Internal Market Monitor (IMM). The purpose of the IMM's review is to prevent capacity from offering at uncompetitively low prices while being subsidized by out-of-market contracts.

All resources have specific offer price review thresholds set in the FCM rules that have been deemed as the lowest price resources can offer their capacity in without being reviewed by the IMM. These prices are called Offer Review Trigger Prices (ORTP). If a developer of a specific resource seeks to offer its capacity in the market at a price below the ORTP, it must provide documentation to the IMM that justify that action. The rules establish the highest ORTP price for resources associated with ETUs, effectively making all ETU price offers subject to review by the IMM. The table below provides the ORTP for different resources including those associated with ETUs for FCA 11:

Technology Type	**Offer Review Trigger Price ($/kW-mo)**
FCA 11 Starting Price: $18.624/kW-mo	
Combustion Turbine	$13.933
Combined Cycle Gas Turbine	$9.465
On-shore wind	$5.698
All other technology types	Starting price
Import associated with an ETU	Starting price + $0.01
Single new resource with a transmission investment to increase the import capability to New England	Based on generation technology type
Import capacity resource backed by a pool or an existing resource that is not associated with an increase in transmission	Starting price + $0.01

Table 1. FCA 11 Offer Review Trigger Prices

ETU project developers provide detailed net cost projections for both transmission and generation assets included in the proposed resource associated with the ETU and will be utilized in delivering the offered capacity. Some of the critical elements included in the offer are capital and other fixed costs of the transmission in both regions (if external) and the cost of any new generation capacity needed to support the transaction, both amortized over some reasonable time-period.

This net cost of providing capacity to New England is adjusted by the net energy revenues realized by the new or incremental transmission and generation. Based on the current methodology, the IMM calculates these revenues based on projected wholesale market prices for energy in New England minus any variable cost or opportunity cost for the entity to provide the energy in other regions. Under the existing ISO-NE process, any probable contract prices for clean energy attributes or energy delivered by the ETU if any, cannot be counted in place of the wholesale market price. One exception exists if the clean energy attributes available to the ETU are considered "broadly available" to other resources such as Renewable Energy Certificates (RECs). In that case, the IMM may consider these additional streams of revenues in place of the projected wholesale energy prices.

The last step in the capacity offer review process is translating the annual net cost from the previous step into a capacity supply offer in terms of cost per kW-month. This calculation includes the division by the number of kW-months the resource can be relied on to serve the New England power system.

When the IMM completes its review, it will set a minimum capacity offer price for the resource associated with the ETU. The developer can offer this resource at a price at or above the IMM minimum capacity offer price but not below.

C. Capacity Clearing Process

Once the resource associated with the ETU has qualified its capacity and has received an approved minimum capacity offer price, the resource can bid its capacity into the FCA. The resource only receives a capacity supply obligation if it clears, based on its offer price. Depending on the specific parameters of the capacity offers, the amount of MW cleared can be affected by whether this resource is the marginal resource in the FCA or not. If the resource only clears a portion of its capacity, it will only receive payments for the MWs cleared in the FCA and not for the entire qualified capacity.

Import resources associated with ETUs must bid in and clear the capacity market each year in order to receive an obligation.[2] This treatment is consistent with how ISO-NE treats other imports into New England from neighboring regions that do not have an executed long-term contract. In order for an import capacity resource associated with an ETU to maintain its Capacity Network Import Interconnection Service as described in the qualification section above, it must

[2] This differs from new conventional supply generators that are guaranteed to receive a locked-in capacity price for the first seven years after it first clears.

offer into each FCA. Otherwise, the qualified MWs may be adjusted by the ISO depending on activity by other bidders in the market.[3]

D. Capacity Market Uncertainty

Daymark conducted its analysis on the participation in and impact of the NECEC Bids on the ISO-NE FCM based on the best information currently available regarding the market rules. However, there are a number of key uncertainties about the future operation of the market that could significantly impact this analysis, with two examples of such uncertainties described below.

First, FCA results are fundamentally the result of discrete decisions by individual market actors. Perceptions of market opportunity and risk can impact bidding behavior and determine future market results. For example, the new Pay for Performance rules impose penalties on cleared capacity resources that fail to perform when called. The implementation of these rules introduces new risk to resources participating in the market, particularly older resources that may not be as reliable. This has the potential to affect market behavior in the future in ways not fully captured in this analysis.

Second, in an effort to address the participation of renewable resources in the FCM, ISO-NE has recently proposed a modification to the FCM to add a secondary auction, called a "substitution auction". The point of this auction would be to allow new renewable resources, which may be subsidized under a policy mechanism such as the Production Tax Credit, to receive a capacity supply obligation transferred from an existing resource that wishes to retire. The substitution auction would determine the price paid to the renewable resource for its capacity. A rule change such as this could impact the market in various ways, but one result could be that older resources may be more inclined to retire if they can transfer their obligation for less than the clearing price and retain a portion of the capacity revenue.

[3] Section III.13.1.3. Import Capacity of ISO-NE Market Rule 1

III. DAYMARK CAPACITY MARKET MODELING

Using a proprietary simulation model, Daymark has evaluated future expectations for the New England capacity position, with and without the NECEC in service. This modeling and analysis contributed to Daymark's evaluation in two ways: First, the capacity market modeling generates the capacity buildout and retirement schedule for the production cost modeling described in Appendix A; and second, the Daymark model is used to calculate the indirect impact of the project on the capacity market.[4]

This section of the appendix describes the model's operation and key assumptions.

A. Model Overview

The Daymark ISO-NE FCM model simulates the annual FCAs that ensure sufficient capacity is available to meet peak demand in the region. The model uses inputs reflecting resource economics for new additions and existing generation units to determine the timing and quantity of new additions and retirements in the market, incorporating several additional factors which reflect actual components of the market, such as capacity imports, energy efficiency, and renewables.

The model uses the ISO-NE demand curve to determine the market clearing price for each auction, which in turn determines the retirements and buildout. As the auctions progress through the study period, clearing prices impact the economics of existing units, and when going-forward costs exceed the capacity revenue, a resource may be retired. The loss of that capacity has a consequent impact on the clearing price. When the clearing price is sufficient to attract new entrants to the market, additional capacity is added, again impacting the FCA clearing price.

The result of the model is a schedule of retirements of existing resources and additions of new generic capacity in the region, as well as the annual FCA clearing prices.

The Section B below provides additional detail on the key elements of the model.

B. Key Components

Net Installed Capacity Requirement

The key component of the model on the demand side is ISO-NE's reliability requirement for capacity, known as the Net Installed Capacity Requirement (NICR). NICR is fundamentally a forecast of peak system load, plus an additional reserve margin. For FCA 11 (delivery in June 2020 through May 2021), ISO-NE established an NICR of 34,075 MW, which results in a 15% reserve margin above the 29,600 MW projected summer peak load for 2020, net of behind-the-

[4] See the Daymark Report, Section IV.E.

meter solar photovoltaics. For subsequent years, we estimate the NICR based on the ISO-NE's peak load forecast, assuming approximately the same reserve margin (15%) found in FCA 11. The resulting NICR grows by an average of 320 MW per year from 34,075 MW in 2020 (FCA 11) to 37,280 MW in 2030 (FCA 21).

Existing Cleared Capacity

As a starting point for FCA 12, the model uses the cleared FCA 11 capacity quantities, both on an aggregate system-wide basis, and for individual resources. The total cleared capacity in FCA 11 was 35,835 MW, including in-region capacity as well as imports. The actual qualified capacity for an individual resource can change year-to-year according to the resource's reliability performance (based on forced outage history) and the resource owner's designation of offered capacity. These changes can impact the overall capacity supply in the region and therefore impact clearing prices, timing of retirements, new capacity build, etc. However, since these changes are based on actual unit operation and bidding decisions, we have not attempted to forecast such changes and instead assume that the qualified and offered capacity of existing units remains the same as FCA 11.

New Energy Efficiency and Renewable Capacity

New energy efficiency (EE) and renewable capacity are eligible to participate in the FCM and receive CSOs, and have been significant sources of new supply in recent auctions.

The development of these resources and their participation in the FCM is dependent on dynamics that are distinct from the supply and demand curves that generally determine how conventional resources participate in the market. Therefore, rather than incorporate these resources in the annual market-clearing process, we have treated these resources separately in our model.

For EE, we have assumed that the existing capacity quantity cleared in FCA 11 persists, and that new EE capacity clears the FCAs in quantities based on the ISO-NE EE forecast prepared as part of the 2016 CELT report. The ISO-NE forecast extends through 2026, with new incremental EE declining each year. We have assumed a continuation of the forecasted trajectory.

Renewable capacity has some additional requirements for qualifying and clearing in the FCA due to its intermittency and any subsidies received (such as the Production Tax Credit). In addition, ISO-NE has proposed changes to the FCM to implement a secondary auction for subsidized resources that may impact the participation of renewables in the market going forward. As a result, there is significant uncertainty regarding the participation of renewables in the FCM.

For this analysis, we have assumed that new renewable capacity associated with the offshore wind projects procured under Section 83C will clear the market. We have assumed a 30% capacity credit for this capacity.

Imports

Capacity from regions interconnected with ISO-NE, including Quebec, New Brunswick, and New York, is eligible to participate in the FCM and receive CSOs, subject to certain rules and processes. In FCA 11, the following imports cleared the market.

External Interface	Capacity Supply Obligation
New York AC Ties	539.4 MW
New Brunswick	200 MW
Phase I/II HQ Express	441 MW
Hydro-Quebec Highgate	55 MW

Table 2. FCA 11 Cleared Import Capacity

Our model uses a supply curve of imports reflecting recent FCA results, such that the amount of imports increases with the clearing price.

Net Cost of New Entry (CONE)

The key assumption determining the timing and quantity of new capacity additions is the Net CONE. This price represents the estimated capacity revenue that would be needed for a new resource to be economically viable in the ISO-NE market, calculated as the cost to develop and construct the resource, plus ongoing operating expenses, minus energy market revenues. In Daymark's model, it is the price that is compared to the clearing price to signify when it is economic to build new capacity.

ISO-NE periodically conducts a study to calculate the Net CONE for various types of new resources. The most recent study, completed in January 2017, determined that for FCA 12, the Net CONE of a new combined cycle would be $10.00/kW-mo and the Net CONE for a combustion turbine would be $8.04/kW-mo. This is an administratively-determined price that is used to define the points of the demand curve and create the starting price.

The ISO estimates reflect generic assumptions and forecasts of costs and revenues, and generally does not reflect actual bids from market entrants. In fact, several new resources cleared the market in FCA 10, when the clearing price was just over $7.00/kW-mo. This indicates that new generation projects are viable when clearing prices are lower than the ISO-NE Net CONE value.

For the purposes of our modeling, Daymark assumed an annual Net CONE value for new resources equal to the $7.00/kW-mo value, escalated at inflation over time. Therefore, the model will clear new capacity when the clearing price exceeds Net CONE.

Demand Curve

The ISO-NE FCM demand curve determines the clearing price at various capacity levels. In recent years, ISO-NE has modified its demand curve multiple times in attempts to better reflect the value of increased reliability resulting from additional procured capacity.

Most recently, in 2016, ISO-NE revised how it constructs the demand curve from a downward-sloping straight line, to a Marginal Reliability Impact (MRI) curve that is convex to the origin and generally shifted to the left (lower price at the same capacity level). Daymark's model incorporates this new MRI curve into the auction simulation.

Resources at Risk of Retirement

Daymark's capacity model evaluates the going-forward cost and potential retirement of 86 existing generators in New England with a total qualified capacity of more than 12,000 MW. Daymark identified the list of units to be evaluated by filtering out units by age, resource type, and primary fuel.

After defining the list of resources that would be evaluated in the model, Daymark created annual going-forward cost (or "delist bid") estimates representing the revenue needed by the resource to be economically viable. This delist bid is constructed using annual net energy revenue (energy revenue net of all variable costs of generation) forecasts from our production cost modeling, and forecasts of fixed O&M expense for each resource.

C. Simulation Process

The key assumptions and components outlined in the previous section provide the basis for the model simulations. The Daymark FCM model dynamically generates annual FCA clearing prices incorporating these various influencing factors.

For each annual auction simulated, the model incorporates resource retirements when delist bids exceed clearing prices, new resource additions when the clearing price exceeds Net CONE, and changes in imports based on the import supply curve described above. Since each of these changes in cleared capacity also impact the clearing price, the process dynamically determines the appropriate capacity changes for each auction.

Once the final schedule of retirements and buildout is determined, the final stage is to allocate the new capacity buildout by type (CC or CT) and location. This process incorporates zone-specific conditions, such as load growth and cumulative capacity resource retirements throughout the study period, to determine the most appropriate location for the buildout. The type of capacity addition is similarly determined based on market conditions (primarily energy price) such that when energy prices are high, more CCs are built, and when prices are low, more CTs are added.

DAYMARK
ENERGY ADVISORS

APPENDIX D: RESUMES

SEPTEMBER 27, 2017

I. DANIEAL E. PEACO

DAYMARK
ENERGY ADVISORS

Daniel E. Peaco

Principal Consultant

SUMMARY

Daniel Peaco is a Principal Consultant, Chairman, and Past-President at Daymark Energy Advisors, a leading provider of integrated policy, planning and strategic decision support services to the North American electric and natural gas industries.

Mr. Peaco has 35 years of experience in the electric industry, both as a utility planning practitioner and, for the past 20 years, as a consultant to the industry. His consulting practice has included engagements relating to strategic planning, competitive electric markets, integrated resource planning evaluation of generation asset investments, renewable energy policy, transmission planning, competitive procurement and power contracts, and industry restructuring.

Prior to joining Daymark Energy Advisors, he held management and planning positions in power supply planning at Central Maine Power, CMP International Consultants, Pacific Gas & Electric, and the Massachusetts Energy Facilities Siting Council. He holds degrees from M.I.T. and Dartmouth College.

EMPLOYMENT HISTORY

Daymark Energy Advisors, Inc.	*Boston, MA*
Chairman	Aug 2015-current
President	2002-July 2015
Managing Director	*1996-2002*
Central Maine Power Company	*Augusta, ME*
Manager, Industrial Marketing and Economic Development	1995-96
Principal, CMP International Consultants	*1993-95*
Director, Power Supply Planning	1987-93
Power Supply Planning Analyst	1986-87
Pacific Gas & Electric Company	*San Francisco, CA*
Power Supply Planning, Hydropower Planning, Cogeneration Contracts	1981-86
Massachusetts Energy Facilities Siting Council	Boston, MA
Planning Engineer	*1978-79*

EDUCATION

Thayer School of Engineering, Dartmouth College	*Hanover, NH*
M.S. in Engineering Sciences, Resource Systems and Policy Design	1981
Massachusetts Institute of Technology	*Cambridge, MA*
B.S. in Civil Engineering, Water Resource Systems	1977

PUBLICATIONS, PRESENTATIONS & CONFERENCES

MCPC Project Benefits; Quantitative and Qualitative Benefits, Confidential Report prepared for Central Maine Power regarding the benefits of the Maine Clean Power Connection, a 345 kV transmission expansion accompanied by 1100 MW of wind energy project development offered in the Massachusetts RFP for Clean Energy Resources, July 27, 2017. Lead Consultant and Principal Author.

NECEC Project Benefits; Quantitative and Qualitative Benefits, Confidential Report prepared for Central Maine Power and H.Q. Energy Services regarding the benefits of the New England Clean Energy Connection, 1200 MW HVDC transmission expansion accompanied by 1090 MW of hydropower and wind energy project development offered in the Massachusetts RFP for Clean Energy Resources, July 27, 2017. Lead Consultant and Principal Author.

Evolving Practices in Electric Company Resource Planning: Key Insights from a Review of 15 Recent Electric Company Resource Plans, report prepared for the Electric Power Research Institute. May 2017. Lead Consultant and Principal Author.

Clean Energy Procurement Mechanisms, instructor for Post-Conference Workshop at the EUCI 3rd Annual U.S./Canada Cross-Border Energy Trade Summit, Boston, Massachusetts, March 2, 2017.

CHP Economic Factors: Electric and Natural Gas Market Trends, keynote presentation for the Efficiency Maine Combined Heat & Power Conference, Portland, Maine, September 29, 2016.

Changes in IRP in Market Transitions, Where Has It Happened?, presentation to the EUCI 16th Annual Integrated Resource Planning Conference, Long Beach, March 22, 2016.

MREI Project Benefits; Direct, Indirect, Qualitative and Other Benefits, prepared for Central Maine Power Company and Emera Maine regarding the benefits of the Maine Renewable Energy Initiative, a 345 kV transmission expansion accompanied by 1200 MW of wind energy project development. January 28, 2016. Lead Consultant and Principal Author.

MCPC Project Benefits; Direct, Indirect, Qualitative and Other Benefits, prepared for Central Maine Power Company regarding the benefits of the Maine Clean Power Connection, a 345 kV transmission expansion accompanied by nearly 600 MW of wind energy project development. January 28, 2016. Lead Consultant and Principal Author.

Independent Valuation Opinion for the Bellows Falls Station in the Town of Rockingham, VT, prepared for the TransCanada Hydro regarding the value of a 49 MW hydropower asset. July 2013 (Updated April 2015). Lead Consultant and Principal Author.

Review of Georgia Power Company Solar Projects at Forts Benning, Stewart, and Gordon, Report for the Georgia Public Service Commission. October 14, 2014. Lead Consultant and Principal Author.

Maine Power Connection: Analysis of Benefits in Maine and New England, Report for Central Maine Power. September 5, 2014. Lead Consultant and Principal Author.

Need For and Alternative To (NFAT) Review of Manitoba Hydro's Proposal for the Keeyask and Conawapa Generating Stations, Initial Expert Analysis Report prepared for the Manitoba Public Utilities Board. January 24, 2014. Supplemental Report. February 28, 2014. Lead Consultant and Principal Author.

Evaluation of the Transaction to Transfer the Entergy Corp. Transmission Business to ITC Holdings, Inc., Initial Report prepared for the General Staff of the Arkansas Public Service Commission. April 19, 2013. Lead Consultant and Principal Author.

Regarding Tri-State G&T's Cost to Serve Its Nebraska Loads and the Nebraska Power Supply Issues Group Loads, prepared for the Nebraska Power Supply Issues Group, two public power districts and two member-owned electric utilities in Western Nebraska. December 2012. Lead Consultant and Principal Author.

Independent Valuation Opinion for the Vernon Station in the Town of Hinsdale, NH, prepared for the TransCanada Hydro regarding the value of a 32 MW hydropower asset. November 2012. Lead Consultant and Principal Author.

Independent Valuation Opinion for the Comerford and McIndoes Stations in the Town of Monroe, NH, prepared for the TransCanada Hydro regarding the value of 179 MW hydropower assets. November 2012. Lead Consultant and Principal Author.

Independent Opinion Regarding the Market Value of Brassua Hydro LP Assets, prepared for the Owners of Brassua Dam regarding the value of a 4 MW hydropower asset. November 2012. Lead Consultant and Principal Author.

Independent Opinion Regarding Amortization Reserve of Brassua Hydro LP, prepared for the Owners of Brassua Dam regarding the amortization reserve value of a 4 MW hydropower asset. November 2012. Lead Consultant and Principal Author.

Regional Framework for Non-Transmission Alternatives, Report prepared for the New England States Committee on Electricity. October 2012. Lead Consultant and Principal Author.

Renewable Energy and Energy Efficiency Portfolio Standards(REPS) And Sustainable Energy in North Carolina, Lessons from the 2011 Energy Policy Committee Study, presentation to the 9th Annual Sustainable Energy Conference, Raleigh, North Carolina April 20, 2012.

Transmission Planning for the Next Generation, Some Implications for Generators in the New England Region of FERC Order 1000, presentation to the Connecticut Power and Energy Society's Energy, Environment, and Economic Development Conference, Cromwell, Connecticut March 14, 2012.

Entergy Arkansas, Inc.'s Withdrawal from the Entergy System Agreement, Response to EAI's Analysis of All Strategic Options, Supplemental Initial Report prepared for the General Staff of the Arkansas Public Service Commission. July 12, 2011. Lead Consultant and Principal Author.

North Carolina's Renewable Energy Policy, A Look at REPS Compliance To Date, Resource Options for Future Compliance, and Strategies to Advance Core Objectives, prepared for the North Carolina Energy Policy Council. June 2011. Lead Consultant and Co-Author.

Energy Policy Implementation, Framework Overview: Paying for the Policies, presentation to the NECA/CPES 18th Annual New England Energy Conference, Groton, Connecticut, May 18, 2011.

Entergy Arkansas, Inc.'s Withdrawal from the Entergy System Agreement, Initial Report prepared for the General Staff of the Arkansas Public Service Commission. February 11, 2011. Lead Consultant and Principal Author.

Non-Transmission Alternatives Assessment for the Lewiston-Auburn Area, Report for Central Maine Power. August 27, 2010. Co-Author.

Emerging Regional Energy Issues, How RPS Requirements will Affect Vermont's Energy Future, presentation to the Vermont's Renewable Energy Future Conference, Burlington, Vermont October 1, 2010.

2010 Comprehensive Plan for the Procurement of Energy Resources, Report prepared for the Connecticut Energy Advisory Board. April 27, 2010. Lead Consultant and Principal Author.

Phase I Report: Assessment of Energy Supply Options for the Town of Millinocket, report to the Town of Millinocket, Maine. December 18, 2009. Lead Consultant and Principal Author.

2009 Comprehensive Plan for the Procurement of Energy Resources, Report prepared for the Connecticut Energy Advisory Board. May 1, 2009. Lead Consultant and Principal Author.

Evaluation of the Grid Solar Proposal, Review of the Economics of the Proposal as an Alternative to the Maine Power Reliability Program, Report prepared for Central Maine Power. April 3, 2009. Lead Consultant and Principal Author.

An Analysis of the Connecticut Light and Power Company's Proposed Greater Springfield Reliability Project and Manchester to Meekville Project and the Non-Transmission Project Proposed as Alternatives, Report prepared for the Connecticut Energy Advisory Board. February 17, 2009. Lead Consultant and Principal Author.

Preparing A State-Centric IRP in a Multi-State Power Market, presentation to the EUCI Conference on Resource and Supply Planning, Scottsdale, Arizona, February 11, 2009.

Resource Considerations of Transmission Planning, half-day workshop presented to the EUCI Conference on Resource and Supply Planning, Scottsdale, Arizona, February 11, 2009.

2008 Comprehensive Plan for the Procurement of Energy Resources, Report prepared for the Connecticut Energy Advisory Board. August 1, 2008. Lead Consultant and Principal Author.

Maine Power Reliability Project: Non-Transmission Alternatives Assessment and Economic Evaluation, Report for Central Maine Power. June 30, 2008. Lead Consultant and Principal Author.

Maine Power Connection: Locational Marginal Price and Production Cost Implications in Maine and New England, Report for Central Maine Power and Maine Public Service Company. June 30, 2008. Lead Consultant and Principal Author.

Impact of Aroostook Wind Energy on New England Renewable Energy Certificate Market, Report for Horizon Wind Energy. June 25, 2008. Lead Consultant.

Initial Review of Integrated Resource Plan for Connecticut, Report for the Connecticut Energy Advisory Board. January 28, 2008. Lead Consultant and Principal Author.

Connecticut's Long-Term Electric Capacity Requirements, Report of the Connecticut Energy Advisory Board. April 7, 2006. Lead Consultant and Principal Author.

Technical Audit – Phase III: Review of Increase in Fuel Component of Power Budget FY 2007 relative to FY 2006, prepared for the New Brunswick Power Distribution and Customer Service Corp., October 5, 2005. Lead Consultant and Principal Author.

Preliminary Assessment of Connecticut's Electric Supply and Demand: Near Term Requirements for Reliability and Mitigation of Federally Mandated Congestion Charges, The Connecticut Energy Advisory Board. September 2, 2005. Lead Consultant and Principal Author.

Technical Audit – Phase II: Review of Increase in Fuel Component of Power Budget FY 2006 relative to FY 2005, prepared for the New Brunswick Power Distribution and Customer Service Corp., July 7, 2005. Lead Consultant and Principal Author.

Technical Audit: Purchased Power Budget April 2005 – March 2006, prepared for the New Brunswick Power Distribution and Customer Service Corp., May 18, 2005. Lead Consultant and Principal Author.

Retail Choice Study: Issues and Options for Electric Generation Service, the Belmont Electricity Supply Study Committee, Belmont, Massachusetts. June 2, 2004. Lead Consultant and Principal Author.

California Energy Markets: The State's Position Has Improved, Due to Efforts by the Department of Water Resources and Other Factors, but Cost Issues and Legal Challenges Continue, California Bureau of State Audits, April 2, 2003. Lead Consultant and a Principal Author.

California Energy Markets: Pressures Have Eased, but Cost Risks Remain, California Bureau of State Audits, December 21, 2001. Lead Consultant and a Principal Author.

Development of Competition in Electric Markets and the Impact on Retail Consumers in Arkansas, Arkansas General Staff's Report, In The Matter of a Progress Report to the Arkansas General Assembly on the Development of Competition in Electric Markets and the Impact, if any, on Retail Consumers, Docket No. 00-190-U, September 4, 2001. Principal Author.

Preliminary Market Value Assessment of PP&L Maine Hydroelectric Plants, August 2001. Proprietary report prepared for American Rivers, the Atlantic Salmon Federation, the Natural Resources Council of Maine, the Penobscot Indian Nation, and Trout Unlimited. Principal Author.

Development of Competition in Electric Markets and the Impact on Retail Consumers in Arkansas, Arkansas General Staff's Report, In The Matter of a Progress Report to the Arkansas General Assembly on the Development of Competition in Electric Markets and the Impact, if any, on Retail Consumers, Docket No. 00-190-U, September 29, 2000. Principal Author.

Wholesale Market Development: Timing and Issues Survey of Activity in Other Regions, FERC Initiatives, In The Matter of a Progress Report to the Arkansas General Assembly on the Development of Competition in Electric Markets and the Impact, if any, on Retail Consumers, Docket No. 00-190-U, September 29, 2000. Principal Author.

Retail Market Development: Timing and Issues Survey of Other States, In The Matter of a Progress Report to the Arkansas General Assembly on the Development of Competition in Electric Markets and the Impact, if any, on Retail Consumers, Docket No. 00-190-U, September 29, 2000. Principal Author.

The Progression toward Retail Competition in Arkansas' Neighboring States, In The Matter of a Progress Report to the Arkansas General Assembly on the Development of Competition in Electric Markets and the Impact, if any, on Retail Consumers, Docket No. 00-190-U, September 29, 2000. Principal Author.

Arkansas General Staff Proposal and Initial Comments, In The Matter of a Generic Proceeding to Establish Uniform Policies and Guidelines for a Standard Service Package, Docket No. 00-148-R, June 13, 2000. Principal Author.

Arkansas General Staff Initial Comments, In The Matter of a Generic Proceeding to Determine if Metering, Billing, and Other Services Are Competitive Services, Docket No. 00-054-U, March 31, 2000. Principal Author.

Arkansas General Staff Initial Comment and Proposed Market Power Analysis Minimum Filing Requirements, In The Matter of a Generic Proceeding to Establish Filing Requirements and Guidelines Applicable to Market Power Analyses, Docket No. 00-048-R, March 28, 2000. Contributing Author.

Vermont Electricity Prices: Regional Competitiveness Outlook; Implications of Restructuring in New England and New York, February 2000 Edition, prepared for Central Vermont Public Service. Principal Author.

Projected Retail Price of Electricity for Massachusetts Electric Company, Boston Edison Company, and Western Massachusetts Electric Company, September 1999, prepared for Massachusetts Municipal Wholesale Electric Company. Principal Author.

Comments of the Commonwealth of Massachusetts Division of Energy Resources, in the Investigation by the Department of Telecommunication and Energy into Pricing and Procurement of Default Service, July 1999 (Initial and Reply Comments). Contributing Author.

Need for Power Supply: The New England Power Pool and the State of Rhode Island, March 1999, prepared for Indeck – North Smithfield Energy Center.

Vermont Electricity Prices: Regional Competitiveness Outlook; Implications of Restructuring in Northeast States, a Report to the Working Group on Vermont's Electricity Future, November 1998, prepared for Central Vermont Public Service. Principal Author.

EXPERT TESTIMONY

Public Service Commission of Utah Docket No. 17-035-39	Division of Public Utilities Department of Commerce	Expert testimony regarding PacifiCorp's application for pre-approval of its proposed repowering of 999 MW of existing wind turbines, including issues regarding PTC qualification, economic benefits analysis, and project risks. Preflied Testimony — September 20, 2017
Superior Court Windham Unit State of Vermont	TransCanada Hydro Northeast, Inc.	Expert testimony regarding the headwater benefits value of Moore Station, a 190 MW hydropower facility in appeal of appraised value in the Town of Waterford, Vermont. Valuation Report — November 11, 2016 Deposition testimony — December 13, 2016
Superior Court Windham Unit State of Vermont Docket No. 413-9-13 Wmcv	TransCanada Hydro Northeast, Inc.	Expert testimony regarding the valuation of a Harriman Station, a hydropower facility (39 MW) in appeal of appraised values in the town of Whitingham, VT. Valuation Report — September 19, 2016 Deposition — November, 2016
Massachusetts Energy Facilities Siting Board Docket No. EFSB 15-06	NRG Energy NRG Canal 3 Development LLC	Testimony regarding NRG's application for siting approval of a proposed 350 MW duel-fueled combustion turbine. Testimony addressed alternative technology assessment and consistency with energy and environmental policies of the Commonwealth, considering reliability, regional fuel diversity, global warming solutions policy, and renewable energy integration. Direct Testimony — December 2, 2015 Pre-filed Testimony — April 4, 2016 Oral Testimony — September 9 & 14, 2016
Georgia Public Service Commission Docket No. 40161	Georgia Public Service Commission Public Interest Advocacy Staff	Witness sponsoring testimony regarding integrated resource planning methods, renewable energy economics and policy, fuel diversity considerations in resource planning. Written Testimony — May 6, 2016 Oral Testimony — May 18, 2016
Superior Court Windham Unit State of Vermont Docket No. 470-10-13 Wmcv	TransCanada Hydro Northeast, Inc.	Expert testimony regarding the headwater benefits value of the Somerset Reservoir in the Deerfield River. Headwater benefits determination were raised as a key issue in the Town of Somerset's valuation of the facility for property tax assessment. Headwater Benefits Report — November 13, 2015 Deposition testimony — February 2, 2016
Superior Court Windham Unit State of Vermont Docket No. 547-11-12 Wmev	TransCanada Hydro Northeast, Inc.	Expert testimony regarding the valuation of a the Bellows Falls hydropower facility (49 MW) in appeal of appraised values in the town of Rockingham VT. Valuation Report — April 23, 2015 Deposition — February 4, 2014 Oral Testimony — May 11, 12 and 13, 2015

Rhode Island Superior Court PC No. 2012-1847	TransCanada; Ocean States Power Holdings, Ltd.	Expert testimony regarding the valuation of a 540 MW combined cycle power plant in appeal of an appraisal conducted for the Town of Burrillville, RI. Prepared analysis of unit operations and revenue forecasts. Report for 12/31/2010 — December 19, 2012 Report for 12/31/2011 — July 17, 2014 Deposition Testimony — May 2, 2015
Oklahoma Corporation Commission Cause No. PUD 201400229	OK Cogeneration	Testimony regarding Oklahoma Gas & Electric Company Application for pre-approval of its Mustang Modernization Plan, addressing planning for retirement of 430 MW of gas-fired steam generation and addition of 400 MW of Combustion turbine generation, cost pre-approval, and Requirements for competitive procurement and alternatives analysis. Pre-filed Testimony — December 16, 2014 Oral Testimony — March 18-19, 2015
Maine Public Utilities Commission Docket No. 2014-048	Central Maine Power	Testimony regarding CMP's application for approval Maine Power Connection Transmission Project. Testimony addressed economic benefits associated with Interregional transmission connection and associated wind energy development benefits. . Expert Report — September 5, 2014 Rebuttal Report — February 27, 2015 Oral Testimony — September 18, 2014 March 31, 2015
US District Court Colorado Civil Action No. 10-CV-02349-WJM-KMT	Nebraska Power Supply Issues Group	Expert testimony regarding Tri-State G&T cost to serve five Nebraska members. Expert Report — December 31, 2012 Deposition Testimony — February 27, 2013 Oral Testimony — May 19, 2014
Public Utilities Board Manitoba, Canada Needs For and Alternatives To (NFAT)	PUB NFAT Panel	Independent Expert (IE) for the review of Manitoba Hydro's Hydropower and Transmission Development Plan for 2,160 MW of hydro capacity at two locations, a 500 kV transmission line to Minnesota, and associated export contracts. Expert Reports I — January 24, 2014 Expert Reports II — February 28, 2014 Oral Testimony — April 8, 9, 10, 11, 2014
Superior Court State of Vermont Docket No. 423-9-12 Wmcv Docket No. 547-11-12 Wmev Docket No. 244-9-12 Cacv Docket No. 245-9-12 Cacv	TransCanada Hydro Northeast, Inc.	Expert testimony regarding the valuation of a four hydropower facilities totaling 260 MW in appeal of appraised values in the towns of Vernon, Rockingham, and Barnet VT. Valuation Report — July 15, 2013 Deposition — February 4, 2014

Arbitration AAA Case No. 11 198 Y 002014 12	City of Burlington, VT Burlington Electric Dept.	Expert testimony regarding the valuation of a 7 MW hydropower facility and the determination of fair value for transfer of ownership of the asset. Valuation Report June 21, 2013 Rebuttal Report July 26, 2013 Deposition Testimony September 12, 2013 Oral Testimony October 4, 2013
Arkansas Public Service Commission Docket No. 12-069-U	General Staff of the AK Public Service Comm.	Testimony regarding the evaluation of Entergy Arkansas's proposed divestiture of its transmission business to ITC Holdings. Direct Testimony April 19, 2013 Surrebuttal Testimony June 7, 2013 Supplemental Testimony - Rate MitigationAug 15, 2013
Arbitration AAA Case No. 11 153 Y 02133 11	Owners of Brassua Dam FPL Hydro Maine LLP Madison Paper Industries Merimil Ltd Partnership	Expert testimony regarding the valuation of a 4 MW hydropower facility and the determination of amortization reserve obligations under FERC license provisions. Valuation Report November 1, 2012 Amortization Reserve Report November 1, 2012 Amortization Reserve Rebuttal November 15, 2012 Oral Testimony December 5, 2012
Arkansas Public Service Commission Docket No. 10-011-U	General Staff of the AK Public Service Comm.	Testimony regarding the evaluation of Entergy Arkansas's strategic reorganization options and request for authorization to transfer control of its transmission asset to the Midwest ISO. Oral Testimony May 31, 2012 Surrebuttal Testimony April 27, 2012 Direct Testimony March 16, 2012
Burrillville Board of Review	TransCanada; Ocean States Power Holdings, Ltd.	Expert testimony regarding the valuation of a 540 MW combined cycle power plant in appeal of an appraisal conducted for the Town of Burrillville, RI. Valuation Report January 4, 2012 Oral Testimony March 1, 2012
Oklahoma Corporation Commission Cause No. PUD 201100186	OK Corporation Commission OK Attorney General	Testimony regarding a 60 MW Wind Energy Purchase Agreement and Cogeneration deferral Agreement proposed by Oklahoma Gas & Electric Company, addressing cost pre-approval, and a requested waiver from competitive procurement requirements. Pre-filed Testimony February 8, 2012
Arkansas Public Service Commission Docket No. 10-011-U	General Staff of the AK Public Service Comm.	Testimony regarding the evaluation of Entergy Arkansas's strategic reorganization options upon its exit from the Entergy System Agreement. Oral Testimony September 9, 2011 Surrebuttal Testimony August 18, 2011 Supplemental Initial Testimony July 12, 2011 Initial Testimony February 11, 2011

State Corporation Commission of the State of Kansas	The Landowner Group	Testimony regarding the application of ITC Great Plains for a siting permit for a 345-kV Transmission Line addressing project need and route selection methodology. Initial Testimony — April 18, 2011
Federal Energy Regulatory Commission (FERC) RM10-23-000	Maine Public Utilities Commission, et. al.	Expert Affidavit regarding economic analysis methodology for transmission project evaluation. Provided in reply comments on the FERC Transmission Planning and Cost Allocation NOPR. Affidavit — November 12, 2010
Maine Public Utilities Commission Docket No. 2008-255	Central Maine Power	Testimony regarding CMP's application for approval the Lewiston Loop 115kV Transmission Project. Testimony addressed non-transmission alternatives. Oral Testimony — November 16, 2008; December 14, 2010 Rebuttal Testimony — November 8, 2010; August 27, 2010
Oklahoma Corporation Commission Cause No. PUD 201000092	OK Corporation Commission OK Attorney General	Testimony regarding a 99.2 MW wind farm power purchase agreement and green energy choice tariff proposed by Public Service Company of Oklahoma, addressing cost pre-approval, resource need, and competitive procurement requirements. Pre-filed Testimony — October 5, 2010 Oral Testimony — November 3, 2010
Oklahoma Corporation Commission Cause No. PUD 201000037	Oklahoma Attorney General	Testimony regarding a 198 MW wind farm proposed by Oklahoma Gas & Electric, addressing cost pre-approval, resource need, and competitive procurement requirements. Pre-filed Testimony — June 11, 2010
Connecticut Dept. of Public Utilities Control (DPUC) Docket No, 10-02-07	Connecticut Energy Advisory Board (CEAB)	Lead witness sponsoring the CEAB's *2010 Comprehensive Plan for the Procurement of Energy Resources*. Oral Testimony — June 2 & 3, 2010
Georgia Public Service Commission Docket No. 31081	Georgia Public Service Commission Public Interest Advocacy Staff	Witness sponsoring testimony regarding integrated resource planning methods, renewable energy, solar PV demonstration projects, and uncertainty analysis. Written Testimony — May 7, 2010 Oral Testimony — May 18, 2010

Maine Public Utilities Commission Docket No. 2008-255	Central Maine Power	Testimony regarding CMP's application for approval $1.5 B Maine Power Reliability Transmission Project. Testimony addressed non-transmission alternatives and economic benefits, economics of proposed solar alternative, wind energy development benefits. . Oral Testimony October 10, 2008 November 19, 2008 December 21, 2009 February 4, 2010 Rebuttal Testimony December 4, 2009 April 3, 2009
Oklahoma Corporation Commission Cause No. PUD 200900167	Oklahoma Attorney General	Testimony regarding a 102 MW wind farm proposed by Oklahoma Gas & Electric, addressing cost pre-approval, resource need, and competitive procurement. requirements. Pre-filed Testimony Sept 29, 2009
Oklahoma Corporation Commission Cause No. PUD 200900099	Oklahoma Industrial Energy Consumers (OIEC)	Testimony regarding a power contract pre-approval and recovery of Independent Evaluator costs of Public Service Company of Oklahoma. Pre-filed Testimony July 14, 2009
Connecticut Dept. of Public Utilities Control (DPUC) Docket No, 09-05-02	Connecticut Energy Advisory Board (CEAB)	Lead witness sponsoring the CEAB's *2009 Comprehensive Plan for the Procurement of Energy Resources*. Oral Testimony June 30, 2009
Connecticut Dept. of Public Utilities Control (DPUC) Docket No, 08-07-01	Connecticut Energy Advisory Board (CEAB)	Lead witness sponsoring the CEAB's *2008 Comprehensive Plan for the Procurement of Energy Resources*. This Plan is the first prepared under the State's new integrated resource planning statute. Oral Testimony August 28, 2008 September 22, 2008 October 3, 2008
Maine Superior Court Civil Action Docket No. cv-06-705	Worcester Energy Co., Inc.	Expert opinion regarding renewable energy and power procurement services. Pre-filed Report January 30, 2008 Oral Testimony March 18, 2009
Massachusetts Dept. Of Telecommunications And Energy Docket No. DTE/DPU-06-60	Russell Biomass	Testimony regarding economic, reliability and environmental need for renewable power in the Massachusetts and New England in support of Russell Biomass petition for a zoning exemption. Pre-filed Testimony June 2007 Oral Testimony October 30, 2007
Hawaii Public Utilities Commission Docket No. 04-0046	Hawaii Division of Consumer Advocacy	Testimony regarding Hawaii Electric Light Company's integrated resource plan. Pre-filed Testimony September 28, 2007 Oral Testimony November 26, 2007

Nevada Public Utilities Commission Docket No. 06-12002	Nevada Attorney General Bureau of Consumer Protection	Testimony regarding the prudency of Sierra Pacific Power Company in its purchased power expenses for the period December 2001 through November 2002. Pre-filed Testimony — September 14, 2007
Oklahoma Corporation Commission Cause No. PUD 2005516 Cause No. PUD 2006030 Cause No. PUD 2007012	Oklahoma Attorney General	Testimony regarding a 950 MW coal-fired generation facility proposed by Public Service of Oklahoma and Oklahoma Gas & Electric, including IRP, competitive procurement, and construction financing issues. Pre-filed Testimony — May 21, 2007 Rebuttal Testimony — June 18, 2007 Oral Testimony — July 26, 2007
Oklahoma Corporation Commission Cause No. PUD 2002-038 REMAND	Oklahoma Industrial Energy Consumers (OIEC)	Testimony regarding a power contract proposal of Lawton Cogeneration and the pricing analysis of Public Service Company of Oklahoma. Pre-filed Testimony — October 28, 2005 Rebuttal Testimony — March 17, 2006 Oral Testimony — May 9, 2006
New Brunswick Board of Commissioners of Public Utilities (PUB) Ref: 2005-002	New Brunswick Power Distribution Company	Testimony regarding La Capra Associates' three technical audits of the NBP-Disco purchased power budget and variance analyses for FY 2004 – 2006. Oral Testimony — February 14-22, 2006
Connecticut Department of Public Utility Control Docket No. 05-07-14 Phases I and II	Connecticut Energy Advisory Board	Testimony regarding Connecticut's need for electric capacity to meet reliability requirements and to mitigate congestion charges in the wholesale markets. Oral Testimony — February 14-22, 2006 May 1, 2006 June 15, 2006 September 26, 2005
Hawaii Public Utilities Commission Docket No. 03-0372	Hawaii Division of Consumer Advocacy	Testimony regarding competitive bidding rules and integrated resource planning. Oral Testimony — December 12-16, 2005
Oklahoma Corporation Commission Cause No. PUD 2005-151	Oklahoma Industrial Energy Consumers (OIEC)	Testimony regarding resource planning, prudency of generation investment of Oklahoma Gas & Electric Company. Pre-filed Testimony — September 12, 2005 Rebuttal Testimony — September 29, 2005 Oral Testimony — October 18, 2005
Oklahoma Corporation Commission Cause No. PUD 2003-076	Oklahoma Industrial Energy Consumers (OIEC)	Testimony regarding resource planning, prudency of generation investment and fuel and purchased power expenses of Public Service Company of Oklahoma. Pre-filed Testimony — January 4, 2005

Oklahoma Corporation Commission Cause No. PUD 2003-633/4	Oklahoma Industrial Energy Consumers (OIEC)	Testimony regarding power contract proposal for Blue Canyon wind development and avoided costs of Public Service Company of Oklahoma. Pre-filed Testimony August 16, 2004
Civil Litigation Maine Superior Court Docket No. CV-01-24	Central Maine Power Co.	Factual and expert witness in litigation regarding pricing provisions of a purchased power agreement between Central Maine Power and Benton Falls Associates. Deposition Testimony April 28, 2004
Oklahoma Corporation Commission	Oklahoma Attorney General	Testimony regarding power contract proposal for PowerSmith Cogeneration and avoided cost analysis of Oklahoma Gas & Electric Company. Pre-filed Testimony February 18, 2004 Rebuttal Testimony March 16, 2004 Oral Testimony August 4, 2004
Nevada Public Utilities Commission	Nevada Attorney General Bureau of Consumer Protection	Testimony regarding the Nevada Power Company's Integrated Resource Plan and associated financial plan. Pre-filed Testimony September 19, 2003 Oral Testimony October 15, 2003
Massachusetts Energy Facilities Siting Council Docket No. EFSB-02-2	Cape Wind	Testimony regarding economic, reliability and environmental need for power in the Massachusetts and New England power markets regarding the need for new wind power facility. Pre-filed Testimony February 14, 2003 Oral Testimony August 6&7, 2003
Maine State Board of Property Tax Review	United American Hydro	Testimony regarding the Maine and New England power market prices pertaining to the valuation of a hydro-electric power facility in Winslow, Maine. Oral Testimony June18, 2003
Nevada Public Utilities Commission Docket No. 03-1014	Nevada Attorney General Bureau of Consumer Protection	Testimony regarding the prudency of Sierra Pacific Power Company in its purchased power expenses for the period December 2001 through November 2002. Pre-filed Testimony April 25, 2003
Oklahoma Corporation Commission Cause No. PUD 2002-038	Oklahoma Attorney General	Testimony regarding a power contract proposal of Lawton Cogeneration and the pricing analysis of Public Service Company of Oklahoma. Pre-filed Testimony December 16, 2002 Oral Testimony May 22, 2003
Arkansas Public Service Commission	General Staff of the AK Public Service Comm.	Testimony regarding the Development of Competition in Electric Markets and the Impact on Retail Consumers in Arkansas. Pre-filed Testimony September 4, 2001
Arkansas Public Service Commission	General Staff of the AK Public Service Comm.	Testimony regarding the Development of Competition in Electric Markets and the Impact on Retail Consumers in

		Arkansas.	
		Pre-filed Testimony	September 29, 2000
Arkansas Public Service Commission	General Staff of the AK Public Service Comm.	Testimony regarding the establishment of uniform Policies and guidelines for a Standard Service Package.	
		Staff Proposal and Comments	June 13, 2000
		Reply Comments	July 21, 2000
		Sur reply Comments	August 2, 2000
		Oral Testimony	August 8, 2000
		Petition for Rehearing	
		Rebuttal Testimony	November 15, 2000
		Oral Testimony	November 29, 2000
Arkansas Public Service Commission	General Staff of the AK Public Service Comm.	Testimony regarding the determination of the merits of declaring retail billing services competitive effective At the start of retail open access.	
		Oral Testimony	June 27, 2000
		Pre-filed Rebuttal Testimony	June 23, 2000
		Pre-filed Testimony	June 16, 2000
		Oral Testimony	May 10, 2000
Arkansas Public Service Commission	General Staff of the AK Public Service Comm.	Testimony regarding the minimum filing requirements for market power studies to be filed by the Arkansas Electric utilities and affiliated retail companies.	
		Oral Testimony	June 1, 2000
Amer. Arb. Assoc. No. 50T 198 00197-98	Vermont Joint Owners	Testimony regarding economic damages resulting from alleged breach of a long-term purchase power agreement between Hydro-Quebec and Vermont utilities (VJO).	
		Oral Testimony	May 25, 2000
		Pre-filed Rebuttal Testimony	February 10, 2000
		Pre-filed Testimony	August 13, 1999
Rhode Island Energy Facilities Siting Board	Indeck-North Smithfield, L.L.C.	Testimony regarding economic, reliability and environmental need for power in the Rhode Island and New England power markets regarding the need for new, merchant power facility.	
		Pre-filed Testimony	August 16, 1999
		Oral Testimony	August 17, 2000
		Pre-filed Testimony	January 26, 2001
		Oral Testimony	March 23, 2001
Civil Litigation Maine Superior Court Docket No. CV-98-212	Central Maine Power Co.	Factual and expert witness in litigation regarding pricing provisions of a purchased power agreement between Central Maine Power and Regional Waste Systems.	
		Deposition Testimony	May 5, 1999
Connecticut Energy Facilities Siting Council Docket No. 190	PDC – El Paso Meriden LLC	Testimony regarding economic, reliability and environmental need for power in the Connecticut and New England power markets regarding the need for new, merchant power facility.	
		Pre-filed Testimony	January 25, 1999

Rhode Island Energy Facilities Siting Council Docket No. SB-98-1	R. I. Hope Energy, L. P.	Testimony regarding economic, reliability and environmental need for power in the Massachusetts and New England power markets regarding the need for new, merchant power facility.	
		Oral Testimony	November 4, 1998
		Pre-filed Testimony	October 30, 1998
Massachusetts Energy Facilities Siting Council Docket No. EFSB-91-101A	Cabot Power Corp.	Testimony regarding economic, reliability and environmental need for power in the Massachusetts and New England power markets regarding the need for new, merchant power facility.	
		Oral Testimony	May 27, 1998
		Pre-filed Testimony	August 15, 1997
Massachusetts Energy Facilities Siting Council Docket No. EFSB-97-2	ANP Blackstone Energy	Testimony regarding economic, reliability and environmental need for power in the Massachusetts and New England power markets regarding the need for new, merchant power facility.	
		Oral Testimony	April 6, 1998
		Pre-filed Testimony	January 23, 1998
Massachusetts Energy Facilities Siting Council Docket No. EFSB-97-1	ANP Bellingham	Testimony regarding economic, reliability and environmental need for power in the Massachusetts and New England power markets regarding the need for new, merchant power facility.	
		Oral Testimony	February 3, 1998
			January 28, 1998
Rhode Island Energy Facilities Siting Board Docket No. SB-97-1	Tiverton Power Associates LP	Testimony regarding economic, reliability and environmental need for power in the Rhode Island and New England power markets regarding the need for new, merchant power facility.	
		Oral Testimony	October 15, 1997
		Pre-filed Testimony	October 1, 1997
Maine Public Utilities Commission Docket No. 92-102	Central Maine Power	Testimony regarding CMP's avoided cost methods and practices pertaining to the prudency of power purchase contract decisions with regard to contract awards and contract management.	
		Oral Testimony	July 1993
		Deposition Testimony	February 25, 1993
			March 1, 1993
		Pre-filed Rebuttal Testimony	June 7, 1993
		Pre-filed Testimony	June 15, 1992
Maine Public Utilities Commission Docket No. 92-315	Central Maine Power	Testimony regarding CMP's avoided cost methods and practices pertaining to the setting of long-term avoided costs, CMP's Energy Resource Plan, and the relationship of marginal costs of generation to embedded costs.	
		Supplemental Pre-filed Testimony	April 20, 1993
		Pre-filed Testimony	February 17, 1993

Maine Public Utilities Commission Docket No. 87-261 Docket No. 88-111	Central Maine Power	Testimony regarding CMP's avoided cost methods and practices pertaining to the setting of long-term avoided costs, CMP's Energy Resource Plan, and the proposal for a 900 MW power Contract with Hydro Quebec. Oral Testimony Summer 1988 Pre-filed Testimony October 31, 1987

II. DOUGLAS A. SMITH

DAYMARK ENERGY ADVISORS

Douglas A. Smith

Managing Consultant and Treasurer

Doug Smith has over thirteen years of experience in the electric industry, bringing diverse strengths to Daymark's project teams by applying his extensive technical and analytical skills. A business professional with over twenty years of increasing responsibility as a consultant to multiple industries, Mr. Smith has a solid background in analysis, finance and accounting, database and software development, quality assurance, and project management.

