Section IV Demand-Side Management Revisions

Exhibit IV-3: CORE Program Capacity Reductions
Based On Measures Installed Between June 16, 2006 and May 31, 2010

	Coincident With ISO-New England Peak	
	Summer kW	Winter kW
Residential		
ENERGY STAR Homes	123.1	493.8
Home Energy Solutions	510.8	1,306.2
Home Energy Assistance	445.1	830.7
ENERGY STAR Lighting	2,521.2	9,487.9
ENERGY STAR Appliances	609.2	763.0
Residential Utility Specific	36.4	1,286.7
Total Residential	**4,245.8**	**14,168.3**
Commercial & Industrial		
Small Business Energy Solutions	5,942.4	4,351.8
Large C & I Retrofit	8,737.3	6,546.5
New Equipment & Construction	5,453.0	3,855.4
C & I Utility Specific	618.3	532.5
Total Commercial & Industrial	**20,751.0**	**15,286.2**
Grand Total (June 16, 2006 – May 31, 2010)	24,996.9	29,454.5
Average kW/Month	526.2	620.1
Annualized Coincident Capacity Savings	**6,315.0**	**7,441.1**

A.4. The CORE Programs as a Demand-Side Resource

In summary, each year the CORE Programs implemented by PSNH save approximately 700 million $kWh_{lifetime}$ and reduce the coincident New England peak by 6.3 MW at a cost of $14.6 million. The average measure life is 12 years.

In applying this resource it is important to consider several restrictions imposed by New Hampshire legislation. The first has to do with targeting the CORE Programs to specific customers. For example, examining Exhibit IV-1 it becomes evident that the cost to save a kWh for a business customer is about half that needed to save a kWh for a residential customer. Shifting program dollars to the commercial and industrial sector would yield more kWh savings per dollar spent. However, PSNH believes that the enabling legislation[10] for the CORE Programs requires that the System Benefits Charge revenues be allocated to customers in proportion to the amount collected from each customer class.

Reliability is another important consideration when evaluating the CORE Programs as a means of meeting the energy and capacity needs of PSNH's customers. In general the key factor in determining their ability to perform when needed is their measure life. Unlike

[10] RSA 374-F:3.VI: BENEFITS FOR ALL CONSUMERS states in part, "Restructuring of the electric utility industry should be implemented in a manner that benefits all consumers equitably and does not benefit one customer class to the detriment of another. Costs should not be shifted unfairly among customers…"

1. Review of the Potentially Obtainable methodology and results;
2. Translation of the Potentially Obtainable savings data from 10-year state-wide estimates into annualized savings values specific to PSNH;
3. Identification of major measure/end use categories in which the estimated potential savings significantly exceeds PSNH's program savings goals reported in the *2010 CORE New Hampshire Energy Programs* plan filed with the Commission on September 30, 2009;
4. Identification of the measures (priority measures) within each major category that account for the majority of potential savings in that category;
5. Review and revision (if warranted) of the technical/market assumptions employed in the development of potential savings estimates for the priority measures;
6. Selection of priority measures for inclusion in the Market Potential Scenario;
7. Determination of the program design elements, customer incentive levels and other program costs required to achieve the estimated market potential;
8. Development of Market Potential Scenario annual program participation, cost and savings projections for the planning period 2011-2015;
9. TRC analysis of Market Potential Scenario.

Each task is described in detail in the following sections.

<u>Market Potential Methodology</u>

1. <u>Review of Potentially Obtainable Scenario</u>
   The methodology employed by GDS to develop the Potentially Obtainable Scenario was reviewed in order to evaluate and utilize the results in the development of PSNH's Market Potential Scenario for the LCIRP. As documented in the study report, GDS utilized a comprehensive modeling approach to analyze the state-wide energy efficiency electric and non-electric savings potential in all customer sectors. Separate models were developed for the Residential, Commercial and Industrial sectors. The model inputs consist of a combination of measure-specific and end-use specific technical, market and forecast sales data that were developed via primary and secondary data collection efforts described in the report. Energy savings, costs, and various market parameters were analyzed for hundreds of energy-saving measures. Every measure was analyzed for cost-effectiveness in order to estimate the aggregate cost-effective potential in New Hampshire.

2. <u>Translation of Potentially Obtainable savings into Annualized Savings Specific to PSNH</u>
   The GDS Study produced state-wide estimates of Demand Side Potential savings from electric and non-electric energy efficiency measures. PSNH's potential savings estimates apply to electric-savings measures installed in customer facilities within PSNH's service territory. The GDS electric savings potential results were therefore reduced by a factor derived from PSNH's percent of New Hampshire forecasted sales by customer sector.

   The GDS Study quantified Demand Side Potential savings in terms of annualized MWh savings in 2018 based on ten years of implementation of energy efficiency measures. The Maximum Achievable potential, defined as the "maximum penetration of an efficient measure that would be adopted absent consideration of

8. Development of Market Potential Scenario
The Market Potential Scenario was developed by increasing program participation from current levels over the period 2011-2015 in order to reach the amount of annualized potential savings in 2015. Once the annual participation trends were set, then the annual savings and costs were calculated on the basis of assumed cost and savings per participant for each measure category.

9. TRC Analysis of Market Potential Scenario
An economic analysis of the Market Potential Scenario was conducted utilizing the Total Resource Cost Test. The details of the benefit-cost analysis methodology are described in Section C.

B.2. Energy Efficiency Program Potential Savings and Costs

Summary of Results

As explained in detail in the following section, the Market Potential Scenario projections are based on increased market penetration in the following priority measure categories identified in the review of the GDS results:

- Expansion of HVAC, refrigeration, and process measure installations in all existing Commercial and Industrial facilities
- Addition of a retro-commissioning service component as part of the program serving large Commercial and Industrial customers
- Expansion of the Residential Energy Star Homes program
- Expansion of the New Hampshire Home Performance with Energy Star program
- The addition of a Residential second refrigerator removal service component
- Expansion of Residential LED and outdoor lighting control penetrations
- Expansion of smart power strip penetration

Exhibit IV-7 presents projected annual program expenditures, annualized electric savings (MWh), lifetime electric savings (MWh) and annualized peak demand savings (MW) for the Market Potential Scenario. Annual program expenditures are escalated at an annual inflation rate of 1.6 percent. Annualized savings represent the estimated savings at the meter from all measures installed during the corresponding year, assuming that all measures are installed at the beginning of the year. This convention is consistent with the GDS presentation of results and the annual CORE Program filings and benefit-cost analysis. Lifetime savings were calculated based on an assumed average life for each measure category.

The 2010 PSNH CORE Program budgeted expenditures and projected savings reported in the *2010 CORE New Hampshire Energy Efficiency Programs* filing (Attachment F) are presented here for comparison. Projected expenditures in 2015 are approximately 2.5 times the amount of current expenditures. Annualized MWh savings in 2015 are 68 percent higher than current projections. The increase in expenditures is greater than the increase in savings because:

component of the Energy Star Lighting program account for 70 percent of the 2010 level of annualized savings.

The magnitude of the effect of the EISA standards is illustrated by the Base Case Scenario projection of savings based on the continuation of the existing energy efficiency programs at current funding levels (see Section A.5). Exhibits IV-9 and IV-10 present a comparison of the expenditures and annualized MWh savings for the Market Potential and Base Case scenarios.

Exhibit IV-9: Market Potential and Base Case Savings

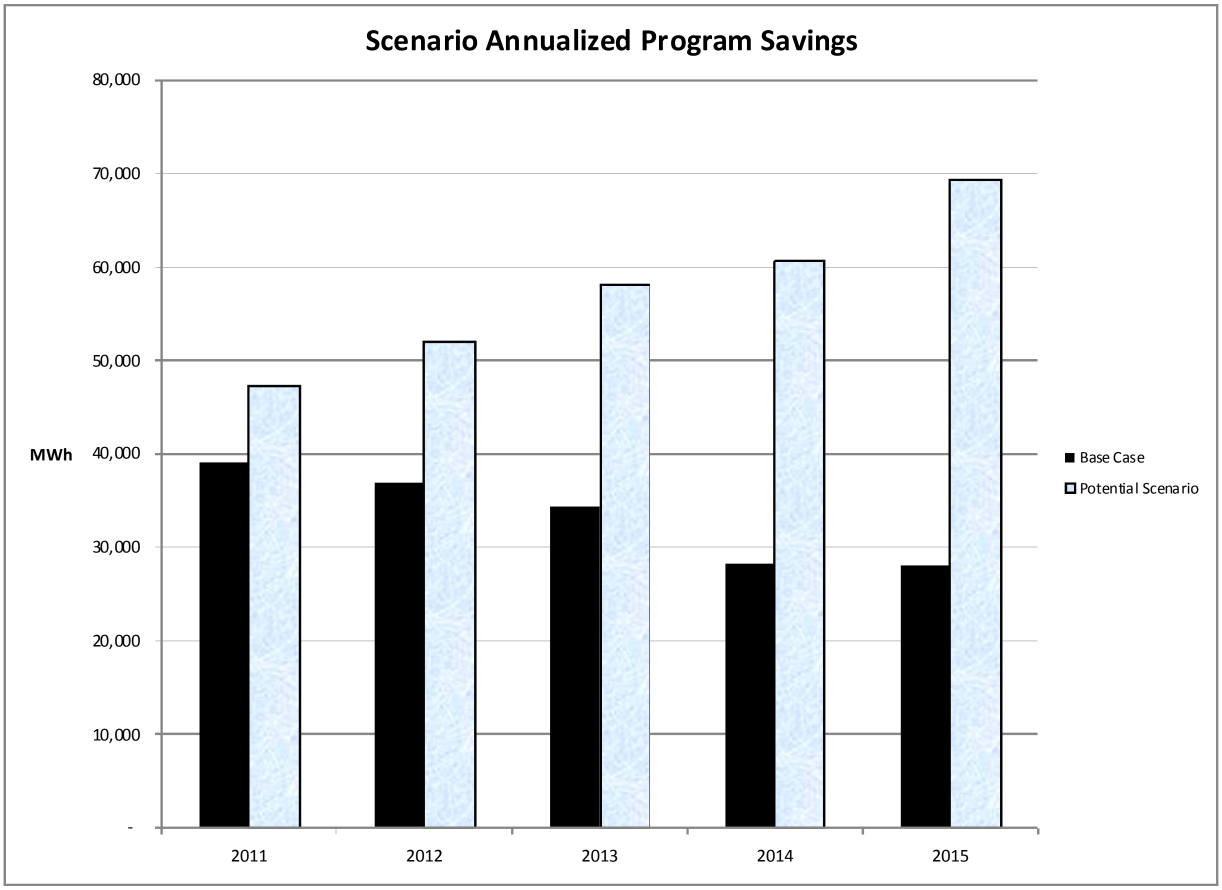


Exhibit IV-10: Market Potential and Base Case Expenditures and Savings

	Expenditures		Savings (MWh)	
Year	Base Case	Potential Scenario	Base Case	Potential Scenario
2011	$14,129,191	$18,943,345	39,075	47,243
2012	$14,349,606	$22,815,951	37,048	52,081
2013	$14,573,460	$27,376,176	34,312	58,159
2014	$14,800,806	$31,616,372	28,133	60,639
2015	$15,031,698	$35,799,709	28,102	69,332

Thus while the 2015 potential savings projection is 68 percent higher than the 2010 projection, as presented in Exhibit IV-7, it is 147 percent higher than the amount of the corresponding 2015 Base Case projection.

Commercial and Industrial (C&I) Sector Potential Analysis and Results

Analysis of Remaining Potential and Identification of Priority Measures

The GDS Study produced state-wide estimates of Demand Side Potential savings from electric and non-electric energy efficiency measures. PSNH's potential savings estimates apply to electric-savings measures installed in customer facilities within PSNH's service territory. The GDS electric savings results were therefore reduced by a factor derived from the PSNH's percent of New Hampshire forecasted sales by customer sector. The Commercial and Industrial factors are respectively 76 percent and 71 percent.

The GDS Obtainable Potential results for the Commercial and Industrial sector were annualized as described in Section B.1. The Obtainable Potential savings, annualized and adjusted for PSNH's service territory, were analyzed in order to identify the major measure/end-use categories in which the estimated potential savings significantly exceeds PSNH's program savings goals reported in the *2010 CORE New Hampshire Energy Programs* plan filed with the Commission on September 30, 2009.

Exhibit IV-11 presents a comparison of the GDS Obtainable Potential annualized MWh savings to PSNH's savings projection reported in the 2010 program plans. This comparison indicates that the current level of energy efficiency program activity is able to achieve the Obtainable Potential savings in New Construction and from the installation of Lighting measures in existing buildings. On the other hand, there remains significant potential to achieve additional savings in the HVAC and Other measure categories in existing buildings.

Exhibit IV-11: C&I Comparison of Obtainable Potential to Current Savings
(Annualized MWh)

Measure Category	Obtainable Potential	2010 CORE Savings	2015 Market Potential
New Construction	2,866	5,642	5,834
Existing Lighting	15,211	15,452	15,452
Existing HVAC	12,350	682	12,350
Existing Other	22,145	4,238	22,145
Total C&I	52,572	26,013	55,781

Exhibit IV-14: C&I Market Potential Scenario Program Expenditures

Program	2010	2011	2012	2013	2014	2015
SmartStart	$ 50,000	$ 50,000	$ 50,780	$ 51,572	$ 52,377	$ 53,194
Customer Partnerships	$ 30,000	$ 30,000	$ 30,468	$ 30,943	$ 31,426	$ 31,916
New Equipment & Construction	$ 1,958,884	$ 2,014,989	$ 2,046,423	$ 2,078,347	$ 2,110,769	$ 2,143,697
Large C&I Retrofit	$ 2,466,743	$ 3,559,620	$ 5,302,779	$ 6,928,998	$ 8,593,639	$ 10,308,530
Small Business Energy Solutions	$ 2,321,641	$ 2,524,561	$ 2,770,030	$ 2,970,971	$ 3,177,508	$ 3,389,765
RFP Program	$ 507,859	$ 766,384	$ 783,760	$ 1,081,138	$ 1,387,603	$ 1,703,366
Education	$ 157,507	$ 157,507	$ 159,964	$ 162,460	$ 164,994	$ 167,568
C&I Total	**$ 7,492,634**	**$ 9,103,061**	**$ 11,144,204**	**$ 13,304,429**	**$ 15,518,315**	**$ 17,798,036**

Residential Sector Potential Analysis and Results

Analysis of Remaining Potential

The GDS Study produced state-wide estimates of Demand Side Potential savings from electric and non-electric energy efficiency measures. PSNH's potential savings estimates apply to electric-savings measures installed in customers' facilities within PSNH's service territory. The GDS electric savings results were therefore reduced by a factor derived from PSNH's percent of New Hampshire forecasted sales by customer sector. The Residential factor is 72 percent.

