STATE OF CONNECTICUT

POWER PROCUREMENT PLAN FOR STANDARD SERVICE

Submitted to:

Public Utilities Regulatory Authority

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Section 16-244m of the Connecticut General Statutes instructs the Procurement Manager to develop a Power Procurement Plan in consultation with Connecticut's electric distribution companies and other stakeholders. While this plan is the responsibility of the Procurement Manager and was prepared under my direction, a working group was put together early in the process that provided invaluable insight and information that was vital to the creation of Connecticut's first Power Procurement Plan. As Power Procurement Manager I would like to acknowledge and thank the following members of the working group:

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Connecticut Light & Power's Procurement Team led by Jim Shuckerow

United Illuminating's Procurement Team led by Alan Trotta

Office of Consumer Counsel represented by David Thompson

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AEC – Atlantic City Electric Co.

ACP – Alternative Compliance Payment

AIC – Ameren Illinois Co.

AGT Citygates – Algonquin Citygates

AIM – Algonquin Incremental Market

APM – Active Portfolio Management

BEF – Block Energy Forward

BFMCC – Bypassable Federally Mandated Congestion Charge

BGE – Baltimore Gas & Electric Co.

BGS – Basic Generation Service

BGS-FP – BGS – Fixed Price

BGS-CIEP – BGS – Commercial and Industrial Energy Pricing

BHE – Bangor Hydro Electric Co.

CCRP – Central Connecticut Reliability Project

CDS – Credit Default Swap

CfD – Contract for Differences

CFTC – Commodities Futures Trading Commission

CHG&E – Central Hudson Gas and Electric

C&I – Commercial and Industrial

C&LM – Conservation and Load Management

CL&P – The Connecticut Light & Power Company

CMEEC – Connecticut Municipal Electrical Energy Cooperative

CMP – Central Maine Power Co.

ComEd – Commonwealth Edison Company

ConEd – Consolidated Edison Company

CPUC – California Public Utilities Commission

CRT – Customer Risk Tolerance

CT Load Zone – Connecticut Load Zone

CY – Calendar Year

DAM – Day-Ahead Market

DCA – Descending Clock Auction

DEEP – Department of Energy and Environmental Protection

DLC – Duquesne Light Co.

DPL – Delmarva Power and Light Co.

DPU – Massachusetts Department of Public Utilities

DSP – Default Service Plan

EDC – Electric Distribution Company

EE/DR – Energy Efficiency and Demand Response

EEI – Edison Electric Institute

E&P – Exploration and Production

FAP – Financial Assurance Program

FCA – Forward Capacity Auction

FCM – Forward Capacity Market

FERC – Federal Energy Regulatory Commission

FGE – Fitchburg Gas & Electric Light Company

FRS – Full Requirements Service

FTR – Financial Transmission Right

GSC – Generation Service Charge

GSRP – Greater Springfield Reliability Project

IBT – Internal Bilateral Transaction

ICAP – Installed Capacity

ICE – Intercontinental Exchange, Inc.

IPA – Illinois Power Agency

IRP – Integrated Resource Plan

ISO – Independent System Operator

ISO-NE – Independent System Operator - New England

ISDA – International Swaps and Derivatives Association, Inc.

JCPL – Jersey Central Power & Light Co.

LAI – Levitan & Associates, Inc.

LFRM – Locational Forward Reserve Market

LMP – Locational Marginal Price

LNG – Liquefied Natural Gas

LOC – Letter of Credit

LREC – Low Emission Renewable Energy Credit

LRS – Last Resort Service

LSE – Load Serving Entity

LSR – Local Sourcing Requirement

MDPSC – Maryland Public Service Commission

MetEd – Metropolitan Edison Co.

MHR – Market Heat Rate

MISO – Midwest Independent System Operator

MMWEC – Massachusetts Municipal Wholesale Electric Cooperative

MPPSA – Master Power Purchase and Supply Agreement

MPS – Maine Public Service Co.

MPUC – Maine Public Utilities Commission

MtM – Mark-to-Market

NCPC – Net Commitment Period Compensation

NEEWS – New England East West Solution

NGL – Natural Gas Liquids

NGrid – National Grid

NHEC – New Hampshire Electric Cooperative

NHPUC – New Hampshire Public Utilities Commission

NITS – Network Integrated Transmission Service

NOI – Notice of Interest

NU – Northeast Utilities

NUSCO – Northeast Utilities Service Co.

NYISO – New York Independent System Operator

NYMEX – New York Mercantile Exchange

NYPSC – New York Public Service Commission

NYSEG – New York State Electric & Gas Corp.

NYSERDA – New York State Energy Research & Development Authority

OATT – Open Access Transmission Tariff

OCC – Connecticut Office of Consumer Counsel

O&R – Orange & Rockland Utilities

OTC – Over-the-Counter

PA – Public Act

PAPUC – Pennsylvania Public Utilities Commission

PECO – PECO Energy Company

Penelec – Pennsylvania Electric Company

Pepco – Potomac Electric Power Company

PHI – Pepco Holdings, Inc.

PJM – PJM Interconnection

PE – Potomac Edison

PPA – Power Purchase Agreement

PPL – Pennsylvania Power and Light

PSE&G – Public Service Electric & Gas

PSNH – Public Service Company of New Hampshire

PURA – Connecticut Public Utilities Regulatory Authority

REC – Renewable Energy Credit or Renewable Energy Certificate

RECO – Rockland Electric Company

RFP – Request for Proposals

RG&E – Rochester Gas and Electric

RIPUC – Rhode Island Public Utilities Commission

RPM – Reliability Pricing Model

RPS – Renewable Portfolio Standard

RTM – Real-Time Market

RTO – Regional Transmission Organization

SEC – Securities and Exchange Commission

SMA – Supply Master Agreement

SOS – Standard Offer Service

TGP Z6 – Tennessee Zone 6

TVaR – Tail Value at Risk

UGI – UGI Utilities, Inc.

UI – The United Illuminating Co.

VaR – Value at Risk

VIX – Volatility Index

VRM – Volumetric Risk Mitigation

WMECO – Western Massachusetts Electric Co.

WP – West Penn Power

ZREC – Zero Emission Renewable Energy Credit

1.0 INTRODUCTION

In 2011, the Connecticut Legislature passed comprehensive energy legislation, Public Act (PA) 11-80, "An Act Concerning the Establishment of the Department of Energy and Environmental Protection and Planning for Connecticut's Energy Future." Among other provisions, PA 11-80 created the position of Procurement Manager within the Department of Energy and Environmental Protection (DEEP). The Procurement Manager has the responsibility to manage the procurement of electricity for the Standard Service customers of the two investor-owned electric distribution companies (EDCs) in Connecticut: The United Illuminating Company (UI) and The Connecticut Light & Power Company (CL&P). Standard Service is the default electric service that the EDCs furnish on behalf of their customers, primarily residential and small commercial and industrial (C&I), who have a maximum demand of less than 500 kW, do not use demand meters, and have not selected an alternative retail supplier.

Section 92 of PA 11-80, now codified at Connecticut General Statutes (Conn. Gen. Stat.) §16-244m, directs the Procurement Manager to "develop a plan for the procurement of electric generation services and related wholesale electricity market products" in consultation with each EDC and with others at the Procurement Manager's discretion. To that end, the Procurement Manager convened a Working Group comprised of representatives from UI, CL&P, the Office of Consumer Counsel (OCC) and the consultant to the Public Utilities Regulatory Authority (PURA, formerly the Department of Public Utility Control), Levitan & Associates, Inc. (LAI). The Procurement Manager also consulted with the Attorney General's office, a representative of the Connecticut Municipal Electrical Energy Cooperative (CMEEC) and representatives of a number of other state regulatory agencies.

This Power Procurement Plan is intended to fulfill the requirements of Section 92 of PA 11-80 and Conn. Gen. Stat. §16-244m The specific Standard Service procurement plans for UI and CL&P are presented in Sections 10.2.1 and 10.2.2, respectively. In support of the recommended procurement design, Section 3.0 provides background information on the legislative history and procurement practices to date. Section 4.0 defines the components of wholesale power supply for Standard Service. Section 5.0 provides the context for wholesale procurement with respect to the natural gas and power markets in New England, as well as an outlook on future market dynamics. Sections 6.0 and 7.0 include an analysis of historic bid information and Standard Service load data, respectively.

This analysis of historic data identified opportunities for potential savings for Standard Service customers, and informed the Procurement Manager's recommended plan. Section 8.0 describes the array of energy products that are available to manage a Standard Service portfolio, considers risk management approaches, and explains the inherent trade-offs between price stability and cost minimization. Section 9.0 presents a comparison of default service procurement approaches adopted in other states where retail choice has been implemented. Wholesale procurement by several municipal electric cooperatives is also covered. Section 9.0 assesses other important procurement design considerations. Finally, Section 10.3 identifies the Procurement Manager's proposed process for regulatory review and approval, and treatment of confidential information.

This Power Procurement Plan does not address any update to the mechanism or timing for establishing retail Standard Service rates. It is the Procurement Manager's intention to address this important aspect of Standard Service in a subsequent update to this plan. Section 92 of PA 11-80 now codified at Conn. Gen. Stat. §16-244m(b) requires the Procurement Manager to meet at least quarterly with the Commissioner of DEEP and prepare a written report on the implementation of the plan. This quarterly update affords the Procurement Manager an opportunity to augment this plan and identify potential process improvements that are revealed during its implementation. Updates to the Power Procurement Plan will also accommodate future market and/or State policy changes.

