Via Electronic Filing and First Class Mail

Ms. Louise E. Rickard, Acting Executive Secretary
Department of Public Utility Control
Ten Franklin Square
New Britain, CT 06051

Re: Docket No. 05-07-14Ph01: DPUC INVESTIGATION OF MEASURES TO REDUCE FEDERALLY MANDATED CONGESTION CHARGES

Dear Ms. Rickard:

On behalf of the Connecticut Energy Advisory Board (CEAB), I am pleased to submit the CEAB's Preliminary Assessment of Connecticut's Electric Supply and Demand Near Term Requirements for Reliability and Mitigation of Federally Mandated Congestion Charges ("Interim Report") pursuant to the Department of Public Utility Control's (DPUC) Procedural Order dated July 25, 2005 in the above captioned matter. The CEAB is pleased that its ongoing energy planning work is able to be of assistance to the DPUC.

Please add the following representatives of the CEAB to the Service List in this matter:

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Thank you for your assistance. Please contact me with any questions about this filing.

Sincerely,

Mary J. Healey  
Mary J. Healey, Esq.  
Consumer Counsel  
Vice Chairman  
Connecticut Energy Advisory Board

cc: CEAB Members  
Service List
Preliminary Assessment

Connecticut’s Electric Supply and Demand

Near Term Requirements for Reliability and Mitigation of Federally Mandated Congestion Charges

The Connecticut Energy Advisory Board

September 2, 2005
Connecticut’s Electric Supply and Demand
Near Term Requirements for Reliability and
Mitigation of Federally Mandated Congestion Charges (“FMCCs”)

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Preface

The Connecticut Energy Advisory Board’s (“CEAB”) composition and function were substantially reformed by Public Act 03-140. The change equipped Connecticut to anticipate rather than react to emerging energy needs. The CEAB’s statutory responsibilities now include, among others: preparing an annual Energy Plan; establishing criteria for evaluating energy proposals; participating in various Siting Council proceedings; implementing and conducting an RFP to solicit energy projects; and representing the State in regional energy system planning processes conducted by New England’s Independent System Operator, ISO-NE. Together, these functions enable Connecticut to facilitate market-based energy solutions that further the State’s energy, environmental, and economic development objectives.

This Preliminary Assessment of Connecticut’s Electric Supply and Demand (“Interim Report”) is part of the CEAB’s 2005 assessment of Connecticut’s need for new energy resources, infrastructure and conservation initiatives (“2005 Needs Assessment”). The Interim Report is provided in response to a request from the Department of Public Utility Control (“DPUC”) in Docket No. 05-07-14 Phase I, in which the DPUC will implement Section 12(a) of Public Act 05-01 “An Act Concerning Energy Independence” (“the Act”). The DPUC intends the Interim Report to provide the factual basis for its orders implementing near term measures to reduce federally mandated congestion charges. The CEAB will provide the DPUC a Final Report in November 2005, coterminal with the completion of the CEAB’s 2005 Needs Assessment. The CEAB Final Report is expected to assist the DPUC in drafting an RFP to solicit long-term projects and in evaluating RFP responses pursuant to Section 12(c) of the Act.

Pursuant to the Procedural Order dated July 25, 2005 in Docket No. 05-07-14, Phase I, all interested parties will have an opportunity to provide written comment on the Interim Report. The CEAB will consider all comments filed in Docket No. 05-07-14 Phase I as it prepares its Final Report. Additionally, if any interested person has comments that may inform the CEAB’s 2005 Needs Assessment but do not pertain to the Interim Report and will not be filed in Docket No. 05-07-14 Phase I, CEAB will also consider them. Please direct comments to:

Gretchen K. Deans
Director of Administration
The Connecticut Economic Resource Center, Inc.
805 Brook St, Bldg 4
Rocky Hill, CT 06067
Phone: 860 571-7147

1 Members of the CEAB include heads of the following agencies: Department of Public Utility Control; Department of Environmental Protection; Office of Consumer Counsel, Office of Policy and Management, Department of Agriculture; and Department of Transportation. In addition, three members of the Board are appointed by the Governor, Speaker of the House and President Pro Tempore of the Senate, respectively.
Fax: 860-571-7150
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Any other inquiries regarding the CEAB’s activities should be directed to CERC, as well.
Acknowledgements

The CEAB has retained a consulting team led by La Capra Associates of Boston, Massachusetts to conduct this assessment. The consulting team is reviewing planning studies and information available from entities involved in Connecticut’s electric sector to assist the CEAB in carrying out its planning responsibilities under Public Act 03-140. The CEAB appreciates the cooperation that has been offered and wishes to acknowledge these efforts.

First, the Connecticut Siting Council (“CSC”) has afforded the CEAB an opportunity to participate in its ongoing proceeding regarding its 2005 Review of the Ten-Year Forecast of Electric Loads and Resources (Docket No. F-2005). The CEAB also appreciates the information provided to the CSC and CEAB in this proceeding by Connecticut’s electric distribution companies and generation companies and by the Independent System Operator of New England (“ISO-NE”).

In addition to its participation in the CSC proceeding, the CEAB acknowledges and appreciates ISO-NE for its planning initiatives, for affording the CEAB the opportunity to participate in its Planning Advisory Committee and Regional System Planning process, and for making its personnel available to the CEAB to describe and explain its planning methods and results. Similarly, Connecticut Light and Power, United Illuminating, and the Connecticut Municipal Electrical Energy Cooperative have made their planning information and personnel available to the CEAB. The ISO-NE and the Connecticut electric distribution companies have direct roles in the planning and implementation of the electric system in Connecticut, and their cooperation with CEAB is appreciated.

Additional sources of information for this effort include the Federal Energy Regulatory Commission, the Connecticut Energy Conservation Management Board, the Connecticut Clean Energy Fund, and the Institute for Sustainable Energy.

The observations and conclusions offered in this report, while relying on information from many, are offered as those of the CEAB alone.
Executive Summary

Connecticut consumers’ exposure to federally mandated congestion charges (“FMCC”s) is substantial and multifaceted. The Independent System Operator of New England’s (“ISO-NE”) plans for both locational capacity markets (postponed to at least October 2006) and a two-zone energy market in Connecticut are important elements of the cost exposure. In addition, other system reliability criteria will result in FMCCs being borne by Connecticut’s consumers. The current Reliability Must Run (“RMR”) contracts between ISO-NE and local generators are perhaps the most obvious example.

The completion of recently approved transmission projects, referred to as Phase I and Phase II, will mitigate some of the FMCCs. However, even after the implementation of the projects, significant transmission constraints – both interstate and intrastate – and associated FMCC cost exposure will remain. Connecticut has available to it a variety of means to mitigate FMCCs, including but not limited to measures created by Public Act 05-01, An Act Concerning Energy Independence. The near term options include measures that reduce peak demand, as well as new generation and additional transmission resources.

The CEAB’s preliminary assessment of Connecticut’s electric system and the near-term outlook for loads, supplies, transmission and FMCCs leads to the following observations:

1. In 2006, FMCC exposures will be most acute in Southwest Connecticut (“SWCT”). Despite FERC’s delay of a final decision on ISO-NE’s Locational Installed Capacity (“LICAP”) proposal, ISO-NE plans to implement a distinct energy pricing zone for SWCT in January, 2006. Reliability Must Run (“RMR”) and operating reserve costs will likely remain high in that area through 2006. The Phase I, Bethel-Norwalk transmission line, is not slated for operation until year-end 2006. Near-term actions to mitigate FMCCs should concentrate in this zone, particularly in the Stamford/Norwalk sub-area, to have maximum benefit to SWCT and the State as a whole.

2. At this juncture, to the CEAB’s knowledge, neither ISO-NE nor the Connecticut electric distribution companies have definitive studies that would provide the information needed to specify optimal locations for distributed resources.

3. Significant FMCC exposures will remain in 2007 and 2008, although completion of the Bethel-Norwalk transmission line is expected to temper the exposure, particularly in SWCT.

4. The level of FMCCs in the 2006 to 2008 period is very sensitive to peak load levels. Forecasts of peak load, net of contributions from conservation and load management

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2 The term SWCT is used in this Report to mean the load-zone as being considered by ISO-NE.
(“CLM”), from ISO-NE and the Connecticut electric distribution companies differ materially and have very different implications for the State’s resource requirements and associated costs.

5. Congestion and FMCCs are significantly determined by usage in peak load or near-peak load conditions and during times when significant amounts of local generation are out of service.

6. Even relatively modest amounts of peak load reduction or increased generation during peak periods can substantially mitigate FMCCs.

7. Connecticut’s significant intra- and inter-state transmission constraints, coupled with the size of the largest units in Connecticut (Millstone Units 2 and 3), mean that the State will require substantial reserves. ISO-NE states that Connecticut now needs an additional 550 MW in quick start capability.

8. FMCC costs associated with RMR contracts and Operating Reserve requirements may well continue to be significant.

Based on these observations, the CEAB offers recommendations on the types of near-term actions that the DPUC should consider to mitigate FMCC’s during 2006 – 2009. The recommendations are as follows:

**Actions to Mitigate Connecticut’s Peak Demand:**

Actions to mitigate the State’s peak demand are a near term priority and should include immediate focus on CLM measures, rate design focused on peak demand reduction, customer-side distributed generation, and public education regarding the benefits associated with the more efficient and timely use of electricity. Because the State’s capacity obligations under LICAP (i.e., for each of the two load zones) will be calculated as a direct function of the ratio of actual in State loads to regional loads for the prior year, actions intended to mitigate LICAP exposure in a given year by reducing peak loads must be producing savings one year in advance. Thus, to the extent that these measures can be implemented by the summer of 2006, it would benefit consumers individually and collectively by reducing the State’s overall cost exposure to LICAP in 2007 (should LICAP be implemented).

**Actions to Preserve Connecticut’s Local Generation:**

Actions to preserve Connecticut’s local generation should include management of RMR contract costs, contractual alternatives to RMR contracts, and consideration of contractual approaches to supply, such as hedging, to mitigate consumer exposure to the potentially volatile spot capacity market (i.e., LICAP).
**Actions Pertaining to Connecticut’s Transmission and Import Capability:**

Steps associated with transmission that could help reduce FMCCs include the timely completion of the Bethel-Norwalk 345 kV line, as well as the Mystic-Wood River reconductoring project, both scheduled for 2007. In addition, it would be useful for Connecticut to assess the possibilities for incremental transmission, particularly intra-state, that may be able to substantially mitigate FMCCs. The Connecticut electric distribution companies should undertake these studies.

**Actions Pertaining to New Generation Resources:**

Generation resources include preferred generation resources – such as distributed generation, combined heat and power, and renewables – as well as other types. The CEAB recommends that the DPUC encourage those resources that compare favorably to the CEAB’s preferential resource criteria with an emphasis on those to be sited in locations that likely will maximize FMCC reductions. As for other generation resources, there are some, such as those providing quick start capabilities, that can provide significant benefits, particularly if located in the Stamford/Norwalk sub-area and elsewhere in SWCT. In general, however, large scale generation resources should be solicited, if at all, through the RFP process.

**Additional Actions:**

Another action that could help advance consumer interests relative to potential cost exposure is active participation in ISO-NE decision-making, which in the near term will include transmission planning studies, notably the Southern New England Reinforcement Project; analyses of near term resource adequacy; and the design and implementation of a locational forward reserve market.
1. Introduction

Connecticut’s electric infrastructure is reaching the limits of its ability to provide reliable service to meet the State’s growing demand for electricity, particularly as it pertains to the electric requirements in southwestern Connecticut. During the past ten years, the supply and demand balance in Connecticut has changed. At this time, Connecticut has come to rely significantly on power imports from sources outside the State during times of peak demand. The State has also become increasingly vulnerable to power disruptions attributable to unplanned outages of in-state generation and transmission facilities.

Peak demand in Connecticut has grown steadily across the last decade. Data from ISO-NE indicates that peak loads in the State increased at an average annual compound rate of 1.2% from 1994 through 2004, reaching 6,444 MW in 2004. This represents a 12% increase over the decade, or about the equivalent of the production capability of one 700 megawatt (“MW”) base load power plant. Since 1994, average growth in peak demand for Connecticut has been somewhat lower than growth in the New England control area. The corresponding annual growth rate for the region has been roughly 1.6%. This is a 17% increase over the decade, or roughly 3,600 MW in total.

Connecticut’s generation supply has not kept pace with its growth in demand. Major power plant retirements – Connecticut Yankee in December 1996 and Millstone Unit 1 in December 1997 – which provided 1,200 MW of base load power production, were replaced gradually over time with 1,650 MW from three gas-fired combined cycle power plants: Bridgeport Energy in 1998, Lake Road in 2001, and Milford Power in 2004. Peaking power plant additions in Wallingford and Devon, which together provide 350 MW, have been offset by the retirement or deactivation of units in Bridgeport Harbor, Devon, and New Haven.

In addition, transmission limitations both within the State and for imports into it have become increasingly problematic. The limitations of the Connecticut transmission system to allow power imports from the rest of New England were evident during the extended outages of the Millstone units in 1997 and 1998 and have remained the focus of transmission planning. While some transmission upgrades have been implemented, other serious limitations to the reliable transfer of power persist. For example, the Lake Road facility’s location in northeastern Connecticut effectively precludes its ability to serve load in Connecticut at peak times. This exacerbates the gap between Connecticut generation and load.

Full solutions to these challenges will take time. The Bethel-Norwalk transmission line, under construction for operation in 2007, and the Middletown-Norwalk transmission line, planned for operation in 2009, will significantly improve the ability to transfer power within the State. With respect to generation however, there are no major facilities currently under active development. And many generation units in the State are quite old. Consequently, in addition to ongoing efforts to utilize energy
more efficiently and manage peak demand, Connecticut needs long-term generation solutions. The State will also need near-term demand and supply actions to resolve these limitations and to mitigate the associated costs.

ISO-NE and FERC have endeavored to address these issues in the context of their responsibilities for regional power system reliability and the administration of wholesale markets. The effect of these actions, the imposition of Federally Mandated Congestion Charges (“FMCCs”), has been substantial price increases for Connecticut consumers over the last two years. Those costs are expected to increase further. Examples of recent actions in this area include the following:

- In March 2003, ISO-NE implemented a new market system that differentiates wholesale spot market energy prices by location in the region, otherwise known as Locational Marginal Pricing (“LMP”). This has led to circumstances in which spot market energy prices in Connecticut are higher or lower than the rest of the region due to transmission limits (or congestion) which preclude full, free flowing economic dispatch in the region.

- Since 2003, in response to some Connecticut generators’ petitions for retirement or deactivation, ISO-NE entered numerous Reliability Must Run (“RMR”) contracts with them to maintain their active status in support of local reliability requirements. Currently, about 2,900 MW of Connecticut capacity holds RMR contracts with ISO-NE. These RMR contracts increase Connecticut’s costs by having generators running in-state for reliability reasons at times when more economically priced energy would otherwise be available.

- ISO-NE has conducted two solicitations through “GAP” RFPs for quick start, near term supply and demand response measures, and has entered into resulted contracts for over 250 MW for the 2004 to 2008 period. The costs of these contracts are allocated to Connecticut consumers by ISO-NE.

Additionally, ISO-NE has proposed and the FERC is considering new market systems, including a Locational Installed Capacity (“LICAP”) market. The intent of LICAP is to provide incentives to encourage development of new generation and demand response resources. If LICAP were to be implemented, it could reduce the need for costly RMR contracts and GAP RFP-like contracts, but it presents the real potential to materially increase FMCC costs to Connecticut consumers in the future in the form of higher capacity costs.

Over the past several years, the State of Connecticut has created mechanisms that enable it to address key electric infrastructure challenges and to mitigate FMCC expenses that might be borne by Connecticut consumers. First, in 2003, the General Assembly passed and the Governor signed Public Act 03-140, “An Act Concerning Long Term Planning for Energy Facilities.” The law reformed the
CEAB’s composition and function. Among other things, it requires long-term energy planning and the development of preferential selection criteria to ensure that the State’s energy decisions work in concert with environmental and other goals; it also institutes a process for the active solicitation of energy infrastructure proposals.

More recently, in July 2005, the General Assembly passed and the Governor signed Public Act 05-01 “An Act Concerning Energy Independence.” Among other things, the Act created a series of instruments that equip the State to encourage and to facilitate the deployment of preferred energy resources so as to mitigate FMCCs.

In furtherance of its energy planning responsibilities under the 2003 Act, the CEAB is comprehensively reviewing Connecticut power system planning studies. Its review will result in an independent energy needs assessment in the fall of 2005. This Interim Report provides a preliminary view of that more comprehensive needs assessment. It is provided at the request of the DPUC in order to help inform the DPUC’s decisions, pursuant to the 2005 Energy Independence Act, as it undertakes to encourage investment in preferred energy resources and maximize the reduction of FMCCs.
2. DPUC Investigation of Measures to Reduce FMCCs

The DPUC opened Docket No. 05-07-14, Phase I to implement Section 12 of the Energy Independence Act. Sections 12(a) and (c) of the Act require the DPUC to implement near-and longer-term measures to reduce FMCCs.

In Phase I, pursuant to Section 12(a), the DPUC will identify by November 1, 2005 those near-term measures that can best reduce FMCCs and that can be implemented by the electric distribution companies at least in part by January 1, 2006. Subsequently, pursuant to Section 12(c), the DPUC will develop and issue an RFP for longer-term projects to further reduce FMCCs.

In a Procedural Order dated July 25, 2005, the DPUC emphasized the need for a sound factual basis to guide its findings and decisions. Accordingly, the DPUC requested that the CEAB submit a report no later than August 18, 2005 to provide a starting point for DPUC decisions on which near-term measures to implement. More specifically, the DPUC requested information related to the CEAB’s ongoing assessment of the State’s supply and demand status, including:

1. quantification of anticipated FMCC costs;
2. an analytical framework to facilitate an assessment of the cost/benefit effectiveness of various measures to mitigate FMCCs; and
3. a description of the type and location of resources that would best reduce FMCCs.

On August 18, 2005, the DPUC modified the procedural schedule, establishing September 2, 2005 as the date to file this report, due to FERC’s action on August 10, 2005 to postpone the start of the LICAP market from January 1, 2006 to no sooner than October 1, 2006.

In this Interim Report the CEAB (1) presents a synopsis of the supply and demand status and outlook for the State; (2) describes the current and proposed market systems that will affect FMCC costs Connecticut consumers are expected to incur; and (3) offers recommendations on the types of measures the DPUC and others in the State could pursue to mitigate high FMCC costs, while assuring cost effective and reliable power supply.

For the purposes of this Report, the term “near term measures” refers to any measures that can be implemented by the DPUC, the electric distribution companies, or other entities in time to influence FMCCs expected upon implementation of LICAP and thereafter. The “near term” is also assumed to include the period 2006 through 2009, which coincides with the planned completion schedule of the Southwest Connecticut Reliability Project (Phases I and II of the Southwestern Connecticut transmission system).
3. Federally Mandated Congestion Charges

This section provides an overview of FMCCs and background on the wholesale power market. FMCCs influence electricity prices in Connecticut, and mitigating them is a focus of the DPUC’s current inquiry.

FMCCs are a component of the costs that are associated with transmission system congestion. Congestion results from physical limits in the transmission system, restricting the free flow of economic power supply from generation to loads in Connecticut. The wholesale power market and regional transmission system are governed by federal regulation (the Federal Energy Regulatory Commission or FERC). Thus, the market rules and rate making policies that determine congestion charges are “federally mandated.” ISO-NE began implementing FERC-authorized market rules associated with congestion in 2003. It is developing additional market rules and mechanisms pertaining to congestion for implementation in 2006.

