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DOCKET NO. 470 – NTE Connecticut, LLC application for a Certificate of Environmental Compatibility and Public Need for the construction, maintenance, and operation of a 550-megawatt dual-fuel combined cycle electric generating facility and associated electrical interconnection switchyard located at 180 and 189 Lake Road, Killingly, Connecticut.

Direct Testimony of Robert Fagan, Synapse Energy Economics

Prepared on Behalf of Not Another Power Plant and Sierra Club
November 15, 2016

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Attachments

1. Robert M. Fagan Resume

Exhibits

1. ISO NE 2016 CELT, Selected Pages.
2. State of Charge: Massachusetts Energy Storage Initiative, Executive Summary.
3. ISO NE FCA 10 Result Summary Page, Surplus Capacity Indication.
4. ISO NE FERC Informational Filing, and Revised ICR Values for 2020/2021, Presentation.
5. ISO NE Webpage: Overview and Timeline of Reconfiguration Auctions and CSO Bilateral Periods.
6. ISO NE Slide on New England State RPS and GHG Reduction Requirements.
7. Analysis Group: "Power System Reliability in New England, Meeting Electric Resource Needs in an Era of Growing Dependence on Natural Gas".
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9. ISO NE ICR Updated Values for 2017/2018, 2018/2019, 2019/2020 ARAs, Presentation.
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12. ISO NE 2016 PV Forecast.
13. ISO NE Remarks to FERC, Winter Reliability, October 2016.
14. Synapse Energy Economics, "The RGGI Opportunity", February 2016.
15. ISO NE 2015 Regional System Plan – Section 10, Integration of Variable Energy Resources.
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17. CT DEEP, GC3 Analysis, Data, and Metrics Meeting, July 26, 2016. Presentation.
18. CT DEEP 2013 GHG Emissions Inventory.

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1 Introduction

Q. Please state your name and occupation.

A. My name is Robert M. Fagan and I am a Principal Associate at Synapse Energy Economics.

Q. Please describe Synapse Energy Economics.

A. Synapse Energy Economics is a research and consulting firm specializing in electricity industry regulation, planning and analysis. Synapse works for a variety of clients, including consumer advocates, regulatory commissions, and environmental advocates.

Q. Please summarize your qualifications.

A. I am a mechanical engineer and energy economics analyst, and I've analyzed energy industry issues for more than 30 years. My activities focus on many aspects of the electric power industry, in particular: production cost modeling of electric power systems, general economic and technical analysis of electric supply and delivery systems, wholesale and retail electricity provision, energy and capacity market structures, renewable resource alternatives, including wind and solar PV, and assessment and implementation of energy efficiency and demand response alternatives. I hold an MA from Boston University in energy and environmental studies and a BS from Clarkson University in mechanical engineering. My resume is included as Attachment 1 hereto.

Q. On whose behalf are you testifying in this case?

A. I am testifying on behalf of Not Another Power Plant ("NAPP") and the Sierra Club.

Q. What is the purpose of your testimony?

A. The primary purpose of my testimony is to demonstrate that current and projected surplus electric capacity in New England indicates there is no electric power sector reliability need for the proposed Killingly Energy Center (KEC) power plant. I present detailed findings on the lack of such a need. I critique aspects of NTE Connecticut, LLC's (NTE's) application before the Connecticut Siting Council (CSC), especially material in the "Needs Analysis" [1], and provide direct evidence rebutting NTE's contention that "capacity resources that clear the FCA [forward capacity auction] are, by definition, needed for reliability"[2], while also noting that the proposed plant has not cleared in any FCA. I include quantitative analysis of key reliability need metrics publicly available from the Independent System Operator of New England (ISO NE), the region's electric power system operator. Connecticut electric reliability or electric resource adequacy[3] is best assessed through examination of New England wide resource adequacy metrics, since Connecticut is an integral part of the ISO NE reliability region. I address the credibility of NTE Connecticut's economic benefit and emission reduction claims which stem in part from electric power sector modeling results, which they summarize in the Needs Analysis.[4] I also address the greenhouse gas (GHG) emissions implications of the proposed plant in light of Connecticut's Global Warming Solutions Act (GWSA) (Public Act 08-98): the existence of the GWSA and similar statutes in Massachusetts and Rhode Island as well as GHG emissions targets in other New

[1] KEC Application, Appendix B-2, "Killingly Energy Center: An Analysis of Need and Economic & Environmental Impacts" ("Needs Analysis"), a PA Consulting Group report.
[2] KEC Application, Section 1, page 9.
[3] Regional or state-wide electric power sector reliability is often considered in two major domains, 1) resource adequacy, or sufficiency of supply to meet demand; and 2) transmission security. This testimony addresses the former. There is no evidence, nor any assertions by the proponent, that the proposed power plant is required to enable or enhance transmission system security.
[4] Electricity cost savings and emission reduction claims are made in Sections 2.3 through 2.5.

England states has a significant bearing on the types of new electric supply and demand-side resources that will be required for Connecticut and other New England states. These resources include energy efficiency and renewable resources that supplant the reliability need for the proposed KEC plant, and storage resources that support renewable resource integration and the development of an inherently more "flexible" electric power system.

Q. What documents do you rely upon in your analysis, and for your findings and observations?

A. I rely primarily upon various ISO NE documents, especially the 2016 Capacity, Energy, Loads, Transmission (CELT) Report[5] in addition to Connecticut Department of Energy and Environmental Protection (CT DEEP) material, the applicant's filing, and responses to discovery requests. I have included these documents, in their entirety or relevant sections, in my attached Exhibits.

Q. How is your testimony structured?

A. After this introductory section I list my summary findings. I then provide background information on the reliability need construct in Connecticut and New England. I address the role that the ISO NE capacity procurement structure - including the forward capacity auction (FCA) and complementary annual reconfiguration auctions - plays in addressing, but not defining, reliability needs. I next provide an analysis of resource adequacy and capacity needs

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[5] ISO NE, 2016-2025 Forecast Report of Capacity, Energy, Loads and Transmission, ("2016 CELT" or "2016 CELT Report"). Available at https://www.iso-ne.com/static-assets/documents/2016/05/2016_celt_report.xls. See attached Exhibit 1 for salient selected pages from this report. I also rely on related CELT historical data, included in an Excel file "2016 Forecast data file", available at https://www.iso-ne.com/static-assets/documents/2016/04/isone_fcst_data_2016.xls.

in Connecticut and New England focusing on the period through roughly the mid-2020s. This includes an extensive assessment of ISO NE's electric load forecasts in New England, a key driver of reliability need, and the critical and timely effects of aggressive energy efficiency and behind-the-meter solar photovoltaic (PV resource installations in southern New England. I then provide specific, limited critique of aspects of NTE's application, especially as it pertains to estimation of electricity cost savings and emissions effects from the proposed plant, and how NTE characterizes reliability need, including winter concerns. I also show why KEC is not needed in order to integrate renewable energy in Connecticut or New England, because the system is sufficiently flexible with existing assets, and new non-gas-fired assets (storage, Canadian hydro, energy efficiency, demand response) will continue to bolster the system's ability to absorb wind and solar power. I also rebut NTE's statement that KEC would be consistent with CT state energy plans. In the final major section, I address the GHG emission implications of the proposed power plant. Lastly, I provide summary conclusions and recommendations based on my findings.

2 Summary Findings

Q. Please summarize your findings.

A. My findings are summarized below. Sections 3 through 6 of this testimony explain these findings in further detail.

Summary Findings

1. **There is no short-term reliability need for this proposed plant**. Reliability need in Connecticut and New England is premised on having sufficient electric resource capacity (in Megawatts, or MW) to meet expected peak load plus a reserve margin. There is no near-term (i.e., through 2020) reliability need for the proposed KEC plant because there is surplus reserve capacity in New England now[6], and projected surplus capacity without this plant through the period of time up to and including when it would come on line (2020, for the capacity commitment period (CCP) 2020/2021)[7]. Recent increases in relative surplus capacity arise primarily from the presence of peak-load-reducing effects of energy efficiency and small solar PV. Overall surplus exists because of the totality of demand-side, import, and supply-side resources that exist in New England.
2. **There is no medium-term reliability need for this proposed plant**. There is no medium term (i.e., 2021-2025) reliability need for this plant because the surplus capacity in New England will continue in the years after the 2020/2021 CCP. Primarily, this is because net peak load growth in New England is projected to be flat, or declining through the next decade (due to energy efficiency and small solar PV resource investment effects,

[6] ISO NE 2016 CELT, installed reserve margin in 2016 was 18-21%, above the required margin of roughly 15%.
[7] ISO NE 2016 CELT, projected reserve margin in 2020 is 19-22%. I find a range of surplus of 317 – 2,162 MW.

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which will continue to compound over time), which means that existing capacity and expected new capacity with supply obligations will be more than sufficient to meet the needs.

3. **There is no longer-term reliability need (i.e., for capacity) for this proposed plant, and steadily increasing GHG emission limits preclude the need for energy from the proposed plant.** Steadily increasing renewable energy supplies and increasing levels of energy efficiency, required by existing energy policies and greenhouse gas emission limitations in all New England states and New York (including by direct legislative action on renewable procurement) will provide both energy and capacity, and (along with the presence of new storage capacity)[8] will eventually lead to increasing retirements of the remaining older, primarily-capacity-providing, fossil units in New England. New gas-fired combined cycle capacity will not be needed to meet reliability requirements if, or as, the remaining older, "at risk" New England fossil plants retire since both ongoing energy efficiency and increases in renewable supply and energy storage provide capacity for reliability. And indeed, the GHG emission characteristics of combined-cycle power plants will continually limit – increasingly so over time - their ability to provide energy in New England as the region progresses towards meeting interim (2030, 2040)

[8] Massachusetts' energy storage policy includes a recommendation to have 600 MW of system storage installed by 2025. It is documented in a new report, "State of Charge: Massachusetts Energy Storage Initiative", sponsored by the Massachusetts Department of Energy Resources (DOER) and the Massachusetts Clean Energy Center (MassCEC), released in September 2016. The Executive Summary notes that "***energy storage is recognized as a game changer in the electric sector***" (page 3). The recently released energy storage study finds that 1,766 MW of energy storage is cost effective for New England. The energy storage report Executive Summary and full report is available at http://www.mass.gov/eea/energy-utilities-clean-tech/renewable-energy/energy-storage-initiative/. See attached Exhibit 2 for the Executive Summary of the report.

and long-term (2050) GHG emission targets.[9]

4. **My reliability assessment for near, medium, and long-term periods accounts for older retiring, or at-risk-of-retiring, units.** This no-reliability-need finding, based on ISO NE data, accounts for all of the older New England power plants that have already retired, or are expected to retire over the next few years, including the large coal (Brayton Point) and nuclear (Pilgrim) units in Massachusetts. The remaining so-called "at-risk" fossil units in New England (as delineated in the second part of NTE's response to Question No. 82 in the second set of the Council's pre-hearing questions to NTE) have already indicated their participation in FCA 11 for 2020/2021 – i.e., they are not retiring before then. A subset of those resources have indicated auction price sensitivity (i.e., they won't retire unless prices are relatively low) but even if that were the case, and all of those indicating price sensitivity did retire (an unlikely outcome), a 317 MW to 540 MW capacity surplus would still exist in 2020.[10] In the immediate period after the FCA 11 CCP, new supply coming online by 2018, and surplus capacity obviates the need for KEC even if at-risk units do begin retiring by the summer of 2021. In the period including and after 2021, flat or declining net peak load and surplus capacity from then-existing resources, along with capacity increases from new energy efficiency, storage, and renewable resources will continue to obviate the need for the proposed KEC plant.[11]

[9] As seen, starkly, in the Connecticut Governor's Council on Climate Change Analysis, Data and Metrics Work Group presentation referenced and explained in Section 6 of this testimony.
[10] See Section 4 of this testimony.
[11] Including, for example, in addition to the energy storage noted in footnote 8, ongoing state energy efficiency resources under "all cost-effective" procurement policies in MA, CT and RI; expected new Canadian imports, and eventual new offshore and onshore wind resources.

5. **KEC impedes Connecticut's progress towards meeting GHG emission limits in 2030, 2040, and 2050.** The proposed KEC plant would annually emit 1.8 million metric tons of CO_2 pollution, 20% of all electric sector CO_2 pollution in Connecticut in 2014.[12] Its proposed operation stands in stark contrast to the suite of GHG emission mitigation measures under consideration by the Connecticut Department of Energy and Environmental Protection (CT DEEP) – <u>none</u> of which, logically and understandably, include a new gas power plant, however relatively-fuel-efficient it claims to be, since Connecticut needs to steadily <u>decrease</u> its reliance on natural gas for electric sector generation starting as early as the initial years of operation of this proposed plant.

Connecticut's GHG emissions limitations will directly lead to increasing levels of energy efficiency and renewable energy sources, providing direct emission mitigation but simultaneously supporting reliability through capacity provision and peak load avoidance thereby minimizing or eliminating the need for new capacity provision from GHG-emitting resources, especially energy-providing combined cycle gas units. NTE's claims of GHG emission reduction from this plant are not only likely exaggerated, as I will demonstrate; NTE's underlying rationale for such claims is weak, because the New England region has already, or will by the first years of this proposed plant's operation, fully eliminated coal use for electric generation and relies on oil use for but a small fraction of annual electric energy needs, primarily in the winter.

The existing gas-fired generation in New England that provides energy is similar

[12] NTE Application, page 95; ISO NE 2014 Air Emissions Report, page 19.

to this proposed plant: relatively fuel-efficient natural-gas fired combined cycle generation, more than 12,000 MW now, and more than 13,000 MW by 2018 (when the CPV Towantic plant in CT, and the new Footprint plant in Salem, Massachusetts will be online).[13] This existing relatively efficient gas-resource base, along with New England's hydro, import, and dispatchable demand-side resources, and projected new storage resources, will be more than sufficient to provide the balancing needs of the region well into the next decade.

Connecticut needs to significantly reduce gas-fired generation in Connecticut by 2030, even under the most lenient of the interim targets under consideration by the CT DEEP on the path to 80% GHG emission reduction by 2050. Those reductions will need to come from combined cycle power plants. Connecticut needs to dramatically reduce its gas-fired generation by 2050, to close to zero, and these reductions too will come from combined-cycle generation decreases. Operation of this plant would be in direct opposition to those goals. [redacted].

6. **There is no winter reliability need for the proposed plant.** The New England region has plentiful winter capacity reserves, in excess of 50% for a system that needs 15%. The region has taken various steps to ensure sufficient fuel availability to the existing asset base to ensure winter reliability, thousands of MW of which are equipped with dual-fuel capability, and no new fossil-fired generation plant is required. This will be so even after

[13] The proposed new 485 MW Bridgeport Harbor Unit 5, which obtained a capacity supply obligation in FCA 10, is also a combined cycle plant.

the eventual retirement of the remaining "at-risk" fossil plant.

7. **The proposed KEC plant is not needed to support the region's integration of increasing levels of renewable resources.** The New England region has sufficient, existing supply and demand-side dispatchable resources and schedulable import resources to balance varying net load patterns that will arise in part because of the presence of increased amounts of variable output, generally renewable, resources (such as solar PV and wind). Future additional import, storage, and demand-side resources can complement this sizable resource base which includes over 12,000 MW of existing combined cycle gas plants. ISO NE's latest Regional System Plan (2015) identified a need for transmission system reinforcement (including voltage support) and better forecasting of the output of solar PV resources as primary concerns for integrating increasing levels of renewable resources. Potential increases in the need for operating reserve to support changing "ramp" or load following requirements, identified by ISO NE as a possible need, can come from the existing resource base, and from new non-fossil resources such as energy storage capacity. While the proposed plant shares some aspects of the characteristics of dispatchability or schedulability (needed for renewable resource integration) with the existing resource base and potential new resources such as storage, there is no evidence that KEC is required to serve this need.

3 Background

Q. Please summarize the meaning of electric power system reliability in Connecticut and New England as it pertains to a potential need for new electric resources.

A. System reliability[14] comprises two aspects: resource adequacy and transmission security. Resource adequacy involves having sufficient resources to meet load at all times.[15] Transmission security means having a system that can withstand contingencies such as the loss of a transmission line, or successive losses of multiple transmission lines, or the loss of a major generation plant, during a time of high system load. North American Electric Reliability Corporation (NERC) standards[16] provide the high level guidance that Regional Transmission Organizations (RTOs) such as ISO NE follow to ensure both resource adequacy and transmission security. As noted above, there is no evidence, nor any assertions by NTE, that the proposed power plant is required to enable or enhance transmission system security. My analysis, therefore, is limited to resource adequacy.

A common measure of resource adequacy needs is the minimum capacity reserve margin (or planning reserve margin) required to meet reliability needs. The planning reserve margin is the amount of capacity above peak load levels required to ensure the lights do not go out. A capacity reserve margin is required because resource outages occur, and because load

[14] System reliability as used here does not refer to distribution system outages or interruptions due to, for example, localized equipment failure or weather-related events.
[15] More specifically, reliability standards for resource adequacy in the US electric power industry generally require no more than a one in-ten years' frequency of "loss of load" events arising from a resource shortage. "Keeping the lights on" refers to this level of reliability. Based on this determination, regions can determine planning reserve margins to ensure adequate installed capacity resources, and ISO NE does that in its annual installed capacity reserve analyses.
[16] The complete set of NERC reliability standards are available here: http://www.nerc.com/pa/Stand/Reliability%20Standards%20Complete%20Set/RSCompleteSet.pdf.

forecasts can vary from the expected peak loads. In New England, ISO NE annually computes installed capacity requirements (ICR) and net ICR (NICR), accounting for resource characteristics (such as outage rates) and the peak load forecast. Net ICR is the installed capacity requirement net of capacity credits from the Hydro Quebec interconnection, and it is lower than the ICR. These two metrics, ICR and NICR, represent the reliability need for capacity resources in New England. Capacity reserve margin can be expressed on a MW or on a percentage (of peak load) basis. Resource capacity in excess of the minimum ICR or NICR levels can be said to be "surplus" to, or in excess of, reliability requirements.[17]

Q. What is the threshold planning reserve margin for Connecticut and New England?

A. ISO NE computes and annually updates an installed capacity requirement for the New England region, which encompasses Connecticut. There is no separate ICR for Connecticut.[18] The planning reserve margin requirement excluding the effect of the capacity imports from the Hydro Quebec interconnection is approximately 15% for 2020/2021, and including the capacity resources from Quebec the margin requirement is 18.4%. Actual or projected reserve margins at any given time can be in excess of this planning reserve margin requirement, indicating a surplus level of capacity. Table 1 below summarizes this information from ISO NE.

[17] E.g., ISO NE results of FCA 10, "Excess capacity above NICR 1,416 MW". See attached Exhibit 3.

[18] There are separate local capacity requirements, known as local sourcing requirements (LSR), for the southeast New England zone (eastern Massachusetts and Rhode Island). Connecticut is part of the greater "rest of pool" (ROP) ISO NE zone, and it is responsible for a peak load share of the capacity obligations of the ROP zone.

Table 1. Installed Capacity Requirements for New England, 2020/2021

	2020/21 Capacity Requirement MW	2020/21 Peak Load Forecast* MW	Min Reserve Margin, MW	Min Reserve Margin, %
Installed Capacity Requirement (ICR)	35,034	29,601	5,433	18.4%
Hydro Quebec Interconnection Capacity Credit (HQICC)	959			
Net Installed Capacity Requirement (NICR)	34,075	29,601	4,474	15.1%

Notes: *50/50 Peak load forecast excluding peak-reducing effect of energy efficiency resources, which are considered as resources used to meet the capacity requirement.
Data Source: ISO NE, Proposed Installed Capacity Requirement (ICR) Values for the 2020-2021 Forward Capacity Auction (FCA11), ISO NE ICR Calculation Details, slide 7. Presentation by ISO NE Maria Scibelli before the Reliability Committee, October 4, 2016. See attached Exhibit 4.

Q. What is the level of planning reserve capacity in New England at this time, accounting for planned retirements and additions?

A. The 2016 CELT report contains a summary of the planning reserve capacity estimated for the next decade. Table 2 below contains those data. Surplus capacity beyond the roughly 15% reserve margin requirement[19] is seen in all years, using two different estimates of the resources available to the system.

Table 2. Section of 2016 ISO NE CELT Indicating Installed Reserves

	2015	2016	2017	2018	2019	2020	2021	2022	2023
4. RESERVES - Based on Reference Load with reduction for Passive DR									
4.1 INSTALLED RESERVES - Based on CSOs of Generating Resources (line 2.1), Active DR (line 2.2.1), and Imports (line 2.3)									
4.1.1 MW	5040	4903	5096	5704	6415	5125	5092	5038	4966
4.1.2 % OF LOAD	19	18	19	21	24	19	19	19	18
4.2 INSTALLED RESERVES - Based on Generation SCC (line 3.1), Active DR (line 2.2.1), Imports (line 2.3), and Exports (see footnote 12)									
4.2.1 MW	5794	5496	5357	6179	7093	5796	5773	5725	5659
4.2.2 % OF LOAD	21.7	20.6	20.1	23.1	26.5	22	22	21	21

Source: ISO NE 2016 CELT, Tab 1.1, Summer Peak

[19] The resources accounted for in this table *exclude* Hydro Quebec interconnection capacity capability, and thus the ~15% planning reserve margin noted in Table 1 applies.

Q. What is the ISO NE forward capacity market and the attendant forward and annual reconfiguration capacity auctions?

A. The forward capacity market (FCM) is the overall construct put in place by the ISO NE (and approved by FERC) for obtaining and selling capacity resources. It is a procurement construct. The time horizon of the FCM starts with a three-year forward capacity auction (FCA) – an auction for capacity supply obligations three years ahead of time - and continues with three, progressively-closer-in-time annual reconfiguration auctions (ARAs)[20] and complementary bilateral trading opportunities. In short, it is a near-term market for capacity that progresses from a three-year forward time frame (the FCA) to a few-months-forward time frame (i.e., the last ARA, known as ARA #3). The last ARA occurs in the spring and locks capacity resources into place for the forthcoming capacity commitment period (CCP), which begins on June 1 for the CCP. If or as needed, ISO NE updates key parameters at each ARA based on the updated load forecast and other system conditions, and entities can acquire, increase, or shed their capacity supply obligations (CSOs). CSOs are tradable, forward obligations to provide capacity to the system during the capacity commitment period.[21]

[20] Reconfiguration auctions timelines are provided by ISO NE. An annual reconfiguration auction occurs in each of the three years following the FCA. Overview and details on the ARA are available at https://www.iso-ne.com/markets-operations/markets/forward-capacity-market/fcm-participation-guide/overview-and-timeline. See also attached Exhibit 5.

[21] ISO NE, "Reconfiguration auctions (RAs) provide an auction-based mechanism for resources to acquire, increase, or shed all or part of their capacity supply obligations (CSOs) for the entire capacity commitment period (CCP) through annual RAs or for specific months of the CCP through monthly RAs. … Additionally, annual RAs give the ISO the chance to procure additional capacity or to shed excess capacity to address changes in system conditions or capacity requirements, if necessary." https://www.iso-ne.com/markets-operations/markets/forward-capacity-market/fcm-participation-guide/reconfigurations-auctions.

Q. Does the FCM construct determine reliability need?

A. No. The FCM construct, through its FCAs and bilateral contracting arrangements,[22] represents procurement arrangements but it does not determine need. Need is represented by the installed capacity requirements.[23] The FCA for any given year does not represent a final determination of capacity need for that future year, but is rather forward-clearing an administratively complex capacity market based on a projected forecast of resource need three years out. It is also not determinative of need for any future year or years beyond the planning period to which it applies. The most recent FCM auction in New England (known as FCA 10 or the tenth forward capacity auction held since the inception of the forward capacity market construct) was held in February of 2016.