2.0 EXECUTIVE SUMMARY

2.1 Background

UI and CL&P purchase wholesale electric generation services to furnish electric supplies for their Standard Service-eligible customers who do not contract with a competitive retail supplier. Under the statute enacted by the Connecticut Legislature in 2003,[1] the EDCs were obligated to procure a portfolio of wholesale electric supply contracts for Standard Service "in an overlapping pattern of fixed periods at such times and in such manner and duration as the department determines to be most likely to produce just, reasonable, and reasonably stable retail rates while reflecting the underlying wholesale market price over time." This language established the principle of "laddering" for wholesale Standard Service supply contracts in order to promote rate stability for customers. The governing decision in 2006 by PURA also mandated that the laddered contracts be for full requirements service and not exceed a term of three years.[2]

Since mid-2006 for Standard Service commencing in January 2007, the EDCs have entered into fixed price contracts in a laddered pattern, up to three years forward.[3] All contracts have been for full requirements service, thereby shifting daily and hourly supply management responsibility to the wholesale supplier, and requiring that the wholesale supplier provide all of the products needed to serve Standard Service load. The component products of full requirements service include load-following energy supply delivered to the Connecticut (CT) Load Zone, capacity as required by ISO-NE rules, other ISO-NE charges, including uplift and ancillary services, and Renewable Portfolio Standard (RPS) requirements. For both EDCs, a contract awarded to a supplier represents a 10% tranche or "slice" across all customer classes within the Standard Service load.

In contracting for full requirements service, the EDC transfers the load asset to the supplier. The supplier assumes all the obligations of a Load Serving Entity (LSE) for its *pro rata* share of the Standard Service load. The supplier is responsible for the daily bidding and scheduling of the load asset with ISO-NE. Under a *fixed price* full requirements contract, the EDC also transfers to the supplier the market and quantity risk associated with serving the load asset. The supplier is paid the contract price for every MWh, regardless of the actual wholesale price in the spot energy market administered by ISO-NE or the actual customer load relative to the supplier's expectation upon contract award. Since each contract is a fixed percentage slice or tranche of Standard Service load, suppliers also bear migration risk, *i.e.*, the risk that the awarded load may shrink or grow as customers switch to competitive retail service providers or return to Standard Service.

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[1] Public Act 03-135

[2] June 21, 2006 Decision in Docket No. 06-01-08PH01

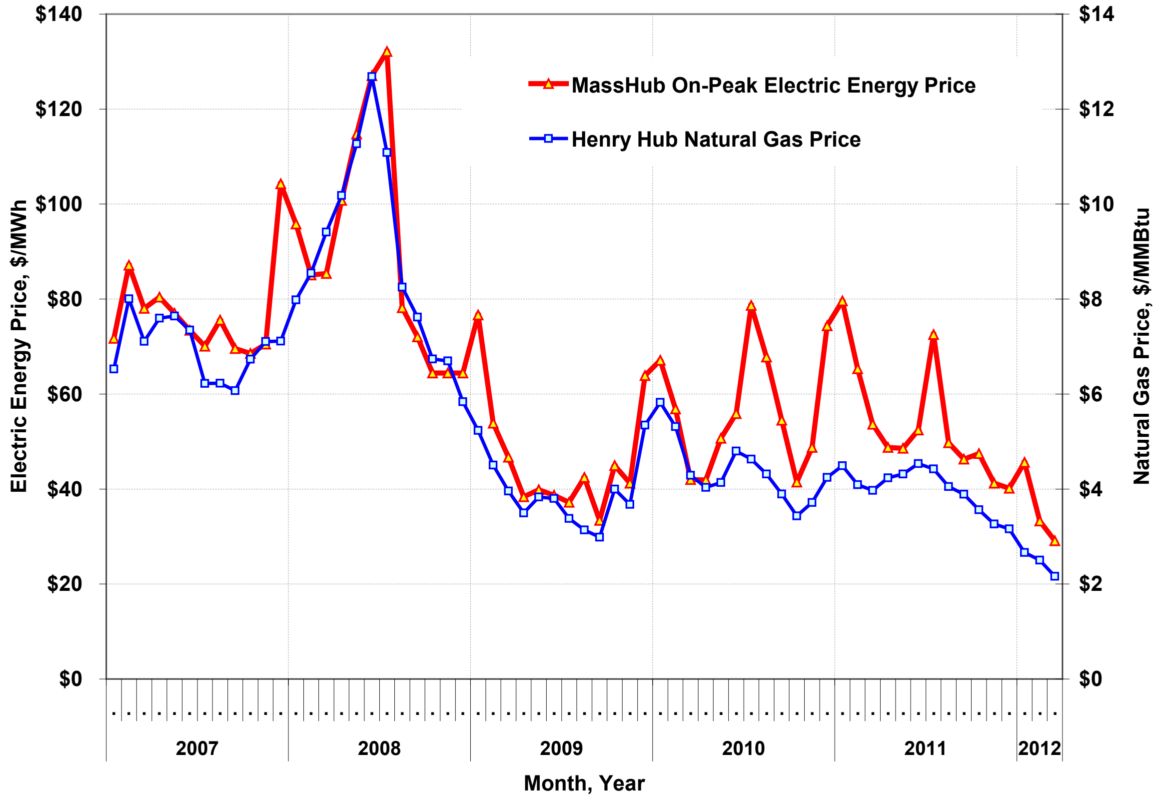
[3] UI has generally procured Standard Service contracts quarterly, whereas CL&P has procured contracts twice each year.

Suppliers mitigate these risks by purchasing a portfolio of hedge products, such as energy futures and options. The incremental cost of risk management is included in the fixed price full requirements service contract. Thus, relying on laddered, fixed price full requirements service contracts promotes retail rate stability for customers, but does so at added cost. This is because fixed price full requirements service incorporates a risk premium ascribable to the transference of market and quantity risk to the suppliers. Analysis of the cost to provide full requirements service as well as historic bid data results in two key observations: first, based on recent supplier pricing patterns, the cost to manage risk, related administrative and credit costs and supplier's profit margin is *roughly* 8% of the total cost;[4] and, second, the size of the risk-management and credit cost components of Standard Service depends on the amount of time between the contract award and the commencement of delivery. This second observation supports the conclusion that a significant portion of the risk-management and credit cost components can be avoided when the service term begins less than 12 months following the contract award date.

As shown in Figure 1, the run-up in wholesale energy prices from 2006 through mid-2008 is explained largely by the high cost of natural gas delivered to New England, the single largest determinant of wholesale spot market prices throughout New England. In Figure 1, the monthly average cost of natural gas "into-the-pipe" at the Henry Hub, Louisiana, is shown from 2007 through May 2012, alongside wholesale power prices at the Massachusetts hub (MassHub), the primary trading point for wholesale power in New England. The financial crisis that began in 2008 coupled with a "sea change" in the natural gas industry related to the production of shale gas across North America has fundamentally altered suppliers' expectations about the cost of producing natural gas for the remainder of this decade. Reflecting abundant shale gas production from the Marcellus basin in western Pennsylvania and West Virginia, wholesale energy prices in New England have steadily declined since mid-2008, decreasing from a high of \$132/MWh in mid-2008 to a low of \$29/MWh at the end of 1Q2012, a price level not observed in New England for over a decade. The favorable production outlook from Marcellus along with new pipeline infrastructure to the greater Northeast is expected to temper any significant run-up in wholesale energy prices and corresponding price volatility over *at least* the next few years.

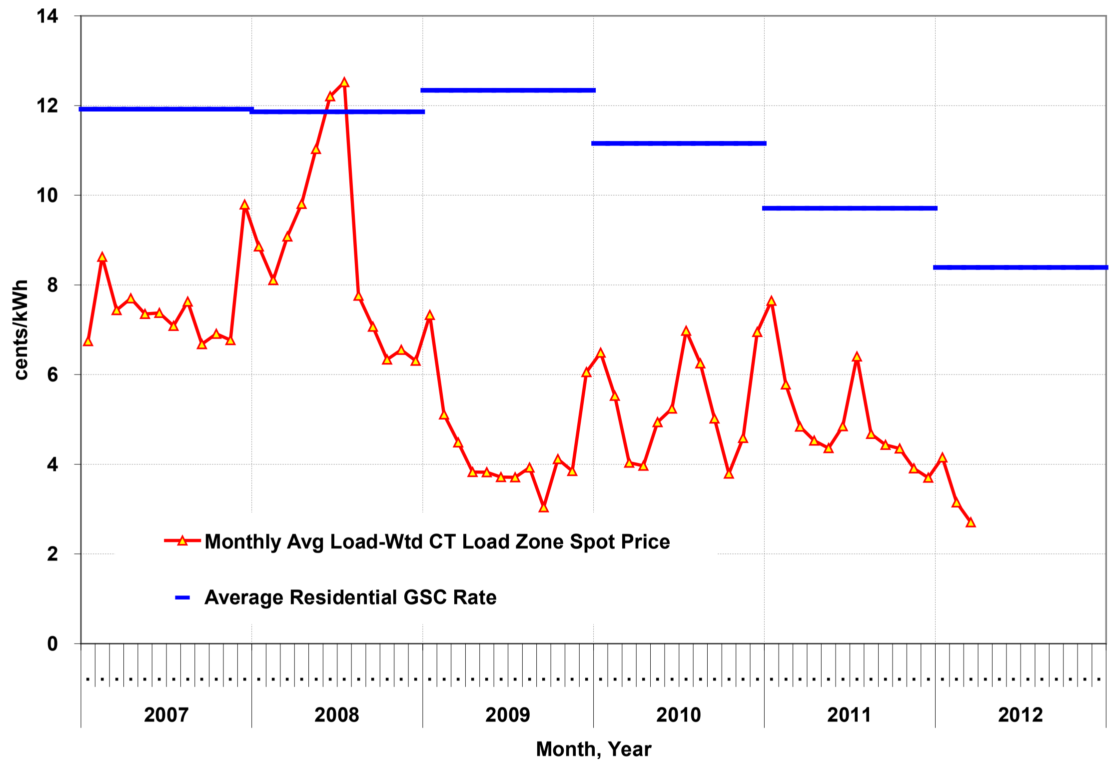
[4] The actual cost for these components varies from supplier to supplier and is also a function of the market prices.

