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STATE OF CONNECTICUT

DEPARTMENT OF PUBLIC UTILITY CONTROL
TEN FRANKLIN SQUARE
NEW BRITAIN, CT 06051

DOCKET NO. 10-02-07 DPUC REVIEW OF THE 2010 INTEGRATED RESOURCE PLAN

Jacobs Exhibit No. 2208
Date 1/31/11 Reporter NS
File No. ER-2010-0355

September 15, 2010

By the following Commissioners:

Amalia Vazquez Bzdyra
Kevin M. DelGobbo
Anthony J. Palermino

DECISION

I. INTRODUCTION

A. SUMMARY

Pursuant to the General Statutes of Connecticut (Conn. Gen. Stat.) §§ 16a-3a through 16a-3c, the Department of Public Utility Control (Department) approves with modifications, the 2010 Integrated Resource Plan (IRP) submitted by the electric distribution companies (EDCs) and the Connecticut Energy Advisory Board (CEAB). The Department agrees with the EDC and CEAB assessment that Connecticut is not forecasted to have a shortage of any energy or capacity requirements during the statutorily-defined planning horizon. The Department finds that no further action needs to be taken at this time to procure new energy or capacity resources. However, because uncertainties exist, the Department will carefully monitor resource need. As such, the Department will initiate a process to develop a Request for Proposal (RFP) and evaluation methodology for repowering and other resources so the Department is ready to act quickly should the need for a procurement occur. The Department supports more conservation but does not endorse a significant increase in ratepayer funding at this time. The Department believes that there are sufficient renewable resources to meet the State's Renewable Portfolio Standard (RPS) over the next few years. However, the supply and cost to meet our renewable resource requirements is more uncertain over the longer term. The Department supports a re-evaluation of the State's RPS requirements to 2020.

B. DEPARTMENT'S LEGAL REQUIREMENTS REGARDING THE IRP

On January 1, 2010, the EDCs submitted their Integrated Resource Plan for Connecticut (EDC Plan) to the CEAB pursuant to Conn. Gen. Stat. § 16a-3a(b). On April 27, 2010, pursuant to Conn. Gen. Stat. § 16a-3a(e), the CEAB submitted its review of the EDC Plan entitled, 2010 Comprehensive Plan for the Procurement of Energy Resources (CEAB Plan) to the Department.

The Department finds that the EDCs and the CEAB have complied with Conn. Gen. Stat. §§ 16a-3a(b) and 16a-3a(e), respectively.

Pursuant to Conn. Gen. Stat. § 16-3a(e), the Department must consider the CEAB Plan filed on April 27, 2010, in an uncontested proceeding, conduct a hearing and provide a opportunity for interested parties to submit comments regarding the CEAB plan. Not later than 120 days after the CEAB files its plan, the Department must approve or modify and approve the CEAB plan.

C. CONDUCT OF THE PROCEEDING

The Department has recognized the following as participants in this proceeding: Comverge, Inc. 4 Woodhaven Road, Newton, MA 02468; Constellation Energy

Commodities Group, Inc., 111 Market Place, Suite 500, Baltimore, MD 21202; Constellation Energy Group, 1810 7th Ave, Suite 400, New York, NY 10019; Constellation Energy Resources, LLC, 100 Constellation Way, Suite 500C, Baltimore, MD 21202; Constellation New Energy, 280 Trumbull Street, Hartford, CT 06103-3597; The Connecticut Energy Advisory Board, 450 Capital Avenue, Hartford, CT 06106; The Connecticut Clean Energy Fund (CCEF), 200 Corporate Place, Rocky Hill, CT 06067; Connecticut Light and Power Company (CL&P), P.O. Box 270, Hartford, CT 06141-0270; Office of the Attorney General (AG), Ten Franklin Square, New Britain, CT 06051; Office of Consumer Counsel (OCC), Ten Franklin Square, New Britain, CT 06051; EnerNoc, Inc., 75 Federal Street, Suite 300, Boston, MA 02110; Environmental Energy Solutions, 38 Brookmoor Road, West Hartford, CT 06107; Environment Northeast (ENE), 15 High Street, Chester, CT 06412; FirstLight Power Resources, Inc., 20 Church Street, 16th Floor, Hartford, CT 06103; Kleen Energy Systems, 90 State House Square, Hartford, CT 06103; NRG Energy, Inc, 211 Carnegie Center, Princeton, NJ 08540-6213; New England Power Generators Association, Inc., 141 Tremont Street, Sixth Floor, Boston, MA 02111; Plainfield Renewable Energy, LLC, 20 Marshall Street, Suite 300, Norwalk, CT 06854; and the United Illuminating Company (UI), 157 Church Street, P.O. Box 1564, New Haven, CT 06506-0901.

Pursuant to Conn. Gen. Stat. § 16a-3a(e), the Department conducted an uncontested proceeding on this Docket. The Department held a hearing on June 2, 3, 4, 7 and 16, 2010, on this matter in the offices of the Department, Ten Franklin Square, New Britain, Connecticut 06051.

II. PARTICIPANT IRP SUBMISSIONS

A. SUMMARY OF EDCS' MAJOR FINDINGS AND RECOMMENDATIONS

On January 1, 2010, the EDCs presented the 2010 EDC Plan, prepared by The Brattle Group, to the CEAB. The EDC Plan builds upon the EDC Plans submitted in 2008 and 2009. The EDC Plan received input from the following stakeholder groups: Connecticut Department of Environmental Protection (DEP), CCEF, ISO-NE, electric generators, and other industry stakeholders and the public. The EDC Plan found that there is no current need for additional resources during the statutorily-mandated IRP planning horizon through 2020, consistent with the findings in the 2008 report. Summarized below are the EDCs' primary findings associated with the submitted white papers:

1. EDC Findings

1. Assuming the New England states are successful in building sufficient new renewable generation and associated transmission to meet each state's RPS requirement, there is no need for additional generation resources to meet resource adequacy requirements during the next ten years, under a wide range of future demand assumptions.

2. Using reasonable assumptions regarding supply and demand transmission, Connecticut has sufficient generation installed or under contract to assure locational

resource adequacy requirements for reliability over the next ten years, even if significant uneconomic, high-emissions generating plants retire.

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

4. A targeted expansion of Demand Side Management (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 I RPS, the region needs to add approximately 4800 MW of new renewable generation, primarily wind, that will be located in areas distant from load centers, which would require investments of approximately $20 billion in new renewable generation and about $10 billion in investment in transmission resources to access this new renewable generation.

6. Assuming the Class I renewable generation additions and continuation of the Connecticut DSM measures, New England's CO_2, NO_x and SO_2 emissions in 2020 will be significantly below 2007 actual levels.

7. New England electric rates are highly dependent on natural gas prices. It is forecasted that the large supply of economically viable shale gas, which can be found in New York and Pennsylvania, may allow natural gas prices to remain moderate and help to moderate energy prices.

EDC Plan, p. I-3.

2. EDC Recommendations:

Based on the analysis undertaken, the EDC Plan contains two primary resource procurement recommendations to be implemented immediately:

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

The EDC Plan includes a third recommendation regarding additional study:

3. UI recommends, in light of the potential benefits of a nuclear strategy identified in EDC Plan, 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.

EDC Plan, p. I-4.

3. EDC Plan Resource Strategy Scenarios

In addition, the EDC Plan examined six resource strategy scenarios:

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

EDC Plan, pp. II-26 – II-27; Sections II and III.

A seventh resource strategy for nuclear energy was developed for illustrative reasons, because it would not be possible to develop and construct a new nuclear plant in Connecticut in the ten-year scope of the IRP. EDC Plan, Section III.5.

B. SUMMARY OF FINDINGS IN EDC IRP WHITEPAPERS

The EDC 2010 IRP, Section III contained ten white papers. The main analyses and conclusions are summarized below:

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

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 Department in its February 18, 2009 Decision in Docket No. 08-07-01, DPUC Review of the Integrated Resource Plan for procurement absent an immediate reliability need by reducing total customer costs and CO_2 and NO_X emissions in all five 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 five 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.

Funding the Targeted DSM Expansion strategy would require an additional outlay of approximately $19 million per year (2010 dollars). 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.

3. Renewable Energy

Connecticut has limited cost-effective renewable potential in-state. Moreover, an in-state renewable strategy would rely heavily on natural gas powered fuel cells, and would not significantly abate CO_2 emissions.

The optimal strategy for meeting the State's RPS requirement is to procure renewable energy as part of a New England regional market. The RPS requirements of the New England states are likely to be met through 2012. Renewable potential in New England is substantially larger than needed to meet the 2020 RPS. Landfill gas, biomass, small hydro, and onshore wind are estimated to require Renewable Energy Credit (REC) prices that are below the Connecticut's Alternative Compliance Payment (ACP). However, fuel cells, offshore wind, and solar PV would require payments greater than the ACP and would require additional subsidies or out-of-market instruments to be developed.

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.

Constructing sufficient new renewable generation in New England would require a major capital investment, about \$20 billion for the generation plus \$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 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 proposed a process to 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., the Department, 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 by participating in regional processes.

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

Connecticut already enjoys high penetration of combined heat and power (CHP) for the most attractive large industrial applications, so there is limited remaining potential in this sector. However, smaller, mostly commercial and institutional applications have significant remaining technical potential in Connecticut.

7. Environmental Regulations Affecting Electricity

The EDC Plan included a range of CO_2 prices in its analysis. Since 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 the DEP have 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; the analysis showed the price of CO_2 allowances can influence the price of SO_2 and NO_X allowances.

8. Energy Security

The power system is planned, designed, and operated to maintain high energy security, building in spare capacity, redundancy, and operational flexibility. National, regional, and state agencies 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. Resources such as oil, coal, and renewables are unlikely to pose similar energy security concerns.

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 other adequate generation resources available to serve winter load, with little or 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.

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.

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 liquified natural gas (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 $4.00-10.00/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

Plug-in electric vehicles (PEV) appear poised to achieve an uncertain but potentially significant fleet penetration over the next decade. A five percent level of fleet penetration by 2020 represents an optimistic view of PEV vehicle sales growth. This level of PEV penetration in New England is unlikely to pose any unmanageable issues for maintaining reliable electric service. The forecasted level of PEV penetration in New England is likely to produce a modest CO_2 and NO_X emissions decrease and 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. AMI programs that encourage these technologies are more likely to yield more pronounced responses.

C. CEAB PLAN

1. 2010 Procurement Plan

In its CEAB Plan, the CEAB established the following key objectives that will drive the need for energy resource implementation over the next decade: (1) provide electric services at an affordable and competitive cost, (2) reliability, (3) improve environmental performance of the electric system, and (4) energy independence and security.

The CEAB noted the following key drivers that underlie energy resource planning:

1. Connecticut and New England are, and will likely continue to be, dependent on natural gas for significant portions of the power supply.
2. Connecticut and other New England states are required to fulfill renewable portfolio standards that will require an approximate 400 percent increase in renewable energy by 2020.
3. Connecticut resource planning must comply with stringent air and water quality regulations.
4. Resource planning must accommodate regional, and possibly, national greenhouse gas emission limits.
5. Many of the resource options under consideration will require significant financing.
6. Connecticut's electric resource demands will need to meet the changing demographics and business activity of its citizens.

CEAB Plan, pp. 6-9.

In evaluating Connecticut's electric system needs and the aforementioned key objectives and drivers, the CEAB considered the following resource portfolio planning options and achieved the following results:

1. Maximize Achievable Energy Efficiency – Across a range of cases and sensitivities evaluated, maximizing the identified cost-effective potential for energy efficiency resources provided the most desirable cost and environmental result, significantly more cost effective during the first ten years and the next ten years thereafter than the range of supply-side alternatives considered.
2. Renewable Energy Development – New England states' RPS requirements, including Connecticut's 20 percent renewable requirement by 2020, will require approximately 4,000 MW of new renewable projects over the next ten years. Meeting Connecticut's aggressive RPS requirement raises several concerns: (a) the ability of market mechanisms to develop the resources on schedule, (b) transmission investments needed to transport renewable resources, (c) the high cost of renewable resources and transmission, and (d) given these high costs, the opportunity cost to Connecticut of developing these resources. CEAB raises the issue whether to reassess the RPS policy in effect for the next ten years.

3. Proactive Assessment of Transmission and Alternatives – The CEAB proposes a Proactive RFP approach to alternatives assessment and plans to undertake that process to the Hartford-area Needs Assessment study now beginning at ISO-NE.
4. Development of Natural Gas Generation – The CEAB's analysis indicates that the region will remain reliant on natural gas in the foreseeable future. Natural gas remains a clean and economically attractive fuel for repowering old fossil fuel plants. However, the reduced growth rate of electric demand due to the economic slowdown and continued Energy Efficiency (EE) programs suggest that procurement for natural gas plants would be premature.
5. Prepare Options for the Future – The CEAB looks toward 2030 in considering lead time for planning for additional energy resources such as emerging end use technologies, nuclear power, imports of hydro power or renewable energy from Canada. The CEAB recommends that Connecticut policymakers begin to plan for the development of these technologies.

CEAB Plan, pp. 12-20.

2. CEAB Findings and Recommendations

The CEAB made the following findings based on the information and planning scenarios in its Plan.

1. Overall, the resource needs over the coming decade are defined by economic and environmental factors. A number of factors lead to the overall cost of power supply to increase, including transmission costs, RPS costs, fuel prices, and, potentially the cost to meet carbon reduction goals. Demand-side resources best meet the combination of economic and environmental objectives.

2. The State and the region are likely to have ample installed capacity to meet resource adequacy for the coming decade assuming current load projections, aggressive regional demand-side programs, development of renewable resources to meet regional RPS targets, and limited retirements of existing fossil steam generation. Reference Case demand-side resources and build-out of renewable to meet the RPS will, if implemented, add significant capacity resources to the State and regional supply over this period.

3. Reliability issues, if any, are most likely to arise as a result of the ISO-NE study of the remaining New England East-West Solution (NEEWS) transmission project and the four area studies underway within Connecticut.

4. Economic analysis of energy efficiency potential shows economic benefits of an aggressive demand-side program to be significant under a broad range of scenarios and assumptions over the longer-term.

5. The estimated cost of renewable energy projects needed to meet Connecticut and regional RPS requirements are high, due to both the amount of supply called for in the RPS and the expected cost of the resources. The scale of the RPS requirement over the next decade could require transmission expansion to integrate those resources into the regional grid.

6. The environmental performance of the Connecticut power system must meet more stringent NO_x emissions in the coming years. Demand-side resources help meet these requirements, along with some assumed retirements and added emissions controls.

7. Under Waxman/Markey-like Federal carbon cap-and-trade regimes, carbon emissions in the region decline somewhat over the planning horizon, due to the addition of RPS renewables and the significant reduction in coal-fired power production when carbon allowance costs approach $30/ton.

CEAB Plan, pp. 20 and 21.

The CEAB made the following procurement recommendation:

1. Maximize the utilization of demand-side resources to achieve all cost-effective energy efficiency (A-ACE) while minimizing ratepayer impacts through the use of expanded financing options, market mechanisms, codes and standards, and other innovative approaches.

CEAB Plan, p. 22.

The CEAB made the following planning recommendations:

1. Conduct a public stakeholder process to fully review Connecticut's renewable portfolio standard and renewable energy policy to assure the policy is consistent with the current objectives of the State.

2. Develop a proposal for the legislature to restructure Connecticut's energy-related entities to provide a single State entity for oversight and accountability of energy policy and planning.

3. Strengthen the CEAB and State connections and coordination with ISO-NE, New England States Committee on Electricity (NESCOE) and other regional organizations whose decision-making directly impacts electric system costs for Connecticut.

4. The CEAB will implement a proactive planning and RFP process, in conjunction with the Department, to assure that Non-Transmission Alternatives (NTAs) to proposed transmission solutions are properly investigated, solicited and, if and as needed, successfully implemented.

5. Collaborate with ISO-NE in its Needs Assessment and Transmission Solutions studies for the Greater Hartford area. Conduct a concurrent assessment of the potential for non-transmission solutions to address the identified reliability need. If warranted, conduct a proactive RFP for non-transmission alternatives.

6. Identify opportunities and promote development of CHP and district energy development.

7. Prepare a potential procurement for efficient, combined-cycle gas unit(s) or comparable facilities following the 2012 IRP process by 2020.

8. Proceed with Connecticut Academy of Science and Engineering (CASE) to study the State's capabilities for nuclear energy options.

CEAB Plan, pp. 24-36.

D. OTHER PARTICIPANTS

The following participants also submitted prefiled testimony.

1. OCC

The OCC's consultant, Levitan & Associates, Inc. (LAI) presented prefiled testimony and evaluated the EDCs' and the CEAB IRP Plans. LAI's major conclusions are as follows:

1. The net benefits of the EDCs' Targeted DSM and CEAB's A-ACE scenarios are overstated and uncertain. Non-participants are likely to see their rates increase under both of these scenarios.

2. No additional funding for DSM in excess of the existing three mill charge is warranted in the near-term.

3. There is no need for conventional supply side resources in Connecticut or the region in the next ten years. However, re-evaluation of the need for procuring new or repowered resources should be undertaken in the 2012 IRP.

4. The OCC concurs with the EDCs and the CEAB that requiring new renewable energy sources to be located in Connecticut would create a significant economic burden on the State's ratepayers.

5. Solar PV energy continues to be the highest cost renewable energy source for Connecticut. The OCC supports evaluating whether additional sources, such as high-head hydro-electric, should be added as an eligible renewable energy source.

LAI PFT, pp. 43-45.

2. CCEF

The CCEF supports the CEAB's recommendation to initiate a public stakeholder process to review the Connecticut RPS and its role in the development of renewable energy projects in the state and the region. The CCEF notes that the cost of renewable resources has declined over time. The development of in-state renewable energy will confer benefits to the state but will be costly. CCEF PFT.

3. ENE

ENE supports the EDCs' proposed All Achievable Cost-Effective DSM strategy, and recommends that the target spending and efficiency levels be ramped up within five years. ENE also supports the CEAB's recommendation to pursue the A-ACE DSM strategy. ENE believes that both the EDCs' and CEAB's strategies minimize the cost of resources and maximize the benefits to customers over time, as required by Conn. Gen. Stat. § 16a-3a. ENE PFT, pp. 2 and 3.

4. Algonquin Power

Algonquin Power (Algonquin) supports the development of long-term purchased power agreements (PPAs) between CHP/cogeneration facilities and the EDCs, subject to approval by the Department, as a means of promoting the development of CHP/cogeneration facilities in Connecticut. According to Algonquin, CHP/cogeneration participation in the ISO-NE regional electric market is overly complex and costly for small facilities; a long-term PPA with an EDC would foster more CHP and cogeneration in the state. Algonquin PFT.

III. DEPARTMENT ANALYSIS

A. RESOURCE ADEQUACY

1. EDC Analysis

The EDCs projected that the supply of capacity over the next ten years will 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 lower load forecast than used in the past due to the economic downturn; 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 DEP imposes strict NO_X emissions rate limits, and the ISO-NE abolishes the capacity price floor, the EDCs estimated 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. EDC Plan, p. II-3.

Two of the seven EDC primary findings are related to meeting resource adequacy requirements are:

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

2. 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 if the New England states are successful in building enough new renewable generation and associated transmission to meet RPS requirements.

EDC Plan, p. I-3.

ISO-NE defines four separate resource adequacy requirements to ensure that there is sufficient capacity to meet expected load and ensure system reliability. The four resource adequacy requirements that affect Connecticut are:

1. ISO-NE-wide Net Installed Capacity Requirement (NICR), which is an ISO-wide requirement to meet a one day in ten years loss-of-load expectation;

2. Connecticut Local Sourcing Requirement (CT LSR) is intended to ensure that sufficient capacity is physically located in a sub-area to maintain local reliability;

3. Connecticut requirement under the Transmission Security Analysis (CT TSA), is a more stringent local requirement that is essentially the ISO's 90/10 peak load forecast plus the capacity required to cover the area's first-order generation contingency which is Millstone 3, or 1,235 MW; and

4. Connecticut requirement in the Locational Forward Reserve Market (LFRM), which provides for local second contingency coverage in the form of non-spinning thirty minute reserves (fast-start capacity).

EDC Plan, p. II-5.

The EDCs claim that these requirements are likely to be met and will have surplus capacity through 2020 and beyond. An important element of the projections is the inclusion of the 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 electrically into the Connecticut sub-area. EDC Plan, p. II-5.

2. CEAB Analysis

The CEAB believes that Connecticut will likely have adequate resources for reliability, as defined by ISO-NE under its current criteria, through 2030 even with assumed retirements of 1,500 MW and assuming all four components of NEEWS are constructed as planned. Under the CEAB Reference Case assumptions, Connecticut surplus does not fall below 500 MW through 2020, while in the same period, the New England regional surplus does not fall below 1,000 MW. Through the next two decades there is generation surplus for Connecticut except under the Local Sourcing Requirement (LSR) criteria in 2030. Key reasons for the Connecticut surplus are slower growth in demand, the expected continued demand response (DR) participation and energy efficiency program expenditures at the current level, along with the recent commitments to new generation and transmission. CEAB Plan, pp.102 and 103.

The ISO-NE region is also in a strong reliability position as a result of the region's plans and targets for energy efficiency, demand response and renewable generation all of which contribute to the surplus on both a regional and in-state basis. CEAB Plan, p.103.

Although Connecticut surplus is expected to be approximately 2,000 MW in 2020, which includes roughly 1,200 MW of existing oil/gas and coal steam fired generating capacity after accounting for 1,500 MW of retirements, there are several resource contingencies that need to be considered relative to this surplus. Out to 2030, the need for local capacity could be triggered by generation retirements, deferral of regional transmission upgrades, or more localized reliability needs. CEAB Plan, p.104.

If the Interstate and Central NEEWS components are not built by 2014 as planned, an additional 1,300 MW of capacity would be required to maintain the same level of surplus. Importantly, if these components are not built, they would reduce the assumed transfer limit and leave the 766 MW Lake Road facility electrically outside of Connecticut. Though there may be alternative ways to bring Lake Road generation to Connecticut, without these NEEWS components, an in-state resource adequacy need could arise within the next decade. CEAB Plan, p.104.

In addition, although it is already under construction and has the commitment of a long-term contract with Connecticut, the recent accident at the Kleen Energy (Kleen) plant has created some uncertainty regarding Kleen's future. It is not yet clear that the 620 MW Kleen gas-fired combined cycle plant will move forward on its proposed schedule to be operational by June 2011. CEAB Plan, p.104.

Another contingency is the impact of higher load growth. Like the EDCs, the CEAB analysis assumes load growth based upon the ISO's 2009 Capacity, Energy, Loads and Transmission (CELT) forecast that reflects normal weather ("50/50") and base economic growth conditions. If higher load growth should result, such as the 2009 CELT's 90/10 projection, then Connecticut may have its surplus reduced by 1,186 MW compared to that projected under the Reference Case assumptions. Though more recent ISO-NE load projections have actually decreased projected load growth, this remains something to monitor. CEAB Plan, pp.104 and 105.

The outlook for 1,500 MW of retirements is also subject to uncertainty. Changes in regional or federal carbon legislation or other environmental policies such as legislated reductions in impacts to marine habitat from generation plant cooling systems could result in a higher level of retirements. Most generation at risk is existing coal-fired unit that would be heavily impacted by proposed federal carbon legislation. CEAB Plan, p.105. Under policies resulting in reference level carbon prices that could result from the Waxman-Markey Bill[1], coal-fired units will become less economically viable due to

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[1] The Waxman-Markey Bill, H.R. 2454: The American Clean Energy and Security Act of 2009, was passed in June 2009 by the full House but as of today, it has not been voted on in the Senate. It is a cap and trade bill that plans to reduce American greenhouse gas emissions to 20% below 2005 levels by 2020, and to 83% below 2005 levels by 2050. It also mandates that 25% of the nation's energy be produced from renewable sources by 2025, creates new energy efficiency programs, puts limits on the carbon content of motor fuels, and requires greenhouse gas standards for new heavy duty vehicles and

lower expected capacity factors. This creates the risk of coal unit retirements due to economic obsolescence and may result in 564 MW of additional retirements in Connecticut not assumed in the Reference Case. Moreover, all aging steam capacity in the region may face obsolescence from potential costs to address environmental challenges like ozone standards and water intake impacts. This places an additional 645 MW in Connecticut at risk for retirement. All of these sensitivity factors must be monitored as Connecticut continues its resource planning efforts over the next several years. CEAB Plan, p.105.

CEAB concluded that Connecticut has adequate resources for reliability, as defined by ISO-NE criteria. Connecticut has resource options at its disposal if needed to address potential resource adequacy concerns in the future, which would support State goals of maximizing DSM, and meeting RPS targets. CEAB Plan, p.110.

3. OCC Position

The OCC states that Connecticut is in a capacity surplus position and is expected to remain in a capacity surplus position throughout the next ten years. Although a number of market-related events could significantly reduce the magnitude of the capacity surplus, the OCC believes that the likelihood of a capacity deficit arising over the planning period is very low. The OCC also believes there will be a much higher level of certainty surrounding these market conditions in the 2012 IRP time frame. The OCC claims that for this reason and others, the evidence before the Department supports the OCC view that the benefit of waiting until 2012 to consider procuring new resources outweighs the risk of not proceeding at once. OCC Brief, p.1.

The OCC found that under the Reference strategy formulated in the EDCs' Plan, a capacity surplus will persist in Connecticut through 2020, even assuming that a total of about 1,500 MW of the State's steam turbine generators (STGs) permanently retires by 2016. The CEAB Plan arrived at a similar result.

The resource adequacy analysis results in a capacity deficiency prior to 2020 only under extreme conditions if:

1. the Kleen project is cancelled;
2. only the Greater Springfield Reliability Project (GSRP) portion of NEEWS is constructed; and
3. all 1,500 MW of Connecticut's old-style steam STGs indeed retire by 2016.

