Integrated Resource Plan for Connecticut

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EXECUTIVE SUMMARY

This report is submitted pursuant to Section 51 of PA 07-242, which requires that electric distribution companies submit a comprehensive resource plan to the Connecticut Energy Advisory Board (CEAB). The creation of this report entailed a collaborative effort by The Connecticut Light and Power Company (CL&P), The United Illuminating Company (UI) (together, "the Companies") and *The Brattle Group*, an independent economic consulting firm. *The Brattle Group* conducted a regional electricity market analysis that examined how well selected resource options fared in meeting the performance criteria outlined in PA 07-242 and the CEAB Preferential Criteria for Evaluation of Energy Projects under a broad range of potential future scenarios. The results of that analysis underlie the findings and recommendations outlined below.

FINDINGS

After taking into account planned generation additions, recent and planned transmission projects, and demand-side measures that are planned or underway, and assuming no retirements, new electricity resources will not be needed to attain reliability targets for several years in Connecticut or elsewhere in New England. Under most plausible futures, New England as a whole will need additional resources mid-way through the next decade for reliability related to resource adequacy. As part of the overall New England market, Connecticut will share in this regional resource need, but additional resources located within Connecticut are not required in this time frame for resource adequacy under the scenarios reviewed. Connecticut will not face a localized resource shortfall for many years under the scenarios examined in this report. The overall New England resource need that emerges mid-way through the next decade could be satisfied by resources located either within or outside of Connecticut. Moreover, recent transmission projects and planned generation additions will largely eliminate the critical power flow bottlenecks into and within Southwest Connecticut that have historically made it difficult and costly to serve load there.

Despite the lack of an imminent need for additional resources to satisfy reliability targets, however, we find that Connecticut power prices will continue to be both high and possibly unstable. This is due primarily to the fact that electricity prices in New England will remain closely linked to natural gas prices, regardless of future events or resource decisions considered in this study. Natural gas prices are volatile and uncertain, and likely to remain fairly high relative to levels experienced in the 1990s. Other important issues for Connecticut's electricity sector include carbon dioxide (CO_2) emissions levels under regional and ultimately national climate policies, the availability and cost of renewable resources to satisfy renewable energy requirements, as well as underlying economic growth and its relationship to future electric load growth. Together, these important concerns can be addressed, at least in part, by resource planning and regulatory policy.

Heavy regional dependence on natural gas for power generation has two potentially harmful implications. First, consumers are exposed to high and uncertain power costs, because gas is the price-setting fuel for electricity. Second, using large amounts of natural gas for electricity generation may increase the potential of gas supply disruptions in the winter months when overall natural gas use peaks (although examining the relationship between using gas as a generation fuel and possible deliverability issues was beyond the scope of this study). But because much of the existing generation base is gas-fired, to substantially change the region's dependence on gas would take a long time and entail exceptional effort and expense. There are supply-side resource options (such as coal or nuclear) that could eventually reduce gas usage for electricity production in New England, but each has capital cost and/or environmental performance issues that may not coincide with other policy objectives. However, enhanced demand-side measures that include energy efficiency can reduce gas usage while helping to meet future resource needs at lower cost and with less environmental impact.

This analysis shows that the potential net benefits of increased DSM – including both energy efficiency and demand response initiatives – are substantial across a range of potential future market conditions. As long as capacity and energy remain expensive, and gas-fired generation is on the margin, reducing capacity needs and energy usage through DSM will be valuable. DSM geared toward energy efficiency can also reduce energy consumption, which can reduce overall energy costs for customers while reducing emissions. (Note that DSM can reduce overall costs, even though under some circumstances, average unit costs (¢/kWh) may actually increase.

When consumption volumes (kWh) change, a change in unit costs may not accurately reflect overall customer impacts. In addition, the effect on particular customers or classes is a question of cost allocation, a ratemaking issue that was not addressed in this study.) It should be noted that the DSM-Focus resource solution represents a very ambitious, program that is unprecedented in New England.

Connecticut and other New England states have ambitious and escalating renewable energy procurement targets. However, the growing demand for renewable electric generation created by these targets may outpace the development of eligible supplies. Connecticut has relatively limited amounts of economically attractive renewable resource options, and New England states on the whole may not achieve their aggregate renewable targets over the next decade. Consequently, the regional price for renewable energy certificates (RECs) could rise above and remain higher than the alternative compliance payment in Connecticut (other states alternative compliance payments are higher than Connecticut's and are likely to set the regional price in a shortage situation). While Connecticut's lower price cap helps contain costs for Connecticut customers, it may also prevent Connecticut load-serving entities (LSEs) from obtaining RECs when regional REC market prices exceed the Connecticut price cap level. Hence, there is a significant possibility that Connecticut's RPS requirements will not be met with renewable electric generation, forcing LSEs increasingly to rely on payments to the state (at $55/MWh) for shortfalls in obtaining renewable energy certificates (RECs). This could place a large economic burden on ratepayers without displacing conventional generation with renewable generation.

Finally, future electricity market prices are likely to vary substantially, depending on future market conditions, particularly the price of natural gas. Analyzing outcomes under a hypothetical cost-of-service regime, in which customers pay for the cost of generation instead of market prices, we find that the range of costs is smaller across different scenarios. Hence, arrangements that incorporate cost-of-service principles could potentially enhance the stability of rates. Although the hypothetical cost-of-service based customer pricing approach examined here did not explore the specific means and conditions under which cost-of-service pricing would yield lower customer costs than market-based pricing, the analysis suggests the potential for lower prices under cost-of-service pricing under some market conditions, than otherwise might occur in the future External factors remain significant influences on customer costs.

RECOMMENDATIONS

The key findings outlined above are based upon the analysis performed by *The Brattle Group*, and lead to four primary recommendations representing a possible path forward to improve electricity procurement in Connecticut. Steps taken in response to these recommendations could help provide Connecticut customers with reliable, environmentally responsible electric service at more stable prices and potentially lower customer costs.

Recommendation 1: Maximize the use of demand side management (DSM), within practical operational and economic limits, to reduce peak load and energy consumption.

The potential for increased DSM to reduce customer costs, gas usage, and environmental emissions demonstrated in this analysis suggests that DSM should be pursued more aggressively. State regulatory authorities should examine, and where possible, explore methods to implement additional, cost-effective DSM. This would facilitate utility DSM programs to exceed current levels and expand upon the success of existing DSM programs. While the need for capacity is several years off in Connecticut, DSM programs are more cost-effective if they are pursued consistently over time, so it is reasonable to begin the ramp-up to more aggressive DSM programs in the near term.

The DSM resource investments assumed in this report far exceed the (already aggressive) levels pursued by the Companies to date. The pace and magnitude of this expansion warrants careful monitoring of resource availability, costs, and operational effectiveness as the programs develop over time.

Recommendation 2: Explore other power procurement structures such as longer term power contracts on a cost-of-service basis with merchant and utility owners of existing and new generation.

At the present time, the Companies are constrained to enter into contracts with third-party suppliers with durations not to exceed three years to satisfy standard offer service obligations, which ensures that customers are exposed to power supply prices driven by short-term market prices. Our finding that customer costs would be more stable under a hypothetical cost-of-service regime suggests that supply arrangements incorporating cost-of-service principles could help to stabilize customer rates and potentially, under certain conditions, lower prices for the customer. This could be achieved by providing the Companies greater flexibility in the structures and duration of their power supply arrangements on behalf of customers.

Options may include long-term contracting, procuring energy, capacity and reserve products individually from generators and/or the outright ownership of generating assets, including baseload generation that is not dependent on natural gas. By reducing the extent to which utilities are forced to procure power through short-term contracts driven by regional spot market prices, such alternative procurement options can reduce customers' exposure to uncertain and potentially high gas prices, and may provide to customers some benefits of a diverse fuel mix. Addressing these issues may involve the use of procurement strategies and risk management tools (such as fuel hedging strategies to complement electricity procurement) that go beyond what can be done in a resource planning context. In addition, strategies such as these should be coupled explicitly with the assurance of recovery of supply costs associated with approved long-term power procurement contracts.

Recommendation 3: Evaluate the structure and costs of Connecticut's renewable portfolio standard (RPS) in the context of a regional re-examination of the goals and costs of similar policies in New England.

Connecticut's renewable portfolio standard as currently structured, while supporting Connecticut's renewable goals, may impose additional costs on Connecticut customers without necessarily promoting new renewable generation to displace conventional generation. This observation suggests that additional study of RPS, structure and costs is warranted at both the state and regional level to determine the best ways to meet future RPS requirements. At the state level, for example, the criteria for disbursing funds derived from alternative compliance payments might be re-examined under the current circumstances. Further analysis could also examine the potential to fashion regionally-coordinated policies to address possible renewable shortfalls and/or regional projects in transmission and renewable capacity.

Recommendation 4: Consider potential ways to mitigate the exposure of Connecticut consumers to the price and availability of natural gas.

Non-gas baseload generation (*e.g.*, coal, and nuclear) offers a greater reduction in gas use (particularly in wintertime, when deliverability concerns are highest) than other resource options studied in this report. Although not assessed in this report significant renewable generation could also mitigate gas dependence.

To the extent that market participants' investment in non-gas-fired baseload generation is deemed insufficient to address these risks, state regulatory authorities should consider allowing contractual or ownership arrangements or other policy options to enable or encourage investment in such baseload capacity. Such options should be considered in concert with efforts to reduce dependence on natural gas use in all sectors (*e.g.* heating). Both the cost and CO_2 emissions implications of all non-gas options should be considered.

SECTION I: INTRODUCTION

A. BACKGROUND

On July 1, 2007 Connecticut Public Act 07-242 became effective, which advanced state energy policy in a variety of areas, including efficiency, electric fuel flexibility, peaking generation and the development of other electricity resources. Section 51 of PA 07-242 requires that the electric distribution companies, The Connecticut Light & Power Company (CL&P) and The United Illuminating Company (UI) submit a joint comprehensive resource plan to the Connecticut Energy Advisory Board (CEAB) by January 1, 2008. A full text of Section 51 is attached as Appendix I.

The primary motivation for Section 51 is a desire on the part of the Legislature to engage the Companies in a comprehensive evaluation and planning process in order to support resource procurement. Prior to enactment of PA 07-242, there was no established comprehensive framework to compare potential investments in generation capacity, demand-side measures or transmission enhancements in order to determine their effects on market outcomes, customer costs or other important objectives. Section 51 outlines a process to establish such a framework, and to provide other stakeholders an opportunity to examine and influence the analysis.

In order to perform the required analysis, CL&P and UI (the Companies) issued a Request for Proposals to selected consultants shortly after PA 07-242 was enacted. After receiving proposals from several organizations, the Companies selected *The Brattle Group* to conduct the analysis. *The Brattle Group* is a privately-owned economic consulting firm with practice areas spanning all major energy markets, finance and regulatory and litigation support. Founded in 1990 and headquartered in Cambridge, Massachusetts, *The Brattle Group* has approximately 200 staff with additional offices in Washington DC, San Francisco, CA, London, England and Brussels, Belgium.

This report is the result of an intensely collaborative process involving the Companies and *The Brattle Group*. *The Brattle Group* provided independent expertise and judgment regarding the scope and framework for the analysis, constructed the scenarios, established the myriad assumptions used in the modeling effort and performed all the analyses. The Companies provided guidance and direction, and helped refine the scenarios and assumptions. *The Brattle Group* and the Companies then interpreted the analysis, identified the primary observations established the key findings, and formulated the recommendations set forth herein.

B. STUDY SCOPE

In broad terms, an analysis designed to fulfill the requirements of PA 07-242 will consist of the following steps:

- Quantify the *need* for additional resources across a broad range of uncertain future market conditions (*i.e.*, under different *scenarios*);
- Identify potential *resource solutions* that are consistent with the goals outlined in the statute;
- Evaluate the performance of resource solutions in future scenarios using *metrics* derived from the statute's requirements;
- Recommend resource procurement strategies and provide comments on other policy changes.

The scope of the analysis was set out in the contract between the Companies and *The Brattle Group*, which is attached as Appendix J. All of the primary objectives were met, although several elements could benefit from additional analysis in subsequent versions, as discussed at the end of this report.

C. LIMITATIONS

A study of this nature cannot simultaneously provide results on or insights into every conceivable topic with the same degree of depth or confidence. Hence, there are limitations to this analysis, many of which can be addressed in other venues (*e.g.*, DPUC dockets) or in subsequent versions of reports that respond to the annual requirements of PA 07-242 Section 51. In particular, this study was not intended to provide a cost/benefit analysis of transmission options; did not compare the economics of transmission vs. generation or vs. demand-side options; and does not constitute a transmission reliability assessment. Such an assessment would address the mandatory reliability criteria and standards established by various national and regional bodies, which are applied to the New England transmission system as part of the annual New England Independent System Operator (ISO-NE) Regional System Plan (RSP).

D. ORGANIZATION OF THIS REPORT

Because of the broad range of issues considered and the comprehensive nature of the analyses, this report is divided into five main sections. The body of the report describes the background, the analytical approach and key assumptions, discusses the observations and key findings from the analysis, and outlines the recommendations, and finally discusses study limitations and suggested further analyses. A series of appendices follow, which further describe the underpinnings of the analysis or provide a more in-depth discussion of important issues that influenced the analysis. These Appendices are:

Appendix	Topic
A	Electricity Market Analysis
B	Scenario Development
C	Generation Supply Characterization
D	DSM-Focus Resource Solution
E	Renewable Energy
F	CO_2 Reduction Policies
G	DAYZER Model Input Assumptions
H	Evaluation Metrics
I	Section 51 of PA 07-242
J	Consultant Scope of Services

Finally, detailed analysis results for each scenario/resource solution/year are provided in a final section.

SECTION II: ANALYTIC METHODOLOGY

A. OVERVIEW

The current uncertainties in energy markets, the complexities of the ISO-NE markets and the implementation of Connecticut energy policies require an innovative approach to assessing resource strategies. Recent developments in global energy markets, volatility in U.S. electric fuel markets, increased renewable energy requirements, emerging climate policies, rapidly escalating utility construction costs, and continuing evolution in ISO-NE market structure has made long-term electric resource planning extremely challenging. *The Brattle Group* has developed a methodology that captures these elements and yields insights into the impacts of alternative resource solutions.

The major elements of the analysis are:

- **Develop scenarios** spanning the range of plausible future trajectories of exogenous factors that are largely beyond state policy makers' control, including economic growth, fuel prices, and federal climate legislation. Four internally-consistent scenarios are constructed, "Current Trends," "Strict Climate," "High Fuel/Growth," and "Low Stress."
- **Quantify the need for new resources** to reliably meet electricity demand by comparing existing (and planned) resources to the ISO-NE-wide installed capacity requirement and the Connecticut local sourcing requirement established by ISO-NE. The requirements vary by scenario because the load forecast varies.
- **Identify candidate resource solutions**, including supply-side and demand-side resources. The four solutions identified for full analysis are "Conventional Gas Expansion," "DSM-Focus," "Nuclear," and "Coal." Each resource solution was further distinguished by the degree of inclusion of the New England East-West Solution (NEEWS) proposed transmission project – a version with all of NEEWS and a version with the Central Connecticut Reliability Project portion omitted. All solutions are a hybrid of demand-side and a variety of supply-side resources, but each has a different emphasis as indicated by the solution name.

- **Analyze resource solutions across scenarios** and over time (2011, 2013, 2018, and 2030) using electricity market models. This was a comprehensive analysis – with four scenarios, four resource solutions, two NEEWS assumptions and four years, the number of cases analyzed became quite large.
- **Define metrics for evaluating resource solutions** along the policy objectives addressed in Section 51, included customer costs, emissions, and reliability/security. Many of these objectives are also reflected in the CEAB Preferential Criteria for Evaluation of Energy Projects.

B. Scenario Definition

Long-range analyses must address substantial uncertainty regarding external factors, which can have important implications for evaluating potential resource solutions. Key external factors include fuel prices, load growth, and changes in environmental regulation.

In this study, we develop several internally consistent future scenarios against which we evaluate the resource solutions. Each scenario reflects a combination of particular values for the relevant external factors and is characterized by an underlying "driver" in combination with settings of other external factors that are consistent with this driver. The scenarios are designed so that the particular combinations of external factors are relatively likely (factors that tend to "go together"), and/or important (combinations that pose particular risks or opportunities to the resource strategies).

One of the key steps in developing the scenarios is to understand the relationship between the scenario drivers – here, economic growth, fuel price and CO_2 allowance price – and electricity prices and power demand. To create consistent relationship between these, we have considered the interaction between economic growth and electric load, and also the feedback effects by which fuel and CO_2 prices affect power price, which then also influences power demand. Different factors may have varying impact on energy demand vs. peak load, and we have captured this distinction as well.

We have developed four scenarios for this analysis. They are described briefly below, and the table following summarizes the scenarios. A complete description of the underlying drivers and analyses that support the scenario parameters is contained in Appendix B.

Table 2.1: Scenario Summary

Scenario Name	Fuel Prices	Load	Cost / Siting	CO_2 Price
"Current Trends"	Moderate	Moderate	Nominal (high)	Moderate (high)
"Strict Climate"	Slightly High	Slightly Low	Nominal (high)	High
"High Fuel/Growth"	Very High	High	Higher	Somewhat Higher
"Low Stress"	Low	Very High	Moderate	Moderate (high)

i. Current Trends

The Current Trends scenario is based on a continuation of current conditions and expectations. Fuel prices follow current futures prices, and are escalated at growth rates beyond the time horizon of futures prices reported in Energy Information Administration (EIA) forecasts. Load growth is based on ISO-NE Reference Case load growth forecast, which does not incorporate the impact of DSM because DSM is represented as a resource and the load forecast reflects electricity service rather than actual loads. This was adjusted for current and projected levels of DSM to derive a net supply requirement to be supplied by resources other than current and projected levels of DSM. Environmental (climate) policy reflects estimated CO_2 emission allowance prices from the Regional Greenhouse Gas Initiative (RGGI) through 2013, after which moderate federal climate legislation is enacted, resulting in a CO_2 price of about $12/metric tonne in 2014, growing to $26/tonne in 2030 (based on the "safety valve" price cap in the recent Bingaman-Specter proposal, the Low Carbon Economy Act of 2007).[1] Construction costs for new generating capacity assume that recent price increases in materials and labor continue.

[1] The analysis was conducted in real 2008 dollars; unless otherwise indicated, all dollar figures are in 2008 year dollars.

ii. Strict Climate Policy

The Strict Climate Policy scenario is driven primarily by more ambitious federal-level climate policy, based loosely on several of the more stringent legislative proposals that have been introduced recently. This leads to higher CO_2 prices: $26/tonne in 2012, to $60/tonne in 2030, which translates into higher fossil fuel prices in the power sector. The higher CO_2 price causes some dispatch switching (from coal to gas) and likely a shift toward natural gas-fired generation for capacity additions across the U.S., (particularly in coal-dominated regions, not necessarily in New England); this increased natural gas demand pushes up U.S. natural gas prices somewhat (though this is partly tempered by a decrease in non-electric use of natural gas). The overall effect on gas prices is to increase them by about 10% (not including the implicit price increase due to higher CO_2 prices). The high CO_2 price and higher gas price are reflected in higher electricity prices, which cause a reduction in load growth relative to the Current Trends scenario.

iii. High Fuel/Growth

The High Fuel/Growth scenario is characterized by high (regional, national and/or global) economic growth, in combination with substantially higher natural gas prices – up about 70% from level assumed in the Current Trends scenario. High natural gas prices are driven at least in part by high U.S. gas demand (and strong global demand for LNG, which limits its role in holding domestic prices down). Oil prices are also increased by 20-30% from the Current Trends scenario. (At this writing, oil prices have already increased nearly 20% since the Current Trends fuel prices were set for the study.) Electric load growth in this scenario is affected by two strong but opposing factors – high economic growth tends to increase load growth, while higher fuel prices push up power prices, which tends to decrease load relative to what it would otherwise be. On balance, the fuel price increase effect is stronger, and actual load growth in this case is lower than in the Current Trends scenario. Federal climate legislation similar to that in the Current Trends Case is assumed (*e.g.*, a "safety valve" caps CO_2 allowance prices), but the CO_2 allowance price cap is assumed to be set at 30% higher than in the Current Trends scenario. This reflects the greater expense of achieving CO_2 reductions with higher natural gas prices, and the political acceptance of setting a higher "safety valve" price in the context of an era of high economic growth.

iv. Low Stress

Historically, periods of high prices are often followed by a return to earlier, lower price trends. The Lowered Stress scenario reflects a return to somewhat lower fuel costs, reversing some of the recent price increases. Fuel prices are about 40% below their Current Trends levels, with oil and gas maintaining the same proportional relationship as in the Current Trends scenario. Similarly, generation construction costs are lower than in the Current Trends scenario, as some of the recent significant and rapid increases in construction costs abate somewhat over the longer run. In response to the resulting decrease in power prices, load is higher than in the Current Trends scenario. Federal climate legislation similar to that in the Current Trends scenario is assumed.

C. QUANTIFICATION OF RESOURCE NEEDS

The purpose of this study is to identify the multi-attribute costs and risks associated with various resources options for meeting future electricity needs. Hence the starting point for the study, before describing the *types* of resources, is to quantify the *amount* of new resources that will be needed. Resource needs are driven primarily by reliability concerns: having enough generating capacity installed to serve all demand during the hottest, highest-demand day of the year given the possibility of unplanned generation outages, using a formal criterion that reduces the probability of having inadequate generation to one day in ten years as required by NPCC.[2]

To that end, there are two simultaneous resource adequacy requirements affecting Connecticut customers. One is the ISO-NE-wide installed capacity requirement (ICR), requiring each load serving entity and the system as a whole to have a certain amount of installed capacity. The

[2] ISO-NE must comply with the Northeast Power Coordinating Council's resource adequacy design criterion, which states, "Each Area's probability (or risk) of disconnecting any firm load due to resource deficiencies shall be, on average, not more than once in ten years. Compliance with this criteria shall be evaluated probabilistically, such that the loss of load expectation [LOLE] of disconnecting firm load due to resource deficiencies shall be, on average, no more than 0.1 day per year. This evaluation shall make due allowance for demand uncertainty, scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring Areas and Regions, transmission transfer capabilities, and capacity and/or load relief from available operating procedures."
See http://www.npcc.org/documents/regStandards/Criteria.aspx for more information.

second is the Connecticut local sourcing requirement (LSR) requiring a certain minimum amount of capacity to be located in Connecticut.

The analysis projects the necessary amount of new resources (the "resource gap") based solely on these two reliability requirements then examines the economics (and other metrics) of various resource options for meeting that gap. This corresponds to the CEAB Preferential Criteria I.A that resource proposals "meet identified energy needs."[3]

i. ISO-NE Resource Requirements

Forecasting the amount of new supply or demand-side resources that must be installed for reliability involves projecting the demand for electricity, then estimating the amount of resources beyond those that are already in place (or already planned and underway) that will be needed to reliably serve the peak demand in each year. The future demand for electricity is influenced by economic growth and electricity prices – therefore both the demand for electricity and the projected resource gap can vary across future scenarios. The following paragraphs describe the resource gap for the Current Trends scenario, followed by a table describing the resource gap for the other three scenarios.

The load forecast used in the Current Trends scenario is taken directly from the ISO-NE's ten-year hourly energy requirements forecast corresponding to normalized weather conditions and that accounts for transmission and distribution losses. Our understanding is that it is not reduced based on any expected demand response or new energy efficiency programs, so additional adjustments were made to incorporate these programs, as described below.

The amount of resources in place must exceed the forecasted peak load in order to prepare for anomalously hot weather and uncontrollable outages of generating plants. Based on standard probabilistic modeling techniques, ISO-NE has determined that the Installed Capacity Requirement (ICR) must exceed the peak load forecast by 16-17% (varies by year) in order to achieve its target reliability standard, which allows for a loss of load expectation (LOLE) of no

[3] The full text of this criterion reads: "The CEAB will evaluate the consistency of a proposal with forecasted energy needs as identified by the Regional System Operator, the Connecticut Siting Council, the State Energy Plan and other resources that it deems to be relevant and appropriate."

more than one day in ten years. Under ISO-NE rules, installed generating capacity, ISO-callable demand response, and firm imports all count toward the ICR.

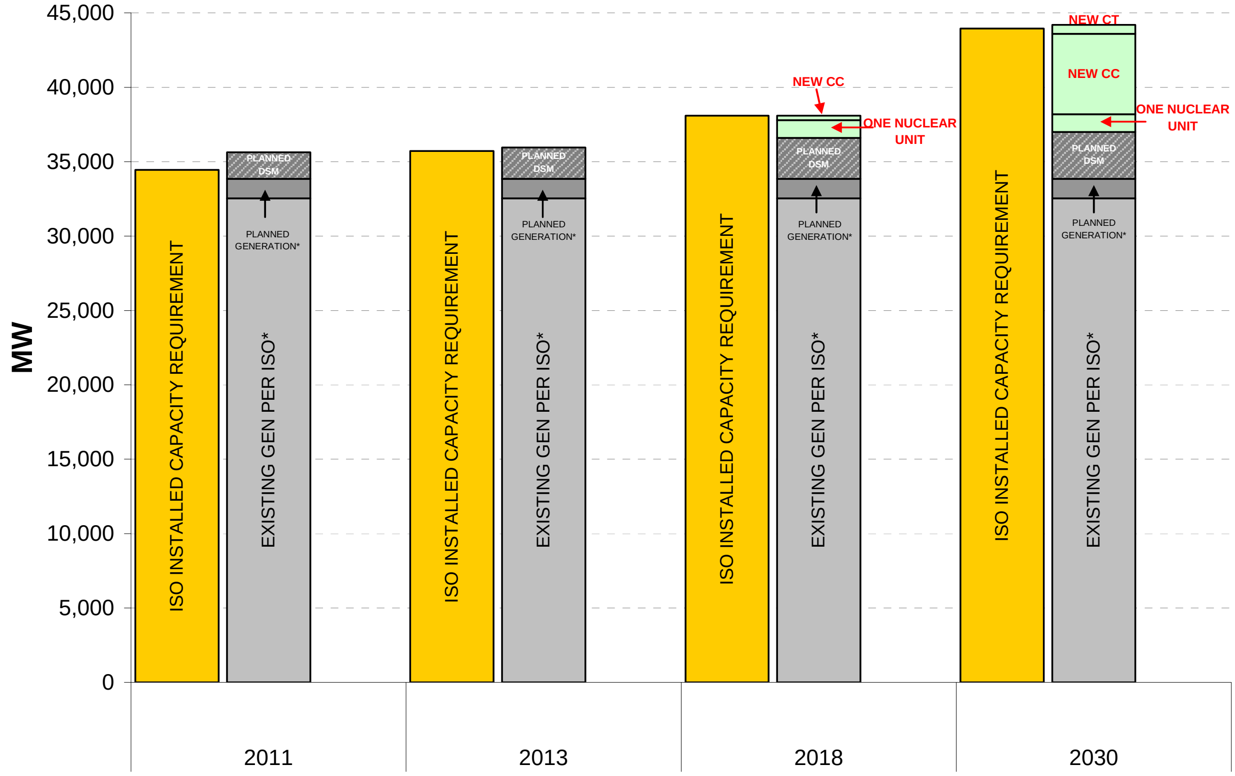
This study also considers planned new resources (described in Appendix A), including:

- 1,107 MW of new generating capacity that is either under construction, under contract or recently operational in Connecticut: Wallingford/Pierce (100 MW), Kleen Energy (560 MW summer/620 MW winter), Waterbury CT (80 MW summer/96 MW winter), DG Capital Grant projects (130 MW; 96 MW of which is counted on the supply side), long-term renewable energy contracts (150 MW), an expansion at Cos Cob (40 MW), and an uprate at Millstone 3 (81 MW).
- 279 MW of new combustion turbines to meet the fast-start requirement in Connecticut based on an analysis of the Local Forward Reserve Market (LFRM) requirements described in Appendix A. This figure was very close to the level reflected in a December 14, 2007 DPUC decision that derived 282 MW of fast-start resources.
- More than 700 MW of peak demand savings by 2011, and more than 1,000 MW of peak demand savings by 2018 from demand response (DR) and energy efficiency (EE) programs already underway or planned by the Companies. EE programs also reduce future energy requirements by 1,168 GWh by 2011 and 2,821 GWh by 2018.
- It was assumed that the rest of New England would also develop new DR and EE at half the rate Connecticut develops new DR and EE per megawatt of load.
- It was assumed that no existing Connecticut capacity would retire, based on a preliminary screening analysis, as discussed further in Appendix C.

Figure 2.1 shows all of these elements and calculates the "resource gap" as the difference between the ICR and the already-planned resources. As the figure shows, there is no gap in the Current Trends scenario in 2011 or 2013. By 2018, ISO-NE will need approximately 1,500 MW of new resources.

Figure 2.1 also shows the unplanned resources that would be added in 2018 and 2030 as part of the Nuclear solution. (Corresponding figures for the other scenarios and solutions are provided in Appendix A.) Note that the "Nuclear" solution is actually a hybrid resource solution (as are the Coal and DSM-Focus solutions, since they also incorporate additional gas-fired generation). It includes one 1,200 MW nuclear unit, assumed to be located in Connecticut, and gas-fired generation is added to meet the remaining resource gap.

Figure 2.1: ISO-NE Supply-Demand Balance and Nuclear Resource Solution in Current Trends Scenario



*Existing generation includes imports, net purchases, and New Boston retirement. All planned generation includes Waterbury, Kleen, Additional LFRM Required CT, Wallingford/Pierce unit, DG Capital Grant Projects, Renewable Energy Contracts, Cos Cob expansion, and Millstone 3 uprate.

Each of the four scenarios analyzed depicts a different future evolution of the New England electricity market. As a result of using different underlying demand forecasts and adjusting for the impact of different fuel and electricity prices expected in the scenarios, the projected peak load levels will vary among the scenarios. Because the other adjustments described above are assumed fixed across scenarios, the magnitude of the expected “resource gap” will therefore vary. Table 2.2 shows how the projected resource gap evolves under each scenario in ISO-NE

As also seen in this table, the ISO-NE resource gap varies dramatically across scenarios. For example, the resource gap in 2018 varies from about 1,000 MW in the Strict Climate scenario (where high fuel and electricity prices depress load growth) to almost 4,500 in the Low Stress scenario (where generally lower fuel and electric prices lead to higher demand growth). The parameterization of the scenarios has captured a broad range of resource needs over the next decade, at least at the ISO-NE level.

Table 2.2: Resource Gap Relative to ISO-NE Installed Capacity Requirement (MW)

		2011	2013	2018	2030
GROSS LOAD BY SCENARIO	[1]				
ISO Base Case Peak Load		29,650	30,675	32,664	37,698
Current Trends Scenario		29,650	30,675	32,664	37,698
Strict Climate Scenario		29,239	30,158	31,871	36,784
High Fuel/Growth Scenario		29,429	30,699	33,391	38,538
Low Stress Scenario		30,692	32,135	35,247	40,680
Reserve Requirement		16.2%	16.5%	16.6%	16.6%
SUPPLY					
2008 Internal Installed Capacity	[2]	30,855	30,855	30,855	30,855
Planned Capacity Additions	[3]	1,107	1,107	1,107	1,107
Assumed Addition of Fast-Start Capacity to Meet LFRM Requirement	[4]	279	279	279	279
Existing Purchases & Sales	[5]	291	291	291	291
Hydro Quebec Imports	[6]	1,400	1,400	1,400	1,400
Adjustment for Planned Additions Already Included in [2]	[7]	(85)	(85)	(85)	(85)
Planned Supply	[8]	33,847	33,847	33,847	33,847
DSM	[9]				
Current Trends Scenario		1,534	1,812	2,355	2,704
Strict Climate Scenario		1,328	1,554	1,959	2,247
High Fuel/Growth Scenario		1,004	1,165	1,456	1,668
Low Stress Scenario		1,534	1,812	2,355	2,704
SHORTFALL (SURPLUS)					
Current Trends Scenario		(1,163)	(225)	1,492	6,957
Strict Climate Scenario		(1,402)	(525)	1,030	6,423
High Fuel/Growth Scenario		(805)	557	3,389	9,144
Low Stress Scenario		48	1,476	4,504	10,433

Sources and Notes:

[1]: Grossed up for DSM.

[2]: 2007 *CELT* report; reduced by 350 MW per ISO to reflect New Boston unit retirement.

[3]: Includes Wallingford/Pierce (100 MW), Kleen Energy (560 MW summer/620 MW winter), Waterbury CT (80 MW summer/96 MW winter), DG Capital Grant projects (130 MW; 96 MW of which is counted on the supply side), long-term renewable energy contracts (150 MW), an expansion at Cos Cob (40 MW), and an uprate at Millstone 3 (81 MW).

[4]: Assumed addition of fast-start capacity to meet Connecticut LFRM requirement.

[5]-[7]: 2007 *CELT* report.

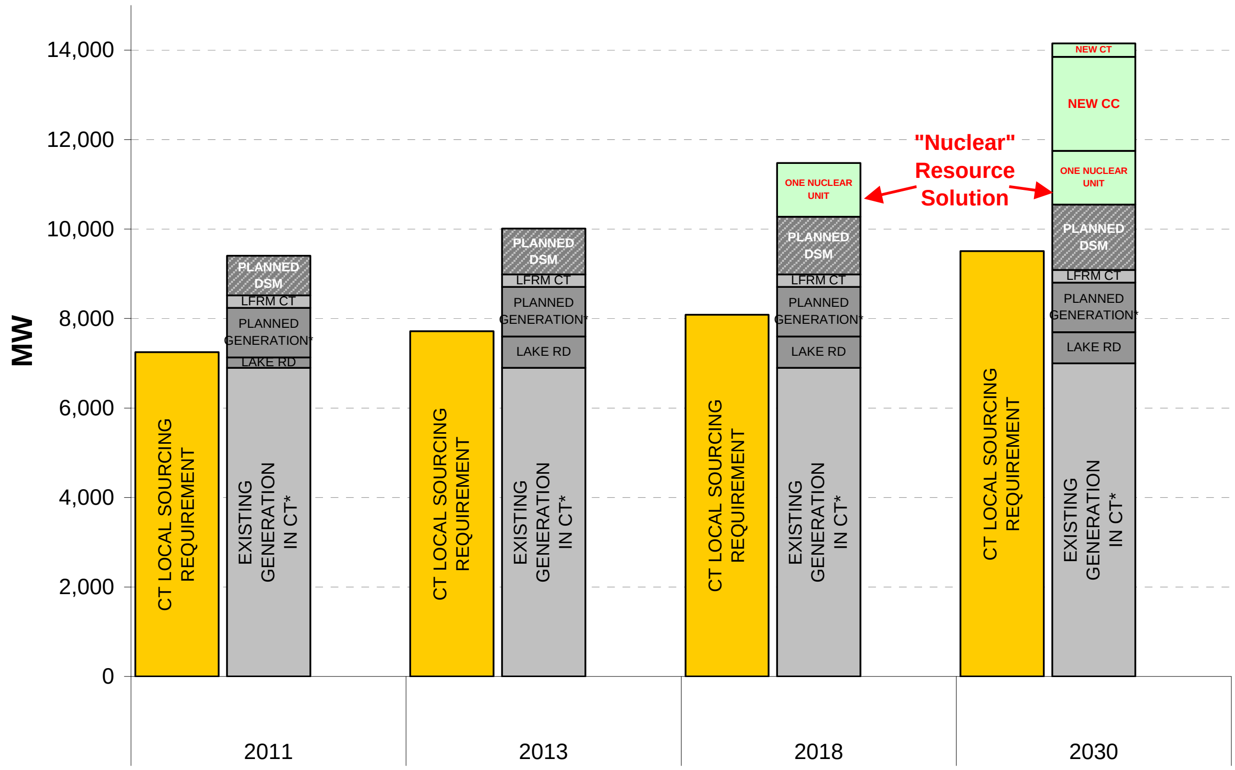
[8]: [2]+[3]+[4]+[5]+[6]+[7].

[9]: Grossed up by a factor of 1.08 for transmission and distribution losses.

ii. Connecticut Local Sourcing Requirement

ISO-NE also imposes local sourcing requirements (LSR) for Connecticut and Boston to ensure that the target LOLE is achieved in these load centers. However, Figure 2.2 shows that there will be no resource gap through 2030 under the Nuclear resource solution – due primarily in the early years (2011 and 2013) to planned generating additions and aggressive DSM measures – and Table 2.3 shows that none of the scenarios have a resource gap with respect to the local sourcing requirement.[4] The candidate resource solutions that add capacity within Connecticut do so for reasons other than the LSR, *i.e.*, to meet the ISO-NE installed requirement and to affect Connecticut's policy objectives regarding cost, environmental emissions, and fuel diversity.

Figure 2.2: Connecticut Supply-Demand Balance and Nuclear Resource Solution in Current Trends Scenario



*Existing generation is net of sales. Other planned generation includes Waterbury, Kleen, Wallingford/Pierce unit, DG Capital Grant Projects, Renewable Energy Contracts, Cos Cob expansion, and Millstone 3 uprate.

[4] ISO-NE has determined the LSR corresponding to the load forecast that is used in the Current Trends scenario. The LSR corresponding to the other scenarios, with their different load forecasts, was estimated based on the relationship between the LSR and load growth implicit in ISO-NE's requirements for 2010 and 2016: for every megawatt of load growth in Connecticut, the LSR increases by 1.26 MW.

Table 2.3: Resource Gap Relative to Connecticut Local Sourcing Requirement (MW)

		2011	2013	2018	2030
LOCAL SOURCING REQUIREMENT IN CONNECTICUT					
Current Trends Scenario		7,251	7,718	8,086	9,506
Strict Climate Scenario		7,114	7,546	7,824	9,210
High Fuel/Growth Scenario		7,177	7,726	8,326	9,778
Low Stress Scenario		7,599	8,204	8,938	10,471
SUPPLY					
2008 Internal Installed Capacity	[1]	6,999	6,999	6,999	6,999
Inclusion of Lake Road Units in Connecticut	[2]	233	699	699	699
Additional Planned Capacity	[3]	1,107	1,107	1,107	1,107
LFRM CT	[4]	279	279	279	279
Purchases & Sales	[5]	(100)	(100)	(100)	-
Internal Gen Capacity	[6]	8,518	8,984	8,984	9,084
DSM	[7]				
Current Trends Scenario		763	881	1,108	1,255
Strict Climate Scenario		709	813	1,005	1,137
High Fuel/Growth Scenario		619	700	833	943
Low Stress Scenario		763	881	1,108	1,255
CONNECTICUT LSR SHORTFALL (SURPLUS)	[8]				
Current Trends Scenario		(2,229)	(2,376)	(2,295)	(1,159)
Strict Climate Scenario		(2,297)	(2,462)	(2,426)	(1,307)
High Fuel/Growth Scenario		(2,120)	(2,140)	(1,708)	(494)
Low Stress Scenario		(1,881)	(1,890)	(1,443)	(194)

Sources and Notes:

[1]: 2007 *CELT* report; Excludes Lake Road units which are physically in Connecticut but electrically in Rhode Island.
[2]: In 2011, one Lake Road unit (233 MW) is electrically transferred to Connecticut via an elective transmission upgrade by Lake Road. In 2013, the remaining two Lake Road units (466 MW) are electrically transferred to Connecticut via the NEEWS transmission project. We conservatively did not account for any additional increase in import capability associated with NEEWS in this analysis of resource adequacy.
[3]: Includes Wallingford/Pierce (100 MW), Kleen Energy (560 MW summer/620 MW winter), Waterbury CT (80 MW summer/96 MW winter), DG Capital Grant projects (130 MW; 96 MW of which is counted on the supply side), long-term renewable energy contracts (150 MW), an expansion at Cos Cob (40 MW), and an uprate at Millstone 3 (81 MW)
[4]: Assumed addition of fast-start capacity to meet Connecticut LFRM requirement.
[5]: 2007 *CELT* report. Accounts for a 100 MW capacity contract with Long Island across the Cross-Sound Cable.
[6]: [1]+[2]+[3]+[4]+[5].
[7]: Grossed up by a factor of 1.08 for transmission and distribution losses.
[8]: DSM is grossed up by 0.26 for consistency with the Local Sourcing Requirement.

It is important to note that the projected LSR surplus under the Current Trends scenario is very different than the Connecticut Resource Balance presented in the recent Connecticut Siting Council (CSC) report.[5] However, the potential resource needs identified in that report were

[5] See *Review of the Ten Year Forecast of Connecticut Electric Loads and Resources 2007-2016*, Connecticut Siting Council, November 14, 2007, Table 3, page 13.

based on the ISO-NE "90/10" forecast (*e.g.*, the peak loads that the ISO would expect would be exceeded only 10% of the time) rather than the normalized forecast distribution used in the LSR determination, and the CSC evaluation also provides for the potential retirement of 1,600 MW of oil-fired capacity in 2011 and 2,000 MW in 2013, as a consequence of capacity reaching 40 years in service. In addition, the CSC accounts for two plants that have been approved (Meriden & Oxford) but not constructed, for a total of about 1,050 MW additions. Perhaps most importantly, however, is the fact that the assumed level of DSM in Connecticut (based on the Companies' current plans) is quite substantial in all scenarios – even before considering the "DSM-Focus" resource solution. These assumptions are different than the expectations that govern our "Current Trends" scenario (see Appendix A for additional information).

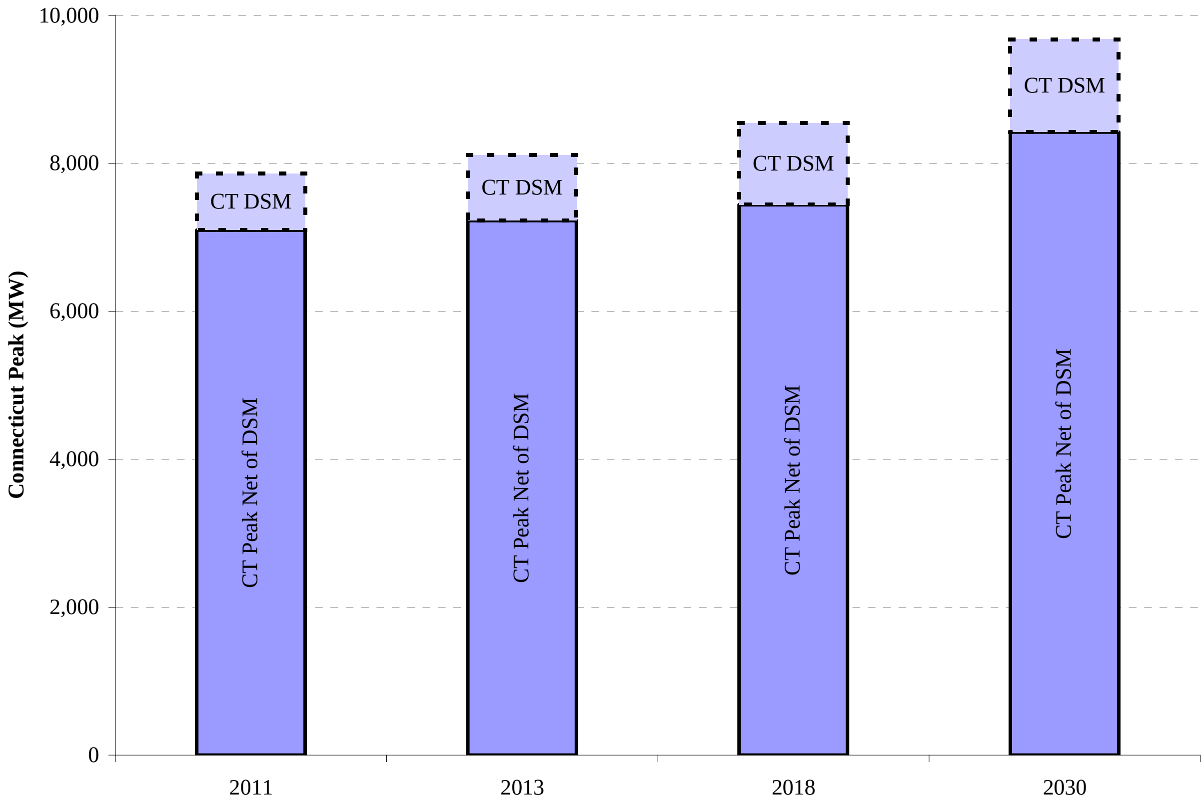
D. Resource Solutions

Resource solutions refer to investments that market participants or the Companies could make in supply or demand-side resources, and/or transmission capability. Potential solutions differ in composition, but this study assumes that they do not differ in the quantity of resources that would be added. All solutions just fill the resource gaps discussed in Section III. To assume less would imply an expectation that planners would fail to maintain a reliable system and/or that market participants would overlook opportunities to earn more than their cost of capital (the forward capacity market would theoretically clear above the net cost of new entry if there were a shortage). To assume more would imply that planners build more capacity than is needed and/or that market participants would make investments that earn less than their cost of capital (the forward capacity market would theoretically clear below net cost of new entry if there were a surplus). This analytical construct does not imply that imbalances in the form of capacity deficiencies or surpluses cannot occur, but simply acknowledges the tendency for markets to trend toward equilibrium over time, and that it is not possible to predict when transient imbalances might actually occur.

One of the challenges of evaluating resource solutions in the context of a deregulated generation market such as ISO-NE is the extent to which cost-of-service based investments or contracts might complement or compete with investments made by third parties such as unaffiliated generation companies. At this stage, we do not distinguish between generation investments made by other market participants and those that may be made by the Companies on a cost-of-service basis (we do assume that the demand-side resource solution is pursued by the Companies). In all resource solutions/scenarios there are assumed generation investments made in other parts of ISO-NE between 2008 and 2018. In some resource solution/scenario combinations additional generation is also built in Connecticut as needed to maintain reliability criteria and/or that reflects economic new entry. Thus, all of the resource solutions examined here represent a blend of supply and demand-side resources that could emerge in the market; the specific resource solutions examined here essentially emphasize particular approaches.

The Companies' "Base" or "Reference" level of planned DSM included in all solutions is aggressive and has a significant impact on Connecticut load and energy. The planned DSM reduces total Connecticut energy by 1,168 GWh by 2011 and 2,821 GWh by 2018, and cuts Connecticut peak load by approximately 10% in 2010. Figure 2.3 shows the impact of planned DSM in the Current Trends Scenario. These programs are expected to cost approximately $120 million per year by 2009 (in 2008 dollars) and stay at that level in real terms for 10 years.

Figure 2.3: Connecticut Planned DSM Shown as a Portion of Peak Load



This study evaluated the economic and other impacts of four types of resource solutions that differ in character and impact: "Conventional Gas Expansion," "Demand-Side Focus," "Nuclear," and "Coal," each of which is described below. It is important to note that all of these solutions contain a blend of generation technologies and significant amounts of DSM. All include at least the "reference" or "base" amount of DSM planned by the Companies, which provides a significant resource before additional resources are added. All resource solutions rely on gas-fired generation (primarily CCs) to meet any resource gap that remains after adding one 1,200 MW nuclear or coal plant or additional DSM measures.

i. Conventional Gas Expansion

The "Conventional Gas Expansion" solution uses only gas-fired combined-cycles (CCs) and combustion turbines (CTs) to meet the identified resource gap in each scenario.[6] The particular

[6] While we model gas-fired CCs and CTs, we recognize that such capacity could be dual-fuel capable with distillate oil back-up.

technology and location of each resource was selected based on economics. Primarily CCs were selected because their higher energy margins more than offset their higher capital costs and fixed operating and maintenance costs. CCs were assumed to be located primarily outside of Connecticut because the incremental energy margins appeared to be insufficient to offset the higher construction and operating costs in Connecticut than in the rest of New England. CCs in Connecticut were estimated to cost $869/kW, and CTs were assumed to cost $598/kW.[7] The three other solutions are similar to the Conventional solution, except that they replace 600-1,200 MW of CCs with alternative resources.

ii. DSM-Focus

Section 51(c) requires that "energy resource needs shall first be met through all available energy efficiency and demand reduction resources that are cost effective, reliable and feasible." The DSM-Focus resource solution assumes the effectiveness of significantly higher amounts of DSM investments that (a) "aim higher/go deeper," *i.e.*, strive for the highest efficiency levels in end-use consumption that are cost-effective; (b) accelerate the retirement of inefficient customer systems; (c) integrate program design and delivery; and (d) integrate with other state-wide initiatives, such as the Climate Change Action Plan and the Governor's Energy Vision. The amount of DSM contemplated in this resource solution is unprecedented in New England.

The DSM-Focus resource solution builds on successful, and aggressive existing DSM programs, *i.e.*, the "Reference Case DSM," that is assumed to be present in all scenarios and thereby implicit in other resource solutions. We use the existing and currently-planned level of DSM investment as the "Reference Case DSM" in all solutions except the DSM-Focus solutions. In the "DSM-Focus" resource solution, the existing DSM programs expand in several directions, enabled by substantially higher funding levels. By 2018, demand savings from the DSM-Focus scenario constitutes about 19.1% reduction of system peak.[8] While Reference DSM eliminates about 93% of potential load growth between 2008 and 2018, the DSM-Focus resource solution

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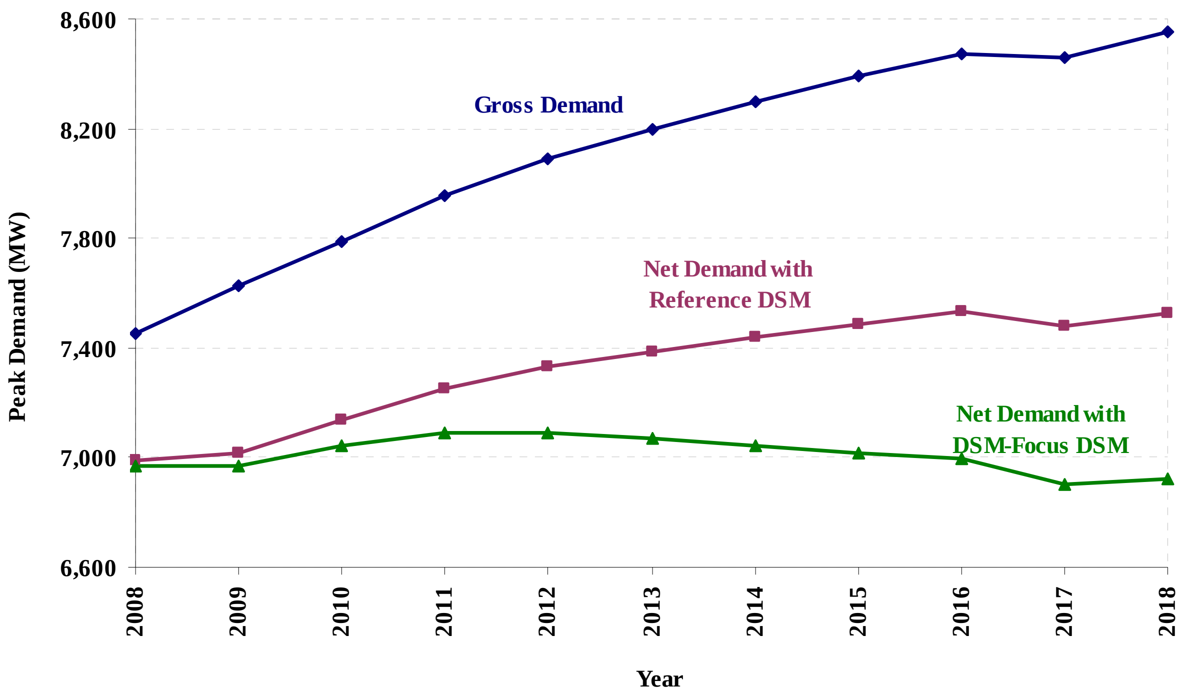
[7] Other key characteristics for CCs and CTs include fixed O&M costs of $29.7 and $26.7, variable O&M costs of $1.4 and $3.2, and heat rates of 7,000 and 10,200, respectively. Real capital charge rates of 10.7% were applied to calculate annual capital carrying charges.

[8] Beyond 2018 savings from EE and DR programs were assumed to grow at the same rate as Connecticut system peak.

actually reduces demand to below current levels by 2018 in the Current Trends scenario, as shown on Figure 2.3.

Figure 2.4: CT Peak Demand (MW) Forecast under Different DSM Scenarios



Source: 2007-2016 CT Peak Demand (MW) data from ISONE spreadsheet titled "isone_2007_forecast_data.xls." 2007-2018 CT Peak Demand (MW) data based on *The Brattle Group* extrapolation of hourly ISONE data. DSM data for the Reference and DSM-Focus cases provided by the Companies.

iii. Nuclear and Coal Solutions

The purpose of the Nuclear and Coal solutions is to evaluate the addition of about 1,200 MW of high capital cost/low fuel cost baseload capacity in Connecticut, with different characteristics. The nuclear generation has very low fuel cost and emissions, but potentially very high capital cost, while coal units have somewhat higher fuel costs and lower capital costs than nuclear but significant CO_2 emissions. These resource solutions are designed to test an alternative to the conventional gas-fired CC and CT generating capacity expansion strategy. The first step to constructing these solutions was to perform a screening analysis to identify the most economic baseload technologies. This analysis is described in Appendix C. The screening analysis indicated that nuclear and super-critical coal without carbon capture and sequestration had relatively favorable costs compared to other possible technologies.

The capital cost of nuclear is a major uncertainty that could have a major effect on its economics relative to coal, and so it is difficult to conclusively prefer one technology over the other. In addition, it should be noted that large baseload coal and nuclear plants have longer lead times than gas-fired combined cycle, and therefore represent a larger financial commitment over a longer period of time.

iv. Characteristics of Resource Solutions

The resource solutions in this study are evaluated primarily based on their expected cost and performance characteristics, such as efficiency and emissions. However, there are many attributes of resource solutions that are not well captured in such an analysis. For example, some resource solutions require more up-front commitment while others are more readily scaled up or scaled back in response to emerging market conditions. These attributes are summarized below. This includes certain risks of costs and operational performance, lead times, and the ability to scale investment commitments over time to respond to evolving market conditions. The following table characterizes the resource solutions along selected dimensions that are not analyzed quantitatively in this study.

Table 2.4: Other Factors Affecting Resource Solutions

	Conventional	**DSM-Focus**	**Nuclear**	**Coal**
Siting/Permitting Challenges	Med	Low	High	High
Capital Cost Uncertainty	Med	Low	Very High	High
Lead Time	Med	Low	Very High	High
Commitment/Scale Risk	Med	Low	Very High	High
Operational Performance Risk	Low	Med	Low	Low

E. ANALYSIS OF SOLUTIONS USING MARKET MODELS

The impact of each of the four resource solutions across all four scenarios is analyzed using structural models of the ISO-NE's energy and capacity markets. These markets, their recent performance, and how they are modeled in this study, are described in detail in Appendix A. This section of the report provides only a brief overview.

i. ISO-NE Energy Market Modeling

The ISO-NE administers day-ahead and real-time energy markets in which the lowest cost generation (based on bids and subject to transmission constraints and operating constraints) is dispatched to meet the demand on the system at each moment. These markets establish a market clearing price, which is the basis for settlement, *i.e.*, the amount that load serving entities pay and generators get paid for energy. The clearing price varies by node, reflecting the costs of transmission congestion and marginal losses when transmitting power between any two nodes.

Because there are transmission constraints and losses both into and within Connecticut, it is important to consider these factors and the broader ISO-NE energy market in an integrated resource plan for Connecticut. To do this, we have employed DAYZER, a state-of-the-art power market simulation model developed by Cambridge Energy Solutions (CES). The data inputs to DAYZER represent all of the elements of supply, demand, and transmission in the ISO-NE system and how these elements evolve over time depending on resource strategies.[9] Using these inputs, DAYZER simulates the ISO-NE's operation of the system and its administration of the energy market. The model outputs include hourly locational marginal prices, dispatch costs, generation, and emissions for every generating unit in New England, and transmission flows and congestion. These outputs are the basis for evaluating outcomes with one resource solution versus another.

In order to be consistent with the statute's requirement for three, five, and ten-year outlooks, it was necessary to simulate years 2011, 2013, and 2018. The year 2030 was also simulated in order to test the long-term implications of decisions made over the next ten years. The data inputs for these future years were developed in four steps.

[9] Data inputs are described in detail in Appendix G.

1. First, by developing an accurate representation of today's system. This involved representing every element of the current transmission system using a dataset from ISO-NE, auditing the load and generation inputs against ISO-NE sources, and reviewing data with the Companies to identify any errors or omissions.
2. Second, by projecting likely changes in fundamentals, including load growth, demand-side management, generation development and retirements, fuel and emission allowance prices, and transmission enhancement, based on current trends and plans (this becomes the "Current Trends" scenario).
3. Third, by adding sufficient unplanned resources to meet the ISO-NE's resource adequacy requirements for ISO-NE as a whole and for Connecticut specifically, as discussed in Section III. The types of unplanned resources vary by Solution: gas-fired combined cycle (CC) plants and combustion turbines (CT) in the Conventional resource solution, large-scale coal or nuclear plants in the Nuclear and Coal resource solutions, and additional demand-side management (DSM) programs in the DSM-Focus solution. Because these cases are otherwise identical, the differences in outcomes reflect only the differences in value among the various solutions tested.
4. Fourth, by varying the uncontrollable, exogenous factors of fuel and allowance prices and economic growth according to the Current Trends, High Fuel/Growth, Strict Climate, and Low Stress scenarios described above.

ii. ISO-NE Capacity Market Modeling

ISO-NE also administers a capacity market to facilitate a liquid, transparent mechanism for market participants to buy and sell capacity to meet their resource adequacy requirement. Capacity payments have been a significant cost component for load serving entities and are likely to become larger in the future as the current ISO-wide capacity surplus diminishes. More information will become available when the first forward capacity market (FRM) auction for 2010/11 delivery occurs in February, 2008.

In this study, it was assumed that the forward capacity price would be at the designated floor of \$4.50/kw-mo in 2011, when there is substantial overcapacity in all scenarios (except Low Stress, which is at equilibrium). The capacity price was then projected to trend toward the net cost of new entry (Net CONE) in the first year in which the market came into supply/demand equilibrium. Net CONE is given by the capital carrying cost plus annual fixed O&M costs minus the energy margins of new units.

As described in greater detail in Appendix A, we have projected capacity prices generally below the initial floor, due to the projected energy margins for CCs, which are much higher than for CTs (which are only slightly less expensive to build) on which the initial floor was based.

F. EVALUATION METRICS

After resource solutions are tested in DAYZER and other offline analyses, they are compared to each other using multiple evaluation metrics that correspond to the objectives outlined in PA 07-242 and also reflect the CEAB Preferential Criteria for the Evaluation of Energy Proposals. These metrics measure economic impacts such as resource costs and customer costs under various assumed pricing regimes; and also include reliability indices, environmental impacts, fuel diversity and energy security considerations. These metrics represent key indicators of the multi-attribute benefits and costs associated with each resource solution, and their values under each scenario help illuminate tradeoffs among the objectives and the expected benefits and risks of pursuing specific investments. These metrics include:

- **Total Going Forward Resource Cost –** a measure of the total value of resources consumed in meeting Connecticut loads.
- **Market Cost of Generation –** a measure of the costs that the Companies bear in serving their retail customers under existing short-term procurement rules and ISO-NE market prices.
- **Cost of Service Generation –** a measure of how the costs of generation would be reflected in Connecticut customers' bills under a hypothetical return to traditional cost-of-service pricing principles.
- **Reserve Margins and Load Factor –** measure the degree to which supply resources exceed demands and the relationship between peak load and average load.

- **Fuel Diversity and Security –** measures of the contribution of power generation to overall gas demand and particularly wintertime peak gas demands.
- **Environmental Outcomes –** measures of generation emissions and degree of compliance with RGGI CO_2 targets and renewable generation goals.

These measures are explained further in Appendix H.

SECTION III: FINDINGS

This section presents the analytical results, with a sub-section and graphs for each evaluation metric described in the previous section (and in more detail in Appendix H). Key conclusions that can be drawn from the analysis are discussed in the final sub-section.

A. EVALUATION METRIC RESULTS

i. Total Going-Forward Resource Cost

Total Going-Forward Resource Cost includes capital carrying cost on new unplanned generation, fixed O&M, variable O&M, fuel cost, allowance cost, RPS cost, the costs of energy and capacity imports into Connecticut (at market prices), and DSM program costs. DSM costs for energy efficiency programs are capitalized over 10 years to reflect an average life of efficiency investments; this treatment differs from that in the Customer Cost metrics, where energy efficiency program costs are expensed in the year incurred in order to be consistent with current ratemaking practices.

Figure 3.1 shows the total annual going-forward resource cost for each resource solution (shown as vertical lines, with color-coded markers) across each scenario (shown as markers on each vertical line) for each year. This figure, and similar figures that follow, makes it possible to compare resource solutions to each other and to see how cost/performance changes over time and as external factors vary.

Some key observations about Figure 3.1 are:

- Costs increase over time, driven by load growth and CO_2 allowance costs.
- Costs in any given year vary more by scenario than by resource solution. For example, costs are highest in the High Fuel/Growth scenario due to a 70% increase in gas prices compared to the Current Trends scenario.
- The costs of various resource solutions are indistinguishable in the initial years because the resource solutions do not yet differ significantly: baseload plants are not online until after 2013, and the additional DSM in the DSM-Focus solution has not yet ramped up to a level that is much higher than in the other resource solutions.

- In 2018 and 2030, the DSM-Focus resource solution has the lowest costs in every scenario except High Fuel/Growth, in which prices are high enough to induce much natural load reductions, reducing the incremental effectiveness of DSM programs. DSM-Focus is a close second in this scenario.

Figure 3.1: Total Going-Forward Resource Cost (Annual)

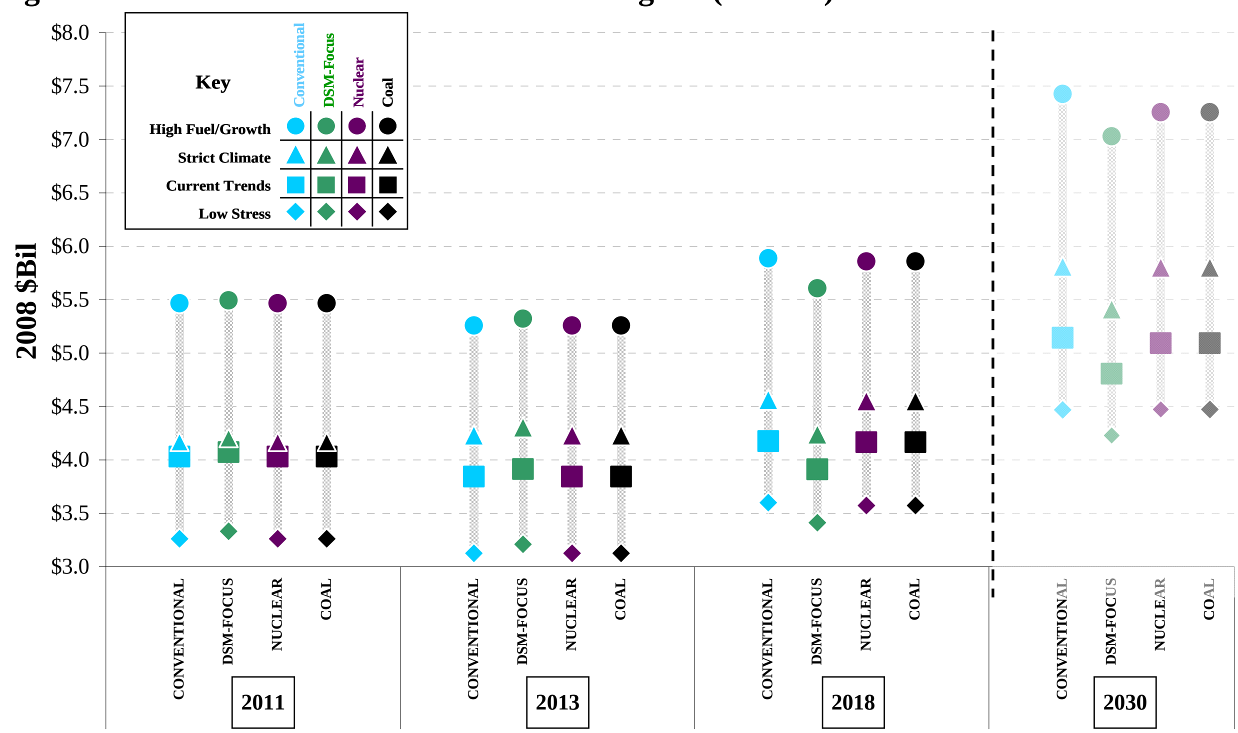
*Total Resource Cost includes capital carrying cost on new unplanned generation, fixed O&M, variable O&M, fuel cost, allowance cost, RPS cost, CT energy import and export cost, net CT capacity import cost, and DSM program costs. Note that DSM costs for energy efficiency programs are capitalized over 10 years here; this treatment differs from that in the Customer Cost graphics, where energy efficiency program costs are expensed in the year incurred.

ii. Customer Costs

Total Customer Cost in the Market Regime includes load at LMP, capacity, revenues from financial transmission rights, an adjustment for losses, spinning reserve costs, uplift costs, the cost of the forward reserve requirement, DSM program costs (expensed, not capitalized), RPS costs, and a 15% premium on the energy and generation components to reflect quantity risk, market price risk, and credit risk faced by wholesale suppliers of standard offer service. Figure 3.2 shows the Total Customer Cost in the market regime following the same format as Figure 3.1. Some key observations about Figure 3.2 that differ from Figure 3.1 are:

- Even more than the Total Resource Cost, market-based Customer Costs vary substantially based on scenario drivers, especially the price of gas and the level of demand.
- The DSM-Focus solution has slightly higher costs in 2011 and 2013 because the cost of energy efficiency programs are expensed instead of capitalized. However, by 2018, substantial energy efficiency has accumulated in addition to demand response, resulting in energy and capacity savings that significantly outweigh ongoing program costs (relative to other resource solutions) in every scenario.

Figure 3.2: Total Customer Cost in Market Regime (Annual)

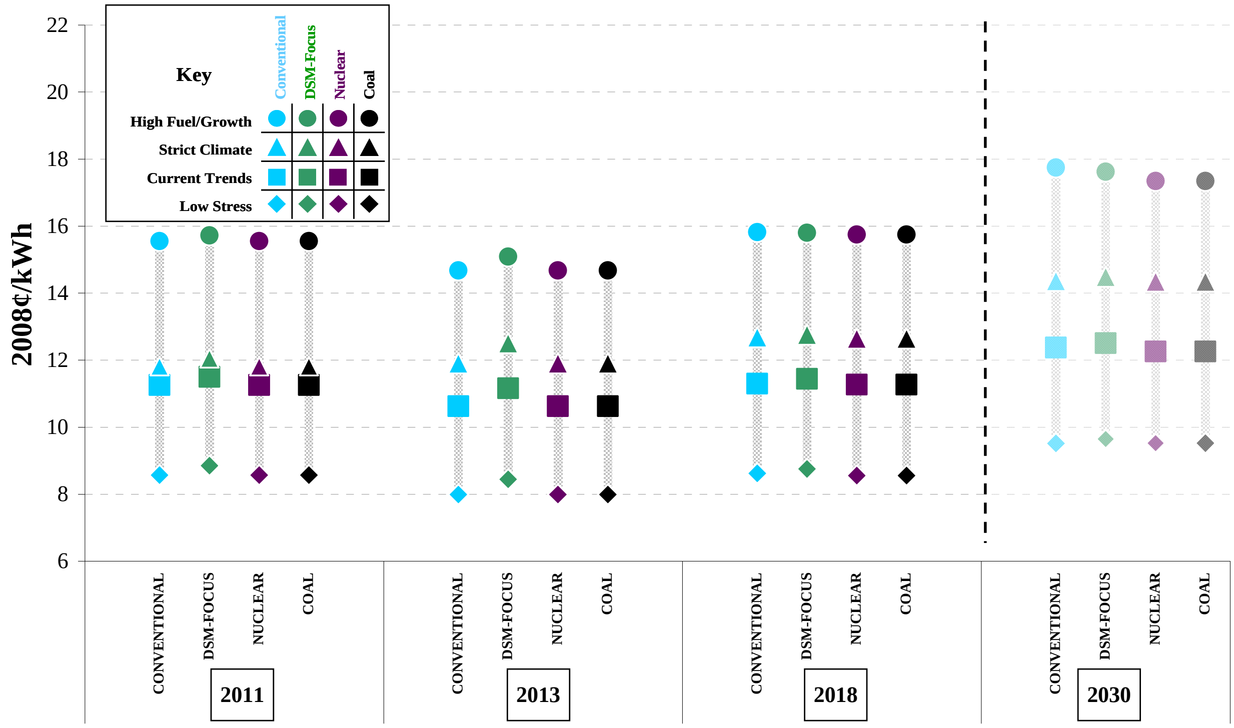


*Total Customer Cost in Market Regime includes load at LMP, capacity, FTRs, adjustment for losses, spin, uplift, fast-start, DSM program costs (expensed, not capitalized), RPS, and a 15% premium on the energy and generation components to reflect quantity risk, market price risk, and credit risk faced by wholesale suppliers of standard offer service.

Figure 3.3 shows Customers' Average Unit Costs in the market regime, given by the annual customer cost divided by the annual energy requirement to serve Connecticut load. (This is not equivalent to the rate for any particular customer class, which will depend on future ratemaking decisions regarding incidence of DSM costs, etc.) Some observations that differ from the previous figures are:

- The various resource solutions have almost no impact on the unit cost since they do not change the fact that gas-fired resources set the market price.
- The cost-savings available from DSM, due to the reduction in volume consumed, is not apparent from unit costs. Hence, unit costs by themselves may not be as useful an indicator as total customer costs.

Figure 3.3: Average Unit Cost in Market Regime



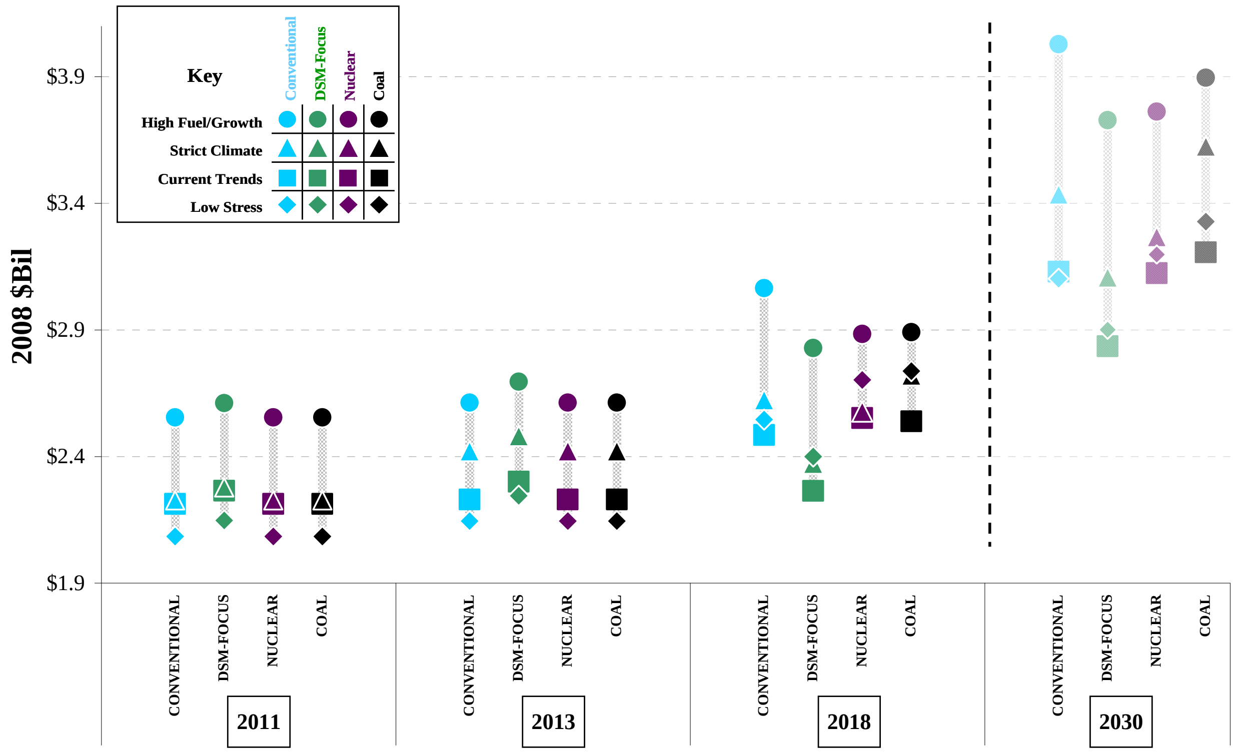
*Average Unit Cost in Market Regime includes load at LMP, capacity, FTRs, adjustment for losses, spin, uplift, fast-start, DSM program costs (expensed, not capitalized), RPS, and a 15% premium on the energy and generation components to reflect quantity risk, market price risk, and credit risk faced by wholesale suppliers of standard offer service.

Total Customer Cost in Cost-of-Service Regime is similar to the Total Resource Cost shown in Figure 3.1 plus a hypothetical "embedded cost" of existing generation, and DSM costs are expensed instead of capitalized. Figure 3.4 shows Customer Costs in the hypothetical cost-of-service regime. Some of the key observations that differ from the previous metrics are:

- Customer costs vary much less than in the market regime because the cost of non-gas-fired generation is fixed as gas prices fluctuate.

- As in the market-based regime, customer costs appear higher initially in the DSM-Focus resource solution if the increased energy efficiency costs are expensed rather than capitalized during the ramp-up/investment period. By 2018, DSM-Focus has the lowest customer cost in every scenario.

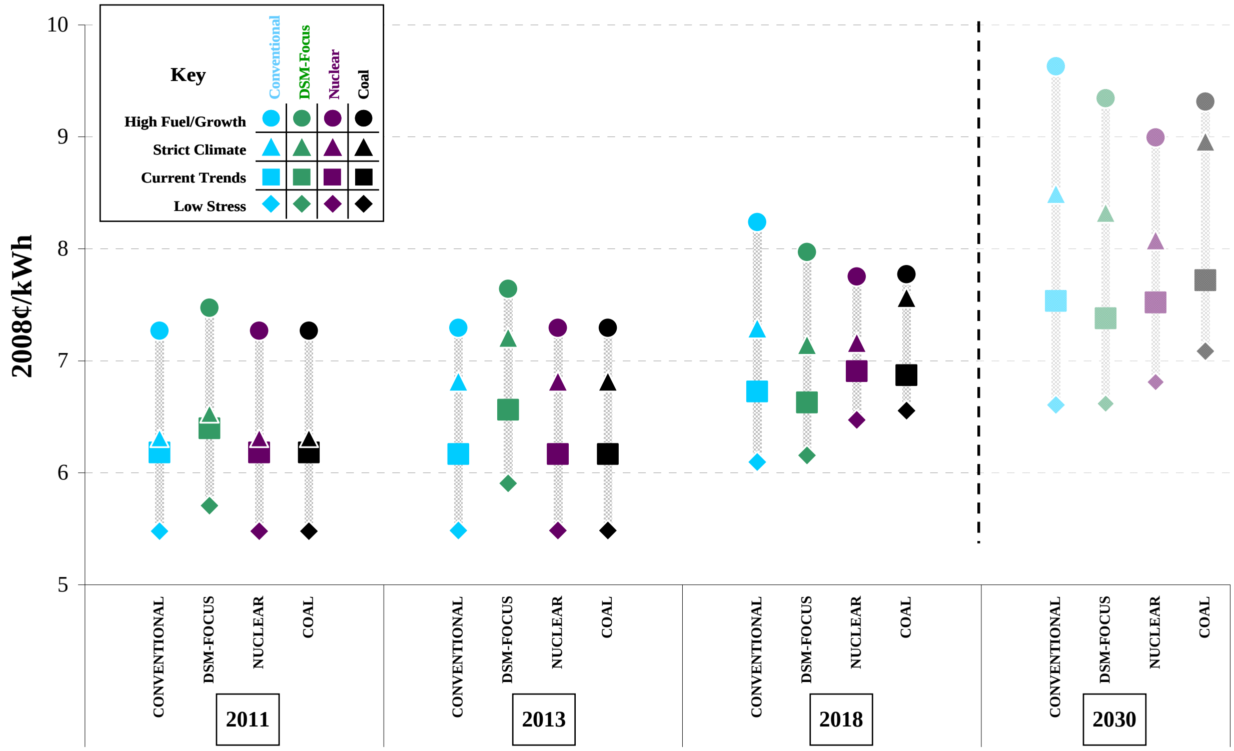
Figure 3.4: Total Customer Cost in Cost-of-Service Regime



*Total Customer Cost in Cost of Service Regime includes capital carrying cost on new unplanned generation, fixed O&M, variable O&M, fuel cost, allowance cost, RPS cost, CT energy import and export cost, net CT capacity import cost, and DSM program costs (expensed, not capitalized).

Figure 3.5 shows the Customers' Average Unit Costs in the cost-of-service regime, given by the annual customer cost divided by the annual energy requirement to serve Connecticut load. Some salient observations are that, again, unit costs are more stable with respect to scenarios than in the market-based regime, and unit costs are not a good indicator of the value of increased DSM.

Figure 3.5: Average Unit Cost in Cost-of-Service Regime



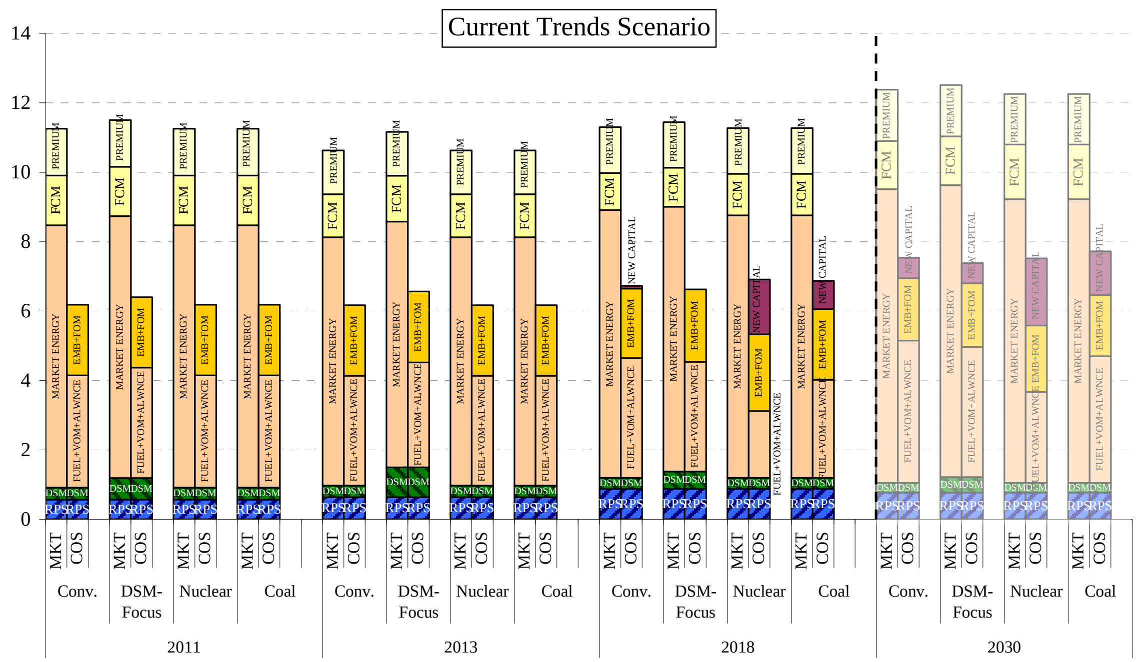
*Average Unit Cost in Cost of Service Regime includes capital carrying cost on new unplanned generation, fixed O&M, variable O&M, fuel cost, allowance cost, RPS cost, CT energy import and export cost, net CT capacity import cost, and DSM program costs (expensed, not capitalized).

Figures 3.6-9 show the components of customer costs under both regimes. Some salient observations are:

- Unit cost projections are lower in the cost-of-service regime because the costs were derived under a hypothetical cost of service regime for all in-State generation, with embedded costs in the cost-of-service regime based on historical book values, known Reliability Must-Run contract costs and asset sales prices. This computation is intended to illustrate qualitative differences between regimes, not to imply that the computed cost-of-service rate can actually be fully realized.
- Energy costs are the largest component of the market-based cost, reflecting wholesale electricity prices that are set largely by (high) natural gas prices. This component is much larger than the corresponding fuel + variable O&M and allowance costs under the cost-of-service regime.

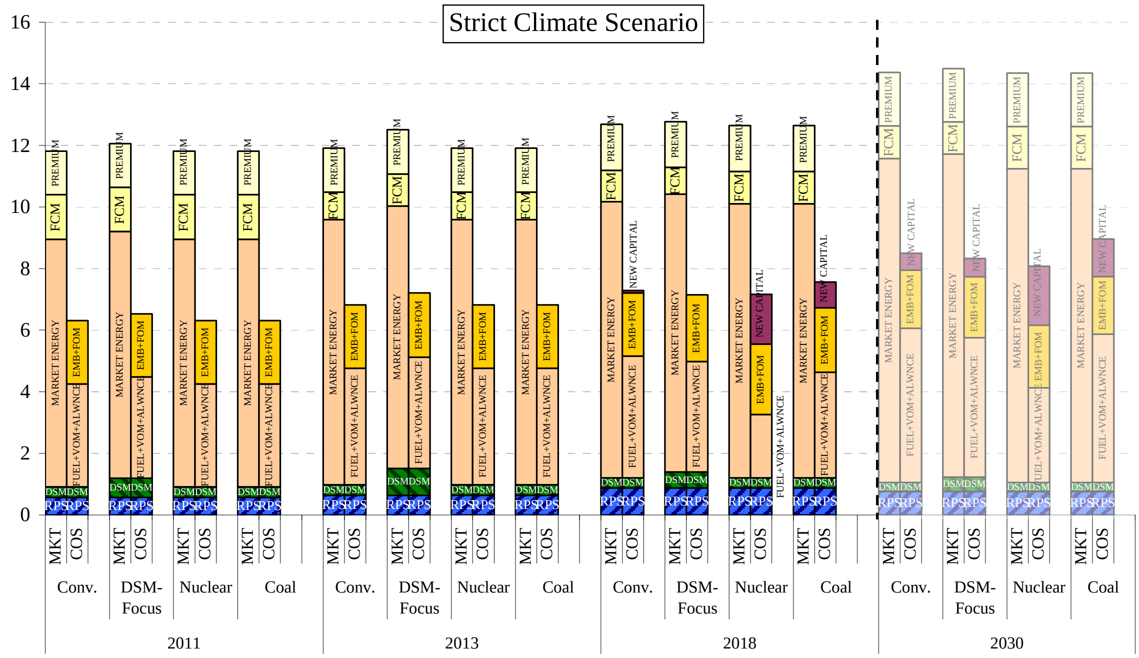
- Across scenarios, the energy cost varies much more in the market-based regime reflecting customers' exposure to gas prices.

Figure 3.6: Average Customer Cost Components (¢/kWh)



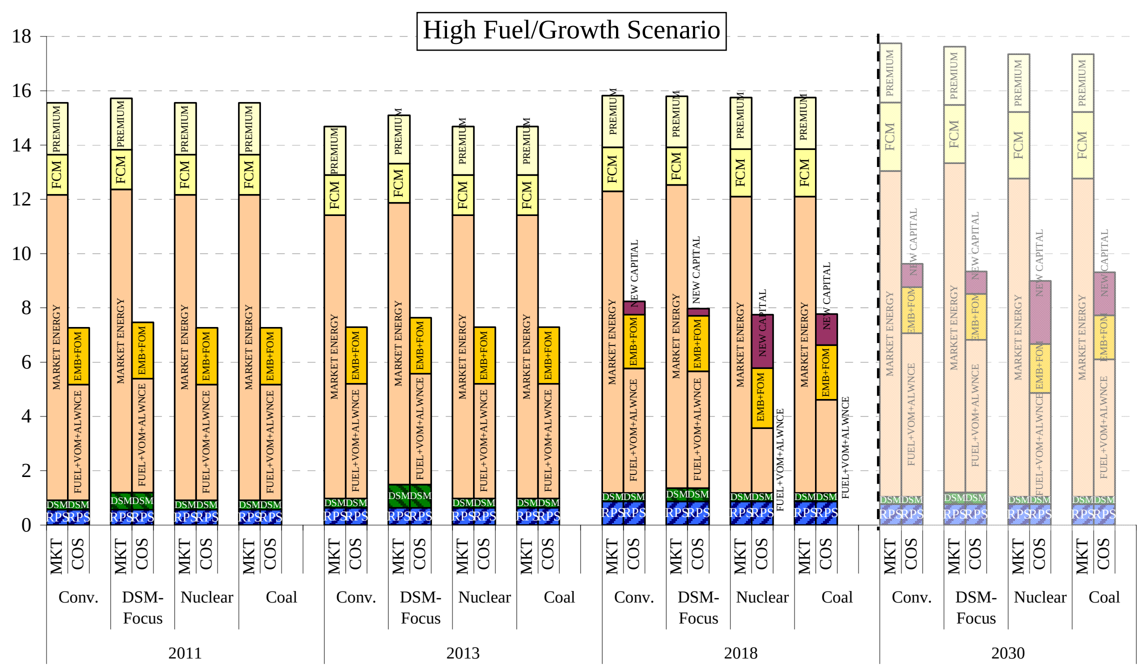
Note: Market energy cost includes load at LMP, FTRs, adjustment for losses, spin, and uplift; FCM includes capacity and foreward reserves; capital cost in COS regime ("EMB+FOM") includes FOM, net capacity imports, and embedded capital cost of planned and existing generation; energy cost in COS regime ("FUEL+VOM+ALWNCE") includes VOM, fuel, emissions allowances, and net energy imports. The premium added represents an estimated additional 15% on the energy and capacity components, charged by wholesale suppliers of standard offer service reflecting quantity risk, market price risk, and credit risk.

