THOMAS B. GETZ
Direct Dial: 603.230.4403
Email: thomas.getz@mclane.com
Admitted in NH
11 South Main Street, Suite 500
Concord, NH 03301
T 603.226.0400
F 603.230.4448

MCLANE MIDDLETON

May 19, 2017

Via Electronic Mail & Hand Delivery

Pamela Monroe, Administrator
New Hampshire Site Evaluation Committee
21 South Fruit Street, Suite 10
Concord, NH 03301-2429

Re: Site Evaluation Committee Docket No. 2015-06
Joint Application of Northern Pass Transmission LLC and Public Service Company of New Hampshire d/b/a Eversource Energy (the "Applicants") for a Certificate of Site and Facility
Inadvertent Disclosure

Dear Ms. Monroe:

Enclosed for filing in the above-captioned docket, please find an original and one copy of a corrected version of the redacted Rebuttal Report on Electricity Market Impacts and Local Economic Benefits Associated with the Proposed Northern Pass Transmission Project, which was filed on April 17, 2017. The corrected version redacts information that the Applicants recently discovered was inadvertently disclosed in the previous version.

Please contact me directly should you have any questions.

Sincerely,

Thomas B. Getz

TBG:slb

Enclosure

REDACTED

Rebuttal Report on Electricity Market Impacts and Local Economic Benefits associated with the proposed Northern Pass Transmission Project

April 17, 2017

Prepared for

NEW HAMPSHIRE SITE EVALUATION COMMITTEE
DOCKET NO. 2015 – 06

LONDON ECONOMICS

London Economics International LLC
717 Atlantic Avenue, Suite 1A
Boston, Massachusetts 02111
T: (617) 933-7200 F: (617) 933-7201
www.londoneconomics.com

Disclaimer

London Economics International LLC ("LEI") was retained by Northern Pass Transmission, LLC ("Northern Pass" or or the "Project") to develop an economic impact analysis of the proposed Northern Pass Transmission Project. 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 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 variations 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 direct or indirect reliance upon LEI's analysis and this report.

London Economics International LLC
717 Atlantic Ave, Suite 1A
Boston, MA 02111
www.londoneconomics.com

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www.londoneconomics.com

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www.londoneconomics.com

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717 Atlantic Ave, Suite 1A
Boston, MA 02111
www.londoneconomics.com

1 Introduction

LEI submitted its report on *Cost-Benefit and Local Impact Analysis of the Proposed Northern Pass Transmission Project* ("Original Report" or "October 2015 Report") in October 2015, with an accompanying pre-filed testimony in this proceeding to assess the Northern Pass Transmission Project ("Northern Pass" or the "Project"). Then, in response to a data request and an order from the New Hampshire Site Evaluation Committee ("SEC") on October 28, 2016, LEI undertook a comprehensive re-calculation of the wholesale electricity market analysis. And consequently, LEI submitted the *Update of the Electricity Market Impacts Associated with the Proposed Northern Pass Transmission Project* ("Updated Analysis") on February 15, 2017, which incorporated the most recent FERC-approved demand curves ("Marginal Reliability Impact" or "MRI" curves) in ISO-NE's Forward Capacity Market ("FCM") and more recent natural gas price trends (based on Energy Information Administration's ("EIA") Annual Energy Outlook ("AEO") 2016[1]) into an updated analysis of the wholesale electricity market benefits created by the Project.

Ms. Frayer of LEI was questioned on the Original Report at a series of technical sessions arranged by the SEC in the fall of 2016, and again in March 2017 (in response to the release of the Updated Analysis). In addition, several intervening parties filed evidence in the case. Some of them retained electricity and economic experts – notably Mr. Fowler on behalf of the New England Power Generators Association ("NEPGA") and The Brattle Group and Kavet, Rockler & Associates, LLC ("KRA") on behalf of the Counsel for the Public ("CFP").

The Brattle Group and Mr. Fowler disagree with LEI primarily on the magnitude of the estimated capacity market benefits created by Northern Pass, which account for over ninety percent of the forecast wholesale electricity market benefits. This report responds to the questions raised by The Brattle Group and Mr. Fowler about the robustness of LEI's estimated capacity market benefits, and shows that LEI's analysis is sound.

On the energy market side, The Brattle Group agreed with LEI's estimation of the energy market benefits, but neither explicitly agreed with or took issue with LEI's identification of other benefit metrics that are important to the evaluation of the Project. Accordingly, this report also points out those significant omissions, carbon emissions reductions, system efficiency improvements (production cost savings), and the relevance of those benefits to public interest.

On the local economic impact analysis, KRA agreed that "in general, the economic impact analysis by LEI was well-performed."[2] However, KRA also performed their own local economic analysis using the same modeling tools as LEI. In LEI's examination of KRA's work, LEI found a number of discrepancies and data-related errors, as well as more conceptual flaws and improper assumptions. LEI has therefore corrected the KRA analysis for these issues and presents in this rebuttal a revised aggregate local economic impact analysis that uses KRA's

[1] The complete Annual Energy Outlook 2016 was released on September 15, 2016.

[2] See Pre-filed Testimony of Thomas E. Kavet (same as the Pre-filed Testimony of Nicholas O. Rockler), Page 3, Line 5. Docket No. 2015-06. Dec 30, 2016. Also See *Economic Impact Analysis and Review of the Proposed Northern Pass Transmission Project*, Dec 30, 2016. Page 2.

component approach but adjusts for areas of disagreement between KRA and LEI (and other experts retained by the Applicants) .

1.1 Wholesale electricity market in New England is composed of several distinct but integrated product markets

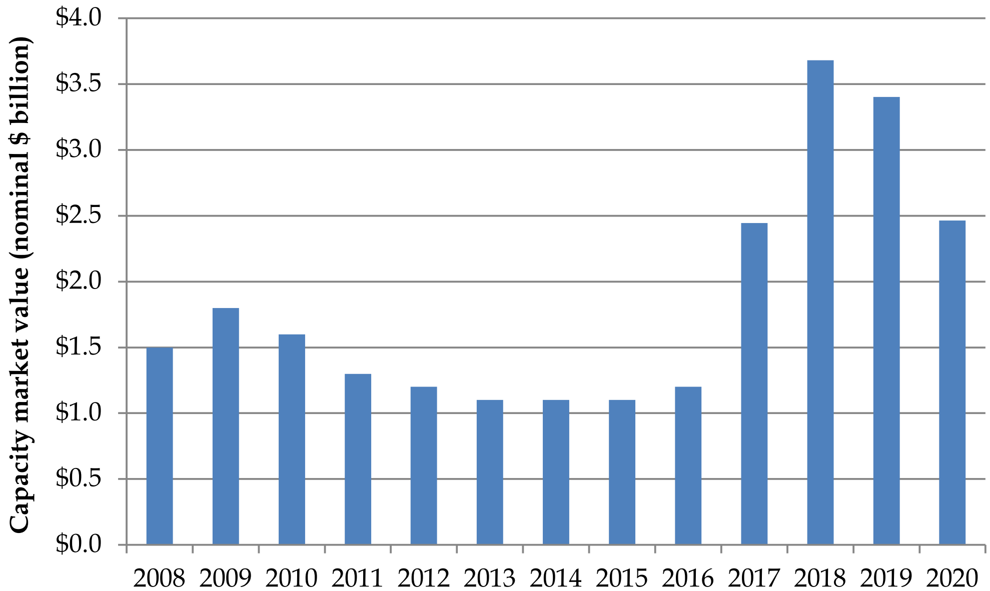
In order to understand why the interveners' concerns and criticisms of LEI's wholesale electricity benefits analysis are unfounded, a high level understanding of the electricity market in New England is essential. The electricity market creates a competitive framework for the procurement of electricity to meet consumers' needs. There are three basic product markets that make up the electricity market: energy, capacity, and ancillary services. Different types of suppliers – different generation technologies with varying cost structures and even demand-side resources – compete to sell their services in these three product markets. The overarching purpose of the market from the perspective of the wholesale market operator, ISO-New England ("ISO-NE"), is to allow market forces to dictate the selection of lowest cost resources to meet consumer demand for electricity at each hour of each day, and to ensure that there are sufficient resources at any given moment to generate enough electricity to guarantee reliable service to consumers.

In the current market design in New England, the variable costs of operations such as fuel costs, variable operating and maintenance ("O&M") expenses, and emissions costs are remunerated through the energy market. These variable costs of operation are essentially short run marginal costs ("SRMC") for producing electricity. It would not be economically rational for a supplier to agree to produce energy and offer to sell it in the energy market if it cannot cover its SRMC. As a result of the single clearing price process in the energy market, some generators may earn some profits from the energy market above and beyond their SRMCs. However, the "marginal" generator whose SRMC costs set the clearing price of energy does not earn any profits above its SRMC.

Fixed costs, on the other hand, are not necessarily covered by the energy market. These fixed costs – which include fixed O&M expenses and return on and return of capital – are monetized and recouped through ISO-NE's capacity market, the Forward Capacity Market ("FCM"). ISO-NE also operates an ancillary services market, where it compensates certain qualified generators for additional services that the ISO needs in order to ensure reliable system operations. Historically, the energy market has been the largest product market in terms of total cost (or market value), but the cost of the capacity market has been growing with time, as shown in Figure 1 on the next page, and especially in recent years once the demand curve was introduced into the market and the supply-demand balance tightened.

Some jurisdictions around the world that have deregulated their electricity sector have opted for a different market design – where they have just an energy market. In such a case, the capacity payment to generators is still part of the market price – but it is not standalone and it is embedded in the price of energy. Therefore, over time in an energy-only market, energy prices would be composed of both the SRMCs and the fixed costs of operation for the marginal (price-setting) resource. A competitive electricity market, regardless of the market design choices or the specific market rules, cannot be sustainable if it cannot provide for recovery of both the SRMC and fixed costs of operation. Market operators and policymakers recognize these issues.

Figure 1. Annual market value of wholesale capacity market

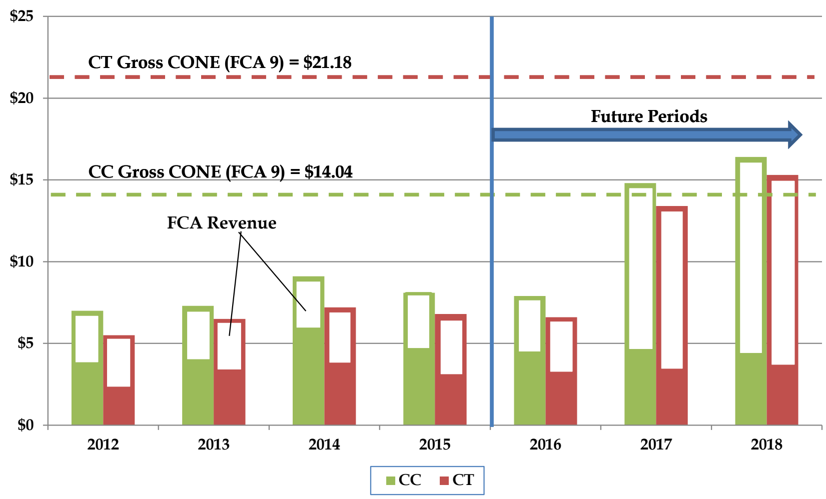


Source: For data between 2008 and 2016, based on ISO-NE, "ISO-NE Overview and Regional Update", Vermont House Committee on Energy and Technology and Vermont Senate Committee on Natural Resources and Energy, January 27, 2017. For data post 2016, costs are calculated based on ISO-NE's press releases for FCA results

It would be unrealistic to project a future world in New England where capacity market rules have changed so much as to reduce the scope of the capacity market without any offsetting adjustment to other product markets (energy and ancillary services) or other income sources (outside the ISO-administered markets). Indeed, ISO-NE's current expectation is that the capacity market will only grow with importance over time, to offset the various exogenous factors that continue to put downward pressure on the value of the energy market. This understanding was clearly shown in ISO-NE's 2015 Annual Market Report.[3] LEI has replicated a chart from ISO-NE's 2015 Annual Market Report in Figure 2 below. This chart shows the expected composition of income from the various ISO-NE product markets for a generic gas-fired plant over time – historically and in the future. Net revenues from energy are represented by the solid bar segments, while capacity market revenues are presented as the outlined bar segments. These are then stacked to compare total expected net revenue to the characteristic cost of new entry (as represented by the horizontal lines). If the size of each segment is compared, it is clear that ISO-NE forecasts growing capacity market revenues in the future.

[3] Source: ISO-NE, ISO New England's Internal Market Monitor, 2015 Annual Markets Report, May 25, 2016

Figure 2. Estimated net revenue from energy and capacity markets for new gas-fired generators



Source: ISO-NE, ISO New England's Internal Market Monitor, 2015 Annual Markets Report, May 25, 2016

Note: Solid bar segments represent the energy market revenues while capacity market revenues are presented as the outlined bar segments.

Very recently, this view was further emphasized in an ISO-NE presentation to state legislators in Vermont. ISO-NE stated: "*New England is moving toward a "hybrid" grid with grid-connected and distributed resources, and a continued shift toward natural gas and renewable energy…….The electric grid of the future will require renewable resources to meet policy goals for clean energy, but also require adequate capacity as a backup when renewable resources cannot deliver energy to consumers…….The capacity market will be an important revenue balancing mechanism to ensure resource adequacy as renewable resources drive down revenues in the energy market.*"[4]

1.2 Capacity market benefits of Northern Pass are linked to the size and design of the capacity market

The current market design, coupled with the market dynamics seen today, supports LEI's forecasted capacity market benefits associated with Northern Pass. Textbook economic theory suggests prices will fall when one introduces new supply into a market. That outcome - response to new supply- is the cornerstone of the competitive electricity market.

LEI, along with ISO-NE, generally expects higher capacity prices as a result of a lower energy price environment.[5] The lower energy prices are expected to continue because of investments in

[4] ISO-NE, "ISO-NE Overview and Regional Update", Vermont House Committee on Energy and Technology and Vermont Senate Committee on Natural Resources and Energy, January 27, 2017.

[5] The additional supply has limited capability to move energy prices further down due to low gas prices and the shape of the supply curve in the energy market. LEI's delivered New England gas price is assumed to be in the range of $5/MWh in 2020 under the Updated Analysis. Higher gas price levels would lead to higher energy market benefits, all things being equal. Furthermore, New England is moving toward a fuel mix that is ever more reliant on natural gas-fired capacity. Natural gas-fired generation is the most frequent fuel on the margin - setting energy market prices. The big influence of natural gas-fired generation in energy price setting

zero SRMC renewable resources to meet the state renewable policy goals and as a result of lower-cost natural gas supply from Marcellus. The addition of zero SRMC renewable supply extends the supply curve to the right and the low natural gas price pushes the supply curve down. However, even as energy prices get pressured down, the system will still need to ensure that dispatchable (non-intermittent) resources are available to backstop resource adequacy requirements. Therefore, while energy prices will stay low, capacity prices need to rise to make up for the lower energy prices in order to retain sufficient dispatchable resources. Higher capacity market prices will need to be sufficient to keep existing resources in the market and attract new resources to come to the market when they are needed.

In conjunction with higher capacity market prices, it is also reasonable to see relatively high capacity market benefits from new supply. Capacity market benefits are a function of price levels– so if capacity prices are high before the new supply is added, then by definition, capacity price reduction and capacity market benefits will also be significant (since capacity benefits are a function of capacity price reduction caused by the new supply). Northern Pass is a considerable infrastructure investment, and it will take some time to fully absorb the 1,000 MW capacity supply, which creates the more lasting (multi-year) benefit.

It is important to note that the capacity market benefit LEI is forecasting for the Project is no different from the capacity market benefits that have been created by new generation and demand-side resources in recent years. For example, LEI has calculated that consumers are enjoying capacity market benefits in the range of $1.7 to $2.2 billion per year due to the new resources that entered and cleared FCA#9 and FCA#10.[6]

1.3 Interveners' concerns as to the magnitude of the capacity market benefits of Norther Pass are baseless

Several interveners in these proceedings, notably Mr. Fowler and The Brattle Group, described various concerns that LEI's estimates of Northern Pass' wholesale capacity market benefits could be overstated in their reports and testimonies. These concerns, which invoked technical issues, market rules, and commercial consideration, include the following:

is due to the shape of supply curve relative to demand. There is so much gas generation in the supply stack, that the introduction of new non-gas energy tends to have a muted impact at most levels of demand. In addition, the ever growing share of renewables or other zero SRMC resources further helps to dampen the shape of the energy market supply curve as it pushes more efficient gas unit more frequently to the margin. Demand levels generally land in the part of the energy supply curve where gas is located – even the low periods of demand. In summary, under normal operating conditions, there is limited room to reduce energy prices significantly given the flat shape of the supply curve.

[6] The calculation is based on the publicly available data on the shape of demand curves that were in place in those prior FCAs. LEI can deduct the capacity price that would have occurred in those prior auctions but for the new supply. In FCA#9, 1,010 MW of new gas-fired capacity cleared the auction, while 1,302 MW of new gas-fired capacity cleared in FCA#10. If this amount of new gas-fired capacity had not cleared in FCA#9 and FCA#10, New England's capacity prices would have been $4/kW-month to $6/kW-month higher, and as such capacity market costs would have been materially higher in the future deliverability periods associated with each of those auctions.

- Does Hydro-Québec Production ("HQP") have sufficient energy and capacity supply to offer 1,000 MW of capacity into the FCM?
- Will HQP's proposal to sell capacity over Northern Pass pass the Minimum Offer Price Rule ("MOPR") in FCM (and allow HQP to clear its 1,000 MW capacity in the FCA)?
- Will HQP be willing to take the Capacity Supply Obligation ("CSO") in ISO-NE's FCM, given the risk associated with Capacity Performance Payments ("CPP")?

This report demonstrates that questions about Northern Pass' ability to provide 1,000 MW of capacity market benefit are unfounded because:

- LEI's outlook for HQP supply and demand shows that HQP does have more than sufficient surplus capacity to export 1,000 MW over Northern Pass into New England;
- LEI does not expect deliverability of Northern Pass' capacity to be an issue, since ISO-NE and the applicant have already performed studies to identify required transmission upgrades, if any;
- LEI's estimate of the MOPR that could be applied to HQP's capacity offer through Northern Pass will be much lower than the expected future FCA clearing prices and therefore the MOPR will not inhibit HQP's offer of 1,000 MW of capacity; and
- FCA revenues for HQP far outweigh risks associated with CPP, as demonstrated by HQP having already acquired significant CSOs for Capacity Commitment Periods which are subject to CPPs.

The concerns raised by Mr. Fowler and The Brattle Group were the result of a lack of serious analysis on their part. Notably:

- both Mr. Fowler and The Brattle Group demonstrated their lack of familiarity with the Québec electricity sector and Hydro-Québec in particular;
- The Brattle Group reviewed the wrong data sources to assess the supply and demand projections for the shipper on Northern Pass (HQP); and
- neither Mr. Fowler, nor The Brattle Group, performed any analysis related to the MOPR issue to prove the validity of their hypothetical concerns.

1.4 LEI's integrated energy and capacity models realistically reflect the dynamics in the New England electricity market and produce a much more accurate depiction of future market outcomes in contrast to The Brattle Group's stylized capacity market model

In the Updated Analysis issued in February 2017, LEI incorporated the latest market rules into its proprietary capacity market model. Even with the significant change in market rules adopted by ISO-NE in 2016, LEI's Updated Analysis demonstrates that there are still significant capacity market benefits being created by Northern Pass. To a great degree, capacity market benefits are resilient to changes in market rules. Even with evolving market dynamics, the capacity market continues to provide a sufficiently robust level of remuneration to resources in order to both attract investment and keep existing resources online. The CFP would like the SEC to believe that there are yet unknown future market rule changes that would reduce the capacity market and thereby the capacity market benefit – but that is simply antithetical to a sustainable market design and in conflict with ISO-NE's own forecasts. LEI agrees that the market design and market rules will undoubtedly evolve over time, but it is incorrect to wager that those changes will always move to reduce the size of the market and marginalize the impact that new supply has on the market. Rather, it should be posited that market changes will happen and that each change in isolation could increase or decrease electricity market benefits of new supply – but in the aggregate, market rules changes cannot ignore the price-reducing effects of increasing supply, as that is the cornerstone of competitive markets.

