Integrated Resource Plan for Connecticut

January 1, 2010

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I. EXECUTIVE SUMMARY

On July 1, 2007, Connecticut Public Act No. 07-242 (Act) became effective and 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 The Connecticut Light & Power Company (CL&P) and The United Illuminating Company (UI) (together referred to herein as the Electric Distribution Companies, Companies, or EDCs) to submit a joint comprehensive resource plan to the Connecticut Energy Advisory Board (CEAB) by January 1, 2008 and each January 1st thereafter. Public Act No. 09-218, which became effective on July 8, 2009, changed the EDC plan submittal to a biennial requirement.

Prior to enactment of the Act, 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, emissions, or other important objectives. Section 51 establishes a process for the EDCs and the CEAB to develop Integrated Resource Plans (IRPs) to "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."[1] Section 51 of the Act, now codified as Section 16a-3a of the Connecticut General Statutes, is included in its entirety in the Appendix.

In accordance with the legislation, the EDCs prepared and submitted IRPs to the CEAB in 2008 and 2009. This 2010 IRP builds upon the 2008 and 2009 IRPs. As stated by the Connecticut Department of Public Utility Control (DPUC) in its September 30, 2009 decision concerning the 2009 IRP in Docket No. 09-05-02: "The 2010 IRP filings will develop a more comprehensive planning document and will provide a quantification or ranking of procurement options that will be useful when the need for new resources occurs. The Department views the 2009 IRP docket as a transitional proceeding and looks forward to developing a more comprehensive IRP proceeding in the next proceeding in 2010." The 2010 IRP represents the comprehensive planning document contemplated by the DPUC.

This IRP presents how Connecticut customers' needs for capacity and energy, as well as State Renewable Portfolio Standard (RPS) requirements can be met while minimizing costs and emissions. The foundation for this IRP is comprised of (i) ten subject-area whitepapers (Section III), and (ii) a detailed ten year analysis (Section II), starting with a Base Case outlook. Alternative scenarios are simulated to analyze the effects of gas prices, CO_2 allowance prices, and load growth. Finally, various resource strategies are analyzed against all scenarios. Resource strategies are evaluated based on their effects on customer costs and emissions.

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[1] Section 51(a).

This IRP is, once again, the result of a collaborative process involving the Companies and *The Brattle Group*, with input and information received via discussions with the CEAB and stakeholders. Under the guidance of the Companies, *The Brattle Group* provided independent expertise and judgment regarding the scope and framework for the analysis, constructed the scenarios, established the myriad of assumptions used in the modeling effort, and performed all the related analyses. The Companies provided guidance, direction and subject matter expertise, 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.

The EDCs engaged in a collaborative process with the CEAB beginning in April 2009. The objective was to develop a common understanding of the approach and process which would be utilized to develop the 2010 IRP. In the Spring and early Summer of 2009, prior to commencing the 2010 IRP analysis, the EDCs participated in several scoping and visioning meetings with the CEAB IRP Subcommittee. The input that the EDCs received during these meetings was incorporated into the 2010 IRP.

Input was also solicited from and received by the following groups of stakeholders:

- CT DEP. Numerous meetings were held with the Connecticut Department of Environmental Protection (DEP) to discuss future emissions levels based on current generator emissions rates as well as the latest load forecasts and resource projections. These factors were modeled to help the DEP determine future allowable emissions rates which might be required to meet environmental objectives in the future. The conclusion of this process determined the assumed timing for setting lower NO_X emission rate limits, which formed the basis for the analysis of likely plant investments and retirements, as described in Section III.1.
- CCEF. The EDCs held meetings with the Connecticut Clean Energy Fund (CCEF) to discuss and receive feedback concerning the intended approach and base assumptions to be used for the evaluation of renewable energy strategies.
- ISO-NE. Early in the process the EDCs met with New England Independent System Operator (ISO New England Inc. or ISO-NE) load forecasting personnel to verify and refine their understanding of the effects of DSM and load control programs taken into account in ISO-NE's long range peak and energy forecasts.
- Generators. The EDCs surveyed the Connecticut generators to verify and clarify generator characteristics, retirement, and repowering plans and intentions concerning the use of existing sites.
- Multiple Stakeholders. The DPUC held a technical meeting on transmission and the CEAB subsequently held a series of related public stakeholder meetings.[2] The stakeholder meetings, in which industry stakeholders, the EDCs, and the public were participants, were conducted on the topics of Connecticut generation, renewable energy, energy security, environmental policy, natural gas, DSM, and nuclear energy.

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[2] Filings made with the DPUC in connection with the technical meeting can be found on the DPUC's website.

PRIMARY FINDINGS

The analysis and research conducted by the EDCs and *The Brattle Group* has resulted in seven primary findings that will heavily impact resource procurement strategies over the next 10 years.

1. Assuming the New England states are successful in building enough new renewable generation and associated transmission to meet RPS requirements, there should be no need for any additional generating resources for resource adequacy purposes over the next ten years under a wide range of demand uncertainty.

2. Predicated on reasonable assumptions regarding supply and demand and transmission, Connecticut has sufficient generation installed or under contract to assure locational resource adequacy requirements for reliability over the next 10 years, even if significant uneconomic, high-emissions generating plants retire.

3. Due primarily to the effects of RPS and climate legislation, power supply-related costs are expected to increase from 11¢/kWh today and in 2013 to nearly 14¢/kWh in 2020 (in 2010 dollars) under expected supply and demand and moderate fuel and emissions costs.

4. A targeted expansion of DSM programs beyond those currently planned can lead to significant reductions in emissions and costs. It is anticipated that the additional program costs would be more than offset by a reduction in generation service costs and rates.

5. For New England to meet each respective state's 2020 Class 1 renewable portfolio requirements, New England needs to add about 4,800 MW (nameplate) of new renewable generation, primarily wind, that will be located in areas distant from load centers that would require investments of approximately $20 billion in new renewable generation and about $10 billion of investment in transmission resources to access this new renewable generation.

6. Assuming the Class 1 renewable generation buildout and continuation of the Connecticut DSM measures, New England's CO_2 emissions, NO_X emissions, and SO_2 emissions in 2020 will be substantially below 2007 actual levels.

7. New England electric energy prices are highly dependent on the price of natural gas. It is expected that the large supply of economically recoverable shale gas, which can be found as close to New England as New York and Pennsylvania, may allow natural gas prices to remain moderate and may thereby help to moderate energy prices.

RECOMMENDATIONS

The comprehensive analysis undertaken in the development of the 2010 IRP has led to two primary resource procurement recommendations that should be implemented immediately, and a third regarding additional study. There are additional recommendations in some of the white papers that do not relate to the near-term procurement of resources.

1. Given that the Targeted DSM Expansion strategy would reduce customer costs and emissions while even reducing rates for non-participants, the Companies recommend that this strategy be funded.

2. Connecticut policy makers need to engage with other New England states to develop a comprehensive regional renewable energy policy. The New England states should work to define the best and most cost-effective means to expand renewable energy development in New England and the surrounding regions while meeting environmental goals.

3. UI recommends, in light of the potential benefits of a nuclear strategy identified in the analysis, that the CEAB conduct, sponsor, or otherwise support a more detailed study of the potential costs and benefits of nuclear power, with the objective of providing a more complete picture of the tradeoffs encountered with nuclear power as a long-term resource strategy for Connecticut.

ANALYTICAL FINDINGS

The following analytical findings were developed for a Reference resource strategy using market simulations for the years 2013, 2015, and 2020. The Reference strategy continues current levels of DSM programs and supports regional development of renewables (primarily wind) sufficient to meet RPS requirements.

1. Predicated on reasonable assumptions regarding supply and demand and transmission, Connecticut has sufficient resources installed or under contract to meet locational resource adequacy requirements over the next 10 years, even if a substantial amount of uneconomic, high-emitting generation retires.

2. Assuming the New England states are successful in building enough new renewable generation and associated transmission to meet the regions' RPS requirements, there should be no need for any additional generating resources for meeting regional resource adequacy requirements over the next ten years under a wide range of demand uncertainty.

3. Renewable portfolio standards for the six New England states will require the development of about 4,800 MW of new Class 1 renewable generation, amounting to nearly 16 percent of total energy generation by 2020. If wind provides most of that additional generation, as assumed in the Base Case, it will diversify and change the dispatch of generating resources in New England, and it will substantially reduce CO_2 emissions, NO_X emissions, and SO_2 emissions.

4. Likely federal climate change legislation will further reduce CO_2 emissions in New England by decreasing the generation output from coal-fired plants and replacing it with gas-fired plants. Combined with the effect of assumed Class 1 renewables, climate legislation will likely help reduce New England's overall CO_2 emissions in 2020 by about 11.5 million tons, or 24 percent, relative to 2007 actual emissions.

5. Due primarily to the effects of RPS and climate legislation, power supply-related costs are expected to increase from 11¢/kWh today and in 2013 to nearly 14¢/kWh in 2020 (in 2010 dollars) under expected supply and demand and moderate fuel and emissions costs. Power supply-related costs are highly uncertain, driven primarily by uncertainty in natural gas prices, which could affect rates in 2020 by as much as 3.5¢/kWh between the low and high gas price projections analyzed.

6. In 2020, the annual NO_X and SO_2 emissions from power generation in Connecticut are expected to decrease by approximately 50 percent and 60 percent, respectively, from 2007 levels. This is due to the effects of strengthened environmental regulation and the regional buildout of renewable generation.

The analytical findings presented below compare five alternative resource strategies to the Reference strategy for the year 2020. That study year was chosen because the impact of resource development strategies would be implemented over a ten-year timeframe, with the differences among strategies being most pronounced at the end of that period.

The six resource strategies examined include the *Reference* strategy, which continues current levels of DSM programs and supports regional development of renewables (primarily wind) sufficient to meet RPS requirements. The *Targeted DSM Expansion* strategy focuses on four high-potential energy efficiency initiatives, while the *All Achievable Cost-Effective DSM* strategy incorporates all achievable efficiency programs that were identified in a recent "Potential" study as having benefits in excess of costs. In the *Limited Renewables* strategy, not enough renewables are developed to comply fully with RPS mandates, and EDCs must resort to making alternative compliance payments. In the *In-State Renewables* strategy, Connecticut's RPS requirements are met through the development of in-state fuel cells and photovoltaics instead of regional (mostly wind) resources. The *Efficient Gas Expansion* strategy involves developing combined cycle capacity in Connecticut, in advance of a reliability-based need for generating capacity.[3]

7. **Targeted DSM Expansion**: This strategy reduces total customer costs and CO_2 and NO_X emissions in all 5 scenarios tested, and slightly reduces average power supply-related costs in all but one scenario. Funding this strategy through the system benefit charge (SBC) would require increasing the SBC rate from 3 mills to 3.7 mills, but based on the 2020 analysis, reduced generation service charge (GSC) costs and rates would more than offset the increase. The annual benefits by 2020 reflect the cumulative impact of ten years of additional DSM program costs for customers, totaling approximately $200 million.

8. **All-Achievable Cost Effective DSM**: This strategy also reduces total customer costs and CO_2 and NO_X emissions in all 5 scenarios, but it raises average costs per kWh consumed. The SBC rate would increase to 5.6 mills, and our 2020 analysis indicates that the GSC

[3] A seventh resource strategy for nuclear energy was also developed, but is not discussed in this section because it would not be possible to develop and construct a new nuclear plant in Connecticut in the 10-year scope of this report. However, the nuclear strategy is useful for illustrative reasons and is detailed in Section III.5 (Nuclear Energy).

rate impacts would not fully offset the SBC rate increase. Hence, costs for non-participants would increase while costs for participants would decrease (by a larger amount). The annual benefits by 2020 reflect the cumulative impact of ten years of additional DSM program costs for customers, totaling approximately $650 million.

9. **Limited Renewables**: As a result of the inability to meet each state's RPS requirement, Connecticut customers pay more than $300 million per year in alternative compliance payments (ACP) in 2020. New England's CO_2 emissions would be about 6 million tons (16 percent) higher. Because this strategy avoids having to support new renewable generation and its corresponding transmission resources, overall customer costs could be slightly lower under some conditions. The analysis indicates that the cost for customers could vary significantly depending upon the scenario.

10. **In-State Renewables**: Under this strategy, Connecticut would build almost 700 MW of fuel cells, more than 200 MW of solar photovoltaics, and about 100 MW of biomass to meet the State's RPS primarily using in-state resources. The cost of this in-state generation is higher than a New England regional buildout of renewable generation and associated transmission. It also leads to nearly 30 percent higher CO_2 emissions in Connecticut.

11. **Efficient Gas Expansion**: This strategy was studied in order to address the requirement in Public Act 07-242 to examine the optimization of existing generating sites and generation portfolio. In order to meet this requirement, the EDCs examined the effects of adding 1,100 MW of hypothetical combined-cycle capacity in Connecticut (installed cost of $906/kW in 2010 dollars; full load heat rate of 7000 Btu/kWh) during the last year of the study, 2020 (even though this was in advance of need).

SUMMARY OF FINDINGS CONTAINED IN THE WHITEPAPERS

1. Resource Adequacy

- There will likely be a substantial surplus relative to Connecticut's local resource requirements through 2020, due to a lower load forecast than utilized in prior IRPs, planned generation additions in Connecticut, planned DSM, and increased Connecticut import capability, even after accounting for forecasted retirements (which are substantial). Given this, Connecticut's access to adequate resources depends on resource adequacy in New England as a whole.

- A capacity surplus is expected in New England through at least 2015, and likely through 2020. This region-wide surplus is due to a lower load forecast than in prior IRPs, the likely addition of renewable generation to meet RPS requirements, planned DSM, and planned generation additions in Connecticut even after accounting for forecasted retirements (which are substantial). Some combinations of strategies and scenarios may lead to a need for additional resources after 2015 in cases that involve higher load, lower renewable additions, and/or higher retirements.

- The prospect of capacity surpluses and consequently low capacity prices, combined with tighter environmental requirements, is likely to induce the retirement of substantial amounts of old, high emission, oil-fired steam units. Retirements are estimated at 2,446 MW in New England in the Base Case (1,504 MW in Connecticut). There is substantial uncertainty around these estimates; retirements could exceed 4,000 MW under market conditions that induce earlier new entry and reduced capacity prices.

2. Demand-Side Management (DSM)

- Although Connecticut is a leader in DSM, with established programs and demonstrated results, there is much unrealized, cost-effective, emissions-reducing potential remaining.
- The Targeted DSM Expansion Strategy meets the criteria established by the DPUC in its decision in Docket No. 08-07-01 for procurement absent an immediate reliability need by reducing total customer costs and CO_2 and NO_X emissions in all 5 scenarios tested, and by slightly reducing rates in all but one scenario. Funding this strategy through the system benefit charge (SBC) would require increasing the SBC rate from 3 mills to 3.7 mills, but based on the 2020 analysis, reduced generation service charge (GSC) costs and rates would more than offset the increase.
- The All-Achievable Cost Effective DSM Strategy also meets the criteria set forth in the Docket No. 08-07-01 decision; but while it reduces total customer costs and CO_2 and NO_X emissions in all 5 scenarios, it also raise average rates per kWh consumed. The SBC rate would increase to 5.6 mills, and the 2020 analysis indicates that the GSC rate impacts would not fully offset the SBC rate increase. Hence, costs for non-participants would increase while costs for participants would decrease (by a larger amount).
- In summary, funding the Targeted DSM Expansion strategy would require an additional outlay of approximately $19 million per year (2010 dollars), and the All Cost-Effective DSM Strategy would require an outlay of approximately $65 million per year through 2020. Although both strategies would create cost savings in excess of the program costs (thus providing emissions reductions at a *negative* net cost), only the Targeted DSM strategy would result in lower rates for non-participants over time.
- Codes and standards are critical components of public policy complementing utility DSM programs, but they are not a substitute for such programs and do not effectively address existing structures.

3. Renewable Energy

- The optimal strategy for meeting the State's RPS requirement is to procure renewable energy as part of a New England regional market.
- Renewable potential in New England is substantially larger than needed to meet RPS.
- Connecticut has limited cost-effective renewable potential in-state.

- The RPS requirements of the New England states are likely to be met through 2012. There is significant uncertainty regarding the overall supply and demand balance and the likely REC prices beyond 2012.
- Substantial transmission investment will be needed to connect sufficient renewables to meet regional RPS requirements. The cost of such transmission is likely to be large, but much less than the cost of building renewables in-state, and not significantly larger than the cost of failing to meet the RPS entirely.
- An in-state renewable strategy would rely heavily on natural gas powered fuel cells, and would not significantly abate CO_2 emissions.
- Based on current cost and price projections, landfill gas, biomass, small hydro, and onshore wind require REC prices that are below the Connecticut's ACP. However, fuel cells, offshore wind, and solar PV would require payments greater than the ACP and would require support from additional subsidies or out-of-market instruments to be developed.
- Investing in new renewable generation provides significant environmental benefits to New England.
- Constructing sufficient new renewable generation in New England would require a major capital investment, in the range of about $20 billion for the generation plus about $10 billion for associated transmission by 2020. Much of the capital investment in generation would be paid for by revenues from the energy and capacity markets, but REC payments and out-of-market payments would also be required for some resources.
- Connecticut policy makers need to engage with other New England states to develop a comprehensive regional renewable energy policy. The New England states should work to define the best and most cost-effective means to expand renewable energy development in New England and the surrounding regions while meeting environmental goals.

4. Transmission

- The EDCs have proposed a process that will provide an efficient and effective means of considering alternatives to transmission upgrades by integrating Connecticut state processes and statutes with the region-wide open and transparent planning process administered by ISO New England.
- Connecticut state agencies (*e.g.*, DPUC, CEAB, OCC) will benefit from early warning of upcoming major transmission projects and have an opportunity to influence outcomes by monitoring the Regional System Plan and the multiple ongoing Connecticut-related transmission studies and participating in regional processes (as appropriate).

5. Nuclear Power

- Nuclear generation has significant environmental benefits, including displacing fossil generation and associated greenhouse gases, while making Connecticut less reliant on natural gas generation.
- Nuclear capacity expansion is a long-term prospect – 10 to 15 years from the start of preparing a license application to commercial online date.
- New merchant nuclear capacity is unlikely to be developed in New England without a cost recovery approach that can mitigate the risks of high and uncertain capital costs, long lead time, and the potential for costly delay.

6. Combined Heat and Power (CHP)

- Connecticut already enjoys high penetration of CHP for the most attractive large industrial applications, so there is limited remaining potential in this sector.
- Smaller, mostly commercial and institutional applications have significant remaining technical potential in Connecticut.

7. Environmental Regulations Affecting Electricity

- While there is uncertainty regarding future Federal climate legislation, the prospects appear likely enough for a range of CO_2 prices to be reflected in our analysis.
- Because Connecticut and other parts of New England are not in attainment with air quality standards, additional NO_X control requirements will likely be imposed on generators. The EDCs and CTDEP worked together to establish likely future NO_X emission requirements which were reflected in the simulation of the New England electricity market. The cost of these controls is projected to cause retirements of older fossil steam units in our analysis.
- Emission allowance prices – for SO_2, NO_X and CO_2 – will raise the costs of generation in proportion to unit emission rates, and will impact the dispatch of resources in New England and thereby reduce overall emissions. Although the prices of allowances for each pollutant are determined by aggregate emissions relative to an emission cap, these markets are not wholly independent. In particular, the price of CO_2 allowances can influence the price of SO_2 and NO_X allowances, an effect that was reflected in the analysis.
- The imposition of new regulations for other environmental sectors (not air) have the potential to introduce greater costs to generators, though the potential impact of these costs cannot be determined at this time and thus were not reflected in the analysis.

8. Energy Security

- The power system is planned, designed, and operated to maintain high energy security, building in spare capacity, redundancy, and operational flexibility. A number of organizations at the national, regional, and state levels oversee and enforce reliability.

- Key resources for energy security include natural gas and nuclear generation, because of the system's heavy reliance on these generation types and the risks that could affect their operability, as well as the electric transmission system. Other resources – oil, coal, renewables – are unlikely to pose energy security concerns of comparable magnitude, due to the smaller role these resources play in providing power, and also because of a lack of exposure to significant risks.
- Natural Gas: The New England power system's reliance on natural gas was stress-tested by analyzing the loss of access to natural gas for several days during the winter months. This analysis suggests that there would be adequate other generation resources available to serve winter load, with no or virtually no reliance on natural gas. This is due to several seasonal factors that improve the winter resource balance, plus dual fuel capability that allows many gas-fired generators to utilize oil if gas is not available.
- Nuclear: A prolonged, simultaneous shutdown of multiple nuclear units at peak load times could stress the system's ability to serve load. However, it appears that even with the loss of both Connecticut nuclear units, the implementation of existing emergency operating procedures and additional reliance on imports from neighboring regions would allow the system to continue to serve load.
- Transmission: The electric transmission system is designed and operated with a level of redundancy that allows it to absorb isolated failures with no impact on customers. If an extreme event were to cause a more widespread transmission failure, the transmission owners' recovery capabilities and procedures ensure that any service interruption would be brief.

9. Natural Gas

- The overall supply picture for domestic natural gas appears promising, due particularly to the advent of new unconventional gas supplies such as shale gas. This expanding supply should be adequate to accommodate even increased gas demand, though the ultimate extent and pace of the new supplies coming online is not certain.
- Pipeline and LNG delivery capacity to New England have increased over the past several years, with additional new expansion projects still in development for the near future. Gas delivery capacity to serve average and peak needs has improved measurably from a few years ago (though this does not address gas local distribution company (LDC) deliverability issues, where additional expansions may be necessary).
- LNG and Canadian conventional gas may be less important for augmenting New England gas supplies than was expected in the recent past, due to the advent of new domestic supplies at lower prices. They will nonetheless continue to serve as a backstop for the availability and price of domestic gas supplies. Regardless of whether it actually does substitute for domestic gas more widely, LNG will remain a

crucial component of New England's ability to meet peak gas demands in the winter heating season.

- Natural gas prices are expected to remain reasonable at around $7.00/MMBtu (real dollars) in the long term, driven largely by new unconventional supply sources. However there is no certainty that these current price expectations will be fulfilled; a long-term gas price range of approximately $4-10/MMBtu was examined in this study. Regardless of what happens to the long-term price of gas, short-term gas prices can be volatile.

10. Emerging Technologies

- Because of the growing commitments to plug-in electric vehicle (PEV) manufacturing and charging infrastructure on the part of vehicle manufacturers and electric utilities, PEVs appear poised to achieve an uncertain but potentially significant fleet penetration over the next decade.
- A 5 percent level of fleet penetration by 2020 represents an optimistic view of PEV vehicle sales over the next decade, but one that is worth exploring for its potential impact on the New England electricity system.
- Even an optimistic view of PEV penetration in New England over the next two decades is unlikely to pose any unmanageable issues for maintaining reliable electric service.
- An optimistic view of PEV penetration in New England is likely to produce a modest environmental benefit, with net CO_2 and NO_X emissions decreasing and only a negligible increase in SO_2 emissions.
- Widespread implementation of advanced metering infrastructure (AMI) has the potential to decrease peak loads. The magnitude of the decrease will depend on customer participation rates in dynamic pricing programs and their responsiveness to near-term price signals.
- Enabling technologies can help customers respond more effectively to price signals, and AMI programs that encourage these technologies are more likely to yield more pronounced responses.

Section II
Analytical Findings

II. ANALYTICAL FINDINGS

A. SUMMARY AND FINDINGS

This Section (II) of the report presents the findings and recommendations resulting from the analyses conducted in accordance with the Act. In short, it informs how Connecticut customers' needs for capacity and energy, and their required compliance with the state's Renewable Portfolio Standard (RPS), can be met while minimizing costs and emissions. Section II.B presents a Base Case ten-year outlook. Section II.C addresses how the outlook changes under alternative scenarios regarding the key variables of gas prices, CO_2 allowance prices, and load growth. Section II.D compares the effectiveness of six resource strategies in reducing customer costs and emissions while still providing adequate capacity, energy, and renewables.

The six resource strategies examined include a Reference strategy that continues current levels of DSM programs and supports regional development of renewables (primarily wind) sufficient to meet RPS requirements. The Targeted DSM Expansion strategy focuses on four high-potential energy efficiency initiatives, while the All Achievable Cost-Effective DSM strategy incorporates all achievable efficiency programs that were identified in a recent "Potential" study as having benefits in excess of costs. In the Limited Renewables strategy, not enough renewables are developed to comply fully with RPS mandates, and EDCs must resort to making alternative compliance payments. In the In-State Renewables strategy, Connecticut's RPS requirements are met through the development of in-state fuel cells and photovoltaics instead of regional (mostly wind) resources. The Efficient Gas Expansion strategy involves developing combined cycle capacity in Connecticut, in advance of a reliability-based need for generating capacity.[1]

The resource strategies are evaluated across scenarios using market simulations for year 2020. That study year was chosen because the strategies would be implemented over a ten-year timeframe, with the differences among strategies being most pronounced at the end of that period.

The key findings from the Ten-Year Outlook can be summarized as follows:

- Predicated on reasonable assumptions regarding supply and demand and transmission, Connecticut has sufficient resources installed or under contract to meet locational resource adequacy requirements over the next 10 years, even if a substantial amount of uneconomic, high-emitting generation retires.

- Assuming the New England states are successful in building enough new renewable generation and associated transmission to meet the regions' RPS requirements, there

[1] A seventh resource strategy for nuclear energy was also developed, but is not discussed in this section because it would not be possible to develop and construct a new nuclear plant in Connecticut in the 10-year scope of this report. However, the nuclear strategy is useful for illustrative reasons and is detailed in Section III.5 (Nuclear Energy).

should be no need for any additional generating resources for meeting regional resource adequacy requirements over the next ten years under a wide range of demand uncertainty.

- Renewable portfolio standards for the six New England states will require the development of about 4,800 MW of new Class 1 renewable generation, amounting to nearly 16 percent of total energy generation by 2020. If wind provides most of that additional generation, as assumed in the Base Case, it will diversify and change the dispatch of generating resources in New England, and it will substantially reduce CO_2 emissions, NO_X emissions, and SO_2 emissions.

- Likely federal climate change legislation will further reduce CO_2 emissions in New England by decreasing the generation output from coal-fired plants and replacing it with gas-fired plants. Combined with the effect of assumed Class 1 renewables, climate legislation will likely help reduce New England's overall CO_2 emissions in 2020 by about 11.5 million tons, or 24 percent, relative to 2007 actual emissions.

- Due to RPS and, to a lesser extent, climate legislation, power supply-related costs are expected to increase from 11¢/kWh today and in 2013 to nearly 14¢/kWh in 2020 (in 2010 dollars) under expected supply and demand and moderate fuel and emissions costs. Power supply-related costs are highly uncertain, driven primarily by uncertainty in natural gas prices, which could affect rates in 2020 by as much as 3.5¢/kWh between the low and high gas price projections analyzed.

- In 2020, the annual NO_X and SO_2 emissions from power generation in Connecticut are expected to decrease by approximately 50 percent and 60 percent, respectively, from 2007 levels. This is due to the effects of strengthened environmental regulation and the regional buildout of renewable generation.

The key findings from our evaluation of alternative resource strategies (relative to the Reference resource strategy) can be summarized as follows:

- **Targeted DSM Expansion**: This strategy reduces total customer costs and CO_2 and NO_X emissions in all 5 scenarios tested, and slightly reduces average power supply-related costs in all but one scenario. Funding this strategy through the system benefit charge (SBC) would require increasing the SBC rate from 3 mills to 3.7 mills, but based on the 2020 analysis, reduced generation service charge (GSC) costs and rates would more than offset the increase. The annual benefits by 2020 reflect the cumulative impact of ten years of additional DSM program costs for customers, totaling approximately $200 million.

- **All-Achievable Cost Effective DSM**: This strategy also reduces total customer costs and CO_2 and NO_X emissions in all 5 scenarios, but it raises average costs per kWh consumed. The SBC rate would increase to 5.6 mills, and our 2020 analysis indicates that the GSC rate impacts would not fully offset the SBC rate increase. Hence, costs for non-participants would increase while costs for participants would decrease (by a larger amount). The annual benefits by 2020 reflect the cumulative impact of ten years of additional DSM program costs for customers, totaling approximately $650 million.

- **Limited Renewables**: As a result of the inability to meet each state's RPS requirement, Connecticut customers pay more than $300 million per year in alternative compliance payments (ACP) in 2020. New England's CO_2 emissions would be about 6 million tons (16 percent) higher. Because this strategy avoids having to support new renewable generation and its corresponding transmission resources, overall customer costs could be slightly lower under some conditions. The analysis indicates that the cost for customers could vary significantly depending upon the scenario.

- **In-State Renewables**: Under this strategy, Connecticut would build almost 700 MW of fuel cells, more than 200 MW of solar photovoltaics, and about 100 MW of biomass to meet the State's RPS primarily using in-state resources. The cost of this in-state generation is higher than a New England regional buildout of renewable generation and associated transmission. It also leads to nearly 30 percent higher CO_2 emissions in Connecticut.

- **Efficient Gas Expansion**: This strategy was studied in order to address the requirement in Public Act 07-242 that optimization of existing generating sites and generation portfolio be explored. In order to meet this requirement, the EDCs examined the effects of adding 1,100 MW of hypothetical combined-cycle capacity in Connecticut (installed cost of $906/kW in 2010 dollars; full load heat rate of 7,000 Btu/kWh) during the last year of the study, 2020 (even though this was in advance of need).

B. BASE CASE TEN-YEAR OUTLOOK

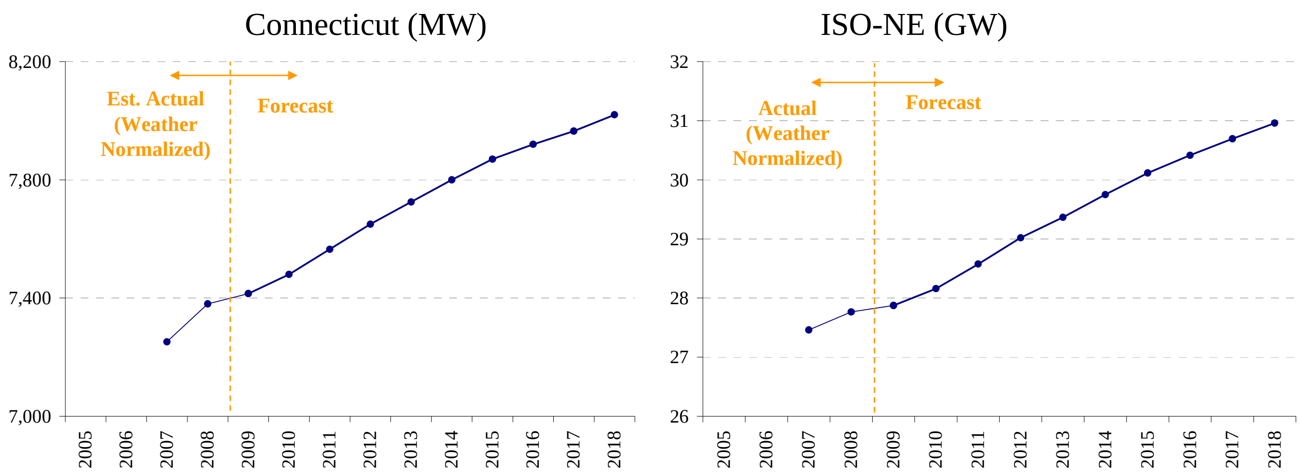
B.1 Supply and Demand for Capacity

As shown in Section III.1 (Resource Adequacy), the supply of capacity over the next ten years is projected to be substantially greater than needed to meet resource adequacy requirements in ISO-NE and in the Connecticut sub-area. The surplus is attributable to a confluence of factors: a forecasted slow recovery of today's depressed demand (due in part to the current economic recession and in part because of continued utility energy efficiency programs and new codes and standards); planned new generation and likely additional generation to meet RPS; and new transmission into Connecticut. However, some of the surplus is likely to be offset by the retirement of existing oil-fired steam units. Assuming the Connecticut Department of Environmental Protection (CT DEP) imposes strict NO_X emissions rate limits, and the ISO-NE abolishes the capacity price floor, we estimate that 2,446 MW of oil-fired steam generation (including 1,504 MW in Connecticut) is likely to retire by 2017. This would advance the need for new capacity in New England from 2029 to 2021. It is unlikely that new capacity will need to be located within Connecticut until well beyond 2020, unless retirements within Connecticut are much higher than anticipated.

Peak Load

Forecasted peak load in ISO-NE and Connecticut are well below prior years' forecasts due to the recession. Over the next ten years, ISO-NE peak load is expected to grow at an annual average rate of 340 MW (1 percent) per year. This forecast is from ISO-NE's 2009 "Capacity, Energy, Load, and Transmission" (CELT) report, as described in Section III.1 (Resource Adequacy).

Figure 1
Peak Load – Historical and Forecast



***Note*: Historic values in 2007 and 2008 are from the ISO-NE; 2009 through 2018 values are from ISO-NE's 2009 CELT report.

New Supply and Retirements

Total supply to meet Connecticut and ISO resource needs include:

- 31,286 MW existing generating resources in ISO-NE as of January 1, 2009, based on values reported in the 2009 CELT;
- 716 MW new capacity contracted under the DPUC Public Act 05-01: Kleen Energy Systems (620 MW combined cycle) and Waterbury Generation (96 MW gas turbine);
- 504 MW planned new capacity contracted under Connecticut's peaking generation contracts;
- 306 MW additional capacity with obligations in the ISO's capacity market;
- 1,552 MW (derated) new renewable capacity expected to be built to meet region-wide Renewable Portfolio Standards, including capacity contracted under Connecticut's "Project 150" RFP;
- Insignificant firm imports by 2020, based on values reported in the 2009 CELT;
- 1,876 MW active demand response (DR) ISO-wide, including that cleared in the ISO-NE's most recent forward capacity auction for 2013/14 (1,794 MW) and a small amount

of price responsive demand (81 MW), both assumed to be constant from 2013 to 2020; and

- 1,160 MW of energy efficiency in 2013 (based primarily the forward capacity auction results), increasing to 1,492 MW in 2020, with the increase reflecting only Connecticut's planned DSM programs.

We estimate 2,446 MW of retirements by 2020 ISO-wide based on economics and expected environmental control requirements. As explained in Section III.7 (Environmental Regulations Affecting Electricity), collaboration with the CT DEP established an assumption that all gas and oil-fired steam units would be required to meet region-wide NO_X emission rate limits of 0.125 lbs/MMBtu by 2013 and 0.07 lbs/MMBtu by 2017 to facilitate region-wide attainment of Federal National Ambient Air Quality Standards (NAAQS), including Connecticut compliance under the Clean Air Interstate Rule (CAIR). Non-compliant units with NO_X emission rates of 0.25 lbs/MMBtu or below are assumed to be able to meet the 2013 limit with temporary measures at relatively little cost, but must install selective catalytic reduction (SCR) to meet the 2017 emission rate limit. It was further assumed that all other non-compliant units would be required to install SCRs to meet the 2013 and 2017 emission rate limits, or else retire. We determined which units were likely to invest in controls versus retire by assuming each unit would make an NPV-maximizing decision given its costs (potentially mitigated by mothballing opportunities) and its expected energy and capacity revenues. These decisions are solved iteratively with multi-year capacity price trajectories and entry decisions until the capacity market clears in every year.

Resource Adequacy

The primary starting point for any resource plan is a projection of available resources relative to resource adequacy requirements. Shortfalls indicate the need for additional resources. ISO-NE defines four separate resource adequacy requirements affecting Connecticut: the ISO-NE-wide Net Installed Capacity Requirement (NICR), the Connecticut Local Sourcing Requirement (CT LSR), the Connecticut requirement under the Transmission Security Analysis (CT TSA), and the Connecticut requirement in the Locational Forward Reserve Market (LFRM). All of these requirements are likely to be met – with surplus capacity – through 2020 and beyond, as described in Section III.1. Figure 2 shows resource adequacy projections for meeting the ISO-NE-wide NICR; Figure 3 shows resource adequacy projections for meeting the CT LSR and TSA requirements. Both figures show supply as colored bars that exceed the resource adequacy requirements, which are indicated with dash lines. An important element of Figure 3 is the inclusion of the New England East-West Solution (NEEWS), a transmission project planned to be in service by 2014. NEEWS will support Locational Resource Adequacy in Connecticut both by increasing the Connecticut Import capability by 1,100 MW and by incorporating the Lake Road generating facility into the Connecticut sub-area.

Figure 2
Resource Adequacy in ISO-NE (Base Case)

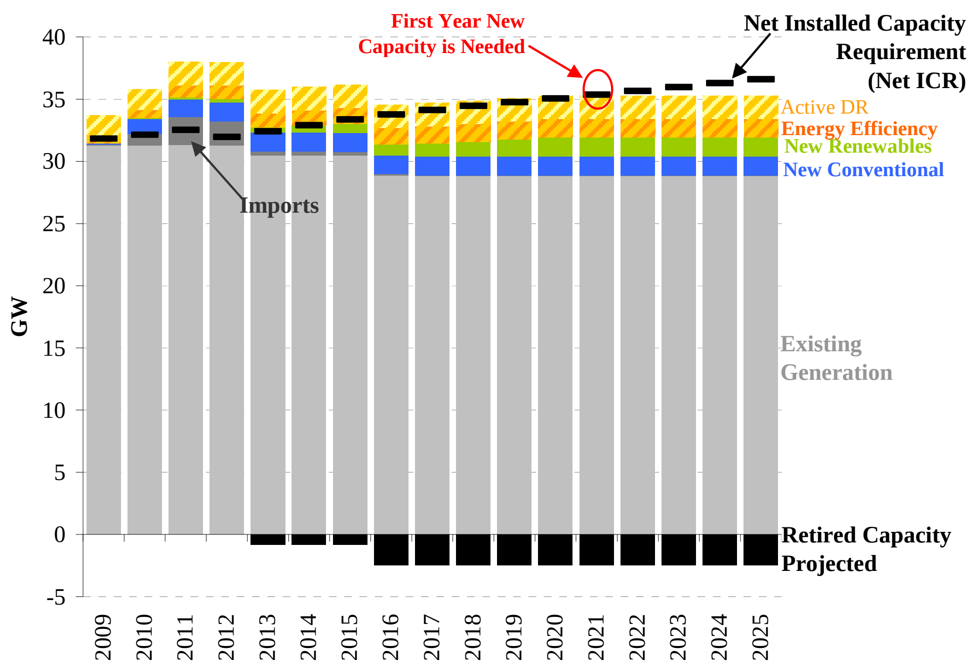
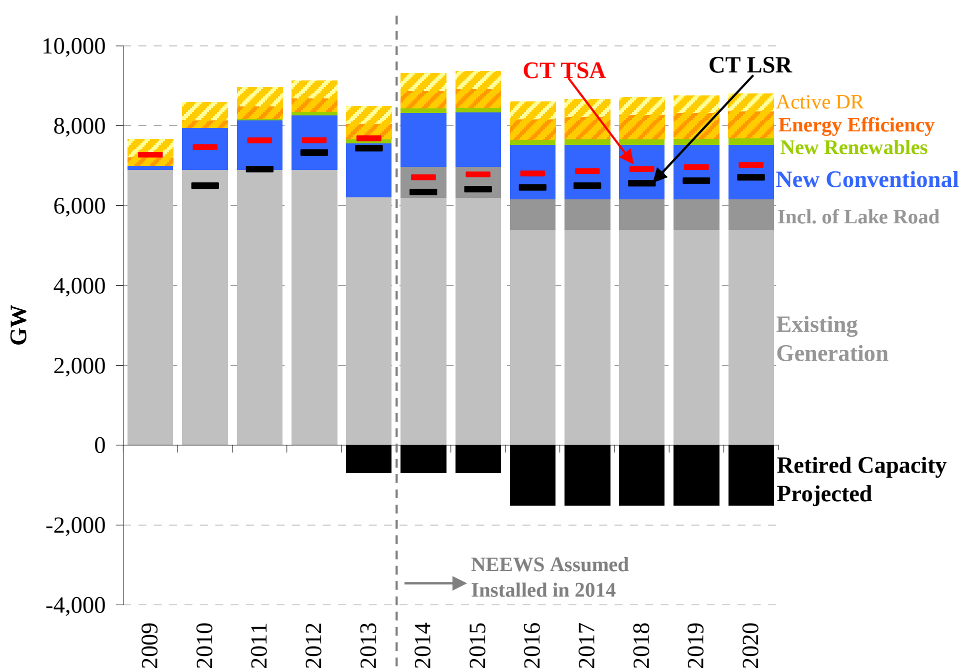


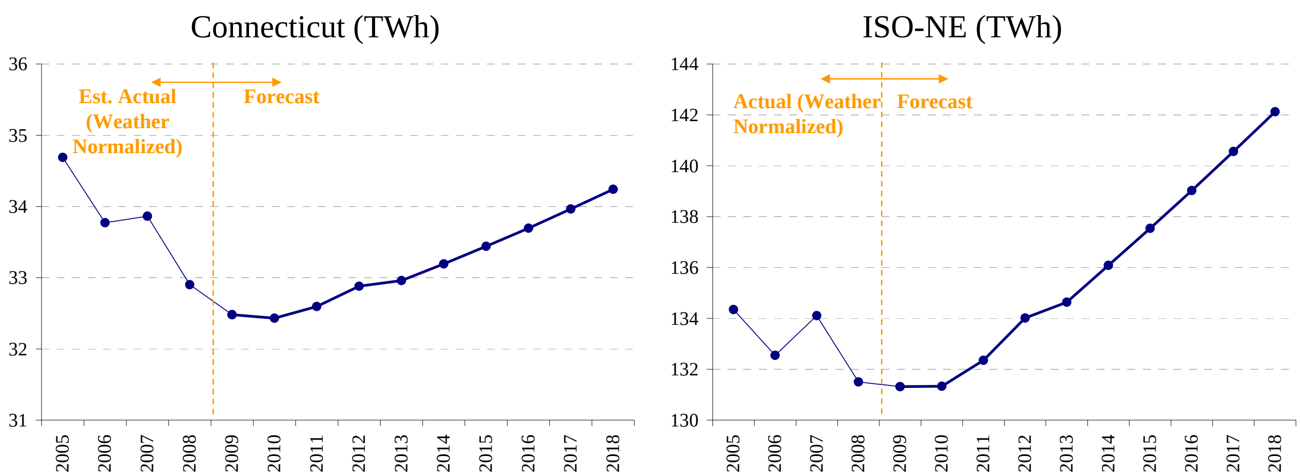
Figure 3
Locational Resource Adequacy in Connecticut



B.2 Supply and Demand for Energy

Energy consumption has declined sharply during the recession. It is expected to take ten years for energy consumption to reach pre-recession levels in Connecticut, as shown in Figure 4. The forecast is based on ISO-NE's load forecast, which accounts for "business as usual" energy efficiency. We have adjusted the load downward to account for Massachusetts' plans to implement energy efficiency more aggressively, as explained in Section III.1.

Figure 4
Annual Energy Consumption – Historical and Forecast



Note**:** Historic values in 2005 through 2008 are from the ISO-NE; 2009 through 2018 values are from ISO-NE's 2009 CELT report.

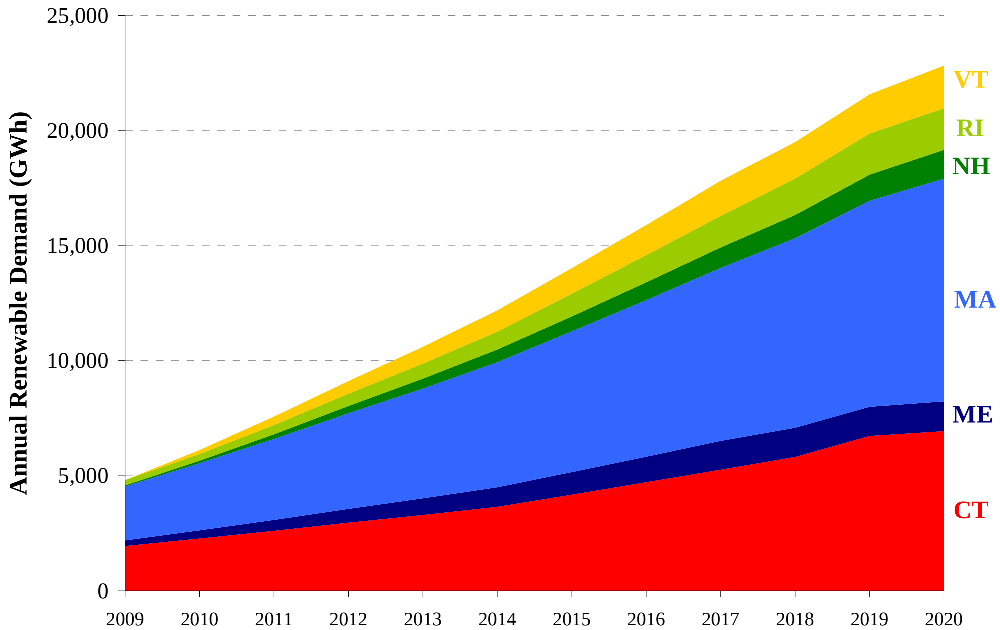
The fact that adequate capacity will be available means that energy requirements will be met reliably (subject to energy security concerns examined separately in Section III.8). *How* energy is produced will depend on the types of resources that are developed or retired in the future, with attendant implications for customer cost, fuel usage, and emissions. Alternatively, energy efficiency can reduce the amount of energy that must be generated, again with implications for costs, fuel usage, and emissions.

This study includes a detailed analysis of future energy production using the DAYZER locational market simulation model, developed by Cambridge Energy Solutions (CES). It takes as data all of the elements of supply, demand (and reductions thereof), and transmission in the ISO-NE system and how these elements evolve over time. Using these data inputs, DAYZER simulates the ISO-NE's operation of the system and its administration of the energy market. The outputs of the model 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 used to construct various performance metrics that are presented in Sections B.4 and B.5 for the Base Case. Simulations under various alternative scenarios and resource strategies are presented in Sections C and D, respectively.

B.3 Supply and Demand for Renewable Generation

The potential impact of adding renewable energy supply to meet the region's Class I renewable energy demand is closely analyzed in Section III.3. The demand for Class I renewable generation in New England is based on each state's Renewable Portfolio Standard (RPS). By 2020, we estimate the demand for renewable energy for New England as a whole is approximately 16 percent of retail load (20 percent for Connecticut).

Figure 5
New England RPS Requirements
(Annual GWh)



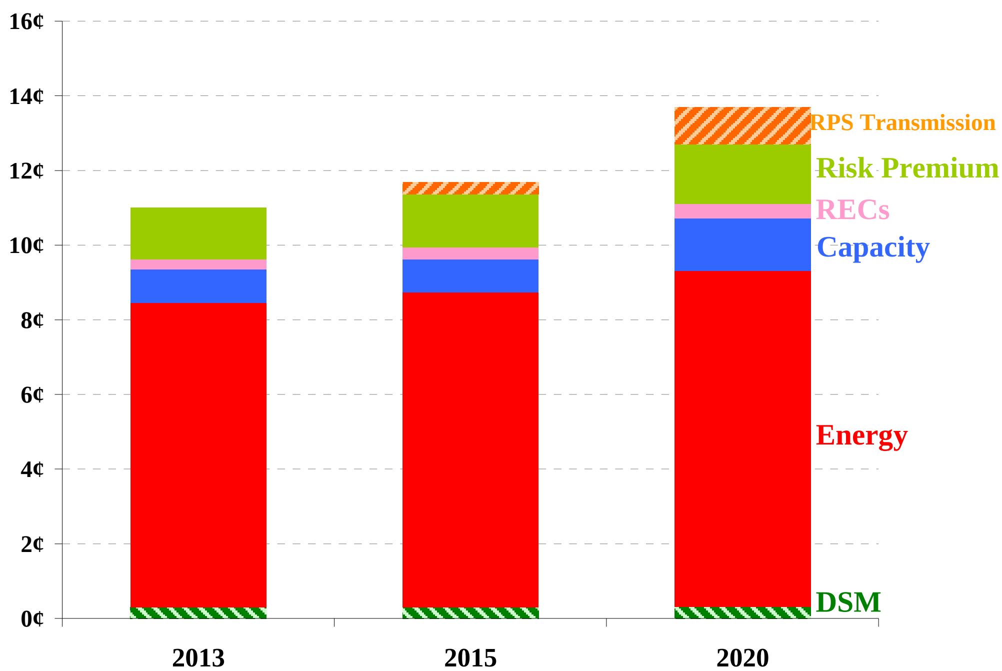
Sources and Notes: 2009 CELT Report Forecast for "Base Case." Growth rate for years beyond 2018 is based on average growth rate between 2017 and 2018. Demand accounts for estimated reductions from 2009 IRP Reference DSM forecast. Massachusetts demand incorporates the increased Class 1 RPS requirement from the 2008 Green Communities Act.

To meet that demand in the Reference Strategy, we assume that all of the New England states meet their respective RPS requirements through the procurement of renewable generation and renewable energy credits (RECs) from within the region and imports from nearby areas. The resource mix to meet that demand is based on an analysis of existing renewable generation, imports that are RPS-qualified, projects currently under development, and the resource potential in the region. The current installed RPS-qualified Class I renewable generating capacity is approximately 1,751 MW. We estimate that New England would need to develop about 4,800 MW (nameplate capacity) of additional renewable resources to meet the region's Class I renewable demand in 2020. For years up through 2013, we assume that a portion of proposed projects will come to fruition, and for years beyond 2013, we assume that renewable development grows toward resource potential. Of the various resource types available, only biomass and wind have the potential to grow significantly in the later years. While biomass is available in many parts of New England, the biomass resource potential will not be sufficient to meet the region's Class I renewable needs. Thus, for years beyond 2013, we assume that on-shore and off-shore wind projects will grow to meet the region's demand that is not met by other renewable resources. Since much of the renewable resource potential is located in remote areas without sufficient transmission to support large generation additions, significant transmission upgrades would be necessary, and are likely to be very costly.

B.4 Customer Cost Outlook

In spite of the capacity surplus, Connecticut customers can expect to face increasing average costs from 2013 to 2015 (a 6 percent increase in real terms) and to 2020 (another 17 percent increase), as shown in Figure 6. Figure 6 shows the components of customer costs that are related to future power supply, *i.e.*, the Generation Service Charge (which provides full-requirements service for energy, capacity, and RECs, with an assumed 15 percent risk premium charged by suppliers), plus an adder for DSM and new transmission needed to support new renewables. Other transmission and distribution costs are excluded.

Figure 6
Connecticut Customers' Annual Average Power Supply-Related Costs (2010 ¢/kWh)
Base Case Projection



As Figure 6 indicates, the 0.68¢/kWh (6 percent) increase from 2013 to 2015 is due primarily to rising energy prices (0.29¢/kWh) and new transmission to reach remote wind resources

(0.32¢/kWh). Energy prices reflect load-weighted average locational marginal prices (LMPs) in Connecticut; these are displayed on a monthly basis below for the three study years. Annual average energy prices increase from \$78.4 to \$80.3/MWh as CO_2 allowance prices increase from \$18 to \$21/ton, while gas prices increase slightly from \$6.7 to \$6.8/MMBtu.

The larger 2.0¢/kWh (17 percent) increase from 2015 to 2020 is driven by three factors: energy (+0.58¢/kWh), capacity (+0.52¢/kWh), and transmission for renewables (+0.68¢/kWh). The 15 percent risk premium increases with energy and capacity prices, adding another 0.17¢/kWh. The projected \$5/MWh increase in energy prices from 2015 to 2020 is only partly explained by the increase in CO_2 prices from \$21/ton to \$30/ton. Simultaneously, the growth in renewable generation from 13.5 TWh (10 percent of total generation) to 23.3 TWh (16 percent of total generation) fundamentally changes the energy market. Renewable generation is greatest during the off-peak (winter and nighttime) periods, when it severely depresses prices in lower-load hours. During summer on-peak periods, renewables, particularly wind which dominates future renewable resource additions, generate the least. Resulting prices are higher than the rest of the year and higher than in 2015 because load is higher and reserve margins are smaller. The capacity surplus is reduced from 2,797 MW in 2015 (8 percent above target, with excess capacity supported by a capacity price floor), to 240 MW in 2020, as the 1,552 MW increase in derated renewable capacity is more than offset by 1,621 MW additional retirements and 1,382 MW load growth. In 2020, the 14 percent reserve margin is really only an 8 percent generation reserve margin, with the remaining 6 percent being provided by active DR that provides little energy price mitigation because it is dispatched only during operating reserve shortages. Hence, summer energy prices are higher in 2020 than in 2015, even though non-summer energy prices are similar or lower, as indicated in Figure 7.

Load growth and retirements also increase the capacity price (after it falls in 2016 due to the assumed removal of the capacity price floor), as discussed on Section III.1 and shown graphically in Figure 8.

The cost of new transmission to access remote wind resources also contributes to the increase in average customer costs, adding 0.31¢/kWh in 2015 and 0.99¢/kWh in 2020.

The cost of RECs grows only 0.06¢/kWh (20 percent) from 2015 to 2020, despite the increasing renewables requirement. The cost is moderated by projected declining market prices for RECs, driven by rising energy and capacity prices. Higher energy and capacity prices cover a larger portion of renewables' costs, leaving a smaller amount that must be recovered through RECs. This observation reflects the general hedging value of renewables: as energy prices trend upward, REC prices should trend downward.

Figure 7
Base Case Projection of Energy Prices (2010 $/MWh)
Load-Weighted Average LMPs in Connecticut

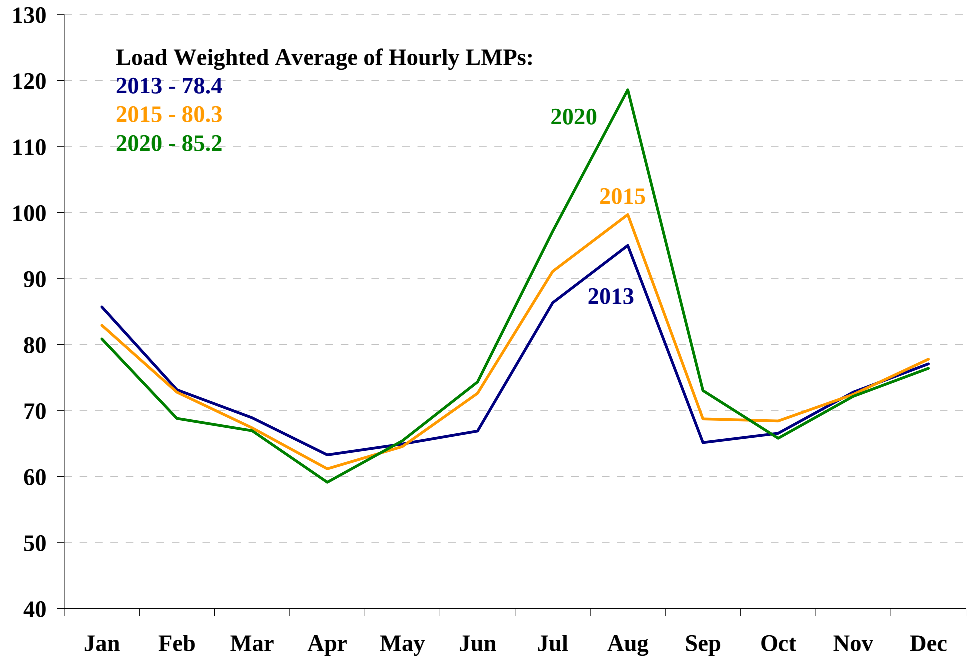
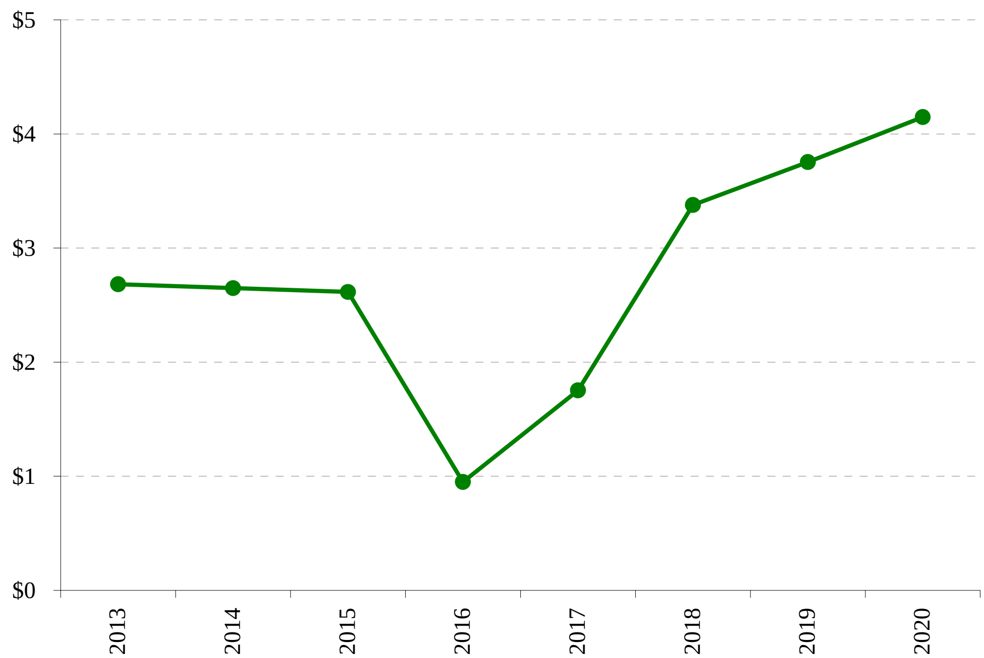


Figure 8
Base Case Projection of Capacity Prices in New England (2010 $/kW-month)



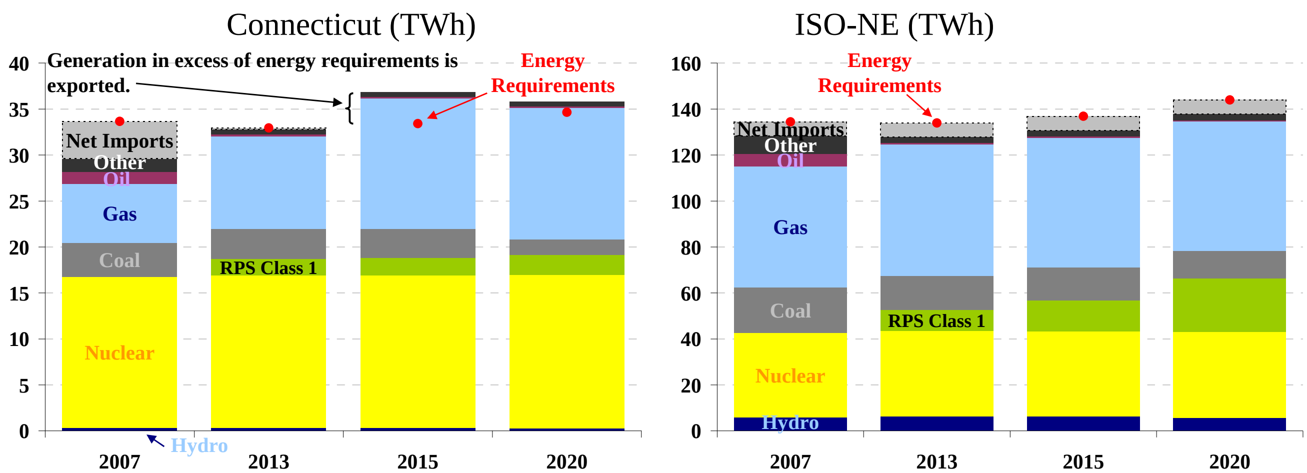
B.5 Fuel and Emissions Outlook

While customers will likely pay more for their electricity over time, they should expect to enjoy cleaner air in return. Electricity production in New England will likely be very different in 2020 than it is today, primarily because of new renewable generation built and operated to meet RPS requirements. New renewable generation is projected to increase by more than 12,000 GWh between 2013 and 2020, which will more than offset load growth of approximately 10,000 GWh over the same period. Because most of the renewable generation expected to be built is wind with zero variable generation costs, it will tend to displace fossil resources with higher variable costs. In particular, wind will displace gas or coal-fired generation during off-peak periods when the wind blows the most, and it will displace some gas or oil-fired generation during on-peak periods. Meanwhile, rising CO_2 prices (combined with moderated gas prices) will shift the economic dispatch from coal-fired generation to cleaner gas-fired combined-cycle generation. In addition, oil-fired generation will be limited by the retirement of 2,446 MW oil-fired steam capacity in 2013 and 2016.

The combined effect on total generation by fuel type is shown in Figure 9 below, which shows 2007 actual data and projections for 2013, 2015, and 2020. This shows the increase in renewable generation from 6 percent of total regional supply in 2007 to 16 percent in 2020, a 40 percent reduction in coal generation, and a steep decline in oil generation. On net, gas-fired generation increases only slightly, partly because of an interesting decrease in winter gas usage that is due to the increased level of wind generation during the winter.

Figure 9 also shows the composition of supply in Connecticut. Total generation in Connecticut in 2013 will be higher than in 2007, mostly because of the 2012 addition of Kleen, a relatively efficient 620 MW gas-fired combined cycle plant, and the incorporation of Lake Road (another gas-fired combined cycle plant) electrically into the Connecticut sub-area due to the NEEWS transmission project. These changes turn Connecticut from an energy importer to a net exporter. Oil-fired generation decreases after 2007 partly because of increased availability of lower-cost gas-fired generation and renewables, but also because of changes in relative fuel prices – oil prices have risen dramatically relative to gas prices, and are expected to remain high.

Figure 9
Base Case Projection of Annual Generation by Fuel Type

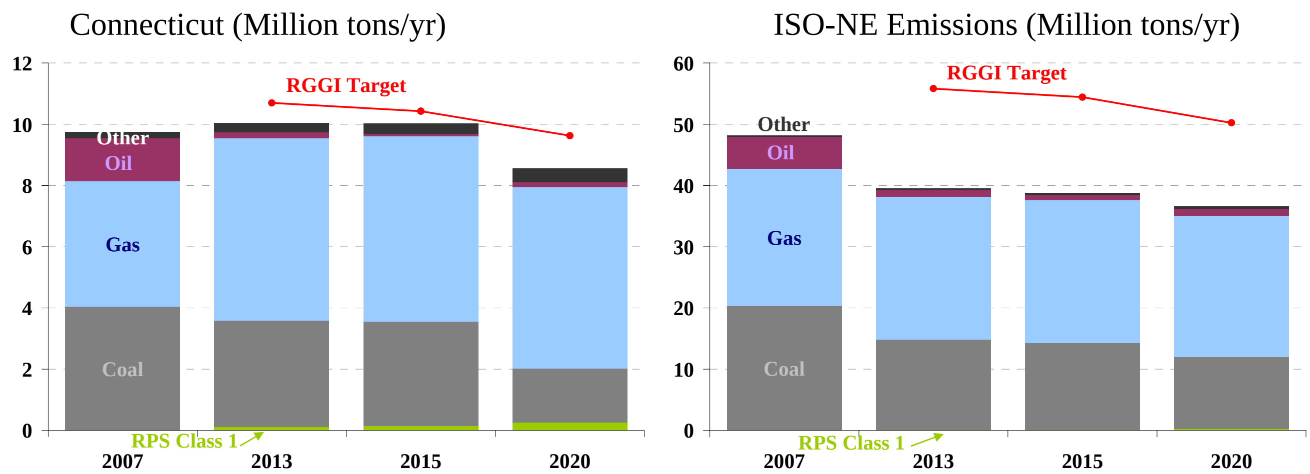


Notes**:** 2007 data derived from the EPA CEMS database. Lake Road generation (approximately 4 TWh) is counted in Connecticut starting in 2015 after the New England East-West Solution (NEEWS) transmission project goes in service and brings Lake Road electrically into the Connecticut sub-area.

Dispatch switching from fossil fuels to renewable generation, and from coal to gas (because of the CO_2 price) will produce a dramatic reduction in regional CO_2 emissions. Regional emissions are projected to decrease by 8.6 million tons (18 percent) from 2007 levels by 2013 then continue to decrease another 2.9 million tons (6 percent) by 2020. This will put New England below its RGGI targets, as shown in Figure 10. However, it should be emphasized that this optimistic outlook is premised on the successful implementation of policy initiatives that are only in their early stages: RPS and federal climate legislation. It also depends on continued funding of energy efficiency programs at least at their current levels as assumed in the load forecast. For example, the Connecticut EDCs' efficiency programs between 2010 and 2020 will save nearly 2,900 GWh annually by 2020; without that, Connecticut electricity consumption would be 8 percent higher in 2020.

Connecticut's in-state CO_2 emissions will actually increase as Kleen and other gas-fired generation turn Connecticut into an energy exporter. However, whether CO_2 emissions occur in-state is not particularly important since the environmental effects of CO_2 occur globally, not locally or regionally like NO_X and SO_2.

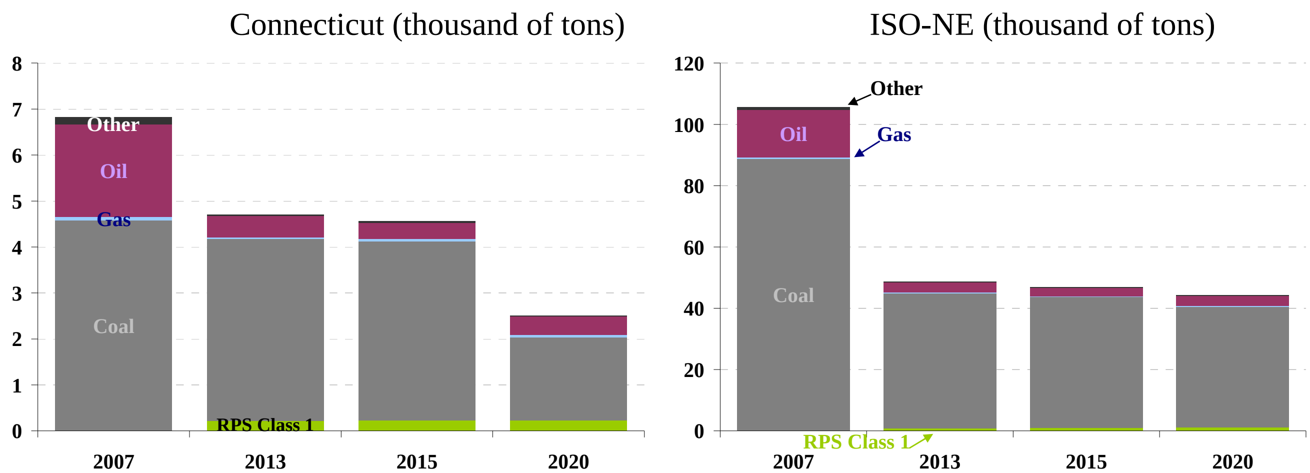
Figure 10
Annual CO_2 Emissions



***Notes*:** 2007 data from EPA CEMS database. Lake Road's emissions are counted in Connecticut in all years, based on its geographical location. There is no RGGI target for 2020; the value shown is the 2018 target.

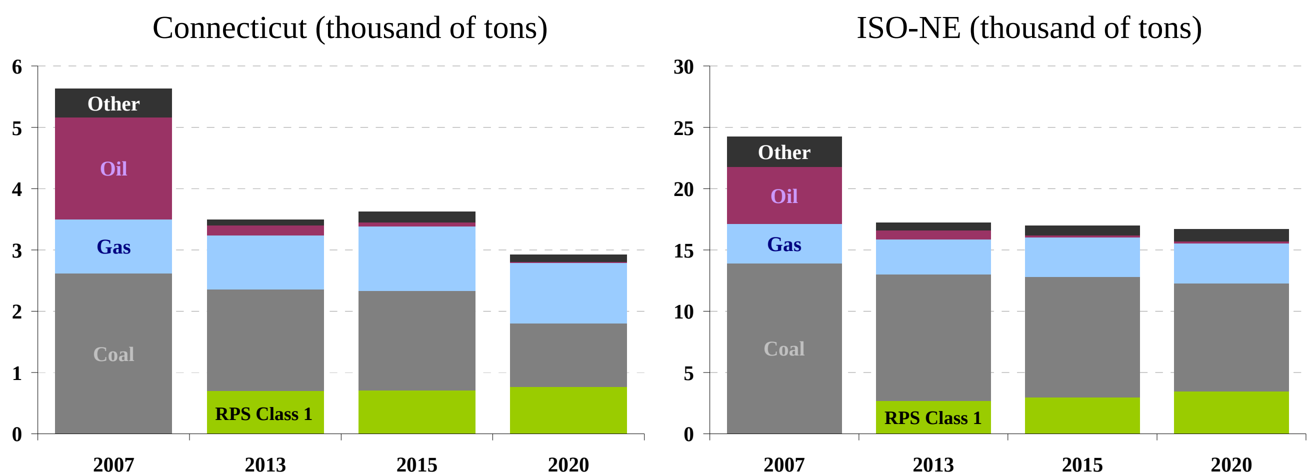
In-state emissions of NO_X and SO_2 do matter to Connecticut because the effects of those pollutants depend on local and regional concentrations. Emissions from the dirtier, older coal and oil-fired steam units in-state can lead to violations of National Ambient Air Quality Standards. Over time, these steam units are projected to generate less, due to displacement by regional renewables and gas-fired generation, and also because of the retirement of 1,504 MW of oil capacity by 2020. As a result, emissions of NO_X and SO_2 are projected to decrease both in Connecticut and across New England, as shown in Figures 11 and 12.

Figure 11
Annual SO_2 Emissions



Note: RPS Class 1 SO_2 emissions are from Biomass and Landfill Gas.

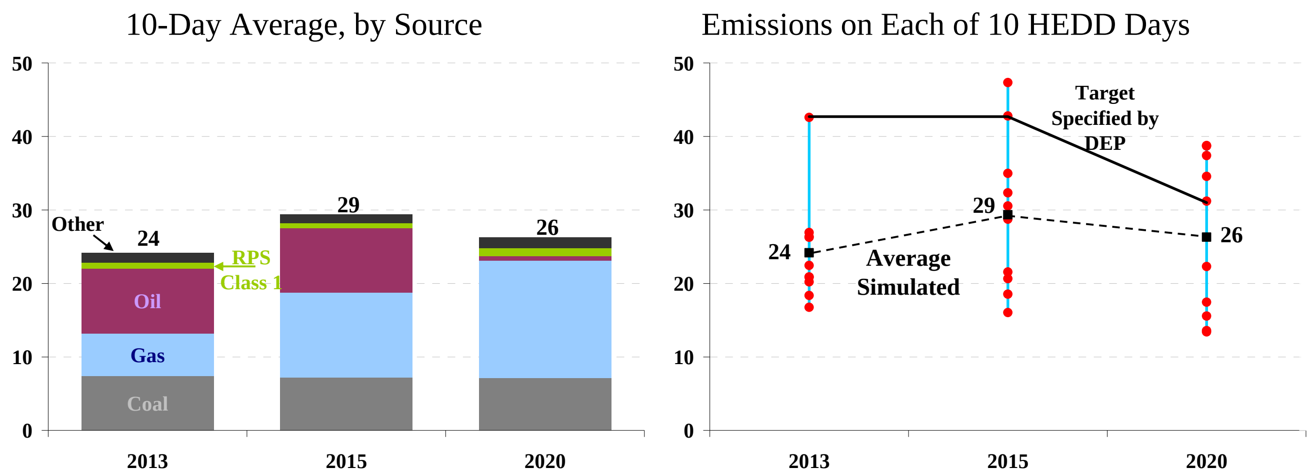
Figure 12
Annual NO_X Emissions



Note: RPS Class 1 NO_X emissions are from Biomass and Landfill Gas.

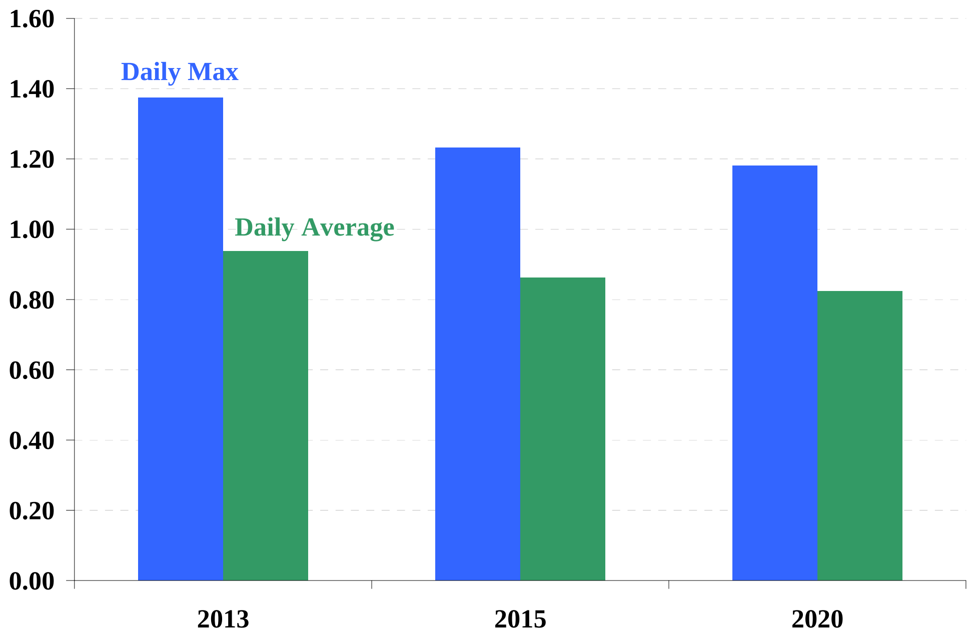
Conversely, NO_X emissions during the hottest days do not decline over time. From 2013 through 2020, the non-retiring steam-oil units, and also combustion turbines, actually produce increasing amounts of energy and NO_X emissions during the highest-load periods in July and August when wind generation is at its low point. These units run more over time because load growth and unit retirements lead to declining reserve margins. Thus, daily NO_X emissions on the 10 Highest Energy Demand Days (HEDD) do not decrease in spite of retirements and the installation of SCRs on non-retiring steam-oil units.

Figure 13
HEDD NO_X Emissions in Connecticut (tons per day)



Since natural gas is often the marginal short-term generation resource that is displaced by wind, and wind tends to blow more in the winter, growth in wind resources will actually reduce winter consumption of natural gas over time, as shown in Figure 14.

Figure 14
New England Winter Gas Usage (Bcf/day)



C. ALTERNATIVE SCENARIOS

C.1 Scenario Definitions

A long-range planning analysis such as this cannot avoid uncertainty. Regardless of the effort and attention that goes into the analysis, key external factors over which utilities and regulators do not have direct control – such as gas price and demand growth – will necessarily remain uncertain. This means that there will also be substantial uncertainty about important outcomes such as resource needs, customer cost, and pollutant emissions. In addition, alternative strategies are likely to be affected differently by the external factors. This implies that in order to understand the strengths and weaknesses of alternative resource strategies, it is imperative to characterize and evaluate the potential uncertainty in external factors. Simply setting each factor to a single "likely" or "expected" value and assuming that will adequately characterize a strategy's performance under alternative settings of those factors may not lead to good decisions.

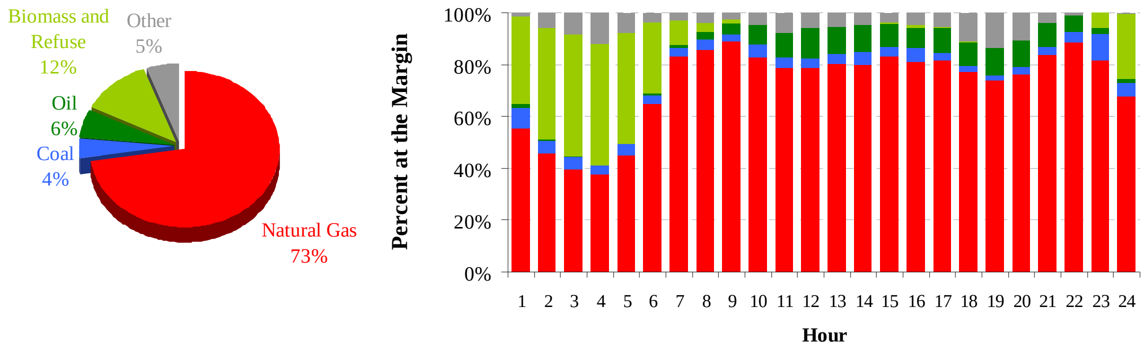
This study characterizes uncertainty explicitly with scenario analysis. That is, it develops a set of internally consistent future scenarios, and evaluates alternative resource solutions against each of these scenarios. First, we identified the key external factors that influence important outcome metrics such as resource needs, customer costs, and emissions. The key external factors were determined to be:

- Natural gas price;
- Climate legislation (manifested in CO_2 price); and
- Electric load (energy and peak).[2]

Gas-fired generation is the marginal, price-setting supply in the energy market most of the time, especially during the hours of the day when consumption is highest, as shown in Figure 15. Thus electricity prices tend to move in tandem with gas prices, and gas prices affect customer costs more than any other variable. Across the scenarios analyzed, gas prices can change average customer costs by 3¢/kWh or more, as discussed below

[2] There may be some control over loads through demand management programs, as discussed later.

Figure 15
New England Marginal Generation by Fuel Type in 2020
Based on DAYZER Simulations for the Base Case



Gas prices, as well as CO_2 prices, will be driven largely by factors that are external to the New England power market. Load is driven by economic growth, but to a significant extent it is also influenced by the price of power – higher prices tend to suppress load, and vice versa. Power prices are in turn heavily affected by gas and CO_2 prices, as well as other factors, such as the supply-demand balance, through a set of feedback relationships that evolve over time.

For each of the scenario variables – gas price, CO_2 price, and load – we characterized possible outcomes, capturing fairly extreme, yet plausible, values of the factors, and the relationships with other factors. The development of Gas Price and CO_2 price scenarios are discussed in Section III.9 (Natural Gas) and Section III.7 (Environmental Regulations Affecting Electricity), respectively. To characterize demand, we begin with ISO New England's current load forecast. This forecast is assumed to be consistent with current expectations for gas price and CO_2 price, and this set of factors together makes up the "Current Trends" scenario – *i.e.*, the outlook in which all factors tend to follow current expectations. When considering other values of Gas Price and/or CO_2 price, we developed a demand elasticity relationship to characterize the effect of power price on load, treating peak and energy load separately, and phasing in both short-term and long-term demand elasticity effects. Independently, we also evaluate a case of high demand that may reflect demand growth independent of price influences (*e.g.*, in response to high regional economic growth).

Almost any combinations of the key factors could be considered a scenario, but only a limited number of scenarios can be evaluated. To select the scenarios that will be most informative, we developed combinations of the external factors – Gas Price, CO_2 Price, and Load – that are relatively likely and internally consistent, but that also stress the resource strategies being considered and help to distinguish between strategies. The particular scenarios chosen are characterized in Table 1. The constituent Low, Medium, and High trajectories of gas price and CO_2 price are shown in Figure 16, and the load trajectories associated with the scenarios are in Figure 17.

Table 1
Scenario Definitions

Scenario	**Gas Price**	**CO_2 Price**	**Load Growth**
"Current Trends"	Medium: futures extrapolated	Medium: EIA "Basic Case" for Waxman-Markey	CELT forecast
"Lo Gas/Lo CO_2"	Low	Low: EIA "High Offset Case" for Waxman-Markey	CELT adjusted up by price elasticity
"Med Gas/Hi CO_2"	Medium	High: EIA "No International Case" for Waxman-Markey	CELT adjusted down by price elasticity
"Hi Load Growth"	Medium	Medium	CELT High Economic Growth forecast
"Hi Gas/Hi CO_2"	High	High	CELT adjusted down by price elasticity

Figure 16
Price Trajectories for Scenarios

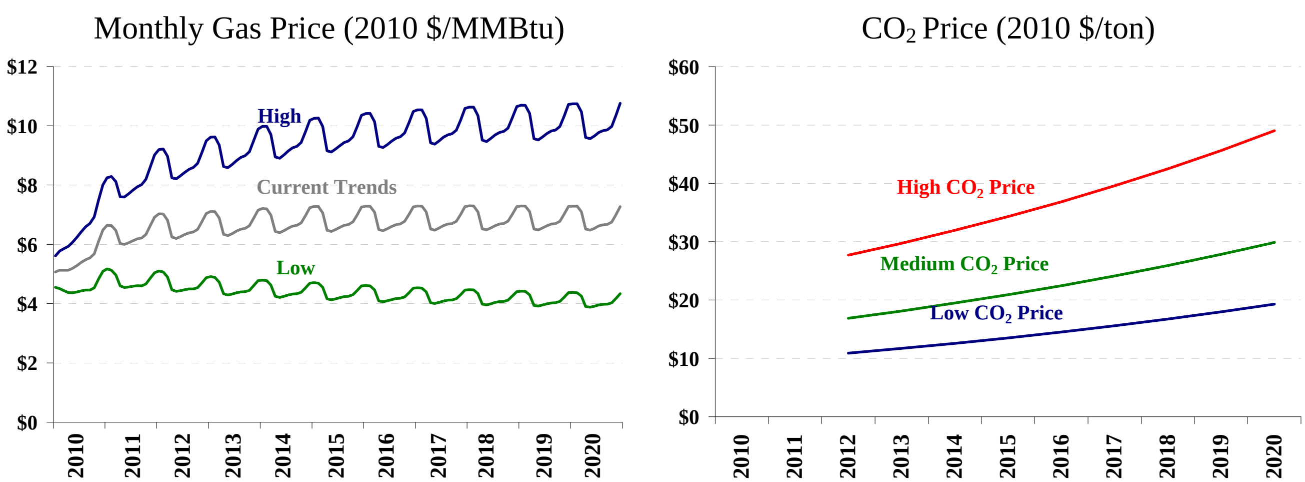
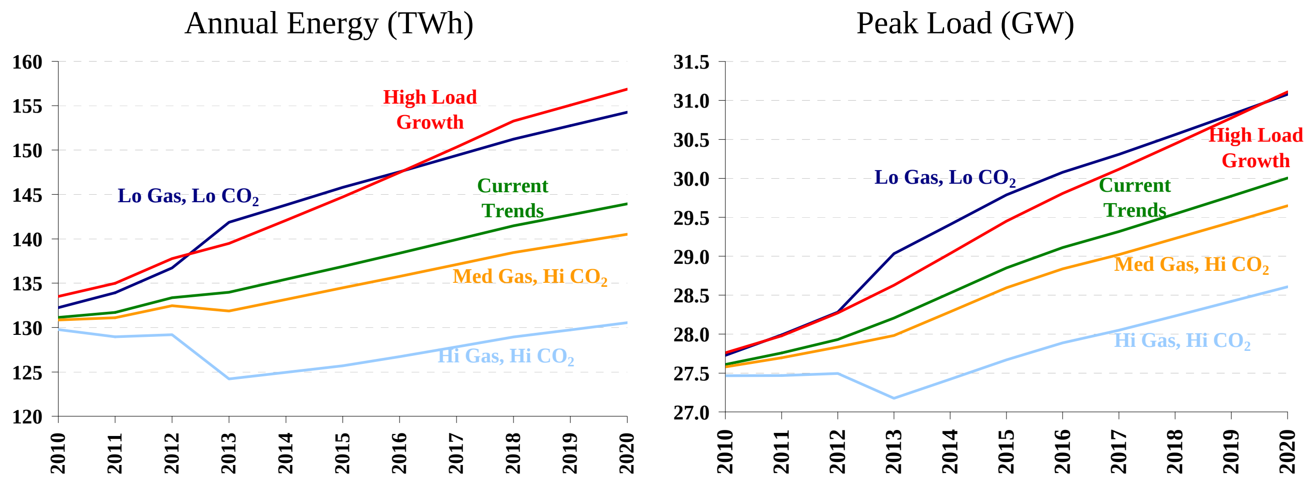


Figure 17
Load Trajectories for Scenarios (New England)



Note that the scenarios characterized here are more "persistent" than the actual future is likely to turn out to be. For instance, even if the future gas prices turns out to be high on average, there will undoubtedly be volatility around that average. Nonetheless, given the goals of the scenario analysis – to characterize potential future outcomes and illuminate differences among alternative strategies – scenarios characterized in this way are useful.

C.2 Effects of Alternative Scenarios on Costs and Emissions

The five scenarios described above were analyzed using the DAYZER model, as variations to the 2013, 2015, and 2020 Base Case described in Section B above. In implementing the scenarios, the effects on resource adequacy, retirement, and new entry were also considered, as documented in Table 1.16 in Section III.1 (Resource Adequacy). For example, higher loads decrease the amount of retirements, because a tighter resource balance leads to higher capacity prices, improving the economics of some capacity that might otherwise retire.

For all scenarios, we produced the same set of metrics as in the Base Case, shown as Figures 18 through 27, below. Some of the most salient observations from these figures are as follows:

- Total cost is driven strongly by gas price, and also by load levels.
- Average cost (per kWh consumed) is also driven primarily by gas price, which causes cost to range by as much as 3 to 3.5¢/kWh; other scenario variables have a smaller effect.
- CO_2 emissions are driven by load, being much higher in scenarios with high load (including cases where high load is driven by low power prices).
- Load levels can affect CO_2 emissions nearly as much as CO_2 price, in the ranges examined.
- New England CO_2 emissions are below the RGGI benchmark, primarily due to large renewable additions and a CO_2 price well beyond expected RGGI price levels.

Figure 18
Energy Prices Across Scenarios (2010 $/MWh)
Load-Weighted Annual Average LMPs in Connecticut

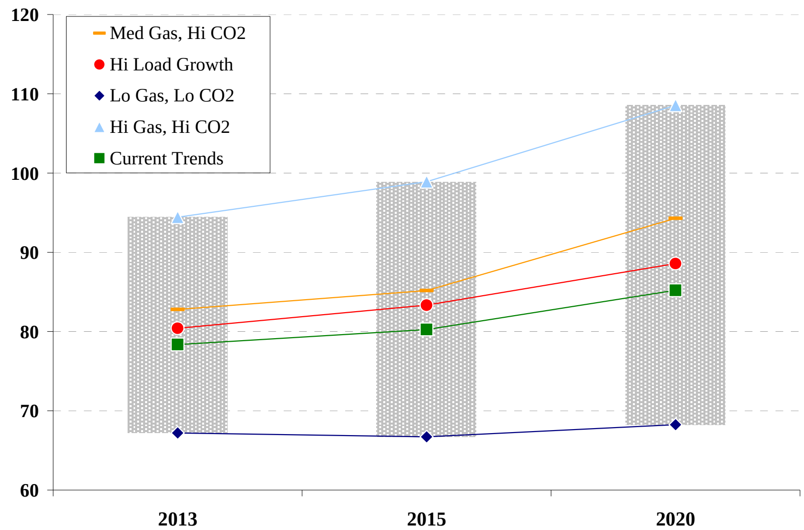


Figure 19
Capacity Prices in New England (2010 $/kW-Yr)

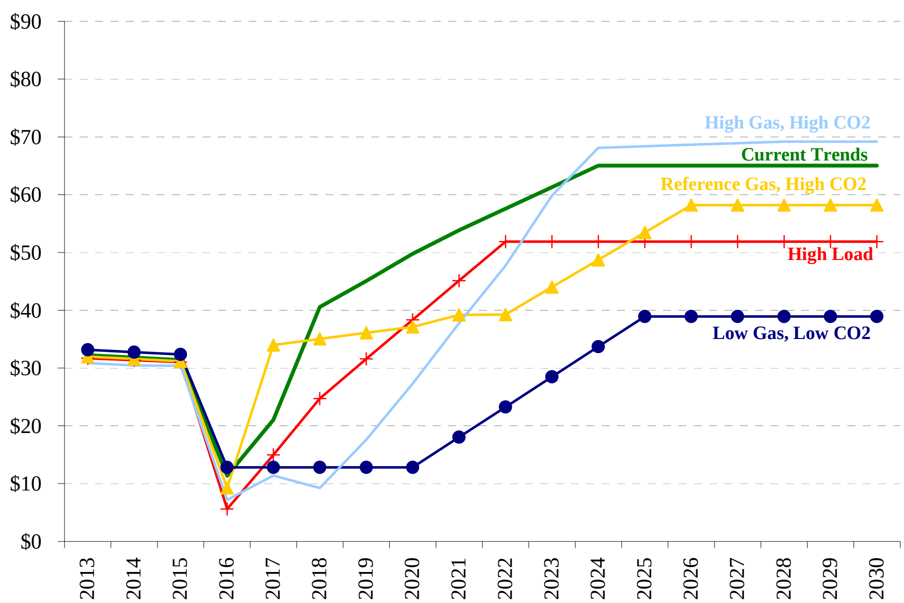


Figure 20
Connecticut Customers' Power Supply-Related Costs Across Scenarios

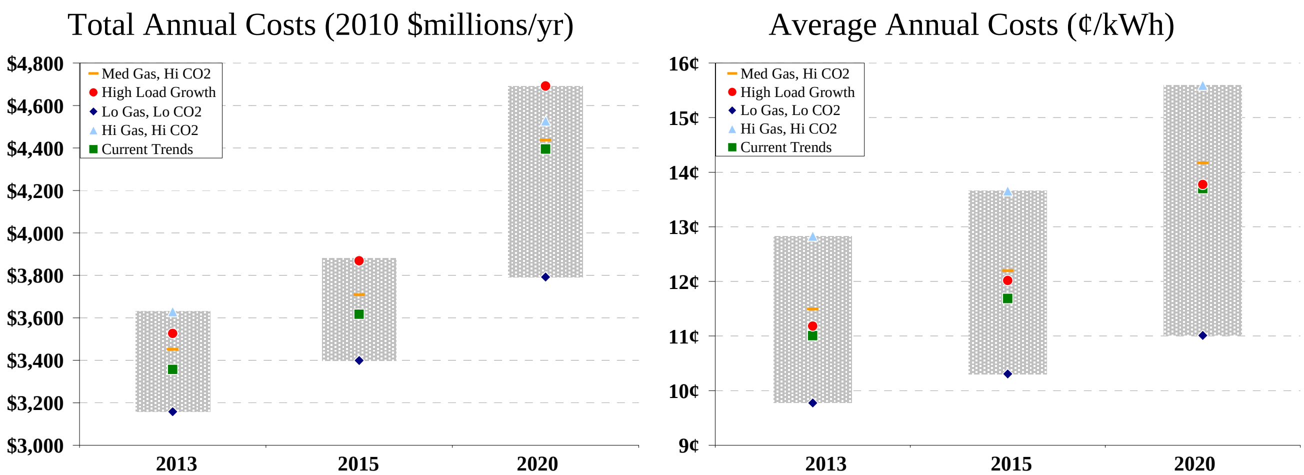
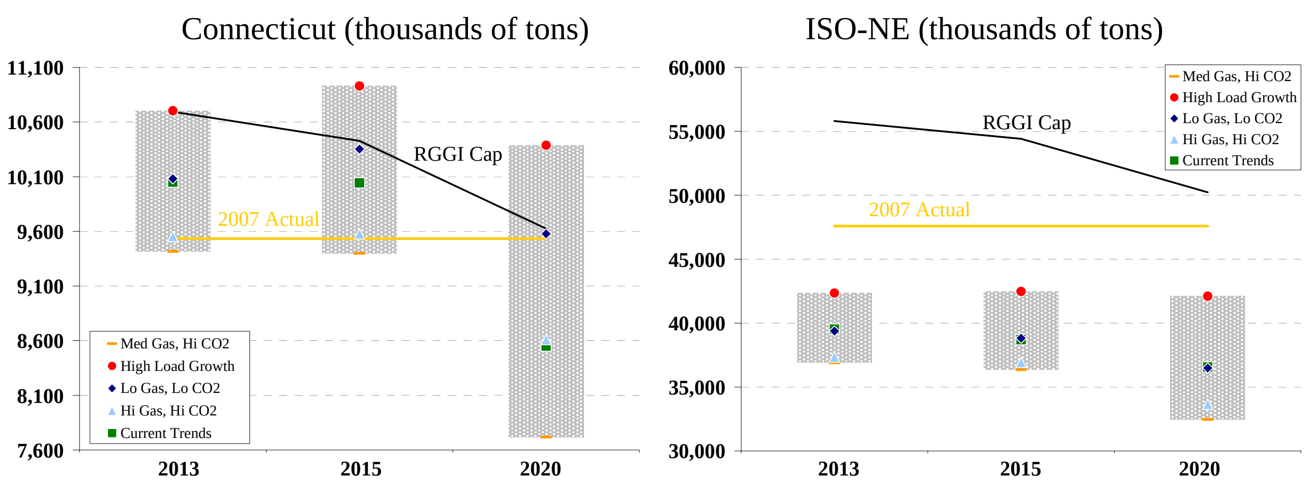


Figure 21
Annual CO_2 Emissions



***Note*: There is no RGGI target for 2020; the value shown is the 2018 target.**

Figure 22
Annual SO_2 Emissions

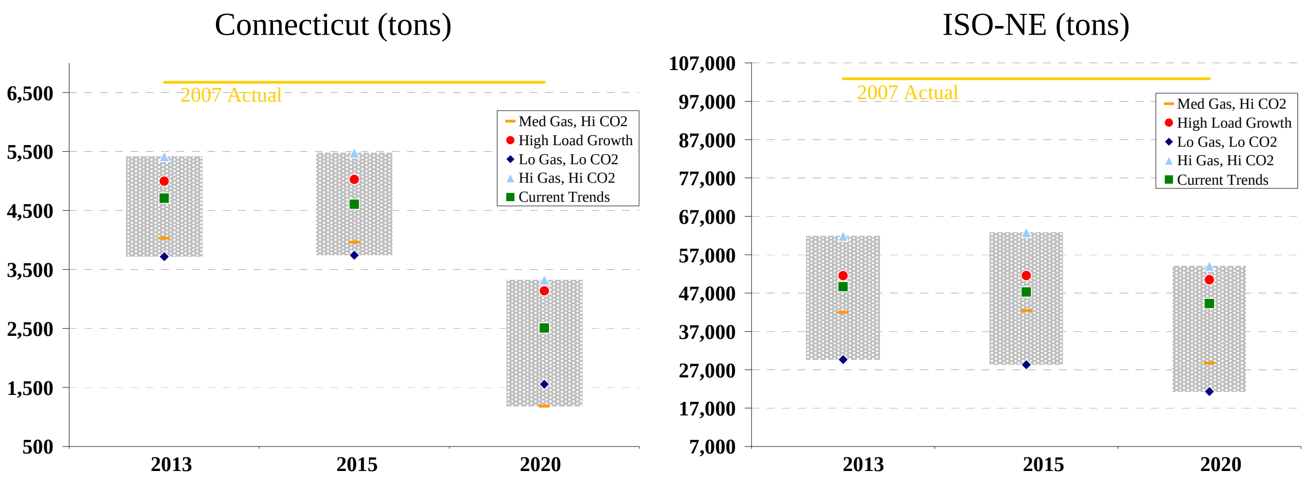


Figure 23
Annual NO_X Emissions

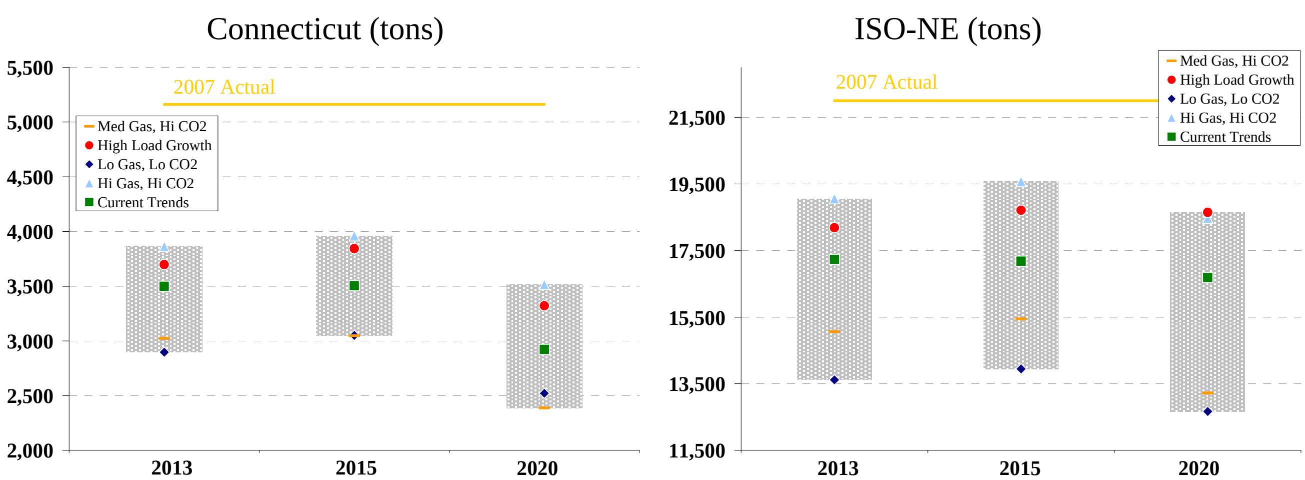


Figure 24
Connecticut HEDD NO_X Emissions (Average Tons per Day)

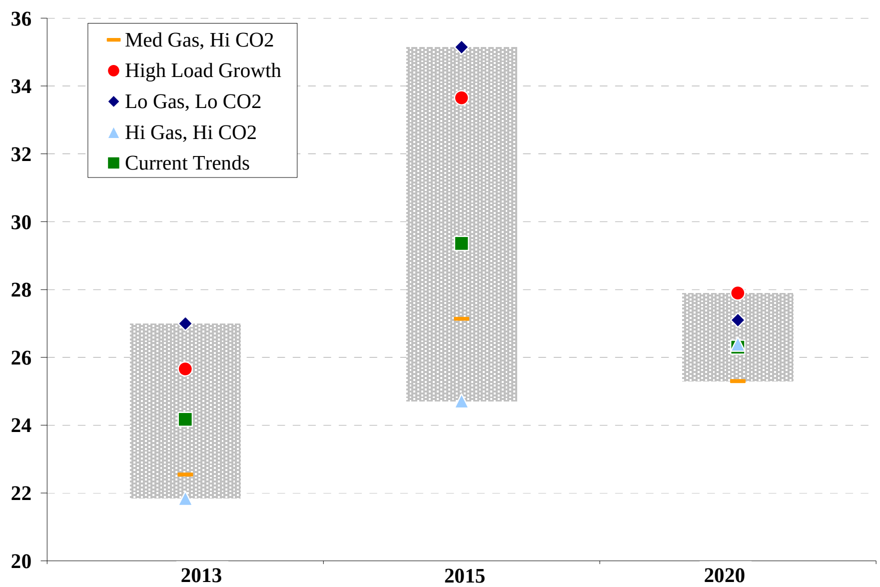


Figure 25
Connecticut HEDD NO_X Emissions on Each of 10 HEDD Days (Daily Tons)

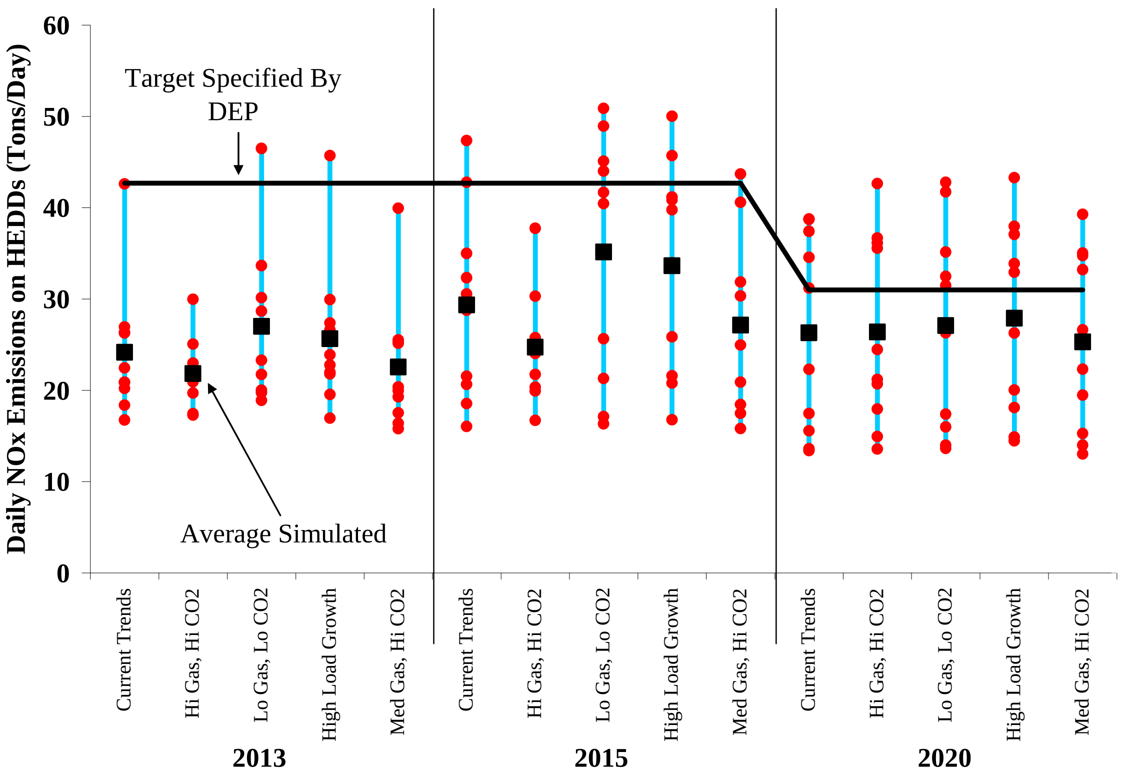


Figure 26
Connecticut Generation by Fuel Type (TWh)

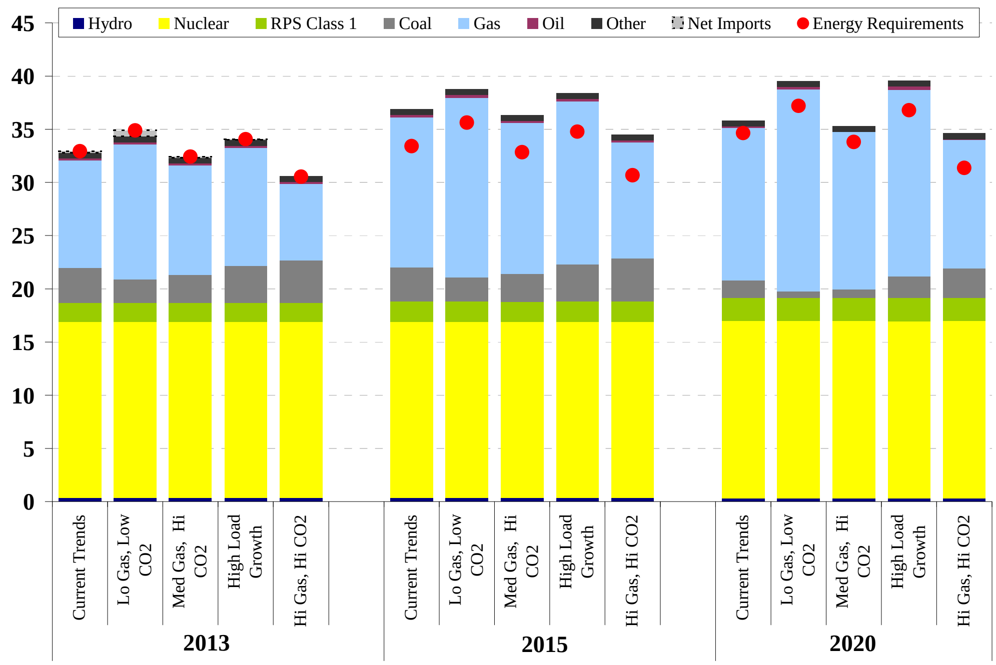
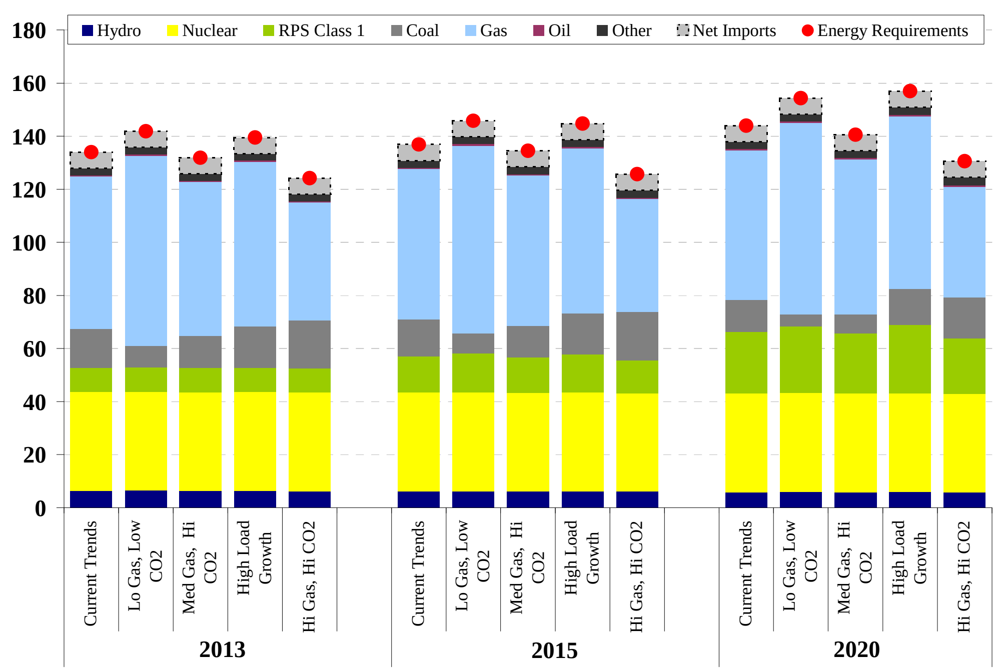


Figure 27
ISO-NE Generation by Fuel Type (TWh)



D. EVALUATION OF RESOURCE STRATEGIES

As discussed in Section B, and in more detail in Section III.1, there is no projected need for new resources in order to meet resource adequacy requirements over the study horizon. However, energy needs must be met (whether through generation or energy efficiency) and renewables mandates must be met (through development of an unprecedented amount of new renewables and enabling transmission and/or paying alternative compliance payments). How these needs are ultimately met will be determined largely by market forces, but also by future state-sponsored procurement and policy initiatives.

The Brattle Group and the Companies developed six potential "resource strategies" for evaluation.[3] These strategies span a range of factors the state and/or utilities may be able to influence through various procurement and policy initiatives: energy efficiency, development of renewable generation and enabling transmission, and development of traditional generation. The six alternative strategies are evaluated, in combination with each of the five scenarios discussed above, in year 2020 using the cost and emissions metrics described in Sections B and C.

Because the evaluation considers only one year, it is only an indicative screening analysis for informing the direction and general magnitude of the effects. Further analysis of strategies and procurement/policy measures that may be required to pursue those strategies will be necessary before taking specific actions.

D.1 Six Alternative Resource Strategies

The six strategies evaluated are:

- ***Reference Strategy:*** This is the strategy embedded in the Base Case described in Section B. It continues current funding for DSM, but no more. It assumes regional development of renewables (primarily wind) and enabling transmission are sufficient to meet regional RPS requirements, as described in Section III.3.

- ***Targeted DSM Expansion:*** This strategy is constructed to achieve zero load growth in five years and a slight reduction thereafter by implementing four specific, high-potential new energy efficiency initiatives: C&I Chiller Retirement, Various High Potential C&I Measures, Residential New Construction "Zero Energy" Homes, and Residential Cooling, as described in Section III.2. The combined effect of these initiatives would be to reduce Connecticut's annual energy requirements relative to the Reference Strategy by 646 GWh (2 percent) and peak loads by 178 MW (2 percent) by 2020.

3 A seventh resource strategy for nuclear energy was also developed, but is not discussed in this section because it would not be possible to develop and construct a new nuclear plant in Connecticut in the 10-year scope of this report. However, the nuclear strategy is useful for illustrative reasons and is detailed in Section III.5 (Nuclear Energy).

- ***All Achievable Cost-Effective DSM:*** This strategy assumes implementation of all achievable cost-effective DSM identified in the "Potential Study" commissioned by the ECMB, as described in Section III.2. This reduces Connecticut's energy requirements by 3.4 TWh (10 percent) and peak loads by 561 MW (7.5 percent) relative to the Reference strategy. Retirements are assumed to increase as the capacity market re-equilibrates.

- ***Limited Renewables:*** This strategy reflects limited renewable development and no transmission expansion to integrate remote and offshore wind resources. Renewable supplies are assumed to grow to meet 2013 RPS requirements, but then to remain constant at that level thereafter, falling well short of later RPS requirements. With the shortfall, Connecticut must pay the ACP for most of its 2020 RPS requirement. New combined cycle generation enters the market to take advantage of high energy prices, and retirements commensurately increase.

- ***In-State Renewables:*** This strategy is based on the "Limited Renewables" strategy, but with Connecticut aggressively supporting in-state renewable development to meet its own RPS requirement. Under such a strategy, out-of-market payments are required to support photovoltaics and fuel cells. In addition, to ensure that the in-state resources are dedicated to satisfy the Connecticut's Class I requirement (and not sold to EDCs in other states to satisfy their RPS requirements), the clearing price for all renewables would be close to the region's ACP (which is greater than Connecticut's ACP).

- ***Efficient Gas Expansion:*** This strategy assumes the development of 1,100 MW of new gas-fired combined cycle capacity in Connecticut, backed by power purchase agreements or other mechanisms to support capacity that might not otherwise be developed by the market (three of the scenarios already have 300 MW CCs, so only 800 MW of additional capacity is added under those scenarios). The concept of this strategy was to examine the value to customers of paying the full cost of new conventional generation and, in return, receiving its full value, and doing so before such a resource would have been developed by merchant developers. This could be achieved through long-term contracts that shift the cost responsibility, operational risks, and market risks and rewards to customers. Such an arrangement would allow a lower cost of capital – we assumed a 10.75 percent return on equity, resulting in a 7.1 percent after tax weighted-average cost of capital. It is assumed that capacity prices and retirements will not be affected, partly because of ISO-NE's Alternative Price Rule that addresses out-of-market entry.

Implementing these strategies in the modeling framework described in Sections B and C required adjustments to various other assumptions. In particular, each strategy would affect the amount of capacity and renewable generation needed to satisfy resource adequacy and RPS requirements. Furthermore, each strategy's effects on market prices of energy and capacity would indirectly affect retirement and investment decisions. We used the capacity market model described in Section III.1 to estimate these effects. The resulting supply impacts are summarized in Table 1.18 in Section III.1 (Resource Adequacy).

D.2 Comparison of Strategies

The metrics presented in Sections B and C above to describe the Reference strategy in several scenarios can also be used to compare alternative resource strategies across scenarios. Beginning with the cost metrics, Figure 28 shows the components of customer costs under each of the resource strategies, in just the Current Trends scenario. This figure illuminates the basic features of each strategy: the DSM strategies have higher DSM program costs but lower energy costs; the Limited Renewables and In-State Renewables avoid transmission costs but pay higher costs of RECs/ACP (including out-of-market subsidies in the In-State strategy); the Efficient Gas Expansion strategy does not significantly affect the RPS or DSM components but temporarily depresses energy prices and thus customer costs. Figure 29 shows the same data for all five of the scenarios, but without showing the cost components (the details are provided in Appendix 1). The key observations relating to these results are presented in Section A, above. Several additional observations about the strategies and their performance in the scenarios are below.

Both of the expanded DSM strategies have lower costs and lower emissions across all scenarios, more so in the All Achievable Cost-Effective DSM strategy. This is not surprising since only cost-effective efficiency measures are included in these strategies. The Targeted DSM strategy has lower average costs, even for non-participants, because energy price impacts offset higher system benefits charges that pay for incremental program costs (an increase from 3 mills to 3.7 mills). The All Achievable Cost-Effective DSM strategy reduces overall costs by more, but it could raise average costs for non-participants because the higher program costs (5.6 mills) are not fully offset by energy price impacts (which are greater than in the Targeted DSM strategy, but not proportionally). Note that for strategies designed to reduce consumption, average costs alone may not be a good measure of overall strategy performance, since the volume is changing.

The Limited Renewables strategy has costs similar to the Reference strategy (which has sufficient renewables) in the Current Trends scenario, but considerably higher variability across scenarios. In the High Gas/High CO_2 scenario, costs are $445 million *higher* than with the Reference strategy, but in the Low Gas/Low CO_2 scenario, costs are $151 million *lower* than with the Reference strategy. What is driving the greater variance is partly the loss of the hedging value of renewables on their share of energy requirements, and other related factors. In the High Gas/High CO_2 scenario, Limited Renewables has transmission savings ($254 million) that are more than offset by higher energy prices (adds $327 million) and higher RPS payments due to paying a $55/MWh ACP (adds $282 million) instead of a $0 REC price. Capacity prices increase slightly because of the lack of new renewable capacity.

In the Low Gas/Low CO_2 scenario, Limited Renewables reduces net costs relative to the Reference strategy because $373 million in RPS transmission savings are only partially offset by higher energy and REC prices. The transmission savings are greater than in the High Gas/High CO_2 scenario because lower prices lead to higher loads, increasing the amount of remote wind resources that are avoided (and associated transmission). The RPS cost increase of $108 million is relatively modest because the $55 ACP is not much higher than the REC price paid under the Reference strategy in the Low Gas/Low CO_2 scenario. The energy price increase due to insufficient renewables is less than in the High Gas/High CO_2 scenario, largely because additional entry of combined cycle capacity (which is more economic at low gas prices) has an offsetting effect. Finally, the capacity price in the Low Gas/Low CO_2 scenario is actually lower than with the Reference strategy because losing the renewables increases energy prices, which reduces the net cost of new entry for new combined cycles, which are setting the capacity price in this scenario.

