COMMONWEALTH OF MASSACHUSETTS

ENERGY FACILITIES SITING BOARD

Petition of NSTAR Electric d/b/a Eversource Energy Pursuant to G.L. c. 164, §69J for Approval to Construct, Operate and Maintain a New 115-kV Transmission Line in the Towns of Sudbury, Hudson and Stow and the City of Marlborough and to Make Modifications to an Existing Substation in Sudbury	**EFSB 17-02; D.P.U. 17-82/17-83**

PRE-FILED TESTIMONY OF

PAUL L. CHERNICK

ON BEHALF OF

THE TOWN OF SUDBURY

Resource Insight, Inc.

OCTOBER 10, 2017

TABLE OF CONTENTS

TABLE OF EXHIBITS

I. Identification & Qualifications

Q: Mr. Chernick, please state your name, occupation, and business address.

A: I am Paul L. Chernick. I am the president of Resource Insight, Inc., 5 Water St., Arlington, Massachusetts.

Q: Summarize your professional education and experience.

A: I received a Bachelor of Science degree from the Massachusetts Institute of Technology in June 1974 from the Civil Engineering Department, and a Master of Science degree from the Massachusetts Institute of Technology in February 1978 in technology and policy.

I was a utility analyst for the Massachusetts Attorney General for more than three years, and was involved in numerous aspects of utility rate design, costing, load forecasting, and the evaluation of power supply options. Since 1981, I have been a consultant in utility regulation and planning, first as a research associate at Analysis and Inference, Inc., and since 1986 as President of PLC, Inc., which was renamed Resource Insight, Inc. in 1990. In these capacities, I have advised a variety of clients on utility matters.

My work has considered, among other things, the cost-effectiveness of prospective new electric generation plants and transmission lines, retrospective review of generation-planning decisions, ratemaking for plant under construction, ratemaking for excess and/or uneconomical plant entering service, conservation program design, cost recovery for utility efficiency programs, the valuation of environmental externalities from energy production and use, allocation of costs of service between rate classes and jurisdictions, design of retail and wholesale rates, and performance-based ratemaking and cost recovery in restructured gas and electric industries. My professional qualifications are further summarized in Exhibit SUD-PLC-2.

Q: Have you testified previously in utility proceedings?

A: Yes. I have testified more than 320 times on utility issues before various regulatory, legislative, and judicial bodies, including utility regulators in thirty-seven states, three other U.S. jurisdictions, and six Canadian provinces, and three U.S. Federal agencies. Several of my previous testimonies have included the review of proposed transmission lines.

Q: Have you testified previously before the Department of Public Utilities ("Department" or "DPU")?

A: Yes. I have testified in nearly 50 dockets before the Department, from the proposed Pilgrim 2 nuclear power plant in 1978 to review of National Grid's contract with Cape Wind in 2010 and the Cape Cod transmission project in 2011.

Q: Have you testified previously before the Energy Facilities Siting Board (the "Board")?

A: Yes. I have testified in approximately 11 dockets before the Board and its predecessor, the Energy Facilities Siting Council, from Boston Edison's load forecast in 1978 to the Eversource (then NStar) Cape Cod transmission project in 2011.

II. Introduction

Q: On whose behalf are you testifying?

A: I am testifying on behalf of the Town of Sudbury (the "Town" or "Sudbury").

Q: What is the purpose of your testimony?

A: I have been asked to review the case that NSTAR Electric d/b/a Eversource Energy ("Eversource") has advanced to justify the construction of a 9-mile, underground 115-kV transmission line from the Hudson municipal substation to Eversource's own Sudbury substation, which Eversource refers to as the "Sudbury-Hudson Transmission Reliability Project" or "Project".

Q: What documents have you reviewed in preparing this testimony?

A: My review started with Eversource's April 2017 "Sudbury-Hudson Transmission Reliability Project: Analysis to Support Petitions before the Energy Facilities Siting Board" filing in this docket ("Analysis") and its Appendices. I have also reviewed all of the need-related discovery responses to Sudbury, PROTECT, and the Board. In addition, I have reviewed materials from other cases before the Department, documents from the New England Independent System Operator (ISO-NE), reports by the Massachusetts Department of Energy Resources (DOER) and the U.S. Department of Energy, and other resources.

Q: What is your understanding of the standard for determination of need for a transmission line?

A: I understand the criteria for the Siting Board to approve a petition to construct a transmission line include the following components, among others:

- The line must provide a reliable energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost. (G.L. c. 164, § 69J)
- The applicant must establish the need for the line, to meet reliability, economic efficiency, or environmental objectives. (G.L. c. 164, § 69H, J). Consistent therewith, G.L. c. 164, § 69J requires applicants to include in their petitions an analysis of need for the facility.
- The application must use reviewable and appropriate methods for assessing system reliability over time.
- The forecasts supporting the need for the line must be based on substantially accurate historical information and reasonable statistical projection methods that include an adequate consideration of conservation and load management,

> and must be reviewable, appropriate and reliable, providing enough information to allow a full understanding of the forecast method and providing a measure of confidence that its data, assumptions and judgments produce a forecast of what is most likely to occur (G.L. c. 164, § 69J).

Q: What is Eversource's rationale for the need for this line?

A: Eversource maintains that certain outages of power lines at extreme summer peak load "could result in the loss of electric service to approximately 80,000 customers in Berlin, Framingham, Grafton, Hudson, Marlborough, Northborough, Shrewsbury, Stow, Southborough and Westborough, totaling over 400 megawatts of load." (Analysis Vol. 1, p. ES-1) Eversource refers to this area as the Marlborough subarea or Subarea D. Since Eversource and ISO-NE use "subarea" for various levels of geographic division, I will generally refer to this area as the Marlboro load pocket.

Specifically, Eversource claims that the sequential loss of two transmission elements at the time of an extreme weather-driven summer peak could lead to the loss of service to over 400 MW of load in the Marlboro load pocket. (Analysis, Vol. 1, p. 1-4)

Q: Please describe the Marlboro load pocket in more detail.

A: The load pocket consists of the loads served off the substations listed in Table 1. Roughly two-thirds of the load in this area is served from National Grid substations, with less than 15% at Eversource's West Framingham substation.

Table 1: Marlboro Load Pocket Substations

		Actual Peak Load (MW)				
Substation	**Owner**	**2012**	**2013**	**2014**	**2015**	**2016**
West Framingham	Eversource	53.5	50.3	49.1	46.3	49.8
Northboro Road	National Grid	41.3	39.3	41	42.8	38.2
South Marlboro	National Grid	25.8	26.7	24.4	23.3	22.5
Marlboro	National Grid	56	58.2	49.7	49.4	50.8
North Marlboro	National Grid	23.8	24.2	22.8	21.6	20.8
Hudson	Hudson	67.8	68.5	65.1	53.6	53.3
East Main Street	National Grid	22.5	21.8	19.8	28.1	32.2
Westborough	National Grid	41.8	45.1	42	35.5	39.1
North Grafton	National Grid	0	0.1	0.1	0	0
Woodside	National Grid	34.9	37.1	31.5	26.9	29.4
Centech	Shrewsbury				5.9	13.2
Total		367	371	346	333	349

From Attachment SUD-N-40(1) and Attachment PROTECT-1b(1)

The feeders running from a substation may serve municipalities other than the one in which the substation is located. For example, the West Framingham substation serves parts of Framingham, Ashland, Dover, and Hopkinton. The National Grid substations in the load pocket also serve parts of Upton and Boylston. All of Hudson, Marlboro, Northborough, Southborough and Westborough are served from substations within the Marlboro load pocket. Parts of Framingham, Shrewsbury, Grafton and Berlin are served from substations within the Marlboro load pocket.[1]

This area is linked to the rest of the New England grid by two 115-kV lines and two or three 69-kV lines (depending on where one draws the pocket borders), as shown in Analysis Figure 2-1.

Q: On what analyses are Eversource's need assertions based?

A: While the Analysis provides analyses of the load flows and potential supply problems in the Greater Boston Area from 2012 and from 2015 (Analysis

[1] I determined the towns served by the substations from the feeder locations listed in NGrid_Circuit_Detail_Mar17.xlsx and NStar_Circuit_Detail_Mar17.xlsx, from DPU Dockets 17-SQ-11 and 17-SQ-13.

Appendices 2-1 and 3-1 through 3-3), those documents primarily deal with a number of other projects, to solve problems throughout the Greater Boston Area. The data in these studies for load growth, energy-efficiency, and behind-the-meter photovoltaics are based on ISO-NE's 2013 Capacity, Energy, Load and Transmission ("CELT") report, and are thus badly dated. Most of the assumptions and modeling described in those documents, such as the dispatch of major generation and the choices of new transmission options into the Boston area from the north, do not appear to be relevant to the current docket.

Eversource updated the need analysis for the Marlboro load pocket based on the extreme load forecast in the 2016 CELT, as described in Analysis Section 2.7. The description of this analysis was limited to about six pages, two of which deal with changes in generation outside the pocket, which Eversource says has no effect on the Marlboro subarea needs. Some additional information on the 2016 study was provided in discovery (e.g., SUD-N-4, N-9, N-10, N-46; PROTECT-2).

Given the vintage of the earlier studies, I will focus on the assumptions and results of the 2016 study.

Q: Please summarize your conclusions.

A: The load forecast that Eversource uses for the Marlboro load pocket is not well documented and is based on forecasting assumptions that have repeatedly overstated need. Eversource has overstated the amount of load reduction within the Marlboro load pocket required to avoid overloads, even if the extreme load forecast it is using were to coincide with a second-contingency event. Eversource and National Grid (which serves most of the load pocket) have multiple options for reducing load, using distributed resources—energy-efficiency, rate design, solar, storage— that would provide a range of benefits (generation savings, pollution reduction, increased resiliency, and more) beyond simply replacing the Project.

As a result, I recommend that the Board deny Eversource's petition and that the Department order National Grid to lead a coordinated effort (with Eversource and the municipal light plants in Hudson and Shrewsbury) to reduce loads in the load pocket.

III. Load-Forecasting Issues

Q: What issues will you deal with in this section?

A: I first discuss ISO-NE's track record of over-forecasting the loads in the large subareas within Massachusetts for which ISO-NE has released forecasts for each year since at least 2002. I focus on the forecasts for the Boston subarea (as that term is used by ISO-NE in the annual CELT reports and the Regional System Plans). I believe that the pattern would be similar for the Central Massachusetts subarea.

I then examine the manner in which ISO-NE developed (with input from Eversource and other utilities) the forecast that Eversource used for the extreme 2013 summer peak load for the Marlboro load pocket.

A. Boston Subarea Forecasts

Q: What issues will you cover in this section?

A: I describe the consistent historical tendency for ISO-NE to overstate its load forecasts, both for normal weather (the 50/50 forecasts) and for extreme weather that ISO-NE would expect to observe only once in every ten years (the 90/10 forecasts). Those extreme peak loads occur in July or August, between 1 PM and 6 PM, with an regional average temperature of 94º and an "average dew point in the upper 60s to low 70s" (SUD-N-13(S-1)). I then explain how the ISO-NE forecasting methodology results in under-forecasting of energy-efficiency savings and hence over-forecasting of load.

1. Historical Accuracy

Q: Have the CELT reports prepared by ISO-NE for the Boston subarea been accurate?