In its capacity market model, LEI relies on a detailed, plant-specific supply curve that is built from the bottom up by modeling specific generators and estimates of their minimum going forward fixed costs. The supply curve reflects the current technology mix and can handle retirements and new entry. Moreover, the supply curve in combination with the MRIs simulates FCA outcomes that are consistent with rational behavior. LEI's model looks at the opportunity cost of going forward decisions for all kinds of resources, new investment, existing generators, and import resources, on an integrated basis with LEI's energy market simulation.[7] For example, if a generator forecasts that it is not going to be performing well in the energy market, and that it cannot earn a sufficient capacity price to cover the costs of providing capacity, it may decide to submit a delist bid, and eventually that will lead to a retirement decision. In addition to considering delisting activities, LEI's capacity market model also reviews the retirement decisions for existing generators and assesses the entry decision for new resources, based on realistic assumptions on different new entrant technologies. In contrast, The Brattle Group's analysis was based on abstract economic proxies for supply and generic assumptions about new entry; the *ad hoc* tool that they created for the singular purpose of this engagement was never tested in the real world, nor employed by The Brattle Group in other engagements. The Brattle Group's negative bias to capacity market benefits is not limited to their *ad hoc* capacity market tool – it also arises in their scenario approach. The Brattle Group's scenario-based analysis is flawed given its focus on detailing only those scenarios that reduce the electricity market benefits of Northern Pass. The Brattle Group conceded that they started with Scenario 1 in their analysis, which is the scenario that is closest to LEI's estimates. They then proceeded to create hypothetical fact patterns that would reduce the wholesale capacity market benefits – all the way down to zero under Scenario 4. For all these reasons, LEI recommends that the SEC put little weight on The Brattle Group's estimate of wholesale capacity market benefits for Northern Pass.

On the issue of energy markets and carbon emission reduction analysis, The Brattle Group adopts LEI's analysis (for the most part) or creates alternative calculations that essentially align with LEI's estimates. Importantly, The Brattle Group also acknowledge that Northern Pass could produce other benefits, some of which they have estimated in other engagements, but examination of those other benefits was outside the scope of their current mandate with the CFP. LEI has provided some additional clarifications on these additional measures of benefit for the SEC's consideration in this rebuttal report.

[7] The lack of integration between The Brattle Group's energy analysis and *ad hoc* capacity market tool also results in an internally inconsistent outcome, leading to an under-estimation of electricity market benefits.

1.5 KRA's estimate of the long-term aggregate local economic impact needs to be corrected for various input errors and methodological flaws

While KRA and LEI shared some common ground, LEI is concerned with the robustness of KRA's analysis, especially the aggregate long-term analysis that examines the combined effect of various factors associated with the Project on the New Hampshire economy. KRA's analysis is based on certain flawed assumptions, and in some cases, erroneous inputs. Moreover, the proposed timeframe of KRA's long-term analysis is far too long – and therefore the results being reported in the last three decades of the 2016-2060 timeframe are especially unreliable. Finally, KRA, like The Brattle Group, put significant effort into identifying negative aspects not captured in LEI's analysis and then monetizing their effects so as to reduce the estimated local economic benefits of the Project, while ignoring positive externalities associated with the Project. To demonstrate the impact of the principal flaws that LEI discovered in KRA's analysis, LEI has re-run that analysis after correcting for the specific mistaken inputs and implausible assumptions that LEI and other experts identified, while maintaining KRA's component level aggregation methodology.[8]

[8] In addition, KRA pointed out what it believed were model specification errors in LEI's analysis, which KRA asserted led LEI to overstate the economic impacts of the Project. However, as shown in this report, these comments were based on a misunderstanding of LEI's modeling methodology and working papers.

2 LEI's estimated wholesale capacity market benefits are more realistic and more reliable than those forecast by The Brattle Group

LEI's overall approach to calculating the wholesale electricity market benefits of Northern Pass has been to measure the difference in market prices between a world that develops without Northern Pass (Base Case) and a world that develops with Northern Pass (Project Case). In doing so, LEI has opted to remain "conservative" in the sense that LEI has not included all the indirect benefits that the Northern Pass could provide, and by using inputs that still leave significant room for upside. This section discusses how LEI modeled the New England capacity market to derive capacity market benefits, and addresses the key criticisms and analyses that other parties have put forward.

2.1 LEI's analysis captures the latest capacity market design

In the course of the first round of technical sessions (Fall of 2016) and in written pre-filed testimonies filed in December 2016, NEPGA criticized LEI for not considering the latest market rules for the ISO-NE capacity market in LEI's October 2015 Report.[9] In LEI's Original Report, LEI did use the prevailing capacity market design at the time, in which the FCM price cleared along a linear downward sloping demand curve.[10] However, by the time discovery began, in mid-2016, new market rules had been formulated by the ISO-NE and accepted by FERC.[11]

LEI submitted an Updated Analysis in February 2017,[12] which incorporates the new market design into the capacity market modeling. Both The Brattle Group and Mr. Fowler confirmed at their technical sessions in February and March 2017 that LEI's Updated Analysis takes into account the new capacity market design. Moreover, the Updated Analysis demonstrates that despite the market design changes, there are still significant capacity market benefits being created by Northern Pass.

2.2 Capacity market benefits are resilient to changes in market dynamics

The CFP was also concerned that there could be a pattern of reduced capacity market benefits. That is a possibility, but it is important to remember that there are many drivers that influence capacity prices in New England, which will undoubtedly evolve over time. Also, changes in market rules and capacity market parameters are not guaranteed to move market outcomes in a

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9 For example, William Fowler's Pre-Filed Testimony on behalf of NEPGA

10 ISO New England Inc. and New England Power Pool, Docket No. ER14-1639-000, Demand Curve Changes

11 By April 2016, ISO-NE had filed with FERC a new demand curve based on engineering and economic principles, which is known as the Marginal Reliability Impact ("MRI") based demand curve. This filing also included information about how ISO-NE would model import-constrained and export-constrained capacity zones, which had their own zonal demand curves. Because of the timing of ISO-NE's filing of the MRI-based demand curve, LEI's Original Report could not have accounted for this update. The Brattle Group acknowledged this on page 10 of their December 2016 Report.

12 This Updated Analysis was submitted as part of a Motion to Compel by the New Hampshire Site Evaluation Committee that required LEI to update the capacity market design and to update natural gas prices to reflect the EIA Annual Energy Outlook 2016 forecast.

singular direction. Future changes in market designs or market developments could increase or decrease wholesale electricity market benefits of Northern Pass.

For example, market developments such as a significant unexpected generation retirement or a disruption in the natural gas pipeline network would likely push both energy and capacity market prices up, and therefore a project like Northern Pass would deliver higher electricity market benefits. Changes in capacity market designs may in fact increase the benefits of Northern Pass, as New England experienced when it first moved to the downward sloping demand curve in FCA#9. Changes in market rules can also result in counteracting effects on electricity market costs because of the linkages between energy and capacity markets. For example, ISO-NE's recent decision to lower the Net Cost of New Entry ("Net CONE") and change the reference technology from a combined cycle plant to combustion turbine peaking plant will, on the one hand, temper capacity market benefits from new supply because it will drive capacity price levels lower (e.g. new capacity can enter the market more cheaply). On the other hand, the change in the reference technology will increase the energy market benefits, because unlike combined cycle plants, peakers run more infrequently and therefore the power flowing through Northern Pass will have a greater and longer lasting impact on energy prices. As these and other examples in this report will demonstrate, electricity market benefits from new supply would never be zero, even if market rules continue to evolve. In addition, some changes may even cause benefits to rise.[13]

There were also some concerns raised about how lower peak demand or increased energy efficiency may affect the benefits of Northern Pass. Lower peak demand or increased energy efficiency may shift the timing of the benefits of Northern Pass, but it does not extinguish them. In response to data request TS 11 1-4, demonstrating the ways in which increased levels of energy efficiency clearing the capacity market would impact the expected benefits of Northern Pass. The results show that the addition of an average of 183 MW per year of energy efficiency from FCA#11 to FCA#21 slightly improved both the energy market and capacity market benefits of Northern Pass. The reason is that incorporating passive demand response creates more oversupply in both the Base Case and Project Case – on a cumulative basis, just over 2,000 MWs more of supply by FCA#21, and therefore lowers the capacity price levels projected in future FCAs under both the Base Case and Project Case. However, the average price differences, and thus market benefits, over the modeling timeframe between the Base Case and Project Case are not significantly different because the benefits *last longer*. The reason that the benefits last longer is because the energy efficiency will cause the system, in both the Base Case and Project Case, to take longer to reach equilibrium, thereby delaying new generating investment by a few more years.

[13] Mr. Fowler noted during the March 2017 technical sessions that he was not expecting the market to change in the future as significantly as the switch to the MRI-based demand curve in 2016, when asked by the CFP. Mr. Fowler also agreed that market rule changes could also lead to higher benefits.

2.3 Concerns over the effect of price separation in Northern New England ("NNE") are over-stated

Mr. Fowler also stated in his December 2016 testimony, and in the March 2017 technical session, that he expected Northern Pass to create price separation in the NNE capacity zone. As discussed in Section 2.2.1 of LEI's "Updated Analysis", LEI does not forecast price separation in either NNE under LEI's Base Case or Project Case based on the projected resources in NNE and the rest of the system. In the event that more supply clears in NNE than LEI modeled and price separation is indeed triggered, it is likely that the capacity market benefits from Northern Pass would be even higher for New Hampshire ratepayers, and not lower, as The Brattle Group's corrections to their analysis demonstrates.[14]

Zonal price separation does not depend only on the resources added in the NNE zone, but also on the supply that exists in the rest of the system. In general terms, there is a lower chance of price separation between NNE and the rest of New England when there is less supply in NNE or in the rest of the system. A key value that determines the likelihood of price separation is the Maximum Capacity Limit ("MCL"). The MCL by definition is the maximum amount of resources that can be purchased within an export-constrained Load Zone. For the NNE capacity zone, the MCL is calculated as the difference between (a) New England ICR (the total amount of resources that need to be procured within New England) and (b) the Local Resource Adequacy ("LRA") Requirement for the Rest of New England (the minimum amount of resources required for that area to satisfy its reliability criterion).

$$\boldsymbol{Maximum\ Capacity\ Limit_{Y} = ICR - LRA_{RestofNewEngland}} \qquad \textbf{(1)}$$

LEI has described its approach for calculating the MCL for each year in response to data request TS 11 1-6. This approach is based on publicly available information, as well as LEI's own supply and demand outlook.[15] As the MCL changes over time (and shifts to the left and right), the NNE local MRI-based demand curve also shifts at the same approximate level.[16]

Figure 3 shows how the NNE zonal demand curve shifted from FCA#11 to FCA #12, and the corresponding congestion price for each MW of capacity in the capacity zone. In LEI's analysis, the MCL grows in FCA #12 as a result of an expected decline in the LRA. After accounting for

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[14] The Brattle Group re-issued their report and the accompanying pre-filed testimony on February 10, 2017 to correct and replace certain values.

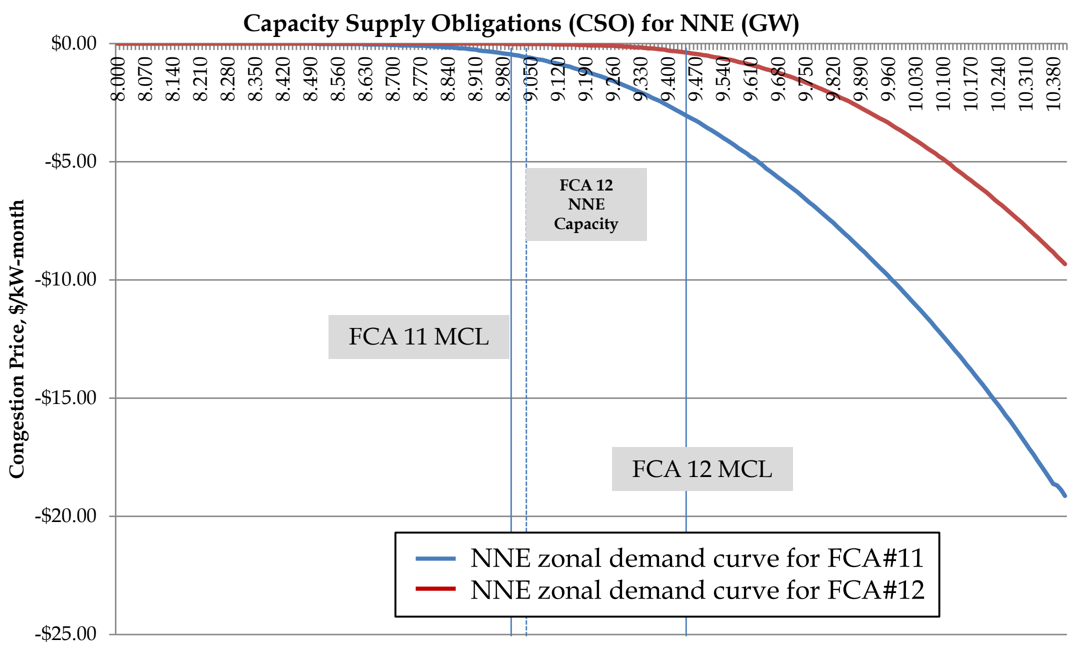
[15] The forecast of New England NICR that LEI used in its modeling is shown in response to data request TS 11 1-9. The LRA for the Rest of New England was projected using ISO-NE's formula and as outlined in Market Rule 1, Section III.12.2.1. For LEI's February 2017 Updated Analysis, LEI reviewed and referenced the ISO-NE presentation "Proposed Installed Capacity Requirement (ICR) Values for the 2020-2021 Forward Capacity Auction (FCA11FCA#11)" at the Reliability Committee Meeting dated October 4, 2016. The presentation can be accessed electronically from this URL: https://www.iso-ne.com/static-assets/documents/2016/09/a2_2020_21_fca11_icr_values_results.pdf

[16] LEI's analysis incorporated Northern Pass' indirect impacts on the NNE export capability itself. The Project will likely involve upgrades to the system that would increase the North-South transfer limit and increase the transfer capability between NNE and the rest of the system, thereby reducing the likelihood of price separation.

retirements and new wind additions in NNE, Northern Pass results in a net increase of approximately 496 MW in NNE or a total of 9,046 MW that cleared in NNE (see the vertical dotted line labeled "FCA#12 NNE Capacity"). Using the FCA #12 local demand curve that LEI estimated based on MCL growth, this does not result in price separation (as can be seen in Figure 3, by looking where the dotted line labeled "FCA#12 NNE Capacity" and the red curve labeled "FCA#12 NNE zonal demand curve" intersect - it is a zero price).

If New England does undergo price separation, it is unlikely to lead to the negative outcomes that Mr. Fowler hypothesized in his December 2016 testimony. For the sake of argument (using Figure 3 as an example), if the MRI curve stayed fixed at FCA #11 level, this would result in a congestion price of less than $0.60/kW-month for FCA #12 (in Figure 3, the dotted line labeled "FCA #12 NNE Capacity" and the red curve labeled "FCA#11 NNE zonal demand curve" intersect at $0.60/kW-month along the Y-axis). Even at this level of price separation, it is not likely to be sufficient to trigger NNE generators to exit the market and negatively impact New Hampshire consumers. The results of FCA#11 from February 2017 show that even at a $5.29/kW-month capacity price level, generators were willing to stay in the market.

Figure 3. Shift in the NNE zonal demand curve for FCA#12



By design, capacity market prices in NNE cannot clear higher than those in the rest of New England. This is because the demand for capacity is highest in the rest of New England. Therefore, if more resources clear in NNE than what LEI modeled, it is likely that the capacity market benefits would be even higher for New Hampshire ratepayers relative to the rest of

New England, not lower, because the reduction in capacity prices will mean that the NNE region will be paying less for capacity. [17]

The Brattle Group's analysis shows minor price separation in NNE in the Project Case, due to the way in which they shifted the zonal demand curve over time. The Brattle Group used the ISO-NE-generated NNE zonal demand curve (as LEI had done), but then shifted the curve to the right each year based on the peak demand growth in the NNE region instead of the growth in the MCL. Price separation is a function of not just the supply and demand in the NNE region, but also the supply and demand conditions in the rest of the system. Shifting the NNE local curve by only the NNE peak demand does not take into account the LRA for the rest of New England.

2.4 LEI's capacity market model realistically accounts for market response

Several parties suggested that LEI's capacity forecasting model was not capturing market response. LEI strongly disagrees with this characterization because LEI's approach resulted in approximately 500-600 MW of market response in the Project Case of the Updated Analysis for the first few years of the forecast timeframe, as well as three years of deferred new generation investment. LEI's capacity market model is specifically designed to emulate market dynamics as realistically as possible. A key feature of LEI's model is that it offers the ability for resources to rationally respond to changes in the market, based on the alternatives that are available to them and an endogenous assessment of those alternatives.

2.4.1 Existing resources

LEI's capacity market analysis starts with the four basic options that generation resources in New England have: i) stay in the market as a price taker, ii) offer a static delist (exit the market once the price falls below the resource's IMM approved offer price), iii) offer a dynamic delist (exit any time below the dynamic delist bid threshold), or iv) offer a retirement delist (permanently retire). At the March 2017 technical sessions, The Brattle Group agreed that these were the options that capacity resources faced.[18,19] However, The Brattle Group's approach to

[17] The Brattle Group showed directionally that increased levels of price separation in NNE increased the capacity market benefits for New Hampshire. The Brattle Group's December 2016 Report showed that there was very little price separation in the Project Case which subsequently disappeared after a few years. However, after making edits to their analysis in February 2017 to include transmission imports from New Brunswick and existing HQ resources as part of NNE capacity, price separation increased (albeit marginally). And consequently, the lower NNE capacity prices increased the capacity market benefits for New Hampshire.

[18] See Section 2.6 for a discussion of The Brattle Group's capacity market modeling approach.

[19] In LEI's capacity market modeling, only plants that are projected to have economic losses on their net going forward costs for multiple years permanently retire. Static delists were limited to resources that were found by LEI to have high net going forward fixed costs. Lastly, dynamic delists would be triggered only in circumstances where capacity prices get so low as to not cover expected costs of the performance obligation (or in the case of imports, where capacity prices in New England are lower than the expected capacity prices available to those resources in alternative destination markets). In the aggregate, LEI's model captures more of the real world dynamics because it more closely reflects the possible options that generators face; this contrasts with The Brattle Group's capacity market analysis where each hypothetical megawatt of supply can only make an economic decision to stay in the market or statically delist. In reality, another economic decision available to

the capacity market only allows for two options to be economically determined: i) whether a resource should to stay in the market as a price taker or ii) statically delist. Retirements are determined outside of the model.

In his December 2016 testimony (p.23), Mr. Fowler mischaracterized LEI's original report as making the unrealistic assumption that "all generators in NNE will stay in an FCM auction, no matter how low the price goes" and that Northern Pass would cause NNE capacity prices to separate by $3.60/kW-month as compared to the $7.03/kW-month price for the rest of the system (thereby resulting in a NNE price of $3.63/kW-month). However, as clarified during his technical sessions on March 6, 2017, Mr. Fowler created this numerical example arbitrarily. He did not perform any quantitative analysis. Rather, Mr. Fowler simply added the FCA#10 resources that cleared in NNE (8,521 MW) to the 1,000 MW CSO from Northern Pass and juxtaposed the total on the FCA#11 MRI demand curve. This exercise is an over- simplification of market supply dynamics and an incorrect characterization of LEI's analysis, precisely because LEI does take into account market response based on all the options that capacity resources have available to them.

2.4.2 New investment

In addition, it should be noted that the market response embedded in LEI's capacity model is not limited to existing generation resources. It can also take the form of deferred investment. In LEI's Original Analysis and Updated Analysis, Northern Pass is found to defer new investment for a number of years. The results are shown in Figure 24 of Section 6.5 in LEI's "Updated Analysis." As a result, new resources are expected to come into the market only when capacity prices reach the level of Net CONE.

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capacity suppliers is to dynamically delist. Furthermore, the costs of an exit or retirement decision creates "supply stickiness," which means that resources will prefer to stay in the capacity market and earn a little less;. As such, static delists are limited, and dynamic delists are typically not triggered as resources committed to continuing operations prefer to get some capacity revenue in lieu of zero capacity revenues. These principles that are consistent with market activity observed over the years in the FCM and in the most recent FCA, specifically, in FCA#11, at $5.29/kW-month capacity price, very few resources delisted. A review of the trends in past FCAs with respect to existing resources suggests that existing resources are not as price sensitive as Mr. Fowler and The Brattle Group suggest.

Part of the reason why more existing resources did not delist at $5.29/kW-month in FCA#11 is because the descending clock auction construct economically motivates resources to stay in the market so long as their costs of performance are being recouped through the capacity price. In other words, dynamic delist bids are keyed off the cost of accepting a CSO (in the form of CPP). So long as the capacity price exceeds the expected cost of the CPP, it is rational for a resource to stay in the FCA, accept a CSO and not to dynamically delist. Even if the capacity price does not cover all fixed costs, a generator should be willing to accept a CSO and get some capacity revenues in lieu of getting nothing from the capacity market. During the March 2017 technical sessions, Mr. Fowler agreed that this assumption was reasonable.