Mr. Smith leads the firm's Market Analytics team which is responsible for maintaining Daymark's wholesale power market model and wholesale market outlook, researching energy and capacity markets throughout North America, and producing a variety of forecasts used to provide decision support for client needs including asset valuation, integrated resource planning, non-transmission alternative analysis and other similar projects. He has strong experience in market and power system dispatch analysis, and has been responsible for projecting market valuation, power costs, and emissions impacts for a number of clients.

SELECTED PROFESSIONAL EXPERIENCE

- Led an analysis of wind energy congestion for a potential New England wind and transmission project; reported on potential local and regional congestion
- Led an offshore wind siting feasibility study related to a potential investment in offshore leasing. Investigated interconnection and market risks and opportunities
- Led an analysis of the regional benefits related to a proposed dual-fuel fired peaker plant in New England; assisted the team in analyzing and reporting on emissions impact scenarios, with the plant operating as either an energy unit or a reserve unit; investigated state emissions policies and their potential impact on plant operations
- Led an analysis of a combined proposal for wind energy and transmission in northern New England; assisted team members in understanding the impacts of various quantities of wind energy and the respective transmission needed to deliver wind energy and provided scenario analysis to quantify the range of potential benefits, which resulted in two public reports as components of responses to a regional energy procurement effort
- Managed the creation of a proof of concept model of the Southern Company balancing authority and surrounding areas, including benchmarking to available public data and forecasting of potential future capacity expansion futures
- Assisted in asset valuation modeling work, including modeling of long term energy and capacity values for a number of coal, natural gas and hydro facilities
- As an input to several economic studies for NYSERDA, provided review and analysis of a third-party, long-term forecast of New York's energy and capacity markets
- Managed the review of a large generation owner's price forecasting process; provided recommendations for process improvements designed to more-closely align forecasting efforts with internal requirements and updated and extended the client's New York modeling capabilities

using the AURORA production cost model; recommended key benchmarking tools for evaluation of specific forecasting results

- Assisted in the assessment of a request to the Arkansas Public Service Commission for a declaratory order; the request sought a finding that installation of environmental controls at the Flint Creek power plant was in the public interest
- Assisted in assessing requests to the North Dakota Public Service Commission for Advanced Determinations of Prudence; requests were sought by the Montana Dakota Utilities GT and the Big Stone Air Quality Control System
- Assisted in a review of Entergy Arkansas's strategic planning for post-System Agreement operation on behalf of the General Staff of the Arkansas Public Service Commission
- Assisted a Vermont-based utility in the evaluation of a potential generation purchase; designed an analytical model for use in evaluating potential revenue and cost streams under a variety of scenarios
- Assisted in evaluating non-transmission alternatives (NTAs) as compared to a set of proposed transmission upgrades in Vermont; assisted in the development of an economic scorecard designed to facilitate the comparison of transmission and non-transmission solutions on equal footing and compared potential rate impacts of the proposed solutions
- Assisted in evaluating non-transmission alternatives (NTAs) as compared to a set of proposed transmission upgrades in Maine; evaluated the economics of transmission and non-transmission solutions and leveraged market simulation models to estimate the impact of solutions on energy clearing prices in Maine and in New England
- On behalf of Vermont-based utility, developed and analyzed non-transmission alternatives (NTAs) to a set of proposed transmission upgrades that would impact the distribution-level supply system; developed an economic tool to evaluate the cost of operating "pre-contingency" generation options
- Analyzes budgetary and other cost-related data on behalf of the National Railroad Passenger Corporation (Amtrak); interacts with the client on a monthly basis to provide analysis of power cost drivers, track monthly power costs, and deliver other accounting and electric consulting services; provides assistance in periodic power procurement activities
- Assisted in planning, managing, and performing an audit of actual and hypothetical purchased power costs for a Michigan utility; issues included market valuation of potential sales, proper treatment of a pumped storage unit, and validation of commitment/dispatch logic; this project also involved a process audit and the review of large volumes of data involved in determining hypothetical system costs
- Assisted in maintaining an Allocated Cost of Service model, including modifying allocators and introducing new methodology
- Researched issues related to state, regional, and Federal environmental regulations and their impacts on energy generation; modeled environmental variables including current SO_2, NO_X and CO_2 rates and allowance prices, emission control technologies, and likely future changes
- Participated in developing revenue projections for valuation of power plants

PUBLICATIONS

MCPC Project Benefits; Quantitative and Qualitative Benefits, Confidential Report prepared for Central Maine Power regarding the benefits of the Maine Clean Power Connection, a 345 kV transmission expansion accompanied by 1100 MW of wind energy project development offered in the Massachusetts RFP for Clean Energy Resources, July 27, 2017. Lead Analyst and Contributing Author.

NECEC Project Benefits; Quantitative and Qualitative Benefits, Confidential Report prepared for Central Maine Power and H.Q. Energy Services regarding the benefits of the New England Clean Energy Connection, 1200 MW HVDC transmission expansion accompanied by 1090 MW of hydropower and wind energy project development offered in the Massachusetts RFP for Clean Energy Resources, July 27, 2017. Lead Analyst and Contributing Author.

MREI Project Benefits; Direct, Indirect, Qualitative and Other Benefits, prepared for Central Maine Power Company and Emera Maine regarding the benefits of the Maine Renewable Energy Initiative, a 345 kV transmission expansion accompanied by 1200 MW of wind energy project development, January 28, 2016. Lead Analyst and Contributing Author.

MCPC Project Benefits; Direct, Indirect, Qualitative and Other Benefits", prepared for Central Maine Power Company regarding the benefits of the Maine Clean Power Connection, a 345 kV transmission expansion accompanied by nearly 600 MW of wind energy project development, January 28, 2016. Lead Analyst and Contributing Author.

EMPLOYMENT HISTORY

Daymark Energy Advisors Inc.	Boston, MA
Treasurer	2016 – Present
Managing Consultant	2017 – Present
Senior Consultant	2008 – 2017
Analyst	2004 – 2008
The Sports Authority	Ft. Lauderdale, FL
Senior POS/EDP Programmer/Analyst	2002 – 2004
University of Colorado	Boulder, CO
*Instructor, Oracle SQL*Plus Class*	2001 – 2001
SHL USA Inc.	Boulder, CO
Software Engineer	2000 – 2001
Strategic Technologies Group	Boulder, CO
Senior Consultant	1995 – 2000

EDUCATION

Syracuse University	Syracuse, NY
B.S., Accounting, Summa Cum Laude	1991

STATE OF MAINE PUBLIC UTILITIES COMMISSION

DOCKET NO. 2017-00232

CENTRAL MAINE POWER COMPANY REQUEST FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE CONSTRUCTION OF THE NEW ENGLAND CLEAN ENERGY CONNECT (NECEC) TRANSMISSION PROJECT

REBUTTAL TESTIMONY OF DAYMARK ENERGY ADVISORS: DANIEL PEACO, DOUGLAS SMITH AND JEFFREY BOWER

On Behalf of Central Maine Power Company

July 13, 2018

[redacted] **End Confidential PO 9]**

Based on all of the evidence related to potential impacts of the NECEC on Maine generators, it is highly unlikely that the NECEC will induce any Maine generators to retire, as both Daymark and LEI models have demonstrated. In addition, if any Maine generators do retire, it will be a voluntary choice of the generator and not an action that is imposed on the generator by the NECEC or ISO-NE. And finally, there is no credible evidence that the NECEC will produce materially different impacts on Maine generator economics as compared to any other state sponsored resource of the same size and characteristics.

VIII. CO_2 EMISSIONS IMPACT OF THE NECEC

A. Review of Daymark Analysis

The Daymark analysis found that adding the NECEC to the supply mix in New England yielded reductions in regional CO_2 emissions. Using the results of the previously discussed energy market modeling, we determined that the NECEC Project will induce annual CO_2 emission reductions of approximately 3.1 million metric tons across New

England and the net emissions from the portion of regional generation serving Maine load will be reduced by approximately 264,000 metric tons per year.[89]

B. LEI Analysis and Conclusions

In similar fashion to the Daymark modeling, LEI produced an analysis of NECEC induced reductions in CO_2 emissions in New England. Their energy model results determined that the "NECEC could reduce CO_2 emissions in New England by approximately 3.6 million metric tons per year."[90]

C. GI Analysis and Conclusions

The energy market model used by Mr. Speyer in his analysis of the impact of the NECEC on CO_2 emissions shows reductions in New England emissions. In fact, according to the Technical Report Mr. Speyer sponsored, "[i]n all cases, the results for New England match the analysis performed by Daymark, coming in at around a 3 million MT reduction in carbon emissions."[91]

Despite the savings in New England emissions, Mr. Speyer states that "[u]nder all scenarios, NECEC increases total carbon emissions." He reaches this conclusion by assuming the NECEC generation will not be incremental to current Hydro-Québec exports, instead reducing New York imports of Hydro-Québec hydropower in amounts equal to the imports of NECEC power. He then states that, "[a]ny reduction in carbon emissions

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[89] **Exhibit NECEC-5** at 4 of 98.

[90] LEI Report at 12 of 85.

[91] Speyer Direct Testimony, **Exhibit JMS-4**, Technical Report: New England Clean Energy Connect (NECEC) Regional Carbon Emissions Impacts, at 3.

ATTACHMENT III

Exhibit No. JMS-4

TECHNICAL REPORT

NEW ENGLAND CLEAN ENERGY CONNECT (NECEC) REGIONAL CARBON EMISSIONS IMPACTS

Prepared by: Energyzt Advisors, LLC

April 2018

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ENERGYZT

TECHNICAL REPORT:
NEW ENGLAND CLEAN ENERGY CONNECT (NECEC)
REGIONAL CARBON EMISSIONS IMPACTS

This technical report provides background, assumptions, and results supporting the analysis of the potential impact of the proposed New England Clean Energy Connect (NECEC) project on regional carbon emissions.

Conclusion:

Due to offsetting effects, NECEC would not generate any significant carbon emissions benefits and may even increase total carbon emissions under certain conditions. Model runs holding Québec energy sales into the United States constant with and without NECEC indicate that carbon emissions could increase by more than 375,000 metric tons on an annual basis.

1. CARBON EMISSIONS ON A REGIONAL AND GLOBAL BASIS

The purpose of this analysis is to determine the potential impact of the New England Clean Energy Connect (NECEC) proposed high voltage direct current transmission line on carbon emissions. NECEC runs from Windsor, Québec through Maine where it would interface with the New England power grid.

Understanding the impacts of carbon emissions must be made on a broad regional and even global basis. Carbon is unlike other pollutants emitted by the electrical plants (such as sulfur, mercury, ash and particulates) that are more of a local problem. Sulfur emissions however, are also a regional but not global since sulfur dioxide are emitted into the lower levels of the atmosphere turn into sulfuric acid that has down-wind affects in a broader region.

Carbon emitted from power plants, automobiles, industrial facilities and mother nature itself moves into the atmosphere where it can accumulate over time, reaching levels of concentration that affect the world's environment. Emissions from New York or New England's generating plants, for example, have impacts both broadly across the NYISO and ISO-NE areas as well as internationally.

Likewise, the benefits of reducing carbon will have broad consequences regionally and internationally, and therefore should be analyzed on a broader basis to understand the true extent of impacts.

2. APPROACH

To conduct an analysis of the impact of NECEC, a number of model runs were developed to understand the impact of different assumptions on carbon emissions. Each set of conditions included the following scenarios for the year 2023:

1. **Without NECEC:** Assumes NECEC would not be built and New England operates according to the assumed market conditions.

2. **With NECEC:** Assumes that NECEC would be operational by 2023, and Hydro-Québec energy sales into the United States would be held constant between scenarios so that energy delivered by NECEC is sourced through reduced exports into other U.S. markets.

Each of these scenarios is run assuming a different combination of natural gas and carbon prices. The results of the model runs were then compared to estimate the net impacts on dispatch and carbon emissions.

3. KEY ASSUMPTIONS

A number of key assumption were made and held constant across both scenarios. The assumptions basically replicate the Daymark study as closely as possible, modify the natural gas price assumption, and modify the carbon price assumption.

For purposes of maintaining Québec exports to the United States constant in both scenarios, scheduled energy flows were removed from the lowest-priced period in the base case without NECEC. Flows across other New England Interties were held constant, reflecting the Massachusetts requirement that the energy supply be incremental to New England. It is possible that the same condition could apply to New Brunswick which can serve as a conduit for energy flows from Québec into New England.

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The contractual arrangements in place between Québec and Ontario to achieve lower carbon emissions in Ontario through power and energy purchases between the provinces limited the potential reduction in Québec sales to Ontario. It also would seem politically difficult for Québec to remove a substantial amount of energy sales from Ontario or New Brunswick and divert those sales to the United States.

4. RESULTS

Figure 1 summarizes the net carbon increase in metric tons for each set of assumptions.

Figure 1: Net Change in Carbon Emissions in 2023 for Each Set of Assumptions

Assumptions	Natural Gas Price ($/mmBtu)	Carbon Price ($/MT)	Net Carbon Increase (Metric Tons)
Daymark Reproduction	5.95 $4/MMBTu - $11.50/MMBTu	15	384,252
Daymark Reproduction with Lower Gas Price	4.65 $3.50/MMBTu - $11/MMBTu	15	341,892
Current Conditions	4.65 $3.50/MMBTu - $11/MMBTu	5	54,314

Under all scenarios, NECEC **increases** total carbon emissions. The magnitude of the increase reflects how steep or flat the supply curve is based on a two key assumptions. The steeper the supply curve (i.e., higher gas and higher carbon price), the greater the impact of NECEC on total carbon emissions.

5. UNDERLYING DETAIL

The basis for the summary table is provided in charts that tally the total carbon emissions by electricity market.

In all cases, the results for New England match the analysis performed by Daymark, coming in at around a 3 million MT reduction in carbon emissions. Once offsetting impacts associated with other areas are incorporated into the analysis, however, NECEC would increase total emissions across the northeastern energy markets.

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5.1 Daymark Replication

Assumptions: UPLAN model maintained by Calpine with replication of key Daymark assumptions in 2023:

- Natural Gas: $5.95/mmBtu
- Carbon Price: $15/MT
- Renewable Build-out: Consistent with Daymark stated RPS requirements

Figure 2: Regional Results – Daymark Replication

State/Region	Carbon Emissions (MT)		Net Carbon Emissions Impact
	Without NECEC	With NECEC	MT
ISONE	**26,808,907**	**23,795,605**	**(3,013,302)**
NYISO	25,820,742	28,127,560	2,306,818
PJM	396,772,050	397,847,160	1,075,110
MISO	351,004,059	350,890,414	(113,645)
Ontario	3,600,282	3,729,553	129,271
NE+NY+PJM+MISO+IESO	**804,006,040**	**804,390,292**	**384,252**

5.2 Daymark Replication with Lower Natural Gas Prices

Assumptions: UPLAN model maintained by Calpine with replication of key Daymark assumptions in 2023 and lower natural gas price:

- Natural Gas: $4.65/mmBtu
- Carbon Price: $15/MT
- Renewable Build-out: Consistent with Daymark stated RPS requirements

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Figure 3: Regional Results - Daymark Assumptions with Lower Gas Price

State/Region	Carbon Emissions (MT)		Net Carbon Emissions Impact
	Without NECEC	With NECEC	MT
ISONE	**24,938,218**	**21,838,538**	**(3,099,680)**
NYISO	28,333,277	30,370,800	2,037,523
PJM	373,320,687	374,150,495	829,808
MISO	344,100,279	344,573,575	473,296
Ontario	2,784,640	2,885,585	100,945
NE+NY+PJM+MISO+IESO	**773,477,101**	**773,818,993**	**341,892**

5.3 Current Conditions

Assumptions: UPLAN model maintained by Calpine with assumptions that are more reflective of current conditions anticipated for 2023:

- Natural Gas: $4.65/mmBtu
- Carbon Price: $5/MT
- Renewable Build-out: Per scheduled operations date

Figure 4: Regional Results – Current Market Conditions Anticipated for 2023

State/Region	Carbon Emissions (MT)		Net Carbon Emissions Impact
	Without NECEC	With NECEC	MT
ISONE	**25,533,455**	**22,212,625**	**(3,320,830)**
NYISO	33,408,823	35,685,592	2,276,769
PJM	373,855,409	374,373,845	518,436
MISO	340,179,476	340,659,823	480,347
Ontario	2,643,966	2,743,558	99,592
NE+NY+PJM+MISO+IESO	**775,621,129**	**775,675,443**	**54,314**

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6. CONCLUSIONS

There are conditions under which NECEC will actually result in higher total carbon emissions across the northeast electricity markets.

In particular, New York tends to have a higher carbon emissions intensity on the margin than New England. Therefore, moving energy sales from New York into NECEC results in higher carbon emissions. The magnitude of the impact, however, will depend on market conditions and how those conditions affect the slope of New England's supply curve.

Although energy from existing hydroelectricity plants owned and operated by Hydro-Québec may seem to be the least costly option compared to other renewables, it could have an adverse consequence on the environment. In contrast, purely incremental clean energy sources such as new solar, new wind turbines, new biomass or new hydroelectric would serve to displace existing carbon-generating resources without the perverse consequences of shifting existing energy supply across boundaries.

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REDACTED PUBLIC VERSION

Independent Analysis of Electricity Market and Macroeconomic Benefits of the New England Clean Energy Connect Project

May 21, 2018

Prepared for

Maine Public Utilities Commission

LONDON ECONOMICS

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Disclaimer

London Economics International LLC ("LEI") was retained by the Maine Public Utilities Commission to develop an independent electricity market and macroeconomic impact analysis of the New England Clean Energy Connect Project and to conduct an independent review of the benefits that were included as part of Central Maine Power's ("CMP") Request for Approval of a Certificate of Public Convenience and Necessity ("CPCN") application. LEI has made the qualifications noted below with respect to the information contained in this report and the circumstances under which the analysis was prepared.

While LEI has taken all reasonable care to ensure that its analysis is complete, wholesale electricity markets are highly dynamic, and thus certain recent developments may or may not be included in LEI's analysis. Interested parties should note that:

- LEI's analysis is not intended to be a complete and exhaustive analysis. All possible factors of importance to all interested parties have not necessarily been considered. The provision of an analysis by LEI does not obviate the need for interested parties to make further appropriate inquiries as to the accuracy of the information included therein, and to undertake their own analysis and due diligence.

- No results provided or opinions given in LEI's analysis should be taken as a promise or guarantee as to the occurrence of any future events.

- There can be substantial variation between assumptions and market outcomes analyzed by various consulting organizations specializing in electricity markets and economic analysis. Neither LEI nor its employees make any representation or warranty as to the consistency of LEI's analysis with that of other parties.

The contents of LEI's analysis do not constitute investment advice. LEI, its officers, employees and affiliates make no representations or recommendations to any party. LEI expressly disclaims any liability for any loss or damage arising or suffered by any third party as a result of that party's, or any other party's, direct or indirect reliance upon LEI's analysis and this report.

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REDACTED PUBLIC VERSION

1 Executive Summary

On September 27, 2017, Central Maine Power Company ("CMP") filed a Request for Approval of a Certificate of Public Convenience and Necessity ("CPCN") with the Maine Public Utilities Commission ("PUC" or "Commission") for the New England Clean Energy Connect ("NECEC" or the "project"). This project consists of the construction of a 1,200 MW high-voltage direct current ("HVDC") transmission line from the Quebec-Maine border to Lewiston, and related network upgrades. Pursuant to Maine Statute, the Commission shall take in to account the costs and benefits of the project to determine the public need for the CPCN.

As part of the process for evaluating whether a CPCN should be awarded, the Commission retained London Economics International LLC ("LEI") to prepare an independent analysis of the wholesale electricity market and macroeconomic impacts of the NECEC, and a review of the project benefits developed by CMP's consultants, including Daymark Energy Advisors ("Daymark") for the wholesale electricity market benefits and University of Southern Maine ("USM") for the macroeconomic benefits.[1] Specifically, the Commission asked LEI to analyze the impact of NECEC on the ISO New England wholesale energy and capacity market costs to Maine electric ratepayers as well as the economic benefits to the state from direct spending and economic activity, job creation, and municipal tax revenues.[2] LEI also analyzed the level of CO_2 emissions reduction, as well as the "insurance value" of the NECEC against high energy market costs for New England (including Maine) electric ratepayers as consequence of extreme summer and winter weather conditions. However, LEI's analysis did not include estimation of all possible market impacts, such as the project's impacts on ancillary services markets, Renewable Energy Credit ("REC") markets, fuel diversification benefits, gas market savings for non-power sector customers, long-term reliability and resiliency benefits, and socio-economic impacts of decarbonization. These benefits were also not quantitatively analyzed by CMP's consultants.

1.1 Overview of the NECEC Transmission Project

The NECEC transmission project is a $1 billion HVDC transmission infrastructure project that can bring up to 1,200 MW of additional transmission capacity between Hydro Québec's system and the New England Control Area ("NECA"). Energy and capacity sales on the project will be sourced from Hydro Quebec's hydroelectric fleet and will flow into NECA through the interconnection point in Maine, starting in 2023. CMP is the developer of the Maine portion of the project, which runs from Beattie Township in the northwest corner of Maine to Lewiston, Maine. The Québec portion will be constructed by Hydro Québec TransEnergie, Inc. ("HQT").

NECEC's bid (specifically, the 100% hydroelectric power-based bid) was selected by Massachusetts as the winner of the Request for Proposal ("RFP") pursuant to Section 83D of the

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[1] CMP's CPCN application includes Exhibit 5 (Peaco, Daniel E, Douglas A Smith, and Jeffrey D Bower. *NECEC Transmission Project: Benefits to Maine Ratepayers Quantitative and Qualitative Benefits*. September 27, 2017.) by Daymark Energy Advisors ("Daymark"), and Exhibit 7 (Wallace, Ryan D, and Charles S Cogan. *The Economic and Employment Contributions of the New England Clean Energy Connect in Maine*. September 2017) by The Maine Center for Business and Economic Research, University of Southern Maine ("USM").

[2] LEI did not estimate the impact on Maine consumers in Northern Maine, given that region is not part of the ISO New England market. Northern Maine is part of the New Brunswick System Operator's control area.

Green Communities Act ("83D RFP") March 2018. According to CMP, construction is set to begin in 2019 and the project life is approximately 40 years based on the RFP application form submitted by NECEC.[3]

1.2 LEI's approach

LEI began by reviewing Exhibit 5 ("Daymark Report") and Exhibit 7 ("USM Report") of the CPCN application, past data responses,[4] oral data requests[5] from other intervenors, and the transcript from Daymark's December 11, 2017 technical conference. LEI also participated in a technical session hosted by the Commission on April 5, 2018, where CMP, Daymark, and USM sponsored witnesses that answered questions from LEI, Commission staff, and other parties. In parallel to LEI's review of the CPCN application and discovery materials, LEI undertook its own simulation-based modeling analysis to determine the potential wholesale energy and capacity market cost impacts, as well as a macroeconomic impacts analysis on jobs and GDP. In addition, LEI re-estimated the municipal taxes that would be payable by the project across the affected towns in Maine.[6]

LEI developed its own estimate of the electricity market and macroeconomic impacts from NECEC using its own proprietary suite of wholesale energy and capacity models and the REMI PI+ models, respectively. To derive the wholesale electricity market and CO_2 emissions impacts, LEI began by developing a "Base Case" in which LEI projected operations of the New England market from 2023 through 2037 without the project. Importantly, the project is assumed to not be built, and no other similar HVDC transmission project is built either (so that the benefits attributable to NECEC could be isolated). Next, LEI modeled a "Project Case" in which NECEC is developed and put into service by 2023. The existence of NECEC also changes the course of other supply decisions - triggering some changes in capacity supply, such as 750 MW of permanent retirements and the deferment of 350 MW of generic new investment. The wholesale electricity market benefits of NECEC are measured as a function of the difference in wholesale energy and capacity market costs between the Base Case and the Project Case.

The Base Case is built upon conservative and reliable market-oriented expectations, which are detailed in Section 7. This includes ISO-NE's 50/50 weather-normal load forecast from its capacity, energy, loads, and transmission ("CELT") 2017 report[7] and a delivered natural gas price forecast based on forwards as well as market trends in the near term and growth trends from the

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[3] Section 83D RFP Application form, pg. 185. Provided by CMP in ICEG-001-034, Attachment 3.

[4] In addition to the data requests issued by LEI on March 9, 2018, LEI also reviewed CMP data responses EXM, CLF, IECG, OPA, and KELLY.

[5] LEI reviewed the oral data requests issued to Daymark following its December 11, 2017 technical conference. LEI also issued its own oral data requests following the April 5, 2018 technical conference.

[6] LEI adopted several key assumptions from CMP, including the commercial operation date ("COD") of 2023 the assumed pattern of energy flows ([redacted] TWh distributed evenly across all hours), the internal New England interface transfer limit upgrades, as well as the updated project costs and local spending information, which was provided in the form or data requests and oral data requests by LEI and other parties.

[7] CELT 2018 was released in early May 2018; however, LEI had already begun modeling the project and estimating the wholesale electricity market impacts. Total demand in CELT 2018 is approximately 3% lower than CELT 2017, and peak demand is approximately 1% lower.

Energy Information Agency's ("EIA") Annual Energy Outlook ("AEO") 2018.[8] In addition, LEI adopted ISO-NE's most recent estimate of the Net Cost of New Entry ("Net CONE"), which has been vetted by stakeholders through the ISO-NE Markets Committee. Furthermore, LEI also adapted its capacity market model to account for ISO-NE's Competitive Auctions for Sponsored Policy Resources ("CASPR") beginning in Forward Capacity Auction ("FCA") #13 (see Section 2 for discussion of CASPR).

The Base Case forecast began with an annual average energy price of [redacted]/MWh in 2023, escalating over time to [redacted]/MWh in 2037 (in nominal dollars). The wholesale capacity price under the Base Case started at [redacted]/kW-month for FCA #14 and converges towards Net CONE in the $11/kw-month range by 2037. While not specifically relevant to the analysis of NECEC, LEI's Base Case outlook in the short term (2018-2020) is consistent with current forward prices and congruent with historical market price trends, normalized against future supply, demand and fuel price assumptions.

LEI engages in extensive benchmarking to ensure the robustness of its forecasts. In addition to considering the congruency of the forecast with recent trends and also market forwards, LEI staff perform backcasts of the New England model using actual historical data every 12-24 months. For more details, of LEI's modeling tools see Section 6.

LEI routinely forecasts future market conditions in New England as part of its various consulting engagements in the region. New England market price outlooks are also included in the company's semi-annual multi-client studies of electricity market trends across deregulated markets in North America. The Base Case and Project Case prepared for this report are customized and extended versions of LEI's multi-client outlooks. LEI's POOLMod simulation model has been used to support millions of dollars in merger and acquisition ("M&A") deals, market design support, and contract evaluations.[9]

1.3 Summary of LEI's independent analysis of the wholesale electricity market impacts and environmental benefits of NECEC

LEI estimates that the 1,090 MW NECEC project (with energy flows of [redacted] TWh per year) would provide $346 million in wholesale electricity market benefits to Maine during the first fifteen years of operation (2023-2037) on a Net Present Value ("NPV") basis in 2023 dollars.[10] Of this, $122 million comes from wholesale energy market benefits and $223 million comes from wholesale capacity market benefits from the sale of 1,090 MW of capacity. This presumed NECEC would clear the primary auction or FCA (its unit-specific Minimum Offer Price Rule ("MOPR")

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[8] These assumptions do not assume sudden spikes in demand or natural gas prices because of heat waves and cold spells which occasionally occur in New England and could increase the value of the wholesale energy market benefits of the project.

[9] In addition to bespoke consulting engagements, LEI performs semi-annual forecasts using POOLMod for 12 wholesale power markets. These forecasts, known as LEI's Continuous Modeling Initiative ("CMI"), examine recent market developments, draw on the latest information and data available, and apply LEI's proprietary modeling tools to provide a 10-year energy, and where applicable, capacity market price outlooks.

[10] Unless otherwise stated, LEI used a 7% discount rate for all the NPV estimates in this report.

would be sufficiently low as to permit it to clear).[11] If NECEC is unable to clear the FCA and then clears the substitution auction (as a Sponsored Policy Resource), then there would be no wholesale capacity market benefits from the project. Therefore, the wholesale electricity market benefits would fall to $122 million in NPV terms for Maine load.

To put the size of these benefits into context, the annual average wholesale electricity market benefits of $346 million constitute approximately 4.4% of the total expected electricity market costs (energy and capacity) between 2023-2037. For Maine retail customers specifically, the annual average retail electricity market benefits constitute approximately 4.2% of the total expected retail market costs over the same timeframe. Figure 1 below shows a summary of the wholesale and retail electricity market and environmental benefits for Maine and for the entire New England region (all six states) under the assumption the NECEC would be able to clear the FCA and create wholesale capacity market benefits.

Figure 1. LEI's analysis of wholesale and retail electricity market benefits and regional CO_2 impacts of NECEC (assuming NECEC clears the FCA)

	Wholesale Impacts		Retail Impacts	
	Maine	New England	Maine	New England
15-yr NPV, $2023 million				
Energy market benefits	$122	$1,197	$119	$1,046
Capacity market benefits	$223	$2,962	$221	$2,734
Total electricity market benefits	$346	$4,160	$341	$3,780
15-yr annual average, $nominal million				
Energy market benefits	$14	$134	$13	$117
Capacity market benefits	$19	$255	$19	$2,734
Total electricity market benefits	$33	$388	$32	$2,851
Potential insurance value against extreme weather (five-day average)				
Summer 2013 heat wave	$6	$52	Not modeled	Not modeled
Winter 2013/14 polar vortex	$4	$72	Not modeled	Not modeled
Annual average CO_2 emissions reduction, million metric tons				
CO_2 reduction	Not modeled	3.58	Not modeled	Not modeled

Note: The energy market results are based on the average of 20 iterations (see Section 6.1) and were found to be statistically significant in all years of the modeling horizon. The retail electricity market benefits are slightly lower than wholesale electricity market benefits for New England as LEI took into account limitations on retail load's exposure to wholesale market conditions, including the generation units that self-supply or are under a long-term contract with fixed prices.

1.3.1 Extreme weather cases

In addition to ISO-NE's 50/50 weather-normal load forecast, LEI considered the impact of more extreme weather conditions on wholesale energy prices and then estimated the energy market cost savings that NECEC could create for electric ratepayers in the face of such extreme conditions. New England on occasion experiences extreme swings in weather, which can cause spikes in natural gas prices during the winter months, or high electricity demand during the

[11] LEI did not attempt to estimate the MOPR of NECEC to determine whether NECEC would clear the primary as auction. CMP did not provide sufficient cost data for LEI to perform such an estimation.

summer months, both of which can drive up wholesale energy prices. To analyze the market impact that NECEC could provide during these events, LEI estimated the impact NECEC would have had on ISO New England's wholesale energy market costs in two past weather-related events over a five-day period – the summer heatwave of July 2013 and the polar vortex of winter 2013/14. LEI's analysis found that NECEC (with [redacted] MW of energy flows per hour) could have resulted in \$6.0 million in wholesale energy market savings for Maine between the five-day period from January 24-28, 2014, and \$4.3 million in wholesale energy market savings between July 15-19, 2013. These savings represent a 12% and 21% reduction, in wholesale energy market costs during the January 24-28, 2014 and July 15-19, 2013 timeframes, respectively. These savings are a form of "insurance" that the project can provide electric ratepayers in the region and would be incremental to the annual wholesale energy market benefits identified in LEI's analysis under weather-normal conditions. These benefits are discussed in Section 2.4.

1.3.2 Environmental impacts

In terms of environmental benefits, LEI estimates that [redacted] TWh of hydroelectric-based energy flows on NECEC could reduce CO_2 emissions in New England by approximately 3.6 million metric tons per year. For this analysis, LEI did not monetize the social benefits of the CO_2 emissions reduction, nor did it analyze the emissions changes in other jurisdictions as a result of NECEC. These results are in line with Daymark's estimate of carbon emission reduction by 3.4 million metric tons.[12] The results of the CO_2 reduction are discussed in Section 2.5. Other greenhouse gas ("GHG") emissions include NO_X and SO_2 (which largely come from oil and coal generation). While LEI was not specifically asked to analyze the reductions in these pollutants, LEI expects the reductions to be small, as oil-fired electric production is minimal under normal weather conditions and coal-fired generation is expected to be phased out in LEI's Base Case forecast in the first few years.

1.4 Summary of LEI's independent analysis of the macroeconomic impacts to Maine

During the development and construction period of 2017 to 2022, the installation of the new transmission line and associated equipment is expected to generate 1,631 total new jobs per year and \$98.2 million increase in GDP in Maine, as presented in Figure 2, LEI's analysis for the development and construction period's macroeconomic impacts is based on \$567.8 million total local spending, and the year-by-year construction cost schedule was provided by CMP in response to ODR-003-011.[13]

For the first 15 years of the project's commercial operations (assumed to be 2023 to 2037), 291 new jobs will be created in Maine, according to LEI's analysis. Across all of New England, LEI's modeling suggests 1,826 new jobs on average per year. In addition, the Maine economy will also enjoy an increase in GDP of \$29.1 million per year. In New England, LEI's results show an increase in the six states' GDP of \$205.3 million per year on average. These benefits to the region accrue

[12] Although Daymark's analysis noted 3.1 million metric tons were attributable to NECEC in its report, 3.4 million metric tons was the approximate value for the 1086 Case based on Daymark's response to IECG-004-001, attachment 4.

[13] LEI did not adjust the project cost estimates provided by CMP. However, LEI is concerned about the local spending might have been over-estimated. Please see Section 5.2.1.

primarily due to lower wholesale electricity market costs. The project's wholesale electricity market savings are enjoyed by electric ratepayers across the region, roughly proportionally to their electric consumption due to the generally uncongested nature of the transmission system (except that Massachusetts retail consumers will see a smaller share of these benefits as compared to its overall load share of the New England regional load, because its electric ratepayers are responsible for the contract costs associated with the project, pursuant to the award made under the 83D RFP).

Figure 2. LEI's independent analysis of macroeconomic benefits (annual average)

Benefit categories	LEI Analysis	
	Maine	New England
Jobs - development and construction period (Annual average for 2017-2022)		
Direct	856	N/A
Indirect and Induced	775	N/A
Total	1,631	N/A
Jobs - operations period (Annual average for 2023-2037)		
Total	291	1,826
GDP - development and construction period (Annual average for 2017-2022), fixed 2009$ million		
	$98.2	N/A
GDP - operations period (Annual average for 2023-2037), fixed 2009$ million		
	$29.1	$205.3

Note: "N/A" signifies "not applicable." LEI did not estimate any macroeconomic benefits to other states in New England during the development and construction period. Economic impacts - new jobs and GDP increases - presented in the table are reported in annual average terms over the relevant modeling period (2017-2022 for the construction period and 2023-2037 for the operations period). The incremental new jobs and GDP impacts in New England during the operations period do not include those created by O&M activities related to the operations of the NECEC. Those pare modeled using the REMI PI+ model for Maine, rather than the REMI PI+ model for New England, to be in consistent with the USM analysis.

1.5 Comparison of LEI's analysis and Daymark's analysis

LEI's estimate of total wholesale electricity market benefits is approximately 58% lower than Daymark's analysis, and the estimate for total wholesale capacity market benefits is approximately 24% lower as shown in the figure below (in NPV terms).[14] The biggest difference lies in relation to Daymark's forecast of energy market benefits, specifically as it relates to the assumed natural gas price levels and generation availability during the summer months.[15] Capacity market differences between LEI and Daymark relate primarily to the FCA parameters for new entry, the slope of the demand curve, and the assumed quantity of cleared capacity in the FCM. In both LEI's and Daymark's analysis of NECEC, capacity market benefits dissipate over time as the capacity market supply-demand balance equilibrates over time, and capacity prices in the Project Case catch up to the capacity price levels forecast under the Base Case.

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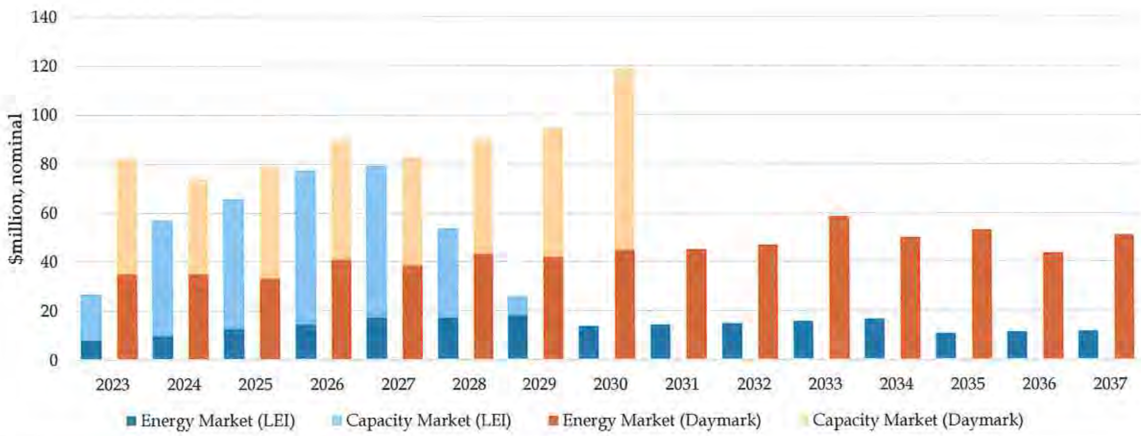
[14] LEI compared its analysis to Daymark's "1086 NECEC Case", as this case is the most similar in terms of total annual energy output.

[15] As noted in Section 7.6.2 of this report, new generation resources in LEI's analysis are in the form of combustion turbines (peakers). If baseload new entry, such as combined cycle gas turbines, were built in lieu of peakers in the long run, energy market benefits would dissipate over time and tend to zero as well.

Figure 3. LEI's and Daymark's estimate of wholesale electricity market benefits associated with NECEC



LEI identified four key drivers (see Section 4.1) that account for most of the differences in the wholesale energy market benefits projected by LEI versus Daymark:

1. Daymark's simplified modeling approach to account for maintenance and forced outages in AURORA resulted in artificially low supply availability when demand conditions peaked in the summer months and therefore overstated energy prices in those periods;

2. Daymark's delivered natural gas price outlook for generators was an average $1.3/MMBtu higher than LEI's outlook because Daymark's was based on an outdated projection for wellhead gas prices;

3. Daymark's energy prices - and therefore energy market benefits - were also affected by the unnecessary addition of "regional" and plant-specific ("peaker") adders to gas prices, which increased delivered gas prices for some units by $2-4/MMBtu above New England delivered gas prices;

4. Daymark used an outdated demand forecast from ISO-NE, which was 4-5% higher than the 2017 demand forecast that LEI relied on.[16]

As for capacity market benefits, LEI identified three key drivers (see Section 4.2) that account for the differences between LEI's and Daymark's capacity market price levels:

1. Daymark assumed a static slope of the demand curve by not adjusting the penalty factor over time. This resulted in slowly rising capacity prices, which prolonged the duration of the capacity market benefits. In addition, the penalty factor was calibrated for an outdated

[16] LEI recognizes that the use of 2016 CELT forecast was required by the MA RFP for purposes of bid submission. However, there is no basis to suggest that this MA RFP requirement should bind the MPUC in its decision-making in this case.

Net CONE of $10.95/kW-month (in January 2017, FERC approved the current Net CONE of $8.04/kW-month for FCA #12. LEI began its forecast with this Net CONE value);

2. Daymark assumed more generic entry at a lower price, which resulted in lower long-run capacity prices;

3. Daymark's analysis exhibited a high level of oversupply, which resulted in lower short-term capacity prices than LEI.

Figure 4 below compares LEI's wholesale electricity market benefits to Daymark's analysis.

Figure 4. Comparison of LEI's analysis and Daymark's analysis of wholesale electricity market benefits

	LEI Analysis		Daymark Analysis (1086 Case)	
	Maine	New England	Maine	New England
15-yr NPV, $2023 million				
Energy market benefits	$122	$1,197	$384	$2,839
Capacity market benefits	$223	$2,962	$292	$3,891
Total electricity market benefits	$346	$4,160	$676	$6,730
15-yr annual average, $nominal million				
Energy market benefits	$14	$134	$44	$384
Capacity market benefits	$19	$255	$27	$355
Total electricity market benefits	$33	$388	$71	$739

Note: LEI's energy market results are based on the average of 20 iterations (see Section 6.1) and were found to be statistically significant in all years of the modeling horizon.

1.6 Comparison of LEI's and USM's macroeconomic benefits

LEI compared its projection of macroeconomics benefits against the projection made by USM and included in the CPCN application (see Figure 5). LEI's analysis of the development and construction period is based on the updated project cost provided by CMP and USM,[17] and the results are generally close to the findings presented by USM. However, LEI notes that the development and construction benefits for Maine are highly correlated to the amount of local spending CMP expects during the installation of the project. CMP provided an estimate that is higher than what LEI has observed in other engagements involving other HVDC transmission projects. LEI recognizes that local spending around the capital costs for an HVDC transmission project will vary depending on location, amount of site preparation, availability of local skilled labor, as well as custom design elements of the project itself. That said, if the local spending amount for NECEC is lower than what CMP has estimated, then the macroeconomic benefits to Maine will be lower, and vice versa.

For the operations period, LEI's estimated macroeconomic benefits are similar to USM's for the State of Maine. A comparison of the results shows that LEI's estimated incremental jobs are lower than those estimated by USM by only 11%, or 37 jobs, per year (329 from the USM study vs. 291

[17] ODR-003-011_Attachment_1_CONFIDENTIAL (2017-232). In the updated construction cost estimate, the development period is 2017 and 2018, and the construction period is 2019-2022. In the original cost estimates, the development period was 2017 and the construction period was 2018-2022.

from the LEI study). In terms of GDP, LEI's results are slightly higher than USM's, primarily because of the additional wholesale capacity market benefits included in LEI's study. However, the inclusion of wholesale capacity market benefit is predicated on NECEC clearing the FCA. If NECEC fails to clear in the FCA (due to MOPR or other circumstances), the wholesale electricity market benefits will be much smaller (due to $0 wholesale capacity market benefits). Under such circumstances, the macroeconomic benefits will be further reduced by about 70% in both Maine and New England. Moreover, if NECEC fails to clear in the FCA but clears in the SA, it would trigger an additional 340MW retirement in New England, which will negatively impact both the New England and Maine economies.

New England wide, LEI's estimated economic benefits are much lower than USM's results. LEI estimated an annual average of 1,826 incremental jobs for all six states, which is 1,909 jobs, or 51%, less than USM's results. LEI's estimate for annual average GDP increase is $205.3 million, which is $200.9 million (or 50%) lower than USM's results. This difference arises mainly because LEI's analysis includes an estimate of the contract cost of the project, to be paid by Massachusetts retail electric ratepayers, as well as the macroeconomic impacts related to early power plant retirement (in Connecticut), triggered by the project's sale of capacity.

Figure 5. Comparison of LEI's analysis and USM's analysis

Benefit categories	LEI Analysis		USM Analysis	
	Maine	New England	Maine	New England
Jobs - development and construction period (Annual average for 2017-2022)				
Direct	856	N/A	868	N/A
Indirect and Induced	775	N/A	824	N/A
Total	1,631	N/A	1,691	N/A
Jobs - operations period (Annual average for 2023-2037)				
Total	291	1,826	329	3,735
GDP - development and construction period (Annual average for 2017-2022), fixed 2009$ million				
	$98.2	N/A	$94.1	N/A
GDP - operations period (Annual average for 2023-2037), fixed 2009$ million				
	$29.1	$205.3	$25.8	$406.2

Note:

1. Economic impacts in terms of incremental jobs and GDP presented in the table are the annual average of the modeling periods in LEI's study, namely 2017-2022 for the construction period and 2023-2037 for the operations period.
2. The incremental jobs and GDP in New England do not include those created by O&M activities of the NECEC project (indicated in the table as "N/A"), since the macroeconomic impacts of O&M spending is modeled within Maine, to be consistent with USM's approach.

The discrepancies in the macroeconomic benefits over the operations period between the two studies are driven by multiple factors as LEI and USM used different policy variables in the REMI PI+ model.[18] However, the biggest difference in the USM and LEI results stems from the inputs.

First, USM's analysis of the electricity cost savings was based on wholesale energy price reductions and these reductions were estimated based on inflated fuel price assumptions. LEI's

[18] For modeling electricity cost savings, LEI used "Consumer Price – Electricity" whereas USM used "Consumer spending – Reallocate consumption: Electricity."

analysis was based on the most up-to-date and realistic fuel price assumptions, and considered changes in both wholesale energy and capacity markets caused by the project.

Second, LEI estimated retail electric cost savings that capture the actual electricity cost reductions that end-users (electric ratepayers) will experience in the region. USM's electricity market benefits were based solely on wholesale energy price reductions, which are higher than retail price reductions, and hence resulted in overestimated macroeconomic benefits across the New England region.[19]

Third, LEI also considered the macroeconomic impacts of the contract costs borne by Massachusetts ratepayers by way of the contract award done for 83D RFP, and the impact of early power plant retirement triggered by the NECEC.[20] See Section 5 for a detailed comparison of LEI and USM analyses.

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[19] Over the modeling period, LEI's analysis shows that New England retail customers are exposed to 88% of wholesale energy price changes and 93% of capacity market price changes. Although LEI assumed that Maine retail consumers are exposed to 100% of wholesale price changes, reduced electricity market benefits in other states in New England will also have some negative impacts on the Maine economy.

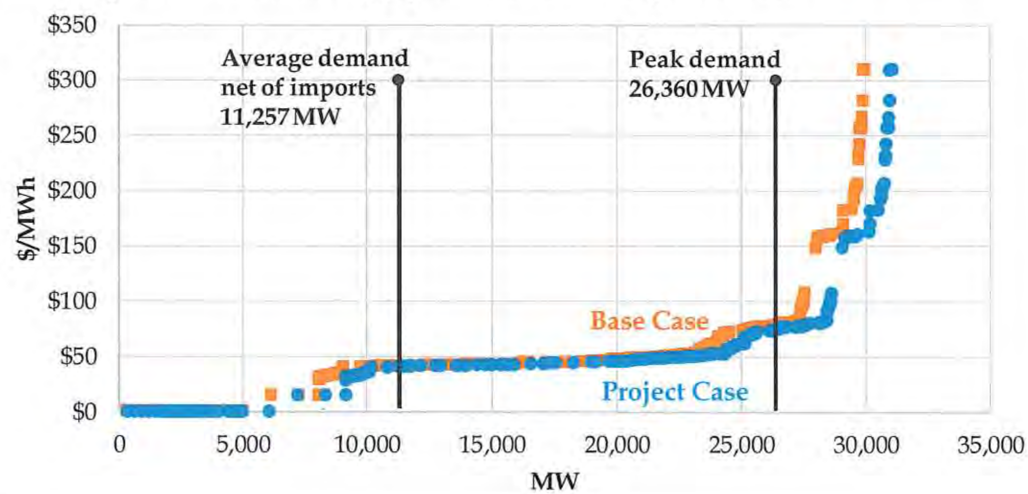
[20] LEI has also forecasted deferred new entry of generation plants in New England due to the project. Such impacts were not modeled in LEI's analysis, because the deferred investment is only for a few years, whereas plant closures imply permanent reduction in employment.

2 Wholesale Electricity Market and Environmental Benefits of NECEC

LEI estimates that NECEC would provide Maine \$346 million (in 2023 dollars) in wholesale electricity market benefits over the first 15 years of operation (2023-2037). Of this amount, \$122 million is expected to come from wholesale energy market savings (average of \$14 million per year in nominal dollars) and \$223 million is expected to come from capacity market savings (average of \$19 million per year in nominal dollars), assuming NECEC clears the primary auction in FCA #14. LEI estimates that if the severe weather conditions that occurred in 2013 were to re-occur in the future, NECEC would have the ability to reduce wholesale energy market costs for Maine ratepayers by \$4.3 million over a five-day period during the summer 2013 heat wave and \$6.0 million over a five-day period during the winter 2013/14 polar vortex. LEI also estimates that NECEC would reduce CO_2 emissions from New England generators by approximately 3.6 million metric tons.