The In-State Renewables strategy has higher costs than Limited Renewables under every scenario. This is because Connecticut customers pay \$423-503 million more for RECs and out-of-market subsidies for in-state resources than they would have to pay for RECs under the Reference strategy, more than offsetting the \$254-373 million transmission savings. In addition, energy market prices are \$2-7/MWh higher than under the Reference strategy due to the absence of low-variable cost regional renewable generation.

In the Efficient Gas Expansion strategy, costs are generally similar to the Reference strategy, but about \$200 million lower. This is primarily because the added capacity depresses LMPs, although this is a temporary effect that lasts only until the market would have built the same amount of capacity (between 2021 and 2024 in the Current Trends scenario, assuming no increase in retirements). The lower cost of capital under the assumed contracting structure keeps the fixed cost sufficiently low that it does not outweigh this energy price effect.

For all of these strategies, average costs show relationships that are similar to those seen with total costs, but average costs are even more sensitive to gas and CO_2 prices. This is because changes in quantities consumed – through the price elasticity of demand – tend to concentrate (or dilute) the cost effect onto less (or more) volume. For example, Average Costs go up proportionally more than Total Costs in the High Gas/High CO_2 scenario since load is depressed by the high prices. They go down more in the Low Gas/Low CO_2 scenario because load is higher in response to lower prices. These effects are manifested in the greater heights of the scenario bands in Figure 30 (average costs) than in Figure 29 (total costs).

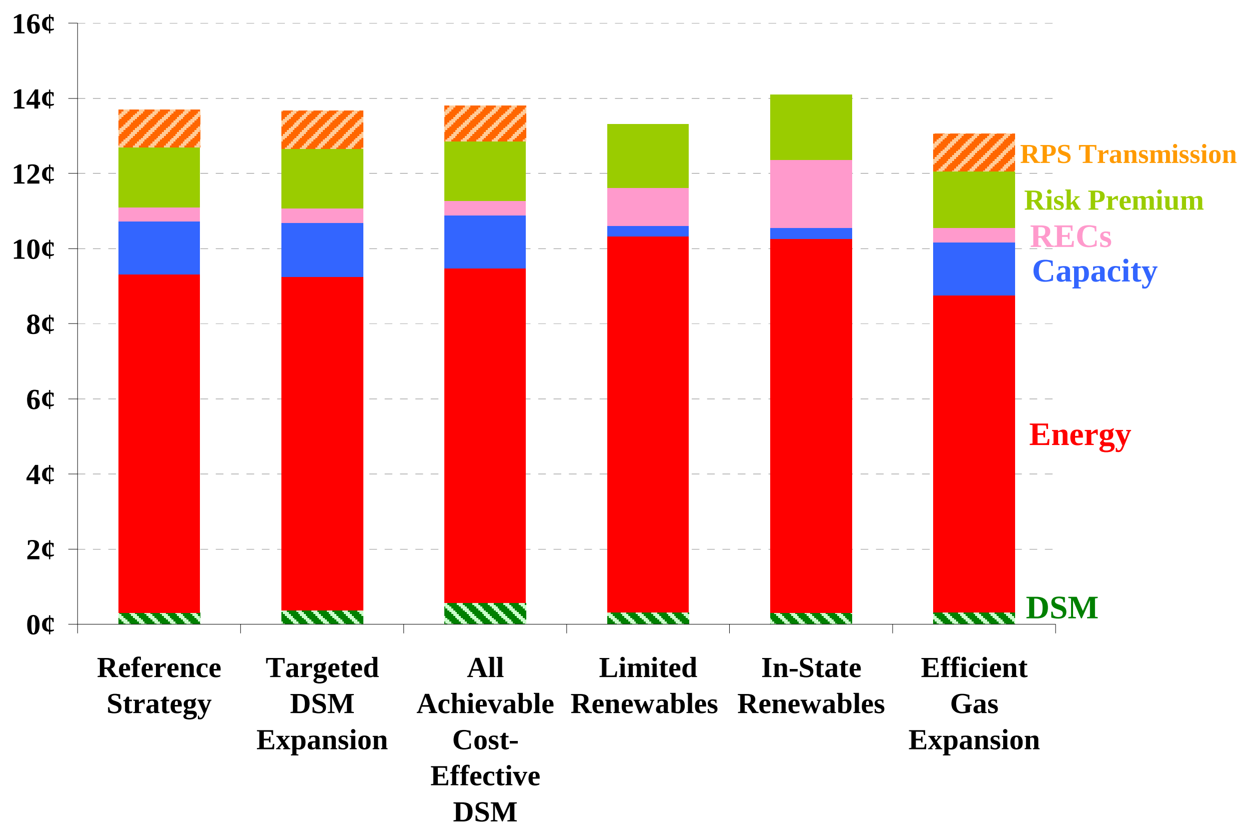
Emissions vary substantially across strategies, as shown in Figures 31 through 37. DSM reduces emissions of all types, with more DSM causing greater reductions. The Targeted DSM Expansion strategy would reduce regional CO_2 emissions and Connecticut NO_X and SO_2 emissions each by approximately one percent, and it would reduce Connecticut NO_X emissions on the top ten High Energy Demand Days (HEDD) by about five percent. In the All Achievable Cost-Effective DSM strategy, regional CO_2, NO_X, and SO_2 emissions would decrease by about 4 percent (varying by scenario); Connecticut SO_2 emissions would decrease by as much as 22 percent while NO_X emissions decrease about five percent.

With the Limited Renewables strategy, CO_2 emissions are higher regionally (14 to 17 percent) and in Connecticut (7 to 23 percent) because of the lack of low-carbon renewable generation. The In-State renewables strategy, which heavily relies on in-state, gas-fired fuel cells, has even higher CO_2 emissions in Connecticut than Limited Renewables because fuel cells produce CO_2.

SO_2 emissions are actually lower in the Limited Renewables strategy and the In-State Renewables strategy than in the Reference strategy with sufficient renewables, as shown in Figures 33 and 34. This surprising result is caused by the economic retirement of additional high-emitting, oil-fired steam generation in response to depressed capacity prices.[4] Capacity prices are depressed by as much as $40/kW-year in the Limited and In-State Renewables strategies because the absence of plentiful regional renewable generation raises energy prices (especially off-peak, when wind output is greatest), which substantially increases the margins new combined cycles can earn. This lowers their net cost of new entry, which reduces current and future capacity prices.

Winter gas use in Connecticut and New England tracks both load and renewable additions. In the cases with lower load (the DSM strategies, as well as the higher-price scenarios), gas use goes down. It goes up in the high-load cases – the low-price, high demand scenarios such as the Low Gas/Low CO_2 scenario, and also under the Limited Renewable and In-State Renewable strategies. However, this reflects the economic use of natural gas, not necessarily reliance on it to meet load (see Section III.8 (Energy Security) for a detailed discussion).

Figure 28
Connecticut Customers' Annual Average Power Supply-Related Costs (2010 ¢/kWh)
All Resource Strategies in the Current Trends Scenario in 2020



[4] Table 1.18 in Section III.1 (Resource Adequacy) documents the differences in retirements among strategies.

Figure 29
Connecticut Customers' Annual Power Supply-Related Costs in 2020 (2010 $Mill)

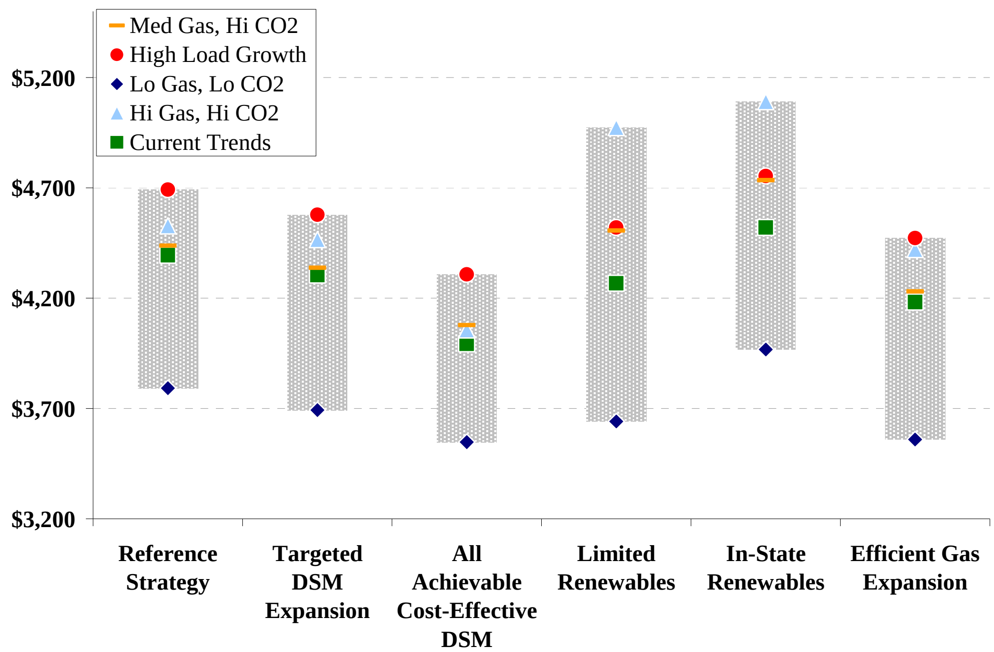


Figure 30
Connecticut Customers' Annual Average Power Supply-Related Costs in 2020 (2010 ¢/kWh)

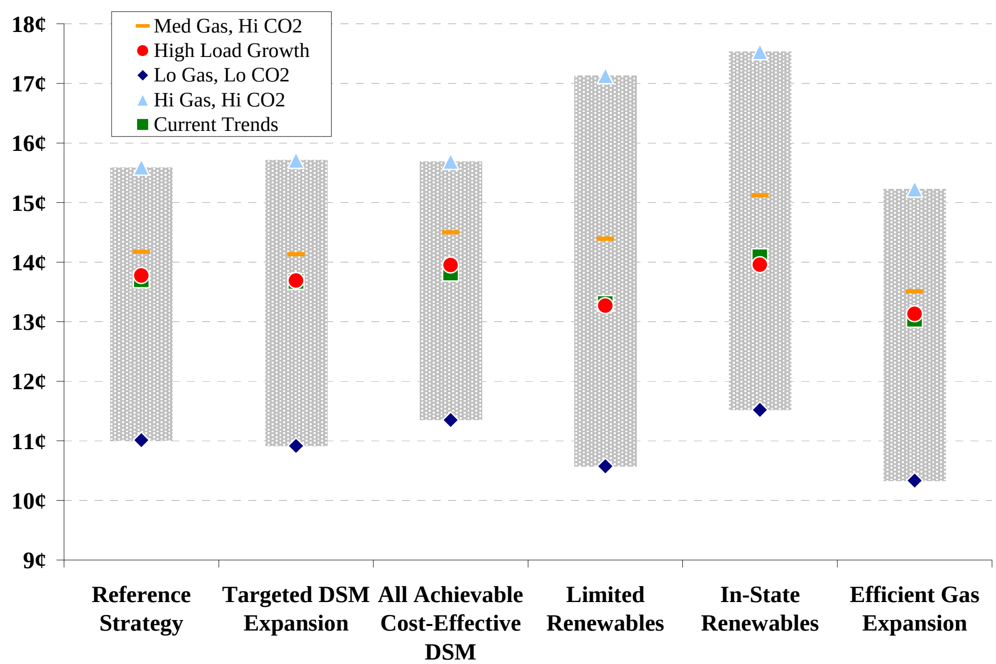


Figure 31
Annual CO_2 Emissions in Connecticut in 2020 (Tons 000)

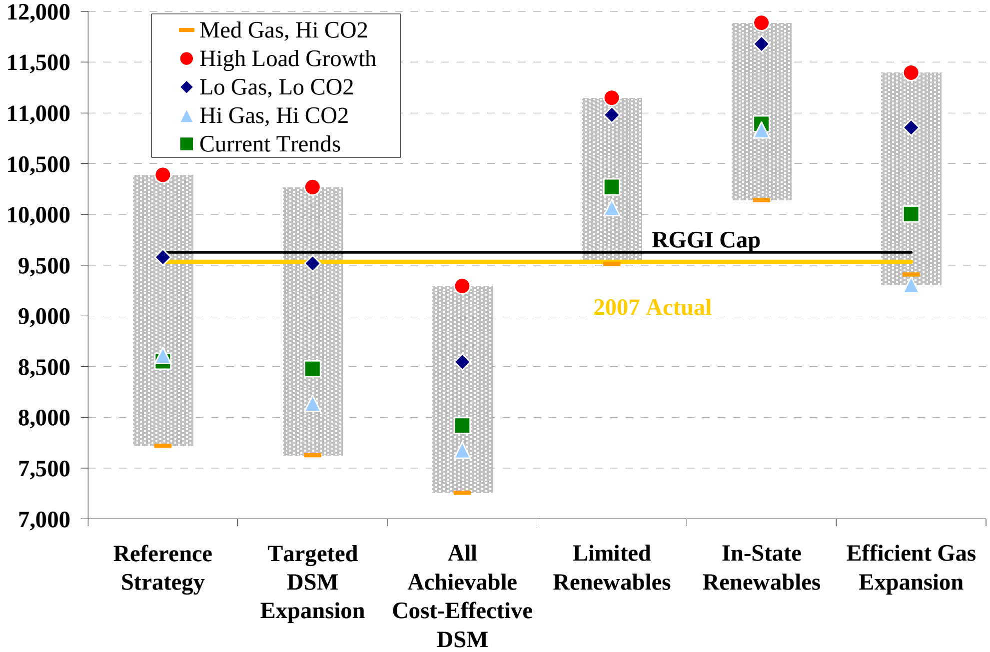
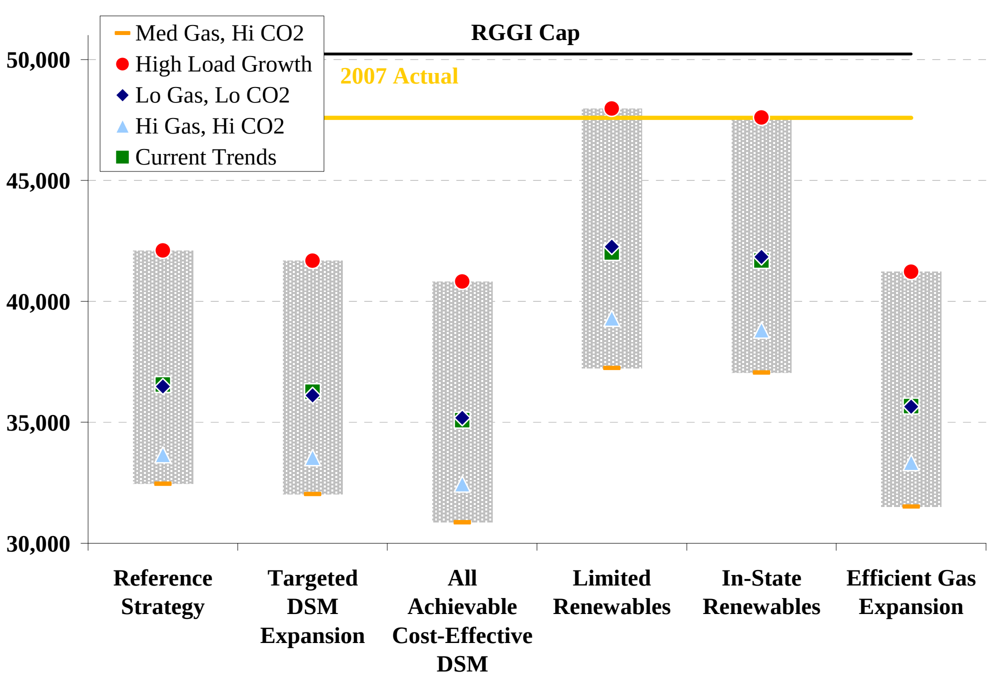


Figure 32
Annual CO_2 Emissions in ISO-NE in 2020 (Tons 000)



Note**:** There is no RGGI target for 2020; the value shown is the 2018 target.

Figure 33
Annual SO_2 Emissions in Connecticut in 2020 (Tons)

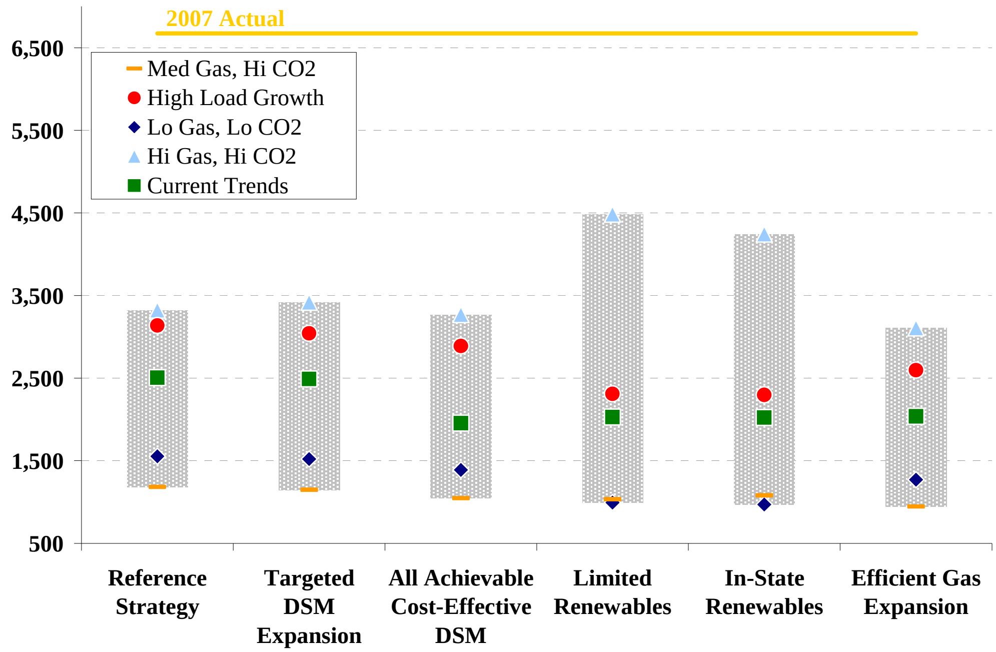


Figure 34
Annual SO_2 Emissions in ISO-NE in 2020 (Tons)

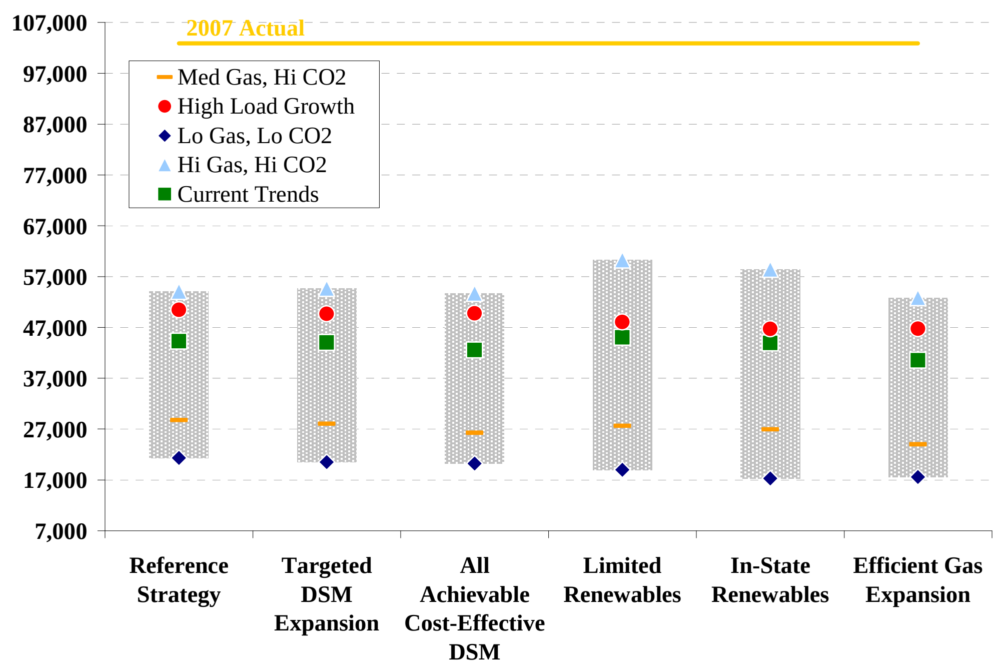


Figure 35
Annual NO_X Emissions in Connecticut in 2020 (Tons)

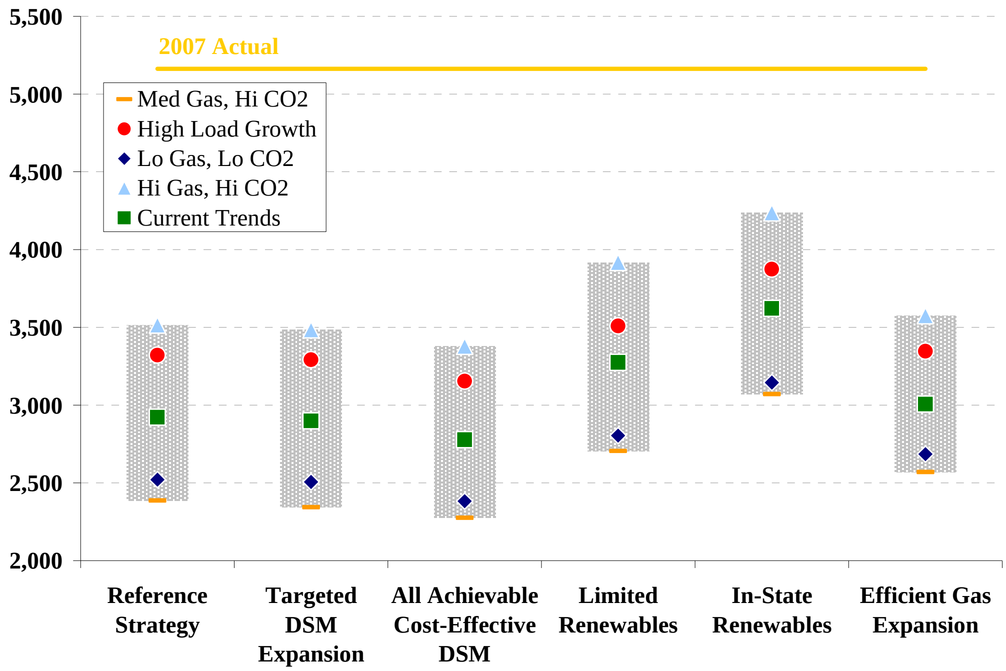


Figure 36
Annual NO_X Emissions in ISO-NE in 2020 (Tons)

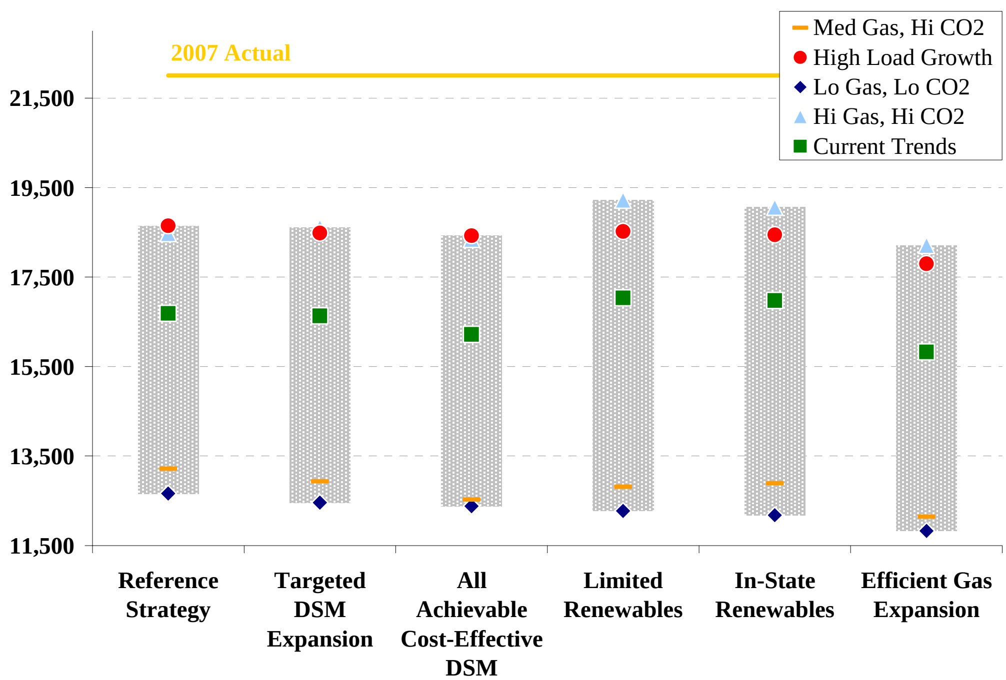


Figure 37
Connecticut HEDD NO_X Emissions in 2020 (Tons in Highest 10 Days)

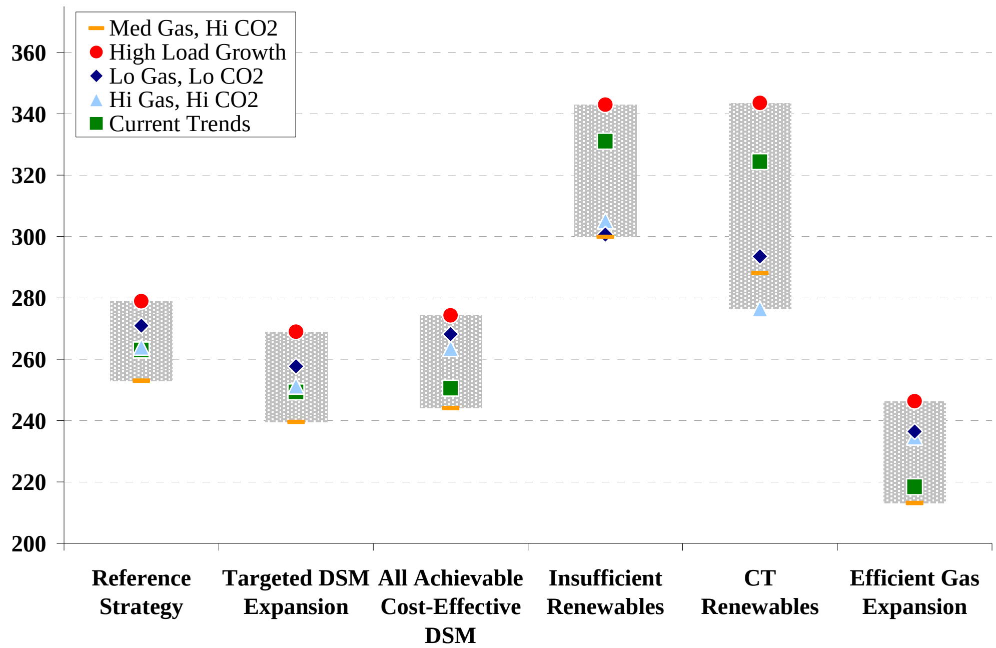


Figure 38
Winter Gas Use in Connecticut in 2020 (MMBtu 000)

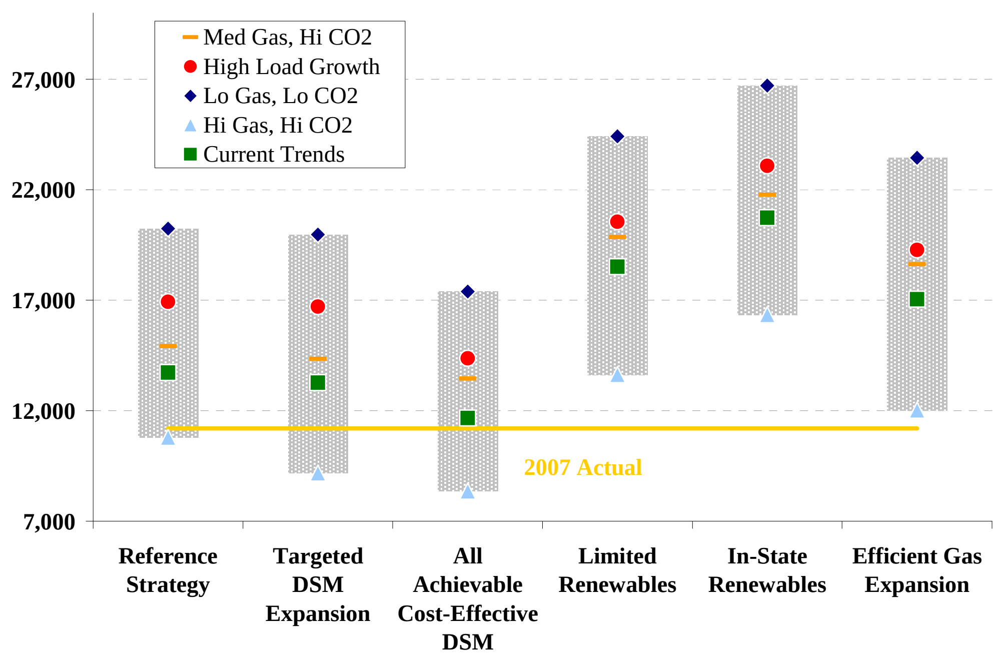


Figure 39
Winter Gas Use in ISO-NE in 2020 (MMBtu 000)

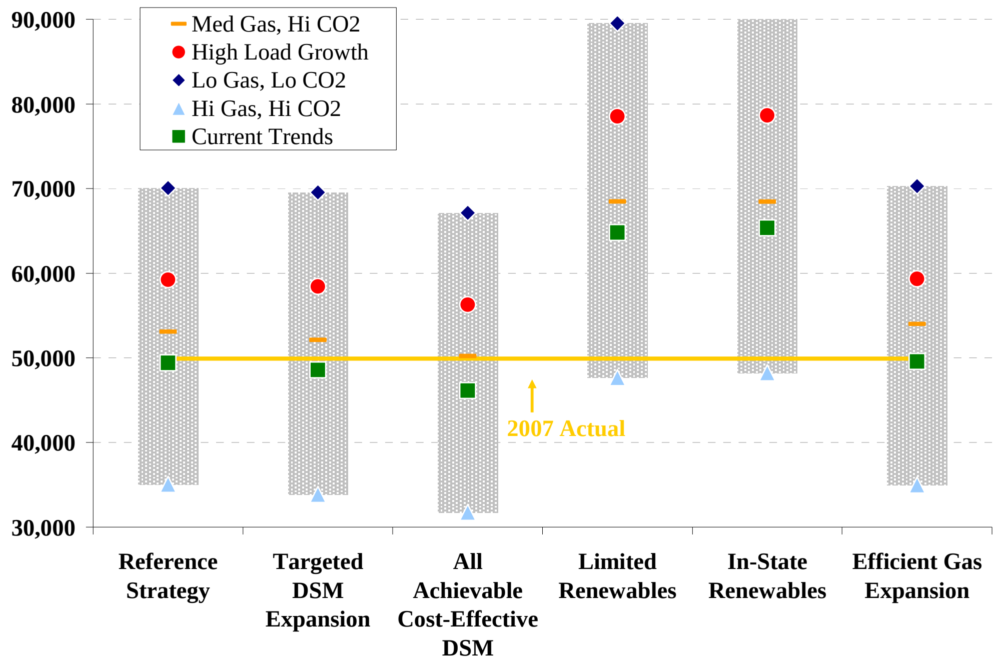


Figure 40
Connecticut Generation by Fuel Type in 2020 (TWh)

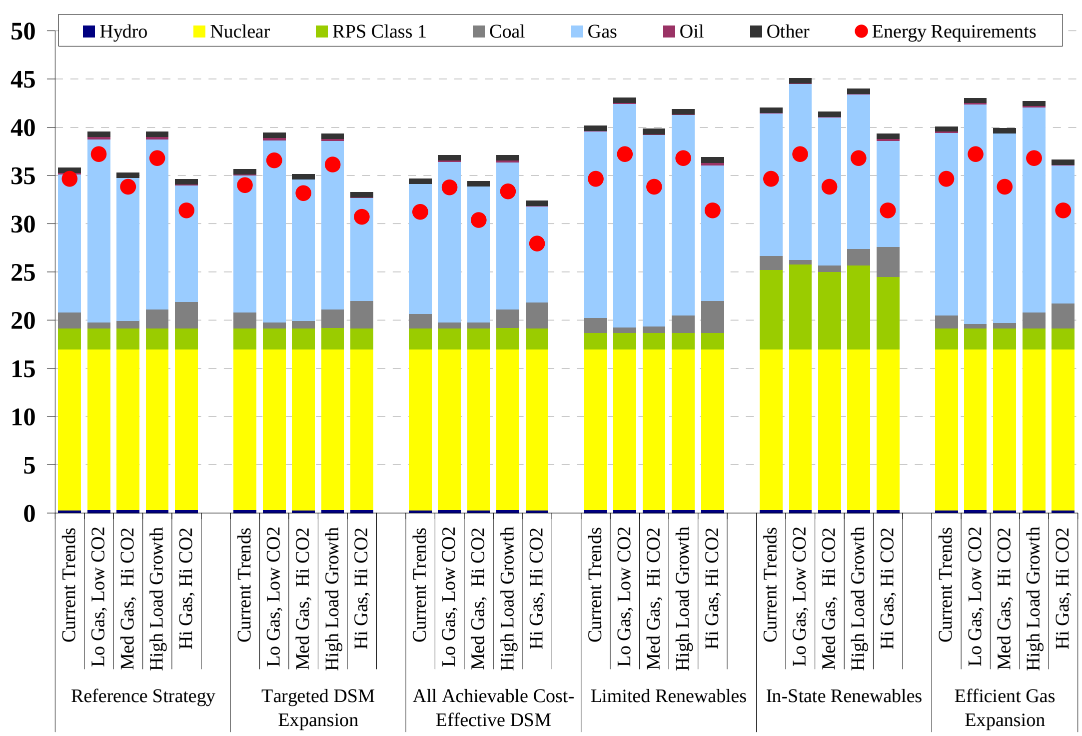
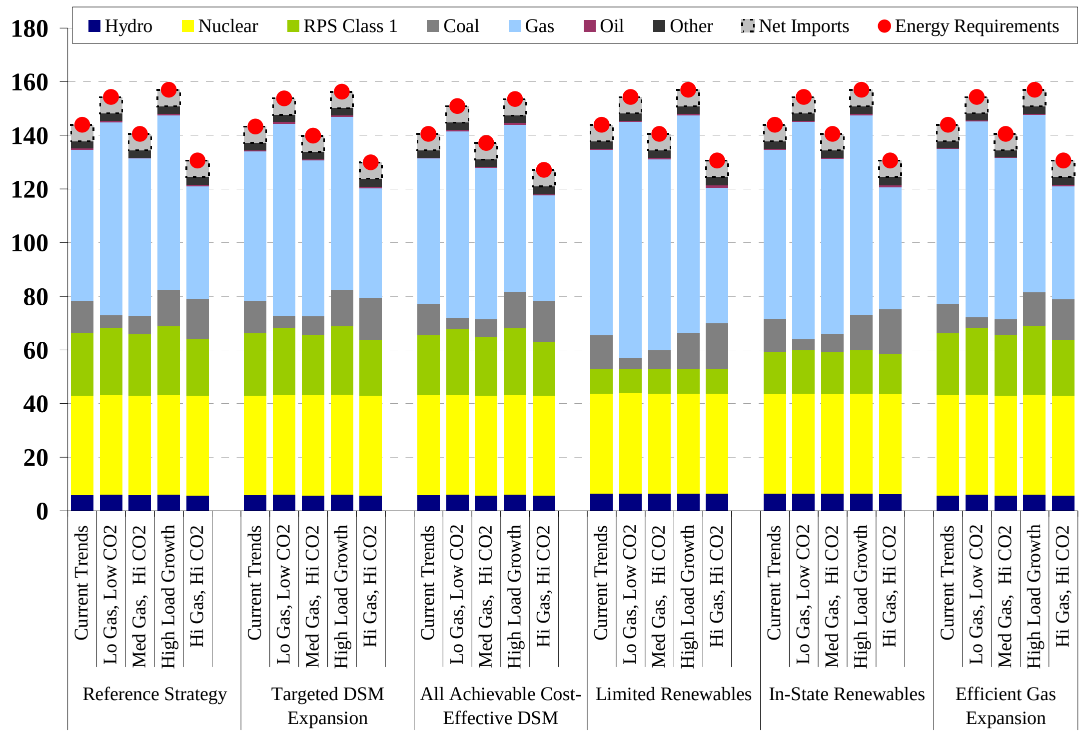


Figure 41
ISO-NE Generation by Fuel Type in 2020 (TWh)



E. Appendix 1: Detailed Tables

Table A.1
Summary of Key Parameters in Connecticut

Scenario	Strategy	Year	Load LMP ($/MWh) [1]	Generation LMP ($/MWh) [2]	Load Factor (%) [3]	Peak Load net of EE (MW) [4]	Energy Requirement net of EE (MWh) [5]	Generation In Connecticut Subarea (MWh) [6]	Net Energy Imports to Connecticut Subarea (MWh) [7]	EE (MW) [8]	DR (MW) [9]	CT LSEs' ICR (does not deduct EE) (MW) [10]	CT Internal Installed Capacity incl. EE & DR (MW) [11]	Capacity Price ($/kW-Mo) [12]	Average Henry Hub Gas Price ($/MMBtu) [13]	CO2 Price ($/ton) [14]	Retired Capacity (MW) [15]	Generic CCs (excl. 1,100 in Efficient Gas strategy) (MW) [16]
Current Trends	**Reference Strategy**	**2013**	**78.4**	**74.6**	**51%**	**7,337**	**32,942,390**	**36,873,881**	**-3,931,491**	**388**	**436**	**8,526**	**8,493**	**2.7**	**6.7**	**18**	**696**	**0**
Lo Gas/Lo CO2	Reference Strategy	2013	67.2	63.4	53%	7,553	34,893,579	38,433,283	-3,539,704	388	436	8,764	8,493	2.8	4.5	12	696	0
Med Gas/Hi CO2	Reference Strategy	2013	82.8	78.9	51%	7,279	32,434,428	36,407,144	-3,972,716	388	436	8,462	8,493	2.7	6.7	30	696	0
Hi Load	Reference Strategy	2013	80.4	76.7	53%	7,393	34,062,162	38,090,115	-4,027,953	388	436	8,577	8,493	2.6	6.7	18	696	0
Hi Gas/Hi CO2	Reference Strategy	2013	94.4	90.2	49%	7,069	30,550,345	34,681,481	-4,131,136	388	436	8,231	8,493	2.6	9.1	30	696	0
Current Trends	**Reference Strategy**	**2015**	**80.3**	**77.1**	**52%**	**7,393**	**33,419,648**	**36,869,806**	**-3,450,158**	**477**	**436**	**8,721**	**9,368**	**2.6**	**6.8**	**21**	**696**	**0**
Lo Gas/Lo CO2	Reference Strategy	2015	66.7	64.0	53%	7,637	35,625,533	38,753,656	-3,128,123	477	436	8,991	9,368	2.7	4.4	14	696	0
Med Gas/Hi CO2	Reference Strategy	2015	85.2	81.8	51%	7,326	32,838,748	36,330,105	-3,491,357	477	436	8,647	9,368	2.6	6.8	34	696	0
Hi Load	Reference Strategy	2015	83.3	80.3	53%	7,479	34,773,069	38,390,836	-3,617,767	477	436	8,805	9,368	2.6	6.8	21	696	0
Hi Gas/Hi CO2	Reference Strategy	2015	98.9	94.9	49%	7,085	30,675,092	34,507,289	-3,832,197	477	436	8,380	9,368	2.5	9.7	34	696	0
Current Trends	**Reference Strategy**	**2020**	**85.2**	**82.1**	**53%**	**7,450**	**34,644,263**	**35,802,962**	**-1,158,699**	**681**	**436**	**9,049**	**8,808**	**4.1**	**6.8**	**30**	**1504**	**0**
Lo Gas/Lo CO2	Reference Strategy	2020	68.3	66.1	55%	7,729	37,194,659	39,515,739	-2,321,080	681	436	9,371	9,108	1.1	4.1	19	1104	300
Med Gas/Hi CO2	Reference Strategy	2020	94.3	90.3	52%	7,357	33,814,811	35,313,058	-1,498,246	681	436	8,935	8,808	3.1	6.8	49	1952	0
Hi Load	Reference Strategy	2020	88.6	86.0	55%	7,603	36,787,236	39,553,543	-2,766,307	681	436	9,261	9,108	3.2	6.8	30	1104	300
Hi Gas/Hi CO2	Reference Strategy	2020	108.5	104.3	50%	7,086	31,361,304	34,603,478	-3,242,174	681	436	8,625	9,108	2.3	10.1	49	2150	300
Current Trends	Targeted DSM Expansion	2020	83.6	80.8	53%	7,272	33,997,732	35,644,222	-1,646,490	888	436	9,080	8,808	4.1	6.8	30		
Lo Gas/Lo CO2	Targeted DSM Expansion	2020	66.1	64.2	55%	7,523	36,542,542	39,396,332	-2,853,791	888	436	9,371	9,108	1.1	4.1	19	1104	300
Med Gas/Hi CO2	Targeted DSM Expansion	2020	92.5	88.9	53%	7,150	33,153,368	35,145,188	-1,991,820	888	436	8,935	8,808	3.1	6.8	49	1952	0
Hi Load	Targeted DSM Expansion	2020	86.7	84.3	56%	7,397	36,122,871	39,339,937	-3,217,065	888	436	9,261	9,108	3.2	6.8	30	1104	300
Hi Gas/Hi CO2	Targeted DSM Expansion	2020	108.9	104.8	51%	6,880	30,699,658	33,288,348	-2,588,690	888	436	8,625	8,808	2.3	10.1	49	2150	0
Current Trends	All Achievable Cost-Effective DSM	2020	83.4	80.2	52%	6,888	31,218,234	34,683,801	-3,465,567	1,242	436	9,048	8,808	3.7	6.8	30	1952	0
Lo Gas/Lo CO2	All Achievable Cost-Effective DSM	2020	69.5	66.8	53%	7,208	33,754,308	37,126,889	-3,372,581	1,242	436	9,414	8,808	0.7	4.1	19	1504	0
Med Gas/Hi CO2	All Achievable Cost-Effective DSM	2020	92.2	88.4	51%	6,795	30,375,549	34,425,578	-4,050,029	1,242	436	8,934	8,808	3.2	6.8	49	1952	0
Hi Load	All Achievable Cost-Effective DSM	2020	90.1	86.9	53%	7,098	33,343,853	37,104,124	-3,760,272	1,242	436	9,323	8,808	2.2	6.8	30	1504	0
Hi Gas/Hi CO2	All Achievable Cost-Effective DSM	2020	108.4	104.2	49%	6,525	27,921,866	32,394,601	-4,472,735	1,242	436	8,624	8,808	1.4	10.1	49	2150	0
Current Trends	Limited Renewables	2020	93.8	89.6	53%	7,450	34,644,263	40,192,774	-5,548,510	681	436	9,049	9,708	0.8	6.8	30	2069	900
Lo Gas/Lo CO2	Limited Renewables	2020	73.7	70.0	55%	7,729	37,194,659	43,039,708	-5,845,049	681	436	9,371	9,708	0.1	4.1	19	1952	900
Med Gas/Hi CO2	Limited Renewables	2020	100.5	96.2	52%	7,357	33,814,811	39,809,020	-5,994,209	681	436	8,935	9,708	1.4	6.8	49	2069	900
Hi Load	Limited Renewables	2020	96.1	92.2	55%	7,603	36,787,236	41,889,557	-5,102,321	681	436	9,261	9,708	0.1	6.8	30	2069	900
Hi Gas/Hi CO2	Limited Renewables	2020	119.9	115.2	50%	7,086	31,361,304	36,865,721	-5,504,416	681	436	8,625	9,108	2.6	10.1	49	1621	300
Current Trends	In-State Renewables	2020	91.4	87.5	53%	7,450	34,644,263	42,035,013	-7,390,750	681	436	9,049	9,108	0.8	6.8	30	2069	300
Lo Gas/Lo CO2	In-State Renewables	2020	70.3	66.7	55%	7,729	37,194,659	45,096,969	-7,902,311	681	436	9,371	9,108	0.1	4.1	19	1952	300
Med Gas/Hi CO2	In-State Renewables	2020	97.9	93.6	52%	7,357	33,814,811	41,581,370	-7,766,559	681	436	8,935	9,108	1.4	6.8	49	2069	300
Hi Load	In-State Renewables	2020	93.3	89.3	55%	7,603	36,787,236	44,003,036	-7,215,801	681	436	9,261	9,108	0.1	6.8	30	2069	300
Hi Gas/Hi CO2	In-State Renewables	2020	115.7	110.7	50%	7,086	31,361,304	39,370,216	-8,008,912	681	436	8,625	8,808	2.6	10.1	49	1621	0
Current Trends	Efficient Gas Expansion	2020	78.4	76.1	53%	7,450	34,644,263	40,055,746	-5,411,483	681	436	9,049	9,908	4.1	6.8	30	1504	0
Lo Gas/Lo CO2	Efficient Gas Expansion	2020	61.7	59.8	55%	7,729	37,194,659	43,047,491	-5,852,832	681	436	9,371	9,908	1.1	4.1	19	1104	0
Med Gas/Hi CO2	Efficient Gas Expansion	2020	87.1	83.9	52%	7,357	33,814,811	39,895,875	-6,081,063	681	436	8,935	9,908	3.1	6.8	49	1952	0
Hi Load	Efficient Gas Expansion	2020	82.7	80.4	55%	7,603	36,787,236	42,738,674	-5,951,438	681	436	9,261	9,908	3.2	6.8	30	1104	0
Hi Gas/Hi CO2	Efficient Gas Expansion	2020	103.7	100.3	50%	7,086	31,361,304	36,631,725	-5,270,421	681	436	8,625	9,908	2.3	10.1	49	2150	0
Current Trends	Nuclear	2020	76.9	72.4	53%	7,450	34,644,263	41,678,836	-7,034,573	681	436	9,049	9,908	4.1	6.8	30	1504	0
Lo Gas/Lo CO2	Nuclear	2020	61.0	57.4	55%	7,729	37,194,659	44,298,946	-7,104,287	681	436	9,371	9,908	1.1	4.1	19	1104	0
Med Gas/Hi CO2	Nuclear	2020	85.1	79.8	52%	7,357	33,814,811	41,493,736	-7,678,925	681	436	8,935	9,908	3.1	6.8	49	1952	0
Hi Load	Nuclear	2020	81.8	77.6	55%	7,603	36,787,236	44,066,528	-7,279,292	681	436	9,261	9,908	3.2	6.8	30	1104	0
Hi Gas/Hi CO2	Nuclear	2020	101.0	94.0	50%	7,086	31,361,304	39,158,114	-7,796,809	681	436	8,625	9,908	2.3	10.1	49	2150	0

Table A.2
Summary of Key Parameters in Connecticut
(Differences, compared to Reference Strategy in the given scenario)

Scenario	Strategy	Year	Load LMP ($/MWh)	Generation LMP ($/MWh)	Load Factor (%)	Peak Load net of EE (MW)	Energy Requirement net of EE (MWh)	Generation In Connecticut Subarea (MWh)	Net Energy Imports to Connecticut Subarea (MWh)	EE (MW)	DR (MW)	CT LSEs' ICR (does not deduct EE) (MW)	CT Internal Installed Capacity incl. EE & DR (MW)	Capacity Price ($/kW-Mo)	Average Henry Hub Gas Price ($/MMBtu)	CO2 Price ($/ton)	Retired Capacity (MW)	Generic CCs (excl. 1,100 in Efficient Gas strategy) (MW)
			[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]
(ABSOLUTE VALUES IN REFERENCE STRATEGY)																		
Current Trends	Reference Strategy	2020	85.2	82.1	53%	7,450	34,644,263	35,802,962	(1,158,699)	681	436	9,049	8,808	4.1	6.8	30	1,504	0
Lo Gas/Lo CO2	Reference Strategy	2020	68.3	66.1	55%	7,729	37,194,659	39,515,739	(2,321,080)	681	436	9,371	9,108	1.1	4.1	19	1,104	300
Med Gas/Hi CO2	Reference Strategy	2020	94.3	90.3	52%	7,357	33,814,811	35,313,058	(1,498,246)	681	436	8,935	8,808	3.1	6.8	49	1,952	0
Hi Load	Reference Strategy	2020	88.6	86.0	55%	7,603	36,787,236	39,553,543	(2,766,307)	681	436	9,261	9,108	3.2	6.8	30	1,104	300
Hi Gas/Hi CO2	Reference Strategy	2020	108.5	104.3	50%	7,086	31,361,304	34,603,478	(3,242,174)	681	436	8,625	9,108	2.3	10.1	49	2,150	300
(DIFFERENCES IN OTHER STRATEGIES, COMPARED TO REFERENCE STRATEGY)																		
Current Trends	Targeted DSM Expansion	2020	(1.6)	(1.3)	0%	(178)	(646,531)	(158,740)	(487,791)	207	0	31	0	0.0	0.0	0	(1,504)	0
Lo Gas/Lo CO2	Targeted DSM Expansion	2020	(2.1)	(1.9)	1%	(206)	(652,117)	(119,407)	(532,710)	207	0	0	0	0.0	0.0	0	0	0
Med Gas/Hi CO2	Targeted DSM Expansion	2020	(1.8)	(1.4)	0%	(206)	(661,444)	(167,870)	(493,574)	207	0	0	0	0.0	0.0	0	0	0
Hi Load	Targeted DSM Expansion	2020	(1.9)	(1.6)	1%	(206)	(664,364)	(213,606)	(450,758)	207	0	0	0	0.0	0.0	0	0	0
Hi Gas/Hi CO2	Targeted DSM Expansion	2020	0.4	0.5	0%	(206)	(661,646)	(1,315,131)	653,484	207	0	0	(300)	0.0	0.0	0	0	(300)
Current Trends	All Achievable Cost-Effective DSM	2020	(1.8)	(1.9)	-1%	(561)	(3,426,030)	(1,119,161)	(2,306,868)	561	0	(0)	0	(0.4)	0.0	0	448	0
Lo Gas/Lo CO2	All Achievable Cost-Effective DSM	2020	1.2	0.7	-1%	(522)	(3,440,351)	(2,388,850)	(1,051,501)	561	0	44	(300)	(0.4)	0.0	0	400	(300)
Med Gas/Hi CO2	All Achievable Cost-Effective DSM	2020	(2.1)	(1.8)	-1%	(561)	(3,439,263)	(887,480)	(2,551,783)	561	0	(0)	0	0.1	0.0	0	0	0
Hi Load	All Achievable Cost-Effective DSM	2020	1.5	0.9	-2%	(505)	(3,443,383)	(2,449,419)	(993,964)	561	0	62	(300)	(1.0)	0.0	0	400	(300)
Hi Gas/Hi CO2	All Achievable Cost-Effective DSM	2020	(0.1)	(0.1)	-2%	(561)	(3,439,438)	(2,208,877)	(1,230,561)	561	0	(0)	(300)	(0.9)	0.0	0	0	(300)
Current Trends	Limited Renewables	2020	8.6	7.5	0%	0	0	4,389,812	(4,389,812)	0	0	0	900	(3.3)	0.0	0	565	900
Lo Gas/Lo CO2	Limited Renewables	2020	5.4	3.9	0%	0	0	3,523,969	(3,523,969)	0	0	0	600	(1.0)	0.0	0	848	600
Med Gas/Hi CO2	Limited Renewables	2020	6.2	6.0	0%	0	0	4,495,962	(4,495,962)	0	0	0	900	(1.7)	0.0	0	117	900
Hi Load	Limited Renewables	2020	7.5	6.2	0%	0	0	2,336,013	(2,336,013)	0	0	0	600	(3.1)	0.0	0	965	600
Hi Gas/Hi CO2	Limited Renewables	2020	11.3	11.0	0%	0	0	2,262,242	(2,262,242)	0	0	0	0	0.3	0.0	0	(529)	0
Current Trends	In-State Renewables	2020	6.2	5.4	0%	0	0	6,232,051	(6,232,051)	0	0	0	300	(3.3)	0.0	0	565	300
Lo Gas/Lo CO2	In-State Renewables	2020	2.1	0.6	0%	0	0	5,581,230	(5,581,230)	0	0	0	0	(1.0)	0.0	0	848	0
Med Gas/Hi CO2	In-State Renewables	2020	3.6	3.4	0%	0	0	6,268,313	(6,268,313)	0	0	0	300	(1.7)	0.0	0	117	300
Hi Load	In-State Renewables	2020	4.7	3.3	0%	0	0	4,449,493	(4,449,493)	0	0	0	0	(3.1)	0.0	0	965	0
Hi Gas/Hi CO2	In-State Renewables	2020	7.2	6.4	0%	0	0	4,766,738	(4,766,738)	0	0	0	(300)	0.3	0.0	0	(529)	(300)
Current Trends	Efficient Gas Expansion	2020	(6.8)	(6.1)	0%	0	0	4,252,784	(4,252,784)	0	0	0	1,100	0.0	0.0	0	0	0
Lo Gas/Lo CO2	Efficient Gas Expansion	2020	(6.5)	(6.3)	0%	0	0	3,531,752	(3,531,752)	0	0	0	800	0.0	0.0	0	0	(300)
Med Gas/Hi CO2	Efficient Gas Expansion	2020	(7.2)	(6.4)	0%	0	0	4,582,817	(4,582,817)	0	0	0	1,100	0.0	0.0	0	0	0
Hi Load	Efficient Gas Expansion	2020	(5.9)	(5.6)	0%	0	0	3,185,131	(3,185,131)	0	0	0	800	0.0	0.0	0	0	(300)
Hi Gas/Hi CO2	Efficient Gas Expansion	2020	(4.8)	(3.9)	0%	0	0	2,028,247	(2,028,247)	0	0	0	800	0.0	0.0	0	0	(300)
Current Trends	Nuclear	2020	(8.3)	(9.7)	0%	0	0	5,875,874	(5,875,874)	0	0	0	1,100	0.0	0.0	0	0	0
Lo Gas/Lo CO2	Nuclear	2020	(7.2)	(8.7)	0%	0	0	4,783,207	(4,783,207)	0	0	0	800	0.0	0.0	0	0	(300)
Med Gas/Hi CO2	Nuclear	2020	(9.2)	(10.5)	0%	0	0	6,180,678	(6,180,678)	0	0	0	1,100	0.0	0.0	0	0	0
Hi Load	Nuclear	2020	(6.8)	(8.3)	0%	0	0	4,512,985	(4,512,985)	0	0	0	800	0.0	0.0	0	0	(300)
Hi Gas/Hi CO2	Nuclear	2020	(7.6)	(10.3)	0%	0	0	4,554,636	(4,554,636)	0	0	0	800	0.0	0.0	0	0	(300)

Table A.3
Power Supply-Related Costs

Scenario	Strategy	Year	LMP*Load *($Mil)* *[17]*	Marginal Loss Refund *($Mil)* *[18]*	Spin (26% of ISO cost) *($Mil)* *[19]*	Uplift (26% of ISO cost) *($Mil)* *[20]*	Capacity Price * ICR *($Mil)* *[21]*	RPS Cost (RECs/ ACPs) *($Mil)* *[22]*	15% Risk Premium *($Mil)* *[23]*	**TOTAL GENERATION SVC COST** *($Mil)* *[24]*	**AVERAGE GENERATION SVC COST** *(¢/kWh)* *[25]*	3 Mill SBC Charge *($Mil)* *[26]*	Additional DSM Program Costs *($Mil)* *[27]*	FCM Credit for Additional DSM *($Mil)* *[28]*	**TOTAL SYSTEM BENEFITS COST** *($Mil)* *[29]*	**AVERAGE SYSTEM BENEFITS COST** *(¢/kWh)* *[30]*	Out-Of-Market Payments for RPS *($Mil)* *[31]*	Payments for New COS Generation *($Mil)* *[32]*	Tx cost for RPS *($Mil)* *[33]*	**TOTAL COST** *($Mil)* *[34]*	**AVERAGE COST** *(¢/kWh)* *[35]*
										Sum[17-23]	[24]/([5]/1.08)				Sum[26-28]	[29]/([5]/1.08)				[24]+[29]+[31]+[32]+[33]	[34]/([5]/1.08)
Current Trends	Reference Strategy	2013	2,534	-76	19	17	275	64	424	**3,247**	**10.65**	92	0	0	**92**	**0.30**	18	0	0	**3,357**	**11.01**
Lo Gas/Lo CO2	Reference Strategy	2013	2,291	-72	31	10	291	107	397	**3,043**	**9.42**	97	0	0	**97**	**0.30**	18	0	0	**3,158**	**9.77**
Med Gas/Hi CO2	Reference Strategy	2013	2,636	-79	18	21	271	49	436	**3,343**	**11.13**	90	0	0	**90**	**0.30**	20	0	0	**3,452**	**11.50**
Hi Load	Reference Strategy	2013	2,691	-82	22	14	272	59	445	**3,414**	**10.82**	95	0	0	**95**	**0.30**	18	0	0	**3,527**	**11.18**
Hi Gas/Hi CO2	Reference Strategy	2013	2,840	-82	13	34	254	11	460	**3,525**	**12.46**	85	0	0	**85**	**0.30**	20	0	0	**3,630**	**12.83**
Current Trends	Reference Strategy	2015	2,643	-78	20	25	274	73	443	**3,400**	**10.99**	93	0	0	**93**	**0.30**	26	0	98	**3,617**	**11.69**
Lo Gas/Lo CO2	Reference Strategy	2015	2,337	-72	29	17	291	138	411	**3,148**	**9.54**	99	0	0	**99**	**0.30**	24	0	128	**3,399**	**10.31**
Med Gas/Hi CO2	Reference Strategy	2015	2,755	-81	18	30	269	52	456	**3,499**	**11.51**	91	0	0	**91**	**0.30**	28	0	91	**3,709**	**12.20**
Hi Load	Reference Strategy	2015	2,857	-85	24	22	273	63	473	**3,625**	**11.26**	97	0	0	**97**	**0.30**	26	0	121	**3,869**	**12.02**
Hi Gas/Hi CO2	Reference Strategy	2015	2,994	-84	17	41	255	0	483	**3,705**	**13.04**	85	0	0	**85**	**0.30**	27	0	62	**3,880**	**13.66**
Current Trends	Reference Strategy	2020	2,904	-90	26	51	451	81	513	**3,936**	**12.27**	96	0	0	**96**	**0.30**	42	0	321	**4,395**	**13.70**
Lo Gas/Lo CO2	Reference Strategy	2020	2,511	-74	35	30	120	227	427	**3,276**	**9.51**	103	0	0	**103**	**0.30**	41	0	373	**3,793**	**11.01**
Med Gas/Hi CO2	Reference Strategy	2020	3,130	-98	27	55	332	26	521	**3,993**	**12.75**	94	0	0	**94**	**0.30**	47	0	304	**4,438**	**14.17**
Hi Load	Reference Strategy	2020	3,229	-93	31	44	355	64	545	**4,175**	**12.26**	102	0	0	**102**	**0.30**	42	0	373	**4,692**	**13.78**
Hi Gas/Hi CO2	Reference Strategy	2020	3,362	-91	24	75	235	0	541	**4,146**	**14.28**	87	0	0	**87**	**0.30**	42	0	254	**4,528**	**15.59**
Current Trends	Targeted DSM Expansion	2020	2,803	-85	25	52	452	81	499	**3,827**	**12.16**	94	31	-10	**115**	**0.37**	42	0	321	**4,305**	**13.68**
Lo Gas/Lo CO2	Targeted DSM Expansion	2020	2,398	-69	31	31	120	227	411	**3,150**	**9.31**	102	31	-3	**130**	**0.38**	41	0	373	**3,693**	**10.91**
Med Gas/Hi CO2	Targeted DSM Expansion	2020	3,017	-92	25	59	332	26	505	**3,872**	**12.61**	92	31	-8	**115**	**0.38**	47	0	304	**4,338**	**14.13**
Hi Load	Targeted DSM Expansion	2020	3,110	-87	28	44	355	64	527	**4,040**	**12.08**	100	31	-8	**123**	**0.37**	42	0	373	**4,579**	**13.69**
Hi Gas/Hi CO2	Targeted DSM Expansion	2020	3,296	-98	25	71	235	0	529	**4,059**	**14.28**	85	31	-6	**111**	**0.39**	42	0	254	**4,466**	**15.71**
Current Trends	All Achievable Cost-Effective DSM	2020	2,578	-76	25	50	404	73	458	**3,513**	**12.15**	87	100	-25	**162**	**0.56**	42	0	276	**3,993**	**13.81**
Lo Gas/Lo CO2	All Achievable Cost-Effective DSM	2020	2,322	-72	38	28	80	206	390	**2,992**	**9.57**	94	100	-5	**189**	**0.60**	41	0	326	**3,547**	**11.35**
Med Gas/Hi CO2	All Achievable Cost-Effective DSM	2020	2,768	-81	27	59	342	23	471	**3,608**	**12.83**	84	100	-21	**163**	**0.58**	47	0	260	**4,078**	**14.50**
Hi Load	All Achievable Cost-Effective DSM	2020	2,982	-90	34	41	246	58	491	**3,761**	**12.18**	93	100	-15	**178**	**0.58**	42	0	326	**4,307**	**13.95**
Hi Gas/Hi CO2	All Achievable Cost-Effective DSM	2020	3,007	-84	26	70	140	0	474	**3,633**	**14.05**	78	100	-9	**168**	**0.65**	42	0	213	**4,056**	**15.69**
Current Trends	Limited Renewables	2020	3,252	-92	41	17	89	311	543	**4,160**	**12.97**	96	0	0	**96**	**0.30**	11	0	0	**4,267**	**13.30**
Lo Gas/Lo CO2	Limited Renewables	2020	2,738	-75	49	8	9	334	459	**3,523**	**10.23**	103	0	0	**103**	**0.30**	15	0	0	**3,641**	**10.57**
Med Gas/Hi CO2	Limited Renewables	2020	3,396	-85	37	21	155	304	574	**4,401**	**14.06**	94	0	0	**94**	**0.30**	11	0	0	**4,506**	**14.39**
Hi Load	Limited Renewables	2020	3,527	-94	46	15	9	331	575	**4,407**	**12.94**	102	0	0	**102**	**0.30**	10	0	0	**4,520**	**13.27**
Hi Gas/Hi CO2	Limited Renewables	2020	3,732	-102	33	34	264	282	636	**4,879**	**16.80**	87	0	0	**87**	**0.30**	8	0	0	**4,974**	**17.13**
Current Trends	In-State Renewables	2020	3,162	-75	37	73	89	424	557	**4,267**	**13.30**	96	0	0	**96**	**0.30**	157	0	0	**4,520**	**14.09**
Lo Gas/Lo CO2	In-State Renewables	2020	2,617	-68	43	63	9	456	468	**3,588**	**10.42**	103	0	0	**103**	**0.30**	276	0	0	**3,967**	**11.52**
Med Gas/Hi CO2	In-State Renewables	2020	3,310	-81	32	65	155	414	584	**4,479**	**14.31**	94	0	0	**94**	**0.30**	161	0	0	**4,735**	**15.12**
Hi Load	In-State Renewables	2020	3,430	-91	41	72	9	451	587	**4,497**	**13.20**	102	0	0	**102**	**0.30**	154	0	0	**4,754**	**13.96**
Hi Gas/Hi CO2	In-State Renewables	2020	3,615	-96	29	85	264	384	642	**4,924**	**16.96**	87	0	0	**87**	**0.30**	80	0	0	**5,091**	**17.53**
Current Trends	Efficient Gas Expansion	2020	2,707	-70	17	58	451	81	487	**3,731**	**11.63**	96	0	0	**96**	**0.30**	42	-8	321	**4,182**	**13.04**
Lo Gas/Lo CO2	Efficient Gas Expansion	2020	2,301	-62	25	33	120	227	397	**3,042**	**8.83**	103	0	0	**103**	**0.30**	41	0	373	**3,559**	**10.33**
Med Gas/Hi CO2	Efficient Gas Expansion	2020	2,926	-75	18	63	332	26	494	**3,785**	**12.09**	94	0	0	**94**	**0.30**	47	0	304	**4,230**	**13.51**
Hi Load	Efficient Gas Expansion	2020	3,045	-80	21	47	355	64	518	**3,972**	**11.66**	102	0	0	**102**	**0.30**	42	-16	373	**4,473**	**13.13**
Hi Gas/Hi CO2	Efficient Gas Expansion	2020	3,233	-81	17	80	235	0	523	**4,008**	**13.80**	87	0	0	**87**	**0.30**	42	30	254	**4,421**	**15.22**
Current Trends	Nuclear	2020	2,651	-101	18	60	451	81	474	**3,633**	**11.33**	96	0	0	**96**	**0.30**	42	43	321	**4,135**	**12.89**
Lo Gas/Lo CO2	Nuclear	2020	2,266	-88	24	34	120	227	386	**2,963**	**8.60**	103	0	0	**103**	**0.30**	41	208	373	**3,688**	**10.71**
Med Gas/Hi CO2	Nuclear	2020	2,856	-109	18	68	332	26	479	**3,670**	**11.72**	94	0	0	**94**	**0.30**	47	-4	304	**4,111**	**13.13**
Hi Load	Nuclear	2020	3,005	-115	21	51	355	64	507	**3,884**	**11.40**	102	0	0	**102**	**0.30**	42	10	373	**4,411**	**12.95**
Hi Gas/Hi CO2	Nuclear	2020	3,143	-117	27	80	235	0	505	**3,874**	**13.34**	87	0	0	**87**	**0.30**	42	-100	254	**4,157**	**14.32**

Table A.4
Power Supply-Related Costs
(Differences, compared to Reference Strategy in the given scenario)

Scenario	Strategy	Year	LMP*Load (\$Mil) [17]	Marginal Loss Refund (\$Mil) [18]	Spin (26% of ISO cost) (\$Mil) [19]	Uplift (26% of ISO cost) (\$Mil) [20]	Capacity Price * ICR (\$Mil) [21]	RPS Cost (RECs/ ACPs) (\$Mil) [22]	15% Risk Premium (\$Mil) [23]	**TOTAL GENERATION SVC COST** (\$Mil) [24]	**AVERAGE GENERATION SVC COST** (¢/kWh) [25]	3 Mill SBC Charge (\$Mil) [26]	Additional DSM Program Costs (\$Mil) [27]	FCM Credit for Additional DSM (\$Mil) [28]	**TOTAL SYSTEM BENEFITS COST** (\$Mil) [29]	**AVERAGE SYSTEM BENEFITS COST** (¢/kWh) [30]	Out-Of-Market Payments for RPS (\$Mil) [31]	Payments for New COS Generation (\$Mil) [32]	Tx cost for RPS (\$Mil) [33]	**TOTAL COST** (\$Mil) [34]	**AVERAGE COST** (¢/kWh) [35]
(ABSOLUTE VALUES IN REFERENCE STRATEGY)																					
Current Trends	Reference Strategy	2020	2,904	(90)	26	51	451	81	513	3,936	12.27	96	0	0	96	0.30	42	0	321	4,395	13.70
Lo Gas/Lo CO2	Reference Strategy	2020	2,511	(74)	35	30	120	227	427	3,276	9.51	103	0	0	103	0.30	41	0	373	3,793	11.01
Med Gas/Hi CO2	Reference Strategy	2020	3,130	(98)	27	55	332	26	521	3,993	12.75	94	0	0	94	0.30	47	0	304	4,438	14.17
Hi Load	Reference Strategy	2020	3,229	(93)	31	44	355	64	545	4,175	12.26	102	0	0	102	0.30	42	0	373	4,692	13.78
Hi Gas/Hi CO2	Reference Strategy	2020	3,362	(91)	24	75	235	0	541	4,146	14.28	87	0	0	87	0.30	42	0	254	4,528	15.59
(DIFFERENCES IN OTHER STRATEGIES, COMPARED TO REFERENCE STRATEGY)																					
Current Trends	Targeted DSM Expansion	2020	(101)	5	(2)	1	2	0	(14)	(109)	(0.11)	(2)	31	(10)	19	0.07	0	0	0	(90)	(0.03)
Lo Gas/Lo CO2	Targeted DSM Expansion	2020	(113)	5	(3)	1	0	0	(16)	(126)	(0.20)	(2)	31	(3)	27	0.08	0	0	0	(100)	(0.10)
Med Gas/Hi CO2	Targeted DSM Expansion	2020	(113)	6	(2)	3	0	0	(16)	(121)	(0.14)	(2)	31	(8)	22	0.08	0	0	0	(100)	(0.04)
Hi Load	Targeted DSM Expansion	2020	(119)	6	(3)	(1)	0	0	(18)	(135)	(0.18)	(2)	31	(8)	21	0.07	0	0	0	(113)	(0.09)
Hi Gas/Hi CO2	Targeted DSM Expansion	2020	(66)	(7)	1	(4)	0	0	(11)	(86)	0.00	(2)	31	(6)	24	0.09	0	0	0	(63)	0.12
Current Trends	All Achievable Cost-Effective DSM	2020	(326)	14	(1)	(1)	(46)	(8)	(55)	(423)	(0.12)	(10)	100	(25)	65	0.26	0	0	(44)	(402)	0.11
Lo Gas/Lo CO2	All Achievable Cost-Effective DSM	2020	(189)	2	3	(2)	(41)	(21)	(37)	(284)	0.06	(10)	100	(5)	86	0.30	0	0	(47)	(245)	0.34
Med Gas/Hi CO2	All Achievable Cost-Effective DSM	2020	(363)	17	(0)	3	10	(3)	(50)	(385)	0.08	(10)	100	(21)	69	0.28	0	0	(44)	(359)	0.33
Hi Load	All Achievable Cost-Effective DSM	2020	(247)	3	3	(3)	(110)	(6)	(54)	(414)	(0.07)	(10)	100	(15)	76	0.28	0	0	(47)	(385)	0.18
Hi Gas/Hi CO2	All Achievable Cost-Effective DSM	2020	(354)	7	2	(5)	(95)	0	(67)	(512)	(0.22)	(10)	100	(9)	81	0.35	0	0	(41)	(472)	0.09
Current Trends	Limited Renewables	2020	348	(3)	15	(34)	(361)	230	29	224	0.70	0	0	0	0	0.00	(31)	0	(321)	(127)	(0.40)
Lo Gas/Lo CO2	Limited Renewables	2020	227	(1)	15	(22)	(111)	108	32	247	0.72	0	0	0	0	0.00	(25)	0	(373)	(151)	(0.44)
Med Gas/Hi CO2	Limited Renewables	2020	266	13	10	(35)	(177)	278	53	408	1.30	0	0	0	0	0.00	(36)	0	(304)	69	0.22
Hi Load	Limited Renewables	2020	297	(1)	15	(29)	(346)	267	30	233	0.68	0	0	0	0	0.00	(32)	0	(373)	(172)	(0.51)
Hi Gas/Hi CO2	Limited Renewables	2020	370	(11)	9	(41)	29	282	96	733	2.52	0	0	0	0	0.00	(34)	0	(254)	445	1.53
Current Trends	In-State Renewables	2020	258	15	11	22	(361)	343	43	331	1.03	0	0	0	0	0.00	116	0	(321)	126	0.39
Lo Gas/Lo CO2	In-State Renewables	2020	106	6	8	34	(111)	229	41	312	0.91	0	0	0	0	0.00	235	0	(373)	175	0.51
Med Gas/Hi CO2	In-State Renewables	2020	180	17	6	10	(177)	388	63	487	1.55	0	0	0	0	0.00	114	0	(304)	297	0.95
Hi Load	In-State Renewables	2020	201	2	10	27	(346)	387	42	323	0.95	0	0	0	0	0.00	112	0	(373)	62	0.18
Hi Gas/Hi CO2	In-State Renewables	2020	253	(5)	5	10	29	384	101	778	2.68	0	0	0	0	0.00	38	0	(254)	562	1.94
Current Trends	Efficient Gas Expansion	2020	(197)	20	(9)	6	0	0	(27)	(205)	(0.64)	0	0	0	0	0.00	0	(8)	0	(213)	(0.66)
Lo Gas/Lo CO2	Efficient Gas Expansion	2020	(210)	13	(10)	3	0	0	(30)	(234)	(0.68)	0	0	0	0	0.00	0	0	0	(233)	(0.68)
Med Gas/Hi CO2	Efficient Gas Expansion	2020	(204)	23	(9)	8	0	0	(27)	(208)	(0.66)	0	0	0	0	0.00	0	0	0	(208)	(0.66)
Hi Load	Efficient Gas Expansion	2020	(184)	13	(9)	3	0	0	(27)	(203)	(0.60)	0	0	0	0	0.00	0	(16)	0	(219)	(0.64)
Hi Gas/Hi CO2	Efficient Gas Expansion	2020	(129)	11	(7)	5	0	0	(18)	(137)	(0.47)	0	0	0	0	0.00	0	30	0	(107)	(0.37)
Current Trends	Nuclear	2020	(253)	(11)	(9)	9	0	0	(40)	(303)	(0.94)	0	0	0	0	0.00	0	43	0	(260)	(0.81)
Lo Gas/Lo CO2	Nuclear	2020	(245)	(14)	(11)	5	0	0	(41)	(313)	(0.91)	0	0	0	0	0.00	0	208	0	(105)	(0.30)
Med Gas/Hi CO2	Nuclear	2020	(274)	(11)	(9)	13	0	0	(42)	(323)	(1.03)	0	0	0	0	0.00	0	(4)	0	(327)	(1.04)
Hi Load	Nuclear	2020	(224)	(22)	(10)	6	0	0	(38)	(291)	(0.85)	0	0	0	0	0.00	0	10	0	(281)	(0.83)
Hi Gas/Hi CO2	Nuclear	2020	(218)	(26)	3	5	0	0	(35)	(272)	(0.94)	0	0	0	0	0.00	0	(100)	0	(371)	(1.28)

Table A.5
Electric Sector Emissions

Scenario	Strategy	Year	**ISO-Wide** CO2 Emissions *(Tons)* *[36]*	**ISO-Wide** SOx Emissions *(Tons)* *[37]*	**ISO-Wide** NOx Emissions *(Tons)* *[38]*	**Connecticut** CO2 Emissions *(Tons)* *[39]*	**Connecticut** SOx Emissions *(Tons)* *[40]*	**Connecticut** NOx Emissions *(Tons)* *[41]*	**Connecticut** Ozone Season NOx Emissions *(Tons)* *[42]*	**Connecticut** HEDD (10-Day) NOx Emissions *(Tons/Day)* *[43]*
Current Trends	Reference Strategy	2013	39,515,485	48,681	17,232	10,051,048	4,707	3,499	1,609	24
Lo Gas/Lo CO2	Reference Strategy	2013	39,373,552	29,658	13,617	10,082,131	3,716	2,897	1,380	27
Med Gas/Hi CO2	Reference Strategy	2013	36,895,864	41,918	15,062	9,416,266	4,030	3,023	1,320	23
Hi Load	Reference Strategy	2013	42,350,296	51,532	18,185	10,703,971	4,996	3,697	1,708	26
Hi Gas/Hi CO2	Reference Strategy	2013	37,345,489	61,854	19,061	9,554,299	5,415	3,863	1,872	22
Current Trends	Reference Strategy	2015	38,701,140	47,285	17,181	10,044,090	4,606	3,505	1,667	29
Lo Gas/Lo CO2	Reference Strategy	2015	38,821,719	28,308	13,946	10,353,148	3,742	3,050	1,573	35
Med Gas/Hi CO2	Reference Strategy	2015	36,362,375	42,375	15,449	9,399,029	3,963	3,047	1,437	27
Hi Load	Reference Strategy	2015	42,474,176	51,560	18,709	10,930,536	5,026	3,843	1,904	34
Hi Gas/Hi CO2	Reference Strategy	2015	36,925,030	62,783	19,573	9,578,504	5,477	3,961	1,957	25
Current Trends	Reference Strategy	2020	36,562,107	44,275	16,689	8,551,076	2,506	2,922	1,424	26
Lo Gas/Lo CO2	Reference Strategy	2020	36,482,554	21,329	12,666	9,577,894	1,554	2,521	1,353	27
Med Gas/Hi CO2	Reference Strategy	2020	32,456,393	28,773	13,219	7,718,352	1,182	2,387	1,255	25
Hi Load	Reference Strategy	2020	42,105,608	50,454	18,645	10,388,323	3,138	3,321	1,636	28
Hi Gas/Hi CO2	Reference Strategy	2020	33,655,282	54,090	18,473	8,610,220	3,324	3,515	1,735	26
Current Trends	Targeted DSM Expansion	2020	36,263,271	44,056	16,631	8,477,812	2,488	2,898	1,396	25
Lo Gas/Lo CO2	Targeted DSM Expansion	2020	36,111,216	20,481	12,460	9,516,314	1,521	2,506	1,321	26
Med Gas/Hi CO2	Targeted DSM Expansion	2020	32,031,803	28,050	12,935	7,625,737	1,149	2,343	1,193	24
Hi Load	Targeted DSM Expansion	2020	41,678,904	49,664	18,483	10,267,256	3,043	3,292	1,589	27
Hi Gas/Hi CO2	Targeted DSM Expansion	2020	33,537,821	54,676	18,610	8,137,983	3,418	3,484	1,713	25
Current Trends	All Achievable Cost-Effective DSM	2020	35,084,502	42,571	16,219	7,917,997	1,954	2,778	1,351	25
Lo Gas/Lo CO2	All Achievable Cost-Effective DSM	2020	35,184,051	20,213	12,382	8,544,795	1,388	2,382	1,277	27
Med Gas/Hi CO2	All Achievable Cost-Effective DSM	2020	30,868,254	26,248	12,526	7,255,879	1,046	2,275	1,173	24
Hi Load	All Achievable Cost-Effective DSM	2020	40,823,967	49,789	18,424	9,293,809	2,888	3,154	1,542	27
Hi Gas/Hi CO2	All Achievable Cost-Effective DSM	2020	32,446,180	53,723	18,343	7,675,781	3,269	3,379	1,670	26
Current Trends	Limited Renewables	2020	42,020,658	45,028	17,035	10,270,603	2,029	3,275	1,584	33
Lo Gas/Lo CO2	Limited Renewables	2020	42,262,550	18,981	12,276	10,980,119	993	2,804	1,479	30
Med Gas/Hi CO2	Limited Renewables	2020	37,248,634	27,623	12,815	9,511,599	1,033	2,705	1,378	30
Hi Load	Limited Renewables	2020	47,969,929	48,052	18,518	11,148,014	2,311	3,509	1,707	34
Hi Gas/Hi CO2	Limited Renewables	2020	39,297,851	60,273	19,217	10,065,439	4,484	3,918	1,938	31
Current Trends	In-State Renewables	2020	41,686,255	43,944	16,976	10,891,654	2,023	3,621	1,688	32
Lo Gas/Lo CO2	In-State Renewables	2020	41,838,254	17,300	12,179	11,679,734	971	3,145	1,578	29
Med Gas/Hi CO2	In-State Renewables	2020	37,058,429	26,948	12,895	10,140,194	1,081	3,071	1,492	29
Hi Load	In-State Renewables	2020	47,604,929	46,726	18,444	11,886,078	2,297	3,874	1,786	34
Hi Gas/Hi CO2	In-State Renewables	2020	38,806,228	58,411	19,060	10,831,134	4,244	4,237	2,027	28
Current Trends	Efficient Gas Expansion	2020	35,665,136	40,544	15,828	10,001,745	2,037	3,006	1,400	22
Lo Gas/Lo CO2	Efficient Gas Expansion	2020	35,645,451	17,584	11,826	10,855,473	1,271	2,684	1,368	24
Med Gas/Hi CO2	Efficient Gas Expansion	2020	31,513,154	24,009	12,144	9,406,163	946	2,570	1,270	21
Hi Load	Efficient Gas Expansion	2020	41,223,145	46,763	17,795	11,395,084	2,596	3,346	1,571	25
Hi Gas/Hi CO2	Efficient Gas Expansion	2020	33,333,849	52,855	18,207	9,306,026	3,108	3,575	1,755	23
Current Trends	Nuclear	2020	31,984,815	38,784	14,917	7,131,383	1,987	2,527	1,169	20
Lo Gas/Lo CO2	Nuclear	2020	32,188,715	17,046	11,213	7,859,939	1,268	2,192	1,132	22
Med Gas/Hi CO2	Nuclear	2020	28,035,222	23,292	11,460	6,552,461	942	2,096	1,056	20
Hi Load	Nuclear	2020	37,619,120	45,794	17,065	8,447,109	2,601	2,895	1,368	23
Hi Gas/Hi CO2	Nuclear	2020	29,521,005	50,468	17,058	6,616,893	2,724	2,976	1,423	22

Table A.6
Electric Sector Emissions
(Differences, compared to Reference Strategy in the given scenario)

Scenario	Strategy	Year	**ISO-Wide** CO2 Emissions *(Tons)* *[36]*	**ISO-Wide** SOx Emissions *(Tons)* *[37]*	**ISO-Wide** NOx Emissions *(Tons)* *[38]*	**Connecticut** CO2 Emissions *(Tons)* *[39]*	**Connecticut** SOx Emissions *(Tons)* *[40]*	**Connecticut** NOx Emissions *(Tons)* *[41]*	**Connecticut** Ozone Season NOx Emissions *(Tons)* *[42]*	**Connecticut** HEDD (10-Day) NOx Emissions *(Tons/Day)* *[43]*
(ABSOLUTE VALUES IN REFERENCE STRATEGY)										
Current Trends	Reference Strategy	2020	36,562,107	44,275	16,689	8,551,076	2,506	2,922	1,424	26
Lo Gas/Lo CO2	Reference Strategy	2020	36,482,554	21,329	12,666	9,577,894	1,554	2,521	1,353	27
Med Gas/Hi CO2	Reference Strategy	2020	32,456,393	28,773	13,219	7,718,352	1,182	2,387	1,255	25
Hi Load	Reference Strategy	2020	42,105,608	50,454	18,645	10,388,323	3,138	3,321	1,636	28
Hi Gas/Hi CO2	Reference Strategy	2020	33,655,282	54,090	18,473	8,610,220	3,324	3,515	1,735	26
(DIFFERENCES IN OTHER STRATEGIES, COMPARED TO REFERENCE STRATEGY)										
Current Trends	Targeted DSM Expansion	2020	(298,836)	(218)	(58)	(73,264)	(18)	(24)	(28)	(1)
Lo Gas/Lo CO2	Targeted DSM Expansion	2020	(371,338)	(848)	(206)	(61,580)	(33)	(15)	(33)	(1)
Med Gas/Hi CO2	Targeted DSM Expansion	2020	(424,590)	(722)	(283)	(92,614)	(33)	(44)	(62)	(1)
Hi Load	Targeted DSM Expansion	2020	(426,704)	(790)	(163)	(121,066)	(96)	(29)	(47)	(1)
Hi Gas/Hi CO2	Targeted DSM Expansion	2020	(117,461)	586	137	(472,237)	94	(31)	(22)	(1)
Current Trends	All Achievable Cost-Effective DSM	2020	(1,477,605)	(1,703)	(469)	(633,079)	(552)	(144)	(73)	(1)
Lo Gas/Lo CO2	All Achievable Cost-Effective DSM	2020	(1,298,503)	(1,116)	(284)	(1,033,099)	(166)	(138)	(77)	(0)
Med Gas/Hi CO2	All Achievable Cost-Effective DSM	2020	(1,588,140)	(2,525)	(693)	(462,473)	(136)	(112)	(82)	(1)
Hi Load	All Achievable Cost-Effective DSM	2020	(1,281,641)	(665)	(221)	(1,094,514)	(250)	(167)	(94)	(0)
Hi Gas/Hi CO2	All Achievable Cost-Effective DSM	2020	(1,209,102)	(367)	(130)	(934,439)	(55)	(136)	(65)	(0)
Current Trends	Limited Renewables	2020	5,458,551	754	346	1,719,527	(477)	352	160	7
Lo Gas/Lo CO2	Limited Renewables	2020	5,779,996	(2,348)	(390)	1,402,225	(561)	283	126	3
Med Gas/Hi CO2	Limited Renewables	2020	4,792,240	(1,149)	(404)	1,793,247	(149)	318	124	5
Hi Load	Limited Renewables	2020	5,864,321	(2,403)	(127)	759,692	(827)	187	70	6
Hi Gas/Hi CO2	Limited Renewables	2020	5,642,569	6,184	744	1,455,219	1,160	403	203	4
Current Trends	In-State Renewables	2020	5,124,148	(330)	287	2,340,578	(483)	699	264	6
Lo Gas/Lo CO2	In-State Renewables	2020	5,355,700	(4,029)	(487)	2,101,840	(583)	624	224	2
Med Gas/Hi CO2	In-State Renewables	2020	4,602,036	(1,825)	(324)	2,421,842	(101)	684	238	4
Hi Load	In-State Renewables	2020	5,499,321	(3,729)	(201)	1,497,755	(841)	552	150	6
Hi Gas/Hi CO2	In-State Renewables	2020	5,150,946	4,321	587	2,220,915	920	722	292	1
Current Trends	Efficient Gas Expansion	2020	(896,971)	(3,730)	(860)	1,450,668	(469)	84	(24)	(4)
Lo Gas/Lo CO2	Efficient Gas Expansion	2020	(837,103)	(3,745)	(840)	1,277,579	(283)	163	15	(3)
Med Gas/Hi CO2	Efficient Gas Expansion	2020	(943,239)	(4,764)	(1,074)	1,687,811	(236)	183	16	(4)
Hi Load	Efficient Gas Expansion	2020	(882,463)	(3,691)	(850)	1,006,762	(542)	25	(66)	(3)
Hi Gas/Hi CO2	Efficient Gas Expansion	2020	(321,433)	(1,235)	(266)	695,806	(216)	60	20	(3)
Current Trends	Nuclear	2020	(4,577,292)	(5,490)	(1,772)	(1,419,694)	(519)	(396)	(255)	(6)
Lo Gas/Lo CO2	Nuclear	2020	(4,293,840)	(4,283)	(1,453)	(1,717,956)	(286)	(329)	(222)	(5)
Med Gas/Hi CO2	Nuclear	2020	(4,421,171)	(5,481)	(1,758)	(1,165,891)	(240)	(291)	(199)	(6)
Hi Load	Nuclear	2020	(4,486,488)	(4,660)	(1,580)	(1,941,213)	(537)	(426)	(268)	(5)
Hi Gas/Hi CO2	Nuclear	2020	(4,134,276)	(3,622)	(1,415)	(1,993,327)	(600)	(539)	(312)	(5)

Table A.7
Summary of Generation in Connecticut

Scenario	Strategy	Year	Biomass and Refuse Generation *(MWh)* *[44]*	Hydro Generation *(MWh)* *[45]*	Wind Generation *(MWh)* *[46]*	Solar Generation *(MWh)* *[47]*	Nuclear Generation *(MWh)* *[48]*	Coal Generation *(MWh)* *[49]*	Natural Gas Generation *(MWh)* *[50]*	Distillate Fuel Oil Generation *(MWh)* *[51]*	Residual Fuel Oil Generation *(MWh)* *[52]*	Other *(MWh)* *[53]*	Total Gas or Oil Generation *(MWh)* *[54]*	Total NOT Gas or Oil Generation *(MWh)* *[55]*	**Total Generation** ***(MWh)*** *[56]*
Current Trends	Reference Strategy	2013	2,024,516	330,603	0	34,610	16,601,698	3,287,419	14,404,316	7,382	178,147	5,190	14,589,845	22,278,846	**36,873,881**
Lo Gas/Lo CO2	Reference Strategy	2013	2,025,136	331,218	0	34,610	16,601,698	2,221,934	16,993,506	14,859	205,868	4,454	17,214,233	21,214,596	**38,433,283**
Med Gas/Hi CO2	Reference Strategy	2013	2,025,110	330,197	0	34,610	16,601,698	2,627,990	14,609,569	6,243	166,370	5,356	14,782,182	21,619,605	**36,407,144**
Hi Load	Reference Strategy	2013	2,025,479	330,603	0	34,610	16,601,698	3,461,107	15,403,018	9,578	217,723	6,300	15,630,319	22,453,496	**38,090,115**
Hi Gas/Hi CO2	Reference Strategy	2013	2,023,324	329,939	0	34,610	16,601,698	3,995,746	11,499,817	2,175	180,872	13,300	11,682,864	22,985,317	**34,681,481**
Current Trends	Reference Strategy	2015	2,009,211	329,678	0	39,007	16,601,698	3,199,832	14,482,619	21,511	179,495	6,754	14,683,625	22,179,427	**36,869,806**
Lo Gas/Lo CO2	Reference Strategy	2015	2,008,225	330,943	0	39,007	16,601,698	2,242,304	17,271,300	37,099	212,093	10,987	17,520,492	21,222,177	**38,753,656**
Med Gas/Hi CO2	Reference Strategy	2015	2,010,084	329,022	0	39,007	16,601,698	2,587,437	14,571,621	18,405	165,840	6,991	14,755,866	21,567,248	**36,330,105**
Hi Load	Reference Strategy	2015	2,011,315	332,264	0	39,007	16,601,698	3,505,598	15,636,305	29,786	224,158	10,706	15,890,248	22,489,882	**38,390,836**
Hi Gas/Hi CO2	Reference Strategy	2015	2,006,868	331,801	0	39,007	16,601,698	4,084,090	11,229,088	11,999	183,450	19,289	11,424,537	23,063,463	**34,507,289**
Current Trends	Reference Strategy	2020	2,082,773	325,038	0	50,071	16,652,420	1,660,722	14,857,050	40,516	113,784	20,587	15,011,351	20,771,025	**35,802,962**
Lo Gas/Lo CO2	Reference Strategy	2020	2,083,602	329,317	0	50,071	16,652,420	590,924	19,544,063	41,373	206,089	17,880	19,791,526	19,706,334	**39,515,739**
Med Gas/Hi CO2	Reference Strategy	2020	2,089,509	326,396	0	50,071	16,652,420	772,861	15,348,598	43,018	0	30,184	15,391,616	19,891,258	**35,313,058**
Hi Load	Reference Strategy	2020	2,098,753	328,398	0	50,071	16,652,420	1,984,159	18,136,829	42,137	237,800	22,974	18,416,766	21,113,802	**39,553,543**
Hi Gas/Hi CO2	Reference Strategy	2020	2,087,678	328,179	0	50,071	16,652,420	2,731,523	12,662,405	43,066	0	48,136	12,705,471	21,849,871	**34,603,478**
Current Trends	Targeted DSM Expansion	2020	2,082,665	326,024	0	50,071	16,652,420	1,665,071	14,707,011	35,364	108,323	17,272	14,850,698	20,776,252	**35,644,222**
Lo Gas/Lo CO2	Targeted DSM Expansion	2020	2,083,244	327,936	0	50,071	16,652,420	602,904	19,444,352	36,805	188,316	10,284	19,669,473	19,716,575	**39,396,332**
Med Gas/Hi CO2	Targeted DSM Expansion	2020	2,085,992	323,672	0	50,071	16,652,420	748,150	15,221,583	37,245	0	26,054	15,258,828	19,860,306	**35,145,188**
Hi Load	Targeted DSM Expansion	2020	2,098,753	326,693	0	50,071	16,652,420	1,958,891	17,984,410	39,080	215,308	14,310	18,238,798	21,086,829	**39,339,937**
Hi Gas/Hi CO2	Targeted DSM Expansion	2020	2,091,237	326,825	0	50,071	16,652,420	2,835,049	11,234,269	42,275	0	56,201	11,276,544	21,955,603	**33,288,348**
Current Trends	All Achievable Cost-Effective DSM	2020	2,082,260	322,317	0	50,071	16,652,420	1,499,998	14,020,916	37,795	0	18,024	14,058,710	20,607,067	**34,683,801**
Lo Gas/Lo CO2	All Achievable Cost-Effective DSM	2020	2,083,130	329,122	0	50,071	16,652,420	598,585	17,229,992	47,116	110,116	26,336	17,387,224	19,713,329	**37,126,889**
Med Gas/Hi CO2	All Achievable Cost-Effective DSM	2020	2,085,642	323,630	0	50,071	16,652,420	654,892	14,593,047	40,517	0	25,359	14,633,564	19,766,655	**34,425,578**
Hi Load	All Achievable Cost-Effective DSM	2020	2,099,025	329,550	0	50,071	16,652,420	1,941,518	15,822,384	48,800	129,527	30,829	16,000,711	21,072,584	**37,104,124**
Hi Gas/Hi CO2	All Achievable Cost-Effective DSM	2020	2,092,013	324,769	0	50,071	16,652,420	2,693,897	10,489,783	46,150	0	45,498	10,535,933	21,813,170	**32,394,601**
Current Trends	Limited Renewables	2020	1,934,763	336,870	0	34,659	16,652,420	1,557,823	19,572,567	80,377	0	23,295	19,652,943	20,516,535	**40,192,774**
Lo Gas/Lo CO2	Limited Renewables	2020	1,934,817	335,959	0	34,659	16,652,420	568,547	23,416,991	68,680	0	27,634	23,485,671	19,526,403	**43,039,708**
Med Gas/Hi CO2	Limited Renewables	2020	1,935,113	338,711	0	34,659	16,652,420	669,963	20,069,205	64,589	0	44,361	20,133,793	19,630,866	**39,809,020**
Hi Load	Limited Renewables	2020	1,934,926	338,054	0	34,659	16,652,420	1,803,459	21,005,943	86,993	0	33,102	21,092,935	20,763,519	**41,889,557**
Hi Gas/Hi CO2	Limited Renewables	2020	1,934,918	340,022	0	34,659	16,652,420	3,309,456	14,277,860	62,628	194,780	58,977	14,535,269	22,271,475	**36,865,721**
Current Trends	In-State Renewables	2020	2,331,632	335,607	101,453	367,401	16,652,420	1,479,343	20,673,733	69,119	0	24,305	20,742,852	21,267,855	**42,035,013**
Lo Gas/Lo CO2	In-State Renewables	2020	2,332,351	334,318	101,453	394,448	16,652,420	476,406	24,738,474	52,168	0	14,932	24,790,642	20,291,396	**45,096,969**
Med Gas/Hi CO2	In-State Renewables	2020	2,332,253	336,297	101,453	358,605	16,652,420	638,066	21,082,529	54,282	0	25,465	21,136,812	20,419,093	**41,581,370**
Hi Load	In-State Renewables	2020	2,332,403	337,711	101,453	390,128	16,652,420	1,717,346	22,368,716	76,159	0	26,700	22,444,876	21,531,461	**44,003,036**
Hi Gas/Hi CO2	In-State Renewables	2020	2,328,588	340,352	101,453	332,586	16,652,420	3,097,079	16,254,074	44,621	166,421	52,623	16,465,116	22,852,477	**39,370,216**
Current Trends	Efficient Gas Expansion	2020	2,079,304	319,823	0	50,071	16,652,420	1,316,803	19,530,431	19,627	81,860	5,406	19,631,918	20,418,422	**40,055,746**
Lo Gas/Lo CO2	Efficient Gas Expansion	2020	2,077,787	327,417	0	50,071	16,652,420	483,004	23,287,266	24,482	140,734	4,309	23,452,483	19,590,700	**43,047,491**
Med Gas/Hi CO2	Efficient Gas Expansion	2020	2,083,441	320,594	0	50,071	16,652,420	557,216	20,202,269	21,416	0	8,447	20,223,685	19,663,743	**39,895,875**
Hi Load	Efficient Gas Expansion	2020	2,097,849	324,040	0	50,071	16,652,420	1,648,646	21,765,124	25,564	167,470	7,490	21,958,158	20,773,026	**42,738,674**
Hi Gas/Hi CO2	Efficient Gas Expansion	2020	2,087,281	322,418	0	50,071	16,652,420	2,560,105	14,901,689	26,299	0	31,441	14,927,988	21,672,296	**36,631,725**
Current Trends	Nuclear	2020	2,055,587	320,383	0	50,071	25,258,820	1,299,127	12,585,712	19,837	83,525	5,775	12,689,073	28,983,988	**41,678,836**
Lo Gas/Lo CO2	Nuclear	2020	2,060,263	324,948	0	50,071	25,258,820	513,867	15,923,130	26,611	136,143	5,092	16,085,884	28,207,969	**44,298,946**
Med Gas/Hi CO2	Nuclear	2020	2,063,304	320,497	0	50,071	25,258,820	577,091	13,194,144	20,653	0	9,156	13,214,796	28,269,784	**41,493,736**
Hi Load	Nuclear	2020	2,086,117	322,918	0	50,071	25,258,820	1,702,059	14,450,029	26,752	162,811	6,950	14,639,592	29,419,985	**44,066,528**
Hi Gas/Hi CO2	Nuclear	2020	2,052,724	319,264	0	50,071	25,232,420	2,228,389	9,212,956	26,499	0	35,790	9,239,455	29,882,868	**39,158,114**

Table A.8
Summary of Generation in ISO-NE

Scenario	Strategy	Year	Biomass and Refuse Generation (MWh) *[44]*	Hydro Generation (MWh) *[45]*	Wind Generation (MWh) *[46]*	Solar Generation (MWh) *[47]*	Nuclear Generation (MWh) *[48]*	Coal Generation (MWh) *[49]*	Natural Gas Generation (MWh) *[50]*	Distillate Fuel Oil Generation (MWh) *[51]*	Residual Fuel Oil Generation (MWh) *[52]*	Other (MWh) *[53]*	Total Gas or Oil Generation (MWh) *[54]*	Total NOT Gas or Oil Generation (MWh) *[55]*	**Total Generation (MWh)** *[56]*
Current Trends	Reference Strategy	2013	8,366,164	6,804,688	2,576,589	195,857	37,133,029	14,787,935	57,529,739	17,900	398,310	49,714	57,945,948	69,864,261	**127,859,923**
Lo Gas/Lo CO2	Reference Strategy	2013	8,370,382	6,943,180	2,576,589	197,157	37,133,029	8,127,725	71,867,438	39,174	479,906	33,103	72,386,518	63,348,062	**135,767,683**
Med Gas/Hi CO2	Reference Strategy	2013	8,370,453	6,790,776	2,576,589	195,519	37,133,029	11,996,540	58,267,418	14,309	375,054	51,998	58,656,782	67,062,906	**125,771,686**
Hi Load	Reference Strategy	2013	8,371,713	6,880,976	2,576,589	197,021	37,133,029	15,528,648	62,130,531	24,459	487,442	57,947	62,642,432	70,687,975	**133,388,354**
Hi Gas/Hi CO2	Reference Strategy	2013	8,362,257	6,669,327	2,576,589	194,263	37,133,029	18,010,369	44,621,156	4,606	405,870	131,820	45,031,632	72,945,835	**118,109,287**
Current Trends	Reference Strategy	2015	9,044,918	6,634,661	6,128,838	254,916	37,133,029	14,137,139	56,890,490	42,455	453,734	49,289	57,386,679	73,333,501	**130,769,469**
Lo Gas/Lo CO2	Reference Strategy	2015	9,040,121	6,730,621	7,174,448	257,118	37,133,029	7,657,332	71,025,536	83,567	560,560	49,670	71,669,664	67,992,669	**139,712,003**
Med Gas/Hi CO2	Reference Strategy	2015	9,050,868	6,627,611	5,850,189	254,337	37,133,029	11,844,657	57,129,971	35,141	399,765	58,885	57,564,877	70,760,692	**128,384,454**
Hi Load	Reference Strategy	2015	9,056,838	6,713,556	7,028,520	256,839	37,133,029	15,333,602	62,430,403	63,473	546,782	66,605	63,040,658	75,522,385	**138,629,649**
Hi Gas/Hi CO2	Reference Strategy	2015	9,028,925	6,554,196	4,821,599	252,174	37,133,029	18,183,803	42,863,496	20,446	534,778	192,755	43,418,720	75,973,726	**119,585,201**
Current Trends	Reference Strategy	2020	10,037,884	6,294,445	14,376,112	410,631	37,245,147	11,930,548	56,971,099	96,441	374,450	99,290	57,441,990	80,294,768	137,836,047
Lo Gas/Lo CO2	Reference Strategy	2020	9,987,666	6,457,381	16,261,757	413,187	37,245,147	4,570,907	72,568,840	96,848	499,707	89,109	73,165,396	74,936,046	**148,190,550**
Med Gas/Hi CO2	Reference Strategy	2020	10,091,972	6,297,903	13,758,015	409,801	37,245,147	7,050,837	59,105,566	95,443	249,123	135,595	59,450,132	74,853,675	**134,439,403**
Hi Load	Reference Strategy	2020	10,118,535	6,484,003	16,662,722	414,218	37,245,147	13,556,823	65,582,750	98,259	529,276	129,994	66,210,285	84,481,447	**150,821,726**
Hi Gas/Hi CO2	Reference Strategy	2020	10,094,866	6,189,147	11,940,582	407,340	37,245,147	15,329,361	42,300,779	100,560	494,794	362,645	42,896,133	81,206,444	**124,465,222**
Current Trends	Targeted DSM Expansion	2020	10,034,034	6,310,906	14,376,112	410,631	37,245,147	11,978,353	56,321,784	82,504	355,522	89,610	56,759,810	80,355,184	**137,204,604**
Lo Gas/Lo CO2	Targeted DSM Expansion	2020	9,986,370	6,454,358	16,261,757	413,187	37,245,147	4,411,802	72,235,836	93,989	475,773	71,336	72,805,598	74,772,621	**147,649,555**
Med Gas/Hi CO2	Targeted DSM Expansion	2020	10,066,537	6,268,982	13,758,015	409,801	37,245,147	6,830,512	58,754,305	83,845	236,279	124,085	59,074,429	74,578,993	**133,777,507**
Hi Load	Targeted DSM Expansion	2020	10,128,611	6,516,754	16,662,722	414,218	37,245,147	13,426,241	65,059,154	98,855	487,574	109,883	65,645,583	84,393,693	**150,149,159**
Hi Gas/Hi CO2	Targeted DSM Expansion	2020	10,120,422	6,210,409	11,940,582	407,340	37,245,147	15,602,012	41,305,349	96,506	500,939	376,714	41,902,793	81,525,912	**123,805,419**
Current Trends	All Achievable Cost-Effective DSM	2020	10,039,059	6,290,982	13,592,701	410,646	37,245,147	11,547,604	54,868,367	90,093	251,281	91,249	55,209,741	79,126,138	**134,427,128**
Lo Gas/Lo CO2	All Achievable Cost-Effective DSM	2020	9,999,317	6,491,054	15,471,093	413,188	37,245,147	4,428,492	70,094,173	110,461	382,712	106,803	70,587,345	74,048,291	**144,742,439**
Med Gas/Hi CO2	All Achievable Cost-Effective DSM	2020	10,069,525	6,276,965	12,968,591	409,801	37,245,147	6,472,633	57,105,966	91,436	238,067	123,788	57,435,469	73,442,661	**131,001,919**
Hi Load	All Achievable Cost-Effective DSM	2020	10,147,287	6,537,023	15,871,036	414,213	37,245,147	13,480,496	62,995,081	107,969	421,287	150,491	63,524,337	83,695,203	**147,370,030**
Hi Gas/Hi CO2	All Achievable Cost-Effective DSM	2020	10,128,548	6,233,883	11,151,495	407,342	37,245,147	15,314,433	39,696,821	109,709	373,923	362,295	40,180,452	80,480,848	**121,023,596**
Current Trends	Limited Renewables	2020	8,353,778	6,834,740	2,587,555	196,451	37,245,147	12,657,633	69,298,646	209,504	282,340	169,429	69,790,490	67,875,305	**137,835,224**
Lo Gas/Lo CO2	Limited Renewables	2020	8,354,467	6,893,111	2,587,555	197,756	37,245,147	4,326,633	88,014,697	171,285	271,191	123,852	88,457,173	59,604,670	**148,185,695**
Med Gas/Hi CO2	Limited Renewables	2020	8,355,474	6,881,349	2,587,555	196,113	37,245,147	7,042,691	71,467,437	164,598	264,273	234,702	71,896,308	62,308,329	**134,439,339**
Hi Load	Limited Renewables	2020	8,354,889	6,876,039	2,587,555	197,619	37,245,147	13,558,494	81,280,463	226,393	306,439	188,016	81,813,295	68,819,744	**150,821,055**
Hi Gas/Hi CO2	Limited Renewables	2020	8,354,583	6,827,879	2,587,555	194,853	37,245,147	17,207,704	50,649,130	155,574	760,812	477,553	51,565,516	72,417,721	**124,460,790**
Current Trends	In-State Renewables	2020	8,750,617	6,810,270	2,689,008	529,193	37,245,147	12,277,919	68,935,793	178,184	277,750	141,342	69,391,727	68,302,154	**137,835,224**
Lo Gas/Lo CO2	In-State Renewables	2020	8,752,353	6,911,314	2,689,008	557,545	37,245,147	3,922,795	87,626,596	136,302	253,910	90,725	88,016,808	60,078,162	**148,185,695**
Med Gas/Hi CO2	In-State Renewables	2020	8,752,244	6,811,645	2,689,008	520,058	37,245,147	6,842,735	71,041,327	135,595	250,841	150,737	71,427,764	62,860,838	**134,439,339**
Hi Load	In-State Renewables	2020	8,751,779	6,870,625	2,689,008	553,088	37,245,147	13,164,538	80,906,230	197,081	288,394	155,167	81,391,705	69,274,184	**150,821,055**
Hi Gas/Hi CO2	In-State Renewables	2020	8,738,339	6,727,170	2,689,008	492,779	37,245,147	16,639,999	50,707,231	106,471	674,486	440,160	51,488,187	72,532,442	**124,460,790**
Current Trends	Efficient Gas Expansion	2020	10,014,546	6,271,420	14,376,112	410,631	37,245,147	10,959,908	58,193,806	51,087	258,827	54,064	58,503,720	79,277,764	**137,835,549**
Lo Gas/Lo CO2	Efficient Gas Expansion	2020	9,943,420	6,501,371	16,261,757	413,187	37,245,147	3,727,068	73,603,971	65,827	377,560	49,851	74,047,357	74,091,951	**148,189,159**
Med Gas/Hi CO2	Efficient Gas Expansion	2020	10,045,656	6,240,335	13,758,015	409,801	37,245,147	5,819,566	60,625,198	55,189	168,164	72,340	60,848,551	73,518,521	**134,439,412**
Hi Load	Efficient Gas Expansion	2020	10,118,598	6,523,059	16,662,722	414,218	37,245,147	12,623,883	66,686,413	68,035	397,281	82,370	67,151,729	83,587,626	**150,821,726**
Hi Gas/Hi CO2	Efficient Gas Expansion	2020	10,091,990	6,164,372	11,940,582	407,340	37,245,147	14,987,439	42,858,351	67,264	392,719	308,223	43,318,334	80,836,870	**124,463,426**
Current Trends	Nuclear	2020	9,865,569	6,109,158	14,376,112	410,631	45,851,547	10,442,168	50,440,520	49,603	242,267	53,250	50,732,389	87,055,186	**137,840,824**
Lo Gas/Lo CO2	Nuclear	2020	9,856,236	6,369,806	16,261,757	413,187	45,851,547	3,685,445	65,261,955	66,120	377,161	49,625	65,705,235	82,437,979	**148,192,840**
Med Gas/Hi CO2	Nuclear	2020	9,920,481	6,095,590	13,758,015	409,801	45,851,547	5,693,054	52,424,408	52,704	166,783	72,912	52,643,896	81,728,488	**134,445,296**
Hi Load	Nuclear	2020	10,044,698	6,408,516	16,662,722	414,218	45,851,547	12,367,778	58,535,674	67,707	388,670	79,992	58,992,051	91,749,479	**150,821,521**
Hi Gas/Hi CO2	Nuclear	2020	9,861,980	5,877,201	11,940,582	407,340	45,825,147	14,161,854	35,682,506	66,219	369,244	309,499	36,117,970	88,074,104	**124,501,572**

Table A.9
Summary of Natural Gas Use for ISO-NE and Connecticut

Scenario	Strategy	Year	**ISO-Wide** January and February *(MMBtu)* *[57]*	**ISO-Wide** July and August *(MMBtu)* *[58]*	**ISO-Wide** Annual *(MMBtu)* *[59]*	**Connecticut** January and February *(MMBtu)* *[60]*	**Connecticut** July and August *(MMBtu)* *[61]*	**Connecticut** Annual *(MMBtu)* *[62]*
Current Trends	Reference Strategy	2013	59,463,795	106,413,698	410,130,394	14,897,008	25,423,228	105,042,656
Lo Gas/Lo CO2	Reference Strategy	2013	71,738,141	122,717,727	517,232,768	17,021,198	28,437,458	124,247,040
Med Gas/Hi CO2	Reference Strategy	2013	58,101,922	106,349,241	415,175,688	14,713,210	25,458,389	106,421,414
Hi Load	Reference Strategy	2013	64,935,147	111,540,302	443,730,221	16,272,718	26,527,954	112,344,050
Hi Gas/Hi CO2	Reference Strategy	2013	48,270,023	88,521,749	315,937,329	12,475,513	21,973,424	83,934,987
Current Trends	Reference Strategy	2015	53,095,116	105,765,950	406,708,192	13,891,648	26,394,921	106,309,891
Lo Gas/Lo CO2	Reference Strategy	2015	67,310,257	123,131,092	513,897,591	16,863,057	29,791,262	128,079,386
Med Gas/Hi CO2	Reference Strategy	2015	51,609,038	105,533,144	408,206,038	13,740,556	26,238,038	106,709,775
Hi Load	Reference Strategy	2015	59,298,465	112,193,261	447,644,557	14,981,289	27,898,916	114,977,688
Hi Gas/Hi CO2	Reference Strategy	2015	40,518,557	86,417,213	304,112,797	10,303,554	22,656,905	82,610,628
Current Trends	Reference Strategy	2020	49,407,469	108,450,836	409,223,914	13,728,088	27,503,062	109,318,731
Lo Gas/Lo CO2	Reference Strategy	2020	70,058,931	127,769,146	527,605,623	20,242,206	33,614,005	144,690,408
Med Gas/Hi CO2	Reference Strategy	2020	53,089,300	109,851,428	424,481,262	14,922,803	27,706,921	112,672,299
Hi Load	Reference Strategy	2020	59,229,500	118,716,165	472,209,789	16,921,050	31,723,078	132,817,020
Hi Gas/Hi CO2	Reference Strategy	2020	35,037,712	86,880,023	299,685,560	10,791,681	25,109,662	92,695,614
Current Trends	Targeted DSM Expansion	2020	48,562,866	107,466,550	404,037,309	13,270,973	27,163,692	108,154,967
Lo Gas/Lo CO2	Targeted DSM Expansion	2020	69,551,732	127,055,175	524,556,964	19,976,022	33,406,215	143,758,892
Med Gas/Hi CO2	Targeted DSM Expansion	2020	52,118,812	109,249,880	421,573,089	14,339,405	27,393,188	111,655,530
Hi Load	Targeted DSM Expansion	2020	58,432,665	117,773,876	467,941,167	16,715,426	31,431,869	131,586,807
Hi Gas/Hi CO2	Targeted DSM Expansion	2020	33,844,088	85,237,258	292,790,706	9,173,213	22,882,460	82,715,310
Current Trends	All Achievable Cost-Effective DSM	2020	46,133,258	105,221,447	393,028,240	11,667,866	26,437,288	103,067,200
Lo Gas/Lo CO2	All Achievable Cost-Effective DSM	2020	67,137,964	123,785,537	509,594,343	17,391,266	30,250,755	128,301,075
Med Gas/Hi CO2	All Achievable Cost-Effective DSM	2020	50,213,291	106,196,994	408,681,606	13,449,986	26,704,170	107,034,326
Hi Load	All Achievable Cost-Effective DSM	2020	56,290,747	115,179,001	453,408,092	14,362,776	28,631,022	116,457,357
Hi Gas/Hi CO2	All Achievable Cost-Effective DSM	2020	31,730,431	83,116,752	281,239,069	8,359,882	22,017,118	77,393,864
Current Trends	Limited Renewables	2020	64,817,143	120,228,077	491,661,534	18,509,088	33,458,976	141,419,670
Lo Gas/Lo CO2	Limited Renewables	2020	89,522,000	143,758,239	633,220,038	24,419,152	38,268,157	171,461,542
Med Gas/Hi CO2	Limited Renewables	2020	68,483,583	121,044,641	507,157,821	19,856,605	33,265,921	144,811,112
Hi Load	Limited Renewables	2020	78,521,428	133,172,916	576,581,392	20,551,391	34,661,657	151,753,292
Hi Gas/Hi CO2	Limited Renewables	2020	47,650,847	94,996,064	358,295,308	13,635,257	26,603,663	103,986,754
Current Trends	In-State Renewables	2020	65,335,078	120,243,902	493,347,421	20,730,290	35,317,766	153,689,068
Lo Gas/Lo CO2	In-State Renewables	2020	90,030,906	144,020,634	634,134,197	26,712,196	40,381,273	185,400,266
Med Gas/Hi CO2	In-State Renewables	2020	68,450,526	122,027,053	508,271,673	21,769,220	35,241,221	156,332,413
Hi Load	In-State Renewables	2020	78,656,141	133,910,026	578,263,609	23,079,688	37,023,607	166,140,487
Hi Gas/Hi CO2	In-State Renewables	2020	48,226,721	95,668,440	362,267,616	16,343,259	29,427,028	121,681,295
Current Trends	Efficient Gas Expansion	2020	49,575,314	110,046,147	414,674,802	17,039,362	34,796,867	141,259,233
Lo Gas/Lo CO2	Efficient Gas Expansion	2020	70,285,235	129,157,541	531,096,307	23,448,796	39,101,134	169,786,143
Med Gas/Hi CO2	Efficient Gas Expansion	2020	53,985,985	111,928,931	432,165,130	18,631,337	35,155,746	145,911,085
Hi Load	Efficient Gas Expansion	2020	59,338,172	119,952,510	477,093,851	19,281,434	37,503,368	157,471,373
Hi Gas/Hi CO2	Efficient Gas Expansion	2020	34,965,766	88,014,046	302,707,729	12,019,059	29,425,254	108,020,266
Current Trends	Nuclear	2020	45,250,327	98,868,289	360,585,396	12,100,850	24,448,909	92,638,070
Lo Gas/Lo CO2	Nuclear	2020	65,523,881	117,471,804	472,559,915	16,973,884	28,536,020	118,173,764
Med Gas/Hi CO2	Nuclear	2020	49,057,516	100,415,639	374,790,745	13,276,493	24,859,981	96,906,320
Hi Load	Nuclear	2020	54,412,030	108,238,652	419,894,172	13,820,264	26,623,614	106,256,359
Hi Gas/Hi CO2	Nuclear	2020	30,871,722	77,585,041	252,705,634	8,408,968	20,144,696	68,256,083

Section III.1
Resource Adequacy

1. RESOURCE ADEQUACY

1.A SUMMARY AND KEY FINDINGS

Summary

The primary starting point for any IRP is a projection of available resources relative to resource adequacy requirements. Shortfalls indicate the need for additional resources. ISO-NE defines four separate resource adequacy requirements affecting Connecticut: the ISO-NE-wide Installed Capacity Requirement (ICR), the Connecticut Local Sourcing Requirement (CT LSR), the Connecticut requirement under the Transmission Security Analysis (CT TSA), and the Connecticut requirement in the Locational Forward Reserve Market (LFRM).[1]

ISO-NE projects that the system-wide net ICR will increase from 31,823 MW in 2009 to 34,454 MW in 2018,[2] driven by its load forecast.[3] It projects that the CT LSR will increase only slightly from 6,496 MW in 2010 to 7,325 MW in 2012. We project that the CT LSR will continue to grow to 7,433 in 2013, and then fall to 6,341 in 2014 due to increased import capability from the assumed 2014 completion of the New England East-West Solution (NEEWS) largely offsetting the effects of a more stringent methodology and load growth.[4] We project the CT LSR will reach 6,708 by 2020. ISO-NE has not yet estimated future CT TSA requirements, so we have developed our own estimates based on the TSA methodology presented by the ISO in an informational filing with the FERC on auction results in the first Forward Capacity Auction and what is likely to come out of the FCM stakeholder discussions that have taken place in 2009. The LFRM requirement is primarily designed to ensure enough fast-start capacity in Connecticut to cover a sub-area's second contingency.