The GDS Obtainable Potential results for the Residential sector were annualized as described in Section B.1. The Obtainable Potential savings, annualized and adjusted for PSNH's service territory, were analyzed in order to identify the major measure/end-use categories in which the estimated potential savings significantly exceeds PSNH's program savings goals reported in the *2010 CORE New Hampshire Energy Programs* plan filed with the Commission on September 30, 2009.

Exhibit IV-15 presents a comparison of the GDS Obtainable Potential annualized MWh savings to PSNH's savings projection reported in the 2010 program plans. This comparison indicates that in all measure categories the current level of CORE Program savings is substantially less than the Obtainable Potential savings and therefore that the remaining potential is significant. Also, in contrast to the C&I sector (see Exhibit IV-15), the projected Market Potential is much less than the Obtainable Potential savings. The reasons for this difference were briefly discussed in Section B.1 Methodology, Sub-Section 5. Review and Revision of Technical Assumptions and are discussed in more detail in the following section.

G. Other Influences

G.1. Legislature

In recent years the New Hampshire General Court has passed legislation related to the state's energy efficiency programs and available funding. Examples include:

- RSA 125-O:5-a established the Energy Efficiency and Sustainable Energy Board "…to promote and coordinate energy efficiency, demand response, and sustainable energy programs in the state."
- Senate Bill 228 (November 2005) and Senate Bill 300 (January 2010) temporarily reduced annual energy efficiency funding by $2.8 and $3.2 million respectively.
- RSA 374-F:4.VIII(e) which provides for limited use the System Benefits Charge for "Targeted conservation, energy efficiency, and load management programs and incentives that are part of a strategy to minimize distribution cost…" (Note: PSNH recently implemented a new Transmission and Distribution Procedure (TD-190) which incorporates into the distribution system planning process an examination of the potential for energy efficiency/demand response to delay infrastructure replacement expenditures.)
- House Bill 1377 (June 2010) permits utilities to establish loan programs for owners of residential and business property engaging in renewable energy and energy efficiency projects.
- Senate Bill 323 (January 2010) directs the Commission to contract an independent study of certain energy policy issues. The study is to include: (1) a comprehensive review and analysis of energy efficiency, conservation, demand response, and sustainable energy programs and initiatives in the state and to make recommendations for possible improvements; (2) the appropriate role of regulated energy utilities, providers of energy and energy efficiency, and others; (3) the effectiveness and sustainability of funds, and; (4) the policy changes that may be necessary to achieve the state's energy efficiency and sustainable energy goals. The final study is due November 1, 2011.

This list is not comprehensive, but serves to illustrate recent legislative actions. It is not the intent here to speculate regarding future legislative actions, but merely to point out that the plans presented here are subject to review and modification.

Appendix G Newington Station CUO Study Revisions

B. Executive Summary

Whether or not the ongoing value ascribable to PSNH's continued ownership and operation of Newington Station is greater than the costs borne by its customers is the central question in this evaluation. On a prospective basis, Newington Station is expected to provide PSNH's retail customers with both physical and financial protection in light of volatile wholesale energy and capacity prices, both in New Hampshire and New England as a whole. In LAI's view, prospective wholesale market dynamics over the study period, 2011 through 2020, are likely to remain both unpredictable and volatile. PSNH's ownership and continued operation of Newington Station confers positive value both to customers and the region.

Based on the quantitative analysis, highlights of the CUO analysis conducted by LAI are as follows:

- Newington Station provides PSNH's customers with 400 MW of capacity at a largely known cost, therefore providing a physical hedge against regulatory uncertainty associated with ISO-NE's administration of the FCM. While capacity prices are known with certainty for the next few years, many uncertainty factors have the potential to exert significant upward pressure on capacity prices from 2016 through 2020. Continued operation of Newington Station shields PSNH's customers from materially adverse economic consequences that may arise from evolving capacity market dynamics in New England. On an expected value basis, the net value of the physical hedge is about $31 million. Under plausible worst case conditions from the standpoint of PSNH's customers, the net value of the physical capacity hedge is about $54 million.

- The expected net present value (NPV) of the incremental revenue requirements indicates substantial economic benefits are associated with PSNH's continued operation of Newington Station. The expected NPV is over $71 million.

- There is virtually no risk of actual benefits resulting in a negative NPV. Simulation of market prices for capacity, energy, and fuels results in a 0% probability that the NPV of benefits will be negative. There is a 5% probability of an NPV outcome between zero and $47 million, and a 90% probability of an NPV between $47 million and $105 million. The median result is $64 million. With respect to an "earnings surprise" related to continued operation of the Station, there is a 5% probability of an NPV greater than $105 million. One reason why the NPV benefits are always positive from the customers' perspective is that Newington Station's sunk costs are excluded from the determination of going-forward cash costs through 2020.

- The risk of market based revenues being lower than Newington Station's incremental revenue requirement in any single year over the ten year study period is low. This is a result of the anticipated deterioration in capacity prices associated with the MW overhang in New England and ISO-NE's FCM restructuring proposal. On an expected value basis, Newington Station *always* shows that market based revenues are higher than its incremental revenue requirement. Simulation indicates less than a 1% chance that market based revenues come in lower than

Newington Station's incremental revenue requirement in either 2017 or 2018, evaluated separately.

- The distribution of economic benefits on an NPV or year-by-year basis is heavily skewed toward relatively small positive outcomes. Given Newington Station's operational characteristics and the range of anticipated capacity prices in New England over the study period, there is only a 25% chance of an NPV greater than $88 million.

- A large portion of the net benefit of Newington Station's continued operation is derived from its ability to operate flexibly in the DA and RT energy markets. The present value of fixed costs (direct and indirect fixed O&M, property taxes, and incremental depreciation and return on rate base) of $80.4 million is offset by an expected value of capacity market revenues of $111.2 million, for a $30.8 million benefit. The remaining $40.7 million in expected value of net benefit is derived from net margins earned in the energy and ancillary service markets, and reflects the physical option values arising from the Station's operational dispatch flexibility and its ability to burn natural gas and/or oil, including adjusting the blend of both fuels on-the-fly. The Station's operational flexibility allows it to serve as a physical hedge against volatile DAM and RTM energy prices, as well as volatile and unpredictable trends in the natural gas and oil commodity markets.

- The additional insurance-like or financial hedge value of Newington Station as a substitute for energy load-following contracts is roughly estimated to be a risk premium equivalent to about 10% of the price of monthly on-peak contracts.

- From PSNH's customers' perspective, the positive expected NPV, coupled with the wide and skewed dispersion of potential economic results around the expected value, supports continued operation of Newington Station through 2020.

In addition to the more readily quantified benefits of continued operation, Newington Station also provides other benefits that are reported on a qualitative basis, as follows:

- The operational flexibility to adjust bidding in the DAM also allows PSNH to operate Newington Station at critical times in a risk-averse manner to safeguard against bad economic outcomes in the RTM. The Station also serves to backstop at a known cost a forced outage at one of PSNH's other generating stations.

- While Newington Station is operational, PSNH customers benefit from the real option value associated with waiting for more information before making a retirement timing decision.

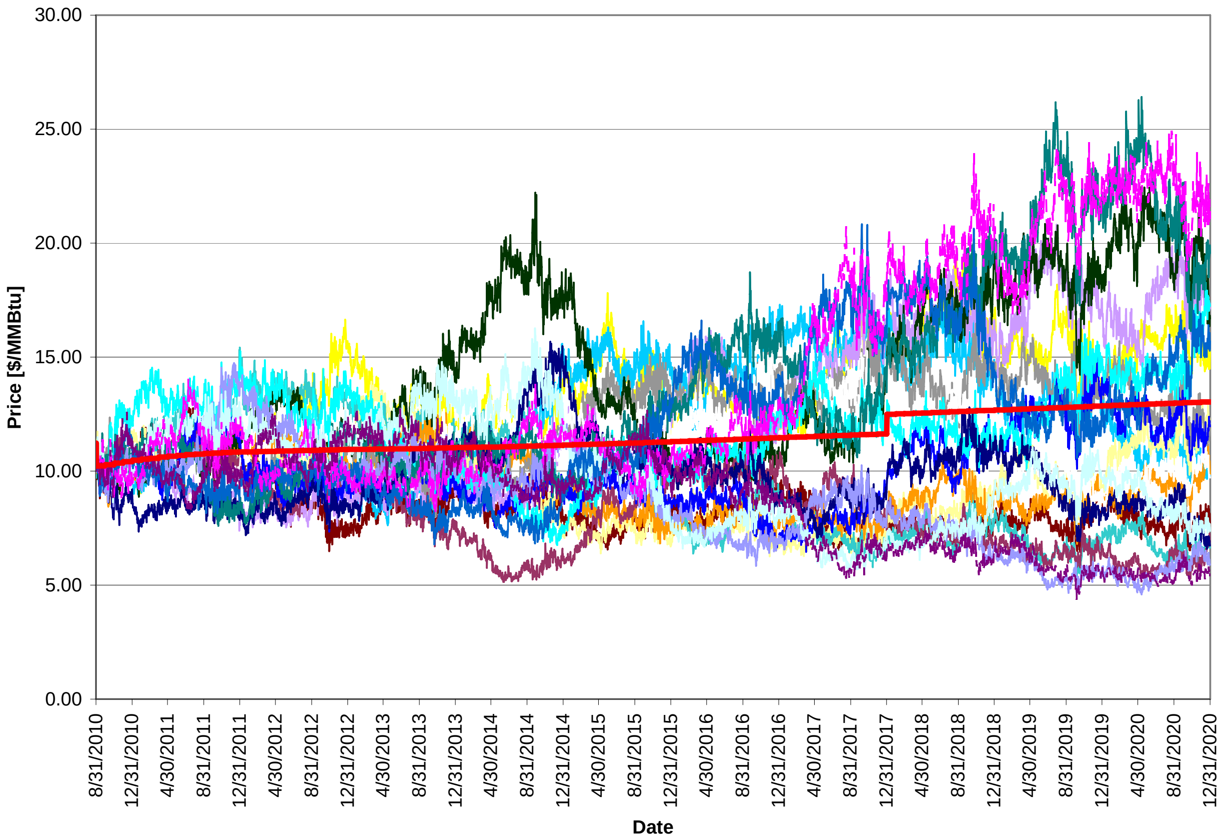
- Newington Station's participation in the FCM provides capacity price suppression benefits to PSNH's customers as well as to other customers throughout New Hampshire and New England.

- Newington Station's electrical interconnection yields transmission and distribution system reliability benefits. Likewise, Newington's flexible fuel mix and large on-site oil tankage provides energy diversity benefits when natural gas deliverability is

Exhibit G.7: Estimated Going Forward Fixed Portion of Annual Revenue Requirements

	Present Value EOY 2010	Calendar Year 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expenses ($000)											
Non-Fuel O&M with Indirects											
Other than Emission Allowances	$57,236	$7,498	$7,706	$7,920	$8,139	$8,366	$8,600	$8,841	$9,089	$9,343	$9,605
Emission Allowances		**Varies with simulated output and fuel mix**									
Total O&M Expense											
Fuel and Fuel Related O&M		**Varies with simulation output, fuel mix, and fuel prices**									
Property Tax	$9,057	$958	$1,034	$1,117	$1,206	$1,303	$1,407	$1,520	$1,641	$1,773	$1,914
Depreciation Expense	$2,879	$50	$106	$168	$240	$323	$423	$548	$715	$965	$1,465
Total Expenses											
Rate Base ($000)											
Incremental Gross Plant Value		$500	$1,000	$1,500	$2,000	$2,500	$3,000	$3,500	$4,000	$4,500	$5,000
Incremental Accum. Depreciation		$50	$156	$324	$563	$886	$1,309	$1,857	$2,571	$3,536	$5,000
Net Plant Value		$450	$844	$1,176	$1,437	$1,614	$1,691	$1,643	$1,429	$964	($0)
Working Capital		$925	$925	$925	$925	$925	$925	$925	$925	$925	$925
Accumulated Deferred Taxes		$12	$32	$64	$112	$181	$279	$417	$613	$898	$1,372
Fuel Inventory (year end)		$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000
NOx, SO2, CO2 Allowance Inventory		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Material & Supply Inventory		$2,500	$2,500	$2,500	$2,500	$2,500	$2,500	$2,500	$2,500	$2,500	$2,500
Total Rate Base		$13,887	$14,301	$14,665	$14,973	$15,219	$15,395	$15,485	$15,466	$15,287	$14,796
Average Return on Rate Base		*11.09%*	*11.09%*	*11.09%*	*11.09%*	*11.09%*	*11.09%*	*11.09%*	*11.09%*	*11.09%*	*11.09%*
Return on Rate Base ($000)	**$11,271**	**$1,540**	**$1,586**	**$1,626**	**$1,660**	**$1,688**	**$1,707**	**$1,717**	**$1,715**	**$1,695**	**$1,641**
Expenses Plus Return on Rate Base											
Revenues ($000)											
Energy		**Varies with simulated output and energy prices**									
Capacity		$17,250	$13,343	$12,121	**Varies with capacity prices**						
Ancillary	$1,367	$200	$200	$200	$200	$200	$200	$200	$200	$200	$200
10 MW Unitil Entitlement	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Revenue											
NET REVENUE REQUIREMENT											

Exhibit G.10: Example of 20 RFO Price Paths and Expected Prices



F.2.3. Stochastic Energy Price Scenarios

Expected monthly DA on-peak and off-peak prices at the Newington node were simulated with a three step procedure. First, monthly and strip (bi-monthly to annual) forward on-peak and off-peak prices at the Massachusetts Hub (MassHub) on August 27, 2010 were used. Second, historical hourly spot price ratios of the Newington node to the MassHub node prices were used to shape the bi-monthly to annual strip forward prices into monthly on-peak and off-peak prices at the Newington node. Third, the Newington node monthly on-peak and off-peak forward prices for the period beyond the end of the MassHub node forwards in 2015 were estimated based on the historical market heat rate relationship between Dracut natural gas spot prices and Newington node hourly energy spot prices. The resulting forward monthly DA on-peak and off-peak prices are shown in Exhibit G.11.

F.3. Modeling Method for Dispatch Simulation

To perform the ROV analysis, a dispatch simulation model was developed that accounts for Newington's chronological constraints, fuel-blending constraints, and ability to dispatch in the RTM as well as the DAM. The dispatch model represented the multiple operating states with respect to natural gas combustion constraints on the fuel mix, the heat rate curve, cold and warm start times and fuel use, the NO_x emissions curve, minimum up and down times, and ramping rates. The model is run with the set of stochastic price paths, and also simulates random forced outages. Newington's commitment and dispatch is simulated with the objective of maximizing its expected net operating revenue (equivalent to minimizing the expected cost to customers). The simulation model dispatches the Station against ISO-NE spot market prices. The dispatch simulation model does not use perfect foresight to "see" RTM prices when bidding into the DAM, and it does not see the onset of a forced outage. By separately dispatching any available capacity against RTM prices, the model allows some additional gross margin to be realized. Net commitment period cost or uplift revenues and expenses were not modeled. Prospective Newington Station fixed O&M costs, including additional capital expenditures to ensure plant availability and efficiency, were not treated as an uncertainty factor.