LEI calculated the expected shortage hours in the Base Case and Project Case, and calculated the expected CPP and the risk premium, which represents the "true floor" in capacity prices. LEI found that at the capacity price levels forecasted in the Base Case and the Project Case in the Updated Analysis, resources would be economically motivated to stay in the market. Under the Project Case, the total PFP risk was estimated at $1.63/kW-month in FCA #11 and rose to $3.55/kW-month by FCA #21. LEI's Project Case also considered import delists, another form of market response, as discussed in Section 2.4.3.

2.4.3 Imports

LEI's market response also included reductions in capacity imports from New York. Resources from outside of New England (such as New York) are priced based on the opportunity cost relative to their respective local market. This is explained in Section 6.2 of LEI's February 2017 Updated Analysis. In determining what resources would delist from the FCM, the Brattle Group did not explicitly consider capacity import delists. However, in the March 2017 technical sessions, the Brattle Group did agree that import delists were a reasonable market response.

If prices in a capacity import resource's local market are very low (for example for Upstate New York resources) or non-existent (such as the case for New Brunswick resource), then those resources would be relatively inelastic and willing to sell into New England at fairly low capacity prices. Nevertheless, for import resources from New York, the decision to continue to sell capacity into New England is contingent on whether capacity prices in New England are higher than those in their local market. If New England capacity prices fall or the New York capacity prices rise, these New York capacity imports would rationally move back to sell in New York.

In LEI's Updated Analysis, LEI took into account the announced generation retirements in New York and factored this into New York's most likely capacity price outlook to determine what the opportunity cost would be for those imports selling capacity to New England. The outcome of the recent FCA#11 confirms the accuracy of LEI's analysis, whereby approximately 500 MW of New York capacity imports delisted in FCA#11.

2.5 LEI's capacity market model inputs are based on publicly available data and outputs are verifiable

Apart from proprietary plant specific fixed costs estimates that are proprietary to LEI's model, all other inputs used in LEI's capacity market model are sourced from publicly available information, details of which were provided to Brattle Group. The plant specific fixed cost estimates are based on LEI research of public records, extrapolation from ISO-NE documents, and survey of generators.

In spite of the extensive description provided by LEI in written data requests and orally at the technical sessions, certain intervenors continue to allege that they cannot verify LEI's FCA simulator. This is surprising since the fundamental principles that inform the market clearing process in the model are based on the market rules, which everyone has the ability to review. In addition, the model logic is described in numerous documents.[20] [21] Market rules, description of the model logic, coupled with all the inputs and outputs that LEI has provided, are sufficient for any market expert to verify and judge LEI's modeling results, for example, by evaluating the

[20] Most recently, LEI has described in response to data request TS 11 1-14 to provide an explanation and justification of the projected price dynamics that the model is producing.

[21] LEI has used its modeling tools repeatedly with many diverse clients, advising on many asset mergers and acquisitions over the years and hundreds of millions of dollars contract negotiations and financings. LEI's models have been vetted throughout years of use, and it has been adapted as new market rules emerge and supply-demand conditions change.

inputs for reasonableness, by comparing the inputs and outputs to actual market outcomes, and by benchmarking LEI's modeling results to their modeling results or other benchmarks such as the long run expected price or "equilibrium price" that Mr. Fowler referred to during his March 6, 2017 technical sessions.

2.6 The Brattle Group's stylized capacity market model does not realistically capture supplier behavior in the FCA, leading to an under-stated capacity market benefit estimate

The Brattle Group's economic model used for the purposes of capacity market analysis is a stylized economic model, meaning that is not based on the characteristics of individual resources in New England, but rather is intended to demonstrate in a generalized way, how many megawatts are expected to clear based on the intersection of supply and demand curves.[22] In other words, The Brattle Group's model does not have actual New England plants that make up the supply curve.

2.6.1 Unrealistic amounts of implied static delists

The Brattle Group's supply curve is unrealistic for two reasons: (i) the supply curve assumes large amounts of implied static delists and (ii) it assumes unlimited quantities of new investment in "perfect" amounts and on a "just in time" basis. Mr. Newell of The Brattle Group noted during the March 2017 technical sessions that The Brattle Group's model implicitly has 2,500 MW of static delist every year, as that is the level of MWs assumed to be above the DDBT. Not only is this inconsistent with what is observed in recent FCAs, but it also does not realistically reflect the economic decision-making of generation resources in the FCM. As noted earlier, in a competitive market, resources are economically motivated to stay in the market so long as their costs of performance are being recouped through the capacity price. The Brattle Group's assumption of 2,500 MWs of static delists (which must leave the FCA once the capacity price goes below $5.50/kW-month), implies that the owners of these resources will be willing to earn nothing.[23] Even as Mr. Fowler noted during his March 2017 technical sessions, a generator should be willing to accept a CSO and get some capacity revenues so long as CPP costs are covered, and Mr. Newell conceded that CPP costs were estimated by ISO-NE staff at $1.80/kW-month for FCA#10. Having too many static delists (as much as 1,083 MW in the Project Case for FCA#12) means that there will always be limited room for any capacity resource to reduce capacity prices in the FCA because an existing resource along the supply curve will always delist in response.[24] However, at the price levels that the Brattle Group has forecasted, this dynamic is neither reflective of observed market outcomes nor rational behavior of market participants that are faced with multiple options in the FCA.

[22] See Page 22 of The Brattle Group Report on how the supply curve is developed.

[23] Resources that delist temporarily or mothball will still incur costs to maintain the plant. Mr. Newell agreed with this point at the March 2017 technical sessions.

[24] The Brattle Group's approach implicitly allows for plants to delist a fraction of their CSO, and for large new resources to offer only a fraction of their CSO.

2.6.2 Unrealistic quantities and timing of new supply

The top portion of the supply curve is based on a $9.00/kW-month Net CONE value that The Brattle Group assumed for a generic combined cycle plant.[25] While this value is slightly below ISO-NE's $10.00/kW-month value for a combined cycle plant, it is not unreasonable. One key issue however, is that the minimum scale for new combined cycle plants is typically around 500 MWs. When adding new entry however, The Brattle Group's analysis does not take this into consideration. The result is that new generation enters the market at the "perfect" quantities (virtually unlimited 1 MW units) to meet NICR, which has the effect of dampening capacity market benefits of any new supply, whether it is Northern Pass or other new supply. Assuming that new resources enter the market at the exact quantities to achieve equilibrium means that capacity prices can never go above $9.00/kW-month (in real terms). Since the capacity market benefits of Northern Pass are a function of the capacity price differences, this assumption limits the benefits that the Project can deliver as the supply and demand tighten.[26] In other words, The Brattle Group's simplified *ad hoc* capacity market tool is too "perfect" in always achieving perfect equilibrium and is therefore an abstract analysis rather than a representation of what happens in the real world.[27]

2.6.3 Unrealistic treatment of the retirements

LEI also disagrees with The Brattle Group's treatment of the retirements and how that treatment those affect the supply curve. The size and timing of retirements are developed ex-ante by the Brattle Group and are not generated by the model. This is essentially an exogenous assumption and not a realistic outcome. The Brattle Group assumes "200 MW per year of retirements between 2020 and 2030, amounting to 2,200 MW out of 5,200 MW of coal-fired, oil-fired, and natural gas-fired steam units currently projected to be operating (after accounting for the planned retirement of Brayton Point 1-4 in 2017 and Bridgeport Harbor 3 coal plant in 2021)."[28] While there is always uncertainty in forecasting plant closures in the context of capacity markets, by levelizing retirements in the way The Brattle Group has done, the capacity market

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[25] ISO-NE developed a $8.04/kW-month value for a single cycle combustion turbine, which it adopted as the reference technology. Combine cycle plants were estimated at $10.00/kW-month. The Brattle Group had agreed that all else being equal, a higher Net CONE should generally result in higher capacity market benefits. Combined cycle plants were chosen by The Brattle Group because they are the most common plant type being constructed in New England. However, Mr. Newell incorrectly stated that no combustion turbines have cleared in recent auctions.

[26] FCA #9 notably cleared at $9.55/kW-month, which is above ISO-NE's latest Net CONE estimate of $8.04/kW-month and The Brattle Group's $9.0/kW-month estimate.

[27] ISO-NE recognizes the lumpiness of investment in capacity markets and states that "it is not possible to clear at the exact intersection of the supply and demand curves because the marginal offer is lumpy." See <https://www.iso-ne.com/static-assets/documents/2016/10/20160926-18-wem101-overview-of-fcm.pdf>. As a result, ISO-NE's market clearing engine is designed to maximize social surplus and minimize deadweight loss.

[28] See Page 27 of The Brattle Group Report. Despite these retirements accounting for nearly half of the 5,200 MW of coal-fired, oil-fired, and natural gas-fired steam units that make up the lower end of the supply curve, it has no impact on the shape of the supply curve in The Brattle Group's tool.

benefits are diminished because the retirements help to smooth out supply changes over time (which helps to create stability in the prices differences between the Base Case and Project Case). In reality, retirements occur abruptly, and often in large chunks, (such as the retirement of Brayton Point and Vermont Yankee) which The Brattle Group's own analysis both recognizes and discusses. Spreading out smaller quantities of retirements over time is akin to spreading out the 1,000 MWs of CSO from Northern Pass over multiple years, thereby smoothing the price impact.

The consequence of perfectly "smooth" capacity market outcomes is a reduction in the price differences between the Base Case and Project Case and therefore the capacity market benefits. In addition, The Brattle Group's capacity model does not allow for the capacity market price to clear beyond a very narrow band of prices, which effectively limits the benefit that any 1,000 MW resource would offer (whether that project is Northern Pass or another 1,000 MW generator).

2.6.4 Uncertainty is not a valid basis for adopting the stylized model

The Brattle Group contended at the technical sessions in March 2017 that their stylized approach to modeling capacity market inputs is appropriate for the purposes of analyzing the benefits of Northern Pass because of the uncertainty about where individual plants would appear on the supply curve, and what their individual net going forward costs are. While LEI agrees that there is forecast uncertainty around any single generator's circumstances and exact costs, a stylized approach that The Brattle Group applied in their *ad hoc* tool is still inferior. First, as mentioned previously, The Brattle Group's modeled dynamics are unrealistic because they forecast too many delists and unrealistically sized and timed new entry. Second, the stylized approach leads to unrealistic market prices.

Figure 4 below shows the capacity market prices forecasted by LEI and The Brattle Group. The Brattle Group's approach of delisting and adding new supply at the perfect quantities results in a very narrow spread between their Base Case and Project Case (under Scenario 1).

Indeed, this smoothing of supply changes means that 2,000 MWs or 3,000 MWs of new generation project will have very little impact on capacity prices. To demonstrate this, Figure 5 below shows illustrative supply curves for FCA#11 based on the parameters that the Brattle Group described in their report. Resources in The Brattle Group's supply curve are forced to exit the market once the capacity price falls below their assumed fixed costs plus their assumed PFP costs. The result of resources having to leave the market at this price and being able to exit the market at any CSO level (without considering the actual size of most plants) results in a situation where they will always be very limited price impacts from any large new entrant in the FCA.

Figure 4. Comparison of capacity market prices for the system, nominal

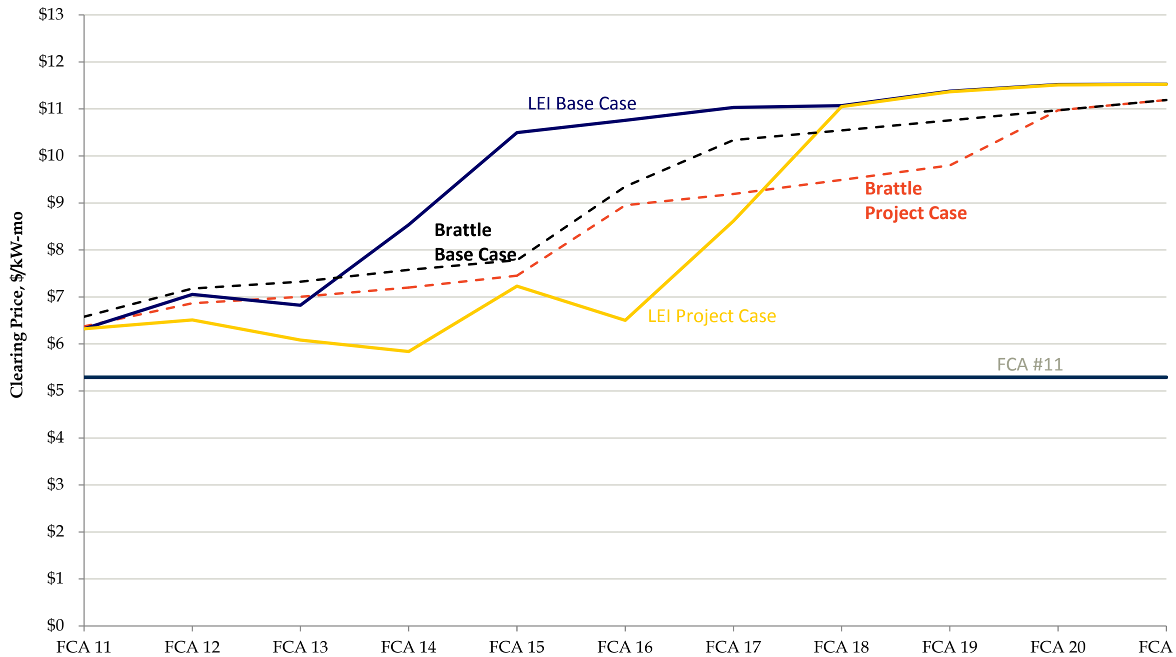
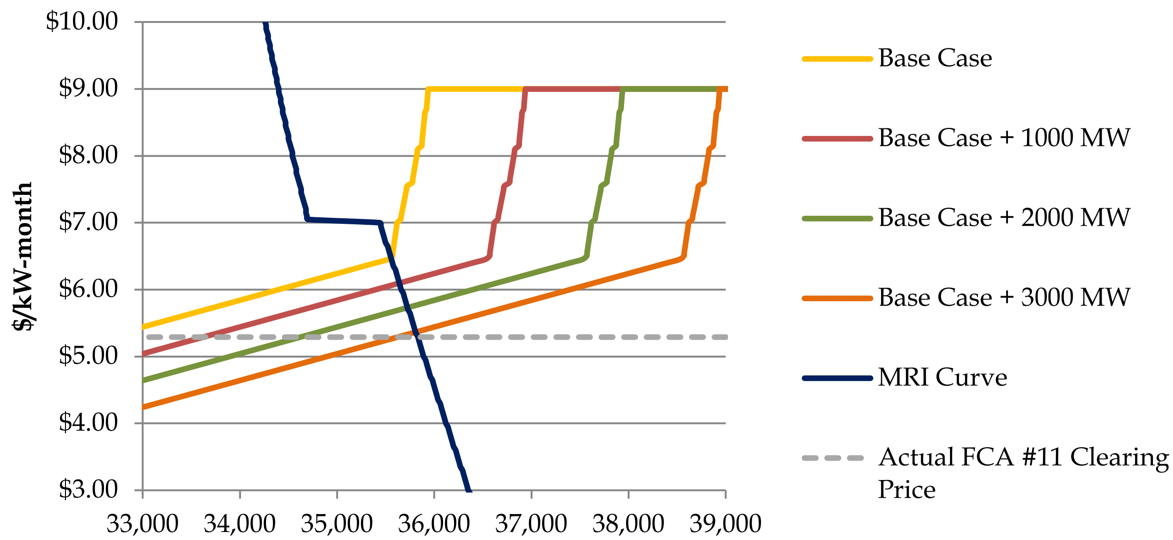
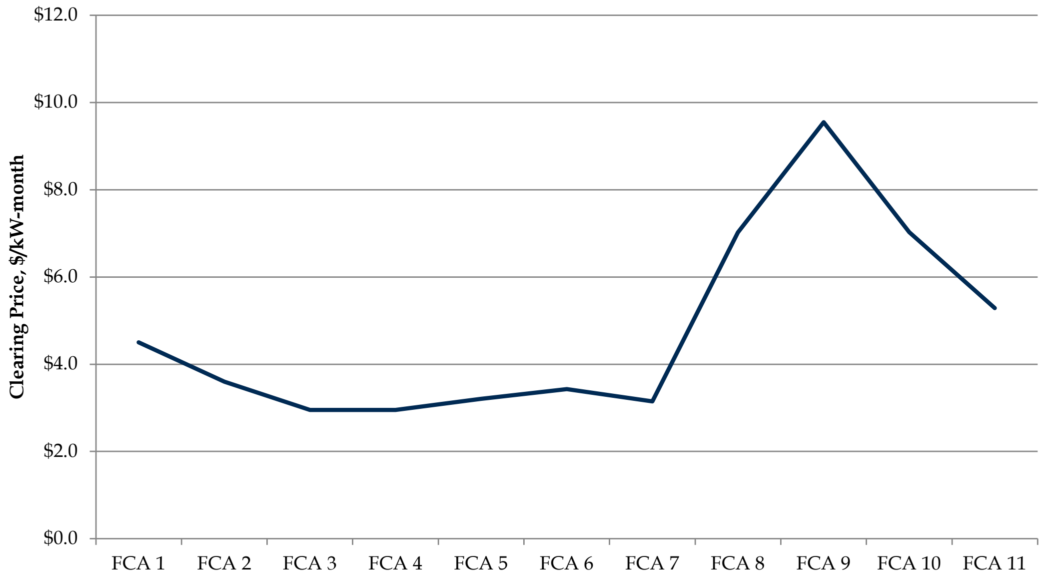


Figure 5. The Brattle Group's Supply Curves for FCA#11 at 1,000 MW, 2,000 MW, and 3,000 MW additions



Furthermore, The Brattle Group's *ad hoc* tool would not be able to replicate actual FCA outcomes. The reason is because a large portion of the supply curve used in The Brattle Group's analysis is comprised of "static delists" that exit the market at a price above the DDBT. In reality, generators will be incentivized to stay in the market as long as their expected costs of CPP are covered.

Figure 6. Historical FCA system prices



LEI does not disagree with the premise of market response – as new resources are added to the system, some may choose to delist. However, The Brattle Group's approach to delisting existing resources does not realistically capture the behavior of market participants during the FCA or over time (over multiple auctions). Another demonstration of this shortcoming is captured by looking at historical market outcomes. Figure 6 above shows the historical market prices. Prices in FCA#9 and #10, which cleared at $9.55/kW-month and $7.03/kW-month respectively, were set by new generation. However, in FCA#11 and all FCAs prior to FCA#9, it was largely existing generation that set the price. The Brattle Group's model would not be able to replicate such outcomes.

London Economics International LLC
717 Atlantic Ave, Suite 1A
Boston, MA 02111
www.londoneconomics.com

3 LEI's analysis addresses all hypothetical concerns about the Project's qualifications and the shipper's ability to participate in the FCM

In its February 15, 2017 Updated Analysis, LEI continued to model Northern Pass as a new 1,000 MW capacity resource in ISO-NE's FCM. This amount of new capacity is consistent with the technical design of the Project (nameplate rating of 1,090 MW), and capabilities of HQP as the likely shipper over the line. However, Mr. Fowler on behalf of NEPGA and The Brattle Group argued that the full capacity market benefits of the Project (as calculated by LEI) may not be realized. Specifically, the experts for NEPA and the CFP raised the following concerns:

- technical deliverability constraints associated with 1,000 MW of capacity on Northern Pass;
- sufficiency of supply (surplus capacity) for the shipper to use in the FCA;
- likelihood of the shipper's capacity offer clearing in the FCA, given MOPR rules; and
- willingness of the shipper to acquire a CSO over Northern Pass, given the risks associated with CPP penalties.

In this section of the report, LEI presents several analyses demonstrating that these concerns raised by Mr. Fowler and The Brattle Group are, in fact, very unlikely to impact the ability of Northern Pass to provide 1,000 MW of capacity market benefit to consumers in New England. LEI also demonstrates that the concerns raised by Mr. Fowler and The Brattle Group were based on supposition rather than analysis.

3.1 Northern Pass should not face deliverability issues that would limit FCM benefits

In his December 20, 2016 testimony, Mr. Fowler stated that Northern Pass' 2013 System Impact Study ("SIS") heightened his "concern about deliverability" of 1,000 MW of capacity over Northern Pass.[29] While an updated version of the Northern Pass SIS from 2016 was available at the time of Mr. Fowler's testimony, he based his evaluation on his review of the 2013 version. However, there have been major changes in the project itself and in the New England transmission system since the 2013 study was complete. Notably, the total capacity of the line was reduced from 1,200 MW to 1,090 MW; the technology used for the Northern Pass converter stations was changed (from Line-Commutated Converter to Voltage Source Converter); and transmission system upgrades have been approved, especially Greater Boston Area reliability upgrades, including the Merrimack Valley reliability Project.