The Energy Independence Act defines FMCCs as follows:

“Federally mandated congestion charges” means any cost approved by the Federal Energy Regulatory Commission as part of New England Standard Market Design including, but not limited to, locational marginal pricing, locational installed capacity payments, any cost approved by the Department of Public Utility Control to reduce federally mandated congestion charges in accordance with this section, sections 16-19ss, 16-32f, 16-50i, 16-50k, 16-50x, 16-244c, 16-244e, 16-245m and 16-245n, as amended by this act, and sections 8 to 17, inclusive, and 20 and 21 of this act and reliability must run contracts.”

3.1 Federal Energy Regulatory Commission and FMCCs

The federal regulatory approach to the nation’s interstate power generation and transmission systems has been evolving from a fully regulated utility monopoly structure to more open, competitive generation markets for nearly 30 years. In 1978, the Public Utility Regulatory Policies Act (“PURPA”) provided the opportunity for entities other than regulated utilities to own generation and sell electricity to third parties. In 1992, the Energy Policy Act established the legal framework for open access to the nation’s transmission systems and the opportunity for the generation of power to be transacted at market-based rates.

In 1996, FERC established rules to implement the open access transmission provisions of the Energy Policy Act of 1992 and adopted a policy to encourage the formation of regional transmission groups to facilitate transmission access. In Order 2000, issued in December 1999, FERC established rules for the
formation of Regional Transmission Organizations (“RTOs”). RTOs are organizations that operate
regional transmission systems and administer wholesale power markets. They are independent from all
market participants.

In Order 2000, FERC also established a policy to address the management of congestion in power
systems by establishing markets based on locational marginal pricing and financial rights for
transmission. These market structure policies are collectively referred to as Standard Market Design
(“SMD”). The Energy Independence Act’s definition of FMCCs refers to SMD. The SMD policy, as
developed and implemented by ISO-NE, is the basis for the FMCCs at issue in Docket No. 05-07-14.

3.2 ISO New England and FMCCs

In response to FERC’s 1996 rules, ISO-NE was created in July 1997 to manage New England’s bulk
power system and wholesale markets. It replaced the power pool approach that had operated the New
England power system since 1965. In February 2005, ISO-NE commenced operations as the RTO for the
New England control area.

From the outset, ISO-NE began developing market systems to implement FERC requirements. In
May 1999, ISO-NE began the management and operation of the wholesale market in New England and
established an operating spot market for wholesale energy, capacity, and ancillary services.

Following FERC’s Order 2000, ISO-NE undertook the changes to implement a congestion
management pricing system and other elements of the SMD, as well as actions to restructure its
operations to meet the Order 2000 RTO requirements. In March 2003, ISO-NE began operation of a
revised wholesale power market utilizing a market design (the “Standard Market Design”) ordered by
FERC. This market system included an LMP spot market for energy (i.e., kilowatthours, or kWh) and
was the first market-based mechanism that created the potential for congestion charges in Connecticut and
other pricing zones in the region.

In April 2003, FERC ordered ISO-NE to develop a market mechanism to implement locational
requirements in ISO-NE’s existing capacity (i.e., megawatts, or MW) market. ISO-NE filed its
Locational Installed Capacity (“LICAP”) market proposal in March 2004. That proposal, as modified
through hearings, is pending FERC consideration. Oral arguments are scheduled for September 20, 2005,
and implementation is to be, if at all, no sooner than October 1, 2006.

In addition to locational pricing in ISO-NE’s energy markets (LMP) and capacity markets (LICAP),
a locational component to the ISO-NE’s Ancillary Services markets is under development.3 ISO-NE

3 Ancillary Services are discussed in Section 3.5 of this Report.
implemented a (non-locational) Forward Reserves market in December 2003, and it is planning to add a locational component in 2006.

### 3.3 Energy Market Congestion: Locational Marginal Pricing

Spot market energy prices in New England currently are based on LMPs, pursuant to FERC’s standard market design policy.\(^4\) Currently, there is one pricing zone in Connecticut, and seven other pricing zones throughout New England.\(^5\) As noted above, LMPs have been operational in the ISO-NE market since March 2003.

FERC has ordered that Connecticut be divided into two LMP zones as of January 1, 2006, one zone in SWCT and one zone for the rest of the State.

At times, when transmission constraints restrict the free flow of power between Connecticut and the rest of New England, LMP prices in the Connecticut zone will differ from the other LMP prices in the region.\(^6\) Absent transmission constraints – or, in other words, absent congestion – the most economical power plants in the region generate electricity. Congestion costs are the result of the need to utilize higher cost local generation when transmission limitations preclude lower cost power from being imported from other zones.

Because of congestion, zonal LMPs in Connecticut have been slightly higher on average than in other pricing zones of New England. Table 3.1 presents ISO-NE’s data on zonal LMP prices in New England in 2004. It shows Connecticut’s annual average real time price of $52.80/MWh to be 1.3% higher than that of the New England Hub (a reference price internal to the ISO-NE control area). The day-ahead prices are slightly higher (3%) in both the Connecticut zone and the New England Hub. The minimum and maximum hourly prices demonstrate that in individual hours, the LMP prices can vary substantially from the annual average price.

In most hours of the year, Connecticut’s zonal LMP prices have not been materially affected by congestion. From July 2004 through June 2005, 50% of the hourly prices in the Connecticut zone were

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\(^4\) “Spot market” is used here to refer to both the day-ahead and real time LMP markets.

\(^5\) These pricing zones determine the prices paid by load serving entities for energy purchased in the spot market to serve load. Prices in each zone are an average of a number of pricing nodes within each zone. Energy produced by generation and sold in the spot market is paid the nodal price applicable to its location. As Docket No. 05-07-14 is assessing measures to mitigate FMCCs to consumers, this discussion focuses on the zonal pricing applicable to consumers.

\(^6\) Line losses also create differences in the LMPs experienced in different zones across the region (i.e., even when there are no transmission constraints).
the within 1% of the New England Hub price, and 95% of the hourly prices were within $5/MWh (i.e., 10%) of the New England Hub price.

Table 3.1 - Summary LMP Statistics by Zone for 2004, All Hours

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<td>$501.18</td>
</tr>
<tr>
<td>SEMA</td>
<td>$52.33</td>
<td>$19.84</td>
<td>$505.18</td>
<td>$908.94</td>
<td>$50.72</td>
<td>$0.00</td>
<td>$501.18</td>
</tr>
<tr>
<td>WCMA</td>
<td>$53.86</td>
<td>$20.32</td>
<td>$518.42</td>
<td>$911.69</td>
<td>$52.33</td>
<td>$0.00</td>
<td>$510.75</td>
</tr>
<tr>
<td>NEMA/Boston</td>
<td>$53.46</td>
<td>$19.96</td>
<td>$508.76</td>
<td>$903.10</td>
<td>$51.46</td>
<td>$0.00</td>
<td>$501.18</td>
</tr>
</tbody>
</table>


Congestion caused the Connecticut zonal LMP prices to differ from the Hub price by more than $5.00/MWh in 5% of the hours. In most of these instances, the Connecticut prices were higher than the Hub price. The hourly percentage difference between the New England Hub and Connecticut Zone real time LMP is depicted in Figure 3.1. That Figure shows the proportion of congested to uncongested hours.
in the July 2004 to June 2005 period. Some statistics on the price variances illustrate the nature of the congestion in that 12-month period:

Connecticut prices were higher than Hub prices:
  - in 5180 hours (59%)
  - by more than $5.00/MWh in 415 hours (4.7%)
  - by more than $25.00/MWh in 79 hours (0.9%)

Connecticut prices were lower than Hub prices:
  - in 3459 hours (39.5%)
  - by more than $5.00/MWh in 32 hours (0.4%)

These statistics indicate that there are few hours in which energy prices are materially increased because of congestion. Those are concentrated in the hours when very high Connecticut demand and/or significant outages of Connecticut generation cause transmission import limits to be reached. Conversely, there are many hours in which Connecticut has economic power supply that cannot be exported. This results in a significant number of hours when Connecticut LMP prices are somewhat lower than those of the New England Hub.

The above data are not necessarily indicative of the LMP prices that would have existed in a SWCT Zone. In 2004, nodal prices in the Stamford/Norwalk sub-area averaged higher than the zonal prices for the State and region. However, such differences between SWCT and the rest of the State will be tempered when the Bethel-Norwalk 345 kV transmission line is completed (currently scheduled for December 2006).


3.4 Capacity Market Congestion: Locational Installed Capacity

The current ISO-NE capacity market is not locational. Therefore, to date no congestion costs have been reflected in the capacity market component of electric costs in Connecticut. If implemented as proposed, ISO-NE’s LICAP market could substantially increase prices in the ISO-NE capacity spot market and would create the potential for congestion to increase Connecticut capacity prices above levels in other New England pricing zones.

At this writing, the form and the timing for a locational capacity market is uncertain. The ISO-NE’s LICAP proposal was approved by the FERC Administrative Law Judge who recommended implementation effective January 1, 2006. That proposal, as modified through subsequent hearings, is currently pending before FERC. As noted earlier, oral arguments are scheduled for September 20, 2005 and implementation is to be no sooner than October 1, 2006.
While the form and timing of a locational capacity market is not entirely clear, it is clear that the FERC and ISO-NE intend to implement changes to capacity markets. FERC has opined that RMR agreements, discussed in Section 3.6, are an inappropriate remedy for reliability concerns. FERC ordered ISO-NE to design and file for approval a system to pay different prices for capacity in zones where transmission limitations and lack of local supply have necessitated non-market-based solutions (such as RMR contracts). The stated intent of the LICAP system was to provide locational capacity prices to encourage construction of new generation where and when it is needed.

Should it be implemented, the LICAP system would introduce two significant changes. First, there would be a downward sloping demand curve in the capacity spot market, which would result in different capacity “clearing” prices depending upon the total amount of capacity participating in the auction. Second, there would be an adjustment of the Capacity Obligation of each load serving entity, such that the total amount of capacity supported (that is, paid for) equals total available supply, even if it exceeds the Capacity Obligation.

An important characteristic of the LICAP market is that it is a residual market. It is designed to be a spot market that will set the price for any capacity not previously secured contractually. Buyers and sellers are free to enter “bilateral” contracts for capacity at mutually agreeable terms and conditions. Only buyers, referred to as load serving entities (“LSEs”), that have not contracted for capacity in advance will pay the LICAP clearing price; and only those generators without contracts will receive the LICAP clearing price. The contractual buyers and sellers of capacity will continue to transact at the contract prices. The ability to contract for capacity rather than pay the LICAP (spot market) clearing prices means that the LICAP market can be hedged. For purposes of this Report, it is assumed that costs under any such capacity contract would qualify as FMCCs, as the contracts would serve to hedge the LICAP market. However, as with any contract, its costs cannot be avoided while the contract is in force.

3.5 Ancillary Services Markets Congestion: Locational Reserve Market

As with capacity markets, New England’s Ancillary Services Markets (“ASMs”) are not currently locational. FERC has ordered consideration of other changes to ISO-NE markets which may affect Connecticut and the future FMCCs paid by Connecticut consumers. One aspect of this is the plans for the addition of a locational component to the forward reserves market.

In addition to energy and installed capacity markets, ISO-NE operates ASMs for operating reserves and regulation. Generating facilities that can offer to stand ready to increase production within 10 or 30 minutes notice are needed to enable the system to respond to unforeseen changes in load and unit outages. In addition, generating facilities that can provide second-to-second variation in output though Automated Generation Control (“AGC”) are needed to regulate frequencies in the power supply system.
In December 2003, ISO-NE implemented a forward reserve market. In this market, generators bid to make available units that can provide operating reserves to the system for a six-month period. The costs incurred by ISO-NE to purchase this service are allocated to customers throughout the region. In 2004, the costs for forward reserves for the entire ISO-NE system were $83 million.\(^7\)

ISO-NE is proposing locational reserve requirements for parts of the power system that routinely require daily RMR commitments (see below) to meet second contingency reliability criteria; in New England, the affected zones are SWCT, the rest of Connecticut (“ROC”), and NEMA/Boston. Locational reserve requirements would reflect the need for additional 30-minute operating reserves (or higher quality reserves) to provide second contingency coverage in these three import-constrained zones. Notably, these requirements would be satisfied by resources located within an import-constrained zone. Planning for locational reserves markets is targeting implementation no sooner than June 2006.\(^8\)

ISO-NE’s proposal for a locational forward reserve market clearly will have an impact on the cost of reserves allocated to Connecticut and SWCT customers and, therefore, will affect FMCCs in Connecticut. As a transmission-constrained area with large outage contingencies to cover, the local operating reserve requirements in Connecticut will be significant.

### 3.6 Out-of-Market Congestion-Related Costs

To date, the market mechanisms implemented by ISO-NE (energy LMP, installed capacity, and ancillary services) have not addressed all aspects of system reliability and operability in a manner that assures existing generation needed for reliability is financially viable. As a result, ISO-NE has used some “out-of-market” mechanisms in this area. Two significant “out-of-market” components are provisions for reliability-based capacity contracts and credits for the provision of operating reserves.

#### 1) Capacity Contracts: Reliability Must Run and Peaking Unit Safe Harbor

ISO-NE has backstopped the installed capacity market by entering special contracts with generation facilities deemed to be needed for reliability purposes. These are generally referred to as Reliability Must Run (“RMR”) contracts. As noted, locational capacity and ancillary services markets are being developed with the intent to substantially reduce or eliminate the need for the RMR contracts.

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\(^8\) At this writing, it is unclear how, if at all, the FERC August 10, 2005 Order on LICAP will affect the design or timing of the design and implementation of a locational reserves market.
In early 2003, ISO-NE and NRG requested FERC approval of four RMR agreements, based on a need determination associated with reliability requirements of SWCT and Connecticut as a whole. In April 2003, FERC concluded that flaws existed in the capacity markets, but rejected the proposed RMR agreements. Instead, FERC created a Peaking Unit Safe Harbor (“PUSH”) mechanism to provide low capacity factor generating units in designated congestion areas an opportunity to recover their fixed costs through the market. At the same time, FERC ordered ISO-NE to file a proposal to establish a permanent capacity market mechanism for locational capacity by March 2004 for implementation in June 2004. The PUSH mechanism was to end when the locational capacity market was implemented.

In June 2004, FERC directed ISO-NE to modify its LICAP proposal and delayed the implementation target date from June 2004 to January 2006. With this delay, FERC received and approved certain RMR contracts. Similar to the PUSH mechanism, the RMR contracts were to be interim mechanisms and to end upon implementation of the LICAP system. RMR contracts were provided to generation units deemed necessary, but which either performed poorly under PUSH or were ineligible for PUSH. The RMR contracts are designed to provide “cost of service” compensation, net of energy revenues obtained in the LMP energy market.

To date, eight sets of RMR contracts have been established with the owners of Connecticut generating stations and eight sets of Connecticut generating units operate under PUSH. The seven sets of RMR contract sets that are currently effective (i.e., “effective with final FERC approval” as of July 27, 2005) are identified in Table 3.2, as are the eight sets of PUSH units. ISO-NE reports that an eighth set of RMR contracts with NRG for its Devon Units 7 and 8 terminated in 2004.

The RMR arrangements are expected to continue until the LICAP system is implemented. In light of FERC’s decision to implement LICAP no sooner than October 2006 (and pending resolution of the locational capacity market implementation), the agreements are expected to operate through at least September 2006.

Localized reliability assessments that ISO-NE may consider in determining the need for RMR contracts can include:

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9 The four NRG contracts were for units at its Devon, Middletown, Montville, and Norwalk facilities, representing 1,728 MW of capacity.

10 ISO-NE reports that, on June 1, 2003, it implemented Peaking Unit Safe Harbor (PUSH) offer rules, allowing owners of low capacity-factor units (less than 10% annual capacity factor) in Designated Congestion Areas (DCAs) to include levelized fixed costs in their energy offers without risk of mitigation. The rules were intended to increase opportunities for fixed cost recovery and to produce signals for investment through higher LMPs in these areas during periods of scarcity. This temporary revision of the ISO’s mitigation rules is to remain in effect until it is replaced by a LICAP market, deliverability requirement, or similar modifications to the existing New England capacity market.
1. **Resource Adequacy** – requirements to meet the local area’s portion of the region’s requirements for installed capacity to meet objective capability requirements.

2. **Operable Capacity** – requirements to have local, installed capacity sufficient to operate the system when high loads and or outages occur.

3. **Operating Reserves** – requirements to have sufficient local quick-response generation that can provide the 10-minute and 30-minute response when outages of large system components occur.

4. **Other** - voltage support, system regulation.

ISO-NE’s assessment of Operable Capacity has been the primary basis for RMR requirements to date. The LICAP proposal, as currently structured, is intended to address Resource Adequacy.

The RMR contracts have significantly affected Connecticut consumers in 2004 and 2005. ISO New England reports that, in 2004, RMR agreements were in effect for six generating stations (with a combined total of 21 units in Connecticut and the NEMA/Boston area); total net costs for 2004 (i.e., in Connecticut and NEMA/Boston), reflecting offsets for energy market and capacity revenues, were approximately $160 million.\(^{11}\) Roughly three-quarters of this total was borne by Connecticut consumers.

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\(^{11}\) See ISO-NE’s “2004 Annual Markets Report” at 79.
During 2005, FERC has approved additional generating units for RMR treatment. Based on RMR contracts currently in effect, fixed RMR payments to Connecticut generators alone in 2005 will reach nearly $300 million, with a net cost to consumers (i.e., net of energy revenues) of about $230 million. In the event that FERC is persuaded that these contracts must be maintained to preserve reliability even after the LICAP market takes effect, Connecticut consumers would incur a like amount of RMR costs during 2006, as well.

<table>
<thead>
<tr>
<th>Owner/Unit</th>
<th>MW</th>
<th>Type</th>
</tr>
</thead>
<tbody>
<tr>
<td>NRG Devon 11-14</td>
<td>121</td>
<td>RMR</td>
</tr>
<tr>
<td>NRG Middletown 2-4,10</td>
<td>770</td>
<td>RMR</td>
</tr>
<tr>
<td>NRG Montville 5,6,10,11</td>
<td>494</td>
<td>RMR</td>
</tr>
<tr>
<td>PSEG New Haven Harbor</td>
<td>448</td>
<td>RMR</td>
</tr>
<tr>
<td>PSEG Bridgeport Hbr. 2</td>
<td>130</td>
<td>RMR</td>
</tr>
<tr>
<td>Milford Power LLC</td>
<td>493</td>
<td>RMR</td>
</tr>
<tr>
<td>Bridgeport Energy</td>
<td>451</td>
<td>RMR</td>
</tr>
<tr>
<td>South Meadow 11-14</td>
<td>149</td>
<td>PUSH</td>
</tr>
<tr>
<td>Branford 10</td>
<td>16</td>
<td>PUSH</td>
</tr>
<tr>
<td>Cos Cob 11-13</td>
<td>55</td>
<td>PUSH</td>
</tr>
<tr>
<td>Torrington Terminal 10</td>
<td>16</td>
<td>PUSH</td>
</tr>
<tr>
<td>Franklin Drive</td>
<td>15</td>
<td>PUSH</td>
</tr>
<tr>
<td>Bridgeport Harbor 4</td>
<td>10</td>
<td>PUSH</td>
</tr>
<tr>
<td>Tunnel 10</td>
<td>16</td>
<td>PUSH</td>
</tr>
<tr>
<td>Middletown 10</td>
<td>*</td>
<td>PUSH</td>
</tr>
<tr>
<td><strong>Totals</strong></td>
<td>3184</td>
<td></td>
</tr>
</tbody>
</table>

* Middletown 10 capacity already included in RMP capacity above.
PUSH payments have not significantly affected Connecticut consumers. The ISO has reported that its PUSH units typically have exhibited low capacity factors; and its calculations suggest that the implementation of PUSH rules increased real-time energy bills to Connecticut by no more than $10.7 million dollars during the summer of 2003.\(^{12}\) PUSH payments during the non-summer months (when Connecticut LMP prices tend to be lower) would be considerably less, and $10 million is a reasonably representative level for annual Connecticut PUSH costs in 2005 and 2006.

