COMMONWEALTH OF MASSACHUSETTS

ENERGY FACILITIES SITING BOARD

NSTAR for Approval to Construct a Transmission Line Pursuant to G.L. c. 164, § 69J, for Exemption from the Zoning Bylaws of Carver, Plymouth, Bourne and Barnstable Pursuant to G.L. c. 40A, § 3 and for Authority to Construct a Transmission Line Pursuant to G.L. c. 164, § 72	)	EFSB 10-2/ D.P.U. 10-131, 10-132

DIRECT TESTIMONY OF

PAUL CHERNICK

ON BEHALF OF

THE TOWN OF SANDWICH

Resource Insight, Inc.

APRIL 5, 2011

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 an SB degree from the Massachusetts Institute of Technology in June 1974 from the Civil Engineering Department, and an SM degree from the Massachusetts Institute of Technology in February 1978 in technology and policy. I have been elected to membership in the civil engineering honorary society Chi Epsilon, and the engineering honor society Tau Beta Pi, and to associate membership in the research honorary society Sigma Xi.

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, after 1986 as president of PLC, Inc., and in my current position at Resource Insight. 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 Exh. SAN-PLC-2.

Q: Have you testified previously in utility proceedings?

A: Yes. I have testified more than two hundred and fifty times on utility issues before various regulatory, legislative, and judicial bodies, including utility regulators in thirty states and five Canadian provinces, and two U.S. Federal agencies. This testimony has included the review of many utility-proposed power plants and purchased-power contracts.

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

A: Yes. I have testified in approximately 47 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.

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

A: Yes. I have testified in approximately 10 dockets before the Board and its predecessor, the Energy Facilities Siting Council, from Boston Edison's load forecast in 1978 to the Greater Springfield Reliability Project in 2010.

II. Introduction

Q: On whose behalf are you testifying?

A: I am testifying on behalf of the Town of Sandwich (the “Town” or (“Sandwich”).

Q: What is the purpose of your testimony?

A: I have been asked to review the petition of NStar Electric Company (“NStar”) in the above captioned docket (“Petition”), regarding the need for the Lower Southeastern Massachusetts (“SEMA”) 345 kV Transmission Project (the “Project”) and the relative costs of (1) the Project, (2) keeping the Canal plant (“Canal Plant” or “Canal”) in operation, and (3) contracting for new combustion-turbine generation or demand response. I reviewed the transmission analyses in Section 2 of the Petition, and the economic analyses prepared by Levitan Associates, Inc. (“Levitan”) and included as Attachment 2-1 of the Petition (the “Levitan Report”), all discovery issued in this proceeding, and various ISO New England, Inc. (“ISO” or “ISO-NE”), Federal Energy Regulatory Commission (“FERC”) and Energy Information Administration documents.

Q: After your review of the Petition, what do you conclude?

A: There does not appear to be a need for the Project. As I explain later in my testimony, as long as load in the Tremont East sub-region (Cape Cod, the Islands, and portions of Wareham and Plymouth) is able to tolerate rolling blackouts in the very rare event of sequential loss of the two existing 345 kV lines currently serving Tremont East, the Project is not necessary. In the event of the loss of both units at very high load levels, NStar might need to shed the entire Tremont East load.

NStar asserts that, in the absence of the Project, the Canal Plant would be needed for reliability and would need to run frequently to back-up the transmission system. However, neither of these assertions appears to be correct. Canal has not been run for local reliability purposes since at least August 2009, when NStar and National Grid completed the short-term SEMA transmission upgrades. There is no reason to expect that Canal would be operated for that purpose in the foreseeable future.

While NStar asserts that keeping Canal on line—were that necessary—would be very expensive for customers, it appears that Canal is likely to be supported by market revenues, unless the Canal Plant is required to install some very expensive environmental control, such as a cooling tower. The continued operation of Canal, all else being equal, would reduce market energy and capacity prices.

Finally, if (1) the Canal Plant were to be retired and (2) some need for additional supply were identified in Tremont East, NStar's analysis of the cost of alternatives to the Project overstates the need and almost certainly overstates the costs of alternatives.

Q: Based upon your review of the Petition, what do you recommend to the Board?

A: I recommend that the Board reject NStar's Petition. If NStar believes that some supply need for Tremont East may arise over the next several years, it should establish a multi-party process to determine the least-cost solution for meeting those needs, including enhanced energy-efficiency programs, local renewables, combined heat and power ("CHP"), demand response, and distributed generation. NStar should also be pursuing changes in ISO procedures to ensure that the least-cost solution for a supply constraint can be supported by the same loads that would pay for a transmission solution.

III. Need

A. Load-Forecasting Issues

Q: What load is most important in the evaluation of need for the Project?

A: While NStar and the ISO periodically refer to various measures being needed at particular load levels for New England, "SEMA", or Lower SEMA, the case for the Project is primarily driven by load in an area that NStar has defined as Tremont East.

NStar's transmission analyses use the 90/10 load forecast (i.e., load levels at temperature levels expected only once in ten years), while the economic analysis in the Levitan Report is driven by normal (50/50) load levels.

Q: What is Lower SEMA?

A: NStar defines Lower SEMA as the area previously served by Commonwealth Electric (now the South region of NStar Electric), plus National Grid's Nantucket service territory.[1] I will refer to the NStar part of Lower SEMA as the CommElec region.

[1] Figure 2-1 of the Petition appears to identify a much smaller area as "Lower SEMA."

Q: What is the Tremont East area?

A: Tremont East consists of Cape Cod, Martha's Vineyard, Nantucket, and loads served by four substations in Wareham and Plymouth (SAN-NSTAR-2-6).

Q: Is this a load area that NStar has generally modeled or monitored?

A: No. When asked for historical data on "Tremont East peak load," NStar responded that "The Tremont East interface was not identified and monitored prior to Fall 2009" (SAN-NSTAR-2-9). While NStar has some information on loads at its Tremont East distribution substations (SAN-NSTAR-2-6, 2-9), at least at the time of the CommElec peak, and data on transmission flows, it does not have pre-2010 data on the Tremont East peak loads (SAN-NSTAR-2-9).

Q: How did NStar forecast the Tremont East load?

A: NStar's Tremont East forecast was developed in the following 12 steps:

1. Regressing CommElec annual peak load for 1990–2009, as a function of gross domestic product ("GDP") in the Providence and Barnstable areas,[2] the temperature-humidity index ("THI"),[3] and dummy variables (one effectively eliminating the year 2000, and the other accounting for the effect of peak loads occurring at 4 PM).

---

[2] These may be references to the Metropolitan Statistical Areas for Barnstable (which covers the Cape) and Providence-New Bedford-Fall River (which comprises Rhode Island and Bristol County), but NStar has not clarified this. There are smaller statistical area for both Barnstable and Providence.

[3] NStar used the average of the THI in the two hours preceding the peak. The discovery responses do not specify the location used for the THI data.

2. Forecasting CommElec's load for 2010–19, from the regression equation in step (1), a forecast of local GDP, and THI for either median (50/50) or extreme (90/10) weather.
3. Reducing CommElec's forecast by an estimate of energy-efficiency peak reductions, based on NStar's 10/31/2009 energy-efficiency filing and the historical load factor.
4. Regressing the load of each of the 20 Tremont East substations coincident with the CommElec annual peak, for various periods ending in 2009, as a function of CommElec peak loads and a different set of dummies for each substation, including several effectively eliminating various years or combination of years.[4]
5. Forecasting the load for each Tremont East substation for 2010–2019, from the equations estimated in step (4), the CommElec forecast from step (2), and for three substations, continuation of permanent load changes estimated by dummies in the regressions.
6. Adding "large customer, i.e., step, loads" to certain of the substation forecasts (SAN-NSTAR-2-6a).
7. Summing the Tremont East substation loads.
8. Performing analyses comparable to steps (5) through (7) for all the CommElec substations.

---

[4] The 20 substations are listed as 14 substations with a total of 20 transformers in NStar FERC Form-1 filings. These substations are served directly off the 115 kV and 345 kV transmission lines, stepping down power to 23 kV distribution. NStar may have additional substations served from the 23 kV lines.

9. Computing the ratio of the CommElec forecast to the sum of the CommElec station forecasts.[5]
10. Multiplying the sum of Tremont East substation loads from step (7) by the ratio from step (9).
11. Adding National Grid's forecast of Nantucket 90/10 peak load.[6]
12. Adding additional losses.

Q: Do you have any concerns about this forecasting methodology?

A: Yes. I have concerns about the poor documentation of the forecast, as well as specific problems with the analysis.

Q: What are your concerns with the documentation?

A: In SAN-NSTAR-2-5, NStar was asked for "the derivation of the Company's 50/50 and 90/10 peak load forecast for LSM." In SAN-NSTAR-2-6, NStar was asked for "the derivation of the Company's 50/50 and 90/10 peak load forecast for Tremont East, including the adjustments for committed and continuing energy-efficiency efforts." The responses contained bits and pieces of the derivation, but fell far short of providing the full derivation.

Prior to the March 25, 2011 Technical Session in this proceeding ("Technical Session"), Sandwich informed NStar that questions would be raised regarding "Development of Tremont East load forecast, including (a) treatment of NStar, Cape Light Compact and NGrid (Nantucket) energy-efficiency programs, and (b) effect of energy-efficiency measures at 90/10 peak." Yet at the

---

5 The ratio may reflect differences in estimation procedures.

6 NStar does not know what load National Grid might forecast for Nantucket of a 50/50 load.

Technical Session, NStar was prepared to answer mostly general qualitative questions, and could not provide specifics on the regressions or the efficiency adjustments.

Areas in which the forecast documentation is incomplete include:

- The derivation of the energy efficiency adjustments.
- The amounts or derivation of any of the large customer loads.
- The meaning in the substation regressions of such variables as VALLEY_1_DUM, @TREND*OAKSTREET_DUM, OAKSTREET_EX, and @TREND*MASHPEE_DUM.[7]
- Why a +5-MW dummy used in 2005–2009 in Manomet is applied through 2020, but a −4-MW dummy applied in 2007–2009 for Orleans 119 is not continued.
- The historical data for the regressions.
- The forecasts by substation for the Cape (which might help in understanding the treatment of some obscure variables and the large-load additions).[8]
- Why 28 MW of 2009 downward dummy adjustments for Falmouth in the regressions were not carried into the forecast.
- Why the Oak Street and Mashpee regressions do not have CommElec load as an independent variable, even though the Petition states:

---

7 These variables were used in the regression for the substation bearing their names, except that the OAKSTREET_EXT variable was used in the Mashpee regression.

8 The forecast in SAN-NSTAR-2-6 aggregates the 16 Cape substations.

> Substation forecasts are then developed by simulating the estimated historic relationship between forecasts of the operating region's peak trend and the THI under the extreme weather assumption. A provision is made to account for large step load projects. (p. 2-21)

These omissions make it impossible to review the forecasts in any detail.

Q: What specific problems have you found in NStar's forecast for its share of Tremont East?