In any case, the effect of the SIS is simply to identify system upgrades that must be made in order to interconnect a new resource, and Northern Pass has priced those upgrades into its construction cost. Since this topic is outside LEI's area of expertise, LEI will refer the SEC to the March 2017 pre-filed testimony of Robert D. Andrew, which concluded that Northern Pass "will

[29] Pre-filed direct testimony of William S. Fowler on behalf of the New England Power Generators Association, Inc. Page 16.

be able to interconnect with the New England transmission system in a manner that assures system stability and reliability".[30]

3.2 The Brattle Group's assessment of Hydro-Québec's supply is based on a misunderstanding of Hydro-Québec's structure and misinterprets recent FCA results

Northern Pass has executed, and secured FERC approval for, a Transmission Service Agreement ("TSA") with an affiliate of Hydro-Québec. As such, it is essentially correct to assume that a division of the company will be the likely shipper on Northern Pass.

The Brattle Group, in their February 10, 2017 updated report, questioned whether Hydro-Québec will have sufficient surplus to qualify 1,000 MW of capacity into ISO-NE's FCM. However, in order to understand Hydro-Québec's supply & demand situation, it is important to first identify the division within Hydro-Québec that would be the shipper.

Hydro-Québec has four major divisions. Hydro-Québec Production ("HQP") is the unregulated generation division, and sells wholesale electricity (energy, capacity, ancillary services) from its generation fleet and contracted assets to Hydro-Québec Distribution ("HQD", Hydro-Québec's regulated electric distribution division) and in various export markets.[31] HQD purchases wholesale electricity from HQP, but also from other generators within or outside the province of Québec. As such, HQP and HQD have different supply and demand outlooks, for both energy and capacity. It is therefore imperative to review documentation for the likely shipper, which is HQP.[32]

The Brattle Group based their assessment of Hydro-Québec's supply on two flawed assumptions:

- They reached incorrect conclusions from capacity sales over the Highgate and Phase II interconnections in recent FCAs; and
- They reviewed the wrong documents in order to assess excess capacity for the likely shipper over Northern Pass.[33]

In their analysis, The Brattle Group incorrectly observed that HQP did not sell as much capacity over the Highgate interface as was allowed by market rules for FCA#9 and FCA#10.[34] Consequently, they concluded that HQP might be capacity constrained. However, they later corrected that statement and acknowledged both during the technical sessions and in their

[30] Substitute Pre-Filed Direct and Supplemental Testimony of Robert D. Andrew, March 24, 2017.

[31] The other divisions are Hydro-Québec TransÉnergie ("HQT" – regulated transmission system operator), and Hydro-Québec Équipement ("HQE" – which serves as EPC contractor for major HQ generation and transmission projects).

[32] Even though The Brattle Group refers to Hydro-Québec in general as the likely shipper over Northern Pass, LEI will actually refer to HQP throughout this report for accuracy purposes.

[33] The Brattle Group's February 10, 2017 updated report on page 36 concluded it is "unclear whether Hydro-Québec will have sufficient surplus to qualify capacity to export to New England".

[34] The Brattle Group's February 10, 2017 updated report on page 37.

answer to LEI's data request, that the Highgate interface was indeed filled during both these FCAs and that HQP could not have sold any more capacity over this interface.[35]

The Brattle Group used Phase II as an example to correctly illustrate that in FCA#10, there remained 259 MW of unused transfer capacity on the interface. However, as acknowledged by Mr. Newell during the technical session, it is impossible to conclude from that one example that HQP lacked sufficient capacity to sell additional capacity to New England in these auctions, and even more so to extrapolate for future auctions. There are a number of commercial considerations that could have led HQP to sell lower amounts of capacity over the interfaces in FCA#10, for instance potential competition from other market participants.[36] Furthermore, results from FCA#11 that were released after The Brattle Group's analysis was performed reveal that HQP did sell as much capacity as allowed by the market rules over the Highgate and Phase II interfaces (respectively 55 MW and 441 MW) for CCP 2020/21.

The Brattle Group's second argument for suggesting HQP might lack sufficient capacity resources is based on their inability to estimate HQP's capacity surpluses. This is not surprising, given the lack of familiarity with Hydro-Québec displayed in their report and during the technical session. For instance, during the technical session, they could not identify which division of Hydro-Québec would be the likely shipper over Northern Pass. This lack of familiarity led The Brattle Group to review the wrong documents in order to assess excess capacity in the province of Québec. Based on the sources cited in the February 2017 report, they reviewed HQD's supply and demand outlook, compared Hydro-Québec's total installed system capacity (sum of HQP and HQD assets or contracted supply) to HQD's capacity requirement, and reviewed the NPCC Québec Balancing Authority Area Comprehensive Review of Resource Adequacy (which is incorrect because Hydro-Québec is not the only owner of electricity generation resources in Québec). As they compared apples to oranges, it is not surprising that they concluded that "those [documents reviewed by The Brattle Group] presented mixed indicators that we have not been able to reconcile".[37]

3.3 Hydro Quebec Production has sufficient export resources to provide capacity on Northern Pass based on LEI's review

Relying on public data from Hydro-Québec documents,[38] LEI evaluated HQP's supply and demand outlook. Based on this analysis, it is clear that HQP will have ample surplus firm capacity to commit 1,000 MW into New England over Northern Pass.

In order to calculate HQP's firm capacity surpluses, LEI first researched HQP's total available generation capacity (including long-term purchases) which for the 2016/17 winter stood at 39,729 MW.[39] LEI then added demand response, trade agreement purchases, and announced

[35] Counsel for the Public's responses to the March 2, 2017 technical sessions memorandum data requests – Samuel Newell and Jurgen Weiss – The Brattle Group. Response to data request number 10.

[36] Brookfield Energy Marketing Inc. has in the past sold capacity over the Phase II interface from its Lièvre River hydroelectric plant in Québec.

[37] The Brattle Group's February 10, 2017 updated report on page 38.

[38] Such as annual reports, strategic plans, and HQD supply procurement plans.

[39] LEI's detailed calculations and data sources can be found in Appendix A.

new generation capacity expected to be online by June 2021 (in time for deliveries resulting from FCA#12, to obtain a total of 41,227 MW. LEI also researched HQP's firm capacity commitments to consumers in the province of Québec under the Heritage contract (with HQD) and other post-Heritage contracts (also with HQD), and other existing HQP long-term commitments in various export markets (such as Ontario or Vermont).

LEI concluded that HQP's surplus capacity generation available for firm exports to neighboring jurisdictions will equal at least 1,527 MW from 2021 onward[40] during the Québec Control Area's winter system-peak period. During the summer period,[41] HQP's surplus capacity is actually much higher, as summer peak load in the province is about half the winter peak load.[42] This amount of excess capacity is sufficient to not only offer 1,000 MW of capacity over Northern Pass, but also offer capacity over the Highgate and Phase II interfaces as well.[43] As such, HQP's capacity sales over Northern Pass would not translate into reduced sales over the other interfaces into New England or other markets.

LEI's detailed calculations and data sources can be found in Appendix A.

3.4 MOPR will not materially void the capacity market benefits of Northern Pass

Having established that there are no technical deliverability or supply deficiency issues associated with a capacity offer by HQP over Northern Pass, we can turn to market-related concerns raised by interveners. Specifically, Mr. Fowler and The Brattle Group suggest that the IMM's Minimum Offer Price Rule ("MOPR") determination could prevent HQP's offer over Northern Pass from clearing in the capacity market. However, neither of them provided an estimate of the results of a MOPR analysis of HQP's offer over Northern Pass. While performing a MOPR analysis in this case requires knowledge of HQP and certain market modeling capabilities, all information required to perform an indicative analysis exists in the public domain. The Brattle Group, despite their knowledge of the MOPR calculation,[44] did not perform such an analysis.

HQP would offer energy and capacity over a new transmission line (Northern Pass, classified as an Elective Transmission Upgrade or "ETU") from its fleet of hydroelectric generation resources. ISO-NE's FCM rules include a review by the Internal Market Monitor of new FCA offers from import resources associated with an ETU to ensure that the offer reflects the true

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40 Hydro-Québec's strategic plan commits to increasing the capacity of existing assets by 500 MW by 2025, but presumably a portion of these uprates could be ready ahead of 2025. Furthermore, although allowed to call up to 1,000 MW of capacity from HQP under the Base & Adjustable contracts, HQD's current supply plan only forecast needing 800 MW.

41 The New England region, contrary to Québec, is summer peaking.

42 NPCC's 2016-17 winter reliability assessment lists the Québec Control Area peak load as 37,870 MW, while the 2016 summer reliability assessment listed the province's peak load as 20,833 MW

43 In recent years, tie benefits have limited capacity sales over Highgate below 60 MW, while HQICCs have limited capacity sales over Phase II below 450 MW.

44 During the course of Ms. Frayer's technical sessions on February 27, 2017, Mr. Newell stated that The Brattle Group put together the template workbooks used by ISO-NE's IMM to perform the MOPR analysis and publicly available on the ISO's website.

costs of the project, excluding potential out-of-market revenues (roughly defined as revenues that are not widely available to other market participants). As such, any new offer for capacity by HQP over Northern Pass would be subject to review. The IMM's determination of a MOPR would represent a floor below which Hydro-Québec Production's capacity would not clear in the FCA. Although the MOPR analysis is performed using a cost workbook and analysis similar to new generation resource, the methodology to calculate some of the inputs is quite different from that of a developer seeking to build and qualify a new CCGT.

In order to estimate the risk associated with MOPR determination for an FCA offer by HQP over Northern Pass, LEI performed an indicative calculation based on ISO-NE's "New Generating Capacity Resource Model", which is the model to be used by import resources associated with an ETU.

Inputs to the MOPR model can be categorized as "Investment Characteristics" and "Project Revenues and Costs." For investment characteristics, LEI relied on publicly available (notably financing parameters available in the TSA approved by FERC and filed with the SEC) and other representative parameters. In order to calculate project revenues, LEI leveraged its own modeling results (as presented in LEI's Original Report) to estimate energy revenues.

On the cost side, LEI relied on the fact that HQP would not build new generation assets in order to provide energy to sell over Northern Pass. Rather, HQP would use its fleet of hydropower assets; the variable costs of hydropower generation are very low. As such, the traditional way of calculating anticipated revenues net of operating costs, such as used for thermal plants, cannot apply in this case (or any other situation where HQP is selling a product from its portfolio, called a "control-area backed resource" by ISO-NE). LEI calculated instead the opportunity cost for HQP as the revenues that could be earned from the sale of an equivalent amount of energy in alternative markets, should Northern Pass not be available. Given HQP's annual export markets energy budget, its ability to store energy in reservoirs, and the transmission interface capacity with neighboring jurisdictions, LEI's model suggests that absent Northern Pass, Ontario's energy market off-peak price for energy is a reasonable proxy for the displaced energy's realized price. It is important to note that the costs of transmission service in Québec (on Hydro-Québec TransÉnergie's network) are incurred by HQP no matter the destination export market, and as such have no impact on the MOPR analysis. Other fixed costs assumed by LEI for Northern Pass include property tax, economic development program, right-of-way lease, O&M, and other support expenses.

LEI's indicative analysis, performed using the cost workbook publicly available on ISO-NE's website, results in an indicative MOPR for HQP's offer over Northern Pass for FCA#11 [redacted]

As such, the IMM MOPR determination is not expected to prevent HQP's capacity offer over Northern Pass from clearing in future capacity auctions.[45]

LEI's detailed calculations and data sources can be found in Appendix A.

3.5 Concerns about MOPR limiting Northern Pass' capacity market benefits are based on a lack of sufficient analysis and inaccurate assumptions

Concerns cited by The Brattle Group and Mr. Fowler with respect to the MOPR determination arose as a result of insufficient analysis, and inaccurate assumptions:

- neither The Brattle Group nor Mr. Fowler performed a quantitative evaluation to estimate a MOPR for HQP's capacity offer over Northern Pass;[46]
- both experts incorrectly cited the lack of public data to complete the analysis;[47] and
- both experts incorrectly assumed that new generation and transmission costs in Québec would factor into the MOPR analysis.[48]

Without the benefit of having performed the MOPR calculations, both The Brattle Group and Mr. Fowler were unable to recognize how the specifics of HQP's capacity offer over Northern Pass would be translated into inputs to the MOPR analysis.

For example, The Brattle Group incorrectly asserted during the technical sessions that the IMM would mandate an analysis using an asset life of 20 years, although it is not standard industry practice to amortize transmission assets over 20 years, and the publicly available ISO-NE cost

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[45] After the capacity offer has cleared in a first capacity auction and construction goes ahead, HQP would be bound by the terms of the Transmission Service Agreement. As such, even though import offers can be considered as "New" every year and undergo a MOPR analysis, the TSA tariff would be considered an unavoidable expense and thus not be considered in any future revenue/opportunity cost analysis. As such, any future MOPR analysis would essentially mirror the assessment that HQP must undergo for selling transmission on existing transmission lines such as Highgate, which has never prevented HQP from clearing capacity in the FCA.

[46] As mentioned previously, both The Brattle Group and Mr. Fowler confirmed during their respective technical sessions that neither of them performed any analysis to back up their suggestion that the MOPR determination could prevent the shipper's offer over Northern Pass from clearing in the FCA.

[47] Inputs to the MOPR calculations for HQP's offer over Northern Pass are very different from the traditional calculations for a new thermal generator, which both experts failed to recognize. This lack of understanding may explain why they believed there was insufficient public data and information to perform a MOPR estimate.

[48] Both Mr. Fowler and The Brattle Group answered during the technical sessions that cost of generation or transmission north of the border would impact the MOPR analysis, when in fact neither of those will. As demonstrated in Appendix A, existing resources and resources nearing the end of construction provide HQP with ample energy surpluses to export over Northern Pass, without the need for additional generation. As such, since no new generation would be associated with the construction of Northern Pass, the MOPR analysis would not include the cost of generation, but rather the opportunity cost of selling the energy from HQP's existing fleet in other markets. Furthermore, Hydro-Québec TransÉnergie ("HQT") is responsible for constructing the portion of the transmission line in Québec, and a review of HQT's OATT indicates that the shipper on the line will be charged the same point-to-point tariff as for any other point-to-point transmission reservation on another existing interface. As such, the cost for transmission on HQT's system would feature both in the revenues analysis for sales over Northern Pass and revenues analysis for opportunity sales, resulting in a net zero effect on the revenue/opportunity cost analysis.

workbook allows for project life up to 40 years. Indeed, 40 years is a more reasonable estimate of the project life for transmission infrastructure.

Similarly, Mr. Fowler incorrectly asserted that generation costs in Québec should be taken into account in the MOPR analysis because he "understands" that the Romaine hydroelectric complex currently under construction would be the single source of energy for Northern Pass.[49] However, it turns out that his understanding was based on incorrect information provided to him by NEPGA.[50] Considering that ISO-NE rules allow for control-area backed resources to participate in the capacity market[51] and that HQP generation is 99% large hydropower,[52] there is no reason to believe HQP would tie the energy and capacity over Northern Pass to a specific set of resources.

Mr. Fowler also incorrectly asserted, without any kind of analysis to back up his claim that "Northern Pass" expects to receive out-of-market revenue from state-backed contracts or other sources sufficient to pay its costs that are not met by market-based sales".[53] Leaving aside the fact that Mr. Fowler conflates Northern Pass' sponsor with the shipper over the line (HQP, who would actually earn energy and capacity revenues), LEI's MOPR analysis clearly demonstrates that with the forecast level of FCA clearing prices and energy market prices, market revenues should be sufficient to cover both HQP's opportunity costs and the investment costs of building and operating the Northern Pass transmission line.

3.6 Revenues from the capacity market far outweigh risks associated with CPP

Mr. Fowler also suggested that HQP may not want to sell capacity over Northern Pass given the risk associated with Capacity Performance Payment penalties. However, Mr. Fowler fails to consider the risk-reward tradeoff. The risks around ISO-NE's Capacity Performance Payment scheme in the capacity market will not change the commercial rationale for HQP to sell capacity on this line, as potential revenues from the capacity market (the "reward") far outweigh the penalty risks, once we take into account historical HQP performance and the low likelihood of events that would trigger CPP.

Moreover, the risk of penalties related to non-performance is actually much lower for HQP than it is for the average resource located within New England. For reference purposes, when calculating the region's Installed Capacity Requirement ("ICR"), ISO-NE assumes an average forced outage rate ("EFORd") for internal resources ranging from 2.5% for nuclear plants and 3.8% for combined cycle plants, to 10.8 % for combustion turbines and 17.6% for fossil-fueled plants. Conversely, ISO-NE assumes that system-backed imports are 100% available.[54]

[49] Pre-filed direct testimony of William S. Fowler on behalf of the New England Power Generators Association, Inc. Footnote 21 on page 18.

[50] In reality, the Romaine complex is a major 1,550 MW, 8 TWh complex comprising four distinct hydroelectric power stations that has been under construction since 2009.

[51] ISO-NE Market Rule 1, Section III.13.1.3

[52] <http://www.hydroquebec.com/about/our-energy/>

[53] Pre-filed direct testimony of William S. Fowler on behalf of the New England Power Generators Association, Inc. Page 14.

[54] ISO-NE, *Assumptions for the Installed Capacity Requirement (ICR) values Calculations*, PSPC Meeting, July 28, 2016.

Furthermore, an analysis by ISO-NE of the forced outage rate of HVDC ties between Québec and New England showed that the average forced outage rate was very low: 0.39% and 0.07% over a five-year period for the Phase II and Highgate interfaces respectively.[55] As a result, considering the following factors, HQP stands a greater chance to benefit from over-performance payments than from penalty charges under CPP.

As further proof of this point, HQP can deliver up to 1,090 MW through Northern Pass, while the capacity obligation would be no greater than 1,000MW. Furthermore, the Internal Market Monitor assumes a balancing ratio around 75%,[56] [57] so HQP's very low forced outage rate would enable them to over-perform for the overwhelming majority of Capacity Scarcity Conditions.

Finally, as a further demonstration that HQP is not deterred by risks associated with CPP, it is useful to recall that HQP has in fact already demonstrated its willingness to acquire capacity obligations in New England despite the risks associated with CPP. Indeed, HQP has already sold significant amounts of capacity in prior FCAs subject to CPP: an average of 204 MW-month in FCA#9 (delivery year 2018/19), 271 MW-month in FCA#10 (delivery year 2019/20), and 896 MW-month in FCA#11 (delivery year 2020/21).

3.7 Mr. Fowler's incorrect evaluation of the CPP risk for HQP is based on erroneous assumptions

Mr. Fowler reached his conclusion about the risk of CPP because:

- he incorrectly assumed that energy and capacity for Northern Pass would be tied to specific resources, as opposed to being control-area backed;
- Mr. Fowler cited specific "HQ reliability events" for illustration of the potential magnitude of the penalty, but did not perform an assessment of probability of occurrence into the future, which is a key element of any risk assessment;[58] and
- Mr. Fowler exaggerated the penalty amount in his hypothetical example, failed to balance penalty payments against capacity auction revenues, and failed to mention the possibility of bonus payments for resources that over-perform with respect to the performance obligation.

[55] ISO-NE, *External Interconnections Forced Outage and Maintenance Outage Assumptions*, Reliability Committee, July 15, 2011.

[56] The Balancing Ratio, representing the ratio of actual load plus reserves over the total capacity supply obligation at the time of a Capacity Scarcity Condition, is used to adjust down the performance obligation of capacity suppliers.

[57] ISO-NE, *Increasing the Dynamic De-list Bid Threshold*, NEPOOL Markets Committee, March 10, 2015

[58] Mr. Fowler cited two specific "HQ reliability events" to illustrate the potential risk incurred by HQP in taking on CSOs. However, Mr. Fowler confirmed during his technical session that he did not calculate how many other such "reliability events" occurred in the past 10 years. As such, he has not calculated a probability of occurrence into the future, which is a key element of any risk assessment. As extensively demonstrated by LEI previously, HQP enjoys a forced outage rate which is significantly lower than most resources located in New England.

Mr. Fowler also claims that HQP "may not want to risk taking on a CSO when the supply of their energy is nearly 1,000 miles north of Boston".[59] However, this statement is based on Mr. Fowler's incorrect assumption that the Romaine complex would be the single source of energy and capacity over Northern Pass.

Nowhere is there any mention from HQP or Northern Pass or any other credible source that supply over the line would be tied to a specific resource or set of resources. In fact, ISO-NE rules explicitly allow for control-area backed resources to participate in the capacity market.[60] This is a win-win situation for both ISO-NE and HQP, as the ability to draw power from a pool of resources, as opposed to a specific resource, increases the reliability of deliveries for the New England Control Area, and decreases the risk of non-performance for HQP.[61]

Mr. Fowler calculated a hypothetical $15.75 million penalty that could have been incurred by HQP should their energy be subject to curtailment.[62] However, Mr. Fowler's calculation did not take into account the balancing ratio, which is an integral part of the penalty formula:

*CPP = shortfall capacity * scarcity conditions duration * balancing ratio* penalty rate*

Mr. Fowler could easily have calculated the balancing ratio for his hypothetical example, so it is unclear why he did not. The balancing ratio should have been calculated as 58.9%,[63] yielding a penalty of $9.3 million, as opposed to $15.75 million as calculated by Mr. Fowler.