Figure 1. Natural Gas at Henry Hub and On-Peak Electric Energy at MassHub (Monthly Average Prices)



The procurement approach set forth by the Connecticut legislature in 2003 and further prescribed by PURA's 2006 decision was designed to stabilize rates for the residential and small C&I customers who comprise the majority of the Standard Service load. When initial Standard Service procurements began in 2006 to mid-2008, laddering indeed mitigated the sharp rise in spot wholesale market prices, and, correspondingly, forward energy markets, as shown by the trends illustrated in Figure 2. Since the market peak in mid-2008, both market prices and Standard Service rates have fallen. However, Standard Service rates have lagged behind the downward trend in wholesale prices, reflecting the expiry profiles of the laddered contracts that were part of each EDC's portfolio to serve Standard Service customers. **Importantly, note that the CT Load Zone Spot price shown in Figure 2 reflects *only* the market energy component, whereas the EDCs' retail generation services charge (GSC) rates include *all* of the other components of full requirements service.**

Figure 2. Comparison of Trends: Connecticut Standard Service Retail GSC Rates and Spot Market Energy Prices



PA 11-80 has paved the way for innovations that are designed to provide Connecticut's EDCs with an expanded arsenal of wholesale products and procurement methods to provide value for Standard Service customers. Consistent with Conn. Gen. Stat. §16-244c as amended by PA 11-80, the Procurement Manager has developed this Power Procurement Plan in consultation with the EDCs and other stakeholders. Emphasis has been placed on recognition of the products and procurement methods that have worked well to date in regard to achieving sensible tradeoffs between cost minimization and rate stability objectives, as well as delineation of new products and procurement approaches to produce additional cost savings beginning as early as 2013. One approach to achieving additional cost savings relates to the EDC's potential self-management of a portion of the Standard Service portfolio. Whereas procurement of full requirements service under the traditional approach has transferred the LSE responsibility to wholesale suppliers, a self-management approach would require an EDC to assume the LSE role.

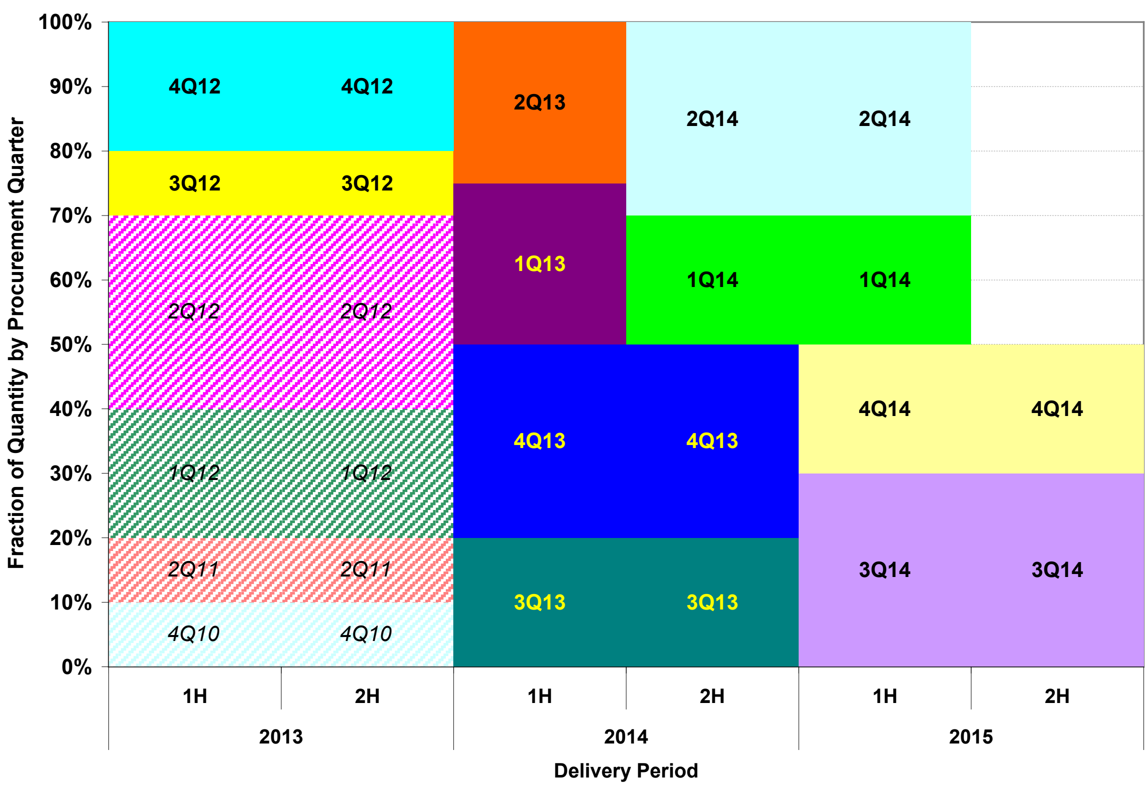
Specific highlights and recommendations for UI and CL&P follow.

2.2 Power Procurement Plan for UI

UI currently has 70% of its Standard Service supplies for 2013 already procured. For the remaining 30%, UI will continue to procure full requirements service in accord with its usual practice, thereby transferring LSE responsibility to the wholesale suppliers. At this time, UI does not have available manpower resources or infrastructure to assume the LSE responsibility without redeploying personnel from other required power supply-related business activities. The opportunity cost of such potential management redeployment is expected to be high in relation to the potential economic benefits associated with the LSE responsibility. In light of UI's relatively small Standard Service load, potential continued migration of customers to competitive retail suppliers, and UI's resource constraints, UI is unlikely to achieve the same portfolio benefit that is available through its wholesale suppliers. Simply put, the incremental cost for UI to add the requisite manpower resources, credit facilities, infrastructure, and risk management procedures to effectuate the LSE role for Standard Service is likely to exceed the expected benefits achievable through self-managing a portion of the Standard Service portfolio.

Benefits for customers may be derived by modifying the schedule of the laddering and the contract terms for 2013 and future years. Shortening the time to delivery is expected to reduce costs to customers. Once the transition to the new design is fully implemented, 12-month contracts for 10% tranches will be procured quarterly, creating a portfolio of overlapping service terms, with the start of delivery not exceeding six months from bid day. As indicated in Figure 3, shorter contract terms and, potentially, larger tranche sizes may be procured for 2014 to accommodate the transition. The Procurement Manager, in consultation with UI, may revise the number of tranches per service term (or the percentage of load per tranche) in the future if the total Standard Service load changes significantly due to migration or reverse migration. This procurement design maintains flexibility insofar as it allows for the selection or rejection of discretionary tranches.

Figure 3. UI Target Laddering Schedule



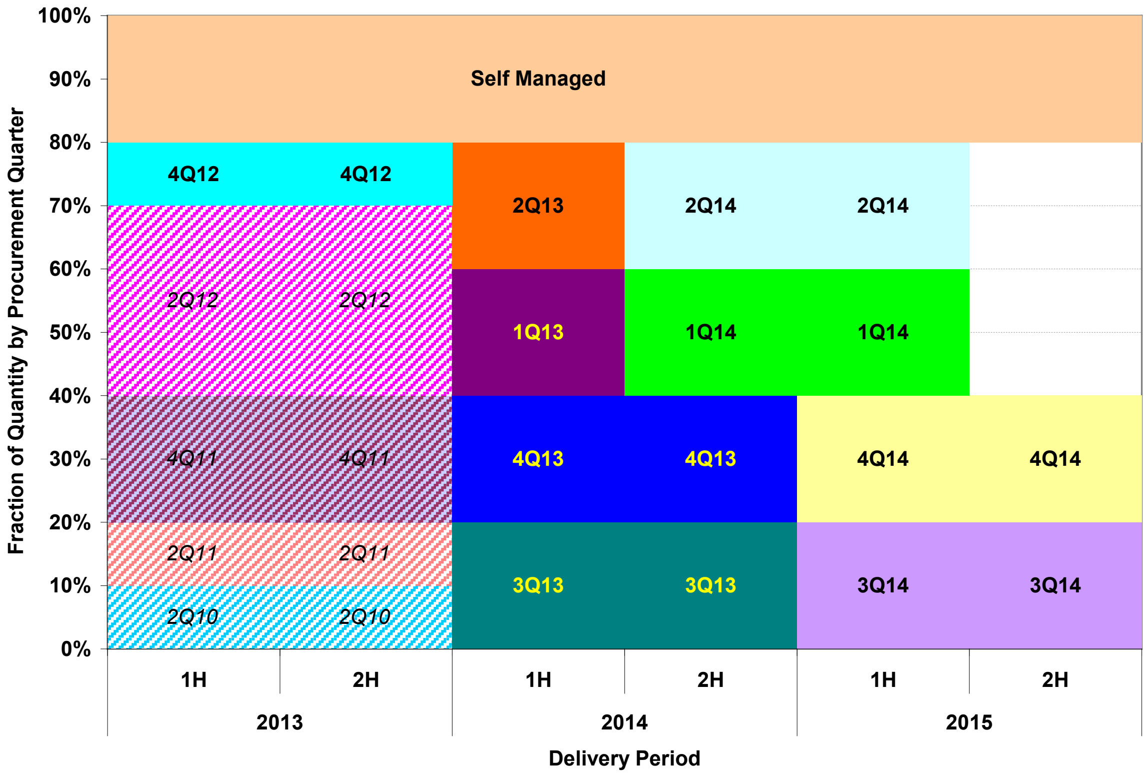
Full requirements service will continue to be solicited by UI through sealed-bid RFPs. On bid day, the Procurement Manager, UI, and the OCC will each receive copies of the bids. Consistent with the current practice, each recipient will independently evaluate the bids. UI and the OCC will each present to the Procurement Manager their respective recommendation(s) as to the selected contracts. On bid day, the Procurement Manager will issue a decision as to the winning bidders, and prepare written documentation of his decision. Provided that the approved contracts are consistent with the PURA-approved Power Procurement Plan, the Procurement Manager's approval will authorize UI to enter into binding agreements with the selected suppliers. The day after bid day, the Procurement Manager, UI, and the OCC will participate in a technical meeting before PURA to document the basis for decision.