Figure 3.7: Average Customer Cost Components (¢/kWh)



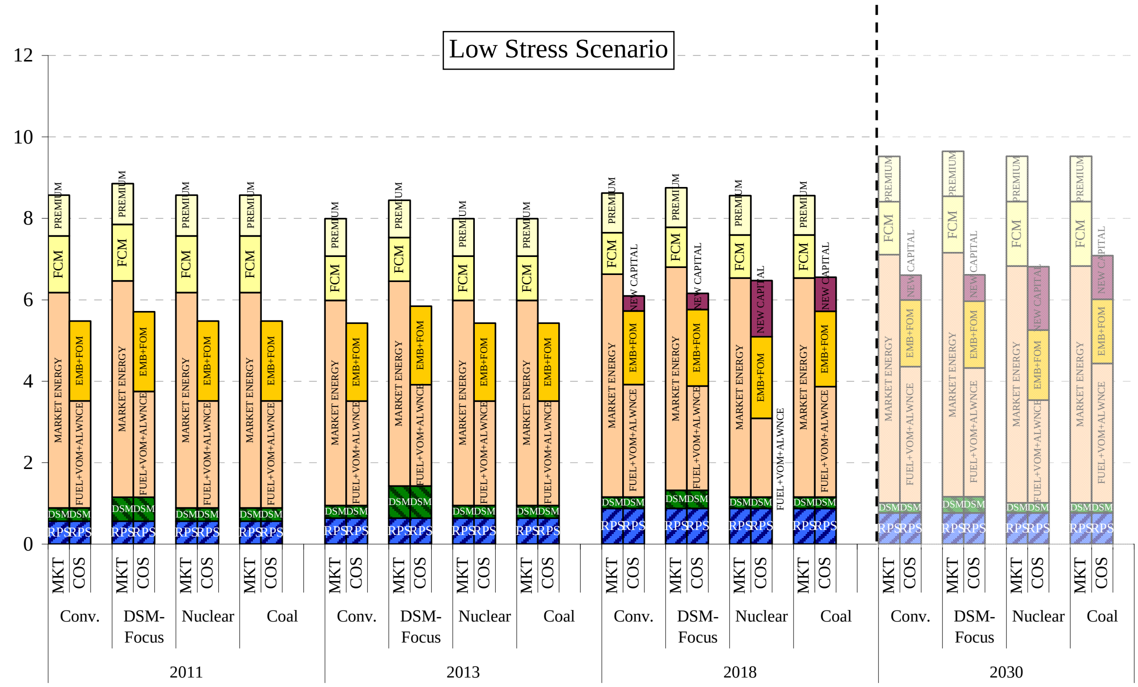
Note: Market energy cost includes load at LMP, FTRs, adjustment for losses, spin, and uplift; FCM includes capacity and foreward reserves; capital cost in COS regime ("EMB+FOM") includes FOM, net capacity imports, and embedded capital cost of planned and existing generation; energy cost in COS regime ("FUEL+VOM+ALWNCE") includes VOM, fuel, emissions allowances, and net energy imports. The premium added represents an estimated additional 15% on the energy and capacity components, charged by wholesale suppliers of standard offer service reflecting quantity risk, market price risk, and credit risk.

Figure 3.8: Average Customer Cost Components (¢/kWh)



Note: Market energy cost includes load at LMP, FTRs, adjustment for losses, spin, and uplift; FCM includes capacity and foreward reserves; capital cost in COS regime ("EMB+FOM") includes FOM, net capacity imports, and embedded capital cost of planned and existing generation; energy cost in COS regime ("FUEL+VOM+ALWNCE") includes VOM, fuel, emissions allowances, and net energy imports. The premium added represents an estimated additional 15% on the energy and capacity components, charged by wholesale suppliers of standard offer service reflecting quantity risk, market price risk, and credit risk.

Figure 3.9: Average Customer Cost Components (¢/kWh)



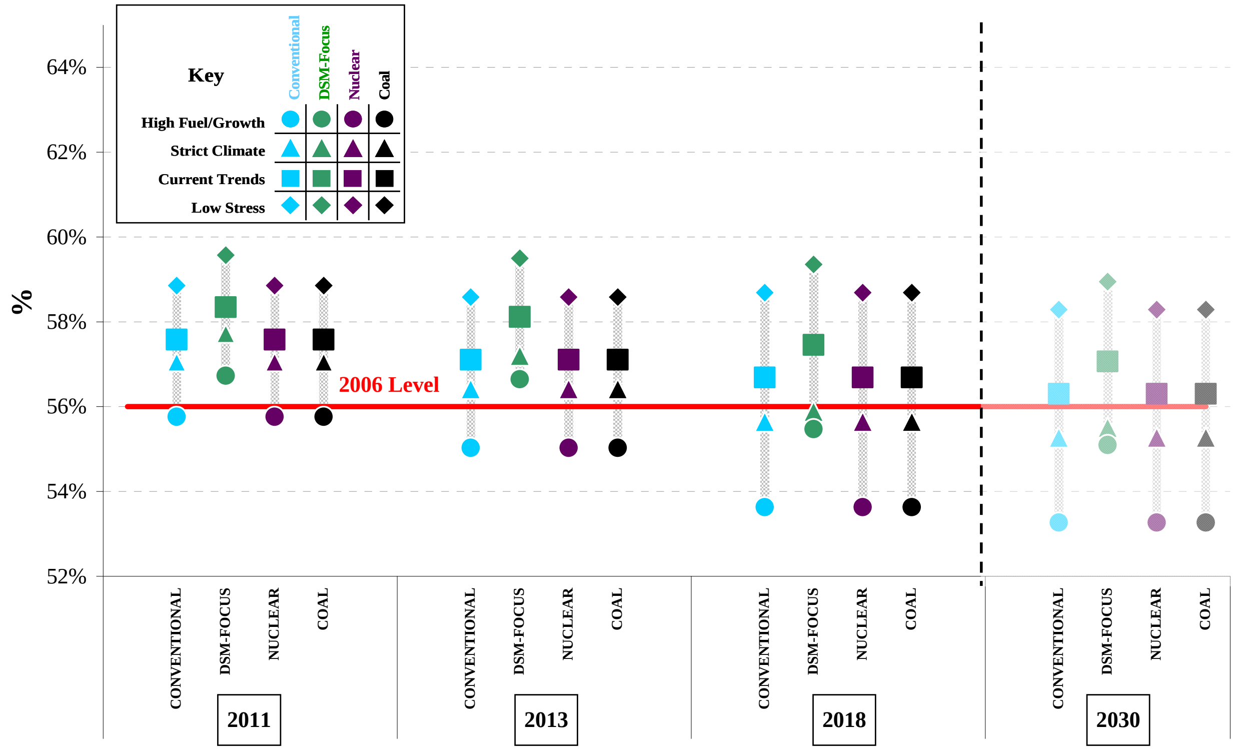
Note: Market energy cost includes load at LMP, FTRs, adjustment for losses, spin, and uplift; FCM includes capacity and foreward reserves; capital cost in COS regime ("EMB+FOM") includes FOM, net capacity imports, and embedded capital cost of planned and existing generation; energy cost in COS regime ("FUEL+VOM+ALWNCE") includes VOM, fuel, emissions allowances, and net energy imports. The premium added represents an estimated additional 15% on the energy and capacity components, charged by wholesale suppliers of standard offer service reflecting quantity risk, market price risk, and credit risk.

iii. Connecticut Load Factors

Figure 3.10 shows the projected load factor for Connecticut under each scenario and resource solution, net of DSM. Key observations are:

- Load factors are projected to improve relative to today then deteriorate from 2011 onward.
- This pattern is driven by the load forecast, the effect of DSM (demand response, which reduces peaks, is assumed to be implemented more rapidly than efficiency), and the differential effect of prices on peak vs. average consumption assumed in the scenarios.

Figure 3.10: Connecticut Load Factor (Net of DSM)



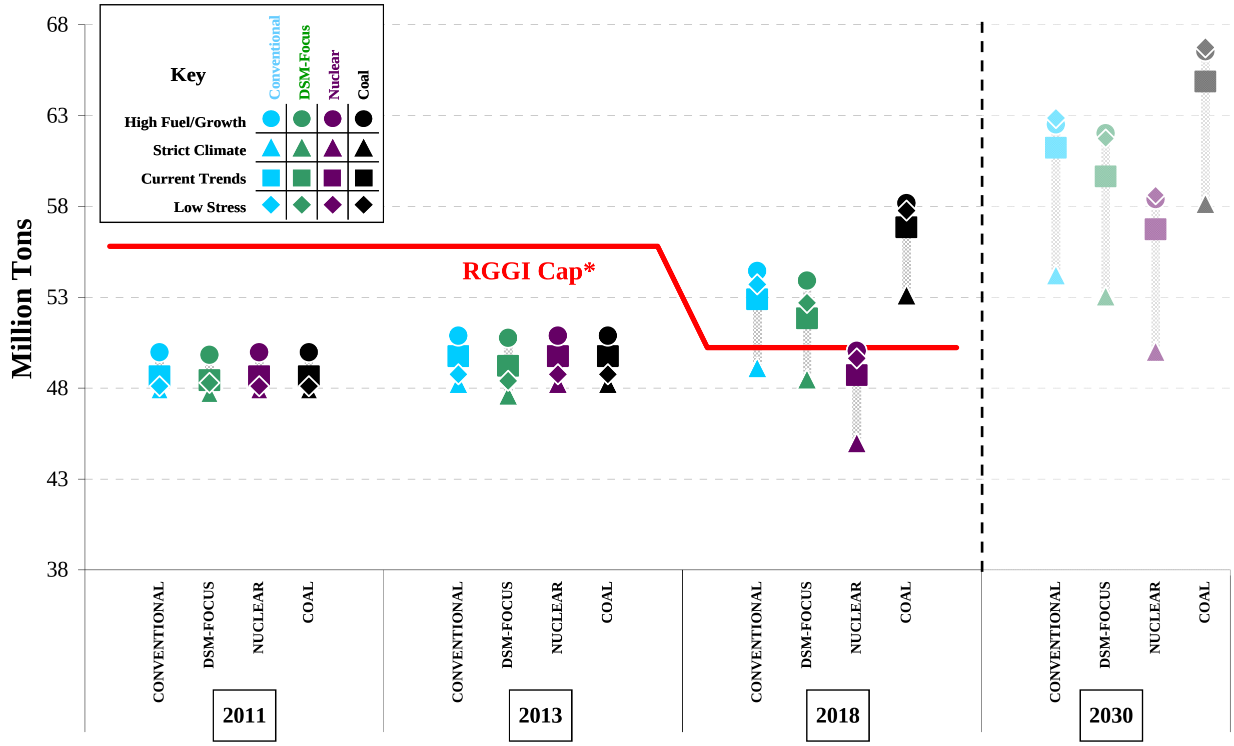
iv. CO_2 Emissions

Figure 3.11 shows power sector CO_2 emissions and the RGGI cap for only the six RGGI states that are located in ISO-NE. A surplus or deficiency does not indicate whole RGGI-region status. Key observations are:

- CO_2 emissions are expected to increase as load grows, except possibly in the Nuclear resource solution (adding more than one nuclear unit would reduce CO_2 emission further).
- Adding even a single coal unit raises emissions substantially above New England's share of the RGGI cap. However, the RGGI cap is indicative only; in our scenarios (and likely in reality) RGGI will be superseded by federal climate legislation in later years.
- Increased DSM reduces CO_2 emissions slightly.
- CO_2 emissions could be higher than indicated here under the following conditions:
  - If nuclear availability is the same as the average of 2001-06 (instead of being similar to 2006, the best historic year) CO_2 emissions could increase by 2 million tons, assuming a 3.4 TWh reduction in generation replaced by gas with an 8000 heat rate and 120 lb/MMBtu CO_2.

- o If hydro output is equal to the average output of 2001-06, CO_2 emission could increase by approximately 1 million tons, assume 1.8 TWh reduction in generation replaced by gas.
- o If imports are less than the 13 TWh assumed, CO_2 emissions could increase substantially.

Figure 3.11: CO_2 Emissions in ISO-NE



*Emissions and RGGI cap shown here reflect the 6 member states of ISO-NE only. A surplus or deficiency does not indicate whole RGGI-region status.

v. Gas Usage and Fuel Diversity

Figures 3.12-17 show gas usage in Connecticut and New England. Key observations are:

- Gas usage will increase in virtually all cases, due to load growth.
- Gas usage increases markedly in low stress, because low gas prices cause low power prices and higher load growth. In the extreme, there is likely to be feedback that limits further load growth if gas supply becomes problematic (higher gas prices will limit further load growth). However, this feedback may not prevent the problem from occurring, but would likely occur only after gas supply problems materialize.

- A baseload resource solution (coal or nuclear) limits the growth in gas usage, though does not eliminate it entirely, particularly in the Low Stress scenario. This is caused by the large amount of gas fired capacity added after 2018 in all cases as a result of the screening analysis.
- Gas share of generation is less important than the actual quantity of gas used (for all purposes), in terms of gas deliverability and customer effects.
- The total quantity of gas used for all purposes is especially important during periods of peak gas demand, *e.g.*, winter.

Figure 3.12: Winter (January - February) Power Sector Gas Use in Connecticut

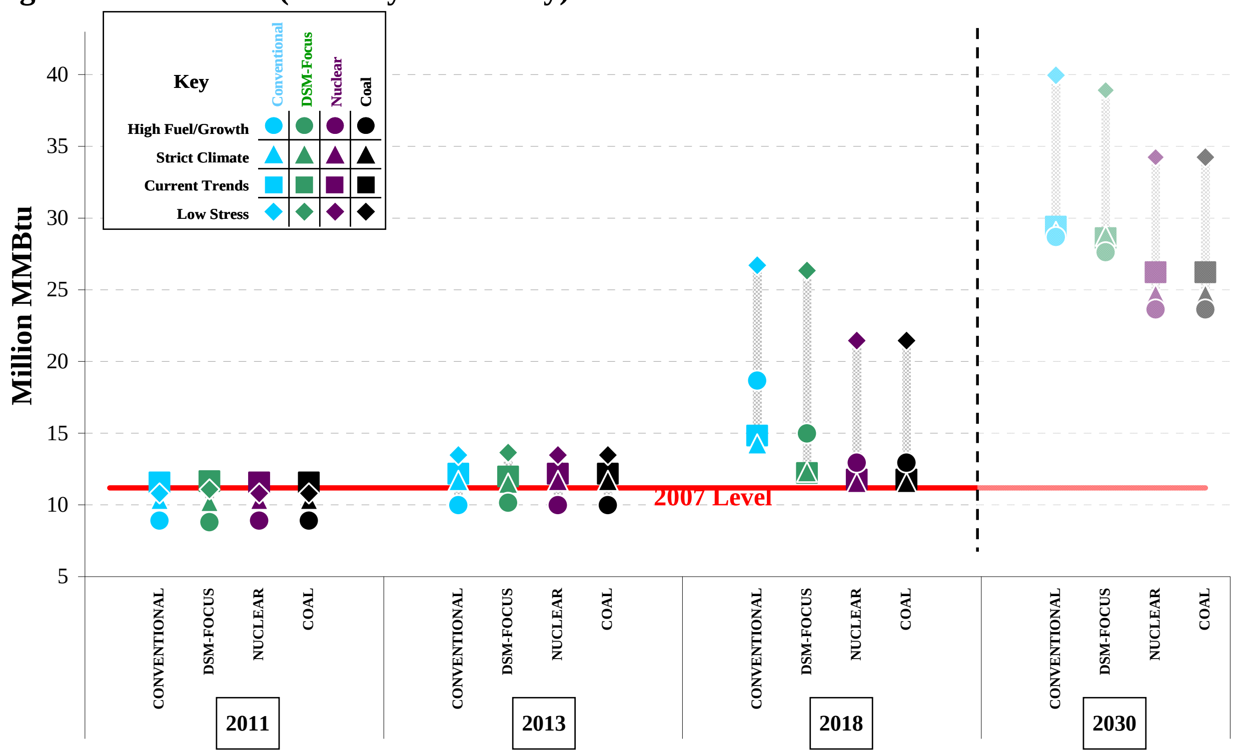


Figure 3.13: Winter (January - February) Power Sector Gas Use in ISO-NE

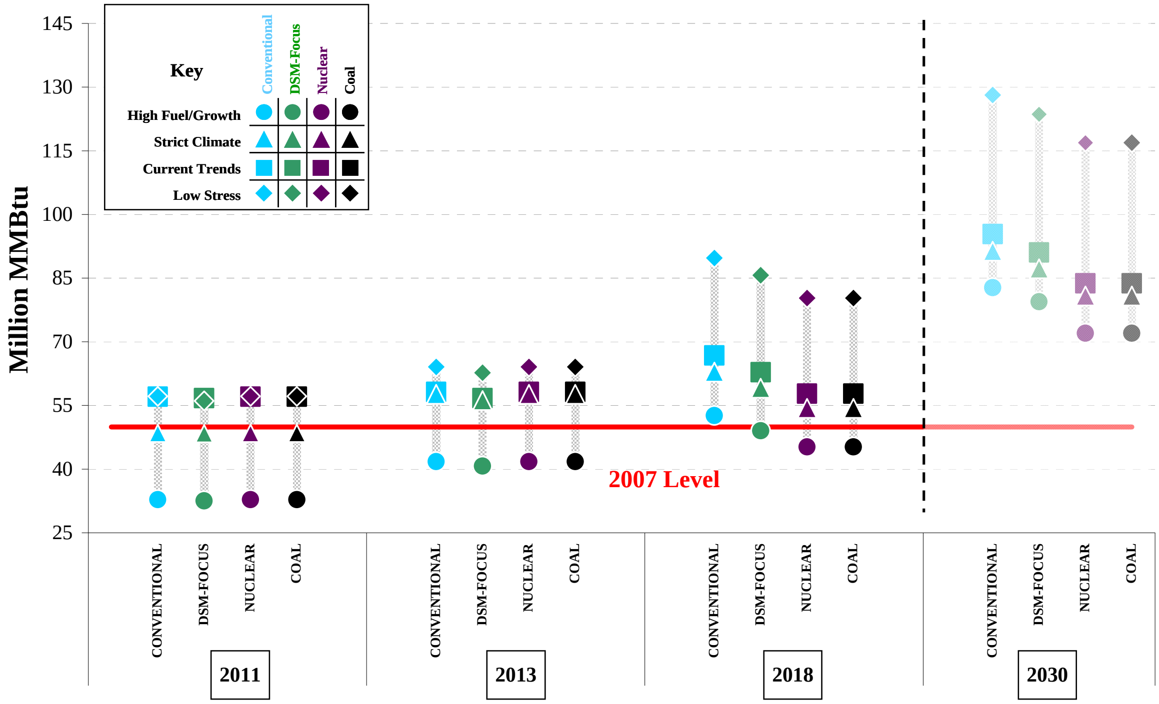


Figure 3.14: Connecticut Gas-fired Generation Share of Total Generation

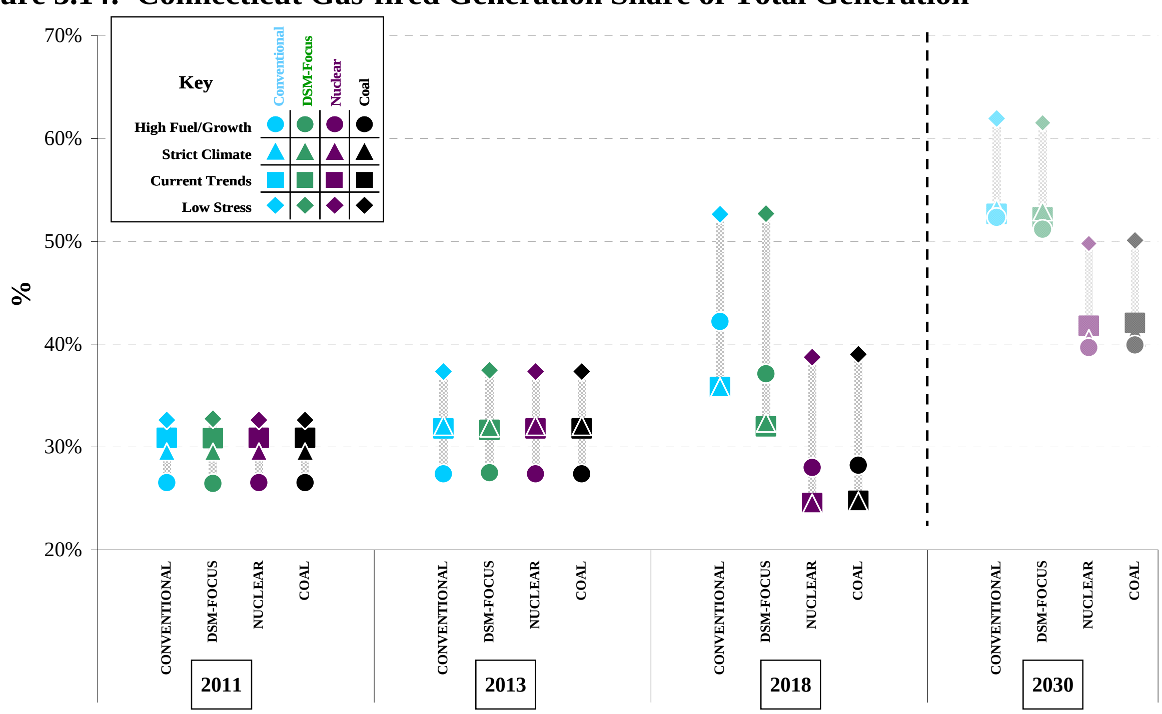


Figure 3.15: ISO-NE Gas-fired Generation Share of Total Generation

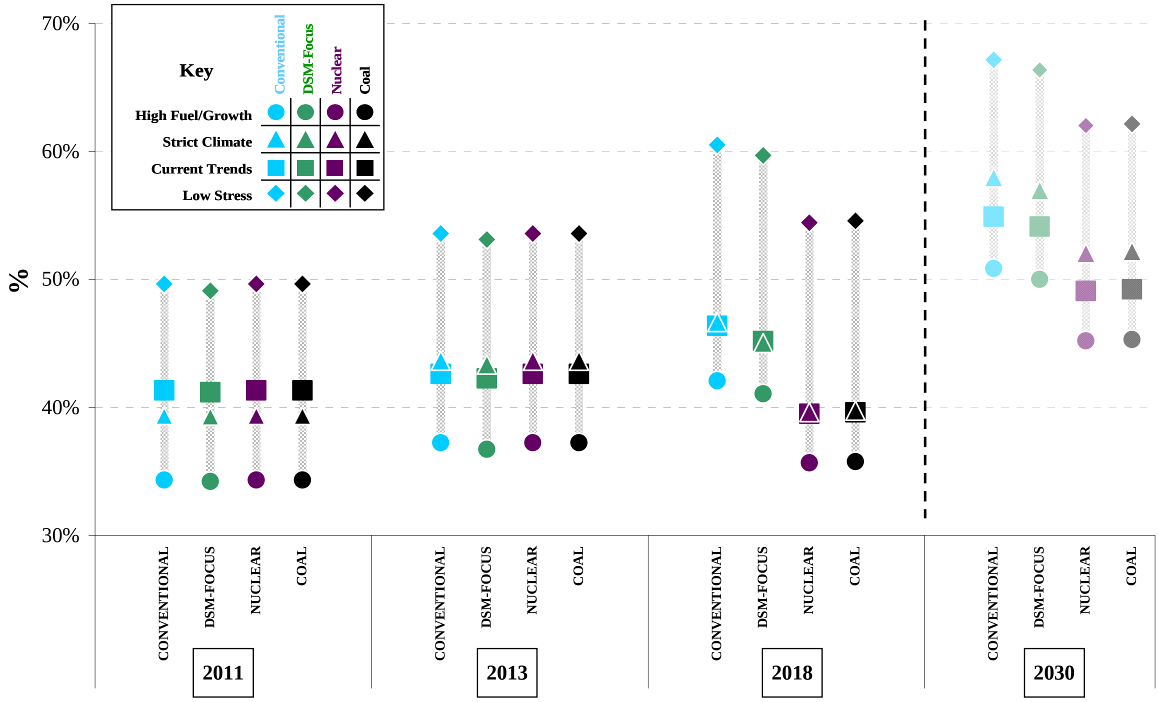


Figure 3.16: Connecticut Fuel Mix (Cumulative Generation in TWh)

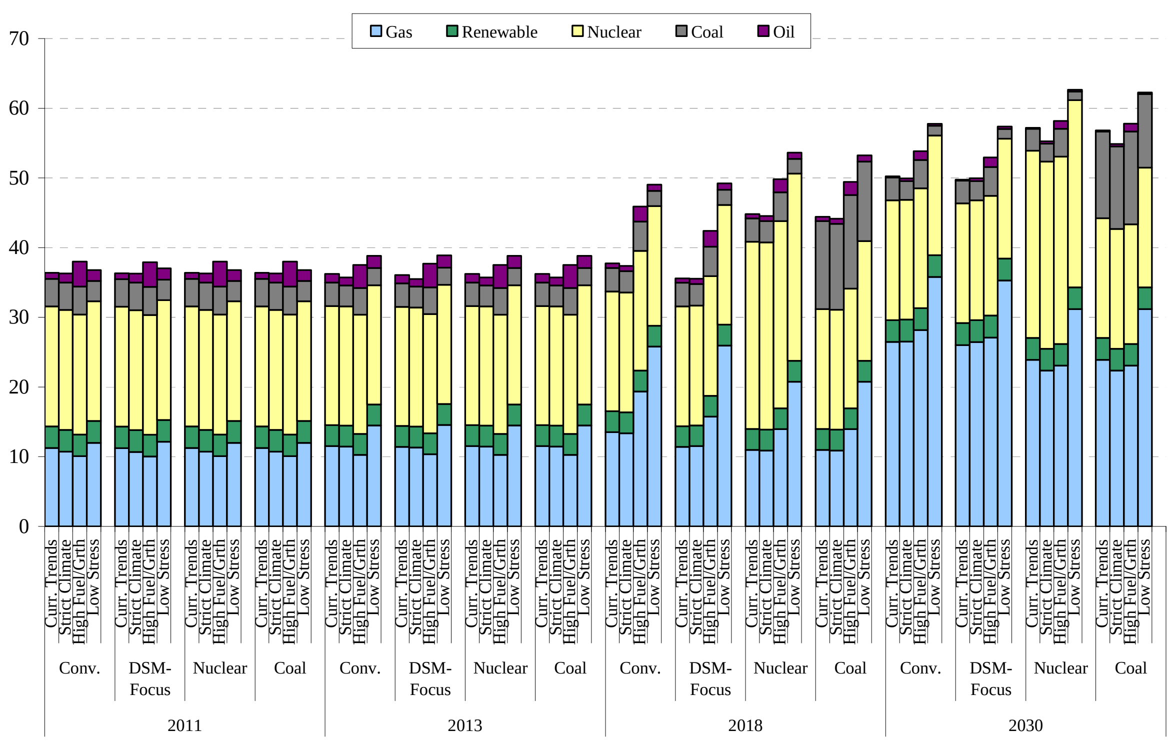
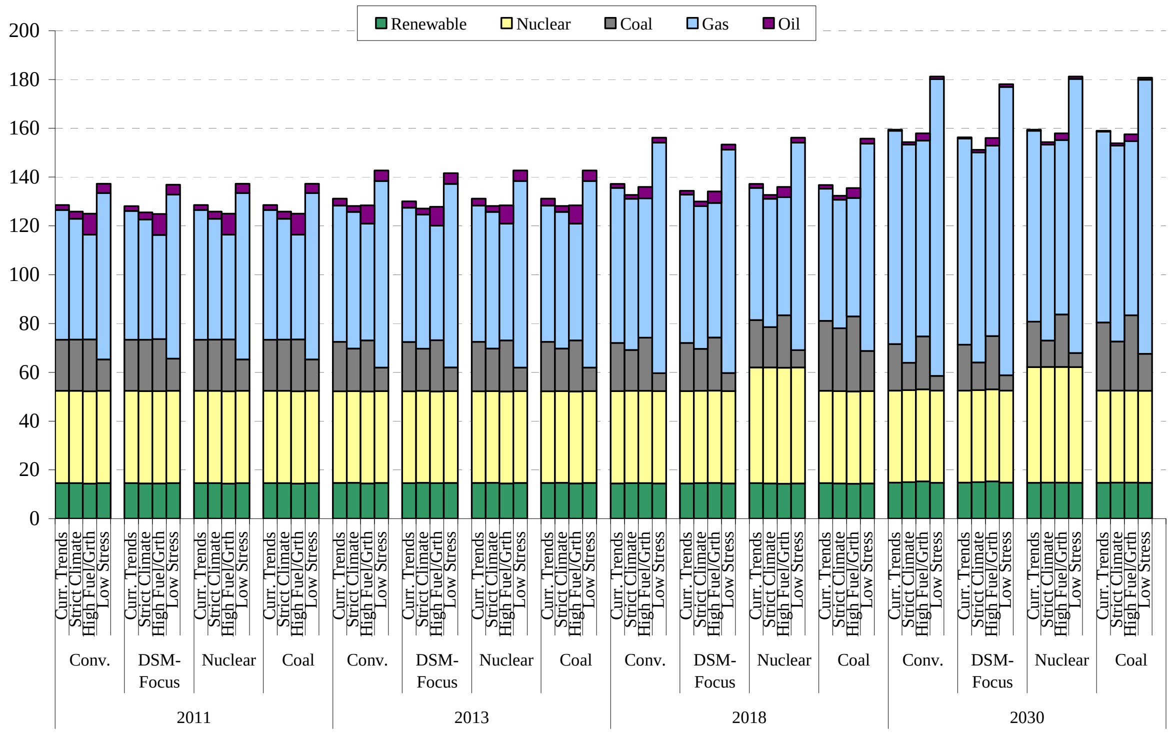


Figure 3.17: Total ISO Fuel Mix (Cumulative Generation in TWh)



B. Summary of Findings

The analytical results presented above suggest the following ten high-level findings, assuming that planned capacity additions and DSM programs are realized as projected in each solution, each of which is discussed in more detail below:

1. Regional resource adequacy needs are satisfied for the next several years
2. Connecticut's local resource adequacy needs are satisfied for the foreseeable future
3. Market prices will continue to be high and volatile
4. Natural gas dependence will persist
5. External, uncontrollable factors are the primary drivers of customer costs
6. Renewable Portfolio Standards are unlikely to be fully met with renewable generation
7. Nuclear and DSM mitigate CO_2 emissions more effectively than other resource solutions
8. Increased DSM could reduce customer Costs, CO_2 emissions, and gas usage
9. Non-gas baseload generation would reduce dependence on natural gas
10. "Market Regime" vs. "Cost-of-Service" affects rate stability, and may have future customer cost implications

1. Regional Resource Adequacy Needs are Satisfied for the Next Several Years

After taking into account planned generation additions, recent and planned transmission projects, and demand-side measures that are planned or underway, and assuming no retirements, new electricity resources will not be needed to attain reliability targets for several years in Connecticut or elsewhere in New England. Under most plausible futures, New England as a whole will need additional resources beyond the next five years. As part of the overall New England market, Connecticut will share in this resource need, but additional resources need not be located within Connecticut in this time frame.

2. Connecticut's Local Resource Adequacy Needs are Satisfied for the Foreseeable Future

Planned generation capacity additions, transmission enhancements and demand-side measures mean that Connecticut will satisfy its Local Sourcing Requirement (LSR) for many years, perhaps decades, under the scenarios examined in this report. This is partially due to the projected addition of DSM and generating capacity, including 279 MW of quick start capacity needed to satisfy the Connecticut Local Forward Reserve Market (LFRM) requirements. However, this analysis assumes no significant retirement of generating capacity in Connecticut, although some of the older oil-fired units are projected to earn sub-normal returns and/or experience difficulties covering their fixed O&M costs over the longer term; potentially resulting in retirement or reapplication for "reliability-must-run" status. Also, no significant congestion price differentials are forecast between Connecticut and the rest of New England. Transmission enhancements already under construction and planned generation will resolve the significant bottlenecks and limited local supply resources that have affected Southwest Connecticut in the past.

3. Market Prices will Continue to Be High and Volatile

Despite an adequate supply of resources, Connecticut and New England electricity prices are likely to remain at levels that will concern consumers and regulators, and prices will remain volatile. This is due primarily to the fact that electricity prices in New England are closely linked to natural gas prices, as our study confirms. Gas prices are volatile and uncertain, and likely to remain fairly high.

4. Natural Gas Dependence Will Persist

Natural gas is the fuel for about 40% of New England's power, but its impact on market prices is disproportionately large. Because it will remain the dominant price-setting fuel for electricity, its influence on prices will continue regardless of future events or resource decisions. Dependence on natural gas for power generation poses two potential problems. First, consumers are exposed to high and uncertain power costs because gas prices are high and volatile. Second, using large amounts of natural gas for electricity generation increases both the likelihood and the potential impact of gas supply disruptions, particularly in the winter months when overall gas usage is highest. This study only notes differences of natural gas consumed, but does not analyze the increased probability or cost of potential fuel disruptions on generating capability.[10] But because much of the existing generation base is gas-fired, and gas is the price-setting fuel for electricity, to substantially change the region's dependence on gas would take a long time and exceptional effort and expense. This analysis did not investigate the sufficiency of gas supply, however; gas supply is a concern, and should be thoroughly investigated prior to developing a long term strategy for the addition of resources in Connecticut.

5. External, Uncontrollable Factors Are Primary Drivers of Customer Costs

External factors that cannot be controlled by utilities or regulators, such as gas prices, climate policy and economic growth, can have a much larger impact on market outcomes and resource costs than the factors that can be controlled. A large part of the reason for this is that factors such as gas prices or climate policy can affect all resources, existing and new, while resource strategies that involve physical investments in new resources only affect the portfolio at the margin. Although the impact of marginal physical resources on the overall market outcomes or resource costs are relatively small (because additions are small relative to the installed capacity base),procurement strategies might alter the contractual relationship between load-serving entities and generators, or direct investment in physical generating capacity by load-serving entities, could impact customer cost.

[10] PA 07-242 supports dual fuel capability with respect to certain generating units and at the discretion of the DPUC.

6. Renewable Portfolio Standards Are Unlikely to Be Fully Met with Renewable Generation

Appendix E describes recent experience under the Connecticut renewable portfolio standard (RPS) requirements as well as under similar policies in New England. The discussion in Appendix E concludes that the Connecticut RPS is unlikely to be met by renewable generation, but instead load serving entities (LSEs) are increasingly likely to rely on alternative payments to the state at a mandated price of $55 per megawatt-hour for any short fall. By the middle of next decade, the statewide annual customer cost of complying with the requirement would exceed $200 million. Connecticut has limited amounts of attractive renewable resource options; it has little economic potential for wind and solar power, and even less for other renewables like wave, tidal, geothermal, etc. Other parts of New England have more promising renewable resource potential (*e.g.*, wind in northern New England). However, even reliance on a regional rather than state-level approach may not resolve the problem for Connecticut, since it is possible that New England in aggregate will be unable to achieve its combined renewable targets. This issue warrants additional study, particularly regarding the potential to access remote renewable resources for Connecticut, which may require the development of additional transmission capacity.

7. Nuclear and DSM Mitigate CO_2 Emissions More Effectively than Other Resource Solutions

CO_2 emissions will increase under a Conventional Gas resource solution (though the additional DSM incorporated in all Resource Solutions helps to mitigate this somewhat.) Additional DSM will further limit CO_2 growth, but not cause a reduction. As expected, the addition of nuclear generation would cut a significant amount of CO_2 emissions, while additional coal capacity would increase it. Opportunities for coal with carbon sequestration are limited by a lack of the appropriate geology in Connecticut and New England.

8. Demand Side Management Could Reduce Customer Costs, CO_2 Emissions, and Gas Usage

If achievable as characterized in our analyses, DSM (both demand response and energy efficiency programs) are effective in mitigating future peak and energy growth. The analyses assume a substantial amount of "Reference Case" DSM in all Resource Solutions (*e.g.*, much more than assumed by the ISO in its load projections), and still more DSM in the DSM-Focus solution. This additional DSM, if it is similarly effective, would also be valuable. (This analysis has not attempted to optimize the type or quantity of DSM programs, but simply evaluated two different levels of specified DSM programs.)

The results show that DSM can reduce overall customer costs. Under some circumstances, DSM can increase average unit costs (¢/kWh). When consumption volumes are changing, a change in unit costs may not accurately reflect customer impacts. How costs are recovered from particular customers or classes can affect whether their rates and/or costs go up or down. This is a question of cost allocation, a ratemaking issue not addressed here.

9. Non-Gas Baseload Generation Would Reduce Dependence on Natural Gas

Baseload generation (coal or nuclear), if procured in a way that mimics cost of service to consumers, can help to limit exposure to natural gas price risks, though if gas prices go down rather than up, this could commit customers to higher fixed costs. Under a purely market-based regime (i.e., if baseload generation was merchant-owned and procured for customers at market prices), customers would receive no protection from gas prices; their costs would be virtually the same as if conventional gas generation had been added.

10. Market Regime vs. Cost-of-Service Affects Rate Stability and May Have Future Customer Cost Implications

As constructed/assumed, the hypothetical “Cost-of-Service” regime has substantially lower costs than the “Market” regime, across all scenarios and strategies studied; however, these results indicate more analysis is warranted. The overall cost levels used in the analysis may not offer a realistic comparison on a regional market basis, because it is probably not possible to put all generating assets back under cost of service regulation at historic embedded costs. The actual purchase costs for existing generation would not likely be at the levels assumed in the Cost of Service results because the fixed costs for some of the existing assets assumed in the Cost of Service analysis are below current market values. However, output from new construction owned outright and output from new assets acquired via long-term contracts could potentially be obtained at prices reflecting Cost of Service, but this was not evaluated in this study. The results also show that the range of costs is much smaller under Cost of Service. The potential range of total supply costs is generally lower than the range of market prices. This is primarily because under a market regime, the market price for <u>all</u> power is determined by the last unit of supply. In very simple terms, if the cost of the last unit of supply increases by 10%, then under a market regime customer costs increase by 10%. But the total cost of generating power from all sources varies by much less than 10% (many of these costs are fixed and don't vary with the last unit's costs). If customers were to be supplied under a regime more closely reflecting actual generating costs, customer costs will increase by less than 10%. Even if only some assets are procured on a cost basis, this will reduce customers' exposure to uncertain and volatile prices. As discussed below, it may be possible to procure power from some existing and/or new resources in ways that mimic cost-based pricing and allow customers to enjoy some cost-stabilization.

It is crucial to note here that while it is possible to reduce the uncertainty and volatility of customers' costs, it may not be possible to <u>substantially</u> reduce the expected level of costs in the near- or mid-term. However, long-term contracts for the output of new or existing assets can reduce uncertainty which can lower costs. Such questions of procurement and risk management are beyond the scope of this resource planning effort, but are likely to be important issues to consider in addressing the concerns of Connecticut customers.

SECTION IV: RECOMMENDATIONS

The key findings outlined above are based upon the analysis performed by *The Brattle Group*, and lead to four primary recommendations representing a possible path forward to improve electricity procurement in Connecticut. Steps taken in response to these recommendations could help provide Connecticut customers with reliable, environmentally responsible electric service at more stable prices and potentially lower customer costs. Our primary recommendations regarding resource planning and procurement are:

1. Maximize the use of demand side management (DSM), within practical operational and economic limits, to reduce peak load and energy consumption.
2. Explore other power procurement structures such as longer term power contracts on a cost-of-service basis with merchant and utility owners of existing and new generation.
3. Evaluate the structure and costs of Connecticut's renewable portfolio standard (RPS) in the context of a regional re-examination of the goals and costs of similar policies in New England.
4. Consider potential ways to mitigate the exposure of Connecticut consumers to the price and availability of natural gas (though it will not be possible to eliminate gas dependence).

Recommendation 1: Maximize the use of demand side management (DSM), within practical operational and economic limits, to reduce peak load and energy consumption.

The potential for increased DSM to reduce customer costs, gas usage, and environmental emissions demonstrated in this analysis suggests that DSM should be pursued more aggressively. State regulatory authorities should examine, and where possible, explore methods to implement additional, cost-effective DSM. This would facilitate utility DSM programs to exceed current levels and expand upon the success of existing DSM programs. While the need for capacity is several years off in Connecticut, DSM programs are more cost-effective if they are pursued consistently over time, so it is reasonable to begin the ramp-up to more aggressive DSM programs in the near term.

The DSM resource investments assumed in this report far exceed the (already aggressive) levels pursued by the Companies to date. The pace and magnitude of this expansion warrants careful monitoring of resource availability, costs, and operational effectiveness as the programs develop over time.

Recommendation 2: Explore other power procurement structures such as longer term power contracts on a cost-of-service basis with merchant and utility owners of existing and new generation.

At the present time, the Companies are constrained to enter into contracts with third-party suppliers with durations not to exceed three years to satisfy standard offer service obligations, which ensures that customers are exposed to power supply prices driven by short-term market prices. Our finding that customer costs would be more stable under a hypothetical cost-of-service regime suggests that supply arrangements incorporating cost-of-service principles could help to stabilize customer rates and potentially, under certain conditions, lower prices for the customer. This could be achieved by providing the Companies greater flexibility in the structures and duration of their power supply arrangements on behalf of customers.

Options may include long-term contracting, procuring energy, capacity and reserve products individually from generators and/or the outright ownership of generating assets, including baseload generation that is not dependent on natural gas. By reducing the extent to which utilities are forced to procure power through short-term contracts driven by regional spot market prices, such alternative procurement options can reduce customers' exposure to uncertain and potentially high gas prices, and may provide to customers some benefits of a diverse fuel mix. Addressing these issues may involve the use of procurement strategies and risk management tools (such as fuel hedging strategies to complement electricity procurement) that go beyond what can be done in a resource planning context. In addition, strategies such as these should be coupled explicitly with the assurance of recovery of supply costs associated with approved long-term power procurement contracts.

Recommendation 3: Evaluate the structure and costs of Connecticut's renewable portfolio standard (RPS) in the context of a regional re-examination of the goals and costs of similar policies in New England.

Connecticut's renewable portfolio standard as currently structured, while supporting Connecticut's renewable goals, may impose additional costs on Connecticut customers without necessarily promoting new renewable generation to displace conventional generation. This observation suggests that additional study of RPS structure and costs is warranted at both the state and regional level to determine the best ways to meet future RPS requirements. At the state level, for example, the criteria for disbursing funds derived from alternative compliance payments might be re-examined under the current circumstances. Further analysis could also examine the potential to fashion regionally-coordinated policies to address possible renewable shortfalls and/or regional projects in transmission and renewable capacity.

Recommendation 4: Consider potential ways to mitigate the exposure of Connecticut consumers to the price and availability of natural gas.

Non-gas baseload generation (*e.g.*, coal, and nuclear) offers a greater reduction in gas use (particularly in wintertime, when deliverability concerns are highest) than other resource options studied in this report. Although not assessed in this report significant renewable generation could also mitigate gas dependence.

To the extent that market participants' investment in non-gas-fired baseload generation is deemed insufficient to address these risks, state regulatory authorities should consider allowing contractual or ownership arrangements or other policy options to enable or encourage investment in such baseload capacity. Such options should be considered in concert with efforts to reduce dependence on natural gas use in all sectors (*e.g.* heating). Both the cost and CO_2 emissions implications of all non-gas options should be considered.

SECTION V: STUDY LIMITATIONS AND FURTHER ANALYSIS

PA 07-242 requires that the Companies submit a resource procurement plan each year and proscribes a process for the CEAB and DPUC to review, modify and approve. As the inaugural effort in this annual process, the analysis in this report is comprehensive and complies with the essential requirements of PA 07-242.

Notwithstanding the overall completeness of the report, any analysis – especially an initial undertaking responding to a recurring requirement – will focus on the most important foundational elements and therefore afford less attention to some topics. Some of these topics are emerging as important, but are more usefully analyzed in detail when the overall direction of procurement policy is established, or are beyond the scope of an initial resource planning analysis. Some of these issues may become more important as procurement plans evolve or as markets change, and could be considered for inclusion in subsequent analyses.

The resource planning analysis contained in this report has the following general limitations (with citations to Section 51 items where appropriate) – all of which could be subject to future analysis as procurement plans and policies evolve:

<u>This study contains only limited analysis related to transmission.</u> This study did not provide a cost/benefit analysis of transmission options; did not compare the economics of transmission vs. generation or vs. demand-side options; and does not constitute a transmission reliability assessment. Such an assessment would address the mandatory reliability criteria and standards established by various national and regional bodies, which are applied to the New England transmission system as part of the annual New England Independent System Operator (ISO-NE) Regional System Plan (RSP). In addition, distribution improvements are not addressed. (Section 51(c)(3) recommends T&D analysis.)

<u>This is not a siting analysis for new generation capacity</u>. While generation capacity expansion was modeled in order to estimate impacts on electricity markets, resource costs and customer costs, the optimal location of such capacity was not addressed (Section 51(d)(3) implies

consideration of location). These issues are reasonably addressed at a later stage in resource planning, and require substantial data on candidate sites.

<u>This is not a procurement risk management study</u>. While the analysis does illuminate some of the risks associated with pursuing different resource strategies under uncertain future market conditions, it does not formally address physical or financial portfolio risk management or hedging considerations. The recommendation to alleviate some of the procurement constraints on contract duration and structure (*e.g.*, prohibition on power supply contracts that exceed three years) is based primarily on the potential benefits implied, but "optimal" contract lengths are not explored, as these are beyond the scope of a resource planning analysis (Section 51(c)(5) specifies such an analysis).

<u>This is not a regional renewable energy market study</u>. The recommendation to analyze and revisit the Connecticut renewable portfolio standard (RPS) policy in light of the evolving renewable energy market in New England is based on the analysis contained in Appendix E. That discussion cites recent market evidence and other analyses that indicate the potential for a New England and Connecticut shortfall in renewable energy development relative to the RPS targets. However, a thorough examination or modeling exercise of the region's renewable energy market is beyond the scope of a resource planning study; hence the recommendation that additional analysis be pursued on this topic.

There also are many ways the existing analysis can be refined or extended if such enhancements are deemed helpful. These include:

- Additional sensitivity/scenario analysis
- Expanding the suite of evaluation metrics to address additional issues and concerns
- Evaluation of blended resource solutions, *e.g.*, DSM and nuclear
- Evaluation of resource solutions at different scales/levels
- Evaluation of hybrid market/cost-of-service procurement strategies
- Examining how periods of market disequilibrium (*e.g.,* capacity market boom-bust cycles) might affect the evaluation of resource solutions

- Harmonizing electricity market price outlooks used in previous DSM evaluations with those in this study to explore the impact on cost-effectiveness tests
- Examining the interplay between market (price-induced) conservation and the incremental impact of DSM programs
- Additional optimization of DSM program elements to enhance overall effectiveness and to maximize desired impacts on energy and peak load
- Additional refinement of resource characterization and potential in light of rapidly changing technology, cost and performance; for example, an examination of the potential of combined heat and power (CHP) and distributed resources to contribute to power supplies over the long run.

Finally, a study of this nature must necessarily utilize current information and data, while energy markets and policies across the U.S. are changing rapidly. Likewise, this analysis will need to evolve as new information becomes available. Critical updates over the next year might include incorporating the following new data:

- Much better information about the capacity balance and costs in ISO-NE will be available after the Forward Capacity Market auction occurs in February, 2008.
- Additional information regarding generation (conventional and renewable) development and retirements or cancellations in ISO-NE.
- New transmission projects that may be proposed.
- New fuel price and emissions (SO_2, NOx, Hg) price forecasts.
- Demand-side management activities in other New England states (*e.g.*, Massachusetts energy goals clarified).
- Information on CO_2 allowance price levels from various states' RGGI allowance auctions.
- Emerging clarity on the direction of national climate change policy.

APPENDIX A: ELECTRICITY MARKET ANALYSIS

This Appendix discusses ISO-NE's energy, capacity, and operating reserve markets generally, outlines recent market performance and the future outlook for Connecticut, and describes this study's analytical approach to projecting prices in these markets.

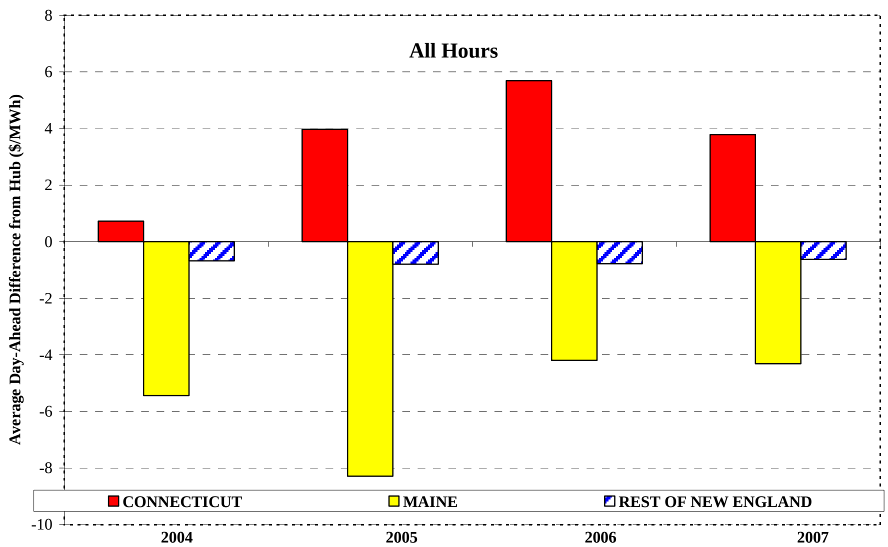
I. ISO-NE MARKET OPERATIONS AND CONCERNS

a. ENERGY

The day-ahead and real-time markets that ISO-NE administers clear and settle at locational marginal prices (LMP). LMPs reflect not only the old-fashioned, merit-order-based, energy clearing price where supply and demand curves intersect, but also transmission congestion and marginal losses. Nodes located electrically near the sending end of a constrained transmission facility are priced lower than their neighbors, reflecting the fact that generation must be re-dispatched out of merit order in order to accommodate load in transmission-constrained areas. Nodes located on or near the receiving terminus of a constrained facility experience higher prices than nodes on the other side of the constraint. Import-constrained load zones,[1] such as Connecticut (and especially Southwest Connecticut over the past several years), tend to have relatively high prices. Generation pockets, such as Maine, tend to have relatively low prices, as illustrated in Figure A.1.

[1] Import constrained load zones are areas within New England that may not have enough local resources and transmission import capability to reliably serve local demand.

Figure A.1: Annual Average Difference in Day-Ahead Prices ($/MWh)



Sources and Notes**:** ISO-NE market data compiled by Global Energy Decisions, Inc., The Velocity Suite; 2007 includes only through October; Rest of New England LMP is obtained using a load weighted average for the other 6 zones in New England i.e. WCMASS, NEMASS, SEMASS, RHODE ISLAND, VERMONT and NEW HAMPSHIRE.

In turn, contracts for power, including wholesale supply contracts for standard offer service, are presumably related to suppliers' expectations for LMPs. Hence, residential rates from 2005 through 2007, and commercial rates and weighted average rates in 2007 have been higher in Connecticut than in Maine or the rest of New England, as shown in Table A.1.

Table A.1: Recent Electricity Rates in ISO-NE States

	Residential Rates (¢/kWh)			Commercial Rates (¢/kWh)			Industrial Rates (¢/kWh)			Weighted Average Rates (¢/kWh)		
State	2005	2006	2007	2005	2006	2007	2005	2006	2007	2005	2006	2007
CT	13.6	16.9	18.8	11.5	14.0	15.4	9.4	11.7	12.8	12.1	14.8	16.3
MA	13.2	13.8	15.1	10.6	12.4	13.2	7.3	8.8	10.3	10.6	11.8	13.2
ME	13.4	16.6	16.5	12.4	15.5	15.3	9.2	13.0	13.5	12.2	15.4	15.4
NH	13.5	14.7	14.9	12.1	14.1	13.9	11.5	11.6	12.7	12.5	13.8	14.0
RI	13.0	15.1	13.9	11.7	13.5	12.7	10.0	12.5	12.3	12.0	14.0	13.1
VT	13.0	13.4	14.1	11.3	11.7	12.2	7.8	8.3	8.8	10.9	11.4	12.0

Source: EIA 826 database, Brattle analysis

LMPs theoretically incorporate into prices the effects of each generator's output and each customer's load on system dispatch costs, thus providing price signals for economically efficient generation dispatch and consumption decisions at every location and every moment. LMPs can also help to induce optimal location of investment in new supply and demand-side resources. However, these theoretical efficiencies have not been fully achieved for a number of reasons, including the inability of the existing transmission system to accommodate new generation (without significant upgrades) in certain locations such as Southwest Connecticut, the lack heretofore of locationally-differentiated capacity prices (discussed below).[2] This led to a situation in which Southwest Connecticut had insufficient supply for reliable operation going forward, even as prices remained the highest in New England.

b. INSTALLED CAPACITY MARKET

ISO-NE imposes a resource adequacy requirement on all load-serving entities (LSEs) in order to limit expected loss of load due to inadequate supply to no more than one day in ten years. ISO-NE also administers a capacity market to facilitate a liquid, transparent mechanism for market participants to buy and sell capacity to meet their resource adequacy requirement.

The capacity market has historically not distinguished between resources located in load pockets from those located in generation pockets. Nor were resource adequacy requirements enforced more than a year forward, thus limiting new resources' ability to secure an initial revenue stream before commencing construction. The perceived failures of the initial capacity market, including the concern that it would not induce sufficient resources to locate in load pockets such as Southwest Connecticut due to the lack of location-specific prices, spurred ISO-NE to commence a stakeholder process to modify the capacity market.

ISO-NE proposed the establishment of a forward market for locationally-differentiated capacity, such as New York and PJM now have. This proposal proved to be highly controversial and was litigated at FERC. Ultimately, a settlement was reached in which ISO-NE agreed to establish a forward capacity market (FCM) with a three-year lead time for one-year capability periods, but with no explicit locational provisions. Locational price premiums or discounts could arise if ISO-NE finds, based on a study conducted annually, that there are binding internal transmission constraints that prevent generation in one part of the region from reliably serving load in another part of the region. The first FCM auction will occur in February, 2008 for the 2010/11 capability year.

[2] In addition, most customers pay fixed rates and are not exposed to time-varying spot prices, allowing them to over-consume during peak periods.

c. Operating Reserves Markets

In order to maintain reliability in the event of contingencies and unexpectedly high load, ISO-NE maintains operating reserves, i.e., capacity that is unloaded and ready to produce power quickly if needed. The region as a whole must carry sufficient operating reserves to cover the single largest contingency and half of the second largest contingency. In addition, the load pockets of Connecticut, and NEMA/Boston, must maintain 30-minute operating reserves locally, which are typically provided by fast-start resources such as combustion turbines.[3]

ISO-NE administers forward and real-time markets in order to facilitate the efficient supply of operating reserves, with the full requirement to be purchased forward semiannually in the non-spinning reserve categories and with spinning reserves and increments/decrements for non-spinning reserves transacting in real time. The forward reserve market (FRM) price, including the locational forward reserve market (LFRM) for Connecticut, is capped at $14/kW-month minus the capacity price.[4] Because there has been a shortage of reserves in Connecticut, the price has been set by the cap in recent auctions. The shortage has also required the use of more expensive spinning reserves (paid for through "uplift" payments) and/or underutilization of the transmission import capacity. These costs are now being addressed in the Department of Public Utility Control's Docket No. 07-08-24, *DPUC Investigation of the Process and Criteria for use in Implementing Section 50 of Public Act 07-242 – Peaking Generation*, as discussed below.

d. Reliability-Must-Run Generation

Much of the generation capacity in Connecticut is composed of old, oil and gas-fired, steam turbines that are expensive to operate. These units have been kept online and operating through reliability-must-run (RMR) contracts with ISO-NE that provide for out-of-market payments. With the introduction of the forward capacity market, these RMR contracts are planned to be eliminated. A concern in Connecticut is that without the RMR contracts, some of the older generating units might retire and leave a critical supply gap in Connecticut.

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[3] The sub-load pocket of Southwest Connecticut has also had its own local requirement, but this requirement is expected to decrease or disappear following the expected completion of the Southwest Connecticut Reliability Project Phase II in 2009, as discussed in ISO-NE's *2007 Regional System Plan* at p. 43-45.

[4] *2006 Annual Markets Report*, ISO New England, June 11, 2007, p. 72.

II. FUTURE OUTLOOK FOR CONNECTICUT

Shortages of capacity and operating reserves in Connecticut, particularly Southwest Connecticut, have been at least partially addressed by new transmission as well as new supply and demand-side resources. As documented more completely in Appendix G, the new resources include:

- **New transmission**, including the Southwest Connecticut Phase I project (345 kV line from Bethel to Norwalk, completed in 2006), the Southwest Connecticut Phase II project (345 kV lines from Middletown to Norwalk, under construction and to be completed in 2009), smaller reliability projects, and potentially the New England East-West-South (NEEWS) project.
- **Recent and planned new DSM** is described in the DSM section, and amounts to an approximate 700 MW peak reduction by 2011 and more than 1,000 peak reduction by 2018.[5] EE programs also reduce future energy requirements by 1,168 GWh by 2011 and 2,821 GWh by 2018.
- **Existing, recent, and planned new generation supply** includes approximately 7000 MW existing and recently installed capacity, plus 1,107 MW of additional planned generation by 2011. Table A.2 shows the additional planned generation by unit.
- In addition, planned projects do not completely fill Connecticut's shortage of operating reserves, so it was assumed that an additional 279 MW of **new fast-start** capacity will be built, as explained below.

Table A.2: Planned Generating Unit Additions and Expansions in ISO-NE by 2011

Unit Name	Unit Type	Zone	Summer Capacity (MW)	Winter Capacity (MW)	Fuel Name
UNIT ADDITIONS					
Waterbury	CT	SW CT	80	96	Natural Gas
Kleen Energy	CC	Rest of CT	560	620	Natural Gas
Wallingford/Pierce	CT	SW CT	100	100	Natural Gas
DG Capital Grant Projects*	CT	SW CT and Rest of CT	96	96	Natural Gas
Renewable Energy Contracts	Steam	SW CT and Rest of CT	150	150	Biomass
UNIT EXPANSIONS					
Cos Cob Expansion	GT	Norwalk-Stamford	40	40	FO2
Millstone Point 3	Nuclear	Rest of CT	81	81	Uranium
		Total (all is in Connecticut)	**1,107**	**1,183**	

*DG Capital Grant projects reduced from 130 MW to 96 MW because 34 MW are counted as demand reductions

[5] Measured at the customer meter.

The potential retirement of existing generating units by plant owners can not be predicted with certainty, but it was assumed that no existing capacity would retire,[6] based on a preliminary economic screening analysis. The analysis consisted of comparing units' energy and capacity revenues to their going-forward avoidable fixed O&M costs. Our data source for the fixed O&M costs was the RMR filings by the old steam turbines in Connecticut, as summarized in Table A.3, below. (This screening analysis considered only the RMR units because their RMR status suggests potentially inadequate earnings to maintain operations and because the RMR contract contains detailed data that facilitates a screening analysis. Units outside of Connecticut were not considered.) Energy and capacity revenues were estimated based on the model results, since RMR contract payments are expected to be discontinued upon the inception of the forward capacity market.

Table A.3: Fixed O&M Costs of RMR Units in Connecticut

Station/Unit	Summer Capacity (MW)	Fixed O&M ($)	FOM ($/kW-Mo)
NRG -- Middletown 2-4, and 10	770	41,071,316	4.44
NRG -- Montville 5, 6, 10, and 11	494	25,608,334	4.32
Milford 1 and 2	492	21,315,292	3.61
PSEG -- New Haven Harbor	448	16,996,000	3.16
PSEG -- Bridgeport Harbor 2	130	6,009,000	3.84
NRG -- Norwalk Harbor 1 and 2	330	29,497,659	7.45

Source: Company RMR Filings to ISO-NE

A unit's entire FOM cost should not be considered avoidable through retirement because there are costs of retiring a plant and maintaining or remediating a site, if applicable. Furthermore, one or two years with low revenues would probably not induce retirement, given the cost of giving up an option to capture significant value in a good year. Hence, we did not consider retiring units unless revenues fell several dollars per kW-month short of covering their fixed O&M costs. With capacity prices in the $3-4/kw-month range in all scenarios for 2013 through 2018 (see Table A.7), all units passed the preliminary screen except for Norwalk Harbor 1 & 2.

[6] However, units that have already retired are treated as such in this study, including New Boston 1 (350 MW), which retired in 2007.

However, we understand that those units or other new resource may be necessary for reliability in the Norwalk area in order to protect against contingencies when one of the new 345 kV transmission lines into Norwalk is out of service. Therefore, we assumed that Norwalk Harbor 1 & 2 would stay online in spite of our screening analysis.

Load growth will partially offset the planned resource additions. ISO-NE forecasts an average annual load growth rate of approximately 1.7% for summer peak load and 1.2% for energy over the next 10 years, before considering new DSM.[7] (Load growth could be higher or lower, depending on economic growth, energy prices, and efficiency, as discussed in the Appendix B).

All planned and expected changes to the supply and demand have been included in the resource balances shown in Tables 2.2 and 2.3 in the main report. As Tables 2.2 and 2.3 indicate, there is no significant resource gap expected in New England until 2013-2016, depending on the trajectory of load, and there is no shortage relative to Connecticut's local sourcing requirement until 2030.

Other fundamental changes likely to affect electricity markets over the next ten years include changes in fuel prices and emission allowance prices. Significantly, carbon allowances will be introduced under RGGI and potential federal climate legislation, as discussed in Appendix F.

III. MODELING APPROACH AND FINDINGS: FUTURE PRICES OF ENERGY, CAPACITY, AND OPERATING RESERVE

This study investigates the resource solutions and procurement strategies that would achieve the best combination of reliability, customer costs, and other policy objectives, including environmental, energy security across a range of potential future scenarios. Resource solutions are evaluated using the DAYZER model to simulate energy market prices, fuel use and emissions, with other complementary analyses to estimate FCM and LFRM prices.

[7] *2007-2016 Forecast Report of Capacity, Energy, Loads, and Transmission*, ISO New England, April, 2007, p. 7.

The starting point for the analysis is an accurate representation of the existing system, which is incorporated in the DAYZER model, plus the planned and expected changes to transmission and generation capacity and DSM, as described above. The key assumptions and data inputs are documented in Appendix G. In addition, the data inputs regarding uncertain exogenous factors, such as load growth and fuel and emission allowance prices, are varied across scenarios, as described in Appendix B.

Finally, in future years in which there is insufficient supply to meet ISO-NE's resource adequacy criteria, it is assumed that additional unplanned resources will be added to fill the gap. The specific "resource solutions" that are evaluated in this study help to fill such gaps, and an economic mix of new gas-fired combustion turbines (CTs) and combined-cycles (CCs) are assumed to be built to fill any remaining gaps.

a. ENERGY MARKET

Given the data inputs representing the elements of supply, demand, and transmission, DAYZER simulates a chronological, bid-based, security-constrained, unit-commitment and dispatch. The model seeks to minimize the total cost to serve load, much like ISO-NE operates the system and administers the market.

It is important to note, however, that the DAYZER forecasts used in this study do not include several elements that create volatility in actual markets. First, there are no transmission outages, which are typically responsible for substantial transmission congestion in actual markets. Second, all generating units are assumed to offer energy at their incremental costs of production: incremental heat rate x fuel price + variable O&M costs + emissions allowance costs. There are no bid adders representing other opportunity costs (such as limited run hours for environmental reasons, or limited fuel supply) or the pursuit of higher margins when market conditions allow. While bidding above marginal cost has been observed in regional organized markets during selected time periods, an estimate of the impact of such behavior is beyond the scope of this study, and is not likely to vary between resource solutions examined. In addition, if there are no barriers to entry, an increase in energy prices would be largely offset by a decrease in capacity prices through a relationship discussed in the next subsection.

The key steps DAYZER performs are:

1. Schedule planned maintenance so as to make the available capacity minus the load as level as possible across the year, i.e., mostly in the Spring and Fall; schedule forced outages randomly such that each unit's target forced outage rate is met.
2. Commit sufficient thermal capacity each day to meet the load plus spinning reserve requirement not already met by hydro generation. Commitment decisions, i.e., when to turn on and off each unit each day, if at all, require a multi-period cost-minimization with many degrees of freedom and can not be optimized perfectly in a reasonable amount of time, hence DAYZER uses heuristics to find a near-optimum. The heuristics account for transmission constraints and the operating characteristics of the units, including their minimum-up-time (MUT) and startup costs as well as their variable costs. DAYZER properly opts not to commit steam units with high-MUT and high startup costs to serve peaking duty when a low-MUT, low startup cost combustion turbine can do it at a lower overall cost (albeit with a higher variable cost setting a higher market price for energy). This, and the fact that generation in constrained-off locations such as Maine is also not committed, often leads to higher and more realistic prices than a simpler production cost model might suggest. (Off-peak prices are also lower due to the fact that MUTs are respected, causing some units whose bids exceed their LMPs to generate at minimum load).
3. Finally, given the generating units that have been committed for each day and each hour, DAYZER dispatches the system to meet the load and provide the required amount of spinning reserves at least cost.

The key outputs of the model are the hourly generation, cost, and emissions at every generating unit, the flows on every monitored transmission facility, and the LMP at every node. As in ISO-NE's actual energy market, DAYZER's hourly LMPs correspond to the marginal cost of serving load at each node, given by the marginal cost of re-dispatching all of the marginal units in order to serve an increment of load at that node without overloading any transmission constraints.[8] LMPs also incorporate a marginal loss component given by the price at the reference bus multiplied by nodal loss factors that DAYZER draws from a database of loss factors under similar load conditions.

Resulting annual average energy prices are shown in Table A.4, below. Table A.4 shows the annual average price in each zone, given by the hourly LMP at a representative node for each

[8] When there are N binding transmission constraints, there are N+1 marginal generating units.

zone summed across hours and divided by 8,760 hours. As the table shows, prices vary much less by solution than by scenario, the differences being driven primarily by gas prices. In addition, prices do not vary by more than a few dollars among Connecticut zones, nor are they significantly higher than prices in nearby West-Central MA. This differs from the recent pricing patterns in which prices were much higher in Norwalk-Stamford than elsewhere (see Table A.5 below), presumably because of the Southwest Connecticut Reliability Projects, which bring two major 345 kV lines into Norwalk and relieve congestion into Norwalk-Stamford.

Table A.4: Average LMP ($/MWh in 2008$) for All Scenarios and Solutions

		2011				2013				2018				2030			
Scenario	**Solution**	**Norwalk**	**SW CT**	**Rest of CT**	**WC MA**	**Norwalk**	**SW CT**	**Rest of CT**	**WC MA**	**Norwalk**	**SW CT**	**Rest of CT**	**WC MA**	**Norwalk**	**SW CT**	**Rest of CT**	**WC MA**
Current Trends	Conventional	73.0	72.0	73.0	71.6	68.7	67.8	68.7	67.4	74.2	73.2	74.3	72.8	82.9	80.5	81.7	80.2
Current Trends	DSM-Focus	73.0	71.9	72.9	71.5	68.4	67.3	68.3	67.0	74.2	72.9	73.9	72.5	82.3	80.5	81.6	80.0
Current Trends	Nuclear	-	-	-	-	-	-	-	-	73.4	72.2	73.2	71.8	80.2	77.5	78.6	78.9
Current Trends	Coal	-	-	-	-	-	-	-	-	73.4	72.2	73.2	71.8	80.2	77.5	78.6	78.9
Strict Climate	Conventional	77.0	76.3	77.4	75.9	83.4	82.0	83.2	81.6	87.0	85.5	86.8	85.1	102.3	100.1	101.5	99.7
Strict Climate	DSM-Focus	76.9	76.2	77.2	75.8	82.9	81.4	82.6	81.0	87.9	86.3	87.6	85.9	102.1	100.3	101.7	99.9
Strict Climate	Nuclear	-	-	-	-	-	-	-	-	86.6	85.1	86.3	84.7	99.9	96.6	98.1	97.7
Strict Climate	Coal	-	-	-	-	-	-	-	-	86.6	85.1	86.3	84.7	99.9	96.6	98.1	97.7
High Fuel/Growth	Conventional	103.7	106.9	108.4	106.4	97.1	99.3	100.7	98.7	105.2	105.7	107.3	105.3	114.0	113.4	115.1	113.0
High Fuel/Growth	DSM-Focus	103.6	106.5	108.0	106.0	97.4	99.2	100.6	98.7	106.7	107.1	108.6	106.5	116.5	116.2	117.8	115.7
High Fuel/Growth	Nuclear	-	-	-	-	-	-	-	-	103.1	103.2	104.7	104.0	112.1	109.9	111.6	113.1
High Fuel/Growth	Coal	-	-	-	-	-	-	-	-	103.1	103.2	104.7	104.0	112.1	109.9	111.6	113.1
Low Stress	Conventional	50.8	50.6	51.4	50.4	48.3	48.0	48.7	47.7	52.9	52.2	53.0	52.0	59.2	57.6	58.5	57.2
Low Stress	DSM-Focus	50.9	50.9	51.6	50.6	48.6	48.1	48.8	47.8	53.3	52.4	53.2	52.2	58.2	57.1	58.0	56.6
Low Stress	Nuclear	-	-	-	-	-	-	-	-	52.2	51.4	52.1	51.6	56.5	54.6	55.4	55.4
Low Stress	Coal	-	-	-	-	-	-	-	-	52.2	51.4	52.1	51.6	56.5	54.6	55.4	55.4

Table A.5: Actual LMP ($/MWh in 2008$) Data at Representative Units

Year	Norwalk	SW CT	Rest of CT	WC MA
2005	108	85	85	83
2006	87	66	67	63
2007*	76	72	73	70
Average	90	74	75	72

Sources and Notes:

*Actual LMP data for 2007 include data through 12/21/2007.
Annual average GDP deflator data are from the Federal Reserve Bank of St. Louis.

Table A.6 below compares zonal average prices from our 2011 "Current Trends" scenario / Conventional resource solution to actual prices from the past three years. DAYZER prices are lower than actual 2005 prices, probably because of the very high gas prices in 2005 following Hurricane Katrina. DAYZER prices are 10-20% higher than actual prices in 2006-07, but average market heat rates (based on the hourly electricity prices divided by gas prices) are similar. DAYZER market heat rates outside Connecticut are a few percent higher than actual 2006-07 heat rates, which makes sense directionally because of load growth (not quite offset by new capacity or DSM), higher oil prices, and the introduction of a small CO_2 allowance price in 2011.

Table A.6: LMP and Market Heat Rate Comparison between DAYZER and Actual Data

	Average Fuel Price ($/MMBtu in 2008$)				LMP ($/MWh in 2008$)				Market Heat Rate (MHR) (Btu/kWh)				% Difference MHR DAYZER vs. Actual		
ZoneName	**DAYZER**	**2005**	**2006**	**2007***	**DAYZER**	**2005**	**2006**	**2007***	**DAYZER**	**2005**	**2006**	**2007***	**2005**	**2006**	**2007***
CT Zone	8.5	10.7	7.9	8.5	73.6	89.7	70.3	71.6	8,741	8,494	8,981	8,837	3%	-3%	-1%
Maine Zone	8.2	10.5	7.8	8.4	68.7	76.4	59.7	63.5	8,168	7,319	7,739	7,955	12%	6%	3%
NE MA Boston Zone	8.5	10.6	7.9	8.5	71.3	86.1	63.3	66.0	8,482	8,223	8,120	8,175	3%	4%	4%
New Hampshire Zone	8.2	10.6	7.8	8.4	71.1	81.2	61.9	66.3	8,745	7,775	7,997	8,282	12%	9%	6%
Rhode Island Zone	8.4	10.6	7.8	8.4	71.2	82.2	61.8	65.5	8,514	7,854	7,943	8,151	8%	7%	5%
South Eastern MA Zone	8.5	10.6	7.9	8.5	71.2	82.1	62.2	67.4	8,469	7,810	7,945	8,359	8%	7%	2%
Vermont Zone	8.2	10.6	7.8	8.4	73.3	85.0	64.0	69.1	8,968	8,091	8,207	8,580	11%	9%	5%
West Central MA Zone	8.5	10.6	7.9	8.5	72.7	84.9	64.0	68.2	8,646	8,073	8,178	8,426	7%	6%	3%

Sources and Notes:
Actual 2007 LMP data only include data up until 10/30/2007, and are compared to DAYZER results from January 1 through October 30.
Actual LMP data are downloaded from Global Energy Decisions, Inc., The Velocity Suite, November 2007 data release.
Annual average GDP deflator data are from the Federal Reserve Bank of St. Louis.
Actual natural gas price data are the Algonquin Citygate prices downloaded from Gas Daily added to the local distribution charges from DAYZER.
DAYZER natural gas price data are the Henry Hub prices plus basis differentials and local distribution charges.
The market heat rate is calculated as the annual average of the hourly LMP/Gas Price x 1000.

b. CAPACITY (FCM)

In the long-run, a competitive market with minimal barriers to entry should price capacity at the net cost of new entry (Net CONE). Net CONE is given by the capital carrying charge and fixed operating and maintenance costs of the new plant that are not expected to be covered by operating margins from the sale of energy and ancillary services. Typically, it is assumed that the relevant capacity price-setting technology is a combustion turbine because it is nearly a pure capacity machine, i.e., it does not earn very large energy margins. For existing resources, ISO-NE has established a price floor for the first FCM auction based on 0.6 x Net CONE and a price ceiling of 1.4 x Net CONE, where Net CONE is assumed to be $7.5/kW-Month for a new combustion turbine. The same floor also applies to new resources that do not leave the auction.

In this study, it is assumed that the capacity market will clear at the floor in 2010/11, when a substantial surplus is expected. It is assumed that the capacity price will then trend toward Net CONE when the market reaches supply/demand equilibrium in 2013-16, depending on the scenario. However, this study deviates strongly from ISO-NE's Net CONE because it rejects

ISO-NE's assumption that a combustion turbine is the relevant technology with the lowest Net CONE. This study finds that, based on the same cost assumptions that ISO-NE used (but slightly inflated to reflect recent increases in the cost of new plant), a combustion turbine would have a Net CONE of approximately $6.1-9.1/kW-Month (=$4.9-6.8 capital carrying cost + $2.2-2.4 FOM –$0.2-1.7 energy margin), depending on the scenario and year. However, for the foreseeable future, a combined cycle would have a much lower Net CONE of $2.2-8.1/kW-mo, depending on the scenario (mostly below $4.5/kW-Month). Net CONE = $5.9-8.7 capital carrying cost + $2.5-2.7 FOM – $2.9-8.0 energy margin (mostly $6.0-8.0) depending on the scenario. This technology has a higher installed cost than a combustion turbine but substantially higher energy margins due to its lower heat rate. With its lower Net CONE, it would set a capacity price significantly below a combustion turbine's Net CONE. (In the alternative, if the capacity price were set by a combustion turbine's Net CONE, a combined cycle could enter and earn more than its cost of capital. More combined cycles would enter until capacity and energy prices dropped to a level at which the last unit just earned its cost of capital).

Table A.7 below shows the elements of these calculations. Note that the costs and revenues vary by location, and Table A.7 shows only the most economic location in each case. Where no unit exists, a 1 MW test unit was used as an indicator. Test units in the Norwalk-Stamford area were excluded because prices and energy margins appear slightly inflated there by a binding transmission constraint (post-contingency flows on Ely-Glenbrook 115 kV) that would probably be economic to resolve through transmission enhancements.

Table A.7: Summary of Connecticut Capacity Price by Scenario, Resource Solution, Study Year, and Unit Type

	2011						2013					2018					2030				
	Capital at Best Location [1]	FOM at Best Location [2]	Energy at Best Location [3]	Best Location	Capacity Price [4]	Price Floor [5]	Capital at Best Location [1]	FOM at Best Location [2]	Energy at Best Location [3]	Best Location	Capacity Price [4]	Capital at Best Location [1]	FOM at Best Location [2]	Energy at Best Location [3]	Best Location	Capacity Price [4]	Capital at Best Location [1]	FOM at Best Location [2]	Energy at Best Location [3]	Best Location	Capacity Price [4]
MARKET-CLEARING CAPACITY PRICE (BASED ON NET CONE FOR A COMBINED CYCLE; $/KW-MONTH)																					
Current Trends Scenario																					
Conventional	7.7	2.5	6.2	Rest of CT	3.9	4.5	7.3	2.5	6.1	WC MA	3.7	7.3	2.5	6.7	WC MA	3.1	7.3	2.5	5.5	WC MA	4.3
DSM-Focus	7.7	2.5	6.1	Rest of CT	4.1	4.5	7.9	2.5	6.3	SW CT	4.1	7.3	2.5	6.5	WC MA	3.3	7.7	2.5	5.8	Rest of CT	4.4
Nuclear	-	-	-	-	-	4.5	-	-	-	-	-	7.3	2.5	6.2	WC MA	3.6	7.3	2.5	4.8	WC MA	5.0
Coal	-	-	-	-	-	4.5	-	-	-	-	-	7.3	2.5	6.2	WC MA	3.6	7.3	2.5	4.8	WC MA	5.0
Strict Climate Scenario																					
Conventional	7.7	2.5	5.8	Rest of CT	4.4	4.5	7.9	2.5	8.0	SW CT	2.4	7.3	2.5	7.0	WC MA	2.8	7.7	2.5	7.2	Rest of CT	3.0
DSM-Focus	7.7	2.5	5.7	Rest of CT	4.5	4.5	7.9	2.5	7.4	SW CT	2.9	7.3	2.5	7.6	WC MA	2.2	7.7	2.5	7.3	Rest of CT	2.9
Nuclear	-	-	-	-	-	4.5	-	-	-	-	-	7.9	2.5	7.4	SW CT	2.9	7.3	2.5	5.6	WC MA	4.2
Coal	-	-	-	-	-	4.5	-	-	-	-	-	7.9	2.5	7.4	SW CT	2.9	7.3	2.5	5.6	WC MA	4.2
High Fuel/Growth Scena																					
Conventional	8.7	2.7	7.1	SW CT	4.3	4.5	8.5	2.7	6.8	Rest of CT	4.4	8.7	2.7	6.5	SW CT	4.9	8.5	2.7	3.1	Rest of CT	8.1
DSM-Focus	8.5	2.7	6.6	Rest of CT	4.6	4.5	8.5	2.7	6.8	Rest of CT	4.4	8.7	2.7	7.3	SW CT	4.1	8.5	2.7	4.2	Rest of CT	7.0
Nuclear	-	-	-	-	-	4.5	-	-	-	-	-	8.0	2.7	5.4	WC MA	5.3	8.0	2.7	2.9	WC MA	7.8
Coal	-	-	-	-	-	4.5	-	-	-	-	-	8.0	2.7	5.4	WC MA	5.3	8.0	2.7	2.9	WC MA	7.8
Low Stress Scenario																					
Conventional	5.9	2.5	5.1	WC MA	3.2	4.5	5.9	2.5	5.0	WC MA	3.3	5.9	2.5	5.3	WC MA	3.1	6.2	2.5	4.4	Rest of CT	4.2
DSM-Focus	5.9	2.5	5.2	WC MA	3.1	4.5	5.9	2.5	5.1	WC MA	3.2	5.9	2.5	5.4	WC MA	2.9	6.2	2.5	4.1	Rest of CT	4.6
Nuclear	-	-	-	-	-	4.5	-	-	-	-	-	5.9	2.5	5.1	WC MA	3.2	5.9	2.5	3.0	WC MA	5.3
Coal	-	-	-	-	-	4.5	-	-	-	-	-	5.9	2.5	5.1	WC MA	3.2	5.9	2.5	3.0	WC MA	5.3
NET CONE FOR A COMBUSTION TURBINE ($/KW-MONTH)																					
Current Trends Scenario																					
Conventional	6.2	2.2	1.0	WC MA	7.4		6.2	2.2	1.5	WC MA	6.9	6.2	2.2	1.7	WC MA	6.7	6.2	2.2	0.9	WC MA	7.5
DSM-Focus	6.2	2.2	0.9	WC MA	7.5		6.2	2.2	1.3	WC MA	7.1	6.2	2.2	1.5	WC MA	6.9	6.2	2.2	1.0	WC MA	7.4
Nuclear	-	-	-	-	-		-	-	-	-	-	6.2	2.2	1.3	WC MA	7.1	6.2	2.2	0.9	WC MA	7.5
Coal	-	-	-	-	-		-	-	-	-	-	6.2	2.2	1.3	WC MA	7.1	6.2	2.2	0.9	WC MA	7.5
Strict Climate Scenario																					
Conventional	6.2	2.2	0.7	WC MA	7.7		6.2	2.2	1.4	WC MA	7.0	6.2	2.2	1.4	WC MA	7.0	6.2	2.2	1.3	WC MA	7.1
DSM-Focus	6.2	2.2	0.7	WC MA	7.7		6.2	2.2	1.2	WC MA	7.2	6.2	2.2	1.6	WC MA	6.9	6.2	2.2	1.3	WC MA	7.1
Nuclear	-	-	-	-	-		-	-	-	-	-	6.2	2.2	1.3	WC MA	7.1	6.2	2.2	1.0	WC MA	7.4
Coal	-	-	-	-	-		-	-	-	-	-	6.2	2.2	1.3	WC MA	7.1	6.2	2.2	1.0	WC MA	7.4
High Fuel/Growth Scena																					
Conventional	6.8	2.4	0.3	WC MA	8.9		6.8	2.4	0.8	WC MA	8.4	6.8	2.4	0.5	WC MA	8.7	6.8	2.4	0.2	WC MA	9.1
DSM-Focus	6.8	2.4	0.3	WC MA	8.9		6.8	2.4	0.7	WC MA	8.6	6.8	2.4	0.6	WC MA	8.7	6.8	2.4	0.2	WC MA	9.0
Nuclear	-	-	-	-	-		-	-	-	-	-	6.8	2.4	0.5	WC MA	8.8	6.8	2.4	0.2	WC MA	9.1
Coal	-	-	-	-	-		-	-	-	-	-	6.8	2.4	0.5	WC MA	8.8	6.8	2.4	0.2	WC MA	9.1
Low Stress Scenario																					
Conventional	4.9	2.2	0.8	WC MA	6.4		4.9	2.2	1.0	WC MA	6.1	4.9	2.2	0.8	WC MA	6.4	4.9	2.2	0.5	WC MA	6.7
DSM-Focus	4.9	2.2	0.9	WC MA	6.3		4.9	2.2	1.0	WC MA	6.2	4.9	2.2	0.8	WC MA	6.4	4.9	2.2	0.3	WC MA	6.9
Nuclear	-	-	-	-	-		-	-	-	-	-	4.9	2.2	0.7	WC MA	6.5	4.9	2.2	0.3	WC MA	6.8
Coal	-	-	-	-	-		-	-	-	-	-	4.9	2.2	0.7	WC MA	6.5	4.9	2.2	0.3	WC MA	6.8

Sources and Notes:

[1]: Future capital cost based on FERC testimony by John J. Reed; Prepared Direct Testimony of John J. Reed on Behalf of ISO New England Inc; Docket No. ER03-563-030; August 31, 2004; Pages 55-57. Adjusted for scenario-specific capital cost adders.

[2]: FOM values are based on EIA-906 data compiled by Global Energy Decisions, Inc., The Velocity Suite; ISO-New England RMR agreements; and FERC testimony by John J. Reed on behalf of ISO-New England. Adjusted for scenario-specific capital cost adders.

[3]: Includes unit average energy margin, plus spin and uplift payments. Adjusted for scenario-specific capital cost adders.

[4]: =[1] + [2] - [3].

[5]: The current price floor of $4.5/kW-Month is assumed to be in effect in 2011. The floor is assumed to diminish in later years, based on 60% of Net CONE.

A natural reaction to this contrarian finding of relatively low capacity prices is to question the energy price forecasts that drive the combined cycles' energy margins so high and their Net CONE so low. The prices can be explained based on the fundamentals of supply and demand, adjusted for unit outages and the non-commitment of units with long MUTs and high startup costs. In addition, as Table A.6 shows, modeled market heat rates are not very different from recent historical prices, although a small percentage increase in market heat rates can increase energy margins by a much larger percentage (based on the difference between market heat rate and a combined cycle's heat rate of 7,000).

c. FORWARD RESERVES MARKET

Absent new investment, the present shortage of fast-start capability capacity in Connecticut is likely to continue. 731 MW of existing[9] plus 220 MW of planned (100 MW Wallingford/Pierce, 80 MW Waterbury, 40 MW Cos Cob) would be insufficient to meet the requirement. We have assumed that the requirement would be set based on the capacity of Millstone 3, approximately 1,236 MW. (This is close to the 1,100-1,200 requirement projected by ISO-NE in its *2007 Regional System Plan*). We have assumed that 279 MW of new combustion turbines would be built in Connecticut in order to fully meet the requirement. This assumption is consistent with the recent recommendation of the DPUC to contract for 282 MW of fast-start capacity, as discussed in Docket No. 07-08-24, *DPUC Investigation of the Process and Criteria for use in Implementing Section 50 of Public Act 07-242 – Peaking Generation* (at p. 16).