Results by simulation path are cumulated over the years of the study period into a NPV for that path. After all the stochastic paths have been simulated, the expected values and probability distributions of annual values and of the NPV are calculated for reporting in tabular or graphical form. Each scenario has the same weight, so the expected value is the simple average or mean value across scenarios.

F.4. Asset Value Simulation Analysis Results

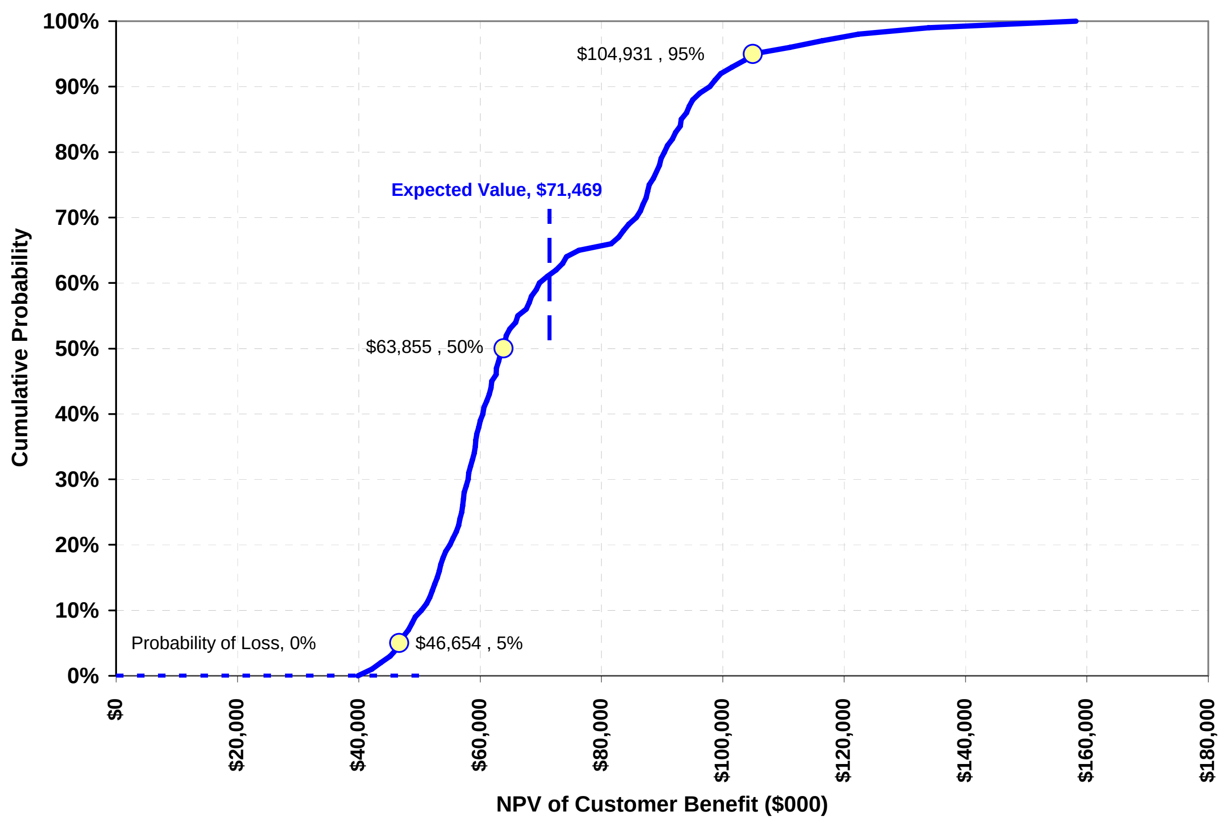
The results of the probabilistic and ROV simulation analysis are presented in the following table and set of graphs. Exhibit G.12 presents the expected annual values of incremental revenue requirements (negative value is customer benefit) for 2011 through 2020 and the NPV of incremental revenue requirements at the end of 2010. The expected values are the equally-weighted average values across the set of simulated scenarios. Incremental revenue requirements for continued operation of Newington Station are negative in every year, indicating that the Station provides value to customers. The expected NPV of customer benefits is over $71 million. Exhibit G.12 shows the same expense and revenue line items as the historical revenue requirements table, Exhibit G.1, in Section D.1. Notice that fuel expenses and energy revenues are fairly uniform over the ten-year simulation period and similar in magnitude as the average of the last five years, shown in Exhibit G.1.

Exhibit G.12: Expected Values of Incremental Revenue Requirements

	Present Value EOY 2010		Calendar Year 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expenses ($000)												
Non-Fuel O&M with Indirects												
Other than Emission Allowances	$57,236		$7,498	$7,706	$7,920	$8,139	$8,366	$8,600	$8,841	$9,089	$9,343	$9,605
Emission Allowances	$2,752		$356	$313	$321	$377	$434	$456	$466	$445	$469	$513
Total O&M Expense	$59,988		$7,854	$8,019	$8,241	$8,516	$8,800	$9,056	$9,307	$9,534	$9,812	$10,118
Fuel and Fuel Related O&M	$142,143		$16,145	$15,692	$17,095	$20,134	$23,027	$23,490	$24,160	$23,878	$25,084	$26,856
Property Tax	$9,057		$958	$1,034	$1,117	$1,206	$1,303	$1,407	$1,520	$1,641	$1,773	$1,914
Depreciation Expense	$2,879		$50	$106	$168	$240	$323	$423	$548	$715	$965	$1,465
Total Expenses	**$214,066**		**$25,007**	**$24,850**	**$26,621**	**$30,096**	**$33,452**	**$34,375**	**$35,535**	**$35,767**	**$37,633**	**$40,352**
Rate Base ($000)												
Incremental Gross Plant Value			$500	$1,000	$1,500	$2,000	$2,500	$3,000	$3,500	$4,000	$4,500	$5,000
Incremental Accum. Depreciation			$50	$156	$324	$563	$886	$1,309	$1,857	$2,571	$3,536	$5,000
Net Plant Value			$450	$844	$1,176	$1,437	$1,614	$1,691	$1,643	$1,429	$964	($0)
Working Capital			$925	$925	$925	$925	$925	$925	$925	$925	$925	$925
Accumulated Deferred Taxes			$12	$32	$64	$112	$181	$279	$417	$613	$898	$1,372
Fuel Inventory (year end)			$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000
NOx, SO2, CO2 Allowance Inventory			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Material & Supply Inventory			$2,500	$2,500	$2,500	$2,500	$2,500	$2,500	$2,500	$2,500	$2,500	$2,500
Total Rate Base			$13,887	$14,301	$14,665	$14,973	$15,219	$15,395	$15,485	$15,466	$15,287	$14,796
Average Return on Rate Base			*11.09%*	*11.09%*	*11.09%*	*11.09%*	*11.09%*	*11.09%*	*11.09%*	*11.09%*	*11.09%*	*11.09%*
Return on Rate Base ($000)	**$11,271**		**$1,540**	**$1,586**	**$1,626**	**$1,660**	**$1,688**	**$1,707**	**$1,717**	**$1,715**	**$1,695**	**$1,641**
Expenses Plus Return on Rate Base	**$225,337**		**$26,547**	**$26,436**	**$28,247**	**$31,756**	**$35,140**	**$36,082**	**$37,252**	**$37,482**	**$39,328**	**$41,993**
Revenues ($000)												
Energy	$184,234		$20,987	$20,366	$22,190	$26,135	$29,886	$30,223	$31,053	$30,887	$32,727	$34,929
Capacity	$111,205		$17,250	$13,343	$12,121	$12,779	$13,791	$14,903	$16,420	$17,830	$22,106	$29,026
Ancillary	$1,367		$200	$200	$200	$200	$200	$200	$200	$200	$200	$200
10 MW Unitil Entitlement	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Revenue	**$296,806**		**$38,437**	**$33,909**	**$34,511**	**$39,114**	**$43,877**	**$45,326**	**$47,673**	**$48,917**	**$55,032**	**$64,156**
NET REVENUE REQUIREMENT	**($71,469)**		**($11,890)**	**($7,473)**	**($6,264)**	**($7,358)**	**($8,737)**	**($9,244)**	**($10,421)**	**($11,435)**	**($15,704)**	**($22,163)**

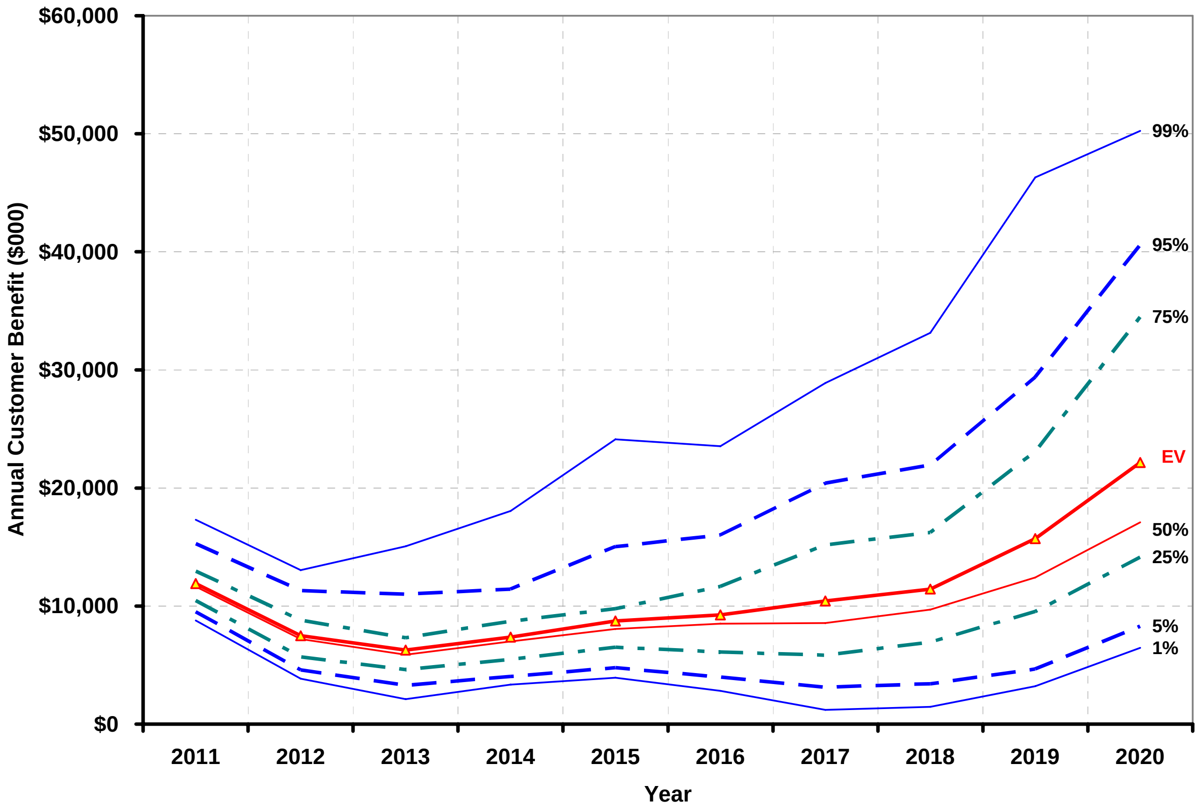
Most of the expense items have the same values in each stochastic scenario. It is therefore convenient to examine the entire probability distribution of customer benefits in the form of a cumulative density function graph, shown in Exhibit G.13. Customer benefits are defined as a reduction in incremental revenue requirements. The shape of the curve allows inspection of the NPV of customer benefits associated with a given probability level. The expected NPV dashed line on the graph corresponds to the expected NPV benefit of a reduction in incremental revenue requirements in Exhibit G.12 of $71 million. Importantly, the distribution indicates that none of the simulated scenarios results in a negative customer benefits NPV outcome. The median NPV of $64 million is substantially less than the mean or expected NPV, indicating significant right skew in the distribution. In other words, more of the equally probable scenarios have outcomes below than above the expected NPV.

Exhibit G.13: Cumulative Distribution of NPV of Customer Benefits



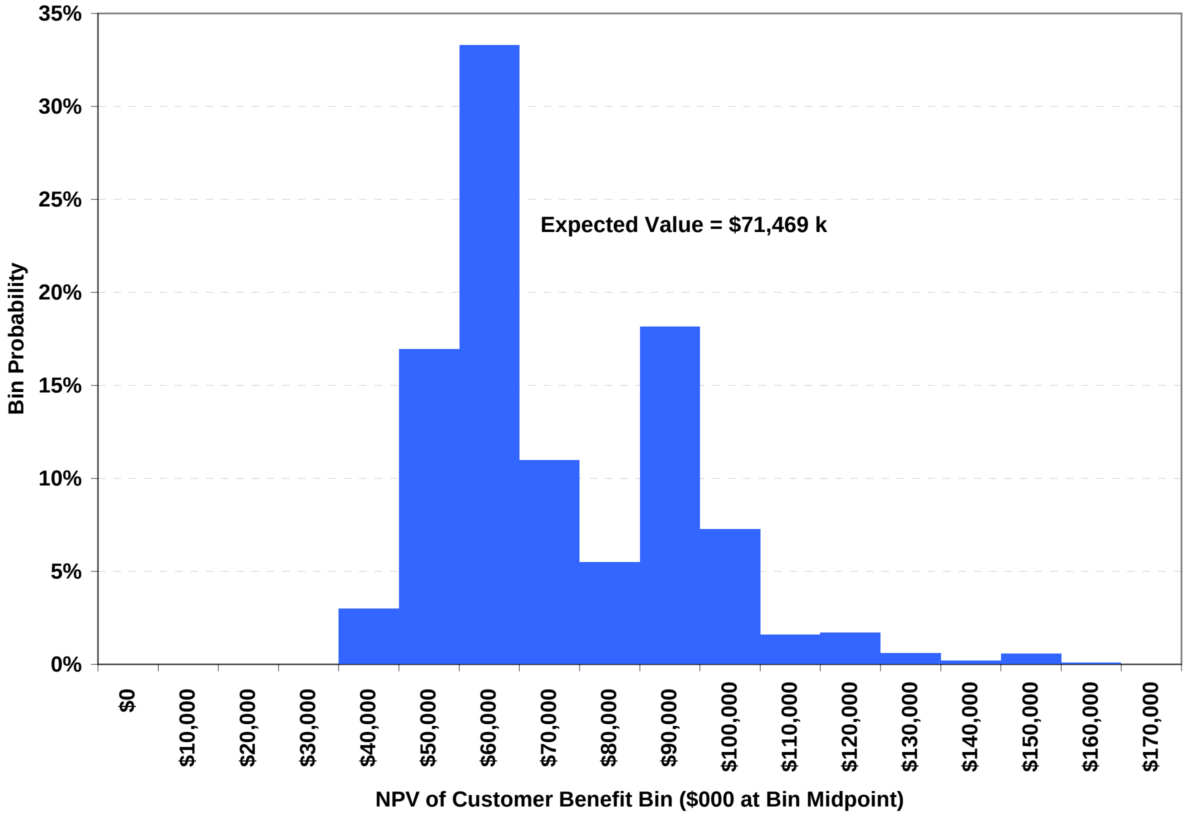
While on a ten-year NPV basis there is no modeled probability of a loss, Exhibit G.14 indicates that the annual energy net margin is very small at the 1% probability level in some years. There is less than a 1% probability that small losses would occur in years 2017 and 2018. The timing of possible annual losses in these years is driven largely by the sudden uncertainty in capacity prices that begins then. The lead time of seven years before any probable losses are expected to occur means that a retirement decision should be deferred until such time that losses begin to occur.