2.3 Power Procurement Plan for CL&P

CL&P currently has 70% of Standard Service supplies for 2013 procured. CL&P, through its corporate service company, Northeast Utilities Service Company (NUSCO), has the requisite manpower resources, information technology, and the credit and risk management policies and procedures to assume the LSE responsibility. Hence, this Power Procurement Plan authorizes CL&P to self-manage 20% of its remaining 2013 Standard Service load, in other words, two of the remaining three slices for 2013. The remaining 10% slice for 2013 will be procured as full requirements service. While the initial limit for the self-managed portfolio is 20% of CL&P's Standard Service load for 2013, the Procurement Manager may increase or decrease the 20% target based on the performance of the self-management portfolio. In accord with past practices, the portfolio for that portion of Standard Service load that is not self-managed will be procured in the same manner as described for UI.

Figure 4 illustrates a potential procurement schedule assuming that CL&P self-manages 20% of its Standard Service load in 2013 and beyond.

Figure 4. CL&P Target Laddering Schedule with Self-Managed Slices (LSE Responsibility)



CL&P will submit a portfolio management plan to the Procurement Manager for review and approval. CL&P's portfolio management plan will identify the mix and types of physical and financial products to be procured, and will inform the Procurement Manager about the composition and expected performance of the portfolio. The portfolio management plan will also quantify downside and upside sensitivity cases oriented around a scenario-based risk analysis. If the portfolio management plan is approved by the Procurement Manager, the Procurement Manager, the OCC, and CL&P will participate in a technical meeting before PURA to inform the PURA of the decision and to document any condition(s) of the approval.

CL&P will provide monthly project control reports to the Procurement Manager that track the actual performance of the self-managed portfolio relative to the expected performance of the portfolio over the service term. The monthly report will also forecast the expected cost of the portfolio through the end of 2013 relative to the outlook presented in the portfolio management plan. If a proposed transaction falls outside of guidelines established in the approved portfolio management plan, the transaction will require the approval of the Procurement Manager in addition to any approvals required in accordance with CL&P's internal policies and procedures. For all other transactions, such prior approval by the Procurement Manager will not be required, but the Procurement Manager shall be routinely notified by telephone or e-mail and in the monthly project control reports regarding the array of physical and financial products entered into by CL&P to self-manage the portfolio.

The approval process for full requirements service contract(s) procured by CL&P will be the same as for UI, described above.

3.0 BACKGROUND

3.1 Legislative and Regulatory History

In 1998, Connecticut adopted PA 98-28, "An Act Concerning Electric Restructuring," opening the State's retail electric industry to competition. Among other things, the legislation required PURA and the State's two EDCs, UI and CL&P, to take steps to establish a competitive electric market. In preparation for the start of retail competition on July 1, 2000, the EDCs unbundled the generation component from the transmission and distribution components of retail electric service, and began offering Standard Offer Service to customers who did not choose an alternative retail supplier for generation service. To serve its customers who continued to rely on the EDC for generation service, each EDC entered into contracts with wholesale suppliers. The legislation capped the GSC rate for Standard Offer Service at 10% below the rates that the EDCs had charged on December 31, 1996.

Following the enactment of PA 03-135, "An Act Concerning Revisions to the Electric Restructuring Legislation," Standard Offer Service expired on December 31, 2003. Standard Offer Service was superseded by Transitional Standard Offer service, which in turn, was replaced by Standard Service and Last Resort Service (LRS), commencing on January 1, 2007. In accordance with §16-244c of the General Statutes of Connecticut (Conn. Gen. Stat.), the EDCs are obligated to provide Standard Service to customers with a maximum demand of less than 500 kW, who do not use demand meters, and who have not selected an alternative retail supplier. The statute also requires that on and after January 1, 2007, the EDCs must provide LRS to customers who are not eligible for Standard Service and have not selected an alternative retail supplier. Conn. Gen. Stat. §16-244c, as amended by PA 03-135, mandated that for Standard Service "the portfolio of service contracts be procured in an overlapping pattern of fixed periods at such times and in such manner and duration as the department determines to be most likely to produce just, reasonable, and reasonably stable retail rates while reflecting the underlying wholesale market price over time." This statutory language established the principle of "laddering" of Standard Service supply contracts. In its June 21, 2006 decision in Docket No. 06-01-08PH01, PURA approved a procurement plan for Standard Service and LRS, and set forth seven principles intended to produce a fair Request for Proposals (RFP) process that results in beneficial rates for customers. The decision specified that Standard Service must be procured as laddered full requirements service contracts, and limited the contract terms to no longer than three years.

In June 2007, the Connecticut General Assembly passed PA 07-242, "An Act Concerning Electricity and Energy Efficiency," which included several provisions that affected the Standard Service procurement process. Section 92, which was codified in Conn. Gen. Stat. §16-244c(n), allowed the EDCs to enter into bilateral arrangements with electric generating facilities for Standard Service, including individual components of Standard Service. At that time, the Legislature perceived that there may be opportunities to reduce rates for customers or provide greater rate stability through bilateral contracts outside of the full requirements procurement process. Section 104 of PA 07-242 directed PURA to examine the feasibility and potential risks associated with pursuing different Standard

Service procurement options, including procuring components of Standard Service directly from a wholesale supplier or one or more generating facilities, as well as procuring physical and financial hedges to manage Standard Service prices. PURA initiated a proceeding in Docket Nos. 06-01-08RE01 and 07-06-58 to examine the merit of those potential innovations to Standard Service procurement process, as required by PA 07-242. In its Final Decision in consolidated Dockets 07-06-58 and 06-01-08RE01, issued April 2, 2008, PURA concluded that it would allow the EDCs to investigate the use of bilateral contracts with the goal of exploring options that would provide lower costs and/or greater price stability.

On April 8, 2009, PURA reopened the proceeding in Docket No. 06-01-08RE03 to provide further details as to the procurement and approval process that would be utilized if the EDCs proposed long-term bilateral contract procurements for Standard Service. The decision in this docket, dated September 30, 2009, committed to a same-day approval process for bilateral contracts for energy with terms two to five years in duration. With respect to long term contracts, PURA limited such products to 20% of the EDCs' Standard Service eligible load, and reserved its prerogative to establish an expedited schedule that corresponds to the comprehensiveness and complexity of the proposals submitted. As further discussed in Section 3.3.2, the EDCs explored the potential benefits of using long-term contracts to serve Standard Service load. After a period of market inquiry and technical review of the net benefits associated with the use of long-term contracts to serve Standards Service loads, the EDCs decided not to continue pursuing this option.

In 2011, PA 11-80 materially revised the approach for procurement of Standard Service. Section 15 of PA 11-80, now codified at Conn. Gen. Stat. §16-2(l), identifies a Procurement Manager of the PURA and charges that individual with overseeing the procurement of electricity for Standard Service. Section 92 of PA 11-80, codified at Con. Gen. Stat. §16-244m, directs the Procurement Manager to develop a Power Procurement Plan in consultation with the EDCs and other stakeholders. This Power Procurement Plan is intended to fulfill the requirements of Section 91 of PA 11-80, now codified within Conn. Gen. Stat. §16-244c(c).

3.2 Power Procurement Plan Goals and Objectives

Section 91(c)(3) of PA 11-80, Conn. Gen. Stat. §16-244c(c)(3), defines the overarching goals of the Power Procurement Plan, as follows:

> Such plan shall require that the portfolio of service contracts be procured in such manner and duration as the authority determines to be most likely to produce just, reasonable and reasonably stable retail rates while reflecting underlying wholesale market prices over time. The portfolio of contracts shall be assembled in such manner as to invite competition; guard against favoritism, improvidence, extravagance, fraud and corruption; and secure a reliable electricity supply while avoiding unusual, anomalous or excessive pricing.

Thus, PA 11-80 preserves the original intent of Standard Service, seeking a balance between the competing objectives of cost minimization and price stability for Standard Service customers. However, the legislation removes the explicit requirement to procure contracts in a laddered, overlapping series. The statute also retains the requirement that the Power Procurement Plan must ensure the integrity of the procurement process, and requires the EDCs to publish Standard Service rates no more frequently than quarterly.

Section 92(a) of PA 11-80, Conn. Gen. Stat. §16-244m(a), further defines the Power Procurement Plan goals and the types of wholesale contracts that may be included in a portfolio for Standard Service:

> [The] plan for the procurement of electric generation services and related wholesale electricity market products…will enable each electric distribution company to manage a portfolio of contracts to reduce the average cost of standard service while maintaining standard service cost volatility within reasonable levels. Each procurement plan shall provide for the competitive solicitation for load-following electric service, and may include a provision for use of other contracts, including, but not limited to, contracts for generation or other electricity market products and financial contracts, and may provide for the use of varying lengths of contracts. If such plan includes the purchase of full requirements contracts, it shall include an explanation of why such purchases are in the best interests of standard service customers.