To estimate future resources available to meet these needs, we have gathered up-to-date data from ISO-NE, the EDCs, and other publicly available sources. The data address existing and planned generation resources, renewable generation, demand response, energy efficiency, imports, and tie-line benefits. Generally, we count new resources toward meeting future resource needs only if they are currently under construction, contracted, or have a capacity obligation in the ISO's capacity market. The exceptions to this rule are: new renewable generation, which is added based on projections of likely future development to meet Renewable

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1 This analysis represents the transmission system's capability to serve sub-area load with available resources, including its capacity to import power across sub-area interfaces. The analysis does not consider whether the transmission system within the sub-area complies with NERC, NPCC, and ISO-NE transmission security criteria.

2 2009 Regional System Plan, ISO-NE, October 15, 2009, Page 33-36, Tables 4-1 and 4-2.

3 Net ICR is the requirement net of tie-line benefits, or the portion of the requirement that must be satisfied in the capacity market.

4 While this analysis counts the transmission import limit change in addition to crediting all the Lake Road units as Connecticut capacity resources, the ISO is assessing the interaction of the change in transfer limit and counting all the Lake Road units due to NEEWS.

Portfolio Standard (RPS) requirements; energy efficiency, which is added consistently with the EDCs' plans based on current funding sources (and estimates for other states); and generation retirements, which we project based on economics and likely future environmental regulations. In addition, we assume imports will be reduced in response to low capacity market prices.

To assess resource adequacy for both Connecticut and the ISO as a whole, a base case, several resource strategies, and several scenarios addressing the impact of other possible changes in key factors driving resources and resource needs were developed. Strategies include variations on demand side resource amounts and renewable generation additions. Scenarios include variations on fuel prices and climate legislation as well as high economic growth in peak demand. These strategies and scenarios may change projected retirements and/or the need for future resources. The various strategies and scenarios are described in detail in Section II (Analytical Findings).

By comparing resource needs to projected resources in a way that mimics ISO-NE's accounting of all of the elements, we have estimated the amount of surplus or deficiency through 2020 that can be expected absent additional procurement. Under the CT LSR calculation we find that Connecticut will likely have more than sufficient resources through 2020, even with 1,504 MW assumed economically and environmentally-driven retirements in Connecticut in the Base Case. Connecticut would even have sufficient resources through 2020 under the ISO-NE's more stringent Transmission Security Analysis.

The broader ISO-NE region is also expected to have sufficient resources through 2020.[5] This includes the impact of an assumed 2,446 MW in economically and environmentally-driven retirements in New England in the Base Case.

Key Findings

- There will likely be a substantial surplus relative to Connecticut's local resource requirements through 2020, due to a lower load forecast than utilized in prior IRPs, planned generation additions in Connecticut, planned DSM, and increased Connecticut import capability, even after accounting for forecasted retirements (which are substantial). Given this, Connecticut's access to adequate resources depends on resource adequacy in New England as a whole.
- A capacity surplus is expected in New England through at least 2015, and likely through 2020. This region-wide surplus is due to a lower load forecast than in prior IRPs, the likely addition of renewable generation to meet RPS requirements, planned DSM, and planned generation additions in Connecticut even after accounting for forecasted retirements (which are substantial). Some combinations of strategies and scenarios may lead to a need for additional resources after 2015 in cases that involve higher load, lower renewable additions, and/or higher retirements.
- The prospect of capacity surpluses and consequently low capacity prices, combined with tighter environmental requirements, is likely to induce the retirement of substantial

[5] Projected surpluses exceed those presented in the 2009 IRP because of a lower load forecast and updated information on planned new resources.

amounts of old, high emission, oil-fired steam units. Retirements are estimated at 2,446 MW in New England in the Base Case (1,504 MW in Connecticut). There is substantial uncertainty around these estimates; retirements could exceed 4,000 MW under market conditions that induce earlier new entry and reduced capacity prices.

1.B DEMAND

All reliability requirements in the ISO are driven primarily by projections of peak demand. Connecticut and ISO-wide reliability requirements are based on ISO's 2009-2018 Forecast Report of Capacity, Energy, Loads, and Transmission (2009 CELT), particularly the load forecast reflecting normal weather ("50/50") and base economic growth conditions for the years 2009 through 2018.[6,7] To forecast peak loads over the entire study period through 2020, we have extrapolated the ISO's forecast using 2017-2018 load growth rates.

The ISO's forecast is a busbar forecast, meaning that it reflects metered load grossed up by eight percent for transmission and distribution losses (*i.e.*, the amount needed to be produced at generation sources to serve all load plus losses). ISO-NE develops its forecasts using regression analyses of the historical weather-normalized load data and economic growth rates, projected forward with adjustments for expected future changes in economic growth. The ISO's 2009 load forecast is lower than its 2008 forecast primarily due to expected continuing economic decline in the short-run forecast. By 2016, the 2009 CELT 50/50 peak load forecast is approximately two to three percent lower ISO-wide than the 2008 CELT 50/50 peak load forecast used in the 2009 IRP.[8] This results in a 555 MW lower 50/50 peak load forecast by 2017 for the ISO, and a 280 MW lower 50/50 peak load forecast by 2017 for Connecticut in the 2009 CELT. Figure 1.1 and Figure 1.2 show the ISO's 2007, 2008, and 2009 CELT 50/50 peak load forecasts for Connecticut and the ISO, respectively.

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6 "2009-2018 Forecast Report of Capacity, Energy, Loads, and Transmission," ISO New England, April 2009. Available at http://www.iso-ne.com/trans/celt/index.html.

7 All Connecticut peak load figures discussed in this section refer to the Connecticut sub-area (ISO zones Norwalk, SW Connecticut, and rest of Connecticut). This excludes a small amount (approximately one percent) of state demand physically in Connecticut but electrically in Western Massachusetts.

8 Differences between the 2008 and 2009 CELT forecasts are also due to recent refinements to the ISO's forecasting methodology. See the ISO's 2009 RSP for further discussion: "2009 Regional System Plan," ISO New England, October 15, 2009, Section 3.3, Pages 26-27.

Figure 1.1
ISO-NE CELT Peak Load Forecast for the Connecticut Sub-Area: 2007, 2008, and 2009

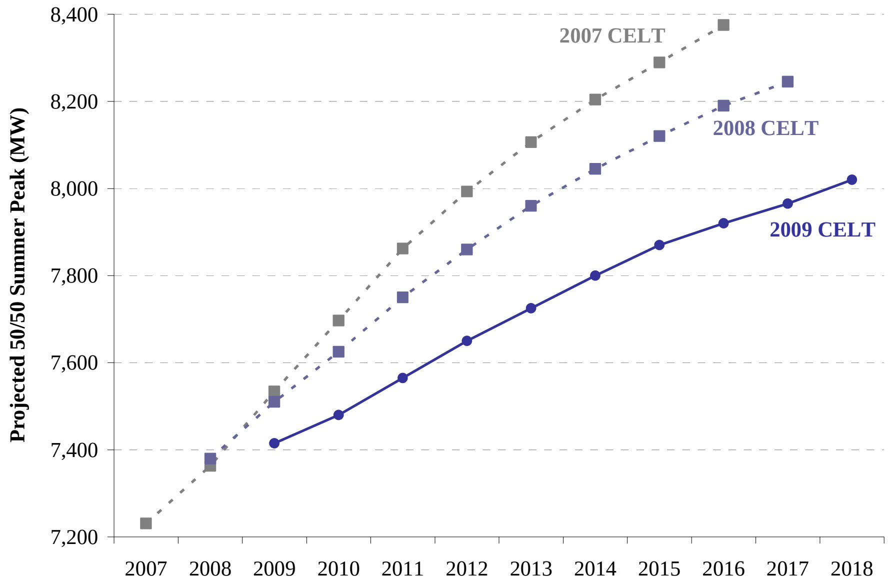
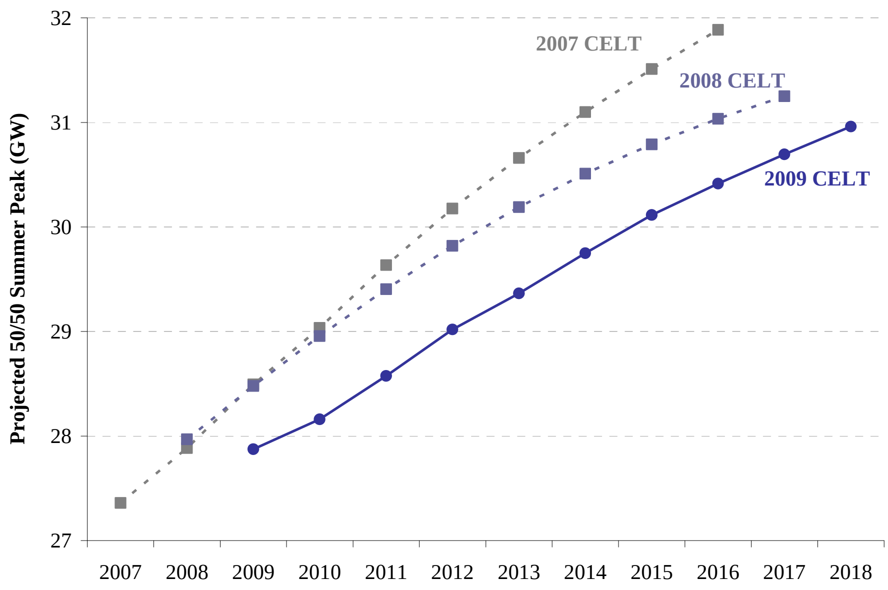


Figure 1.2
ISO-NE CELT Peak Load Forecast for the Entire ISO: 2007, 2008, and 2009



The 2009 CELT 50/50 peak load forecast also incorporates information on demand-side resources that receive capacity credit during the capacity market transition period, and those that have been committed in the first three Forward Capacity Auctions (corresponding to peak reductions in 2010, 2011, and 2012). Since these resources meet reliability requirements as "supply-side" resources, the ISO adds them back to the peak load forecast based on how they have reduced historic loads. Other demand-side resources, such as voluntary demand response (DR) and older, existing energy efficiency (EE) that do not receive capacity credit are not added back to the forecast. To the extent such resources have reduced historical loads on which the forecast is based, they may reduce the forecast.

However, ensuring that both past and future energy efficiency measures are accounted for correctly can be difficult. In particular, the peak load forecast does not define explicitly the amount of future EE that is embedded implicitly in the forecast, making it unclear whether the full amount of EE described in the DSM section of this report can be subtracted from the ISO's load forecast to yield an accurate net peak load forecast (the forecast could include some new EE to the extent that past EE increases have tempered historical load growth rates that are used to extrapolate future loads). However, through collaboration with ISO staff we have determined that (1) since historic EE peak impact did not change substantially from the period 2000 through 2007, there is no extrapolated effect of EE on peak loads, hence no implicit new EE embedded in the ISO's peak load forecast, and (2) the ISO does include reductions from the expected impact of a Federal mandate to phase out incandescent light bulbs.

Based on this information, we have concluded that the effects of DR and future EE (except replacement of incandescent light bulbs with compact fluorescent bulbs) on future peak loads are not accounted for in the load forecast. Thus, we include their effects as supply-side resources that help to meet peak demand. This treatment is consistent with their treatment in the Forward Capacity Market. However, the effect of EE on the energy forecast is quite different from its effect on the peak forecast, as described in Section 1.D.

1.C CONNECTICUT AND ISO-WIDE RELIABILITY REQUIREMENTS

The ISO-NE has developed several reliability requirements to ensure the procurement of sufficient capacity to meet expected load and to ensure system reliability. The Installed Capacity Requirement (ICR) is an ISO-wide requirement to meet a one day in ten years loss-of-load expectation, which the ISO calculates using a probabilistic analysis of load uncertainty, resource availability, and tie-line benefits. The resulting ICRs, when expressed in terms of "pool reserve margin," or the percentage above and beyond the corresponding year's 50/50 peak load forecast, varies from 10.1 percent to 14.2 percent for the years 2009 through 2018.[9] An ICR for any given year is continuously updated by the ISO as it receives new information about expected load, resource availability, and system conditions. In this report, we use the most updated information available, although ICR values will likely be adjusted by the ISO in the near future. 2009-2018 ICR values are based on indicative values published in the ISO's 2009 RSP.[10] 2019 and 2020

[9] Resources to meet the ICR are procured through the ISO's Forward Capacity Market (FCM), through auctions starting three years prior to the capacity delivery year.

[10] 2009 Regional System Plan; Pages 34-35, Tables 4-1 & 4-2.

ICR values are extrapolated by applying the 2018 pool reserve margin of 11.3 percent to our extrapolated peak load forecast.

All load serving entities (LSEs) must procure sufficient capacity to meet their peak load share of the ICR which results in the region as a whole meeting the ICR. However, the ISO may also impose additional LSR to ensure that sufficient capacity is *physically located* in a sub-area to maintain local reliability. If there is insufficient capacity physically located in a sub-area, the LSR could "bind" in the Forward Capacity Market, and the local clearing price would rise above the ISO-wide clearing price. This would result in the sub-area's consumers paying the higher local price on a portion of their ICR (equal to the LSR or TSA).

The ISO calculates the CT LSR using a probabilistic analysis of expected Connecticut system conditions. We use the ISO's most recent CT LSR values from 2010 through 2012, which include updated load assumptions from the 2009 CELT, and extrapolate to 2020 using predicted values from a fitted line against expected load based on previously published CT LSR forecasts. As such, the CT LSR forecast beyond 2012 reflects a CT LSR calculation where the resources available to Connecticut are limited to the ICR of ISO-NE, *i.e.*, the CT LSR is calculated under "At-Criterion" conditions. Whether CT LSR will be calculated this way going forward is still the subject of ISO-NE stakeholder discussion.

To determine the reliability impact of existing resources "delisting" from the FCM and not committing themselves as capacity resources in Connecticut, ISO may rely on an even more stringent Transmission Security Analysis. The TSA, in part, results in a local requirement which is essentially the ISO's 90/10 peak load forecast plus the capacity required to cover the area's first-order generation contingency. In Connecticut, that contingency is Millstone 3, or 1,235 MW. In the case of Norwalk Harbor's dynamic delist bid in the first Forward Capacity Auction (FCA#1), the ISO required the plant to stay online because of its impact on Connecticut's ability to meet its requirement under TSA.[11] Based on the ISO's methodology requirements, resources, and resource adequacy under the CT TSA is expressed in terms of unforced, or derated, capacity. For better comparison with ICR and CT LSR, which express requirements, resources, and resource adequacy in terms of installed capacity, we present the CT TSA requirement in a slightly different, but mathematically equivalent, format from those previously presented by the ISO and in the 2009 IRP. Rather than derating the capacity of resources available to meet the CT TSA we have added the derate quantity to the requirement itself. By doing this, all requirements, resources, and resource surpluses or gaps under the ICR, CT LSR, and CT TSA are consistently expressed in terms of installed capacity.

Two of the reliability requirements considered in this report – Connecticut's LSR and Connecticut's requirement under TSA – are shown in Table 1.1 for each year 2009 through 2020, along with their key components. Table 1.2 shows the 2009 through 2020 ISO-wide ICR and its key components.

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[11] See the Testimony of Stephen J. Rourke in the ISO New England Forward Capacity Auction Results Filing with FERC, available at http://www.iso-ne.com/markets/othrmkts_data/fcm/filings/index.html. We have also included subsequent changes to the TSA methodology resulting from stakeholder discussions, such as changing the derate on peaking generation from 33 percent to 20 percent.

As a result of ISO-NE stakeholder discussions in 2009, it is possible that starting in the 2014/15 delivery year the amount of capacity needed locally will be driven by the greater of that area's TSA or LSR values. Since the issue is still in open discussion, and any proposed rule changes to this affect have yet to be filed at the FERC, the results under both metrics are presented in this report.

Table 1.1
Estimated Reliability Requirements in Connecticut
2009-2020

		2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Local Sourcing Requirement in CT	*(MW)*	**n/a**	**6,496**	**6,912**	**7,325**	**7,433**	**6,341**	**6,408**	**6,455**	**6,498**	**6,557**	**6,625**	**6,708**
Pre-NEEWS LSR	*(MW)*	n/a	6,496	6,912	7,325	7,433	7,516	7,583	7,630	7,673	7,732	7,800	7,883
NEEWS Impact on LSR	*(MW)*	0	0	0	0	0	(1,175)	(1,175)	(1,175)	(1,175)	(1,175)	(1,175)	(1,175)
Connecticut Requirement under Transmission Security Analysis	*(MW)*	**7,273**	**7,464**	**7,631**	**7,637**	**7,683**	**6,706**	**6,782**	**6,803**	**6,863**	**6,913**	**6,964**	**7,015**
Connecticut Sub-Area 90/10 Peak Load	*(MW)*	7,940	8,010	8,105	8,205	8,285	8,370	8,445	8,505	8,565	8,615	8,665	8,716
Additional Required Reserves (Millstone Unit 3)	*(MW)*	1,137	1,235	1,235	1,235	1,235	1,235	1,235	1,235	1,235	1,235	1,235	1,235
Additional Requirement for Installed Capacity Derate	*(MW)*	696	719	791	697	663	701	702	663	663	663	664	664
Reduction per Connecticut Import Limit	*(MW)*	(2,500)	(2,500)	(2,500)	(2,500)	(2,500)	(3,600)	(3,600)	(3,600)	(3,600)	(3,600)	(3,600)	(3,600)

Note: The TSA shown here adds back the installed capacity derate, for better comparison with the ICR and LSR requirements.

Table 1.2
ISO-NE Actual and Representative Installed Capacity Requirements
2009-2020

		2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
ISO-NE 50/50 Peak Load	*(MW)*	**27,875**	**28,160**	**28,575**	**29,020**	**29,365**	**29,750**	**30,115**	**30,415**	**30,695**	**30,960**	**31,227**	**31,497**
Net Installed Capacity Requirement	*(MW)*	**31,823**	**32,137**	**32,528**	**31,965**	**32,411**	**32,901**	**33,370**	**33,757**	**34,120**	**34,454**	**34,751**	**35,051**
Installed Capacity Requirement (adds back HQICC)	*(MW)*	33,023	33,321	33,439	32,879	33,325	33,815	34,284	34,671	35,034	35,368	35,665	35,965
HQICC	*(MW)*	1,200	1,400	911	914	914	914	914	914	914	914	914	914
Other Tie-Line Benefits (NY & NB)	*(MW)*	800	460	889	751	751	751	751	751	751	751	751	751
Pool reserve	*(%)*	14.2%	14.1%	13.8%	10.1%	10.4%	10.6%	10.8%	11.0%	11.2%	11.3%	11.3%	11.3%

Note: The 2010 net ICR is increased by a 216 MW reserve margin gross-up for DR and NYPA imports, per ISO practices.

To meet the fourth reliability requirement considered in this report – Connecticut's LFRM requirement – both Southwest Connecticut and Connecticut overall must provide local second contingency coverage in the form of non-spinning thirty minute reserves. The ISO's 2009 Regional System Plan (RSP09) indicates that through 2013 Southwest Connecticut may have a need of between zero and 180 MW in the summer (June - September) and no requirement in the winter (October - May).[12] Greater Connecticut may have a need of 1,100 to 1,250 MW the summer, and 700 to 1,250 in the winter.[13] Since no new generation is planned that would exceed Connecticut's current second contingency (Millstone 3), Connecticut's requirement under LFRM is expected to remain constant at up to 1,250 MW through 2013. In terms of summer capacity there are currently 990 MW of existing Connecticut peaking resources participating in LFRM,

[12] "2009 Regional System Plan," ISO New England, October 15, 2009, Page 55, Table 5-1.

[13] *Ibid.*

and an additional 504 MW of planned new Connecticut peaking resources to meet and exceed the requirement have recently been contracted.[14,15]

While no definitive studies have been preformed to date by ISO-NE, based on LFRM requirement changes experienced in NEMA/Boston and Southwest Connecticut after transfer capabilities were increased there is a basis to forecast that Connecticut LFRM requirements will decline once NEEWS is in-service. Connecticut LFRM requirements could also be reduced as a result of increased economic generation being counted inside Connecticut when determining local reserve requirements (*e.g.*, Kleen or Lake Road once NEEWS is in-service). ISO-NE is expected to provide the impact on LFRM sometime after the current review of the NEEWS Interstate and Central Connecticut Reliability Projects is completed.

Table 1.3 shows the existing and planned seasonally rated MW available to meet each area's requirement under LFRM, assuming only internal combustion units are likely to participate. Resources in Southwest Connecticut can meet both Southwest Connecticut's requirement while also meeting the greater Connecticut requirement. Absent significant retirements, both areas are forecast have sufficient resources to meet LFRM requirements.

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14 See Table 1.3.

15 Includes 504 MW new peaking capacity contracted in DPUC Docket No. 08-01-01.

Table 1.3
Expected Resources Available to Meet Southwest Connecticut and Greater Connecticut LFRM Requirements

Unit Name	Unit Status	RSP Area	Winter Claimed Capability *(MW)*	Summer Claimed Capability *(MW)*	Unit Type	In-Service Date	Notes
BRIDGEPORT HARBOR 4	Existing	SWCT	20	15	GT	1-Oct-67	
BRANFORD 10	Existing	SWCT	21	16	GT	1-Jan-69	
COS COB 10	Existing	NOR	24	19	GT	1-Sep-69	
COS COB 11	Existing	NOR	22	17	GT	1-Jan-69	
COS COB 12	Existing	NOR	23	18	GT	1-Jan-69	
DEVON 10	Existing	SWCT	19	14	GT	1-Apr-88	
DEVON 11	Existing	SWCT	39	29	GT	1-Oct-96	
DEVON 12	Existing	SWCT	38	29	GT	1-Oct-96	
DEVON 13	Existing	SWCT	39	30	GT	1-Oct-96	
DEVON 14	Existing	SWCT	40	30	GT	1-Oct-96	
NORWALK HARBOR 10 (3)	Existing	NOR	17	12	GT	1-Oct-96	
PPL WALLINGFORD UNIT 1	Existing	SWCT	48	43	GT	31-Dec-01	
PPL WALLINGFORD UNIT 2	Existing	SWCT	51	40	GT	7-Feb-02	
PPL WALLINGFORD UNIT 3	Existing	SWCT	48	43	GT	31-Dec-01	
PPL WALLINGFORD UNIT 4	Existing	SWCT	48	42	GT	23-Jan-02	
PPL WALLINGFORD UNIT 5	Existing	SWCT	52	41	GT	7-Feb-02	
WATERSIDE POWER	Existing	NOR	73	71	GT	1-May-04	
PIERCE STATION	Existing	SWCT	95	75	GT	1-Oct-07	
COS COB 13	Existing	NOR	24	19	GT	29-May-08	
COS COB 14	Existing	NOR	23	20	GT	29-May-08	
ROCKY RIVER	Existing	SWCT	29	29	PS	1-Jan-28	
JOHN STREET #3	Existing	SWCT	2	2	IC	26-Sep-07	
JOHN STREET #4	Existing	SWCT	2	2	IC	26-Sep-07	
JOHN STREET 5	Existing	SWCT	2	2	IC	1-Nov-07	
WATERBURY GENERATION	New	SWCT	96	96	GT	1-Jul-09	[1]
DEVON 15 - 18	Planned	SWCT	197	188	GT	1-Jun-10	[2]
SW Connecticut (including Norwalk) Subtotal:			**1,094**	**944**			
FRANKLIN DRIVE 10	Existing	CT	21	15	GT	1-Nov-68	
MIDDLETOWN 10	Existing	CT	22	17	GT	1-Jan-66	
NORWICH JET	Existing	CT	19	15	GT	1-Sep-72	
SO. MEADOW 11	Existing	CT	47	36	GT	1-Aug-70	
SO. MEADOW 12	Existing	CT	48	38	GT	1-Aug-70	
SO. MEADOW 13	Existing	CT	48	38	GT	1-Aug-70	
SO. MEADOW 14	Existing	CT	46	37	GT	1-Aug-70	
TORRINGTON TERMINAL 10	Existing	CT	21	16	GT	1-Aug-67	
TUNNEL 10	Existing	CT	22	17	GT	1-Jan-69	
MONTVILLE 10 and 11	Existing	CT	5	5	IC	1-Jan-67	
PSEG NEW HAVEN	Planned	CT	146	130	GT	1-Jun-12	[2]
MIDDLETOWN 12 and 13	Planned	CT	197	186	GT	1-Jun-11	[2]
Rest-of-Connecticut Subtotal:			**642**	**550**			
Available for SW Connecticut LFRM:			**1,094**	**944**			
Available for Greater Connecticut LFRM:			**1,736**	**1,494**			

Sources and Notes:

Source: 2009 CELT; excludes a small amount of new capacity (16 MW) with no resource name.

[1]: Capacity CfD winner, Winter value not in 2009 CELT so conservatively assumed equal to summer value.

[2]: Peaking generation RFP winner; values based on executed contracts filed at CT DPUC.

1.D ENERGY NEEDS

In addition to resources needing to reliably meet demand during peak hours, the ISO needs resources to meet total demand for energy in all hours. These needs can be met by any combination of resources, but they are primarily met by low variable cost, baseload generation such as renewable, nuclear, and coal resources, and some efficient gas combined cycle resources.

In the 2009 CELT report, the ISO projects significantly lower energy needs compared to the 2008 CELT report. This is consistent with the recent economic downturn and corresponding decline in actual energy use from 2007 through 2009. For the system as a whole, the ISO projects that energy needs will reach 2007 levels again by 2012, and for Connecticut by 2017. Although projected energy needs have declined, the development of future resources such as new renewables for RPS, new energy efficiency, and other baseload will play a key role in meeting future energy needs, particularly if energy needs increase due to higher than expected economic growth or lower than expected energy prices. Figure 1.3 and Figure 1.4 show the ISO's 2007, 2008, and 2009 CELT 50/50 energy forecasts for Connecticut and the ISO, respectively. The figures also include lines indicating actual energy use in 2007 and 2008.

The 2009 CELT 50/50 energy forecast also incorporates information on energy efficiency. The energy forecast is explicitly reduced to account for the impact of CFLs. Implicitly, the forecast also reflects a continuation of "business-as-usual" efficiency improvements, since the forecast is based on an extrapolation of historical growth rates that were tempered by past efficiency improvements. The ISO has not quantified this implicit effect on the CELT energy forecast. We had to estimate it in order to determine how much of the EDCs' planned and proposed DSM programs described in Section III.2 (DSM) are already accounted for in the CELT energy forecast, and how much of their effect should be subtracted from the CELT forecast to estimate net energy for load in Connecticut. We compared the EDC EE projections to historic EE levels and determined that the Reference-level EE projections are consistent with business-as-usual efficiency improvements. Thus, we concluded that the future effects of the Reference-level EE are already accounted for in the CELT energy forecast, so no adjustments were necessary in Connecticut. However, a similar analysis of efficiency programs in Massachusetts indicated that planned EE (through 2011) exceeds our estimated business-as-usual baseline by 651 GWh, so we subtracted that amount from the CELT energy forecast.

Figure 1.3
ISO-NE CELT Energy Forecast for the Connecticut Sub-Area: 2007, 2008, and 2009

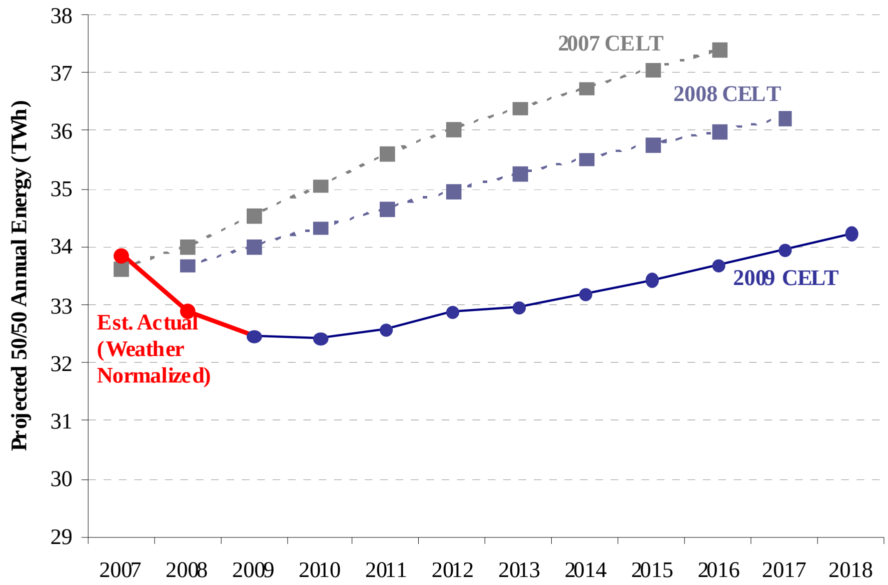
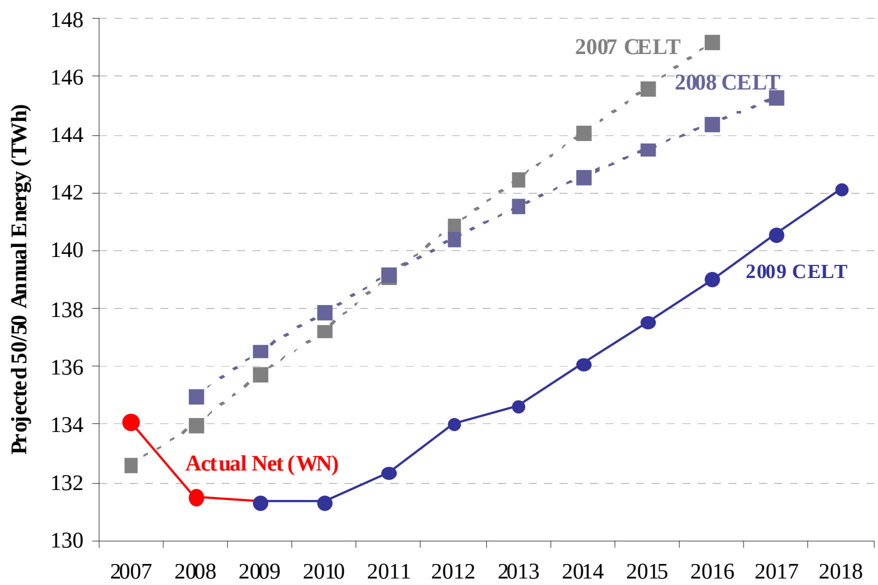


Figure 1.4
ISO-NE CELT Energy Forecast for the Entire ISO: 2007, 2008, and 2009



1.E GENERATION RESOURCES

Generation online as of January 1, 2009 is documented in the 2009 CELT. The amount of planned new generation is estimated using information from several sources, including results from the ISO's FCAs, projects listed in the ISO generation interconnection queue, state docket and RFP information, publicly-available information on generation development and contracting, and other third-party data. Only projects cleared in FCM, under construction, or contracted have been counted in this IRP for meeting future reliability needs, with the exception of additional assumed new renewable generation to meet RPS requirements. Table 1.4 and Table 1.5 list all planned generation projects considered, including those that we do not count toward future reliability needs. The MW by type and state of additional new renewable generation assumed in each year is listed separately in Table 1.6. 150 MW of new renewable resources has already been contracted in Connecticut through the state's "Project 150" RFP. An additional 103 MW of new renewable generation is assumed to be developed in Connecticut and 4,712 MW for ISO-NE by 2020, corresponding to 83 MW and 1,467 MW in capacity value, respectively.[16] The derivation of these values is based on the analysis presented in the Renewables section of this IRP, with the assumption that renewable portfolio standard requirements are met region-wide and not exceeded.

[16] Reflects the capacity value of these units, with onshore wind derated to 20 percent, offshore wind derated to 26 percent, and solar resources derated to 40 percent.

Table 1.4
Planned New Units Included as Available Future Resources
(Includes Traditional Generation Only)

Unit Name	Unit Type	Zone	Installation Date	Summer Capacity (MW)	Note
PLANNED NEW UNITS					
Kleen Energy Project	NCC	Rest of CT	6/1/2010	620	DPUC PA 05-01 Contract[1]; summer MW increased per FCM auction results
New Haven Harbor	GT	Rest of CT	6/1/2012	130	Connecticut Peaking Generation Contract
Devon 15 - 18	NGT	South Western CT	6/1/2010	188	Connecticut Peaking Generation Contract
Middletown 12 & 13	NGT	Rest of CT	6/1/2011	186	Connecticut Peaking Generation Contract
Thomas A. Watson	NGT	NE MA Boston	6/1/2010	105	Cleared in FCA#1
Ansonia Generating Facility	NGT	South Western CT	6/1/2010	60	Cleared in FCA#1
Swanton Gas Turbine 1	NGT	Vermont	6/1/2010	20	Cleared in FCA#1
Swanton Gas Turbine 2	NGT	Vermont	6/1/2010	20	Cleared in FCA#1
EXPANSIONS AT EXISTING SITES					
Millstone Point 3 expansion	NU	Rest of CT	6/1/2010	80	Cleared in FCA#1
Lake Road 1 expansion	NCC	Rhode Island	6/1/2010	6	Cleared in FCA#1
Lake Road 2 expansion	NCC	Rhode Island	6/1/2010	15	Cleared in FCA#1
Total				1,430	

Notes:
Excludes all planned new renewables.
[1]: Ameresco (5 MW) will be counted demand-side; Waterbury (96 MW) is already online.

Table 1.5
Units Contracted under Connecticut Project 150 Contracts
(Renewable Generation Only)

Unit Name	RFP Round #	Unit Type	Nameplate Capacity *(MW)*	Location	Installation Date	Development Status	Assumed Probability of Development *(%)*	Expected Capacity (Derated) *(MW)*
[1]	*[2]*	*[3]*	*[4]*	*[5]*	*[6]*	*[7]*	*[8]*	*[9]*
Watertown Renewable Power	1	Biomass/Biofuels	15	Watertown, CT	12/31/11	Proposed	55%	8
Plainfield Renewable Energy	2	Biomass/Biofuels	30	Plainfield, CT	11/1/11	Permitted	70%	21
DFC-ERG Milford	2	Fuel Cells	9	Milford, CT	5/29/10	Proposed	55%	5
Clearview Renewable Energy	2	Biomass/Biofuels	30	Bozrah, CT	12/1/11	App Pending	60%	18
Clearview East Canaan Energy	2	Biomass/Biofuels	3	North Canaan, CT	6/1/10	Proposed	55%	2
Hospital Energy Development (Waterbury Hospital)	2	Fuel Cells	2	Waterbury, CT	12/31/10	Proposed	55%	1
Hospital Energy Development (Stamford Hospital)	2	Fuel Cells	5	Stamford, CT	12/31/10	Proposed	55%	3
South Norwalk Renewable Generation	2	Landfill Gas	30	South Norwalk, CT	6/1/11	Proposed	55%	17
Cube Fuel Cell	3	Fuel Cells	3	Danbury, CT	7/1/11	Proposed	55%	2
DFC-ERG Glastonbury	3	Fuel Cells	3	Glastonbury, CT	7/1/11	Proposed	55%	2
DFC-ERG Trumbull	3	Fuel Cells	3	Trumbull, CT	6/1/11	Proposed	55%	2
DFC-ERG Bloomfield	3	Fuel Cells	4	Bloomfield, CT	5/1/11	Proposed	55%	2
Bridgeport Fuel Cell Park	3	Fuel Cells	15	Bridgeport, CT	1/1/11	Proposed	55%	8
Total			**153**					**90**

Sources and Notes:
[1]-[6]: Data on renewables contracted under DPUC docket no. 07-06-61.
[7]: Status based on data compiled by Ventyx Energy, The Velocity Suite.
[8]: The derating is based on both technology and progress toward completion.
[9]: =[4]*[8].

Table 1.6
Additional New Renewable Generation Assumed to Meet RPS

Technology	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
NEW ENGLAND												
Biomass/Biofuels	0	36	72	109	145	183	221	253	286	318	350	382
Fuel Cells	0	8	15	23	30	36	42	47	52	57	61	66
Landfill Gas	0	9	18	27	36	37	38	39	40	41	42	43
Small Hydro	0	1	2	2	3	8	12	16	19	23	27	31
Solar PV	0	33	66	99	131	151	171	192	213	234	254	275
Wind												
w/ existing transmission	0	60	120	180	239	239	239	239	239	239	239	239
incremental w/ transmission	0	0	0	0	0	257	514	751	988	1,225	1,462	1,699
base case total	0	60	120	180	239	497	754	991	1,228	1,465	1,702	1,939
Offshore Wind												
w/ existing transmission	0	92	184	275	367	367	367	367	367	367	367	367
incremental w/ transmission	0	0	0	0	0	257	514	751	988	1,225	1,462	1,699
base case total	0	92	184	275	367	624	881	1,118	1,355	1,592	1,829	2,066
New England: Total Supply with New Transmission												
Nameplate capacity	0	238	476	714	952	1,536	2,120	2,656	3,193	3,729	4,266	4,802
Project 150	0	11	90	90	90	90	90	90	90	90	90	90
Nameplate capacity, excluding p.150	**0**	**227**	**386**	**624**	**862**	**1,446**	**2,030**	**2,566**	**3,103**	**3,639**	**4,176**	**4,712**
Capacity value, excluding p.150	**0**	**80**	**160**	**240**	**320**	**496**	**672**	**831**	**990**	**1,149**	**1,308**	**1,467**
New England: Adjustment to Supply Assuming No New Transmission												
Nameplate, compared to with Tx	0	0	0	0	0	(514)	(1,029)	(1,503)	(1,977)	(2,451)	(2,925)	(3,399)
Capacity value, excluding p.150	0	0	0	0	0	(118)	(237)	(346)	(455)	(564)	(673)	(782)
CONNECTICUT												
Biomass/Biofuels	0	13	25	38	51	53	55	57	60	62	64	66
Fuel Cells	0	8	15	23	30	36	42	47	52	57	61	66
Landfill Gas	0	5	10	15	20	21	22	23	24	25	26	27
Small Hydro	0	0	0	0	0	0	0	0	0	0	0	0
Solar PV	0	6	12	18	24	25	27	28	30	31	33	34
Connecticut: Total Supply												
Nameplate capacity	0	31	62	93	124	135	146	156	165	174	184	193
Project 150	0	11	90	90	90	90	90	90	90	90	90	90
Nameplate capacity, excluding p.150	**0**	**21**	**(28)**	**3**	**34**	**45**	**56**	**65**	**75**	**84**	**94**	**103**
Capacity value, excluding p.150	**0**	**5**	**10**	**15**	**20**	**30**	**40**	**49**	**57**	**66**	**74**	**83**

Sources and Notes:
Solar PV values include 28 MW of existing solar ISO-wide that is not included as existing in this section of this IRP.
For further discussion on the derivation of these values see the Renewables section of this IRP.
Unless noted otherwise all values are nameplate capacity, and include project 150 capacity.

1.F UNIT RETIREMENTS

Projected capacity surpluses and likely environmental requirements may cause some of the older oil- and gas-fired steam units to retire. We have analyzed potential retirements under all resource strategies and scenarios by evaluating unit costs and revenues, where the costs include primarily fixed O&M and capital expenditures necessary to comply with likely environmental regulations, and the revenues include capacity and energy margins. The capacity revenues are solved jointly with the retirement (and mothball) decisions by letting prices descend until sufficient capacity delists for the market to clear or reach a price floor. At the "optimum," each unit should be making profit-maximizing short-term decisions (operate versus mothball) and long-term decisions (invest in environmental controls versus retire). The assumptions and interdependent components of this multi-period analysis are described below, followed by an explanation of results and sensitivity analyses.

1.F.1 Assumptions

Potential Environmental Regulations Requiring Major Capital Expenditure

All units are assumed to be required to meet region-wide NO_X emission rate limits of 0.125 lbs/MMBtu by 2013 and 0.07 lbs/MMBtu by 2017 to facilitate region-wide Federal National Ambient Air Quality Standards (NAAQS) compliance, including Connecticut compliance under Clean Air Interstate Rule (CAIR). These rate limits were developed in consultation from the Connecticut Department of Environmental Protection (CT DEP, or DEP), and are based on Ozone Transport Commission (OTC) studies and recommendations on achievable NO_X rate targets. Non-compliant units with NO_X emission rates of 0.25 lbs/MMBtu or below are assumed to be able to meet the 2013 limit with temporary measures at relatively little cost, such as with a selective non-catalytic reducer (SNCR) or through adjustments to fuel or operations. These units must install a selective catalytic reducer (SCR) to meet the 2017 emission rate limit. All other non-compliant units must install a SCR to meet the 2013 and 2017 emission rate limits. To meet these emission rate requirements we also assume the following:

- **SCR capital costs:** Estimates of the overnight capital cost of SCR installation at Middletown 4, Montville 6, and Norwalk Harbor 1 & 2 have been provided by DEP staff. At Middletown 4 a SCR is assumed to cost \$113/kW, \$110/kW at Montville 6, \$123/kW at Norwalk Harbor 1, and \$119 at Norwalk Harbor 2. A capacity-weighted average of these values, \$114/kW, is assumed for all other units.
- **SCR revenue requirement:** The SCR capital cost is expressed in terms of a 10-year annuitized revenue requirement. This is derived using a capital charge rate of 22.5 percent, assuming 50/50 debt-to-equity ratio, a debt rate of 7 percent, and a 15 percent return on equity reflecting risk associated with merchant generation. There are also relatively small fixed O&M costs.
- **SCR emission rate reduction:** 90 percent.
- **Newington 1 exemption:** Newington 1, a 400 MW steam oil/gas unit in New Hampshire, is supported through Public Service New Hampshire's (PSNH) Energy Service (ES) rate, and is assumed to provide sufficient value to ES customers to warrant investing in an SCR in 2017 and operate in all year.

Fixed O&M While Operating or Mothballed

Data on unit-specific Fixed O&M (FOM) are based on reliability agreements with the ISO and data compiled by Ventyx. If either (1) unit-specific data are unavailable, or (2) the unit-specific FOM value is inconsistent with FCA de-list bids or lack thereof, then we assume generic FOM values of \$30-34/kW-year. Rather than retiring permanently, a unit may choose to temporarily go offline ("mothball") during poor market conditions, and then return online when market prices are more favorable. The annual cost to mothball a unit is assumed to be one-half of FOM cost. Depending on a unit's energy margins, capacity payments, and investment requirements, it may be more favorable to operate with a small loss in some years rather than incur a mothball cost, or retire permanently and forego future net revenues.

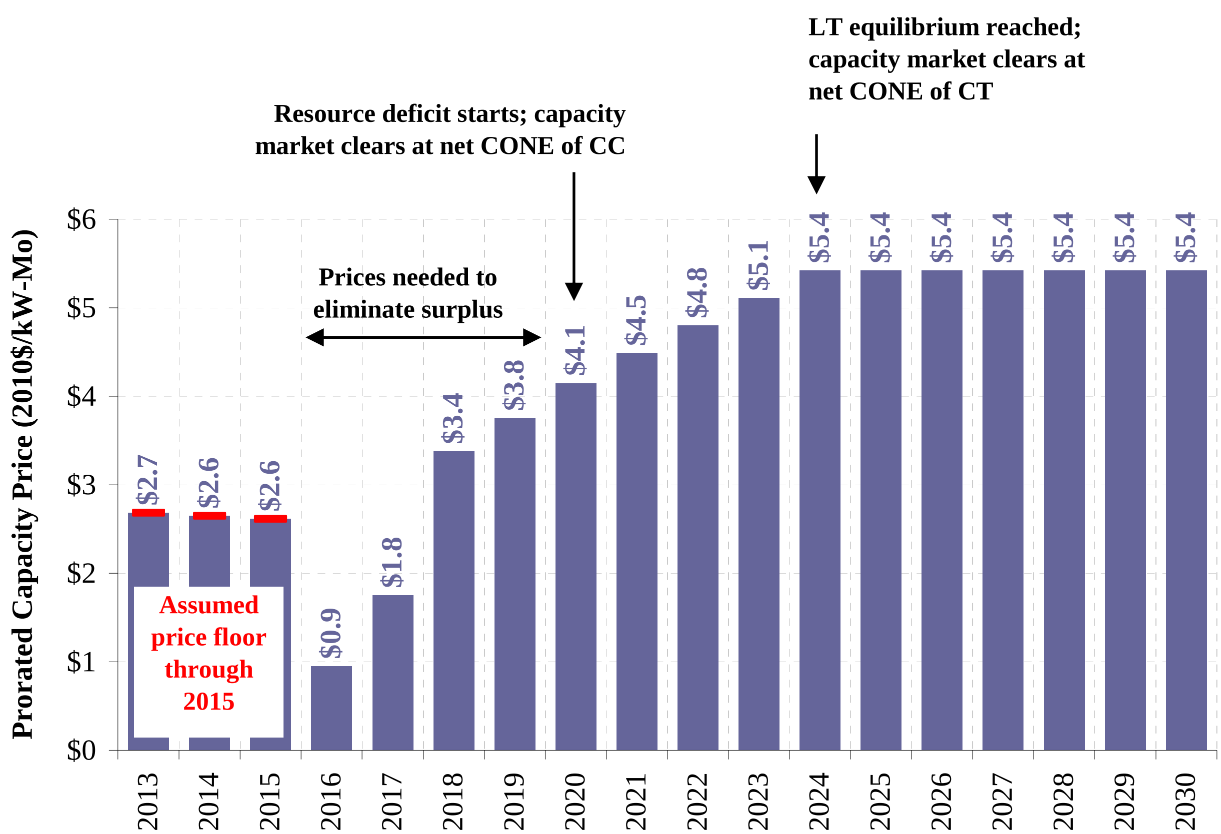
Energy Market Revenues

Unit-specific energy margins are based on market simulation results for each of the study years 2013, 2015, and 2020. Energy margins are interpolated between study years, and are assumed to stay constant in real terms after 2020.

Capacity Prices

Capacity prices are determined using an iterative calculation in each year 2013-2030, using each unit's economics (capital cost, operating cost, energy margins). Capacity prices are initially set to high values, and then are lowered to clear the capacity market of its surplus in each year. Figure 1.5 shows projected capacity prices for the period 2013-2030 for the Base Case.

Figure 1.5
Projected Capacity Prices (prorated)
2013-2030



Due to the large projected market surplus in the next ten years, prices drop to low levels in the near term. A price floor of $3/kW-month is enforced through May 2016 based on recent ISO discussions with market participants. After the price floor capacity prices drop to very low levels, then make a slow recovery over the next five years. In later years, prices must be higher to clear the market and eventually approach the net cost of new entry (CONE). The 2013-2030 capacity price trajectory is roughly optimized such that a resource deficit begins in the same year price reaches CONE of a new combined cycle unit. The market is assumed to reach a long-term equilibrium with prices at net CONE of a new combustion turbine unit approximately 4-5 years later. Values for net CONE are based on PJM capital cost estimates, adjusted downward for the recent downturn in construction costs, and preliminary market simulation results. Net CONE values are shown in Table 1.7. Capacity prices were developed in the same manner as the Base Case for all strategies and scenarios.

Table 1.7
Estimates of Net CONE for New Combustion Turbine and Combined Cycle Units

			Combustion Turbine	Combined Cycle
Overnight cost	*(2008 $/kW)*	*[1]*	$720	$1,131
Economic downturn multiplier from CERA		*[2]*	79%	79%
Adjusted cost	*(2010 $/kW)*		$576	$906
Annual capital carrying charge rate	*(%)*	*[3]*	13.10%	10.65%
Annual capital carrying charge	*(2010 $/kW-Yr)*	*[4]*	$75	$96
FOM	*(2008 $/kW-Yr)*	*[5]*	$27	$30
	(2010 $/kW-Yr)		$27	$30
Energy Margin (incl. spin + uplift)	*(2010 $/kW-Yr)*	*[6]*	$38	$77
Cost of New Entry (CONE)	***(2010 $/kW-Yr)***	***[7]***	**$65**	**$50**
	(2010 $/kW-Mo)		**$5.4**	**$4.2**

Sources and Notes:
[1]: Combined Cycle: PJM updated net cone assumptions for CC;
PJM CMEC meeting materials Sept 4, 2008; see
See http://www.pjm.com/committees/cmec/downloads/20080904-item-04a-pasteris-cone-cc-update.pdf.
Combustion Turbine: "Proposed Update to CONE" Excel file to accompany 2011/12 capacity market auction assumptions.
See http://www.pjm.com/markets-and-operations/rpm/rpm-auction-user-info.aspx#Item05.
[2]: Based on CERA Power Capital Costs Index.
See http://www.cera.com/aspx/cda/public1/news/pressReleases/pressReleaseDetails.aspx?CID=10429.
[3]: 2008 IRP, Tables C1 & C.2.
[4]: = [1]*[3].
[5]: 2008 IRP, Tables C1 & C.2.
[6]: Based on preliminary market simulation results for representative units.
[7]: = [4]+[5]-[6].

1.F.2 Methodology

For each resource strategy and scenario retirements and mothballing are determined iteratively, along with capacity prices. Both are roughly optimized such that the capacity market clears in the initial years, and the capacity market reaches equilibrium such that the capacity price reaches net CONE in the year an ISO-wide resource deficit begins.

Each unit faces a two-part decision: (1) in each year would it be better to operate and incur any required expenses or mothball, and (2) given the long-term outlook would it be better to permanently retire?

Mothball Versus Operate

Prior to making a decision on permanent retirement, some units may find it more economic to mothball in a given year in order to either delay incurring major capital costs or to avoid losses in years with extremely low capacity prices. The retirement analysis includes as an initial step a year-by-year assessment of unit decisions to either mothball or operate. In each year, a unit is assumed to mothball if its required SCR capital cost, expressed as the portion of the 10-year annuitized SCR revenue requirement over and above its cost to mothball, plus net operating expenses, exceed its cost to mothball (½ FOM). Once the SCR capital cost is incurred it is considered “sunk” and is not included in the decision to mothball versus retire in subsequent years. For example, a unit that must install a SCR in 2013 in order to operate will mothball if its cost to mothball is less than SCR capital cost plus net operating expenses. If it is more economic to install the SCR and operate, then in 2014 it will mothball only if its net operating expenses exceed its cost to mothball.

In the next step of the retirement analysis these year-by-year decisions to mothball versus operate are used to develop long-term net revenue projections for each unit, which are then used to determine which units will likely retire. Key factors for the next step are (1) the year of SCR installation, if needed, and (2) cumulative net revenues, including SCR capital costs, over time.

Permanent Retirement

Using the results of the annual mothball versus operate decision, we calculate each unit’s annual net revenue including only the cost to mothball in a mothball year, and during operations the capital cost of SCR installation (again, expressed as a 10-year annuitized revenue requirement, over the full 10 years after SCR investment) if required, plus net operating costs. If a unit cannot recover all of its costs, including any cumulative losses prior to the SCR investment, in cumulative 2013 PV terms within 8 years after SCR investment, then it is assumed to retire. A given unit will retire in either 2013 or, if it does not need to install a SCR to meet the 2013 limit, may retire in a later year to capture net revenues before 2017.

1.F.3 Results

Unit-level results are provided in Table 1.8 and Table 1.9 for the Base Case. Table 1.9 includes an explanation by unit of unit-level economics including SCR investment and retirement.

This analysis results in 2,446 MW existing steam oil and gas capacity retired ISO-wide, as follows:

- **Permanently retired units in Connecticut (1,504 MW):** Bridgeport Harbor 2, Middletown 3, Middletown 4 (marginal),[17] Montville 6 (marginal), Norwalk Harbor 1-2.

[17] These units may not retire given slightly different assumptions.

- **Permanently retired units in other states (942 MW):** Cleary 8, West Springfield 3, Yarmouth 1-4.
- **Mothballed units:** none.

Table 1.10 shows the resulting impact on ICR resource adequacy. With 2,446 in unit retirements the ISO still has sufficient resources through 2020, although the resource surplus drops from 2,686 to 240. Connecticut would also have sufficient resources through 2020 to meet requirements under both CT LSR and CT TSA.

In addition for the Base Case, several sensitivities to address some uncertainties in this analysis that could have significant impacts on the results were performed:

- **No emission rate limit**: This sensitivity tests for potential economic retirements without additional capital cost requirements. Prices reach the 2013-2015 price floor, drop to extremely low levels (about $1/kW-month) after the price floor is removed, and do not recover until 2024. Capacity prices increase thereafter and reach net CONE by 2027. In this sensitivity there are only 459 MW in permanent retirements ISO-wide, and 330 MW in Connecticut.
- **High mothball cost:** This sensitivity increases the cost to mothball from 50 percent of FOM to 75 percent of FOM, testing the impact of lower cost savings for mothballed units. With this cost increase there are 410 MW in additional retired capacity, including Middletown 4 (CT) and Cabot 8 (MA). Both units are marginal, and retire due to much lower capacity prices in 2016-19, which causes them to carry cumulative net losses even eight years after SCR installation in 2017. Prices are lower initially (then higher) than the original case. This is because the high mothball cost allows prices to drop a lot before there would be scarcity. The lower prices in turn cause slightly higher retirements.
- **No emission rate limit and extended price floor:** This sensitivity tests for potential retirements under continued surplus conditions. Capacity permanently retired is the same as under the no emission rate limit sensitivity, but capacity prices remain at the price floor through 2026, before reaching net CONE in 2027.
- **High merchant cost of equity:** This sensitivity examines merchant risk associated with uncertain SCR capital cost values by raising return on equity (ROE). Assumed merchant ROE is increased from 15 percent to 20 percent. This increases the total capital cost of a SCR by increasing the levelized annual revenue requirement from 19.4 percent to 22.5 percent. It also increases the value of short-term net revenues by increasing the real discount rate on cash flows from 7.3 percent to 9.7 percent.

Table 1.8
Base Case Cumulative NPV of Net Revenues, Assuming No Retirement (after-tax $/kW-yr)
Includes 10-year annuitized revenue requirement of SCR of approx. $22/kW-yr, (indicated with bold text)
The data used to determine retirements are shaded

Unit	Capacity *(MW)*	State	FOM *($/kW-Yr) (2010 $)*	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
BRIDGEPORT HARBOR 2	130	CT	30	(12)	(22)	(31)	(47)	(58)	(61)	(62)	(62)	(60)	(58)	(49)	(40)	(31)	(23)	(15)	(8)	(1)	5
MIDDLETOWN 2	117	CT	30	2	4	7	3	(7)	(9)	(9)	(8)	(6)	(3)	1	6	10	14	22	29	36	43
MIDDLETOWN 3	236	CT	30	(10)	(19)	(27)	(41)	(51)	(53)	(53)	(52)	(50)	(47)	(38)	(28)	(19)	(10)	(2)	5	12	19
MIDDLETOWN 4	400	CT	30	0	1	2	(4)	(15)	(18)	(19)	(19)	(18)	(16)	(13)	(9)	(6)	(3)	5	12	18	24
MONTVILLE 5	81	CT	30	3	7	12	9	1	1	3	6	10	15	20	26	32	37	46	55	63	71
MONTVILLE 6	407	CT	30	(0)	(1)	(1)	(8)	(20)	(23)	(25)	(25)	(24)	(22)	(19)	(16)	(13)	(9)	(2)	5	11	17
NEW HAVEN HARBOR	448	CT	30	1	2	3	(3)	(14)	(17)	(18)	(17)	(15)	(12)	(8)	(4)	0	4	12	19	26	33
NORWALK HARBOR 1	162	CT	66	(18)	(34)	(50)	(64)	(78)	(95)	(109)	(121)	(130)	(138)	(145)	(150)	(155)	(159)	(163)	(162)	(162)	(161)
NORWALK HARBOR 2	168	CT	66	(18)	(34)	(50)	(64)	(78)	(95)	(109)	(122)	(132)	(140)	(147)	(153)	(158)	(162)	(167)	(167)	(167)	(166)
BRAYTON PT 4	435	MA	30	1	3	5	0	(10)	(12)	(13)	(12)	(10)	(7)	(3)	2	6	9	17	25	32	38
CANAL 1	573	MA	30	0	1	1	(5)	(7)	(1)	6	14	23	33	42	53	62	71	79	86	93	100
CANAL 2	545	MA	30	1	3	5	(0)	(10)	(13)	(13)	(12)	(10)	(7)	(3)	1	6	10	18	25	32	39
CLEARY 8	26	MA	34	(15)	(29)	(42)	(59)	(73)	(79)	(82)	(85)	(85)	(85)	(78)	(71)	(64)	(57)	(51)	(45)	(40)	(35)
HOLYOKE 6/CABOT 6	10	MA	34	(1)	(1)	1	(5)	(15)	(17)	(17)	(15)	(13)	(10)	(6)	(1)	4	8	16	24	31	38
HOLYOKE 8/CABOT 8	10	MA	34	(1)	(1)	(1)	(7)	(18)	(21)	(21)	(19)	(17)	(13)	(9)	(4)	0	5	13	21	28	35
KENDALL STEAM 1 2 3	53	MA	34	0	1	3	(2)	(12)	(14)	(13)	(10)	(7)	(3)	2	8	13	18	26	35	43	50
MYSTIC 7	578	MA	30	3	7	12	11	5	7	12	18	25	32	40	48	56	63	74	85	95	104
SALEM HARBOR 4	437	MA	30	2	4	6	1	(7)	(7)	(5)	(0)	5	11	17	25	31	37	47	57	66	74
WEST SPRINGFIELD 3	94	MA	30	0	1	3	(3)	(14)	(17)	(18)	(18)	(17)	(14)	(11)	(7)	(4)	(0)	7	14	21	27
YARMOUTH 1	52	ME	34	(2)	(5)	(8)	(15)	(22)	(28)	(32)	(34)	(35)	(35)	(34)	(32)	(30)	(29)	(27)	(21)	(16)	(11)
YARMOUTH 2	51	ME	34	(2)	(5)	(7)	(15)	(22)	(28)	(32)	(34)	(34)	(34)	(33)	(31)	(29)	(27)	(25)	(20)	(14)	(9)
YARMOUTH 3	116	ME	30	0	0	0	(6)	(12)	(16)	(19)	(19)	(19)	(17)	(15)	(12)	(9)	(6)	(3)	3	9	15
YARMOUTH 4	603	ME	30	(0)	(0)	(1)	(7)	(13)	(17)	(20)	(20)	(20)	(18)	(16)	(12)	(9)	(7)	(4)	3	9	15
NEWINGTON 1	400	NH	30	2	4	5	(1)	(12)	(16)	(17)	(18)	(17)	(15)	(12)	(9)	(6)	(3)	5	12	18	24
ISO-NE Net Installed Capacity Requirement (MW)				32,411	32,901	33,370	33,757	34,120	34,454	34,751	35,051	35,354	35,659	35,967	36,278	36,591	36,907	37,225	37,547	37,871	38,198
Resource Surplus (Deficit) without Retirements (MW)				4,175	3,925	3,622	3,262	3,027	2,890	2,790	2,686	2,383	2,078	1,770	1,459	1,146	830	512	190	(134)	(461)
Final Retired/MB Capacity (MW)				825	825	825	2,446	2,446	2,446	2,446	2,446	2,446	2,446	2,446	2,446	2,446	2,446	2,446	2,446	2,446	2,446
Connecticut Only				696	696	696	1,504	1,504	1,504	1,504	1,504	1,504	1,504	1,504	1,504	1,504	1,504	1,504	1,504	1,504	1,504
All Mothballed Capacity				0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Resource Surplus (Deficit) with Retirements (MW)				3,350	3,100	2,797	816	581	444	344	240	(63)	(368)	(676)	(987)	(1,300)	(1,616)	(1,934)	(2,256)	(2,580)	(2,907)
Capacity Price with Retirements (2010$/kW-Year, prorated)				32	32	31	11	21	41	45	50	54	58	61	65	65	65	65	65	65	65
				Floor			In balance					Supply deficit									

Table 1.9
Base Case Final Unit Retirement Analysis Results, by Unit

Unit Name	Summer Capacity (MW)	State	Pre-Investment NO_X Rate (Reflects gas if available)	Final Retirement Decision	Notes and Observations
BRIDGEPORT HARBOR 2	130	CT	0.43	**Retire in 2013**	Must install SCR in 2013 to operate. In 2013 PV terms, its net revenues in later years when capacity prices are high do not offset its early investment cost.
MIDDLETOWN 2	117	CT	0.15	Operate	Can operate and wait until 2017 to install SCR; sees cumulative net gains 5 years after installing SCR.
MIDDLETOWN 3	236	CT	0.31	**Retire in 2013**	Must install SCR in 2013 to operate. In 2013 PV terms, its market gains in later years when capacity prices are high do not offset its early investment cost.
MIDDLETOWN 4	400	CT	0.25	**Retire in 2016**	Can meet 2013 requirements without a SCR; sees very marginal cumulative net losses 8 years after installing SCR.
MONTVILLE 5	81	CT	0.10	Operate	Can operate and wait until 2017 to install SCR; has relatively high energy margins and sees cumulative net gains in all years.
MONTVILLE 6	407	CT	0.20	**Retire in 2016**	Can meet 2013 requirements without a SCR, but has very low energy margins. It sees marginal net losses in early years due to low capacity prices; with SCR investment it would not see cumulative net gains until 2026.
NEW HAVEN HARBOR	448	CT	0.15	Operate	Can operate and wait until 2017 to install SCR; sees cumulative net gains 8 years after installing SCR.
NORWALK HARBOR 1	162	CT	0.21	**Retire in 2013**	Has extremely high FOM (even with $25 adjustment for Connecticut former “RMR” units).
NORWALK HARBOR 2	168	CT	0.20	**Retire in 2013**	Has extremely high FOM (even with $25 adjustment for Connecticut former “RMR” units).
BRAYTON PT 4	435	MA	0.24	Operate	Can operate and wait until 2017 to install SCR; sees cumulative net gains 5 years after installing SCR.
CANAL 1	573	MA	0.05	Operate	Is not required to install a SCR in any year. [maybe it already has one?]
CANAL 2	545	MA	0.20	Operate	Can operate and wait until 2017 to install SCR; sees cumulative net gains 5 years after installing SCR.
CLEARY 8	26	MA	0.26	**Retire in 2013**	Must install SCR in 2013 to operate. In 2013 PV terms, its market gains in later years when capacity prices are high do not offset its early investment cost.
HOLYOKE 6/CABOT 6	10	MA	0.20	Operate	Can operate and wait until 2017 to install SCR; sees cumulative net gains 8 years after installing SCR.
HOLYOKE 8/CABOT 8	10	MA	0.20	Operate	Can operate and wait until 2017 to install SCR; sees cumulative net gains 8 years after installing SCR.
KENDALL STEAM	53	MA	0.20	Operate	Can operate and wait until 2017 to install SCR; sees cumulative net gains 5 years after installing SCR.
MYSTIC 7	578	MA	0.11	Operate	Can operate and wait until 2017 to install SCR; has relatively high energy margins and sees cumulative net gains in all years.
SALEM HARBOR 4	437	MA	0.22	Operate	Can operate and wait until 2017 to install SCR; has relatively high energy margins and sees cumulative net gains in all years.
WEST SPRINGFIELD 3	94	MA	0.14	**Retire in 2016**	Can meet 2013 requirements without a SCR, but has very low energy margins. Slight net gains in early years due to low capacity prices; with SCR investment, it would not see cumulative gains until 2026 or later.
YARMOUTH 1	52	ME	0.23	**Retire in 2013**	Can meet 2013 requirements without a SCR, but has very low energy margins. Loses money in early years due to low capacity prices; with SCR investment, it would not see cumulative gains until 2026 or later.
YARMOUTH 2	51	ME	0.25	**Retire in 2013**	Can meet 2013 requirements without a SCR, but has very low energy margins. Loses money in early years due to low capacity prices; with SCR investment, it would not see cumulative gains until 2026 or later.
YARMOUTH 3	116	ME	0.14	**Retire in 2016**	Can meet 2013 requirements without a SCR, but has very low energy margins. No gains in early years due to low capacity prices; with SCR investment, it would not see cumulative gains until 2026 or later.
YARMOUTH 4	603	ME	0.15	**Retire in 2016**	Can meet 2013 requirements without a SCR, but has very low energy margins. Slight net losses in early years due to low capacity prices; with SCR investment, it would not see cumulative gains until 2026 or later.
NEWINGTON 1	400	NH	0.17	Operate	Unit is supported by customers through a cost based rate and is assumed to operate.

Table 1.10
Base Case Impact of Retirements on Net ICR

		2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Net Installed Capacity Requirement, no retirements	***(MW)***	**31,823**	**32,137**	**32,528**	**31,965**	**32,411**	**32,901**	**33,370**	**33,757**	**34,120**	**34,454**	**34,751**	**35,051**
Total Installed Capacity	***(MW)***	**33,714**	**35,803**	**38,006**	**38,002**	**36,586**	**36,826**	**36,992**	**37,019**	**37,147**	**37,344**	**37,541**	**37,737**
Retired Capacity	***(MW)***	**0**	**0**	**0**	**0**	**825**	**825**	**825**	**2,446**	**2,446**	**2,446**	**2,446**	**2,446**
ISO-NE Surplus (Shortfall), no retirements	*(MW)*	1,891	3,666	5,478	6,037	4,175	3,925	3,622	3,262	3,027	2,890	2,790	2,686
ISO-NE Surplus (Shortfall), with retirements	*(MW)*	1,891	3,666	5,478	6,037	3,350	3,100	2,797	816	581	444	344	240

1.G DEMAND-SIDE RESOURCES

Demand-side resources, which include demand response (DR) and energy efficiency (EE), are widely heralded as low-cost resources, and energy efficiency reduces environmental emissions.[18] However, forecasting demand-side resources' contributions to meeting reliability requirements presents a unique set of challenges. The amount of demand-side resources depends strongly on year-to-year implementation of utility-based programs and marketing by third-party curtailment service providers, and these resources can be developed (or simply registered) with the ISO much more quickly than it takes new generation to be developed. Other than being committed in the FCM, it is unclear with what certainty a planned demand-side resource will come online, since it does not typically meet publicly-known milestones in development like a new generator going into construction does.

Another challenge is in estimating the responsiveness and availability of DR. Responsiveness at a customer site can vary a great deal depending on day or time of day, site conditions, and weather conditions. At the start of FCM, the ISO had assumed 100 percent availability of demand-side resources and recognized the additional capacity value of that availability by grossing-up demand reduction values by the delivery year's reserve margin. The ISO has since recognized that audits and other performance statistics indicate that the availability of these resources can be much lower than 100 percent. Revisions to the ISO-NE Tariff to remove the reserve margin gross-up have been implemented, and these revisions apply to EE as well as DR.[19]

To address these challenges we have attempted to recognize the potential for development of new demand-side resources, while being conservative about how much can be expected to meet reliability requirements. We have:

- Counted the EDC's planned Reference Strategy EE[20];
- Counted all non-EDC EE resources committed in FCA#1 (assumed to be online by 2010), FCA#2 (assumed to be online by 2011), and FCA#3 (assumed to be online by 2012);
- Counted all DR ("active demand-side resources") committed in FCAs#1-3, but limited real-time emergency generation to 600 MW in accordance with ISO rules;

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[18] Demand response refers to resources that can be actively dispatched during peak hours or system emergencies (*e.g.*, direct load control, distributed generation), and energy efficiency refers to passive resources that cannot be dispatched but reduce load during pre-specified times and days (*e.g.*, efficient commercial lighting, efficient home appliances).

[19] "Reserve Margin 'Gross-Up' for Demand Resources," ISO New England presentation by Bob Ethier and Henry Yoshimura, August 27, 2008. Available at http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2008/sep24252008/a6_iso_presentation_09_17_08.ppt.

[20] See the DSM Section of this report for further discussion.

- Counted a small amount (81 MW ISO-wide) of economic DR currently participating in the ISO markets;
- Assumed additional EE resources developed in Massachusetts to meet the state's short-term EE goals; and
- Removed the reserve margin gross-up from the capacity value of all demand-side resources starting in 2012, consistent with current ISO-NE capacity market rules.

Table 1.11 and Table 1.12 summarize Reference Strategy DR and EE for Connecticut and total ISO, respectively.[21] As discussed previously the ISO's 2009 CELT peak load forecast already includes the impact of CFLs, so all EE values are reduced by an estimate of retail products to prevent double-counting of these measures.

Table 1.11
Reference Strategy DSM in Connecticut

			2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Gross-up Factor for Losses	*(MW)*	*[1]*	1.08	1.08	1.08	1.08	1.08	1.08	1.08	1.08	1.08	1.08	1.08	1.08
Gross-up Factor for Reserves	*(MW)*	*[2]*	1.15	1.14	1.16	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Total DR and EE Cleared in FCA#1-3 (at capacity value)		*[3]*												
DR, excluding RTEG	*(MW)*	*[4]*		288	313	273								
DR - RTEG	*(MW)*	*[5]*		342	269	203								
EE	*(MW)*	*[6]*		218	370	365								
Total	*(MW)*	*[7]*		**848**	**952**	**841**								
Reference Level DR (at capacity value)		*[8]*												
DR cleared in FCA#1-3, net of RTEG cap	*(MW)*	*[9]*	446	444	469	429	429	429	429	429	429	429	429	429
Additional economic DR	*(MW)*	*[10]*	7	7	7	7	7	7	7	7	7	7	7	7
Total DR	***(MW)***	***[11]***	**453**	**451**	**476**	**436**	**436**	**436**	**436**	**436**	**436**	**436**	**436**	**436**
Reference Level EE (at capacity value)		*[12]*												
DR cleared in FCA#1-3, net of CFLs	*(MW)*	*[13]*	226	185	314	336	345	353	353	353	365	365	365	365
Additional planned EE	*(MW)*	*[14]*	0	0	0	0	43	85	125	164	204	242	280	317
Total EE	***(MW)***	***[15]***	**226**	**185**	**314**	**336**	**388**	**437**	**477**	**517**	**568**	**607**	**644**	**681**
Total Reference Level DR and EE (at capacity value)	***(MW)***	***[16]***	**678**	**636**	**790**	**771**	**824**	**873**	**913**	**952**	**1,004**	**1,043**	**1,080**	**1,117**

Sources and Notes:
[3]: Reflects values reported by the ISO; see http://www.iso-ne.com/markets/othrmkts_data/fcm/index.html. All values include gross-up factors in [1] & [2].
[4]: All "active" demand resources, excluding real-time emergency generation.
[5]: All "active" real-time emergency generation resources; values may exceed Connecticut's share of the ISO-wide RTEG cap of 600 MW.
[6]: All "passive" demand resources.
[9]: Sum of [4] & [5], with RTEG limited to Connecticut's share of the ISO-wide RTEG cap of 600 MW.
10]: Includes Real-Time Price Response DR (economic DR) as of 7/1/2009. See ISO-NE presentation "Demand Response" NPC Meeting - July 7, 2009 Posting COO report, page 4.
13]: Values are grossed down by estimated share of Retail Products already included in the ISO's load forecast.
14]: Additional EE planned by EDCs in 2013-2020.
16]: Sum of [11] and [15].

[21] Note that for production cost modeling purposes EE is treated on the demand side as a load reducer, and DR is treated on the supply side as resources dispatchable at certain prices.

Table 1.12
Reference Strategy DSM ISO-Wide

			2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Gross-up Factor for Losses	*(MW)*	*[1]*	**1.08**	**1.08**	**1.08**	**1.08**	**1.08**	**1.08**	**1.08**	**1.08**	**1.08**	**1.08**	**1.08**	**1.08**
Gross-up Factor for Reserves	*(MW)*	*[2]*	**1.15**	**1.14**	**1.16**	**1.00**	**1.00**	**1.00**	**1.00**	**1.00**	**1.00**	**1.00**	**1.00**	**1.00**
Total DR and EE Cleared in FCA#1-3 (at capacity value)		*[3]*												
DR, excluding RTEG	*(MW)*	*[4]*		979	1,200	1,194								
DR - RTEG		*[5]*		875	759	630								
EE	*(MW)*	*[6]*		700	978	1,073								
Total	*(MW)*	*[7]*		**2,554**	**2,937**	**2,898**								
Reference Level DR (at capacity value)		*[8]*												
DR cleared in FCA#1-3, net of RTEG cap	*(MW)*	*[9]*	1,585	1,579	1,800	1,794	1,794	1,794	1,794	1,794	1,794	1,794	1,794	1,794
Additional economic DR	*(MW)*	*[10]*	81	81	81	81	81	81	81	81	81	81	81	81
Total DR	*(MW)*	***[11]***	**1,666**	**1,660**	**1,881**	**1,876**	**1,876**	**1,876**	**1,876**	**1,876**	**1,876**	**1,876**	**1,876**	**1,876**
Reference Level EE (at capacity value)		*[12]*												
DR cleared in FCA#1-3, net of CFLs	*(MW)*	*[13]*	608	594	830	987	1,014	1,037	1,037	1,037	1,073	1,073	1,073	1,073
Additional planned EE	*(MW)*	*[14]*	0	34	119	103	146	187	227	267	306	345	382	419
Total EE	*(MW)*	***[15]***	**608**	**628**	**949**	**1,090**	**1,160**	**1,224**	**1,264**	**1,304**	**1,379**	**1,417**	**1,455**	**1,492**
Total Reference Level DR and EE (at capacity value)	*(MW)*	***[16]***	**2,274**	**2,288**	**2,830**	**2,965**	**3,036**	**3,100**	**3,140**	**3,179**	**3,255**	**3,293**	**3,331**	**3,368**

Sources and Notes:

[3]: Reflects values reported by the ISO; see http://www.iso-ne.com/markets/othrmkts_data/fcm/index.html. All values include gross-up factors in [1] & [2].
[4]: All "active" demand resources, excluding real-time emergency generation.
[5]: All "active" real-time emergency generation resources; values may exceed the ISO-wide RTEG cap of 600 MW.
[6]: All "passive" demand resources.
[9]: Sum of [4] & [5], with RTEG limited to the ISO-wide RTEG cap of 600 MW.
10]: Includes Real-Time Price Response DR (economic DR) as of 7/1/2009. See ISO-NE presentation "Demand Response" NPC Meeting - July 7, 2009 Posting COO report, page 4.
13]: Values are grossed down by estimated share of Retail Products already included in the ISO's load forecast.
14]: Additional EE planned by EDCs in 2013-2020, plus an additional amount is assumed in MA to meet 2010 and 2011 short-term goals beyond business-as-usual levels.
16]: Sum of [11] and [15].

A concern for the ISO and market participants is the impact of increased levels of active demand-side resources, DR in Tables 1.11 and 1.12 above, on system reliability during shortage hours. As DR are committed for reliability in larger amounts, they will be called more often during critical peak hours, including hours during shoulder months and off-peak periods. Since DR are limited in what hours in the year they can perform, it is unclear at what amount of concentration they will start to be called during times when they are unable to perform. In addition, customers enrolled in programs committed in FCM may not have a tolerance for an increased frequency of dispatch, and may drop out of programs to avoid undesired interruption of processes. We have not analyzed the impact of the above concerns on resource needs, which is being discussed in the ISO stakeholder process.

1.H NET IMPORTS AND TIE-LINE BENEFITS

Net imports to the ISO-NE system in 2009 (58 MW), and 2013-2018 (334 MW in 2013, reduced to 6 MW by 2018) are consistent with those assumed in the 2009 CELT. 2019 and 2020 net imports are held constant at the 2018 value of 6 MW. Net imports in 2010, 2011, and 2012 are consistent with those cleared in the ISO's Forward Capacity Market auctions.

Tie-line benefits are consistent with those assumed by the ISO in calculating system-wide ICR, and contribute 1,665 to 2,000 MW per year.

Connecticut import capability cannot be used as a supply resource in meeting its LSR, but has a direct impact on the CT LSR itself. The New England East-West Solution (NEEWS) is a planned transmission project assumed to be online by 2014, and reduces Connecticut's LSR by approximately 1,175 MW while also making Lake Road available to meet the CT LSR (760 MW). The ISO is assessing the interaction of the change in transfer limit and counting the Lake Road units as Connecticut capacity resources.

1.I RESOURCE ADEQUACY OUTLOOK

Table 1.13, Table 1.14, and Table 1.15 below show for the Base Case the 2009 through 2020 supply/demand balance for Connecticut and the ISO, respectively, including resource needs under each requirement considered. Both are expected to have sufficient resources through 2020 to meet reliability requirements.

Table 1.13
Resource Adequacy under Connecticut Local Sourcing Requirement, CT LSR (MW)
Base Case

Reference Case	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
CT Local Sourcing Requirement*	**n/a**	**6,496**	**6,912**	**7,325**	**7,433**	**6,341**	**6,408**	**6,455**	**6,498**	**6,557**	**6,625**	**6,708**
Existing Capacity	7,001	7,001	7,001	7,001	7,001	7,001	7,001	7,001	7,001	7,001	7,001	7,001
Inclusion of Lake Road Units in Connecticut	0	0	0	0	0	766	766	766	766	766	766	766
Planned New Capacity	96	1,049	1,266	1,444	1,444	1,444	1,444	1,444	1,444	1,444	1,444	1,444
Assumed New Renewable Generation for RPS (excl. P.150)	0	5	10	15	20	30	40	49	57	66	74	83
Demand Response	453	451	476	436	436	436	436	436	436	436	436	436
Energy Efficiency	226	185	314	336	388	437	477	517	568	607	644	681
Firm Purchases and Sales	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)
Assumed Retirements, Cancellations, or Delays	0	0	0	0	(696)	(696)	(696)	(1,504)	(1,504)	(1,504)	(1,504)	(1,504)
Total Available Resources	**7,675**	**8,591**	**8,967**	**9,132**	**8,493**	**9,318**	**9,368**	**8,609**	**8,669**	**8,716**	**8,762**	**8,808**
Connecticut LSR Surplus (Shortfall)	**n/a**	**2,095**	**2,055**	**1,807**	**1,060**	**2,978**	**2,960**	**2,154**	**2,171**	**2,159**	**2,137**	**2,099**

Note: The ISO is continuing to assess the interaction of the change in transfer limit and counting the Lake Road units as Connecticut capacity resources due to NEEWS.

* 2010-11 uses "as-is" methodology from current ISO rules; 2012 and beyond assume proposed "at-criterion" methodology; LSR assumes NEEWS impact starting in 2014.

Table 1.14
Resource Adequacy under Connecticut Transmission Security Analysis (TSA) Requirement (MW)
Base Case

Reference Case	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
CT Requirement under Transmission Security Analysis*	**7,273**	**7,464**	**7,631**	**7,637**	**7,683**	**6,706**	**6,782**	**6,803**	**6,863**	**6,913**	**6,964**	**7,015**
Connecticut Subarea 90/10 Peak Load	7,940	8,010	8,105	8,205	8,285	8,370	8,445	8,505	8,565	8,615	8,665	8,716
Required Reserves (Millstone Unit 3)	1,137	1,235	1,235	1,235	1,235	1,235	1,235	1,235	1,235	1,235	1,235	1,235
Connecticut Import Limit	2,500	2,500	2,500	2,500	2,500	3,600	3,600	3,600	3,600	3,600	3,600	3,600
Installed capacity derate	696	719	791	697	663	701	702	663	663	663	664	664
Existing Capacity	7,001	7,001	7,001	7,001	7,001	7,001	7,001	7,001	7,001	7,001	7,001	7,001
Inclusion of Lake Road Units in Connecticut	0	0	0	0	0	766	766	766	766	766	766	766
Planned New Capacity	96	1,049	1,266	1,444	1,444	1,444	1,444	1,444	1,444	1,444	1,444	1,444
Assumed New Renewable Generation for RPS (excl. P.150)	0	5	10	15	20	30	40	49	57	66	74	83
Demand Response	453	451	476	436	436	436	436	436	436	436	436	436
Energy Efficiency	226	185	314	336	388	437	477	517	568	607	644	681
Assumed Retirements, Cancellations, or Delays	0	0	0	0	(696)	(696)	(696)	(1,504)	(1,504)	(1,504)	(1,504)	(1,504)
Firm Purchases & Sales	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)
Total Available Resources	**7,675**	**8,591**	**8,967**	**9,132**	**8,493**	**9,318**	**9,368**	**8,609**	**8,669**	**8,716**	**8,762**	**8,808**
Connecticut TSA Surplus (Shortfall)	**402**	**1,128**	**1,336**	**1,495**	**809**	**2,612**	**2,587**	**1,806**	**1,806**	**1,802**	**1,798**	**1,792**

Note: The ISO is continuing to assess the interaction of the change in transfer limit and counting the Lake Road units as Connecticut capacity resources due to NEEWS.

* This analysis represents the transmission system's capability to serve sub-area load with available resources, including its capacity to import power across subarea interfaces. The analysis does not consider whether the transmission system within the subarea complies with NERC, NPCC and ISO-NE transmission security criteria. TSA assumes NEEWS impact starting in 2014.

** Millstone 3 is not derated but forced outage rates are applied to remaining capacity; demand-side resources exclude real-time emergency generation and are not grossed up for reserves. This methodology is consistent with the ISO methodology used to assess Norwalk Harbor's dynamic delist bid in FCM

Table 1.15
Resource Adequacy Outlook under ISO-NE Net Installed Capacity Requirement (MW)
Base Case

Reference Case	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Net Installed Capacity Requirement	**31,823**	**32,137**	**32,528**	**31,965**	**32,411**	**32,901**	**33,370**	**33,757**	**34,120**	**34,454**	**34,751**	**35,051**
Existing Capacity	31,286	31,286	31,286	31,286	31,286	31,286	31,286	31,286	31,286	31,286	31,286	31,286
Planned New Capacity	96	1,216	1,432	1,610	1,610	1,610	1,610	1,610	1,610	1,610	1,610	1,610
Assumed New Renewable Generation for RPS (excl. P.150)	0	80	160	240	320	496	672	831	990	1,149	1,308	1,467
Demand Response*	1,666	1,660	1,881	1,876	1,876	1,876	1,876	1,876	1,876	1,876	1,876	1,876
Energy Efficiency**	608	628	949	1,090	1,160	1,224	1,264	1,304	1,379	1,417	1,455	1,492
Firm Purchases and Sales	58	934	2,298	1,900	334	334	284	112	6	6	6	6
Assumed Retirements, Cancellations, or Delays	0	0	0	0	(825)	(825)	(825)	(2,446)	(2,446)	(2,446)	(2,446)	(2,446)
Total Available Resources	**33,714**	**35,803**	**38,006**	**38,002**	**35,761**	**36,001**	**36,167**	**34,573**	**34,701**	**34,898**	**35,095**	**35,291**
ISO-NE Surplus (Shortfall)	**1,891**	**3,666**	**5,478**	**6,037**	**3,350**	**3,100**	**2,797**	**816**	**581**	**444**	**344**	**240**

* Demand response values are based on market results from the Forward Capacity Market, plus a small amount (81 MW) of economic DR based on historic values.

** Energy efficiency values are based on market results from the Forward Capacity Market, plus additional new EE needed to meet MA short-term goals.

1.J SCENARIOS AND STRATEGIES

In addition to analyzing resource adequacy under the Base Case (Current Trends scenario with Reference resource strategy), resource adequacy was also analyzed under combinations of four alternative scenarios and six alternative strategies. The scenarios examine different combinations of natural gas price, CO_2 price, and load, and the strategies examine alternative resource outlooks (generation, transmission, demand-side). These alternative scenarios and strategies are described in detail in Section II (Analytical Findings). Tables 1.16, 1.17, and 1.18 summarize the resource adequacy impacts of each of the scenarios and strategies on the Connecticut LSR, the Connecticut TSA, and the ISO-wide ICR, respectively.

Table 1.16
Potential Impact of Scenarios and Strategies on Resource Adequacy under CT LSR
Reference Strategy, All Scenarios, 2010- 2020

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Base Case LSR		6,496	6,912	7,325	7,433	6,341	6,408	6,455	6,498	6,557	6,625	6,708
Peak Load		7,480	7,565	7,650	7,725	7,800	7,870	7,920	7,965	8,020	8,075	8,131
LSR/MW Load		0.9	0.9	1.0	1.0	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Retired Capacity		0	0	0	696	696	696	1,504	1,504	1,504	1,504	1,504
Additional new renewable generation for RPS		5	10	15	20	30	40	49	57	66	74	83
Total generic CC capacity added												0
Base Case LSR Surplus (Shortfall)		**2,095**	**2,055**	**1,807**	**1,060**	**2,978**	**2,960**	**2,154**	**2,171**	**2,159**	**2,137**	**2,099**
(01) HIGH GAS AND HIGH CO_2												
Approximate incremental peak load impact*		31	65	103	244	220	235	243	251	259	268	277
Incremental retirement impact		0	0	0	0	0	0	(117)	(646)	(646)	(646)	(646)
Incremental renewables impact		0	0	0	0	0	0	0	0	0	0	0
Total generic CC capacity added												300
Resulting LSR Surplus (Shortfall)		**2,126**	**2,120**	**1,910**	**1,303**	**3,198**	**3,195**	**2,280**	**1,776**	**1,772**	**1,759**	**2,031**
(02) LOW GAS AND LOW CO_2												
Approximate incremental peak load impact*		(25)	(52)	(83)	(196)	(176)	(186)	(192)	(196)	(202)	(207)	(213)
Incremental retirement impact		0	0	0	0	0	0	400	400	400	400	400
Incremental renewables impact		0	0	0	0	0	0	0	0	0	0	0
Total generic CC capacity added											300	300
Resulting LSR Surplus (Shortfall)		**2,071**	**2,003**	**1,724**	**864**	**2,802**	**2,774**	**2,363**	**2,374**	**2,358**	**2,629**	**2,586**
(03) HIGH LOAD GROWTH												
Approximate incremental peak load impact*		(21)	(31)	(51)	(54)	(57)	(70)	(89)	(105)	(112)	(119)	(126)
Incremental retirement impact		0	0	0	0	0	0	400	400	400	400	400
Incremental renewables impact		0	0	0	0	0	0	0	0	0	0	0
Total generic CC capacity added											300	300
Resulting LSR Surplus (Shortfall)		**2,075**	**2,024**	**1,756**	**1,006**	**2,921**	**2,890**	**2,465**	**2,466**	**2,447**	**2,718**	**2,673**
(04) MEDIUM GAS AND HIGH CO_2												
Approximate incremental peak load impact*		7	14	22	53	48	51	55	58	62	67	71
Incremental retirement impact		0	0	0	0	0	0	(448)	(448)	(448)	(448)	(448)
Incremental renewables impact		0	0	0	0	0	0	0	0	0	0	0
Total generic CC capacity added												0
Resulting LSR Surplus (Shortfall)		**2,102**	**2,069**	**1,829**	**1,113**	**3,025**	**3,011**	**1,761**	**1,781**	**1,774**	**1,755**	**1,722**

*Impact based on approximate LSR/MW ratio of 0.8-1.

All Strategies, All Scenarios, 2020

		Targeted DSM Expansion	All Achievable Cost-Effective DSM	Limited Renewables	In-State Renewables	Efficient Gas Expansion (+1100 MW CCs)
(00) CURRENT TRENDS						
Surplus with Reference Strategy	*[a]*	2,099	2,099	2,099	2,099	2,099
Incremental DSM impact	*[b]*	206	561	0	0	0
Incremental retirement impact	*[c]*	0	(448)	(565)	(565)	0
Incremental renewables impact	*[d]*	0	(0)	(0)	699	0
Change in CC Additions (from 0 MW)	*[e]*	0	0	900	300	1,100
Resulting LSR Surplus (Shortfall)	*[f]*	***2,306***	***2,213***	***2,434***	***2,533***	***3,199***
(01) HIGH GAS AND HIGH CO_2						
Surplus with Reference Strategy	*[a]*	2,031	2,031	2,031	2,031	2,031
Incremental DSM impact	*[b]*	206	561	0	0	0
Incremental retirement impact	*[c]*	0	0	529	529	0
Incremental renewables impact	*[d]*	0	0	0	614	0
Change in CC Additions (from 300 MW)	*[e]*	(300)	(300)	0	(300)	800
Resulting LSR Surplus (Shortfall)	***[f]***	***1,937***	***2,292***	***2,560***	***2,874***	***2,831***
(02) LOW GAS AND LOW CO_2						
Surplus with Reference Strategy	*[a]*	2,586	2,586	2,586	2,586	2,586
Incremental DSM impact	*[b]*	206	561	0	0	0
Incremental retirement impact	*[c]*	1,046	646	198	198	1,046
Incremental renewables impact	*[d]*	0	0	0	764	0
Change in CC Additions (from 300 MW)	*[e]*	0	(300)	600	0	800
Resulting LSR Surplus (Shortfall)	***[f]***	***3,838***	***3,493***	***3,384***	***3,548***	***4,432***
(03) HIGH LOAD GROWTH						
Surplus with Reference Strategy	*[a]*	2,673	2,673	2,673	2,673	2,673
Incremental DSM impact	*[b]*	206	561	0	0	0
Incremental retirement impact	*[c]*	0	(400)	(965)	(965)	0
Incremental renewables impact	*[d]*	0	0	0	754	0
Change in CC Additions (from 300 MW)	*[e]*	0	(300)	600	0	800
Resulting LSR Surplus (Shortfall)	***[f]***	***2,879***	***2,534***	***2,308***	***2,462***	***3,473***
(04) MEDIUM GAS AND HIGH CO_2						
Surplus with Reference Strategy	*[a]*	1,722	1,722	1,722	1,722	1,722
Incremental DSM impact	*[b]*	206	561	0	0	0
Incremental retirement impact	*[c]*	0	0	(117)	(117)	0
Incremental renewables impact	*[d]*	0	0	0	677	0
Change in CC Additions (from 0 MW)	*[e]*	0	0	0	0	1,100
Resulting LSR Surplus (Shortfall)	***[f]***	***1,929***	***2,284***	***1,605***	***2,283***	***2,822***

Sources and Notes:

[a]: See 2020 value in previous table with Reference Strategy.
[b]: Incremental supply-side impact of difference in EE on surplus; compared to EE assumed in Reference Strategy.
[c]: Incremental retirements, compared to retirements in Reference Strategy. Negative indicates more capacity retired.
[d]: Incremental renewable capacity (in capacity value) added for RPS, compared to renewables in Reference Strategy. Positive indicates more capacity added.
[e]: Incremental generic CC capacity added to meet resource deficit, plus 1,100 MW built in Efficient Gas Expansion Strategy, relative to CC capacity built in Reference Case.
Note that generic CCs are built to meet approximate resource balance and total MW do not exactly equal MW deficit.
[f]: Resulting ICR surplus (shortfall) in the given scenario and strategy.

Table 1.17
Potential Impact of Scenarios and Strategies on Resource Adequacy under CT TSA Requirement

Reference Strategy, All Scenarios, 2009 – 2020

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Base Case TSA Requirement	7,273	7,464	7,631	7,637	7,683	6,706	6,782	6,803	6,863	6,913	6,964	7,015
90/10 Load	7,940	8,010	8,105	8,205	8,285	8,370	8,445	8,505	8,565	8,615	8,665	8,716
50/50 Load	7,415	7,480	7,565	7,650	7,725	7,800	7,870	7,920	7,965	8,020	8,075	8,131
Retired Capacity	0	0	0	0	696	696	696	1,504	1,504	1,504	1,504	1,504
Additional new renewable generation for RPS	0	5	10	15	20	30	40	49	57	66	74	83
Total generic CC capacity added												0
Base Case TSA Surplus (Shortfall)	**402**	**1,128**	**1,336**	**1,495**	**809**	**2,612**	**2,587**	**1,806**	**1,806**	**1,802**	**1,798**	**1,792**
(01) HIGH GAS AND HIGH CO_2												
Approximate incremental peak load impact*	0	38	76	115	271	290	310	320	331	340	350	360
Incremental retirement impact	0	0	0	0	0	0	0	(111)	(614)	(614)	(614)	(614)
Incremental renewables impact	0	0	0	0	0	0	0	0	0	0	0	0
Total generic CC capacity added												285
Resulting TSA Surplus (Shortfall)	**402**	**1,166**	**1,412**	**1,610**	**1,081**	**2,903**	**2,896**	**2,015**	**1,522**	**1,529**	**1,534**	**1,824**
(02) LOW GAS AND LOW CO_2												
Approximate incremental peak load impact*	0	(31)	(61)	(93)	(219)	(232)	(246)	(252)	(259)	(265)	(271)	(277)
Incremental retirement impact	0	0	0	0	0	0	0	380	380	380	380	380
Incremental renewables impact	0	0	0	0	0	0	0	0	0	0	0	0
Total generic CC capacity added											285	285
Resulting TSA Surplus (Shortfall)	**402**	**1,097**	**1,275**	**1,402**	**591**	**2,380**	**2,341**	**1,934**	**1,928**	**1,918**	**2,193**	**2,181**
(03) HIGH LOAD GROWTH												
Approximate incremental peak load impact*	(17)	(26)	(36)	(57)	(60)	(75)	(92)	(117)	(139)	(147)	(156)	(164)
Incremental retirement impact	0	0	0	0	0	0	0	380	380	380	380	380
Incremental renewables impact	0	0	0	0	0	0	0	0	0	0	0	0
Total generic CC capacity added											285	285
Resulting TSA Surplus (Shortfall)	**385**	**1,102**	**1,300**	**1,438**	**749**	**2,537**	**2,494**	**2,070**	**2,048**	**2,036**	**2,308**	**2,294**
(04) MEDIUM GAS AND HIGH CO_2												
Approximate incremental peak load impact*	0	8	17	25	59	63	67	72	77	82	87	92
Incremental retirement impact	0	0	0	0	0	0	0	(426)	(426)	(426)	(426)	(426)
Incremental renewables impact	0	0	0	0	0	0	0	0	0	0	0	0
Total generic CC capacity added												0
Resulting TSA Surplus (Shortfall)	**402**	**1,136**	**1,353**	**1,520**	**868**	**2,675**	**2,653**	**1,452**	**1,457**	**1,459**	**1,459**	**1,459**

*Impact based on % difference between 90/10 and 50/50 forecasts in Current Trends scenario.
The shortfall would increase (decrease) by one MW for every one MW increase (decrease) in load.

All Strategies, All Scenarios, 2020

		Targeted DSM Expansion	All Achievable Cost-Effective DSM	Limited Renewables	In-State Renewables	Efficient Gas Expansion (+1100 MW CCs)
(00) CURRENT TRENDS						
Surplus with Reference Strategy	*[a]*	1,792	1,792	1,792	1,792	1,792
Incremental DSM impact	*[b]*	206	561	0	0	0
Incremental retirement impact	*[c]*	0	(426)	(537)	(537)	0
Incremental renewables impact	*[d]*	0	(0)	(0)	665	0
Change in CC Additions (from 0 MW)	*[e]*	0	0	856	285	1,046
Resulting TSA Surplus (Shortfall)	*[f]*	***1,999***	***1,928***	***2,111***	***2,205***	***2,838***
(01) HIGH GAS AND HIGH CO_2						
Surplus with Reference Strategy	*[a]*	1,824	1,824	1,824	1,824	1,824
Incremental DSM impact	*[b]*	206	561	0	0	0
Incremental retirement impact	*[c]*	0	0	503	503	0
Incremental renewables impact	*[d]*	0	0	0	584	0
Change in CC Additions (from 285 MW)	*[e]*	(285)	(285)	0	(285)	761
Resulting TSA Surplus (Shortfall)	***[f]***	***1,745***	***2,100***	***2,327***	***2,626***	***2,585***
(02) LOW GAS AND LOW CO_2						
Surplus with Reference Strategy	*[a]*	2,181	2,181	2,181	2,181	2,181
Incremental DSM impact	*[b]*	206	561	0	0	0
Incremental retirement impact	*[c]*	0	(380)	(806)	(806)	0
Incremental renewables impact	*[d]*	0	0	0	727	0
Change in CC Additions (from 285 MW)	*[e]*	0	(285)	571	0	761
Resulting TSA Surplus (Shortfall)	***[f]***	***2,387***	***2,077***	***1,945***	***2,101***	***2,942***
(03) HIGH LOAD GROWTH						
Surplus with Reference Strategy	*[a]*	2,294	2,294	2,294	2,294	2,294
Incremental DSM impact	*[b]*	206	561	0	0	0
Incremental retirement impact	*[c]*	0	(380)	(918)	(918)	0
Incremental renewables impact	*[d]*	0	0	0	717	0
Change in CC Additions (from 285 MW)	*[e]*	0	(285)	571	0	761
Resulting TSA Surplus (Shortfall)	***[f]***	***2,500***	***2,189***	***1,947***	***2,093***	***3,055***
(04) MEDIUM GAS AND HIGH CO_2						
Surplus with Reference Strategy	*[a]*	1,459	1,459	1,459	1,459	1,459
Incremental DSM impact	*[b]*	206	561	0	0	0
Incremental retirement impact	*[c]*	0	0	(111)	(111)	0
Incremental renewables impact	*[d]*	0	0	0	644	0
Change in CC Additions (from 0 MW)	*[e]*	0	0	856	285	1,046
Resulting TSA Surplus (Shortfall)	***[f]***	***1,665***	***2,020***	***2,203***	***2,277***	***2,505***

Sources and Notes:

[a]: See 2020 value in previous table with Reference Strategy.
[b]: Incremental supply-side impact of difference in EE on surplus; compared to EE assumed in Reference Strategy.
[c]: Incremental retirements, compared to retirements in Reference Strategy. Negative indicates more capacity retired.
[d]: Incremental renewable capacity (in capacity value) added for RPS, compared to renewables in Reference Strategy. Positive indicates more capacity added.
[e]: Incremental generic CC capacity added to meet resource deficit, plus 1,100 MW built in Efficient Gas Expansion Strategy, relative to CC capacity built in Reference Case.
Note that generic CCs are built to meet approximate resource balance and total MW do not exactly equal MW deficit.
[f]: Resulting ICR surplus (shortfall) in the given scenario and strategy.

Table 1.18
Potential Impact of Scenarios and Strategies on Resource Adequacy under ISO-NE Net ICR

Reference Strategy, All Scenarios, 2009 – 2020

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Base Case ICR	31,823	32,137	32,528	31,965	32,411	32,901	33,370	33,757	34,120	34,454	34,751	35,051
Peak Load	27,875	28,160	28,575	29,020	29,365	29,750	30,115	30,415	30,695	30,960	31,227	31,497
Retired Capacity	0	0	0	0	825	825	825	2,446	2,446	2,446	2,446	2,446
Additional new renewable generation for RPS	0	80	160	240	320	496	672	831	990	1,149	1,308	1,467
Total generic CC capacity added												0
Base Case ISO-NE Surplus (Shortfall)	**1,891**	**3,666**	**5,478**	**6,037**	**3,350**	**3,100**	**2,797**	**816**	**581**	**444**	**344**	**240**
(01) HIGH GAS AND HIGH CO_2												
Incremental peak load impact	0	164	329	481	1,136	1,222	1,309	1,359	1,408	1,457	1,505	1,555
Incremental retirement impact	0	0	0	0	(19)	(19)	(19)	(1,170)	(1,699)	(1,699)	(1,699)	(1,699)
Incremental renewables impact	0	(0)	(0)	(0)	(0)	(44)	(88)	(103)	(118)	(133)	(147)	(162)
Total generic CC capacity added												300
Resulting ICR Surplus (Shortfall)	**1,891**	**3,831**	**5,807**	**6,518**	**4,466**	**4,258**	**3,999**	**902**	**172**	**70**	**3**	**233**
(02) LOW GAS AND LOW CO_2												
Incremental peak load impact	0	(132)	(265)	(387)	(914)	(976)	(1,039)	(1,072)	(1,103)	(1,134)	(1,165)	(1,196)
Incremental retirement impact	0	0	0	0	0	0	0	610	610	610	610	610
Incremental renewables impact	0	0	0	0	0	35	70	81	92	104	115	126
Total generic CC capacity added											300	300
Resulting ICR Surplus (Shortfall)	**1,891**	**3,534**	**5,213**	**5,650**	**2,436**	**2,159**	**1,828**	**435**	**181**	**24**	**203**	**79**
(03) HIGH LOAD GROWTH												
Incremental peak load impact	(80)	(171)	(250)	(336)	(425)	(520)	(621)	(727)	(845)	(957)	(1,071)	(1,186)
Incremental retirement impact	0	0	0	0	0	0	0	494	494	494	494	494
Incremental renewables impact	0	0	0	0	0	30	60	79	97	116	134	153
Total generic CC capacity added											300	300
Resulting ICR Surplus (Shortfall)	**1,811**	**3,495**	**5,228**	**5,701**	**2,925**	**2,611**	**2,237**	**662**	**328**	**97**	**202**	**0**
(04) MEDIUM GAS AND HIGH CO_2												
Incremental peak load impact	0	36	71	104	246	264	282	305	328	351	374	397
Incremental retirement impact	0	0	0	0	0	0	0	(467)	(467)	(467)	(467)	(467)
Incremental renewables impact	0	(0)	(0)	(0)	(0)	(9)	(19)	(23)	(28)	(32)	(37)	(41)
Total generic CC capacity added												0
Resulting ICR Surplus (Shortfall)	**1,891**	**3,702**	**5,549**	**6,141**	**3,596**	**3,355**	**3,060**	**630**	**414**	**296**	**214**	**129**

All Strategies, All Scenarios, 2020

		Targeted DSM Expansion	All Achievable Cost-Effective DSM	Limited Renewables	In-State Renewables	Efficient Gas Expansion (+1100 MW CCs)
(00) CURRENT TRENDS						
Surplus with Reference Strategy	*[a]*	240	240	240	240	240
Incremental DSM impact	*[b]*	206	561	0	0	0
Incremental retirement impact	*[c]*	0	(467)	(1,618)	(1,618)	0
Incremental renewables impact	*[d]*	0	(52)	(782)	(89)	0
Change in CC Additions (from 0 MW)	*[e]*	0	0	1,800	1,200	1,100
Resulting ICR Surplus (Shortfall)	*[f]*	***446***	***282***	***(360)***	***(267)***	***1,340***
(01) HIGH GAS AND HIGH CO_2						
Surplus with Reference Strategy	*[a]*	233	233	233	233	233
Incremental DSM impact	*[b]*	206	561	0	0	0
Incremental retirement impact	*[c]*	0	(437)	529	529	0
Incremental renewables impact	*[d]*	0	(52)	(620)	(12)	0
Change in CC Additions (from 300 MW)	*[e]*	(300)	(300)	0	(300)	800
Resulting ICR Surplus (Shortfall)	*[f]*	***140***	***5***	***142***	***450***	***1,033***
(02) LOW GAS AND LOW CO_2						
Surplus with Reference Strategy	*[a]*	79	79	79	79	79
Incremental DSM impact	*[b]*	206	561	0	0	0
Incremental retirement impact	*[c]*	0	(516)	(1,017)	(1,017)	0
Incremental renewables impact	*[d]*	0	(52)	(907)	(148)	0
Change in CC Additions (from 300 MW)	*[e]*	0	(300)	1,800	1,200	800
Resulting ICR Surplus (Shortfall)	*[f]*	***286***	***(227)***	***(45)***	***114***	***879***
(03) HIGH LOAD GROWTH						
Surplus with Reference Strategy	*[a]*	0	0	0	0	0
Incremental DSM impact	*[b]*	206	561	0	0	0
Incremental retirement impact	*[c]*	0	(494)	(2,112)	(2,112)	0
Incremental renewables impact	*[d]*	0	(52)	(933)	(185)	0
Change in CC Additions (from 300 MW)	*[e]*	0	(300)	2,400	1,800	800
Resulting ICR Surplus (Shortfall)	*[f]*	***207***	***(285)***	***(645)***	***(497)***	***800***
(04) MEDIUM GAS AND HIGH CO_2						
Surplus with Reference Strategy	*[a]*	129	129	129	129	129
Incremental DSM impact	*[b]*	206	561	0	0	0
Incremental retirement impact	*[c]*	0	(435)	(1,151)	(1,151)	0
Incremental renewables impact	*[d]*	0	(52)	(741)	(69)	0
Change in CC Additions (from 0 MW)	*[e]*	0	0	1,800	1,200	1,100
Resulting ICR Surplus (Shortfall)	*[f]*	***335***	***203***	***37***	***109***	***1,229***

Sources and Notes:

[a]: See 2020 value in previous table with Reference Strategy.

[b]: Incremental supply-side impact of difference in EE on surplus; compared to EE assumed in Reference Strategy.

[c]: Incremental retirements, compared to retirements in Reference Strategy. Negative indicates more capacity retired.

[d]: Incremental renewable capacity (in capacity value) added for RPS, compared to renewables in Reference Strategy. Positive indicates more capacity added.

[e]: Incremental generic CC capacity added to meet resource deficit, plus 1,100 MW built in Efficient Gas Expansion Strategy, relative to CC capacity built in Reference Case.
Note that generic CCs are built to meet approximate resource balance and total MW do not exactly equal MW deficit.

[f]: Resulting ICR surplus (shortfall) in the given scenario and strategy.

1.K APPENDIX

Table 1.A-1
Resource Adequacy Outlook under Connecticut Local Sourcing Requirement (MW)
Base Case

Local Sourcing Requirement in Connecticut		2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Connecticut Sub-Area 50/50 Peak Load	*[1]*	7,415	7,480	7,565	7,650	7,725	7,800	7,870	7,920	7,965	8,020	8,075	8,131
Local Sourcing Requirement in CT	*[2]*	n/a	6,496	6,912	7,325	7,433	6,341	6,408	6,455	6,498	6,557	6,625	6,708
CT Sub-Area Internal Installed Capacity as of 1/1/2009 per ISO-NE	***[3]***	**7,001**	**7,001**	**7,001**	**7,001**	**7,001**	**7,001**	**7,001**	**7,001**	**7,001**	**7,001**	**7,001**	**7,001**
Additional Planned Capacity													
Inclusion of Lake Road Units in CT	*[4]*						766	766	766	766	766	766	766
Connecticut peaking generation contracts	*[5]*	0	188	374	504	504	504	504	504	504	504	504	504
DPUC Public Act 05-01 contracts	*[6]*	96	716	716	716	716	716	716	716	716	716	716	716
Additional new capacity cleared in FCA#1, FCA#2, FCA#3	*[7]*	0	140	140	140	140	140	140	140	140	140	140	140
Connecticut Project 150 contracts not in FCM	*[8]*	0	6	37	85	85	85	85	85	85	85	85	85
Assumed new renewable generation	*[9]*	0	5	10	15	20	30	40	49	57	66	74	83
Assumed delists, retirements	*[10]*	0	0	0	0	(696)	(696)	(696)	(1,504)	(1,504)	(1,504)	(1,504)	(1,504)
Net Planned Capacity Additions	***[11]***	**96**	**1,054**	**1,276**	**1,459**	**768**	**1,544**	**1,554**	**755**	**764**	**772**	**781**	**789**
Demand-Side Management	*[12]*												
"Active" demand resources cleared in FCA#1, FCA#2, FCA#3	*[13]*	446	444	469	429	429	429	429	429	429	429	429	429
Incremental (decremental) expected DR	*[14]*	7	7	7	7	7	7	7	7	7	7	7	7
"Passive" demand resources cleared in FCA#1, FCA#2, FCA#3	*[15]*	226	185	314	336	345	353	353	353	365	365	365	365
Additional Connecticut planned EE not in FCAs	*[16]*	0	0	0	0	43	85	125	164	204	242	280	317
Total Demand Resources	***[17]***	**678**	**636**	**790**	**771**	**824**	**873**	**913**	**952**	**1,004**	**1,043**	**1,080**	**1,117**
Purchases & Sales	***[18]***	**(100)**	**(100)**	**(100)**	**(100)**	**(100)**	**(100)**	**(100)**	**(100)**	**(100)**	**(100)**	**(100)**	**(100)**
Total Installed Capacity in CT	***[19]***	**7,675**	**8,591**	**8,967**	**9,132**	**8,493**	**9,318**	**9,368**	**8,609**	**8,669**	**8,716**	**8,762**	**8,808**
CT LSR Surplus (Shortfall)	***[20]***	n/a	**2,095**	**2,055**	**1,807**	**1,060**	**2,978**	**2,960**	**2,154**	**2,171**	**2,159**	**2,137**	**2,099**

Sources and Notes:

[1]: 2009 CELT 50/50 base economic growth peak load forecast through 2018 then extrapolated at 2017-18 growth rate.
Sum of three electrically-defined Connecticut sub-areas: Norwalk, SW Connecticut, and rest of Connecticut.

[2]: **2010:** 2010/11 reconfiguration auction #3 LSR value shown in the PSPC meeting 267 presentation on Oct 13, 2009, slide 21. The LSR includes a reserve margin adjustment.
This LSR is consistent with the 2009 CELT load forecast.
2011: 2011/12 reconfiguration auction #2 LSR value shown in the PSPC Meeting 270, December 1, 2009, slide 6. The LSR includes a reserve margin adjustment on slide 9.
This LSR is consistent with the 2009 CELT load forecast.
2012: 2012/13 LSR value using "at criterion" assumptions, shown in the in PSPC meeting 262 presentation on Jul 9, 2009, slide 14.
This LSR is consistent with the 2009 CELT load forecast.
2013-2020: "at criterion" LSR estimated with a fitted line, based on historic published values.

[3]: Value from 2009 CELT report workbook, tab "Section 2.1 Existing Cap by LP;" sum of all capacity online as of 1/1/2009 in column "SECTION 3.2 EXPECTED SUMMER SCC AUG 1, 2009."

[4]: Assumes NEEWS in 2014, which would bring these Lake Road units electrically into Connecticut.

[5]: Includes peaking generation contracted in Docket 08-01-01: Devon 15-18 online by June, 2010 (188 MW); Middletown 12-13 online by June, 2011 (188 MW); and New Haven Harbor online by June, 2012 (130 MW).

[6]: Includes Kleen online by June, 2011 (620 MW) and Waterbury online by June, 2009 (96 MW); Waterside is already included as existing in [6]; Amaresco is counted as a demand resource.

[7]: Includes fossil-fired units only. Due to the timeline of this study a small amount of new fossil generation (4 MW) cleared in FCA#3 has been excluded.

[8]: Uses data on projects as of July, 2009, with capacity derated for probability of operation; Milford (8 MW, probability derated to 5 MW) is already counted in the FCA data.

[9]: Assumed new renewable generation developed in the Renewables section of this IRP. Excludes Project 150.

[10]: Assumed environmentally-driven retirements in 2013 consistent with NRG comments in 2008 IRP (environmental analysis indicates these units would retire as early as 2011, although no static or permanent delist bids were submitted in FCA #2).

[11]: Sum of [4] through [10].

[12]: All demand resource capacity values reflect the removal of the reserve margin gross-up in the years 2012 through 2020, consistent with ISO practices.

[13]: 2009: Assumes 2010 value, with 2009 RM gross-up, and excluding emergency generation in excess of assumed 26% share of the ISO's 600 MW capacity value limit.
2010-2020: "active" resources cleared in FCAs, excluding emergency generation in excess of assumed 26% share of the ISO's 600 MW capacity value limit.
All years assume emergency generation remains at 26% of the ISO's 600 MW capacity value limit.

[14]: Includes Real-Time Price Response DR (economic DR) as of 7/1/2009. See ISO-NE presentation "Demand Response" NPC Meeting - July 7, 2009 Posting COO report, page 4.

[15]: 2009: Registered ODR average on-peak reduction as of June, 2009, grossed up for losses and reserves. DR working group intro presentation for October 7, 2009.
See http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/dr_wkgrp/mtrls/2009/oct72009/index.html.
2010-2020: "passive" demand resources cleared in FCAs.
Values are grossed down by estimated share of Retail Products.

[16]: Additional EE planned by EDCs, beyond business-as-usual levels embedded in the ISO's load forecast
Values are grossed down by estimated share of Retail Products.

