Congestion Management Under Standard Market Design

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Congestion Management Under SMD

I. Summary

ISO-NE will implement its “Standard Market Design” (SMD) for the region’s wholesale electricity markets on March 1, 2003. SMD is based on the successful PJM market and is consistent with the recent Notice of Proposed Rulemaking (NOPR) for a national SMD issued by the Federal Energy Regulatory Commission (FERC). SMD will change the way electricity is priced, from the current method of a single price for the entire region to locational prices based on the cost of serving load in each area. It also adds a financially binding Day-Ahead market to the current Real-Time market for electricity.

One important objective of the New England SMD is to improve the efficiency of the wholesale electric power market by ensuring that the cost of congestion is reflected in electricity prices. To help relieve congestion, the new market provides location-specific prices that should encourage transmission and generation enhancements, as well as additional demand response. Electric load and generation pockets in New England will persist under SMD, and some regions will continue to experience periodic transmission congestion.

Current plans for transmission and generation improvements should reduce congestion in several locations. However, some individual sub-areas remain highly sensitive to disturbances in system conditions. Congestion could present significant problems in these zones if actual loads are higher than projected, if generation or transmission resources suffer long outages, or if expected system enhancements are not forthcoming. This sensitivity could pose greater risks to entities serving load in congested areas under SMD than in the current market, because the costs of congestion will be borne exclusively by the congested region, rather than spread equally throughout the system. To help Market Participants manage their congestion-related risks, SMD’s multi-settlement system offers hedging opportunities. Additional risk-management tools take the form of Financial Transmission Rights (FTRs). In addition, market monitoring and mitigation rules will continue to protect load pockets against the exploitation of market power, while preserving market incentives to the fullest extent possible.

Various studies have analyzed congestion and the related consequences of implementing SMD in New England. Drawing on these studies, this paper reflects upon SMD and its impact on New England and the individual sub-areas within New England. Some of the major findings in these studies include:

- If new transmission and generation facilities are completed as scheduled, and if load growth occurs as forecast, the megawatt hours of congestion throughout most of the New England power system will fall from their current levels.\(^1\) Nonetheless, load and generation pockets will endure under SMD. Load pockets will be found in Southwest Connecticut, Northeast

\(^1\) ISO New England, RTEP02, November 2002.
Massachusetts/Boston and Northwest Vermont. The degree of competition and congestion will vary amongst the load pockets, as described later in the report. Transmission congestion is of greatest concern in Southwest Connecticut.

• The impact of Locational Marginal Prices ("LMPs") cannot be predicted with certainty, because unanticipated events, such as the loss of a transmission line or generator during an inopportune period of time, can significantly affect prices. The price impact of congestion is likely to be the greatest in Connecticut because of constraints limiting the amount of power that can be imported into Southwest Connecticut. The NEMA/Boston load pocket has experienced significant congestion in the current market, but that situation should be alleviated before the implementation of SMD. At times, Vermont could experience somewhat higher prices. Because Maine has locked-in generation, LMPs are expected to be lower there.

• Local transmission problems, even in areas that are not load pockets, will cause local LMPs occasionally to diverge from the Hub price.

• Market Power Mitigation rules under SMD should impede the exercise of market power within load pockets.

• SMD and the bilateral market provide complementary tools for managing the risks of congestion. These tools will enable participants to hedge against the increased volatility associated with LMPs.

The following studies were used to prepare this report:

1. **LMP White Paper** – This paper provides a technical overview of how locational prices will be calculated under Standard Market Design. It is attached as Appendix A.

2. **Regional Transmission Expansion Plan** – The Regional Transmission Expansion Plan (RTEP02) report is a planning document that addresses the state of the transmission system in New England, identifies problems and evaluates a wide range of potential solutions in a comprehensive and integrated manner. The goal of the ongoing Regional Transmission Expansion Planning process is a reliable electric system that facilitates the development of a robust market, with due consideration of environmental issues. ISO-NE commenced the RTEP process with the approval of the 66th Agreement amending the Restated NEPOOL Agreement (RNA) in September 2000. In response to recognized needs for the construction or implementation of system improvements, the ongoing RTEP process seeks a “request for solutions” from the marketplace, including generation, merchant transmission facilities, elective upgrades, demand-side management (DSM), and demand-response programs (DRP). In case voluntary projects are insufficient to meet its objectives, the RTEP report also contains a coordinated transmission plan that identifies projects that will do
so. Thus, the RTEP process seeks to integrate market responses with needed reliability enhancements and economic upgrades. RTEP includes projections of the cost impacts of congestion on the entire region and on individual sub-areas. The Executive Summary of RTEP02 is attached as Appendix B.