Under these extreme conditions, the EDCs forecast a small resource deficiency starting in 2016 – about 100 MW for the LSR analysis, and about 300 MW for the TSA analysis. The OCC asserts that this combination of market conditions is highly improbable. Therefore the likelihood of a capacity deficit materializing in Connecticut on

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engines. This bill would give away most of the initial carbon credits, auction off some, and then use the proceeds to give subsidies to some industries including coal as well as to low-in-come tax payers. It explicitly states that the new cap and trade system it creates will replace any regulation promulgated by the Environmental Protection Agency under the authority of the Clean Air Act. http://www.govtrackinsider.com/articles/2010-04-27/climate-change.

or about 2016 is low. If transmission security objectives are in jeopardy, ISO-NE would not allow needed capacity resources in Connecticut to retire. Furthermore, if the capacity overhang incorporated in the EDCs' Plan diminishes at a faster rate than contemplated in the EDCs' capacity price forecast, there would be upward pressure on FCM prices resulting in greater supply elasticity. STG units that were predicted to retire under the EDCs' Reference strategy attrition model would be financially revitalized by higher capacity revenues, thereby making it easier to rationalize incremental investment in required environmental upgrades while operating under more stringent regulations. Higher capacity prices under the FCM would also attract new DSM resources. The OCC believes that under the range of scenarios contemplated in this proceeding, it is difficult to construe a likely scenario that would result in a significant capacity resource deficit prior to 2020. OCC Brief, pp. 37-36.

Mr. Shuckerow of CL&P concurred that issues surrounding Kleen and NEEWS will become more certain in two years, but they will be replaced with other uncertainties two years from now. Tr. 6/3/10, p. 431. The OCC agrees that there will always be economic, market, political and regulatory uncertainties affecting the long-term resource planning process that warrant sensitivity analysis. In this instance, the resource swing of over 2,100 MW attributable to Kleen and NEEWS will likely be resolved in a reasonably short time. In light of the anticipated capacity overhang, Connecticut can afford to delay a procurement decision for a year or so, by which time there is likely to be resolution at ISO-NE regarding the interstate segment of NEEWS and much greater clarity on the timing of Kleen, and greater clarity about carbon reduction. Confirming that these resources will or will not be constructed will sharpen the forecast of Connecticut's need date under the LSR and TSA analyses. Moreover, an assessment of the net benefits of proposed new resources will be facilitated and refined if this uncertainty is removed. OCC Brief, pp. 35-37.

The OCC asserts that if a recommendation to procure new generation resources emerges upon issuance of the next IRP on January 1, 2012, then the regulatory and development timeline would allow for such new resources to be commercialized substantially before 2020. Assuming the Department issues its final decision approving such procurement by August 2012, the RFP process would need to be completed no later than the second quarter of 2014, but reasonable efforts to reduce the RFP process should be exercised in order to shave one or two quarters from the regulatory review process. According to Mr. Milley of NRG, a three to five year period would be required for design, financing and construction thereby culminating in new operational capacity substantially ahead of the EDCs' expected 2021 need date. Tr. 6/7/10, p. 1312. In the unlikely event that a capacity crunch materializes as early as 2016 as shown in Late Filed Exhibit No. 19, the OCC acknowledges that there will not be sufficient time for new or repowered generation assets to achieve commercial operation if the procurement decision is delayed until the next biennial planning cycle. However, the OCC asserts that the risk of a capacity shortfall is low and worth the potential reward associated with investing the time to undertake the requisite analysis of the best repowering plan for Connecticut. If capacity markets tighten in New England, FCM prices will rise, thereby providing incumbent generators that might otherwise retire or mothball with the necessary economic inducement to delay such decisions. OCC Brief, p. 43.

4. Department Analysis of Resource Adequacy

(a) Base Case and Alternative Scenarios

The EDC and the CEAB Connecticut base case plans are the same and were developed upon the following assumptions:

1. The 2009 Independent System Operator of New England (ISO-NE) 50/50 peak load forecast;

2. The 504 MW of peaking facilities under Department contracts come on-line by 2012;

3. PA 05-01 contracts add 716 MW by 2010, which includes the 620 MW Kleen Energy Plant;

4. 140 MW of new capacity cleared in Forward Capacity Auction (FCA) #1, #2 and #3 starting in 2010;

5. Renewable Project 150 supplies 85 MW starting in 2012;

6. New RPS sources increase from 5 MW in 2010 to 83 MW in 2020;

7. Connecticut fossil fired retirements of 696 MW occur in 2013 and 1,504 MW in 2016;

8. The four NEEWS projects come on line in 2014 increasing transfer capability (import limits) by 1,100 MW and the 766 MW Lake Road facility is counted as a Connecticut supply source;

9. Demand Resources increase from 636 MW in 2010 to 1,117 MW in 2020; and

10. Purchase and sales of 100 MW from 2010 through 2020 through the Cross Sound Cable.

Table 1 and Figure 1 illustrate the resource surplus under the three ISO-NE resource adequacy requirements pertaining to Connecticut in the EDC and the CEAB Plans under base case assumptions. Table 1 illustrates that Connecticut is expected to have adequate capacity over the next ten years. Connecticut is projected to have a surplus of over 2000 MW under the CT LSR analysis and over 1,000 MW under the stricter TSA analysis in 2010. The surplus declines significantly in 2013 but then increases again in 2014 and remains high for the rest if the decade.

The large decrease in the 2013 surplus from that in 2012, 747 MW in LSR and 685 MW in TSA is primarily due to the retirement of 696 MW of fossil units. The large decrease in the 2016 surplus from that in 2015, 806 MW in LSR and 780 MW in TSA is primarily due to the retirement of 808 MW of fossil units.

The large increase in the 2014 surplus from that in 2013, 1,917 MW in LSR and 1,802 MW in TSA is primarily due to the four NEEWS projects coming on line and providing 1,866 MW by increasing the transfer limits by 1,100 MW and allowing the 766 MW Lake Road facility to be counted as a Connecticut resource.

The LFRM 260 MW shortfall in 2009 increases to a 244 MW surplus in 2012 due to a Department peaking contract unit coming on line each year beginning in 2010 through 2012 to provide required quick start capacity.[2]

Table 1
Resource Adequacy under EDC Base Case Assumptions (MW)

Local Sourcing Requirement in Connecticut (LSR) Source: EDC Plan, Table 1.A-1

		2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Connecticut Sub-Area 50/50 Peak Load	*a*	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	*b*	n/a	6,496	6,912	7,325	7,433	6,341	6,408	6,455	6,498	6,557	6,625	6,708
Total Installed Capacity in CT	*c*	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)	*c-b*	**n/a**	**2,095**	**2,055**	**1,807**	**1,060**	**2,977**	**2,960**	**2,154**	**2,171**	**2,159**	**2,137**	**2,100**

Connecticut Requirement Under Transmission Security Analysis (TSA) Source: EDC Plan, Table 1.A-2

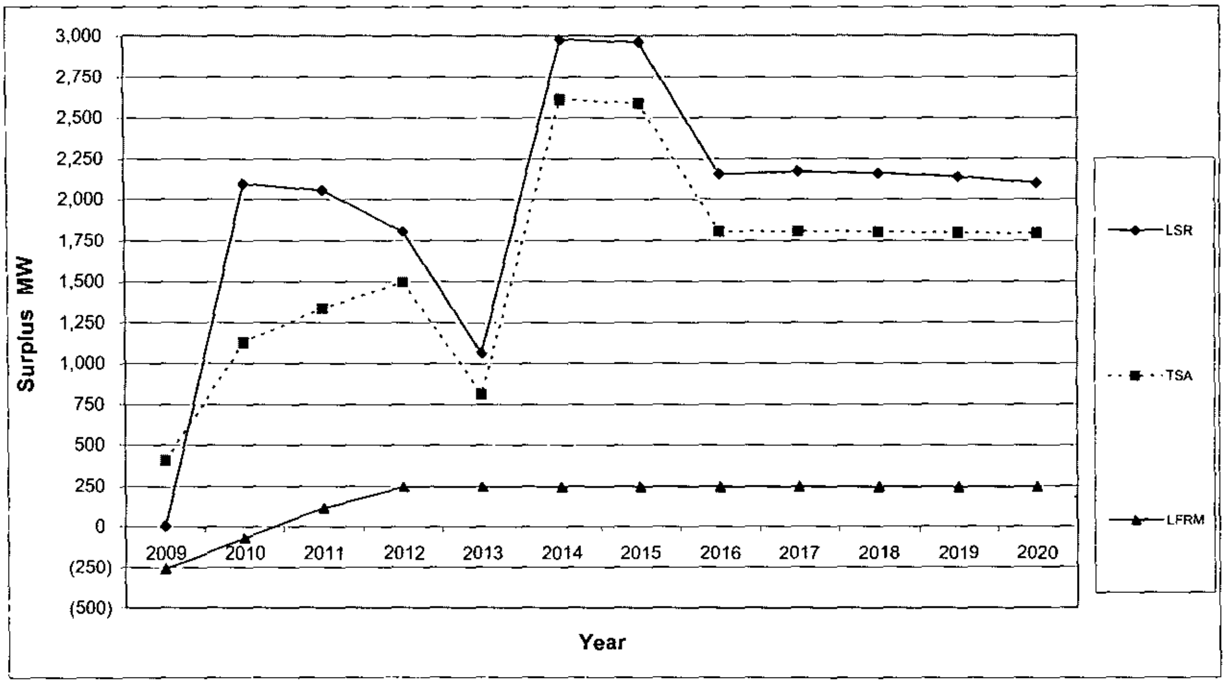
		2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Connecticut Requirement under Transmission Security Analysis	*a*	7,273	7,464	7,631	7,637	7,683	6,706	6,782	6,803	6,863	6,913	6,964	7,015
CT Sub-Area 90/10 Peak Load	*b*	7,940	8,010	8,105	8,205	8,285	8,370	8,445	8,505	8,565	8,615	8,665	8,716
Total Installed Capacity in CT	*c*	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)	*c-a*	**402**	**1,127**	**1,336**	**1,495**	**810**	**2,612**	**2,586**	**1,806**	**1,806**	**1,803**	**1,798**	**1,793**

Connecticut Requirement Under Locational Forward Reserve Market, Summer (LFRM)
Source: EDC Plan, pp. 1-7 and 1-8, Table1.3

		2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Connecticut Requirement Under LFRM (may be reduced after 2013)	*a*	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250
CT Sub-Area Internal Quick Start Capacity-Installed	*b*	894	990	1,178	1,364	1,494	1,494	1,494	1,494	1,494	1,494	1,494	1,494
CT Sub-Area Internal Quick Start Capacity-Planned	*c*	96	188	186	130								
Total Installed Quick Start Capacity in CT	*d*	990	1,178	1,364	1,494	1,494	1,494	1,494	1,494	1,494	1,494	1,494	1,494
CT LFRM Surplus (Shortfall)	*d-a*	**(260)**	**(72)**	**114**	**244**	**244**	**244**	**244**	**244**	**244**	**244**	**244**	**244**

[2] The Department's peaking contract units are GenConn's 188 MW in Devon coming on-line in 2010, 188 MW in Middletown coming on-line in 2011 and PSEG's 130 MW in New Haven coming on-line in 2012.

Figure 1
Annual Surplus under ISO-NE Requirements for Base Case Assumptions



Source: Table 1

Based on the resource surplus shown in Table 1 for the three ISO-NE resource adequacy requirements for Connecticut, the Department agrees with the CEAB and the EDCs that Connecticut can meet its capacity requirements during the next ten years under the assumptions for resource availability utilized in their base case plans.

(b) Resource Uncertainty

The base case makes several key assumptions that have a large impact on resource adequacy. The most significant are retirements, Kleen and the NEEWS transmission projects. During the hearings, the Department asked for a late file exhibit to examine the sensitivity of the EDCs' findings to these key assumptions. Tr. 6/4/10, pp 802 and 845.

In the EDCs' response to Interrogatory EL-12, resources were reduced in an alternative scenario to determine the effect on the resource surplus due to the recent Kleen accident in February 2010 and ISO-NE's decision to re-evaluate alternatives for the last two NEEWS projects. It was assumed that the Kleen plant would be delayed three years to 2013 and that the last two NEEWS projects would not be built.

Table 2 and Figure 2 illustrate the resource surplus under LSR and TSA analysis for resource adequacy using the EDCs' response to Interrogatory EL-12 assumptions. Compared to the base case surplus, the LSR surplus decreases by 620 MW in 2010 and by 683 MW in 2012. The surplus under TSA requirements decreases by 588 MW in 2010 and 649 MW in 2012. The LRS and TSA surplus decreases are primarily due to due to the 620 MW three year delay of Kleen.

After Kleen comes on-line in 2013, the surplus for LSR decreases by 1,708 MW and the surplus under TSA requirements decreases by 1,593 MW compared to the 2014 base case due to the last two NEEWS projects not being built. Most of the LSR surplus decrease, 1,532 MW, is due to the 766 MW Lake Road facility not being classified as a Connecticut resource and another 766 MW increase in local source requirements. The majority of the TSA surplus decrease is due to the 766 MW Lake Road facility not being classified as a Connecticut resource and an 800 MW reduction in import limits from the NEEWS projects not being constructed.

After 2015 the surplus drops below 500 MW in the LSR analysis and to approximately 200 MW in the TSA analysis. Under these assumptions, Connecticut would meet its LSR and TSA requirements if Kleen is delayed three years to 2013 and if the last two NEEWS projects are not built before 2020 due to the minimum surplus under LSR being 369 MW and under TSA being 179 MW both occurring in 2020, the last year of Connecticut's required planning period.

Table 2
Resource Adequacy under EDCs' response to Interrogatory EL-12 Assumptions

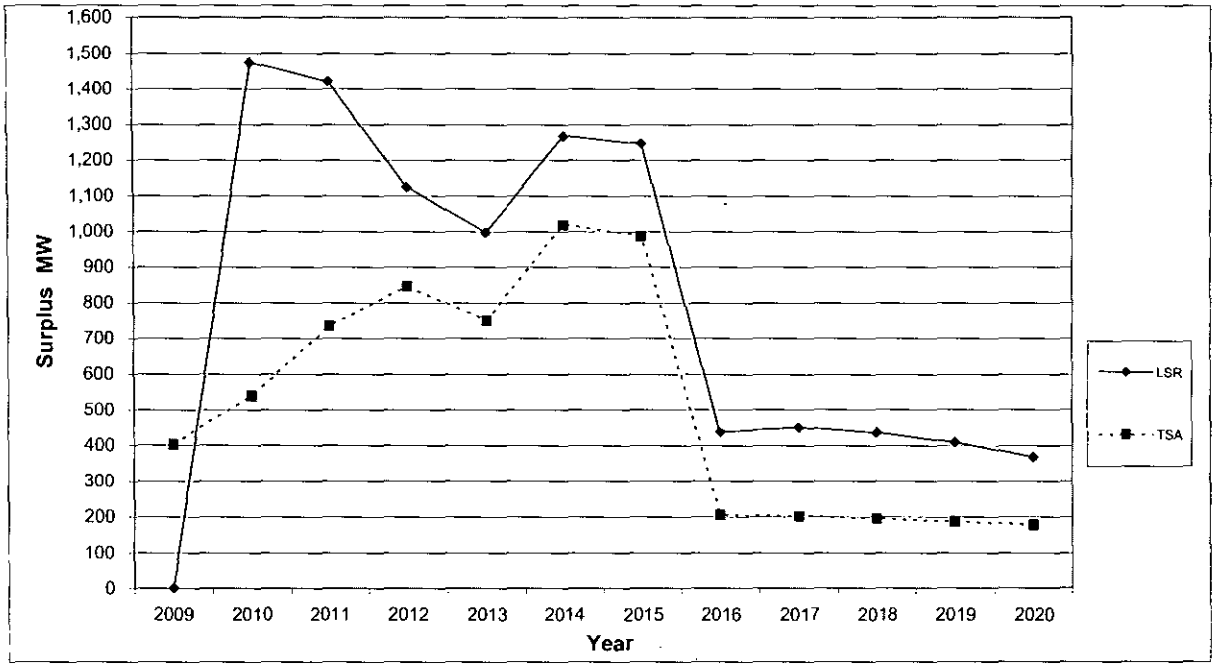
Local Sourcing Requirement in Connecticut (LSR) Source: EDC Response to Interrogatory EL-12

		2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Connecticut Sub-Area 50/50 Peak Load	a	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	b	n/a	6,496	6,912	7,325	7,433	7,216	7,283	7,330	7,373	7,432	7,500	7,583
Total Installed Capacity in CT	c	7,675	7,971	8,333	8,449	8,430	8,485	8,530	7,767	7,824	7,867	7,910	7,952
CT LSR Surplus (Shortfall) - with EL-12 modifications	c-b	**n/a**	**1,475**	**1,421**	**1,124**	**997**	**1,269**	**1,247**	**437**	**450**	**435**	**409**	**369**

Connecticut Requirement Under Transmission Security Analysis (TSA) Source: EDC Response to Interrogatory EL-12

		2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Connecticut Requirement under Transmission Security Analysis	a	7,273	7,432	7,599	7,604	7,680	7,465	7,541	7,561	7,622	7,672	7,722	7,773
CT Sub-Area 90/10 Peak Load	b	7,940	8,010	8,105	8,205	8,285	8,370	8,445	8,505	8,565	8,615	8,665	8,716
Total Installed Capacity in CT	c	7,675	7,971	8,333	8,449	8,430	8,485	8,530	7,767	7,824	7,867	7,910	7,952
CT TSA Surplus (Shortfall) - with EL-12 modifications	c-a	**402**	**539**	**734**	**846**	**750**	**1,019**	**989**	**205**	**202**	**195**	**187**	**179**

Figure 2
Annual Surplus under ISO-NE Requirements for EDCs' Response to Interrogatory EL-12 Assumptions



Source: Table 2

In Late Filed Exhibit 19, resource assumptions were reduced further than in the EDCs' response to Interrogatory EL-12 to determine the effect on the resource surplus due to the Kleen accident in February 2010 and the re-evaluation of alternatives for the last two NEEWS projects. It was assumed that in addition to the last 2 NEEWS projects not being built, the Kleen plant would also not be built before 2020.

Table 3 and Figure 3 illustrate the resource surplus under LSR and TSA ISO-NE resource adequacy requirements pertaining to Connecticut in the EDC and the CEAB plans under LFE-19 assumptions. Without Kleen and the last two NEEWS projects, a resource shortfall of 107 MW under LSR and 312 MW under TSA requirements occur in 2016 and both increase slightly through 2020.

Based on EL-12 and LFE-19, the critical year for new resources is 2016. The 2016 shortfall can be avoided if Kleen is delayed six years until 2016 or if the last two NEEWS projects are delayed two years to 2016 but still come into service. Another key assumption that was not examined in these late filed exhibits scenarios is retirements. Changes to the level of retirements could compound or offset any problems due to Kleen or NEEWS.

Table 3. Resource Adequacy under LFE-19 Assumptions (MW)

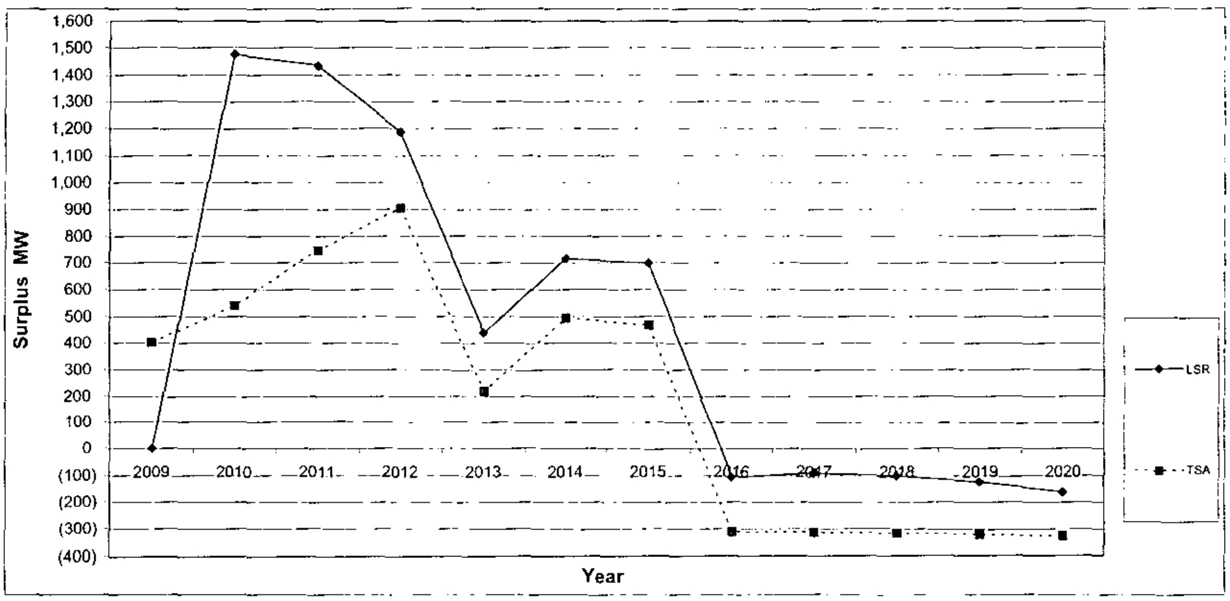
Local Sourcing Requirement in Connecticut (LSR) Source: LFE-19

		2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Connecticut Sub-Area 50/50 Peak Load	a	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	b	n/a	6,496	6,912	7,325	7,433	7,216	7,283	7,330	7,373	7,432	7,500	7,583
Total Installed Capacity in CT	c	7,675	7,971	8,347	8,512	7,873	7,932	7,982	7,222	7,283	7,330	7,376	7,421
CT LSR Surplus (Shortfall) - with LF-19 modifications	c-b	n/a	**1,475**	**1,435**	**1,187**	**440**	**716**	**699**	**(107)**	**(90)**	**(102)**	**(125)**	**(162)**

Connecticut Requirement Under Transmission Security Analysis (TSA) Source: LFE-19

		2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Connecticut Requirement under Transmission Security Analysis	a	7,273	7,432	7,599	7,607	7,653	7,438	7,514	7,535	7,595	7,646	7,696	7,747
CT Sub-Area 90/10 Peak Load	b	7,940	8,010	8,105	8,205	8,285	8,370	8,445	8,505	8,565	8,615	8,665	8,716
Total Installed Capacity in CT	c	7,675	7,971	8,347	8,512	7,873	7,932	7,982	7,222	7,283	7,330	7,376	7,421
CT TSA Surplus (Shortfall) - with LF-19 modifications	c-a	**402**	**539**	**748**	**905**	**220**	**494**	**468**	**(312)**	**(312)**	**(316)**	**(320)**	**(326)**

Figure 3. Annual Surplus under ISO-NE Requirements for LFE-19 Assumptions



Source: Table 3

The Department concludes that Connecticut should have adequate resources to meet its reliability requirements over the next decade; however, there is significant uncertainty surrounding this forecast. The fate of the Kleen project is expected to be more certain in the months ahead. In addition, both NEEWS projects are being reviewed and decisions to permit these projects to be constructed should be made by ISO-NE and the Connecticut Siting Council (CSC) within the next few months. The CEAB and the Department therefore should not wait until the next IRP filing to examine resource adequacy again. The Department must continually monitor resource adequacy to ensure that there will be sufficient time to develop and install alternative solutions if action is required.

B. IMPACT OF ENVIRONMENTAL REGULATIONS ON RESOURCE PLANNING

The Clean Air Act was last amended in 1990 and required the United States Environmental Protection Agency (EPA) to set National Ambient Air Quality Standards (NAAQS) for six identified criteria pollutants. Five of the pollutants commonly associated with electric generating units are: particulate matter, lead, nitrogen oxide (NO_X), ozone, and sulfur dioxide (SO_2). The Clean Air Act established primary and secondary national air quality standards. Primary standards protect public health, whereas secondary standards protect public welfare, including protection against visibility impairment, damage to animals, crops, vegetation, and buildings. EDC Plan, pp. 7-11.

Connecticut is one of the states engaged in implementing environmental regulations to meet its air quality standards. The EDC Plan discussed Connecticut's effort in implementing measures to meet Federal NO_X emissions standards. The Federal climate change and greenhouse policies are all efforts to help control air quality standards in the environment. EDC Plan, pp. 7-1 and 7-3. The EDC Plan discussed several other state and federal environmental regulations regarding CO_2 and NO_X emission limits. Currently, Connecticut is participating in the Regional Greenhouse Gas Initiative (RGGI), a market based program designed to reduce CO_2 emissions in the Northeast and Mid-Atlantic states. CEAB Plan, p. 164. RGGI was proposed in April 2003 and implementation began on January 1, 2009. The program targets fossil fuel-fired electricity generating units with a capacity of at least 25 MW and implements a regional CO_2 emissions cap and allowance trading program. On January 1, 2009, electric generators in RGGI states began collecting enough allocations to balance what they pollute or emit. EDC Plan, p. 7-3; Tr. 6/4/10, p. 831.

The EDC Plan addressed the issue of the anticipation of a federally mandated, economy-wide approach to limit or discourage CO_2 emissions from fossil fuel combustion. EDC Plan, p. 7-1. The DEP testified in support of the Federal approach to limit or discourage CO_2 emissions from fossil fuel combustion. The proposed Federal standards would require higher emitting generating units to install additional emission control equipment. The DEP stated that Connecticut does not have a CO_2 emissions standard at the moment. However, there is a possibility for EPA to provide some measures of guidance to the states on how to review permitting requirements associated with a CO_2 emission standard. Tr. 6/2/10, pp. 210-215.