[17]: Sum of [13] through [16].

[18]: Reflects the LIPA contract for 100 MW capacity over Cross Sound Cable through 2018. Assumed in place in 2019 and 2020.

[19]: Sum of [3], [11], [17], and [18].

[20]: Equals [2] minus [19].

Table 1.A-2
Resource Adequacy Outlook under
Connecticut Transmission Security Analysis Requirement (MW)
Base Case

Connecticut Requirement Under Transmission Security Analysis

		2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Connecticut Requirement under Transmission Security Analysis	*[1]*	**7,273**	**7,464**	**7,631**	**7,637**	**7,683**	**6,706**	**6,782**	**6,803**	**6,863**	**6,913**	**6,964**	**7,015**
Connecticut Sub-Area 90/10 Peak Load	*[2]*	7,940	8,010	8,105	8,205	8,285	8,370	8,445	8,505	8,565	8,615	8,665	8,716
Required Reserves (Millstone Unit 3)	*[3]*	1,137	1,235	1,235	1,235	1,235	1,235	1,235	1,235	1,235	1,235	1,235	1,235
Connecticut Import Limit	*[4]*	2,500	2,500	2,500	2,500	2,500	3,600	3,600	3,600	3,600	3,600	3,600	3,600
Installed capacity derate	*[5]*	696	719	791	697	663	701	702	663	663	663	664	664
CT Sub-Area Internal Installed Capacity as of 1/1/2009 per ISO-NE	***[6]***	**7,001**	**7,001**	**7,001**	**7,001**	**7,001**	**7,001**	**7,001**	**7,001**	**7,001**	**7,001**	**7,001**	**7,001**
Additional Planned Capacity													
Inclusion of Lake Road Units in CT	*[7]*	0	0	0	0	0	766	766	766	766	766	766	766
Connecticut peaking generation contracts	*[8]*	0	188	374	504	504	504	504	504	504	504	504	504
DPUC Public Act 05-01 contracts	*[9]*	96	716	716	716	716	716	716	716	716	716	716	716
Additional new capacity cleared in FCA#1, FCA#2, FCA#3	*[10]*	0	140	140	140	140	140	140	140	140	140	140	140
Connecticut Project 150 contracts not in FCM	*[11]*	0	6	37	85	85	85	85	85	85	85	85	85
Assumed new renewable generation	*[12]*	0	5	10	15	20	30	40	49	57	66	74	83
Assumed delists, retirements	*[13]*	0	0	0	0	(696)	(696)	(696)	(1,504)	(1,504)	(1,504)	(1,504)	(1,504)
Net Planned Capacity Additions	***[14]***	**96**	**1,054**	**1,276**	**1,459**	**768**	**1,544**	**1,554**	**755**	**764**	**772**	**781**	**789**
Demand-Side Management	*[15]*												
"Active" demand resources cleared in FCA#1, FCA#2, FCA#3	*[16]*	446	444	469	429	429	429	429	429	429	429	429	429
Incremental (decremental) expected DR	*[17]*	7	7	7	7	7	7	7	7	7	7	7	7
"Passive" demand resources cleared in FCA#1, FCA#2, FCA#3	*[18]*	226	185	314	336	345	353	353	353	365	365	365	365
Additional Connecticut planned EE not in FCAs	*[19]*	0	0	0	0	43	85	125	164	204	242	280	317
Total Demand Resources	***[20]***	**678**	**636**	**790**	**771**	**824**	**873**	**913**	**952**	**1,004**	**1,043**	**1,080**	**1,117**
Firm Purchases & Sales	***[21]***	**(100)**	**(100)**	**(100)**	**(100)**	**(100)**	**(100)**	**(100)**	**(100)**	**(100)**	**(100)**	**(100)**	**(100)**
Total Installed Capacity in CT	***[22]***	**7,675**	**8,591**	**8,967**	**9,132**	**8,493**	**9,318**	**9,368**	**8,609**	**8,669**	**8,716**	**8,762**	**8,808**
CT TSA Surplus (Shortfall)	***[23]***	**402**	**1,128**	**1,336**	**1,495**	**809**	**2,612**	**2,587**	**1,806**	**1,806**	**1,802**	**1,798**	**1,792**

Sources and Notes:

[1]: Equals [2] + [3] - [4] + [5].
[2]: 2009 CELT 90/10 base economic growth peak load forecast through 2018 then extrapolated at 2017-18 growth rate.
[3]: 2009: summer expected capacity of Millstone 3 in 2009 CELT.
2010-19 represents commitment in FCA#1 and includes an 80 MW uprate.
[4]: NEEWS is assumed in 2014, and increases the Connecticut import limit from 2,500 MW to 3,600 MW.
[5]: Demand resources exclude real-time emergency generation and the reserve margin gross-up, then are derated based on ICR assumptions.
Millstone 3 is not derated; all other generating resources are derated based on ICR assumptions.
[6]: Value from 2009 CELT report workbook, tab "Section 2.1 Existing Cap by LP;" sum of all capacity online as of 1/1/2009 in column "SECTION 3.2 EXPECTED SUMMER SCC AUG 1, 2009."
[7]: Assumes NEEWS in 2014, which would bring these Lake Road units electrically into Connecticut.
[8]: Includes peaking generation contracted in Docket 08-01-01: Devon 15-18 online by June, 2010 (188 MW); Middletown 12-13 online by June, 2011 (188 MW); and New Haven Harbor online by June, 2012 (130 MW).
[9]: Includes Kleen online by June, 2011 (620 MW) and Waterbury online by June, 2010 (96 MW); Waterside is already included as existing in [6]; Amaresco is counted as a demand resource.
[10]: Includes fossil-fired units only. Due to the timeline of this study a small amount of new fossil generation (4 MW) cleared in FCA#3 has been excluded.
[11]: Uses data on projects as of July, 2009, with capacity derated for probability of operation; Milford (8 MW, probability derated to 5 MW) is already counted in the FCA data.
[12]: Assumed new renewable generation developed in the Renewables section of this IRP. Excludes Project 150.
[13]: Assumed environmentally-driven retirements in 2013 consistent with NRG comments in 2008 IRP (environmental analysis indicates these units would retire as early as 2011, although no static or permanent delist bids were submitted in FCA #2).
[14]: Sum of [7] through [13].
[15]: All demand resource capacity values reflect the removal of the reserve margin gross-up in the years 2012 through 2020, consistent with ISO practices.
[16]: 2009: Assumes 2010 value, with 2009 RM gross-up, and excluding emergency generation in excess of assumed 26% share of the ISO's 600 MW capacity value limit.
All years assume emergency generation remains at 26% of the ISO's 600 MW capacity value limit.
[17]: Includes Real-Time Price Response DR (economic DR) as of 7/1/2009. See ISO-NE presentation "Demand Response" NPC Meeting - July 7, 2009 Posting COO report, page 4.
[18]: 2009: Registered ODR average on-peak reduction as of June, 2009, grossed up for losses and reserves. DR working group intro presentation for October 7, 2009.
See http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/dr_wkgrp/mtrls/2009/oct72009/index.html.
2010-2020: "passive" demand resources cleared in FCAs.
[19]: Additional EE planned by EDCs, beyond business-as-usual levels embedded in the ISO's load forecast
[20]: Sum of [16] through [19].
[21]: Reflects the LIPA contract for 100 MW capacity over Cross Sound Cable through 2018. Assumed in place in 2019 and 2020.
[22]: Sum of [6], [14], [20], and [21].
[23]: Equals [22] minus [1].

Table 1.A-3
Resource Adequacy Outlook under
ISO-NE Net Installed Capacity Requirement (MW)
Base Case

ISO-NE Zone													
		2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
ISO-NE 50/50 Peak Load	*[1]*	27,875	28,160	28,575	29,020	29,365	29,750	30,115	30,415	30,695	30,960	31,227	31,497
Net Installed Capacity Requirement (all tie-line benefits removed)	***[2]***	**31,823**	**32,137**	**32,528**	**31,965**	**32,411**	**32,901**	**33,370**	**33,757**	**34,120**	**34,454**	**34,751**	**35,051**
HQICC	*[3]*	1,200	1,400	911	914	914	914	914	914	914	914	914	914
Other Tie-Line Benefits (NY & NB)	*[4]*	800	460	889	751	751	751	751	751	751	751	751	751
Pool reserve	*[5]*	14.2%	14.1%	13.8%	10.1%	10.4%	10.6%	10.8%	11.0%	11.2%	11.3%	11.3%	11.3%
Internal Installed Generating Capacity as of 1/1/2009 (excl. RTEG)	***[6]***	**31,286**	**31,286**	**31,286**	**31,286**	**31,286**	**31,286**	**31,286**	**31,286**	**31,286**	**31,286**	**31,286**	**31,286**
Additional Planned Capacity													
Connecticut peaking generation contracts	*[7]*	0	188	374	504	504	504	504	504	504	504	504	504
DPUC Public Act 05-01 contracts	*[8]*	96	716	716	716	716	716	716	716	716	716	716	716
Additional new capacity cleared in FCA#1, FCA#2, FCA#3	*[9]*	0	306	306	306	306	306	306	306	306	306	306	306
Connecticut Project 150 contracts not in FCM	*[10]*	0	6	37	85	85	85	85	85	85	85	85	85
Additional assumed new renewable generation for RPS	*[11]*	0	80	160	240	320	496	672	831	990	1,149	1,308	1,467
Assumed delists, retirements	*[12]*	0	0	0	0	(825)	(825)	(825)	(2,446)	(2,446)	(2,446)	(2,446)	(2,446)
Net Planned Capacity Additions	***[13]***	**96**	**1,295**	**1,592**	**1,850**	**1,105**	**1,281**	**1,457**	**(5)**	**154**	**313**	**472**	**631**
Demand Resources	*[14]*												
"Active" demand resources cleared in FCA#1, FCA#2, FCA#3	*[15]*	1,585	1,579	1,800	1,794	1,794	1,794	1,794	1,794	1,794	1,794	1,794	1,794
Incremental (decremental) expected DR	*[16]*	81	81	81	81	81	81	81	81	81	81	81	81
"Passive" demand resources cleared in FCA#1, FCA#2, FCA#3	*[17]*	608	594	830	987	1,014	1,037	1,037	1,037	1,073	1,073	1,073	1,073
Incremental (decremental) expected EE	*[18]*	0	34	119	103	146	187	227	267	306	345	382	419
Total Demand Resources	***[19]***	**2,274**	**2,288**	**2,830**	**2,965**	**3,036**	**3,100**	**3,140**	**3,179**	**3,255**	**3,293**	**3,331**	**3,368**
Existing Purchases & Sales per ISO-NE	***[20]***	**58**	**934**	**2,298**	**1,900**	**334**	**334**	**284**	**112**	**6**	**6**	**6**	**6**
Total Installed Capacity	***[21]***	**33,714**	**35,803**	**38,006**	**38,002**	**35,761**	**36,001**	**36,167**	**34,573**	**34,701**	**34,898**	**35,095**	**35,291**
ISO-NE Surplus (Shortfall)	***[22]***	**1,891**	**3,666**	**5,478**	**6,037**	**3,350**	**3,100**	**2,797**	**816**	**581**	**444**	**344**	**240**

Sources and Notes:

[1]: 2009 CELT 50/50 base economic growth peak load forecast through 2018 then extrapolated at 2017-18 growth rate.
[2]: 2009: 2009 Regional System Plan, ISO-NE, October 15, 2009, Page 34, Table 4-1. Note that using the ISO's values for peak load and net ICR results in a pool reserve of 14.2%, not 14.1%.
2010-2018: 2009 Regional System Plan, ISO-NE, October 15, 2009, Page 35, Table 4-2; note that 2010 value reflects a reserve margin gross-up for DR/NYPA imports of 216 MW.
2019-2020: assumes the 2018 pool reserve of 11.3%
[3]-[4]: ISO-NE assumptions used to calculate the ICR in [2].
[5]: Net ICR (with tie-line benefits excluded), over peak load in [1].
[6]: Value from 2009 CELT report workbook, tab "Section 2.1 Existing Cap by LP;" sum of all capacity online as of 1/1/2009 in column "SECTION 3.2 EXPECTED SUMMER SCC AUG 1, 2009."
[7]: Includes peaking generation contracted in Docket 08-01-01: Devon 15-18 online by June, 2010 (188 MW); Middletown 12-13 online by June, 2011 (188 MW); and New Haven Harbor online by June, 2012 (130 MW).
[8]: Includes Kleen online by June, 2011 (620 MW) and Waterbury online by June, 2009 (96 MW); Waterside is already included as existing in [6]; Amaresco is counted as a demand resource.
[9]: Includes fossil-fired units only. Due to the timeline of this study a small amount of new fossil generation (25 MW) cleared in FCA#3, mostly expansions at existing sites, has been excluded.
[10]: Uses data on projects as of July, 2009, with capacity derated for probability of operation; Milford (8 MW, probability derated to 5 MW) is already counted in the FCA data.
[11]: Assumed new renewable generation developed in the Renewables section of this IRP. Excludes Project 150.
[12]: Assumed environmentally-driven retirements in 2013 consistent with NRG comments in 2008 IRP (environmental analysis indicates these units would retire as early as 2011, although no static or permanent delist bids were submitted in FCA #2).
[13]: Sum of [7] through [12].
[14]: All demand resource capacity values reflect the removal of the reserve margin gross-up in the years 2012 through 2020, consistent with ISO practices.
[15]: 2009: Assumes 2010 value, with 2009 RM gross-up, and excluding emergency generation in excess of the ISO's 600 MW capacity value limit.
2010-2020: "active" resources cleared in FCAs, excluding emergency generation in excess of the ISO's 600 MW capacity value limit.
All years assume emergency generation remains at the ISO's 600 MW capacity value limit.
[16]: Includes Real-Time Price Response DR (economic DR) as of 7/1/2009. See ISO-NE presentation "Demand Response" NPC Meeting - July 7, 2009 Posting COO report, page 4.
[17]: 2009: Registered ODR average on-peak reduction as of June, 2009, grossed up for losses and reserves. DR working group intro presentation for October 7, 2009.
See http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/dr_wkgrp/mtrls/2009/oct72009/index.html.
2010-2020: "passive" demand resources cleared in FCAs.
Values are grossed down by estimated share of Retail Products.
[18]: Additional EE planned by EDCs in 2013-2020, plus an additional amount is assumed in MA to meet 2010 and 2011 short-term goals beyond business-as-usual levels.
Values are grossed down by estimated share of Retail Products.
[19]: Sum of [15] through [18].
[20]: 2009, and 2013-2018: 2009 CELT, page 1.
2010, 2011, and 2012: Based on FCA#1-3 results.
2019-2020: Assumes 2018 value.
[21]: Sum of [6], [13], [19], and [20].
[22]: Equals [2] minus [21].

Section II.2
Demand-Side Management

2. DEMAND-SIDE MANAGEMENT

2.A SUMMARY AND KEY FINDINGS

This section of the IRP describes the DSM assumed in the Reference resource strategy, which reflects a continuation of the Connecticut EDCs' current energy efficiency programs at current funding levels, and the resulting effects on resource adequacy. Connecticut's energy efficiency programs are also compared to those in other states.

In addition, this section develops the two expanded energy efficiency resource strategies[1] -- "Targeted DSM Expansion" and "All Achievable Cost-Effective DSM"-- that are evaluated in this IRP. Targeted DSM Expansion is comprised of four high potential initiatives that would require additional funding and would achieve a net reduction in customer costs while eliminating load increases over the next five years. All Achievable Cost-Effective DSM reflects a major expansion of cost-effective programs, similar to the Expanded EE case presented in the 2009 IRP. This strategy was constructed based on a draft Connecticut energy efficiency potential study completed in 2009 by the Energy Conservation Management Board (ECMB).[2] Both the Targeted DSM Expansion and the All Achievable Cost-Effective DSM resource strategies are compared to the Reference resource strategy based on customer costs and emissions.

The end of this section describes funding mechanisms that could be considered for expanding DSM beyond what the Connecticut Energy Efficiency Fund (CEEF) provides to support the Reference level. This section also discusses how DSM programs and codes and standards complement each other.

Key Findings

- Although Connecticut is a leader in DSM, with established programs and demonstrated results, there is much unrealized, cost-effective, emissions-reducing potential remaining.
- The Targeted DSM Expansion Strategy meets the criteria established by the DPUC in its decision in Docket No. 08-07-01 for procurement absent an immediate reliability need by reducing total customer costs and CO_2 and NOx emissions in all 5 scenarios tested, and by slightly reducing rates in all but one scenario. Funding this strategy through the system benefit charge (SBC) would require increasing the SBC rate from 3 mills to 3.7 mills, but based on the 2020 analysis, reduced generation service charge (GSC) costs and rates would more than offset the increase.
- The All-Achievable Cost Effective DSM Strategy also meets the criteria set forth in the Docket No. 08-07-01 decision; but while it reduces total customer costs and CO_2 and

1 This IRP focuses on the energy efficiency component of DSM. The other traditional component, demand response (DR), is de-emphasized since there will no longer be planned funding beyond what would pay for itself through participation in the forward capacity market (FCM). The quantity of cost-effective DR is forecasted in this IRP by using cleared offers from the forward capacity auctions with no growth or attrition assumed over time nor variation across resource strategies evaluated.

2 "Potential for Energy Efficiency in Connecticut," KEMA, Inc., May 2009.

NOx emissions in all 5 scenarios, it also raise average rates per kWh consumed. The SBC rate would increase to 5.6 mills, and the 2020 analysis indicates that the GSC rate impacts would not fully offset the SBC rate increase. Hence, costs for non-participants would increase while costs for participants would decrease (by a larger amount).

- In summary, funding the Targeted DSM Expansion strategy would require an additional outlay of approximately $19 million per year (2010 dollars), and the All Cost-Effective DSM Strategy would require an outlay of approximately $65 million per year through 2020. Although both strategies would create cost savings in excess of the program costs (thus providing emissions reductions at a *negative* net cost), only the Targeted DSM strategy would result in lower rates for non-participants over time.
- Codes and standards are critical components of public policy complementing utility DSM programs, but they are not a substitute for such programs and do not effectively address existing structures.

Given that the Targeted DSM Expansion strategy would reduce customer costs and emissions while even reducing rates for non-participants, we recommend that this strategy be funded. It will be necessary to identify the best sources to fund increased program costs and also to provide financing options to help customers pay for out-of-pocket costs, as discussed in Section 2.F.

The All Achievable Cost-Effective DSM resource strategy is also worth considering because it provides positive economic benefit to Connecticut while reducing emissions substantially (at a negative net cost). However, because of potential rate impacts for non-participants, the initial expansion should focus on the Targeted DSM strategy. The All Achievable Cost-Effective DSM Strategy can be revisited in the future, with additional effort to identify the highest-potential opportunities. This recommendation also recognizes that the DSM delivery infrastructure takes time to build (or to rebuild if programs are cut).

This is a recommendation for a policy direction, not an application for approval of a specific program plan. The energy efficiency programs administered by the Companies would still have to go through rigorous planning, approval, and evaluation process that is currently in existence. Specific Conservation and Load Management (C&LM) program plans and the corresponding Program Savings Documentation are drafted by the Companies annually with program design advice and recommendations by the Energy Conservation Management Board and their consultants. Once completed, the plan is reviewed and approved by the Connecticut Department of Public Utility Control. This approval process is a public process and various interested stakeholders intervene. At the conclusion of this process, a final budget and plan is approved for the delivery of cost-effective energy efficiency programs. As a follow-up to this process, the Companies and the ECMB hire third party evaluation firms to periodically evaluate the programs savings, and other pertinent assumptions that impact program savings and cost effectiveness. The results of these evaluations are used to refine and adjust subsequent C&LM Plans and savings assumptions.

2.B INTRODUCTION: CHARACTERISTICS OF DSM AS A RESOURCE

There are two main types of utility DSM programs: load response programs (also called demand response, or DR) and energy efficiency programs. This IRP focuses on energy efficiency because its primary benefits are from energy savings and reduced emissions, which have significant value under all market conditions. DR's benefit lies in its capacity value, which will have relatively little value over the next 5-10 years, given the projected surplus of capacity documented in Section III.1 (Resource Adequacy). Nor will DR receive funding beyond the payments it receives in the forward capacity market, as discussed in subsection 2.C.2 below.

In resource planning, energy efficiency must be recognized for its energy, capacity, and emissions value, comparable to generation resources. However, there are also some special characteristics of EE resources that must be considered in constructing a resource strategy. EE programs rely heavily on skilled and experienced engineers and technicians to identify savings opportunities, recommend saving strategies and then implement those strategies. Although there are some solutions that can be applied to mass markets through generic approaches, the vast majority of savings opportunities must be customized to the specific application. EE specialists must have the technical skill identify energy savings opportunities and the sales skill to convince the customer to invest in the savings approach. In Connecticut, these staff resources are found partly within the utility program administrators and more so in the energy services companies who implement the savings measures in customer facilities.

The need for skilled staff to implement the programs impacts the ability of the programs to rapidly change size and scope. If the current programs are curtailed from the current levels, these staff resources would likely move to other regions or industries. When the programs were restored, time would be required to develop additional resources to implement the goals of the program. Likewise, if funding were to be increased beyond current levels, time would be required to fully implement the expanded funding. Because of this constraint, the Companies recommend a deliberate, consistent approach to delivering efficiency programs be maintained.

2.C REFERENCE-LEVEL DSM

2.C.1 Reference-Level EE in Connecticut

The Reference level of energy efficiency reflects "business-as-usual" DSM, with continuation of the program structures and designs currently deployed in Connecticut within state approved program budgets. The 2010 Electric and Natural Gas Conservation and Load Management Plan provide the foundation on which the ten year forecast is based.

In addition to the EE achieved through the Companies' programs, there is a much smaller amount of EE being implemented within the state by other parties. In the first Forward Capacity Auction (FCA#1), additional demand resources of 22 MW (at customer meter) cleared as “passive” demand resources.[3] In FCA#2 and FCA#3 another 14 MW and 9 MW cleared, respectively.

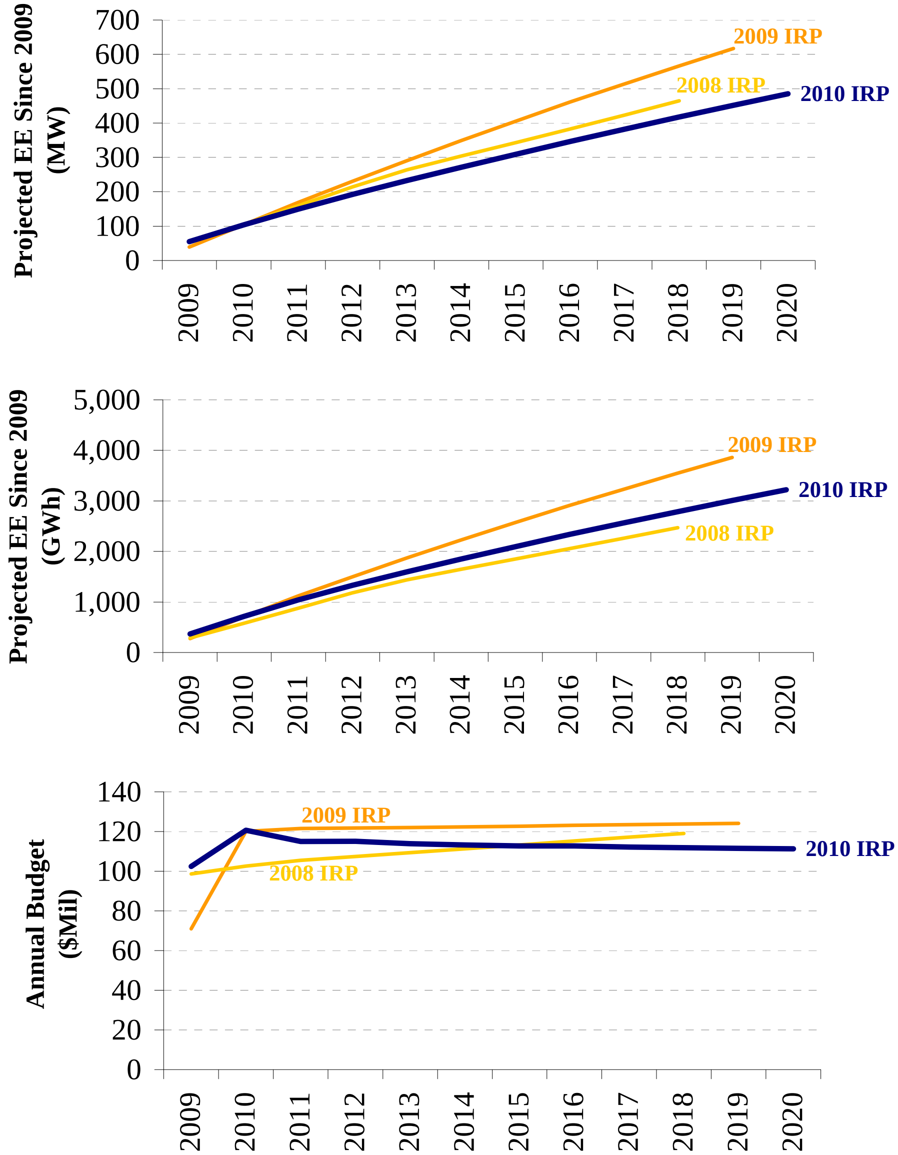
In comparison to the Reference level presented in the 2009 IRP, the 2010 Reference-level energy efficiency includes load reductions due to the inclusion of American Recovery and Reinvestment Act (ARRA) funded programs. The end-of-year impacts on peak load, annual energy, and annual budgets are shown in Figure 2.1, along with dotted lines representing the Reference level of EE in the 2009 IRP, for comparison.

The Companies’ Reference level EE projections represent what is achievable through the following existing funding sources:

- Funding received through the 3 mill charge on customer bills provided for in the Connecticut General Statute 16-245m;
- Revenues received from ISO-NE for EE capacity entered into ISO-NE’s Transition Period and Forward Capacity Market;
- Revenues resulting from the sale of Class III Renewable Energy Credits (RECs) provided for under Docket No. 05-07-19RE01 and PA 07-242;
- Revenues from the Regional Greenhouse Gas Initiative (RGGI); and
- Funding provided to the Companies from the American Recovery and Reinvestment Act (ARRA).

[3] In its Forward Capacity Market, the ISO characterizes demand resources as “active” or “passive.” Active resources are dispatchable resources (demand response and some distributed generation) that must respond during shortage events, and passive resources are non-dispatchable resources (energy efficiency, plus a small amount of distributed generation) that reduce load during pre-defined hours and periods.

Figure 2.1
Summary of Reference Level EE Programs: 2008, 2009, and 2010 IRPs
Projected Levels Since 2009 and Annual Budget



2.C.2 Demand Response

The Companies and other third-party vendors promote customer enrollment in ISO-NE-operated load response programs. The Companies' program provides enrolling customers with the ISO-NE-required internet-based communications system. The Demand Response program mandates load curtailments from customers who enroll and provides enhanced system reliability during peak system load conditions. Utilizing a current Department of Environmental Protection (CT

DEP) Permit, customers may run emergency generators to reduce load on the grid under emergency conditions for participation in the Demand Response program. CL&P and UI provide periodic customer orientation regarding performing in the Demand Response program and on operating emergency generators in compliance with Connecticut air quality requirements during Demand Response events.

The Companies have provided customers who participate in the Demand Response program with Supplemental Payments (funded by the 3 mill charge on customer bills provided for in Connecticut General Statutes 16-245m and from Non-Bypassable Federally Mandated Congestion Charges) in addition to the capacity payments from ISO-NE. However, based on the Final Decision in Docket No. 07-10-03, the Companies are not offering Supplemental payments to any new demand response customers and the phasing out of these Supplemental payments will be complete by May 31, 2010. This will result in a program that is operated based solely on funding from ISO-NE capacity payments.

As a result, the amount of DR in the Reference strategy is based solely on projected FCM outcomes. This IRP assumes that amount of DR that cleared the third Forward Capacity Auction (FCA#3) persists over time (in Connecticut as well as the rest of New England), as discussed in Section III.1 (Resource Adequacy). This assumption does not vary across scenarios or resource strategies considered.

2.C.3 Impact of Reference Level DSM on Resource Adequacy

For resource adequacy, this IRP counts EE and DR as supply-side resources rather than reductions to the load forecast, consistent with the ISO-NE methodology in its Forward Capacity Market. Three distinct adjustments to metered load reductions are required:

- <u>Summer reduction value adjustment</u>: In its Forward Capacity Market, the ISO must procure resources to meet its Installed Capacity Requirement (ICR), which is based on the ISO's summer peak load forecast.[4] Each resource's potential contribution to the ICR is therefore based on the capacity it can provide during the summer of any given delivery year. The Companies' EE and DR projections are based on reductions achievable by the end of each calendar year. To convert to summer reduction values the Companies' projections are assumed to achieve 1/3 of its annual calendar-year reductions by the summer. So, an annual mid-year projection of 2012 EE, for example, would include 1/3 of the Companies' 2012 calendar year projected level, plus 2/3 of the Companies' 2011 calendar year projected level.
- <u>Adjustment for losses</u>: The ISO's ICR is based on its load forecast at the generation busbar. Any at-meter EE and DR values are grossed up by eight percent to reflect savings in transmission and distribution losses, consistent with ISO treatment of demand resources.
- <u>Adjustment for reserves</u>: In the delivery years 2009/10 through 2011/12 the ISO will provide additional capacity credit to demand resources to reflect assumed high

[4] See Section III.1 (Resource Adequacy) for more discussion on ISO reliability requirements.

availability factors of demand resources and the subsequent reduction in reserves needed to meet reliability requirements.

The capacity value of Reference-level EE and DR in Connecticut is tabulated in Table 1.11 in Section III.1 (Resource Adequacy) and reproduced here as Table 2.1.

Table 2.1
Connecticut DR and EE Savings at Customer Meter and Capacity Value

			2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Gross-up Factor for Losses	*(MW)*	*[1]*	1.08	1.08	1.08	1.08	1.08	1.08	1.08	1.08	1.08	1.08	1.08	1.08
Gross-up Factor for Reserves	*(MW)*	*[2]*	1.15	1.14	1.16	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Total DR and EE Cleared in FCA#1-3 (at capacity value)		*[3]*												
DR, excluding RTEG	*(MW)*	*[4]*		288	313	273								
DR - RTEG	*(MW)*	*[5]*		342	269	203								
EE	*(MW)*	*[6]*		218	370	365								
Total	*(MW)*	*[7]*		**848**	**952**	**841**								
Reference Level DR (at capacity value)		*[8]*												
DR cleared in FCA#1-3, net of RTEG cap	*(MW)*	*[9]*	446	444	469	429	429	429	429	429	429	429	429	429
Additional economic DR	*(MW)*	*[10]*	7	7	7	7	7	7	7	7	7	7	7	7
Total DR	***(MW)***	***[11]***	**453**	**451**	**476**	**436**	**436**	**436**	**436**	**436**	**436**	**436**	**436**	**436**
Reference Level EE (at capacity value)		*[12]*												
DR cleared in FCA#1-3, net of CFLs	*(MW)*	*[13]*	226	185	314	336	345	353	353	353	365	365	365	365
Additional planned EE	*(MW)*	*[14]*	0	0	0	0	43	85	125	164	204	242	280	317
Total EE	***(MW)***	***[15]***	**226**	**185**	**314**	**336**	**388**	**437**	**477**	**517**	**568**	**607**	**644**	**681**
Total Reference Level DR and EE (at capacity value)	***(MW)***	***[16]***	**678**	**636**	**790**	**771**	**824**	**873**	**913**	**952**	**1,004**	**1,043**	**1,080**	**1,117**

Sources and Notes:
[3]: Reflects values reported by the ISO; see http://www.iso-ne.com/markets/othrmkts_data/fcm/index.html. All values include gross-up factors in [1] & [2].
[4]: All "active" demand resources, excluding real-time emergency generation.
[5]: All "active" real-time emergency generation resources; values may exceed Connecticut's share of the ISO-wide RTEG cap of 600 MW.
[6]: All "passive" demand resources.
[9]: Sum of [4] & [5], with RTEG limited to Connecticut's share of the ISO-wide RTEG cap of 600 MW.
10]: Includes Real-Time Price Response DR (economic DR) as of 7/1/2009. See ISO-NE presentation "Demand Response" NPC Meeting - July 7, 2009 Posting COO report, page 4.
13]: Values are grossed down by estimated share of Retail Products already included in the ISO's load forecast.
14]: Additional EE planned by EDCs in 2013-2020.
16]: Sum of [11] and [15].

2.C.4 Comparison of Connecticut's DSM Programs to Other States

Connecticut already leads most other states in the implementation of energy efficiency. In October 2009, the American Council for an Energy-Efficient Economy (ACEEE) published its assessment of each state's 2007 achievements and activities in developing energy efficiency.[5] The report evaluates each state based on its program spending, energy savings, targets, and development of incentives and removal of disincentives.[6] Vermont continues to rank highest overall for its achievements in utility and public programs while Connecticut fell one spot from second to a tie for third. Table 2.2 summarizes the ACEEE rankings and levels of achievements in four categories within the state rankings for utility and public programs, plus overall rankings in all categories for the New England states.

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[5] Eldridge, Maggie, *et al*., "The 2009 State Energy Efficiency Scorecard," American Council for an Energy-Efficient Economy Report Number E097, October 2009.

[6] Each state is also evaluated on gas program spending under utility and public benefits programs and policies, which is not directly relevant to this discussion.

Table 2.2
ACEEE New England State Rankings for Utility and Public EE Programs and Policies Relative to all 50 States[7]

State	Program Spending				Electricity Savings				Current Annual Savings Target		Utility Incentives/ Removal of Disincentives				**State Ranking for Utility and Public Programs**		**Overall State Ranking**	
	% of Revenues		Rank		% of Total Sales		Rank				Decoupling or Related Mechanism		Performance Incentives					
	2008	2009	2008	2009	2008	2009	2008	2009	2008	2009	2008	2009	2008	2009	**2008**	**2009**	**2008**	**2009**
Connecticut	1.5%	2.0%	7	5	1.04%	1.10%	3	4	1.0%, binding	1.0%, binding	Yes	Yes	Yes	Yes	**2**	**3 (tied)**	**3**	**3**
Vermont	2.4%	3.4%	1	1	1.23%	1.80%	2	1	1.8%, binding	2.0%, binding	Yes	Yes	Yes	Yes	**1**	**1**	**4**	**6**
Massachusetts	1.5%	1.4%	8	10	0.82%	0.86%	4	7	none	2.4%, binding	Yes	Pending	Yes	Yes	**6**	**3 (tied)**	**7**	**2**
Rhode Island	1.6%	1.9%	6	6	1.23%	0.81%	1	8	none	none	No	No	Yes	Yes	**10**	**9 (tied)**	**11**	**9**
New Hampshire	1.1%	1.3%	10	11	0.67%	0.70%	9	11	none	none	Pending	No	Yes	Yes	**17**	**15**	**18**	**13**
Maine	0.8%	1.0%	17	15	0.61%	0.91%	13	5	none	none	No	Pending	No	Pending	**18**	**18 (tied)**	**19**	**10**

Sources:

Eldridge, Maggie, et al., "The 2008 State Energy Efficiency Scorecard," American Council for an Energy-Efficiency Economy Report Number E086, October 2008.

Eldridge, Maggie, et al., "The 2009 State Energy Efficiency Scorecard," American Council for an Energy-Efficiency Economy Report Number E097, October 2009.

Connecticut continues to rank third nationally in *overall* state scoring, which also considers non-utility programs and policies such as building codes, combined heat and power, appliance standards, and Research, Development and Deployment. The only New England state that did not rank in the top 10 this year was New Hampshire (13).

Though Connecticut is both a regional and national leader in its achievements with efficiency according to the ACEEE scorecard, the majority of data used in the most recent (October 2009) report is slightly outdated (based on 2007 information). Since that time, other New England states have been aggressively pursuing energy efficiency targets. This fact is partly reflected in Table 2.2's "Current Annual Savings Target" column, as this data set uses current, not 2007, information. As described in this column, Connecticut's annual savings target between 2008 and 2009 has stayed constant while Vermont's target has slightly increased and Massachusetts has recently created the highest target in New England. Comparing only across 2009 values in Table 2.2, both Vermont's and Massachusetts's annual savings targets (two and 2.4 percent, respectively) are at least twice that of Connecticut's (one percent).

Connecticut can continue to be a leader in efficiency even while other states pursue efficiency more aggressively. In 2007, Connecticut utilities reported a 1.35 percent reduction in total retail electricity sales due to its efficiency programs,[8] and the ECMB's 2009 Energy Efficiency Potential study indicates that Connecticut could capture an additional 20 percent of cost-effective efficiency by 2018.[9] The 2008 Connecticut Energy Excellence Plan (Excellence Plan), developed by the Connecticut Energy Efficiency Fund (CEEF) pursuant to Section 97 of PA 07-242, describes how EE programs can improve Connecticut's business environment by increasing efficiency and lowering costs, how Connecticut can remain a national leader in EE, and how to

[7] The 2008 report is based on 2006 data, and the 2009 report based on 2007 data. Data does not reflect current expansion plans.

[8] American Council for an Energy-Efficient Economy. "Connecticut." http://www.aceee.org/energy/state/connecticut/ct_utility.htm. Last accessed December 18, 2009.

[9] "Potential for Energy Efficiency in Connecticut," KEMA, Inc., May 2009.

reduce peak demand by at least ten percent by 2010.[10] The Excellence Plan recommends a number of initiatives that would have the potential to flatten peak load growth by 2010, and to *reduce* peak loads in later years. Other states are identified as having similar strong EE initiatives, including California, Texas, New York, New Jersey, Florida, and Maryland.

Within the New England states, Massachusetts and Vermont have recognized the opportunity for substantial increases in cost-effective energy efficiency and have aggressive plans that are more comparable to our All Achievable Cost-Effective DSM resource strategy than our Reference strategy. Massachusetts recently enacted its Green Communities Act, which creates substantial opportunities for EE. The Green Communities Act:

- Mandates utility EE plans every three years, and requires all utilities to secure cost-effective EE as a resource of first recourse;
- Applies strict building codes; and
- Allocates 80 percent of RGGI proceeds to utility EE programs.

Vermont has also recently dramatically increased its EE efforts, particularly evidenced by Efficiency Vermont. Efficiency Vermont refers to 2006-2008 contracts for EE services between Vermont Energy Investment Corporation and the Vermont Public Service Board. Efficiency Vermont publishes annual plans that outline contract goals, historic performance, and projected progress towards meeting contract goals. The 2007-2008 annual plan reflects a 46 percent increase in EE funding over the previous plan, and projects an additional 50 GWh of EE savings in 2008 over the original contract savings goals.[11]

Other states have recognized the value of EE resources. Rhode Island has recently approved least-cost procurement. The Public Utilities Commission in New Hampshire recently ordered Public Service of New Hampshire (PSNH) to conduct a "systematic evaluation of reasonably available DSM programs."[12] As part of an integrated resource plan completed in 2007, PSNH addresses this directive and conducts an assessment of the available demand side potential. This assessment is followed up with an examination of the programs currently offered by PSNH as well as some programs the Company has analyzed as possible future offerings, and several different expanded DSM scenarios are considered.

This IRP must account for EE in other states because it affects resource adequacy and energy use in New England. However, the EDCs were not able to obtain detailed EE plans from EDCs in other states. We can only estimate the amount of EE based on publicly available data, including FCM results, surveys, and announced plans. EE and DR levels assumed in other states are explained in the Section III.1 (Resource Adequacy).

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10 "2008 Connecticut Energy Excellence Plan," The Connecticut Energy Efficiency Fund c/o Office of Consumer Counsel, May 27, 2008.

11 "Efficiency Vermont Annual Plan 2007-2008," Prepared for the Vermont Public Service Board by Vermont Energy Investment Corporation, June 1, 2007.

12 Public Service of New Hampshire, Least Cost Integrated Resource Plan, September 30, 2007.

2.D CONNECTICUT "TARGETED DSM EXPANSION" RESOURCE STRATEGY

2.D.1 Description

This IRP evaluates additional EE in a "Targeted DSM Expansion" resource strategy, which is constructed as an intermediate step between the Reference level and the All Achievable Cost-Effective DSM level of EE presented below in Section 2.D. The Targeted DSM Expansion strategy produces significant energy savings while also eliminating growth in peak demand in five years and a slight reduction thereafter. The Targeted DSM Expansion strategy is comprised of four high potential initiatives addressing residential new construction "zero energy homes," residential cooling, various commercial and industrial (C&I) applications, and C&I chiller retirement, as described in more detail below.

2.D.2 Components of the Targeted DSM Expansion Resource Strategy

Residential New Construction (RNC) – "Zero Energy Homes" Initiative

The ZEH would build on a Zero Energy Home Pilot that was started in 2009. The 2009 ZEH pilot is a statewide competition which provides cash prizes to participants for building zero energy homes. Eighteen builders representing over 100 homes are participating in the pilot. The initial results of the pilot suggest that there is a significant untapped potential for Zero Energy Homes in Connecticut. The Zero Energy Homes initiative would build on the initial pilot and would greatly expand the number of Zero Energy Homes in Connecticut to approximately 600 units per year in ten years at which time the residential new construction market would be transformed to the point where incentives and support can be reduced or eliminated altogether.

The Companies would start the Zero Energy Homes initiative that involves moving builders and consumers beyond the existing ENERGY STAR homes to near Zero Energy Homes by incorporating EE and renewable features. Other technologies such as ductless and geothermal heat pumps, combined heat and power systems, LED lights, time-of-use rate structures, and real time feedback mechanisms may be incorporated. The ZEH would be a joint natural gas and electric initiative and would leverage CEEF funding from the natural gas and electric distribution companies. If available, federal and state tax credits would be leveraged as well as the CCEF Solar Photovoltaics and solar thermal rebate programs with the Zero Energy Homes initiative offering. Program efforts would focus on working with market leaders to demonstrate the approach and benefits of building homes that minimize the peak load growth on the electric and natural gas systems.

Incentives from multiple parties would be packaged and offered to high-performance projects meeting prescribed levels of efficiency and incorporating renewable features to approach Zero Energy Home performance. The same HVAC incentives offered through the Home Energy Solutions program would be available to all RNC projects. Similarly, RNC would offer the same natural gas domestic hot water rebate as the stand alone program.

Table 2.3 below shows the costs and cumulative savings this initiative would achieve. The customer benefits are calculated using the difference in customers' power supply-related costs between the Targeted DSM Expansion resource strategy and the Reference resource strategy, as estimated in Section II (Analytical Findings) for the 2020 Current Trends Scenario. Approximately half of the estimated $109 million annual reduction in generation service costs reflects the value of energy (and capacity) not consumed, and half is attributed to impacts on energy market prices. This customer cost savings is divided by approximately 600 GWh annual savings (measured at the customer meter) that the entire package of Targeted DSM Expansion initiatives would achieve by 2020. It is assumed that the resulting $202/MWh benefit would be constant in real terms and would apply to all savings over the lifetime of each initiative. This analysis differs from the ones typically submitted with C&LM filings because it uses the IRP modeling platform instead of market price projections provided by Synapse, and because it extrapolates benefits from only one study year.

Table 2.3
Cumulative Savings from RNC Zero Energy Homes Initiative

Targeted DSM -- Zero Energy Homes	
Cumulative Annual peak load reduction achieved by year 10 (MW)	**32**
Cumulative Annual energy savings achieved by year 10 (GWh)	**67**
Lifetime energy savings from all measures installed in 10 years (GWh)	**1,664**
NPV of program costs over 10 years (2010 $)	**$34,293,139**
NPV of participant out-of-pocket costs over 10 years (2010 $)	**$34,293,139**
Customer benefits measured in 2020 IRP analysis (2010 $/MWh saved)	**$202**
NPV of customer benefits from all measures installed in 10 years, assuming the benefits are always $202/MWh (2010 $)	**$140,720,409**
Benefit to Program Cost ratio	**4.1**
Benefit to Total Cost ratio	**2.1**

Residential Cooling

The residential cooling initiative is a set of measures offering savings above and beyond the “business as usual” residential reference level EE. These measures and savings potential were identified in the 2009 study “Potential for Energy Efficiency in Connecticut, KEMA, Inc.” The measures that are included in this initiative represent measures with a high level of cost effective savings potential which may not be fully realized under the base funding scenario. The following table shows the total potential energy savings and summer demand savings from the top residential cooling measures from the 2009 study. Residential measures include high efficiency central AC (15 SEER and above), high efficiency room air conditioners (CEE Tier 1), ENERGY STAR dehumidifiers, high performance ceiling and wall insulation, ENERGY STAR phase-2 windows and attic venting.

Table 2.4
Cumulative Savings from Residential Cooling Initiative

Targeted DSM -- Residential Cooling	
Cumulative Annual peak load reduction achieved by year 10 (MW)	**28**
Cumulative Annual energy savings achieved by year 10 (GWh)	**35**
Lifetime energy savings from all measures installed in 10 years (GWh)	**624**
NPV of program costs over 10 years (2010 $)	**$34,292,654**
NPV of participant out-of-pocket costs over 10 years (2010 $)	**$17,146,327**
Customer benefits measured in 2020 IRP analysis (2010 $/MWh saved)	**$202**
NPV of customer benefits from all measures installed in 10 years, assuming the benefits are always $202/MWh (2010 $)	**$71,525,790**
Benefit to Program Cost ratio	**2.1**
Benefit to Total Cost ratio	**1.4**

High Potential C&I Measures

This initiative is comprised of a set of measures selected from the recent study, "Potential for Energy Efficiency in Connecticut, KEMA, Inc., 2009." They were selected from the top twenty demand savings measures listed in the potential study and consist of new or enhanced measures. The measures listed below would be new offerings or have only been recently explored:

- DX Tune-up/Advanced Diagnostics – the savings from testing/tune-up of commercial direct expansion cooling systems comprise 70 percent (53 MW) of the total estimated peak demand savings from all High Potential C&I Measures.
- Fluorescent Fixtures Continuous Dimming
- Compressed Air - System Optimization
- Efficient Refrigeration Operations

The following measures are currently offered but could be enhanced to achieve greater savings:

- High Performance HVAC
- More Efficient Design of Refrigeration Systems

The following table shows the total potential energy savings and summer demand savings for the C&I measures selected from the 2009 potential study.

Table 2.5
Cumulative Savings from High Potential C&I Measures

Targeted DSM -- High Potential C&I Measures	
Cumulative Annual peak load reduction achieved by year 10 (MW)	**76**
Cumulative Annual energy savings achieved by year 10 (GWh)	**317**
Lifetime energy savings from all measures installed in 10 years (GWh)	**3,174**
NPV of program costs over 10 years (2010 $)	**$82,923,018**
NPV of participant out-of-pocket costs over 10 years (2010 $)	**$41,461,509**
Customer benefits measured in 2020 IRP analysis (2010 $/MWh saved)	**$202**
NPV of customer benefits from all measures installed in 10 years, assuming the benefits are always $202/MWh (2010 $)	**$398,567,603**
Benefit to Program Cost ratio	**4.8**
Benefit to Total Cost ratio	**3.2**

C&I Chiller Retirement Initiative

The 2007 & 2008 Energy Opportunities (EO) Accelerated Chiller Retirement initiative to impact summer peak demand by identifying and removing old, inefficient chillers from the system was successful in achieving its goal of reducing summer peak demand. This initiative specifically targeted chillers that operated coincident with the summer peak and, in order to manage demand on program budgets, was restricted to equipment greater than 23 years old. Reducing the age limit to qualify additional equipment was envisioned to address additional market opportunity but was never enacted due to funding limitations. The initiative was successful in identifying and replacing several large chiller installations. Not all identified projects proceeded forward at that time and the initiative was subsequently suspended due to funding constraints. Chiller loads are one of the largest contributors to the summer peak demand and reinstating and expanding this initiative would target this market opportunity. Accelerating chiller replacements is one of the best ways to reduce summer peak kW demand and also offer substantial energy savings to the customer.

The Companies would be offering this initiative to target old inefficient chillers and replace them with high efficient air-cooled or water-cooled equipment. This effort would further enhance the Companies' C&I programs to assist Connecticut businesses in mitigating energy and demand cost increases.

The following table shows the cumulative energy and demand savings projection for the high efficiency chiller replacement initiative. These savings potential are estimated based on the actual program data from 2007 & 2008 EO Accelerated Chiller Retirement Initiative.

Table 2.6
Cumulative Savings for C&I Chiller Initiative

Targeted DSM -- C&I Chillers	
Cumulative Annual peak load reduction achieved by year 10 (MW)	**55**
Cumulative Annual energy savings achieved by year 10 (GWh)	**194**
Lifetime energy savings from all measures installed in 10 years (GWh)	**3,874**
NPV of program costs over 10 years (2010 $)	**$84,050,606**
NPV of participant out-of-pocket costs over 10 years (2010 $)	**$84,050,606**
Customer benefits measured in 2020 IRP analysis (2010 $/MWh saved)	**$202**
NPV of customer benefits from all measures installed in 10 years, assuming the benefits are always $202/MWh (2010 $)	**$397,531,571**
Benefit to Program Cost ratio	**4.7**
Benefit to Total Cost ratio	**2.4**

2.D.3 Combined Impacts of the Targeted DSM Expansion

Table 2.7 below summarizes the costs and benefits of the entire package of initiatives in the Targeted DSM Expansion resource strategy as compared to the Reference resource strategy.

Table 2.7
Total Incremental Effects of Targeted DSM Expansion

Targeted DSM -- All Initiatives	TOTAL
Cumulative Annual peak load reduction achieved by year 10 (MW)	**191**
Cumulative Annual energy savings achieved by year 10 (GWh)	**612**
Lifetime energy savings from all measures installed in 10 years (GWh)	**9,336**
NPV of program costs over 10 years (2010 $)	**$235,559,417**
NPV of participant out-of-pocket costs over 10 years (2010 $)	**$176,951,581**
Customer benefits measured in 2020 IRP analysis (2010 $/MWh saved)	**$202**
NPV of customer benefits from all measures installed in 10 years, assuming the benefits are always $202/MWh (2010 $)	**$1,008,345,373**
Benefit to Program Cost ratio	**4.3**
Benefit to Total Cost ratio	**2.4**

The Targeted DSM Expansion strategy would reduce generation service costs by $109 million in 2020 in the Current Trends scenario, a savings that far exceeds the $19 million annual program cost (net of $10 million FCM funding). The generation cost savings is approximately half from the value of energy not consumed, and about half from a slight reduction in market energy prices. Although average costs (per kWh consumed) are not a good measure of overall program performance when the quantity consumed is changing, average costs do decrease under this strategy due to the market energy price effect. Hence, overall rates would likely decrease even for non-participants in the additional DSM programs, in spite of a 0.7 mill increase in the system benefit charge (SBC) to fund the programs.

The Targeted DSM Expansion resource strategy would not only reduce customer costs, but it would also reduce CO_2 and NOx emissions in all 5 scenarios and reduce SO_2 emissions in 4 of the scenarios. Hence, this strategy may present an opportunity to reduce emissions at a *negative* net cost.

2.E ALL ACHIEVABLE COST-EFFECTIVE DSM RESOURCE STRATEGY

The "DSM-Focus" and "Expanded EE" cases in the 2008 and 2009 IRP relied on the ECMB's 2004 Energy Efficiency Potential Study. The 2004 study estimated the maximum achievable potential for all cost effective energy efficiency measures that could be implemented in Connecticut with unlimited conservation program funding. The ECMB has completed a new potential study in 2009 which estimated the maximum achievable cost effective energy efficiency potential based on several conservation program funding scenarios. The Integrated Resource Plan Funding Scenario in the 2009 potential study is the basis for the All Achievable Cost-Effective DSM resource strategy evaluated in this IRP. It is based on the maximum funding levels that the conservation program would expect to receive as a result of the IRP and would produce approximately 20 percent less peak demand and 10 percent less energy savings than programs with unlimited funding.

The IRP Funding Scenario in the 2009 potential study estimates that cost effective cumulative annual savings of 1,095 MW and 5,910 GWh by 2018, with an expected average annual program cost of $206 million.[13] For the period 2004 through 2018 the Potential Study estimates the corresponding total program and customer costs at $3.75 billion ($1.9 billion in program costs plus $1.8 billion in customer costs), and total program benefits at $9.9 billion.[14] This yields an overall benefit/cost ratio of 2.65.[15]

However, this IRP includes a different approach to estimating benefits, by comparing customer costs between the All Achievable Cost-Effective DSM Expansion resource strategy and the Reference resource strategy. Relative to the Reference resource strategy, we estimate that the All Achievable Cost-Effective DSM resource strategy produces an incremental 561 MW and

13 KEMA study, tables 1-1 and 1-2; MW and GWh values at customer meter.

14 KEMA study, table 3-1.

15 *Ibid.*

3,439 GWh in cumulative annual savings by 2018.[16] This reduces customer costs by $402 million annually (in the Current Trends scenario) after accounting for the $90 million in incremental annual program costs. Most of the benefit is due to reduced energy and associated RPS needs, and approximately a quarter from market price impacts.

Although average costs (per kWh consumed) are not a good measure of overall program performance when the quantity consumed is changing, average costs increase under this strategy because a slight reduction in GSC rates would not fully offset the SBC rate increase to 5.6 mills from 3 mills in the Reference strategy. Hence, costs for non-participants could increase while costs for participants would decrease (by a larger total amount).

In addition, regional CO_2, NO_X, and SO_2 emissions would decrease by about 4 percent; Connecticut SO_2 emissions would decrease by as much as 22 percent while annual and HEDD NO_X emissions would decrease by up to five percent, depending on the scenario. The results are presented in Figure 2.2 and Table 2.9 below.

[16] The achievable savings identified in the KEMA Potential study of 16 percent peak load and 20 percent total energy by 2018 include the effects of "business-as-usual" levels of EE, which are already included in our Reference-level DSM (approximately 9 percent peak and 11 percent energy by 2018), plus incremental savings from expanded programs (incremental 7 percent peak and 9 percent energy savings by 2018). These percentages can be found in Tables 1.1 and 1.2 of the KEMA study. Business-as-usual savings was verified against our Reference-level DSM, and the incremental savings of 7 percent peak and 9 percent energy savings by 2018 was translated into GW and GWh savings using gross load levels assumed in this IRP, not gross load levels assumed in the KEMA study. In our 2020 analysis, we held incremental savings (relative to Reference-level DSM) constant at 2018 levels.

Figure 2.2

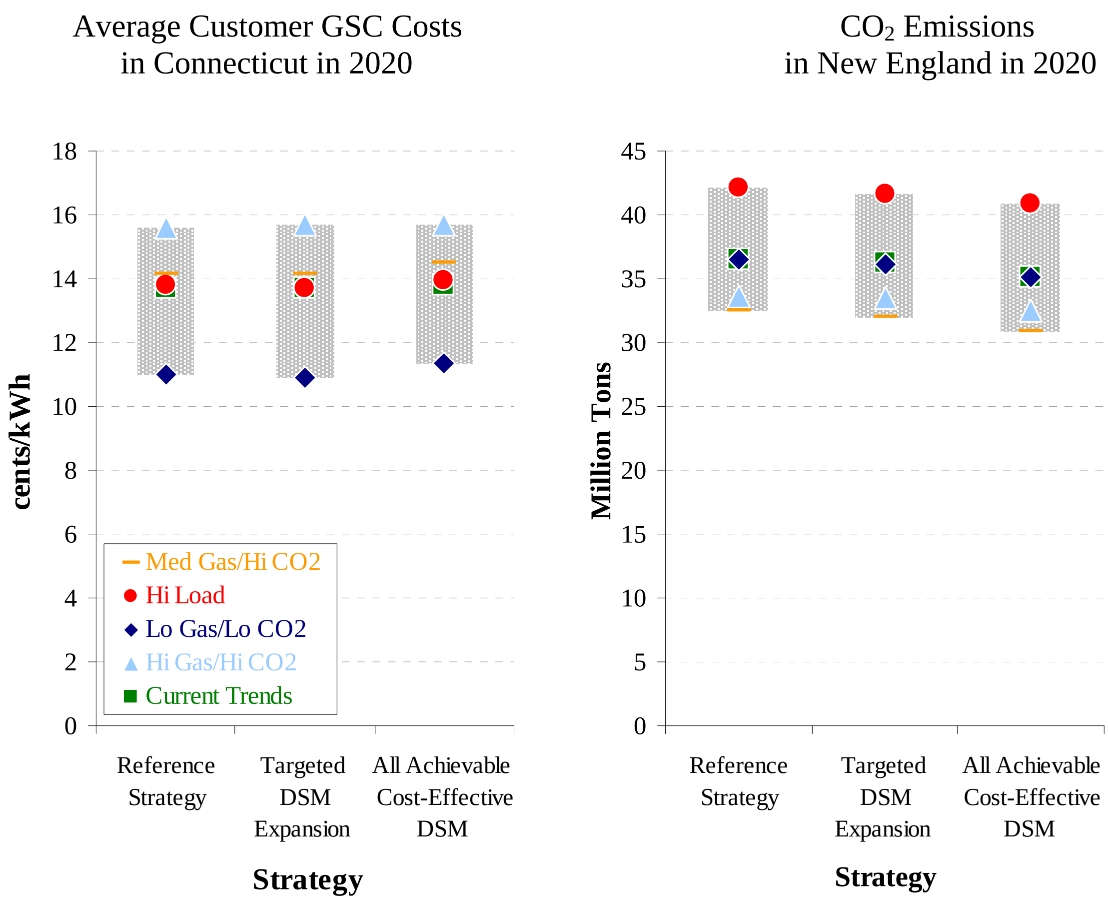

Table 2.8
Average Customer Power Supply-Related Cost in Connecticut in 2020

Scenario	**Strategy**		
	Reference Strategy *(¢/kWh)*	Targeted DSM Expansion *(¢/kWh)*	All Achievable Cost-Effective DSM *(¢/kWh)*
Current Trends	13.70	13.68	13.81
Lo Gas/Lo CO2	11.01	10.91	11.35
Med Gas/Hi CO2	14.17	14.13	14.50
Hi Load	13.78	13.69	13.95
Hi Gas/Hi CO2	15.59	15.71	15.69

Table 2.9
Summary of CO_2, NOx, and SO_2 Emissions in Connecticut and New England (2020)

	Connecticut Emissions			ISO-NE Emissions		
	Reference Strategy	Targeted DSM Expansion	All Achievable Cost-Effective DSM	Reference Strategy	Targeted DSM Expansion	All Achievable Cost-Effective DSM
CO_2 *(thousands of tons)*						
Current Trends	8,551	8,478	7,918	36,562	36,263	35,085
Lo Gas/Lo CO2	9,578	9,516	8,545	36,483	36,111	35,184
Med Gas/Hi CO2	7,718	7,626	7,256	32,456	32,032	30,868
Hi Load	10,388	10,267	9,294	42,106	41,679	40,824
Hi Gas/Hi CO2	8,610	8,138	7,676	33,655	33,538	32,446
SO_x *(tons)*						
Current Trends	2,506	2,488	1,954	44,275	44,056	42,571
Lo Gas/Lo CO2	1,554	1,521	1,388	21,329	20,481	20,213
Med Gas/Hi CO2	1,182	1,149	1,046	28,773	28,050	26,248
Hi Load	3,138	3,043	2,888	50,454	49,664	49,789
Hi Gas/Hi CO2	3,324	3,418	3,269	54,090	54,676	53,723
NO_x *(tons)*						
Current Trends	2,922	2,898	2,778	16,689	16,631	16,219
Lo Gas/Lo CO2	2,521	2,506	2,382	12,666	12,460	12,382
Med Gas/Hi CO2	2,387	2,343	2,275	13,219	12,935	12,526
Hi Load	3,321	3,292	3,154	18,645	18,483	18,424
Hi Gas/Hi CO2	3,515	3,484	3,379	18,473	18,610	18,343
NO_x HEDD *(tons/day)*						
Current Trends	26.3	24.9	25.1	-	-	-
Lo Gas/Lo CO2	27.1	25.8	26.8	-	-	-
Med Gas/Hi CO2	25.3	24.0	24.4	-	-	-
Hi Load	27.9	26.9	27.4	-	-	-
Hi Gas/Hi CO2	26.4	25.1	26.3	-	-	-

2.F FUNDING OPTIONS FOR EXPANDED EE PROGRAMS IN CONNECTICUT

In order to fully capture the potential benefits of expanded DSM programs, funding for the programs as well as funding for the customer costs associated with the programs will need to be put in place.

2.F.1 Options for Funding Expanded Program Costs

The funding for the program costs has changed over the last few years, shifting from almost complete reliance on the charge on customer electric bills to include other sources of revenues. These additional sources of revenues include funding from the ISO-NE Forward Capacity Market, the Class III REC program, funding from the Regional Greenhouse Gas Initiative (RGGI), and most recently funding through the American Recovery and Reinvestment Act (ARRA). Identifying new sources of funding could include strategies such as increasing the conservation charge on customers' bills, allowing the EDCs to include funding for energy efficiency in distribution rates, or finding other new sources of funding. All of these options would help customers to save money while also reducing emissions. A few examples of these funding sources are provided below.

Funding program costs directly from ratepayers is one option to increase program funding. The Connecticut Legislature could adjust the current 3 mill charge. The 3 mill charge has been in place since the year 2000. Since that time the per kWh cost of electricity has nearly doubled, while the overall size of the total C&LM collection has remained fairly flat due to decreasing energy sales.

DSM Program costs could also be included in rate base. This allows the benefits of energy efficiency, which accrue over the life of the efficiency installations, to match the costs associated with those installations. This concept also treats DSM more like traditional resources where investments are made and those costs are recovered through rates over a period of time. The state of Nevada has allowed utilities to put energy efficiency costs in the rate base (as a regulatory asset). This asset is then depreciated over five years and the asset is allowed to earn a return during the period. As an incentive, Nevada allows the utility to earn its standard allowed ROE plus up to five percent on the equity portion of the capitalized energy efficiency costs. The debt portion earns the embedded cost of debt. This provides the utility with an incentive to engage in energy efficiency initiatives.[17]

DSM programs can also be recovered through rates using other recovery mechanisms. The gas programs in Connecticut use a Conservation Adjustment Mechanism (CAM) to fund programs through gas rates. This approach is another means to increase ratepayer funding for DSM programs.

The newer sources of program funding in Connecticut such as the Forward Capacity Market, the Class III REC program, RGGI, or ARRA funding have been important contributors of incremental dollars in recent years. Those sources of funding should be maximized to the extent possible, but there may be limited potential to increase those funding sources to the levels envisioned in the IRP scenarios.

2.F.2 Options for Financing Participants' Increased Out-of-Pocket Costs

In addition to program funding, customers need to be able to provide the customer cost share of installations of energy efficiency technology. Customer contributions to overall project costs typically are in the range of 50 percent to 70 percent (or more) of the overall project cost. The Companies have developed a number of financing options as part of the current battery of program offerings to assist customers in obtaining the required funding to implement efficiency measures.

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[17] See Chapter 704-9522 to 704-9523 of Nevada Administrative Code. See also "Nevada Energy Efficiency Strategy," by Howard Geller, Cynthia Mitchell and Jeff Schlegel of the Southwest Energy Efficiency Program January 2005.

Financing options for the commercial and industrial programs have been segmented to meet the needs of the various customer classes. For the smallest commercial customers, the Companies have developed their award winning Small Business Program. This Program features interest free financing that is repaid on the customer's electric bill every month. This approach allows smaller customers to use the savings from the efficiency installations to at least offset the cost of the loan payment resulting in no increase in the customer's electricity costs even when repaying the loan. Larger and more sophisticated customers have access to lenders associated with the programs and can choose between an option of reduced financing rates or higher incentive payments.

The residential class of customers also has financing needs as part of many residential efficiency installations. When a customer installs more efficient air conditioning or more insulation, the rebates provided cover only a portion of the cost. The current programs provide financing options as a tool to assist customers in completing these installations. The Companies have begun to work with both national energy efficiency financing companies as well as local credit unions to offer flexible packages of financing options to assist the residential customer in installing more efficient equipment.

There are currently many financing options associated with the programs, but increased program activity will carry with it a need for more capital investments on the customer's part. Financing packages are not a replacement for a comprehensive energy efficiency program. There are however some new approaches to financing energy efficiency measures that would be worthy of further examination as part of any expanded program offerings.

One of the approaches for financing is for municipalities to offer property assessments as a means of repayment. Palm Desert, California, and Berkeley, California, are examples of cities that have decided to provide financing for energy efficiency and renewable energy. These approaches seem to have merit, but may require legislative changes to allow their adoption in Connecticut.

In Palm Desert, the Energy Independence Program (EIP) offers residents affordable financing for major energy-saving home improvements, such as high-efficiency air conditioners, dual-pane windows, and solar panels. The long-term payback of these home improvements are linked to the owner's property taxes.[18] The EIP has made loans totaling $7.5 million in its first two phases. The first $2.5 million of funding came from the city's general fund for Phase I, while Phase II funding of $5 million came from a bond issued by the city's Redevelopment Agency.[19]

The City of Berkeley also offers financing to its residents through its Financing Initiative for Renewable and Solar Technology (FIRST) program. This program allows residents to finance projects through a 20-year special tax on the property. Because the investment stays with the house, so does the tax obligation; if the house is transferred or sold, the new owners pay the

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18 http://www.cityofpalmdesert.org/Index.aspx?page=484. Last accessed November 25, 2009.

19 Fuller, Merrian C., Cathy Kunkel, and Daniel M. Kammen. "Guide to Energy Efficiency & Renewable Energy Financing Districts for Local Governments," September 2009.

remaining tax obligation.[20] While the pilot of the FIRST program only allowed for solar photovoltaics, the City is currently evaluating the pilot results and assessing the ability to launch energy efficiency programs.[21]

Other approaches to creating repayment mechanisms include loan pools, energy efficient mortgages, and other repayment mechanisms. Each of these must be explored for their applicability to the program they are intended to complement. Financing is an important tool to implement energy efficiency, but there is no universal solution that causes efficiency investments to magically occur.

2.G STATE AND REGIONAL EFFORTS VIA CODES AND STANDARDS

In parallel to utility DSM programs, state and federal governments play an important role in EE by setting codes and standards. Codes and standards have historically stimulated a significant amount of EE savings that likely would not have been achieved otherwise by setting a minimum level of EE. For example, studies on the effectiveness of appliance standards have estimated tens of billions of dollars nationally for past savings, and over a hundred billion dollars, in present value terms, through the next 20 to 40 years.[22]

Because codes and standards are implemented in parallel with utility DSM programs, it is important to understand how they differ, including their effectiveness at overcoming barriers to various types of cost-effective EE. Codes and standards work by preventing new investment in inefficient equipment (but without subsidizing purchases). However, appliance standards are set federally, usually at a minimum level that is broadly acceptable politically, not necessarily at the level that is most economic for Connecticut. Codes are set by the state, but they address only new buildings and major renovations (the development of which is quite low in the current economy), and they are effective only to the extent that local building inspectors enforce them.

In contrast, utility DSM programs can promote efficiency investments in both new and retrofit applications, and they can target technologies and applications that are cost-effective for Connecticut. Utility DSM programs also help to reduce the upfront cost of purchasing efficient equipment. A perceived disadvantage is that, if the program is funded through rates, customers not able to participate in the program must pay for other customers' purchases. Each of these differences is described in more detail below.

First, consider the scope of codes and standards versus utility DSM programs. Codes and standards have been particularly effective in achieving EE savings with new construction and new appliances, respectively, by eliminating the option to purchase inefficient equipment.

[20] http://www.ci.berkeley.ca.us/ContentDisplay.aspx?id=26580. Last accessed November 25, 2009.

[21] Fuller, Merrian C., Cathy Kunkel, and Daniel M. Kammen. "Guide to Energy Efficiency & Renewable Energy Financing Districts for Local Governments," September 2009.

[22] "Energy Efficiency Policies: A Retrospective Examination," Gillingham, K., R. Newell, and K. Palmer, *Annual Review of Environment and Resources*, Vol 31:161–92.

Mandating that manufacturers produce, and that developers or consumers buy, more efficient equipment avoids the market barriers cited in a study by ACEEE: split incentives between those who purchase the equipment versus those who benefit from the EE savings, low-price "panic purchases" for replacement equipment, and the bundling of EE features only as high-cost "extras" on equipment.[23] However, utility DSM programs have a broader scope than codes and standards because they are not limited to only new construction and purchases. Utility DSM programs can also accelerate the replacement of old, inefficient equipment.

A barrier to EE is access to and the understanding of information.[24] Many consumers neither have detailed information about the full range of energy-savings options, the ability to decipher the option that best suites their particular circumstances, nor detailed knowledge of specific technologies available. Both utility DSM programs and codes and standards provide information to consumers, though in different ways. Codes and standards narrow the available technologies to only ones that meet a certain minimum level of EE (because they limit choices, they are generally set conservatively). Utility DSM programs can provide information to consumers by promoting certain energy-saving options and/or devices (without excluding others). Furthermore, utility DSM programs can provide tools and/or access to specialized professionals that assist consumers by making information more accessible and understandable.

Another barrier to EE is the initial installation cost,[25] even if expected future savings are more than sufficient to pay for the investment. The capital expenditure for an energy efficient technology has to be paid in full before a consumer receives any savings, often making EE investments unappealing to consumers. Codes and standards are unable to address this timing issue directly. In fact, codes and standards can increase the installation cost of new equipment (sometimes acting as a barrier to retrofitting) if they limit customer choice to more expensive technologies. Utility DSM programs, however, are able to lessen the up front cost of EE by providing customers with financing or including EE costs as a part of the rate. The latter EE funding option has the disadvantage, compared to codes and standards, that all consumers must pay for the EE program, regardless of their EE efforts.[26] A mitigating factor is that all customers benefit from the environmental externalities and market price impacts from EE.

Because appliance standards are set by the federal government, an individual state does not have jurisdiction or much influence in the resulting standards. Building codes are currently set by states and implemented locally, but the American Clean Energy and Security Act passed by the House of Representatives[27] includes language to require a mandatory nationwide building

23 "Energy Efficiency Resource Standards: Experience and Recommendations," Steven Nadel, ACEEE Report E063, March 2006.

24 United States Department of Energy and United States Environmental Protection Agency. "National Action Plan for Energy Efficiency," July 2006.

25 *Ibid*. 24.

26 For example, consumers who never participate in an EE program pay even though they do not receive any benefit. Similarly, consumers who have already maximized their individual EE before the utility's DSM program begins will pay even though they are unable to receive further EE benefit.

27 H.R. 2454 – 111th Congress: American Clean Energy and Security Act of 2009, June 2009.

efficiency code. Furthermore, the revision of codes and standards take multiple years; building codes in Connecticut change no more than every four years[28] and federal appliance standards can go as long as seven years before an update.[29] When codes and standards are updated, they must meet a level of efficiency that is broadly acceptable regionally and politically (and that survives industry lobbying).[30] On the other hand, states have much more control over utility DSM programs as these are determined by the public utilities commission. Additionally, utility DSM programs are more flexible because they can be revised each year.

Finally, compared to utility DSM programs, building codes can be difficult to enforce. For example, because building codes are implemented locally, changes to them can require significant training for both builders and inspectors. Lack of training and sometimes lax enforcement can lead to poor compliance with building codes. California estimates that the 30-50 percent of HVAC systems are not being installed properly and that has led to an estimated 20-30 percent increase in the peak energy needed on hot summer afternoons.[31] Furthermore, according to a recent study, approximately 80 percent of EE savings are derived from standards, compared to 20 percent from codes.[32]

Examples of how codes and standards are used in Connecticut are described below.

Codes

In addition to the savings contemplated in the Reference, Targeted DSM Expansion, and All Achievable Cost-Effective DSM strategies, codes and standards can provide further savings. To that end, continued support for adoption of International Energy Conservation Codes and ASHRAE/IESNA Standards into the State Building Code will be needed.

As administrators and supporters of the CEEF programs, the Companies will remain actively involved in the code adoption process for the State of Connecticut. The Companies have representation on the Coalition for the Adoption of a Unified Code that works to promote the adoption of a single family of codes that are consistent and coordinated in form and language, sharing common definitions and requirements. Effective and consistent enforcement of requirements leading to better, not more, regulation is the goal of the Coalition. The Coalition is comprised of representatives of design, enforcement, construction, and owner organizations.

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28 http://bcap-energy.org/node/58#adoption. Last accessed November 30, 2009.

29 United States Department of Energy. "Seventh Semi-Annual Report to Congress on Appliance Energy Efficiency Rulemakings – Implementation Report: Energy Conservation Standards Activities." August 2009.

30 Krauss, Clifford. "A New Enforcer in Buildings, the Energy Inspector." The New York Times. July 17, 2009. http://www.nytimes.com/2009/07/18/business/energy-environment/18codes.html. Last accessed November 30, 2009.

31 California Public Utilities Commission. "California Long Term Energy Efficiency Strategic Plan." September 2008.

32 Rohmund, Ingrid *et al.*, "Assessment of Electricity Savings in the U.S. Achievable through New Appliance/Equipment Efficiency Standards and Building Efficiency Codes (2010 – 2020)." December 2009.

While code improvements are necessary, changes to the energy section of the code often create adoption and enforcement challenges which need to be addressed in order to realize the full benefit of energy code improvements. Resources will be allocated to support the needs, as they relate to code change issues, of the design, construction and enforcement communities.

To that end, new training opportunities will be developed to educate building developers, designers, owners, and building officials regarding new building codes and their implications on design strategies and energy efficiency program designs. The Companies will continue to develop and deploy a broad training/outreach schedule that incorporates topics including but not limited to the amendments to the Connecticut State Building Code adopting the International Energy Conservation Code ("IECC"), Connecticut Energy Regulations, Energy Policy Act of 2005, and new technologies and design processes that can be used to achieve or go beyond new code requirements.

Standards

As administrators and supporters of the CEEF programs, the Companies must stay actively involved with regional efforts to promote the efficient use of energy in homes, buildings, and industry. For example, Northeast Energy Efficiency Partnership (NEEP) has established the Northeast States Minimum Efficiency Standards Project. This project is a regional coalition of consumer, environmental and energy efficiency groups advocating for the enactment of state energy efficiency standards for a range of commercial and residential products including appliances.

Section III.3
Renewable Energy

3. RENEWABLE ENERGY

3.A SUMMARY AND KEY FINDINGS

This section of the IRP is focused on the supply, demand, and future development of renewable energy resources. Since the 2009 IRP was completed, there has been significant activity surrounding renewable energy in New England. On September 15, 2009, the New England Governors adopted the New England Governors' Renewable Energy Blueprint (the "Governors' Renewable Blueprint"), which was prepared by the New England States Committee on Electricity ("NESCOE"). In developing the Governors' Renewable Blueprint, NESCOE enlisted ISO New England ("ISO-NE") to perform an analysis of the economics of various development scenarios for the year 2030 (the "ISO-NE Renewable Scenario Analysis"[1]). The Governors' Renewable Blueprint and ISO-NE's analysis have informed the development of this IRP and are discussed in more detail below. On April 8, 2009, KEMA, Inc. released a study on solar power in Connecticut for the Long-Term Sustainable Solar Strategy Work Group and the Connecticut Clean Energy Fund ("CCEF") (the "KEMA Solar Study").

From the regional perspective, additional work will continue to be done in analyzing the renewable development in New England. ISO-NE is in the midst of performing a study of the physical impact of integrating large scale renewables onto the regional grid, the CCEF has commenced a study to assess Connecticut in-state renewable resource potential, and the Massachusetts Renewable Energy Trust is conducting additional analyses on potential regulatory strategies for building transmission used to interconnect offshore wind onto the New England grid. As such, this IRP is not intended to be the final word on renewable energy strategy for Connecticut, but is instead a way marker along the road to a comprehensive state and regional strategy on renewable energy. Analysis performed to date shows that the cost of new renewables and associated transmission could be substantial, and further analysis needs to be performed.

The Renewable Energy section of the 2009 IRP laid the groundwork for the analysis that was conducted for this IRP. For this IRP, simulation of the dispatch of the New England bulk power system was performed by *The Brattle Group* using the DAYZER model. This simulation modeling allowed for the comparison of resource development strategies using a variety of economic, reliability and environmental metrics. Three "Strategies" were selected and analyzed using DAYZER. Here is a summary of the Strategies which are discussed in more detail in Section 3.C below:

1. Reference Strategy: The Reference Renewable Strategy assumes that all of the New England states meet their respective Renewable Portfolio Standard ("RPS") requirements through the procurement of renewable energy certificates ("RECs") from resources located in New England with some imports. This strategy is consistent with the vision of the Governors' Renewable

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[1] As used herein, the ISO-NE Renewable Scenario Analysis is comprised of two August 14, 2009 Planning Advisory Committee public documents: 1) Preliminary Results for New England Governors' 2009 Economic Study; and 2) New England 2030 Power System Study: Preliminary Maps and Cost Estimates for Potential Transmission.

Blueprint, and includes an estimation of the cost of transmission needed (based on the ISO-NE Renewable Scenario Analysis) to integrate the substantial development of renewables needed to meet the RPS into the regional grid.

2. In-State Renewables Strategy: This strategy assumes that Connecticut would meet the Connecticut RPS requirement through aggressive development of in-state renewable resources.

3. Limited Renewable Strategy: This strategy examines the potential for insufficient renewable resource development, such that Connecticut and possibly other New England states would not meet their respective RPS requirements. Under such situation, Connecticut customers may need to pay the Alternative Compliance Payment ("ACP") for RECs.

The analysis contained herein interacts with other aspects of the overall IRP, most notably Resource Adequacy, DSM and Transmission. In addition, this section also includes the RPS as its own adequacy measure. As Connecticut is part of an integrated electric grid, external supply and demand have a substantial impact on the ability of load serving entities in Connecticut to meet the RPS requirements. Therefore, the analysis contained herein is generally regional in scope, with the exception of the analysis performed for the In-State Renewable Development Strategy.

The findings, recommendations, and analysis presented in this section of the IRP are primarily focused on renewables that qualify as Class I resources under Connecticut statute. Class I resources generally include premium, non-emitting, or low-emitting resources such as wind, solar, landfill gas, small hydro, and sustainable biomass. Therefore, unless otherwise stated herein, the context of this discussion of renewables and RECs is primarily directed toward Class I resources.

The analysis conducted for this IRP has resulted in the following key findings:

- The optimal strategy for meeting the State's RPS requirement is to procure renewable energy as part of a New England regional market.
- Renewable potential in New England is substantially larger than needed to meet RPS.
- Connecticut has limited cost-effective renewable potential in-state.
- The RPS requirements of the New England states are likely to be met through 2012. There is significant uncertainty regarding the overall supply and demand balance and the likely REC prices beyond 2012.
- Substantial transmission investment will be needed to connect sufficient renewables to meet regional RPS requirements. The cost of such transmission is likely to be large, but much less than the cost of building renewables in-state, and not significantly larger than the cost of failing to meet the RPS entirely.
- An in-state renewable strategy would rely heavily on natural gas powered fuel cells, and would not significantly abate CO_2 emissions.
- Based on current cost and price projections, landfill gas, biomass, small hydro, and onshore wind require REC prices that are below the Connecticut's ACP. However, fuel

cells, offshore wind and solar PV would require payments greater than the ACP and would require support from additional subsidies or out-of-market instruments to be developed.

- Investing in new renewable generation provides significant environmental benefits to New England.
- Constructing sufficient new renewable generation in New England would require a major capital investment, in the range of about $20 billion for the generation plus about $10 billion for associated transmission by 2020. Much of the capital investment in generation would be paid for by revenues from the energy and capacity markets, but REC payments and out-of-market payments would also be required for some resources.
- Connecticut policy makers need to engage with other New England states to develop a comprehensive regional renewable energy policy. The New England states should work to define the best and most cost-effective means to expand renewable energy development in New England and the surrounding regions while meeting environmental goals.

3.B BACKGROUND AND CURRENT EVENTS AFFECTING RENEWABLE ENERGY

3.B.1 New England Governors' Renewable Energy Blueprint

The Governors' Renewable Blueprint promotes the development of significant renewable and other low or non-carbon emitting resources in and adjacent to New England, as well as associated transmission. While the Governors' Renewable Blueprint does not identify specific solutions, it does set forth a set of conclusions to support the Governors' collective vision, including:

- Development of New England's renewable potential can easily meet the region's renewable energy goals and could reduce both emissions and marginal clearing prices for energy;
- New England has recent experience in siting and building new transmission in densely populated areas, and is capable of siting and developing the transmission necessary to integrate a substantial quantity of renewable energy;
- Each New England state has the necessary authority and ability to approve contracts for capacity, energy and/or RECs to meet the renewable energy goals and such contracts are typically sought through competitive solicitations; and
- The development of renewables and associated transmission in New England and neighboring control areas would require less capital investment than importing renewables from remote (Midwestern) resources over new high voltage transmission lines.

The Governors' Renewable Blueprint advocates for a state-federal partnership to achieve the region's renewable energy development goals along with federal emissions reduction goals. The document concludes that the region has a multitude of options for meeting its renewable energy goals through the development of renewables within and near New England, and that the selection of these options can be informed by cost considerations, particularly with respect to transmission. As is discussed in more detail below, the ISO-NE Renewable Scenario Analysis shows that the potential cost of transmission for integrating new wind resources is significant.

While the Governors' Renewable Blueprint is not specific in how to achieve the Governors' vision, it does clearly demonstrate that renewable energy is a cornerstone of the Governors' plans for New England's energy future. It also demonstrates that the Governors are committed to using competition as a means to achieve their vision, be it through reliance on organized markets or reliance on long-term contracts obtained via competitive solicitations.

3.B.2 ISO New England Renewable Development Scenario Analysis

ISO-NE supported the development of the Governors' Renewable Blueprint by producing ISO-NE Renewable Scenario Analysis. This analysis is similar in many ways to the modeling effort performed for this IRP, and some results are similar. However, whereas this IRP specifically provides analysis for three, five, and ten years into the future, the ISO-NE Renewable Scenario Analysis was focused on the year 2030. Also, in evaluating the economics of renewable energy ISO-NE did not fully consider all of the potential customer costs, but rather only considered the price impact of various development strategies on ISO-NE administered markets and (in a separate study) the cost of incremental transmission. While this information is valuable, there are other costs that customers may face, particularly the costs of RECs and any state-provided subsidies or long-term contracts that are not economic. This IRP estimates these additional cost drivers.

The ISO-NE Renewable Scenario Analysis compared the performance of 34 scenarios under a variety of economic and environmental measures. While there is a wealth of interesting information in the analysis, there are two interesting comparisons that we will note here. First, ISO-NE's Base Case included 4,000 of on and offshore wind. An alternative base case was run that substituted 1,500 MW of new combined cycle for the 4,000 MW of wind (001a_Base). Second, ISO-NE analyzed a case that added a combined total of 12,000 MW (4,000 MW from Base Case plus 8,000 incremental MW) of onshore and offshore wind energy (the "12,000 Wind" case), and a case where existing resources 50 years and older were retired and replaced with new, efficient gas combined cycle generation (The "Retire 50" case, which also included the 4,000 MW of wind from the Base Case). Table 3.1 below summarizes how these cases compare under certain cost and environmental metrics:

Table 3.1
Summary of Selected ISO-NE's Renewable Energy Scenario Analysis
(2009 Dollars)

	Base	001a_Base	Retire 50	12,000 Wind
LMP (no transmission constraints)	$75.76/MWh	$75.60/MWh	$67.36/MWh	$68.78/MWh
LMP (existing transmission constraints)	$75.70/MWh	$75.60/MWh	$67.26/MWh	$71.80/MWh
LMP (high fuel prices)	$144.34/MWh	$144.16/MWh	$128.35/MWh	$124.72/MWh
SO_2 (ktons)	73.6	73.6	2.9	66.9
NO_2 (ktons)	32.4	32.7	18.7	29.3
CO_2 (Mtons)	53.7	58.9	40	42.2
Incremental Transmission Investment	$10.7-$14.3 billion[2]	N/A (likely low)	$10.7-$14.3 billion	$19.3-$25.2 billion

The first comparison that we would note is that, in terms of economics, there is a minimal difference between the Base and 001a_Base cases other than the cost of transmission required to connect the 4,000 MW of new wind in the Base Case.[3] The 001a_Base case also resulted in CO_2 emissions that were about 10 percent higher than the Base Case. The Base and 001a_Base case resource additions were consistent in scale with the resource additions contemplated in this IRP, and as discussed in more detail below, our modeling results under similar assumptions are also consistent with ISO-NE's results.

The second comparison that we would note is the comparison between the Retire 50 and 12,000 Wind cases. A comparison of these two aggressive resource development cases shows that the replacement of ~9,000 MW of older fossil generation with new gas-fired combined cycle generation may abate emissions more economically than an aggressive build-out of 8,000 additional MW of wind (both cases include 4,000 of new wind). Our IRP analysis does not test or confirm this result for three reasons. First, the IRP analyzes the year 2020 where new resource requirements are less than they are likely to be in 2030. Second, the IRP is focused on Connecticut which limits the scale of resource development that Connecticut policy will drive. Finally, we could not economically justify the retirement of all older fossil resources in New England. However, we find that this comparison is very informative for long-run regional policy and should be considered.

ISO-NE is in the midst of assessing the physical impact of integrating (largely intermittent) renewables into the regional grid on a large scale. The EDCs understand that this new analysis will provide better specificity than the ISO-NE Renewable Scenario Analysis with regard to the

2 Transmission cost associated with 4,000 MW of onshore and offshore wind in the base assumptions

3 We assume that transmissions costs for the 001a_Base case are minimal because, unlike wind, the gas combined cycle units can be built close to load.

additional resources that would be needed, possibly including transmission and associated equipment, and fast start generation for balancing intermittent energy production with load. We anticipate that the ISO's new analysis will help to further inform policy makers and future IRPs. As for now, this IRP considers the cost of transmission based on the latest information available, but does not consider the cost of additional fast start generation because the need has not yet been quantified.

3.B.3 Potential for Federal RPS

Renewable energy policy at a national level is a major uncertainty that could have an impact on RPS policies in New England and the customer costs of meeting renewable energy goals. For example, the House Climate Change (Waxman-Markey) bill requires retail electricity suppliers with annual sales over 4 million MWhs (roughly 1,000 MW peak load with 45 percent load factor) to serve 20 percent of their electric energy load with qualified renewable energy sources or electricity efficiency savings by 2020.[4] The requirement starts at 6 percent in 2012, reaches 9.5 percent in 2015, and 20 percent in 2020. It is also proposed that at least 75 percent of the requirement must be provided by qualified renewable energy sources, and the remaining can be achieved through electric efficiency savings.[5] The proposed bill has a national ACP of $25/MWh (indexed to inflation) as penalty for non-compliance. One of the unresolved issues around having a federal RPS is how such a program would interact with the existing state-specific RPS policies that govern the retail suppliers' renewable energy obligations today. It is generally understood that the national RPS would not supplant the state policies, but rather, would set the minimum renewable requirement for all retail electric suppliers such that those states with more stringent requirements would not incur additional costs associated with meeting the federal RPS requirements. In other words, a federal RPS would set a minimum renewable energy target, allowing states to be more aggressive in requiring more renewable energy deployment than the national standard. In that sense, Connecticut already has a more stringent requirement than the proposed House Bill. However, the details regarding how the RECs markets would function is yet to be determined. For instance, a resource that qualifies simultaneously as a state and a national renewable resource may prove to have two values, one under the federal RECs market and another under the state or regional RECs market. It is not yet clear whether such a resource may receive two payments, or if not, how REC payments associated with the same MWh produced would be tracked to avoid double-counting. In addition, it is not yet clear if having a federal REC market might mean that Connecticut might not need to purchase RECs from resources that deliver power to New England. These are just some examples of the uncertainties around the renewable regulatory policies.

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[4] It is not clear how the 4 million MWh in the Waxman-Markey bill would be counted or if it is only applicable to certain load-serving entities, because the specifics in the proposed legislation are still uncertain. Currently, UI's combined standard and default service sales are less than 4,000,000 MWhs per year, but we doubt that UI would be exempt from a national RPS. Thus, the ambiguity in the proposed federal legislations demonstrates the uncertainties in the overall renewable energy regulation and associated markets.

[5] The bill allows states to petition to increase the portion of electric efficiency savings from 25 percent up to 40 percent.

3.B.4 KEMA Sustainable Solar Strategy for Connecticut Study

The KEMA Solar Study recommended that Connecticut add a "carve-out" for solar energy to its RPS legislation, and target 300 MW of solar installations by 2025. The In-State Renewables Strategy in this IRP assumes a similar approach by including 237 MW of solar PV (which produces energy equal to approximately 1 percent of Connecticut load) in the State by 2020. The KEMA Solar Study discusses several complimentary approaches to achieving the 300 MW by 2025 goal including solar incentive/rebate and lease programs, grants for new zero-energy homes, solar RECs, installation of solar PV on government buildings, and utility development of solar projects. The analysis contained herein is not specific with regards to program, or to whether or not the solar PV developed is added to the grid or behind customer meters and similar results would be expected independent of the means of achieving that goal. The KEMA Solar Study also goes beyond the scope of this IRP by evaluating indirect benefits such as spin-off economic activity.

One key point in the KEMA Solar Study is that consistent funding is needed to avoid the "boom and bust" cycles that can occur under traditional funding mechanisms. Whatever level of solar development the State ultimately adopts, it is important that funding be established in a manner that allows for the sustainability of the local solar industry. The KEMA Solar Study suggests alternative funding mechanisms such as feed-in tariffs (used widely in Europe), a solar REC carve-out in the Connecticut RPS, state or local loans, utility financing and reduced interest rate programs.

3.B.5 CCEF Study on Connecticut Renewables

As part of its Renewable Energy/Energy Efficiency Economy Baseline Study for the State of Connecticut, the CCEF has initiated a study of renewable energy potential in Connecticut with a focus that delves deeper into the availability of renewable energy resources in the state of Connecticut. This work is on-going and CCEF anticipates that the results will help inform the public about the likelihood of Connecticut meeting its RPS requirements with mostly Connecticut-based renewable resources.

3.B.6 Referring Back to the 2009 IRP

The 2009 IRP concluded that New England has more than adequate renewable potential to meet the combined New England states' RPS throughout the planning horizon, but that there is substantial uncertainty whether that renewable potential will be developed to the extent necessary to meet the aggressive renewable targets in the region.[6] In addition, the 2009 IRP assessed the likely supply and demand balance in the near-term years through 2013 and concluded that it is likely that supply will be sufficient to meet demand through 2013. These conclusions from the 2009 IRP remain valid. The analysis in this IRP goes beyond the 2009 analysis by thoroughly examining three different renewable resource strategies and providing economic, environmental and reliability metrics on them. The Reference Strategy assumption that the 2020 RPS is met in New England was made to support the analysis, and is not a forecast.

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6 January 1, 2009 Integrated Resource Plan for Connecticut, page ES-2.

3.B.7 What the Analysis is Telling us about Current Policy Goals

Our analysis aligns with the conclusion that the development of substantial renewables in New England would likely reduce both emissions and energy clearing prices. However, this is only part of the economic picture. First, the ISO-NE Renewable Scenario Analysis shows that the cost of transmission needed to integrate wind resources could be very high, or even prohibitive. Second, the anticipated clearing prices alone may be insufficient to result in the large scale development of enough renewable energy to meet the region's RPS targets. To the extent that load serving entities are required to support the development of renewable facilities, they may have to do so via long-term contracts that could be uneconomic for customers, and could impair the financial health of the buyers. At modest levels of resource development, both the ISO-NE Renewable Scenario Analysis and this IRP show that the development of renewables is likely to be beneficial for customers and the environment. However, ISO-NE's analysis of more aggressive development shows that an alternative strategy of replacing older fossil units with new gas combined cycle generation may have the potential to reduce emissions more cost effectively than an aggressive renewable buildout.

Extensive development of renewables in New England may very well be the optimal strategy for emissions abatement and cost reduction, but it is not yet clear that this is the case. The EDCs suggest that further regional analysis be conducted to compare the potential effects of new natural gas combined cycle generation to new renewable generation on a regional scale, and under a variety of retirement scenarios. Since the potential emissions and customer cost reductions could benefit the region, the EDCs believe such an analysis is best conducted at the regional level, not just in the Connecticut IRP.[7] When considering policy uncertainties (mostly at the federal level) and potential customer costs, caution should be exercised before embarking on a large scale development of renewables.

More specific to Connecticut, the IRP analysis demonstrates that a regional strategy for renewable energy development is the most effective way for Connecticut to meet its RPS requirements. As is discussed in more detail below, aggressive in-state renewable development is not likely to be cost-effective, and will likely increase emissions compared to the Reference Strategy. It is important for Connecticut to work with other New England states to analyze options for the region to meet its renewable energy needs.

3.C MODELING AND TESTING OF RENEWABLE SUPPLY STRATEGIES

The Brattle Group and the EDCs utilized the DAYZER model to test and compare three distinct resource strategies for regional renewable energy development. DAYZER simulates the dispatch of resources in the New England grid and produces outputs that can be used to measure economic performance and emissions levels. The Reference Strategy was run in DAYZER for 2013, 2015, and 2020. As with all other alternative strategies in this IRP, the two alternative renewable strategies were simulated for 2020 to provide the basis for conducting the economic analysis of the three renewable strategies for Connecticut.

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[7] UI also believes that a nuclear development alternative should be examined.

3.C.1 Reference Strategy

The Reference Strategy for the 2010 IRP includes an assumption that the development of renewable energy in New England (and including some imports) is sufficient to meet the collective RPS requirements of the region. The Reference Strategy does not determine whether such development would take place in response to market signals or other mechanisms such as long-term contracting or a combination of both. The EDCs' assessment of transmission costs was based on the ISO-NE Renewable Scenario Analysis, and formed a substantial part of the costs associated with the Reference Strategy.

3.C.2 In-State Renewables Strategy

In the 2009 IRP, the EDCs concluded that most renewable potential in New England is outside of Connecticut, and that Connecticut will have to rely on out-of-state resources to meet its RPS. The EDCs decided to test a Connecticut in-state renewable resource development strategy to compare the costs relative to the Reference Strategy and the Limited Renewable Strategy. Under the In-State Renewables Strategy, in-state biomass, landfill gas and wind are assumed to be built close to their potential. Solar PV also is assumed to be built to meet an aggressive penetration rate of one percent of Connecticut's load. Any shortfall relative to Connecticut's RPS requirement is then met by the addition of natural gas powered fuel cells. The In-State Renewables Strategy assumes that the rest of the region does not develop sufficient renewables to meet their RPS requirements. It is important to note that this strategy could result in the EDCs' customers paying twice, once for their full share of the cost of development of the in-state renewable resources, and a second time for their proportionate share of the cost of new transmission that would be used to move renewable power to other New England states if the other New England states pursue a strategy of developing renewables on a regional basis. The In-State Renewables Strategy does not include the cost impact of paying twice.

3.C.3 Limited Renewable Development Strategy

While the Reference Strategy includes the assumption that the New England states will meet their respective RPS requirements through the development of new renewable resources, there is no assurance that this will actually occur. Thus, from the perspective of testing the potential outcomes, this IRP examines the possibility that Connecticut fails to meet the state's renewable energy mandate (and New England as a whole also fails to meet the region's renewable requirement). Under such a situation, the load serving entities in Connecticut would have to meet the RPS requirement through a mix of ACP payments and the procurement of Connecticut Class I Only RECs purchased at or near the ACP rate. Under the Limited Renewable Development Strategy, renewable development was arbitrarily halted at 2013 Reference Strategy levels to test the impact of a substantial shortfall of renewables on cost and environmental metrics in the year 2020.[8] Any resulting resource shortfalls in the region were assumed to be filled by new gas combined cycle generation.

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[8] We have chosen to freeze the renewable development at the 2013 levels because most of the planned renewable projects have an expected in-service date of 2013 or earlier. Thus renewable project development for years beyond 2013 are based on our assumptions of the pace at which each resource would likely be developed.

3.C.4 Comparison of the Three Strategies

Table 3.2 below shows a breakdown of the quantity of each type of renewable energy source in MW, both in Connecticut and in New England as a whole.

Table 3.2
Summary of Renewables Buildout in Connecticut and New England
(Nameplate Capacity MW, Current Trends Scenario)

Renewable Technology	**Existing Renewable Capacity**	**New Renewable Capacity Additions**				
		Reference Strategy			In-State Renewables	Limited Renewables
	2009	2013	2015	2020	2020	2020
	(MW)	*(MW)*	*(MW)*	*(MW)*	*(MW)*	*(MW)*
Connecticut						
Biomass/Biofuels	0	51	55	66	100	51
Fuel Cells	3	30	42	66	693	30
Landfill Gas	8	20	22	27	20	20
Small Hydro	5	0	0	0	0	0
Solar PV	13	10	13	21	237	10
Wind	0	0	0	0	40	0
Offshore Wind	0	0	0	0	0	0
CT Total	**31**	**111**	**133**	**180**	**1,090**	**111**
ISO New England						
Biomass/Biofuels	457	145	221	382	194	145
Fuel Cells	4	30	42	66	693	30
Landfill Gas	111	36	38	43	36	36
Small Hydro	87	3	12	31	3	3
Solar PV	28	103	143	247	330	103
Wind	97	239	754	1,939	279	239
Offshore Wind	0	367	881	2,066	367	367
ISO-NE Total	**785**	**924**	**2,092**	**4,774**	**1,903**	**924**

Table 3.3 below compares the customer cost (in \$2010 ¢/kWh) of the three renewable strategies. Of the three renewable resource strategies, the Reference Strategy exhibits much less cost variability under the five scenarios tested than the other two strategies. What this means is that customer rates would likely be more stable under the Reference Strategy. The In-State Renewables Strategy is more expensive than the Reference Strategy in all scenarios. The Limited Renewable Strategy is more expensive than the Reference Strategy under the Medium Gas/High CO_2 and High Gas/Hi CO_2 scenarios. These results are intuitive because these alternatives Strategies rely more heavily on natural gas in lieu of renewable sources compared to the Reference Strategy.

Table 3.3
Comparison of Average Customer Costs in Connecticut (2020)

Scenario	Strategy		
	Reference Strategy *(¢/kWh)*	In-State Renewables *(¢/kWh)*	Limited Renewables *(¢/kWh)*
Current Trends	13.70	14.09	13.30
Lo Gas/Lo CO2	11.01	11.52	10.57
Med Gas/Hi CO2	14.17	15.12	14.39
Hi Load	13.78	13.96	13.27
Hi Gas/Hi CO2	15.59	17.53	17.13

Table 3.4 below compares the total emissions in Connecticut and New England under the 3 renewable resource strategies. As would be expected, the two alternatives to the Reference Strategy result in substantially higher CO_2 emissions due to additional reliance on natural gas, and both strategies would push CO_2 emissions in Connecticut above the State's share of the RGGI cap. NO_X and SO_2 emissions for the two alternative strategies are either higher or lower than those of the Reference Strategy depending on gas price, CO_2 price and load growth, with NO_X emissions being generally higher in Connecticut, and SO_2 emissions being generally lower.

Table 3.4
Summary of CO_2, NO_X, and SO_2 Emissions
in Connecticut and New England

CONNECTICUT EMISSIONS IN 2020

Scenario	CO_2 *(thousands of tons)*			SO_x *(tons)*			NO_x *(tons)*		
	Reference Strategy	In-State Renewables	Limited Renewables	Reference Strategy	In-State Renewables	Limited Renewables	Reference Strategy	In-State Renewables	Limited Renewables
Current Trends	8,551	10,892	10,271	2,506	2,023	2,029	3,060	3,639	3,293
Low CO2 and Low Gas	9,578	11,680	10,980	1,554	971	993	2,808	3,215	2,878
Reference Gas and High CO2	7,718	10,140	9,512	1,182	1,081	1,033	2,447	3,087	2,722
High Load Growth	10,388	11,886	11,148	3,138	2,297	2,311	3,609	3,892	3,528
High Gas and High CO2	8,610	10,831	10,065	3,324	4,244	4,484	3,515	4,342	4,040

ISO-WIDE EMISSIONS IN 2020

Scenario	CO_2 *(thousands of tons)*			SO_x *(tons)*			NO_x *(tons)*		
	Reference Strategy	In-State Renewables	Limited Renewables	Reference Strategy	In-State Renewables	Limited Renewables	Reference Strategy	In-State Renewables	Limited Renewables
Current Trends	36,562	41,686	42,021	44,275	43,944	45,028	17,520	17,329	17,407
Low CO2 and Low Gas	36,483	41,838	42,263	21,329	17,300	18,981	13,910	13,024	13,236
Reference Gas and High CO2	32,456	37,058	37,249	28,773	26,948	27,623	13,908	13,206	13,150
High Load Growth	42,106	47,605	47,970	50,454	46,726	48,052	19,750	18,809	18,912
High Gas and High CO2	33,655	38,806	39,298	54,090	58,411	60,273	18,731	19,428	19,632

Figure 3.1
Summary of Customer Cost and CO_2 Emission Comparison (2020)

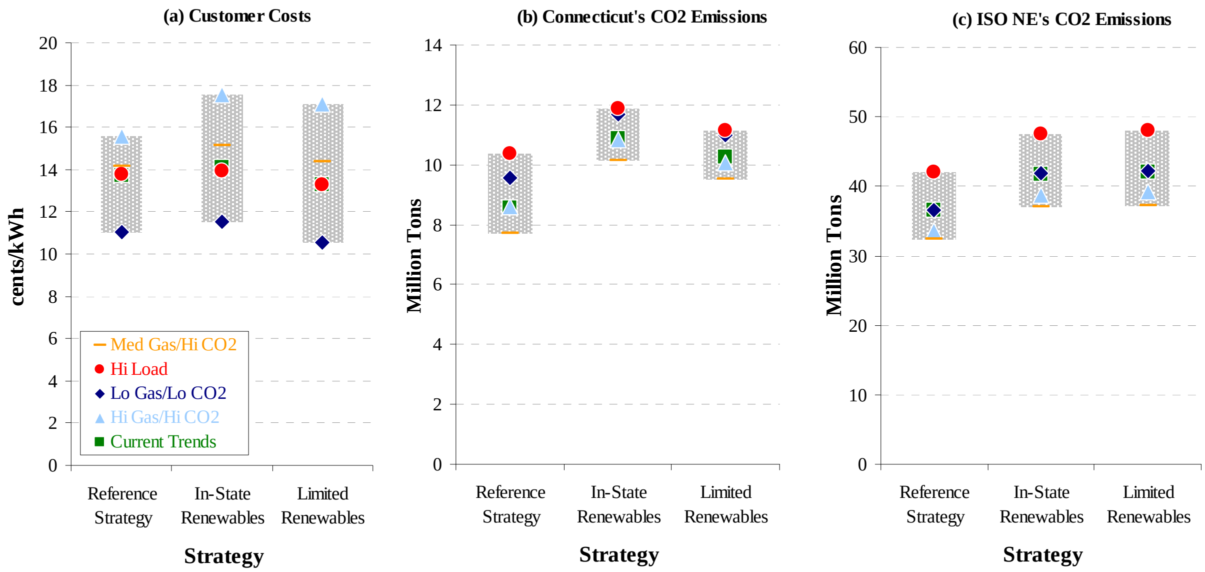

Figure 3.1 shows the same results in graphical form. These results suggest that, of the three renewable strategies, the Reference Strategy is likely to be less costly than the cost of building renewables in-state, and not significantly more costly than unable to meet the RPS. The two alternative strategies have costs that vary more greatly with natural gas and CO_2 prices than in the Reference Strategy, and do not provide substantial emissions benefits relative to their costs. It should be noted for clarity that the presence of the high CO_2 emissions (from sources within Connecticut) in the In-State Renewables Strategy are mostly driven by the inclusion of 693 MW of fuel cells. While 237 MW of solar PV is also included in that strategy, solar does not contribute to the higher emissions results. However, solar is a key contributor to the exceptionally high cost of the In-State Renewables Strategy.

The results in Table 3.4 show that as an incremental 627 MW of fuel cells (relative to the Reference Case in 2020) are added to Connecticut's supply mix, the Connecticut's CO_2 emissions increases relative to the Reference Strategy and the Limited Renewable Strategy. This is due to the fact that the fuel cell units will be operated at a high capacity factor for the purpose of meeting Connecticut RPS requirement, which increases the in-state energy production (and the associated CO_2 emissions from natural gas usage). Such fuel cell addition also reduces the out-of-state energy imports into Connecticut. Thus, relative to the Limited Renewable Strategy, the In-State Renewables Strategy also shows slightly higher CO_2 emission because more energy and therefore more CO_2 emissions are produced from the fuel cells in Connecticut than would in the Limited Renewable Strategy (where Connecticut meets its RPS by paying the ACP for at least a portion of its renewable requirement).

As was mentioned above, the Limited Renewable Strategy is similar to the alternative base case (the 001a_Base case) in the ISO-NE Renewable Scenario Analysis. The ISO-NE 001a_Base case replaced 4,000 MW of wind with 1,500 MW of gas combined cycle in the year 2030. Our Limited Renewable Development Strategy replaces around 3,400 MW of wind with sufficient gas combined cycle generation additions to meet reliability requirements (quantity varies by scenario) in the year 2020. Both the ISO-NE and IRP analysis show similar results: a marginal cost benefit, but significant (5 Mtons/year) increase in CO_2 emissions for the limited renewables cases. Due to the similarity of results from independent credible analyses, the numbers should be viewed with a fair level of confidence.

3.D RENEWABLE ENERGY REGULATIONS

3.D.1 Renewable Energy Regulations in Connecticut

The Connecticut RPS regulation has a tiered structure with three classes of resources. To reiterate 2009 IRP, on the resource supply side, following are the class definitions in the Connecticut RPS regulation:

- Class I resources include energy derived from solar, wind, fuel cell, methane gas from landfills, ocean thermal, wave, tidal, run-of-river hydropower (<5MW, began operation after July 1, 2003), and sustainable biomass (NO_X emission <0.075 lbs/MMBtu of heat input).
- Class II resources include biomass (NO_X emission <0.2 lbs/MMBtu of heat input, began operation before July 1, 1998), small run-of-river hydroelectric (<5MW, began operation before July 1, 2003), and trash-to-energy facilities.
- Class III resources include customer-sited combined heat and power (with operating efficiency >50 percent of facilities installed after January 1, 2006), waste heat recovery systems (installed on or after April 1, 2007), electricity savings from conservation, and load management programs (began on or after January 1, 2006).

In setting the standards for renewable energy usage, the Connecticut RPS regulation sets the percentage of Connecticut retail load that must be met by each class of renewable energy resource through 2020. Table 3.5 below shows the summary of those percentages:

Table 3.5
Connecticut RPS Requirements
(Percentage of Retail Load)

Year	Class I	Class II or Class I (add'l)	Class III	Total
2008	5.0%	3.0%	2.0%	10.0%
2009	6.0%	3.0%	3.0%	12.0%
2010	7.0%	3.0%	4.0%	14.0%
2011	8.0%	3.0%	4.0%	15.0%
2012	9.0%	3.0%	4.0%	16.0%
2013	10.0%	3.0%	4.0%	17.0%
2014	11.0%	3.0%	4.0%	18.0%
2015	12.5%	3.0%	4.0%	19.5%
2016	14.0%	3.0%	4.0%	21.0%
2017	15.5%	3.0%	4.0%	22.5%
2018	17.0%	3.0%	4.0%	24.0%
2019	19.5%	3.0%	4.0%	26.5%
2020	20.0%	3.0%	4.0%	27.0%

Source: Conn. Gen. Stat § 16-245a et seq. and Public Act No. 07-242, § 40-44.

As discussed in the 2009 IRP, the analysis of renewables for long-term planning purposes is focused primarily on Class I requirements, because it is expected that the demand for Class I resources will drive the development of new renewable energy resources. Connecticut's Class II requirement is relatively static at three percent of retail usage, and only grows at the rate of retail load growth. It is anticipated that the existing supply will continue to exceed the Class II purchase requirement over the foreseeable future, particularly if DSM programs reduce or eliminate load growth as anticipated. Class III requirements focus on energy efficiency, other demand side measures, and combined heat and power resources that are necessary and important, but are not necessarily driving the demand for new renewable energy resources.

Connecticut's RPS regulations have some unique characteristics that create disparity between Connecticut and other New England states, and effectively create a subclass of Class I RECs that are only eligible in Connecticut. First, aside from small hydro facilities, the definition of Class I "new" renewable resources in Connecticut does not specify a "vintage" requirement, unlike Massachusetts and Rhode Island, where Class I renewables must have entered service after December 31, 1997 to be eligible to meet RPS requirements.[9,10] Due to the lack of vintage requirement, existing resources that were built before 1998, such as existing landfill gas, wind,

9 Run-of-river hydropower facilities less than 5 MW, do not cause an appreciable change in river flow, and began operation after July 1, 2003 are qualified Connecticut Class I resources. Section 16-1(a)(26) of Connecticut State Statute.

10 New Hampshire's Class I Renewables must have begun operation after January 1, 2006; Maine's vintage requirement is September 1, 2005; Vermont's is December 31, 2004.

and low emission biomass plants can qualify as Class I renewable resources in Connecticut, but not in other New England states. Second, Connecticut has included natural gas-powered fuel cells as Class I resources. Finally, Connecticut allows the generation of Class I RECs by some natural gas fired generators that import landfill gas from outside of the state via interstate natural gas pipeline.[11] Due to these distinctions, some resources are effectively Connecticut Class I Only resources because they do not qualify as Class I renewable resources in other New England states.

Another distinction between the Connecticut RPS and those of other New England states is that the ACP for Connecticut is fixed at $55/MWh for Class I, with no escalation. To the extent that the ACPs in other states escalate to above $55 during periods of shortage, Connecticut EDCs would likely be unable to procure Class I RECs from sources other than Connecticut Class I Only resources.[12] Under such a scenario, if the New England REC prices exceed the Connecticut's ACP, the EDCs would procure RECs from the Connecticut Class I Only resources (to the extent that their REC prices are lower than the ACP), and meet the remainder of the RPS through ACP payments.

For the In-State Renewables Strategy, we have assumed that if the necessary REC payment for a Connecticut-based resource is above the Connecticut's ACP, those REC payments would need to be made outside of the conventional REC market. Those payments are considered "out-of-market" payments that represent premiums above the conventional REC market. Also relevant is the fact that if the rest of New England is short relative to their RPS requirements (as we have assumed in the In-State Renewables Strategy), the regional REC market price would rise above the Connecticut ACP, closer to the regional ACP. Thus, if we were to assume that all in-state resources are willing to "stay" within the state (or used to satisfy Connecticut's RPS requirements), they will need to be paid a REC price that is akin to the regional ACP.

The Connecticut RPS was established to provide a threshold quantity requirement and thereby support for the development of renewable projects. In a market-based environment, such quantity-based regulation should provide the price necessary to support project developers and to help them secure financing for their projects. In fact, the RPS and the market that is based on the RPS (including qualifying renewable projects from facilities that were built prior to the establishment of the RPS), has resulted in a near-term surplus of Class I RECs in New England. However, due to the 2008-2009 economic downturn, some project developers have had significant difficulties in obtaining the necessary financing for the development of the additional renewable facilities that may be necessary in the future to meet increasing RPS requirements.

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11 The allowance of landfill gas delivered via interstate gas pipeline is a wild card in the assessment of the supply of Connecticut Class I Only RECs because it would be necessary to evaluate the supply of landfill gas and demand for landfill gas as a renewable fuel source for all states connected to interstate gas pipelines either directly or indirectly connected to New England in order to perform a comprehensive analysis of the supply of such landfill gas. Such analysis is beyond the scope of this IRP.

12 Since all of the cost analysis is based on 2010 constant dollars, the Connecticut ACP is effectively decreasing over time in terms of 2010 constant dollars. In contrast, because the ACPs in other New England states increase nominally with inflation, those ACPs remain constant in 2010 constant dollars.

Absent market-based development, long-term contracts with credit-worthy entities are another means to support the development of renewable projects. However, in Connecticut, load serving entities ("LSEs") are responsible for meeting the state's RPS requirements. The EDCs currently meet their share of the RPS by shifting the obligations to wholesale suppliers of full requirements service under contracts ranging from three months to three years in duration. This business model provides limited support for the development of renewable energy because suppliers generally have no known load serving obligation beyond three years in the future and therefore limits the LSEs' interest and abilities to enter into long-term contracts with any suppliers. This limitation on long-term contracting does little to help developers finance new projects.

3.D.2 Renewable Energy Regulations in New England

All six New England states have set explicit renewable energy usage targets through state legislative and regulatory processes. Since the 2009 IRP filing, some additional regulations have been set by the New England states. Specifically, Massachusetts, in implementing the Clean Communities Act, has approved a regulation that requires the local electric distribution company to enter into cost-effective long-term contracts (of 10-15 years) with renewable energy providers for at least three percent of the retail load. The Massachusetts distribution companies must do so by conducting at least two contract solicitations over a five year period.[13] In addition, Massachusetts has began to increase its focus on growing the use of solar PV and is in the midst of developing a solar-REC support mechanism to encourage solar deployment in Massachusetts, starting with approximately 20 MW in 2010, increasing at 30 percent per year (adjusted to market conditions).[14] Since the Massachusetts solar carve-out has not yet been implemented, we also have not incorporated the full scale of the solar targets for Massachusetts into our analysis. In Rhode Island, new legislation enacted in June 2009 requires the local electric distribution company to enter into long-term contracts for at least 90 MW (of dependable capacity) in Rhode Island or surrounding waters–based resources by 2014. Of the 90 MW long-term contract requirement, at least 3 MW must be solar or photovoltaic projects.[15] While these new regulations in Massachusetts and Rhode Island do not change the total quantity targets in their respective RPS, they increase the likelihood that the renewable projects located in Massachusetts and Rhode Island and the surrounding waters would obtain the necessary off-take contract, financing, ultimately be constructed.