A: No. Table 2 shows that the ISO-NE forecasts for median weather produced in 2010 through 2017 CELTs have been overstated for 28 of the 36 observations for which we have weather-normalized peak loads.[2] The average difference between the forecast and the actual peak was 344 MW, or about 6% of the forecast load. For forecasts more than two years into the future, the average overstatement was 556 MW, about 10% of the forecast load. For comparison, the 2016 forecast for 2023 was looking seven years into the future.

---

[2] The peak for 2017 is the actual peak from June 13, 5 PM, since ISO-NE does not appear to have released the weather-normalized values. The regional temperature was 91° on that day, higher than the 90.2° that ISO-NE considers normal, but lower than the 94º that the ISO-NE expects to produce a 90/10 peak. The dew point was 65º, at the lower end of the range that ISO-NE would expect for a 90/10 peak. ISO-NE weather-normalizes summer peaks based on temperature and weighted temperature-humidity index, including conditions on the two previous days, which I do not have. In any case, the 2017 weather-normalized peak is likely to be similar to the actual peak load.

Table 2: History of ISO-NE 50/50 Forecasts for the Boston Subarea

	Weather -Normal	Actual	CELT Forecast Date 2009	2010	2011	2012	2013	2014	2015	2016	2017
2010	5,420	5,580	5,735	5,456							
2011	5,493	5,803	5,805	5,516	5,592						
2012	5,576	5,498	5,885	5,530	5,658	5,457					
2013	5,529	5,733	5,940	5,600	5,706	5,482	5,629				
2014	5,664	5,259	6,005	5,675	5,791	5,510	5,645	5,602			
2015	5,575	5,178	6,080	5,760	5,867	5,561	5,717	5,663	5,656		
2016	5,484	5,361	6,145	5,830	5,942	5,614	5,808	5,756	5,734	5,703	
2017		5,003	6,205	5,895	6,012	5,644	5,843	5,746	5,695	5,640	5,626
2018			6,260	5,955	6,083	5,663	5,868	5,785	5,717	5,641	5,624
2019				6,015	6,148	5,678	5,890	5,812	5,735	5,644	5,622
2020					6,208	5,695	5,911	5,848	5,748	5,644	5,591
2021						5,714	5,941	5,877	5,754	5,648	5,565
2022							5,958	5,914	5,764	5,657	5,549
2023								5,949	5,777	5,671	5,542
2024									5,794	5,688	5,544
2025										5,707	5,554
2026											5,572

Q: Why did you choose to present the data on 50/50 forecasts for the period 2010–2017?

A: Forecasts much prior to the 2010 CELT might have overstated future load, since they would not have anticipated the Great Recession. In addition, it was in the 2010 CELT that ISO-NE enhanced its forecasting methodology to explicitly reflect future energy-efficiency programs. I examined earlier CELT forecasts, going back to the 2003 CELT, and found over-forecasts comparable to those in Table 2.

Figure 1 shows Boston subarea forecasts since 2003, from the CELT Forecast Data files, along with the actual and weather-normalized peaks from SUD-N-14(S-1).[3] Weather-normalized loads have essentially been unchanged over the last decade or more. ISO-NE has not yet reported the weather-normalized peak for 2017, but the actual Boston-area peak was 19% below the 50/50 forecasts for the 2017 peak

[3] ISO-NE does not report weather-normalized peaks before 2005.

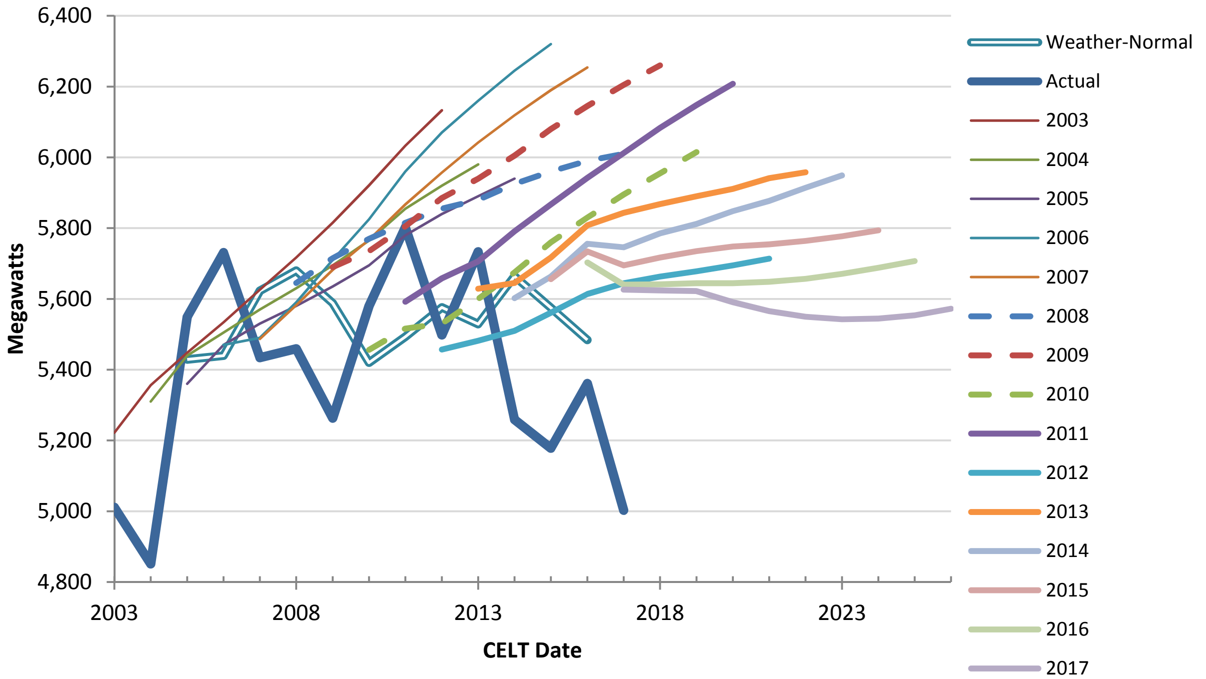
from the 2017 CELT and 20% lower than the 2011 CELT.[4] Even the 2017 CELT 10/90 forecast for this summer (which ISO-NE thought had a 90% chance of being higher than the actual peak, and would occur if the peak temperature were 88.5°F) was just 5% below the 50/50 forecast, so this 20% shortfall at 91°F is unlikely to be primarily due to weather.

The pattern in Figure 1 is clear. The CELT forecasts have consistently projected rapid increases in peak load; as the loads failed to materialize, ISO-NE has pushed the forecasts further into the future, but has continued to assume that peak load growth will resume immediately. The forecasts have mostly exceeded the weather-normalized actual peak, even for the year in which the CELT was prepared; i.e., the forecast released in April exceeded the actual peak a few months later in nine years, by an average of about 244 MW, while the normalized peak exceeded the forecast in only three years (all before 2009), by an average of 80 MW.[5]

[4] The 2011 CELT was prepared six years before the 2017 peak, just as the 2017 CELT was prepared six years before the 2023 peak.

[5] Adding 2017 data would increase the number of over-forecasts to ten, while the average over-forecast would rise to more than 300 MW.

Figure 1: ISO-NE Peak Forecasts for Boston Sub-Region, with Actuals



Q: Have you prepared a similar comparison for the Central Massachusetts sub-region?

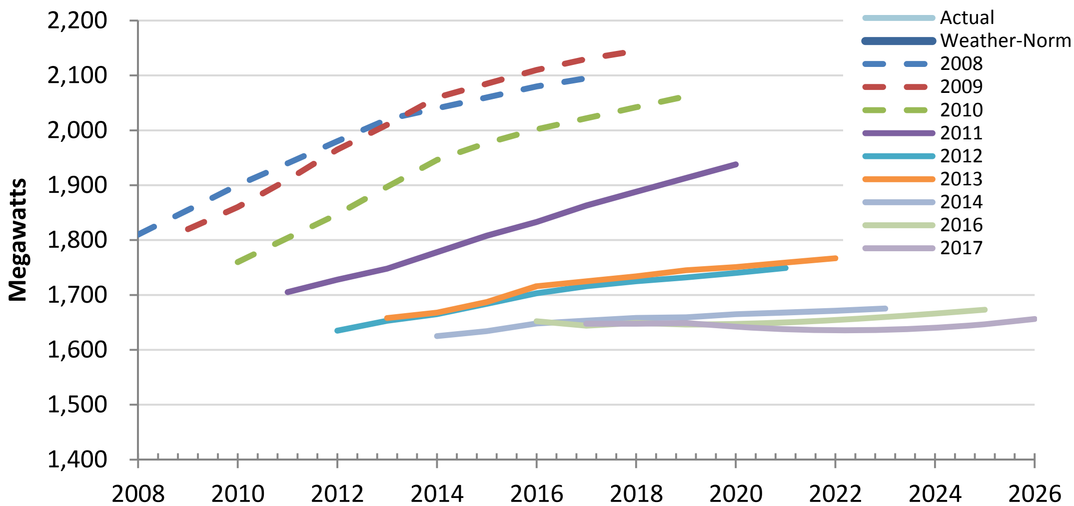
A: To the extent I could. I do not have actual or weather-normalized loads for the CMA sub-region. Figure 2 shows the CMA summer peak forecasts from the CELT reports from 2006 through 2017, except for 2015, when the CMA forecast dropped anomalously.[6]

The CMA load forecasts fell rapidly from the 2008 and 2009 CELTs, through the 2014 CELT, and more slowly since 2014.

---

[6] The CMA forecast for the current year fell from 1,625 MW in the 2014 CELT to 1,484 MW in the 2015 CELT, recovering to 1,652 MW in the 2016 CELT. The sum of CMA and Western Massachusetts (WMA) current-year forecasts were 3,668 MW in 2014, 3,543 MW in 2015, and 3,573 MW in 2016, suggesting that IS-NE may have redefined the boundary between those regions for 2015.

Figure 2: ISO-NE Peak Forecasts for the CMA Sub-Region

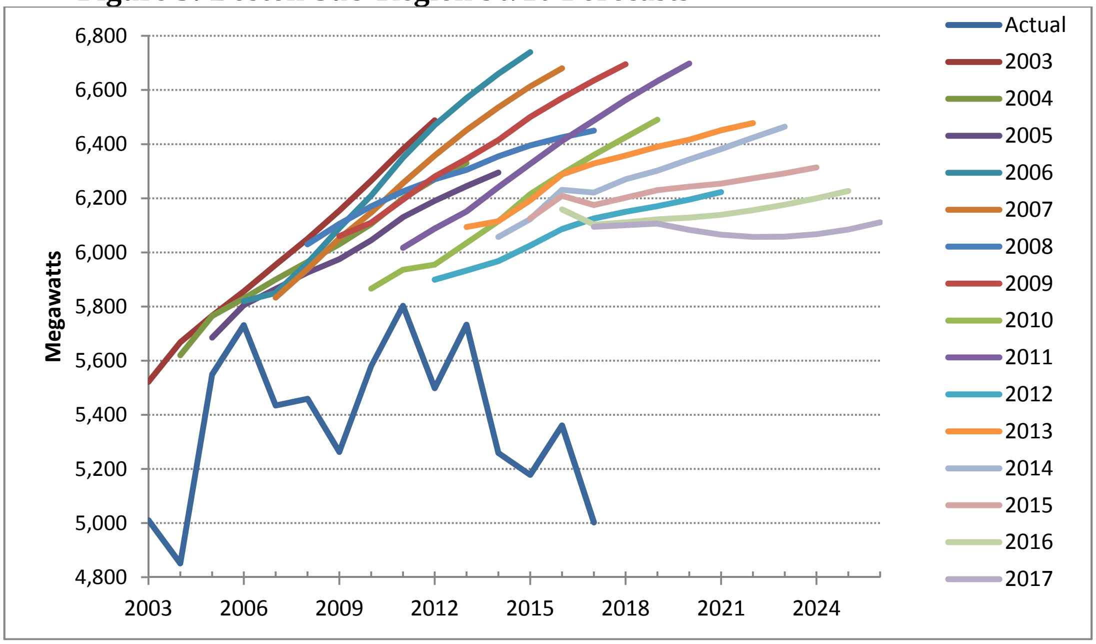


Q: Does ISO-NE do any better with its 90/10 forecasts?