2) **Operating Reserve Credits**

In addition payments concerning RMR contracts and PUSH rules, ISO-NE makes out-of-market payments to certain generators that can provide operating reserves when needed for system operability purposes. In the event that the generators selected for operation in the day-ahead energy market are deemed to be unable to provide needed operating reserve (10-minute and 30-minute contingency response capability), ISO-NE reschedules generation to provide such reserves and makes payments to these generators to compensate for added costs or lost revenue. These payments are referred to as Operating Reserve Credits ("ORCs").

The Operating Reserve Credits expenses are significant in Connecticut. Transmission import limitations, coupled with large operating reserve requirements due to the size of the largest units in the State, create significant requirements for ORCs.

In 2004, the total cost of ORCs in the ISO-NE system was $91 million. Nearly all of that expense was incurred in Connecticut or in the Boston area. Half of that total was in the form of ORC payments to generators operating under RMR Agreements (Table 3.3). ORC payments in 2004 were particularly significant in the Stamford/Norwalk sub-area. Generators committed for RMR payments in Stamford/Norwalk satisfied local-area reserve requirements for all of Connecticut. However, due to import constraints into the Stamford/Norwalk sub-area, generators committed in the rest of Connecticut cannot satisfy all of Stamford/Norwalk’s reserve requirements.

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### Table 3.3 2004 RMR-ORC Payments by Sub-Area

<table>
<thead>
<tr>
<th>Sub-Area</th>
<th>Day-Ahead</th>
<th>Real-Time</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Stamford/Norwalk</td>
<td>$5,955,780</td>
<td>$16,591,505</td>
<td>$22,547,285</td>
</tr>
<tr>
<td>Southwest Connecticut</td>
<td>$322,735</td>
<td>$1,315,412</td>
<td>$1,638,147</td>
</tr>
<tr>
<td>Rest of Connecticut</td>
<td>0</td>
<td>$5,147,579</td>
<td>$5,147,579</td>
</tr>
<tr>
<td><strong>Total CT</strong></td>
<td>$6,278,515</td>
<td>$23,054,496</td>
<td>$29,333,011</td>
</tr>
<tr>
<td><strong>Total NEMA-Boston</strong></td>
<td></td>
<td></td>
<td>$16,084,893</td>
</tr>
<tr>
<td><strong>TOTAL ISO-NE</strong></td>
<td></td>
<td></td>
<td>$45,417,904</td>
</tr>
</tbody>
</table>

Source: ISO NE 2004 Annual Markets Report

Note: Economic ORC payments of $45.5 million not included.

### 3.7 Cost Recovery of FMCCs

The FMCC’s incurred by Connecticut’s electric distribution companies are categorized as bypassable (i.e., avoidable/energy related) and non-bypassable (i.e., unavoidable/reliability related). Bypassable FMCCs generally include the costs associated with transitional standard offers and congestion risk mitigation. Non-bypassable FMCCs generally include RMR, SWCT energy resources and other ISO-related costs. Both cost categories are subject to change over time. The following tables provide a list of currently approved FMCC costs, which are reflected in the electric distribution companies’ tariffs.\(^\text{13}\)

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\(^\text{13}\) DPUC Final Decision in Docket No. 04-03-19, dated November 24, 2004.
### Tables 3.3 (1) and (2) - Summary of FMCC Rate Components in CT

#### Table 1

**Approved Costs - Bypassable FMCC Rates**

<table>
<thead>
<tr>
<th>Cost</th>
<th>Source</th>
<th>Allocation Method</th>
</tr>
</thead>
<tbody>
<tr>
<td>TSO Supply Costs</td>
<td>TSO Supplier Invoices</td>
<td>As Billed</td>
</tr>
<tr>
<td>Operating Reserves</td>
<td>ISO-NE Bill</td>
<td>As Billed</td>
</tr>
<tr>
<td>Regulation</td>
<td>ISO-NE Bill</td>
<td>As Billed</td>
</tr>
<tr>
<td>FTR Auction Expense</td>
<td>ISO-NE Bill</td>
<td>As Billed</td>
</tr>
<tr>
<td>FTR Market Revenue</td>
<td>ISO-NE Bill</td>
<td>As Billed</td>
</tr>
<tr>
<td>ARR Revenue</td>
<td>ISO-NE Bill</td>
<td>As Billed</td>
</tr>
</tbody>
</table>

#### Bilateral Transactions

<table>
<thead>
<tr>
<th>Cost</th>
<th>Source</th>
<th>Allocation Method</th>
</tr>
</thead>
<tbody>
<tr>
<td>Congestion Risk Mitigation</td>
<td>Counterparty Invoices</td>
<td>As Billed</td>
</tr>
<tr>
<td>TSO Consulting Fees</td>
<td>Consultant Invoices</td>
<td>As Billed</td>
</tr>
</tbody>
</table>

#### Capacity

<table>
<thead>
<tr>
<th>Cost</th>
<th>Source</th>
<th>Allocation Method</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capacity for TSO</td>
<td>Invoices from counterparties for capacity related transactions</td>
<td>As Billed</td>
</tr>
<tr>
<td>Brokers Fees for TSO</td>
<td>Broker Invoices for capacity related transactions</td>
<td>As Billed</td>
</tr>
<tr>
<td>ICAP for TSO</td>
<td>ISO-NE Bill</td>
<td>As Billed</td>
</tr>
</tbody>
</table>

#### Table 2

**Approved Costs - Non-Bypassable FMCC Rates**

<table>
<thead>
<tr>
<th>Cost</th>
<th>Source</th>
<th>Allocation Method</th>
</tr>
</thead>
<tbody>
<tr>
<td>ISO Schedule 1</td>
<td>ISO-NE Bill</td>
<td>Share of Network Load</td>
</tr>
<tr>
<td>ISO Schedule 2</td>
<td>ISO-NE Bill</td>
<td>As Billed</td>
</tr>
<tr>
<td>ISO Schedule 3</td>
<td>ISO-NE Bill</td>
<td>As Billed</td>
</tr>
<tr>
<td>RMR-Fixed</td>
<td>ISO-NE Bill</td>
<td>Share of Reliability Region</td>
</tr>
<tr>
<td>ISO Load Response Program</td>
<td>ISO-NE Bill</td>
<td>As Billed</td>
</tr>
<tr>
<td>VAR Support</td>
<td>ISO-NE Bill</td>
<td>Share of Network Load</td>
</tr>
<tr>
<td>Black Start</td>
<td>ISO-NE Bill</td>
<td>Share of Network Load</td>
</tr>
<tr>
<td>D&amp;D Legacy Costs (Note 1)</td>
<td>D&amp;D Invoice from US DOE</td>
<td>Annual Bill/12 mos.</td>
</tr>
<tr>
<td>2003 SW CT Summer Generation</td>
<td>Invoices - contractors/others</td>
<td>As Billed</td>
</tr>
<tr>
<td>ISO Transition Cost Reconciliation</td>
<td>ISO-NE Bill</td>
<td>As Billed</td>
</tr>
<tr>
<td>ISO Credit Insurance Charge</td>
<td>ISO-NE Bill</td>
<td>As Billed</td>
</tr>
<tr>
<td>ISO Participant Defaults</td>
<td>ISO-NE Bill</td>
<td>As Billed</td>
</tr>
<tr>
<td>SWCT Energy Resources</td>
<td>ISO-NE Bill</td>
<td>Share of Reliability Region</td>
</tr>
</tbody>
</table>

Note 1: CL&P only. D&D costs will end in 2006.
FMCCs generally are passed on to customers through a DPUC-approved rate adjustment mechanism. The electric distribution companies can seek DPUC approval to recover any new FMCC costs, such as those that may be created in the course of implementing the Act Concerning Energy Independence, in semi-annual FMCC reconciliation proceedings. The DPUC has found that, while the filed rate doctrine limits state regulatory review of wholesale power costs, it does not eliminate state jurisdiction altogether. Accordingly, the DPUC maintains that, although many FMCC-related fact patterns preclude state inquiry, there may be scenarios in which state review of FMCC costs would not interfere with FERC regulation. Moreover, FMCCs generally are subject to Conn. Gen. Stat. §§ 16-19b(c) and 16-19e(a)(5), both of which require the level and structure of rates to reflect prudent and efficient management.\(^{14}\)

The electric distribution companies cannot control all FMCC costs, but there are strategies and tools through which they can manage price fluctuations and mitigate some of the FMCCs on behalf of ratepayers. For example, United Illuminating’s (“UI”) transitional standard offer (“TSO”) supplier provides a fixed price contract, and is thus responsible for all directly related FMCC related costs.\(^{15}\) This TSO structure insulates UI’s customers from the risk of bypassable FMCC price increases over the TSO period as those costs are assumed by the supplier and factored into its bid price. By contrast, Connecticut Light & Power (“CL&P”) purchases its TSO supply under contracts structured differently, such that the TSO contract may not include congestion costs. CL&P also flows through to customers the costs and revenues associated with Financial Transmission Rights and Auction Revenue Rights, which can be used to hedge FMCCs.


\(^{15}\) UI customers are not necessarily protected from all FMCC costs. UI may still be responsible for RMR charges allocated to UI by ISO-NE.
3.8 Assessment of Key Determinants of FMCCs

Each component of FMCCs is a direct consequence of the limitations in the capability of the transmission system to reliably allow the free flow of economic power into and across the State. The vast majority of these costs today and in the near future, if a locational capacity market is implemented, are determined by reliability criteria. The following three factors are the most significant determinants of near-term FMCCs in Connecticut.

1) **Peak Load**

The very small fraction of hours in the year when electric usage is at its highest is a primary determinant of each of the components of FMCC. The LICAP formula is based on the requirements for total generation needed in New England to assure sufficient supplies during peak times. Connecticut’s share of the regional requirement in any year is determined by the ratio of its load to the overall New England load at the time of the region’s annual peak load in the prior year. For example, the ratio of Connecticut’s peak load to the New England annual peak load in 2006 will be the fraction of the region’s capacity obligation assigned to Connecticut in 2007. In other words, the State’s capacity obligations under LICAP (i.e., for each of the two load zones) will be calculated as a direct function of (1) the ratio of actual in-State loads to regional loads for the prior year, and (2) ISO-NE’s FERC-approved regional OC for that year.

ISO-NE determines the need for RMR contracts by considering the ability of the system to reliably serve load during the peak load expected to occur roughly once per decade as a result of the “really hot” summer. Although congestion in the energy prices (LMPs) is not exclusively in the one peak hour, the likelihood of higher prices due to congestion is highly correlated to the peak load hours.

2) **Large System Components**

Reliability planning includes consideration of reserves to cover an outage of the largest system element. In Connecticut, at times when imports are limited due to congestion, installed and operating reserves are needed within the State to cover the largest contingencies, usually the loss of Millstone Unit 3 when it is operating. Reliability studies that consider the reserves needed in Connecticut to maintain reliability during such an outage at the time of extreme peak loads have a direct bearing on the RMR contracts and operating reserve requirements.
3) **Planning Criteria and Standards**

Reliability planning criteria, standards and analysis are conducted by ISO-NE. The ISO routinely conducts its reliability assessments to be consistent with nationally accepted reliability standards. Many of the specific parameters are established through the application of planning models and assumptions. Parameters that affect the requirements in Connecticut include Objective Capability (sometimes known as “Installed Capacity”), Operable Capacity, Operating Reserves requirements, and Import Limits. Each of these criteria is established and updated in a market participant stakeholder process administered by ISO-NE. Transmission planning, load forecasts and reliability planning studies and assumptions are used in this stakeholder process. Policy choices included in this process can have a material affect on the requirements for Connecticut. For example, ISO-NE has just initiated a two-year stakeholder process to do a comprehensive review of the methods used to set the Installed Capacity requirements, a key parameter in the proposed LICAP pricing system.
4. Connecticut’s Electric Supply and Demand Status

On July 19, 2005, hot and humid weather drove demand for electricity in New England to record levels. New England’s peak demand reached 26,749 MW, exceeding the prior record set in August 2002 by 1,400 MW. A Connecticut peak demand load of 7,065 MW was 50 MW higher than the previous high set in July 2003.

Eight days later, hot and humid weather returned, driving peak demand for electricity to new record levels, with regional demand reaching 26,922 MW and Connecticut demand reaching about 7,150 MW. On that day, demand stressed the limits of the power system, causing ISO-NE to invoke emergency measures in Southwest Connecticut to avoid the loss of load. These measures included calling on emergency supplies and demand reduction contracts, and issuing appeals for voluntary conservation, thereby reducing what otherwise would have been an even greater demand for power.

These extreme demands on the power system are driven largely by customer air conditioning loads, which are at a maximum during hot, humid weather. In response to peak demand conditions, ISO-NE calls into service all available generation in the State and region, transmission imports are increased to maximum possible levels, and transmission lines are fully loaded. It is at these times that the overall reliability of the system is most vulnerable to unplanned outages of key generation and transmission elements.

Events such as these are the measure of the electric system’s reliability. They also are key contributors to FMCCs because load forecasts that anticipate such events are central to planning for investment in new transmission and generation facilities. Power systems are planned to meet the pertinent standards for system reliability. Hence, in order to assess whether one has sufficient resources – which means amount and type, properly located – the key question is: What are the reliability planning standards?

The CEAB has reviewed loads and resource information prepared by ISO-NE and the Connecticut electric distribution companies, as well as the measures of system reliability used by ISO-NE to determine system requirements. This section provides a synopsis of the load forecast, the demand, supply and transmission resources, and assessments of the supply/demand balance in the context of the measures of reliability.
4.1 Peak Demand and Energy Requirements

Electrical energy (i.e., megawatthours, or gigawatthours) is required in all hours to satisfy consumer demands, although the need to meet system peak requirements imposes the greatest challenges and costs. Hence, following a brief overview of actual (historical) usage and the forecasts of Connecticut’s energy requirements, the focus shifts to the availability of generation, transmission and demand-side resources during peak load conditions.

1) Description of Forecasts Used

The analysis here used two sets of energy and peak load forecasts in its assessment of Connecticut’s needs. Each is described below:

ISO New England Energy and Peak Load Forecasts

One forecast of Connecticut’s power requirements was that prepared by ISO-NE as part of its 2005 Capacity, Energy, Loads and Transmission (2005 CELT) Report and subsequently used in its Draft Regional System Plan 2005 Report (RSP05). That forecast contains ISO-NE’s view of Connecticut’s anticipated energy and peak demands for a ten-year period ending in 2014. Importantly, ISO-NE indicates that its forecasts of energy use and peak demand are explicitly adjusted to reflect the reductions in energy use and peak loads from utility-sponsored conservation and load management programs; these latter data are collected each year from the electric distribution companies. ISO-NE also provides a breakdown of its state-wide forecast for Connecticut into the SWCT and “rest of Connecticut” (“ROC”) load zones that would be implemented under the LICAP proposal, and includes associated growth rates for both energy and peak demands across the period.16

The “Sum of the Utilities” Energy and Peak Load Forecasts

A second forecast of Connecticut’s power requirements was developed from the energy and peak demand forecasts submitted to the Siting Council by CL&P, UI, and CMEC in its Docket No. F-2005 proceeding investigating the status of electric loads and resources in the State. To establish the “Sum of the Utilities” energy forecast for Connecticut, the electric distribution companies’ forecasts of energy for each year were added together. For CL&P, the “updated” forecast that was presented to the Siting Council in its July 14, 2005 hearing was used. For the forecast of peak loads, a similar approach was used.

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16 In its Draft RSP05 report, ISO-NE provides two forecasts of Connecticut loads, one of which includes load served in the Western Massachusetts load zone via Connecticut (i.e., which corresponds to a “Greater Connecticut” load total of 7,125 MW in 2005. The forecast used in this report exhibits slightly lower peak load levels (e.g., 7,055 MW in 2005), and applies only to Connecticut load zones.
2) Connecticut’s Energy Requirements

Electric energy requirements for Connecticut have grown steadily across the last decade. Data from ISO-NE indicate that energy usage in the State has increased at an average annual compound rate of 1.2% from 1994 through 2004, reaching 34,171 GWH in 2004. The growth rate in recent years has exceeded that ten-year average. For example, across the three years 2001 to 2004, Connecticut’s energy usage increased at an average annual compound rate of 1.6%. In recent years, the rate of growth in energy requirements for the State has been about the same as that of New England as a whole.

ISO-NE forecasts that Connecticut’s energy requirements will increase to 34,620 GWH in 2005, and will grow thereafter at a 1.8% average compound annual growth rate to 40,500 in 2014. This rate is somewhat higher than its corresponding growth rate for New England (i.e., 1.5%).

According to the Sum of the Utilities forecast, by contrast, Connecticut’s energy requirements will increase to 34,037 GWH in 2005, and then will grow at a 1.3% average compound annual growth rate to 38,186 GWH in 2014.

The electric distribution companies’ forecasted growth rate for Connecticut is obviously lower than ISO-NE’s corresponding forecast (1.3% versus 1.8%); in addition, their growth rate is lower than that forecast by ISO-NE for New England (1.3% versus 1.5%). Figure 4.1 compares the history (actual) and projected energy consumption in Connecticut, where the forecasted data are from the ISO-NE and Sum of the Utilities forecasts of energy requirements.
The ISO-NE and Connecticut electric distribution companies use different forecasting methods that were prepared at different points in time. An important factor in the differences in these forecasts is CL&P’s recent update provided to the CSC in Docket F-2005, which captures CL&P’s recent observations on price-induced reductions in demand and going forward price effects due to increasing costs (including increasing FMCCs) in wholesale power markets.

3) Connecticut’s Peak Demand Requirements

Peak demand in Connecticut has grown steadily across the last decade. Data from ISO-NE show that peak loads in the State increased at an average annual compound rate of 1.2% from 1994 through 2004, reaching 6,444 MW in 2004. Since 1994, the average growth in peak demand for Connecticut has been lower than growth in the New England control area, where the corresponding growth rate in actual peak loads for the region has been roughly 1.6%. Figure 4.2 provides a graphic representation of seasonal peak demand requirements for 1994 through 2004.17

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17 The annual peak demand has occurred during the summer. Based on an analysis conducted by CL&P, which serves approximately three-quarters of the State, weather conditions have affected actual peak demand in Connecticut by as much as 8.4% in years in which conditions were significantly hotter than typical peaking conditions. The CL&P analysis also looks at “normalized” actual peaks, which examines what the peak loads would have been had weather conditions been consistent with the typical weather conditions under which peak loads occur (i.e., rather than unusually hot, humid summer weather). CL&P’s analysis shows that normalized summer peaks on the CL&P system increased by 5.5% and 2.1%, respectively, in 2002 and 2003, and then declined by 1.4% in 2004. Normalized historical peaks calculated at the state level would be expected to follow this pattern.
As noted above, two forecasts of Connecticut’s peak demand requirements were utilized in assessing the State’s future capacity needs: the ISO-NE and Sum of the Utilities forecasts. ISO-NE forecasts that Connecticut’s peak demand requirements will increase to 7,055 MW in 2005 and, thereafter, grow at a 1.7% average compound annual growth rate to 8,305 MW in 2014. This rate is somewhat higher than ISO-NE’s corresponding growth rate for New England (i.e., 1.5%).