The EDC Plan discussed Connecticut's effort to implement a more stringent NO_X emissions standard. In support of this, the DEP testified that Connecticut is not in attainment with Federal air quality standards, and as a result, it is always looking for reductions on an ongoing basis. Tr. 6/2/10, pp. 205 and 206. The EDC Plan also indicated that Connecticut has signed a Memorandum of Understanding (MOU) with other Ozone Transport Commission states to reduce NO_X emissions from high electric demand days (HEDD) units. HEDD are days most likely to result in ozone standard violations due to the ambient air quality standards. This is because higher demand for electricity results in a dramatic increase in ozone forming air pollution on summer days. EDC Plan, pp. 7-13 and 7-14. The EDC Plan indicates that under the MOU, Connecticut agreed to an overall NO_X reduction of 11.7 tons per day, which represents a 25% reduction in emissions from HEDD units. EDC Plan, p. 7-14; Tr. 6/2/10, p. 204. In its simulation in this year's IRP modeling, the EDCs indicated that uncontrolled NO_X emissions in Connecticut on HEDD days would exceed target levels of 42.7 tons/days in 2013 and 2015, and 31 tons/day in 2020, even under normal conditions. Based on these observations, the DEP advised it would likely need to restrict oil and gas fired steam units' emission rate to 0.125 lb/MMBtu by 2013 and 0.07 lb/MMBtu by 2017. EDC Plan, p. 7-14. The DEP testified that NO_X emission rules have been made at the Federal level. The finalization of Federal rules will prompt Connecticut to proceed with setting its own regulations on the emission rate. Tr. 6/2/10, p. 211.

With regard to the allowable running time permitted for generating units that switch and use alternative fuels such as No. 2 fuel oil on a peak day under the DEP air permit, the DEP testified that the allowable operating hours depends on the specific unit. Nonetheless, most of the permits include provisions to run on dual fuels. The DEP explained that the allowable running time is exercised annually unless the unit is a base load unit. The DEP stated that the new standard for generating units would require emission control equipment, but not necessarily reduce run time for units with alternative fuels. Tr. 6/2/10, pp. 208-214.

The EDCs forecasted that 1,504 MW of oil-fired steam capacity would retire in Connecticut and 646 MW would install emissions controls such as selective catalytic reduction (SCR). EDC Plan, p. 7-14. The cause for retiring and installing SCRs on oil-fired steam generators is the result of lower HEDD NO_X emissions. The EDCs performed an analysis through its energy and capacity price forecasts to project each unit's revenues to determine if it stays on line and compared that to future costs. The analysis indicated that if the net present value of the units' expected future value would be negative, then that unit is better off retiring. Most of the retirements would likely occur in 2013 and 2020, and possibly 2027 due to the timing of the changes in environmental regulations. Tr. 6/4/10, pp. 833-835.

The EDC Plan and the 2010 CEAB Plan raised concerns regarding environmental regulations affecting electricity generation. The Department reviewed and analyzed the existing and potential future environmental regulations and legislation presented in this proceeding. The Department concludes that the approach to limit or discourage CO_2 emissions from fossil fuel combustion and the effort to reduce NO_X emissions limit on HEDD units do not pose any immediate reliability concerns to electric generating units. However, if the proposed emission limits are implemented in response to Federal requirements, it will force older electric generating units to either retire or to be upgraded. The Department finds that while the implementation of these proposed emission limits are possible, it is not certain when it would occur. The Department determined that the proposed emission limits would not have any impact on the number of hours generation units using alternative fuel could operate annually. The Department believes these units would need to install new environmental emission control units to meet the new standards. The Department will monitor and keep abreast of changes on the timeline for the implementation of these proposed emission limits.

C. TRANSMISSION PLANNING:

The Department recognizes that the EDCs' and CEAB's transmission process continues to improve and be refined, with processes such as the technical meeting which commenced in November of 2009 moving the process forward.

The Department will reiterate its conclusion from Docket No. 09-05-02 that a longer time frame between the IRP process and the proposed transmission project is necessary in order to have a successful process that does not jeopardize the system's reliability. The Department again stresses extreme caution in the upcoming CEAB RFP process when considering alternatives to the NEEWS transmission project. The Department is concerned that the appropriate expertise and process has not been developed to make those decisions without jeopardizing system reliability. The Department will give careful consideration to ISO-NE findings of the need for NEEWS to support reliability and the inherent risks of moving down another path at this late stage in the process. The Department continues to stand by its previous conclusion that it is highly improbable that in the limited time frame available to review alternatives to the Greater Springfield Reliability Project, the Rhode Island Reliability Project, and the Interstate Reliability Project portions of NEEWS that CEAB or any third party can adequately model all of the issues of reliability that the NEEWS project will resolve. Further, the Department finds that the regional aspect of the NEEWS projects would make any comparison of the reliability benefits of those projects as compared to NTAs especially difficult. The Department also recognizes that any options considered during any RFP process will only be in the initial phase. The Department's experience has been that a comparison of a fully fleshed out project with cost data and significant modeling of the reliability benefits is far different from an initial proposal without any type of contract.

In the last IRP, the Department concluded that CEAB must continue to work with the parties to further improve this process of looking at alternatives to transmission at a much earlier stage of the process. Further, the Department found that the CEAB must provide firm deliverables for alternatives so that they can craft a proposal that meets the need and is fully comparable. Docket No 09-05-02, DPUC Review of the 2009 Integrated Resource Plan, p. 11. Included in CEAB's request for alternatives should be such critical data as MWs provided by the proposed transmission, and the types of benefits that are provided by the transmission proposal (voltage support, capacity imports, etc.). The Department is including this language again to clarify that the transmission owners (TOs) have not been assigned the task of identifying non-transmission alternatives that would fulfill needs identified by ISO-NE. The Department does not concur with the CEAB that it is appropriate that the EDCs provide hypothetical alternatives as suggested in the testimony. Tr. 6/3/10, p. 702. However, the Department does find that there would be a benefit if the EDCs filed a report as outlined in the CEAB Plan and noted in CL&P's brief. The report would provide an explanation of needs for which transmission solutions may be proposed, in sufficient detail, for market participants to come forward with a market alternative that will obviate the need for the transmission improvement; or, failing that, for the CEAB to issue a pro-active RFP for alternative solutions that could involve State procurement actions. CL&P Brief, p. 18. However, the Department finds that the section described as "assessment of alternatives" would only be included to the extent that a non-transmission alternative (NTA), had been proposed and its description, economic, environmental, and social objectives were developed by the proponent. NTAs may include energy efficiency, generation, demand resource, and other alternatives that delay or replace the need for transmission. Lastly, any costs associated with the analysis of an NTA must be absorbed by the proponent and would be eligible for recovery only if their project were chosen to replace a transmission project.

The Department concurs with the CEAB that initiating an NTA process associated with the Hartford needs assessment is appropriate. The Department will work with the CEAB, and other interested parties, to better define the appropriate process. The Department's involvement with this process would be to assist CEAB to define the process and then to allow CEAB to conduct and evaluate an RFP that would then be filed with the Department. The Department would make a final decision as to the merits of the CEAB evaluation and recommendation on the NTA and then would approve or reject the proposal. Further, the Department supports the CEAB's collaboration with ISO-NE's needs assessment and transmission solution studies as necessary to achieve this goal.

The Department believes that the necessary initiatives and processes are in place for the state to effectively coordinate with ISO-NE, NESCOE, and other regional organizations whose organizations impact electric systems costs. Therefore, the Department does not think that there is any need to take any actions with regard to the CEAB's suggestion to alter these relationships.

D. Gas Generation

1. RFP Design Compliance

The Department has carefully reviewed the recommendations of CEAB, the OCC, the AG, CL&P, UI, and others who generally, or specifically, proposed that the Department should forego issuing an RFP for any generation resources and those such as NRG which recommends initiating an RFP process immediately. The Department will not address all of the points that the parties made on an issue-by-issue basis in this Decision regarding any future RFPs.

First, the Department notes that the EDCs have the responsibility and the opportunity under current statutory authority to investigate and enter into bi-lateral contracts, pending Department approval that can bring forth new resources and benefit ratepayers. The Department encourages the EDCs to thoroughly investigate opportunities and to bring any proposals forward. The Department's process, set forth in this Docket, does not replace the EDCs' statutory authority, pursuant to Conn. Gen. Stat. §16-244c(n) and as further spelled out in 06-01-08 RE03 <u>Development and Review of Standard Service and Last Resort Service – Long-Term Contract Review</u>, Decision dated September 30, 2009, but rather complements it and acts as a backstop should such deals not materialize. The Department recognizes that the EDCs can play an important role with their ability to leverage their expertise to negotiate and analyze proposals that provide opportunities to yield meaningful benefits. The Department will give expeditious treatment to any plans brought forward by the EDCs under their statutory authority.

The Department believes that establishing a process now to look at what a future RFP might look like is prudent. Such an RPF might solicit bids simultaneously for repowering at existing cites, generation at new cites, renewables, EE and DSM. The Department would want such an RFP to generate bids from disparate resources but comparable on a consistent, and preferably quantitative, basis. The Department recognizes that the "RFP question", if not formulated carefully, can predetermine or bias the "bid answer." The Department's intent here is to avoid the question predetermining the answer. The Department's goal is to seek the assistance of the providers of disparate resource types and solutions in designing an RFP and RFP process that, if and when it need to be used, would sufficiently value their resource, allow for effective comparisons between resources and enable the Department to efficiently identify the best bids.

The Department believes that the benefit/cost methodology described in Section III.I.1. Benefit Cost Methodology would provide a good analytical tool to evaluate the economic benefits of projects. Rate impacts and other economic and environmental matrices used by the EDCs in their IRP analysis might also be used to evaluate actual projects. It would be helpful to determine how such measures should be balanced and weighted to evaluate projects in an RFP.

The ability to issue an RFP that is structured or designed so that disparate resources proposals received under the RFP would enable the Department to determine the best course of action is highly valuable. The Department views the development of an RFP or process that can accomplish this as an important goal in and of itself, which will require the parties to propose potential RFP terms, conditions, elements, time frames, metrics, formulas, etc.

The Department believes that under the most likely scenarios, no further capacity resources will be required in Connecticut over the near term; however, the Department also recognizes that the assumptions underlying these scenarios can change rapidly and there are some scenarios where Connecticut could end up capacity constrained over the near-term or in which other economic and environmental opportunities beneficial to ratepayers present themselves. Therefore, establishing a process now to craft an RFP and have it ready to execute when necessary will provide the Department with a much more organized and fruitful end result when a resource need or benefit does appear.

Further, the Department concludes that waiting to establish a process in or upon the conclusion of the 2012 IRP or when an EDC brings forth a proposal, may not yield a sufficiently robust analysis of conflicting goals and methods to resolve them. The assumptions relied on by many of the participants that recommended for or against any procurement starting at this time are the same assumptions that encourage the Department to begin establishing an RFP design process now. As a result, undertaking this process now will prepare the Department to react quickly and efficiently should any economic, environmental, or unforeseen event change the landscape of the Connecticut electric market. The Department must have the RFP process described above readily available to be most prepared to support system reliability if market solutions fail to materialize under the adverse assumptions discussed during this proceeding.

Additionally, the Department cannot ignore the possibility raised by the CEAB that the repowering of resources, or other actions, can potentially provide substantial economic or environmental benefits to Connecticut ratepayers. The Department believes it is important to note that legislation passed the House and Senate this past session, Public Act No. 10-97, but was vetoed by Governor Rell on May 24, 2010. That legislation, among other things, would have required the IRP developed in 2010 to indentify options to reduce the price of electricity by at least fifteen percent. Though the parties noted in this Docket that a 15% rate reduction was almost assuredly unachievable, the Department cannot ignore that the resource decisions made now and in the future effect current and future rates. The Department encourages the parties to include in their filings an RFP proposal and RFP process that could lead to bids that significantly reduce current rates. Such a bid result would most certainly be found to be one of the best bids.

The Department believes that these filings can provide the Department with information necessary to provide the most informed input to Connecticut's lawmakers. Further, any RFP design or RFP process proposed by the parties should be mindful of the Department's criteria in Docket No. 08-07-01 when there is no resource need. If there is no resources need, would the proposal be funded by ratepayer investment rather than market revenues, direct participant funding, private investor funding, or other market-based means? Is there a great degree of certainty that the proposal will substantially reduce costs or produce savings for ratepayers that exceed the cost of ratepayers' investment or substantially improve the environment? Would any near-term rate increases cause substantial hardship to ratepayers? Would the products or services offered in the proposal count toward satisfying Connecticut's energy or capacity requirements? Would they displace some existing older, more expensive, less efficient, more polluting resources? Would they reduce the future need for additional resources to meet Connecticut's requirements? See, Docket No. 08-07-01, Decision at p. 14.

Based on several methods of statutory construction, (See, Decision, Section III.E.5.(a)) the Department continues to believe that any resource selected must meet a high standard to justify its procurement if there is not a reliability based need in the near or intermediate term. A resource proposal, absent a near or immediate need must provide a cost savings or remedy a significant environmental deficiency to justify its selection. The resource should identify and quantify the resources to be acquired, replaced or eliminated and a quantifiable goal. An RFP or RFP process that fails to meet these objectives would be inadequate at worst and difficult to justify at best. The Department will determine how it will proceed after reviewing the RFP design filings. As appropriate, the Department may conduct a compliance filing review or open a docket regarding the substance of the compliance filings as may be appropriate at the time.

2. Peak Day Gas Demand Forecast and Delivery Capacity

The EDCs report that natural gas plays a critical role in the Connecticut and New England electric systems. Gas fuels the largest share of New England's power generation, approximately 41% of the electricity produced in 2008. EDC Plan, p. 9-1. The availability of natural gas supplies needed to operate gas-fired electric generation is a concern during New England's winter heating season, when gas demand is at its peak. Natural gas is used primarily by gas LDCs to serve their core customers and by electric generators. Gas LDCs contract for primary firm service on the gas transportation system. 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 interstate pipeline system is constrained, gas LDCs have first priority and the electric generators face potential curtailment. If this constraint occurs at a time when gas is needed to fuel generators to meet electric load, it could potentially cause a reliability concern for electric generation units. EDC Plan, pp. 8-7 and 8-8.

The EDCs indicated that the current electric system reliance on natural gas for electric generation during the winter peak gas demand period is mitigated by various factors. Due to lower ambient air temperatures, the electric generators' ability to generate electricity is about 9% higher during the winter than in the summer. However, the winter electric peak day demand is 20% lower than the summer peak day demand. Due to these two factors, there is additional slack in the winter resource balance and winter peak loads can be served with significantly less reliance on gas-fired capacity compared to the summer peak. The EDCs also stated that the generators' dual-fuel capability can help alleviate the gas dependence issues. Dual fuel capability is the ability of a generation unit to switch fuels and burn oil instead of natural gas. In total, about 25% of New England's generation consists of dual fuel units that have both the physical capability and the necessary permits to burn either gas or oil. EDC Plan, pp. 8-7 and 8-8.

The EDCs provided in two tables the overall natural gas demand and supply; Table 9.1 "Peak Day New England Natural Gas Demand Forecast" (Table 9.1) and Table 9.2 "Peak Day Natural Gas Delivery Capacity into New England" (Table 9.2). EDC Plan, pp. 9-2 and 9-22. The tables are a combination of data from the March 2005 report by The Power Planning Committee of the New England Governors Conference and additional forecast data determined by the EDCs. The tables indicate that since 2005, there has been an increase in pipeline expansions and new LNG import terminals. Based on the data presented in the tables, the EDCs concluded that capacity to deliver gas has increased in New England by about 40% and, therefore, total gas supply exceeds total gas and electric demand. The EDCs believe that there is adequate gas supply to serve both gas LDC customers plus electric generation demand for years to come. The EDCs state that the delivery capacity presented in Table 9.2 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. The EDCs' Base Case simulation of electric demand and supply concludes that the winter electric demand for gas decreases during the forecast period. At the same time, the IRP states that non-electric (gas LDC customer usage) winter demand for gas may increase over the forecast period. The EDCs concluded that the balance between gas supply and gas demand has improved during the last several years and is likely to improve during the foreseeable future. EDC Plan, pp. 9-20 to 9-22; Tr. 6/3/10, p. 609.

Using the data in Tables 9.1 and 9.2 of the EDC Plan, the CEAB consultants arrived at the same conclusions as the EDCs. The CEAB Plan states that the EDCs' tables illustrated that there is sufficient interstate pipeline capacity available in New England to serve all demand. This includes projected gas LDC usage plus electric generation load under both normal and high demand scenarios. The CEAB Plan assumes there will be no change in gas delivery capacity. Therefore, New England appears to have more than enough capacity to meet the estimated electric summer and winter peak-day demands between 2013 and 2020. CEAB Plan, p. 187.

The OCC disputes the findings in both the EDC Plan and CEAB Plan. The OCC believes that the supply data presented in Table 9.2 improperly assumes that specific LNG terminals add delivery capacity to New England. The OCC described the presentation in Table 9.2 as a rosy characterization of New England's peak day gas delivery capacity, arguing that the presentation is unrealistically optimistic. Finally, Tables 9.1 and 9.2 improperly combine sources of gas supply with conventional interstate gas pipeline capacity and local peaking resources. Tr. 6/3/10, pp. 531-537; OCC Brief, p. 41.

The gas LDCs also disputed the findings of these reports. Specifically, the gas LDCs state that LNG imports are not a capacity resource unless they are coupled with a primary firm transportation capacity contract. Gas LDC Written Comments, p. 4. The gas LDCs question the title of the EDC Plan Table 9.2, which cited natural gas delivery capacity, versus the actual data included in the table, which is specifically related to supply. Natural gas delivery capacity is a separate function from gas supply and should not be mixed together. The table should have been labeled, "Supply Availability into the Region" as opposed to Take-Away or Delivery Capacity. Tr. 6/4/10, pp. 984 and 985.

The gas LDCs testified that Table 9.2 portrays the potential of delivering gas to the border of New England. It does not indicate whether any LNG facilities listed in the table can increase the delivery of gas to specific points in New England for the consumption of electric generation units. Tr. 6/4/10, pp. 991-998. The EDCs responded that this table was a simplified analysis and did not portray the details of delivery capacity in New England. The EDCs did not try to link the LNG terminal capacity to interstate pipeline capacity because it was beyond the scope of their analysis. Tr. 6/3/10, pp. 614-617.

The EDC witnesses testified that Table 9.2 included LNG peaking facilities both owned and operated by gas LDCs and other entities. According to the witnesses, the gas LDCs are not expected to use LNG peaking resources to satisfy electric generation needs on a peak day or a peak period. The EDC witnesses did not assume that any LNG peaking facility in New England could be relied on to serve electric generation load. Tr. 6/4/10, pp. 988 and 989. Finally, the EDC witnesses claim that it would be very difficult to imagine any gas LDC's storage supplies being used to serve power generation on a peak day or during peak conditions. Storage is typically a component of the gas LDCs' gas supply portfolio, which is designed to meet firm load rather than interruptible load. Tr. 6/3/10, p. 524.

The Department finds that the data and conclusions presented in the testimony and tables of the EDC Plan have numerous inaccuracies and shortcomings that need to be addressed in future IRP electric filings. The EDC Plan focuses on the supply of natural gas as opposed to the ability of the generation facilities to transport and deliver gas to specific power plants. There are three areas that should have been included in the EDC Plan: 1) distinguishing between gas supply commodity and gas deliverability capacity with the focus on deliverability rather than supply; 2) the practical availability of gas LDC peaking facilities to serve electric generator loads and the estimated level of availability; and 3) a description of the ability of the current gas infrastructure to deliver gas to electric generators including identifying any limitations during both summer and winter periods. Based on the above, the Department directs the EDCs to include in future IRP filings accurate testimony on these three issues.

3. EDC and CEAB Findings Regarding Natural Gas

The EDCs and their consultant, the Brattle Group, testified that they jointly had made several inaccurate key findings and statements regarding natural gas deliverability and the gas LDCs' distribution systems in the EDC Plan. These same inaccurate key findings and statements were then repeated verbatim in the CEAB Plan. Tr. 6/3/10, p. 626.

The key findings in both reports state that the gas LDCs have the following issues regarding the delivery of natural gas to their customers. Specifically, each report stated that the "[g]as delivery capacity to serve average and peak needs has improved measurably from a few years ago (though this does not address gas local distribution deliverability issues, where additional expansions may be necessary)." EDC Plan, p. 9-3; 2010 CEAB Plan, p. 179. The Department finds that the EDCs' testimony regarding this statement needs further review and analysis. The Department finds that the data and conclusions presented in the testimony and tables of the EDC Plan fail to include certain areas that need to be addressed in future IRP filings. The EDCs admitted during the hearing that the key finding regarding gas LDC deliverability issues was improper and should not have been included in the IRP filing. Tr. 6/3/10, pp. 626-629.

Second, the EDC Plan filing specifically stated that "[i]n deregulated markets, gas LDCs and electric distribution companies may have difficulty in getting regulatory support for long-term contracts." EDC Plan, p. 9-18. During cross-examination, the EDCs and the Brattle Group were specifically asked to provide relevant evidence supporting the above cited statement. Neither could support the statement. However, another EDC witness who indicated that he had direct experience with gas LDC purchases of pipeline capacity stated that the gas LDCs had not historically obtained or requested pre-approval by the Department of purchases of long-term capacity contracts. Tr. 6/3/10, pp. 637 and 638.

As stated above, the gas LDCs do not have deliverability issues on their distribution systems or difficulty obtaining long-term capacity contracts associated with pipeline capacity, storage contracts or even peaking resources. Many of the EDCs' and CEAB key findings and statements indicate a limited understanding regarding the operations of the gas LDCs' distribution systems and gas supply portfolios.

All future IRP testimony and gas capacity and demand table presentations should accurately portray gas supply and capacity issues and the ability of the gas infrastructure to serve the future needs of electric generators. This can be accomplished in the IRP process through direct interactions and communication with the gas LDCs regarding their expertise related to gas capacity and deliverability issues in New England. Several issues arose during this proceeding that may potentially affect the future supply and demand of natural gas for Connecticut. These issues will be examined further by the Department in Docket No. 08-10-02, DPUC Review of the Connecticut Gas Utilities Forecast of Demand and Supply 2009-2013.

E. DEMAND SIDE MANAGEMENT

1. Position of the EDCs

The EDCs provided the DSM analysis 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. The EDCs also compared Connecticut's energy efficiency programs to those in other states. EDC Plan pp. 2-1 and 2-2.

The EDCs also developed and evaluated two expanded energy efficiency resource strategies - Targeted DSM Expansion and A-ACE.[3] The EDCs state that Targeted DSM Expansion comprises 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. A-ACE reflects a major expansion of cost-effective programs and is similar to the expanded energy efficiency case presented in the 2009 IRP. This strategy was constructed based on a draft of the Connecticut energy efficiency potential study completed in 2009 by the Energy Efficiency Board.[4] Both the Targeted DSM Expansion and the A-ACE resource strategies are compared to the Reference resource strategy based on customer costs and emissions. Id.

The EDCs presented these key findings:

1. Although Connecticut is a leader in DSM, with established programs and demonstrated results, there is much unrealized, cost-effective, emissions-reducing potential remaining;
2. The Targeted DSM Expansion strategy meets the criteria established by the Department in its February 18, 2009 Decision in Docket No. 08-07-01, DPUC Review of the Integrated Resource Plan, for procurement absent an immediate reliability need by reducing total customer costs and CO_2 and NO_x emissions in all five scenarios tested, and by slightly reducing rates in all but one scenario. Funding this strategy through the SBC would require increasing the SBC rate from

[3] This IRP focuses on the energy efficiency component of DSM. The other traditional component, demand response, is de-emphasized since there will no longer be planned funding beyond what would pay for itself through participation in the 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.

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

3 mills/kWh to 3.7 mills/kWh. However, based on the 2020 analysis, reduced generation service charge (GSC) costs and rates would more than offset the increase.

3. A-ACE also meets the criteria set forth in the Docket No. 08-07-01 Decision; however, while it reduces total customer costs as well as CO_2 and NOx emissions in all five scenarios, this approach would impact electric rates, increasing the SBC rate to 5.6 mills/kWh. Additionally, the 2020 analysis indicates that the GSC rate reduction 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).
4. In summary, funding the Targeted DSM Expansion strategy would require an increase in annual rates by approximately $19 million (2010 dollars), and the A-ACE would increase annual rates by approximately $65 million 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 Expansion would result in lower rates for non-participants over time.
5. 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.

Based on their review, the EDCs recommend the Targeted DSM Expansion strategy be funded because it would reduce customer costs and emissions while reducing rates for non-participants. However, it will be necessary to identify the best source(s) of funding to meet increased program costs and also to provide financing options to help customers pay for their out-of-pocket costs. Id.; UI Brief, pp. 11-17.

Regarding the All Achievable Cost-Effective DSM strategy, the EDCs do not recommend this approach because of the potential rate impacts for non-participants. However, they believe this strategy is worth considering for future implementation because it provides positive economic benefits to Connecticut while substantially reducing emissions (at a negative net cost). The EDCs note that this recommendation recognizes that the DSM infrastructure necessary to deliver this level of efficiency would take time to build (or rebuild if programs are cut). Id.

The EDCs state that pursuing the Targeted DSM Expansion is a recommended policy direction, not an application for approval of a specific program plan. Program planning to implement this strategy would still have to go through the rigorous planning, review, approval, and evaluation process that is in place for current Conservation and Load Management (C&LM) programs. Id.

2. Position of the CEAB

The CEAB's economic analysis of energy efficiency potential shows the economic benefits of an aggressive demand-side program to be significant under a broad range of scenarios and assumptions over the longer-term. CEAB Plan, p. 21.

The CEAB states that the analytics conducted by the EDCs and the CEAB show clearly that energy efficiency is superior to the alternatives in terms of reducing the need to invest in increasingly expensive supply resources and added transmission. Further, investments in efficiency mitigate reliance on imported fuels, reduce the emission of key air pollutants, while providing in-state jobs. On a total resource cost basis, the untapped potential for investments in efficiency are significant, based on work commissioned by the Energy Efficiency Board, and are much less costly than other supply options, particularly the renewable resources anticipated to meet the RPS requirements. Id., p. 22.