A: Not much. The Boston-area 90/10 forecasts for the current year, from the 2003 CELT to the 2017 CELT, have all been higher than actual peak for the forecast year, as shown in Figure 3.[7] The closest that the CELT forecasts got to a 90/10 peak was in 2006, when the peak was 1.6% lower than the 90/10 forecast from the 2006 CELT. The 1.6% shortfall may seem close, but the difference between the 50/50 and 90/10 forecasts was only 6.5%, so the shortfall was 25% of the additional load that ISO-NE expects from extreme weather. The 2008 load was closer to the 80/20 peak forecast than the 90/10 forecast. If the forecasts were unbiased, the probability of having no peaks above the 90/10 forecasts for fifteen years would be about 20%.

[7] Eversource declined to provide these data (SUD-N-15), so I assembled them myself.

Figure 3: Boston Sub-Region 90/10 Forecasts



Q: Does Eversource accept your observation that the 2017 forecast for 2023 is lower than the 2016 forecast for 2023 used in Eversource's updated analysis?

A: No. Eversource asserts that its update used the "2016 CELT Report forecast, which had a value of 7,094 MW for 2023 for the Boston area. [That] load level used for the Boston area was actually slightly below the value now in the 2017 CELT Report for the Boston area in 2023." (SUD-N-3). Unfortunately, Eversource tends to be quite vague regarding which of the forecast values (gross, net of PDR, or net of PDR and PV) it is citing in its documents. In fact, the 2016 forecast data file from ISO-NE shows a gross Boston 90/10 peak load of 7,128 MW; net of behind-the-meter photovoltaics, that load was 7,072 MW; and net of PDR as well, it fell to 6,176 MW. None of those values match the 7,094 MW claimed by Eversource, so it is impossible to determine what regional load forecast drove Eversource's forecasts of the substation loads.

In the 2017 ISO-NE forecast, the corresponding loads were 7,105 MW (23 MW below 2016), 7,017 MW (55 MW lower), and 6,058 MW (136 MW lower than the 2016 forecast).[8] Eversource's claim to have used loads higher than the 2017 forecast does not withstand scrutiny.

2. Potential Origin of Overestimates

Q: Why might ISO-NE have a consistent bias toward overstating its load forecasts?

A: I have not examined this issue in detail, but the load forecasts appear to have understated the amount of load reduction that would occur due to energy-efficiency programs. The amount of passive demand response ("PDR"), most of which is energy efficiency, forecast in the CELT reports rose rapidly from the 2010 CELT to the 2012 and later versions. In addition, ISO-NE ignored behind-the-meter solar installations until the 2015 forecast; through 2017, that omission accounts for about a 1% overstatement in the net load forecast.

A more serious problem may be that the CELT load forecasts recognize only the amount of energy-efficiency savings that has cleared in the Forward Capacity Auctions ("FCAs") for the next three years. (SUD-N-6(S-1)) To the extent that utilities (and other parties) do not bid all of their energy-efficiency peak reductions into the FCAs, the ISO-NE forecast will understate the effect of energy-efficiency programs on actual load.

Q: Why might an energy-efficiency program administrator bid in less than its full energy-efficiency peak reductions into the FCA?

A: One motivation would be uncertainty regarding the extent to which the program administrators can receive full capacity credit for their peak energy-efficiency

[8] The gross forecast matches to the 7,105 MW for the 2017 forecast that Eversource claims in SUD-N-3. Eversource says that it (and ISO-NE) commonly state load in gross terms, even though "The loads net of PV, forecast energy efficiency, passive demand response and active demand response are typically used in the actual analysis." (SUD-N-38) This disconnection between stated loads and the loads actually used introduces another level of difficulty in interpreting Eversource's limited documentation of its analysis.

savings, considering the ISO-NE verification rules for energy-efficiency measure or program and the assumptions that ISO-NE makes in converting energy savings to peak reductions. Another concern for the program administrators is whether they can commit to deliver results from programs that may not yet be designed or approved, let alone implemented. Under those circumstances, it is entirely rational for the program administrators be somewhat conservative in bidding capacity into the annual capacity auctions.

Eversource has claimed that it cannot provide the data necessary to test ISO-NE's assumption for its own bidding strategy, let alone that of National Grid (SUD-N-52, 52(S-1)). However, comparing the data on the load reductions reported by program administrators (from the historical ISO energy-efficiency forecast documents for various years) to the cleared PDR capacity (from the load forecast data files) indicates that the program administrators have been bidding in much less capacity than they report achieving. For example, ISO-NE's 2017 energy-efficiency forecast reports that 196 MW of load reductions were achieved by the Massachusetts program administrators in 2015 (the last year reported by ISO-NE), but the 2014 CELT forecast showed an increase in Massachusetts PDR capacity obligations of just 109 MW for 2015. In other words, ISO-NE now acknowledges that the Massachusetts energy-efficiency load reduction in 2015 was 80% greater than it assumed the year before.[9]

Q: How does the ISO-NE forecast energy-efficiency load reductions after the three future years for which the forward capacity auctions have been conducted?

A: ISO-NE assumes that the energy-efficiency budgets will remain flat (or nearly so), while the cost of savings will increase radically, resulting in falling energy-efficiency savings over time. Figure 4 shows the estimates of energy-efficiency costs used in the annual CELT reports, from 2012 through 2017. In each year, ISO-

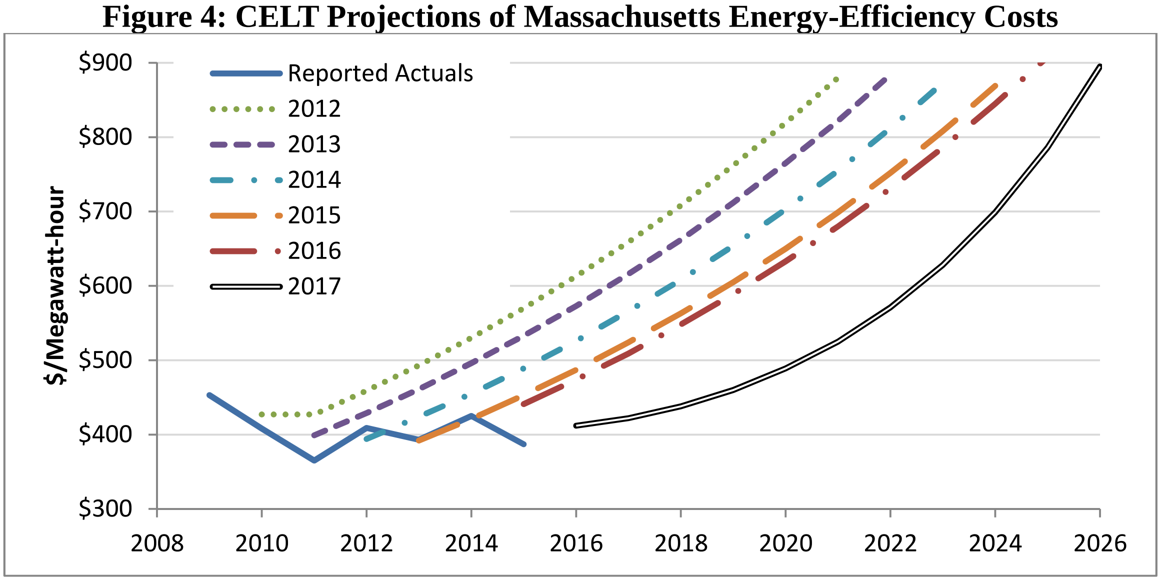
[9] The increase in energy-efficiency resources may include resources implemented before 2014 that the program administrators delayed bidding into the capacity market.

NE assumes that the cost of energy-efficiency would be similar to the historical average cost in the short term, but rise abruptly thereafter. As that projection fails to materialize, ISO-NE pushes the cost curve to the right; in 2017, ISO-NE assumed that the costs would increase more slowly for the first five years than it had previously, but also assumed that the cost would skyrocket after that.

Q: What is the result of ISO-NE's assumptions on the energy-efficiency forecasting for the CELT reports?

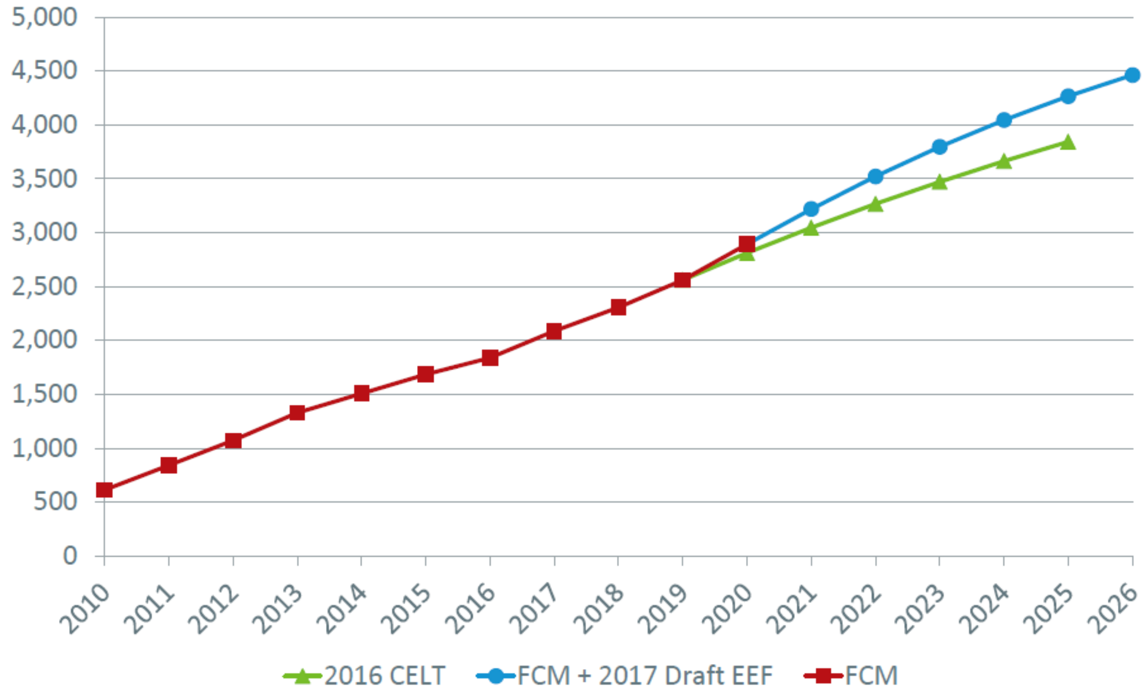
A: Those assumptions—which are inconsistent with experience and not supported by any analysis in the energy-efficiency reports—result in understatements of the energy-efficiency for the CELT forecasts. For example, the 2016 CELT (which Eversource used in its analysis of need for the Project) converted the assumed energy-efficiency budget for 2023 into 44% lower savings than if the cost of energy-efficiency had been kept at the value it assumed for 2015.