3. ISO-NE Indicative LMPs – To assist market Participants and other stakeholders in understanding the impact of SMD, ISO-NE currently is calculating hourly Indicative LMPs. They are developed with Day-Ahead market software and based on forecasted system conditions, including load, operating reserve requirements, external transactions, transmission outages and interface limits for the next operating day. Indicative LMPs rely on assumptions, constraints, and procedures that are similar, but not identical, to those that will be used after SMD is implemented, and they are published for informational purposes only. The Indicative LMPs produced thus far show price separation across regions when the system is congested. They are available at http://www.iso-ne.com/smd/indicative-lmp.

4. Market Rule 1, Appendix A – ISO-NE's market monitoring and mitigation plan has been revised to be consistent with the SMD market rules. This section of Market Rule 1 is attached as Appendix D.

5. Christensen Associates’ Study of Transmission Congestion Patterns in New England – The Christensen study was commissioned to investigate traditional patterns of transmission congestion during peak hours within the New England power system, the causes for this congestion, and means for relieving it. The study examines 20 “significantly congested” days during the historical period January 1, 2000 through April 30, 2001. The measure of congestion was the amount of “uplift”, 2 which is related to, but not identical with, congestion under SMD. For these 20 days, the study identifies the most congested facilities and the factors that constrain them, categorizes congestion situations, and quantifies congestion costs by cause and area for a limited number of scenarios. The study did not investigate local transmission constraints or the resulting divergence of the LMPs from a security-constrained dispatch of the system.

The Christensen study also analyzes load pockets, as well as the entire region, to evaluate the short-run effect of SMD on "workable" competition in New England. Christensen et. al. estimate nodal and zonal LMPs for selected conditions during 2003. Finally, the study reviews ISO-NE's congestion management system, including its market monitoring and mitigation processes, compares congestion management methods across the Northeast ISOs, and recommends enhancements to ISO-NE's procedures. The Christensen study is attached as Appendix E.

Drawing on these studies, this report describes the impact that SMD is expected to have on wholesale electricity costs in New England. It identifies the sub-areas of New England that are apt to experience congestion, and provides a qualitative assessment of the likely impact of congestion on wholesale electricity costs.

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2 The Christensen report analyzes the historical period before “Net Commitment Period Compensation” replaced “Uplift”.
Following this Summary, the essential features of the new Standard Market Design are reviewed in Section II. Section III considers the market impacts of the new design. Finally, the recommendations put forth by Christensen et. al.\(^3\) and ISO-NE’s responses are addressed in Section IV.

II. Essential Features of SMD

SMD is a multi-settlement system comprised of two markets: a Day-Ahead market and a Real-Time balancing market. Prices in both markets will be determined as LMPs. The markets are consistent with the spirit of the FERC NOPR that proposes a standard market design across all of the country. The NOPR also calls for a multi-settlement system with bid-based, security-constrained spot markets.

The potential congestion-related benefits of SMD range from improving transmission planning, to alleviating transmission congestion, to providing incentives for generators to locate where they are most needed. Several aspects of SMD allow congestion to be managed financially in a manner that is consistent with the complexities of the physical transmission system. Some of the key features of the SMD congestion management system are LMPs, a financially firm Day-Ahead market, and a market for Financial Transmission Rights (FTRs).

A. Locational Marginal Prices

Under LMP in New England, prices for energy will be calculated at several hundred locations\(^4\), based on generators’ offers, load, and the network’s transmission and operating constraints. LMPs are determined by the cost of serving an increment of load at each location. The LMP methodology uses a security-constrained dispatch that maintains system energy balance and reliability. Since each price reflects the cost of supplying one more increment of load at a given location, it provides a precise, market-based method for valuing energy that includes the cost of congestion.

Each LMP is the sum of three components:

\[
\text{LMP ($/MWh)} = (\text{Energy component} + \text{Loss component}) + \text{Congestion Component}
\]

The energy component is the energy-clearing price in a non-congested system free of losses, and it is the same at all locations. The loss component reflects the marginal cost of system losses at the location, and the congestion component represents the marginal cost of transmission congestion at each location.