The CEAB notes that a finding regarding the economics of increasing energy efficiency is not a surprise; however, significant challenges remain to realize this additional efficiency potential. While the determination that significant, additional cost-effective energy efficiency potential is clear, the best approach to acquiring those demand-side resources has yet to be determined. Connecticut's current approach, primarily a ratepayer-funded incentive mechanism, is already a substantial program by national standards. Therefore, rather than expanding the current paradigm (i.e., business-as-usual with higher incentives from ratepayer funds through increased rates) the CEAB recommends that the State identify and develop ways to help reach A-ACE while seeking to avoid increasing the burden on ratepayers generally. Therefore, the Department should adopt a longer term goal of A-ACE as the level of efficiency that Connecticut is committed to achieving and to achieve A-ACE by using its best efforts to maximize the utilization of energy efficiency resources by expanding financing options, market mechanisms, codes and standards, and by refocusing the ratepayer-funded programs as a way to complement and expanded current initiatives. Id.; CEAB Brief, p. 3.

The CEAB believes that moving from the current approach of developing C&LM programs to planning for the most effective use of available funds to creating plans that seek to capture all cost-effective energy efficiency opportunities requires a new paradigm, not simply a bigger budget. A larger budget from ratepayers, such as for the EDCs' proposed Targeted DSM Expansion, may be part of that new paradigm, at least as a transitional measure. However, a plan to accomplish this aggressive goal must consider broader approaches to overcome the barriers to energy efficiency that currently precludes the primary beneficiaries of the energy efficiency savings from pursing those savings themselves. CEAB Brief, p. 4.

To fulfill its recommendations, the CEAB requests that the Department require the EDCs and Energy Efficiency Board to develop the following three-alternative C&LM program plan and budget scenarios for submission in October 2010:

1. A plan that complies with the Department's most recent C&LM order, which would maximize the amount of energy savings and demand reduction without increasing any funding beyond the current System Benefits Charge and the current secondary funding sources such as the capacity market payments and from RGGI collections;
2. A schedule and goals for the implementation of the Targeted DSM Expansion, including the year-by-year costs, savings, benefit and rate impacts; and,
3. A strategy to target A-ACE and provide a full reexamination of programs including pilot programs and legislative initiatives to promote enactment of changes in codes

and standards to achieve the levels of A-ACE efficiency within the next ten years. This should include recommendations for legislative actions that could support energy efficiency measure implementation without requiring Energy Efficiency Board programs.

This preliminary plan toward the implementation of A-ACE efficiency levels should be filed in October 2010 in order to provide context and comparison for the consideration of any program funding expansion required by the Targeted DSM Expansion EE strategy. Id.

The CEAB states that recent legislative action redirecting funds from the Energy Efficiency Fund to the General Fund underscores the need to find more funding as well as more non-ratepayer funded sources for energy efficiency, like those described in the CEAB 2010 Plan. ENE Brief, p. 3, footnote.

3. Position of the OCC

The OCC states that neither the CEAB nor the EDCs established a reliability-based procurement need in this proceeding. The OCC's consultants also confirmed this finding. Therefore, since no capacity need exists, the OCC concludes that any procurement of resources ordered in this proceeding, would have to meet both the statutory criteria and the Three Criteria Test established by the Department in the 2009 IRP Decision. OCC Brief, p. 3.

The OCC states that despite the clear evidence that no capacity need exists, the EDCs, ENE and the CEAB advocate for additional spending on DSM, while others do not. Although most parties agree that funding should not be provided for an immediate implementation of A-ACE, various parties seem to operate under the assumption that A-ACE is the assumed ultimate goal for DSM resources within the IRP and that funding at a level to achieve the Targeted DSM Expansion should be provided to the Energy Efficiency Board as a means of "ramping up" to A-ACE. Thus, the primary area of disagreement among the key participants is whether to increase energy efficiency spending to the Targeted DSM Expansion level as part of a goal to ultimately ramp-up to the A-ACE level. Id., p. 4.

The OCC believes it is necessary to address a recurring and legally unsupported notion among various parties to the IRP proceeding that an assumed goal of the IRP process is the eventual implementation of A-ACE, with the only issue for debate being how to fund or "ramp up" to it. The OCC argues that Conn. Gen. Stat. §16-3a does not require the implementation of A-ACE, because it is not cost-effective (as defined in statute) and does not pass the Department's Three Criteria Test. Id., p. 10.

The OCC asserts that by evaluating the cost-effectiveness of the energy efficiency programs across all classes and groups of customers, the proponents of the proposed incremental DSM programs obscure the reality that only a relatively small segment of ratepayers (i.e., participants), primarily commercial and industrial (C&I) and affluent residential customers, would realize significant benefits from expansion of the existing C&LM programs. In actuality, most of the remaining customers (non-participants) would subsidize the programs without realizing any meaningful reduction in their electric bill. As a result, the OCC concludes that A-ACE is not cost-effective because it will benefit relatively few at the expense of many. Id. pp. 10-12.

The OCC also notes that resources must demonstrate reliability in order to be procured under the IRP statute, Conn. Gen. Stat. § 16a-3a(c). The OCC points out however that the CEAB testified that the A-ACE DSM programs were not intended to be a fixed and immutable set of measures implemented over a specific time period. Instead, the programs would be reviewed and revised based on achieved interim results. More specifically, the CEAB suggested that the State should start with the Targeted DSM Expansion and then move to the A-ACE level, perhaps five years down the road. This evidence leads the OCC to conclude that there is insufficient basis in the record to determine that the A-ACE level of DSM meets statutory reliability standards. In summary, the OCC believes A-ACE is a theoretical construct rather than a program with concrete achievable goals; thus the claimed benefits are vague and therefore, unreliable. Id.

Additionally, the OCC also believes that there is significant uncertainty surrounding primary participant benefit (i.e., the impact on the price of energy) as well as the basis for the claimed value of capacity benefits. Id., p. 18.

The OCC further states that A-ACE does not meet the Department's Three Criteria Test for the following reasons. Criteria 1 requires that the proposal needs to be funded by ratepayer investment rather than market revenues, direct participant funding, private investor funding, or other market-based means. The OCC believes that there is no need for further EDC sponsorship (i.e., ratepayer funding) of energy efficiency beyond the current level of ratepayer funded C&LM activity because merchant providers will enter the market to provide these services when ratepayer supported programs are curtailed. In support of its position, the OCC cites to the increased penetration in market-based demand response activity that occurred when the Energy Efficiency Fund withdrew its support for these services. By withdrawing support, Connecticut essentially removed a barrier to increased participation that existed in the form of unfair competition among demand response providers. The increased penetration occurred despite the decline in FCM payment rates. The OCC sees no reason to believe that energy efficiency would not perform in a similar manner. OCC speculates that the continued use of the current paradigm (i.e., ratepayer supported/EDC administered programs) may be creating a barrier to merchant participation and that by terminating ratepayer funding, Connecticut may actually remove the same barrier, unfair competition, for those wishing to enter the energy efficiency market. Id., p. 20.

Criteria 2 states that there must be a great degree of certainty that the proposal will substantially reduce costs or produce savings for ratepayers that exceed the cost of ratepayer investment or substantially improve the environment and any near-term rate increases do not cause substantial hardship to ratepayers. OCC reiterates its earlier argument regarding the ability of these resources to produce reliable results. In addition, OCC notes that the forecasting of Demand Reduction Induced Price Effect (DRIPE) LMP benefits is highly speculative. The OCC submits that the unreliability of benefit calculations, coupled with the cost-shifting from participating to non-participating load, leads it to conclude that A-ACE does not meet the Department's second criterion. Id., p. 23.

Criteria 3 requires that the products or services offered in the proposal will count toward satisfying Connecticut's energy or capacity requirements; can displace some existing older, more expensive, less efficient, more polluting resources; or, can reduce the future need for additional resources to meet Connecticut's requirements. The OCC indicates that changes regarding the bidding of EDC-sponsored DSM into the FCM under proposed new rules make it unclear whether these assets will be eligible to participate in the capacity market in the future. Further, there has been no analysis presented in this docket that demonstrates the ability of energy efficiency to displace older, more polluting capacity resources. The OCC believes the retirement of older, more polluting units in the EDCs' attrition model is effectuated by imposition of more stringent air emission limits, not by the implementation of energy efficiency measures. Finally, some participants in this docket continue to claim a reason to ramp up the State's energy efficiency spending is the potential for infrastructure avoidance. The OCC argues that in light of the recent major investment in transmission facilities, the likelihood of infrastructure avoidance through greater energy efficiency spending has steeply declined over the planning horizon. Therefore, Criteria 3 cannot be satisfied. Id., pp. 23 and 24.

The OCC states that the evidence in this proceeding also argues against the EDCs' Targeted DSM proposal. For instance, the EDCs were unable to support their claim that the Targeted DSM Program would yield much higher DRIPE savings than the average of the C&LM programs. The OCC also observes that baselines were adjusted to make the Targeted DSM Program look more cost-effective than those same measures in the C&LM program. This makes the Targeted DSM Proposal appear unduly favorable in comparison to other IRP resources. Id., p. 30.

Additionally, the OCC states that the Targeted DSM Expansion proposal also fails to meet Conn. Gen. Stat. § 16a-3a(c), which requires that demand side resources have to be evaluated on an equitable basis with supply-side resources, which was not done in this case. The OCC compares the potential to approve the Targeted DSM Expansion proposal based on the EDCs' evidence as submitted to the approval to build a power plant as follows: Connecticut would not hold a procurement for supply-side resources "where we simply offer up a pot of dollars to a generation company with the details of the size of a power plant, the generating fuel, and the location to be worked out later." In essence, the Targeted DSM Expansion takes that approach and in that regard the EDCs are asking that they and the Energy Efficiency Board be authorized to receive dollars for this purpose, with all of the essentials to be determined as it proceeds. Id.

Further, the OCC states that the primary area of disagreement among key participants is whether to increase energy efficiency spending to the Targeted DSM Expansion as part of a goal to ultimately ramp-up to the A-ACE Level. For example, the OCC notes that the EDCs recommend the increase in the C&LM budget to the Targeted DSM Expansion as a step toward A-ACE. The OCC also notes that despite the lack of clarity about the economic merit of the specific measures, the CEAB endorses the Targeted DSM Expansion for the first five years of the IRP horizon. The OCC further notes that the CEAB makes this endorsement while attempting to avoid increasing the burden on ratepayers and not continue the business-as-usual approach with higher incentives from ratepayer funds but instead considering a broader portfolio of financing mechanisms and implementation approaches. Moreover, the OCC cites to the CEAB, this should be accomplished through a re-engineering and re-allocation of the C&LM Plan to make it compatible with the goal of A-ACE. OCC Brief, p. 6.

The OCC does not support any additional funding for DSM at this time. The OCC acknowledges that most Participants agree that funding should not be provided for an immediate implementation of A-ACE, and that some Participants seem to operate under the mistaken assumption that A-ACE is the assumed ultimate goal for DSM resources in the IRP and that funding at the Targeted DSM Expansion level should be provided to the ECMB as a means of "ramping up" to A-ACE. As a result, the OCC believes that it is necessary to address a recurring and legally unsupported notion that an assumed goal of the IRP process is the eventual implementation of A-ACE, with the only issue for debate being how to fund, or ramp up spending to achieve A-ACE. The OCC believes that testimony in this case conveys that the CEAB has been persuaded to adopt an incorrect assumption, namely that A-ACE is an inherent goal of IRP under the statutory language. OCC Brief, p. 8.

Based on the above, the OCC requests that the Department specifically disavow the assumption that an inherent goal of the IRP process is achievement of A-ACE.[5] Rather, the goal of the IRP process is to evaluate resource needs and perform a comparison of relevant resources, within the framework set forth in the statute and in the Department's Three Criteria Test.

4. Position of ENE

ENE supports the CEAB's finding that maximizing the identified cost-effective potential for energy efficiency resources provides the most favorable cost and environmental performance across the range of cases and sensitivities evaluated. ENE believes that the analyses conducted by the CEAB and the EDCs show that the additional energy efficiency resource potential identified is a significant resource option and is superior to the range of supply-side alternatives considered. Energy efficiency resources are cost-effective today and, more importantly, later in this decade and beyond 2020, proving to be significantly more cost-effective than any of the power supply options considered in this proceeding. ENE Brief, p. 1.

ENE further supports the Energy Efficiency Board's recommendation to pursue the benefits of the A-ACE energy resource strategy to provide significant energy cost savings for consumers and businesses, help meet environmental requirements, provide jobs and economic benefits, and achieve Connecticut's policy's objectives. ENE

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[5] Inherent in the notion that A-ACE is an assumed goal of IRP is the notion that A-ACE is an actual, achievable end-goal. This is clearly not the case. We will not be able to take stock in 2030 and say, "finally, we have achieved A-ACE"; no matter how much money we spend between now and then. This is so because of constant changes in codes and standards, the cost of efficiency measures, and improvements in technologies, which render A-ACE a constantly moving target rather than an end goal.

believes the Department should adopt this recommendation and increase funding as set forth in the Targeted DSM Expansion strategy as the next step to ramping up to the higher levels of customer energy efficiency described as A-ACE. The Department would then determine specific programs and details in the upcoming annual C&LM docket. Id., p. 2.

ENE agrees that the cost of energy, as captured in electric rates, is volatile and largely beyond the Department's control. However, the Department can influence lower energy costs by encouraging decreased energy consumption. Therefore, ENE urges the Department to procure increased levels of energy efficiency to meet Connecticut's energy resource needs in a manner that minimizes the cost of energy resources to consumer over time and maximizes consumer benefits consistent with the state's environmental goals and standard. Id.

ENE also believes the conclusion that sufficient capacity facilities exist to meet reliability requirements does not terminate the inquiry into whether the resource mix minimizes customer costs. According to ENE, just because the electric system can burn enough natural gas to meet total electric energy requirements, does not mean that such an approach is economically desirable for consumers of the State. Further goals of the statute direct the Department to determine the manner of how best to eliminate growth in electric demand and mitigate environmental impacts. Therefore, ENE concludes the Department is required to pursue additional energy efficiency in this proceeding. ENE Brief, pp. 3 and 4.

In support of its recommendation to pursue A-ACE, ENE notes that the Targeted DSM Expansion provides a very narrow focus consisting of four program areas that would not address many of the savings opportunities identified in the KEMA Potential Study. Thus, the corresponding incremental benefits from the Targeted DSM Expansion would be much smaller than those for the A-ACE Strategy. As a result, A-ACE is clearly the lowest cost energy resource option against all other scenarios and across all of the sensitivities examined. Id., p. 6.

ENE argues that an important factor in considering the benefits that DSM programs can bring to ratepayers and to the State is the effect that they have on the State's economy by contributing to the Gross State Product and increasing employment within Connecticut. While these economy-wide impacts were not included in the resource plan metrics, ENE believes that the Department should consider them as part of its evaluation of efficiency strategy benefits. Id., p. 7.

ENE cites environmental benefits in support of its position as well as pointing out that Connecticut has been designated as non-attainment for ozone, signifying an existing need for emissions reductions from all sectors. While Connecticut has already mandated economy-wide greenhouse gas emissions targets, the State, along with the rest of the country, already faces tighter standards, such as deeper reductions in ozone, CO_2, NO_x, SO_2, and other pollutants, including greenhouse gases. The EDC modeling demonstrates that, compared to the Reference Strategy, in a single snapshot year the A-ACE Strategy results in significant reductions in these pollutants. Further, peak load reductions from the A-ACE Strategy are estimated to be 561 MW above the Reference

Strategy, compared to an incremental 191 MW for the Targeted DSM Expansion. Id., p. 8.

Regarding the CEAB's recommendation to reengineer the current Energy Efficiency Fund programs, ENE cautions that many of the suggested methods have not been made clear nor have they been validated and not all of the key assumptions relied on by CEAB in formulating this recommendation are reasonable. In fact, certain assumptions appear overly optimistic. Despite this opinion, ENE thoroughly supports the CEAB's goals of finding innovative ways to make the programs as cost-effective as possible and finds that this goal has always been central to the Energy Efficiency Board's planning process and C&LM docket. However, while the shopping list of program improvements is an important tool, it can neither stand alone nor replace the added cost-effective efficiency attainable with increased investments. Id., p. 18.

In summary, ENE requests the Department approve the objectives of the A-ACE Strategy with an efficiency ramp-up that begins in 2011 with the goal of achieving A-ACE Strategy funding level within five years. ENE urges the Department to set budget levels and estimated annual energy savings targets for the next two years, and to direct the Energy Efficiency Board and the EDCs to develop detailed plans and budget modifications to reflect the ramp-up in the 2011 C&LM plan which should also include the longer-term budget and program details needed to achieve the full ramp-up. This process will allow the Department ample opportunity to review annual program plans and budgets to ensure that the programs meet cost-effectiveness requirements established by law. Id., p. 19.

5. Department Analysis

The Participants agree with the EDC and CEAB assessments that Connecticut is not forecasted to have a shortage of energy or capacity requirements during the statutorily-defined planning horizon. They therefore agree that no new generation resources should be procured at this time. The Department agrees with these conclusions. Despite these findings, which were also reached in Docket No. 08-07-01, the EDCs and ENE once again argue for a significant increase in spending for energy efficiency.

The first procurement recommendation by the CEAB is: Maximize the utilization of demand-side resources to achieve A-ACE while minimizing ratepayer impacts through the use of expanded financing options, market mechanisms, codes and standard, and other innovative approaches. 2010 CEAB Plan, p. 22. The CEAB proposes A-ACE but does not recommend any increases to the DSM budget due to the negative impact of rate increases. CEAB supports measures that will not impact rates, such as the use of existing funding to support additional financing, reconfiguring current DSM programs to increase cost-effectiveness, and implementing more stringent building codes.

The EDCs recommended a more modest increase to conservation they call Targeted DSM Expansion. The Targeted DSM Expansion is comprised of four initiatives that would target residential and business consumption The EDCs recommend increases of approximately $22 million to $36 million annually over the next eleven years. LFE-16. The EDCs did not recommend the A-ACE strategy, noting that under A-ACE that the "costs for non- participants would increase." EDC Plan 1-4- through 1-6. The EDCs agree that funding to achieve A-ACE at this time should not be authorized. However, the EDCs support increasing rates to support a ramp-up to A-ACE through the proposed Targeted DSM Expansion.

The 2008 IRP Decision states:

> Effectively, the DSM Focus Case sets an "install the maximum feasible DSM projects that are justified by the Total Resource Test" agenda. The Department believes this approach is an incorrect interpretation of §16a-3a(c), for several reasons. The Statute requires all cost-effective DSM to be installed before other resource types, <u>subject to the need for more resources</u>, but does not require the installation of all cost-effective DSM before the need for resources has been found. No need for new resources has been found in this proceeding. Second, the Department does not believe that it must automatically increase budgets simply because additional DSM spending will result in lower overall revenue requirements. The Department does not believe that "all cost-effective" simply means passing the electric cost or total resource test. The Department believes that revenue requirements and rate impacts to all customers must be considered when DSM funding is considered. Given the high rates in Connecticut, the state of the economy, and the current budget of approximately $104 million for 2009, increased expenditures are not warranted.

2008 IRP Decision, p. 47.

No new generation resources need to be procured at this time. So, in that regard little has changed since the 2008 IRP Decision. However, since that time the total C&LM budget has increased from $104 million for the 2009 program year to just over $123 million for 2010. The increase is due to funding provided by sources other than the three mill/kWh conservation assessment, such as the sale of Class III RECs and revenues from the RGGI. Revenues from these sources will continue going forward. See, Decision dated March 17, 2010, in Docket No. 09-10-03, <u>DPUC Review of The Connecticut Energy Efficiency Fund's Conservation and Load Management Plan for 2010</u>, and Docket No. 08-10-02 – <u>DPUC Review of the Connecticut Gas Utilities Forecasts of Demand and Supply 2009-2013 and Joint Conservation Plans</u> (2010 C&LM Decision), p. 6.

(a) Three Criteria Test

In the 2009 IRP Decision the Department established standards related to whether a procurement may occur even in the absence of a strict reliability need. The Department laid out what has come to be known as the Three Criteria Test for new resources to be authorized when there is no reliability requirement. The Department indicated it would consider performing a procurement of resources to lower costs or improve environmental quality if:

Criteria 1 - the proposal needs to be funded by ratepayer investment rather than market revenues, direct participant funding, private investor funding, or other market-based means;[6]

Criteria 2 - there is a great degree of certainty that the proposal will substantially reduce costs or produce savings for ratepayers that exceed the cost of ratepayers' investment or substantially improve the environment and any near-term rate increases do not cause substantial hardship to ratepayers;

Criteria 3 - products or services offered in the proposal will count toward satisfying Connecticut's energy or capacity requirements, can displace some existing older, more expensive, less efficient, more polluting resources, or, can reduce the future need for additional resources to meet Connecticut's requirements.

(b) Criteria 1

To meet criteria one the proposal needs to be funded by ratepayers.

All cost-effective DSM

The ECMB and ENE insist that all cost effective conservation must be pursued and funded by ratepayers. They strongly believe that the ultimate goal is A-ACE. EDCs support A-ACE, but propose to ramp up spending beginning with Targeted DSM Expansion. The CEAB proposes A-ACE but does not recommend any increases to the DSM budget due to the negative impact of rate increases. The OCC requests the Department address a recurring and legally unsupported notion among various parties to the IRP proceeding than an assumed goal of this process is the eventual implementation of A-ACE. OCC Brief, p. 7.

In their Written Exceptions, ENE suggests that the only method to interpret Conn. Gen. Stat. § 16a-3a is by reference to legislative history. See, ENE Written Exceptions, pp. 1-3. By this method they conclude that the statute requires the Department to approve the CEAB plan as filed and fund all cost effective EE regardless of impact on current rates. Although legislative history is a method to interpret a statute, it is but one of many. See, e.g., 82 C.J.S. §§ 311-398. Equally valid statutory constructions include construing statutes in context and harmoniously with other statutes, construing a statute with a presumption in favor of coordination and consistency with other statues and construing economic regulatory based statutes with an understanding of systemic effects caused by regulatory acts. Towards these methods of statutory construction of Conn. Gen. Stat. § 16a-3a the Department refers to Conn. Gen Stat. § 16-19e, "there shall be a clear public need for the services provided ... that the level and structure of

[6] This standard means the Department will consider procuring a project or resource if said project or resource requires direct ratepayer support because it is unlikely to be developed through market channels.

rates charged customers shall reflect prudent and efficient management"; all of which is reinforced by Conn. Gen. Stat. § 16-11.

In the 2009 IRP Decision the Department rejected the assumption that an inherent goal of the IRP is achievement of A-ACE, stating:

> The Department believes this approach is an incorrect interpretation of 16a-3a(c), for several reasons. The Statute requires all cost-effective DSM to be installed before other resource types, <u>subject to the need for more resources</u>, but does not require the installation of all cost-effective DSM before the need for resources has been found. No need for new resources has been found in this proceeding. 2009 IRP Decision, p. 47.

The goal of the IRP is to identify reliability, cost and environmental needs and then evaluate, in an integrated manner, the resources necessary to meet those needs. Identified needs should then be met through the most cost-effective means identified. While C&LM will be evaluated as part of this process, increased spending will only be approved to the extent warranted to meet needs. A-ACE is not a goal in itself.

Need for Funding

The Department views the A-ACE proposal as thoughtful and laudable; however, it does not satisfy the statutory requirement that would be necessary to approve the proposal. Significant ratepayer support for C&LM initiatives would be necessary to reach the level of conservation savings envisioned by A-ACE. The Department wholeheartedly supports increases to energy efficiency. The Department believes that more reasonable goals can be achieved and savings should increase over the planning horizon without large increases to program budgets.

Utility-sponsored programs have long been used to transform the market for a wide range of energy efficient products and services (e.g., compact fluorescent bulbs (CFLs), commercial lighting, and demand response programs). Market transformation in this regard generally implies that ratepayer funded financial support is necessary to stimulate the market for specific products or services because markets will not support them. In part, this has been necessary because historically, society did not value energy efficiency. As the product or service being supported becomes more generally accepted, or embedded in product standards, ratepayer support is no longer necessary and is therefore withdrawn. A recent example of such transformation is demonstrated by the penetration in market-based demand response activity that occurred as the Energy Efficiency Fund phased-out its support for these services.

Driven by global events, environmental concerns and significant and sustained increases in energy costs, energy efficiency is fast becoming a standard for an increasingly energy conscious nation; clearly a cultural shift is emerging. In response, Connecticut's energy policies have rapidly evolved over the last five years resulting in myriad programs and policy initiatives designed to reduce energy consumption, control peak demand and increase awareness about the benefits that energy efficiency provides. These programs include Energy Efficiency Partners, Stimulus funding and designating DSM as a Class 3 renewable energy resource. Independent conservation and demand side management projects can also sell capacity into the ISO-NE FCM market to generate revenues. Demand response resources have participated in significant numbers which continue to increase. These efforts, in addition to the programs sponsored by the Energy Efficiency Fund and Clean Energy Fund, have furthered the cultural shift noted above. Generally speaking, conservation and energy efficiency are being embraced by an ever increasing number of consumers. This presents an opportunity to move away from traditional approaches to stimulating interest in energy efficiency such as ratepayer funding for coupons, rebates or direct financial grants, and to pursue strategies that do not require increasing utility rates to achieve greater penetration.

As a result of this cultural shift, the Department is witnessing increased market-based demand for energy efficiency.[7] Therefore, unlike the atmosphere that existed in the early 1990s when energy efficient products and services were first introduced to the public, today's environment allows the Department to leverage this cultural shift and let markets work in advance of requiring rate increases to support rebates or incentives. Instead, the Energy Efficiency Fund should provide support for these market-based energy efficiency initiatives through education and outreach.[8] This is not to say that financial support for technologies or service is unwarranted. Rather, the Department must be convinced that markets will not support an initiative before increasing rates to support it.