ISO New England ("ISO-NE") oversees and administers the competitive wholesale electricity markets for the six states of New England. It operates a day-ahead and real-time energy market, a forward capacity market ("FCM"), an ancillary services market, and a market for financial transmission rights. LEI's analysis focused on the most significant cost components of the wholesale electricity markets, which include the wholesale energy and capacity markets. Pursuant to Avangrid's commitment under the MA RFP, LEI assumed that NECEC delivers energy around the clock, totaling [redacted] GWh per year (spread evenly across all hours).[21] LEI also assumed that the shippers on NECEC would offer as price takers in the wholesale energy market in order to fulfill their contractual obligations to Massachusetts. By virtue of these energy sales, other more expensive generation resources will not be dispatched and consequently, the market clearing price for energy (i.e., Locational Marginal Prices ("LMPs")) will decline, as suggested in the illustrative supply curve diagram below.

Figure 6. Example of the internal supply curve for New England in 2027



[21] LEI understands that NECEC was selected as part of the Massachusetts 83D RFP, providing up [redacted] GWh of energy annually into the New England wholesale energy market; this value was also confirmed by Mr. Jared des Rosiers during the April 5, 2018 Technical Conference.

LEI understands that NECEC is not selling capacity as part of the long-term commitment under Massachusetts' 83D RFP.[22] LEI evaluated the possibility of wholesale capacity market benefits using the latest capacity market rules as of the first quarter of 2018. Recently, FERC approved ISO-NE's proposed CASPR rules.[23] The objective of CASPR is to develop a transparent, market-based approach that results in competitive capacity pricing and accommodates the entry of new capacity resources that have been sponsored through various state policy initiatives, without shifting the costs of one state's subsidies to another state's consumers.[24] To best satisfy these objectives, ISO-NE proposed conducting the capacity market in two stages. In the first stage (known as the primary auction), the ISO would clear the FCA as it does today, with new resources subject to the existing MOPR rules.[25] In the second stage, which immediately follows the primary auction, ISO-NE would administer a new, voluntary secondary market known as a substitution auction. In the substitution auction, existing capacity resources that obtained capacity supply obligations ("CSOs") in the primary auction and are willing to exit all ISO-NE-administered markets permanently may transfer their CSOs (in their entirety) to Sponsored Policy Resources ("SPRs") that did not acquire a CSO in the primary auction. The transferring resources must pay the SPR a portion of their capacity revenue (the clearing price in the substitution auction), and then permanently retire from all ISO-NE-administered markets. As such, existing resources represent the "demand" in the substitution auction, and new SPRs represent the "supply."

As a result of being selected for the Massachusetts 83D RFP, NECEC would qualify as a SPR. LEI did not conduct an analysis to estimate NECEC's MOPR. Such an analysis could be used to determine whether a new resource could clear the FCA. CMP did not provide sufficient data for LEI to perform such analysis. LEI's capacity market benefits assume that NECEC's MOPR is sufficiently low that the project would clear the primary auction at the [redacted]/kW-month estimated price level for FCA #14. However, if NECEC does not clear the primary auction and has to go into the substitution auction, then the FCA price would not be affected and there would not be any wholesale capacity market benefits from NECEC. Because an equivalent amount of capacity would need to exit all ISO-NE administered markets in the substitution auction in order for an SPR to clear, adding 1,090 MW of capacity from NECEC would result in 1,090 MW of permanent retirements.

2.1 LEI's Base Case view of wholesale energy and capacity prices

LEI employed its proprietary simulation model, POOLMod, to develop a wholesale energy price forecast for the Base Case and Project Case. The FCA Simulator, a proprietary modeling tool created by LEI, was used to forecast capacity market prices under the Base Case and Project

[22] The Energy Diversity Act directs Massachusetts Electric Distribution Companies ("EDCs") to jointly and competitively solicit proposals for and to enter long-term contracts for Clean Energy Generation and/or RECs only, associated with clean energy in an annual amount of [redacted] MWh.

[23] ER18-619-000 Revisions to ISO-NE Tariff Related to Competitive Auctions with Sponsored Policy Resources. <https://www.iso-ne.com/static-assets/documents/2018/01/er18-619-000_caspr_filing.pdf>

[24] ISO-NE. *Competitive Auctions with Subsidized Policy Resources: ISO Discussion Paper*. April 2017. < https://www.iso-ne.com/static-assets/documents/2017/04/caspr_discussion_paper_april_14_2017.pdf>

[25] Under the MOPR, capacity market bids below the minimum price thresholds set by the ISO will clear only if they passed a unit-specific review by the ISO's market monitor where any "out-of-market" revenues - such as bilateral contracts with Massachusetts - would be excluded in its bid analysis. Under CASPR, the Renewable Technology Resource ("RTR") MOPR exemption would be phased out.

Case.[26] In order to isolate and estimate the potential benefits that NECEC can provide to Maine, LEI developed energy and capacity price forecasts in New England without the addition of any large Elective Transmission Upgrade ("ETU") such as NECEC or any equivalent project.

2.1.1 Gas prices are a key factor driving future energy price trends in New England

Because the dominant fuel in New England is natural gas (therefore in most hours, natural gas-fired generation is marginal), energy price levels are mostly impacted by natural gas prices. LEI relied on the Algonquin Citygate price as the estimate of the delivered natural gas price for gas-fired generators in New England. LEI relied on the forward markets for projecting the starting values for Algonquin Citygate gas prices for 2018 and 2019.[27] From 2020 and onward, LEI projected the Algonquin Citygate gas price based on a supply hub price plus a transportation adder to New England calculated by LEI's proprietary Levelized Cost of Pipeline ("LCOP") model.[28] To derive that monthly profile, LEI applied the historical five-year (2013-2017) seasonality of Algonquin Citygate prices.[29] Figure 7 below shows the monthly delivered natural gas prices used in LEI's wholesale energy market modeling.

Figure 7. Monthly Algonquin Citygate prices (historical and LEI's outlook)

[redacted]

Source: SNL (2014-2017) and LEI's LCOP (2018-2037)

[26] Detailed descriptions of POOLMod and FCA Simulator can be found in Section 6 and detailed assumptions used in the modeling can be found in Section 7.

[27] LEI used the three-month average of daily forwards (January 1, 2018 - March 31, 2018), as reported by OTC Global Holdings ("OTCGH") for the 2018 and 2019 monthly prices.

[28] The LCOP model assumes that price spreads between any two gas pricing hubs cannot, in the long run, persist above the levelized cost of building a new pipeline between the two hubs. The LCOP model assumes that if the price spread rises above the levelized cost of building a pipeline between any two hubs for three consecutive years, then a pipeline will be built between the two hubs to reduce the price spread.

[29] LEI used historical seasonality in monthly prices rather than the seasonality of the forward curve. Historical seasonality reflects the actual experience in the market; using an average of 2013-2017 captures warmer-than-normal, colder-than-normal, and normal winters. The difference between using the historical method versus using the seasonality of the current forward curve is very small, except for February, when the historical method projects slightly higher prices (e.g., $10 per MMBtu for Algonquin Citygate in 2018 and 2019) than the forward curve projects (about $9 per MMBtu for Algonquin Citygate in 2018 and 2019). The historical method captures the larger impact of cold weather at the end of the season (in February), when gas inventories tend to be relatively depleted.

The Base Case energy price forecast for the ISO-NE control area largely resembles the trend in natural gas prices as shown below in Figure 8. Two factors, however, should be noted, which affect the energy market trends slightly. Between 2023 and 2029, implied market heat rates improve as a result of the addition of offshore wind resources (as a consequence of Massachusetts' 83C RFP) and also as a result of declining total demand. Then, beginning in 2030, a reduction in New York import volumes due to the retirement of Ginna (2030) and Fitzpatrick (2035) nuclear stations necessitates more local gas-fired generation in New England and increases the implied market heat rates. LEI also retired Millstone 2 in 2035[30] when its nuclear license expires; this plant retirement has a similar effect on energy market prices as the New York retirements (and changing pattern of imports).

Figure 8. LEI's Base Case energy and natural gas price forecasts

[redacted]

2.1.2 Peak demand growth and CONE are key determinants of capacity price in New England

LEI's capacity market analysis requires a forecast of future Net Installed Capacity Requirement ("NICR"), Net CONE, and consideration of supply changes (new entry and retirements). LEI's NICR is a function of ISO-NE's CELT 2017 peak demand net of behind-the-meter solar PV.[31] The Base Case and Project Case rely on the same peak demand forecast (CELT 2017) and therefore have the same NICR.

LEI's Net CONE is based on ISO-NE's estimate of Net CONE for a combustion turbine in its latest published Net CONE and Offer Review Trigger Price ("ORTP") study.[32] LEI then forecasted the Net CONE by escalating the gross CONE by the inflation rate from the Bureau of Labor Statistics's Producer Price Index for Turbine and Turbine Generator Set Units Manufacturing, and inflating the energy and ancillary services offset by the trend in wholesale energy price growth from LEI's simulation modeling results. As a result of these calculations, the Net CONE differs slightly between the Base Case and the Project Case.

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[30] Millstone 3's nuclear license expires in 2045, and Seabrook is currently looking to extend its license to 2050.

[31] ISO-NE, CELT 2017.

[32] ISO-NE FERC Filing ER-17- 795-000. January 13, 2017.

For supply assumptions, results from New England's most recent FCA, FCA #12, showed that New England is oversupplied for the 2021-2022 capability period by approximately 1,103 MW. The amount of oversupply has grown over time - after FCA #9, New England was only oversupplied relative to NICR by 506 MW for the capability period of 2018-2019. Because much of the peak demand (net of behind-the-meter solar PV) growth is offset by the growth in energy efficiency, LEI's analysis projected that even in the Base Case, no new generation would be needed until FCA #18 (2027). This projection assumed offshore wind SPRs would clear in the substitution auction, and therefore would not impact capacity clearing prices. In the short-term, LEI assumed that coal would exit the Base Case by FCA #14, based on LEI's estimate of coal units' net going-forward costs. LEI also assumed that Mystic 7 would exit in FCA #13, as it has already submitted a retirement de-list bid. ISO-NE is seeking to retain Mystic 8 and 9 for fuel security reasons, based on the latest available information at the time that LEI was conducting its independent analysis. Therefore, LEI assumed Mystic 8 and 9 would participate in the ISO-NE markets in FCA #13 and onwards.[33]

In the long-run, capacity prices are expected to converge towards Net CONE as shown below in Figure 9. New entry in the form of combustion turbines (in 50 MW increments) was added to the New England power system. As such, the long run qualified capacity is almost identical to the NICR.

Figure 9. LEI's Base Case capacity prices and Net CONE

[redacted]

2.2 Projected energy market benefits

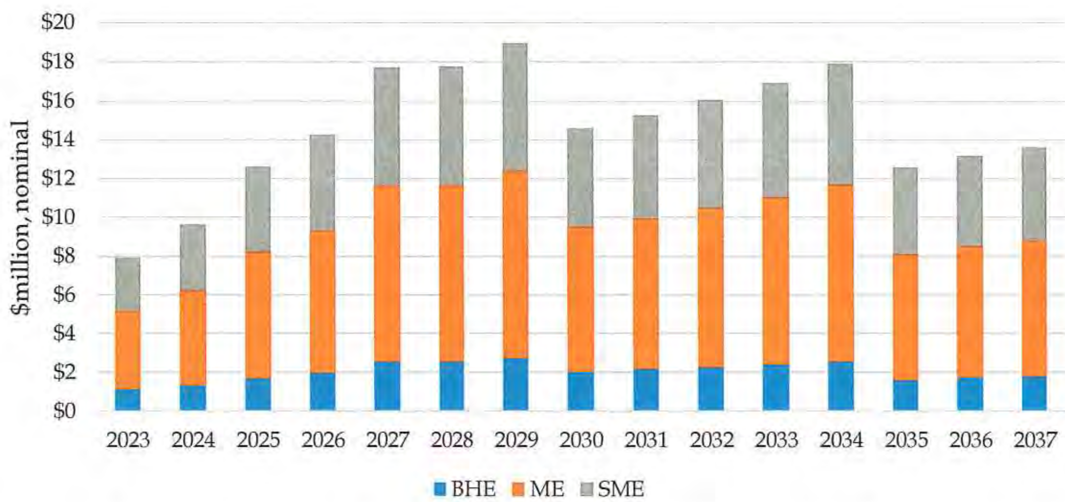
After developing the Base Case, LEI ran a simulation model to estimate the LMP impact of injecting [redacted] GWh of energy into New England over NECEC. LEI estimates that wholesale energy prices will decline by approximately [redacted] per MWh across New England in nominal dollars over the first 15 years of operations (2023-2037). For Maine, wholesale energy prices are

[33] On April 3, 2018, ISO-NE released a memo to the NEPOOL Participants Committee citing near-term fuel security concerns. These concerns prompted ISO-NE to request FERC to waive ISO's Tariff to allow the ISO to retain Mystic 8 and 9 to maintain fuel security on the system.

expected to decline by a weighted average of [redacted] per MWh in nominal dollars (load-weighted average of Bangor Hydro Electric, Maine, and Southern Maine) over the same timeframe. This is equivalent to wholesale energy market benefits of roughly $14 million annually (nominal dollars) for Maine, or $134 million annually (nominal dollars) for all wholesale load across the six states in New England on average for the forecasted timeframe.

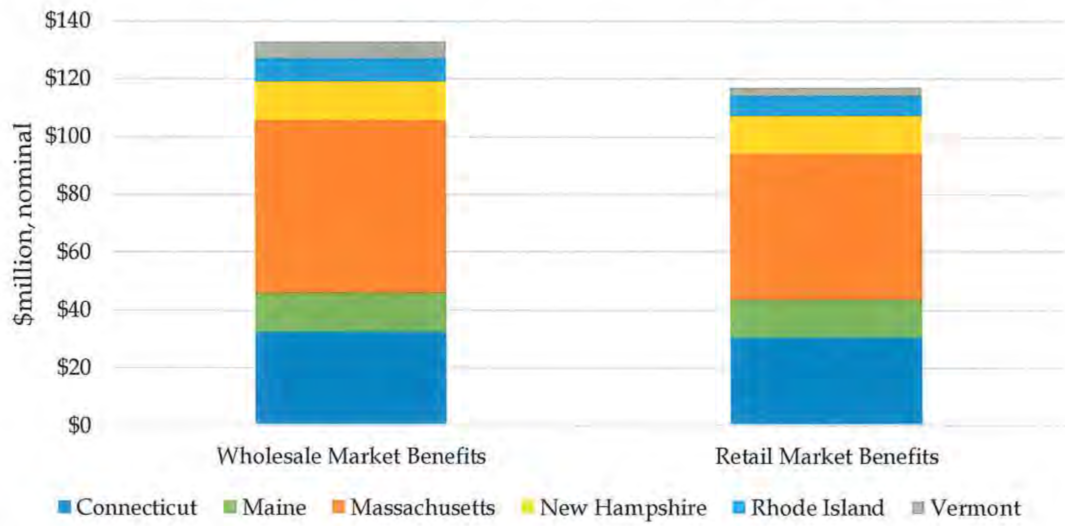
The 15-year NPV of NECEC's wholesale energy market benefit over the same timeframe is $122 million (in 2023 dollars) for Maine and $1.2 billion (in 2023 dollars) for all of New England. Figure 10 below shows the annual energy market benefits for the Maine zones over the first 15 years of operations. LEI also estimated the market impacts for retail customers in Maine and New England, which is shown in Figure 11. This accounts for the energy and capacity under long-term contracts or self-supply.

Figure 10. Annual wholesale energy market benefits in Maine



Note: The three Maine zones modeled include Bangor Hydro Electric ("BHE"), Maine ("ME"), and Southern Maine ("SME").

Figure 11. Annual average wholesale versus retail energy market benefits by state



Note: Retail energy market benefits in New England are lower than wholesale market benefits because some portion of energy or capacity is under contract or self-supply.

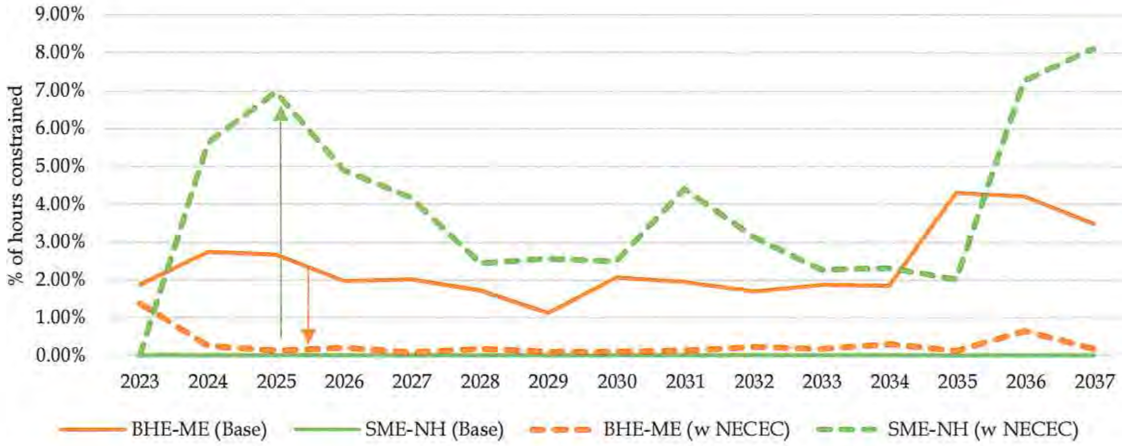
As indicated in ISO-NE's CELT 2017 forecast, overall energy demand is expected to decline as a result of energy efficiency and solar PV resources. Against this backdrop of falling demand, LEI also expects that Massachusetts will procure 1,600 MW of offshore wind between 2024 and 2027, resulting in even less need for thermal generation within New England. During the shoulder months (September - November, and April - May), off-peak demand in New England can be particularly low (about 8,000 MW in some hours). When coupling the large amounts of renewable energy with low demand, LEI found that the injection of nearly 1,090 MW around the clock through NECEC can reduce average off-peak prices considerably, as opposed to just average peak prices. LEI, therefore, observed increasing energy market benefits during that period.

LEI also found that the nuclear retirements in New England and New York will require higher-cost generation to run in New England. This caused LMPs in the Project Case to rise slightly faster than in the Base Case, particularly during the off-peak hours. As such, even though the nuclear retirements cause price levels to rise in both the Base Case and Project Case, the energy market benefits decline in 2030 and 2035, because of the higher *relative* price level increase in the Project Case.

In LEI's wholesale energy market analysis, the energy market benefits do not fully dissipate because new resources added in the Base Case (combustion turbines) are not inframarginal in most hours. If inframarginal generation resources (i.e. baseload resources such as combined cycle gas turbines) were added in the Base Case, LEI expects that the energy market benefits would dissipate over time towards zero (if, over time, [redacted] TWh of baseload energy is added in the Base Case, the LMP would be the same as in the Project Case).

As noted above, the LMP reduction in Maine is slightly higher than the rest of New England. The reason is that LEI's modeling indicated that some minor congestion would occur along the Maine - New Hampshire interface. LEI adopted Daymark's assumptions of increasing the transfer limit of the SME-NH interface by 1,000 MW from 1,600 MW to 2,600 MW.[34] LEI's flow duration curve indicates that on average, approximately 4.3% of hours are constrained along this interface. Figure 12 shows the congestion along the Orrington South and SME-NH interfaces.

Figure 12. Percentage of hours BHE-ME and SME-NH interfaces are binding



2.3 Projected capacity market benefits

LEI's modeling results indicate that 1,090 MW of qualified capacity from NECEC clearing in the primary auction of the FCM will decrease capacity prices by an average of [redacted] per kW-month (nominal dollars) in New England for six years between FCA #12 - #19 (2023–2029). This represents wholesale capacity market benefits of roughly $19 million annually for Maine (nominal dollars), or $255 million annually for all wholesale load across the six states in New England over the 15-year modeling timeframe (nominal dollars). In NPV terms, the 15-year wholesale energy market benefit is equivalent to $223 million for Maine, and $2.9 billion for all of New England (in 2023 dollars). If NECEC's MOPR price is higher than the clearing price and NECEC is cleared in the substitution auction, then there would be no capacity market benefits. Figure 13 below shows the capacity market benefits split between Maine and the rest of New England. Maine's benefits are relative to its share of peak load, which is approximately 7.5% on average.

[34] CMP response to ODR-003-019

Figure 13. Annual wholesale capacity market benefits

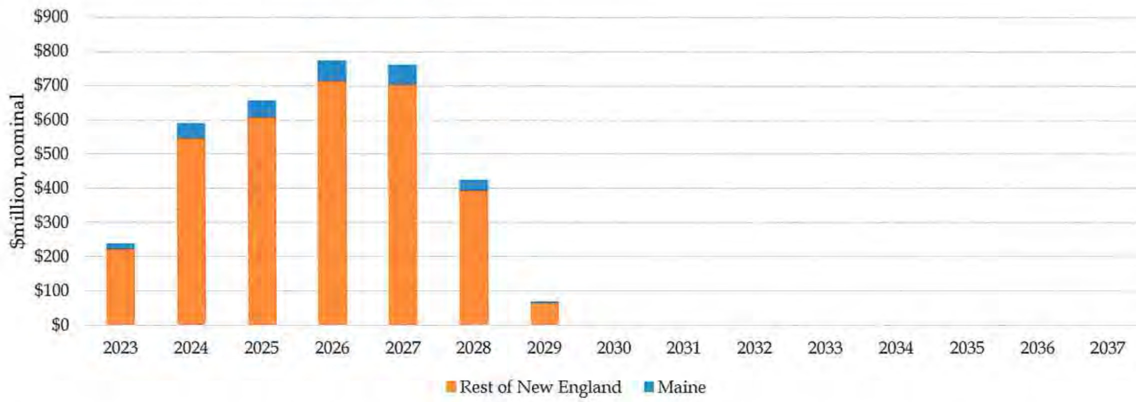
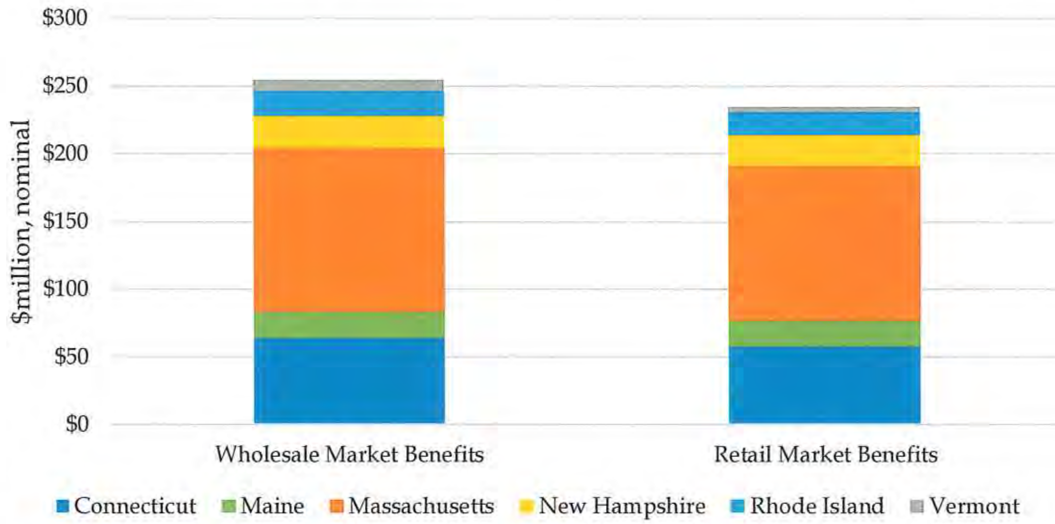


Figure 14. Annual average wholesale versus retail capacity market benefits by state



Note: Retail capacity market benefits in New England are lower than wholesale market benefits because some portion of capacity is under contract or self-supply.

As noted previously, NECEC may need to clear in the substitution auction, for example, if its custom MOPR price turns out to be above the capacity market clearing price ([redacted]/kW-month in LEI's estimate). It may also qualify in subsequent primary auctions (FCAs), and result in capacity market benefits in the future (although the magnitudes of those benefits have not been studied in this report). However, if NECEC were to clear in the primary auction of FCA #14, LEI estimates that given the current level of supply and demand in the FCM, NECEC would displace approximately 750 MW of existing capacity resources in the FCM. This is because New England is currently already oversupplied, particularly given the growth in energy efficiency in the past two auctions, FCA #11 and #12. The most recent FCA, FCA #12, cleared at $4.63/kW-month, which is the lowest price in five years. However, this low price was sustained due to ISO-NE retaining Mystic 7 and 8 for local reliability needs in Boston. Were Mystic 7 and 8 allowed to exit FCA #12, capacity prices would have been higher.

In order to estimate the level of market response, LEI prepared proxy retirement de-list bids (taking into account future expected energy and capacity revenues as specified in ISO-NE's retirement de-list workbook). These bids include fixed O&M, risk premiums, and incremental capital expenditures based on a mix of publicly available information, third-party commercially available data, and LEI's original research. While there is uncertainty about the exact price of the retirement de-list bids for New England generators, FCA #12 does provide some indication that at least some plants are looking to retire or de-list in the $2/kW-month to $5/kW-month range.

In LEI's modeling, supply and demand are expected to rebalance over the next few FCAs and supply (total CSO) roughly equals demand (NICR). By ISO-NE's design, the resulting capacity price at this level of supply would equal the Net CONE. The Net CONE represents the break-even price that the most cost-effective resource would require to be economic. Therefore, in the long run, new resources should enter the market when it is economic, which is when the capacity price is at Net CONE.

Similar to the Base Case, the capacity market under the Project Case would also rebalance. Because 1,090 MW of new capacity from NECEC is only offset by 750 MW of retirements, approximately 340 MW of *incremental* capacity is added. The size of this incremental capacity relative to peak load growth means that it will take *longer* for the capacity price to reach long-run equilibrium. By 2030, both the Base Case and the Project Case rebalance towards the net CONE in LEI's modeling of NECEC, and the capacity market benefits end.[35]

2.4 Insurance value from NECEC due to weather-driven events

In periods of system stress, NECEC can provide significant additional value to electric ratepayers across New England because they can extinguish or partially dampen the higher energy prices associated with extremely high demand or high fuel prices. New supply projects like NECEC could offset very high-cost generation. For example, when load peaks over repeated days during New England's summertime or when the gas infrastructure is highly constrained and gas supply is limited (and expensive), the energy flows on NECEC can provide a source of lower-cost energy that cannot otherwise be generated by local resources in New England. NECEC can serve as a form of "insurance" against the financial impact of such events, protecting consumers from at least a portion of the higher market costs that are a consequence of such events. Through backcast simulation modeling, LEI recreated past market conditions that exhibited very high energy prices under summer and winter stress events. LEI then added expected energy imports that would be available through NECEC into the backcast supply mix and thereby evaluated the wholesale market cost savings produced by NECEC under such system stress conditions.

2.4.1 Summer system stress event

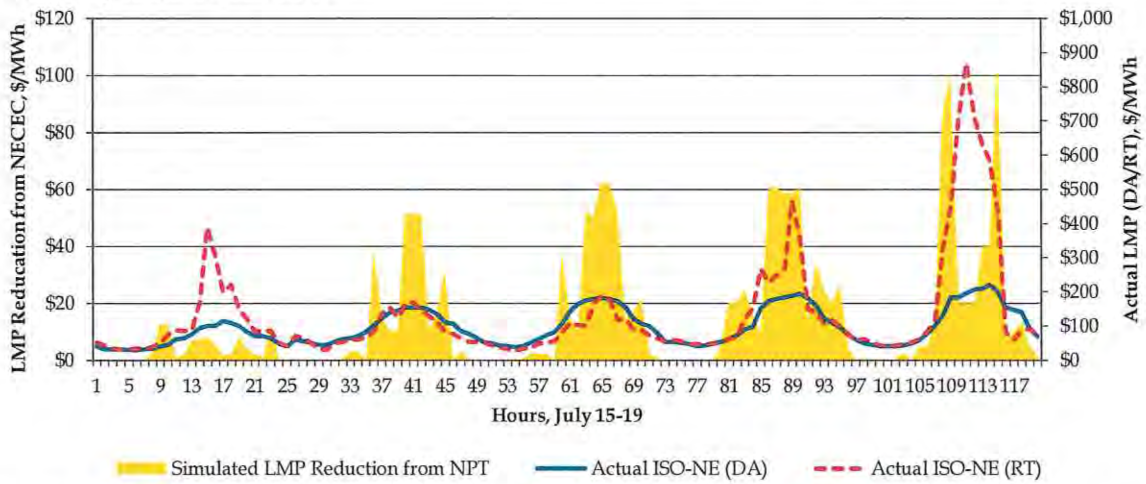
Between July 15 and July 19, 2013, New England experienced a prolonged heat wave. During this period, more expensive peaking units were dispatched to serve the higher electricity load in the

[35] LEI's analysis shows a very small difference of 13 MW in the total amount of cleared capacity beyond FCA #19. This results solely from the differences between the amount of capacity that enters in the Base Case (50 MW increments) and the amount of market response in the Project Case. Therefore, LEI assumes that the benefits beyond FCA #19 are zero.

region. Day-Ahead ("DA") and Real-Time ("RT") wholesale energy prices rose markedly in comparison to the normal range of energy prices for this time of the year. For example, Real-Time LMPs exceeded $400/MWh for seven hours on July 19th, while the typical LMP during this month is only $40/MWh (based on the prior two years). The weather was a big contributor to the high prices, as peak load surpassed the ISO-NE's 90/10 demand forecast from the prior year. Similar peak demand occurrences have occurred in other years - indeed, ISO-NE has recorded actual demand exceeding 90/10 expectations six times in the last 24 years.[36] In addition to high LMPs on this day, ISO-NE had a capacity deficiency, which resulted in the ISO-NE declaring an "OP4" event.[37] There were 4,724 MW of generator outages and reductions over the peak hour of the day that contributed to system stress and ultimately the OP4 declaration.[38]

If such summer extreme weather were to re-occur, energy flowing on NECEC could have reduced energy prices by more than $20/MWh on average across New England over this period. In summary, during this five-day heat wave, LEI estimates that the "insurance" value that NECEC could have provided New England consumers is approximately $51.7 million.

Figure 15. Illustration of LMP reductions associated with NECEC's energy flows during a summer system stress event



Note: The hourly DA and RT LMPs shown are sourced from actual ISO-NE data. The LMP reduction is based on market simulations using actual conditions (actual hourly levels of demand, actual hourly interchange between neighboring markets, and actual reported costs for various fuel types).

2.4.2 Winter system stress event

The winter of 2013/14 was extreme in terms of natural gas prices in New England as well as low temperatures. Periods of severe cold weather resulted in increased gas demand from Local Distribution Companies ("LDCs", entities that source natural gas on behalf of their retail

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[36] ISO-NE. *2015 Regional System Plan*, pg. 34

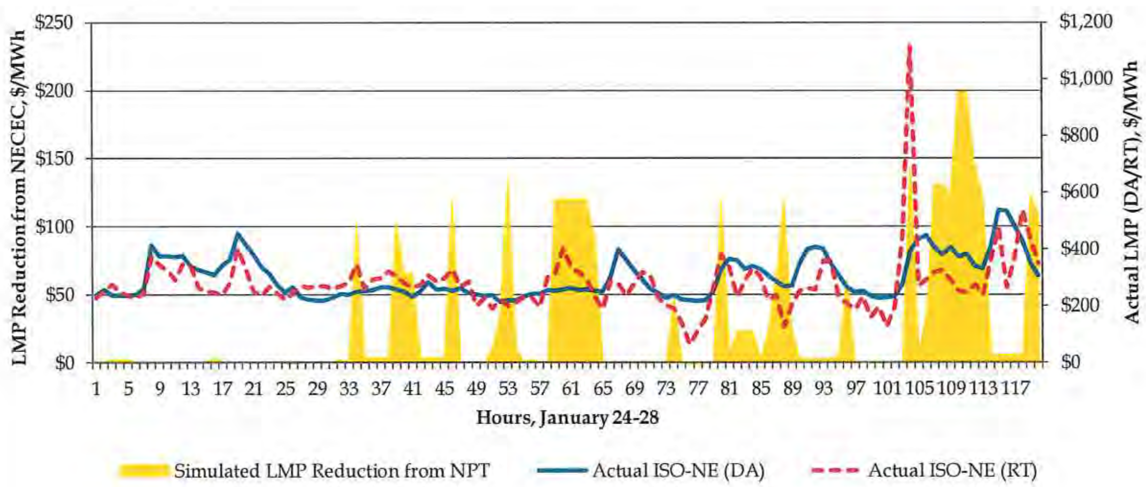
[37] Operation Procedure No. 4 ("OP4") establishes criteria and guides for actions during capacity deficiencies, as directed by ISO-NE, such as when available resources are insufficient to meet the anticipated load plus operating reserve requirements.

[38] ISO-NE. 2014 Third Quarter - Quarterly Markets Report.

customers for heating load) and, consequently, physical limits on the region's natural gas pipeline network emerged. These fuel delivery constraints, along with a number of unplanned outages at other generators, led to exceptionally high delivered natural gas prices, and, as a result, very high wholesale energy prices.[39] In addition, ISO-NE's Winter Reliability Program ("WRP") caused oil-fired generation to displace gas-fired generation during some periods, resulting in unusual changes in the generators' merit order where oil was setting prices.

The $24.5/MMBtu average price for natural gas in January 2014 was the highest average monthly price in more than 10 years, with a daily price of over $73/MMBtu on one day (occurring on January 28, 2014). As a result of high delivered gas prices, oil-fired generation became cheaper than gas-fired generation on some days and given the availability of oil on-site for those plants that signed up for the WRP, some oil-fired units were able to be dispatched. These oil-fired units contributed to system security during these Polar Vortex events, particularly in January 2014. However, emissions of various pollutants increased as a result of oil-fired generation of electricity. And, nonetheless, both DA and RT energy prices were high, relative to historical prices during the winter peak.

Figure 16. Illustration of LMP reductions associated with NECEC's energy flows during winter system stress event



Note: The hourly DA and RT LMPs shown are sourced from actual ISO-NE data. The LMP reduction is based on market simulations using actual conditions (actual hourly levels of demand, actual hourly interchange between neighboring markets, and actual reported costs for various fuel types).

Based on LEI's simulation-based backcast, NECEC could have reduced energy prices during such conditions by $37/MWh on average over this five-day period. LEI estimates that this equates to an implied "insurance" value for consumers across New England of approximately $72.3 million over a five-day period.

ISO-NE's most recent Operational Fuel-Security Analysis suggests that fuel security, particularly during the high-demand cold spells, presents the foremost risk to current and future power

[39] ISO-NE. *Cold Weather Operations*. Peter Brandien. April 1, 2014.

system reliability. ISO-NE also noted that a resource mix with higher levels of liquefied natural gas ("LNG"), imports, and renewables shows less system stress than its reference case, and that "to achieve these levels of LNG, imports, and renewables, firm contracts for LNG delivery, assurances that electricity imports will be delivered in winter, and aggressive development of renewables, including expansion of the transmission system to import more clean energy from neighboring systems, would be required."[40]

2.5 Environmental benefits

The results of LEI's modeling show that NECEC reduces annual CO_2 emissions from New England generators by approximately 3.6 million metric tons.[41] The CO_2 emissions reduction is fairly constant over time because of the assumed level of energy flows on NECEC and the similarity in the emissions footprint of the generating resources that are being displaced by the energy flows on NECEC. This average is approximately equivalent to removing 767,000 passenger vehicles from the road based on estimates by the Environmental Protection Agency.[42]

However, the 3.6 million metric tons of CO_2 reductions estimate are based on how much CO_2 is reduced from internal New England generators. There is also substantial scientific and policy debate on how to estimate possible CO_2 emissions from large hydroelectric resources that would flow through NECEC. LEI acknowledges that large hydroelectric resources may emit carbon due to the decomposition of biological material in a newly-formed reservoir. Based on studies conducted by Hydro Québec scientists, it has been forecast that a large hydroelectric complex such as Eastmain 1/1A had a lifecycle emissions profile of greenhouse gases of 136 lbs./MWh.[43] This figure is higher than the actual historical system-wide profile of CO_2 emissions reported by Hydro Québec of 239 metric tons/TWh (approximately 0.5 lbs./MWh).[44] Although the emissions profile of new large hydroelectric plants is likely to be higher in the initial years than this lifecycle figure, it is difficult and intractable to pinpoint the exact, time-specific emissions profile of the energy flows on NECEC. Based on a lifecycle rate of 136 lbs./MWh, LEI estimates that this results in approximately [redacted] metric tons based on [redacted] GWh. This value, however, still contrasts significantly with the emissions associated with a natural gas-fired generation, which can typically emit between 700-1,000 lbs./MWh (depending on the heat rate).

Figure 17 below shows the CO_2 emissions reductions for New England over the modeling timeframe. As noted previously, as a result of nuclear retirements in New York and New England, more local fossil-fuel generation is required in 2030 and 2035. As a result, similar to the

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40 ISO-NE, Operational Fuel-Security Analysis, January 17, 2018. <https://www.iso-ne.com/static-assets/documents/2018/01/20180117_operational_fuel-security_analysis.pdf>

41 According to the calculator available on the Environment Protection Agency website, this is equivalent to removing approximately 675,000 passenger vehicles per year. *See.* "Calculations and References." <https://www.epa.gov/energy/ghg-equivalencies-calculator-calculations-and-references#vehicles>. Accessed December 28, 2016.

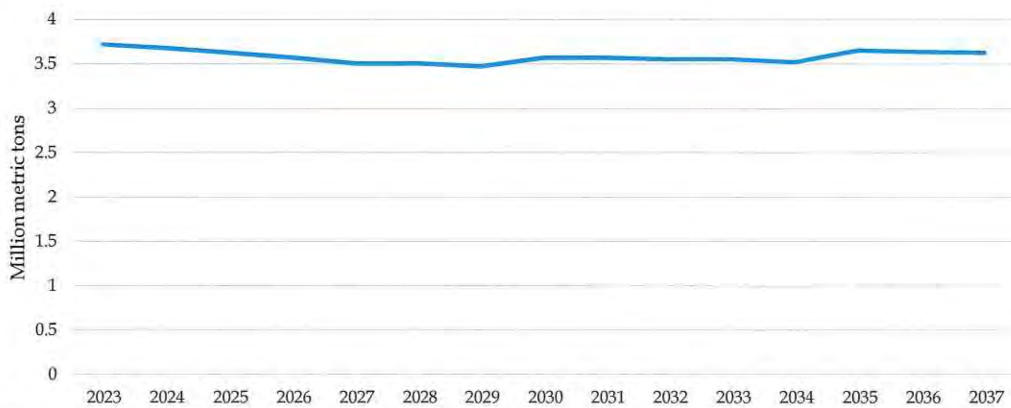
42 EPA, Greenhouse Gas Equivalencies Calculator. <https://www.epa.gov/energy/greenhouse-gas-equivalencies-calculator>

43 Teodoru, C. R., et al. (2012), The net carbon footprint of a newly created boreal hydroelectric reservoir, Global Biogeochem. Cycles, 26, GB2016.

44 Hydro Québec Production's Electricity Facts. 2013.

energy market benefits, the emissions reductions fall slightly in 2030 and 2035 as more of that fossil-fuel generation is required in the Project Case relative to the Base Case.

Figure 17. Projected CO_2 emissions reduction for New England



3 Macroeconomic Benefits Analysis of NECEC

This section discusses the methodology adopted by LEI in its independent analysis of the macroeconomic results surrounding the construction and operations of NECEC. LEI estimated the development and construction impacts of the project using CMP's estimate of local spending and the timetable of construction (2017-2022). Maine would expect an average 1,631 jobs per year, and a $98.2 million GDP increase over this period. LEI then estimated the macroeconomic impact of the electricity savings created by NECEC once it starts operating in 2023. During the first 15 years of operations (2023-2037), LEI projects 272 new jobs per year and a $27.1 million increase in GDP per year for Maine related to the project's O&M activities and ratepayers' electricity savings.

LEI used a suite of proprietary wholesale electricity market modeling tools (described in detail in Section 2.1) and the widely-accepted PI+ macroeconomic model by REMI to analyze the macroeconomic impact of the NECEC project on the local economy in Maine, as well as the impacts on the entire New England region. Section 3.1 below explains the modeling tools and analytical methodology used in LEI's macroeconomic analysis. Section 3.2 and Section 3.3 present the local and regional economic impacts of the project during the construction and operations periods, respectively.

3.1 The modeling tool and analytical methodology

3.1.1 REMI PI+

LEI analyzed the macroeconomic benefits of the proposed transmission investment using a regional economic modeling tool, the REMI PI+ model. The REMI PI+ model was developed by the Regional Economic Modeling, Inc. ("REMI"). REMI PI+ is a dynamic simulation-based model of local (state and county) level economic activity. It is commonly used to model and measure the impact of various supply and demand shocks (new infrastructure is like a supply shock) and policy changes on the local economic activity and labor markets.[45]

LEI used the same PI+ software (in terms of regional configuration and industry depth) as USM for analyzing the macroeconomic impacts of the NECEC project. This eliminated any discrepancies in results that may have otherwise been caused by differences in model vintages and/or granularity of the representation of local economy. Specifically, LEI used a seven-region, 70-sector regional model of the Maine economy for studying the economic impacts of construction and operations spending associated with the project in Maine, and a six-region, 20-

[45] The REMI PI+ model is a regional economic model that incorporates basic Input/ Output ("I/O") functionality in a Computable General Equilibrium model with advanced Economic Geography and other econometric time-series modeling capabilities, and regression techniques. Economic shocks and policy changes can be captured and simulated in the REMI's PI+ model through adjustment of different categories of policy variables. These variables are interconnected through geographical linkages and industrial ties, and affect each other through direct and indirect economic impacts. Such dynamic impacts are ultimately reflected in the modeling results, through changes in population, trading activities, economic outputs, employment, product prices and labor compensation rates.

sector regional model of the six New England states for estimating wholesale electricity market impacts.

3.1.2 Analytical methodology

LEI analyzed the macroeconomic impacts of the project during the development and construction period and the operations period separately, as the economic activities and the socio-economic impacts across these two periods are different.

During the development and construction period, a transmission project's capital expenditure has direct economic impacts on the local economy, through boosting demand and economic activities in the construction sector and related supporting sectors. The result of local spending to install infrastructure is increased local GDP and new jobs.

During the operations period, a transmission project's local spending on operations and maintenance ("O&M") activities creates direct local jobs and contributes to local GDP growth. Meanwhile, the reduced wholesale electricity market costs lower electricity consumers' bills, increase households' disposable income, and decrease businesses' operations costs, which can have a widespread and long-lasting positive impact on the local economy.

In estimating the macroeconomic impacts from the wholesale electricity market, LEI employed its proprietary simulation model, POOLMod, and its FCA simulator, to forecast wholesale energy and capacity prices in ISO-NE, with and without the project. After converting the wholesale electricity benefits into retail electricity savings, these results are then fed into the 6-region REMI PI+ model for New England and modeled as reductions in energy costs for commercial, industrial, and residential consumers.

3.2 LEI's independent analysis for the development and construction period

The most critical input during the development and construction period is the project cost, including the total level, how it is broken down between local and non-local spending, how it is broken down between labor and material, and how it is broken down between different industries and sectors. LEI's analysis of the development and construction period (2019-2022) is based on the most updated project cost provided by USM and CMP,[46] which is estimated to be a total of $573.9 million across the development and construction period of 2017-2022 (a 2% increase from the original estimated local project cost of $561.9 million).

The preferred approach to developing project cost is to break it down into detailed granular labor and material expenditure categories. However, LEI was limited by the lack of detail in the cost estimates provided by CMP, and therefore modeled the construction cost at a more aggregated level. LEI modeled the project costs as increased industry sales in relevant sectors, including the power and communication structures construction; management of companies and enterprises; architectural, engineering, and related services; as well as professional, scientific, and technical

[46] ODR-003-011_Attachment_1_CONFIDENTIAL_(2017-232). In the updated construction cost estimate, the development period is 2017 and 2018, and the construction period is 2019-2022. In the original cost estimates, the development period was 2017 and the construction period was 2018-2022.

services. The project expenditure is allocated by year and by region based on information provided by USM and CMP.

Results shown in Figure 18 below suggest that the project is expected to create an average of 1,631 jobs every year during the development (2017-2018) and construction periods (2019-2022) in Maine, of which 856 jobs are directly created due to the project, and 775 indirect and induced jobs are created through increased local spending by the project's construction workers and in sectors that provide supporting material and services to the development and construction activities. In addition to the new jobs, the Maine economy is expected to see a GDP surge by a total of $589 million over these years, or $98.2 million on an annual average basis.

Figure 18. LEI's estimated macroeconomic impacts of the NECEC project during the development and construction period based on the updated project cost

Economic Impact Category	Unit	Development		Construction				Annual Average
		2017	2018	2019	2020	2021	2022	
Direct Employment	Individuals	48	103	754	1,716	1,621	892	856
Indirect & Induced Employment	Individuals	67	119	653	1,409	1,500	900	775
Total Employment	Individuals	115	222	1,407	3,126	3,121	1,792	1,631
GDP	Millions of Fixed 2009 $	$8.8	$14.7	$84.8	$184.0	$189.1	$107.7	$98.2

The increase in new jobs and GDP related to the development and construction of the project is temporary. Once the construction is completed and the project enters commercial operations, such economic benefits will dissipate (and sometimes a negative employment change in the local economy can be observed as a natural effect of the economy rebounding from an economic shock).

Moreover, although the new jobs created by development and construction of the project are located in Maine, the positions are not necessarily filled by local Maine residents. The new jobs consist of a mix of full-time and temporary jobs and can be held by Maine residents or by migrant workers that move to Maine specifically for this project, and who might move out of the region right after the construction work is completed.

3.3 LEI's independent analysis of the operations period

LEI took a comprehensive view of the macroeconomic impacts of the NECEC over the 15-year modeling period. Specifically, LEI took into consideration the impacts due to O&M activities of the project, ratepayer's savings created by energy and capacity price reductions, the project's contract costs borne by the Massachusetts ratepayers, and early retirement of generating plants triggered by the project. Figure 19 and Figure 20 provide an itemized macroeconomic impact summary for Maine and for all of the New England states.

As shown in Figure 19, Figure 19. Aggregated economic benefits in Maine during the operations period (2023-2037)during the period of 2023-2037, Maine is expected to see an increase of 291 total jobs per year, of which 38 direct jobs are directly created by supporting O&M activities related to the project, and 309 jobs are generated through indirect and induced effects from ratepayers' electricity cost savings. The GDP increase in Maine during this period is expected to be on average

$29.1 million per year. The net contract costs with NECEC's award of the contract from the 83D RFP will be borne by Massachusetts electric ratepayers. However, the contract costs will reduce the retail electric savings that Massachusetts consumers would have otherwise seen. Due to the close linkages between the state economies in New England, this will have a negative impact on the Maine economy, causing an average of 55 job lost per year, and GDP loss of $4.9 million per year during the 15 years modeled. The generation units that are expected to retire early as a result of the NECEC participating in the FCM are located in Connecticut. Therefore, these generation retirements will have only a minor impact on Maine, reducing the new job count by three jobs and pulling GDP benefits down by $0.3 million per year during the modeling period.

Figure 19. Aggregated economic benefits in Maine during the operations period (2023-2037)

Economic Impact Category	Economic Impact item	Operations 2023-2027	2028-2032	2033-2037	2023-2037 Average
Employment (Individuals)	O&M	38	38	38	38
	Ratepayers' savings	732	263	-59	312
	Contract Cost	-112	-54	-1	-55
	Early Retirement	-3	-3	-3	-3
	Total	**655**	**244**	**-25**	**291**
GDP (Millions of Fixed 2009 $)	O&M	$2.2	$2.3	$2.4	$2.3
	Ratepayers' savings	$61.0	$30.4	$4.5	$31.9
	Contract Cost	-$8.9	-$5.2	-$0.7	-$4.9
	Early Retirement	-$0.2	-$0.3	-$0.3	-$0.3
	Total	**$54.0**	**$27.2**	**$5.9**	**$29.1**

Note: Economic impacts in terms of incremental jobs, GDP, and total compensation are presented in the form of annual average of corresponding modeling period.

As shown in Figure 20 below, during 2023-2037, an increase of 1,826 total jobs per year is expected to be created across all of the New England states, primarily through ratepayers' electric cost savings. The six states in New England are expected to see their GDPs increase by $205.3 million per year on average through the modeling period. The macroeconomic impacts from incorporating the contract cost of the project (paid by Massachusetts electric ratepayers) and the early retirement of several units (located in Connecticut) have a more significant effect on New England as a whole than Maine. Specifically, the contract cost of the project is expected to reduce 2,355 jobs and $288.3 million GDP per year in New England; the early power plant retirement triggered by the project is expected to lead to a reduction of 392 jobs and lower GDPs by $72.4 million every year in all states in New England.

LEI's results using REMI PI+ also show that during the outer years of the modeling period (2033-2037), Maine and New England are expected to see economic losses. This is primarily because LEI's electricity market modeling results show huge energy and capacity cost savings in the first five years, which immediately results in macroeconomic benefit hikes for local and regional economies. In the latter years, as the wholesale energy and capacity markets recalibrate to reach new equilibriums, the electricity market benefits will decline. As a result, the Maine and New

England economies will go through a rebound effect, meaning that after an economic shock, economies will shrink rapidly back to or even below the pre-shock status.