The following are key factors determining the magnitude of LMPs:

- Energy offers and unit operating parameters
- Energy demand
- External transactions


\(^4\) From NEPOOL Market Rule 1 (July 2002): “Location” is a Node, External Node, Load Zone or Hub.
• Unit commitment
• Economic dispatch
• Transmission network topology
• Network and reliability constraints
• Reserve requirements

Thus, an LMP reflects the marginal cost of supplying energy at a particular location, including line losses and congestion. If transmission constraints prevent the lowest incremental cost energy in the New England market from flowing to a particular location, price at that location will be determined by the least expensive energy that can be delivered there.

1. Congestion Management and Uplift

To assure that generators recover their as-offered costs, the market rules provide for all generators to be paid their as-offered energy, start-up and no-load costs for all energy generated. If a generator operates in merit, most of its compensation will be from the energy market, unless the energy revenues are insufficient to cover its start-up and no-load costs.

Uplift occurs when a generating unit is dispatched out of merit order (i.e., the unit’s offer price is above the energy-clearing price). This out-of-merit operation may be required to provide cheaper energy in future hours or to assure reliable system operation. The former reason for out-of-merit operation gives rise to energy uplift, while the latter creates transmission or congestion uplift.

In New England’s current single clearing-price, single-settlement system, uplift is the difference between the unit’s offer and the New England market-clearing price. The uplift costs are shared by all load in New England. Under SMD, energy uplift costs will continue to be borne by the entire region. However, congestion uplift payments will now be borne by the reliability region in which they occur.

While LMP will not eliminate the need for certain units to run out of merit order from time to time, it should considerably reduce energy and congestion uplift. Resources that are dispatched to satisfy the energy or reliability needs of a zone would be eligible to set zonal LMP, provided that they meet other eligibility criteria. Thus, the incremental cost of meeting load within a zone affected by transmission congestion likely will be higher than in unconstrained zones. Therefore, the cost of units on-line because of transmission constraints often will be realized as higher LMP, rather than as uplift, thereby reducing uplift from its current levels.

Transmission uplift should also be reduced under SMD because the system will be re-dispatched more efficiently when constraints are in
effect. With ISO-NE's new security-constrained dispatch algorithm, generators will be automatically dispatched above their economic low limit and deemed eligible to set the market-clearing price if they are needed to meet transmission constraints. In the current market, the economic low operating limits of these units must be raised to achieve the proper dispatch, and units at low operating limit are ineligible to set the market-clearing price, thereby creating uplift.

B. Risk Management and SMD

LMP reflects the cost of congestion in the electric power system pricing more accurately than the current market does, thus revealing price risks that now are hidden. The price of power delivered to each location will vary, and will be sensitive to changes in underlying supply or demand conditions at that location, including actual and potential forced outages of generation or transmission facilities. To help participants manage these risks, SMD includes two hedging mechanisms: the Day-Ahead market and FTRs. SMD also supports bilateral arrangements as a third, and perhaps the most effective, hedging mechanism. In fact, experience in the Northeast electricity markets (PJM, NYISO, and ISO-NE) to date indicates that between 70 percent and 80 percent of energy is traded bilaterally, with only 20 percent to 30 percent clearing in the spot markets.

1. Day-Ahead Market

The Day-Ahead market can help participants hedge the risks in the Real-Time market. In most markets, risks increase as the delivery date approaches, as unforeseen events can cause prices to spike or to plummet. This principle should apply to electric power as well, and has been verified by the experience of the New York and PJM markets. The risks related to system contingencies in real time can be managed by using the Day-Ahead market as a hedging mechanism.

2. Financial Transmission Rights and Auction Revenue Rights

A Financial Transmission Right is a financial instrument that entitles the holder to compensation for costs associated with transmission congestion between two locations in the Day-Ahead energy market. When congestion occurs on the NEPOOL transmission system the congestion components of the LMPs differ between the delivery and receipt points. The holder of an FTR is entitled to a share of the resulting congestion revenues.