Aside from the changes described for Massachusetts and Rhode Island, the Class I renewable requirement, in terms of percentage of load, has remained substantially unchanged from analysis contained in the 2009 IRP.

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[13] Massachusetts Department of Public Utility, Order to Docket 08-88-A, and Regulation in Appendix A, 220 CMR 17.00: Long-term Contracts for Renewable Energy.

[14] Solar RPS Carve-Out: S-REC Price Support Mechanism, Public Stakeholder Meeting, Boston, Massachusetts, October 23, 2009.

[15] Rhode Island H5002, as enacted on June 26, 2009.

3.D.3 Uncertainties in Renewable Energy Regulations and the REC Market

While in this Renewable Section we present an in-depth analysis of the renewable energy regulations in New England, the projected supply and demand balance of resources in the region, the REC market dynamics and the necessary out-of-market payments for certain resources, we also want to point out that there are significant uncertainties around several dimensions. These uncertainties include, but are not limited to: a) the potential implementation of a federal renewable energy policy and how a federal REC market might interact with the state REC markets; b) the potential for dramatic changes in future load growth, including the effects of demand-side resources; c) the magnitude of transmission additions and the associated costs necessary to support a renewable build-out; d) the potential operational effects and therefore resource needs and costs for compensating variable generation such as wind on the grid; and e) the potential for changes in the economics of renewable resources and other low-emissions technologies.

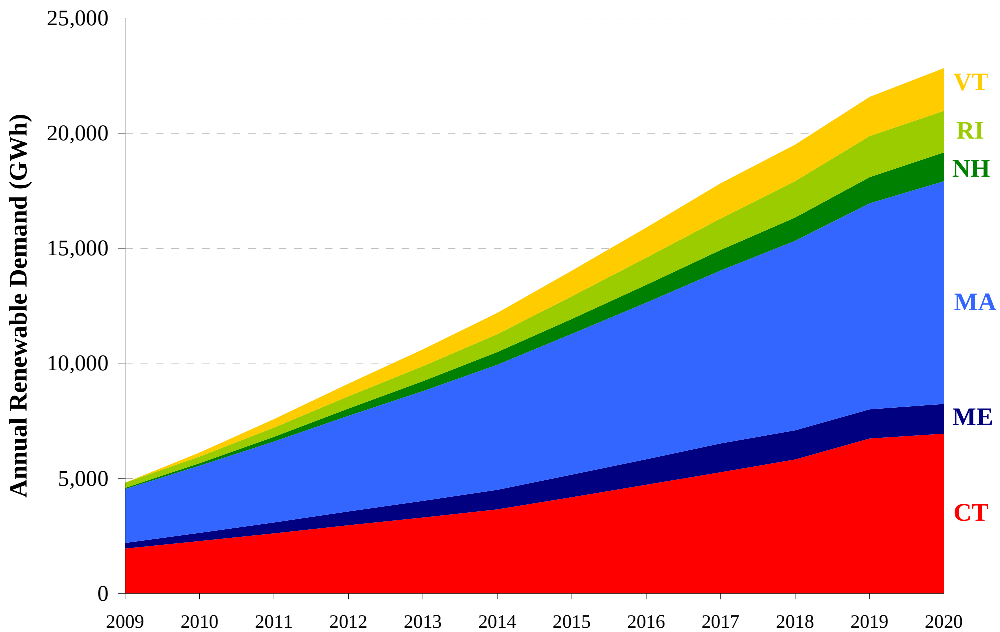
3.E REGIONAL DEMAND FOR RENEWABLE ENERGY

Although the qualification requirements for Class I renewable resources are similar in all New England states, there are some differences in vintage and emissions requirements. In addition, the in-state resource requirements in Massachusetts and Rhode Island have somewhat segregated a small portion of the market to be state-specific markets. Likewise, since some of the Connecticut resource requirements differ slightly from those of other New England states, there are some short term effects. However, since the total amount of Connecticut Class I Only resources is limited, as renewable targets in all of the New England states increase over time, the various in-state requirements and the differences between resource qualifications are likely to become less significant. As a result, the demand for Connecticut Class I RECs and their counterparts from other states are expected to behave as a single New England market over the long-run. Since virtually all of the New England states have set their renewable targets as annually ascending percentages of load, the region's renewable demand is expected to grow over the planning horizon even as energy conservation and efficiency programs can reduce the expected load growth. Below in Table 3.6 and Figure 3.2, we estimate the magnitude of demand for Class I renewable energy in the six-state region through 2020 after considering energy conservation and efficiency increases relative to current levels.

Table 3.6
New England RPS Requirements
(Percentage of Retail Load)

State	Class	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
CT	Class I	6.0%	7.0%	8.0%	9.0%	10.0%	11.0%	12.5%	14.0%	15.5%	17.0%	19.5%	20.0%
ME	Class I	2.0%	3.0%	4.0%	5.0%	6.0%	7.0%	8.0%	9.0%	10.0%	10.0%	10.0%	10.0%
MA	Class I	4.0%	5.0%	6.0%	7.0%	8.0%	9.0%	10.0%	11.0%	12.0%	13.0%	14.0%	15.0%
NH	I + II	0.5%	1.0%	2.1%	3.2%	4.2%	5.3%	6.3%	7.3%	8.3%	9.3%	10.3%	11.3%
RI	All	2.0%	2.5%	3.5%	4.5%	5.5%	6.5%	8.0%	9.5%	11.0%	12.5%	14.0%	14.0%
VT	All	0.0%	2.5%	5.0%	7.5%	10.0%	12.5%	15.0%	17.5%	20.0%	20.6%	21.9%	23.8%
Total		**3.7%**	**4.7%**	**5.7%**	**6.8%**	**7.9%**	**9.0%**	**10.2%**	**11.5%**	**12.7%**	**13.8%**	**15.1%**	**15.9%**

Figure 3.2
New England RPS Requirements
(Annual GWh)



Sources and Notes: 2009 CELT Report Forecast for "Base Case." Growth rate for years beyond 2018 is based on average growth rate between 2017 and 2018. Demand accounts for estimated reductions from 2009 IRP Reference DSM forecast. Massachusetts demand incorporates the increased Class 1 RPS requirement from the 2008 Green Communities Act.

3.F RENEWABLE ENERGY SUPPLY IN NEW ENGLAND

The prospects for renewable energy development in New England are generally good, but do vary based on the cost and subsidies for each specific technology. Section 3.G below discusses the economics for each technology in detail. Technical potential in the region is substantial, and the political climate is highly favorable for renewable development (as shown in the Governors' Renewable Blueprint). While the prospects for development are good, there is still uncertainty whether sufficient amount of renewables will be developed to meet the RPS of the region. This section examines existing generation and projects the development of new renewables.

3.F.1 Existing Renewable Generation in New England

In 2008, the EDCs met their Class I RPS requirements through a mix of wood biomass (80 percent), landfill gas (14 percent), small hydro (3 percent), wind (1 percent), and fuel cells (1 percent). Therefore, while future supply sources are diverse and include significant wind potential, the current supply makeup for Connecticut is nearly 95 percent biomass and landfill gas, consistent with the assessment of Connecticut Class I Only qualification. Of the existing generating resources in New England, approximately 166 MW of biomass and landfill gas plants currently qualify for Connecticut's Class I requirement.[16] In addition, there are approximately another 402 MW of biomass and landfill projects that have qualified to meet Class I requirement in at least one of the New England states. Together, there are approximately 568 MW of biomass and landfill gas projects that are currently used to satisfy New England's Class I RPS requirements.

Onshore wind makes up approximately 97 MW of existing renewable resources in New England today. This is over 90 MW increase from last year's IRP. Wind resources from outside of New England that have qualified to meet New England's RPS also have increased from 396 MW[17] to 862 MW. Out of the wind energy imported from outside of the ISO-NE system, approximately 463 MW is from New York, 357 from Canada (including Quebec, New Brunswick, and Prince Edward Island), and 42 MW from Northern Maine (the portion of Maine that is outside of ISO-NE).

Table 3.7 below depicts current renewable energy supply that has qualified as Class I resources in New England (categorized by location of the facilities and technologies). These qualified resources include those physically located in New England and imports from neighboring regions. We compiled this information from the renewable qualification databases of Connecticut, Massachusetts, Maine, New Hampshire, and Rhode Island. At the time of the report preparation, Vermont does not yet publish qualified resources.

[16] Some of the information included in the state databases for qualified renewable facilities is not up-to-date or accurate. Where updated information has become available, we have updated the database accordingly.

[17] January 1, 2009 Integrated Resource Plan for Connecticut page, 3-9, Table 3.2.

Table 3.7
Existing Class I Renewable Energy Resources by State, by Technology
(Nameplate Capacity in MW)

Technology	Regional Supply by State							Imports by Origin							TOTAL
	CT	*MA*	*ME*	*NH*	*RI*	*VT*	*TOTAL*	*New Brunswick*	*NY*	*NMISA*	*OH*	*PEI*	*Quebec*	*TOTAL*	***Regional Supply & Imports***
Landfill Gas	8	39	6	26	21	10	111	0	95	0	4	0	0	99	**210**
Wind	0	9	62	25	1	0	97	150	463	42	0	99	108	862	**959**
Small Hydro	5	5	13	34	1	28	87	0	0	0	0	0	0	0	**87**
Biomass/Biofuels	0	1	250	153	0	54	457	0	6	0	0	0	0	6	**463**
Offshore Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Fuel Cells	3	0	0	0	0	0	4	0	0	0	0	0	0	0	**4**
Solar PV	13	15	0	0	0	0	28	0	0	0	0	0	0	0	**28**
TOTAL MW	**31**	**69**	**331**	**239**	**23**	**92**	**785**	**150**	**564**	**42**	**4**	**99**	**108**	**966**	**1,751**

3.F.2 Supply Under Development

According to the 2009 Regional System Plan, approximately 4,300 MW of renewable energy projects are in the ISO-NE's interconnection queue.[18] This is a significant drop from the 5,800 MW of renewable energy projects in the queue as of November 7, 2008[19] without a comparable amount being completed, indicating that there is a significant attrition rate for the queued projects. In general, ISO-NE has estimated an attrition rate of about 45-60 percent for all queue projects, and 38-64 percent for wind projects in particular.[20] Since ISO-NE does not provide sufficient information regarding the identity or the status of specific projects in the queue, additional information is necessary to assess the overall status of supply under development. We have used Ventyx Energy's Velocity Suite Generating Unit Capacity database to provide the most updated project status information. Using Ventyx Energy's data, state qualifying renewable databases and our projections of solar PV penetration rate, we estimate that approximately 3,600 MW of new renewable resources are under development in New England (including the Project 150 projects in Connecticut). While we use Ventyx Energy data in analyzing each proposed project, the ISO queue attrition rate is a useful benchmark against our supply estimates (to be described in more detail below).

The Ventyx Energy information provides the cumulative MW of renewable energy projects under development, broken down by state and by technology, including offshore wind adjacent to each of the coastal states. This information is summarized in Table 3.8 below. This table shows that most of the projects currently in various stages of development are projected to be in-service by 2013. While there is a substantial amount of supply under development that has been publicly announced, there are likely other projects on the horizon that are not captured by this snapshot.

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18 2009 Regional System Plan, pages 6 and 90.

19 January 1, 2009 Integrated Resource Plan for Connecticut, page 3-9.

20 For ISO-NE's queue attrition rate, the first numbers (*i.e.* 45 percent and 38 percent) are based on number of projects whereas the second numbers are based on MWh of attrition. Source: 2009 Regional System Plan, page 91.

Table 3.8
Proposed Class I Renewable Capacity
(Cumulative Nameplate Capacity in MW)

Technology	2010	2011	2012	2013
Landfill Gas	44	74	74	74
Wind	734	1,017	1,417	1,417
Small Hydro	3	11	14	28
Biomass/Biofuels	136	411	531	615
Offshore Wind	468	912	912	1,273
Fuel Cells	67	96	96	96
Solar PV	30	60	81	103
TOTAL MW	**1,482**	**2,582**	**3,125**	**3,606**

Sources and Notes: The nameplate capacities do not depict the level of capacity contribution for Resource Adequacy purposes. Onshore and offshore wind resources are estimated to have a capacity contribution of 20 percent of nameplate capacities.

These numbers include solar photovoltaic facilities that are expected be behind-the-meter.

In addition to the supply resources obtained from the state-specific renewable qualifying databases, proposed projects from Ventyx Energy, and Connecticut's Project 150 projects, we have also included a solar supply projection based on our analysis of each state's policy objectives with a qualitative consideration for costs as a potential barrier for achieving some of the more aggressive targets. Table 3.9 below shows the details of our solar projection.

Table 3.9
Projected Solar Photovoltaic Capacity in New England
(Cumulative Nameplate Capacity in MW)

State	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
CT	19	21	22	24	25	27	28	30	31	33	34
ME	0	0	0	0	0	0	0	0	0	0	0
MA	29	44	47	53	59	66	74	83	93	104	116
RI	6	13	19	25	28	31	34	37	41	45	50
NH	3	6	11	15	22	23	23	23	24	24	24
VT	1	6	11	16	21	25	30	35	40	45	50
Total	**58**	**89**	**109**	**131**	**154**	**171**	**189**	**208**	**229**	**251**	**275**

Supplementing Table 3.8 and Table 3.9 with the amount of resources currently in service (from Table 3.7), we show in Table 3.10 the cumulative amount of Class I renewable resources that could become available, if proposed projects are all developed as planned.

Table 3.10
Cumulative Existing and Planned Class I Capacity in New England and from Imports
(Nameplate Capacity in MW)

Technology	2009	2010	2011	2012	2013
Landfill Gas	111	155	185	185	185
Wind	97	831	1,114	1,514	1,514
Small Hydro	87	91	99	101	115
Biomass/Biofuels	457	593	868	988	1,072
Offshore Wind	0	468	912	912	1,273
Fuel Cells	4	71	99	99	99
Solar PV	28	58	89	109	131
Imports	966	966	966	966	966
TOTAL	**1,751**	**3,233**	**4,333**	**4,876**	**5,357**

As indicated in the 2009 IRP, while the amount of planned renewable generation in the region is significant, not all of the planned projects will be built. Every power generation project under development faces risks associated with obtaining environmental and regulatory permits, interconnection agreements, and financing. New projects also face varying levels of local opposition, generally known as the "not in my back yard" or "NIMBY" risk. As an attempt to predict the number of MW likely to be built, we developed a probability matrix to estimate each project's likelihood of being built based on information available at the time of the report preparation.[21] The analysis assigns increasing probability to each project achieving milestones toward commercial operation. Table 3.11 below shows the probabilities that we assign to projects at various stages of development for purposes of developing a reasonable projection of renewable supply.[22] These probabilities have been updated since the submittal of the 2009 IRP.

[21] This probability matrix used in this analysis has been shared with the CCEF when we were developing the analysis.

[22] In addition to assigning a probability to proposed projects, we have also assigned a 50 percent probability to existing imports that have qualified as Class I resources in Connecticut, Massachusetts, Maine, and Rhode Island. Empirical data from Massachusetts 2007 RPS Report has been examined and in 2007, qualified imports only delivered about 41 percent of their estimated energy output potential into New England. 41 percent is derived from adding up all the qualified renewable energy (MWh) imported into Massachusetts divided by the MW qualified for Massachusetts accounting for each resource's estimated capacity factor and the date from which each resource began importing into Massachusetts.

Table 3.11
Probability Assignment for Projects Under Development

Project Status	Probability Assignment
Feasibility Study	5%
Proposed Project	15%
Application Filed for Permit	20%
Two or More Permits Approved, or Contract Signed	30%
Preparing for Construction	60%
Under Construction	75%
Testing Generator	95%
Operating	100%
Postponed	5%

In addition to the probability assignment shown in Table 3.11 above, we also increase the probability of Connecticut Project 150 by 40 percent and those for Massachusetts and Rhode Island-based projects by 12 percent. These *supplemental* probability increases are intended to indicate that those projects have strong state support and therefore may have a stronger probability of project completion.[23]

After we assign the probabilities to each project based on the information that we have gathered, we estimate the cumulative amount of new renewable generation that could be available in the market.[24] As in the 2009 IRP, the probability assignments help us to quantitatively assess the likelihood of each project reaching completion. While this approach is not intended to predict the outcome of specific projects, it provides a reasonable estimate of the likely MWs of new renewable resources entering the system each year. If some projects drop out of the development process, other new ones may take their places, and thus the total MWs after applying the probability assignment will still represent a reasonable approximation. Below in Table 3.12, we estimate that the amount of supply resources that are likely to be in service between 2010 and 2013 are likely to be sufficient to meet the region's demand. As indicated before, the actual project completion rate will depend on many other factors outside of the EDC's purview. Thus, our expectation is not meant to provide a definitive projection of supply quantity.

[23] The 12 percent for Massachusetts is set to achieve serving approximately 3 percent of Massachusetts retail load with Massachusetts-based renewable resources by 2013.

[24] The probability assignment does not help inform the likelihood of project delays, thus the timing of the projects can shift the annual supply quantity depending on the ultimate timing project in service dates.

Table 3.12
Cumulative Existing and Planned Class I Capacity
(Probability Weighted Nameplate Capacity in MW)

Technology	2009	2010	2011	2012	2013
Landfill Gas	111	131	147	147	147
Wind	97	284	316	336	336
Small Hydro	87	88	89	89	91
Biomass/Biofuels	457	479	565	584	602
Offshore Wind	0	150	270	270	367
Fuel Cells	4	18	34	34	34
Solar PV	28	58	89	109	131
Imports	483	483	483	483	483
TOTAL	**1,268**	**1,691**	**1,993**	**2,053**	**2,192**

3.F.3 Renewable Potential in New England

The most abundant renewable energy resource in New England is wind. Wind resources are most plentiful in Northern Maine, New Hampshire, Vermont, and off the coast of Massachusetts and Rhode Island. Wind resources are also abundant in New York and in the Eastern Canadian Provinces. Next to wind potential, biomass and landfill gas resources are second in magnitude. Table 3.13 below shows a summary of the renewable resource potential in each New England state, including the potential for offshore wind development.

Table 3.13
New England Renewable Resource Potential
(Cumulative Nameplate Capacity in MW)

Technology	Capacity (MW)						
	CT	MA	ME	NH	RI	VT	***TOTAL***
Landfill Gas	52	39	6	27	37	10	**171**
Wind	40	901	5,320	1,224	1	1,947	**9,433**
Offshore Wind	0	6,566	1,211	0	431	0	**8,208**
Small Hydro	6	11	97	34	5	28	**181**
Biomass/Biofuels	100	298	446	328	35	182	**1,388**
TOTAL	**351**	**7,815**	**7,080**	**1,613**	**509**	**2,168**	**19,535**

* Small hydro and landfill gas potential levels are updated to be at least as great as the MW projected for 2013.

Sources:

Onshore Wind: "Report Of The Governor's Task Force On Wind Power Development: Finding Common Ground For A Common Purpose, Final Report," State of Maine, February 2008

Onshore Wind for Connecticut: Discussion with CCEF

Offshore Wind: "Development of a Wind Power Resource Deployment Framework for Maine & New England," Bob Grace, October 30, 2007; based on NREL data

Biomass/biofuel: "Securing A Place For Biomass In The Northeast United States: A Review Of Renewable Energy And Related Policies," Xenergy, March 31, 2003; we a assumed capacity factor of 85 percent for converting MWh to MW potential.

Biomass for Connecticut: CCEF Report, Prepared by Antares Group, April 21, 2005 and discussion with CCEF

Note: The level of supply does not yet consider higher cost resources are more unlikely to be needed/built.

Table 3.13 above does not include provide resource potential for solar and fuel cells because those resources are more economic dependent than fuel resource dependent. Solar PV in theory can be installed on most rooftops, however the cost of the equipment is currently still too high for most commercial and residential electric consumers. Likewise, the cost of fuel cell generation is still too high for broad adoption.

Relative to the 2009 IRP report, the only significant changes are revisions to the resource potential for wind energy in Connecticut from 25 MW to 40 MW[25] and biomass potential in Connecticut from 235 MW to 100 MW.[26] As shown in Table 3.13, the potential for renewable development in New England is substantially larger than needed to meet the region's RPS requirements. Different potential analyses and studies may show different results, but all studies show a large potential. Thus, it is clear that the key issue in considering the amount of renewable

25 This change is based on input provided by CCEF.

26 The biomass potential has been revised after reviewing the Report commissioned by CCEF, authored by Antares and conversation with CCEF.

energy available in future years for New England is not the magnitude of the resource potential, but instead, is how much of that potential will be realized given the uncertainties around policies, economics, and market drivers for energy costs from conventional resources.

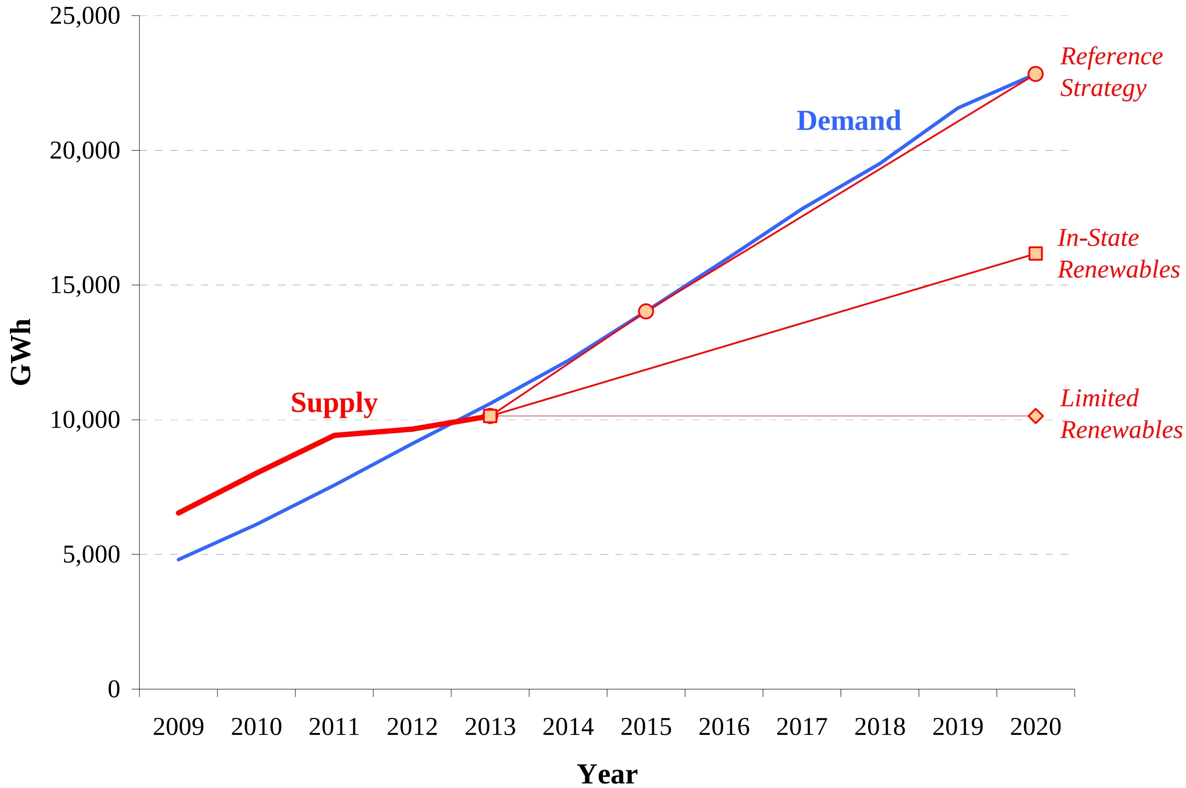
3.F.4 Supply Growth for Years Beyond 2013

In the 2009 IRP, we had taken a qualitative approach to illustrate that there are significant uncertainties about renewable supply growth for the outer years. Since then, we have improved our analytical approach and this report focuses on three future scenarios of renewable energy deployment in New England. While the details of each scenario will be described in more detail in the price curve discussion in Section 3.H, here, we provide an overview of the approach used to estimate our Reference Strategy renewable resources.

As our Reference Strategy, we show a scenario in which New England will deploy sufficient renewable energy projects to meet the region's renewable energy demand. Given the results of the ISO-NE Renewable Scenario Analysis, we expect that a significant amount of transmission upgrades will be needed to reach the region's RPS goals in years beyond 2013. To quantitatively estimate the amount of renewable energy supply in the outer years, we make three assumptions. First, we assume the deployment of biomass resources would grow toward the resource potential in each state. Second, since very limited amount of new landfill gas and small hydro are available, and because fuel cell resources would likely require explicit out-of-market support on top of REC market prices, we assume that they grow very modestly beyond the amount assumed to be developed by 2013. Third, to meet the region's aggregate RPS requirement, a significant amount of wind generation will need to be developed. Effectively, we assume that wind resources will be the "marginal" resources that fill the gap between the New England's demand and supply of renewable energy. Fourth, half of the wind projects to be built will be onshore and the other half will be deployed offshore.

Below in Figure 3.3, we show the estimated GWh of renewable resource expected to be in-service between 2010 through 2013, compared to the amount needed to satisfy the region's RPS. As indicated before, through 2013, the supply resources are estimated by weighing each proposed project by a probability of completion. For years beyond 2013, we assume that supply will be built to meet the region's overall Class I RPS requirement in the Reference Strategy. The same figure also depicts the level of renewable energy deployment and production for the In-state Renewables Strategy and the Limited Renewable Strategy. For the Limited Renewable Strategy, we freeze the renewable deployment at the 2013 level of the Reference Strategy. For the In-State Renewables Strategy, we assume all renewable deployment freezes at the 2013 level except for Connecticut-based projects, which expands to meet the Connecticut RPS requirements, yielding an increase in the overall supply level for New England.

Figure 3.3
New England Class I Renewable Resource Supply and Demand Balance
Including Qualified Imports



3.F.5 Supply External to New England

As in the 2009 IRP, we expect that the New England RPS can also be met through the purchase of RECs from external control areas, primarily New York and Canada. As indicated in Table 3.7 above, some renewable resources from New York and the Canadian Provinces have already qualified to meet the Class I renewable demand of various New England states. The potential exists for much of the New England RPS to be met with out-of-region resources if such resources can be developed and delivered more cost-effectively than New England resources. However, for this potential to be developed and its RECs used in New England, it is likely that significant transmission upgrades will have to be developed. The ISO-NE Renewable Scenario Analysis considered imports from Quebec and New Brunswick, and estimated the cost of 1,500 MW interconnections to each province (Quebec \$2 billion, New Brunswick \$1.6 billion). However, the analysis did not consider the cost and cost allocation for transmission that may be required on the Canadian side of the border, or the cost of Canadian generation. Our general conclusion is that, if added in large quantities, wind energy developed within New England, including off the shores of New England, or imported from Canada and New York will likely require substantive transmission upgrades in New England and the supplying control area(s).

3.G RENEWABLE ENERGY TECHNOLOGIES

In this section, we describe each of the renewable energy technologies available to meet New England's Class I RPS. We also discuss generally about the potential economic benefits that investments in renewable energy may provide, and compare the costs of each technology.

3.G.1 Renewable Energy Technology

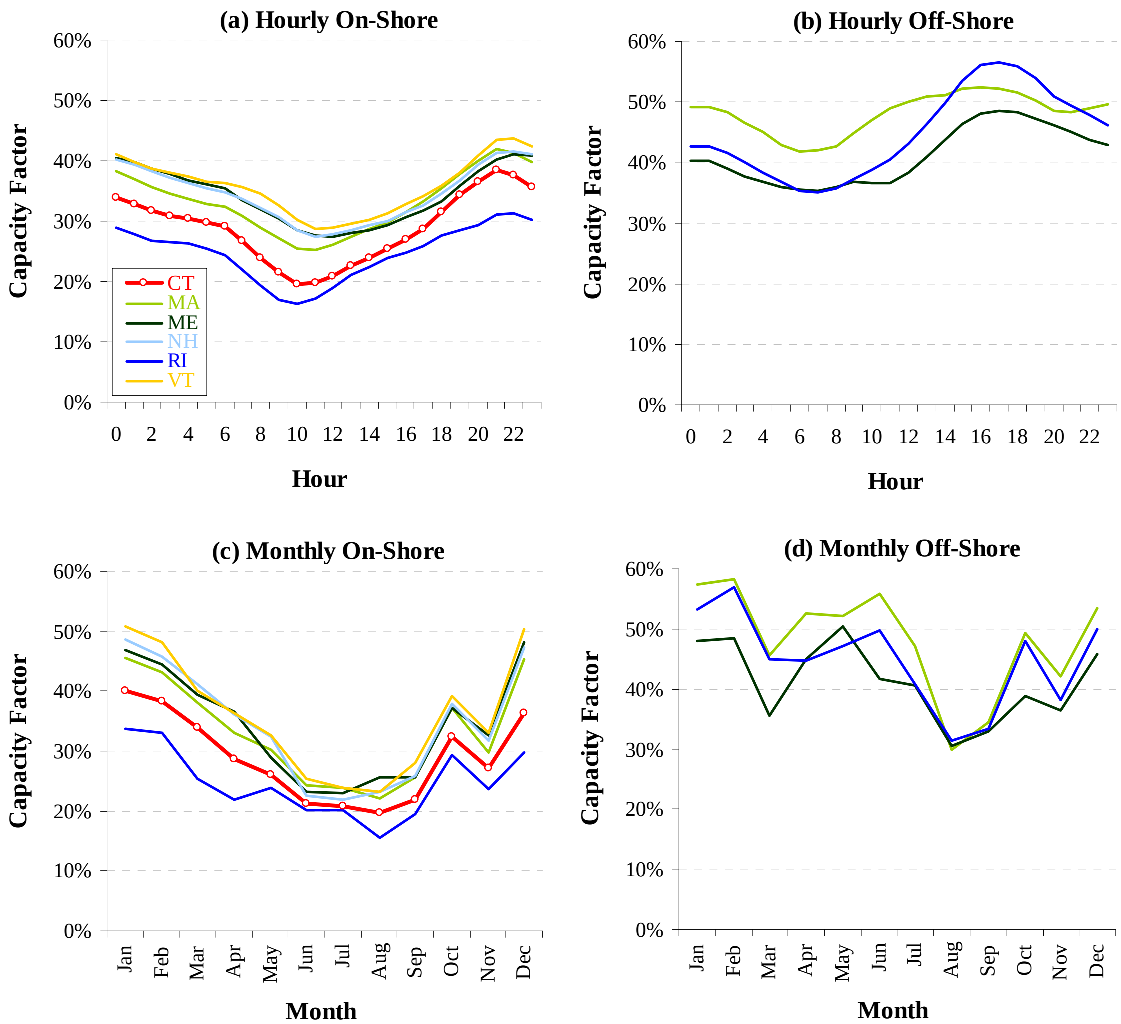
Below in Table 3.14 is a summary of the operating characteristics of renewable energy technologies.

Table 3.14
Operating Characteristics of Various Renewable Technologies

Technology	Fuel Description	Air Emissions	Operational Features	Typical Capacity Factor (in New England)	Estimated Overnight Development Cost
Landfill Gas	Methane from landfills	Similar to natural gas, but is considered carbon neutral	Can be limited by the methane produced by the landfills	85%	\$2,000 – \$2,700
Biomass	Primarily wood waste and paper mill waste	Closed loop biomass are considered carbon neutral, but emit SO2 and NOx	Can be limited by biomass availability	85%	\$2,500 – \$3,500
Small Hydro	Run-of-river	None	Weather-dependent	48%	\$3,000 – \$4,000
On-shore Wind	Wind	None	Intermittent	32%	\$2,000 – \$2,550
Off-shore Wind	Wind	None	Intermittent	37%	\$4,500 – \$5,500
Fuel Cells	Mostly natural gas in Connecticut, but can be biomass	CO2 emissions are similar to conventional natural gas	Not likely to be limited by fuel, unless using biomass	90%	\$3,500 – \$4,600
Solar PV	Solar energy	None	Intermittent	14% - 16%	\$5,200 – \$6,200

We anticipate that the largest renewable energy investment for the region is wind (both onshore and offshore). As assumed in the Reference Strategy, (and shown on Table 3.2), we anticipate about 4,000 MW of wind will be added by 2020 to meet the region's Class I renewable requirement. Adding about 4,000 MW of wind is a significant change to the resource mix in the region. Wind energy is variable in nature and with significant forecast errors in the day-ahead time frame. The variable nature of wind is shown in the following graphs. The top two graphs in Figure 3.4 show the hourly profile of the onshore and offshore wind energy production on an average day. The general hourly trend shows that the onshore wind produces the greatest energy in the night. Offshore wind seems to perform better, producing more during the afternoon peak hours.

Figure 3.4
Hourly and Monthly Wind Generation Profiles in New England (from NREL)



The bottom graphs in the same figure shows the monthly profile of the wind production. Onshore and offshore wind have the greatest production in the winter months with offshore performing relatively better than onshore wind in the spring and fall seasons. Operationally, having wind at its greatest production during off-peak hours can create or amplify over-generation conditions if existing and/or new baseload generation cannot back down in a cost-effective manner. In addition, lack of accurate forecast of the wind generation in the day-ahead time-frame could create inefficient generation commitment decisions, increase the need for regulation and load-following capabilities, and thereby raise the operational cost of the system. Some of these costs have not been quantified to date.

Natural gas fuel cells have been included as Class I renewable resources because they qualify as such under Connecticut's RPS. However, they do not offer the environmental benefits that other renewable resources provide. First, when natural gas is used, the CO_2 emissions from fuel cell power generation are similar to that from conventional natural gas power plants. Also, natural gas powered fuel cells do not reduce the region's dependency on fossil fuels.

3.G.2 Cost Comparison for Renewable Energy Technologies

Renewable energy is perceived by some as an inexpensive alternative to burning fossil fuels. In some cases, this may be true. However, there is substantial variability in the cost of renewable energy based on technology and location. Table 3.15 below shows the projected levelized cost of various renewable technologies under development or consideration in New England, ranked from the least to the most expensive REC price requirement. In this table, in column [a], we estimate the levelized all-in cost of electricity production for each technology in 2010$ per MWh of energy produced. Column [b] shows the estimated market energy revenue in 2013 (in $2010), column [c] is the estimated capacity market revenue, column [d] is the estimated levelized production or investment tax credit each technology is expected to receive, and column [e] is the sum of [b] through [d], and this is the amount of revenues that developers can expect to receive. Column [f] is the difference between [a] and [e], or the net amount of revenues needed that provide developers an opportunity to earn a reasonable return. The amount in column [f] is then the estimated REC price or other financial subsidies necessary to support each technology. The supporting input assumptions are included in Section 3.M (Appendices to the Renewable Energy Section).

Table 3.15
Estimated Cost of Energy, Revenues and REC Price (or Other Financial Incentives) for New Renewable Resources in New England
(2013 Current Trend Scenario)

Technology	Estimated Levelized Costs	Estimated Levelized Revenues				Estimated REC Price Needed
		Energy	Capacity	PTC/ITC	TOTAL	
	($/MWh)	*($/MWh)*	*($/MWh)*	*($/MWh)*	*($/MWh)*	***($/MWh)***
	[a]	[b]	[c]	[d]	[e]=[b]+[c]+[d]	**[f] = max{[a]-[e],0}**
Landfill Gas	56.6	76.6	4.3	7.2	88.0	**0.0**
Biomass/Biofuels	110.1	76.6	4.3	14.3	95.2	**14.9**
Hydro	110.0	76.6	7.6	7.2	91.3	**18.6**
Wind	112.5	76.6	2.2	14.3	93.1	**19.4**
Fuel Cells	174.4	76.6	4.1	15.6	96.3	**78.1**
Offshore Wind	199.2	76.6	2.6	14.3	93.5	**105.7**
Solar PV	520.2	76.6	9.3	120.7	206.5	**313.7**

Because the relative economics of each technology vary, one would expect that as the market prices for electricity increases, more renewable energy supplies will become economical and therefore more likely to be developed. While some renewable energy projects may be fully capable of operating profitably in the existing energy and capacity markets, others will require one or more additional financial incentives or subsidies to ensure their build-out, such as RECs, in addition to the Production Tax Credits ("PTCs") or Investment Tax Credits ("ITCs") that developers already receive from the federal government.

3.H REC PRICES

The 2009 IRP highlighted numerous uncertainties associated with the development of new renewable projects, and their potential effect on REC prices. The analysis conducted herein goes a step further by estimating the cost of RECs and associated RPS compliance through the use of supply curve analysis. This estimation is achieved by estimating the REC demand and supply balance for each year, under alternative assumptions, and setting the estimated market REC price equal to the required REC payment for the marginal technology. A key requirement of projecting the likely REC prices is to determine whether certain technologies should be considered ineligible to set the marginal REC price because they would be developed through the use of subsidies or targeted development irrespective of their required REC prices. A prime example is solar PV. With a required REC price of $314/MWh, solar PV would not be developed if energy and Class I REC markets were its primary sources of revenue. However, it appears likely that some quantity (possibly a large quantity) of solar PV will be developed over the next 10 years irrespective of the cost of development versus potential market revenues. While not perfect, this methodology does provide a reasonable estimate of the cost of RPS compliance under the resource strategies modeled.

3.H.1 Supply Curve Analysis: Reference Strategy

In Figure 3.5 through Figure 3.7 below, we show the Reference Strategy supply and demand balances for 2013, 2015, and 2020. In each of the graphs, the grey lines mark the ACPs in the region. The vertical line at which the ACP line ends marks the total demand for Class I renewable requirement for the region for each year graphed. The first graph is the supply and demand balance for Class I renewable resources for New England for the year 2013. For 2013, as described earlier, the magnitude of supply that we assume would materialize is based on weighing each proposed renewable project with an assumed probability of success based on the project status shown in the Ventyx database. We assume that the resulting resources would be built without a substantial infrastructure upgrade. Beyond 2013, we assume that for renewable projects (particularly wind) to continue to grow to meet the region's RPS, significant transmission upgrades will be necessary.

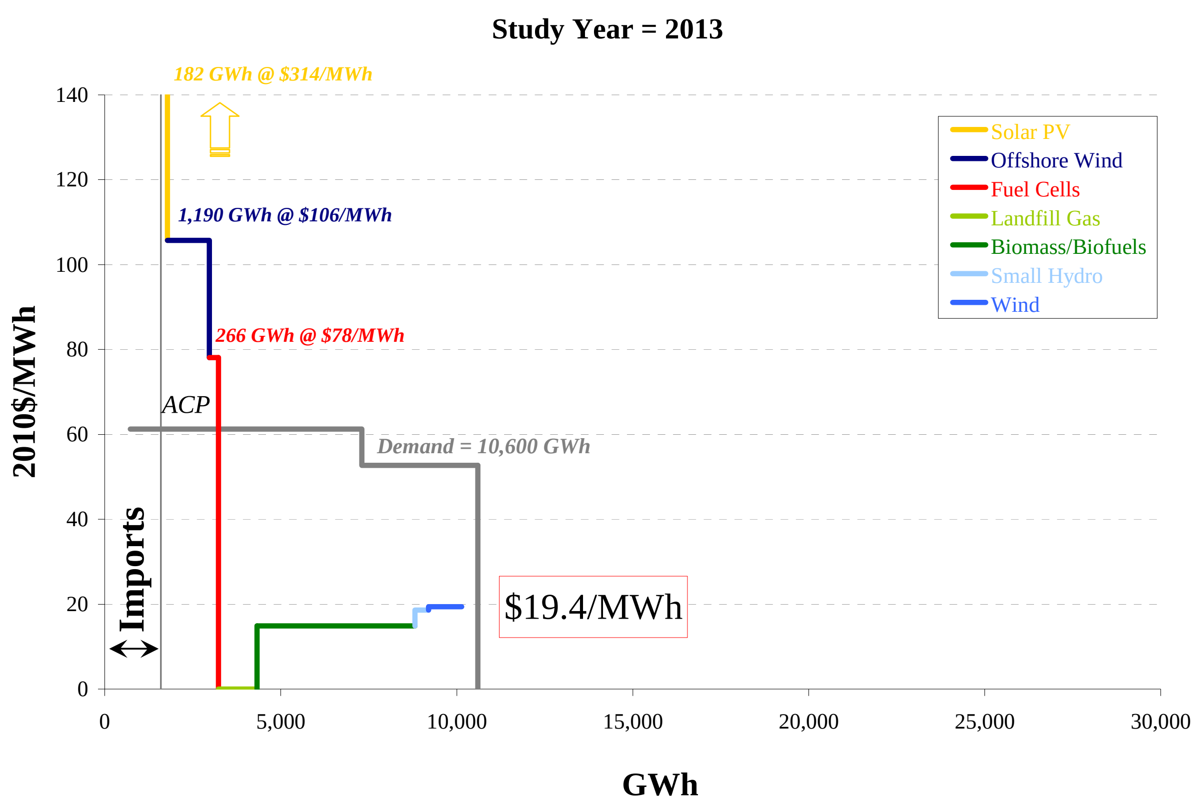
In Figure 3.5 below, the supply of each resource is shown by the colored steps. Starting from the left hand side of the graph, we first mark the renewable import amount to be approximately 1,600 GWh. Following imports, we show the price and the quantity of three resources that require out-of-market support from the states. Since we have already witnessed political pressures to encourage resources that require either REC prices above the ACP or require a higher ACP for specific technologies, we depict solar PV, offshore wind, and fuel cells as out-of-market resources. We mark these three resources on the left side of a traditional supply curve to signify that they require out-of-market support to be made available. Specifically, solar PV supply is shown as 182 GWh requiring $314/MWh of REC payment. To the right of the solar PV, we show offshore wind with approximately 1,190 GWh requiring $106/MWh of REC payment. To the right of offshore wind, we show fuel cells with 266 GWh requiring $78/MWh of REC payment.

As an example of policies that seem to support some of the out-of-market resources to be built, the Rhode Island legislation requires the local distribution company to procure at least 90MW (capacity factor weighted) of renewable resources from Rhode Island and nearby waters. The published cost for offshore wind near Rhode Island is between $200 and $300/MWh, which implies a REC payment that would be well above the current ACPs in New England. The latest cost for offshore wind for Rhode Island is approximately $240/MWh. While this cost is for a relatively small project and lower costs are expected for larger offshore project, it supports the notion that the regional ACP would not be sufficient to pay for offshore wind RECs.

Similarly, the implementation of Massachusetts' Green Communities Act is requiring Massachusetts electric distribution companies to procure renewable resources from within the state or nearby waters for three percent of Massachusetts' load. To meet that requirement, it is possible that offshore wind, even with REC payments above the ACPs would be procured and built. Thus, Figure 3.5 shows offshore wind REC supplies at payments above the ACP.

To the right of the resources that require out-of-market support, we then show the four other resources that are likely to provide RECs at prices below the region's ACPs. In increasing REC prices, we show landfill gas, biomass, small hydro, and onshore wind.

Figure 3.5
Supply Curve analysis for New England
(Current Trend Scenario, Reference Strategy)



As shown in Figure 3.5 above, after accounting for the resources likely to require out-of-market support, the remaining supply curve consists of landfill gas, biomass, small hydro, and onshore wind, with onshore wind at the margin. This means that if supply meets demand in 2013, the marginal resource, onshore wind would likely set the market price for RECs in New England. In our analysis, supply resources may be slightly short of demand in 2013. As indicated in Section 3.F above, since the supply mix for 2013 is based on our probability assessment for projects under development, we would not be completely accurate in our assessment. However, if onshore wind is the marginal resource, as we expect, the REC price under our market assumptions would be approximately $19/MWh.

Next, in the following graphs, we show the supply and demand balance for the years 2015 and 2020 under the Reference Strategy. Since in our Reference Strategy, we assume that supply will meet demand for Class I renewables in the region as a whole, we have shown the amount of each resource supply necessary to reach that assumption. In 2015, we show that, again the solar PV, offshore wind and fuel cells require out-of-market treatment, and therefore they are graphed on the left-hand side of the graphs. The rest of the renewable resources are graphed by their REC prices, showing that, once again, we anticipate onshore wind to be the marginal resource that is likely to set the region's REC price at approximately $18/MWh. The decrease in the marginal REC price is due to increases in energy and capacity revenues that renewables are expected to receive from the market, thus reducing the REC price required to pay for the renewable resources. Likewise, for 2020, under the Reference Strategy, we estimate the marginal resource, onshore wind, to set the REC price as approximately $12/MWh under our Reference Strategy, Current Trend Scenario.

Figure 3.6
Supply Curve analysis for New England
(Current Trend Scenario, Reference Strategy)

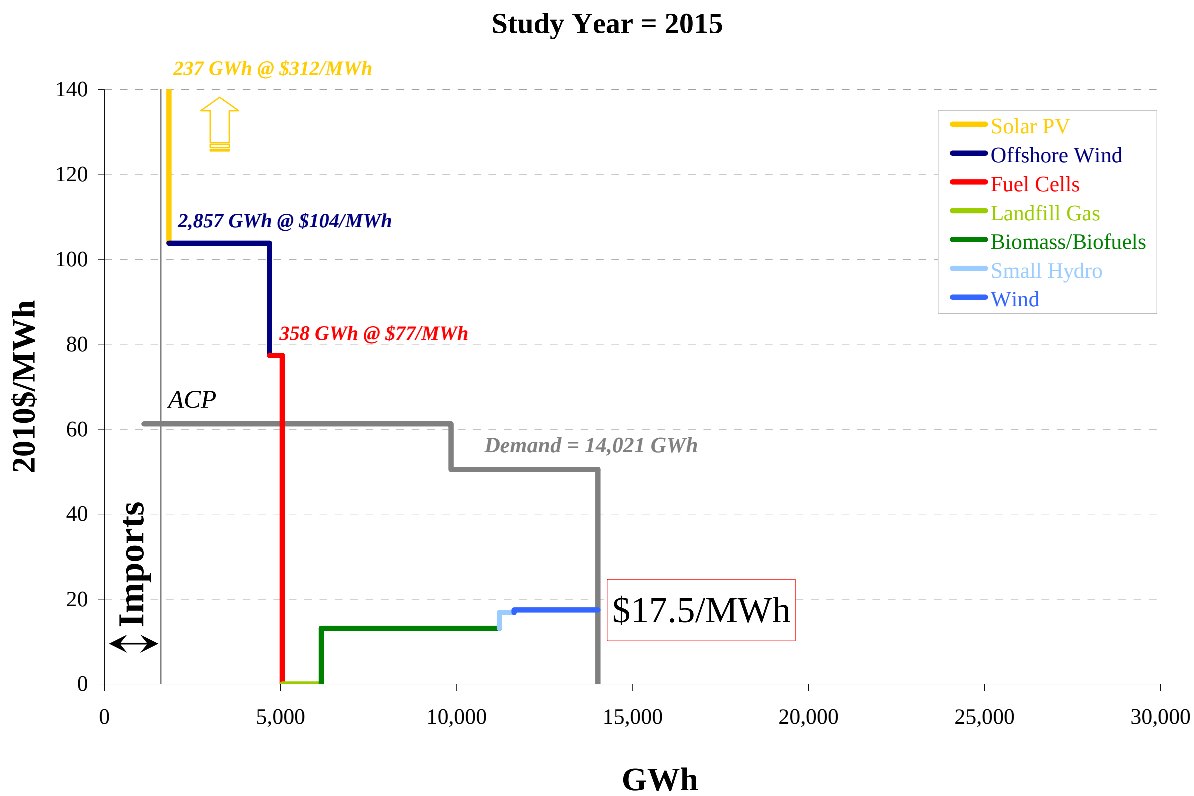
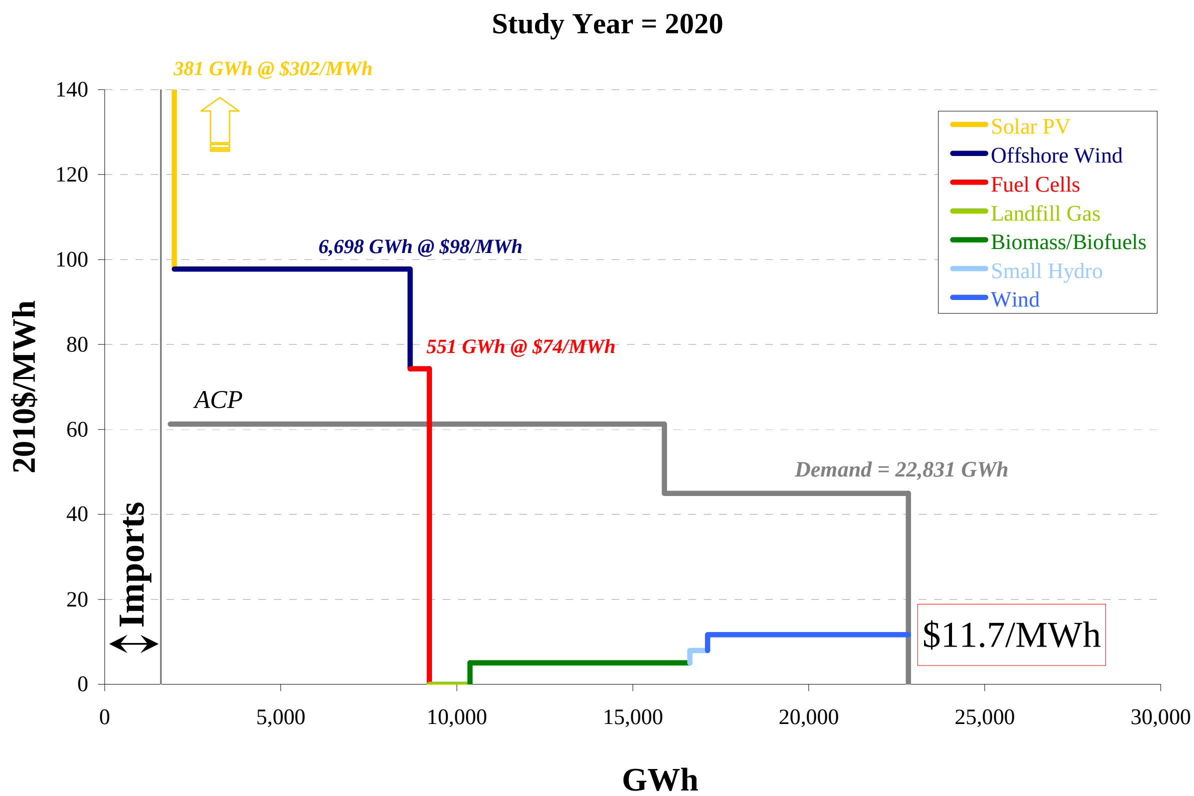


Figure 3.7
Supply Curve analysis for New England
(Current Trend Scenario, Reference Strategy)

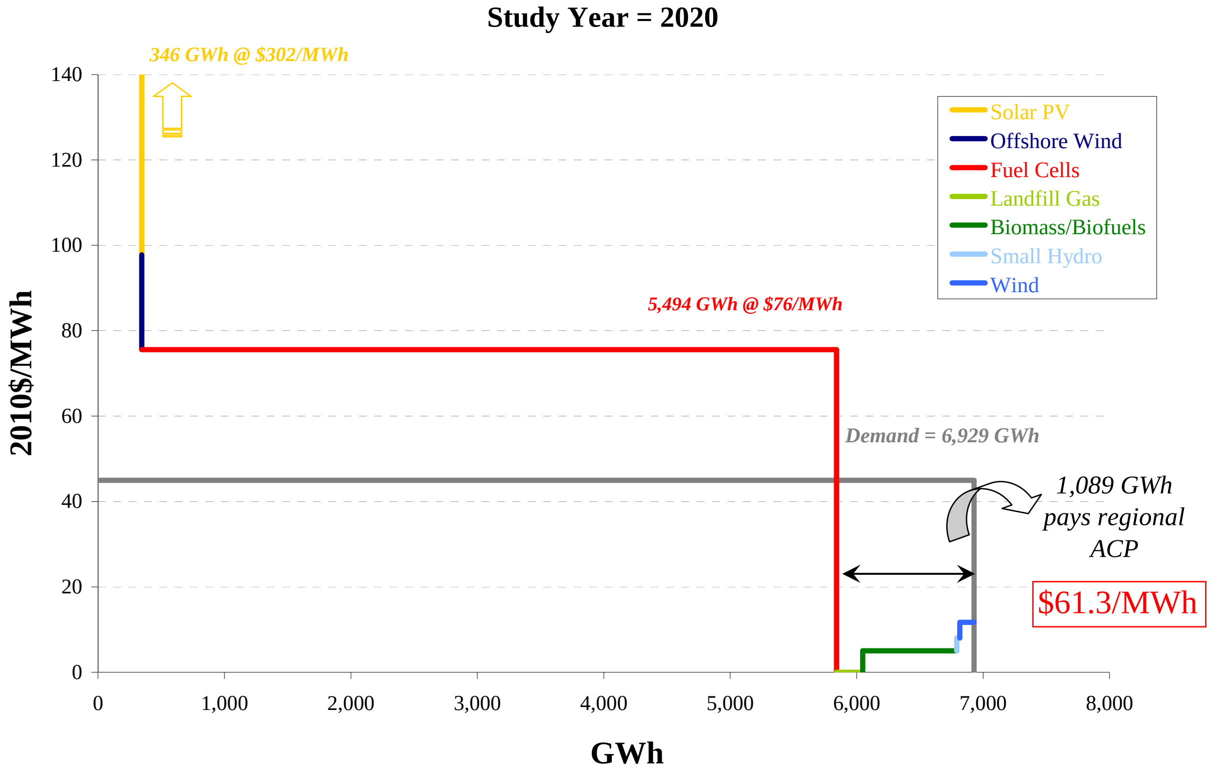


According to the Governors' Renewable Blueprint and the supporting ISO-NE documents, significant amount of transmission upgrades will be necessary to integrate thousands of MW of wind resources. Thus beyond the REC costs shown in the above figures, transmission costs would add to the customer costs. In Section 3.K below, we provide a rough estimate of the incremental transmission cost necessary to meet the region RPS, under the scenarios we have assumed in the Reference Strategy.

3.H.2 Supply Curve Analysis: In-State Renewables Strategy

Given the assumption that transmission upgrade costs will be significant, we analyzed an alternative renewable strategy where Connecticut would meet its Class I RPS with in-state resources without relying on renewable development elsewhere in New England (thus avoiding additional transmission costs). Below in Figure 3.8, we show the supply and demand balance for Connecticut's Class I renewable resources.

Figure 3.8
Supply Curve Analysis for RECs in Connecticut
(Current Trend Scenario, In-State Renewables Strategy)



For the In-State Renewables Strategy, we made several assumptions about Connecticut's renewable resource build-out. First, we assume the build-out of solar PV would be expanded aggressively. As an approximation, we assume that one percent of Connecticut's load in 2020 would be met by solar PV. Next, we assume that in-state biomass and wind close to the estimated potential will be developed. Third, we assume that the wind resources off the shore of Connecticut are not attractive enough for developers to be built.[27] Fourth, we assume that no more additional landfill gas and small hydro resources relative to the 2013 levels could be added. After maximizing the build-out of solar PV, biomass and onshore wind, the only other resource left to meet Connecticut's needs is fuel cells. Figure 3.8 shows that the remaining demand would require approximately 693 MW of fuel cells to be built in Connecticut by 2020. In addition to these resource supply assumptions, we also assume that while Connecticut decides to build in-state renewable resources to meet its RPS, the rest of New England is short of meeting the region's renewable requirement and no large incremental transmission upgrade is developed. This also means that to ensure that Connecticut-based renewables would be willing to be used as

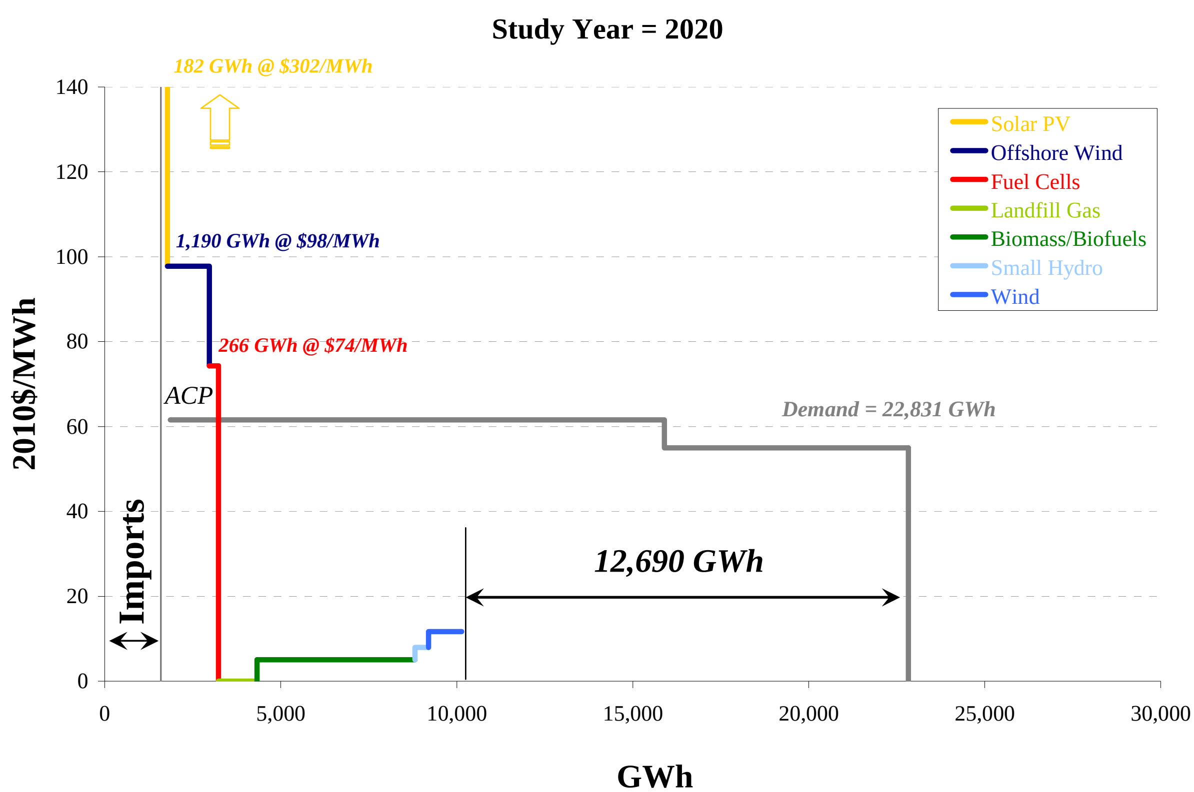
[27] This is information gathered from a developer at the 2010 CEAB Procurement Plan Review: 2010 IRP Work Session, Session on Renewable Energy, conducted on November 5, 2009 (presentation materials are available at http://www.ctenergy.org/2010ProcurementPlan.html).

Connecticut REC, instead of selling to other states that would be willing to pay up to the other states' ACP, the market clearing price for RECs would be at least the regional ACP.

3.H.3 Supply Curve Analysis: Limited Renewable Development Strategy

In the third renewable strategy, we explore the scenario in which insufficient renewable resources are constructed in New England. In Figure 3.9, we show that the region is short of the region's Class I Renewable Energy demand by approximately 12,690 GWh in 2020. More specifically, as depicted by Figure 3.9 below, we have assumed the same amount of resources would be built as in the year 2013 in the Reference Strategy. While it is likely that some resources may continue to grow slightly, we use this scenario to depict the cases in which New England would be significantly short of the region's renewable demand. Under such a situation, Connecticut utilities turn to paying the ACP for the portion of the RPS requirement that is not met with out-of-market resources. Under this case, any regional shortfall in energy and capacity supply is met by new combine cycle gas generation.

Figure 3.9
Supply Curve Analysis for New England
(Current Trend Scenario, Limited Renewable Strategy)



3.H.4 Potential Effects of Natural Gas, CO2 Prices and Load Growth on REC Prices

Two other factors that are very likely to influence the development of renewables are the future cost of natural gas and carbon emissions allowances and impact of that cost on energy market prices. Specifically, the impact of gas and CO_2 prices on the energy price in the wholesale market would affect the energy margin that renewable resources would receive from the wholesale market, which in turn would reduce the REC prices necessary to pay for the all-in costs of the renewable energy.[28] In general, high gas and CO_2 prices allow renewables to be more competitive and would require lower REC prices from the market. Likewise, capacity payments that renewable resources receive from the capacity market also affect REC prices. In our simulation, as load grows, we anticipate that capacity prices increase, and thereby decrease the REC prices needed by the renewable resources.

Table 3.16 below is a modified form of Table 3.15 that demonstrates the impact of varying gas, CO_2 prices, and load growth assumptions on the REC payments necessary for each renewable technology. As this table shows, we estimate that increasing gas and CO_2 prices would increase the average energy price in New England which in turn reduces the necessary REC payment for each technology. To clarify, Table 3.16 does <u>not</u> show the market-clearing prices for RECs. Instead, the table summarizes the REC payments <u>necessary</u> for each technology (under each scenario and year) to pay for the return on and of capital of the investors and the on-going costs to operate those generating resources. Under the High Load Scenarios, REC payments required are lower than those in the Current Trends because capacity prices have increased to reduce the REC payment needed for each technology.

[28] Fuel cell fired by natural gas may need to purchase emissions allowances which would increase their operating costs.

Table 3.16
Estimated Required REC Payments for New Renewable Resources in New England
(Across Scenarios for 2013, 2015 and 2020)

Technology	Year	Current Trends *(2010$/MWh)*	Lo Gas/Lo CO2 *(2010$/MWh)*	Med Gas/Hi CO2 *(2010$/MWh)*	Hi Load *(2010$/MWh)*	Hi Gas/Hi CO2 *(2010$/MWh)*
Landfill Gas	2013	0.0	0.0	0.0	0.0	0.0
Landfill Gas	2015	0.0	0.0	0.0	0.0	0.0
Landfill Gas	2020	0.0	0.0	0.0	0.0	0.0
Biomass/Biofuels	2013	14.9	26.2	9.7	12.9	0.0
Biomass/Biofuels	2015	13.1	26.8	7.3	10.2	0.0
Biomass/Biofuels	2020	5.0	21.9	0.0	3.0	0.0
Hydro	2013	18.6	29.7	14.4	16.7	3.2
Hydro	2015	16.8	30.2	12.1	14.0	0.0
Hydro	2020	8.0	23.1	0.7	7.2	0.0
Wind	2013	19.4	30.6	15.1	17.4	3.7
Wind	2015	17.5	31.0	12.7	14.6	0.0
Wind	2020	11.7	27.6	3.4	8.8	0.0
Fuel Cells	2013	78.1	86.5	78.7	76.1	67.3
Fuel Cells	2015	77.4	87.8	78.3	74.5	64.7
Fuel Cells	2020	74.3	85.6	74.5	72.1	60.9
Offshore Wind	2013	105.7	116.9	101.5	103.7	90.0
Offshore Wind	2015	103.8	117.3	99.0	100.9	85.4
Offshore Wind	2020	97.8	113.7	89.6	95.0	75.6
Solar PV	2013	313.7	324.6	309.4	311.7	298.2
Solar PV	2015	311.9	325.2	307.2	309.1	293.7
Solar PV	2020	302.1	317.0	295.1	302.0	282.8

As Table 3.16 shows, landfill gas, biomass, small hydro, and wind resources are expected to require REC payments below the Connecticut ACP, and therefore do not require additional subsidies from the EDCs or the states. However, fuel cells, offshore wind, and solar PV require payments above the Connecticut ACP across all Scenarios. This suggests that out-of-market payments are required to induce the development of the latter three resources. In fact, we already witness some out-of-market arrangements for fuel cells, offshore wind, and solar PV in the form of long-term contracts outside of the REC market and RPS "carve-outs" for solar (which require a certain amount of solar build-out).

3.I Renewable Energy Development Mechanisms

There are many mechanisms that could be used to encourage the development of renewable facilities. The four mechanisms listed below are listed in a general order of preference, although it would likely be appropriate to blend these mechanisms to ensure the most efficient and certain expansion of renewables, and to avoid scenarios where renewable development deviates from demand to the point where there is either a shortage or glut of RECs.

3.I.1 Market-Based Renewable Expansion

There are organized markets that are designed to encourage the development of renewable energy. In addition to the ISO-NE administered energy and capacity markets, each state has an RPS with ACPs exceeding $50/MWh for Class I resources. Ideally, in a market-based environment, these markets should produce the price support necessary to allow for the financing and development of renewable facilities. The EDCs believe that market development of new renewables is the optimal way to meet state and regional RPS targets. For the market to achieve this goal, it is essential that the RPS requirements of the New England states remain consistent and viable. Developers would likely shy away from building renewable generation in New England if there were a lack of confidence in the continuation of regional RPS laws and regulations (including the continued allowance of REC banking to help balance supply and demand).

Despite the presence of these markets, there is substantial uncertainty regarding whether the market will build enough renewable resources to meet regional RPS targets. Many believe that reliance on markets alone will not result in renewable targets being met, and thus additional measures must be taken.

The 2009 IRP discussed the risks and uncertainties associated with obtaining environmental and regulatory permits, interconnection agreements and “NIMBY” risk for renewable energy developers. These risks and uncertainties remain valid today, however the development of renewables on New England soil appears to be very favorable in the political arena, and the development of additional subsidies to encourage development is possible.

3.I.2 State Financing of Renewable Energy

An approach that has not been discussed in previous IRPs is to increase the level of state assistance in the development of both in-state and out-of-state renewables. This action could be taken by some or all of the states in the region. This assistance could be funded either directly from the state or through charges to electric customers. Connecticut currently provides a level of this support by utilizing funds collected through the renewables charge currently included in electric rates and used for the many programs supported by the CCEF. Opportunities for state investment include:

- Increasing the renewable charge to electric customers to provide additional funds;
- Using ACP payments to provide additional support (please note that ACP payments could increase substantially if renewable development lags behind that envisioned in the RPS);
- Providing grants of state funds to support the economic development that may result from renewable construction and operation;
- Providing loans at the lower interest rates available to state agencies;
- Providing loan guarantees to project developers:
- Purchasing RECs; or

- Facilitation of a REC trading markets in a manner that provides a floor price.

These options all have the advantage that the EDCs may not be required to enter into long-term contracts, which could avoid some of the potential adverse impacts discussed in Section 3.I.3 below. The EDCs suggest that any process of this nature be subject to approval by the Connecticut Department of Public Utility Control to be sure that they are vetted in a public process.

3.I.3 Long-Term Contracts

The 2009 IRP discussed the use of long-term contracts at length and presented two primary recommendations: first, the EDCs should conduct periodic market solicitations to procure RECs, and/or bundled RECs, energy and capacity under long-term contracts; and second, to ensure that consumers benefit from cost-effective renewable supplies, there should not be a mandate for EDCs to enter into long-term contracts. Long-term contracts for bundled energy, capacity and RECs have the potential to assist in compliance with the RPS at a price lower than the ACP. However, for long-term contracts to provide these benefits they must be cost-effective. Mandatory contracting tends to raise prices because sellers know that the buyer does not have the option of rejecting all offers if they are uneconomic, and as such it should be avoided when it is not driven by a clear reliability need.

The EDCs are generally looked to as the "default" buyers under long-term contracts by virtue of their status as the entities connected to load. EDCs in Connecticut have been required to sign long-term contracts as the result of three separate legislative initiatives, including Project 150. The resulting contracts from these three programs are priced significantly above the market on a cumulative basis. One aspect of long-term contracting that should be considered is the potential adverse financial impact on the buyer. Accounting rules governing long-term contractual commitments include: (i) the need to disclose projected payments under these contracts, (ii) under certain circumstances, the need to record a capital lease or a derivative or to consolidate the supplier on the EDCs' balance sheets. Absent legislative and regulatory protections, requiring EDCs in Connecticut to procure long-term power under contracts could require on-balance-sheet accounting treatment or create a risk that rating agencies impute the present value of these purchases as debt when they conduct the next credit review of the EDC. It is also conceivable that rating agencies could treat a tariff in similar context to that of a contract. The presence of additional debt at the EDC through accounting guidance or rating agency imputation would likely place downward pressure on the EDCs' financial ratios and credit ratings that would potentially affect the EDCs' ability to meet bond covenants and raise new capital for infrastructure improvements, and which as a result could raise customer rates over the long-run.

3.I.4 The EDCs as Developers of Renewable Energy

The 2009 IRP concluded that the EDCs should be considered as alternate developers of renewable energy facilities if the market does not respond with cost-effective contracts at prices that approximate a renewable generator's costs. This conclusion remains valid in that allowing the EDCs to be the developers of last resort will help to ensure the development of renewable facilities if neither of the options discussed above are successful.

There are other reasons to consider the EDCs as potential developers and owners of renewable energy facilities. First, the facilities can be used for the benefit of customers throughout its operating life. Conversely, facilities that are financed by virtue of a long-term contract will operate for the benefit of the owner for any remaining operating life after the contract terminates. These benefits to the owner may be substantial, since debt associated with the original financing for the project may be paid off during the contract term. Second, as is discussed above, long-term contracts have the potential to adversely impact the financial health of the EDCs, particularly as long-term contractual commitments increase relative to the EDCs' size. EDCs do not face the same issues with resources that are developed and owned in rate base. Third, the development of smaller renewables within EDC service territories (typically sited at customer or EDC owned facilities) can be achieved with economies of scale by the EDCs, as well as cost savings associated with rate basing and cost of service pricing. This is particularly true with respect to resources that are out-of-market and require subsidies to be cost-competitive (*e.g.*, solar PV or fuel cells). On the flip side, the EDCs would need to bear the risks associated with construction and long-term operations, which could be substantial. Thus, the EDCs are not advocating EDC development of renewables as a primary strategy, but if it becomes evident that the market is not developing renewables without the extensive use of long-term contracts, it should be considered as an option.

3.J RENEWABLE ENERGY AND ECONOMIC DEVELOPMENT

One of the policy goals commonly associated with renewable energy is economic development. Adding renewable energy facilities in the state and region could create jobs both for construction and for ongoing operation and maintenance of facilities. While economic development is obviously good, the economic benefit of adding "green" jobs in the renewable energy sector could be outweighed by the adverse impact of higher energy rates for all other businesses if the subsidies or investments are too costly and cause a financial burden in the form of higher rates or taxes to subsidize renewable development. These unintended consequences could result in net negative economic development. This is a tightrope challenge that policy-makers face, and it is important that the tightrope be traversed carefully, particularly given the already high electric rates in Connecticut. The EDCs recommend that caution be exercised before establishing further renewable development policies under the auspices of economic development.

3.K CAPITAL COST FOR RENEWABLE RESOURCES AND ASSOCIATED TRANSMISSION

Adding renewable resources provide significant benefits, particularly environmental benefits discussed in Section Table 3.17. Above in Section 3.C.4, we have already discussed the potential customer costs associated with each strategy. Those customer cost metrics incorporate the full impact of wholesale energy, capacity and REC market dynamics, plus out-of-market payments for fuel cells and solar PV, and Connecticut's portion of the transmission upgrades necessary in the Reference Strategy. In this section, we estimate the total capital needed to support the renewable build-out in the Reference Strategy.

Table 3.17
Estimated Capital Costs
Associated with Incremental Renewables Additions in New England,
Excluding Transmission
(Reference Strategy)

Scenario	Overnight Cost for Incremental Renewable Supply *($Million)* [a]	Capital Charge Rate *(%)* [b]	Annualized Capital Cost *($Million/year)* [c] = [a]×[b]
2015			
Current Trends	8,624	11.2%	967
Lo Gas/Lo CO2	9,848	11.2%	1,104
Med Gas/Hi CO2	8,298	11.2%	930
Hi Load	9,678	11.2%	1,085
Hi Gas/Hi CO2	7,093	11.2%	795
2020			
Current Trends	19,445	11.2%	2,180
Lo Gas/Lo CO2	21,638	11.2%	2,425
Med Gas/Hi CO2	18,727	11.2%	2,099
Hi Load	22,106	11.2%	2,478
Hi Gas/Hi CO2	16,613	11.2%	1,862

Table 3.17 above shows an estimate of the annual capital cost associated with developing the amount of renewables needed in New England under the Reference Strategy. Specifically shown in the table, we estimate the total capital needed under each scenario by adding up the installed cost of each technology by the cumulative MW amount installed by year 2015 and 2020 (shown in column [a]). Next, we estimate the annual capital charge rate of private developers to be approximately 11.2 percent (shown in column [b]). Overall, by year 2020, we estimate that the total capital necessary to support the new Class I renewable resources in New England is in the range of $17 to $22 billion, with an annual capital carrying cost of about $1.9 to $2.5 billion (in column [c]). The numbers in Table 3.17 are only the capital costs associated with the renewable generation assumed in the Reference Strategy. Much of this cost would be paid for through revenues from the energy and capacity markets, with the rest paid for through REC payments and/or out-of-market instruments. As pointed out before, these capital investments would bring about significant environmental benefits. Nevertheless, it is still important to take note the large estimated upfront capital investment necessary to meet the region's RPS.

As was noted in the 2009 IRP, while some biomass, landfill gas, and small hydro resources are available in New England, the greatest renewable potential in New England is from wind. Currently, more than 1,400 MW of onshore wind and about 1,300 MW of offshore wind projects are in the development phase in New England. The onshore wind projects are located mostly in Northern New England. As ISO-NE indicated in its 2009 Regional System Plan, "Interregional planning activities will become increasingly important to ensure the coordination of studies of the widespread growth in the use of renewable resources throughout the United States and Canada and the transmission projects that may be needed to access the remote development of these resources."[29] While we cannot be certain at this point exactly how much of the regional renewable targets can be met without significant transmission investments, it is safe to say that at least a portion of the proposed renewable projects will not be built if cost-effective and adequate transmission solution cannot be provided. For this IRP, we have assumed the transmission cost associated with accommodating renewable build-out (particularly wind) to be $3,125/kW of wind installed beyond the 2013 amount. The $3,125/kW cost is the midpoint of the estimated transmission cost associated with a 2,000 MW of onshore and 2,000 MW of offshore wind build-out case (in 2009$) from the ISO-NE's Renewable Scenario Analysis.[30] We understand that ISO-NE's high transmission cost is likely to be associated with a relatively robust transmission over-lay system and perhaps an incremental transmission expansion plan for integrating renewables may cost significantly less than those estimates. Furthermore, we have made a simple assumption that the magnitude of transmission upgrade is dependent on the nameplate capacity of wind resources added to the system, without considering the time of transmission usage from wind resources or the economic tradeoff between curtailing some wind output as opposed to sizing the transmission to accommodate the peak wind generation output. While the cost of new transmission is dependent on the amount of new renewables in this IRP, the transmission of course would be available to transmit any other energy as well, and would improve overall reliability. For the reasons discussed above, we believe that the customer costs for the Reference Strategy are slightly more conservative (higher than they would be if a lower transmission cost is assumed) than the customer costs for the two alternative renewable strategies.

Since we have not conducted a full transmission engineering analysis for renewables, we do not know precisely how much renewable energy can be integrated onto the ISO-NE's system without significant transmission upgrades. However, we make the assumption that any incremental transmission upgrades associated with the renewable growth to meet the region's 2013 RPS does not significantly change between the scenarios. Thus, we did not incorporate any *incremental* transmission cost associated with meeting RPS through 2013 in any of the cases. For years beyond 2013, the transmission costs in the Reference Strategy are estimated using a levelized annual fixed cost equivalent to the $3,125/kW of wind added. Below in Table 3.17, the annual transmission cost and associated calculations are shown.

[29] 2009 Regional System Plan, ISO-NE, page 160.

[30] The midpoint between $10.7 billion and 414.3 billion is $12.5 billion. These transmission cost estimates are shown in ISO-NE's Renewable Scenario Analysis with 2,000 MW on-shore and 2,000 offshore wind build-out scenario. $12.5 billion divided by 4,000 MW of new wind installed is $3,125/kW of wind. We then escalate this cost from 2009$ to 2010$ in the quantitative analysis.

Table 3.18
Estimated Transmission Costs
Associated with New Wind Installations in Reference Strategy Scenarios

Scenario	Incremental Wind Capacity	Unit Transmission Cost	Total Transmission Cost	Capital Charge Rate	Annualized Transmission Cost	Connecticut's Load Share	Transmission Cost Allocated to Connecticut
	(MW)	*($/kW)*	*($Million)*	*(%)*	*($Million/year)*	*(%)*	*($Million/year)*
	[a]	[b]	[c]=[a]×[b]/1000	[d]	[e] = [c]×[d]	[f]	[g] = [e]×[f]
2015							
Current Trends	1,029	3,137	3,227	12.5%	403	24.4%	**98**
Lo Gas/Lo CO2	1,331	3,137	4,177	12.5%	522	24.4%	**128**
Med Gas/Hi CO2	948	3,137	2,974	12.5%	372	24.4%	**91**
Hi Load	1,289	3,137	4,044	12.5%	505	24.0%	**121**
Hi Gas/Hi CO2	650	3,137	2,039	12.5%	255	24.4%	**62**
2020							
Current Trends	3,399	3,137	10,662	12.5%	1,333	24.1%	**321**
Lo Gas/Lo CO2	3,942	3,137	12,367	12.5%	1,546	24.1%	**373**
Med Gas/Hi CO2	3,220	3,137	10,103	12.5%	1,263	24.1%	**304**
Hi Load	4,058	3,137	12,730	12.5%	1,591	23.4%	**373**
Hi Gas/Hi CO2	2,696	3,137	8,459	12.5%	1,057	24.0%	**254**

Note: The High Load scenarios use the annual GWh for each state specified in ISO-NE's CELT Report. The change in Connecticut's load share is then derived from the Connecticut's annual GWh load relative to ISO-NE's total. We use this metric as a proxy for the 12-Coincident Peak portion that is typically used in cost allocations for pool transmission resources.

As Table 3.18 shows, we estimate the transmission cost based on the incremental amount of wind resources (including onshore and offshore) added to the system beyond the 2013 levels (shown in column [a]). We use the escalated transmission cost of $3,137 per kW (from 2009$ to 2010$) of wind added (in column [b]). Column [c] shows that the total estimated transmission cost is about $2.0 to $4.2 billion by 2015 and $8.5 to $12.7 billion by 2020. The annual capital charge rate of 12.5 percent (in column [d]) is estimated based on the EDCs' cost of capital, with a property taxes and fixed maintenance costs adder necessary for transmission. In column [e], we estimate the annual capital carrying charge required for the transmission upgrades to be in the range of $1.1 to $1.6 billion per year by 2020, to support the renewable development Reference Strategy. Columns [f] and [g] estimates the amount of transmission cost that could be allocated to Connecticut customers if the cost were allocated on a load-share basis.

While the environmental benefits of renewables are substantial and of the three renewable strategies examined, pursuing the Reference Strategy is the best, we anticipate that the capital necessary to support such a strategy is also significant. Thus, again, the EDCs suggest that policy makers think comprehensively about setting renewable policies and Connecticut should work with the other New England states to define the best means to expand renewable energy development in New England and the surrounding regions.

3.L ENVIRONMENTAL BENEFITS OF RENEWABLE ENERGY

The development of renewable energy generation is largely driven by concern for the environment. The use of renewable energy can help reduce the overall air pollution resulting from the burning of fossil fuels and thereby reduce climate change and other major adverse environmental impacts.

As shown in previously in Table 3.4, the environmental benefit associated with building sufficient renewables to meet the region's RPS is significant. In all scenarios, the estimated CO_2 emission is between 10 to 20 percent less in the Reference Strategy than in the alternative renewable strategies. Comparing the Reference with the Limited Renewable Buildout Current Trend Scenarios, we can attribute the change in CO_2 emission primarily to the amount of renewable energy added. A simple calculation shows that for every incremental MWh of renewable energy generated, approximately 0.43 tons of CO_2 emission is avoided. Below in Table 3.19, the average amount of CO_2 emissions avoided under each scenario is estimated.

Table 3.19
Impact of Renewables Additions on System CO_2 Emissions (2020)

Scenario	**Total Renewable Generation**			**CO2 Emissions**			**Avoided CO2 Emission per MWh of Renewables Added**
	Reference Strategy	Limited Renewables	Difference	Reference Strategy	Limited Renewables	Difference	
	(GWh/yr) [a]	*(GWh/yr)* [b]	*(GWh/yr)* [c]=[a]-[b]	*('000 tons/yr)* [d]	*('000 tons/yr)* [e]	*('000 tons/yr)* [f]=[d]-[e]	*(tons/MWh)* [g]=[f]/[c]
Current Trends	22,830.7	10,140.2	12,690	36,562	42,021	-5,459	-0.43
Low CO2 and Low Gas	24,476.0	10,141.4	14,335	36,483	42,263	-5,780	-0.40
Reference Gas and High CO2	22,291.4	10,139.9	12,151	32,456	37,249	-4,792	-0.39
High Load Growth	24,826.3	10,141.3	14,685	42,106	47,970	-5,864	-0.40
High Gas and High CO2	20,705.6	10,138.7	10,567	33,655	39,298	-5,643	-0.53

While the costs of emissions are incorporated in estimating the overall customer costs in the three renewable strategies, Table 3.3 above in Section 3.C also shows that a change in those costs can significantly alter the customer costs. This means that if the CO_2 price becomes higher than that is assumed in the High CO_2 scenarios, the potential customer costs associated with building the non-emitting renewable technologies may be less than anticipated.

3.M APPENDICES TO THE RENEWABLE ENERGY SECTION

Table 3-A.1
Cost Assumptions for Renewable Technologies
(Used in support of Tables 3.15, 3.16, and 3.17)

Technology	Installed Cost *(2010$/kW)*	Fixed O&M Cost *(2010$/kW-yr)*	Variable O&M Cost, Excluding Fuel Cost *(2010$/MWh)*	Heat Rate *(Btu/kWh)*
Landfill Gas	2,639	118.6	0.0	10,500
Biomass/Biofuels	2,931	66.9	7.0	14,000
Hydro	3,730	24.4	5.6	N/A
Wind	2,540	30.5	0.0	N/A
Fuel Cells	4,573	2.2	37.3	8,000
Offshore Wind	5,487	30.5	0.0	N/A
Solar PV	6,200	25.0	0.0	N/A

Cost Data Sources:

Landfill Gas: Assume Overnight Cost as Installed Cost; Overnight Cost: Energy Information Administration, Annual Energy Outlook 2009, New Generation Assumptions, Table 8.2, escalated from 2007$ to 2010$. Fixed O&M, Variable O&M, and Heat Rate: ISO-NE Final Scenario Analysis Assumptions, May 21, 2007 Page 8, in 2006$.

Biomass: Installed Cost: ISO-NE Final Scenario Analysis Assumptions, May 21, 2007 Page 8; range of $2500-$3500/kW in 2006$. Fixed O&M, Variable O&M, Heat Rate: Energy Information Administration, Annual Energy Outlook 2009, New Generation Assumption, Table 8.2, escalated from 2007$ to 2010$.

Small Hydro: Installed Cost: ISO-NE Final Scenario Analysis Assumptions, May 21, 2007 Page 8; mid-point of $3000-$4000/kW in 2006$. Fixed O&M, Variable O&M: Massachusetts Renewable Energy Potential, Final Report," Prepared for Massachusetts Department of Energy Resources (DOER) and Massachusetts Technology Collaborative (MTC), August 6, 2008, page 96, in 2008$.

On-shore Wind: Installed Cost, Fixed O&M, Variable O&M: Massachusetts Renewable Energy Potential, Final Report," Prepared for Massachusetts Department of Energy Resources (DOER) and Massachusetts Technology Collaborative (MTC), August 6, 2008, page 68, $2500/kW in 2008$.

Off-shore Wind: Installed Cost: Massachusetts Renewable Energy Potential, Final Report," Prepared for Massachusetts Department of Energy Resources (DOER) and Massachusetts Technology Collaborative (MTC), August 6, 2008, page 75, $5400/kW in 2008$. Fixed O&M and Variable O&M assumed to be the same as Fixed O&M and Variable O&M for On-shore Wind, in 2008$.

Fuel Cell: Installed Cost: EPG Fuel Cell, LLC Comments on CCEF Motion for Refreshed Project Bids," Connecticut DPUC Docket No. 08-03-03. Fixed O&M: Cost of Electricity Generation, June 12, 2007, Navigant; page 81, $2.1/kW-yr in 2006$. Variable O&M: Cost of Electricity Generation, June 12, 2007, Navigant; page 81, $35/MWh in 2006$. Heat Rate: ISO-NE Final Scenario Analysis Assumptions, May 21, 2007 Page 8; 8,000Btu/kWh.

Solar PV: Installed capital cost, Fixed O&M: National Renewable Laboratory's Solar Advisor Model, Version 2009.10.13, set to Massachusetts, Commercial PV system.

Table 3-A.2
Capital Charge Estimation Assumptions for Renewable Technologies
(Used in support of Tables 3.15, 3.16, and 3.17)

Operating Life (Years)	20
Tax Depreciation Schedule	5yr SLD
Debt Rate	7.0%
Equity Rate	15.00%
Debt Fraction	50.0%
Effective Tax Rate	42.5%
Inflation Rate	2.1%
ATWACC	9.5%
ATWACC Real	7.3%
Resulting Capital Charge Rate	11.21%

Table 3-A.3
Solar Build-Out Assumption and Related References
(Used in support of Table 3.9)

State	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
CT	13	19	21	22	24	25	27	28	30	31	33	34
ME	0	0	0	0	0	0	0	0	0	0	0	0
MA	15	29	44	47	53	59	66	74	83	93	104	116
RI	0	6	13	19	25	28	31	34	37	41	45	50
NH	0	3	6	11	15	22	23	23	23	24	24	24
VT	0	1	6	11	16	21	25	30	35	40	45	50
Total	**28**	**58**	**89**	**109**	**131**	**154**	**171**	**189**	**208**	**229**	**251**	**275**

Sources and Notes:

CT: MW in 2010 is equal to 19.11 MW of installed and in-progress residential and commercial solar PV. MW (cumulative) in years post-2010 are equal to existing capacity in 2010 plus 1.5 MW per year of estimated new solar PV installations. Data vetted with CCEF.

ME: No solar carve-out in RPS. No additional goals for solar in place.

MA: MWs in 2010 through 2012 are equal to cumulative installations as a result of Utility Ownership and Federal Stimulus Programs + installations resulting from the Commonwealth Solar Rebate Program, administered by MTC. MWs (cumulative) in years post-2012 are increased by average annual growth rate of about 12 percent.

RI: MWs between 2010 and 2013 are derived from linear interpolation between 0 MW in 2009 and 25 MW in 2013. MW in 2013 is equal to 25 MW (3 MW capacity value) of in-state solar PV required under RI's Long-Term Contracting Standard for Renewable Energy per Rhode Island House Bill H 5002, enacted June 26, 2009. MWs in years beyond 2013 increase by annual average growth rate of about 15 percent

NH: Based on solar PV carve-out in state RPS (Class II requirement). MW values derived from *Brattle* RPS Demand analysis, using an assumed capacity factor of 15.8 percent. Percent requirements from NH Code of Administrative Rules, Chapter PUC 2500 Electric Renewable Portfolio Standard.

VT: MWs in 2010 equal to total solar PV capacity of Implementation Projects funded by Vermont Clean Energy Development Fund (Source: "Vermont Clean Energy Development Fund Projects August 2007 through April 2009") with MW derived from Estimated Annual kWh Produced using an assumed CF of 15.8 percent. MWs in years between 2010 and 2020 are derived from linear interpolation between respective MW values in 2010 and 2020. MWs in 2020 of 50 MW is a modest progress toward Vermont's goal of 200 MW of installed solar PV by 2025. 2025 goal derived from the Vermont 25 x '25 Initiative (Source: "Vermont 25 x '25 Initiative Preliminary Findings and Goals," January 23, 2008).

Table 3-A.4
Capacity Factor and Capacity Credit Assumptions for Renewable Technologies
(Used in support of Tables 3.15, 3.16, and 3.17)

Technology	Capacity Factor (%)
Solar PV	15.8%
Hydro	48.4%
Wind	32.0%
Offshore Wind	37.0%
Biomass/Biofuels	85.0%
Landfill Gas	85.0%
Fuel Cells	90.0%

Technology	Capacity Credit (%)
Solar PV	40.0%
Hydro	100.0%
Wind	19.0%
Offshore Wind	26.0%
Biomass/Biofuels	100.0%
Landfill Gas	100.0%
Fuel Cells	100.0%

Sources and Notes: Onshore and offshore wind: ISO New England Final Scenario Analysis Modeling Assumptions Stakeholder Meeting – May 21, 2007; and "Massachusetts Renewable Energy Potential, Final Report," Prepared for Massachusetts Department of Energy Resources and Massachusetts Technology Collaborative (MTC), August 6, 2008

Section III.4
Transmission

4. TRANSMISSION

4.A FINDINGS AND RECOMMENDATION

4.A.1 Findings

- The EDCs have proposed a process that will provide an efficient and effective means of considering alternatives to transmission upgrades by integrating Connecticut state processes and statutes with the region-wide open and transparent planning process administered by ISO New England.
- Connecticut state agencies (*e.g.*, DPUC, CEAB, OCC) will benefit from early warning of upcoming major transmission projects and have an opportunity to influence outcomes by monitoring the Regional System Plan and the multiple ongoing Connecticut-related transmission studies and participating in regional processes (as appropriate).

4.A.2 Recommendation

1. Adopt the process proposed by the EDCs for consideration of alternatives to transmission upgrades and advocate the statutory and procedural changes outlined in this paper.

4.B INTRODUCTION AND BACKGROUND

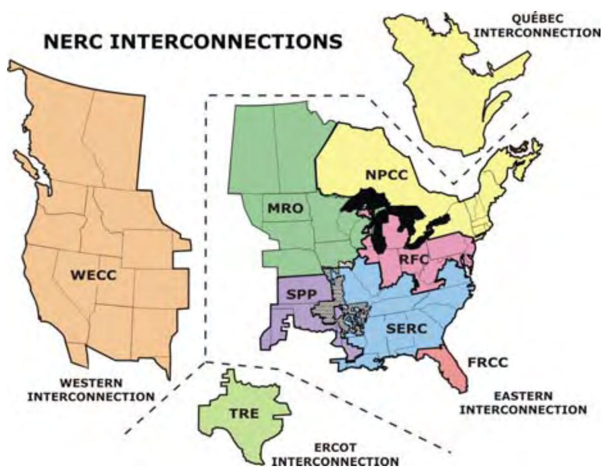
The transmission section of the IRP provides some background information on transmission and provides several recommendations as to how the state can increase its participation in the regional process going forward. This section is summarized as follows:

- Part 4.A summarizes primary findings and recommendations related to transmission.
- Part 4.B provides background information including a description of the role of transmission and the role of the regional transmission planning process to ensure compliance with mandatory reliability performance standards.
- Part 4.C delineates a proposed process to address and identify reliability needs for the state of Connecticut. The proposal is organized by State agencies and highlights process and areas for improvement. This section follows The Connecticut Light & Power Company (CL&P) and United Illuminating Company (UI) response to the Notice of Request for Comments by the Department on November 25, 2009 in Docket No. 09-05-02.
- Part 4.D discusses a proposed outline for determining which regional reliability projects/needs in Connecticut may be viable candidates for consideration for non-transmission resources as alternatives to a backstop transmission solution.
- Part 4.E discusses an application of the proposed process based on a review of ISO-NE Regional System Plan Project Listing dated October 2009.
- Part 4.F provides an overview on New England East-West Solution (NEEWS) and provides a high level summary of the status for each of the component projects in the New England Planning Process.

4.B.1 Background

The transmission system in Connecticut is not isolated from the electric power grid. It is interconnected to New England and the rest of the Eastern Interconnection reaching west to the Rockies and south through Florida, as shown in Figure 4.1. This inter-regional system is operated by Independent System Operators – New England (ISO-NE) and other similar regional transmission organizations (RTOs) in such a way that all market participants can access the system to transmit energy subject to flow limits, the laws of physics, and various market rules. This allows some of the energy consumed in Connecticut to be produced elsewhere, whether for economic or environmental reasons or because local supplies are insufficient to serve customer load demands. The region's integration also means that reliability events in one area can affect another, as made readily apparent by the August 2003 blackout that affected over 50 million people in the Midwest, Northeast and Ontario.

Figure 4.1
NERC Interconnections



4.B.2 Ensuring a Reliable Transmission System

Pursuant to the Federal Power Act of 1935, as amended by the Energy Policy Act of 1992, the Federal Energy Regulatory Commission (FERC) has jurisdiction over the interstate transmission of electricity and has the authority to ensure the reliability of the interstate transmission system. The *Federal Power Act* directed FERC to establish one Electric Reliability Organization (ERO) with the statutory responsibilities to establish and enforce standards for the North American bulk power system and periodically publish reliability reports.[1] FERC designated the North American Electric Reliability Corporation (NERC) as the ERO. NERC develops, administers, maintains, and enforces Planning and Operating Performance Standards for the electric power grid in North America.

1 "NERC Company Overview FAQs" provides information about NERC as the ERO (Princeton, NJ: NERC, 2008); http://www.nerc.com/page.php?cid=1|7|114.

The NERC Planning and Operating Performance Standards were developed to assure the reliability (adequacy and security) of North America's bulk electric system. The planning standards address how NERC will carry out its reliability mission by: (a) establishing the standard; (b) measuring performance; and (c) ensuring compliance with NERC policies, standards, principles, and guides.

Regional performance reliability standards provide for as much consistency as possible with NERC reliability standards. However, the Northeast Power Coordinating Council (NPCC) and Independent System Operators (ISO) standards and criteria are more stringent than the NERC standards as needed to address specific characteristics of the Northeast / New England regional system.

In 2006, NERC designated the NPCC as the "Regional Entity" with authority to promote and enhance the reliable and efficient operation of the interconnected bulk power system in Northeastern North America (including but not limited to New England). The NPCC assures NERC requirements are satisfied in Northeastern North America (Northeast United States and Eastern Canada) through the development, compliance monitoring, and enforcement of a set of more stringent regionally-specific reliability standards and criteria.

ISO-NE is the not-for-profit RTO for the six New England states and is designated by FERC as the Planning Authority for New England. ISO-NE plans and operates the New England system in full compliance with NERC and NPCC criteria, standards, guidelines, and procedures. The ISO-NE's three main responsibilities are:

- Reliable day-to-day operation of New England's bulk power generation and transmission system;
- Oversight and administration of the region's wholesale electricity markets; and
- Management of a comprehensive regional power system planning process.

Pursuant to the 2005 Energy Act, the regulated providers of transmission services (Transmission Owners, or TOs) are required by federal law and binding tariff provisions to propose and design transmission improvements that will ensure that the integrated regional transmission system will comply with applicable mandatory system security standards. These include performance standards issued by NERC, NPCC, and ISO-NE.

Based on these mandatory standards, ISO-NE and the TOs in New England (including CL&P and UI) are responsible for performing annual transmission reliability assessments looking forward ten years (*i.e.*, needs assessments), and for establishing corrective action plans (*i.e.*, proposed transmission projects) necessary to address the future reliability needs of the region. Prior to being constructed, proposed projects are studied in accordance with the ISO-NE tariff and planning procedures, and must demonstrate that its implementation will not create a significant adverse effect on the stability, reliability, or operating characteristics of the transmission system.

4.B.3 New England's Transmission Planning Process

In 2008, ISO-NE implemented FERC Order 890 planning process enhancements to meet the requirements of Attachment K of the *Open Access Transmission Tariff* (OATT). ISO-NE's FERC Order 890 requires all transmission providers to implement a coordinated, open and transparent transmission planning process that complies with the following nine principles:

- Coordination
- Openness
- Transparency
- Information Exchange
- Comparability
- Dispute Resolution
- Regional Coordination
- Economic Planning Studies
- Cost Allocation

Consistent with Attachment K, ISO-NE has established a Planning Advisory Committee (PAC) which provides input and feedback to ISO-NE concerning the regional system planning process, including the development of and review of Needs Assessments, the conduct of Solutions Studies, the development of the Regional System Plan (RSP), and updates to the RSP Project List.

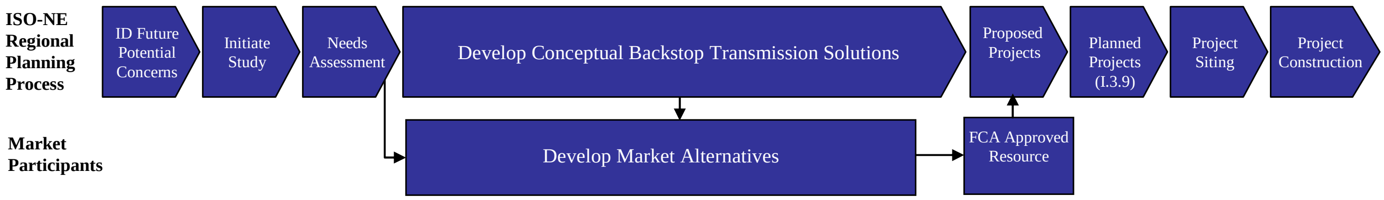
Through an open stakeholder process, the ISO-NE develops its plan to address system needs and cost effectiveness. All proposed system modifications, whether generation, transmission, or significant load reductions, must be analyzed and designed carefully to ensure system-wide coordination and continued system reliability for the New England system.

Any entity, including State regulators or agencies, End Users, Generators, Suppliers, Transmission Owners, Demand-Side resources, or other alternative resources may designate a member to the PAC. Specifically, the PAC serves to review and provide input and comment on:

- The development of the RSP;
- Assumptions for studies;
- The results of Needs Assessments and Solutions Studies; and
- Potential market responses to the needs identified by ISO-NE in a Needs Assessment or the RSP.

The FERC approved Regional Planning Process for New England is summarized below in Figure 4.2.

Figure 4.2
FERC Approved Regional Planning Process for New England



As part of this regional planning process, which supports the ISO-NE's compliance with NERC and NPCC planning standards, ISO-NE and the TOs assess the performance of the New England transmission system for a ten-year period through reliability assessment studies. Individual sub-area studies, referred to as needs assessments, are performed to identify future system needs. The results of these needs assessments are updated as necessary and communicated to the PAC. This process provides market proponents with opportunities to develop market responses that may address identified system reliability needs. These market responses may include investments in resources (*e.g.*, demand-side projects, generation, and distributed generation) and Merchant Transmission Facilities, to solve identified system reliability needs.

When a system reliability problem is identified from a needs assessment, ISO-NE and the TOs develop one or more transmission system options and alternatives (*i.e.*, transmission backstop solutions) to address all of the transmission reliability needs and to ensure that NERC and NPCC reliability standards are met. These alternatives are often identified first as conceptual solutions until they are further analyzed and determined to be effective in meeting the system reliability need. Stakeholders (*i.e.*, PAC) also review the alternatives and provide input as part of this process. The viable alternatives are further evaluated to determine feasibility of construction, environmental impacts, cost, longevity, and operational considerations. When the analysis of the alternatives is complete, the TOs recommend a proposed transmission project to ISO-NE and the PAC. These studies, and the proposed transmission solutions, are documented in a solutions study, and in aggregate provide the basis to update ISO-NE's RSP.

In addition, as described in Attachment K of the ISO-NE Open Access Transmission Tariff (OATT), market responses that are identified to ISO-NE and are determined by ISO-NE, in consultation with the PAC, to be sufficient to alleviate the need for a particular backstop transmission solution, and are judged by ISO-NE to be achievable within the required time period, shall be reflected in the next RSP and/or in a new or updated Needs Assessment. Specifically, ISO-NE must incorporate or update information regarding resources in the Needs Assessments that have been proposed and meet the following criteria:

- Have cleared in a Forward Capacity Auction pursuant to Market Rule 1 of the ISO-NE Tariff; or
- Have been selected in, and are contractually bound by, a state-sponsored Request For Proposals; or
- Have a financially binding obligation pursuant to a contract.

The backstop transmission solution will be suspended/ terminated if it is determined to be no longer needed. If the market response does not fully address the defined needs, or if additional transmission infrastructure is required to facilitate the efficient operation of the market response, the RSP must also include a transmission solution (although it may be a different project than that originally contemplated). It is important to note that the backstop transmission solution will continue to be developed through the ISO-NE Regional Planning Process until ISO-NE determines that the reliability need has been fully addressed and formally notifies the Transmission Owners.

Any proposed project (*i.e.*, transmission, generation, or merchant) that integrates to the New England transmission system must also demonstrate that it produces no adverse impact on the reliability or operability of the transmission system, as required by Section I.3.9 of the ISO-NE OATT. This is a technical approval process, which typically consist of thermal, voltage, stability, and short-circuit studies (*i.e.*, system impact studies) that are evaluated by ISO-NE appointed technical committees and recommended for ISO-NE approval by the New England Power Pool (NEPOOL) Reliability Committee.

After ISO-NE issues a formal no adverse impact determination, planned projects typically proceed to the State siting approval process (as required), detailed engineering and then to construction.

4.C THE EDCS' PROPOSED CONNECTICUT PROCESS RELATED TO IDENTIFIED RELIABILITY NEEDS

The Connecticut Department of Public Utility Control (Department) is currently developing a process for evaluating non-transmission resources as potential alternatives to backstop transmission projects located in Connecticut which may satisfy ISO-NE’s reliability needs (as identified through the ISO-NE Regional Planning Process). On November 2, 2009, the Department held a technical meeting to discuss the development of the process and on November 25, 2009, they solicited comments on their Straw Proposal from various stakeholders. Comments were provided by various stakeholders to the Department for their consideration in further development of this process.

CL&P and UI submitted the proposal described below and illustrated in Figure 4.3 in response to the Department’s request for comments, with recognition that the final process is still under development with due consideration from all stakeholders.

The CEAB was reconstituted for the purpose of allowing the state, through its various agencies, to assure that the regional planning process did not exclude consideration of alternatives that the state might prefer. The process proposed by the companies is consistent with this purpose. If Connecticut believes the ISO-NE regional Planning Process did not adequately identify and consider viable non-transmission resource projects within the state, the companies suggested process will provide Connecticut state agencies with an opportunity to ensure that viable non-transmission resource projects receive appropriate consideration.

We believe that the process we are proposing should allow ample opportunity for the state of Connecticut to ensure that non-transmission resources are appropriately considered and that the state process will integrate into the regional planning process without jeopardizing the system reliability or overly extending the timeline. This proposal is organized by State agency and highlights the various processes that are currently in place as well as areas for improvement. Suggested revisions to State statutes/processes are shown in italics.

4.C.1 CEAB

1. If CEAB finds that a state need is unlikely to be satisfactorily met by the regional market system, CEAB may initiate a Proactive Request For Proposal (PRFP) process.
    - Provided the State concludes that a PRFP is likely to yield viable resources/ alternative, and there is sufficient time to develop and implement potential alternative responses.
    - A PRFP should not be considered for minor backstop transmission solutions.
    - *Suggested Change: If CEAB determines that the RSP process has not adequately identified alternatives for Connecticut projects, prior to initiating any action, CEAB consults with the Department to seek their approval before issuing a PRFP, regarding the Department's willingness to subsequently solicit and commit to alternate resources.*
2. To initiate a PRFP process, CEAB first assesses the market for realistic non-transmission alternatives by issuing a Notice of Intent to Issue (NOII) a PRFP. This notice requests formal Notices of Intent to Respond (NOIR) from qualified market participants. This request (NOII) should be made well in advance of initiating the actual PRFP process.
    - This will provide potential respondents with ample opportunity to perform analysis and prepare their responses.
    - *The CEAB should request/suggest early submittal of supporting documentation, and.*
    - *The CEAB should advise potential respondents that without early submittal, it may not be practical to thoroughly and fairly assess their proposals.*
3. If CEAB finds that one or more qualified NOIRs are for projects that are likely to meet the identified reliability needs and are likely to produce a more cost effective solution than the transmission solution, CEAB may formally start the PRFP process by requesting proposals from those received in conjunction with step 2 above.
4. CEAB screens all proposals against its threshold criteria. These criteria must ensure that any single or combined set of proposals meet all of the same ISO-NE identified reliability needs that the backstop transmission project is designed to meet.
    - Alternative resources should be assessed using the same reliability measures applicable to the backstop transmission solution.
    - In addition, economic, financial feasibility, and preferential criteria should be considered.
    - *The prescribed time limit for evaluation (45 days) appears impractical. Consideration should be given to revising the statute.*
    - Note: At this juncture, the CEAB's determination alone regarding the effectiveness of any potential alternate resources is unlikely to influence the regional planning process

as ISO-NE is the Planning Authority for New England and Section 4.2(a) of Attachment K of New England Open Access Transmission Tariff specifies the criteria for including market resources in needs assessments.

- Under these circumstances, the Reliability Transmission Upgrade sponsor will continue with development consistent with its FERC/ISO-NE/Regional obligations independent of any CEAB conclusions.

5. CEAB documents its findings from #4 above in its Evaluation Report and submits it to the Connecticut Siting Council (CSC) and the Department.
   - The currently prescribed CSC submittal does not lead to possible solicitation and/or commitment and begins to run a statutory siting "clock" prematurely and without the Department's or ISO-NE's evaluation of the potential alternative project.
   - *Suggested changes to statute: (a) Report should go to Department in lieu of CSC; and (b) Any statutorily prescribed deadlines for PRFP-related siting filings with the CSC should be eliminated.*
6. Separately and independently of the PRFP process, CEAB reviews the draft Integrated Resource Plan (IRP) base case model simulations, identifies the need for RFPs for procurement of additional resources, and submits the IRP to Department.
   - Only include in the IRP any non-transmission resources that have cleared in the Forward Capacity Auction (FCA) or have received a state commitment and will clear in a future FCA – consistent with Attachment K of the ISO-NE OATT.

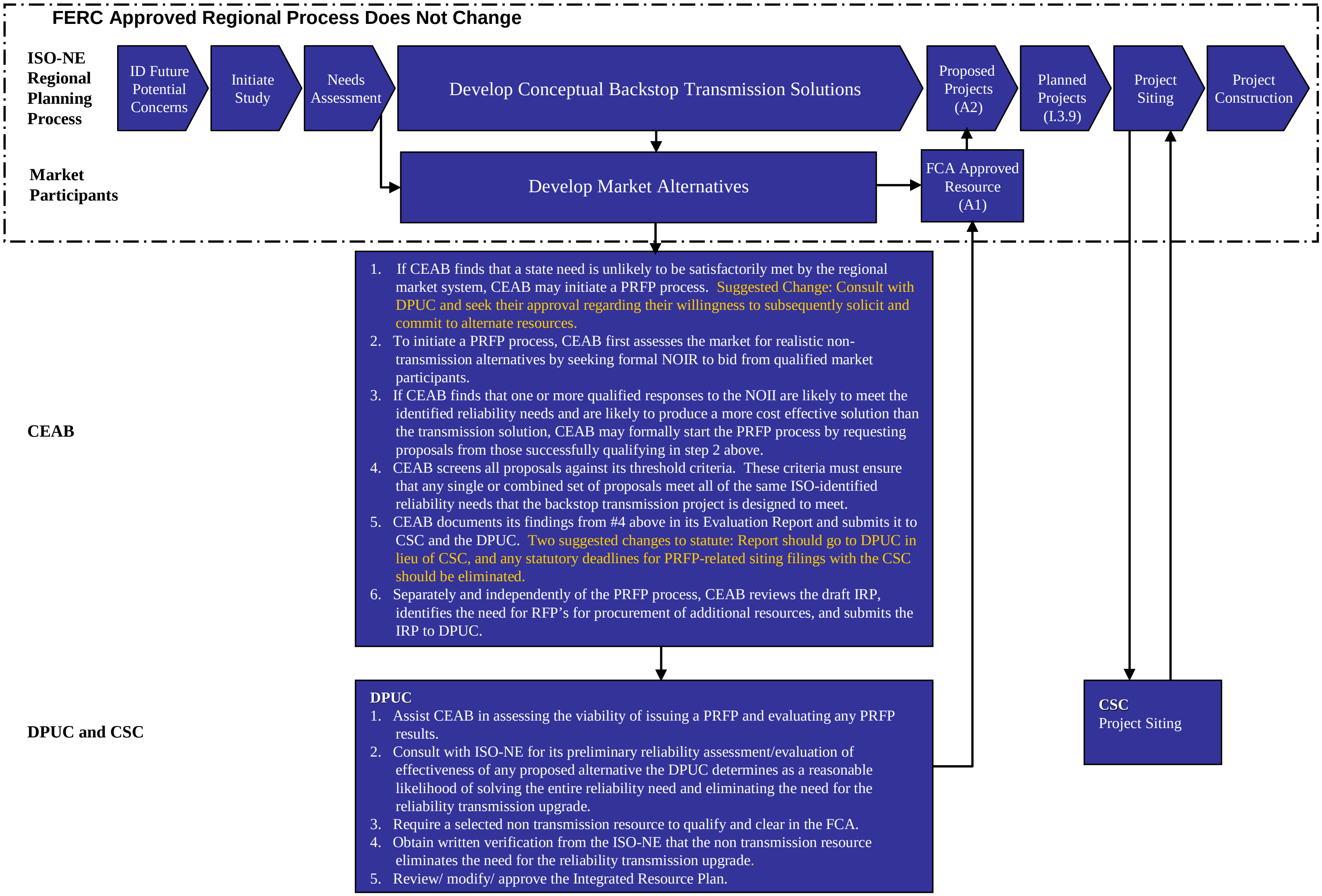
4.C.2 DPUC

1. Assist CEAB in assessing the likely effectiveness of issuing a PRFP and the practicality and benefits of evaluating any PRFP results.
2. Consult with ISO-NE for its preliminary reliability assessment/evaluation of effectiveness of any proposed alternative the Department determines has a reasonable likelihood of solving the entire reliability need and eliminating the need for the Reliability Transmission Upgrade.
   - If the Department concludes a financial commitment is necessary then such commitment should be conditioned upon a final determination from ISO-NE that the non-transmission resource eliminates the need for the Reliability Transmission Upgrade. Otherwise, Connecticut customers may have to bear the cost of both projects when only one is ultimately needed.
   - Note that ISO-NE's determination regarding eliminating the need for a Reliability Transmission Upgrade requires alternate resources to clear in the FCA.
   - Require selected non-transmission resource to qualify and clear in the FCA.
3. Obtain written verification from the ISO-NE that the non-transmission resource eliminates the need for the Reliability Transmission Upgrade.
4. Review/modify/approve the Integrated Resource Plan.

4.C.3 CSC

1. There are no proposed changes to CSC jurisdiction. However:
   - If above suggested changes are accepted, the Department would assume CSC's present role of accepting the CEAB's Evaluation Report from a PRFP.
   - Review siting application for electric facilities in Connecticut.
   - Approve / disapprove or modify siting applications or proposals for electric facilities.
   - Consider applications for approval of non-transmission resources, if any, filed by proponents of those projects either on their own initiative or following the CEAB's Reactive RFP process.
   - An alternative project sponsor participating in the PRFP process may file a siting application on its own initiative at any time. *However, if the above suggested changes are accepted, the statutorily prescribed deadlines for filing an application following a PRFP would be eliminated, allowing the Department and ISO-NE first to fully evaluate the alternative project and determine the reasonable likelihood that it could displace the transmission solution.* It would therefore be highly unlikely that, following a PRFP, the CSC would be in a position to consider applications of "competing" facilities in a single docket. ISO-NE would make a final determination as to which project(s) meet the entire need and those projects would likely proceed into siting.
   - To the extent that the Evaluation Report is to be submitted to the CSC, it should be for information purposes only, until ISO-NE determines whether or not the non-transmission resources resolve the reliability problems in their entirety.

Figure 4.3
CL&P/UI Proposed Connecticut Process to Address Identified Reliability Needs



A1 Forward Capacity Market (FCM) for non transmission resources.

A2 Within this step of the regional planning process, ISO performs evaluation reflecting the market participants and FCA's and makes determination on whether or not reliability needs still exist or have been mitigated by market responses.

4.D IDENTIFICATION OF VIABLE CANDIDATES FOR CONSIDERATION AS ALTERNATE MEANS OF SATISFYING RELIABILITY NEEDS (IMPLEMENTATION/APPLICATION OF THE EDCS PROPOSED PROCESS)

As discussed in Section 4.B above, the FERC-approved New England model requires TOs to identify backstop transmission solutions to meet identified reliability needs. Non-transmission resource projects can participate in the ISO-NE markets in response to these needs or for other purposes. All real and predictable non-transmission resources, as defined by ISO-NE market rules, are fully considered by ISO-NE when determining if a backstop transmission solution is required to meet the region's reliability need.

After the 2003 blackout, new federal and regional reliability standards were established to ensure that system reliability was made a high priority. The Companies believe that any process that considers non-transmission resources should not jeopardize system reliability in any manner. If the State chooses to identify and recommend non-transmission resources that only partially meet reliability needs or are speculative, it would add length to the project planning approval schedule, complexity to the planning and siting process, and risk to system reliability. The EDCs advise against any approach which has the potential to jeopardize regional reliability.

Similarly, the EDCs advise against the study of hypothetical or speculative non-transmission resources. Hypothetical resources lack the specificity necessary to perform a meaningful comparison, and this analysis could also significantly lengthen the schedule and divert attention from the task of evaluating actual projects and true, bona-fide alternatives to projects designed to ensure a reliable transmission system.

It should be noted that larger Reliability Transmission Upgrades are generally very comprehensive and address a multitude of complex transmission reliability needs. Therefore it is unlikely that a single non-transmission resource would be capable of providing a level of reliability comparable to a Reliability Transmission Upgrade.

In addition, absent significant changes in expectations about future conditions, Connecticut should avoid more than one PRFP to ensure there is adequate time to plan, site, engineer, and construct the facilities needed to fully address the identified reliability needs without jeopardizing system reliability.

The EDCs propose the following criteria for determining which regional reliability projects/needs in Connecticut may be viable candidates for the consideration of non-transmission resources as alternatives to a backstop transmission solution.

4.D.1 Proposed Criteria

Commencing with the Regional System Plan and the ISO-NE area needs assessment reports for system reliability as discussed previously, transmission reliability projects planned for Connecticut can be categorized as outlined below.