More importantly, Mr. Fowler fails to compare the hypothetical penalty to revenues from the capacity market. The FCA clearing price for FCA#11 was $5.30/kW-month. For a 1,000 MW CSO, this translates into revenues of $63.6 million for the 12-month Capacity Commitment Period. No rational entity would forfeit revenues of that magnitude, even if the penalty risks were as high as Mr. Fowler believes (which they are not, as demonstrated above). In his analysis, Mr. Fowler also fails to mention the possibility of bonus payments for over-performing resources (even if they acquire a 1,000 MW CSO), from which HQP could benefit as discussed previously.

Finally, Mr. Fowler tries to suggest that HQP imports into New England are at risk of being curtailed because he "would expect HQ to serve its Quebec customers at the expense of its exports, as was the case during these HQ curtailments."[64]

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[59] Pre-filed direct testimony of William S. Fowler on behalf of the New England Power Generators Association, Inc. Page 18.

[60] ISO-NE Market Rule 1, Section III.13.1.3

[61] Interestingly, HQP has been selling energy and capacity to New England since before inception of the organized wholesale markets, while the overwhelming majority of their generation capacity is located between 600 miles (Manic region) to 800 miles (James Bay region) north of Boston. It is worth mentioning that the Romaine complex is closer to 750 miles North of Boston, not 1,000 miles as Mr. Fowler indicated.

[62] Pre-filed direct testimony of William S. Fowler on behalf of the New England Power Generators Association, Inc. Page 18.

[63] The average load + reserve requirement in New England from Hour Ending 17 to Hour Ending 21 on December 8, 2014, was 21,968 MW; the FCA5 total CSO for December 2014 was 37,276 MW. Source: ISO-NE historical data.

[64] Pre-filed direct testimony of William S. Fowler on behalf of the New England Power Generators Association, Inc. Page 18.

This statement is not backed by any data or citation, and Mr. Fowler confirmed during his technical sessions that this represents his personal belief, and this belief is not the product of research. In fact, Mr. Fowler's belief is false. A simple look at ISO-NE's qualification rules for import capacity resources shows that these resources need to include documentation to the contrary, specifically that "the neighboring and any intervening control area will afford the export the same curtailment priority as native load". In other words, HQP must demonstrate to ISO-NE that HQT (as the system operator) will afford capacity exports to New England (or to any other jurisdiction) the same curtailment priority as native Québec load.[65] Furthermore, HQT's OATT includes the provisions under which point-to-point transmission service such as reserved by HQP for its export transactions can be curtailed proportionally to Native-Load customers.[66]

3.8 The Brattle Group's scenario approach is flawed due to its exclusive focus on negatively-oriented uncertainties

The Brattle Group developed a Base Case and a Project Case whereby Northern Pass clears 1,000 MW of CSO (Scenario 1). As The Brattle Group noted during the technical sessions, this Scenario 1 is the most akin to LEI's analysis. The Brattle Group also developed three other Project Case scenarios that account for uncertainty over how the Project will be positioned in the FCM. LEI would describe these as "what if" cases, rather than scenarios testing *market uncertainty*. Scenario 2, 3 and 4 simply consider hypothetical "worse", "much worse", and "worst" cases for Northern Pass with respect to capacity sales and capacity market benefits.

While scenario analysis can be a good tool, it is being misapplied in this instance.[67] The Brattle Group recognizes the possibility of upside but chooses not to assess those potential market outcomes. The scenario design should cover the plausible and potentially likely future worlds. Some scenarios should provide the upside while others should provide the downside. The three scenarios The Brattle Group designed are all more negative views of Scenario 1 and designed intentionally to measure decreases in capacity market benefits compared to Scenario 1. Scenarios should look at all uncertain factors but The Brattle Group only looked at the project characteristics and how the project qualifies in the capacity market. Scenario analysis could have evaluated how exogenous factors impact benefits. For example, what would happen if we see other unexpected power plant retirements in New England? Or what if we have higher gas prices? Or what would happen if there are different supply conditions in neighboring markets. None of these market uncertainties were examined.

3.9 The Brattle Group's Scenario 2 and 3 are unrealistic

The Brattle Group's Scenarios 2 and 3 are not plausible scenarios because each partially or completely ignores capacity sales. The basis for this assumption is wrong as discussed above. It is also not a rational business strategy for the shipper, again as discussed above.

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[65] In fact, as noted in Mr. Fowler's own pre-filed testimony on page 18, native load in Québec was curtailed concurrently with transactions to New England during the so-called "HQ reliability events".

[66] Hydro-Québec Open Access Transmission Tariff, section 13.6. <http://www.oatioasis.com/HQT/HQTdocs/HQT_OATT_2017_2016-12-13.pdf>

[67] Pierre Wack, "Scenarios: Uncharted Waters Ahead", Harvard Business Review. September–October, 1985.

Some interveners claimed that Northern Pass will not quality and clear its full capacity in FCA. LEI has demonstrated in the previous sections that MOPR will not affect the ability of HQP to sell the full 1,000 MW of CSO. LEI also concluded that HQP has surplus capacity generation available for firm exports to neighboring jurisdictions in more than sufficient quantities to meet the CSO on Northern Pass (and continue sales on other existing interties). As such, HQP's capacity sales over Northern Pass would not translate into reduced sales over the other interfaces between Québec and New England. Furthermore, Scenario 3 is premised on an ineffective business strategy for the shipper. The risks around ISO-NE's CPP scheme in the capacity market will not change the commercial rationale for HQP to sell capacity on this line, as potential revenues from the capacity market far outweigh penalty risks. Assuming, as The Brattle Group does, that the capacity value of the line would not be monetized by the shipper is akin to building a transmission line and not using it. The shipper would be irrational to make such an investment. In addition, from the system operator's point of view, we would wager that ISO-NE would not accept such an inefficient use of infrastructure. Given all the above reasons, The Brattle Group's Scenario 2 and 3, should be given zero weight in SEC's deliberation.

3.10 The Brattle Group's Scenario 4 is not properly considering the value of Northern Pass

The Brattle Group's Scenario 4 theorizes a situation that is not likely. Moreover, based on the constructs of the scenario, The Brattle Group does not properly consider the purpose of LEI's analysis in the SEC proceeding, which is to evaluate the impacts of Northern Pass (rather than to hypothesize whether alternative projects could be developed).

To the extent that Scenario 4 is meant to represent the various policy initiatives in the region to bring additional zero-carbon resources into the energy supply mix, a more reasonable version of Scenario 4 would have posited that New England would see multiple carbon-reducing projects develop. The Brattle Group should have modeled a Project Case that builds upon the Base Case, rather than substituting for the exact same resources in the Base Case. In this LEI alternative Scenario 4, the Base Case would be meant to mimic the implementation of Massachusetts legislation[68] that aim to procure additional energy from large hydro and offshore wind resources. This scenario is plausible, as more than one transmission project is needed in order to meet Massachusetts' Global Warming Solutions Act (GWSA).[69] In this alternative Scenario 4, we would likely see some lower wholesale market benefits associated with Northern Pass, all things being equal. However, we would not see zero benefits associated with Northern Pass. As such, the conclusions of The Brattle Group's scenario 4 are invalid, and should be ignored by the SEC.

[68] House Bill No. 4568 and Senate Bill No. 1965

[69] The Massachusetts Global Warming Solutions Act (GWSA), signed in August of 2008, created a framework for reducing heat-trapping emissions to levels that scientists believe give us a reasonable chance of avoiding the worst effects of global warming. It requires reductions in greenhouse gas (GHG) emissions from each sector of the economy summing to a total reduction of 25% below the 1990 baseline emission level in 2020 and at least an 80% reduction in 2050.

4 LEI's estimate of wholesale energy market benefits are undisputed – and other additional benefits are possible

Intervening parties generally agreed with the magnitude of the other benefits that LEI's analysis considered outside of capacity market benefits despite having some differences in how those benefits should be calculated. This section discusses the problems that LEI identified with those alternative methods, and why LEI continues to believe its analysis is valid. In addition, LEI maintains that its analysis does not consider all the potential indirect benefits that Northern Pass could offer, making its overall economic assessment conservative.

4.1 Brattle generally agrees with LEI's estimate of the wholesale energy market benefits from Northern Pass

The Brattle Group did not conduct an independent energy modeling analysis because, as they had noted in their report, they "adopted LEI's because we [The Brattle Group] found that it appropriately captures the key characteristics of the New England energy market, including the flat energy supply curve and future natural gas prices"[70] and "found that it appropriately captures the key characteristics of the New England energy market, including the flat energy supply curve and future natural gas prices."[71]

The Brattle Group did make adjustments to the energy market benefits based on their own new entry schedule informed by their capacity market analysis. This was done solely using LEI's energy price outputs. While The Brattle Group's analysis shows higher wholesale energy market benefits than what LEI had estimated, there are a number of simplifying assumptions that they made which create consistency problems. The Brattle Group adjusted the energy market benefits by first measuring what the $/MWh impact is for each MW of new thermal capacity, based on LEI's October 2015 Report (LEI's Original Report assumed that new resources would be combined cycle plants, which typically have lower heat rates than peakers).

As discussed previously, The Brattle Group's new generic supply resources were sized such that total supply would meet NICR. In doing so, The Brattle Group modeled one type of technology as new entry (combined cycle gas turbines), but the size of those resources (in the 90 MW – 350 MW range) more closely reflect a peaking frame unit.[72] Due to peaking units run infrequently, they have very little impact on energy prices and would therefore result in higher energy market impacts of Northern Pass.[73] Alternatively, if The Brattle Group's new supply resources were truly combined cycle plants with the minimum scale in mind, then The Brattle Group's analysis would likely show delayed new entry and higher capacity market prices.

[70] The Brattle Group Report, Page viii

[71] The Brattle Group Report, Page viii

[72] The minimum scale of modern combined cycle plants is roughly 500 MWs.

[73] Energy market impacts of combined cycle units versus peakers are discussed in Section 3.1 of LEI's "Updated Analysis".

4.2 Northern Pass can also provide production cost savings which is a form of allocating efficiency gains benefiting all New England ratepayers, including those in New Hampshire

The Brattle Group did not include the discussion of system-wide production cost savings in their December 2016 report. During the technical sessions on March 2, 2017, they did recognize the existence of production cost savings and that production cost savings are tied to the energy market analysis. And, given they had agreed with LEI's energy market analysis, at the technical sessions, they noted that they were satisfied with LEI's estimate of production cost savings from Northern Pass, as well.

However, when further questioned about why they did not comment or include the system-wide production cost savings benefit in their report at the technical sessions, Brattle argued that it is due to its impact on ratepayers. Unlike energy market benefits, production cost saving amounts are not dollar for dollar benefits that show up on consumers' bills, and more technically, it is impossible to allocate a portion of the system-wide production cost savings to New Hampshire consumers. That said, it is important to understand how production cost savings impacts consumers in a region – because they do benefit consumers in the long run. In fact, electricity planners, including ISO-NE, routinely study how investments and market rule changes can impact production cost savings. In economic terms, production cost savings measure the efficiency improvements in the production of the energy in a system, because of fuel savings and avoided variable O&M costs, as well as carbon allowance costs. The improvement in production costs for the price-setting generator will further in fact translate into a lower energy price. The improvements also happen for infra-marginal generators (below the price-setting generator) and efficiency gains would translate into lower energy prices in the future under a different set of supply and demand conditions. Due to the nature of capturing efficiency gains, it has always been considered an important benefit metric in its own right. More importantly, while the wholesale energy market benefits may dissipate with time, as the market rebalances, production cost savings are a more permanent improvement in the overall system.

ISO-NE considers production cost savings when evaluating market efficiency transmission upgrades. ISO-NE looks at projects with benefit/cost ratios greater than one where benefits refer to production cost reduction and costs refer to carrying cost of a transmission project over a 10-year timeframe. Many ISOs use both the wholesale electricity market savings and production cost saving measures for evaluating economic transmission investments (or "market efficiency" upgrades). For example, PJM, MISO, and CAISO consider production cost savings and wholesale electricity market savings. PJM is currently using a 50/50 weighting when it evaluates the benefits stemming from production cost saving benefits and direct benefits to load customers[74], while MISO is using a 70/30 weighting between these two measures.[75]

[74] In PJM, the stakeholders agreed the change in the benefit determination for market efficiency projects to a 50/50 split between production cost benefits and direct benefits to load customers better equalizes consideration of market efficiency needs due to overall system conditions and direct impact on load customers. Sources: PJM Interconnection, L.L.C., Docket No. ER14-1394-000, February 28, 2014, page 6-7.

The Brattle Group, in study of transmission upgrade benefits performed for the Staff of the New York Department of Public Service,[76] not only relied heavily on production cost savings, but also suggested that the production costs savings value from their energy market simulations be scaled up by a multiple of 1.6 to account for additional production cost savings that cannot be adequately captured in energy simulation modeling tools without performing extensive sensitivity analyses. If LEI were to apply the same multiplier (i.e., 1.6) that the Brattle Group had used in that case to the production cost savings estimated in the Updated Analysis, [redacted]

4.3 The level of CO_2 reductions is not disputed

Carbon emissions reduction benefit is another "by-product" of the energy market simulation analysis performed by LEI. The Brattle Group also adopted LEI's estimate of the amount of CO_2 reduction realized by operations of Northern Pass. In order to monetize the benefits of reduced CO_2 emissions, LEI applied the Social Cost of Carbon ("SCC"), which is discussed in Section 3.4 of LEI's Updated Analysis. The Brattle Group presented two alternatives to monetizing the CO_2 emissions reduction benefit.

One method that The Brattle Group applied was an "opportunity cost" approach, which looks at how much renewable entry would be needed, and how much it would cost (in terms of renewable energy subsidies), in order to create the same level of CO_2 emissions reductions as the Project. The Brattle Group estimated this to be $40 to $100 per avoided metric ton per year, which corresponds to a value of CO_2 emissions reduction between $140 million and $340 million per year. LEI's estimate is in fact more conservative: in the Updated Analysis, the incremental benefit to society of the CO_2 emissions reductions was estimated between [redacted] per year when applying varying estimates of the SCC values from the Interagency Working Group. The problem with The Brattle Group's approach is that it is simply not realistic to assume that local renewable resources, like solar PV or onshore wind would be able to replace Northern Pass on the same timetable as Northern Pass, given that there are significant transmission infrastructure constraints and land acquisition costs (discussed further

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[75] For a proposed project to qualify as a Regionally Beneficial Project in the Midwest ISO's Regional Transmission Expansion Plan ("MTEP") process, both the Adjusted Production Cost benefit (production cost benefit) and the Locational Marginal Pricing (LMP)-based energy cost benefit are considered the total project benefit is a weighted value defined as the sum of 70 percent of the production cost benefit and 30 percent of the load's LMP energy cost benefit. Source: FERC order conditionally accepting tariff revisions, March 15, 2007, page 3.

[76] The Brattle Group, *Benefit-Cost Analysis of Proposed New York AC Transmission Upgrades*, NY PSC Case Cases 12-T-0502, September 15, 2015.

[redacted]

below). Factoring these costs into these GHG reduction alternatives would likely lead to an opportunity cost that far exceeds the $40 to $100 per metric ton value that the Brattle Group derived.

The second approach that The Brattle Group took was to determine New Hampshire's willingness to pay for CO_2 emissions reduction. For this, The Brattle Group considered legislation enacted by the Northeast states to meet their GHG emissions reduction goals. The Brattle Group argued that if GHG emission reduction targets are not binding in New Hampshire, "then the proper valuation metric from New Hampshire's perspective would be the lower of the cost of meeting the (non-binding) GHG reduction targets and the value New Hampshire places on GHG emissions reductions, i.e., New Hampshire's willingness to pay for emissions reductions."[78] New Hampshire's willingness to pay is not directly observable, so The Brattle Group points to RGGI as a possible inference of the state's willingness to pay, which is in the range of $4 per metric ton to $9 per metric ton of CO_2. However, the problem with associating this level of willingness to pay is that it underrates New Hampshire's many other initiatives to reduce GHG emissions,[79] and it does not capture the true costs of the negative externalities that CO_2 emissions creates. While The Brattle Group experts correctly noted during the technical sessions that the damages to society from carbon emissions are global, that does not invalidate that this Project, located in New England, positively contributes to reducing GHG emissions. New Englanders should be able to take credit for this positive externality aspect of the Project. LEI's estimate of the substantive positive societal benefits of reduced CO_2 emissions should not be ignored by the SEC.

4.4 Building local renewables to fully substitute for Northern Pass would be technically and financially challenging

Several intervening parties argued that local solar PV or onshore wind technologies could be more financially viable relative to Northern Pass in the near future. For example, Mr. Petrofsky noted in his testimony that "*large scale hydro will not be competitive against either solar PV technologies or onshore wind in the near future*."[80] Other intervening parties also argued, more generally, that Northern Pass' benefits could be substituted by other transmission projects, onshore wind and solar PV development. For example, the Brattle Group noted in the testimony that "*Absent Northern Pass, one or several alternative options, such as the New England Clean Power Link through Vermont, or incremental wind and photovoltaic resources in New England, might be developed instead*.[81]

LEI disagrees. An equivalent level of onshore wind or solar PV would be technically challenging and very costly. In order to deliver 1,000 MW of CSO and 7,900 GWh of energy

[78] The Brattle Group Report, Page 59

[79] New Hampshire has taken other steps to reduce CO_2 emissions which include New Hampshire's 25 by 25 plan to obtain 25% of its energy from clean energy by 2025, approved capital projects for PSNH aimed at reducing overall emissions and carbon footprint, and a host of other initiatives that are aimed at promoting alternative fuels and building compliance standards.

[80] John Petrofsky testimony, Page 8

[81] The Brattle Group testimony, Page v.

annually, 1,500 MW of wind and 1,950 MW of solar PV nameplate capacity would be required.[82] In New England, most wind resources are located in Maine but Maine cannot accommodate such quantities of new on-shore wind owing to transmission constraints that prevent that much wind energy from flowing. If more wind is built in Maine, it would require additional transmission upgrades to solve the delivery issue. In terms of solar, the required land for 1,950 MW of solar is almost 10,000 acres.

Furthermore, building a mix of solar and wind to substitute for Northern Pass is not likely to be a cheaper option. Using National Renewable Energy Laboratory's (NREL) 2016 Annual Technology Baseline report, and assuming a capital cost for wind at $1,790/kW and solar at $1,416/kW in 2020, the portfolio of wind and solar to substitute for Northern Pass (1,550 MW of onshore wind and 1,950 MW of solar PV) would cost $5.5 billion. This estimate does not even include the billions of dollars of additional transmission investment[83] that would be necessary needed to accommodate the scale of proposed onshore wind resources in Northern New England.

4.5 Transmission projects like Northern Pass can deliver other benefits

Another area of apparent agreement between LEI and The Brattle Group relates to the potential for Northern Pass to create other benefits. Other potential benefits that a transmission project can deliver are widely recognized and quantified. Ms. Frayer acknowledged it in her testimony.[84] She stated "*…there are other electricity market benefits to ratepayers, which extend beyond the readily measureable reductions in market prices, associated retail electricity cost savings, and emissions reductions…*" The Brattle Group prepared an analysis for WIRES that documented comprehensively the potential benefits of transmission investments.[85] below replicates a table from that report. LEI added two columns (highlighted in orange) that specify which benefits LEI or The Brattle Group identified and/or quantified in each expert's analysis of Northern Pass.

At the technical sessions, The Brattle Group conceded that other benefits presented in the table above are possible for Northern Pass, but measuring them was outside their scope of work. Nevertheless, it is instructive consider these other benefits, especially as LEI has considered some of these other benefits. For example, in the Original Report back in October 2015, LEI quantified the insurance value of Northern Pass. New England's system is susceptible to system stress events, as a result of extreme weather conditions, volatile natural gas markets, and unplanned generation outages. Such system stress events have occurred in recent years – they are not hypothetical. LEI quantified the benefit that the Project would create for consumers in

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82 The nameplate capacity was derived based on the derate factor of 15% for wind and 40% for solar in the capacity market and the load factor of 37% for wind and 18% for solar in the energy market.