Once SMD is implemented, FTRs will be awarded and traded in auction markets that embody participants' estimates, as reflected in their bids in the auction, of the differences in spot market prices between locations. Recognizing that load-serving entities (LSEs) have paid for the transmission system, the revenue from the FTR auction will flow back to

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5 As measured by the standard deviation of price, the Real-Time market has shown greater volatility, on average, than the Day-Ahead market in both regions.
them in the form of Auction Revenue Rights. A LSE can bid for the FTRs in the auction, and if it wins, it will be awarded the FTR and the associated auction revenue. Alternatively, if another party bids more for the FTR, the load-serving entity will receive the auction revenues, which will be greater than its original bid for the FTR.

FTRs clear in the Day-Ahead market. Participants without FTRs who purchase energy in the Day-Ahead market are responsible for paying congestion charges. Those who hold FTRs receive the associated congestion costs, if any. If a LSE purchases additional energy in the Real-Time market, it must pay the congestion costs for that energy.

3. Market Monitoring and Mitigation
As in today’s market, monitoring and mitigation rules will be essential to protect load pockets against the exploitation of market power, while preserving market incentives to the fullest extent possible. Overall for most hours, ISO-NE expects workable competition to prevail outside of load pockets. This expectation is confirmed by the Christensen et. al. study. However, analysis suggests that generation ownership within identified load pockets is sufficiently concentrated to warrant market power mitigation rules.

The degree of concentration of ownership in a load pocket is important only when local generation is necessitated by reliability requirements. When transmission constraints do not exist, the concentration of ownership within New England as a whole is the key factor to be monitored.

Thus, several aspects of the congestion management system planned for SMD will influence the cost impact of the new market design. These determinants include the multi-settlement system, locational pricing, additional hedging opportunities, and market monitoring and mitigation rules.

III. Qualitative Assessment Of The Impact Of SMD On Wholesale Electric Prices

A. Background
The New England bulk power system is a relatively unconstrained main system, with a few “load pockets” and “generation pockets.” The flow of energy into a load pocket or out of a generation pocket is restricted by interface constraints caused by thermal, voltage, or stability limits. The frequency with which the restrictions occur determines the amount of congestion – more frequent restrictions mean more congestion.
1. **Locational Marginal Pricing under SMD**

There are three location categories defined in SMD: nodes, zones and a hub. Nodes are points where power is injected or withdrawn from the system. Zones are aggregations of nodes. The hub is a special aggregation of fairly unconstrained nodes that is designed to facilitate trading. By definition, prices at the hub should not be affected significantly by contingencies in one of its constituent nodes. Generation will be priced nodally, while load in a zone will pay a price that is uniform for its zone. This report uses the term “load zone” to refer to the eight zones for which prices for load will be calculated under SMD.

Under SMD, wholesale electricity prices will be calculated separately for each of the eight different load zones shown in Figure 1. These load zones generally follow the political boundaries of the six New England states, except that Massachusetts is sub-divided into three separate load zones. The price at each zone is the megawatt-weighted average of all nodal prices within the zone. Thus, relatively high locational prices at one node in the zone are averaged together with all other nodal prices within the zone to yield a single price for load. This attribute is of particular interest in Connecticut. For pricing under SMD, the entire state is designated as a single load zone; however, prices at southwest Connecticut nodes are likely to be higher than prices in the state as a whole.

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6 Market Rule 1 – NEPOOL Standard Market Design specifies the criteria that the ISO shall use to establish a Hub. (Page 50, Section 2.8).

7 Under SMD, there are two zonal concepts, reliability regions and load zones. Upon implementation of SMD, the reliability regions and load zones will be the same.
Figure 1: Pricing Zones in New England
2. **RTEP Study and RTEP Zones**

To accomplish its objectives, RTEP02 divided New England into a total of 13 sub-areas. These sub-areas had to be defined in order to study certain congested regions, analyze the impact of congestion on costs in those sub-areas, and develop possible solutions for eliminating the congestion.

RTEP estimated the costs of congestion under many different sets of assumptions. It used a transportation model of the transmission system to forecast locational prices in each of the thirteen zones. Each price was multiplied by the MW of load in the zone, yielding an estimate of the total cost of energy in the zone. RTEP evaluated the impact of SMD on electricity costs by comparing cases with assumptions that caused congestion to a case free from transmission constraints. The differences between the constrained and the unconstrained cases also were used to estimate Auction Revenue Rights, and to allocate these revenues back to the LSEs that paid for the congestion.

To assess the full impacts of locational prices, estimates of uplift costs need to be included in both the constrained and the unconstrained cases. These values were not accounted for in the RTEP study.