Q. Why is the timeframe of the forward capacity auctions, the annual reconfiguration auctions, and the use of annually updated load forecast and capacity need projections important in the context of assessing reliability need for this proposed KEC plant?

A. The temporal aspects are critically important for several reasons.

First, as I show in subsequent sections of this testimony, the forecast of load and capacity requirements changes every year; recently, these changes have led to flattening, and even declining, net load forecast trends. This is a significant departure from historical trends (increasing net load) on which the capacity need construct is based. Historically, with increasing load, being a year or two off on a "need" designation was not that crucial, from a

[22] Parties with "capacity supply obligations" can generally trade those obligations to other parties at market rates.
[23] The applicant directly states this, "The capacity that is required to meet ISO-NE's future system-wide demand is called the Installed Capacity Requirement (ICR)". Appendix B-2, Needs Analysis, at page 12.

planning perspective, because the need would arise eventually. That is not the case now in New England, and thus there is a real risk of investment in non-renewable capacity that is unneeded.

Second, relatedly, state laws in Connecticut, Massachusetts and Rhode Island (which comprise roughly three-quarters of the New England load)[24] and in the other New England states and New York all require dramatic reductions to greenhouse gas emissions by 2050, and by interim 2030 and 2040 periods.[25] The other New England states, and New York, also required increased renewable resource energy and/or limits on CO_2 emissions.[26] The ISO NE capacity market construct does not address these critically important milestone requirements[27] and thus does not represent an optimal economic mechanism to gauge and guide investment in new resources in New England at this time.[28] The combination of these two critical factors – a change in the historical pattern of net load forecast trends, and the need to reduce gas use in generation – allows, and requires, the region to stop building new gas-fired combined cycle plants for energy production, and work towards lowering GHG emissions through ongoing energy efficiency and renewable resource investment.

Q. Do the reliability requirements noted above for New England include resources for the

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[24] E.g., see ISO NE generation and load data by state. In 2015, CT, MA and RI combined were 77% of the net energy for load in New England.
[25] As seen, e.g., in CT DEEP's current process, addressed in this testimony in Section 6.
[26] See, e.g., slide 8 of ISO NE's 9/28/2016 presentation, "The Transformation of the New England Power System: Infrastructure Needs and Market Implications available at https://www.iso-ne.com/static-assets/documents/2016/09/gvw__nec_9_28_2016.pdf. See key page in attached Exhibit 6.
[27] Currently, the Regional Greenhouse Gas Initiative (RGGI) construct is the only means by which CO_2 emissions are represented in the ISO NE marketplace. RGGI does not yet address the more stringent GHG emission constraints reflected in the CT, MA and RI statutes.
[28] The "Integration of Markets and Public Policy" (IMAPP) initiative at NEPOOL and ISO NE is just beginning to address this issue. See information at https://www.iso-ne.com/committees/participants/wholesale-markets-state-public-policy-initiative.

summer and the winter?

A. Yes. Reliability requirements – the need for capacity – are driven by summer loads because they are much greater than winter loads. Net summer peak load in 2016 in New England, forecast to be 26,704 MW and actually reaching just 25,466 in August, is greater than projected winter peak loads which are on the order of 21,000 to 22,000 MW. ISO NE must be assured of fuel supplies for generators in the winter, but there is more than adequate electrical generation capacity to meet the winter demands.[29] I address this in more detail in Section 5 of this testimony.

Q What is the Connecticut Global Warming Solutions Act (GWSA) and why is it important in the context of any purported need for the proposed KEC plant?

A. The Connecticut GWSA is a statutory requirement that Connecticut reduce greenhouse gas emissions to 80% below 2001 levels by 2050. The CT DEEP is in the process of developing interim targets to place CT on track to meet the 2050 mandate. The proposed plant would emit as much as 20% of the electric sector GHG emissions seen in Connecticut in 2014. Section 6 of this testimony addresses the implications of the proposed KEC plant on these GHG emission limits.

[29] See for example, the Analysis Group report on New England winter period electric reliability, developed on behalf of the Massachusetts Attorney General: "Power System Reliability in New England, Meeting Electric Resource Needs in an Era of Growing Dependence on Natural Gas", attached as Exhibit 7.

4 Analysis of Resource Adequacy, Capacity and Load Forecasts

Resource Adequacy and Capacity

Q. What do you analyze in this section of your testimony?

A. I examine the current and projected reliability or resource adequacy needs of the New England region, based on ISO NE's installed capacity requirement projections to meet peak load; how those needs have changed over time; and how the recent patterns of load forecast trends in New England – flattened and declining net peak loads - will continue to shape those needs over the next five to ten years.

Q. Does this section support the summary findings seen in Section 2 of your testimony?

A. Yes. This section provides the underlying data and context that supports those findings.

Q. How is resource adequacy, or reliability need, determined for New England?

A. ISO NE determines reliability need using a probabilistic-based model of the electric power system that determines the level of capacity needed to keep the lights on. The modeling process is updated regularly and is documented in annual ISO NE annual filings to FERC[30]. The most recent filing documenting the installed capacity requirements for 2019/2020 was made in January of 2016, and is referred to as the 2019/2020 ICR Values Report. ISO NE will file the next ICR values report in early 2017 to document the requirements for 2020/2021, although

[30] See "ISO NE Installed Capacity Requirements, Local Sourcing Requirements and Capacity Requirement Values for the System-Wide Capacity Demand Curve for the 2019/20 Capacity Commitment Period (January, 2016)", also known as the 2019/20 ICR Values Report, available at http://www.iso-ne.com/static-assets/documents/2016/01/icr_values_2019_2020_report_final.pdf. This is also attached as Exhibit 8 to this testimony.

preliminary projected requirements are already known and publicly available from ISO NE.[31] As stated in the 2016 filing:

> "The Installed Capacity Requirement (ICR) is a measure of the installed resources that are projected to be necessary to meet both ISO New England's (ISO-NE) and the Northeast Power Coordination Council's (NPCC) reliability standards[11], with respect to satisfying the peak load forecast for the New England Balancing Authority area while maintaining required reserve capacity. More specifically, the ICR is the amount of resources (MWs) needed to meet the reliability requirements defined for the New England Balancing Authority area of disconnecting non-interruptible customers (a loss of load expectation or "LOLE"), on average, no more than once every ten years (an LOLE of 0.1 days per year). This criterion takes into account: other possible levels of peak electric loads due to weather variations, the impacts of resource availability, and the potential load relief obtainable through the use of ISO New England Operating Procedure No. 4 – *Actions During a Capacity Deficiency* (OP-4)." [2019/20 ICR Values Report FERC filing at page 9]

The filing also describes the derivation of the net installed capacity requirement (NICR), which accounts for the capacity value associated with imports to New England over the Hydro Quebec interconnection (known as the HQICC, or Hydro-Quebec Interconnection Capability Credits). The net ICR or NICR is the requirement used in the forward capacity and annual reconfiguration auctions for procurement of resources.

Q. What is the current estimate of ICR, NICR, and surplus capacity for New England?

A. ISO's most recent information presented to the ISO NE Reliability Committee contains the ICR and NICR values.[32] I summarize that information in Table 3 below, and show the level of surplus capacity procured (at the associated FCA) above the current reliability requirement (the

[31] See ISO NE "Informational Filing for Qualification in the Forward Capacity Market", November 8, 2016 and "Proposed Installed Capacity Requirement (ICR) Values for the 2020-2021 Forward Capacity Auction (FCA11) (Revised)", ISO NE Presentation before the Reliability Committee, October 4, 2016. Available at https://www.iso-ne.com/static-assets/documents/2016/09/a2_2020_21_fca11_icr_values_results.pdf. These are also included as Exhibit 4 to this testimony.

[32] See Exhibits 4 and 9 on updated/revised ICR, NICR values for the four capacity commitment periods 2017/18, 2018/19, 2019/20, and 2020/2021.

net ICR) or estimated surplus (2020/21) for each of the delivery years beginning June 1 of 2017, 2018, 2019 and 2020. The table contains the installed capacity requirements, net ICR, and surplus capacity above need for the next four years.

Table 3. Installed Capacity Requirements (MW) and Capacity Surplus (MW) for New England

Peak Load Period Beginning Summer of:	**2017**	**2018**	**2019**	**2020**
Capacity Commitment Period (CCP):	**2017/18**	**2018/19**	**2019/20**	**2020/21**
FCA Associated with CCP:	**FCA 8**	**FCA 9**	**FCA 10**	**FCA 11**
Date or expected date of auction:	**Feb 2014**	**Feb 2015**	**Feb 2016**	**Feb 2017**
Installed Capacity Requirements (ICR) – as of October 2016	34,246	34,374	34,730	35,034
Net ICR - – as of October 2016	33,138	33,421	33,755	34,075
Capacity Supply Obligations (CSO) cleared at FCA	33,712	34,695	35,567	
Surplus (CSO – Net ICR) from auction as of October 2016	**574**	**1,274**	**1,812**	
Existing resources available for FCA 11				**34,505**
Estimated Surplus using only "existing" resources (existing resources minus NICR)				**430**
Range of 2020/21 surplus if "new" demand and import similar to last three FCAs				**1,939-2,162**
Worst case range of surplus – all "static de-list" bids retire, new demand, import as last 3 FCAs				**317-540**

Note: New demand and import resources in past three FCAs were 1,509 MW (FCA 8), 1,727 MW (FCA 9), and 1,732 MW (FCA 10). Existing resources for FCA 11 (2020/2021) include 31,625 generation, 2,926 MW of demand, and 83 MW of imports. Static de-list bids total 1,622 MW.

Q. Please explain what Table 3 shows.

A. Table 3 shows that there is no reliability need for the proposed KEC plant because even if there were no "new"[33] resources cleared in the forthcoming FCA 11, there would be a 430 MW surplus above the reliability need in 2020. The table shows projected surplus capacity of 574 MW in 2017, 1,274 MW of surplus capacity in 2018, and 1,812 MW of surplus capacity in

[33] ISO NE forward capacity auctions categorize cleared resources as either "existing" or "new".

2019 based on the current load forecast and balance of available capacity.

It is very unlikely that there would be no new demand-side or import resources cleared in the forthcoming auction – over the past three years (FCA 8 through FCA 10), there has been roughly 1,500 to 1,700 MW of those resources clearing each auction. Thus the actual surplus capacity for the 2020/2021 period is likely to be in the range of 1,939 to 2,162 MW, as seen in the table. If new generation resources are also cleared – such as new solar, wind, or conventional resources – the surplus would be even higher than shown, and more than 5,900 MW of new resources are qualified to participate in the auction.[34]

Lastly, the table also shows a "worst case" range of surplus, if resources with approved static de-list bids actually fail to clear in the auction. These 1,622 MW of static delist bids likely include some of the "at-risk" fossil resources. Even if all of them did fail to clear, and retired, there would still be a projected surplus of 317 to 540 MW of capacity in the summer 2020, based on current information.

Q. Can you summarize how New England's electric power sector reliability needs as projected for 2020 have changed over time?

A. Yes. Figure 1 shows net installed capacity requirements, ISO NE's peak load forecast, and the net peak load forecast, as those metrics have changed over time, in tabular and graphical format. The data are taken from the ISO NE Regional System Plans, and the annual CELT forecasts.

[34] See Exhibit 4, ISO NE Informational Filing for Qualification in the Forward Capacity Market, at page 5.

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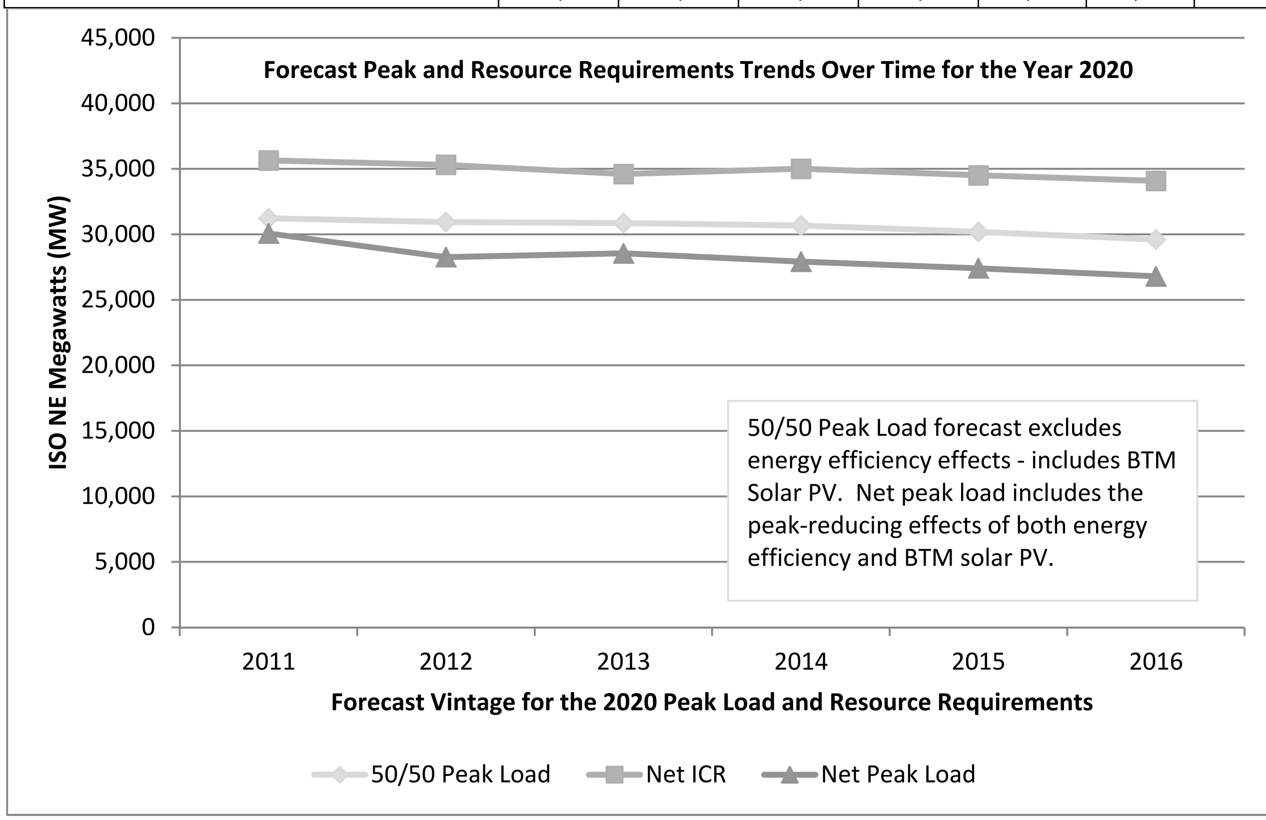
Figure 1. Forecast Peak Load and Resource Requirements for 2020 – by Vintage of Forecast

	ISO NE Regional System Plan Vintage or CELT Year						
	2011	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
Net Installed Capacity Requirement (NICR) for 2020	35,635	35,300	34,600	35,000	34,500	34,075	TBD
ISO NE 50/50 Peak Load Forecast - 2020 Excludes Energy Efficiency, Includes BTMPV	31,215	30,930	30,860	30,675	30,182	29,600	TBD
ISO NE Net Peak Load Forecast for 2020	30,067	28,257	28,546	27,911	27,400	26,788	TBD



Source: ISO NE Regional System Plans, CELT reports, and ICR Value estimation.

Q. What does Figure 1 indicate?

A. It indicates, broadly, that at least over the past five years the projections made by ISO NE for future needs have been overstated; and it illustrates that the reason the future need has been overstated is because the load forecast has been overstated. This is logical – capacity needs are driven by peak load needs in New England.

Q. What are the implications going forward for these trends?

A. Data from the summer of 2016 shows this trend continuing. In the winter/spring of 2016, ISO NE published its 2016 CELT report. The 2016 net peak load forecast was 26,704 MW, for a "normal" expected summer peak day. The actual peak load on August 12, 2016 was 25,466 MW, roughly 1,200 MW lower than forecast peak.[35] This lower load level occurred even though it was an abnormally hot and humid summer weekday – the weighted temperature-humidity index (WTHI) was 81.12, and the expected WTHI on a 50/50 peak load day (or "normal" peak load day) was 79.88. In other words, it was hotter and more humid than the forecast peak day, yet the net load was still more than 1,200 MW lower than forecast.

Q. What does this indicate?

A. It indicates that the next load forecast, to be formalized with the publication of the 2017 ISO NE CELT report, could include a reduction to projected peak load going forward, relative to what was included in the 2016 ISO NE CELT report. This in turn would lead to relative reductions in reliability requirements – as estimated by the installed capacity requirement (ICR) or the net ICR. The surplus capacity above reliability needs projected for 2020 would, in this circumstance, increase.

Q. Can you further illustrate how surplus capacity has changed as the load forecasts are updated each year?

A. Yes. ISO NE's most recent forward capacity market auction, FCA 10, held in February of 2016 for the capacity commitment period of 2019/2020 (June 1, 2019 through May 31, 2020)

[35] See attached Exhibit 10, pages from the ISO NE presentation in September 2016 on the August peak load days.

cleared 35,567 MW of resources for the summer period.[36] The net installed capacity requirement for 2019/2020 at the time of that auction was 34,151 MW, thus there was a surplus of 1,416 MW cleared in that auction, for the applicable 2019 summer period.

Q. What load forecast was used to estimate capacity needs for the 2019/2020 period as used for the FCA 10 auction, and has it now been updated?

A. The 2015 CELT load forecast was used. Since the auction was completed, ISO NE produced a new forecast, the 2016 CELT report, available in May of 2016.

Q. Did the 2016 CELT report forecast a lower peak load for the summer of 2019?

A. Yes. The 2016 CELT report projected a summer peak load for 2019 that was 518 MW lower than the forecast for 2019 contained in the 2015 CELT report.

Q. What effect did that updated 2016-vintage forecast have on the estimated capacity surplus in the summer of 2019?

A. It increased the estimated capacity surplus. The lower load forecast resulted in a change to the net installed capacity requirement for 2019, from 34,151 MW to 33,755 MW, a difference of 396 MW. Thus, when ISO NE updated its load forecast for the summer of 2019 using the CELT report from 2016, it resulted in an increased in the projected surplus for 2019 of 386 MW, from the original 1,416 MW surplus to a new surplus of 1,812 MW, for all of New England. That new surplus amount is shown, for 2019/2020, in Table 3 above.

Q. Does that surplus account for the obligations obtained by then-proposed new major natural gas fired resources?

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[36] ISO NE, FCA 10 results. See attached Exhibit 3.

A. Yes, it includes an accounting of all the resources that "cleared" or obtained a capacity supply obligation (CSO) in the FCA 10 auction. It also assumes that no additional retirements will take place prior to 2019 (Brayton Point and Pilgrim are already assumed retired by summer of 2019).

Q. Does this take into consideration any changes to the load forecasts for 2019 or 2020 that might occur over the next few years of forecasts?

A. No. For example, the data in Figure 1 do not account for any potential changes to peak load forecasts for 2020.

Q. Do these surplus capacity projections account for the fact that both Pilgrim nuclear power plant, and the Brayton Point coal plant are slated for retirement (in 2019, and 2017, respectively)?

A. Yes. The auction conducted in February 2016 for the 2019/2020 period accounted for the retirement of both of these plants.

Q. Is the proposed KEC plant needed because of the risk of retirement of other units in New England?

A. No. Table 4 summarizes the rest of the units in New England "at risk" of retirement, and places them into context with the rest of the capacity supply that is projected for 2019/2020. Currently, none of the remaining "at risk" units are planning to retire prior to FCA 11 in February of 2017.[37]

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[37] ISO NE, ICR ISO NE Proposed Installed Capacity Requirement (ICR) Values for the 2020-2021 Forward Capacity Auction (FCA11) (Revised), Presentation to ISO NE Reliability Committee, October 4, 2016, e.g., slides 17, 21, 37. See attached Exhibit 4.

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Table 4. Remaining "At Risk" Units and Capacity Supply Obligation Accounting

At Risk Plant Name	# units	Summer Seasonal Claimed Capability, Aug 2016, MW	State	FCA 10 Zone	CSO FCA 10 (for 2019-2020), MW	Fuel Primary and Alternative by Unit
BRAYTON PT 1-4	4	1,473	MA	SENE	-	Coal (1-3), Oil/Gas (4)
BRIDGEPORT HARBOR 3	1	383	CT	ROP	383	Coal
CANAL 1 and 2	2	1,121	MA	SENE	1,092	Oil (1), Oil/Gas (2)
MERRIMACK 1 and 2	2	436	NH	ROP	438	Coal
MIDDLETOWN 2, 3, 4	3	744	CT	ROP	751	Oil/Gas (2, 3), Oil (4)
MONTVILLE 5 and 6	2	467	CT	ROP l	486	Oil/Gas (5), Oil (6)
MYSTIC 7	1	575	MA	SENE	571	Gas/Oil
NEW HAVEN HARBOR	1	447	CT	ROP	448	Oil/Gas
NEWINGTON 1	1	400	NH	ROP	400	Oil/Gas
SCHILLER 4 and 6	2	95	NH	ROP	95	Coal/Oil
WEST SPRINGFIELD 3	1	94	MA	ROP	94	Gas/Oil
YARMOUTH 1, 2, 3, 4	4	811	ME	ROP	818	Oil
Total Remaining At Risk Fossil		7,047			5,577	
						CSO Share
SENE Total		3,169			1,663	4.7%
All Other Zones		3,877			3,914	11.0%
Total Remaining At Risk Fossil					5,577	15.7%
Remaining Generation CSOs (FCA 10)					25,794	72.5%
Demand Resources CSOs (FCA 10)					2,746	7.7%
Imports CSOs (FCA 10)					1,450	4.1%
Subtotal Non-At Risk, Demand, Imports					29,990	84.3%
Total CSOs					35,567	100.0%

Source: ISO NE: FCA 10 Results, 2016 CELT. Tabulation by Synapse.

Q. What does this table indicate?

A. It indicates that even without the at-risk units, which remain viable providers of capacity resources in New England, New England has a substantial level of other existing and planned capacity resources.

Q. What might influence or accelerate those units' retirement, and what effect would such retirement have on a reliability need for the proposed KEC plant?

A. Sufficiently available renewable resources such as solar PV, energy efficiency, new Canadian imports and offshore wind, along with energy storage and demand response – resources that are required to help states' meet GHG emissions goals - would increase overall capacity and energy supplies, lower energy and capacity prices, and support reliable system operation such that those units would then have an economic incentive to retire. Their retirement, however, would not require new gas-fired combined cycle resources such as the proposed KEC plant because of the presence of the new renewable, demand-side and storage capacity (along with existing non-at-risk capacity).

Q. What new resources are expected separate from behind-the-meter (BTM) solar PV that reduces peak load?

A. New Canadian hydro imports, new onshore wind, new storage capacity, new utility-scale solar, and new offshore wind resources are all likely to be installed on the New England system over the next 5 to 15 years, because of favorable economics and to meet emission and RPS requirements and state policy goals. In the very near term, two large transmission import resources (from Quebec) are seeking to be connected to the New England grid, and if successful would provide on the order of 2,000 MW of new capacity resource, available to offset a portion of eventual "at risk" fossil unit retirements. Massachusetts, Connecticut and Rhode Island are seeking additional renewable resource installations, and Massachusetts has specific timeframes in place to secure 1,600 MW (nameplate) of offshore wind resources before the end the 2020s decade. Massachusetts also has specific policy recommendations to install new storage resources over the next decade, as noted earlier. All of those resources would provide new capacity and energy into the New England region and further reduce New England's reliance on natural gas-fired generation resources.