A: In addition to the inconsistencies listed above, I have two brief observations and several problems with the treatment of energy-efficiency and other load-reduction programs.

First, NStar appears to have double-counted large-customer loads, since those loads are included in the historical CommElec data, and hence in the CommElec forecast and the substation forecasts driven by the CommElec forecasts.[9] I cannot determine how much this factor matters, due to NStar's limited responses to discovery.

Second, it is not clear that the 5–6% (or about 30 MW) upward adjustment to the Tremont East forecast in step (10) is justified. Without understanding the derivation of the substation load forecasts in the rest of the CommElec territory, it is impossible to determine whether the discrepancy between the CommElec forecast and the sum of the substation load is properly allocated to Tremont East.

Q: Do you have any concerns about the Nantucket forecast?

---

9 The recognition of individual large loads may be appropriate in projecting upgrade needs for individual substations, since the exact location of load within the CommElec territory is critical in planning at the substation level.

A: Yes. NStar has not provided any source document or other description of the derivation or meaning of the Nantucket forecast. When I was last involved in reviewing the load forecast of Nantucket Electric Company (now part of National Grid), the summer peak load on Nantucket occurred due to summer heating load. The typical Nantucket peak occurred when the summer homes and rental units were occupied and temperatures dropped due to evening fog and cold air flowing in from the North Atlantic. Much of the seasonal housing was electrically heated (which made sense, given the small annual heating load).

If Nantucket's peak loads (which are relevant for assessing the reliability of supply to the island, in the event of the loss of either of the 46kV lines from Barnstable and Harwich) are still driven by evening heating loads, the Nantucket peak load is not additive to the NStar Tremont East load on very hot late afternoons.

Q: What are your concerns with NStar's treatment of load reduction from energy efficiency and other programs?

A: NStar appears to have overstated load growth in the following ways:

- understating projected energy-efficiency efforts in Tremont East;
- failing to reflect the higher level of energy savings expected at higher temperatures;
- ignoring the effect of net metering and small renewables;
- ignoring the potential for reducing load through voltage reductions, following a first contingency; and
- ignoring the effects of improved rate designs that would result from deployment of smart meters.

Q: How did NStar understate projected energy-efficiency efforts in Tremont East?

A: I do not know exactly how NStar estimated energy-efficiency in the CommElec territory, since NStar failed to provide that information in response to clear requests in discovery (SAN-NSTAR-2-4 and 2-6) and in the Technical Session. In any case, the energy-efficiency adjustment that NStar allocates to Tremont East is woefully understated.

I tried to go back to NStar's filing in DPU 09-120 to reproduce NStar's projection of energy-efficiency effects for CommElec, but I derived higher values, as shown in Table 1.[10] The second column shows the amount of energy-efficiency used in the Petition, while the rightmost shows the sum of the Cape Light Compact ("Compact") plans and an allocated portion of NStar's planned savings, covering the non-Cape portions of NStar's Tremont East territory. The plans announced by the program administrators are more than double the savings assumed in the Petition. This difference arises largely from the fact that the Compact projects higher savings than the Petition's entire projection for the CommElec area (which would include the Compact's programs and about 12% of NStar's non-Cape load).

[10] I tried other approaches, including allocating just NStar's projected savings over its three operating regions, ignoring the Compact's savings, but I still derived higher savings values than NStar reports.

Table 1: Estimates of Planned Tremont East Cumulative Energy-Efficiency Savings for 2010–2012, excluding Nantucket (MW)

	NStar Forecast[b]				NStar Filed Plan[d]				
		Allocated Efficiency							
	Comm-Elec[a]	Tremont East	Cape	**Cape Compact Plans[c]**	NStar	Non-Cape Comm-Elec Allocation[e]	**Total Comm-Elec Projection[f]**	**Tremont East Share of NStar[g]**	**Total Tremont East**
2010	7	4	3	7	43	5	12	0.8	7.6
2011	16	9	7	16	107	13	29	2.0	18.4
2012	27	15	13	28	183	21	50	3.4	31.8

NOTE: Savings at meter increased by 8% to transmission level.

[a]IR SAN 2-4

[b]Ratios from IR SAN 2-6: 55% for Tremont East, 47% for Cape.

[c]from DPU 09-119, Table 3.2.i and Cape Light Compact response to ISO-NE Survey of Planned Energy Efficiency.

from NStar Exhibit 3, DPU 09-120

[d]from NStar Exhibit 3, DPU 09-120

[f]Sum of Cape Compact Plans and Non-Cape CommElec Allocation.

[g]15.7% ratio from substations loads in IR SAN 2-6.

Q: Does the energy-efficiency projection in the Petition continue this under-statement of savings beyond the end of the current program plans in 2012?

A: The Petition assumes that annual savings rise from 2012 to 2016, and then drop off rapidly, as shown in Table 2. Those savings never reach even the 2010 levels in the program plans filed in DPU Docket No. 09-119 and 09-120, or half the 2012 levels.

By 2012, the Compact and NStar programs are projected to be saving an incremental 13.4 MW annually, nearly 50% more than the Petition's 6 MW.

Table 2: Extrapolation of Post-2013 Energy-Efficiency Savings (MW)

	Petition Allocation to Tremont East		Program Plans		Extrapolated: *Per Petition*		Extrapolated: *Continue 2012 Incremental*	
	Cum.	Annual	Cum.	Annual	Annual	Cum.	Annual	Cum.
2010	3.9	3.9	7.6	7.6				
2011	8.8	4.9	18.4	10.8				
2012	14.8	6.0	31.8	13.4				
2013	21.4	6.5			14.6	46.4	13.4	45.3
2014	28.5	7.1			15.9	62.3	13.4	58.7
2015	35.0	6.5			14.5	76.9	13.4	72.2
2016	41.5	6.5			14.5	91.4	13.4	85.6
2017	47.5	5.9			13.3	104.6	13.4	99.0
2018	52.3	4.8			10.8	115.4	13.4	112.5
2019	55.5	3.2			7.1	122.5	13.4	125.9

Q: Have you been able to similarly review and correct the treatment of energy-efficiency in the load forecast for Nantucket?

A: No. NStar has provided only a final 90/10 forecast for Nantucket. As noted above, it is not even clear that this forecast is for a peak load coincident with the Tremont East load, let alone that it has been appropriately adjusted for National Grid's energy-efficiency programs.

Q: How did you extrapolate the savings in Table 2?

A: I used two approaches for projecting incremental efficiency savings, both shown in Table 2. In the first, I project Tremont East savings as the Petition's incremental projection for Tremont East, increased by the ratio of the program plan projection for 2012 to the Petition's projection for 2012. In the second, I simply continue the planned 2012 incremental savings.

Each of these approaches produces savings in Tremont East about 25 MW greater than those underlying the Petition for 2013, and 67–70 MW for 2018.

In addition to the NStar and Compact programs, load will be reduced starting in 2013 by the Federal phase-out of standard-efficiency incandescent lamps. The ISO load forecast includes a 1% drop in energy in 2013 due to this requirement, growing to 1.6% in 2019.[11]

Q: Do you have any additional comments on the energy-efficiency savings?

A: Yes. The demand savings in the NStar and Compact energy-efficiency plans appear to be computed using the on-peak measurement approach that the ISO uses in assigning capacity value to energy-efficiency in the forward capacity market: average savings in the period 1 pm to 5 pm, in the months of June–August. Some of the savings may be computed using the ISO's seasonal-peak method, which uses the average savings in hours within 5% of the forecasted peak load. Both of these would be computed for average summer weather distributions.

Both the seasonal and on-peak average savings are computed for loads that are less than the normal annual peak, let alone the extreme weather of the 90/10 peak. At the peak hour, either normal or 90/10, cooling equipment (as well as associated ventilation and some refrigeration equipment) would be working harder than in the average on-peak hour, or even in the highest 5% of hours, in a normal year. In general, the high-efficiency cooling equipment installed by the

[11] "A General Discussion of the Forecast Model Structures of the ISO New England Short and Long Run Energy and Seasonal Peak Forecasts for the 2010 CELT Report and 2010 Regional System Plan," ISO-NE, April 2010, p. 5.

efficiency programs will produce greater savings at the 90/10 peak than the 50/50 peak, and both will produce greater savings than in the top 5% of normal hours or the average summer peak hour.

Q: How did NStar account for the increased load reductions from energy-efficiency measures at the 90/10 peak hour, compared to normal summer weather?

A: NStar ignored this effect (SAN-NSTAR-2-6a).

Q: How much effect might net metering and small renewables have on loads in Tremont East?

A: That depends on how much additional distributed generation is installed in Tremont East. The Levitan Report mentions 2 MW of small wind turbines, which are also listed in the 2010 CELT. The response to SAN-NSTAR-2-7 lists large amounts of applications for net metering in Tremont East, including applications for a 17.5 MW wind project and 2.9 MW of other wind and solar projects under evaluation, and more than 500 approved applications totaling about 59 MW, of which about 13 MW is on line and 36 MW is still in the pipeline.[12] Most of the projects for which SAN-NSTAR-2-7 provides any dates at all had their applications acknowledged in later 2009 or 2010, so little of the

[12] In addition, the Cape & Vineyard Electric Cooperative, Inc. intends to award through a public procurement process the development of at least 15 MW of ground-mounted solar on Cape Cod and Martha's Vineyard that is not accounted for in the response SAN-NSTAR-2-7.

on-line capacity would have been reflected in the regression analysis for CommElec or the Tremont East substations.[13]

The ISO-NE interconnection queue lists two wind projects that would connect to the Valley substation in Tremont East, totaling 24.8 MW.

Q: Are there any larger renewable resources in Tremont East that would reduce the loads on the lines serving Tremont East?

A: There are no such resources in service at the moment, but about 230 MW of Cape Wind are under contract to National Grid and is likely to enter service within the next couple years. This phase of Cape Wind would produce an average of about 90 MW, which would be delivered in Tremont East. The ISO's modeling of 20% renewables includes six times this much wind capacity off -shore from Tremont East.[14]

Q: How does NStar treat Cape Wind?

A: The economic analysis in the Levitan Report assumes the operation of increasing amount of Tremont East wind (from Cape Wind or other projects), rising from 50 MW in 2013 to 450 MW in 2017 (Levitan Report, p. 8). The critical reliability analysis in Section 2 of the Petition (Dispatch 3) assumes that Cape Wind and all other Tremont East renewables are off-line at the 90/10 peak hour.

---

13 The 28 MW drop in Falmouth load in the substation regressions may be partially due to net-metering installations, but NStar does not project that drop to continue.

14 Wayne Coste, "Preliminary Results for 2010 Economic Study Request," Planning Advisory Committee, ISO-NE, February 16, 2011.

Q: Does NStar have any idea what amount of Cape Wind would typically be operating when high on-shore temperatures would be generating the 90/10 peak?

A: No. NStar presents no basis for assuming that zero wind output from Cape Wind, or other wind generation in Tremont East, would be common, or even plausible, under these weather conditions, and admits that it has no "estimate of the average generation output expected from Cape Wind at the times of typical Tremont East annual peak load." (SAN-NSTAR-2-27)

Q: What is NStar's basis for ignoring Cape Wind in its reliability analyses?