Figure 4: CELT Projections of Massachusetts Energy-Efficiency Costs



ISO-NE continues to find that its forecast of energy-efficiency load reductions are understated. Figure 5 shows that ISO-NE recognizes that the reduction for energy-efficiency in the 2016 CELT was too small, resulting in an increase of over 10% in the 2017 CELT forecast of 2023 energy-efficiency.[10]

Figure 5: ISO-NE 2017 Update of Energy Efficiency on Summer Peak (MW)



B. Substation Forecasts

Q: How did Eversource forecast the 90/10 peak loads in the Marlboro load pocket for its 2016 analysis of the need for the Project?

A: Eversource's explanation of the source of its forecasts has been confusing at best. Eversource did not discuss the basis for the substation forecasts in the Analysis, but in early discovery responses, Eversource said that the forecasts of gross load (before energy-efficiency, other passive demand, and behind-the-meter solar) and load reductions were "Based on 2016 CELT" (PROTECT-2; SUD-N-9; Attachment SUD-N-46(1)). When asked how Eversource derived the forecasts from the 2016

---

[10] Final 2017 CELT ISO-NE Annual Energy and Summer Peak Forecast presentation, May 1, 2017, www.iso-ne.com/static-assets/documents/2017/05/final_eef_2017_v2.pdf.

CELT, Eversource said that "Eversource does not allocate CELT data" (SUD-N-51), and instead said that the "values used were extracted from the ISO-NE base case database. The information is based on the ISO-NE CELT forecast for each year." (SUD-N-41, N-42b, N-43, N-49c).

In response to later discovery, Eversource clarified that each utility prepares a load forecast for each substation and that ISO-NE then adjusts those forecasts to match ISO-NE's forecast for the RSP subarea, such as Boston or Central Massachusetts (SUD-N-65). The adjustments by ISO-NE are not consistent across substations, even within a single subarea, as shown in Table 3.

Table 3: ISO-NE Adjustments to Utility Forecasts, 2017 CELT

Substation	Utility	ISO-NE	% Change
West Framingham	53.5	63.9	19.4%
Northboro	41.1	49.7	20.9%
South Marlboro	25.9	31.4	21.2%
Marlboro	59.1	73.4	24.2%
North Marlboro	25.4	32.3	27.2%
Hudson	70.6	76.5	8.4%
East Main Street	32	23.1	-27.8%
Westborough	50.1	62.4	24.6%
North Grafton	17.2	–	
Woodside	28.9	35	21.1%
Centech	18.8	21	11.7%
Total	422.6	468.7	10.9%

Sources: Attachment SUD-N-65(1) and Attachment SUD-N-65(2)

Eversource has not provided any explanation of this process, and may not even understand ISO-NE's methodology. The basis of substation-level forecasts is simply unreviewable.

ISO-NE's adjustments to the basic forecast for behind-the-meter photovoltaics, energy-efficiency programs, other PDR (such as non-PV customer-side generation), and demand response appear to be proportional across the subarea. This is a more straightforward and consistent approach than the unexplained adjustments shown in Table 3, but it does not reflect local conditions. Eversource has not prepared its own forecasts of these distributed resources (SUD-N-12, N-20,N-21, N-50).

IV. Distributed Alternatives to the Project

Q: As you understand it, what is the legal standard for demonstrating that a transmission line is the preferred alternative?

A: G.L. c. 164, § 69J requires that the project proponent present alternatives to the proposed facility, including energy storage, generation, and load reductions. I understand that the Siting Board requires a petitioner to show that its proposed project is superior to the alternatives in terms of cost, environmental impact, and ability to meet the identified need.

Q: Why should the Board consider distributed alternatives to the Project?

A: There are two basic reasons for carefully considering distributed alternatives. First, these alternatives are favored by Commonwealth energy policy and Department decisions. Second, while the Project would simply allow power to flow into the Marlboro load pocket (if a second contingency ever occurs at a time of extreme loads), distributed alternatives would provide multiple other benefits.

As I explain below, there are multiple options for reducing loads in the Marlboro pocket, and the required reduction appears to be much smaller than Eversource asserts.

Q: Please explain how distributed alternatives are favored by Commonwealth energy policy and Department decisions?

A: In general, it is important to note that the Commonwealth has been rated by the American Council for an Energy-Efficient Economy as having the most active energy-efficiency effort in the nation, for each of the last seven years.[11] The

[11] https://www.mass.gov/news/massachusetts-named-most-energy-efficient-state.

Commonwealth's energy policy is diverse, focusing on, among other things, development of clean energy and peak-demand reduction projects to avoid and delay electric transmission and distribution investments.

In June 2017, the current Administration announced a 200 MWh energy storage target to be achieved by January 1, 2020, supplementing the Administration's $10 million Energy Storage Initiative to consider ways to support Commonwealth storage companies and develop policy options to encourage the deployment of energy storage.[12]

The Commonwealth is also in the process of implementing its third iteration of a solar incentive program. The Solar Massachusetts Renewable Target ("SMART") program is intended to create a long-term sustainable solar incentive program that promotes cost-effective solar development (the program goal is 1,600 MW of new solar generating capacity) in the Commonwealth. The purposes of the solar incentive include, among other things, to encourage continued use and development of solar photovoltaic technology by residential, commercial, governmental and industrial electricity customers throughout the Commonwealth, which, "has the potential to reduce peak demand, system losses, the need for investment in new infrastructure, and distribution congestion." (225 C.M.R.§20.01)

The Department has also focused on efforts to modernize the electric grid, to facilitate the control of loads and the integration of distributed resources. In June 2014, the Department issued an order in D.P.U. 12-76-B directing the Massachusetts electric distribution companies in the Commonwealth to develop and submit grid modernization plans (GMP or GMPs) for Department approval.[13] In that Order (at 2), the Department required each distribution company to propose measureable progress towards a set of grid-modernization objectives, including optimizing demand, reducing system and customer costs and integrating distributed

[12] http://www.mass.gov/eea/pr-2017/doer-sets-200-megawatt-hour-energy-storage-target.html.

[13] *Investigation by the Department of Public Utilities on its own Motion into Modernization of the Electric Grid*, D.P.U. 12-76 B, June 12, 2014.

resources. The Department directed each distribution company to include a plan for implementing advanced metering functionality ("AMF"), which the Department characterized as the "basic technology platform for grid modernization," within five years of GMP approval. (D.P.U. 12-76-B at 3, 14) The Department defined AMF as including the capability for the utility to collect interval usage data, in near-real time, to communicate with customers, and to control customer loads. (D.P.U. 12-76-B at 3).

The Department also issued a separate order laying out its final policy framework for time-varying rates ("TVR") for basic service and expressing its intent that some form of TVR be implemented as AMF is deployed.[14]

Q: What benefits would distributed alternatives provide that would not be provided by the Project?

A: Distributed resources provide multiple benefits that the Project would not provide, including:

- reducing the average cost of energy consumed by participants (by reducing energy use and/or shifting load from high-cost to lower-cost hours),
- reducing the amount of generating capacity charged to the participants,
- reducing the market prices of energy and capacity for all customers,
- reducing the need for other transmission and distribution equipment,
- reducing air pollutants and greenhouse gas emissions.

Some distributed resources would also produce ancillary services, facilitate integration of renewable resources (such as by shifting consumption to times with low loads and high renewable output), and/or allow customers (or microgrids connecting several customers) to operate when some portion of the transmission or

[14] *Investigation by the Department of Public Utilities upon its own Motion into Time Varying Rates,* D.P.U. 14-04-C, November 5, 2014.

distribution system is out of service. This last point is very important. Distributed generation (combined heat and power or photovoltaic panels plus storage) can increase the resiliency of customers to an extent that another transmission line cannot. In severe weather events (*e.g.*, ice storms, hurricanes, nor'easters), a customer will lose grid power supply if any of the levels of supply—generation, bulk transmission, local transmission, the distribution feeder, the line transformer, secondary, or service drop—is unavailable. Distributed resources can continue to serve a customer (or a group of customers, linked through a microgrid), despite failure of upstream components.

Q: Has Eversource undertaken any effort to propose distributed resources as an alternative to the Project?

A: No. Even though Eversource says that it has known since 2013 that the Marlborough load could experience supply constraints, it has not made any effort to use distributed resources to mitigate the potential problem.

> The Company has not undertaken a specific effort to reduce or shift loads in the Marlboro load pocket beyond the Company's regional energy efficiency programs and other incentives available to behind-the-meter resources in the Commonwealth….the level of load reduction needed in a very specific geographic area over a relatively short time frame makes it impractical from a feasibility and cost perspective that targeted behind-the-meter solutions would be effective in offsetting the need for the proposed Project. (SUD-N-62)

That response repeated the assertion that "the level of load reduction needed in a very specific geographic area over a relatively short time frame make it unlikely that targeted behind the meter solutions would be effective in offsetting the proposed project within the time scales required" from SUD-N-26, which also noted that "The Company is also proposing pilot programs for energy storage systems currently pending before the Department of Public Utilities…, although these pilot programs will not address the system needs relieved by the proposed project."[15] It is unfortunate that neither National Grid nor Eversource is proposing to use storage to address the perceived Marlborough-area system needs.

The London Economics International ("London Economics" or "LEI") study (Analysis Appendix 3-5) briefly considers a few distributed resources, but dismissed them as being individually inadequate to meet the perceived need.[16] A comprehensive strategy for using distributed resources to avoid supply problems in the Marlboro load pocket would include reducing peak load with targeted energy-efficiency and rate-design programs, reducing load at times of system stress, and installing solar generation and storage.

Q: How is the remainder of this section structured?

A: I start in Section A with a discussion of load relief required to avoid overloads in the event of a second-contingency incident in the Marlboro load pocket. In Section B, I discuss the opportunity for rate design options to reduce peak loads and avoid overloads. Section C discusses the potential for distributed solar and storage to flatten the peak load in the Marlboro pocket. Section D describes some experience with geographically targeted load reductions.

A. Amount of Load Relief Required

Q: How much load relief does Eversource claim is needed in the Marlboro load pocket, to avoid shedding load in the event of a second-contingency outage at an extreme peak?

A: Eversource presents results from two analyses: an analysis based on the 2013 CELT loads, and Eversource's update based on the 2016 CELT. I will only discuss the

---

[15] The projects proposed by Eversource are "front-of-the-meter energy storage investments," which will not provide the customer reliability benefits of behind-the-meter and microgrid applications. (SUD-N-23)

[16] As discussed in Section A, below, London Economics incorrectly believed that about 250 MW of load relief was necessary.

updated results. Table 4 reproduces Eversource's summary of the generation requirements for 2023, from EFSB-PA-10.