As detailed in the RTEP02 report, a number of sensitivity analyses examined changes in bid levels, transmission constraints and generation availability. Those results are the basis for the discussions below:

3. **Transmission Constraints and Locational Pricing**

A major aim of SMD is to price congestion by allowing energy prices to vary by location. This structure is designed to send price signals that will provide incentives for generation, demand response, and transmission owners to locate new projects in areas where they are most needed. As transmission constraints are relieved, increased export capability will lead to lower prices in import-constrained regions, while prices in the export-constrained zones may rise somewhat.

The following discussion of load pockets and generation pockets considers the problems in specific load pockets (e.g. Southwest Connecticut). However, because under SMD, pricing will be done by load zone, effects are discussed only for the load zone (e.g. Connecticut).

Appropriately located generation additions, demand response, and transmission will increase the competitiveness of the New England market. First, access to a larger number of competing suppliers helps to enforce market discipline without resorting to administratively applied

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8 Import-constrained zones cannot import sufficient economic energy to meet the load and reserves in the area, and must often rely on more expensive local generation.

9 An export-constrained zone has more economic generation capacity available that can be sent to other regions after the zone's own load is served.
market power remedies. Increased access to energy from lower cost generators or imported power will ensure robust, competitive prices. Additionally, increased competition from strategically located lower-cost units and demand response will benefit much of New England as the transmission grid is utilized more efficiently. In the longer term, increased competition should result in a more efficient energy market with lower costs, all else remaining constant.

B. The Impact of LMP on New England’s Wholesale Electricity Costs

The RTEP02 results indicate that if currently planned generation and transmission projects are completed on schedule, the implementation of LMP pricing will not have a significant impact on average annual wholesale electric costs. Delays in major enhancements to the system, or unforeseen retirements, are likely to cause higher congestion costs.

While the annual costs for the region as a whole are expected to remain about the same under SMD, hourly prices in specific locations may rise or fall quickly when a transmission constraint prohibits the flow of low-cost power into or out of an area. Such effects can be expected not only during periods of high demand, but also when generators or transmission lines unexpectedly go out of service.

1. Indicative LMP Results

Table (1) summarizes the Indicative LMPs that have been calculated by ISO-NE since early September. Price separation occurs when a zonal LMP diverges from the energy component, which is the same for all zones. Price separation is due to differences in the congestion and loss components of the LMP. Marginal losses will cause prices to deviate from one load zone to another in most situations. Analysis of the Indicative LMP data confirms additional price separation in the expected direction when constraints are binding.

10 Indicative LMPs rely on assumptions, constraints, and procedures that are similar, but not identical, to those that will be used after SMD is implemented, and are published for informational purposes only. They are available at http://www.iso-ne.com/smd/indicative-lmp.
Table 1: Average Indicative LMPs

<table>
<thead>
<tr>
<th>Zone</th>
<th>(B) Average LMP ($/MWh)</th>
<th>(C) Average Congestion Component ($/MWh)</th>
<th>(D) % Average Congestion (C/B)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Connecticut</td>
<td>45.62</td>
<td>1.80</td>
<td>3.94%</td>
</tr>
<tr>
<td>Maine</td>
<td>38.23</td>
<td>-3.82</td>
<td>-9.99%</td>
</tr>
<tr>
<td>NEMA/Boston</td>
<td>47.24</td>
<td>3.52</td>
<td>7.46%</td>
</tr>
<tr>
<td>New Hampshire</td>
<td>41.29</td>
<td>-2.70</td>
<td>-6.54%</td>
</tr>
<tr>
<td>Rhode Island</td>
<td>41.79</td>
<td>-1.70</td>
<td>-4.06%</td>
</tr>
<tr>
<td>SEMA</td>
<td>41.98</td>
<td>-1.62</td>
<td>-3.87%</td>
</tr>
<tr>
<td>Vermont</td>
<td>42.55</td>
<td>-1.83</td>
<td>-4.31%</td>
</tr>
<tr>
<td>WCMA</td>
<td>42.18</td>
<td>-1.61</td>
<td>-3.81%</td>
</tr>
<tr>
<td>Hub</td>
<td>41.38</td>
<td>-2.05</td>
<td>-4.95%</td>
</tr>
<tr>
<td>Grand Total</td>
<td>42.47</td>
<td>-1.11</td>
<td>-2.62%</td>
</tr>
</tbody>
</table>

a. Connecticut

The congestion component for Connecticut was almost 4 percent of the zone’s average LMP, and 10 percent above the average hub price. Most of the congestion in Connecticut occurs in Southwest Connecticut.