The Procurement Manager is not restricted to seeking full requirements contracts for Standard Service, but is free to identify a portfolio of wholesale products that best meets the stated goals of PA 11-80. Thus, the requirement to provide "load-following electric service" may be interpreted to include a portfolio of products that, in the aggregate, match the diurnal and seasonal profile of Standard Service customer load. Unlike PURA's Decision in 06-01-08PH01, PA 11-80 does not place any restrictions on the type or term of contracts, including the use of both financial and physical products to serve Standard Service. Importantly, the Power Procurement Plan may consider portfolios and transactions in which the EDC assumes the responsibility of a LSE. As further described in Section 8.1, LSEs are ISO-NE market participants, thereby bearing the obligation to bid and schedule load in ISO-NE's Day-Ahead Market (DAM) and Real-Time Market (RTM). As an LSE doing business through ISO-NE, a number of rigid credit requirements would also apply to the EDCs.

In accordance with PA 11-80, this Power Procurement Plan seeks to evaluate a broad array of products available to the EDCs through ISO-NE, over-the-counter (OTC) or exchange-traded bilateral purchases, RFP processes, or through directly negotiated arrangements with creditworthy counterparties. Products may be physical or financial. This Power Procurement Plan identifies the function of each product within a load-following portfolio, explores pros and cons, identifies contracting mechanisms, and considers how a portfolio of products may be assembled to balance the competing objectives of cost minimization and price stability for Standard Service customers. Lastly, the Power Procurement Plan evaluates potential improvements to the procurement mechanism; that is, how bids and offers are solicited and awarded to maximize competition and reduce administrative costs.

3.3 Current Standard Service Procurement Process

3.3.1 Procurement Process Established By PURA

Under the framework initiated by PURA's decision in Docket No. 06-01-08PH01, both EDCs solicit firm bids for full requirement service through a sealed bid RFP process. In 2006, PURA directed the EDCs to procure Standard Service as a series of overlapping contracts of terms no longer than three years, creating a blended portfolio that reduces price volatility while reflecting underlying wholesale electric prices over time. In 2006 and 2007, UI solicited Standard Service bids twice a year, and quarterly thereafter. CL&P has solicited bids at least twice each year since 2006. As of June 1, 2012, UI has held 21 rounds of Standard Service bids. UI has procured all of its supplies for 2012, 70% for 2013, but none for 2014. CL&P has held 16 rounds and has procured all of its supplies for 2012, 70% for 2013, but none for 2014.

In accordance with Conn. Gen. Stat. §16-244c(c)(4), PURA engaged a third party to oversee the development of the RFP and the procurement process. Since 2006, PURA's oversight consultant has been LAI, a Boston-based energy management consulting firm that specializes in diverse wholesale electric procurements throughout the U.S. The PURA consultant is required to review all bids and to submit to PURA a joint recommendation with the EDC as to the recommended contracts and bidders. In accordance with PURA's decision in Docket No. 06-01-08PH01, the EDC and the consultant also must attest that the procurement complied with established criteria to ensure that the procurement process was competitive, fair and transparent. The OCC also files a report with PURA commenting on the conduct of the procurement and the recommended contracts.

For both EDCs, Standard Service is procured as a 10% slice (or tranche) of the system.[5] Throughout this Power Procurement Plan, the terms slice and tranche are used synonymously. Thus, within each slice or tranche, all four customer classes in the Standard Service customer group are represented – residential, small commercial & industrial (C&I), large C&I not subject to LRS, and street lighting. The number of slices and the service terms solicited and actually procured by the EDC may vary from round to round, depending on the laddering objectives, number of slices already procured for the term, and number of opportunities that remain for each EDC to shop for Standard Service until the start of the service term. Bidders must provide a firm, irrevocable and binding price for each month, for each of the four rate classes, and for on-peak and off-peak hours. For a one-year service term, this represents 96 distinct firm prices. As part of the

[5] In the first four rounds of Standard Service bidding, UI solicited tranches representing one third of the load for delivery in 2007, 2008, and 2009. In Round 5 (February 2008), tranches of one-sixth of the load for 2009 delivery were solicited to bring the amount acquired to 50%. Since then, all tranches have been for 10% of load.

procurement process, the EDCs provide bidders with historical load data, as well as an estimate of energy load or fraction of total energy load for each rate class, month, and time period. The evaluation of bids is based on the load-weighted average of the prices for a service term using that estimate. However, compensation to the selected suppliers is based on the prices as bid and on the actual energy load for each rate class, month, and time period.

Both EDCs invite bidders to submit bids under two different pricing scenarios: Scenario A and Scenario B.[6] Under Scenario A, the supplier assumes the load obligation at the UI or CL&P Metering Domain within the CT Load Zone, and assumes all associated Locational Marginal Price (LMP) costs. Under Scenario B, the supplier assumes the load obligation at the UI or CL&P Metering Domain within the CT Load Zone, but the EDC reimburses the supplier wholly for the differential in LMPs between the MassHub and the CT Load Zone. Thus, in accepting Scenario A bids, the EDCs lay off the risk of congestion and transmission losses to the supplier. In contrast, in accepting Scenario B bids, the EDCs manage congestion risk. The management of congestion risk is discussed more fully in Section 5.3.3. Retaining the option to manage congestion has resulted in significant savings to ratepayers. UI reports net savings to its Standard Service customers in the amount of $1.25 million in 2010, and $3.1 million in 2011. CL&P reports net savings to its customers in the amount of $43 million in 2007, $31 million in 2008, $37 million for 2009, $14 million for 2010, and $9 million for 2011.

All participating bidders must have an executed master wholesale power supply agreement in place prior to bid day. Upon award, the successful bidders execute a transaction confirmation. All material terms in the agreements are the same for all bidders. The agreement covers the nature of the requested services, such as points of delivery, LMP responsibility, load bidding and ISO tariff responsibility, responsibility for forward capacity and locational forward reserves, the process for payment to suppliers, RPS requirements, remedies in the event of default or early termination, financial performance assurance and confidentiality requirements. Both EDCs' wholesale agreements establish unilateral credit and collateral thresholds based on each supplier's respective credit rating. The supplier's collateral requirement is periodically recalculated based on the actual mark-to-market (MtM) exposure over the contract term, subject to a minimum guarantee and the threshold guarantee amount.

Bid assurance (letter of credit (LOC), cash, or equivalent) is due at least two business days (UI) and three business days (CL&P) before bid day. Bid assurance is subsequently returned to all bidders. Winning bidders post performance assurance upon award with the minimum amount based on the number of tranches or slices awarded.

Prior to each bid day, the EDC, PURA's consultant, and OCC's consultant, Resource Insight, Inc., independently develop proxy prices for both Scenario A and Scenario B products for each service term. The proxy price is intended to reflect a competitive price

[6] UI solicited only Scenario A bids in the first four rounds of Standard Service bidding in 2006 and 2007.

benchmark from a creditworthy supplier. Proxy prices are used during the bid evaluation process to gauge the competitiveness of the bids received and to provide guidance to the EDCs, PURA's consultant and the OCC regarding the relative economic merit of selecting a discretionary tranche.

The bid and approval process for Standard Service covers a two-day period. Firm bids to the EDCs are due by 10:00 AM on bid day, and remain binding until a prescribed time on the afternoon of bid day. Successful bidders are notified prior to the expiration of the bids, and transaction confirmations are subsequently executed. No later than the morning following bid day, the EDC, third party consultant, and the OCC file their recommendations with PURA. According to Conn. Gen. Stat. §16-244(c), PURA "may, within ten business days of submission of the overview, reject the recommendation regarding preferred bidders." As a matter of practice, however, PURA holds a technical meeting with the EDCs, third party consultant, and the OCC on the morning following bid day, and issues a final decision regarding the recommended bids in a Special Meeting later in the afternoon. According to the wholesale power supply agreement, the transaction between the EDC and the supplier does not become binding until the final decision by PURA.

Once a service term is fully procured, the EDCs determine the Standard Service rates that result from the blended full requirements contracts, including any true-ups resulting from over or under-collections in the prior period. Although Conn. Gen. Stat. §16-244(c) specifies that Standard Service rates must be established "not more often than every calendar quarter," for the last several years the EDCs have each published rates for the entire calendar year generally no later than mid-November of the prior year.[7]

3.3.2 Standard Service Procurement Process Innovations

Since Standard Service procurements were initiated in 3Q2006, the EDCs have undertaken several initiatives to enhance the procurement process. Such initiatives have been within the limits set by statute and governing PURA decisions.

For the first Standard Service term in 1Q2007, there was a limited period to mitigate market risk. At that juncture the EDCs' respective efforts to ladder supply contracts were fledgling, thus inducing the EDCs to roll out the laddered portfolios through only one or two Standard Service procurements for the first delivery period. The EDCs and PURA's oversight consultant were therefore concerned that procuring a large portion of the Standard Service load on a single day could expose ratepayers to undue risk if the market moved unfavorably between bid day and the start of the delivery period. To hedge against adverse price risk in late 2006 the EDCs, in consultation with PURA's consultant, explored the use of a "one-touch barrier put option." The barrier put option represents a customized risk management product designed to protect Standard Service customers in

[7] PURA's decision in Docket No. 06-01-08RE02 revised certain protocols regarding public disclosure of bid results to be consistent with ISO-NE's information policies. This decision also required that Standard Service rates be published no later than 45 days prior to the start of a service term.

the event wholesale energy prices plummet after supply contracts are executed. Financial counterparties doing business in New England and elsewhere in the U.S. were acquainted with the option, and could have been induced by one or both of the EDCs to structure and then price the product to meet each company's risk tolerance requirement. Whether or not the "after-deductible" payout of this insurance product was worth the price of the barrier option required the EDCs to evaluate the net benefit of using a customized risk product to safeguard against low probability, but potentially costly adverse movements in wholesale markets between bid day and the commencement of delivery. This option would have provided a financial hedge oriented around MassHub energy prices beginning January 1, 2007. The option was intended to lower the cost to Standard Service customers if there were a significant decline in forward energy prices between the date of the option purchase and the start of deliveries under the first set of Standard Service contracts. When indicative bids for the barrier option were submitted by creditworthy financial counterparties accustomed to transaction types contemplated by the EDCs, each EDC and PURA's consultant evaluated the cost of the financial product relative to the likelihood that the option would "knock in," in other words, pay out. The EDCs and PURA's consultant determined that the substantial cost of purchasing the insurance associated with the barrier option outweighed its potential benefit. Based on the notional pricing of the barrier option revealed through preliminary discussions with creditworthy counterparties, the EDCs, in consultation with PURA's consultant, rejected the use of this financial product. The use of the barrier option has not since been revisited.