4.D.2 Category A – New Substations (and Significant Additions to Substations)

Category A includes new substation facilities that are planned to ensure that the reliability and demand needs of end-use customers are met. In recent years, the CEAB solicited RFP's for alternatives to planned new substations as part of the CSC's Reactive RFP process. These resulted in no respondents for all of the four RFP's issued. Subsequently, the applicable statute was amended to exempt substations from the Reactive RFP Process. It appears that RFPs related to projects in this category are not likely to result in viable alternatives, and the EDC's recommend that PRFPs not be conducted except under unusual circumstances (see the recommendation under Table 4.1 of this paper). Table 4.1 summarizes future Connecticut projects in this category, currently listed in the Regional System Plan.

4.D.3 Category B – Infrastructure Upgrades

Category B is for various reliability upgrades to existing substations and other existing transmission infrastructure, typically necessary to address the following specific reliability concerns: (1) high system short-circuit current levels, (2) low thermal ratings of equipment and conductors, (3) poor voltage performance/voltage collapse exposure, (4) system instability risks, (5) antiquated/obsolete equipment, and (6) risk of equipment failure related to age/condition. Table 4.2 summarizes future Connecticut projects in this category, currently listed in the Regional System Plan.

> Substations: These upgrades are performed within the fenced-in perimeter and often include replacement, addition or upgrade of existing infrastructure. Examples include: relaying and control systems, transformers, auto-transformers, circuit breakers, disconnect switches, bus systems, grounding systems, auxiliary equipment such as potential transformers, current transformers, batteries, lightning arrestors, and reactive devices (such as shunt capacitors, shunt reactors, static VAR compensators, phase-angle regulators, *etc*.).
>
> Other Transmission Infrastructure: These upgrades are generally needed to ensure the reliable operation of the existing integrated electric system network, typically within the same right-of-way. Examples include separation of structures, thermal ratings upgrades (reconductoring; rebuilding or retensioning of structures and/or conductors), replacement of structures, and reconfiguration of lines required for the purpose of interconnection new generators and/or substations.

Non-transmission resources are generally not effective in addressing the reliability concerns addressed by projects in this category. Consequently, the companies recommend that reliability upgrades to existing substations and other existing transmission infrastructure be waived from non-transmission alternative consideration.

4.D.4 Category C – New Transmission Lines

Category C includes new transmission lines (typically 115 kV or 345 kV in Connecticut) proposed as backstop solutions intended to address specific reliability needs that can not typically be addressed by upgrading existing infrastructure. Table 4.3 summarizes future

Connecticut projects in this category, currently listed in the Regional System Plan. Note that although this category has attracted the most interest in recent years, there is only one post-NEEWS project included in the listing at this time. However as described in Section 4.E.2, there are several reliability studies that are underway in Connecticut, and/or are expected to be initiated in the near future. Depending on the ISO-NE needs assessments, transmission backstop solutions may be identified and these solutions may be of a type that would be in this Category C in the future. There will be ample time for the PRFP process to be utilized early enough to permit alternative solutions to be implemented if that is appropriate.

Under certain circumstances, alternatives to some future projects in this category might be solicited in conjunction with the CEAB's PRFP Process. The companies recommend that the following circumstances be considered before issuing a PRFP associated with a future project in this category:

- The PRFP process should be implemented early enough to ensure that any viable and preferred substitutes can come to fruition in time to fully address the anticipated need; and
- It should not be implemented too early; *i.e.* it should be delayed until ISO-NE has identified the needs and the potential solutions are reasonably well defined; and
- The PRFP process is more appropriate for larger / more significant projects; and
- There should be preliminary indications that substitutes are likely to be effective and viable; and that there is some serious interest among potential sponsors of said substitutes.

4.E APPLICATION OF PROPOSED CRITERIA TO ISO-NE RSP 2009 PROJECTS IN CONNECTICUT AND STATUS OF RELIABILITY STUDIES IN CONNECTICUT

4.E.1 Category A, B, and C Projects

The tables below provide a summary of Connecticut transmission reliability projects shown in the RSP Project Listing dated October 2009. The projects are grouped into the categories summarized above (A, B, or C); and the Companies have provided recommendations consistent with the proposed criteria, regarding consideration of non-transmission resources as potential alternatives to the listed projects.

Table 4.1
Category A - New Substations (and Significant Additions)

Project Name	Location	Owner	RSP Project ID	Description	Projected In-Service Year	Status
Waterside S/S	Stamford	NU	1055	Addition of a 115/13.2 kV transformer	2010	Concept
Broadway S/S	New Haven	UI	1110	Substation addition	2010	Planned
Sherwood S/S	Westport	NU	1056	Addition of a 115/13.2 kV transformer	2011	Planned
Union Ave S/S	New Haven	UI	1111	New 115/ 26.4 kV substation	2011	Planned
Shelton S/S	Shelton	UI	721	New 115/ 13.8 kV substation	2013	Planned
Pequonnock S/S Fault Duty Mitigation	Bridgeport	UI	975	New 115 kV substation/ reconfiguration to transmission	2013	Concept

Recommendations:

1. *Past solicitations related to these types of projects have not yielded any responses. A recent statutory change has exempted these types of projects from the Reactive RFP requirement. Generally, the projects in this category and the nature of need they satisfy do not appear to be good candidates for a PRFP process, i.e. it does not appear that alternatives will be viable. We recommend that state agencies monitor projects of this type in the regional planning process, and only under extreme conditions (i.e. where alternatives are obviously/likely to be viable) consider utilizing the PRFP process.*

Table 4.2
Category B – Infrastructure Upgrades

Project Name	Location	Owner	RSP Project ID	Description	Projected In-Service Year	Status
East Shore S/S TRV Mitigation	New Haven	UI	1049	115 kV Capacitor Bank upgrade	2010	Planned
310/368 Line Separation	Manchester	NU	582	Separate 310 and 368 345-KV lines and create 368/1767 DCT	2010	Planned
Water Street Fault Duty Mitigation	New Haven	UI	1112	Replace 115 kV Circuit Breakers	2010	Planned
East Shore OCB Replacement	New Haven	UI	974	Replace 115 kV Circuit Breakers	2011-2013	Planned
Grand Avenue Switching Station	New Haven	UI	976	Rebuild 115 kV Switching Station	2012	Planned
Devon Tie Switching Station BPS Upgrades	Milford	UI	1050	Upgrade station to NPCC BPS standards	2011	Planned
Bunker Hill S/S Upgrades	Waterbury	NU	809	Upgrade terminal equipment at Bunker Hill 115 kV substation	2009	Planned
HPFF Cable Pumping Plant Replacements	New Haven	UI	1150	Grand Avenue - West River 115 kV Pumping Plant Replacements	2010	Planned
West River Fault Duty Mitigation	New Haven	UI	1151	Grand Avenue - West River 115 kV Pumping Plant Replacements	2010	Planned
Naugatuck Valley 115 kV reliability improvement	Shelton/ Derby	UI	699	Upgrade and reconfigure transmission, separate structures	2012	Concept
Waterside S/S Upgrades	Stamford	NU	1147	Waterside Substation - install a three-breaker 115kV ring bus	2011	Proposed
1440 Line Relay Upgrades	Glenbrook to Waterside	NU	1148	Add a 2nd high speed relay on the Glenbrook to Waterside 115kV 1440	2011	Proposed
South Meadow S/S BPS Upgrades	Hartford	NU	85	Upgrade station to NPCC BPS standards	TBD	Concept
Various	Various	NU	879	Upgrade 7 of 8 Dynamic Swing Recorders in New England to comply with NERC, NPCC, and ISO-NE Standards.	TBD	Planned

Recommendations:

1. *Please notice the descriptions shown, e.g. capacitor banks, breakers, relays, reconfigurations, bulk-power-system standards compliance. These upgrades and the reliability needs they address are unlikely to be resolved by non-transmission alternatives. We recommend refraining from issuing PRFPs associated with these projects.*

Table 4.3
Category C - New Transmission Lines

Project Name	Location	Owner	RSP Project ID	Description	Projected In-Service Year	Status
Manchester-E. Hartford 115 kV UG Line Addition	E. Hartford to Manchester	NU	801	Build Manchester to East Hartford 115-kV cable with a series reactor	TBD	Concept
NEEWS	Various	NU	Various	GSRP, Interstate, Central CT	2013	Planned

Recommendations:

1. *Regarding NEEWS, please refer to the DPUCs comments issued in conjunction with both the 2008 and 2009 IRP DPUC decisions. See footnote 3 and Section 4.F for the status update on NEEWS.*
2. *Regarding Manchester-East Hartford 115 kV Underground Line Addition: Recommend monitoring the Hartford Area Needs Assessment study described below for potential PRFP/RFP consideration of non-transmission resources when the needs assessment is complete.*

4.E.2 Current Status of Reliability Studies in Connecticut

Studies to address a wide range of system concerns in Connecticut are underway, and/or are expected to be initiated in the near future. No new needs assessments have been issued by ISO-NE for Connecticut and no specific solutions have been identified. However, transmission planning studies (needs assessments and solution studies) are being assessed by ISO-NE and the TOs to focus on the load areas which pose the most significant risk to reliability. Many of the studies have been focused on potential near-term solutions but there are also several long-term analyses that are being conducted to address potential future concerns. When the ISO-NE needs assessments are complete, ISO-NE will share the findings with the PAC (informing proponents of market-based solutions) and incorporate the identified needs into a subsequent RSP.

Recommendations:

1. The EDCs recommend that CEAB monitor current and upcoming need assessments being performed by ISO-NE and/or being scheduled for the future including: (i) Southwest Connecticut (ii) Eastern Connecticut (iii) Northwest Connecticut, and (iv) Hartford, Connecticut area. These studies are in the preliminary stages of the planning process, specifically the "Identify Future Potential Concerns" and "Needs Assessment" stages as

shown previously in Figure 4.3. Long-term transmission reliability needs for these areas are planned for completion in 2010/2011.

4.F STATUS UPDATE - NEEWS

The NEEWS is a series of projects designed to improve system reliability and increase power flows from east to west in New England, which include thermal, voltage, and transfer import capabilities. The 2009 RSP shows that projects in the Greater Springfield and Rhode Island areas should proceed as planned.

The Rhode Island system is overly dependent on limited transmission lines or autotransformers to serve its need, resulting in thermal overloads and voltage problems for contingency problems. The Rhode Island Reliability Project (RIRP) greatly improves the reliability of the state's transmission system and reduces dependence on local generation by providing another avenue to generation resources outside the state.

The Springfield, Massachusetts area experiences thermal overloads under forecasted normal conditions and significant thermal overloads and voltage problems under numerous conditions. Furthermore, the transmission network in the Greater Springfield area provides a source of power into Connecticut from north to south from the rest of New England. Unfortunately at times this transmission system limits the amount of power transfer. The Greater Springfield Reliability Project (GSRP) addresses these issues.

The limited transmission capacity between Connecticut and Massachusetts further exacerbates the system reliability problems in the greater Springfield area. The existing 115 kilovolt (kV) lines around Springfield, and the 115-kV underground cables that traverse Springfield, serve a double duty of supplying local load and supporting interstate transfers. Under the present system configuration, a portion of the power flowing into Connecticut from CL&P's North Bloomfield Substation transfer through the greater Springfield 115-kV system under normal conditions. Under many contingency conditions modeled in accordance with applicable reliability criteria, the power flows cause severe overload and voltage problems on the 115-kV system. The inadequacy of the existing 115-kV lines is compounded because many of the 115-kV circuits in the area share common support structures. These reliability problems exist now, with today's system configuration and loads that have already occurred and will continue to grow as the load increases.

Also, as reflected in the Department's Decision in Docket No. 09-05-02, page 9, the initial hurdle for the comparison of any proposed alternative to NEEWS is the required certainty that a project can be done within the prescribed timeframes and meet all of the same reliability benefits so as not to jeopardize system reliability. The Department is skeptical that portfolios of projects can be evaluated against the reliability benefits of NEEWS, or any single portion of NEEWS, at this late date.[2]

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[2] It is important to note that the Department continues to caution that at this late stage it would be extremely difficult to develop alternatives to NEEWS. See Docket No. 08-07-01, DPUC Review of The Integrated Resource Plan, Decision dated February 18, 2009 at 40; Docket No. 09-05-02, DPUC Review of the 2009 Integrated Resource Plan, Decision dated September 30, 2009 at 8.

The summary below provides a status for the various NEEWS projects.

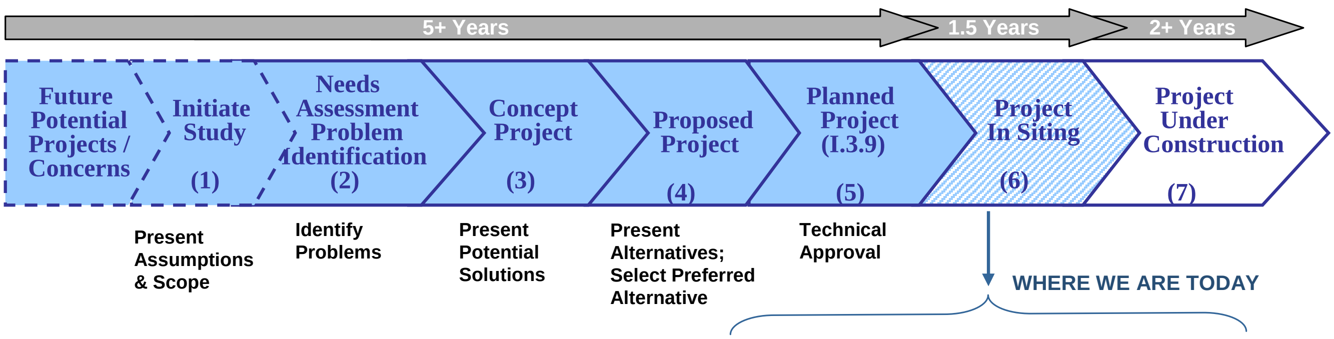
Interstate Reliability Project (Interstate): This project includes a 345 kV line planned into and through central Connecticut, which is under review by ISO-NE. In addition, it increases the transmission capability into Connecticut and across the ISO-NE East-West interface. The ISO-NE East-West interface extends from Connecticut northward through central Massachusetts and further north between Vermont and New Hampshire. Interstate increases the regional integration across the East West corridor of the ISO-NE system, and between Connecticut and the rest of ISO- NE. The current expectation is that ISO-NE should be completed with its review early in 2010.

The Central Connecticut Reliability Project (CCRP): This project is needed to eliminate a bottleneck between eastern Connecticut and the southwest Connecticut loop by the addition of another 345-kV connection between these subareas. The addition of CCRP provides an additional transmission path to North Bloomfield substation, which serves the north-central areas of Connecticut under varying contingency conditions. This project is also under review by ISO-NE. The current expectation is that ISO-NE should be completed with its review in 2010 after or concurrent with the review of Interstate.

A high level summary of the status of NEEWS projects are in the New England Planning Process is provided in the Figure 4.4 below. The figure highlights where each of the projects is in the planning cycle along with additional details.

Figure 4.4
NEEWS Projects Update

High Level Planning and Siting Summary



	Greater Springfield	Interstate	Central Connecticut
File siting application	✓	Mid 2010	Late 2010
Receive Decision and Order	Early/Mid 2010	2011	Early/Mid 2012
Start Construction	Mid/Late 2010	Early 2012	2012

Section III.5
Nuclear Power

5. NUCLEAR POWER

5.A SUMMARY AND KEY FINDINGS

Summary

In considering Connecticut's future resource plan, the question of a new nuclear plant has arisen. In light of some of the concerns facing New England, nuclear generation has some advantages, though it also faces many obstacles. This section explores factors affecting nuclear power as a potential future baseload resource addition, providing background and context that will help frame discussion. This section also presents the results of an analysis of the market and emissions impacts of a new nuclear plant sited in Connecticut, which illustrate the magnitude of the costs and benefits that might be expected from pursuing a nuclear-based resource solution.

Although the analysis of market impacts of a new nuclear plant in Connecticut has limitations, the results suggest the potential to realize both economic and environmental benefits. New nuclear capacity in Connecticut would displace generation from fossil-fired plants, substantially reducing emissions of CO_2 as well as NO_X and SO_2. The relative cost of a nuclear resource option depends on the ultimate nuclear construction cost, a figure that is subject to significant uncertainty and possible upside risk. Once built, however, a nuclear plant's operating costs are not subject to fluctuations in the price of natural gas or CO_2 emissions. If the cost recovery of a nuclear plant is based on cost-of-service principles, a new nuclear plant could reduce customers' exposure to the potentially volatile costs of natural gas and CO_2 emissions. While the economic benefits and costs of a new nuclear facility in Connecticut are uncertain, the potential environmental benefits are much clearer. The costs and benefits are discussed in detail in Section 5.H below.

Key Findings

- Nuclear generation has significant environmental benefits, including displacing fossil generation and associated greenhouse gases, while making Connecticut less reliant on natural gas generation.
- Nuclear capacity expansion is a long-term prospect – 10 to 15 years from the start of preparing a license application to commercial online date.
- New merchant nuclear capacity is unlikely to be developed in New England without a cost recovery approach that can mitigate the risks of high and uncertain capital costs, long lead time and the potential for costly delay.

In light of the potential benefits of a nuclear strategy identified in our analysis, UI recommends that the CEAB conduct, sponsor, or otherwise support a more detailed study of the potential costs and benefits of nuclear power, with the objective of providing a more complete picture of the tradeoffs encountered in considering nuclear power as a long-term resource strategy for Connecticut.

5.B STATE OF THE NUCLEAR INDUSTRY – U.S. AND WORLDWIDE

5.B.1 U.S. Operating Experience

The existing nuclear fleet in the U.S. is composed of 104 generating units with a total of 100,300 MW of generating capacity, accounting for 10 percent of installed capacity and generating 20 percent of all electricity produced in 2008 (over 70 percent of the CO_2-free generation). Most of these plants were built in the 1970s and 1980s, and nearly all experienced substantial cost overruns, lengthy construction delays, and initially poor availability and operating economics. However, the turnaround in performance the nuclear industry has realized in the past decade has been as dramatic as its early performance was disappointing. Since 2000, U.S. nuclear units have achieved capacity factors between 88 and 92 percent, and experienced operating costs (including fuel) at or just below 2 cents per kilowatt hour.

The contrast between the initially poor performance of the nuclear industry and its recent record of safe, reliable, and economic operation underlies the current policy debate about the role of nuclear power in the electricity mix. Opponents of nuclear power point to the experience of the 1970s and 1980s and suggest that any new expansion of nuclear capacity will confront similar challenges of cost overruns, construction delays, poor performance, and safety concerns. Proponents of nuclear power point to the industry's recent record of operating excellence and believe that improvements in design, streamlined regulation, and vigilant construction management would avoid the pitfalls that plagued the industry in the 1970s and 1980s. Both sides recognize the fact that no permanent approach exists for managing high-level civilian nuclear waste, but differ on the risk implications of continuing to generate waste under current on-site storage protocols. Nuclear power remains controversial.

5.B.2 Current U.S. Expansion Outlook

In the U.S., no new nuclear plants have started construction since the 1970s (a couple nuclear units that previously suspended construction or temporarily shut down now have been completed or restarted).[1] However, a resurgence in fossil fuel prices, increasing concern about greenhouse gas emissions, and a decade of low operating costs and high reliability of the U.S. nuclear fleet have revived interest in nuclear power as a future generation option. Even some environmental advocates, most of whom have historically opposed nuclear power, have begun to support it as a response to global climate change.[2] In addition, a new generation of nuclear technology is being developed, designed to be simpler, safer, and easier to site and build. A number of companies have proposed or are considering new nuclear plants: Constellation, Duke, Entergy, Exelon, FPL, NRG, Progress Energy, and Southern Company, among others, are planning or considering new nuclear units, sometimes in collaboration with other developers or equipment suppliers. There are also several joint ventures or consortia investigating new nuclear plants. Unistar is a

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1 TVA decided in 2002 to restart Browns Ferry 1. It had been out of service since 1985, and returned to service in 2007. TVA also decided in 2007 to complete construction of its Watts Bar 2 unit (construction was suspended in 1988 before the plant was completed). It is scheduled to come online in 2013.

2 *E.g.*, Patrick Moore, a Greenpeace founder and former nuclear opponent, has become a supporter, as has Stuart Brand, founder of the Whole Earth Catalog. See "Going Nuclear – A Green Makes the Case" Patrick Moore, The Washington Post, Sunday, April 16, 2006.

joint venture between Constellation Energy and Électricité de France; NuStart is a consortium of 10 utilities plus two reactor vendors; AREVA NP, a nuclear design and construction company owned by AREVA (and previously a joint venture with Siemens[3]), is itself owned largely by the French state.

There are some recent federal incentives to build new nuclear capacity, and the Nuclear Regulatory Commission (NRC) has streamlined its approval process in order to avoid some of the regulatory delays that have hampered the industry in the past. A number of new nuclear plants are now proposed and in various stages of planning and approval around the country, mostly at existing nuclear plant sites, and most by regulated utilities under cost of service regulation, though none are in New England. None of these have actually begun construction, nor have they received the required Combined Construction and Operating License (COL) from the U.S. Nuclear Regulatory Commission. Still, there are 25 units at various states of planning; 13 units totaling 26,600 MW have submitted COL applications to the NRC and are under scheduled for review; another eight plants are proposed (three of which formally intend to submit COL applications). See Table 5.1 and Figure 5.1.

3 See “Siemens pulls out of nuclear venture with Areva,” The New York Times, January 26, 2009.

Table 5.1
Status of Planned and Proposed New U.S. Nuclear Plants

No.	Plant	Developer	State	Reactor Design [1]	No. of Units	Total MW [2]	COL Submittal Date [3]	Est. COL Approval Date [4]	Est. Cost ($/kW) [5]	Online Date
PROPOSED AND COLA SUBMITTED										
1	Bell Bend	PPL Corp. / Unistar	PA	EPR	1	1,600	2008	2012	6,250	2016
2	Bellefonte	TVA (NuStart)	AL	AP1000	1	1,100	2007	2011	6,227	-
3	Calvert Cliffs	Constellation / UniStar	MD	EPR	1	1,600	2008	2011	5,250	2015
4	Comanche Peak	Luminant	TX	APWR	2	3,400	2008	2012	4,191	2018
5	Fermi	Detroit Edison	MI	ESBWR	1	1,550	2008	2012	6,452	-
6	Harris	Progress Energy	NC	AP1000	2	2,200	2008	2011	4,227	2018
7	(Levy County)	Progress Energy	FL	AP1000	2	2,200	2008	2012	7,727	2020
8	North Anna	Dominion	VA	ESBWR	1	1,550	2007	2011	-	2018
9	South Texas Project	NRG Energy / STPNOC	TX	ABWR	2	2,600	2007	2011	6,538	2016
10	Turkey Point	Florida Power & Light	FL	AP1000	2	2,200	2009	2012	6,926	2019
11	V.C. Summer	South Carolina Electric & Gas	SC	AP1000	2	2,200	2008	2011	5,136	2018
12	Vogtle	Southern Company	GA	AP1000	2	2,200	2008	2011	6,300	2017
13	William States Lee	Duke	SC	AP1000	2	2,200	2007	2011	6,364	2022
Sub-Total						*26,600*				
PROPOSED AND COLA NOT SUBMITTED										
14	(Amarillo)	Amarillo Power / Unistar	TX	EPR	2	3,200	2010	2014	3,125	-
15	Blue Castle	Blue Castle Holdings	UT	*TBD [6]*	-	-	2010	2014	-	-
16	Clinton	Exelon	IL	*TBD [6]*	-	-	-	-	-	-
17	(Davie County)	Duke	NC	*TBD [6]*	-	-	-	-	-	-
18	(Elmore County)	AEH / Unistar	ID	EPR	1	1,600	2010	2014	2,813	-
19	(Lower Alloways Creek)	PSEG	NJ	*TBD [6]*	-	-	-	-	-	-
20	Oconee	Duke	SC	*TBD [6]*	-	-	-	-	-	-
21	(Victoria County)	Exelon	TX	*TBD [6]*	-	3,000	-	-	4,333	-
COLA REVIEW SUSPENDED										
22	Callaway	AmerenUE / Unistar	MO	EPR	1	1,600	2008	-	5,625	-
23	Grand Gulf	Entergy (NuStart)	MS	ESBWR	-	1,550	2008	-	3,548	-
24	Nine Mile Point [7]	Constellation / UniStar	NY	EPR	1	1,600	2010	-	-	-
25	River Bend	Entergy	LA	*TBD [6]*	-	1,550	2008	-	4,000	-

Sources and Notes:

[1]: ABWR, Advanced Boiling Water Reactor; AP 1000, Advanced Passive 1000 reactor; EPR, Evolutionary Power Reactor; ESBWR, Economic Simplified Boiling Water Reactor (in U.S.), and US-APWR, U.S. Advanced Pressurized Water Reactor.

[2]: Total MW based on capacity of proposed reactor design, where applicable.

[3]: Estimated COL approval date based on assumed 3.5 year addition to COL application submittal date.

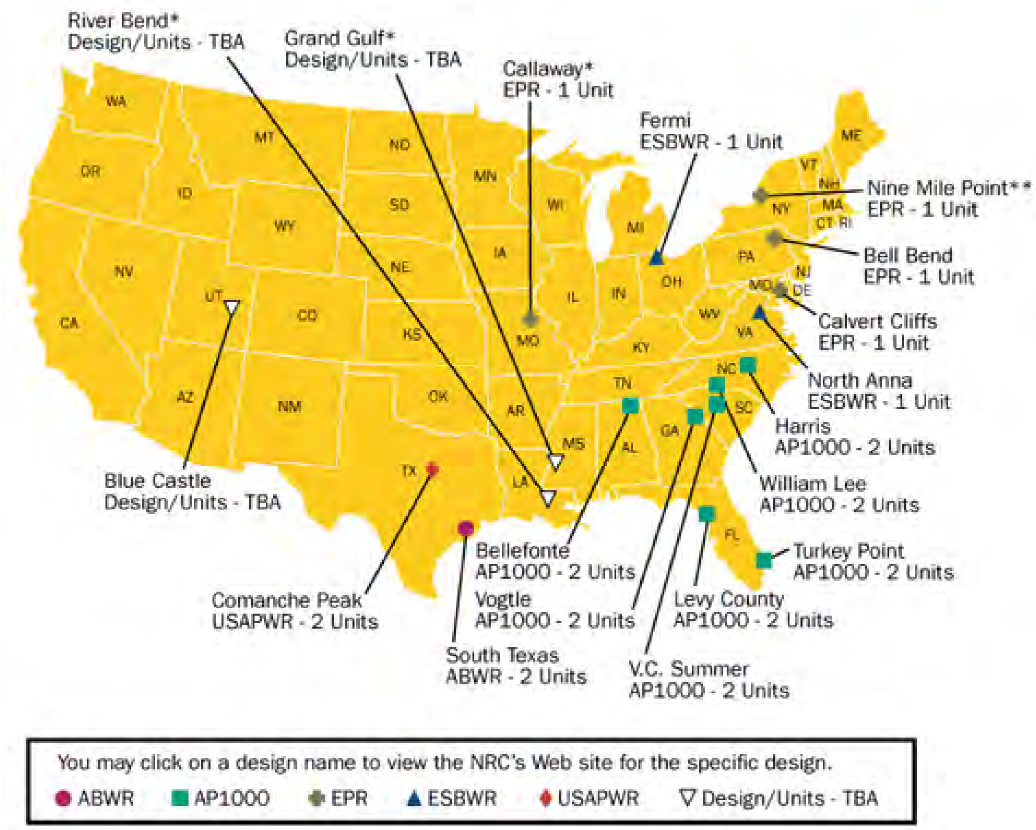
[4]: Amarillo, Blue Castle, and Elmore County COL application submittal and approval dates are estimated.

[5]: Many cost estimates do not specify whether they include construction interest, so they may not all be directly comparable.

[6]: To Be Determined.

[7]: In August 2009, Unistar asked the NRC to partially suspend review of the COLA for Nine Mile Point until September 2010.

Figure 5.1
Location of Projected New Nuclear Power Reactors in the U.S.

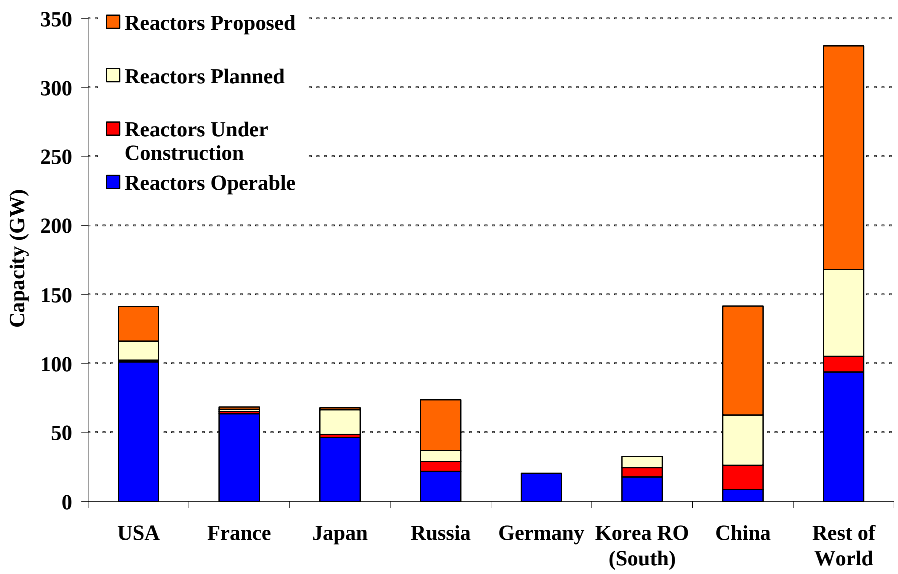


*Review Suspended
**Review Partially Suspended

Source: "Location of Projected New Nuclear Power Reactors," U.S. Nuclear Regulatory Commission, October 22, 2009.

Worldwide, there are currently about 373,000 MW of operating nuclear capacity, with another 48,000 MW under construction and a further 454,000 MW planned or proposed, as illustrated in Figure 5.2. The U.S., France, and Japan account for the bulk of existing world nuclear capacity, but have very little new construction in process (and only a modest number of plants planned or proposed). Among emerging economies, China, Russia, Ukraine, India, and South Korea all have relatively little existing generation but together have over 270,000 MW of plants in construction, planned, or proposed (mostly proposed).

Figure 5.2
World Nuclear Capacity



Source: World Nuclear Power Reactors and Uranium Requirements, World Nuclear Association, October 2009.

5.C TECHNOLOGY OF THE NEXT GENERATION OF NUCLEAR UNITS

The nuclear reactors currently operating in the U.S., including all of the reactors in service in New England, are Generation II reactors. Generation III reactor designs were conceived after the accidents at Three Mile Island and Chernobyl, and generally feature improved safety design over the previous generation. The most important safety advances involve the incorporation of "passive" safety systems that rely on predictable natural forces such as gravity or convection to operate, in contrast to Generation II reliance on "active" safety systems that require the intervention and operation of electrical or mechanical systems when a safety-related event occurs. Passive safety systems are often simpler in design and considered far more reliable than active safety systems. Nuclear plants currently proposed in the U.S. are based on Generation III+ reactor technology, and feature improved safety and economics over the Generation III reactor designs certified in the 1990s by the NRC.[4] (Fourth-generation reactors are currently in the concept stage and will not be operational before 2020.) Generation III and III+ reactors are characterized by the following features:

- **Standardized designs**, which expedite licensing processes for multiple plants, and also help reduce capital costs and construction time as lessons learned from the construction of initial plants are readily transferred to subsequent plants.

4 "Nuclear Power 2010," U.S. Department of Energy. http://www.ne.doe.gov/np2010/overview.html.

- **Simpler designs**, which enable more modular construction techniques, shrink the physical "footprint" of the facility, ease operation and maintenance, reduce the likelihood of operational upsets, and are projected to increase availability and extend operating life.
- **Passive safety systems**, which rely on well-understood and predictable natural forces rather than operator intervention with electrical or mechanical systems. Passive safety systems significantly reduce the possibility of core melt accidents.
- **Hardened protective structures**, which enhance resistance to external damage from earthquake, severe weather, or aircraft impact.
- **Improved operating economics**, due to higher burn-up to reduce the amount of waste generated and managed.

The first Generation III+ reactor design type to be certified as a standard design by the NRC was the Westinghouse AP1000.[5] Other Generation III+ reactor designs are currently undergoing review by the U.S. NRC for certification. Table 5.2 below details reactor designs that represent the currently proposed fleet of nuclear plants in the U.S.

Table 5.2
NRC Certification Status for Currently Proposed U.S. Reactor Types

Reactor	Vendor	Technology Generation	Approximate Capacity (MWe)	Reactor Type	Date of Application if Under Review	Certification Status	Target Certification
ABWR*	GE et al	III+	1,300	BWR	N/A	Certified / Amendment under review	1997 / 2011
ESBWR*	GE	III+	1,550	BWR	2005	Active Review	2011
AP1000*	Westinghouse	III+	1,100	PWR	2008	Certified / Amendment under review	2006 / 2011
EPR*	AREVA NP	III+	1,600	PWR	2007	Active review	2012
US APWR	Mitsubishi	III+	1,700	PWR	2007	Active review	>2011

Sources and Notes:
BWR stands for Boiling Water Reactor. PWR stands for Pressurized Water Reactor.
* Supported by electricity generating firms or organizations publicly investigating possible construction in the U.S
** Expected date of submission.
"Advanced Nuclear Power Reactors," World Nuclear Association, September 2009.
"Design Certification Applications for New Reactors," US Nuclear Regulatory Commission, December, 2009.
"Backgrounder on New Nuclear Plant Designs," US Nuclear Regulatory Commission, June 2008.
"New Commercial Reactor Designs," US Energy Information Administration, November 2006.
"Small Nuclear Reactor Designs," World Nuclear Association, October 2009.

In addition to new nuclear designs for centralized power generation, smaller reactor designs are also being developed.[6] At the lower end of the capacity spectrum for these designs are "package" nuclear plants, or mini-reactors, ranging from about 10 to 50 MW, with a 5-10 year life that can be replaced and refurbished offsite. These would be used primarily for large, remote heat and power applications, such as oil shale, tar sands, *etc.*, though in principle could be used

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5 "Advanced Nuclear Power Reactors," World Nuclear Association, September 2009.

6 See "Nuclear Power in a Small Package: LANL Has Stake In Mini-Reactor," Albuquerque Journal, December 15, 2008.

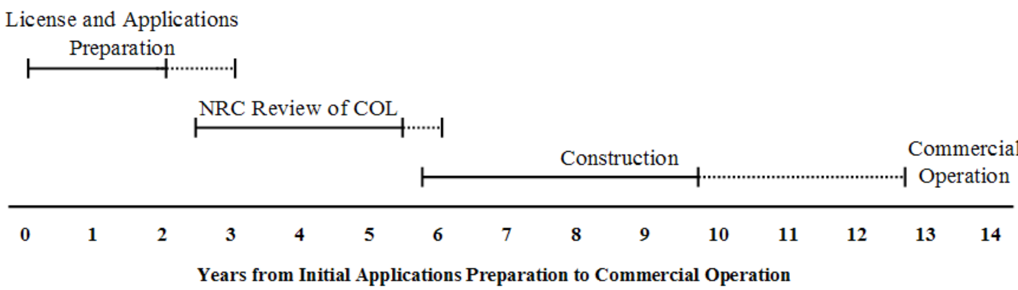
for grid-based power generation. Licensing of these units is likely to be delayed relative to the large-scale designs currently under consideration, as they are relatively low priority for the NRC.

At the higher end of the range of small-scale reactor designs are modular units with capacities ranging from about 50 to 300 MW and anticipated service lives of about 50 to 60 years.[7] These units potentially can be used for grid-based power generation, and multiple modules may be linked together to create plant capacities of several hundreds of MW. Two vendors, Babcock & Wilcox and NuScale Power, have modular designs in the works and anticipate filing for NRC certification of their designs in 2011.[8] Current industry sentiment suggests that small-scale reactors like those being designed by Babcock & Wilcox will not be built in the U.S. before the middle of the next decade.[9]

5.D NUCLEAR SITING, PERMITTING, AND REGULATORY APPROVAL PROCESS

Nuclear plants must go through several licensing and permitting steps before both federal and state regulatory bodies prior to the start of construction. These processes contribute a significant amount of time to the planning horizon for a new nuclear plant. At the federal level, developers must receive an Early Site Permit (ESP), Design Certification (DC), and a Combined Construction and Operating License (COL) from the NRC before the plant may be built. In parallel with federal licensing and permitting, developers must also receive state siting permits and other state regulatory approvals. Figure 5.3 below shows an estimated timeline for nuclear plant licensing and construction.

Figure 5.3
Approximate Timeline of Nuclear Plant Development



Sources and Notes: Based on timeframes expected by several nuclear developers, including Ameren, Constellation Energy, Dominion, Duke Energy, Entergy, NRG, PA Power and Light, Progress Energy, and Unistar Nuclear Energy LLC.

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7 See "Small Nuclear Power Reactors," World Nuclear Association, October 2009. http://www.world-nuclear.org/info/inf33.html.

8 "B&W Signs MOU with Utilities on mPower Reactors," The Nuclear N-Former, June 10, 2009.

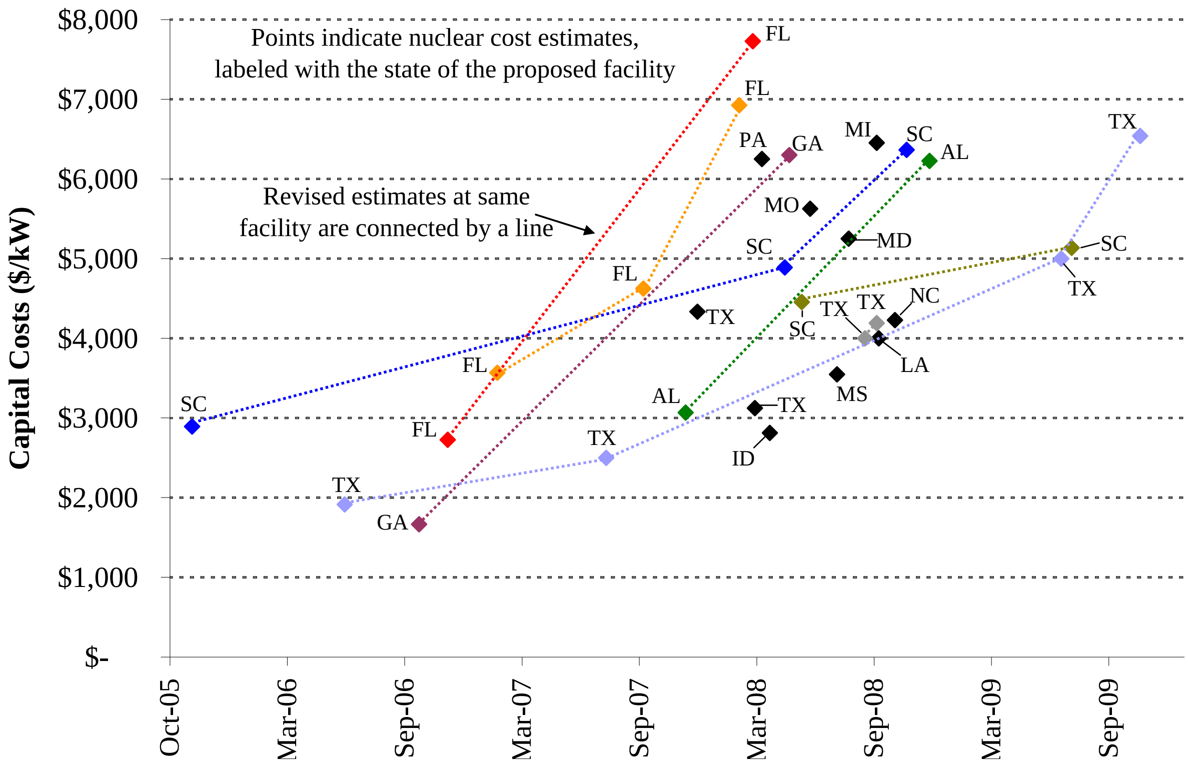
9 See "The New Nukes," The Wall Street Journal, September 8, 2009.

In Connecticut, the timeframe for a hypothetical new nuclear unit would be longer than the 10-15 years illustrated in the timeline, since Connecticut is not yet at the start of this timeline. Although this implies that a potential new nuclear unit is well beyond the ordinary 10-year time horizon of this report, we perform an analysis of new nuclear capacity in Connecticut in 2020 in order to illustrate the potential impacts and compare those impacts with other resource solutions. Nuclear plants are naturally long lead time decisions, and if one is to be considered at all, the investigation must begin far in advance of a potential online date.

5.E CONSTRUCTION COST OF NUCLEAR GENERATION

Despite some cost savings expected due to greater standardization of reactor designs and streamlining of the permitting and regulatory approval process, nuclear capital costs remain higher than the cost of other conventional baseload generation technologies. Cost projections for new nuclear capacity increased substantially between 2005 and 2008 as labor costs rose, and commodity prices for construction materials escalated dramatically. This trend of rapidly rising input costs reversed somewhat with the global economic crisis and U.S. recession, although few nuclear construction cost estimates have since been revised to reflect these subsequent cost declines. Figure 5.4 below illustrates the announced cost of a number of planned nuclear generators in the U.S.; each point indicates a cost estimate made at the indicated time; two points connected by a line indicate a later update for the same proposed plant. It must be noted that many of these estimates from published announcements include financing costs, which can easily be 25 percent to 35 percent of the total cost of the plant. This explains why many of these estimates are significantly higher than recent published estimates of nuclear “overnight” capital costs, which generally do not include the financing costs.

Figure 5.4
Announced Costs of Proposed U.S. Nuclear Plants



Sources and Notes: Nuclear capital costs estimates from different sources or at different times may not be directly comparable, as many do not specify whether they include costs of construction financing, interconnection costs, *etc.*

Building a nuclear plant in Connecticut would likely cost more than the U.S. average, since New England is a relatively high-cost region for construction projects. For example, the U.S. Army Corps of Engineers estimates a 20 percent premium in Connecticut over national averages for all civil works projects, primarily due to higher labor costs.[10]

5.F COST RECOVERY AND FINANCING FOR NUCLEAR GENERATION

Developing a nuclear plant involves substantial financial risk, significantly greater in some respects than most other generating technologies. Nuclear power is extremely capital-intensive, with high – and highly uncertain – capital costs, as seen above. A nuclear plant also has a very long lead time, which increases construction financing costs, and also has the potential for construction delays that can increase costs further. The long lead time also means that it can be difficult to be sure that there will be sufficient demand for its output by the time it is completed.

10 *Civil Works Construction Cost Index System*, U.S. Army Corps of Engineers, EM1110-2-1304, March 2009.

The operating income of a merchant nuclear plant is also exposed to uncertainty in the price of natural gas and CO_2 emission allowances, since these will both have a major effect on wholesale market power prices and thus revenues. In contrast, the operating income of a merchant gas plant in New England is somewhat insulated from changes in gas and CO_2 prices, since gas plants frequently set the market price of power (thus both their costs and revenues both move with gas and CO_2 prices, leaving their net revenue less affected.)

These factors imply that it may be easier to develop a nuclear plant under cost-recovery regulation, as opposed to merchant operation.[11] Since nuclear costs are not influenced by CO_2 and gas prices, regulated cost recovery may help to insulate customers' costs from these external influences (though this also means that customers would not receive the benefit if gas and CO_2 prices are low). As shown in Figure 5.1 above, most of the currently proposed nuclear plants are located in the southeastern U.S., a region that remains dominated by cost-recovery retail regulation. However, using a cost-recovery regulatory approach does not necessarily imply EDC ownership.

The Energy Policy Act of 2005 included several provisions that will help to encourage new nuclear plants. It created an eight-year, \$18/MWh production tax credit for the output of the first 6,000 MW of new nuclear capacity, limited federal insurance against costs associated with delays in commercial operation, and perhaps most importantly, federal loan guarantees for up to 80 percent of total project cost. Such loan guarantees are viewed as necessary by some in the industry for developing new nuclear facilities (*e.g.*, Exelon, PPL, NEI). Given the high interest in the production tax credit and loan guarantees expressed by current nuclear proposal sponsors, however, such federal support may not be available for projects not already underway.

5.G NUCLEAR DEVELOPMENT POTENTIAL IN CONNECTICUT

Although no new nuclear plants have been proposed for New England, there are five operating units at four sites, and three additional sites where reactors have been shut down and decommissioned. New England already gets a greater fraction of its electricity from nuclear power than the U.S. as a whole. Table 5.3 below shows the operating nuclear plants in New England; one of the sites (Millstone, with two operating reactors and a third shut down) is located in Connecticut. It is usually easier to develop a new nuclear unit at an existing "brownfield" reactor site, rather than at a greenfield site. Brownfield sites offer access to existing infrastructure (*e.g.*, transmission, cooling water, rail access), may streamline the siting and licensing processes, and might also offer greater public acceptance. However, no siting comparison or analysis has been performed as part of this report.

[11] This view is widely shared by potential nuclear developers. For example, Dan Weekley, managing director of Northeast government affairs at Dominion: "You're going to have to build a nuclear unit in a regulated environment, not deregulated like Connecticut." ("New Nukes?" Liese Klein, Connecticut Business News Journal, August 4, 2008.) Similarly, Duke Energy's Chairman James Rogers: "There is almost no chance that a new U.S. nuclear plant would be built in a state with a deregulated electricity market." ("Duke CEO a 'skeptical optimist' on future of U.S. nuclear power," Nucleonics Week, June 21, 2007.)

Table 5.3
Operating Nuclear Reactors in New England

Unit Name	Operator	Reactor	Vendor/Type	Location	Current License Expiration Date	MW Rating	Site Size
Pilgrim	Entergy	BWR	GE Type 3	Plymouth, MA	6/8/2012	677	1600 acres
Vermont Yankee	Entergy	BWR	GE Type 4	Vernon, VT	3/21/2012	604	125 acres
Seabrook	FPL Group	PWR	Westinghouse 4-Loop	Seabrook, NH	3/15/2030	1,245	889 acres
Millstone 2	Dominion	PWR	Combustion Engr	Waterford, CT	7/31/2035	877	500 acres (all units)
Millstone 3	Dominion	PWR	Westinghouse 4-Loop	Waterford, CT	11/25/1945	1,235	500 acres (all units)
Total Capacity						4,639	

Source: 2009 CELT Report, ISO New England, April 2009. Millstone 3 capacity was adjusted for the capacity uprate that took effect in Fall 2008.

Connecticut is one of 12 states with a moratorium on new nuclear construction.[12] This impediment is found in Connecticut General Statute 22a-136:

> "No construction shall commence on a fifth nuclear power facility until the Commissioner of Environmental Protection finds that the United States Government, through its authorized agency, has identified and approved a demonstrable technology or means for the disposal of high level nuclear waste. As used in this section, "high level nuclear waste" means those aqueous wastes resulting from the operation of the first cycle of the solvent extraction system or equivalent and the concentrated wastes of the subsequent extraction cycles or equivalent in a facility for reprocessing irradiated reactor fuel and shall include spent fuel assemblies prior to fuel reprocessing."

Although a 1987 amendment of the Nuclear Waste Policy Act of 1982 directs the Administration to study a nuclear waste repository at Yucca Mountain, its operation has not been approved and the Secretary of Energy has testified that the current Administration intends to terminate this project.[13] However, there currently exists no obvious alternative site or disposal technology. Given that no means of nuclear waste disposal has been approved and there appears to be little near-term prospect for such approval, legislative action would be necessary to reverse the moratorium before construction could begin on a new nuclear plant within Connecticut. Beyond

[12] In addition to CT, the states with expansion prohibitions are CA, HI, IL, KY, ME, MN, MT, OR, WV, WI, and VT, with half of the states actively pursuing repeal. See "Nuclear Power Across the US" presentation to the CEAB by Dominion, December 7, 2009.

[13] U.S. Government Accountability Office, *Nuclear Waste Management: Key Attributes, Challenges and Costs for the Yucca Mountain Repository and Two Potential Alternatives*, GAO-10-48, November 2009.

this, the spent fuel issue may affect public perception and acceptability of new nuclear development. Nonetheless, if this hurdle can be overcome, the spent fuel management question would likely have only a very modest economic impact on new nuclear development, regardless of when and whether a permanent storage solution is agreed. It is relatively inexpensive (compared to the capital cost of the plant itself) to store spent nuclear fuel onsite essentially indefinitely in dry storage, and those costs would be delayed many decades until after the plant is shut down. The present value of the cost of long-term onsite storage is less than one percent of the initial capital cost of a new nuclear plant, so long-term storage costs appear to be manageable for the time being, and should not be considered a major hurdle to overcome.

As discussed above, it may be difficult to develop a merchant nuclear plant, and no merchant developers are known to be considering a nuclear plant in New England. Thus if Connecticut would like nuclear power to be a potential future option, it will likely need to take action to facilitate the process. There are a number of steps that would need to be taken, including:

- Identify potential developer(s) and owner(s);
- Identify potential cost recovery approaches and assess their likely impact on costs and risk allocation;
- Identify and perform preliminary feasibility assessment of potential sites, including existing nuclear sites and greenfield sites;
- Identify siting and licensing requirements;
- Perform a preliminary cost estimate (site specific, if possible);
- Identify federal and potential state-level incentives; and
- Further research regarding potential legal and regulatory barriers, and what may be required to overcome them.

One of the most important steps may be to identify and ultimately enable a cost recovery approach that will be attractive to a potential developer, financing entities, and electricity consumers. If that is in place, the developer may be willing to pursue some of the other steps.

5.H POTENTIAL IMPACTS OF NEW NUCLEAR GENERATION IN CONNECTICUT

In order to compare the long-run potential of new nuclear generation in Connecticut to other resource solutions, this section analyzes the electricity market and environmental impact of a hypothetical new nuclear plant presumed to enter service in 2020. Given the regulatory approval and construction timeline described earlier, even a decision to pursue nuclear development now would almost certainly miss a 2020 in-service date. However, the market and environmental impacts would be similar for a plant that came on-line in the 2020 – 2025 timeframe. Thus, this strategy is intended to be more illustrative than practical in nature, which is why the analysis is shown separately from other resource strategies in this IRP.

In the Nuclear Strategy, we assume a new nuclear unit to be operable at the existing Millstone Nuclear Power Station by January 1, 2020. The Millstone site is selected on the basis of economic reasonability – it is an existing site with likely cost advantages when compared to a new, or greenfield, site. [14] Nonetheless, if Connecticut were to pursue a nuclear strategy, a full and comprehensive nuclear siting analysis should be conducted. This illustrative example is by no means intended as a substitute such an analysis.

The reactor chosen for our analysis is the AP1000, designed by Westinghouse Electric Company LLC, a Toshiba company. The AP1000 is a Generation III+ design type and was first certified by the NRC in 2006. However, Westinghouse submitted a design amendment to the NRC in 2008, and, due to a recent design concern raised by the NRC,[15] the AP1000 will probably not receive final NRC certification before 2012.[16]

To model new nuclear capacity for the Nuclear Strategy in DAYZER, we assume the reactor characteristics noted in Table 5.4. For modeling purposes, we assume a construction schedule of 6 years, which is consistent with assumptions in the 2008 Connecticut IRP, and only one year additional to the schedule assumed by Westinghouse.[17]

Table 5.4
Assumed Characteristics of Modeled Nuclear Reactor

Parameter	Units	Value
Vendor	-	Westinghouse
Reactor Design	-	AP1000
Net Capacity	*(MW)*	1,100
Capital Cost	*(2010$/kW)*	5,000
FOM	*(2010$/kW-yr)*	111
VOM	*(2010$/MWh)*	1.8
Online Year	*(year)*	1/1/2020
Economic Life	*(years)*	40
Capital Charge Rate	*(%)*	8.21%
Heat Rate	*(Btu/kWh)*	10,207
Capacity Factor	*(%)*	89%
Lead Time	*(years)*	6

[14] The Millstone site is owned by Dominion Nuclear Connecticut, Inc. (Dominion) and nothing herein should be interpreted as indicating that Dominion intends to pursue further development at the Millstone site.

[15] "NRC Informs Westinghouse of Safety Issues with AP1000 Shield Building," U.S. NRC, October 15, 2009, http://www.nrc.gov/reading-rm/doc-collections/news/2009/09-173.html.

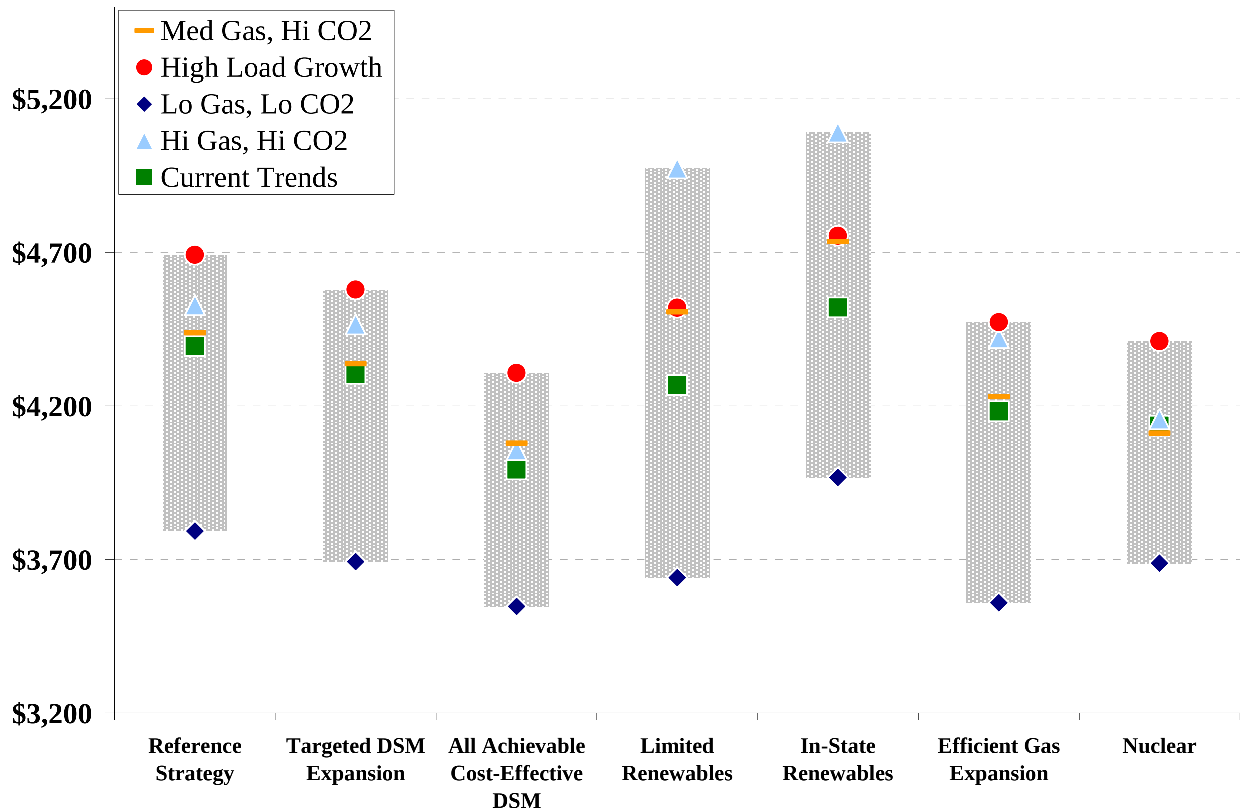
[16] "NRC to Meet With Toshiba on Nuclear-Reactor Design," Bloomberg, November 12, 2009, http://www.bloomberg.com/apps/news?pid=20601101&sid=aG5TOwGH.f64.

[17] Westinghouse AP1000 brochure. http://www.westinghousenuclear.com/docs/AP1000_brochure.pdf.

The Nuclear Strategy was run for the year 2020 under the five scenarios described in Section II.[18] In order to estimate costs to customers, we assumed that the nuclear plant will be built under a cost-of-service arrangement (*e.g.*, through various contractual arrangements), meaning that customers would pay operating costs and a return of and return on invested capital under a levelized cost recovery schedule. Because customers would pay for capital costs, and thus implicitly bear some construction cost risk, the developer's cost of capital is assumed to be consistent with that of a regulated utility.[19]

Figure 5.5 compares the total customer costs of the Nuclear Strategy in 2020 to other resource strategies, and Figure 5.6 shows average customer costs.

Figure 5.5
Total Customer Costs of Selected Resource Strategies in 2020 ($2010)



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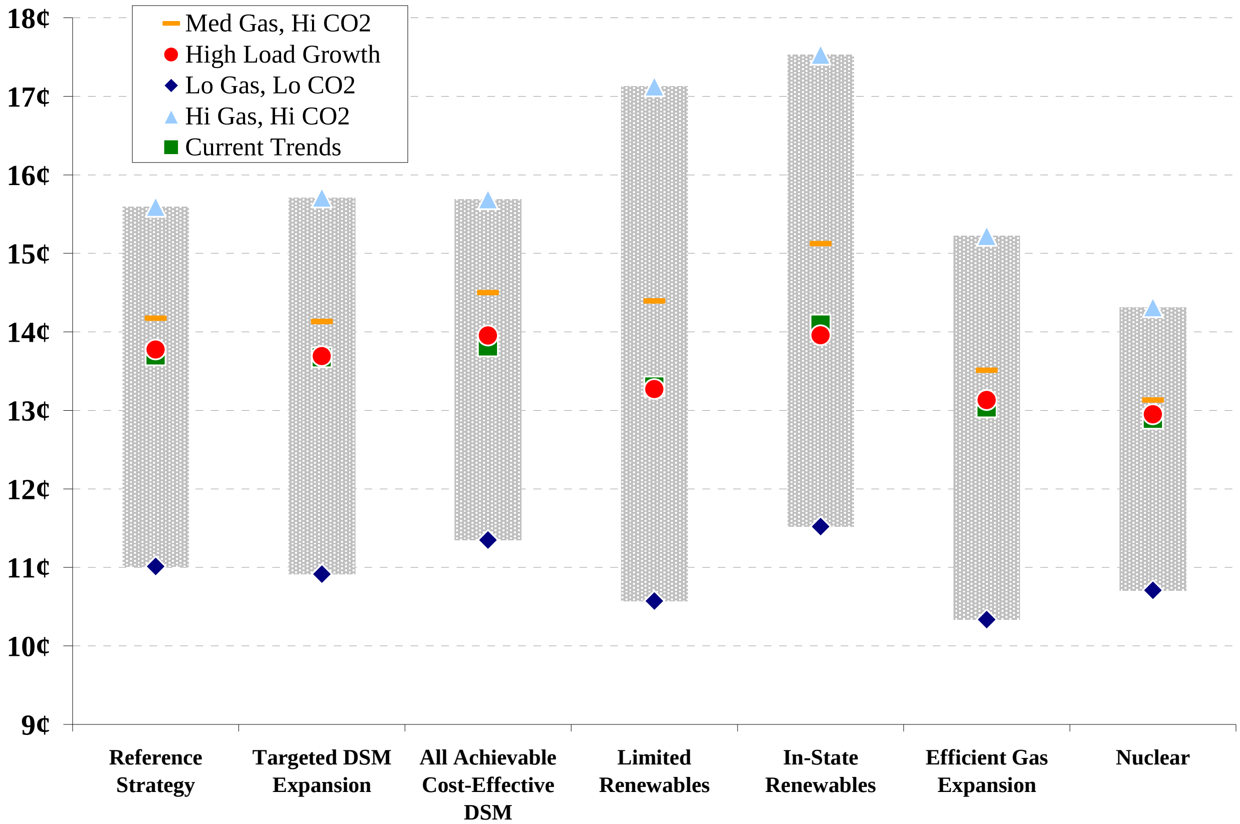
[18] The five scenarios are Current Trends, High Load Growth, Medium Gas/High CO_2, High Gas/High CO_2 and Low Gas/Low CO_2.

[19] Specifically, we assumed a debt/equity proportion of 50 percent, a cost of debt of 6 percent and an equity rate of 10.75 percent.

Figure 5.6
Average Customer Costs of Selected Resource Strategies in 2020 ($2010)



Figures 5.5 and 5.6 both show the Nuclear Strategy as having costs in the lower end of the range of the resource strategies examined. This is largely a function of the assumed capital costs; higher actual capital costs would shift the costs of the Nuclear Strategy up by identical amounts across all scenarios. The key benefit of the Nuclear Strategy is seen in the low variation of cost outcomes across scenarios, which is a function of both the cost-of-service assumption, and the insulation from natural gas and CO_2 emissions price exposure. Customer costs in the Nuclear Strategy are relatively immune to variations in market outcomes, and therefore are likely to be more stable over time.

Like renewable generation, nuclear power does not directly emit SO_2, NO_X, or CO_2 into the atmosphere. Figure 5.7 shows Connecticut CO_2 emissions across alternative resource strategies and scenarios. The Nuclear Strategy has the lowest CO_2 emissions of all resource strategies tested, and this result is robust across various scenarios. A similar outcome is shown for Connecticut NO_X emissions on the ten highest energy demand days (HEDD) when air pollution concentrations are most likely to exceed health-based standards. As seen in Figure 5.8, the Nuclear Strategy has lower NO_X emissions on critical days than other resource strategies, in every scenario.

Figure 5.7
Connecticut CO_2 Emissions From Electricity Generation in 2020

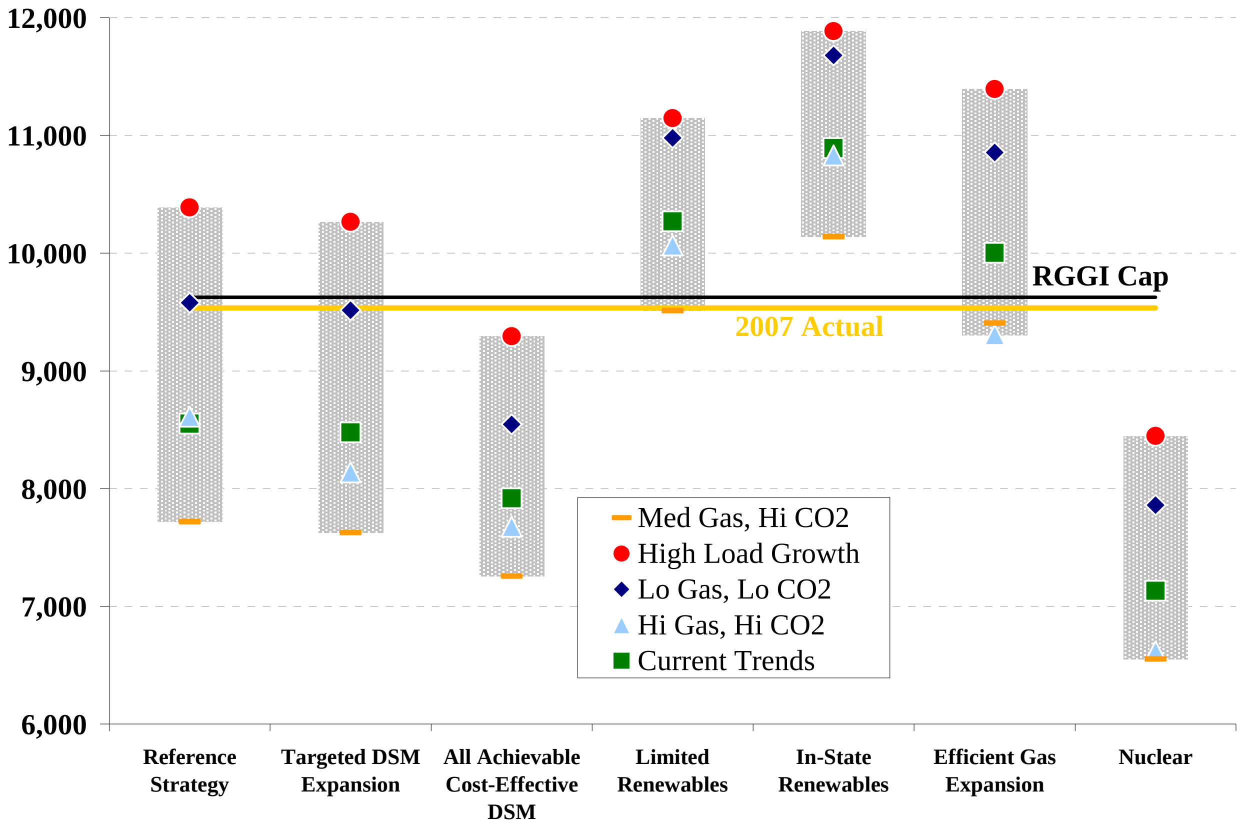
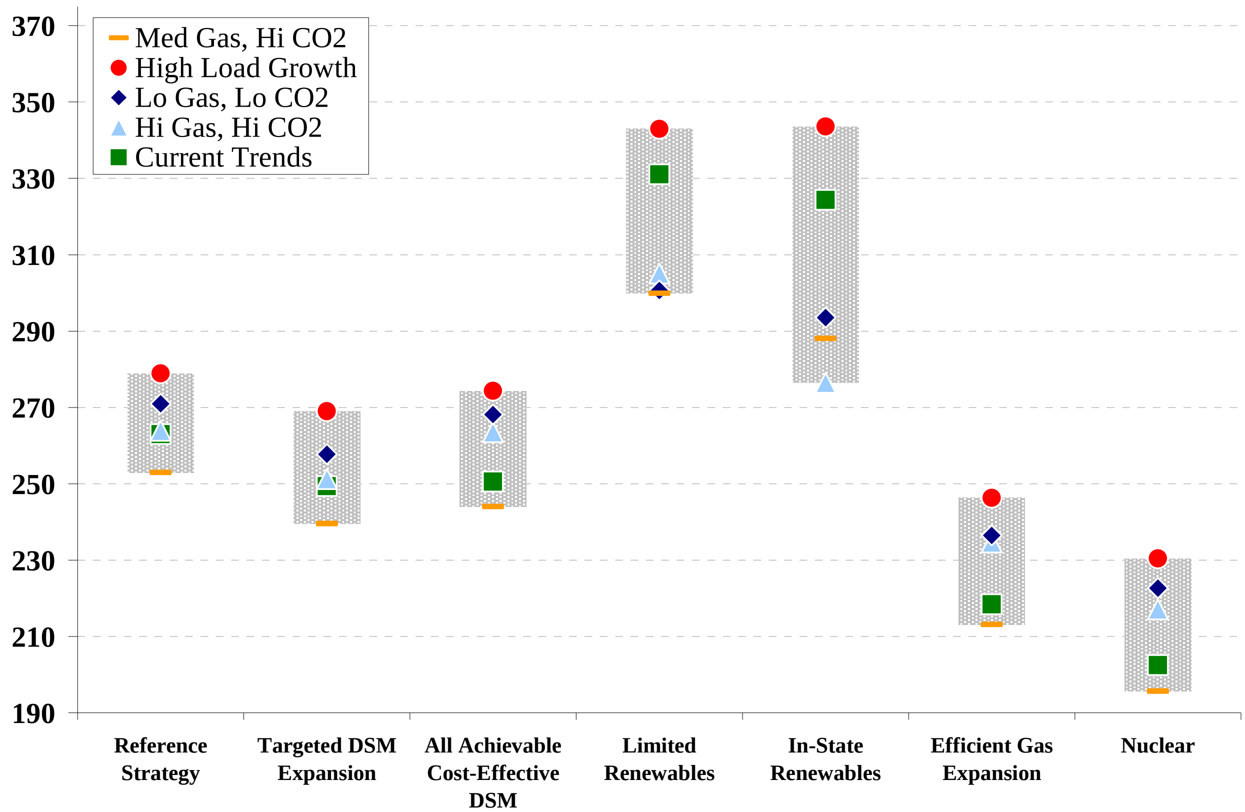
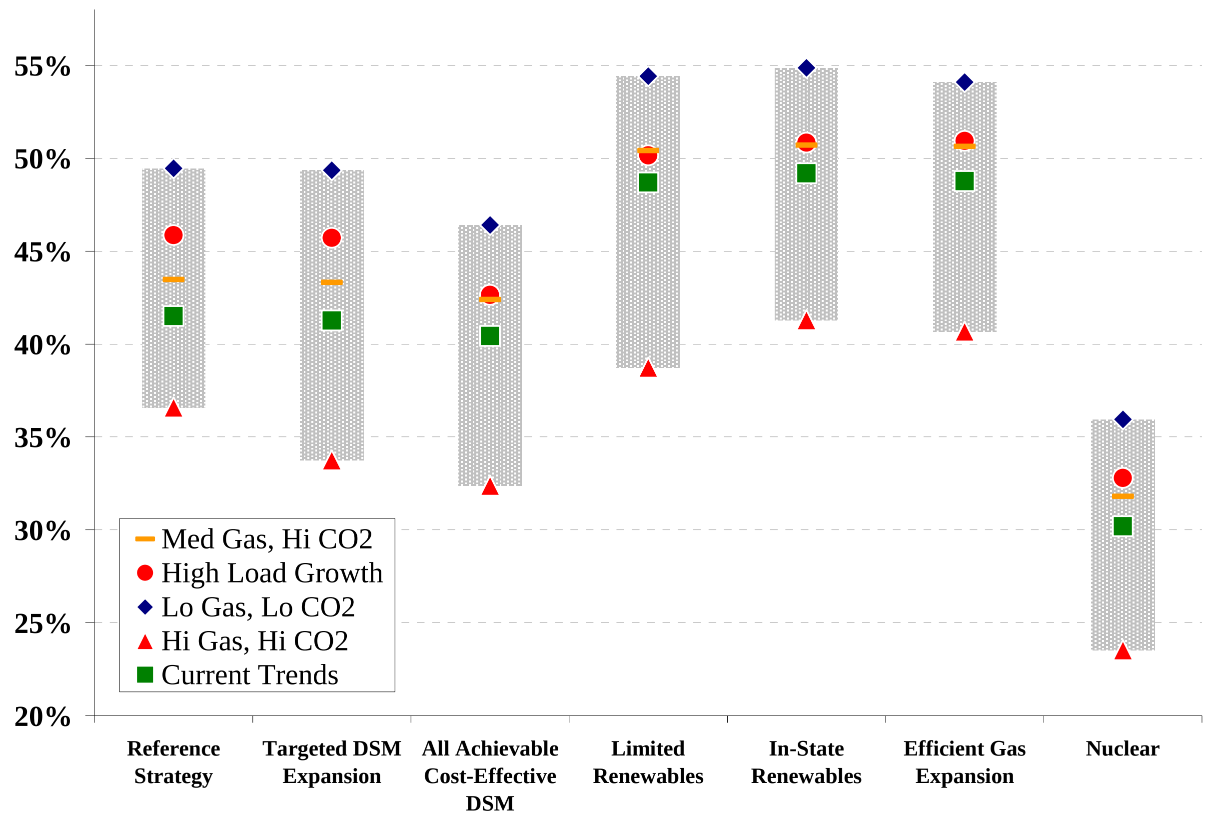


Figure 5.8
Connecticut NO_X Emissions From Electricity Generation on Highest Energy Demand Days in 2020



A Nuclear Strategy could also reduce natural gas use for electricity generation, even more than renewables or additional efficiency. This is shown in Figure 5.9, which displays the fraction of Connecticut generation in 2020 that comes from natural-gas fired capacity.

Figure 5.9
Share of Natural-Gas Fired Generation in Connecticut in 2020



Although there appear to be economic, environmental and energy security benefits to nuclear development, the economic results must be viewed with caution, owing to several limitations of this analysis approach:

- As discussed before, the actual capital cost of a new nuclear plant is subject to high degree of uncertainty, particularly if a plant is built under a cost-of-service arrangement where customers bear some of the construction cost risk. Shifting more construction cost risk onto a developer, on the other hand, would likely raise any firm bid or contract for construction and/or increase the developer's cost of capital, which would have the same effect.

- Only annual costs incurred in 2020 are compared. Once built, the value of a nuclear plant increases if natural gas or CO_2 prices rise in the future – producing benefits to customers paying for nuclear generation under a cost-of-service arrangement if natural gas or CO_2 prices increase over time. Under cost-of-service principles, however, customers would not benefit from lower than expected gas or CO_2 prices. A nuclear plant built under a cost-of-service arrangement may have (*ex ante*) an uncertain capital cost, but, once built (at whatever cost) will have low and stable operating costs that would limit customers' exposure to future market risks.

- While the economic results are highly uncertain, the environmental results are more predictable and likely to occur.

Section III.6
Combined Heat and Power

6. COMBINED HEAT AND POWER

6.A SUMMARY AND KEY FINDINGS

Summary

Combined heat and power (CHP) is an integrated system that combines electricity production with a heat recovery system to utilize the thermal output that would otherwise be wasted. Most CHP applications take the form of distributed generation (DG), located near the point of energy use. By utilizing the waste heat from power generation to serve a thermal load (and also by reducing transmission and distribution network losses in DG applications), overall energy use is more efficient.

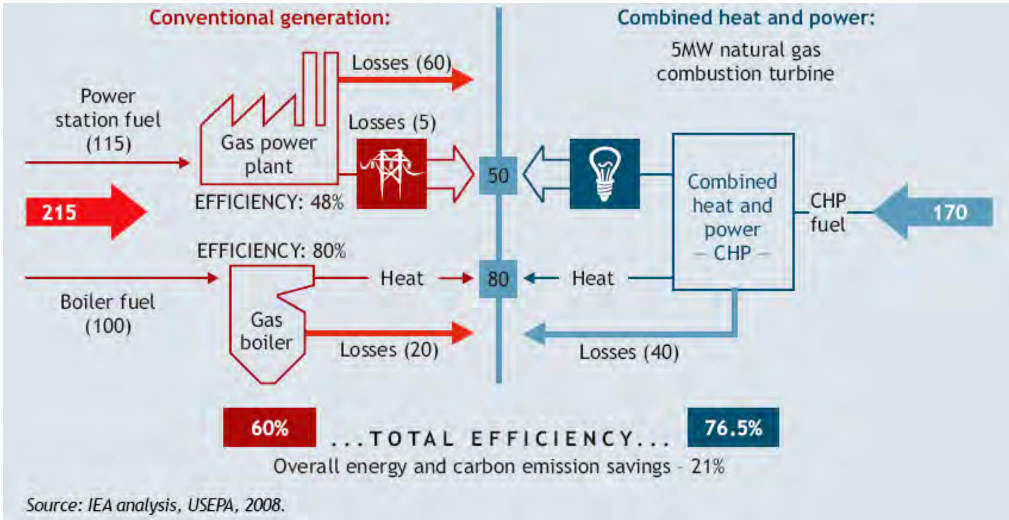
Key Findings

- Connecticut already enjoys high penetration of CHP for the most attractive large industrial applications, so there is limited remaining potential in this sector.
- Smaller, mostly commercial and institutional applications have significant remaining technical potential in Connecticut.

6.B OVERVIEW OF CHP TECHNOLOGIES

Figure 6.1 illustrates the benefits of CHP compared to conventional generation where the electricity and heat are separately produced.

Figure 6.1
Example for Efficiency Gains of CHP



The overall efficiency of a CHP system is typically in the range of 70 percent to 90 percent (compared to 50 percent to 60 percent for conventional generation). The major factors that affect the efficiency of CHP include the generator technology, fuel type, plant size, and power-to-heat ratio.

The main components of CHP systems are the prime mover (engine or drive system), the electricity generator, the heat recovery system, and the control system. The technologies are often classified by the prime mover in the system. The main types are reciprocating engines, gas turbines, steam turbines, microturbines, and fuel cells. Table 6.1 summarizes some of the advantages and disadvantages of each type, and Table 6.2 illustrates typical cost and performance characteristics.

Table 6.1
Comparison of CHP Technologies

CHP System		Advantages	Disadvantages
Reciprocating Engine	Spark Ignition; Diesel/ Compression Ignitions	High power efficiency with partload operational flexibility. Fast start-up. Relatively low investment cost. Can be used in island mode and have good load following capability. Can be overhauled on site with normal operators. Operate on low-pressure gas.	High maintenance costs. Limited to lower temperature cogeneration applications. Relatively high air emissions. Must be cooled even if recovered heat is not used. High levels of low frequency noise.
Gas Turbine		High reliability. Low emissions. High grade heat available. No cooling required.	Require high pressure gas or inhouse gas compressor. Poor efficiency at low loading. Output falls as ambient temperature rises.
Steam Turbine		High overall efficiency. Any type of fuel may be used. Ability to meet more than one site heat grade requirement. Long working life and high reliability. Power to heat ratio can be varied.	Slow start up. Low power to heat ratio.
Microturbine		Small number of moving parts. Compact size and light weight. Low emissions. No cooling required.	High costs. Relatively low mechanical efficiency. Limited to lower temperature cogeneration applications.
Fuel Cells		Low emissions (NO_x and SO_x) and low noise. High efficiency over load range. Modular design.	High costs. Low durability and power density. Fuels requiring processing unless pure hydrogen is used.

Source: Catalog of CHP Technologies, U.S. Environmental Protection Agency, December 2008.

Table 6.2
Typical Cost and Performance Characteristics of CHP Technologies

	Steam Turbine [1]	Reciprocating Engine	Gas Turbine	Microturbine	Fuel Cells
Capacity (kW)	500 - 250,000	100 - 5,000	500 - 250,000	30 - 250	5 - 2,000
Installed Costs ($/kW) [2]	430 - 1,100	1,100 - 2,200	970 - 1,300 [3]	2,400 - 3,000	5,000 - 6,500
O&M Costs (cents/kWh) [2]	< 0.5	0.9 - 2.2	0.4 - 1.1	1.2 - 2.5	3.2 - 3.8
Electric Efficiency (percent), HHV	10% -36%	28% - 39%	21% - 37%	22% - 26%	33% - 43%
Heat Rate (Btu/kWh), HHV	9,500 - 34,000	8,750 - 12,000	9,000 - 16,000	13,000 - 15,000	8,000 - 9,500
Power to Heat Ratio	0.1 - 0.3	0.5 - 1.0	0.5 - 2.0	0.4 - 0.7	1.0 - 2.0
Availability	Near 100%	92% - 97%	90% - 98%	90% - 98%	> 95%
Start-up Time	1 hr - 1 day	10 sec	10 min - 1 hr	60 sec	3 hrs - 2 days
Noise	high	high	moderate	moderate	low
Fuels	all	natural gas, biogas, propane, landfill gas	natural gas, biogas, propane, oil	natural gas, biogas, propane, oil	hydrogen, natural gas, propane, methanol
NO_x Emissions (lbs/MMBtu) [4]	Gas 0.1 - 0.2 Wood 0.2 - 0.5 Coal 0.3 - 1.2	0.013 rich burn [5] 0.8 lean burn	0.17 - 0.25	0.08 - 0.20	0.011 - 0.016

Source: Catalog of CHP Technologies, U.S. Environmental Protection Agency, December 2008.

Notes:

[1] For steam turbine, not entire boiler package.
[2] All costs are in 2007 dollars.
[3] This price range is valid for turbines with a capacity of 5-40 MW. Costs are higher for smaller systems (*e.g.*, $3,324/kW for a 1 MW gas turbine).
[4] Does not include selective catalytic reduction (SCR)
[5] With 3-way catalyst exhaust treatment.

Because fuel cells are considered Class I resources under Connecticut's renewable portfolio standard (a provision only found in Connecticut), they occupy a unique role in the potential CHP landscape. Fuel cells are electrochemical conversion devices that produce direct current electricity (and heat) from fuel and oxidants. Because the chemical reactions that produce the electricity are exothermic, they give off waste heat that is available for CHP applications, enhancing their overall energy efficiency. Today's fuel cell systems operate with hydrogen fuel, typically derived from other fuels such as natural gas, although it is possible to build fuel cells that run directly on other types of fuels, such as methanol. Since the main source of hydrogen is natural gas, it is not emission-free, but still relatively clean compared to most other conventional generation technologies. On the cost side, Table 6.2 shows that fuel cells have higher capital costs, but greater fuel efficiency than other available CHP technologies. Table 6.3 provides a summary of available fuel cell technologies, with a list of typical applications and major industry players.

Table 6.3
Summary of Fuel Cell Technologies

Technology	System Output	Efficiency Electrical	Applications	Advantages	Disadvantages	Industry Players
Polymer Electrolyte Membrane (PEM)	1KW -250 KW	25-40%	Transportation, Portable Power, Backup Power, Small Dist.Gen.	Solid electrolyte reduces corrosion & electrolyte management problems; low temperature; quick startup	Requires expensive catalysts (platinum), sensitivity to fuel impurities; low temperature waste heat	Ballard, Plug, United Technology, Nedstack, Nuvera, ReliOn; auto makers including Toyota and GM
Direct Methanol and Direct Liquid Fuel Cells (DMCF & DLFC)	< 20KW	40%	Consumer electronics and other	Direct technology limits size and complexity	Potential more expensive catalyst, water management issues	**Medis,** PolyFuel, SFC Smart Fuell Cell, Acta, CMR Fuel Cells, Samsung, Sony, MTI Micro
Alkaline (AFC)	10KW-100KW	60%	Military, Space	Cathode reaction faster in alkaline electrolyte, higher performance	Expensive removal of CO2 from fuel and air streams required	Nuvera, Nedstack, United Technologies
Phosphoic Acid (PAFC)	50KW-1MW	32-40% higher with CHP	Dist.Gen.	Higher efficiency with CHP, Able to handle hydrogen impurities	Expensive catalysts, low current and power; large weight, size	United Technologies
Molten Carbonate (MCFC)	1KW-3MW+	45-47% higher with CHP	Electric Utility, Large Dist.Gen.	High efficiency, fuel flexibility, flexible catalysts, higher CHP efficiency	High temp speeds corrosion, complex electrolyte management, slow startup	**FuelCell**
Solid Oxide (SOFC)	5KW-50MW+	35-43% higher with CHP	Electric Utility, Large Dist.Gen.	High efficiency, fuel flexibility, flexible catalysts; solid electrolyte reduces electrolyte management problems; CHP capable	High temp speeds corrosion, slow start up, Extreme heat difficult to handle	Large SOFC: **FuelCell,** GE, Rolls Royce, Siemens, Mitsubishi

Source: Cook, B. Fuel Cell Industry Review. JP Morgan report, North America Equity Research, November 2007.

6.C INDUSTRIAL AND COMMERCIAL APPLICATIONS FOR CHP

The implementation of CHP systems is mainly driven by economics, which ultimately depends on the cost and performance of CHP technologies as compared to those of separate provision of heat and power. A key driver of the economics of a CHP unit is the coincidence of the electric and thermal loads of the host site. Grid connection and standby charges can also play an important role, and are cited by some as major barriers to market entry for CHP systems in some jurisdictions.[1,2,3]

According to International Energy Agency's CHP Scorecard for United States, 88 percent of current CHP capacity is in industrial applications, primarily providing heat and power to large industries such as chemicals, paper, refining, food processing, and metals. There are two main reasons for this. First, larger CHP systems are less capital intensive on a per-kW basis than smaller ones. This is seen in Table 6.2, which shows an estimate of $970/kW installed cost for a 40 MW gas turbine CHP, but $1,300/kW for a 5 MW gas turbine, and $2,200/kW for a 100 kW reciprocating engine CHP (2007 dollars). Second, industrial facilities typically have higher and more stable thermal loads coincident with the electric loads, which increases the overall utilization of the CHP system.[4] In comparison, thermal loads for commercial applications are often primarily space heating loads, which are highly seasonal.

Commercial and institutional applications account for 12 percent of U.S. CHP capacity. This could expand further with certain developments in technology; *i.e.*, cost reduction in smaller CHP systems (microturbines and fuel cells), use of thermal output for absorption cooling, and heat storage. A market study prepared for U.S. Department of Energy in 2000 estimated that the technical potential for CHP systems in existing commercial and institutional buildings in the U.S. was about 77,000 MW in terms of the electric capacity, almost 8 times higher than the then currently installed capacity.[5] According to the study, more than 85 percent of this potential comes from applications of less than 5 MW. Office buildings, schools, hospitals, and hotels provide the highest potential capacities.

Construction lead times for CHP installations can vary according to the installation, with smaller installations generally having shorter construction times (though this can vary by particular application). The siting and permitting process can require additional time prior to start of construction, and has been identified by some as a barrier to CHP penetration. A comparison of the siting and permitting process in Connecticut with other states has not been performed.

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1 Hedman, B., *et al. Combined Heat and Power Market Potential for New York State*. Energy Nexus Group (2002).

2 International Energy Agency, *Combined Heat and Power: Evaluating the Benefits of Greater Global Investment*, IEA/OECD (2008).

3 Brooks, S., *et al. Combined Heat and Power: Connecting the Gap between Markets and Utility Interconnection and Tariff Practices (Part I),* American Council for an Energy-Efficient Economy (2006).

4 Under most current CHP technologies, the ideal power-to-heat ratios fall into a range of 0.5 to 2.5.

5 *The Market and Technical Potential for Combined Heat and Power in the Commercial/Institutional Sector*. ONSITE SYCOM Energy Corporation (2000).

6.D EMISSIONS PERFORMANCE OF CHP

Due to higher efficiencies compared to central station generation systems and avoided T&D losses, CHP can reduce fuel consumption; hence, it would produce correspondingly lower emissions of pollutants related to fuel consumption, such as greenhouse gases and SO_2. However, since the smaller size generators in typical CHP systems are less efficient than large central generators (*e.g.*, the electric efficiency of a 40 MW gas turbine is 37 percent whereas it is 21 percent for a one MW gas turbine), the environmental advantages may not be as great as it initially appears.[6] For pollutants not directly related to fuel consumption (*e.g.*, NO_X), different technologies may have very different emissions profiles. Reciprocating engines, common among small CHP applications, can have much higher NO_X output than turbines, particularly if they lack pollution controls. Controls are possible, but can be costly, particularly for small systems.[7] For pollutants such as NO_X where localized concentrations may be important, and potential CHP installations may be closer to urban areas with high pre-existing pollutant concentrations, the emissions performance of CHP may be very important. In this regard, fuel cells perform better than other CHP technologies. Ultimately, it is difficult to make generalizations about the emissions performance of CHP as compared with separate heat and power systems, since there are numerous different potential systems, sizes, technologies, and locations that would need to be considered.

6.E CURRENT STATUS OF CHP

Industrial applications currently represent 88 percent of total U.S. CHP capacity. Figure 6.1 below shows the growth of CHP capacity in the US since 1950.[8] The rapid increase starting in the 1980s is attributed largely to the Public Utilities Regulatory Policies Act (PURPA) and increased tax incentives. There is currently about 85,000 MW of total existing CHP capacity, which is about 8 percent of total U.S. power generation capacity. Over 60 percent of this capacity is in the chemical, refining, and paper industries, mostly fueled with natural gas.

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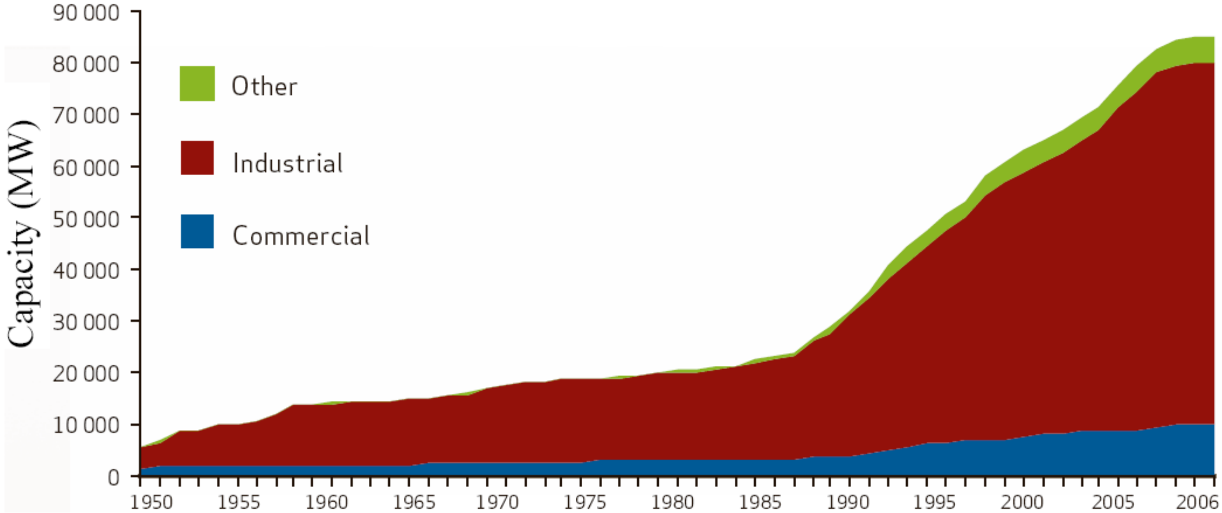
6 Catalog of CHP Technologies, U.S. Environmental Protection Agency, December 2008.

7 Control options include water injection and post-combustion controls such as selective catalytic reduction (SCR), three-way catalysts (TWC), oxidation catalysts, and lean-NO_X catalysts; these may reduce emissions significantly.

8 International Energy Agency, CHP/DHC Country Scorecard: United States, 2008.

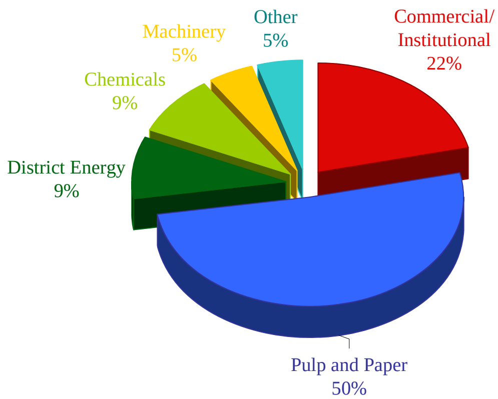
Figure 6.1
Cumulative CHP Capacity Growth in the U.S.



In Connecticut, CHP currently accounts for 611 MW of generating capacity (about 9 percent of total capacity).[9] As shown in Figure 6.2, most of this capacity is for large industrial use (paper, chemicals, and machinery). There is also 56 MW of district heating. Only about one fifth of existing CHP capacity (~132 MW) is in commercial and institutional applications, mainly colleges, universities, and hospitals. Table 6.4 summarizes the existing CHP capacity in Connecticut by technology.

9 Source: Combined Heat and Power Installation Database, EEA/ICF (as of November 2009).

Figure 6.2
Breakdown of Existing CHP Capacity in Connecticut



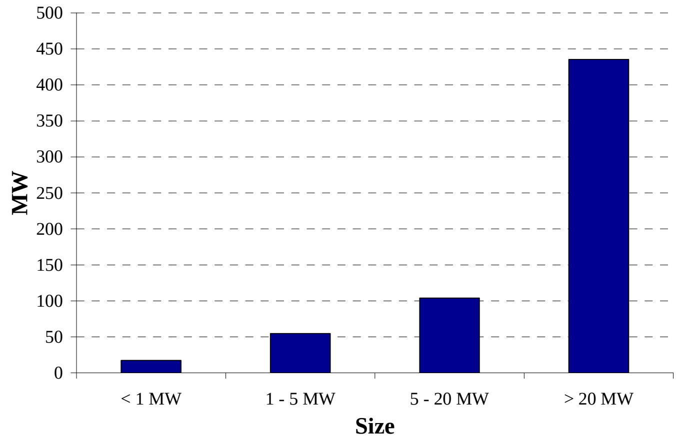


Table 6.4
Existing CHP Capacity by Technology[10,11,12]

CHP System	Electric Utility *(MW)*	Industrial *(MW)*	Commercial/ Institutional *(MW)*	Other *(MW)*	TOTAL *(MW)*	TOTAL *(%)*
Reciprocating Engine	0	6	17	3	27	4%
Gas turbine	0	127	70	0	198	32%
Steam turbine	0	231	24	0	254	42%
Microturbine	0	0	1	0	1	0%
Fuel cells	0	1	3	0	3	1%
Combined Cycle	56	56	17	0	129	21%
Total	**56**	**421**	**132**	**3**	**611**	**100%**

Until a March 2009 decision discontinued the program, the DPUC had offered monetary grants to retail end-use customers for the installation of customer-side distributed generation (DG) resources, including CHP resources, with a maximum capacity of 65 MW. The capital grant for base load generation was $450/kW. There were approximately 119 approved or pending combined heat and power project applications with the DPUC as of December 12, 2008, and 258

10 Combined Cycle CHP includes the combine cycle plants that utilize the thermal output for heating purposes, in addition to electricity generation.

11 There is only one site under "Electric Utility," a 56 MW-combined cycle plant used for district energy.

12 "Other" refers to apartments and private households.

MW were approved out of 358 MW proposed. It is not clear how much of the capacity that was approved will actually be developed.

The Project 150 Initiative is a state grant program funded by the Connecticut Clean Energy Fund (CCEF). It mandates that the local electric distribution companies enter into long-term power purchase agreements for no less than 150 MW of Connecticut Class I renewable energy generation. Three CHP projects (one biomass and two small fuel cells projects) that qualified as Class I resources were selected, with a capacity of 37.2 MW out of 153 MW total.

Connecticut's Renewable Portfolio Standard (RPS) requires 4 percent of Class III resources by 2010. Class III resources include customer-sited CHP systems with a minimum operating efficiency of 50 percent (installed after January 1, 2006) and electricity savings from conservation and load management programs (started after January 1, 2006). The new CHP capacity and efficiency measures already committed should satisfy this requirement.

6.F MARKET POTENTIAL FOR CHP APPLICATIONS

6.F.1 Technical Potential

Relatively coincident and stable electric and thermal loads with a power-to-heat ratio of 0.5-2.5 are desirable for implementing CHP. Moderate to high operating hours (>4,000 hours/year) give good system utilization to help justify the initial capital costs.

Although industrial applications are generally better suited for CHP than commercial applications, most studies show that industrial applications have reached high saturation rates and therefore have limited remaining potential. Two market reports prepared for the U.S. Department of Energy (DOE) in 2000 estimate that CHP has around 75,000 MW remaining potential in terms of generation capacity in the commercial/institutional sector in the U.S., and around 90,000 MW in the industrial sector.[13,14,15] Note that about one quarter of industrial potential has materialized over the last 6-8 years, while over the same period commercial sector CHP has increased much more modestly (see Figure 6.1).

A market study prepared for New York State Energy Research and Development Authority estimates that about 75 percent of remaining technical potential is in commercial sector, most of

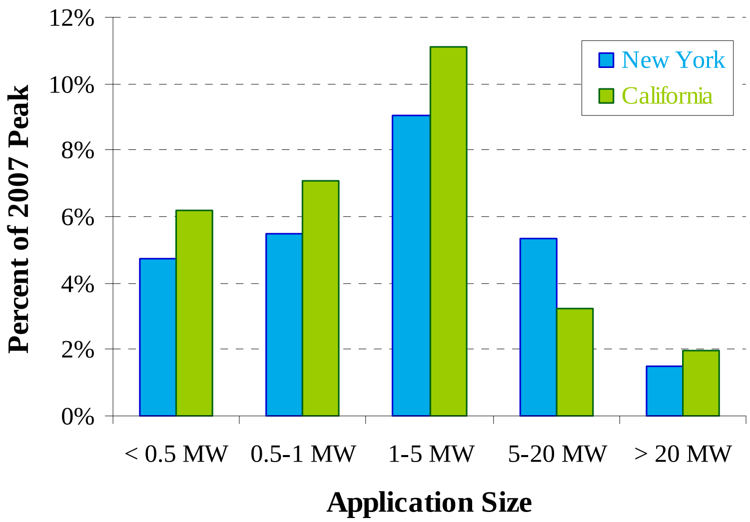
13 *The Market and Technical Potential for Combined Heat and Power in the Commercial/Institutional Sector*. ONSITE SYCOM Energy Corporation (2000).

14 *The Market and Technical Potential for Combined Heat and Power in the Industrial Sector*. ONSITE SYCOM Energy Corporation (2000).

15 The technical potential estimate is based on market size constrained only by technological limits (*i.e.*, the ability of CHP technologies to fit existing customer energy needs). The definition of technical potential varies slightly by application, but basically consists of the existence of thermal loads (steam or hot water) that are relatively coincident with electrical loads, moderate to high operating hours (>4,000 hrs/yr) and appropriate power-to-heat ratios (*e.g.*, between 0.5 and 2.5 for commercial applications).

which is from applications with less than 5 MW of capacity.[16] In a similar study for California, more than two-thirds of the estimated remaining technical potential is in the commercial and institutional applications.[17] Figure 6.3 shows the distribution of estimated technical potential as a function of size.

Figure 6.3
Remaining Technical CHP Potential in New York and California[18]



There are no recent Connecticut-specific market studies available at the level of the New York and California studies. A report with state-by-state estimation of CHP potential in the commercial/institutional sector finds that Connecticut has about 1,000 MW of total potential from existing facilities in this sector.[19] Currently, Connecticut's CHP capacity in commercial/institutional applications is 115 MW (171 MW including district energy). In terms of potential industrial applications, recent detailed data is unavailable for Connecticut. To provide a rough proxy estimate of Connecticut industrial CHP potential, if its industrial CHP potential is a proportionate share of the U.S. total industrial CHP potential (according to overall industrial energy consumption), its total potential would be 491 MW, 135 MW above the existing 356 MW of industrial CHP already in Connecticut.[20,21] Note that Connecticut has

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16 Hedman, B., et al. *Combined Heat and Power Market Potential for New York State*. Energy Nexus Group (2002).

17 *Assessment of California CHP Markets and Policy Options for Increased Penetration*. EPRI and California Energy Commission, Report No: 1012075 (2005).

18 Includes only traditional CHP applications from existing facilities (no cooling).

19 *The Market and Technical Potential for Combined Heat and Power in the Commercial/Institutional Sector*. ONSITE SYCOM Energy Corporation (2000).

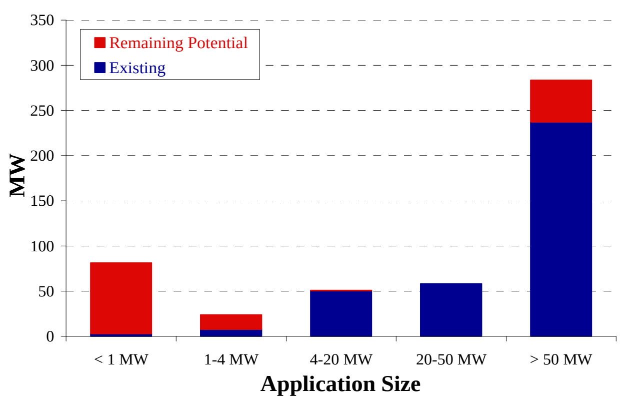
20 *The Market and Technical Potential for Combined Heat and Power in the Industrial Sector*. ONSITE SYCOM Energy Corporation (2000).

relatively less energy-intensive industry than other states, meaning that its natural CHP potential is lower than other regions (Connecticut's industrial energy consumption is 14 percent of its total consumption, versus 32 percent in the U.S. overall).

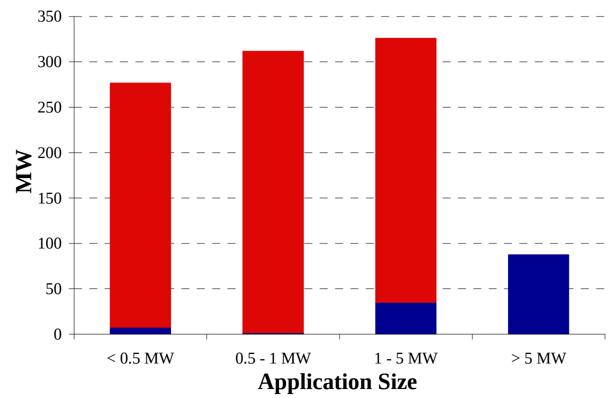
Figure 6.4 shows the estimated distribution of technical CHP potential in industrial and commercial/institutional sectors. The remaining potential in small and medium size commercial/institutional applications is significantly greater than in industrial applications. Even within industrial, there is more remaining potential in small-size applications than in large applications.

Figure 6.4
Estimated Technical CHP Potential in Connecticut
Industrial and Commercial/Institutional

(a) Industrial[22,23]



(b) Commercial/Institutional[24,25]



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21 EIA reports Connecticut's 2006 industrial energy consumption is 119 trillion Btu, 0.37 percent of the U.S. total of 32,196 trillion Btu.

22 Existing CHP capacity is calculated based on EEA/ICF Combined Heat and Power Installation Database (as of November 2009).

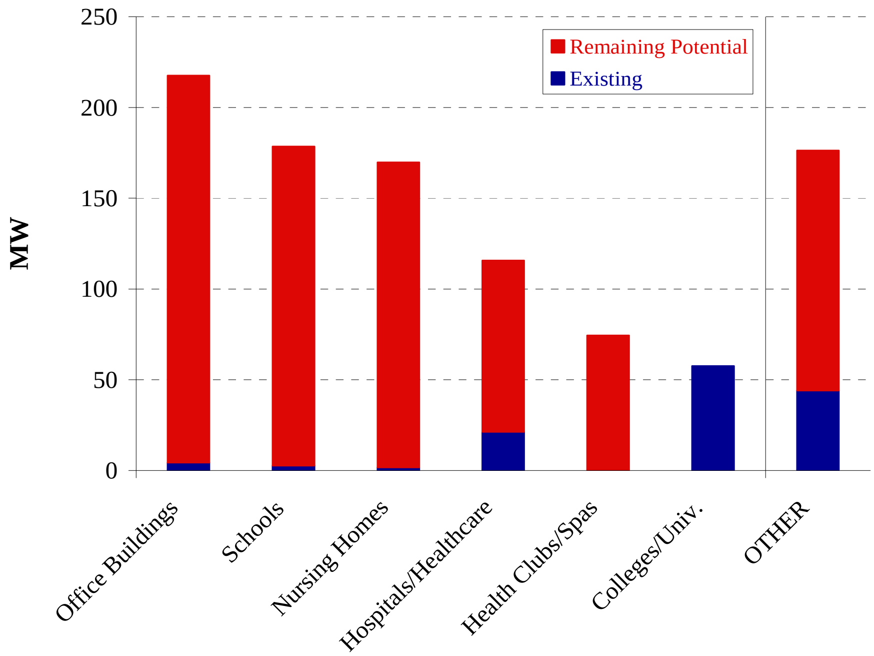
23 U.S. total technical CHP potential provided in the Onsite Sycom Energy's report (for industrial sector) is scaled by a factor of 0.37 percent (Connecticut's share of U.S. industrial energy consumption) in order to get the Connecticut's total technical CHP potential in industrial applications.

24 Existing CHP capacity is calculated based on EEA/ICF Combined Heat and Power Installation Database (as of November 2009). It does not include "district energy," which is consistent with technical potential estimates.

25 Total CHP potential is based on Onsite Sycom Energy's report (for commercial/institutional sector) prepared for US. Department of Energy.

Figure 6.6 shows the particular commercial and institutional applications with the highest remaining CHP potential. Office buildings, schools, nursing homes, hospitals, and health clubs are listed as the most promising categories (730 MW total remaining generation capacity). This is mainly driven by relatively high and coincident thermal and electric loads, high annual operating hours, and attractive power-to-heat ratios. Universities have a large share of existing CHP capacity, but relatively less remaining potential.

Figure 6.5
Technical CHP Potential in Connecticut
Commercial and Institutional[26,27]



6.F.2 Economic Potential and Market Penetration

Technical potential provides an upper bound on potential market penetration, but does not consider factors such as economics, electrical integration issues and regulatory factors that can ultimately have a significant effect on actual CHP deployment. Some of the important technical, market and regulatory factors that could influence future penetration of CHP, especially in small-size commercial and institutional applications, include:

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26 Existing CHP capacity is calculated based on EEA/ICF Combined Heat and Power Installation Database (as of November 2009).

27 Total CHP potential is based on Onsite Sycom Energy's report (for commercial/institutional sector) prepared for DOE.

- **Cost and performance of CHP technologies –** Recent technological developments have increased the system efficiencies of small-size CHP technologies, but they are still much more capital intensive on a $/kW basis.

- **Utilization of thermal output –** Long, steady operating hours with coincident electric and thermal loads increase the overall utilization of CHP, hence increase the corresponding net savings available. Large-scale industrial applications which use thermal energy primarily for process heat tend to have relatively uniform thermal needs, but smaller commercial and institutional facilities are more likely to have uneven seasonal thermal loads for space heating. While it is possible to use waste heat to provide space cooling using absorption cooling technology, it is a less efficient use of heat and is less likely to be economical.

- **Fuel prices –** All else equal, higher fuel costs tend to encourage CHP penetration in a region, such as New England, where natural gas sets the price of electricity as well as being a typical boiler fuel and fuel for CHP. (CHP uses gas more efficiently, which becomes more valuable as gas price increases.) See EPRI's market report for a sensitivity analysis which shows how the interaction between natural gas and electricity prices may affect the overall CHP market penetration in California.[28]

- **Standby/back-up charges –** CHP system owners must typically contract with their utility service provider for backup and supplemental power. The structure of these rates may play an important role on the overall economics of a potential CHP system. For example, in New York State, the existing level of standby charges has been identified as a major barrier for future CHP penetration.[29]

- **Siting and Permitting –** CHP systems may need siting approval, a grid interconnection agreement, and environmental permitting that can add economic and technical hurdles.

- **Financial incentives, tax credits –** Financial incentives, such as subsidies or tax credits, can significantly affect the economics of investing in a new CHP system. For example, EPRI's market report estimates that the extension of the current Self-Generation Incentive Program (SGIP) in California may result in a 50 percent increase in CHP penetration in the medium term.[30] In Connecticut as elsewhere, the economic attractiveness of small-size CHP applications technologies can be enhanced by subsidies, as appears to have occurred already via the DG Capital Grants and Project 150 programs.

Estimating the future additional market penetration of CHP in Connecticut would require a comprehensive economic analysis incorporating the factors above, and is beyond the scope of this study. It appears that the most attractive potential CHP applications, large industrial

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28 *Assessment of California CHP Markets and Policy Options for Increased Penetration*. EPRI and California Energy Commission, Report No: 1012075 (2005).

29 Hedman, B., *et al. Combined Heat and Power Market Potential for New York State*. Energy Nexus Group (2002).

30 *Assessment of California CHP Markets and Policy Options for Increased Penetration*. EPRI and California Energy Commission, Report No: 1012075 (2005).

applications, have mostly already been tapped. The remaining untapped potential consists mostly of smaller commercial/institutional applications, which offer less in the way of improved energy efficiency and cost effectiveness.

6.G CASE Study on CHP at Central Power Generation Sites

In July 2009, the Connecticut Academy of Science and Engineering (CASE) published a feasibility study on utilizing waste heat recovered from existing central electric power generation station.[31] The Clean Water Act may require such facilities to install expensive new cooling technologies to reduce thermal releases and minimize impact on water quality, spurring interest in potential beneficial uses of the waste energy. The study was initiated by the Connecticut Energy Advisory Board (CEAB).

The study concludes that, although there is plenty of "rejected" waste heat available, it may not suitable for distribution and high-value end use. It cites proximity to population centers, continuous operation, and steam quality among important factors that could facilitate utilization of waste heat from existing power generating stations. The study describes district heating and cooling, algae farms to generate biofuel, and industrial ecology parks as potential applications, but does not provide any economic analysis to compare costs and benefits. The study concludes that there is a significant potential for beneficial use of power plant waste heat in Connecticut, but it would require energy policy makers and planners to adopt a more holistic approach to consider all energy forms, how energy might be exchanged between economic sectors and the impact of such energy flows on the environment and economic development. It also recommends a more detailed analysis to fully understand the technical and economic implications, and estimate how much waste heat could practically be utilized.

[31] *A Study of the Feasibility of Using Waste Heat from Central Electric Power Generating Stations and Potential Applications,* Report by the Connecticut Academy of Science and Engineering for Connecticut Energy Advisory Board, July 2009.

Section III.7
Environmental Regulations Affecting Electricity

7. ENVIRONMENTAL REGULATIONS AFFECTING ELECTRICITY

7.A SUMMARY AND KEY FINDINGS

Summary

This section builds upon the earlier 2009 summary of existing and potential future environmental regulations and legislation, and provides some additional detail on the environmental selection criteria applied to certain modeling assumptions in this year's modeling effort. Further, some greater detail has been provided on the two "front runner" bills working their way through Congress on greenhouse gas emissions (GHG), especially carbon dioxide (CO_2). Additional discussion has been added regarding allowance pricing for CO_2, sulfur dioxide (SO_2), and nitrogen oxides (NO_X).

Controlling the environmental impacts from electricity production entails both complex regulations and market-based interventions such as cap-and-trade systems. Such environmental controls impose costs and introduce additional sources of uncertainty into resource planning, particularly when proposals to address chronic or emerging environmental issues are not yet finalized. Such is the situation facing generators in Connecticut and New England.

Chief among these uncertainties is the anticipation of a federally mandated, economy-wide approach to limit or discourage CO_2 emissions from fossil fuel combustion. Recent bills in Congress have adopted a cap-and-trade allowance system for CO_2 as the primary mechanism to limit CO_2 emissions, but important policy details are not yet determined. In response to a recent U.S. Supreme Court ruling, the Environmental Protection Agency (EPA) has determined that CO_2 is a pollutant under the Clean Air Act. This report assumes the implementation of federal GHG policy and adopts estimates of CO_2 prices applied to fossil-fuel fired generation that are derived from recent analyses by the Energy Information Administration. These CO_2 prices can have a direct and material influence on generation costs, system dispatch, new resource selection and retirement decisions.

Another significant influence on generation costs and potential retirements are state and regional efforts to control NO_X from existing fossil-fired generating units, especially on days when hot weather coincides with high electricity demand and ground-level ozone concentrations exceed federal limits. The Connecticut Department of Environmental Protection (CT DEP) has expressed interest in the EDC analysis on likely future emissions from generation during these episodes. The EDCs and the CT DEP established a collaborative process in order to provide the CT DEP with the results of specific simulations that could assist their efforts to craft regulatory approaches to address these emissions. This collaboration has yielded benefits for the EDCs (insofar as the analysis can better reflect the current policies of the CT DEP) as well as for the CT DEP, which can utilize the simulation results to determine possible impacts of emission controls on Connecticut generation and capacity availability.

Customers and generators bear the costs of existing and potential environmental controls in different ways, depending on how such programs are implemented and the nature of the costs incurred. In general, market-based programs that operate through emission allowance markets affect the operating cost of generating facilities, and generators will reflect these costs in supply bids into the wholesale market. If such supply bids are setting the wholesale price in any hour, then prices will rise and consumers will bear those costs through increased generation rates. Supply bids that reflect allowance costs, but which remain "inframarginal" (*i.e.*, below the market price) will not affect price. The energy margins of inframarginal generators will be reduced by the amount of allowance cost, but these losses can be offset (at least in part) as a result of higher market prices due to allowance costs of marginal suppliers.

Environmental regulations that require existing generators to install emission control equipment will impose capital costs that are born exclusively by generators, since fixed costs are not recovered in higher wholesale prices. However, these requirements can induce generating units to retire if their energy margins are insufficient to cover the additional fixed cost. This is a key concern for older, infrequently operating generating units facing NO_X controls to address ozone concentrations, particularly on hot days when such units are typically dispatched to meet higher loads. The implications of such requirements on generator retirements are examined in Section III.1 (Resource Adequacy).

Finally, there are myriad environmental regulations that address the air, water, and land-use impacts of existing and future generation capacity and transmission facilities. Many of these regulations are subject to periodic review and tightening. The evolution of such regulation is likely to impose additional costs on electricity supply, and such costs are often difficult to predict.

Key Findings

- While there is uncertainty regarding future Federal climate legislation, the prospects appear likely enough for a range of CO_2 prices to be reflected in our analysis.
- Because Connecticut and other parts of New England are not in attainment with air quality standards, additional NO_X control requirements will likely be imposed on generators. The EDCs and CTDEP worked together to establish likely future NO_X emission requirements which were reflected in the simulation of the New England electricity market. The cost of these controls is projected to cause retirements of older fossil steam units in our analysis.
- Emission allowance prices – for SO_2, NO_X, and CO_2 – will raise the costs of generation in proportion to unit emission rates, and will impact the dispatch of resources in New England and thereby reduce overall emissions. Although the prices of allowances for each pollutant are determined by aggregate emissions relative to an emission cap, these markets are not wholly independent. In particular, the price of CO_2 allowances can influence the price of SO_2 and NO_X allowances, an effect that was reflected in the analysis.
- The imposition of new regulations for other environmental sectors (not air) have the potential to introduce greater costs to generators, though the potential impact of these costs can not be determined at this time and thus were not reflected in the analysis.

7.B CLIMATE CHANGE POLICY

7.B.1 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. RGGI is the first regional greenhouse gas emissions reduction program and the first mandatory greenhouse gas allowance trading system in the United States.

RGGI was proposed in April 2003 and implementation began 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 percent of the original budget per year so that each state's budget in 2018 is 10 percent below its initial budget. RGGI is an auction-based program, and not a free allocation program and therefore each covered unit must obtain credits for CO_2 emissions through a regional auction.

The impact of the RGGI CO_2 prices on electricity markets and emissions in New England has been minimal and is expected to remain modest based on the current low prices of about $2/ton. A $2/ton cost adder is not high enough to trigger much dispatch switching from CO_2-intensive generation plants (coal plants or oil-fired peakers) to low-CO_2 generation plants (*e.g.*, renewables, gas combined-cycle (CC) plants). In the absence of any significant dispatch switching, the operating margins of the peakers and gas CCs, which typically set the electricity market prices when they run, are not materially affected as they are able to pass the cost of allowances to the electricity prices through higher offer prices in the energy market. The operating margins of coal plants are reduced as a result of RGGI CO_2 allowance costs, but not enough to cause retirement.