Q. What is the status of Canadian hydro incremental import transmission projects?

A. There are two projects that are well-advanced in project planning: the Northern Pass transmission line, a planned 1,090 MW project that would bring Quebec-sourced energy into the New England transmission grid at a terminal point in southern New Hampshire; and the New England Clean Power Link, a planned 1,000 MW cable to be installed on the bottom of Lake Champlain, and in underground sections, terminating in Southern Vermont.

Q. What are the planned operation dates for these two projects?

A. The Northern Pass line is intended for operation in mid-2019,[38] and the Clean Energy Link is also intended for operation in 2019.[39]

Q. How much power and energy would those projects bring to New England?

A. Generally, those projects would bring over 2,000 MW in total of capacity to New England, and depending on the overall capacity utilization at which the new transmission lines would operate, energy amounts would vary; at a 75% annual average capacity factor the new lines would carry over 13 million MWh per year. That is roughly 10% of the net annual energy needs in New England.

[38] "Northern Pass Announces Contractors for Project's Construction", April 21, 2016, http://blog.northernpass.us/.
[39] http://www.necplink.com/schedule.php. Updated May 10, 2016.

Q. How much capacity and energy would result from offshore wind resources pursuant to Massachusetts' aims alone?

A. Massachusetts is targeting 1,600 MW of offshore wind resource by the later part of the 2020s. Depending on capacity accreditation for that resource, it could result in 600-800 MW of capacity (to contribute towards NICR); along with multiple millions of MWh per year in energy. If all 2,000 MW of currently-leased major offshore MA/RI areas come into service, they would supply 7.5 million MWh per year (e.g., at an average annual capacity factor of 43%).

Q. Is it reasonable to consider those projects when modeling New England's future supply portfolio and estimating any GHG emissions avoidance that could be ascribed from the proposed KEC plant?

A. Yes, it is reasonable to include them in any baseline assessment of the region because 1) current Massachusetts law supports contracting for additional offshore wind and imports,[40] and 2) to meet GHG emission limits in CT, MA and RI, some analysis has concluded that these sources may be required.[41] I also note that ISO NE is considering additional means to better incorporate State planning policies, such as the aforementioned MA law, in ISO NE's overall energy and capacity market construct.[42] For any longer-term assessments, it is reasonable to assume some level of installed offshore wind capacity in the region. [redacted]

[40] Bill H.4385, https://malegislature.gov/Bills/189/House/H4385. It became law in August of 2016.

[41] See, e.g., the [Massachusetts] 2015 Update of the Clean Energy and Climate Plan for 2020, page 15, and 32.

[42] See ISO NE, "The Transformation of the New England Power System: Infrastructure Needs and Market Implications", New England Council Regional Energy Discussion, September 28, 2018. Available at https://www.iso-ne.com/static-assets/documents/2016/09/gvw__nec_9_28_2016.pdf. Slides 14-16, also included as part of attached Exhibit 11.

[redacted].[43]

Q. Has the proposed KEC plant obtained an obligation to supply capacity in New England?

A. No. The proposed KEC does not have an obligation from ISO NE to supply capacity for the 2020/2021 period, or for any other period.

Q. Please summarize the resource adequacy and capacity outlook for New England at this time.

A. There is a projected surplus of resource adequacy for New England in 2020, and for all future years out to the mid-2020s. Continuing investment in energy efficiency and behind-the-meter solar PV has contributed to lower net peak loads, and forecasts for reliability requirements remain roughly flat. GHG emission limitations in place in New England states will continue to promote 1) additional installation of renewable energy, 2) investment in energy efficiency, and 3) new policy initiatives on storage resources. Since all of these resources provide capacity, there will continue to be no reliability need for the proposed KEC plant.

<u>Energy Efficiency and Small Solar PV Effect on Net Load Forecasts</u>

Q. What do you address in this section of the testimony?

A. I present New England and Connecticut region electric power load, both peak demand and total annual energy use, in historical and forecast contexts. ISO NE updates its load forecasts every year, and produces an annual Capacity, Energy, Loads, and Transmission (CELT) Report, and accompanying data. The ISO NE data allows for a comprehensive look back at actual load conditions in New England and in individual states, and allows for a comparison of

[43] [redacted]

forecasts made at different points in time.

Q. Why is this information important in the context of the proposed KEC plant, and reliability needs in New England?

A. Peak load (in MW) is the key driver of reliability needs. Reliability needs are met with capacity resources. The need for capacity resources is primarily based on expected peak load levels.

Q. In this section you use two related, but distinct terms: net peak load, and annual net energy. Please define and explain these terms.

A. Net peak load (in megawatts, or MW) is the summer peak load (or maximum rate of power consumption seen all year, in MW, occurring in the summer) net of the load-reducing effects of peak-period energy efficiency and solar PV output from panels installed behind customer meters ("behind-the-meter solar PV" or BTM solar PV, or small solar PV). ISO NE, in its annual CELT reports, provides historical and forecast data for gross peak load, net peak load, and the peak-reducing effects of energy efficiency and BTM PV resources. Annual net energy (GWh) is the annual energy consumed net of the effects of both energy efficiency and the output of BTM solar PV on gross load. Net load is the load that must be provided with grid-connected resources such as existing or future utility-scale wind power, utility-scale solar PV, hydroelectric power, imports from Canada and New York, conventional nuclear and natural gas resources, and coal and oil-fired resources. As ISO NE states, "'net' forecasts… are []

representative of the energy and loads expected to be observed in New England."[44] In this testimony, I refer to New England, and to Connecticut when using these terms. ISO NE provides (in its CELT reports) historical and forecast data for these metrics for the entirety of New England, and for each state. Lastly, I use ISO NE's "50/50" net peak load forecast. The 50/50 forecast is the forecast of peak load for which there is a 50% probability it will be higher, and a 50% probability it will be lower.[45] This 50/50 peak load value is the forecast value ISO NE uses in assessing resource adequacy for reliability purposes.[46]

Q. What is your main observation from examining the historical and projected net load forecasts in New England?

A. Net peak load has declined over the past decade. Actual summer net peak loads, and actual net annual electricity consumption, has declined in both Connecticut and New England over the past decade, as directly seen in ISO NE annual CELT report data. Future net peak load is currently projected to be flat or declining in New England. In recent years, each successive annual update to ISO NE's 10-year-forward load forecast shows a lower peak load forecast for any given future year relative to the earlier vintage forecast. The highest value of net peak load forecasted by ISO NE in 2016 - for the year 2025 - is lower than the historical net peak load from 2006 (28,130 MW), and lower than the three highest net peak load levels seen over the past decade (in 2006, 2011, and 2013).

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[44] ISO NE, "Forecast Model Structures of the ISO New England Long-Run Energy and Seasonal Peak Load Forecasts, for the 2016 CELT Report", available at https://www.iso-ne.com/static-assets/documents/2016/06/forecast_model_structures_2016.pdf. Page 1.

[45] See the ISO NE 2016 CELT, Tab "1.6 Frcst Distributions".

[46] See for example, ISO NE 2015 Regional System Plan, Table 4-7, Future Systemwide Needs (MW), using "50/50 Peak Load" when determining representative net ICR (installed capacity requirement) need.

Q. What is the historical pattern of electric peak load and electric energy consumption in Connecticut and New England as a whole?

A. Figures 2 and 3 show the historical pattern of net peak load and annual energy consumption in Connecticut and New England. The values shown are from the ISO NE 2016 CELT report data, and the actual peak load that occurred in New England in the summer of 2016.

Q. What do these figures illustrate?

A. The figures show that for both Connecticut and New England as a whole, net electrical load (both summer net peak load, and annual net energy) has flattened, and has begun to trend downward over the past decade.

Figure 2. New England Net Summer Peak Load and Net Energy for Load, 1991-2016

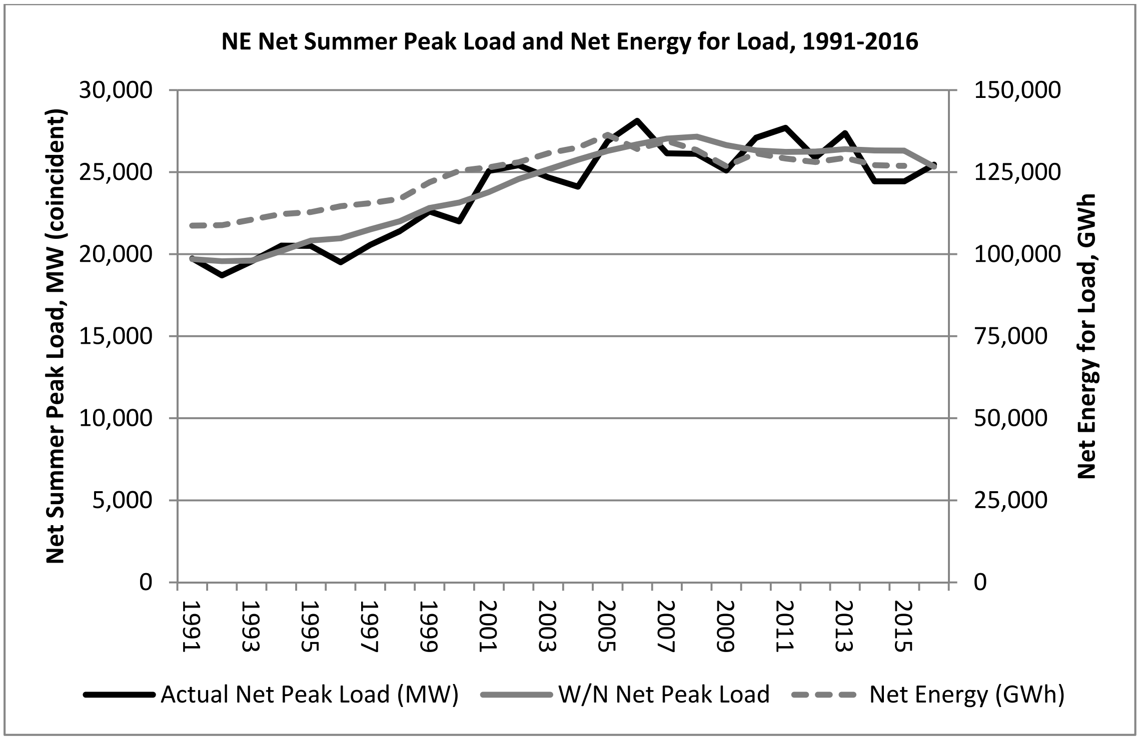
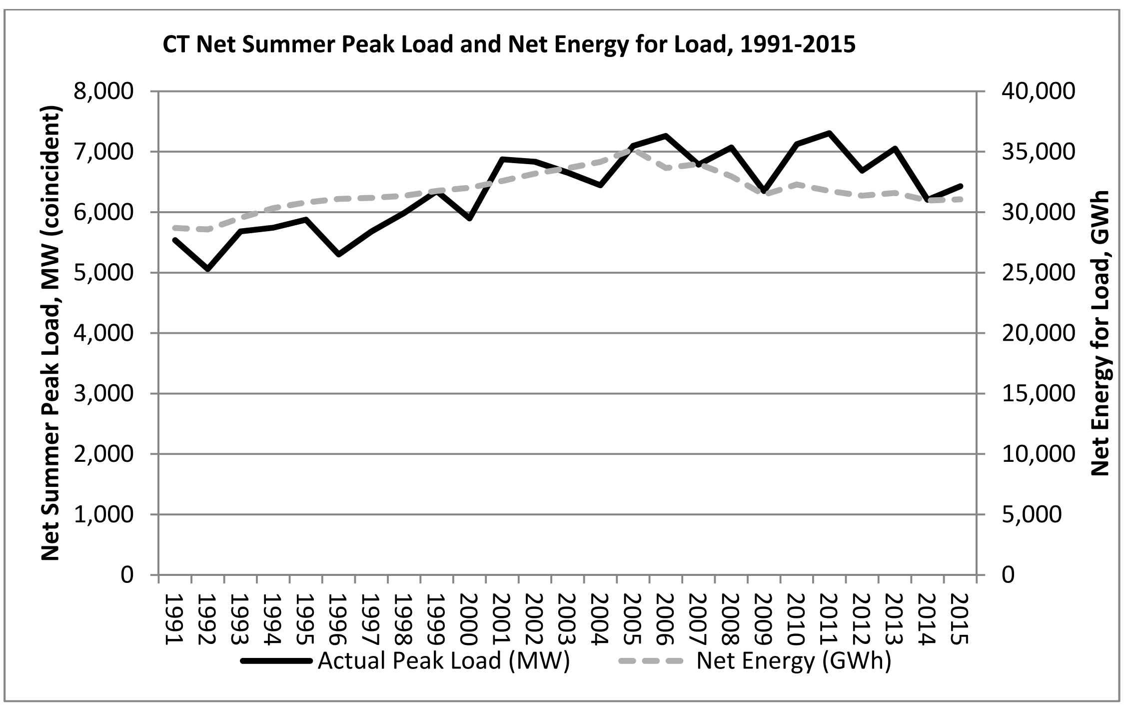


Figure 3. Connecticut Net Summer Peak Load and Net Energy for Load, 1991-2015



Source for Figures 2 and 3 ISO NE 2016 CELT data.

Q. Why has net load flattened and begun to decline?

A. There are multiple factors, but two dominating factors are Connecticut and New England's increasing investment in energy efficiency resources[47], and the region's investment in behind-the-meter solar PV resources. New England also has significant levels of utility-scale solar PV resources, in addition to its behind-the-meter solar PV resources.[48] Utility-scale solar resources are available to serve a portion of net load needs.

Q. Has the Connecticut Siting Council already recognized the critical importance that energy efficiency resources play in reducing the need for new generation?

A. Yes. The CSC noted the importance of this resource in its final biennial report reviewing Connecticut's forecast of loads and resources.[49] From the report:

> "The data in this forecast show that energy efficiency and related programs are an extremely important part of Connecticut's electric energy strategy. Increased efficiency allows the State's electric needs to be met, in part, without incurring the financial costs and the incremental pollution that would be caused by dispatching generation to serve the additional load. Reductions in peak load due to increased efficiency can also impact the schedule of necessary changes to existing utility infrastructure, such as transmission lines and substation equipment (transformers, distribution feeders, etc.) and hence tend to hold down utility costs. Electric energy efficiency also reduces federal congestion charges and the costs of new generation. Currently, Connecticut ranks sixth for energy efficiency in the national rankings put out by the American Council for an Energy-

[47] See, for example, the CT 2016-2018 Conservation and Load Management Plan, page 29, Table 1-3: Electric Companies—Summary of Annual Savings and Percentage of Sales. Connecticut's plan calls for increasing levels of electric efficiency resource acquisition, from 1.42% to 1.52% to 1.60% of annual sales, for 2016 through 2018. At http://www.ct.gov/deep/lib/deep/energy/conserloadmgmt/2016_2018_CLM_PLAN_FINAL.pdf. See also MA Energy Efficiency Advisory Council's most recent Three-Year Plan, which projects for 2016-2018 annual efficiency savings of 2.93% of electric sales, the highest energy efficiency savings rate in the nation. At http://ma-eeac.org/plans-updates. And see e.g., RI PUC approval of its most recent three-year energy efficiency plan, which projects annual electric efficiency achievements of 2.5% (2015), 2.55% (2016), and 2.6% (2017). RI PUC, Docket 4443.

[48] See ISO NE, Final 2016 PV Forecast, April 15, 2016, page 9 (New England) and 27 (Connecticut).

[49] Connecticut Siting Council, Docket No. F-2014/2015, "Connecticut Siting Council Review of the Ten-Year Forecast of Connecticut Electric Loads and Resources, Final Biennial Report", December 10, 2015.

Efficient Economy for 2015. (See annual scorecard at http://aceee.org/research-report/u1509)" [page 22]

Q. Does the newer forecast of electric load for Connecticut contained in the ISO NE 2016 CELT Report further validate the finding in the CSC review of the then-current forecast, and does the latest ACEEE "scorecard" report also validate this finding?

A. Yes. The ISO NE 2016 CELT forecast shows projected net energy in 2024 for Connecticut that is 3.7% lower than projected net energy for Connecticut for the same year from the 2015 CELT report.[50] The ACEEE 2016 scorecard shows that Connecticut has improved from last year, from sixth place to fifth place nationwide.[51]

Q. What is the gross energy, energy efficiency and BTM solar PV forecast, and net annual energy forecast, for New England and Connecticut?

A. Table 5 below shows the 2016 CELT forecast of gross annual energy consumption, and for energy efficiency and BTM solar PV energy, for New England and Connecticut; and the resulting forecast for net annual energy need (which is equal to the gross amounts minus the energy efficiency and the solar PV) for New England and Connecticut. Table 6 shows the 2016 CELT forecast for gross peak load, energy efficiency and BTM solar PV peak-reducing effects, for New England and Connecticut; and the forecast for summer net peak load (which is equal to the gross amounts minus the energy efficiency and the solar PV reductions from peak) for New England and Connecticut.

[50] 2015 CELT report, projected net energy for Connecticut in 2024 is 32,326 GWh. 2016 CELT report, projected net energy in 2024 is 31,132 GWh.
[51] http://aceee.org/sites/default/files/pdf/state-sheet/2016/connecticut.pdf.

Table 5. 2016 CELT Forecast of Annual Energy, New England and Connecticut

Annual GWh	Gross Energy		Energy Efficiency		BTM PV		Net Load	
	ISO NE	CT	ISO NE	CT	ISO NE	CT	ISO NE	CT
2016	140,269	34,484	10,954	2,588	1,301	283	128,014	31,613
2017	141,997	34,936	11,903	2,357	1,655	394	128,439	32,185
2018	143,775	35,363	13,279	2,428	1,898	500	128,598	32,435
2019	145,268	35,677	14,911	2,970	2,097	600	128,260	32,107
2020	146,486	35,896	16,800	3,338	2,278	699	127,408	31,859
2021	147,706	36,103	18,567	3,685	2,444	788	126,695	31,630
2022	148,982	36,317	20,220	4,012	2,582	857	126,180	31,448
2023	150,267	36,525	21,765	4,320	2,713	919	125,789	31,286
2024	151,513	36,718	23,209	4,611	2,836	975	125,468	31,132
2025	152,731	36,900	24,559	4,884	2,959	1,030	125,213	30,986
Compound Annual Growth Rate, 2016-2025							-0.25%	-0.22%

Source: ISO NE, 2016 CELT Report.

Table 6. 2016 CELT Forecast of 50/50 Peak Load, New England and Connecticut

Summer Peak, MW	Gross Peak		Energy Efficiency		BTM PV		Net Peak	
	ISO NE	CT	ISO NE	CT	ISO NE	CT	ISO NE	CT
2016	28,966	7,594	1,839	450	423	92	26,704	7,052
2017	29,307	7,670	2,089	421	520	124	26,698	7,125
2018	29,652	7,744	2,306	459	582	154	26,764	7,131
2019	29,975	7,810	2,561	533	632	181	26,782	7,096
2020	30,276	7,869	2,812	581	676	208	26,788	7,080
2021	30,578	7,927	3,047	626	714	231	26,817	7,070
2022	30,883	7,985	3,267	668	746	248	26,870	7,069
2023	31,190	8,043	3,473	708	775	263	26,942	7,072
2024	31,493	8,100	3,665	746	802	276	27,026	7,078
2025	31,794	8,156	3,844	781	828	288	27,122	7,087
Compound Annual Growth Rate, 2016-2025							0.17%	0.06%

Source: ISO NE, 2016 CELT Report.

Figures 4 and 5 present Table 5 and 6 data for New England in graphical form.

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Figure 4. Gross and Net Summer Peak Load – EE, Solar PV Forecast Effects in New England

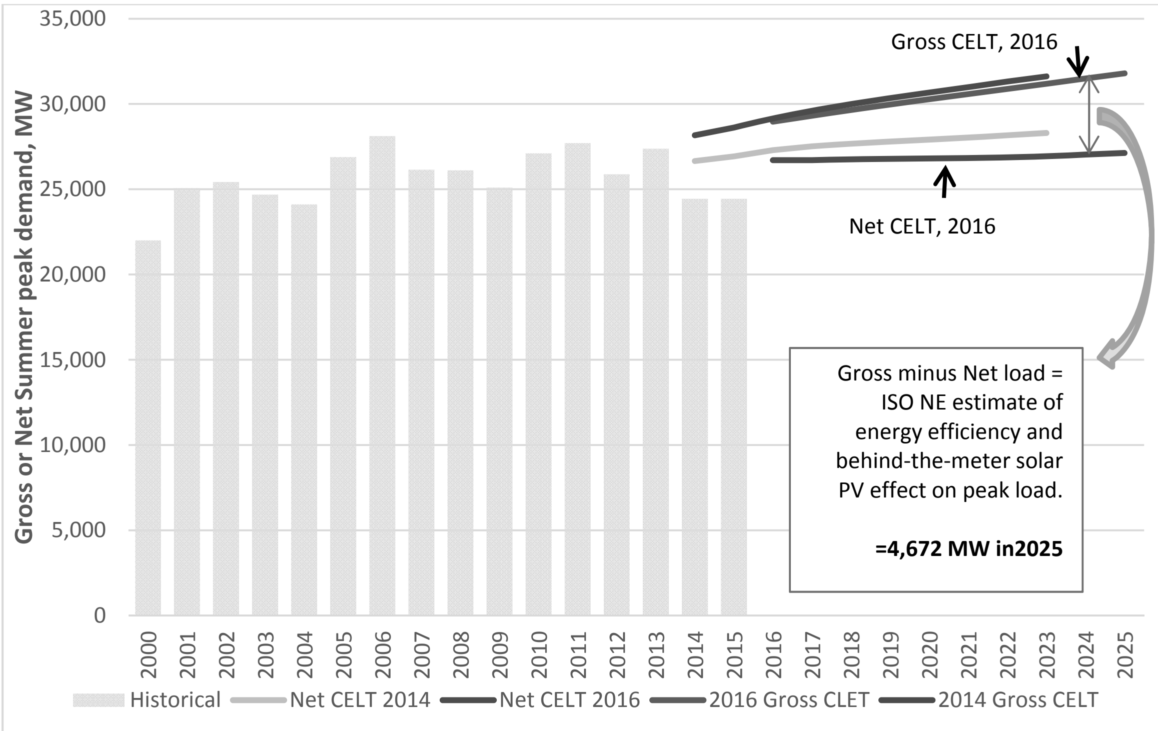
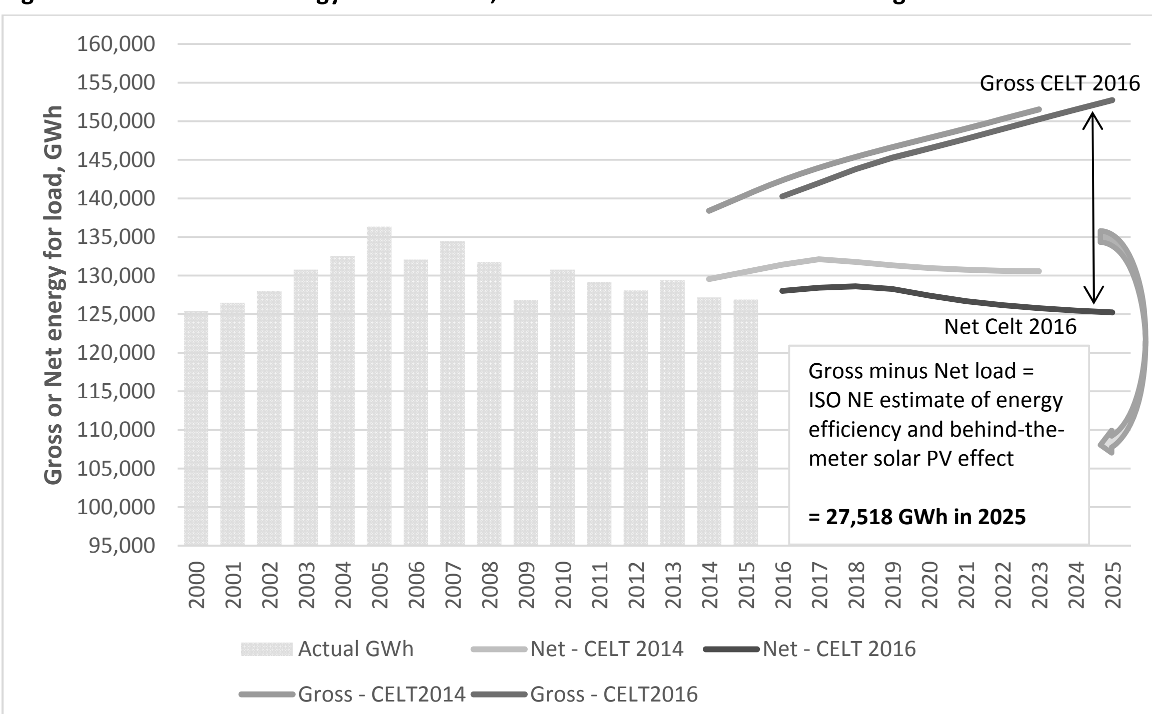


Figure 5. Gross and Net Energy for Load – EE, Solar PV Forecast Effects in New England



Source, Figures 4 and 5: ISO NE, CELT Reports Data, 2016 and 2014. Compilation by Synapse

Q. What do the data in Tables 5 and 6, and Figures 4 and 5, demonstrate for New England and Connecticut?

A. The data show the critical importance of energy efficiency and BTM solar PV resources in reducing the peak demand, and reducing net annual energy consumption, in New England and Connecticut. The effect of increasing levels of energy efficiency and BTM solar PV is to provide the New England system with significant reductions in the need for capacity – more than 4,600 MW by 2025 – and annual energy consumed – more than 27,000 GWh by 2025 - as shown by inspection of the "gross" and "net" forecast data or trend lines seen in the graphs. The tables also clearly show the increasing year-over-year levels of these resources in both Connecticut and New England, reducing peak demand and reducing annual energy needs. These reductions allow the system to provide "net" consumption and peak needs with fewer resources than would otherwise be required. Critically, as more of this year-over-year declining net energy consumption requirement is provided by utility-scale renewable resources such as grid-connected solar PV, on-shore wind, imports, and (eventually, commencing with the new Block Island wind farm) offshore wind, there will be declining needs for natural-gas fired generation to make up the remaining energy requirement.