Following PURA's decision in consolidated Docket Nos. 07-06-58 and 06-01-08RE01, the EDCs both launched an initiative to explore long term contracts for certain components of Standard Service. CL&P and UI issued a joint Notice of Interest and Market Survey (NOI) on August 4, 2008 to explore the opportunities for long term power contracts. The primary goal of the NOI was to obtain information on the technology types, terms, indicative prices, and contract provisions that would govern the purchase of energy and capacity from existing or new resources.[8] CL&P received over 75 individual proposals from approximately two dozen respondents. The spectrum of projects, products and pricing was diverse. In reviewing the responses from many market participants, CL&P, in consultation with PURA's consultant, determined that none provided a significant advantage to CL&P's Standard Service customers. Therefore CL&P chose not to move forward with the long term contracting initiative. UI, on the other hand, decided to move beyond the NOI phase. On May 18, 2009, UI issued an RFP and Invitation to Negotiate to the wholesale supplier/generator/developer community. UI's goal was to examine contracts in which pricing for energy was not linked to future spot prices for natural gas, consistent with the consolidated decision in Docket Nos. 07-06-58 and 06-01-08RE01. On July 24, 2009, UI received 32 indicative proposals from 29 bidders. The proposals included conventional and renewable generation, as well as market transactions not tied to specific generators. The indicative proposals did not

[8] Renewable generation was invited to participate in this RFP. However, since PURA issued a separate decision in Docket No. 07-06-61 covering contracts for Renewable Energy Credits (RECs), RECs were carved out under this RFP.

warrant proceeding from the indicative phase to a binding phase. UI, in consultation with PURA's consultant, elected to terminate the procurement.

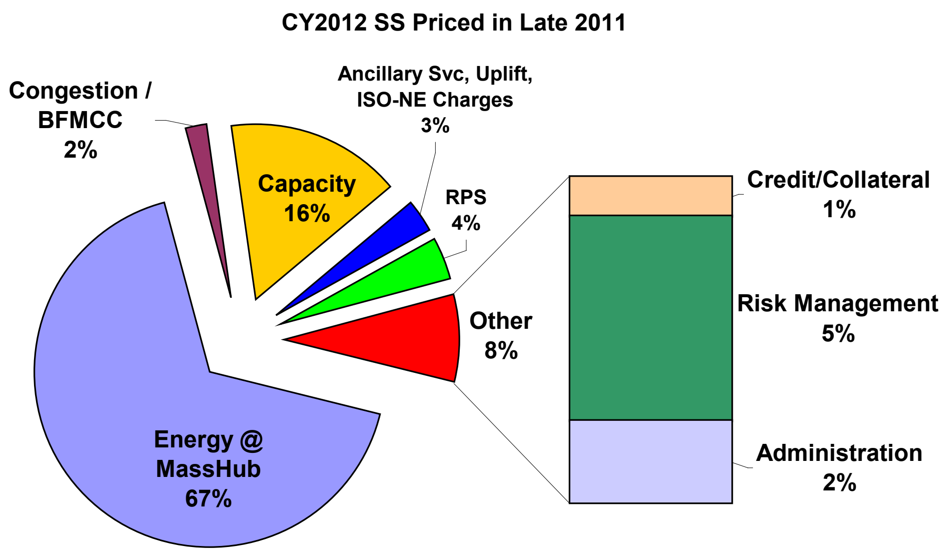
The high cost of stabilizing Standard Service revealed through the indicative long term bids, coupled with the accounting related uncertainties associated with the use of long-term contracts were reasons cited by both EDCs in regard to the rejection of this option. How a long term contract for energy would be integrated into a full requirements portfolio was also unresolved. Moreover, one key policy issue remained problematic: the fairness of assigning a long term energy contract to a Standard Service customer base that could shrink over time as customers migrate to competitive retail suppliers. With continued migration, the contract cost would be shifted to fewer Standard Service customers, thereby potentially increasing rates for those Standard Service customers who do not elect to switch to competitive retail suppliers.

In accordance with statutory requirements, PURA's consultant filed a "Lessons Learned" report on PURA's behalf in June 2007, based on observations from the first six months of Standard Service procurements. Among other findings, the report concluded that laddering of tranches over several procurement events to create blended Standard Service prices was an effective mechanism to reasonably reduce the risk of market timing. Barring catastrophic events such as hurricanes Katrina and Rita, the report advised that attempting to time the market in response to short-term fluctuations is ill-advised. The report also concluded that allowing bidders the flexibility to offer bids with negative contingencies (*i.e.*, accepting one bid withdraws another) or linked bids (multiple service terms offered together) yielded ratepayer benefits through lower bid prices. Lastly, the report found no evidence of gaming or manipulation.

4.0 COMPONENTS OF STANDARD SERVICE SUPPLY

Under the framework established in Docket No. 06-01-08PH01, the Connecticut EDCs procure wholesale supplies for Standard Service as fixed price, full requirements service. Under a full requirements supply contract, the supplier is responsible for all products necessary to serve the load in each and every hour of the contract period regardless of the actual load level or spot market price. The components of full requirements service include load-following energy supply delivered to the CT Load Zone, capacity as required by ISO-NE rules, other ISO-NE charges, including uplift and ancillary services, and RPS requirements. In addition, full requirements service includes risk management costs, that is, hedging both price and quantity risks, as well as other financial and administrative costs incurred by the supplier. On an indicative basis, Figure 5 shows the breakdown of cost for Calendar Year (CY) 2012 Standard Service based on pricing trends in 4Q2011. Each of the components in relation to the cost of providing full requirements service is discussed below.

Figure 5. Components of Standard Service Supply Cost[9]



4.1 Energy

Energy, including bypassable federally mandated congestion charges (BFMCC), is by far the largest component of full requirements service, about 69% as of 4Q2011. Prior to the dramatic drop in natural gas costs since July 2008, the energy component represented an even larger portion of total cost of providing Standard Service. The energy component of full requirements service is settled through the DAM and RTM administered by ISO-NE. The LSE bids an estimate of hourly load into the DAM and settles any differences

[9] The relative proportion of the components of Standard Service developed by LAI is based on forward market prices, implied volatility, wholesale power supply contract terms, and regulatory requirements for 4Q2011.

between the estimate and actual load in the RTM. Prices paid by wholesale customers in each load zone across New England are settled hourly in both the DAM and the RTM based on the interaction of supply bids (from generators) and load bids (from LSEs). The wholesale energy price – the LMP – varies by hour and by load zone. Because both the load and price vary hour by hour, the total cost for load-following energy over a day, month, or year cannot be determined ahead of time. ISO-NE invoices each LSE on a biweekly basis for its obligation in the DAM and RTM. As discussed in Section 8.2, suppliers generally undertake risk management strategies to reduce their exposure to load and price uncertainty.

While full requirements contracts with the Connecticut EDCs require delivery of the energy to the CT Load Zone, suppliers may purchase forward energy contracts for delivery to any New England zone, and then manage the LMP differential -- congestion and transmission losses -- between that zone and Connecticut. The "center of gravity" for energy trading in New England is referred to as the MassHub, the commonly accepted liquid pricing point in New England. The volume of trading around Connecticut is less than MassHub; therefore suppliers incur a low illiquidity premium in purchasing forward energy contracts that are priced at the CT Load Zone. If forward energy contracts are purchased at MassHub, the congestion can be hedged through annual and/or monthly Financial Transmission Rights (FTRs) auctioned by ISO-NE, or through other types of bilateral arrangements that can be purchased OTC. Management of congestion risk is discussed further in Section 5.3.3.

4.2 Capacity

The cost of providing capacity represents about 16% of full requirements service. The Standard Service loads of each EDC are assigned a capacity obligation by rate class (Residential, Small C&I, Large C&I, and Street Lighting) on a daily basis by ISO-NE. This capacity obligation is indicative of the share of system-wide capacity obligation and cost which must be covered on a *pro rata* basis by the suppliers of Standard Service. The system-wide capacity obligation cost is established for a capacity year running from June 1 to May 31, based on the system peak established in the prior capacity year and the clearing price established through the Forward Capacity Market (FCM) three years prior to delivery. For a Standard Service supplier, the capacity obligation cost can be unitized against energy with reasonable certainty over the short term: the cost per kW of capacity obligation is known, and the relationship between energy and capacity obligation is comparatively stable by rate class, provided the load shape does not significantly change. To the extent that the load shape changes, then the unitized cost of the capacity obligation on a per MWh basis will change. Even though the market value of capacity is known in New England three years into the future, there is no market product available for suppliers to hedge the capacity-related quantity risk. The capacity does not need to be purchased by the supplier ahead of the delivery period. The capacity obligation for each load asset is billed monthly to each LSE by ISO-NE.