Based on the foregoing, the evidence does not support a finding that the proposal needs to be funded by ratepayer investment rather than market revenues, direct participant funding, private investor funding, or other market-based means. Therefore, the proposal fails Criteria 1. As discussed below, the Department has supported additional financing for over five years and views this as another way of achieving greater market participation.

(c) Criteria 2

Rate Impacts

The CEAB and the EDCs have analyzed a vast amount of information and presented it in a format that is easy to understand in their 2010 IRP. As part of the analysis, several metrics were used to compare resources with regard to reliability, cost and environmental impacts. The cost metric most commonly used to justify increased DSM expenditures compares the total generation cost. This is a comparison of the cost of conservation to other generation options. Under this analysis, conservation results in a lower overall revenue requirement than other resource options.

The lower costs from DSM can be somewhat misleading when considering the impact to non-participants. The CEAB Plan states that nearly all the benefits of reduced electric bills from the current efficiency programs are captured by the program

[7] Implementation of the Class III REC market is another example of market-based activity that does not rely on direct ratepayer funding.

[8] As an example, the first CFLs required a significant ratepayer supported subsidy to increase consumer awareness and acceptance and to overcome a price tag of up to $20/bulb.

participants, while incentives are paid by all ratepayers including non-participants. Although there are large participant benefits, DSM programs are still predicted to remain a net cost to non-participants. CEAB Plan, p. 77. The OCC noted that many of the cost reduction benefits from DSM relate to avoided energy, which are captured by participating customers. OCC's calculations indicate that of the $90 million in total net benefits projected for the Targeted DSM Expansion in 2020 $82 million, or 91%, accrues to participants through avoided electricity costs leaving only $8 million, or 9% of net benefits for non-participating load. OCC PFT p. 21.

The CEAB and the EDCs did a good job in presenting their analyses. However, although rate impact concerns were acknowledged, and were considered in molding the CEAB and the EDC C&LM recommendations, the rate impact analysis was inadequate. While the rate impact analysis addressed the impact that C&LM processes can have on generation costs it failed to include the potential rate increase that occurs when transmission and distribution costs are shifted to other customers. As a result, the Department believes that the rate impacts of the Targeted DSM Expansion and A-ACE conservation options are calculated incorrectly, significantly understating the rate increases that will result from higher DSM expenditures.

The Department addressed the difference between costs and rates in the 2009 IRP Decision, concluding that a balanced approach is appropriate and that consideration of both revenue requirements and rate impacts must be considered when evaluating resource options in the IRP. 2009 IRP Decision, pp. 20 and 21 and 45-48. The Decision states:

> [t]he Department does not believe that it must automatically increase budgets simply because additional DSM spending will result in lower revenue requirements. The Department does not believe that "all cost effective" simply means passing the electric or total resource test. The Department believes that the revenue requirements and rate impacts to all customers must be considered when DSM funding is considered. 2009 IRP Decision, p. 47.

In the 2008 IRP Decision, the Department stated, "Connecticut has the highest electric rates in the continental U.S. and many ratepayers in Connecticut are experiencing financial hardship in the current economic downturn." 2008 IRP Decision, p. 49. In the Decision dated June 30, 2010, in Docket No. 09-12-05, Application of The Connecticut Light and Power Company to Amend Its Rate Schedules, (CL&P 2010 Rate Decision) the Department recognized that CL&P rates were among the highest in the nation and many Connecticut residents have felt the impact of the current economic downturn and continue to struggle. The Department also recognized that the slowdown has created even more stress on low income families and that uncollectibles, while at historical levels, continue to increase each year." CL&P 2010 Rate Decision, p. 2. In the Decision dated June 30, 2009, in Docket No. 08-07-04, Application of The United Illuminating Company To Increase Its Rates and Charges – Reconsideration, (UI 2009 Rate Decision) the Department stated, "given that UI's rates are among the highest in the country the Department must retain incentives for UI to control its costs with the goal of achieving lower rates." UI 2009 Rate Decision, p. 128. Despite a significant increase to the C&LM budget in 2010 and the repeated concern surrounding electric rates expressed by the Department in a variety of proceedings the Participants to this proceeding persist in their attempt to further increase electric rates. In addition, the Department notes that the CEAB states that recent legislative action redirecting funds from the C&LM Societal Benefits Fund to the general fund underscores the need to find more funding and more non-ratepayer funded sources for energy efficiency, like those described in the CEAB Plan.

The Department has also discussed the importance of rates in its annual C&LM Plan decisions. The Department has required the EDCs to include the rate impact of each C&LM program in their annual conservation filing and ordered improvements to the methodology in the latest decision. 2010 C&LM Decision, p. 59. The Department continues to believe that rate impact is important and therefore will require the CEAB and the EDCs to include a metric for rates when comparing resource options. This metric must include a base case for rates and a comparison of the impact under different resource options and should include the full impact on total rates

Cost of DSM

The Department would like to see large increases to conservation without increasing ratepayer funding as proposed by the CEAB. The Department supports more financing and has been working on this over the past five years. The Department also welcomes and encourages any new ideas to improve programs. Each year programs are scrutinized at the time of the annual C&LM filing. The programs are constantly evolving to reduce costs and improve efficiency. Realistically, however, the Department does not believe that huge increases in C&LM, approaching A-ACE can be accomplished at this time without significant ratepayer funding. The EDCs estimated that A-ACE could cost $65 million annually. It is within this context that the EDCs evaluated A-ACE and in which the Department will evaluate this proposal.

Late Filed Exhibit 16 provides information regarding the cost of DSM used by the EDCs and the CEAB in their analysis of resource options. The exhibit includes the costs for the Reference Resource Strategy, Targeted DSM Expansion and A-ACE. The exhibit indicates that the cost per kW will decline by approximately 32% in 2011 from $2,498/kW in the Reference Resource Strategy case to $1,741/kW in the Targeted DSM Expansion case. The costs are reduced further in the A-ACE case to $1,235/kW, or 50% lower than the Reference Resource Strategy. Costs increase on a kWh basis in the Targeted DSM Expansion case, but decline under A-ACE from 3.5 cents/kWh to 2.2 cents/kWh in 2011.

The Department has limited faith in these estimates. C&LM costs have been increasing annually on a kW basis and to achieve increased savings through increased DSM expenditures, requires the EDCs to pursue more expensive, less cost-effective measures. It is difficult to imagine that with new lighting and other appliance efficiency standards how costs per unit of savings will decline in the future as incremental expenditures increase. As an example, the Department for years has directed the EDCs and the Energy Efficiency Board to improve the cost effectiveness of the Residential New Construction program which is expected to cost CL&P $4,530/kW and 6.1 cents/kWh during the 2010 C&LM program year. 2010 C&LM Plan, Table B. In the

IRP filing the EDCs propose a Zero Energy Homes program, an initiative that is similar to the Residential New Construction program but which includes additional, more costly measures. The cost is estimated at approximately $1,071/kW and 2 cents/kWh. EDCs Response to Interrogatory OCC-3. The Department can only ask: "if such cost reductions are possible, why haven't they been implemented under the existing C&LM budgets?"

The Department recognizes that the IRP proceeding is an overview of the issues and not a venue for detailed program planning. At the same time, it is important to have reasonable estimates and feasible program plans to compare resource options in the IRP process. At present there are few if any consequences to the EDCs for poor C&LM estimates, lower savings or higher program costs. Incentives may decline if costs are higher than expected but there are no penalties. Lower savings have even less of an impact. For instance, if an impact evaluation determines that savings were lower than planned, the estimates will be adjusted for the next year; but there is no impact on the company's incentive. DSM should be held to the same standards as other types of energy projects. For instance, in most cases the contracts with renewable projects, peaking and base load generators and non-utility administered DSM projects (e.g., the capacity contract with Ameresco) have defined pricing terms and strict deliverables for capacity and energy. Failure to meet these standards results in penalties to the responsible party. The Department will require program administrators to live within their estimates of program costs and savings by designing incentives that align with the above noted standards for other projects if DSM expenditures are increased in the future.

Based on the foregoing, there is a not a great degree of certainty that the A-ACE proposal will substantially reduce costs to customers. Overall generation costs would decline from additional DSM but most of these benefits are captured by participating customers. Rates to all customers would likely increase electric bills to non participants. Thus, additional DSM would raise costs to many ratepayers and would not be cost effective. There is considerable uncertainty associated with the cost of additional C&LM programs. Nor is there evidence that any near-term rate increase necessary to support the proposals would not cause hardship to ratepayers. Therefore, the proposal fails Criteria 2. As discussed below, the Department has scrutinized and reconfigured programs annually since 2000 to improve cost-effectiveness.

(d) Criteria 3

In order to satisfy the third criterion A-ACE would need to satisfy Connecticut's energy and capacity requirements, displace older, expensive, less efficient more polluting resources and reduce the need for additional resources. DSM does help to meet Connecticut energy and capacity requirements. There is uncertainty to the exact savings attributable to conservation activities, however, DSM reduces energy consumption and thereby reduces pollution that would be produced from other generation sources. DSM also provides capacity value regardless of whether it can be sold into the ISO FCM market, since system demands are reduced. The value of capacity however is low at this time due to excess capacity. Therefore there is little likelihood that new generation resources will be avoided over the next ten years.

6. DSM Conclusion

For the foregoing reasons, the A-ACE proposal to procure more DSM resources does not pass the Three Criteria Test. Therefore, the Department will not authorize an increase to customer rates to fund it. The Department believes that large increases to the DSM budget would be required, adversely impacting rates.

The Department supports increased energy efficiency but reasonable objectives must be pursued. The Department believes that a goal of zero demand growth as proposed by the EDCs under their Targeted DSM Strategy is appropriate. The EDCs, however, estimate that this strategy would require an additional outlay of approximately $22 to $36 million annually through 2020.

The Department believes that zero demand growth is an appropriate goal and may be achievable within current spending levels through the strategies suggested by CEAB, discussed below, which minimize the need for additional funding by ratepayers. However, this may require the reallocation of current budgets. Therefore, the Department will require the EDCs to examine this issue and be prepared to address it in the Department's review of the 2011 C&LM Plan.

The Department will pursue greater efficiency through strategies it has encouraged for many years; specifically, expanding financing options and market mechanisms, and by supporting energy efficient codes and product standards, as a way to complement and expand current initiatives in order to leverage the energy-related cultural shift Connecticut and the nation are experiencing. The Department will also continue to examine and refocus all C&LM programs to maximize energy efficiency at the lowest possible cost. The Department fully supports an effort to redirect current spending within the customer class spending guidelines (i.e., rate class parity) noted above in an effort to refocus ratepayer funded programs to increase savings and improve the cost-effectiveness of these programs. The Department's support for redirecting current funding by eliminating high cost programs is not new and is also well documented in past C&LM Decisions. See, 2006 C&LM Decision, p. 8, Residential New Construction Program.

The Department will not rule on the programs included in the Targeted DSM Expansion proposal by the EDCs at this time. The Department will allow the EDCs to submit additional program proposals at the time of their annual C&LM filing. The Department must point out that funding even this additional level of DSM may not be possible immediately. Unfortunately, legislative actions through the adoption of Public Act 10-179 will take approximately $19 million from the C&LM fund in 2012 and $27 million annually from 2013 through 2018 to help reduce the State deficit. The Department will consider how to deal with this reduction and any program modifications and new proposals at the time of the annual C&LM review.

In its Written Exceptions ENE criticizes the Department's decision to not increase customer rates in order to pursue additional energy efficiency, stating that despite clear legislative direction to "meet the state's energy needs first with all available energy efficiency" the Department refuses to approve any additional investment to provide consumers the tools necessary to comply with this directive. In so doing, the

Department has substituted its judgement for that of the General Assembly. ENE Written Exceptions, p. 2.

ENE also states that "Connecticut will see its C&LM investments tumble in the near term "as the result of the expiration of ARRA funding and the 35% diversion of funding pursuant to Public Act 10-179," leaving the programs with reduced funding within the biennial time frame of the current IRP. ENE notes that this reduced spending comes at a time when surrounding states are ramping up their investment in energy efficiency, citing for example Rhode Island's commitment to "ramp-up efficiency spending from $14 million in 2008 to more than $43 million in 2011 for all customer sectors." ENE Brief, p. 4. ENE also indicates that the Massachusetts Department of Public Utilities approved a three-year plan to investment about $1.2 billion in electric efficiency programs and approximately $355 million in natural gas programs. ENE believes this increased spending will leave Connecticut vulnerable to an exodus of energy efficiency vendors and a relocation of jobs to areas where there is a more sustained level and commitment to C&LM spending. Id., p. 3.

Finally, ENE states:

> Policymakers enacted P.A. 07-242 to provide Connecticut's residents and businesses with the tools to take control of their energy use. These are not the tools the legislature intended to make available only when Connecticut was resource constrained. Rather, the purpose of the IRP was to implement a comprehensive energy plan for the state, while increasing our energy independence and moving away from the need for building new, expensive fossil-fuel power plants. Id., p. 5.

Commencing with Public Act 98-28, An Act Concerning Electric Industry Restructuring and culminating with Public Act 07-242, An Act Concerning Energy Independence, the General Assembly has provided myriad tools over the last decade to address Connecticut's energy needs and keep pace with rapidly changing energy policies over this time. The result has been a wide range of programs and policy initiatives designed to reduce energy consumption, control peak demand and increase awareness about energy in general. These efforts include the following:

- ✓ Connecticut Energy Efficiency Fund
- ✓ Connecticut Clean Energy Fund
- ✓ The Distributed Generation Grant Program;
- ✓ The Electric Energy Efficiency Partners Programs;[9]
- ✓ Mandatory TOD rates of large use business customers[10];
- ✓ Voluntary variable peak price tariffs;
- ✓ Revised net metering standards to encourage smaller renewable projects;
- ✓ Increased efforts to enroll customers in demand response programs;
- ✓ Short-term measures under Docket No. 05-07-14;
- ✓ Class III RECs;

Most of these initiatives operate under the traditional model in which rates are increased to cover the cost of the programs, which include customer and utility incentives, while others increase rates by providing revenues to support market participants, such as Class III RECs. As noted herein, Connecticut has supported energy efficiency for over two decades and has seen a ramp-up to current funding levels during this time. As a result, Connecticut has supported energy efficiency at levels that far exceed the historical spending of surrounding states and most states nationally. The increased spending in Massachusetts and Rhode Island therefore reflect these states "catching up" to Connecticut. To illustrate, the Department provides the following tables. National Grid serves about 465,000 customers in 38 Rhode Island communities.[11] Therefore, using the $14 million and $43 million cited by ENE, (and assigning this spending only to National Grid) National Grid spent about $30/per customer in 2008 to fund these investments ($14 million/465,000) and will spend about $92/per customer in 2011.

By comparison, in 2000 Connecticut's three mill/kWh assessment provided about $90 million[12] to the Energy Efficiency Fund, for spending of about $63/customer, over twice the historical National Grid amount. Customers were assessed the three mill/kWh charge from 2000 to present.[13] In 2010,[14] spending increased to about $86/customer.[15]

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[9] This program alone has the potential to increase ratepayer funding for energy efficiency by $60 million per year. This equals about 66% of the current statewide C&LM budget.

[10] Implementation of mandatory TOD rates for residential customers has been delayed pending the outcome of the Department's investigation of metering options for CL&P. See, Decision dated December 19, 2007, in Docket No. 05-10-03RE01, Application of The Connecticut Light and Power Company To Implement Time Of Use, Interruptible Or Load Response, And Seasonal Rates – Review Of Metering Plan.

[11] National Grid website, www.nationalgridus.com/narragansett/about_us/aboutus.asp.

[12] These revenues are based on combined annual sales for CL&P and UI of approximately 30 billion kWhs.

[13] Between 2000 to present, customers have contributed three mills/kWh to the Energy Efficiency Fund. However, during this period Legislative action has diverted some of these revenues.

[14] A significant increase to spending occurred in 2000 with the creation of the Energy Efficiency and Clean Energy Funds. Total spending on energy efficiency further increased in 2006 as the result of spending authorized under Public Act 05-01, An Act Concerning Energy Independence. This increase was funded through the Non Bypassable Federally Mandated Congestion Charge on customer bills. Additional spending occurred in 2007 with the infusion of other revenues, such as those provided under the RGGI.

These amounts do not include spending for Connecticut's Clean Energy Fund, which totals about $30 million annually (30 billion kWh x one mill/kWh), or an additional $21/customer per year. The second table below shows the impact of including Clean Energy Fund spending.

Table 4

	Connecticut		National Grid	
	2000[1]	2010[2]	2008	2011
Budget	$90,000,000	$123,300,000	$14,000,000	$43,000,000
No. of Customers[3]	1,425,000	1,425,000	465,000	465,000
Spending per customer	$63.16	$86.53	$30.11	$92.47

[1] Revenues based on three mill/kWh assessment only and combined sales (CL&P & UI) of approximately 30 billion kWh.
[2] Reflects all revenue sources for the 2010 budget. 2010 C&LM Decision, p. 6.
[3] Customers - Approximate number of customers for CL&P 1.1 million; for UI 325,000.

Table 5

	Connecticut		National Grid	
	2000[1]	2010[2]	2008	2011
Energy Efficiency	$90,000,000	$123,300,000	$14,000,000	$43,000,000
Clean Energy Fund	$30,000,000	$30,000,000	-	-
Total	$120,000,000	$153,300,000	$14,000,000	$43,000,000
No. of Customers[3]	1,425,000	1,425,000	465,000	465,000
Spending per customer	$84.21	$107.58	$30.11	$92.47

[1] Revenues based on three mill/kWh assessment only and combined sales (CL&P & UI) of approximately 30 billion kWh.
[2] Reflects all revenue sources for the 2010 budget. 2010 C&LM Decision, p. 6.
[3] Customers - Approximate number of customers for CL&P 1.1 million; for UI 325,000.

Some of the above noted programs are mature while others have only begun to achieve their energy savings potential. For instance, the Energy Efficiency Fund and Clean Energy Fund have been in place for over ten years while the Electric Efficiency Partners Program was established only recently. Combined with increased opportunities for financing, enhanced code enforcement, and improved appliance standards, these programs and the emerging cultural shift offer an unprecedented opportunity to produce significant energy savings without increasing to utility rates. However, this potential has not been measured or considered. The Department believes it appropriate to consider these impacts before we burden ratepayers with additional increases to electric rates.

7. Other CEAB Recommendations

(a) Financing

CEAB recommends that a strategy to implement A-ACE must consider a broader portfolio of financing mechanisms and implementation approaches. In support of its recommendation CEAB indicates that one of the most significant barriers to investment in energy efficiency is access to investment capital. This can be especially true for

[15] These are arithmetic averages of total revenues divided by total customers and are illustrative only. The actual customer contribution varies by class and consumption and is based on the three mill/kWh assessment.

households and small businesses that either don't have the cash on hand to invest in energy efficiency or do not have access to financing at attractive rates. Even though energy efficiency can save money for years after the initial investment is made, the initial cost of the energy efficiency, even with incentives or rebates offered by government and utility programs, can be a significant obstacle to implementation of even the most cost-effective energy efficiency measures. For that reason, energy efficiency financing offered by the Energy Efficiency Fund program administrators and other entities such as banks, manufacturers, leasing companies and energy service companies is a key feature of successful EE programs. Finally, CEAB lists a variety of financing models that should be considered. CEAB Plan, pp. 294-305.

The Department believes that residential and business consumers are eager to reduce their energy consumption and/or address their peak electric demand. However, many consumers cannot afford energy efficiency projects that require a capital investment; projects that can provide significant and sustainable savings. In addition, the current lending environment and general economic conditions have made it difficult for customers to access financing for these projects through traditional channels. As a result, many projects do not proceed resulting in lost savings opportunities. Providing easy access to lower cost financing for energy efficiency is critical to addressing this barrier.

The Energy Efficiency Board and Department have long recognized the benefits that financing provides in achieving energy savings. For example, for years small business customers have been afforded the opportunity to finance their energy efficiency projects through unsecured loans offered at zero percent interest with convenient on-the-bill loan repayment offered through the Energy Efficiency Fund's Small Business Energy Advantage (SBEA) Program. The benefits of this financing model and its relationship to the success of the SBEA program are well documented. See the Decision dated June 19, 2008, in Docket No. 07-10-03 <u>DPUC Review of The Connecticut Light and Power Company's And The United Illuminating Company's Conservation and Load Management Plan For Year 2008</u>, (2008 C&LM Decision), pp. 28-31.

CL&P and UI provide the capital that is loaned under the SBEA program, earning interest on these funds at each company's respective allowed rate of return. The Energy Efficiency Fund supports the interest paid to the utilities (i.e. the interest buy-down) as well as the cost of any loan defaults. As such, these are guaranteed investments. This lending structure leverages Energy Efficiency Fund dollars into a larger loan pool. However, the total available capital for these loans is limited to the amount each utility is willing to invest. As a result, the total number of projects and resulting energy savings are limited. Securing lower cost capital for these loans would reduce the cost to the Energy Efficiency Fund thereby allowing more projects to proceed. Therefore, greater energy savings would be achieved.

(b) Residential Financing

The Department has addressed the need to expand the availability of residential financing for energy efficiency in several C&LM decisions since 2002. See the Decision dated March 17, 2010, in Docket No. 09-10-03, <u>DPUC Review of The Connecticut</u>

Energy Efficiency Fund's 2010 Conservation and Load Management Plan For 2010 and Docket No. 08-10-02, DPUC Review of the Connecticut Gas Utilities Forecast of Demand and Supply 2009-2013 and Joint Conservation Plan, (2010 C&LM Decision), pp. 31-40; the Decision dated September 24, 2008, in Docket No. 07-10-03RE01 DPUC Review of The Connecticut Light and Power Company's and The United Illuminating Company's Conservation and Load Management Plan For Year 2008 - Program Incentive Structure, (Reopened 2008 C&LM Decision), pp. 15-17; the Decision dated May 23, 2007, in Docket No. 06-10-02, DPUC Review of CL&P and UI Conservation and Load Management Plan for Year 2007 and 2008, (2007 C&LM Decision), p. 15; the Decision dated June 7, 2006 in Docket No. 05-10-02, DPUC Review of The Connecticut Light and Power Company and The United Illuminating Company Conservation and Load Management Plan for 2006, (2006 C&LM Decision), pp. 4-6; the Decision dated March 30, 2005, in Docket No. 04-11-01, DPUC Review of CL&P and UI Conservation and Load Management Plan For Year 2005, (2005 C&LM Decision), p. 27; Decision dated May 28, 2003, in Docket No. 03-01-01, DPUC Review of The Connecticut Light and Power Company's and The United Illuminating Company's Conservation and Load Management Programs and Budgets for Year 2003 and 2004, (2003 C&LM Decision), pp. 18-20; and, Decision dated May 29, 2002, in Docket No. 02-01-22, DPUC Review of The Connecticut Light and Power Company's and The United Illuminating Company's Budgets and Modifications for Conservation and Load Management Activities for Year 2002 (2002 C&LM Decision), p. 24.

In summary, the Department has sought to provide residential customers the same benefits that are available to business customers by implementing an SBEA-like financing and repayment model for the residential class.

The above noted rulings culminated in the implementation of a residential finance pilot (Finance Pilot) which was launched on May 26, 2010. 2010 C&LM Decision, pp. 31-40; Docket Nos. 09-10-03 and 08-10-02, letters dated June 2, and July 1, 2010. As recommended by the Energy Efficiency Board's Residential Financing Committee, the Financing Pilot established a $5 million loan buy-down and/or reserve pool (Loan Reserve) using Energy Efficiency Fund dollars in an attempt to attract private investors or potentially publicly invested funds (e.g. State Treasurer's Office). CL&P and UI issued an RFP to select a financial institution to support the Finance Pilot to attract lower-than-market rates for these risk-free investments. The response to the RFP was limited and resulted in the Companies securing relatively high cost capital. See, letter dated June 25, 2010, in Docket Nos. 09-10-03 and 08-10-02. As a result, the Loan Reserve will support fewer projects than could have been financed if lower cost capital had been secured. Despite this challenge, the Finance Pilot is underway and will provide valuable insight regarding residential customer interest in energy efficiency stimulated through unsecured loans at attractive rates.

Key features of the Finance Pilot include:

- The Finance Pilot offers tiered interest rates of 0.00% and 2.99% towards the implementation of recommended eligible energy efficiency measures;
- There are no income restrictions;
- *Loans are unsecured;*

- Minimum amount eligible for financing is $2,500 per household;
- Maximum amount eligible for financing is $20,000 per household;
- Loan repayment term ranges from 12 to 120 months for all amounts financed; and,
- Direct billing is done by the financial institution, i.e., no on-the-bill repayment.

A Loan Reserve enables the Energy Efficiency Fund to create leverage in attracting multiples of the initial reserve. The Energy Efficiency Board's Residential Finance Committee estimated that a reserve could leverage between five and ten times the amount of the reserve.[16] 2010 C&LM Decision, p. 36. Funds not used by losses are recycled into the reserve to be leveraged again into new loans. Similar to the SBEA Program, the Finance Pilot has been structured to be nearly risk-free for the entity providing the capital. Id.

The Finance Pilot only recently began and the Companies report that $1 million in loans has been committed in the first five weeks. As a result, the Companies believe the Finance Pilot shows great promise in encouraging customers to make energy efficiency upgrades and improvements to their homes that will provide long-term benefits. While this information is far from conclusive, it is very positive. Docket Nos. 09-10-03 and 10-02-07, letter dated July 14, 2010. The Department and Energy Efficiency Board will continue to explore ways to expand residential and business financing and to aggressively pursue the use of publicly invested funds for this purpose.