Exhibit G.14: Annual Distributions of Undiscounted Customer Benefits



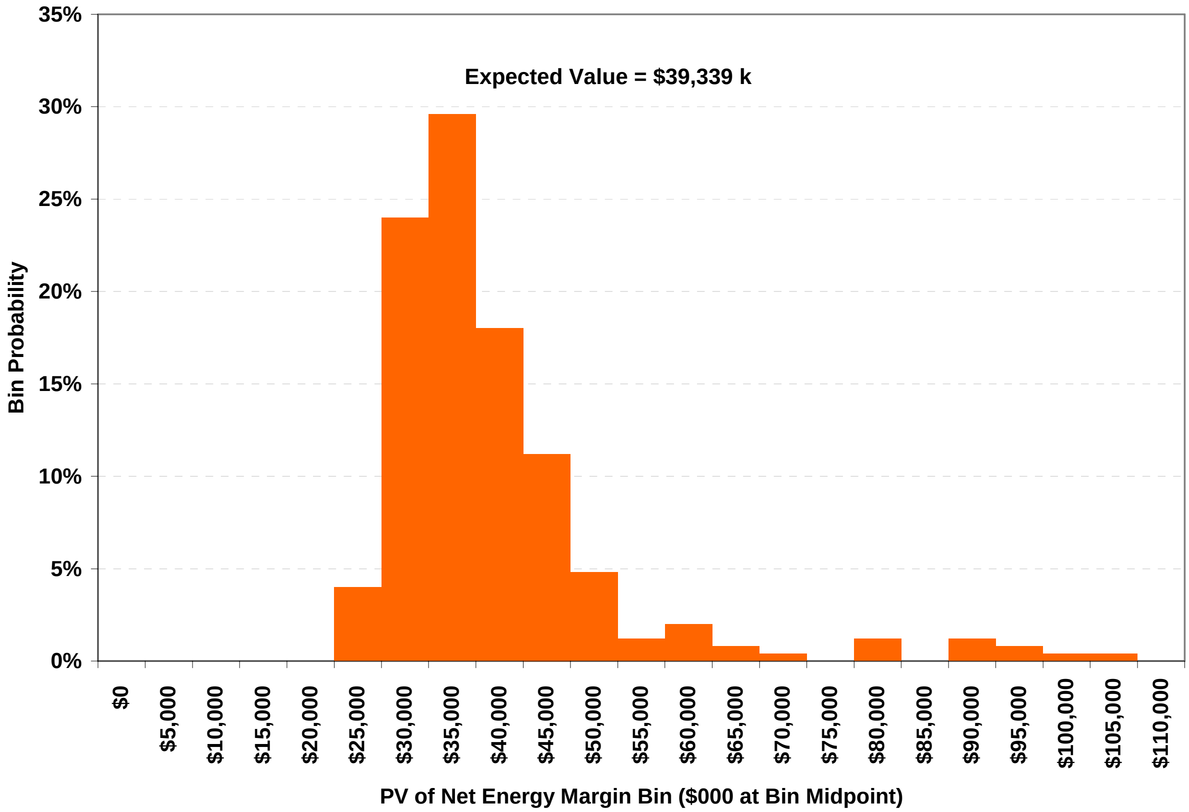
The skew in the distribution is more easily visualized in a probability distribution function histogram, shown in Exhibit G.15. Around the mean or expected NPV of $71 million, the distribution has a much longer right tail than left tail. While representing a small portion of the probable outcomes, the very large benefits in the right-hand tail of the histogram indicate a large portion of the hedge or insurance value of keeping Newington Station in operation. Without Newington, these low-probability but large benefits would instead be high cost outcomes for customers.

Exhibit G.15: Probability Distribution of NPV of Customer Benefits



A substantial portion of the right-tail skew of the NPV of revenue requirements reduction benefits is due to the completely skewed distribution of energy net revenues (revenues minus fuel and fuel-related expenses), shown in the histogram of Exhibit G.16. Around the expected NPV of energy net revenue of over $39 million ($184 million energy revenue minus $145 million fuel and emission costs), there are only three smaller bins but 13 larger bins. The largest bin of energy net revenues is the third from the left, and the probabilities drop off quickly at higher energy revenue levels. The reason the NPV of revenue requirements reduction distribution in Exhibit G.15 has a less skewed distribution is due to the relatively symmetric weighting of the three capacity price scenarios (20%, 50%, and 30% probability, respectively, for the Low, Mid, and High price scenarios), combined with the assumption that fuel and energy prices are not correlated with capacity prices. The assumption of a zero correlation between energy and fuel prices versus capacity prices is a relatively conservative assumption. It is possible that the true correlation is slightly negative, meaning that if the spark spread for combustion turbine peaking units tended to decrease (increase) over time, then capacity prices would tend to be adjusted upwards (downwards), thereby mitigating the combined net impacts of capacity and energy products for generators and load.

Exhibit G.16: Probability Distribution of NPV of Energy Net Revenue



The annual capacity factor, service factor, number of starts, and fuel mix at the expected (mean), P50 (median), and P25 levels of energy net revenue for each year in the analysis (2011-2020) are shown in Exhibit G.17. The P50 and P25 results are for the individual scenarios at the 50th and 25th percentiles, respectively, of energy net revenue.

Exhibit G.17: Operational Performance at Selected Annual Energy Net Revenue Probability Levels

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expected Value										
DAM Dispatch Hours	911	797	791	890	981	1009	1024	1031	1058	1147
RTM Dispatch Hours	55	42	55	71	83	85	86	73	78	85
Generation (GWh)	279.8	244.0	248.3	285.8	321.8	332.7	338.5	332.6	344.9	375.8
Number of Starts	39	38	33	37	40	44	45	44	45	47
2FO Consumption (BBtu)	10.6	9.9	9.6	10.4	11.0	11.6	11.7	11.5	11.8	12.1
RFO Consumption (BBtu)	15.7	33.7	75.7	189.6	359.7	465.2	511.5	371.3	504.6	589.8
Gas Consumption (BBtu)	3,113.5	2,704.3	2,707.5	3,011.8	3,238.8	3,255.6	3,272.3	3,348.4	3,349.6	3,606.3
CO2 Emitted (1000 ton)	184.3	161.9	165.7	193.4	221.6	231.7	236.7	229.0	240.7	263.1
SO2 Emitted (ton)	22.0	30.2	51.4	112.8	203.9	261.0	285.7	113.7	149.2	172.7
NOx Emitted (ton)	184.6	162.9	168.3	199.8	233.1	245.8	252.1	240.3	255.3	280.5
Capacity Factor (%)	8.0%	7.0%	7.1%	8.2%	9.2%	9.5%	9.7%	9.5%	9.8%	10.7%
Service Factor (%)	11.0%	9.6%	9.7%	11.0%	12.2%	12.5%	12.7%	12.6%	13.0%	14.1%
Energy Revenue ($1000)	20,987	20,366	22,190	26,135	29,886	30,223	31,053	30,887	32,727	34,929
Energy Cost ($1000)	16,501	16,005	17,416	20,511	23,461	23,945	24,626	24,323	25,553	27,369
Net Revenue ($1000)	4,486	4,362	4,775	5,624	6,426	6,278	6,426	6,565	7,174	7,560
P50 (Median)										
DAM Dispatch Hours	838	571	804	1185	937	940	1498	1595	1767	1498
RTM Dispatch Hours	16	48	28	41	192	77	92	101	100	48
Generation (GWh)	253.0	180.7	243.5	362.3	361.2	298.4	461.5	488.6	539.5	450.2
Number of Starts	22	20	25	35	49	37	76	73	88	61
2FO Consumption (BBtu)	7.5	7.1	8.6	10.5	12.9	11.3	17.6	16.0	21.5	14.9
RFO Consumption (BBtu)	0.0	34.1	7.8	13.4	931.2	50.9	83.5	57.3	124.0	5.6
Gas Consumption (BBtu)	2,796.9	1,994.3	2,719.7	4,034.3	3,106.5	3,295.2	5,102.2	5,416.7	5,939.0	5,036.7
CO2 Emitted (1000 ton)	164.2	120.2	160.4	238.0	263.6	198.1	307.1	323.1	359.8	296.3
SO2 Emitted (ton)	6.7	25.2	11.9	19.8	508.1	38.6	68.9	40.3	62.7	22.3
NOx Emitted (ton)	165.7	121.1	160.8	240.4	296.2	200.1	309.6	323.9	363.1	297.4
Capacity Factor (%)	7.2%	5.2%	6.9%	10.3%	10.3%	8.5%	13.2%	13.9%	15.4%	12.8%
Service Factor (%)	9.7%	7.1%	9.5%	14.0%	12.9%	11.6%	18.2%	19.4%	21.3%	17.6%
Energy Revenue ($1000)	16,766	17,101	20,478	23,946	30,062	24,785	26,735	24,676	29,314	28,969
Energy Cost ($1000)	12,542	13,030	16,096	18,694	24,283	19,276	21,264	18,870	23,553	22,659
Net Revenue ($1000)	4,225	4,072	4,382	5,252	5,779	5,509	5,471	5,805	5,762	6,310
P25										
DAM Dispatch Hours	787	772	1099	625	839	643	610	928	721	870
RTM Dispatch Hours	42	53	31	12	69	80	47	56	28	76
Generation (GWh)	239.1	236.4	328.5	187.1	265.8	218.2	189.0	285.0	215.4	268.9
Number of Starts	36	43	43	30	26	29	32	43	31	56
2FO Consumption (BBtu)	9.9	11.5	12.8	7.8	8.4	8.9	8.6	10.3	7.8	13.7
RFO Consumption (BBtu)	1.5	0.0	0.0	15.5	11.2	162.9	2.8	0.0	0.0	38.5
Gas Consumption (BBtu)	2,686.7	2,664.7	3,683.7	2,085.4	2,959.2	2,288.4	2,124.9	3,191.2	2,416.7	2,986.0
CO2 Emitted (1000 ton)	158.1	156.8	216.5	123.9	174.7	148.7	125.2	187.5	142.0	179.1
SO2 Emitted (ton)	13.7	15.3	13.8	17.0	16.4	96.1	12.6	15.4	10.6	28.0
NOx Emitted (ton)	157.7	155.7	216.6	125.0	176.1	155.1	124.6	187.5	141.4	178.6
Capacity Factor (%)	6.8%	6.7%	9.4%	5.3%	7.6%	6.2%	5.4%	8.1%	6.1%	7.7%
Service Factor (%)	9.5%	9.4%	12.9%	7.3%	10.4%	8.3%	7.5%	11.2%	8.6%	10.8%
Energy Revenue ($1000)	15,042	15,695	16,350	18,130	19,560	23,628	21,981	24,288	20,666	24,132
Energy Cost ($1000)	11,984	13,116	13,242	14,374	15,382	19,332	17,912	20,025	16,377	19,295
Net Revenue ($1000)	3,059	2,578	3,109	3,756	4,178	4,296	4,069	4,263	4,289	4,837

F.5. Additional Insurance-Like Hedge Value Results

As discussed in Section E.2.2, in addition to Newington Station's operational flexibility and fuel-blending flexibility, which provide physical option values, the Station also helps to protect PSNH's customers from adverse market conditions on an annual and shorter-term timeframe in the power and fuel markets for forward and option contracts. Also, Newington Station provides RTM protection without the need to enter into contracts for supplemental power and outage insurance. Absent Newington Station, PSNH would consider entering into such arrangements to protect its customers during infrequent but materially adverse economic consequences that may arise from evolving capacity market dynamics in New England. On an expected value basis, the net value of the physical capacity hedge is about $31 million. Under plausible worst case conditions the net value of the physical capacity hedge is about $54 million.

- Second, the expected NPV of customer benefits (decrease in incremental net revenue requirements) indicates substantial economic benefits associated with PSNH's continued operation of Newington Station. The expected NPV is $71 million, an outcome that can be represented as deep-in-the-money from PSNH's customers' perspective.

- Third, the risk of negative NPV of customer benefits is low. Simulation of market prices for capacity, energy, and fuels results in a 0% probability that the NPV of benefits will be negative. There is a 5% probability of an NPV outcome between zero and $47 million, and a 90% probability of NPV between $47 million and $105 million. The median result is $64 million. With respect to a positive "earnings surprise" related to continued operation of the Station, there is a 5% probability of an NPV greater than $105 million. One of the reasons why the NPV benefits are always positive from the customers' perspective is explained by the proper exclusion of Newington Station's sunk cost in the determination of going-forward cash costs through 2020.

- Fourth, the risk of not covering Newington Station's incremental revenue requirements in any single year over the ten year study period is low. On an expected value basis, Newington Station *always* covers its incremental revenue requirement. However, there is less than a 1% chance that market based revenues will be insufficient for Newington Station to cover its incremental revenue requirement in 2017 and 2018, evaluated separately. This is a result of the anticipated deterioration in capacity prices associated with the MW overhang in New England and ISO-NE's FCM restructuring proposal. The trough in the capacity price forecasts for the Low and Mid scenarios is the 2016/17 capacity year. A combination of low capacity prices and low energy net revenues in some simulated scenarios results in low total revenues in the 2017 and 2018 calendar years.

- Fifth, the distribution of economic benefits on an NPV or year-by-year basis is heavily skewed toward relatively small positive outcomes. Given Newington Station's operational characteristics and the range of anticipated capacity prices in New England over the study period, there is a low probability of very large benefits, in other words, only a 25% chance of an NPV greater than $88 million.