In addition, ISO-NE prepared ten year forecasts of zonal peak demand projections and documented the results in a report entitled “2005 CELT & RSP Forecast Detail: ISO-NE control area and LICAP Zones.” Evidently, to develop these zonal forecasts, ISO-NE collected the FERC 715 filings for CL&P, UI, and CMEEC, which detailed bus level load and energy projections. According to the ISO-NE’s forecast, the (summer) compound annual average peak load growth rates for the ten-year planning period are 1.5% for SWCT, and 1.9% for the ROC zone.

According to the Sum of the Utilities forecast, by contrast, Connecticut’s peak demand requirements (net of DSM) will increase to 6,744 MW in 2005, and then grow at a lower 1.25% average compound annual growth rate to 7,545 MW in 2014. This rate is also somewhat lower than ISO-NE’s corresponding
1.5% growth rate for New England. Zonal peak demand values under the Sum of the Utilities forecast are calculated under the assumption that state-wide demands will be evenly divided between the two zones.

Several aspects of this peak load forecast require mention. First, ISO-NE’s peak load forecast for Connecticut differs substantially from the Sum of the Utilities forecast. The forecast peak loads (i.e., net of DSM) during that year are 7,055 MW and 6,744 MW respectively. This initial 311 MW differential is substantial; it increases to as much as 747 MW during the ten-year planning horizon. The source of this differential is unclear. It may lie, at least in part, in the “base” year from which the two forecasts were derived. As can be seen from Figure 4.2, there has been variation in the actual peak loads experienced in Connecticut in recent years.

Second, the Sum of the Utilities peak load forecast combines the projected peak loads of each of the three utilities. As a theoretical matter, the three utility systems would not necessarily experience peak demands simultaneously. Thus, this combination of peak loads might somewhat overstate the peak load experienced by the State as a whole at any given point in time.

Third, as with the ISO forecast, the “base case” forecasts the electric distribution companies project peak loads during “normal” weather conditions: that is, under the hottest, most humid weather conditions that would be expected during an average summer. However, the ISO and Sum of the Utilities forecasts exhibit different approaches, in concept, for the “high” case forecasts. Where ISO-NE calculates its “high” case forecast at the “90/10” level (as described above), each electric distribution company adopts a different approach. CL&P’s “high” case forecast is based on the hottest peak day weather that has occurred in the last thirty years. It can be expected to yield a higher peak demand forecast, all else being equal, than would a forecast at the “90/10” level. UI provided a “high” case load projection that uses its actual 2002 peak load and the same economic assumptions (including CLM impacts, large account changes and incremental sales activities) as are used in its “normal” forecast. CMEEC did not provide to the Siting Council peak load forecasts under “high” case conditions. Thus, the ISO-NE and Sum of the Utilities high case forecasts may not permit an “apples to apples” comparison.

Forecasts that progress from one base year might be quite different from those that progress from another, even if very similar growth rates are utilized. In addition, CL&P’s forecast incorporates the effects of increased electricity prices under the assumption that LICAP would be implemented while the State is somewhat short of capacity. ISO-NE assumes flat real electricity prices in its model. Evidently, CL&P’s assumption of increasing real prices depressed its peak demand projection, as would be expected. Also note that the recent actual summer peak value experienced by CL&P corresponds well with its forecast peak for 2005, once “weather normalized.”

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18 On July 27, 2005, CL&P reported that Connecticut set an actual peak load record of about 7,150 MW. CL&P's actual peak load (5,401 MW) on that day considerably exceeded its forecast peak for 2005 (5,116 MW). However, when that actual peak load is adjusted (i.e., downward) to account for "higher than normal"
The foregoing details regarding the various approaches to both energy and peak load forecasting matter substantially. The difference in the forecasts can have major implications for resource planning. As shown in Table 4.2, the projected difference of over 300 MW in 2005 grows to a nearly 750 MW difference by 2012.

4) Connecticut's Customer Classes and End Uses

Electric service in Connecticut is provided primarily to customers classified as residential, commercial, or industrial. Approximately 40% of total energy sales are consumed by residential customers, 38% by commercial customers, 15% by industrial customers, and 7% by other customers such as street lighting customers and railroads.

Peak demand levels in Connecticut are a direct function of the customer end-uses served by the State’s electric distribution companies. A breakdown of summer peak demand by class and end-use is presented in Table 4.1. Note that loads by specific end-use are not available for the industrial class; therefore, all industrial loads are included in the row designated as “Other.”

At present, over 40% of Connecticut’s peak loads are driven by cooling requirements, which shows that summer air conditioning is a significant force behind the State’s need for incremental capacity resources. This is important relative to the peak load reduction strategies that might be considered to mitigate FMCCs.

<table>
<thead>
<tr>
<th>End-Use</th>
<th>Residential</th>
<th>Commercial</th>
<th>Industrial</th>
<th>Other</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>2005</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cooling</td>
<td>23%</td>
<td>18%</td>
<td>0%</td>
<td>0%</td>
<td>40%</td>
</tr>
<tr>
<td>Lighting</td>
<td>1%</td>
<td>10%</td>
<td>0%</td>
<td>0%</td>
<td>11%</td>
</tr>
<tr>
<td>Other</td>
<td>20%</td>
<td>17%</td>
<td>11%</td>
<td>0%</td>
<td>49%</td>
</tr>
<tr>
<td>Total</td>
<td>44%</td>
<td>44%</td>
<td>11%</td>
<td>0%</td>
<td>100%</td>
</tr>
</tbody>
</table>

temperatures at the time of system peak, the weather-adjusted value for July 27 falls into line (to within a fraction of a percent) with the forecast value.
4.2 Demand Side Resources

Connecticut consumers pay considerable sums annually for various FMCCs that are driven by system reliability and the State’s peak load requirements. Demand side resources can offset the growth in peak loads that drive these and other costs. Consequently, such resources merit close consideration in any needs assessment. A variety of foreseeable capacity savings (MW) from demand-side initiatives will influence Connecticut’s energy profile. The capacity savings include the following:

1. Existing CLM Program Savings: Savings from conservation and load management (CLM) programs administered by the electric distribution companies, for which savings measures were installed prior to the “effective date” of each utility’s peak load forecast, and for which consequent capacity savings are incorporated;

2. Planned CLM Program Savings: Savings from CLM programs administered by the electric distribution companies which are planned, but not reflected in each utility’s peak load forecast;

3. ISO Demand Response Program Savings: Savings from programs administered by Connecticut’s electric distribution companies and otherwise, that qualify under ISO-NE’s demand response programs. For sake of clarity, this list distinguishes demand-side programs that qualify under the ISO’s load response programs (whether administered by electric distribution companies or otherwise) from other demand-side programs; and

4. Other Demand-Side Programs, including:
   - Time-of-Use Pricing Programs: Savings that may result from rate design contemplated by the Energy Independence Act;
   - Class III Renewables: Savings from CLM programs and cogeneration facilities that qualify as Class III renewables pursuant to the Energy Independence Act (to the extent not otherwise recognized);
   - Energy Efficiency TSO: Savings that may result from CLM programs implemented as part of the energy efficiency TSO as reflected in a DPUC Decision in Docket No. 05-03-14 (to the extent not otherwise recognized); and

1. Existing CLM Program Savings

CL&P provided the CEAB with forecast estimates of the likely capacity savings from its existing CLM programs, reflective of measures implemented through December 31, 2004. CL&P stated that these savings were included in the initial and updated peak load forecast presented to the Siting Council’s 2005 Load Forecast proceeding. UI and CMEEC have indicated that their peak load forecasts were net of
capacity savings from existing demand-side program measures; however, neither provided a forecast of specific savings levels from such measures.19

2. Planned CLM Program Savings

CL&P provided forecast estimates of the likely capacity savings from its various CLM programs, from measures that would be implemented beginning on January 1, 2005. Several items merit attention in this regard. First, the initial estimates submitted to the Siting Council (i.e., with CL&P’s March 1, 2005 filing) reflected only capacity savings from measures that were included in its proposed 2005 budget. The DPUC approved a considerably larger 2005 budget later this spring. Therefore, CL&P provided revised incremental savings estimates to reflect consequent, foreseeable increases in capacity savings levels.20

Second, CL&P noted its capacity savings estimates assume that programs being implemented during the budget year (i.e., 2005) would continue for five years, and would produce incremental savings from one year to the next. Savings from installed measures are assumed to persist throughout an estimated “life” for each measure. The measures and their capacity savings are assumed to expire at the end of the measure’s life.

UI and CMEEC did not provide separate forecasts of the capacity savings expected from demand-side program measures to be installed during the term of their load forecasts. It appears, but is not entirely clear, that such planned savings levels are implicit in their forecasts. If not, further capacity savings reductions should be recognized in a thorough accounting of loads and resources.

It is important to establish to what degree capacity savings estimates are included in ISO-NE’s forecast of peak loads for Connecticut (i.e., for each of the State’s load zones) as presented in the supporting documentation to the 2005 CELT Report and used in the Draft RSP05 report. To date, it has not been possible to ascertain that information. The 2005 CELT forecast makes clear that ISO-NE’s “adjusted, reference case” peak load forecast is reduced relative to the “unadjusted” forecast as a consequence of demand-side program savings. Thus, the ISO-NE peak load forecast for Connecticut appears to be a direct function of its peak load forecast for the region. As such, while it might be reasonable to assume that Connecticut’s share of the New England region’s demand-side capacity savings (which are explicit in the 2005 CELT Report) follows that same ratio, this is not now known for certain. Nor is it clear what level of Connecticut demand-side capacity savings were factored into the 2005 CELT Report projections. While it appears that the electric distribution companies share their projections of

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19 UI filed with the CSC a forecast of future conservation program savings that combines savings from current and projected CLM measures.

20 Note that the Energy Conservation Management Board recently filed goals for CLM programs for 2005 that reflect revised savings estimates, in keeping with the approved 2005 electric distribution company budgets.
capacity savings from demand-side programs with ISO-NE, it was not possible to reconcile the 2005 CELT forecast quantities with the electric distribution companies’ projected savings estimates.

3. ISO Demand Response Program Savings

ISO-NE’s demand response programs are an important part of the near-term plan for ensuring reliability in Connecticut as are the GAP RFP resources (about 250 MW). The associated demand response potential is augmented by other potential capacity offsets from participants in ISO-NE load response programs. ISO-NE provided an August 2004 summary of capacity resources committed to load response programs in each Connecticut load zones. CL&P also developed an estimate of the capacity savings that might be recognized from participation in the ISO-NE demand response program. However, the two sets of projections were not able to be reconciled. It is evident that additional savings are expected to result from investments ordered by the DPUC subsequent to the date of the ISO-NE publication.

4. Savings From Other Demand-Side Programs

There are other demand-side initiatives that are anticipated to produce capacity savings during the planning horizon for which quantifiable estimates are not available, including: Time-of-Use Pricing Programs, Class III Renewables, Energy Efficiency TSO, and Energy Efficiency Standards. Further analysis is warranted to determine whether there currently exists roughly 50 MW of cogeneration in CL&P’s service area that has not received, but may deserve to receive credit in ISO-NE’s accounting of installed capacity in Connecticut.

5. Potential for Additional Demand-side Savings

There appears to be a considerable potential for Connecticut to secure substantial, additional, cost-effective capacity savings from demand-side programs. In June 2004, the Energy Conservation Management Board completed a study of the potential for additional savings from energy efficiency programs. Energy efficiency opportunities typically are physical, long-lasting changes to buildings and

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21 The SWCT RFP yielded contracts for (1) approximately 5 MW from CLM programs, (2) 150 MW from emergency generation (including 69 MW from portable generators), (3) 74 MW from Load Reduction, and (4) 27 MW from “Emergency Generation and Load Reduction”.

22 Customer-cited generation would serve to reduce loads to be served by an electric distribution company. Moreover, such resource would not require the application of a reserve margin under the proposed settlement system under LICAP. Therefore, for purpose of this presentation the CEAB presents cogeneration as a “demand-side” resource.
equipment that result in decreased energy use while maintaining the same or improved levels of energy service.

The June 2004 ECMB study indicates that there is significant savings potential in Connecticut for the implementation of additional energy efficiency measures. By its estimate, capturing the maximum achievable cost-effective potential for such measures would reduce peak load by 13% (i.e., 908 MW) by 2012 and, in effect, eliminate growth in peak load through 2012. In any event, whether or not all of the foregoing is achievable, the savings possibilities are substantial. In addition, the potential capacity savings from load management and load response measures were not included in the ECMB study. Thus, investments in such programs are likely to be an opportunity to obtain even more capacity savings for Connecticut.

4.3 Connecticut Supply Resources

Connecticut has substantial existing generating resources. Based on summer claimed capabilities, as summarized by ISO-NE, 6,774 MW of operable generating capacity is installed within state borders. Of this total, only 2,376 MW is located in SWCT. Connecticut’s generation base is augmented by various supplies, including: (1) roughly 212 MW from the deactivated units Devon 7 and 8, which evidently qualify as installed capacity under the rules of ISO-NE’s installed capacity (and LICAP) markets; (2) roughly 250 MW from the GAP RFP, which established contractual rights to this capacity through the year 2008; and (3) another 40 MW, or more, that result from other demand response programs implemented by ISO-NE.23

Connecticut’s capacity resources consume a variety of fuels, including uranium, coal, oil, natural gas, landfill gas, and biomass. Connecticut also has a number of hydropower facilities. The Millstone 2 and 3 nuclear units are a substantial portion of the State’s baseload supply, totaling 2,037 MW. Other baseload facilities include Bridgeport Harbor 3 (372 MW) and AES Thames (182 MW). Various hydropower facilities deliver another 150 MW in baseload generation, bringing the State’s baseload total to 2,741 MW, or about 40% of installed capacity.

A number of new generating facilities have entered the Connecticut supply mix in recent years. Baseload / intermediate units include the Lake Road facility (693 MW), Milford Power 1 and 2 (492 MW), Bridgeport Energy (451 MW), Bridgeport RESCO. Peaking unit additions include Wallingford Power (220 MW), Devon 11 through 14, (120 MW), and Norwalk Harbor 10 (11 MW). This 1,350-plus MW of new generation has dramatically improved the State’s supply situation, but concerns remain.

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23 These demand-side resources are credited as “capacity” by ISO-NE in its calculations determining capacity cost obligations under LICAP.
First, the capacity from the Lake Road facility is not included in the capacity total for Connecticut. While the facility lies well within Connecticut’s borders, ISO-NE treats its capacity as outside of the State (i.e., for purpose of calculating responsibilities in its capacity markets) because a single contingency can cause the facility to become electrically isolated from Connecticut. Improvements to the transmission system (e.g., the Southern New England Reliability Project, or SNERP) could remedy this situation, but have not yet been approved by the ISO or regulators in affected states.24

Second, these new facilities are, by and large, natural gas-fired facilities. In recent years, questions have arisen regarding the ability of the natural gas transmission system to meet New England’s demands at the time of peak gas loads (i.e., during the winter months). Moreover, the feasibility of further expansion of the natural gas transmission system into Connecticut and New England is uncertain. If such expansion is shown to be infeasible, the generation facilities that are sited in Connecticut in the future would have to rely on other fuel sources.

Third, setting aside the new natural gas-fired and the nuclear generating units, the bulk of Connecticut’s generating fleet consists of relatively old, thermal generating units. By 2010, over 3,700 MW (i.e., 55%) of the State’s generating capacity will be over 30 years old. Of this amount, over 1,400 MW (i.e., 20%) of the State’s generating will be over 40 years old. Moreover, 900 MW of this older capacity is located in SWCT. While this capacity may be needed for reliability purposes, because of poor power plant efficiencies (heat rates) it tends to be dispatched less frequently in energy markets.

### 4.4 Transmission System

There have been recent improvements to the transmission system serving Connecticut. As a result of these system upgrades, the current import limits for Connecticut and SWCT have been increased. At present, a combined import limit of 2,300 MW applies to the various transmission ties that cross Connecticut’s borders from Massachusetts, Rhode Island and New York. Transmission import limits also exist within the State, the most notable of which is the import limit into SWCT, also set at 2,300 MW. The implication here is that, if 2,300 MW is flowing into the State from elsewhere and 2,300 MW is simultaneously being delivered into SWCT, then ROC would experience a net zero transmission flow. To the extent that ROC must retain some of the capacity inflow to meet its needs, then transmission flows into SWCT necessarily would be reduced MW for MW.

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24 As can be seen from Table 5.1 below, the FMCC cost savings to consumers under LICAP associated with adding a nearly 700 MW generating facility to in-State load zones may be (depending on specific market circumstances) hundreds of millions of dollars annually.
Transmission infrastructure plays an important role in Connecticut’s energy picture. The total installed capacity in Connecticut (6,774 MW) is very close to the level required to serve customer peak demands (actual peak loads were 6,444 MW in 2004 and roughly 7,150 MW in 2005). As such, transmission becomes a critical resource, particularly during periods of high demand. In addition to ensuring access to economical generation, when the transmission infrastructure is adequate, it also enables a response to contingencies such as unforeseen generation outages, that otherwise could lead to a loss of load.

Investments in new transmission have been undertaken or are being planned to improve reliability and to mitigate exposure to FMCCs. The Southwest Connecticut Reliability Project (Phases I and II) improves power transfer capabilities into SWCT and overall transmission system performance. The impact of the completion of Phase I (the Bethel-Norwalk 345 kV project) in 2007 will increase transmission import capability into SWCT by 275 MW. Once Phase II (the Middletown-Norwalk 345 kV project) is completed in December 2009, the combination of the Phase I and II improvements will increase the transmission transfer capability into SWCT by 575 MW. It is important to note that neither Phase I nor Phase II significantly affect transmission capacity into Connecticut as a whole, as the improvements focus on in-State transmission infrastructure.

Other transmission improvements will affect Connecticut’s import capabilities. These include (1) the Mystic, Connecticut to Wood River, Rhode Island 115 kV reconductoring, which will increase Connecticut’s import capability by 150 MW in 2007, and (2) the SNERP project, which would substantially increase transmission into the State. However, the SNERP project is still being studied, and is not expected to enter commercial service until at least 2011.

With respect to capacity imports, note that New England’s capacity market has had surplus capacity across much of the last decade; hence, the present transmission constraints preclude the import of some less costly power from outside Connecticut. There are, however, strong signs that the surplus may be abating. At present, few new generation projects in the region are being advanced beyond initial, low cost developmental milestones. ISO-NE forecasts of system requirements and capability suggest that the region may begin to experience capacity deficiencies within the next several years. The ISO indicates that, under its 50/50 load forecast, New England could experience a negative operable capacity margin of approximately 160 MW beginning in 2008, increasing to 2,600 MW by the summer of 2014. Under its 90/10 load forecast, New England could experience a negative operable capacity margin of roughly 1,070 MW beginning in 2006 increasing to 4,470 MW by the summer of 2014. The upshot is this: the value to Connecticut of an improved interstate transmission infrastructure cannot be assessed without a reasonable view of the conditions in the external markets into which in-State generation resources might sell and from which in-State loads might buy.
4.5 Near Term Reliability Assessment

Based on a review of the forecast loads that might arise on the power system, and the generation, demand-side and transmission resources that may be available to address those loads, the central question is this: What does it mean for reliability in Connecticut? As noted earlier, there are three different, albeit related, reliability standards. Each poses unique issues for planners.

As noted in Section 3.6, there are at least three distinct reliability metrics that ISO-NE considers in its planning, including:

1. **Resource Adequacy** – requirements to meet the local area’s portion of the region’s requirements for installed capacity. Resource adequacy is the composite ability of generation in the region to continuously serve load considering probabilities of generation outages and peak load events. This resource adequacy standard has historically and is currently computed by ISO-NE assuming no transmission constraints in the region. This approach is used to determine Objective Capability (which is also referred to as Installed Capacity requirements), the reliability requirement that has been used in ISO-NE’s capacity market and is proposed to be used in the LICAP market pricing formula.