7.B.2 Federal GHG Policy Initiatives

Numerous federal policy proposals have been introduced to curtail emissions of CO_2 and other GHG emissions. The proposals exhibit differences such as types of policy mechanisms (*e.g.*, CO_2 fee, mandatory CO_2 controls, cap-and-trade), differing levels of emission caps or targets over time, covered sectors and emission sources, free allocation or auctioning of emission allowances or tax credits, treatment of domestic and international offsets, *etc*.

Although the policies being considered are both regulatory and legislative, this report focuses on legislative options for inclusion in the analysis. At this time, legislative options have been more developed, are moving forward more quickly and have been analyzed by several organizations. These developments do not preclude regulatory options that might affect generation at some point in the future. In response to a recent U.S. Supreme Court ruling, the Environmental Protection Agency (EPA) has determined that CO_2 is a pollutant under the Clean Air Act. Accordingly, they have proposed regulations to limit CO_2 emissions from major stationary sources. Should the regulatory options become more developed and/or supersede legislation, their impacts can be incorporated into subsequent analyses.

As the climate debate moves on in Congress, it is apparent that any Federal legislation will likely take the form of an economy wide cap-and-trade. Two bills, Waxman-Markey and Kerry-Boxer, are currently thought of as the fore-runners in the policy debate. At this time, analysts expect that the two bills will eventually be merged into one (probably in 2010) and that the resultant bill will go forward and become law. The summaries below are for each of the bills.

Waxman-Markey

Representatives Waxman and Markey introduced the American Clean Energy and Security Act of 2009 (ACESA, HR 2454, or "Waxman-Markey") on May 15, 2009. It was passed by the House on July 26, 2009.

Title III of the Act establishes a cap and trade system for greenhouse gas emissions. The cap gradually reduces covered greenhouse gas emissions to 17 percent below 2005 levels by 2020, and 83 percent below 2005 levels by 2050. The bill covers 85 percent of domestic emission sources, including electricity producers, oil refineries, natural gas suppliers, and energy-intensive industries like iron, steel, cement, and paper manufacturers. The bill allows unlimited banking of allowances, with borrowing limited from 2 to 5 years ahead.

Under Waxman-Markey, certain sources and programs will receive free allowances, known as "allocations." About 85 percent of emission permits would be given away free at the start of the program, with the percentage decreasing over time. The remaining allowances are auctioned to sources, with the resulting revenues dedicated to various programs such as low-carbon energy technology development and deployment. Additionally, the bill included a weak price collar with a floor of $10 and a minimum strategic reserve auction price at 60 percent above a rolling 36-month average of the daily closing price.

Kerry-Boxer

The Senate version bill, known as "Kerry-Boxer" (S. 1733) was released in draft form in late September 2009. Since then it has undergone some revisions and the "chairman's mark" passed out of committee in November. The bill will next be heard on the Senate floor, but this is not expected to occur until Spring 2010. The Kerry-Boxer bill and the Waxman-Markey bill are very similar. Key provisions of the Kerry-Boxer bill include:

- **Emissions Reduction Targets:** The Kerry-Boxer bill includes a declining cap on carbon pollution from 20 percent below 2005 levels by 2020 (versus 17 percent in Waxman-Markey) to an 83 percent reduction below 2005 levels by 2050.
- **Cap and Trade and Allowances:** The Kerry-Boxer bill calls for cap and trade program "pollution reduction" as the primary mechanism for attaining the emissions reduction targets, similar to Waxman-Markey.
- **Allocations:** Kerry-Boxer gives similar percentage of overall allocations (free allowances) to sources. However, the bill gives a greater portion of the initial auction

revenues to deficit reduction, the pool of free allowances is smaller. Therefore, the overall number of allocations that sources may receive is fewer than those under Waxman-Markey.

- **Clean Air Act:** Unlike Waxman-Markey, the Kerry-Boxer bill allows the development of new source performance standards (NSPS) for sources that could be covered by the bill. It also establishes performance standards for coal-fired power plants permitted in 2009 or after, and different standards for those permitted in 2020 or after.

7.C ALLOWANCE PRICING

7.C.1 CO_2 Allowance Prices

For purposes of utility, state, or regional level resource planning, it is generally sufficient to use a CO_2 allowance price projection to reflect the imposition of national climate policies. These CO_2 prices are then added to the fuel costs of fossil-fueled generation (both existing and new) and influence both the dispatch of existing units and the economics of new investments in generation, transmission and efficiency resources. Of course, any price forecast is subject to substantial uncertainty and analyses of climate change proposals show a very wide range of possible CO_2 prices. This, in turn raises significant issues regarding the choice of CO_2 price in resource modeling.

The most carefully studied recent proposal was the Waxman-Markey bill, which was described above. Many organizations generated economic analyses of Waxman-Markey, including the Energy Information Administration (EIA), the EPA and several private consultants on behalf of advocacy groups.[1] This report uses EIA analysis as the source for CO_2 prices in the electricity market analysis, primarily because EIA is statutorily non-partisan and independent, and therefore the results are generally recognized as unbiased and free from any advocacy position.[2]

The EIA analysis of Waxman-Markey is based on reference case projections of economic growth, fuel prices and emissions that are updated annually in the *Annual Energy Outlook* (AEO), which reflects a 25-year energy forecast without new federal policy to combat climate change. The EIA Waxman-Markey analysis started with the most recent AEO reference case, which included the impacts of the economic stimulus bill.[3] It incorporated key provisions of the Waxman-Markey bill into the policy simulations, such as:

- The combined efficiency and renewable electricity standards;
- Carbon capture and storage (CCS) demonstrations and early deployment;

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[1] The Congressional Research Service produced useful summary of results and key issues identified by the economic analyses conducted on W-M. See *Climate Change: Costs and Benefits of the Cap-and-Trade Provisions of H.R. 2454* by Larry Parker and Brent D. Yacobucci, September 14, 2009.

[2] *Energy Market and Economic Impacts of H.R. 2454, the American Clean Energy and Security Act of 2009*, Energy Information Administration, August 2009 SR/OIAF/2009-05.

[3] *Annual Energy Outlook 2009*, Energy Information Administration, DOE/EIA-0383(2009), March 2009.

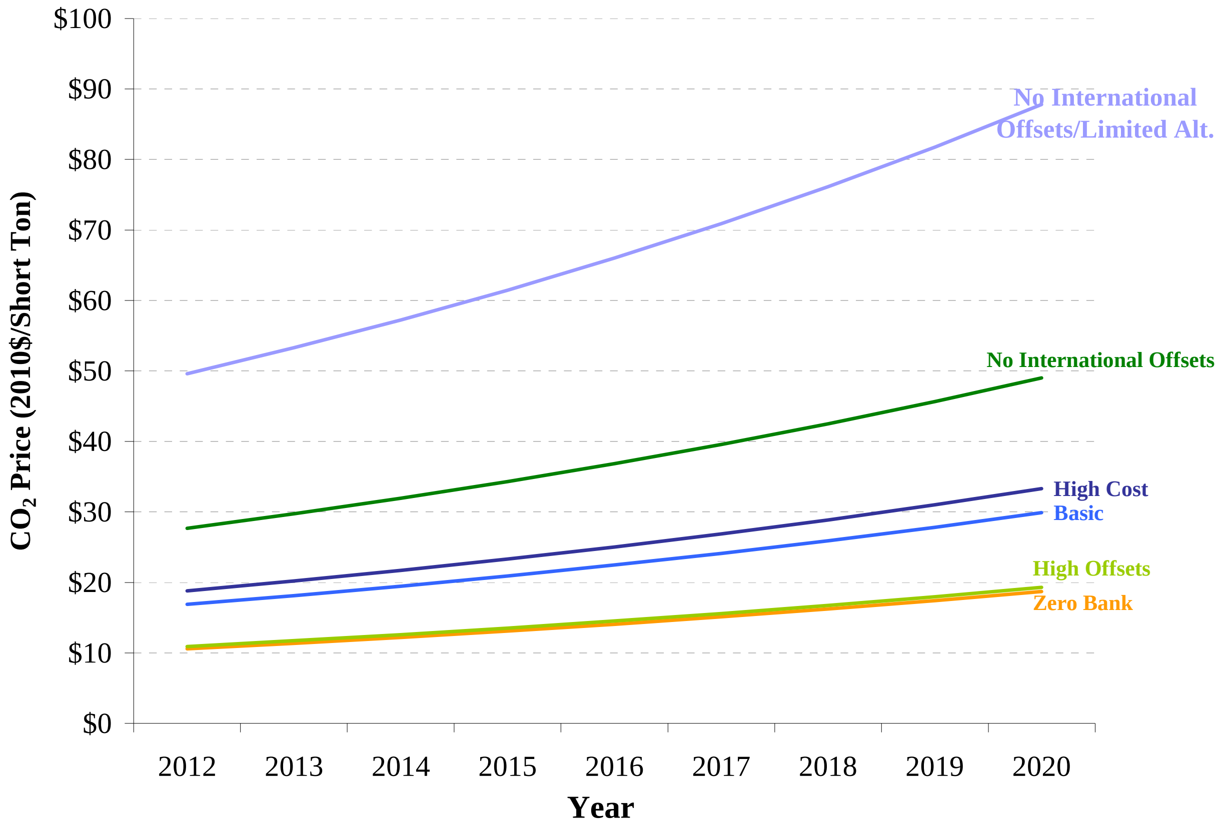
- Building code revisions for residential and commercial buildings;
- Federal appliance and lighting efficiency standards;
- Technology improvements as a result of federal program support; and
- Smart grid peak savings program.

EIA then simulated the imposition of the greenhouse gas emission cap-and-trade program on the energy sector, which produced forecasts of CO_2 prices. EIA analyzed alternative policy implementation scenarios for analysis under different assumptions regarding the availability, cost, and market penetration of new low-carbon energy technologies over time; the amount of allowance banking assumed; and the availability, cost and utilization of emission offsets (domestic and international) that are permitted. The six primary cases EIA examined were:

- The *Basic Case*, which reflects expected improvements in technology, a moderate degree of domestic and international offset use, and significant banking of allowances through 2030;
- The *Zero Bank Case*, which did not assume any accumulated banked allowances;
- The *High Offset Case*, which assumed that international offsets are available and used to the ceiling imposed by the W-M bill;
- The *High Cost Case*, which assumed higher costs for low-CO_2 generation technologies;
- The *No International Case*, which significantly constrained the availability of international offsets; and
- The *No International/Limited Case* which constrained both international offset use and the deployment of low-CO_2 generation technologies.

Figure 7.1 shows the range of CO_2 allowance price forecasts from the EIA analyses of Waxman-Markey.

Figure 7.1
CO_2 Allowance Price Forecasts from EIA Analysis of Waxman-Markey



Source: Energy Information Administration.

7.C.2 CO_2 Allowance Price Projection: Current Trends Scenario

The electricity market analysis in this report adopts the assumption that a climate policy similar to Waxman-Markey is enacted. This assumption does not reflect an endorsement of the Waxman-Markey approach, but provides an analytic basis to explore the impacts of a range of CO_2 prices under different scenarios. The EIA analysis suggests that a significant source of uncertainty regarding near-term (*i.e.*, through 2020) CO_2 allowance prices under the Waxman-Markey approach is the degree to which international and/or domestic offsets are utilized, and the cost of obtaining such offsets. There is a wide disparity of opinion on this, ranging from almost no utilization (due to regulatory and/or cost barriers) to full utilization up to the limits contained in the Waxman-Markey proposal. Another large uncertainty (particularly through 2030) is the timing, cost and adoption of low- and no- carbon technologies, which itself might be affected by an allowance price that is influenced by the degree of offset usage.

The EIA Basic Case takes a "middle ground" view of both offset usage and technology development under the Waxman-Markey bill. As described by EIA in their August 2009 analysis:

> *The ACESA* [Waxman-Markey] *Basic Case represents an environment where key low-emission technologies, including nuclear, fossil with CCS, and various renewables, are developed and deployed on a large scale in a timeframe consistent with the emission reduction requirements of ACESA without encountering any major obstacles. It also assumes that the use of offsets, both domestic and international, is not severely constrained by cost, regulation or the pace of negotiations with key countries covering key sectors.*[4]

This report adopts the EIA Basic Case for CO_2 prices in the "Current Trends" scenario. The EIA Basic Case recognizes that offsets might be available in some quantities at a price lower than that of domestic abatement, but does not assume that valid, low-cost offsets would be available in quantities that would be constrained by the near-term limits in the Waxman-Markey bill. Thus, the EIA Basic Case offers a plausible view of an aggressive climate policy with some offset use, but one not dominated by cheap offsets in the compliance mix. The EIA Basic Case CO_2 allowance prices rise from $17/ton in 2012 to $30/ton in 2020 (2010 dollars).

7.C.3 CO_2 Allowance Prices For Alternative Scenarios

Since the availability, cost and ultimately the degree of offset utilization appears to be the most influential determinant of near-term (*e.g.*, 2020) CO_2 allowance prices, suitable high/low allowance price cases can be fashioned from varying assumptions regarding offset utilization. The IRP process adopted the EIA High Offset Case as a low CO_2 allowance price scenario, and the EIA No International Case as a high CO_2 allowance price scenario. These two cases represent upper and lower bounds on the availability of cost-effective international offsets used for domestic compliance in the near term, and the resulting range of projected allowance prices is broad enough to encompass many of the other sources of uncertainty in allowance prices, such as economic growth, fuel prices and the near-term cost of domestic CO_2 abatement.

The High Offset case assumes that international offsets are available in sufficient quantities and at moderate costs so that they are utilized for compliance at levels at or near the limits contained in the Waxman-Markey bill. As a result of larger amounts of low-cost international offsets available for domestic compliance with the emission targets, the CO_2 allowance price is $19/ton in 2020 (about 35 percent lower than in the Basic Case). In contrast, the No International Case reflects a scenario where the use of international offsets is severely constrained by cost, regulation or slow progress in obtaining agreements with key countries. In this case, the CO_2 allowance prices are $49/ton in 2020, or about 65 percent higher than in the Basic Case.

Figure 7.2 shows the range of CO_2 prices used in our scenarios, expressed in 2010 constant dollars.

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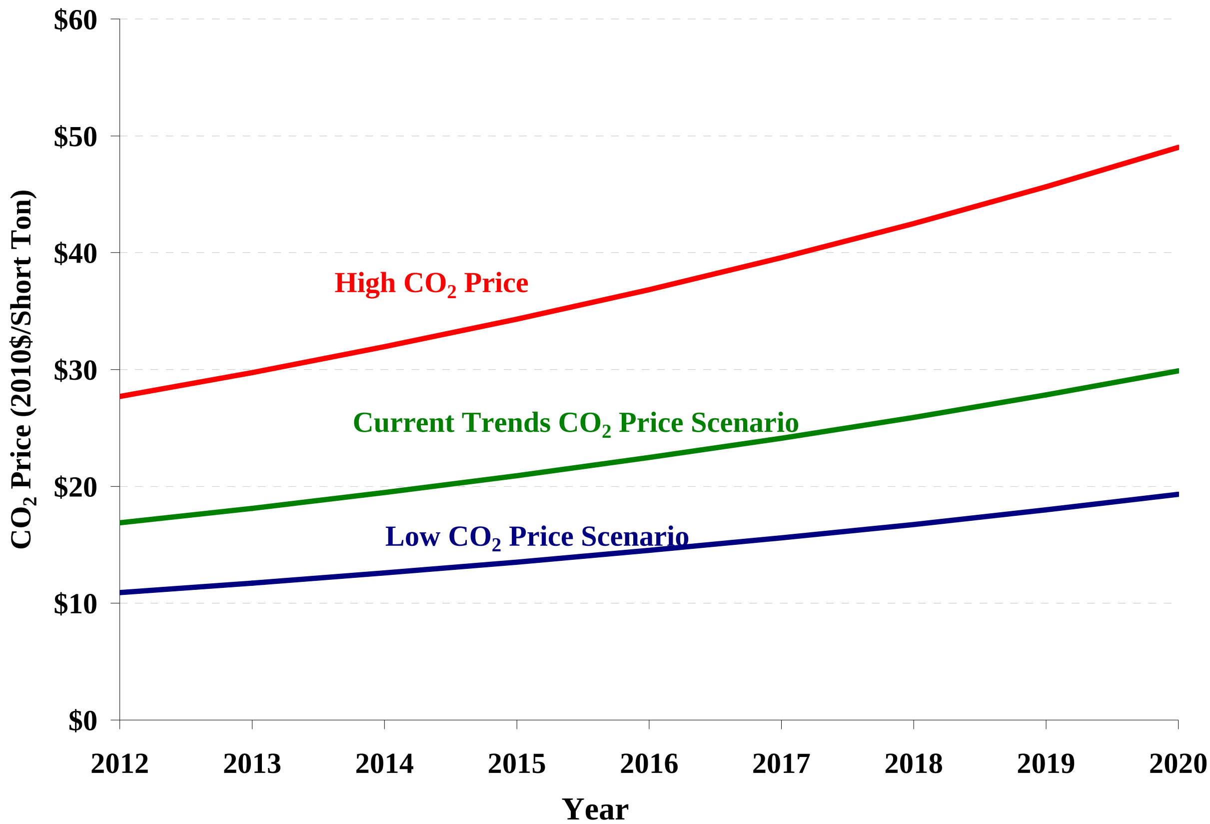
[4] *Energy Market and Economic Impacts of H.R. 2454, the American Clean Energy and Security Act of 2009*, Energy Information Administration, August 2009 SR/OIAF/2009-05, p viii.

Figure 7.2 CO_2 Allowance Prices Used In Scenarios



Source: Energy Information Administration.

7.C.4 NO_X and SO_2 Allowance Pricing

This analysis also uses EIA as a source for NO_X and SO_2 allowance price projections. In the EIA modeling framework, allowance prices for CO_2, NO_X and SO_2 are determined simultaneously by the model to attain the relevant emission targets. *The Brattle Group* obtained the SO_2, NO_X and CO_2 allowance price forecasts from the EIA analysis of Waxman-Markey, which displayed an inverse relationship between CO_2 allowance prices and NO_X and SO_2 allowance prices; see Table 7.1

Table 7.1
Emissions Price Forecast Under Waxman-Markey

	(units)	**2013**	**2015**	**2020**
REFERENCE CO2				
CO_2	*($/ton)*	18	21	30
NO_x	*($/ton)*	1962	2147	0
SO_2	*($/ton)*	726	831	301
HIGH CO2				
CO_2	*($/ton)*	30	34	49
NO_x	*($/ton)*	0	105	0
SO_2	*($/ton)*	339	160	3
LOW CO2				
CO_2	*($/ton)*	12	14	19
NO_x	*($/ton)*	2423	2592	2417
SO_2	*($/ton)*	756	762	936

Sources and Notes:
U.S. Energy Information Administration.
All values are in 2010$ per short ton.

As CO_2 allowance prices increase, the generation from coal-fired capacity decreases and this reduces NO_X and SO_2 emissions as well, reducing the allowance prices necessary to attain compliance with national and regional NO_X and SO_2 emission targets. This effect is clearly seen in comparisons between the High and Low CO_2 price forecasts. Under a High CO_2 price, the prices of NO_X and SO_2 allowances fall significantly relative to the Reference CO_2 price case, while in the Low CO_2 price forecasts, NO_X and SO_2 emission allowances remain at much higher levels. In scenarios that assumed higher or lower CO_2 prices than in the Current Trends scenario, the allowance prices for NO_X and SO_2 from the corresponding EIA analysis cases were used in the simulations.

7.C.5 Collaborative Effort with the CT DEP

In its 2009 IRP report the EDCs recommended that the CT DEP and the EDCs collaborate on modeling inputs for the 2010 IRP and jointly review the assumptions underlying emission rates in the production cost simulations. To that end, the EDCs and *The Brattle Group* worked collaboratively with the CT DEP to develop realistic assumptions regarding future regulations that will ensure compliance with National Ambient Air Quality Standards (NAAQS). The effort was informed by extensive analysis using the DAYZER market simulation model. Together with the CT DEP, *The Brattle Group* and the EDCs validated the input data in the model, including comparison of generating unit emissions rates to publicly available historical data. As specified by the CT DEP, the initial simulations assumed no new environmental regulations, no new investment in environmental controls, and no environmentally-driven retirements. This made it possible to observe simulated “uncontrolled” emissions. (See also detailed discussion under Section 7.D.4. for more information regarding CT DEP modeling and results.)

7.D EXISTING AIR LAWS AND REGULATIONS AFFECTING GENERATING UNITS

7.D.1 National Ambient Air Quality Standards (NAAQS)

The Clean Air Act, which was last amended in 1990, requires the United States Environmental Protection Agency (EPA) to set NAAQS for six identified criteria pollutants. Five of these pollutants (particulate matter, lead, nitrogen dioxide, ozone, and sulfur dioxide) are commonly associated with electric generating units (EGUs). The Clean Air Act established two types of national air quality standards: primary standards to protect public health and secondary standards to protect public welfare, including protection against visibility impairment, damage to animals, crops, vegetation, and buildings. When an area does not meet the air quality standard, it is designated as a “non-attainment area.” Each state that includes a non-attainment area must develop a plan for attaining the standards, called a State Implementation Plan (SIP).

Connecticut faces challenges attaining ambient air quality standards, particularly during high electric demand days in the summer. Hot and humid days can produce spikes in ground-level ozone (smog) as such weather conditions encourage ozone formation from air pollutants (primarily NO_X) and emissions are higher as a result of increased air conditioning loads requiring relatively high emission, less efficient generation resources to operate.

The Connecticut SIP gives special attention to these high electric demand days (HEDD) because they represent the most challenging periods for keeping air quality within federal standards. One control option is to require all coal- and oil-fired steam units to install SO_2 and NO_X controls. Although some of these units operate infrequently during the year (and therefore do not contribute significant emissions on an annual basis) they are responsible for a significant portion of the stationary source emissions during HEDD episodes.

For the areas in New England that are classified as non-attainment, the states will implement (or in some cases have implemented) regulations that restrict emissions from sources including EGUs. The stringency of the standards depends on the emissions reductions needed to meet the NAAQS. An analysis of the likely impacts on existing generating units of meeting these standards in Connecticut is discussed later in this Section.

7.D.2 Clean Air Interstate Rule (CAIR)

Federal

Citing significant health and clean air benefits, EPA finalized the Clean Air Interstate Rule (CAIR) on March 10, 2005. The rule targets reductions in SO_2 and NO_X emissions using a regional cap-and-trade program. The final rule covered 28 eastern states and the District of Columbia. Air emissions in these states were believed to contribute to unhealthy levels of ground-level ozone, fine particles or both in downwind states.

The D.C. Circuit Court, in The State of North Carolina, *et al.*, v. The United States Environmental Protection Agency, vacated the CAIR rule and remanded it entirely on July 11, 2008. This was a unanimous decision and based on "several fatal flaws" identified by the Court in its decision that the rule could not be transformed into an acceptable rule. The EPA and others have requested a re-hearing of the case and submitted briefs and responses. The Court requested additional information from the parties involved in the case. They asked the parties to submit opinion on maintaining the *vacatur* or issuing a stay of CAIR in lieu of the immediate *vacatur*. On December 23, 2008, the Court upheld the remand, but reversed the *vacatur*. This action essentially allows CAIR to remain in effect while the EPA is compelled to rewrite the regulations.

New England

Both Connecticut and Massachusetts are considered CAIR states. These states included language in their SIPs incorporating CAIR reductions. The SIPs will need to be re-examined by the state and federal authorities and likely revised to account for the *vacatur* of CAIR.

In general, non-CAIR states such as Maine and Vermont may not opt into CAIR. New Hampshire is not a CAIR state and was not required to submit a SIP related to CAIR. However, there are special provisions for Rhode Island and New Hampshire since they have been part of a region-wide NO_X trading program in the past. Advantages include regional trading partners for their sources and in Rhode Island's case, not having to find another NO_X SIP Call strategy for its current program.

Implications

Currently, the EPA is working to propose new CAIR rules. These rules could:

- include more stringent standards, with greater impact on sources in Connecticut and Massachusetts, and possibly even pull other New England states into CAIR;
- include more states and or sources in the program, which could pull in some sources in Connecticut and Massachusetts that are not currently covered, and could pull in other states; and
- include other pollutants, such as mercury, which could impact existing and new generation.

Before new rules are implemented or CAIR is reinstated, there will continue to be economic uncertainty for EGUs that would have been subject to CAIR. Affected companies will have to evaluate whether to delay equipment installation, install new equipment but not use it until requirements are in place (which raises cost recovery issues), risk exposure to potential enforcement actions and/or market fluctuations, as high sulfur content coal is used or not used. Finally, sources that had purchased credits speculatively for use in the NO_X and SO_2 markets may need to declare them as losses to the investment community.

In CAIR states such as Massachusetts and Connecticut, the state environmental agencies will still need to meet their SIP requirements for NO_X and SO_2 as a CAIR-fix is implemented. If NAAQS deadlines come up before a fix is in place, then the states will be required to make up the difference in emissions reductions from in-state sources, such as generation. Therefore, we could see additional standards coming into play in these states within the next few years to address the emission reduction shortfalls.

7.D.3 Clean Air Mercury Rule (CAMR)

On March 15, 2005, the EPA issued the Clean Air Mercury Rule (CAMR) to permanently cap and reduce mercury emissions from coal-fired power plants by 70 percent and required installation of continuous emissions monitors (CEMs) by January 1, 2009. CAMR sets a cap on mercury emissions from new and existing coal-fired EGUs in each state. A state may meet its state budget by either joining the federal cap-and-trade program or by demonstrating that the mercury emissions from the CAMR units in the state will not exceed the state budget in any given year.

On February 8, 2008, the U.S. Court of Appeals for the District of Columbia Circuit struck down CAMR in part because the rule did not go far enough to protect human health and welfare. The ruling sent CAMR back to the EPA for reconsideration. The EPA appealed the Court's decision but the Court decided not to hear the appeal. Therefore, the EPA intends to adopt more stringent standards in place of the CAMR in the form of Maximum Achievable Control Technology (MACT) standards. Until that time, states are expected to review new projects for MACT on a case-by-case basis.

In the fall of 2008, the Courts were asked to rehear the case. There is no timeline for the Court to decide whether or not it will grant a rehearing. Until the Court makes its decision, the rule remains in limbo.

Connecticut introduced the statewide Mercury Plan in October 2007. The plan only applies to the three coal units in the state (Bridgeport Harbor #3 and AES Thames Units 1 and 2). As of July 1, 2008, permitted annual mercury mass emissions from all three CAMR units were well below the CAMR Phase I and Phase II mercury emissions caps assigned to Connecticut. Therefore, Connecticut will not need to participate in the CAMR program as originally written by the EPA.

7.D.4 Other Air Regulations Under Development in Connecticut

Connecticut High Electric Demand Days (HEDD)

On summer days, higher demand for electricity results in a dramatic increase in ozone-forming air pollution. These are called high electric demand days or HEDD. The emission peaks occurring on HEDD are an obstacle to the continued progress in attaining air quality improvements in Connecticut and throughout the Northeast region. HEDDs are the days most likely to result in ozone standard violations due to the ambient conditions. This situation can be exacerbated by transmission constraints which sometimes require generation to be provided by small, local, and infrequently operated electric generating sources. These generating sources add a small amount of megawatts to the system while causing a drastic increase in NO_X emissions.

Connecticut has signed a Memorandum of Understanding (MOU) with the other Ozone Transport Commission (OTC) states to reduce NO_X emissions from HEDD units. Connecticut has agreed to a NO_X reduction of 11.7 tons per day, which represents a 25 percent reduction in emissions from HEDD units. The CT DEP continues to formulate a strategy for achieving this target by the May 2012 implementation deadline.

The most salient observation from the initial simulations in this year's IRP modeling, was that uncontrolled NO_X emissions in Connecticut on HEDD days would exceed target levels of 42.7 tons/day in 2013 and 2015, and 31 tons/day in 2020, even under normal-year weather conditions. (The model also simulated extreme weather conditions using the ISO's "90/10" forecast). A large fraction of emissions on those days came from oil-fired steam units that operate on HEDD days, although little the rest of the year. Initial 2013 simulations with uncontrolled NO_X emissions and 50/50 weather conditions indicated that Connecticut would exceed its target on three of the ten High Electric Demand Days (HEDDs). Using 90/10 weather conditions that number rose to nine of the ten HEDDs.

Based on these observations, the CT DEP advised that it would likely need to restrict oil- and gas-fired steam units' emission rates to 0.125 lb/MMBtu by 2013 and 0.07 lb/MMBtu by 2017 in order to meet applicable HEDD targets. Further, the CT DEP suggested that such limits might be adopted throughout New England. Though the OTC has not specified limits, the CT DEP's suggested limits are consistent with proposals and analyses by the OTC.[5] However, the CT DEP did not provide guidance on future regulations regarding coal units or SO_2.

The regulations described by the CT DEP would force units with higher emissions rates to either invest in retrofit NO_X emission controls such as selective catalytic reduction (SCR) or else retire. The implications for investment/retirement decisions are analyzed in Section III.1 (Resource Adequacy), which describes capacity market dynamics and unit-level economic decisions. As Section III.1 (Resource Adequacy) describes, 1,504 MW of oil-fired steam capacity would retire in Connecticut and 646 MW would install SCR in the Base Case (different amounts in alternative scenarios and resource strategies). These retirements and investments result in lower HEDD NO_X emissions. In the Base Case, Connecticut complies with the NO_X target in 2013, exceeds it on two days in 2015, and exceeds it on five days in 2020. To meet NO_X targets in the future, therefore, CT DEP may have to apply even more stringent standards than analyzed here.

Connecticut Industrial/Commercial/Institutional Boilers and Electric Generating Unit Boilers (aka "Boilers" rule)

As part of implementing standards to meet the HEDD emissions reductions, the CT DEP is developing a rule that will apply to industrial, commercial, and institutional (ICI) boilers. It is expected to cover units between 25 and 250 MMBtu/hr, which are considered medium to large-size units. At this time the CT DEP has not specified standards that will need to be met by the ICI boilers. Separate standards will be developed to cover all boilers at EGUs. The CT DEP has discussed the possibility of 1.00 lbNO_X/MWh emissions limit for oil and gas-fired EGUs.

[5] See Final Joint Recommendation Letter from OTC to U.S. EPA, September 2, 2009; Final Letter on Additional Recommendations from OTC to U.S. EPA, September 10, 2009; and OTC CAIR Replacement Rule Recommendation Technical Support Document, September 10, 2009.

A stakeholder committee has been established by the CT DEP to review data and draft rules. The committee has not met in over a year and there have been no drafts released recently. It is our understanding that the CT DEP is looking at options to reducing the NO_X emissions from the EGUs using non-regulatory approaches. See also the OTC proposals below.

Regional Haze Rule

In 1999, the EPA introduced the Regional Haze Rule to improve the visibility in 156 national parks and wilderness areas. The rule applies to emissions of SO_2, NO_X, volatile organic compounds (VOCs), and particulate matter (PM), and requires states to develop SIPs. The implementation activities in the New England area are coordinated by the Mid-Atlantic/Northeast Visibility Union (MANE-VU). In 2005, the EPA issued the final Best Available Retrofit Technology (BART) rule, requiring facilities built between 1962 and 1977 and that have the potential to emit more than 250 tons of any visibility-impairing pollutant to use BART. In 2006, the EPA amended this rule to allow facilities to use an emissions trading program to satisfy requirements under the regional haze rule, provided that the emissions reduction resulting from the trading program meets or exceeds the visibility improvements under BART.

MANE-VU has set recommended limits, or "presumptive BART," for emissions of SO_2, NO_X, and PM from electric generators (by fuel type) and other facilities.[6] In 2007, MANE-VU committed to reducing emissions by 90 percent by 2018 at the 167 EGUs identified as most affecting visibility at Class I areas in the MANE-VU region. In addition, it has committed to implementing a low-sulfur fuel strategy.

Connecticut has created a SIP in response to MANE-VU. It was submitted to the Federal Land Managers (FLM) and the EPA for comments in February 2009. Following that, the CT DEP solicited comments from the general public and held a public hearing in August 2009. The final document was submittal to the EPA on November 18, 2009 and is awaiting approval and publication in the Federal Register.

OTC Proposals

The Ozone Transport Commission (OTC) is a multi-state organization created under the Clean Air Act. They are responsible for advising the EPA on transport issues and for developing and implementing regional solutions to the ground-level ozone problem in the Northeast and Mid-Atlantic regions.

Various draft guidelines have been developed by the OTC targeting NO_X and VOC emissions (precursors of ozone) from stationary sources. Specifically, VOC measures taken have been to update existing rules with new categories and limits including rules for Architectural Industrial Maintenance coatings, Consumer Products, and Solvent cleaning, as well as rules for large, above ground storage tanks. The OTC continues to evaluate potential control strategies,

[6] NESCAUM, BART Resource Guide, August 23, 2006, at pages 2-2 and 2-3, posted at http://www.nescaum.org/documents/bart-resource-guide/bart-resource-guide-08-23-06-final.pdf/.

including evaluating recently sought stakeholder input on summary rules released in August 2009. Additional measures that are currently under consideration by the OTC include performance standards for electric generating units, HEDD units and Institutional (ICI) boilers, requirements for minor new source review at facilities with stage 1 and 2 vapor recovery at gas station fueling pumps and coordination with energy efficiency and renewable energy programs. OTC has not drafted guidelines for these strategies at this time.

CT DEP is waiting to update Connecticut NO_X emission limits to new lower emission limits identified by OTC. It is anticipated all owners of stationary sources of NO_X will be impacted by either restrictions on use, or by the addition of add-on control equipment.

7.E OTHER ENVIRONMENTAL REGULATIONS/REVIEWS

In addition to existing and future air regulations, there are other environmental regulations or reviews with varying degrees of influence on operating costs, higher capital cost for new capacity, potential retrofit capital costs, restricted operations, and/or potential retirement. These have been included because of the potential impacts. The costs can not yet be qualified but on a case-by-case basis, though some general statements are possible.

7.E.1 Clean Water Act (CWA) 316.b – Cooling Water Intake Structures

The withdrawal of cooling water removes billions of aquatic organisms from waters regulated by the State with most impacts to early life stages of fish and shellfish due to the impingement and entrainment of these organisms. The EPA had developed national standards for cooling water withdrawals by new and existing large electric generating facilities centered on the implementation or retrofit of Best Technology Available (BTA) to reduce aquatic mortality. For Phase II of the rule, which addressed existing facilities, EPA allowed generators a range of compliance strategies and cost-benefit demonstrations. These were challenged in court by environmental groups, and the case was argued before the Supreme Court in December 2008. Recently, the 2nd Circuit officially remanded the rule to EPA. Generators assert that strict adherence to BTA will immediately require cessation of “once through cooling” operations and a retrofit with expensive alternative cooling technologies (primarily cooling towers), some of which may not be achievable or cost effective for existing facilities. Further, in non-attainment areas cooling towers may be prohibited or subject to additional restrictions. Dry cooling options are expensive, and because they reduce the efficiency of the boiler, they increase GHG emission rates.

Current understanding is that EPA will be looking to consolidate the Phase II and III rules (Phase III applies to small generators and other minor sources) into one rule that is targeted to be proposed mid-2010 and finalized by summer of 2012.

7.E.2 Environmental Equity/Environmental Justice

Environmental equity means that all people should be treated fairly under environmental laws regardless of race, ethnicity, culture, or economic status and is a direct result of a growing body of evidence that low-income racial and ethnic minority groups are exposed to a higher than average amount of environmental pollution. In December 1993, CT DEP issued an Environmental Equity policy that strives for increased broad community participation on agency advisory boards and commissions, regulatory review panels, and in the development of program and permitting activities.

Recent legislation passed in Connecticut (Public Act No. 08-94) specifically sought relief for "environmental justice communities" as defined in the Act and for "distressed municipalities" as defined in subsection (b) of section 32-9 of the general statutes. The Act describes new requirements for new or expanded generating facilities of greater than 10 megawatts and which are located within environmental justice communities (the "affected facility"). The requirements of the Act direct the affected facility to file and then execute a public participation plan in addition to those public participation activities that occur with permit or siting reviews. As an outcome of the public participation plan, the affected facility may enter into a "community environmental benefit agreement" and could address mitigation issues, community improvements such as walking or bike trails, and funding environmental education.

Since the Connecticut legislation was enacted, PSEG Power Connecticut, which owns New Haven Harbor Station in New Haven, reached an agreement with the City of New Haven and the environmental community (the Memorandum of Understanding or MOU) to ensure that there is no net increase in emissions when three new peaking generators (130 megawatts total) are added to the existing facility. PSEG has agreed to certain modifications and restrictions to the operation of its existing New Haven Harbor Unit (NHH #1) as well as certain operating protocols when all units are in service. In short, PSEG has agreed that there will be no net increase in emissions from the site. PSEG's strategy to achieve this goal relies on a number of operating protocols related to daily and annual offsets, optimizing boiler efficiency at NHH #1 for reductions in particulates and primary fuel (natural gas) designation for the new turbines. Further, PSEG has agreed to request that the CT DEP modify the Title V Operating Permit (currently undergoing review) to provide for permit enforceability of the operating protocols set forth in the MOU. Operating protocols are not applicable during an emergency event on the system as declared by ISO-New England.

Most recently EPA announced an initiative to address Environmental Justice challenges in 10 communities and help highlight the disproportionate environmental burdens placed on low-income and minority communities. Bridgeport, Connecticut has been selected by EPA as one of these Environmental Justice Showcase Communities and it is EPA's stated intention to work collaboratively with a wide range of stakeholders to address a number of Environmental Justice issues including reducing asthma and toxics exposure.

7.E.3 Endangered Species Act

Last year this section reported a potential for the Endangered Species Act (ESA) to be used to regulate GHG emissions from automobiles, power plants and other source. Such an initiative could come about under amended, but not yet proposed, regulations governing interagency cooperation. Current indicators suggest that this is less likely and that any regulation of GHG will occur under revisions to the Clean Air Act.

7.E.4 Coal Ash

In December 2008, a catastrophic release of coal fly ash slurry (a coal ash and water mix) occurred at the Tennessee Valley Authority (TVA) Kingston Fossil Plant, a coal-fired power plant located in Roane County, Tennessee. The release was caused when the dike for the 84 acre containment area ruptured and released approximately 1.1 billion gallons of slurry into the surrounding land (approximately 300 acres), damaging homes and impacting adjacent waterways (the Emory and Clinch Rivers). Clean up of the spill is estimated at nearly $1 billion.

Following the spill there have been numerous legal actions and discussion of potential regulatory initiatives, the most sever being to classify coal ash as a hazardous waste. This is becoming one of the most pressing issues facing new and existing coal plants as financial impacts to manage and dispose of coal ash would be substantive. However, the cost implications can not be determined at this time. The EPA is expected to issue draft regulation on coal ash in the first quarter of 2010.

7.E.5 Water

In the future, there will be increasing competition for an essentially static source of water supply. Electricity generation, through its withdrawal and consumption of water, significantly impacts this supply. Fossil fuel generators may require additional large increases in water consumption to facilitate control of emissions. Increased pressure to use gray water and other alternative supplies (such as municipal effluent) and tighter restrictions on water diversions could have an effect on plant processes and/or cost of operations.

As of December 1, 2009, new standards require a National Pollution Discharge Elimination System (NPDES) permit for construction activities, including linear projects like transmission lines, that impact more than 10 acres of land at one time. Threshold standards for some priority pollutants were also tightened. Some steam electric effluent guidelines, for metals in particular from coal pile run off, could increase the cost of pollution control substantially. These new standards introduce direct cost impacts, such as compliance controls, permit application development and execution and monitoring and possible “externality costs,” such as negative impacts to the construction schedule (such as in the case of a transmission line) for additional permitting.

7.E.6 Siting of Transmission and Generation

Environmental reviews for siting new transmission and generating facilities consider and balance several criteria, including compatibility with surrounding land use, aesthetics and whether or not the proposed project makes use of an existing “facility,” as defined by the statute (in Connecticut). Construction and operating impacts to the environment are also evaluated. Sites that have the least over all environmental impact are favored. Reuse of, or additions to, existing facilities is encouraged, rather than the development of green field sites or establishing new transmission line rights-of-way. Synergies with certain environmental permitting may also be possible at existing facilities. Due to the length of time and expense associated with siting new facilities, reuse of existing generating and transmission facilities remains likely. Though there may be eventual retirements of individual generating units, it seems reasonable that a specific “site” may remain in use for future/new generation, though possibly be subjected to ever increasing operating restrictions due to regulatory considerations and constraints with available space to accommodate required technologies.

Other stakeholders, such as members of the public, may be strongly opposed to a proposed facility and, for many and varying reasons, disagree with the philosophy outlined above, including reuse of an existing facility. Alternatives advocated by other stakeholders may be too expensive, not technically feasible or result in unpalatable strategies such as condemnation, as may be the case with establishing new overhead transmission line rights-of-way. Eventually, however, modifications to existing facilities may no longer be possible and the establishment of new generating sites and/or new overhead transmission line corridors would need to be considered. The potential impacts to in-service schedules, planning and cost could be substantial.

Section III.8
Energy Security

8. ENERGY SECURITY

8.A SUMMARY AND KEY FINDINGS

Summary

Section 51 of PA 07-242 calls for, among other things, an evaluation of energy security: "the companies shall submit to the Connecticut Energy Advisory Board an assessment of … (5) energy security and economic risks associated with potential energy resources, …" The Connecticut Energy Advisory Board, in its 2009 Comprehensive Plan for the Procurement of Energy Resources, identified energy security as "reliability of the power system … vulnerability to natural disasters, terrorism, fuel supply disruptions, or over reliance on foreign sources of fuel." In this resource plan, energy security is interpreted similarly to mean the reliable delivery of sufficient electric power to meet load under severe adverse events. Energy security can be measured in terms of involuntary load curtailment, *e.g.*, in MW and duration.[1] The effect of an energy security event can also be characterized in terms of the same metrics used elsewhere: prices, costs, emissions, fuel mix, *etc*.

In this section, we examine risks to the operability of particular types of resources and how they may affect the security of electric energy delivery. We do not explicitly analyze particular risks (*e.g.*, natural disaster, accident, sabotage) to the operation of individual system components, including risks to specific Critical Energy Infrastructure components. The power system is already designed and operated to protect against individual element outages (for example, planning and operating reserve requirements enable the system to sustain the outage of individual resources without compromising the overall ability to deliver power). The system's design and operating policies that protect against such component outages are in large developed and regulated by a number of national, regional and state-level organizations, as discussed further below. This section also largely excludes discussion of economic risks – factors that may affect the cost of energy rather than its security. We do consider risks that are broad enough that they might potentially threaten system reliability, including systematic risks that might affect multiple resources simultaneously.

Because Connecticut is a part of an electric market that spans most of New England, New England is generally the appropriate geographic scope for an energy security analysis. Connecticut itself, though it is the focus of this IRP, does not typically stand alone regarding electric energy security. In most circumstances, it will have adequate electric energy, or not, as a part of the New England market, not based on events and circumstances in Connecticut alone. For example, assuming that electric transmission capacity is available, whether some Connecticut generators are inoperable does not directly affect Connecticut electric loads. If sufficient other New England generators are operable, then Connecticut electric loads will be served. Conversely, even if all Connecticut generation is operable and is sufficient for

[1] This would generally exclude the localized effects of distribution outages, such as those caused by lightning strikes or tree falls.

Connecticut loads, if New England has insufficient generation overall, Connecticut's electric load may share in the shortage (Connecticut's operating capacity would be helping the overall New England situation, but could not ensure that Connecticut loads are served).

Connecticut currently has several groups investigating issues concerning energy security, and in recent years has enacted some legislation to study and address these issues. This legislation focuses on several different energy security issues, including studying the degree of dependence on fossil fuels, and promoting development of renewable energy sources and energy efficiency through comprehensive energy plans. Some of these reach beyond the power sector, though for this investigation the focus is primarily on the power sector. Below is a brief overview of several of these organizations and pieces of legislation as they relate to energy security.

P.A 08-168, An Act Concerning Energy Scarcity and Security, Renewable and Clean Energy and a State Solar Strategy, passed in 2008, mandates that:

- A task force to study energy scarcity and sustainability will be created to generate scenario planning for long-term petroleum and natural gas scarcity, and volatility in prices and supply.
- The Office of Policy and Management will conduct a study of petroleum consumption and dependence by state departments and agencies.
- The Renewable Energy Investment Board will determine how other states promote and implement the use of clean and renewable energy.
- The Renewable Energy Investment Board will develop a plan to maximize use of solar power and develop a self-sustaining solar industry in Connecticut to help meet requirements agreed to in the Regional Greenhouse Gas Initiative.

In addition, the Connecticut Siting Council's (CSC) Docket No. 346 was developed in response to Public Act 07-242 to investigate energy security with regard to the siting of electric generating and transmission facilities. The CSC received comments from numerous parties including the CEAB, the Connecticut Department of Emergency Management and Homeland Security (DEMHS) and the EDCs. The CSC concluded the proceeding with the development of a "White Paper on the Security of Siting Energy Facilities." As this whitepaper describes, the CSC has focused on physical threats (from trespassing to vandalism to dedicated acts of sabotage) to particular electric generating and transmission facilities, and primarily on threats that are related to location and siting. The energy security analysis here takes a somewhat different and broader perspective. We focus not so much on location-related threats to individual facilities, but more on system reliability and systematic risks that might affect multiple resources simultaneously. As discussed below, the power system is designed and operated so that individual facility failures do not threaten system reliability.

Key Findings

- The power system is planned, designed, and operated to maintain high energy security, building in spare capacity, redundancy, and operational flexibility. A number of organizations at the national, regional and state levels oversee and enforce reliability.

- Key resources for energy security include natural gas and nuclear generation, because of the system's heavy reliance on these generation types and the risks that could affect their operability, as well as the electric transmission system. Other resources – oil, coal, renewables – are unlikely to pose energy security concerns of comparable magnitude, due to the smaller role these resources play in providing power, and also because of a lack of exposure to significant risks.
- Natural Gas: The New England power system's reliance on natural gas was stress-tested by analyzing the loss of access to natural gas for several days during the winter months. This analysis suggests that there would be adequate other generation resources available to serve winter load, with no or virtually no reliance on natural gas. This is due to several seasonal factors that improve the winter resource balance, plus dual fuel capability that allows many gas-fired generators to utilize oil if gas is not available.
- Nuclear: A prolonged, simultaneous shutdown of multiple nuclear units at peak load times could stress the system's ability to serve load. However, it appears that even with the loss of both Connecticut nuclear units, the implementation of existing emergency operating procedures and additional reliance on imports from neighboring regions would allow the system to continue to serve load.
- Transmission: The electric transmission system is designed and operated with a level of redundancy that allows it to absorb isolated failures with no impact on customers. If an extreme event were to cause a more widespread transmission failure, the transmission owners' recovery capabilities and procedures ensure that any service interruption would be brief.

8.B ENERGY SECURITY – ORGANIZATIONAL AND MARKET FACTORS

The fundamental design and operating standards of the power system are used to ensure energy security – *i.e.*, to ensure that there are sufficient resources to meet load in actual operation. Generally, in both planning and operational contexts, the only alternatives that are even considered are those that satisfy explicit and stringent reliability standards. For example, generation adequacy standards (planning reserve margins) are set to achieve a probabilistic risk of generation insufficiency of not more than one day in ten years. This standard is implemented via ISO New England's Forward Capacity Market (FCM). Load-serving entities are required to acquire, several years in advance, sufficient generating capacity to meet their forecast load plus a reserve margin (designed to meet the one-day-in-ten-year criterion). The ISO also operates a market to procure such capacity. Alternatives that involve having generation resource levels that are insufficient to meet these reserve targets are not considered; reliability is not traded off against other dimensions (such as cost). Transmission is similar – it is planned and operated to meet very high reliability standards.

Several regional and national organizations play a role in analyzing reliability and energy security and protecting against these risks in power system planning and operation, in part by developing requirements, mechanisms and procedures such as those described above. At the national and regional level, in response to a 1998 Presidential Directive, the U.S. Department of

Energy was designated as the lead agency for protecting critical energy infrastructure. The DOE in turn designated the North American Electric Reliability Council (NERC) as the Electricity Sector Coordinator, and NERC issued a set of voluntary guidelines related to energy security. Under authority of the 2005 Energy Policy Act, the Federal Energy Regulatory Commission (FERC), designated NERC as the national Electric Reliability Organization (ERO), and as the ERO, NERC converted many of its voluntary guidelines into mandatory requirements. The Northeast Power Coordinating Council (NPCC) is the regional organization under NERC that is responsible for electric reliability throughout Northeastern North America (the six New England states plus New York, and the Canadian provinces of Ontario, Quebec, and Maritimes). Under the NPCC, the New England ISO (ISO-NE) is the regional transmission operator (RTO) with responsibility for ensuring reliability in New England. At the state level, there are additional organizations involved with ensuring energy security, such as the CSC and the Connecticut Department of Emergency Management and Homeland Security. The Connecticut Siting Council's whitepaper regarding energy security in the siting of energy facilities (Docket 346) provides a good high-level overview of existing security standards and guidelines at national, regional, and state levels.[2]

In addition to the formal organizations that work to ensure energy security, the competitive New England power market creates financial incentives that also help to maintain supply reliability. Most generators are merchants who must produce power in order to be paid, resulting in strong financial incentives for generators to produce power when it is needed, including during a potential energy security event. A merchant generator will forego energy revenues if they do not deliver power during an energy security event, and energy prices are likely to be quite high during a supply-related energy security failure. Further, a generator faces potentially disproportionate capacity revenue losses; an energy security event does not provide a waiver for failure to perform. A generator can lose up to 5 percent of its annual capacity revenue if it is unavailable during a single shortage event, and for repeated or extended outages can lose 100 percent of their capacity revenues. Thus the financial incentives in the capacity and energy markets directly encourage generating resources to minimize their exposure to energy security events and to be able to successfully manage such events.

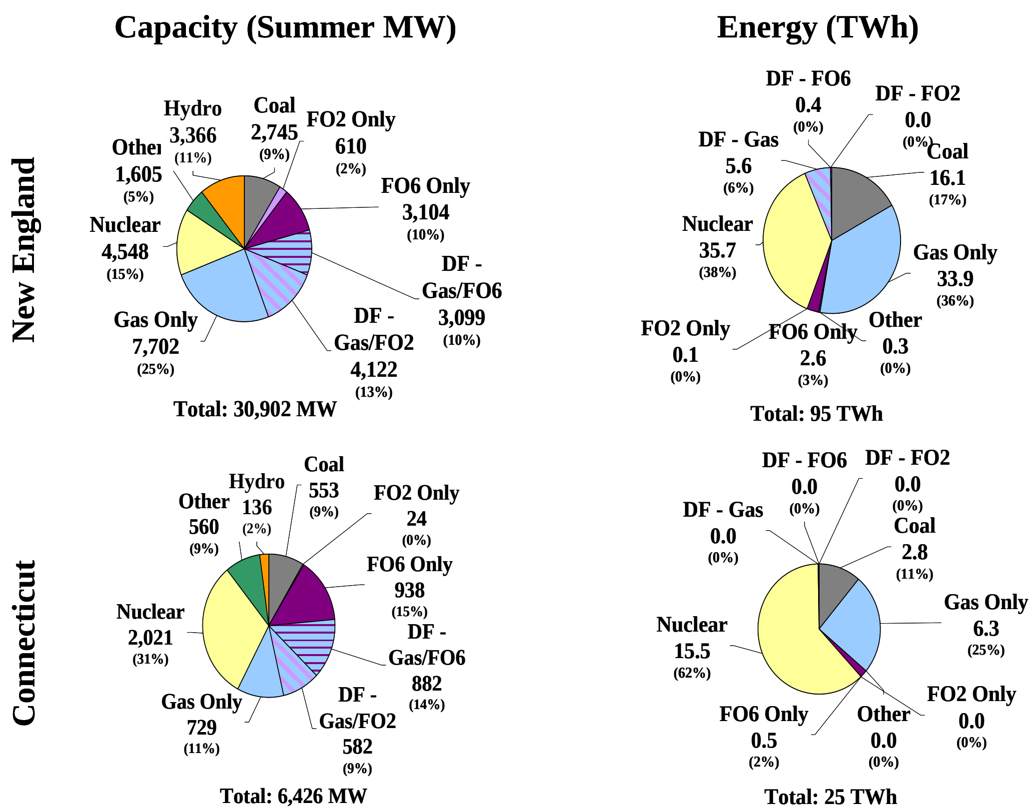
Beyond recognizing the organizational mechanisms and market incentives that help to protect against potential energy security problems, to explore energy security further this IRP considers a number of specific potential energy security issues. We consider the extent to which the regional power system relies on particular generation resources, and the degree to which these may be exposed to some level of common-mode failure (*e.g.*, fuel supply disruption or common outage) which might create a significant loss of generating capacity. We also consider the energy security implications of several non-generation resource types (transmission, demand-side resources). In addition, we examine in greater detail two particular types of energy security events: one related to winter natural gas availability, and the other a shutdown of nuclear generators. Although it would not be possible to analyze or even identify every possible configuration of occurrences that might raise energy security concerns, these particular events were chosen and defined to be extreme cases affecting resources that New England relies upon to a particularly great extent, in order to stress-test potential energy security issues.

[2] White Paper on the Security of Siting Energy Facilities, Connecticut Siting Council, October 8, 2009.

8.C RELIANCE ON DIFFERENT GENERATION TYPES IN NEW ENGLAND

With respect to a particular type of resource, energy security is related to the level of reliance on that resource type, as well as the risks that it may be exposed to. If New England is heavily reliant on a particular type of generation whose operability is exposed to a particular event, then that event may be an energy security concern for the region. Figure 8.1 below shows the capacity and energy shares of the major classes of generating capacity in New England in 2008. (This is illustrated at the Connecticut level as well as New England overall, though as discussed above, it is usually the New England level that is most relevant to energy security.)

Figure 8.1
2008 Capacity and Energy Shares for New England and Connecticut



Sources: Capacity ratings: 2009 CELT Report, ISO New England, April 2009. Energy production: *The Brattle Group* analysis of generating data, as compiled in Ventyx Energy, The Velocity Suite.

Though neither the capacity nor energy share metrics reflect directly the energy security impact of different generation types, the capacity shares are more relevant, because they represent the extent to which particular generation types may be available to produce power, if necessary. Almost half of New England's total generating capacity is capable of burning natural gas (though only about 40 percent indicate that gas is their primary fuel). About 25 percent of the total can burn only natural gas, and a little under a quarter has dual-fuel (DF) capability to burn either gas or oil fuel - distillate (FO2) or residual oil (FO6). Nuclear accounts for about 15 percent of overall capacity, hydroelectric for 11 percent, FO6-only capacity for 10 percent, and coal for 9 percent.

Energy shares tend to reflect the relative economics of different generating types, rather than the ability to rely on them for energy security and reliability. Generators that are more costly to operate usually provide less energy because that is the most economic way to operate the system, not because the resources are unimportant to energy security. Resources that are seldom operated and rarely produce energy can nonetheless contribute importantly to energy security, if they are available to run when needed. As an example of this effect, natural gas prices were very high in 2008 but have fallen since; they are expected to rebound somewhat though still to remain well below 2008 levels. Due to the likely lower future cost of gas, New England may generate more energy with gas in the future than it has in the past, but that simply reflects the relative economics of alternative fuels; it does not necessarily mean that New England will rely more heavily on natural gas in an energy security context.

Nonetheless, New England clearly does rely heavily on both natural gas and nuclear power for capacity and energy, with the gas reliance tempered by the fact that much gas-fired capacity can also burn oil (more on this below). Connecticut-based generation leans even more heavily toward these two resource types. For future years, the picture may differ in detail though it will be fundamentally similar, and the differences are easy to understand. For example, as New England adds renewable resources to meet RPS requirements, the renewable energy share (included within the "Other" category in Figure 8.1) will increase over time. If the region adds more new gas plants to meet future needs, it will rely more heavily on natural gas. A new nuclear plant would increase New England nuclear capacity by about 25 percent of its current value, with a corresponding decrease in the use of gas and other fuels. But within the ten-year time frame of this study (and likely well beyond that), under just about any future state of the world, New England will still be heavily reliant on natural gas and nuclear generation for both capacity and energy.

So at least qualitatively, factors that may affect the operability of gas or nuclear resources on a large scale could have energy security implications. For instance, fuel availability for gas-fired electric generators, which we know from experience can be stressed during New England's winter heating season, might potentially affect electric reliability (gas use for heating is a large share of peak gas requirements and generally has priority over gas for electric generation). Likewise, a shutdown of even one nuclear unit during peak times can be a significant event. The simultaneous shutdown of multiple units, *e.g.*, due to the discovery of a potential technical problem with a shared reactor design, or regulatory concern about operational issues, might have a bigger effect. Other generation types are likely to be less vulnerable to large-scale outages, because they account for less capacity, and/or because they are less subject to common-mode failures of large amounts of capacity. For example, 10 percent of total capacity is fired by residual oil, and another 9 percent by coal, but since these fuels can be inventoried onsite and are not subject to particular limits on delivery capacity, a fuel supply disruption is of less concern than for natural gas.

The next several sub-sections address potential energy security risks related to gas-fired and nuclear generation, including simulations of extreme stress cases designed to explore the system's potential exposure to energy security concerns. Following that, we consider demand-side resources, which will begin to deliver capacity starting in the summer of 2010 through the Forward Capacity Market. Beginning June 2010, the system will rely on demand resources for capacity to a much greater extent than it has previously. A final topic considered is transmission – not a supply source but nonetheless a vital component of the power system and energy security.

8.D NATURAL GAS-FIRED GENERATION

Natural gas-fired generation has numerous advantages, including high reliability, relatively low construction cost, and modest environmental impacts. However, the availability of natural gas supplies needed to operate this capacity can be a concern. In New England's winter heating season, when gas demand is at its peak, the ability of the gas transportation and delivery system to deliver all the gas desired by all customers can be stressed.[3] Natural gas is used primarily by local distribution companies (LDCs) to serve their core customers – mostly residential and commercial heating – and by electric generators (with a much smaller amount used by non-core industrial customers). LDCs pay for primary firm service on the gas transportation system, and electric generators typically either contract for a lower quality delivery service (non-firm, or interruptible), or purchase spot supplies on a daily basis. When the system is constrained, the core customers have priority and it is the electric generators who face potential curtailment If this occurs at a time when the gas is needed to fuel generators to meet electric load, it could potentially cause a reliability concern. Even if gas delivery to non-firm customers is not curtailed, during peak winter periods spot gas prices can increase to several times typical levels, which could lead to a significant short term electricity price spike. In the past several years there have been a couple of incidents in which gas-fired generators had difficulty getting sufficient gas supplies (*e.g.*, a cold snap in January 2004; a disruption of Sable Island gas supplies in December 2007). In those incidents, however, the power system was still able to serve all load.

The system's reliance on natural gas for electric generation during the winter peak gas demand period is mitigated by several seasonal factors. First, winter generating capacity for thermal units is higher than summer capacity (about 9 percent higher, in aggregate) due to lower ambient temperatures. Second, winter electric demand is substantially lower (winter peak is about 20 percent lower than summer peak). Finally, wind turbines, which are added in large numbers to meet RPS requirements, produce significantly more energy (and thus provide more reliable capacity) in the winter season than in the summer. Since electric capacity needs are determined by summer peak conditions where wind contributes very little, wind's higher winter production further reduces gas reliance. These three factors mean that there is quite a bit of additional slack

[3] As discussed above with respect to the overall energy security question, New England is the relevant geographic scope for assessing natural gas dependence. Both the electricity and natural gas markets are generally span New England, with Connecticut being an integral part of the larger regional market.

in the winter resource balance, and winter peak loads can be served with significantly less reliance on gas-fired capacity as compared with the summer peak.[4]

In addition, dual-fuel capability (the ability to switch fuels to burn oil instead of gas) can help to further alleviate the gas-dependence problem. ISO-NE has no dual-fuel requirement, and a significant amount of gas-fired capacity in New England does not have dual fuel capability. As shown above, gas-only generators provided about 25 percent (7,702 MW) of New England's generating capacity in 2008. In its 2008 Regional System Plan, ISO-NE looked at the region's dependence on natural gas for electric fuel.[5] It found that 8,896 MW of capacity was gas-only, though 3,091 MW of this gas-only capacity did have permits to burn oil but had not added the physical capability to do so (it may take as little as a few months to physically add oil-burning capability once the necessary permits are in place). Table 8.1 shows New England dual-fuel capabilities according to the ISO.[6] Since then, in its 2009 Regional System Plan, ISO-NE reported that 40 percent of New England's 2009 summer installed generating capacity (total 31,443 MW) consisted of generators that use natural gas as their primary fuel, and about one-third of these generators have dual-fuel capability (fuel oil).[7] In total about 25 percent of New England's overall generation consists of dual fuel units that have both the physical capability and the necessary permits to burn either gas or oil. In addition, ISO-NE Cold Weather Rules, firm gas contracts at some gas-only plants, improved operating procedures within ISO-NE, and improved coordination between pipelines and ISO-NE, NYISO, and PJM can help mitigate concerns about gas availability.

Table 8.1
New England Dual Fuel Capability

Unit Type	Winter Claimed Capability *(MW)*
Gas only (no oil permit)	5,805
Gas with oil permit	3,091
Dual fuel	7,628
Total	16,524

Source:
2008 Regional System Plan, Section 7.4.1.

4 "2008-2017 Forecast Report of Capacity, Energy, Loads, and Transmission," ISO New England, April 2008.

5 2008 Regional System Plan, ISO-NE, Section 7.4.1.

6 In the Connecticut Peaker Solicitation (Docket 08-01-01), DPUC Review of Peaking Generation Projects, all 506 MW of new capacity will be dual fuel. This new capacity is not reflected in the table.

7 2009 Regional System Plan, ISO-NE, Section 6.

The Natural Gas section of this IRP discusses in greater detail the availability and deliverability of natural gas to fuel electric generation; see that section for a detailed discussion. It concludes that increases and greater diversity of gas supplies, particularly unconventional resources like shale gas, and improved gas transportation infrastructure including pipeline expansions and new LNG import terminals, lead to an improved outlook for the availability and reliability of gas delivery to electric generators. Also, prices are expected to remain reasonable, largely due to the recent increases in shale gas supplies. A similar conclusion was reached by the New England ISO in its 2009 Regional System Plan: "Recent infrastructure enhancements to the regional natural gas systems should satisfy the needs of New England's core space heating and power generation markets for years to come." Nonetheless, since New England does rely heavily on natural gas for power, to test this reliance and the potential for vulnerability to gas supply, we have simulated the effects of a gas supply disruption.

8.D.1 Natural Gas Supply Disruption – Simulation

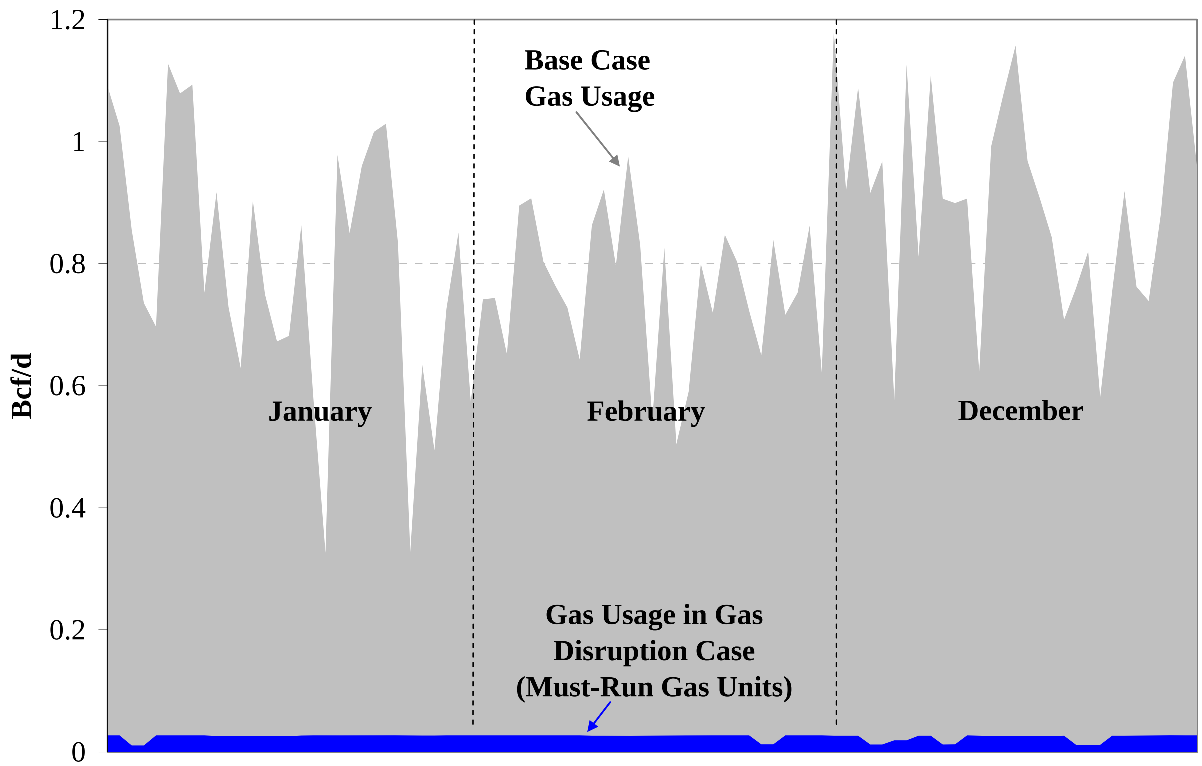
We have analyzed a case to test the reliance of the New England power sector on natural gas in the winter peak gas demand season, simulating gas use only as a last resort (dual fueled units were assumed to use their alternate fuel rather than natural gas). This allows us to see the extent to which the system actually needs to rely on natural gas during the winter period. We performed this Gas Supply Disruption simulation for the entire winter season (December, January, February), using a case that is otherwise identical to the 2020 Base Case simulation described in Section II (Analytical Findings). Of course, an actual winter gas disruption, if it occurred, would likely last only a few days during an extreme cold snap, and would be unlikely to make gas entirely unavailable for power generation (*i.e.*, the severity of the gas restrictions would probably vary over the period of the cold snap). But structuring the analysis as we did exposes the extent to which there may be any shorter periods within the winter season where a gas supply disruption might cause problems, as well as to determine the extent to which the system actually needs to rely on natural gas for generation.

The Gas Supply Disruption simulation results showed that it would be possible for the system to meet winter loads with very little reliance on natural gas, and quite possibly none at all, throughout the winter season. In the simulation, the only gas-fired capacity that was operated is a small amount of must-run gas-fired generation (about 126 MW) that runs in all hours (other than outage hours). All of this must-run generation is new generation located in Connecticut.[8] The amount of gas used in the gas supply disruption simulation is very small, averaging 0.025 Bcf/d, with a maximum of 0.027 Bcf/d. This is 97-98 percent below the amount of gas that would be used if gas supplies were not limited – in the Base Case, winter gas use averages approximately 0.82 Bcf/d, and up to 1.18 Bcf/d. Thus the system is able to meet load using only 2-3 percent as much gas as it would otherwise use, and it is likely that not even this amount of gas capacity is actually needed – *i.e.,* that it is running only because of its must-run designation. Although New England normally does use a significant amount of gas for winter power generation, this is primarily because that is the most economical way to operate the system. The

[8] Of this, 60 MW is the Ansonia Generating Facility, a monetary grant distributed generation project. About 23 MW consists of Project 150 fuel cells, which are required to have firm gas supplies, and another 42 MW is a fuel cell generator not under Project 150.

seasonal factors discussed above: higher winter generating capacities, lower winter loads, and more wind energy in winter, in addition to dual fuel capability, combine to alleviate the system's need to rely on winter gas use for energy security. Figure 8.2 compares the amount of winter gas used in the Base Case with that used in the Gas Disruption simulation.

Figure 8.2
Winter Natural Gas Usage in Base Case versus Gas Disruption Simulation



Note that this one simulation does not indicate that New England's concerns regarding natural gas availability for electric generation have been permanently resolved. This simulation characterizes a future year in which the winter need for natural gas to fuel electric generation has decreased, due to increased wind generation and modest load growth, and significant dual fuel capacity is available. The future may turn out differently in many respects, and in some such possible futures, gas dependence could be higher. However, the result is quite striking, and should give some comfort that New England's reliance on natural gas for electric generation is likely to be lower than in the past.

8.E NUCLEAR GENERATION

New England has over 4,600 MW of operating nuclear capacity. About 1,300 MW of this capacity (Pilgrim and Vermont Yankee) will reach license expiration in 2012, though those units have applied for and expect to receive 20-year license extensions. Table 8.2 shows the operating New England reactors.

Table 8.2
Operating Nuclear Reactors in New England

Unit Name	Operator	Reactor	Vendor/Type	Location	Current License Expiration Date	MW Rating
Pilgrim	Entergy	BWR	GE Type 3	Plymouth, MA	6/8/2012	677
Vermont Yankee	Entergy	BWR	GE Type 4	Vernon, VT	3/21/2012	604
Seabrook	FPL Group	PWR	Westinghouse 4-Loop	Seabrook, NH	3/15/2030	1,245
Millstone 2	Dominion	PWR	Combustion Engr	Waterford, CT	7/31/2035	877
Millstone 3	Dominion	PWR	Westinghouse 4-Loop	Waterford, CT	11/25/1945	1,235
Total Capacity						**4,639**

Source: 2009 CELT Report, ISO New England, April 2009. Millstone 3 capacity was adjusted for the capacity uprate that took effect in Fall 2008.

Fuel supply is unlikely to be an issue for nuclear plants, since nuclear fuel is procured on a relatively long advance schedule. Also, unlike fossil plants which must be continuously provided with fuel to sustain power output, a nuclear plant typically operates for about 18 months on a single fuel cycle, and there is some flexibility in how long a plant runs on a single fueling. Similarly, nuclear spent fuel storage, though it may be a substantial long-term policy issue, is unlikely to cause energy security problems. Fuel storage limitations can be foreseen far in advance and there are several technical options to address them.

A more likely energy security issue for nuclear plants is the potential for an unplanned and potentially extended shutdown of one or more units. Technical or operational problems, or even just the suspicion of such problems (*e.g.*, due to the discovery of a problem at similar units) could cause such a shutdown. A single-unit shutdown would result in the loss of from 600 to over 1,200 MW, depending on the unit. Although the New England power supply system plans for such contingencies and has sufficient generating capacity reserves to accommodate such an event, it can still put stress on the system. An outage of multiple nuclear units could have even greater consequences, and in the extreme (*e.g.*, at summer peak) might begin to raise energy security concerns.

Perhaps the most likely scenario for a multiple-unit shutdown would be the discovery of a problem with reactor design or operating procedures that would cause the precautionary shutdown of multiple similar units. Not all the nuclear units in New England have a common design, nor are all run by the same operator. However, the two largest units, Seabrook and Millstone 3, are of the same design (Westinghouse Four Loop reactor) and combined represent nearly 2,500 MW. Dominion operates both Millstone 2 and 3, with combined capacity of over 2,100 MW. The loss of either of these pairs of units could be substantial for the New England power system, particularly if it coincided with summer peak load times.

8.E.1 Simultaneous Nuclear Outage – Simulation

To explore the potential impact of a multi-unit simultaneous nuclear outage, and one that might have the greatest impact on Connecticut, we simulated an outage of both of the Millstone nuclear units at a time of approximate resource balance with the nuclear units in service (*i.e.*, when the current generation surplus has been eliminated).[9] Together the two Millstone units account for over 2,100 MW of capacity.[10]

The simulation showed that a simultaneous outage of both Millstone nuclear units, if it were to coincide with peak summer loads, could put significant stress on the system. During as many as 60 high load hours, there could be a generating capacity deficiency. In the few most extreme hours, the magnitude of the deficiency could be similar to the combined capacity of the nuclear units, and the deficiency would apply across much of the New England region, not just Connecticut. Of course, in a scenario like a multiple nuclear outage, other stochastic events could ameliorate the problem or exacerbate it further. For example, if an unusually high outage rate among other generators happened to coincide with peak load, or if the peak were higher than normal due to unusually extreme weather, the effect of a nuclear outage could be more severe.

However, the fact that the simulation shows a capacity deficiency does not necessarily mean that there would be involuntary load curtailment. The simulation is unable to characterize the standard operational steps available to the system operator to respond to a capacity deficiency condition. The New England ISO has a clearly identified set of steps that it would take to respond to a capacity deficiency, codified in its Operating Procedure No. 4 (OP #4). This operating procedure includes a number of ways to make additional generation available or reduce load, including:

- allow 30-minute operating reserves to go to zero;
- allow the depletion of 10-minute operating reserves;
- acquire emergency support from neighboring control areas (curtail exports, increase imports, reserve sharing);
- voltage reduction;
- dispatch real-time emergency generation; and
- request voluntary load curtailment.

9 Other than the absence of the nuclear units, the simulation was the same as the 2020 Base Case discussed in Section II (Analytical Findings).

10 The loss of comparable amounts of any generation type would have similar effects.

In total, the ISO estimates that from 4,628 to 5,633 MW of additional generation and load relief may be available to it under OP #4, before needing to institute further actions such as involuntary load curtailment.[11] This is more than twice the 2,100 MW capacity of the two Millstone units, and is similar to the total capacity of all five New England nuclear plants combined. In addition, the OP #4 steps are all short-term reactive responses to an unexpected shortage. A large outage of sustained duration may give sufficient lead time to investigate and implement slightly longer lead-time solutions, such as returning any mothballed units to service or bringing in portable generation. If such an outage were to occur at a time of capacity surplus, as exists currently and is expected to continue for some years, the effect on the system would be correspondingly less severe. It appears that although a multiple unit nuclear outage would impose substantial stresses, the electric system is likely to be able to manage such an event without needing to resort to involuntary load curtailment even in peak hours.

8.F DEMAND-SIDE MANAGEMENT

Demand-side management (DSM) can alleviate energy security risks by reducing overall energy demand and therefore reducing reliance on other resources that may present risks. However, in the coming decade New England is expected to rely to an unprecedented extent on DSM to augment its energy and capacity resources. DSM consists of energy efficiency (EE) measures which reduce the energy consumed by a particular end use, as well as demand response (DR) in which loads curtail only when needed in response to instructions from the ISO or an intermediary. In the Forward Capacity Market (FCM), 700 MW of EE resources have been committed for delivery in the first FCM commitment period, June 2010-May 2011. For the second commitment period, 2011-2012, this increases to 978 MW, and to 1,073 MW for the third commitment period, 2012-2013.[12] Once an EE measure is installed and demonstrates its capacity, which it must do to participate in the Forward Capacity Market, it should be highly reliable and so should present no energy security concerns.

Demand response resources have committed even more capacity in the FCM – 979 MW (excluding emergency generation) for the first FCM commitment period, 1,200 MW for the second, and 1,194 MW for the third period. One potential issue with DR capacity is that as the total amount of demand response capacity on the system increases, each DR participant may be called upon more frequently. In the past, interruptible load programs in New England (and most other markets) have actually interrupted loads very infrequently, but ISO-NE forecasts it may call DR resources quite frequently given the increased levels of DR now committed – around 60 hours per year with the 50/50 load forecast, but if loads are high (*e.g.*, the ISO's 90/10 forecast) this could increase to over 80 hours just in the month of August. (An individual resource might be called significantly less often, since only a fraction of total DR capacity may be called in any given instance, but the number of hours may nonetheless be significant).[13] Whether these DR

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[11] ISO New England Operating Procedure No. 4, Action During a Capacity Deficiency – Appendix A – Estimates of Additional Generation and Load Relief, May 19, 2009, Revision No. 16.

[12] These figures include all "passive" demand resources.

[13] For example, see ISO-NE's "Demand Resource Operable Capacity Analysis – Assumptions for 2013/14 (FCA4)", October 15, 2009.

resources will be fully dependable has not been demonstrated, and will not at least until the first commitment period begins June 2010. In the face of such high call rates, DR participation may hypothetically be discouraged, and/or participants may fail to respond, leading to a situation where DR might not provide as much capacity as expected. On the other hand, by current ISO rules, if an individual participant fails to respond, they (or the load response aggregator, if applicable) are financially responsible. The ISO has identified this issue as a concern and is taking steps to inform DR participants of how frequently their capacity may be called so that the potential high call rate is understood.

8.G TRANSMISSION

Electric transmission is clearly an integral part of the power system in New England as well as Connecticut and plays a key role in energy security – transmission must function reliably in order to deliver power to customers. Through its external interfaces with New York and Canada, New England both imports and exports power. Connecticut itself is integrated with the remainder of the New England power system via several transmission interconnections, and is also connected to New York via a 345kV tie line and other lower voltage links. At any given moment, power may be (and almost always is) flowing into or out of Connecticut, or both simultaneously over different transmission links. Transmission flows can vary significantly over short periods as total load and its geographic pattern change, generation dispatch changes, or generation and transmission elements may experience outages. Flows generally tend to follow some predictable patterns (at least when the system is in normal conditions), though the underlying patterns can change over longer periods as generating capacity is added or retired, load patterns change, or the transmission system is enhanced.

Flows on the transmission system are determined by the amounts and locations of power injections by generators and power withdrawals by load, as well as the characteristics of the transmission system itself. At any point in time, the system is operated by ISO-NE in order to meet load reliably (operating the system primarily means dispatching generation to provide energy and reserves; the transmission system itself is mostly passive). System operation is based on a security-constrained economic dispatch that takes account of the locations of generation and load and the capabilities of the transmission system to move power between them. It ensures that reliable service can be maintained even in the event of a contingency (*e.g.*, the unexpected failure of one or more generation or transmission components). Over the longer-term planning horizon, ISO-NE's transmission planning protocols are documented in its Regional System Plan. It determines installed capacity requirement (ICR), locational requirements for generation infrastructure (such as the Local Sourcing Requirements, LSR, and Locational Forward Reserve Market, LFRM), and performs a Transmission Security Analysis (TSA) to ensure that the system infrastructure will be adequate to support continued reliable operation in the future. All of these analyses take account of the transmission infrastructure available and possible contingencies.

In operation, system dispatch is driven largely by economics, within the operating constraints that ensure system performance and reliability. While there are many different dispatch combinations that would serve load, each leading to its own pattern of transmission flows, the economically lowest cost dispatch (among those that respect operating constraints) is the one that is implemented by ISO-NE. This means that when transmission imports into Connecticut (or any other sub-region of a larger market) do occur, they do not necessarily indicate a "reliance" on imports. Imports are often the result of economic factors and/or reliability needs given the state of the system (*e.g.*, actual and potential outages).

In the future, significant changes in the geographic patterns of generating capacity and loads may affect transmission flows and transmission requirements in Connecticut and New England, and may ultimately require enhancements to the transmission system beyond those currently being considered. For example, the addition of significant amounts of remote renewable generating capacity or the retirement of local generation may increase the need to import power to Connecticut, and the transmission system may need to be expanded to support those flows.

8.G.1 Transmission Planning for Reliability and Energy Security

ISO-NE is obligated by NERC (via TPL Standards) and NPCC (Directory #1 Design and Operation of the Bulk Power System) to perform an annual reliability assessment of the New England bulk electric system for both the short-term (1-5 years) and long-term (6-10 years) planning horizons. These studies include assessments of the system's ability to meet steady-state (thermal, voltage, short-circuit) and dynamic (angular and voltage stability) criteria during normal and stressed system conditions, including after unexpected system disturbances (contingencies).

In these assessments, "normal contingencies" are evaluated which mainly involve loss of a single element of the system (N-1, *e.g.*, loss of a single element such as a critical transmission line), and loss of a single element followed by the loss of another single element (N-1-1, *e.g.*, loss of two elements, such as a critical generator and a critical transmission line, or two transmission lines).

In addition, it is recognized that the bulk electric system can be subjected to much lower probability and much more severe conditions than those simulated with normal contingencies in reliability assessments. Therefore, ISO-NE also evaluates the risks and consequences of what are referred to as "extreme contingencies" (EC) or "extreme events," which allow ISO-NE to obtain an indication of system robustness and to determine the extent of a widespread adverse system response. In these extreme contingency studies, ISO-NE's transmission planners assess what are considered to be some of the most critical, albeit low probability, events across the New England bulk electric system, including Connecticut. Examples of extreme events analyzed include:

- Loss of all transmission circuits on a common Right-of-Way (*e.g.*, multiple Extra-High Voltage (EHV) 345 kV transmission circuits)
- Loss of an entire substation
- 3-phase system faults (most severe) with a malfunction of circuit breakers to clear the fault as designed (*i.e.*, "stuck breakers").

These types of contingencies will often result in the loss of two or more critical transmission elements.

In its most recent assessment, ISO-NE analyzed numerous extreme criteria contingencies across New England.[14] Some contingencies resulted in the loss of generation, as a part of the contingency studied, as a result of Special Protection System (SPS) operation or because of generating units being transiently unstable. However, with consideration of reliability projects already in-service or planned, ISO-NE does not anticipate any adverse system impacts due to most of the extreme contingencies analyzed, and ascertained that the probability of certain other extreme contingencies to cause adverse effects was very low. Therefore, ISO-NE concluded that additional measures, beyond projects already planned in New England, are not required to mitigate reliability exposures to the transmission system.

8.G.2 Response to a Transmission Contingency

Most isolated transmission contingency events – like the failure of a line or transformer – can be accommodated by adjusting system operation. In fact, the system is required to operate so that it can withstand the loss of any single transmission (or generation) component, as well as the loss of a second component with a first component already out of service. Of course, low probability events that may have a more widespread effect can and do occur on occasion. For example, a severe hurricane or ice storm could damage several parts of the transmission infrastructure simultaneously.[15] Of course such an event could lead to many different possible combinations of particular components being affected; whether such an event would have a major effect on the system depends on the particular infrastructure affected and the capability of the system to respond. It is impossible to evaluate all such possibilities for their potential effects, but in general there is a three-stage response following a major transmission contingency event.

1. **Operational Response**: The power system is designed to be robust and operated to be flexible to respond to unforeseen events. Within minutes of an event, system operation is adjusted to accommodate the contingency as best as possible. For example, if a transmission line is lost, spinning reserves and fast start units, which are kept available at all times, may be dispatched to produce energy in the area that the lost line had been serving. Over the ensuing minutes or hours, additional redispatch may occur to restore the system's ability to respond to another event, and to operate as economically as possible given the new system configuration. In most but not all cases, service can be maintained by adjusting system operation.
2. **Temporary Repair**: If permanent repairs to failed infrastructure cannot be implemented readily, the transmission owner may perform temporary repairs to the failed component(s) to restore the system to normal or near-normal operation. Such temporary repairs typically are completed very quickly.
3. **Permanent Repair**: Permanent repairs may begin as an initial response to an extreme or widespread failure, or some time later if a temporary repair was implemented to address the failure immediately. Depending upon the type and extent of the failure, a permanent

14 2008 Comprehensive Area Transmission Review, ISO New England.

15 Such an event can also cause widespread outages at the distribution level, which are more common and often more extensive than transmission failures, though are not generally considered to be energy security concerns.

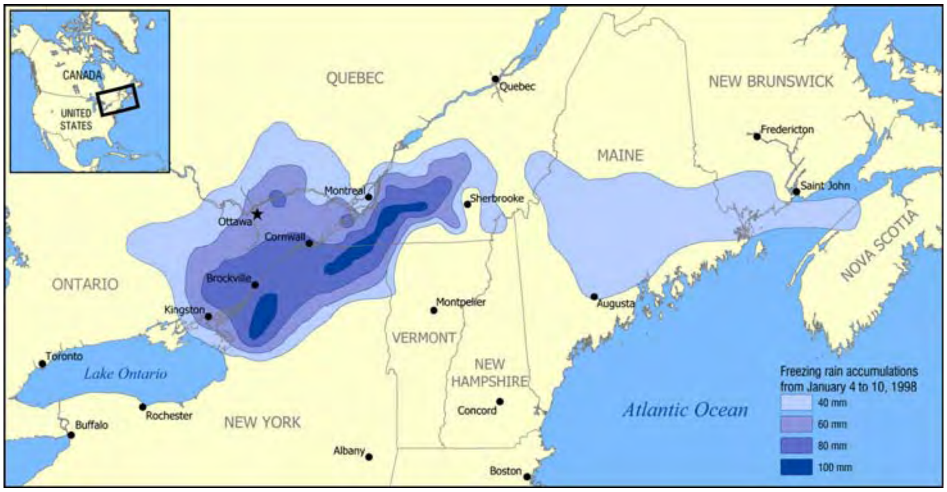
repair may take a longer time to implement, due to the potential need to procure replacement equipment or to deliver stored equipment from company stock or from neighboring utilities through mutual assistance agreements. However, as discussed above, temporary infrastructure may be put in place to restore the transmission system to near normal conditions very quickly.

In order to enable an effective response, well in advance of any event and on an ongoing basis the transmission owners analyze the transmission system to identify critical components that might have long lead times. As a result of such analyses, they inventory spares of the key components, including components that may be needed for temporary restoration. Such components include but are not limited to transformers, reels of transmission conductors, circuit breakers, insulators, spare conducting cables, and transmission components. Since some of these components are large and difficult to transport (*e.g.*, may be unable to cross some bridges or underpasses), the transmission owners also warehouse these spares strategically at diverse locations across the system to facilitate delivery to the needed location.

In addition, transmission owners have long maintained mutual assistance agreements with other transmission owners, whereby a system that suffers a significant failure can call on neighboring systems (or even distant ones) for crews and equipment to facilitate repairs. They also rely on other transmission owners to augment their access to spare components that they may not inventory themselves. Such assistance is typically reciprocal. Connecticut's transmission owners have both received and provided such assistance numerous times, working with other transmission companies as far away as Florida, the Midwest or Canada.

An example of one of the most extreme possible transmission (and distribution) contingencies is the North American ice storm of 1998. This was a massive ice storm that struck a relatively narrow region of Canada including eastern Ontario and southern Quebec, and bordering U.S. areas from northern New York to central Maine (see Figure 8.3). For more than 80 hours in early January 1998, steady freezing rain and drizzle fell over an area of several thousand square miles, causing ice buildup of three to four inches. The weight of this ice accumulation caused massive damage to electrical infrastructure all across the region. About 1,000 steel transmission pylons (said, in Quebec, to be the most solid in the world) collapsed in chain reactions as one crumpling tower pulled down the next, and 35,000 wooden utility poles were crushed. Over 4 million people were left without power for periods ranging from days to nearly a month. There were about 30 fatalities, a shut-down of activities in large cities like Montreal and Ottawa, and overall damage estimated at around $5 billion. Damage to the power grid was so severe that unprecedented reconstruction, rather than repair, was required to restore the regional electrical grid.

Figure 8.3
The North American Ice Storm of 1998 – Freezing Rain Accumulation



Source: Wikimedia, based on data from Environment Canada.

Still, despite the magnitude and broad geographic extent of the damage to the power system, service was restored relatively quickly. Many areas were returned to service within days, and virtually all within several weeks. (Further, many of the outages were at the distribution level, not necessarily at the transmission level.)

The electric system is designed and operated with a level of redundancy that allows it to absorb most isolated transmission failures with no impact on customer service. Even in those cases where an extreme event does cause a significant transmission failure, the transmission owners' recovery capabilities and procedures typically ensure that any service interruption is brief – probably measured in hours or at most days.

Section III.9
Natural Gas in Connecticut and New England Electricity Markets

9. NATURAL GAS IN CONNECTICUT AND NEW ENGLAND ELECTRICITY MARKETS

9.A SUMMARY AND KEY FINDINGS

Summary

The objective of this whitepaper is to examine the natural gas outlook from a regional perspective, focusing on natural gas supply, import and delivery capacity, and demand. We assess how potential constraints might affect the availability and reliability of natural gas supply in Connecticut and New England over a three, five and ten year horizon and beyond. This report has drawn on data and information from a variety of sources, including the Northeast Gas Association, the Energy Information Administration, the interstate pipelines, LNG developers, natural gas and electricity distribution companies serving the region, and publicly available industry analysis and news. Efforts have been made to consider stakeholder input and incorporate numerous views.

Natural gas plays a critical role in the Connecticut and New England electric systems. It fuels the largest share of New England's power generation, about 41 percent of electricity produced in 2008. Gas-fired generators account for 38 percent of New England's generation capacity and set the ISO locational marginal price (LMP) 62 percent of the time in 2008.[1] Although generation actually located within Connecticut is more heavily weighted toward nuclear, natural gas is critical to supply and plays a key role in setting the market price of power in all of New England.

The New England region does not have indigenous natural gas production or underground storage capacity and is dependent upon long-haul, interstate gas transmission pipelines. Since the 1950s, gas has been imported via pipeline from the Texas-Louisiana Gulf Coast, with additional supply sources from Canada via several new pipelines built in the 1990s. Since 1971, liquefied natural gas (LNG) at the Distrigas/Suez terminal in Everett, Massachusetts has supplemented the import portfolio.

New England's heavy reliance on natural gas has negatively affected power consumers during recent high gas price periods (late 2005 with Hurricanes Katrina and Rita, and in 2007 with the run-up in oil price), but has lately been a boon as gas prices have fallen to the lowest levels in recent memory (see spot gas prices in Figure 9.1). Current low gas prices are due in large part to recession-induced demand weakness and conservation, but also by supply strength. Excess supplies have been injected into storage, pushing inventories to record levels and driving natural gas prices and New England power prices down precipitously. Though natural gas prices are relatively attractive now, the public and policy makers are appropriately concerned about the potential for a long-term price increase or another gas price spike.

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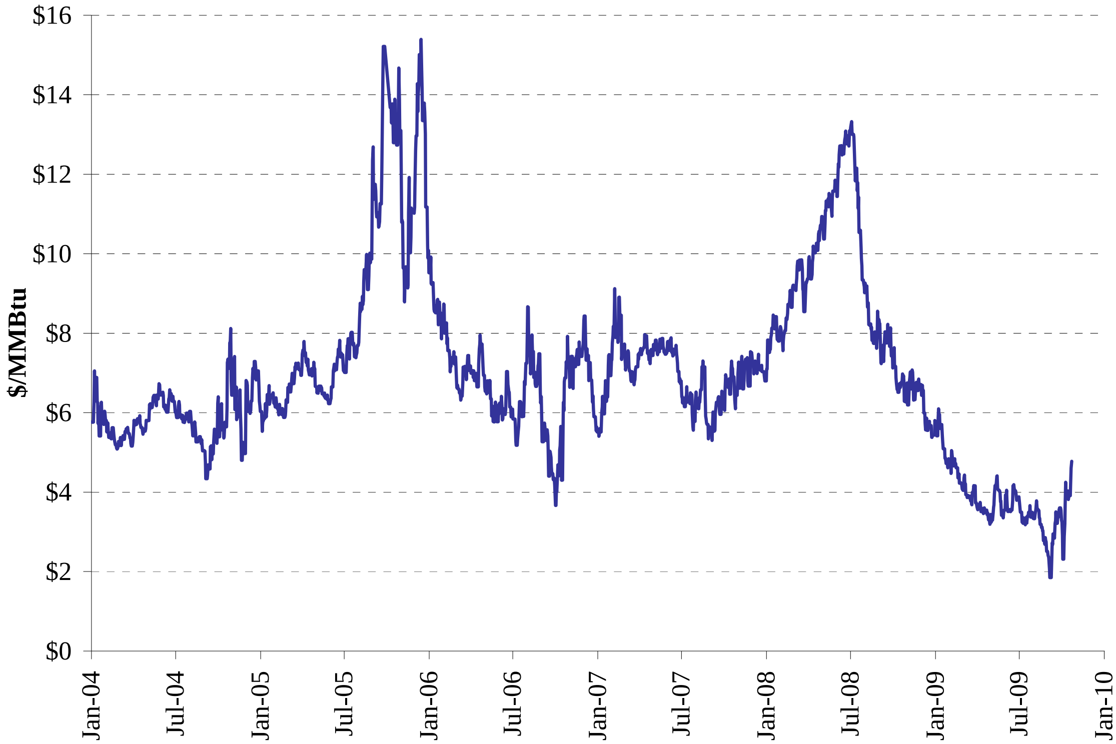
1 ISO New England 2009 Regional System Plan, October 15, 2009.

Figure 9.1
Henry Hub Spot Price



Source: Platts, Gas Daily.

Recent developments suggest that the long term outlook for natural gas in New England is positive. There has been a dramatic improvement in the outlook for long-term U.S. natural gas supply and price in the last year, driven primarily by increasing "unconventional gas" production and reserves – mostly shale gas, but also coal bed methane and other "tight" gas formations. These unconventional sources have been called a "game changer" and the "biggest energy innovation of the decade" that could "transform the debate over generating electricity."[2] Analysts have forecast that the major shale gas plays can cover their break-even costs for around $4.00/MMBtu.[3] Of particular interest to the Northeast is the Marcellus Shale, due to the magnitude of the supply potential, its expected low cost and its nearby Appalachian location. Additional supplies are coming via new pipeline capacity from the Rocky Mountains and from new LNG terminals, and additional infrastructure is being developed to deliver these supplies into New England. Both short-term and long-term gas prices have declined markedly. While this new potential supply, particularly shale gas, has yet to be fully realized, and factors could yet hinder its development, the outlook for natural gas supply for power generation in New England is significantly improved compared to even just a few years ago.

2 "America's Natural Gas Revolution," Wall Street Journal, November 2, 2009.

3 *E.g.*, see the November 30, 2009 report by Scotiabank Group analyst Patricia Mohr.

Key Findings

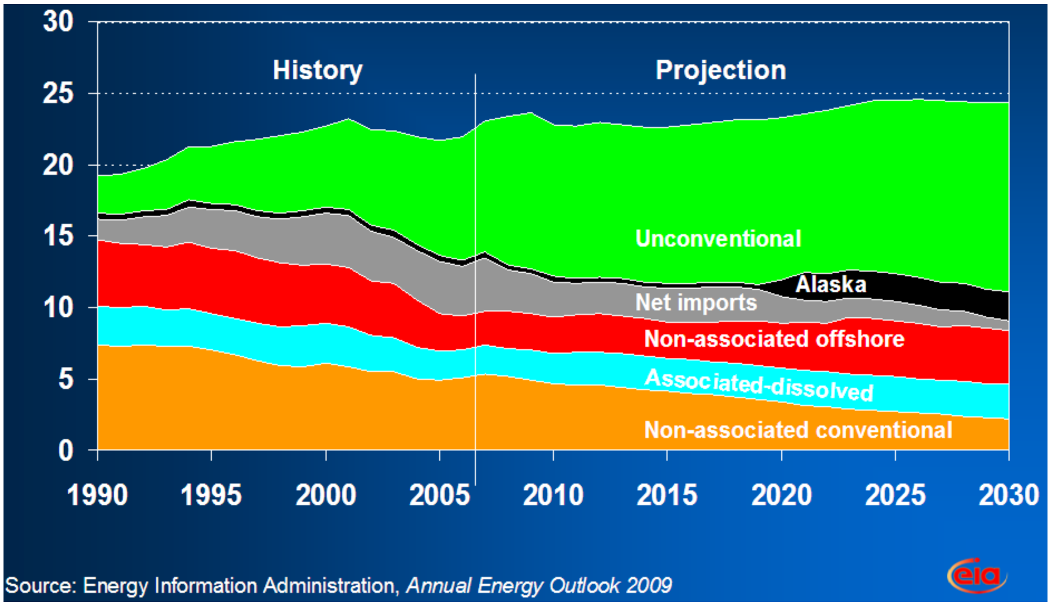
- The overall supply picture for domestic natural gas appears promising, due particularly to the advent of new unconventional gas supplies such as shale gas. This expanding supply should be adequate to accommodate even increased gas demand, though the ultimate extent and pace of the new supplies coming online is not certain.
- Pipeline and LNG delivery capacity to New England have increased over the past several years, with additional new expansion projects still in development for the near future. Gas delivery capacity to serve average and peak needs has improved measurably from a few years ago (though this does not address gas local distribution company (LDC) deliverability issues, where additional expansions may be necessary).
- LNG and Canadian conventional gas may be less important for augmenting New England gas supplies than was expected in the recent past, due to the advent of new domestic supplies at lower prices. They will nonetheless continue to serve as a backstop for the availability and price of domestic gas supplies. Regardless of whether it actually does substitute for domestic gas more widely, LNG will remain a crucial component of New England's ability to meet peak gas demands in the winter heating season.
- Natural gas prices are expected to remain reasonable at around $7.00/MMBtu (real dollars) in the long term, driven largely by new unconventional supply sources. However there is no certainty that these current price expectations will be fulfilled; a long-term gas price range of approximately $4-10/MMBtu was examined in this study. Regardless of what happens to the long-term price of gas, short-term gas prices can be volatile.

9.B U.S. NATURAL GAS SUPPLY

As indicated in Figure 9.2 below, U.S. production from conventional sources has declined recently and is projected to continue to decrease. Similarly, though Canada has been a valuable supplier of gas to the U.S. and the Northeast for decades and will remain important for years, its share of the U.S. market is expected to decline over the long term as Western Canadian sources decline and Canada's own gas demand increases. Offsetting these trends, however, production from unconventional sources has exploded, more than making up for the decline in conventional production. This production increase has occurred despite a drop in U.S. drilling activity. U.S. gas-targeted drilling activity dropped by 42 percent from January through July 2009, but there was only a 1.5 percent decline in U.S. natural gas production in the third quarter compared to the same quarter in 2008. According to Scotiabank Group analyst Patricia Mohr, "This apparent disconnect between drilling activity and production reflects much greater individual well productivity with horizontal, multiple-fracturing drilling and considerably greater initial flow rates from shale developments than conventional vertical wells."[4]

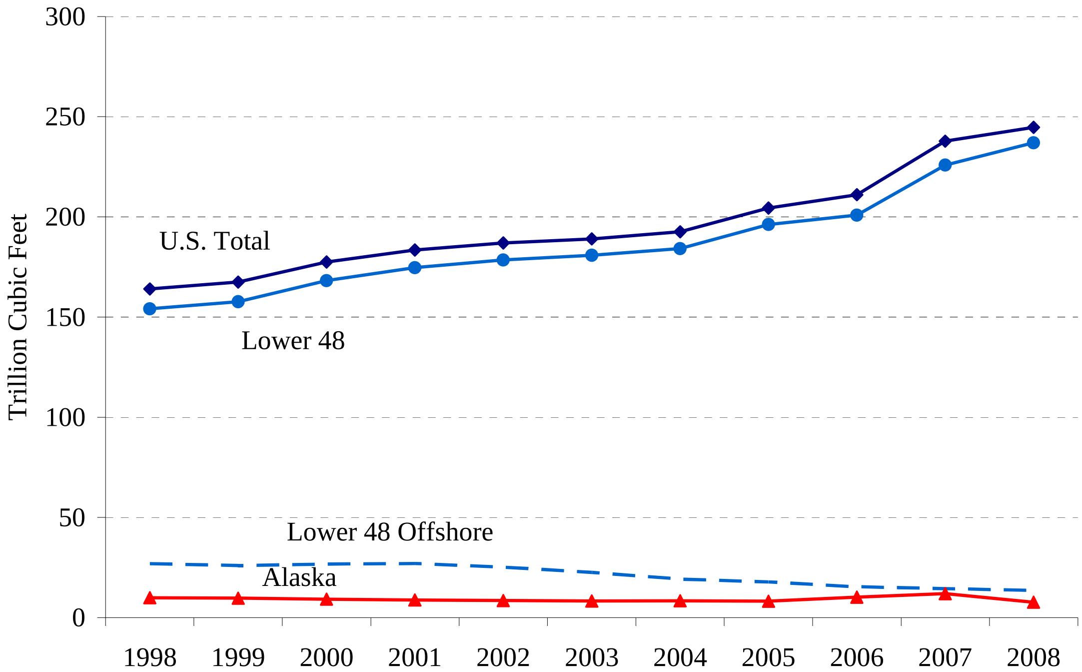
[4] November 30, 2009 report by Scotiabank Group.

Figure 9.2
Sources of Natural Gas Supply (Tcf)



Furthermore, overall U.S. reserves are increasing as indicated in Figure 9.3 below, largely due to these unconventional sources. The U.S. EIA reported that in 2008, proved natural reserves rose enough not only to replace production, but also to grow by almost 3 percent over 2007. Proved reserves attributable to shale reservoirs grew dramatically, up 51 percent to 32.8 trillion cubic feet (Tcf), or 13 percent of the 245 Tcf total. In a June 2009 resource assessment, the Potential Gas Committee estimated total U.S. natural gas resources at 1,836 Tcf, the highest resource evaluation in their history. At current consumption rates, this represents over 80 years of supply.

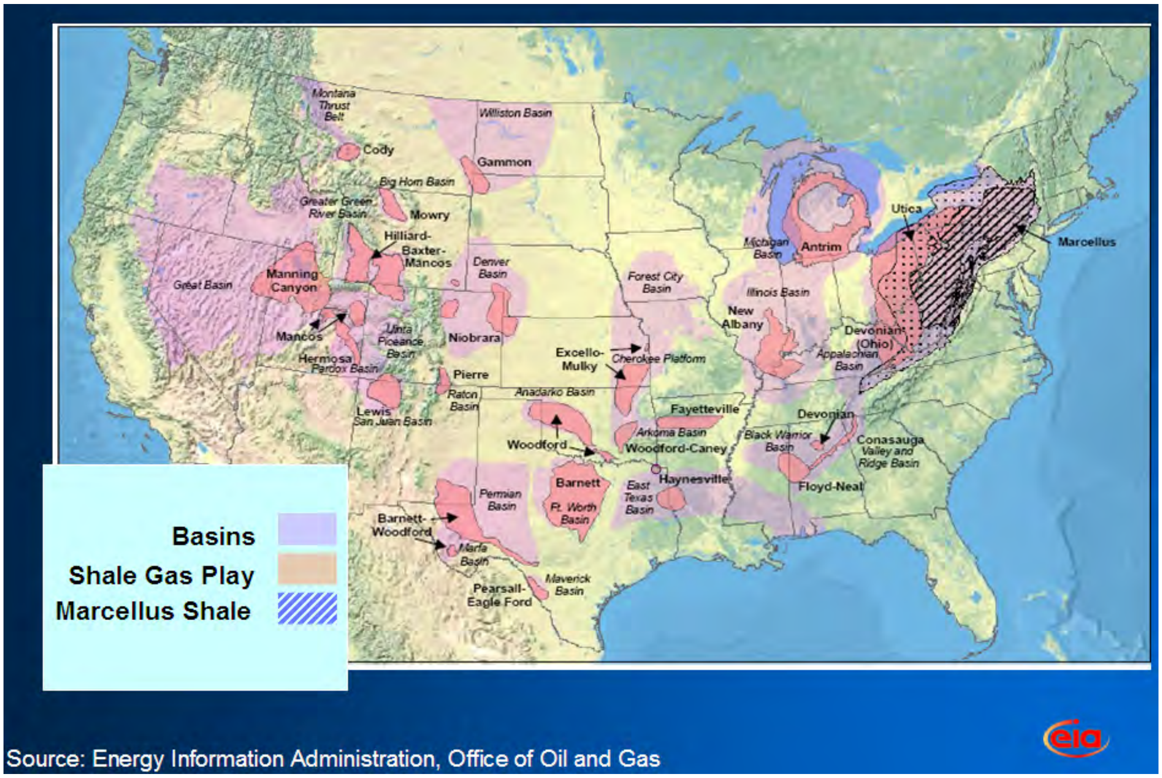
Figure 9.3
U.S. Dry Natural Gas Proved Reserves



Source: EIA, Dry Natural Gas Reserves.

While geologists have known for decades that shale contained large quantities of natural gas, only in the last few years have producers been able to develop this resource economically. The key to unlocking it has been a new drilling technique that combines horizontal drilling and hydraulic fracturing. Shale formations have low permeability, meaning that gas molecules do not flow easily through the rock. With horizontal drilling, producers drill parallel to grade of the formation, reaching a far larger area of productive capacity than with traditional vertical wells. Improved hydraulic fracturing techniques inject a mixture of water and sand under high pressure to open pathways through which gas molecules can flow. Drilling success with shale gas is far more certain than with conventional resources, and shale gas wells tend to produce a large volume of gas initially, after which they drop quickly to a much lower long-term production rate. This drilling technique, developed by U.S. independent gas producers, dramatically increases the amount of gas that can be developed at relatively low cost compared to only a few years ago. It is perhaps surprising that this technological development, which could have such a dramatic impact on U.S. and potentially on world energy supplies, has occurred with so little fanfare. Figure 9.4 shows the location of U.S. shale deposits now being commercially developed.

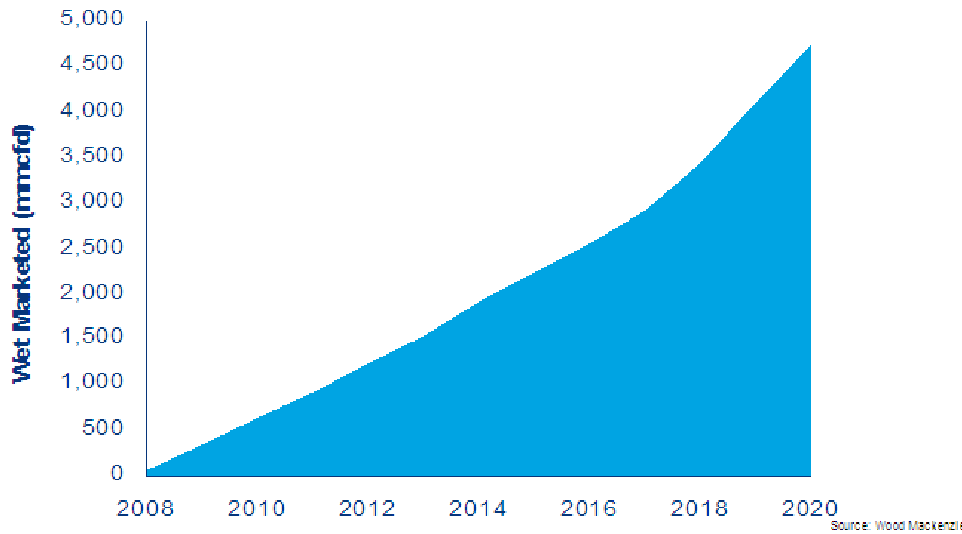
Figure 9.4
U.S. Gas Shale Gas Plays



Particularly encouraging for New England is that one of the most promising shale deposits, the Marcellus Shale, is located within 300 miles of Connecticut. In early 2008, geology professors Terry Engelder and Gary Lash estimated the Marcellus might contain more than 500 Tcf of gas, about 10 percent of which might be recoverable.[5] Figure 9.5 shows projected production from the Marcellus Shale. To put these numbers in context, total New England natural gas usage currently averages about 2,000 MMcf/d.

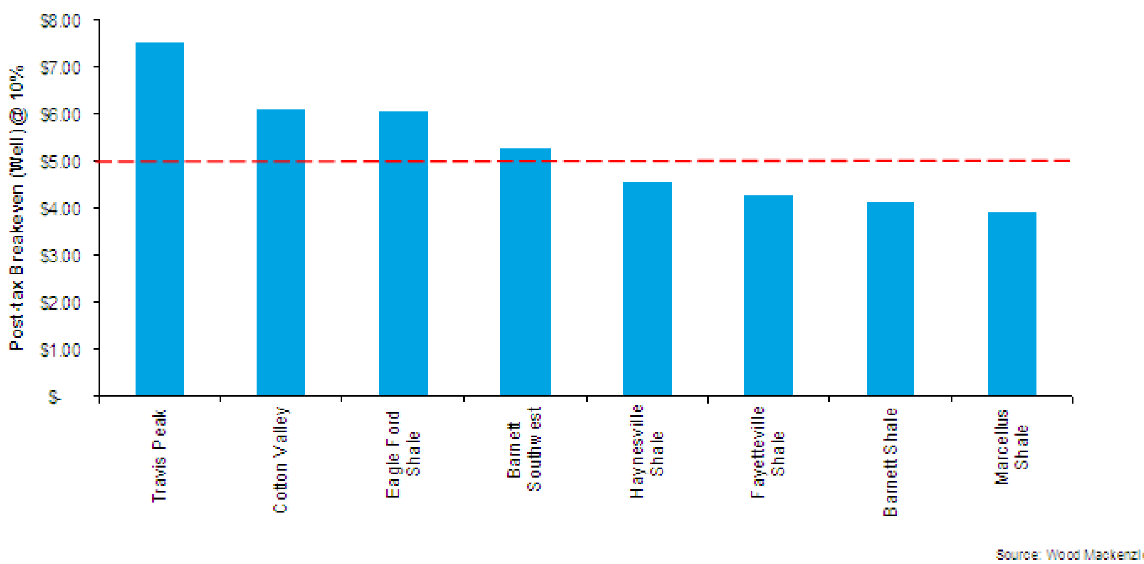
[5] For example, see http://geology.com/articles/marcellus-shale.shtml. Also, Engelder, Terry and Lash, Gary (2008). "Unconventional Natural Gas Reservoir Could Boost U.S. Supply," Penn State Live, http://live.psu.edu/story/28116.

Figure 9.5
Marcellus Shale Projected Production



Importantly, recent production cost estimates indicate that shale gas can be developed relatively inexpensively. Figure 9.6 shows that many shale formations may be developed at $4-6/MMBtu. The Marcellus Shale may be at the lower end of that range. Further, since shale gas wells tend to produce a burst of gas initially and decline quickly, increased shale development may increase overall supply flexibility, both upward and downward, which could help to mitigate future gas price volatility (though other factors may also affect volatility).

Figure 9.6
Shale Gas Development Economics (2009 Real $)



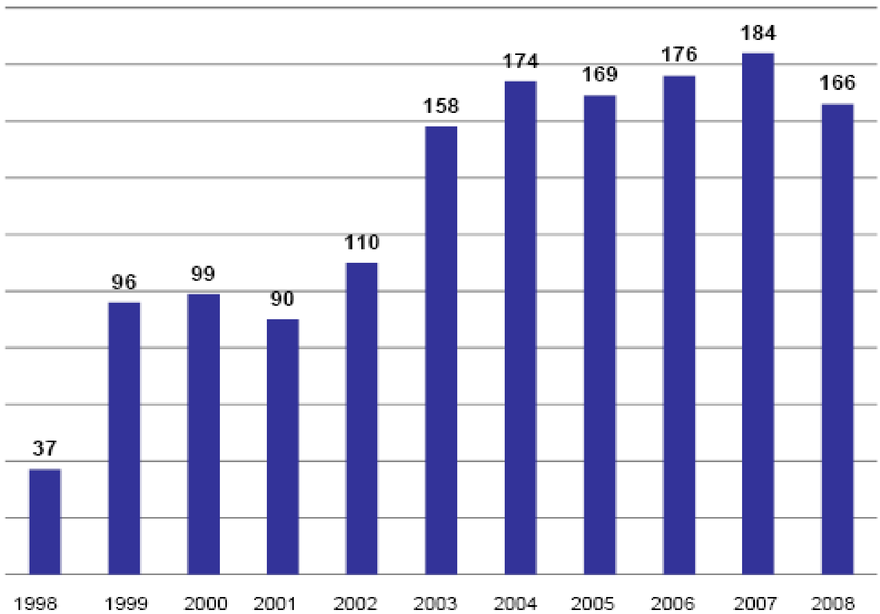
Beyond the new unconventional domestic supplies, across North America a number of new LNG import terminals have recently come online and more are scheduled, including several in and around New England. These projects were inspired by the market view that prevailed a few years ago when they were planned, which held that conventional supplies were in decline but gas demand was still rising, with long-term gas price expectations high enough to support LNG from world markets.

More recently, that view has been upended by the factors discussed above. The increase in unconventional supply, combined with the recent short-term drop in demand, has pushed U.S. gas prices downward and made LNG much less attractive as a supply resource. After rising fairly consistently from 2001 through 2007, New England's LNG imports fell in 2008 (see Figure 9.7). The Northeast Gateway LNG terminal (offshore near Boston), which was fully operational in early 2008, received its first LNG shipment in May 2008 but did not receive another shipment for at least the next six months.[6]

Regardless of this, the fact that these import terminals are now in place creates a potential backstop supply source. World LNG production capacity continues to increase as new liquefaction facilities come online, and may be in surplus for some time. If the U.S. outlook were to change such that supply is tight and prices rise sufficiently, LNG imports could serve as a supply backstop to help to ensure availability and mitigate further price increase. One caution is that if New England or other U.S. regions needed to rely on LNG, they would have to compete in international markets for price and availability. Some LNG cargoes can be diverted to where supplies are most needed, but most LNG is delivered under long-term contract and there is not yet a well-developed LNG spot market. Further, world LNG markets may be dominated by a few large and potentially unappealing suppliers. Russia, Iran, and Qatar rank first, second, and third in gas reserves, together holding nearly 60 percent of world reserves. Eighty percent of world reserves are in Russia and OPEC countries, opening the potential for cartelization of LNG markets. If the LNG market were to become uncompetitive, and if New England were to begin relying heavily on LNG for generation, then New England customers could be exposed to any resulting LNG price and availability risks.

6 Northeast Gas Association Statistical Guide 2008, page 9.

Figure 9.7
Annual New England LNG Imports (Bcf/year)



Source: U.S. DOE, Office of Fossil Energy, Office of Natural Gas Regulatory Activities, via Northeast Gas Association.