If Connecticut's LFRM requirement is met but not exceeded, the LFRM price can be expected to remain at the price cap given by $14/kW-mo minus the capacity price. This amount, multiplied by a cost allocation factor is applied to Connecticut customers in evaluating rates under each scenario/solution combination. The cost allocation factor is assumed to be 45% to account for both Connecticut customers' share of the Connecticut LFRM costs (some of which are socialized across New England) and Connecticut's share of FRM costs from the rest of New England.

[9] *2007 Regional System Plan*, ISO New England, October 18, 2007, p. 44.

APPENDIX B: SCENARIO DEVELOPMENT

Long-range planning analyses must typically address substantial uncertainty regarding external factors. In order to understand the strengths and weaknesses of potential resource solutions, it is important to look at how they are affected by changes in these external factors. This can be done in several ways, including sensitivity analysis, scenario analysis, and Monte Carlo simulation.

In this study, we use scenario analysis, developing several internally consistent future scenarios against which the resource solutions are evaluated. Each scenario reflects a combination of particular values for the relevant external factors and is characterized by an underlying "driver" in combination with settings of other external factors that are consistent with this driver. The scenarios are designed so that the particular combinations of external factors are relatively likely (are internally consistent), and/or important (combinations that pose particular risks or opportunities to the resource solutions). To test the resource solutions under consideration and expose their strengths and weaknesses, the scenarios are intentionally relatively extreme, but not implausibly so. Together the scenarios depict a broad range of potential future conditions. However, the scenario set developed here is not intended to thoroughly cover the full range of potential outcomes.[1]

In contrast to scenario analysis, sensitivity analysis typically defines a "baseline" with all parameters set at nominal or expected levels, and varies one parameter at a time to evaluate the resource solutions.[2] Sensitivity analysis can of course be a valid and useful technique, but scenario analysis has some advantages here. Scenarios can better capture qualitatively different multi-dimensional futures, rather than examining only uni-dimensional variations from an

[1] In some analyses, scenarios are used to span the full range of possible future outcomes, but that is not possible here, given the small number of scenarios that can be evaluated and the large number of potential combinations of external factors. Similarly, some scenario analyses weight scenarios with probabilities and calculate probability-weighted quantitative outcome measures. No attempt was made here to weight scenarios or average outcome measures. The goal of this study is to use scenarios to gain insights about the strengths and weaknesses of solutions, not to develop a single quantitative measure of their merit.

[2] The ISO-NE's "New England Electricity Scenario Analysis" is an example of a study that uses sensitivity analysis. Note that the ISO uses the term "scenario" to indicate what we call a "resource solution" – a way to meet resource needs. The ISO uses sensitivity analysis to examine different settings of external factors like fuel prices and CO_2 price.

assumed baseline. This avoids a “basecase” preference in which one particular setting of factors dominates the analysis.

Another approach to characterizing uncertainty is with Monte Carlo analysis, where many different combinations of external factors are generated randomly according to specified probability distributions, and resource solutions are evaluated against each combination. This would result in a probability distribution for each resource solution, and solutions could be compared based on their expected values and variances. However, a Monte Carlo approach would not be as informative here because it would embed our own subjective probability assessments and thereby obscure the dependence of resource solutions’ relative values on very different future trajectories of external factors. It is important that this study illuminate for policy makers how the value of each resource solution depends on key external factors such as fuel prices, load growth, generation technology capital costs, and changes in environmental regulations, including climate legislation. Such factors are likely to vary not by a few percent along a well-behaved continuum, but by large jumps sometimes, and in ways that are interrelated. Hence, constructing a range of internally-consistent scenarios that address the range of plausible future trajectories of external factors is more informative in this context than Monte Carlo analysis.

One of the key steps in developing the scenarios for this study is to understand the relationship between the scenario drivers – economic growth, fuel price and CO_2 allowance price – and electricity prices and power demand. To create consistent relationship between these, we have considered the interaction between economic growth and electric load, and also the feedback effects by which fuel and CO_2 prices affect power price, which then also influences power demand. Different factors may have varying impact on energy demand vs. peak load, and we have captured this distinction as well.

Three interacting effects can influence energy and peak demand – the price of electricity, active demand-side management programs, and economic growth in the region. For the scenarios here, energy and peak forecasts are obtained by adjusting ISO New England’s Base Case Load Forecast for these three effects:

1) Price Effect

One of the key parts of developing scenarios for the IRP is to understand the relationship between external drivers – fuel and CO_2 prices – and electricity prices and load. To approximate this relationship in developing scenarios, we used the fact that New England power prices are very closely linked to natural gas prices, and that CO_2 prices will affect power prices almost entirely through their effect on gas prices. In each scenario, we determined the approximate effect on retail power prices of changes in gas and CO_2 prices, assuming a 90% effect of gas prices on power prices, and accounting for the fact that wholesale power price is "diluted" by T&D charges in the retail price. Given this estimate of how power prices would change in a given scenario, we estimated the price effect on electric load using a price elasticity relationship.

Price elasticity for power is often estimated to be in the range of -0.8 to -1.0. (This is a long-run elasticity; short-run elasticities are much lower –around -0.1 to -0.2. Also, cross price elasticities between power and other energy sources are very small, and were ignored here.) This elasticity range is almost certainly too high in the context of large price changes, because of diminishing marginal effects. We assumed a long run energy price elasticity of -0.35 and short run energy price elasticity of -0.20, consistent with the Energy Information Administration's National Energy Modeling System (NEMS) elasticity estimates reported in Annual Energy Outlook 2003 (AEO2003). NEMS elasticities are more relevant in our context for two main reasons. First, these elasticity estimations are forward looking in the sense that they weigh potential long-run adjustments in the efficiency of equipment stock. Second, NEMS elasticities are estimated for a large price change which conforms to the case in our scenarios. We phase in short run elasticity response over three years starting in 2008, while the remaining effect (the difference between long run and short run) is phased in smoothly over 7 years starting in 2011. We also follow the same methodology to determine the price effect on peak load. Peak elasticity is smaller than energy elasticity (around half the magnitude) due to the limited substitutability of consumption during peak times. Accordingly, we assumed a long run peak price elasticity of -0.175 and short run peak price elasticity of -

0.10 for the effects on peak load, and phased in as for energy elasticity effects. This approach is used for all scenarios to adjust ISO-NE's Base Case Peak and Energy Forecasts for elasticity responses to scenario-specific fuel and CO_2 prices.

2) DSM Effect

The ISO-NE Base Case energy and peak forecasts are adjusted for DSM that is not included in the ISO-NE's forecasts. The "DSM Effect" represents how much lower the load will be relative to the ISO-NE's Base Case due to DSM activities. Two different levels of DSM (corresponding to DSM activities in the Resource Solutions) are studied; "Base DSM" is a component of all the Resource Solutions, and "Heavy DSM" characterizes additional DSM activities that occur in the DSM Focus resource solution. The nominal amount of DSM activities undertaken in either Base or Heavy DSM is the same across all scenarios, but the interaction with the price effect is taken into account to develop the resulting DSM response and scenario-specific loads. That is, the Resource Solution characterizes the amount of effort put into DSM activities, but given that, the quantity reduction in peak and energy that is actually achieved depends on the scenario.

3) Economic Growth Effect

Two of our scenarios do not start from the ISO-NE's Base Case energy and peak load forecasts, but instead work from the ISO's High Growth case (or a combination of that with the Base Case). For those scenarios, we define the "growth effect" to represent the deviation from the Base Case forecast in a given year.

After defining these effects for each of the scenarios, the next step is to adjust the ISO-NE's Base Case forecast by a combination of the three effects to arrive at the scenario load forecasts. For all scenarios except the Low-Stress Scenario, price effect and DSM effect work in the same direction to reduce the forecasts below ISO-NE's Base Case Forecast. These two effects compete to an extent (the price effect essentially "cannibalizes" the DSM effect), and to account for this we reduce the combined effect by half the magnitude of the smaller individual effect. In the Low Stress scenario, these two effects work in opposite directions and do not cannibalize one another, so they are simply summed. This combined impact of price and DSM effects is applied in addition to the growth effect present to develop the scenario-specific peak and energy demand forecasts for the scenarios.

The primary dimensions on which scenarios are defined are:

A. Fuel prices - natural gas prices are of primary importance, but petroleum prices are also relevant.
B. Load growth
C. Cost of new generating capacity
D. Environmental policy – in particular, climate policy, represented by CO_2 price.

The table below summarizes the primary parameters that characterize each of the scenarios.

Table B.1: Scenario Summary

	A. Fuel Prices	B. Load Growth	C. Cost / Siting	D. Environment (CO_2 Price)
I. **Current Trends**	Gas: NYMEX w/ EIA growth rate Oil: NYMEX w/ EIA growth rate	ISO Base Case Load, adjusted for DSM (~2%, then 1.5% peak growth; ~1% energy growth)	nominal cost & siting parameters (see screening analysis)	RGGI 2011, 2013; Bingaman safety valve thereafter ($5 in 2011-13; ~$15 in 2018 to $26 in 2030)
II. **Strict Climate**	Gas price ~10% higher, due to higher gas demand from electric gen (<u>partially</u> offset by non-electric gas use). Oil same as Current Trends.	Below Current Trends Case, due to higher power price (from CO_2 price, gas price), though based on ISO Base Case Load.	nominal cost & siting parameters	Strict climate: 2x EPA Assessment of S.280, starting 2012 (RGGI pre-2012) ($26/t 2012; $34/t 2018; $60/t 2030)
III. **High Fuel / Growth**	Gas ~$11/MMBtu (.85 parity to $85/bbl crude, 1.7*Ref gas price) FO_2, FO_6 similar to Ref prices (maintain relative rel'n to crude)	Substantially below Current Trends Case due to higher power price (from CO_2 price and gas price) despite being based on high growth case.	Higher costs; additional 10% above Ref Case on Capital costs, FOM, VOM	30% over Current Trends prices starting in 2014 ($16 in 2014; $20 in 2018; $35 in 2030)
IV. **Low Stress**	HH gas at ~$5; Crude at ~$40 (in 2012, 2008$)	Based on economic growth only slightly higher than nominal, but load is much higher than Current Trends due to lower power prices.	low cost / easy siting Reduce Capital costs by ~20% vs Current Trends Case (all techs)	Same as Current Trends Case: RGGI/Bingaman

I. SCENARIO DESCRIPTIONS

A. Current Trends Scenario

The Current Trends scenario is based on a continuation of current conditions and expectations. It is specified as follows.

i. Fuel Prices

a. Henry Hub natural gas prices are from NYMEX Henry Hub Futures as of 9/27/2007, with data available October 2007 through December 2012. After 2012, prices are extrapolated through 2030 using EIA annual growth rates for natural gas prices (from the 2007 Annual Energy Outlook). Delivered natural gas prices are obtained by adding a New England basis differential; this adder to Henry Hub prices is differentiated monthly but is assumed to remain constant over years, with an annual average of $1/MMBtu.

b. Residual Fuel Oil (FO_6) prices are forecast for October 01, 2007 through December 01, 2012 based on NYMEX crude oil futures prices, adjusted based on the historical relationship between crude and FO_6 (from a simple linear regression). After 2012, FO_6 prices are extrapolated to 2030 using EIA annual growth rates for FO_6.

c. Distillate Fuel Oil (FO_2) prices are NYMEX Heating Oil futures from October 2007 through September 2010. Prices are extrapolated beyond 2010 to 2030 using EIA annual growth rates for FO_2.

ii. Load

a. Growth Effect: No additional growth effects; energy and peak load are based on the ISO-NE Base Case forecast. ISO-NE forecasts are only available from 2007 through 2016. Therefore, energy and peak load are extrapolated through 2030 by using the 2015-2016 forecast energy growth rate (approximately 1%) and peak load growth rate (approximately 1.5%).

b. DSM Effect: Base and Heavy DSM efforts have their nominal specified effects, as described in Appendix D.

c. Price Effect: No additional price effect, since prices are assumed to be at nominal levels. Price effects for other scenarios are defined relative to the Current Trends Scenario.

iii. Cost and Siting

a. Costs for new generation are as described in Appendix C. This reflects Connecticut locational construction costs, as well as the recent substantial increase in capital costs of generating technologies (up by roughly 25-35% over typical cost estimates from just a few years ago).

iv. Environmental Regulations (CO_2)

a. Starting in 2010 when RGGI comes into effect, CO_2 prices are based on RGGI (approximately \$5/t CO_2). Beginning in 2014 and continuing through 2030, prices are based on the safety valve price in the Bingaman-Specter Low Carbon Economy Act of 2007. The safety valve begins at \$12/t (in 2012\$) and grows at 5% in real terms. This yields approximately \$12/t in 2014, \$16/t in 2020 and \$26/t in 2030 (all in 2008\$). For comparison, in its Scenario Planning exercise, the ISO-NE assumed a CO_2 price of \$20/t in its Base Case. Allowance prices for SO_2, NO_X and mercury are based on EIA forecasts (these are not varied across other scenarios, as they are a relatively small cost component).

B. Strict Climate Scenario

This scenario is driven primarily by strict climate policy, based loosely on several of the more stringent legislative proposals that have been put forward recently (*e.g.*, 70% reduction in GHG emissions by 2050). The primary implication for the power sector is a substantially higher price of CO_2. The high CO_2 price causes some dispatch switching (from coal to gas) and a shift toward gas-fired generation for capacity additions; this increased in gas demand from the electric sector is partially offset by a decrease in non-electric use of gas, and the resulting moderate increase in gas demand causes natural gas commodity prices to increase somewhat. The high CO_2 price and higher gas price are reflected in higher electricity prices, which cause a reduction in load relative to the Current Trends Scenario.

i. Fuel Prices

a. Henry Hub natural gas prices are 10% above the Current Trends scenario due to increased gas demand. Higher gas demand for electric generation is partially offset by decreased non-electric gas consumption (in response to the increase in effective gas prices caused by the higher CO_2 price). The basis differential to New England is unchanged from the Current Trends scenario.

b. FO_2 and FO_6 prices are the same as the Current Trends Scenario.

ii. Load

a. Growth Effect: No growth effects as energy and peak is assumed to grow at the same rate as ISO-NE's Base Case energy and peak forecasts.

b. DSM Effect: DSM effect interacts with price effect as described in the introduction to this Appendix.

c. Price Effect: ISO-NE Base Case forecasts for energy and peak are adjusted for the impact of higher electricity prices, which are driven by higher gas and CO_2 prices. In addition to the 10% increase in the cost of gas itself, the higher CO_2 price will increase the effective natural gas price by an additional 14% (compared to the Current Trends scenario). This resulting 24% increase in effective gas prices will cause a 14% increase in delivered power prices. This will induce:

- Energy decreases by 5%, relative to ISO-NE Base Case energy forecast in 2018. The short-term response, a 3% decrease in energy, is phased in smoothly over the first 3 years through 2011 and the remaining 2% decrease (long-term response) is phased in over the following 7 years through 2018. The percentage difference in energy relative to the Base Case is assumed to remain constant beyond 2018.

- Peak decreases by 2.5%, relative to ISO-NE Base Case peak forecast in 2018. The 1.5% short-term decrease in the peak is phased in smoothly over the first 3 years through 2011 and the remaining 1% decrease (long-term) is phased in over the following 7 years through 2018. The percentage difference in peak relative to the Base Case is assumed to remain constant beyond 2018.

iii. Cost and Siting

a. Same as the Current Trends Scenario.

iv. Environmental Regulations (CO_2)

a. For 2010 and 2011, CO_2 prices are based on RGGI (approximately \$5/t CO_2). Starting in 2012, CO_2 prices are substantially higher than the Current Trends scenario, due to strict federal climate policy coming into effect then. The effect of such a strict climate policy on CO_2 price is based on the EPA assessment of S.280, the Lieberman Climate Stewardship and Innovation Act of 2007. EPA's estimated CO_2 prices were doubled for this scenario; the EPA analysis found that CO_2 prices were very sensitive to the amount of offsets allowed, and that under the same bill but without any offsets, the price would approximately triple. A price of double the EPA "Lower Nuclear Power Generation" case estimate is reasonably representative of a strict but credible climate policy. Other analyses suggest that prices of around this level are probably necessary to prompt a significant change in CO_2 emissions, particularly from the power sector (*e.g.*, to cause dispatch switching from coal to gas generators, and to prompt the construction of lower-CO_2 new generation). This leads to CO_2 prices of \$26/t in 2012; \$37/t in 2020 and \$60/t in 2030. For comparison, in its Scenario Planning exercise, the ISO-NE used a CO_2 price of \$40/t in its high carbon price sensitivity case. The current CO_2 allowance price in the EU ETS is €22, or \$32/t CO_2.

v. High Fuel/ Growth Scenario

This scenario is characterized by high (regional or global) economic growth, in combination with substantially higher natural gas prices. High natural gas prices are driven at least in part by high U.S. gas demand (and strong global demand for LNG, which prevents it from holding domestic prices down). Petroleum prices are somewhat higher than the Current Trends scenario. *E.g.*, FO_2 prices are 30% higher on average over the horizon; FO_6 prices average 20% higher. Electric load growth in this scenario is affected by two strong but opposing factors – high economic growth tends to increase load, while higher fuel and CO_2 prices push up power prices, which tends to decrease load. On balance (and perhaps somewhat surprisingly), electric energy demand in this case is slightly lower than under the Current Trends scenario, though peak load is higher (peak demand is less sensitive to the price of power).

vi. Fuel Prices

a. Currently, gas is priced at roughly 60% parity with crude on a Btu basis, substantially below the historical pricing relationship of about 85% parity. High economic growth, which is assumed in this scenario, will lead to high gas demand, which could cause gas to return to its relative pricing relationship with oil. A 70% increase in gas price from the Current Trends scenario puts gas at 85% pricing parity with crude at \$85/bbl (2008\$). Note that current futures price for 2011 – \$80/bbl (2008\$) – is somewhat above the \$67/bbl crude futures price that prevailed in September when fuel price data was sampled this study. Gas price in this scenario is defined as 170% of the Current Trends gas price. These are Henry Hub prices; since the New England basis differential is assumed to be unchanged, the delivered price increases by about 60% relative to the Current Trends delivered price.

b. Crude prices in this scenario are assumed to maintain this 85% parity relationship with gas prices; i.e., gas and crude prices move together. This differs from other scenarios but is consistent with gas and oil having a stable long-term pricing relationship. FO_2 prices are estimated in relation to this crude price trajectory, based on the EIA forecast of the relationship between crude and FO_2. FO_6 prices are forecasted using the estimated relationship between historic crude oil and FO_6 prices.

vii. Load

a. Growth Effect

- Under this scenario, the growth effect on energy is based on the ISO-NE's "High Case" energy forecast which reflects strong economic growth. The effect in year 2018 is assumed to remain constant through 2030.
- The growth effect on peak load is based on the ISO-NE's "High Case" peak load forecast. The effect in year 2018 is assumed to remain constant through 2030.

b. DSM Effect: DSM effect interacts with price effect as described in the introduction to this Appendix.

c. Price Effect: ISO-NE Base Case forecasts for energy and peak are adjusted for the impact of 36% increase in power price that was prompted by a 67% increase in gas prices (due to higher gas and CO_2 prices relative to the Current Trends Scenario). This results in:

- A 13% decrease in energy demand relative ISO-NE's Base Case forecast in 2018. The short-term effect, 7.5%, is phased in the first 3 years through 2011, and the remaining (long-term) 5.5% decrease is phased in over 7 years through 2018. Beyond 2018, this 13% decrease in energy demand relative to the ISO-NE Base Case is maintained.

- A 6.5% decrease in peak relative ISO-NE's Base Case forecast in 2018. The short-term effect, 3.5%, is phased in the first 3 years through 2011, and the remaining (long-term) 3% decrease is phased in over 7 years through 2018. Beyond 2018, this 6.5% decrease in peak is maintained.

viii. Cost and Siting

a. Costs of new generation (capital costs, FOM, and VOM) are increased by an additional 10% over Current Trends values to reflect higher costs (*e.g.*, for labor and materials) in a high economic growth case.

ix. Environmental Regulations (CO_2)

a. CO_2 prices are based on RGGI from 2010 until 2014. Beginning in 2014 and continuing through 2030, prices are 30% higher than the Current Trends scenario CO_2 prices, due to the additional demand for CO_2 allowances created by high economic growth.

C. Low Stress Scenario

Historically, periods of high prices are often followed by a return to earlier, lower price trends. The Low Stress scenario reflects a return to somewhat lower fuel and generator costs, reversing some (though not necessarily all) of these recent price increases. Slightly higher economic growth, combined with substantially lower power prices, results in both peak and energy load that are much higher than in the Current Trends Scenario.

i. Fuel Prices

a. All fuel prices are 40% below their corresponding Current Trends values. Both oil and gas prices fall so that their current relationship is maintained. For natural gas, the New England basis differential is assumed to be unchanged, so the proportional effect on delivered gas prices is smaller (about 35%).

ii. Load

a. Growth Effect

- This scenario assumes an energy load that is the midway between ISO-NE's High Case and Base Case energy forecasts.[3] The growth effect in year 2018 is assumed to remain the same beyond 2018.
- Peak load is midway between ISO-NE's High Case and Base Case peak forecasts. The growth effect in year 2018 is assumed to remain the same beyond 2018.

b. DSM Effect: DSM effect interacts with price effect as described in the introduction to this Appendix.

c. Price Effect: ISO-NE Base Case forecasts for energy and peak are adjusted for the impact of lower gas prices on load. The 35% decrease in delivered gas price will cause a 20% decrease in delivered power prices. This leads to:

- A 7% increase in energy demand relative ISO-NE's Base Case forecast in 2018. The short-term effect, 4%, is phased in the first 3 years through 2011, and the remaining (long-term) 3.3% increase is phased in over 7 years through 2018. Beyond 2018, this 7% increase in energy demand relative to the ISO-NE Base Case is maintained.
- A 3.5% increase in peak relative ISO-NE's Base Case forecast in 2018. The short-term effect, 2%, is phased in the first 3 years through 2011, and the remaining (long-term) 1.5% increase is phased in over 7 years through 2018. Beyond 2018, this 3.5% increase in peak is maintained.

iii. Cost and Siting

a. Generator costs are lower than in the Current Trends scenario, reflecting a reversal of at least some of the recent increases in construction costs. Capital costs are reduced by 20% relative

[3] This assumption is consistent with a scenario in which low fuel prices are stimulating moderately higher economic growth. However, economic growth is assumed to be less extreme than in the ISO-NE's High Case, since it is less likely that fuel prices would remain low if the economy were growing at this high rate. This logic affects both peak and energy demand.

to the Current Trends scenario for all technologies. (FOM and VOM are unchanged from Current Trends levels.)

iv. Environmental Regulations (CO_2)

a. Same as the Current Trends Scenario.

II. Graphical Depictions

Fuel prices, CO_2 prices and loads (peak and energy) of the four scenarios are depicted graphically below.

Figure B.1: Current Trends Scenario – Fuel Prices

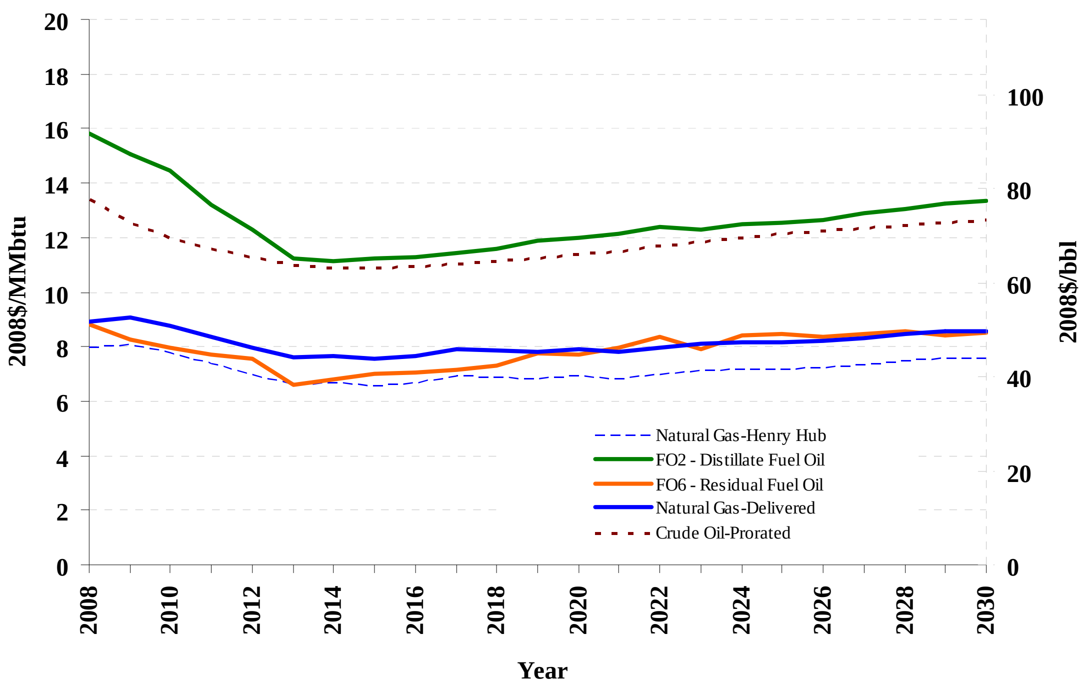


Figure B.2: Strict Climate Scenario – Fuel Prices

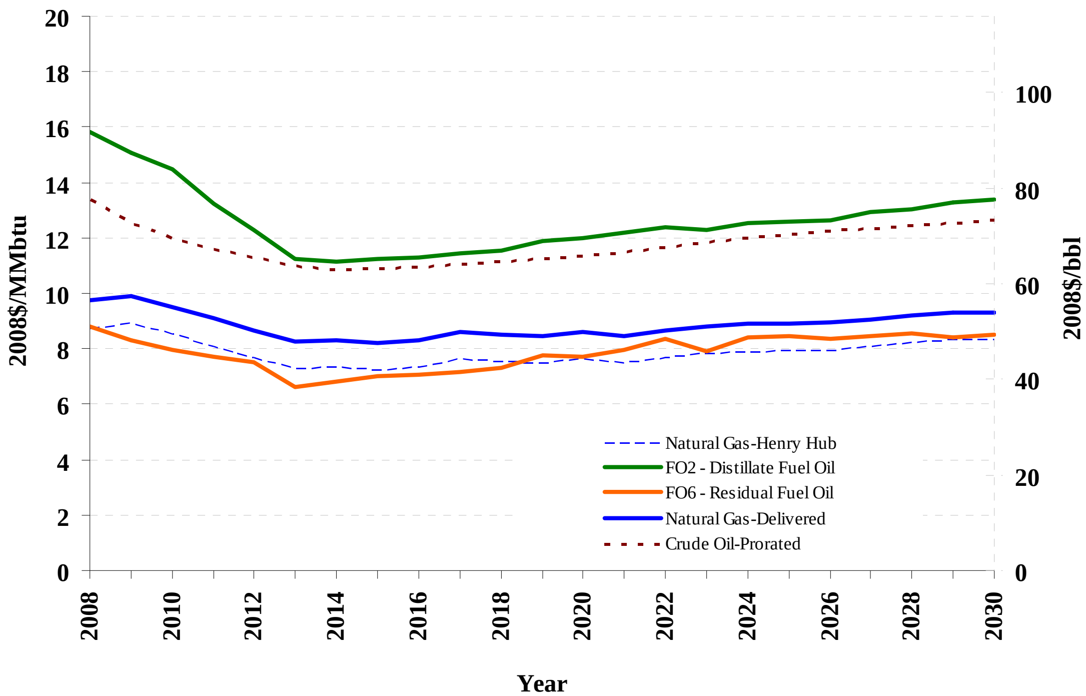


Figure B.3: High Growth/Fuel Scenario – Fuel Prices

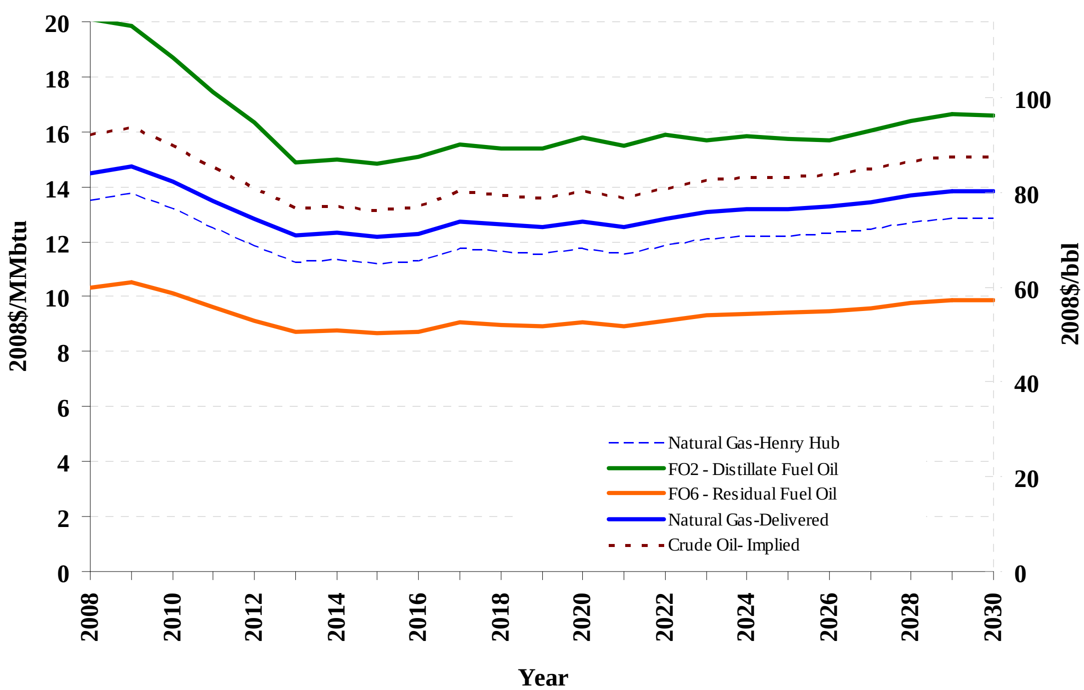


Figure B.4: Low Stress Scenario – Fuel Prices

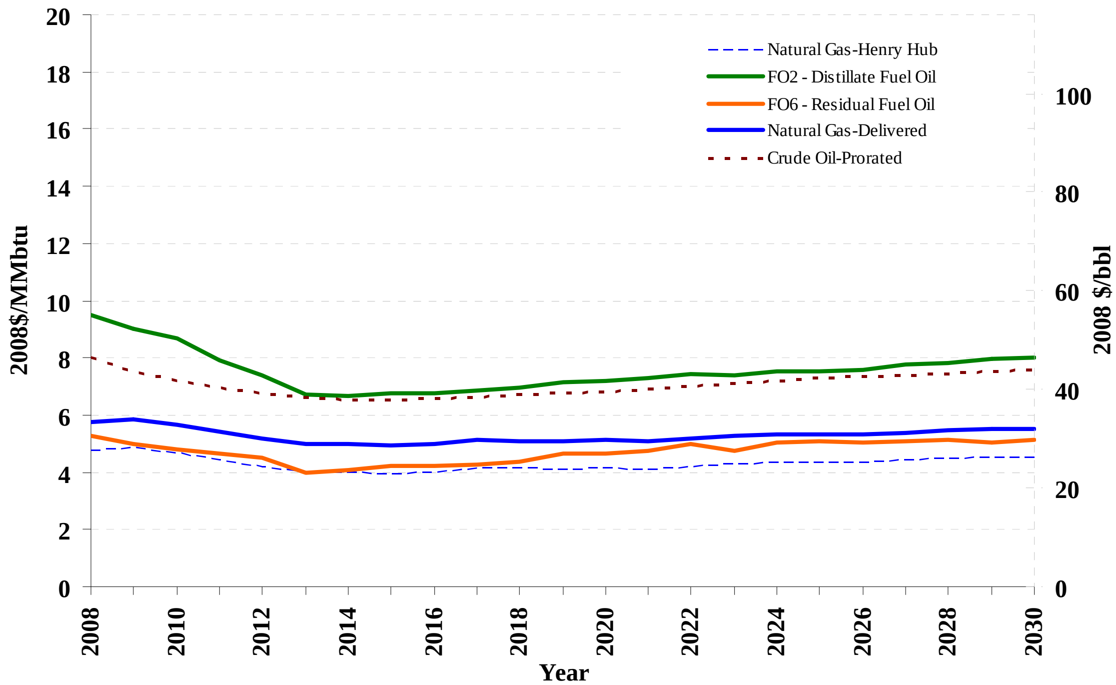


Figure B.5: Delivered Natural Gas Prices (All Scenarios)

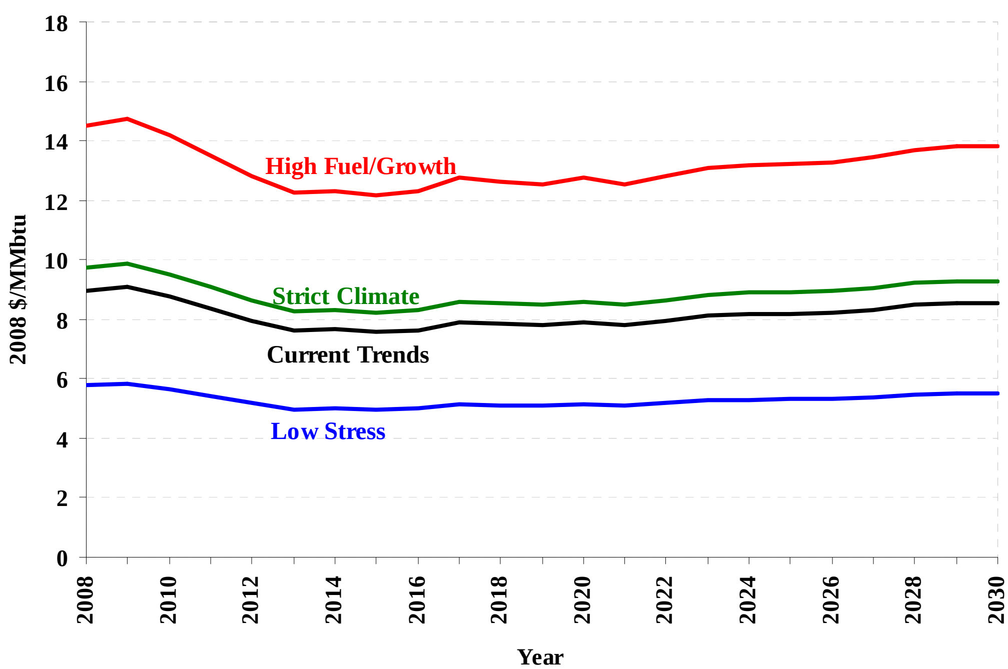


Figure B.6: CO_2 Allowance Prices (All Scenarios)

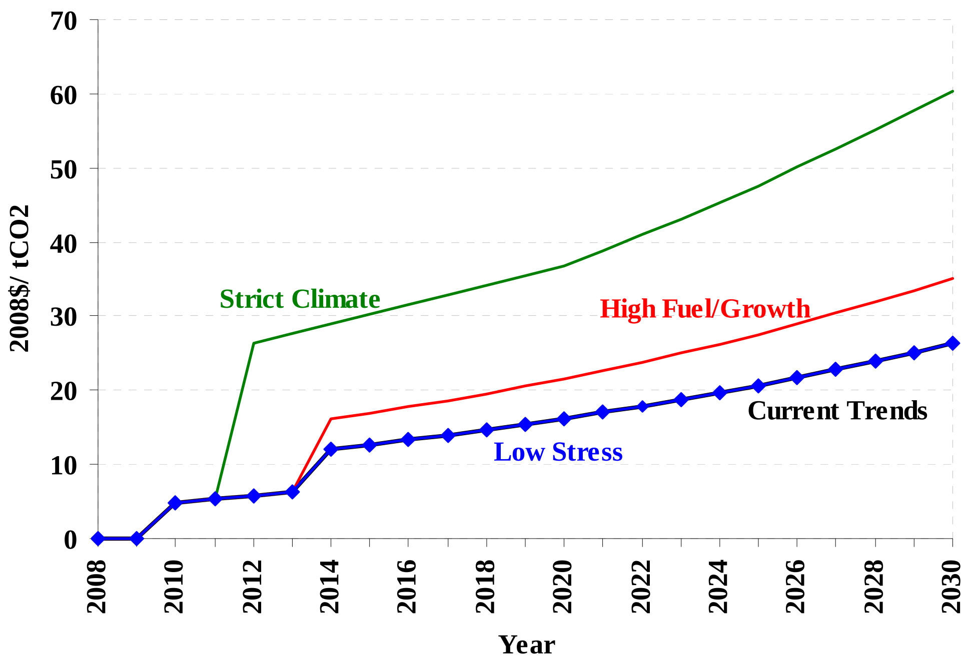


Figure B.7: Energy Profile (All Scenarios; Conventional and DSM-Focus Solutions)

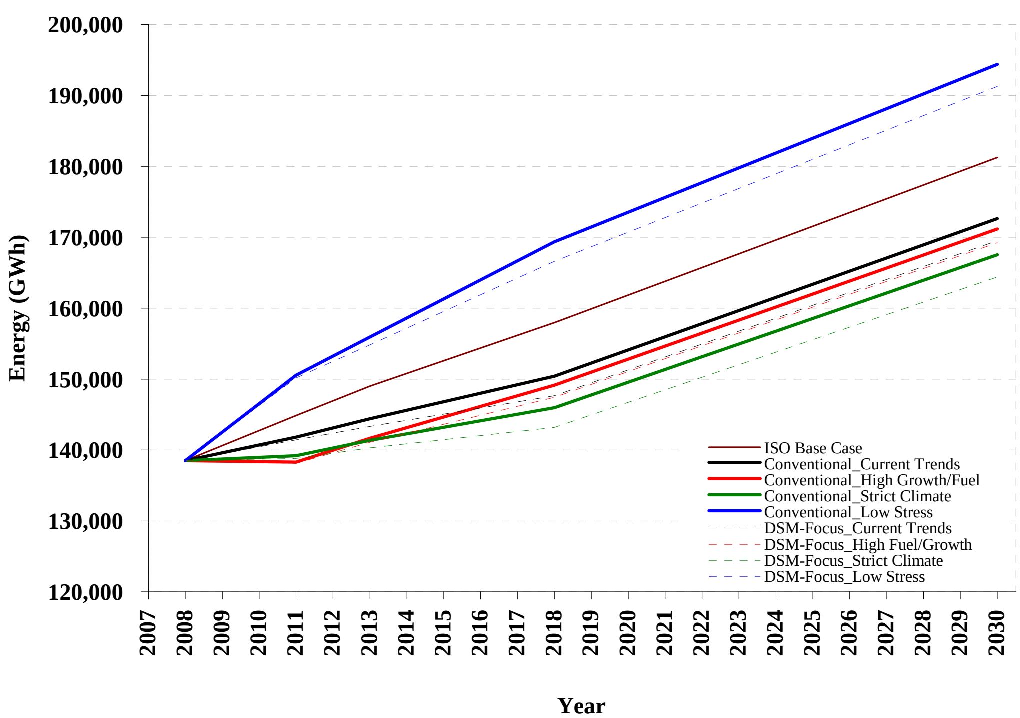
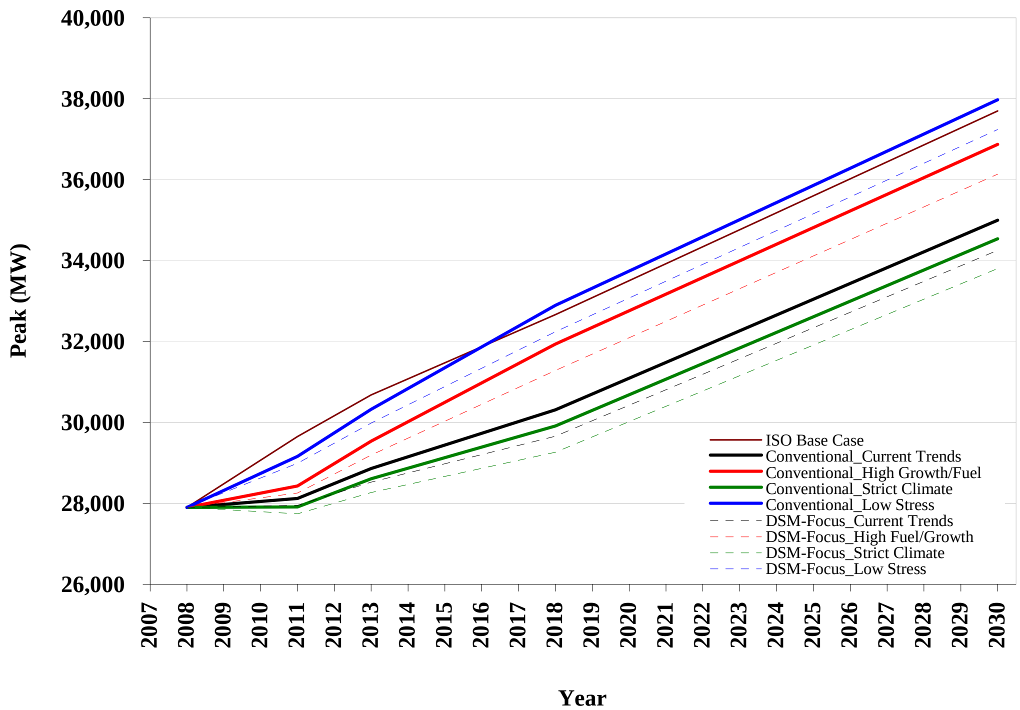


Figure B.8: Peak Profile (All Scenarios; Conventional and DSM-Focus Solutions)



APPENDIX C: GENERATION SUPPLY CHARACTERIZATION

I. CONVENTIONAL GAS-FIRED TECHNOLOGY

The characterization of conventional gas-fired generating technology – combustion turbines (CTs) and combined cycle generators (CCs) – is based on the review of numerous sources for the cost and performance of these technologies. This includes the testimony of John Reed on behalf of ISO-NE in the development of the ISO's locational capacity market. Mr. Reed performed a detailed assessment of the fixed costs of combustion turbine capacity installed at different locations on the ISO-NE grid; this locational cost information is particularly important in the context of the IRP. We updated Mr. Reed's assumptions to current values, supplemented variable operating cost information and adjusted for technological evolution over time.

Since combined cycle technology is very similar to combustion turbine technology, we used the CT costs described above as a basis for estimating combined cycle costs. Combined cycle installed costs were assumed to be 150% of CT installed costs, consistent with other sources (different construction schedules cause overnight costs to have a slightly different relationship). These costs were then adjusted for technological evolution over time. Combined cycle operating costs were also based on an adjustment to combustion turbine operating costs.

Table C.1 presents a high-level characterization of CT and CC technology cost and performance. The values in this table represent capacity located within Connecticut but outside Southwest Connecticut. Values for Southwest Connecticut and for other locations in New England were also developed and used for the simulation analyses. The cost parameters reflect the Current Trends scenario; in other scenarios these cost parameters take on different values.[1]

[1] Table C.1 shows heat rates of 6,508 and 9241 Btu/kWh for CCs and CTs, respectively, which reflect full-load heat rates at ideal conditions. Heat rates of 7,000 and 10,200 Btu/kWh, respectively, were used in the simulation analyses. The simulation produces capacity factors that differ from the capacity factors shown in Table C.1 for screening purposes. (However, the cost parameters shown in Table C.1 were used in our analysis of capacity prices.)

Table C.1: Gas-Fired Generating Technology Characteristics (2015 Online Date)

Parameter	Units	Combustion Turbine	Combined Cycle
Overnight Cost	(2008$/kW)	598	869
Fixed O&M	(2008$/kWyr)	26.7	29.7
Variable O&M	(2008$/MWh)	3.2	1.4
Economic Life	(Years)	20	40
Capital Charge Rate	(%)	13.1%	10.7%
Fuel Type	(type)	Gas	Gas
Heat Rate	(Btu/kWh)	9,241	6,508
CO2 Emissions	(tons/MWh)	0.50	0.35
Assumed Capacity Factor	(%)	20%	85%

Notes: Costs reflect generation sited in Connecticut. Emissions are in metric tonnes.

II. BASELOAD GENERATION CHARACTERIZATION AND SCREENING

The Baseload Generation resource solution examines the addition of a significant amount of baseload generating capacity (i.e., capacity with high fixed cost but relatively low operating cost) within Connecticut. There are several candidate baseload generating technologies to consider, including nuclear and several versions of coal-fired generators. The question of which of these potential baseload technologies to consider is addressed first with a screening analysis, which calculates the all-in cost (the levelized lifecycle cost) of the different technologies.

A number of data sources were considered for the capital and operating costs and performance parameters of several potential baseload technologies, including:

- Pulverized coal (supercritical)
- Pulverized coal with carbon capture and sequestration (CCS)
- Integrated gasification combined cycle (IGCC)
- IGCC with CCS
- Advanced Nuclear

Estimating the cost and performance of generating technologies is complicated by the fact that the industry has little or no recent experience building many of the potential technologies (*e.g.*, advanced nuclear, carbon sequestration). Further, even conventional technologies have experienced major increases in capital costs in the past several years, making it difficult to estimate costs even for well-understood technologies. In addition, regional cost differences mean that a generic technology cost comparison may not be appropriate for Connecticut. For example, the cost of building new generation in Connecticut is significantly above U.S. average construction costs, as are delivered fuel costs and O&M costs.

Many of the cost assumptions for this analysis are based on the recent study by the National Energy Technology Laboratory (NETL) on fossil generation costs, though numerous other sources were also reviewed, including EIA technology projections, MIT's Future of Coal and Future of Nuclear studies, ISO New England’s recent Scenario Analysis study, and others. Because the NETL study is recent, thorough and done consistently across most of the relevant technologies, it is a useful source here. Capital costs were increased to account for recent cost increases, and further adjusted to reflect regional cost differences for Connecticut. Similarly, operating costs are adjusted to reflect a Connecticut location. Fuel and emissions costs used in the screening analysis are based on levelized equivalents to the fuel and emission cost trajectories from the four scenarios. All-in costs are evaluated at 85% capacity factor for all fossil technologies, and 90% for nuclear. Although different technologies might have capacity factors that differ slightly from these assumptions, the differences would be modest on the New England grid, and subsequent sensitivity analyses showed that the conclusions of the screening analysis would not change in light of this.

Table C.2 presents a high-level characterization of cost and performance parameters for baseload technologies located within Connecticut, outside Southwest Connecticut. Again, these cost parameters reflect the Current Trends scenario; they take on different values in other scenarios. To facilitate a high-level comparison, we also include here the parameters of a gas-fired combined cycle plant, both with and without CCS.

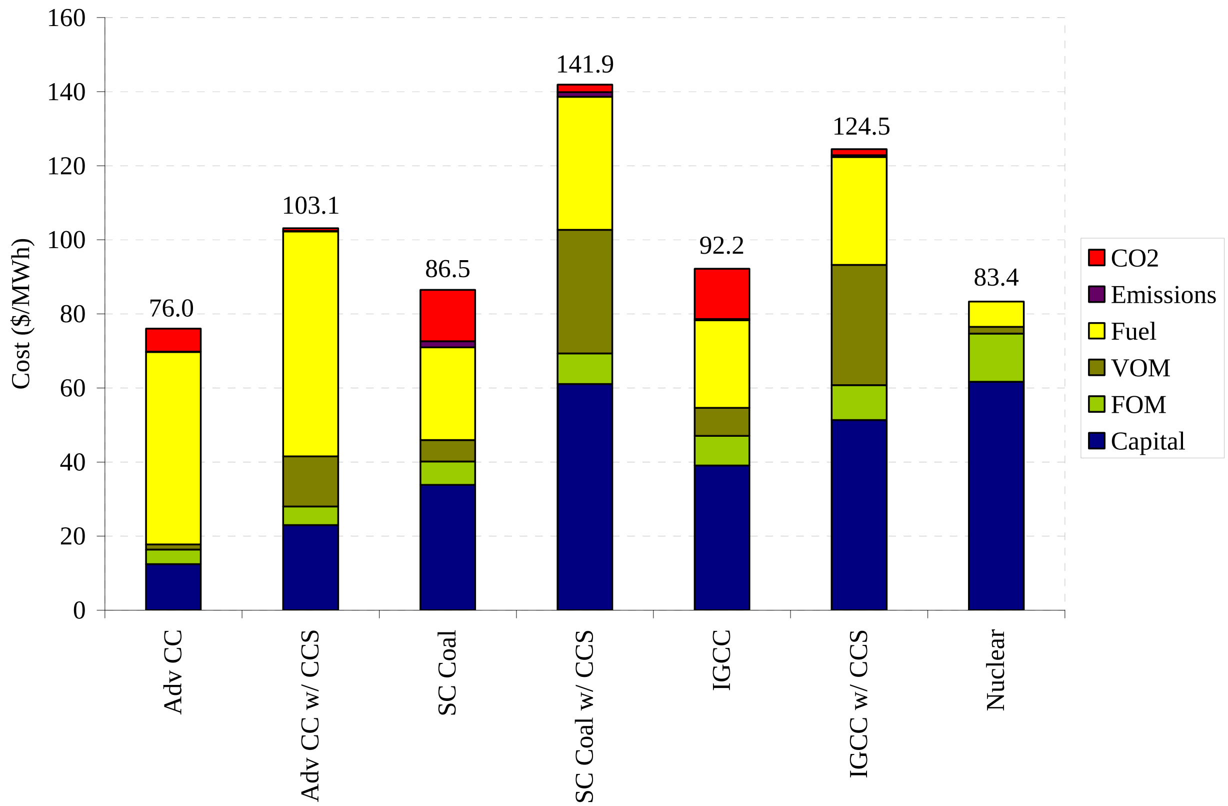
Table C.2: Baseload Generating Technology Characteristics (2015 Online Date)

Parameter	Units	Combined Cycle	Combined Cycle w/ CCS	Supercritical Coal	Supercritical Coal w/ CCS	IGCC	IGCC w/ CCS	Advanced Nuclear
Overnight Cost	(2008$/kW)	869	1,558	2,214	4,037	2,567	3,387	4,038
Fixed O&M	(2008$/kWyr)	29.7	37.1	47.3	62.0	59.2	70.3	102.9
Variable O&M	(2008$/MWh)	1.4	13.6	5.8	33.4	7.6	32.5	1.8
Economic Life	(Years)	40	40	40	40	40	40	40
Capital Charge Rate	(%)	10.7%	10.7%	11.1%	11.1%	11.1%	11.1%	11.9%
Fuel Type	(type)	Gas	Gas	Coal	Coal	Coal	Coal	Nuclear
Heat Rate	(Btu/kWh)	6,508	7,609	8,620	12,367	8,144	10,039	10,280
CO2 Emissions	(tons/MWh)	0.35	0.04	0.79	0.11	0.78	0.10	0.00
Assumed Capacity Factor	(%)	85%	85%	85%	85%	85%	85%	90%

Notes: Costs reflect generation sited in Connecticut. Emissions are in metric tonnes. CCS is carbon capture and sequestration. Technologies with CCS assume offshore sequestration.

Figure C.1 below illustrates the result of the initial all-in cost analysis, using cost and price parameters (construction and O&M costs, as well as emissions prices and CO_2 price) that reflect the environment of the Current Trends scenario. To facilitate an approximate high-level comparison in the screening analysis, we included a gas-fired CC, both with and without CCS. Note that a screening analysis like this may not account accurately for system interactions, so the comparison with a gas CC may be incomplete. For a proper comparison of gas-fired versus baseload capacity, a system simulation is necessary; this was done in the simulation analyses comparing the Conventional vs. Baseload resource solutions.

Figure C.1: Levelized Electricity Cost for Baseload Technologies (Current Trends parameters)



The same technologies can be evaluated against the parameters that reflect each of the other scenarios as well, as is illustrated in Figure C.2. The different scenarios have different fuel and CO_2 prices, as well as different technology costs, and all these differences may affect the comparison. Figure C.3 following shows the same information as Figure C.2, but groups results by scenario rather than by technology, which makes some effects easier to observe.

Figure C.2: Levelized Electricity Cost for Baseload Technologies (All Scenarios) – by Technology

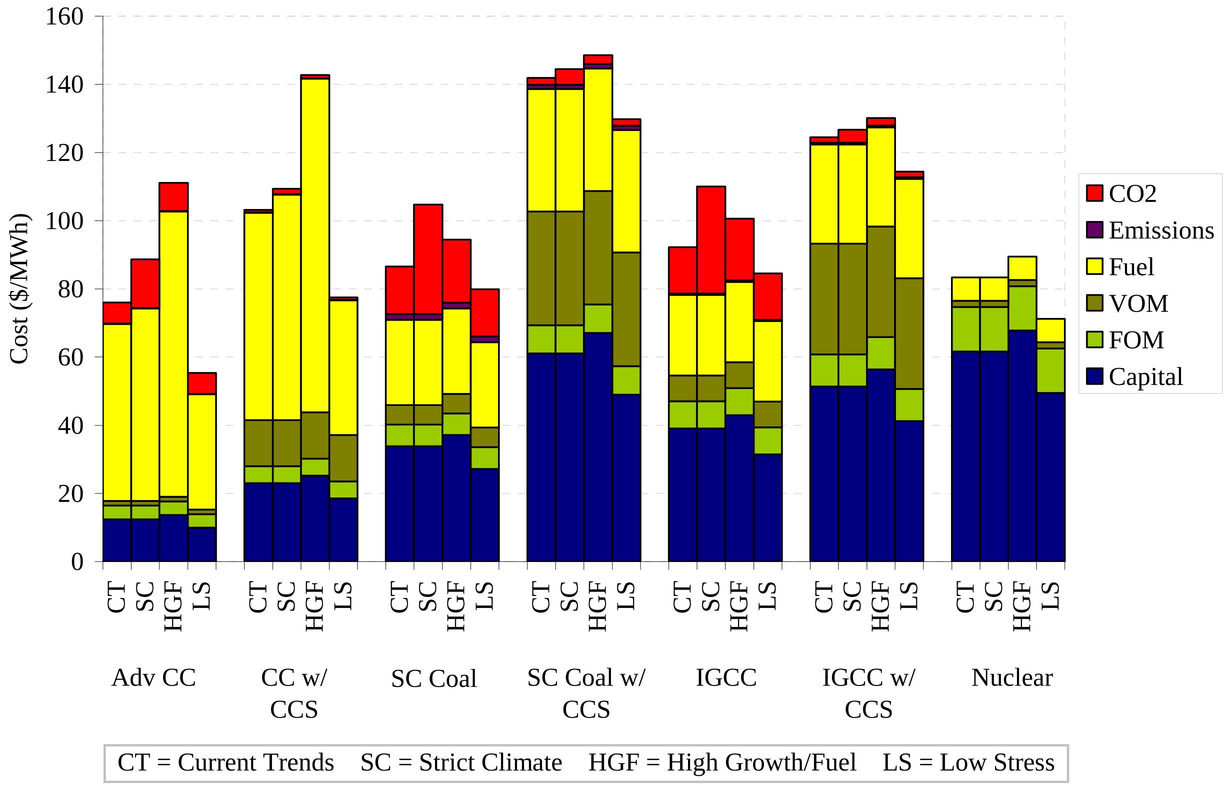
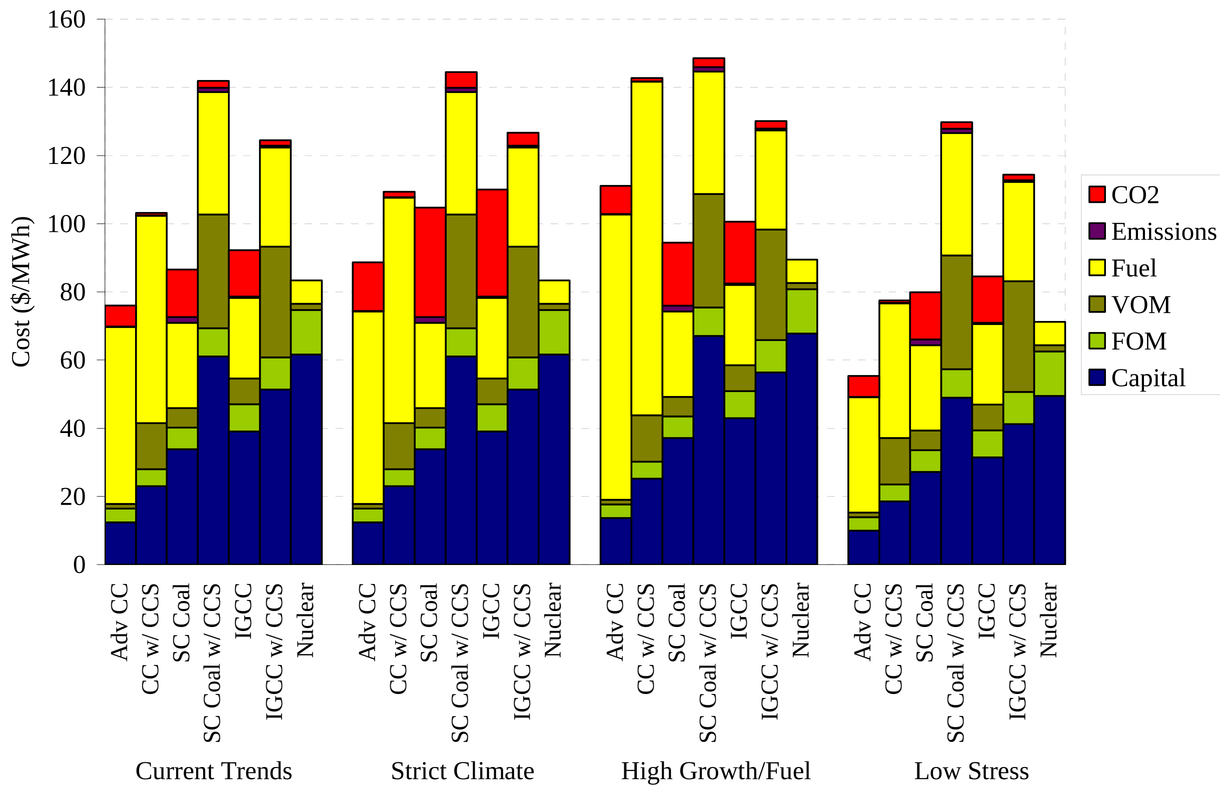


Figure C.3: Levelized Electricity Cost for Baseload Technologies (All Scenarios) – by Scenario



<u>Discussion of Screening Results</u>

The results illustrated above display several effects. First, compare the various coal technologies - supercritical coal and IGCC with and without CCS. The screening results suggest that it would make most sense to consider either a supercritical coal plant without CCS, or IGCC with CCS, but not the alternative combinations (SC Coal w/ CCS or IGCC without CCS). Figure C.1 shows that SC Coal is less costly than IGCC without CCS, but IGCC w/ CCS is less costly than SC Coal w/ CCS. That is, by itself, SC Coal is the more economical technology, but the incremental costs of CCS are larger on SC coal so that the economics reverse with CCS. This same observation applies in the other scenarios in Figures C.2 and C.3; the primary factors that change across scenarios are capital costs and CO_2 emissions costs, and these do not alter the relationships above. We did not explicitly analyze here the option to add CCS to a coal plant originally developed without it (what is sometimes referred to as a “capture ready” plant). Other analyses suggest that this option is unlikely to be attractive, in part because an IGCC plant must be configured differently to operate with CCS, so that adding CCS after the fact is much more costly.

The screening analysis suggests coal with carbon sequestration is unlikely to be a viable option in New England. I.e., SC Coal is more attractive than IGCC w/ CCS. This is in part because it appears that New England does not have favorable geology for carbon sequestration. This makes it necessary to do offshore (undersea) sequestration with attendant higher transportation, storage and monitoring costs. These additional costs appear as components of Variable O&M (VOM) in the graphs above. Even if lower-cost onshore CCS was feasible, CCS would likely still be unattractive in Connecticut. New England has higher regional construction costs and higher coal prices than other regions. Higher construction costs disadvantage capital-intensive technologies like IGCC w/ CCS, and combined with higher coal costs, make it more difficult to compete with gas-fired technologies. It could well be that under strict climate legislation, IGCC w/ CCS becomes economical in many regions of the country, but not in New England. Under federal climate legislation, CO_2 prices would be uniform nationwide, but higher Connecticut capital costs would still tip the economic balance away from a capital-intensive technology that sequesters carbon to avoid its price. Higher coal prices and higher sequestration costs would reinforce this effect.

As an aside, we note that based on this screening analysis, adding CCS capability to a gas-fired combined cycle plant appears economically unattractive. Although the incremental capital costs associated with CCS are smaller than for coal, they are not justified by the savings in CO_2 emissions costs avoided (a conventional gas CC emits only about half as much CO_2 as a coal plant). The lower efficiency and higher operating costs of a CC with CCS further reinforces this effect.

This leaves the SC Coal and Nuclear options remaining as potentially attractive baseload generation options. There are substantial differences in the uncertainties that affect these two technologies. The economics of a coal plant are exposed to very uncertain, potentially high CO_2 costs. The economics of nuclear generation are subject to large capital cost uncertainties, further complicated by other factors not modeled explicitly here, but nonetheless important – potential siting difficulties, concerns about nuclear proliferation and spent fuel disposal, etc. While Figure C.2 above appears to show that nuclear involves less cost uncertainty, this is simply because the scenarios do not reflect the uncertainty in nuclear construction costs (since it does not interact with other scenario variables, this uncertainty can be considered separately).

Because this screening analysis does not show a clear preference for either SC Coal or Nuclear, we evaluate both as baseload alternatives in the simulation analyses. On the New England grid, where the large majority of capacity has much higher variable cost than either nuclear or coal, these two baseload technologies will operate in essentially the same way. This is in contrast with some other regions, where a coal plant may operate at a lower capacity factor because of large amounts of low-cost generation.

This screening analysis also suggests that gas-fired combined cycle technology is likely to be attractive, but since that is being considered as a separate resource strategy and modeled with full system simulations, we do not attempt to draw conclusions about the relative merits of gas-fired versus baseload technologies from this screening analysis.

III. RENEWABLE GENERATION CHARACTERIZATION

The discussion of renewable energy sources is contained in Appendix E: Renewable Energy.

IV. SOURCES

The following sources were reviewed in characterizing supply side generating technologies.

"Annual Energy Outlook 2007." Energy Information Administration. February, 2007. http://www.eia.doe.gov/oiaf/archive/aeo07/index.html.

"Bingaman/Specter Climate Change Bill." Sen. Bingaman, Jeff. July 11, 2007. http://energy.senate.gov/public/_files/END07842_xml1.pdf.

"Civil Works Construction Cost Index; March 30, 2007 Revision." US Army Corps of Engineers. March 30, 2007. http://www.usace.army.mil/publications/eng-manuals/em1110-2-1304/entire.pdf.

"Economic and Energy Impacts from Maryland's Potential Participation in the Regional Greenhouse Gas Initiative." Maryland Department of the Environment. January, 2007.

"The EIA Petroleum Navigator." Energy Information Administration. http://tonto.eia.doe.gov/dnav/pet/pet_sum_top.asp

"EPA Analysis of The Climate Stewardship and Innovation Act of 2007: S.280 in 110th Congress." U.S. Environmental Protection Agency. July 16, 2007. http://epa.gov/climatechange/downloads/s280fullbrief.pdf.

"Final Scenario Analysis Modeling Assumptions." ISO-New England. May 16, 2007. http://www.iso-ne.com/committees/comm_wkgrps/othr/sas/mtrls/may212007/final_sa_modeling_assumptions.pdf.

"Fossil Energy Cost and Performance Baseline Studies: Volume 1; August Revision." National Energy Technology Laboratory. August, 2007. http://www.netl.doe.gov/energy-analyses/baseline_studies.html.

"The Future of Coal: An Interdisciplinary MIT Study." Massachusetts Institute of Technology. 2007. http://web.mit.edu/coal/.

"The Future of Nuclear: An Interdisciplinary MIT Study." Massachusetts Institute of Technology. 2003. http://web.mit.edu/nuclearpower/.

"Gas Daily." Platts. http://www.platts.com/Natural%20Gas/Newsletters%20&%20Reports/Gas%20Daily/.

"Gross Domestic Product: Implicit Price Deflator." U.S. Department of Commerce: Bureau of Economic Analysis. October 10, 2007. http://research.stlouisfed.org/fred2/series/GDPDEF/.

"The Handy-Whitman Bulletin, No. 165." Whitman, Requardt & Associates, LLP.

"New England Electricity Scenario Analysis." ISO-New England. August 2, 2007. http://www.iso-ne.com/committees/comm_wkgrps/othr/sas/mtrls/elec_report/scenario_analysis_final.pdf

"Nymex Futures Prices." http://www.nymex.com/media/092707.pdf.

"Testimony in FERC Docket No. ER03-563-030." Ex. ISO-8. Reed, John. August 31, 2004.

APPENDIX D: DEMAND-SIDE MANAGEMENT RESOURCE SOLUTION

I. INTRODUCTION

This Appendix describes the demand-side management (DSM)-focused resource solution for Connecticut, based on an evaluation of DSM conducted by *The Brattle Group* with substantial involvement by the Companies. This resource solution builds on work that the Companies have been carrying out over the past several years in collaboration with the Department of Public Utilities Control (DPUC), the Energy Conservation Management Board (ECMB) and other stakeholders. This resource solution envisions a significant increase in spending on DSM programs, with the objective of eliminating substantially all load growth over the next decade.

These goals incorporate the ECMB's Vision Statement to assist Connecticut's businesses to embrace energy efficiency and load management as an integral part of their business operation. The assessment contained in this section builds on work contained in prior documents:

- *Independent Assessment of Conservation and Energy Efficiency Potential for Connecticut and the Southwestern Connecticut Region*, Final Report for the Connecticut ECMB, GDS Associates, Inc. and Quantum Consulting, June 2004
- *New England Electricity Scenario Analysis*, ISO New England Inc., August 2, 2007
- *Conservation and Load Management Portfolio Plan*, Docket 06-10-02, Scenario 2 (Zero load growth) Supplemental Filing with the DPUC, The Companies, January 31, 2007

II. CONSERVATION AND ENERGY EFFICIENCY POTENTIAL

The energy efficiency potential study issued in 2004 identified the maximum achievable cost-effective potential for energy conservation and peak demand reduction associated with some 300 energy efficiency measures. The study built on research findings from over 200 other studies. It did not evaluate the potential for demand response measures. It found that 13% of energy consumption (4,466 GWh) and 13% of peak demand (908 MW) could be cost-effectively saved in Connecticut through commercially-available energy efficiency measures over a ten year period from 2003 through 2012. The estimate assumes that all measures that pass the Total Resource Cost (TRC) test are implemented for the maximum number of customers that can be recruited through a concerted and sustained campaign involving highly aggressive program designs and delivery channels. Based on the study, if these savings were achieved, they would eliminate load growth in Connecticut out to 2012.

Although this study is a few years old, and there have been changes in the underlying assumptions for costs and savings, it is the most current estimate of the available potential in Connecticut. The ECMB, as required by statute, is in the process of initiating a more current effort that can be used to update future IRP efforts.

We estimate that approximately one-third of the savings from the 2004 Potential study has already been captured through changes in codes and standards and/or conservation efforts since its completion, leaving about 600 MW still available. At the same time, energy prices and avoided costs have increased substantially since 2004, which should raise the cost-effectiveness of other measures that otherwise were not found cost-effective in the 2004 study. Considering both of these effects, we expect that the increase in avoided costs since 2004 should more than offset the already-realized energy savings identified in the 2004 Potential Study. The Companies' ten year estimate of energy efficiency potential is 952 MW, which is approximately 5% higher than the 908 MW from the 2004 study and approximately 50% higher than the estimated remaining potential from the 2004 study.

We compared this estimate of achievable conservation to potential studies that have recently been completed in other areas of the country, including Vermont, Michigan, and California. Based on a review of those studies, the 952 MW estimate of maximum achievable energy efficiency potential appears reasonable. However, there remains some degree of uncertainty surrounding this estimate. The ECMB will be updating the 2004 Potential Study in 2008. Results from this effort may determine that DSM potential is even greater than currently anticipated. The Companies will utilize this updated study to refine and revise the estimates of maximum achievable cost effective savings.

III. New England Electricity Scenario Analysis

ISO New England undertook an eight-month long assessment of the future energy needs of the New England region. The assessment was carried out through an open process involving one hundred stakeholders. It yielded seven scenarios of the economic, reliability and environmental impacts of various demand-side and supply-side technologies on the New England power system that serves the needs of its 14 million inhabitants.

One of these scenarios involved an intense focus on energy efficiency and demand response measures. Called Scenario 2, its portfolio of demand-side resources was divided evenly between energy efficiency and demand response measures. In the aggregate, the scenario incorporated a significant investment in demand-side resources of some 5,400 MW in New England.

Results from this scenario and the study of potential savings have been used to develop estimates of the potential size of the DSM resource in Connecticut.

IV. Conservation & Load Management Scenario II Plan

The Companies developed a high level multi-year plan for achieving zero peak demand growth in the state by 2010, equivalent to a 140 MW reduction in peak demand. The plan assumed that funding constraints on several core DSM programs would be removed and those programs would be ramped up to substantially higher funding levels. The plan cited a recommendation made to the state's General Assembly by the Connecticut Academy of Science and Engineering which said, in part, "The state should adopt the principle that energy resource needs will first be met through all available energy efficiency and demand reduction resources that are cost effective, reliable and feasible" – the precise language adopted in PA 07-242 Section 51(c).

The plan intended to achieve its aggressive goals by "aiming higher/going deeper," i.e., striving for the highest efficiency levels that are cost-effective. In addition, it sought to accelerate the replacement of older inefficient systems before the end of their useful lives. Another feature was integrated program design and delivery, i.e., integration of electric and gas programs and the initiation of one-stop shopping for all DSM programs. Finally, the plan involved integration with other state-wide initiatives, such as the Climate Change Action Plan and the Governor's Energy Vision.

V. PROGRAM OPERATION

The current portfolio of programs offered by the Companies under the direction of the ECMB provides a solid foundation on which to build upon for the future. Despite this existing structure, a ramp-up period will be required to achieve a higher level of program operation. This ramp-up period would allow the expansion of vendor staff that is currently available and an increase in the number of vendors available to the program administrators. The DSM Focus resource solution envisions a ramp-up period of approximately 3 years before the programs could move to the next level of saving. It is expected that the programs will peak around 2014 and decline steadily out to 2018. The decline in program activity is due to anticipated changes in codes and standards as well as market transformation. For instance, if incandescent bulb conversions to Compact Fluorescent Lamps (CFLS) were no longer considered as an energy efficiency measure due to a code change, the potential DSM savings from residential programs would be significantly reduced (although energy savings would still result). Similarly, as an energy efficiency program matures, the high efficient equipment tends to become the baseline due to market transformation.

a. Residential DSM Programs

The key residential DSM programs designed to meet the aggressive goals are summarized below. Some of the offerings are based on the development of certain technologies within the next few years. For instance, light-emitting diode (LED) technology has developed rapidly in recent years to the point where it is an emerging (yet relatively expensive) option for residential usage. There is little doubt that LED is the lighting form of the future. However, its current use in the residential setting is still very limited and significant further development is necessary before it will go "mainstream" and become a significant program offering.

This LED example illustrates the technical challenges encountered when constructing a 10-year program expansion resource solution. Given the uncertainty of future technologies and of the regulatory and political framework that the Companies work in, the following program descriptions should not be considered absolute, but rather, reasonable projections of an uncertain future based on the Companies experience and knowledge of DSM Program design. The following program summaries are high level descriptions of the Companies' "core" programs, i.e. programs that result in direct energy savings. Educational programs and offerings are not included below. By design, the Program descriptions do not provide the same level of detail that is found in the Companies annual C&LM Plan. The Companies fully anticipate that these programs will be refined and enhanced on an annual basis over the course of the next ten years as new technologies and markets are developed. These updates and additional detail will be provided in future annual C&LM plans.

Retail Products – This program mainly comprises of efficient lighting equipment, including LED technology, and high efficiency appliances. It is anticipated that compact fluorescent lamps (CFLs), which provide the bulk of current program savings, will become the norm a few years out in the future, due to changes in legislation and codes/standards changes and due to market transformation. It is expected that new technologies and initiatives will evolve such that they will mitigate to some degree the sizeable loss in savings that will accrue when CFL savings are no longer applicable. In addition, other initiatives such as energy efficient electronics will be considered for this program as those technologies become available.

Home Energy Solutions (HES) – This program has three components: 1) An in-home services program; 2) an HVAC component consisting of installation of high efficiency HVAC equipment and HVAC quality installation including ground source heat pumps; and 3) installation of high efficiency heat pumps (based on a pilot program) for customers with electric heat. Among the offerings of the In-Home HES program are comprehensive auditing of air sealing, duct sealing and direct installation of measures, early retirement of older appliances, customized energy conservation strategies for customers (including time-of-use rates), renewable options and loan and financing options. The three natural gas companies in Connecticut provide for the gas measures associated with the program. The HVAC component consists of rebates for high efficiency central air conditioning (and heat pump) systems for systems that pass performance testing. In addition, there are ground source heat pump incentives that are based on actual tested performance of the units. Finally, the Companies are currently conducting a pilot program through HES to test the feasibility of using high efficiency ductless heat pumps to help residential customers who have electric resistance heat. The results of this pilot program (which are expected in 2008) will likely lead to some type of high-efficiency heat pump offering.

New Homes – The goal of this program is to minimize peak load growth associated with new residential construction. Currently, Program offerings include incentives for the installation of high performance insulation, high efficiency equipment, energy efficient lighting, and successful performance testing of homes *e.g.*, blower door testing and duct blasting. The Program offers Energy Star certification for qualifying homes and leverages the federal tax credits that are currently available. Since residential cooling is a significant driver behind peak load growth, the Companies will work on minimizing the impact of cooling on peak demand within the New Homes Program. Going forward, the Program will move towards Green Building and Zero "Peak" Energy options. By collaborating with the Connecticut Clean Energy Fund, the Program offerings may include installations of photovoltaic systems, as well as solar thermal water heater options. In conjunction with this program, the Companies will work with local building officials to help increase awareness of energy issues in residential construction and to assist building officials with the enforcement of energy related building codes.

Water Heating – This program will target all cost effective water heating solutions to residential customers with high hot water loads and is not expected to start until 2013. It is at this point that the Companies are estimating that the next generation of viable electric (i.e. heat pump) water heating technologies will be fully developed and commercially available.

Low Income Program – Both UI and CL&P offer a Low Income Program to their customers that are at or below 60% of state median income level. Both the UI Program ("UI Helps") and the CL&P Program ("WRAP") are in-home services programs that offer full weatherization, replacement of less efficient appliances, installation of water saving measures, and energy efficient lighting upgrades. Both UI and CL&P have agreements with most of the local Community Action Agencies in their territories and utilize those relationships to identify clients and to "piggy-back" available services and offerings to customers.

Direct Load Control Program – The Direct Load Control Program will target homes (and small businesses) with central air conditioning systems. The goal of the program will be to reduce summer peak loads by remotely cycling the compressors in central air conditioning systems. In addition, the application of direct load control technology to other end-uses such as water heating and pool pumps will be investigated. This program may be offered in conjunction with the Home Energy Solutions Program and the New Homes Program to offer customer a complete package of energy savings and peak reducing measures. In addition, program design will compliment the future deployment of advanced metering infrastructure (AMI) meters and time-of-use rates.

The following tables illustrate the ramp-up of Residential DSM programs from 2009 through 2018.

Table D.1: Residential DSM Programs: 3, 5, and 10-Year Plans

Program Strategy	**3 Year Plan – 2011**	**5 Year Plan > 2013**	**10 Year Plan > 2018**
Retail Products	• 2008 transition year • Fully in effect by 2009 • Maximize CFL's • Increase appliance portfolio	• Achieve near complete saturation of CFL's • Developing new technology including high efficiency appliances, LED lighting and electronics.	• CFL's no longer available or drastically reduced. • New high efficient appliances and LED lighting main focus of program.
Home Energy Solutions	• 2009 – first year of ramp-up. Begin the development of infrastructure of home performance technicians	• Significant participation • New technology implemented • Migration towards a market based program,	• CFL's no longer available or drastically reduced. • New high efficient appliances and equipment, home performance, and lighting main focus of program
New Homes	• 2009 – first year of ramp-up • Coordinate with CT Clean Energy Fund to offer renewable options.	• New technology implemented • Code Support • Core focus of green building, zero "peak" energy, and renewable features	• High penetration of Zero "Peak" Energy, Green homes.
Water Heating	• 2009 – first year of ramp-up	• New technology implemented	• New technology fully developed and market transformed
Low Income	• 2009 – first year of ramp-up	• Significant Participation • Higher efficient equipment being utilized	• High saturation
Direct Load Control	• 2008 transition year • Fully in effect by 2009	• Increased Participation and integration with AMI Meter deployment and TOU rates	• Significant participation and load reduction • Fully integrated with TOU rates

b. Commercial and Industrial DSM Programs

The key commercial and industrial DSM programs designed to meet the goals of this report are summarized below. As is the case with the Residential Programs, the C&I Program descriptions were challenging in nature because of the long time frame involved and the large uncertainties regarding the development of technologies and markets, the ability to ramp up programs, and the long planning horizon.

High Performance Core Connecticut Energy Efficiency Fund (CEEF) Programs – Within this category are the Energy Conscious Blueprint, Energy Opportunities and Small Business Energy Advantage programs which have been expanded from current efforts.

Energy Conscious Blueprint - The Energy Conscious Blueprint program is a lost opportunity program which assists building/facilities to achieve 30-50% energy savings beyond the Connecticut's building code. This program also integrates with other initiatives such as commercial lighting, green schools, etc. Outreach, training and educational efforts to achieve these goals also form a core part of the program.

Energy Opportunities - The goal of the Energy Opportunities program is to promote high performance equipment, designs, systems and process retrofits that result in energy efficiency of entire buildings. Incentives will also be provided to replace older, inefficient equipment such as chillers, old HVAC units etc. with high performing solutions.

Small Business Energy Advantage - The Small Business Energy Advantage program is designed for smaller facilities (under 200 kW) with the main goal of moving from narrow incremental retrofit efforts to comprehensive projects and measure bundles that include demand response capabilities.

Integrated O&M Strategy – The goal of this program is to integrate operational, maintenance and commissioning opportunities for buildings/facilities to integrate energy efficiency solutions into daily operations. Educational outreach and certification programs are also envisioned to be an integral part of this program effort.

Code Support and Code Commissioning – The goal of this program is to provide support for codes and standards compliance and an expanded effort to commission current and future codes and standards through CEEF C&I programs.

Energy Efficiency Infrastructure Development and Market Transformation Initiatives - In order to meet the aggressive demand side management goals set for Connecticut, support through educational efforts, training and professional development have to be an integral part of the portfolio. This is achieved through partnerships with educational institutions, trade and business associations and other market allies. These market transformation initiatives will strengthen strategic alliance with other utilities, government agencies and other key players to achieve broad market changes.

Business Energy Services – The goal of this program is to provide a holistic one-stop energy solution to businesses through integration of energy efficiency, load management, load response, direct load control, distributed generation, renewable energy systems, CHP and other initiatives to facilitate an effective use of CEEF and other C&I programs.

Business Energy Challenge – This program calls for businesses to make commitments to aggressive energy efficiency and load reduction goals by participating in a strategic planning effort that includes an executive-level assessment of business energy management practices, energy efficient capital improvement plan, and a commitment of adequate staffing and other resources. Participants in this program will be expected to implement all or most of the recommended measures that are cost effective from a life cycle costing perspective. In exchange for accepting this energy challenge businesses will receive a custom tailored package of the entire CEEF conservation and load management offerings into one cost-effective bundle, technical consulting services, and other support to necessary to make the transition.

Under-Utilized/Emerging Technologies, Designs and Practices – Efforts will be made to incorporate under-utilized and emerging technologies (such as daylighting design, ductless mini-split heat pumps, etc.) into C&I programs as deemed fit.

Load Response Program –This program is designed to promote customer enrollment in one of several ISO-NE-operated load response programs. CL&P and UI provide enrolling customers with the ISO-NE-required internet-based communications system. CL&P and UI also provide enrolling customers with a one-time set-up incentive to cover costs for data, phone, or metering connections. The program mandates load curtailments from customers who enroll and provides enhanced system reliability during peak system load conditions. The Price Response program helps to mitigate high Locational Marginal Prices throughout the year. Utilizing a current Department of Environmental Protection ("DEP") Permit, customers may run emergency generators to reduce load on the grid under emergency conditions. CL&P and UI provide direction on operating emergency generators in compliance with Connecticut air quality requirements during Demand Response events.

The following table illustrates the ramp-up of C&I DSM programs from 2009 through 2018.

Table D.2: Commercial & Industrial DSM Programs: 3, 5, and 10-Year Plans

Program Strategy	**3 Year Plan – 2011**	**5 Year Plan > 2013**	**10 Year Plan > 2018**
High Performance Core Programs (ECB, EO, SBEA)	• 2008 transition year • Fully in effect by 2009 • ECB = improved code compliance	• Continuously improving strategy • ECB supports next code upgrade	• Continuously improving strategy
Integrated O&M strategy	• 2008 development year • 2009 – first year of ramp-up • Pilot in 2009 w/ 10 businesses	• 3 year ramp-up, fully integrated into core programs	• Continuously improving • Market transformation
Code Support and "Commissioning"	• 2008-9 continue training and education • Participate in regional/national initiatives • Partial compliance	• Continued participation in regional/national codes and standards initiatives • Significantly Improve compliance	• Update strategy for the next generation of codes and standards • Near total compliance
Business Energy Services	• 2008 development year • 2009 – first year of ramp-up • Integration w/ load management • Partial participation rate	• 2 year ramp-up, fully integrated into core programs • Integration w/ load management • Partial participation rate	• Continuously improving strategy • Major driver of integrated energy efficiency and load management • Integration w/ load management • Significant participation rate
Business Energy Challenge	• 2008 – pilot project • 2009 – first year of ramp-up • 2009 = 4-6 companies	• 3 year ramp-up • Apply also to small-medium sized businesses • By 2011 – Several companies	• Major driver of market transformation • Significant company participation
Under-utilized & emerging technologies, practices and designs	• 2008 transition year, tech assessment • Update measure lists by 2009 • Savings factored into core programs	• Continuously incorporating new technologies/etc. • Savings factored into core programs	• Major driver of market transformation • Savings factored into core programs

c. Projected Savings in Energy Consumption and Peak Demand

The Companies provided *The Brattle Group* with the most recent (October 2007) data on their DSM plans. Based on review and discussion, two DSM cases were developed, a Reference Case (which is the basis for DSM assumptions in the other resource solutions) and the DSM – Focus resource solution, which includes the program expansions. The following are net estimates of direct program savings and do not include the long term market impacts that may be associated with programs; changes in codes and standards that may be influenced by programs; or naturally occurring conservation that would have occurred in absence of the programs.

- Reference Case: This includes all DSM programs, both EE and DR, that were relatively certain of approval and funding
- DSM Focus Resource Solution: This extends the Reference Case DSM programs in several directions, assuming that the state's policy makers would find it in the public interest to pursue additional cost-effective DSM. It was also assumed that the DPUC would order and specify funding sources for this expanded effort.

The Companies provided end-of-year estimates of savings from their energy efficiency and demand response programs and the corresponding budgets for those programs and indicated that one-third of savings were realized in the current year and two-thirds savings were realized in the following year. In other words, one-thirds of the savings are from that year's programs and two-thirds from the previous the year's programs. The following tables and figures summarize the demand and energy savings and budgets that correspond with the DSM programs discussed above.