LEI has also analyzed the cost savings that NECEC could create for electric ratepayers by enhancing grid reliability and protecting ratepayers against energy shortages and electricity price hikes under extreme weather conditions. However, LEI cannot predict when such extreme weather conditions would materialize and therefore did not incorporate these additional wholesale electricity market benefits into any specific year of the modeling time frame. As a result, these additional wholesale electricity market benefits are not captured in the macroeconomic benefits during the operating period of the project.

Figure 20. Aggregated economic benefits from electricity market in New England (2023-2037)

Economic Impact Category	Economic Impact item	Operations 2023-2027	Operations 2028-2032	Operations 2033-2037	2023-2037 Average
Employment (Individuals)	O&M	N/A	N/A	N/A	N/A
	Ratepayers' savings	10,777	3,685	-742	4,573
	Contract Cost	-4,267	-2,433	-367	-2,355
	Early Retirement	-426	-394	-357	-392
	Total	**6,084**	**858**	**-1,465**	**1,826**
GDP (Millions of Fixed 2009 $)	O&M	N/A	N/A	N/A	N/A
	Ratepayers' savings	$1,091.6	$526.7	$79.5	$565.9
	Contract Cost	-$432.0	-$314.4	-$118.4	-$288.3
	Early Retirement	-$68.6	-$72.6	-$76.1	-$72.4
	Total	**$591.0**	**$139.8**	**-$115.0**	**$205.3**

Note: Economic impacts in terms of incremental jobs, GDP, and total compensation are presented in the form of annual average of corresponding modeling period.

3.4 LEI's independent analysis of municipal tax revenue

LEI estimated the potential tax revenue received by affected municipalities. As shown in Figure 21, assuming the project's taxable value (i.e. approximately $1 billion) provided by CMP is reliable, the listed municipalities are expected to receive around $18.1 million in annual tax revenue paid by the NECEC project.

LEI's analysis is based on the taxable value of the project in each municipality provided by USM in response to data request EXM-003-008 (see Column "Additional Valuation" in Figure 21) and the 2016 municipal full value tax rate[47] estimated by the Department of Administrative and Financial Services of the Maine state government.

[47] 2016 Equalized Tax Rate is derived by dividing 2016 Municipal Commitment by 2018 State Valuation with adjustments for Homestead and Business Equipment Tax Exemption ("BETE") and Tax Increment Financing ("TIF"). Full Value Tax Rates Represent Tax per $1,000 of Value.

However, the actual tax revenue is subject to the taxable valuation assessed by each municipality and the adjusted property tax rates (i.e. mill rates) in each of these municipalities. Specifically, how mill rates will change is subject to a combination of several factors, including the budget plan of the municipality (e.g. how much revenue to be collected, the amount of government spending in public services, other sources of revenue), the change in market value of other properties, etc. In fact, any estimates will only provide a proxy for the actual tax rate change and tax revenue received by each affected municipality.

Figure 21. LEI's estimated municipal tax revenue from NECEC

Municipality	Municipal Full Value Tax Rates ($ per $1000 of property value)	Additional Valuation ($Million)	Additional Tax Revenue ($Million)
Alna	$17.82	$18.91	$0.34
Anson	$19.17	$21.95	$0.42
Caratunk	$7.39	$13.96	$0.10
Chesterville	$16.23	$2.19	$0.04
Cumberland	$15.40	$15.60	$0.24
Durham	$16.49	$3.31	$0.05
Embden	$13.20	$20.23	$0.27
Farmington	$19.70	$22.62	$0.45
Greene	$14.69	$20.75	$0.30
Industry	$13.48	$10.69	$0.14
Jay	$21.24	$22.18	$0.47
Leeds	$15.86	$26.77	$0.42
Lewiston	$27.54	$304.79	$8.39
Livermore Falls	$20.75	$24.96	$0.52
Moscow	$16.50	$41.98	$0.69
New Sharon	$17.71	$4.87	$0.09
Pownal	$15.99	$85.99	$1.37
Starks	$15.46	$19.00	$0.29
Whitefield	$15.63	$56.84	$0.89
Wilton	$20.90	$2.52	$0.05
Windsor	$15.30	$8.54	$0.13
Wiscasset	$18.76	$26.61	$0.50
Woolwich	$13.01	$5.72	$0.07
Unorganized Territories and Townships	$8.08	$227.71	$1.84
Total		**$1,008.67**	**$18.09**

Sources:
Municipal Full Value Tax Rates: Department of Administrative and Financial Services of the Maine state government. < http://www.maine.gov/revenue/propertytax/municipalservices/fullvaluerates.pdf>
Additional Valuation: Provided by USM in response to data request EXM-003-008. Based on tax revenue estimated by CMP.

In addition, LEI's estimates show the potential revenues for municipalities for one year at the beginning of the project's commercial operations period. Over the life of a transmission project, once operational, its taxable value will slowly decline due to depreciation. Therefore, property tax payments by NECEC and the local tax relief it could provide will be larger in the early years and gradually decline over the life of the project.[48]

[48] There may be a residual market value which could establish a floor.

4 Comparison of LEI and Daymark Wholesale Electricity Markets Analysis

LEI finds that key differences between LEI's and Daymark's energy market forecasts are primarily due to the compounded effect of Daymark's use of low availability of generators in the summer, high delivered natural gas prices, the inclusion of various adders to the natural gas price, and the CELT 2016 demand forecast. The differences in capacity market price forecasts are primarily due to Daymark's improper calibration of the penalty factor, the low entry prices for new capacity resources, and the level of oversupply assumed in the Base Case. However, Daymark's CO_2 emissions reductions are roughly in line with LEI's estimate.

CMP's CPCN application included the Daymark Report which estimated the wholesale market benefits (Exhibit 5). Similar to LEI's approach, Daymark looked at the differences between a Base Case without NECEC and a Project Case in which NECEC is built. The following sections discuss LEI's findings of the key differences between LEI's and Daymark's price forecasts and resulting benefits.

4.1 Comparison of electricity market and environmental benefits

At a high level, the premise of Daymark's report is that NECEC would lower wholesale energy and capacity market costs for Maine consumers through a reduction in energy market and capacity market prices. Daymark's analysis also qualitatively discussed other benefits that the project could provide, such as CO_2 emissions reductions, ancillary services cost reductions, increases in REC supply, and reduced congestion costs. Figure 22 below shows the energy market price forecasts for LEI and Daymark. On average, Daymark's Base Case energy prices are 68% higher than LEI's.

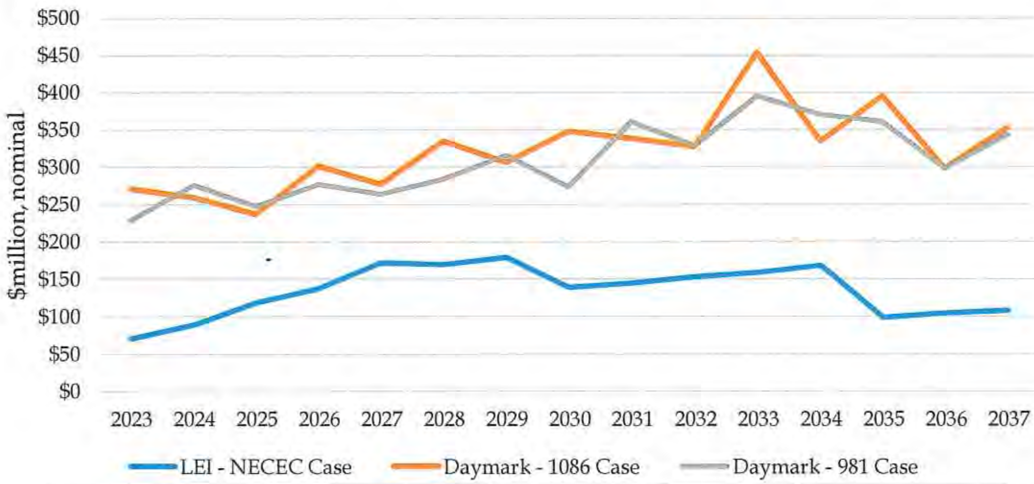
Figure 22. Comparison LEI's and Daymark's wholesale energy price forecasts for Maine

[redacted]

Note: LEI's prices shown above are a weighted average of the three Maine zones modeled. Daymark's price shown is for the ME zone.

Figure 23 below shows the energy market benefits for New England. It shows that on average, Daymark's 1086 NECEC Case energy market benefits are 141% higher than in LEI's. In reviewing the detailed assumptions of Daymark's analysis, there are a number of key drivers that lead Daymark to forecast higher wholesale energy prices and therefore higher energy market benefits for NECEC.

Figure 23. Comparison of LEI's and Daymark's wholesale energy benefits for New England



4.1.1 LEI calculated the impact of Daymark's assumptions on energy prices

LEI calculated the impact of each of Daymark's assumptions on Daymark's New England energy market benefits, compared with LEI's. LEI performed this calculation by layering each of the four Daymark assumptions (or "drivers") on top of LEI's own estimate of the energy market benefits (LEI baseline) (see Figure 24).[49]

- First, LEI adopted the natural gas index price contained in AEO 2016. This increased LEI's energy market benefits by approximately 38% above LEI's baseline estimate (which relied on AEO 2017).
- Second, LEI included Daymark's "regional adder" on top of the index natural gas price from AEO 2016 for Northern New England generators. This increased the energy market benefits by 45% above LEI's baseline.
- Third, LEI found that approximately 33% of Daymark's energy market benefits were attributed to the month of July, where Daymark had modeled some extremely high energy prices. LEI determined from the implied market heat rates (see Figure 32) that this dynamic in Daymark's modeling is explained largely by a combination of a super peaker adder (on gas prices) and the simplified approach Daymark took in AURORA to represent generator availability. By applying a 33% increase in energy market benefits as a proxy

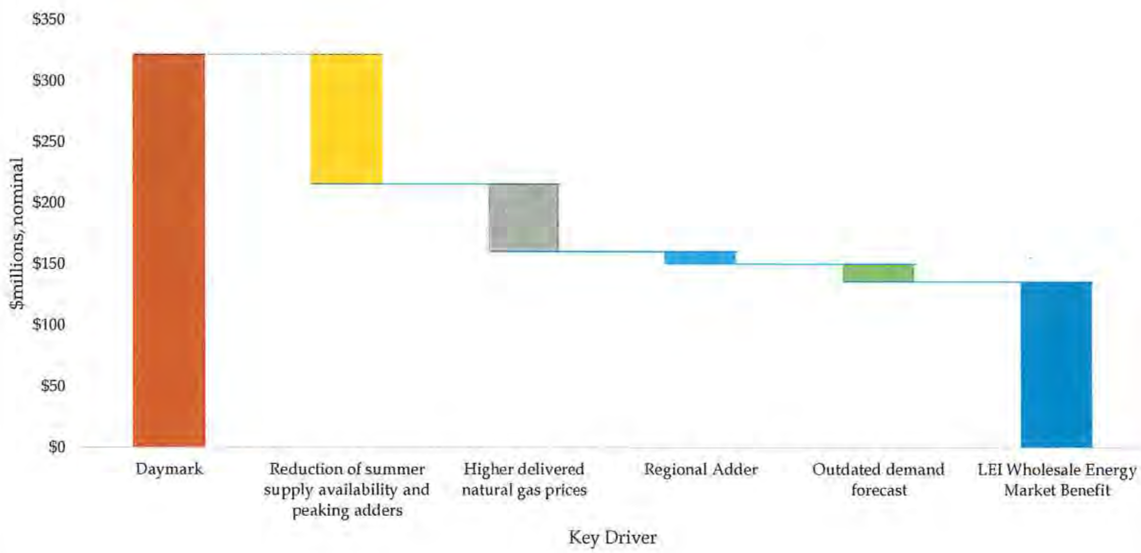
[49] In testing the impact of the various drivers of energy market benefits, LEI only conducted one single seed. Therefore, LEI's baseline shown differs slightly from the average of the 20-seeds.

for the super peaker adder and the summer availability, the energy market benefits increased to 119% above LEI's baseline estimate.

- Lastly, LEI estimated that the contribution to Daymark's energy market benefits from the higher demand forecasts in CELT 2016 increased the energy market benefits to roughly 129% above LEI's baseline estimate.

By stacking these increments on top of LEI's baseline, most of Daymark's higher energy market benefits could be accounted for. Overall, for the reasons described below, LEI believes that these four assumptions significantly overestimate the energy market benefits.

Figure 24. Illustration of LEI's estimate of the impact of key assumptions in Daymark's annual average energy market benefits in New England



Note: The key drivers shown above are scaled to illustrate the relative impact of each driver in Daymark's analysis

4.1.2 Daymark's simplified modeling of maintenance and forced outages by de-rating monthly availability creates perpetually tight summer supply conditions, high summer LMPs, and therefore high LMP reductions

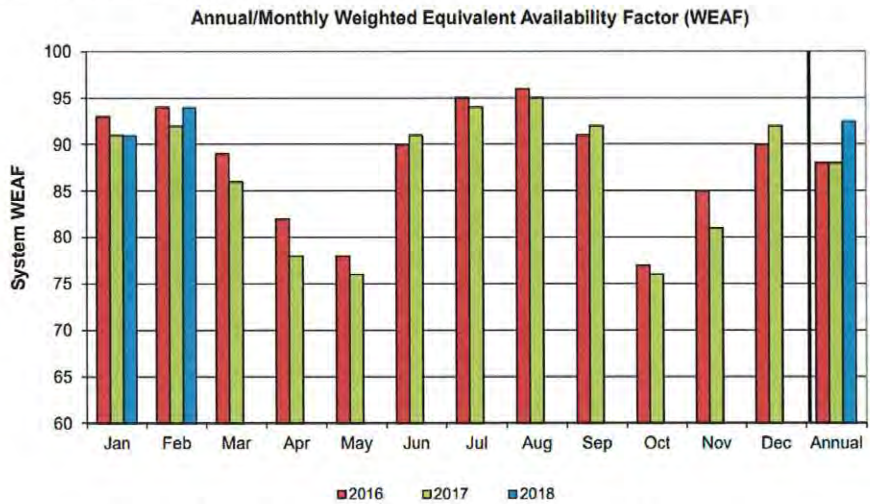
LEI understands that AURORA "limits the amount of capacity available to dispatch to reflect a normalized amount of forced outage per hour such that the annual generation of AURORA units reflect the annual forced outage rate assumed for that unit."[50] It is well understood that for thermal units, warm ambient air temperature typically reduces unit performance. As a result, the Seasonal Claimed Capability ("SCC"), which represents the amount of capacity determined by ISO-NE's capability audits during the summer and winter months, are typically lower in the summer than in the winter. However, while capacity supply is lowest during the summer, this is

[50] Daymark response to ODR-003-021. Daymark also noted in the April 5, 2018 technical session that the de-rating also reflects maintenance, not just forced outages.

when demand is highest. Therefore, most units will typically avoid maintenance during the summer - particularly intermediate resources that will run much more often during the summer and therefore earn energy market revenues.

Forced outages are much less predictable than maintenance and can vary by plant and technology type. If a unit experiences a forced outage, its available capacity will fall to zero (unless it is only a partial de-rate). In other periods, when a unit is not on forced outage, then the available capacity is high. For planning purposes, ISO-NE calculates what is known as the weighted average equivalent availability factor ("WEAF") for units in New England. As shown in Figure 25, the highest rates of monthly availability typically occur in the summer when resources are needed the most to meet demand.

Figure 25. System unit availability in New England



Source: NEPOOL Committee Meeting Report, March 2018. <https://www.iso-ne.com/static-assets/documents/2018/03/20180302_npc_addl.pdf>

Figure 26. Daymark's assumed monthly supply and demand in ISO-NE's energy market, 2023

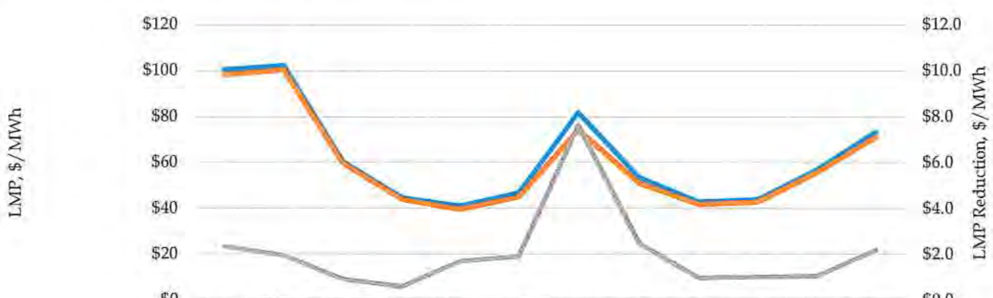
Source: ODR-003-021, CELT 2016. AURORA + Avg Import includes the average hourly import volume per hour

In analyzing the amount of capacity available in Daymark's energy market modeling against the monthly peak demand in each month based on CELT 2016, LEI found that capacity is very tight in the summer months, likely requiring highly expensive generation to run in order to meet demand. Figure 26 shows the monthly supply and demand in ISO-NE's energy market in 2023. The blue line represents total nameplate capacity, while the orange line shows the capacity based on SCC.[51] The grey line is the capacity available for dispatch based Daymark's approach to de-rating units. This represents a reduciton of 18% to 24% in capacity from the ISO-NE SCC values across all months.

The implication of having such tight supply when demand is highest is that it requires resources from the steep portion of the generation supply curve (causing high energy market prices). Because the marginal unit is from the steep portion of the curve, the flows from NECEC could have very large price reduction effects. While LEI believes such tightness is possible during extreme weather or load conditions, LEI finds it unlikely that this would reoccur every single year as Daymark's analysis implies. Daymark's high energy prices are also incongruent with historical monthly energy prices (see the implied market heat rates in Figure 32).

Figure 27 below shows an example of the average monthly LMP reductions in the first year that NECEC is in service from Daymark's analysis. Because of the very steep supply curve in July, NECEC is able to reduce LMPs much more effectively than in other months, when demand crosses the flatter part of the supply curve. This issue grows over time, as natural gas prices and demand rise.

Figure 27. LMP reductions in Daymark's analysis, 2023



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Base	$100	$102	$60	$44	$41	$47	$82	$53	$43	$43	$56	$73
Project	$98	$100	$59	$44	$39	$45	$74	$51	$42	$42	$55	$71
LMP Difference	$2.3	$1.9	$0.9	$0.6	$1.7	$1.9	$8	$2	$1.0	$1.0	$1.0	$2.2

Base Project LMP Difference

Source: ODR-003-022.

4.1.3 Daymark's natural gas price methodology overestimates the cost of gas in New England

Both LEI's and Daymark's analysis use EIA's Henry Hub outlook albeit in different ways. In the short-term (2018 and 2019) LEI relied on the forward markets for projecting Henry Hub gas

[51] Ibid.

prices. LEI depends on forwards only to the extent they are liquid, and liquidity drops off dramatically after two years. For the longer term, the eventual increase in gas prices in the EIA's AEO 2018 Reference Case forecasts is consistent with the four key North American natural gas supply and demand trends discussed in Section 7.3. However, LEI believes that EIA's typically conservative outlooks for natural gas production growth have led it to ignore the impact of strong production on gas prices in the near term. EIA's Reference Case outlooks have shifted downward substantially in recent years (see Figure 56 in Section 7).

Daymark's New England natural gas index outlook is significantly higher than LEI's as shown below in Figure 28 because Daymark used EIA AEO prices directly (absolute levels) while LEI adjusts it forecast for near-term realities (by using forwards in the near term), and then escalates its forecast using the AEO growth rates. EIA's Reference case outlooks have been under-forecasting gas supply and over forecasting near-term Henry Hub prices for several years, which is why LEI chooses not to use Henry Hub absolute price levels in our gas price outlook.

Furthermore, Daymark has said that their model used the AEO 2017 outlook (Figure IV-3 on their report).[52] However, LEI checked Daymark's gas index price provided on April 2018 as a response to a DR (ODR-003-015_Att_1), as well as Figure IV-3 in the Daymark report, and the data in the figure is from AEO 2016 outlook and not from AEO 2017. If Daymark used the AEO 2016 outlook, their gas price outlook is 7% higher than if they used AEO 2017.

Figure 28. LEI versus Daymark Henry Hub and New England price outlook

[redacted]

Source: LEI and Daymark Report Exhibit NECEC-5

4.1.4 Daymark's New England natural gas index price outlook is an average market price and therefore should not include adders

Daymark's New England natural gas forecast is a New England annual average price, referred to by Daymark as an "index price," a monthly shaping factor, and a set of adders to create separate

52 ODR-EXM-003-024.

natural gas outlooks for plants located in northern New England and for peaking plants (see Figure 29).

Figure 29. Daymark New England January and July natural gas prices in 2023 (recreated by LEI)

Source: Recreated with data from Daymark Report, Exhibit NECEC-5 and answers to DRs[53]

Regional adder

The regional adder is an additional layer of gas price cost applied to generators located in northern New England (Maine, New Hampshire, and Vermont). Daymark explained that they developed this adder in the process of calibrating their model; the added cost is needed to replicate the pattern of generation by the plants in these regions.[54] Daymark calculated the regional adder based on the annual backhaul rate for firm transmission ("FT") from the Maritimes and Northeast Pipeline ("M&NE") scaled for each month by the Portland Natural Gas Transmission System ("PNGTS") monthly rate multiplier. This approach implicitly assumes northern New England plants use FT services for natural gas delivery all the time. However, most plants use interruptible transmission ("IT"), which has lower rates than FT.

Peaking unit adder

On top of the regional adder, Daymark applied another adder to plants that they argued generate only during peak days or hours. According to Daymark, the adder aims to represent the higher cost of procuring fuel during high demand periods, when peaking units are burning gas. This adder creates a separate natural gas outlook for the peaking units in Figure 30 (column "Resources in Class").

[53] Index Price from IECG-003-003_Att_1 CONFIDENTIAL (2017-00232); Monthly adder from EXM-002-016_Att_1; Regional adder from EXM-002-018_Attachment_1_(2017-232); and Peaking adder from Daymark Report Exhibit NECEC-5, Table IV-1 (Page 49 of 98).

[54] Transcript 5 Tech Session CONFIDENTIAL, pg. 122-123

Figure 30. Daymark peaking unit adder

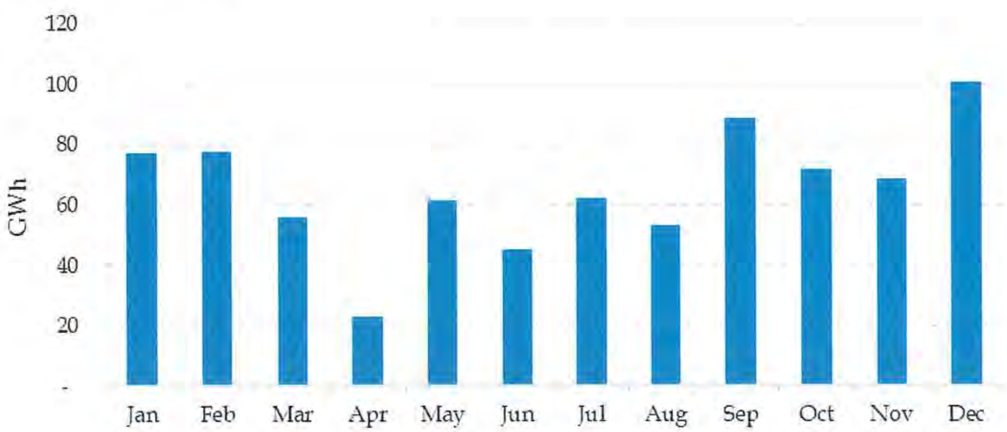
Natural Gas Delivery Class	Fuel Adder (2017$/MMBtu)	Resources in Class
Peaking	$0.89	New Haven Harbor Units 2-4 (151MW); Androscoggin Energy Center CT03 (51MW); Swanton Peaking Generation Project #10 (40MW); Algonquin Windsor Locks (38MW); Lowell Cogeneration #GEN1-2 (32MW); Capital District Energy Center STG (29MW); Waters River #1 (20MW); Pawtucket Power #1 (20MW); 15 smaller units totaling 33MW.
Super Peaking	$1.74	Devon 11-14 (161MW); Cleary Flood #9a (106MW).
Standard (Non-Peaking)	$0.00	All Remaining units.

Table IV-1. NMM Peaking Unit Fuel Price Adder Assumptions

Source: Daymark Report Exhibit NECEC-5. Table IV-1 (Page 49 of 98)

LEI believes this methodology does not accurately represent the pattern of operations of peaking units and the inherent gas (fuel) costs that these units would face. The Androscoggin Energy Center CT03, for example, operates throughout the entire year, not just at peak demand hours in the summer (see Figure 31). In fact, it has run most in September, when natural gas prices are typically low, and December when gas prices have not yet reached their seasonal (January and February) peaks. In Daymark's model, this unit is paying a premium above the monthly price for every hour it runs.

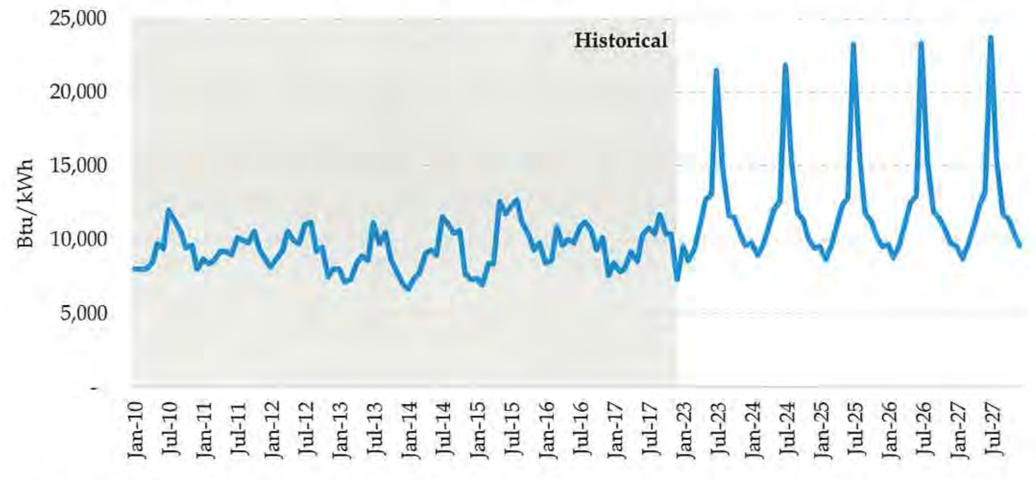
Figure 31. Androscoggin Energy Center CT03 generation profile (accumulated generation by month from 2012 to 2017)



Source: Ventyx Velocity Suite

When compounding the impact of tight summer supply, a high natural gas price for New England, and peaking adders, the result is extremely high implied market heat rates that far exceed historical evidence as shown in Figure 32 below.

Figure 32. New England monthly implied heat rate - historical and Daymark outlook



Source: SNL (2010-2017) and Daymark (2023-2027)[55]

4.1.5 Daymark used a higher energy demand forecast

One other key difference is that as described in pg. 4 of the Daymark Report, Daymark used the CELT 2016 forecast, as Section 2.3.1.2 of the MA 83D RFP notes that "[t]he reference case system topology will be based on the 2016 ISO New England Capacity, Energy, Load and Transmission (CELT) report." Total demand net of energy efficiency and behind-the-meter solar PV in CELT 2017 is approximately 4-5% lower than in CELT 2016. Because the energy market costs are a direct function of the level of energy demand, higher energy demand will result in higher energy market benefits.

4.2 Comparison of capacity market benefits[56]

Capacity market benefits stem from the fact that NECEC would result in lower capacity prices. Figure 33 below shows the capacity prices in the Base Case and Project Case in LEI's and Daymark's analysis, against the Net CONE.[57] It shows that LEI's long-run capacity prices are higher as a result of LEI's higher Net CONE assumption (based on the extrapolation of ISO-NE's Net CONE assumption) estimate for FCA #12, while Daymark extrapolated the Net CONE based on the results of FCA #10 in which the FCA concluded with new entry at $7.03/kW-month. On

[55] Historical data was calculated with the monthly average of New England Internal Hub DA LMP prices and Algonquin prices. Daymark's implied heat rate was calculated with Daymark's Base Case LMP price outlook provided on ODR-003-022_Att_1 and Daymark's gas index price outlook provided on ODR-003-015_Att_1.

[56] LEI did not conduct a MOPR analysis of NECEC to determine whether it would clear the primary auction as CMP did not provide sufficient data for LEI to perform such an analysis. In this section, all the comparisons are based on the assumption that NECEC would clear in the primary auction for FCA #14. However, if NECEC clears the through the substitution auction, then the wholesale capacity market benefits would fall to zero and therefore the electricity market benefits to electric ratepayers would be smaller.

[57] LEI understands that Daymark used the ISO-determined Net CONE for the purposes of setting the price cap. However, the assumed entry prices for new capacity used a modified Net CONE or investment trigger price, which is what is shown in Figure 33 of the Daymark Report.

top of the lower net CONE assumption, Daymark's outlook projects that New Entry constantly clears below its "modified Net CONE" value, leading to lower long-run capacity prices.

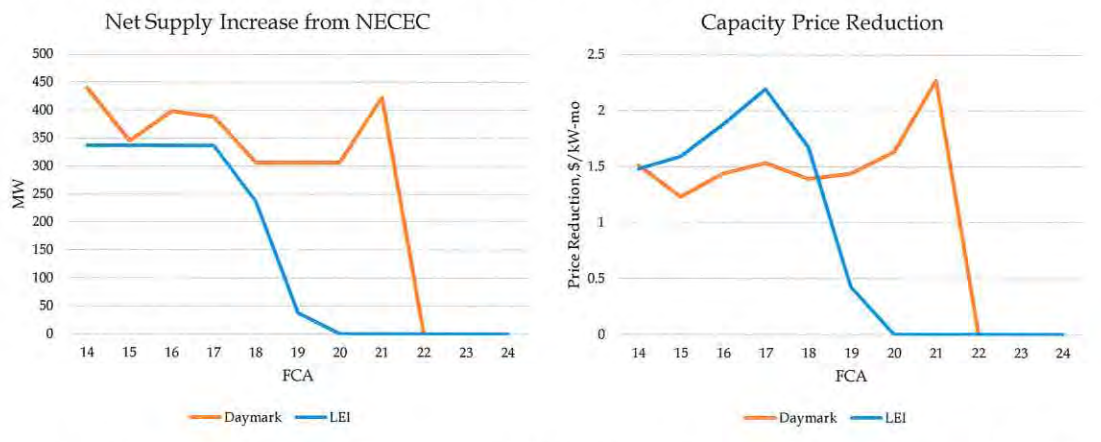
Figure 33. Comparison LEI's and Daymark's wholesale capacity price forecasts

[redacted]

Note: Daymark's capacity market analysis for NECEC concluded after FCA 24. However, only eight years of benefits (up to FCA #21) were included.

Daymark's analysis projects that the capacity market benefits will end after eight years (FCA #14 - #21) when the first generic new entry enters the Base Case in FCA #22. In LEI's model, the convergence of the Base Case and Project Case converges after six years, two years earlier. As shown on the left side of Figure 34, despite 1,090 MW of capacity, NECEC only results in 300 - 400 MW of *incremental* capacity in New England because of market response. Over time, new resources will be added to the system in the Base Case first, until the point where the Base Case and Project Case reach approximate parity.

Figure 34. Comparison of net supply from NECEC and capacity price reduction



Note: For this figure, LEI applied a value of zero for FCA #23 and #24 to Daymark's figures, to account for the fact that no capacity market benefits are assumed in these years.

The wholesale capacity price reduction on the right side of Figure 34 also shows a similar trend, whereby the highest capacity market price reductions occur when there is the greatest level of oversupply in the Project Case relative to the Base Case. Over the first few years, Daymark projects a smaller price-reducing impact than LEI. This is because Daymark's capacity market assumptions lead to a propensity to accept oversupply, as discussed in more detail below. The following sections explain the major differences in capacity market price levels, and the wholesale capacity market benefits between the LEI and Daymark reports.

4.2.1 LEI calculated the impact of Daymark's assumptions on capacity prices

Figure 15 below demonstrates LEI's calculation of approximately how much each assumption (or driver) discussed below contributed to New England capacity market benefits. LEI layered each of the three drivers on top of LEI's estimate of the capacity market benefits (LEI baseline).[58] Because the timeframe for benefits is different between LEI's and Daymark's analyses, LEI compared the *cumulative* capacity market benefits.

- First, LEI changed the price for new entry to Daymark's modified Net CONE. This lowered the long-term capacity prices and reduced LEI's cumulative capacity market benefits by 26%.
- Second, LEI use Daymark's level of cleared capacity in the Base Case and Project Case (which does not include FCA #12 results and more recent retirement de-list bids). Combined with Daymark's lower investment trigger prices for new capacity, the difference in starting points increased the capacity market benefits to 11% above LEI's estimate.
- Third, LEI adjusted the penalty factor to the constant value that Daymark used in their analysis. This increased the wholesale capacity market benefits to 35% above LEI's capacity market benefits.

By stacking these components on top of LEI's baseline, LEI obtained a similar level of capacity market benefits as Daymark. Despite the low entry prices that Daymark assumed for new generation (which has the effect of reducing the capacity market benefits), LEI believes that when the drivers are taken together, the overall capacity market benefits are overstated in the Daymark analysis, given market developments since Daymark wrote their report. In addition, if the project does not clear in the FCA, then LEI would expect capacity market benefits to go to zero, as the goal of the substitution auction under CASPR is to create a one-for-one swap of capacity such that capacity prices to ratepayers do not change.

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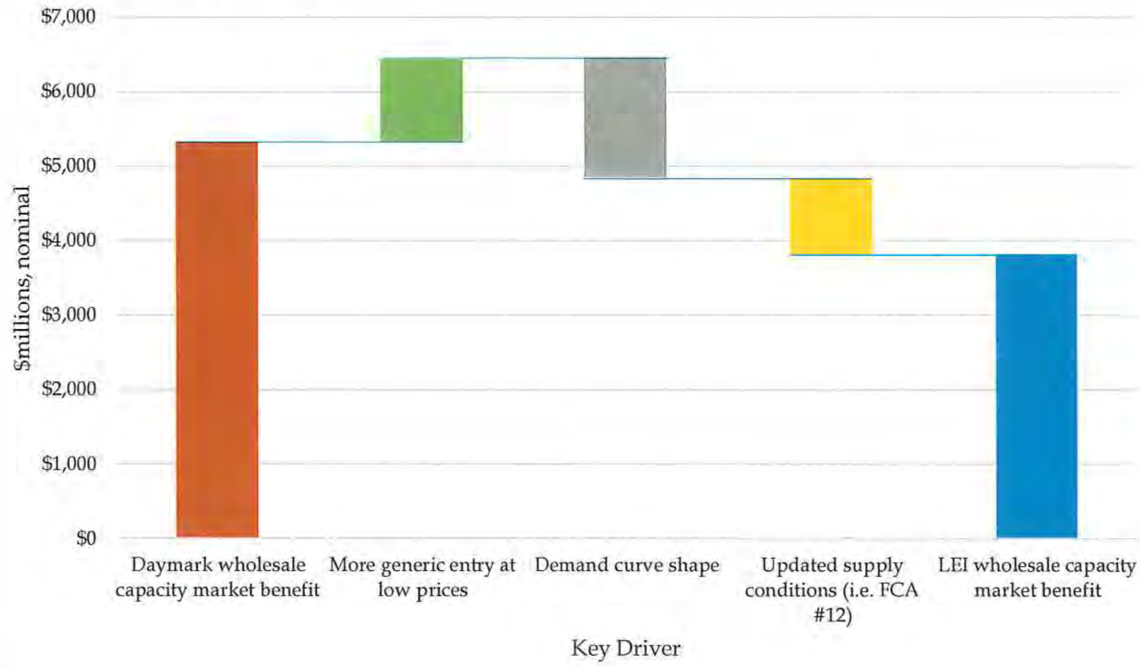
[58] In testing the impact of the various drivers of energy market benefits, LEI only conducted one single seed. Therefore, LEI's baseline shown differs slightly from the average of the 20-seeds.

Figure 35. LEI's estimate of key driver impacts in Daymark's cumulative capacity market benefits in New England



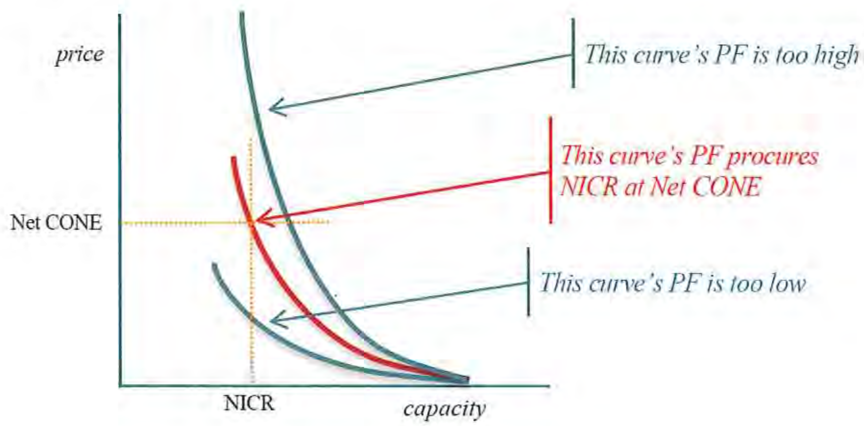
Note: The key drivers shown above are scaled to illustrate the relative impact of each driver in Daymark's analysis

4.2.2 Daymark's capacity prices are not accurately calibrated to account for changes to Net CONE and NICR over time, resulting in a capacity price that takes longer to reach long-run equilibrium and prolonging capacity market benefits

To account for changes each year, Daymark shifted the demand curve to the right by the growth in NICR. Daymark also adjusted the price cap (set at 1.6x Net CONE) to adjust for Net CONE growth over time. By ISO-NE's design, this should steepen the demand curve to properly send accurate price signals in the market, since it must attract new investment that becomes more expensive over time.

However, as described in Section 6.2, the capacity price is the penalty factor multiplied by the MRI, and therefore the penalty factor used will directly impact the capacity price. In order to scale the MRI curve properly and account for the growth of Net CONE, the penalty factor must be adjusted such that if the market procures *exactly* the same amount of capacity as NICR, the resulting capacity price should clear exactly at Net CONE. Figure 36 below is from one of ISO-NE's technical memos regarding where the penalty factor should be set.

Figure 36. Setting the penalty factor



Source: ISO-NE. FCM Zonal Demand Curve Methodology – Revised Edition. December 7, 2015.

While Daymark does increase the price cap to account for the growing Net CONE, it does not adjust the penalty factor to scale the MRI curve properly. The impact of not adjusting the penalty factor will result in capacity prices that take longer to rise (essentially, the capacity price will be too high relative to the level of cleared capacity). As shown previously in the right side of Figure 34, the capacity price reduction rises in LEI's curve even though the oversupply in the Project Case relative to the Base Case is constant. This demonstrates that the penalty factor is being adjusted along with the Net CONE growth. As a result, capacity prices rise faster in LEI's analysis, and therefore the market rebalances faster as well.

A second issue with Daymark's model is that the penalty is actually calibrated for a much higher Net CONE of \$10.95/kW-month. This was easily tested by determining the clearing price when the qualified capacity is equal to NICR. This further adds to the fact that Daymark's model is not properly calibrated to develop capacity prices that are consistent with the quantity levels assumed.

4.2.3 Daymark's modified Net CONE for new entry leads to lower long-run capacity *price levels* and persistent oversupply in the capacity market

ISO-NE calculated that the Net CONE for FCA #12 was \$8.04/kW-month, based on its estimate for a combustion turbine. Daymark notes that the "ISO estimates reflect generic assumptions and forecasts of costs and revenues, and generally does not reflect actual bids from market entrants. In fact, several new resources cleared the market in FCA 10, when the clearing price was just over \$7.00/kW-mo. This indicates that new generation projects are viable when clearing prices are lower than the ISO-NE Net CONE value."[59] However, Daymark did not note that several of the units that cleared FCA #10 were developed at brownfield sites (i.e. Bridgeport Harbor and Canal), or have been able to make use of tax incentives in the form of bonus depreciation.[60] Because actual

[59] Daymark Report, pg. 10.

[60] 30% bonus depreciation is allowed for units in service by 2019.

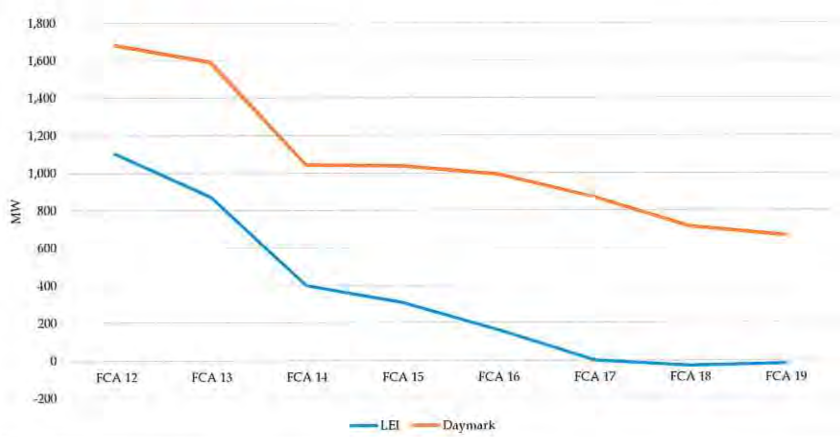
bids can vary significantly from project to project, LEI's analysis adopted ISO-NE's estimates which was vetted through the ISO Markets Committee.

The impact of using Daymark's reduced Net CONE is that the new entry enters the FCM in the Base Case sooner. Because Daymark assumes that there are no capacity market benefits after new entry enters the FCM in the Base Case, a lower Net CONE to trigger new entry actually *reduces* capacity market benefits. LEI estimates that the capacity market benefits in FCA #22 in Daymark's analysis would be even higher than in FCA #21 if they used a higher price for new investment (see Figure 34). However, this does not imply that Daymark's analysis is conservative. Rather, LEI believes Daymark's capacity market analysis is not formulating capacity prices correctly as discussed in the previous section due to the PF.

4.2.4 Daymark's analysis exhibited a high level of oversupply, resulting in lower short-term capacity prices than LEI's analysis

Another issue that LEI considered was whether Daymark's starting point for analysis (FCA #12) adopted reasonable assumptions. The latest auction that occurred at the time Daymark prepared its analysis was FCA #11. In FCA #12, total demand resources grew by 390 MW from 3,210 MW to 3,600 MW. However, this growth in demand was offset by the dynamic de-list of Mystic 9. As a result, FCA #12 was only oversupplied by 1,103 MW, while in Daymark's starting point for the analysis, FCA #12 was 1,685 MW above its assumed NICR. LEI believes that the effect of this oversupply in Daymark's analysis for FCA #12 carries into FCA #14, resulting in lower capacity prices than LEI's, particularly over the first few FCAs that NECEC is in service. This is shown below in Figure 37, whereby Daymark's oversupply is long-lasting, resulting in lower capacity market prices in their Base Case and Project Case and therefore a longer capacity price difference.

Figure 37. Comparison of net oversupply relative to NICR in LEI's and Daymark's Base Case



LEI believes that the reason Daymark's model exhibited such a high degree of oversupply is due to the fact that the penalty factor is set too high. For example, while FCA #12 cleared with 1,103 MW above NICR at $4.63/kW, Daymark's analysis suggests FCA #12 would have cleared with

1,685 MW above NICR at $[redacted]/kW-month.[61] This incorrect price formation carries over in future years.

By FCA #14, ISO-NE is expected to implement the full MRI curve. All else being equal, compared to the transition curve, LEI expects capacity prices to drop due to the convex shape of the MRI demand curve. In LEI's Base Case, this caused some resources to retire in FCA #14, namely the remaining coal units. As discussed previously, because the penalty factor in Daymark's analysis was set too high, the resulting capacity price was also too high relative to the level of oversupply. It is likely that if the penalty factor was calibrated appropriately, capacity prices (in both Daymark's Base Case and Project Case) would drop, causing more de-lists or retirements in the Base Case and Project Case.

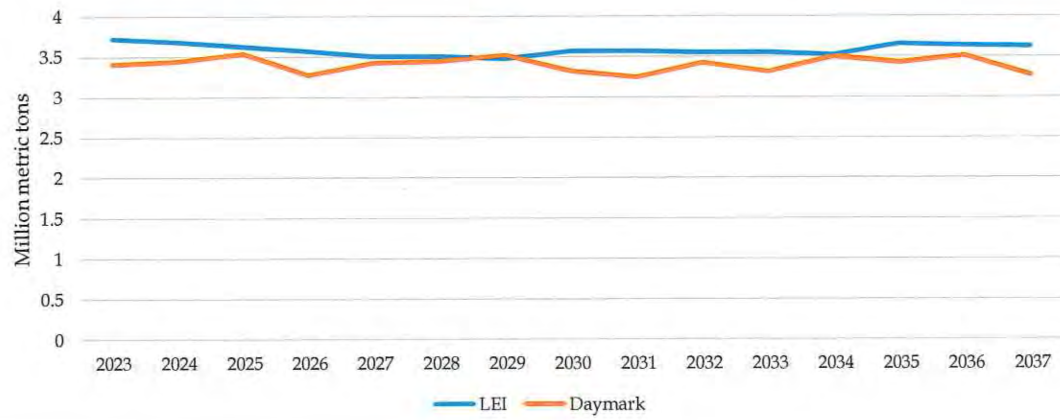
4.3 CO_2 emissions reductions

CO_2 emissions reductions are a function of the emissions rates of the resources that NECEC will replace. By and large, New England's generation is natural gas-fired, meaning that NECEC is likely to displace [redacted] GWh of natural gas generation, which typically has emissions rates of approximately 700-1,000 lbs./MWh.

LEI finds that Daymark's estimate of 3.4 million metric tons is reasonable, but perhaps slightly conservative. Based on Daymark's own analysis, supply conditions in New England can become very tight during the summer, which would likely result in more oil-fired generation, which typically has a higher emission rate than natural gas units. Therefore, intuitively, since the energy flows are comparable, Daymark's tight supply conditions should, at least in theory, yield higher CO_2 emissions. The most likely explanation is that there are slight differences between the emissions rates assumed for the resources that are being offset by NECEC between LEI's and Daymark's models, although the results suggest that it is not much. Figure 38 below shows the CO_2 emissions reductions in LEI's and Daymark's analysis side-by-side.

[61] LEI understands that for FCA #12, Daymark used the MRI curve to establish a capacity price and added $1.6/kW-month.

Figure 38. Comparison of CO_2 emissions reductions in LEI's and Daymark's analysis



5 Comparison of LEI and USM Macroeconomic Benefits Analysis

This section provides LEI's evaluation of USM's analysis based on a side-by-side comparison of LEI's and USM's results. LEI finds USM's analysis for the development and construction period to be reasonable, although the relatively high local share of the development and construction cost remains subject to some uncertainty in terms of realization of those positive macroeconomic impacts to Maine. During the operations period, USM over-estimated the macroeconomic benefits of the operations of NECEC, because it relied on inflated electricity market benefits provided by Daymark. The inputs USM used in its macroeconomic model for measuring the electricity market benefits were also incomplete as they ignored the capacity market benefits, contract costs, and the impact of early retirement. During the first 15 years of operations period (2023-2037), LEI projects 272 new jobs per year and $27.1 million GDP increase per year for Maine related to the project's O&M activities and ratepayers' electricity savings.

For the macroeconomic impacts during the development and construction period, the differences between LEI's and USM's results are fairly minor. However, LEI is concerned about the assumed high share of the project cost USM attributed to activity Maine. Limited by the lack of granularity in the cost estimates provided by CMP, LEI cannot verify if the 60% local cost share is reasonable. If the local share of the project's cost turns out to be 10% lower, the estimated macroeconomic benefits in terms of incremental jobs and GDP for Maine will drop by 10%.

LEI found the macroeconomic impacts during the operations period, especially with regards to the ratepayers' benefits in USM's study are overstated in certain ways, and incomplete in other respects. First, the wholesale energy market benefits estimated by Daymark and used by USM for modeling macroeconomic benefits are based on higher fuel price forecasts and an artificially inflated supply shortfall in the summer months. These flaws in the energy market modeling results have led to an overestimation of macroeconomic impacts.

Second, USM only studied the impact of wholesale energy cost reductions and did not consider the impacts from the capacity market,[62] the contract costs borne by Massachusetts ratepayers, the early retirement of generation capacity triggered by the project, and deferred investment in local new generation due to introducing lower-cost resource to the New England power market.[63] All these factors should be considered in an integrated manner for analyzing the project's impacts on the Maine and New England regional economy. A detailed discussion of the operations period analysis is presented in Sections 5.3 and 5.4.

5.1 Comparison for the development and construction period

LEI's analysis is based on the updated project cost and is compared with USM's modeling results which are based on the original project cost. For the purpose of an apples-to-apples comparison,

[62] As mentioned in footnote 56, in this section, all the comparisons are based on the assumption that NECEC would clear the primary auction for FCA #14. However, if NECEC clears the FCA through the substitution auction, then an equivalent amount of supply would need to exit the FCA and the capacity market benefits would be zero. And the macroeconomic benefits would be reduced.

[63] Lastly, USM did not convert the wholesale capacity impact into a retail rate impact figure, which is more appropriate in evaluating the impact of NECEC on New England's retail consumers.

LEI also modeled the original project costs using LEI's approach and compared the results with USM's approach (see Appendix C).