Table 4: Eversource Claimed Generation Needs

Location (Substation)	Size (MW)
West Framingham	88.3
East Main Street	42.1
Northboro	19.1
North Marlboro	56.9
Woodside	23.6
Total	230.0

Q: Is this tabulation by Eversource correct?

A: I do not believe so. It appears that the London Economics report (Analysis Appendix 3-5) has misinterpreted the amount of generation in the load pocket that would be needed to support the transmission system in the event of a second contingency at a hypothetical peak load. Table 5 summarizes the data shown in Attachment SUD-N-56(1), which shows Eversource's estimates of the amount of capacity at various load-pocket substations that would relieve the overloads in the event of the second contingency. I have replaced the descriptions of the contingencies (which are provided only in the confidential version of the response) with codes.

Table 5: Megawatts of Generation Needed in Marlboro Load Pocket, at 469 MW Peak, by Contingency Combination

Second Contingency	First Contingency Code			
Code	A	C	C	D
103	104.4	92.2	55.4	97.1
114	82.6	72.8	45.4	76.3
115	81.5	76.6	51.5	74.7
116	109.1	85.0	59.3	83.4
117	**128.6**	96.1	63.7	86.4
121	72.7	65.9	48.2	64.7
122	63.2	76.3	28.9	56.1
203	71.7	62.1	33.6	63.5
214	52.8	45.3	14.6	45.8
215	96.5	44.9	13.9	44.7
216	60.1	52.8	24.2	54.3
217	77.3	73.6	49.2	73.7
221	56.2	63.0	4.7	44.7
222	56.6	47.6	8.0	46.5

The maximum amount of generation that is needed in any of the scenarios is 128.6 MW, which could comprise [redacted] MW at West Framingham, [redacted] MW at North Marlboro and [redacted] MW at Northboro Road.

Q: How did Eversource estimate these values?

A: Eversource explains its approach as follows:

> The analysis was conducted using the PowerGEM Transmission Analysis and Reliability Assessment ("TARA") application—the same analytical tool used in the Solutions Study. TARA has the ability to optimize the dispatch of a multitude of generating resources across a defined area to mitigate transmission overloads that are the consequence of single contingency (N-1) or multiple contingency (N-1-1) events.

> The optimization process attempts to identify the minimum level of resources required to address identified overloads. TARA first finds a helpful location to place a resource and then continues to increase the dispatch level of the resource until either the maximum output is reached, or additional increases are no longer helpful. The software then proceeds to the next most helpful location and continues the process until all overloads have been mitigated and/or all possible helpful locations have been used. (Analysis p. 3-9)

As I read Attachment SUD-N-56(1), Eversource ran its transmission model with 250 MW of capacity at each substation, priced or otherwise constrained to limit the output of the capacity to the amount necessary to avoid overloads.[17]

Q: So how did Eversource get its total of 230 MW of capacity requirement?

A: Eversource appears to have selected the maximum amount of generation at each substation in any of the 56 cases and summed those amounts. As shown in Table 6, the values that Eversource used occurred for the five substations were from five different contingency cases.

Table 6: Eversource Claimed Capacity Need, by Contingency Case

Location (Substation)	Size (MW)	Case Using this Amount	Total Case Requirement
West Framingham	88.3	215A	96.5
East Main Street	42.1	121D	64.7
Northboro	19.1	117A	128.6
North Marlboro	56.9	103D	97.1
Woodside	23.6	117C	63.7
Total/Maximum	230.0		128.6

Eversource apparently took the maximum of generation that the model used at each substation in any contingency case, and summed those substation maxima. This approach would only make sense if the stations were disconnected from one

[17] Unfortunately, these data were not provided in the Analysis or in early rounds of discovery, so I have not been able to follow up to get additional information about Eversource's methods or the meanings of some of the codes in Attachment SUD-N-56(1).

another. But the contingencies generally appear to reduce the import capacity into the load pocket, rather than disconnecting the substations from one another.[18]

In a supplemental response on September 27, Eversource provided the following text explaining the meaning of the values in Attachment SUD-N-56(1):

> The attachment shows the amount of MW injection that would be needed to mitigate the overloads from the worst-case contingencies. It is the output from the load flow analysis. For the worst-case contingencies, 88.3 MW of NTA would need to be injected at West Framingham Substation. 42.1 MW of NTA must be injected at E. Main St Substation to mitigate the overloads. 19.1 MW of NTA injection was noted as required at Northboro Rd Substation on the 115-kV bus. 56.9 MW of injection was identified as required at North Marlboro Substation and 23.6 MW at Woodside Substation. (SUD-N-56(S-1))

Notice that this response refers to the "worst-case contingencies," rather than a single occurrence. Unfortunately, Eversource does not address why it used the sum of the energy dispatched for different combinations contingencies, each representing the "worst-case" second contingency for the computer program's selection of generation at each substation.[19]

Q: Are there other reasons to believe that Eversource overstated the required capacity of distributed resources?

[18] Eversource documents are somewhat confusing about the nature of the contingencies. For example, Attachment PROTECT-2-5(1) (which is an excerpt of Analysis Appendix 2-1) describes the 455-507 transmission line as running from W. Framingham to Northboro Road (inside the load pocket), even though this line actually runs from W. Framingham to Sherborn (outside the load pocket). A contingency on the 455-507 line would not disconnect the substations within the Marlboro pocket from one another, but the text of Attachment PROTECT-2-5(1) suggests that it would. Perhaps the description in Attachment PROTECT-2-5(1) is just a typographical error.

[19] The same supplemental response also asserts that "[a]dditional load flow analysis was done starting with the largest injection point at West Framingham and it was verified that all injection amounts were needed to mitigate the overloads." It is not clear what Eversource is trying to say in that sentence, since West Framingham is the largest injection point in most of the contingency combinations, except (somewhat counterintuitively) the cases in which the supply to [redacted] is assumed to be interrupted.

A: Yes. As I described above, ISO-NE has consistently over-forecasted load, while understating future load reductions from energy-efficiency and behind-the-meter solar.

In addition, Eversource did not run its load-flow models with the other transmission facilities from the Greater Boston Area study in place, even those that are complete or under construction (SUD-N-16).[20] A large share of those projects have been completed or are under way, which may change the overloads and voltage drops in the Marlboro pocket. In particular, the X-24E and X-24W lines serving the load pocket have been refurbished (SUD-G-14(S-1).

B. Rate Design Options

Q: Which rate-design options will you discuss in this section?

A: I discuss time-varying rates for peak demand and time-of-use pricing.

1. Peak-Driven Time-Varying Rates

Q: What do you mean by peak-driven time-varying rates?

A: This categories of rate design includes such options as:

- real-time TVR, in which prices vary hourly, depending on market prices and supply conditions,
- critical-peak pricing ("CPP"), which charges a premium price in certain hours that are declared to be critical peaks, typically the previous evening, but potentially on short notice,

[20] Oddly enough, Eversource claims in EFSB-N-8 that "the Company performed additional needs analysis for the Project assuming all the other Greater Boston Projects were in-service." It is very difficult to determine what Eversource actually modeled, given the contradictions in its evidence.

- critical-peak rebates ("CPR"), which reward customers for using less power in the critical peak hours than the customer would usually use under comparable conditions, and
- variable pricing options under the CPP and CPR programs, in which the premium price depends on system conditions.

Q: What forms of time-varying pricing would be most appropriate for the Marlboro load pocket?

A: Real-time pricing or CPP could be offered on an opt-in basis for larger non-residential customers and sophisticated residential customers. The easiest and fastest option for the mass residential and small-commercial market would be to implement CPR, which can be added on as a credit to the existing rates, without calculating or explaining a whole new rate design. In Maryland, the utilities (Baltimore Gas and Electric, Potomac Electric Power, and Delmarva Power) do not even require customers to opt in to the CPR option; customers receive rebates when their usage in the critical-peak hours is lower than in the reference period. The Maryland utilities pay rebates of $1.25/kWh for the estimated load reductions in the critical-peak hours (about four hours a day, about four days per summer), while other CPR rates pay more like $0.50/kWh.

Eversource and National Grid could pay a relatively low rebate (e.g., $0.40 or $0.50/kWh) during the highest-load or highest-cost hours in more summers, to reduce capacity and energy prices, and to make sure that customers remain familiar with the program, while promising a very high rebate (perhaps $5/kWh) in the unlikely event of a 90/10 peak load coinciding with a first-contingency event.

Q: What savings might you expect from the general application of a CPR incentive structure in the Marlborough load pocket?

A: In DPU 15-120, National Grid filed a report from Concentric Energy Advisors (Time-Varying Rates: Industry Experience, May 2015, National Grid's Grid

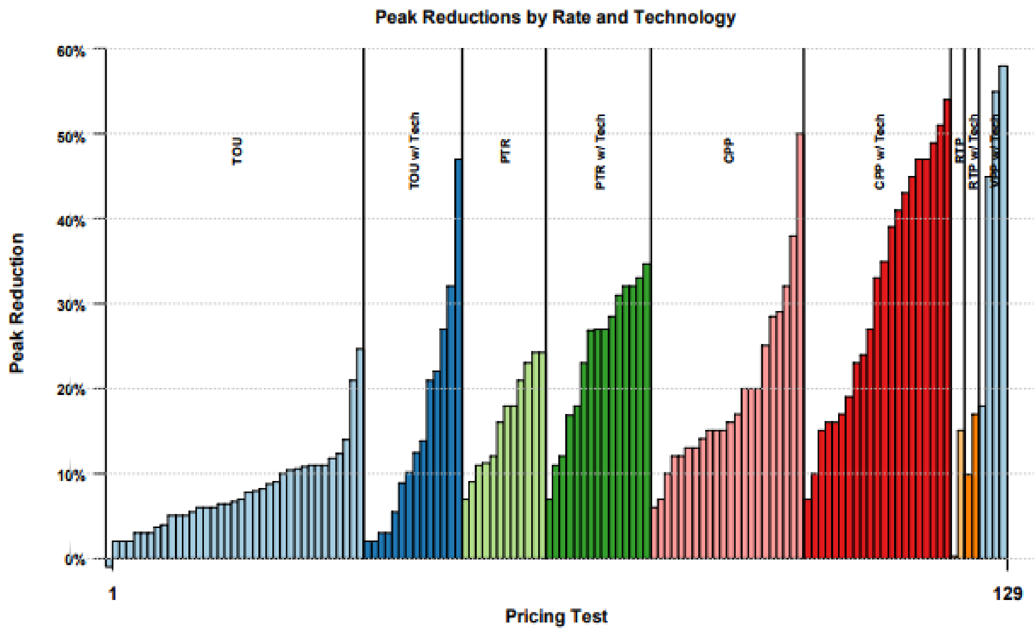
Modernization Plan, Attachment 13), prepared for the Massachusetts distribution companies, including Eversource. That report summarizes the experience with a large number of rate programs using CPP and CPR to target peak loads. That analysis indicated that the programs often reduce load by 10% or more, with CPP programs reducing load more than CPR, and load reductions with enabling technologies (information and control system) greatly exceeding those without. That study is attached as Exhibit SUD-PLC-3.