Table D.3: Reference Level DSM MW Savings

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
UI EE	10	13	23	35	48	61	74	86	98	110	123	137
UI DR	18	39	82	83	84	84	85	86	87	87	88	89
CL&P EE	36	47	83	124	165	206	246	281	308	335	362	390
CL&P DR	326	358	420	411	411	411	411	411	411	411	411	411
Total (UI + CL&P)	389	457	608	653	707	762	816	863	904	944	985	1,026

Figure D.1: Reference Level DSM MW Savings

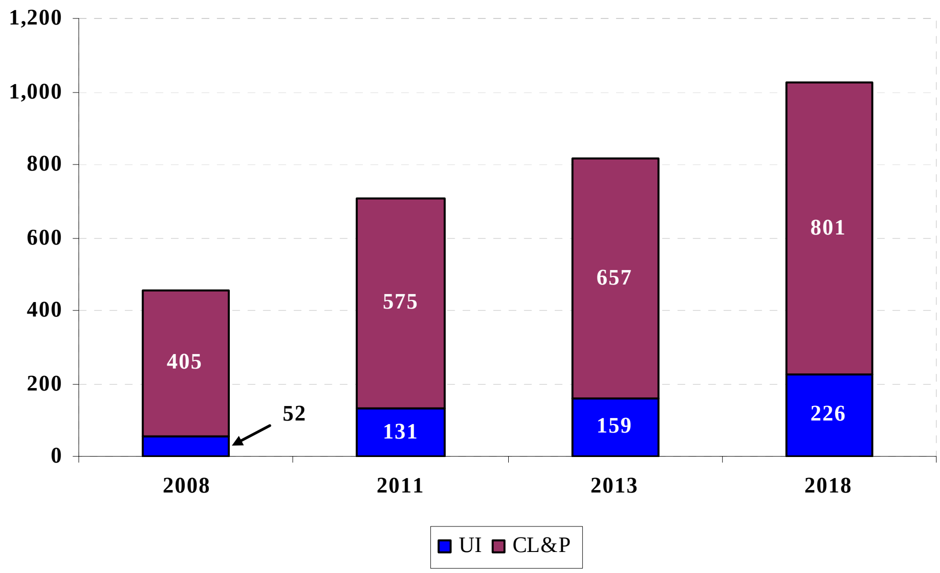
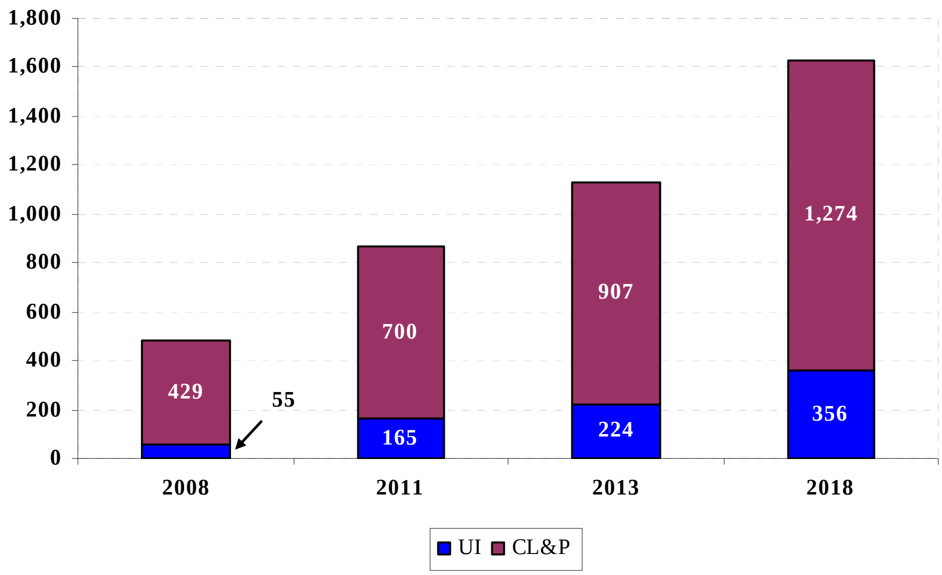


Table D.4: DSM-Focus Level DSM MW Savings

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
UI EE	10	13	24	38	57	81	107	131	157	182	208	234
UI DR	20	42	92	103	108	113	118	118	119	120	121	122
CL&P EE	36	50	96	154	224	308	401	501	594	668	723	768
CL&P DR	346	380	447	453	476	496	506	506	506	506	506	506
Total (UI + CL&P)	410	484	658	748	865	998	1,131	1,257	1,376	1,476	1,558	1,630

Figure D.2: DSM-Focus Level DSM MW Savings



In 2008, demand savings from the Base DSM programs constitutes about 6.1% reduction of system peak (most of this through DR) whereas the DSM Focus resource solution constitutes about 6.5% reduction of system peak. By 2018, demand savings from the Base DSM scenario constitutes about 12% reduction of system peak whereas DSM Focus resource solution constitutes about 19.1% reduction of system peak.[1] DSM efforts in the Base scenario lead to about 93% offset of load growth between 2008 and 2018. The next two tables show the energy savings from the DSM efforts.

[1] Beyond 2018 savings from EE and DR programs were assumed to grow at the same rate as Connecticut system peak.

Table D.6: Reference Level DSM GWh Savings

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
UI EE	54	72	131	198	269	343	412	467	524	582	642	704
UI DR	0	0	0	0	0	0	0	0	0	0	0	0
CL&P EE	194	256	455	678	898	1,123	1,343	1,531	1,680	1,824	1,969	2,117
CL&P DR	0	0	0	0	0	0	0	0	0	0	0	0
Total (UI + CL&P)	248	329	586	876	1,167	1,466	1,754	1,998	2,204	2,406	2,612	2,821

Figure D.3: Reference Level DSM GWh Savings

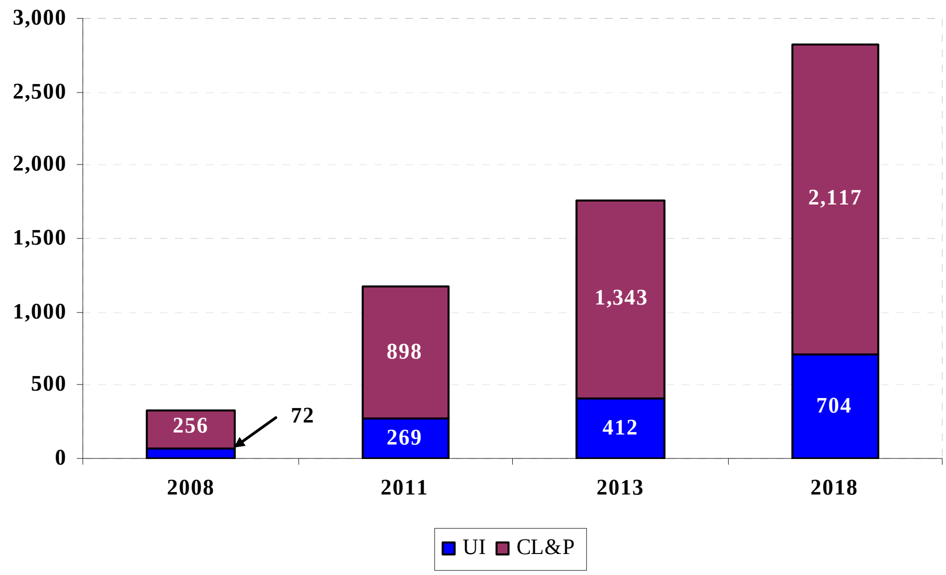
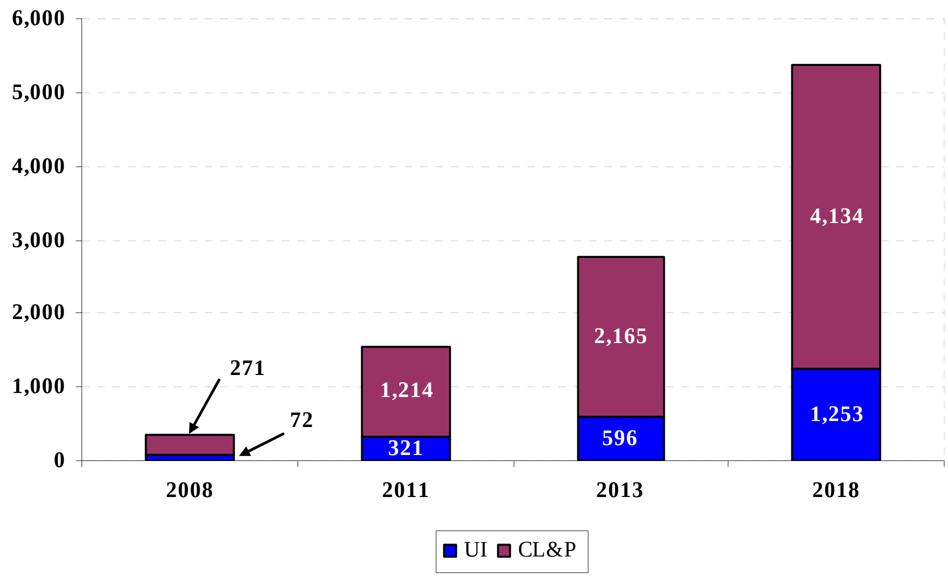


Table D.7: DSM-Focus Level DSM GWh Savings

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
UI Total	54	72	133	214	321	455	596	724	854	985	1,118	1,253
CL&P Total	194	271	521	832	1,214	1,663	2,165	2,702	3,203	3,597	3,892	4,134
Total (UI + CL&P)	248	344	654	1,046	1,536	2,117	2,761	3,426	4,057	4,582	5,010	5,387

Figure D.4: DSM-Focus Level DSM GWh Savings



The budgets corresponding to the above DSM programs are shown in the following tables.

Table D.8: Reference Level DSM Annual Budgets (Nominal $ Million)

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
UI EE	$17	$17	$19	$21	$23	$24	$25	$25	$26	$27	$28	$29
UI DR	$1	$2	$4	$4	$4	$4	$5	$5	$5	$5	$5	$5
CL&P EE	$68	$68	$71	$78	$81	$82	$83	$85	$86	$87	$88	$89
CL&P DR	$25	$24	$23	$23	$23	$23	$23	$23	$23	$23	$23	$23
Total (UI + CL&P)	$111	$112	$118	$128	$131	$134	$136	$138	$140	$142	$144	$146

Figure D.5: Reference Level DSM Annual Budgets (Nominal $ Million)

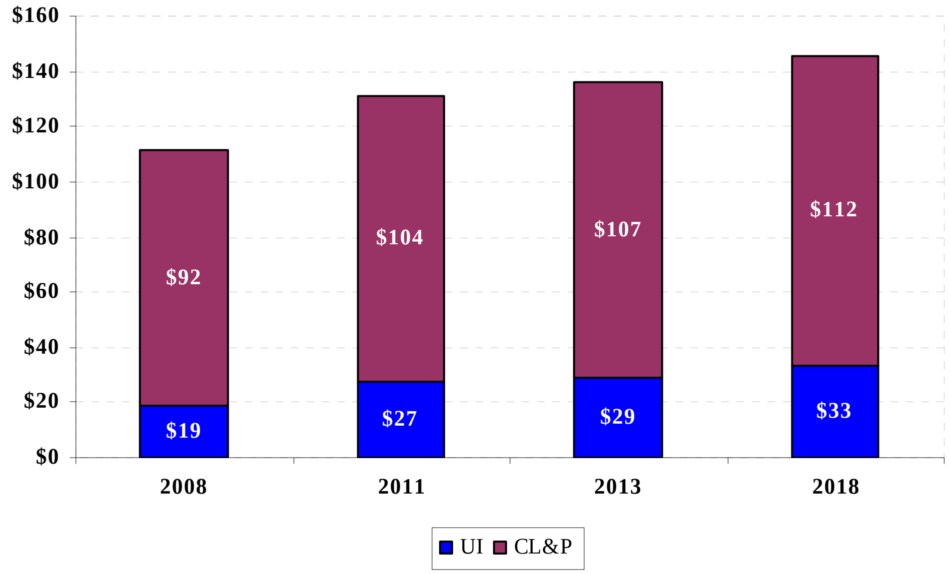
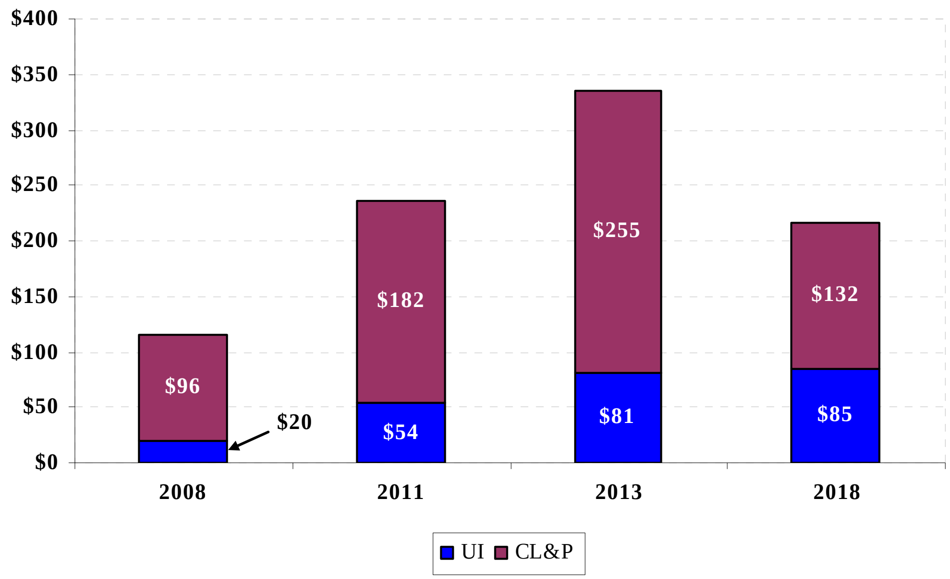


Table D.9: DSM-Focus Level DSM Annual Budgets (Nominal $ Million)

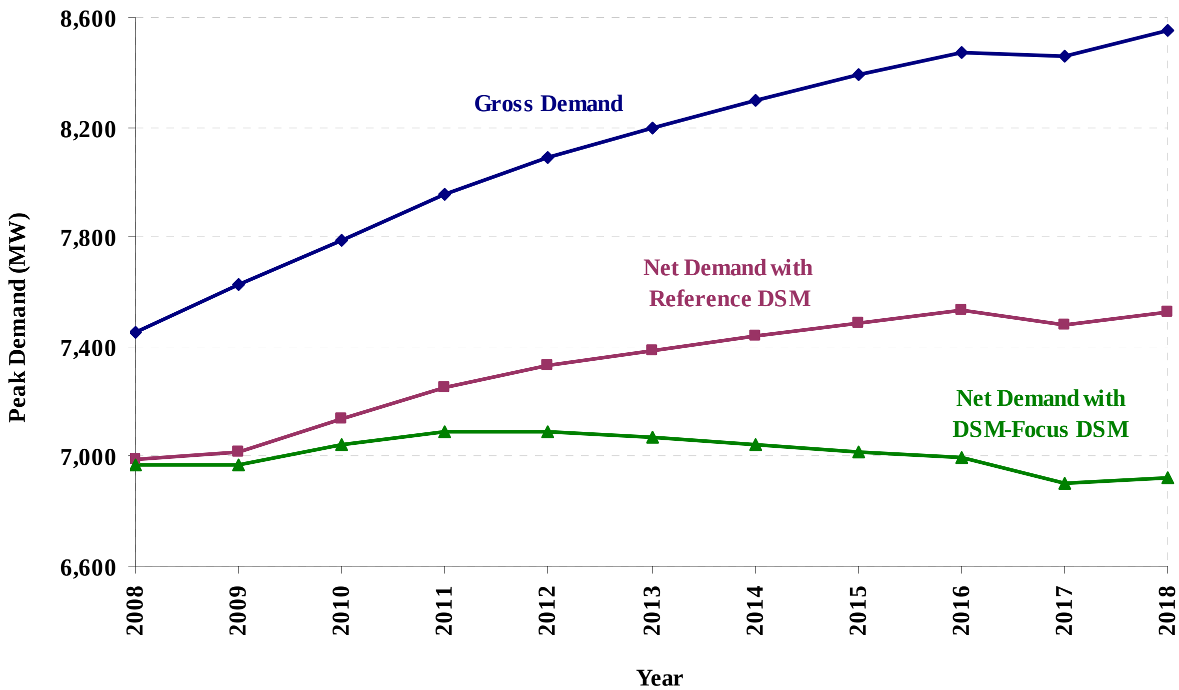
	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
UI Total	$18	$20	$26	$38	$54	$70	$81	$81	$82	$83	$84	$85
CL&P Total	$94	$96	$109	$140	$182	$226	$255	$270	$256	$206	$153	$132
Total (UI + CL&P)	$112	$116	$135	$177	$236	$296	$336	$352	$338	$289	$236	$216

Figure D.6: DSM-Focus Level DSM Annual Budgets (Nominal $ Million)



The next figure shows Connecticut peak demand under different scenarios.

Figure D.7: CT Peak Demand (MW) Forecast under Different DSM Scenarios



Source: 2007-2016 CT Peak Demand (MW) data from ISO-NE spreadsheet titled "isone_2007_forecast_data.xls." 2017-2018 CT Peak Demand (MW) data based on *The Brattle Group* extrapolation of hourly ISO-NE data. DSM data for the Reference and DSM-Focus cases provided by CL&P and UI.

VI. FUTURE DEVELOPMENTS

It is anticipated that a new study on the potential savings from new DSM programs will be carried out next year to update the estimate of potential DSM savings that was carried out in the 2004 report. The new study will be helpful in refining the Companies' 10 year DSM estimates and may help identify new technological developments and innovations in program and marketing. In addition, it may identify opportunities associated with demand response programs that were not covered in the previous effort. New technology developments have been anticipated, but evolving technologies may create new opportunities for savings. Advances in communication and metering technology may make program offerings possible that could not previously be envisioned. Finally, the new study may assess the likely impact of dynamic pricing programs which are not included in the current plan.

Another factor to keep in mind is that increasing amounts of savings will likely be achieved at increasing unit cost. There is ample evidence from the vast literature on DSM programs that the "supply curve" of savings is subject to the law of diminishing returns and exhibits an upward slope. Studies carried out in large states such as California and Florida suggest that budgets have to be raised substantially if the DSM strategy calls for achieving all cost effective potential. In reference cases, many analysts assume that utilities will have to provide incentives to customers in order to buy down the payback period to two years. This usually yields market penetration rates in the 15 to 25% range. In order to achieve the maximum achievable potential, which may range from 50 to 65% of the economic potential, the utility or other agency administering the DSM program has to cover one hundred percent of the customer's incremental cost. Even then, many customers would still not bother to sign up. The only way to achieve the entire economic potential is through more stringent codes and standards.

However, more stringent codes and standards will reduce the potential savings that can be achieved through utility DSM programs. In California, about half of the efficiency gain during the past three decades has come from the state's Title 20 and 24 standards for appliances and buildings respectively. As one looks at the future, the same is likely to be true. In addition, due to new legislation and changes in codes and standards in several states (and other nations such as Australia and the United Kingdom), no incandescent bulbs will be sold. This would eliminate savings from any utility programs that are directed at replacing incandescent bulbs with CFLs. While LEDs can be brought into the picture, to take the place of CFLs, on an absolute basis, the savings per bulb change out will be a lot lower.

VII. SOME KEY CONSIDERATIONS OF THE DSM SOLUTION INCLUDE:

- **Continued Funding of Reference Case DSM**

  Continued and consistent funding of DSM is crucial to Connecticut's ability to achieve the levels of capacity savings estimated in this IRP. An interruption or curtailment in funding can have negative impacts on the infrastructure (contractors, vendors, engineers, etc) needed to support the design, implementation and administration of DSM activities as well as have a negative impact on customer acceptance of DSM programs and initiatives.

- **This IRP is not a C&LM planning document**
  This document is not a C&LM planning document nor does it replace the rigor involved with planning and evaluating cost-effective measures and programs. Instead, the IRP document utilizes the approved programs and measures created during this planning process to develop the potential capacity resulting from Reference Case and increased levels of DSM activity.

- **The IRP is not a DSM potential study**
  The IRP utilizes the potential for DSM from the most recent achievable potential study and overlays the programs and measures that were developed during the C&LM planning process to obtain the quantity of DSM capacity estimated in this report. The achievable potential study is a study that is required to be updated by the ECMB in PA 07-242. The capacity estimate in future IRPs from DSM will be updated based upon new information from the updated potential study.

- **DSM ramp up is unprecedented**
  The IRP estimates a tripling of DSM activity in five years. The amount of achievable DSM is expected to be constrained by the physical resources necessary to design, install, and administer programs and initiatives. An increase in DSM activity will require changes in program design, additional engineer time for design of energy efficiency projects, additional contractor labor to construct and install projects, vendor support to supply the necessary energy efficient equipment, as well as skilled resources to administer and evaluate project installation and program performance.

APPENDIX E: RENEWABLE ENERGY

Renewable electric generation is a key aspect of utility resource planning in New England. Connecticut and other New England states have been in the forefront of a movement to require a certain percentage of renewable energy in the generation supply mix. However, the rapidly increasing renewable energy requirements in New England may exceed the near-term potential of renewable energy developers to produce the required amounts in the coming years. This has some important implications for resource costs and customer rates. Because of the importance of state, regional and federal policies in encouraging renewable energy development, this appendix begins with policy issues, then concludes with a discussion of availability and cost of renewable energy in Connecticut.

I. CONNECTICUT RENEWABLE PORTFOLIO STANDARD

Connecticut, like other New England states, has a renewable resource requirement that applies to load-serving entities. Under the Connecticut Renewable Portfolio Standard (RPS), a certain percentage of electricity sold at the retail level must come from renewable or otherwise eligible resources. The Connecticut RPS segments eligible resources into three classes:

- **Class I:** Wind, Solar Thermal, Photovoltaic, Wave, Tidal, Ocean Thermal, Landfill Gas, Low-emission Sustainable Biomass, Fuel Cells and certain Small (<5 MW) Hydroelectric
- **Class II:** Other Biomass, Small Hydroelectric, Municipal Solid Waste (MSW)
- **Class III:** Energy Efficiency Measures (instituted after January 1, 2006) and Combined Heat and Power (CHP)

The required percentage of retail load that must be served by each resource class escalates as follows:

Table E.1: Percentage Requirements under the Connecticut Renewable Portfolio Standard

Year	Class I	Class II	Class III
2007	3.5%	3.0%	1.0%
2008	5.0%	3.0%	2.0%
2009	6.0%	3.0%	3.0%
2010	7.0%	3.0%	4.0%
2011	8.0%	3.0%	4.0%
2012	9.0%	3.0%	4.0%
2013	10.0%	3.0%	4.0%
2014	11.0%	3.0%	4.0%
2015	12.5%	3.0%	4.0%
2016	14.0%	3.0%	4.0%
2017	15.5%	3.0%	4.0%
2018	17.0%	3.0%	4.0%
2019	19.5%	3.0%	4.0%
2020	20.0%	3.0%	4.0%

There are three basic ways that utilities can comply with the RPS requirement:

- A utility can purchase generation from eligible sources in Connecticut or in ISO-NE for physical delivery to Connecticut customers, bundled with the Renewable Energy Certificates (RECs) that the source generates (bundled compliance).
- A utility can purchase RECs from generators that can physically deliver eligible renewable electric power into ISO-NE, but who sell the renewable attribute separately from the energy produced (REC compliance).
- Utilities can "buy-through" the RPS compliance obligation by making a payment to the State (sometimes called an Alternative Compliance Payment or ACP) that is set at a constant $55/MWh. The funds are deposited in the Renewable Energy Investment Fund and used by the Connecticut Clean Energy Fund to promote Class I renewable energy projects in Connecticut.

II. PROJECT 100

In order to stimulate the development of Class I renewable resources (especially fuel cells manufactured in Connecticut), the Legislature has required that the Companies enter into long-term contracts with renewable developers for a total of 150 MW of Class I generating capacity. This initiative was initially called "Project 100" as it required 100 MW of Class I resources under contract by 2008. PA 07-242 expanded this requirement to 150 MW under contract by

2010. The DPUC approved a 15 MW biomass facility in the Project 100 Round 1 solicitation in 2006. The facility was originally due to begin operations on December 31, 2007; however, the operation date has been pushed back to May 2010 by the project developer. On December 21, 2007, the DPUC announced a Draft Decision in the Round 2 solicitation, conditionally approving 7 projects totaling about 109 MW (giving a total approved capacity of about 124 MW) and ordered the commencement of a Round 3 solicitation to obtain the remainder of the 150 MW requirement.[1]

Under these contracts, the Companies would retain the Class I RECs associated with the eligible generation, except in the case of fuel cells where the developer can keep 50% to 100% of the RECs. Thus, the contract prices will reflect the presumed avoided costs of acquiring RECs. However, none of the Round 2 approved projects are currently competitive even with REC prices at $25/MWh, although several biomass facilities may be roughly competitive if one assumes REC prices at $50/MWh, according to the analyses submitted to the DPUC. The three fuel cell projects approved (total of 16 MW), on the other hand, were not remotely competitive even with REC prices of $50/MWh.

The Round 2 solicitation suggests several observations regarding the prospects for renewable energy development in Connecticut. First of all, the lack of competitive projects with REC prices below $50/MWh – even with the prospects of guaranteed long-term contracts – means that the growing Connecticut RPS requirements will likely be met with (1) high REC prices for in-state renewable development; (2) significant volumes of RECs from elsewhere in New England (assuming they are available); (3) substantial reliance on alternative compliance payments, or a combination of all of these.[2] Second, recalling the project delay from the Round 1 project, some of the Round 2 projects may not be operational within the proposed timeframe, even with a long-term contract in place. Renewable project attrition is high – experience from other procurements suggests that 20% - 50% of projects are delayed or abandoned at some stage, for a variety of

[1] Docket No. 07-04-27 DPUC Review of Long-Term Renewable Contracts – Round 2 Results, December 21, 2007.

[2] CL&P paid over $3 million in alternative compliance payments in 2006, according to a filed report (DPUC Docket 07-09-14, October 15 (corrected) letter). The corresponding figure for UI remains confidential under their supplier agreement.

reasons. Even if all of the Round 2 projects were built by the end of 2009 (under their proposed schedules) they would supply roughly an additional 925 GWh of Class I renewables to satisfy the 2010 RPS requirement (assuming an 85% capacity factor for all projects). However, the Class I RPS requirement by 2010 is 7.0% of Connecticut electricity sales, or double the 3.5% requirement for 2007. The 2010 requirement for Class I renewables will likely approach 2,500 GWh, and so the combined output from the entire slate of Round 2 project (if operating) would not meet the incremental Class I requirement (above the 2007 level) of about 1,300 GWh. Therefore, unless additional Class I renewables emerge by 2010, the REC price for Class I renewables in Connecticut will remain high – at or near the $55/MWh alternative compliance payment level – and at least part of the requirement would be met by alternative compliance payments rather than renewable generation.

The Project 100 experience also suggests that there are limits to which long-term contracts can help reduce REC prices, at least in Connecticut. In general, long-term contracts with renewable developers can reduce the cost of acquiring RECs. A long-term contract for RECs at a specific price can hedge renewable developers against a potential drop in the REC spot price in the event that surplus renewable generation emerges. This hedge can enable renewable developers to obtain project financing.[3] When a renewable developer can profitably build and operate a project while receiving guaranteed REC payments, utilities can sometimes negotiate a long-run REC price that is well below the ACP. Although such an arrangement would represent a savings for utilities compared with paying higher spot REC prices or making alternative compliance payments, should REC prices actually drop below long-term contract prices, utilities would hold out-of-market REC contracts that could prove expensive for customers and risky for utilities.

III. RPS AND RENEWABLE DEVELOPMENT IN NEW ENGLAND

The Connecticut RPS (primarily Class I) is very similar to other RPS requirements in New England in terms of required percentages as well as the flexibility to obtain RECs throughout the New England market. Therefore, the New England States are usefully analyzed as a single RPS

[3] Developers still incur operational risks that REC production will not meet contract levels. If that happens, future net revenues fall from fewer REC sales and from covering contractual amounts with market purchases of RECs or liquidated damages.

compliance market. However, there are two aspects of the Connecticut RPS that will affect how the Companies might be able to comply with the requirement over the long run. First, as discussed later, Connecticut has significantly lower Class I renewable resource potential (especially wind) than other New England states, meaning that long-run compliance with the Connecticut RPS could depend substantially on RECs from elsewhere in New England. Second, the ACP is not indexed to inflation as it is in Maine, Massachusetts, New Hampshire and Rhode Island. In those states, the ACP levels were established at $50/MWh in 2003 and escalated at the Consumer Price Index (CPI); they reached $57.12/MWh in 2007.

Because of the likely dependence on RECs generated elsewhere in ISO-NE, the economic impact of RPS in Connecticut is heavily influenced by the growth of renewable electric generation in other New England states relative to the escalating RPS requirements across the region. Recent experience in New England suggest a potentially protracted period of high REC prices (close to ACP levels), as actual renewable development lags the rapidly escalating regional RPS requirements. Construction costs for renewable generation have increased significantly in the past several years and in some cases renewable resource development has encountered local resistance. As a consequence, renewable developers have commanded REC price premiums that are close to ACP in other New England states.

Although it is beyond the scope of this study to estimate the future renewable energy development in New England, the ISO-NE *2007 Regional System Plan* (RSP) examines the escalating regional RPS requirements through 2016 and compares them to the eligible resources in the ISO-NE Generator Interconnection Queue (a list of proposed projects that have requested an interconnection study from ISO-NE). This comparison revealed that if all of the projects in the Interconnection Queue were built, the additional renewable generation (8,866 GWh) would exceed the incremental requirements from RPS in New England between 2006 and 2012 (5,881 GWh) by a comfortable margin. In fact, the majority of these projects may never come to fruition. For example, about 63% of the new renewable generation in the Interconnection Queue comes from on-shore and off-shore wind projects, many of which have experienced significant resistance from local communities. According to ISO-NE:

> In the past, the region has experienced the withdrawal of a significant portion of projects in the queue before the projects were built. The project attrition has been due to project cost escalation, financing, siting, permitting problems, or a combination of these issues.[4]

If half of the eligible generation from the ISO-NE Interconnection Queue were available by 2012, then there would remain a significant shortfall in new renewable generation to satisfy growing RPS demands. This possibility does not reflect a stagnant outlook for renewable development in New England – renewable power is a vibrant industry that certainly will grow. However, the <u>pace</u> of renewable development <u>relative</u> to the ambitious, rapidly escalating regional RPS requirements will determine REC prices in the near and mid-term. There is growing concern in the region that currently high REC prices (near ACP levels) may persist for some time. While high REC prices will help stimulate renewable project interest from developers, other constraints on renewable development such as siting and permitting could retard the pace of development to keep REC prices very near ACP levels.

For this study's purpose, however, the most important aspect of the Connecticut RPS is the constant ACP price that is not adjusted for inflation over time. As inflation-adjusted ACP prices rise in other New England states, then Connecticut utilities may have very limited access to scarce RECs, since they will naturally flow toward those states where the ACP price is higher. Under these conditions, even renewable generators that might chose to locate in Connecticut might elect to sell RECs to utilities in other states with higher ACP levels. Thus, there is a very real prospect that Connecticut utilities will eventually comply with the Class I RPS primarily or nearly exclusively through the $55/MWh alternative compliance payments. While the $55/MWh price level in Connecticut will serve to limit the impact of higher regional REC prices for Connecticut retail customers, it also could eliminate access to RECs produced elsewhere in New England if regional REC prices exceed this level.

[4] *2007 Regional System Plan*, ISO-NE, p. 71. Projects often enter the Interconnection Queue in early stages of development; a position in the queue is more an expression of development interest than actual viability.

IV. DAYZER ANALYSIS ASSUMPTIONS

In this study, we assume no significant contribution of Class I resources to meet the Connecticut RPS from resources physically located in CT beyond the Project 100 capacity, where we assume the full 150 MW of development.[5] This is probably an overstatement, since even legislatively mandated contracts do not guarantee eventual project development. However, we assume that the price paid by the Companies for Class I RPS compliance through RECs, contract premiums with Project 100 developers, or through alternative compliance payments are all at the $55/MWh level in nominal terms, reflecting the market outlook described above. This translates into a cost burden on Connecticut customers of about $200 million in 2011, $230 million in 2013 and between $300 and $320 million in the 2018 Current Trends Scenario (in 2008 dollars).

Table E.2: Cost of Compliance with RPS Assuming $55/MWh Nominal REC or ACP

	2011	2013	2018
Current Trends Scenario			
Conventional	202	231	324
DSM-Focus	200	224	299
Nuclear	202	231	324
Coal	202	231	324
Strict Climate Scenario			
Conventional	199	227	315
DSM-Focus	197	220	291
Nuclear	199	227	315
Coal	199	227	315
High Fuel/Growth Scenario			
Conventional	199	229	326
DSM-Focus	197	225	311
Nuclear	199	229	326
Coal	199	229	326
Low Stress Scenario			
Conventional	215	250	366
DSM-Focus	213	243	342
Nuclear	215	250	366
Coal	215	250	366

[5] We do track the energy from refuse-fired facilities (Class II), and the demand-side management (DSM) programs included in all resource solutions are estimated to satisfy the Class III requirements.

V. Remote Renewables and Enabling Transmission

Explicitly analyzing renewable energy potential or projections of renewable energy development in New England is beyond the scope of this analysis. However, there is growing interest in the prospects for building substantial windpower capacity in northern New England (*e.g.*, Maine and New Brunswick) along with transmission that might enable energy delivery into the rest of ISO-NE in order to satisfy growing renewable energy demands. Because this resource strategy must be pursued on a regional basis, it is not one that the Companies can pursue as an independent procurement strategy. However, some of the illustrative tradeoffs can be shown with a simple model that estimates the value of windpower revenues (including RECs) in excess of construction and operating costs, and compares that net revenue to the potential costs of building transmission. This helps highlight some of the basic economic considerations that would be encountered in examining the prospects for combined windpower and transmission development in northern New England. The screening analysis assumes:

- A 1,000 MW wind project in northern New England
- An overnight cost of for wind capacity of $2000/kW, a real capital charge rate of 11.36%, and fixed O&M of $30.5/kW-year.
- Energy revenues are derived using DAYZER prices adjusted for seasonal and daily windpower capacity factors, under an assumed annual capacity factor of 32%.
- The value of renewable energy credits is assumed to be $55/MWh (in 2008 dollars), which is slightly below the ACP in other New England states of approximately $59/MWh.
- Federal production tax credits are assumed to remain at the current rate of $20/MWh (in real terms) for the first ten years of operation.
- Each MW of windpower would offset only 0.2 MW of other capacity, consistent with ISO-NE rules, and the capacity price value is derived from the Current Trends scenario with the Conventional resource solution.

Table E.3 shows the annual revenues and costs of windpower on a $/kW basis, and the annual surplus of revenues over costs. Assuming 1,000 MW of wind capacity, the annual surplus could support the annual capital requirements of $952 million worth of transmission construction. If transmission costs $3 million per mile, then the annual surplus of wind revenues over costs could support 317 miles of needed transmission.

Table E.3: Windpower Net Revenues and Transmission Costs

REVENUE (2008$/kW-year)	
Energy Revenue	183.2
Production Tax Credit	20.0
Renewable Energy Credits	153.5
Capacity Revenue	9.1
Total Revenue	**365.8**
COST (2008$/kW-year)	
Capital Cost	227.2
'Fixed O&M Cost	30.5
Total Cost	**257.7**
NET FUNDS - Available for Transmission	
Maximum Transmission Costs (2008$/kW/yr)	**108.09**
Maximum Transmission Costs (millions of 2008$)	**952**
Miles of Transmission @ $3 million/mile	**317**

This stylized example illustrates the potential relationship between the value of windpower and the cost of building transmission to deliver the energy to the rest of ISO-NE. Note that under the assumptions outlined above, the REC revenues are over 40% of the total. Of course, not all of the surplus revenue would necessarily be available for transmission construction, and 300 miles of transmission may or may not suffice to deliver energy from 1,000 MW of wind capacity to the rest of New England.

Although only a rough approximation of the magnitude of costs involved, the assumptions can be altered in the example above to examine how the outcomes might vary as a result. Table E.4 shows how much transmission could be built from windpower surplus revenues under alternative assumptions. Different wind capacity factors, capital costs, and REC prices all can impact the surplus available for transmission investment, which varies from $460 million to $1,452 million – corresponding to 150 miles to nearly 500 miles of transmission under an assumed $3 million per mile cost. This illustrates some of the risks of combined windpower/transmission resource development. As expected, the performance of the wind generation (measured by capacity factor) affects revenues significantly, and the construction costs have a significant impact on the overall project economics. But the REC price received by the wind developers also has a strong effect on the project economics – and that poses unique risks insofar that the amount of generation (and RECs) available from the project itself could affect REC prices throughout the region. At a 32% capacity factor, a 1,000 MW wind project will generate about 2,800 GWh per year. If that were enough to turn a regional REC deficit into a surplus, then REC prices could fall – imperiling the overall project economics.

Table E.4: Transmission Investment from Windpower Net Revenues Under Alternative Assumptions

Variable	Value	Total Cost of New Transmission (in millions; $2008)	Miles of Transmission Feasible (miles)
Base	No Change	952	317
Annual Capacity Factor	30%	769	256
Annual Capacity Factor	35%	1261	420
Overnight Cost	$1750/kW	1202	401
Overnight Cost	$1500/kW	1452	484
Renewable Energy Credit	$45.00	706	235
Renewable Energy Credit	$35.00	460	153

Because a large project combining wind and transmission would face significant risks, a regional approach to renewable resource development may become necessary to realize the aggregate goals of New England RPS targets. The economics of such investments may prove attractive enough to pursue, although much more study will be required to outline the risks, equitably allocate costs and benefits, and identify specific transmission projects and wind resources. For example, there are other potential benefits that could help justify transmission expansion in northern New England, such as reliability, access to unused summer peaking capacity in Southeastern Canada, enhanced market competitiveness, and economic development. Evaluating such benefits is outside of the scope of this study but should be addressed in detail as specific projects are considered.

VI. AVAILABILITY AND COST OF RENEWABLE ELECTRIC GENERATION IN CONNECTICUT

Although a thorough examination of renewable energy potential in New England is beyond the scope of this report, we consider – on a high level – the costs and availability of several Class I and Class II renewable resources in Connecticut. Primary renewable technologies, for which we calculate a levelized cost of electricity, include wind, solar photovoltaic, biomass, landfill methane gas, and fuel cells. Other renewable resources are screened out based on the unavailability of resources — unexploited or entirely absent — in Connecticut, or on the basis of the technological immaturity. Theses technologies include geothermal, solar thermal, hydropower, wave, and tidal.

i. Primary Renewables in Connecticut

Wind, solar photovoltaic, biomass, landfill methane, and fuel cells (although commercial fuel cells operate on natural gas) qualify as a Class I resource in the Connecticut RPS; as such, we characterize and estimate the levelized cost of electricity from these renewable technologies. The cost and performance characteristics of these technologies are based on the review of several sources, including the ISO-NE's 2007 "Scenario Analysis" and the EIA's "Annual Energy Outlook 2007". Table E.5 illustrates the renewable technology generation characteristics, based on current technology, assumed in this analysis. Overnight costs reflect unit siting in New England.

Table E.5: Renewable Technology Generation Characteristics (Current Technology).

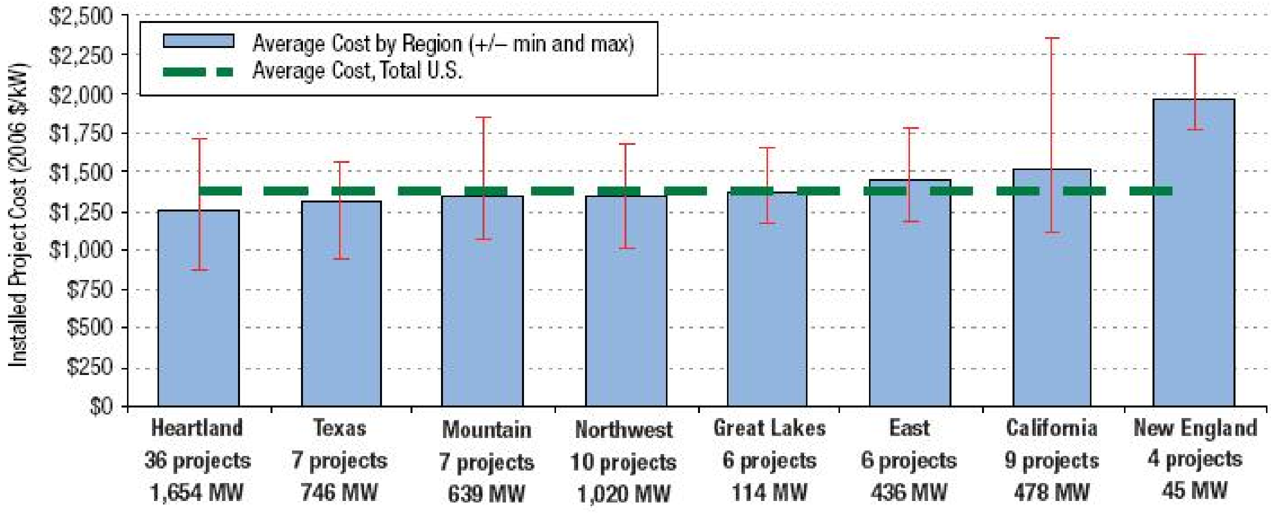
Parameter	Units	Wind	Solar Photovoltaic	Biomass	Landfill Methane Gas	Fuel Cell
Overnight Cost	(2008$/kW)	2,000	5,237	3,142	2,356	3,927
Fixed O&M	(2008$/kWyr)	30.5	11.9	54.1	115.9	5.7
Variable O&M	(2008$/MWh)	0.0	0.0	3.2	0.0	48.6
Economic Life	(Years)	20	20	20	20	20
Capital Charge Rate	(%)	11.4%	11.3%	12.1%	11.6%	11.6%
Fuel Type	(type)	Renew	Renew	Woodchips	Renew	Gas
Heat Rate	(Btu/kWh)	0	0	14,000	10,500	8,000
CO2 Emissions	(tons/MWh)	0.00	0.00	1.08	0.00	0.44
Assumed Capacity Factor	(%)	30%	16%	85%	85%	90%

Notes: Emissions are in metric tonnes.

Construction costs are higher in New England relative to other regions of the US. The Department of Energy's "Annual Report on Wind Power Installation, Cost, and Performance

Trends: 2006" illustrates this cost differential. Specifically, Figure E.1 below, from the DOE report, illustrates higher wind project costs in New England.[6]

Figure E.1: Regional Installed Wind Project Costs



Source: Berkeley Lab database.

Fuel costs and emissions allowances are relevant to fuel cells and biomass in our analysis. Fuel cells are assumed to operate on natural gas, while biomass is assumed to combust woodchips. Natural gas costs and emissions costs used in the renewable technology analysis are based on levelized equivalents to the fuel and emission cost trajectories (from 2008 through 2030) from the Current Trends scenario. The cost of woodchips is derived from the ISO-NE's Scenario Analysis. Although landfill methane gas operates on methane, we assume it to have zero fuel costs, given that methane gas is freely available as a waste byproduct from landfills. Additionally, landfill methane gas is assumed to be carbon neutral, as its emissions do not add to what is all ready emitted by landfills.

All-in costs for Connecticut are evaluated at 30% capacity factor for wind, 16% for solar photovoltaic, 85% for biomass and landfill methane, and 90% for fuel cells. Capacity factors for wind and solar photovoltaic depend on regional environmental conditions. The capacity factors

[6] See Figure 20, p. 16 in the "Annual Report on Wind Power Installation, Cost, and Performance Trends: 2006" US Department of Energy, 2007.

assumed for wind and solar photovoltaic in our analysis reflect environmental conditions in Connecticut.

Figure E.2 below illustrates the results of the all-in cost analysis for renewable technologies. Federal production tax credits for eligible technologies are reflected in the capital costs in this graph, although they actually are related to generation (production) levels. Table E.6 shows the effect of the Production Tax Credit (PTC) on renewable generation costs.

Figure E.2: Levelized Electricity Cost for Renewable Technologies

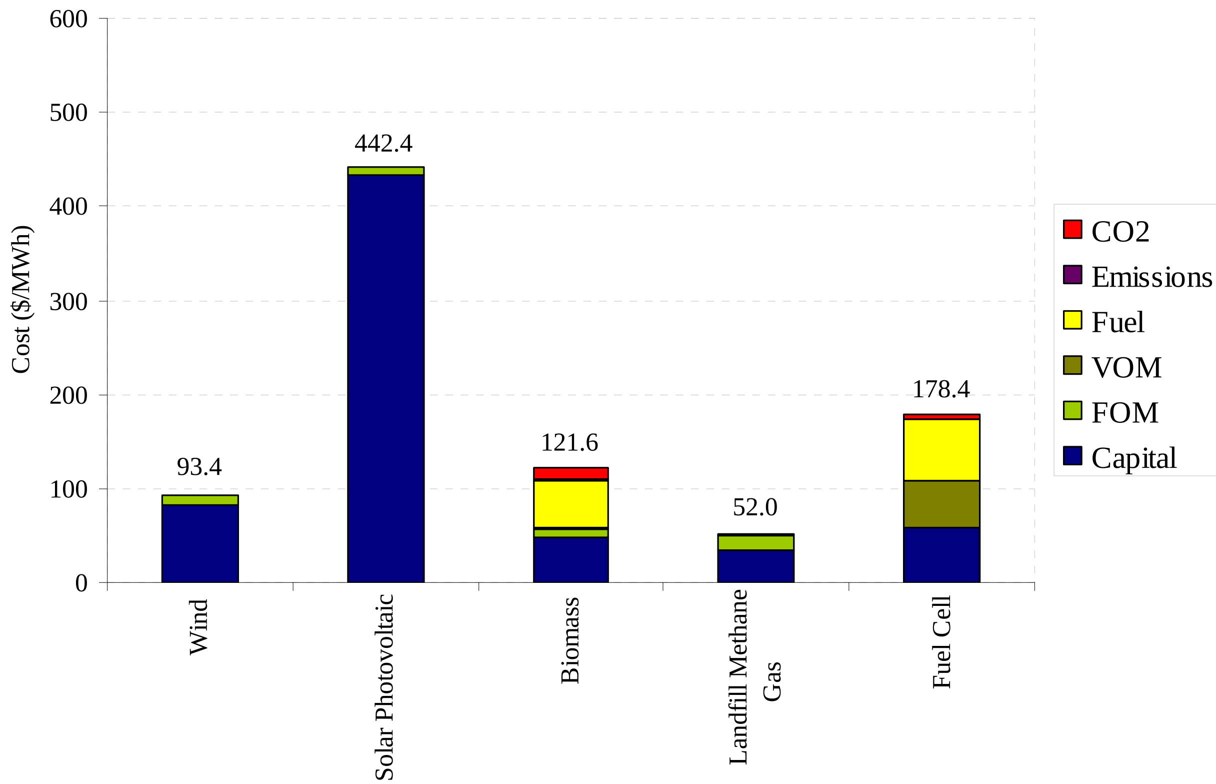


Table E.6: Levelized Electricity Cost for Renewable Technologies Including PTC

Renewable Resource	Connecticut RPS Class (Class)	LCOE (2008$/MWh)	PTC (2008$/MWh)	LCOE After PTC (2008$/MWh)
Wind	1	100.2	6.8	93.4
Solar Photovoltaic	1	449.3	6.8	442.4
Biomass	1	125.0	3.4	121.6
Landfill Methane Gas	1	55.4	3.4	52.0
Fuel Cell	1	178.4	0.0	178.4

Under these cost assumptions, wind, landfill methane, and biomass appear roughly cost competitive against current market prices assuming REC prices of $50/Mwh. However, the availability of these resources in Connecticut will limit their potential contribution to RPS compliance.

Wind resource potential is limited in Connecticut, and is concentrated in the northwest portion of the State. A 2007 study by Levitan & Associates Incorporated cited one estimate of the potential for onshore wind generation in Connecticut at only 43 MW.[7] The best wind resources in New England are offshore and further north, especially Maine. However, offshore wind projects are extremely controversial and much more expensive, and generally not considered viable over the next decade. Landfill Methane Gas potential is less than 20 MW; most sites have been exploited; other landfills are not highly-feasible candidates. This is confirmed in the EPA's Landfill Methane Outreach Program (LMOP) database.[8]

ii. Other Renewable Technologies

Geothermal

Geothermal electric generation is not eligible for contributing to the Connecticut RPS, although it is eligible in Maine, Rhode Island and New Hampshire (Class I). On this basis alone, geothermal is not a relevant candidate for cost considerations. Furthermore, New England does not feature conventional geothermal resource suitable for hydrothermal generation based on

[7] See "Technical Assessment of Onshore and Offshore Wind Generation Potential in New England" prepared by Levitan & Associates (May 1, 2007) Table 8.

[8] See "Landfill Gas Energy Projects and Candidate Landfills" map from the Environmental Protection Agency at:

current technology, nor does it offer potential for economical implementation of enhanced hydrothermal generation systems such as "hot dry rock" water injection and heat recovery.[9]

A recent study estimated costs for enhanced geothermal system generation at a site in New Hampshire. Using current technology, the study finds costs ranging from $340 to $680 per MWh; clearly, this technology is uneconomic compared to alternatives. However, the study finds that under advanced technology scenarios, costs may fall to a range of $83 to $92 per MWh. Nevertheless, such technology developments will take decades to achieve.[10]

Wave, Tidal, and Ocean Thermal

Technologies utilizing Wave, Tidal, and Ocean Thermal resources are in relatively early stages of research and development, and are not yet widely commercial in the US. Furthermore, ocean resources near Connecticut offer little in the way of electric generation potential based on current technology.[11] In California, where generation potential from ocean resources is much more abundant, costs are still extremely prohibitive.[12] Analogously, ocean energy, based on current technology, is not considered economical in Connecticut.

Solar Thermal

Solar thermal electricity generation is only feasible in selected areas of the U.S. southwest, where solar insolation rates can reach 6.0 kW-hr/m2/day or higher. In comparison, NE insolation rates typically fall below 4.0 kW-hr/m2/day.[13]

[9] See Table A.2.1 of Chapter 2—Appendix A. "The Future of Geothermal Energy: Impact of Enhanced Geothermal Systems (EGS) on the United States in the 21st Century" by Massachusetts Institute of Technology. 2006.

[10] See Table 1.3, p.1-29. "The Future of Geothermal Energy: Impact of Enhanced Geothermal Systems (EGS) on the United States in the 21st Century" by Massachusetts Institute of Technology. 2006.

[11] An EPRI study on tidal resources available near Massachusetts suggests that other regions of the US and Canada offer significantly better tidal resources. See "North America Tidal In-Stream Energy Conversion Technology Feasibility Study"; EPRI TP-008-NA by Electric Power Research Institute. June 11, 2006.

[12] The levelized cost of electricity for a 750 MW wave resource plant owned by an independent utility is approximately $846.60 per MWh in nominal dollars; see Table 4 in "Comparative Costs of California Central Station Electricity Generation Technologies"; CEC-200-2007 011-SD; by the California Energy Commission. June 2007.

[13] See Figure 13.5 in "Power Technologies Data Book, 4th Ed" by National Renewable Energy Laboratories. August 2006.

Hydropower

Most sites with feasible generation capacity in Connecticut are developed. Other potential sites either are not economically feasible, or the costs are not known until development interest emerges.

APPENDIX F: CO_2 REDUCTION POLICIES

Emerging concerns regarding climate change have focused on the electric power sector in the U.S. In New England, a regional program to address CO_2 emissions from power plants, the Regional Greenhouse Gas Initiative (RGGI) will take effect in 2009. The U.S. Congress is actively debating proposals to restrict CO_2 emissions from all sectors of the economy. While it is not possible to accurately predict the level and economic impacts of eventual national CO_2 policy, it is important to consider the prospects of such policies in utility resource planning analysis.

I. REGIONAL GREENHOUSE GAS INITIATIVE (RGGI)

The Regional Greenhouse Gas Initiative (RGGI) is a market-based program designed to reduce CO_2 emissions in the Northeast and Mid-Atlantic states. The program targets fossil fuel-fired electricity generating units with a capacity of at least 25 MW, and it implements a regional CO_2 emissions cap and allowance trading program.[1] RGGI is the first regional greenhouse gas emissions reduction program and the first mandatory greenhouse gas allowance trading system in the U.S.

RGGI was first proposed in April 2003 and will begin implementation on January 1, 2009. Ten states, including Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont, have agreed to participate in the program. RGGI set the regional base for the annual CO_2 emissions budget for the ten states at 188,076,983 tons, and apportions CO_2 emission allowance budgets to each state. The state budgets remain unchanged between 2009 and 2014. Beginning in 2015, each budget declines by 2.5% of the original budget per year so that each state's budget in 2018 is 10% below its initial budget. Table F.1 below shows the RGGI emission budgets for ISO-NE states in 2011, 2013 and 2018.

[1] There is no definitive list of RGGI affected units, as the original state budgets were based on a preliminary list, and the criteria for plant selection remains somewhat ambiguous because it uses original "nameplate" capacity ratings which can be different from more recent capacity measures, and applies to units that use more than 50% fossil fuel, which may vary over time.

Table F.1: RGGI State Emissions Budgets by Year (CO_2 Emissions in Short Tons)

	2011	2013	2018
CT	10,695,036	10,695,036	9,625,532
ME	5,948,902	5,948,902	5,354,012
MA	26,660,204	26,660,204	23,994,184
NH	8,620,460	8,620,460	7,758,414
RI	2,659,239	2,659,239	2,393,315
VT	1,225,830	1,225,830	1,103,247
New England Total	55,809,671	55,809,671	50,228,704

Since RGGI is a 10-state regional cap, compliance is not mandatory for any given source or even at the statewide level, provided that sufficient allowances can be obtained from other sources in states with emissions below their allocated budget. It is possible that aggregate CO_2 emission from affected units in the 10-state region will be slightly below the 188 million ton budget level in 2009. Analysis of the six New England states suggests that as a sub-region in RGGI, New England initially will be in surplus because emissions will be below the combined budgets of the New England states.[2]

Because states have not allocated or auctioned any allowances, the price for RGGI allowances is not known at this time. Even if the entire RGGI region (or just the New England portion) were in an initial surplus, however, one would expect that positive prices would emerge from initial auctions because the allowances are tradable across the RGGI region and bankable for future use. Unfortunately, past analyses that have estimated RGGI allowance prices were conducted during a time when states were still joining (or planning to join) the RGGI program. For example, the most recent estimate from RGGI was for the 7-state region (*e.g.*, before MA, RI and MD officially joined) and examined a 121 million ton budget.[3] The most recent analysis of which we are aware was commissioned by the State of Maryland, which looked at joining the 7-state region but did not examine the 10-state region because it was conducted prior to Massachusetts

[2] *Evaluation of Impact of regional Greenhouse Gas Initiative CO_2 Capon the New England Power System*, ISO-NE, October 26, 2006.

[3] See "RGGI Preliminary Electricity Sector Modeling Results: Phase III RGGI Reference and Package Scenario" ICF Consulting, August 17, 2006.

and Rhode Island formally joining the program.[4] The NE-ISO study of October 2006 considered the prospects of Massachusetts and Rhode Island joining the other New England RGGI states, but did not estimate allowance prices because it instead examined the impacts of a range of assumed allowance prices on the region's emissions and energy prices. Lacking a definitive study, we derived our assumed RGGI allowance prices from the Maryland study, because this study was the most recent, and thus incorporated more recent fuel prices in its estimates. These prices were \$4.85 per ton of CO_2 in 2011 and \$5.69 per ton of CO_2 in 2013 (converted to 2008 dollars).[5] By 2018, we assume that RGGI program is supplanted by a federal program with higher allowance prices than expected under RGGI, except for in the Strict Climate Scenario, where the Federal program becomes effective by 2013.

In this study, we have modeled compliance with RGGI from a financial perspective, *e.g.*, the dollar value of allowances that are implied by each covered source's CO_2 emissions. That is, we allocate a CO_2 price to each affected fossil-fuel generation unit in proportion to its CO_2 emissions, and that becomes part of the variable cost of dispatch. This is a correct way of modeling costs even when allowances are allocated freely (although there will be differences between cost-of-service ratemaking and unregulated generators' rate impacts). In the case of Connecticut, however, the state has announced its intention to auction off 100% of the RGGI budget allowances, which would clearly make CO_2 both an expense from the standpoint of an unregulated generator as well as a cost from the standpoint of a cost-of-service price.

II. Federal Climate Policy

This study assumes that a market-based national climate policy will emerge early in the next decade, which will be more stringent than the RGGI targets and which will result in a CO_2 allowance price that is higher than prices assumed under RGGI.

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[4] See *Economic and Energy Impacts from Maryland's Potential Participation in the Regional Greenhouse Gas Initiative*, A Study Commissioned by the Maryland State Department of the Environment, January 2007.

[5] These were derived from interpolating the figures in Table 9.10 under the "Maryland Joins RGGI" column for 2010 and 2015, and converting from \$2004 to \$2008.

While the emergence of a federal CO_2 policy is plausible, and even probable in the timeframe we consider, it is too early in the debate to make accurate predictions regarding the level and timing of the emission reductions, the presence or absence of cost-containment mechanisms such as allowance price caps ("Safety Valve Price") or international offsets, and therefore the resultant CO_2 prices. Nevertheless, we assume that a market-based allowance program will be in place by the middle of the next decade in all scenarios, except for the Strict Climate scenario where the federal program will be in effect by 2013.

One of the primary debates regarding policy is the issue of whether a "safety valve" price should be included. A safety valve is a cap on the price of CO_2 emissions: at this price, the government will issue additional CO_2 allowances and thereby permit emissions to exceed the overall target. Absent a safety valve, allowance prices are both uncertain (it is not possible to estimate the initial levels easily) and potentially volatile (they will be prone to frequent changes as fuel prices and other costs change over time). A safety valve set at a high level (i.e., much higher than the expected price) may only rarely come into play, while a safety valve set at a relatively low level (i.e., closer to the "expected price") will probably determine the CO_2 allowance price most or all of the time.

Although we are not predicting whether or not an actual safety valve price will be utilized, we used the "safety valve" prices contained in recent legislation to guide our CO_2 allowance price assumptions in the Current Trends scenario. In the Current Trends scenario, we assume that the CO_2 allowance price will follow the safety valve price featured in the Bingaman-Specter Low Carbon Economy Act of 2007. In the Bingaman-Specter bill, the safety valve price begins at \$12/ton of CO_2 (in 2012\$) and grows at 5% in real terms. This yields approximately \$13/ton in 2018 and \$24/ton in 2030 (all in 2008\$). We assume that this allowance price path does not begin until after 2013, however, so that it only affects the 2018 and 2030 analysis years (RGGI prices are assumed for the 2011 and 2013 in the Current Trends scenario). This is also the assumption in the Lower Stress scenario.

In the Strict Climate scenario, we assume that (1) federal climate policy begins earlier, and thus is in effect by 2013, and (2) that the level of emission reductions sought are much more aggressive than the levels determined by the safety valve price contained in the Bingaman-Specter proposal.[6] For the Strict Climate scenario, we assumed implementation of a climate policy similar to S.280, the Climate Stewardship and Innovation Act of 2007, introduced into the 110th Congress by Senator Leiberman on January 12, 2007. S.280 contains a set of economy-wide CO_2 emission targets, which return to 2004 levels by 2012, fall to their 1990 levels by 2020, and in the long run (*e.g.*, 2050) are 60% below the 1990 levels. Up to 30% of emission reductions can arise from international offsets from CO_2 emission reductions pursued abroad, and the proportion of domestic CO_2 allowances that are auctioned (rather than distributed free to affected entities) is gradually increased. Because S.280 did not have a safety valve allowance price cap, however, allowance prices are uncertain. Analyses by the Energy Information Administration and the Environmental Protection Agency suggest a wide range of possible CO_2 allowance prices under S.280. These CO_2 prices will depend upon fuel prices, energy demands, the cost and availability of nuclear power, the cost and availability of carbon capture and storage (CCS) technologies for coal-fired generation, and the cost and availability of international offsets that can be substituted for domestic emission reductions. Projections of CO_2 allowance prices in the early years (i.e., 2012 to 2015) range from about $10 to $40 per ton, with the low end of the range roughly similar to the Bingaman-Specter safety valve price. Projections of CO_2 allowance prices for the 2030 timeframe range from below $30 to over $80 per ton.

Since the scenario analysis is designed to explore significant differences in external factors, we selected an allowance price path that was on the high end of the range of the overall set of projections. In doing so, we are not predicting such CO_2 prices, but rather examining the impact on resource decisions from an aggressive national CO_2 policy that does not benefit from optimistic technology or international offset assumptions.[7] This results in a much higher CO_2 price in 2013 than other scenarios ($25/ton compared with less than $6/ton in other scenarios, in year 2008 dollars); however the ratio narrows over time from over four times as high to roughly double. The CO_2 allowance price in 2018 is about $31/ton in the Strict Climate scenario (vs.

[6] See *Energy Market and Economic Impacts of S.280, the Climate Stewardship and Innovation Act of 2007*, (EIA, July 2007) and *EPA Analysis of The Climate Stewardship and Innovation Act of 2007* (EPA, July 16, 2007).

[7] We chose the allowance price projections derived from Scenario 6 from the EPA analysis, which assumes a lower growth rate in nuclear power generation than other EPA scenarios.

$13/ton in the Current Trends and Low Stress scenarios) and $55/ton in 2030 (vs. $24/ton in the Current Trends and Low Stress scenarios). In the High Fuel/Growth Price scenario, the 2018 and 2030 prices are assumed to be one-third higher than in the Current Trends scenarios. The Table below shows the assumed CO_2 allowance prices assumed in the study.

Table F.2: CO_2 Emissions Permit Prices by Scenario (Short Tons)

Year	Current Trends (2008 $/tCO2)	Strict Climate (2008 $/tCO2)	High Growth& Fuel Prices (2008 $/tCO2)	Low Stress (2008 $/tCO2)
2011	4.85	4.85	4.85	4.85
2013	5.69	25.05	5.69	5.69
2018	13.32	30.92	17.76	13.32
2030	23.92	54.80	31.90	23.92

APPENDIX G: DAYZER MODEL INPUT ASSUMPTIONS

I. INTRODUCTION

The analysis of energy production, costs, and emissions was performed using the DAYZER model. DAYZER is an electricity market simulation model designed by Cambridge Energy Solutions (CES) to mimic ISO-NE's operation of the New England electricity market. The model takes as inputs the fundamental elements of supply, demand, and transmission; the outputs include generation outputs, costs, prices, transmission flows, and emissions. Although CES provides a complete set of data that can be used as model inputs, *The Brattle Group* refined and developed the data to better reflect current and expected ISO-NE market conditions for the purpose of this study. This appendix describes the resulting data inputs and key assumptions.

II. SIMULATION CASES

Each DAYZER simulation case incorporates a combination of (1) market assumptions, including load growth, capacity online, and the price of fuel and emission allowances, which vary by scenario; (2) the degree of inclusion of the New England East-West Solution (NEEWS) transmission project; and (3) a candidate resource solution to meet any resource gap relative to reliability requirements. Varying these factors to test each resource solutions across a range of market and system conditions yields numerous possible combinations and, hence, numerous potential simulations. Figure G.1 presents the dimensions in any given simulation case. Each dimension has an abbreviated name found in the DAYZER input and output files, and a corresponding description for clarification. Note that the Coal resource solution in italics does not require separate simulations for evaluation. The Coal resource solution is evaluated by making adjustments to the Nuclear resource solution simulation results.

Figure G.1: Summary of Simulation Case Dimensions

#	DAYZER Short Name	Description
Scenario: Exogenous System Condition		
1	REF(CurrTrends)	Current Trends Scenario
2	SCE1(StrictClimate)	Strict Climate Scenario
3	SCE2(HighGrowth)	High Fuel/Growth Scenario
4	SCE3(LowStress)	Low Stress Scenario
Resource Solution: Evaluated Companies Resource Solution		
1	IRP1(Conv)	Conventional Approach
2	IRP2(HvyDSM)	DSM-Focus Solution
3	IRP3(BaseGen)	Nuclear Solution (Simulated in Study Years with Resource Gap Only)
4	*IRP3a(BaseGen-Coal)*	*Coal Solution - Coal (Not Simulated)*
Study Year: Subject to Variations on New England East-West Solution Transmission Inclusion		
1	2011	
2	2013	
3	2018	
4	2030	
Degree of New England East-West Solution Transmission Inclusion		
1	nNEEWS	No NEEWS (2011 Only); Includes Middletown/Norwalk project
2	pNEEWS	Partial NEEWS (2013, 2018, and 2030 Only); Excludes Central Connecticut Reliability Component
3	tNEEWS	Total NEEWS (2013, 2018, and 2030 Only)

III. GENERAL MODEL ASSUMPTIONS

The model assumes a competitive market in which energy bids are based on incremental costs. Incremental costs are assumed to be given by the incremental heat rate + variable O&M costs, without regard to potential opportunity costs. However, the unit commitment algorithm that precedes the generation dispatch also considers unit startup costs, minimum up time, and other operating constraints, as described in Appendix A.

IV. EXISTING CAPACITY

Existing capacity as of 2007 is generally consistent with the ISO-NE 2007 Regional System Plan (RSP) and the 2007 Capacity, Energy, Loads, and Transmission (*CELT*) report.[1] Figure G.2 summarizes ISO-NE existing generating unit capacity used in the DAYZER model compared to the 2007 RSP and the *CELT* report.

[1] However, capacity in the supply-demand balance used for defining the resource gap is exactly consistent with CELT. Please see Table 2.2 of the main report.

Figure G.2: ISO-NE Existing Generating Unit Capacity by State

State	Total Installed Capacity (MW)	
	Assumed Existing Capacity	2007 Regional System Plan
Connecticut	7,552	7,535
Maine	3,199	3,084
Massachusetts	13,213	13,027
New Hampshire	3,991	3,979
Rhode Island	1,803	1,818
Vermont	877	1,084
Total	30,636	30,527
CELT		30,945

As shown in Figure G.2, the Connecticut capacity in the DAYZER model is 7,552 MW, which is almost the same as the 7,535 MW reported in the RSP. Both numbers include the approximately 700 MW Lake Road units which are located geographically in Connecticut, but electrically in Rhode Island. The *CELT* report shows Connecticut existing capacity as 6,999 MW not including the Lake Road units, and 7,697 MW including the Lake Road units (i.e., within 200 MW of the capacity listed in RSP and DAYZER).

Outside of the DAYZER model, in our determination of the resource needs relative to Connecticut's local sourcing requirement (LSR), we used CELT's 6,999 MW until the NEEWS transmission project brings Lake Road electrically into Connecticut, as shown in Table 2.3. Further clarification on the Connecticut units and ratings used in this study to define the Connecticut resource needs (according to the *CELT* report) are shown in Figure G.3.

Figure G.3: *CELT* Existing Generating Units in Connecticut Area

CELT Generator Name	Area	Summer Capacity *(MW)*
MILLSTONE POINT 3	CT	1,155
MILLSTONE POINT 2	CT	880
NEW HAVEN HARBOR	CT	448
MONTVILLE 6	CT	407
MIDDLETOWN 4	CT	400
MIDDLETOWN 3	CT	236
AES THAMES	CT	181
MIDDLETOWN 2	CT	117
MONTVILLE 5	CT	81
CDECCA	CT	52
SO. MEADOW 13	CT	38
DEXTER	CT	38
SO. MEADOW 12	CT	38
SO. MEADOW 14	CT	37
SO. MEADOW 11	CT	36
PFIZER #1	CT	33
SO. MEADOW 6	CT	27
SO. MEADOW 5	CT	26
UCONN COGEN	CT	25
EXETER	CT	24
PRATT & WHITNEY (UTC)	CT	24
US NAVAL SUBMARINE BASE	CT	19
MIDDLETOWN 10	CT	17
SECREC-PRESTON	CT	16
TUNNEL 10	CT	16
TORRINGTON TERMINAL 10	CT	16
FRANKLIN DRIVE 10	CT	15
NORWICH JET	CT	15
BRISTOL REFUSE	CT	13
LISBON RESOURCE RECOVERY	CT	13
AGGREGATE UNITS <10 MW	CT	90
NORWALK HARBOR 2	NOR	168
NORWALK HARBOR 1	NOR	162
WATERSIDE POWER	NOR	70
COS COB 10	NOR	19
COS COB 12	NOR	18
COS COB 11	NOR	18
NORWALK HARBOR 10 (3)	NOR	12
AGGREGATE UNITS <10 MW	NOR	3
BRIDGEPORT ENERGY 1	SWCT	448
BRIDGEPORT HARBOR 3	SWCT	372
MILFORD POWER 2	SWCT	253
MILFORD POWER 1	SWCT	239
BRIDGEPORT HARBOR 2	SWCT	130
BRIDGEPORT RESCO	SWCT	59
PPL WALLINGFORD UNIT 3	SWCT	44
PPL WALLINGFORD UNIT 1	SWCT	44
PPL WALLINGFORD UNIT 4	SWCT	43
PPL WALLINGFORD UNIT 5	SWCT	43
SHEPAUG	SWCT	42
PPL WALLINGFORD UNIT 2	SWCT	41
DEVON 13	SWCT	31
DEVON 14	SWCT	30
DEVON 11	SWCT	30
ROCKY RIVER	SWCT	29
DEVON 12	SWCT	29
STEVENSON	SWCT	28
BRANFORD 10	SWCT	16
DEVON 10	SWCT	14
AGGREGATE UNITS <10 MW	SWCT	33
Total		**6,999**

Source: *CELT* file "2007-celt_spreadsheets.xls."
See http://www.iso-ne.com/trans/celt/report/index.html.

V. GENERATING UNIT RETIREMENTS

Only one unit that is included in Table G.2 is assumed to retire: New Boston 1, a 350 MW unit in the NEMASS/Boston zone.[2] Coal units are assumed to have indefinite life, and nuclear units are assumed to receive 40-year NRC license extensions, which makes all nuclear units operable through 2030. Other units are assumed to stay online, based on the preliminary screening analysis described in Appendix A.

VI. PLANNED UNIT ADDITIONS AND UPGRADES

1,107 MW of planned unit additions and upgrades that are recently completed, currently under construction, or under contract are assumed to come online by 2011, as summarized in Figure G.4. In addition, 279 MW of combustion turbines are assumed to be added to meet the local forward reserve requirement in Connecticut, as described in Appendix A.

Figure G.4: ISO-NE Planned Generating Unit Additions and Expansions by 2011

Unit Name	Unit Type	Zone	Summer Capacity (MW)	Winter Capacity (MW)	Fuel Name
UNIT ADDITIONS					
Waterbury	New CT	South Western CT Zone	80	96	Natural Gas
Kleen Energy	New CC	Rest of CT Zone	560	620	Natural Gas
Wallingford/Pierce	New CT	South Western CT Zone	100	100	Natural Gas
DG Capital Grant Projects	New CT	CT Zones	96	96	Natural Gas
Renewable Energy Contracts	ST	South Western CT Zone	75	75	Biomass
Renewable Energy Contracts	ST	Rest of CT Zone	75	75	Biomass
UNIT EXPANSIONS					
Cos Cob Expansion	GT	Norwalk- Stamford Zone	40	40	FO2
Millstone Point 3	NU	Rest of CT Zone	81	81	Uranium
		Connecticut Total	**1,107**	**1,183**	

The DG Capital Grant projects are small (<70 MW) projects estimated by the Companies.[3] All DG Capital Grant projects are derated by a 50% attrition rate to account for the risk that some

[2] Based on New Boston's permanent de-list bid submitted to ISO-NE in 2007.
[3] Based on a list of these projects as of 8/24/07.

projects may not come online as expected. In addition to the 96 MW included on the supply side (as shown in Figure G.4) 34 MW of the DG Capital Grant projects are implemented as load reductions. The supply-side units are combined into aggregate units by zone for simplicity. The Renewable Energy Contracts units refer to the 150 MW of renewable energy contracts the Companies are required to sign by state law, and are also implemented in the model as aggregate units by zone.

VII. FUTURE UNPLANNED CAPACITY

The future capacity that is added to the model depends on the resource solutions being evaluated:

- In the Conventional Gas resource solution, only gas-fired CCs and CTs are added;
- In the Nuclear resource solution a 1,200 MW nuclear unit is added at the Millstone station, although it is meant to represent any brownfield nuclear site in New England. This unit, named "Millstone 4," is installed as of January 1, 2015, is assigned the unit characteristics of Millstone 3, with the exception of a heat rate lowered to reflect an assumed "learning curve;"
- The Coal resource solution is not simulated separately; it is evaluated by making adjustments to the Nuclear resource solution simulation results; and
- In the DSM-Focus resource solution, additional DSM is added to the already aggressive amount of DSM assumed in all of the resource solutions. DSM is modeled as demand reductions, the additional amount being +160 MW/ 370 GWh in 2011, +320 MW / 1000 GWh by 2013, +600 MW / 2600 GWh in 2018, and with no further growth as a percentage of load by 2030, as described in Appendix D.

Apart from the candidate resources described above, additional unplanned gas-fired CCs and CTs are added with each "resource solution" as needed to meet any resource gap relative to the ISO-NE installed capacity requirement.[4] (The resource gap varies by scenario, as summarized in Tables 2.2 and 2.3 in the main report). Unplanned new capacity is added to the model in 300 MW increments, and the technology and location are selected based on economics, i.e., with the

[4] No capacity was added specifically to satisfy the Connecticut local sourcing requirement because no additional resources were needed in any scenario, as shown in Table 2.3.

lowest all-in cost net of energy revenues. The selection of locations accounts for locational differences in construction costs, as discussed in Appendix C. For simplicity, all future unplanned units are added to major 345 kV substations and are given generic unit characteristics by unit type as shown in Figure G.5.[5]

Total unplanned new capacity amounts by type for each scenario/resource solution combination are summarized in Figure G.6.

Figure G.5: Unplanned Generating Unit Characteristics by Unit Type

Unit Type	Must Commit = 1	Must Run = 1	Planned Outage Rate (%)	Heat Rate (Btu/kWh)	Variable O&M ($/MWh)	NOx Rate (Lbs/MMBtu)	SOx Rate (Lbs/MMBtu)	CO2 Rate (Lbs/MMBtu)
New CC	0	0	4.1%	7,000	2.5	0.020	0.001	116
New CT	0	0	9.1%	10,200	5	0.020	0.001	116
Nuclear	0	1	1.4%	10,207	1.8	0	0	0

[5] All costs and prices have been converted to real 2008 dollars using a 2.3% inflation rate, unless otherwise noted. This inflation rate is based on forecasted Consumer Price Index in *Blue Chip Economic Indicators*, Long-Range Consensus U.S. Economic Projections, March 10, 2007.

Figure G.6: Unplanned New Capacity by Unit Type and Scenario/Resource Solution Combination

	Gross Cumulative Unplanned Generic Capacity Added (MW)												Totals by Year (MW)			
	2011			2013			2018			2030			2011	2013	2018	2030
	NCC	NGT	Baseload	NCC	NGT	Baseload	NCC	NGT	Baseload	NCC	NGT	Baseload				
TOTAL ISO																
Current Trends Scenario																
Conventional	-	-	-	-	-	-	1,500	-	-	5,700	1,500	-	-	-	1,500	7,200
DSM-Focus	-	-	-	-	-	-	900	-	-	5,700	600	-	-	-	900	6,300
Nuclear	-	-	-	-	-	-	300	-	1,200	5,400	600	1,200	-	-	1,500	7,200
Strict Climate Scenario																
Conventional	-	-	-	-	-	-	1,200	-	-	5,700	900	-	-	-	1,200	6,600
DSM-Focus	-	-	-	-	-	-	300	-	-	5,100	600	-	-	-	300	5,700
Nuclear	-	-	-	-	-	-	-	-	1,200	4,800	600	1,200	-	-	1,200	6,600
High Fuel/Growth Scenario																
Conventional	-	-	-	600	-	-	3,000	600	-	7,800	1,500	-	-	600	3,600	9,300
DSM-Focus	-	-	-	300	-	-	2,400	300	-	6,900	1,500	-	-	300	2,700	8,400
Nuclear	-	-	-	-	-	-	2,400	-	1,200	6,600	1,500	1,200	-	-	3,600	9,300
Low Stress Scenario																
Conventional	300	-	-	1,500	-	-	3,900	600	-	9,000	1,500	-	300	1,500	4,500	10,500
DSM-Focus	-	-	-	1,200	-	-	3,300	600	-	8,100	1,500	-	-	1,200	3,900	9,600
Nuclear	-	-	-	-	-	-	2,700	600	1,200	7,800	1,500	1,200	-	-	4,500	10,500
CONNECTICUT																
Current Trends Scenario																
Conventional	-	-	-	-	-	-	300	-	-	2,100	600	-	-	-	300	2,700
DSM-Focus	-	-	-	-	-	-	-	-	-	2,100	300	-	-	-	-	2,400
Nuclear	-	-	-	-	-	-	-	-	1,200	2,100	300	1,200	-	-	1,200	3,600
Strict Climate Scenario																
Conventional	-	-	-	-	-	-	300	-	-	2,100	300	-	-	-	300	2,400
DSM-Focus	-	-	-	-	-	-	-	-	-	2,100	300	-	-	-	-	2,400
Nuclear	-	-	-	-	-	-	-	-	1,200	1,800	300	1,200	-	-	1,200	3,300
High Fuel/Growth Scenario																
Conventional	-	-	-	-	-	-	1,500	300	-	3,000	600	-	-	-	1,800	3,600
DSM-Focus	-	-	-	-	-	-	900	-	-	2,700	600	-	-	-	900	3,300
Nuclear	-	-	-	-	-	-	900	-	1,200	2,700	600	1,200	-	-	2,100	4,500
Low Stress Scenario																
Conventional	-	-	-	300	-	-	1,800	300	-	3,300	600	-	-	300	2,100	3,900
DSM-Focus	-	-	-	300	-	-	1,800	300	-	3,300	600	-	-	300	2,100	3,900
Nuclear	-	-	-	-	-	-	1,200	300	1,200	3,000	600	1,200	-	-	2,700	4,800

VIII. GENERATING UNIT AVAILABILITY

a. Forecasted Maintenance Outages

Maintenance outages for each generating unit are forecasted within the DAYZER model based on load input, the assumed planned outage rate and duration for that unit, and a seasonal maintenance outage pattern. Maintenance outage rates are based on ISO-NE's recommended maintenance allotments by unit type,[6] as summarized in Figure G.8. The resulting maintenance outage schedules for all units are summarized in Figure G.7 below, along with the forecasted forced outage schedules. As Figure G.7 shows, the maintenance outages are properly concentrated in the Spring and Fall when load is the lowest, and gaps in the maintenance outage curve indicate days in which no maintenance outages occur.

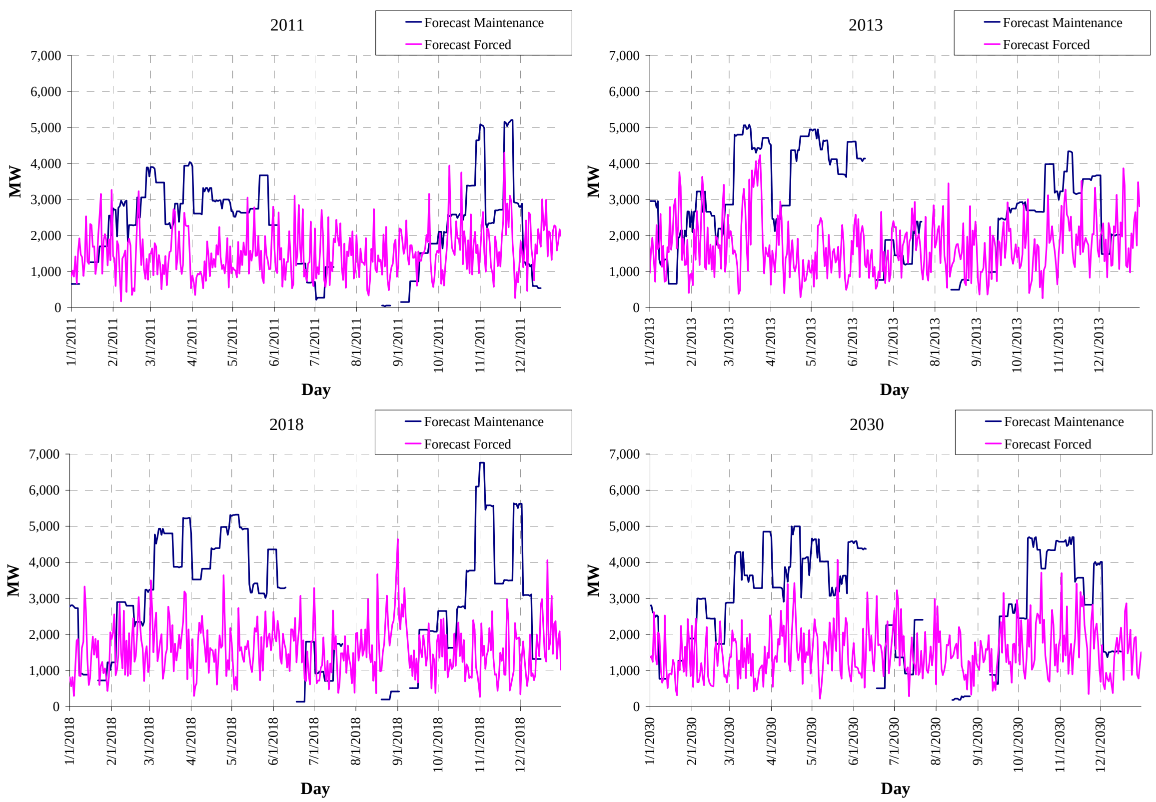
[6] *ISO New England Recommended FCM Maintenance Allotments*; 12/07/2007 Draft; Table 2.

b. Random Forced Outages

Forced outages are randomly selected by the model based on the specified forced outage rate and duration for each unit. Forced outage rates are based on the 2006 PJM State of the Market Report outage rates by unit type.[7] The panels in Figure G.7 show forecasted total ISO maintenance and forced outages assumed in each study year. Importantly, outage schedules are held constant across all resource solutions and scenarios within each study year.

Generic unplanned units are not given a forced outage schedule. These units are instead derated by their forced outage rates.

Figure G.7: Forecasted Total Maintenance and Forced Outages by Study Year



[7] *PJM State of the Market Report*, PJM Market Monitoring Unit, Volume II, Section 5 – Capacity Markets,, March 8, 2007, at Table 5-16, p. 232. See http://www.pjm.com/markets/market-monitor/som.html.

Figure G.8: Outage Rates and Durations by Unit Type

Unit Type	Final POR (%)	Final FOR (%)	Final PO Duration (Days)	Final FO Duration (Days)
CC	5.6%	4.1%	13	1
GEO	n/a	n/a	7	n/a
GT	4.6%	9.1%	12	4
GT+	4.6%	9.1%	13	2
Hydro	n/a	n/a	n/a	n/a
NCC	5.6%	4.1%	13	1
NGT	4.6%	9.1%	13	2
NU	6.5%	1.4%	24	9
PS	n/a	n/a	n/a	n/a
PUR	n/a	n/a	n/a	n/a
SOL	n/a	n/a	n/a	1
STc+	9.1%	8.2%	21	2
STc100	9.1%	8.2%	20	2
STc200	9.1%	8.2%	18	2
STg+	8.2%	8.2%	24	2
STg100	8.2%	8.2%	20	3
STg200	8.2%	8.2%	24	3
STo+	8.2%	8.2%	25	2
STo100	8.2%	8.2%	30	3
STo200	8.2%	8.2%	27	2
STr	8.2%	8.2%	14	7
WND	n/a	n/a	n/a	1

IX. UNIT CHARACTERISTICS

a. Dual-Fuel Units

Dual-fuel capability of steam units and combustion turbines is consistent with the ISO's 2007 *CELT* report. Dual-fuel steam units are set to burn FO6 in the winter (it is cheaper than natural gas in the winter) and are allowed to switch to gas in the summer (April through October) if gas price is less than the oil price including a 3% switching cost.[8] Dual-fuel combustion turbines with gas as the primary fuel and Distillate Fuel Oil (FO2) as the secondary fuel are allowed to switch to FO2 in January if the oil price is less than the gas price net of an assumed 5% switching cost. FO2-fired units with natural gas capability are allowed to switch to gas year-round due to the consistently lower price of projected natural gas prices. Figure G.9 summarizes all dual-fuel units by unit type.

[8] Dual-fuel steam units with gas listed as the primary fuel are allowed to switch to FO6 year-round, but only Kendall Steam is in this group.

b. Steam Unit Characteristics

Due to the sensitivity of the market to steam oil-fired unit flexibility and startup costs these characteristics have been more finely tuned based on historic generation patterns found in the EPA CEMS database.[9] Minimum uptime, minimum downtime, and startup energy for all steam oil-fired units are summarized in Figure G.10.

c. Other Unit Characteristics

All other units have assumed generic unit characteristics by unit type. These are summarized in Figure G.11 below.

[9] CEMS data compiled by Global Energy Decision, Inc., The Velocity Suite.