b. NEMA/Boston

During this period, the NEMA/Boston zone experienced the highest congestion costs across the zones. Prices for NEMA/Boston were higher than the hub price when import limits into the zone were binding. The congestion component was about 7.5 percent of the zone's average LMP. The Indicative LMPs are consistent with the significant transmission congestion that this zone has experienced in recent years. In the current market, this load pocket has been responsible for over half of the congestion uplift. These results emphasize the importance of the generation and transmission projects planned for NEMA/Boston. The transmission enhancements and generation projects planned for NEMA/Boston will noticeably diminish the frequency of binding transmission import limits, alleviate congestion, and reduce the likelihood that LMPs in NEMA/Boston will be higher than those in the rest of New England.

c. Vermont

On average during this period, Vermont’s LMPs were above the hub price. Vermont’s Indicative LMPs tend to be higher than the hub price when the Merrimack line is constrained, but below the hub price when the Boston and North/South lines are constrained.
d. Generation Pockets

In export-constrained zones, average LMPs tend to be lower than the hub price. Congestion costs are a larger share of the LMP in export-constrained locations than for the hub. For example, the congestion component is nearly 10 percent of Maine’s average LMP, and it drives the zonal LMP 7.5 percent below the average Hub price.

In the single-settlement system, owners of resources in generation pockets have incentives to bid below their marginal costs because they receive the region-wide clearing price. The incentives to bid below marginal cost or to self-schedule will diminish under SMD because the generators will receive the local clearing price.

2. RTEP Analysis of the Cost Impacts of LMP

Not surprisingly, the impacts of implementing Locational Marginal Pricing will vary by region. Connecticut will experience the largest increase in power costs, with potential small increases in costs in NEMA/Boston and Vermont. Much of the region will experience little change in power costs, while slight decreases are likely in Maine and SEMA/RI. If load is higher than forecast, if planned generation or transmission improvements are not constructed, if significant unplanned retirements occur, or if outages of generation or transmission lines occur at inopportune times, the impact of congestion could be noticeably greater. For example, the RTEP base case assumes that 1850 MW can be imported into Southwest Connecticut. If this limit were to drop to 1700 MW, then congestion impacts on Connecticut would be substantial.

a. Connecticut

RTEP02 shows that SMD is expected to have the greatest impact on the Connecticut load zone. Most of the congestion in Connecticut will occur in Southwest Connecticut and the Norwalk-Stamford area.

Short-term impacts. The RTEP study base case suggests that in 2003, implementation of LMP pricing in Connecticut will result in higher wholesale power costs in the state. Nearly all of the increase can be attributed to the Southwest Connecticut load pocket. These results are consistent with the Indicative LMPs.

Longer-term impacts: In the longer term, higher prices in Connecticut will continue until the planned transmission upgrades are built or additional generation or demand response is implemented.

Sensitivities: Figure 2 shows the sensitivity of total congestion costs in New England to load growth in the Southwest Connecticut load zone. It suggests that changes in load in this sub-area can have a major
impact on congestion costs in New England. For example, if loads in Southwest Connecticut grow by 5 percent more than forecast, then congestion costs will double for all of New England. Load growth can be used to represent other contingencies as well; e.g. a reduction in import capability into Southwest Connecticut for any reason would have an impact similar to an equivalent increase in load. While the figure depicts the impact for all of New England, much of the cost increase will occur in Connecticut.

**Figure 2: Connecticut Pricing Zone**

![Impact of SW-CT Load Growth on Congestion Costs in New England, 2003](image)

b. **NEMA/Boston**

The NEMA/Boston load zone has experienced significant transmission congestion in recent years. In fact, NEMA/Boston has been responsible for over half of the congestion uplift in the current market. Planned transmission upgrades and generation projects contemporaneous with SMD should significantly reduce the amount of congestion in NEMA/Boston.

**Short-term impacts** – The planned transmission enhancements and generation projects will noticeably reduce the frequency with which transmission import limits bind, alleviate congestion, and reduce the likelihood that NEMA/Boston LMPs will be greater than those in the rest of New England. However, specific units may need to run out of merit order occasionally to provide local voltage and power distribution support for the Boston transmission network. This out of
merit operation should not affect LMPs, but will create uplift, which could be charged either to the NEMA/Boston region or the entire New England region, depending on the cause.