4.3 Ancillary Services, Net Commitment Period Compensation, and ISO Tariff Charges

Under ISO-NE's Transmission, Markets and Services Tariff, ISO-NE assesses LSEs with various charges to cover services purchased from generators to maintain system operating security and reliability, including regulation and operating reserves. Ancillary services (which include Automatic Generation Control, forward reserves and real time reserves), as a component of Standard Service supplier cost, is a relatively small percentage of the total cost to serve load.

ISO-NE also imposes Net Commitment Period Compensation (NCPC) charges reflecting the cost to support the operation of generating assets critical to maintaining system reliability in specific locations of the system or across the entire system. These charges, sometimes referred to as "uplift," are imposed on a system-wide basis (First Contingency NCPC) or on a zonal basis (Second Contingency NCPC). Uplift for the CT Load Zone has historically been high, but has diminished significantly over the last several years in response to new generation and transmission resources added to Connecticut's energy infrastructure. Like ancillary service charges, NCPC represents a small percentage of the total cost to serve load.

ISO-NE's cost of operation is recovered by way of a self-funding tariff – Section IV of the ISO's Transmission, Markets and Services Tariff. Under Section IV of the Tariff, LSEs are responsible for ISO Schedule 2 charges (Energy Administration Service), and ISO Schedule 3 charges (Reliability Administration Service).

These charges are included in ISO-NE's monthly and biweekly bills to LSEs and are not separately procured by suppliers.

4.4 Renewable Portfolio Standard

Connecticut, like other states with an RPS, sets forth a percentage of retail electric load to be met with qualified renewable energy. This requirement can be met by acquiring Renewable Energy Credits (RECs), where one REC represents the renewable attributes associated with one MWh of qualified renewable energy. Standard Service supplies must include three classes of RECs (Class I, Class II, and Class III) and there is a required percentage of load for each class that must be met in each calendar year. The required percentage of Class I RECs increases in each year until 2020. The cost of meeting the State's RPS in 2012 represents about 4% of the cost of full requirements service. According to PA 11-80, Section 91, now codified within Conn. Gen. Stat. §16-244c(c), EDCs' contracts with their wholesale suppliers must ensure that the suppliers meet the RPS requirements or pay the Alternative Compliance Payment (ACP). Suppliers can acquire RECs through bilateral arrangements with renewable generators, marketers or other parties, or through an exchange. However, since the deadline for demonstrating compliance with the RPS is June 15 for the prior compliance year, RECs can be purchased opportunistically until the compliance deadline. Because the total quantity of RECs required is not known until the end of the compliance year, suppliers are unavoidably exposed to a small spot REC price risk. The ACP is $0.055/kWh for Class I and II, and $0.031/kWh for Class III. The ACP constitutes a ceiling on the REC price.

4.5 Risk Management

The "Other" slice shown in Figure 5 includes several cost elements: risk management/hedging, credit, and administrative costs. The aggregate cost of risk management, credit support, and administrative costs constitutes roughly 8% of the total cost of full requirements service, but has significantly varied over time. Suppliers' profits are also included in this slice, but not explicitly assigned to any of these "Other" components.

Since Standard Service is currently procured on a fixed price basis for a term up to three years, suppliers generally implement risk management measures to hedge their exposure to uncertain future market prices and quantities. The structure and cost of risk management instruments differ in response to the duration of the contract and the number of months or years prior to the commencement of delivery. The energy component expressed on a $/MWh basis is the largest and most uncertain component. Moreover, energy price and quantity risks are typically positively correlated – zonal energy prices increase (decrease) when load in the zone increases (decreases). Suppliers generally hedge a substantial portion of their expected energy supply obligation with forward natural gas and/or power contracts, which may be transacted at the same time that the EDC informs the suppliers that their bid(s) have been awarded or by using other hedging instruments in their existing portfolios. A supplier might also secure options to buy additional energy or to sell surplus energy at an agreed-upon strike price, based on the perceived uncertainty of the load obligation, the current price, and the time to expiry of the option.

To protect customers in the event of default, the wholesale contracts between the EDCs and the Standard Service suppliers require the suppliers to provide credit support for the transaction. The EDCs can call for additional collateral from the wholesale suppliers during the contract term if the market price rises above the contract price, such that the contract is out-of-the-money from the supplier's perspective. The suppliers, in turn, may have credit and margining arrangements with their counterparties. Applying credit and/or collateral to support a transaction creates an opportunity cost of lost earnings potential for the supplier. Actual costs may also be incurred, such as fees payable to a bank in order to obtain a LOC.

The accepted level of unsecured credit and the cost of the credit is a function of the creditworthiness of the counterparty. Suppliers with higher credit ratings can offer lower bid prices for Standard Service, all other things being the same. These direct costs, as well as the indirect costs of administering the contract and risk management strategy, are rolled into the fixed price offered by potential suppliers. The cost to hedge a forward contract increases with the duration between bid day and the commencement of delivery under the contract: the longer the duration, the greater the price and quantity uncertainty, and *vice versa*. Also, for longer term contracts suppliers are required to post credit and collateral for a longer period, the cost of which is ultimately included in the price of Standard Service.

5.0 NATURAL GAS AND POWER MARKET DYNAMICS AFFECTING STANDARD SERVICE PRICING

5.1 Background on Natural Gas Market Events and Prices

The first Standard Service procurements, in August and September of 2006, occurred approximately one year after Hurricanes Katrina and Rita (Katrina/Rita) in August and September 2005. The damage to natural gas infrastructure in the Gulf Coast caused by these extreme climatic events triggered an historic, but not unprecedented run-up in natural gas prices in the second half of 2005 and early 2006. The monthly average spot market natural gas prices at the Henry Hub from 2002 through 2012 are shown in Figure 6. Following Katrina/Rita, offshore and onshore oil and gas production infrastructure was restored comparatively quickly in light of the magnitude of the devastation in the Gulf of Mexico. By the spring of 2006, natural gas prices into-the-pipe at the Henry Hub generally reverted to pre-hurricane levels. However, commodity price volatility persisted, as market participants worried about the upcoming 2006 and 2007 hurricane seasons, among other things. Throughout 2007, Henry Hub spot prices remained volatile, fluctuating within the $6/MMBtu to $8/MMBtu range.

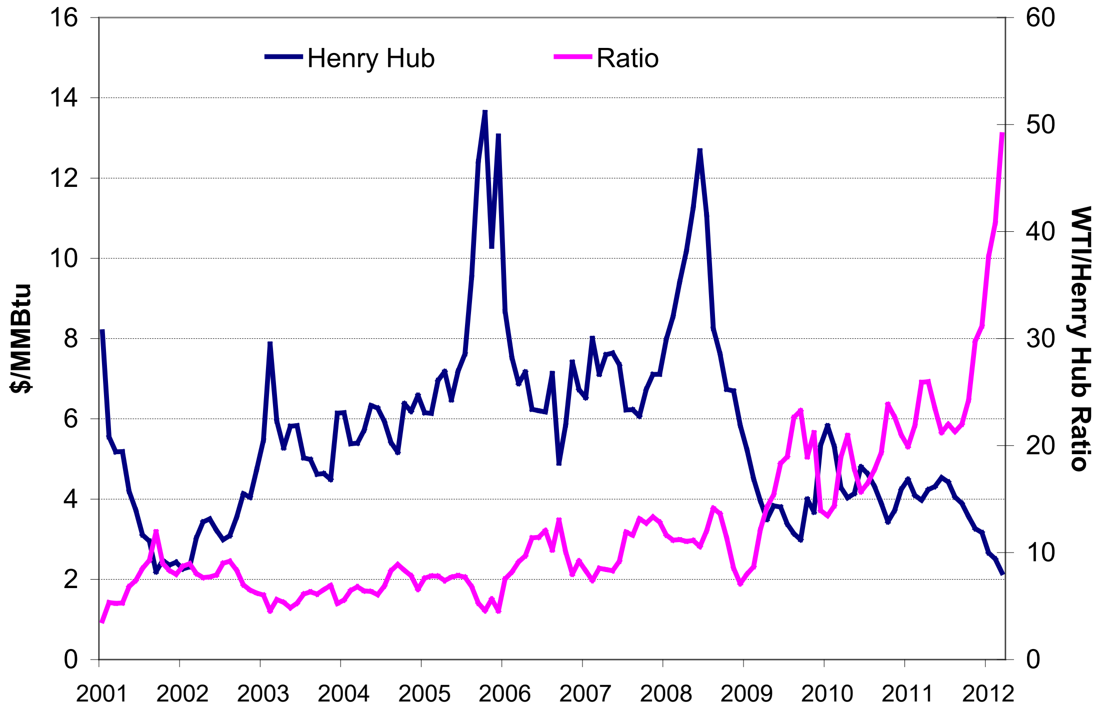
During the first half of 2008, spot gas prices showed a steady upward trend. Consistent with historic pricing relationships between premium fossil fuels, natural gas price movements remained largely correlated with changes in global oil prices. Natural gas prices at the Henry Hub peaked in June 2008, exceeding $10/MMBtu on an average monthly basis for the summer of 2008, and approaching the record price following Katrina / Rita. By the summer 2008, commodity prices collapsed reflecting the impact of weak demand, adequate natural gas supplies across North America, and the U.S. financial crisis. Abundant natural gas held in conventional storage facilities across the U.S. also exerted downward pressure on natural gas prices. Also, in 2008 new natural gas supplies derived from unconventional shale gas formations in Texas, Oklahoma, West Virginia and Pennsylvania materialized, thereby altering the conventional wisdom from supply deficits to surpluses.