2. **Operable Capacity** – requirements to have local installed capacity sufficient to operate the system when high loads and/or outages occur. Operable Capacity is a standard planning measure applied when transmission limitations are important. This analysis looks at the ability of a particular portion of the system (such as SWCT or the State of Connecticut) to serve load under certain combinations of outage events (e.g., very high summer peak loads and the loss of the largest unit). This standard can produce requirements well in excess of the resource adequacy standard when a local area includes a large unit or large transmission element, for which potential outages represent substantial risks.

3. **Operating Reserves** – requirements to have sufficient local quick-response generation that can provide the 10-minute and 30-minute response when outages of large system components occur. This criterion specifically looks at the subset of generation units in a system, or in a constrained zone that are capable of providing this quick response service.
ISO-NE also looks at other measures of system reliability, including, for example, voltage regulation. For purposes of assessing FMCC exposures, Resource Adequacy, Operable Capacity, and Operating Reserves assessments are most relevant to Connecticut at this juncture. The following is a review of these measures as they pertain to this assessment of FMCCs.

It is important to note that the scenarios examined assume that, in the near term, all existing generation in Connecticut remains available and contributes to the supplies needed to maintain reliability.

1) **Resource Adequacy**

Appendix 1 contains the results of a series of calculations to forecast Objective Capability (OC), based on information on Connecticut loads and resources as described above. This analysis shows that across the near-term planning horizon extending through 2009, Connecticut (taken as a whole), and the SWCT and ROC zones (taken individually) will have sufficient resources to meet their OC requirements, as would be calculated under ISO-NE’s proposed LICAP market. This is the case regardless of whether one utilizes the ISO-NE forecast or the Sum of the Utilities forecast, as described earlier. Obviously, the extent to which the OC standard is exceeded depends, in the first place, on which forecast is utilized to project future OC requirements.

The charts in Appendix 1 identify (1) the degree to which local capacity markets are forecast to be in a surplus condition, and (2) the level of incremental resources that would be necessary to resolve any deficiencies necessary to bring the zone into compliance with (a) OC, (b) a zonal capacity target established at 1.038 times OC, and (c) 1.15 times OC, each of which is relevant if the ISO-NE LICAP proposal is implemented in its present form.25

These analyses indicate that, under ISO-NE load forecast assumptions, Connecticut meets or exceeds the Objective Capability in all years. The LICAP formula includes prices for capacity to be paid on a sliding scale until Connecticut reaches a supply level of 115% of the Objective Capability.

ISO-NE plans to begin a stakeholder process within the next few months to re-evaluate the appropriateness of the current methodology in the current deregulated market environment, and discuss possible modifications or alternatives.26

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25 ISO-NE’s proposed LICAP demand curve establishes that capacity prices would (1) correspond to twice the costs of a peaking unit if a zone’s capacity level equals OC, (2) correspond to the cost of a peaking unit if a zone’s capacity level equal 1.038 times OC, and (3) fall to zero if a zone’s capacity level is 1.15 times OC.

26 See March 21, 2005 ISO-NE Filing to FERC in Docket ER05-715-000; 2005/2006 Power Year Installed Capacity Requirements (Objective Capability Values), n.11, page 7 and Section 6.2.1 of RTEP 04.
2) **Operable Capacity**

Appendix 1 also contains the results of a series of calculations to forecast Operable Capability requirements (OpCap), based on Connecticut loads and resources as described above. This analysis shows that across the near-term planning horizon extending through 2009, Connecticut (taken as a whole), and the SWCT zone will not have sufficient resources to meet the Operable Capacity standard. Because of the size of the largest unit in Connecticut (Millstone 3), this standard becomes significantly more stringent than the Resource Adequacy standard.

3) **Operating Reserves**

ISO-NE has stated that Connecticut has a 1,200 MW operating reserve requirement, which is based on treatment of Millstone 3 (1,155 MW, summer) as a potential contingency. Based on its analysis of reserve requirements and available quick start generation, ISO-NE indicates that an additional 550 MW of generating reserves (capable of providing ten- and/or thirty-minute operating reserves) is now needed in Connecticut. Moreover, ISO-NE indicates that 350 MW will be needed in Southwest Connecticut once Phase II enters service. Accordingly, Southwest Connecticut would be the logical choice for at least 350 MW of the additional 550 MW required by Connecticut, leaving an approximately 200 MW quick start generation requirement for the rest of Connecticut. Note that, in general, if more quick start resources are located in SWCT, less would be required in ROC.
5. Anticipated Near Term FMCC Costs

As described in Section 3, FMCCs derive from several market and out-of-market mechanisms which include the following:

1. Locational Energy Market;
2. Locational Capacity Market (pending implementation);
3. Locational Ancillary Services (pending implementation); and
4. Out-of-Market Costs, including
   a) Reliability Must Run Contracts; and
   b) Operating Reserve Credits.

Of these components, the costs related to the capacity market present the largest potential FMCC exposure for Connecticut consumers. There have been a number of estimates – which vary widely – of the costs that the region would face if the LICAP spot market is implemented. For example, estimates of five-year added costs to the region ranging from $2.3 billion to over $14 billion have been presented in FERC proceedings. CL&P presented an analysis of Connecticut costs to the Siting Council in July 2005 in Docket F-2005 which estimates annual costs to Connecticut of $587 to $796 million. RMR contract costs, also a capacity-related cost, were $121.8 million in 2004\(^{27}\) and likely will be nearly $300 million in 2005 given the additional contracts that were approved by FERC.

Other FMCC components are significant, as well. However, the order of magnitude of these components is less than the $100 million-plus range that capacity costs represent. For example, ISO-NE reports that Connecticut’s costs for Operating Reserves for 2004 to be nearly $40 million.\(^{28}\)

In this context, this assessment focuses on the potential costs of LICAP, if implemented, and the exposure to RMR contract costs. Issues associated with exposures to other components of FMCC’s are also discussed.

\(^{27}\) This figure presents the annual fixed costs of RMR contracts, prior to any energy offsets. See ISO New England 2004 Annual Market Report, Table 29.

\(^{28}\) See ISO New England 2004 Annual Report, Figure 6.4.
5.1 Outlook for LICAP Costs in Connecticut

As noted above, the costs to Connecticut under the ISO-NE LICAP market proposal have been projected to be very significant. LICAP pricing and the associated costs to Connecticut, based on the ISO-NE proposal, will vary in accordance with a sliding price scale (known as the “LICAP Demand Curve”) tied to the relationship between the actual capacity supply and the ISO’s Installed Capacity requirement for each Connecticut load zone. The range of price and cost outcomes for Connecticut is illustrated in Table 5-1. This illustration assumes that 8,000 MW is the Installed Capacity requirement in Connecticut. This is representative of current requirements but combines the results of the two in-state load zones. In this idealized example, if Connecticut just meets the 8,000 MW requirement (with no reserve), the payments for capacity would be based on a price of $18/kW-mo price and would result in an annual cost of $1.5 billion. If 1,200 MW of additional capacity were to be added, the price and the cost under LICAP would drop to zero.

<table>
<thead>
<tr>
<th>CT Resources (MW)</th>
<th>Additional MW</th>
<th>Percent Over Installed Capacity Requirement</th>
<th>Gross LICAP Price(^{29}) $/kW-mo</th>
<th>CT LICAP Annual Payments(^{30}) ($millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>8,000</td>
<td>--</td>
<td>0%</td>
<td>$18.00</td>
<td>$1,514</td>
</tr>
<tr>
<td>8,240</td>
<td>240</td>
<td>3%</td>
<td>$10.89</td>
<td>$927</td>
</tr>
<tr>
<td>8,480</td>
<td>480</td>
<td>6%</td>
<td>$7.23</td>
<td>$618</td>
</tr>
<tr>
<td>8,720</td>
<td>720</td>
<td>9%</td>
<td>$4.82</td>
<td>$409</td>
</tr>
<tr>
<td>8,960</td>
<td>960</td>
<td>12%</td>
<td>$2.41</td>
<td>$187</td>
</tr>
<tr>
<td>9,200</td>
<td>1,200</td>
<td>15%</td>
<td>$0.00</td>
<td>$0</td>
</tr>
</tbody>
</table>

\(^{29}\) LICAP prices were calculated based on the assumption that the EBCC is $9/kW-month after EFORd is calculated.

\(^{30}\) Connecticut LICAP annual payments shown are net of Peak Revenue Payments ($0.48/kW-month) and EFORd (10%), but not CTR benefits.
From this illustration, it is apparent that the LICAP costs can be very large and that one or two major additions can substantially reduce that cost. Indeed, particularly in some areas of the LICAP curve, prices can be quite sensitive to even small changes in supply. As an example of the effect of a major supply change, the addition of a 480 MW combined cycle unit (roughly equivalent to the new facility at Milford) can result in a substantial difference in the price and cost under this formula.

The CEAB conducted a review of the CL&P model and prepared some alternative scenarios, based on updated information. The scenarios tested different inputs and compared the results to those produced by CL&P (a description of these scenarios and results can be found in Appendix 2). The scenarios were as follows:

- **Scenario CL&P OC**: Retained the Installed Capacity targets utilized by CL&P under the updated assumptions reflecting recent capacity and transmission changes;
- **Scenario Case 1 OC**: Installed Capacity targets were updated in ROC and SWCT to reflect those used by ISO-NE in its Draft RSP05 report. These revised inputs correspond to the “Case 1” series of load projections from Appendix 1; and
- **Scenario Case 2 OC**: Installed Capacity targets were updated in ROC and SWCT to reflect peak load forecasted by Connecticut electric distribution companies. These revised OC inputs correspond to the “Case 2” series of load projections from Appendix 1.

Notable assumptions updates include the increase in current import limits into SWCT (up 300 MW) and into Connecticut (up 100 MW) and the inclusion of the Mystic-Wood River reconductoring effect on import limits (up 150 MW).

In addition, the CEAB modeled several strategies for mitigating LICAP costs to Connecticut. Each strategy was developed as a variation on both Scenarios Case 1 OC and Case 2 OC above. These included the following:

- **Strategy X** includes 100 MW of additional capacity (in the form of either load response or additional generating plant) to each of SWCT and ROC, beginning in June 2006;
- **Strategy Y** includes Devon 7 and 8 as LICAP resources in determining LICAP clearing prices for the 2006/2007 planning year; and
- **Strategy Z** includes a reduction in the peak load for SWCT (such as might be achieved through additional CLM measures) by summer 2006 (note that this load reduction would not affect LICAP calculations until the following summer).

A number of important observations can be made from the results of the modeling exercise. These are as follows:
1. Transmission infrastructure likely will be effective in allowing LICAP prices in Connecticut’s two load zones to equilibrate, even during high load conditions. The “Gross Clearing Prices” for the scenarios show that LICAP prices between SWCT and ROC equilibrate as a result of recent transmission upgrades between SWCT and CT, even prior to the completion of Phase I of the Southwest Connecticut Reliability Project.

2. The New England LICAP market likely will be highly volatile from one period to the next. LICAP prices, and associated consumer costs, are quite sensitive to relatively small changes in the supply/demand balance (compare for example, the results of Scenarios Case 1 OC to Case 2 OC, where the only difference is the different input assumption regarding Connecticut OC). Given this sensitivity, generating unit retirements in this market (i.e., absent offsetting new unit additions) may threaten to substantially increase LICAP costs across the State and region – if ISO-NE allows such retirements to occur. As discussed below, preserving OpCap may cause ISO-NE to enter into new RMR contracts to achieve necessary levels of operable capacity, which effectively may prevent such retirements from occurring.

3. The non-Connecticut load zones around New England may exhibit a surprising degree of sensitivity to relatively small improvements in the capacity balance in Connecticut. By comparing the Gross Clearing Prices of each of the Scenarios, it can be seen that relatively small movements in Connecticut load and resource levels can precipitate major changes in LICAP prices both in Connecticut and in other New England load zones.

4. Exposure to LICAP market prices can be mitigated by engaging short- and long-term capacity purchases. The results under Strategy X show that Connecticut LICAP costs fall substantially with the addition of relatively little capacity (again, this capacity can take the form of DSM measure savings or generating plant). In this context, the cost of these various Connecticut initiatives can be significantly offset by reductions in LICAP prices that impact the total market for LICAP.

The results shown through this analysis, regarding the potential cost implications in each of Connecticut’s load zones and across the State, may differ from the projections developed by others. The reasons for these differences likely fall into one or more of the following categories:

1. Differences in Assumed Contributions From New Transmission Upgrades: Recognition of new transmission facilities that recently have entered service or are likely to enter service in the near term will change the Capacity Transfer Limit (CTL) between zones and allow more congested zones to achieve parity with their neighbors;

2. Differences in Forecast Peak Loads: Peak load assumptions impact LICAP by affecting the required zonal OC level, which contributes to the clearing price;

3. Differences in Anticipated Contributions From Utility CLM Programs: Forecast savings from utility DSM programs can alter forecasted peak load and affect OC;
4. Differences in Anticipated Contributions from ISO-NE Load Response Programs: Load response programs can alter a zone’s supply that counts toward LICAP;

5. Differences in Anticipated Contributions from New Generation Resources; and

6. Differences in Counting Deactivated Generation Resources as a LICAP Resource: As noted earlier, deactivated generation can be recognized as LICAP capacity.

5.2 Outlook for Reliability Must Run Costs

Currently, Connecticut’s capacity costs are tied to RMR contracts. These agreements were established by the FERC to ensure reliability until the LICAP market system is implemented. Because the FERC has delayed implementation of ISO-NW’s LICAP market system, it is apparent that RMR contract costs will be a major component of Connecticut’s capacity costs in 2006, and perhaps beyond.

At present, RMR agreements are in effect for units in Connecticut representing some 2,900 MW of capacity (listed in the Table 5-2). The fixed cost obligation, on an annualized basis, for these current agreements is about $300 million (fixed annual payments before netting of energy revenues). The need for these units derives primarily from Operable Capacity assessments conducted by ISO-NE. Based on the CEAB’s assessment of that standard (as discussed in Section 4), the units may continue to be needed through the 2006 to 2008 period.

In the event that the LICAP pricing system is implemented, FERC policy on the use of RMR contracts is unclear. However, it is likely that special contracts, in some form, may continue to be needed with some of the units that now have RMR contracts. The concerns here include:

1. RMR contract need is based on Operable Capacity, which is a significantly more stringent criteria than the Installed Capacity requirement in Connecticut. On this basis, reliability need will continue through the near term.

2. The pricing terms for many of the current RMR contracts are high relative to many of the LICAP scenarios considered. It is unclear whether LICAP revenues will provide revenues sufficient to ensure that this capacity remains financially viable.
5.3 Outlook for Locational Energy Prices and Congestion

In the near term, market and infrastructure changes are pending that will have some bearing on locational energy prices. These include the following:

1. **Two Energy Pricing Zones in Connecticut**
   
   FERC and ISO-NE may implement two energy pricing zones in Connecticut, beginning in January 1, 2006. Absent other changes, this would tend to increase LMPs and other FMCCs in SWCT, at least over the next few years.

2. **Bethel-Norwalk 345 kV Transmission Line**
   
   This transmission line is currently under construction and is scheduled to enter service by December 2006. One anticipated benefit of this line is a 275 MW increase in import capability into SWCT during summer peak conditions. This change will tend to reduce LMPs and other FMCCs in SWCT by reducing congestion through increased access to less expensive energy and reserves in ROC, alleviating the reliance on higher cost resources in SWCT.

3. **Mystic-Wood River Reconductoring**
   
   This transmission line is currently under construction and is scheduled for operation by the summer of 2007. One anticipated benefit of this line is a 150 MW increase in import...
capability into Connecticut during summer peak conditions. This change will tend to reduce LMPs and other FMCCs throughout the State by reducing congestion and allowing increased access to less expensive energy and reserves elsewhere in New England.

The CEAB has not conducted any analysis of expected LMP levels during 2006-2008, and is not aware of studies of this type by ISO-NE or the Connecticut electric distribution companies. The level of LMPs will be affected by events in the marketplace, such as generation unit and transmission facility outages, load levels (particularly in the event of any extreme weather events), and any changes in the inventory of generation facilities in the market.
6. Cost/Benefit Assessment of FMCC Mitigation Measures

The Energy Independence Act requires the DPUC to identify measures by November 1, 2005 that can reduce FMCCs and can be implemented, in whole or in part, on or before January 1, 2006. These resources can include demand response, distributed resources, and contracts for capacity from generation resources.

In its implementation of Section 12(a) of the Act, the DPUC will be required to make a determination regarding the cost-effectiveness of measures proposed for implementation in 2006. This section offers an analytical framework to facilitate the DPUC’s assessment of these near term measures.

6.1 General Considerations

As a general matter, the economic analysis of proposed measures should provide a basis to determine whether the cost of the measures are materially less than the FMCC costs that would otherwise be incurred by Connecticut consumers. Because of the near-term, compressed timeframe in which the Section 12(a) process must be implemented, the CEAB offers a simple screening approach as an analytical framework that will allow the DPUC to identify the best programs quickly.

A. Basic Approach

The primary focus of the measures to be implemented will be peak demand reduction and installed capacity that qualifies as Installed Capacity under ISO-NE’s rules. The CEAB suggests that the recommended measures initially be ranked on a cost per kW-month basis, and then by resource and location preferences.

The cost per kW-month assessment is effectively an “avoided cost” approach, comparing the proposed measures to other alternative measures that could be implemented in lieu of the measure in question. The anticipated cost of the FMCC to be avoided would establish a ceiling price.

B. Consideration of Additional Avoided Cost Benefits

For those measures that offer benefits in addition to capacity in suitable locations, further analysis or assessment will be necessary. Additional benefits may include reduction of LMPs and associated energy congestions costs, reduced cost of operating reserves and associated uplift payments.
C. Capacity and Energy Market Benefits

In addition to the “avoided cost” benefits, the LICAP proposal and the LMP energy spot markets are designed to pay all power supply clearing in the spot markets the same market clearing price. This creates the potential for a multiplier effect. For example, a 100 MW increase in Installed Capacity in Connecticut will reduce the LICAP price paid to all Installed Capacity serving Connecticut load from the spot market. Such benefits should be factored into the cost-effectiveness analysis.

The magnitude of this multiplier effect is related to the amount of Connecticut load purchased from the spot market. For example, in 2006, all of UI’s TSO capacity and energy is purchased through bilateral contracts and, as a result, prices to consumers in 2006 are not tied to spot market pricing.\(^{31}\) In 2007 and beyond, the contracting approach to the supply of Standard Offer service will have a direct role in determining this effect.

D. Participant Costs and Benefits

The avoided cost approach suggested for screening would consider the costs to consumers of the measure. Some customer-side measures may involve cost to the customer in excess of the payments made. The recommended avoided cost screening test only would consider the cost to consumers of various measures. Alternative economic tests, such as the total resource cost test or a societal cost test may be warranted in some instances, but is not recommended for the general screening of measures for purpose of expediency.

6.2 Demand Response and Load Management Measures

Demand Response and Load Management measures are two forms of peak load management. The economic evaluation of demand reductions from these measures will be of two types.

Certain measures will qualify for ISO-NE demand response program and will qualify as Installed Capacity. The benefits of these measures in terms of LICAP mitigation will occur in each year the measure is operational (i.e., assuming continued participation in an ISO-NE demand response program).

Other programs (e.g., those that do not qualify as Installed Capacity in ISO-NE settlement) will simply reduce peak demand in Connecticut. This peak load reduction will affect LICAP pricing with a one-year lag. The lag is due to the use of prior year peak loads in determination of the Installed Capacity requirement each year. For example, reductions in Connecticut peak load in 2006 will be reflected in the calculation of Connecticut’s Installed Capacity requirement in 2007.