(c) Building Codes, Market Mechanisms and Other

It is widely accepted that integrating energy efficiency into any building during its design and construction is far more cost-effective than attempting to retrofit a structure once it has been built. Thus, building codes provide the means to assure that energy efficiency is incorporated into Connecticut's homes and businesses. While these codes may impact the cost of construction, they do not increase utility rates. Therefore, enacting and ensuring compliance with energy efficient building codes provides another strategy to pursue additional cost-effective conservation and energy efficiency measures without increasing rates. However, energy-related building codes only achieve their savings potential when enforced and the degree to which code compliance is being achieved is unclear. The Department is aware of this issue and has directed the Energy Efficiency Board to study the matter and develop proposals to improve compliance and promote efficient building practices in Connecticut. See, 2010 C&LM Decision, p. 49.

Lack of compliance implies that the building community is either not aware of the codes, doesn't know how to implement them, or is deliberately avoiding them. In its analysis of this issue the Department stressed the critical role that education[17] plays in fulfilling this potential, stating:

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16 Due to the higher interest costs for the Finance Pilot, the program will only support about three times the Loan Reserve, or about $15 million in total loans.

17 The Department's support for education in general is well documented. See, Decision dated May 7, 2009, in Docket No, 08-10-03, DPUC Review of The Connecticut Light and Power Company's and The United Illuminating Company's Conservation and Load Management Plan For the Year 2009, pp. 3, 15, 16, 20, and 24-30; Decision dated June 19, 2008, in Docket No. 07-10-03 DPUC Review of

> The Department believes that ISE [Institute for Sustainable Energy] performs an essential role in training building inspectors and administers its operations very cost-effectively. The Department would like to support ISE to the extent that it wishes to initiate additional activities to promote better code compliance, such as additional courses, resources for curriculum development, on-line instruction, assistive technology, etc. To obtain additions to its 2010 budget, ISE should present any proposals to the ECMB. According to ISE, the key to energy efficient building practices is incorporating energy efficiency training in building design and construction curriculum and developing curriculum within vocational schools and community colleges to emphasize efficient technologies and practices is critical to success. The Department directs ISE and the ECMB to work toward developing a strategic plan and a budget for curriculum development in vocational schools and community colleges to be submitted in the 2011 C&LM Plan.
>
> 2010 C&LM Decision, p. 49.

Code compliance will be assured if the building community embraces these standards. However, anecdotal evidence suggests that it can sometimes be difficult to change the culture of the building community as relates to construction standards generally. Therefore, the cultural change regarding energy efficiency must be leveraged to assure that members of the building community recognize the value that energy efficiency provides so that ever changing and increasingly more stringent efficiency standards are not viewed as burdensome or onerous but as beneficial (e.g., an efficient home has greater market value). Based on the foregoing, while building codes have advanced over time we should move more quickly toward higher efficiency standards while simultaneously providing the education necessary to have everyone involved in the construction industry understand the benefits of these requirements and how to incorporate them into their everyday practices.

Market mechanisms, such as the Energy Efficiency Fund's Retail Products Program, also provide opportunities to educate consumers. The Department has long recognized the value that these programs provide and has supported their use since the Energy Efficiency Fund's inception. This support is well documented in the Department's C&LM Decisions. In 2010, these efforts will escalate as the Department has directed the Energy Efficiency Fund to take aggressive steps toward market transformation efforts for mature products. For example, beginning in 2010, the EDCs

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<u>The Connecticut Light and Power Company's and The United Illuminating Company's Conservation and Load Management Plan For Year 2008</u>, pp. 17-19, 22, and 36; and, Decision dated September 19, 2001, in Docket No. 01-01-04, <u>DPUC Review of The Connecticut Light and Power Company And The United Illuminating Company Conservation and Load Management Plan For Year 2001</u>, pp. 5, 11-13, 16-20, and 26. Other examples of educational efforts include the SmartLiving Center and Energy Information Line, 877-WISE USE.

will conduct intensified marketing efforts starting with compact fluorescent lighting products. See 2010 C&LM Decision, pp. 60-67.

Embedding energy efficiency into product standards will provide the same benefits that embedding efficiency into building codes, provide; that is, capturing long-term energy efficiency without increasing utility rates. However, higher energy efficiency typically adds cost to a product. While higher prices in the past may have created a barrier to a consumer's buying decision, increased awareness about the need to use energy wisely is likely removing this barrier. Therefore, consumers are more likely than ever to accept stringent product efficiency standards. As a result, this strategy too should be aggressively pursued.

(d) Refocus Ratepayer Funded Programs

The CEAB recommends that ratepayer funded programs be refocused to optimize their role in the overall implementation of A-ACE, a strategy that would not increase rates but rather redirect current spending to increase energy efficiency. The Department agrees with this approach but notes that the Energy Efficiency Fund Programs are constantly being reviewed and modified to maximize savings at lower cost. This too is well documented in the Department's C&LM Decisions. A recent example is the Residential Finance Pilot in which the EDCs modified the program's guidelines within the first six weeks of the program to assure more projects could be completed at an overall lower cost. See Docket No. 09-10-03, letter dated July 14, 2010. See also the Department's directives to reduce the cost of the Energy Star Homes Program in the 2006 C&LM Decision, p. 8.

Further, the Department, Energy Efficiency Board and EDCs have long been aware that targeting energy efficiency efforts at larger commercial and business applications will provide greater savings at lower cost. However, to assure parity in the allocation of Energy Efficiency Fund revenues, the Energy Efficiency Board recommended, and the Department approved, a standard by which spending for each major customer class would, within reasonable limits, mirror each class' contribution to that fund. Therefore, if recommended by the Energy Efficiency Board, this policy could be reviewed to allow a greater emphasis on the allocation of funds to commercial and industrial applications. However, this significant shift in policy must be fully vetted in a C&LM proceeding.

(e) Energy Efficiency: The Most Efficient Use of Fossil Fuels

The EDCs state that of the four measures proposed under the Targeted DSM Expansion, that the Chiller Retirement Initiative achieved significant and immediate peak load reduction. The EDCs indicate that although this program was successful in identifying and replacing several large chiller installations, not all identified projects were allowed to proceed due to funding constraints. Since chiller loads are one of the largest contributors to Connecticut's summer peak demand, reinstating this initiative would target this market opportunity. Therefore, the EDCs acknowledge that accelerating chiller replacements is one of the best ways to reduce summer peak kW demand while offering substantial energy savings to the customer. EDC Plan, p. 2-13.

The Chiller Retirement Initiative achieved reductions totaling approximately 55 MW by replacing working, but older, electric chillers with higher efficiency electric chillers. However, significant additional peak load reductions, totaling potentially hundreds of MWs, would have been achieved had natural gas engine driven chillers been selected to replace some or all of these units. It is not clear whether the option to select gas chillers was presented to these customers.

The traditional approach to conservation and load management has not focused on determining the most efficient use of the fuel needed to power end use equipment or the environmental impact of these decisions. Instead, as the Chiller Retirement Initiative demonstrates, energy efficiency has meant reducing the electricity needed to power electric equipment. The current energy environment and cultural shift noted above demands that we modify our approach and look to determine the most efficient use of the fuel used to power our needs. Fuel switching must be examined to achieve this benefit. Therefore, a comparison of the costs and benefits of alternate fuels (where applicable) must be integrated into the review of C&LM activity.

In addition, because some energy-related decisions require immediate action to address "emergency" situations, some efforts must target the early retirement of working equipment to achieve this goal. As an example, the failure of a residential electric water heater requires an immediate replacement of the equipment. As a result, while propane or natural gas may be the most efficient use of the fuel needed to supply domestic hot water (and where these fuels may be available to the homeowner) the opportunity to capture these savings and benefits is lost for the life of the replacement electric water heater because of the need to immediately replace the failed equipment. This situation will repeat itself when the electric water heater fails in the future. The Department is interested in aggressively pursuing the above strategies and will require the EDCs to submit information for its review. The EDCs shall provide the information necessary to develop a comparison of each customer's electric and gas options for chillers and residential electric water heaters. This matter will be more fully explored during the 2011 C&LM Plan review.

F. RENEWABLE ENERGY SOURCES

1. Connecticut RPS Requirements

Conn. Gen. Stat. §§ 16-245a and 16-243q establish annual requirements for Class I,[18] Class II[19] and Class III[20] resources. The RPS requires 7% of electric supply to be met by Class I resources in 2010, rising annually to 20% in 2020. The Class II resource requirement remains at 3% until 2020, and Class III requirement stays at 4% until 2020. Connecticut RPS annual requirements are as follows:

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[18] Wind, solar thermal, photovoltaic, wave, tidal, ocean thermal, landfill gas, low-emission sustainable biomass, fuel cells, and qualified small (<5 MW) hydroelectric.

[19] Other biomass, other small hydroelectric, municipal solid waste facilities.

[20] Energy efficiency measures, CHP installed after January 1, 2006; waste heat recovery installed after April 1, 2007.

Table 6

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%

Conn. Gen. Stat. §§ 16-245a and 16-243q

As another policy instrument to develop renewable energy, Conn. Gen. Stat. § 16-244c(j)(2) requires the Department to implement long-term contracts for 150 MW of in-state installed renewable energy between the EDCs and renewable energy projects (Project 150). The Department has fulfilled its requirement to procure 150 MW pursuant to its statutory requirements.[21] Subsequent to Department approval, project developers of several approved projects have indicated that constrained financial markets have rendered the projects unfinanceable, as discussed below.

2. EDC Renewable Forecasts

A thorough analysis of Connecticut's Class I resource adequacy can only be viewed as part of a regional trading market. Each of the New England states has an RPS that requires renewable energy resources as a percentage of the production mix. Although there is a small variation in the types resources that qualify as renewable energy sources, all New England states have qualified solar, wind, small hydroelectric, ocean and biomass[22] (subject to emission limits and other qualifications) as renewable resources. The renewable attributes of these qualified resources are traded as RECs in a regional settlement account, the New England Power Pool Generation Information System (NEPOOL GIS). In addition, Connecticut and other New England states have also allowed renewable resources generated in adjacent operating systems to satisfy their respective state's RPS requirements.

[21] See Docket Nos. 03-07-17RE03, DPUC Review of Long-Term Renewable Energy Contract—Round 1 Results and Contract, Accounting and Allocation Issues Decision dated September 27, 2006; Docket No. 07-04-27, DPUC Review of Long-Term Renewable Contracts—Round 2 Results Decision dated January 30, 2008; and Docket No. 08-03-03, DPUC Review of Long-term Renewable Contracts – Round 3 Results; Decision dated April 8. 2009.

[22] Massachusetts is currently reviewing biomass to determine eligibility in its RPS.

Some types of CT Class I resources present unique characteristics that create a slight differentiation for CT Class I RECs in the New England trading market. Unlike other New England states, Connecticut does not have a vintage requirement for its Class I resources. Also, Connecticut is the only New England state that qualifies fuel cells and the importation of landfill gas via natural gas pipeline as Class I resources. As a result of these distinctions, "older" Class I and pipeline natural gas resources qualify as Class I resources only in Connecticut. Finally, the ACP in Connecticut is $55/MWh with no escalation. The ACPs in some New England states are higher than $55/MWh. If the market price exceeds $55/MWh, RECs will migrate to other New England states, Connecticut will face a shortage of Class I RECs and Connecticut suppliers will pay the ACP. Notwithstanding these minor distinctions, CT Class I RECs are traded throughout New England and their market behavior follows substantially that of other New England states' RECs. EDC 2010 IRP, pp. 3-14 – 3-16.

Annual renewable requirements also show variation for each New England state; however, RPS requirements as a percent of load show an increase for all state over the period 2010-2020. Vermont has not established a REC system, but has a legislative goal of supplying 20% of its energy needs with renewable energy sources by 2017. The EDC Plan presented New England States' RPS requirements as a percent of each state's retail load as follows:

Table 7
State RPS Requirements
(Percent of Retail Load)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
CT Class I	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	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	5.0%	6.0%	7.0%	8.0%	9.0%	10.0%	11.0%	12.0%	13.0%	14.0%	15.0%
NH Class I & II	1.0%	2.1%	3.2%	4.2%	5.3%	6.3%	7.3%	8.3%	9.3%	10.3%	11.3%
RI All	2.5%	3.5%	4.5%	5.5%	6.5%	8.0%	9.5%	11.0%	12.5%	14.0%	14.0%
VT All (see note)	2.5%	5.0%	7.5%	10.0%	12.5%	15.0%	17.5%	20.0%	20.6%	21.9%	23.8%

Sources: EDC Plan, p. 3-18; 2010 CEAB Report, p. 14. Energy forecasts based on 2009 Capacity, Energy, Load and Transmission (CELT) Report, p. 5.

Note: Vermont renewable requirements are estimated, but are not based on a percent of load.

The EDCs estimate that, based on increasing electric demand and rising annual renewable requirements, total New England demand for renewable energy will increase from approximately 5,000 GWh in 2010, to 22,500 GWh in 2020. EDC Plan, Figure 3.2, p. 3-18. CEAB's estimates of renewable demand in New England are similar; CEAB projects an annual GWh requirement of 20,000, excluding Vermont. 2010 CEAB Plan, pp. 429-430. Neither projection explicitly mentioned the voluntary renewable market, which would account for a minimal demand for renewable energy. The Department accepts the EDCs' and CEAB's projections of renewable energy demand as reasonable.

Currently, the New England states have 785 MW of installed nameplate capacity of renewable energy resources. Biomass makes up 457 MW, or approximately 58%. Connecticut has only a modest percentage of installed renewable capacity in the region.

Table 8
Nameplate Capacity (MW) Renewable Energy Resources

	CT	MA	ME	NH	RI	VT	Total
Landfill Gas	8	39	6	26	21	10	111
Wind	0	9	62	25	1	0	97
Small Hydro	5	5	13	34	1	28	87
Biomass/Biofuels	0	1	250	153	0	54	457
Offshore Wind	0	0	0	0	0	0	0
Fuel Cells	3	0	0	0	0	0	4
Solar PV	13	15	0	0	0	0	28
Total MW	31	69	331	239	23	92	785

Source: 2010EDC IRP, p. 3-20; columns and rows may not sum due to rounding errors.

There is also 966 MW of installed capacity available for import from regions outside ISO-NE for a total of 1,751 MW of installed renewable generation qualified as Class I in New England. EDC Plan, p. 3-20.

The EDC Plan reports that approximately 4,300 MW of renewable energy projects were in the ISO-NE interconnection queue as of 2009. The EDC IRP incorporated probability analysis to assign probability weights to each of the projects. The EDCs estimate the following existing and cumulative new Class I resources, taking into account probability weights, states' solar policies and imports:

Table 9
Cumulative Existing and Planned Class I Capacity in New England
New England States and Imports

	2009	2010	2011	2012	2013
Landfill Gas	111	155	185	185	185
Wind	97	831	1114	1514	1514
Small Hydro	87	91	99	101	115
Biomass/Biofuels	457	593	868	988	1072
Offshore Wind	0	468	912	912	1273
Fuel Cells	4	71	99	99	99
Solar PV	28	58	89	109	131
Imports	966	966	966	966	966
Total	1751	3233	4333	4876	5357

Source: EDC Plan, p. 3-22: columns and rows may not sum due to rounding errors

Based on the forecasted demand in EDC Plan, Figure 3.2 and supply projection in Table 9, the EDCs conclude that the region's short-term renewable supply is likely to be sufficient to meet the states' respective RPS requirements. EDC Plan, p. 3-22. EDC witnesses testified that REC prices are in the lower price range, approximately $20/MWh, indicating that that the marketplace is producing an adequate supply to meet regional demand. They also testified that, given current REC prices and renewable projects in the pipeline, "it looks like New England's in pretty good shape for 2013." Tr. 6/4/2010, p. 764.

According to the EDCs, forecasts of regional Class I resource adequacy to 2020 are substantially dependent on the technological potential of specific resources and policy decisions taken to support above-market price renewable resources. To develop its 2020 regional Class I supply forecast, the EDCs first evaluate independent studies of the technological potential for each renewable technology. These independent studies suggest that wind would provide the greatest renewable potential, followed by off-shore wind and biomass:

Table 10

	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		6,566	1,211		431		8,208
Small Hydro	6	11	97	34	5	28	181
Biomass/Biofuels	100	298	446	328	35	182	1,389
	198	7,815	7,080	1,613	509	2,167	19,382

Source: EDC Plan, Table 3.13, p. 3-25
Note: Table 3.13 incorrectly sums Connecticut's Renewable potential to 351 MW.

For the resources studied (omitting fuel cells and solar PV), Connecticut shows a very limited renewable resource potential, approximately 1%, of the region's total.

The EDCs estimate the cost of each renewable technology, by calculating the levelized cost, revenues, and REC price required for each renewable resource type to be financially viable. Landfill gas, biomass, hydro and onshore wind are estimated to be financially viable, with onshore wind setting the marginal REC price of $19.40/MWh. Offshore wind, fuel cells, and solar PVs are estimated to require REC prices (or other financial incentives) in excess of states' ACPs, which are in the $55/MWh to $60/MWh range:

Table 11

Estimated REC Price (or other financial incentives) Needed for New Renewable Resources in New England	$/MWh
Landfill Gas	0
Biomass/Biofuels	14.9
Hydro	18.6
Wind	19.4
Offshore Wind	78.1
Fuel Cells	105.7
Solar PV	313.7

Source: EDC Plan, Table 3.15, p. 3-30

The EDCs next estimate the supply curve for each technology in 2013, 2015 and 2020, under each of the three policy scenarios: Reference Strategy, In-state Renewables Strategy and Limited Renewables Strategy. The analysis shows that under all three policy scenarios and a range of economic assumptions[23] landfill gas, biomass/biofuels, hydro and wind would require REC support well below the $55 - $60 ACP range. Hydro and wind generally set the marginal REC prices, which, under current economic trends assumptions, are estimated to be in the range of $15 to $20 in 2013, and fall to $8 to $12 in 2020. REC price estimates for fuel cells, offshore wind and solar PV are in the range of $75, $100 and $300, respectively, which would require additional financial incentives such as a higher ACP or other subsidies. EDC Plan, Table 3.16, p. 3-39.

The Reference Strategy assumes that the regional development of renewables, including imports, will be sufficient to meet the New England States' RPS requirements. Transmission costs, estimated in the range of $10 billion, are estimated to be a substantial portion of the renewable costs in the Reference Strategy. EDC Plan, p. 3-9.

In the case of the In-state Renewables Strategy, 1% of the State's electricity demand is assumed to be met with solar PV. Since in-state biomass and wind resources are limited, the scenario assumes that 693 MW of fuel cells would be built, a modest amount of landfill gas and small hydro would also be added, and a portion of the remaining RPS would be met via the ACP. EDC Plan, Figure 3.8, p. 3-36. This scenario would not require major transmission upgrades, but since it would rely heavily on natural gas powered fuel cells, it would not significantly abate CO_2 emissions.

The Limited Renewable Development Strategy assumes that a substantial portion of the RPS would be met by the ACP and that efficient natural gas units would supply the regional energy and capacity shortfall.

The Reference Strategy yields customer supply related costs (2020 ¢/kWh) that are estimated to be lower than the In-state Renewable Scenario, but higher than the Limited Renewable Scenario, which assumes an expansion of efficient gas units. EDC

[23] Economic assumptions used were: Current Economic Trends; Low Gas, Low CO_2 Prices; Medium Gas/High CO_2 Prices; High Load Forecast; and High Gas/High CO_2 Forecasts.

Plan, pp. II-30-31. Both the In-state Renewables Strategy and the Limited Renewable Development Strategy would yield higher CO_2 and NO_x emissions than the Reference Strategy due to more intensive use of natural gas. The In-state Renewables Strategy and Limited Renewable Development Strategy would yield CO_2 emissions that would exceed the RGGI cap. EDC Plan, pp. II-32-35.

The EDC Plan finds that 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. For New England to meet each respective state's 2020 Class I RPS, the region needs to add approximately 4,800 MW 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 in investment in transmission resources to access this new renewable generation. 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.

The EDCs' recommended 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 the RPS. The EDCs recommend that Connecticut policy makers 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. EDC Plan, p. I-4.

3. CEAB Analysis

Although the CEAB offered several critiques of the EDC analysis, the CEAB stated that the EDCs had performed a creditable analysis on modeling the renewable supply response to RPS policy options. The CEAB viewed the EDCs' assumption of 2,000 MW of offshore wind capacity by 2020 as too optimistic, given that offshore wind is still a developing technology and that no wind farm has been installed off the coast of New England. The CEAB projected that 400 MW would be constructed by 2020. The CEAB Report, pp. 419-422.

The CEAB also constructed a forecast model of several renewable buildout scenarios. CEAB built a regional renewable energy supply curve, based on resource technology and their associated costs and included imports from adjacent areas. CEAB used New England demand for renewable energy to determine REC prices that "clear" the market for each forecast year and developed forecasts for 2020 and 2030. CEAB developed a forecast model for the following scenarios:

1. Reference -- Renewable buildout to meet existing Connecticut and regional RPS requirements.

2. In-State Renewables – All of Connecticut's RPS requirements are met in–state resources.
3. A-ACE as a Renewable Resource – Energy efficiency savings achieved by the A-ACE DSM resource option fulfils Connecticut Class I renewable resource requirements.
4. Reduced Connecticut RPS – Renewable Buildout meets lower RPS; Current Connecticut RPS of 20% by 2020 is reduced to 11.5%.

CEAB Report, pp. 430 and 431.

The CEAB Reference and In-State Renewables scenarios reached similar conclusions as the EDCs. Connecticut's pro rata share of cost of renewable energy projects needed to meet Connecticut and regional RPS requirements will be substantial, and the scale of the RPS requirement over the next decade could require a significant transmission expansion to integrate those resources into the regional grid. The CEAB has estimated that meeting the 2020 New England states' RPS standards will cost the region an estimated $13.6 billion in generation capital investment, of which Connecticut's share would be approximately $4.7 billion. The additional cost of renewable generation translates into an additional 0.83¢/KWh for generation costs. An additional $10 billion in transmission costs would also be required. Meeting the 2020 Connecticut RPS requirements with in-state renewable resources would cost ratepayers 1.4¢/KWh for generation costs, or 0.57¢/KWh more than the Reference Case. However, the In-state Scenario would not require additional transmission investments. CO_2 emissions are 2% higher in the In-State Scenario compared to the Reference Case. 2010 CEAB Report, pp. 412, 435, 437. Scenarios 3 and 4 were not offered by the EDCs, and are discussed below.

The A-ACE as a Renewable Resource scenario, which classifies Energy Efficiency as a Class I resource, would substantially reduce the quantity of new renewable resources required to meet the RPS. This scenario would only allow Project 150 generation (or equivalent renewable MW) as new renewable resources until 2020. CEAB modeling results showed that this scenario, which effectively replaces required renewable energy with DSM to meet the RPS, produces power prices (KWh) that are 92% less than the Reference Case.[24]. Implementing the A-ACE as a Renewable Resource Scenario produced similar regional CO_2 emissions as implementing the 20% RPS requirement by 2020. 2010 CEAB Plan, pp. 435-437.

The CEAB Reduced Connecticut RPS is modeled after a proposal in the Connecticut legislature to reduce the 2020 RPS requirements from 20% to 11.5% of load. This scenario results in per kWh power prices that are 89% less than the reference case, but would not provide the environmental benefits of meeting the 20% renewable energy RPS requirement. CEAB Report, pp. 435-437.

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[24] This excludes savings to participants in energy efficiency programs, estimated at $450-$500 million, over the life of the installations. 2010 CEAB Plan, p. 436.

4. CCEF Position

The CCEF states that the EDCs and the CEAB transmission projections overstate transmission costs associated with a renewable build-out. The CEAB points out that these estimates represent hypothetical systems that do not reflect any system optimization, cost minimization, or reliability benefits of the transmission infrastructure. CCEF Brief, pp. 7-9.

The CCEF takes issue with the CEAB's projection of relatively flat prices for renewable resources and the assumption that offshore wind will not play a substantial role in the New England renewable supply mix. The CCEF indicated that REC prices have declined substantially over the past year, which is consistent with a short-term surplus condition for renewable energy in the region, as well as indicative of steady technological progress and a decline in the cost trajectory for some renewable technologies. The CCEF views the careful tracking of the cost trajectory of renewable resources as an important factor in projecting the cost of RPS and in setting renewable policy. CCEF PFT, pp. 7-9.

The CCEF supports a renewable procurement as a policy instrument to promote the orderly development of renewable resources. Despite the lower REC prices since 2008 and a current short-term surplus, the CCEF believes that financial markets indicate that renewable projects will have difficulty obtaining external financing. The CCEF maintains that additional incentives will be necessary to induce additional renewable projects. This could be in the form of a renewable procurement as part of a regional procurement or pursuant to the IRP proceeding.

The CCEF favors state policy to support in-state renewables. The CCEF recognizes that in-state renewables are more expensive than regional resources; however, in-state renewable generation has greater economic and environmental benefits for the state. The CCEF rejects a "wait and see" toward solar development, instead, favoring the promotion of high cost solar PV as a means to develop the industry, reduce costs, and create associated in-state jobs. The CCEF believes that resource planning should have a metric to measure the tradeoffs between higher ratepayer costs and greater in-state benefits. CCEF PFT, p. 3; CCEF Brief, p. 5.

The CCEF urges the Department not to support making Class I and Class III RECs interchangeable, as suggested in the 2010 CEAB Plan. According to the CCEF, least cost energy efficiency projects do not need the same level of financial support as renewable energy projects in order to be financially viable. Although a few states treat DSM as a renewable resource, the vast majority of states do not allow DSM as a Class I resource. Allowing Class III and Class I resources to become interchangeable would cause imbalances in both markets. CCEF PFT, p. 7; CCEF Brief, pp. 9 and 10.

The CCEF supports an assessment of the RPS policy and a review of its objectives. The CCEF supports the CEAB's recommendation to initiate a public stakeholder process to review the Connecticut RPS and its role in the development of renewable energy projects in the state and the region. The CCEF notes that the cost of renewable resources has declined over time. CCEF Brief, p. 9.