<u>**Connecticut Solar PV and Energy Efficiency Effects on Reliability**</u>

Q. What level of overall solar PV exists in Connecticut, and what levels are forecast for Connecticut?

A. ISO NE's PV forecast presents these data in detail by state, and by the size of the resource – either BTM, or utility-grid-connected solar PV. The data shown in Tables 5 and 6 comprise only behind-the-meter solar PV. As of the end of 2015, 188 MW exists, of which 185 MW is behind-the-meter. Through 2020, 433 MW of additional solar PV is projected to be added, for a cumulative amount of 621 MW. 580 MW of this cumulative amount is behind-the-meter solar, impacting the net peak demand and net energy forecast for Connecticut as seen in the above tables and graphs. Through 2025, ISO NE (in its 2016 estimate) projects a total of 866 MW of solar PV in Connecticut. Of this amount, 809 MW is behind the meter solar PV.[52]

Q. How do solar PV resources – either behind-the-meter, or utility scale – support reliability needs in New England and Connecticut?

A. Behind-the-meter solar PV resources reduce peak load and the attendant distribution and transmission losses that occur on peak; they are accorded a peak-load-reducing credit proportional to their output during times of peak demand. Peak demand generally occurs after the time of peak solar PV output, but still reduces peak by a value currently equal to roughly 40% of their nameplate AC rating.[53] Solar PV contributes to reducing peak load because total nameplate capacity is producing (albeit at lower than maximum levels) during the peak hours, which occur in the mid to later afternoon in New England.

Q. How do energy efficiency resources help ensure reliability in New England and Connecticut?

A. Energy efficiency resources reduce peak load by reducing end use load during times of

[52] See ISO NE Final 2016 PV Forecast, Distributed Generation Forecast Working Group, April 15, 2016. Pages 9 and 27. Attached as Exhibit 12.

[53] See 2016 ISO NE CELT, Tab 3.1.2 PV Forecast - BTM MW, which indicates a 40% peak load reduction credit for 2015, decreasing to 34.1% by 2025. The value reduces over time because the time of net system peak is moving towards later in the day, when solar output is lower (than earlier in the day).

system peak, including reduced lighting, air conditioning, and other loads. Energy efficiency resources also reduce attendant transmission and distribution system losses, which are highest during peak periods.

Q. How do energy efficiency and behind-the-meter solar PV resources together help ensure reliability in New England and Connecticut?

A. Energy efficiency and behind-the-meter solar PV resources exert continuous downward pressure on net peak load and net annual energy trajectories in New England, and in Connecticut.

Q. Are there specific reasons to think that the solar PV forecast contained in the current CELT report is conservative, that is, is lower than what will actually occur?

A. Yes. The ISO-NE 2016 solar PV forecast resulted in a significantly higher level of solar PV projected for New England than the 2015 ISO-NE solar PV forecast, which itself exhibited a significant increase above 2014 projections.[54] ISO-NE traditionally assumes that "historical PV growth trends across the region are indicative of future intra-annual growth rates",[55] but declining solar PV costs could reasonably result, and have resulted recently, in increases to the future growth rates, relative to historical forecasts.

Q. How do you explain these solar PV forecast trends?

A. The underlying economics of solar PV drive the increasing penetration of the resource. Solar PV costs have dropped dramatically over the past few years, and are expected to continue

[54] See attached Exhibit 12, at slide 10.
[55] ISO NE Final 2016 PV Forecast, slide 12.

to decline in cost.[56]

Q. Please summarize this section.

A. Energy efficiency and behind-the-meter solar PV result in declining net peak load and declining annual net energy needs in New England and Connecticut. Net peak load and net energy are the peak load seen by, and the energy needed from, the transmission grid; net peak load is equal to gross load minus the effect of energy efficiency and behind-the-meter solar PV. The existence of these resources alone – energy efficiency and behind-the-meter solar PV – lowers forecast net demand. When coupled with existing capacity resources, additional utility-scale renewable resources, and a much-enhanced transmission grid across New England,[57] near-term reliability for Connecticut and the New England region is ensured without the proposed KEC plant.

<u>ISO NE Load Forecasts by CELT Report Vintage</u>

Q. Please present the trends seen in load forecasting by ISO NE over the recent years.

A. Figures 6 and 7 show projected net peak load in New England and Connecticut, by ISO NE load forecast vintage. Figures 8 and 9 show projected net annual energy consumption in New England and Connecticut, also by ISO NE load forecast vintage.

Q. What do these figures illustrate?

A. The figures clearly illustrate the upward bias that exists in earlier-year ISO NE load

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[56] Solar PV costs have declined dramatically over the past five years, and are projected to continue to decline. See, for example, the US DOE, Solar Energy Technologies Office, "On the Path to Sunshot: Executive Summary", Figure 1. Solar PV LCOE – historical, current, and 2020 targets (page 4). Available at http://energy.gov/sites/prod/files/2016/05/f31/OTPSS%20-%20Executive%20Summary-508.pdf. State net metering laws also promote continuing development of small solar PV.

[57] Major reinforcements or additions have been made to the backbone 345 kV grid in New England in recent years.

forecasts, for both peak load and energy consumption. For example, in Figure 6, the forward-looking compound annual growth rate (CAGR) for New England net peak load declines from 1.61% (contained in the 2010 CELT forecast) to 0.17% by the 2016 forecast. For Connecticut (Figure 7), the net peak CAGR is practically zero – 0.06% for the 2016-2025 period (a projected net increase of 35 MW statewide over ten years). For net energy consumption, the CAGR projections are negative (and coincidently, equal) in both New England and Connecticut, at minus 0.22% (a projected decrease of net energy consumption from the grid of 2,801 GWh in New England over the ten years).

Q. Do you anticipate that the bias present in the forecast trends will continue?

A. Data from 2016 suggest that the trend will continue, and that 2017 load forecasts will be lower than those made in 2016. As noted, and as seen in Figure 6, the 2016 peak load was significantly lower than the 2016-vintage forecast for 2016, even though the peak load day was relatively hotter and more humid than what was considered "normal" for a 50/50 peak load day.[58] Notably, as seen in the downward progression of the forward-looking CAGR for net peak load for both New England (Figure 6) and Connecticut (Figure 7), it is apparent that the system appears to be on the verge of a negative CAGR for net peak demand for both New England and Connecticut. In 2016, this was already the case for Rhode Island.

Q. What does this imply for reliability need for the proposed KEC plant?

A. It suggests that there will be even less of a potential need for new capacity resources in

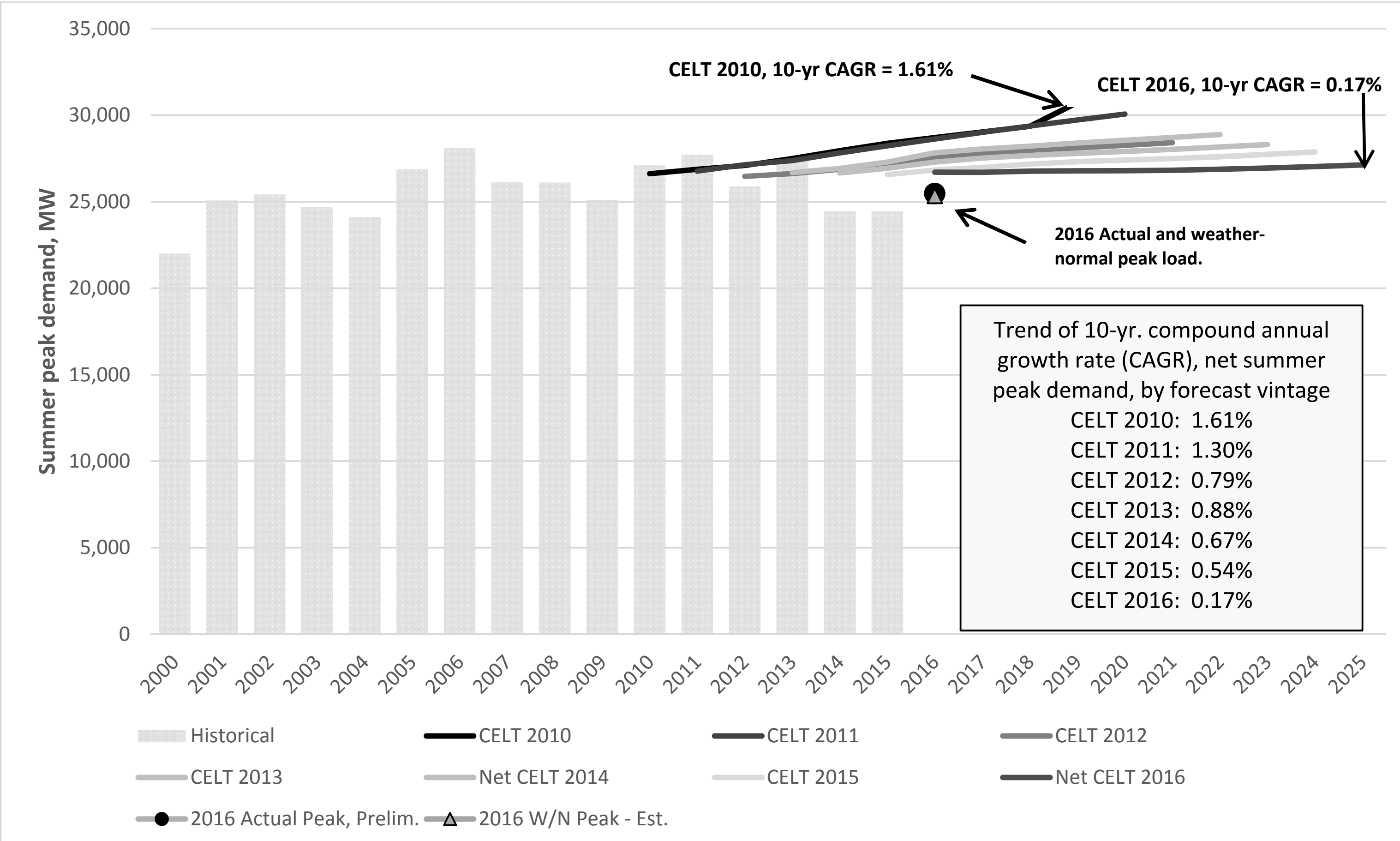
[58] ISO NE Chief Operating Officer presentation to the ISO NE Participants Committee meeting, September 9, 2016. Slides 24 – 33, "Highest Demand Days August, 2016" and "Comparison of Five Top Peak Days to 2016 Long-Term Load Forecast". Slides attached as Exhibit 10.

New England, relative to the situation that exists now - surplus (as described in the above portions of this testimony). It also suggests that as Connecticut considers additional GHG mitigation measures such as further increases beyond its projected increases in energy efficiency investment (see footnote 47), and potential increases in BTM solar PV, as I address in the next section, the net peak load projections will continue to decline relative to earlier forecasts.

Q. What else does the declining net annual energy requirement indicate?

A. The data indicate a lower need for net energy provision from the grid, i.e., from utility scale renewables, hydro, nuclear, imports, and conventional fossil fuel resources, with each successive future year. To the extent that new grid-scale renewables resources are built, as they must be to meet GHG emission limitations, the net energy need from conventional natural gas-fired resources declines even further.

Figure 6. New England Summer Net Peak Load, Actual 2000-2016, and ISO NE Forecast by Vintage



Note: Net energy for load is energy net of energy efficiency and behind-the-meter (BTM) solar PV resources. Net summer peak load is summer coincident peak load, net of the effects of energy efficiency and BTM solar PV. Source: ISO NE, 2016 CELT.
Source: ISO NE CELT Reports, 2010 through 2016. ISO NE COO Report for August 2016, 2016 peak load data. Tabulation of CAGR by Synapse.

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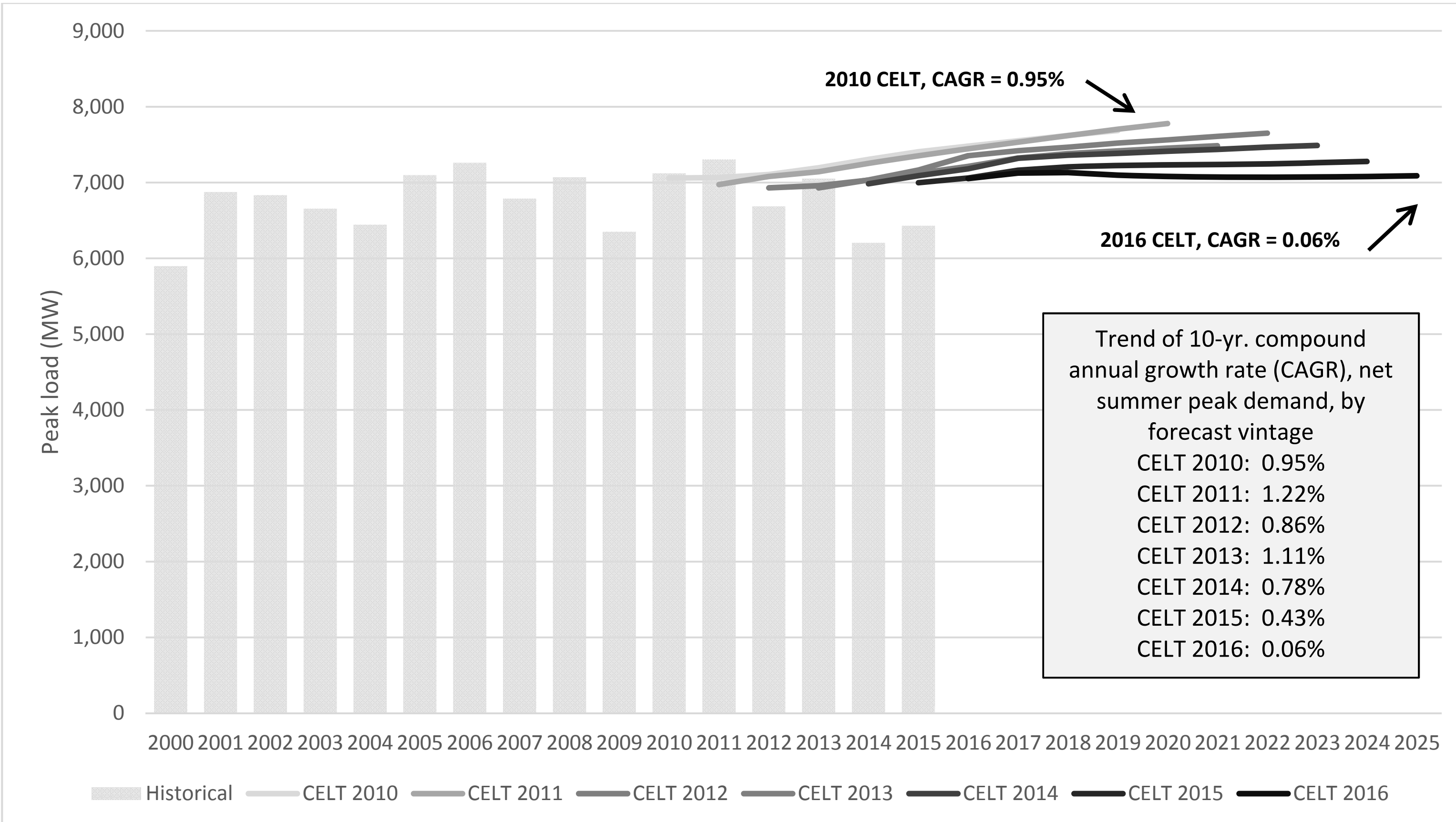
Figure 7. Connecticut Summer Net Peak Load, Actual 2000-2015, and ISO NE Forecast by Vintage



Note: Net energy for load is energy net of energy efficiency and behind-the-meter (BTM) solar PV resources. Net summer peak load is summer coincident peak load, net of the effects of energy efficiency and BTM solar PV. Source: ISO NE, 2016 CELT.
Source: ISO NE CELT Reports, 2010 through 2016. ISO NE COO Report for August 2016, 2016 peak load data. Tabulation of CAGR by Synapse.

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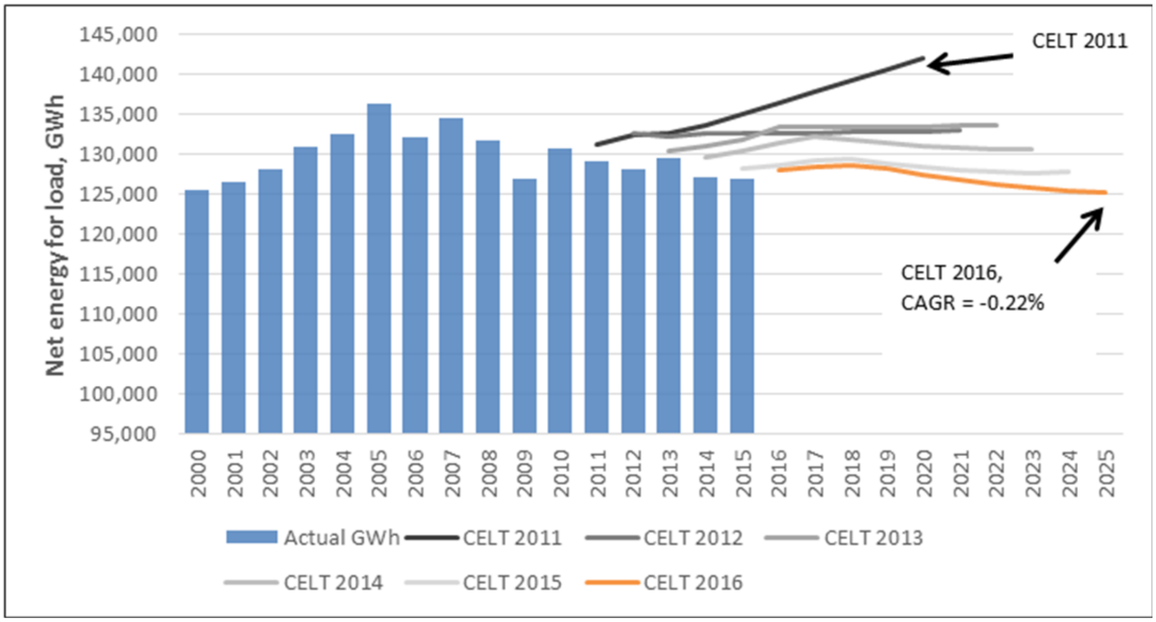
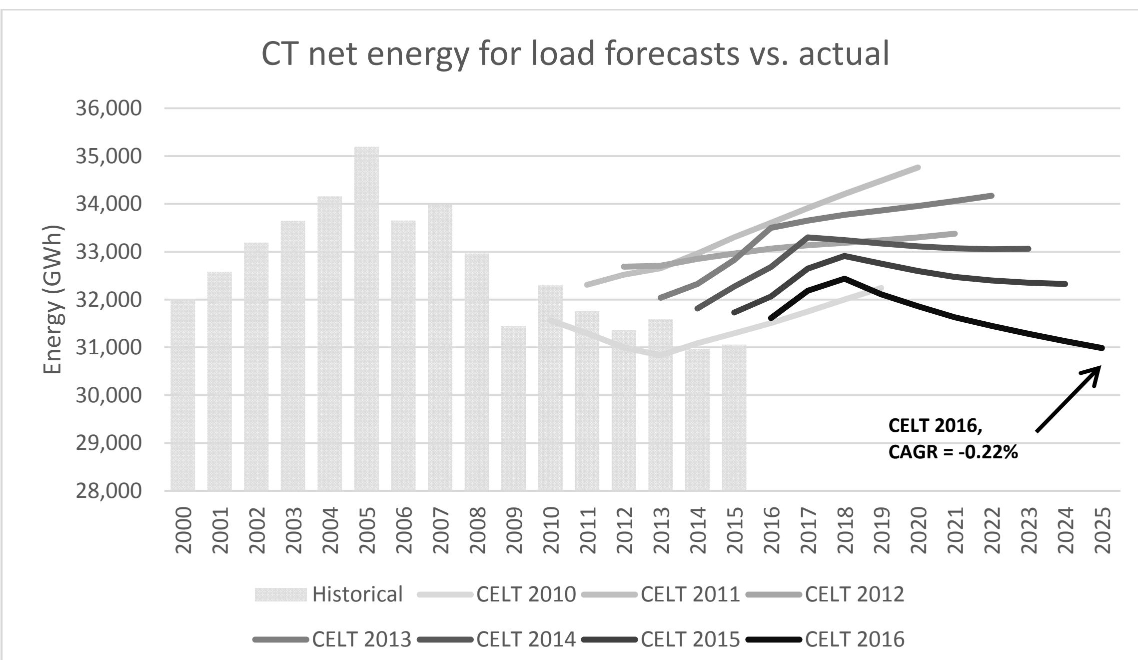
Figure 8. Net Energy for Load - Forecast Trends in New England by Forecast Vintage



Source: ISO NE CELT Reports, 2011 through 2016.

Figure 9. Net Energy for Load - Forecast Trends in Connecticut by Forecast Vintage



5 Critique of NTE Application

Q. What do you address in this section?

A. I provide additional specific critique of information in NTE's application beyond what I have addressed in the above sections.

No Reliability Need

Q. Does the KEC application present any evidence for a near-term, medium-term, or long-term reliability need for the proposed plant?