83 See footnote 39 of LEI's October 2015 Report.

84 See pre-filed direct testimony of Julia Frayer, Page 54.

85 The Brattle Group, "*A WIRES Report on the Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments*", Judy W. Chang, Johannes P. Pfeifenberger and J. Michael Hagerty, July 2013

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terms of energy price savings, based on a five-day heat wave event such as occurred in 2013: [redacted] LEI also quantified the benefit of Northern Pass in the event of a winter polar vertex event (a repeat of the conditions that prevailed in New England in the winter of 2013-14). [redacted]

Figure 7. Potential benefits of transmission investments

Benefit Category	Transmission Benefit	LEI	Brattle Group
1. Traditional Production Cost Savings	Production cost savings as traditionally estimated	●	○
1a-1i. Additional Production Cost Savings	a. Reduced transmission energy losses	◑	◑
	b. Reduced congestion due to transmission outages	○	○
	c. Mitigation of extreme events and system contingencies	●	○
	d. Mitigation of weather and load uncertainty	●	○
	e. Reduced cost due to imperfect foresight of real-time system conditions	○	○
	f. Reduced cost of cycling power plants	○	○
	g. Reduced amounts and costs of operating reserves and other ancillary services	○	○
	h. Mitigation of reliability-must-run (RMR) conditions	○	○
	i. More realistic representation of system utilization in "Day-1" markets	○	○
2. Reliability and Resource Adequacy Benefits	a. Avoided/deferred reliability projects	○	○
	b. Reduced loss of load probability or	◑	○
	c. Reduced planning reserve margin	○	○
3. Generation Capacity Cost Savings	a. Capacity cost benefits from reduced peak energy losses	●	●
	b. Deferred generation capacity investments	●	●
	c. Access to lower-cost generation resources	●	●
4. Market Benefits	a. Increased competition	○	○
	b. Increased market liquidity	○	○
5. Environmental Benefits	a. Reduced emissions of air pollutants	●	●
	b. Improved utilization of transmission corridors	○	○
6. Public Policy Benefits	Reduced cost of meeting public policy goals	○	○
7. Employment and Economic Development Benefits	Increased employment and economic activity; Increased tax revenues	●	● (KRA)
8. Other Project-Specific Benefits	Examples: storm hardening, increased load serving capability, synergies with future transmission projects, increased fuel diversity and resource planning flexibility, increased wheeling revenues, increased transmission rights and customer congestion hedging value, and HVDC operational benefits	◑	○

● = quantified ◑ = partially quantified/qualitatively identified ○ = not quantified/not identified

Source: The Brattle Group, "*A WIRES Report on the Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments*," Judy W. Chang, Johannes P. Pfeifenberger and J. Michael Hagerty, July 2013

As an extension of the polar vortex, energy flows on Northern Pass may also catalyze savings for gas consumers who use natural gas and are exposed to spot gas prices. Although LEI did not quantify those benefits, that does not make the benefits such consumer savings any less real.[86] The energy flows on Northern Pass can be expected to reduce the natural gas usage for

[86] To quantify such natural gas market impacts, on would need to employ a gas model that is integrated with the production cost simulation model. LEI did use the Gas Pipeline Competition Model ("GPCM"), produced by RBAC, to develop one of the gas scenarios in the Original Report. In other assignments, the GPCM model has been integrated in LEI's POOLMod. However, due to the time and effort involved, LEI did not deploy GPCM to measure the incremental impact on gas prices due to the flows on Northern Pass.

electric generation sector. As a result, regional demand for natural gas will be lower and that reduce the price of natural gas used by power plants in the region (especially during periods of high natural gas demand), which would then furthering decrease energy prices.

5 KRA's analysis of local economic impacts is flawed

In December 2016, Mr. Thomas E. Kavet and Mr. Nicolas O. Rockler of Kavet, Rockler & Associates, LLC ("KRA") released their study report entitled "Economic Impact Analysis and Review of the Proposed Northern Pass Transmission Project" ("KRA Report"), which was prepared on behalf of CFP. The KRA Report critiqued the analysis that LEI performed with respect to Northern Pass' New Hampshire and regional (New England) economic impacts. Mr. Rockler and Mr. Kavet also conducted their own analysis and presented the results in the KRA Report.

In the KRA Report (and the associated Pre-filed Testimonies), KRA agreed that "in general, the economic impact analysis by LEI was well-performed."[87] There are several important areas of agreement between KRA and LEI, including, but not limited to, the fact that the Project will undoubtedly generate material direct employment benefits for the state of New Hampshire and other indirect and induced positive net economic impacts during the construction and development phase. KRA and LEI also agree in principle that in the first 10 years of operations of the Project, there are significant economic benefits in New England (and New Hampshire) from reduced retail electricity market costs, even using the understated electricity market benefits that KRA carried over from The Brattle Group's analysis.

Nevertheless, there are several areas of disagreement between LEI and KRA. Most importantly, LEI believes that KRA's aggregate analysis of economic benefits to 2060 is flawed and unreliable. The forecast error of any model, even a sophisticated computable general equilibrium model like REMI PI+, will increase with time. Therefore the robustness of the projections will decline and in the words of Mr. Kavet, the analysis will become "sketchier."[88] In addition, KRA focused, much like The Brattle Group, on negative factors and excluded consideration of any offsets or positive externalities of the Project. More specifically, KRA, although admittedly not an electricity market expert, developed electricity market-related impacts that imply negative local economic impacts to New Hampshire (notably, those electricity market-related impacts are not supported in The Brattle Group's modeling).

5.1 KRA's long term economic impact analysis is not reliable

Typical modeling timeframes for macroeconomic analysis using REMI PI+ are in the range of 10 to 20 years.[89] In fact, KRA's other transmission-related studies that they mentioned in the technical sessions had looked over a 10 year operating timeframe.[90] This is not to imply that an infrastructure project such as Northern Pass would stop providing benefits to consumers and

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[87] See Pre-filed Testimony of Thomas E. Kavet (same as the Pre-filed Testimony of Nicholas O. Rockler), Page 3, Line 5. Docket No. 2015-06. Dec 30, 2016. Also See *Economic Impact Analysis and Review of the Proposed Northern Pass Transmission Project*, Dec 30, 2016. Page 2.

[88] Technical sessions, March 7, 2017

[89] Also during the technical sessions on March 7, 2017, KRA admitted that "*usually for a similar infrastructure development project, we model the construction period and about 10 years of the operations period.*"

[90] They only modeled 10 years of the operations period in their study for the New England Clean Power Link Project ("NECPL"), which is a similar project to Northern Pass.

the economy. Rather, modeling experts like KRA and LEI routinely constrain the timeframe of analysis in order to hedge the consequence of inherent modeling forecast error. LEI considered a timeframe of 11 years for its assessment of the local economic impacts of Northern Pass, once operations began, as discussed in the Original Report.[91] LEI could have extended the analysis perhaps another 5-10 years, but going any further, in the firm's opinion, creates significant concerns that the cumulative impact of modeling forecast error in REMI PI+ exceeds the confidence that we would like to show in the local economic projections. Although the firm may be somewhat uncertain about future gas prices and demand growth in the next 20 years, it is truly speculating about the structure of the electricity market and the economy 40+ years from today.[92]

Some of the inputs KRA used for the REMI modeling are also too "rough" for inclusion in a comprehensive aggregate economic impact analysis, especially the loss in tourism and the construction disruptions. Their assessment of the 1,000 MW retirement is not only inconsistent with The Brattle Group's modeling (as noted above), but also an exaggeration of the impact of such an unlikely event, as it is implausible to believe that the power plants that KRA retired would have continued to operate through 2060. Any minor underestimates or overestimates of these impacts that are put into the model can result in huge differences in economic outcomes in the long-term, especially in the later years when the estimated electricity benefit to ratepayers dissipates, and the impacts from the assumed power plant retirements and tourism-related effects dominate, as Mr. Kavet and Mr. Rockler agreed at the March 7, 2017 technical session. Moreover Mr. Kavet and Mr. Rockler conceded that the forecast error in their analysis increases over time.

KRA's approach for estimating long-term tourism impact is not based on reliable assumptions. For example, they assumed that the impacts will "phase in" over six years but then remain constant for the balance of the Project's life. In addition to the fact that KRA's tourism impacts are not based on the tourism sector directly, there is no foundation for assuming that the effects would not diminish with time. As new generations of tourists will come to New Hampshire, they will not have the same non-pecuniary concerns about the transmission infrastructure as it becomes an established element of the landscape. As described in the rebuttal report of Mr. Mitch Nichols of Nichols Tourism Group, Northern Pass should have no material lasting effect on tourism.

LEI does not find the long-term aggregate economic impact analysis presented in Figure 24 and Figure 25 on Page 75-76 in the KRA Report to be believable, because of the unreliable assumptions on which it is based, and the long forecast period. As presented in Section 5.6, the firm has provided for SEC's consideration a modified version of Table 24 and Table 25 from the KRA Report that corrects the errors and omissions in KRA's assumptions and aggregate impact analysis.

[91] LEI. "Cost-Benefit and Local Economic Impact Analysis of the Proposed Northern Pass Transmission Project." October 16, 2015. Page 13

[92] Unexpected changes in the local and national economics might happen and cannot be captured in the current model used by LEI. Even small changes that affect the forecast each year will compound over time to produce potentially large errors when predicting the long-term future.

5.2 Consideration of externalities by KRA was biased toward negative externalities

While criticizing LEI for not including certain negative externalities in the LEI Original Report,[93] KRA did not model negative externalities like traffic delays, property valuation loss and loss of local businesses in their study for the New England Clean Power Link Project ("NECPL") either. In their testimony on behalf of the NECPL before the Vermont Public Service Board, Mr. Kavet claimed that "impacts of such externalities are temporary and not significant enough to be included in the model."[94] Although KRA acknowledged that it was hard to model such externalities with high precision, they nevertheless included them in the analysis of Northern Pass. In LEI's opinion, including negative externalities in the REMI modeling without solid foundation only renders the modeling results less reliable.

Perhaps most concerning, KRA did not consider any offset or positive externalities in their aggregate analysis. For example, for the negative externalities projected to be experienced for the Town of Plymouth during construction due to traffic delays, there may be offsetting temporary positive economic impacts for surrounding communities with similar business.[95] In addition, Mr. Rockler conceded that the carbon emission reductions of the Project would be a measurable positive externality (and indeed he had in another project considered similar emissions reductions as an important economic benefit to the community).

Carbon emissions reduction is a valuable positive externality to the region of New England (and New Hampshire residents). LEI used the REMI PI+ model to estimate the economic consequences of this positive externality, based on the estimates presented in LEI's Updated Analysis and in The Brattle Groups' December 2016 Report.

Pursuant to LEI's Updated Analysis, the firm began with the estimated incremental societal benefits associated with CO_2 emissions reduction (based on the varying SCC values). These dollars were represented in the REMI PI+ model through the non-pecuniary amenity[96] policy variable, which proxies for observed regional distinctions in how the population values "qualify

[93] See Page 2 of the KRA Report, where KRA stated "We did not find the Applicants' stark conclusions regarding the complete absence of any potential negative property valuation or tourism impacts to be credible."

[94] Pre-filed direct testimony of Thomas Kavet on behalf of Champlain VT, LLC. December 8, 2014. Page 17 Line 20 – Page 18 Line 2. Docket No. 8400.

[95] KRA's assumption of 30% tourism loss is questionable as well. The loss rate stems from a Boston Globe news article about an underground construction of a drainage and sewage project upgrade in West Cambridge. This 30% is based on the voice of one business owner being interviewed, where she mentioned foot traffic, not sales, in her store went down 20-30%, though that has been made up for in higher sales per customer. There were also other business owners being interviewed mentioned 15%-20% percent. The people being interviewed were taken from a pre-selected group in the first place – people who were not affected might not have the incentive to express their voice. KRA took the highest percentage mentioned in the article, ignoring the fact that there were other lower numbers voiced by other business owners. KRA has also mistaken the loss in "foot traffic" as "sales," ignoring the fact that the loss in foot traffic could be made up for in higher sales per customer.

[96] The "Non-Pecuniary (Amenity) Aspects (amount)" policy variable changes the non-market "quality of life" component within the migration equation in the REMI PI+ model. For simulation purposes, the change may be quantified in terms of a real compensation change equivalent for Economic Migrants. An amenity increase perceived as a real compensation gain makes the region more attractive, so a greater number of economic migrants enter the region annually. This then affects the entire working age labor force.

of life" in the region.[97] Based on population-scaled allocations of the annual societal benefits, the states of New England are expected to attract more labor to the region, which then creates an opportunity for scaling up of economic activities.

LEI also tested the modeling of the positive externalities using The Brattle Group's estimates of the societal benefits of CO2 emissions reduction. The Brattle Group preferred to estimate this positive externality of the Project by reference to the avoided cost of alternative GHG emissions reduction options, as explained in their December 2016 report. Pursuant to their methodology, the societal benefit can be represented as the avoidance of direct subsidies that would otherwise be necessary in order to motivate other zero-carbon resources (wind and solar generation investment) in sufficient quantities to substitute for Northern Pass (in terms of carbon emissions avoided). LEI modeled The Brattle Group's positive externality value by simulating The Brattle Group's projection of the required retail electricity market subsidies in REMI PI+ (and to be conservative, LEI relied on the lower bound of $140 million per year from The Brattle Group's posited range).[98]

The results of this analysis, illustrated in the figures below, shows that the positive externality associated with carbon emissions reduction has significant value for both New England and specifically New Hampshire. LEI's approach shows the positive economic benefits are much more modest as compared to The Brattle Group's approach. This is because monetizing the CO_2 emissions reductions based on rising opportunity cost of retail electricity has more profound direct and indirect impact on the local economy, and therefore creates a bigger economic gain than what is implied by the scaling of the "quality of life" indicator).

On the basis of the more conservative LEI approach, the Project will create on average of 5 to 37 local jobs per year, and an average of $0.6 to $4.1 million increase in GDP per year during 2019-2029 in New Hampshire. Given that the social and economic benefits are concentrated more in the states of Massachusetts and Connecticut, the New England region as a whole will see more significant socio-economic benefits, namely improved employment of 52 to 386 jobs/year and $6.7 to $49.0 million increase in GDP annually during 2019-2029. On the other hand, if The Brattle Group's lowest estimates of the annual value of CO_2 emissions reduction are replied upon,[99] then the socio-economic benefits for New Hampshire average 140 additional jobs per year over the modeling timeframe, and $21.5 million increase in annual GDP. For the New

97 An example of prior studies that involved using REMI model to forecast amenity benefits from reduced GHG emissions include, but not limited to, Peter Gunther, "*Driving Smart Growth: Electric Vehicle Adoption and Off-Peak Electricity Rates.*" In this study Mr. Gunther analyzed the environmental amenity benefits due to the adoption of electricity vehicles in Connecticut.

98 The Brattle Group, "Electricity Market Impacts of the Proposed Northern Pass Transmission Project" Revised on February 10, 2017. Page xiii.

99 LEI I used The Brattle Group's low-end annual estimate of social value of $140 million per year. This estimate is for New England as a whole. LEI allocated to each state by on energy consumed, on the conservative assumption that each state in New England would want their pro rata share of the achieved CO_2 emissions reductions from new zero-emitting renewables. LEI modeled the avoided opportunity cost as electricity cost savings of various classes consumers (industrial, commercial, residential) in the REMI PI+ model.

England region as a whole, the Project would bring 1,368 new jobs on average per year and $236.7 million increase in the regional GDP.

Figure 8. Economic impacts on employment associated with carbon emission reduction due to the Project (annual average)

Employment impacts - annua average (Jobs)		Operations (Near-term) 2019-2029	
Impact Elements		New Hampshire	New England
Social cost of carbon - LEI	With 2.5% Discount rate	37	386
	With 3.0% Discount rate	25	253
	With 5.0% Discount rate	5	52
Opportunity cost for GHG emission - Brattle Group	$140 million per year	140	1368

Figure 9. Economic impacts on GDP associated with carbon emission reduction due to the Project (annual average)

GDP impacts - annua average (Millions of nominal $)		Operations (Near-term) 2019-2029	
Impact Elements		New Hampshire	New England
Social cost of carbon - LEI	With 2.5% Discount rate	4.1	49.0
	With 3.0% Discount rate	2.7	32.1
	With 5.0% Discount rate	0.6	6.7
Opportunity cost for GHG emission - Brattle Group	$140 million per year	21.5	236.7

Note: LEI's analysis of SCC starts from 2020 and The Brattle Group's for GHG emission cost starts from 2019. Hence the tables show the average annual economic impacts during 2020-2029 for the three LEI estimates, and the annual economic impacts during 2019-2029 for The Brattle Group's estimates.

5.3 KRA's analysis of the electricity market benefits of the Project is based on unreliable assumptions

Based on LEI's review, the largest differences in net economic impacts stems from the understated electricity market benefits calculated by The Brattle Group and used in KRA's study. During the operations period, the electricity benefits created by the Project are the major driver for the local economic benefits, outweighing other elements such as the O&M spending and economic development programs funded by the Project. Thus, accurately capturing the electricity market benefits is critical for analyzing the operations period economic benefits for the Project. Mr. Rockler and Mr. Kavet, however, are not experts in electricity markets and they simply relied on The Brattle Group's scenario 2 in their analysis.

In addition, KRA's decision to use The Brattle Group's Scenario 2 in the aggregate long-term economic impact analysis, shown in Table 24 and 25 of the KRA Report was not based on any critical and objective consideration, other than the fact that results of Scenario 2 landed somewhere in between the results of The Brattle Group's Scenario 1 and Scenario 3.

KRA's lack of expertise in wholesale electricity market dynamics was reflected in their inclusion of the effects of an additional of 500 MW of mothballing and 500 MW of retirement. For example, it became clear in the course of the March 7, 2017 technical session that KRA has assumed certain retirements that would create negative locate economic impacts fore New Hampshire, but which The Brattle Group had not projected specifically in their modeling. Although at the technical session, KRA modified their position slightly by suggesting that the retirements "could" happen, they did not adjust their aggregate, long term impact analysis.[100] KRA had to therefore develop their own assumptions about the effects of these plant closures. The labor data they used is not readily applicable[101] and KRA over-estimated the loss in employment by wrongly assuming, without any justification, that these units would have otherwise remained operating through 2060.

Figure 10 shows LEI's calculations (using KRA's version of the REMI PI+ workbook) of the difference associated in the net electricity market economic impacts from KRA's use of The Brattle Group's Scenario 2 with and without the additional 1,000 MW retirement. It appears that this assumption of 1,000 MW of generation retirement decreased the estimated employment and GDP impacts for New Hampshire considerably – after the correction, new jobs increased from 131 to 263 per year, and GDP growth increased from on average $10 million to $32 million per year during the near term operations period. In later periods (2030-2060), when the electricity market benefits are expected to dissipate according to The Brattle Group's assumption, the additional retirement applied by KRA becomes the driving factor for economic impacts, and the difference in impacts on GDP and employment are even bigger, even turning from negative to positive after the correction.

Figure 10. Comparison of KRA's economic impacts associated with electricity market benefits of The Brattle Group's Scenarios 2, with and without the impact of the assumed 1,000 MW of generation retirement

Impacts	Scenarios	2016-2020	2020-2030	2030-2040	2040-2050	2050-2060
Employment (individuals)	Brattle Scenario 2 w/ 1000MW retirement	40	131	-192	-183	-198
	Brattle Scenario 2 w/o 1000MW retirement	40	263	-33	-7	9
	Difference	**0**	**-131**	**-159**	**-176**	**-208**
GSP (MM fixed 2016$)	Brattle Scenario 2 w/ 1000MW retirement	$4	$10	-$30	-$40	-$54
	Brattle Scenario 2 w/o 1000MW retirement	$4	$32	$4	$4	$4
	Difference	**$0**	**-$22**	**-$34**	**-$44**	**-$59**

[100] For example, KRA could have probability-adjusted the results and that would have reduced the negative impact. However, they chose to leave the impacts at the implied 100% likelihood.

[101] Mr. Kavet and Mr.Rockler mentioned in the technical sessions on March 7th 2017, that they used FERC Form 1 and EIA data for estimating potential retirements. This means that they had to use proxies, as many of the IPPs are no longer filing the labor information on FERC Form 1. Specifically, utilities under the FERC jurisdictions that don't engage in wholesale transmission are not required to file these forms. Also, some State Regulatory Agencies have adopted the form under their regulatory process and some utilities are now filing this data under the State Regulator and not with FERC.

5.4 KRA's estimates of the local economic impacts associated with property tax revenue are too low[102]

In LEI's Original Analysis, LEI did not quantify the local economic impacts of property taxes because of uncertainty on how those taxes would impact New Hampshire. KRA posited in their report that property tax would be a net benefit and should therefore be included in the analysis. KRA provided tax benefit simulation in their report based on the assumption of 50% of the property tax revenue is used for increased local government spending, and the other 50% is modeled as a reduction in local government spending due to a reduction in debt.

First, it's important to note that KRA's property tax estimate is based on an incorrect specification of effective property taxes for utilities. KRA also simply assumed that the property taxes would go to $0 after 40 years. Lastly, KRA overlooked the possibility that there could be increased spending that might be associated with increased state business income taxes payable by Northern Pass.[103]

KRA also took the most extreme assumption that future property tax rates over the next 40 years will stay constant. KRA's specification of the impacts from debt reduction is inconsistent with their own statements that it is a benefit. In fact, KRA ignores the benefit from the reduction on property tax burdens due to the addition of the Northern Pass property tax revenue.