A: The Company explains that "from a transmission planning perspective, Cape Wind has not yet bid into the Forward Capacity Market and, to the best of the Company's understanding, it does not yet have firm capacity commitments to supply generation during peak periods" (SAN-NSTAR-2-27).

Q: Is this a valid basis for ignoring Cape Wind?

A: No. Any resource expected to enter service after June 2013 would not yet have bid into the Forward Capacity Market.

Q: Does NStar's analysis incorporate any effects on peak load of improved rate designs made possible by the deployment of smart meters?

A: No.

Q: Does NStar consistently use the Tremont East load forecast documented in SAN-NSTAR-2-6?

A: No. The Tremont East load forecast used in Petition Table 2-2 and the Levitan Report (Table 7) is about 2 MW higher than the forecast provided in SAN-NSTAR-2-6.

B. *Probability of Double Outage*

Q: How likely is the simultaneous outage of both the existing 345 lines that serve Tremont East?

A: In the thirty-nine years since the second line was added, in 1972 (SAN-NSTAR-2-71), the two lines have been out of service simultaneously only once (SAN-NSTAR-2-69).

According to the "Joint Report of ISO New England, National Grid and NSTAR Electric on the Cape Cod Outage of December 1, 2003" (December 19, 2003), Line 331, which feeds Line 322, was taken out of service due to brush fires. Following their procedural guidelines, the operators opened a breaker at the Canal station "but were unaware that with the breaker open, the Canal substation was now configured so that if the Canal #2 generator shut down, it would cause the remaining 345 kV line (the 342 line) to go out of service." (Joint Report, p. 4). As a result,

> Power was interrupted to approximately 300,000 customers (approximately 630 megawatts of load) starting at 6:21 p.m. Operators acted immediately to restore power to the area. The first customers had power restored approximately 20 minutes later at 6:44 p.m. Operators had restored approximately 25% of load by 7:08 p.m., approximately 75% by 7:33 p.m. and approximately 99% by 7:45 p.m. Power was restored to the last customers at 8:15 p.m. (Joint Report, p. 5)

Power was interrupted to significant numbers of customers for about 90 minutes. That is about 0.00044% of the time since the second line was installed.

Q: What would be the effect of a second occurrence of sequential outages of the two 345 kV lines, if the Canal Plant is on line?

A: Nothing. One Canal unit and the 115 kV lines can serve the Tremont East load.

Q: What would be the effect of a second occurrence of sequential outages of the two 345 kV lines, if the Canal Plant is not on line?

A: That depends on the load level. At loads (net of renewable and distributed power) up to about 460 MW, the 115 kV lines can handle the entire Tremont East load. Another 39 MW of Tremont East load can be transferred to other substations, and 19 MW of diesels and combustion turbines are in service on the islands, 16.5 MW of which NStar assumes will be available at any one time.[15] The Levitan Report (Table 7) also estimates about 16 MW of real-time demand response would be available in Tremont East. Until Tremont East net load exceeds about 532 MW, even loss of both 345 kV lines would require no load shedding.

Q: What load levels have been reached in Tremont East in recent years, without operation of either Canal unit?

[15] The Levitan Report further discounts this capacity by 20%, apparently double-counting forced outages.

A: According to SAN-NSTAR-2-33, Tremont East reached a load of 606 MW in August 2009 in hours with no Canal generation.[16]

C. Load Transfers and Load Relief

Q: Can any load be shifted out of the Tremont East area, in response to an outage on one of the 345 kV lines?

A: Yes. According to SAN-NSTAR-2-60, "Approximately 39 MVA of load can be transferred out of the Tremont-East area in response to a 1st contingency event." These are the entire load on the Manomet substation and one Wareham feeder, plus part of another Wareham feeder. NStar does not specify whether this load estimate is for 50/50 or 90/10 load. From the data in SAN-NSTAR-2-33, the power factor in Tremont East averages about 99.7% when neither Canal unit is operating, so the Tremont East load can be reduced by about 39 MW after the first 345 kV line is lost.

Q: Are there any dispatchable resources in Tremont East, other than Canal?

A: Yes. There are five diesels totaling about 13.7 MW on Martha's Vineyard (as backup to the 23 kV cable serving the island) and two combustion turbines totaling about 5.2 MW at Bunker Road, Nantucket (also as transmission backup). Of these 18.9 MW, NStar counts 16.5 MW as being available, due to

---

16 Curiously, SAN-NSTAR-2-33 never reports zero output from Canal. In many hours, output from each unit is reported as 0.022889 MW. The EPA emissions database show no fuel use or emissions at Canal in those hours, so the units appear to have been entirely offline in those hours.

round-off and an allowance for one of the seven units to be unavailable. The Levitan Report further discounts that capacity 20%, counting only 13.2 MW.

NStar also counts about 20 MW of real-time demand response in Tremont East, of which about 16 MW is assumed available.

Another 11 or 12 MW of diesels are mothballed at Bunker Road, owned by National Grid. Since each of the transmission lines to Nantucket can carry about 35 MW (Order in DPU 04-10, p. 6), National Grid will need to bring these units back into service as Nantucket load exceeds about 40 MW, if it is to maintain service following a first contingency. According to SAN-NSTAR-2-6, National Grid projects that the 90/10 forecast will exceed this level in 2011; that event would require the reactivation of some of the diesels.

Q: Are there any non-dispatchable resources in Tremont East that would reduce loading on the 115 kV transmission lines following outages on both 345 kV lines?

A: Yes. I discussed those in Section III.A, as contributors to reducing net load in Tremont East and hence the loading on the transmission lines.

D. Load Shedding

Q: Would load shedding be a disastrous response to simultaneous loss of the two 345 kV lines?

A: No. Prior to the short-term upgrades, the ISO was concerned that the loss of both lines without Canal in operation could bring down the transmission system in a large part of SEMA, potentially requiring lengthy restoration procedures. Following the completion of those upgrades in the summer of 2009, the prospect of unlikely, limited, short-duration outages is no longer problematic. As the ISO concludes:

> As a result of the improvements that result from the short term upgrades, posturing the system after the occurrence of a first contingency for post second contingency load shedding becomes a viable option and much less load will need to be shed in the event of a second contingency in order to keep power lines within their ratings. The ISO and NSTAR will be able to posture the system after a first contingency so that load in excess of the remaining transmission capability is selectively shed, rather than shedding the entire Cape Cod area, which is approximately 685 MW on peak. In the event that load is shed as a result of a second contingency, the improved system performance that results from the short term upgrades allows load to be restored as peak loads subside …, the outage is rotated to a different part of Cape Cod, or the cause of the contingency is repaired.
>
> Because of the dramatically reduced number of days and hours that load shedding would be relied upon, the significantly reduced level of exposed load, and the reduced potential duration of any outage, the ISO believes that the lower SEMA area can be operated reliably and within criteria after the completion of the short term upgrades without the need to operate the generation at Canal station at current system load levels.[17]

NStar is able to shed load individually at each of the Tremont East substations, allowing for rolling blackouts. Based on experience from the 2003 outage, these blackouts would not continue for very long.[18]

---

[17] "Long-Term Report of ISO New England Inc. Required Pursuant to Section 6.1(c) of the SEMA Settlement Agreement," ISO New England Inc., January 20, 2009, pp. 4–5. The origin of the "approximately 685 MW on peak" is not clear, since NStar's 90/10 forecast for Tremont East does not reach that level until sometime after 2020.

[18] The 2003 outage was more widespread and less controlled than pre-planned shedding of substation load. Service was restored to all customers in less than two hours. Controlled load shedding would end when the first 345 kV line is restored (apparently within 20 to 40 minutes in the 2003 outage) or customers respond to requests for conservation, bringing net load in Tremont East below the 460 MW capacity of the 115 kV lines.

Q: Isn't any outage a problem for consumers?

A: Yes. Hardly anyone enjoys a power outage. Routines are interrupted, clocks must be reset, and comfort levels decline. (Given the short expected duration of a dual outage, the consequences of longer outages, such as spoilage of food, seem unlikely.)

However, all electric customers experience periodic power outages, due to problems on the local transmission and distribution systems. In the case of Tremont East, this could include problems at transmission substations, local 115 kV lines, distribution substations (stepping down from 115 kV to 23 kV, or 23 kV to 4 kV), 23 kV and 4 kV primary lines, line transformers, secondary lines, or service drops. According to NStar's filing in DPU 11-SQ-13, over the last ten years its customers have experienced an average of about one outage and two hours without power annually. Any customer for whom reliability is crucial (e.g., network servers, communications equipment, health-care facilities) will need to have back-up supplies. The possibility of an outage on both of the 345 kV lines would not add substantially to customer outage risks.

In particular, it is hard to see how avoiding this very unlikely outage would justify spending $100 million on a third transmission line.

Q: Would outage of the two 345 kV lines at some load level result in a broader outage?

A: Yes, according to NStar, loss of the two 345 kV lines at a lower SEMA load level of about 1,100 MW (SAN-NSTAR-2-18)—which would be a Tremont East load level of about 630 MW (SAN-NSTAR-2-6)—"would require shedding of up to 500 MW in peak load to forestall voltage collapse and sustain the operability of the electric system on Cape Cod" (Petition, p. 2-31). The potential voltage collapse would affect "the transmission system east of the Bourne 115 kV Substation" (SAN-NSTAR-2-20), that is, the Cape and Islands.

Q: Does NStar accept the view that load shedding is a reasonable response to very unlikely situations?

A: No. NStar's position is as follows:

> This would mean that it would be necessary for the Company to cut electric service across Cape Cod to all customer groups, including residences, commercial customers, including hotels, restaurants, transportation and fueling stations, as well as critical services such as utilities, healthcare facilities and emergency services, and to do so without notice or preparation. In the Company's operating judgment, this is an unacceptable risk that needs to be addressed because the ramifications of load shedding to the extent that would have to occur to avoid complete voltage collapse would jeopardize the health and welfare of NSTAR Electric customers and the general public on Cape Cod. (Petition, p. 2-32)

As I point out above, customers must expect some outages. The critical services to which NStar refers typically have backup power supplies; many are required to do so by law.

NStar also alleges, for the purposes of this proceeding, that the load shedding on which the ISO and NStar currently rely, and which the ISO extols in the Long-Term Report of ISO-New England of the SEMA Settlement Agreement ("Long-Term Report"), is not really workable.