A. No. The applicant relies on the prospective results of the ISO NE capacity market auction to indicate a reliability need for the plant. They state "by definition, if KEC clears FCA 11, then ISO NE (and, by proxy, Connecticut LSEs that are participants in ISO-NE) will have determined KEC to be needed for the reliability of Connecticut and the wider New England market".[59] They provide no additional information to suggest a need for the plant out towards the middle of the next decade, nor do they indicate how the plant might be needed over the longer term. They provide generic reference to the plant's relative fuel-efficiency in comparison to coal and oil-fired generation, but they provide no assessment of what that implies for any year past 2024.

Q. The applicants state "it is through the FCM that ISO-NE determines the reliability-driven need for new capacity resources like KEC"[60] and that the "capacity resources that clear

[59] Appendix B-2, "Need Analysis", page 14.
[60] Appendix B-2, "Need Analysis", page 11.

the FCA are, by definition, needed for reliability"[61], and "this auction [FCA 11, for 2020/2021] will determine the capacity that is needed for reliability in ISO-NE during the 2020/2021 DY [delivery year]"[62]. Is this correct?

A. No. As I noted in "Section 3 Background" in this testimony, clearing a forward capacity auction does not mean a resource is needed for reliability.

Q. Is it true that if this plant were to clear the FCA 11 and obtain a CSO for 2020/2021, that ISO-NE has determined a reliability need for this plant?

A. No, not at all. Physical reliability needs are defined, in the near-term (for the three-year ahead, 1-year period covered by any given FCA) by the installed capacity requirement for the New England system as a whole, and by the local sourcing requirements. A proposed resource such as the KEC plant clearing the FCA means that the resource obtains a capacity supply obligation but it doesn't mean that the resource will be physically needed for reliability. In subsequent "reconfiguration" auctions, the capacity supply obligations can be sold, or traded, to other parties; and/or, the resource need for the given FCA period is updated with the most recent forecast information available.

<u>Winter Reliability Issues</u>

Q. Is the proposed KEC plant needed for winter period reliability?

A. No. The New England region has sufficient dual-fuel capabilities, plentiful reserve

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[61] Ibid., Page 12.
[62] Ibid., Page 13.

capacity, and extensively developed policies in place[63] to ensure winter reliability without the additional generating capacity of the proposed KEC plant, in both the near term and in the longer-term. Also, the winter season's net peak load is declining because of the beneficial effects of energy efficiency provision in the region. As the Analysis Group report[64] summarized,

> ***"Under the base case analysis, power system reliability can and will be maintained over time, with or without additional new interstate natural gas pipeline capacity.*** New England's existing market structure, including recent changes to address reliability during challenging system conditions at the time of winter peak demand, will provide the resources and operational practices needed to maintain power system reliability. The region will continue to rely on natural gas as the dominant fuel of choice, but we find that under existing market conditions there is no electric sector reliability deficiency through 2030. This result reflects both the declining long-term forecast of peak winter demand and the increasing availability of new non-gas resources, including dual-fuel capable units that can generate on oil during peak winter periods." [65]

Even in the Analysis Group's "stressed system sensitivities", the alternatives available to ensure winter reliability do not include new gas-fired power plants such as the proposed KEC plant.[66]

Q. What is meant by "dual-fuel" capability, and what is the extent of dual-fuel capability in the New England region?

A. Dual-fuel capability generally refers to the ability of a natural-gas fired power plant to also burn an alternative fuel, usually oil; or an oil-fired plant to burn gas. ISO NE tracks the fuel capabilities of all generation: the 2016 CELT Report lists all generating sources with dual fuel

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[63] See attached Exhibit 13, Remarks by Peter Brandien, Vice President, Operations, ISO New England, Federal Energy Regulatory Commission (FERC) Panel Discussion, Winter 2016-2017 Operations and Market Performance in Regional Transmission Organizations and Independent System Operators (Docket No. AD16-24-000),October 20, 2016. The remarks indicate that winter reliability steps taken by ISO NE to ensure oil supplies will be sufficient at least through the winter of 2017/2018, and that "Pay for Performance" market structures in place in the ISO NE forward capacity market should ensure market-based provision of any fuel capabilities or fuel supply assurances required to meet winter concerns.

[64] Analysis Group, Inc., Paul J. Hibbard and Craig P. Aubuchon,"Power System Reliability in New England, Meeting Electric Resource Needs in an Era of Growing Dependence on Natural Gas", November 2015.
See attached Exhibit 7.

[65] Ibid., Executive summary, Page iii.

[66] Ibid., pages iii to vii.

capability. Table 7 below (data from the CELT report) shows that there will be more than 4,000 MW of dual-fueled combined cycle units in New England by next winter; and an additional roughly 3,000 MW of MW of dual-fueled combustion turbine (i.e., peaker) and steam resources. In total, New England has more than 7,000 MW of dual-fueled resources. Additionally, New England has more than 1,700 MW of oil-fired combustion turbines, and more than 2,100 MW of the older, oil-only steam units.

Table 7. Winter Capability (MW) by Fuel - New England Generation, 2016-2025

Winter MW (1)	15/16	16/17	17/18	18/19	19/20	20/21 through 25/26
Nuclear Steam	3,877	4,010	4,023	4,024	3,347	3,347
Hydro and Pumped Storage	3,215	3,260	3,297	3,255	3,259	3,359
Gas Combined Cycle	8,898	8,285	9,022	10,146	10,640	10,640
Gas/Oil Combined Cycle	3,290	3,983	4,020	4,027	4,090	4,090
Gas Combustion Turbine	374	221	239	523	1,335	1,335
Gas/Oil Combustion Turbine	629	542	554	552	549	549
Oil Combustion Turbine	1,613	1,719	1,702	1,736	1,770	1,770
Coal Steam	1,981	1,947	927	922	917	917
Gas/Oil Steam	2,777	2,831	2,481	2,481	2,479	2,479
Oil Steam	2,185	2,128	2,201	2,148	2,192	2,192
IC, Bio/Refuse, Wind, Gas Fuel Cell	1,231	1,253	1,406	1,294	1,413	1,413
Solar PV	0	0	0	0	0	0
Subtotal ISO-NE Capacity (2) (4)	30,070	30,178	29,872	31,108	31,990	32,090
Demand Resources (2)	2,285	2,427	2,799	2,752	2,746	2,746
Imports (3)	1,326	1,137	1,406	1,017	1,069	89
Total ISO NE Capacity (4)	33,682	33,742	34,076	34,877	35,805	34,925

Source: ISO NE, 2016 CELT Report, Tab 1.4, Winter By Fuel-Unit Type. Some aggregation by Synapse.
Notes:
(1) Gas/oil units are not necessarily fully operable on both fuels.
(2) The 2015/16 through 2019/20 capacity values consist of the Forward Capacity Market CSOs as of March 18, 2016. The 2019/20 FCM CSO is assumed to remain in place through the end of the CELT reporting period. It is assumed that the 211 MW of Static De-List Bids that were cleared to leave the 2019/20 Forward Capacity Auction will remain de-listed through the reporting period.

(3) Imports are from entities outside the ISO-NE Reliability Coordinator Area boundary. The 2015/16 through 2019/20 imports are based on FCM import CSOs. An Export De-List of 100 MW is taken into account in the generation capability values through 2019/20. The imports beyond the 2019/20 Capacity Commitment Period reflect only known, long-term contracts.
(4) May not equal sum due to rounding.

Q What is the peak load forecast outlook for New England for winter periods?

A. The net peak load forecast for winter – i.e., actual loads after accounting for the effects of energy efficiency – shows declining peak loads through the end of the forecast, starting with the winter period 2017/2018, after a small net peak increase forecast for this winter. This declines stems in significant part from the effects of increased investment in energy efficiency in New England. Table 8 below contains the winter net peak load forecast for New England.

Q. What is the level of winter capacity reserve in New England?

A. Table 8 below also contains winter reserve capacity data. It shows excess, and increasing, capacity reserves for the winter period in New England. Reserve margins exceed 50% for all years in which the proposed plant may be online, based on the capacity supply obligations (CSOs) that exist. Using seasonal claimed capability (SCC)[67], a different measure of capacity, winter reserve margins range from 61 to 70 percent.

Q. NTE has asserted a winter reliability need[68] for the proposed KEC plant, yet these reserve quantities indicate that there is not a concern. Please discuss.

A. NTE is basing its assertion on concern over fuel sources available to New England power generators, but there is no need for new fossil-fired generating plant. As ISO NE's remarks to

[67] SCC MW represents the total of resources that have CSOs, plus other resources that do not have CSOs.
[68] For example, in response to discovery request No. 83 from the Council.

FERC illustrate[69], there has been significant policy development and ISO NE market development to address this issue, which is centered on the presence of market or non-market mechanisms to ensure oil, or liquefied natural gas (LNG) supplies, to units capable of operating on these fuels. In short, there are adequate safeguards in place to ensure oil or LNG availability in the near term to meet any winter reliability concerns. In the medium term, ISO NE's Pay for Performance construct, noted in ISO NE's remarks and applicable to the forward capacity market, is intended to incentivize existing generation to secure needed winter fuels. Over the longer-term, new resources such as renewable supplies, energy efficiency, demand response, and energy storage will be available to complement the dual-fuel capabilities of the existing efficient fossil-fueled resource base and ensure winter reliability if or as more of the older steam units retire.

[69] Attached Exhibit 13.

Table 8. Sections of 2016 ISO NE CELT Indicating Installed Winter Peak Load and Winter Capacity Reserves

Winter year:	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24
1. Load (1) (2) (3)									
1.1 REFERENCE LOAD - Without reductions	22,860	22,992	23,170	23,353	23,507	23,633	23,758	23,890	24,022
1.1.1 Behind-the-Meter (BTM) PV (4)	0	0	0	0	0	0	0	0	0
1.2 REFERENCE - With reduction for BTM PV	22,860	22,992	23,170	23,353	23,507	23,633	23,758	23,890	24,022
1.2.1 Passive DR (PDR) used in System Planning (5)	1,663	1,652	1,832	2,171	2,371	2,604	2,821	3,025	3,215
1.3 REFERENCE - With reduction for BTM PV and PDR	21,197	21,340	21,338	21,183	21,136	21,029	20,937	20,865	20,807
Synapse Compuation of Year over Year change:		0.67%	-0.01%	-0.73%	-0.22%	-0.51%	-0.44%	-0.34%	-0.28%

4. RESERVES - Based on Reference Load with reduction for Passive DR	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24
4.1 INSTALLED RESERVES - Based on CSOs of Generating Resources (line 2.1), Active DR (line 2.2.1), and Imports (line 2.3)									
4.1.1 MW	10,799	10,518	10,782	11,540	12,301	11,528	11,620	11,692	11,750
4.1.2 % of LOAD	51	49	51	54	58	55	55	56	56
4.2 INSTALLED RESERVES - Based on Generation SCC (line 3.1), Active DR (line 2.2.1), Imports (line 2.3), and Exports (see footnote 11)									
4.2.1 MW	13,697	13,285	13,120	13,746	14,901	14,128	14,220	14,292	14,350
4.2.2 % of LOAD	65	62	61	65	70	67	68	68	69

Source/Notes: Tab 1.2, "Winter Peak", ISO NE 2016 CELT Report. See Attached Exhibit 1.

Notes for Table from ISO NE CELT Report:

(1) Represents MW load level associated with a reference forecast having a 50% chance of being exceeded. More information on the April 2016 CELT forecast, including the high and low bandwidths, is available on the ISO-NE Website located at http://www.iso-ne.com/system-planning/system-plans-studies/celt.

(2) Two versions of the seasonal peak load forecast are shown. The first forecast does not reflect the peak and energy savings of the passive demand resources. The second forecast shown reflects a reduction for that passive DR. Detailed forecast documentation on the ISO-NE website includes both the original CELT forecast and the forecast minus passive demand resources.

(3) The 2015/16 winter peak load shown reflects weather normalization. Prior to weather normalization, the actual metered 2015/16 winter peak of 19,524 MW occurred on February 15, 2016 at hour ending 18:00. See Section 1.5 for actual and estimated peaks and energies. The reconstituted (for the load reducing action of FCM Passive Demand Resources) peak of 21,860 MW occurred on February 15, 2016 at hour ending 18:00.

(4) Behing-the-Meter PV is assumed to be zero during the winter peak.

(5) The passive DR shown on line 1.2.1 consists of the Qualified Capacity (QC) of existing resources and primary auction (FCA) results for new resources. These values are used by ISO-NE System Planning in their long-term Needs Assessments and Solutions Studies (see Sec. 5.2 of this report for a breakdown by Load Zone and DR

type), <u>and are different from the Capacity Supply Obligations shown on line 2.2.2</u>. Beginning in 2020-2021, passive DR includes an ISO-NE forecast of incremental EE beyond the FCM.

(6) The 2016/17 through 2019/20 capacity for generating and demand resources consists of the Forward Capacity Market CSOs current as of March 18, 2016, and the 2015/16 CSOs are based on the ARA 3 results. The 2019/20 FCM CSO is assumed to remain in place through the end of the CELT reporting period. It is assumed that the 211 MW of Static De-List Bids that were cleared to leave the 2019-2020 Forward Capacity Auction will remain de-listed through the reporting period. The Citizens Block Load CSO is treated as an import rather than a generating resource.

(7) The demand resource values are based on DR with FCM CSOs, including an 8% transmission and distribution loss gross-up. A passive DR forecast is included with the QC-based DR values on line 1.2.1, beginning in 2019/20.

(8) The 2015/16 through 2019/20 imports are based on FCM import CSOs. An Administrative Export De-List of 100 MW, which expires on May 31, 2020, is taken into account in the generation capability values from 2015/16 through 2019/20. The purchases beyond the 2019-2020 Capacity Commitment Period reflect only known, long-term contracts. Note that one of those long-term contracts is a 6 MW contract that ends October 2020. The FCA #11 qualification process will take this into account in determining its qualified capacity for the upcoming auction.

(9) May not equal sum due to rounding.

(10) The generating capability based on SCC values includes all existing ISO New England generating assets as well as projected additions and retirements. Future generating assets consist of non-FCM resources that are expected to go commercial in 2016 or 2017, and all new resources with FCM CSOs. The capabilities of the FCM resources are based on their Qualified Capacity.

(11) Exports consist of a 100 MW Administrative Export De-List through 2019/20.

Q. Please summarize what Table 8 shows.

A. Table 8 has two sections. The first section shows a winter net peak load forecast declining to 20,807 by 2023/2024, with year-over-year winter peak load declines continuing each year commencing with the winter of 2017/2018. As seen in the row labeled "1.2.1 Passive DR [Demand Resources] (PDR) Used in System Planning (5)", accumulating energy efficiency effects result in a winter peak load reduction of 3,215 MW by 2023/2024, leading to the net peak load shown.

The second section of the table contains ISO NE's forecast of winter capacity resources, and shows the planning reserve margin resulting from capacity available in excess of the net peak load. The reserve margin in excess of net peak load is what is used to address the presence of forced outages at capacity resources, uncertainties and weather deviations in the load forecast, and provision of operating reserves to address contingencies and provide related ancillary service capacity.

<u>KEC is Inconsistent with CT State Plans</u>

Q. The applicants state that the proposed KEC plant exhibits "Consistency with state plans".[70] Is the plant consistent with state plans?

A. No. In particular, the proposed plant stands in stark opposition to what is required to meet GHG emission limits for the Connecticut Global Warming Solutions Act.

Section 3.8 of the applicant's Needs Assessment refers to the 2014 Integrated Resource Plan, which was conducted during 2014 and was released in early 2015; and Section 3.8 refers to winter fuels concerns that the facility would alleviate. The 2014 Integrated Resource Plan relied on load and resource data that is now stale; and Connecticut's current energy plans include focus on meeting GHG emission targets in interim (2030, 2040) periods and by 2050. NTE does not address any emissions effect of the plant towards Connecticut's 2030 or 2040 interim GHG emission limits.[71] As noted in the above section, there is no winter reliability concern in New England that requires a new KEC plant.

The applicants also refer to proposed plant's role in complying with the US EPA Clean Power Plan (CPP), and references Connecticut's participation in the Regional Greenhouse Gas Initiative (RGGI).[72] However, the applicants do not address how the KEC plant would contribute towards meeting GHG emission goals pursuant to Connecticut statute Public Act 08-98, which

[70] Application Appendix B-2, Needs Assessment, Section 3.8, page 15.
[71] See Section 6 of this testimony below.
[72] Application, Appendix B-2, Needs Analysis, page 10.

embodies more stringent limits than either current RGGI limits or the US EPA's CPP.[73] It provides no analysis of KEC's effect on GHG emissions in any years after 2024.[74] As I address in the following Section 6 of this testimony, the plant will hinder, not help, Connecticut's progress towards meeting the GWSA law.

Cost Savings and Emissions Reduction Based on Flawed Model Construct and Faulty Input Assumptions

Q. NTE asserts electricity cost savings, and projected emission reductions resulting from its proposed KEC plant, for the period 2020 to 2024. Please comment on NTE's assertions and its overall modeling of the electric power sector in New England.

A. The claims of emission reductions and electricity cost savings are not credible because [redacted] the modeling methodology used is flawed. The modeling also gives no consideration to alternative, realistic resource projections that would materially affect the cost and emission implications; thus the results, even if they were valid, are not at all robust across a number of reasonable increased renewable resource deployment scenarios.

[redacted]

[73] See for example, Synapse Energy Economics, "The RGGI Opportunity, RGGI as the Electric Sector Compliance Tool to Achieve 2030 State Climate Targets", February 5, 2016. Attached as Exhibit 14.

[74] See response to NAPP's Question 9. NTE does not provide any further analysis beyond that contained in the Needs Assessment, which only addresses emissions over the 2020-2024 period for a plant expected to be in service through 2050 (expected service life of 30 years, KEC Application, page 39).

[redacted][75] [redacted][76] These two resources alone can have a significant effect, on the margin, of resource use in New England to meet load.[77] [redacted].[78] [redacted], and they [redacted].[79] These resources would have a significant impact on the cost and emission effects for the modeling scenario that includes the proposed KEC plant.

The applicant does not produce any modeling that tests the robustness of its cost savings and emissions reduction results to any reasonable change in future resource assumptions, especially associated with additional renewable energy increases in New England.

The modeling methodology is flawed because PA's construct changed just one variable when they modeled a "baseline without KEC" and a "scenario with KEC" in order to compare the effects of the presence of the KEC plant.[80] Given the substitutability of resources in New England, it would be important to at least attempt to account for how the market responds if a

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[75] [redacted]

[76] [redacted]

[77] As net peak load is lower on the New England system, there is less need to use higher cost, generally higher emitting units to meet requirements. This implies that to the extent NTE's modeled level of energy efficiency and BTM solar PV are too low, the cost savings and emission reduction claims are exaggerated.

[78] [redacted]

[79] [redacted]

[80] Applicant response to NAPP discovery Question 2.

proposed plant doesn't materialize. For example, in the capacity market, a different resource could take the place of KEC, such as an increment of demand response or an increment of new storage resource. Instead, they assume that absent the KEC plant, nothing else changes in New England relative to a scenario with the plant. This leads to a "without KEC" or baseline scenario that fails to account for manner in which the competitive capacity market selects resources in New England.

[redacted]

Q. The applicant suggests that the KEC facility will result in GHG emission reductions in the period 2020-2024.[81] Please comment.

A. The applicant's assertion that GHG emission reductions will occur as a result of the construction and operation of the proposed facility, even in just the early years 2020-2024, is not supported [redacted], as I note above. The applicant's omission of *any* information on GHG emissions over the remaining life of the facility (beyond 2024, in the years when Connecticut's

[81] Application, Appendix B-2, "Need Assessment", at pages 9-10.

GHG emission reduction targets continue to increase) is concerning, because sustained GHG reductions are needed in Connecticut and New England beyond 2024. The applicant notes, generically, that "…the environmental benefits of burning less fuel and displacing older, less efficient, higher-emitting sources, are significant".[82] While that may be true in a generic, theoretical sense, the extent of its applicability to New England for the period from 2020 onward is highly suspect because coal use will be eliminated by the early 2020s, and oil use in New England does not result in appreciable amounts of annual energy generation.

By 2021, perhaps earlier, Connecticut – and possibly the rest of New England – will no longer produce any electricity from coal-fired resources.[83] Less-efficient oil-fired resources are rarely used for electricity production in New England: in 2015, oil produced only 1.5% of the region's "net energy for load", almost all of it during January and February; to date in 2016, oil has only produced 0.3% of the region's electricity.[84]

Q. The applicants state that the FCA [forward capacity auction] process selects resources "while simultaneously maximizing social surplus".[85] Does the FCA maximize social surplus?

A. No, not for any reasonable interval associated with capacity investment; and exclusive of the constraints that Connecticut policies might have on the procurement of future electricity-providing resources. The forward capacity market auction clears a three-year forward, one-year-period market for capacity. But it does not address a myriad of issues concerning the

[82] Application, page 33.

[83] After Brayton Point retires in 2017, there will be just three remaining coal plants: Bridgeport Harbor, retiring by 2021, and two plants in New Hampshire (Schiller and Merrimack) whose fate is unclear.

[84] ISO NE, energy and load data report available at https://www.iso-ne.com/isoexpress/web/reports/load-and-demand/-/tree/net-ener-peak-load.

[85] Needs Analysis, page 12.

longevity of capacity resource investment and State policies towards GHG emission limitations. From the perspective of long-term planning for resource development in Connecticut, maximizing social surplus implies a longer time horizon than just the one-year FCA, and it would include Connecticut's state policies that are not currently accounted for in the ISO NE's FCM construct.[86]

KEC is Not Needed to Support Renewable Generation Increases in New England

Q. KEC's response to CSC Question No. 84 states that KEC is needed to support the growth of renewable forms of power generation.[87] Is this correct?

A. No. ISO NE requires a relatively "flexible" system in order to dispatch the system in consideration of the variable output of renewable energy sources, but the existing system has adequate capacity resources to provide such flexibility. The installed capacity requirement includes all capacity reserves required to provide the ancillary services needed for the New England system. All flexibility needs are contained within this capacity requirement.

New fossil-fired resources are not the only source for contributing to the flexibility needs of the system. Existing supply resources (e.g., fossil, hydro, and pumped storage), existing and new import resources, existing and new demand-side resources, and new energy storage resources can and will contribute to the "flexibility" needs of the ISO-NE system. The applicant provides no analysis that shows that its proposed plant is required to meet the flexibility needs of the ISO NE system. While the proposed KEC plant has attributes that may

[86] This may be changing: as noted, NEPOOL and ISO NE are investigating "IMAPP" or the integration of wholesale markets and public policies in New England.
[87] The response states that KEC is needed for "supporting the growth of renewable forms of power generation".

contribute to a flexible ISO-NE system, the existing fleet and interconnection capabilities already provides sufficient flexibility in the near-term and beyond.

Q. Does ISO NE indicate it needs new combined cycle plants like the proposed KEC in order to support more renewable integration?

A. No. ISO NE summarizes its needs in Section 10, "Integration of Variable Energy Resources", of its 2015 Regional System Plan.[88] In that section, ISO NE identifies a number of requirements to support increased levels of renewable resources injected onto the New England grid. Those needs include:

- New transmission reinforcement and related voltage support, to allow for the connection and delivery of additional wind power sourced in Maine;
- Better forecasting of solar PV resource output;
- Possible need for increased operating reserve, for example for load following;
- Possible additional transmission reinforcement associated with increased solar PV.

ISO NE does not identify any need for new resources to address the integration issues. The existing resource base in New England contains more than 13,000 MW of dispatchable, existing combined cycle units; more than 3,000 MW of hydro and pumped storage resources, much of which is dispatchable at least to some extent; dispatchable demand response resources; more than 1,600 MW of schedulable imports from Hydro Quebec; additional import capability from New York and New Brunswick; and state policies in Massachusetts and Connecticut that are poised to add at least multiple hundreds of MW of dispatchable storage resources.