As shown in Figure 39, in general, LEI's estimates for macroeconomic benefits for the development and construction period are similar to USM's results. LEI's estimated annual average job creation is 4% lower than USM's results, and LEI's estimated GDP increase is 4% higher than USM's results. The difference in total compensation is marginal.

Figure 39. Side-by-side comparison of the development and construction period

Economic Impact Category	Unit	Annual Average (2017-2022)		Differences
		USM	LEI	
Direct Employment	Individuals	868	856	-1%
Indirect & Induced Employment	Individuals	824	775	-6%
Total Employment	Individuals	1,691	1,631	-4%

Economic Impact Category	Unit	Total (2017-2022)		Annual Average (2017-2022)		Differences
		USM	LEI	USM	LEI	
GDP	Millions of Fixed 2009 $	$564.8	$589.0	$94.1	$98.2	4%
Total Compensation	Millions of Nominal $	$435.7	$433.6	$72.6	$72.3	0%

The small differences in results can be explained by two factors. First, LEI's analysis is based on the updated local project cost estimates, which are 2% higher than the original project cost estimates. This may lead to slightly higher overall GDP and job increases for Maine in LEI's analysis. Second, LEI used more detailed industrial sectors for modeling the development and construction costs, based on the available cost breakdown provided by USM and CMP. This resulted in minor differences in the macroeconomic outcomes given that the project investment is captured and modeled through different interconnections among relevant sectors in the REMI PI+ model.

5.2 Drivers of differences between LEI's and USM's analysis of the development and construction period

LEI's major concern about USM's analysis for the development and construction period is the high share of the project's local spending in Maine provided by CMP, which leads to inflated macroeconomic benefits. LEI has two minor concerns with regard to the modeling methodology and how the results were presented. Aside from these, LEI finds USM's analysis for the development and construction period to be reasonable.

5.2.1 USM assumes an unusually high share of local spending of the project cost

The share of local expenditures (i.e., Maine) estimated in the original cost estimate comprises 56.2% of the project costs, while 60.4% of the updated total project costs are estimated to be local. USM compared the local share of the NECEC project cost with that of the Maine Power Reliability Program ("MPRP") project, whose share of local spending was estimated to be 67% and claimed that local share estimate of the NECEC project is reasonable. However, the two projects (NECEC and MPRP) are very different. MRPP is a 345kV line while NECEC project is an HVDC transmission line. HVDC projects generally require more skilled labor and equipment to be sourced from other states.

Without more detailed project estimates than those provided by CMP, LEI cannot determine if the local cost estimates are reasonable. However, comparing to what LEI has observed in other engagements involving other HVDC transmission projects, this local share appears to be on the high end. If the actual project spending was to be 10% lower, then it would be expected to see a drop by approximately 10% in the projected macroeconomic benefits as well, based on LEI's prior analysis.

5.2.2 Jobs created by the project should not be considered cumulatively

USM's report shows cumulative job increases for the development and construction periods.[64] However, the REMI PI+ model outputs job increases in the term of Job-Year, meaning that a job created in the first year of the construction period and lasting for the entire four years of the construction period will appear as a job increase in every year. Therefore, showing the cumulative number of new jobs is misleading to readers who are not familiar with the characteristics of REMI PI+ models. Presenting the annual average employment change is a better and more meaningful metric to understand the macroeconomic impact of the project. Therefore, the Table 1.1 on page 1 of the USM report should read as "during the development and construction periods, the NECEC project is expected to generate 1,691 total jobs per year between 2017 and 2022" not 10,147 total jobs between 2017 and 2022.

5.2.3 USM modeled construction cost at a very general level

USM modeled project cost at a general level by using only three cost categories, namely (i) construction, (ii) management of companies and enterprises, and (iii) professional scientific, and technical services. Using general categories of inputs in the REMI modeling might result in inaccurate outcomes. For example, the REMI PI+ model will take the total amount of project spending in the construction sector and then automatically spread and allocate it to subsectors of construction based on the configurated input/output relationship among these sub-sectors, which include power infrastructure construction, residential structure construction, and educational and recreational structure, etc. Some of these sub-sectors such as residential structure construction, are not relevant to the project and may distort the modeling results.

Given that the 70-sector PI+ model allows us to model project cost with more granularity, LEI chose a set of more detailed and relevant policy variables for modeling the construction cost impacts on the Maine economy. LEI also tested modeling the original project cost at a more detailed level and compared the results with USM's estimates based on the same set of project cost estimates, for the purpose of an apples-to-apples comparison. Results show that LEI arrived at local job creation estimates that are about 6% lower than USM's estimates (see Appendix C). LEI's estimate of GDP increase is 2.5% higher while the total compensation increase is 1.5% less than USM's estimates.

In conclusion, LEI finds USM's macroeconomic analysis for the development and construction period might be over-estimated given the high assumed percentage of local (Maine) spending.

[64] See Column "Total" in Table 1.1 on pg. 1 of the USM Report, 4.1 on pg. 9 of the same USM Report, and Table 10 on pg. 4.3 of the USM's Report.

LEI also wants to stress that the new jobs and GDP increases in the development and construction period are temporary and will dissipate once the construction is completed. Furthermore, not all the new jobs will be filled by Maine residents, but would also have migrants who would temporarily move to Maine to work on this project.

5.3 Comparison of the macroeconomic impacts during the operations period

As shown in Figure 40 and Figure 41 below, LEI's estimates for the macroeconomic impacts during the operations period due to the NECEC project is significantly higher than USM's estimates in the first five years of the operations of the project, but is lower for the latter period. In fact, LEI's modeling results show that during 2033-2037, Maine and New England are expected see economic losses. This is mainly due to the fact that LEI included the contract costs while USM did not, and is also because of the rebound effect as discussed in Section 3.3.

Figure 40. Estimated macroeconomic impacts on employment in Maine during the operations period (2023-2037)

Scenario	Economic Impact Category	Unit	Operations 2023-2027	2028-2032	2033-2037	2023-2037 Average
USM's Results (a)	Total Employment	Individuals	357	351	278	329
	GDP	Millions of Fixed 2009 $	$22.7	$27.7	$27.1	$25.8
LEI's Results (b)	Total Employment	Individuals	655	244	-25	291
	GDP	Millions of Fixed 2009 $	$54.0	$27.2	$5.9	$29.1
Differences [(b-a)/a]	Total Employment	%	83%	-30%	-109%	-11%
	GDP	%	137%	-2%	-78%	12%

Figure 41. Estimated macroeconomic impacts on GDP and compensation in New England during the operations period (2023-2037)

Scenario	Economic Impact Category	Unit	Operations 2023-2027	2028-2032	2033-2037	2023-2037 Average
USM's Results (a)	Total Employment	Individuals	4,129	3984	3091	3,735
	GDP	Millions of Fixed 2009 $	$365.1	$432.2	$421.3	$406.2
LEI's Results (b)	Total Employment	Individuals	6,084	858	-1,465	1,826
	GDP	Millions of Fixed 2009 $	$591.0	$139.8	-$115.0	$205.3
Differences [(b-a)/a]	Total Employment	%	47%	-78%	-147%	-51%
	GDP	%	62%	-68%	-127%	-49%

Note:
1. USM's results are based on wholesale energy market cost savings, while LEI's estimates are based on retail electricity market savings (including energy and the capacity markets), also adjusted for the net contract costs of the 83C RFP award being paid by Massachusetts electric ratepayers, and early retirement of generating plant.
2. Economic impacts from O&M in New England are not included in either USM's or LEI's aggregated results shown in Figure 40 and Figure 41, but are included in the Maine results, since those impacts were estimated within Maine.
3. Economic impacts in terms of incremental jobs and GDP are presented in the form of annual average of corresponding modeling period.

5.4 Drivers of differences from LEI and USM's analysis of the operations period

While the total macroeconomic benefits for Maine in terms of incremental GDP and jobs in the USM study and LEI study do not differ much, the analytical approach and results are quite different when looking at them component by component.

As illustrated in Figure 42 and Figure 43 below, including capacity market benefits significantly increase the total macroeconomic benefits in LEI's analysis. On the other hand, LEI's results show lower wholesale energy market benefits as compared to USM's study (which was based on inflated fuel prices). However, there are other opposing differences that net out the impact between two studies. For example, LEI's inclusion of capacity market benefits creates a higher job and GDP impact. On the other hand, taking into consideration the impacts from the contract cost paid by Massachusetts ratepayers lowers the macroeconomic benefits in Maine. In addition, the early retirement of generating plants will negatively impact the Maine economy as well. Although retail electricity consumers in Maine are assumed to be exposed to the entire amount of wholesale electricity price changes, retail consumers in other states in New England are expected to enjoy only a portion of the wholesale electricity cost savings and less macroeconomics benefits than if modeled with wholesale market savings. Such reduced macroeconomic benefits in other New England states will also impact the Maine economy.

Figure 42. Breakdown of macroeconomic benefits for the operations period between the USM and LEI studies in Maine, annual average jobs (2023-2037)

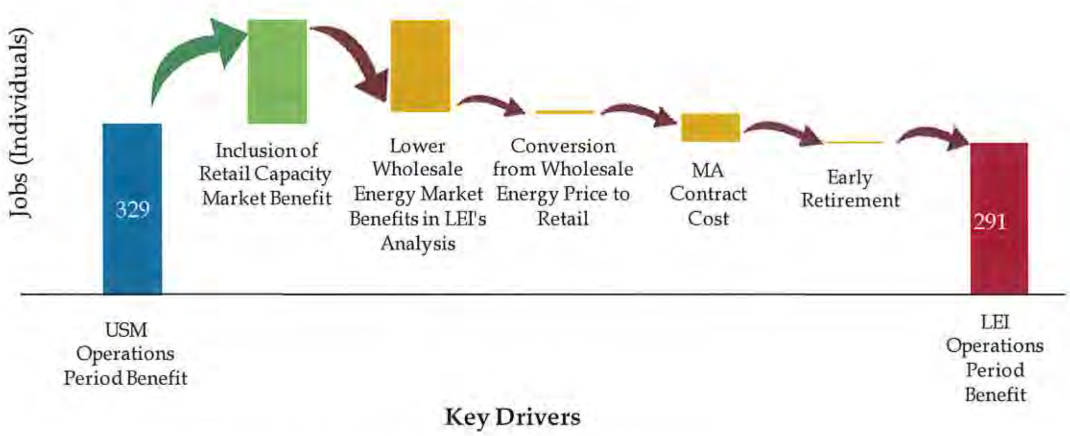


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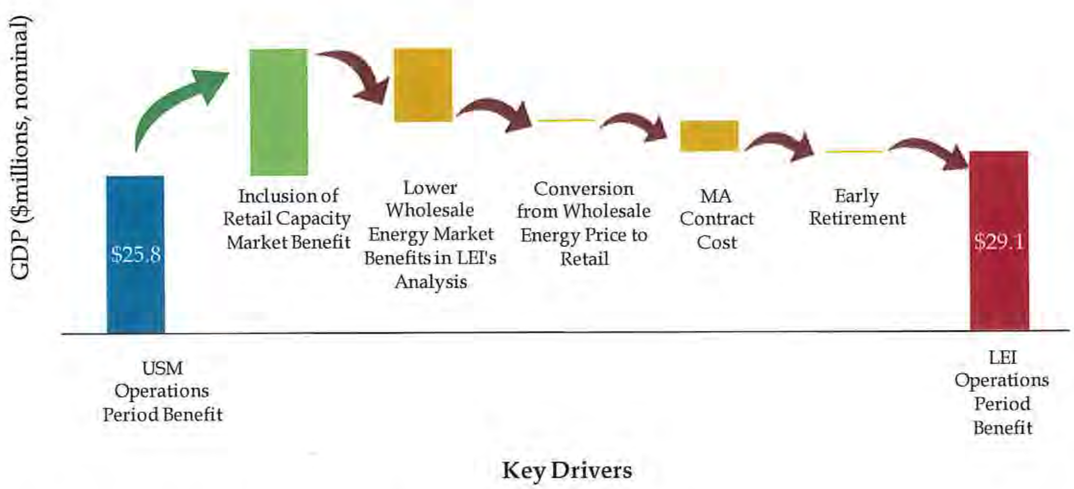
Figure 43. Breakdown of macroeconomic benefits for the operations period between the USM and LEI studies in Maine, annual average GDP (2023-2037)



Note: The "USM Operations Period Benefit" includes annual average incremental jobs and GDP during the operations period from O&M spending of the project and wholesale energy market benefit from the project. The "LEI Operations Period Benefit" includes annual average incremental jobs and GDP during the operations period from O&M spending of the project and retail electricity market benefit from the project.

5.4.1 Different components of ratepayers' savings between two studies

Figure 44 and Figure 45 provide a comparison between USM's and LEI's estimates for the electricity market benefits. [65] There are three main differences between LEI's and USM's electricity market savings and LEI documents the differences in the following sections.

The wholesale vs. retail energy market savings

USM adopted Daymark's wholesale energy market savings and fed that into the macroeconomic model. However, this approach is incomplete as it does not correctly reflect the electricity price change experienced by the ratepayers. In order to properly evaluate the impact of NECEC on New England's retail consumers, LEI converted the wholesale energy price impacts into a retail rate impact figure. To estimate the effect of the wholesale market changes on retail rates, LEI took into account limitations on retail load's exposure to wholesale market conditions. For example, in some states, utilities still own generation and that generation is under-regulated cost-of-service regime; therefore, through the continued operation of such regulated generation (which we also refer to as "self-supply"), the utilities' customers are shielded from wholesale market changes. Similarly, if a utility or retail load-serving entity has signed a long-term contract with fixed pricing terms (that are not indexed to the trends in the wholesale electricity market), the energy

[65] Aside from the conversion from wholesale price change to retail price changes, LEI further adjusted for net contract costs in Massachusetts, as well as potential early generation retirement triggered by the NECEC project in New England (discussed fully in Section 5.4.2 and Section 5.4.3 below).

and capacity terms of that contract would also limit retail customers' exposure to wholesale market prices. Based on LEI's research on the presence of long-term contracts in New England and regulated self-supply arrangements, LEI concluded that retail customers in Maine are exposed to 100% of the wholesale energy price changes, whereas in other five New England states, retail electricity consumers are exposed to 88% of wholesale energy price changes and 93% of capacity market price changes, on average, over the forecast timeframe. While LEI correctly used the retail electricity market benefits (including both energy and capacity markets), USM only included the wholesale energy market benefits.

Adoption of the inflated energy market savings from Daymark's "special case" analysis

USM's analysis of ratepayers' savings from the project is built upon the outputs of a "special case" of energy market modeling performed by Daymark. This special case is different from the electricity market cost savings presented in Daymark's report. On average, during the 2023-2042 period, the oil price and gas price in the "special case" is 9% and 24% higher than the oil and gas prices, respectively, that are used in the base case in Daymark's report.[66] The wholesale energy cost reduction in Maine in the "special case" is 1% higher than the results presented in Daymark's report.[67] For New England as a whole, the wholesale energy market benefits are 26% higher than what presented in Daymark's study on an annual average basis. Under a higher fuel and electricity prices scenario, injecting low or zero cost price resources into the electricity market will trigger more significant price reductions, which would then lead to greater macroeconomic benefits. Therefore, the macroeconomic benefits presented by Daymark are prone to overestimation given the higher wholesale energy market savings from the "special case."

Capacity market benefits were omitted in USM's analysis

USM assumed zero capacity market benefits even though Daymark analyzed the capacity market impacts of the project in their study, rendering their analysis for electricity market benefits incomplete.

Although USM's and LEI's results are comparable in terms of 15-year annual average for the period of 2023-2037, the components from each study are different. LEI's results present a higher benefit (almost double) than USM's during the first 5 years because of the inclusion of the capacity market benefits. Excluding capacity market benefits, LEI's results for retail energy benefit from the project will be about 70% lower for incremental jobs and GDP. Also, if the project fails to clear in the FCA but clears in the SA, it will cause an additional 340MW retirement in New England. Such early retirement, if included in the macroeconomic analysis, will result in even lower macroeconomic benefits in all the New England states.

LEI results show that during the end of the modeling period of 2033-2037, Maine and New England are expected to see economic losses. As explained earlier, this is primarily because LEI's electricity market modeling results show high capacity cost savings in the first five years, which results in economic benefits for local and regional economies. In the latter years, as the market

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[66] Results for the low gas price, 981MW committed project case.

[67] Results for the low gas price, 981MW committed project case.

recalibrates itself to reach a new equilibrium, such benefits dissipate starting from 2030 over time. Similarly, the energy price reductions start to decline from 2034 onward in LEI's modeling. As a result, the Maine and New England economies will go through a rebound effect, meaning that after an economic boost, economies will shrink back to their steady state size or even below the pre-shock status.

Figure 44. Estimated macroeconomic impacts in Maine due to electricity market savings (2023-2037)

Scenario	Economic Impact Category	Unit	Operations 2023-2027	Operations 2028-2032	Operations 2033-2037	2023-2037 Average
USM's Results (a)	Total Employment	Individuals	319	313	240	291
	GDP	Millions of Fixed 2009 $	$20.5	$25.3	$24.7	$23.5
LEI's Results (b)	Total Employment	Individuals	732	263	-59	312
	GDP	Millions of Fixed 2009 $	$61.0	$30.4	$4.5	$31.9
Differences [(b-a)/a]	Total Employment	%	129%	-16%	-125%	7%
	GDP	%	197%	20%	-82%	36%

Figure 45. Estimated macroeconomic impacts in New England due to electricity market savings (2023-2037)

Scenario	Economic Impact Category	Unit	Operations 2023-2027	Operations 2028-2032	Operations 2033-2037	2023-2037 Average
USM's Results (a)	Total Employment	Individuals	4,129	3984	3091	3,735
	GDP	Millions of Fixed 2009 $	$365.1	$432.2	$421.3	$406.2
LEI's Results (b)	Total Employment	Individuals	10,777	3,685	-742	4,573
	GDP	Millions of Fixed 2009 $	$1,091.6	$526.7	$79.5	$565.9
Differences [(b-a)/a]	Total Employment	%	161%	-8%	-124%	22%
	GDP	%	199%	22%	-81%	39%

Note:
1. Economic impacts in terms of incremental jobs and GDP are presented in the form of annual average of corresponding modeling period.
2. LEI's results represent macroeconomic benefits from retail energy and capacity market impacts, while USM's results are based on wholesale energy market impacts.

5.4.2 Contract cost borne by the Massachusetts ratepayers are not considered in USM's analysis

Under the Massachusetts 83D clean energy Request for Proposal ("Clean Energy RFP"), contract costs of the project, if selected, will be passed through and paid for by consumers of the electric distribution utilities in Massachusetts. However, the project's contract cost borne by Massachusetts ratepayers are not factored into the macroeconomic impact analysis conducted by USM.

Taking into consideration the contract costs, Massachusetts ratepayers would see less electricity price reductions brought by the project. As a result, Massachusetts would see lower job and GDP increases from electricity market savings during the modeling period, compared to the results shown in Table 5.1 of USM's report. Furthermore, as Massachusetts is the biggest economy in New England, economic shocks in Massachusetts will ripple through and impact other New England states that are economically and geographically connected with Massachusetts.

LEI has estimated how the RFP contract cost[68] of the NECEC project will affect the Maine economy as well as the New England economy as a whole. As shown in Figure 46, ratepayers in Maine are expected to see 55 jobs lost and reduction in GDP by $4.9 million per year during 2023-2037.

When looking at New England as a whole, the net contract costs will result in 2,355 job losses and a $288.3 million reduction in GDP every year during 2023-2037.

Figure 46. Estimated macroeconomic impacts in Maine and New England due to contract cost

Region	Economic Impact Category	Unit	Operations			2023-2037 Average
			2023-2027	2028-2032	2033-2037	
Maine	**Total Employment**	Individuals	-112	-54	-1	-55
	GDP	Millions of Fixed 2009 $	-$8.9	-$5.2	-$0.7	-$4.9
New England	**Total Employment**	Individuals	-4,267	-2,433	-367	-2,355
	GDP	Millions of Fixed 2009 $	-$432.0	-$314.4	-$118.4	-$288.3

[68] Net contract cost is calculated by adding up the transmission cost of the Project and the hedge benefits. Transmission cost is calculated by multiplying the committed energy [redacted] by the estimated bid price for transmission [redacted] provided by CMP in response to ODR-001-034. Then the hedge benefit of the contract is calculated by taking the hourly energy price in the Project Case netting it against the indicative bid price for energy [redacted] in the contract, as provided by CMP in response to ODR-003-016, and then multiplying all this by the committed energy. LEI modeled the indicative price of energy because CMP could not provide more accurate data. The transmission cost and the hedge benefit are added together to yield the net contract costs. LEI estimates the net contract cost to be a total of [redacted] on an annual average basis, during the modeling period of 2023-2037.

5.4.3 Early plant retirement and deferred local investment are not included in USM's analysis

Introducing lower-cost energy and capacity into the local energy market will potentially trigger early retirement of local generation capacity. The projected early retirements are expected to prevail whether NECEC clears the primary auction (FCA) or the substitution auction.[69] Such early retirement will cause loss of employment and reduction in economic activity in the utility sector and then induced effects in other sectors of the economy.

Daymark's analysis found that "the impact of the additional capacity supply also advances the retirement of a small amount of capacity in the region that was dependent on capacity revenue for viability." Yet, such early retirement caused by the project was not factored into USM's macroeconomic impact analysis. This leads to overestimation of employment and GDP increase for the operations period of the project.

LEI modeled early retirement of generation capacity triggered by the project as loss of jobs during the year of retirement in the Project Case until the end of the modeling period (2037) or until the original planned retirement of that plant, whichever is earlier.[70] Figure 47 below shows that the impacts are not significant in Maine - about two jobs are lost and $0.2 million reduction in GDP per year is incurred. New England as a whole is expected to see on average 251 job losses per year and loss in GDP of $46.4 million per year during the modeling period of 2023-2037.

Aside from the early retirements, LEI expects a total of 550MW of new gas generation capacity in Massachusetts to be displaced or deferred due to the NECEC. Unlike closure of a plant, which will lead to permanent and certain loss in employment, deferral of investment in new entry is only for a few years and therefore is not included in LEI's modeling. These deferred or displaced investments, if incorporated in the macroeconomic modeling, will have additional negative impacts on local employment and GDP in New England and in Maine.

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[69] In the substitution auction, NECEC must swap with an equivalent amount of resources in order to obtain a CSO.

[70] LEI forecasted that [redacted] will be retired earlier than the original planned retirement date (no announced retirement date yet) in 2030 due to the NECEC. Based on employment from Bureau of Labor Statistics and the installed capacity data from the 2018 CELT ISO-NE Annual Energy and Summer Peak Forecast, LEI estimated that labor demand for fossil fuel generation sector is approximately 0.05 jobs/MW in Connecticut. Therefore, LEI modeled 39 job losses in the Utilities sector in Connecticut to estimate the macroeconomic impacts from the [redacted] retirement in the 6-region REMI PI+ model for New England.

Figure 47. Estimated macroeconomic impacts in Maine and New England due to early retirement triggered by NECEC

Region	Economic Impact Category	Unit	Operations			2023-2037
			2023-2027	2028-2032	2033-2037	Average
Maine	Total Employment	Individuals	-3	-3	-3	-3
	GDP	Millions of Fixed 2009 $	-$0.2	-$0.3	-$0.3	-$0.3
New England	Total Employment	Individuals	-426	-394	-357	-392
	GDP	Millions of Fixed 2009 $	-$68.6	-$72.6	-$76.1	-$72.4

5.4.4 Jobs created by ratepayers' benefits should not be considered "direct jobs"

LEI found the direct job increase due to ratepayers' benefits presented in USM's report incorrect and misleading. USM in their report on Pg. 11, Table 5.1 showed that between 2023 and 2042, the project was expected to create 89 direct jobs per year on average. However, ratepayers' benefits do not create jobs through direct investment; rather they create local benefits through increasing households' disposable income and lowering local businesses' operations costs. Therefore, new jobs related to ratepayers' benefits should be categorized as "indirect and induced jobs" rather than "direct jobs."[71, 72]

5.5 Comparison of the tax revenue estimates

LEI's estimates for municipal tax revenue received from NECEC are $18.09 million a year for Maine communities. This is comparable with USM's estimates of $18.38 million[73]. This is because both analyses are based on the same valuation of the projects' taxable value provided by CMP, and the mill rates used by LEI and USM are about the same[74].

Again, as explained fully in Section 3.4, the actual tax payment from the NECEC will depend on the taxable valuation assessed by each municipality and the adjusted property tax rates (i.e. mill

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[71] In macroeconomic language, "direct jobs" are considered as jobs created as a result project investment (e.g. construction workers). Jobs created by increased demand in sectors that provide supporting services and goods are considered as "indirect jobs" (e.g., truck drivers that deliver cement used for the construction of the project). Jobs created through the increased spending of local residents are categorized as "induced costs" (construction workers spend the salary earned from the project in local restaurants, leading to increased demand for new workers in the restaurant).

[72] The report's author, Mr. Ryan Wallace, agreed during the technical session held on April 5, 2018, that they used different definitions for interpreting the "direct job" impacts during construction period and the operations period. He also mentioned that the jobs created by ratepayers' savings should technically be considered as "indirect and induced jobs."

[73] See USM's report, Section 6.

[74] LEI used the Estimated 2016 Municipal Full Value Tax Rates reported by the Department of Administrative and Financial Services of the Maine state government. USM used the actual mill rate for each municipality for 2016.

rates) in each of these municipalities, which is determined by a number of factors, such as the budget plan of the municipality, the change in market value of other properties, etc.

How the tax revenue will further affect the local economy in the affected municipalities and in the State of Maine as a whole is determined by the actual tax revenue received by the municipal governments and their budget plan. They can use the tax revenue to pay off government debts, which will not have direct impacts on the local economy. Alternatively, they could increase government spending in providing common goods as services (e.g. education and healthcare), which will create macroeconomic benefits. Since such budget decision is unknown and varies from municipality to municipality, LEI did not model such impacts in the REMI PI+ model.

In any case, tax payments from the NECEC project are expected to decline over the projects' life as the taxable value of the project depreciates. Therefore, in later years of the project's operations period, the actual tax revenue received by the affected municipalities is expected to be lower than the estimates presented in LEI's and USM's studies.

6 Appendix A: LEI Modeling Tools

6.1 Overview of the energy market forecasting model

LEI employed its proprietary simulation model, POOLMod, to develop the wholesale energy price forecast. POOLMod simulates the dispatch of generating resources in the market subject to least cost dispatch principles to meet projected hourly load, technical assumptions on generation operating capacity, and availability of transmission. POOLMod consists of a number of key algorithms, such as maintenance scheduling, assignment of stochastic forced outages, hydro shadow pricing, commitment, and dispatch. The initial stage of analysis requires the development of an availability schedule for system resources. First, POOLMod determines a near optimal maintenance schedule on an annual basis, accounting for the need to preserve regional reserve margins across the year and a reasonable baseload, mid-merit, and peaking capacity mix. Then, POOLMod allocates forced (unplanned) outages randomly across the year based on the forced outage rate specified for each resource.

Figure 48. POOLMod's two-stage process

In addition, POOLMod is a transportation-based model, giving it the ability to take into account transmission limits on the network. The New England Control Area is modeled on a zonal basis, consistent with ISO-NE's own economic models and analyses for system planning purposes. POOLMod has been used to support millions of dollars in merger and acquisition ("M&A") deals, market design support, and contract evaluations.[75] It is a general model that can be applied to many different markets but calibrated to suit the specific characteristics of New England and reflect ISO-NE's energy market rules.

When running POOLMod, the generation plants are modeled to take maintenance outages and forced outages. The scheduling of the forced outages is subject to a stochastic algorithm. The timing of forced outages (and maintenance) can affect LMPs - even annual average LMPs. As

[75] In addition to bespoke consulting engagements, LEI performs semi-annual forecasts using its POOLMod for 12 wholesale power markets. These forecasts, known as LEI's Continuous Modeling Initiative ("CMI"), examine recent market developments, draw on the latest information and data available, and apply LEI's proprietary modeling tools to provide a 10-year energy, and where applicable, capacity market price outlooks.

such, LEI ran 20 iterations of the energy model for 2023-2037 for the Base Case and the Project Case where the timing of these generation outages varied within each year (although the same number of outages were maintained between iteration for each plant). The observed wholesale energy prices from these iterations (including the average across all 20 iterations for each year and the standard deviation) were then used to assess whether the observed average of the annual price differences in a given year between the Project Case and the Base Case are statistically significant relative to the variance in LMPs created by stochastic variation in generation outages. In other words, LEI can test whether the price impact caused by NECEC is statistically robust relative to "modeling noise" caused by the randomness of forced outage and maintenance schedules of generation. Based on observed average price impacts from the 20 iterations and the variance in price impacts across the iterations, LEI concluded that the observed energy price differences in all years are statistically significant.

6.2 Overview of the capacity market forecasting model

For the capacity market analysis, LEI used the FCA Simulator, a proprietary modeling tool developed by LEI to replicate the offer strategy of suppliers in the auction, which includes offers from existing and new suppliers of capacity. New suppliers in the FCA are assumed to offer at their technology-specific Net CONE. As such capacity prices are projected to converge towards the Net CONE forecast associated with a gas-fired generator. This Net CONE is not kept constant but grows over time based on expected inflation, technological/cost improvements, and the change over time in future energy and ancillary services revenues. Existing suppliers will drive price outcomes in LEI's simulation of the FCA in periods when total existing supply exceeds the projected NICR, subject to retirement decisions (which may drive prices to new entry levels).

LEI's analysis also took into account the convex demand curves aimed to address the shortcomings of the linear downward sloping demand curve that was used for FCA #9 and #10. The new set of demand curves - known as Marginal Reliability Impact ("MRI") curves - take on a curved or convex shape so as to reflect the nonlinear relationship between quantity and ISO-NE's willingness to pay for the marginal improvement in reliability associated with adding new capacity.[76]

An MRI curve has a steeper slope left of the NICR value because the marginal impact of adding one additional resource is high. Once supply crosses to the right over the NICR level on the MRI, the curve has a flatter slope to signify that the marginal impact of adding one additional resource is lower. The linear demand curve assumes implicitly that each additional MW has the same marginal reliability impact. Figure 49 below shows an illustrative example of the MRI curve against the downward sloping demand curve for FCA #10 based on ISO-NE's indicative demand curve example.[77]

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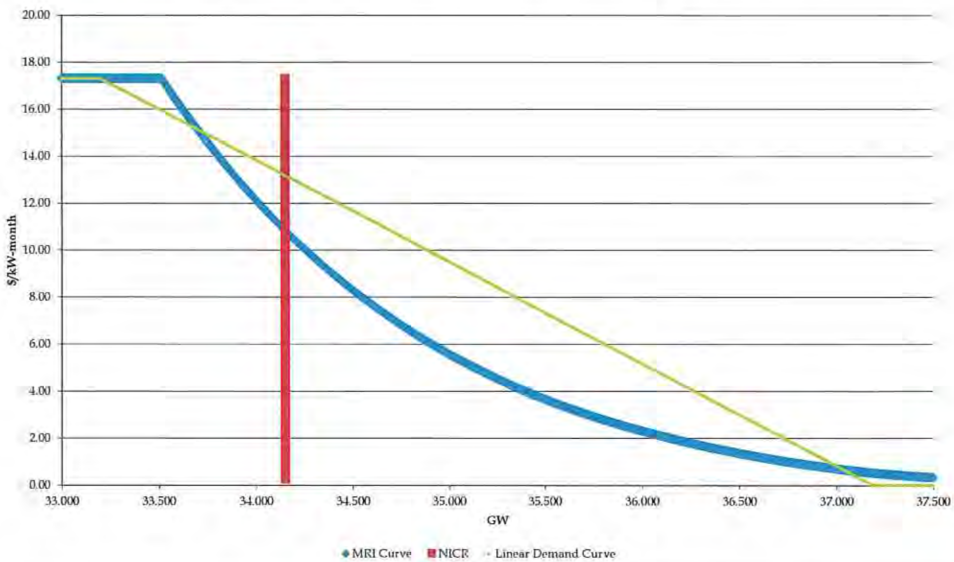
[76] For more details, see ISO-NE's December 7, 2015 technical memorandum to the NEPOOL Markets Committee on the FCM Zonal Demand Curve Methodology.

[77] ISO-NE Indicative Demand Curve Values for FCA 10 Zones. <https://www.iso-ne.com/static-assets/documents/2016/01/a02_iso_indicative_demand_curve_values_fca10_zones_01_06_16.xlsx>. Demand curves for FCA #12 have been released, however, as explained in this section, a function of the MRI curve is the Net CONE, which requires coefficients to construct a polynomial curve. These coefficients are not explicitly

Figure 49. Illustrative example of the linear demand curve and MRI curve



To obtain the capacity clearing price in the FCA, the following equation must be applied against the MRI curve:

$$Price_{System}(Quantity_{System}) = -Penalty\ Factor\ \times MRI$$

PF, refers to the Penalty Factor, which LEI sets each year such that the clearing price capacity at NICR will equal Net CONE (where the Loss-of-Load Expectation is 0.1 days/year), consistent with ISO-NE's methodology. Therefore, at any given level of Quantity (i.e. the amount of resources that clear the FCA), the price can be determined by the MRI at that particular quantity and the PF.

In practice, the MRI would change over time as new resources enter and exit the system and demand grows. ISO-NE's engineering-based approach to build up the MRI produces a set of coefficients that are used to plot the convex demand curve for each capacity zone. While the shape of the zonal convex demand curves produced for each auction may change slightly each year, ISO-NE expects these curves to be quite stable from year to year.[78] LEI therefore used the latest available coefficients from ISO-NE[79] to create the MRI demand curve, and then shifted the curves to the right each year (to account for growth in NICR), and scaled the curves using expected Net CONE values.

In order to test whether price separation would occur in the import-constrained ("NNE") or export-constrained (SENE) zones, LEI considered the representative Maximum Capacity Limit ("MCL") and Local Sourcing Requirements ("LSR") parameters calculated by ISO-NE through

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published for the FCA #12 curves, and therefore LEI continues to use the coefficients for the FCA #10 MRI curve. As noted in ISO-NE's demand curve filings, the MRI is expected to remain fairly stable.

[78] See Pg. 6 of Christopher Geissler and Matthew White Testimony on behalf of ISO-NE. Docket ER16-1434-000.

[79] LEI used the coefficients from the *ISO Indicative Demand Curve Values for FCA Zones*, March 2, 2016. See footnote 77.

FCA #17.[80] LEI then shifted the local demand curve to the right by the quantity change in the MCL or LSR. For example, a 100 MW increase in the MCL would yield a rightward shift of the NNE demand curve by 100 MW. However, as a result of LEI's retirements schedule in the Project Case, LEI found that no price separation is expected to occur with the introduction of NECEC's 1,090 MW, based on the current market topology and approved zonal definition in the FCM. LEI understands that ISO-NE is currently in the process of considering Maine as a separate export-constrained zone from the rest of New England. However, LEI is unaware of any local demand curves that have been produced by ISO-NE specifically for Maine to determine whether price separation would occur and how much.

6.3 Integration of energy and capacity market models

The capacity market model is integrated with LEI's energy market simulation, POOLMod, in that decisions to introduce new resources or retire existing resources in the capacity market is then also reflected in the energy market simulations. Furthermore, the energy market outcomes (energy prices) directly affect the Net CONE for new entrants that the ISO-NE is assumed to use to calibrate the MRI curves. Therefore, checking if a new entrant is economic or whether retirements are needed is an iterative process. Similarly, potential energy market and capacity market profits, as modeled, were compared to the breakeven prices required for new entrants, in order to simulate economic new entry. New entry and retirement decisions were then accounted for in both the FCA simulations and the energy market simulations.

[80] FCA 12 values are found in ISO-NE's *Proposed Installed Capacity Requirement (ICR) Values for the 2021-2022 Forward Capacity Auction (FCA #12)*, August 17, 2017 and FCA #13-#17 values are found in ISO-NE's *Future Representative Capacity Requirements for CCP 2022-2023 through CCP 2026-2027*, May 24, 2017 as well as the ISO-NE Draft 2017 Regional System Plan. These three zones are the ones currently defined, but in the future, there may be new boundaries for import and export constrained zones, no only one single capacity zone. However, this is not known today.

7 Appendix B: Electricity Market Assumptions

The table below provides the key assumptions utilized in the development of the inputs for the natural gas and wholesale electricity markets forecasts, the key markets these assumptions affect, and the degree of price impacts these assumptions have.

Figure 50. Summary of key modeling assumptions

Assumption	Approach
Network Topology[i]	LEI divided the ISO-NE Control Area into 11 sub-zones, corresponding to observed historical major transmission congestion. Thermal limits were based on the operating limits provided by Daymark and CMP for the Base Case and Project Case. Apart from the Maine interfaces, all other transfer limits were based on ISO-NE data.
Load Growth[ii]	ISO-NE's 2017 CELT Report provided the demand outlook until 2026. Beyond this, LEI extrapolated the demand for each zone using a three-year rolling average growth rate.
Load Shape[iii]	Forecasted hourly load shape by ISO-NE for 2017 under ISO-NE P50 (weather normalized) forecast
Existing Resources	Summer/winter capacity for energy market simulations are taken from the CELT 2017 Report. Capacity supply obligations are taken from FCA #12 results. Plant parameters such as fuel type, heat rate, emissions rates, variable O&M, maintenance and forced outage rates were sourced from third party data providers, which aggregate data from EIA, NERC, FERC, and the EPA. Energy schedules for hydro plants were developed from 10-year average historical production profile, if reported. For smaller hydro plants that are not required to report monthly generation, an average was used as a proxy, based on profiles of neighboring, similar facilities
New Entry/ Retirements	Planned short-term thermal new entry was based on resources that cleared FCA #12. Additional thermal resources were added, when the projected economics (in the capacity and energy markets) justified such additions. Generic renewable new entry was added pursuant to states' renewable renewable portfolio standards ("RPS") goals. However, new on-shore wind in northern parts of Maine was capped at 1,000 MW to account for transmission constraints
Natural Gas	Natural gas prices were derived based on LEI's proprietary Levelized Costs of Pipeline ("LCOP") forecast model. LEI relied on the forward market for projecting locational gas prices in the near term and a fundamental analysis using a reference point plus a transportation adder to project gas prices in the long run
Other Fuels[iv]	Residual and distillate prices were based on NYMEX forwards and the AEO 2018 growth rates for crude oil. Coal prices were modeled for each coal plant based on actual historical costs and EIA's growth rate for regional coal supplies
Carbon Allowance Prices[v]	The average of January - March forward RGGI prices were used until 2020. LEI then adopted the results of No National Policy Model Rule Scenario by RGGI
Interchange[vi]	Imports and exports were modeled on based on historical interchange from recent years, 2015-2017.

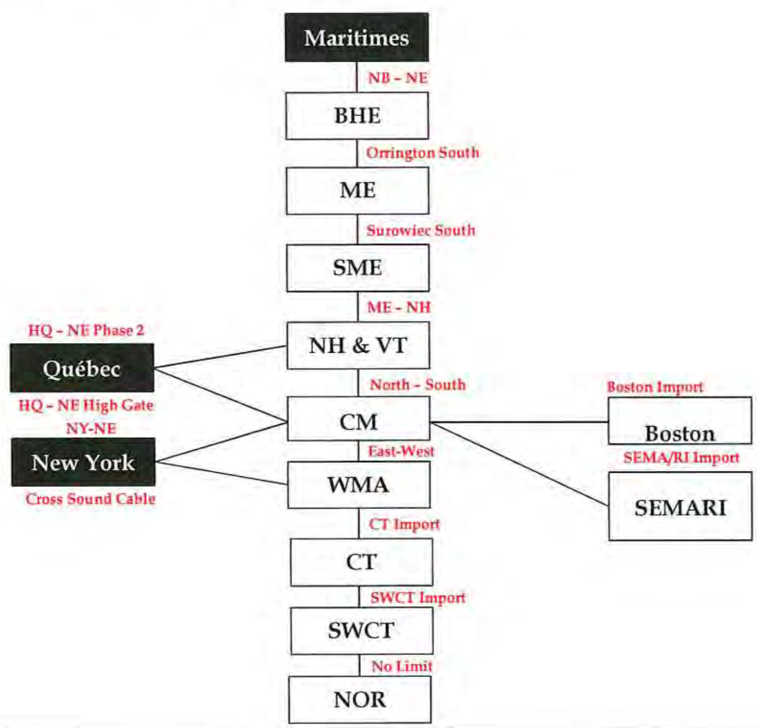
Notes:
i) Daymark response to ODR-003-019
ii) ISO-NE CELT Forecast Data 2017, <https://www.iso-ne.com/static-assets/documents/2017/05/forecast_data_2017.xlsx>
iii) ISO-NE 2017-2026 *NE Region Hourly Load Forecast*, <https://www.iso-ne.com/static-assets/documents/2017/05/rsp17_iso_eei.txt>
iv) EIA, *Annual Energy Outlook 2017*. <https://www.eia.gov/outlooks/aeo/>
v) Draft 2017 Model Rule Policy Scenario Overview. September 25, 2017. <https://www.rggi.org/docs/ProgramReview/2017/09-25-17/Draft_IPM_Model_Rule_Results_Overview_09_25_17.pdf>
vii) ISO-NE, External Interface Metered Data. <https://www.iso-ne.com/isoexpress/web/reports/grid/-/tree/external-interface-metered-data>

7.1 Market topology

LEI's model of the New England power grid uses 11 zones in ISO-NE as shown below in Figure 51: (i) Bangor Hydro Electric ("BHE"); (ii) Maine ("ME"); (iii) Southern Maine ("SME"); (iv) New Hampshire/Vermont ("NH/VT"); (v) Central Massachusetts ("CM"); (vi) Western Massachusetts ("WMA"); (vii) Connecticut, ("CT"); (viii) Southwest Connecticut ("SWCT"); (ix) Norwalk ("NOR"); (x) Northeast Massachusetts/Boston ("NB"); (xi) Southeast Massachusetts/Rhode Island ("SEMARI"). This is consistent with the market topology used by ISO-NE in their long-term planning models and the location of the most binding transmission constraints.[81]

LEI adopted CMP's estimates of the transfer limits along the three Maine interfaces, based on Daymark's response to response to ODR-003-019. This includes upgrades made when NECEC is in service.

Figure 51. Regional transmission interface limits



81 For long-term planning purposes, ISO-NE models the ISO-New England Control Area ("NECA") on the basis of thirteen sub-regions defined by binding transmission constraints. For modeling, the market topology is simplified, while being consistent with ISO-NE's approach. NH and VT are modeled as one zone, and SEMA and RI are modeled as one zone.

7.2 Load Growth

LEI adopted ISO-NE's CELT forecast, which includes its 10-year forecast of peak demand and total demand. The gross demand projections are lower than previous CELT reports due to ISO-NE's revised outlook on actual consumption in recent years, and expectations of passive demand response ("PDR") and behind the meter solar PV.

LEI specifically used ISO-NE's peak demand and total demand forecasts from ISO-NE's CELT 2017 for its P50 case that represents the expected or 50/50[82] outlook; this covers the period of 2017 to 2026. Energy efficiency and behind-the-meter solar PV are treated as a reduction in demand for the energy market simulation purposes. For the capacity market, incremental energy efficiency is treated as a supply resource, not a reduction from NICR. Beyond 2026, LEI extrapolated ISO-NE's demand forecasts using a three-year rolling average growth rate.

For the hourly load profile, LEI used ISO-NE's hourly load forecast for 2017 for each sub-region under the P50 case. Based on this sub-regional hourly load shape, LEI forecasted the hourly load shape in future years by scaling the shape with the forecasted peak load and total energy demand in those years.

7.3 Natural gas projections

LEI identified four key drivers of for natural gas price in North America. Three of these point to strong growth in supply; one of them points to growth in demand:

- Continued development of Marcellus and Utica shale plays in the Eastern United States
- Continued growth in crude oil and natural gas production from Permian Basin in West Texas
- Growing gas production in Western Canada
- Growing demand for gas in the form of LNG and pipeline exports

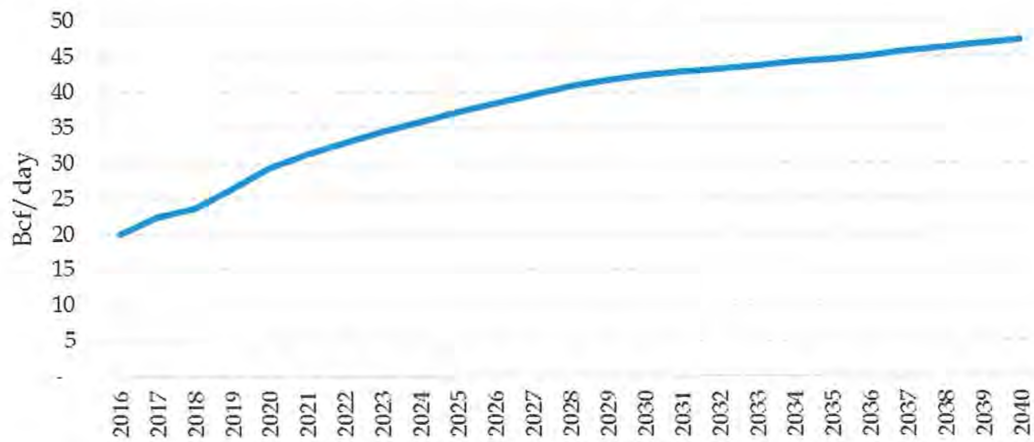
7.3.1 Supply-side drivers

Continued development of Marcellus and Utica shale plays in the Eastern US is one of the key drivers of North American gas prices. Though Energy Information Administration ("EIA") has tended to be conservative in its supply outlooks from the East region, in its Annual Energy Outlook ("AEO") 2018, EIA projected that dry gas production in the East would grow from 22 billion cubic feet ("Bcf") per day in 2017 to 47 Bcf per day in 2040, at a compound annual growth rate ("CAGR") of 3.3% (see Figure 52). These two Appalachian shale gas plays have remained

[82] By definition, the 50/50 load forecast is an expected weather forecast – peak load under the 50/50 load forecast has a 50% chance of being exceeded. Major assumptions and conditions, including weather, are assumed to approach or approximate the long run average.

resilient to low natural gas prices and are projected to continue to drive total US production in the long term, especially as pipeline takeaway capacity expands.

Figure 52. EIA AEO 2018 Reference Case outlook for dry gas production in East region



Source: EIA AEO 2018 Reference Case

In West Texas, Permian Basin recent gas production growth is based on associated gas, which is gas that is produced from oil-directed wells, essentially as a by-product. This production does not depend much on natural gas prices—the gas is recovered with the oil, and producers need to find a home for it. The US Geological Survey ("USGS") estimates that recoverable shale gas resources in the Midland Basin portion of Texas' Permian Basin could exceed 16 trillion cubic feet of natural gas, a substantial 40% of the recoverable natural gas resources from Marcellus and Utica.[83] Thus, LEI expects ongoing growth in crude oil production in the Permian Basin to keep Henry Hub gas prices in check.

As shown in Figure 53, AEO 2018 Reference Case projects that crude oil production from Southwest (the region which includes the Permian Basin) will grow from two million barrels per day to four million barrels per day from 2017 to 2040, while natural gas production is projected to grow from 10 Bcf per day in 2017 to 14 Bcf per day in 2040.

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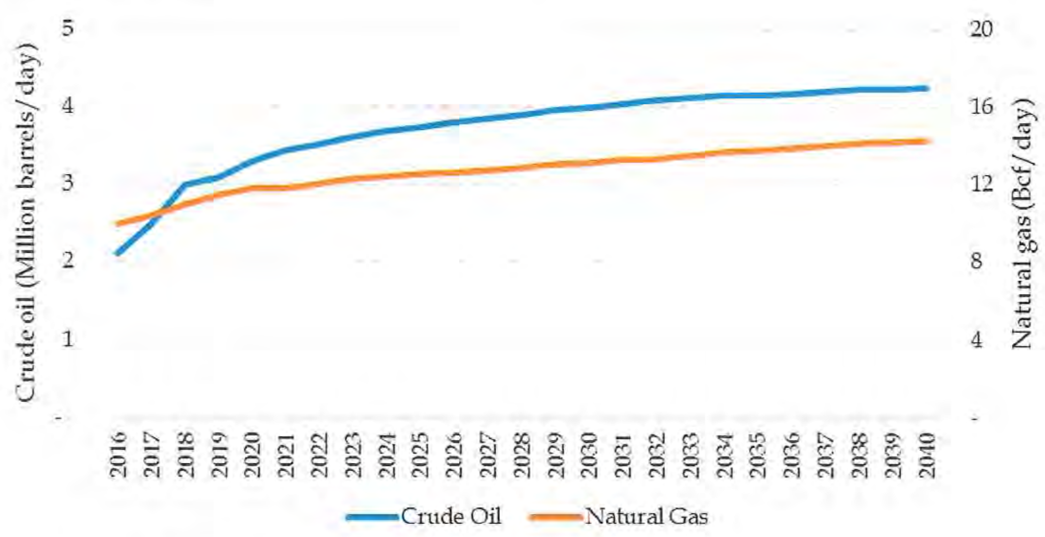
[83] USGS. Assessment of undiscovered continuous oil resources in the Wolfcamp shale of the Midland Basin, Permian Basin Province, Texas, 2016. November 2016. <https://pubs.usgs.gov/fs/2016/3092/fs20163092.pdf>

Figure 53. EIA AEO 2018 Reference Case outlook for crude oil and natural gas production in the Southwest region



Source: EIA AEO 2018 Reference Case

Furthermore, there is growing natural gas production in Western Canada's Montney and Duvernay shales which will also help maintain downward pressure on gas prices. Natural gas net exports from Canada to the US have increased from 5.4 Bcf per day in 2012 to 5.8 Bcf per day in 2017.[84] Natural gas production from Western Canada has increased from 13.6 Bcf per day in 2012 to 15.4 Bcf per day in 2017.[85]

7.3.2 Demand-side drivers

In the long term, increasing global demand for natural gas is likely to provide a potentially large market for US exports of natural gas via pipeline to Mexico, and in the form of liquefied natural gas ("LNG") to overseas markets. This demand can eventually support the recovery of US Henry Hub prices from the current low levels.