> Small amounts of load shedding following loss of a second element are not a feasible approach, as load shedding for the Tremont East area requires pre-staged reconfiguration of the transmission system such that large amounts of load are interrupted following a second contingency to avoid overloads that may damage equipment. Such load shedding is considered an interim solution and as such was not included in the assessment of the long-term requirements of the system. (SAN-NSTAR-1-62)

Despite NStar's claim that "small amounts of load shedding…are not a feasible approach," NStar also states,

> Every load serving substation within NSTAR and Tremont East in particular can be shed individually from the transmission system by remotely or locally opening the step-down transformer breaker that supplies the substation…. the system operator must be able to assess the event that has occurred and determine how many substations must be shed and their locations. The amount of time available to make these determinations and then conduct the switching before equipment damage is sustained is inversely proportional to the scale of the event." (SAN-NSTAR-2-18)

Most of the Tremont East substations that NStar lists in SAN-NSTAR-2-6 have capacities of 20 MVA to 50 MVA; while NStar does not provide data on the loads of individual Cape substations, the two Valley substations have 90/10 loads of about 7 and 16 MW, respectively, and the average loads on the 17 Cape District substations are about 25 MW. Thus, small amounts of load shedding seem to be highly feasible.

NStar's claims about the burden on the operator to "assess the event that has occurred and determine how many substations must be shed and their locations" may be relevant concerns in a more complex network arrangement, but not in the radial Tremont East system with only one important double-contingency situation (or at least only one such situation that would be alleviated by the Project). In the case of the 345 kV contingencies in Tremont

East, NStar should have "assessed the event" in advance (presumably around 2008, as part of the short-term solution project) and have readily available to the dispatchers a list of substations to shed as a function of load level.

Q: Does NStar acknowledge that load shedding can be a valid response to some transmission contingencies?

A: Yes. NStar states:

> Under some circumstances, load shedding may be a viable tool for addressing gaps in resources requirements and resource availability and NERC/ISO-NE standards involve a certain level of reliance on load-shedding as a resource tool." (Petition, p. 2-32)

Q: What reasons does NStar offer for not relying on any load-shedding in the event of a second contingency taking out both of the 345 kV lines to Tremont East?

A: NStar offers the following four reasons:

- The duration of load interruption that would be needed given load-cycle characteristics and the difficulty of restoring service in a relatively short time period.
- The duration of time that the affected system components could be out of service.
- The number of days or hours in the summer season that the potential for load interruptions exists.
- The load characteristics of affected customers and the potential impact to the health and safety of customers. (Petition, p. 2-32)

Q: What was the "duration of load interruption" on the one occasion that both 345 kV lines were disconnected simultaneously?

A: I quoted the Joint Report on page 19 of this testimony regarding the length of restoration efforts. Following loss of an area larger than Tremont East, some customers were restored in 20 minutes, while almost all were restored within 90 minutes. This is not a long outage.

Q: Does NStar explain why the "affected system components" would be out of service for a particularly long period?

A: No. The 345 kV lines are overhead (rather than underground or submarine) and do not seem particularly difficult to work on, except possibly for the crossing of the Cape Cod Canal.

Q: Is the "number of days or hours in the summer season that the potential for load interruptions exists" particularly great?

A: That depends on whether Canal continues to operate, and how much additional generation is developed in Tremont East. Since August of 2009, Canal's economic dispatch at times of high load appears to have covered most of the hours in which load exceeded the capacity of the 115 kV transmission and other resources on the Cape. Levitan's analysis found that operation of Cape Wind would similarly cover most of those occasions; for 2015–2022, Levitan's model predicts the commitment of Canal perhaps once a year to cover the potential loss of the 345 kV lines, even were no load shedding considered acceptable.

Even when two contingencies on the 345 kV lines could result in load interruptions of some magnitude in Tremont East, the extreme rarity of those contingencies makes that a minimal contributor to reliability problems for Tremont East customers.

Q: Is there anything special about "the load characteristics of affected customers and the potential impact to the health and safety of customers" in Tremont East?

A: No. NStar's description of this area is not much different than any other part of its service territory. Every inhabited part of the Commonwealth has residences, commercial customers, hotels, restaurants, transportation facilities, gas stations, utilities, healthcare facilities and emergency services. If anything, a summer service interruption on the Cape and Islands would seem to be less serious than a similar interruption for customers in hotter urban environments, where fear of crime may make apartment residents reluctant to open windows or go sit in the shade (if they could find any shade).

E. Need for the Canal Plant without the Project

Q: What is NStar's position on the need for the Canal Plant in the absence of the Project?

A: NStar asserts that Canal (or a large amount of other resource) is needed for reliability if the Project is not built. For example, NStar states that "one Canal unit is committed out of economic merit order for approximately 42–58 days per year to maintain reserve requirements" (Petition, p. 2-34; Attachment 2-1, p. 1).

Q: What is the basis for this assertion by NStar?

A: NStar states that this claim "is supported by page 4 of the Executive Summary Excerpt from the Long-Term Report of ISO-New England of the SEMA Settlement Agreement." (SAN-NSTAR-2-36, 2-63) That document actually describes when Canal would *not* be needed:

> Even without consideration for the additional operational steps to eliminate reliance on the existing area generation discussed in this report, the short term upgrades result in not needing to have a Canal generating unit on-line until regional load levels exceed a level of 20,000 MW in the summer and 24,000 MW in the winter; approximately 42 to 58 days a year.

In footnote 9, the Long-Term Report observes,

> Regional loads levels do not directly correlate to load levels in SEMA, which are the load levels that determine operations for the area. However, regional load levels are used in this report as an approximate proxy for ease of discussion.

NStar also concedes that the Long-Term Report "was based on a planning study that used a 90/10 peak load forecast…. This planning study also did not include any offshore wind generation in the Tremont East area…" (SAN-NSTAR-2-63)

Q: Is it true that "one Canal unit is committed out of economic merit order for approximately 42–58 days per year?"

A: No. Were Canal committed out of economic order to back up the local transmission lines, the costs would be recovered in the second-contingency Net Commitment Period Compensation ("NCPC") charge for SEMA[19] (SAN-NSTAR-1-5).

---

[19] Second-contingency NCPC, and other costs, are sometimes called "uplift."

That charge has in fact been zero every month from July 2009 through February 2011.[20]

Canal was economic to operate whenever needed, even though the ratio of the oil burned at Canal 1 (and recently, primarily at Canal 2 as well) has been quite expensive compared to the gas that usually sets the market price. Gas prices are expected to recover over the next few years, which should make Canal more competitive and less likely to be operated out of economic order.

The Petition repeatedly refers to Canal operation and uplift charges in 2006–2008 (Section 1.3; Attachment 2-1, pp. 2 and 13; pp. 2-3, 2-35, 3-2; SAN-NSTAR-1-3), but totally ignores the steep drop in these charges during late 2008 and early 2009, and their total elimination from July 2009 onward.

Q: Does the modeling in the Petition indicate that Canal will be frequently committed out of merit order in the future?

A: No. The modeling in the Levitan Report predicts that Canal would be run in very few hours for transmission support, which equate to zero to perhaps 20 days per year, rather than the 42–58 days NStar claims. Levitan's results, from SAN-NSTAR-1-47, are summarized in Table 3. Since Levitan assumed that Canal would be committed to limit the Tremont East import to 479.5 MW (SAN-NSTAR-1-43), rather than the much higher levels at which NStar currently operates the system without Canal, Levitan's results probably overstate the use

[20] Presented with this discrepancy, NStar repeated its reference to the Long-Term Report and ignored the actual data indicating zero payments for second-contingency NCPC in SEMA (SAN-NSTAR-2-36). It also conflated the payments to SEMA generators for regional first-contingency NCPC with the non-existent payments to SEMA generators for second-contingency NCPC due to transmission constraints (SAN-NSTAR-1-20, 2-48).

of Canal for transmission support. Indeed, while Levitan predicted 40 hours of operation for transmission support in 2010, Canal was not committed at all for that purpose.

Table 3: Levitan Projection of Canal Operating Hours for Transmission Support

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Unit-Hours	40	80	93	79	35	9	0	8	8	8	13	4	12

SOURCE: IR SAN 1-47

With realistic reliance on the possibility of shedding load in a very rare contingency, Canal is unlikely to operate significantly out of merit order.

IV. Canal Plant Economics

Q: What is the basis for NStar's assertion that special customer support payments to Canal would be required to keep the Canal Plant on line?

A: The Levitan Report (Petition Attachment 2-1) compares (1) estimates of the cost of continuing to operate the Canal Plant for two levels of cooling-system retrofit requirements to (2) an estimate of the revenues that would be received by the Canal Plant.[21]

Q: Is Levitan's analysis reasonable?

---

[21] In some other analyses, Levitan assumes the retirement of Canal 1 and continued operation of Canal 2 under a reliability contract, but for the computation of the Canal Plant's viability, Levitan appears to have only analyzed the economics of the entire Canal Plant.

A: No. While almost all of the inputs to the economic analyses of Canal are difficult to pin down with any precision, the Levitan analysis understates Canal's likely revenues and overstates its likely costs.

Q: Why are almost all of the inputs to the economic analyses of Canal difficult to pin down with any precision?

A: The major inputs, and the reasons they are hard to project with confidence, include the following:

- Capacity revenues, which depend on the following factors:
  - the decisions of various merchant-plant owners regarding decisions to retire or mothball generation (and hence on regulatory and legislative restrictions on those plants);
  - future environmental costs imposed on various generators to mitigate cooling-water impacts (Section 316(b) of the Clean Water Act ("316(b)")), NO_X emissions, particulate emissions (including heavy metals) and ash-disposal effects for coal plants;
  - the success of energy-efficiency programs throughout the region;
  - the addition or reduction of imports from surrounding regions;
  - the rate at which renewable resources are added in New England (and the amount of capacity credit afforded those resources); and
  - the future rules governing the capacity market.
- Energy revenues, which depend on the following factors:
  - the retirements and additions listed above;
  - increases in transmission from Quebec, and to a lesser extent within New England; and

   - relative prices of coal, gas and oil.
- Canal's operating costs for the existing plant, which are not publically reported and may change over time.
- Future environmental requirements on Canal.
- The business strategies of GenOn regarding Canal, which may result in GenOn keeping the Canal Plant on line (1) as a hedge against high ratios of gas to oil prices, or (2) to maintain rights to transmission, making the site more valuable for future development.

Each of these factors is uncertain in the future; in some cases, current values are unknown.

Q: Does this analysis accurately reflect the decision making of generation owners in New England?

A: No. In the face of capacity prices of about $35/kW-year in 2012–2016, with the prospect of mounting environmental compliance costs, and the possibility of even lower capacity prices after 2016, owners have continued to accept capacity obligations for old steam plants, including New Haven Harbor 1 & 2, which appear to have O&M costs on the order of $70/kW-year.

For various reasons, probably including the option value of oil-fired plants in the event of another gas price shock and the value of maintaining the embedded entitlement to transmission, owners have behaved very differently than Levitan assumes, and GenOn may also behave differently.[22]

---

[22] Indeed, Levitan cannot reconcile its greatest estimate of the Canal O&M with GenOn's decision to accept the low FCM prices in the last three auctions, and says, "LAI cannot speculate on the business decision making process of

Q: Did you identify any structural problems in the Levitan analysis of the economics of Canal?