Figure G.9: Dual-Fuel Units by Unit Type

Unit Name	Primary Fuel	Alternate Fuel	Zone	State	Summer Capacity (MW)
DUAL-FUEL STEAM OIL UNITS					
NEW HAVEN HARBOR	FO6	NG	Rest of CT Zone	CT	461
BRAYTON PT 4	FO6	NG	South Eastern MA Zone	MA	435
MYSTIC 7	FO6	NG	NE MA Boston Zone	MA	555
NEWINGTON 1	FO6	NG	New Hampshire Zone	NH	400
MIDDLETOWN 3	FO6	NG	Rest of CT Zone	CT	236
CANAL 2	FO6	NG	South Eastern MA Zone	MA	553
HOLYOKE 8/CABOT 8	FO6	NG	West Central MA Zone	MA	9
HOLYOKE 6/CABOT 6	FO6	NG	West Central MA Zone	MA	9
MONTVILLE 5	FO6	NG	Rest of CT Zone	CT	81
WEST SPRINGFIELD 3	FO6	NG	West Central MA Zone	MA	101
MIDDLETOWN 2	FO6	NG	Rest of CT Zone	CT	117
* KENDALL STEAM 1 2 3	NG	FO6	NE MA Boston Zone	MA	60
DUAL-FUEL GT UNITS					
DEVON 11	NG	FO2	South Western CT Zone	CT	30
DEVON 13	NG	FO2	South Western CT Zone	CT	33
DEVON 12	NG	FO2	South Western CT Zone	CT	30
DEVON 14	NG	FO2	South Western CT Zone	CT	30
* IPSWICH #12	FO2	NG	NE MA Boston Zone	MA	1
* WATERS RIVER JET 2	FO2	NG	NE MA Boston Zone	MA	30
* WATERS RIVER JET 1	FO2	NG	NE MA Boston Zone	MA	14
* SCHILLER CT 1	FO2	NG	New Hampshire Zone	NH	17
DUAL-FUEL COMBINED CYCLE UNITES					
NEA BELLINGHAM	NG	FO2	South Eastern MA Zone	MA	265
CDECCA	NG	FO2	Rest of CT Zone	CT	51
DARTMOUTH POWER	NG	FO2	South Eastern MA Zone	MA	62
MANCHESTER 10/10A CC	NG	FO2	Rhode Island Zone	RI	141
MANCHESTER 11/11A CC	NG	FO2	Rhode Island Zone	RI	142
MANCHESTER 9/9A CC	NG	FO2	Rhode Island Zone	RI	142
ALTRESCO (pittsfield)	NG	FO2	West Central MA Zone	MA	141
MASS POWER	NG	FO2	West Central MA Zone	MA	232
NEWINGTON ENERGY	NG	FO2	New Hampshire Zone	NH	508
* STONY BROOK GT1C	FO2	NG	West Central MA Zone	MA	104
* STONY BROOK GT1B	FO2	NG	West Central MA Zone	MA	100
* STONY BROOK GT1A	FO2	NG	West Central MA Zone	MA	104

*Allowed to use alternate fuel year-round.

Figure G.10: Steam Oil Unit Characteristics

Unit Name	Zone	State	Summer Capacity (MW)	Minimum Down Time (Hours)	Minimum Up Time (Hours)	Startup Energy (MMBtu)
STEAM OIL UNITS						
YARMOUTH 4	Maine Zone	ME	609	8	11	10
NEW HAVEN HARBOR	Rest of CT Zone	CT	461	8	16	10
BRAYTON PT 4	South Eastern MA Zone	MA	435	8	18	10
SALEM HARBOR 4	NE MA Boston Zone	MA	380	8	18	10
MYSTIC 7	NE MA Boston Zone	MA	555	8	22	10
MONTVILLE 6	Rest of CT Zone	CT	407	8	22	10
NEWINGTON 1	New Hampshire Zone	NH	400	7	8	10
MIDDLETOWN 4	Rest of CT Zone	CT	400	8	24	10
MIDDLETOWN 3	Rest of CT Zone	CT	236	8	24	10
CANAL 2	South Eastern MA Zone	MA	553	8	24	10
CANAL 1	South Eastern MA Zone	MA	254	8	24	10
HOLYOKE 8/CABOT 8	West Central MA Zone	MA	9	6	10	10
HOLYOKE 6/CABOT 6	West Central MA Zone	MA	9	6	10	10
KENDALL STEAM 1 2 3	NE MA Boston Zone	MA	60	6	10	10
MONTVILLE 5	Rest of CT Zone	CT	81	6	10	10
YARMOUTH 1	Maine Zone	ME	52	6	10	10
YARMOUTH 2	Maine Zone	ME	52	6	10	10
CLEARY 8	South Eastern MA Zone	MA	26	6	10	10
WEST SPRINGFIELD 3	West Central MA Zone	MA	101	6	10	10
YARMOUTH 3	Maine Zone	ME	117	6	10	10
BRIDGEPORT HARBOR 2	South Western CT Zone	CT	130	6	15	10
MIDDLETOWN 2	Rest of CT Zone	CT	117	6	20	10
NORWALK HARBOR 1	Norwalk- Stamford Zone	CT	162	6	24	10
NORWALK HARBOR 2	Norwalk- Stamford Zone	CT	168	6	24	10

Figure G.11: Unit Characteristics by Unit Type

Unit Type	Minimum Downtime (Hours)	Minimum Uptime (Hours)	Startup Energy (MMBtu/MW)	FOR (%)	FO Duration (Days)	POR (%)	PO Duration (Days)	Spinning Reserve (%)	Quickstart Reserve (%)	AGC Reserve (%)	Ramp Up (%/Hour)	Ramp Down (%/Hour)	Variable O&M ($/MWh)	Fixed O&M ($/kW-Yr)
Combined Cycle	7	8	7	4%	1	6%	13	20%	0%	10%	75%	100%	2.5	21
New Combined Cycle	7	8	7	4%	1	6%	13	20%	0%	10%	75%	100%	2.5	15
Combustion Turbine	1	1	0	9%	4	5%	12	0%	100%	0%	100%	100%	7	15
Combustion Turbine >100 MW	1	1	0	9%	2	5%	13	0%	100%	0%	100%	100%	7	15
New Combustion Turbine	1	1	0	9%	2	5%	13	0%	100%	0%	100%	100%	5	5
Steam Turbine [Coal] < 100 MW	6	8	15	8%	2	9%	20	10%	0%	10%	50%	100%	3	45
Steam Turbine [Coal] < 200 MW	7	8	15	8%	2	9%	18	10%	0%	0%	25%	50%	3	35
Steam Turbine [Coal] > 200 MW	12	24	15	8%	2	9%	21	10%	0%	0%	15%	30%	1	35
Steam Turbine [Gas] <100 MW	6	10	10	8%	3	8%	20	10%	0%	10%	75%	100%	5	34
Steam Turbine [Gas] <200 MW	6	16	10	8%	3	8%	24	10%	0%	10%	35%	100%	4	30
Steam Turbine [Gas] > 200 MW	8	24	10	8%	2	8%	24	10%	0%	10%	15%	100%	3	30
Steam Turbine [Oil] <100 MW	6	10	10	8%	3	8%	30	10%	0%	10%	75%	100%	5	34
Steam Turbine [Oil] <200 MW	6	16	10	8%	2	8%	27	10%	0%	10%	35%	100%	4	30
Steam Turbine [Oil] >200 MW	8	24	10	8%	2	8%	25	10%	0%	10%	15%	100%	3	30
Nuclear	163	164	0	1%	9	6%	24	0%	0%	0%	10%	20%	0	0
Wind	1	1	0	70%	1	0%	0	0%	0%	0%	100%	100%	0	0
Hydro	0	0	0	0%	0	0%	0	25%	0%	0%	50%	50%	0	0
PS	0	0	0	0%	0	0%	0	0%	0%	0%	0%	0%	0	0
Steam Turbine [Refuse]	6	10	0	8%	7	8%	14	10%	0%	0%	100%	100%	0	0
Geothermal Units	1	1	0	1%	0	3%	7	0%	0%	0%	100%	100%	0	0
Solar	1	1	0	80%	1	0%	0	0%	0%	0%	100%	100%	0	0

X. EMISSIONS RATES AND PRICES

a. Current Trends Scenario

CO_2 emission allowance prices correspond to the Regional Greenhouse Gas Initiative (RGGI) through 2013 and federal legislation thereafter, as described in Appendix F. RGGI CO_2 allowance prices in 2011 and 2013 are based on the January, 2007 Maryland RGGI study (Maryland Study),[10] which projects CO_2 emission allowance prices for years 2010, 2015, 2020, and 2025. The 2011 and 2013 simulation prices are based on the Maryland Study projected 2010 prices, grown at the projected 2010-2015 annual growth rate.

CO_2 emissions prices in the study years 2018 and 2030 are based on the proposed 2007 Bingaman Bill Safety Valve.[11] This bill assumes a nominal safety valve price of $12 in 2012, escalating in real terms at 5% per year. For further discussion of assumptions related to this bill and other CO_2 reduction policies please see Appendix F.

NO_x and SO_x emissions allowance prices for all study years are based on the Energy Information Administration's (EIA) most recent reference case forecast.[12] Figure G.12 summarizes the NO_x, SO_x, and CO_2 allowance prices assumed in each study year.

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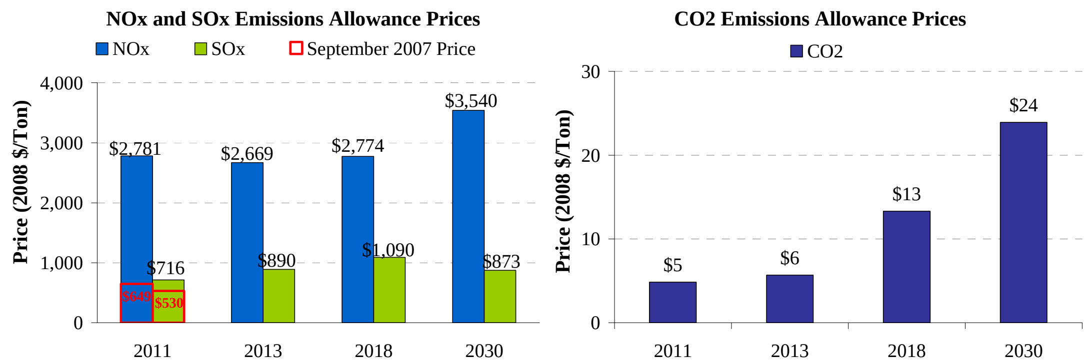
[10] *Economic and Energy Impacts from Maryland's Potential Participation in the Regional Greenhouse Gas Initiative*, Maryland Department of the Environment, January 2007.
[11] *Low Carbon Economy Act of 2007*, Page 16.
[12] *2007 Annual Energy Outlook*, Energy Information Administration, Reference Case Files.

Figure G.12: Emissions Allowance Prices in Current Trends Scenario



Emission rates in 2011 and 2013 assume (1) unit-specific emissions rates for the "Sooty Six" plants based on EPA CEMS data,[13] (2) average NO_x and SO_x rates by fuel type for all other fossil fuel-burning plants greater than 25 MW, and (3) average CO_2 rates by fuel type for all other units subject to RGGI.[14] Some generating units in Connecticut must submit two SO_2 allowances for each ton emitted under Connecticut law. This is implemented by increasing SO_x VOM by the additional SO_x cost for all units in CT>25 MW to reflect the additional SO_2 cost. In 2018 and 2030, the list of CO_2-monitored units under federal legislation includes all fossil-fuel-burning units greater than 25 MW. Figures G.13 and G.14 show the assumed unit-specific NO_x, SO_x, and CO_2 emissions rates for the "Sooty Six" plants, and the generic emissions rates used for all other plants, respectively.

[13] Sooty Six units include Bridgeport Harbor 2 & 3, Devon 7 & 8 (retired), Middletown 2-4, New Haven Harbor, Norwalk Harbor 1 & 2, Middletown 2 & 3 and Montville 5 & 6. Emissions rates are averages of reported CEMS rates in 2006. Rates for Middletown 2 & 3 and Montville 5 have been set to the average Sooty Six levels for the unit types due to poor data quality. Unit-specific rates for Montville 6 are not captured in this analysis, so generic rates are applied.

[14] Average CO2 rates are calculated based on EPA carbon content coefficients. See http://www.epa.gov/climatechange/emissions/downloads/2007GHGFastFacts.pdf. Units subject to RGGI are based on a draft list published by RGGI at http://www.rggi.org/draftlists.htm; however, there is no definitive list of RGGI affected units. The original state budgets were based on a preliminary list, and the criteria for plant selection remain somewhat ambiguous. The criteria refer to original "nameplate" capacity ratings, which can be different than more recent capacity measures. It also applies to units that use more than 50% fossil fuel, which may vary over time.

Figure G.13: Assumed Emissions Rates for Sooty Six Units

Unit Name	Assumed Emissions Rate (Lbs/MMBtu)		
	CO2	SOx	NOx
BRIDGEPORT HARBOR 2	162	0.272	0.302
BRIDGEPORT HARBOR 3	205	0.181	0.136
DEVON 7*	N/A	N/A	N/A
DEVON 8*	N/A	N/A	N/A
MIDDLETOWN 2	162	0.276	0.171
MIDDLETOWN 3	162	0.276	0.171
MIDDLETOWN 4	162	0.275	0.149
MONTVILLE 5	162	0.276	0.171
MONTVILLE 6**	N/A	N/A	N/A
NEW HAVEN HARBOR	162	0.257	0.134
NORWALK HARBOR 1	162	0.292	0.142
NORWALK HARBOR 2	162	0.286	0.129
Average	167	0.266	0.167

*Devon 7 & 8 are retired.
**Generic rates are applied.

Figure G.14: Assumed Emissions Rates for All Other Units

Fuel Category	CO2 Emissions from Combustion *(Lbs CO2/MMBtu)*	NOx Emissions from Combustion *(Lbs NOx/MMBtu)*	SOx Emissions from Combustion *(Lbs SOx/MMBtu)*
NG	115.8	0.020	0.001
FO2	159.7	0.040	0.060
FO6	172.0	0.200	0.800
Coal	204.0	0.300	1.200

b. Strict Climate Scenario

The Strict Climate scenario assumes strict Federal legislation on CO_2 emissions to be in effect by the 2013 study year, so 2011 monitored units and emissions prices are identical to the Current Trends scenario. In 2013, the CO_2-monitored units under Federal legislation includes all fossil-fuel-burning (and refuse-burning) units greater than 25 MW, as in Current Trends 2018 and 2030 study years. Emissions rates are the same as the Current Trends scenario during the period in which Federal legislation is assumed to be in effect.

CO_2 emissions allowance prices under Strict Climate Federal legislation (study years 2013, 2018, and 2030) are based on the EIA assessment of S.280, the Lieberman Climate Stewardship and Innovation Act of 2007 (EIA S.280). The EIA S.280 CO_2 prices are doubled to account for offset sensitivity.[15]

c. High Fuel/Growth Scenario

The High Fuel/Growth scenario assumes all emissions rates, and 2011 and 2013 emissions allowance prices are unchanged from the Current Trends scenario. 2018 & 2030 CO_2 emission allowance prices are assumed to be 30% higher than in the Reference Case. NO_x and SO_x emissions allowance prices are unchanged from the Current Trends scenario.

d. Low Stress Scenario

All emissions rates and prices are unchanged from Current Trends scenario.

XI. Fuel Prices

a. Natural Gas

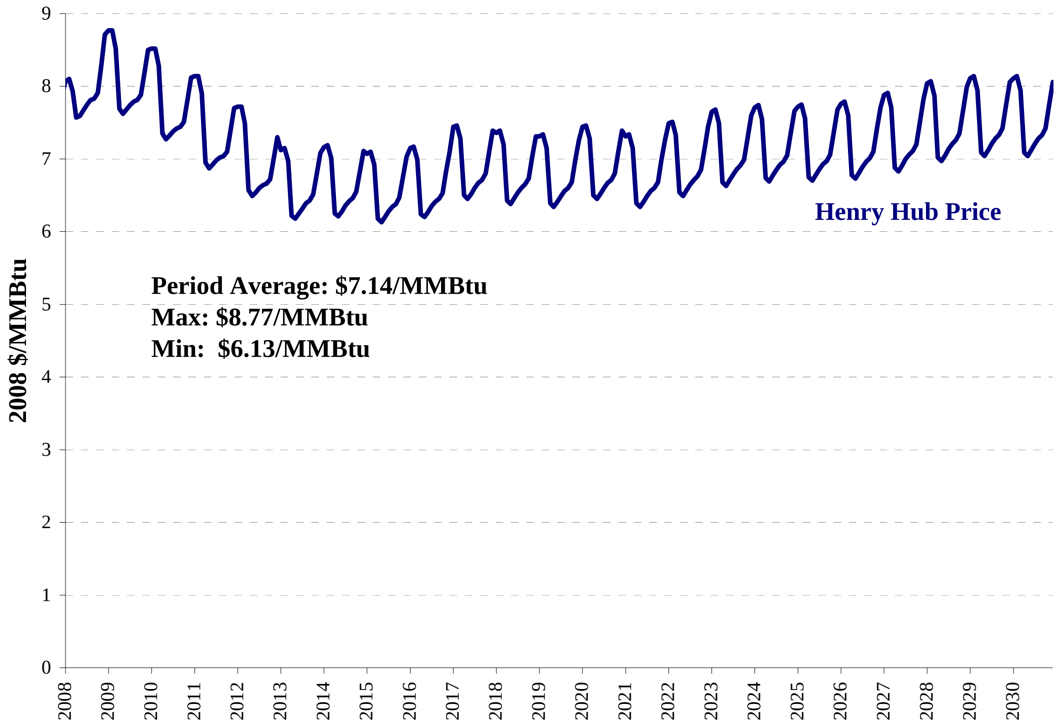
2011 Henry Hub natural gas prices are from NYMEX Henry Hub Futures as of 9/27/2007,[16] with prices available October 2007 through December 2012. 2013, 2018, and 2030 Henry Hub natural gas prices are derived using the previous year's average price, adjusted with a monthly multiplier to reflect seasonal variation, then grown using the annual EIA growth rate.[17] Monthly multipliers are calculated by using the NYMEX 2010 monthly/annual average price, removing the trend to leave only a seasonal pattern. Figure G.15 shows assumed monthly Henry Hub natural gas prices through 2030.

[15] The EIA analysis found that CO_2 prices were very sensitive to the amount of offsets allowed, and that under the same bill but without any offsets, the price would approximately triple.

[16] NYMEX futures prices as of September 27th, 2007: http://www.nymex.com/media/092707.pdf.

[17] *2007 Annual Energy Outlook*, Energy Information Administration, Table 11: Energy prices by Sector and Source (New England).

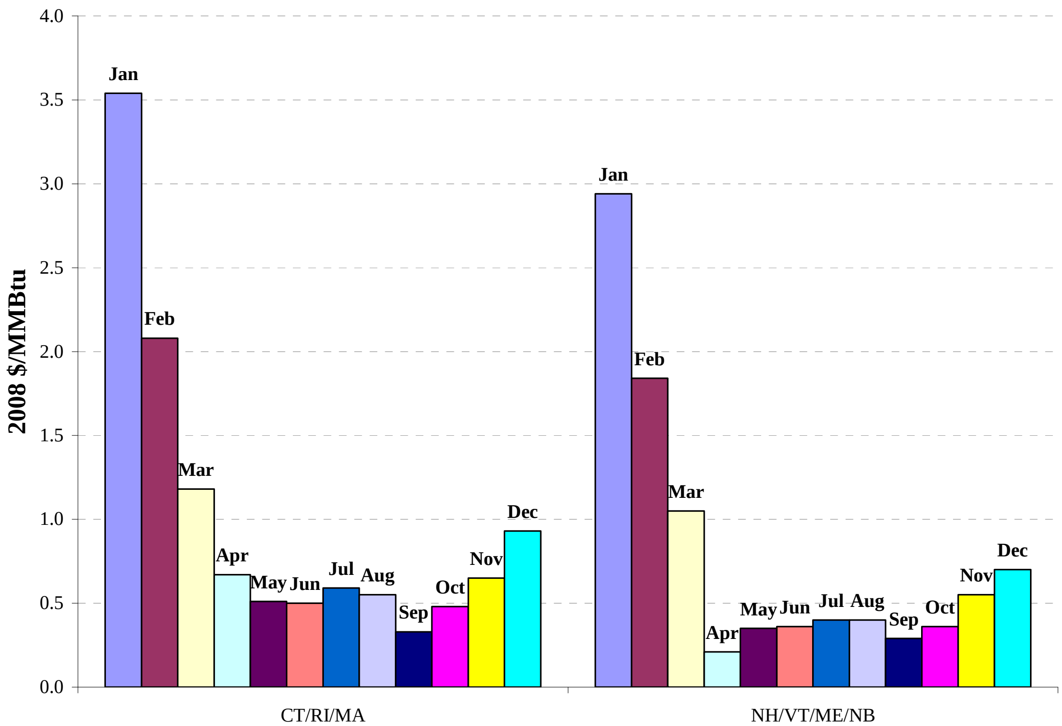
Figure G.15: Monthly Henry Hub Natural Gas Prices through 2030 in the Current Trends Scenario



Future basis differentials from Henry Hub are based on historical average monthly basis differentials from 2003, 2004, and 2006.[18] Algonquin prices are used for Southern New England (CT, RI, MA), and Dracut prices (price of Canadian gas flowing south) are used for Northern New England (NH, VT, ME).[19] The average Algonquin winter differential is ~$1.70/MMBtu; summer is ~$.50/MMBtu; and the Algonquin annual average is $1.00/MMBtu, with Dracut at about 20 cents below Algonquin. Figure G.16 shows the assumed natural gas basis differentials used in all scenarios and study years.

[18] 2005 is excluded due to an unusually cold October.
[19] Monthly averages of Spot Prices for Henry Hub, Algonquin City gate and Dracut are from Platts *Gas Daily*. See www.platts.com.

Figure G.16: Assumed Natural Gas Basis Differentials in All Scenarios and Study Years



b. Distillate and Residual Fuel Oil

2011 Residual Fuel Oil (FO6) prices are based on NYMEX Crude Oil futures as of 9/27/2007, with prices available from October 2007 through December 2012. After 2012, FO6 prices are based on EIA daily historic (June 2, 1986-Sep 27, 2007) Crude Oil and Residual Fuel Oil spot prices.[20] A relationship between the historic Crude Oil prices and FO6 prices was determined using a simple linear regression, and FO6 prices are then predicted through 2030 based on this relationship. 2013, 2018, and 2030 FO6 prices use these predicted prices, grown at the annual EIA predicted growth rate.[21]

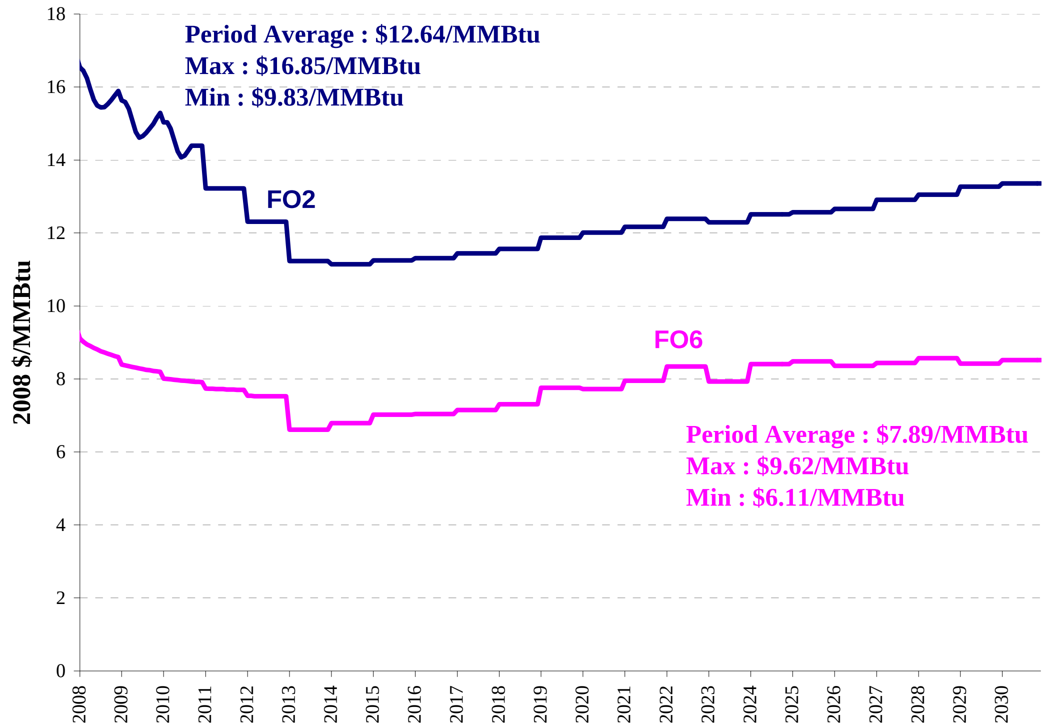
Distillate Fuel Oil (FO2) prices for all years are based on NYMEX Heating Oil futures as of 9/27/2007, with prices available from October 2007 through September 2010. All prices are then

[20] EIA: Petroleum Navigator: Spot Prices: Downloaded from the EIA Website: http://tonto.eia.doe.gov/dnav/pet/xls/pet_pri_spt_s1_d.xls.

[21] *2007 Annual Energy Outlook*, Energy Information Administration, Table 11: Energy prices by Sector and Source (New England).

grown at the annual EIA predicted growth rate.[22] Figure G.17 shows the assumed FO6 and FO2 prices through 2030 in the Current Trends Scenario.

Figure G.17: 2008-2030 Assumed FO2 and FO6 Prices in the Current Trends Scenario



c. Coal

2011 and 2013 delivered coal prices are unit-specific and are compiled by CES based on historic values. 2018 and 2030 prices for coal and "other" fuel use the CES-estimated 2015 nominal values. Figure G.18 summarizes delivered coal prices by unit for each of the study years.

[22] *2007 Annual Energy Outlook*, Energy Information Administration, Table 11: Energy prices by Sector and Source (New England).

Figure G.18: Assumed Delivered Coal Prices in All Scenarios and Study Years

Unit Name	Zone	State	Summer Capacity (MW)	Average Price (2008 $/MMBtu) 2011	2013	2018	2030
AES THAMES	Rest of CT Zone	CT	181	$3.13	$2.99	$2.87	$2.87
BRAYTON PT 1	South Eastern MA Zone	MA	243	$3.01	$2.88	$2.76	$2.76
BRAYTON PT 2	South Eastern MA Zone	MA	222	$3.01	$2.88	$2.76	$2.76
BRAYTON PT 3	South Eastern MA Zone	MA	612	$3.01	$2.88	$2.76	$2.76
BRIDGEPORT HARBOR 3	South Western CT Zone	CT	372	$3.13	$2.99	$2.87	$2.87
MEAD	Maine Zone	ME	75	$3.01	$2.88	$2.76	$2.76
MERRIMACK 1	New Hampshire Zone	NH	112.5	$2.82	$2.70	$2.59	$2.59
MERRIMACK 2	New Hampshire Zone	NH	320	$2.82	$2.70	$2.59	$2.59
MT TOM	West Central MA Zone	MA	145	$3.09	$2.96	$2.84	$2.84
SALEM HARBOR 1	NE MA Boston Zone	MA	82	$3.27	$3.13	$3.00	$3.00
SALEM HARBOR 2	NE MA Boston Zone	MA	80	$3.27	$3.13	$3.00	$3.00
SALEM HARBOR 3	NE MA Boston Zone	MA	149	$3.27	$3.13	$3.00	$3.00
SCHILLER 4	New Hampshire Zone	NH	47.5	$2.82	$2.70	$2.59	$2.59
SCHILLER 5*	New Hampshire Zone	NH	47	$2.82	$2.70	$2.59	$2.59
SCHILLER 6	New Hampshire Zone	NH	47	$2.82	$2.70	$2.59	$2.59
SOMERSET	Maine Zone	ME	10	$3.01	$2.88	$2.76	$2.76
SOMERSET 6	South Eastern MA Zone	MA	105	$3.11	$2.97	$2.85	$2.85
	Total		**2850**				

*Schiller 5 has been converted to wood, which is not captured in the model.

XII. DEMAND-SIDE MANAGEMENT (DSM) [23]

All Connecticut demand response programs have been forecasted through 2018 by the Companies.[24] The Companies have provided calendar-year estimates of DSM programs by company, including 2007-2018 energy and peak reduction values for energy efficiency (EE) and 2007-2018 peak reduction values for demand response (DR). After 2018, DSM-induced load reductions are assumed to remain constant as a percentage of load. Data are adjusted to mid-year values using a 33% half-year factor.[25] The data are at-meter estimates so all DSM values are grossed up by 8% for transmission and distribution losses before being deducted from the energy needed to meet load. For capacity planning purposes, load reductions that are counted as supply

[23] Here, "demand-side management" refers to both energy conservation and demand response. "Energy efficiency" in this appendix refers only to the energy conservation element of DSM.

[24] See "CT DSM Sum_Ver 7_CLP UI Rev-with Stata input database_ 31 Oct 07_HEAVY and BASE CASE.xls." The Client provided an updated version as of November 1, 2007 which could not be implemented due to schedule requirements.

[25] Mid-year estimates are calculated as 2/3*(preceding year EOY estimates) + 1/3*(current year's EOY estimates).

are grossed up by an additional 16.6% to account for the associated reduction in required reserves.[26]

The companies have forecasted a "Reference" level of DSM which is used in the Conventional, Nuclear, and Coal resource solutions, and a "Heavy" level of DSM which is used in the DSM-Focus resource solution. Since there are detailed data on DSM plans only for Connecticut, Base DSM programs are extrapolated to the rest of New England (RONE) assuming half as much growth in DSM per megawatt of total load. In the DSM-Focus resource solution RONE is assumed to continue with Base DSM, while Connecticut implements Heavy DSM. Once the Connecticut and RONE DSM values are determined, the data are split into DAYZER subzones by share of summer peak reference case forecast gross load.

DSM in the Current trends scenario is assumed to be achieve the load reductions shown in Tables 2.2 and 2.3 and described in Appendix D, and this effectiveness is reduced in other scenarios in which elevated prices induce a "natural" reduction in load, leaving a smaller incremental effect of DSM.

XIII. GROSS AND NET LOAD[27]

All DSM is implemented in DAYZER via load adjustments from the "gross" load forecast, producing a "net" load. Gross and net load implementation is described below for each scenario. The methodology of determining the gross and net load levels is described in more detail in Appendix B.

a. Current Trends Scenario

Load in the Current Trends scenario is based on the ISO-NE weather-normalized 2008-2016 hourly subzonal forecast shown in the *CELT* report (*CELT* Load Forecast),[28] extrapolated to the 2018 and 2030 study years. The 2016 *CELT* Load Forecast is extrapolated through 2030 by using the long-term 2015-2016 summer and winter reference case peak load growth rates. Weekdays in 2017-2030 are aligned with 2016 weekdays, and the long-term seasonal growth

[26] Also, the data do not include RGGI savings.
[27] Net load refers to load net of DSM program effects.
[28] http://www.iso-ne.com/trans/*CELT*/fsct_detail/index.html

rates are applied to the 2016 load forecast. Demand-side Management (DSM) load reductions are not included in the *CELT* Load Forecast, as indicated in the ISO's Representative ICR Calculation.[29] However, Companies' estimates of future DSM are ultimately reflected in the load inputs to the model, the implementation of which is explained at the end of this section.

The *CELT* Load Forecast subzones BOSTON/CMASS, WMASS, and NEMASS do not correspond directly with DAYZER subzones, so the Massachusetts load data are split into redefined DAYZER subzones. DAYZER NEMASS/BOSTON and WCMASS zones are derived from the *CELT* Load Forecast subzones by using the *CELT* Load Forecast reported demand shares by zone. The *CELT* Load Forecast reports that WCMASS is 13.4% of ISO-NE in the summer and 13.7% of ISO-NE in the winter, and NEMASS/BOSTON is 19.4% of ISO-NE in the summer and 19.2% of ISO-NE in the winter. Hence, for summer months (April through October in the model), the total WCMASS/NEMASS/BOSTON subzone share of total ISO is 32.8%. WCMASS is 40.854% of this share, and NEMASS/BOSTON is the remaining 59.146% of this share. For winter months, the total WCMASS/NEMASS/BOSTON subzone share of total ISO is 32.9%. WCMASS is 41.641% of this share, and NEMASS/BOSTON is the remaining 58.359% of this share, and the load is divided accordingly. Figure G.19 displays the DAYZER subzones, and overlapping ISO subzones.

Figure G.19: DAYZER and ISO Subzones

DAYZER Subzone	State	ISO Subzone	
Rest of CT Zone	CT	CT	
Norwalk- Stamford Zone	CT	NOR	
South Western CT Zone	CT	SWCT	
NE MA Boston Zone	MA	BOSTON/CMA-NEMA	*
South Eastern MA Zone	MA	SEMA	
West Central MA Zone	MA	W-MA/CMA-NEMA	*
Maine Zone	ME	ME/S-ME/BHE	
New Hampshire Zone	NH	NH	
Rhode Island Zone	RI	RI	
Vermont Zone	VT	VT	

*Load in these ISO subzones is split to correspond with the DAYZER subzones.

[29] Agustin, Maria, "Representative Installed Capacity Requirements for RSP07," PSPC Meeting No. 233, Agenda Item 5.0, August 16, 2007, slide 14.

In its forecast, the ISO-NE projects a long-term declining growth rate, which is consistent with the CT DPUC's understanding of long-term growth rates.[30] For years beyond 2016 we extrapolate 2015-2016 growth rates, which are approximately only one percent. Figure G.20 shows 2015 and 2016 peak load by ISO-NE subzone, long-term peak growth rates, and subzone shares of total ISO non-coincident peak load.

Figure G.20: Summary of ISO-NE Long-Term Peak Load Forecast and Load Growth Rates

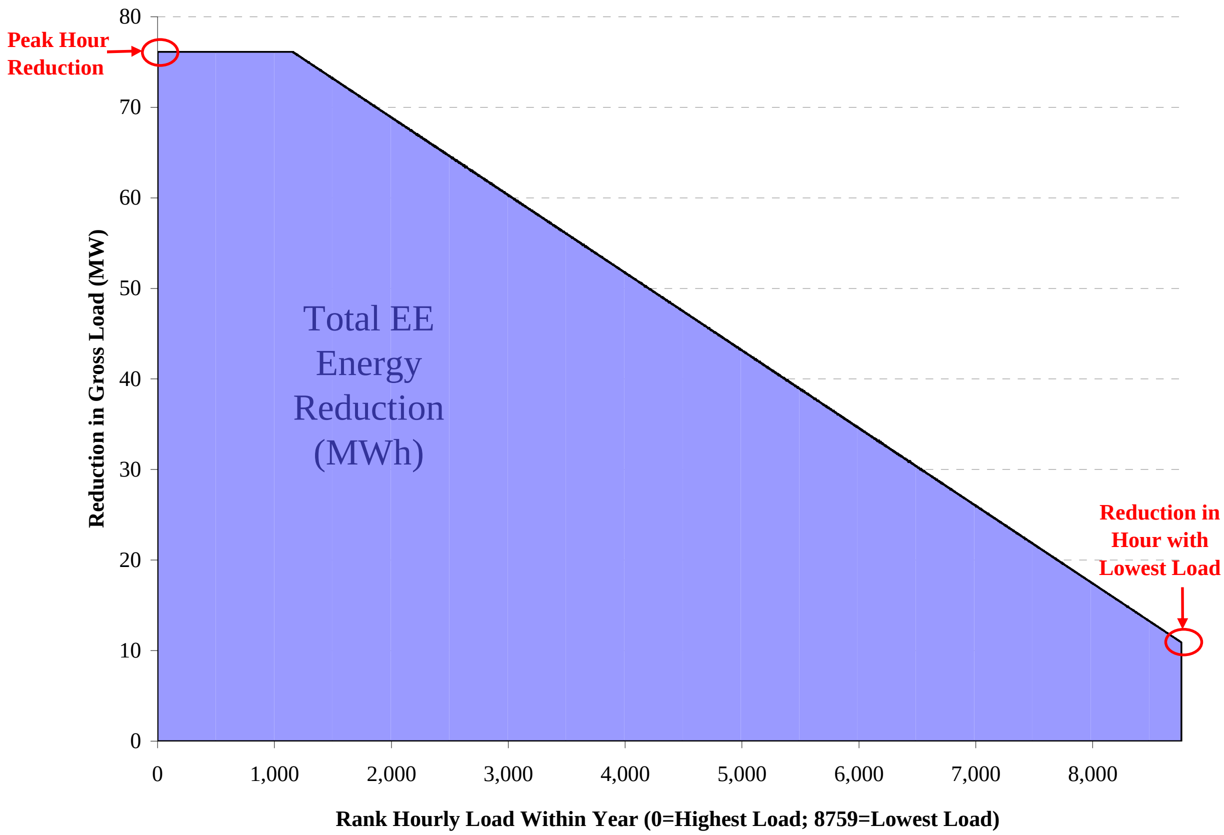
	2015 Peak Load		2016 Peak Load		CAGR Growth		2015-2016 Growth		2016 Subzone Shares	
ISO-NE Subzone	Summer Peak (50/50) (MW)	Winter Peak (50/50) (MW)	Summer Peak (50/50) (MW)	Winter Peak (50/50) (MW)	Summer Peak (50/50)	Winter Peak (50/50)	Summer Peak (50/50)	Winter Peak (50/50)	Summer Peak (50/50)	Winter Peak (50/50)
BHE	347	331	350	335	1.6%	1.4%	0.9%	1.2%	1.1%	1.3%
BOSTON	6,190	4,912	6,254	4,966	1.5%	1.1%	1.0%	1.1%	19.6%	19.4%
CMANEMA	2,075	1,641	2,104	1,658	1.3%	1.0%	1.4%	1.0%	6.6%	6.5%
CT	4,092	3,255	4,139	3,284	1.7%	1.1%	1.1%	0.9%	13.0%	12.8%
ME	1,241	1,217	1,259	1,232	2.0%	1.4%	1.5%	1.2%	3.9%	4.8%
NH	2,477	1,968	2,523	2,001	2.7%	1.5%	1.9%	1.7%	7.9%	7.8%
NOR	1,455	1,124	1,471	1,134	1.5%	1.1%	1.1%	0.9%	4.6%	4.4%
RI	2,917	2,063	2,951	2,082	1.8%	1.0%	1.2%	0.9%	9.3%	8.1%
SEMA	3,336	2,595	3,377	2,621	1.6%	1.1%	1.2%	1.0%	10.6%	10.2%
SME	768	660	779	667	1.9%	1.2%	1.4%	1.1%	2.4%	2.6%
SWCT	2,742	2,237	2,765	2,258	1.6%	1.5%	0.8%	0.9%	8.7%	8.8%
VT	1,441	1,342	1,457	1,361	1.8%	1.2%	1.1%	1.4%	4.6%	5.3%
WMA	2,423	2,005	2,452	2,023	1.8%	0.9%	1.2%	0.9%	7.7%	7.9%
Total									100.0%	100.0%

EE is implemented by (1) reducing the peak load by the EE peak hour reduction (2) reducing gross load such that hours are not reordered in the load duration curve and (3) making total reductions consistent with the required EE energy reduction. This is achieved by first reducing the peak load by the peak hour reduction, reducing the last hour on the load duration curve by 1 MW, interpolating reductions between these two points on the load duration curve, then iteratively reducing each hour by .01 MW increments (subject to the max peak hour reduction) until the required EE energy reduction is met. Figure G.21 illustrates Reference DSM EE

[30] December 5, 2006 Addendum Updated Load Forecast; Connecticut Department of Public Utility Contro Request for Proposals to Reduce Impact of FMCCs; Docket No. 05-07-14PH02. See http://www.connecticut2006rfp.com/rfp_docs.php.

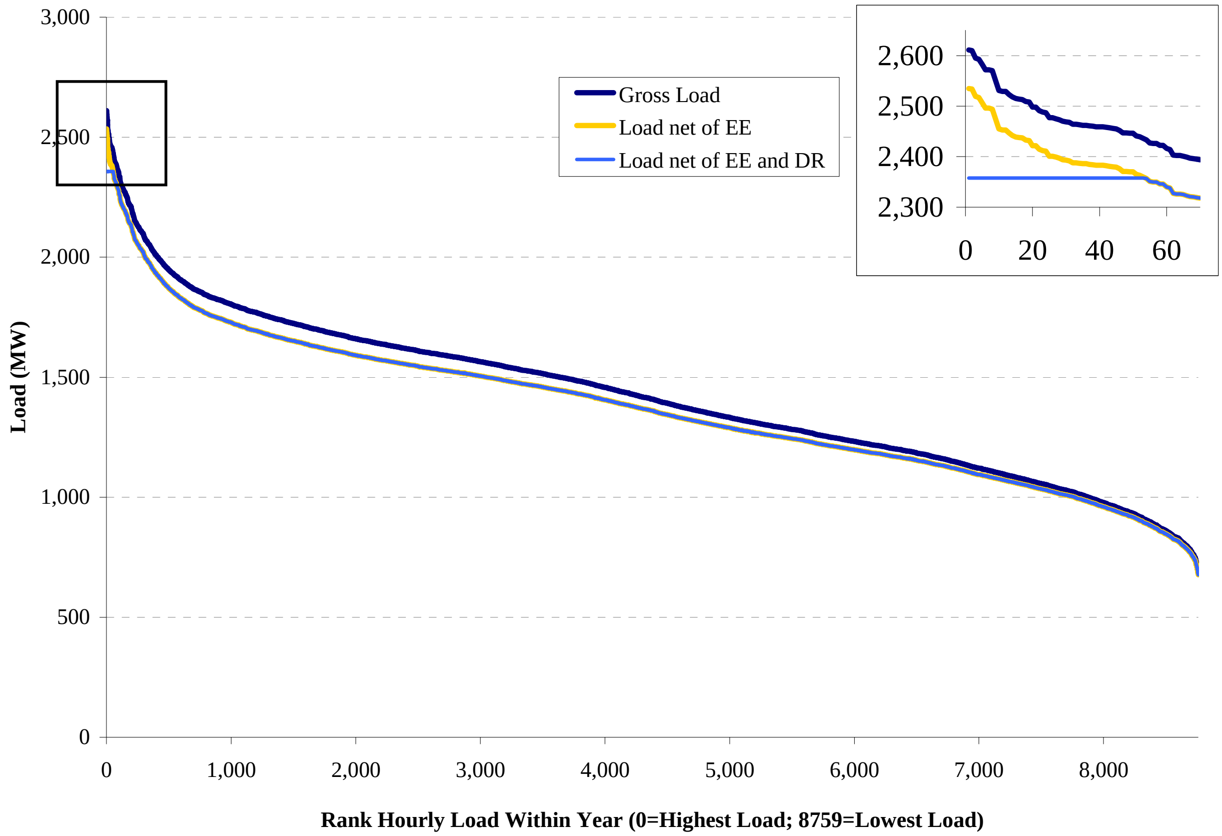
reductions on 2011 gross load for the SW-CT subzone in the Current Trends Scenario. This subzone and level of DSM is used as an example to demonstrate load adjustment methodology in all scenarios, as shown in Figures G.21 through G.28 described in this section. DR is always implemented by "shaving" the peak load after EE reductions have been implemented: the peak hour load minus the DR peak hour reduction becomes the max load for the year.[31] Figure G.22 shows the final net load after Reference DSM EE and DR reductions in the Current Trends Scenario.

Figure G.21: Methodology for Implementing Peak and Energy Adjustments due to Reference DSM in the Current Trends Scenario: 2011 SW-CT Example



[31] This is a simplification that does not account for the shifting of load to other hours.

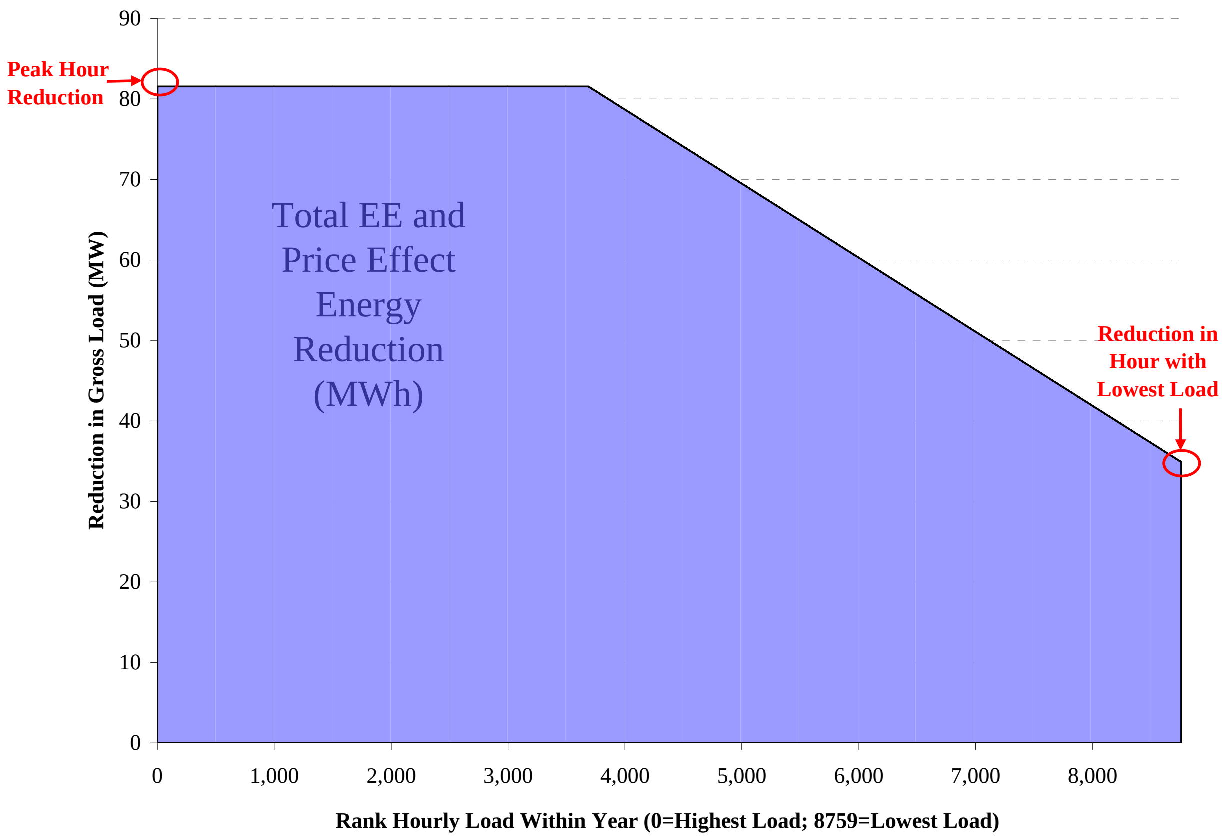
Figure G.22: Net Load with Reference DSM in the Current Trends Scenario: 2011 SW-CT Example



b. Strict Climate Scenario

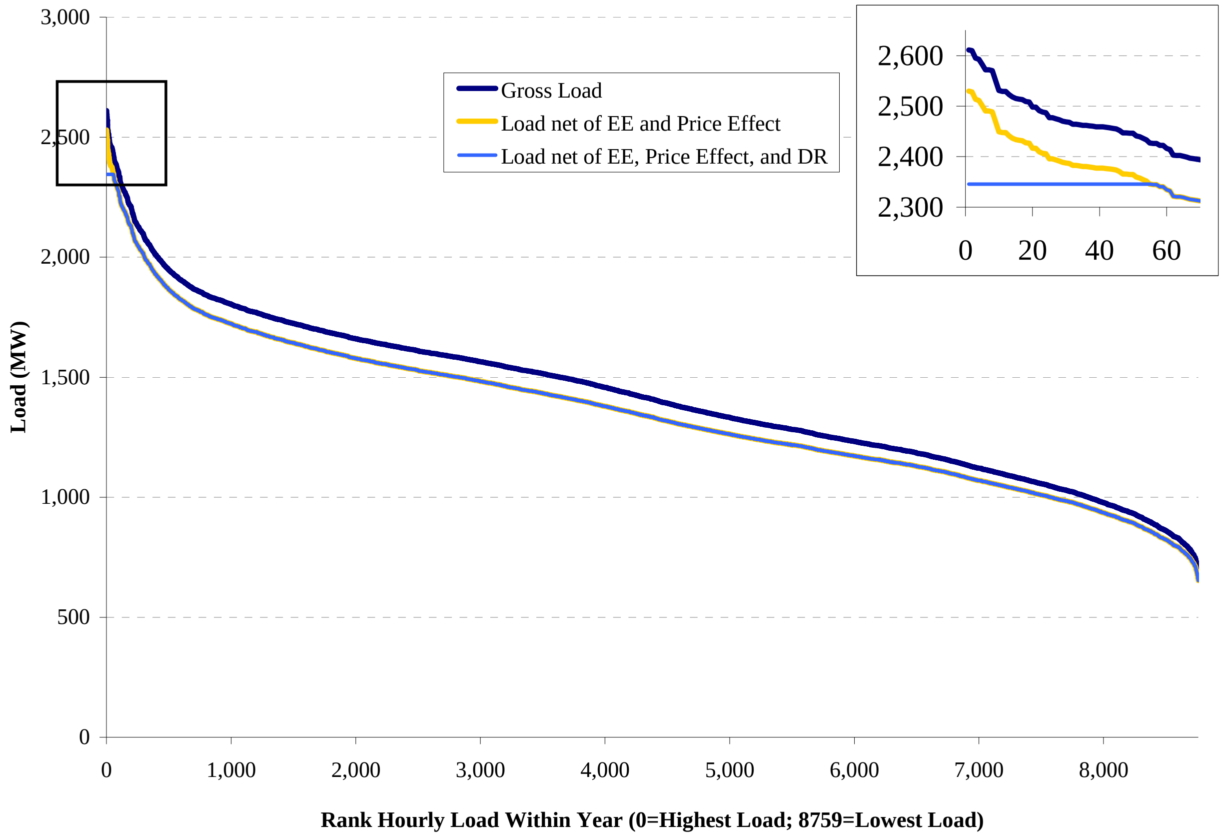
The Strict Climate scenario assumes the same gross load (without DSM effects) as the *CELT* Load Forecast, but with load reductions due to response to higher fuel prices, and lowered effectiveness of DSM efforts due to these load reductions. The full price impact is realized by 2018, and consists of a short-term peak impact of -1.39%, phased in over three years from 2009 through 2011, and an additional long-term impact of -1.04%, phased in over the next seven years from 2012 through 2018. After 2018 load is assumed to continue at a 1% growth rate. Load adjustments to the *CELT* Load Forecast are applied simultaneously with DSM adjustments. Combined price effect and EE peak and energy reductions are implemented as in the Current Trends Scenario, as are DR reductions. Figure G.23 illustrates the 2011 SW-CT combined EE and fuel price effect peak and energy reductions, and Figure G.24 shows the net load after all adjustments, including DR.[32]

Figure G.23: Methodology for Implementing Peak and Energy Adjustments due to Reference DSM and Fuel Price Effects in the Strict Climate Scenario: 2011 SW-CT Example



[32] DR implementation in all scenarios is the same: once gross load is determined and fuel price effects and EE peak and energy reductions are applied, the DR peak shaving is implemented.

Figure G.24: Net Load with Fuel Price Effect and Reference DSM in the Strict Climate Scenario: 2011 SW-CT Example



c. High Fuel/Growth Scenario

Energy in the High Fuel/Growth scenario is assumed to grow at a rate 0.8% higher than in the Current Trends scenario through 2018 to reflect a high growth environment, then at a long-term growth rate of approximately 1% through 2030. High fuel prices are assumed to induce a price impact on this high growth load, consisting of a short-term impact of -3.68% phased-in over 3 years, plus an additional -2.76% long-run reduction phased-in over the next 7 years. Changes from the *CELT* Load Forecast in the underlying gross load, fuel price effects, and EE peak and energy reductions are implemented simultaneously.

In this scenario, the combined average energy reduction is typically greater than the peak reduction, and in these cases the hourly reduction in absolute terms is assumed to ramp up on the load duration curve to meet the required total energy reduction. This implies a relative insensitivity during the highest load hours to load reduction forces, and the slope of the ramp in each subzone has been made proportional to that subzone's share of total load to reflect greater peak insensitivity in smaller subzones. Figure G.25 illustrates the 2011 SW-CT combined change in gross load, EE, and fuel price effect peak and energy reductions. If the combined average energy reduction is smaller than the combined average peak reduction then adjustments are made following the EE adjustment methodology in the Current Trends Scenario. Figure G.26 shows the net load after all 2011 High Fuel/Growth Scenario adjustments in SW-CT, including DR.

Figure G.25: Methodology for Implementing Peak and Energy Adjustments due to Differences in Gross Load, Reference DSM, and Fuel Price Effects in the High Fuel/Growth Scenario: 2011 SW-CT Example

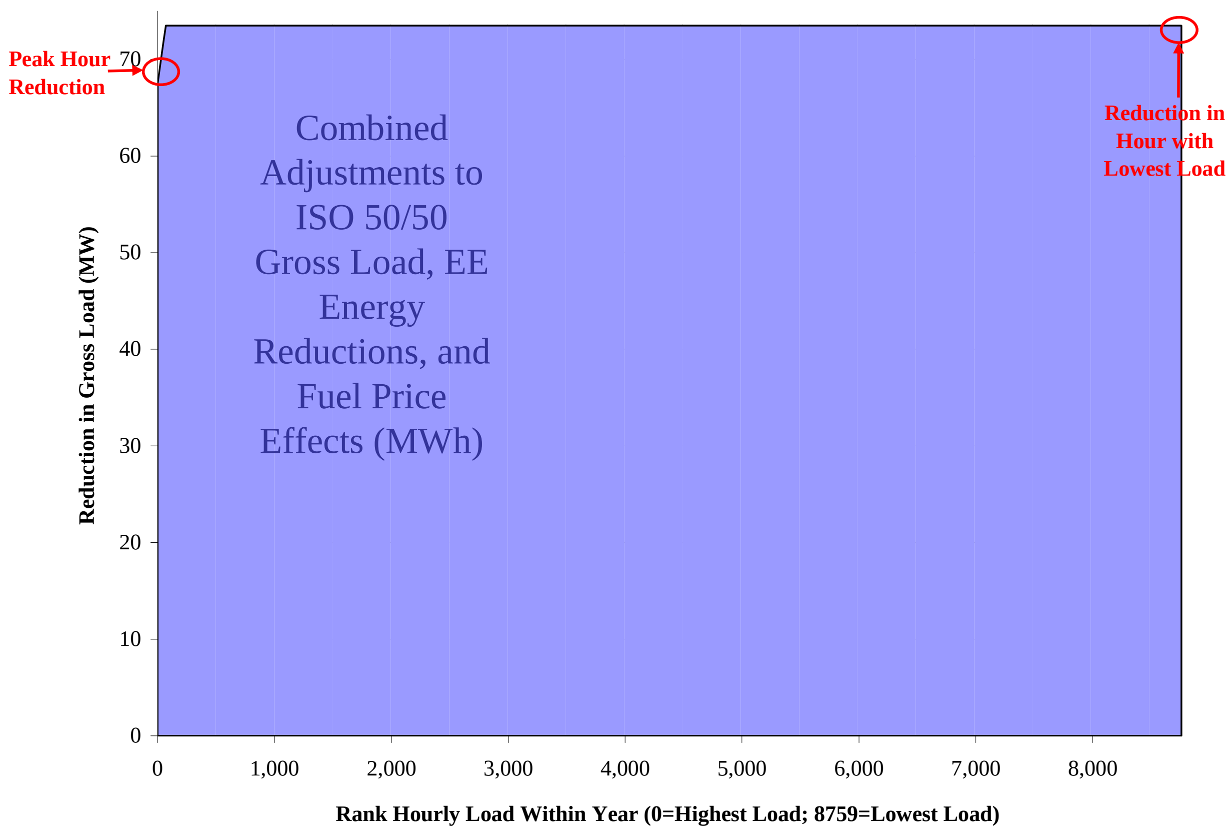
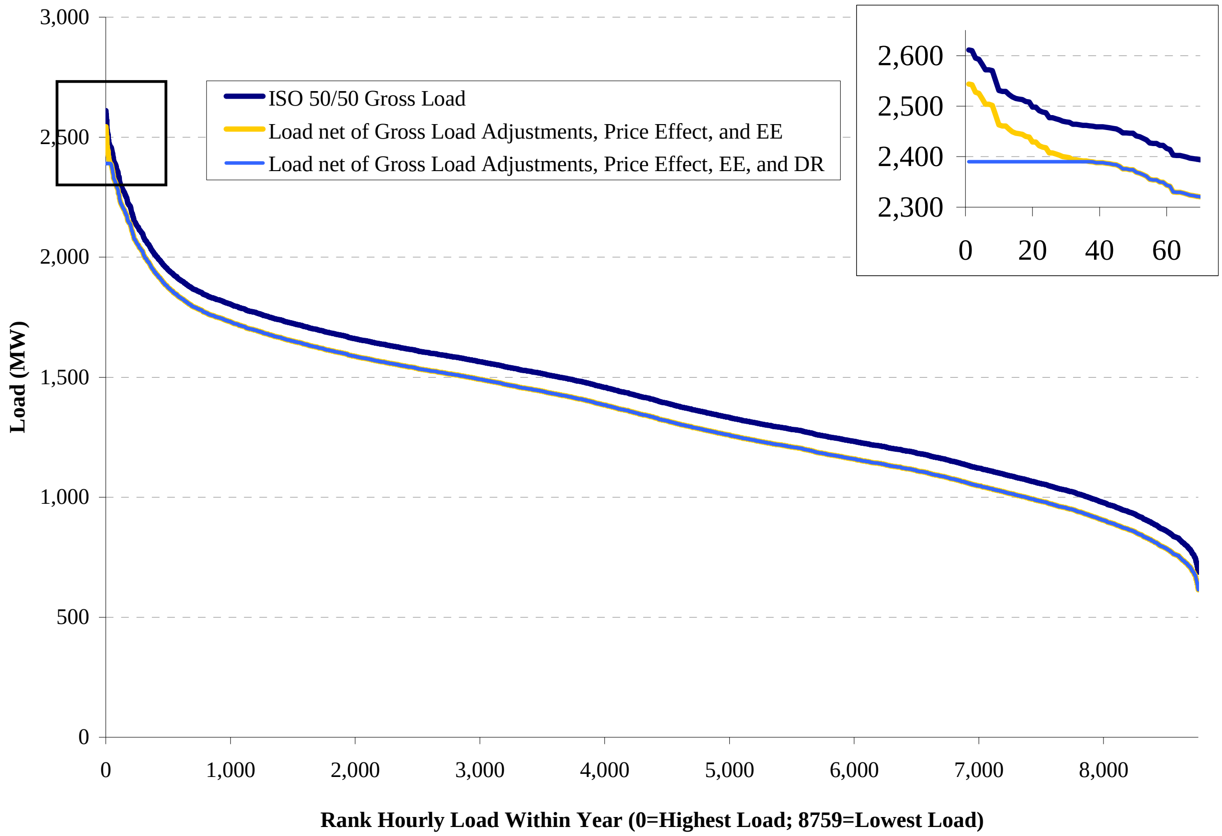


Figure G.26: Net Load with Gross Load Adjustments, Fuel Price Effect, and Reference DSM in High Fuel/Growth Scenario: 2011 SW-CT Example



d. Low Stress Scenario

Energy in the Low Stress scenario is assumed to grow at a rate 0.4% higher than in the Current Trends scenario through 2018 to reflect a high growth environment, then at a long-term growth rate of approximately 1% through 2030. High fuel prices are assumed to induce a price impact on this low stress load, consisting of a short-term impact of 2.04% phased-in over 3 years, plus an additional 1.53% long-run reduction phased-in over the next 7 years.

Combined gross load adjustments, fuel price effects, and EE peak and energy reductions typically lead to large positive peak reductions, coupled with very small energy reductions (sometimes *negative* – an energy *increase*). In some cases, there is an increase in both peak and energy. These results indicate some energy shifting in this scenario, and the combined adjustments to the *CELT* Load Forecast gross load (excluding DR) are implemented assuming that the relative energy reductions in the highest load hours are shifted to off-peak hours. So, some off-peak hours always show a net energy increase, regardless of the sign of total energy adjustments. Figure G.27 shows the 2011 SW-CT combined change in gross load, EE, and fuel price effect peak and energy reductions. Figure G.28 shows the net load after all 2011 Low Stress Scenario adjustments in SW-CT, including DR.

Figure G.27: Methodology for Implementing Peak and Energy Adjustments due to Differences in Gross Load, Reference DSM, and Fuel Price Effects in the Low Stress Scenario: 2011 SW-CT Example

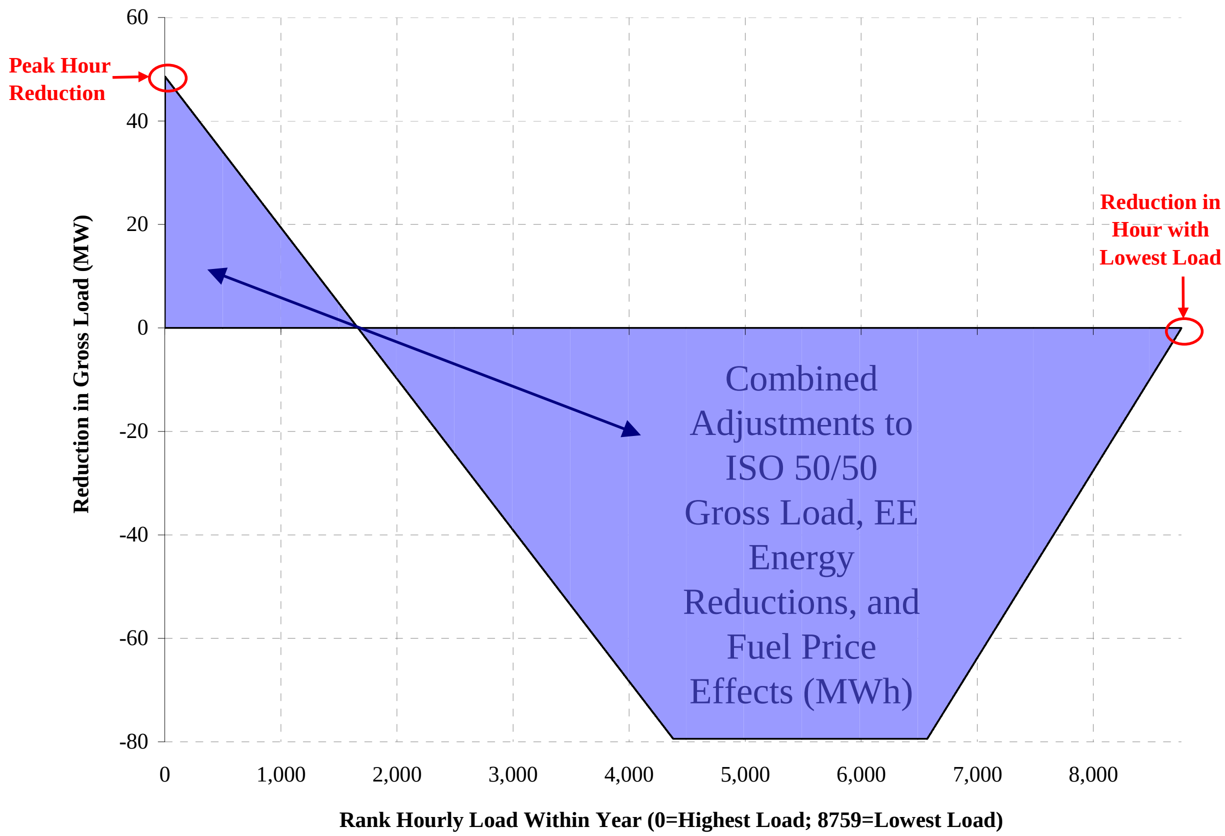
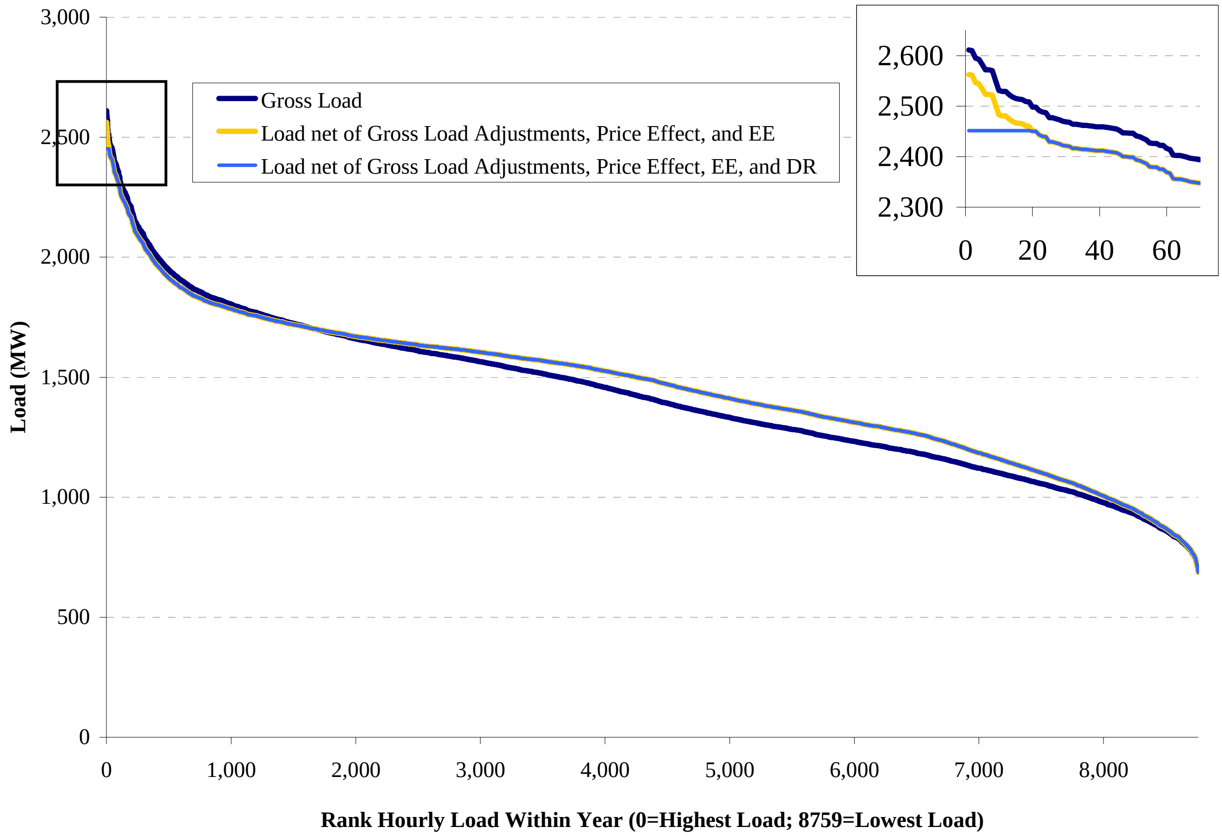


Figure G.28: 2011 SW-CT Net Load with Gross Load Adjustments, Fuel Price Effect, and Reference DSM in Low Stress Scenario

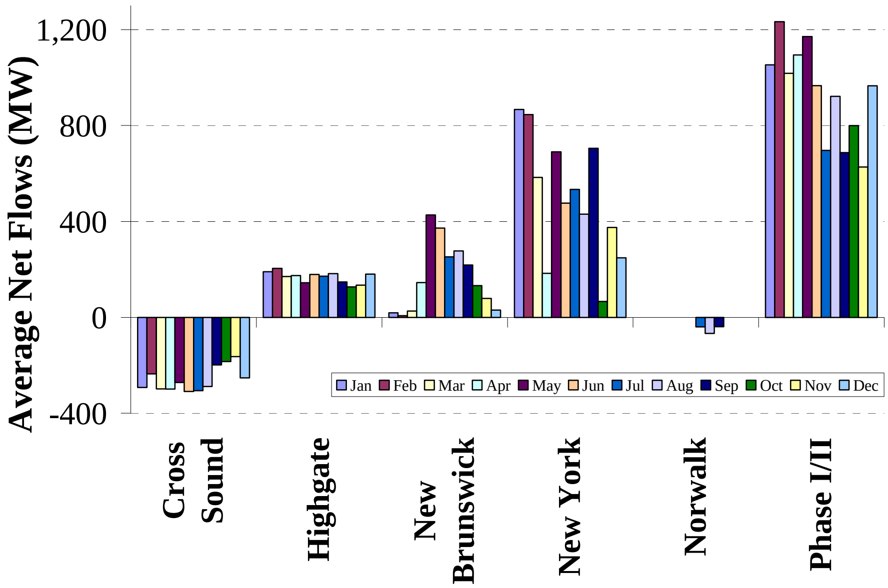


XIV. External Flows: ISO-NE Net Imports

DAYZER models ISO-NE independently, and flows in and out of the ISO-NE system are non-dynamic. 2011 hourly net imports are forecasted by CES by extrapolating the most recent[33] ISO-NE actual import/export data by weekday/weekend and month. 2013, 2018, and 2030 net imports use 2011 values, realigned by weekday. Figure G.30 summarizes the assumed ISO import/export schedule for all cases.

[33] As of September, 2007. Import/export data are downloaded from the ISO-NE website.

Figure G.30: Average Net Imports to ISO-NE System



XV. RESERVE REQUIREMENTS

2011 hourly spin and AGC reserve requirements are forecasted by CES by extrapolating historical values by weekday/weekend and season. 2013, 2018, and 2030 net imports use 2011 values, realigned by weekday. Hourly spin requirements range from 1267-1320 MW, and hourly AGC reserve requirements (added to the spin requirement in the model) range from 100-280 MW. Quickstart requirements not modeled.

XVI. TRANSMISSION

a. Topology

The transmission system representation is based on the load flow used for the ISO-NE November 2006 FTR auction, which we upgraded to include Phase II of the Southwest Connecticut Reliability Project (345-kV Middletown-Norwalk Project) and the 345 kV Ludlow-Barbour Hill Project by the 2011 study year, then further upgraded to include major New England East/West Solution (NEEWS) elements by the 2013 study year. Full project details are extensive so, for simplicity, only major elements expected to have a significant impact on the simulation results (all 345kV and 115kV elements) of each project are implemented. The major additions to the November 2006 load flow to represent these transmission enhancements in the 2011 and 2013 study years are listed in Figures G.31 and G.32, respectively.

Figure G.31: Additions to 2006 Load Flow to Represent the 345-kV Middletown-Norwalk Project and the 345 kV Ludlow-Barbour Hill Project by the 2011 Study Year

Element Name	Element Type	Summer Rating A	Summer Rating B
BESECK 345	Substation		
HADAMNK 345 - BESECK 345	Line	1488	1793
HADDAM 345 - BESECK 345	Line	1488	1912
SOTHNGTN 345 - BESECK 345	Line	1488	1912
E_DEVON 345	Substation		
BESECK 345 - E_DEVON 345	Line	2038	2634
DEVON - E_DEVON	Transformer	707	797
SINGER 345	Substation		
E_DEVON 345 - SINGER 345 CKT1	Line	600	1128
E_DEVON 345 - SINGER 345 CKT2	Line	600	1128
BRIDGEPT 115 - SINGER 345	Transformer	435	440
SINGER 345 - NORWLK 345 CKT1	Line	600	1128
SINGER 345 - NORWLK 345 CKT2	Line	600	1128
BARBOURH 345	Substation		
BARBOURH 115 - BARBOURH 345	Transformer	747	795
BARBOURH 345 - LUDLOW 345	Line	1240	1604
BARBOURH 345 - MEEK_J 345	Line	1240	1604

Figure G.32: Additions to 2006 Load Flow to Represent NEEWS by the 2013 Study Year

Element Name	Element Type	Summer Rating A	Summer Rating B
Manchester 345 - Card 345 CKT 2	Line	1488	1912
Card 345 - Millstone 345 CKT 2	Line	1255	1446
Manchester 115 - East Hartford 115 CKT 2	Line	250	371
SW Hartford 115 - NW Hartford 115	Line	250	371
S Meadow 115 - SW Hartford 115 CKT 2	Line	171	307
Frost Bridge 345 - N Bloomfield 345	Line	2035	2635
Frost Bridge 115 - Frost Bridge 345	Transformer	632	780
Lake Road 345 - West Farnum 345	Line	2035	2635
Card 345 - Lake Road 345 CKT 2	Line	2035	2635
W. Farnum 345 - Millbury 345	Line	2172	2696
W. Farnum 345 - Kent Co. 345 CKT2	Line	1545	1908
Kent Co. 345 - Kent Co. 115 (2)	Transformer	487	580
Kent Co. 345 - Kent Co. 115 (3)	Transformer	487	580
Berry 345	Substation		
Berry 345 - Bellingham 345	Line	1007	1157
Berry 345 - Brayton Point 345	Line	1007	1157
Berry 115	Substation		
Berry 115 - Berry 345	Transformer	515	580
Berry 115 - S. Wrenthem 115 CKT1	Line	287	330
Berry 115 - S. Wrenthem 115 CKT2	Line	287	330
Berry 115 - N. Attleboro 115 CKT1	Line	287	330
Berry 115 - N. Attleboro 115 CKT2	Line	287	330
Agawam 345	Substation		
Agawam 345 - Agawam 115 (1)	Transformer	632	780
Agawam 345 - Agawam 115 (2)	Transformer	632	780
Ludlow 345 - Agawam 345	Line	2035	2635
Agawam 345 - N. Bloomfield 345	Line	1200	2400
Stony Brook 115 - 5 Corners 115	Line	678	878
Stony Brook 115 - 5 Corners 115	Line	678	878
N. Bloomfield 115- N. Bloomfield 345 (2)	Transformer	632	780
Southwick 115 - S. Agawam 115	Line	143	165
Shawington 115 - Fairmont 115	Line	593	764
Chicopee 115 - Fairmont 115	Line	339	439
Piper 115 - Fairmont 115	Line	339	439
E. Springfield 115 - Clinton 115	Line	250	371
E. Springfield 115 - Breckwood 115 CKT1	Line	250	371
E. Springfield 115 - Breckwood 115 CKT2	Line	250	371

b. Interface Limits

Interface limits vary by degree of NEEWS inclusion in the 2011 and 2013 study years, and are assumed to remain at 2013 levels in the 2018 and 2030 study years, since the transmission system is assumed to remain unchanged after 2013. 2011 Interface limits are consistent with those published in the ISO-NE October 26, 2006 Draft *Regional System Plan*[34] and the ISO-NE FERC Form No. 715.[35] Post-NEEWS East/West Interface and Connecticut Import limits have been projected by Northeast Utilities. Figure G.33 summarizes assumed interface limits by study year and degree of inclusion of NEEWS.

[34] *Draft Regional System Plan*, ISO-NE, Page 38, Table 4-5, October 26, 2006.
[35] *ISO-NE FERC Form No. 715*, Pages 6-3 through 6-6, March 31, 2007.

Figure G.33: Major Interface Limits by Study Year and Degree of NEEWS Inclusion

Interface Constraint	2011 Limit		2013 Limit: Partial-NEEWS		2013 Limit: Full-NEEWS	
	Summer Max (MW)	Summer Min (MW)	Summer Max (MW)	Summer Min (MW)	Summer Max (MW)	Summer Min (MW)
New Brunswick - New England	1,000	-250	1,000	-250	1,000	-250
Orrington South	1,200	NL	1,200	NL	1,200	NL
Surowiec South	1,250	NL	1,250	NL	1,250	NL
Maine-New Hampshire	1,550	-1,700	1,525	-1,700	1,525	-1,700
New England North-South	2,700	NL	2,700	NL	2,700	NL
New England East-West	2,400	-2,400	3,100	-3,100	3,500	-3,500
Boston Import	4,900	NL	4,900	NL	4,900	NL
SEMA: Southeast MA	NL	NL	NL	NL	NL	NL
SEMARI: SE MA RI Ex	3,000	NL	3,000	NL	3,000	NL
Connecticut Import	2,500	-2,030	3,200	-3,200	3,600	-3,600
SW Connecticut Import	3,650	NL	3,650	NL	3,650	NL
Norwalk-Stamford Import	1,650	NL	1,650	NL	1,650	NL
New York - New England	1,175	-1,150	1,175	-1,150	1,175	-1,150

Note: NL=No Limit

c. Contingencies and Line Constraints

First-order N-1 contingencies corresponding to the varying degrees of transmission inclusion are provided by the Companies and are included in the model. Second-order (N-2) contingencies are not modeled. 115kV line and contingency constraints that bind frequently in the 2018 and 2030 study years are assumed to spur mitigation efforts to avoid high congestion costs via equipment upgrades, and are concurrently removed as constraints from the model.

d. Transmission Outages

Transmission outages are not modeled.

APPENDIX H: EVALUATION METRICS

This Appendix describes the Evaluation Metrics and reports the results for all of the cases studied (Scenario-Resource Solution-Year combinations).

I. DESCRIPTION OF METRICS

The DAYZER simulations produce an enormous quantity of detailed information on the operation of each generating unit in the ISO-NE system and the economics of serving loads under the assumed conditions. These can be distilled to produce summary statistics that address the criteria in PL 07-242 in order to evaluate the resource solutions, which we term "Evaluation Metrics." These measures also are consistent with the CEAB "Preferential Criteria for Evaluation of Energy Proposals" (Effective December 1, 2004); however, the Preferential Criteria are more project-based (as opposed to generic resources) and therefore the measures examined in this report do not perfectly map into the Criteria. These various metrics fall into several categories, reflecting diverse objectives and criteria for evaluating the performance of resource solutions.

a. Total Annualized Going-Forward Resource Cost of Meeting Load

Resource cost represents the economic value of resources consumed in supplying Connecticut loads, without regard to who incurs those costs or the possible ratemaking treatment of such costs. These are annualized "going-forward" generation and DSM-related costs that do not take into account the value of capital in existing or already-committed capacity (i.e., they do not account for "embedded" capital cost) but do account for the annualized capital costs of new generation plant in Connecticut and the capitalized cost of DSM programs. The costs of resources located outside of Connecticut are included by pricing imported energy and capacity at market prices. The value of energy and capacity exported outside of Connecticut is counted as a credit, again valued at market prices. More specifically, total going-forward annual resources costs for Connecticut include:

- Capital carrying costs on new generation located in Connecticut (this includes the new baseload plant in the Nuclear and Coal Solutions, and new CCs or CTs used to meet ISO-NE's required reserve margin).
- Fixed O&M for all operating plants in Connecticut.
- Variable O&M for all operating plants in Connecticut.

- Fuel and emission allowance costs for operating plants in Connecticut
- RPS costs, i.e., Renewable Energy Credits (RECs) and alternative compliance payments to meet Connecticut RPS requirements, both priced at a nominal level of $55/MWh according to the Connecticut rules regarding RPS.
- The cost of imports of energy, priced at the load LMP in Connecticut, minus the value of exports priced at the generation-weighted average generator LMP in Connecticut.
- The cost of capacity imports or the value of capacity exports priced at the ISO-NE capacity price, which is discussed in Appendix A.
- Demand-side program costs, including the annual costs of administering demand response programs and an annuitized cost of efficiency investments (using a 10-year annuity equivalent at a real after-tax weighted average cost of capital of 7%).

While these total going-forward resource costs are not precisely customer costs (which depend on many factors, including ratemaking treatment) this is the single most comprehensive measure of cost that must be recovered in the long run from customers in order for utilities to provide economic service. Therefore, they correspond to the CEAB Preferential Criteria II.B and II.C over the long run.

b. Market-Based Generation Cost

In Connecticut's restructured retail environment, customers' generation service rates are determined by the procurement costs incurred by the Companies and other load serving entities as they pay for energy, capacity and ancillary services supplied from the ISO-NE market. The cost elements are:

- Generation Service Charges
  - Energy cost, based on the hourly load times the load bus locational marginal prices (LMPs), a standard spot market-based measure of the cost of serving load in an LMP market.
  - Capacity cost, given by the peak load times the required planning reserve margin of approximately 16.6% times the capacity price. As discussed in Appendix A, the capacity price is given by the net cost of new entry (Net CONE) when the market is in supply-demand balance. In 2011, the market is in surplus and the price is set by the $4.50/kW-month floor that has been established by ISO-NE.
  - Fast-start costs, or local forward reserve market (LFRM) costs are based on the formulas ISO-NE uses to allocate LFRM and FRM costs across ISO-NE, which result in Connecticut customers having to pay approximately 45% of LFRM costs incurred in

Connecticut, depending on market conditions, as discussed in Appendix A. LFRM costs incurred in Connecticut are given by the required reserves (approximately 1,300 MW, given by the capacity of the largest unit) multiplied by the LFRM price, which is assumed to be at the cap due to the lack of surplus of fast-start capacity in Connecticut. The cap is given by $14/kW-month minus the capacity price.

- Revenues from financial transmission rights (FTRs), assuming load serving entities have FTRs providing revenues sufficient to cover 75% of the congestion costs incurred between Connecticut generators and Connecticut load (calculated by multiplying the load versus the generators in Connecticut.
- A loss adjustment is needed because DAYZER double-counts losses. First, the load forecast already includes losses, which sets the total amount of generation customers must pay for. Second, marginal losses are calculated as part of the LMP in order to produce efficient dispatch signals (the loss component of the LMP at each node is given by the price at the reference bus times a nodal marginal loss factor drawn from a database of loss factors under similar load conditions). In order to avoid double-count losses, the loss component is reduced to that at the Connecticut generators by subtracting the difference between the load's and generators' loss components from the load's LMP.
- The cost of spinning reserves and uplift are each calculated from the Connecticut load ratio share of ISO-NE payments to all generators in ISO-NE. Both quantities are modeled explicitly in DAYZER.
- Supplier risk premium, estimated at 15% to account for the risks that wholesale suppliers assume when bidding to serve retail loads. These include credit, price and volume risks, and represent the difference between the pure "market cost" of resources and the prices typically observed in the market for serving retail loads.

- System Benefits Charges
  - Renewable Energy Certificates (RECs) or alternative compliance payments valued at a nominal level of $55/MWh.
  - DSM program costs, including the annual cost of administering demand response programs and the annual cost of efficiency investments. Efficiency investments are not capitalized, as they are in the calculation of Total Annualized Going-Forward Resource Cost, in order to reflect the current rate treatment.

These customer costs are divided by the Connecticut loads to estimate an average customer generation rate, in ¢/kWh. These metrics correspond most closely to CEAB Criteria II.B and II.C.

c. Cost of Service Generation Rates

In addition to calculating customer generation rates under prevailing rules, we also estimate customer generation rates under a hypothetical alternative where Connecticut generators are paid under traditional cost-of-service principles. This proxy cost of service was constructed from the following elements:

- Generation Service Charges
  - ▸ Total (going-forward) Resource Costs as described above, but excluding RPS and DSM costs, plus
  - ▸ Annualized embedded costs of generators in Connecticut, consisting of estimates of annualized capital payments:
    - ▪ For Connecticut generating units that have obtained “reliability-must-run” (RMR) contracts, we use the nominal difference between the Annualized Fixed Revenue Requirement (AFRR) and the annual Fixed O&M (FOM) obtained from the RMR dockets and settlement agreements.
    - ▪ For the Millstone nuclear unit, an annual capital payment based on the purchase price in 2001 and utility financing assumptions.
    - ▪ For recent new units an estimate of annual capital payments based on technology type
    - ▪ We assume embedded costs of zero for numerous old, small plants for which FOM is the primary going-forward cost
- System Benefits Charges are calculated the same as in the Market-Based Customer Costs.

These costs are divided by Connecticut loads to estimate an average customer cost under the cost of service accounting in ¢/kWh.

Average customer generation rates are calculated by dividing the total cost by the total load. In turn, a monthly “typical bill” is calculated for a hypothetical customer with 700 kWh of load (prorated in the “DSM-Focus” solution).

d. Electric Reliability

The ISO-NE planning reserve margin (Installed Capacity – Peak Load / Peak Load) and Connecticut planning reserve surplus (relative to the LSR) are calculated to convey differences in electrical reliability, which addresses CEAB Criteria I.B.

e. Fuel Diversity and Security

We report the fuel consumption metrics that are most relevant to the objectives of fuel diversity and security: the quantity of natural gas burned in Connecticut and New England all year and during the peak heating season. We also report the quantities and percentages of other fuels.

f. Load Factor

We calculate the Connecticut load factor (the ratio of average annual load level to system hourly peak, net of DSM) to measure progress toward leveling load by shifting energy from peak to off-peak time, corresponding to CEAB Criteria III.B.

g. Environmental & Renewables

These metrics include annual emissions in ISO-NE and Connecticut of sulfur dioxide (SO_2), nitrogen oxides (NO_x), and carbon dioxide (CO_2). The CO_2 emissions can be compared to the RGGI cap.

For RPS compliance, metrics reported are annual renewable energy requirements (state loads x required percentages) and eligible renewable electricity generation.