My own reanalysis of the CPR program of Baltimore Gas and Electric ("BGE") (the largest CPR program in the country, according to the FERC Form 861 database for 2016), reducing the reported savings to account for free riders, indicates that the program reduced the peak contribution by their entire residential class by about 6% under normal peak weather. I would expect similar results for customers in other classes, most of whom would be more sophisticated and have more controllable loads than the residential customers. The BGE CPR program did not include any special measures to increase the ability of the participants to follow their loads (such as in-home displays) or to control loads (such as remote thermostat controls). Experience indicates that adding information and control technologies greatly increases customer response to CPR and CPP rates.

Other studies have found a range of results, depending on the specific time-varying program design**.** A report from the Regulatory Assistance Project ("RAP") identified a peak load reductions up to 58% for participants in one-hundred and twenty-nine pricing tests in North America, Europe, and Australia[21]. Figure 6 reproduces a graph from the RAP report that provides the results for seventy-four pricing tests (those that used randomized trials). The largest peak load reductions are found in the CPP programs enabled with technology (programmable thermostats or home energy manager devices). The CPR programs with technology also can achieve over 20% load reductions.

[21] "Time-Varying and Dynamic Rate Design," Faruqui, A., et al., July 2012, http://www.raponline.org/wp-content/uploads/2016/05/rap-faruquihledikpalmer-timevaryingdynamicratedesign-2012-jul-23.pdf, page 28.

Figure 6: Average Peak Reduction from Time-Varying Rate Pilots



Q: Would a CPR or CPP rate design be expensive to implement?

A: The costs of implementing a CPR program are minimal for utilities that have installed AMF. The filings in DPU 15-120 by National Grid, which serves about 70% of the load pocket, demonstrate strong support for the installation of AMF in its service territory.[22] The Marlboro load pocket would be an ideal area to pilot National Grid's AMI installations and messaging.[23] In its Attachment 14 to its filing in DPU 15-120, National Grid proposes to implement a combination of a default CPP program and a CPR program for customers who choose to opt out of the default program. While I have not found a public statement of National Grid's expectation for the load reduction, it is proposing a critical-peak price about 9 times

---

[22] Petition of Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid for Approval of its Grid Modernization Plan, D.P.U. 15-120, Reply Brief of National Grid at 7 (August 18, 2017).

[23] The same may be true for the areas served by potentially overloaded feeders from the Bloomingdale and Millbury substations, which National Grid wants to transfer to a new North Grafton substation, increasing load in the Marlboro pocket (SUD-N-45 (S-1), Attachment N-45(1), Attachment N-45(2)).

the off-peak price (DPU 15-120, Attachment 14, p. 6) which National Grid says would be expected to reduce peak about 15% (*ibid*). Recognizing that opt-out programs have lower average response than opt-in programs, National Grid assumed 56% of the observed peak reduction, or about 8%. For a load-pocket peak load of 450 MW, National Grid's model would expect a reduction of about 36 MW, for full deployment.

I understand that Eversource is resisting the Department's initiative to deploy AMF, so the availability of that option may be delayed for residential customers served from the West Framingham substation in the near term.[24] I do not know where the Hudson and Sterling municipal utilities stand on AMF. In any case, for industrial and large commercial customers (including the industrial parks that apparently dominate the load on Sterling's Centech substation), a range of demand-response options are feasible, without mass deployment of smart meters.

Where the metering technology is in place, the costs of a CPR program are primarily those of software for estimating customer load reductions and outreach efforts.

2. *Time-Of-Use Pricing*

Q: How would time-of-use pricing improve the reliability of transmission supply to the Marlboro load pocket?

---

[24] Eversource currently has a proposal before the Department for a series of demonstration projects, which are "designed to leverage opportunities to lower peak demand and save customers money, and include battery storage, thermal storage, software & controls, active demand response, and integrated energy efficiency approaches that reduce energy use and peak demand." (D.P.U. 16-178, Initial Filing, Attachment A to Goldman Affidavit at 3 (Oct. 31, 2016)) Eversource requested a total budget of more than $21 million and expects to involve 975 to 1,695 customers. (*Ibid*., Attachment A at 4-7) Eversource stated that it expects that these demonstration projects themselves will result in demand reductions by 2018. (*Ibid*., Attachment A at 3) Eversource projects peak demand reductions of 12.17 MW to 28.25 MW per year and on-peak energy savings of 5,475 MWh to 12,714 MWh of energy. (*Ibid*., Attachment A at 8) Eversource referenced these proposals in discovery, but Eversource says it "has no additional forecast of the potential for summer thermal storage to reduce peak loads in the Marlboro Subarea." (SUD-N-24).

A: Energy prices that are higher in the high-load summer hours and lower in low-load hours would encourage customers in all major classes to use less energy during the times in which loads could approximate the 90/10 peak, including installing and equipment, such as set-back thermostats and ice-storage chilling, that facilitates that load shift.

Q: How much reduction in peak load would you expect with time-of-use rates?

A: The Concentric study (Exhibit SUD-PLC-3, Table 3) indicates that peak savings from TOU rate can be four to twelve percent. Figure 6, above, shows similar or larger savings for TOU programs, especially for those with enabling technology.

The Sacramento Municipal Utility District ("SMUD") found that its opt-in TOU rate pilot reduced participant peak load on critical days by 13.3% with in-home displays and 10.1% without, and that default TOU rates reduced peak load on critical days by 5.9%.[25]

C. Distributed Solar and Storage

1. The Eversource Analysis

Q: What does London Economics assume about the potential of storage plus solar to solve the reliability needs of the Marlborough load pocket?

A: London Economics concludes that distributed generation solar PV and utility-scale solar PV are not viable on their own because outages could occur in evening hours while load is above the reliability threshold but after the sun has set. LEI does

[25] SMUD SmartPricing Options Pilot Evaluation, Gearge, SS, et al., submitted to Sacramento Municipal Utility District Submitted by Nexant, August 6, 2014, attached to "SmartPricing Options Final Evaluation: final report on pilot design, implementation, and evaluation of the Sacramento Municipal Utility District's Consumer Behavior Study," Potter, JM, et al., September 5, 2014. www.smartgrid.gov/files/SMUD-CBS_Final_Evaluation_Submitted_DOE_9_9_2014.pdf. SMUD also found that default CPP reduced critical peak load by 14%.

investigate the pairing of solar resources with energy storage that could provide discharge for a 12-hour duration (pp. 11–12). LEI finds utility scale-solar paired with energy storage has a net levelized cost of electricity ("LCOE") of $241 to $301/kW-year depending on compensation structure (LEI Figure 4).

In addition to the economic considerations, LEI adds two other constraints. First, LEI asserts that all solar and storage resources must be installed by 2019 to be comparable to the Project. Second, LEI expresses skepticism that there is sufficient area around the Northboro Road and Woodside Substations to accommodate sufficient levels of distributed generation (pp. 12–13). That concern is based on the incorrect assumption that the generation would need to be located at two specific substations, rather than distributed along the feeders served by any of the ten substations in the load pocket.

Q: Is the LEI analysis reasonable?

A: No. The LEI analysis is flawed for a number of reasons, including some I have described above, and the use of outdated cost information for solar and storage.

Q: What data did LEI use to assess the cost of solar and storage? Is this reasonable?

A: LEI generally uses proprietary data to assess the cost of solar and storage resources in its analysis. For example, it notes for distributed solar that "Gross LCOE was estimated through LEI's proprietary LCOE model. Key inputs to LEI's proprietary LCOE model such as capital costs and O&M provided by the Utilities. Results were then cross-checked against industry's estimates (from NREL and DOE)" (LEI Figure 24). The reference that LEI provided to National Renewable Energy Laboratory ("NREL") data is from 2014; considering the rate at which solar prices have been falling, this estimate is woefully out of date.

In the NREL study cited by LEI, residential solar systems less than 10kW, and installed in 2014, have a median cost of $4.50/Watt. Systems larger than 100kW have a median cost of $3.52/Watt. The cost of photovoltaic systems has declined dramatically in the past three years, as shown in Table 7.

Table 7: Cost of Solar Systems in 2014 and 2017

		$/Watt		
Value	**Period**	**Small**	**Large**	**Source**
NREL Solar Cost cited by LEI	1H2014	4.50	3.52	(a)
Current NREL Solar Costs	1Q2017	3.08	1.89	(b)
Cost Decline from 2014 to 2017		32%	46%	

Sources:
(a) P9, https://www.nrel.gov/docs/fy14osti/62558.pdf
(b) Fig 15, https://www.nrel.gov/docs/fy17osti/68925.pdf

According to NREL data, residential solar costs have fallen 32% since 2014 while large commercial systems have fallen 46%. If LEI is using the cost data it cited, its analysis is based on obsolete cost data that are overstated by 50% to 100%, compared to current values. Unfortunately, there is no way to determine what LEI actually assumed in its confidential modeling.

LEI's listed costs for energy storage are no better. The two citations provided in their appendix are from 2012 and 2013, respectively. A paper published in *Nature* found that actual costs of lithium-ion cell in 2016 were below many forecasts for 2020.[26] The Lazard Levelized Cost of Storage Version 2.0 ("LCOS") estimates cost reduction for battery storage systems will fall by 11% annually from 2016 through 2020.[27] The 2020 projections are less than half the historical cost given in the Pacific Northwest National Lab report that LEI cites as a cost source.

Put simply, LEI's analysis of solar and storage costs are very poorly documented and appear to be biased towards the high side of costs.

[26] Rapidly falling costs of battery packs for electric vehicles, Björn Nykvist and Måns Nilsson, *Nature Climate Change* 5, 329–332 (2015). www.nature.com/nclimate/journal/v5/n4/full/nclimate2564.html or https://www.researchgate.net/publication/274407248_Rapidly_falling_costs_of_battery_packs_for_electric_vehicles

[27] https://www.lazard.com/media/438042/lazard-levelized-cost-of-storage-v20.pdf at 20

Q: What amount of generation does the Eversource filing assume would be needed to provide second-contingency reliability for the load pocket under a second contingency?

A: Based on the results of load-flow studies based on the 2013 CELT forecast and dismissing solar and storage, LEI decided that the best available option is a 249 MW combined-cycle combustion turbine at Northboro Road and a 32 MW aeroderivative combustion turbine at Woodside. In EFSB-PA-10, Eversource notes that its 2016 update found that less total generation would be required (230 MW vs 264 MW) and that the resources could be more distributed, as discussed in Section IV.A.