A: Yes. Levitan computes the present value of the cash flow for 2012 through 2022, and assumes that the cooling-system modifications occur in 2012. This is clearly unrealistic, since the draft 316(b) regulations proposed by the Environmental Protection Agency ("EPA") are not likely to be final until 2012, and a lengthy regulatory process is likely before a final determination of the upgrades required at any particular plant, and the actual design and installation of the upgrades may take a couple years more. Since Levitan projects that the economics of Canal will improve rapidly after 2016, an analysis of the economics of cooling-system modifications starting with investments in 2015 or 2020 would be much more favorable to continued operation.

Q: How did Levitan overstate the likely costs of Canal?

A: Levitan selected a very high O&M value, which is not justified by the historical record, assumed that Canal would be more vulnerable to environmental requirements than other oil- and gas-fired boiler plants, and ignored the pending and likely retirement of nuclear and coal plants.

A. Canal O&M

Q: How did Levitan estimate the O&M cost of Canal?

merchant generators" (SAN-NSTAR-1-36). It is actually easy to speculate on the decision-making of merchant generators; it is very difficult to accurately predict their decisions.

A: The analysis starts with a review of Canal's reported O&M in 1995–1998, the last years of utility ownership. The average cost in this period was $37.07 million in 2010 dollars (Levitan Report, Table 3). Levitan says that this result "represents an average 2010 cost of about $37/kW-yr.," implicitly assuming that Canal's capacity is 1,000 MW. In fact, Canal's summer rating is 1,095 MW, and Levitan used a capacity of 1,126 MW in estimating the cost of operating (Canal SAN-NSTAR-1-63 Attachment; Levitan Report, p. 22). Using these measures of Canal's capacity, the historical O&M was about $34.40 or $33.50/kW-yr.

Levitan then examines the O&M claimed by the owners of the oil/gas steam plants that received reliability-must-run contracts, and concluded that those values averaged about $50/kW-year (Levitan Report, p. 22). Yet Levitan acknowledges that it does not know how the O&M claims are audited, if at all, or what O&M costs are included (SAN-NSTAR-1-33).[23]

Q: Have you found any more-recent data on the O&M costs of New England oil/gas steam-electric plants?

A: Yes. The Newington plant and a small part of Wyman 4 are owned by the Public Service Company of New Hampshire ("PSNH"), which still reports cost data in its FERC Form 1, with criminal penalties for false statements. According to Levitan's analysis of continued Newington operation, filed as part of PSNH's 2010 IRP, Newington non-fuel O&M for 2007 to mid-2010 averaged about

[23] Levitan asserts that the "cost test applied by FERC is intended to capture only the cost of continued operation." (SAN-NSTAR-1-33c) This may be FERC's current test, but the RMR contracts for relatively new units, such as the West Springfield CTs and Berkshire Power, clearly included sunk costs.

$18.50/kW-year in 2010 dollars. This is essentially the same as the 1995–98 average. Levitan also included about $10/kW-yr in carrying charges for fuel stocks. For Wyman 4, PSNH's FERC Form returns indicate an average O&M cost of about $13/kW-year (in 2010 dollars), about 11% less than the $14.60/kW-year reported in 1995–1998.[24]

These results suggest that the O&M costs of large oil- and gas-fired plants have not increased since 1995–98. Indeed, the one plant for which we have data whose lead owner is subject to the competitive market (Wyman 4), costs have fallen in real terms.

Q: What do these data suggest for Canal O&M?

A: It seems reasonable to assume that Canal's O&M would have declined from the $34/kW-year in 1995–98, due to competitive pressures and the reduction in Canal's capacity factor, from baseload in the 1990s to peaking operation in 2007–2009.[25]

Q: What effect would the use of $34/kW-year O&M have on Levitan's analysis of Canal economics?

A: At $50/kW-year, Levitan concludes that running both units and installing screens would have a negative present value over 2012–2022 of $68 million. At $34/kW-year, that would change to a positive present value of $4 million over

---

24 Connecticut's 2010 IRP, on which Levitan relies for its analysis of New England power-plant retirements, assumes that Canal's fixed O&M is $30/kW-year, the same as Newington and Wyman 4.

25 In other words, the historical data would include considerable variable O&M, in addition to fixed O&M.

2012–2022. Since Canal has already committed in the FCM to operate through May 2014, costs through that date are irrelevant.

Levitan also overstates the present-value costs of the cooling-system upgrade by assuming that the screens or cooling towers are installed in 2012. The draft 316(b) rules were issued March 28, 2011; once the rules are published in the Federal Register, a 90-day comment period will begin. The EPA is committed to issue a final action by July 27, 2012. Then plant-specific analyses will start for each plant; assuming EPA allocates its resources efficiently, its staff will start with the baseload coal and nuclear plants, moving on to peaking plants like Canal much later.

Assuming that the screens would actually be installed in 2015 (which is still very optimistic), the present value over 2015–2022 would rise to about $11 million. If the net benefits stay constant in real terms after 2022, the net present value through 2025 would be about $77 million.

Q: In the cases in which one Canal unit was retired, how did Levitan model the O&M for the remaining unit?

A: Levitan assumed that each unit's O&M was only 33% of the total plant cost, with 34% being common costs required regardless of whether one or two units are in operation (SAN-NSTAR-1-63). Levitan has no basis or data for this assumption (SAN-NSTAR-3-2), which raises the cost per kW-year for Canal 2 alone to $67.6/kW-year, twice the historical cost for Canal as a whole and three times the current cost per kW for the smaller Newington unit.

B. Environmental Costs and Retirements

Q: Are the environmental costs borne by Canal the only such costs relevant to the fate of that plant?

A: No. The prices that Canal receives in the capacity and energy markets (and to a smaller extent in ancillary-services markets) depend on how much and which other plants would retire, shut down, or withdraw from the capacity market before Canal.[26]

Levitan's retirement estimate starts with the results of the Brattle Group's ("Brattle") analysis for the 2010 Connecticut IRP. Brattle projected that 2,445 MW would be economic in the face of uniform regional requirements to reduce NO_X emissions and would be retired by 2016. Of the remaining capacity, which Brattle expected to survive the low market prices through 2017 or so, another 868 MW were expected to be less economic than Canal 2, and yet another 1,123 MW (not counting Canal 2) appeared to be less economic than Canal 1. See Table 4.

---

26 "Before" can mean in earlier years or earlier in the Forward Capacity Auction ("FCA").

Table 4: Retirement Analysis Results, 2010 Connecticut IRP

	Capacity (MW)	PV/kW 2013−2030	Retirement Projection
Bridgeport Harbor 2	130	−$277.10	Retire in 2013
Middletown 3	236	−$223.12	Retire in 2013
Norwalk Harbor 1	162	−$650.29	Retire in 2013
Norwalk Harbor 2	168	−$657.63	Retire in 2013
Cleary 8	26	−$408.80	Retire in 2013
Yarmouth 1	52	−$142.68	Retire in 2013
Yarmouth 2	51	−$139.02	Retire in 2013
Middletown 4	400	−$45.29	Retire in 2016
Montville 6	407	−$76.86	Retire in 2016
West Springfield 3	94	−$37.32	Retire in 2016
Yarmouth 3	116	−$54.80	Retire in 2016
Yarmouth 4	603	−$59.44	Retire in 2016
Holyoke 8/Cabot 8	10	−$43.35	
Newington 1	400	−$32.07	
New Haven Harbor	448	−$27.26	
Holyoke 6/Cabot 6	10	−$26.07	
Canal 2	545	−$2.09	
Brayton Point 4	435	−$1.84	
Kendall Steam 1 2 3	53	$6.86	
Middletown 2	117	$19.47	
Salem Harbor 4	437	$68.54	
Montville 5	81	$98.92	
Canal 1	573	$130.57	
Mystic 7	578	$166.48	

SOURCE:
Integrated Resource Plan for Connecticut, January 1, 2010, Table 1.8

Connecticut's IRP assumed that all New England oil/gas units would need to install selective catalytic reduction ("SCR") to meet the 2017 emissions rate proposed for Connecticut compliance under the proposed Clean Air Interstate Rule, which has since been replaced by the proposed Clean Air Transport Rule. The new rule (which has yet to be promulgated) would not cover NO_X emissions in New England for ozone, other than in Connecticut.

Since the new rule would not impose NO_X requirements on Massachusetts plants as stringent as assumed in Connecticut's IRP, Canal 2 would be more cost-effective than indicated in the Connecticut IRP.[27] Since Canal present value in Table 4 includes $22/kW-year of SCR costs, its present value would rise to the $100–$200/kW-year range without the SCR requirement.

Of the oil/gas units in New England, the two Holyoke/Cabot units and Bridgeport Harbor 2 were delisted in the third FCA, suggesting that they will be shut down in 2013. The other units listed by Brattle as retired in 2013 have cleared in the third and fourth FCAs, and are thus under contract with the ISO to operate through May 2014.

Q: How did Levitan modify the Brattle analysis?

A: Interestingly, Levitan did not reproduce or modify the Brattle analysis, other than assuming that the 2013 analyses would be delayed to 2014. Levitan adopts some, but not all, of Brattle's conclusions, and then assumes that only Canal would be subject to restrictions on cooling-water use.

Levitan lists some units that it assumes will be retired (p. 9, corrected in SAN-NSTAR-1-8), but apparently ignored Brattle's conclusion that West Springfield 3 and Cleary 8 (totaling 120 MW) will be retired. On discovery, Levitan corrects the Report's assertion that Middletown 4 was assumed to be retired. Rather than accept Brattle's conclusion, Levitan assumed that Middletown 4 could comply with NO_X emission rates with a low-cost "layered"

[27] Canal 1 already has SCR, which is one reason that the Connecticut IRP found that unit to be so overwhelmingly cost-effective.

approach (SAN-NSTAR-1-7, 1-8). Levitan conducted no economic or technical analysis of the effectiveness or cost of this approach for Middletown 4, and has no basis for assuming that Middletown 4 would be more economic to operate than Canal (SAN-NSTAR-2-40).[28]

Thus, of the 2,445 MW of retirements estimated by Brattle, Levitan accepts only 1,925 MW. While Levitan did not provide its assumption regarding the actual amount of capacity that would be active in New England, the decline in the surplus of capacity reported in SAN-NSTAR-1-42 is consistent with that magnitude of retirements.

In addition to the specific retirements that Levitan accepts, at least in part, from Brattle, Levitan subtracts 1,258 MW of unidentified capacity from the capacity market throughout the analysis period, to force a need for capacity about 2019.

Q: Would the other steam-electric plants in New England be subject to the 316(b) cooling-water restrictions?

A: Yes. The Brayton Point plant, long under pressure due to its effect on the aquatic life of Mount Hope Bay, has started installation of cooling towers. It appears that all of the older steam plants (oil, gas, coal, or nuclear) will be subject to the new rules. If the other steam-electric plants face 316(b) costs comparable to

[28] Levitan says it viewed Middletown 4 "as more viable, in part due to its age relative to comparably sized plants in the 2016 retirement group." (SAN-NSTAR-2-40) It is curious that Levitan chose this unit to keep operating, since it has always run at much lower capacity factors than the Canal and most other oil/gas steam plants, including much smaller and older units and some that are already retired, such as Devon 7 and 8. This pattern dates back to a period in which all the plants were burning primarily oil.

those Levitan assumes for Canal, the Brattle analysis suggests that the cost-effectiveness of such units as Newington and New Haven Harbor would fall dramatically.