- Sixth, a large portion of the net benefit of Newington Station's continued operation is derived from its ability to operate flexibly in the DAM and RTM energy markets. The present value of fixed costs (direct and indirect fixed O&M, property taxes, and incremental depreciation and return on rate base) of $80.4 million is first offset by an expected value of capacity market revenues of $111.2 million, for a $30.8 million benefit. The remaining $40.7 million in expected value of net benefit is derived from net margins earned in the energy and ancillary service markets, and reflects the physical option values from the Station's operational dispatch flexibility and ability to burn natural gas and/or oil, including adjusting the blend of both fuels on-the-fly.

Section IV Demand-Side Management Revisions

Exhibit IV-3: CORE Program Capacity Reductions Based On Measures Installed Between June 16, 2006 and May 31, 2010

	Coincident With ISO-New England Peak	
	Summer kW	**Winter kW**
Residential		
ENERGY STAR Homes	123.1	493.8
Home Energy Solutions	510.8	1,306.2
Home Energy Assistance	445.1	830.7
ENERGY STAR Lighting	2,521.2	9,487.9
ENERGY STAR Appliances	609.2	763.0
Residential Utility Specific	36.4	1,286.7
Total Residential	**4,245.8**	**14,168.3**
Commercial & Industrial		
Small Business Energy Solutions	5,942.4	4,351.8
Large C & I Retrofit	8,737.3	6,546.5
New Equipment & Construction	5,453.0	3,855.4
C & I Utility Specific	618.3	532.5
Total Commercial & Industrial	**20,751.0**	**15,286.2**
Grand Total (June 16, 2006 – May 31, 2010)	24,996.9	29,454.5
Average kW/Month	526.2	620.1
Annualized Coincident Capacity Savings	**6,315.0**	**7,441.1**

A.4. The CORE Programs as a Demand-Side Resource

In summary, each year the CORE Programs implemented by PSNH save approximately 700 million $kWh_{lifetime}$ and reduce the coincident New England peak by 6.3 MW at a cost of $14.6 million. The average measure life is 12 years.

In applying this resource it is important to consider several restrictions imposed by New Hampshire legislation. The first has to do with targeting the CORE Programs to specific customers. For example, examining Exhibit IV-1 it becomes evident that the cost to save a kWh for a business customer is about half that needed to save a kWh for a residential customer. Shifting program dollars to the commercial and industrial sector would yield more kWh savings per dollar spent. However, PSNH believes that the enabling legislation[10] for the CORE Programs requires that the System Benefits Charge revenues be allocated to customers in proportion to the amount collected from each customer class.

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Reliability is another important consideration when evaluating the CORE Programs as a means of meeting the energy and capacity needs of PSNH's customers. In general the key factor in determining their ability to perform when needed is their measure life. Unlike

[10] RSA 374-F:3.VI: BENEFITS FOR ALL CONSUMERS states in part, "Restructuring of the electric utility industry should be implemented in a manner that benefits all consumers equitably and does not benefit one customer class to the detriment of another. Costs should not be shifted unfairly among customers…"

1. Review of the Potentially Obtainable methodology and results;
2. Translation of the Potentially Obtainable savings data from 10-year state-wide estimates into annualized savings values specific to PSNH;
3. Identification of major measure/end use categories in which the estimated potential savings significantly exceeds PSNH's program savings goals reported in the *2010 CORE New Hampshire Energy Programs* plan filed with the Commission on September 30, 2009;
4. Identification of the measures (priority measures) within each major category that account for the majority of potential savings in that category;
5. Review and revision (if warranted) of the technical/market assumptions employed in the development of potential savings estimates for the priority measures;
6. Selection of priority measures for inclusion in the Market Potential Scenario;
7. Determination of the program design elements, customer incentive levels and other program costs required to achieve the estimated market potential;
8. Development of Market Potential Scenario annual program participation, cost and savings projections for the planning period 2011-2015;
9. TRC analysis of Market Potential Scenario.

Each task is described in detail in the following sections.

Market Potential Methodology

1. Review of Potentially Obtainable Scenario
   The methodology employed by GDS to develop the Potentially Obtainable Scenario was reviewed in order to evaluate and utilize the results in the development of PSNH's Market Potential Scenario for the LCIRP. As documented in the study report, GDS utilized a comprehensive modeling approach to analyze the state-wide energy efficiency electric and non-electric savings potential in all customer sectors. Separate models were developed for the Residential, Commercial and Industrial sectors. The model inputs consist of a combination of measure-specific and end-use specific technical, market and forecast sales data that were developed via primary and secondary data collection efforts described in the report. Energy savings, costs, and various market parameters were analyzed for hundreds of energy-saving measures. Every measure was analyzed for cost-effectiveness in order to estimate the aggregate cost-effective potential in New Hampshire.

2. Translation of Potentially Obtainable savings into Annualized Savings Specific to PSNH
   The GDS Study produced state-wide estimates of Demand Side Potential savings from electric and non-electric energy efficiency measures. PSNH's potential savings estimates apply to electric-savings measures installed in customer facilities within PSNH's service territory. The GDS electric savings potential results were therefore reduced by a factor derived from PSNH's percent of New Hampshire forecasted sales by customer sector.

   The GDS Study quantified Demand Side Potential savings in terms of annualized MWh savings in 2018 based on ten years of implementation of energy efficiency measures. The Maximum Achievable potential, defined as the "maximum penetration of an efficient measure that would be adopted absent consideration of

8. Development of Market Potential Scenario
   The Market Potential Scenario was developed by increasing program participation from current levels over the period 2011-2015 in order to reach the amount of annualized potential savings in 2015. Once the annual participation trends were set, then the annual savings and costs were calculated on the basis of assumed cost and savings per participant for each measure category.

9. TRC Analysis of Market Potential Scenario
   An economic analysis of the Market Potential Scenario was conducted utilizing the Total Resource Cost Test. The details of the benefit-cost analysis methodology are described in Section C.

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B.2. Energy Efficiency Program Potential Savings and Costs

Summary of Results

As explained in detail in the following section, the Market Potential Scenario projections are based on increased market penetration in the following priority measure categories identified in the review of the GDS results:

- Expansion of HVAC, refrigeration, and process measure installations in all existing Commercial and Industrial facilities
- Addition of a retro-commissioning service component as part of the program serving large Commercial and Industrial customers
- Expansion of the Residential Energy Star Homes program
- Expansion of the New Hampshire Home Performance with Energy Star program
- The addition of a Residential second refrigerator removal service component
- Expansion of Residential LED and outdoor lighting control penetrations
- Expansion of smart power strip penetration

Exhibit IV-7 presents projected annual program expenditures, annualized electric savings (MWh), lifetime electric savings (MWh) and annualized peak demand savings (MW) for the Market Potential Scenario. Annual program expenditures are escalated at an annual inflation rate of 1.6 percent. Annualized savings represent the estimated savings at the meter from all measures installed during the corresponding year, assuming that all measures are installed at the beginning of the year. This convention is consistent with the GDS presentation of results and the annual CORE Program filings and benefit-cost analysis. Lifetime savings were calculated based on an assumed average life for each measure category.

The 2010 PSNH CORE Program budgeted expenditures and projected savings reported in the *2010 CORE New Hampshire Energy Efficiency Programs* filing (Attachment F) are presented here for comparison. Projected expenditures in 2015 are approximately 2.5 times the amount of current expenditures. Annualized MWh savings in 2015 are 68 percent higher than current projections. The increase in expenditures is greater than the increase in savings because:

component of the Energy Star Lighting program account for 70 percent of the 2010 level of annualized savings.

The magnitude of the effect of the EISA standards is illustrated by the Base Case Scenario projection of savings based on the continuation of the existing energy efficiency programs at current funding levels (see Section A.5). Exhibits IV-9 and IV-10 present a comparison of the expenditures and annualized MWh savings for the Market Potential and Base Case scenarios.

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Exhibit IV-9: Market Potential and Base Case Savings

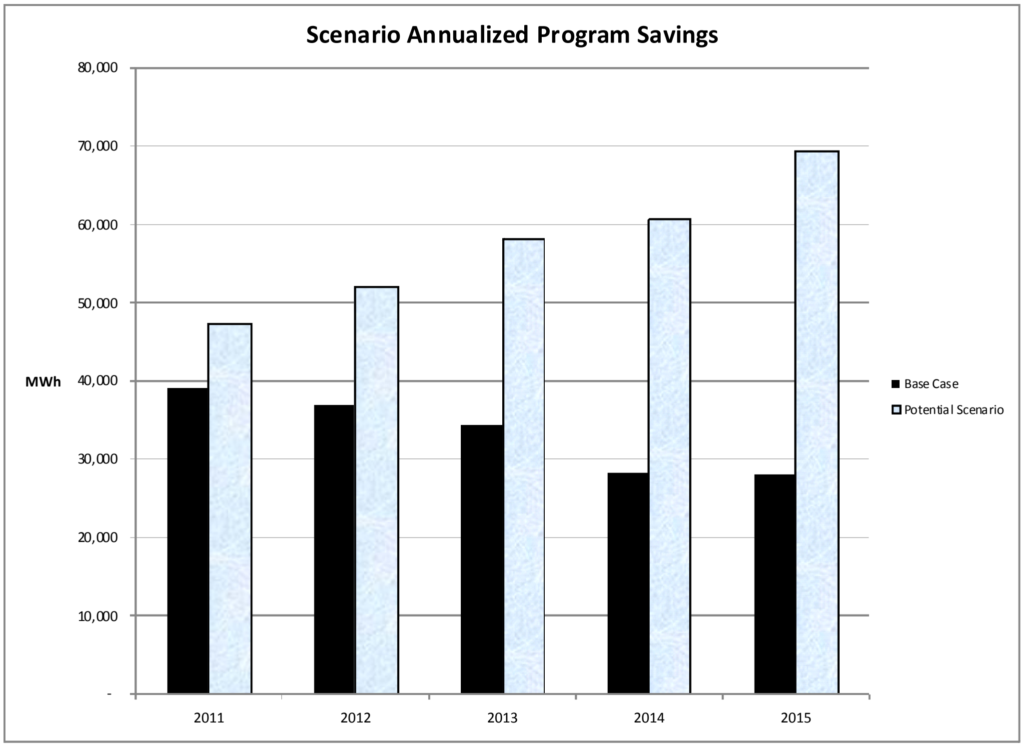

Exhibit IV-10: Market Potential and Base Case Expenditures and Savings

	Expenditures		Savings (MWh)	
Year	Base Case	Potential Scenario	Base Case	Potential Scenario
2011	$14,129,191	$18,943,345	39,075	47,243
2012	$14,349,606	$22,815,951	37,048	52,081
2013	$14,573,460	$27,376,176	34,312	58,159
2014	$14,800,806	$31,616,372	28,133	60,639
2015	$15,031,698	$35,799,709	28,102	69,332

Thus while the 2015 potential savings projection is 68 percent higher than the 2010 projection, as presented in Exhibit IV-7, it is 147 percent higher than the amount of the corresponding 2015 Base Case projection.

Commercial and Industrial (C&I) Sector Potential Analysis and Results

Analysis of Remaining Potential and Identification of Priority Measures

The GDS Study produced state-wide estimates of Demand Side Potential savings from electric and non-electric energy efficiency measures. PSNH's potential savings estimates apply to electric-savings measures installed in customer facilities within PSNH's service territory. The GDS electric savings results were therefore reduced by a factor derived from the PSNH's percent of New Hampshire forecasted sales by customer sector. The Commercial and Industrial factors are respectively 76 percent and 71 percent.

The GDS Obtainable Potential results for the Commercial and Industrial sector were annualized as described in Section B.1. The Obtainable Potential savings, annualized and adjusted for PSNH's service territory, were analyzed in order to identify the major measure/end-use categories in which the estimated potential savings significantly exceeds PSNH's program savings goals reported in the *2010 CORE New Hampshire Energy Programs* plan filed with the Commission on September 30, 2009.

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Exhibit IV-11 presents a comparison of the GDS Obtainable Potential annualized MWh savings to PSNH's savings projection reported in the 2010 program plans. This comparison indicates that the current level of energy efficiency program activity is able to achieve the Obtainable Potential savings in New Construction and from the installation of Lighting measures in existing buildings. On the other hand, there remains significant potential to achieve additional savings in the HVAC and Other measure categories in existing buildings.

Exhibit IV-11: C&I Comparison of Obtainable Potential to Current Savings
(Annualized MWh)

Measure Category	Obtainable Potential	2010 CORE Savings	2015 Market Potential
New Construction	2,866	5,642	5,834
Existing Lighting	15,211	15,452	15,452
Existing HVAC	12,350	682	12,350
Existing Other	22,145	4,238	22,145
Total C&I	52,572	26,013	55,781

Exhibit IV-14: C&I Market Potential Scenario Program Expenditures

Program	2010	2011	2012	2013	2014	2015
SmartStart	$ 50,000	$ 50,000	$ 50,780	$ 51,572	$ 52,377	$ 53,194
Customer Partnerships	$ 30,000	$ 30,000	$ 30,468	$ 30,943	$ 31,426	$ 31,916
New Equipment & Construction	$ 1,958,884	$ 2,014,989	$ 2,046,423	$ 2,078,347	$ 2,110,769	$ 2,143,697
Large C&I Retrofit	$ 2,466,743	$ 3,559,620	$ 5,302,779	$ 6,928,998	$ 8,593,639	$ 10,308,530
Small Business Energy Solutions	$ 2,321,641	$ 2,524,561	$ 2,770,030	$ 2,970,971	$ 3,177,508	$ 3,389,765
RFP Program	$ 507,859	$ 766,384	$ 783,760	$ 1,081,138	$ 1,387,603	$ 1,703,366
Education	$ 157,507	$ 157,507	$ 159,964	$ 162,460	$ 164,994	$ 167,568
C&I Total	**$ 7,492,634**	**$ 9,103,061**	**$ 11,144,204**	**$ 13,304,429**	**$ 15,518,315**	**$ 17,798,036**

Residential Sector Potential Analysis and Results

Analysis of Remaining Potential

The GDS Study produced state-wide estimates of Demand Side Potential savings from electric and non-electric energy efficiency measures. PSNH's potential savings estimates apply to electric-savings measures installed in customers' facilities within PSNH's service territory. The GDS electric savings results were therefore reduced by a factor derived from PSNH's percent of New Hampshire forecasted sales by customer sector. The Residential factor is 72 percent.

The GDS Obtainable Potential results for the Residential sector were annualized as described in Section B.1. The Obtainable Potential savings, annualized and adjusted for PSNH's service territory, were analyzed in order to identify the major measure/end-use categories in which the estimated potential savings significantly exceeds PSNH's program savings goals reported in the *2010 CORE New Hampshire Energy Programs* plan filed with the Commission on September 30, 2009.