[88] Attached as Exhibit 15.

6 GHG Emission Implications of the Proposed Plant

Q. What do you address in this section?

A. I address the greenhouse gas (GHG) emissions implications if this plant is constructed. I show that KEC is a relatively ineffective source of GHG emission mitigation. I provide evidence from ISO NE and CT DEEP that dramatic reductions in natural gas generation are required to meet GHG emission targets. I show that existing and planned efficient gas-fired combined cycle generation in New England will utilize the shrinking GHG emission budget that now exists in New England because of state laws mandating declining GHG emission levels over the next few decades.

Q. Please summarize Connecticut's Global Warming Solutions Act (Public Act No. 08-98).

A. Connecticut's GWSA mandates total GHG emissions drop to 80% of the state's 2001 emissions by the year 2050. The total emissions include GHG emissions from the electric power sector. Similar GHG emission reduction targets exist in the other New England states.[89]

Q. Do GHG emissions implications have an effect on reliability need assessment?

A. Yes. GHG emission policies in Connecticut, Massachusetts and Rhode Island, and other New England states, and New York, will have a major impact on the set of electric resources used to meet load between now and 2050, including impacts on near-term resource development if, or as, states set interim GHG emission reduction targets for 2030 or other years.[90] The resource choices made to address these GHG emission policies will have a direct

[89] See attached Exhibit 6 from ISO NE.
[90] For example, in addition (or as a complement) to its GWSA-related policies, Connecticut has plans to enter into long-term contracts for large-scale renewable resource supply. These plans will effect near-to-medium term (now

effect on reliability needs, and thus form an integral part of the assessment of the applicant's assertion of a reliability need for the KEC plant. For example, accelerated investments in solar and wind resources and energy efficiency to help meet GHG emission targets leads to a direct reduction in need for conventional fossil-fueled energy and capacity resources.

Q. Please summarize your examination of the proposed plant's effect on Connecticut's ability to mitigate GHG emissions and meet its 2050 and interim GHG emission limitations.

A. The proposed KEC plant will hinder, not support, progress towards reaching CT's interim (2030, 2040) and 2050 GHG emission limits under Public Act 08-98 and the Connecticut DEEP's implementation of that Act, as I describe in this section. Connecticut and New England in general need to dramatically lower natural gas consumption in the electric power sector in order to reach such goals. To do so, relatively low-cost GHG mitigation options, primarily increased energy efficiency implementation and procurement of renewable energy resources are required. Those measures are much more effective at reducing GHG emissions than is a plant like KEC, as I show.

<u>KEC is a Relatively Ineffective GHG Mitigation Tool</u>

Q. How does the claimed GHG emission reduction capabilities of the proposed KEC plant compare with the GHG emission reduction capabilities of alternative energy efficiency and renewable energy sources?

A. Even when using NTE's claimed rate of CO_2 emission avoidance from the proposed

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through 2025) resource development. Massachusetts in 2016 passed a law requiring sizable amounts of Canadian hydro imports and new offshore wind resources.

plant, which I do not find credible, energy efficiency and renewable energy sources are at least on the order of [redacted] as effective, on a per MWh basis, as the proposed plant at reducing CO_2 emissions. Table 9 below shows this information, computed from [redacted], NTE's claimed CO_2 emission reductions, and marginal CO_2 emission rates from ISO NE's estimates of 2015 system emissions.

Table 9. Relative Effectiveness of Energy Efficiency and Renewable Energy at Reducing CO2 Emissions, vs. KEC

Year	CO2 Emission Reduction from KEC Plant, Tons/Year	Annual MWh from KEC	Avoided CO2 Tons Per KEC MWh	Avoided CO2 Pounds Per KEC MWh	NE Marginal CO2 Emission Rate, Pounds/MWh	Relative Effectiveness of EE/RE Sources vs. KEC Sources - CO2 Emission Reduction
2020	243,000	[redacted]	[redacted]	[redacted]	857	[redacted]
2021	311,000	[redacted]	[redacted]	[redacted]	857	[redacted]
2022	360,000	[redacted]	[redacted]	[redacted]	857	[redacted]
2023	307,000	[redacted]	[redacted]	[redacted]	857	[redacted]
2024	334,000	[redacted]	[redacted]	[redacted]	857	[redacted]

Source: NTE Needs Analysis, p.10; [redacted] and 2015 ISO-NE Electric Generator Air Emissions Report, Draft Results, November 1, 2016. Slide 28. Available at https://iso-ne.com/static-assets/documents/2016/10/2015_emissionsupdate_20161101.pdf.

Q. Please explain how you developed Table 9, and what it means.

A. The marginal CO2 emission rate in New England represents the increase or decrease in CO_2 emissions that occurs if there is a change in demand for electricity, or if a renewable source added to the grid reduces the use of a marginal fuel (generally natural gas). For each MWh provided by a renewable resource, CO_2 emissions decline; and for each MWh of energy saved through energy efficiency, CO_2 emissions decline. The marginal emission rate is the metric to use to attribute CO_2 reduction to these resources. The KEC plant, by comparison, reduces much less CO_2 on a per-MWh basis (because it emits CO_2) than either of these other CO_2 mitigating measures, even when using the applicant's claimed CO_2 emission reduction capability, which as I note above is likely exaggerated [redacted].

Thus, the table clearly shows the ineffectiveness of KEC at reducing GHG emissions, relative to the suggested mitigation measures from CT DEEP.

Q. Is it possible that the relative ineffectiveness of KEC as a GHG-avoiding resource is even greater than Table 9 suggests?

A. Yes. We do not have any results for production cost modeling runs that use more reasonable input assumptions, and a less-flawed construct for measuring avoided emissions. Such modeling runs could reasonably show reduced (or even negative) avoided CO_2 emissions from the proposed plant. In that instance, the relative effectiveness of GHG avoidance provided by energy efficiency and renewable resources in comparison to KE would increase. For example, in 2020, if the GHG emission avoidance from the proposed plant was half of what NTE estimated, the relative effectiveness of energy efficiency and renewable energy as GHG emission mitigation measures would [redacted] as effective as the proposed plant.

<u>**KEC GHG Emissions, Connecticut Electric Generation, and CT GWSA**</u>

Q. What is the estimated level of annual GHG emissions from the proposed plant?

A. The proposed plant would emit almost 2 million short tons of CO2 annually, or 1.8 million metric tons.[91]

Q. How does that compare to Connecticut's total and electric power sector GHG emission levels?

A. It is a sizable fraction of both total and electric power sector GHG emissions. In 2013, total GHG emissions in Connecticut were between 41 and 43 million metric tons[92] (the range reflects two different accounting methods used to attribute GHG emissions to the electric sector in Connecticut[93]). Of that range, the electric power sector produced 7.4 to 9.5 million metric tons in 2013. In 2014, electric generation emissions were 9.7 million tons, or 8.8 million metric tons (generation-based accounting); in 2015, Connecticut electric power sector emissions were 10.6 million tons, or 9.6 million metric tons.[94]

Q. What level of natural gas generation corresponds to these electric power sector emissions?

A. ISO NE's total gas-fired generation in 2015 was roughly 53 million MWh; Connecticut's natural gas generation was roughly 17 million MWh in 2015.[95] Most of New England's gas-fired generation is from combined cycle facilities, roughly 50 million MWh in 2015. Table 10 below lists the most efficient of these facilities, which together produced more than 36 million MWh in 2015. This generation level is exclusive of natural gas use for power generation that will

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[91] Application, page 95. KEC potential emissions, in tons per year. One US ton is equivalent to 1.1 metric tons.

[92] CT Department of Energy and Environmental Protection (DEEP), "2013 Connecticut Greenhouse Gas Emissions Inventory", table entitled "Connecticut Emissions by Sector ($MMTCO_2e$)".

[93] GHG emissions for the electric power sector are tracked under "generation" or "consumption" based accounting methods. Generation based methods include all emissions from generators located in Connecticut. Consumption based methods reflect Connecticut's load share of total New England emissions, under the premise that the New England electric system is operated as an interconnected whole.

[94] ISO NE 2014 Air Emission Report, page 19. ISO NE Draft Results for Air Emissions in 2015, slide 14.

[95] US DOE/EIA Form 923 data.

occur once the CPV Towantic gas-fired plant comes on line in 2018, and if or when the Bridgeport Harbor 5 plant comes on line. At an annual capacity factor of 65%, those two plants combined (750 MW plus 485 MW, respectively, or 1,235 MW) would produce more than 7 million MWh in a year. The under-construction Footprint combined cycle power plant (674 MW) in Massachusetts (in service in 2017) would also generate roughly 3.8 million MWh (at 65% capacity factor).

Table 10. Illustration of Most Efficient Combined Cycle Generation in New England

Combined Cycle Plant Name	Ave. Annual Heat Rate, BTU/kWh	2015 MWh
Westbrook Energy Center Power Plant	7,064	1,848,004
Kleen Energy Systems Project	7,091	4,370,283
Millennium Power	7,176	2,101,441
Rhode Island State Energy Center	7,213	1,811,668
Granite Ridge	7,243	4,691,973
Tiverton Power Plant	7,322	1,354,120
Bridgeport Energy Project	7,330	3,035,491
Milford Power Project	7,343	3,488,446
Lake Road Generating Plant	7,383	4,732,544
Fore River Generating Station	7,473	3,801,336
Essential Power Newington LLC	7,487	1,342,994
Mystic Generating Station	7,503	2,727,242
Berkshire Power	7,512	1,108,977
SubTotal - above Plants		36,414,519
Total all NE natural gas combined cycle		50,866,024
Above share of Total NE combined cycle		72%
Additional combined cycle generation – annual MWh at 50% Annual Capacity Factor		
Footprint (Salem, MA), 674 MW		2,952,120
CPV Towantic, 750 MW		3,285,000
Bridgeport Harbor 5, 485 MW		2,124,300
Burrillville – Clear River Energy Center, 484 MW		2,119,920
Total – new plant		10,481,340

Source: Existing plant, EIA Form 923 Data for 2015. New plant and tabulation by Synapse.

Q. What is particularly notable about the data in the above Table 10?

A. The total generation from just the two most efficient existing plants, plus the four planned or under construction plants, is roughly 17 million MWh. As the next section shows, this is roughly the level of generation "allowed" from natural gas generation in New England in 2030 if more stringent RGGI targets associated with GWSA statutes are to be met, and it conservatively estimates just a 50% average annual capacity factor from the new plants, illustrating that even more energy headroom exists for those plants.

Q. What is the estimated heat rate for the proposed plant?

A. The applicants state that the full load heat rate is 6,529 BTU/kWh without duct burners, and 7,069 BTU/kWh with duct burners, at 59 degrees ambient temperature.[96] The heat rate would also be higher (i.e., less efficient) when burning ultra-low sulfur diesel (ULSD).[97] The heat rate could also be higher if the unit were to cycle more frequently, and/or need to start and stop more often.[98]

Q. What does this mean for its ability to displace emissions from other natural gas fired facilities in New England?

A. It suggests that its ability to displace emissions from other natural gas fired facilities will be relatively limited. As seen in Table 10, there are a large number of combined cycle facilities already in operation in New England, and a number of them exhibit similar efficiency levels as

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[96] See, e.g., NTE Application, Appendix G4, Permit Application for Stationary Sources of Air Pollution – New Source Review, Appendix A – Supporting Emissions Calculations, page 3 of 16.
[97] Ibid., page 2 of 16.
[98] See, e.g., NREL Power Plant Cycling Costs, April 2012. Report NREL/SR-5500-55433. Available at http://www.nrel.gov/docs/fy12osti/55433.pdf.

the proposed plant; new combined cycle facilities coming online over the next few years will also be relatively efficient. And as renewable energy sources increase in the region, the remaining energy needs for natural gas fired generation will decrease. Decreasing overall operation of the fleet of combined cycle generation units would likely lead, all else equal, to lower attained heat rates since this measure of efficiency changes when a plant is cycled more often.[99]

Q. Do ISO NE and CT DEEP studies confirm that the level of gas generation in New England in future years would need to be much lower than what is seen today?

A. Yes. I show this in the next section.

<u>ISO NE 2016 Economic Studies Draft Results</u>

Q. Please describe ISO NE studies that examine the level of natural gas use for electricity generation in New England under policies that meet state GWSA GHG emission targets.

A. Recent ISO NE economic studies[100] demonstrate that the path to meeting 2030 GHG emission levels in line with Connecticut, Massachusetts and Rhode Island's GWSA statutes and related interim GHG emission level targets includes much higher levels of renewable energy and much lower levels of natural gas generation than status quo arrangements that include

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[99] Modeling such changes in heat rate across the operating regime of a fleet of combined cycle plants can be complex.

[100] ISO NE, "2016 Economic Studies, Draft Results". The economic studies material at this time consists of a series of detailed presentations by Michael Henderson of ISO NE. The materials used are available at: https://www.iso-ne.com/static-assets/documents/2016/08/a6_2016_economic_study_draft_results.pdf, https://www.iso-ne.com/static-assets/documents/2016/08/a6_2016_economic_study_draft_results_appendix.pdf, https://www.iso-ne.com/static-assets/documents/2016/09/a6_2016_economic_study_draft_results_part_2.pdf, and https://www.iso-ne.com/static-assets/documents/2016/09/a7_2016_economic_study_part_2_appendix.pdf.
A selection of key pages from the studies is attached as Exhibit 16.

new natural gas fired generation.

Q. Can you summarize what the ISO NE studies found in this regard?

A. Yes. The ISO NE studies analyzed five different resource scenarios for New England, looking at the years 2025 and 2030. Production cost analysis was used to determine the cost, resource mix, and GHG emissions on the system for each of the scenarios. Two scenarios, S2 and S3, used increased levels of renewable energy and energy efficiency, and no new natural gas fired generation.[101] The studies found that in order to meet GHG emissions targets in line with regional greenhouse gas initiative reductions[102], under either "status quo" GHG reduction trajectories (2.5%/year decline in GHG emissions, post-2020) or more intensive GHG emission reduction trajectories (5%/year decline, post-2020) necessary to meet New England states' 2050 goals on GHG emissions, natural gas fired generation would need to drop considerably from current levels.

Q. Why do you present these ISO NE study results?

A. I present these results not only because they demonstrate the need to reduce natural gas use in the electric power sector, significantly, by 2030, but also because their results are aligned with the findings of the CT DEEP on the need to reduce electric power sector use of natural gas for generation, which I address next in this section.

Q. What are the salient results from the ISO NE studies?

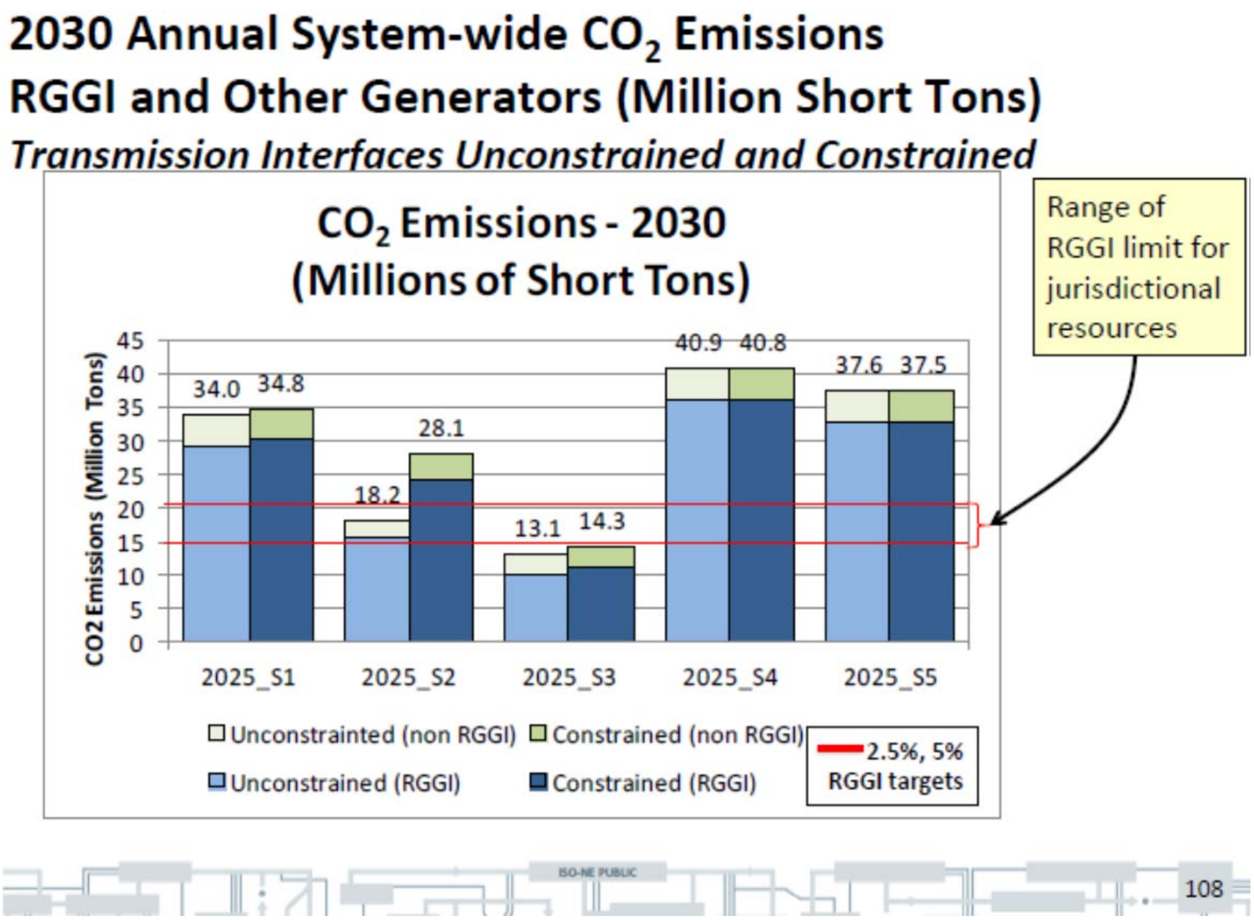
A. I present two key graphics from ISO NE's material. Figure 10 below, taken directly from

[101] See attached Exhibit 16 for a description of the scenario details.
[102] Two levels of RGGI GHG limits were assumed: 1) post-2020, a 2.5%/year decline in GHG emissions is presumed, continuing the current trend, and 2) post-2020, a 5.0%/year decline in the emissions is presumed, which is a declining emissions rate in line with regional emissions that meet the 80% GHG emission reduction target by 2050.

REDACTED VERSION

ISO NE's presentation, shows modeled projections of GHG emissions for the five resource scenarios studied. Only two scenarios – S2 and S3 in the figure below – approach or meet either the "status quo" RGGI GHG emission target, or a stricter RGGI GHG emission target required, for 2030. Both of those scenarios use increased renewable resources, and no new natural gas combined cycle generation, to meet 2030 targets. The other scenarios, all of which use natural gas for electricity generation at levels similar to, or higher, than New England's current use, all fail – exceedingly so - to meet GHG target emission levels for 2030.

Figure 10. ISO NE 2016 Economic Studies Draft Results – New England Electric Power Sector CO_2 Emissions, 2030



Source: ISO NE, 2016 Economic Study Draft Results, Slide 108, available at https://www.iso-ne.com/static-assets/documents/2016/09/a6_2016_economic_study_draft_results_part_2.pdf.

The second graphic, Figure 11 below, shows the mix of energy resources used to meet ISO NE requirements in 2030, for each of the five scenarios. Of particular importance is the level of New England-wide natural-gas fired generation, which is only 17 million MWh in S3, the scenario whose broad outlines[103] are required in order to the met the 2030 RGGI GHG targets, either "status quo" or more stringent.

Figure 11. ISO NE 2016 Economic Studies Draft Results – Energy Contribution by Resource Technology, 2030

Energy Contribution by Resource Technology 2030 (TWh and Percent), Transmission Interfaces Constrained

Scenario	2030 S1		2030 S2		2030 S3**		2030 S4		2030 S5	
Coal	0.15	0.09%	0.04	0.02%	0.05	0.03%	5.23	3.31%	0.15	0.09%
NG	58.73	37.16%	46.86	29.67%	17.04	9.96%	58.32	36.91%	63.33	40.07%
Oil	0.00	0.000%	0.00	0.002%	0.00	0.000%	0.01	0.009%	0.00	0.000%
Wood	4.48	2.83%	3.64	2.30%	3.50	2.05%	4.93	3.12%	4.94	3.13%
EE/DR	25.86	16.36%	25.86	16.37%	54.08	31.60%	25.86	16.36%	25.86	16.36%
Nuc	27.26	17.25%	27.26	17.26%	27.24	15.92%	27.26	17.25%	27.26	17.25%
PV	5.49	3.47%	8.32	5.27%	16.03	9.37%	5.49	3.47%	5.49	3.47%
Misc.*	3.29	2.08%	2.95	1.87%	2.26	1.32%	3.30	2.09%	3.37	2.13%
Wind	13.19	8.34%	25.73	16.29%	22.43	13.11%	6.49	4.11%	6.49	4.11%
Hydro/ES	3.89	2.46%	3.34	2.11%	3.68	2.15%	3.98	2.52%	3.98	2.52%
Import	15.72	9.95%	13.94	8.83%	24.83	14.51%	17.16	10.86%	17.17	10.86%
Total TWh	158.05	100.00%	157.94	100.00%	171.15	100.00%	158.04	100.00%	158.04	100.00%

* Includes old tire fuel, municipal solid waste, land fill gas, wood waste, etc.
** Plug-in Electric Vehicles charging increased the total energy consumed in S3.

ISO-NE PUBLIC 60

Source: ISO NE, 2016 Economic Study Draft Results, Appendix, Slide 60. Available at: https://www.iso-ne.com/static-assets/documents/2016/08/a6_2016_economic_study_draft_results_appendix.pdf.

[103] S3 contains a particular mix of energy efficiency, wind, and solar resources, and energy storage and imports of Canadian hydroelectricity. There are a number of different permutations of this resource mix that could produce similar emission results and limited natural gas generation requirements. For example, different permutations of 2030 offshore wind, and 2030 Canadian import energy, could produce similar results.

<u>Connecticut DEEP GHG Emission Reduction Targets for 2030, 2040, 2050</u>

Q. Does CT DEEP anticipate the use of additional natural gas generation as a means to mitigate or reduce GHG emissions?

A. No. This is not surprising, given the findings of the earlier section, which demonstrated how relatively ineffective KEC would be at mitigating GHG emissions.

Q. What are the GHG emission reduction levels and the types of GHG emission mitigation measures that CT DEEP is considering to meet the GWSA emission limitations?

A. Connecticut DEEP activities include setting interim GHG emission targets, and estimating the reductions in natural gas generation in Connecticut required to meet GHG emission limits.