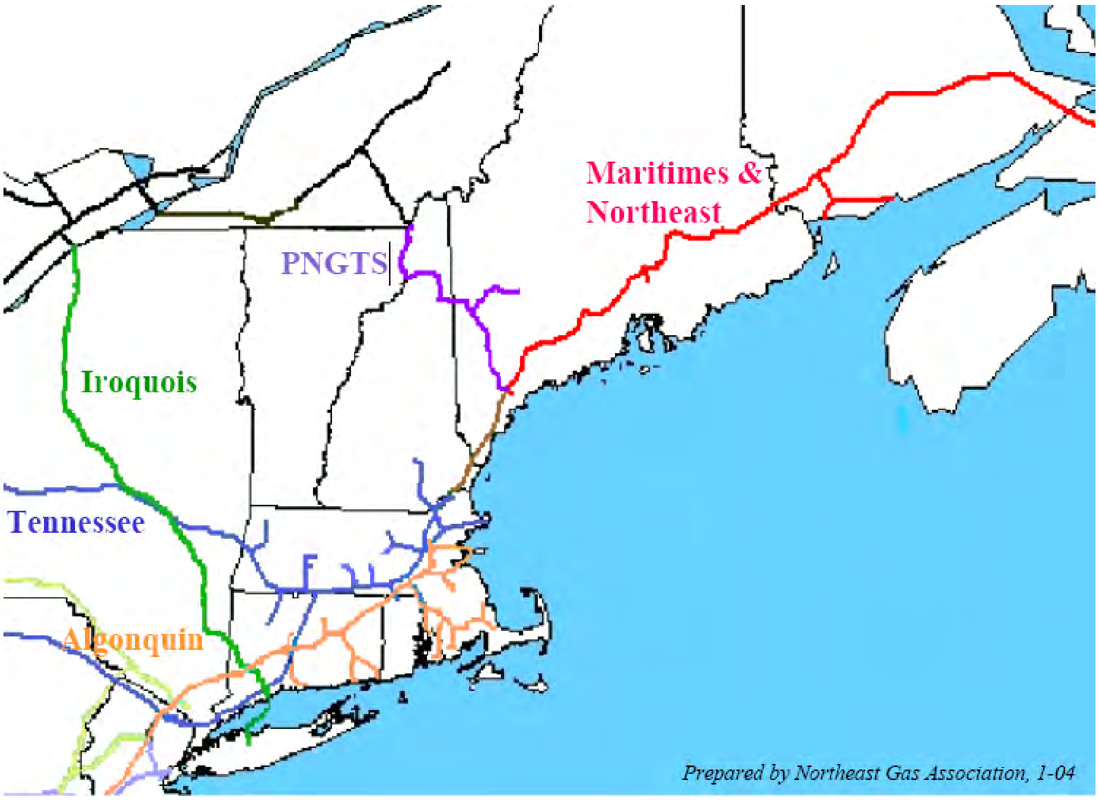
Another potential long-term supply source is Alaska and northern Canada. There is strong production potential in Alaska and the Mackenzie Delta in Canada, which could access the lower 48 states if a natural gas pipeline were constructed. Such a pipeline has been discussed for decades, and it remains a long-term possibility, but for many of the same reasons already discussed, it is receiving much less interest recently. Its high cost and long lead time make it relatively unattractive in the face of the optimistic outlook for unconventional production in the lower 48 states. Whether these remote supply basins and a pipeline are developed will likely be determined by how the development of shale and other unconventional sources progress in the North American market.

9.C NATURAL GAS DELIVERY TO NEW ENGLAND

With no natural gas production of its own, New England relies on deliveries through five major interstate pipelines, supplemented by liquefied natural gas and propane supplies to meet peak day requirements. Approximately 80 percent of New England's total annual gas supplies come from North America (mostly the U.S., plus a significant share from Canada) and the remaining 20 percent from LNG and propane. Historically, most natural gas has been delivered to New England from Gulf of Mexico supply basins along the Tennessee Gas Pipeline (TGP) and the Algonquin Gas Transmission Pipeline (AGT), both built in the 1950s. Imports from Western Canada commenced in 1992 through the Iroquois Gas Transmission System (IGTS); in 1999 the Portland Natural Gas Transmission System (PNGTS) added additional Canadian capacity. Also in 1999, the Maritimes & Northeast Pipeline began to bring gas from Sable Island in Eastern

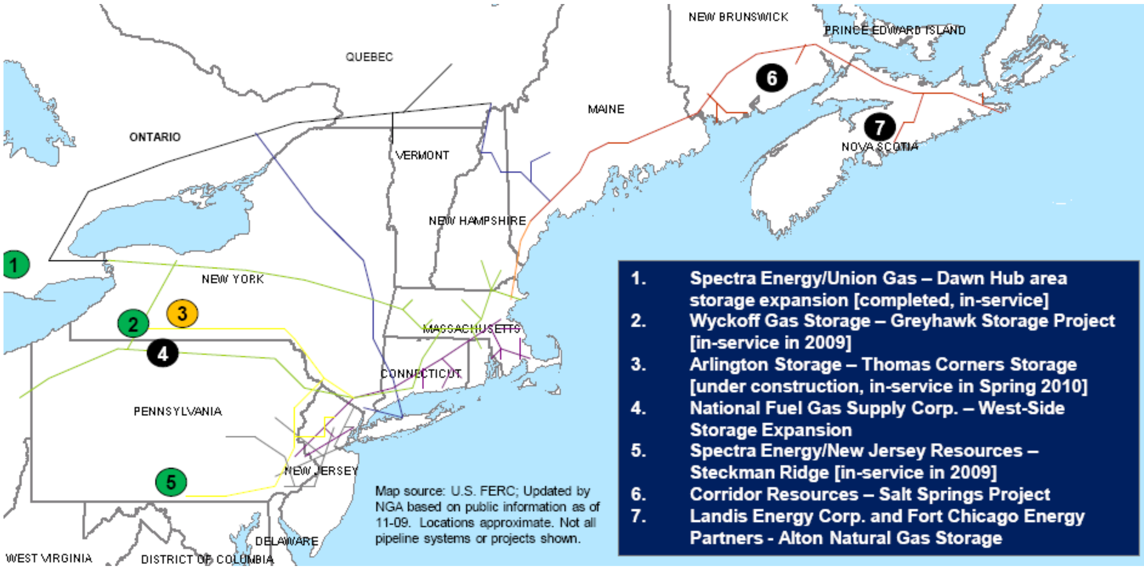
Canada. (Granite State Gas Transmission is a sixth interstate pipeline within New England, but it does not bring additional gas into New England.) The five pipelines serving New England are shown in Figure 9.8, with additional detail in Appendix 9-1.

Figure 9.8
New England Natural Gas Transmission System



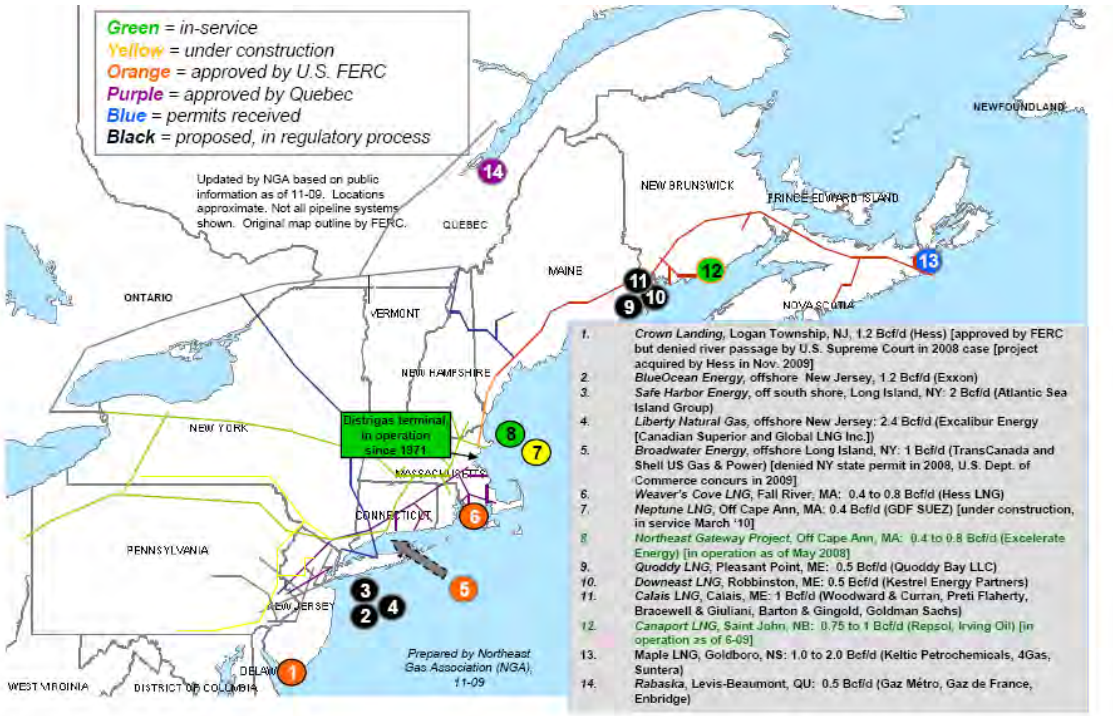
With no underground storage of its own, New England also relies on storage capacity in Pennsylvania, New York, and Michigan as a critical part of the natural gas supply and delivery chain. These storage areas are accessed via the major interstate pipelines – particularly the Tennessee, Algonquin, and Iroquois pipelines. As indicated in Figure 9.9, a number of new storage projects have recently been completed or are proposed. Greyhawk and Steckman Ridge Storage (6 and 12 Bcf, respectively) were put into service in 2009. The Salt Springs Storage Project (4 Bcf) in south-central New Brunswick is evaluating the potential for underground salt cavern storage to supplement the Canaport LNG facility or other regional Canadian production. Other salt cavern project sites are being evaluated near Truro, Nova Scotia. In aggregate, these storage expansions are a relatively small increment to the approximately 1,000 Bcf storage capacity in New York and Pennsylvania.

Figure 9.9
Northeast U.S. Underground Storage Projects – New and Proposed



LNG supplies about 20 percent of the natural gas used within New England. New England is the site of two operating import terminals for LNG, with another in nearby New Brunswick and a fourth scheduled to be brought into service in 2010. The Distrigas terminal at Everett, Massachusetts, owned by GDF SUEZ and operating since 1971, has historically imported LNG from Trinidad & Tobago, though some cargoes from Egypt were received in 2009. This facility has storage capacity of 3.4 Bcf. The second LNG facility, Northeast Gateway owned by Excelerate Energy and located offshore Cape Ann, Massachusetts, became fully operational in early 2008, receiving its first delivery in May 2008. A third facility, Canaport LNG, owned and operated by Repsol and Irving Oil, became operational in mid-2009. It is located outside of New England in New Brunswick, Canada. It can deliver up to 1 Bcf of gas a day into the Brunswick Pipeline, which connects with the Maritimes & Northeast Pipeline and then into the New England market. It also receives its LNG principally from Trinidad, but has plans to diversify its supply sources in the future (a cargo from Qatar arrived in late 2009). In spring 2010, another offshore LNG facility off Cape Ann, Massachusetts will become operational – the Neptune LNG facility of GDF SUEZ. These existing and new LNG import facilities are indicated in Figure 9.10, along with several additional facilities in earlier planning stages.

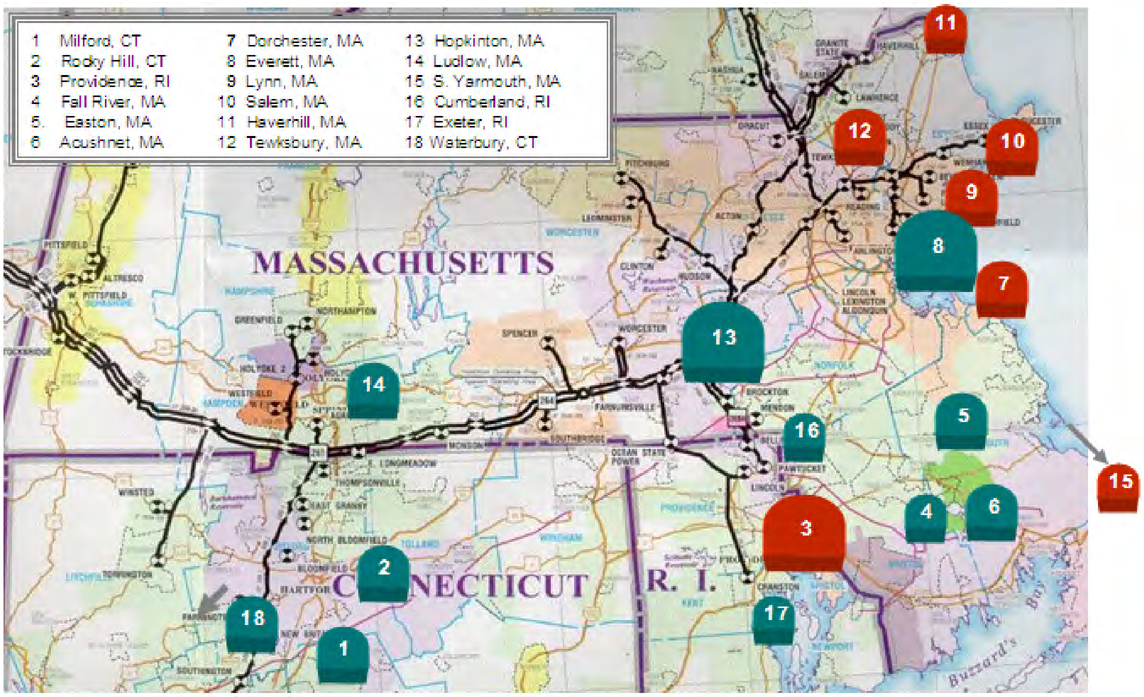
Figure 9.10
Existing and Proposed LNG Import Facilities



In contrast to the majority of supply that is delivered by interstate pipeline from the south and west, the LNG facilities feeding New England are generally located north and east of the load centers. "Backfeeding" LNG from this direction means that LNG not only helps to increase supply diversity into the region, but it also avoids the potentially constrained pipelines from the Gulf and Western Canada, allowing higher total volumes to be delivered on an annual and peak day basis.

With no local underground storage, New England relies on LNG storage to meet 30 percent of peak day requirements. Much of this is delivered from satellite LNG storage facilities on the LDC systems (propane is also used for this purpose but to a much lesser extent). New England LDCs own 47 satellite LNG tanks with 16.2 Bcf of storage capacity allowing deliveries of almost 1.5 Bcf/d. They also have 189 propane tanks with 0.75 Bcf storage capacity, and delivery capability of about 50 MMcf/d, though propane vaporization capacity has been reduced recently, reflecting its high cost relative to LNG. The LNG served from the satellite facilities can be trucked in from LNG import terminals, or it can be produced at the LNG storage facility by processing pipeline supplies. The location of the major satellite LNG storage facilities is shown in Figure 9.11 below.

Figure 9.11
Major LNG Storage Facilities in New England

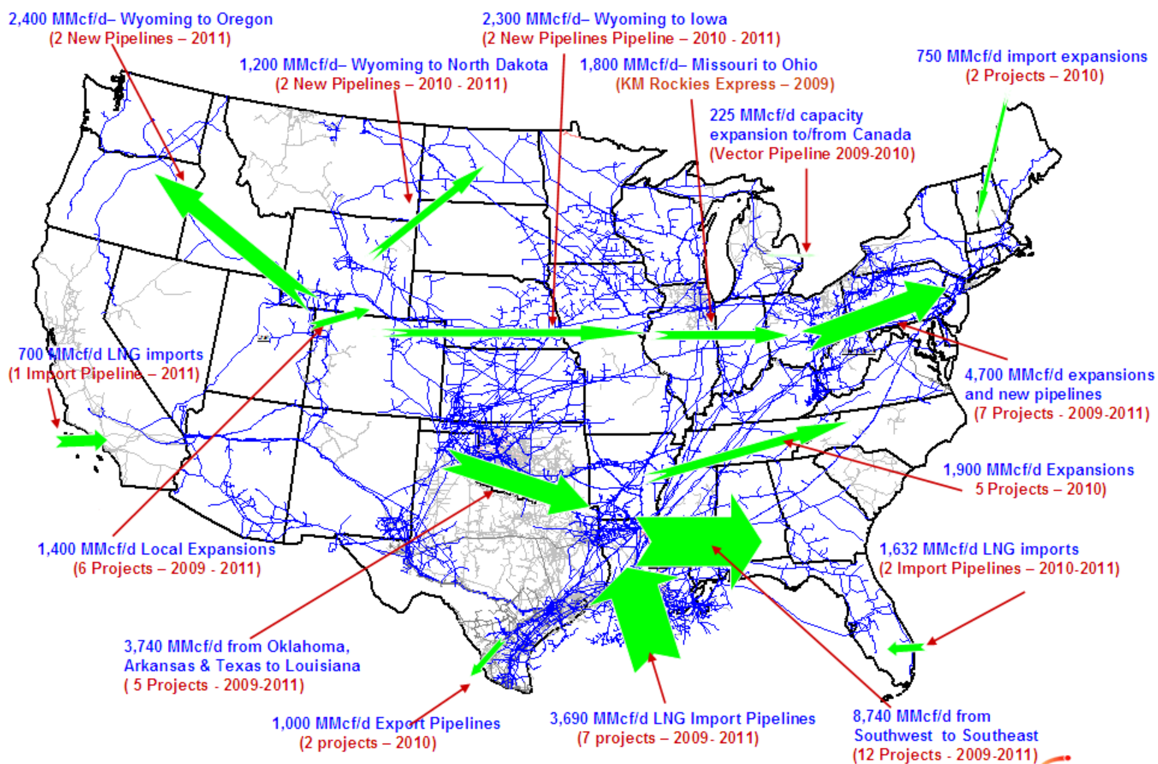


Source: Yankee Gas.

9.D INTERSTATE PIPELINE EXPANSION PROJECTS

The last several years have seen a significant increase in pipeline infrastructure development across the U.S., largely to accommodate the increased production from shale gas and new LNG import capability. Increased production from new supply areas has created pipeline constraints and the need to add new capacity. Dozens of projects have been completed and many others are being proposed, as illustrated in Figure 9.12. The pace of construction has increased appreciably from previous years.

Figure 9.12
Major Potential Natural Gas Pipeline Expansions, 2009-2011

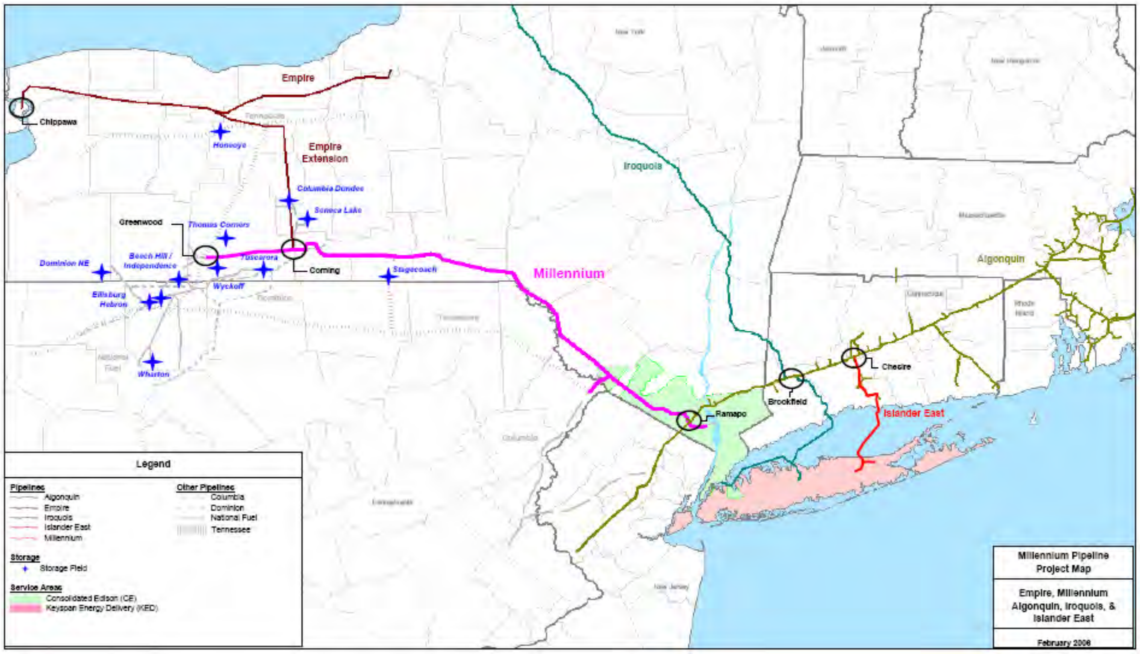


MMcf/d = million cubic feet per day. LNG = liquefied natural gas.
Source: Energy Information Administration, GasTran Gas Transportation Information System, Natural Gas Pipeline Projects Database.

Several of these projects have been important to New England:

- **Algonquin Pipeline:** Algonquin is in the process of completing the "HubLine/East to West Project" designed to accommodate increased receipts of LNG sourced at the east end of their system. Shipper contracts have been signed and the project is awaiting final FERC approval before construction begins.
- **Maritimes & Northeast Pipeline Phase IV Project:** This pipeline, owned by Spectra (77.53 percent), Emera (12.92 percent), and ExxonMobil (9.55 percent), was initially built to transport supply from Sable Island offshore Nova Scotia into New England. In 2009, it was expanded from about 400 to 800 MMcf/d to accommodate LNG shipments from the newly constructed Canaport facility in New Brunswick.
- **Millennium Pipeline:** Millennium, owned jointly by subsidiaries of NiSource, National Grid, and DTE Energy, started commercial operation in December 2008 and is designed to bring up to 525 MMcf/d from western New York to Algonquin Pipeline at Ramapo, New York as indicated in Figure 9.13. This pipeline allows increased deliveries of storage gas in Western New York as well as Marcellus production to New England's border.

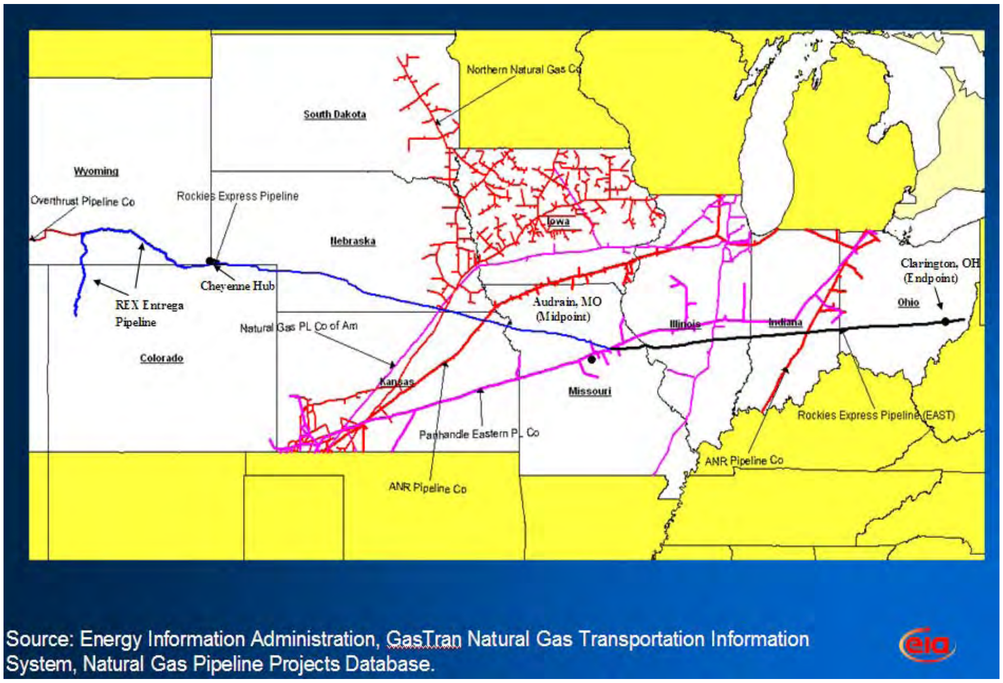
Figure 9.13
Millennium Pipeline



Source: Millennium Pipeline Company, LLC.

- **Rockies Express Pipeline:** Rockies Express has been one of the largest new pipelines ever built in the U.S., bringing 1.8 Bcf/d gas from production areas in the Rocky Mountains across the country and ultimately to the Northeast, as illustrated in Figure 9.14. The western portion of the pipeline began service June 29, 2009, and the final 195 miles to Clarington, Ohio began operating in December 2009.

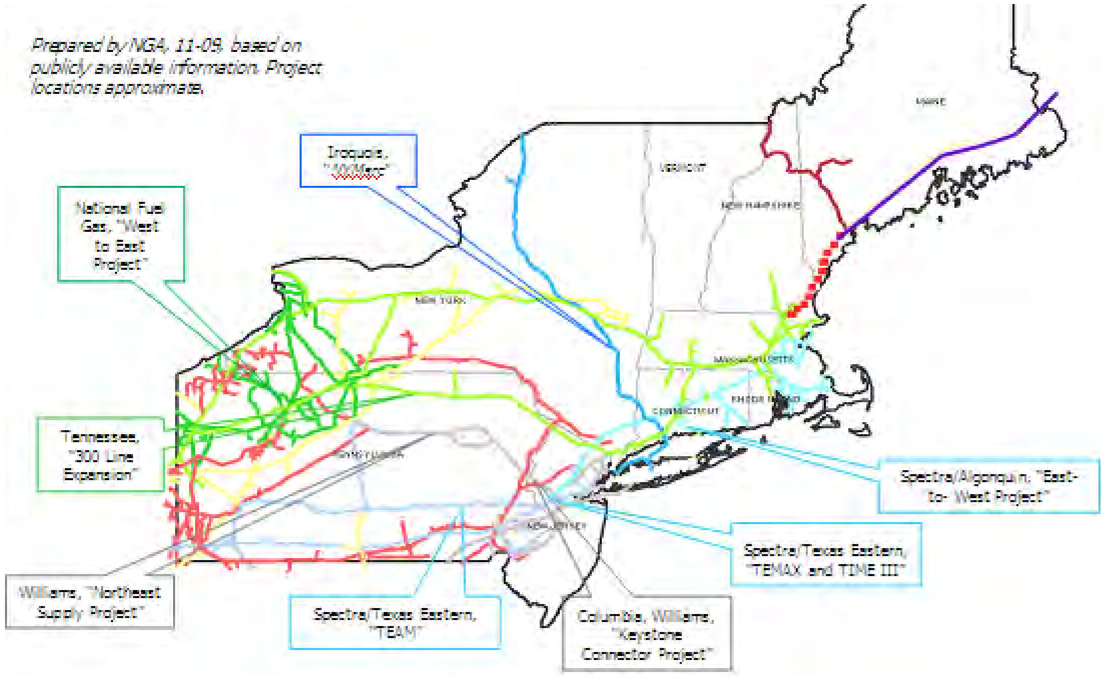
Figure 9.14
Rockies Express Pipeline



Source: Energy Information Administration, GasTran Natural Gas Transportation Information System, Natural Gas Pipeline Projects Database.

In addition to these recently completed pipeline expansion projects, numerous other projects are proposed. Figure 9.15 shows some of these, with additional information in Appendix 9-2. Some of these projects ultimately might not be developed, and of course other new projects may be proposed. Nevertheless, this large number of additional proposals is indicative that some may ultimately go forward and further increase the capability and reliability of New England's natural gas delivery system.

Figure 9.15
Proposed New Interstate Pipeline Projects



Source: Northeast Gas Association.

9.E Potential Natural Gas Supply and Delivery Capacity Challenges

While production from the Marcellus Shale has begun, the size, recoverability, and cost of the resource base are not known with confidence. Also, environmental issues could hamper its development. Most significant are the availability of the large volumes of water required to fracture the shale, and the corresponding potential for contamination of drinking water aquifers by hydrocarbons and chemicals used in fracturing. So far, the evidence suggests that groundwater contamination is of greatest concern with surface treatment and operational errors rather than with proper undersurface drilling. Deeper lying gas-bearing rock layers typically are separated from aquifers by thousands of vertical feet of rock. Pollution can occur at the surface, however, or if wells are drilled improperly. For example, in September 2009, Cabot Oil and Gas was required to suspend fracturing operations for 3 weeks after causing 3 surface spills in 19 days. It was fined by the state of Pennsylvania for contaminating domestic water wells.

While the New York Times reported recently that "the evidence of groundwater pollution is thin," in the same article, Aubrey McClendon, the chief executive of Chesapeake Energy, one of the largest Marcellus producers, acknowledged that, "To be able to scale up our drilling, clearly we have to be in sync with people's concerns about water...It's our biggest challenge."[7] Rodney

[7] "Dark Side of a Natural Gas Boom," New York Times, December 8, 2009.

L. Waller, a senior Vice President at Range Resources, another large producer in the Marcellus, indicated, “It’s not going to stop us, but we do have to resolve the problem in a prudent manner.” While the EPA concluded in a 2004 study that hydraulic fracturing was essentially harmless, the issue has the potential to slow the development of the Marcellus and other shales, and EPA may oversee hydraulic fracturing activities.

Another potential concern is the development of the pipeline capacity required to bring shale gas to market. Pipeline projects are costly and generally must secure long term contracts with creditworthy shippers in order to be developed. In deregulated markets, gas LDCs and electric distribution companies may have difficulty in getting regulatory support for long term contracts. Competitive gas suppliers and power plants may also find it difficult to support long term contracts, since they may not be able to count on a stable long-term gas demand. Even if long term contracts can be secured, the recent credit crisis has made project financing difficult to obtain. Although some of this void is being filled by gas producers looking for a secure outlet for their gas, the difficulty in securing long term contracts and construction financing can be impediments to infrastructure development.

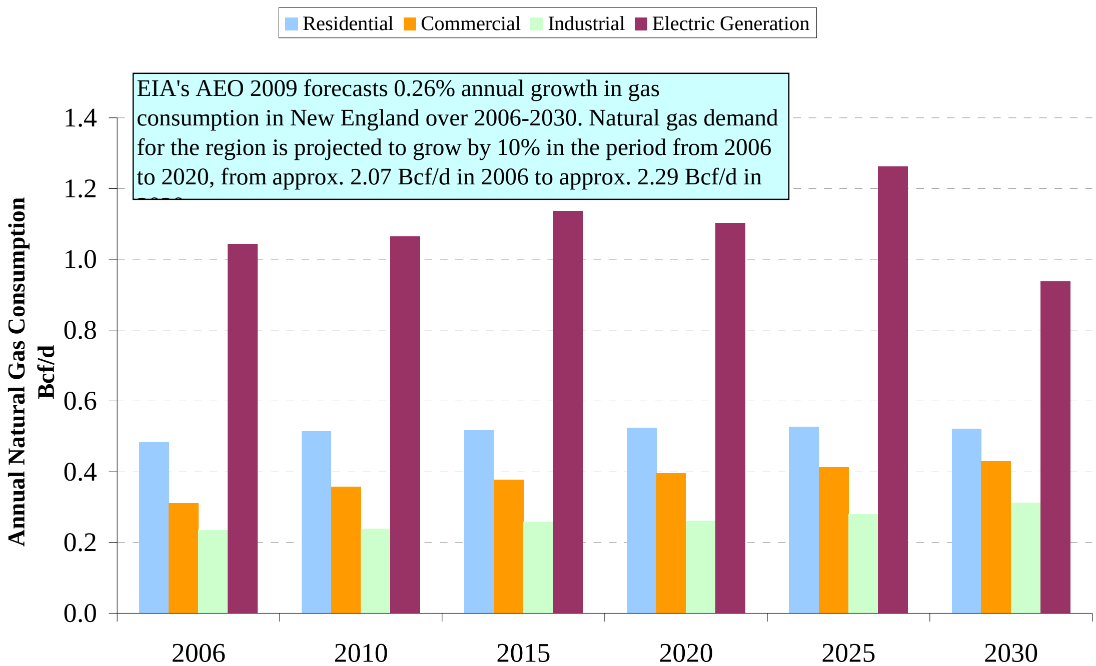
Several of the interstate pipeline expansion projects discussed above will improve the ability to deliver gas close to New England. However, it may still be necessary to expand local LDC pipelines as well in order to deliver gas to the ultimate users.

9.F NEW ENGLAND NATURAL GAS DEMAND

Figure 9.16 shows the Energy Information Administration's (EIA's) 2009 forecast for growth in New England's gas consumption until 2030.[8] Much of the overall growth is in electric generation. However, overall gas demand is only part of the story, and does not measure the ability to deliver gas at all the times when it is actually needed (it also does not distinguish dual-fuel from gas-only capacity, which is important for understanding the degree of actual reliance on natural gas for power). To approach this question, we look at regional peak day gas demand, which occurs during the winter heating season. Although gas demand from electric generation accounts for about half of New England’s total annual gas demand, it is a relatively small share of peak day gas demand. There are two primary reasons for this. First, electric demand for gas is typically lower in winter than during the summer electric peak. Second and more important, non-electric gas demand is much higher on a winter peak day than it is on average.

8 EIA, Annual Energy Outlook 2009, Supplemental Table 1.

Figure 9.16
EIA's Projected Growth in New England Gas Consumption
(2005-2030)



Source: US Energy Information Administration, "2009 Annual Energy Outlook."

Table 9.1 presents the 2005–2020 peak day natural gas demand forecast for New England from a 2005 report to the New England Governors, showing forecasted peak day LDC demand, as well as natural gas demand by electric generators on regional peak day. The total natural gas capable installed capacity for winter 2003-04 was 17,341 MW or 52 percent of all installed generating capacity in New England. The Governors' study assumed that all gas-fired capable power plants, net of average winter forced and unforced outages, need to operate and be dispatched on the theoretical peak day to maintain electric reliability. However, it reduced electric generator gas demand to 61 percent of calculated demand to reflect the fact that generators typically do not arrange for firm gas supplies.

Table 9.1
Peak Day New England Natural Gas Demand Forecast (Bcf/d)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
LDC-Delivered Demand																
Normal	3.3	3.4	3.5	3.6	3.6	3.7	3.8	3.9	4.0	4.0	4.1	4.2	4.3	4.4	4.5	4.6
High	3.8	3.9	4.0	4.1	4.2	4.3	4.4	4.5	4.6	4.7	4.8	4.9	5.1	5.2	5.3	5.4
Generation Demand																
Normal	1.0	1.0	1.0	1.1	1.1	1.1	1.2	1.2	1.2	1.3	1.3	1.3	1.4	1.4	1.5	1.5
High	1.0	1.0	1.1	1.1	1.2	1.3	1.3	1.4	1.4	1.5	1.6	1.7	1.8	1.9	1.9	2.0
Total Peak Day Demand																
Normal	**4.3**	**4.4**	**4.5**	**4.6**	**4.7**	**4.8**	**5.0**	**5.1**	**5.2**	**5.3**	**5.4**	**5.6**	**5.7**	**5.8**	**6.0**	**6.1**
High	**4.8**	**4.9**	**5.1**	**5.2**	**5.4**	**5.5**	**5.7**	**5.9**	**6.0**	**6.2**	**6.4**	**6.6**	**6.8**	**7.0**	**7.2**	**7.4**

Sources and Notes:
Meeting New England's Future Natural Gas Demands: Nine Scenarios and Their Impacts," A Report to the New England Governors, The Power Planning Committee of The New England Governors' Conference, Inc., March 1, 2005.

9.G NEW ENGLAND NATURAL GAS DELIVERY CAPACITY – ADEQUACY TO MEET PEAK DEMAND

Accounting for the gas infrastructure discussed above – existing pipelines and expansion projects, existing and new LNG terminals and satellite LNG vaporization facilities, Table 9.2 shows how the total capacity to deliver gas to New England is increasing over time (taking care to avoid double-counting of LNG capacity that feeds into pipeline capacity).[9] Starting from about 5.4 Bcf/d in 2005, several pipeline expansions and new LNG import terminals have increased this significantly, to 7.6 Bcf/d in 2010.

[9] Other proposed infrastructure additions that are more speculative have not been included here. *E.g.*, the proposed Weaver's Cove LNG terminal in Fall River, Massachusetts is farther from completion, and is not included here. Also, to avoid double-counting, LNG facilities that feed pipelines already considered do not appear separately here. *E.g.*, the Canaport LNG terminal feeds into the Maritimes & Northeast pipeline, so does not appear separately.

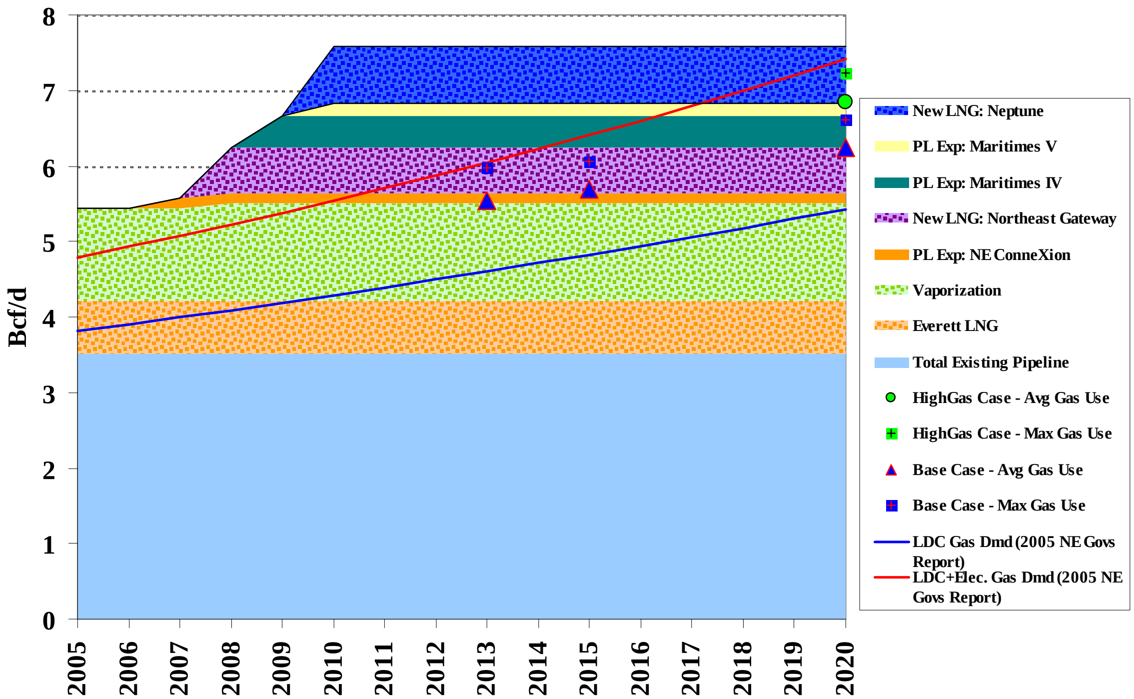
Table 9.2
Peak Day Natural Gas Delivery Capacity into New England (Bcf/d)

		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013-2020	Notes
Existing Pipeline												
Algonquin		1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	[1]
Tennessee		1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	[1]
Iroquois		0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	[1]
Vermont Gas		0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	[1]
PNGTS		0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	[1]
Maritimes & Northeast		0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	[1]
Total Existing Pipeline (2004):	**[a]**	**3.5**	**3.5**	**3.5**	**3.5**	**3.5**	**3.5**	**3.5**	**3.5**	**3.5**	**3.5**	[1]
Everett LNG	**[b]**	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	[1]
Northeast Gateway (Excelerate)	**[c]**					0.6	0.6	0.6	0.6	0.6	0.6	[4]
Satellite Vaporization	**[d]**	1.2	1.2	1.2	1.2	1.3	1.3	1.3	1.3	1.3	1.3	[1]
Proposed Pipeline Expansions												
Northeast ConneXion (Tennessee)					0.1	0.1	0.1	0.1	0.1	0.1	0.1	[2]
Maritimes & Northeast Phase IV							0.4	0.4	0.4	0.4	0.4	[6]
Maritimes & Northeast Phase V								0.2	0.2	0.2	0.2	[5]
Total Pipeline Expansion (2007- 2020):	**[e]**				**0.1**	**0.1**	**0.6**	**0.7**	**0.7**	**0.7**	**0.7**	
Total Pipeline Capacity Including Expansions:		**5.4**	**5.4**	**5.4**	**5.6**	**6.2**	**6.7**	**6.8**	**6.8**	**6.8**	**6.8**	
New LNG Projects												
Neptune LNG (Suez)								0.8	0.8	0.8	0.8	[3]
Total New LNG Capacity:	**[f]**					**0.0**	**0.0**	**0.8**	**0.8**	**0.8**	**0.8**	
Total Peak Day Capacity (a+b+c+d+e+f):		**5.4**	**5.4**	**5.4**	**5.6**	**6.2**	**6.7**	**7.6**	**7.6**	**7.6**	**7.6**	

Sources and Notes:
[1]: March 2005 report by The Power Planning Committee of the New England Governors' Conference, page 24, Table 3-5. All numbers in Table 3-5 were correct as of 2004, the same numbers are extrapolated beyond 2012.
[2]: Statistical Guide to the Northeast U.S. Natural Gas Industry 2007, by Northeast Gas Association, page 45-47.
[3]: NECA Fuel Conference Presentation by Tom Lockett, September 2009.
[4]: Statistical Guide to the Northeast U.S. Natural Gas Industry 2008, by Northeast Gas Association, page 13.
[5]: NECA Fuel Conference, 2008 by Rob Hansen.
[6]: NECA Fuel Conference, 2009 by Sean Foley.

Figure 9.17 illustrates how this delivery capacity has changed over time, and compares this with illustrative composite projections of peak-day demand. The Governors' study noted above did not capture potential future variation in the gas demand from electric generation, *e.g.*, due to differences in future buildout of gas-fired generation, the effects of carbon legislation which may shift consumption from coal and oil to natural gas, and the effect of intermittent renewables which may put more reliance on gas-fired capacity to meet reliability. Because of this, we considered the gas demand from electric generation that was found in the simulation results from this study. The solid blue line in Figure 9.17 shows LDC demand only from the March 2005 New England Governors' Report (the solid red line adds electric peak-day gas demand from that report). The individual green points in Figure 9.17 start with the Governors' LDC-only demand projection, and add the power sector gas demand from the Base Case simulation results of this study. One important point here is that the electric sector's <u>winter</u> gas demand is actually decreasing over time, driven by the large increase in wind capacity to meet renewable portfolio standards. (Average annual gas demand for power generation is fairly flat, and summer gas demand is increasing.) Wind capacity produces a lot of energy (displacing mostly gas-fired generation) in the winter months, but produces much less energy in the summer season. Thus, although the added wind capacity contributes relatively little toward summer peak electric capacity requirements, it does help to reduce the system's reliance on natural gas during the winter heating season when gas supplies are tightest. The blue points on the figure show the gas demand in a scenario with particularly high gas demand – the case with insufficient renewable capacity, combined with low gas price and low CO_2 price. This case does result in significantly higher winter gas demand for power generation.

Figure 9.17
New England Peak-Day Delivery Capacity and Winter Demand for Natural Gas



Note: Gas use for electric generators represents the Base Case (2013, 2015, and 2020) and a High Gas Demand Case (2020) from the 2010 IRP simulations.

Note that this analysis of gas demand does not account for the ability to rely on non-gas generation if gas supplies are tight, nor for dual-fuel capability of some gas-fired generating capacity. Instead, it essentially reflects the extent that gas would be used if delivery capacity were not an issue. Also, the delivery capacity displayed here does not account for a number of contractual and operating constraints that would affect actual gas deliverability at a particular point in time, nor does it reflect deliverability to particular generators or other loads within New England. Thus it is not possible to directly compare the gas demand with the delivery capacity shown here to reach a firm conclusion about the sufficiency of gas deliverability to meet electric generation needs at any particular location and point in time.

However, what is apparent is that from about 2005 to 2010, gas delivery capacity to New England has increased markedly – by about 40 percent. While non-electric winter demand for gas may increase over time, winter electric demand for gas actually decreases in our Base Case simulation. Combined, these factors imply that the balance between gas supply and demand has improved and is likely to remain better for some time, at least until winter gas demand grows to utilize the expanded delivery capacity.

ISO-NE also concludes that gas supply infrastructure has improved and should be adequate for electric needs for years:

> Recent infrastructure enhancements to the regional natural gas systems should satisfy the needs of New England's core space heating and power generation markets for years to come. These improvements include new and expanded natural gas sources, pipelines, storage, and liquefied natural gas (LNG) facilities. The improvements in the natural gas system and the addition of dual-fuel electric power resources have reduced the historical concerns about electric power system reliability stemming from the high dependence on gas-fired generation within New England.[10]

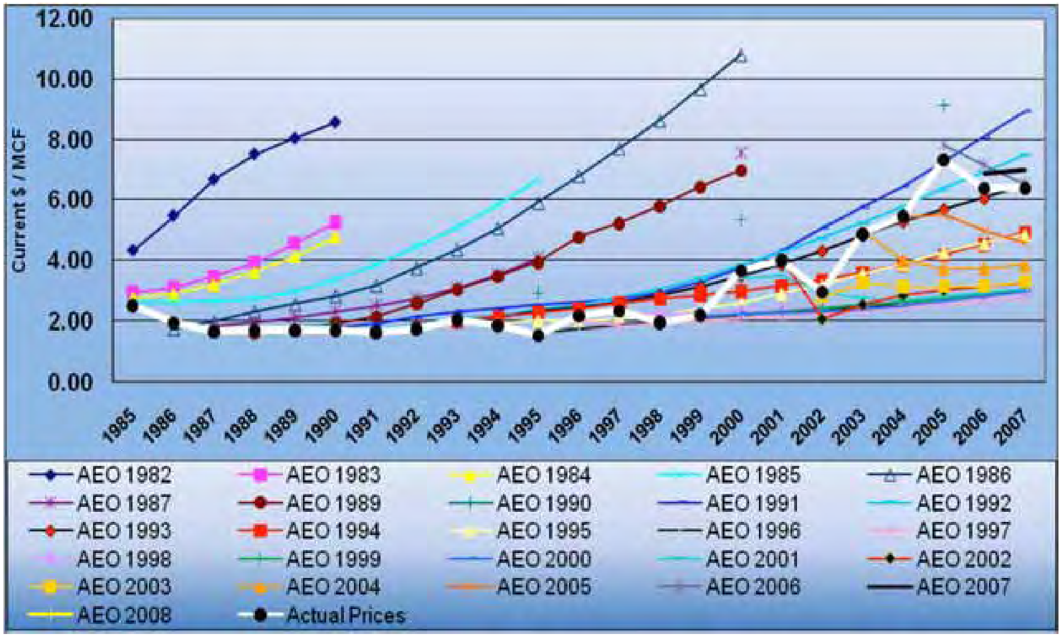
In the Energy Security section of this report, we perform an analysis of the limits of winter gas dependency, in which we simulate the extent that the system actually relies on natural gas, accounting for winter electric demand and non-gas and dual fuel generating capability.

9.H NATURAL GAS PRICE FORECAST AND SCENARIOS

For the purpose of a planning study such as this, it is important to characterize future fuel prices, particularly for so important a fuel as natural gas is to New England. Unfortunately, it is not possible to predict accurately what natural gas prices will be in the future. Past gas prices have varied widely, and have deviated widely from prior forecasts and predictions. As an example, the EIA graphic in Figure 9.18 below compares actual gas prices (white line) to the various forecasts it has made over time (colored lines). As can be seen, for over a decade actual prices were far below prior EIA forecasts. Then starting around 2000, the relationship largely reversed, with actual prices being generally higher than recent prior forecasts. The "forecast error" illustrated here has often been on the order of a factor of two or even more; that is, actual prices have often been double, or at other times half, the value forecasted by EIA even just a few years before. This is not simply the consequence of poor forecasting. Similar results can be seen by comparing actual gas prices with just about any series of long-term gas price forecasts, including the market's own "forecast" of natural gas prices – NYMEX futures prices for natural gas.

[10] ISO-NE 2009 Regional System Plan, page 60.

Figure 9.18
EIA Natural Gas Wellhead Price Forecast Comparison—
AEO 1982–2008



Source: EIA: *Annual Energy Outlook 2008 Retrospective Review.*

Future uncertainties affecting gas prices include the amount of recoverable gas in new unconventional reserves, the cost of developing it and the rate at which it will be developed. These may be affected by incomplete information about the geology, environmental concerns and requirements, and technological progress. Natural gas demand is also quite uncertain – influenced by factors such as overall economic activity and energy demand, the extent of switching from higher-carbon fossil fuels to natural gas that may be prompted by carbon legislation (which is itself highly uncertain), and the availability of other energy sources, such as renewables. Shorter-term and more localized factors such as seasonal weather demands, storage inventories and deliverability constraints can also have an effect.

However, while future natural gas prices cannot be predicted with confidence, it is possible to develop a reasonable characterization of their likely value and the potential range over which they may vary. Though a wide range of potential gas prices may be plausible, in order to understand the effect on the power system it can be useful to examine several particular gas price levels, chosen to illustrate the potential range. Considering several different scenarios on natural gas prices – *e.g.*, Expected, High and Low gas price cases – in combination with other variables that affect the power system, can be an important part of evaluating different resource strategies.

The relevant natural gas price for New England power markets is the delivered price paid by generators. This delivered price can be thought of as the sum of three components:

- Commodity Price (typically quoted at Henry Hub, Louisiana)
- Basis Differential (difference between New England price and Henry Hub price)

- Distribution Cost (local distribution company charges or pipeline interconnection costs)

Of these three price components, the commodity (Henry Hub) price dominates, both in magnitude and in its effect on the uncertainty in the overall delivered gas price.

The gas basis differential, the price difference between Henry Hub and the New England market region, shows substantial seasonality (higher in the winter heating season), and also some short-term variability, but it is not a primary driver of gas price or price uncertainty. In the long run, basis differentials may be affected by changes in the geographic patterns of gas flows and prices. Traditional Gulf and Canadian gas supplies, which were already in decline, are likely to diminish further. Unconventional gas supplies, some located much closer to gas demand centers including New England, will become more prominent. The basis differential between New England and Henry Hub could fall considerably if nearby Marcellus Shale supplies are developed and there is adequate delivery capacity over the short distance to New England.

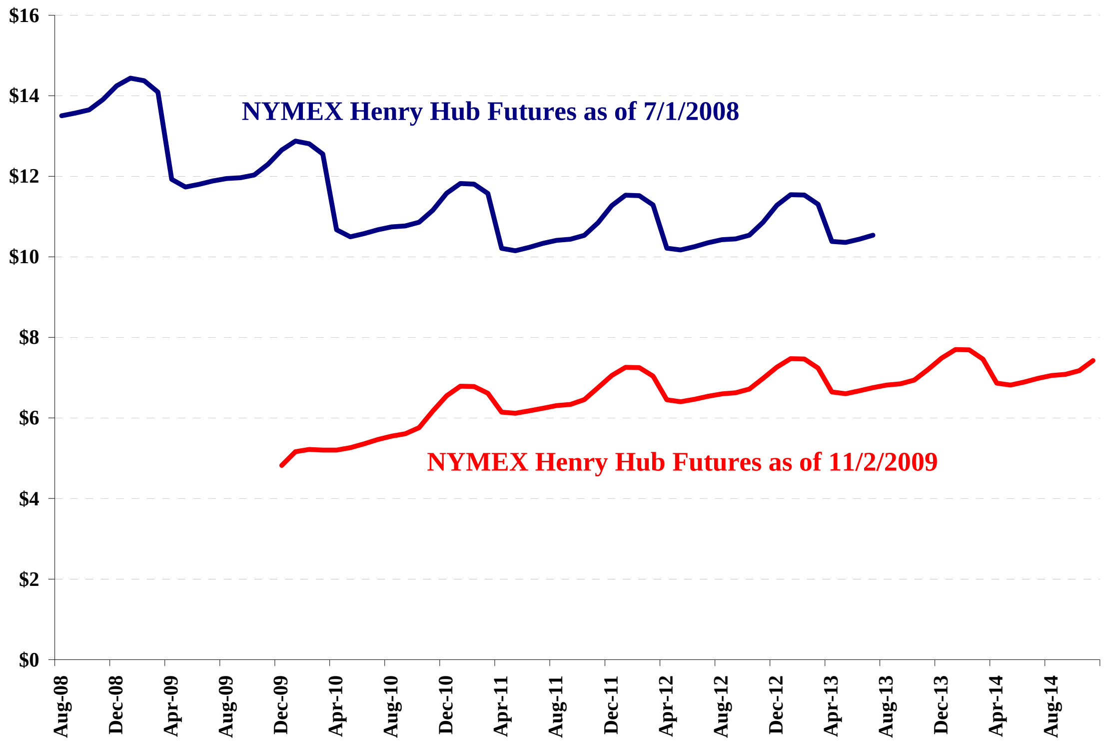
The distribution costs paid by a generator can vary by location and individual plant, but are modest and typically fixed. For the purpose of this planning study distribution costs are assigned by state, and are also varied based on the in-service date of the plant as a proxy for whether the plant is served via a local distribution company (LDC) or is directly connected to a pipeline (newer plants tend to have direct pipeline connection, which is typically less costly).

In developing scenarios on natural gas price below, we do not explicitly characterize uncertainty on each of the three components of gas price. The resulting delivered price scenarios should be interpreted as scenarios on the full delivered price, recognizing that these delivered price values might be achieved with different combinations of the price components.

9.H.1 Developing Natural Gas Price Scenarios

Market information about future natural gas prices can be used to guide judgment about choosing a set of gas price cases for planning purposes. Natural gas futures contracts (standardized, exchange-traded forward contracts to transact gas) are widely traded for a number of years into the future. The current futures price is essentially the market's "expectation" of future gas price (though strictly speaking, it also includes a risk adjustment). Recent changes in market prices reflect the change in the supply outlook discussed above (as well as shorter-term demand effects). Over the past year or two, gas prices have fallen dramatically; only in the past couple months have they begun to recover, but not to previous levels (Figure 9.19). This is particularly true of short-term gas prices, which have fallen from over $13.50/MMBtu in summer 2008 to a low of $2.85/MMBtu in September, 2009, and have more recently rebounded to over $5.00/MMBtu. Long-term gas prices have also moved significantly, if not quite as dramatically. Gas for delivery in 2013 (12-month average) was $10.05/MMBtu in July 2008, but by November 2008 it was at $7.01/MMBtu.

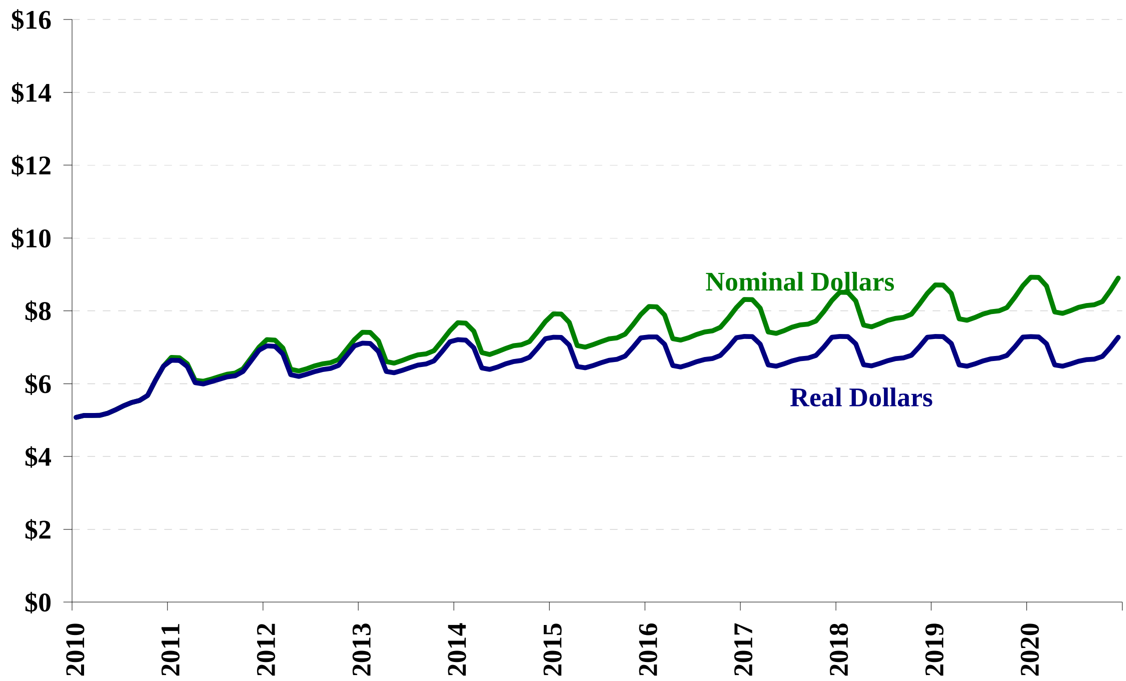
Figure 9.19
Natural Gas Futures Price Change – July 2008 to November 2009



Source: NYMEX.

Current gas futures prices show gas prices increasing for several years from depressed near-term prices, and then staying essentially level in real terms thereafter (*i.e.*, growing roughly with expected inflation), illustrated in Figure 9.20. The upper curve is the actual NYMEX futures prices, which are in nominal dollars; the lower curve is the same values converted to real 2010 dollars. Hereafter, prices are in real dollars unless otherwise indicated. As this figure shows, the market is essentially predicting that long term gas prices are expected to be flat at about $7.00/MMBtu in real 2010 dollars.

Figure 9.20
NYMEX Natural Gas Futures Prices



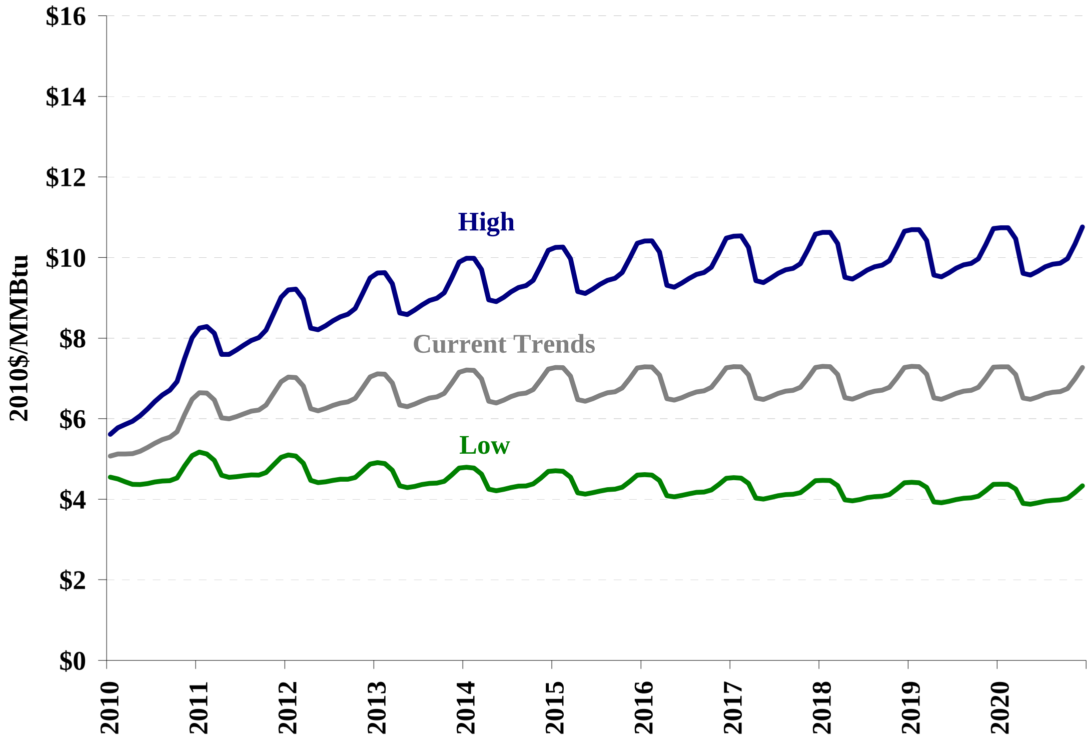
Source: NYMEX.

The market also offers options on natural gas, which gives information about the market's view of the potential range of future gas prices. A "call" option gives the holder the right, but not the obligation, to purchase gas at a specified price at a particular future time; a "put" option gives the right to sell at a specified price. The market price of the option is related to the market's assessment of the range of potential future gas prices. A higher option price implies the market believes there is a wider range of potential future gas prices. This makes it possible to estimate the market's view of the potential range of future gas prices (this is referred to as "implied volatility" – the volatility in future gas prices that is implied by the observed market price of options contracts). This approach yields a full implied probability distribution on future prices, which can be illustrated with percentiles on the estimated distribution. (For example, there is a 90 percent chance that the actual value will be below the 90th percentile value.)

Figure 9.21 below shows the "expected" price of natural gas given by NYMEX natural gas futures price data. It also illustrates potential High and Low values of gas prices – the 10th and

90th percentiles of the implied distribution on 5-year average gas prices, based on the implied future volatility as derived from the current market price of option contracts.[11]

Figure 9.21
Natural Gas Price Scenarios



Source: NYMEX.

Current option prices imply that by 2015, there is a 10 percent chance that the (long-term) gas price will be above about $9.68/MMBtu, and a 10 percent chance it will be below $4.37, with an expected value of $6.82. These 90/10 percentile bands are used to characterize potential High and Low gas price trajectories, which are used in the development of scenarios against which to evaluate potential resource strategies in this IRP.

[11] The exchange-traded options for which data is available are monthly options – *i.e.*, each option contract is for a specific monthly delivery period. The monthly price volatility implied by the monthly option contract data was adjusted to reflect the volatility of 5-year average gas price. There are a number of short-term factors, such as weather, storage conditions and pipeline events, that can drive gas prices to temporary extremes, and this is reflected in the prices of the monthly options contracts. But the price for a longer delivery period tends to be significantly less volatile than monthly prices. The adjustment performed here corrects for this to reflect the volatility in 5-year average gas prices that is implied by the monthly options prices (see *Uncertainty Representation: Estimating Process Parameters for Forward Price Forecasting*, EPRI TR-114201). This adjustment was made because the very short-term component of volatility was judged to be less relevant for a long-term planning study such as this; much of this short-term variability tends to "average out" over longer time periods.

To develop the final delivered natural gas trajectories, the Reference, High and Low values here are increased by the basis differential and distribution cost adders discussed above to yield scenarios on the delivered gas price.[12] Though the scenario development process did not separately characterize uncertainty on each of the three components of gas price, the resulting delivered prices should interpreted as scenarios on the full delivered price, recognizing that these delivered price values might be achieved with different combinations of the price components.

The High Gas Price scenario, nearly $3/MMBtu (over 35 percent) above the reference price by 2015, could occur if the expected development of shale gas is delayed or limited (*e.g.*, due to environmental concerns), which might accompany a high basis differential, or could occur if it is simply more costly than expected. The Low Gas Price scenario, about $2.50/MMBtu (over 30 percent) below the reference price, could occur if the Marcellus and other shale plays are developed quickly and extensively, at costs that are on the low side of current estimates, which might correspond to a fall in the basis differential (Henry Hub to New England). Of course, variants of these or entirely different combinations of factors could also explain these price levels.

9.H.2 The Relationship between Natural Gas and Oil Prices

Oil, in the form of FO2 (distillate) and FO6 (residual fuel oil), is also used as a generation fuel in New England. It plays a much smaller role than natural gas, particularly when, as now, oil is costly compared to natural gas. Nonetheless, it is necessary to consider petroleum fuels and their prices. As with natural gas, futures markets for oil products provide information about the expected price of FO2 and FO6.[13] Since oil plays a relatively minor role in New England power markets, considering separate scenarios on high or low oil prices, independent of gas prices, would not be a significant driver of power markets. However, oil and natural gas prices have been related historically, so it is important to ensure that oil and gas prices are consistent within the scenarios that will be analyzed.

Gas prices have often maintained about an 85 percent parity with crude oil on a Btu basis. That is, a Btu of natural gas has typically cost about 85 percent of the cost of a Btu of crude oil. However, recent developments in the U.S. natural gas market have pushed gas prices sharply downward relative to world oil prices, causing gas and oil prices to break from this historical relationship. Current gas prices (including gas futures) are significantly below that 85 percent parity level. For example, gas futures for 2013 delivery are now approximately 45 percent of the cost of crude oil futures on a Btu basis. The market appears to believe that, at least in expectation, natural gas and oil prices are likely to remain de-linked for some time into the future.

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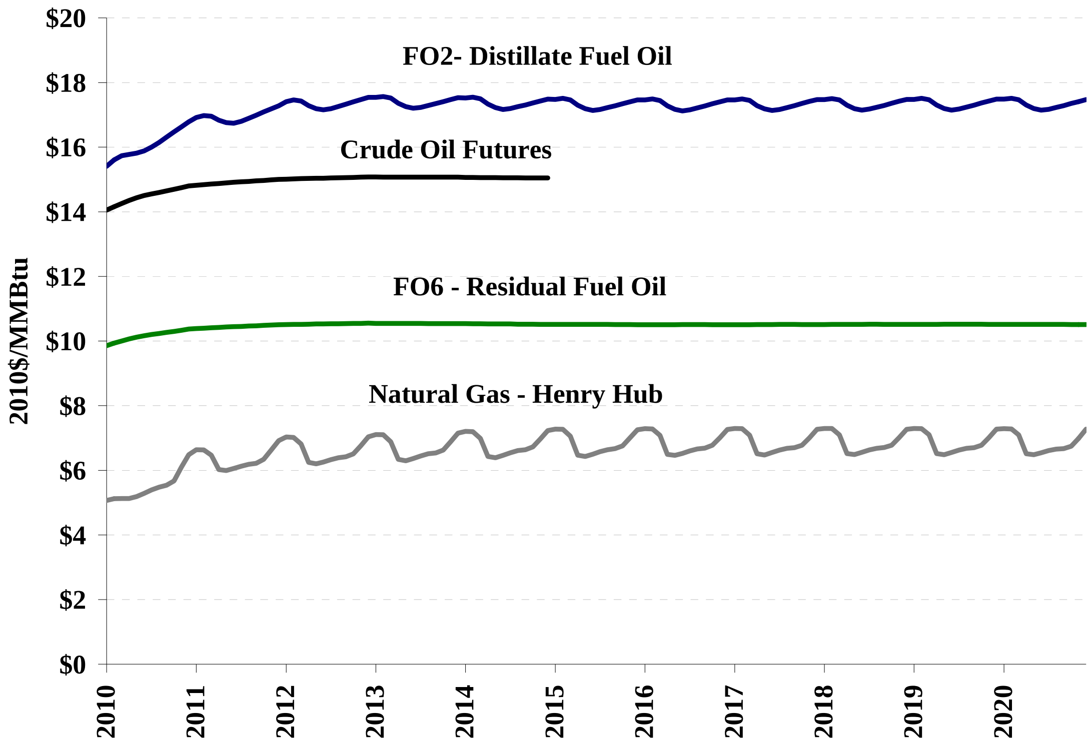
[12] The basis differential is a monthly adder, distinguished between southern New England (Connecticut, Massachusetts, Rhode Island; annual average $1.09/MMBtu) and northern New England (Maine, New Hampshire, Vermont; averaging $0.84/MMBtu). Distribution costs vary by state and plant, range from 2.5 to 30¢/MMBtu.

[13] Futures prices are not available directly for FO6. A proxy for FO6 prices is developed from futures on crude oil, adjusting according to the statistical relationship between historical FO6 and crude oil prices.

However, if gas prices were to increase significantly, this parity relationship could in principle be restored, and this should be considered in developing scenarios to ensure that the gas and oil prices within a given scenario are consistent. For example, in a high gas price scenario, the gas price might get high enough to re-link with oil prices. In fact, current expectations of gas and oil prices are such that even in the high gas price case developed above, the gas price would still be below the 85 percent parity level with crude oil.[14] Because of this, oil prices were maintained at their expected level across all scenarios, as illustrated in Figure 9.22

Figure 9.22
Oil Price Trajectories



Source: NYMEX.

14 A new factor may be CO_2 prices, which would have a differential effect on the effective price of natural gas and oil (oil has more CO_2 per Btu than gas), and thus might enter the gas/oil pricing relationship if they were to re-link. That is, in future the 85 percent price parity relationship, if it is restored, might apply to the effective price of gas and oil, inclusive of CO_2 price. Considering this, we found that the conclusion regarding expected oil price being above even the high gas price is still true (and in fact is even more true) if CO_2 price were to enter the traditional price parity relationship.

9.I APPENDIX 9-1: PIPELINE/LNG IMPORT CAPACITY SERVING NEW ENGLAND

Algonquin Gas Transmission Company (Sub. of Spectra Energy): Interstate pipeline with 11 interconnections/receipt points between New Jersey (Texas Eastern) and southeastern Massachusetts. Capacity = 2.5 Bcf/d.

Distrigas of Massachusetts Corporation (DOMAC) (Sub. of GDF SUEZ): LNG import terminal in Everett, Massachusetts with interconnections with Tennessee and Algonquin systems. Capacity = about 1 Bcf with sustained vaporization sendout of approximately 715 MMcf/d, with another 100 MMcf/d by truck. Storage capacity = 3.4 Bcf.

Granite State Gas Transmission, Inc. (Sub. of Unitil): Interstate pipeline from Massachusetts-New Hampshire border to Portland, Maine connecting Maritimes & Northeast and Portland Natural Gas Transmission pipelines.

Iroquois Gas Transmission System (Owned by a partnership of 5 United States and Canadian energy companies): Transports from TransCanada PipeLine at the Ontario/New York border through New York and Connecticut to Long Island and the New York City area. Capacity = about 1.5 Bcf/d.

Maritimes & Northeast Pipeline (M&NE) (Sponsored by an international consortium

of energy companies): Transports from the Sable Island Offshore Energy Project of Nova Scotia to markets in Atlantic Canada and New England. Capacity = 800 MMcf/d.

Northeast Gateway LNG Port facility (Sub. Of Excelerate Energy): 13 miles offshore Cape Ann, Massachusetts. First shipment May 2008. Interconnects with HubLine pipeline operated by Algonquin Gas Transmission. Capacity = 800 MMcf/d.

Portland Natural Gas Transmission (PNGTS) (Sponsored by an international consortium of energy companies - TransCanada PipeLines and Gaz Métro): Transports western Canadian gas to New England from an interconnection with TransCanada PipeLines (through the TQM extension). Interconnects with Maritimes & Northeast through the Joint Facilities line. Capacity = 168 MMcf/d.

Repsol/Irving Oil Canaport LNG facility in Saint John, New Brunswick, Canada: First shipment in June 2009. Two storage tanks of 3.3 Bcf each, and third tank of similar size expected in-service in spring 2010. Capacity = 1 Bcf/day. Regasified LNG from the terminal flows through the Brunswick Pipeline, a 90 mile pipeline connecting the terminal to the Maritimes & Northeast Pipeline at the Maine border.

Tennessee Gas Pipeline Company (Sub. Of El Paso Corporation): Enters New England at two points: western Massachusetts near West Pittsfield and southern Connecticut near Greenwich. Storage capacity = 90 Bcf; capacity = 6.5 Bcf/d.

Source: Northeast Gas Association (www.northeastgas.org)

9.J APPENDIX 9-2: NORTHEAST PIPELINE PROJECTS IN PROGRESS

PROJECT	COMPANY	DESCRIPTION	EST. IN-SERVICE
Thomas Corners Storage Project	Arlington Storage Company LLC, subsidiary of Inergy	Arlington Storage plans to construct and operate the Thomas Corners facility in Steuben County, NY, with 7 Bcf of working gas capacity. The Thomas Corners facility is expected to be connected to TGP's Line-400 and Columbia Gas Transmission's A-5 Line that accesses the Millennium Pipeline. Under construction.	April 2010
East to West Expansion Project	Spectra Energy / Algonquin Gas Transmission	An expansion of the Algonquin pipeline system that will transport 281 MDth/d of eastern LNG-based supplies into regional market.	Nov. 2010
TEMAX and TIME III	Spectra Energy / Texas Eastern	Spectra Energy and ConocoPhillips have executed an agreement to deliver up to 395 million cubic feet per day of Rocky Mountain natural gas from the Clarington, Ohio, supply point to the Northeast U.S. by November 2010 (TEMAX). It involves about 30 miles of pipeline in OH and PA. In addition, Spectra will transport another 60 MMcf/d of supply in PA (TEAM).	Nov. 2010
West to East	National Fuel Gas	Would transport new supplies from the Rockies supply basin to markets in the Northeast, with a new pipeline from the vicinity of Clarington, OH to Corning, NY – as well as links to developing Marcellus Shale supplies. Phase I is designed to move approx. 200 MDth/d from Marcellus supplies, by 2011; Phase II will move an additional 300 MDth/d by 2012.	2011-2012
300 Line Expansion	Tennessee Gas Pipeline	Tennessee plans to expand its 300 Line to transport new, diversified natural gas supplies, including Appalachian and Marcellus Shale gas. Involves the installation of new looping segments totaling aprox. 128 miles of 30" pipe in PA and NJ. Capacity of 350 MDth/d.	Nov. 2011
Northeast Supply Project	Williams / Transco	The Project includes a system expansion, Northeast Connector, that will access additional supply beginning at Station 195 in southeastern PA and create capacity to deliver this supply to Transco's Rockaway Delivery Lateral. The Rockaway Delivery Lateral will extend approximately three miles from Transco's Lower New York Bay Lateral to a new delivery point with National Grid's distribution system in New York. Capacity of 100 MDth/d and 647 MDth/d.	Late 2012
TEAM	Spectra Energy	The Texas Eastern Appalachian Market Supply Project (TEAM) provides for multiple year supply connection and expansion. Texas Eastern is proposing an expansion to increase its system's capacity by up to 300 Mmcf/d, commencing in fourth quarter 2012. Targeted in service for the second phase expansion would be 2013.	2012
Appalachian Gateway Project	Dominion	Proposed facilities include construction of about 110 miles of 20-, 24- and 30-inch diameter pipeline between WV and PA, as well as four new gas compressor stations. Dominion will ultimately deliver this natural gas to Texas Eastern Transmission at Dominion's Oakford Station in Delmont, PA. Total firm transportation delivery for the Project will be 484,260 dekatherms of natural gas per day.	2012
Keystone Connector	Columbia Gas Transmission / Williams	Proposed 240 mile pipeline, to extend from terminus of REX-East to Williams' Transco Station 195 in southeastern PA. Could transport up to 1 Bcf/d of natural gas produced in Rockies and Marcellus Shale.	2013
NYMarc	Iroquois Gas Transmission	Proposes to connect NY and New England markets to Marcellus and Rockies supplies. Approx. 66-mile, 36-inch pipeline and one compressor station in NY. As proposed, NYMarc would receive gas from Tennessee Pipeline in NJ and Millennium Pipeline in NY. Initial capacity is expected to be 500 MDth/d.	2014

Source: Northeast Gas Association (www.northeastgas.org)

Section III.10
Emerging Technologies

10. EMERGING TECHNOLOGIES

10.A SUMMARY AND KEY FINDINGS

Summary

A number of uncertainties come into play in resource planning, and one is the potential for new or emerging technologies to change the planning landscape. In the 2009 IRP, we explored a range of new technologies, several of which were found to have limited relevance or application to New England, such as geothermal, concentrating solar thermal electric and carbon capture and storage. Other technologies were potentially more relevant, but their prospects showed little change over the past year, such as energy storage. Two technologies more likely to affect resource planning over the next decade are examined in other sections of this report: photovoltaic (PV) systems are discussed in the Renewables Section and fuel cells are incorporated into the Combined Heat and Power Section.

In this section, we examine two emerging technologies that were addressed in the 2009 IRP and which appear to have gained momentum in their prospects for influencing electricity demand over the next decade. These are plug-in electric vehicles (PEVs) and advanced metering infrastructure (AMI), which is a critical component of the "Smart Grid" concept that has gained momentum over the past several years. Although advances in these technologies over the past year warrants additional analysis, their potential impacts over the next decade are not yet sufficiently clear to incorporate into the simulation analyses presented in Section II.

Key Findings

- Because of the growing commitments to plug-in electric vehicle (PEV) manufacturing and charging infrastructure on the part of vehicle manufacturers and electric utilities, PEVs appear poised to achieve an uncertain but potentially significant fleet penetration over the next decade.
- A 5 percent level of fleet penetration by 2020 represents an optimistic view of PEV vehicle sales over the next decade, but one that is worth exploring for its potential impact on the New England electricity system.
- Even an optimistic view of PEV penetration in New England over the next two decades is unlikely to pose any unmanageable issues for maintaining reliable electric service.
- An optimistic view of PEV penetration in New England is likely to produce a modest environmental benefit, with net CO_2 and NO_X emissions decreasing and only a negligible increase in SO_2 emissions.
- Widespread implementation of advanced metering infrastructure (AMI) has the potential to decrease peak loads. The magnitude of the decrease will depend on customer participation rates in dynamic pricing programs and their responsiveness to near-term price signals.

- Enabling technologies can help customers respond more effectively to price signals, and AMI programs that encourage these technologies are more likely to yield more pronounced responses.

10.B PLUG-IN ELECTRIC VEHICLES (PEV)

Powering a vehicle using a rechargeable battery and an electric motor is not a new concept; electric vehicles (EVs) have been around for more than a century. However, due to their relatively limited driving range, long recharging times, high costs and lack of availability, EVs have not had a significant market penetration.[1] The introduction of hybrid electric vehicles (HEVs) offers a new way to capture some of the advantages of EVs by combining the internal combustion engine of a conventional vehicle with the battery and electric motor of an electric vehicle. HEV sales have grown by more than 80 percent annually in the US over the last 8 years, and they currently represent about 3 percent of total U.S. vehicle sales.[2,3]

Plug-in electric vehicles (PEVs) are seen as a next step in advanced vehicle technologies. There are several types of PEVs, ranging from pure electric vehicles (EVs) to plug-in hybrid electric vehicles (PHEVs) that combine grid-rechargeable electric motors with internal combustion engines. A PHEV is essentially a hybrid vehicle with a much larger battery, and the ability to be plugged into the electric grid for charging that battery. Its primary source of power is electricity, so it can potentially provide a cleaner option than conventional hybrids, depending on the electricity source. Toyota announced its plug-in version of the Prius hybrid in December 2009, with an all-electric range of about 14 miles. There are also extended range electric vehicles (EREVs) that primarily operate on battery power with a small gasoline engine available to charge batteries, instead of providing power directly to the drivetrain as in a conventional hybrid. General Motors plans to launch an extended-range (40 mile) EREV, the Chevy Volt, by late 2010. It is also possible that all-electric vehicle technology may become a viable alternative; recent and projected improvements in battery technology may finally make all-electric vehicles attractive. Ford intends to start selling a battery-powered version of its Transit Connect commercial van in 2010, followed by an electric Ford Focus sedan in 2011. Nissan is introducing its electric car, the Leaf, to selected business fleets next year and to consumers by 2011.

The electric utility industry has begun to consider investments in charging infrastructure. In Connecticut, the EDCs participate in the Governor's Electric Vehicle Infrastructure Council established under Executive Order No. 34, and also have joined the Regional Electric Vehicle Initiative (REVI), a collaborative effort of New England utilities to promote the development of electric transportation infrastructure.

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1 According to Annual Energy Review 2007 (EIA), there are about 55,000 electric vehicles in use in the United States by 2007 (less than 0.05 percent of total light-duty vehicles).

2 Lemoine, D., *et al. An innovation and policy agenda for commercially competitive plug-in hybrid electric vehicles*, Environmental Research Letters 3, 1-10 (2008).

3 Madian, A. L., *et al. U.S. Plug-In Hybrid and U.S. Light Vehicle Data Book: Hybrid Vehicles, Battery Technology, Travel Patterns, Vehicle Stock, Sales Trends, Performance Trends.* LECG (2008).

Since PEVs would be a fundamentally new electric load, they have the potential to increase the overall electricity demand, but may also have the potential to reduce overall greenhouse gas (GHG) emissions as well as dependence on imported oil. Important questions for the electric sector are what level of penetration PEVs might have, and whether the level of penetration will be enough to materially affect electric loads (peak and/or energy) or overall emissions. Because of the growing commitments to PEV manufacturing and charging infrastructure on the part of vehicle manufacturers and electric utilities, PEVs appear poised to achieve an uncertain but potentially significant fleet penetration over the next decade.

10.B.1 Potential Market Penetration

The market penetration rate of PEVs depends in part on the relative economics compared to conventional vehicles (including gas-electric hybrids) as well as performance, customer acceptance, and concerns on energy security and climate change. Depending on how each of these factors may evolve, future market share projections range widely. On purely economic terms (*i.e.*, comparison of fuel cost savings to higher vehicle prices), PEVs face substantial hurdles unless battery costs decline substantially and/or gasoline prices rise dramatically. However, potential customers may embrace PEVs for reasons beyond a strict cost advantage over conventional vehicles, and supportive public policies coupled with innovative designs and effective marketing will broaden their appeal.

The Energy Information Administration (EIA) estimates that the annual sales of PEVs will grow to almost 140,000 vehicles by 2015, and 400,000 vehicles by 2030, supported by tax credits enacted in 2008. Other studies have analyzed the impacts of plug-in hybrid technology penetration on the electric grid and the environment. A report prepared by MIT Laboratory for Energy and Environment assumes plug-in hybrids will account for 2-3 percent of new car sales by 2020, and 10 percent by 2030.[4] A more optimistic scenario prepared by the Electric Power Research Institute (EPRI) assumes 35 percent for 2020, and 50 percent for 2030.[5]

Most recently, the National Research Council released a study that projected a “maximum practical” overall fleet penetration of PHEVs of about 13 percent by 2030, with a “more probable” penetration of less than 5 percent of the vehicle fleet by 2030.[6] The share of PEVs in the stock of the vehicle fleet at any given time is much lower than the percentage of new car sales, because older vehicles are only slowly replaced by newer ones. However, the impact of PEVs on transportation fuel demand, electricity use and the environment is more closely related to the composition of the fleet (and the usage of those vehicles) than to annual new car sales.

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[4] Heywood, J., *et al*. *On the Road in 2035: Reducing Transportation’s Petroleum Consumption and GHG Emissions*. MIT Laboratory for Energy and the Environment, Report No. LFEE 2008-05 RP (2008).

[5] Duvall, M., E. Knipping. *Environmental Assessment of Plug-In Hybrid Electric Vehicles. Volume 1: Nationwide Greenhouse Gas Emissions.* Report No. 1015325, Electric Power Research Institute (2007).

[6] National Research Council Committee on Assessment of Resource Needs for Fuel Cell and Hydrogen Technologies, *Transition to Alternative Transportation Technologies – Plug-in Hybrid Electric Vehicles*, National Academy of Sciences, 2009.

Overall, it seems that the short-term market penetration of PEVs would be limited to only a few percentages of new car sales (primarily due to barriers such as cost, uncertainty and need to develop manufacturing capability). *If these barriers could quickly be reduced or eliminated*, and initial consumer acceptance is high and sustained over time, it appears possible that PEVs could achieve a 20 percent share of new car sales by 2020, and perhaps 50 percent by 2030 (accounting for roughly 5 percent of the overall automobile fleet in 2020, and about 25 percent in 2030). A 5 percent level of fleet penetration by 2020 represents an optimistic view of PEV vehicle sales over the next decade, but one that is worth exploring for its potential impact on the New England electricity system.

10.B.2 Impact on the Grid

A recent study by Pacific Northwest National Laboratory shows that up to 84 percent of the U.S. cars, pickup trucks, and SUVs could theoretically be converted to plug-in hybrids without the need for additional electric infrastructure, if all the excess generating capacity could be fully utilized (*i.e.*, by charging only at off-peak times when much of the electric generating capacity is otherwise idle).[7] However, the actual timing of electric demand will depend heavily on drivers' recharging patterns (when, how often, and how quickly). It is very unlikely that the additional electricity demand from plug-in hybrid cars would be perfectly aligned with the system's excess generating capacity.

Another study by Oak Ridge National Laboratory examines how increased penetration of plug-in hybrids could affect the regional power requirements, depending on when and how quickly the batteries are recharged.[8] It estimates that the increase in the energy demand will be about 1-2 percent in 2020, and about 2-5 percent in 2030 (assuming that plug-in hybrids will have 10 percent fleet penetration by 2020, and 25 percent by 2030). It finds that faster recharging, if concentrated on the evening period after people go home from work, could increase the annual peak demand substantially (in some extreme scenarios, increases could be as high as 10 percent in 2020, and more than 25 percent in 2030). However, if PEVs are recharged at times that are less coincident with system peak (*i.e.*, recharged later or more slowly, or not at the same time), they might have a much modest effect on peak load, and potentially no effect at all (if all recharging occurs during off-peak times).

Access to charging spots is an important factor shaping drivers' recharging patterns. More diverse opportunities to charge vehicles would reduce the likelihood of all drivers recharging their batteries within a very narrow time window that is coincident with peak demand hours. Increased deployment of charging spots at private homes, workplaces, and public locations could encourage drivers to recharge their batteries more than once per day (which also increases the fraction of vehicle miles traveled in electric mode).

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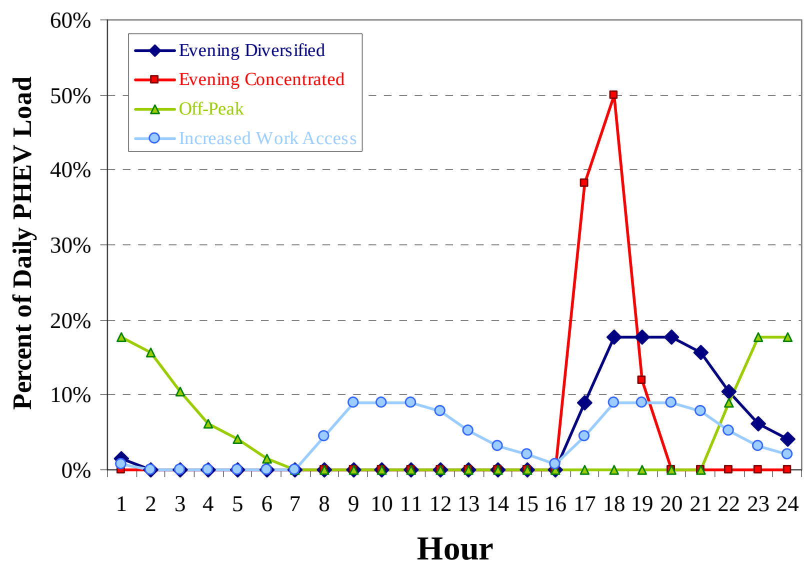
7 Kintner-Meyer, *et al. Impacts Assessment of Plug-in Hybrid Vehicles on Electric Utilities and Regional U.S. Power Grids. Part 1: Technical Analysis*. Pacific Northwest National Laboratory (2007). This study assumes 260-450 Wh per mile in battery-depleting mode, depending on vehicle size.

8 Hadlew, S.W. and A. Tsvetkova. *Potential Impacts of Plug-in Hybrid Electric Vehicles on Regional Power Generation*. ORNL/TM-2007/150, Oak Ridge National Laboratory (2008).

Time-varying electricity prices, facilitated by new electric metering infrastructure, could enhance consumers' incentives for off-peak recharging. Yet, it is not clear how the PEVs drivers would respond to such programs. Many PEV drivers may prefer to keep their batteries full, just in case, instead of getting the savings offered by lower off-peak prices.

Figure 10.1 below illustrates how the distribution of incremental PEV load can vary under different recharging patterns. *Evening Concentrated* assumes that all drivers' start recharging their batteries more or less at the same time around 5-6pm, and they use rapid chargers. *Evening Diversified* assumes that some drivers' start around 5-6pm, some a little later, and they use relatively slower, more gradual chargers. In *Increased Work Access*, half of the recharging starts during morning around 8-9am, and the other half starts around 5-6pm. In *Off-Peak*, recharging occurs during night, starting from 10-11pm until early morning.

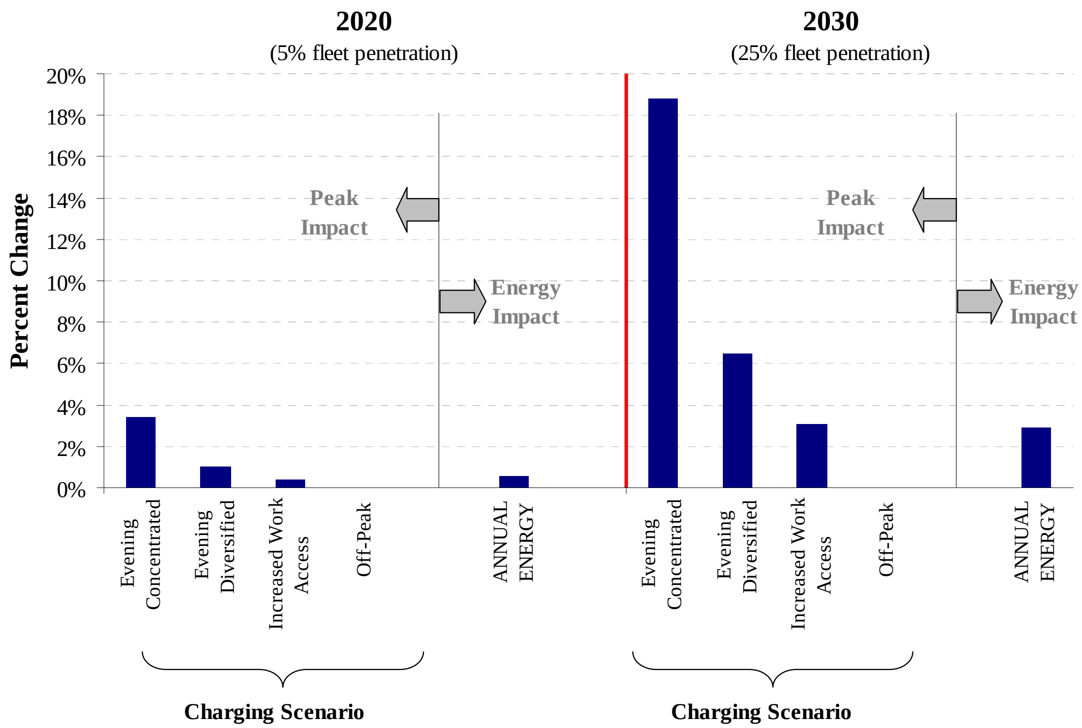
Figure 10.1
Hourly Distribution of the Incremental Plug-in Hybrid Load



Source: *The Brattle Group*, based primarily on 2008 Oak Ridge study.

Figure 10.2 below illustrates the potential impact of plug-in hybrids on the New England electricity demand for different charging scenarios. Bars represent impacts for an assumed fleet penetration rate of 5 percent in 2020 and 25 percent in 2030). The results indicate that the peak increase due to plug-in hybrids would be limited to 3.5 percent in 2020, and less than 0.5 percent in most cases. The incremental energy added to the system is below 0.6 percent in all charging scenarios. On the other hand, 25 percent fleet penetration rate may significantly affect the system peak if all drivers simultaneously charge their batteries close to the peak hours, adding between nearly 19 percent to peak demand for evening concentrated charging modes. However, with a little bit of diversification in charging time, the peak impact could be greatly reduced, and since the impact on peak would grow slowly over two decades, any implied increase in generating capacity needs should be easily met through normal market-driven adjustments. The potential increase in annual energy consumption is estimated to be about 3 percent in 2030.[9] Therefore, even an optimistic view of PEV penetration in New England over the next two decades is unlikely to pose any unmanageable issues for maintaining reliable electric service.

Figure 10.2
Potential Impact of Plug-In Hybrids on New England System Demand



Notes:
[1] 40 miles/day, 42 mpg (CS mode) and 200 Wh/mi (CD mode) for PHEV
[2] 200 million fleet size for the U.S. in 2020, and 5.2 percent fleet share for New England.
[3] 2020 hourly system load based on DAYZER simulation inputs.
[4] 2030 projections are based on 2020 hourly data, assuming an average 1.1 percent/year growth rate from 2020 to 2030.

9 Although the impact on overall system demand appears modest, it is possible that some localized constraints could emerge depending on the geographic patterns of PEV charging

10.B.3 Gasoline Savings

A fleet penetration rate of 5 percent reduces the gasoline consumption in New England by about 200 million gallons in 2020 (assuming that PEVs replace 25 mpg ICE vehicles). This corresponds to roughly 2.5 percent of total current motor-fuel use in New England.[10]

10.B.4 Impact on the Environment

Carbon dioxide (CO_2) emissions from internal combustion engine cars depend on the carbon content of the fuel used, and the fuel economy of the cars (which in turn depends on the technical fuel efficiency and vehicle use, *e.g.*, urban or highway driving). For gasoline-powered cars, the emission rate is about 19.4 lbs/gallon. This corresponds to a total of 11,330 lbs CO_2 emission per year for a car that averages 25 miles/gallon with an average daily commute of 40 miles.[11]

Nitrogen oxide (NO_X) and sulfur oxide (SO_2) emission rates depend, to a great extent, on the exhaust control technologies and the vehicles driving cycles (urban vs. highway). The average emission rates provided by the model developed by Argonne National Laboratory are 0.069 grams of NO_X and 0.006 grams of SO_2 per mile for a standard 25 mpg gasoline-powered vehicle.[12]

Plug-in electric vehicle emissions, on the other hand, depend largely on the emission rates associated with marginal electricity generated to recharge the batteries. Figure 10.3 below shows the marginal generation by fuel type in New England derived from the 2020 Base Case simulations. Annually, natural gas has the largest share on the margin (73 percent), followed by biomass and refuse (12 percent), and then oil (6 percent). During the day, the share of natural gas is about 80 percent, and oil covers most of the remaining 20 percent. However, between 11pm and 8am, biomass and refuse is about 40-50 percent of the time at the margin, and share of natural gas drops to 40 percent.

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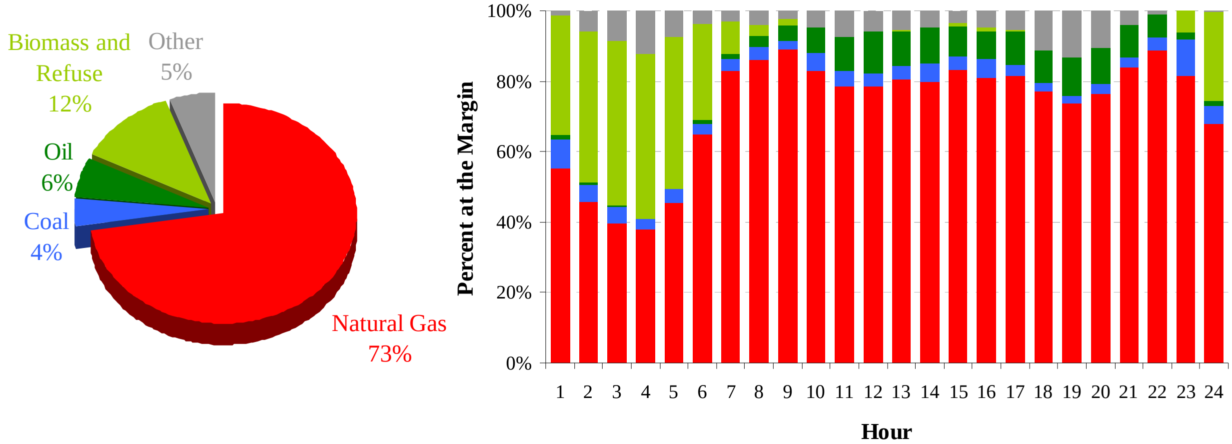
10 U.S. Department of Transportation, Federal Highway Administration, Highway Statistics 2007, Washington, DC: 2008, table MF-21, available at http://www.fhwa.dot.gov/policy/ohpi/hss/hsspubs.cfm as of February 17, 2009.

11 However, this only accounts for the emissions directly generated by the vehicles (*i.e.*, tank-to-wheels). CO_2 emission rate related to the production of gasoline (*i.e.*, well-to-tank) is another 4.6 lbs/gallon, which increases the total emissions to almost 10,000 lbs per year. In these comparisons, we will not consider full fuel cycle emissions of either gasoline or the production of electric generating fuels.

12 http://www.transportation.anl.gov/modeling_simulation/GREET/.

Figure 10.3
New England Marginal Generation by Fuel Type in 2020



Source and Notes:
[1] DAYZER simulation results for 2020 Base Case.
[2] "Other" includes pumped storage, hydro, and nuclear.

Figure 10.4 plots the average marginal emission rates by hour, based on DAYZER simulation results for 2020. Our analysis suggests that marginal emission rates are relatively stable between 10am to 10pm, as the marginal generation mix does not dramatically change. However, the CO_2 emission rates decrease, and NO_X/SO_2 emission rates increase significantly in other hours. These figures suggest that the future New England marginal fuel mix may be quite different than in many other regions, in that CO_2 rates decline in off-peak hours. In contrast, many other electricity systems' overnight marginal fuel mix is dominated by coal, which would yield greater marginal CO_2 emission rates during off-peak hours.

Figure 10.4
Average Hourly Marginal Emission Rates for Electricity Generation in New England in 2020

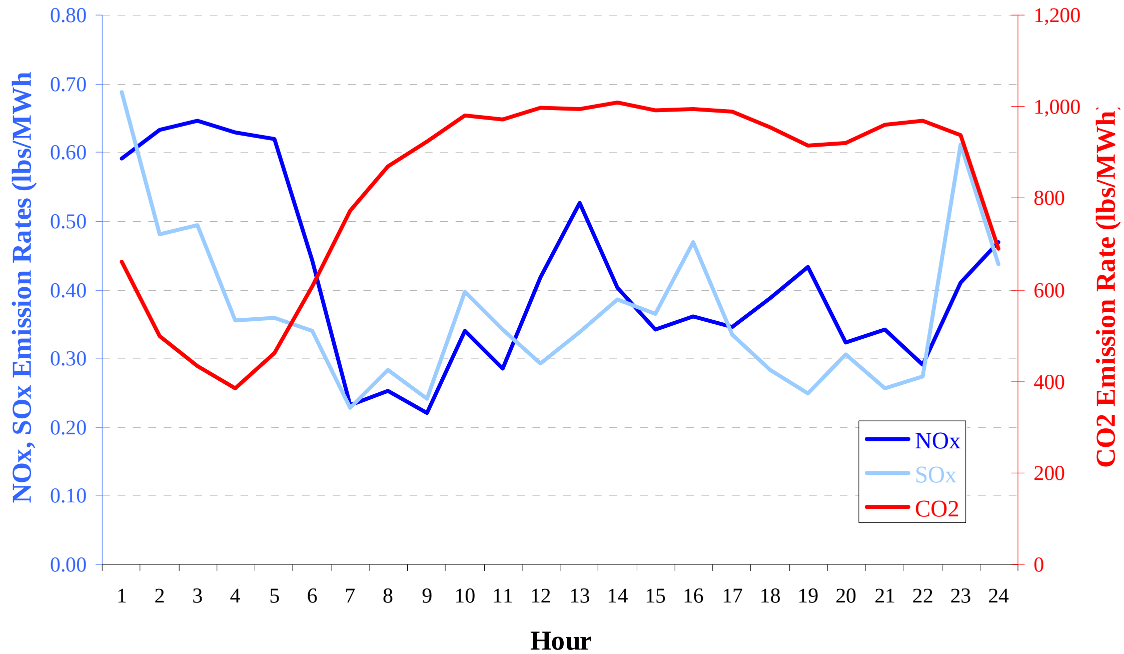
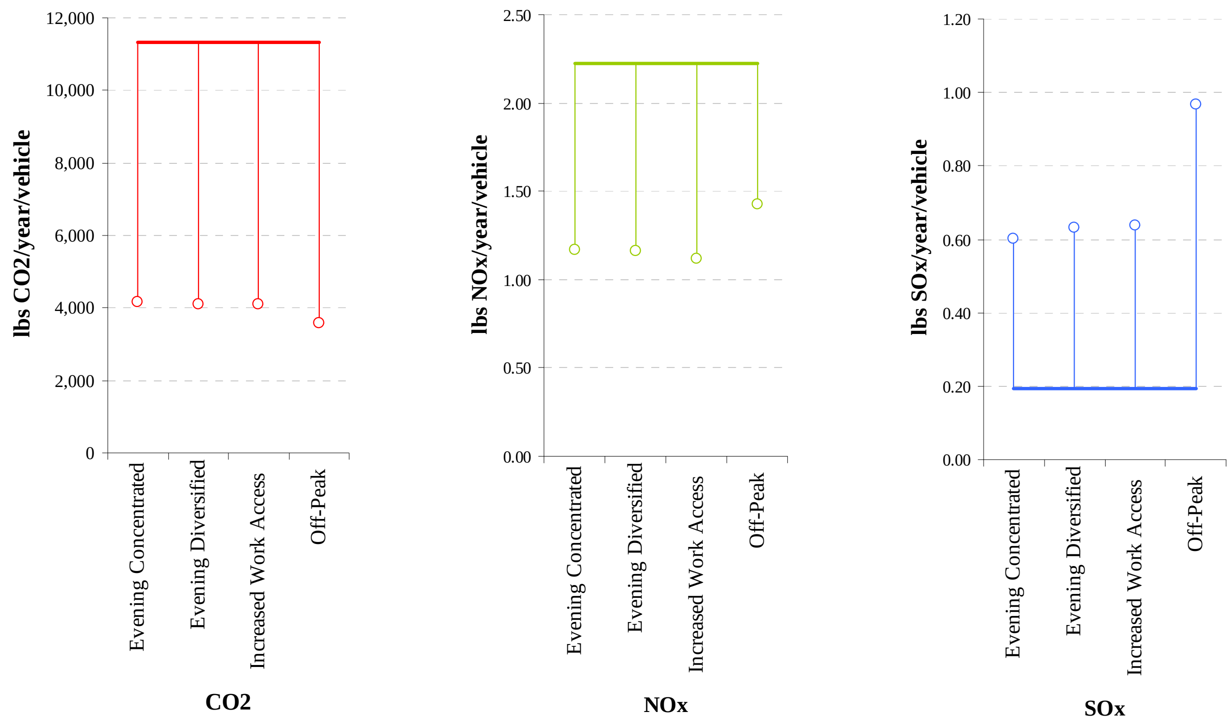


Figure 10.5 compares the emissions from a plug-in hybrid to the emissions from a 25 mpg gasoline ICE. Horizontal bars represent “tank-to-wheels” emissions from the gasoline ICE, which of course are invariant to the charging profile of the PEV vehicle. The circles represent the “direct” emissions from a 40-mile range plug-in hybrid (direct emissions from marginal electricity generation, plus tank-to-wheel emissions from the additional gasoline consumption). The differences between the emissions expected from the PEV and the ICE vehicle is represented by the vertical lines. Since the marginal generation type and emissions are not constant across all hours, the results differ based on charging scenario considered.

In this single-vehicle comparison analysis, CO_2 emissions are reduced by 65 percent to 70 percent for all scenarios, with *Off-Peak* showing the largest reductions because more biomass is at the margin during off-peak hours, with lower CO_2 emission rates. NO_X emissions are reduced by about 40 percent-50 percent for all scenarios, but for NO_X the *Off-Peak* charging pattern yields smaller reductions because biomass typically has higher NO_X emission rates. In contrast, SO_2 emission rates more than triple relative to gasoline ICE, and increase by a factor of five for the *Off-Peak* charging profile.

Figure 10.5
Potential Impact of Plug-In Hybrids on CO_2, NO_X and SO_2 Emission Rates



Assuming that this single vehicle comparison were representative of an overall PEV penetration scenario in 2020, the results can be aggregated to derive the magnitude of emissions changes expected. A 70 percent reduction of CO_2 emissions from 5 percent of the New England passenger car fleet would translate into an overall reduction of 1.5 million tons of CO_2 per year (equivalent to 4 percent of the total CO_2 emissions associated with power generation in New England in 2020). Similarly, a 50 percent reduction in NO_X emissions from 5 percent of the New England passenger car fleet would reduce the emissions by about 250 tons/year (equivalent to 1.5 percent of the total NO_X emissions from power generation in 2020). On the other hand, 400 percent increase in SO_2 emissions from 5 percent of the New England passenger car fleet increases emissions by 170 tons/year (equivalent to less than 0.4 percent of the SO_2 emissions from power generation in 2020). Therefore, an optimistic view of PEV penetration in New England is likely to produce a modest environmental benefit, with net CO_2 and NO_X emissions decreasing and only a negligible increase in SO_2 emissions.

It is important to note that this analysis is only for illustrative purposes, and care must be taken not to generalize the results, as they could readily change for different sets of assumptions (all-electric range, driving cycle, emission control technologies, marginal generation mix, *etc.*). Also, as the incremental load due to plug-in hybrids increase, the incremental generation needed for recharging batteries may not be identical to the marginal generation simulated without accounting for the additional demand (although this potential effect is probably small).

10.C ADVANCED METERING INFRASTRUCTURE

10.C.1 Technology and Pricing Systems

Advanced metering infrastructure (AMI) is a critical component of the "Smart Grid" concept that has gained momentum over the past several years. The Smart Grid represents a broad vision in electricity supply and transmission management, real-time communication, and customer participation. Whether this broad vision is achieved over the next decade or several, the growing interest and investment in AMI and associated enabling customer technologies represents the initial stages of Smart Grid development.

AMI refers to a measurement and two-way data collection system that includes meters at the customer site, communication networks between the customer and a service provider, and data reception and management systems that make the information available to the service provider.[13] Unlike automated meter reading (AMR), it is capable of two-way communication between the customer and the service provider, enabling customers to receive pricing signals and respond to dynamic pricing programs such as critical-peak-pricing (CPP), peak time rebates (PTR) or real-time pricing (RTP).[14] AMI also enables time-of-use (TOU) pricing on a broad scale. Dynamic pricing can decrease the need for peaking generation capacity, reducing energy and capacity costs (generation, transmission, and distribution). AMI also offers operational benefits including faster outage detection, improved energy theft detection capability, enhanced communications with customers, better management of connects and disconnects and avoided meter reading costs (either manual or from an existing automated meter reading system) and could facilitate the integration of distributed generation. However, these benefits must be weighed against the costs of installing AMI systems, which encompasses a range of equipment such as meters, communication systems and IT systems.[15]

The installation of an AMI system would also open the door to a new suite of enabling technologies which would allow customers to take advantage of the enhanced communication capability and more granular usage information that the system provides. One such technology is the programmable communicating thermostat (PCT). With a PCT, a customer's thermostat can receive signals directly from the utility and automatically reduce air-conditioning load in response to critical events. The presence of this technology has been shown to significantly increase customer response to dynamic rates.[16] This concept could be extended to other end-uses within the home as well, such as smart appliances (*i.e.*, washer dryers, refrigerators, etc.), leading to even greater peak reductions (a concept often referred to as "prices-to-devices"). In fact, the Auto-DR system for commercial and industrial customers does exactly that, by coordinating energy reductions at multiple end-uses through a facility's energy management system. These

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[13] Electric Power Research Institute (EPRI).

[14] TOU: price depends on time of use, prices typically varies modestly; CPP: high prices at declared critical peak times, timing is unknown in advance; RTP: linked to hourly wholesale prices, either day-ahead or hour-ahead basis.

[15] Faruqui, A. and L. Wood. *Quantifying the Benefits of Dynamic Pricing in the Mass Market*. Prepared for Edison Electric Institute, January 2008.

[16] *Ibid*.

systems have been shown to produce large incremental increases in customer response as well, depending largely on the size and type of customer that is equipped with the system.[17]

A second type of technology that is enabled by an AMI system is the in-home display (IHD). Whereas the smart meter provides real-time electricity consumption data to the utility, the IHD provides this information to the consumer. The IHD essentially acts as a speedometer for the customer's electricity consumption. It can provide recent information on hourly (or even quarter-hourly) consumption patterns as well as pricing information. Information can also be sent to a website where utilities can give recommendations to customers for easy ways to consume electricity more efficiently to reduce costs. By increasing customer awareness of the relationship between the amount of electricity they consume and the cost of consuming it, IHDs have been shown to produce an overall conservation effect of anywhere between 0 and 28 percent.[18] IHDs can take many forms, from internet websites to simple electrical socket plug-ins to more advanced and interactive display modules.

10.C.2 Recent Activity in AMI in Connecticut

The potential impact of AMI deployment on system peak reduction depends on several factors such as dynamic rate design, customer participation level, and customer responsiveness, factors that interact at the customer levels. For example, alternative rate designs can attract different levels of customer participation and influence the degree of responsiveness to price signals. The amount of peak reduction achievable depends on the type of pricing program that is offered. Time-of-use (TOU) pricing, although not a dynamic pricing program, typically generates less peak reduction than critical-peak-pricing (CPP) or peak-time rebates (PTR).

Of course, some loads in Connecticut and New England, particularly large industrials, already have some version of advanced metering installed, and the Demand-Side Management section evaluates the effect of existing and planned DSM programs, some of which rely on AMI. UI has had a version of advanced metering in place for nearly a decade, which has enabled about 13 percent of its residential customers to elect TOU pricing rates, and over 25 percent of its commercial customers. UI has also proposed to enhance their metering system to AMI and explore dynamic pricing systems.[19] UI's approved plan outlines the manner in which UI intends to "migrate" to an enhanced (*i.e.*, full mesh, two-way communication) AMI system in a scalable and flexible manner that maintains full current system capabilities while allowing for full deployment of "smart" meters throughout the service territory, where appropriate and where required. This approach meets customer, supplier and regulatory needs, is a cost effective approach and maintains UI's "smart metering system" for all consumers and rate payers. This approach is a low cost solution that will enable the utilization of emerging technologies, allow for a more robust communication network, and be capable of incorporating "smart" meter

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[17] G. Wikler *et al.* "Enhancing Price Response Programs through Auto-DR: California's 2007 Implementation Experience," prepared for Lawrence Berkeley National Laboratory, January 2008.

[18] EPRI. Characterizing and Quantifying the Societal Benefits Attributable to Smart Metering Investments. July 2008.

[19] UI submitted its proposal *Advanced Metering Infrastructure Plan* to the DPUC (Docket No. 07-07-02) in July 2007. The DPUC approved the UI plan in a March 19, 2008 decision.

installations where required. The system would also enable future benefits such as home automation, full programmability and firmware upgrade of meters and internal disconnect switch, to name a few. This, in concert with the Meter Data Management (MDM) and Customer Information System (CIS) system upgrade/integration will enable all future requests for enhanced services, rates, Real Time Pricing/"Dynamic Pricing" (RTP) and options.

CL&P conducted a Rate Pilot and the Meter Study from June 1, 2009 through August 31, 2009, in order to ascertain the magnitude of potential impacts of AMI coupled with dynamic pricing. The pilot, branded the "Plan-it Wise Energy Program," helped gain insight into customer interest in, and response to, dynamic pricing rates, while at the same time gathered experience and insight into the capabilities and maturity of certain AMI technologies.[20] The pilot enrolled 1,251 residential customers and 1,186 commercial and industrial (C&I) customers and offered three types of rates:

- A critical peak pricing (CPP) rate that used higher rates during 40 "critical peak" hours over 10 designated event days, and offered slightly lower rates otherwise
- A peak time rebate (PTR) rate that retained normal rates but provided a significant rebate for reducing energy consumption during 40 critical peak hours
- A time-of-use rate that featured static differentials between peak and off-peak hours.

Table 10.1 shows the rate differentials for the three rates in $/kWh.

Table 10.1
Rate Price Differentials by Rate Design
($/kWh)

	RATE->	TOU		PTR		CPP	
Customers	**Period**	Low	High	Low	High	Low	High
Residential (Rate 1 & 5)	Peak	0.071	0.142	0.655	1.614	0.655	1.614
	Off-Peak	-0.029	-0.058	0.000	0.000	-0.015	-0.036
C&I (Rate 30 & 35)	Peak	0.069	0.138	0.650	1.601	0.650	1.601
	Off-Peak	-0.031	-0.062	0.000	0.000	-0.020	-0.049

Some participants were given enabling technologies such as PCT or central air conditioning switches to assist them to manage energy use to determine what impact such technologies might have on customer responses.

[20] Docket No. 05-10-03 DPUC, Compliance Filing, December 1, 2009.

The results of the pilot program were deemed useful in assessing the prospects for wider deployment of AMI and dynamic pricing systems. As expected, the two dynamic rates (CPP and PTR) elicited the greatest customer response (especially for residential customers), while TOU rates had very little impact. Enabling technologies has a measurable impact on enhancing customer response under dynamic rates. Overall energy consumption remained about the same under all rates. The results on measured peak load and energy use are shown in Table 10.2.

Table 10.2
Demand Impact Results of CL&P Pilot Program

Customers	Period	TOU High Diff.	TOU With Tech	PTR High Diff.	PTR With Tech	CPP High Diff.	CPP With Tech
Residential (Rate 1 & 5)	Peak Load Reduction	-3.1%		-10.9%	-17.8%	-16.1%	-23.3%
	Monthly consumption change	-0.1%		-0.2%		+0.2%	
C&I (Rate 30 & 35)	Peak Load Reduction	0%		0%	-4.1%	-2.8%	-7.2%
	Monthly consumption change	0%		0%		0%	

The results of the pilot suggest that dynamic price programs could reduce participating customers' peak energy use by somewhere between 11 and 23 percent in the residential sector, and up to 7 percent in the C&I customer class. Caution must be used in generalizing the results of the pilot program, since the customers who opted into the pilot might not be representative of average customer responsiveness over longer time periods, not all customers would elect to participate in a broader AMI effort and the summer of 2009 was unusually mild. Based on results and insights gained from the pilot, CL&P is evaluating the cost-effectiveness of a future AMI and dynamic rate program, and will present its recommendations to the DPUC by March 31, 2010.

While revealing important insights into potential customer responsiveness, the pilot program did not explore many other interactions that may prove important over the long run. For example, as was discussed above, if plug-in vehicles achieve significant market penetration, AMI may become particularly important as a way to manage the new transportation loads. This may provide a particular motivation for increasing AMI for residential customers. The pilot program also did not fully explore the potential impact of AMI on customer energy consumption habits or conservation efforts.

In summary, widespread implementation of AMI has the potential to decrease peak loads. The magnitude of the decrease will depend on customer participation rates in dynamic pricing programs and their responsiveness to near-term price signals. Enabling technologies can help customers respond more effectively to price signals, and AMI programs that encourage these technologies are more likely to yield more pronounced responses.

APPENDIX: 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.