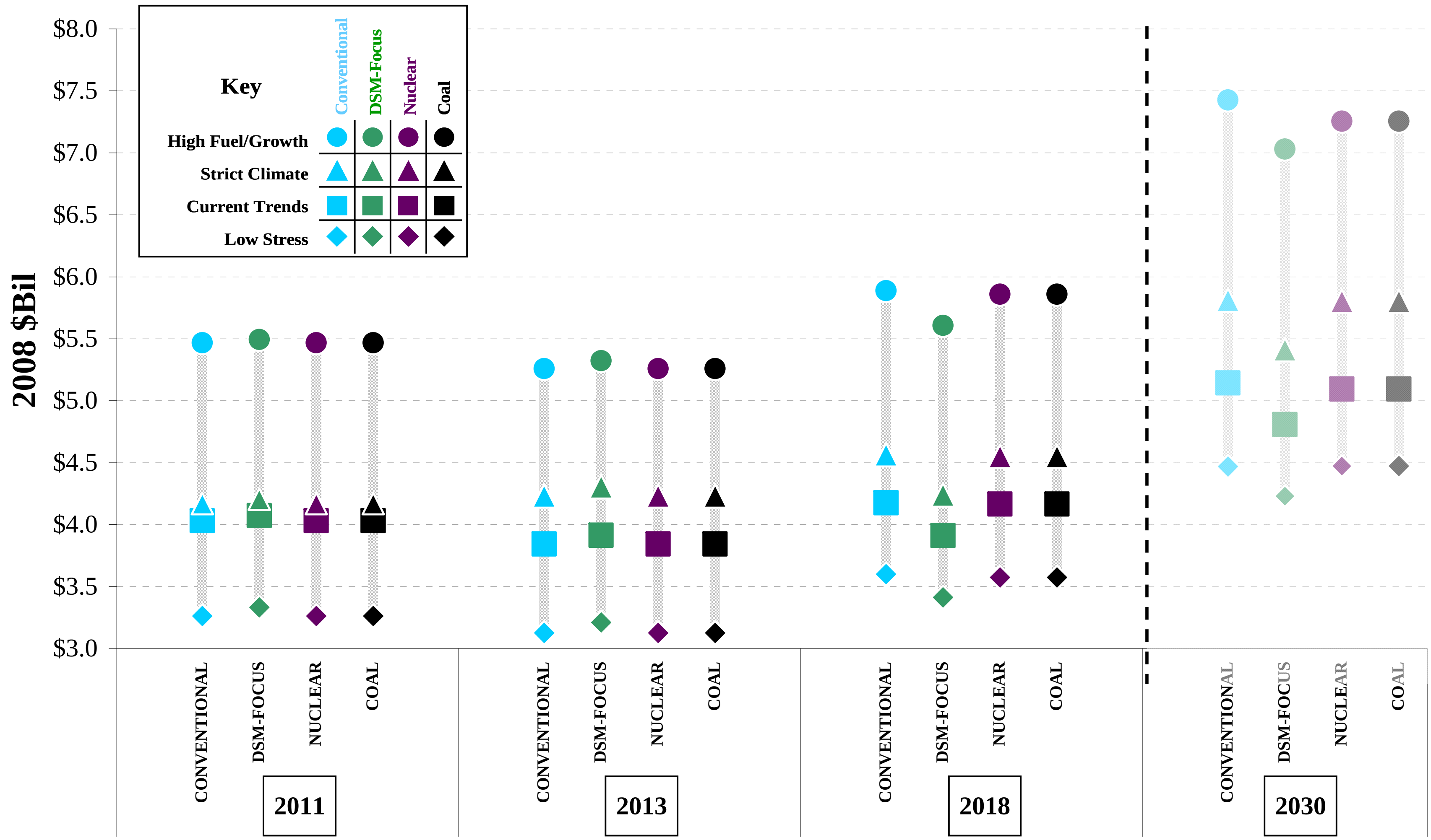
II. Documentation of Metrics for All Cases

The results for each metric are summarized across all cases in the graphs shown below (a subset of these also appears in Section III of the Report). Immediately following are the detailed metrics results for each case (Scenario-Solution Set-Year combinations).

Figure H.1: Total Going-Forward Resource Cost (Annual)

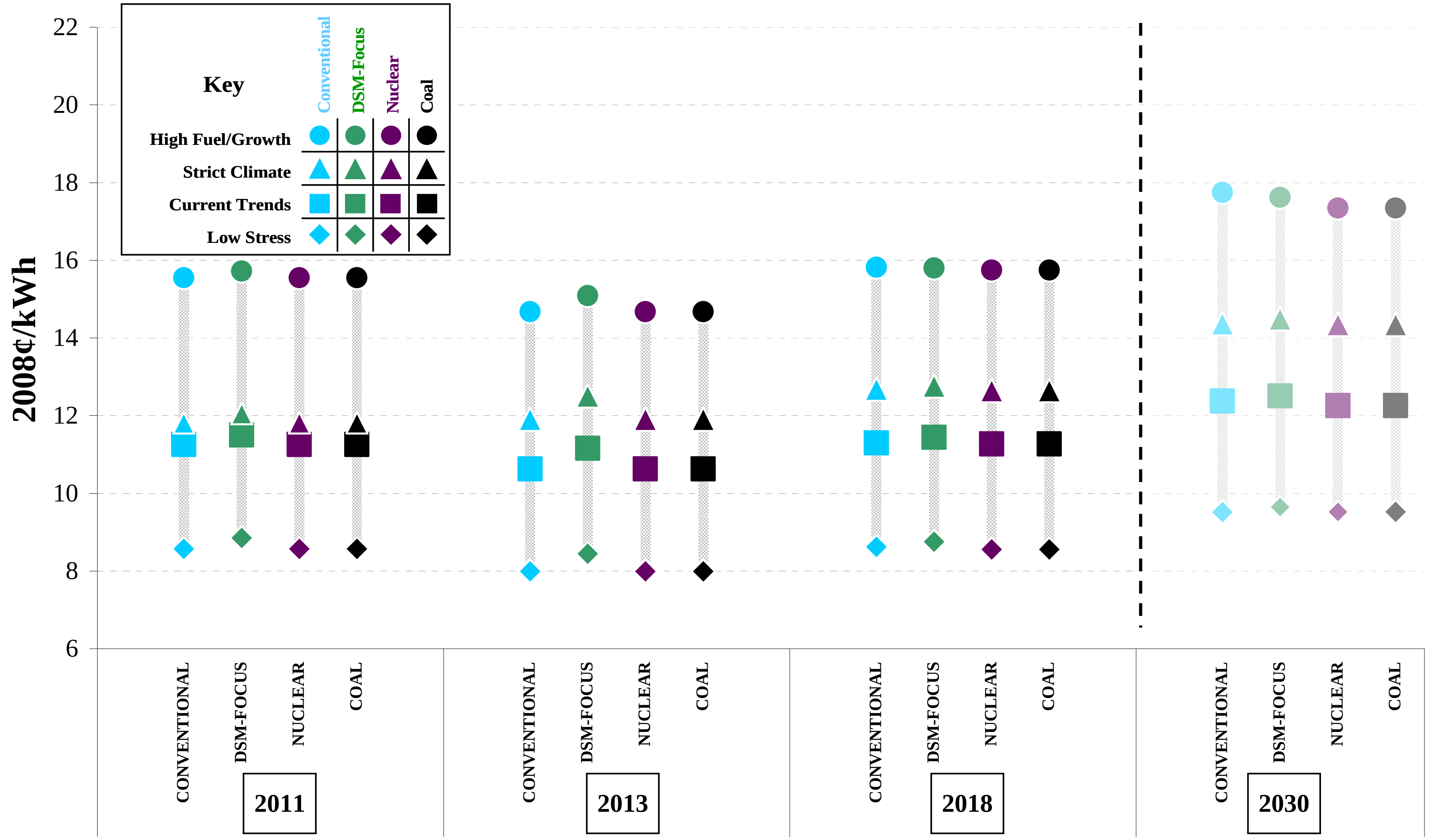
*Total Resource Cost includes capital carrying cost on new unplanned generation, fixed O&M, variable O&M, fuel cost, allowance cost, RPS cost, CT energy import and export cost, net CT capacity import cost, and DSM program costs. Note that DSM costs for energy efficiency programs are capitalized over 10 years here; this treatment differs from that in the Customer Cost graphics, where energy efficiency program costs are expensed in the year incurred.

Figure H.2: Total Customer Cost in Market Regime (Annual)



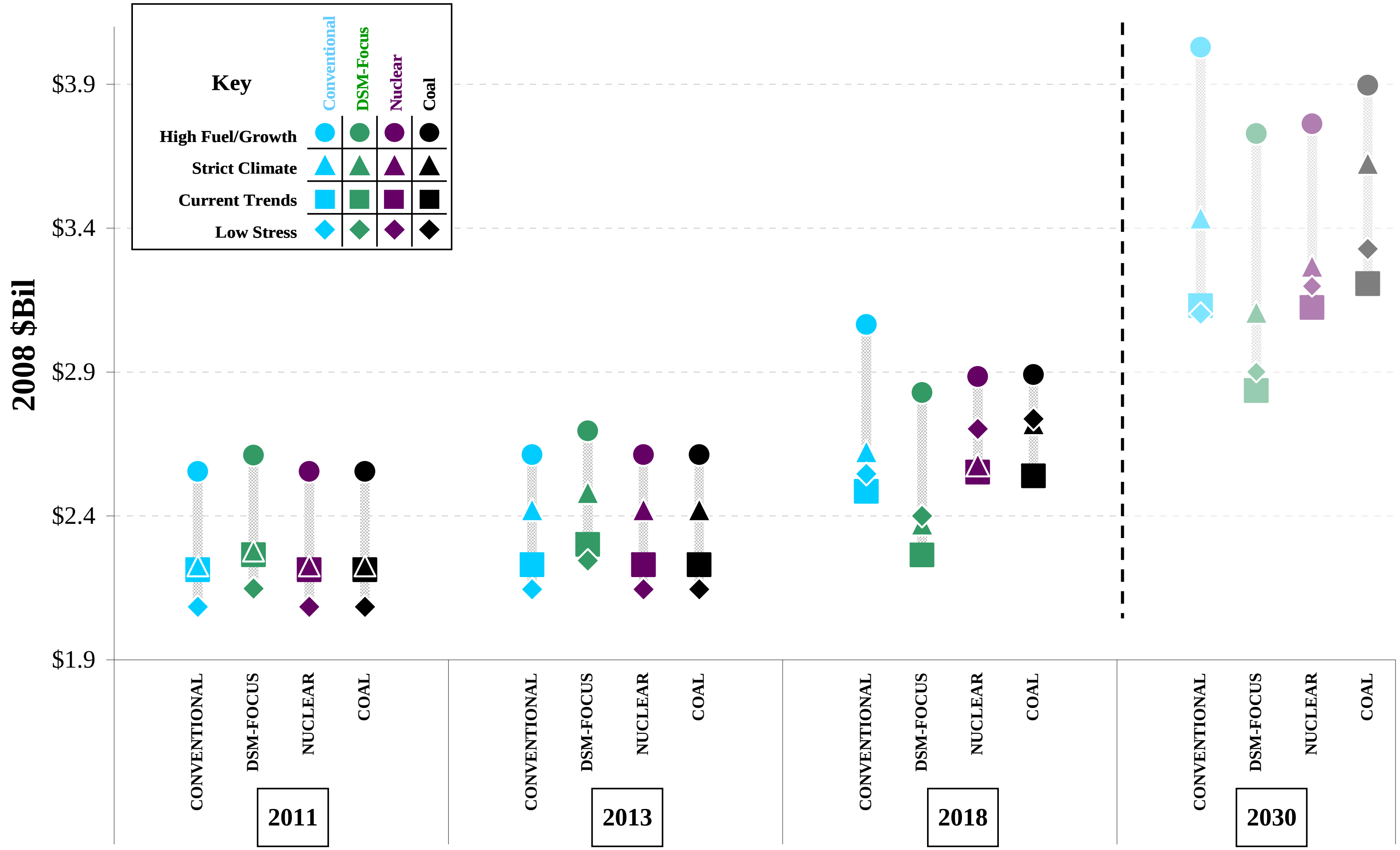
*Total Customer Cost in Market Regime includes load at LMP, capacity, FTRs, adjustment for losses, spin, uplift, fast-start, DSM program costs (expensed, not capitalized), RPS, and a 15% premium on the energy and generation components to reflect quantity risk, market price risk, and credit risk faced by wholesale suppliers of standard offer service.

Figure H.3: Average Unit Cost in Market Regime



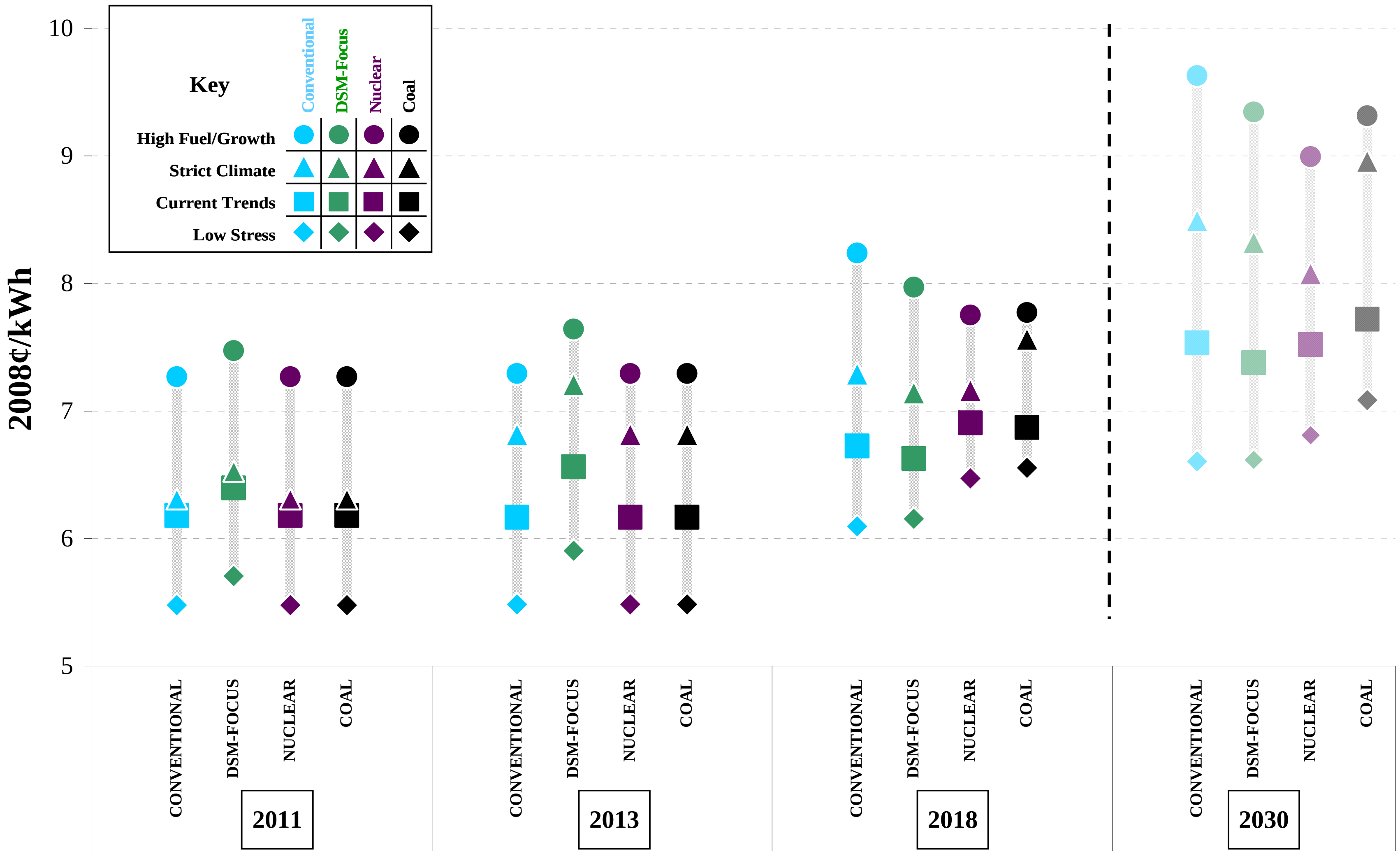
*Average Unit Cost in Market Regime includes load at LMP, capacity, FTRs, adjustment for losses, spin, uplift, fast-start, DSM program costs (expensed, not capitalized), RPS, and a 15% premium on the energy and generation components to reflect quantity risk, market price risk, and credit risk faced by wholesale suppliers of standard offer service.

Figure H.4: Total Customer Cost in Cost-of-Service Regime



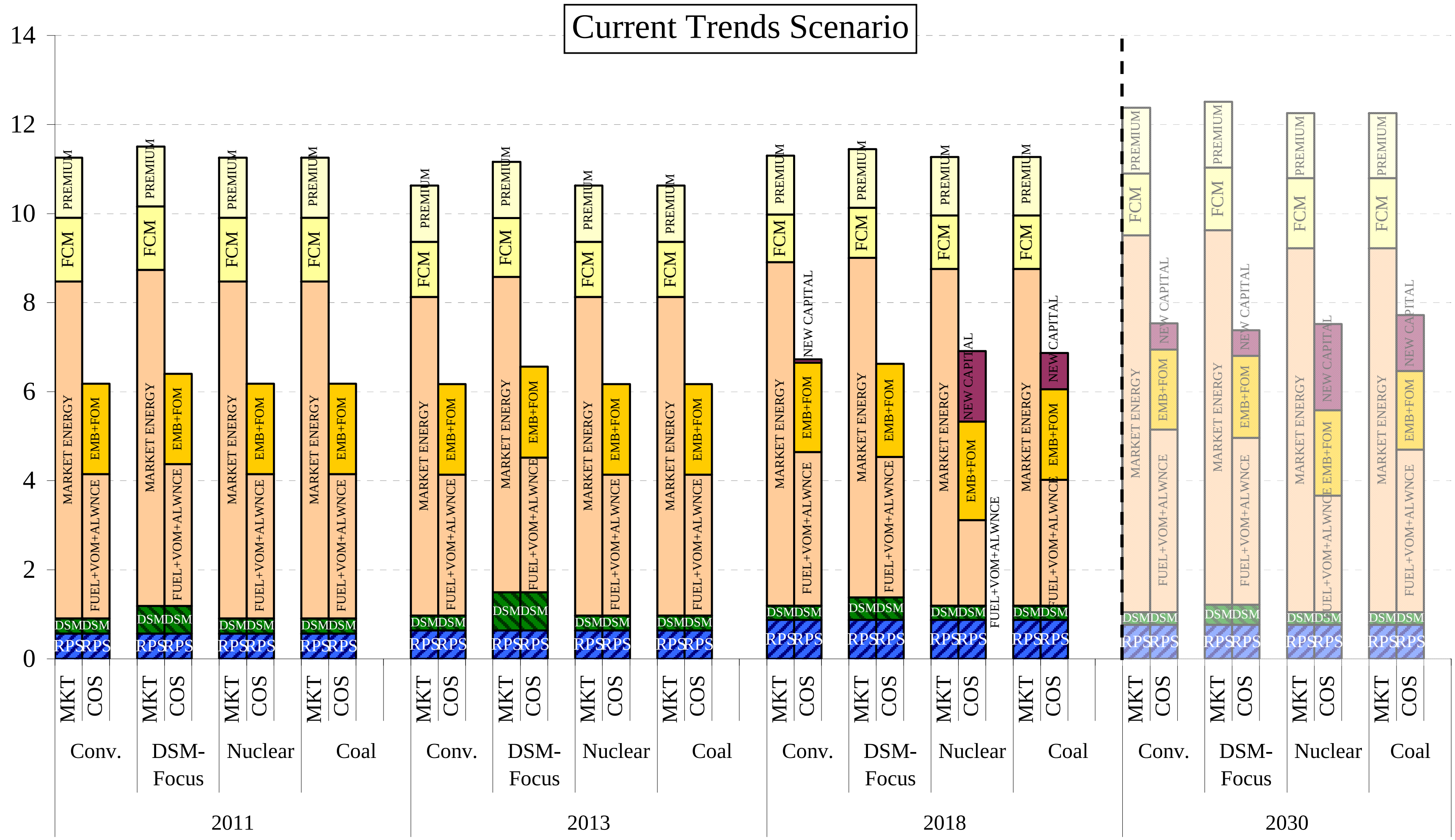
*Total Customer Cost in Cost of Service Regime includes capital carrying cost on new unplanned generation, fixed O&M, variable O&M, fuel cost, allowance cost, RPS cost, CT energy import and export cost, net CT capacity import cost, and DSM program costs (expensed, not capitalized).

Figure H.5: Average Unit Cost in Cost-of-Service Regime



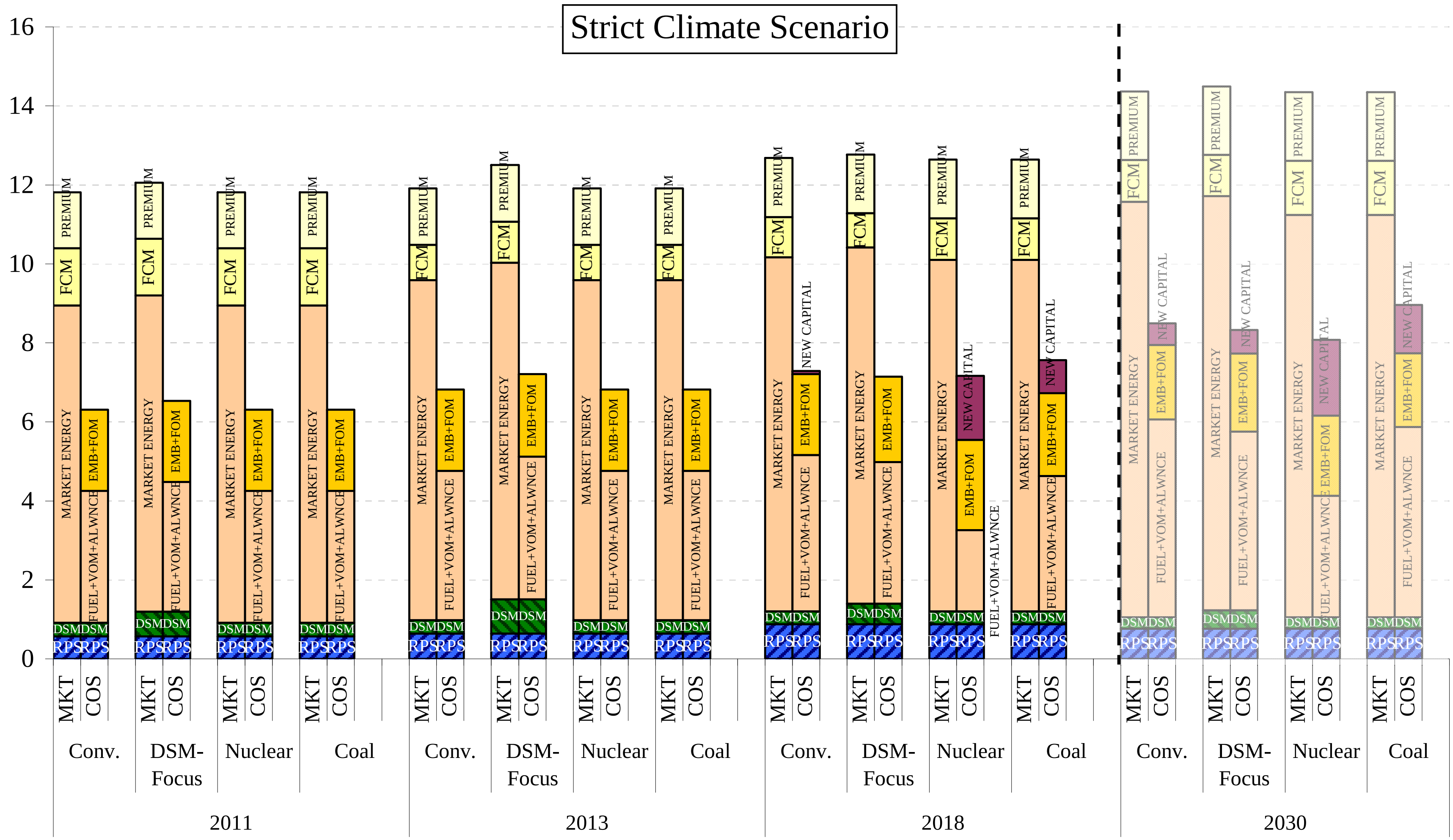
*Average Unit Cost in Cost of Service Regime includes capital carrying cost on new unplanned generation, fixed O&M, variable O&M, fuel cost, allowance cost, RPS cost, CT energy import and export cost, net CT capacity import cost, and DSM program costs (expensed, not capitalized).

Figure H.6: Average Customer Cost Components (¢/kWh)



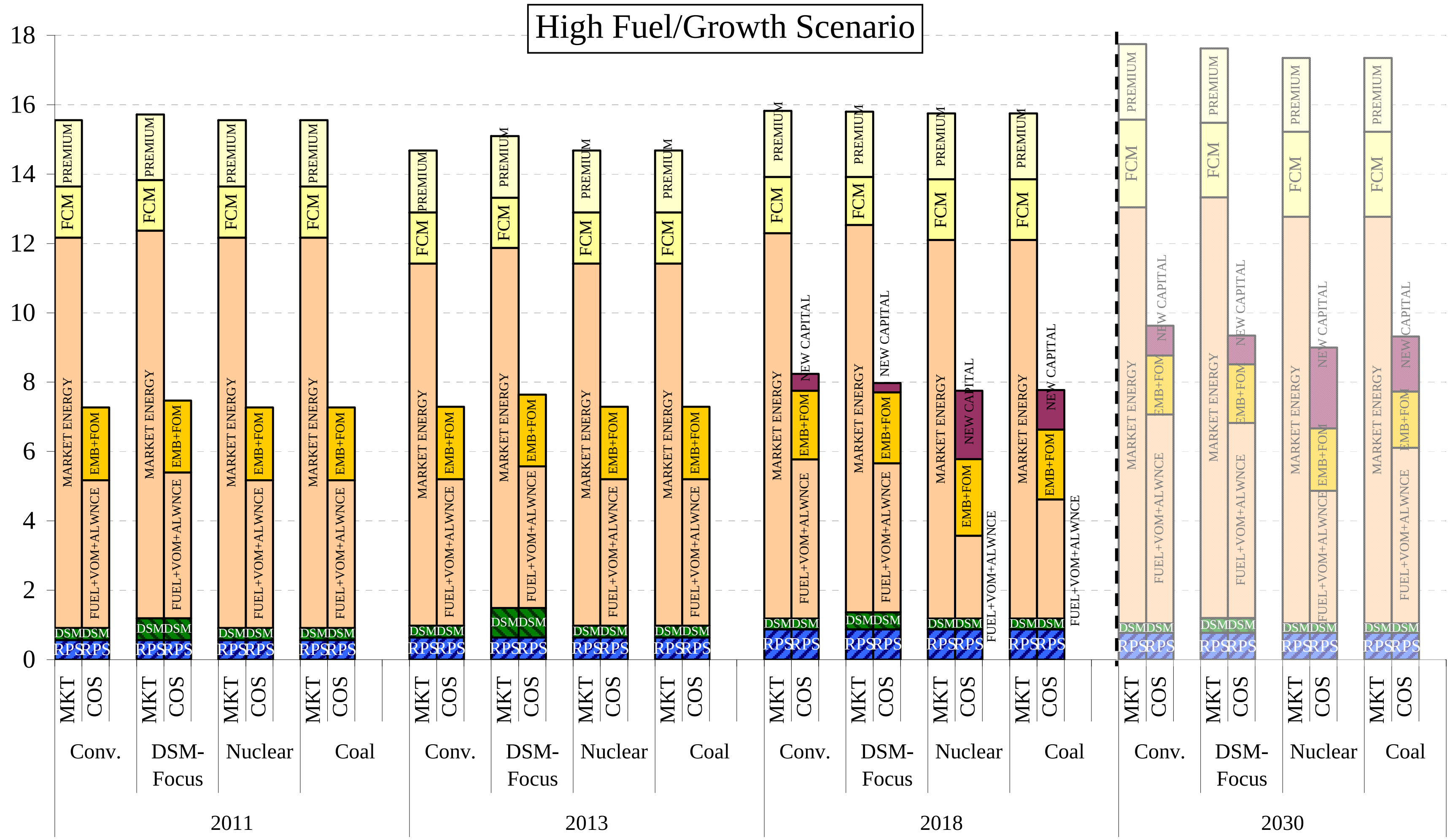
Note: Market energy cost includes load at LMP, FTRs, adjustment for losses, spin, and uplift; FCM includes capacity and forward reserves; capital cost in COS regime ("EMB+FOM") includes FOM, net capacity imports, and embedded capital cost of planned and existing generation; energy cost in COS regime ("FUEL+VOM+ALWNCE") includes VOM, fuel, emissions allowances, and net energy imports. The premium added represents an estimated additional 15% on the energy and capacity components, charged by wholesale suppliers of standard offer service reflecting quantity risk, market price risk, and credit risk.

Figure H.7: Average Customer Cost Components (¢/kWh)



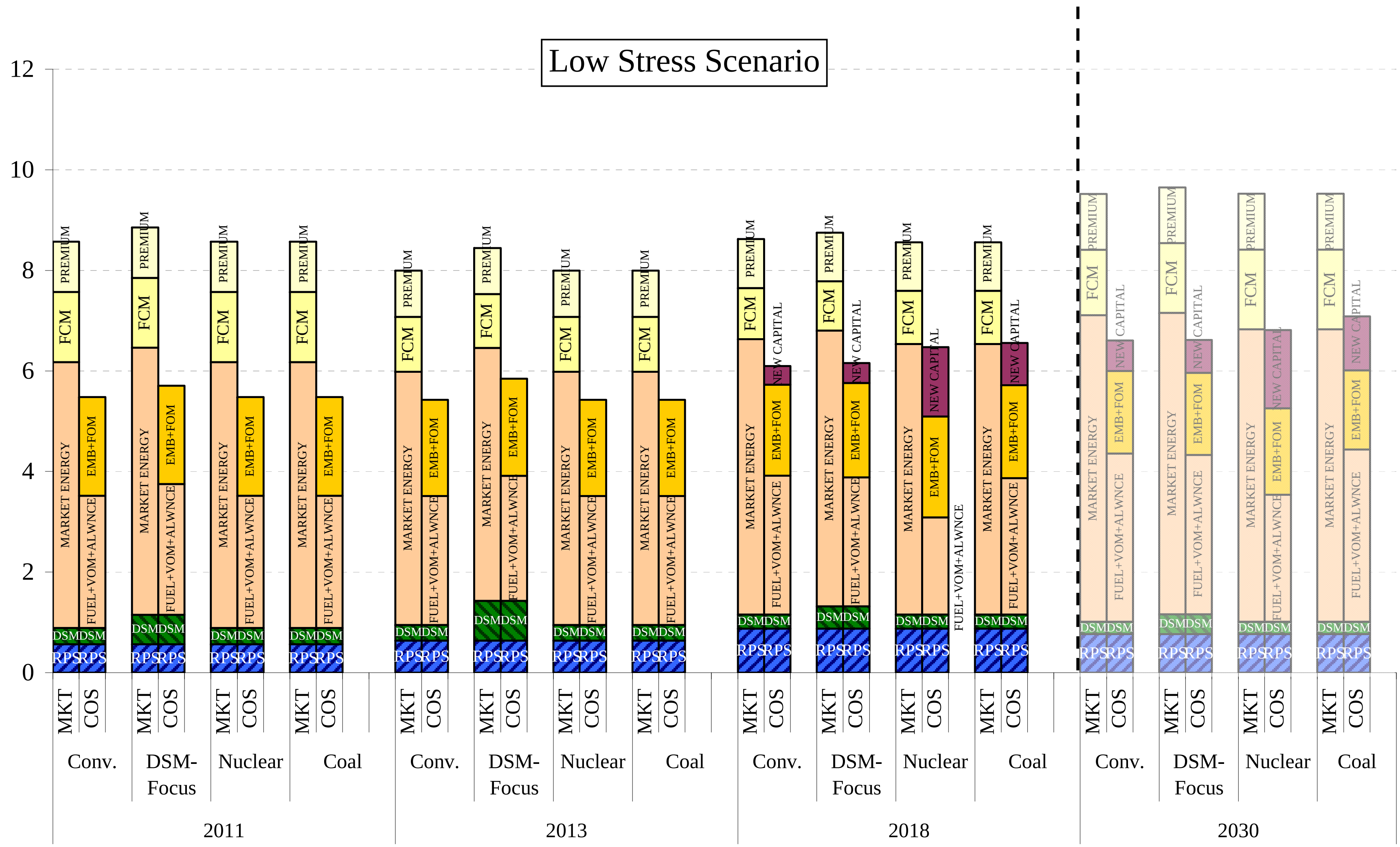
Note: Market energy cost includes load at LMP, FTRs, adjustment for losses, spin, and uplift; FCM includes capacity and forward reserves; capital cost in COS regime ("EMB+FOM") includes FOM, net capacity imports, and embedded capital cost of planned and existing generation; energy cost in COS regime ("FUEL+VOM+ALWNCE") includes VOM, fuel, emissions allowances, and net energy imports. The premium added represents an estimated additional 15% on the energy and capacity components, charged by wholesale suppliers of standard offer service reflecting quantity risk, market price risk, and credit risk.

Figure H.8: Average Customer Cost Components (¢/kWh)



Note: Market energy cost includes load at LMP, FTRs, adjustment for losses, spin, and uplift; FCM includes capacity and forward reserves; capital cost in COS regime ("EMB+FOM") includes FOM, net capacity imports, and embedded capital cost of planned and existing generation; energy cost in COS regime ("FUEL+VOM+ALWNCE") includes VOM, fuel, emissions allowances, and net energy imports. The premium added represents an estimated additional 15% on the energy and capacity components, charged by wholesale suppliers of standard offer service reflecting quantity risk, market price risk, and credit risk.

Figure H.9: Average Customer Cost Components (¢/kWh)



Note: Market energy cost includes load at LMP, FTRs, adjustment for losses, spin, and uplift; FCM includes capacity and forward reserves; capital cost in COS regime ("EMB+FOM") includes FOM, net capacity imports, and embedded capital cost of planned and existing generation; energy cost in COS regime ("FUEL+VOM+ALWNCE") includes VOM, fuel, emissions allowances, and net energy imports. The premium added represents an estimated additional 15% on the energy and capacity components, charged by wholesale suppliers of standard offer service reflecting quantity risk, market price risk, and credit risk.

Figure H.10: Connecticut Load Factor (Net of DSM)

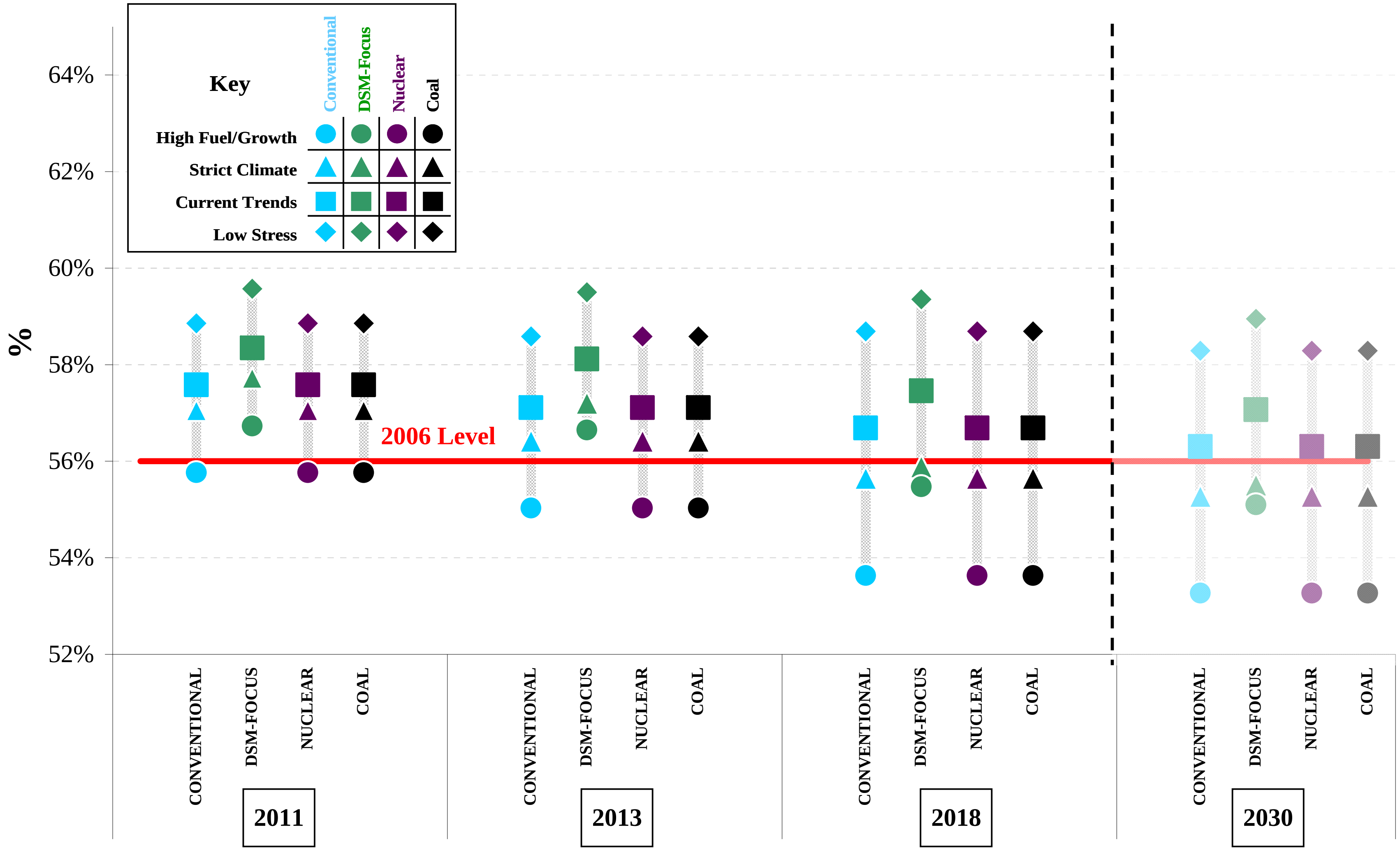
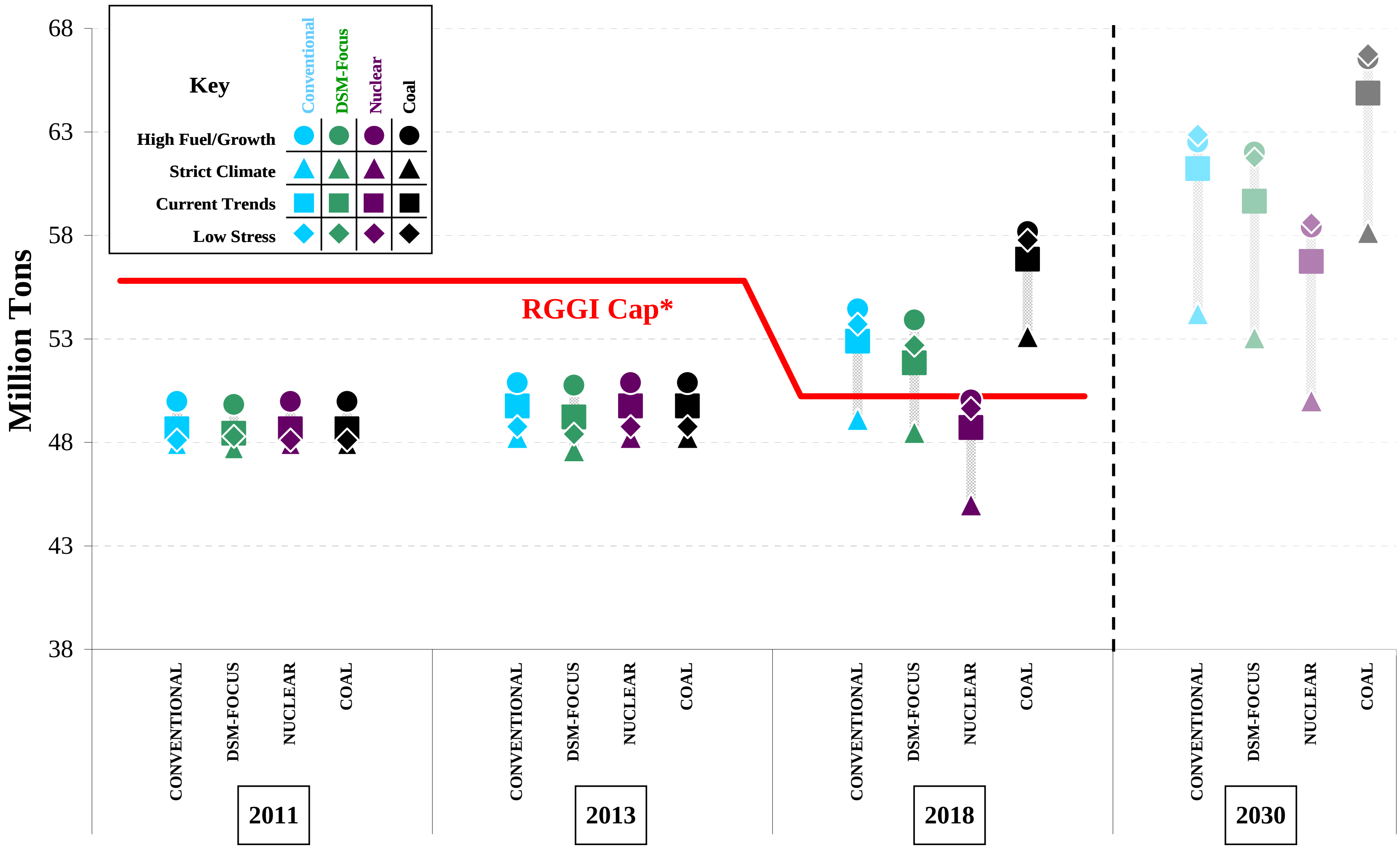


Figure H.11: CO$_2$ Emissions in ISO-NE



*Emissions and RGGI cap shown here reflect the 6 member states of ISO-NE only. A surplus or deficiency does not indicate whole RGGI-region status.

Figure H.12: Winter (January – February) Power Sector Gas Use in Connecticut

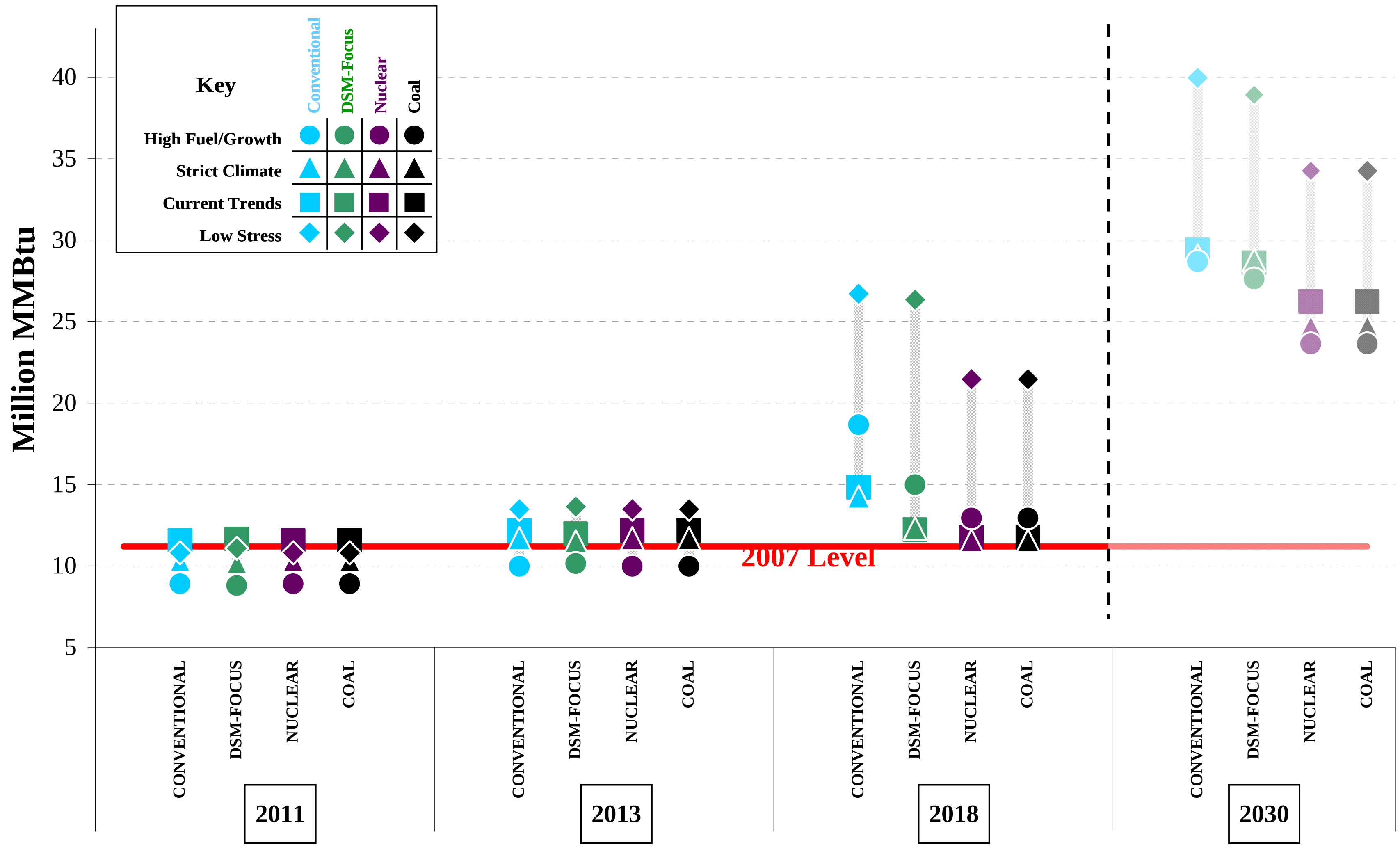


Figure H.13: Winter (January – February) Power Sector Gas Use in ISO-NE

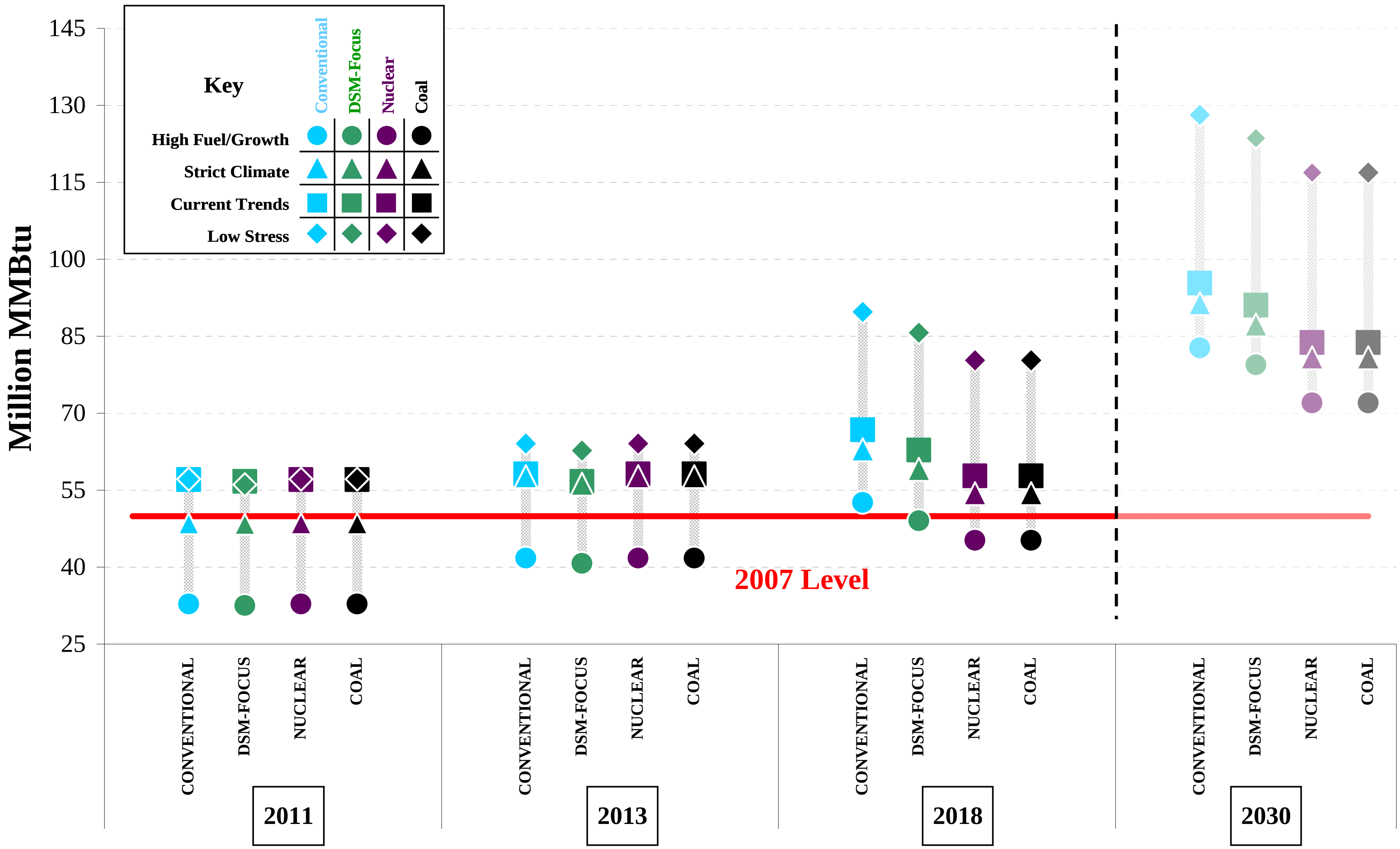


Figure H.14: Annual Power Sector Gas Use in Connecticut

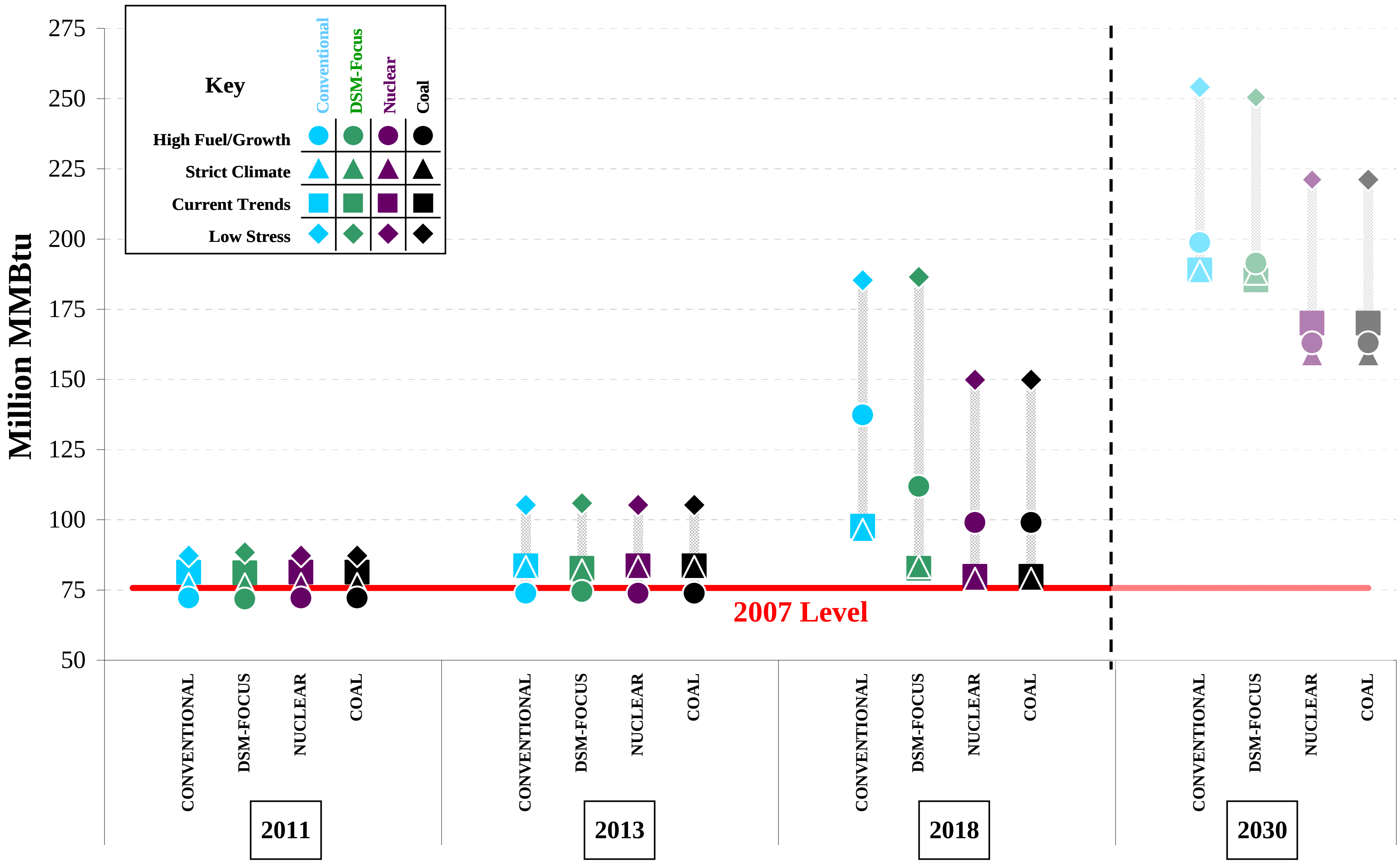


Figure H.15: Annual Power Sector Gas Use in ISO-NE

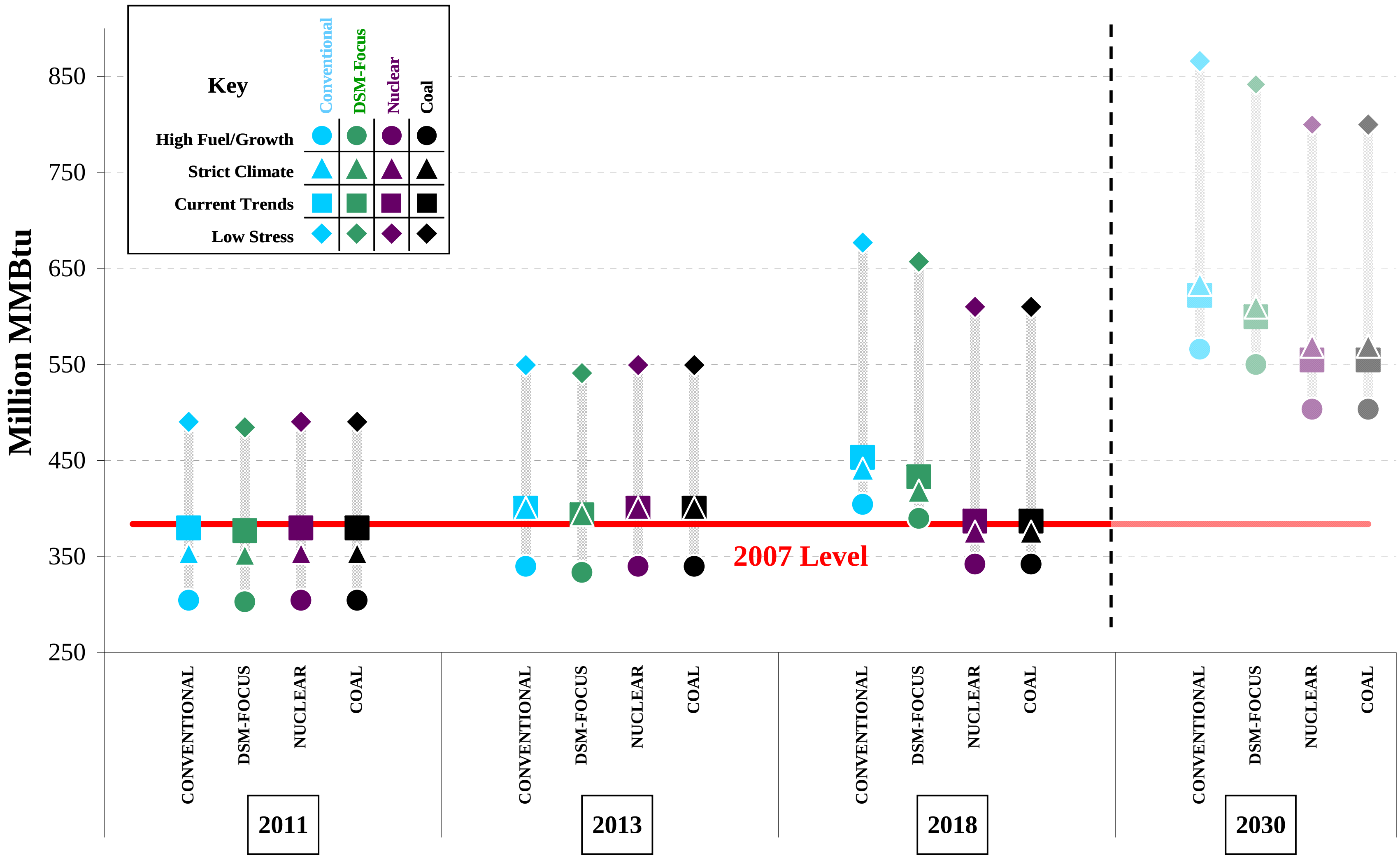


Figure H.16: Connecticut Gas-fired Generation Share of Total Generation

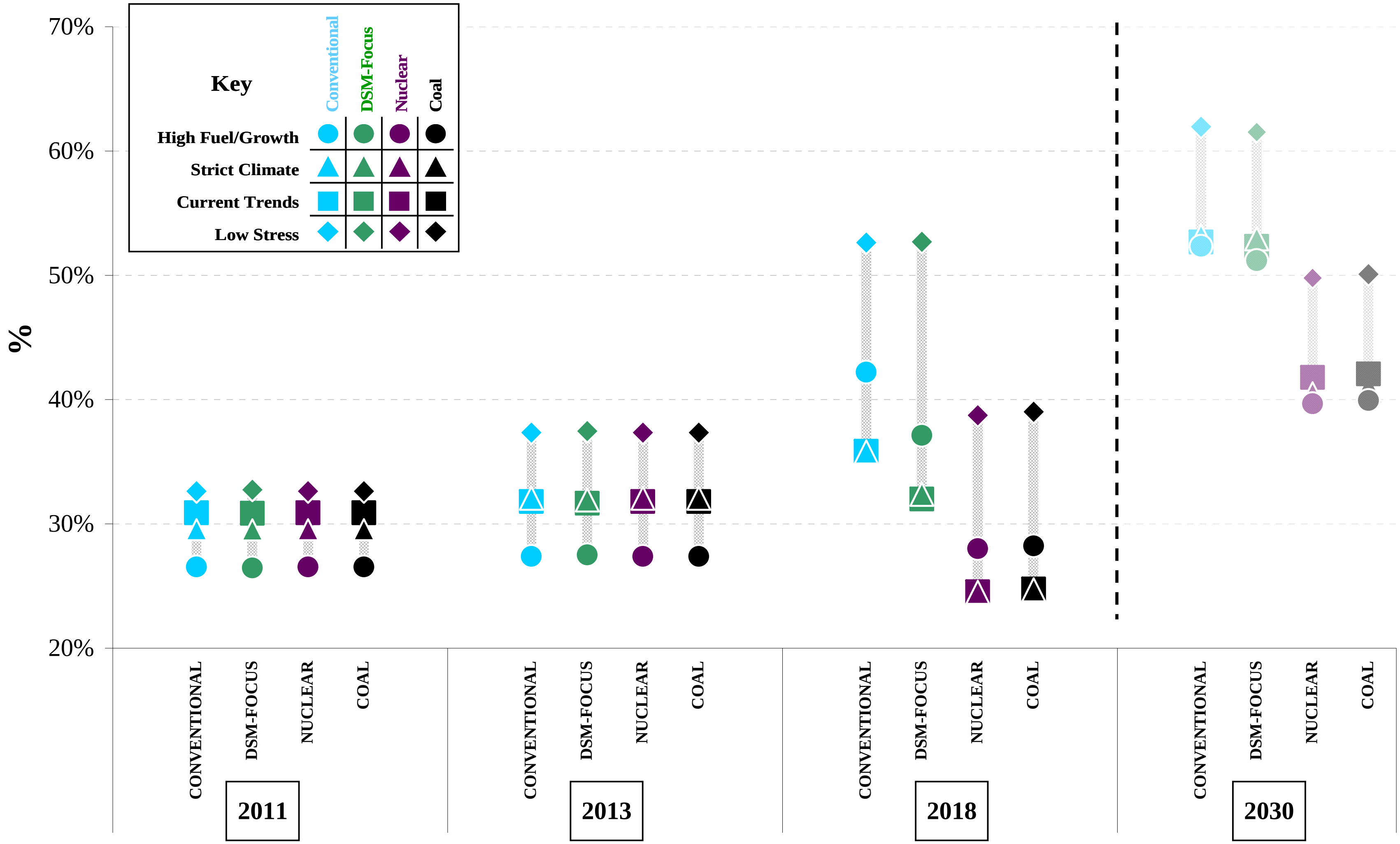


Figure H.17: ISO-NE Gas-fired Generation Share of Total Generation

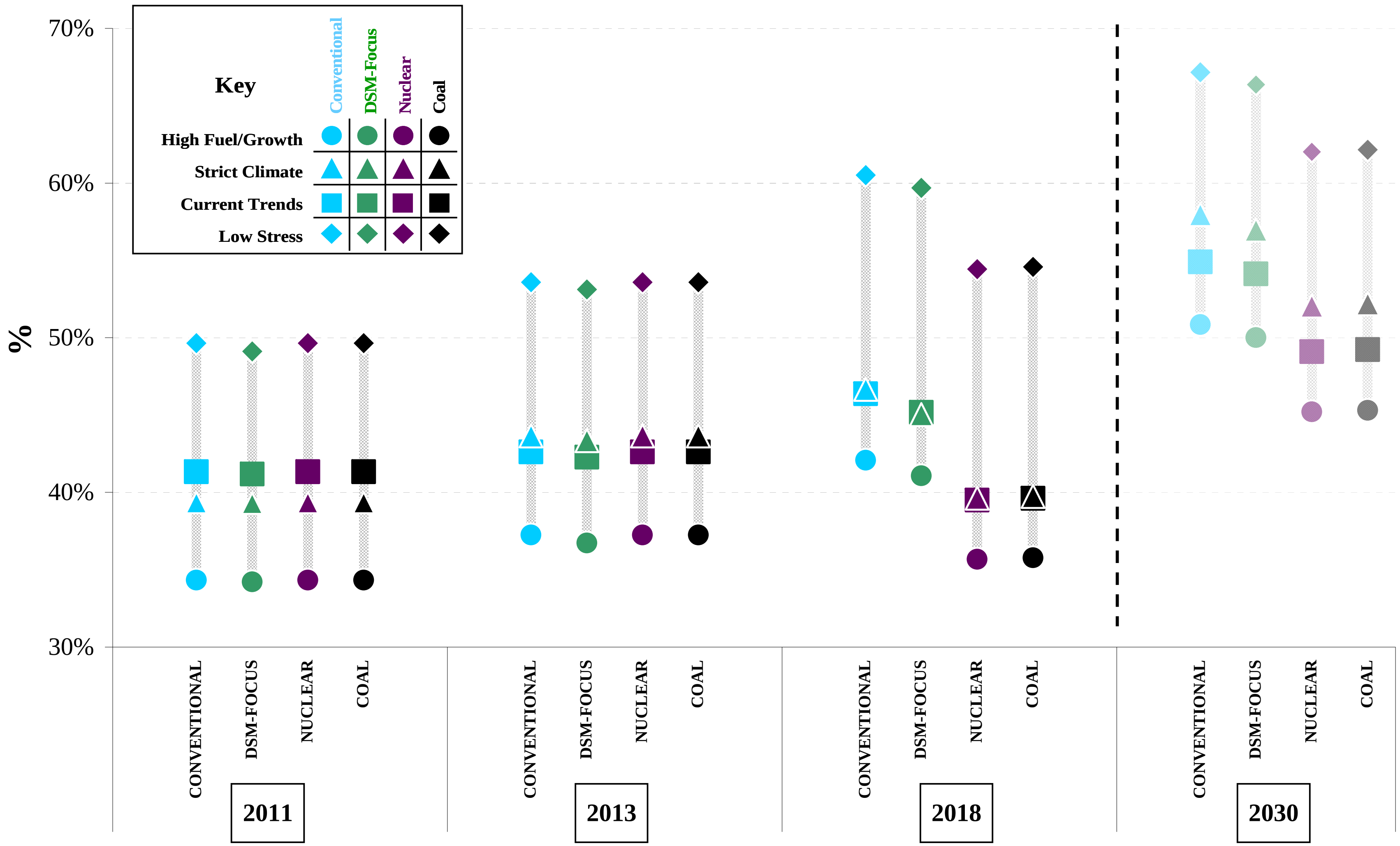


Figure H.19: Connecticut Fuel Mix (Cumulative Generation in TWh)

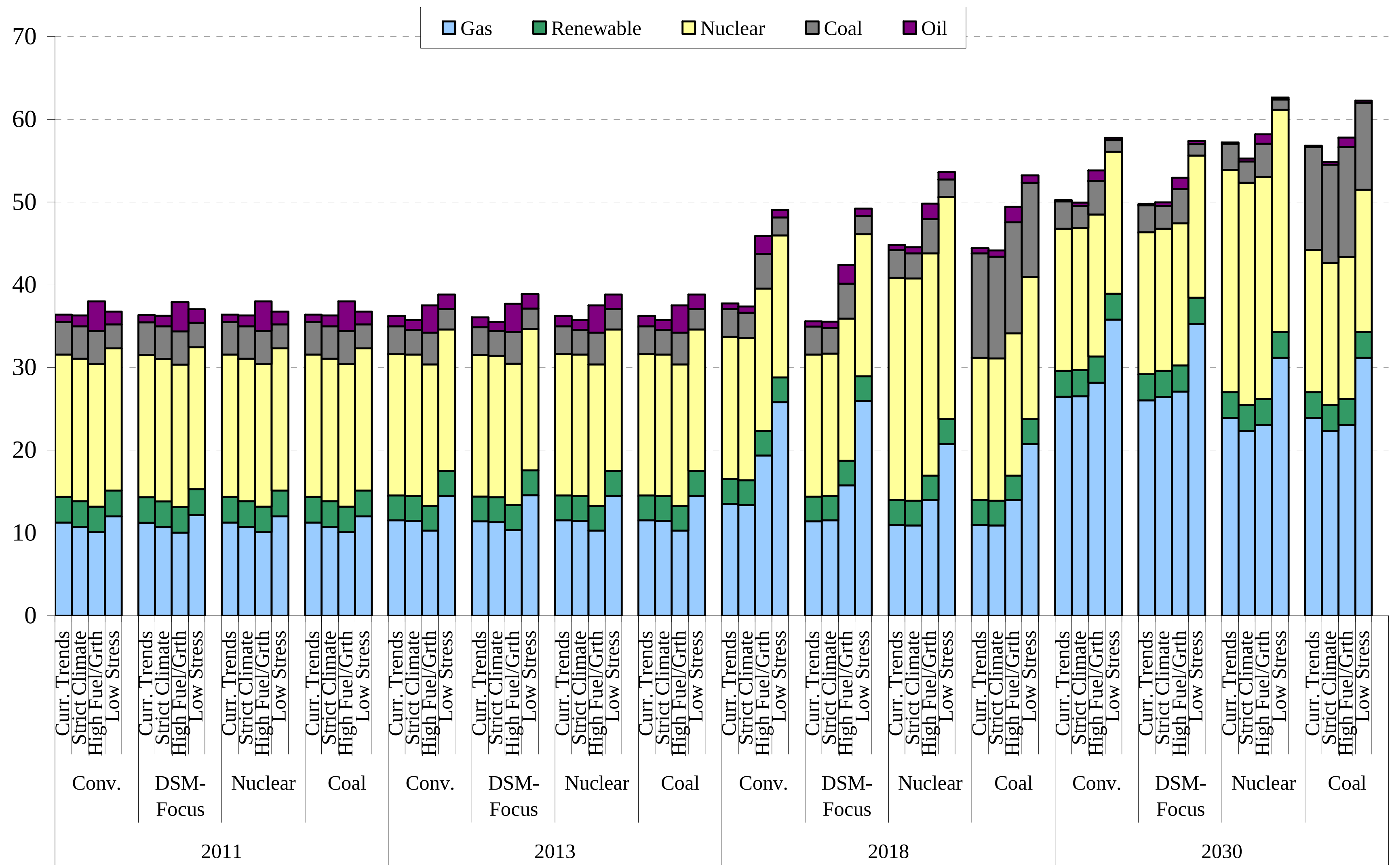
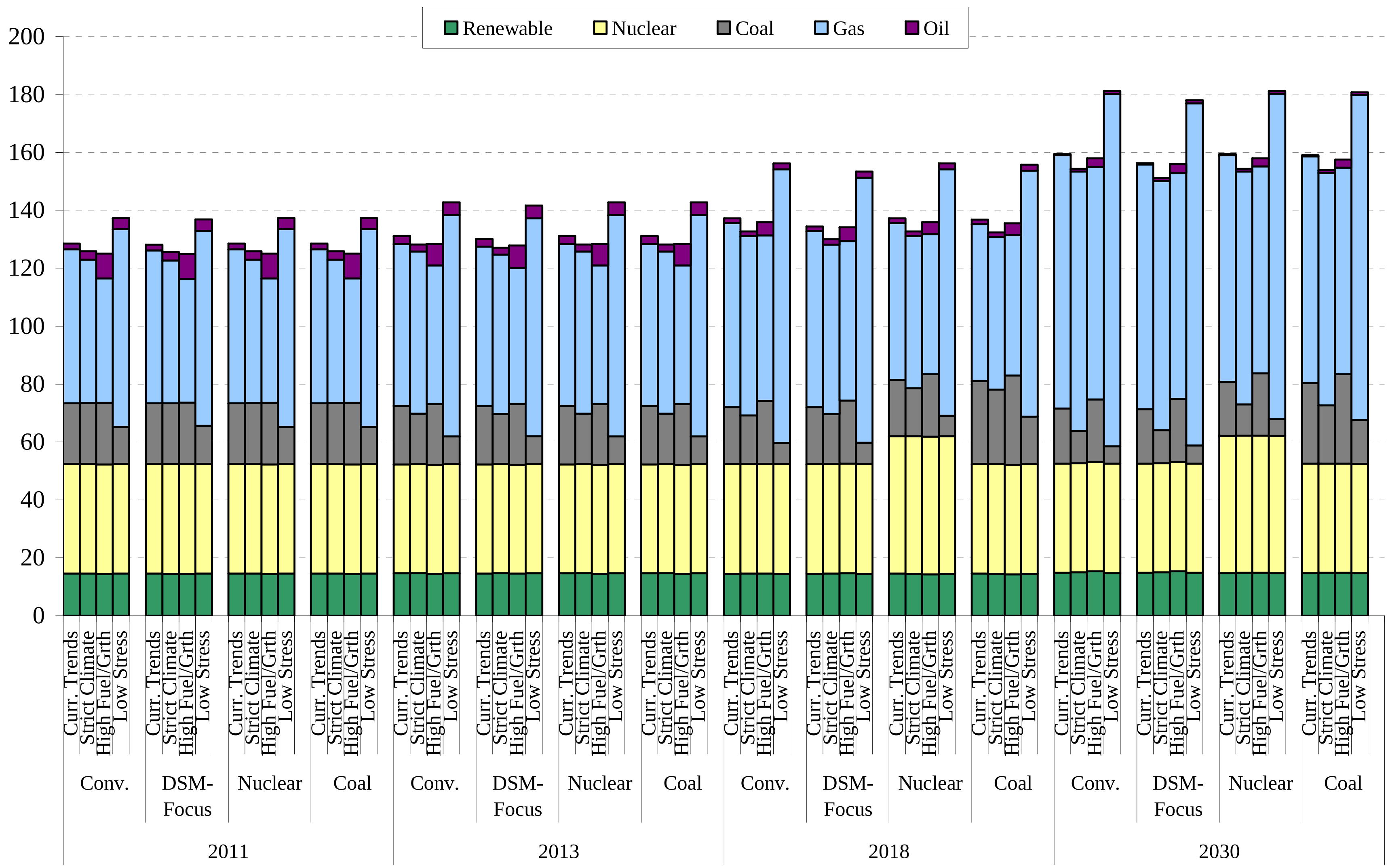


Figure H.20: Total ISO Fuel Mix (Cumulative Generation in TWh)



Summary of Results: 2011 Current Trends Scenario, Conventional Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation In Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
77.0	73.9	58%	7,098	35,803,769	36,386,989	-583,215	8,276	8,251	25	4.5	9.5	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	**TOTAL RESOURCE COST**
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
0	314	39	1,065	60	202	169	-173	1	76	**1,754**

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	**TOTAL GENERATION SVC COST + 15% PREMIUM**	**AVERAGE GENERATION SVC COST + 15% PREMIUM**	Adder for DSM Programs	RPS Cost (RECs + ACPs)	**TOTAL SYSTEM BENEFITS COST**	**AVERAGE SYSTEM BENEFITS COST**	**TOTAL COST**	**AVG COST**
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,758	447	-7	-67	22	3	67	**3,705**	**10.35**	123	202	**325**	**0.91**	**4,030**	**11.26**

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	**TOTAL GENERATION SVC COST**	**AVERAGE GENERATIO N SVC COST**	Adder for DSM Programs	RPS Cost (RECs + ACPs)	**TOTAL SYSTEM BENEFITS COST**	**AVERAGE SYSTEM BENEFITS COST**	**TOTAL COST**	**AVG COST**
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
1,475	413	**1,888**	**5.27**	123	202	**325**	**0.91**	**2,213**	**6.18**

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
21.3%	2,145

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
11,563,150	17,018,423	81,372,563	31%	57,039,604	86,136,899	379,620,145

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	9,992,814	11,699	5,248	10,084,834	27,195	7,604
ME	6,079,793	3,592	1,583	6,079,890	3,982	1,681
MA	21,605,001	75,625	20,156	21,577,823	75,632	20,152
NH	7,668,049	24,877	6,773	7,672,330	24,878	6,774
RI	2,703,592	23	467	2,703,592	23	467
VT	603,161	2	2	611,113	2	2
Total	**48,652,410**	**115,817**	**34,230**	**48,729,583**	**131,712**	**36,681**

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,508,310	615,630	3,123,940	36,386,700	35,803,769	11%	8%	3%	1,275,490	1,237,610	81,622,175
1,958,970	3,020,750	4,979,720	15,965,780	12,739,797						
1,685,120	895,330	2,580,450	38,924,440	62,783,072						
678,940	2,024,940	2,703,880	24,697,540	10,825,805						
92,980	0	92,980	6,466,110	11,944,435						
588,050	439,090	1,027,140	6,117,740	7,699,469						
7,512,370	**6,995,740**	**14,508,110**	**128,558,310**	**141,796,347**						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,508,310	615,630	17,201,880	3,939,820	11,240,540	14,070	866,450	12,121,060	24,265,640	36,386,700
ME	1,958,970	3,020,750	0	584,240	10,215,340	90	186,390	10,401,820	5,563,960	15,965,780
MA	1,685,120	895,330	5,597,860	12,518,620	17,327,470	4,780	895,260	18,227,510	20,696,930	38,924,440
NH	678,940	2,024,940	10,000,870	3,937,230	7,978,970	2,180	74,410	8,055,560	16,641,980	24,697,540
RI	92,980	0	0	0	6,373,130	0	0	6,373,130	92,980	6,466,110
VT	588,050	439,090	5,074,090	0	11,870	4,640	0	16,510	6,101,230	6,117,740
Total	**7,512,370**	**6,995,740**	**37,874,700**	**20,979,910**	**53,147,320**	**25,760**	**2,022,510**	**55,195,590**	**73,362,720**	**128,558,310**

Summary of Results: 2011 Current Trends Scenario, DSM-Focus Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation In Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
76.7	73.8	58%	6,926	35,400,744	36,328,686	-927,937	8,076	8,251	-175	4.5	9.5	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	**TOTAL RESOURCE COST**
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
0	314	39	1,061	60	200	151	-184	-9	94	**1,726**

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	**TOTAL GENERATION SVC COST + 15% PREMIUM**	**AVERAGE GENERATION SVC COST + 15% PREMIUM**	Adder for DSM Programs	RPS Cost (RECs + ACPs)	**TOTAL SYSTEM BENEFITS COST**	**AVERAGE SYSTEM BENEFITS COST**	**TOTAL COST**	**AVG COST**
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,717	436	-5	-67	25	3	67	**3,652**	**10.32**	220	200	**420**	**1.19**	**4,072**	**11.50**

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	**TOTAL GENERATION SVC COST**	**AVERAGE GENERATION SVC COST**	Adder for DSM Programs	RPS Cost (RECs + ACPs)	**TOTAL SYSTEM BENEFITS COST**	**AVERAGE SYSTEM BENEFITS COST**	**TOTAL COST**	**AVG COST**
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
1,431	413	**1,845**	**5.21**	220	200	**420**	**1.19**	**2,265**	**6.40**

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
22.1%	2,360

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
11,647,589	16,942,276	81,113,617	31%	56,689,966	85,559,983	376,927,551

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	9,954,491	11,628	5,218	10,044,293	27,078	7,572
ME	6,063,822	3,605	1,583	6,063,897	3,995	1,681
MA	21,490,783	75,457	20,101	21,461,937	75,461	20,096
NH	7,660,440	24,866	6,769	7,664,564	24,867	6,770
RI	2,667,989	23	461	2,667,989	23	461
VT	603,041	2	2	610,900	2	2
Total	**48,440,566**	**115,581**	**34,134**	**48,513,580**	**131,425**	**36,582**

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,508,180	615,600	3,123,780	36,328,369	35,400,744	11%	8%	3%	1,275,420	1,237,550	79,969,402
1,958,750	3,020,750	4,979,500	15,922,460	12,739,797						
1,685,040	912,770	2,597,810	38,720,780	62,783,072						
678,720	2,024,870	2,703,590	24,681,840	10,825,805						
92,980	0	92,980	6,384,500	11,944,435						
587,980	439,060	1,027,040	6,117,420	7,699,469						
7,511,650	**7,013,050**	**14,524,700**	**128,155,369**	**141,393,322**						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,508,180	615,600	17,201,880	3,935,690	11,210,370	12,059	844,590	12,067,019	24,261,350	36,328,369
ME	1,958,750	3,020,750	0	583,930	10,169,420	70	189,540	10,359,030	5,563,430	15,922,460
MA	1,685,040	912,770	5,597,860	12,510,830	17,142,720	4,250	867,310	18,014,280	20,706,500	38,720,780
NH	678,720	2,024,870	10,000,870	3,936,560	7,965,880	2,110	72,830	8,040,820	16,641,020	24,681,840
RI	92,980	0	0	0	6,291,520	0	0	6,291,520	92,980	6,384,500
VT	587,980	439,060	5,074,090	0	11,710	4,580	0	16,290	6,101,130	6,117,420
Total	**7,511,650**	**7,013,050**	**37,874,700**	**20,967,010**	**52,791,620**	**23,069**	**1,974,270**	**54,788,959**	**73,366,410**	**128,155,369**

Summary of Results: 2013 Current Trends Scenario, Conventional Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation In Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
72.7	70.2	57%	7,229	36,164,316	36,239,984	-75,664	8,429	8,251	178	3.7	10.3	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	**TOTAL RESOURCE COST**
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
0	314	39	1,022	63	231	149	-130	8	103	**1,799**

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	**TOTAL GENERATION SVC COST + 15% PREMIUM**	**AVERAGE GENERATION SVC COST + 15% PREMIUM**	Adder for DSM Programs	RPS Cost (RECs + ACPs)	**TOTAL SYSTEM BENEFITS COST**	**AVERAGE SYSTEM BENEFITS COST**	**TOTAL COST**	**AVG COST**
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,631	377	-4	-64	21	3	72	**3,491**	**9.65**	121	231	**352**	**0.97**	**3,843**	**10.63**

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	**TOTAL GENERATION SVC COST**	**AVERAGE GENERATION SVC COST**	Adder for DSM Programs	RPS Cost (RECs + ACPs)	**TOTAL SYSTEM BENEFITS COST**	**AVERAGE SYSTEM BENEFITS COST**	**TOTAL COST**	**AVG COST**
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
1,465	413	**1,878**	**5.19**	121	231	**352**	**0.97**	**2,230**	**6.17**

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
18.2%	2,292

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
12,168,538	17,301,526	83,585,989	32%	58,197,697	89,611,741	400,263,330

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	9,808,968	9,264	4,757	9,944,981	24,997	7,080
ME	6,431,259	4,265	1,774	6,432,590	4,704	1,884
MA	22,119,220	74,473	19,975	22,093,744	74,458	19,966
NH	7,861,319	25,688	6,983	7,865,377	25,689	6,984
RI	2,989,495	26	516	2,989,495	26	516
VT	553,065	2	2	560,351	2	3
Total	**49,763,326**	**113,719**	**34,007**	**49,886,538**	**129,876**	**36,433**

RPS Summary

State	Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
CT	2,384,820	616,070	3,000,890	36,239,650	36,164,316	13%	10%	3%	1,131,740	1,257,870	121,971,119
ME	2,093,810	3,020,440	5,114,250	16,573,980	13,086,492						
MA	1,761,630	929,100	2,690,730	40,314,226	63,882,777						
NH	708,780	2,025,080	2,733,860	24,979,480	11,203,706						
RI	94,240	0	94,240	7,122,850	12,184,916						
VT	539,190	439,310	978,500	5,966,600	7,873,275						
Total	**7,582,470**	**7,030,000**	**14,612,470**	**131,196,786**	**144,395,481**						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,384,820	616,070	17,091,580	3,373,550	11,525,020	35,740	1,212,870	12,773,630	23,466,020	36,239,650
ME	2,093,810	3,020,440	0	657,440	10,536,430	1,380	264,480	10,802,290	5,771,690	16,573,980
MA	1,761,630	929,100	5,597,860	12,129,950	18,721,980	28,096	1,145,610	19,895,686	20,418,540	40,314,226
NH	708,780	2,025,080	10,000,870	4,033,330	8,086,320	2,600	122,500	8,211,420	16,768,060	24,979,480
RI	94,240	0	0	0	7,028,610	0	0	7,028,610	94,240	7,122,850
VT	539,190	439,310	4,969,930	0	12,490	5,680	0	18,170	5,948,430	5,966,600
Total	**7,582,470**	**7,030,000**	**37,660,240**	**20,194,270**	**55,910,850**	**73,496**	**2,745,460**	**58,729,806**	**72,466,980**	**131,196,786**

Summary of Results: 2013 Current Trends Scenario, DSM-Focus Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation In Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
72.0	69.7	58%	6,888	35,070,158	36,048,440	-978,268	8,032	8,251	-219	4.1	9.9	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	**TOTAL RESOURCE COST**
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
0	314	39	1,009	62	224	114	-163	-11	155	**1,743**

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	**TOTAL GENERATION SVC COST + 15% PREMIUM**	**AVERAGE GENERATION SVC COST + 15% PREMIUM**	Adder for DSM Programs	RPS Cost (RECs + ACPs)	**TOTAL SYSTEM BENEFITS COST**	**AVERAGE SYSTEM BENEFITS COST**	**TOTAL COST**	**AVG COST**
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,526	394	-3	-62	21	3	70	**3,391**	**9.67**	300	224	**524**	**1.49**	**3,914**	**11.16**

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	**TOTAL GENERATION SVC COST**	**AVERAGE GENERATIO N SVC COST**	Adder for DSM Programs	RPS Cost (RECs + ACPs)	**TOTAL SYSTEM BENEFITS COST**	**AVERAGE SYSTEM BENEFITS COST**	**TOTAL COST**	**AVG COST**
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
1,364	413	**1,778**	**5.07**	300	224	**524**	**1.49**	**2,301**	**6.56**

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
19.6%	2,721

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
11,972,371	17,170,853	82,685,196	32%	56,705,208	88,494,646	393,408,240

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	9,690,136	9,032	4,662	9,819,715	24,657	6,985
ME	6,404,295	4,242	1,765	6,405,452	4,680	1,874
MA	21,878,882	74,236	19,882	21,854,107	74,222	19,874
NH	7,823,480	25,571	6,951	7,826,995	25,572	6,952
RI	2,872,410	25	496	2,872,410	25	496
VT	552,226	1	1	557,427	1	2
Total	**49,221,428**	**113,106**	**33,757**	**49,336,107**	**129,157**	**36,183**

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,385,170	615,720	3,000,890	36,048,150	35,070,158	13%	10%	3%	1,132,020	1,257,940	116,586,260
2,094,050	3,020,430	5,114,480	16,513,170	13,086,492						
1,761,600	903,030	2,664,630	39,801,440	63,882,777						
709,060	2,024,150	2,733,210	24,919,020	11,203,706						
94,230	0	94,230	6,856,900	12,184,916						
539,250	438,970	978,220	5,963,650	7,873,275						
7,583,360	**7,002,300**	**14,585,660**	**130,102,330**	**143,301,323**						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,385,170	615,720	17,091,580	3,354,880	11,408,790	29,780	1,162,230	12,600,800	23,447,350	36,048,150
ME	2,094,050	3,020,430	0	657,570	10,481,710	1,210	258,200	10,741,120	5,772,050	16,513,170
MA	1,761,600	903,030	5,597,860	12,111,340	18,278,840	24,820	1,123,950	19,427,610	20,373,830	39,801,440
NH	709,060	2,024,150	10,000,870	4,027,580	8,051,540	1,930	103,890	8,157,360	16,761,660	24,919,020
RI	94,230	0	0	0	6,762,670	0	0	6,762,670	94,230	6,856,900
VT	539,250	438,970	4,969,930	0	12,290	3,210	0	15,500	5,948,150	5,963,650
Total	**7,583,360**	**7,002,300**	**37,660,240**	**20,151,370**	**54,995,840**	**60,950**	**2,648,270**	**57,705,060**	**72,397,270**	**130,102,330**