5. OCC Position

The OCC concurs with the EDCs and the CEAB that requiring new renewable energy sources to be located in Connecticut would create a significant economic burden on the state's ratepayers. Solar PV energy continues to be the highest cost renewable energy source for Connecticut. Because the low capacity factor limits competitiveness of solar PV relative to other renewables, the OCC believes that Connecticut should not commit to securing solar PV as part of Connecticut's RPS portfolio until there is evidence that the cost of solar justifies the benefits of the technology. OCC PFT, p. 73.

The OCC opposes the requirement that the EDCs procure long-term contracts for renewable and CHP resources. The OCC notes that the EDCs have received offers to enter into long-term procurements, but no offer has yet provided ratepayers sufficient benefits. The OCC noted that the EDCs stated that mandatory contracts would likely result in higher prices to the ratepayers since the EDCs would be required to sign a contract for the renewable energy. OCC Brief, pp. 45-48.

The OCC also supports a policy review of the Connecticut RPS. The OCC is in favor of evaluating the inclusion of additional eligible resource types, such as broadening the definition of hydroelectric sources that could fulfill the states' environmental policy objectives and provide lower cost to ratepayers. OCC PFT, pp. 65 and 66; 69 and 70; OCC Brief, p. 46.

6. Department Analysis of Renewable Resource Adequacy

Both the EDCs and the CEAB estimate Class I REC demand using a regional New England forecast of demand for renewable energy based on the aggregation of each state's RPS requirements. Regional projected electric demand is based on the ISO-NE CELT forecast. Using the CELT forecast of electric demand, the EDCs and the CEAB estimate REC demand to be in the 20,000 to 22,000 GWh range in 2020. The Department finds both the EDC and CEAB Class I REC demand forecasts to be reasonable and consistent. EDC Plan, p. 3-27; 2010 CEAB Report, p. 430.

Both the EDCs and the CEAB constructed a supply curve for each renewable technology to estimate the cost of renewable resources and forecasted REC prices. The CEAB estimated 2020 marginal REC prices to be in the $40 range, significantly higher than the EDCs' 2020 Reference Case estimate of $12/MWh for the marginal renewable resource, onshore wind. 2010 CEAB Report, p. 434; EDC Plan, pp. 3-33 and 3-35. The EDCs projection of 2020 REC prices in the $12/MWh range assumes a very optimistic forecast of the cost structure for the marginal technology, wind, in effect, a 40% cost decline in constant (2010) dollars.

The EDCs had a significantly higher projection than the CEAB for the development of offshore wind capacity. The Department concurs with the CEAB that that the EDCs' estimate of 2,000 MW of offshore wind, based on ISO-NE's Renewable Development Scenario Analysis, is very optimistic, given that no offshore wind generation has been developed in the U.S. The CEAB projects that 400 MW of offshore wind facilities will be built by 2020. Moreover, the estimated $98/MWh (2010 dollars) cost of offshore wind would require out-of-market financial support significantly in excess of the ACP. EDC Plan, pp. 3-30, 3-32 – 3-37.

The Department recognizes the uncertainties that underlie ten year projections for the cost structure and project development of renewables. There are also policy uncertainties with regard to the continuation of Federal Production Tax Credit and Investment Tax Credit, as well as possible changes in New England states' laws and policy directives pertaining to their RPS requirements. The Department finds that the EDCs' energy supply curve and declining real prices by 2020 to be highly optimistic. As pointed out by the CCEF, it is likely that the on shore wind cost structure would reflect diminishing returns over time as the most favorable sites are built out first. Moreover, meeting the current regional RPS requirements will require a portion of the capacity to be met with expensive resources such as off-shore wind and fuel cells. The Department also believes the CEAB's supply curve is more realistic of the likely trend of future renewable costs and REC prices, but still may be optimistic. CCEF Brief, p. 4. Additionally, the Department believes a lower estimate than 2,000 MW is reasonable, since offshore wind is a new technology with high operational costs and longer project development timelines. The EDCs' own forecast shows that offshore wind RECs at approximately $100/MWh (2010 dollars) for all forecast scenarios. EDC Plan, p. 3-39. This would require out-of-market financial support significantly in excess of the ACP.

The Department notes that in the EDCs and the CEAB analyses, there was virtually no discussion of potential for development of pipeline methane gas from remote landfills, which qualifies as a Connecticut Class I resource.[25] The EDCs estimate landfill gas (LFG) as the lowest cost renewable technology. EDC Plan, p. 3-28. Although the EDCs, the CEAB and the CCEF all concluded that Connecticut's Class I development potential is limited, remote methane gas provides a lower cost Class I technology that is not limited by the state's resource base. The Department supports additional development of this technology and will direct the EDCs and the CEAB to evaluate the potential for development of this potential as a Connecticut Class I resource and provide estimates in future IRP proceedings.

Based on the evidence provided by the EDCs and the CEAB, the Department concludes that there is likely to be short-term renewable resource adequacy in the region to meet regional and Connecticut Class I RPS requirements. However, there is considerable uncertainty after 2013. Long-term renewable resource adequacy is dependent on state and regional policy decisions regarding RPS requirements, transmission planning, and resource acquisitions and procurements.

The EDCs and the CEAB each presented a Reference Case and an In-state Renewable forecast scenario. The CEAB also presented the A-ACE scenario that significantly boosts DSM activity as a substitute for renewables. The reference cases assume that regional development of renewables plus imports will be sufficient to meet the New England States' RPS requirements and would require approximately $10 billion in transmission costs. The Department supports the reference cases over the In-state

[25] See Docket No. 08-06-16, Application of Bridgeport Energy, LLC for Qualification of Facility at 10 Atlantic Street, Bridgeport, CT as a Class I Renewable Energy Source, Decision dated October 29, 2008.

scenario. For both the EDCs and the CEAB analyses, the reference case would result in lower electric costs and lower emissions than the In-state scenario, which relies heavily on fuel cells. Due to the high cost of the Reference Case, the Department believes that the RPS requirements should be re-examined. Although the Department does not support the CEAB's A-ACE scenario, reduced RPS options should be considered. EDC Plan, p. 3-9; CEAB Plan, pp. 432-437.

The Department concludes that Class III energy efficiency resources should not be allowed to qualify for Class I resources. Class I and Class III energy sources are rightfully treated as separate markets. Class I renewable resources have a considerably higher cost structure than DSM installations. Recognition of these cost differences are reflected in their respective ACPs; Class I resources have a $55/MWh ACP while the ACP is $31/MWh for DSM resources. If Class I resources included Class III resources, at their original ACP of $31MWH, it would draw down Class I REC prices. If Class I resources included Class III resources at an ACP equivalent to that of Class I ($55/MWh), DSM resources would receive a higher subsidy than is required for market participation, resulting in excessive costs to ratepayers.

Both the EDCs and the CEAB estimates project hefty transmission expenditures in the range of $10 billion for their respective 2020 Reference Case renewable build-out to meet regional RPS demand. The CCEF maintains that these costs are significantly overstated because they do not take into account an optimized, least cost transmission build out. The CCEF takes issue with the EDCs and the CEAB projections of the $10 billion in transmission costs associated with a renewable build-out. CEAB points out that these estimates represent hypothetical systems that do not reflect any system optimization or cost minimization of transmission infrastructure. Since such a major transmission build-out would also confer reliability benefits, the imputed cost to renewable energy projects would be overstated. The CCEF also points to specific renewable projects that have taken on a portion of transmission costs; assuming all transmission costs would be imputed in retail rates would overstate renewable transmission costs. CCEF Brief, pp. 7-9.

The EDCs and the CEAB $10 billion projection is a "stand alone" cost estimate, which infers that all of the renewable transmission costs would be socialized across the New England region. Although the EDCs and the CEAB Reference Cases would require extensive transmission infrastructure, this estimate is very uncertain. Understanding the regional transmission infrastructure requirements is essential as the region moves forward in meeting its states' RPS obligations. The Department will establish as a priority for the EDCs and the CEAB to provide more in-depth analysis regarding transmission requirements of an optimized and least cost transmission system to accommodate a substantial increase in capacity of renewable generation. Connecticut and the New England states need to have better technical information regarding the reliability requirements, architecture and cost of a transmission infrastructure to accompany renewable resources, which are often more remotely located and have a lower capacity factor than fossil generation. The EDCs and the CEAB are directed to provide in the next IRP the findings of the most recent ISO-NE analysis on regional transmission planning to meet the needs of their respective anticipated reference case renewable build-out.

The EDCs and the CEAB reference cases pose major uncertainties as to how the renewable capacity will be built that will fulfill the 2020 New England states' 2020 RPS requirements. The EDCs and the CEAB scenarios both infer that meeting the 2020 requirements will require a substantial portion of renewable capacity to be built at costs that would require financial support in excess of projected REC prices. The scenarios do not specify how or by what policy this out-of-market support would be achieved.

Although there will be adequate renewable supply until 2013, the Department is concerned that tight credit markets and the current economic downturn have placed constraints on the types of renewable projects that can obtain financing. The CEAB testified that virtually all recent renewable projects are being financed and developed via a long-term contract with an EDC or through a bilateral contract between private entities. Tr., 6/2/10, p. 105. The CCEF also stated that renewable projects are unlikely to be developed without long-term contracts that provide a sufficient revenue stream to attract financing. CCEF Brief, p. 3.

The mandates of the 2020 RPS, coupled with the current challenges for renewable projects in obtaining financing, as well as concerns about the development of in-state renewables, suggest that the Department may need to consider renewable resource procurements to assure an adequate and affordable regional supply of Class I resources and as a means to fulfill the policy objective to develop in-state energy.

The Department notes that the New England Governor's Renewable Energy Blueprint has called for coordinated regional development of renewable resources, and has enlisted the NESCOE to provide regional coordination and policy development. The Department may, under its IRP statutory authority, consider Connecticut participation in a regional renewable procurement if it deems it appropriate to assure adequate Class I resources to meet Connecticut's RPS at the least cost to ratepayers. The Department shares the EDCs and the OCC concern that a mandatory procurement may provide greater bargaining power to renewable developers and hence may increase the price to ratepayers. Tr., pp. 770 and 771; OCC Brief, p. 45. The Department will not require that any renewable energy or capacity must be acquired in a procurement at this time.

Connecticut has established a priority to develop in-state renewable resources. The Department has done its part to implement the Connecticut legislature's mandate to develop in-state renewable energy capacity, despite its high cost and the state's limited potential for development. Project 150 is an important initiative to advance this aim. Several Project 150 approved contracts are not going forward, as the project developers have indicated that current credit conditions have rendered their projects unfinanceable. Docket No. 03-07-17RE05, DPUC Review of Long-Term Renewable Energy Contracts – Proposed Contract Modifications, Draft Decision dated July 29, 2010. Although the inability to finance the full 150 MW of renewable energy will not create a major setback in terms of regional supply, it is an impediment in the effort to develop renewables in Connecticut.

The Department believes it is important to support state policy that supports the development of in-state renewables. The Department has fulfilled its legislative mandate to approve 150 MW under Conn. Gen. Stat. § 16-244c(j)(2). However, recognizing that the state's policy objectives are not being fulfilled due to project attrition, the Department may elect to exercise its authority, pursuant to its statutory authority in the IRP, to open a subsequent competitive procurement RFP, subject to the conditions set forth in the Decision in Docket No. 03-07-17RE05, at pages 8 and 9, to solicit renewable projects in Connecticut so that renewable projects are actually built in the state. As stated in that Decision at page 8, a solicitation under the IRP statutes would provide more flexibility for projects than the pricing requirements under Conn. Gen. Stat. § 16-244c(j)(2).

The Department concurs with EDCs, CEAB and OCC that Connecticut should re-evaluate its 20% Class I RPS requirement by 2020 in light of its impact on electric generation and transmission costs and environmental benefits. In the Draft Decision in this Docket, the Department indicated that it will direct the CEAB to conduct a study to explore the objectives, and the costs and benefits of the current Connecticut RPS statutory requirement and alternatives that might meet those objectives more cost effectively. In its Written Exceptions, CEAB stated that it had already commenced a study to reevaluate the Class I RPS requirement. The Department supports CEAB's initiative to evaluate this issue further.

The CEAB should consider changes to the RPS eligible technologies, such as the inclusion of large scale hydro, modifications to the annual renewable requirements as well as other options that might be more cost effective to meet the RPS objectives. Among the policy alternatives, the CEAB shall consider (1) an increase the annual Class I RPS requirement from 7% in 2010 to a percentage lower than 20% in 2020, and (2) a commensurate increase the annual Class III RPS requirement from 4% in 2010 to a higher percentage in 2020. Increasing the Class III requirement is one policy option that could alleviate the current Class III oversupply, provide greater incentives for independent energy efficiency projects and meet environmental goals at a lower cost than Class I resources. The CEAB should work with the DEP and other stakeholders; however, the study should be primarily analytical and quantitative. The Department will allow CEAB up to approximately $50,000 for the cost of the study and direct that that it be completed by May 15, 2011.

G. COMBINED HEAT AND POWER

1. Development of CHP Facilities

The EDC Plan concludes that Connecticut already has a high penetration of CHP for the most attractive large industrial applications and that there is limited remaining potential for large applications. However, smaller, mostly commercial and institutional applications of less than 5 MW -- office buildings, schools, nursing homes, etc. -- have significant remaining technical potential in Connecticut. Although no recent Connecticut specific study has been performed, the remaining technical potential in this sector could approach 850 MW, although there are still significant market and cost barriers. EDC Plan, p. 6-11.

The CEAB provided a white paper on cogeneration as part of its Plan. The paper concludes that reliability is a key driver of existing CHP systems. Small-scale commercial applications with a need for reliable power, such as hospitals, universities, hotels, and large office buildings are important potential growth areas for CHP in Connecticut. Even in the absence of a reliability driver, CHP can still provide economic and environmental benefits for other applications as long as there are sufficient economies of scale. These CHP systems would require coordinated planning and high capital investment, which can be facilitated through public policy. The CEAB recommends: (1) a review of existing policies to prevent the closure of existing CHP facilities, (2) coordination with the Department of Economic and Community Development and the Connecticut Development Authority to identify the best sites for CHP or district energy, (3) an investigation of the interest and obstacles of municipalities to pursue energy independence districts, and (4) finding a more detailed policy to examine policies that could incentivize CHP and distributed generation (DG). CEAB Plan, pp. 233-237, 255.

The Department has supported the development of cogeneration facilities. During the 1980s and early 1990s, approximately 280 MW of cogeneration capacity was developed and approved for long-term contracts with the LDCs. These projects were developed in response to the Public Utilities Regulatory Policy Act (PURPA) and tax incentives made available at that time. These projects are still providing power in Connecticut but are reaching the end of their contract lives.

More recently, ratepayers have supported DG development though the Distributed Generation Capital Grants Program, DG Gas Rebate Program, Project 150, and renewable energy credits. The Capital Grant program provided grants for CHP and other DG projects up to 65 MW. Funding was approved for 258 MW of DG capacity. This program, however, was discontinued in March 2009. Project 150 authorized the EDCs to make long-term power purchase agreements with Class I renewable energy providers for 150 MW of new capacity. This program approved 37 MW of new CHP capacity for fuel cells and biomass projects. Finally, fuel cells are considered Class I renewable energy resources and CHP are considered Class III resources under the Connecticut RPS. Projects can sell their RECs, increasing their revenues and improving the economic viability of CHP projects.

The EDCs indicate that approximately 135 MW of industrial capacity and about 835 MW of commercial CHP capacity remains to be utilized. They state that the large majority of this capacity is in applications of five MW or less. The CEAB white paper discussed large scale district heating projects in Denmark and London, suggesting that much more potential exists in Connecticut.

Many generation facilities are designed to meet the thermal and electric needs of the host facility. Electricity is used behind the meter which has the impact of reducing electric requirements on the system similar to DSM. These are projects are generally five MW or smaller. Cogeneration facilities have also been developed in Connecticut that are significantly larger than the hosts' heating and electric requirements which were still eligible as a cogeneration facility under PURPA and as a Class III resource. These facilities can be 30 to 60 MW or larger. They sell excess power to the grid similar to a base load generation facility.

The Department believes that whenever economically and technologically feasible, efforts should be taken to capture waste heat at baseload generation facilities. The Department believes that the CEAB Plan may be too optimistic. The Department does not see much interest to develop new large-scale district heating projects. The Department agrees with the EDCs' assessment as to the smaller scale of CHP potential although there is probably some potential for larger oversized cogeneration facilities.

The Department was forced to shut down the DG Capital Grant program because the glut of capacity has driven down capacity prices making the grants uneconomic. Although this aspect of the program was discontinued, the Department believes that there still remains adequate incentives to encourage DG development. First, high electric rates provide a big incentive for customers to consider on-site CHP applications. Other incentives also remain available. These incentives include a discount for natural gas distribution costs, low interest loans, no backup charges and the Class I and Class III REC. Connecticut also allows net energy billing.

The Department believes that CHP should remain an option to meet Connecticut's resource needs. The Department would make all efforts to include larger scale cogeneration projects in any RFP for base load generation. The Department notes that capital grants were from $450 to $500/kW under the DG program with the remaining cost paid by the customer installing the DG facility. This compares favorably with all resource options including conservation. The Department does not believe that additional incentives are needed at this time given the current surplus situation. The Department would consider additional incentives in the future if the need for resources arises and it was determined that the market mechanisms and existing incentives were inadequate.

2. Existing CHP Facilities

Algonquin urges the Department to order the EDCs to conduct a competitive solicitation for long-term PPAs for cost effective CHP plants. In the alternative, Algonquin recommends that the Department order CL&P to enter into bilateral contract negotiations with Algonquin Power to renegotiate the recently expired 20 year PPA with CL&P. Algonquin Brief, p. 1.

Algonquin is a 56 MW CHP project located in Windsor Locks. The plant produces and sells electricity and steam to an adjacent paper mill and sells excess electricity to the grid. Algonquin claims that CL&P has been unwilling to discuss the possibility of renegotiating a new PPA. The absence of a new or renegotiated long-term PPA with CL&P has forced Algonquin to operate the CHP plant at drastically inefficient operating levels, which may have a detrimental effect on the plant's ability to economically serve the paper mill over the long term. Algonquin argues that there are strong public benefits to ensuring that the State's existing fleet of highly cost effective CHP plants continues operating. Algonquin Brief, pp. 1-3.

The Department agrees that it is in the best interest of ratepayers to keep the facility operating. The Algonquin plant is a little more than 20 years old. This is not old for a power plant and therefore should be technologically and economically viable since much of its fixed costs have likely been recovered. It is the Department's hope that such facilities would operate freely in the market without long-term contracts with the EDCs unless substantial benefits exist. The Department views the IRP as a forum for new projects or repowering and therefore will not conduct a solicitation for long term PPAs with existing projects. The Department has allowed CL&P and UI to investigate long-term contracts with generators to reduce the cost of standard service. The Department will not order CL&P to enter negotiations with Algonquin, but encourages both CL&P and UI to negotiate with Algonquin as well as other projects to develop bilateral contracts to reduce the cost of standard generation service.

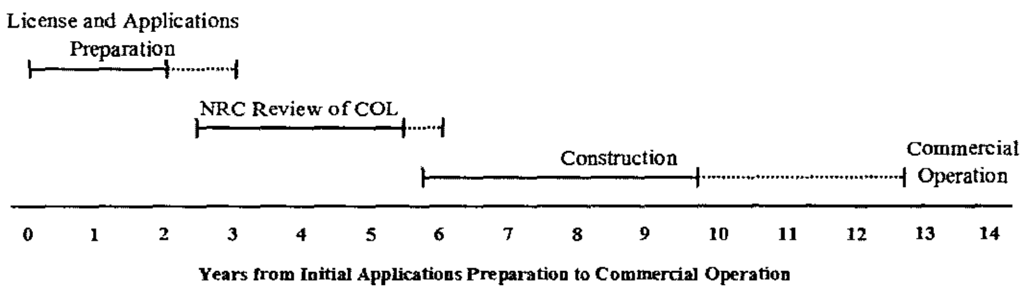
H. NUCLEAR POWER

1. EDCs' Position

Nuclear reactors currently operating in the U.S., including all of the reactors 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. 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. The next generation of reactors is currently in the concept stage and will not be operational before 2020. EDC Plan, pp. 5 and 6.

Nuclear plants must go through several licensing and permitting steps before federal and state regulatory bodies prior to the start of construction. These processes contribute a significant amount of time to the planning phase for a new nuclear plant. In parallel with federal licensing and permitting, developers must also receive state siting permits and other state regulatory approvals. Figure 4 below shows an estimated timeline for nuclear plant licensing and construction. EDC Plan, p. 5-9.

Figure 4
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.

Source: EDC Plan, p.5-8.

The timeframe for a new nuclear unit In Connecticut would be longer than the 10 to 15 years illustrated in the above timeline, since Connecticut is not yet at the start of this timeline. Although this timeline is well beyond the 10-year time horizon of this IRP, the EDCs performed an analysis of new nuclear capacity in Connecticut in 2020 in order to illustrate the potential impacts and compare these impacts with other resource solutions. Nuclear plants require long lead times, and if one is to be considered, the investigation must begin far in advance of a potential online date. EDC Plan, p. 5-9.

Nuclear capital costs are 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. A nuclear plant in Connecticut would cost more than the U.S. average, since New England is a high-cost region for construction projects. 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. EDC Plan, pp. 5-9.

The EDCs analyzed the electricity market and environmental impact of a hypothetical new 1,100 MW nuclear plant in Connecticut presumed to enter service in 2020 under the five scenarios described in Section II of the EDC Plan. Given the regulatory approval and construction timeline described above, 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 to 2025 timeframe; therefore, this analysis is intended to be more illustrative than practical in nature. EDC Plan, pp. 5-13.

The EDCs concluded that there are economic, environmental and energy security benefits to nuclear development but the economic results must be viewed with caution. The environmental results are more predictable and likely to occur. A Nuclear Strategy could also reduce natural gas use for electricity generation, even more than renewables or additional efficiency. EDC Plan, p. 5-19.

The EDCs believe that if Connecticut were to pursue a nuclear strategy, a full and comprehensive nuclear siting analysis should be conducted. In light of the potential benefits of a nuclear strategy identified in its analysis, UI recommends that the CEAB conduct or sponsor a more detailed study of the potential costs and benefits of nuclear power to provide a more details of the tradeoffs encountered in considering nuclear power as a long-term resource strategy for Connecticut. EDC Plan, p. 5-1.

2. CEAB Position

The CEAB believes that nuclear power should be investigated as a potential long-term supply option for Connecticut. CEAB Plan, p. 378. The CEAB states that since the EDCs' analysis used a ten-year time horizon, it did not fully consider the potential for certain resources to play a role in Connecticut's resource mix over the long term. The CEAB analysis has attempted to take a broader view of the potential of these resources. However, the CEAB did not attempt to quantify costs. Only the emissions impacts were addressed in detail, with some additional discussion of potential reliability impacts. CEAB Plan, p. 64.

Nuclear power was considered mainly for its potential to reduce greenhouse gas emissions. CEAB Plan, p. 64. To expand the analysis of new nuclear generating capacity in Connecticut begun by the EDCs, the CEAB modeled a new 1,000 MW reactor at the Millstone site in years 2025 and 2030. The CEAB found the following benefits compared to the Reference Case: 6% to 8% reduction in air emissions, a 2% reduction in the marginal clearing price and Connecticut natural gas-fired generation reduced from 42 percent to 33 percent in 2025 and from 43 percent to 34 percent in 2030. This analysis did not attempt to model the full cost of a new nuclear reactor under any financing scenarios, but this would be necessary for quantifying all costs and benefits of new nuclear power. CEAB Plan, p. 404.

Improved nuclear reactor designs were conceived after the Three Mile Island Accident with goals of increased safety and design standardization. CEAB Plan, p. 385. The lack of plant construction since the 1980s has reduced the number of certified vendors to manufacture plant components. This leads to higher costs and longer lead times. The U.S. nuclear industry labor pool has been reduced, making it more difficult to find qualified people to design and manufacture new reactors and also regulators to certify designs. With so few Generation III reactors under construction worldwide, and none in the U.S., it is difficult to assess what nuclear power's actual capital cost will be over the next twenty years. CEAB Plan, p. 392.

Financing nuclear projects is one of, if not the largest obstacle to actual plant construction, especially given today's challenging economic climate. CEAB Plan, p. 394. Currently, constructing a nuclear plant is a costly endeavor. Recent industry estimates of proposed projects range from $4,800 to up to $6,500 per kW, which is $4.8 to $6.5 billion for a typical 1,000 MW plant. CEAB Plan, p. 378.

Other countries have provided greater support for nuclear power in recent years. These international projects will become important proving grounds for the nuclear industry to display its ability to build reactors on schedule and on budget and show that they can be operated safely. CEAB Plan, p. 386.

There is one existing site within Connecticut available for future nuclear reactor construction and operation, Millstone, a 535-acre site with three reactors, two still in operation. The site was originally intended for six reactors and the current nuclear plant only utilizes about 50 acres, so more land is available for new construction. CEAB Plan, p. 390.

The U.S. government has yet to license a national repository for high-level nuclear waste, but the US Department of Energy (DOE) has tasked a panel of experts to evaluate a range of waste disposal solutions, though not the Yucca Mountain site. CEAB Plan, p. 378. A Connecticut moratorium on new nuclear construction will largely prevent any new construction in the State for the foreseeable future because Conn. Gen. Stat. § 22a-136 states:

> 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. CEAB Plan, p. 401.

The EDCs point out that only sluggish progress has been made by the federal government on waste disposal. The disposal of high-level radioactive waste is under the exclusive purview of the Federal government, and government efforts have been focused on one disposal option, permanent geologic storage at the Yucca Mountain site in Nevada. However, the current administration does not support the Yucca Mountain solution. The DOE Secretary, Stephen Chu, has announced that a commission of experts will review alternative disposal options, and their final report will be due by January 29, 2011. CEAB Plan, pp. 401-402.