According to the AEO 2018 Reference Case, the US became a net exporter of natural gas in 2017, driven by declining pipeline imports, growing pipeline exports and growing exports of LNG.[86] In AEO 2018, EIA projects that exports of natural gas through pipelines to Mexico will increase from 4.3 Bcf per day in 2017 to 6.6 Bcf per day in 2040.[87] US natural gas exports to Mexico have doubled since 2009 and are expected to continue increasing through at least 2029 due to the

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[84] National Energy Board. *2017 Natural Gas Exports and Imports Summary.*

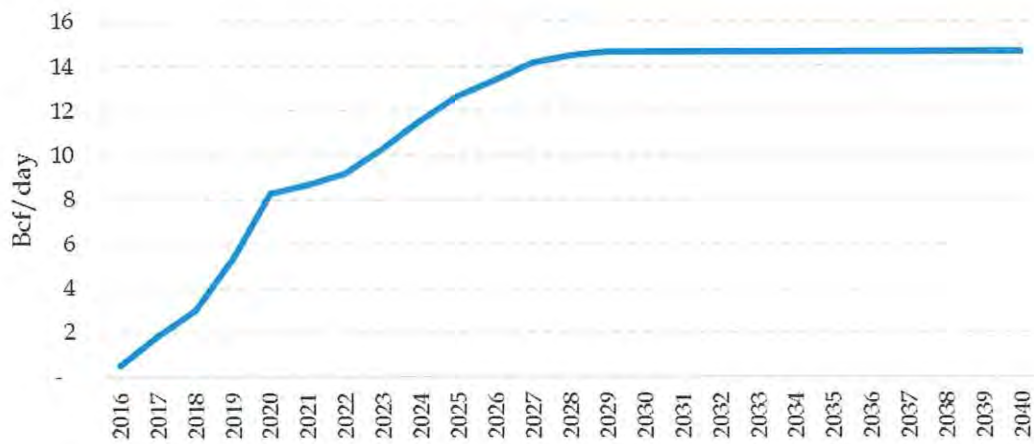
[85] National Energy Board. *Marketable Natural Gas Production in Canada.*

[86] EIA AEO 2018. Table 62. Natural Gas Imports and Exports. <https://www.eia.gov/outlooks/aeo/data/browser/#/?id=76-AEO2017&cases=ref2017&sourcekey=0>

[87] EIA AEO 2018. Table 62. Natural Gas Imports and Exports. <https://www.eia.gov/outlooks/aeo/data/browser/#/?id=76-AEO2017&cases=ref2017&sourcekey=0>

pipelines that are currently under construction. The growth of projected natural gas exports is also supported by new LNG terminals recently completed, and others currently under construction and in early stages of development. EIA's outlook estimates LNG exports to grow from less than 1 Bcf per day in 2017 to 15 Bcf per day in 2040, at a CAGR of 9.5% (see Figure 54).

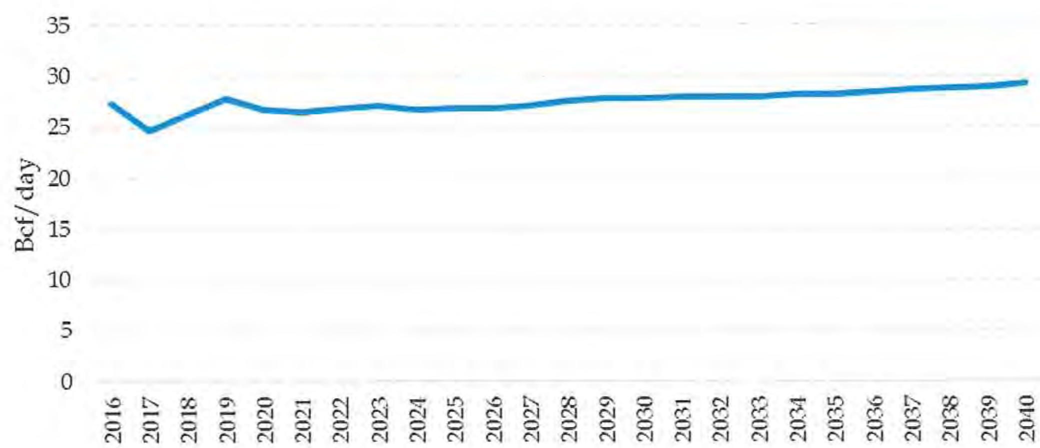
Figure 54. EIA AEO 2018 Reference Case outlook for liquefied natural gas exports



Source: EIA AEO 2018 Reference Case

With the retirement of coal and nuclear power plants, it could be assumed that demand for natural gas from the US electric power sector would be poised to increase dramatically. However, the EIA AEO 2018 does not project strong growth in gas demand from the power sector (see Figure 55). This weak growth is mainly owing to EIA's projected annual growth of power demand of 0.7% on average.

Figure 55. EIA AEO 2018 Reference Case outlook for gas consumed in electricity generation



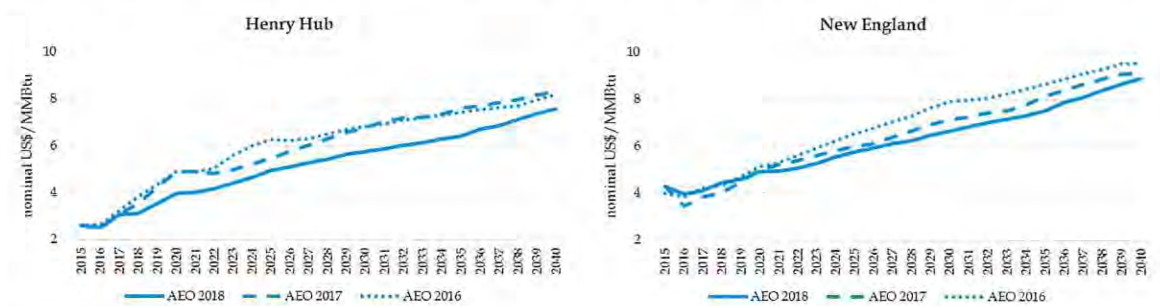
Source: EIA AEO 2018 Reference Case

The 3.1 Bcf per day of demand growth from the power sector from 2018 to 2040 is not enough to make a dent in the abundant supply of US natural gas.

7.3.3 LEI's outlook for Henry Hub gas prices

For the longer term, the eventual increase in gas prices in the EIA's AEO 2018 Reference Case forecasts is consistent with the four key North American natural gas supply and demand trends discussed above. However, LEI believes that EIA's typically conservative outlooks for natural gas production growth have led it to miss the impact of strong production on gas prices in the near term. EIA's Reference case outlooks have shifted downward substantially in recent years (see Figure 56). AEO 2016 reference case for Henry Hub price forecast was 20% lower on average than the AEO 2015 (nominal basis, 2023-2040); AEO 2017 was 2% lower than AEO 2016, and the recently published AEO 2018 is 13% lower than AEO 2017. EIA's New England outlooks have also shifted downward. On a nominal basis, for the years 2023-2040, the AEO 2017 outlook was 7% lower than the AEO 2016; and AEO 2018 is 5% lower than AEO 2017. AEO 2018 reference case compound annual growth (nominal basis, 2023-2040) for Henry Hub is 3.4% and for New England is 3.2%.

Figure 56. Vintages of AEO Reference cases, Henry Hub and New England outlooks



There are two main drivers for the lower outlook in AEO 2018[88] compared with AEO 2017:

- greater natural gas volumes of low-cost resources available for production, particularly in the Marcellus shale gas play and the tight oil plays in the Permian Basin; and
- lower per unit cost of production to reflect increased rates of technological drilling progress.

Given the strong supply-side drivers, LEI believes that robust gas price recovery projected by AEO 2018 Reference Case in the near term (specifically, in next two to four years) may not materialize. Therefore, LEI chose to use the AEO 2018 Reference Case annual trend, but not the absolute price level, in LEI's long-term outlook for Henry Hub prices. LEI applied this trend to

[88] EIA. "Oil and Natural Gas Resources and Technology." March 26, 2018. <https://www.eia.gov/outlooks/aeo/section_issues.php#grt>

the 2019 futures market price, to create our projection of Henry Hub prices for 2020 and beyond (see Figure 57).

Figure 57. LEI's natural gas price forecast

[redacted]

7.3.4 LEI's outlook for New England gas prices

In LEI's power sector modeling, the Algonquin Citygate price serves as the delivered natural gas price for gas-fired generators in New England.

In the near term (first two years of the outlook (2018 and 2019)), LEI relied on the forward markets for projecting Algonquin Citygate gas prices. LEI used the three-month average of daily forwards (January 1, 2018 - March 31, 2018), as reported by OTC Global Holdings ("OTCGH") for the 2018 and 2019 monthly prices.

From 2020 and onward, LEI projected the Algonquin Citygate gas price based on a supply hub price plus a transportation adder to New England calculated by LEI's proprietary Levelized Cost of Pipeline ("LCOP") model. The LCOP model assumes that price spreads between any two gas pricing hubs cannot, in the long run, persist above the levelized cost of building a new pipeline between the two hubs. The LCOP model assumes that if the price spread rises above the levelized cost of building a pipeline between any two hubs for three consecutive years, then a pipeline will be built between the two hubs to reduce the price spread.

Traditionally, Henry Hub has been the reference point for the North American gas market. However, due to the relatively low-cost shale gas production from Marcellus and Utica, these locations now supply much more gas to New England than the Gulf Coast does. LEI, therefore, chose Dominion South (a hub located in the Marcellus region) as the reference point for projecting Algonquin Citygate gas prices. LEI projects Dominion South to trade at a discount to Henry Hub, reflecting the ongoing need to add pipeline capacity from the Marcellus to market regions. LEI projects Dominion South prices to increase at the same rate as Henry Hub, based on the 2018 EIA AEO, although they reflect the persistent discount.

For 2018 and 2019, the transportation adder to arrive at the Algonquin price is the difference in the futures price between Dominion South and Algonquin Citygate gas hub.

For 2020 and 2021, the LCOP indicates that new pipeline capacity will be needed. This is the result of the first three years of the outlook for Algonquin prices relative to Marcellus area prices. The difference between Algonquin and TETCO M3 prices from 2019 and 2020 is around $1.6 per MMBtu, and the cost of building a pipeline is $1.12 per MMBtu (see Figure 58). This price signal induces a pipeline expansion. The LCOP model "expands" pipeline capacity, by, in effect, reducing the basis to the LCOP, in 2021. Although in practice pipeline expansions are not perfectly timed to meet market demand, the LCOP model represents a long-term equilibrium which is appropriate for a long-time horizon such as the 2018-2037 for the NECEC analysis.

Figure 58. LCOP Algonquin and TETCO M3 price differential and pipeline cost

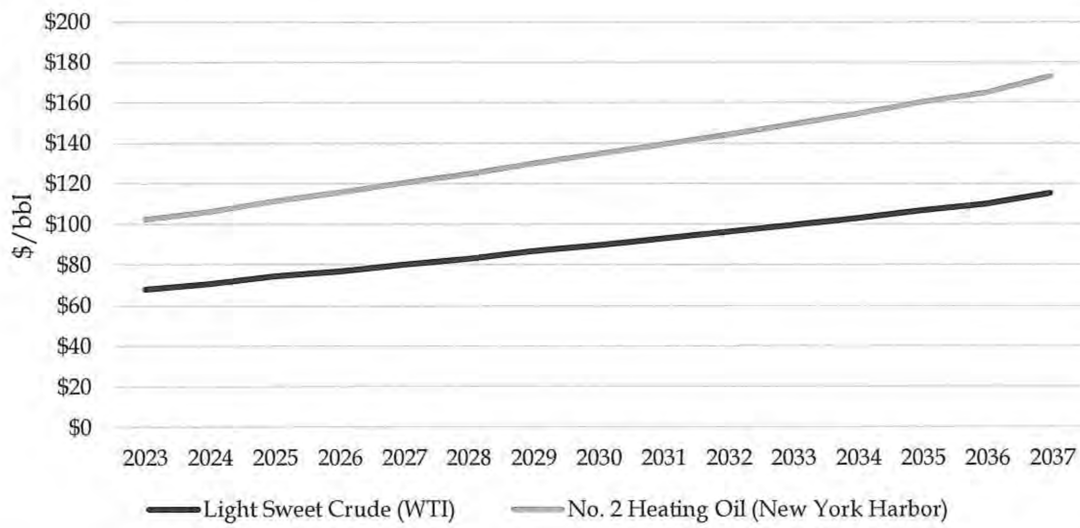
Source: LCOP

LEI projects the Algonquin Citygate price to increase from $3.6 per MMBtu in 2018 to $6.78 per MMBtu in 2037 (in nominal terms). The Algonquin Citygate prices are on average $2.0 per MMBtu higher than Dominion South (a point which is further away from Algonquin Citygate than TETCO M3, so it has a correspondingly higher cost to build a pipeline), reflecting the long-term transportation adder generated by LEI's LCOP model.

7.4 Other fuels

Although natural gas-fired resources are price setting for the vast majority of hours, oil-fired resources occasionally do run, although this typically accounts for less than 1% of total generation. The distillate oil price is based on the heating oil forwards for the first two years and escalated at the same rate as the EIA crude oil forecast in the long term. The residual oil price was developed based on a multi-year average of the ratio of residual and distillate oil prices. Figure 59 below shows the natural gas and oil prices over the modeling timeframe.

Figure 59. Forecast of various oil prices



Given the diversity in coal sourcing, quality, and price, LEI developed plant-specific coal price outlooks. LEI began with an estimate of 2017 actual delivered costs, taking into account the type of coal used at each plant (since each coal plant has different sulfur content levels and different contracts for price and transportation). LEI then escalated the estimated costs with the longer-term trends for the commodity using coal-based inflation rates from AEO 2018.[89] Notably, all coal units are projected to be retired by 2023 in the region, based on the analysis described in Section 7.7 below.

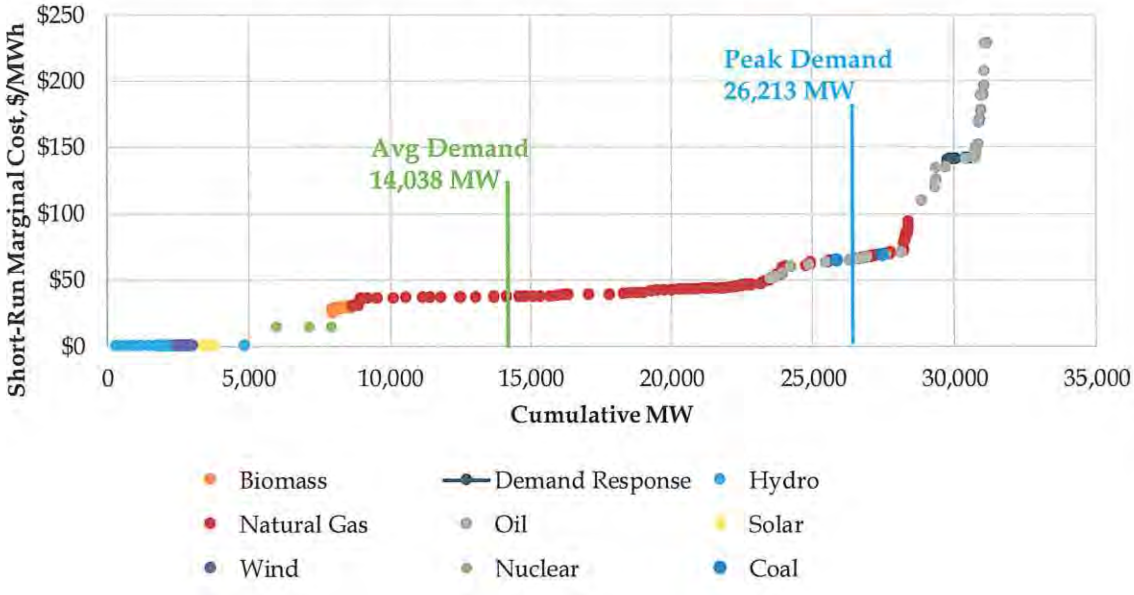
7.5 Existing Supply

Existing supply (for the energy market simulations) in New England was based on the ISO-NE 2017 CELT, which provides plant-specific demonstrated capacity ratings for both summer and winter seasons, as of May 2017. LEI supplemented this data with plant parameters (heat rates, variable O&M, forced outage rate, etc.) from commercially available databases. LEI also added in changes in the resource mix based on FCA #12 results.

The system-wide supply curve in Figure 60 shows that gas-fired plants are the main price setting units for average load, and oil is expected to set prices during the highest load hours. Note that the chart below shows the indicative internal supply curve which is adjusted (seasonal ratings, maintenance, forced outage) for availability, and therefore may understate the capacity in any given hour when units are available at full capacity. It does not incorporate imports from neighboring markets.

[89] EIA, *Annual Energy Outlook 2017*, Table 66. Coal Production and Minemouth Prices by Region.

Figure 60. Indicative energy market supply curve of New England resources for 2021



Note: Supply curve is adjusted for availability but not for transmission constraints; illustration excludes imports and exports.

For the capacity market, LEI assumed that all the resources that cleared FCA #12 (including imports and demand response) remain in the market as existing resources unless the modeling suggests units will retire. Going forward, incremental energy efficiency from ISO-NE's forecast will be included as supply in the FCA simulations.

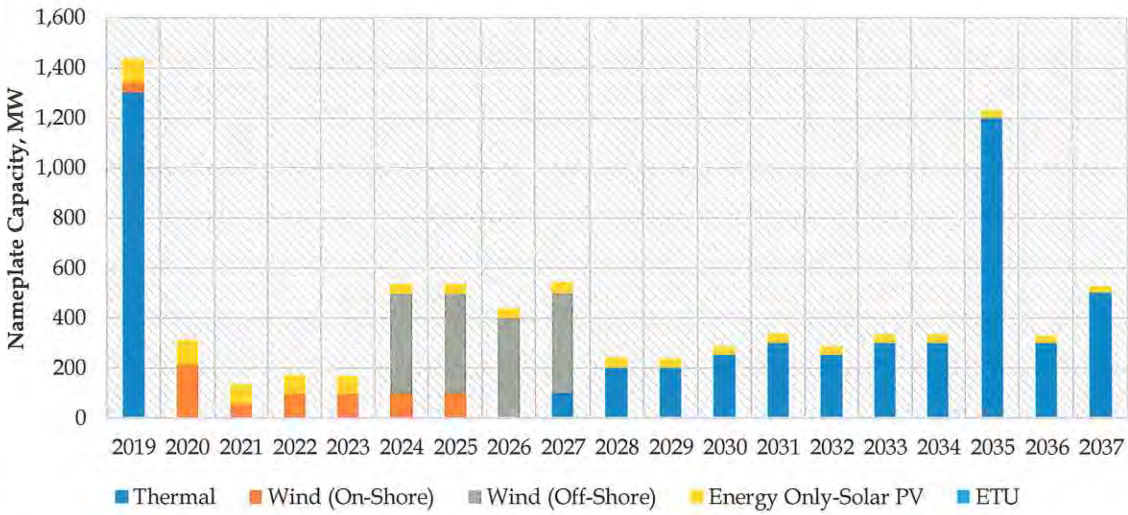
7.6 New entry

Over the long term, LEI assumed that generators make economically rational ("just-in-time") capacity investment decisions timed to load growth and earnings potential across the wholesale electricity markets. In considering new entry, the modeling has taken the following criteria into account, namely: (1) state procurements of clean energy resources and Renewable Portfolio Standards ("RPS"); and (2) the economics of new entry based on LEI's FCA Simulator and (3) the NICR (growth in demand).

7.6.1 State procurements of clean energy

LEI factored in contracted and expected resources from the various state solicitations for clean energy. This includes all renewables from the Clean Energy RFP, CT-2-20 MW, as well as any resources cleared up to FCA #12. Future resources procured in MA RFP Sections 83C will be assumed to compete in the energy market but will only participate in the capacity market if they clear through the substitution auction. Lastly, the full amount of solar PV energy only resources based on the ISO-NE's 2017 Solar PV Forecast was assumed to participate in the energy market (only).[90] LEI found that by combining the energy output from these various solicitations and projections, New England exceeded RPS requirements by the mid-2020s. While a forecast for Renewable Energy Credits ("RECs") is not part of this report, LEI expects that the resulting REC prices would reflect that oversupply and be significantly lower than they have been over the last several years. Figure 61 below shows the schedule of new resources included in LEIs forecast.

Figure 61. New entrants included in LEI's Base Case forecast (MW)



7.6.2 Economics of new entry and Net CONE

Ultimately, the mix of new entry is a function of market economics (i.e. profitability of generators) and policy priorities, as well as political realities (i.e. coal is unlikely to be a realistic candidate for these markets given the lack of commercial capability for carbon sequestration in New England, even though it could be competitive at high gas prices). The new entry decisions are conditioned on modeled outcomes such that additional new entry is introduced if and when it is economically feasible given the simulated market dynamics.

ISO-NE posits that the Net CONE has come down based on more recent information and that a combustion turbine is, in fact, cheaper than a combined cycle power plant. The Net CONE is an important parameter in the FCM, as it directly affects the administrative price cap and impacts the slope of the demand curve. All else being equal, a lower starting Net CONE value will result in lower capacity market prices. LEI's forecast used the FERC-approved Net CONE values as an input to the FCA simulations. To calculate the Net CONE, LEI started with ISO-NE's current cost of new combustion turbines ($8.04/kW-month for FCA #12), then escalated the capital costs with inflation (plus a 2% technology efficiency improvement every four years) and inflated the energy and ancillary services offset by the trends in energy market prices.

[90] Behind the meter solar PV based on ISO-NE's 2017 Solar PV Forecast will be assumed to reduce demand.

London Economics International LLC
717 Atlantic Ave, Suite 1A
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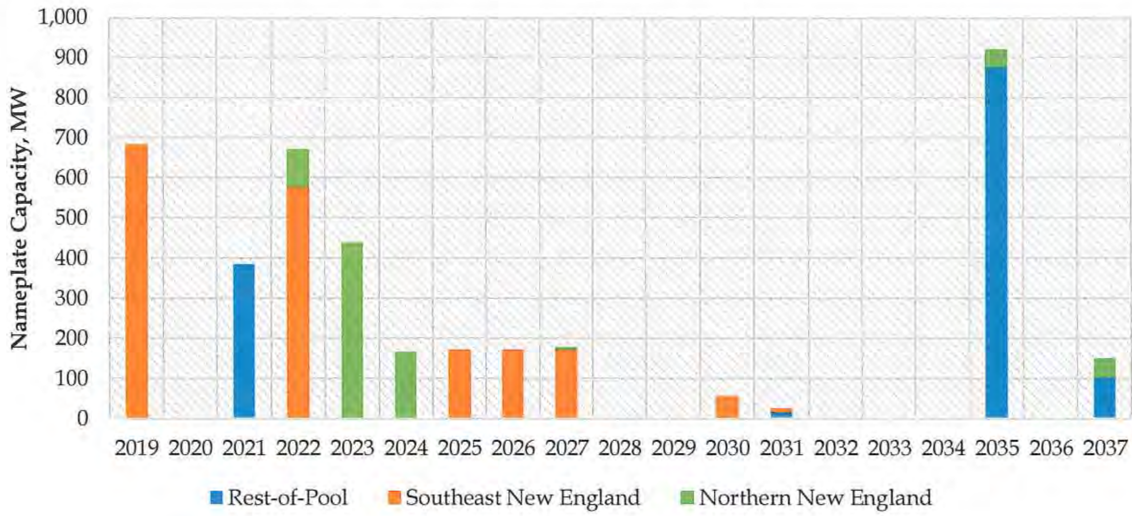
Due to the addition of nearly 2.5 GW of new gas-fired units that cleared in FCA #9 and #10, 1.7 GW clean energy resources (planned onshore wind to meet the states' RPS and offshore wind per MA RFP 83C), energy efficiency across New England states according to ISO-NE's forecast, and slow demand growth, additional generators are unlikely to enter the market in the short term without more offsetting retirements as forecasted energy and capacity prices remain below levels necessary to motivate and fully remunerate a new generation entrant.[91]

7.7 Retirements

LEI incorporated all announced retirements into the analysis as of Q1 2018, which includes Pilgrim Nuclear Power Station (retirement date of June 2019) and Bridgeport Harbor 3 (retirement date of July 2021), as well as any other de-list bids for FCA #12. Given Exelon's decision to retire Mystic 7, 8, and 9, and the fact that ISO-NE is seeking to retain Mystic 8 and 9, LEI only retired Mystic 7 in this forecast.[92]

Figure 62. Retirements included in LEI's Base Case forecast (MW)



Note: Some retirements include Active DR resources that filed for submitted retirement de-list bids for FCA #12

In addition, LEI reviewed the minimum going forward costs of existing power plants and assumed that if resources are not expected to meet their minimum going forward costs for three consecutive years, then they would retire. This approach is consistent with how the IMM reviews

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[91] LEI understands that in the past, some resources have been able to clear well below the ISO-determined Net Cone values, although these resources tended to be brownfield units, had good connections to existing pipelines or transmission infrastructure, or were able to make use of certain tax advantages. LEI does not expect these opportunities to be available in the future, and therefore expects thermal units not to clear until beyond the modeling timeframe.

[92] ISO-NE memo. *Discussions of Near-Term Fuel Security Concerns*. NEPOOL Participants Committee. April 3, 2018.

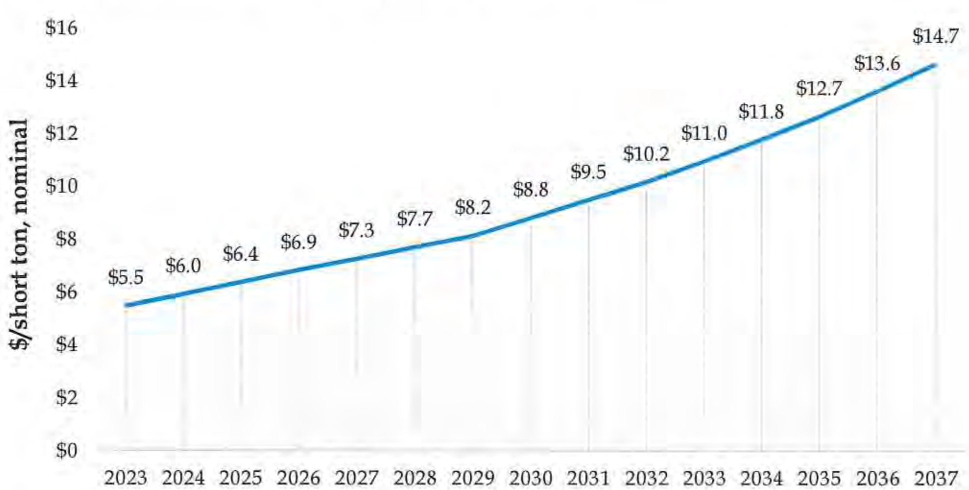
retirement de-list bids when testing for the economic life of an asset.[93] Based off this analysis, LEI found that nearly 3,100 MW of resources would retire by the mid-2020s (including the 1,250 MW that has already announced retirements or submitted retirement delist bids such as Pilgrim nuclear plant and Bridgeport Harbor 3).

However, this capacity reduction will be more than offset by the 4,200 MW of new thermal and renewable generation that is expected over the next several years in LEI's forecast (clearing in FCA #9 - FCA #18), which still results in oversupply on a net basis for New England. Figure 62 below shows the retirements by year that are included in LEI's forecast, with most retirements occurring in the early 2020s.

7.8 Carbon allowance costs

LEI expects that the regional greenhouse gas emissions trading program, RGGI, would continue over the modeling timeframe. Under RGGI, power plants with an installed capacity of over 25 MW must reduce their CO_2 emissions by 50% by the year 2020 relative to their 2005 emissions level. LEI assumes that all ISO-NE states will auction 100% of their CO_2 allowances under RGGI. Each plant is required to purchase an allowance to offset each ton of CO_2 it emits. The RGGI cap declines 2.5% each year from 2018 to 2020. Therefore, forwards for carbon allowance prices have been used in the modeling up to 2020. Beyond 2020, LEI adopted the results of "No National Policy Model Rule Scenario" forecast by RGGI in September 2017.[94] This results in a $5.5/short ton price in 2023 rising to a $14.7/short ton price in 2037, in nominal dollars, as shown below.

Figure 63. Carbon emissions allowance price projection



Sources: RGGI, Draft 2017 Model Rule Policy Scenario Overview. September 25, 2017.

[93] ISO-NE Forward Capacity Market Retirement Reforms. Docket ER16-551-000. <https://www.iso-ne.com/static-assets/documents/2015/12/er16-551-000_retire_reforms.pdf>

[94] RGGI, Draft 2017 Model Rule Policy Scenario Overview. September 25, 2017.

7.9 Import and export flows

ISO-NE is well interconnected with surrounding regions, with ties to the New Brunswick, Québec, and New York power markets. External resources available for imports are modeled on an aggregate rather than an individual unit basis. New England had traditionally been a net exporter, but since 2011 has become a net importer. LEI expects imports from Québec (mainly from hydroelectric resources) to continue into the future at historical levels. Imports from Québec to New England occur via the interties of NE-HQ Phase II and NE-HQ Highgate.

To model the interchange between ISO-NE and external regions, LEI reviewed historical hourly interchange data. Exports to New York, through the Cross-Sound Cable ("CSC") at Shoreham and Northport, are also expected to continue at historical levels due to the projected continuation of tight in-city reserve margins (New York City and Long Island) and the average between 2015-2017 were used.[95]

Over the past four years, trends in the net interchange level from ISO-NE to NYISO via the Roseton intertie have changed. For modeling purposes, the Roseton target was based on the average interchange of 2015-2017 levels until 2030, when nuclear retirements in New York are expected to reduce imports from New York on only the Roseton line by approximately two-thirds. However, this is beyond the modeling horizon for this forecast, and while LEI does not expect all nuclear plants in New York to retire within the modeling horizon, such an event may cause a reversal in flows from New England to New York in the mid-2030s.

LEI expects imports from the Canadian Maritimes to be similar to 2015-2017 levels where Point Lepreau nuclear plant resumed operation in New Brunswick in November 2012, subject to existing transmission constraints from New Brunswick to Maine, Maine to Southern Maine, and Southern Maine to New Hampshire.

Figure 64. Net annual imports with neighboring regions

	Northport (NY)	Roseton (NY)	Shoreham (CSC)	New Brunswick	Phase II (HQ)	Highgate (HQ)
Total GWh	-404	5,102	-1,675	4,411	11,382	1,821

Note: Positive numbers imply net imports, and negative numbers imply net exports. Beginning in 2030, imports along the Roseton interface drop by approximately 5.1 TWh, then reverse to a net import of 1.8 TWh in 2035.

Source: ISO-NE historical interchange data, LEI analysis

[95] In addition, the Norwalk Harbor – Northport, NY, 138 kV cable (NNC) replacement project (formerly known as the 1385 cable) was placed in service during 2008. Since its operation, a significant amount was exported from NE to NY.

8 Appendix C: Comparison of Macroeconomic Impact Estimates

Figure 65. A year-by-year comparison of LEI's and USM's economic impact estimates based on the original project cost estimates – Incremental jobs during the development and construction period

Scenario	Category	Unit	Development 2017	Construction 2018	2019	2020	2021	2022	Annual Average
USM	Direct Employment	Individuals	48	281	569	1,775	1,811	723	868
	Indirect & Induced Employment	Individuals	67	252	585	1,517	1,695	824	824
	Total Employment	Individuals	115	533	1,154	3,292	3,506	1,547	1,691
LEI	Direct Employment	Individuals	48	268	545	1,677	1,713	680	822
	Indirect & Induced Employment	Individuals	67	239	563	1,401	1,570	758	766
	Total Employment	Individuals	115	507	1,108	3,078	3,283	1,438	1,588
% Diff	Direct Employment	%	0%	-4%	-4%	-6%	-5%	-6%	-5%
	Indirect & Induced Employment	%	0%	-5%	-4%	-8%	-7%	-8%	-7%
	Total Employment	%	0%	-5%	-4%	-6%	-6%	-7%	-6%

Figure 66. A year-by-year comparison of LEI's and USM's economic impact estimates based on the original project cost estimates – Incremental GDP during the development and construction period

Scenario	Category	Unit	Development 2017	Construction 2018	2019	2020	2021	2022	Total	Annual Average
USM	GDP	Millions of Fixed 2009 $	$ 8.8	$ 30.0	$ 69.0	$ 177.4	$ 194.2	$ 85.3	$ 564.8	$ 94.1
	Total Compensation	Millions of Nominal $	$ 5.9	$ 22.0	$ 52.6	$ 132.4	$ 150.6	$ 72.2	$ 435.7	$ 72.6
LEI	GDP	Millions of Fixed 2009 $	$ 8.8	$ 30.8	$ 70.5	$ 183.0	$ 199.3	$ 86.8	$ 579.0	$ 96.5
	Total Compensation	Millions of Nominal $	$ 5.9	$ 21.9	$ 52.6	$ 130.5	$ 148.1	$ 70.2	$ 429.2	$ 71.5
Difference	GDP	%	0.0%	2.6%	2.1%	3.1%	2.6%	1.7%	2.5%	2.5%
	Total Compensation	%	0.0%	-0.5%	-0.1%	-1.4%	-1.7%	-2.7%	-1.5%	-1.5%

REDACTED

STATE OF MAINE PUBLIC UTILITIES COMMISSION

DOCKET NO. 2017-00232

CENTRAL MAINE POWER COMPANY REQUEST FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE CONSTRUCTION OF THE NEW ENGLAND CLEAN ENERGY CONNECT (NECEC) TRANSMISSION PROJECT

NEW ENGLAND CLEAN ENERGY CONNECT

CENTRAL MAINE POWER

POST HEARING BRIEF

February 1, 2019

Attorneys for Central Maine Power Company

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Sarah B. Tracy
Liam J. Paskvan
Krystal D. Williams

MDEP has stated that the shift to lower carbon fuels, such as natural gas, has driven statewide CO_2 emissions levels to at least 10% below 1990 levels and contributed significantly to Maine's progress towards its 2020 goals.[298] However, in order for Maine to meet its long-term GHG reduction goal to reduce GHG emissions "sufficient to eliminate any dangerous threat to the climate," Maine will need to take substantial steps to reduce the emissions of GHGs in the energy production and energy consumption sectors. In fact, based on the Legislature's guidance that a reduction of Maine GHG emissions "to 75% to 80% below 2003 levels may be required" to achieve the long-term GHG reduction goal,[299] the State will need to reduce its CO_2 or carbon dioxide equivalents (CO2e)(MMTCO2e) emissions by 19.94 million metric tons (to get to 75% below 2003 levels) to 21.26 million metric tons (to get to 80% below 2003 levels).[300] Accordingly, substantial action to reduce GHG emissions levels in a sufficient quantity to meet, or even to make material progress towards meeting, this long-term goal is necessary, and the NECEC represents a concrete step the State can take now to achieve this goal.

B. The Clean Hydropower Delivered by the NECEC Will Reduce Carbon Dioxide Emissions in Maine, New England, and Beyond, Consistent with Maine's Long-Term GHG Emissions Reductions Goals.

Once the NECEC goes into service in late 2022, it will significantly advance Maine's progress towards meeting the long-term GHG reduction goals set forth in 38 M.R.S. § 576

[298] Seventh Biennial Report on Progress Toward Greenhouse Gas Reduction Goals: Report to the Joint Standing Committee on Environmental and Natural Resources 128th Legislature, Second Session at 6, 11 (Jan. 2018)(hereafter "2018 DEP GHG Biennial Report") (stating that "[t]he data in Appendix A show that in 2015, Maine's GHG emissions were 11.7% below 1990 levels, and that Maine is on track to meet the second statutory reduction target of 10% below 1990 levels by 2020.").

[299] 38 M.R.S § 576(3).

[300] In 2003, emission levels equaled 26.58 million metric tons of CO2 emissions (MMTCO2e). When calculated, the lower limits set by the Legislature equal 6.65 and 5.32 MMTCO2e, respectively (26.58*(1-0.75) or 26.58*(1-0.80)). 2018 DEP GHG Biennial Report at 12.

by substantially reducing CO_2 emissions across Maine and New England, through the delivery of clean energy into the ISO-NE Control Area that will displace fossil-fuel-fired generation. In fact, three different production cost modeling experts in this proceeding, CMP's consultant Daymark, the Commission Staff's consultant LEI, and the Generator Intervenors' consultants James Speyer and Tanya Bodell of Energyzt using Calpine's model, have modeled the CO_2 emissions reductions in New England resulting from the injection of 9.45 TWhs of clean hydroelectric energy into ISO-NE and have found that the NECEC will drive significant carbon emissions reductions in Maine, Massachusetts and the entire New England region.

Specifically, Daymark concluded that adding the NECEC-delivered hydropower to the supply mix in New England will induce annual CO_2 emission reductions of approximately 3.1 million metric tons across New England and the net emissions from the portion of regional generation serving Maine load will be reduced by approximately 264,000 metric tons per year.[301] This is roughly equivalent to taking 56,051 passenger vehicles off the road in Maine each year.[302]

LEI's analysis found even greater emissions reductions from the NECEC-delivered clean energy, stating that the NECEC could reduce CO_2 emissions in New England by approximately 3.6 million metric tons per year.[303] The Energyzt/Calpine modeling likewise found that the NECEC-delivered clean energy will result in an annual reduction of 3 million

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[301] Daymark Rebuttal at 40:18-41:2 (citing Exhibit NECEC-5 (Daymark Report) at 4 of 98).

[302] GHG metric ton reduction equivalencies calculated using the U.S. Environmental Protection Agency Greenhouse Gas Equivalencies Calculator (updated Dec. 2018), *available at* https://www.epa.gov/energy/greenhouse-gas-equivalencies-calculator.

[303] LEI Report at 12 of 85.

metric tons of CO_2 emissions in New England.[304] Neither LEI's analysis nor Energyzt's analysis included a specific finding as to the Maine-based GHG reductions, but using Daymark's approach of calculating the Maine GHG reductions based upon a ratio of Maine load to New England load,[305] the NECEC would result in approximately 255,000 metric tons of GHG reductions per year in Maine using the results of Energyzt's analysis and approximately 306,000 metric tons of GHG reductions per year in Maine using the results of LEI's analysis. This is roughly equivalent to taking between 54,140 to 64,968 passenger vehicles off the road in Maine each year.[306]

C. Hydro-Québec has Sufficient Clean Energy Available for Export to Meet its Obligations to New England without Shifting Exports Away from New York or other Regions.

Their findings of NECEC's facilitation of carbon emission reductions in New England aside, the Generator Intervenors argue that the NECEC will result in increased total carbon emissions across the Northeast region, because, they claim, Hydro-Québec will have to divert exports to other energy markets in order to increase exports to New England over the NECEC. As discussed below, the record demonstrates that this claim is unfounded and contradicted by information provided directly by Hydro-Québec.

In his direct testimony, Generator Intervenor witness Mr. Speyer claims that in the 2023 study year, Hydro-Québec would have to reduce exports to other markets in order to supply energy to Massachusetts via the NECEC transmission line. Mr. Speyer asserts that

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304 Speyer Direct, Exhibit JMS-4, Technical Report: New England Clean Energy Connect (NECEC) Regional Carbon Emissions Impacts at 3 (Apr. 2018).

305 Exhibit NECEC-5 (Daymark Report) at 21 of 98.

306 U.S. Environmental Protection Agency Greenhouse Gas Equivalencies Calculator (updated Dec. 2018), *available at* https://www.epa.gov/energy/greenhouse-gas-equivalencies-calculator.

XII. CONCLUSION

For the foregoing reasons, CMP respectfully requests the Commission conclude that a public need exists for the NECEC. The Commission should therefore grant a CPCN for the NECEC, as described in Appendix 1.

Respectfully submitted,

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MAINE PUBLIC UTILITIES COMMISSION
AUGUSTA, MAINE

IN RE:	)	
	)	Docket No. 2017-232
CENTRAL MAINE POWER COMPANY	)	March 7, 2019
	)	

Request for Approval of CPCN for the New England Clean Energy Connect Construction of 1,200 MW HVDC Transmission Line from Québec-Maine Border to Lewiston (NECEC)

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BOB HAYNES, Old Canada Road Scenic Byway
DOT KELLY

in New England, we soften demand for RGGI allowances, the bank goes up, and the number of allowances that get sold in the market are less overall. And that affects how it works over time because of the bank and because the states may adjust the state -- or RGGI may decide to adjust the state budgets. But more importantly, there is a direct correlation between the price of RGGI allowances and the revenue that Maine and, therefore, Efficiency Maine Trust receive. And this can only help suppress prices in the RGGI market. And I think that it's unfortunate that that wasn't considered earlier in the case as I said, and I think it's very unfortunate that that's not considered in the context of the settlement. Thank you.

MR. TANNENBAUM: I'd like to follow up on that, John. The issue about the impact on the Efficiency Maine Trust is that a reduction in CO_2 emissions will reduce the price of RGGI allowances.

MR. FLUMERFELT: That's correct.

MR. TANNENBAUM: But would that mean that the NECEC will reduce carbon emissions?

MR. FLUMERFELT: NECEC will certainly reduce carbon emissions in New England by displacing existing fossil fuel generation both in Maine and across New England.

MR. TANNENBAUM: Okay.

MR. FLUMERFELT: There's the broader question about net carbon emissions, but that's not part of the settlement.

STATE OF MAINE PUBLIC UTILITIES COMMISSION

DOCKET NO. 2017-00232

CENTRAL MAINE POWER COMPANY REQUEST FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE CONSTRUCTION OF THE NEW ENGLAND CLEAN ENERGY CONNECT (NECEC) TRANSMISSION PROJECT

NEW ENGLAND CLEAN ENERGY CONNECT

CENTRAL MAINE POWER

REBUTTAL TESTIMONY OF THORN DICKINSON, ERIC STINNEFORD AND BERNARDO ESCUDERO

On Behalf of Central Maine Power Company

July 13, 2018

incremental hydropower generation in response to any particular solicitation. Thus, for example, it was not possible for Hydro-Québec to build additional new hydropower resources to meet the timeline for the 83D RFP. It is for this reason that Hydro-Québec indicated as part of the NECEC bid that the offered hydropower supply would come from Hydro-Québec's existing facilities. This, however, does not mean that Hydro-Québec's deliveries under the NECEC will not be incremental to its historic exports to New England (and regionally). Hydro-Québec has pursued an incremental and on-going development program to add capacity based on its expectations of increasing demand for clean energy across the northeast U.S. and Canada and in order to permit it to participate in solicitations like the Massachusetts 83D RFP. CMP understands that Hydro-Québec's selection to provide Massachusetts the 9.45 TWh of incremental hydropower under the NECEC PPAs is an important next step for Hydro-Québec as a prominent source of clean energy for the region. It justifies Hydro-Québec's on-going capacity expansion efforts which Hydro-Québec expects to complete in 2025 and provides a basis for Hydro-Québec to begin work on the next round of capacity expansions to meet the northeast region's increasing demand for clean energy.[68]

3. Nearly All Hydro-Québec Deliveries Under The NECEC PPAs Will Be Incremental To Its Historical Energy Exports To Surrounding Regions.

CMP understands, based on publicly available information, that upon the commencement of deliveries under the NECEC PPA Hydro-Québec will be able to increase its total energy exports to ensure that all, or at least the vast majority, of the 9.45 TWh

[68] *See* Hydro-Québec, *Strategic Plan 2016-2020 Stetting new sights with our clean energy* (Hydro-Québec 2016-2020 Strategic Plan), at 7, available at http://www.hydroquebec.com/data/documents-donnees/pdf/strategic-plan.pdf.

delivered to the Massachusetts EDCs will be incremental over Hydro-Québec's recent export levels. To measure the incremental nature of Hydro-Québec's future increased exports it is important to set a baseline based on Hydro-Québec historical exports. Using a historical average over the last five years is appropriate given variances that may occur in any particular year in terms of rainfall, weather, market and other conditions. Hydro-Québec's average annual level of exports over the most recent five year period of 2013-2017 is 30.5 TWh.

Starting with a 30.5 TWh export baseline, CMP has assessed, using publicly available information, whether Hydro-Québec will be able to increase its exports to adjoining control areas, including New England, to 40.5 TWh (including a gross up for line losses) per year starting in 2023. This level will ensure Hydro-Québec maintains historical exports to adjoining control areas while adding the 9.45 TWh of exports to New England called for in NECEC PPAs.

CMP understands that Hydro-Québec plans to achieve this increased export level by using its existing hydropower capacity, including the Romaine 3 unit (395 MW) added in 2017, plus certain capacity additions that are expected by 2025. These capacity additions are made up of new hydropower generation facilities, Romaine 4 unit (245 MW expected in service in 2020), and capacity upgrades at existing hydro facilities (such as the replacement of aging turbines with more efficient, new equipment) (500 MW by 2025).

In addition, to achieve the necessary energy output, CMP believes that Hydro-Québec will use the energy it has stored in its hydropower reservoirs. In recent years, Hydro Québec

December 14, 2018

Thorn Dickinson
Vice President, Business Development
Iberdrola USA Management Corporation
52 Farm View Drive
New Gloucester, Maine 04260

Good Afternoon Thorn:

You have requested Hydro-Québec's assistance in responding to certain data requests pertaining to Hydro-Québec operations received in the CPCN proceeding for the New England Clean Energy Connect ("NECEC") project.

Below is information in response to questions 004-001 and 004-002.

004-001

Regarding the existing hydro-electric facilities that will provide electricity for NECEC, have those dams spilled water instead of generating electricity due to a lack of economic transmission in any of the years 2012-2017? If so,

a. Please provide a volume estimate per year of that spillage.

b. Please provide the reason(s) for that spillage.

Answer:

Yes, in 2017 Hydro-Québec spilled water due to a lack of economic transmission.

The quantity of spilled water in 2017 for this reason represents approximately 4.5 TWhs worth of energy. In the normal course of business, Hydro-Québec uses water to generate electricity. Excess water not used to generate electricity is stored in large reservoirs for use in later periods. As the reservoirs become full, and storing water is no longer an option, water is spilled.

In this category to date in 2018, Hydro-Québec has spilled approximately 10.4 TWhs worth of energy. Without additional transmission export capability, the quantity of spilled water in future years is expected to be comparable to the quantity of spilled water in 2018 under comparable market and operational conditions.

For the 2050 horizon, independent meteorological studies indicate that average flows in northern Québec are expected to increase by approximately 12%. This could lead to additional spilling[1].

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[1] https://www.ouranos.ca/publication-scientifique/Synthesis_Summary.pdf

004-002

Does Hydro-Québec have an estimate of the maximum export capacity that existed at the end of 2017, without the existence of the NECEC line? (If that estimate is not available, but an estimate from a different year is, please provide that).

a. Please provide that estimate in aggregate or to the four export markets of Ontario, ISO New England, Maritimes, and New York ISO.

b. Please provide a discussion of factors that formed the basis of the estimate.

Answer:

Hydro-Québec's maximum export capability during 2017 is estimated at 34.4 TWh. Below is the breakdown of these exports to Hydro-Québec's primary external markets:

- Ontario: 4.6 TWh
- New England: 18.2 TWh
- Maritimes: 2.1 TWh
- New York: 7.9 TWh
- PJM/MISO/Other: 1.6 TWh

Many factors determine the maximum export capability for Hydro-Québec's hydropower system including the following:

- Water levels in individual Hydro-Québec reservoirs
- Specific transmission availability within Québec
- Specific generation availability
- Transmission availability to external markets
- Transmission congestion in external markets
- Wholesale market prices and demand in Hydro-Québec's export markets
- Operational constraints in Hydro-Québec's export markets

Please don't hesitate to contact me if you have any questions about this information.

Sincerely,

Simon Bergevin
Director, Energy Transactions
Hydro-Québec
75 Réne Levesque Blvd
Montreal, QC H2Z 1A4

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In addition, to achieve the necessary energy output, CMP believes that Hydro-Québec will use the energy it has stored in its hydropower reservoirs. In recent years,

EXHIBIT NO. FBS-1.COR
CORRECTED

Prepared Corrected Supplemental Testimony of
William S. Fowler and Tanya L. Bodell

A: Yes. Both Hydro-Québec's strategic plan and Hydro-Québec Distribution's planning documents indicate that the region is short capacity.

- **Strategic Plan:** Hydro-Québec's Strategic Plan 2016-2020 indicates that Québec is short capacity and will be meeting its capacity requirements through energy efficiency initiatives, issuing tenders for capacity, Romaine-4 coming online in 2020, Hydro-Québec Production's anticipated upgrades of 500 MW in 2025, and potentially other hydroelectric investments.[45]
- **Supply Plan for the Integrated Network:** A detailed supply procurement planning document and a status report issued by Hydro-Québec Distribution projects a capacity shortfall of 1,100 MW by 2022/23 increasing up to 1,900 MW by 2025/26, even accounting for increased capacity commitments that appear to correspond to the Romaine units. Exhibit Nos. FBS-3 and FBS-4 provide a translation of the projections from the 2016 and 2017 plans, respectively, including an excerpt of the discussion that indicates Hydro-Québec Distribution anticipates capacity purchases on a short-term basis to cover its shortfalls. In fact, the company is looking for new interties with the U.S. that would allow for increased *purchases* of capacity *from U.S. markets into Québec*:

> Furthermore, the Distributor is eagerly awaiting the development of interconnection projects between Québec and the United States. However, uncertainties regarding these various projects do not allow the

[45] NECEC – 54: Hydro-Quebec, Strategic Plan 2016-2020, p. 7 and Maine PUC Docket 2017-00232, Hearing (In Camera), October 19, 2018, pp. 129-131.