\(^{31}\) UI’s customers may remain exposed to RMR contract costs allocations by ISO-NE.
With the FERC’s recent action to defer LICAP implementation, demand response and load management measures installed for the summer of 2006 would not affect LICAP costs until at least October 2006.

### 6.3 Distributed Resources

In addition to the demand response and load management measures, Distributed Resources, as defined in the Act, can include generation projects with a rating of not more than 65 MW and reductions in end-use consumption. A second screening level can be established for Distributed Resources that provide energy production or conservation benefits in addition to capacity or peak load management benefits.

Energy conservation programs should first be screened by impact on peak load and then by energy savings. Energy savings benefit can be conducted on an avoided cost basis.

Distributed Generation projects may require analysis of specific energy production and operating reserve attributes that may be available. Generation projects that qualify as quick start capability for operating reserves at ISO-NE should be given preference.

For purposes of the Section 12(a) assessment, generation projects will necessarily be limited to those that readily can comply with the interconnection protocols approved by the DPUC in Docket No. 03-01-15, DPUC Investigation into the Need for Interconnection Standards for Distributed Generation.

### 6.4 Additional Generation Resources

Generation resources other than those that qualify as distributed resources are expected to require project specific assessment of costs and benefits. Capacity, energy, operating reserve and interconnection aspects of the project should be considered on a project specific basis.
7. Location of Resources

The location of supply and demand resources within Connecticut will have a significant bearing on the extent to which FMCCs can be mitigated. Specific location requirements cannot be precisely defined at this time, particularly for grid-connected generation, because many project- and location-specific transmission considerations should be determined through project-specific assessments. However, general guidelines can be articulated. This section of the report describes several of the key considerations that affect the location preferences for FMCC mitigation measures within Connecticut.

7.1 Proximity to Load

The simplest guideline is to locate resources close to load. This minimizes losses in the transmission system and requirements for power flows across transmission interfaces.

Conservation and load management measures have clear location-specific benefits. Reducing the volumes of power, particularly at times of system peak requirements (either regionally or locally) will, in turn, reduce the power transfer requirements that would otherwise be placed on the transmission system. Customer-sited generation, if sized such that it does not adversely affect transmission (or distribution) systems.

Beyond customer on-site load reduction resources, resources located in close proximity to load concentrations within Connecticut will generally be of high value in mitigating FMCCs. Figures 7-1 and 7-2 include ISO-NE graphic illustrations of load concentrations in New England and Connecticut, which shows the concentration of load along the coast in Southwest Connecticut and along the Connecticut River. Resources located in those portions of Connecticut are much more likely to have high value in mitigating FMCCs than in other locations in the State.
Figure 7-1
Load Concentrations in New England

Source: ISO New England
Figure 7-2
Load Concentrations in Connecticut

Source: ISO New England
7.2 Pricing Zone Location Considerations

ISO-NE’s energy market is currently structured with the entire State as a single pricing zone for load. ISO-NE and FERC are considering implementation of a two-zone system for energy in Connecticut beginning in January 2006 and contemplate the same two-zone system for the pending implementation of location capacity and forward reserve markets.

The two zones are referred to as the Southwest Connecticut Zone (SWCT) and the Rest of Connecticut (ROC) Zone. The demarcation between these zones is illustrated in Figure 7-3 with the dashed line labeled “SWCT Interface”. Areas to the south and west of the SWCT Interface are included in the Southwest Connecticut Zone. Areas to the north and east of the SWCT Interface are included in the Rest of Connecticut Zone. In the event that the two-zone markets are implemented, resources located in the Southwest Connecticut Zone will generally provide the most FMCC mitigation potential. Due the interconnection configuration between the two zones, resources located in the SWCT Zone can also mitigate FMCCs in the ROC zone. However, the reverse is not the case. Resources located in ROC have a much more limited potential to mitigate FMCCs in SWCT.

ISO-NE’s energy pricing system for generation is “nodal”, not zonal. The nodal system allows for prices to be set at many more discrete delivery points in the system. On average, the highest nodal prices in Connecticut are in the western-most areas of southwest Connecticut. Resources located in that location have the highest potential to reduce the market prices of energy paid to generation.
Figure 7-2

Southwest Connecticut Transmission Interfaces

Source: ISO New England
7.3 Transmission System and System Operation Considerations

Identification of precise locations in the transmission and distribution system for the development of new generation projects can best be done through project- and location-specific studies. The identification of the requirements to interconnect a project to the system necessitates project specific designs. In addition, an assessment of the deliverability of the power from a project during peak periods requires transmission system studies.

With that said, the configuration of the transmission system and the results of recent transmission studies conducted by ISO-NE can offer some guidance on better locations in the system. The system interfaces depicted in Figure 7-2 offer some general guidance on preferred locations. ISO-NE transmission planning studies typically consider three areas in Connecticut: the Stamford/Norwalk sub-area, the balance of Southwest Connecticut, and the balance of the State. As a general proposition, resources that can be located in the Stamford/Norwalk sub-area have the best potential for favorable locations on the transmission system; Southwest Connecticut is next. In the very near term, however, prior to the installation of the Bethel-Norwalk 345 kV transmission line, it may be difficult to accommodate added generation in these areas.

In addition to the three transmission areas in Connecticut, intra-state transfers within the State make locations east of the Connecticut River more problematic. Approximately 40% of Connecticut’s generation is located in the eastern portion of the State, an area that has only 15% of the State’s total load. In short, generation in eastern Connecticut, along with generation in Rhode Island and Southeastern Massachusetts, compete for space on limited east to west transfer facilities to Southwest Connecticut. As a result, locating resources in Eastern Connecticut to address FMCCs is, from a transmission system deliverability perspective, more difficult.

Lastly, ISO-NE is conducting studies regarding specific areas of concern in Connecticut. These studies will be reported in ISO-NE’s Regional System Plan 2005. For example, studies for the Middletown area and the Connecticut River area between Windsor Locks and Springfield, Massachusetts are in progress and may identify opportunities for resources to locate in areas that address local concerns.
8. Conclusions and Recommendations

Connecticut’s exposure to FMCCs is substantial and multifaceted. ISO-NE’s plans for locational capacity markets (now postponed to at least October 2006) and the potential for a two-zone energy market in Connecticut are important elements of the cost exposure. In addition, as discussed in Section 4, other system reliability criteria (such as OP CAP) will result in FMCCs to be borne by Connecticut’s consumers. The RMR contracts are perhaps the most obvious example.

The Phase I and Phase II transmission projects will mitigate some of the FMCCs. However, even after the implementation of both projects, significant transmission constraints – both interstate and intrastate – and associated FMCCs will remain. The ways to mitigate the FMCCs will include measures that affect peak demand, as well as generation and additional transmission resources. The CEAB’s recommendations regarding these resources are discussed below in Sections 8.1-8.5.

The CEAB’s preliminary assessment of Connecticut’s current electric system and the near-term outlook for loads, supplies, transmission and FMCCs leads to the following observations:

1. 2006 FMCC exposures will be most acute in Southwest Connecticut. ISO-NE plans to implement a distinct energy pricing zone in that area in January. Reliability Must Run and Operating Reserve costs will likely remain high in that area through 2006. The Bethel-Norwalk transmission line is not slated for operation until year-end 2006. Near term actions should concentrate in this area, particularly in the Stamford/Norwalk sub-area, to have maximum benefit to Southwest Connecticut and the State as a whole.

2. At this juncture, to the CEAB’s knowledge, neither ISO-NE nor the Connecticut electric distribution companies have definitive studies that would provide the information needed for more targeted locations for distributed resources.

3. Significant FMCC exposures will remain in 2007 and 2008, although the completion of the Bethel-Norwalk transmission line is expected to temper the exposure, particularly in Southwest Connecticut, by increasing intra-state transfer capabilities.

4. The level of FMCCs in the 2006 to 2008 period is very sensitive to peak load levels. Forecasts of peak load, net of CLM contributions, from ISO-NE and the Connecticut electric distribution companies differ materially and have very different implications for the State’s resource requirements, as lower peak loads will translate into lower FMCCs.

5. Congestion and FMCCs are significantly determined by usage in peak load or near peak load conditions and during times when significant amounts of local generation are out of service.
6. Even relatively modest amounts of peak load reduction or increased generation at peak times can have substantial positive effect on overall FMCCs.

7. The *Energy Independence Act* and the *Act Concerning Long Term Planning for Energy Facilities* establish preferences for distributed generation, combined heat and power, and certain renewable energy resources. In addition, the CEAB has set forth its Preferential Criteria for Evaluation of Energy Proposals. The DPUC should seek to advance those resources specifically encouraged in the Public Acts which measure favorably against the preferential criteria.

8. Connecticut’s significant transmission constraints, both inter- and intra-state, coupled with the size of the largest units in Connecticut (Millstone Units 2 and 3), mean that local reliability requirements will require substantial reserves in Connecticut. ISO-NE states that Connecticut now needs an additional 550 MW in quick start capability.

9. Out-of-market FMCC costs associated with Reliability Must Run contracts and Operating Reserve requirements may well continue to be significant.

Based on these observations, the CEAB offers recommendations on the types of near-term actions that the DPUC should consider to mitigate FMCC’s during 2006 – 2009. The recommendations in Sections 8.1-8.5 cover the following: Actions to Mitigate Connecticut’s Peak Demand; Actions to Preserve Connecticut’s Local Generation; Transmission and Import Capability; Generation Resources; and Other Actions.

### 8.1 Actions to Manage Connecticut’s Peak Demand

The most direct way that Connecticut consumers can mitigate FMCCs is through reduction in peak demand. Measures that affect the level of usage during peak conditions will be highly beneficial in reducing FMCCs, as well as other system costs. Such measures may either improve the efficiency of usage (particularly air conditioning) during peak load periods or manage the time of use for those loads that can be shifted to off-peak periods. Both will be beneficial as regards FMCC mitigation, although they have different implications with respect to overall energy consumption.

Because the State’s capacity obligations under LICAP (i.e., for each of the two load zones) will be calculated as a direct function of the ratio of actual in-State loads to regional loads for the prior year, actions intended to mitigate LICAP exposure in a given year by reducing peak loads must be producing savings one year in advance. The specific areas that warrant the DPUC’s consideration include the following:
A. ECMB/Utility Conservation and Load Management Measures

The Energy Independence Act requires the ECMB to give preference to programs that maximize the reduction of FMCCs. The CEAB’s preliminary assessment of mitigation opportunities for FMCC indicates that this preference should be directed to:

1. Programs that qualify for ISO-NE’s Real Time Demand Response program, that is, that provide Installed Capacity credit;
2. Programs that qualify for ISO-NE’s Real Time Price Response or Profiled Response programs;
3. Programs that are targeted to reduce peak load; and
4. Energy efficiency programs that have a high coincidence factor with peak demand.

To maximize FMCC mitigation, the CEAB recommends that support for programs, such as load response programs and the Price Response Supplemental Payment Pilot Program, be increased materially in the near term, albeit subject to review of the available 2005 data. The CEAB recognizes that the dedication of conservation fund dollars in this manner may be a departure from programs that may be preferred in other circumstances. Nonetheless, current circumstances warrant a strong near term commitment to load response.

Locational preference should be given to those measures that can be implemented in the Stamford/Norwalk sub-area to have the maximum effect on reduction on energy congestion and operating reserves. Measures implemented in other locations in the Southwest Connecticut zone will also provide substantial benefits. As a general matter, measures implemented in all locations in Connecticut will provide benefits in mitigating LICAP costs, although if ranked by their respective benefits and costs, near term implementation will tend to favor Southwest Connecticut.

B. Rate Design

The Energy Independence Act recognized the potential for rate design to contribute to demand reduction and FMCC mitigation. Specifically, Section 13 of the Act requires that the DPUC consider rate design adjustments including: mandatory peak, shoulder, and off-peak time of use (TOU) rates for customers with a maximum demand of not less than 350 kW on or before January 1, 2007 (subject to a TOU exemption option to be determined by the DPUC); optional interruptible or load response rates for customers that have a maximum demand of not less than 350 kW; and optional seasonal and TOU rates for all customers on or before June 1, 2006. The Act also contemplates mandatory seasonal rates for all customers beginning April 1, 2007.
The Act also calls for the electric distribution companies to provide customers with comparative bill analysis to illustrate the effects of various TOU options prior to their implementation.

Prior to the Act, the DPUC had initiated Docket No. 04-05-06, DPUC Review of Rate Design for Electric Distribution Companies. In the Notice of Scope, the DPUC stated its intent to conduct a comprehensive review of the electric distribution companies’ rate design, noting that rate design had not been evaluated in over ten years. The DPUC set forth a series of rate design issues including, among other items: on and off peak periods used under each TOU tariff; enrollment in residential TOU rates; seasonal rates; congestion cost recovery; the potential for rates designed for the largest residential customers; whether modifications to rate design could encourage greater participation in conservation and load management programs; interruptible rates; and, rate design implications to stimulate retail competition.

In the near term, the CEAB recommends that the DPUC identify the rate design modifications that have the maximum potential to reduce peak demand and that can be implemented by the spring of 2006. In particular, the DPUC should implement those rate design changes – even if on a pilot basis, and even if in a targeted geographic area – that provide the strongest possible price signals to customers to reduce load during the 2006 critical peak periods. These 2006 peak load reductions will have the greatest mitigating affect on any potential LICAP allocation in 2007. Putting such targeted rate design changes in place before the summer of 2006 would complement the Energy Act’s overall direction and further its rate design provisions.

The DPUC should complete its broad review of the electric distribution companies’ rate design and adjust it to positively influence consumption patterns and to reflect the current market structure.

C. GAP RFP Resources

The GAP RFP resources in many ways exemplify the types of resources that can best help manage peak load and mitigate FMCCs. ISO-NE’s contracts with suppliers to provide demand response programs provide an important resource for mitigating peak load during times of a declared system emergency. Many of these sources are limited to use only during declared system emergencies due to the terms of ISO-NE’s contracts. It is possible that some of these resources may be able to provide service at other times – such as during non-emergency peak load periods – under alternative contractual arrangements.

The CEAB recommends that the DPUC consider options to restructure any of the GAP RFP contracts where the resource could provide services in a broader set of hours, accelerate implementation, or extend the term of the agreements. The more likely the implementation of LICAP prior to summer 2007, the greater will be the impetus to accelerate contract renegotiations that can deliver peak load reductions in 2006. Obviously, since the present GAP RFP contracts are between the resource
providers and ISO-NE, there are a number of issues that would need to be resolved in order to effectuate any contractual changes.

The CEAB recommends that the DPUC determine whether – and, if so, in what circumstances – the suggested renegotiation of the foregoing contracts can take place.

D. Customer-Side Distributed Resources

The *Energy Independence Act* establishes a preference for customer-side distributed resources, which may include conservation and load management, including peak reduction and demand response, or generation (up to 65 MW) at a retail customer location. The Act also authorizes the DPUC to establish grants for these resources for the purpose of reducing FMCCs.

Customer-side distributed resources that have the highest potential to reduce FMCCs include:

1. Peak reducing conservation and load management measures as described above with respect to ECMB/utility sponsored programs;

2. Distributed generation resources that are controlled and callable for 10- and 30-minute response that qualify for ISO-NE operating reserves; and

3. Distributed generation used in response to calls for peak load reduction or used for peak shaving.

A preference should be given to those measures that can be implemented in the Stamford/Norwalk sub-area so as to have the maximum effect on the reduction on energy congestion and operating reserves. Measures implemented in other locations in the Southwest Connecticut zone also provide substantial benefits, thus also may deserve preferential treatment. For example, such projects could receive priority treatment in any utility or public permitting reviews that must be performed. Measures implemented in the rest of Connecticut also can mitigate LICAP costs (should that ISO proposal be implemented), perhaps to a somewhat lesser degree.

E. Public Education

To achieve the maximum benefits from rate design changes and load response programs to reduce peak demand during the summer of 2006, the DPUC should consider taking steps to provide consumers with objective information about the economic importance of reducing consumption during peak periods and the means by which to do so. Typically, the need for energy curtailment is presented to the public in the context of concerns about system reliability. It may help to reduce peak
demand if customers also understood the economic benefits – for themselves and for the State – in doing so. The ECMB’s recently announced public awareness campaign on energy efficiency is an example of this and may be a mechanism to accomplish this purpose.

8.2 Actions to Preserve Connecticut’s Local Generation

It is apparent that most, if not all of the current generation capacity in Connecticut will be necessary to meet ISO-NE reliability requirements in the near term. This is clearly the case at least through 2009, when the Phase II transmission project is scheduled for completion; and it is expected to be the case for some time thereafter, as well. It would require substantial new local generation or substantial new transmission import capability to render current generation expendable from a reliability perspective.32 Actions taken to secure as much of the existing generation base in the near term will ease the challenges of managing FMCCs through new supply, demand, and transmission resources.

The specific areas that warrant DPUC’s consideration include:

A. Management of RMR Contract Costs

FERC’s recent action to defer LICAP until at least October 2006 means that RMR contracts will continue to govern the costs to Connecticut for certain sources in 2006, and perhaps for some time to come. The DPUC and other Connecticut public parties should ensure that the Connecticut consumers’ interests continue to be vigorously represented regarding ISO-NE and FERC determinations of need for such contracts and that the DPUC has as central a role as possible in establishing the costs and terms and conditions of those contracts.

B. Contractual Alternatives to RMR Contracts

Recognizing that ISO-NE’s reliability assessments will likely find that most, if not all, of Connecticut’s current generation supply is needed for the next several years, the DPUC should consider contractual alternatives to the RMR contracts with ISO. These may include contracts between the local utilities and local generators as part of future standard offer supplies, much in the way UI currently includes capacity agreements in its TSO supply. It may be possible to structure mutually beneficial contractual arrangements between the utilities and some generators that mitigate the near-term FMCCs in return for, for example, longer term arrangements. The DPUC will need to determine whether any renegotiated contract is a suitable hedge against prospective FMCCs.

32 The recent deactivations of Devon Units 7 and 8 do not indicate a lack of need for such generation in Connecticut in the near term. Rather, these units became unable to serve load because of local transmission system limitations that preclude the simultaneous delivery of power from the Devon 7 and 8 and Milford Power facilities.
C. Contracting Approaches to Mitigate Exposure to Spot Markets

The current circumstances may warrant consideration of standard offer supply procurement methods that depart from procedures reasonably followed in the prior capacity market, particularly as they pertain to the mitigation of FMCCs and price volatility risks in the ISO’s proposed LICAP market. Standard offer designs which include forward contracting for capacity, reserves, and ancillary services will reduce the portion of Connecticut load exposed to spot markets for energy, capacity, and ancillary services. Contracting approaches may serve to mitigate the inherent price volatility of these markets and could offer cost-effective alternatives to purchases directly from these markets. It should be recalled that parties to a contract for capacity pay (or receive, as the case may be) the contract prices for the duration of their contract. That is, exposure to the capacity spot market (such as LICAP) is reduced by contracted capacity amounts.

8.3 Transmission and Import Capability

Inter- and intra-state transmission will remain constrained even after the implementation of the Phase I and II projects. A number of transmission projects are under development that will provide some measure of mitigation to FMCCs in SWCT or in the State more generally. Two projects scheduled for completion in 2007 are noted below. Also discussed below is a recommendation for additional transmission studies to be undertaken by the Connecticut utilities.

A. Bethel-Norwalk 345 kV Transmission Line

This line is under construction and scheduled for completion in December 2006. If completed on this schedule, is expected to increase import capability into SWCT by 275 MW. This upgrade will make a significant contribution to the mitigation of FMCC’s in SWCT.