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Exhibit IV-15 presents a comparison of the GDS Obtainable Potential annualized MWh savings to PSNH's savings projection reported in the 2010 program plans. This comparison indicates that in all measure categories the current level of CORE Program savings is substantially less than the Obtainable Potential savings and therefore that the remaining potential is significant. Also, in contrast to the C&I sector (see Exhibit IV-15), the projected Market Potential is much less than the Obtainable Potential savings. The reasons for this difference were briefly discussed in Section B.1 Methodology, Sub-Section 5. Review and Revision of Technical Assumptions and are discussed in more detail in the following section.

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G. Other Influences

G.1. Legislature

In recent years the New Hampshire General Court has passed legislation related to the state's energy efficiency programs and available funding. Examples include:

- RSA 125-O:5-a established the Energy Efficiency and Sustainable Energy Board "…to promote and coordinate energy efficiency, demand response, and sustainable energy programs in the state."
- Senate Bill 228 (November 2005) and Senate Bill 300 (January 2010) temporarily reduced annual energy efficiency funding by $2.8 and $3.2 million respectively.
- RSA 374-F:4.VIII(e) which provides for limited use the System Benefits Charge for "Targeted conservation, energy efficiency, and load management programs and incentives that are part of a strategy to minimize distribution cost…" (Note: PSNH recently implemented a new Transmission and Distribution Procedure (TD-190) which incorporates into the distribution system planning process an examination of the potential for energy efficiency/demand response to delay infrastructure replacement expenditures.)
- House Bill 1377 (June 2010) permits utilities to establish loan programs for owners of residential and business property engaging in renewable energy and energy efficiency projects.
- Senate Bill 323 (January 2010) directs the Commission to contract an independent study of certain energy policy issues. The study is to include: (1) a comprehensive review and analysis of energy efficiency, conservation, demand response, and sustainable energy programs and initiatives in the state and to make recommendations for possible improvements; (2) the appropriate role of regulated energy utilities, providers of energy and energy efficiency, and others; (3) the effectiveness and sustainability of funds, and; (4) the policy changes that may be necessary to achieve the state's energy efficiency and sustainable energy goals. The final study is due November 1, 2011.

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This list is not comprehensive, but serves to illustrate recent legislative actions. It is not the intent here to speculate regarding future legislative actions, but merely to point out that the plans presented here are subject to review and modification.

Appendix G Newington Station CUO Study Revisions

B. Executive Summary

Whether or not the ongoing value ascribable to PSNH's continued ownership and operation of Newington Station is greater than the costs borne by its customers is the central question in this evaluation. On a prospective basis, Newington Station is expected to provide PSNH's retail customers with both physical and financial protection in light of volatile wholesale energy and capacity prices, both in New Hampshire and New England as a whole. In LAI's view, prospective wholesale market dynamics over the study period, 2011 through 2020, are likely to remain both unpredictable and volatile. PSNH's ownership and continued operation of Newington Station confers positive value both to customers and the region.

Based on the quantitative analysis, highlights of the CUO analysis conducted by LAI are as follows:

- Newington Station provides PSNH's customers with 400 MW of capacity at a largely known cost, therefore providing a physical hedge against regulatory uncertainty associated with ISO-NE's administration of the FCM. While capacity prices are known with certainty for the next few years, many uncertainty factors have the potential to exert significant upward pressure on capacity prices from 2016 through 2020. Continued operation of Newington Station shields PSNH's customers from materially adverse economic consequences that may arise from evolving capacity market dynamics in New England. On an expected value basis, the net value of the physical hedge is about $31 million. Under plausible worst case conditions from the standpoint of PSNH's customers, the net value of the physical capacity hedge is about $54 million.

- The expected net present value (NPV) of the incremental revenue requirements indicates substantial economic benefits are associated with PSNH's continued operation of Newington Station. The expected NPV is over $71 million.

- There is virtually no risk of actual benefits resulting in a negative NPV. Simulation of market prices for capacity, energy, and fuels results in a 0% probability that the NPV of benefits will be negative. There is a 5% probability of an NPV outcome between zero and $47 million, and a 90% probability of an NPV between $47 million and $105 million. The median result is $64 million. With respect to an "earnings surprise" related to continued operation of the Station, there is a 5% probability of an NPV greater than $105 million. One reason why the NPV benefits are always positive from the customers' perspective is that Newington Station's sunk costs are excluded from the determination of going-forward cash costs through 2020.

- The risk of market based revenues being lower than Newington Station's incremental revenue requirement in any single year over the ten year study period is low. This is a result of the anticipated deterioration in capacity prices associated with the MW overhang in New England and ISO-NE's FCM restructuring proposal. On an expected value basis, Newington Station *always* shows that market based revenues are higher than its incremental revenue requirement. Simulation indicates less than a 1% chance that market based revenues come in lower than

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Newington Station's incremental revenue requirement in either 2017 or 2018, evaluated separately.

- The distribution of economic benefits on an NPV or year-by-year basis is heavily skewed toward relatively small positive outcomes. Given Newington Station's operational characteristics and the range of anticipated capacity prices in New England over the study period, there is only a 25% chance of an NPV greater than $88 million.

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- A large portion of the net benefit of Newington Station's continued operation is derived from its ability to operate flexibly in the DA and RT energy markets. The present value of fixed costs (direct and indirect fixed O&M, property taxes, and incremental depreciation and return on rate base) of $80.4 million is offset by an expected value of capacity market revenues of $111.2 million, for a $30.8 million benefit. The remaining $40.7 million in expected value of net benefit is derived from net margins earned in the energy and ancillary service markets, and reflects the physical option values arising from the Station's operational dispatch flexibility and its ability to burn natural gas and/or oil, including adjusting the blend of both fuels on-the-fly. The Station's operational flexibility allows it to serve as a physical hedge against volatile DAM and RTM energy prices, as well as volatile and unpredictable trends in the natural gas and oil commodity markets.

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- The additional insurance-like or financial hedge value of Newington Station as a substitute for energy load-following contracts is roughly estimated to be a risk premium equivalent to about 10% of the price of monthly on-peak contracts.

- From PSNH's customers' perspective, the positive expected NPV, coupled with the wide and skewed dispersion of potential economic results around the expected value, supports continued operation of Newington Station through 2020.

In addition to the more readily quantified benefits of continued operation, Newington Station also provides other benefits that are reported on a qualitative basis, as follows:

- The operational flexibility to adjust bidding in the DAM also allows PSNH to operate Newington Station at critical times in a risk-averse manner to safeguard against bad economic outcomes in the RTM. The Station also serves to backstop at a known cost a forced outage at one of PSNH's other generating stations.

- While Newington Station is operational, PSNH customers benefit from the real option value associated with waiting for more information before making a retirement timing decision.

- Newington Station's participation in the FCM provides capacity price suppression benefits to PSNH's customers as well as to other customers throughout New Hampshire and New England.

- Newington Station's electrical interconnection yields transmission and distribution system reliability benefits. Likewise, Newington's flexible fuel mix and large on-site oil tankage provides energy diversity benefits when natural gas deliverability is

Exhibit G.7: Estimated Going Forward Fixed Portion of Annual Revenue Requirements

	Present Value EOY 2010	Calendar Year 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
<u>**Expenses ($000)**</u>											
Non-Fuel O&M with Indirects											
Other than Emission Allowances	$57,236	$7,498	$7,706	$7,920	$8,139	$8,366	$8,600	$8,841	$9,089	$9,343	$9,605
Emission Allowances		**Varies with simulated output and fuel mix**									
Total O&M Expense											
Fuel and Fuel Related O&M		**Varies with simulation output, fuel mix, and fuel prices**									
Property Tax	$9,057	$958	$1,034	$1,117	$1,206	$1,303	$1,407	$1,520	$1,641	$1,773	$1,914
Depreciation Expense	$2,879	$50	$106	$168	$240	$323	$423	$548	$715	$965	$1,465
Total Expenses											
<u>**Rate Base ($000)**</u>											
Incremental Gross Plant Value		$500	$1,000	$1,500	$2,000	$2,500	$3,000	$3,500	$4,000	$4,500	$5,000
Incremental Accum. Depreciation		$50	$156	$324	$563	$886	$1,309	$1,857	$2,571	$3,536	$5,000
Net Plant Value		$450	$844	$1,176	$1,437	$1,614	$1,691	$1,643	$1,429	$964	($0)
Working Capital		$925	$925	$925	$925	$925	$925	$925	$925	$925	$925
Accumulated Deferred Taxes		$12	$32	$64	$112	$181	$279	$417	$613	$898	$1,372
Fuel Inventory (year end)		$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000
NOx, SO2, CO2 Allowance Inventory		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Material & Supply Inventory		$2,500	$2,500	$2,500	$2,500	$2,500	$2,500	$2,500	$2,500	$2,500	$2,500
Total Rate Base		$13,887	$14,301	$14,665	$14,973	$15,219	$15,395	$15,485	$15,466	$15,287	$14,796
Average Return on Rate Base		*11.09%*	*11.09%*	*11.09%*	*11.09%*	*11.09%*	*11.09%*	*11.09%*	*11.09%*	*11.09%*	*11.09%*
<u>**Return on Rate Base ($000)**</u>	**$11,271**	**$1,540**	**$1,586**	**$1,626**	**$1,660**	**$1,688**	**$1,707**	**$1,717**	**$1,715**	**$1,695**	**$1,641**
Expenses Plus Return on Rate Base											
<u>**Revenues ($000)**</u>											
Energy		**Varies with simulated output and energy prices**									
Capacity		$17,250	$13,343	$12,121	**Varies with capacity prices**						
Ancillary	$1,367	$200	$200	$200	$200	$200	$200	$200	$200	$200	$200
10 MW Unitil Entitlement	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Revenue											
NET REVENUE REQUIREMENT											

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Expenses ($000)
Non-Fuel O&M with Indirect
Other than Emission Allow
Emission Allowances
Total O&M Expense
Fuel and Fuel Related O&M
Property Tax
Depreciation Expense
Total Expenses
Rate Base ($000)
Incremental Gross Plant Valu
Incremental Accum. Depreci
Net Plant Value
Working Capital
Accumulated Deferred Taxes
Fuel Inventory (year end)
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Return on Rate Base ($000)
Expenses Plus Return on
Revenues ($000)
Energy
Capacity
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10 MW Unitil Entitlement
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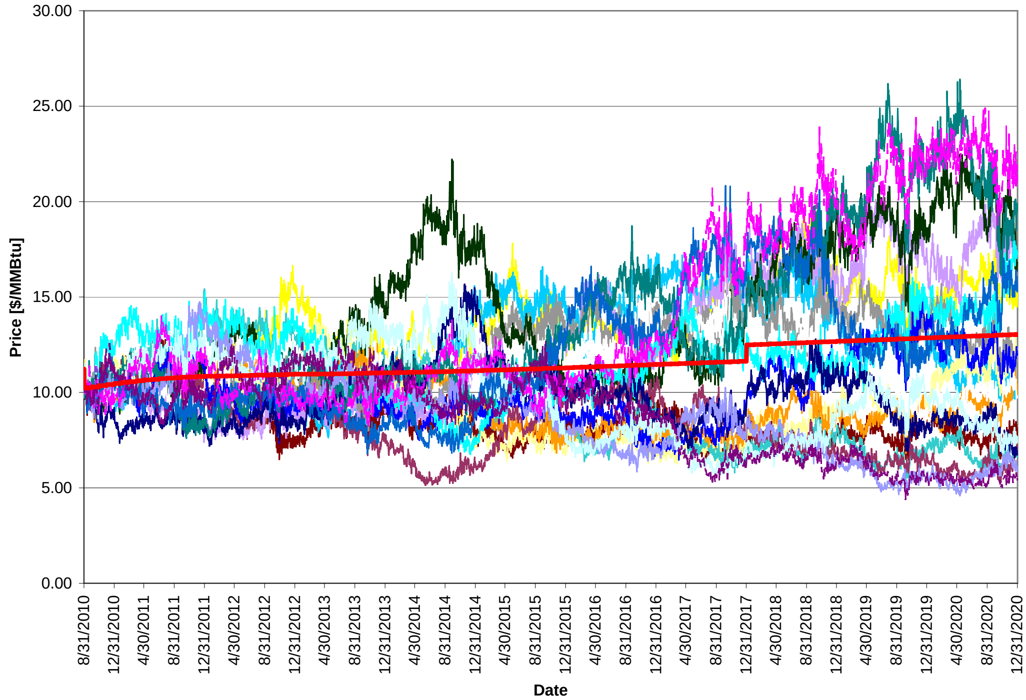
NET REVENUE REQUII

Exhibit G.10: Example of 20 RFO Price Paths and Expected Prices



F.2.3. Stochastic Energy Price Scenarios

Expected monthly DA on-peak and off-peak prices at the Newington node were simulated with a three step procedure. First, monthly and strip (bi-monthly to annual) forward on-peak and off-peak prices at the Massachusetts Hub (MassHub) on August 27, 2010 were used. Second, historical hourly spot price ratios of the Newington node to the MassHub node prices were used to shape the bi-monthly to annual strip forward prices into monthly on-peak and off-peak prices at the Newington node. Third, the Newington node monthly on-peak and off-peak forward prices for the period beyond the end of the MassHub node forwards in 2015 were estimated based on the historical market heat rate relationship between Dracut natural gas spot prices and Newington node hourly energy spot prices. The resulting forward monthly DA on-peak and off-peak prices are shown in Exhibit G.11.

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F.3. Modeling Method for Dispatch Simulation

To perform the ROV analysis, a dispatch simulation model was developed that accounts for Newington's chronological constraints, fuel-blending constraints, and ability to dispatch in the RTM as well as the DAM. The dispatch model represented the multiple operating states with respect to natural gas combustion constraints on the fuel mix, the heat rate curve, cold and warm start times and fuel use, the NO_x emissions curve, minimum up and down times, and ramping rates. The model is run with the set of stochastic price paths, and also simulates random forced outages. Newington's commitment and dispatch is simulated with the objective of maximizing its expected net operating revenue (equivalent to minimizing the expected cost to customers). The simulation model dispatches the Station against ISO-NE spot market prices. The dispatch simulation model does not use perfect foresight to "see" RTM prices when bidding into the DAM, and it does not see the onset of a forced outage. By separately dispatching any available capacity against RTM prices, the model allows some additional gross margin to be realized. Net commitment period cost or uplift revenues and expenses were not modeled. Prospective Newington Station fixed O&M costs, including additional capital expenditures to ensure plant availability and efficiency, were not treated as an uncertainty factor.

Results by simulation path are cumulated over the years of the study period into a NPV for that path. After all the stochastic paths have been simulated, the expected values and probability distributions of annual values and of the NPV are calculated for reporting in tabular or graphical form. Each scenario has the same weight, so the expected value is the simple average or mean value across scenarios.