TECHNICAL REPORT

HYDRO-QUÉBEC EXPORTS

Prepared by: Energyzt Advisors, LLC

April 2018

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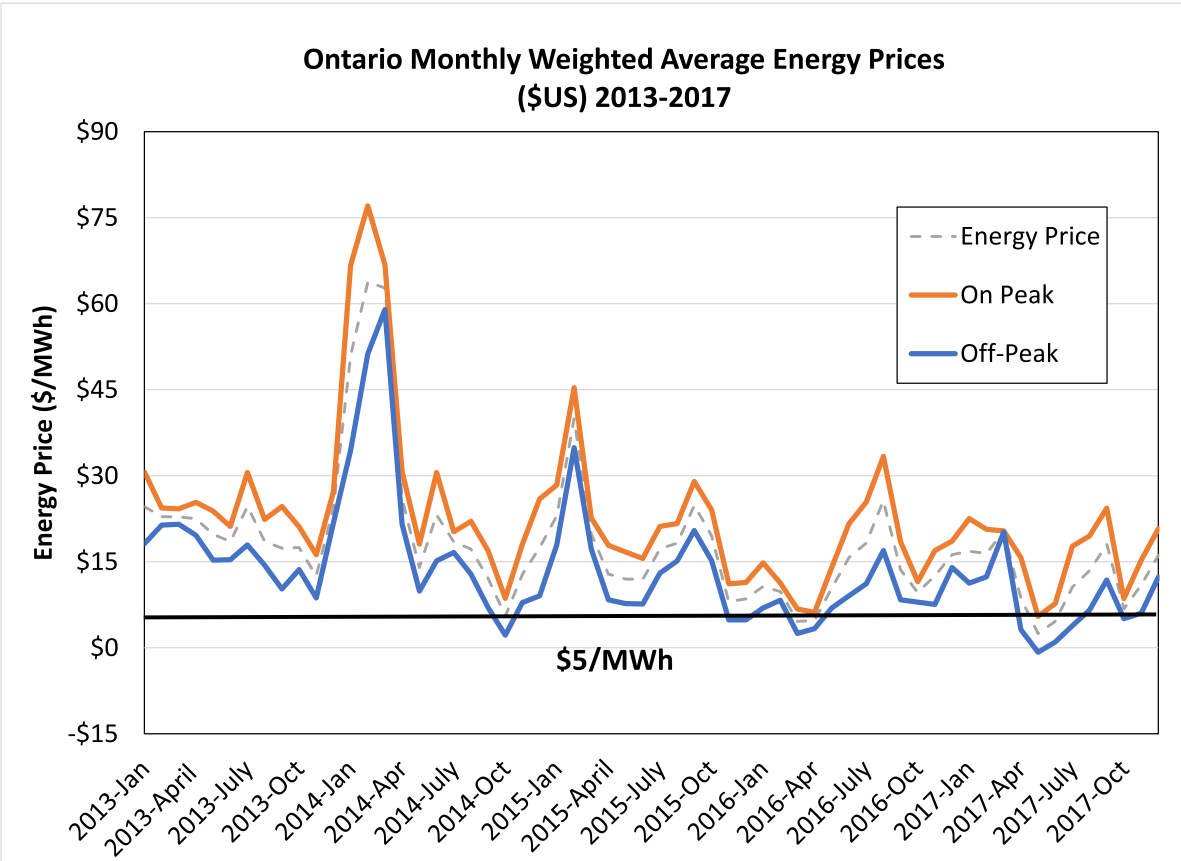
Figure 7: Ontario Wholesale Energy Market Prices



Source: Ontario IESO

3. PROJECTED EXCESS ENERGY IN 2023

Between 2017 and 2023, Hydro-Québec is scheduled to bring a new hydroelectric generation project online: Romaine-4. Romaine-4 would add another 245 MW of capacity and 1.3 TWh of energy. However domestic load also is expected to be higher according to the Hydro-Québec Distribution's long-range plan for 2017 - 2026.[12]

[12] Hydro-Québec Distribution Plan, ÉTAT D'AVANCEMENT 2017 DU PLAN D'APPROVISIONNEMENT 2017-2026, p. 10.

http://www.regie-energie.qc.ca/audiences/Suivis/SuiviR-3986-2016_PlanAppro2017-2026/HQD_SuiviPlanAppro2017-2026_31oct2017.pdf

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Figure 8 provides an estimate of the excess energy that would be available for export in 2023 based on the projected energy (including Romaine-4) less projected domestic load requirements.

Figure 8: Calculation of Québec's Excess Energy in 2023

Excess Energy Available for Export	Net Output (GWh/year)
Total Energy Generated or Purchased in 2016[13]	217,200
Romaine 3 and Romaine 4 Hydroelectric Facilities[14]	1,300
Incremental Long-term Non-Heritage Supply (2017-2026)[15]	3,500
Projected energy in 2023[16]	222,000
Projected domestic requirements in 2023[17]	(188,500)
Excess energy available for export in 2023	33,500

Excess energy of 33.5 TWh would not be constrained by limited tieline capacity of more than 60 TWh.

Therefore, if the New England Clean Energy Connect (NECEC) transmission line were to come online, Québec will supply energy into Maine by simply reducing its exports into other markets.

13 Hydro-Québec,

www.hydroquebec.com/sustainable-development/energy-environment/power-generation-purchases-exports.html

14 Hydro-Québec, "A Natural Ally for Massachusetts' Energy Transition," http://news.hydroquebec.com/media/filer_private/2018/01/25/a_natural_ally_for_massachusetts_energy_transition.pdf

15 Difference between 2026 value of 18.8 TWh and 2017 value of 15.3 TWh.

www.hydroquebec.com/sustainable-development/energy-environment/power-generation-purchases-exports.html

16 Sum of individual components above the line in the table.

17 État d'avancement 2017 du Plan d'approvisionnement 2017-2026, 10/31/2017, Table 1, p. 6 and Table 2, p. 8.

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Translated english transcript for Le Journal de Quebec, Video Interview With Eric Martel (in French), “Hydro-Québec donne la priorité à l’exportation” [Hydro-Québec gives priority to exportation] (Nov. 21, 2018), located at https://www.journaldequebec.com/2018/11/21/entrevue-avec-eric-martel--hydro-quebec-donne-la-priorite-a-lexportation.

Now let's talk about Hydro-Québec, which has a number of cases.

That's still the case, however. A lot of cases on the sketch board. We have the opportunity, with us today, to ask all the questions because the president, Éric Martel, is here.

- Good morning, Mr. Martel. - Good morning, Mr. Dumont.

Let us start with a very simple issue that has been a major issue in the news.

- The famous overpayments. - Overpayments.

Some people said, "Well, Mr. Legault, he had complained about overpayments. Once elected, Hydro will send us cheques." You have to accept first of all what overpayments are when you talk about them.

You know, every year, we go before the Régie de l'énergie and work with them on a budget, and we say, for example, we will provide you, Quebeckers, with full service, for example, $12 billion.

- At the end of the year... - This determines the price.

It determines the price. That's how we calculate the rate based on it.

It's never a perfect calculation. A budget will happen - We in general, we reach 99.5 on average, over the last 10-15 years, of that budget.

We always do it at a lower cost.

We are providing the same service that we promised Quebeckers.

But it costs a little less than expected, about $50 million.

Because you're budgeting too high. So some would say too cautious.

Exactly. You could say that. But imagine the opposite, that we are over $200 million, and then we turn around and say you owe us $200 million for next year. So there, at that point, it would be - - We would complain. - We'd complain too. Achieving 100% is almost impossible. So we usually arrive, perhaps in a conservative way, but we always get into our budget.

So, over seven - eight years, these sums that you spent a little less than expected each year, it was one and a half million - - One and a half billion. - A billion and a half, I'm sorry, - what we called overpayments. - Exactly.

So it's true that we received that as an extra, but at the same time, it's a service that we have to measure. We provided the service we said we would provide to Quebeckers, but we often made efficiency gains. We did it more efficiently.

And the previous government had said: "We are in a deficit situation.", when they took power, "We're going to keep all these sums." It had been like that for several years.

So they went into the public treasury.

- It went into the public treasury. - Via the Ministry of Finance.

The good news is that it does not go into the pockets of a wealthy shareholder because Hydro-Québec belongs to us and it is obviously redistributed, the state redistributes it, in health services and elsewhere.

So that money is not in the vaults of the basement - the Hydro-Québec building. - Not at all.

In treasure chests We wrote the cheque, but in Quebec City. So, Quebec City has it.

What is happening now is that there was a change in the law that took shape last year. Now we share them.

Last year, we shared, from memory, about 45 million dollars that we gave back to the people.

Now, we don't write a check to everyone or send you a check for a few dollars. Let's put it back into the new tariff case.

It's like a credit. We start the new year with a credit.

- On the rates. - On the rates.

So, how many more years do we have to have a credit like that - on rates? - Oh, well, the law tells us, - every year - - Every year.

Half of the overpayments we had before, we say, you will give it back to Quebeckers and the rest will keep it for you because, as I tell you, it still remains in the taxpayers' pockets.

Let's move on. Let's talk about rates because people are always complaining about the electricity bill and now it's already getting cold by November 15. It doesn't look good this year.

How do you rate our rates? What do you promise us for the next few years?

The good news is that I made a promise when we started about three and a half years ago together.

We're going to make you rate increases under inflation.

- So we're happy to say - - Is that what it's been like so far?

This is the fourth year that we have just filed our rate case.

This year we are at 0.3, next year we asked for 0.8.

So, we're at the bottom of inflation four years ago.

- You're below 1%. - Yes, we're below 1%.

So, we're very happy about that. We delivered our promise on that and at the same time, the company is doing well because we have succeeded...

You may have seen our financial results last week, we are 18% more profitable than last year. So, it's going well.

We have to say to ourselves, at Hydro-Québec, we have good financial results and we have succeeded in lowering rates. Our rates are still today and even widening the gap, the lowest rates in North America.

Even when compared to the European Union, we have the lowest rates.

So, we can say that, we can be happy about that, and these rates, what is interesting to say is that when we look at... When I took office, we were about 13% better than the second ones and now we're 17, 18% better. So we're digging that gap.

It is a competitive advantage for Quebec as well.

First, we know that we heat with electricity, but it also allows us to attract companies, and that is our mission to keep them down.

Well, I'm going to go through the news. There are so many subjects.

The famous Apuiat project. Wind power project in collaboration with the Innu of the North Shore. The government did not want to, but what is happening now, what people were told at home, that it was Martel who did not want to, is the president of Hydro-Québec who started putting in Legault's head that this is a bad project. True or false?

Listen, I, what I did, as the person responsible for managing Hydro-Québec with my team, we had to make sure, with the former government, that we put the facts on the table and say, "Look, we are in a surplus situation." - So we don't need it. - We don't need it.

That's clear and I'm not coming back for that and I'm not hiding.

We don't need it this year, Mr. Dumont, we spilled 10 terawatt hours of electricity.

That means we didn't turbinate water, we let it pass by the dams because we had too much.

How much could it cost if we could sell this?

If we sell it on the American market right now, maybe $500 million in additional revenue.

- That we let it flow there. - Hence the importance of having additional transmission lines because we have energy.

It's here... We have to sell it to the Americans.

And I will come back to our export projects later.

But to repeat your question on the Apuiat project, we don't need it.

We have a surplus for a long time to come.

There was a letter that went out in the media under your name, I don't know if you're going to tell me it's real or not.

- It was the real letter. - Was that the real letter?

That was about the loss over the term of the contract, - a billion and a half, two billion. - To the government, the message is exactly that, Mr. Dumont, it was: "We don't need it." But the government owns Hydro-Québec.

In the end, I have to respect that, but I have to put the facts on the table.

They were informed, at that time, that they would say: "Look, if we ever move forward, it will cost Hydro-Québec between $1.5 billion and $2 billion in net income.

- Those were real numbers. - They were real numbers.

In fact, our own number was 1,667,000, but here, - there are more optimistic scenarios - - I understand, I understand.

It's between 1.5 and 2 and that's what I had to say.

So we said it. Unfortunately, the letter leaked and there was an outcry.

We were in the middle of an election campaign. You know, when you're in charge of Hydro-Québec or the caisse, we always try not to interfere in the election campaign.

We knew we had a long list of topics. This one, unfortunately, has become a campaign issue. - It still brought up the idea that there was between you and the new Prime Minister, Mr. Legault, an accomplice, a lot of chemistry.

Did you have any privileged or unique meetings with him before the election campaign?

I haven't had any meetings with Mr. Legault.

I know there were rumours going around that we were seen at the restaurant, maybe I have a look-alike, but it didn't happen.

- That is not true. - That is not true.

That is completely false. Mr. Legault and I, like all party leaders, and I made that clear when I arrived at the head Hydro-Québec, I meet everyone. I met Mr. Legault in Hydro-Québec's offices, but it was a year or so - before the campaign. - Not a secret restaurant.

- No, no, no, no. - At the office.

And the government knew about it. I met Mr. Péladeau at the time, I met Mr. Lisée too.

I took my precautions, I run Hydro-Québec, I'm not politicized, and I made sure to keep everyone informed about our cases and what we were doing and to listen to them too, to hear them.

Since we are talking about the new government, I will take you to these projects.

A willingness to export, to sell to Americans, Ontarians, potentially even to develop new dams, something that had not been discussed much in recent years.

Does that make sense, does it fit into your business plan?

It's absolutely in our plan. The plan we tabled three years ago in the National Assembly, which was approved, is that we said, "Look, priority number one, we are in surplus.

It takes us lines to export that." I don't want to throw ten terawatt-hours of water away every year and not monetize it.

It's really our inability to transport it.

- Absolutely. - It's the lack of lines.

Quebec is saturated. Obviously, we have growth in Quebec.

We work hard to bring in data centres, people who consume a lot, and that has had some success.

In the last quarter, we had about 4-5% of our growth coming from the efforts we made, but exports, we need lines to go down more.

That's why we're happy at the beginning of the year, we won our biggest lifetime contract with Massachusetts.

- We signed - - We still have a problem, no one wants to have the line on their property.

But that's part of it, you see, it's long term projects with Maine. We're getting there, getting permits - - We're going around New Hamsphire. - We'll find somewhere else.

And we have yet another solution, a plan C, if necessary.

You're not worried that we're going to do this line.

We're going to make it, they want it. We were still in Massachusetts last week, you know the Prime Minister was there.

So what the Prime Minister is saying is that we have to export and we are completely in this.

Our strategic plan, which is also a three-year plan, will have to be looked at over the next five years, Hydro-Québec, to see on which river we could go on another major project. I've always said - But now we're already in surplus. If we do another big project, it must be sold in advance.

It has to be sold, and it has to be profitable.

And at the same time, it takes 15 to 18 years to build a new project.

I can easily see that in 21, 22 we will have to make a decision to perhaps build something that would be ready in 38, 39, 40,

but don't forget that there are major milestones coming in 2040.

What is happening with aluminum smelters? There are several contracts that are ending. What's going on with Churchill Falls post 41. So there are some big questions that are open to us to answer and we are preparing for that. We will be ready in 2021-22, Hydro-Québec, we say if we have to build for the future, here is the project we recommend.

Let's talk about internal management: do you pay irregular bonuses that are not recorded in your executives' official remuneration books?

So, look, it's been positioned a little like a secret, etc.

It's no secret at all. We did a mea culpa last week.

We did... This is a mistake. We have a compensation policy in place since 1997. In 2008, new rules were introduced in a decree that affected part of our policy.

- It was from the government. - It came from the government on the variable pay policy.

We had an interpretation. Our compensation people, our experts at the time, looked at it and said: "There are things we can do, there are things we can no longer do." But there have been interpretations of data on so-called retention bonuses. And now I'm correcting right now, it's not just on executives.. We have a duty...

Of the 75 people affected by this case, we have about 13 who are executives; the others are employees.

- Employees who - - What's so special about them?

That's it, that's it. They are employees who arrive with specific skills.

Manage a pension plan. Manage, for example, all the exports we make. You know we have a group of about 40 people on the phone.

It is a transitional floor where we sell imported energy. It's people - a rare pearl species that's hard to replace.

Absolutely. So we are willing to pay them more because we keep the retention and we want to have the best too, because I don't want to come back in a year and say, "Look, we mismanaged our pension plan or our exports.

It cost us two, three hundred million dollars." It wouldn't be good for anyone.

Because we didn't have the right employee, we put an incompetent one in.

Exactly. It's better to have competent employees.

It costs us about $1.9 million a year.

Why is that in the news? Now you're explaining it to me, - That's a good question. - like a hidden thing.

Our auditor, it's his job to do that.

He checks all our processes to ensure that...

You know, at Hydro-Québec, we have to be whiter than white and he discovered that. He asked himself questions and his questions were true, were fair.

When we looked at this, the compensation people said it was okay. We double-checked that and said that maybe we stretched the elastic, and maybe we couldn't do it.

Corrective measures are being taken to ensure that this is done in the right way. We must ensure that we do not lose these employees who make a significant contribution to Hydro-Québec.

So, we're in this right now, but there was nothing secret, no bad faith and no bad intention to hide it.

When we saw it, we said to ourselves that there was a problem, that we had just realized it, that we were simply going to manage it.

Éric Martel, thank you very much for being with us today.

- Thank you, Mr. Dumont. - Goodbye.

Goodbye.

Observed Trends in Canada's Climate and Influence of Low-Frequency Variability Modes

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ABSTRACT

Trends in Canada's climate are analyzed using recently updated data to provide a comprehensive view of climate variability and long-term changes over the period of instrumental record. Trends in surface air temperature, precipitation, snow cover, and streamflow indices are examined along with the potential impact of low-frequency variability related to large-scale atmospheric and oceanic oscillations on these trends. The results show that temperature has increased significantly in most regions of Canada over the period 1948–2012, with the largest warming occurring in winter and spring. Precipitation has also increased, especially in the north. Changes in other climate and hydroclimatic variables, including a decrease in the amount of precipitation falling as snow in the south, fewer days with snow cover, an earlier start of the spring high-flow season, and an increase in April streamflow, are consistent with the observed warming and precipitation trends. For the period 1900–2012, there are sufficient temperature and precipitation data for trend analysis for southern Canada (south of 60°N) only. During this period, temperature has increased significantly across the region, precipitation has increased, and the amount of precipitation falling as snow has decreased in many areas south of 55°N. The results also show that modes of low-frequency variability modulate the spatial distribution and strength of the trends; however, they alone cannot explain the observed long-term trends in these climate variables.

1. Introduction

Over the past several decades, the northern regions have experienced some of the most rapid warming on Earth (Alexander et al. 2013; Houghton et al. 2001). The annual mean temperature over the high-latitude land area has increased by almost twice the rate of the global average (AMAP-SWIPA 2011; Anisimov et al. 2007; ACIA 2005). The cause of the warming amplification in the northern regions has been attributed primarily to temperature and albedo feedbacks because of complex interactions between land surface temperature, snow cover or sea ice extent, and the atmosphere (Pithan and Mauritsen 2014; Serreze and Barry 2011). Canada, with a large northern landmass, is also experiencing rapid warming with nationwide annual mean surface air temperature increasing by 1.5°C over the period 1950–2010 (Vincent et al. 2012). This warming has been accompanied by significant changes in many other climate elements, in different parts of the country, including increases in precipitation (Mekis and Vincent 2011), decreases in the duration of snow cover (Brown and Braaten 1998), and decreases in streamflow (Zhang et al. 2001). These changes in Canada's climate have widespread impacts on the environment, economic activities, and human health, especially in the north, where warming is proceeding more rapidly and where ecosystems and traditional lifestyles are particularly sensitive to warming (Warren and Lemmen 2014; Allard and Lemay 2012).

Recent changes in Canada's climate have been attributed, at least in part, to the increase in the concentration of atmospheric greenhouse gases associated with anthropogenic activities. Evidence of an anthropogenic influence was found on temperature in the southern regions of Canada (Zhang et al. 2006), in the Arctic (Najafi et al. 2015; Gillett et al. 2008), on Arctic sea ice and precipitation (Min et al. 2008a,b), and to a lesser extent on heavy precipitation events over a large part of the Northern Hemisphere land areas (Min et al. 2011).

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Barnett et al. (2008) attributed much of the observed changes during the second half of the twentieth century seen in winter surface air temperature, river flow, and snowpack in the western United States to anthropogenic forcing.

Previous studies have documented significant links between low-frequency modes of atmospheric–oceanic variability and Canadian climate. For example, positive phases of the Pacific decadal oscillation (PDO) and El Niño–Southern Oscillation (ENSO) have been associated with warm winter temperatures in western and central Canada (Shabbar and Yu 2012; Bonsal et al. 2001; Shabbar and Khandekar 1996) and a reduction of snow cover in western Canada (Brown 1998). An abrupt transition to lower snow depths in the mid-1970s was related to a shift in the Pacific–North America (PNA) index (Brown and Braaten 1998). Interannual variations in Canadian Prairies precipitation have been associated with ENSO variations (Bonsal and Lawford 1999; Shabbar et al. 1997). Positive phases of the PNA pattern and PDO corresponded to shorter durations of ice cover on lakes and rivers (Bonsal et al. 2006), increasing streamflow regime in spring (Brabets and Walvoord 2009), and earlier high-flow season (Stewart et al. 2005). Trends toward positive modes of the North Atlantic Oscillation (NAO) were associated with cold and dry winters in northeastern Canada (Bonsal et al. 2001). Brown (2010) documented evidence of an abrupt decrease in snow depth in southern Quebec around 1980 linked to a reduction in the number of winter storms over the region (Wang et al. 2006) coinciding with a transition to more positive values of the NAO.

It is important to improve our understanding of the various mechanisms responsible for changes in regional surface climate. Large-scale oscillations have a significant influence on climate trends: at times, they can mask or enhance the trends depending on the phase of the oscillation and the time period selected for trend analysis. Canada's climate shows multidecadal-scale variability over the past century associated with oceanic and atmospheric modes: the relationships are however regionally based and are more evident during the boreal winter. Canada's climate has also been influenced by anthropogenic warming in recent decades. It is therefore a complex task to estimate the magnitude of climate trends and their potential causes.

The first objective of this study is to provide a comprehensive analysis of the climate trends in Canada, including those for temperature, precipitation, snowcover, and streamflow indices using recently updated data, and to highlight the consistency among the trends in related climate variables over similar periods of time. The second objective is to evaluate the climate trends after removing the potential effects of low-frequency variability modes in order to determine if the trends remain significant and if they become more consistent across the country. To this end, climate trends are reassessed when indices of large-scale oscillations are used as explanatory variables in the trend estimation. Section 2 describes the datasets and section 3 presents the methodology. The trends in Canada's climate are described in section 4. The climate trends after removing the influence of low-frequency variability modes are provided in section 5. A summary and discussion follow in section 6.

2. Data

A number of data-related issues arise when attempting to analyze climate trends in Canada. There have been changes in instrumentation, observing practices, and relocation of observing sites that have introduced nonclimatic variations in climate datasets (also called ''inhomogeneities''), which can interfere with the proper assessment of any climate trends. In addition, the climate observing surface network in Canada has changed considerably in the past, especially since the 1990s, because of the downsizing of the traditional observing network and the increased use of automated systems (Milewska and Hogg 2002). Extensive research has been carried out over the past 15 yr to develop adjusted and homogenized surface air temperature, precipitation, wind speed, and pressure data for Canada to address many of the above concerns (Vincent et al. 2012; Mekis and Vincent 2011; Wan et al. 2010, 2007). However, more work is still needed, especially to address the issues related to the introduction of automated systems for precipitation.

a. Surface air temperature

Homogenized daily maximum and minimum temperatures for 338 locations across the country were retrieved from the second generation of homogenized temperature dataset (Vincent et al. 2012). Observations at collocated sites were sometimes joined in order to create longer time series for use in trend analysis. Daily temperatures from automatic systems were included at some stations. Two types of adjustments were performed to produce homogenized datasets. Daily minimum temperature recorded at 120 synoptic stations (mainly airports) was first adjusted to account for the bias due to the change in observing time in July 1961 (Vincent et al. 2009). A second adjustment based on the quantile-matching algorithm, as applied in Wang et al. (2014), was performed as part of the homogeneity assessment carried out by Vincent et al. (2012) to address shifts due to site relocation and changes in observing practices. The daily mean temperature is derived from the daily maximum and minimum. Monthly mean temperature is computed as the average of the daily means and is set to missing if more than five random or three consecutive daily values are missing. Seasonal and annual means are obtained if all corresponding monthly values are nonmissing. The seasons are defined as winter (December–February), spring (March–May), summer (June–August), and autumn (September–November).

b. *Precipitation*

Adjusted daily rainfall and snowfall amounts at 464 locations were taken from the second generation adjusted precipitation dataset (Mekis and Vincent 2011). The data were adjusted to account for known measurements issues such as wind undercatch, evaporation and wetting losses for each type of rain gauge (Devine and Mekis 2008), conversion to snow water equivalent from snow ruler measurements (Mekis and Brown 2010), trace observations, and accumulated amounts from several days. As for temperature, observations from nearby collocated stations were sometimes merged to produce longer time series (Vincent and Mekis 2009). Measurements from automatic systems were not included. The adjusted daily total precipitation is the sum of the adjusted rainfall and adjusted snow water equivalent. The monthly total precipitation is the sum of the adjusted daily total precipitation amounts following the previously defined rule for missing daily temperature. Seasonal and annual totals are obtained if all corresponding monthly values are nonmissing. Trends in the ratio of snowfall to total precipitation (hereinafter ''snowfall ratio'') are also examined since they provide information regarding changes in solid precipitation, which is a very important climate characteristic in Canada. The snowfall ratio is defined as the total snowfall water equivalent divided by the total precipitation obtained for each season and annually and is expressed as a percentage.

c. *Gridding temperature and precipitation data*

Since stations recording temperature and precipitation observations are irregularly distributed across the country with more stations in the south than in the north, temperature and precipitation data were interpolated to evenly spaced point locations for a better spatial representation of the climate variations over the country. Seasonal and annual temperature anomalies from the 1961–90 reference period were first obtained at individual stations. They were interpolated to 50-km spaced grid points (E. Milewska and R. D. Whitewood 2011, unpublished manuscript) using the method of Gandin's optimal interpolation (Gandin 1965; Bretherton et al. 1976; Alaka and Elvander 1972). Normalized seasonal and annual precipitation anomalies (normalized by dividing the anomalies by the 1961–90 averages) and snowfall ratio were gridded using the same method. Seasonal and annual grid point values were averaged together in order to produce seasonal and annual time series representing the whole country. The spatial representativeness of the climate network in Canada and the uncertainty associated to the interpolation were assessed in previous studies (Milewska and Hogg 2001; Zhang et al. 2000).

d. *Snow cover*

Snow cover data were derived from daily snow depth observations made at climate and synoptic stations since the beginning of the 1950s. Most of the observations were made at open sites or near populated regions and may not be representative of the surrounding area, particularly in regions with higher terrain and forest cover. Nonetheless, these observations still represent a consistent measure of temporal and spatial variations in snow cover in Canada. The data were taken from an update of the Canadian snow cover data (Meteorological Service of Canada 2000), which includes data rescue of previously undigitized Canadian snow depth data and the reconstruction of missing values as outlined in Brown and Braaten (1998). These data were supplemented with daily snow depth observations from the Digital Climate Archive of Environment Canada to the end of the 2012/13 snow season. A homogeneity assessment of the observations was carried out by Brown and Braaten (1998) with little evidence of detectable inhomogeneities due to station relocations.

The snow cover variables selected for this analysis are the annual maximum snow depth; date of the annual maximum snow depth; and snow-cover duration (SCD), which is defined as the number of days with at least 2 cm of snow on the ground during the snow year (August–July). The SCD is also computed over the first (August–January) and second (February–July) halves of the snow year providing a more objective way to monitor snow-cover onset and disappearance than the beginning and ending dates of continuous snow cover (which are sensitive to the definition of ''continuous'' snow cover). The number of stations recording snow depth has seriously decreased since the mid-1990s. There are only 104 stations with sufficient data for trend analysis for 1950–2012 (allowing for 10 missing years). Snow cover data were not gridded since there are too few stations to adequately represent spatial variations over the entire country.

e. *Streamflow*

Streamflow data were retrieved from the Reference Hydrometric Basin Network of Environment Canada

(Zhang et al. 2001; Scott et al. 1999), which has been updated to 2012 and contains daily mean streamflow observations at 226 basins, mainly located in the south, with at least 20 yr of data. The streamflow variables selected for this analysis are annual maximum and minimum daily mean streamflow (annual highest and lowest daily mean river discharge; expressed in $m^3 s^{-1}$); annual, April, and September mean streamflow; starting date of spring freshet; and river ice freezeup and breakup dates. The starting date of the spring freshet (also called high-flow season) is the date when the cumulative sum of the difference between the daily mean streamflow and its climatology reaches a minimum during the hydrological year, from October to September (Liebmann et al. 2007). In this study, there are only 53 sites with streamflow data and 20 sites with river ice breakup and freezeup dates with sufficient data for trend analysis over 1950–2012. Because of the limited number of sites with river ice data in the past 53 yr, the trends in streamflow indices are also examined over the shorter 1967–2012 period at 57 sites.

f. Large-scale atmospheric and oceanic oscillation indices

Low-frequency modes of climate variability linked to the Pacific and Atlantic Oceans are investigated to assess their influence on long-term climate variations in Canada. Four main modes of variability are assessed: the North Pacific index (NPI), Pacific decadal oscillation, North Atlantic Oscillation, the Atlantic multidecadal oscillation (AMO). NPI represents Pacific Ocean–related atmospheric oscillations and is defined as the area-weighted sea level pressure over the region 30°–65°N and 160°E–140°W (Trenberth and Hurrell 1994); this index was further normalized for this study. PDO represents Pacific Ocean oscillations and is defined as standardized values of the leading principal component of the monthly sea surface temperature anomalies north of 20°N (Zhang et al. 1997; Mantua et al. 1997). In the Atlantic, atmospheric oscillations are provided by NAO that are based on the difference in normalized sea level pressure between the Azores and Iceland (Osborn 2011; Jones et al. 1997; Hurrell 1995). Atlantic oceanic oscillations are represented by AMO defined by the normalized and detrended Kaplan sea surface temperature in the North Atlantic Ocean over 0°–70°N (Enfield et al. 2001). Monthly data for atmospheric and ocean oscillations were extracted from various publically available sources. ENSO is not used in this study since its high-frequency oscillations are not helpful for explaining long-term trends. Seasonal means of the oscillations' indices were computed following the season's definition used for temperature and precipitation (winter average indices for NPI, NAO, PDO, and AMO are presented in Fig. 1).

3. Methodology

Since the climate observing network in the northern regions was established during the late 1940s, there are very few locations in the north with observations prior to 1948. For this reason, temperature and precipitation trends are examined for two periods: 1948–2012 for Canada (the entire country) and 1900–2012 for southern Canada (south of 60°N). The trends for snow-cover and streamflow indices were analyzed for 1950–2012. The trend calculation methodology follows Zhang et al. (2000) with slope estimation from Sen (1968) and statistical significance based on the nonparametric Kendall's test (Kendall 1955). This test is less sensitive to the nonnormality of the data distribution and less affected by extreme values and outliers as compared to the commonly used least squares method. Since serial correlation is often present in climatological time series, the method involves an iterative procedure that takes into account the lag-1 autocorrelation of the time series (Zhang et al. 2000). The temperature and precipitation trends are computed at each grid point and for the time series averaged over Canada and southern Canada. The trends for the snow-cover and streamflow indices are obtained at individual stations. The statistical significance of the trends is assessed at the 5% level (statistically significant trends are reported as significant trends in the text). The uncertainty related to the linear trend is quantified using the 95% confidence interval (reported in square brackets in the text).

A multivariate regression modeling approach was used to evaluate the degree to which low-frequency variability modes (represented by the large-scale oscillations) were able to explain annual and seasonal variations over the short and long periods of time. A regression model was first fitted to the data at each grid point (for temperature and precipitation) or each station (for snow-cover and streamflow indices). Two explanatory variables were used to represent the Pacific and Atlantic influence (e.g., the indices for PDO and NAO) and the dependent variable was the climate element (temperature, precipitation, snow-cover, or streamflow indices). Then the method based on the Kendall test (described above) was applied directly on the residuals at each grid point (or station) in order to estimate the trends after removing the effects of the low-frequency variability modes. Annual and seasonal grid point (or station) residuals were averaged together in order to produce a single time series of residuals representing the entire country (or southern Canada).

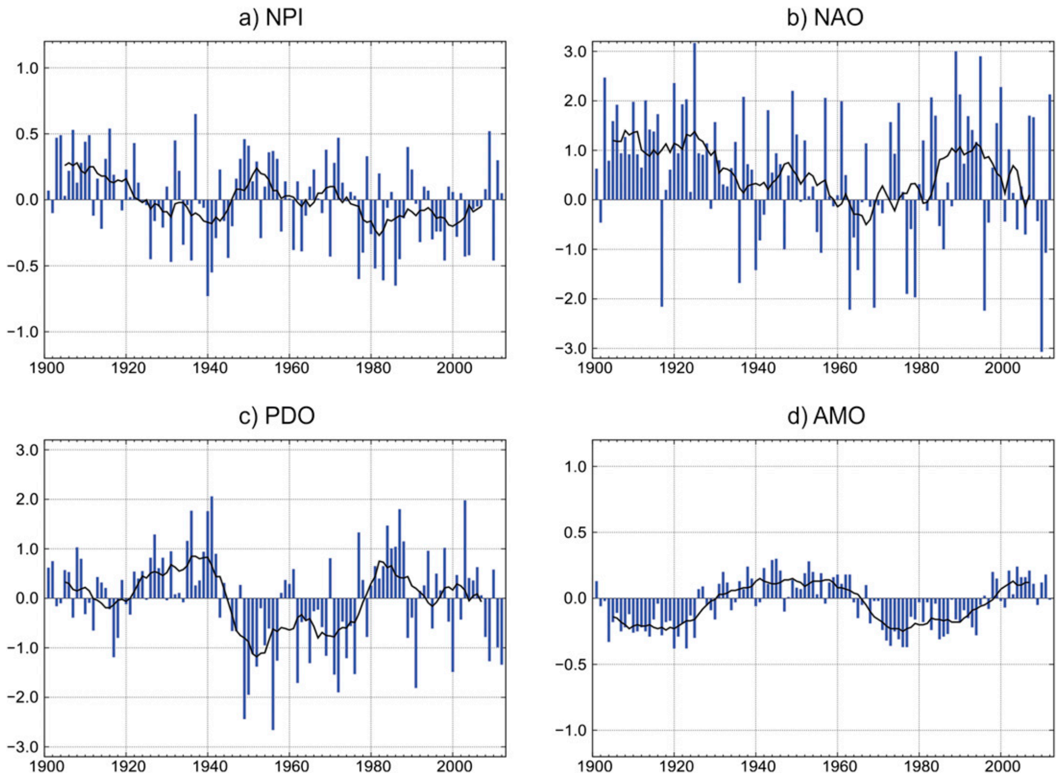

FIG. 1. Winter standardized anomalies of the (a) NPI, (b) NAO, (c) PDO, and (d) AMO indices for 1900–2012. The black line is an 11-yr running mean.

The NAO and PDO indices were first introduced in the regression model since their influence on the Canada's climate is well documented. The annual and seasonal time series of these two indices are not correlated in time and only exhibit a significant positive trend in winter PDO for 1948–2012 and a significant negative trend in winter NAO for 1900–2012. The same procedure is repeated when the NPI and NAO indices (representing atmospheric oscillations in the North Pacific and North Atlantic) and PDO and AMO indices (representing the Pacific and Atlantic oceanic oscillations) are introduced in the regression model in order to determine if the results are similar. It is important to note that the annual and seasonal time series of the PDO and NPI, or AMO and NAO, are significantly correlated in time but inversely and cannot be used in the same regression model. There was no evidence of significant trends in annual or seasonal time series of NPI and AMO over the 1948–2012 and 1900–2012 periods.

4. Observed climate trends in Canada

a. *Trends in surface air temperature*

Significant trends in annual mean temperature ranging from 1° to 3°C are found almost everywhere across the nation for 1948–2012 (Fig. 2a). The anomalies averaged over the country indicate a significant increase of 1.7°C [1.1°–2.3°C] over the past 65 yr (Fig. 2b). The national time series exhibits considerable variability, although a steady increase is observed from the beginning of the 1970s to 2012. Seasonally, the greatest warming is found during winter (Fig. 3a). The winter trends are predominant in the western regions (northern British Columbia and Alberta, Yukon, Northwest Territories, and western Nunavut), ranging from 4° to 6°C over the past 65 yr. In spring, the warming is less pronounced, but significant warming trends are also dominant over the western regions (Fig. 3b). Summer mean temperature has increased much less than the winter and spring mean temperatures, but the magnitude of the warming is generally more consistent across the country (Fig. 3c). During autumn (Fig. 3d), most of the warming is observed in the Arctic and northern Quebec. Seasonal mean temperature anomalies averaged over Canada indicate significant increases of 3.3° [1.8°–4.8°C], 1.8° [0.7°–3.0°C], 1.4° [0.8°–1.8°C], and 1.5°C [0.5°–2.6°C] over 1948–2012 for winter, spring, summer, and autumn, respectively.

The results for southern Canada (Fig. 2c) show significant warming across the entire region averaging

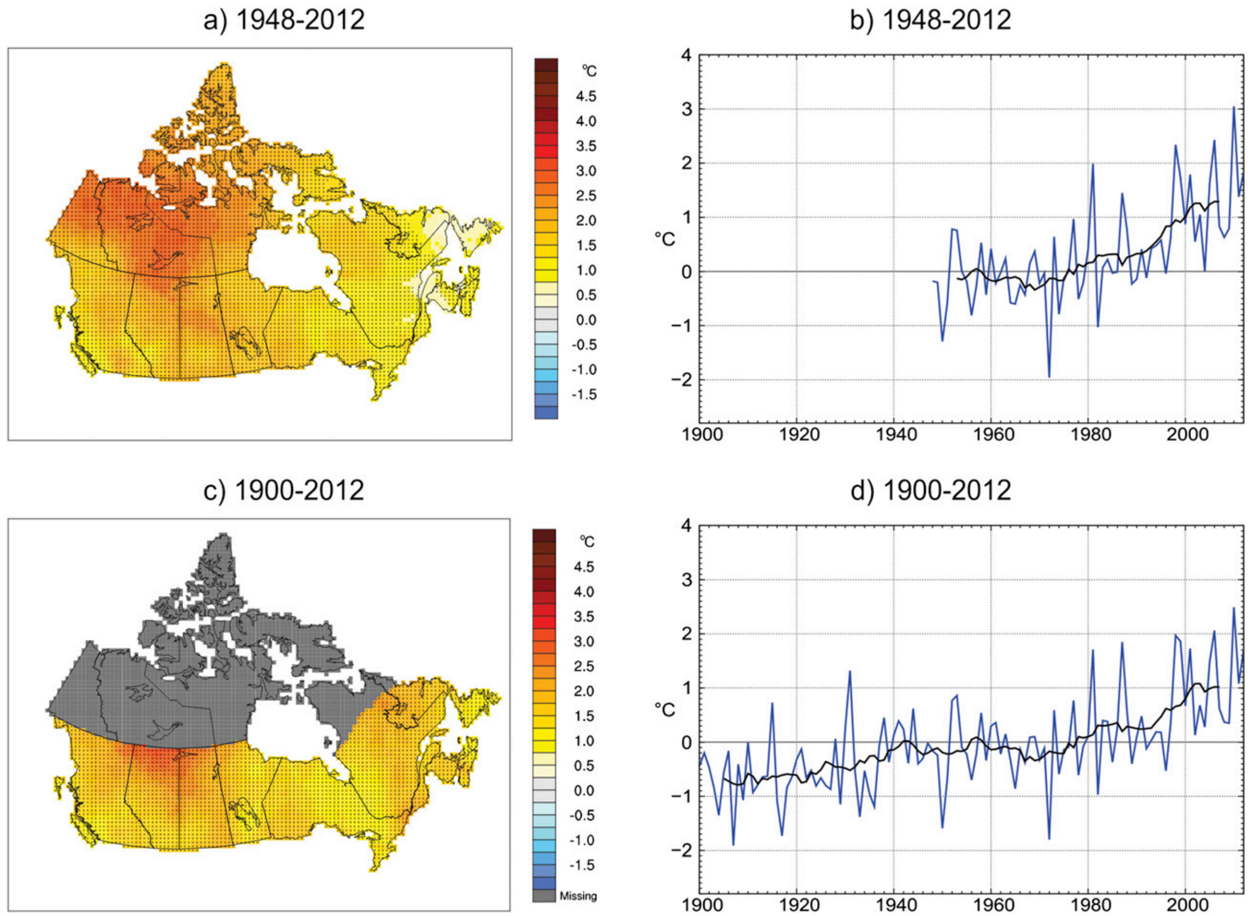

FIG. 2. Trends in annual mean temperature for (a) 1948–2012 [°C (65 yr)$^{-1}$] and (c) 1900–2012 [°C (113 yr)$^{-1}$]. Grid squares with trends statistically significant at the 5% level are marked with a dot. Annual mean temperature anomalies for (b) Canada (1948–2012) and (d) southern Canada (1900–2012). The black line is an 11-yr running mean.

1.6°C [1.2°–2.0°C] over the 1900–2012 period (Fig. 2d). The warming is not monotonic, with periods of more rapid increase evident prior to the 1940s and after the 1970s and with a modest cooling observed over 1940–70. The seasonal trend results (not shown) indicate significant warming in all seasons over southern Canada, averaging 2.6° [1.4°–3.8°C], 1.9° [1.1°–2.7°C], 1.4° [1.1°–1.8°C], and 1.0°C [0.3°–1.8°C] for winter, spring, summer, and autumn, respectively. The winter warming is more pronounced in the western regions (eastern British Columbia, Alberta, Saskatchewan, and western Manitoba), with trends of 2°–4°C over the 113-yr period. These trends are consistent with previous results (Vincent et al. 2012, 2007; Zhang et al. 2000) obtained over shorter periods of time. A reconstruction of global surface air temperature over 1901–2012 suggests that the greatest warming has occurred over northwestern North America and central Eurasia (Vose et al. 2012).

b. Trends in precipitation

Annual total precipitation has increased mainly in the northern regions during 1948–2012 (Yukon, Northwest Territories, Nunavut, and northern Quebec), although some areas in the south (eastern Manitoba, western and southern Ontario, and Atlantic Canada) have also experienced significant increasing trends (Fig. 4a). There is more spatial variability in precipitation trends than in temperature trends. The anomalies averaged over the country indicate a significant increase of 19% [15%–22%] during the past 65 yr (Fig. 4b). It is important to note that the percentage anomalies in the north represent much less precipitation amounts than the same percentage in the south. In all seasons, total precipitation has increased mainly in the north (Fig. 5). In winter, decreasing trends are dominant in the southwest (British Columbia, Alberta, and Saskatchewan). There is less evidence of significant changes in the south during spring, summer, and autumn.

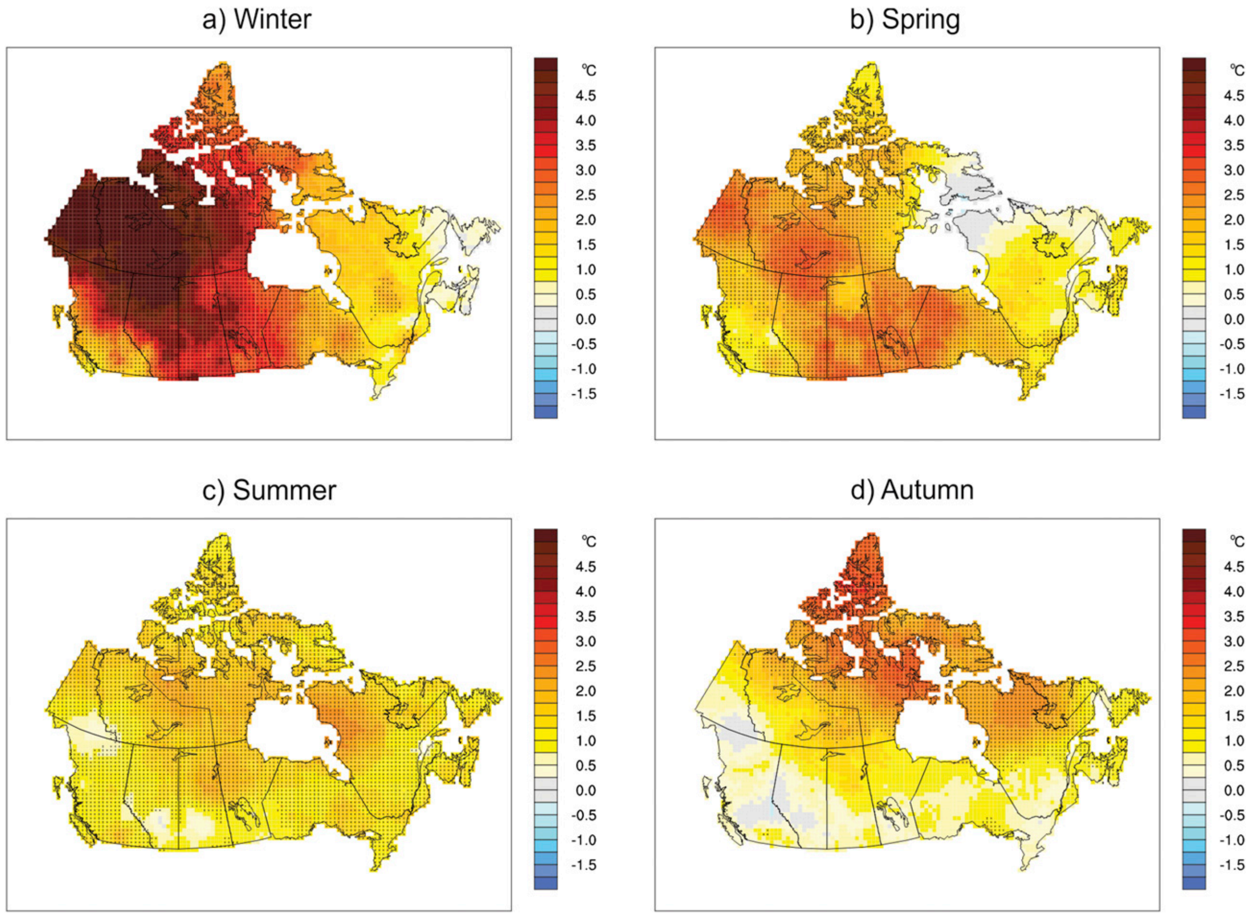

FIG. 3. Trends in mean temperature for 1948–2012 for (a) winter, (b) spring, (c) summer, and (d) autumn. Grid squares with trends statistically significant at the 5% level are marked with a dot. The units are degrees Celsius per 65 yr.

For 1900–2012, annual total precipitation has generally increased across southern Canada (Fig. 4c). The anomalies averaged over the region show a significant increase of 18% [14%–21%] during the 113-yr period (Fig. 4d). The rise in total precipitation results from a steady increase from the 1920s to the 1970s and a modest increase from the 1970s. The pattern of increasing trends is similar in all seasons (figures not presented). Seasonal positive trends are generally significant from coast to coast, with the exception of some areas in the central western (Alberta and Saskatchewan) and central eastern (eastern Ontario and southern Quebec) regions.

Trends in snowfall ratio reflect the combined effect of both precipitation and temperature. The annual trends are generally decreasing over 1948–2012 in many areas south of 65°N while they are increasing in the north (Fig. 6a). The snowfall ratio averaged over the country shows an increase from the beginning of the record to the 1970s, followed by a decrease to 2012 (Fig. 6b). The peak snowfall ratio in the 1970s is consistent with North American winter snow cover extent, which reached twentieth-century maximum values around this time (Brown 2000). In winter, there is less evidence of change although significant decreasing trends are observed in the west (British Columbia) and east (southeastern Quebec) over the past 65 yr (figure not presented). The changes are more pronounced in spring and autumn. In spring, significant decreasing trends are found across western and central Canada (Fig. 7a). Since spring precipitation has not essentially changed in the past 65 yr over this area (Fig. 5b), the decreasing trends in snowfall ratio during spring is mainly due to the spring warming (Fig. 3b), which effectively decreased the proportion of snow. A similar connection is seen in autumn, where significant decreasing trends in northern Quebec (Fig. 7b) correspond to the autumn warming over the past 65 yr (Fig. 3d).