To mitigate FMCCs in 2007, this project must be completed on schedule; if delayed, added actions may be necessary to mitigate FMCC costs in that year. The progress of this project should be actively monitored to ensure that all actions needed from the State to implement it on schedule are taken. The DPUC should, in the CEAB’s view, require regular and detailed project status reports, including disclosure at the earliest possible time of any potential or foreseeable delays; this will maximize the time available, in the event of a delay, to take actions to mitigate FMCCs in 2007.

B. Mystic-Wood River Reconductoring

This line is under construction and scheduled for completion prior to the summer of 2007. It is expected to increase import capability into Connecticut by
approximately 150 MW. This upgrade will contribute to the mitigation of FMCC’s in Connecticut generally, as well as in SWCT more particularly. Some caution is required here regarding the impact of this reconductoring project. Although ISO-NE studies have indicated the 150 MW import capability increase, official notice of its capacity must await the outcome of the ISO-NE stakeholder process which will discuss and vote on the matter. The CEAB does not know when this vote may take place.

To mitigate FMCC’s in 2007 and subsequently, this project must be completed on schedule. As with Bethel-Norwalk, if it is delayed, added actions may be necessary for 2007 to mitigate FMCC costs in that year.

The progress of this project should be actively monitored to assure all actions needed from the State to implement this on schedule are taken. The DPUC should require regular and detailed project status reports including disclosure at the earliest possible time of any potential or foreseeable delays so that, in the event of delay, the DPUC has the maximum possible time to mitigate 2007 FMCCs.

C. Other Transmission

As noted a number of times in this report, Connecticut suffers from inadequate inter- and intrastate transmission. Clearly, new transmission must be considered alongside other resources for its potential to mitigate FMCCs. It is the CEAB’s view that, at present, the electric distribution companies are in the best position to identify new intrastate transmission projects that may have the desired effect. One possibility may be a wholly intra-state transmission link from Lake Road to the grid that would mitigate an existing contingency and allow the generation to be considered as part of Connecticut’s supply for reliability purposes.

When identified, any viable transmission projects would be evaluated against other resources on criteria that would include, among others, price and consistency with the State’s preferential criteria. CEAB recommends to the DPUC that it delegate this responsibility to the utilities in a manner that it deems appropriate and require a report of their analysis by a date certain.

8.4 Generation Resources

This section addresses generation resources in two parts: preferred generation resources and others. In the CEAB’s view, any generation resources that satisfy the preferential criteria, and which, because of type and location, can reduce near term FMCCs should be encouraged, unless the associated longer-term contractual obligations are unreasonable.
With respect to other generation, with one exception, the CEAB recommends that no new major projects be undertaken until need is more precisely established and decisions regarding the extent to which hedges in the capacity market should be sought have been made. That is, any long-term contract for capacity is a hedged instrument and should be part of an overall portfolio strategy. The exception noted above refers to quick start capacity, as will be discussed below.

A. Preferred Generation Resources

The *Energy Independence Act* and the *Act Concerning Long Term Planning for Energy Facilities* establish preferences for distributed generation, combined heat and power, and certain renewable energy resources. In addition, the CEAB has set forth its Preferential Criteria for Evaluation of Energy Proposals. The DPUC should seek to advance those resources specifically encouraged in the Public Acts which measure favorably against the preferential criteria. One example of such an initiative concerns the process by which the State is implementing a program that calls for the electric distribution companies to enter long-term contracts for 100 MW of renewable energy pursuant to Con. Gen. Stat. Sec. 16-244c(j)(2).

As with the conservation and load management measures described above, locational preference should be given to those measures that can be implemented in the Stamford/Norwalk sub-area; these measures will have the maximum effect on reducing energy congestion and operating reserves. Measures implemented in other locations in SWCT also provide substantial benefits. Measures implemented in other locations in Connecticut may provide some benefits in mitigating LICAP costs.

B. Other Generation

In addition to the preferred generation resources discussed above, other generation resources that could best mitigate Connecticut’s FMCCs in the near term would be those that provide quick start capabilities in the form of 10- and 30-minute operating reserves. Facilities of this type should be located in the Stamford/Norwalk sub-area to have the maximum effect on the reduction of costs associated with energy congestion and operating reserves. Such facilities in other locations in SWCT may also provide substantial benefits. Fuel security (in the form of firm fuel supply contracts) or dual fuel capabilities should be a priority, as well.

In normal circumstances, the CEAB would recommend that any major generation capacity be acquired through the contemplated RFP process described in the Act. Projects that participate in the RFP process could include already-permitted generation facilities that have not yet been constructed, among others. A possible exception to this suggested RFP process may be incremental quick start capacity in the
right location that can be available for summer 2006 at a reasonable price. If a short-term contract is contemplated, the price would of course need to be less than the ongoing costs of meeting operational requirements. A longer term contract would clearly be more problematic without going through the RFP process.

8.5 Other Actions

The level of FMCC’s are determined, in part, by market rules, technical studies, and policy decisions established by ISO-NE and the associated stakeholder processes. The CEAB observes that the FMCCs that Connecticut consumers pay can be materially affected in these determinations (see, for example, the earlier discussion of the Mystic-Wood River transmission project in Section 8.3). The CEAB recommends that the DPUC, the CEAB, the Connecticut Office of Consumer Counsel, and the Connecticut electric distribution companies establish an approach to participation and oversight of these decisions to assure that Connecticut consumer interests continue to be properly advocated in these stakeholder processes and to assure a commonality of direction, where possible, among Connecticut interests.

ISO-NE activities having direct bearing on FMCCs in Connecticut include:

A. Transmission Planning Studies

ISO-NE is currently conducting a study of a Southern New England Reinforcement Project which is focused on solutions that could increase import capability into Connecticut by 1,000 MW. This study is currently underway and scheduled for an ISO-NE approved project plan by July 2006. The project plan will be reviewed by a stakeholder process.

B. Installed Capacity Requirements for June 2006 to May 2007

ISO-NE annually conducts an analysis of regional resource adequacy to set the reserve requirements in the region. These values are direct inputs to ISO-NE’s proposed LICAP formula. This study will be reviewed by a stakeholder process and submitted to FERC for approval in early 2006.

A major input to this study is ISO-NE’s annual load forecast. ISO-NE’s forecasts of peak loads in Connecticut and SWCT have a direct bearing on the installed reserve requirements for the coming power year.
C. Forward Reserve Market Design

ISO-NE, in conjunction with a stakeholder committee, is developing a locational market structure for operating reserves. This work is scheduled to be conducted for implementation in the latter half of 2006. Connecticut has substantial local operating reserve requirements due to transmission limitations.
Reference List

Appendix 1

Connecticut’s Needs for Additional Resources

This Appendix presents several views of Connecticut’s needs for additional electric capacity resources, based on information that has been obtained to date. Connecticut’s needs are driven by three sets of power system reliability calculations.

The first reliability calculation pertains to ISO-NE’s proposed LICAP market, whereby capacity costs to entities serving domestic loads (and by direct extension, to customers under the State’s regulatory framework for recovery of FMCCs) will be established. These LICAP charges will vary, depending on how the total quantity of qualifying in-zone generating capacity (i.e., as measured in megawatts, MWs) and Capacity Transfer Limits (CTL)\(^{33}\) combined compared to a monthly Objective Capability (OC) target that is set by ISO-NE for each LICAP zone. The higher the ratio is, the lower the resulting LICAP prices. Thus, it is important that Connecticut planners have a clear view of the degree to which its likely capacity resource levels will affect LICAP costs.

Connecticut’s needs also may be affected by an Operable Capacity (OpCap) assessment that ISO-NE routinely performs to test the ability of the bulk power system to respond to hypothetical contingencies, which typically include outages at the largest transmission or generating facilities. It is not yet clear what actions ISO-NE may take to ensure that OpCap remains at acceptable levels into the future. Consequently, the cost impacts of OpCap are uncertain.

ISO-NE also prescribes a third reliability requirement in order to ensure a sufficient level of operating reserves that includes quick-start units. In its recent Draft RSP05 Report, ISO-NE recommends that an additional 550 MW of quick-start units are needed in Greater Connecticut to meet its 1,200 MW operating reserve requirement. Of the 550 MW, 350 MW would be needed in SWCT once Phase II of the SWCT Reliability project enters service.

This Appendix assesses the performance of Connecticut taken as a whole and one of its two LICAP zones (i.e., Southwest Connecticut, or SWCT) relative to the OC and OpCap reliability standards. In the attached charts, we also provide a view of the ISO’s stated requirement for additional quick start operating reserves. As a general matter, to the extent that the majority of the State’s resources are located in the Rest of Connecticut (ROC) load zone, ROC has sufficient resources to meet the OC and OpCap reliability standards. Two cases based on different sets of load forecasts are presented to explore Connecticut’s needs. Each case is briefly described below and presented in the tables that follow.

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\(^{33}\) The CTL is the upper limit of capacity transfers allowed across an interface, but the actual amount of imported capacity may be less than the limit depending supply/demand balance of other zones.
Case 1: ISO New England Peak Load Forecast

Case 1 is based on the peak load forecasts found in the NE-ISO’s Draft 2005 Regional System Plan (RSP05) which has their origin in the 2005 Capacity, Energy, Loads and Transmission (CELT) report. Calculations for the State and for Southwest Connecticut (SWCT) are presented in Cases 1a and 1b, respectively. Since a majority of the generation in Connecticut sits in the Rest of Connecticut (ROC), OC and OpCap comparisons do not provide additional insight into ROC’s needs, thus an assessment for ROC is not explicit in this analysis.

Case 1a is a calculation of the State of Connecticut’s needs for additional capacity resources, as would be necessary to meet foreseeable OC target values and to satisfy the State’s OpCap requirements. An ISO-NE peak load forecast for the state as a whole serves as the point of departure for both the OC and OpCap need calculations. Because NE-ISO’s peak load forecast appears to be calculated directly from the Adjusted Reference Case forecast in its 2005 CELT Report, it is net of various load offsets, such as for energy efficiency programs (note that Lines 4 through 10 of the tables below identify the full range of potential offsets to loads in Connecticut that have been identified to date).

OC requirements for Connecticut and its SWCT LICAP zone are estimated as the product of (a) forecast Peak Load, Net of Offsets, and (b) reserve margins reflecting the degree to which ISO-NE’s forecast Regional OC values exceed its forecast regional peak loads (i.e., a 14 percent reserve margin is applied). The Total Available Resources that are measured relative to the OC requirement reflect a summation of various existing generation and transmission resources, and potential resource additions.

Note that ISO-NE’s proposed LICAP market divides Connecticut into two zones with separate OC requirements: Southwest Connecticut and Rest of Connecticut. Connecticut taken as a whole does not have an OC obligation. Thus, this presentation of the State’s position reflects a hypothetical, state-wide requirement where there are no transfer constraints within Connecticut.

The lower half of the Case 1a table presents an OpCap assessment for the state. In keeping with established methods, the capacity of the largest generating unit in the state is added to Peak loads, Net of Offsets (in this case, an addition also is made which reflects the load increment necessary to bring the peak load value to the “90/10” level reflecting more severe weather at the time of system peak) to set the annual OpCap requirement. The OpCap assessment is completed by comparing the OpCap Requirement for CT, so derived, to the Total Resources for OpCap (i.e., the sum total of those that qualify under the ISO-NE’s rules, adjusted downward to reflect a level of assumed outages).

The assessment in Case 1b mirrors that presented in Case 1a, with the exception that the load forecast on which the calculations derive is ISO-NE’s peak load forecast for the SWCT load zone. In addition, various capacity and transmission resources are identified as applicable to that zone.

The calculations in Case 1a and Case 1b result in sufficient resource (i.e., capacity) surpluses under OC and OpCap across the planning horizon, with the exception of slight resource deficiencies in 2008 under OpCap for the State as a whole. These surpluses/deficiencies also are compared to the quick-start units that are required for operating reserves.

Case 2: Sum of the Utilities Peak Load Forecast

The assessment in Case 2 mirrors that presented in Case 1, with the exception that the load forecast from which the calculations derive is the sum total of the peak load forecasts presented by each of CL&P, UI and CMEEC in the Connecticut Siting Council’s Docket No. F-2005 proceeding. Note that there are known Offsets to Load that
are not reflected in the referenced forecast, thus Case 2a identifies several such offsets in calculating Peak Load, Net of Offsets values that flow into the OC and OpCap need calculations.

In Case 2a, calculations for the State are based on the sum of the state utilities’ forecasts, while in Case 2b, calculations for Southwest Connecticut are based on an estimate of its portion of the statewide load (i.e., calculated as half of the sum of the utilities’ peak load forecasts, as identified under Case 2a above). Various capacity and transmission resources are the same as in Case 1 for CT and SWCT.

The calculations in Case 2 result in substantial resource (i.e., capacity) surpluses under OC, OpCap, and operating reserve requirements across the planning horizon.
# Projected Capacity Situation - Case 1a

State of Connecticut: Using ISO Load Forecast

<table>
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<tr>
<th>Notes</th>
<th>Capacity Situation (Summer MW)</th>
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<td>Other</td>
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<td>12</td>
<td><strong>Required Reserve Margin for OC</strong></td>
<td>14%</td>
<td>14%</td>
<td>14%</td>
<td>14%</td>
<td>14%</td>
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<td><strong>Required Reserves for OC</strong></td>
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<td><strong>OC Requirement For CT</strong></td>
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<td>8,231</td>
<td>8,345</td>
<td>8,493</td>
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<td><strong>SWCT RFP</strong></td>
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<td><strong>ISO Load Response per ISO</strong></td>
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<td>22</td>
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<td><strong>Phase I SWCT Transmission Improvements</strong></td>
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<td><strong>Total Available Resources</strong></td>
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*September 2, 2005*
(Continued from previous page)

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<td>n. Peak Load, Net of Offsets</td>
<td>7,125</td>
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<td>7,450</td>
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<th>Reserves for Op Cap:</th>
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<tr>
<td>o. Largest Unit</td>
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<td>p. 90/10 Load Increment</td>
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<tr>
<td>q. Assumed Unavailable Capacity</td>
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<td>Total Required Reserves</td>
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<th>Op Cap Requirement for CT</th>
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<tr>
<td>Current In-State Capacity</td>
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<td>r. Deactivated Capacity (Devon 7 and 8)</td>
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<td>s. Current In-State Import Limit</td>
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<td>t. Phase I SWCT Transmission Upgrade</td>
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<td>u. Mystic CT to Wood River RI Trans. Upgrade</td>
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<td>51 SWCT RFP</td>
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<td>Total Other Load Response Programs</td>
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<td>53 Total Resources for Op Cap</td>
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<th>CT Op Cap Surplus (Deficiency)</th>
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<td>72</td>
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Notes to Case 1a:

a. ISO-NE's unadjusted 50/50 forecast for CT is not known. Calculations derive from the adjusted forecast for CT, as shown in Line 13.
b. This ISO-NE peak load forecast for CT appears to tie directly to the CELT Adjusted Reference Case forecast (which is net of DSM offsets), as reflected in backup materials to the 2005 CELT Report.
c. The forecast reserve margin for the region, as reflected in ISO-NE's forecast of Objective Capability.
d. Total July 2005 Seasonal Claimed Capability for Connecticut generating units.
e. ISO-NE rules may permit the capacity from these deactivated facilities to qualify as installed capacity for purposes of determining LICAP charges, for a period of three years (assumed to end after 2006).
f. It is not known whether any new units, or which, will enter commercial service during the forecast period.
g. Connecticut's recent Energy Bill requires load serving entities to present to the DPUC contracts for at least 100 MWs of new renewable generating capacity, by July 2008.
h. The forecast capacity from temporary generation under the "GAP RFP" is assumed to expire after 2008. Capacity from load response programs contracted under the GAP RFP is assumed to remain available to CT after 2008 and 2009.
i. ISO-NE identifies 25 MW of load response in ROC as under contract.
j. CL&P identifies a larger number of MWs as participating in ISO-NE load response programs. One cannot determine whether or to what degree CL&P's numbers duplicate those in Line 24. It is clear that the DPUC directed CL&P to invest an additional $1 million in ISO-NE load response programs, which CL&P estimates represents an additional 12.5 MWs, after the January 2005 date of the FERC filing from which Line 24 derives.
k. This Capacity Transfer Limit for CT is identified in ISO-NE's LICAP Model for CT. 100 MWs are added to reflect increased transmission capability into CT per the Draft RSP 2005, and 300 MWs to SWCT's CTL.
l. Phase 1 improvements are not expected to increase transmission capacity into Connecticut.
m. Transmission improvements reported by ISO-NE are expected to increase transfers into CT by 150 MWs.

n. From Line 13.
o. The OpCap Requirement is calculated as a function of the largest unit on the system, which for Connecticut is Millstone 3.
p. The OpCap Requirement is calculated using a 90/10 forecast, in order to simulate more severe weather conditions. Line 38 is the difference between ISO-NE's 50/50 forecast for CT and its 90/10 forecast.

q. The OpCap Requirement calculation anticipates that not all generating capacity will be available to respond to system disturbances, because of planned and unplanned outages. The forecast estimates are from ISO-NE.

r. Devon 7 and 8 are not recognized in calculating OpCap Requirements.
s. Transmission import capabilities are used in determining the degree to which a zone is in compliance with its OpCap Requirement. The 2,300 MW value is from ISO-NE's Draft 2006 RSP.
t. Phase I improvements are not expected to increase transmission capacity into Connecticut as a whole.
u. Transmission improvements reported by ISO-NE are expected to increase import capability.
Case 1a: OC and OP CAP Comparisons for CT Using ISO-NE Forecast Method
Case 1a: OC, OP CAP and Quick Start Surplus (Deficit) for CT Using ISO-NE Forecast Method
# Projected Capacity Situation - Case 1b

## SWCT: Using ISO Load Forecast

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<th>Notes</th>
<th>Capacity Situation (Summer MW)</th>
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*Connecticut Energy Advisory Board*  
77  
*September 2, 2005*
## Preliminary Assessment

**CT Electric Supply & Demand**

(continued from previous page)

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<th>2008</th>
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### Notes to Case 1b:

Unless noted herein, notes from Case 1a apply.

- **a.** From ISO-NE’s 2005 CELT
- **b.** Estimated at half of the amount identified in Case 1a.
- **c.** Estimated at half of the amount identified in Case 1a.
- **d.** This Capacity Transfer Limit for CT is identified in ISO-NE’s LICAP Model for CT. We add 100 MWs to reflect increased transmission capability into CT per the Draft RSP for 2005.
- **e.** Phase 1 will improve transmission capacity into SWCT.
- **f.** These transmission improvements do not apply to SWCT.
- **g.** This capacity value reflects the largest generating unit in SWCT, Bridgeport Energy.
- **h.** The 2,300 MW value is from ISO-NE’s Draft 2005 RSP.