To correct for KRA's methodology for estimating LEI modified the inputs to be consistent with the calculations prepared by Dr. Lisa Shapiro in her analysis in October 2015.[104] Based on Dr. Lisa Shapiro's guidance, LEI analyzed the economic impacts in New Hampshire due to tax revenues under two scenarios:

1) Low tax revenue scenario: 50% of property tax with 1% annual growth rate, plus 50% of the state business tax revenue;
2) High tax revenue scenario: 50% of property tax with 2% annual growth rate, plus 100% of the state business tax revenue.

Results shown in [redacted] and [redacted] below suggest that in the high tax revenue scenario, the State of New Hampshire will benefit from property tax revenues with employment improvements of 477 jobs per year during 2019–2029, and 203 jobs per year during 2030–2040. The high tax revenue scenario also shows an increase in GDP on average by $44 million and $26 million annually during the near- and mid-term operations periods, respectively. In the low tax revenue scenario, New Hampshire will see an increase in employment by 382 jobs per year during 2019–2029, and by 175 jobs per year during 2030–2040. The low tax revenue scenario also

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102 The observations and critiques of KRA's property tax analysis are based on the joint analysis of LEI and Dr. Lisa Shapiro

103 See Dr. Lisa Shapiro's Supplemental Testimony, April 17, 2017, Attachment A. And Northern Pass' Response to Counsel for the Public Expert-Assisted Data Request EXP-1-2-30.

104 Lisa Shapiro. "Northern Pass Transmission Project - Estimated New Hampshire Property Tax Payments Report." October 16, 2015. Page 16. LEI extended the property tax payment by two years to 2040 with guidance from Dr. Lisa Shapiro.

shows an increase in GDP on average by $36 million and $22 million annually during the near- and mid-term operations periods respectively.

Figure 11. Economic impacts on employment associated with property tax and state business income tax from the Project (annual average)

Employment impacts in NH - annual average (Jobs)				
Scenarios	**Assumptions**	**2015-2019**	**2019-2029**	**2030-2040**
High Tax Revenue Scenario	50% Property Tax (2% Growth Rate)	0	293	142
	100% State Business Income Tax	0	184	61
	Total	**0**	**477**	**203**
Low Tax Revenue Scenario	50% Property Tax (1% Growth Rate)	0	289	143
	50% State Business Income Tax	0	93	32
	Total	**0**	**382**	**175**

Figure 12. Economic impacts on GDP associated with property tax and state business income tax from the Project (annual average)

GDP impacts in NH - annual average (Millions of nominal $)				
Scenarios	**Assumptions**	**2015-2019**	**2019-2029**	**2030-2040**
High Tax Revenue Scenario	50% Property Tax (2% Growth Rate)	$0	$27	$18
	100% State Business Income Tax	$0	$17	$8
	Total	**$0**	**$44**	**$26**
Low Tax Revenue Scenario	50% Property Tax (1% Growth Rate)	$0	$27	$18
	50% State Business Income Tax	$0	$9	$4
	Total	**$0**	**$36**	**$22**

Source: LEI's analysis, Lisa Shapiro's analysis

5.5 KRA's workbook contains errors that erroneously lower the economic benefits to New Hampshire from labor spending during construction of the Project

When modeling labor cost with REMI PI+ model, KRA claimed they used the same compensation inputs as LEI, except for necessary currency unit conversions. However, they mistakenly mismatched the "Compensation"[105] inputs for the "Professional, Scientific, and Technical Service" sector among the six New England states. Specifically, they had mistakenly input a zero dollar value for "Compensation" variable under the "Professional, Scientific, and Technical Service" sector the in New Hampshire, which is impossible because the majority of the construction activities will take place in New Hampshire. It appears that KRA may have mixed up rows from LEI's inputs (LEI, appropriately, had a zero value for Rhode Island in its workbook).[106] The impact on the modeling results caused by this mistake is significant,

[105] The "Compensation (amount)" policy variable is used to adjust the compensation associated with exogenous employment changes without changing the compensation rate for all employees within a given industry.). In addition to having a zero value for New Hampshire, KRA put in the Compensation values that should have been associated with New Hampshire into the Compensation input field for Connecticut.

[106] KRA has also mistakenly placed Maine's inputs into the field for Rhode Island, and Connecticut's inputs into the field for Maine.

especially given that the KRA Report only presents the economic impacts to New Hampshire in Table 24 and 25.

LEI corrected "Compensation" inputs allocated to each state in KRA's version of the REMI PI+ workbook and re-ran the PI+ model (holding all else constant, including the currency units used by KRA and any other adjustments made by KRA). The corrected modeling results are presented in Figure 13 below. During the operations period of 2020-2030, the economic impacts on both employment and GDP change from negative to positive, for example from -$5 million to $27 million for New Hampshire's annual average change in GDP in the 2020-2030 timeframe.

Figure 13. KRA's economic impacts in New Hampshire due to labor spending during construction with corrected compensation inputs

Impacts	Scenarios	2016-2020	2020-2030	2030-2040	2040-2050	2050-2060
Employment (individuals)	KRA's estimates	1050	-53	-2	13	14
	KRA's estimates with corrected Compensations	1159	202	-37	7	25
	Difference	**-110**	**-255**	**35**	**5**	**-11**
GDP (MM fixed 2016$)	KRA's estimates	$85	-$5	$0	$2	$2
	KRA's estimates with corrected Compensations	$94	$27	$5	$6	$6
	Difference	**-$9**	**-$32**	**-$5**	**-$4**	**-$5**

Source: LEI's analysis and the KRA Report

The corrected result shows negative impact on employment during the decade of 2030-2040. This is not related to any direct impact of the Project, but a result of the REMI PI+ model's logic for representing modest and temporary contractions of the economy after a construction boom.

5.6 KRA's other criticisms of LEI's REMI PI+ analysis are not material to the conclusions

Some of KRA's criticisms of LEI's local economic impact analysis appear to be triggered by KRA's misunderstanding of LEI's methodology and analysis. On Page 53 of the KRA report, KRA faulted LEI for not including the local economic impacts of the Forward New Hampshire Fund[107] – but LEI had in fact included that during the operating period and specifically brought that to KRA's attention in the course of the discovery process. On page 14 of the KRA Report, Mr. Rockler faulted LEI for not considering the overestimating of intermediary goods and services related to the material expenditure of the Project, but in fact LEI had considered this issue – but had adjusted for it in a different way. Similarly, Mr. Rockler complained that LEI used high compensation rates (see page 12 of the KRA Report), but he failed to acknowledge that using a modified approach resulted in almost the same outputs.

As KRA acknowledged in their report and also at the technical sessions, the REMI model is very flexible.[108] There are multiple approaches for modelers to take within the model to simulate an impact – for example, in order to capture the impacts of labor-related spending, a modeler can input total dollars spent in "industry sales" or use the combination of "employment" and "compensation" policy variables. When reviewing KRA's criticisms, LEI found that in most

[107] See Page 53 of the KRA Report, "The economic benefits from these [Forward New Hampshire Plan] expenditures were not included in the LEI economic model run as a part of the Applicants' SEC submission."

[108] See *Economic Impact Analysis and Review of the Proposed Northern Pass Transmission Project*, Dec 30, 2016. Page 10. They also agreed on this point during the technical sessions on March 7th 2017.

cases, KRA raised modeling issues that fall within this area of professional judgment. Moreover, based on LEI's tests using KRA's version of the REMI PI+ workbook, the results are not materially affected by the choice of approach.

5.6.1 KRA overlooked LEI inclusion of the Forward New Hampshire Fund in LEI's original analysis

Based on the information provided by the Applicant to LEI at the time of LEI's October 2015 Report, Northern Pass will spend $205.3 million from 2019 to 2038 on the Forward New Hampshire Plan to support clean energy innovations, economic development, community investment, and tourism. LEI included this local spending as a component of "Economic Development" in its REMI PI+ modeling, and it was labeled as such in the work papers provided to KRA dated September 2016.[109] Ms. Frayer also clarified this aspect of LEI's analysis several times in her technical sessions on September 16, 2016 and September 30, 2016, as well as in her response to Information Request CFP 1-16.[110]

It appears that KRA did not review LEI's work papers and data request responses thoroughly. On Page 53 of KRA's Report, they asserted that "the economic benefits from [the Forward New Hampshire Plan] were not included in the LEI economic model run as a part of the Applicants' SEC submission."

5.6.2 LEI's approach to modeling labor spending was conservative

KRA in their report on Page 12 argued that LEI used extraordinarily high compensation rates for estimating labor cost of the Project's construction period. The data for labor spending for third party services was provided by the Applicants. The compensation rates were for fully-loaded compensation. LEI used the fully-loaded compensation in order to be consistent with the REMI Policy Variable of "Annual Compensation Rate" that was used as baseline data. LEI could have modeled labor-related expenditure as Industry Sales, and that would have led to a higher number of increased GDP and Employment than what LEI had presented. Therefore, LEI's approach, despite the use of arguably high compensation rates, was conservative.[111]

5.6.3 LEI had corrected for potential overestimation of spending on materials by using a "value added correction" technique

When modeling the Project's expenditure on materials as industrial sales in the REMI PI+ model, one needs to consider potential double counting of intermediate demands for labor and materials, that are not relevant or may already be captured somewhere else due to the linkages between sectors in the REMI PI+ model. LEI recognized this issue and adjusted for the potential over-estimation by using a "value added correction" technique.

KRA argued on Page 14 of their report, that "because LEI allowed REMI to utilize its own default material purchases, a significant additional set of expenditures were included in the LEI

[109] It's shown in the workbook "LEI Labor and Wage Data_0920.xlsx," Tab "To REMI" Row 94.

[110] See Docket No. 2015-06, CFP 1-16.

[111] And notably, if LEI had used the REMI baseline data and BLS data as proxies for a lower compensation rates (as suggested by KRA), that would have resulted in higher GDP impacts and bigger job increases.

analysis that are both erroneous and irrelevant to transmission line construction." In their Table 4 on Page 15 of their report, they showed a total of "$336 million were incorrectly included in the impact estimates."

In fact, LEI was aware of this potential over-estimation. While LEI did not have the benefit of a detailed schedule of intermediate demand resulting from expenditures on materials, it was able to estimate the net value added to the local economy by the Project's construction, excluding irrelevant or intermediate demands that would outflow to other economies. As a result of this adjustment, the total material expenditure that went directly into the PI+ model decreased from $134.3 million to $35.7 million, a 74% reduction. This adjustment allowed LEI to more accurately and conservatively reflect the supply-demand relationship behind the overall project spending and its impact to the local economy. [112]

KRA apparently either did not see this in LEI's work papers, or did not understand the "value added" correction performed by LEI.[113] In Table 4 (Page 19 of their report) KRA tried to show the difference between LEI's GDP outputs and KRA's estimation of "direct" economic impacts of the Project. KRA calculated the "direct" impacts by entering only direct employment estimated by LEI into the REMI PI+ model. By including only the direct employment into the model, KRA is actually assuming that there will not be any induced economic impacts owing to supply-chain effects, or new investment owing to the investment of this Project. This is an extreme underestimation of the economic outputs.

5.6.4 Adjusting for capital stock change is not required owing to its marginal impact[114]

As stated on page 15 of the KRA Report, LEI did not adjust for the capital stock in the REMI model. KRA then went on to claim that by not doing this adjustment, LEI neglected the negative impact from displaced investment, which otherwise might have occurred in the absence of the Project.

First, it is important to note that LEI modeled the construction and operations periods separately, as is the convention in the field of economic impact analysis. When looking at only the economic impacts for the construction period of the Project, it is not necessary to change the capital stock baseline in the REMI PI+ model at the end of the construction period. For the construction period, as KRA acknowledged in their report (see footnote 4 on page 15), adding the capital stock will have only minimum impacts on the economic outputs, because even with the Project, the capital stock is still substantially below the ideal level in New Hampshire.

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112 The procedure is described in detail in LEI's REMI workbook "LEI Labor and Wage Data_0920.xlsx," within the tab called "NU Material data," This work paper was provided to KRA in September 2016.

113 On page 14 of the KRA Report, they observe that LEI did in fact make the "value added" correction, but fail to link it to the issue that they raise with respect to intermediary demand: "LEI separately shows material purchases in New Hampshire of $134 million…LEI's REMI input files show only $35.7 million for nonmetallic mineral production (i.e., ready-mix concrete) manufacturing. We do not know what happened to the other $98 million of materials purchases that were to have occurred in New Hampshire." The total raw material expenditure in NH provided by the Applicants was $134.3 million, and the $35.7 million was the amount used by LEI in the REMI PI+ model after the "value added" correction.

114 According the logic of the REMI PI+ model, in the capital stock adjustment process, investment occurs to fill the difference between optimal and actual capital stock for investment.

Second, KRA incorrectly allocated the capital stock value among the six states in New England using the ratio of the six states' GDP. This allocation is not reasonable given the entire Project is sited in New Hampshire, and therefore only New Hampshire will see a change in capital stock from this Project.

Third, while adding capital stock to an economy can have minor negative impact in the near term as a result of potentially displaced investment, in the longer term, infrastructure could make this economy more attractive to investors, and therefore bring economic prosperity to this economy. Indeed, KRA's long term aggregate results show this positive value in the long run. LEI's approach, therefore, was conservative as it did not include this adjustment.

5.7 LEI's comprehensive corrections and adjustments to KRA's long-term aggregate economic impacts

Section 12 of the KRA report discusses the aggregate economic impacts over the modeling period from 2016 to 2060.[115] Tables 24 and 25 on Pages 75 and 76 of the KRA Report summarized the Project's impacts on Employment and GDP within New Hampshire, for each individual "Impact Element" considered by KRA and on a composite basis over each decade of KRA's selected modeling periods.

As stated at the start of Section 5, LEI does not believe that KRA's estimate of the long-term aggregate economic impacts is reliable. Therefore, the value of the information conveyed in KRA's table is questionable, especially in the longer term. Even the accuracy and reliability of the analysis of the construction period and the near-term operations period is jeopardized by errors in KRA's inputs and other unjustified assumptions.

Figure 14. Aggregate economic impact of the Project on New Hampshire's Employment (annual average jobs)

Employment impacts - annual average (Jobs)	Planning & Construction	Operations (Near-term)	Operations (Mid-term)
Impact Elements	**2015-2019**	**2019-2029***	**2030-2040**
Construction & Development	1139	-62	-1
Electricity Market Effects	0	941	-252
Operations & Maintenance	0	16	10
Property Tax Effect	0	289 - 293	142 - 143
Forward NH Plan	0	191	103
Tourism Effects	0	0	0
Construction Disruption	0	0	0
Business income tax	0	93 - 184	32 - 61
Reduced Carbon Emissions	0	5 - 140	15 - 97
Total	**1139**	**1301 - 1703**	**49 - 161**

[115] The modeling period is further divided into: Construction Period (2016-2019), Near-Term Operational Period (2020-2030), Mid-Term Operational Period (2030-2040), Late-Term Operational Period (2040-2050), and Long-Term Operational Period (2040-2050).

Figure 15. Aggregate economic impact of the Project on New Hampshire's GDP (annual average GDP in millions of nominal dollars)

GDP - annual average (Millions of nominal $)	Planning & Construction	Operations (Near-term)	Operations (Mid-term)
Impact Elements	**2015-2019**	**2019-2029***	**2030-2040**
Construction & Development	$92	-$8	$1
Electricity Market Effects	$0	$141	$2
Operations & Maintenance	$0	$3	$4
Property Tax Effect	$0	$27	$18
Forward NH Plan	$0	$18	$13
Tourism Effects	$0	$0	$0
Construction Disruption	$0	$0	$0
Business income tax	$0	$9 - $17	$4 - $8
Reduced Carbon Emissions	$0	$1 - $22	$5 - $25
Total	**$92**	**$191 - $220**	**$46 - $70**

Notes:

1. Near-term Operations period of 2019-2029*: LEI's updated analysis of SCC starts from 2020. Hence the tables show the average annual economic impacts during the Near-term Operations period of 2020-2029 for the LEI's estimates for the socio-economic benefits for the "Reduced Carbon Emissions" impact element.

2. In the Mid-term Operations period (2030-2040), the "Construction & Development" Impact Element exhibits negative average impacts on employment. This is not related to any direct effect of the Project, but a result of the REMI PI+ model's logic for representing modest and temporary contractions of the economy after a construction boom.

3. In the Mid-term Operations period (2030-2040), for the "Electricity Market Effects" Impact Element, the REMI PI+ model is projecting negative average impacts on employment. This is not because of any specific electricity market cost increases associated with the Project. Rather, this projected outcome is the result of the REMI PI+ model's logic for representing modest and temporary contractions of the economy due to the end of a high economic growth period during 2019-2029.

Hence, LEI has computed an alternative long-term aggregate economic impact matrix, correcting for the mistakes, unjustified assumptions, and omissions in KRA's analysis. The results are presented in [redacted] and [redacted] above. The details behind LEI calculation of the results shown in [redacted] and [redacted] are described in the summary table in both Figure 16 and in Appendix C.

By comparing LEI's [redacted] and [redacted] with KRA's Table 24 and 25 in the KRA Report, keeping in mind the currency unit conversions,[116] LEI finds that the total economic impacts during the Planning & Construction periods are similar, despite errors in KRA's inputs. This is because LEI is looking at the construction period independently of the operations period, and strictly assumes there are no positive economic impacts from other Impact Elements. On the other hand, KRA in their Table 25 and Table 26 included positive economic impacts from

[116] LEI's results are presented in current dollars while KRA presented their results in 2016 real dollars.

"Electricity Market Effects", "Property Tax Effects", and "Forward NH Plan" during their Planning & Construction period. Therefore, a better point of comparison is only the results of KRA's "Construction & Development" Impact Element to LEI's total (LEI's total for this first period shows an employment improvement of 1,139 new jobs/year and a GDP increase of $93 million per year on average, versus KRA's Table 24 and Table 25, which show an increase in employment by 1,050 jobs/year and a GDP increase of $84 million per year on average).

The differences in the LEI and KRA estimates over the Near- and Mid- Term Operations periods are more stark. LEI projects 1,301 to 1,703 new jobs per year and $191 to $220 million increase in GDP during 2019-2029 period for New Hampshire on an aggregate basis, while KRA only forecasts 321 new jobs per year and $22 million annual increase in GDP. During the Mid- Term Operations periods, LEI's [redacted] and [redacted] show 49 to 161 new jobs per year and on average of $46 to $70 million increase in GDP every year in New Hampshire. On the other hand, KRA shows negative economic impacts of 191 job losses per year and on average $31 million decrease in GDP. The comparisons highlight the magnitude of the underestimation of the local economic benefits of the Project by KRA, as a result of their flawed inputs and assumptions.

By presenting these aggregate economic impacts, LEI is not trying to illustrate a "best case scenario." Rather, LEI hopes that its correction and re-estimation of the aggregate longer term impacts of the Project provides a robust data point for the SEC to consider, and one that is well-grounded in the evidence presented in this proceeding.

A brief explanation of the inputs and adjustments included in LEI's aggregate longer term analysis are described in the figure below. For more details, please also refer to Appendix C.

Figure 16. Summary of inputs and adjustments for LEI's aggregate economic impact analysis

Impact Elements	LEI's Inputs and Adjustments
Construction & Development	LEI's Original Analysis (KRA's inputs had errors as discussed in Section 5.5)
Electricity Market Effects	LEI's Original Analysis; LEI also removed KRA's additional retirement
Operations & Maintenance	LEI's Original Analysis, excluding Forward NH Plan so that it can be modeled as a separate impact element
Property Tax Effect	Based on Dr. Lisa Shapiro's rebuttal analysis (50% of the total property tax revenue with 1% and 2% annual growth rates)
Forward NH Plan	LEI's Original Analysis
Tourism Effects	Removed KRA's estimates based on conclusions from Mr. Nichols
Construction Disruption	Removed KRA's estimates based on conclusions from Mr. Nichols. Negative impacts will be neutralized by increased economic activities in other locations
Business income tax	Estimated by Eversource; LEI modeled 50% and 100% of the state business income tax revenues, based on guidance from Dr. Lisa Shapiro
Reduced Carbon Emissions	Two approaches that considered socio-economic benefits of positive externality as discussed in Section 5.2

6 Appendix A – LEI's estimate of Hydro-Québec Production supply and demand outlook

6.1 LEI's estimate of HQP energy supply and demand outlook

[redacted] summarizes LEI's analysis for HQP's energy supply and demand outlook. The "Firm" outlook represents a forecast of HQP's surplus energy in 2021 considering its current firm commitments; the "Forecast" outlook represent HQP's excess energy in 2021 considering the forecast usage by HQD of the Heritage Contract (which is below the contracted maximum energy). Given a forecast energy supply of 211 TWh and firm commitments of 184 TWh, LEI expects HQP to have 27.1 TWh available for export. Taking into account existing long-term commitments in the export markets and losses, this leaves 21.5 TWh of "firm" energy surpluses available for exports over Northern Pass or other transmission paths in 2021. In all cases, HQP has more than sufficient energy surpluses to serve New England via Northern Pass,[117] without a need for additional generation beyond what currently exists or is in construction.