For 1900–2012, the annual snowfall ratio has generally increased in the northern part of southern Canada

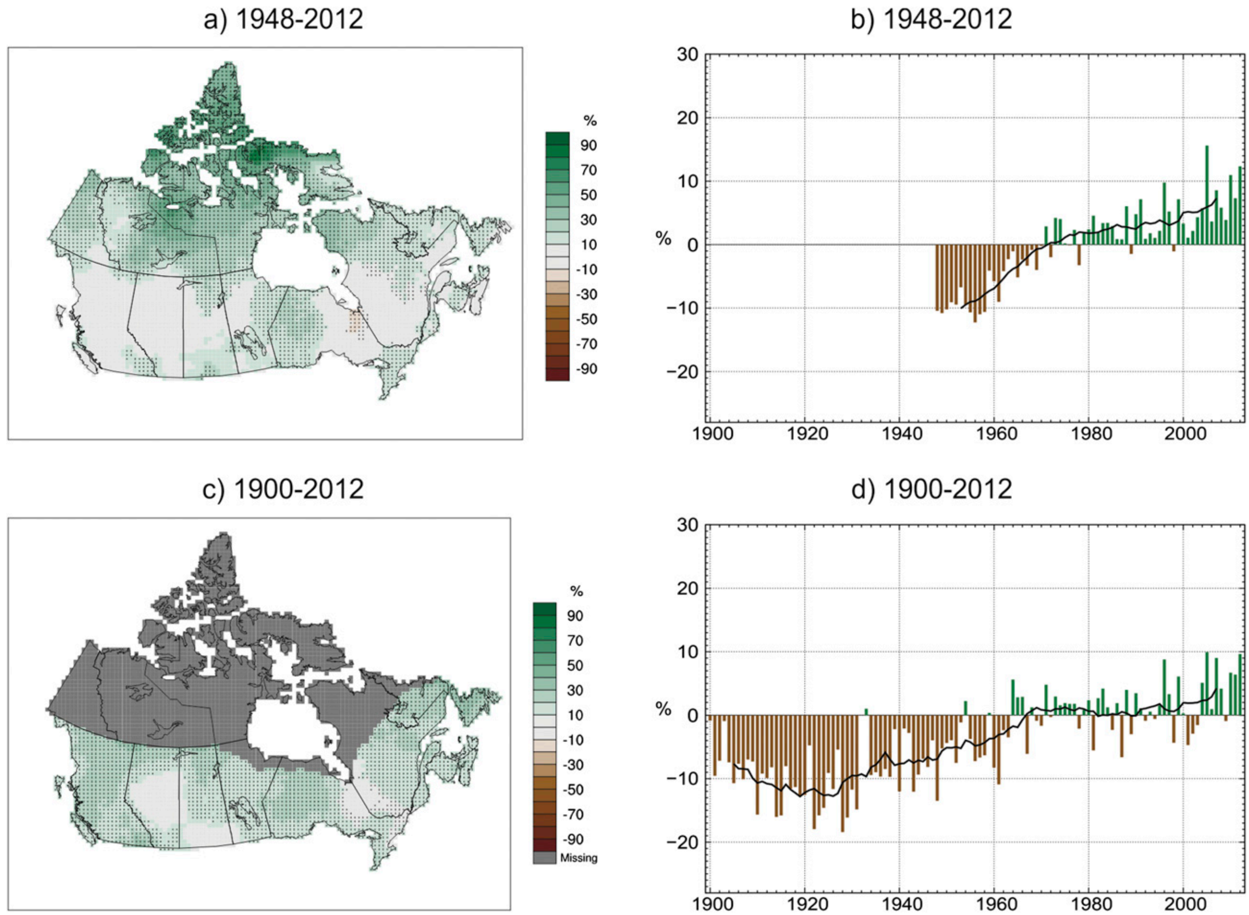

FIG. 4. Trends in annual total precipitation for (a) 1948–2012 [% $(65\,\mathrm{yr})^{-1}$] and (c) 1900–2012 [% $(113\,\mathrm{yr})^{-1}$]. Grid squares with trends statistically significant at the 5% level are marked with a dot. Annual total precipitation anomalies for (b) Canada (1948–2012) and (d) southern Canada (1900–2012). The black line is an 11-yr running mean.

(north of 55°N) and decreased in several regions in the south (Fig. 6c). The snowfall ratio averaged over the region shows a steady increase from the 1920s to the 1970s, followed by a decrease to 2012 (Fig. 6d). Similar to the shorter period, there is less evidence of change in the winter snowfall ratio (not shown), except for some small areas of decreasing trends in the west (southern British Columbia) and east (southern Quebec). The changes in snowfall ratio during 1900–2012 are more pronounced in spring and autumn when increasing (decreasing) trends are found in the northern (southern) part of southern Canada. The increasing snowfall ratio trends north of 55°N are mainly due to increasing precipitation, whereas the decreasing trends in the south are largely due to the warming trends during the past 113 yr. Precipitation trends for 1948–2012 and 1900–2012 are generally in agreement with previous findings (Mekis and Vincent 2011; Zhang et al. 2000).

c. Trends in snow cover

Snow-cover duration has decreased in Canada and most of the decreasing trends are observed in spring. About 22% of the stations have significant decreasing trends in the first half of the snow year (Fig. 8a), whereas 43% of the stations have significant decreasing trends in the second half of the snow year (Fig. 8b). The SCD anomalies from the 1961–90 reference period averaged over the 104 stations show a significant decrease of 8 [3–14 days] and 10 days [5–15 days] during 1950–2012 for the first and second halves of the snow year. The trend toward earlier snow disappearance in the spring was previously documented by Brown and Braaten (1998) and is part of a hemispheric-wide trend of earlier melt of snow and ice (Lemke et al. 2007; Vaughan et al. 2013). Snow cover in North America was characterized by rapid decreases in the 1980s and early 1990s with a significant decreasing trend in April snow water equivalent for 1915–97 (Brown 2000).

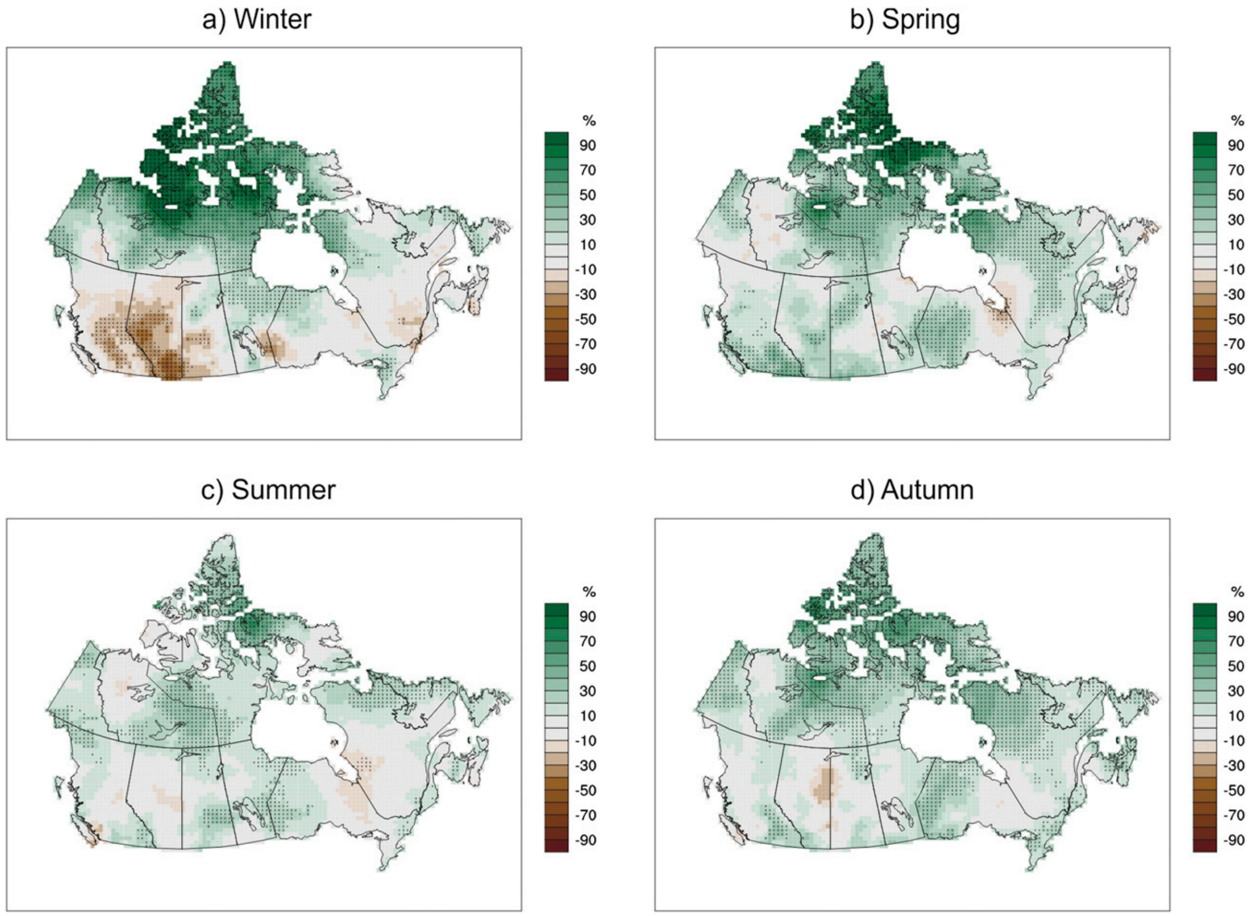

FIG. 5. Trends in total precipitation for 1948–2012 for (a) winter, (b) spring, (c) summer, and (d) autumn. Grid squares with trends statistically significant at the 5% level are marked with a dot. The units are percentage per 65 yr.

The annual maximum snow depth shows a general tendency toward smaller values (Fig. 8c). A decrease of 4 cm [3–11 cm] during 1950–2012 is found when the anomalies are averaged over the 104 stations: of these, 23% exhibit a significant decrease of more than 20 cm. The decrease in the maximum snow depth in the southern regions is being driven by less winter precipitation (Fig. 5a) and a lower fraction of precipitation falling as snow from the winter warming (Fig. 3a). Significant trends toward earlier dates of maximum snow depth are observed at 26% of the stations (Fig. 8d). The data also indicate that, when averaged over the 104 stations, the annual maximum snow depth occurs earlier in the year by about 13 days [6–21 days]. These results are consistent with winter warming. They are also in agreement with broad-scale trends toward declining spring snowpack and earlier runoff over the northwestern United States (Mote 2006; Barnett et al. 2008).

d. *Trends in streamflow*

Evidence of significant change is mainly found in April mean streamflow and in the starting date of high-flow season over 1950–2012. The results show significant increasing trends in April mean streamflow at 25% of the sites (Fig. 9a) and significant decreasing trends in the starting date of the high-flow season at 21% of the sites (Fig. 9b), mostly located in the western and eastern parts of the country. The trends toward earlier high-flow season and increase in April mean streamflow were previously documented in Zhang et al. (2001) and are consistent with the trends found across western North America (Stewart et al. 2005; Brabets and Walvoord 2009). The earlier start of spring freshet and increasing streamflow in April may be attributed to a combination of several factors, including earlier spring snowmelt and an increased proportion of liquid precipitation, depending on location. However, they are also dependent

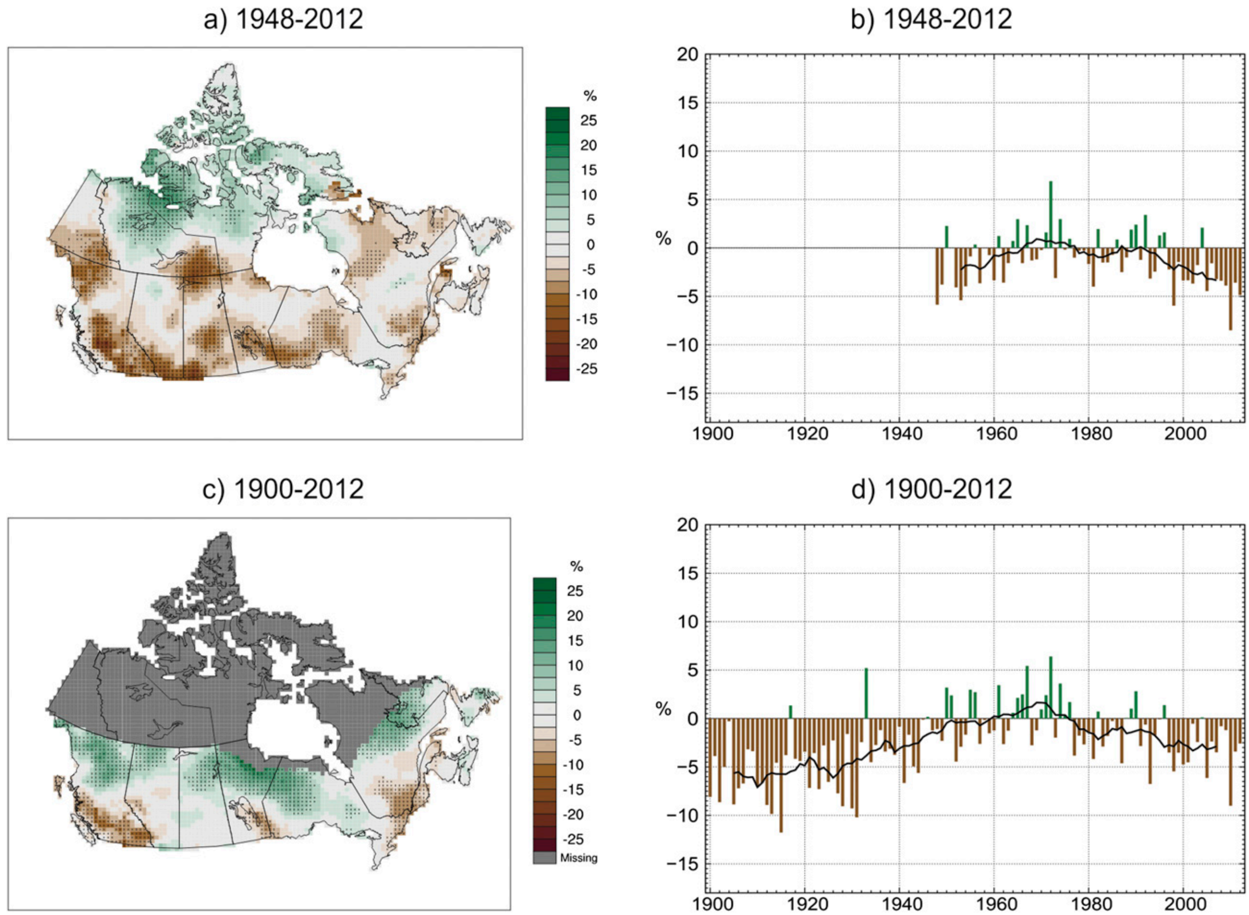

FIG. 6. Trends in annual snowfall ratio for (a) 1948–2012 [% $(65\,\mathrm{yr})^{-1}$] and (c) 1900–2012 [% $(113\,\mathrm{yr})^{-1}$]. Grid squares with trends statistically significant at the 5% level are marked with a dot. Annual snowfall ratio for (b) Canada (1948–2012) and (d) southern Canada (1900–2012). The black line is an 11-yr running mean.

on the maximum water storage of the snowpack and any changes in the distribution of the runoff. A recent study suggests that a shift in precipitation from snow toward rain does not necessary lead to increasing streamflow overall (Berghuijs et al. 2014).

Analysis of the date of river ice breakup and freezeup indicate some evidence of trends toward earlier river ice breakup at most locations for 1950–2012 (Fig. 9c) and 1967–2012. There is less evidence of changes in the date of river ice freezeup (not shown). These results are consistent with previously published studies (Duguay et al. 2006; Latifovic and Pouliot 2007) that report widespread trends to earlier spring breakup with strong regional variability in freezeup dates. These trends are consistent with warmer spring temperature and earlier start of the spring freshet. They are also in agreement with the trends observed over shorter periods of time (Zhang et al. 2001; Bonsal et al. 2006).

5. Influence of large-scale oscillation indices on observed trends

a. Influence of the PDO and NAO indices on temperature trends

The regression coefficients associated with the PDO and NAO are first examined when the model is fitted for 1948–2012. The coefficients are significant for a higher number of grid points in winter and spring than in summer and autumn. Significant positive coefficients for PDO are found in the west (Figs. 10a,d), while significant negative coefficients for NAO are observed in the northeast (Figs. 10b,e). These results are consistent with those presented in previous studies (Liu et al. 2007; Wang et al. 2005; Bonsal et al. 2001), which showed positive correlation between surface air temperature and PDO in the west and negative correlation between surface air temperature and NAO in the northeast. The

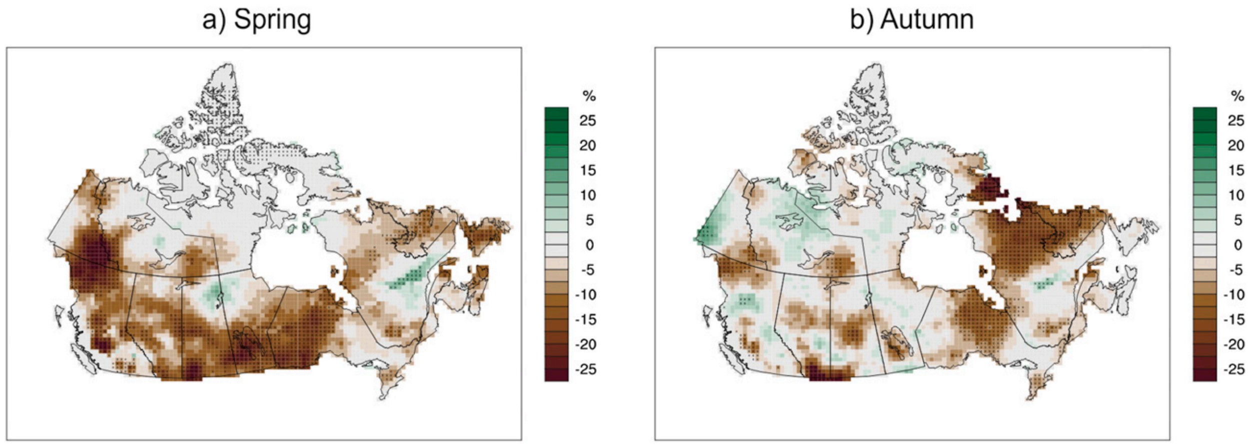

FIG. 7. Trends in snowfall ratio for 1948–2012 for (a) spring and (b) autumn. Grid squares with trends statistically significant at the 5% level are marked with a dot. The units are percentage per 65 yr.

combination of the PDO and NAO indices explain about 21% (13%) of the variation in winter (spring) mean temperature in Canada during 1948–2012 (this percentage is calculated at each grid point and averaged over the nation). This percentage is much smaller for summer and autumn.

When the trends in the residuals are assessed for 1948–2012, the winter and spring warming (Figs. 10c,f) is

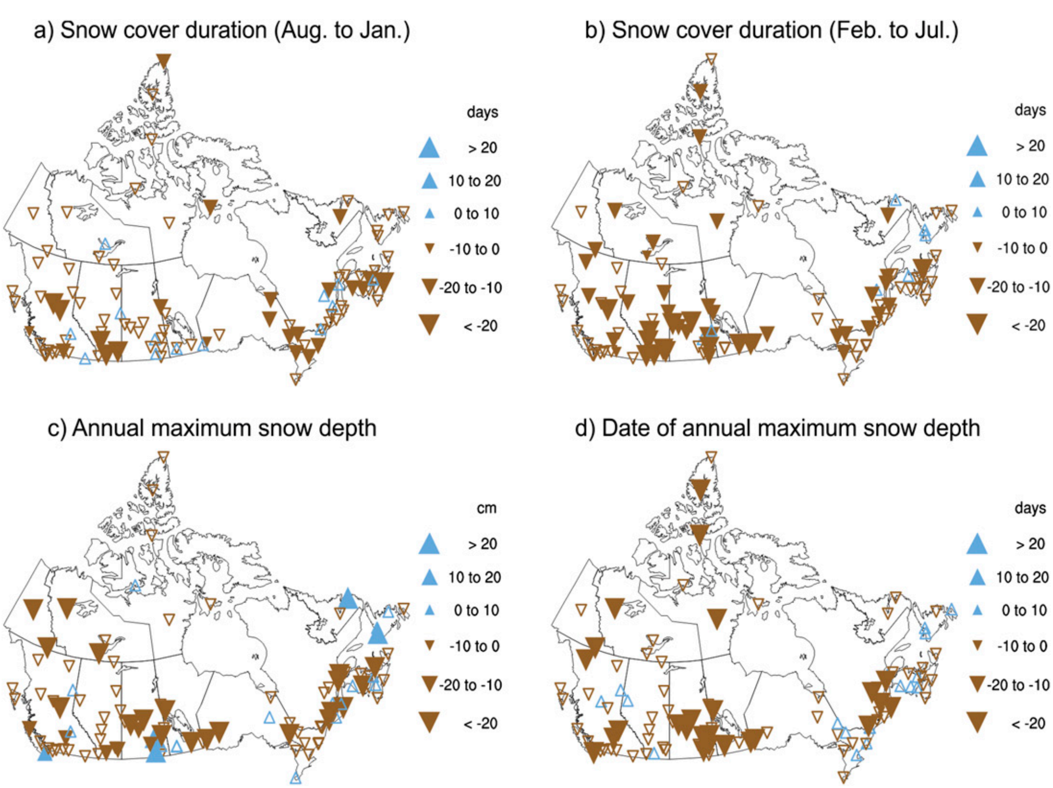

FIG. 8. Trends in snow cover data for 1950–2012: snow-cover duration (number of days with snow on the ground ≥ 2 cm) during (a) the first half of the snow season (August–January) and (b) the second half of the snow season (February–July); (c) annual maximum snow depth; and (d) date of annual maximum snow depth. Upward (downward) pointing triangles indicate positive (negative) trends. Solid triangles correspond to trends significant at the 5% level.

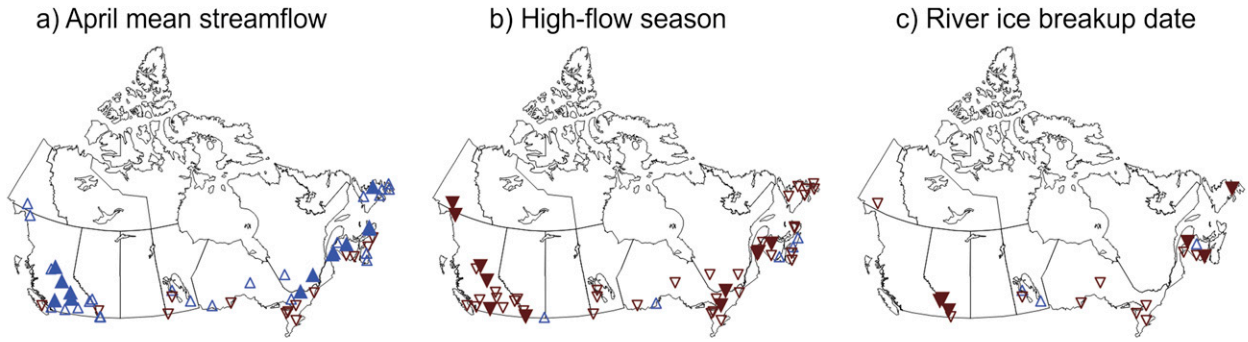

FIG. 9. Trends in (a) April mean streamflow, (b) starting date of high-flow season, and (c) date of river ice breakup for 1950–2012. Upward (downward) pointing triangles indicate positive (negative) trends. Solid triangles correspond to trends significant at the 5% level.

less pronounced than the warming observed in the original data (Figs. 3a,b), mainly in the western and central regions. However, the trends are still significant in many regions and their magnitude is more consistent across the country. The winter (spring) time series of the residuals averaged over the nation indicate a significant warming of 2.1°C (1.0°C) over the past 65 yr while the original winter (spring) data show a significant increase of 3.3°C (1.8°C). These results demonstrate that, while the oscillations explain some of the temperature variations over 1948–2012, the observed trends cannot be explained by low-frequency variability modes alone since there is still significant warming after removing the effects of the PDO and NAO indices. The summer and autumn trends are basically the same before and after removing the influence of the oscillations.

For 1900–2012, significant positive coefficients for PDO are found in the southwest, whereas significant negative coefficients for NAO are observed over a small area in the southeast, during winter and spring (figures not presented). The PDO and NAO indices explain only 16% (10%) of the variation in winter (spring) mean

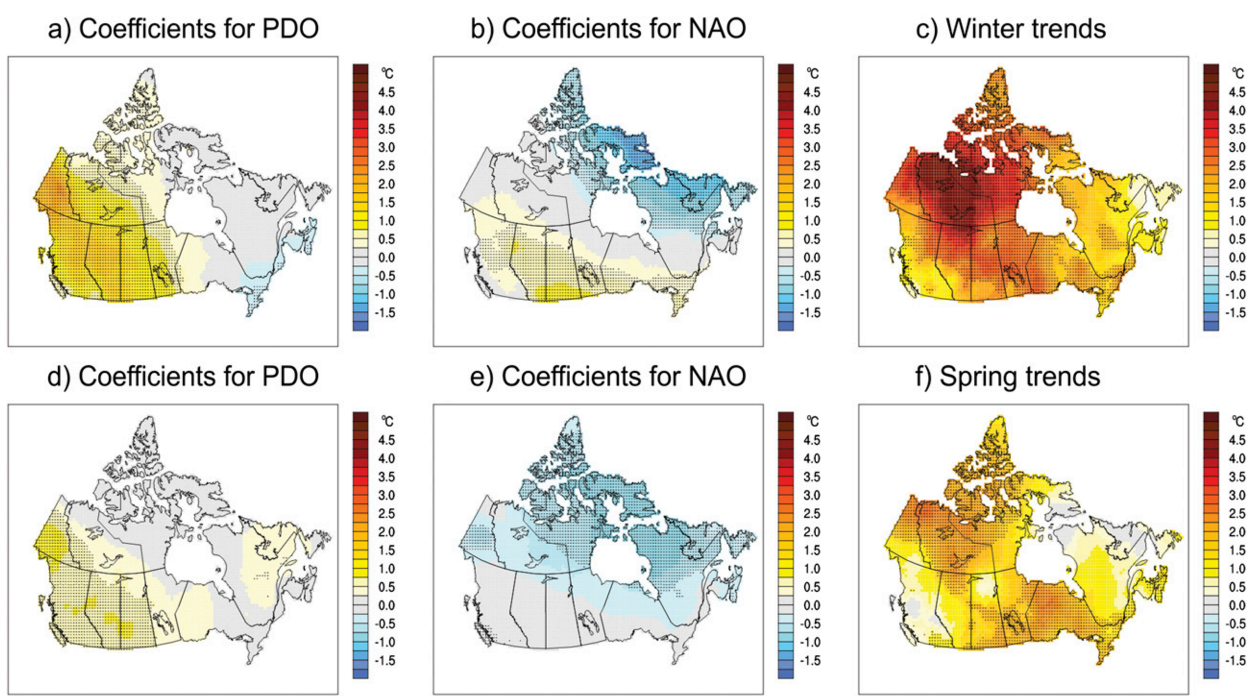

FIG. 10. Regression coefficients for (a) PDO and (b) NAO when the model is fitted to winter mean temperature. (c) Trends in winter mean temperature for 1948–2012 after removing the influence of PDO and NAO. Regression coefficients for (d) PDO and (e) NAO when the model is fitted to spring mean temperature. (f) Trends in spring mean temperature for 1948–2012 after removing the influence of PDO and NAO. Grid squares with trends (or coefficients) statistically significant at the 5% level are marked with a dot. The units are degrees Celsius per 65 yr.

temperature in southern Canada during 1900–2012. The temperature trends after removing the influence of the PDO and NAO indices are almost identical to those observed in the original data (Fig. 2c). The winter (spring) time series of the residuals averaged over the southern Canada indicate a significant warming of 2.5°C (1.8°C) over the past 113 yr, while the original winter (spring) data show a significant increase of 2.6°C (1.9°C). The results indicate that the influence of the PDO and NAO oscillations on the observed temperature trends is very small in southern Canada over the past 113 yr. They also suggest that the magnitude of the trends is more similar over both periods of time after removing the influence of the oscillations. In particular, the winter mean temperature has increased by 2.1°C in Canada for 1948–2012 while it has increased by 2.5°C in southern Canada for 1900–2012 after removing the effects of the oscillations (although the area covered is different).

b. *Influence of NPI and NAO (or PDO and AMO) on temperature trends*

Annual and seasonal mean temperature trends are also examined after removing the influence of the atmospheric (NPI and NAO) and oceanic (PDO and AMO) oscillations separately. The resulting trends for 1948–2012 and 1900–2012 are similar to those obtained when the effects of the PDO and NAO are taken into account. In winter and spring, significant negative coefficients for NPI are mainly found in the western and central regions and significant negative coefficients for NAO prevail in the northeast (figures not presented). For the same seasons, significant positive coefficients for AMO are found in the central and eastern regions whereas significant positive coefficients for PDO prevail in the west. The 1948–2012 trends in winter and spring mean temperatures after removing the effects of NPI and NAO (PDO and AMO) are very similar to those presented in Figs. 10c,f. Overall, these results indicate that the warming is still significant and more consistent across the country after removing the influence of the large-scale oscillations. They also suggest that the observed temperature trends cannot be explained by low-frequency variability modes alone.

c. *Influence of PDO and NAO on the trends in other climate elements*

Annual and seasonal total precipitation and snowfall ratio trends are assessed after removing the influence of the PDO and NAO indices. The combination of the PDO and NAO explain less than 10% of the variation in these two elements for 1948–2012 and 1900–2012. The regression coefficients are significant for a greater number of grid points for winter precipitation and spring snowfall ratio during 1948–2012. For winter precipitation, significant negative coefficients for PDO are found in the south (Fig. 11a) and significant negative coefficients for NAO are found in the northeast (Fig. 11b). The trends in winter precipitation for 1948–2012 after removing the effect of the oscillations (Fig. 11c) are similar to those obtained from the original data (Fig. 5a) with the exception of weaker decreasing trends in the southwest. For spring snowfall ratio, significant negative coefficients for PDO prevail in the west (Fig. 11d), whereas coefficients for NAO are generally near zero (Fig. 11e). The trends in spring snowfall ratio for 1948–2012 after removing the influence of PDO and NAO (Fig. 11f) are similar to those obtained from the original data (Fig. 7a), with the exception of less extensive decreasing trends in the west. The results indicate that, while the PDO index explains some of the variations in winter precipitation and spring precipitation falling as snow during 1948–2012, the magnitude and significance of the trends do not change very much after removing the influence of the PDO and NAO for 1948–2012. There is no evidence of the PDO and NAO impact on the precipitation and snowfall ratio trends during 1900–2012.

When the trends are assessed for various snow-cover and streamflow indices, the regression coefficients associated with the PDO and NAO are significant at a few stations only. The trends after removing the effects of PDO and NAO are almost identical to those obtained from the original values (Figs. 8 and 9). There is no evidence that the PDO and NAO are affecting the trends in the snow-cover and streamflow indices by very much during 1950–2012 (although the number of stations used in this study is limited).

6. Summary and discussion

The trend results reported in this study present a picture of a changing climate in Canada which is consistent across multiple climate elements. Over the past six decades, surface air temperature has increased in Canada, with the largest warming occurring in winter and spring. Precipitation totals have increased principally in the north in all seasons. Winter precipitation has decreased in the southwest and there have been widespread decreases in the amount of precipitation falling as snow in the south. These changes in temperature and precipitation have led to a shorter snow-cover season, mainly in response to earlier snowmelt (in all regions) and lower snowfall amounts (in southern regions). A shorter snow accumulation period and reduced snowfall amounts has resulted in a decrease in annual maximum snow accumulations and earlier dates of maximum snow

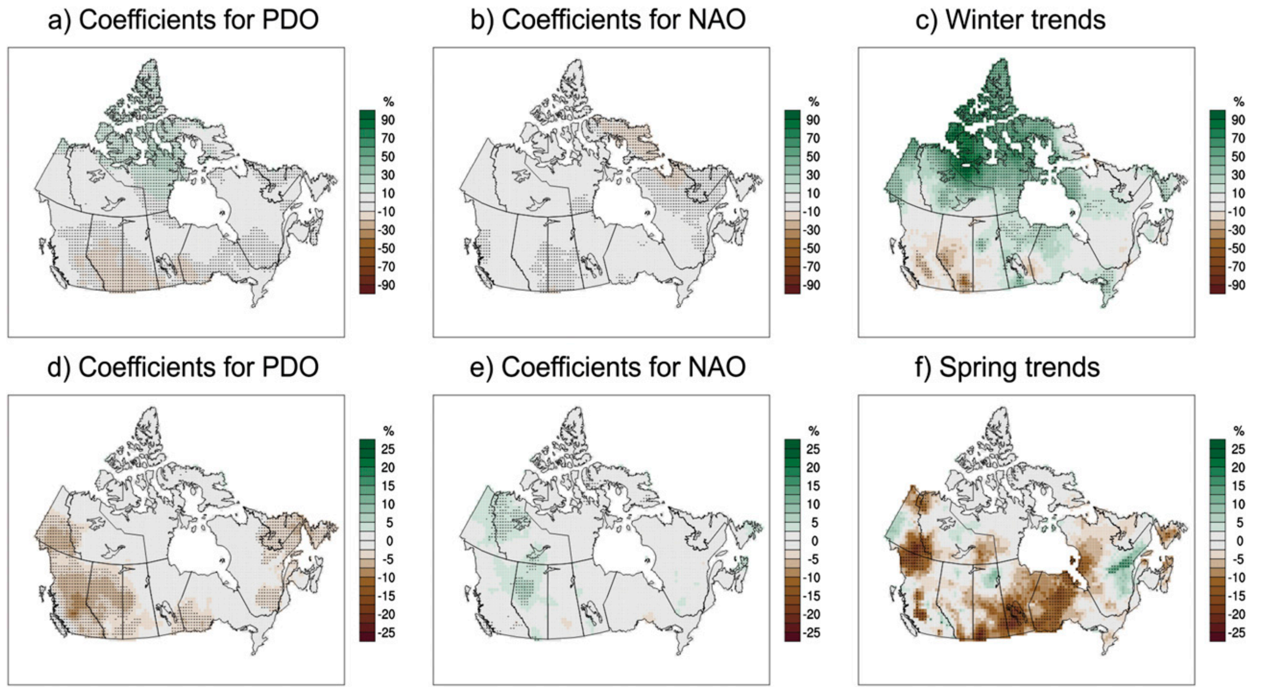

FIG. 11. Regression coefficients for (a) PDO and (b) NAO when the model is fitted to winter precipitation. (c) Trends in winter precipitation for 1948–2012 after removing the influence of PDO and NAO. Regression coefficients for (d) PDO and (e) NAO when the model is fitted to spring snowfall ratio. (f) Trends in spring snowfall ratio for 1948–2012 after removing the influence of PDO and NAO. Grid squares with trends (or coefficients) statistically significant at the 5% level are marked with a dot. The units are percentage per 65 yr.

depth at many stations. An observed earlier start of spring freshet and increasing streamflow in April are consistent with earlier spring snowmelt because of winter and spring warming. Over the past century, temperature has increased in southern Canada, but the rate of increase was not consistent and included a modest cooling during 1940–70. During the same period, the precipitation has increased almost everywhere across the region and the amount of precipitation falling as snow has increased north of 55°N and decreased in the south.

When the influence of large-scale oscillations is taken into account, the warming observed in Canada during 1948–2012 is slightly reduced in the western regions, especially during winter and spring, but the temperature trends are still significant and the warming is more consistent across the country. There are less decreasing trends in winter precipitation totals and spring precipitation falling as snow during 1948–2012 in the southwest after removing the effects of the oscillations, but the overall pattern of increasing winter precipitation trends in the north and decreasing spring snowfall ratio trends in the south remains the same. There is no evidence that the large-scale oscillations have influenced the temperature and precipitation trends over 1900–2012 and the snow-cover and streamflow indices trends over 1950–2012. These results clearly demonstrate that, while the oscillations explain some of the climate variations during 1948–2012, the observed temperature and precipitation trends cannot be explained by low-frequency variability modes alone. Other factors, external to the climate system, such as increase in greenhouse gases and aerosols in the atmosphere may have played a significant role in the observed changes in climate (Wan et al. 2015; Gillett et al. 2008; Min et al. 2008a; Zhang et al. 2006). Ongoing work involves the comparison of the changes observed in historical data with those simulated by climate models under various external forcing and the results will be reported in a different study.

This study presents an analysis of trends in several climate elements using the best updated data available over similar periods of time in order to highlight the consistencies among the trends in related climate variables. It is important to closely monitor climate change in order to improve our understanding regarding the various mechanisms responsible for climate variations. Canada's climate shows multidecadal-scale variability over the past century associated with low-frequency atmospheric and oceanic oscillations. This study reports, for the first time, climate trends in Canada after removing potential mechanisms representing low-frequency variations. The results show that large-scale atmospheric and oceanic oscillations have influenced regional climate trends to some extent. However, it also reveals that these indices alone do not explain long-term changes observed in various climate elements in Canada.

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Climate Risks & Adaptation Practices

For the Canadian Transportation Sector 2016

Canada

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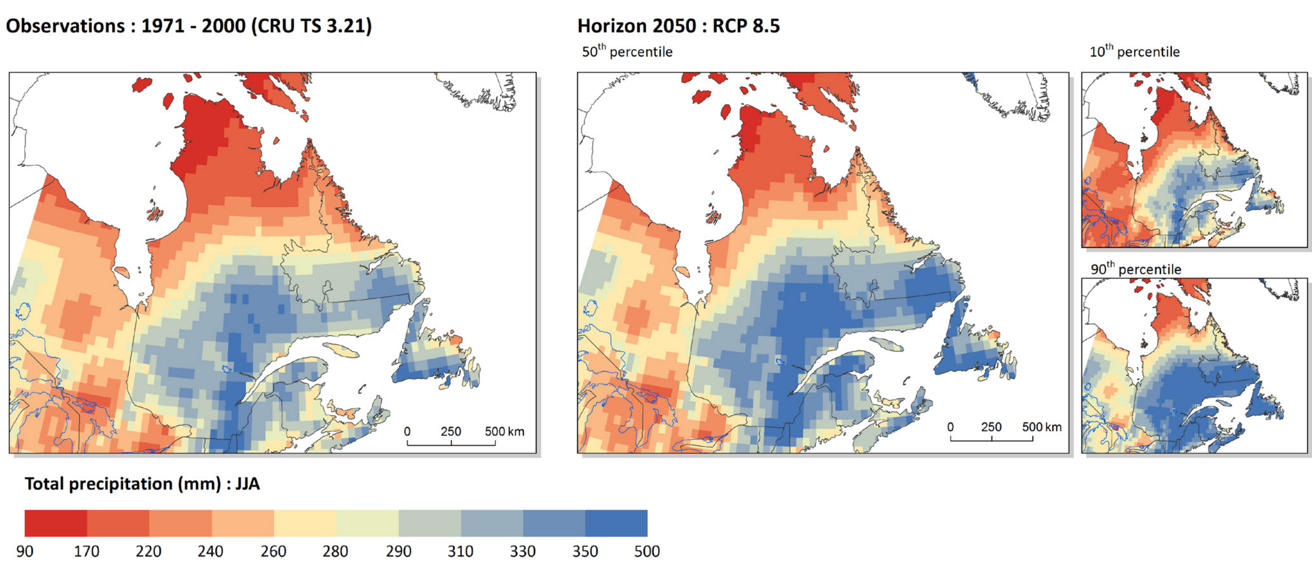
3.2 MORE INTENSE PRECIPITATION EVENTS

Total annual precipitation from observed data shows significant upward trends for many of the weather stations located in the south of the province. For some of these stations, the trends are associated with increases in spring and fall precipitation.

Increases in precipitation are expected in winter and spring throughout Québec. In the northern and more central regions, this would also be the case in the summer and fall seasons. As in the case of temperatures, these increases will be more significant for extreme precipitation events than for averages. In fact, all climate models agree on future upward trends for extreme precipitation events, everywhere in Québec, although these changes are more substantial moving northward. This applies for maximum annual amounts in addition to all durations and frequencies. For example, a maximum annual rainfall event with a 20-year return period over the 1986-2005 timeframe could occur more frequently by 2046-2065 with a return period of around 7 to 10 years. Preliminary studies suggest that future climate conditions could be more conducive to thunderstorms, which are usually accompanied by larger quantities of precipitation, although the robustness of these projections is uncertain.
For winter precipitation, the proportion of snow and rainfall relative to total accumulation depends on temperature. Given that the climate has been warming in the recent past, downward snow precipitation trends are already being observed in the south of Québec. An analysis of several different data sources reveals that snow cover duration has decreased by approximately 2 days per decade in the south of Québec between 1948 and 2005.

Even if snowfall events decrease due to a shorter cold season, rainfall events during this season should increase with warming temperatures in winter (see Figure 6). Changes in snow cover with respect to these trends will vary according to the region, altitude, climatic regime, type of surface and vegetation. Compared to the 1970-1999 average, snow cover duration by 2041-2070 could decrease by up to 25 days in the North of Québec, from 25 to 45 days in the central region, from 45 to 75 days for the Gulf of the St. Lawrence and between 45 and 65 days for the south of Québec.

Figure 6: Observed total summer (JJA: June, July and August) and winter (DJF: December, January and February) precipitation for the period 1971-2000 (left panel) and projected (right panels) for the 2050 horizon (2041-2070). The observed average is calculated using the CRU TS 3.21 dataset (CRU TS = Climatic Research Unit Timeseries, 3.21 dataset is the name of the release). Future maps present the ensemble median (i.e. the median of all available projections) as well as the 10th and 90th percentiles (i.e., lower and higher bounds) of 19 future climate scenarios. Future climate scenarios were produced using the "delta" method calculated from the using CMIP5 (Coupled Model Intercomparison Project Phase 5) simulations (RCP 8.5) applied to the observed data (see Charron, 2014). (Source: Ouranos)



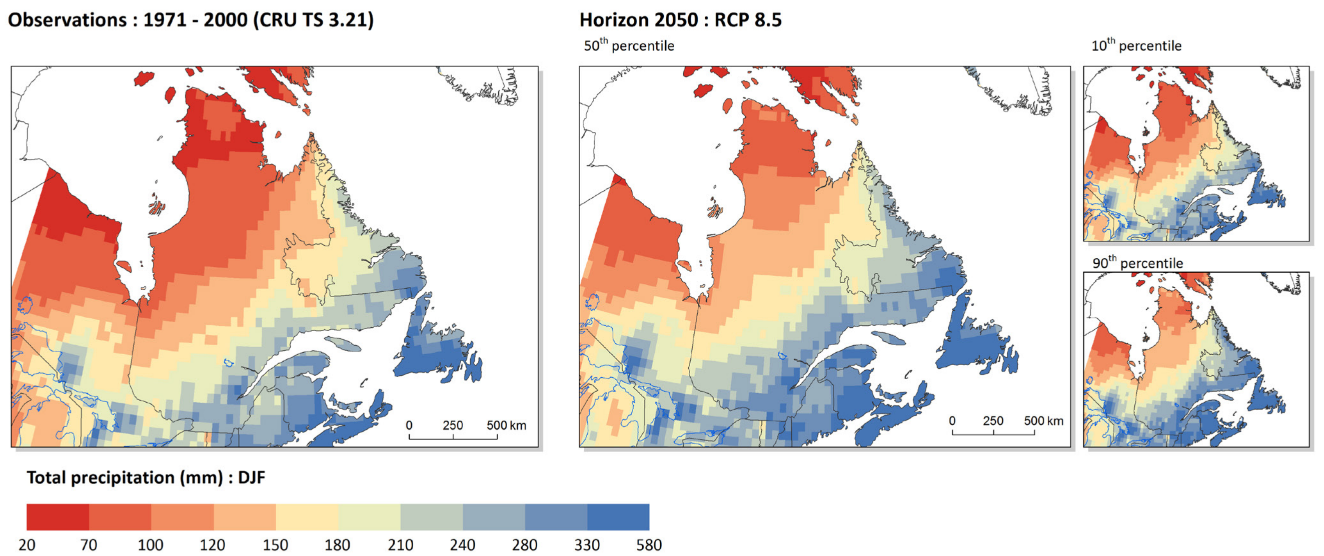
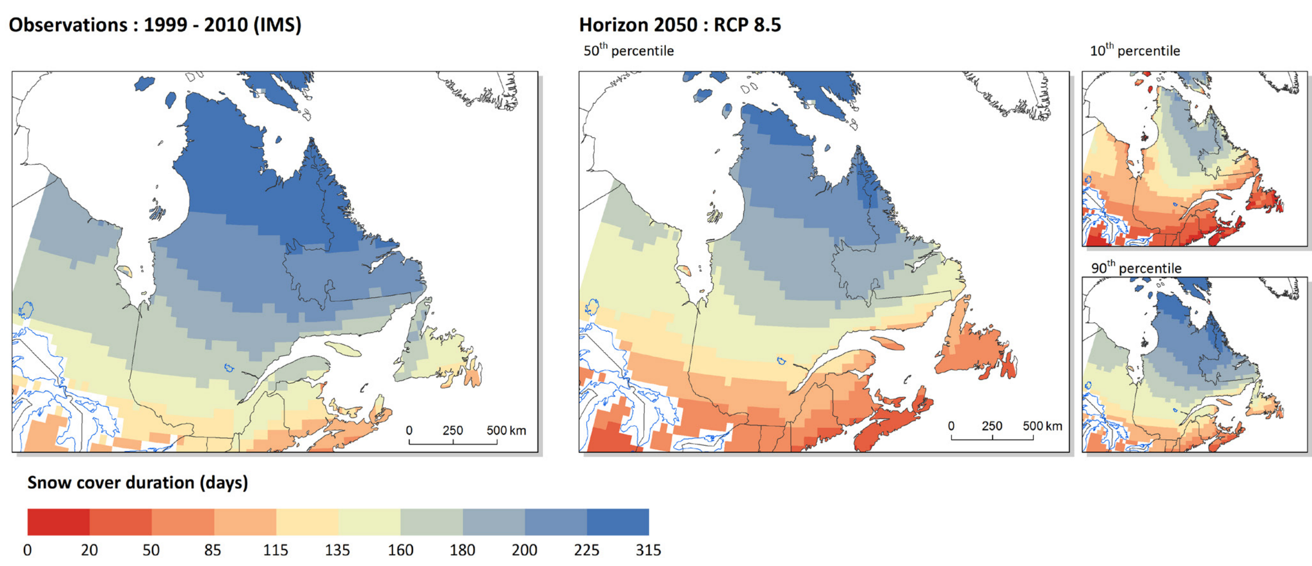


Figure 7: Observed snow cover duration for the period 1999-2010 (left panel) and projected (right panels) for horizon 2050 (2041-2070). The observed average is calculated using the IMS 24 dataset (IMS Ice mapping System 24 km resolution) (National Ice Center, 2008). Future maps present the ensemble median (i.e., the median of all available projections) as well as the 10th and 90th percentiles (i.e., lower and higher bounds) of 19 future climate scenarios. Future climate scenarios were produced using the "delta" method calculated from the CMIP5 (Coupled Model Intercomparison Project Phase) (RCP 8.5) and applied to the observed data (see Charron, 2014). (Source: Ouranos)



With respect to freezing rain, this is a phenomenon that predominantly affects the Saint-Lawrence valley due to its morphology and position (Ressler et al., 2012). While great progress has been made to improve knowledge in terms of the conditions likely to generate this type of event, it remains uncertain whether the number, duration and intensity of these events will change in Québec over the coming decades.

QUÉBEC IN ACTION GREENER BY 2020

2013-2020 Government Strategy for Climate Change Adaptation

A collective effort to strengthen the resilience of Québec society
June 2012

A PLAN FOR QUÉBEC

Québec

1 PRESENT AND PROJECTED CLIMATE

In the last few decades, Québec's climate has changed significantly. Daily mean temperatures in southern Québec have risen by 0.2°C to 0.4°C per decade, with minimum temperatures rising more than maximums, and greater change inland than in maritime regions.

Generally, the climate will grow warmer over the entire territory of Québec, more dramatically in winter than in summer, and more in the North than the South. In winter, by 2050, temperatures are expected to be 2.5°C to 3.8°C higher in southern Québec, and 4.5°C to 6.5°C higher in the North. Summer temperatures are expected to rise by 1.9°C to 3.0°C in the South and by 1.6°C to 2.8°C in the North.

More abundant precipitation is expected in winter and in Nord-du-Québec. Increases in winter precipitation of 8.6% to 18.1% in the South, and 16.8% to 29.4% in North, are expected by 2050. The rise in winter precipitation will lead to deeper accumulations of snow in the North. In southern Québec the opposite is expected: less snow accumulating through the winter due to higher temperatures and a shorter cold season. Summer precipitation is expected to rise by 3.0% to 12.1% in the North, with no significant change expected in the South.

Climate change will result in extreme weather events (winter storms, violent winds, torrential rains, etc.) becoming more frequent and more intense. In turn, such events will sometimes lead to flooding, erosion, landslides and so on.

Changes in temperature and precipitation will also affect many other climate-related phenomena; some of them are well understood, and their changes can be predicted with a high degree of certainty. Thus, it is highly probable that coming decades will see the following:

- A shrinking of the ice cover, with winter ice forming later and melting earlier;
- Winters becoming shorter;
- Less intense and less frequent cold waves;
- Permafrost melting at an increasing rate;
- Hotter and more frequent heat waves;
- Extreme storm surges in coastal areas.

There is also reason to believe that the following will occur as well[1]:

- More frequent winter warm spells;
- More extreme fluctuations in water levels (higher flood levels and lower low-water levels), with increased erosion of shorelines;
- A northward shift of storm trajectories;
- Greater numbers of tropical storms and more intense hurricanes;
- Longer summer droughts.

1 Based on historical trends and less certain scientific understanding.