Q: Did Levitan ignore any other likely retirements?

A: Yes. Vermont Yankee, Salem 1–3 and some other coal plants, and the Salem 4 oil unit are at particular risk.

The Nuclear Regulatory Commission recently granted Vermont Yankee (604 MW) a 20-year license extension, but the plant also requires state permission to operate past March 2012. The Vermont Senate voted 26–4 in February 2010 to deny that extension, in part due to tritium leaks, a cooling-tower collapse, and errors found in the owner's testimony before the legislature. Since then, the plant has experienced additional tritium leaks. Vermont Yankee is of the same vintage (early 1970s) and design (Mark I boiling-water reactor) as the Fukushima Daiishi reactors that suffered fuel melting, explosions, radiation releases, and draining of the spent-fuel pools in March 2011. The Vermont Legislature appears unlikely to reverse its decision under these circumstances.

Salem 1–3 (about 308 MW) have submitted high bids for the third and fourth FCA. Units 1 and 2 were allowed to delist, but Unit 3 has been required to stay on line for reliability, at a price of $5.22/kW-month. Salem filed permanent delist bids for all four units in FCA 5, which were rejected, and then filed a non-price bid. Salem has no baghouse, SCR or scrubber, and is subject to 316(b) requirements. All indications are that the owner intends to retire the plant. I treat Units 1 and 2 as being retired in June 2012, and Unit 3 as being retired in June 2015, assuming that transmission upgrades will eliminate the reliability need for the plant.

Salem 4 (437 MW) burns only oil, and its owner has been attempting to delist it from the FCAs, along with the coal units.

Q: Has Levitan expressed any opinion regarding the fate of Vermont Yankee?

A: Yes. Levitan refers to unspecified "discussions that indicated the Legislature would consider approving the license extension provided that Entergy (i) fixes all of the plant's problems and (ii) offers state residents a beneficial power contract" (SAN-NSTAR-1-13).[29] Levitan continues:

> During 2010, Entergy embarked on a groundwater monitoring and extraction effort as well as plant design review and correction. In November, 2010, Entergy announced that it was exploring the potential sale of Vermont Yankee. Our expectation is that a new owner, coupled with a beneficial power contract to Vermont utilities, would convince the Legislature to approve the license extension. (SAN-NSTAR-1-13)

This response was optimistic when it was written in February 2011. It became highly unrealistic when the fuel melted at Fukushima. On March 30, 2011, Entergy announced that "the previously announced process to explore the

---

[29] Indeed, Entergy claimed on March 30, 2011, that it had "completed negotiations on a 20-year agreement to sell power from the Vermont Yankee nuclear plant to customers of Vermont Electric Cooperative." ("Entergy, Vermont Electric Cooperative Complete Negotiations on Power Contract," PR Newswire). The Cooperative, which serves about 8% of Vermont load, denies that any agreement was reached: "Although negotiations to purchase power from Vermont Yankee have ended, at the present time there is no agreement to purchase power from Entergy beyond March, 2012…. there is presently no agreement" (http://www.vermontelectric.coop/news-center/205-vecs-response-to-entergy-press-release "VEC's Response to Entergy Press Release: VEC Board to Review Entergy Proposal" press release 3/30/2011, http://www.vermontelectric.coop/news-center/205-vecs-response-to-entergy-press-release, accessed 4/4/2011).

sale of the 605-megawatt plant has concluded without a sale…. Although we received interest from a number of companies, the conclusion of the sale process, without a sale, was driven primarily by the uncertain political environment in Vermont…. The plant's strong operating performance was attractive to potential buyers; the political uncertainty was not." ("Entergy, Vermont Electric Cooperative Complete Negotiations on Power Contract," PR Newswire).

Q: Has Levitan expressed any opinion regarding the fate of Salem?

A: Yes. Levitan explained why it "did not include the retirement of the entire Salem Harbor plant, given the static de-list bids filed for all four units and accepted for units 1 and 2 in the third and fourth FCA" as follows:

> In the third FCA, ISO-NE accepted the static de-list bids for units 1 and 2, but rejected the static de-list bids for units 3 and 4. In the fourth FCA, ISO-NE rejected the de-list bids for all four units. Therefore,…none of the Salem Harbor units were assumed to retire in our analysis. (SAN-NSTAR-1-11)

On further questioning, Levitan admitted

> the ISO rejected the de-list bid prices submitted by Dominion, but determined cost-based bid prices for all four units of $5.224/kW-year…. Salem Harbor Units 3 and 4 were retained for reliability, while Salem Harbor Units 1 and 2 were allowed to de-list…. LAI did not analyze transmission upgrades that would eliminate the reliability requirement for Salem Harbor Units 3 and 4.

Levitan's initial response was simply misleading; it has no justification for assuming that Salem Harbor 1 and 2 would remain in operation past 2012, or that Salem Harbor 3 and 4 would remain on line once the Northeastern Massachusetts transmission upgrades are completed.

Q: Are there other analyses that suggest that New England coal units will be retired?

A: Yes. A study by the Brattle Group projected about 700 MW of additional coal-plant retirements in New England by 2015 if scrubbers and SCR are required.[30] Additional coal plants would retire if required to install cooling towers; Brattle does not break that estimate out by region.

A Charles River Associates study of the effects of its pending regulations covering NO_X, mercury, SO_2 and particulates on coal plant operations projected the retirement of Salem 1 & 2, Merrimack 1, and Schiller 4 & 6, a total of 366 MW of coal capacity.[31]

A study by the North American Electric Reliability Corporation ("NERC") of the effects of the pending air-emission rules, 316(b) limits on cooling water intake, and coal-ash disposal rules, projected the retirement of 2,925 MW of oil/gas steam plants and 479 MW of coal in the event of "moderate" enforcement, and 3,325 MW of oil/gas steam and 1,042 MW of coal in the event

[30] Celebi, Metin, Frank Graves, Gunjan Bathla, and Lucas Bressan. 2010. "Potential Coal Plant Retirements Under Emerging Environmental Regulations." The Brattle Group; December 8, 2010.

[31] Shavel, Ira, and Barclay Gibbs. 2010. "A Reliability Assessment of EPA's Proposed Transport Rule and Forthcoming Utility MACT." Charles River Associates, December 16, 2010.

of "strict" enforcement of these rules.[32] Interestingly, the NERC study finds that Newington would retire with strict enforcement, but Canal would not. As part of the 2010 PSNH IRP, Levitan found that Newington would continue to be cost-effective to operate. The results of the NERC study are summarized in Table 5.

Neither study finds that either Canal unit is particularly likely to retire.

[32] "2010 Special Reliability Scenario Assessment: Resource Adequacy Impacts of Potential US Environmental Regulations," August 2010. The report lists the capacity and number of units retired in various size ranges by region, from which individual units can be readily identified.

1 **Table 5: New England Retirements in NERC Study of Environmental Regulations**

	MW	Moderate Enforcement	Strict Enforcement
Oil and Gas Steam			
Bridgeport Harbor 2	130	Y	Y
Middletown 2	117		
Middletown 3	236		
Middletown 4	400	Y	Y
Montville 5	81	Y	Y
Montville 6	407	Y	Y
New Haven Harbor	448	Y	Y
Norwalk Harbor 1	162	Y	Y
Norwalk Harbor 2	168	Y	Y
Brayton Pt 4	435		
Canal 1	573		
Canal 2	545		
Cleary 8	26	Y	Y
Holyoke 6/Cabot 6	10		
Holyoke 8/Cabot 8	10		
Kendall Steam 1 2 3	53		
Mystic 7	578		
Salem Harbor 4	437	Y	Y
West Springfield 3	94	Y	Y
Yarmouth 1	52	Y	Y
Yarmouth 2	51	Y	Y
Yarmouth 3	116	Y	Y
Yarmouth 4	603		
Newington 1	400		Y
Coal			
Salem 1	80		Y
Salem 2	78		Y
Salem 3	150		Y
Bridgeport Harbor 3	383	Y	Y
Brayton 1	243		
Brayton 2	244		
Brayton 3	612		
Mt Tom	143		Y
Merrimack 1	113		Y
Merrimack 2	320		
Schiller 4	48	Y	Y
Schiller 6	48	Y	Y
MW retired		**3,051**	**4,014**

Q: What do you conclude from your review of the treatment of retirements in the Connecticut IRP, the Levitan Report, and the three national studies of retirements driven by environmental regulations?

A: Both of the studies that rank oil/gas steam plants—Connecticut's IRP with only NO_X controls and the NERC study with air, water, and ash control—found that most of the oil/gas steam units in New England would retire before Canal. All three of the studies that examine the economics of coal units find that 400–1,000 MW of New England coal would retire under the pending rules. In addition, the efforts of Salem to delist and the regulatory status of Vermont Yankee suggest that they will retire.

Q: What are the implications of these retirement studies for the economics of Canal?

A: The more capacity that is retired, the greater will be the energy and capacity prices received by Canal. Any megawatt of capacity withdrawn from the FCM will have the same effect on market prices, while loss of nuclear or coal capacity will have more effect on Canal's energy revenues than will the loss of the oil/gas capacity that is more expensive than Canal and operates less frequently.

Q: Have you been able to correct Levitan's capacity-price model for the effect of the additional retirements?

A: I have not been able to fully reproduce Levitan's computations. As I noted above, Levitan's documentation does not start with the available resources and the capacity requirement, but instead starts with a stream of excess capacity values by year. Accepting this approach, and Levitan's assumptions regarding load, reserve requirements, capacity additions, and the supply curve (the relationship between excess supply and market capacity price), I re-estimated the forward capacity price and Canal's economics for the following two cases:

- "IRP and committed," adding the three units retired in the Connecticut 2010 IRP but not in Levitan's analysis, plus the units that seems to be committed to retirement (Vermont Yankee, Holyoke/Cabot 6 & 8, and Salem 1–4).
- "Plus Uneconomic Coal," adding to the first case Bridgeport Harbor 3 and Schiller 4 & 6, which are retired in the NERC moderate case.[33]

Table 6 compares the amount of excess in Levitan's "Base" projection, the calibrated projection Levitan actually used (both from SAN-NSTAR-1-42), and the base with my two level of retirements.

Table 6: Excess Capacity Cases (MW)

	Levitan Excess		**Other Retirements**			**Adjusted Base Excess**	
	Base	Calibrated	In CT IRP	Committed	Projected Coal	IRP and Committed	Plus Uneconomic Coal
2013	5,484	4,225		−604		4,880	4,880
2014	4,734	3,476	−26	−20	−383	4,084	3,701
2015	4,622	3,364		−308	−48	3,664	3,233
2016	2,654	1,396	−494	−437	−48	765	286
2017	2,609	1,351				720	241
2018	2,619	1,360				730	251
2019	2,370	1,112				481	2
2020	2,122	863				233	−246
2021	1,898	640				9	−470
2022	1,641	383				−248	−727

[33] I do not include retirements of 656 MW at three units retired in the NERC strict case: Mt. Tom, Merrimack 1 (also retired in the EPA study) and Newington.