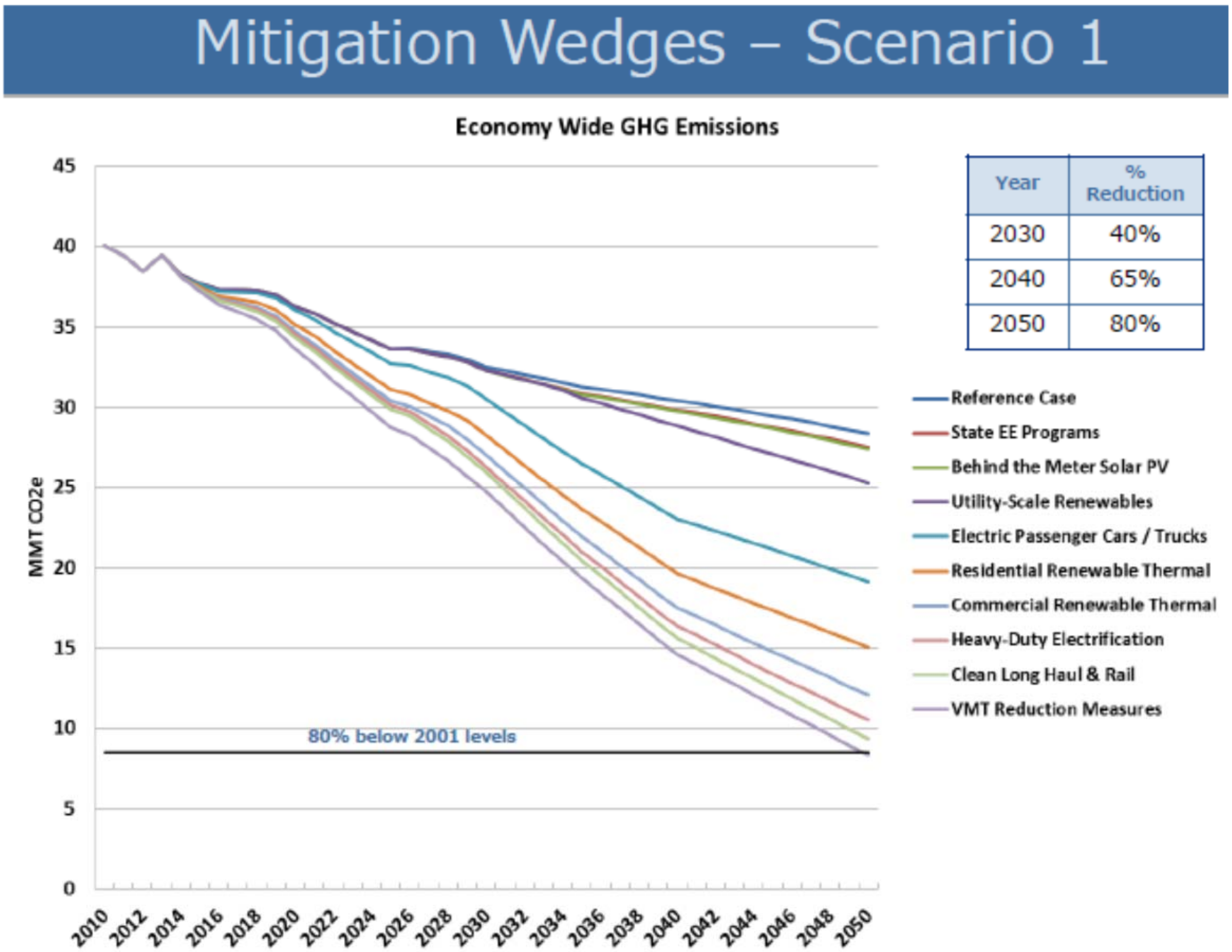
Connecticut is currently developing interim GHG emission reduction targets that would apply to emissions for 2030 and 2040, in addition to the 80% GHG emission reduction target for 2050.[104] 2030 interim targets range from 40% of 2001 GHG emission levels, to 55% of 2001 GHG emission levels.

GHG emissions are categorized into seven sectors: electric power, transportation, agriculture, residential, commercial, industrial, and waste.[105] Mitigation measures are applicable to emissions from all sectors, but most reduction is estimated to come from the electric power, transportation, and residential/commercial sectors, as is seen in the following Figure 12 from CT DEEP. Mitigation measures include increases in energy efficiency, including stretch building codes; utility-scale renewables, behind-the-meter solar PV, various

[104] See CT DEEP presentation from 7/26/2016 GC3 Analysis, Data and Metric (ADM) meeting. Attached as Exhibit 17.
[105] Exhibit 17, slide 9; and also CT DEEP 2013 Connecticut Greenhouse Gas Emissions Inventory, attached as Exhibit 18, page 3.

transportation sector measures (e.g., electric vehicles and increased rail usage), electrification of residential and commercial building heating and hot water systems ("renewable thermal").[106]

Figure 12. CT DEEP "Scenario 1" Estimates of GHG Emission Mitigation Wedges



Source: CT DEEP, GC3 Analysis, Data, and Metrics Meeting, July 26, 2016. Slides 16. Available at http://www.ct.gov/deep/lib/deep/climatechange/gc3_adm_group/adm_meeting_7_26_2016.pdf.

Q. What does Figure 12 illustrate?

A. Figure 12 shows expected declines in economy-wide emissions, seen as "mitigation wedges" in the above graph, with particular trajectories targeting a 40% GHG emission

[106] Exhibit 17, slide 13, "Mitigation Building Blocks".

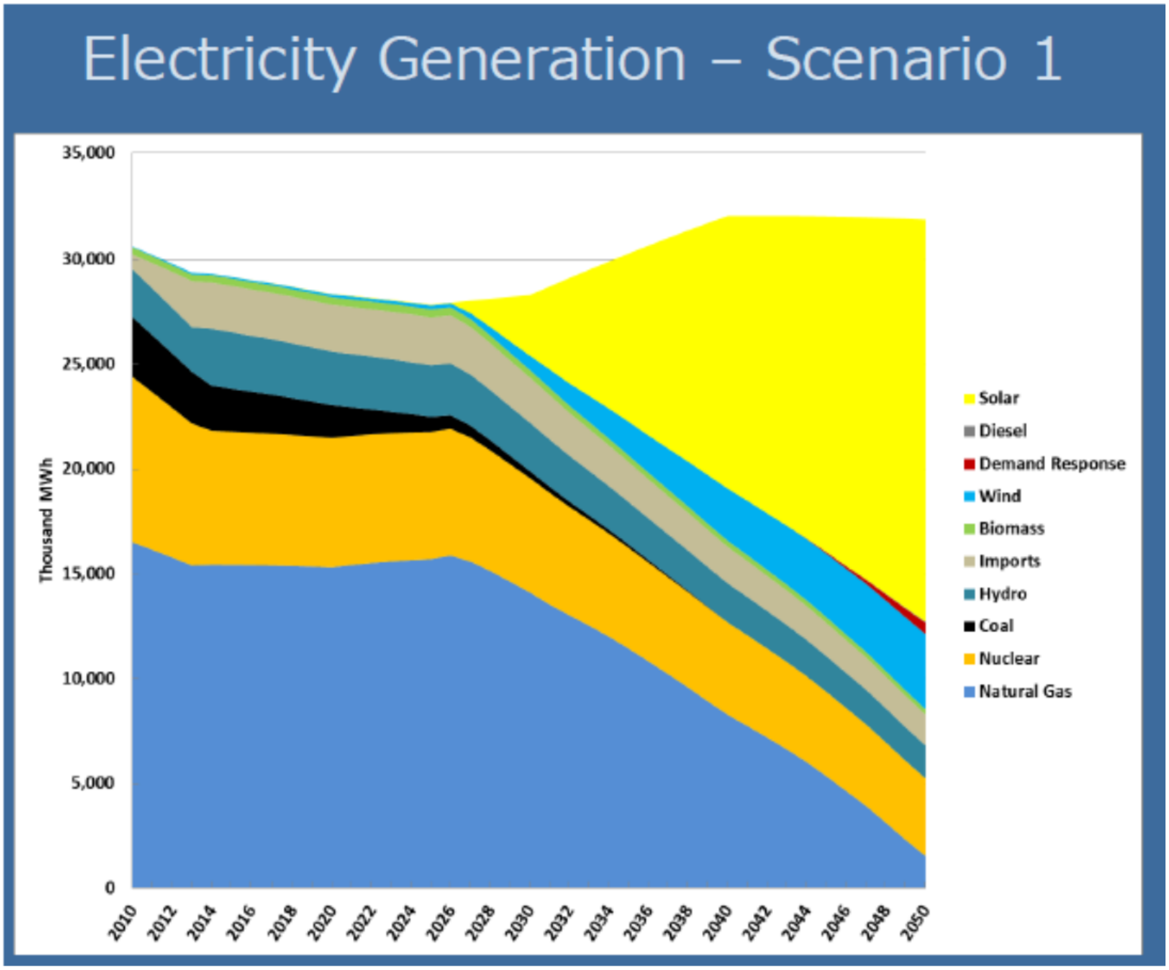
reduction by 2030. Those wedges illustrate GHG emission reductions to reach an economy-wide GHG emission goal of under 10 million tons by 2050. As seen, significant reductions come from “State EE Programs”, “Behind the Meter Solar PV”, and “Utility-Scale Renewables”.

Q. What is the primary GHG emission source of the GHG emission reductions that are required from the electric power sector?

A. As seen in Figure 13 below, the primary source of the GHG emission reductions from the electric power sector is an anticipated dramatic reduction in the use of natural gas and coal-fired generation (i.e., increasingly lower amounts of annual energy (MWh or GWh) production over the period through 2050). Connecticut has only one remaining coal plant for electric power production, and it is scheduled to be shut down by 2021.[107] Thus much of the remaining electric power sector GHG emission reductions seen after the early-to-mid 2020s will need to come from reduced production of electricity using natural gas, which declines to almost zero for power generation in 2050.

[107] See, for example, an article in the Hartford Courant from February 2016, available at http://www.courant.com/community/bridgeport/hc-last-ct-coal-plant-20160211-story.html.

Figure 13. "Scenario 1" Estimates of Trajectory of Connecticut Electric Power Sector Generation



Source: CT DEEP, GC3 Analysis, Data, and Metrics Meeting, July 26, 2016. Slides 17 (Sc. 1).
Notes: Scenario 1 is "reference scenario", using a 40% (of 2001 GHG emissions) 2030 interim target. Scenario 4 is "accelerated penetration scenario", using a 55% 2030 interim target.

Q Please summarize what the CT DEEP mitigation approaches illustrate, especially in combination with the findings from the ISO NE 2016 Economic Studies and the rest of the information in this Section 6 of your testimony.

A. The declining GHG emission targets will result in a requirement for lower use of natural gas for electricity generation in New England and Connecticut over the next few decades. The current fleet of combined cycle generation in New England is already relatively fuel efficient, and when considered with the new plants coming online, they are more than sufficient to meet the declining natural gas generation needs expected in New England. The KEC plant, whose emissions were modeled only out to 2024, will not be an effective contributor to GHG emission reduction, even when using the applicant's flawed estimates of its GHG-emission-reducing potential. I note that the other scenarios looked at by CT DEEP result in the same primary finding, a need for much lower use of natural gas for electricity generation.

7 Conclusions

Q. Please summarize your conclusions.

A. Based on the analysis and observations in the body of my testimony, I conclude the following seven major points in regards to the proposed KEC plant:

1. Overall reliability need for the proposed KEC is non-existent. Capacity surplus undeniably exists in the near term in New England (through 2020), and is projected to exist through the middle of the next decade. Sufficient new additions, along with declining net load trends and the structure of the ISO NE capacity market will ensure reliability even if at-risk plants begin to retire during the decade of the 2020s.
2. There are no winter reliability concerns sufficient to suggest a need for the proposed KEC plant. Excess generation capacity reserve exists, and mechanisms are in place to ensure fuel supplies during winter periods.
3. Historical and continuing investment in energy efficiency and small solar PV has lowered the net load on the New England system, and net load is projected to be flat or declining over

the next decade. This allows the region sufficient time to ensure new, larger-scale renewables and Canadian imports are online to help meet GHG emission targets and simultaneously contribute to ensuring reliability through capacity provision.

4. The existing fleet of supply and demand-side capacity resources in New England, along with existing and new imports and new storage resources is more than sufficient to ensure reliable integration of increasing levels of renewable energy in New England, especially if or as needed transmission reinforcement and solar PV forecasting is implemented; there is no evidence that the KEC plant is required to provided additional operating reserve to help with integration needs.
5. GHG emission limitations in place throughout New England will continue to lower the need for energy from combined cycle gas-fired facilities like the proposed KEC, and the amount of gas-fired generation already on the system exceeds modeled scenarios that achieve mid- and long-term GHG goals.
6. The applicant's GHG emission and electricity cost savings modeling uses a flawed construct [redacted]. The applicants conduct no sensitivity tests around the input assumptions used, and thus do not demonstrate robust or even credible findings on GHG emission reductions and cost savings from this proposed plant.
7. Renewable energy provision and energy efficiency resource investment exhibit [redacted] compared to the proposed KEC plant.

Q. Does this conclude your testimony?

A. Yes.

Robert M. Fagan, Principal Associate

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rfagan@synapse-energy.com

SUMMARY

Mechanical engineer and energy economics analyst with over 25 years of experience in the energy industry. Activities focused primarily on electric power industry issues, especially economic and technical analysis of transmission, wholesale electricity markets, renewable resource alternatives and assessment and implementation of demand-side alternatives.

In-depth understanding of the complexities of, and the interrelationships between, the technical and economic dimensions of the electric power industry in the US and Canada, including the following areas of expertise:

- Wholesale energy and capacity provision under market-based and regulated structures; the extent of competitiveness of such structures.
- Potential for and operational effects of wind and solar power integration into utility systems; modeling of such effects.
- Transmission use pricing, encompassing congestion management, losses, LMP and alternatives; transmission rights; and transmission asset pricing (embedded cost recovery tariffs).
- Physical transmission network characteristics; related generation dispatch/system operation functions; and technical and economic attributes of generation resources.
- RTO and ISO tariff and market rules structures and operation, and related FERC regulatory policies and initiatives, including those pertaining to RTO and ISO development and evolution.
- Demand-side management, including program implementation and evaluation; and load response presence in wholesale markets.
- Building energy end-use characteristics, and energy-efficient technology options.
- Fundamentals of electric distribution systems and substation layout and operation.
- Energy modeling (spreadsheet-based tools, industry standard tools for production cost and resource expansion, building energy analysis, understanding of power flow simulation fundamentals).
- State and provincial level regulatory policies and practices, including retail service and standard offer pricing structures.
- Gas industry fundamentals including regulatory and market structures, and physical infrastructure.

PROFESSIONAL EXPERIENCE

Synapse Energy Economics, Inc., Cambridge, MA. *Principal Associate*, 2004 – Present.

Responsibilities include consulting on issues of energy economics, analysis of electricity utility planning, operation, and regulation, including issues of transmission, generation, and demand-side management. Provide expert witness testimony on various wholesale and retail electricity industry issues. Specific project experience includes the following:

- Analysis of California renewable energy integration issues, local and system capacity requirements and purchases, and related long-term procurement policies.
- Analysis of air emissions and reliability impacts of Indian Point Energy Center retirement.
- Analysis of PJM and MISO wind integration and related transmission planning and resource adequacy issues.
- Analysis of Nova Scotia integrated resource planning policies including effects of potential new hydroelectric supplies from Newfoundland and demand side management impact; analysis of new transmission supplies of Maritimes area energy into the New England region.
- Analysis of Eastern Interconnection Planning Collaborative processes, including modeling structure and inputs assumptions for demand, supply and transmission resources. Expanded analyses of the results of the EIPC Phase II Report on transmission and resource expansion.
- Analysis of need for transmission facilities in Maine, Ontario, Pennsylvania, Virginia, Minnesota.
- Ongoing analysis of wholesale and retail energy and capacity market issues in New Jersey, including assessment of BGS supply alternatives and demand response options.
- Analysis of PJM transmission-related issues, including cost allocation, need for new facilities and PJM's economic modeling of new transmission effects on PJM energy market.
- Ongoing analysis of utility-sponsored energy efficiency programs in Rhode Island as part of the Rhode Island DSM Collaborative; and ongoing analysis of the energy efficiency programs of New Jersey Clean Energy Program (CEP) and various utility-sponsored efficiency programs (RGGI programs).
- Analysis of California renewable integration issues for achieving 33% renewable energy penetration by 2020, especially modeling constructs and input assumptions.
- Analysis of proposals in Maine for utility companies to withdraw from the ISO-NE RTO.
- Analysis of utility planning and demand-side management issues in Delaware.
- Analysis of effect of increasing the system benefits charge (SBC) in Maine to increase procurement of energy efficiency and DSM resources; analysis of impact of DSM on transmission and distribution reinforcement need.

- Evaluation of wind energy potential and economics, related transmission issues, and resource planning in Minnesota, Iowa, Indiana, and Missouri; in particular in relation to alternatives to newly proposed coal-fired power plants in MN, IA and IN.
- Analysis of need for newly proposed transmission in Pennsylvania and Ontario.
- Evaluation of wind energy "firming" premium in BC Hydro Energy Call in British Columbia.
- Evaluation of pollutant emission reduction plans and the introduction of an open access transmission tariff in Nova Scotia.
- Evaluation of the merger of Duke and Cinergy with respect to Indiana ratepayer impacts.
- Review of the termination of a Joint Generation Dispatch Agreement between sister companies of Cinergy.
- Assessment of the potential for an interstate transfer of a DSM resource between the desert southwest and California, and the transmission system impacts associated with the resource.
- Analysis of various transmission system and market power issues associated with the proposed Exelon-PSEG merger.
- Assessment of market power and transmission issues associated with the proposed use of an auction mechanism to supply standard offer power to ComEd native load customers.
- Review and analysis of the impacts of a proposed second 345 kV tie to New Brunswick from Maine on northern Maine customers.

Tabors Caramanis & Associates, Cambridge, MA. *Senior Associate*, 1996 – 2004.

- Provided expert witness testimony on transmission issues in Ontario and Alberta.
- Supported FERC-filed testimony of Dr. Tabors in numerous dockets, addressing various electric transmission and wholesale market issues.
- Analyzed transmission pricing and access policies, and electric industry restructuring proposals in US and Canadian jurisdictions including Ontario, Alberta, PJM, New York, New England, California, ERCOT, and the Midwest. Evaluated and offered alternatives for congestion management methods and wholesale electric market design.
- Attended RTO/ISO meetings, and monitored and reported on continuing developments in the New England and PJM electricity markets. Consulted on New England FTR auction and ARR allocation schemes.
- Evaluated all facets of Ontario and Alberta wholesale market development and evolution since 1997. Offered congestion management, transmission, cross-border interchange, and energy and capacity market design options. Directly participated in the Ontario Market Design Committee process. Served on the Ontario Wholesale Market Design technical panel.

- Member of TCA GE MAPS modeling team in LMP price forecasting projects.
- Assessed different aspects of the broad competitive market development themes presented in the US FERC's SMD NOPR and the application of FERC's Order 2000 on RTO development.
- Reviewed utility merger savings benchmarks, evaluated status of utility generation market power, and provided technical support underlying the analysis of competitive wholesale electricity markets in major US regions.
- Conducted life-cycle utility cost analyses for proposed new and renovated residential housing at US military bases. Compared life-cycle utility cost options for large educational and medical campuses.
- Evaluated innovative DSM competitive procurement program utilizing performance-based contracting.

Charles River Associates, Boston, MA. *Associate*, 1992 – 1996.

Developed DSM competitive procurement RFPs and evaluation plans, and performed DSM process and impact evaluations. Conducted quantitative studies examining electric utility mergers; and examined generation capacity concentration and transmission interconnections throughout the US. Analyzed natural gas and petroleum industry economic issues; and provided regulatory testimony support to CRA staff in proceedings before the US FERC and various state utility regulatory commissions.

Rhode Islanders Saving Energy, Providence, RI. *Senior Commercial/Industrial Energy Specialist*, 1987 – 1992.

Performed site visits, analyzed end-use energy consumption and calculated energy-efficiency improvement potential in approximately 1,000 commercial, industrial, and institutional buildings throughout Rhode Island, including assessment of lighting, HVAC, hot water, building shell, refrigeration and industrial process systems. Recommended and assisted in implementation of energy efficiency measures, and coordinated customer participation in utility DSM program efforts.

Fairchild Weston Systems, Inc., Syosset, NY. *Facilities Engineer*, 1985 – 1986.

Designed space renovations; managed capital improvement projects; and supervised contractors in implementation of facility upgrades.

Narragansett Electric Company, Providence RI. *Supervisor of Operations and Maintenance*, 1981 – 1984.

Directed electricians in operation, maintenance, and repair of high-voltage transmission and distribution substation equipment.

EDUCATION

Boston University, Boston, MA

Master of Arts in Energy and Environmental Studies – Resource Economics, Ecological Economics, Econometric Modeling, 1992

Clarkson University, Potsdam, NY
Bachelor of Science in Mechanical Engineering – Thermal Sciences, 1981

ADDITIONAL EDUCATION

- **Utility Wind Integration Group**: Short Course on Integration and Interconnection of Wind Power Plants into Electric Power Systems, 2006
- **University of Texas at Austin**: Short course in Regulatory and Legal Aspects of Electric Power Systems, 1998
- **Illuminating Engineering Society**: courses in lighting design, 1989
- **Worcester Polytechnic Institute and Northeastern University**: Coursework in Solar Engineering; Building System Controls; and Cogeneration, 1984, 1988 – 1989
- **Polytechnic Institute of New York**: Graduate coursework in Mechanical and Aerospace Engineering, 1985 – 1986

REPORTS AND PAPERS

Jackson, S., J. Fisher, B. Fagan, W. Ong. 2016. *Beyond the Clean Power Plan: How the Eastern Interconnection Can Significantly Reduce CO_2 Emissions and Maintain Reliability.* Prepared by Synapse Energy Economics for the Union of Concerned Scientists.

Luckow, P., B. Fagan, S. Fields, M. Whited. 2015. *Technical and Institutional Barriers to the Expansion of Wind and Solar Energy.* Synapse Energy Economics for Citizens' Climate Lobby.

Stanton, E. A., P. Knight, J. Daniel, R. Fagan, D. Hurley, J. Kallay, E. Karaca, G. Keith, E. Malone, W. Ong, P. Peterson, L. Silvestrini, K. Takahashi, R. Wilson. 2015. *Massachusetts Low Gas Demand Analysis: Final Report.* Synapse Energy Economics for the Massachusetts Department of Energy Resources.

Fagan, R., R. Wilson, D. White, T. Woolf. 2014. *Filing to the Nova Scotia Utility and Review Board on Nova Scotia Power's October 15, 2014 Integrated Resource Plan: Key Planning Observations and Action Plan Elements.* Synapse Energy Economics for the Nova Scotia Utility and Review Board.

Fagan, R., T. Vitolo, P. Luckow. 2014. *Indian Point Energy Center: Effects of the Implementation of Closed-Cycle Cooling on New York Emissions and Reliability.* Synapse Energy Economics for Riverkeeper.

Fagan, R., J. Fisher, B. Biewald. 2013. *An Expanded Analysis of the Costs and Benefits of Base Case and Carbon Reduction Scenarios in the EIPC Process.* Synapse Energy Economics for the Sustainable FERC Project.

Fagan, R., P. Luckow, D. White, R. Wilson. 2013. *The Net Benefits of Increased Wind Power in PJM.* Synapse Energy Economics for the Energy Future Coalition.

Hornby, R., R. Fagan, D. White, J. Rosenkranz, P. Knight, R. Wilson. 2012. *Potential Impacts of Replacing Retiring Coal Capacity in the Midwest Independent System Operator (MISO) Region with Natural Gas or Wind Capacity.* Synapse Energy Economics for the National Association of Regulatory Utility Commissioners.

Fagan, R., M. Chang, P. Knight, M. Schultz, T. Comings, E. Hausman, R. Wilson. 2012. *The Potential Rate Effects of Wind Energy and Transmission in the Midwest ISO Region*. Synapse Energy Economics for the Energy Future Coalition.

Woolf, T., M. Wittenstein, R. Fagan. 2011. *Indian Point Energy Center Nuclear Plant Retirement Analysis.* Synapse Energy Economics for the Natural Resources Defense Council (NRDC) and Riverkeeper.