F.4. Asset Value Simulation Analysis Results

The results of the probabilistic and ROV simulation analysis are presented in the following table and set of graphs. Exhibit G.12 presents the expected annual values of incremental revenue requirements (negative value is customer benefit) for 2011 through 2020 and the NPV of incremental revenue requirements at the end of 2010. The expected values are the equally-weighted average values across the set of simulated scenarios. Incremental revenue requirements for continued operation of Newington Station are negative in every year, indicating that the Station provides value to customers. The expected NPV of customer benefits is over $71 million. Exhibit G.12 shows the same expense and revenue line items as the historical revenue requirements table, Exhibit G.1, in Section D.1. Notice that fuel expenses and energy revenues are fairly uniform over the ten-year simulation period and similar in magnitude as the average of the last five years, shown in Exhibit G.1.

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Exhibit G.12: Expected Values of Incremental Revenue Requirements

	Present Value EOY 2010	Calendar Year 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expenses ($000)											
Non-Fuel O&M with Indirects											
Other than Emission Allowances	$57,236	$7,498	$7,706	$7,920	$8,139	$8,366	$8,600	$8,841	$9,089	$9,343	$9,605
Emission Allowances	$2,752	$356	$313	$321	$377	$434	$456	$466	$445	$469	$513
Total O&M Expense	$59,988	$7,854	$8,019	$8,241	$8,516	$8,800	$9,056	$9,307	$9,534	$9,812	$10,118
Fuel and Fuel Related O&M	$142,143	$16,145	$15,692	$17,095	$20,134	$23,027	$23,490	$24,160	$23,878	$25,084	$26,856
Property Tax	$9,057	$958	$1,034	$1,117	$1,206	$1,303	$1,407	$1,520	$1,641	$1,773	$1,914
Depreciation Expense	$2,879	$50	$106	$168	$240	$323	$423	$548	$715	$965	$1,465
Total Expenses	**$214,066**	**$25,007**	**$24,850**	**$26,621**	**$30,096**	**$33,452**	**$34,375**	**$35,535**	**$35,767**	**$37,633**	**$40,352**
Rate Base ($000)											
Incremental Gross Plant Value		$500	$1,000	$1,500	$2,000	$2,500	$3,000	$3,500	$4,000	$4,500	$5,000
Incremental Accum. Depreciation		$50	$156	$324	$563	$886	$1,309	$1,857	$2,571	$3,536	$5,000
Net Plant Value		$450	$844	$1,176	$1,437	$1,614	$1,691	$1,643	$1,429	$964	($0)
Working Capital		$925	$925	$925	$925	$925	$925	$925	$925	$925	$925
Accumulated Deferred Taxes		$12	$32	$64	$112	$181	$279	$417	$613	$898	$1,372
Fuel Inventory (year end)		$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000
NOx, SO2, CO2 Allowance Inventory		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Material & Supply Inventory		$2,500	$2,500	$2,500	$2,500	$2,500	$2,500	$2,500	$2,500	$2,500	$2,500
Total Rate Base		$13,887	$14,301	$14,665	$14,973	$15,219	$15,395	$15,485	$15,466	$15,287	$14,796
Average Return on Rate Base		*11.09%*	*11.09%*	*11.09%*	*11.09%*	*11.09%*	*11.09%*	*11.09%*	*11.09%*	*11.09%*	*11.09%*
Return on Rate Base ($000)	**$11,271**	**$1,540**	**$1,586**	**$1,626**	**$1,660**	**$1,688**	**$1,707**	**$1,717**	**$1,715**	**$1,695**	**$1,641**
Expenses Plus Return on Rate Base	**$225,337**	**$26,547**	**$26,436**	**$28,247**	**$31,756**	**$35,140**	**$36,082**	**$37,252**	**$37,482**	**$39,328**	**$41,993**
Revenues ($000)											
Energy	$184,234	$20,987	$20,366	$22,190	$26,135	$29,886	$30,223	$31,053	$30,887	$32,727	$34,929
Capacity	$111,205	$17,250	$13,343	$12,121	$12,779	$13,791	$14,903	$16,420	$17,830	$22,106	$29,026
Ancillary	$1,367	$200	$200	$200	$200	$200	$200	$200	$200	$200	$200
10 MW Unitil Entitlement	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Revenue	**$296,806**	**$38,437**	**$33,909**	**$34,511**	**$39,114**	**$43,877**	**$45,326**	**$47,673**	**$48,917**	**$55,032**	**$64,156**
NET REVENUE REQUIREMENT	**($71,469)**	**($11,890)**	**($7,473)**	**($6,264)**	**($7,358)**	**($8,737)**	**($9,244)**	**($10,421)**	**($11,435)**	**($15,704)**	**($22,163)**

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Expenses ($000)
Non-Fuel O&M with Indirect
Other than Emission Allow
Emission Allowances
Total O&M Expense
Fuel and Fuel Related O&M
Property Tax
Depreciation Expense
Total Expenses
Rate Base ($000)
Incremental Gross Plant Valu
Incremental Accum. Depreci
Net Plant Value
Working Capital
Accumulated Deferred Taxes
Fuel Inventory (year end)
NOx, SO2, CO2 Allowance I
Material & Supply Inventory
Total Rate Base
Average Return on Rate Bc
Return on Rate Base ($000
Expenses Plus Return on
Revenues ($000)
Energy
Capacity
Ancillary
10 MW Unitil Entitlement
Total Revenue
NET REVENUE REQUI

Most of the expense items have the same values in each stochastic scenario. It is therefore convenient to examine the entire probability distribution of customer benefits in the form of a cumulative density function graph, shown in Exhibit G.13. Customer benefits are defined as a reduction in incremental revenue requirements. The shape of the curve allows inspection of the NPV of customer benefits associated with a given probability level. The expected NPV dashed line on the graph corresponds to the expected NPV benefit of a reduction in incremental revenue requirements in Exhibit G.12 of $71 million. Importantly, the distribution indicates that none of the simulated scenarios results in a negative customer benefits NPV outcome. The median NPV of $64 million is substantially less than the mean or expected NPV, indicating significant right skew in the distribution. In other words, more of the equally probable scenarios have outcomes below than above the expected NPV.

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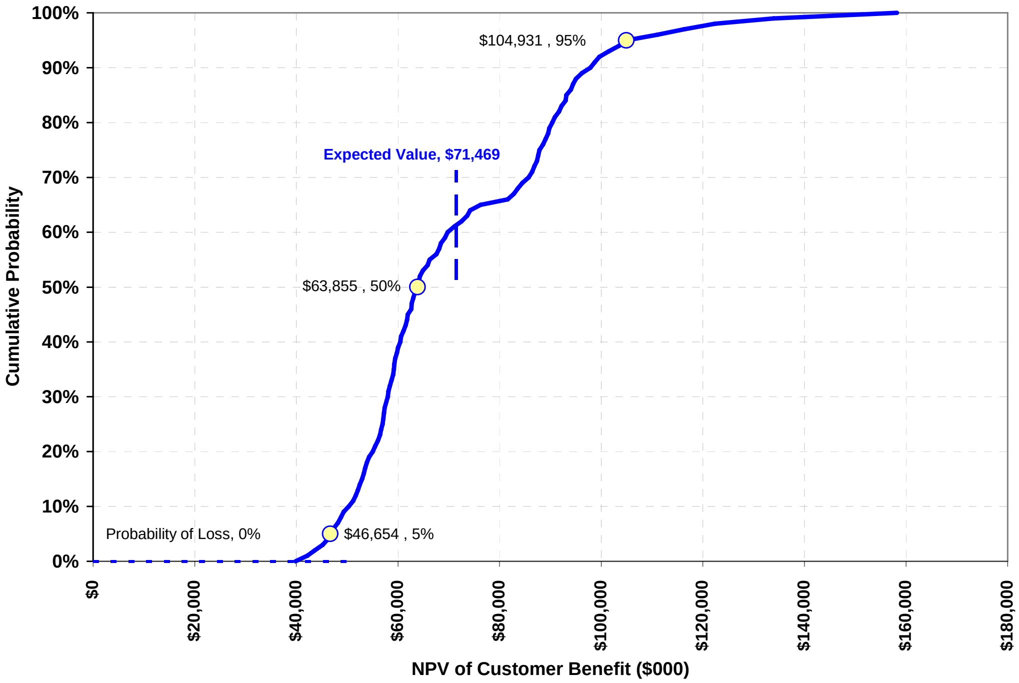
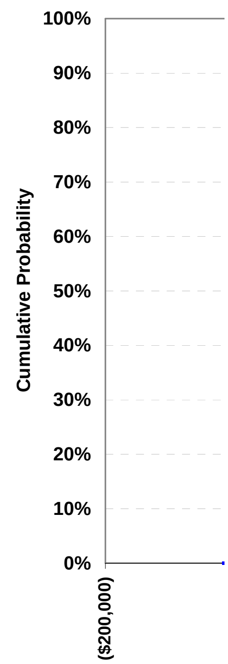
Exhibit G.13: Cumulative Distribution of NPV of Customer Benefits





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While on a ten-year NPV basis there is no modeled probability of a loss, Exhibit G.14 indicates that the annual energy net margin is very small at the 1% probability level in some years. There is less than a 1% probability that small losses would occur in years 2017 and 2018. The timing of possible annual losses in these years is driven largely by the sudden uncertainty in capacity prices that begins then. The lead time of seven years before any probable losses are expected to occur means that a retirement decision should be deferred until such time that losses begin to occur.

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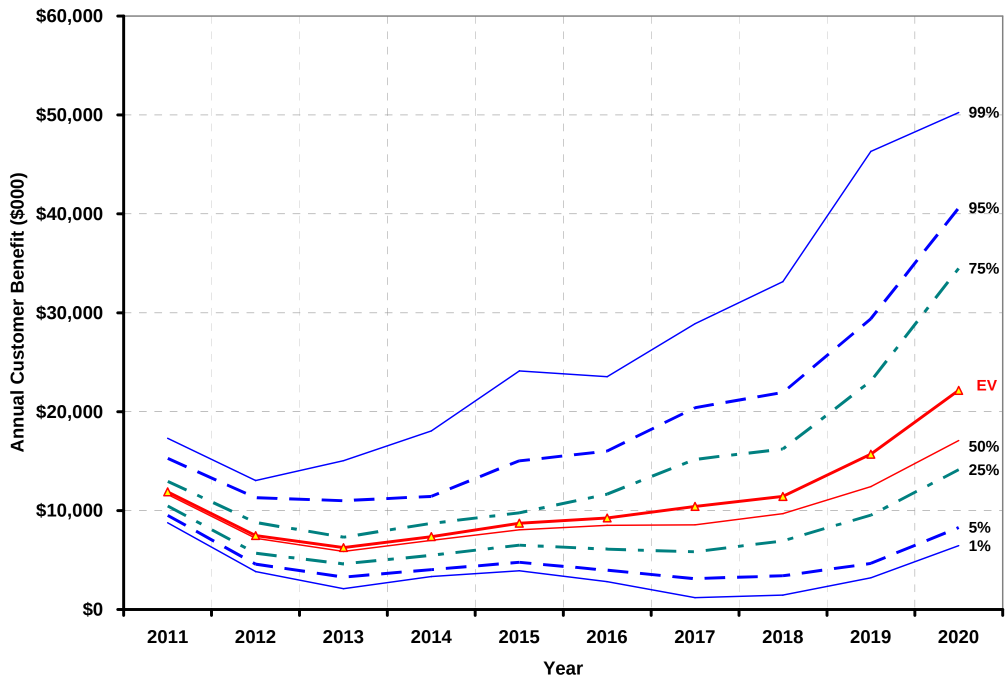
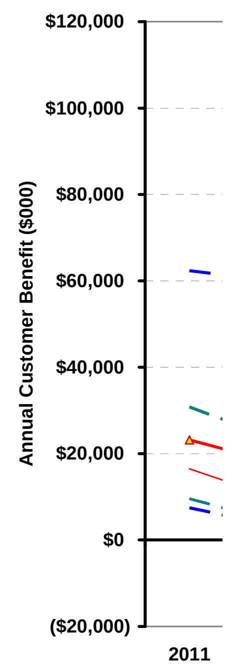
Exhibit G.14: Annual Distributions of Undiscounted Customer Benefits





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The skew in the distribution is more easily visualized in a probability distribution function histogram, shown in Exhibit G.15. Around the mean or expected NPV of $71 million, the distribution has a much longer right tail than left tail. While representing a small portion of the probable outcomes, the very large benefits in the right-hand tail of the histogram indicate a large portion of the hedge or insurance value of keeping Newington Station in operation. Without Newington, these low-probability but large benefits would instead be high cost outcomes for customers.

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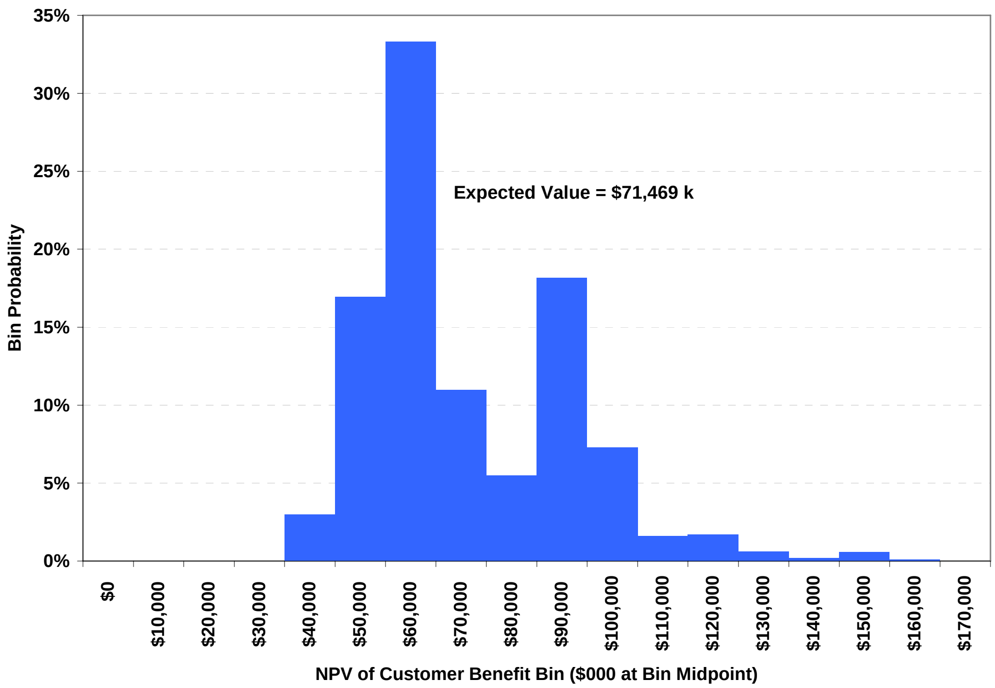
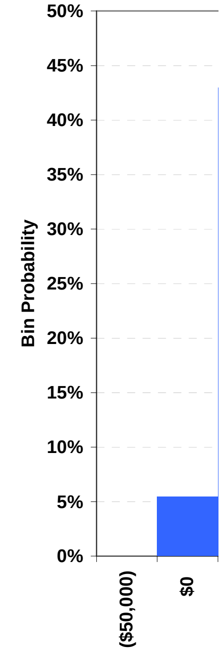
Exhibit G.15: Probability Distribution of NPV of Customer Benefits





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A substantial portion of the right-tail skew of the NPV of revenue requirements reduction benefits is due to the completely skewed distribution of energy net revenues (revenues minus fuel and fuel-related expenses), shown in the histogram of Exhibit G.16. Around the expected NPV of energy net revenue of over $39 million ($184 million energy revenue minus $145 million fuel and emission costs), there are only three smaller bins but 13 larger bins. The largest bin of energy net revenues is the third from the left, and the probabilities drop off quickly at higher energy revenue levels. The reason the NPV of revenue requirements reduction distribution in Exhibit G.15 has a less skewed distribution is due to the relatively symmetric weighting of the three capacity price scenarios (20%, 50%, and 30% probability, respectively, for the Low, Mid, and High price scenarios), combined with the assumption that fuel and energy prices are not correlated with capacity prices. The assumption of a zero correlation between energy and fuel prices versus capacity prices is a relatively conservative assumption. It is possible that the true correlation is slightly negative, meaning that if the spark spread for combustion turbine peaking units tended to decrease (increase) over time, then capacity prices would tend to be adjusted upwards (downwards), thereby mitigating the combined net impacts of capacity and energy products for generators and load.