Summary of Results: 2018 Current Trends Scenario, Conventional Solution

Summary of Key Parameters in Connecticut

Load LMP ($/MWh)	Generation LMP ($/MWh)	Load Factor	Peak Load Net of DSM * 1.08 loss grossup (MW)	Total Energy Needed to Meet Customer Load (MWh)	Total Generation In Connecticut (MWh)	Net Imports (MWh)	CT LSEs' ICR (MW)	CT Internal Installed Capacity (MW)	Net Capacity Imports (negative denotes exports) (MW)	Capacity Price ($/kW-Mo)	Fast-Start Price ($/kW-Mo)	Fast-Start Requirement (MW)
78.6	75.9	57%	7,441	36,952,178	37,751,551	-799,366	8,677	8,550	127	3.1	10.9	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT ($Mil)	Fixed O&M (FOM) ($Mil)	Variable O&M (VOM) ($Mil)	Cost of Fuel ($Mil)	Total Allowance Cost ($Mil)	RPS Cost (RECs + ACPs) ($Mil)	CT Energy Import Cost ($Mil)	CT Energy Export Cost ($Mil)	CT Capacity Import Cost (Negative Denotes Benefits) ($Mil)	Adder for DSM Programs ($Mil)	**TOTAL RESOURCE COST** ($Mil)
28	323	42	1,123	148	324	143	-180	5	156	**2,112**

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP ($Mil)	ICR*Price ($Mil)	FTRs (Assume 75% Coverage for Internal Gen to Load) ($Mil)	Adjustment for Overcounting Losses ($Mil)	Spin ($Mil)	Uplift ($Mil)	Connecticut Fast-Start Cost ($Mil)	**TOTAL GENERATION SVC COST + 15% PREMIUM** ($Mil)	**AVERAGE GENERATION SVC COST + 15% PREMIUM** (¢/kWh)	Adder for DSM Programs ($Mil)	RPS Cost (RECs + ACPs) ($Mil)	**TOTAL SYSTEM BENEFITS COST** ($Mil)	**AVERAGE SYSTEM BENEFITS COST** (¢/kWh)	**TOTAL COST** ($Mil)	**AVG COST** (¢/kWh)
2,906	320	-11	-67	21	4	77	**3,736**	**10.11**	116	324	**440**	**1.19**	**4,176**	**11.30**

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS ($Mil)	Annualized Embedded Cost of Generators ($Mil)	**TOTAL GENERATION SVC COST** ($Mil)	**AVERAGE GENERATION SVC COST** (¢/kWh)	Adder for DSM Programs ($Mil)	RPS Cost (RECs + ACPs) ($Mil)	**TOTAL SYSTEM BENEFITS COST** ($Mil)	**AVERAGE SYSTEM BENEFITS COST** (¢/kWh)	**TOTAL COST** ($Mil)	**AVG COST** (¢/kWh)
1,632	413	**2,045**	**5.53**	116	324	**440**	**1.19**	**2,485**	**6.73**

Electric Reliability and Availability

ISO-NE Reserve Margin (%)	CT LSR Surplus (Deficit) (MW)
17.5%	2,510

Fuel Security

CT NG Demand in January and February (MMBtu)	CT NG Demand in July and August	Total CT NG Demand (MMBtu)	CT NG Share of Total CT Generation (%)	ISO-NE NG Demand in January and February (MMBtu)	ISO NG Demand in July and August	Total ISO-NE NG Demand (MMBtu)
14,825,016	20,059,989	97,714,790	36%	66,768,645	97,549,818	453,252,636

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units (Tons)	Total SOx Emissions - Monitored Units (Tons)	Total NOx Emissions - Monitored Units (Tons)	Total CO2 Emissions - All Units (Tons)	Total SOx Emissions - All Units (Tons)	Total NOx Emissions - All Units (Tons)
CT	11,871,777	7,387	4,309	10,210,320	22,566	6,613
ME	7,813,168	3,958	1,953	7,814,468	4,394	2,062
MA	22,105,232	67,518	18,445	22,087,337	67,542	18,447
NH	7,871,126	26,990	7,274	7,874,248	26,954	7,268
RI	2,708,347	23	468	2,708,347	23	468
VT	511,265	1	2	516,989	2	3
Total	**52,880,915**	**105,877**	**32,450**	**51,211,709**	**121,482**	**34,860**

RPS Summary

Biomass and Refuse Generation (MWh)	Hydro Generation (MWh)	Renewable Generation (MWh)	Total Generation (MWh)	Total Retail Sales (MWh)	Overall Renewables Requirement (%)	Class I Renewables Requirement	Class II Renewables Requirement (%)	Class I Eligible Renewable Generation (MWh)	Class II Eligible Renewable Generation (MWh)	Alternative Compliance Payments ($)
2,379,340	616,590	2,995,930	37,751,230	36,952,178	20%	17%	3%	1,211,280	1,172,860	222,159,494
2,011,340	3,020,530	5,031,870	20,128,500	13,807,015						
1,781,890	921,570	2,703,460	42,123,270	66,657,772						
697,470	2,026,170	2,723,640	24,665,340	12,047,803						
95,270	0	95,270	6,485,050	12,665,021						
494,600	439,700	934,300	6,027,740	8,272,718						
7,459,910	**7,024,560**	**14,484,470**	**137,181,130**	**150,402,507**						

Fuel Usage Summary

State	Biomass and Refuse Generation (MWh)	Hydro Generation (MWh)	Nuclear Generation (MWh)	Coal Generation (MWh)	Natural Gas Generation (MWh)	Distillate Fuel Oil Generation (MWh)	Residual Fuel Oil Generation (MWh)	Total Gas or Oil Generation (MWh)	Total NOT Gas or Oil Generation (MWh)	Total Generation (MWh)
CT	2,379,340	616,590	17,180,880	3,356,720	13,524,340	41,660	651,700	14,217,700	23,533,530	37,751,230
ME	2,011,340	3,020,530	0	666,230	14,252,710	1,340	176,350	14,430,400	5,698,100	20,128,500
MA	1,781,890	921,570	5,597,860	11,344,870	21,827,060	37,880	612,140	22,477,080	19,646,190	42,123,270
NH	697,470	2,026,170	10,000,870	4,317,890	7,602,050	3,210	17,680	7,622,940	17,042,400	24,665,340
RI	95,270	0	0	0	6,389,780	0	0	6,389,780	95,270	6,485,050
VT	494,600	439,700	5,074,090	0	13,940	5,410	0	19,350	6,008,390	6,027,740
Total	**7,459,910**	**7,024,560**	**37,853,700**	**19,685,710**	**63,609,880**	**89,500**	**1,457,870**	**65,157,250**	**72,023,880**	**137,181,130**

Summary of Results: 2018 Current Trends Scenario, DSM-Focus Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation In Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
77.5	75.2	57%	6,790	34,173,972	35,589,118	-1,415,134	7,917	8,251	-334	3.3	10.7	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	**TOTAL RESOURCE COST**
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
0	314	37	998	136	299	104	-196	-13	303	**1,982**

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	**TOTAL GENERATION SVC COST + 15% PREMIUM**	**AVERAGE GENERATION SVC COST + 15% PREMIUM**	Adder for DSM Programs	RPS Cost (RECs + ACPs)	**TOTAL SYSTEM BENEFITS COST**	**AVERAGE SYSTEM BENEFITS COST**	**TOTAL COST**	**AVG COST**
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,650	310	-2	-67	21	3	75	**3,439**	**10.06**	172	299	**472**	**1.38**	**3,911**	**11.44**

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	**TOTAL GENERATION SVC COST**	**AVERAGE GENERATION SVC COST**	Adder for DSM Programs	RPS Cost (RECs + ACPs)	**TOTAL SYSTEM BENEFITS COST**	**AVERAGE SYSTEM BENEFITS COST**		**TOTAL COST**	**AVG COST**
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)		($Mil)	(¢/kWh)
1,380	413	**1,793**	**5.25**	172	299	**472**	**1.38**		**2,264**	**6.63**

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
18.1%	3,032

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation		ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)		(MMBtu)		(MMBtu)
12,212,419	17,177,664	82,687,710	32%		62,830,362	93,252,893	432,967,129

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	11,002,542	7,366	4,145	9,313,418	22,501	6,446
ME	7,148,130	4,045	1,858	7,149,004	4,481	1,967
MA	22,323,530	67,788	18,540	22,304,171	67,803	18,540
NH	8,142,530	27,386	7,407	8,143,062	27,316	7,392
RI	2,717,219	23	469	2,717,218	23	469
VT	509,303	1	1	514,602	1	2
Total	**51,843,253**	**106,609**	**32,420**	**50,141,476**	**122,126**	**34,817**

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,379,340	616,230	2,995,570	35,588,810	34,173,972	20%	17%	3%	1,211,280	1,172,860	201,466,668
2,011,470	3,020,740	5,032,210	18,457,040	13,807,015						
1,781,920	923,660	2,705,580	42,603,670	66,657,772						
697,480	2,024,670	2,722,150	25,221,120	12,047,803						
95,330	0	95,330	6,506,800	12,665,021						
494,560	439,420	933,980	6,025,440	8,272,718						
7,460,100	**7,024,720**	**14,484,820**	**134,402,880**	**147,624,301**						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,379,340	616,230	17,180,880	3,374,900	11,389,760	31,920	615,780	12,037,460	23,551,350	35,588,810
ME	2,011,470	3,020,740	0	667,010	12,560,220	900	196,700	12,757,820	5,699,220	18,457,040
MA	1,781,920	923,660	5,597,860	11,352,250	22,245,580	28,860	673,540	22,947,980	19,655,690	42,603,670
NH	697,480	2,024,670	10,000,870	4,344,630	8,090,050	2,150	61,270	8,153,470	17,067,650	25,221,120
RI	95,330	0	0	0	6,411,470	0	0	6,411,470	95,330	6,506,800
VT	494,560	439,420	5,074,090	0	14,060	3,310	0	17,370	6,008,070	6,025,440
Total	**7,460,100**	**7,024,720**	**37,853,700**	**19,738,790**	**60,711,140**	**67,140**	**1,547,290**	**62,325,570**	**72,077,310**	**134,402,880**

Summary of Results: 2018 Current Trends Scenario, Nuclear Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation In Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
77.4	73.7	57%	7,441	36,952,178	44,825,452	-7,873,238	8,677	9,451	-774	3.6	10.4	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	**TOTAL RESOURCE COST**
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
583	437	53	1,062	132	324	22	-558	-33	156	**2,179**

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	**TOTAL GENERATION SVC COST + 15% PREMIUM**	**AVERAGE GENERATION SVC COST + 15% PREMIUM**	Adder for DSM Programs	RPS Cost (RECs + ACPs)	**TOTAL SYSTEM BENEFITS COST**	**AVERAGE SYSTEM BENEFITS COST**	**TOTAL COST**	**AVG COST**
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,858	370	-9	-81	24	3	73	**3,726**	**10.08**	116	324	**440**	**1.19**	**4,166**	**11.27**

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	**TOTAL GENERATION SVC COST**	**AVERAGE GENERATIO N SVC COST**	Adder for DSM Programs	RPS Cost (RECs + ACPs)	**TOTAL SYSTEM BENEFITS COST**	**AVERAGE SYSTEM BENEFITS COST**	**TOTAL COST**	**AVG COST**
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
1,699	413	**2,113**	**5.72**	116	324	**440**	**1.19**	**2,552**	**6.91**

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
17.5%	3,410

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
11,750,563	16,804,772	79,798,717	25%	57,787,987	85,930,202	386,843,587

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	10,726,869	7,072	4,031	9,083,554	22,130	6,325
ME	6,213,591	4,018	1,692	6,215,424	4,454	1,802
MA	20,635,541	66,221	17,907	20,617,943	66,238	17,908
NH	8,059,254	26,964	7,299	8,058,513	26,878	7,280
RI	2,566,406	22	443	2,566,405	22	443
VT	510,073	1	1	515,346	2	2
Total	**48,711,733**	**104,298**	**31,374**	**47,057,186**	**119,724**	**33,761**

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,379,180	616,100	2,995,280	44,825,060	36,952,178	20%	17%	3%	1,211,200	1,172,770	222,162,999
2,011,170	3,021,530	5,032,700	16,148,240	13,807,015						
1,781,770	948,080	2,729,850	38,913,400	66,657,772						
697,310	2,025,140	2,722,450	25,124,130	12,047,803						
95,260	0	95,260	6,148,220	12,665,021						
494,540	439,490	934,030	6,025,980	8,272,718						
7,459,230	**7,050,340**	**14,509,570**	**137,185,030**	**150,402,507**						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,379,180	616,100	26,864,210	3,315,660	10,998,590	31,770	619,550	11,649,910	33,175,150	44,825,060
ME	2,011,170	3,021,530	0	657,700	10,252,080	1,890	203,870	10,457,840	5,690,400	16,148,240
MA	1,781,770	948,080	5,597,860	11,128,540	18,814,070	25,000	618,080	19,457,150	19,456,250	38,913,400
NH	697,310	2,025,140	10,000,870	4,270,750	8,060,800	2,550	66,710	8,130,060	16,994,070	25,124,130
RI	95,260	0	0	0	6,052,960	0	0	6,052,960	95,260	6,148,220
VT	494,540	439,490	5,074,090	0	13,860	4,000	0	17,860	6,008,120	6,025,980
Total	**7,459,230**	**7,050,340**	**47,537,030**	**19,372,650**	**54,192,360**	**65,210**	**1,508,210**	**55,765,780**	**81,419,250**	**137,185,030**

Summary of Results: 2018 Current Trends Scenario, Coal Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation In Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
77.4	73.7	57%	7,441	36,952,178	44,825,452	-7,873,238	8,677	9,451	-774	3.6	10.4	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	**TOTAL RESOURCE COST**
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
302	371	89	1,234	259	324	22	-558	-33	156	**2,166**

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	**TOTAL GENERATION SVC COST + 15% PREMIUM**	**AVERAGE GENERATION SVC COST + 15% PREMIUM**	Adder for DSM Programs	RPS Cost (RECs + ACPs)	**TOTAL SYSTEM BENEFITS COST**	**AVERAGE SYSTEM BENEFITS COST**	**TOTAL COST**	**AVG COST**
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,858	370	-9	-81	24	3	73	**3,726**	**10.08**	116	324	**440**	**1.19**	**4,166**	**11.27**

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	**TOTAL GENERATION SVC COST**	**AVERAGE GENERATIO N SVC COST**	Adder for DSM Programs	RPS Cost (RECs + ACPs)	**TOTAL SYSTEM BENEFITS COST**	**AVERAGE SYSTEM BENEFITS COST**	**TOTAL COST**	**AVG COST**
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
1,686	413	**2,099**	**5.68**	116	324	**440**	**1.19**	**2,539**	**6.87**

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
17.5%	3,410

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
11,750,563	16,804,772	79,798,717	25%	57,787,987	85,930,202	386,843,587

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	18,860,481	7,072	4,031	17,217,166	22,130	6,325
ME	6,213,591	4,018	1,692	6,215,424	4,454	1,802
MA	20,635,541	66,221	17,907	20,617,943	66,238	17,908
NH	8,059,254	26,964	7,299	8,058,513	26,878	7,280
RI	2,566,406	22	443	2,566,405	22	443
VT	510,073	1	1	515,346	2	2
Total	**56,845,345**	**104,298**	**31,374**	**55,190,798**	**119,724**	**33,761**

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,379,180	616,100	2,995,280	44,825,060	36,952,178	20%	17%	3%	1,211,200	1,172,770	222,162,999
2,011,170	3,021,530	5,032,700	16,148,240	13,807,015						
1,781,770	948,080	2,729,850	38,913,400	66,657,772						
697,310	2,025,140	2,722,450	25,124,130	12,047,803						
95,260	0	95,260	6,148,220	12,665,021						
494,540	439,490	934,030	6,025,980	8,272,718						
7,459,230	**7,050,340**	**14,509,570**	**137,185,030**	**150,402,507**						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,379,180	616,100	17,180,880	12,611,657	10,998,590	31,770	619,550	11,649,910	32,787,817	44,437,727
ME	2,011,170	3,021,530	0	657,700	10,252,080	1,890	203,870	10,457,840	5,690,400	16,148,240
MA	1,781,770	948,080	5,597,860	11,128,540	18,814,070	25,000	618,080	19,457,150	19,456,250	38,913,400
NH	697,310	2,025,140	10,000,870	4,270,750	8,060,800	2,550	66,710	8,130,060	16,994,070	25,124,130
RI	95,260	0	0	0	6,052,960	0	0	6,052,960	95,260	6,148,220
VT	494,540	439,490	5,074,090	0	13,860	4,000	0	17,860	6,008,120	6,025,980
Total	**7,459,230**	**7,050,340**	**37,853,700**	**28,668,647**	**54,192,360**	**65,210**	**1,508,210**	**55,765,780**	**81,031,917**	**136,797,697**

Summary of Results: 2030 Current Trends Scenario, Conventional Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation In Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
86.7	82.8	56%	8,424	41,549,275	50,226,725	-8,677,412	9,823	10,947	-1,124	4.3	9.7	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	**TOTAL RESOURCE COST**
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
244	392	73	1,942	368	319	19	-698	-58	156	**2,757**

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	**TOTAL GENERATION SVC COST + 15% PREMIUM**	**AVERAGE GENERATION SVC COST + 15% PREMIUM**	Adder for DSM Programs	RPS Cost (RECs + ACPs)	**TOTAL SYSTEM BENEFITS COST**	**AVERAGE SYSTEM BENEFITS COST**	**TOTAL COST**	**AVG COST**
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
3,604	510	-40	-72	16	9	68	**4,709**	**11.33**	116	319	**435**	**1.05**	**5,143**	**12.38**

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	**TOTAL GENERATION SVC COST**	**AVERAGE GENERATIO N SVC COST**	Adder for DSM Programs	RPS Cost (RECs + ACPs)	**TOTAL SYSTEM BENEFITS COST**	**AVERAGE SYSTEM BENEFITS COST**	**TOTAL COST**	**AVG COST**
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,283	413	**2,696**	**6.49**	116	319	**435**	**1.05**	**3,131**	**7.53**

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
18.0%	3,771

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
29,403,944	40,105,707	189,023,414	53%	95,381,976	143,570,649	621,922,415

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	16,752,426	6,372	4,802	15,035,322	20,065	6,888
ME	9,396,131	3,695	2,158	9,397,718	4,141	2,270
MA	23,170,241	63,534	17,757	23,065,590	62,277	17,471
NH	7,476,317	26,114	7,014	7,479,512	26,030	6,997
RI	2,997,715	26	518	2,997,715	26	518
VT	1,428,394	12	147	1,433,535	13	148
Total	**61,221,224**	**99,753**	**32,395**	**59,409,391**	**112,552**	**34,291**

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,523,650	617,700	3,141,350	50,226,470	41,549,275	23%	20%	3%	1,254,600	1,273,850	235,294,330
2,105,950	3,022,930	5,128,880	24,077,360	16,096,049						
1,761,170	913,200	2,674,370	45,918,748	76,092,263						
674,640	2,053,640	2,728,280	23,857,840	14,892,841						
90,730	0	90,730	7,237,680	14,386,939						
571,520	443,200	1,014,720	8,097,450	9,600,632						
7,727,660	**7,050,670**	**14,778,330**	**159,415,548**	**172,617,999**						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,523,650	617,700	17,180,600	3,298,140	26,460,350	33,730	112,300	26,606,380	23,620,090	50,226,470
ME	2,105,950	3,022,930	0	700,160	18,176,280	1,600	70,440	18,248,320	5,829,040	24,077,360
MA	1,761,170	913,200	5,597,860	10,837,320	26,671,140	15,768	122,290	26,809,198	19,109,550	45,918,748
NH	674,640	2,053,640	9,912,880	4,195,820	7,012,600	8,260	0	7,020,860	16,836,980	23,857,840
RI	90,730	0	0	0	7,146,950	0	0	7,146,950	90,730	7,237,680
VT	571,520	443,200	5,014,570	0	2,053,490	14,670	0	2,068,160	6,029,290	8,097,450
Total	**7,727,660**	**7,050,670**	**37,705,910**	**19,031,440**	**87,520,810**	**74,028**	**305,030**	**87,899,868**	**71,515,680**	**159,415,548**

Summary of Results: 2030 Current Trends Scenario, DSM-Focus Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation In Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
85.6	82.4	57%	7,687	38,425,488	49,751,361	-11,325,831	8,963	10,647	-1,684	4.4	9.6	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	**TOTAL RESOURCE COST**
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
220	384	71	1,908	361	295	6	-906	-89	232	**2,482**

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	**TOTAL GENERATION SVC COST + 15% PREMIUM**	**AVERAGE GENERATION SVC COST + 15% PREMIUM**	Adder for DSM Programs	RPS Cost (RECs + ACPs)	**TOTAL SYSTEM BENEFITS COST**	**AVERAGE SYSTEM BENEFITS COST**	**TOTAL COST**	**AVG COST**
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
3,289	475	-15	-68	16	8	67	**4,340**	**11.30**	172	295	**467**	**1.22**	**4,807**	**12.51**

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	**TOTAL GENERATION SVC COST**	**AVERAGE GENERATION SVC COST**	Adder for DSM Programs	RPS Cost (RECs + ACPs)	**TOTAL SYSTEM BENEFITS COST**	**AVERAGE SYSTEM BENEFITS COST**	**TOTAL COST**	**AVG COST**
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
1,955	413	**2,369**	**6.16**	172	295	**467**	**1.22**	**2,836**	**7.38**

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
17.9%	4,400

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
28,591,941	38,915,589	185,448,816	52%	91,066,125	138,194,327	599,699,315

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	16,477,094	6,032	4,688	14,774,143	19,774	6,779
ME	9,329,153	3,685	2,144	9,331,329	4,132	2,256
MA	22,301,117	62,456	17,370	22,205,200	61,217	17,089
NH	7,432,014	25,888	6,956	7,434,232	25,781	6,934
RI	2,682,341	23	463	2,682,341	23	463
VT	1,424,150	13	146	1,429,267	14	148
Total	**59,645,870**	**98,098**	**31,767**	**57,856,513**	**110,941**	**33,669**

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,523,650	617,870	3,141,520	49,751,100	38,425,488	23%	20%	3%	1,254,600	1,273,850	214,458,531
2,105,910	3,023,580	5,129,490	23,918,520	16,096,049						
1,761,170	941,880	2,703,050	44,229,210	76,092,263						
674,640	2,056,180	2,730,820	23,807,640	14,892,841						
90,730	0	90,730	6,498,550	14,386,939						
571,520	443,520	1,015,040	8,084,900	9,600,632						
7,727,620	**7,083,030**	**14,810,650**	**156,289,920**	**169,494,212**						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,523,650	617,870	17,180,600	3,249,180	26,030,690	26,000	123,110	26,179,800	23,571,300	49,751,100
ME	2,105,910	3,023,580	0	700,590	18,018,420	2,200	67,820	18,088,440	5,830,080	23,918,520
MA	1,761,170	941,880	5,597,860	10,654,460	25,107,320	19,090	147,430	25,273,840	18,955,370	44,229,210
NH	674,640	2,056,180	9,912,880	4,155,630	6,998,420	9,890	0	7,008,310	16,799,330	23,807,640
RI	90,730	0	0	0	6,407,820	0	0	6,407,820	90,730	6,498,550
VT	571,520	443,520	5,014,570	0	2,039,340	15,950	0	2,055,290	6,029,610	8,084,900
Total	**7,727,620**	**7,083,030**	**37,705,910**	**18,759,860**	**84,602,010**	**73,130**	**338,360**	**85,013,500**	**71,276,420**	**156,289,920**

Summary of Results: 2030 Current Trends Scenario, Nuclear Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation In Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
84.1	79.5	56%	8,424	41,549,275	57,195,648	-15,646,330	9,823	11,847	-2,024	5.0	9.0	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	**TOTAL RESOURCE COST**
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
803	507	83	1,863	336	319	1	-1,194	-122	156	**2,751**

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	**TOTAL GENERATION SVC COST + 15% PREMIUM**	**AVERAGE GENERATION SVC COST + 15% PREMIUM**	Adder for DSM Programs	RPS Cost (RECs + ACPs)	**TOTAL SYSTEM BENEFITS COST**	**AVERAGE SYSTEM BENEFITS COST**	**TOTAL COST**	**AVG COST**
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
3,493	593	-40	-85	15	12	63	**4,659**	**11.21**	116	319	**435**	**1.05**	**5,094**	**12.26**

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	**TOTAL GENERATION SVC COST**	**AVERAGE GENERATION SVC COST**	Adder for DSM Programs	RPS Cost (RECs + ACPs)	**TOTAL SYSTEM BENEFITS COST**	**AVERAGE SYSTEM BENEFITS COST**	**TOTAL COST**	**AVG COST**
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,276	413	**2,690**	**6.47**	116	319	**435**	**1.05**	**3,124**	**7.52**

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
18.0%	4,670

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
26,218,583	36,558,105	170,059,081	42%	83,771,422	130,686,765	554,643,325

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	15,360,496	5,758	4,427	13,790,048	19,210	6,487
ME	9,255,887	3,659	2,126	9,258,325	4,106	2,238
MA	21,660,807	62,031	17,167	21,568,694	60,868	16,904
NH	7,370,588	25,874	6,943	7,374,396	25,791	6,926
RI	2,491,206	22	430	2,491,206	22	430
VT	600,282	5	4	605,201	6	5
Total	**56,739,266**	**97,348**	**31,097**	**55,087,870**	**110,003**	**32,990**

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,508,200	617,350	3,125,550	57,195,380	41,549,275	23%	20%	3%	1,244,920	1,268,070	235,617,160
2,105,900	3,023,090	5,128,990	23,739,510	16,096,049						
1,761,160	894,330	2,655,490	42,723,320	76,092,263						
674,640	2,053,140	2,727,780	23,657,940	14,892,841						
90,680	0	90,680	6,042,880	14,386,939						
571,480	443,590	1,015,070	6,055,680	9,600,632						
7,712,060	**7,031,500**	**14,743,560**	**159,414,710**	**172,617,999**						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,508,200	617,350	26,863,930	3,173,880	23,898,660	35,230	98,130	24,032,020	33,163,360	57,195,380
ME	2,105,900	3,023,090	0	696,210	17,844,630	2,460	67,220	17,914,310	5,825,200	23,739,510
MA	1,761,160	894,330	5,597,860	10,599,390	23,718,200	18,620	133,760	23,870,580	18,852,740	42,723,320
NH	674,640	2,053,140	9,912,880	4,155,700	6,852,750	8,830	0	6,861,580	16,796,360	23,657,940
RI	90,680	0	0	0	5,952,200	0	0	5,952,200	90,680	6,042,880
VT	571,480	443,590	5,014,570	0	11,860	14,180	0	26,040	6,029,640	6,055,680
Total	**7,712,060**	**7,031,500**	**47,389,240**	**18,625,180**	**78,278,300**	**79,320**	**299,110**	**78,656,730**	**80,757,980**	**159,414,710**

Summary of Results: 2030 Current Trends Scenario, Coal Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation In Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
84.1	79.5	56%	8,424	41,549,275	57,195,648	-15,646,330	9,823	11,847	-2,024	5.0	9.0	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	**TOTAL RESOURCE COST**
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
522	441	119	2,037	556	319	1	-1,194	-122	156	**2,834**

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	**TOTAL GENERATION SVC COST + 15% PREMIUM**	**AVERAGE GENERATION SVC COST + 15% PREMIUM**	Adder for DSM Programs	RPS Cost (RECs + ACPs)	**TOTAL SYSTEM BENEFITS COST**	**AVERAGE SYSTEM BENEFITS COST**	**TOTAL COST**	**AVG COST**
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
3,493	593	-40	-85	15	12	63	**4,659**	**11.21**	116	319	**435**	**1.05**	**5,094**	**12.26**

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	**TOTAL GENERATION SVC COST**	**AVERAGE GENERATION SVC COST**	Adder for DSM Programs	RPS Cost (RECs + ACPs)	**TOTAL SYSTEM BENEFITS COST**	**AVERAGE SYSTEM BENEFITS COST**	**TOTAL COST**	**AVG COST**
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,359	413	**2,772**	**6.67**	116	319	**435**	**1.05**	**3,207**	**7.72**

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
18.0%	4,670

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
26,218,583	36,558,105	170,059,081	42%	83,771,422	130,686,765	554,643,325

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	23,494,109	5,758	4,427	21,923,661	19,210	6,487
ME	9,255,887	3,659	2,126	9,258,325	4,106	2,238
MA	21,660,807	62,031	17,167	21,568,694	60,868	16,904
NH	7,370,588	25,874	6,943	7,374,396	25,791	6,926
RI	2,491,206	22	430	2,491,206	22	430
VT	600,282	5	4	605,201	6	5
Total	**64,872,878**	**97,348**	**31,097**	**63,221,482**	**110,003**	**32,990**

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,508,200	617,350	3,125,550	57,195,380	41,549,275	23%	20%	3%	1,244,920	1,268,070	235,617,160
2,105,900	3,023,090	5,128,990	23,739,510	16,096,049						
1,761,160	894,330	2,655,490	42,723,320	76,092,263						
674,640	2,053,140	2,727,780	23,657,940	14,892,841						
90,680	0	90,680	6,042,880	14,386,939						
571,480	443,590	1,015,070	6,055,680	9,600,632						
7,712,060	**7,031,500**	**14,743,560**	**159,414,710**	**172,617,999**						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,508,200	617,350	17,180,600	12,469,877	23,898,660	35,230	98,130	24,032,020	32,776,027	56,808,047
ME	2,105,900	3,023,090	0	696,210	17,844,630	2,460	67,220	17,914,310	5,825,200	23,739,510
MA	1,761,160	894,330	5,597,860	10,599,390	23,718,200	18,620	133,760	23,870,580	18,852,740	42,723,320
NH	674,640	2,053,140	9,912,880	4,155,700	6,852,750	8,830	0	6,861,580	16,796,360	23,657,940
RI	90,680	0	0	0	5,952,200	0	0	5,952,200	90,680	6,042,880
VT	571,480	443,590	5,014,570	0	11,860	14,180	0	26,040	6,029,640	6,055,680
Total	**7,712,060**	**7,031,500**	**37,705,910**	**27,921,177**	**78,278,300**	**79,320**	**299,110**	**78,656,730**	**80,370,647**	**159,027,377**

Summary of Results: 2011 Strict Climate Scenario, Conventional Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation In Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
81.6	78.4	57%	7,061	35,287,973	36,291,706	-1,003,716	8,233	8,251	-18	4.5	9.5	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	**TOTAL RESOURCE COST**
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
0	314	39	1,120	62	199	162	-203	-1	76	**1,767**

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	**TOTAL GENERATION SVC COST + 15% PREMIUM**	**AVERAGE GENERATION SVC COST + 15% PREMIUM**	Adder for DSM Programs	RPS Cost (RECs + ACPs)	**TOTAL SYSTEM BENEFITS COST**	**AVERAGE SYSTEM BENEFITS COST**	**TOTAL COST**	**AVG COST**
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,880	445	-7	-70	28	4	67	**3,848**	**10.90**	123	199	**322**	**0.91**	**4,170**	**11.82**

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	**TOTAL GENERATION SVC COST**	**AVERAGE GENERATION SVC COST**	Adder for DSM Programs	RPS Cost (RECs + ACPs)	**TOTAL SYSTEM BENEFITS COST**	**AVERAGE SYSTEM BENEFITS COST**	**TOTAL COST**	**AVG COST**
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
1,492	413	**1,905**	**5.40**	123	199	**322**	**0.91**	**2,227**	**6.31**

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
22.1%	2,213

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
10,297,896	16,440,405	77,350,274	30%	48,466,931	82,678,365	353,195,084

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	10,094,871	12,328	5,537	10,205,368	28,859	7,980
ME	5,963,600	3,886	1,626	5,963,605	4,275	1,724
MA	21,293,052	77,268	20,453	21,270,749	77,279	20,451
NH	7,543,581	25,005	6,779	7,546,712	25,006	6,780
RI	2,404,712	21	415	2,404,712	21	415
VT	602,613	2	2	609,628	2	2
Total	**47,902,429**	**118,509**	**34,812**	**48,000,773**	**135,442**	**37,352**

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,507,570	615,550	3,123,120	36,291,410	35,287,973	11%	8%	3%	1,275,100	1,237,260	79,522,367
1,957,990	3,020,430	4,978,420	15,591,556	12,454,988						
1,684,550	917,550	2,602,100	37,829,259	61,570,447						
678,320	2,024,640	2,702,960	24,351,100	10,614,392						
92,870	0	92,870	5,766,270	11,731,213						
587,840	438,910	1,026,750	6,115,520	7,528,882						
7,509,140	**7,017,080**	**14,526,220**	**125,945,114**	**139,187,895**						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,507,570	615,550	17,201,880	3,951,830	10,721,360	13,260	1,279,960	12,014,580	24,276,830	36,291,410
ME	1,957,990	3,020,430	0	582,630	9,770,930	6	259,570	10,030,506	5,561,050	15,591,556
MA	1,684,550	917,550	5,597,860	12,507,930	15,776,019	4,360	1,340,990	17,121,369	20,707,890	37,829,259
NH	678,320	2,024,640	10,000,870	3,932,930	7,601,450	1,940	110,950	7,714,340	16,636,760	24,351,100
RI	92,870	0	0	0	5,673,400	0	0	5,673,400	92,870	5,766,270
VT	587,840	438,910	5,074,090	0	10,460	4,220	0	14,680	6,100,840	6,115,520
Total	**7,509,140**	**7,017,080**	**37,874,700**	**20,975,320**	**49,553,619**	**23,786**	**2,991,470**	**52,568,874**	**73,376,240**	**125,945,114**

Summary of Results: 2011 Strict Climate Scenario, DSM-Focus Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation In Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
81.3	78.2	58%	6,899	34,885,917	36,261,874	-1,375,936	8,044	8,251	-206	4.5	9.5	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	**TOTAL RESOURCE COST**
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
0	314	39	1,117	62	197	144	-216	-11	94	**1,739**

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	**TOTAL GENERATION SVC COST + 15% PREMIUM**	**AVERAGE GENERATION SVC COST + 15% PREMIUM**	Adder for DSM Programs	RPS Cost (RECs + ACPs)	**TOTAL SYSTEM BENEFITS COST**	**AVERAGE SYSTEM BENEFITS COST**	**TOTAL COST**	**AVG COST**
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,838	434	-6	-69	27	4	67	**3,788**	**10.86**	220	197	**417**	**1.20**	**4,205**	**12.05**

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	**TOTAL GENERATION SVC COST**	**AVERAGE GENERATION SVC COST**	Adder for DSM Programs	RPS Cost (RECs + ACPs)	**TOTAL SYSTEM BENEFITS COST**	**AVERAGE SYSTEM BENEFITS COST**	**TOTAL COST**	**AVG COST**
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
1,447	413	**1,861**	**5.33**	220	197	**417**	**1.20**	**2,278**	**6.53**

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
22.8%	2,429

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
10,152,447	16,428,066	77,213,673	30%	48,378,189	82,431,741	351,524,518

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	10,083,099	12,322	5,527	10,190,357	28,839	7,974
ME	5,942,814	3,781	1,600	5,942,827	4,170	1,698
MA	21,146,697	76,917	20,353	21,123,091	76,924	20,350
NH	7,530,843	24,975	6,770	7,533,921	24,975	6,771
RI	2,392,894	21	413	2,392,894	21	413
VT	602,573	2	2	609,635	2	2
Total	**47,698,919**	**118,017**	**34,665**	**47,792,726**	**134,932**	**37,207**

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,507,410	615,540	3,122,950	36,261,600	34,885,917	11%	8%	3%	1,274,910	1,237,290	77,879,739
1,958,040	3,020,750	4,978,790	15,571,740	12,454,988						
1,684,450	870,320	2,554,770	37,527,625	61,570,447						
678,240	2,024,700	2,702,940	24,328,610	10,614,392						
92,860	0	92,860	5,742,740	11,731,213						
587,750	438,940	1,026,690	6,115,634	7,528,882						
7,508,750	**6,970,250**	**14,479,000**	**125,547,949**	**138,785,838**						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,507,410	615,540	17,201,880	3,956,270	10,700,950	11,410	1,268,140	11,980,500	24,281,100	36,261,600
ME	1,958,040	3,020,750	0	583,240	9,775,930	10	233,770	10,009,710	5,562,030	15,571,740
MA	1,684,450	870,320	5,597,860	12,502,110	15,607,945	3,490	1,261,450	16,872,885	20,654,740	37,527,625
NH	678,240	2,024,700	10,000,870	3,931,390	7,585,370	1,890	106,150	7,693,410	16,635,200	24,328,610
RI	92,860	0	0	0	5,649,880	0	0	5,649,880	92,860	5,742,740
VT	587,750	438,940	5,074,090	0	10,600	4,254	0	14,854	6,100,780	6,115,634
Total	**7,508,750**	**6,970,250**	**37,874,700**	**20,973,010**	**49,330,675**	**21,054**	**2,869,510**	**52,221,239**	**73,326,710**	**125,547,949**

Summary of Results: 2013 Strict Climate Scenario, Conventional Solution

Summary of Key Parameters in Connecticut

Load LMP ($/MWh)	Generation LMP ($/MWh)	Load Factor	Peak Load Net of DSM * 1.08 loss grossup (MW)	Total Energy Needed to Meet Customer Load (MWh)	Total Generation In Connecticut (MWh)	Net Imports (MWh)	CT LSEs' ICR (MW)	CT Internal Installed Capacity (MW)	Net Capacity Imports (negative denotes exports) (MW)	Capacity Price ($/kW-Mo)	Fast-Start Price ($/kW-Mo)	Fast-Start Requirement (MW)
87.6	84.5	56%	7,187	35,522,074	35,737,361	-215,288	8,380	8,251	129	2.4	11.6	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT ($Mil)	Fixed O&M (FOM) ($Mil)	Variable O&M (VOM) ($Mil)	Cost of Fuel ($Mil)	Total Allowance Cost ($Mil)	RPS Cost (RECs + ACPs) ($Mil)	CT Energy Import Cost ($Mil)	CT Energy Export Cost ($Mil)	CT Capacity Import Cost (Negative Denotes Benefits) ($Mil)	Adder for DSM Programs ($Mil)	**TOTAL RESOURCE COST ($Mil)**
0	314	38	1,054	237	227	182	-169	4	103	**1,990**

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP ($Mil)	ICR*Price ($Mil)	FTRs (Assume 75% Coverage for Internal Gen to Load) ($Mil)	Adjustment for Overcounting Losses ($Mil)	Spin ($Mil)	Uplift ($Mil)	Connecticut Fast-Start Cost ($Mil)	**TOTAL GENERATION SVC COST + 15% PREMIUM** ($Mil)	**AVERAGE GENERATION SVC COST + 15% PREMIUM** (¢/kWh)	Adder for DSM Programs ($Mil)	RPS Cost (RECs + ACPs) ($Mil)	**TOTAL SYSTEM BENEFITS COST** ($Mil)	**AVERAGE SYSTEM BENEFITS COST** (¢/kWh)	**TOTAL COST** ($Mil)	**AVG COST** (¢/kWh)
3,110	237	-4	-76	24	3	82	**3,883**	**10.93**	121	227	**348**	**0.98**	**4,231**	**11.91**

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS ($Mil)	Annualized Embedded Cost of Generators ($Mil)	**TOTAL GENERATION SVC COST** ($Mil)	**AVERAGE GENERATIO N SVC COST** (¢/kWh)	Adder for DSM Programs ($Mil)	RPS Cost (RECs + ACPs) ($Mil)	**TOTAL SYSTEM BENEFITS COST** ($Mil)	**AVERAGE SYSTEM BENEFITS COST** (¢/kWh)	**TOTAL COST** ($Mil)	**AVG COST** (¢/kWh)
1,660	413	**2,074**	**5.84**	121	227	**348**	**0.98**	**2,422**	**6.82**

Electric Reliability and Availability

ISO-NE Reserve Margin (%)	CT LSR Surplus (Deficit) (MW)
19.1%	2,378

Fuel Security

CT NG Demand in January and February (MMBtu)	CT NG Demand in July and August	Total CT NG Demand (MMBtu)	CT NG Share of Total CT Generation (%)	ISO-NE NG Demand in January and February (MMBtu)	ISO NG Demand in July and August	Total ISO-NE NG Demand (MMBtu)
11,675,121	17,368,184	83,046,098	32%	57,657,821	90,106,227	400,253,976

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units (Tons)	Total SOx Emissions - Monitored Units (Tons)	Total NOx Emissions - Monitored Units (Tons)	Total CO2 Emissions - All Units (Tons)	Total SOx Emissions - All Units (Tons)	Total NOx Emissions - All Units (Tons)
CT	11,112,968	6,923	4,109	9,446,287	22,341	6,411
ME	6,373,569	4,040	1,715	6,375,627	4,478	1,825
MA	19,999,797	62,010	16,864	19,994,130	62,036	16,869
NH	7,213,902	21,882	6,032	7,220,031	21,884	6,034
RI	2,985,374	26	516	2,985,374	26	516
VT	553,503	1	1	560,093	2	3
Total	**48,239,114**	**94,881**	**29,237**	**46,581,543**	**110,768**	**31,657**

RPS Summary

Biomass and Refuse Generation (MWh)	Hydro Generation (MWh)	Renewable Generation (MWh)	Total Generation (MWh)	Total Retail Sales (MWh)	Overall Renewables Requirement (%)	Class I Renewables Requirement	Class II Renewables Requirement (%)	Class I Eligible Renewable Generation (MWh)	Class II Eligible Renewable Generation (MWh)	Alternative Compliance Payments ($)
2,385,430	616,770	3,002,200	35,737,050	35,522,074	13%	10%	3%	1,132,160	1,258,070	118,797,798
2,094,210	3,020,750	5,114,960	16,496,370	12,747,271						
1,761,770	1,004,380	2,766,150	38,466,275	62,513,186						
709,130	2,025,980	2,735,110	24,386,530	10,961,724						
94,240	0	94,240	7,118,770	11,950,422						
539,300	439,660	978,960	5,967,710	7,672,083						
7,584,080	**7,107,540**	**14,691,620**	**128,172,705**	**141,366,760**						

Fuel Usage Summary

State	Biomass and Refuse Generation (MWh)	Hydro Generation (MWh)	Nuclear Generation (MWh)	Coal Generation (MWh)	Natural Gas Generation (MWh)	Distillate Fuel Oil Generation (MWh)	Residual Fuel Oil Generation (MWh)	Total Gas or Oil Generation (MWh)	Total NOT Gas or Oil Generation (MWh)	Total Generation (MWh)
CT	2,385,430	616,770	17,091,580	3,027,940	11,458,880	37,750	1,118,700	12,615,330	23,121,720	35,737,050
ME	2,094,210	3,020,750	0	639,240	10,506,990	2,150	233,030	10,742,170	5,754,200	16,496,370
MA	1,761,770	1,004,380	5,597,860	10,280,290	18,856,000	35,525	930,450	19,821,975	18,644,300	38,466,275
NH	709,130	2,025,980	10,000,870	3,447,260	8,092,030	4,380	106,880	8,203,290	16,183,240	24,386,530
RI	94,240	0	0	0	7,024,530	0	0	7,024,530	94,240	7,118,770
VT	539,300	439,660	4,969,930	0	14,290	4,530	0	18,820	5,948,890	5,967,710
Total	**7,584,080**	**7,107,540**	**37,660,240**	**17,394,730**	**55,952,720**	**84,335**	**2,389,060**	**58,426,115**	**69,746,590**	**128,172,705**

Summary of Results: 2013 Strict Climate Scenario, DSM-Focus Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation In Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
86.6	83.7	57%	6,871	34,429,862	35,479,485	-1,049,607	8,011	8,251	-240	2.9	11.1	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	**TOTAL RESOURCE COST**
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
0	314	37	1,036	232	220	141	-203	-8	155	**1,923**

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	**TOTAL GENERATION SVC COST + 15% PREMIUM**	**AVERAGE GENERATION SVC COST + 15% PREMIUM**	Adder for DSM Programs	RPS Cost (RECs + ACPs)	**TOTAL SYSTEM BENEFITS COST**	**AVERAGE SYSTEM BENEFITS COST**	**TOTAL COST**	**AVG COST**
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,983	280	-3	-73	23	4	78	**3,786**	**11.00**	300	220	**519**	**1.51**	**4,305**	**12.50**

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	**TOTAL GENERATION SVC COST**	**AVERAGE GENERATION SVC COST**	Adder for DSM Programs	RPS Cost (RECs + ACPs)	**TOTAL SYSTEM BENEFITS COST**	**AVERAGE SYSTEM BENEFITS COST**	**TOTAL COST**	**AVG COST**
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
1,549	413	**1,962**	**5.70**	300	220	**519**	**1.51**	**2,481**	**7.21**

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
20.4%	2,807

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
11,488,297	17,144,988	81,884,585	32%	56,195,381	88,874,956	393,555,334

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	10,918,030	6,542	3,970	9,261,310	21,774	6,257
ME	6,309,421	3,955	1,686	6,311,280	4,394	1,796
MA	19,751,754	61,529	16,716	19,744,632	61,549	16,719
NH	7,172,654	21,779	6,003	7,177,832	21,780	6,004
RI	2,892,664	25	500	2,892,664	25	500
VT	552,469	0	1	558,513	1	2
Total	**47,596,993**	**93,830**	**28,875**	**45,946,233**	**109,524**	**31,278**

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,384,990	616,340	3,001,330	35,479,170	34,429,862	13%	10%	3%	1,131,940	1,257,840	113,447,033
2,093,930	3,020,030	5,113,960	16,361,570	12,747,271						
1,761,500	1,032,490	2,793,990	38,044,980	62,513,186						
708,990	2,024,380	2,733,370	24,311,610	10,961,724						
94,240	0	94,240	6,908,530	11,950,422						
539,190	439,350	978,540	5,965,640	7,672,083						
7,582,840	**7,132,590**	**14,715,430**	**127,071,500**	**140,274,548**						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,384,990	616,340	17,091,580	2,993,680	11,322,590	31,130	1,038,860	12,392,580	23,086,590	35,479,170
ME	2,093,930	3,020,030	0	635,660	10,392,140	1,940	217,870	10,611,950	5,749,620	16,361,570
MA	1,761,500	1,032,490	5,597,860	10,203,220	18,495,350	28,840	925,720	19,449,910	18,595,070	38,044,980
NH	708,990	2,024,380	10,000,870	3,438,880	8,039,670	3,690	95,130	8,138,490	16,173,120	24,311,610
RI	94,240	0	0	0	6,814,290	0	0	6,814,290	94,240	6,908,530
VT	539,190	439,350	4,969,930	0	13,650	3,520	0	17,170	5,948,470	5,965,640
Total	**7,582,840**	**7,132,590**	**37,660,240**	**17,271,440**	**55,077,690**	**69,120**	**2,277,580**	**57,424,390**	**69,647,110**	**127,071,500**

Summary of Results: 2018 Strict Climate Scenario, Conventional Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation In Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
91.3	88.0	56%	7,381	35,980,213	37,365,682	-1,385,459	8,606	8,550	56	2.8	11.2	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	**TOTAL RESOURCE COST**
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
28	323	41	1,170	302	315	151	-239	2	156	**2,250**

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	**TOTAL GENERATION SVC COST + 15% PREMIUM**	**AVERAGE GENERATION SVC COST + 15% PREMIUM**	Adder for DSM Programs	RPS Cost (RECs + ACPs)	**TOTAL SYSTEM BENEFITS COST**	**AVERAGE SYSTEM BENEFITS COST**	**TOTAL COST**	**AVG COST**
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
3,287	286	-9	-76	22	4	79	**4,132**	**11.48**	116	315	**431**	**1.20**	**4,563**	**12.68**

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	**TOTAL GENERATION SVC COST**	**AVERAGE GENERATION SVC COST**	Adder for DSM Programs	RPS Cost (RECs + ACPs)	**TOTAL SYSTEM BENEFITS COST**	**AVERAGE SYSTEM BENEFITS COST**	**TOTAL COST**	**AVG COST**
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
1,779	413	**2,192**	**6.09**	116	315	**431**	**1.20**	**2,623**	**7.29**

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
17.8%	2,640

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
14,234,387	19,931,247	96,239,386	36%	62,884,236	95,562,172	441,165,588

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	11,486,141	5,473	3,805	9,837,973	20,849	6,168
ME	7,037,219	3,823	1,790	7,038,379	4,259	1,899
MA	20,361,916	57,439	15,920	20,366,662	57,478	15,930
NH	6,991,151	21,014	5,802	6,998,931	21,015	5,804
RI	2,731,082	24	472	2,731,082	24	472
VT	508,874	0	1	516,049	2	2
Total	**49,116,382**	**87,773**	**27,791**	**47,489,076**	**103,626**	**30,276**

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,379,560	616,940	2,996,500	37,365,400	35,980,213	20%	17%	3%	1,211,390	1,172,970	214,915,216
2,011,630	3,021,810	5,033,440	18,239,770	13,300,363						
1,782,070	954,900	2,736,970	40,518,460	64,675,456						
697,550	2,026,720	2,724,270	24,047,420	11,688,543						
95,340	0	95,340	6,535,510	12,333,051						
494,600	440,050	934,650	6,027,710	7,972,790						
7,460,750	**7,060,420**	**14,521,170**	**132,734,270**	**145,950,416**						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,379,560	616,940	17,180,880	3,071,690	13,376,310	39,650	700,370	14,116,330	23,249,070	37,365,400
ME	2,011,630	3,021,810	0	628,170	12,382,770	1,220	194,170	12,578,160	5,661,610	18,239,770
MA	1,782,070	954,900	5,597,860	9,728,580	21,822,430	37,190	595,430	22,455,050	18,063,410	40,518,460
NH	697,550	2,026,720	10,000,870	3,339,850	7,913,240	3,520	65,670	7,982,430	16,064,990	24,047,420
RI	95,340	0	0	0	6,440,170	0	0	6,440,170	95,340	6,535,510
VT	494,600	440,050	5,074,090	0	14,800	4,170	0	18,970	6,008,740	6,027,710
Total	**7,460,750**	**7,060,420**	**37,853,700**	**16,768,290**	**61,949,720**	**85,750**	**1,555,640**	**63,591,110**	**69,143,160**	**132,734,270**

Summary of Results: 2018 Strict Climate Scenario, DSM-Focus Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation In Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
91.8	88.8	56%	6,782	33,205,201	35,556,826	-2,351,606	7,908	8,251	-343	2.2	11.8	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	**TOTAL RESOURCE COST**
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
0	314	37	1,061	281	291	96	-284	-9	303	**2,090**

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	**TOTAL GENERATION SVC COST + 15% PREMIUM**	**AVERAGE GENERATION SVC COST + 15% PREMIUM**	Adder for DSM Programs	RPS Cost (RECs + ACPs)	**TOTAL SYSTEM BENEFITS COST**	**AVERAGE SYSTEM BENEFITS COST**	**TOTAL COST**	**AVG COST**
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
3,048	204	-3	-76	24	3	83	**3,776**	**11.37**	172	291	**463**	**1.39**	**4,239**	**12.77**

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	**TOTAL GENERATION SVC COST**	**AVERAGE GENERATION SVC COST**	Adder for DSM Programs	RPS Cost (RECs + ACPs)	**TOTAL SYSTEM BENEFITS COST**	**AVERAGE SYSTEM BENEFITS COST**	**TOTAL COST**	**AVG COST**
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
1,496	413	**1,909**	**5.75**	172	291	**463**	**1.39**	**2,372**	**7.14**

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
17.1%	3,162

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
12,286,756	17,307,236	83,350,578	32%	59,050,149	90,942,649	418,068,811

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	10,845,368	5,723	3,752	9,149,445	21,162	6,119
ME	6,327,467	3,998	1,707	6,330,734	4,435	1,816
MA	20,438,209	59,109	16,300	20,440,942	59,149	16,309
NH	7,410,316	22,495	6,200	7,419,119	22,497	6,202
RI	2,951,131	25	510	2,951,131	25	510
VT	509,261	1	1	517,219	2	3
Total	**48,481,752**	**91,352**	**28,469**	**46,808,590**	**107,270**	**30,959**

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,379,520	617,070	2,996,590	35,556,510	33,205,201	20%	17%	3%	1,211,360	1,172,960	194,247,501
2,011,480	3,022,870	5,034,350	16,439,110	13,300,363						
1,782,000	939,370	2,721,370	40,187,230	64,675,456						
697,410	2,028,250	2,725,660	24,692,390	11,688,543						
95,290	0	95,290	7,049,430	12,333,051						
494,560	440,280	934,840	6,029,480	7,972,790						
7,460,260	**7,047,840**	**14,508,100**	**129,954,150**	**143,175,404**						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,379,520	617,070	17,180,880	3,099,580	11,513,940	36,900	728,620	12,279,460	23,277,050	35,556,510
ME	2,011,480	3,022,870	0	639,200	10,539,620	3,330	222,610	10,765,560	5,673,550	16,439,110
MA	1,782,000	939,370	5,597,860	9,953,760	21,196,070	39,660	678,510	21,914,240	18,272,990	40,187,230
NH	697,410	2,028,250	10,000,870	3,555,840	8,307,860	5,110	97,050	8,410,020	16,282,370	24,692,390
RI	95,290	0	0	0	6,954,140	0	0	6,954,140	95,290	7,049,430
VT	494,560	440,280	5,074,090	0	15,850	4,700	0	20,550	6,008,930	6,029,480
Total	**7,460,260**	**7,047,840**	**37,853,700**	**17,248,380**	**58,527,480**	**89,700**	**1,726,790**	**60,343,970**	**69,610,180**	**129,954,150**

Summary of Results: 2018 Strict Climate Scenario, Nuclear Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation In Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
91.0	86.6	56%	7,381	35,980,213	44,542,266	-8,562,015	8,606	9,451	-845	2.9	11.1	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	**TOTAL RESOURCE COST**
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
583	437	52	1,107	269	315	20	-707	-30	156	**2,204**

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	**TOTAL GENERATION SVC COST + 15% PREMIUM**	**AVERAGE GENERATION SVC COST + 15% PREMIUM**	Adder for DSM Programs	RPS Cost (RECs + ACPs)	**TOTAL SYSTEM BENEFITS COST**	**AVERAGE SYSTEM BENEFITS COST**	**TOTAL COST**	**AVG COST**
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
3,274	301	-8	-92	25	4	78	**4,119**	**11.45**	116	315	**431**	**1.20**	**4,550**	**12.65**

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	**TOTAL GENERATION SVC COST**	**AVERAGE GENERATION SVC COST**	Adder for DSM Programs	RPS Cost (RECs + ACPs)	**TOTAL SYSTEM BENEFITS COST**	**AVERAGE SYSTEM BENEFITS COST**	**TOTAL COST**	**AVG COST**
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
1,732	413	**2,146**	**5.96**	116	315	**431**	**1.20**	**2,577**	**7.16**

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
17.8%	3,541

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
11,533,870	16,816,017	78,886,941	24%	54,317,618	83,869,991	375,580,717

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	10,412,733	5,479	3,616	8,795,803	20,644	5,945
ME	6,139,168	3,779	1,627	6,141,637	4,215	1,736
MA	18,335,491	56,365	15,339	18,336,893	56,401	15,347
NH	6,947,261	20,569	5,696	6,954,744	20,571	5,698
RI	2,639,368	23	456	2,639,368	23	456
VT	508,361	0	1	515,636	2	2
Total	**44,982,381**	**86,215**	**26,734**	**43,384,082**	**101,855**	**29,184**

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,379,130	616,490	2,995,620	44,541,930	35,980,213	20%	17%	3%	1,211,090	1,172,830	214,928,360
2,011,300	3,022,340	5,033,640	16,023,090	13,300,363						
1,781,860	934,440	2,716,300	35,774,810	64,675,456						
697,260	2,026,900	2,724,160	24,049,090	11,688,543						
95,320	0	95,320	6,320,240	12,333,051						
494,490	439,760	934,250	6,027,200	7,972,790						
7,459,360	**7,039,930**	**14,499,290**	**132,736,360**	**145,950,416**						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,379,130	616,490	26,864,210	3,038,860	10,909,520	36,050	697,670	11,643,240	32,898,690	44,541,930
ME	2,011,300	3,022,340	0	609,520	10,168,570	2,590	208,770	10,379,930	5,643,160	16,023,090
MA	1,781,860	934,440	5,597,860	9,576,540	17,308,680	31,630	543,800	17,884,110	17,890,700	35,774,810
NH	697,260	2,026,900	10,000,870	3,255,320	7,981,740	4,010	82,990	8,068,740	15,980,350	24,049,090
RI	95,320	0	0	0	6,224,920	0	0	6,224,920	95,320	6,320,240
VT	494,490	439,760	5,074,090	0	15,100	3,760	0	18,860	6,008,340	6,027,200
Total	**7,459,360**	**7,039,930**	**47,537,030**	**16,480,240**	**52,608,530**	**78,040**	**1,533,230**	**54,219,800**	**78,516,560**	**132,736,360**

Summary of Results: 2018 Strict Climate Scenario, Coal Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation In Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
91.0	86.6	56%	7,381	35,980,213	44,542,266	-8,562,015	8,606	9,451	-845	2.9	11.1	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	**TOTAL RESOURCE COST**
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
302	371	88	1,284	548	315	20	-707	-30	156	**2,348**

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	**TOTAL GENERATION SVC COST + 15% PREMIUM**	**AVERAGE GENERATION SVC COST + 15% PREMIUM**	Adder for DSM Programs	RPS Cost (RECs + ACPs)	**TOTAL SYSTEM BENEFITS COST**	**AVERAGE SYSTEM BENEFITS COST**	**TOTAL COST**	**AVG COST**
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
3,274	301	-8	-92	25	4	78	**4,119**	**11.45**	116	315	**431**	**1.20**	**4,550**	**12.65**

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	**TOTAL GENERATION SVC COST**	**AVERAGE GENERATION SVC COST**	Adder for DSM Programs	RPS Cost (RECs + ACPs)	**TOTAL SYSTEM BENEFITS COST**	**AVERAGE SYSTEM BENEFITS COST**	**TOTAL COST**	**AVG COST**
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
1,877	413	**2,290**	**6.36**	116	315	**431**	**1.20**	**2,721**	**7.56**

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
17.8%	3,541

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
11,533,870	16,816,017	78,886,941	25%	54,317,618	83,869,991	375,580,717

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	18,546,345	5,479	3,616	16,929,415	20,644	5,945
ME	6,139,168	3,779	1,627	6,141,637	4,215	1,736
MA	18,335,491	56,365	15,339	18,336,893	56,401	15,347
NH	6,947,261	20,569	5,696	6,954,744	20,571	5,698
RI	2,639,368	23	456	2,639,368	23	456
VT	508,361	0	1	515,636	2	2
Total	**53,115,994**	**86,215**	**26,734**	**51,517,694**	**101,855**	**29,184**

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,379,130	616,490	2,995,620	44,541,930	35,980,213	20%	17%	3%	1,211,090	1,172,830	214,928,360
2,011,300	3,022,340	5,033,640	16,023,090	13,300,363						
1,781,860	934,440	2,716,300	35,774,810	64,675,456						
697,260	2,026,900	2,724,160	24,049,090	11,688,543						
95,320	0	95,320	6,320,240	12,333,051						
494,490	439,760	934,250	6,027,200	7,972,790						
7,459,360	**7,039,930**	**14,499,290**	**132,736,360**	**145,950,416**						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,379,130	616,490	17,180,880	12,334,857	10,909,520	36,050	697,670	11,643,240	32,511,357	44,154,597
ME	2,011,300	3,022,340	0	609,520	10,168,570	2,590	208,770	10,379,930	5,643,160	16,023,090
MA	1,781,860	934,440	5,597,860	9,576,540	17,308,680	31,630	543,800	17,884,110	17,890,700	35,774,810
NH	697,260	2,026,900	10,000,870	3,255,320	7,981,740	4,010	82,990	8,068,740	15,980,350	24,049,090
RI	95,320	0	0	0	6,224,920	0	0	6,224,920	95,320	6,320,240
VT	494,490	439,760	5,074,090	0	15,100	3,760	0	18,860	6,008,340	6,027,200
Total	**7,459,360**	**7,039,930**	**37,853,700**	**25,776,237**	**52,608,530**	**78,040**	**1,533,230**	**54,219,800**	**78,129,227**	**132,349,027**

Summary of Results: 2030 Strict Climate Scenario, Conventional Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation In Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
107.6	102.5	55%	8,355	40,456,272	49,918,087	-9,461,776	9,742	10,647	-904	3.0	11.0	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	**TOTAL RESOURCE COST**
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
220	384	72	2,080	777	310	25	-929	-33	156	**3,063**

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	**TOTAL GENERATION SVC COST + 15% PREMIUM**	**AVERAGE GENERATION SVC COST + 15% PREMIUM**	Adder for DSM Programs	RPS Cost (RECs + ACPs)	**TOTAL SYSTEM BENEFITS COST**	**AVERAGE SYSTEM BENEFITS COST**	**TOTAL COST**	**AVG COST**
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
4,352	351	-40	-86	18	11	77	**5,386**	**13.31**	116	310	**426**	**1.05**	**5,812**	**14.37**

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	**TOTAL GENERATION SVC COST**	**AVERAGE GENERATIO N SVC COST**	Adder for DSM Programs	RPS Cost (RECs + ACPs)	**TOTAL SYSTEM BENEFITS COST**	**AVERAGE SYSTEM BENEFITS COST**	**TOTAL COST**	**AVG COST**
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,596	413	**3,010**	**7.44**	116	310	**426**	**1.05**	**3,436**	**8.49**

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
17.6%	3,619

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
29,038,185	37,541,948	188,385,786	53%	91,373,474	140,284,997	633,427,818

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	16,220,265	3,745	4,048	14,538,105	17,066	6,133
ME	9,277,973	2,274	1,824	9,282,933	2,721	1,937
MA	19,437,874	38,762	11,647	19,449,033	38,822	11,662
NH	4,667,918	9,101	2,775	4,683,958	9,106	2,779
RI	3,177,354	27	549	3,177,354	27	549
VT	1,437,845	12	148	1,448,383	14	151
Total	**54,219,229**	**53,921**	**20,991**	**52,579,766**	**67,757**	**23,211**

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,523,640	621,430	3,145,070	49,917,740	40,456,272	23%	20%	3%	1,254,600	1,273,860	228,003,953
2,105,920	3,028,300	5,134,220	24,132,630	15,506,927						
1,761,150	1,107,820	2,868,970	43,112,390	73,831,318						
674,630	2,058,510	2,733,140	21,331,200	14,450,182						
90,720	0	90,720	7,661,610	14,013,464						
571,520	445,740	1,017,260	8,131,440	9,246,022						
7,727,580	**7,261,800**	**14,989,380**	**154,287,010**	**167,504,187**						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,523,640	621,430	17,180,600	2,680,620	26,534,340	44,850	332,260	26,911,450	23,006,290	49,917,740
ME	2,105,920	3,028,300	0	443,040	18,487,590	5,080	62,700	18,555,370	5,577,260	24,132,630
MA	1,761,150	1,107,820	5,597,860	6,648,020	27,561,870	27,290	408,380	27,997,540	15,114,850	43,112,390
NH	674,630	2,058,510	9,912,880	1,454,910	7,205,090	11,530	13,650	7,230,270	14,100,930	21,331,200
RI	90,720	0	0	0	7,570,890	0	0	7,570,890	90,720	7,661,610
VT	571,520	445,740	5,014,570	0	2,084,440	15,170	0	2,099,610	6,031,830	8,131,440
Total	**7,727,580**	**7,261,800**	**37,705,910**	**11,226,590**	**89,444,220**	**103,920**	**816,990**	**90,365,130**	**63,921,880**	**154,287,010**

Summary of Results: 2030 Strict Climate Scenario, DSM-Focus Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation In Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
106.7	102.6	56%	7,678	37,335,975	49,950,425	-12,614,407	8,953	10,647	-1,694	2.9	11.1	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	**TOTAL RESOURCE COST**
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
220	384	72	2,078	782	286	6	-1,248	-59	232	**2,754**

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	**TOTAL GENERATION SVC COST + 15% PREMIUM**	**AVERAGE GENERATION SVC COST + 15% PREMIUM**	Adder for DSM Programs	RPS Cost (RECs + ACPs)	**TOTAL SYSTEM BENEFITS COST**	**AVERAGE SYSTEM BENEFITS COST**	**TOTAL COST**	**AVG COST**
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
3,983	312	-16	-80	19	10	78	**4,952**	**13.26**	172	286	**459**	**1.23**	**5,410**	**14.49**

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	**TOTAL GENERATION SVC COST**	**AVERAGE GENERATION SVC COST**	Adder for DSM Programs	RPS Cost (RECs + ACPs)	**TOTAL SYSTEM BENEFITS COST**	**AVERAGE SYSTEM BENEFITS COST**	**TOTAL COST**	**AVG COST**
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,236	413	**2,649**	**7.10**	172	286	**459**	**1.23**	**3,108**	**8.32**

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
17.3%	4,548

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
28,770,447	37,521,315	187,820,624	53%	87,210,667	134,429,956	609,862,626

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	16,289,013	3,860	4,122	14,618,355	17,717	6,290
ME	9,348,329	2,375	1,858	9,352,741	2,823	1,971
MA	19,479,959	38,783	11,657	19,494,983	38,854	11,675
NH	4,810,226	9,524	2,892	4,827,003	9,529	2,897
RI	2,528,889	22	437	2,528,889	22	437
VT	600,244	4	3	611,055	7	6
Total	**53,056,660**	**54,568**	**20,970**	**51,433,027**	**68,950**	**23,275**

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,523,650	621,640	3,145,290	49,950,120	37,335,975	23%	20%	3%	1,254,600	1,273,860	207,191,432
2,105,950	3,029,610	5,135,560	24,283,810	15,506,927						
1,761,170	1,101,630	2,862,800	43,235,610	73,831,318						
674,640	2,059,010	2,733,650	21,573,090	14,450,182						
90,730	0	90,730	6,052,710	14,013,464						
571,520	446,010	1,017,530	6,065,895	9,246,022						
7,727,660	**7,257,900**	**14,985,560**	**151,161,235**	**164,383,889**						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,523,650	621,640	17,180,600	2,764,730	26,445,890	38,850	374,760	26,859,500	23,090,620	49,950,120
ME	2,105,950	3,029,610	0	462,840	18,619,260	4,490	61,660	18,685,410	5,598,400	24,283,810
MA	1,761,170	1,101,630	5,597,860	6,610,350	27,675,910	28,760	459,930	28,164,600	15,071,010	43,235,610
NH	674,640	2,059,010	9,912,880	1,522,900	7,379,450	11,850	12,360	7,403,660	14,169,430	21,573,090
RI	90,730	0	0	0	5,961,980	0	0	5,961,980	90,730	6,052,710
VT	571,520	446,010	5,014,570	0	18,610	15,185	0	33,795	6,032,100	6,065,895
Total	**7,727,660**	**7,257,900**	**37,705,910**	**11,360,820**	**86,101,100**	**99,135**	**908,710**	**87,108,945**	**64,052,290**	**151,161,235**

Summary of Results: 2030 Strict Climate Scenario, Nuclear Solution

Summary of Key Parameters in Connecticut

Load LMP ($/MWh)	Generation LMP ($/MWh)	Load Factor	Peak Load Net of DSM * 1.08 loss grossup (MW)	Total Energy Needed to Meet Customer Load (MWh)	Total Generation In Connecticut (MWh)	Net Imports (MWh)	CT LSEs' ICR (MW)	CT Internal Installed Capacity (MW)	Net Capacity Imports (negative denotes exports) (MW)	Capacity Price ($/kW-Mo)	Fast-Start Price ($/kW-Mo)	Fast-Start Requirement (MW)
104.5	99.0	55%	8,355	40,456,272	55,252,527	-14,796,212	9,742	11,547	-1,804	4.2	9.8	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT ($Mil)	Fixed O&M (FOM) ($Mil)	Variable O&M (VOM) ($Mil)	Cost of Fuel ($Mil)	Total Allowance Cost ($Mil)	RPS Cost (RECs + ACPs) ($Mil)	CT Energy Import Cost ($Mil)	CT Energy Export Cost ($Mil)	CT Capacity Import Cost (Negative Denotes Benefits) ($Mil)	Adder for DSM Programs ($Mil)	**TOTAL RESOURCE COST** ($Mil)
776	499	79	1,886	674	310	1	-1,395	-90	156	**2,894**

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP ($Mil)	ICR*Price ($Mil)	FTRs (Assume 75% Coverage for Internal Gen to Load) ($Mil)	Adjustment for Overcounting Losses ($Mil)	Spin ($Mil)	Uplift ($Mil)	Connecticut Fast-Start Cost ($Mil)	**TOTAL GENERATION SVC COST + 15% PREMIUM** ($Mil)	**AVERAGE GENERATION SVC COST + 15% PREMIUM** (¢/kWh)	Adder for DSM Programs ($Mil)	RPS Cost (RECs + ACPs) ($Mil)	**TOTAL SYSTEM BENEFITS COST** ($Mil)	**AVERAGE SYSTEM BENEFITS COST** (¢/kWh)	**TOTAL COST** ($Mil)	**AVG COST** (¢/kWh)
4,227	487	-35	-103	17	14	69	**5,377**	**13.29**	116	310	**426**	**1.05**	**5,804**	**14.35**

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS ($Mil)	Annualized Embedded Cost of Generators ($Mil)	**TOTAL GENERATION SVC COST** ($Mil)	**AVERAGE GENERATION SVC COST** (¢/kWh)	Adder for DSM Programs ($Mil)	RPS Cost (RECs + ACPs) ($Mil)	**TOTAL SYSTEM BENEFITS COST** ($Mil)	**AVERAGE SYSTEM BENEFITS COST** (¢/kWh)	**TOTAL COST** ($Mil)	**AVG COST** (¢/kWh)
2,428	413	**2,841**	**7.02**	116	310	**426**	**1.05**	**3,268**	**8.08**

Electric Reliability and Availability

ISO-NE Reserve Margin (%)	CT LSR Surplus (Deficit) (MW)
17.6%	4,518

Fuel Security

CT NG Demand in January and February (MMBtu)	CT NG Demand in July and August	Total CT NG Demand (MMBtu)	CT NG Share of Total CT Generation (%)	ISO-NE NG Demand in January and February (MMBtu)	ISO NG Demand in July and August	Total ISO-NE NG Demand (MMBtu)
24,690,535	32,403,356	158,826,885	40%	80,808,780	127,742,070	569,031,090

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units (Tons)	Total SOx Emissions - Monitored Units (Tons)	Total NOx Emissions - Monitored Units (Tons)	Total CO2 Emissions - All Units (Tons)	Total SOx Emissions - All Units (Tons)	Total NOx Emissions - All Units (Tons)
CT	14,214,658	3,471	3,631	12,671,167	16,233	5,632
ME	8,419,439	2,490	1,724	8,422,906	2,937	1,836
MA	18,083,041	36,978	11,021	18,096,120	37,044	11,037
NH	4,719,654	9,472	2,865	4,737,201	9,477	2,870
RI	2,419,681	21	418	2,419,681	21	418
VT	2,161,019	23	274	2,172,375	25	277
Total	**50,017,492**	**52,455**	**19,933**	**48,519,449**	**65,738**	**22,071**

RPS Summary

Biomass and Refuse Generation (MWh)	Hydro Generation (MWh)	Renewable Generation (MWh)	Total Generation (MWh)	Total Retail Sales (MWh)	Overall Renewables Requirement (%)	Class I Renewables Requirement	Class II Renewables Requirement (%)	Class I Eligible Renewable Generation (MWh)	Class II Eligible Renewable Generation (MWh)	Alternative Compliance Payments ($)
2,507,160	619,010	3,126,170	55,252,240	40,456,272	23%	20%	3%	1,244,420	1,267,540	228,343,458
2,105,350	3,026,340	5,131,690	21,945,690	15,506,927						
1,760,690	908,910	2,669,600	40,040,850	73,831,318						
674,410	2,065,640	2,740,050	21,368,140	14,450,182						
90,660	0	90,660	5,792,400	14,013,464						
571,310	444,960	1,016,270	9,894,914	9,246,022						
7,709,580	**7,064,860**	**14,774,440**	**154,294,234**	**167,504,187**						

Fuel Usage Summary

State	Biomass and Refuse Generation (MWh)	Hydro Generation (MWh)	Nuclear Generation (MWh)	Coal Generation (MWh)	Natural Gas Generation (MWh)	Distillate Fuel Oil Generation (MWh)	Residual Fuel Oil Generation (MWh)	Total Gas or Oil Generation (MWh)	Total NOT Gas or Oil Generation (MWh)	Total Generation (MWh)
CT	2,507,160	619,010	26,863,930	2,569,980	22,359,070	37,440	295,650	22,692,160	32,560,080	55,252,240
ME	2,105,350	3,026,340	0	455,500	16,255,670	3,540	99,290	16,358,500	5,587,190	21,945,690
MA	1,760,690	908,910	5,597,860	6,323,580	24,998,400	26,360	425,050	25,449,810	14,591,040	40,040,850
NH	674,410	2,065,640	9,912,880	1,504,850	7,171,330	12,410	26,620	7,210,360	14,157,780	21,368,140
RI	90,660	0	0	0	5,701,740	0	0	5,701,740	90,660	5,792,400
VT	571,310	444,960	5,014,570	0	3,837,130	26,944	0	3,864,074	6,030,840	9,894,914
Total	**7,709,580**	**7,064,860**	**47,389,240**	**10,853,910**	**80,323,340**	**106,694**	**846,610**	**81,276,644**	**73,017,590**	**154,294,234**

Summary of Results: 2030 Strict Climate Scenario, Coal Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation In Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
104.5	99.0	55%	8,355	40,456,272	55,252,527	-14,796,212	9,742	11,547	-1,804	4.2	9.8	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	**TOTAL RESOURCE COST**
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
494	432	115	2,068	1,160	310	1	-1,395	-90	156	**3,252**

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	**TOTAL GENERATION SVC COST + 15% PREMIUM**	**AVERAGE GENERATION SVC COST + 15% PREMIUM**	Adder for DSM Programs	RPS Cost (RECs + ACPs)	**TOTAL SYSTEM BENEFITS COST**	**AVERAGE SYSTEM BENEFITS COST**	**TOTAL COST**	**AVG COST**
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
4,227	487	-35	-103	17	14	69	**5,377**	**13.29**	116	310	**426**	**1.05**	**5,804**	**14.35**

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	**TOTAL GENERATION SVC COST**	**AVERAGE GENERATION SVC COST**	Adder for DSM Programs	RPS Cost (RECs + ACPs)	**TOTAL SYSTEM BENEFITS COST**	**AVERAGE SYSTEM BENEFITS COST**	**TOTAL COST**	**AVG COST**
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,785	413	**3,198**	**7.91**	116	310	**426**	**1.05**	**3,625**	**8.96**

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
17.6%	4,518

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
24,690,535	32,403,356	158,826,885	41%	80,808,780	127,742,070	569,031,090

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	22,348,270	3,471	3,631	20,804,779	16,233	5,632
ME	8,419,439	2,490	1,724	8,422,906	2,937	1,836
MA	18,083,041	36,978	11,021	18,096,120	37,044	11,037
NH	4,719,654	9,472	2,865	4,737,201	9,477	2,870
RI	2,419,681	21	418	2,419,681	21	418
VT	2,161,019	23	274	2,172,375	25	277
Total	**58,151,104**	**52,455**	**19,933**	**56,653,061**	**65,738**	**22,071**

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,507,160	619,010	3,126,170	55,252,240	40,456,272	23%	20%	3%	1,244,420	1,267,540	228,343,458
2,105,350	3,026,340	5,131,690	21,945,690	15,506,927						
1,760,690	908,910	2,669,600	40,040,850	73,831,318						
674,410	2,065,640	2,740,050	21,368,140	14,450,182						
90,660	0	90,660	5,792,400	14,013,464						
571,310	444,960	1,016,270	9,894,914	9,246,022						
7,709,580	**7,064,860**	**14,774,440**	**154,294,234**	**167,504,187**						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,507,160	619,010	17,180,600	11,865,977	22,359,070	37,440	295,650	22,692,160	32,172,747	54,864,907
ME	2,105,350	3,026,340	0	455,500	16,255,670	3,540	99,290	16,358,500	5,587,190	21,945,690
MA	1,760,690	908,910	5,597,860	6,323,580	24,998,400	26,360	425,050	25,449,810	14,591,040	40,040,850
NH	674,410	2,065,640	9,912,880	1,504,850	7,171,330	12,410	26,620	7,210,360	14,157,780	21,368,140
RI	90,660	0	0	0	5,701,740	0	0	5,701,740	90,660	5,792,400
VT	571,310	444,960	5,014,570	0	3,837,130	26,944	0	3,864,074	6,030,840	9,894,914
Total	**7,709,580**	**7,064,860**	**37,705,910**	**20,149,907**	**80,323,340**	**106,694**	**846,610**	**81,276,644**	**72,630,257**	**153,906,901**

Summary of Results: 2011 High Fuel/Growth Scenario, Conventional Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation In Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
114.5	109.5	56%	7,196	35,151,628	37,980,107	-2,828,471	8,390	8,251	140	4.5	9.5	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	**TOTAL RESOURCE COST**
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
0	315	44	1,630	77	199	164	-416	8	76	**2,095**

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	**TOTAL GENERATION SVC COST + 15% PREMIUM**	**AVERAGE GENERATION SVC COST + 15% PREMIUM**	Adder for DSM Programs	RPS Cost (RECs + ACPs)	**TOTAL SYSTEM BENEFITS COST**	**AVERAGE SYSTEM BENEFITS COST**	**TOTAL COST**	**AVG COST**
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
4,024	453	-23	-94	41	7	67	**5,146**	**14.64**	123	199	**321**	**0.91**	**5,468**	**15.55**

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	**TOTAL GENERATION SVC COST**	**AVERAGE GENERATION SVC COST**	Adder for DSM Programs	RPS Cost (RECs + ACPs)	**TOTAL SYSTEM BENEFITS COST**	**AVERAGE SYSTEM BENEFITS COST**	**TOTAL COST**	**AVG COST**
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
1,820	413	**2,234**	**6.35**	123	199	**321**	**0.91**	**2,555**	**7.27**

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
19.9%	2,036

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
8,904,919	15,397,223	72,194,727	27%	32,831,563	76,720,129	304,338,432

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	11,639,511	15,642	7,250	11,841,934	37,926	10,197
ME	6,009,497	6,032	2,092	6,009,507	6,421	2,189
MA	22,337,753	88,011	22,930	22,327,076	88,068	22,940
NH	7,512,683	26,620	7,120	7,514,628	26,620	7,121
RI	1,874,915	16	324	1,874,915	16	324
VT	602,427	0	1	605,306	1	1
Total	**49,976,786**	**136,321**	**39,717**	**50,173,366**	**159,052**	**42,771**

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,507,410	616,360	3,123,770	37,979,840	35,151,628	11%	8%	3%	1,275,000	1,237,200	78,967,150
1,957,710	3,021,100	4,978,810	15,077,350	12,365,342						
1,684,440	773,500	2,457,940	37,535,260	61,126,883						
678,310	2,031,570	2,709,880	23,815,030	10,538,022						
92,830	0	92,830	4,542,140	11,646,713						
587,800	441,070	1,028,870	6,113,210	7,474,709						
7,508,500	**6,883,600**	**14,392,100**	**125,062,830**	**138,303,296**						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,507,410	616,360	17,201,880	4,010,420	10,079,980	16,530	3,547,260	13,643,770	24,336,070	37,979,840
ME	1,957,710	3,021,100	0	586,020	8,746,870	10	765,640	9,512,520	5,564,830	15,077,350
MA	1,684,440	773,500	5,597,860	12,669,070	12,938,780	1,650	3,869,960	16,810,390	20,724,870	37,535,260
NH	678,310	2,031,570	10,000,870	3,981,930	6,703,770	1,510	417,070	7,122,350	16,692,680	23,815,030
RI	92,830	0	0	0	4,449,310	0	0	4,449,310	92,830	4,542,140
VT	587,800	441,070	5,074,090	0	8,900	1,350	0	10,250	6,102,960	6,113,210
Total	**7,508,500**	**6,883,600**	**37,874,700**	**21,247,440**	**42,927,610**	**21,050**	**8,599,930**	**51,548,590**	**73,514,240**	**125,062,830**

Summary of Results: 2011 High Fuel/Growth Scenario, DSM-Focus Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation In Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
113.7	109.0	57%	7,033	34,947,699	37,910,324	-2,962,593	8,200	8,251	-51	4.5	9.5	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	**TOTAL RESOURCE COST**
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
0	315	44	1,622	77	197	149	-423	-3	94	**2,072**

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	**TOTAL GENERATION SVC COST + 15% PREMIUM**	**AVERAGE GENERATION SVC COST + 15% PREMIUM**	Adder for DSM Programs	RPS Cost (RECs + ACPs)	**TOTAL SYSTEM BENEFITS COST**	**AVERAGE SYSTEM BENEFITS COST**	**TOTAL COST**	**AVG COST**
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
3,974	443	-20	-93	35	9	67	**5,076**	**14.52**	220	197	**418**	**1.20**	**5,493**	**15.72**

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	**TOTAL GENERATION SVC COST**	**AVERAGE GENERATIO N SVC COST**	Adder for DSM Programs	RPS Cost (RECs + ACPs)	**TOTAL SYSTEM BENEFITS COST**	**AVERAGE SYSTEM BENEFITS COST**	**TOTAL COST**	**AVG COST**
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
1,781	413	**2,194**	**6.28**	220	197	**418**	**1.20**	**2,611**	**7.47**

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
20.6%	2,252

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
8,786,743	15,264,127	71,780,566	26%	32,542,906	76,344,263	302,751,186

ISO-NE Emissions by State

State	Total CO_2 Emissions - Monitored Units	Total SO_x Emissions - Monitored Units	Total NO_x Emissions - Monitored Units	Total CO_2 Emissions - All Units	Total SO_x Emissions - All Units	Total NO_x Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	11,605,041	15,608	7,223	11,804,518	37,874	10,179
ME	5,978,189	5,940	2,067	5,978,188	6,330	2,165
MA	22,299,406	87,964	22,913	22,287,717	88,014	22,922
NH	7,478,427	26,539	7,097	7,480,175	26,539	7,098
RI	1,860,842	16	321	1,860,842	16	321
VT	602,346	0	1	605,155	1	1
Total	**49,824,250**	**136,067**	**39,623**	**50,016,595**	**158,773**	**42,686**

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,507,400	616,020	3,123,420	37,910,062	34,947,699	11%	8%	3%	1,274,910	1,237,280	78,133,655
1,957,870	3,020,750	4,978,620	15,028,140	12,365,342						
1,684,470	855,630	2,540,100	37,543,610	61,126,883						
678,210	2,031,050	2,709,260	23,754,770	10,538,022						
92,860	0	92,860	4,511,300	11,646,713						
587,750	441,000	1,028,750	6,112,860	7,474,709						
7,508,560	**6,964,450**	**14,473,010**	**124,860,742**	**138,099,367**						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,507,400	616,020	17,201,880	4,012,920	10,026,990	14,322	3,530,530	13,571,842	24,338,220	37,910,062
ME	1,957,870	3,020,750	0	586,540	8,719,590	0	743,390	9,462,980	5,565,160	15,028,140
MA	1,684,470	855,630	5,597,860	12,675,040	12,878,480	1,260	3,850,870	16,730,610	20,813,000	37,543,610
NH	678,210	2,031,050	10,000,870	3,984,790	6,664,580	1,450	393,820	7,059,850	16,694,920	23,754,770
RI	92,860	0	0	0	4,418,440	0	0	4,418,440	92,860	4,511,300
VT	587,750	441,000	5,074,090	0	8,650	1,370	0	10,020	6,102,840	6,112,860
Total	**7,508,560**	**6,964,450**	**37,874,700**	**21,259,290**	**42,716,730**	**18,402**	**8,518,610**	**51,253,742**	**73,607,000**	**124,860,742**

Summary of Results: 2013 High Fuel/Growth Scenario, Conventional Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation In Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
106.4	101.9	55%	7,431	35,821,252	37,510,361	-1,689,077	8,664	8,251	413	4.4	9.6	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	**TOTAL RESOURCE COST**
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
0	315	44	1,507	83	229	174	-294	22	103	**2,182**

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	**TOTAL GENERATION SVC COST + 15% PREMIUM**	**AVERAGE GENERATION SVC COST + 15% PREMIUM**	Adder for DSM Programs	RPS Cost (RECs + ACPs)	**TOTAL SYSTEM BENEFITS COST**	**AVERAGE SYSTEM BENEFITS COST**	**TOTAL COST**	**AVG COST**
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
3,813	461	-19	-90	28	8	67	**4,908**	**13.70**	121	229	**350**	**0.98**	**5,258**	**14.68**

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	**TOTAL GENERATION SVC COST**	**AVERAGE GENERATION SVC COST**	Adder for DSM Programs	RPS Cost (RECs + ACPs)	**TOTAL SYSTEM BENEFITS COST**	**AVERAGE SYSTEM BENEFITS COST**	**TOTAL COST**	**AVG COST**
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
1,850	413	**2,263**	**6.32**	121	229	**350**	**0.98**	**2,613**	**7.29**

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
17.5%	2,056

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
9,975,296	15,620,439	73,819,031	27%	41,765,137	82,569,221	339,588,175

ISO-NE Emissions by State

State	Total CO_2 Emissions - Monitored Units	Total SO_x Emissions - Monitored Units	Total NO_x Emissions - Monitored Units	Total CO_2 Emissions - All Units	Total SO_x Emissions - All Units	Total NO_x Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	11,373,248	15,015	6,875	11,584,180	35,912	9,712
ME	6,842,349	5,678	2,146	6,842,373	6,116	2,255
MA	22,675,975	84,195	22,153	22,671,112	84,239	22,161
NH	7,414,839	26,652	7,116	7,415,392	26,652	7,116
RI	2,032,557	18	351	2,033,356	19	351
VT	550,728	0	1	553,161	1	1
Total	**50,889,696**	**131,558**	**38,642**	**51,099,574**	**152,939**	**41,597**