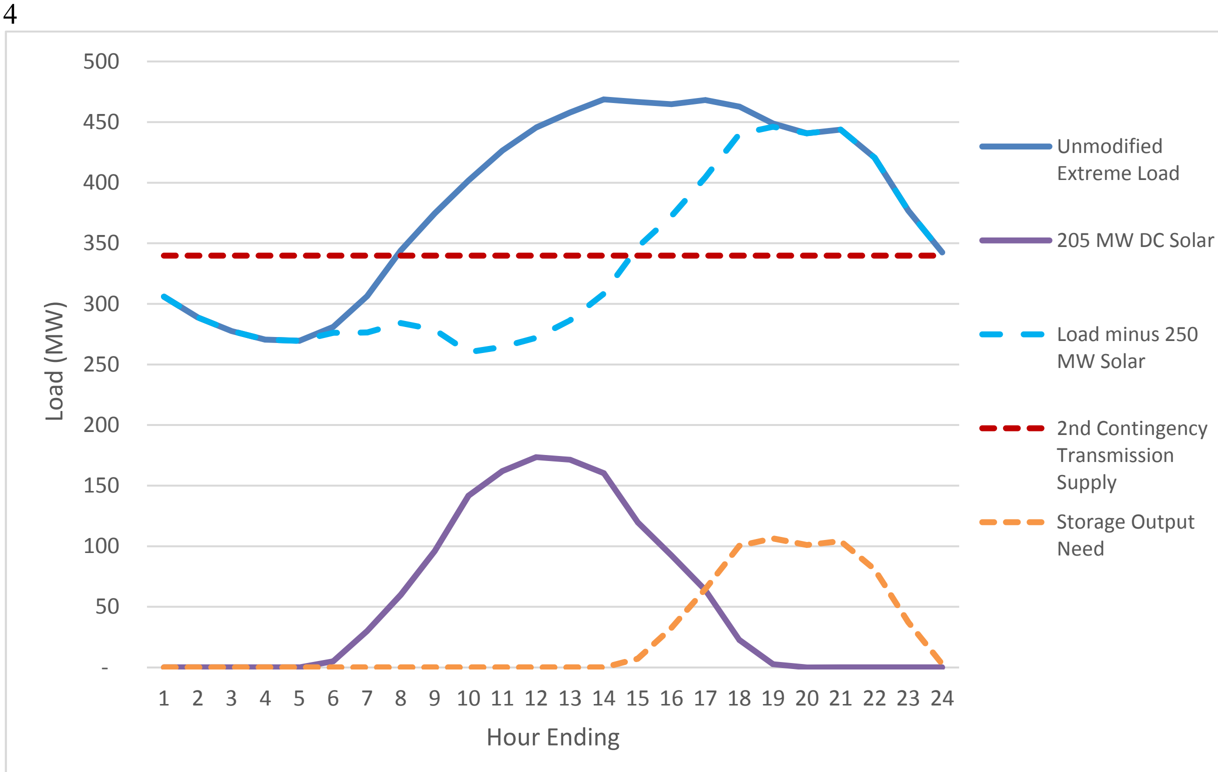
2. Solar and Storage Resource Potential and Requirement

Q: How much solar and storage would be required to meet the reliability needs of the Marlborough load pocket on the peak day?

A: About 250 MW (at the installed DC rating) of distributed solar and 160 MW of distributed storage (with four hours of storage, or 638 MWh) could shave the load pocket's gross load to a safe threshold for the extreme peak loads from the 2016 CELT. A lesser quantity of storage would be sufficient for outages of lower duration or if outages occurred in periods of the year when demand was lower. While there should be a great deal of flexibility in the location of this capacity, it would be most valuable in avoiding losses and reducing load on other transmission and distribution equipment if it were spread out through the load pocket, preferably behind the meters of a large number of customers.

Figure 7 depicts the relationship between gross load in the Marlborough area, the net load after adding 250 MW of solar to the system, and the load that Eversource's runs suggest could be met by the transmission system following the most restrictive second-contingency event. I estimated the threshold as the difference between the ISO-NE 2016 extreme forecast for the load pocket in 2023 and the maximum capacity that the Eversource analysis indicates would be needed to alleviate overloads at that load level under a second contingency. Figure 7 uses the load shape for the central Massachusetts ("CMA") subarea, using the hourly load forecasts from the 2017 CELT for the 2023 normal peak day, scaled to a load-pocket extreme peak load of 469 MW. As I note in Section III above, that peak forecast is poorly documented and almost certainly overstated. The evening load is unlikely to shift upward on an extreme day by as much as the midday peak, so the evening load in Figure 7 may be overstated. Indeed, ISO-NE indicates that summer peak exposure is concentrated "between Hour Ending 14 and Hour Ending 18" (SUD-N-13(S-1)b).

Figure 7: Solar and Storage Requirement,
Based on 2017 CELT 90/10 Load for 2023



ISO-NE projects that the CMA region would see its maximum demand at hour ending 14, but load on a normal peak day remains high throughout much of the day.

Eversource reports that the 90/10 peak will usually occur between 1 PM and 6 PM. (SUD-N-13(S-1)b) I used NREL's PVWatts tool to estimate hourly output, using energy-maximizing south-facing solar arrays; if the panels were installed facing further west, the peak output would shift later in the day, when it would be more valuable.[28] The result is a net load that is flat until hour 14 (the hour ending at 2 PM) and then rises throughout the evening (blue dashed line). The storage output (orange dashed line) then picks up in hour 16 and continues to support load through the evening.

While it is true that solar could not reduce demand in the evening hours, solar paired with storage could yield the required net demand reductions. To simplify Figure 7, I have not shown the charging of storage, but there would be ample energy over night and in the sunny morning hours to recharge the storage equipment.

Q: Would other combinations of solar and storage work?

A: Other combinations of solar and storage are possible but at different costs. As the markets for solar, storage, and their combined installation evolve, so too will the optimal mix of the two resources. A solution that relied 100% on storage would cost more than one that relied on a mixture of solar and storage because of the better economics of solar today. As LEI notes, a pure solar solution is infeasible given the possibility of an evening contingency on an extreme-peak day. Figure 8 depicts how the need for storage capacity would rise as installed solar capacity fell.

[28] Utility incentives and time-of-use rates would both encourage this solar orientation.

Figure 8: Alternative Portfolios

Installed Solar (MW)	Required Storage (MW)	
	(MW)	(MWh)
250	159	638
200	175	699
150	202	808
100	249	997
50	309	1234
0	370	1480

All these values would be reduced by load reductions from demand-response, rate design, and targeted energy-efficiency efforts.

Q: What does this imply about the potential benefits of solar and storage?

A: This means that the storage that is deployed in the region can be used for other economic applications for most of the year, while the bulked-up transmission system would provide few benefits outside of a few peak hours. The solar would keep generating zero-emissions energy year-round, storage could be used for energy time shifting, demand charge management, ancillary services, microgrid, local reliability, among other possible applications.

Q: Is there enough space for 250 MW of solar in the Marlborough load pocket?

A: Yes. I estimated the potential for rooftop solar for an approximation of the load pocket, consisting of all the towns of Marlborough, Southborough, Westborough, Northborough, Stow, Hudson, Berlin, Shrewsbury, Grafton, and 21% of Framingham. This approximation includes some parts of some towns outside the load pocket, but excludes other towns (Ashland, Hopkinton, Dover) partly or entirely served from the load pocket.

There is approximately 565 MW of rooftop solar capacity in the approximated load pocket, using data from Google's Project Sunroof. Even if this assessment is overstated by a factor more than 2.0, there is still enough rooftop solar to provide 250 MW of DC capacity that would provide reliability in the load pocket with minimal storage and no other distributed resources. ISO-NE allocated only 7 MW of behind-the-meter solar to load pocket for the 2016 CELT, so most of this potential is untapped.

Figure 9 depicts my rough town-level estimates for rooftop solar for towns within the approximate load pocket. Due to data availability issues, assessment of many towns required partial interpolation or scaled comparison to other comparable towns with better data. For these extrapolations, I assumed that solar potential (which includes space on non-residential buildings) scales with the number of households.

Google defines a "viable" roof as one receiving "at least 75% of the maximum annual sun in the county," which is 974 kWh/kW for Middlesex County and 983 kWh/kW for Worcester County.

Figure 9: Solar Potential Estimate by Town

	House-holds	Sunroof Data Coverage	1,000s of Roofs	Viable Roofs	1,000s Viable Roofs	Roof Area (M sq ft)	Capacity (MW DC)	Energy (GWh)
Stow	2,338	0	2.2	58%	1.3	1.3	18	20
Hudson	7,746	0	7.3	58%	4.3	4.2	60	67
Berlin	1,038	0	1.0	58%	0.6	0.6	8	9
Marlborough	15,730	0	14.8	58%	8.7	8.6	122	137
Northborough	5,079	0	4.8	58%	2.8	2.8	39	44
Westborough	6,980	0	6.6	58%	3.8	3.8	54	61
Southborough	3,266	84%	3.8	63%	2.4	3.0	41	47
Grafton	6,447	33%	6.1	69%	4.2	3.9	57	65
Shrewsbury	13,014	73%	11.5	70%	8.1	7.9	112	127
Framingham (21%)	5,565	62%	3.7	64%	2.4	3.7	3.7	3.7
Pocket Total	67,203		62		38	40	565	637

Sources: from Google Project Sunroof, except for number of households by town.

The capacity values in Figure 9 (and Figure 10) are in terms of the direct-current output of the panels. I convert that capacity to hourly output in alternating-current megawatts below, accounting for inverter losses and sun angle.

This estimate does not include any ground-mounted solar PV arrays which could potentially offer hundreds of MW of solar capacity, at unused but capped landfills, highway medians, and the like.

Q: How was the rooftop solar potential estimate calculated?

A: The estimate was calculated using data directly from Google's Project Sunroof for the towns in which Project Sunroof has coverage and interpolated data for the areas in which no direct estimates were offered. The towns of Southborough, Grafton, Shrewsbury and Framingham are partially covered by Project Sunroof. While the other towns in the load pocket are not analyzed by Google, other comparable towns in the area are assessed. I use Project Sunroof data for seven comparable towns outside in eastern Massachusetts to find the number of viable roofs and roof area per household. Figure 10 depicts the number of households in each town from the 2010 Census as well as relevant statistics from Project Sunroof on the number of viable rooftops and their area. Since preparing this estimate, I have learned that Ashland and Dover are served from the West Framingham substation, making this comparison group even more appropriate than I originally believed.

Figure 10: Solar Potential Estimates for Comparable Towns

	Households Covered by Sunroof	Sunroof Data Coverage	1,000s of Roofs	Viable Roofs	1,000s Viable Roofs	Roof Area (M sq ft)	Capacity (MW DC)	Energy (GWh)
Lexington	11,541	99%	10.2	56%	5.7	5.5	77.7	87.0
Dover	1,891	99%	2.4	50%	1.2	0.9	12.8	14.1
Sherborn	1,427	99%	1.8	48%	0.9	0.6	8.7	9.5
Ashland	6,702	99%	5.1	59%	3.0	3.1	44.5	50.3
Needham	10,519	99%	9.8	59%	5.8	5.8	81.9	92.6
Wellesley	8,544	93%	7.6	45%	3.4	3.5	49.2	55.1
Natick	4,877	95%	10.4	55%	5.7	6.4	91.4	102.0
Southborough	2,743	84%	3.2	*63%*	*2.0*	*2.5*	*34.7*	*39.5*
Grafton	2,127	33%	2.0	*69%*	*1.4*	*1.3*	*18.9*	*21.5*
Shrewsbury	9,500	73%	8.4	*70%*	*5.9*	*5.8*	*81.7*	*92.7*
Framingham	16,430	62%	10.9	64%	7	11	156	177
Household-weighted Average				58%	5.1	6.0		

In this region approximately 58% of all assessed roofs are viable for solar panels, and each of those rooftops is approximately 1,000 square feet. This allows for an average of 14 kW per household with an average capacity factor of 13%. The

14 kW figure averages in a significant amount of rooftop space on commercial or industrial facilities.

I assume that the towns within the load pocket are comparable to those outside of it both with regard to general viability (e.g. unshaded), rooftop size, and orientation. I further assume that the ratio of rooftops to census households is roughly equal from the Project Sunroof sample to the load pocket.

Q: What is Google Project Sunroof?