Q: How would these adjustments affect the projection of FCM prices?

A: Table 7 provides the capacity prices used by Levitan, as well as the results of the Levitan model with the capacity surplus I identify in Table 6.

Table 7: Forward Capacity Price Projections ($/kW-month)

	Levitan	IRP & Committed	Plus Coal
2013	2.62	2.56	2.59
2014	2.74	2.71	2.74
2015	2.82	2.86	2.90
2016	2.61	4.45	6.01
2017	3.24	5.09	6.65
2018	3.71	5.55	7.12
2019	4.98	6.87	8.43
2020	5.94	7.86	9.43
2021	6.81	8.77	10.34
2022	7.80	9.80	11.37

Q: How would these higher capacity prices affect the economics of Canal?

A: With the capacity prices resulting from the IRP and committed retirements, continued operation of both Canal units would be cost-effective, even with Levitan's very high O&M projection, for installation of screens as early as 2015, including profits through 2025. With the $34/kW-year O&M value, both units would be cost-effective (just counting benefits to 2022) even if screens were somehow installed in 2012.

Were the cooling towers required, with $50/kW-year O&M, the Canal Plant would not be cost-effective. With the cooling towers and the $34/kW-year O&M value, Canal would be cost-effective even if the cooling towers could be installed as early as 2015, so long as the analysis is continued through 2024.

This analysis period of nine years after the cooling-system investment is shorter than the ten years used in Levitan's analysis.

All of these analyses include only the effects of the retirements on the capacity market. In addition, the retirement of Vermont Yankee and Salem 1–3 would increase market energy prices in essentially all the hours that Canal would operate and also increase the number of hours in which Canal would be economic to operate, and retirement of over 2,000 MW of oil and gas steam capacity would increase energy prices in some part of the hours that Canal operates.

Q: What happens to the cost-effectiveness of Canal with the additional coal retirements projected in the NERC study?

A: Both units of Canal would be cost-effective to continue operating, even with Levitan's very high O&M projection, for installation of screens as early as 2015, and only including profits through 2022. With the $34/kW-year O&M value, both units would be cost-effective (just counting benefits to 2022) even if screens were somehow installed in 2012.

Were the cooling towers required in 2016, with $50/kW-year O&M, the Canal Plant would need to operate until 2026 to be cost-effective (again, assuming that the 2022 profits rise with inflation). With the cooling towers and the $34/kW-year O&M value, Canal would be cost-effective even if the cooling towers could be installed as early as 2015, so long as the analysis is continued through 2023.

Q: What would be the effect on the revenues to Canal 2 if Canal 1 were to shut down, as Levitan assumes it would?

A: Capacity prices would be about $1.90/kW-month higher with the loss of another 563 MW from Levitan's FCM model. Levitan assumes that both Canal units are in the FCM in all its retirement analyses (SAN-NSTAR-1-69b), that effect is unlikely to bring the price back to the level that would have occurred with Canal 1. If the market-clearing price with Canal 1 were high enough to keep the hypothetical replacement unit on line, it would have been on line in the base case with Canal 1. In any case, Levitan did no economic analysis to support its estimate of the magnitude of the price rebound for the Canal 1 retirement, which is central to most of Levitan's analyses.

Q: What effect did Levitan suggest Vermont Yankee's retirement would have on Canal's revenues?

A: Levitan suggested retirement of Vermont Yankee would result in new resources with higher operating costs offsetting the effects of the retirement, then admitted that it had no basis for estimating the magnitude of the offset, and finally asserted that the FCM price was somehow immune to Vermont Yankee retirement.

> If, contrary to our expectations, Vermont Yankee were to retire in March 2012, the effect would be some increase in market energy and capacity prices in New England, especially in the Vermont region. Such higher prices could provide an incentive for other generation entry, thereby mitigating any impacts of higher prices, particularly if such new generation has higher operating costs than Vermont Yankee. (SAN-NSTAR-1-13)

> LAI cannot predict the future regarding exactly what types of "other generation" would be induced to enter the market. In light of the lack of natural gas infrastructure throughout most of Vermont, "other generation" types would likely be delivered via transmission from Quebec or northern New York State. Additional renewable technology, such as biomass and wind, may be developable in Vermont as well. (SAN-NSTAR-2-47a)
>
> …the retirement of Vermont Yankee may delay the retirement of one or more resources in Rest of Pool. (SAN-NSTAR-2-47b)
>
> We do not know if the entry of other generation would "fully offset" the impact of Vermont Yankee's retirement on market prices. We note, however, that the combination of new generation and incremental DR/EE could combine to offset the impact of the loss of Vermont Yankee. (SAN-NSTAR-2-47c)
>
> …LAI did not quantify the change in Canal's operating revenues following the retirement of Vermont Yankee. Under the existing FCM rules, the impact of the loss of Vermont Yankee on capacity prices in SEMA would likely be insignificant, if any. (SAN-NSTAR-2-47c)[34]

In Levitan's analysis, the retirement of oil and gas plants increases the FCM prices, and rerunning the production costing model without Vermont Yankee would surely produce higher energy prices and higher revenues for Canal. Levitan does not identify resources that would be added to Quebec or New York State to replace Vermont Yankee.

This attempt to suggest that Canal economics are independent of supply and demand conditions in New England is not credible.

[34] This statement may suggest that Levitan believes that Vermont would become a separate load zone in the FCM upon retirement of Vermont Yankee, without any effect on the rest of the region. While ISO-NE has never recognized a separate import-constrained capacity zone, it seems likely that, even if it became a capacity zone, Vermont's net demand for capacity from the rest of the pool would increase regional capacity prices.

V. Benefits to Consumers

Q: Other than avoiding the cost of the Project, is there any benefit to energy consumers from the continued operation of Canal, or any replacement generation?

A: Yes. As Levitan points out in the Report, the existence of Canal (or a combustion turbine) will tend to suppress prices in the energy market.[35] While Levitan asserts that the capacity price it projects would be the same regardless of whether Vermont Yankee is in the capacity market (SAN-NSTAR-1-13, 2-47), that position is obviously incorrect: so long as the FCM price is determined by a supply curve, removing a large low-bid unit from the curve would push the price upward, and keeping that unit in operation will suppress prices.[36]

An increase of just $1/kW-month in the price paid by retail load would increase New England retail bills by about $360 million annually (depending on the amount of capacity owned by or under long-term contract to utilities), of which about $150 million annually would be borne by Massachusetts ratepayers.

Q: Did Levitan estimate reasonably the effect of Canal on market energy prices?

A: No. Levitan based its estimate of price suppression on comparing the market prices from its production-costing model, comparing the results with and

[35] For some reason, Levitan calls this price suppression benefit "mark-to-market" or "MTM."

[36] Once the FCM price reaches the costs of new market entry, the slope of the supply curve may be low, but it should not be zero.

without Canal. Unfortunately, stochastic production-costing models are not very stable, and great care must be employed in comparing the market prices from different runs. The model uses a random-number generator to estimate forced outages; from one run to the next, the random-number generator may select different outages at different times, resulting in different prices, even with all the inputs exactly the same. In addition, changing the number of generators in the model (such as by removing Canal 1 and 2) will change the order in which random numbers are assigned to the remaining units. The scheduling of maintenance outages in the model may also be affected by the number of units that the model must schedule.

Taken together, the different order of random numbers, the different matching of random numbers to unit outages, and the different arrangement of maintenance outages can cause significant increases or decreases in market prices, just due to the luck of the draw and which outages happen to occur simultaneously.

This problem was less important in the pre-restructuring environment, when utilities and regulators were concerned about total costs, since those are much less volatile than market prices.

Q: Do you observe this phenomenon in Levitan's modeling?

A: Yes. In the nine years reported in SAN-NSTAR-1-73, Levitan reports that Canal's operation would reduce market energy prices in four years, and increase prices in five years. Levitan projects a $24 million present-value benefit over the nine years, but deleting either the first or last year would make the present value negative.

Q: Are these results plausible?

A: No. Adding a resource to the dispatch stack should either reduce price (if the unit is dispatched) or have no effect (if it is not needed).

Q: Is the volatility in these results due to an error in Levitan's application of the production-cost model?

A: Not that I am aware of. In the development of price-suppression effects for the regional avoided costs (through the Avoided Energy Supply Cost Working Group), Synapse Energy Economics has attempted to use the same production-costing model to produce estimates of the effects of small changes in load (e.g., about 1%) on market prices, and encountered similar instability in results. As a result, Synapse and I have estimated price suppression based on statistical analysis of historical loads and prices.

VI. Least-Cost Alternatives

Q: Were Canal to become uneconomical to operate at market prices, given some future set of environmental requirements, what would be an appropriate response for NStar?

A: First, if load in Tremont East remains at or near current levels, reliability would be adequate without any uneconomic commitment of Canal or construction of a replacement resource. NStar arbitrarily decides that no reliance on load shedding in the event of the loss of both 345 kV lines would be prudent (SAN-NSTAR-1-62, 2-32), but there does not appear to be any rationale for that change from current practice, as I describe in Section III.D. If the effects of energy-efficiency programs continue (supplemented by Federal efficiency standards, on-shore and off-shore wind, other renewables, and CHP) at the levels of the current three-year plans, the 90/10 net peak load would stay below 610 MW. NStar estimates that controlled load shedding would be viable up to a load of about 1,100 MW in Lower SEMA, which appears to be equivalent to about 626 MW in Tremont East. Even if loads exceed this threshold, a very rare loss of both 345 kV lines near the rare extreme peak hour could result in loss of all Tremont East load. This possibility does not appear to justify the expenditure of $100 million or so for the Project.

Second, if some additional operating reserve is desired, there are many options that may be better uses of the Project budget. For any of these options, the capacity required would be much lower than assumed in the Petition (Section 2 and the Levitan Report), which exclude any load shedding. These options for increasing capacity in Tremont East include the following:

- *Increasing incentives for demand response in Tremont East.* NStar has not even attempted to determine how much demand response, including emergency generation, was offered into the capacity market at the higher prices of 2009 and 2010.
- *Deeper investment in energy-efficiency in Tremont East,* through NStar's own programs and additional subsidies to the Compact and NGrid's Nantucket efforts. A similar approach has been pursued in supply-constrained areas in Vermont.
- *Reactivation of the Nantucket diesels,* for use in transmission contingencies. As I discuss above, it appears that National Grid will need

to reactivate some of the diesels as backup to the Nantucket transmission lines.