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*September 2, 2005*
Case 1b: OC and OP CAP Comparisons for SWCT Using ISO-NE Forecast Method

- 1.0xOC
- 1.038x OC
- 1.15x OC

Year
- 2006
- 2007
- 2008

MW
- 0
- 2,000
- 4,000
- 6,000
- 8,000
- 10,000
- 12,000

Connecticut Energy Advisory Board
Case 1b: OC, OP CAP and Quick Start Surplus (Deficit) for SWCT Using ISO-NE Forecast Method
## Projected Capacity Situation - Case 2a


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<tr>
<th>Notes</th>
<th>Capacity Situation (Summer MW)</th>
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<th>2006</th>
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<th>2008</th>
<th>2009</th>
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<td>19</td>
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Notes to Case 2a:
Unless noted herein, notes from Case 1a apply.

a. The sum of the “base” case load forecasts, per utility filings to the CSC in F-2005. We understand this to be a weather-normalized forecast. On July 27, 2005, CL&P’s actual peak load (5,401 MWs) considerably exceeded its forecast value for 2005 (5,116 MWs). However, when that actual peak load is adjusted (downward) to account for "higher than normal" temperatures, the weather-adjusted value for July 27 falls into line (within a fraction of a percent) with the forecast value.

b. Savings from demand-side measures installed prior to roughly January 1, 2005, are included in (i.e., reduce what otherwise would be) CL&P’s load forecast. This Line 4 forecast of Known Utility DSM Programs assumes that current measures will continue to be installed for six years, and that incremental capacity savings will result across the useful life of each measure. Demand side saving identified here also reflect additional further DSM investments that the DPUC has directed CL&P to pursue. CL&P’s known savings estimates are reduced somewhat to remove savings from ISO-NE demand response programs that were part of the Company’s projections in its CSC F-2005 filing.

c. The new Energy Bill requires load serving entities to make purchases from "Class III Renewables." These include cogeneration and load management programs, that may offset projected savings in Line 4, but to an unknown degree.

d. The capacity impacts of the Time-of-use Pricing provisions of the Energy Bill are not known.

e. The capacity impacts of the DPUC’s initiative to increase cash incentives to Distributed Generation are not known.

f. The capacity impacts of the DPUC’s recent decision to allow Energy Efficiency Alternative TSO products are not known.

g. The capacity impacts of new Federal and State legislation to improve Energy Efficiency standards are not known.
h. Other offsets are not yet identified.

i. Here, the increment to achieve a "90/10" forecast is calculated as the "90/10 Load Increment" from case 1a times the ratio of the Peak Load, Net of Offsets under the combined utilities forecast (Line 13, above) to the same figure under the ISO forecast (i.e., Line 13 in Case 1a).
Case 2a: OC and OP CAP Comparisons for CT Using Sum of Utilities’ Forecast Method

Connecticut Energy Advisory Board
Case 2a: OC, OP CAP and Quick Start Surplus (Deficit) for Greater CT Using Sum of Utilities' Forecast Method

Year

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Connecticut Energy Advisory Board
## SWCT: Using Utility Combined Forecasts

### Notes

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<th>2007</th>
<th>2008</th>
<th>2009</th>
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<td>n/a</td>
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<td>4,863</td>
<td>4,932</td>
<td>4,932</td>
<td>4,873</td>
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<td>1,007</td>
<td>909</td>
<td></td>
</tr>
</tbody>
</table>
### Preliminary Assessment

#### CT Electric Supply & Demand

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(continued from previous page)

<table>
<thead>
<tr>
<th>Notes</th>
<th>Capacity Situation (Summer MW)</th>
<th>2005</th>
<th>2006</th>
<th>2007</th>
<th>2008</th>
<th>2009</th>
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<tbody>
<tr>
<td>Peak Load, Net of Offsets</td>
<td>3,372</td>
<td>3,388</td>
<td>3,422</td>
<td>3,443</td>
<td>3,477</td>
<td></td>
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<tr>
<td>Reserves for Op Cap:</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>Largest Unit</td>
<td>451</td>
<td>451</td>
<td>451</td>
<td>451</td>
<td>451</td>
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<tr>
<td>90/10 Load Increment</td>
<td>225</td>
<td>230</td>
<td>240</td>
<td>240</td>
<td>250</td>
<td></td>
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<tr>
<td>Assumed Unavailable Capacity</td>
<td>232</td>
<td>232</td>
<td>232</td>
<td>232</td>
<td>232</td>
<td></td>
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<tr>
<td>Total Required Reserves</td>
<td>908</td>
<td>913</td>
<td>923</td>
<td>923</td>
<td>933</td>
<td></td>
</tr>
<tr>
<td>Op Cap Requirement for SWCT</td>
<td>4,280</td>
<td>4,301</td>
<td>4,345</td>
<td>4,366</td>
<td>4,410</td>
<td></td>
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<tr>
<td>Current In-State Capacity</td>
<td>2,376</td>
<td>2,376</td>
<td>2,376</td>
<td>2,376</td>
<td>2,376</td>
<td></td>
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<tr>
<td>Deactivated Capacity (Devon 7 and 8)</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td></td>
</tr>
<tr>
<td>New Capacity (e.g., Kleen)</td>
<td>?</td>
<td>?</td>
<td>?</td>
<td>?</td>
<td>?</td>
<td></td>
</tr>
<tr>
<td>New Renewable Capacity</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>10</td>
<td></td>
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<tr>
<td>Current SWCT Import Limit</td>
<td>2,300</td>
<td>2,300</td>
<td>2,300</td>
<td>2,300</td>
<td>2,300</td>
<td></td>
</tr>
<tr>
<td>Phase I SWCT Transmission Upgrade</td>
<td>0</td>
<td>0</td>
<td>275</td>
<td>275</td>
<td>275</td>
<td></td>
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<tr>
<td>Mystic CT to Wood River RI Trans. Upgrade</td>
<td>n/a</td>
<td>n/a</td>
<td>n/a</td>
<td>n/a</td>
<td>n/a</td>
<td></td>
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<tr>
<td>SWCT RFP</td>
<td>218</td>
<td>250</td>
<td>256</td>
<td>256</td>
<td>187</td>
<td></td>
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<tr>
<td>Total Other Load Response Programs</td>
<td>6</td>
<td>6</td>
<td>6</td>
<td>6</td>
<td>6</td>
<td></td>
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<tr>
<td>Total Resources for Op Cap</td>
<td>4,900</td>
<td>4,932</td>
<td>5,213</td>
<td>5,213</td>
<td>5,154</td>
<td></td>
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<tr>
<td>SWCT Op Cap Surplus (Deficiency)</td>
<td>620</td>
<td>632</td>
<td>868</td>
<td>847</td>
<td>744</td>
<td></td>
</tr>
</tbody>
</table>

---

**Notes to Case 2b:**

Unless noted herein, notes from Case 2a and Case 1b apply.

a. Estimated at half of the Case 2a forecast.

b. Estimated at half of the Case 2a forecast.
Case 2b: OC and OP CAP Comparisons for SWCT Using Sum of Utilities' Forecast Method
Appendix 2

Estimated LICAP Costs to Connecticut

This Appendix presents the results of a series of estimates of the costs that load serving entities in Connecticut, and thus the consumers that they serve, may incur under ISO-NE’s proposed LICAP market (which, if implemented, will be in place no earlier than October 1, 2006). The CEAB modified and ran a model for estimating LICAP costs that initially was developed by ISO-NE in August 2004, and later was converted to a multi-year model with assumptions as detailed in Table 1. ISO-NE describes its LICAP model as follows:\(^{34}\)

The clearing portion of the model includes the five proposed LICAP zones and models the capacity transfer constraints (CTRs) between the zones, the quantity of capacity actually in each zone, the LICAP obligation assigned to each zone, and the demand curve adjusted to fit the parameters for each zone. Using linear optimization techniques implemented in the "solver" module of the Microsoft Excel spreadsheet software, the model varies the amount of capacity transferred over each zonal interface, subject to the transfer limits, with the objective of maximizing social benefit. Social benefit is maximized when the marginal benefit from increasing transfers to the constrained side of an interface is equal to the marginal cost of the change. This benefit optimization considers costs and benefits to suppliers as well as to load in arriving at an optimal solution.

The remainder of this model deals with the process of settling the market to develop cost projections. Issues addressed include the quantity of capacity purchased in each zone and the price paid for that capacity, the quantity of capacity actually transferred over each interface, and the settlement of capacity transfer rights….

Inputs to the model include the demand curve parameters for each LICAP zone and the planning assumptions for the year analyzed. The planning assumptions include the quantity of capacity assumed to be available in each zone, the transfer limits between zones, and the total obligation of each zone….

CL&P used the same multi-year model and assumptions as ISO-NE, except it updated the Objective Capability (OC) for the New England control area in its assessment of LICAP costs.\(^{35}\) The CEAB subsequently updated or modified a number of the assumptions model, including OC, generating unit re-rates, retirements and reactivations, and transmission upgrades. The CEAB and ISO-NE/CL&P input assumptions are presented in Table 2.

LICAP clearing prices and net cost to load by zone were estimated starting with the 2006/2007 planning year and continuing through planning year 2008/2009.

\(^{34}\) Excerpt from Exhibit No. ISO-39, Revised Page 51 of 74, Prepared Rebuttal Testimony of Mark Karl on Behalf of ISO-NE, in FERC Docket No. ER03-563-030.

\(^{35}\) Zonal OCs are allocated based on a zone’s share of the previous calendar year’s actual, ISO-NE control area, system-wide peak.
Table 1: ISO-NE LICAP Cost Projection Assumptions

<table>
<thead>
<tr>
<th>Transmission</th>
<th>Year</th>
<th>Region</th>
<th>Project</th>
<th>Size (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2007</td>
<td>SWCT</td>
<td>Phase 1 Transmission Upgrade</td>
<td>550</td>
</tr>
<tr>
<td></td>
<td>2007</td>
<td>NEMA</td>
<td></td>
<td>900</td>
</tr>
<tr>
<td></td>
<td>2009</td>
<td>SWCT</td>
<td>Phase 2 Transmission Upgrade</td>
<td>850</td>
</tr>
<tr>
<td></td>
<td>2009</td>
<td>NEMA</td>
<td></td>
<td>200</td>
</tr>
<tr>
<td></td>
<td>2010</td>
<td>ROC</td>
<td>SNERP</td>
<td>900</td>
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</table>

<table>
<thead>
<tr>
<th>Generation</th>
<th>Year</th>
<th>Region</th>
<th>Project</th>
<th>Size (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2007</td>
<td>NEMA</td>
<td>Kendall Retirement</td>
<td>-187</td>
</tr>
<tr>
<td></td>
<td>2007</td>
<td>NEMA</td>
<td>New Boston Retirement</td>
<td>-352</td>
</tr>
<tr>
<td></td>
<td>2009</td>
<td>ROC</td>
<td>KLEEN Power</td>
<td>620</td>
</tr>
<tr>
<td></td>
<td>2009</td>
<td>NEMA</td>
<td>Peabody</td>
<td>140</td>
</tr>
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</table>

<table>
<thead>
<tr>
<th>Capacity Imports</th>
<th>Year Following</th>
<th>Region</th>
<th>Interface</th>
<th>Size (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>ROC Price &gt; $8.00</td>
<td>ROC</td>
<td>Cross Sound Cable</td>
<td>150</td>
</tr>
<tr>
<td></td>
<td>ROP Price &gt; $5.00</td>
<td>ROP</td>
<td>NY Interface</td>
<td>600</td>
</tr>
<tr>
<td></td>
<td>Maine Price &gt; $3.00</td>
<td>Maine</td>
<td>Maine/New Brunswick line</td>
<td>200</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Load Growth</th>
<th>RTEP '04 Assumptions</th>
<th>1.3% per year</th>
</tr>
</thead>
</table>

| Peak Energy Rent (PER) | Peak Energy Rent | $0.48/kw-month |

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36 Assumptions were released as work papers to the CT DPUC/ISO-NE 3-1 Discovery Response in FERC Docket No. ER03-563-030.
## Table 2: Comparison of CL&P to CEAB Modeling Assumptions

<table>
<thead>
<tr>
<th>ISO-NE/CL&amp;P Assumptions</th>
<th>CEAB Assumptions</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>New England Control Area OC</strong></td>
<td>The zonal OCs for New England’s non-Connecticut zones were calculated as a fixed percentage of the Control Area’s July OC value for each forecast year, as taken from &quot;TABLE 1: Draft - 05/06 OC Values Assuming 2,000 MW Tie Benefits.&quot; The two sets of SWCT and ROC zonal OCs reflect two different load scenarios, as described in Appendix 1.</td>
</tr>
<tr>
<td><strong>Capacity Transfer Limit (CTL)</strong></td>
<td>The CEAB used the same CTLs as ISO-NE/CL&amp;P with adjustments described in New Capacity/Transmission below.</td>
</tr>
<tr>
<td>CL&amp;P maintained same capacity CTLs used by ISO-NE in its model.</td>
<td></td>
</tr>
<tr>
<td><strong>Zonal OC Allocations</strong></td>
<td>Zonal OCs for non-Connecticut zones were calculated using same percentages of regional peaks as CL&amp;P, applied to the July OC as described above. However, zonal OCs for SWCT and ROC were calculated using an alternative method, as described in Appendix 1.</td>
</tr>
<tr>
<td>The shares used by ISO-NE in its December 2004 Analysis were applied to the new control area OC to allocate zonal OC for each year going forward.</td>
<td></td>
</tr>
<tr>
<td><strong>Available Local Capacity</strong></td>
<td>The CEAB updated claimed capacity levels within each zone to reflect ISO-NE’s July 2005 Seasonal Claimed Capability report. The total available MW capacity for the ISO-NE control area was similar to CL&amp;P values, except that NEMA capacity was adjusted to reflect reactivation of the Kendall units (166 MW) and capacity retirements and derates (-190 MW).</td>
</tr>
<tr>
<td>CL&amp;P used the ISO-NE assumptions from its December 2004 LICAP Cost Analysis.</td>
<td></td>
</tr>
<tr>
<td><strong>Capacity Transfer Rights (CTR) Allocation Method</strong></td>
<td>The CEAB calculated CTRs using “Adjusted Clearing Prices,” i.e., after PER and EFORd were taken into account.</td>
</tr>
<tr>
<td>CTRs were calculated in the model using Gross Clearing Price, which is the clearing price from the LICAP demand curve before any adjustments are made for Peak Energy Rents (PER) and Equivalent Capacity.</td>
<td></td>
</tr>
</tbody>
</table>

---

37 OC for Rest of Connecticut is not presented in Appendix 1, but is calculated based on the State’s calculated OC minus SWCT’s calculated OC from each of the two Load Cases in Appendix 1.

38 Capacity contributions from the GAP RFP and 1200 MW of HQ transmission capability into New England included in the calculation were similar to ISO-NE’s assumptions.

39 The Kendall CT and Steam Unit 3 were reactivated for reliability purposes. Mirant and ISO-NE are currently negotiating an RMR agreement that would expire when LICAP takes effect (see FERC Docket No. ER05-26). However, it is assumed that the reactivated units would be counted toward LICAP in the 2006/2007 planning year.
Year Designation

- Demand Forced Outage Rate (EFORd).

- LICAP cost estimates appear to apply to Calendar years, beginning with 2006.

- The CEAB calculated LICAP costs based on ISO-NE’s Planning Year, which begins in June and runs through May of the subsequent year (i.e. June-May for 2006/2007 through 2008/2009).

New Capacity/Transmission

- See Table 1.

- Per ISO-NE’s “Draft RSP05: Connecticut Results.”

- 2006/2007: SWCT’s CTL increases by 300 MW and ROC’s CTL increases by 100 MW to reflect recently completed upgrades.

- 2007/2008: ROC’s CTL increases another 150 MW due to RI-CT upgrade at Mystic; SWCT Phase I adds another 275 MW; NEMA CTL adds another 900 MW.

- Assumes Kendall units and New Boston retire in 2007.

For the CEAB’s analysis, using the revised assumptions above, three scenarios were tested to reflect the changes made to available capacity and zonal OC that differ from the ISO-NE/CL&P analyses. The scenarios are as follows:

- **Scenario CL&P OC:** Retained the zonal OC targets utilized by CL&P under the updated assumptions reflecting recent capacity and transmission changes.

- **Scenario Case 1 OC:** Zonal OC targets were updated in ROC and SWCT to reflect those used by ISO New England in its Draft RSP05 report. These revised OC inputs correspond to the “Case 1” load projections from Appendix 1; and

- **Scenario Case 2 OC:** Zonal OC targets were updated in Rest of Connecticut (ROC) and Southwest Connecticut (SWCT) to reflect peak load forecasted by Connecticut utilities. These revised OC inputs correspond to the “Case 2” load projections from Appendix 1.

The results are presented below from CL&P’s original analysis and each test scenario as described above.
LICAP Prices from CL&P

Figure 1: LICAP Prices from CL&P
Figure 2: LICAP Prices Using CL&P OC and Updated Assumptions
Figure 3: Case 1-LICAP Prices Using ISO-NE Load Forecast OC
In addition, for the scenarios using Case 1 OC and Case 2 OC above, strategies for mitigating LICAP costs for Connecticut were modeled, including (a) increasing capacity in Rest of CT and SWCT, (b) counting deactivated units in supply, and (c) reducing peak load in SWCT. In strategy (a) “Added Capacity,” 100 MW of additional capacity or LICAP-qualified demand response was added to both ROC and SWCT starting June 2006. For strategy (b) “Devon In,” deactivated units Devon 7 and 8 (212MW) were counted toward the available capacity for purposes of setting LICAP prices for SWCT for 2006/2007. The current version of LICAP rules indicates that units on inactive reserve will be considered in the supply stack up to three years after deactivation for purposes of determining LICAP price.

The impact on LICAP costs under strategy (c) where SWCT’s Peak Load is reduced by 200 MW by the summer of 2006 also was tested. This load reduction impacts subsequent years’ control area OC starting 2007/2008 and percentage of coincident peak for SWCT. Results of the analyses, under the assumption that all capacity is transacted on the spot market, are shown below. Bars in graphs below represent total Net LICAP Cost to Load in ROC and SWCT zones.40

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40 Net LICAP cost to load is net of PER, EFORD, and CTR benefits.
Figure 5: Case 1 OC Strategies
Case 2: Net LICAP Cost Reduction Relative to Base


$\text{million/year}$

Case 2 Base
Case 2(X) Added Capacity
Case 2(Y) Devon In
Case 2 Base
Case 2(X) Added Capacity
Case 2(Z) Load Reduction
Case 2 Base
Case 2(X) Added Capacity
Case 2(Z) Load Reduction

Figure 6: Case 2 OC Strategies

Note that the assumption that all capacity is acquired through the spot market provides a simple, but potentially unrealistic, estimate of LICAP costs. It is more likely that at least some load serving entities (e.g., the electric distribution companies) will have in place contracts that entitle them to receive capacity at contract prices (fixed or otherwise) across some period of time for a portion of their capacity obligations. If so, their exposure to the LICAP spot market would be correspondingly reduced, albeit replaced by the contract costs.
Appendix 3

Glossary of Acronyms

AGC        Automated Generation Control
ASMs       Ancillary Services Markets
CEAB       Connecticut Energy Advisory Board
CEF        Connecticut Clean Energy Fund
CLM        Conservation and Load Management
CL&P       Connecticut Light and Power
CMEEC      Connecticut Municipal Electrical Energy Cooperative
CSC        Connecticut Siting Council
CTR        Capacity Transfer Constraints
DPUC       Department of Public Utility Control
DSM        Demand Side Management
EBCC       Estimated Benchmark Cost of Capacity
ECMB       Connecticut Energy Conservation Management Board
EFORd      Equivalent Demand Forced Outage Rate
FERC       Federal Energy Regulatory Commission
FMCCs      Federally Mandated Congestion Charges
ISE        Institute for Sustainable Energy
ISO-NE     Independent System Operator of New England
KWh        Kilowatt-Hours
LICAP      Locational Installed Capacity
LMP        Locational Marginal Pricing
LSE        Load Serving Entities
MW         Megawatt
MWh        Megawatt-hours
OC         Objective Capability
OpCap      Operable Capability
ORC        Operating Reserve Credits
PUSH       Peaking Unit Safe Harbor
RFP        Request for Proposals
RMR        Reliability Must Run
ROC        Rest of Connecticut Zone
RSP        Regional System Plan
RTEP       Regional Transmission Expansion Plan
RTO        Regional Transmission Organizations
SMD        Standard Market Design
SWCT       Southwest Connecticut Zone
TOU        Time of Use
TSO        Transitional Standard Offer
UI         United Illuminating