Due to some contracts ending in the 2020s (such as the Base & Adjustable contracts with HQD), HQP's firm energy surplus is expected to remain at the same level or even rise going forward. Construction of new generating capacity over the longer term, either hydropower or wind powered, is also a possibility.

[117] Flows over Northern Pass are expected to be less than 8 TWh annually.

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Figure 17. LEI's estimate of HQP firm energy supply and demand outlook

2021 TWh	Firm	Forecast	Sources
Total Energy Supply	**211.3**	**211.3**	
(1) Hydro Generation	178.0	178.0	*Hydro-Québec 2009-2013 Strategic Plan*
(2) Thermal Generation	-	-	*HQP capacity demonstration, December 2014*
(3) Purchases (incl. Churchill)	33.3	33.3	*HQP capacity demonstration, December 2014*
Total Energy Commitments	**184.2**	**172.0**	
(4) Heritage Contract	178.9	166.7	*HQD supply plan, 2017-2026*
(5) Base & Adjustable Contracts	3.2	3.2	*HQD supply plan, 2017-2026*
(6) Long-term RFP 2015-01 (HQD)	0.0	0.0	*HQD supply plan, 2017-2026*
(7) Deliveries & Plant Usage	2.1	2.1	*Hydro-Québec 2009-2013 Strategic Plan*
Availability for exports	**27.1**	**39.3**	
(8) Long-Term Sales outside Québec	2.0	2.0	*Hydro-Québec 2014 Annual report*
(9) Ontario electricity trade agreement	2.0	2.0	*IESO 18-month outlook, 2017-2018*
(10) Losses on spot exports	1.6	2.4	*HQT Provisional Tariff, 2017*
Availability for spot market exports	**21.5**	**32.9**	

Available on www.hydro-quebec.com
Available on www.regie-energie.qc.ca
Available on www.ieso.ca
Available on www.oatioasis.com/hqt

Notes:

(1) Includes 8 TWh generation from the 1,550 MW Romaine complex, scheduled be fully commissioned by 2021

(2) HQP's generation fleet includes one 411 MW thermal plant, however it is used for reserve purposes and as such does not generate any material quantity of energy

(3) Includes long-term energy purchases from the Churchill Falls hydropower station in Labrador, and other private producers

(4) Annual energy deliveries under the Heritage Contract are capped at 178.9 TWh however, HQD expects needing only 166.7 TWh in 2021

(5) These so-called "Post-Heritage" contracts were entered into between HQP and HQD following a competitive solicitation, and will expire in 2027

(6) HQP won HQD's 2015 RFP for 500 MW of capacity; however, HQD does not forecast using any material quantity of energy in 2021 from that contract

(7) Energy used for the generating stations' own energy needs (station service)

(8) Includes sales to Cornwall Electric (Ontario) and the Vermont Joint Owners

(9) As part of the electricity trade agreement between Ontario and Québec announced in October 2016, Ontario will receive up to 2 TWh of clean energy annually

(10) Transmission losses on HQT system are 6.0%. While HQD accounts for transmission losses in its energy needs forecast, HQP is responsible for losses on export transactions

6.2 LEI's estimate of Hydro-Québec Production's capacity supply and demand outlook

[redacted] summarizes LEI's analysis for HQP's capacity supply and demand outlook. In 2021, HQP has more than sufficient excess capacity not only to provide 1,000 MW over Northern Pass, but also provide capacity over the Phase II and Highgate interfaces,[118] without a need for additional generation beyond what currently exists or is already under construction.

LEI estimates that HQP's excess capacity could rise going forward. Notably, Hydro-Québec's strategic plan commits to increasing the capacity of existing assets by 500 MW, by 2025, but presumably a portion of these uprates could be ready ahead of 2025. Furthermore, the Base & Adjustable contracts are set to expire in 2027. Finally, the construction of new generating capacity over the longer term, either hydropower or wind powered, is also a possibility.

It is important to note that the Québec Control Area is a winter-peaking region. As such, the amount of excess capacity shown in LEI's outlook represents excess capacity for the coldest months from the perspective of Quebec, typically January or February. As summer peak load in Québec is approximately half of the winter load,[119] it follows that HQP has much greater excess capacity to sell at the time of ISO-NE's expected summer peak than the forecast 1,527 MW presented in [redacted].

[118] In recent years, tie benefits have limited capacity sales over Highgate below 60 MW, while HQICCs have limited capacity sales over Phase II below 450 MW.

[119] NPCC's 2016-17 winter reliability assessment lists the Québec Control Area peak load as 37,870 MW, while the 2016 summer reliability assessment listed the province's peak load as 20,833 MW

Figure 18. LEI's estimate of HQP capacity supply & demand outlook

2021 MW	Capacity	Sources
HQP Winter Resources	**41,427**	
(1) Available Generation	39,729	*HQP capacity demonstration, December 2016*
(2) Demand Response	358	*HQP capacity demonstration, December 2016*
(3) La Romaine add. post 2016-17	640	*La Romaine project website*
(4) Ontario electricity trade agreement	500	*IESO 18-month outlook, 2017-2018*
(5) Other capacity purchases	200	*HQP capacity demonstrations, historical*
HQP Domestic Commitments	**39,648**	
(6) Heritage Contract (HQD)	34,342	*HQD supply plan, 2017-2026*
(7) Base & Adjustable contracts (HQD)	1,000	*HQD supply plan, 2017-2026*
(8) Wind Integration Contract (HQD)	371	*HQD supply plan, 2017-2026*
(9) Long-term RFP 2015-01 (HQD)	500	*HQD supply plan, 2017-2026*
(10) Short-term transaction (HQD)	0	*HQD supply plan, 2017-2026*
(11) LCHM	94	*HQP website*
(12) Plant Usage	56	*HQP capacity demonstration, December 2016*
(13) Reserve Margin	3,285	*HQP capacity demonstration, December 2016*
Excess Capacity	**1,779**	
(14) Cornwall Electric	145	*HQP capacity demonstration, December 2014*
(16) Losses on Exports	107	*HQT Provisional Tariff, 2017*
Excess Capacity for Exports	**1,527**	

Available on www.hydro-quebec.com
Available on www.regie-energie.qc.ca
Available on www.ieso.ca
Available on www.oatioasis.com/hqt

Notes:

(1) Includes resource capabilities as of December 2016
(2) Only includes demand response resources that are activated by HQP
(3) Include two units totaling 295 MW from the "Romaine 3" plant to be commissioned at the end of 2017, and two units totaling 245 MW from the "Romaine 4" plants to be commissioned at the end of 2020

(4) As part of the electricity trade agreement between Ontario and Québec announced in October 2016, Ontario will supply 500 MW of capacity to Québec during the winter months
(5) Based on the average from historical HQP capacity demonstrations
(6) Hourly deliveries under the Heritage Contract are capped at 34,342 MW
(7) HQD holds an option for 400 MW in addition to the base 600 MW capacity commitment, as such HQP cannot commit the capacity to another buyer until HQD notifies whether it calls on the capacity or not
(8) Corresponds to the difference in contractual capacity provided to HQD (40% of nameplate) versus recognized capacity contribution of wind resources (30% of nameplate)
(9) HQP won HQD's 2015 RFP for 500 MW of capacity, for a 20-year term
(10) HQP does not currently have a short-term capacity commitment to HQD
(11) McCormick generating station is operated by a limited partnership between Hydro-Québec (60%) and Alcoa (40%)
(12) Maximum station service load
(13) Reserve margin necessary for HQP to guarantee its capacity commitments, so that the Québec Control Area can meet the NERC LOLE criterion of 1 day in 10 years
(14) HQP has a contract to supply a maximum of 145 MW to Cornwall Electric (Ontario)
(15) Transmission losses on HQT system are 6.0%. Sales to HQD are not be subject to transmission losses

7 Appendix B – LEI's indicative MOPR analysis for a 1,000 MW CSO on Northern Pass

In order to perform its MOPR analysis, LEI used ISO-NE's "New Generating Capacity Resource Model" provided on the ISO website.[120] LEI relied on ISO-NE's cost workbook for FCA#11, so as to be consistent with other LEI analyses.

7.1 Inputs, sources and methodologies

The following section describes each input used by LEI, as well as the source or method used to derive the input:

Input	Value	Source
Project Overview		
Nameplate capacity	1,090 MW	Section 4 of LEI's October 2015 report
Assumed average capacity factor over lifetime	83.3%	Section 2.9 of LEI's October 2015 report
Estimated FCM qualified capacity	1,000 MW	Section 4.2 of LEI's October 2015 report
Commercial operation date	6/1/2020	ISO-NE workbook default value for FCA#11
Estimated project life	40 years	Applicant's filing - Northern Pass Transmission Project – Estimated New Hampshire Property Tax Payments Report, Section III
Investment Characteristics		
EPC cost (2017$)	$1,627 million	Publicly released by applicant in SEC proceedings
Debt ratio	50%	Section III, attachment B of the Transmission Service Agreement
Pre-tax cost of debt	5%	Consistent with cost of debt for corporations having similar credit rating as applicant
After-tax cost of equity	11.74%	Calculated from information in Section III, attachment B of the Transmission Service

[120] According to model instructions, "Import resources associated with an Elective Transmission Upgrade […] should utilize the New Generation Resource workbook and related User Guide".

		Agreement
Inflation rate	2%	LEI estimate, consistent with all LEI analyses in these proceedings
Federal tax rate	35%	ISO-NE workbook default value
State tax rate	8.5%	ISO-NE workbook default value for NH
MACRS depreciation Schedule	15-year MACRS (100% weight)	Standard industry practice for transmission
Project Revenues and Costs		
Energy revenues	See note (1) below	
CPP and other revenues	See note (2) below	
Energy opportunity cost	See note (3) below	
Capacity opportunity cost	See note (4) below	
Property tax	Applicant's filing - Northern Pass Transmission Project – Estimated New Hampshire Property Tax Payments Report, figure 9	
Economic Development Programs	Released in LEI workbooks	
ROW lease	Released in LEI workbooks	
Transmission Support Expense	Released in LEI workbooks	
Operation & maintenance	Released in LEI workbooks	

Notes:

(1) Represents the energy revenues as calculated by LEI (8.0 TWh of energy multiplied by the annual realized energy price), as disclosed in LEI's February 2017 Updated Analysis

(2) In order to conservatively calculate CPP bonus payments over the life of the transmission line, LEI assumed that:

a. HQP would deliver on average 1,000 MW during all Capacity Scarcity Conditions (which actually represents a discount of 8.3% with respect to Northern Pass' nameplate capacity);
b. The balancing ratio would average 75% during Capacity Scarcity Conditions, as assumed by the ISO-NE IMM in calculating the dynamic de-list bid threshold; and
c. The number of Scarcity Condition Events over the life of the asset is calculated as shown in LEI's answer to CFP's technical sessions Data Request number seven.

Furthermore, Northern Pass would likely be eligible to receive compensation for providing blackstart or VAR support service. However, LEI did not consider those revenues in the present analysis out of an abundance of caution.

(3) As shown in the energy supply & demand outlook, HQP will not need to build additional generation infrastructure in order to supply energy over Northern Pass. As such, given that HQP operated large hydroelectric plants with very low variable costs, the "cost" of providing energy over Northern Pass is not the cost incurred to generate electricity, but rather the value of foregone opportunities from selling that energy in other markets (the "opportunity cost"). Given the anticipated levels of HQP's annual exports and the transfer capacity of other interfaces between Québec and the neighboring jurisdictions, LEI's modeling suggests that, absent Northern Pass, HQP would be forced to sell an equivalent amount of energy in the Ontario market during off-peak hours. As such, LEI leveraged its Continuous Modeling Initiative ("CMI")[121] energy price forecast for IESO markets to calculate HQP's energy opportunity cost. This is actually a conservative estimate, as HQP's marginal sales would more likely earn a realized price much below the average off-peak price.

It is important to note, as discussed previously, that HQP must pay the same tariff for point-to-point transmission service on HQT's system for all sales outside Québec are always. This includes sales over legacy interfaces, as well as sales over a new interface such as Northern Pass. As such, HQP does not incur any additional charge for selling energy over Northern Pass versus selling energy over a legacy interface. It results that the transmission costs north of the border net out in the opportunity cost calculation, and have therefore no impact on the MOPR calculation.

(4) HQP does not have capacity opportunity costs. Among the markets adjoining the Québec Control Area, only NYISO and ISO-NE have organized capacity markets. In NYISO, HQP has External CRIS Rights[122] to sell capacity for the months of April to November but they do not possess such rights for the months of December through

[121] As part of its CMI initiative, LEI creates bi-annual energy and capacity (if applicable) price outlooks for most markets in Canada and the US. For the MOPR analysis, LEI relied on its 2016 Q3 CMI results for the IESO markets. The CMI reports can be obtained from www.londoneconomicspress.com

[122] External CRIS Rights allow external resources to sell capacity to the NYISO. Since NYISO holds monthly "spot" capacity auctions (as opposed to ISO-NE's annual FCA), each resource has the ability to sell capacity only for some portions of the year

March.[123] Since Québec is a winter-peaking region and summer peak load in Québec is approximately half of the winter load, it follows that HQP has much more excess capacity to sell during the summer period than the forecast 1,527 MW.[124] Given HQP's large surplus capacity in the summer months, they are able to sell capacity to NYISO as well as in ISO-NE's FCM. Therefore, selling capacity over Northern Pass on an annual basis would not reduce HQP's ability to sell capacity in the NYISO for all the months for which they possess External CRIS Rights in NYSIO.

7.2 Results

[redacted]

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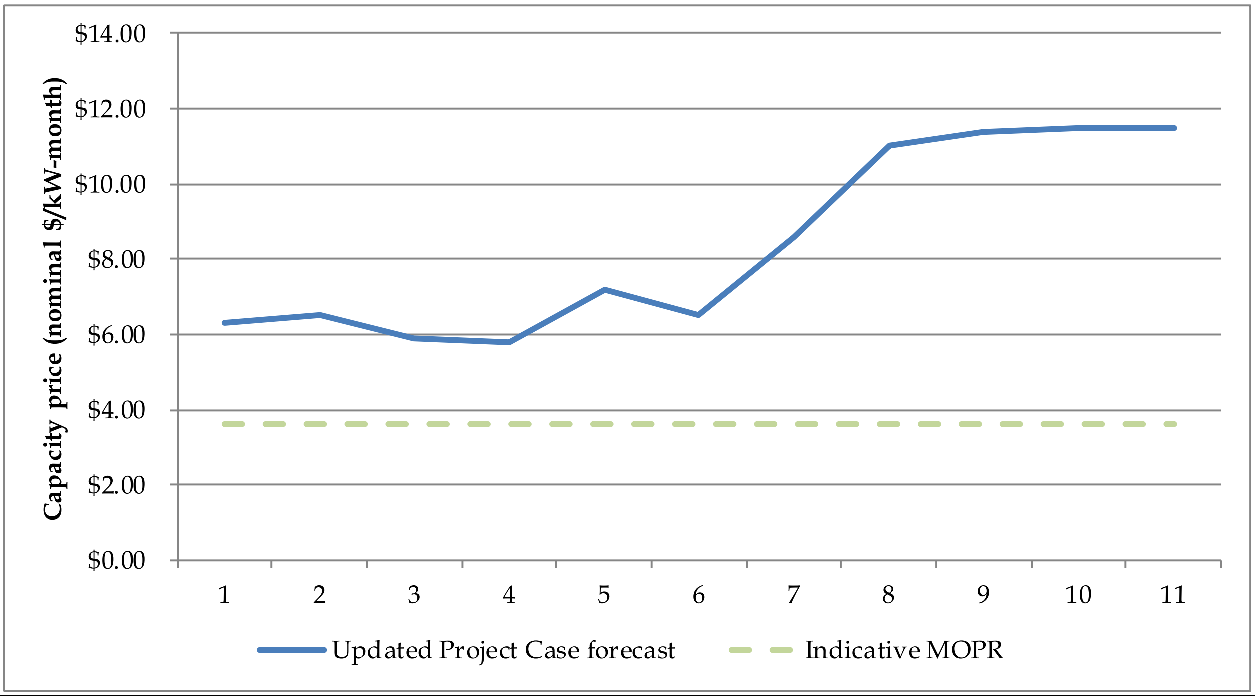
[123] Source: NYISO <http://www.nyiso.com/public/webdocs/markets_operations/market_data/icap/ICAP_Auctions/2017/Summer_2017/External%20rights/Import%20Rights%20Availability%20-%20Summer%202017.pdf>

[124] NPCC's 2016-17 winter reliability assessment lists the Québec Control Area peak load as 37,870 MW, while the 2016 summer reliability assessment listed the province's peak load as 20,833 MW

Figure 20. LEI indicative MOPR analysis results



7.3 Sensitivity analyses

[redacted]

[redacted]

8 Appendix C – Background on LEI's aggregate, longer term economic impact analysis (as summarized in [redacted] and [redacted])

This section summarizes the assumptions used in LEI's aggregate, longer term economic impact analysis.

Construction & Development:

Inputs for the Construction & Development period are taken from LEI's Original Report from October 2015, where LEI analyzed the Construction Period of 2015-2019 with data provided by the Applicants. LEI chose to rely on its own analysis, because of the errors in KRA's inputs as discussed in Section [redacted].

Electricity Market Effects:

Inputs for Electricity Market Effects are taken from LEI's Original Report from October 2015. Conservatively, LEI continued to assume that the electricity market benefits dissipate after 2029. That said, LEI did extend the reporting timeframe in the REMI PI+ model to 2040, acknowledging that the EMI PI+ model is going to show some negative indirect and induced affects once the construction boom ends and once the direct retail electricity market benefits dissipate.

Based on the revised modeling for the Updated Analysis, it is likely that some small segment of electricity market benefits may continue into the longer term, after 2030. However, LEI conservatively did not consider such an extended duration of positive electricity market benefits in this aggregate local economic impact analysis.

LEI did not adopt The Brattle Group's scenario 2, as LEI has serious concerns with The Brattle Group's *ad hoc* tool and modeling of capacity market benefits. LEI also removed the impacts that KRA modeled on the basis of their assumed additional 1,000 MW of power plant retirements. As discussed in Section 5.3, LEI finds KRA's assumptions on this issue to be unreliable.

Operations and Maintenance:

Inputs for Operations and Maintenance period during 2019-2029 are taken from LEI's Original Report from October 2015. In this longer term aggregate analysis, LEI extended the Operations & Maintenance spending out to 2040, based on the same information LEI received from the Applicants originally regarding the funding for this program. LEI has also excluded the impacts of the Forward New Hampshire Plan, which is analyzed as a separate impact element (see below).

Property Tax Effects:

Pursuant to Dr. Lisa Shapiro's analysis and rebuttal, LEI modeled two tax benefit scenarios that measured the economic impacts of the tax revenues collected from the Project during 2019-2040, as described in details in Section [redacted]. LEI modeled property tax revenues using the "Local Government Spending" policy variable, which is same as KRA's approach. The state business income tax revenues were modeled using "State Government Spending" policy variable. LEI removed the debt reduction elements in KRA's analysis of property tax impacts, consistent with Dr. Lisa Shapiro's observations.

Forward NH Plan:

In the Original Study submitted in October 2015, LEI modeled the project's spending plans around the Forward NH Plan until 2029. In this longer term aggregate analysis, LEI extended the local spending associated with the Forward NH Plan out to 2038, based on the same information LEI received from the Applicants originally regarding the funding for this program.

Tourism Effects & Construction Disruption

LEI employed and reflected in its modeling the conclusions of other professional experts retained by the Applicants, i.e. Chalmers & Associates LLC and the Nichols Tourism Group. These experts concluded that the tourism, property valuation, and temporary construction impacts caused by the Project are not significant enough to be included in the local economic impact modeling. Therefore, LEI zeroed out KRA's entries for these components in the REMI PI+ model.

Reduced Carbon Emission

Finally, LEI also added the positive externality effects to society from the Project's effect on regional CO_2 emissions. The modeling methodology used for estimating the impacts from avoided carbon emission is described in details in Section 5.2 above. Total economic impacts for LEI's (more conservative) approach versus that of The Brattle Group are shown separately in and .

For analyzing the economic effects of the positive externalities carbon reduction using LEI's assumptions, the firm extended LEI's updated SCC analysis from 2030 to 2040 using the implicit rate of change in carbon reduction benefits in the 2028-2030 timeframe (based on the results reported in the Updated Analysis). When modeling the opportunity cost for carbon emissions reduction identified by The Brattle Group in their report, LEI conservatively took the lower end of the estimated annual average opportunity cost ($140 million), and used that figure as the annual cost savings for electricity consumers throughout the near-and mid- term operations periods.