The CEAB believes that it is highly unlikely a new reactor will be built anywhere in the New England region within the next ten years, due to the long lead times for nuclear power plant planning, permitting and construction, as well as the considerable barriers of siting, financing and waste disposal that would need to be overcome. On balance, however, given the potential Connecticut to need non-carbon based generation requirements, and given the CEAB's commitment to consider all energy sources on equal footing, the CEAB believes it is timely to study nuclear power in a serious, objective manner to determine its potential as a long-term, safe supply option. CEAB Plan, p. 379.

Based on the preliminary analysis of a new 1,000 MW nuclear reactor at the Millstone site, the CEAB recommends the initiation of a CEAB-sponsored study on nuclear power with the Connecticut Academy of Science and Engineering (CASE) to address specified outstanding issues. The CASE study structure including the convening of a research team, active public input, and peer review committees may ensure objective, robust information development. A CEAB nuclear power subcommittee should be created to oversee the study, monitor industry signposts, request periodic DEP updates on the waste issue and convene a stakeholder workshop on nuclear power when conditions warrant. Such a study may include a time horizon beyond 2030 and a more thorough analysis of barriers. CEAB Plan, p. 408.

The CEAB states that it is too premature to recommend changes to Connecticut's moratorium on nuclear power. The waste disposal issues upon which the moratorium is based continue to be pursued at the federal level. CEAB Plan, p. 408.

3. OCC Position

The OCC recognized that the EDC Plan analyzed the possibility that a new nuclear plant could assist with Connecticut's electricity cost and reliability goals, reduce dependence on fossil fuels, have low greenhouse gas and other emissions, while also noting some potential drawbacks. The CEAB Plan also evaluated these possibilities. OCC Brief, p. 48.

The OCC believes that the possibility of new nuclear power warrants further study in subsequent dockets. The upfront costs of building a new nuclear power plant are very high. Connecticut is presently in a capacity surplus situation, so a need for a large resource like a nuclear plant is not imminent. The OCC anticipates that other states may take the plunge into a return to nuclear first, and that should help Connecticut to better analyze the costs and benefits, as well as clarify any resolution of the waste disposal issue. OCC Brief, pp. 48-49.

4. Department Analysis

The Department believes the nuclear option is too early to consider in this filing due to the extreme length of time to develop and construct such an option. Today, this is more of an academic exercise. A modern, safe technology for construction still has to be determined. Related costs are very high, in excess of $6,000/kW and are extremely uncertain. A nuclear plant cannot be constructed in Connecticut until the Federal government determines how to dispose of high level nuclear waste, which is scheduled for January 2012. After the Federal government decides how to dispose of nuclear waste, the EDCs might consider an RFC for its nuclear study. Nuclear projects in other states and countries should be observed and tracked by the EDCs until nuclear power options become more competitive to be seriously considered as a resource option in Connecticut.

The Department is very disturbed that CEAB did not inform the Department and all parties during hearings that CEAB had commenced its proposed nuclear study at a cost of $120,000 to ratepayers, but only offered the information as a comment at Oral Arguments[26] on September 3, 2010.[27,28] The Department will order that in future IRP proceedings, CEAB shall update the Department on the status and costs of all new or ongoing CEAB studies related to IRP topics intended to be used in future IRP proceedings, studies intended to produce solutions to provide resource needs and studies being paid by ratepayers.

The Department believes that CEAB must be more conscious of funding such research studies for long-term resource solutions under today's constrained economic conditions, especially where the long-term study findings may not be implemented for an extremely long period such as nuclear solutions that may not be installed for 15 to 20 years after the study is produced.

I. IRP METHODOLOGY

1. Benefit Cost Analysis

The matricies used by the EDCs and the CEAB are acceptable but do not provide a complete analysis. The EDC and the CEAB analysis is best at showing the relationship of different levels of conservation to the base case or the impact on cost and environmental impacts of different renewable scenarios. The analysis is weaker at comparing the relationship between various resource options. This occurs because

26 Oral Arguments is the last public meeting for a party to verbally clarify its interpretation of the draft decision and comment on other parties' interpretations and positions on the draft decision. It is <u>not</u> an occasion to present new evidence.

27 The last public hearing occurred on 6/16/2010, which ended the period to present new evidence in this proceeding.

28 During Oral Arguments, CEAB commented that the nuclear study is underway and will cost approximately $120,000. It will be a broad study that looks at nuclear costs, and environmental and economic development impacts of nuclear on the state and will include an economic impact analysis. Tr. 9/3/10, pp. 1611 and 1612.

projects of different sizes are often compared over different time periods. Other inconsistencies also exist. The CEAB indicated that they had not done a benefit/cost analysis over the useful lives of various resource options.

A full benefit/cost analysis of different resource options would provide a better understanding of the cost/price impacts to all customers. Fixing some of the variables such as the size of the project, implementation date and length of the analysis would improve the benefit/cost analysis by providing more comparable results.

The CEAB Plan provides a benefit/cost analysis of conservation programs. The exhibit on page 78 is a cost or revenue requirement analysis similar to that used to screen the DSM programs. The CEAB analysis indicates that the vast majority of benefits of lower costs accrue to the participants. The analysis presented by the CEAB indicates that the only benefit to all ratepayers resulting from DSM is market price savings. CEAB Plan, p. 78. The Department agrees that the majority of benefits are energy savings. These savings result from lower kWh sales and accrue to participants through lower electric bills. The Department, however, does not believe that the analysis captures all the costs and benefits that result from DSM to all ratepayers.

On page 80 of the CEAB Plan, the CEAB provides a benefit/cost analysis of a repowering project. The analysis is similar in many respects to the cost categories indentified in the analysis on page 78 but includes both costs and revenues. The analysis on pages 78 and 80 can be combined and modified to be used as a consistent benefit/cost analysis to compare all types of projects. This analysis is from a total ratepayer prospective the results of which can be used to develop rates.

The CEAB is hereby directed to include the following components in its benefit/cost analysis: cost, net energy revenues, capacity revenues, market price savings, net REC costs, and net T&D costs.

Cost -- Fixed capital costs of the generation facility or total program costs for DSM.

Net Energy Revenues -- Energy cost minus the energy revenues. Generators incur fuel costs but sell the power generating revenues. DSM does not incur any additional costs but at the same time generates no energy revenues. Renewable projects such as solar or wind incur no fuel cost to produce power but generate revenues for each kWh sold. This revenue helps to offset the high fixed costs of renewable facilities.

Capacity revenues -- Capacity revenues are included and provide an offset to fixed cost. Generators and DSM can sell capacity into the market.

Market Price Savings -- Generators and DSM would also create energy and capacity price benefits. Capacity benefits would be the same for similar sized projects. Energy benefits might vary depending on the heat rate of fossil generators and the capacity factor of different projects.

Net REC costs -- Net REC costs, like energy, are similar for generators and DSM. A kWh generated requires RECs but customers will pay for them. DSM does not require RECs and no revenues are received. Renewables provide RECs and no additional cost which are sold. This provides a benefit to renewable projects compared to other generators and DSM which helps to offset their higher costs.

Net T&D Costs -- Generation requires T&D investment to deliver power. T&D costs are collected through rates providing revenues. To the extent that marginal T&D costs are greater than average this would be an added cost to all ratepayers. DSM has little impact on T&D investment. Costs may be slightly less than generation but T&D investment is still necessary. Participants, however, do not pay for those costs and they are shifted to other customers. This is a major cost to other ratepayers associated with DSM. Renewables also require T&D facilities to deliver their power. These incremental costs could be significantly higher than other generation or DSM since it may be require traveling long distances to load.

If only the cost side is examined, DSM is the least cost when compared to generation options. When the costs and revenues are considered, the analytical results for DSM are less clear. DSM is less costly but also generates less revenues and shifts T&D costs to other ratepayers. Renewables generally have high fixed costs but they are offset to some extent by energy, capacity and REC revenues. The Department believes a more consistent life cycle analysis of the costs and benefits of resources would help to understand the relationships between various resource options.

In its written exceptions, OCC recommends that the Department enhance the benefit cost analysis by including environmental impacts. Resources that help Connecticut achieve its air quality goals should receive credit for that in the benefit/cost analysis." OCC suggests that the Department guide the EDCs and the CEAB to use the RGGI carbon price or a national carbon price (should one be developed) in comparing resource types for IRP purposes.

The Department agrees that environmental impacts must be considered when resource options are evaluated. It was not the intent of the Department that the benefit/cost analysis would be the only analytical consideration. The EDCs have developed matricies for economic factors and non economic factors including environmental impacts, fuel use and reliability measures. These should continue to be part of the evaluation process.

The Department will not rule on the OCC request since it came in written exceptions and was not explored during the proceeding. The Department does not believe that the economic evaluation discussed herein should be modified at this time. The Department would encourage the CEAB and the EDCs to continue to refine the environmental and other non-economic matricies, including methods to monetize the impacts as suggested by the OCC.

2. Base Load and Peaking Resources

In the first IRP Decision, the Department directed the CEAB to provide more analysis of existing resources. The needs assessment should examine current resources to indicate which resources may retire and those that are expensive to operate or highly detrimental to the environment. In addition, that Decision emphasized the importance of distinguishing between the need for base load and peaking resources. Docket No. 08-07-01 Decision, p. 18.

The CEAB and the EDCs provided more analysis of costs of existing resources which was used to forecast retirements. Retirements are a big unknown that can have a large impact on resource adequacy. Although retirements are very difficult to predict, this analysis better frames the possible outcomes. Although most of the retirements over the next ten years will be old fossil units that operate at low capacity factors, essentially as peaking units, the resource options considered by the CEAB were all base load options. Adding peaking units or demand response should be examined in the future to replace aging fossil units. Peaking resources might also meet other objectives to lower costs and improve the environment.

J. CEAB Proposal for a Single State Policy and Planning Entity

The second planning recommendation offered by the CEAB is to develop a proposal for the legislature to restructure Connecticut's energy-related entities to provide a single state entity for oversight and accountability of energy policy and planning. The CEAB has learned through its planning process that there is a need for integration between electric sectors resources and policy, electric and natural industries, transportation sectors, environmental policy and economic development. The CEAB believes that a central, unifying voice on energy issues would enhance the ability of the state to identify opportunities to lower costs, reduce environmental impacts, and ensure reliability and balance security concerns and economic development considerations. Chief among the myriad functions of this entity would be the development of a comprehensive energy plan in addition to the CEAB's responsibility as the state's representative to ISO-NE. The CEAB intends to coordinate the various stakeholders to define the potential functions and structure of this entity and submit the proposal within a timeframe necessary to be actionable during the 2011 state legislative session. CEAB Report, pp. 26 and 27.

The LDCs indicated that as gas continues to play a larger role in electric generation, it can greatly impact operations on both sides. The LDCs state that the electric and gas industries have made substantial progress in working with one another over the last decade or so and have improved their communications and coordination. From a regional operational perspective, the LDCs and the EDCs work very closely with ISO-NE, New England Gas Association and other independent system operators. These entities meet periodically and provide updates on system issues. From a planning perspective, the EDCs and the CEAB sought gas industry input into the 2010 Integrated Resource Plan. The LDCs, interstate pipelines and other gas industry representatives participated in the CEAB Natural Gas Stakeholder Meeting held on November 19, 2009. Many of the comments of the LDCs and others are reflected in the natural gas section of the EDCs and CEAB reports filed in this docket. This collaborative dialogue regarding gas supply, capacity planning and other planning issues is critically important and valuable. LDC Joint Written Comments, p. 6; Late Filed Exhibit No. 24.

The Department believes that the implementation of energy policy in Connecticut can be efficiently and effectively achieved through the Department, its regulated utilities and other stakeholders. There is no evidence that the creation of an additional independent entity would result in lower energy costs in today's market. It is highly speculative that such an independent entity can realize enough savings for ratepayers to offset its additional cost. The Department also notes that there is a great deal more collaboration between the gas and electric companies in Connecticut than several years ago. This should continue for the foreseeable future, especially given the recent merger and acquisition activity involving gas and electric companies in the state. The Department urges the CEAB not to spend resources to pursue this issue.

IV. CONCLUSION AND ORDERS

A. DEPARTMENT CONCLUSION

The Department approves with modifications, the 2010 IRP submitted by the EDCs and the CEAB. The Department concurs with the EDC and CEAB assessment that Connecticut is not forecasted to have a shortage of any energy or capacity requirements during the statutorily-defined planning horizon. The Department finds that no further action needs to be taken at this time to procure new energy or capacity resources. However, because uncertainties exist, the Department will carefully monitor resource need. The Department will initiate a process to develop an RFP and evaluation methodology for repowering and other resources so the Department is ready to act quickly should the need for a procurement occur. The Department supports more DSM but does not endorse a significant increase in ratepayer funding at this time. The Department believes that there are sufficient renewable resources to meet the State's RPS requirements in the near-term; however, future supply and cost to meet the RPS are more uncertain over the longer term. The Department supports a re-evaluation of the State's RPS requirements to 2020.

B. DEPARTMENT RESPONSES TO CEAB RECOMMENDATIONS

Below is a summary of the Department's conclusion on and responses to the CEAB Procurement and Planning Recommendations. 2010 CEAB Plan, pp. 22-36.

1. CEAB Procurement Recommendation

1. Maximize the utilization of demand-side resources to achieve all cost-effective energy efficiency (A-ACE) while minimizing ratepayer impacts through the use of expanded financing options, market mechanisms, codes and standards, and other innovative approaches. CEAB 2010 IRP Plan, p. 22.

The Department supports increasing the level of energy efficiency in Connecticut. However, the Department does not support significantly increasing ratepayer funding at this time.

2. CEAB Planning Recommendations

1. Conduct a public stakeholder process to fully review the State's renewable portfolio standard and renewable energy policy to assure the policy is consistent with the current objectives of the State.

The Department agrees that Connecticut needs to re-evaluate its 20% Class I RPS requirement by 2020 in light of its impact on electric generation and transmission costs and environmental benefits.

2. Develop a proposal for the legislature to restructure Connecticut's energy-related entities to provide a single State entity for oversight and accountability of energy policy and planning.

The Department believes that the implementation of energy policy in Connecticut can be efficiently and effectively achieved through the Department, its regulated utilities and other stakeholders. There is no evidence that the creation of an additional independent entity would result in lower energy costs in today's market.

3. Strengthen the CEAB and State connections and coordination with ISO-NE, NESCOE and other regional organizations whose decision-making directly impacts electric system costs for Connecticut.

The Department believes that the CEAB has exercised sufficient coordination with ISO-NE, NESCOE and other regional organizations.

4. The CEAB will implement a proactive Planning and RFP process, in conjunction with the Department, to assure that Non-Transmission Alternatives (NTAs) to proposed transmission solutions are properly investigated, solicited and, if and as needed, successfully implemented.

The Department will work with the CEAB and other interested parties to better define and to initiate a non-transmission alternative process associated with the Hartford needs assessment.

5. Collaborate with ISO-NE in its Needs Assessment and Transmission Solutions studies for the Greater Hartford area. Conduct a concurrent assessment of the potential for non-transmission solutions to address the identified reliability need. If warranted, conduct a Proactive RFP for non-transmission alternatives.

The Department does not believe there is any need to take actions with regard to the CEAB's recommendation to alter initiatives and processes for the state to effectively coordinate with ISO-NE, NESCOE, and other regional organizations that impact electric systems costs.

6. Identify opportunities and promote development of CHP and district energy development.

   The Department concludes that no additional incentives are needed at this time.

7. Prepare a potential procurement for efficient, combined-cycle gas unit(s) or comparable facilities following the 2012 IRP process by 2020.

   The Department will proceed to develop an RFP and evaluation methodology.

8. Proceed with CASE to study the State capabilities for nuclear energy options.

The Department believes that proceeding with a study of nuclear energy options is not warranted at this time.

C. ORDERS

For the following Orders, submit one original and five (5) copies of the required documentation to the Executive Secretary, 10 Franklin Square, New Britain, CT 06415. Submissions filed in compliance with Department Orders must be identified by all three of the following: Title, Docket Number, and Order Number.

1. Any parties seeking to assist the Department in designing an RFP or RFP process shall provide, no later than November 1, 2010, a compliance filing as discussed in Section III.D.1 above.

2. In the next IRP filing, CEAB shall submit its study, not to exceed $50,000, of the objectives, costs and benefits of the current Connecticut RPS statutory requirement and alternatives that might meet those objectives more cost effectively.

3. On or before October 1, 2010, at the time of the 2011 C&LM filing, the EDCs shall propose program modifications and program additions to meet a zero MW growth goal as discussed in Section III.E.6 herein.

CEAB and/or the EDCs shall include the following in their future IRP Plans:

4. CEAB and the EDCs shall include a metric for rates when comparing resource options. This metric must include a base case for rates and a comparison of the rate impacts under different resource options. The analysis should include the full impact on total rates, as discussed in Section III.E.5.(b), Criteria 2.

5. CEAB shall update the Department on the status and costs of all new or ongoing CEAB studies related to IRP topics intended to be used in future IRP proceedings.

6. The EDCs and the CEAB shall include the potential for development of landfill gas as a Connecticut Class I resource in the renewable energy supply forecast.

7. The EDCs and the CEAB shall provide the findings of the most recent ISO-NE analysis on regional transmission planning to meet the needs of their respective Reference Case renewable build-out projections.

GLOSSARY

Algonquin Power (Algonquin);
All Achievable Cost-Effective DSM (A-ACE)
Alternative compliance payment (ACP);
Office of the Attorney General (AG);
Capacity, Energy, Loads and Transmission (CELT);
Combined heat and power (CHP);
Commercial and Industrial (C&I)
Compact fluorescent light bulb (CFL);
Connecticut Academy of Science and Engineering (CASE);
Connecticut Clean Energy Fund (CCEF);
Connecticut Energy Advisory Board (CEAB);
2010 Comprehensive Plan for the Procurement of Energy Resources (CEAB Plan)
Connecticut Department of Environmental Protection (DEP);
Connecticut Energy Efficiency Fund (Energy Efficiency Fund)[29];
Connecticut Light and Power Company (CL&P);
Connecticut Local Sourcing Requirement (CT LSR);
Connecticut Siting Council (CSC);
Conservation and Load Management (C&LM);
Demand Reduction Induced Price Effect (DRIPE);
Demand response (DR);
Demand Side Management (DSM);
Department of Public Utility Control (Department);
Distributed generation (DG);
Electric Distribution Company (EDC);
EDCs and LDCs together (Companies);
Integrated Resource Plan for Connecticut (EDC Plan)
Energy Conservation Management Board (Energy Efficiency Board)[30];
Energy efficiency (EE);
Environment Northeast (ENE);
United States Environmental Protection Agency (EPA);
Forward Capacity Auction (FCA);
Generation service charge (GSC);
Greater Springfield Reliability Project (GSRP);
High electric demand days (HEDD);
Independent System Operator of New England (ISO-NE);
Integrated Resource Plan (IRP);
Kilowatt (kW);
Kilowatt-hour (kWh);

[29] Since 2000 the Connecticut Energy Efficiency Fund has been referred to as the C&LM Fund or simply the Fund. To improve consumer awareness about the Connecticut Energy Efficiency Fund the Department believes it is appropriate to use the phrase Energy Efficiency Fund in its Decisions, and will do so going forward. See, 2010 C&LM Decision, p. 2.

[30] Conn. Gen. Stat. § 16-245m identifies the Energy Conservation Management Board as the entity which advises and assists the electric distribution companies to develop conservation programs and market transformation initiatives. Past Department rulings have referred to this entity as the ECMB. The Department is transitioning from the acronym 'ECMB' to the use of the phrase Energy Efficiency Board to better promote the Energy Efficiency Fund. See, 2010 C&LM Decision, p. 2.

Landfill gas (LFG);
Levitan & Associates, Inc. (LAI);
Liquified natural gas (LNG);
Local distribution company (LDC)
Local Sourcing Requirement (LSR);
Locational Forward Reserve Market (LFRM);
Megawatt (MW);
Megawatt-hour (MWh);
New England Power Pool Generation Information System (NEPOOL GIS);
Net Installed Capacity Requirement (NICR);
New England East-West Solution Transmission Project (NEEWS);
New England States Committee on Electricity (NESCOE);
Nonbypassable Federally Mandated Congestion Charge (NBFMCC).
Non-Transmission Alternatives (NTA);
Office of Consumer Counsel (OCC);
Public Utilities Regulatory Policy Act (PURPA);
Purchased power agreements (PPAs);
Regional Greenhouse Gas Initiative (RGGI);
Renewable Energy Certificate (REC);
Renewable Portfolio Standard (RPS);
Request for proposal (RFP);
Selective catalytic reduction (SCR)
Small Business Energy Advantage Program (SBEA);
Steam turbine generators (STGs);
The Connecticut Light and Power Company (CL&P)
Three gas distribution companies (LDCs);
Transmission and distribution (T&D);
Transmission Security Analysis (CT TSA);
The United Illuminating Company (UI);
U.S. Department of Energy (DOE);

APPENDIX

The following is a list of documents referred to throughout this Decision:

Connecticut's Joint 2009 Natural Gas Conservation Plan (2009 Gas Plan);
Connecticut Siting Council 2008 Forecast of Loads and Resources (2008 CSC Report);
CEAB's 2010 IRP for Connecticut (CEAB Plan);
EDCs' 2010 IRP for Connecticut (EDC Plan);
Decision dated May 10, 2000, in Docket No. 99-09-30, DPUC Review of The Connecticut Light and Power Company's Conservation and Load Management Programs for 2000 (2001 C&LM Decision)
Decision dated May 28, 2003, in Docket No. 03-01-01, DPUC Review of The Connecticut Light and Power Company's and The United Illuminating Company's Conservation and Load Management Programs and Budgets for Year 2003 and 2004 (2003 C&LM Decision);
Decision dated February 4, 2004, in Docket No. 03-11-01, DPUC Review of the CL&P and UI Conservation and Load Management Plan for Year 2004 (2004 C&LM Decision);
Decision dated July 28, 2004, in Docket No. 03-11-01PH02, DPUC Review of CL&P and UI Conservation and Load Management Plan For Year 2004 – Phase II, (2004 Phase II C&LM Decision);
Decision dated March 30, 2005 in Docket No. 04-11-01, DPUC Review of CL&P and UI Conservation And Load Management Plan For Year 2005 (2005 C&LM Decision)
Decision dated June 7, 2006, in Docket No. 05-10-02, DPUC Review of The Connecticut Light and Power Company and The United Illuminating Company Conservation and Load Management Plan for 2006 (2006 C&LM Decision);
Decision dated May 23, 2007, in Docket No. 06-10-02, DPUC Review of CL&P and UI Conservation and Load Management Plan For Year 2007 and 2008 (2007 C&LM Decision);
Decision dated April 30, 2008 in Docket No. 03-09-08RE01, Applications of The Connecticut Light and Power Company and The United Illuminating Company for Issuance of Financing Order – Funding for the Energy Conservation and Load Management Fund and the Renewable Energy Investment Fund, (C&LM Fund Restoration Decision);
Decision dated June 19, 2008, in Docket No. 07-10-03 DPUC Review of The Connecticut Light and Power Company's And The United Illuminating Company's Conservation and Load Management Plan For Year 2008 (2008 C&LM Decision);
Decision dated June 19, 2008, in Docket No. 07-10-03, DPUC Review of The Connecticut Light and Power Company's And The United Illuminating Company's Conservation and Load Management Plan For Year 2008 – Program Incentive Structure, (2008 C&LM Decision);
Decision dated September 24, 2008, in Docket No. 07-10-03RE01 DPUC Review of The Connecticut Light and Power Company's And The United Illuminating Company's Conservation and Load Management Plan For Year 2008 – Program Incentive Structure (Reopened 2008 C&LM Decision);
Decision dated February 18, 2009, in Docket No. 08-07-01, DPUC Review of The Integrated Resource Plan (2009 IRP Decision);
Interim Decision dated February 25, 2009 in Docket No. 08-10-02, DPUC Review of the Connecticut Gas Utilities Forecasts of Demand and Supply 2009-2013 and Joint Conservation Plans (Interim Gas Supply Decision);

Decision dated May 7, 2009, in Docket No. 08-10-03, DPUC Review of The Connecticut Light and Power Company's and The United Illuminating Company's Conservation and Load Management Plan For the Year 2009 (2009 C&LM Decision);
Decision dated March 17, 2010, in Docket No. 09-10-03, DPUC Review of The Connecticut Energy Efficiency Fund's Conservation and Load Management Plan for 2010, and Docket No. 08-10-02 – DPUC Review of the Connecticut Gas Utilities Forecasts of Demand and Supply 2009-2013 and Joint Conservation Plans (2010 C&LM Decision):

Pursuant to a Notice of Taking of Administrative Notice dated July 27, 2010, the Department took administrative notice of the following three documents from Docket No. 09-10-03, DPUC Review of The Connecticut Energy Efficiency Fund's Conservation and Load Management Plan for 2010, and Docket No. 08-10-02 – DPUC Review of the Connecticut Gas Utilities Forecasts of Demand and Supply 2009-2013 and Joint Conservation Plans.

1. June 25, 2010 DPUC letter to CL&P and UI, requesting information regarding the residential Financing Pilot;
2. July 1, 2010 joint letter from CL&P and UI responding to the Department's June 25, 2010, Request For Information; and,
3. July 14, 2010 joint letter from CL&P and UI to explain modifications to the residential Financing Pilot Program.

DOCKET NO. 10-02-07 DPUC REVIEW OF THE 2010 INTEGRATED RESOURCE PLAN

This Decision is adopted by the following Commissioners:

Amalia Vazquez Bzdyra

Kevin M. DelGobbo

Anthony J. Palermino

CERTIFICATE OF SERVICE

The foregoing is a true and correct copy of the Decision issued by the Department of Public Utility Control, State of Connecticut, and was forwarded by Certified Mail to all parties of record in this proceeding on the date indicated.

K. Santopietro

09/16/2010

Kimberley J. Santopietro
Executive Secretary
Department of Public Utility Control

Date