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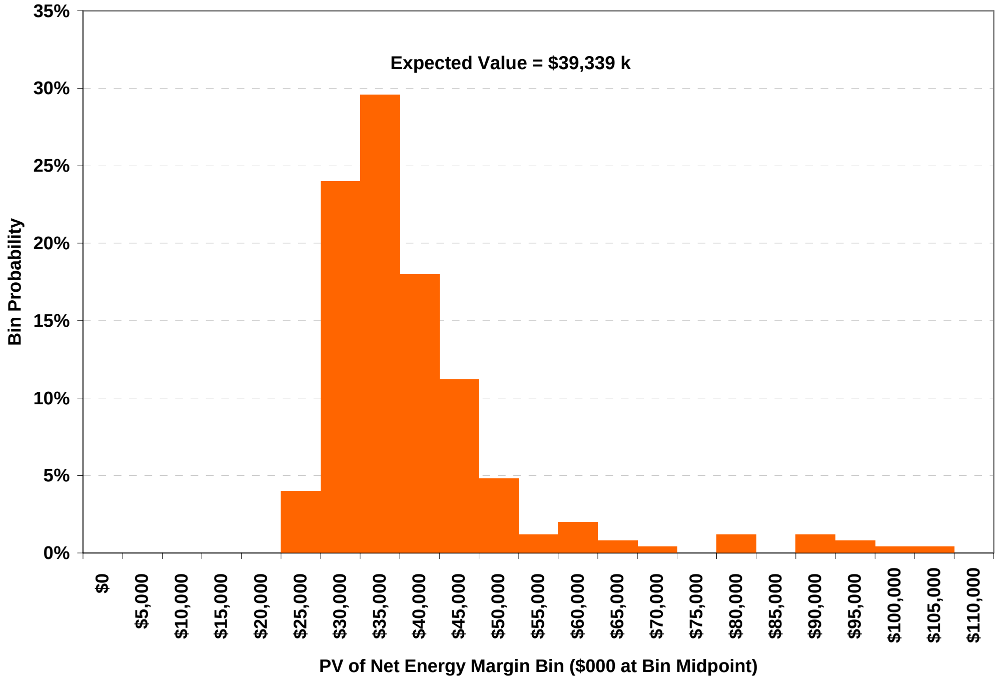
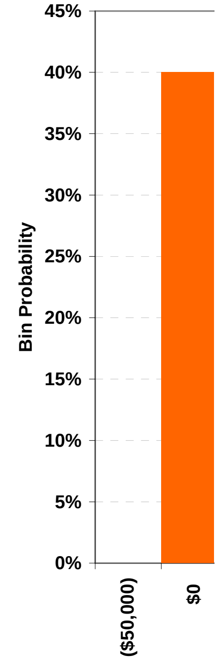
Exhibit G.16: Probability Distribution of NPV of Energy Net Revenue





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The annual capacity factor, service factor, number of starts, and fuel mix at the expected (mean), P50 (median), and P25 levels of energy net revenue for each year in the analysis (2011-2020) are shown in Exhibit G.17. The P50 and P25 results are for the individual scenarios at the 50^{th} and 25^{th} percentiles, respectively, of energy net revenue.

Exhibit G.17: Operational Performance at Selected Annual Energy Net Revenue Probability Levels

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expected Value										
DAM Dispatch Hours	911	797	791	890	981	1009	1024	1031	1058	1147
RTM Dispatch Hours	55	42	55	71	83	85	86	73	78	85
Generation (GWh)	279.8	244.0	248.3	285.8	321.8	332.7	338.5	332.6	344.9	375.8
Number of Starts	39	38	33	37	40	44	45	44	45	47
2FO Consumption (BBtu)	10.6	9.9	9.6	10.4	11.0	11.6	11.7	11.5	11.8	12.1
RFO Consumption (BBtu)	15.7	33.7	75.7	189.6	359.7	465.2	511.5	371.3	504.6	589.8
Gas Consumption (BBtu)	3,113.5	2,704.3	2,707.5	3,011.8	3,238.8	3,255.6	3,272.3	3,348.4	3,349.6	3,606.3
CO2 Emitted (1000 ton)	184.3	161.9	165.7	193.4	221.6	231.7	236.7	229.0	240.7	263.1
SO2 Emitted (ton)	22.0	30.2	51.4	112.8	203.9	261.0	285.7	113.7	149.2	172.7
NOx Emitted (ton)	184.6	162.9	168.3	199.8	233.1	245.8	252.1	240.3	255.3	280.5
Capacity Factor (%)	8.0%	7.0%	7.1%	8.2%	9.2%	9.5%	9.7%	9.5%	9.8%	10.7%
Service Factor (%)	11.0%	9.6%	9.7%	11.0%	12.2%	12.5%	12.7%	12.6%	13.0%	14.1%
Energy Revenue ($1000)	20,987	20,366	22,190	26,135	29,886	30,223	31,053	30,887	32,727	34,929
Energy Cost ($1000)	16,501	16,005	17,416	20,511	23,461	23,945	24,626	24,323	25,553	27,369
Net Revenue ($1000)	4,486	4,362	4,775	5,624	6,426	6,278	6,426	6,565	7,174	7,560
P50 (Median)										
DAM Dispatch Hours	838	571	804	1185	937	940	1498	1595	1767	1498
RTM Dispatch Hours	16	48	28	41	192	77	92	101	100	48
Generation (GWh)	253.0	180.7	243.5	362.3	361.2	298.4	461.5	488.6	539.5	450.2
Number of Starts	22	20	25	35	49	37	76	73	88	61
2FO Consumption (BBtu)	7.5	7.1	8.6	10.5	12.9	11.3	17.6	16.0	21.5	14.9
RFO Consumption (BBtu)	0.0	34.1	7.8	13.4	931.2	50.9	83.5	57.3	124.0	5.6
Gas Consumption (BBtu)	2,796.9	1,994.3	2,719.7	4,034.3	3,106.5	3,295.2	5,102.2	5,416.7	5,939.0	5,036.7
CO2 Emitted (1000 ton)	164.2	120.2	160.4	238.0	263.6	198.1	307.1	323.1	359.8	296.3
SO2 Emitted (ton)	6.7	25.2	11.9	19.8	508.1	38.6	68.9	40.3	62.7	22.3
NOx Emitted (ton)	165.7	121.1	160.8	240.4	296.2	200.1	309.6	323.9	363.1	297.4
Capacity Factor (%)	7.2%	5.2%	6.9%	10.3%	10.3%	8.5%	13.2%	13.9%	15.4%	12.8%
Service Factor (%)	9.7%	7.1%	9.5%	14.0%	12.9%	11.6%	18.2%	19.4%	21.3%	17.6%
Energy Revenue ($1000)	16,766	17,101	20,478	23,946	30,062	24,785	26,735	24,676	29,314	28,969
Energy Cost ($1000)	12,542	13,030	16,096	18,694	24,283	19,276	21,264	18,870	23,553	22,659
Net Revenue ($1000)	4,225	4,072	4,382	5,252	5,779	5,509	5,471	5,805	5,762	6,310
P25										
DAM Dispatch Hours	787	772	1099	625	839	643	610	928	721	870
RTM Dispatch Hours	42	53	31	12	69	80	47	56	28	76
Generation (GWh)	239.1	236.4	328.5	187.1	265.8	218.2	189.0	285.0	215.4	268.9
Number of Starts	36	43	43	30	26	29	32	43	31	56
2FO Consumption (BBtu)	9.9	11.5	12.8	7.8	8.4	8.9	8.6	10.3	7.8	13.7
RFO Consumption (BBtu)	1.5	0.0	0.0	15.5	11.2	162.9	2.8	0.0	0.0	38.5
Gas Consumption (BBtu)	2,686.7	2,664.7	3,683.7	2,085.4	2,959.2	2,288.4	2,124.9	3,191.2	2,416.7	2,986.0
CO2 Emitted (1000 ton)	158.1	156.8	216.5	123.9	174.7	148.7	125.2	187.5	142.0	179.1
SO2 Emitted (ton)	13.7	15.3	13.8	17.0	16.4	96.1	12.6	15.4	10.6	28.0
NOx Emitted (ton)	157.7	155.7	216.6	125.0	176.1	155.1	124.6	187.5	141.4	178.6
Capacity Factor (%)	6.8%	6.7%	9.4%	5.3%	7.6%	6.2%	5.4%	8.1%	6.1%	7.7%
Service Factor (%)	9.5%	9.4%	12.9%	7.3%	10.4%	8.3%	7.5%	11.2%	8.6%	10.8%
Energy Revenue ($1000)	15,042	15,695	16,350	18,130	19,560	23,628	21,981	24,288	20,666	24,132
Energy Cost ($1000)	11,984	13,116	13,242	14,374	15,382	19,332	17,912	20,025	16,377	19,295
Net Revenue ($1000)	3,059	2,578	3,109	3,756	4,178	4,296	4,069	4,263	4,289	4,837

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Expected Value
DAM Dispatch Hours
RT Dispatch Hours
Generation (GWh)
Number of Starts
#2 Oil Consumption (BB
RFO Consumption (BBtu
Gas Consumption (BBtu
CO2 Emitted (1000 ton)
SO2 Emitted (ton)
NOx Emitted (ton)
Capacity Factor (%)
Service Factor (%)
Energy Revenue ($1000
Energy Cost ($1000)
Net Revenue ($1000)
P50 (Median)
DAM Dispatch Hours
RT Dispatch Hours
Generation (GWh)
Number of Starts
#2 Oil Consumption (BB
RFO Consumption (BBtu
Gas Consumption (BBtu
CO2 Emitted (1000 ton)
SO2 Emitted (ton)
NOx Emitted (ton)
Capacity Factor (%)
Service Factor (%)
Energy Revenue ($1000
Energy Cost ($1000)
Net Revenue ($1000)
P25
DAM Dispatch Hours
RT Dispatch Hours
Generation (GWh)
Number of Starts
#2 Oil Consumption (BB
RFO Consumption (BBtu
Gas Consumption (BBtu
CO2 Emitted (1000 ton)
SO2 Emitted (ton)
NOx Emitted (ton)
Capacity Factor (%)
Service Factor (%)
Energy Revenue ($1000
Energy Cost ($1000)
Net Revenue ($1000)

F.5. Additional Insurance-Like Hedge Value Results

As discussed in Section E.2.2, in addition to Newington Station's operational flexibility and fuel-blending flexibility, which provide physical option values, the Station also helps to protect PSNH's customers from adverse market conditions on an annual and shorter-term timeframe in the power and fuel markets for forward and option contracts. Also, Newington Station provides RTM protection without the need to enter into contracts for supplemental power and outage insurance. Absent Newington Station, PSNH would materially adverse economic consequences that may arise from evolving capacity market dynamics in New England. On an expected value basis, the net value of the physical capacity hedge is about $31 million. Under plausible worst case conditions the net value of the physical capacity hedge is about $54 million.

- Second, the expected NPV of customer benefits (decrease in incremental net revenue requirements) indicates substantial economic benefits associated with PSNH's continued operation of Newington Station. The expected NPV is $71 million, an outcome that can be represented as deep-in-the-money from PSNH's customers' perspective.

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- Third, the risk of negative NPV of customer benefits is low. Simulation of market prices for capacity, energy, and fuels results in a 0% probability that the NPV of benefits will be negative. There is a 5% probability of an NPV outcome between zero and $47 million, and a 90% probability of NPV between $47 million and $105 million. The median result is $64 million. With respect to a positive "earnings surprise" related to continued operation of the Station, there is a 5% probability of an NPV greater than $105 million. One of the reasons why the NPV benefits are always positive from the customers' perspective is explained by the proper exclusion of Newington Station's sunk cost in the determination of going-forward cash costs through 2020.

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- Fourth, the risk of not covering Newington Station's incremental revenue requirements in any single year over the ten year study period is low. On an expected value basis, Newington Station *always* covers its incremental revenue requirement. However, there is less than a 1% chance that market based revenues will be insufficient for Newington Station to cover its incremental revenue requirement in 2017 and 2018, evaluated separately. This is a result of the anticipated deterioration in capacity prices associated with the MW overhang in New England and ISO-NE's FCM restructuring proposal. The trough in the capacity price forecasts for the Low and Mid scenarios is the 2016/17 capacity year. A combination of low capacity prices and low energy net revenues in some simulated scenarios results in low total revenues in the 2017 and 2018 calendar years.

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- Fifth, the distribution of economic benefits on an NPV or year-by-year basis is heavily skewed toward relatively small positive outcomes. Given Newington Station's operational characteristics and the range of anticipated capacity prices in New England over the study period, there is a low probability of very large benefits, in other words, only a 25% chance of an NPV greater than $88 million.

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- Sixth, a large portion of the net benefit of Newington Station's continued operation is derived from its ability to operate flexibly in the DAM and RTM energy markets. The present value of fixed costs (direct and indirect fixed O&M, property taxes, and incremental depreciation and return on rate base) of $80.4 million is first offset by an expected value of capacity market revenues of $111.2 million, for a $30.8 million benefit. The remaining $40.7 million in expected value of net benefit is derived from net margins earned in the energy and ancillary service markets, and reflects the physical option values from the Station's operational dispatch flexibility and ability to burn natural gas and/or oil, including adjusting the blend of both fuels on-the-fly.

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