Napoleon, A., W. Steinhurst, M. Chang, K. Takahashi, R. Fagan. 2010. *Assessing the Multiple Benefits of Clean Energy: A Resource for States*. US Environmental Protection Agency with research and editorial support from Stratus Consulting, Synapse Energy Economics, Summit Blue, Energy and Environmental Economics, Inc., Demand Research LLC, Abt Associates, Inc., and ICF International.

Peterson, P., E. Hausman, R. Fagan, V. Sabodash. 2009. *Synapse Report and Ohio Comments in Case No. 09-09-EL-COI, "The Value of Continued Participation in RTOs."* Synapse Energy Economics for Ohio Consumers' Counsel.

Hornby, R., J. Loiter, P. Mosenthal, T. Franks, R. Fagan and D. White. 2008. *Review of AmerenUE February 2008 Integrated Resource Plan.* Synapse Energy Economics for the Missouri Department of Natural Resources.

Hausman, E., R. Fagan, D. White, K. Takahashi, A. Napoleon. 2007. *LMP Electricity Markets: Market Operations, Market Power, and Value for Consumer.* Synapse Energy Economics for the American Public Power Association.

Fagan, R., T.Woolf, W. Steinhurst, B. Biewald. 2006. “Interstate Transfer of a DSM Resource: New Mexico DSM as an Alternative to Power from Mohave Generating Station.” Proceedings and presentation at 2006 American Council for Energy Efficient Economy (ACEEE) Summer Study on Energy Efficiency in Buildings Conference, August 2006.

Fagan, R., R. Tabors, A. Zobian, N. Rao, R. Hornby. 1999. *Tariff Structure for an Independent Transmission Company*. Tabors Caramanis & Associates Working Paper 101-1099-0241.

Fagan, R. 1996. *The Market for Power in New England: The Competitive Implications of Restructuring*. Tabors Caramanis & Associates and Charles River Associates for the Office of the Attorney General, Commonwealth of Massachusetts.

Fagan, R., D. Gokhale, D. Levy, P. Spinney, G. Watkins. 1995. “Estimating DSM Impacts for Large Commercial and Industrial Electricity Users.” Proceedings and presentation at The Seventh International Energy Program Evaluation Conference in Chicago, IL, August 1995.

Fagan, R., P. Spinney. 1995. *Demand-side Management Information Systems (DSMIS) Overview*. Charles River Associates for Electric Power Research Institute. Technical Report TR-104707.

Fagan, R., P. Spinney. 1994. *Northeast Utilities Energy Conscious Construction Program (Comprehensive Area): Level I and Level II Impact Evaluation Reports*. Charles River Associates, Energy Investments (Abbe Bjorklund) for Northeast Utilities.

PRESENTATIONS

Fagan, R., R. Tabors. 2003. "SMD and RTO West: Where are the Benefits for Alberta?" Keynote kaper prepared for the 9th Annual Conference of the Independent Power Producers Society of Alberta, March 2003.

Fagan, R. 1999. "A Progressive Transmission Tariff Regime: The Impact of Net Billing". Presentation at the Independent Power Producer Society of Ontario Annual Conference, November 1999.

Fagan, R. 1999. "Transmission Congestion Pricing Within and Around Ontario." Presentation at the Canadian Transmission Restructuring Infocast Conference in Toronto, June 1999.

Fagan, R. 1998. "The Restructured Ontario Electricity Generation Market and Stranded Costs." Presentation to the Ontario Ministry of Energy and Environment on behalf of Enron Capital and Trade Resources Canada Corp., February 1998.

Fagan, R. 1998. "Alberta Legislated Hedges Briefing Note." Presentation to the Alberta Department of Energy on behalf of Enron Capital and Trade Resources Canada, January 1998.

Fagan, R. 1997. "Generation Market Power in New England: Overall and on the Margin." Presentation at Infocast Conference: New Developments in Northeast and Mid-Atlantic Wholesale Power Markets in Boston, MA, June 1997.

Spinney, P., J. Peloza, R. Fagan presented. 1993. "The Role of Trade Allies in C&I DSM Programs: A New Focus for Program Evaluation." Charles River Associates and Wisconsin Electric Power Corp presentation at the Sixth International Energy Evaluation Conference in Chicago, IL, August 1993.

TESTIMONY

Rhode Island Public Utilities Commission (Docket No. 4609): Pre-Filed Direct Testimony examining reliability need for the proposed Clear River Energy Center in Burrillville, RI. Testimony filed on behalf of Conservation Law Foundation, June 14, 2016.

California Public Utilities Commission (Docket No. A.15-04-012): Testimony examining San Diego Gas & Electric's Marginal Energy Costs and LOLE Allocation among TOU Periods. Jointly, with Patrick Luckow. On behalf of the California Office of Ratepayer Advocate. June, 2016.

Massachusetts Electric Facilities Siting Board (Docket 15-1): Testimony regarding the impact of Exelon's proposed Medway power plant on compliance with the Global Warming Solutions Act. On behalf of Conservation Law Foundation. November 13, 2015.

California Public Utilities Commission (Docket No. A.14-06-014): Testimony examining Southern California Edison (SCE) proposals for Marginal Energy and Capacity Costs in Phase 2 of its 2015 General Rate Case (GRC). On behalf of the California Office of Ratepayer Advocate. Jointly, with Patrick Luckow. February 13, 2015.

California Public Utilities Commission (Docket No. A.14-11-014): Testimony examining Pacific Gas and Electric's Marginal Energy Costs and LOLE Allocation among TOU Periods. Jointly, with Patrick Luckow. On behalf of the California Office of Ratepayer Advocate. May 1, 2015.

California Public Utilities Commission (Docket No. A.14-11-012): Testimony reviewing Southern California Edison 2013 local capacity requirements request for offers for the western Los Angeles Basin, specifically related to storage. On behalf of Sierra Club. March 25, 2015.

California Public Utilities Commission (Docket No. A.14-01-027): Testimony examining San Diego Gas & Electric's proposal to change time-of-use periods in its application for authority to update its electric rate design. Jointly, with Patrick Luckow. On behalf of the California Office of Ratepayer Advocate. November 14, 2014.

California Public Utilities Commission (Docket No. R.12-06-013): Rebuttal testimony regarding the relationship between California investor-owned utilities hourly load profiles under a time-of-use pricing and GHG emissions in the WECC regions in the Order Instituting Rulemaking on the Commission's Own Motion to Conduct a Comprehensive Examination of Investor Owned Electric Utilities' Residential Rate Structures, the Transition to Time Varying and Dynamic Rates, and Other Statutory Obligations. On behalf of the California Office of Ratepayer Advocate. October 17, 2014.

California Public Utilities Commission (Docket No. R.13-12-010): Direct and reply testimony on Phase 1a modeling scenarios in the Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans. On behalf of the California Office of Ratepayer Advocate. August 13, 2014, October 22, 2014, and December 18, 2014.

New York State Department of Environmental Conservation (DEC #3-5522-00011/000004; SPDES #NY-0004472; DEC #3-5522-00011/00030; DEC #3-5522-00011/00031): Direct, rebuttal, and surrebuttal testimonies regarding air emissions, electric system reliability, and cost impacts of closed-cycle cooling as the "best technology available" (BTA), and alternative "Fish Protective Outages" (FPO), for the Indian Point nuclear power plant. On behalf of Riverkeeper. February 28, 2014, March 28, 2014, July 11, 2014, June 26, 2015, and August 10, 2015.

California Public Utilities Commission (Docket No. RM.12-03-014): Reply and rebuttal testimony on the topic of local reliability impacts of a potential long-term outage at the San Onofre Nuclear Power Station (SONGS) in Track 4 of the Order Instituting Rulemaking to Integrate and Refine Procurement Policies and

Consider Long-Term Procurement Plans. On behalf of the California Office of Ratepayer Advocate. September 30, 2013 and October 14, 2013.

Nova Scotia Utility and Review Board (Matter No. 05522): *Filing to the Nova Scotia Utility and Review Board on Nova Scotia Power's October 15, 2014 Integrated Resource Plan, Key Planning Observations and Action Plan Elements*. On behalf of Board Counsel to the Nova Scotia Utility and Review Board, October 20, 2014. With Rachel Wilson, David White and Tim Woolf.

Nova Scotia Utility and Review Board (Matter No. M05419): Direct examination regarding the report *Economic Analysis of Maritime Link and Alternatives: Complying with Nova Scotia's Greenhouse Gas Regulations, Renewable Energy Standard, and Other Regulations in a Least-Cost Manner for Nova Scotia Power Ratepayers* jointly authored with Rachel Wilson, Nehal Divekar, David White, Kenji Takahashi, and Tommy Vitolo. In the Matter of The Maritime Link Act and In the Matter of An Application by NSP MARITIME LINK INCORPORATED for the approval of the Maritime Link Project. On behalf of Board Counsel to the Nova Scotia Utility and Review Board. June 5, 2013.

Prince Edward Island Regulatory and Appeals Commission (Docket UE30402): Jointly filed expert report with Nehal Divekar analyzing the Proposed Ottawa Street – Bedeque 138 kV Transmission Line Project in the matter of Summerside Electric's Application for the Approval of Transmission Services connecting Summerside Electric's Ottawa Street substation to Maritime Electric Company Limited's Bedeque substation. Oh behalf of the City of Summerside. November 5, 2012.

New Jersey Board of Public Utilities (Docket No. GO12070640): Direct testimony regarding New Jersey Natural Gas Company's petition for approval of the extension of the SAVEGREEN energy efficiency programs. On behalf of the New Jersey Division of the Ratepayer Advocate. October 26, 2012.

California Public Utilities Commission (Docket No. RM.12-03-014): Direct and reply testimony regarding the long-term local capacity procurement requirements for the three California investor-owned utilities in Track 1 of the Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans. On behalf of the California Office of Ratepayer Advocate. June 25, 2012 and July 23, 2012.

California Public Utilities Commission (Docket No. A.11-05-023): Supplemental testimony regarding the long-term resource adequacy and resource procurement requirements for the San Diego region in the Application of San Diego Gas & Electric Company (U 902 3) for Authority to Enter into Purchase Power Tolling Agreements with Escondido Energy Center, Pio Pico Energy Center, and Quail Brush Power. On behalf of the California Office of Ratepayer Advocate. May 18, 2012.

New Jersey Board of Public Utilities (Docket No. GO11070399): Direct testimony in the matter of the petition of Pivotal Utility Holdings, Inc. D/B/A Elizabethtown Gas for authority to extend the term of energy efficiency programs with certain modifications and approval of associated cost recovery. On behalf of New Jersey Division of Rate Counsel. December 16, 2011.

New Jersey Board of Public Utilities (Docket No. EO11050309): Direct testimony regarding aspects of the Board's inquiry into capacity and transmission interconnection issues. October 14, 2011.

Federal Energy Regulatory Commission (Docket Nos. EL11-20-000 and ER11-2875-000): Affidavit regarding reliability, status of electric power generation capacity, and current electric power procurement policies in New Jersey. On behalf of New Jersey Division of Rate Counsel. March 4, 2011.

New Jersey Board of Public Utilities (Docket Nos. GR10100761 and ER10100762): Certification before the Board regarding system benefits charge (SBC) rates associated with gas generation in the matter of a generic stakeholder proceeding to consider prospective standards for gas distribution utility rate discounts and associated contract terms. On behalf of New Jersey Division of Rate Counsel. January 28, 2011.

New Jersey Board of Public Utilities (Docket No. ER10040287): Direct testimony regarding Basic Generation Service (BGS) procurement plan for service beginning June 1, 2011. On behalf of New Jersey Division of Rate Advocate. September 2010.

State of Maine Public Utilities Commission (Docket 2008-255): Direct and surrebuttal testimony regarding the non-transmission alternatives analysis conducted on behalf of Central Maine Power in the Application of Central Maine Power Company and Public Service of New Hampshire for a Certificate of Public Convenience and Necessity for the Maine Power Reliability Program Consisting of the Construction of Approximately 350 Miles of 345 and 115 kV Transmission Lines, a $1.55 billion transmission enhancement project. On behalf of the Maine Office of the Public Advocate. January 12, 2009 and February 2, 2010.

Virginia State Corporation Commission (CASE NO. PUE-2009-00043): Direct testimony regarding the need for modeling DSM resources as part of the PJM RTEP planning processes in the Application of Potomac-Appalachian Transmission Highline (PATH) Allegheny Transmission Corporation for CPCN to construct facilities: 765 kV proposed transmission line through Loudoun, Frederick, and Clarke Counties. On behalf of Sierra Club. October 23, 2009.

Pennsylvania Public Utility Commission (Docket number A-2009-2082652): Direct and surrebuttal testimony regarding the need for additional modeling for the proposed Susquehanna-Roseland 500 kv transmission line in portions of Luckawanna, Luzerne, Monroe, Pike, and Wayne counties to include load forecasts, energy efficiency resources, and demand response resources. On behalf of the Pennsylvania Office of Consumer Advocate. June 30, 2009 and August 24, 2009.

Delaware Public Service Commission (Docket No. 07-20): Filed the expert report *Review of Delmarva Power & Light Company's Integrated Resource Plan* jointly authored with Alice Napoleon, William Steinhurst, David White, and Kenji Takahashi In the Matter of Integrated Resource Planning for the Provision of Standard Offer Service by Delmarva Power & Light Company Under 26 DEL. C. §1007 (c) & (d). On behalf of the Staff of Delaware Public Service Commission. April 2, 2009.

New Jersey Board of Public Utilities (Docket No. ER08050310): Direct testimony filed jointly with Bruce Biewald on aspects of the Basic Generation Service (BGS) procurement plan for service beginning June 1, 2009. On behalf of the New Jersey Division of the Ratepayer Advocate. September 29, 2008.

Wisconsin Public Service Commission (Docket 6680-CE-170): Direct and surrebuttal testimony in the matter of the alternative energy options available with wind power, and the effect of the MISO RTO in helping provide capacity and energy to the Wisconsin area reliably without needed the proposed coal plant in the CPCN application by Wisconsin Power and Light for construction of a 300 MW coal plant. On behalf of Clean Wisconsin. August 11, 2008 and September 15, 2008.

Ontario Energy Board (Docket EB-2007-0707): Direct testimony regarding issues associated with the planned levels of procurement of demand response, combined heat and power, and NUG resources as part of Ontario Power Authority's long-term integrated planning process in the Examination and Critique of Demand Response and Combined Heat and Power Aspects of the Ontario Power Authority's Integrated Power System Plan and Procurement Process. On behalf of Pollution Probe. August 1, 2008.

Ontario Energy Board (Docket EB-2007-0050): Direct and supplemental testimony filed jointly with Peter Lanzalotta regarding issues of congestion (locked-in energy) modeling, need, and series compensation and generation rejection alternatives to the proposed line of in the matter of Hydro One Networks Inc.'s application to construct a new 500 kV transmission line between the Bruce Power complex and the town of Milton, Ontario. On behalf of Pollution Probe. April 18, 2008 and May 15, 2008.

Federal Energy Regulatory Commission (Dockets ER06-456, ER06-954, ER06-1271, ER07-424, EL07-57, ER06-880, et al.): Direct and rebuttal testimony addressing merchant transmission cost allocation issues on PJM Regional Transmission Expansion Plan (RTEP) Cost Allocation issues. On behalf of the New Jersey Division of the Ratepayer Advocate. January 23, 2008 and April 16, 2008.

State of Maine Public Utilities Commission (Docket No. 2006-487): Pre-file and surrebuttal testimony on the ability of DSM and distributed generation potential to reduce local supply area reinforcement needs in the matter of the Analysis of Central Maine Power Company Petition for a Certificate of Public Convenience and Necessity to Build a 115 kV Transmission Line between Saco and Old Orchard Beach. On behalf of Maine Office of the Public Advocate. February 27, 2007 and January 10, 2008.

Minnesota Public Utilities Commission (OAH No. 12-2500-17037-2 and OAH No. 12-2500-17038-2; and MPUC Dkt. Nos. CN-05-619 and TR-05-1275): Supplemental testimony and supplemental rebuttal testimony on applicants' estimates of DSM savings in the Certificate of Need proceeding for the Big Stone II coal-fired power plant proposal In the Matter of the Application by Otter Tail Power Company and Others for Certification of Transmission Facilities in Western Minnesota and In the Matter of the Application to the Minnesota Public Utilities Commission for a Route Permit for the Big Stone Transmission Project in Western Minnesota. On behalf of Fresh Energy, Izaak Walton League of America – Midwest Office, Wind on the Wires, Union of Concerned Scientists, Minnesota Center for Environmental Advocacy. December 8, 2006 and December 21, 2007.

Pennsylvania Public Utility Commission (Docket Nos. A-110172 *et al.*): Direct testimony on the effect of demand-side management on the need for a transmission line and the level of consideration of potential carbon regulation on PJM's analysis of need for the TrAIL transmission line. On behalf of the Pennsylvania Office of Consumer Advocate. October 31, 2007.

Iowa Public Utilities Board (Docket No. GCU-07-01): Direct testimony regarding wind energy assessment in Interstate Power and Light's resource plans and its relationship to a proposed coal plant in Iowa. On behalf of Iowa Office of the Consumer Advocate. October 21, 2007.

New Jersey Board of Public Utilities (Docket No. EO07040278): Direct testimony on certain aspects of PSE&G's proposal to use ratepayer funding to finance a solar photovoltaic panel initiative in support of the State's solar RPS. September 21, 2007.

Indiana Utility Regulatory Commission (Cause No. 43114): Direct testimony on the topic of a proposed Duke – Vectren IGCC coal plant and wind power potential in Indiana. On behalf of Citizens Action Coalition of Indiana. May 14, 2007.

British Columbia Utilities Commission: Pre-filed evidence regarding the "firming premium" associated with 2006 Call energy, liquidated damages provisions, and wind integration studies In the Matter of BC Hydro 2006 Integrated Electricity Plan and Long Term Acquisition Plan. On behalf of the Sierra Club (BC Chapter), Sustainable Energy Association of BC, and Peace Valley Environment Association. October 10, 2006.

Maine Joint Legislative Committee on Utilities, Energy and Transportation (LD 1931): Testimony regarding the costs and benefits of increasing the system benefits charge to increase the level of energy efficiency installations by Efficiency Maine before in support of an Act to Encourage Energy Efficiency. On behalf of the Maine Natural Resources Council and Environmental Defense. February 9, 2006.

Nova Scotia Utility and Review Board: Direct testimony and supplemental evidence regarding the approval of the installation of a flue gas desulphurization system at Nova Scotia Power Inc.'s Lingan station and a review of alternatives to comply with provincial emission regulations In The Matter of an Application by Nova Scotia Power Inc. for Approval of Air Emissions Strategy Capital Projects and The Public Utilities Act, R.S.N.S., 1989, c. 380, as amended. On behalf of Nova Scotia Utility and Review Board Staff. January 30, 2006.

New Jersey Board of Public Utilities (BPU Docket EM05020106): Joint direct and surrebuttal testimony with Bruce Biewald and David Schlissel regarding the Joint Petition Of Public Service Electric and Gas Company And Exelon Corporation For Approval of a Change in Control Of Public Service Electric and Gas Company And Related Authorizations. On behalf of New Jersey Division of the Ratepayer Advocate. November 14, 2005 and December 27, 2005.

Indiana Utility Regulatory Commission (Cause No. 42873): Direct testimony addressing the proposed Duke – Cinergy merger. On behalf of Citizens Action Coalition of Indiana. November 8, 2005.

Indiana Utility Regulatory Commission (Causes No. 38707 FAC 61S1, 41954, and 42359-S1): Responsive testimony addressing a proposed Settlement Agreement between PSI and other parties in respect of issues surrounding the Joint Generation Dispatch Agreement in place between PSI and CG&E. On behalf of Citizens Action Coalition of Indiana. August 31, 2005.

Illinois Commerce Commission (Dockets 05-0160, 05-0161, 05-0162): Direct and rebuttal testimony addressing wholesale market aspects of Ameren's proposed competitive procurement auction (CPA). On behalf of Illinois Citizens Utility Board. June 15, 2005 and August 10, 2005.

Illinois Commerce Commission (Docket 05-0159): Direct and rebuttal testimony addressing wholesale market aspects of Commonwealth Edison's proposed BUS (Basic Utility Service) competitive auction procurement. On behalf of Illinois Citizens Utility Board and Cook County State's Attorney's Office. June 8, 2005 and August 3, 2005.

State of Maine Public Utilities Commission (Docket No. 2005-17): Joint testimony with David Schlissel and Peter Lanzalotta regarding an Analysis of Eastern Maine Electric Cooperative, Inc.'s Petition for a Finding of Public Convenience and Necessity to Purchase 15 MW of Transmission Capacity from New Brunswick Power and for Related Approvals. On behalf of Maine Office of the Public Advocate. July 19, 2005.

Indiana Utility Regulatory Commission (Cause No. 38707 FAC 61S1): Direct testimony in a Fuel Adjustment Clause (FAC) proceeding concerning the pricing aspects and merits of continuation of the Joint Generation Dispatch Agreement in place between PSI and CG&E, and related issues of PSI lost revenues from inter-company energy pricing policies. On behalf of Citizens Action Coalition of Indiana. May 23, 2005.

Indiana Utility Regulatory Commission (Cause No. 41954): Direct testimony concerning the pricing aspects and merits of continuation of the Joint Generation Dispatch Agreement in place between PSI and CG&E. On behalf of Citizens Action Coalition of Indiana. April 21, 2005.

State of Maine Public Utilities Commission (Docket No. 2004-538): Joint testimony with David Schlissel and Peter Lanzalotta regarding an Analysis of Maine Public Service Company Request for a Certificate of Public Convenience and Necessity to Purchase 35 MW of Transmission Capacity from New Brunswick Power. On behalf of Maine Office of the Public Advocate. April 14, 2005.

Nova Scotia Utility and Review Board (Order 888 OATT): Testimony regarding various aspects of OATTs and FERC's *pro forma* In The Matter of an Application by Nova Scotia Power Inc. for Approval of an Open Access Transmission Tariff (OATT). On behalf of the Nova Scotia Utility Review Board Staff. April 5, 2005.

Texas Public Utilities Commission (Docket No. 30485): Testimony regarding excess mitigation credits associated with CenterPoint's stranded cost recovery in the Application of CenterPoint Energy Houston Electric, LLC. for a Financing Order. On behalf of the Gulf Coast Coalition of Cities. January 7, 2005.

Ontario Energy Board (RP-2002-0120): Filed testimony and reply comments reviewing the Transmission System Code (TSC) and Related Matters, Detailed Submission to the Ontario Energy Board in Response

To Phase I Questions Concerning the Transmission System Code and Related Matters. On behalf of TransAlta Corporation. October 31, 2002 and November 21, 2002.

Alberta Energy and Utilities Board (Application No. 2000135): Filed joint testimony with Dr. Richard D. Tabors in the matter of the Transmission Administrator's 2001 Phase I and Phase II General Rate Application pertaining to Supply Transmission Service charge proposals. On behalf of Alberta Buyers Coalition. March 28, 2001.

Ontario Energy Board (RP-1999-0044): Testimony critiquing Ontario Hydro Networks Company's Transmission Tariff Proposal and Proposal for Alternative Rate Design. On behalf of the Independent Power Producer's Society of Ontario. January 17, 2000.

Massachusetts Department of Public Utilities (Docket # DPU 95-2/3-CC-l): Filed a report (Fagan R., G. Watkins. 1995. *Sampling Issues in Estimating DSM Savings: An Issue Paper for Commonwealth Electric*. Charles River Associates). On behalf of COM/Electric System. April 1995.

Massachusetts Department of Public Utilities (Docket # DPU 95-2/3-CC-l): Filed initial and updated reports (Fagan R., P. Spinney, G. Watkins. 1994. *Impact Evaluation of Commonwealth Electric's Customized Rebate Program*. Charles River Associates. Updated April 1996). April 1994 and April 1995.

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