- *New generation resources in Tremont East,* including renewables and CHP (which would contribute to meeting the Alternative Energy Portfolio Standard). This could require that NStar take actions to encourage development of these resources, including giving preference to resources in Tremont East and assisting customers in developing projects. Interestingly, in the recent renewables RFP, NStar was offered at least two projects in Tremont East, as well as capacity from Cape Wind, but chose projects outside Tremont East, and mostly outside Massachusetts.[37]
- *Contracting for a small amount of combustion-turbine capacity* to make up whatever deficiency remains between the load and sum of transmission capacity, generation resources, demand response, and acceptable load shedding.

Most of these potential resources would benefit power consumers by reducing market prices for energy and capacity (and in some cases, renewable energy credits) and increasing system reliability, in addition to providing the Project's benefits of reducing line losses and marginally improving delivery reliability to Tremont East.

---

[37] In addition to reducing the need for the Project, the proposed renewables in Tremont East would have greater energy and capacity value than the projects NStar selected in New Hampshire and especially Maine, have a larger effect on Massachusetts market energy price prices, and reduce stress on the North-South interface across New England. The Project would not provide those benefits.

None of these resources need to be acquired with any great haste, since Canal appears to be a viable peaking resource for years to come. In any case, pursuing the Project in the near term threatens to produce stranded transmission investment, if loads do not grow and resources do.

Q: Is there any action that might be cost-effective for NStar to undertake to reduce the chance of simultaneous outage?

A: Yes. Currently, the two 345 kV transmission lines are separate, except for the structures supporting the lines as they cross the Cape Cod Canal. If something were to happen on the canal crossing itself, it might be difficult and time-consuming to fix. At the Technical Conference, NStar indicated that replacing the current canal-crossing structure with two new, separate structures would costs only about $8 million. This relatively small expenditure may be prudent.

VII. NStar Incentives Regarding Transmission Expansion

Q: Does NStar have any reason to favor transmission where no new resource is needed, or favor transmission over other resource solutions?

A: Yes. In the state's restructured electric industry, NStar generally cannot participate in generation solutions. Were it allowed to offer a generation alternative, it would have to compete with many other suppliers. In transmission, the large integrated utilities are the dominant players. Transmission investments are large and long-lived, and NStar is well positioned to earn a continuing return on that investment.

Transmission is also a particularly lucrative investment. Utilities are allowed to earn higher returns from transmission investments than from other investments. While NStar has not been through a distribution rate case in many years, the DPU allowed National Grid an equity return of 10.35% in its latest rate case (D.P.U. 09-39). NStar would probably expect something similar in its next case (which I believe must be filed at the end of 2012), unless market conditions change significantly. Transmission rates are regulated by the FERC, rather than the DPU, and FERC allows an equity return of at least 11.64% for transmission in New England (Dockets Nos. ER08-1548-000, November 17, 2008, 125 FERC 61,183, ¶82).

Normally, a high allowed or target return would be associated with a high-risk investment, entailing a significant chance of low or no return for the investor. This is not true for FERC-regulated transmission. FERC has rarely found any transmission or generation investment to be imprudent or otherwise unrecoverable.

Part of the job of utility management is to look for opportunities to increase shareholder return without increasing risk. Considered in that light, an investment in transmission would be difficult to resist. While the bias of utility managers toward transmission is understandable, it is important to recognize that the most profitable actions for shareholders are not necessarily the best for ratepayers.

Q: Does this conclude your testimony?

A: Yes.

ERRATA

<table>
<tr><th>Page Number</th><th>Line</th><th>Correction</th></tr>
<tr><td>i</td><td>13</td><td>Benefits to Consumers……~~54~~ 55</td></tr>
<tr><td>2</td><td>6</td><td>summarized in~~-~~Exh. SAN-PLC-2</td></tr>
<tr><td>4</td><td>6</td><td>~~The Canal~~ Canal</td></tr>
<tr><td>4</td><td>8</td><td>~~The Canal~~ Canal</td></tr>
<tr><td>4</td><td>10</td><td>~~The Canal~~ Canal</td></tr>
<tr><td>4</td><td>12</td><td>~~The Canal~~ Canal</td></tr>
<tr><td>4</td><td>14</td><td>~~The Canal~~ Canal</td></tr>
<tr><td>4</td><td>16</td><td>Finally, if ~~the~~ (1) the</td></tr>
<tr><td>13</td><td>2</td><td>
<table>
<tr><th></th><th colspan="3">NStar Forecast[b]</th><th></th><th colspan="2">NStar Filed Plan[d]</th><th></th><th></th><th></th></tr>
<tr><th></th><th></th><th colspan="2">Allocated Efficiency</th><th></th><th></th><th></th><th></th><th></th><th></th></tr>
<tr><th></th><th>Comm-Elec[a]</th><th>Tremont East</th><th>Cape</th><th>Cape Compact Plans[c]</th><th>NStar</th><th>Non-Cape Comm-Elec Allocation[e]</th><th>Total Comm-Elec Projection[f]</th><th>Tremont East Share of NStar[g]</th><th>Total Tremont East</th></tr>
<tr><td>*2010*</td><td>7</td><td>4</td><td>3</td><td>7</td><td>43</td><td>5</td><td>12</td><td>0.8</td><td>7.6</td></tr>
<tr><td>*2011*</td><td>16</td><td>9</td><td>7</td><td>16</td><td>107</td><td>13</td><td>29</td><td>2.0</td><td>~~19.2~~ 18.4</td></tr>
<tr><td>*2012*</td><td>27</td><td>15</td><td>13</td><td>28</td><td>183</td><td>21</td><td>50</td><td>3.4</td><td>~~34.6~~ 31.8</td></tr>
</table>
</td></tr>
<tr><td>13</td><td>10</td><td>~~15.4 MW~~ 13.4 MW</td></tr>
<tr><td>13</td><td>10</td><td>~~9 MW~~ 6MW</td></tr>
</table>

14	1	**Table 8: Extrapolation of Post-2013 Energy-Efficiency Savings** (MW)

	Petition Allocation to Tremont East		Program Plans		Extrapolated			
					Per Petition		*Continue 2012 Incremental*	
	Cum.	Annual	Cum.	Annual	Annual	Cum.	Annual	Cum.
2010	3.9	3.9	7.6	7.6				
2011	8.8	4.9	~~19.2~~ 18.4	~~11.6~~ 10.8				
2012	14.8	6.0	~~34.6~~ 31.8	~~15.4~~ 13.4				
2013	21.4	6.5			~~16.7~~ 14.6	~~51.3~~ 46.4	~~15.4~~ 13.4	~~50.0~~ 45.3
2014	28.5	7.1			~~18.2~~ 15.9	~~69.5~~ 62.3	~~15.4~~ 13.4	~~65.4~~ 58.7
2015	35.0	6.5			~~16.7~~ 14.5	~~86.2~~ 76.9	~~15.4~~ 13.4	~~80.8~~ 72.2
2016	41.5	6.5			~~16.6~~ 14.5	~~102.8~~ 91.4	~~15.4~~ 13.4	~~96.2~~ 85.6
2017	47.5	5.9			~~15.2~~ 13.3	~~118.0~~ 104.6	~~15.4~~ 13.4	~~111.6~~ 99.0
2018	52.3	4.8			~~12.3~~ 10.8	~~130.3~~ 115.4	~~15.4~~ 13.4	~~126.9~~ 112.5
2019	55.5	3.2			~~8.1~~ 7.1	~~138.4~~ 122.5	~~15.4~~ 13.4	~~142.3~~ 125.9

15	3	Continue planned 2012 incremental savings
15	4	Savings in Tremont East about ~~30~~ 25
15	5	and ~~75-78 MW~~ 67-70 MW for 2018
18	10	~~NSTAR~~ The Company explains that
21	10	~~The Canal~~ Canal
28	6	~~The Canal~~ Canal
28	7	~~The Canal~~ Canal
28	9	Capacity of the ~~155~~ 115
28	12	~~The Canal~~ Canal
28	21	No load shedding ~~is~~ considered acceptable.
29	9	~~The Canal~~ Canal

29	18	~~The Canal~~ Canal
30	11	~~The Canal~~ Canal
30	16	~~The Canal~~ Canal
30	20	~~The Canal~~ Canal
31	1	~~The Canal~~ Canal
31	6	~~The Canal~~ Canal
31	8	~~The Canal~~ Canal
31	12	~~The Canal~~ Canal
31	14	~~The Canal~~ Canal
31	15	~~The Canal~~ Canal
31	17	~~The Canal~~ Canal
31	21	~~The Canal~~ Canal
32	3	~~The Canal~~ Canal
32	10	~~The Canal~~ Canal
32	11	~~The Canal~~ Canal
32	13	~~The Canal~~ Canal
33	15	~~The Canal~~ Canal
33	17	~~The Canal~~ Canal
33	18	~~The Canal~~ Canal
34	13	~~The Canal~~ Canal
35	4	~~The Canal~~ Canal
35	6	~~The Canal~~ Canal
35	4	~~The Canal~~ Canal
35	6	~~The Canal~~ Canal

35	10	~~The Canal~~ Canal
35	11	~~The Canal~~ Canal
35	15	~~The Canal~~ Canal
35	15	~~The Canal~~ Canal
35	18	~~The Canal~~ Canal
36	19	~~The Canal~~ Canal
37	1	~~The Canal~~ Canal
37	3	~~The Canal~~ Canal
37	6	~~The Canal~~ Canal
37	10	~~The Canal~~ Canal
38	1	Would rise to about $12 ~~14~~ million
38	2	Would be about $41 ~~77~~ million.
38	12	~~The Canal~~ Canal
38	17	~~The Canal~~ Canal
40	4	Emissions in New England for ozone
40	7	~~The Canal~~ Canal
40	19	~~The Canal~~ Canal
41	7	~~The Canal~~ Canal
42	3	~~The Canal~~ Canal
43	1	And unit 3 as being retired in June 2015
45	9	A Charles River Associates study ~~for the EPA~~
46	1	~~The Canal~~ Canal
48	6	~~The Canal~~ Canal
48	12	~~The Canal~~ Canal

48	14	~~The Canal~~ Canal
48	16	~~The Canal~~ Canal
48	17	~~The Canal~~ Canal
49	3	I re-estimated the forward capacity price and ~~the~~ Canal's economics
49	Ftnt.	~~or~~ and Newington
50	5	~~The Canal~~ Canal
50	15	~~The Canal~~ Canal
51	6	~~The Canal~~ Canal
51	7	~~The Canal~~ Canal
51	9	~~The Canal~~ Canal
51	10	~~The Canal~~ Canal
51	12	~~The Canal~~ Canal
51	20	~~The Canal~~ Canal
52	11	~~The Canal~~ Canal
53	15	~~The Canal~~ Canal
53	17	~~The Canal~~ Canal
54	3	~~The Canal~~ Canal
54	5	~~The Canal~~ Canal
54	17	~~The Canal~~ Canal
55	1	~~The Canal~~ Canal
55	20	~~The Canal~~ Canal
56	14	~~The Canal~~ Canal
56	18	~~The Canal~~ Canal
57	23	As I discuss~~ed~~ above

58	18	~~The Canal~~ Canal