**Long-term impacts** – In the longer term, the ongoing improvements to the electric system in NEMA/Boston, which are under development, will reduce the likelihood that congestion will cause LMPs in NEMA/Boston from becoming greater than those in the rest of New England. The design of the improvements should also reduce uplift further.

**Sensitivities** – Figure 3 shows the sensitivity of total congestion costs in New England to load growth in the NEMA/Boston load zone, and it suggests that large changes in load in this sub-area can have a major impact on congestion costs. Again, load growth can be used to represent other contingencies; e.g. a reduction in import capability into NEMA/Boston, or outages of key generating units under heavy load conditions, would have an impact similar to an equivalent increase in the peak load. Higher rates of load growth (or other equivalent changes in conditions in the load zone) could cause total congestion costs for New England to rise steeply. Assuming existing import capability and on-time adoption of planned enhancements to the system, load growth in NEMA/Boston will not noticeably increase total congestion costs for New England as long as that growth is below about 20 percent.
c. Vermont

The Vermont load zone experienced some uplift during the period analyzed. RTEP found that Vermont has local transmission reliability and security problems, with only a limited amount of generation available to replace transmission capability in the event of major contingencies. For example, the largest sources of power to Northwestern Vermont are (1) the PV20 phase shifter that controls power imports from New York, and (2) the Highgate Converter. The loss of either of these facilities at inopportune times could cause a violation of established reliability standards.

The RTEP02 study did not assess the impact of local transmission constraints in sub-areas of Vermont on the zone’s total electricity costs under SMD. However, additional analysis by the ISO-NE planning group shows that congestion costs in localized areas of Vermont could be significant when loads reach levels forecast for the year 2006.

**Short-term impacts** – The implementation of LMP is not expected to change Vermont’s annual electricity costs significantly. However, occasional price separation may lead to higher prices at certain locations in Vermont.
Long-term impacts – Analysis conducted by the ISO Planning Department subsequent to the RTEP02 study indicates that as load grows in the coming years, congestion in Vermont could become significant over the summer months when load reaches levels currently forecast for the year 2006.

Sensitivities: The Northwestern Vermont area has many risk factors that could lead to remarkably volatile prices. The effect of these factors on wholesale power costs is currently under investigation. RTEP02 did not analyze these costs.

3. The Impact of LMP on Sub-Area Generation Pockets

The Maine, Southeastern Massachusetts, and Rhode Island zones are subject to export constraints. When these zones are constrained, the supply of generation effectively increases, potentially driving down the LMP relative to the hub price. Costs in these constrained-in zones are expected to decrease slightly upon implementation of SMD, because the marginal unit in Maine is likely to have lower costs than the marginal unit in the rest of the system.

IV. Conclusions and Recommendations from the Christensen Study

The study by Christensen et. al. notes that [p. 1-4] New England’s proposed SMD:

- Is consistent with neighboring northeastern markets
- Contains the features of a sound management plan
- Makes significant steps toward improving the overall efficiency of New England’s wholesale power markets
- Moves the market toward increased competitiveness
- Promises to benefit both wholesale and retail electricity customers.

The study also made several recommendations that are summarized below. ISO-NE generally supports these recommendations, with some exceptions, as noted. Implementation of the suggestions must be consistent with FERC policy, and made in consultation with representatives of interested stakeholders, including NEPOOL and the public utility commissions. Any program changes also are subject to prioritization, as well as an evaluation of the costs of instituting them.

- Nodal pricing of loads – The ISO agrees with this recommendation.
- Locational pricing of reserves – The ISO agrees that locational reserves are desirable.

11 Power Technology, Inc. SCED model was used to analyze the system.
• **Revision of the uplift charge policies under SMD** – This policy currently is under review.

• **Re-consider offering transmission rights to purchasers as a choice of options or obligations** – The ISO believes that transmission rights options are desirable, as underscored by the FERC in its July 31 2002 SMD NOPR (¶ 245).

• **Expand demand response programs** – The ISO is in the process of expanding these programs.

• **The use of “rational” price caps instead of hard price caps** – Price caps are a FERC policy issue. ISO-NE presently has no plans to recommend changes to the current price caps.