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,385,120	617,890	3,003,010	37,510,090	35,821,252	13%	10%	3%	1,131,930	1,257,990	120,277,724
2,093,880	3,020,750	5,114,630	17,174,250	12,743,007						
1,761,600	768,900	2,530,500	39,262,050	62,491,915						
708,950	2,027,470	2,736,420	23,612,300	10,958,032						
94,260	0	94,260	4,907,940	11,946,395						
539,210	440,670	979,880	5,959,870	7,669,557						
7,583,020	**6,875,680**	**14,458,700**	**128,426,500**	**141,630,157**						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,385,120	617,890	17,091,580	3,851,870	10,274,420	36,340	3,252,870	13,563,630	23,946,460	37,510,090
ME	2,093,880	3,020,750	0	661,990	10,803,900	20	593,710	11,397,630	5,776,620	17,174,250
MA	1,761,600	768,900	5,597,860	12,360,470	15,420,590	21,500	3,331,130	18,773,220	20,488,830	39,262,050
NH	708,950	2,027,470	10,000,870	4,102,330	6,524,450	350	247,880	6,772,680	16,839,620	23,612,300
RI	94,260	0	0	0	4,808,960	4,720	0	4,813,680	94,260	4,907,940
VT	539,210	440,670	4,969,930	0	8,720	1,340	0	10,060	5,949,810	5,959,870
Total	**7,583,020**	**6,875,680**	**37,660,240**	**20,976,660**	**47,841,040**	**64,270**	**7,425,590**	**55,330,900**	**73,095,600**	**128,426,500**

Summary of Results: 2013 High Fuel/Growth Scenario, DSM-Focus Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation In Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
105.6	101.6	57%	7,109	35,272,768	37,698,174	-2,425,394	8,289	8,251	38	4.4	9.6	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	**TOTAL RESOURCE COST**
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
0	315	45	1,521	84	225	131	-339	2	155	**2,138**

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	**TOTAL GENERATION SVC COST + 15% PREMIUM**	**AVERAGE GENERATION SVC COST + 15% PREMIUM**	Adder for DSM Programs	RPS Cost (RECs + ACPs)	**TOTAL SYSTEM BENEFITS COST**	**AVERAGE SYSTEM BENEFITS COST**	**TOTAL COST**	**AVG COST**
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
3,726	443	-14	-88	30	8	67	**4,799**	**13.60**	300	225	**525**	**1.49**	**5,324**	**15.09**

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	**TOTAL GENERATION SVC COST**	**AVERAGE GENERATION SVC COST**	Adder for DSM Programs	RPS Cost (RECs + ACPs)	**TOTAL SYSTEM BENEFITS COST**	**AVERAGE SYSTEM BENEFITS COST**	**TOTAL COST**	**AVG COST**
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
1,758	413	**2,171**	**6.16**	300	225	**525**	**1.49**	**2,696**	**7.64**

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
17.7%	2,485

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
10,143,294	15,580,025	74,445,477	28%	40,733,520	80,669,625	333,484,868

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	11,486,995	15,158	6,969	11,696,916	36,301	9,814
ME	6,226,145	6,035	2,117	6,226,950	6,473	2,226
MA	22,863,598	84,392	22,227	22,857,451	84,435	22,235
NH	7,598,890	26,821	7,183	7,599,787	26,821	7,184
RI	2,036,507	18	352	2,036,506	18	352
VT	550,614	0	1	552,953	0	1
Total	**50,762,747**	**132,424**	**38,849**	**50,970,564**	**154,048**	**41,812**

RPS Summary

State	Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
CT	2,385,120	617,300	3,002,420	37,697,850	35,272,768	13%	10%	3%	1,131,940	1,257,980	117,584,781
ME	2,093,920	3,021,440	5,115,360	15,547,710	12,743,007						
MA	1,761,580	823,230	2,584,810	39,736,010	62,491,915						
NH	708,960	2,029,610	2,738,570	24,018,280	10,958,032						
RI	94,260	0	94,260	4,919,260	11,946,395						
VT	539,220	440,670	979,890	5,959,860	7,669,557						
Total	**7,583,060**	**6,932,250**	**14,515,310**	**127,878,970**	**141,081,674**						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,385,120	617,300	17,091,580	3,850,300	10,370,270	27,600	3,355,680	13,753,550	23,944,300	37,697,850
ME	2,093,920	3,021,440	0	662,590	9,091,550	830	677,380	9,769,760	5,777,950	15,547,710
MA	1,761,580	823,230	5,597,860	12,363,770	15,786,960	17,560	3,385,050	19,189,570	20,546,440	39,736,010
NH	708,960	2,029,610	10,000,870	4,104,440	6,890,350	370	283,680	7,174,400	16,843,880	24,018,280
RI	94,260	0	0	0	4,825,000	0	0	4,825,000	94,260	4,919,260
VT	539,220	440,670	4,969,930	0	8,930	1,110	0	10,040	5,949,820	5,959,860
Total	**7,583,060**	**6,932,250**	**37,660,240**	**20,981,100**	**46,973,060**	**47,470**	**7,701,790**	**54,722,320**	**73,156,650**	**127,878,970**

Summary of Results: 2018 High Fuel/Growth Scenario, Conventional Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation In Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
113.4	108.8	54%	7,919	37,205,520	45,876,343	-8,670,786	9,234	10,047	-813	4.9	9.1	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	**TOTAL RESOURCE COST**
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
180	372	66	2,262	283	326	17	-924	-47	156	**2,692**

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	**TOTAL GENERATION SVC COST + 15% PREMIUM**	**AVERAGE GENERATION SVC COST + 15% PREMIUM**	Adder for DSM Programs	RPS Cost (RECs + ACPs)	**TOTAL SYSTEM BENEFITS COST**	**AVERAGE SYSTEM BENEFITS COST**	**TOTAL COST**	**AVG COST**
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
4,217	538	-31	-90	26	11	64	**5,445**	**14.64**	116	326	**442**	**1.19**	**5,887**	**15.82**

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	**TOTAL GENERATION SVC COST**	**AVERAGE GENERATIO N SVC COST**	Adder for DSM Programs	RPS Cost (RECs + ACPs)	**TOTAL SYSTEM BENEFITS COST**	**AVERAGE SYSTEM BENEFITS COST**	**TOTAL COST**	**AVG COST**
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,210	413	**2,623**	**7.05**	116	326	**442**	**1.19**	**3,065**	**8.24**

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
18.0%	3,420

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
18,661,537	28,205,072	137,379,696	42%	52,584,701	94,415,382	404,168,554

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	16,010,988	14,683	7,081	14,625,431	33,667	9,778
ME	7,154,313	4,554	1,968	7,154,652	4,989	2,077
MA	21,677,286	78,704	20,806	21,670,031	78,736	20,811
NH	7,556,502	28,860	7,631	7,558,074	28,861	7,631
RI	1,542,869	13	266	1,543,212	14	267
VT	506,264	0	1	509,111	0	1
Total	**54,448,222**	**126,815**	**37,752**	**53,060,511**	**146,268**	**40,565**

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,378,930	617,340	2,996,270	45,876,060	37,205,520	20%	17%	3%	1,211,000	1,172,730	224,058,714
2,010,900	3,021,340	5,032,240	18,324,820	13,537,869						
1,781,590	999,890	2,781,480	38,568,880	65,830,301						
697,070	2,029,760	2,726,830	23,384,550	11,897,230						
95,230	0	95,230	3,744,460	12,553,624						
494,430	440,800	935,230	6,019,670	8,115,192						
7,458,150	**7,109,130**	**14,567,280**	**135,918,440**	**149,139,734**						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,378,930	617,340	17,180,880	4,207,710	19,358,580	29,830	2,102,790	21,491,200	24,384,860	45,876,060
ME	2,010,900	3,021,340	0	669,740	12,306,210	350	316,280	12,622,840	5,701,980	18,324,820
MA	1,781,590	999,890	5,597,860	12,343,070	15,890,190	12,150	1,944,130	17,846,470	20,722,410	38,568,880
NH	697,070	2,029,760	10,000,870	4,538,190	5,988,100	540	130,020	6,118,660	17,265,890	23,384,550
RI	95,230	0	0	0	3,647,220	2,010	0	3,649,230	95,230	3,744,460
VT	494,430	440,800	5,074,090	0	9,290	1,060	0	10,350	6,009,320	6,019,670
Total	**7,458,150**	**7,109,130**	**37,853,700**	**21,758,710**	**57,199,590**	**45,940**	**4,493,220**	**61,738,750**	**74,179,690**	**135,918,440**

Summary of Results: 2018 High Fuel/Growth Scenario, DSM-Focus Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation In Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
113.5	109.8	55%	7,302	35,484,718	42,407,372	-6,922,618	8,514	9,148	-634	4.1	9.9	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	**TOTAL RESOURCE COST**
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
93	344	56	1,948	259	311	29	-766	-31	303	**2,546**

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	**TOTAL GENERATION SVC COST + 15% PREMIUM**	**AVERAGE GENERATION SVC COST + 15% PREMIUM**	Adder for DSM Programs	RPS Cost (RECs + ACPs)	**TOTAL SYSTEM BENEFITS COST**	**AVERAGE SYSTEM BENEFITS COST**	**TOTAL COST**	**AVG COST**
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
4,029	423	-15	-89	29	10	69	**5,124**	**14.44**	172	311	**483**	**1.36**	**5,608**	**15.80**

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	**TOTAL GENERATION SVC COST**	**AVERAGE GENERATION SVC COST**	Adder for DSM Programs	RPS Cost (RECs + ACPs)	**TOTAL SYSTEM BENEFITS COST**	**AVERAGE SYSTEM BENEFITS COST**	**TOTAL COST**	**AVG COST**
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
1,932	413	**2,345**	**6.61**	172	311	**483**	**1.36**	**2,829**	**7.97**

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
17.5%	3,342

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
14,972,881	23,251,240	111,939,552	37%	49,033,175	90,971,413	389,691,369

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	14,695,836	14,907	6,942	13,278,911	34,270	9,676
ME	7,264,921	4,683	2,014	7,265,221	5,119	2,123
MA	22,133,920	79,168	20,984	22,127,753	79,203	20,990
NH	7,663,220	29,005	7,680	7,664,916	29,005	7,681
RI	1,647,281	14	284	1,647,281	14	284
VT	506,563	0	1	509,719	0	1
Total	**53,911,740**	**127,778**	**37,906**	**52,493,800**	**147,611**	**40,757**

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,379,200	618,130	2,997,330	42,407,070	35,484,718	20%	17%	3%	1,211,190	1,172,810	211,233,395
2,011,300	3,021,190	5,032,490	18,559,360	13,537,869						
1,781,810	1,060,940	2,842,750	39,604,906	65,830,301						
697,410	2,029,960	2,727,370	23,607,707	11,897,230						
95,330	0	95,330	3,994,180	12,553,624						
494,520	441,140	935,660	6,020,960	8,115,192						
7,459,570	**7,171,360**	**14,630,930**	**134,194,183**	**147,418,932**						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,379,200	618,130	17,180,880	4,215,500	15,740,490	25,950	2,246,920	18,013,360	24,393,710	42,407,070
ME	2,011,300	3,021,190	0	670,690	12,511,250	300	344,630	12,856,180	5,703,180	18,559,360
MA	1,781,810	1,060,940	5,597,860	12,373,640	16,766,430	11,056	2,013,170	18,790,656	20,814,250	39,604,906
NH	697,410	2,029,960	10,000,870	4,550,440	6,182,670	557	145,800	6,329,027	17,278,680	23,607,707
RI	95,330	0	0	0	3,898,850	0	0	3,898,850	95,330	3,994,180
VT	494,520	441,140	5,074,090	0	10,020	1,190	0	11,210	6,009,750	6,020,960
Total	**7,459,570**	**7,171,360**	**37,853,700**	**21,810,270**	**55,109,710**	**39,053**	**4,750,520**	**59,899,283**	**74,294,900**	**134,194,183**

Summary of Results: 2018 High Fuel/Growth Scenario, Nuclear Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation In Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
111.3	105.6	54%	7,919	37,205,520	49,820,246	-12,614,684	9,234	10,348	-1,114	5.3	8.7	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	**TOTAL RESOURCE COST**
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
735	480	69	1,844	237	326	3	-1,267	-71	156	**2,512**

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	**TOTAL GENERATION SVC COST + 15% PREMIUM**	**AVERAGE GENERATION SVC COST + 15% PREMIUM**	Adder for DSM Programs	RPS Cost (RECs + ACPs)	**TOTAL SYSTEM BENEFITS COST**	**AVERAGE SYSTEM BENEFITS COST**	**TOTAL COST**	**AVG COST**
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
4,141	590	-26	-108	40	12	61	**5,416**	**14.56**	116	326	**442**	**1.19**	**5,858**	**15.75**

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	**TOTAL GENERATION SVC COST**	**AVERAGE GENERATION SVC COST**	Adder for DSM Programs	RPS Cost (RECs + ACPs)	**TOTAL SYSTEM BENEFITS COST**	**AVERAGE SYSTEM BENEFITS COST**	**TOTAL COST**	**AVG COST**
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,029	413	**2,442**	**6.56**	116	326	**442**	**1.19**	**2,885**	**7.75**

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
18.0%	3,720

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
12,941,741	21,677,682	99,072,667	28%	45,243,899	83,273,637	342,026,325

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	13,361,508	14,061	6,443	12,121,701	32,244	9,043
ME	6,880,019	4,437	1,896	6,880,527	4,872	2,005
MA	20,719,801	77,415	20,361	20,719,245	77,460	20,371
NH	7,267,499	28,279	7,455	7,269,163	28,279	7,455
RI	1,308,827	11	226	1,308,827	11	226
VT	505,287	0	0	507,919	0	1
Total	**50,042,942**	**124,205**	**36,382**	**48,807,382**	**142,867**	**39,101**

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,370,800	616,830	2,987,630	49,819,940	37,205,520	20%	17%	3%	1,205,350	1,170,250	224,306,260
2,008,080	3,022,030	5,030,110	17,676,710	13,537,869						
1,779,520	770,050	2,549,570	36,382,820	65,830,301						
695,550	2,029,370	2,724,920	22,830,700	11,897,230						
95,040	0	95,040	3,190,820	12,553,624						
493,720	440,360	934,080	6,017,910	8,115,192						
7,442,710	**6,878,640**	**14,321,350**	**135,918,900**	**149,139,734**						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,370,800	616,830	26,864,210	4,132,680	13,953,570	25,390	1,856,460	15,835,420	33,984,520	49,819,940
ME	2,008,080	3,022,030	0	664,130	11,685,680	520	296,270	11,982,470	5,694,240	17,676,710
MA	1,779,520	770,050	5,597,860	12,199,380	14,192,340	16,150	1,827,520	16,036,010	20,346,810	36,382,820
NH	695,550	2,029,370	10,000,870	4,479,020	5,544,520	400	80,970	5,625,890	17,204,810	22,830,700
RI	95,040	0	0	0	3,095,780	0	0	3,095,780	95,040	3,190,820
VT	493,720	440,360	5,074,090	0	8,930	810	0	9,740	6,008,170	6,017,910
Total	**7,442,710**	**6,878,640**	**47,537,030**	**21,475,210**	**48,480,820**	**43,270**	**4,061,220**	**52,585,310**	**83,333,590**	**135,918,900**

Summary of Results: 2018 High Fuel/Growth Scenario, Coal Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation In Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
111.3	105.6	54%	7,919	37,205,520	49,820,246	-12,614,684	9,234	10,348	-1,114	5.3	8.7	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	**TOTAL RESOURCE COST**
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
425	406	109	2,028	402	326	3	-1,267	-71	156	**2,519**

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	**TOTAL GENERATION SVC COST + 15% PREMIUM**	**AVERAGE GENERATION SVC COST + 15% PREMIUM**	Adder for DSM Programs	RPS Cost (RECs + ACPs)	**TOTAL SYSTEM BENEFITS COST**	**AVERAGE SYSTEM BENEFITS COST**	**TOTAL COST**	**AVG COST**
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
4,141	590	-26	-108	40	12	61	**5,416**	**14.56**	116	326	**442**	**1.19**	**5,858**	**15.75**

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	**TOTAL GENERATION SVC COST**	**AVERAGE GENERATION SVC COST**	Adder for DSM Programs	RPS Cost (RECs + ACPs)	**TOTAL SYSTEM BENEFITS COST**	**AVERAGE SYSTEM BENEFITS COST**	**TOTAL COST**	**AVG COST**
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,036	413	**2,450**	**6.58**	116	326	**442**	**1.19**	**2,892**	**7.77**

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
18.0%	3,720

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
12,941,741	21,677,682	99,072,667	28%	45,243,899	83,273,637	342,026,325

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	21,495,120	14,061	6,443	20,255,314	32,244	9,043
ME	6,880,019	4,437	1,896	6,880,527	4,872	2,005
MA	20,719,801	77,415	20,361	20,719,245	77,460	20,371
NH	7,267,499	28,279	7,455	7,269,163	28,279	7,455
RI	1,308,827	11	226	1,308,827	11	226
VT	505,287	0	0	507,919	0	1
Total	**58,176,554**	**124,205**	**36,382**	**56,940,994**	**142,867**	**39,101**

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,370,800	616,830	2,987,630	49,819,940	37,205,520	20%	17%	3%	1,205,350	1,170,250	224,306,260
2,008,080	3,022,030	5,030,110	17,676,710	13,537,869						
1,779,520	770,050	2,549,570	36,382,820	65,830,301						
695,550	2,029,370	2,724,920	22,830,700	11,897,230						
95,040	0	95,040	3,190,820	12,553,624						
493,720	440,360	934,080	6,017,910	8,115,192						
7,442,710	**6,878,640**	**14,321,350**	**135,918,900**	**149,139,734**						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,370,800	616,830	17,180,880	13,428,677	13,953,570	25,390	1,856,460	15,835,420	33,597,187	49,432,607
ME	2,008,080	3,022,030	0	664,130	11,685,680	520	296,270	11,982,470	5,694,240	17,676,710
MA	1,779,520	770,050	5,597,860	12,199,380	14,192,340	16,150	1,827,520	16,036,010	20,346,810	36,382,820
NH	695,550	2,029,370	10,000,870	4,479,020	5,544,520	400	80,970	5,625,890	17,204,810	22,830,700
RI	95,040	0	0	0	3,095,780	0	0	3,095,780	95,040	3,190,820
VT	493,720	440,360	5,074,090	0	8,930	810	0	9,740	6,008,170	6,017,910
Total	**7,442,710**	**6,878,640**	**37,853,700**	**30,771,207**	**48,480,820**	**43,270**	**4,061,220**	**52,585,310**	**82,946,257**	**135,531,567**

Summary of Results: 2030 High Fuel/Growth Scenario, Conventional Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation In Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
122.7	116.8	53%	8,965	41,834,315	53,826,644	-11,992,289	10,453	11,847	-1,393	8.1	5.9	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	**TOTAL RESOURCE COST**
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
362	430	87	3,211	568	321	15	-1,359	-136	156	**3,655**

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	**TOTAL GENERATION SVC COST + 15% PREMIUM**	**AVERAGE GENERATION SVC COST + 15% PREMIUM**	Adder for DSM Programs	RPS Cost (RECs + ACPs)	**TOTAL SYSTEM BENEFITS COST**	**AVERAGE SYSTEM BENEFITS COST**	**TOTAL COST**	**AVG COST**
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
5,131	1,018	-67	-99	10	42	41	**6,989**	**16.71**	116	321	**437**	**1.04**	**7,426**	**17.75**

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	**TOTAL GENERATION SVC COST**	**AVERAGE GENERATION SVC COST**	Adder for DSM Programs	RPS Cost (RECs + ACPs)	**TOTAL SYSTEM BENEFITS COST**	**AVERAGE SYSTEM BENEFITS COST**	**TOTAL COST**	**AVG COST**
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
3,178	413	**3,591**	**8.58**	116	321	**437**	**1.04**	**4,028**	**9.63**

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
17.7%	4,006

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
28,668,462	40,598,720	198,699,947	52%	82,757,080	133,975,762	565,950,383

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	18,742,811	12,774	6,868	17,392,460	29,528	9,349
ME	8,380,710	3,911	2,031	8,381,983	4,357	2,142
MA	24,126,111	76,643	20,787	24,130,615	76,721	20,804
NH	7,023,482	28,636	7,494	7,030,741	28,639	7,496
RI	1,938,968	17	335	1,938,968	17	335
VT	2,302,726	30	300	2,307,648	32	301
Total	**62,514,808**	**122,010**	**37,814**	**61,182,415**	**139,295**	**40,429**

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,522,460	619,700	3,142,160	53,826,350	41,834,315	23%	20%	3%	1,253,890	1,273,370	237,219,236
2,105,030	3,026,750	5,131,780	21,504,230	15,783,869						
1,760,530	1,423,400	3,183,930	45,590,370	75,149,717						
674,320	2,077,300	2,751,620	22,098,230	14,708,453						
90,650	0	90,650	4,708,320	14,263,839						
571,240	446,840	1,018,080	10,212,227	9,411,148						
7,724,230	**7,593,990**	**15,318,220**	**157,939,727**	**171,151,340**						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,522,460	619,700	17,180,600	4,098,320	28,167,030	35,310	1,202,930	29,405,270	24,421,080	53,826,350
ME	2,105,030	3,026,750	0	699,320	15,545,240	1,300	126,590	15,673,130	5,831,100	21,504,230
MA	1,760,530	1,423,400	5,597,860	12,285,880	23,011,240	14,020	1,497,440	24,522,700	21,067,670	45,590,370
NH	674,320	2,077,300	9,912,880	4,589,920	4,823,520	8,780	11,510	4,843,810	17,254,420	22,098,230
RI	90,650	0	0	0	4,617,670	0	0	4,617,670	90,650	4,708,320
VT	571,240	446,840	5,014,570	0	4,139,827	39,750	0	4,179,577	6,032,650	10,212,227
Total	**7,724,230**	**7,593,990**	**37,705,910**	**21,673,440**	**80,304,527**	**99,160**	**2,838,470**	**83,242,157**	**74,697,570**	**157,939,727**

Summary of Results: 2030 High Fuel/Growth Scenario, DSM-Focus Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation In Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
123.5	119.1	55%	8,266	39,900,137	52,934,914	-13,034,735	9,639	11,547	-1,908	7.0	7.0	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	**TOTAL RESOURCE COST**
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
331	420	85	3,121	560	306	5	-1,525	-160	232	**3,375**

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	**TOTAL GENERATION SVC COST + 15% PREMIUM**	**AVERAGE GENERATION SVC COST + 15% PREMIUM**	Adder for DSM Programs	RPS Cost (RECs + ACPs)	**TOTAL SYSTEM BENEFITS COST**	**AVERAGE SYSTEM BENEFITS COST**	**TOTAL COST**	**AVG COST**
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
4,928	807	-37	-95	15	30	49	**6,552**	**16.42**	172	306	**478**	**1.20**	**7,030**	**17.62**

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	**TOTAL GENERATION SVC COST**	**AVERAGE GENERATION SVC COST**	Adder for DSM Programs	RPS Cost (RECs + ACPs)	**TOTAL SYSTEM BENEFITS COST**	**AVERAGE SYSTEM BENEFITS COST**	**TOTAL COST**	**AVG COST**
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,837	413	**3,250**	**8.15**	172	306	**478**	**1.20**	**3,728**	**9.34**

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
17.5%	4,636

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
27,608,124	39,014,358	191,351,978	51%	79,448,937	129,781,519	549,995,272

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	18,551,788	13,120	6,934	17,120,563	30,332	9,476
ME	8,490,433	3,898	2,047	8,491,904	4,344	2,158
MA	23,839,692	77,542	20,935	23,843,616	77,624	20,953
NH	7,223,238	28,967	7,601	7,230,313	28,970	7,604
RI	1,955,328	17	338	1,955,328	17	338
VT	1,966,715	22	241	1,971,690	23	242
Total	**62,027,194**	**123,565**	**38,094**	**60,613,415**	**141,311**	**40,771**

RPS Summary

State	Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
CT	2,523,540	619,910	3,143,450	52,934,595	39,900,137	23%	20%	3%	1,254,540	1,273,800	224,296,506
ME	2,105,850	3,026,830	5,132,680	21,783,814	15,783,869						
MA	1,761,110	1,389,020	3,150,130	44,627,880	75,149,717						
NH	674,620	2,074,170	2,748,790	22,501,380	14,708,453						
RI	90,730	0	90,730	4,753,130	14,263,839						
VT	571,490	446,760	1,018,250	9,406,180	9,411,148						
Total	**7,727,340**	**7,556,690**	**15,284,030**	**156,006,979**	**169,217,163**						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,523,540	619,910	17,180,600	4,137,690	27,093,370	24,835	1,354,650	28,472,855	24,461,740	52,934,595
ME	2,105,850	3,026,830	0	703,810	15,828,430	1,524	117,370	15,947,324	5,836,490	21,783,814
MA	1,761,110	1,389,020	5,597,860	12,409,730	21,908,990	14,070	1,547,100	23,470,160	21,157,720	44,627,880
NH	674,620	2,074,170	9,912,880	4,641,340	5,176,120	8,380	13,870	5,198,370	17,303,010	22,501,380
RI	90,730	0	0	0	4,662,400	0	0	4,662,400	90,730	4,753,130
VT	571,490	446,760	5,014,570	0	3,346,290	27,070	0	3,373,360	6,032,820	9,406,180
Total	**7,727,340**	**7,556,690**	**37,705,910**	**21,892,570**	**78,015,600**	**75,879**	**3,032,990**	**81,124,469**	**74,882,510**	**156,006,979**

Summary of Results: 2030 High Fuel/Growth Scenario, Nuclear Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation In Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
120.3	113.4	53%	8,965	41,834,315	58,190,024	-16,355,665	10,453	12,747	-2,293	7.8	6.2	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	**TOTAL RESOURCE COST**
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
973	556	92	2,792	494	321	0	-1,780	-215	156	**3,389**

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	**TOTAL GENERATION SVC COST + 15% PREMIUM**	**AVERAGE GENERATION SVC COST + 15% PREMIUM**	Adder for DSM Programs	RPS Cost (RECs + ACPs)	**TOTAL SYSTEM BENEFITS COST**	**AVERAGE SYSTEM BENEFITS COST**	**TOTAL COST**	**AVG COST**
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
5,031	981	-70	-118	14	47	43	**6,819**	**16.30**	116	321	**437**	**1.04**	**7,256**	**17.35**

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	**TOTAL GENERATION SVC COST**	**AVERAGE GENERATIO N SVC COST**	Adder for DSM Programs	RPS Cost (RECs + ACPs)	**TOTAL SYSTEM BENEFITS COST**	**AVERAGE SYSTEM BENEFITS COST**	**TOTAL COST**	**AVG COST**
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,912	413	**3,326**	**7.95**	116	321	**437**	**1.04**	**3,763**	**8.99**

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
17.7%	4,906

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
23,628,554	35,849,690	163,006,192	40%	72,011,881	122,498,272	503,328,579

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	16,247,743	12,397	6,346	15,136,673	28,554	8,754
ME	8,433,008	3,943	2,046	8,434,708	4,389	2,158
MA	23,462,470	76,493	20,640	23,466,772	76,577	20,659
NH	7,131,780	28,551	7,494	7,138,380	28,554	7,496
RI	1,868,670	16	323	1,868,670	16	323
VT	1,256,506	11	117	1,260,901	12	118
Total	**58,400,177**	**121,411**	**36,966**	**57,306,105**	**138,103**	**39,507**

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,484,140	617,230	3,101,370	58,189,740	41,834,315	23%	20%	3%	1,231,520	1,257,390	237,965,280
2,104,980	3,024,570	5,129,550	21,617,588	15,783,869						
1,760,480	959,770	2,720,250	43,546,540	75,149,717						
674,300	2,068,810	2,743,110	22,379,950	14,708,453						
90,650	0	90,650	4,546,350	14,263,839						
571,220	446,020	1,017,240	7,674,420	9,411,148						
7,685,770	**7,116,400**	**14,802,170**	**157,954,588**	**171,151,340**						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,484,140	617,230	26,863,930	4,011,920	23,083,820	36,470	1,092,230	24,212,520	33,977,220	58,189,740
ME	2,104,980	3,024,570	0	699,820	15,652,720	1,748	133,750	15,788,218	5,829,370	21,617,588
MA	1,760,480	959,770	5,597,860	12,257,620	21,449,640	12,210	1,508,960	22,970,810	20,575,730	43,546,540
NH	674,300	2,068,810	9,912,880	4,577,160	5,129,250	7,390	10,160	5,146,800	17,233,150	22,379,950
RI	90,650	0	0	0	4,455,700	0	0	4,455,700	90,650	4,546,350
VT	571,220	446,020	5,014,570	0	1,627,300	15,310	0	1,642,610	6,031,810	7,674,420
Total	**7,685,770**	**7,116,400**	**47,389,240**	**21,546,520**	**71,398,430**	**73,128**	**2,745,100**	**74,216,658**	**83,737,930**	**157,954,588**

Summary of Results: 2030 High Fuel/Growth Scenario, Coal Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation In Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
120.3	113.4	53%	8,965	41,834,315	58,190,024	-16,355,665	10,453	12,747	-2,293	7.8	6.2	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	**TOTAL RESOURCE COST**
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
663	483	132	2,981	783	321	0	-1,780	-215	156	**3,524**

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	**TOTAL GENERATION SVC COST + 15% PREMIUM**	**AVERAGE GENERATION SVC COST + 15% PREMIUM**	Adder for DSM Programs	RPS Cost (RECs + ACPs)	**TOTAL SYSTEM BENEFITS COST**	**AVERAGE SYSTEM BENEFITS COST**	**TOTAL COST**	**AVG COST**
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
5,031	981	-70	-118	14	47	43	**6,819**	**16.30**	116	321	**437**	**1.04**	**7,256**	**17.35**

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	**TOTAL GENERATION SVC COST**	**AVERAGE GENERATIO N SVC COST**	Adder for DSM Programs	RPS Cost (RECs + ACPs)	**TOTAL SYSTEM BENEFITS COST**	**AVERAGE SYSTEM BENEFITS COST**		**TOTAL COST**	**AVG COST**
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)		($Mil)	(¢/kWh)
3,047	413	**3,460**	**8.27**	116	321	**437**	**1.04**		**3,897**	**9.32**

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
17.7%	4,906

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
23,628,554	35,849,690	163,006,192	40%	72,011,881	122,498,272	503,328,579

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	24,381,355	12,397	6,346	23,270,286	28,554	8,754
ME	8,433,008	3,943	2,046	8,434,708	4,389	2,158
MA	23,462,470	76,493	20,640	23,466,772	76,577	20,659
NH	7,131,780	28,551	7,494	7,138,380	28,554	7,496
RI	1,868,670	16	323	1,868,670	16	323
VT	1,256,506	11	117	1,260,901	12	118
Total	**66,533,789**	**121,411**	**36,966**	**65,439,717**	**138,103**	**39,507**

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,484,140	617,230	3,101,370	58,189,740	41,834,315	23%	20%	3%	1,231,520	1,257,390	237,965,280
2,104,980	3,024,570	5,129,550	21,617,588	15,783,869						
1,760,480	959,770	2,720,250	43,546,540	75,149,717						
674,300	2,068,810	2,743,110	22,379,950	14,708,453						
90,650	0	90,650	4,546,350	14,263,839						
571,220	446,020	1,017,240	7,674,420	9,411,148						
7,685,770	**7,116,400**	**14,802,170**	**157,954,588**	**171,151,340**						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,484,140	617,230	17,180,600	13,307,917	23,083,820	36,470	1,092,230	24,212,520	33,589,887	57,802,407
ME	2,104,980	3,024,570	0	699,820	15,652,720	1,748	133,750	15,788,218	5,829,370	21,617,588
MA	1,760,480	959,770	5,597,860	12,257,620	21,449,640	12,210	1,508,960	22,970,810	20,575,730	43,546,540
NH	674,300	2,068,810	9,912,880	4,577,160	5,129,250	7,390	10,160	5,146,800	17,233,150	22,379,950
RI	90,650	0	0	0	4,455,700	0	0	4,455,700	90,650	4,546,350
VT	571,220	446,020	5,014,570	0	1,627,300	15,310	0	1,642,610	6,031,810	7,674,420
Total	**7,685,770**	**7,116,400**	**37,705,910**	**30,842,517**	**71,398,430**	**73,128**	**2,745,100**	**74,216,658**	**83,350,597**	**157,567,255**

Summary of Results: 2011 Low Stress Scenario, Conventional Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation In Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
53.9	51.9	59%	7,380	38,049,374	36,771,453	1,277,907	8,605	8,251	354	4.5	9.5	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	**TOTAL RESOURCE COST**
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
0	314	40	821	51	215	168	-79	19	76	**1,625**

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	**TOTAL GENERATION SVC COST + 15% PREMIUM**	**AVERAGE GENERATION SVC COST + 15% PREMIUM**	Adder for DSM Programs	RPS Cost (RECs + ACPs)	**TOTAL SYSTEM BENEFITS COST**	**AVERAGE SYSTEM BENEFITS COST**	**TOTAL COST**	**AVG COST**
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,051	465	-8	-49	15	2	67	**2,925**	**7.69**	123	215	**338**	**0.89**	**3,262**	**8.57**

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	**TOTAL GENERATION SVC COST**	**AVERAGE GENERATION SVC COST**	Adder for DSM Programs	RPS Cost (RECs + ACPs)	**TOTAL SYSTEM BENEFITS COST**	**AVERAGE SYSTEM BENEFITS COST**	**TOTAL COST**	**AVG COST**
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
1,334	413	**1,747**	**4.59**	123	215	**338**	**0.89**	**2,084**	**5.48**

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
18.0%	1,797

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
10,797,520	17,970,888	87,278,666	33%	57,129,726	105,175,546	490,310,721

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	9,680,309	6,125	4,172	9,830,066	22,990	6,612
ME	6,551,225	3,290	1,593	6,551,555	3,678	1,690
MA	20,783,670	47,636	13,808	20,737,449	47,631	13,798
NH	6,314,312	14,774	4,303	6,320,037	14,775	4,304
RI	4,170,744	36	720	4,172,856	39	721
VT	605,309	3	3	617,435	4	4
Total	**48,105,569**	**71,864**	**24,598**	**48,229,398**	**89,117**	**27,129**

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,508,850	615,460	3,124,310	36,771,150	38,049,374	11%	8%	3%	1,275,980	1,237,660	90,826,097
1,959,050	3,020,390	4,979,440	17,166,690	13,486,356						
1,685,440	954,860	2,640,300	43,461,563	66,668,114						
679,060	2,023,990	2,703,050	23,950,120	11,493,296						
92,770	0	92,770	9,833,230	12,702,495						
588,290	438,770	1,027,060	6,124,330	8,152,408						
7,513,460	**7,053,470**	**14,566,930**	**137,307,083**	**150,552,042**						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,508,850	615,460	17,201,880	2,912,240	11,993,320	20,430	1,518,970	13,532,720	23,238,430	36,771,150
ME	1,959,050	3,020,390	0	417,650	11,442,340	340	326,920	11,769,600	5,397,090	17,166,690
MA	1,685,440	954,860	5,597,860	7,306,590	26,223,560	10,213	1,683,040	27,916,813	15,544,750	43,461,563
NH	679,060	2,023,990	10,000,870	2,189,790	8,780,530	3,280	272,600	9,056,410	14,893,710	23,950,120
RI	92,770	0	0	0	9,727,970	12,490	0	9,740,460	92,770	9,833,230
VT	588,290	438,770	5,074,090	0	14,440	8,740	0	23,180	6,101,150	6,124,330
Total	**7,513,460**	**7,053,470**	**37,874,700**	**12,826,270**	**68,182,160**	**55,493**	**3,801,530**	**72,039,183**	**65,267,900**	**137,307,083**

Summary of Results: 2011 Low Stress Scenario, DSM-Focus Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation In Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
54.1	52.2	60%	7,215	37,648,904	37,049,707	599,205	8,412	8,251	161	4.5	9.5	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	**TOTAL RESOURCE COST**
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
0	314	41	833	52	213	146	-94	9	94	**1,609**

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	**TOTAL GENERATION SVC COST + 15% PREMIUM**	**AVERAGE GENERATION SVC COST + 15% PREMIUM**	Adder for DSM Programs	RPS Cost (RECs + ACPs)	**TOTAL SYSTEM BENEFITS COST**	**AVERAGE SYSTEM BENEFITS COST**	**TOTAL COST**	**AVG COST**
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,038	454	-7	-48	15	3	67	**2,900**	**7.70**	220	213	**433**	**1.15**	**3,333**	**8.85**

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	**TOTAL GENERATION SVC COST**	**AVERAGE GENERATIO N SVC COST**	Adder for DSM Programs	RPS Cost (RECs + ACPs)	**TOTAL SYSTEM BENEFITS COST**	**AVERAGE SYSTEM BENEFITS COST**	**TOTAL COST**	**AVG COST**
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
1,302	413	**1,715**	**4.56**	220	213	**433**	**1.15**	**2,148**	**5.71**

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
17.6%	2,012

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
11,087,443	18,144,676	88,410,296	33%	56,081,987	103,645,045	484,552,190

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	9,856,700	6,368	4,280	10,014,857	23,577	6,770
ME	6,583,605	3,380	1,618	6,583,952	3,768	1,715
MA	20,504,199	49,254	14,115	20,452,241	49,229	14,100
NH	6,433,686	15,372	4,455	6,439,881	15,374	4,456
RI	4,308,235	37	744	4,309,089	38	744
VT	605,388	3	3	618,096	4	4
Total	**48,291,814**	**74,414**	**25,215**	**48,418,116**	**91,991**	**27,790**

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,509,160	615,520	3,124,680	37,049,390	37,648,904	11%	8%	3%	1,276,150	1,237,800	89,171,495
1,959,260	3,020,750	4,980,010	17,223,250	13,486,356						
1,685,620	944,230	2,629,850	42,283,955	66,668,113						
679,160	2,024,210	2,703,370	24,089,810	11,493,296						
92,720	0	92,720	10,141,900	12,702,495						
588,320	438,840	1,027,160	6,125,130	8,152,408						
7,514,240	**7,043,550**	**14,557,790**	**136,913,435**	**150,151,572**						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,509,160	615,520	17,201,880	2,940,420	12,134,990	21,200	1,626,220	13,782,410	23,266,980	37,049,390
ME	1,959,260	3,020,750	0	426,270	11,478,940	360	337,670	11,816,970	5,406,280	17,223,250
MA	1,685,620	944,230	5,597,860	7,546,050	24,752,770	11,285	1,746,140	26,510,195	15,773,760	42,283,955
NH	679,160	2,024,210	10,000,870	2,278,760	8,818,290	3,440	285,080	9,106,810	14,983,000	24,089,810
RI	92,720	0	0	0	10,044,130	5,050	0	10,049,180	92,720	10,141,900
VT	588,320	438,840	5,074,090	0	14,860	9,020	0	23,880	6,101,250	6,125,130
Total	**7,514,240**	**7,043,550**	**37,874,700**	**13,191,500**	**67,243,980**	**50,355**	**3,995,110**	**71,289,445**	**65,623,990**	**136,913,435**

Summary of Results: 2013 Low Stress Scenario, Conventional Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation In Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
51.2	49.4	59%	7,622	39,117,038	38,813,649	303,379	8,887	8,550	337	3.3	10.7	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	**TOTAL RESOURCE COST**
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
23	323	47	860	61	250	122	-87	13	103	**1,714**

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	**TOTAL GENERATION SVC COST + 15% PREMIUM**	**AVERAGE GENERATION SVC COST + 15% PREMIUM**	Adder for DSM Programs	RPS Cost (RECs + ACPs)	**TOTAL SYSTEM BENEFITS COST**	**AVERAGE SYSTEM BENEFITS COST**	**TOTAL COST**	**AVG COST**
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,003	351	-7	-44	14	3	75	**2,755**	**7.04**	121	250	**371**	**0.95**	**3,126**	**7.99**

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	**TOTAL GENERATION SVC COST**	**AVERAGE GENERATION SVC COST**	Adder for DSM Programs	RPS Cost (RECs + ACPs)	**TOTAL SYSTEM BENEFITS COST**	**AVERAGE SYSTEM BENEFITS COST**		**TOTAL COST**	**AVG COST**
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)		($Mil)	(¢/kWh)
1,361	413	**1,774**	**4.54**	121	250	**371**	**0.95**		**2,145**	**5.48**

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
17.7%	2,105

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation		ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)		(MMBtu)		(MMBtu)
13,470,101	21,174,018	105,291,286	37%		64,093,035	115,310,015	549,462,783

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	10,449,987	5,318	4,063	10,632,248	21,128	6,328
ME	8,294,082	3,119	1,836	8,294,117	3,557	1,945
MA	19,817,511	36,286	11,125	19,781,886	36,364	11,134
NH	5,414,470	10,451	3,196	5,418,033	10,451	3,197
RI	4,233,827	37	731	4,266,184	80	746
VT	553,186	1	1	560,287	2	3
Total	**48,763,062**	**55,212**	**20,953**	**48,952,754**	**71,581**	**23,352**

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,385,280	615,590	3,000,870	38,813,340	39,117,038	13%	10%	3%	1,132,130	1,257,940	136,446,606
2,093,810	3,020,420	5,114,230	21,416,460	14,068,666						
1,761,640	974,930	2,736,570	43,698,660	68,992,625						
709,020	2,023,730	2,732,750	22,879,210	12,097,990						
94,150	0	94,150	9,957,670	13,189,124						
539,270	438,860	978,130	5,967,329	8,467,445						
7,583,170	**7,073,530**	**14,656,700**	**142,732,669**	**155,932,889**						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,385,280	615,590	17,091,580	2,469,670	14,496,230	43,670	1,711,320	16,251,220	22,562,120	38,813,340
ME	2,093,810	3,020,420	0	359,870	15,573,270	30	369,060	15,942,360	5,474,100	21,416,460
MA	1,761,640	974,930	5,597,860	5,240,820	28,321,730	35,390	1,766,290	30,123,410	13,575,250	43,698,660
NH	709,020	2,023,730	10,000,870	1,540,300	8,402,710	1,650	200,930	8,605,290	14,273,920	22,879,210
RI	94,150	0	0	0	9,671,920	191,600	0	9,863,520	94,150	9,957,670
VT	539,270	438,860	4,969,930	0	15,030	4,239	0	19,269	5,948,060	5,967,329
Total	**7,583,170**	**7,073,530**	**37,660,240**	**9,610,660**	**76,480,890**	**276,579**	**4,047,600**	**80,805,069**	**61,927,600**	**142,732,669**

Summary of Results: 2013 Low Stress Scenario, DSM-Focus Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation In Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
51.1	49.4	60%	7,295	38,026,450	38,880,567	-854,112	8,506	8,550	-43	3.2	10.8	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	**TOTAL RESOURCE COST**
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
23	323	47	862	61	243	89	-113	-2	155	**1,687**

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	**TOTAL GENERATION SVC COST + 15% PREMIUM**	**AVERAGE GENERATION SVC COST + 15% PREMIUM**	Adder for DSM Programs	RPS Cost (RECs + ACPs)	**TOTAL SYSTEM BENEFITS COST**	**AVERAGE SYSTEM BENEFITS COST**	**TOTAL COST**	**AVG COST**
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
1,942	331	-3	-43	15	3	76	**2,669**	**7.02**	300	243	**542**	**1.43**	**3,211**	**8.44**

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	**TOTAL GENERATION SVC COST**	**AVERAGE GENERATION SVC COST**	Adder for DSM Programs	RPS Cost (RECs + ACPs)	**TOTAL SYSTEM BENEFITS COST**	**AVERAGE SYSTEM BENEFITS COST**	**TOTAL COST**	**AVG COST**
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
1,290	413	**1,703**	**4.48**	300	243	**542**	**1.43**	**2,246**	**5.91**

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
18.0%	2,534

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
13,647,823	21,127,937	105,900,023	37%	62,734,869	113,101,078	541,071,853

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	10,478,431	5,307	4,067	10,658,903	21,133	6,334
ME	7,600,435	3,445	1,788	7,600,715	3,883	1,897
MA	19,920,764	36,465	11,182	19,883,829	36,544	11,192
NH	5,564,581	10,625	3,258	5,568,312	10,625	3,259
RI	4,285,984	37	740	4,319,304	82	755
VT	552,999	1	1	559,533	1	2
Total	**48,403,194**	**55,879**	**21,037**	**48,590,595**	**72,268**	**23,439**

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,385,460	615,590	3,001,050	38,880,210	38,026,450	13%	10%	3%	1,132,180	1,258,070	131,090,555
2,094,240	3,020,750	5,114,990	19,611,030	14,068,666						
1,761,790	987,650	2,749,440	43,919,510	68,992,625						
709,140	2,023,880	2,733,020	23,198,420	12,097,990						
94,230	0	94,230	10,072,630	13,189,124						
539,320	438,880	978,200	5,966,838	8,467,445						
7,584,180	**7,086,750**	**14,670,930**	**141,648,638**	**154,842,300**						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,385,460	615,590	17,091,580	2,478,380	14,567,460	34,880	1,706,860	16,309,200	22,571,010	38,880,210
ME	2,094,240	3,020,750	0	380,190	13,694,550	290	421,010	14,115,850	5,495,180	19,611,030
MA	1,761,790	987,650	5,597,860	5,277,550	28,498,980	29,130	1,766,550	30,294,660	13,624,850	43,919,510
NH	709,140	2,023,880	10,000,870	1,537,890	8,678,650	1,420	246,570	8,926,640	14,271,780	23,198,420
RI	94,230	0	0	0	9,781,100	197,300	0	9,978,400	94,230	10,072,630
VT	539,320	438,880	4,969,930	0	15,260	3,448	0	18,708	5,948,130	5,966,838
Total	**7,584,180**	**7,086,750**	**37,660,240**	**9,674,010**	**75,236,000**	**266,468**	**4,140,990**	**79,643,458**	**62,005,180**	**141,648,638**

Summary of Results: 2018 Low Stress Scenario, Conventional Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation In Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
55.9	53.7	59%	8,123	41,761,644	49,032,530	-7,270,851	9,471	10,347	-875	3.1	10.9	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	**TOTAL RESOURCE COST**
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
154	375	73	1,253	195	366	19	-386	-32	156	**2,173**

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	**TOTAL GENERATION SVC COST + 15% PREMIUM**	**AVERAGE GENERATION SVC COST + 15% PREMIUM**	Adder for DSM Programs	RPS Cost (RECs + ACPs)	**TOTAL SYSTEM BENEFITS COST**	**AVERAGE SYSTEM BENEFITS COST**	**TOTAL COST**	**AVG COST**
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,335	348	-19	-46	15	3	77	**3,119**	**7.47**	116	366	**482**	**1.15**	**3,601**	**8.62**

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	**TOTAL GENERATION SVC COST**	**AVERAGE GENERATION SVC COST**	Adder for DSM Programs	RPS Cost (RECs + ACPs)	**TOTAL SYSTEM BENEFITS COST**	**AVERAGE SYSTEM BENEFITS COST**	**TOTAL COST**	**AVG COST**
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
1,651	413	**2,064**	**4.94**	116	366	**482**	**1.15**	**2,546**	**6.10**

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
18.3%	3,455

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
26,706,899	36,170,443	185,288,212	53%	89,753,010	137,292,054	676,842,788

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	15,880,682	3,413	3,945	14,178,225	15,976	5,829
ME	8,974,223	1,788	1,674	8,974,750	2,223	1,783
MA	19,354,554	24,272	8,413	19,297,326	24,236	8,396
NH	4,866,662	6,812	2,302	4,873,781	6,814	2,304
RI	4,119,141	36	711	4,139,695	63	721
VT	514,905	2	2	521,755	3	4
Total	**53,710,167**	**36,324**	**17,047**	**51,985,533**	**49,317**	**19,036**

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,379,310	615,580	2,994,890	49,032,210	41,761,644	20%	17%	3%	1,211,270	1,172,830	261,488,033
2,011,340	3,020,420	5,031,760	23,510,850	15,433,413						
1,781,870	914,620	2,696,490	45,409,090	75,047,489						
697,410	2,024,470	2,721,880	22,469,910	13,563,067						
95,240	0	95,240	9,696,710	14,311,295						
494,550	438,890	933,440	6,032,430	9,251,557						
7,459,720	**7,013,980**	**14,473,700**	**156,151,200**	**169,368,466**						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,379,310	615,580	17,180,880	2,159,350	25,803,380	32,550	861,160	26,697,090	22,335,120	49,032,210
ME	2,011,340	3,020,420	0	304,850	18,051,670	540	122,030	18,174,240	5,336,610	23,510,850
MA	1,781,870	914,620	5,597,860	3,745,550	32,516,060	27,730	825,400	33,369,190	12,039,900	45,409,090
NH	697,410	2,024,470	10,000,870	1,073,290	8,637,890	4,480	31,500	8,673,870	13,796,040	22,469,910
RI	95,240	0	0	0	9,479,770	121,700	0	9,601,470	95,240	9,696,710
VT	494,550	438,890	5,074,090	0	16,810	8,090	0	24,900	6,007,530	6,032,430
Total	**7,459,720**	**7,013,980**	**37,853,700**	**7,283,040**	**94,505,580**	**195,090**	**1,840,090**	**96,540,760**	**59,610,440**	**156,151,200**

Summary of Results: 2018 Low Stress Scenario, DSM-Focus Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation In Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
55.7	53.8	59%	7,499	38,987,396	49,225,310	-10,237,876	8,743	10,347	-1,604	2.9	11.1	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	**TOTAL RESOURCE COST**
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
154	375	73	1,260	197	342	5	-535	-56	303	**2,118**

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	**TOTAL GENERATION SVC COST + 15% PREMIUM**	**AVERAGE GENERATION SVC COST + 15% PREMIUM**	Adder for DSM Programs	RPS Cost (RECs + ACPs)	**TOTAL SYSTEM BENEFITS COST**	**AVERAGE SYSTEM BENEFITS COST**	**TOTAL COST**	**AVG COST**
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,171	304	-9	-43	16	3	78	**2,898**	**7.43**	172	342	**514**	**1.32**	**3,412**	**8.75**

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	**TOTAL GENERATION SVC COST**	**AVERAGE GENERATION SVC COST**	Adder for DSM Programs	RPS Cost (RECs + ACPs)	**TOTAL SYSTEM BENEFITS COST**	**AVERAGE SYSTEM BENEFITS COST**	**TOTAL COST**	**AVG COST**
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
1,473	413	**1,886**	**4.84**	172	342	**514**	**1.32**	**2,400**	**6.16**

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
18.7%	4,276

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
26,345,419	36,462,310	186,492,140	53%	85,662,368	133,202,424	656,985,885

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	15,998,110	3,473	4,001	14,295,961	16,250	5,908
ME	8,248,330	2,008	1,598	8,248,872	2,444	1,707
MA	18,694,331	24,193	8,283	18,635,209	24,150	8,264
NH	5,030,516	7,098	2,393	5,037,960	7,100	2,395
RI	4,209,914	36	727	4,234,040	69	738
VT	513,969	2	2	520,940	3	4
Total	**52,695,170**	**36,811**	**17,004**	**50,972,983**	**50,015**	**19,014**

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,379,560	615,540	2,995,100	49,225,010	38,987,396	20%	17%	3%	1,211,390	1,172,960	237,313,519
2,011,630	3,020,750	5,032,380	21,657,680	15,433,413						
1,782,070	936,010	2,718,080	43,768,180	75,047,489						
697,550	2,024,400	2,721,950	22,796,370	13,563,067						
95,340	0	95,340	9,905,830	14,311,295						
494,600	438,860	933,460	6,032,011	9,251,557						
7,460,750	**7,035,560**	**14,496,310**	**153,385,081**	**166,594,217**						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,379,560	615,540	17,180,880	2,174,480	25,937,600	24,940	912,010	26,874,550	22,350,460	49,225,010
ME	2,011,630	3,020,750	0	327,610	16,150,590	570	146,530	16,297,690	5,359,990	21,657,680
MA	1,782,070	936,010	5,597,860	3,730,470	30,877,740	23,670	820,360	31,721,770	12,046,410	43,768,180
NH	697,550	2,024,400	10,000,870	1,102,120	8,912,000	4,060	55,370	8,971,430	13,824,940	22,796,370
RI	95,340	0	0	0	9,667,630	142,860	0	9,810,490	95,340	9,905,830
VT	494,600	438,860	5,074,090	0	17,470	6,991	0	24,461	6,007,550	6,032,011
Total	**7,460,750**	**7,035,560**	**37,853,700**	**7,334,680**	**91,563,030**	**203,091**	**1,934,270**	**93,700,391**	**59,684,690**	**153,385,081**

Summary of Results: 2018 Low Stress Scenario, Nuclear Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation In Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
55.1	52.5	59%	8,123	41,761,644	53,610,563	-11,848,876	9,471	10,947	-1,475	3.2	10.8	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	**TOTAL RESOURCE COST**
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
576	481	77	1,155	166	366	1	-592	-57	156	**2,330**

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	**TOTAL GENERATION SVC COST + 15% PREMIUM**	**AVERAGE GENERATION SVC COST + 15% PREMIUM**	Adder for DSM Programs	RPS Cost (RECs + ACPs)	**TOTAL SYSTEM BENEFITS COST**	**AVERAGE SYSTEM BENEFITS COST**	**TOTAL COST**	**AVG COST**
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,302	366	-17	-56	15	4	76	**3,092**	**7.40**	116	366	**482**	**1.15**	**3,574**	**8.56**

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	**TOTAL GENERATION SVC COST**	**AVERAGE GENERATIO N SVC COST**	Adder for DSM Programs	RPS Cost (RECs + ACPs)	**TOTAL SYSTEM BENEFITS COST**	**AVERAGE SYSTEM BENEFITS COST**	**TOTAL COST**	**AVG COST**
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
1,807	413	**2,221**	**5.32**	116	366	**482**	**1.15**	**2,703**	**6.47**

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
18.3%	4,054

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
21,460,406	30,234,897	149,855,791	39%	80,326,898	125,901,496	609,989,983

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	13,723,283	3,347	3,555	12,068,944	15,663	5,400
ME	8,183,621	1,900	1,563	8,184,140	2,334	1,672
MA	18,197,774	23,547	8,056	18,140,888	23,506	8,038
NH	4,962,599	6,854	2,328	4,969,600	6,856	2,329
RI	4,058,853	35	701	4,082,888	67	712
VT	513,539	2	2	520,071	3	3
Total	**49,639,670**	**35,684**	**16,205**	**47,966,531**	**48,430**	**18,154**

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,367,290	614,680	2,981,970	53,610,260	41,761,644	20%	17%	3%	1,204,100	1,167,970	262,015,108
2,010,890	3,020,430	5,031,320	21,523,850	15,433,413						
1,781,760	898,140	2,679,900	42,740,918	75,047,489						
697,300	2,024,370	2,721,670	22,691,710	13,563,067						
94,980	0	94,980	9,556,170	14,311,295						
494,530	438,790	933,320	6,030,864	9,251,557						
7,446,750	**6,996,410**	**14,443,160**	**156,153,772**	**169,368,466**						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,367,290	614,680	26,864,210	2,110,550	20,767,350	27,630	858,550	21,653,530	31,956,730	53,610,260
ME	2,010,890	3,020,430	0	311,730	16,039,560	520	140,720	16,180,800	5,343,050	21,523,850
MA	1,781,760	898,140	5,597,860	3,629,910	30,016,480	20,558	796,210	30,833,248	11,907,670	42,740,918
NH	697,300	2,024,370	10,000,870	1,065,790	8,848,330	4,250	50,800	8,903,380	13,788,330	22,691,710
RI	94,980	0	0	0	9,318,880	142,310	0	9,461,190	94,980	9,556,170
VT	494,530	438,790	5,074,090	0	16,750	6,704	0	23,454	6,007,410	6,030,864
Total	**7,446,750**	**6,996,410**	**47,537,030**	**7,117,980**	**85,007,350**	**201,972**	**1,846,280**	**87,055,602**	**69,098,170**	**156,153,772**

Summary of Results: 2018 Low Stress Scenario, Coal Solution

Summary of Key Parameters in Connecticut

Load LMP ($/MWh)	Generation LMP ($/MWh)	Load Factor	Peak Load Net of DSM * 1.08 loss grossup (MW)	Total Energy Needed to Meet Customer Load (MWh)	Total Generation In Connecticut (MWh)	Net Imports (MWh)	CT LSEs' ICR (MW)	CT Internal Installed Capacity (MW)	Net Capacity Imports (negative denotes exports) (MW)	Capacity Price ($/kW-Mo)	Fast-Start Price ($/kW-Mo)	Fast-Start Requirement (MW)
55.1	52.5	59%	8,123	41,761,644	53,610,563	-11,848,876	9,471	10,947	-1,475	3.2	10.8	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT ($Mil)	Fixed O&M (FOM) ($Mil)	Variable O&M (VOM) ($Mil)	Cost of Fuel ($Mil)	Total Allowance Cost ($Mil)	RPS Cost (RECs + ACPs) ($Mil)	CT Energy Import Cost ($Mil)	CT Energy Export Cost ($Mil)	CT Capacity Import Cost (Negative Denotes Benefits) ($Mil)	Adder for DSM Programs ($Mil)	**TOTAL RESOURCE COST** ($Mil)
351	414	114	1,318	293	366	1	-592	-57	156	**2,364**

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP ($Mil)	ICR*Price ($Mil)	FTRs (Assume 75% Coverage for Internal Gen to Load) ($Mil)	Adjustment for Overcounting Losses ($Mil)	Spin ($Mil)	Uplift ($Mil)	Connecticut Fast-Start Cost ($Mil)	**TOTAL GENERATION SVC COST + 15% PREMIUM** ($Mil)	**AVERAGE GENERATION SVC COST + 15% PREMIUM** (¢/kWh)	Adder for DSM Programs ($Mil)	RPS Cost (RECs + ACPs) ($Mil)	**TOTAL SYSTEM BENEFITS COST** ($Mil)	**AVERAGE SYSTEM BENEFITS COST** (¢/kWh)	**TOTAL COST** ($Mil)	**AVG COST** (¢/kWh)
2,302	366	-17	-56	15	4	76	**3,092**	**7.40**	116	366	**482**	**1.15**	**3,574**	**8.56**

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS ($Mil)	Annualized Embedded Cost of Generators ($Mil)	**TOTAL GENERATION SVC COST** ($Mil)	**AVERAGE GENERATION SVC COST** (¢/kWh)	Adder for DSM Programs ($Mil)	RPS Cost (RECs + ACPs) ($Mil)	**TOTAL SYSTEM BENEFITS COST** ($Mil)	**AVERAGE SYSTEM BENEFITS COST** (¢/kWh)	**TOTAL COST** ($Mil)	**AVG COST** (¢/kWh)
1,842	413	**2,255**	**5.40**	116	366	**482**	**1.15**	**2,737**	**6.55**

Electric Reliability and Availability

ISO-NE Reserve Margin (%)	CT LSR Surplus (Deficit) (MW)
18.3%	4,054

Fuel Security

CT NG Demand in January and February (MMBtu)	CT NG Demand in July and August	Total CT NG Demand (MMBtu)	CT NG Share of Total CT Generation (%)	ISO-NE NG Demand in January and February (MMBtu)	ISO NG Demand in July and August	Total ISO-NE NG Demand (MMBtu)
21,460,406	30,234,897	149,855,791	39%	80,326,898	125,901,496	609,989,983

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units (Tons)	Total SOx Emissions - Monitored Units (Tons)	Total NOx Emissions - Monitored Units (Tons)	Total CO2 Emissions - All Units (Tons)	Total SOx Emissions - All Units (Tons)	Total NOx Emissions - All Units (Tons)
CT	21,856,895	3,347	3,555	20,202,556	15,663	5,400
ME	8,183,621	1,900	1,563	8,184,140	2,334	1,672
MA	18,197,774	23,547	8,056	18,140,888	23,506	8,038
NH	4,962,599	6,854	2,328	4,969,600	6,856	2,329
RI	4,058,853	35	701	4,082,888	67	712
VT	513,539	2	2	520,071	3	3
Total	**57,773,282**	**35,684**	**16,205**	**56,100,143**	**48,430**	**18,154**

RPS Summary

Biomass and Refuse Generation (MWh)	Hydro Generation (MWh)	Renewable Generation (MWh)	Total Generation (MWh)	Total Retail Sales (MWh)	Overall Renewables Requirement (%)	Class I Renewables Requirement	Class II Renewables Requirement (%)	Class I Eligible Renewable Generation (MWh)	Class II Eligible Renewable Generation (MWh)	Alternative Compliance Payments ($)
2,367,290	614,680	2,981,970	53,610,260	41,761,644	20%	17%	3%	1,204,100	1,167,970	262,015,108
2,010,890	3,020,430	5,031,320	21,523,850	15,433,413						
1,781,760	898,140	2,679,900	42,740,918	75,047,489						
697,300	2,024,370	2,721,670	22,691,710	13,563,067						
94,980	0	94,980	9,556,170	14,311,295						
494,530	438,790	933,320	6,030,864	9,251,557						
7,446,750	**6,996,410**	**14,443,160**	**156,153,772**	**169,368,466**						

Fuel Usage Summary

State	Biomass and Refuse Generation (MWh)	Hydro Generation (MWh)	Nuclear Generation (MWh)	Coal Generation (MWh)	Natural Gas Generation (MWh)	Distillate Fuel Oil Generation (MWh)	Residual Fuel Oil Generation (MWh)	Total Gas or Oil Generation (MWh)	Total NOT Gas or Oil Generation (MWh)	Total Generation (MWh)
CT	2,367,290	614,680	17,180,880	11,406,547	20,767,350	27,630	858,550	21,653,530	31,569,397	53,222,927
ME	2,010,890	3,020,430	0	311,730	16,039,560	520	140,720	16,180,800	5,343,050	21,523,850
MA	1,781,760	898,140	5,597,860	3,629,910	30,016,480	20,558	796,210	30,833,248	11,907,670	42,740,918
NH	697,300	2,024,370	10,000,870	1,065,790	8,848,330	4,250	50,800	8,903,380	13,788,330	22,691,710
RI	94,980	0	0	0	9,318,880	142,310	0	9,461,190	94,980	9,556,170
VT	494,530	438,790	5,074,090	0	16,750	6,704	0	23,454	6,007,410	6,030,864
Total	**7,446,750**	**6,996,410**	**37,853,700**	**16,413,977**	**85,007,350**	**201,972**	**1,846,280**	**87,055,602**	**68,710,837**	**155,766,439**

Summary of Results: 2030 Low Stress Scenario, Conventional Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation In Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
62.8	59.5	58%	9,196	46,957,157	57,773,738	-10,816,540	10,722	12,147	-1,424	4.2	9.8	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	**TOTAL RESOURCE COST**
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
286	428	94	1,682	406	360	11	-623	-72	156	**2,729**

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	**TOTAL GENERATION SVC COST + 15% PREMIUM**	**AVERAGE GENERATION SVC COST + 15% PREMIUM**	Adder for DSM Programs	RPS Cost (RECs + ACPs)	**TOTAL SYSTEM BENEFITS COST**	**AVERAGE SYSTEM BENEFITS COST**	**TOTAL COST**	**AVG COST**
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,950	541	-53	-55	10	12	69	**3,993**	**8.50**	116	360	**476**	**1.01**	**4,470**	**9.52**

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	**TOTAL GENERATION SVC COST**	**AVERAGE GENERATIO N SVC COST**	Adder for DSM Programs	RPS Cost (RECs + ACPs)	**TOTAL SYSTEM BENEFITS COST**	**AVERAGE SYSTEM BENEFITS COST**	**TOTAL COST**	**AVG COST**
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,213	413	**2,626**	**5.59**	116	360	**476**	**1.01**	**3,102**	**6.61**

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
18.3%	4,006

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
39,954,200	50,260,360	254,143,323	62%	128,120,277	178,164,952	866,016,581

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	18,677,299	2,104	3,766	16,972,654	9,148	4,803
ME	9,873,936	1,787	1,816	9,879,652	2,233	1,929
MA	21,834,189	19,892	7,885	21,811,928	19,824	7,867
NH	4,885,543	7,582	2,475	4,905,616	7,530	2,469
RI	5,395,732	47	932	5,397,682	49	933
VT	2,198,071	39	283	2,213,361	43	288
Total	**62,864,770**	**31,450**	**17,156**	**61,180,893**	**38,827**	**18,288**

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,521,650	617,250	3,138,900	57,773,380	46,957,157	23%	20%	3%	1,253,270	1,273,170	275,929,945
2,103,560	3,021,980	5,125,540	25,683,280	17,993,893						
1,759,740	880,530	2,640,270	52,666,730	85,671,806						
673,360	2,060,490	2,733,850	22,254,580	16,767,908						
90,240	0	90,240	12,884,470	16,261,026						
570,830	443,740	1,014,570	9,915,350	10,728,869						
7,719,380	**7,023,990**	**14,743,370**	**181,177,790**	**194,380,658**						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,521,650	617,250	17,180,600	1,392,600	35,788,210	41,630	231,440	36,061,280	21,712,100	57,773,380
ME	2,103,560	3,021,980	0	295,440	20,122,320	4,970	135,010	20,262,300	5,420,980	25,683,280
MA	1,759,740	880,530	5,597,860	3,175,160	40,797,870	29,080	426,490	41,253,440	11,413,290	52,666,730
NH	673,360	2,060,490	9,912,880	1,202,940	8,375,260	23,360	6,290	8,404,910	13,849,670	22,254,580
RI	90,240	0	0	0	12,782,700	11,530	0	12,794,230	90,240	12,884,470
VT	570,830	443,740	5,014,570	0	3,817,190	69,020	0	3,886,210	6,029,140	9,915,350
Total	**7,719,380**	**7,023,990**	**37,705,910**	**6,066,140**	**121,683,550**	**179,590**	**799,230**	**122,662,370**	**58,515,420**	**181,177,790**

Summary of Results: 2030 Low Stress Scenario, DSM-Focus Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation In Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
61.1	58.8	59%	8,489	43,837,798	57,366,012	-13,528,171	9,898	12,147	-2,249	4.6	9.4	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	**TOTAL RESOURCE COST**
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
286	428	93	1,664	403	336	2	-773	-123	232	**2,548**

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	**TOTAL GENERATION SVC COST + 15% PREMIUM**	**AVERAGE GENERATION SVC COST + 15% PREMIUM**	Adder for DSM Programs	RPS Cost (RECs + ACPs)	**TOTAL SYSTEM BENEFITS COST**	**AVERAGE SYSTEM BENEFITS COST**	**TOTAL COST**	**AVG COST**
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,680	543	-22	-51	9	11	66	**3,722**	**8.49**	172	336	**509**	**1.16**	**4,230**	**9.65**

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	**TOTAL GENERATION SVC COST**	**AVERAGE GENERATIO N SVC COST**	Adder for DSM Programs	RPS Cost (RECs + ACPs)	**TOTAL SYSTEM BENEFITS COST**	**AVERAGE SYSTEM BENEFITS COST**	**TOTAL COST**	**AVG COST**
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
1,979	413	**2,392**	**5.46**	172	336	**509**	**1.16**	**2,901**	**6.62**

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
18.2%	4,936

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
38,914,559	49,366,321	250,471,647	62%	123,619,994	173,274,656	841,651,173

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	18,523,172	2,258	3,806	16,828,588	9,554	4,866
ME	9,881,429	1,707	1,800	9,887,211	2,153	1,913
MA	21,433,419	21,041	8,069	21,417,425	21,013	8,061
NH	4,942,347	7,724	2,516	4,960,755	7,677	2,511
RI	4,712,627	41	814	4,715,806	45	815
VT	2,236,928	40	290	2,251,920	43	294
Total	**61,729,923**	**32,811**	**17,295**	**60,061,706**	**40,485**	**18,460**

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,521,660	617,470	3,139,130	57,365,720	43,837,798	23%	20%	3%	1,253,190	1,273,260	252,002,410
2,103,760	3,022,430	5,126,190	25,723,730	17,993,893						
1,759,900	915,280	2,675,180	51,420,630	85,671,806						
673,620	2,059,380	2,733,000	22,357,110	16,767,908						
90,320	0	90,320	11,174,840	16,261,026						
570,770	443,480	1,014,250	10,009,390	10,728,869						
7,720,030	**7,058,040**	**14,778,070**	**178,051,420**	**191,261,300**						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,521,660	617,470	17,180,600	1,412,530	35,294,390	26,030	313,040	35,633,460	21,732,260	57,365,720
ME	2,103,760	3,022,430	0	293,050	20,180,190	4,990	119,310	20,304,490	5,419,240	25,723,730
MA	1,759,900	915,280	5,597,860	3,372,410	39,275,940	29,240	470,000	39,775,180	11,645,450	51,420,630
NH	673,620	2,059,380	9,912,880	1,227,620	8,454,100	21,300	8,210	8,483,610	13,873,500	22,357,110
RI	90,320	0	0	0	11,065,720	18,800	0	11,084,520	90,320	11,174,840
VT	570,770	443,480	5,014,570	0	3,911,520	69,050	0	3,980,570	6,028,820	10,009,390
Total	**7,720,030**	**7,058,040**	**37,705,910**	**6,305,610**	**118,181,860**	**169,410**	**910,560**	**119,261,830**	**58,789,590**	**178,051,420**

Summary of Results: 2030 Low Stress Scenario, Nuclear Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation In Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
60.1	56.4	58%	9,196	46,957,157	62,644,881	-15,687,680	10,722	13,047	-2,324	5.3	8.7	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	**TOTAL RESOURCE COST**
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
730	542	99	1,577	354	360	0	-845	-148	156	**2,825**

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	**TOTAL GENERATION SVC COST + 15% PREMIUM**	**AVERAGE GENERATION SVC COST + 15% PREMIUM**	Adder for DSM Programs	RPS Cost (RECs + ACPs)	**TOTAL SYSTEM BENEFITS COST**	**AVERAGE SYSTEM BENEFITS COST**	**TOTAL COST**	**AVG COST**
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,820	684	-49	-68	8	18	61	**3,996**	**8.51**	116	360	**476**	**1.01**	**4,472**	**9.52**

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	**TOTAL GENERATION SVC COST**	**AVERAGE GENERATION SVC COST**	Adder for DSM Programs	RPS Cost (RECs + ACPs)	**TOTAL SYSTEM BENEFITS COST**	**AVERAGE SYSTEM BENEFITS COST**	**TOTAL COST**	**AVG COST**
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,309	413	**2,722**	**5.80**	116	360	**476**	**1.01**	**3,198**	**6.81**

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
18.3%	4,906

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
34,255,381	44,346,037	221,160,619	50%	116,883,099	166,190,997	799,941,659

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	16,469,825	1,793	3,275	14,882,923	8,159	4,230
ME	9,844,279	1,783	1,811	9,849,641	2,227	1,923
MA	20,722,736	19,299	7,564	20,709,398	19,267	7,555
NH	4,890,298	7,565	2,472	4,910,527	7,538	2,472
RI	4,575,466	40	790	4,575,466	40	790
VT	2,118,924	37	270	2,132,985	41	274
Total	**58,621,529**	**30,517**	**16,182**	**57,060,941**	**37,271**	**17,244**

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,489,300	615,340	3,104,640	62,644,580	46,957,157	23%	20%	3%	1,234,170	1,259,900	277,009,491
2,101,570	3,023,240	5,124,810	25,617,260	17,993,893						
1,758,770	869,110	2,627,880	50,069,880	85,671,806						
672,190	2,060,380	2,732,570	22,268,150	16,767,908						
89,870	0	89,870	10,863,760	16,261,026						
569,660	443,440	1,013,100	9,726,396	10,728,869						
7,681,360	**7,011,510**	**14,692,870**	**181,190,026**	**194,380,658**						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,489,300	615,340	26,863,930	1,254,450	31,187,840	39,600	194,120	31,421,560	31,223,020	62,644,580
ME	2,101,570	3,023,240	0	307,020	20,061,910	4,620	118,900	20,185,430	5,431,830	25,617,260
MA	1,758,770	869,110	5,597,860	3,066,560	38,321,320	28,740	427,520	38,777,580	11,292,300	50,069,880
NH	672,190	2,060,380	9,912,880	1,206,620	8,392,250	22,540	1,290	8,416,080	13,852,070	22,268,150
RI	89,870	0	0	0	10,773,890	0	0	10,773,890	89,870	10,863,760
VT	569,660	443,440	5,014,570	0	3,633,890	64,836	0	3,698,726	6,027,670	9,726,396
Total	**7,681,360**	**7,011,510**	**47,389,240**	**5,834,650**	**112,371,100**	**160,336**	**741,830**	**113,273,266**	**67,916,760**	**181,190,026**

Summary of Results: 2030 Low Stress Scenario, Coal Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation In Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
60.1	56.4	58%	9,196	46,957,157	62,644,881	-15,687,680	10,722	13,047	-2,324	5.3	8.7	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	**TOTAL RESOURCE COST**
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
505	475	135	1,742	574	360	0	-845	-148	156	**2,954**

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	**TOTAL GENERATION SVC COST + 15% PREMIUM**	**AVERAGE GENERATION SVC COST + 15% PREMIUM**	Adder for DSM Programs	RPS Cost (RECs + ACPs)	**TOTAL SYSTEM BENEFITS COST**	**AVERAGE SYSTEM BENEFITS COST**	**TOTAL COST**	**AVG COST**
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,820	684	-49	-68	8	18	61	**3,996**	**8.51**	116	360	**476**	**1.01**	**4,472**	**9.52**

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	**TOTAL GENERATION SVC COST**	**AVERAGE GENERATION SVC COST**	Adder for DSM Programs	RPS Cost (RECs + ACPs)	**TOTAL SYSTEM BENEFITS COST**	**AVERAGE SYSTEM BENEFITS COST**	**TOTAL COST**	**AVG COST**
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,438	413	**2,851**	**6.07**	116	360	**476**	**1.01**	**3,328**	**7.09**

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
18.3%	4,906

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
34,255,381	44,346,037	221,160,619	50%	116,883,099	166,190,997	799,941,659

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	24,603,437	1,793	3,275	23,016,536	8,159	4,230
ME	9,844,279	1,783	1,811	9,849,641	2,227	1,923
MA	20,722,736	19,299	7,564	20,709,398	19,267	7,555
NH	4,890,298	7,565	2,472	4,910,527	7,538	2,472
RI	4,575,466	40	790	4,575,466	40	790
VT	2,118,924	37	270	2,132,985	41	274
Total	**66,755,141**	**30,517**	**16,182**	**65,194,553**	**37,271**	**17,244**

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,489,300	615,340	3,104,640	62,644,580	46,957,157	23%	20%	3%	1,234,170	1,259,900	277,009,491
2,101,570	3,023,240	5,124,810	25,617,260	17,993,893						
1,758,770	869,110	2,627,880	50,069,880	85,671,806						
672,190	2,060,380	2,732,570	22,268,150	16,767,908						
89,870	0	89,870	10,863,760	16,261,026						
569,660	443,440	1,013,100	9,726,396	10,728,869						
7,681,360	**7,011,510**	**14,692,870**	**181,190,026**	**194,380,658**						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,489,300	615,340	17,180,600	10,550,447	31,187,840	39,600	194,120	31,421,560	30,835,687	62,257,247
ME	2,101,570	3,023,240	0	307,020	20,061,910	4,620	118,900	20,185,430	5,431,830	25,617,260
MA	1,758,770	869,110	5,597,860	3,066,560	38,321,320	28,740	427,520	38,777,580	11,292,300	50,069,880
NH	672,190	2,060,380	9,912,880	1,206,620	8,392,250	22,540	1,290	8,416,080	13,852,070	22,268,150
RI	89,870	0	0	0	10,773,890	0	0	10,773,890	89,870	10,863,760
VT	569,660	443,440	5,014,570	0	3,633,890	64,836	0	3,698,726	6,027,670	9,726,396
Total	**7,681,360**	**7,011,510**	**37,705,910**	**15,130,647**	**112,371,100**	**160,336**	**741,830**	**113,273,266**	**67,529,427**	**180,802,692**

APPENDIX I: SECTION 51 of PA 07-242

Sec. 51. (NEW) (*Effective from passage*) (a) The electric distribution companies, in consultation with the Connecticut Energy Advisory Board, established pursuant to section 16a-3 of the general statutes, as amended by this act, shall review the state's energy and capacity resource assessment and develop a comprehensive plan for the procurement of energy resources, including, but not limited to, conventional and renewable generating facilities, energy efficiency, load management, demand response, combined heat and power facilities, distributed generation and other emerging energy technologies to meet the projected requirements of their customers in a manner that minimizes the cost of such resources to customers over time and maximizes consumer benefits consistent with the state's environmental goals and standards.

(b) On or before January 1, 2008, and annually thereafter, the companies shall submit to the Connecticut Energy Advisory Board an assessment of (1) the energy and capacity requirements of customers for the next three, five and ten years, (2) the manner of how best to eliminate growth in electric demand, (3) how best to level electric demand in the state by reducing peak demand and shifting demand to off-peak periods, (4) the impact of current and projected environmental standards, including, but not limited to, those related to greenhouse gas emissions and the federal Clean Air Act goals and how different resources could help achieve those standards and goals, (5) energy security and economic risks associated with potential energy resources, and (6) the estimated lifetime cost and availability of potential energy resources.

(c) Resource needs shall first be met through all available energy efficiency and demand reduction resources that are cost-effective, reliable and feasible. The projected customer cost impact of any demand-side resources considered pursuant to this subsection shall be reviewed on an equitable bases with nondemand-side resources. The procurement plan shall specify (1) the total amount of energy and capacity resources needed to meet the requirements of all customers, (2) the extent to which demand-side measures, including efficiency, conservation, demand response and load management can cost-effectively meet these needs, (3) needs for generating capacity and transmission and distribution improvements, (4) how the development of such resources will reduce and stabilize the costs of electricity to consumers, and (5) the manner in which each of the proposed resources should be procured, including the optimal contract periods for various resources.

(d) The procurement plan shall consider: (1) Approaches to maximizing the impact of demand-side measures; (2) the extent to which generation needs can be met by renewable and combined heat and power facilities; (3) the optimization of the use of generation sites and generation portfolio existing within the state; (4) fuel types, diversity, availability, firmness of supply and security and environmental impacts thereof, including impacts on meeting the state's greenhouse gas emission goals; (5) reliability, peak load and energy forecasts, system contingencies and existing resource availabilities; (6) import limitations and the appropriate reliance on such imports; and (7) the impact of the procurement plan on the costs of electric customers.

(e) The board, in consultation with the regional independent system operator, shall review and approve or review, modify and approve the proposed procurement plan as submitted not later than one hundred twenty days after receipt. For calendar years 2009 and thereafter, the board shall conduct such review not later than sixty days after receipt. For the purpose of reviewing the plan, the Commissioners of Transportation and Agriculture and the chairperson of the Public

Utilities Control Authority, or their respective designees, shall not participate as members of the board. The electric distribution companies shall provide any additional information requested by the board that is relevant to the consideration of the procurement plan. In the course of conducting such review, the board shall conduct a public hearing, may retain the services of a third-party entity with experience in the area of energy procurement and may consult with the regional independent system operator. The board shall submit the reviewed procurement plan, together with a statement of any unresolved issues, to the Department of Public Utility Control. The department shall consider the procurement plan in an uncontested proceeding and shall conduct a hearing and provide an opportunity for interested parties to submit comments regarding the procurement plan. Not later than one hundred twenty days after submission of the procurement plan, the department shall approve, or modify and approve, the procurement plan. For calendar years 2009 and thereafter, the department shall approve, or modify and approve, said procurement plan not later than sixty days after submission.

(f) On or before September 30, 2009, and every two years thereafter, the Department of Public Utility Control shall report to the joint standing committees of the General Assembly having cognizance of matters relating to energy and the environment regarding goals established and progress toward implementation of the procurement plan established pursuant to this section, as well as any recommendations for the process.

(g) All electric distribution companies' costs associated with the development of the resource assessment and the development of the procurement plan shall be recoverable through the systems benefits charge.

APPENDIX J: SCOPE OF SERVICES

Subject to the joint direction from the United Illuminating Company (UI) and The Connecticut Light and Power Company (CL&P), review the State of Connecticut energy and capacity resource assessment and develop a comprehensive plan (the Plan) for the procurement of energy resources as required by Section 51 of Public Act Number 07-242 (the Act). In addition to the work proposed in Consultant's response to the Request for Proposal dated July 23, 2007 and pursuant to the Act, Consultant shall develop a Plan that includes but is not limited to the following:

1. Review the state's energy and capacity resource assessment and develop a comprehensive plan for the procurement of energy resources, including, but not limited to, conventional and renewable generating facilities, energy efficiency, load management, demand response, combined heat and power facilities, distributed generation and other emerging energy technologies to meet the projected requirements of their customers in a manner that minimizes the cost of such resources to customers over time and maximizes consumer benefits consistent with the state's environmental goals and standards.
2. Assess and provide detailed reporting on the energy and capacity requirements of customers for the next three, five and ten years; and extend the analyses and assess required/recommended resources for the timeframe required to substantially demonstrate the long term impact of various potential solutions (said timeframe shall not be less than 20 years).
3. Assess and report on the manner of how best to eliminate growth in electric demand.
4. Assess how best to level electric demand in the state by reducing peak demand and shifting demand to off-peak periods.
5. Assess and report on the impact of current and projected environmental standards, including, but not limited to, those related to greenhouse gas emissions and the federal Clean Air Act goals and how different resources could help achieve those standards and goals.
6. Assess and report on energy security and economic risks associated with potential energy resources.
7. Assess and report on the estimated lifetime cost and availability of potential energy resources.
8. Consider approaches to maximizing the impact of demand-side measures.
9. Consider the extent to which generation needs can be met by renewable and combined heat and power facilities.
10. Consider the optimization of the use of generation sites and generation portfolio existing within the state.
11. Consider fuel types, diversity, availability, firmness of supply and security and environmental impacts thereof, including impacts on meeting the state's greenhouse gas emission goals.
12. Consider reliability, peak load and energy forecasts, system contingencies and existing resource availabilities.
13. Consider import limitations and the appropriate reliance on such imports.
14. Consider the impact of the procurement plan on the costs of electric customers.
15. Resource needs shall first be met through all available energy efficiency and demand reduction resources that are cost-effective, reliable and feasible. The projected customer cost impact of any demand-side resources considered pursuant to this subsection shall be reviewed on an equitable bases with nondemand-side resources.
16. Specify the total amount of energy and capacity resources needed to meet the requirements of all customers.
17. Specify the extent to which demand-side measures, including efficiency, conservation, demand response and load management can cost-effectively meet these needs

18. Specify needs for generating capacity and transmission and distribution improvements. Note that UI and CL&P will perform some of the work and provide inputs related to the referenced distribution improvements.
19. Specify how the development of such resources will reduce and stabilize the costs of electricity to consumers.
20. Specify the manner in which each of the proposed resources should be procured, including the optimal contract periods for various resources.
21. Compare various solutions on a cost-of-service/revenue requirement basis, for all relevant future scenarios.
22. Compare various solutions based on predicted/resulting market revenues, including: wholesale Locational Marginal Pricing (LMP*), FCM, LFRM, and ancillary services; for all relevant future scenarios.

    *LMP shall mean the hourly price for energy, congestion, and marginal losses at a node.
23. Forecast resulting retail prices**, i.e. Generation Service Charge (GSC) for each proposed solution for all relevant future scenarios under both of the following regimens:
    a. Market-based pricing (non-dedicated resources, marginal based pricing).
    b. Cost of service based pricing (dedicated resources, supplied at cost).

       **Retail price (also referred to as generation service charge, GSC): full requirements load following power supply priced at the customer's meter, including but not limited to changing hourly energy requirements, capacity, operating reserves (forward pool-wide, forward local and spinning), automatic generation control, uplift charges allocated to energy market loads, ISO charges, NEPOOL charges, supplier administration costs, and the costs of managing the various risks and uncertainties attendant to serving load with retail choice.
24. Assess the relative influence of all factors on predicted outcomes.
25. Assess the robustness of various possible/proposed solutions; including but not limited to subjecting each/all solutions to multiple future conditions/scenarios, and rating the performance of the possible solutions using an agreed upon weighting of measures of merit.
26. Deliver to UI and CL&P in both detailed written and electronic form:
    a. Inputs
    b. Assumptions
    c. Outputs
    d. Modeling bases
    e. Detailed descriptions of the inputs, outputs, each model's mechanics, and the process used to integrate the various components and development of the results.
    f. Identification of likely ranges for all inputs and outputs and provide assessments of uncertainty related to the same.
    g. Basis for combinations of factors used to develop the relevant future scenarios, and an explanation of any known or suspected correlations between factors.
27. Deliver to UI and CL&P interim work products, presentations, draft reports, and final reports as specified in Exhibit B, Schedule.
28. Provide ongoing consultation, testimony, analysis, revisions, and defense of the Plan in conjunction with the CEAB submittal and review scheduled to commence on January 1, 2008.
29. Provide ongoing consultation, testimony, analysis, revisions, and defense of the Plan in conjunction with the DPUC submittal and review scheduled to commence no later than 120 days after January 1, 2008.