A: Google Project Sunroof uses satellite imagery and Light Detection and Ranging ("LIDAR") data from its Google Maps and Google Streetview projects to develop regional estimates of solar capacity with building-level granularity. It uses the imagery data to estimate the size, pitch, and orientation of building rooftops and then applies assumptions about insolation, panel efficiency, and other factors to estimate annual energy production placed on each roof.[29]

Q: Are there reasons to believe that Project Sunroof may underestimate solar potential in the load pocket?

A: Yes. Project Sunroof estimates a lower capacity factor than assumed by LEI and also found fewer viable rooftops (and less capacity and energy) than a tool developed for the City of Cambridge.

LEI assumed that solar in the load pocket would have an annual capacity factor of approximately 15%, based on NREL data, while I used a 13% capacity factor implied by the Project Sunroof data. While this may seem like a modest difference, the 250 MWs of capacity would generate 43.8 GWh less using the Project Sunroof estimates, compared to the LEI/NREL estimates. The capacity factor does not directly affect the potential for reducing peak loads, but it does

[29] The full methodology paper can be found at: https://static.googleusercontent.com/media/www.google.com/en//get/sunroof/assets/data-explorer-methodology.pdf

affect the energy benefit of the solar installations. I may have been conservative in my assumptions.

Project Sunroof underestimates solar capacity potential compared to another solar capacity mapping project developed by Mapdwell and the City of Cambridge. The latter mapping tool was developed by the MIT Sustainable Design Lab for Cambridge and has since expanded to several other cities. While it is hard to directly compare how these tools would compare in the Marlborough load pocket, Google's mapping tool anecdotally offers more conservative estimates. In Cambridge, Project Sunroof estimates that rooftop solar could provide 221 MW of capacity while the City's tool estimates potential capacity of 326 MW, as shown in Figure 11.

Figure 11: Comparison of Solar Potential Estimates for Cambridge

	Energy (GWh/yr)	Capacity (MW)
Mapdwell	366	326
Google Project Sunroof	252	221
Difference	114	105
Difference	45%	48%

Q: Is it technically possible to deploy 160 MW of energy storage in the load pocket?

A: There are two components to technical feasibility: on-site footprint requirements and production capability of the storage industry. Behind the meter storage has a small footprint compared to behind-the-meter solar because it takes up a volume rather than a plane and need not have any particular orientation or exposure. A common 18 kW system is about the size of a school locker; a 1 MW array of Tesla Powerpacks would require a 15'x 20' space in a utility room or on an outdoor pad.

The storage industry itself would be able to provide the target 160 MW of storage equipment over the next several years, as well. GTM Research forecasts that annual storage deployment will be 327 MW in 2017, rising rapidly to 2,528

MW in 2022.[30] Storage for the Marlborough pocket would require about 1.8% of the roughly 8,600 MW of stationary battery storage expected to be deployed from now until 2022. GTM expects that California will dominate the storage market, while Massachusetts and four other states (Hawai'i, Arizona, New York and Texas) will "battle for second place, with each market forming a significant chunk of deployments through 2022, driven by a combination of state mandates, resource-planning-related utility procurement, and the increasingly favorable economics of behind-the-meter storage projects." (*ibid*) If California uses half of GTM's projected storage installations and the rest is divided five ways, Massachusetts would deploy 860 MW of storage.

The solar build-out would also help the Commonwealth reach its energy-storage target of 200 MWh by the beginning of 2020 and the 600 MW of storage capacity recommended by 2025 in the *State of Charge* report from DOER.[31]

Q: What would be the net cost of 250 MW of solar and 160 MW of storage?

A: Behind-the-meter solar is cost-effective today. The Massachusetts Energy Storage Initiative also found that storage is cost-effective.[32] Therefore, 250 MW of solar and 160 MW of storage would break even or yield modest profits, compared with a cost of $91 million for the Project.

Installed solar capacity in Massachusetts has grown rapidly over the past decade. Over the past decade, 71,953 solar projects have been installed comprising 1,699 MW of capacity. In 2016, 340 MW of solar power was installed and another 304 MW was installed between January and June 2017.[33] Most of these projects

---

[30] "U.S. Energy Storage Monitor: Q3 2017," Executive Summary, GTM Research, September 2017, p. 11; www.greentechmedia.com/research/subscription/u-s-energy-storage-monitor#. These values appear to be demand-limited, rather than supply-limited.

[31] www.mass.gov/eea/pr-2017/doer-sets-200-megawatt-hour-energy-storage-target.html; *State Of Charge*, Massachusetts Energy Storage Initiative, 2016, pp. xviii; www.mass.gov/eea/docs/doer/state-of-charge-report.pdf.

[32] Ibid., pp. xiii, xvi, Section 5.5.

[33] http://www.mass.gov/eea/docs/doer/renewables/installed-solar.pdf

would not exist if the economics of solar were not favorable. The economics of installing solar should continue to be favorable as the market transitions from the Solar Renewable Energy Credit incentive programs to the SMART program, which is designed to support an additional 1,600 MW of new solar generating capacity.

The *State of Charge* report (referenced in footnote 31) found storage is cost effective today when considering ratepayer benefits like energy cost reduction, reduced peak capacity requirements, and deferral of transmission and distribution capacity investments. More specifically, the report notes that "1,766 MW of new advanced energy storage would maximize Massachusetts ratepayer benefits...This optimized amount of storage is estimated to cost $970 million to $1.35 billion…The modeling results indicate that there will be a total storage value of $3.4 billion, where $2.3 billion comes from system benefits, i.e. cost savings to ratepayers, and $1.1 billion in market revenue to the resource owners" (xi). Storage has a positive total resource cost test value but a negative participant test value.

Q: What benefits would a 250 MW solar array yield?

A: Unlike the Project, 250 MW of behind-the-meter solar would yield many benefits. Fully deployed, these systems would generate approximately 282 GWh per year, displacing 105,000 short tons of CO_2 annually.[34] They would also provide a range of benefits for the host facilities and Massachusetts energy consumers, including the resiliency benefits I discussed above.

Q: What would the benefits and costs of 160 MW of energy storage in the Marlborough load pocket?

A: Assuming that the benefits offered in the Marlboro load pocket are proportional to those reported in the *State of Charge* report for Massachusetts as a whole, the end-user benefits could be worth $100 million and system benefits worth $207 million while costs would be in the range of $88 million to $122 million. Table 8 scales

[34] ISO-NE calculates average emissions rates of 747lbs/MWh for 2015, the most recent data available (Table 1-1 in https://www.iso-ne.com/static-assets/documents/2017/01/2015_emissions_report.pdf)

down the estimates in the *State of Charge* report to the scale of installations that would be adequate for the load pocket.

Table 8: Costs and Benefits of Distributed Storage

	MA Total	Marlborough Load Pocket
Storage Quantity (MW)	1,766	160
Cost Low ($M)	967	88
Cost High ($M)	1,350	122
End User Benefits ($M)	1,100	100
Total System Benefits ($M)	2,289	207
Energy Cost Reduction	*275*	*25*
Reduced Peak Capacity	*1,093*	*99*
AS Cost Reduction	*200*	*18*
Wholesale Market Cost Reduction	*197*	*18*
T&D Cost Reduction	*305*	*28*
Integrating Renewables Cost Reduction	*219*	*20*

The T&D savings estimated in Table 8 do not include the avoided cost of the Project.

The storage capacity is likely to be comparable in cost to the Project, but would provide a plethora of additional benefits.

Q: What are the other benefits of combined solar and storage systems?

A: These systems can provide consumers with better price certainty and better reliability than system upgrades further up the system. The proposed transmission line would offer added transmission voltage reliability but not distribution level reliability. Behind the meter storage in homes and businesses can provide resilience to winter storms, fallen trees, and other distribution level circuit failure.

Q: What might these resilience benefits be worth to end-users?

A: The specific value of added reliability is difficult to measure and depends on the value of electricity to each customer. A report by Lawrence Berkeley National Lab found interruption costs ranging from a few dollars per kWh to $2,401/kWh depending on customer class and outage duration.[35] The Electric Power Research Institute found outages cost up to $18,000 per hour per customer, depending on duration and commercial sector.[36]

The Marlboro load pocket, along with much of the I-495 corridor, has businesses that may have uncommonly high interruption costs. Firms in Marlborough itself include advanced manufacturing for products as diverse as missile systems and salad dressing.[37]

Q: Is solar the only form of distributed generation that may be viable in the load pocket?

A: Other forms of distributed generation, such as combined heat and power, may also be viable for some facilities in the load pocket.

D. Experience with Targeted Load Reductions

Q: Have utilities used targeted load reductions, from energy-efficiency measures, demand-response and distributed generation?

A: Yes. There are several examples of that approach, a few of which I will describe here.

In 2014, Consolidated Edison ("Con Edison") initiated its Brooklyn Queens Demand Management project to defer a new substation. As of mid-2017, Con Edison had procured 52 MW of demand reductions and 17 MW of distributed resource investments.

---

[35] Michael J. Sullivan, Matthew Mercurio, and Josh Schellenberg, "Estimated Value of Service Reliability for Electric Utility Customers in the United States," LBNL-2132E, June 2009

[36] "The Cost of Power Disturbances to Industrial & Digital Economy Companies," David Lineweber and Shawn McNulty, for EPRI's Consortium for Electric Infrastructure for a Digital Society, June 29, 2001, p. 2-4; www.epri.com/#/pages/product/000000003002000476/.

[37] http://marlboroughedc.com/about-marlborough/key-industries/.

A 2015 report by the Northeast Energy Efficiency Partnerships ("NEEP") lists several additional targeted efforts to avoid transmission and distribution investments.[38] One interesting result from this report is that the Vermont targeted energy-efficiency programs increased participation by two to four times and per-customer savings by 20%–30%, compared to Vermont's already aggressive statewide program. (NEEP report p. 49).

The NEEP report also describes National Grid's targeted energy efficiency and demand response program targeted in the municipalities of Tiverton and Little Compton, Rhode Island. The peak-load reductions deferring the need for a new feeder.[39]

In California, targeted energy efficiency is one of the solutions that is being deployed in an effort to offset potential reliability impacts caused by a leak at Southern California Gas Company's ("SoCal Gas") Aliso Canyon Storage Facility. SoCal Gas has committed $145 million in targeted energy efficiency measures to households in the Los Angeles to offset reliability impacts caused from the leak. Targeted households will receive installed energy-efficiency measures, reducing household demand by 10%.[40]

Q: Does this conclude your testimony?

A: Yes.

---

[38] Energy Efficiency as a T&D Resource: Lessons from Recent U.S. Efforts to Use Geographically Targeted Efficiency Programs to Defer T&D Investments, Chris Neme and Jim Grevatt, January 9, 2015. http://www.neep.org/sites/default/files/products/EMV-Forum-Geo-Targeting_Final_2015-01-20.pdf

[39] Accessed on 10/2/2017 at 4:18 P.M. Available at: https://www.cesa.org/about-us/member-news/newsitem/exploring-the-benefits-of-distributed-solar-in-rhode-island.

[40] "CPUC Continues to Support Conservation Efforts to Ensure Reliable Energy to Southern California Following Aliso Canyon Leak," California Public Utilities Commission, April 21, 2016. docs.cpuc.ca.gov/PublishedDocs/Published/G000/M160/K095/160095970.pdf.