By 2009, shale gas producers' ever-optimistic outlook regarding the recoverability of this unconventional resource continued to exert downward pressure on commodity prices at key pricing points across North America. By the 3Q2009, Henry Hub spot prices broke through the $3.00/MMBtu resistance level. While prices increased significantly later that year reflecting demand fundamentals and supply-related uncertainty, for the majority of 2010 and 2011 commodity prices remained comparatively flat and less volatile than recent historic norms, averaging $4.12/MMBtu over the two-year period. The minimum average monthly price was $2.98/MMBtu and the maximum average monthly price was $5.26/MMBtu. Reflecting warmer-than-normal temperature conditions and massive working gas storage overhang in the East, commodity prices at the Henry Hub recently traded below $2.00/MMBtu. These prices are the lowest observed in the last ten years.[10]

[10] The recent low prices would be even lower compared to previous lows in early 2002 if the data were adjusted for inflation.

As shown in Figure 6, by 2011 the historic pricing relationship between premium fossil fuels ended as the oil-to-gas parity ratio blew out to unprecedented highs. Whereas the historic average had oscillated between about 1 and 4, as the price of West Texas Intermediate oil exceeded $100 per barrel while natural gas prices at the Henry Hub fell below $2.00 / MMBtu, the ratio has approached 50.

Figure 6. Average Henry Hub Spot Prices Compared to Oil-to-Gas Price Ratio (Nominal $)

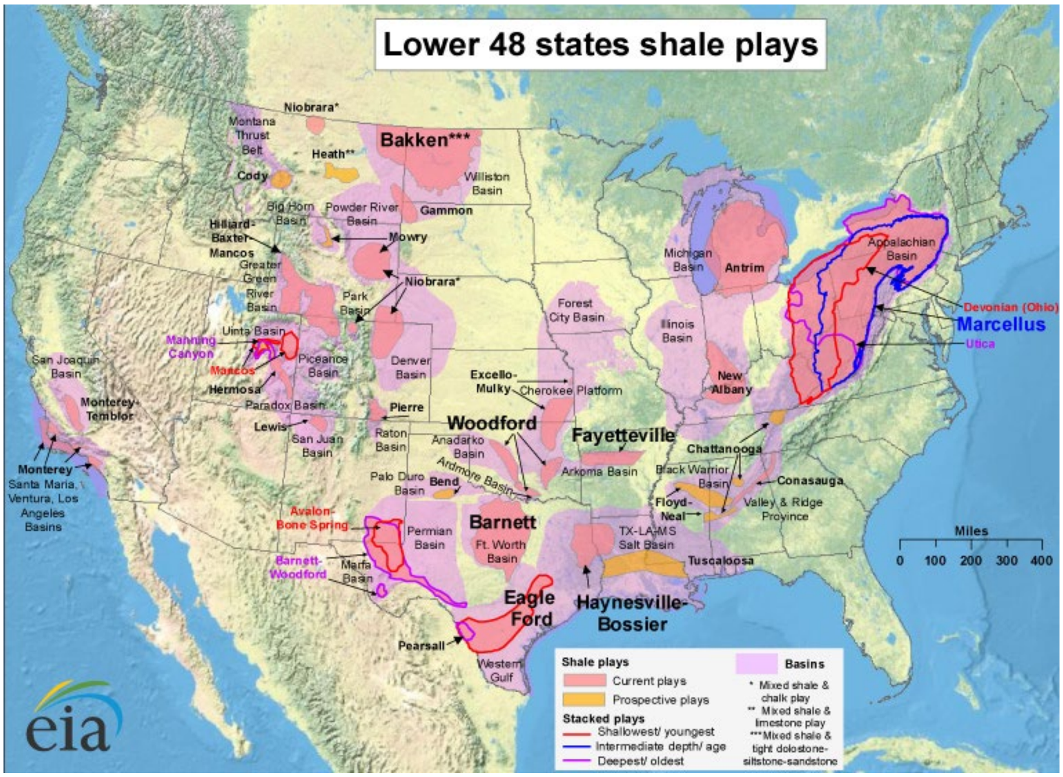


5.2 Natural Gas Outlook

As discussed in Section 5.3.1, wholesale electric prices in New England are strongly correlated with delivered natural gas prices in the region. The strong correlation between natural gas and wholesale electric prices in the DAM and RTM was observed during the run-up in commodity prices prior to mid-year 2008 as well as the subsequent market correction in gas prices. As the composition of New England's generation fleet is not expected to change significantly in the remainder of this decade, it is reasonable to expect wholesale electric prices to remain closely linked to gas prices at key pricing points across New England. Therefore the natural gas outlook with respect to the exploration and production (E&P) of natural gas and deliverability to New England has a direct bearing on the relevant dynamics affecting the prospective pricing of Standard Service.

Over the last three years, a number of factors have contributed to the material decline in gas prices. Key among them is the enormous increase in gas production from shale gas formations across North America, in particular, the Marcellus Shale in West Virginia/Pennsylvania and Barnett Shale in Texas.[11] Production from these prolific basins has more than quintupled within the last three years, and there are few signs of production tailing off in light of the E&P outlook and the value of the liquids associated with shale gas production. Figure 7 shows the major U.S. shale gas and oil plays.

Figure 7. Shale Gas and Oil Plays in the Continental U.S.[12]



In addition to the positive E&P outlook across shale gas formations, in particular the Marcellus and Utica Shale basins, there are other factors that explain the downward pressure on natural gas prices at the Henry Hub. First, the economic recession weakened demand across the U.S. Second, warmer-than-normal temperature conditions, in particular during the 2011/12 heating season, reduced the demand for natural gas for conventional gas utility send-out. Third, working gas storage inventories in the East resulted in a large storage overhang, thereby depressing commodity prices.

Many industry experts expect natural gas demand to rebound over the next decade. Continued production from unconventional shale resources will keep the continental gas

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[11] Shale gas is natural gas trapped within a shale rock formation and is often associated with valuable liquids as well. The development of hydraulic fracturing techniques has resulted in producers' ability to extract massive quantities of dry (non-associated) and wet (associated) shale gas throughout the U.S and western Canada.

[12] ftp://ftp.eia.doe.gov/natgas/usshaleplays.pdf

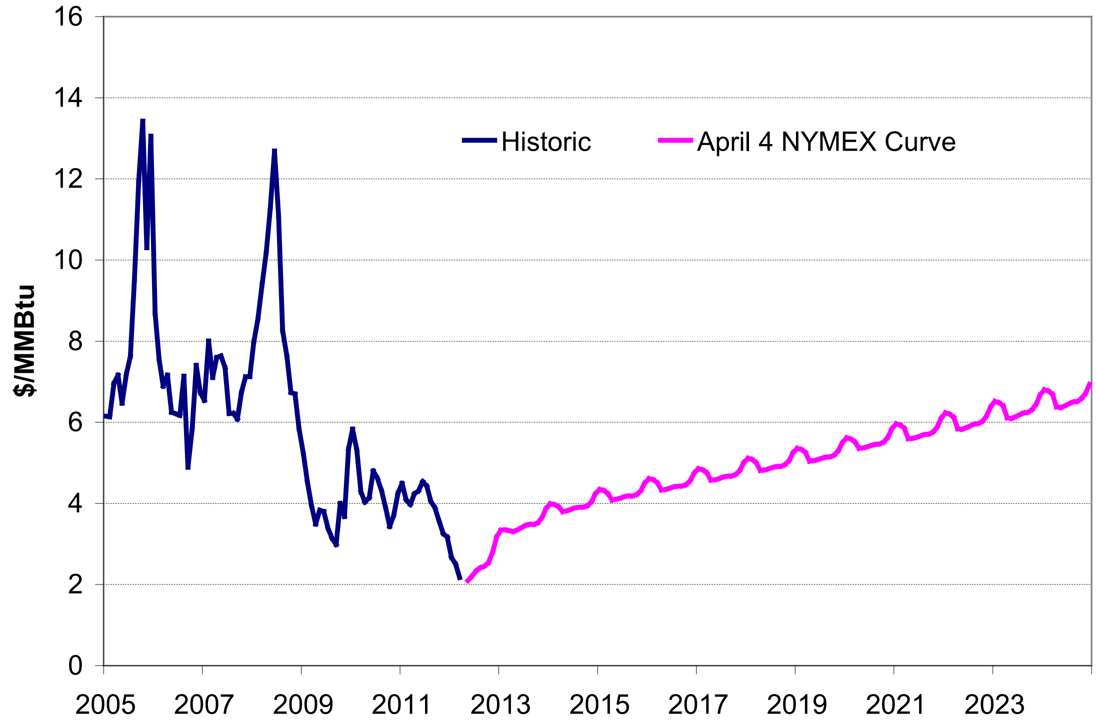
market well supplied, thereby reducing New England's traditional reliance on western Canada and the Gulf of Mexico. Relative to natural gas prices prior to 2008, the commodity price outlook throughout the remainder of the decade appears favorable from a buyer's perspective. Despite the favorable E&P outlook, price pressures on producers throughout North America may result in a significant reduction in the rig count and production of natural gas, in particular, in dry gas formations where producers' operating cash flows are *not* buoyed by the sale of valuable natural gas liquids (NGLs). The rapidly growing production of natural gas from the Marcellus Shale has brought with it a major increase in the production of NGLs from the wet-gas corridor of the shale play that runs west of a north-to-south line in western Pennsylvania and northern West Virginia. These NGLs -- primarily ethane, propane and butane -- must be processed out of the gas in order to meet pipeline gas quality requirements. At the current low prices for natural gas, NGLs are much more valuable than natural gas as they can substitute for oil products as well as be used as a petrochemical feedstock.[13] The value of the NGLs in part explains the continued high level of gas production from Marcellus Shale even though underlying natural gas prices are presently depressed.

In formulating the outlook for natural gas prices in the years ahead, it is worth noting that history reminds us that "conventional wisdom" can quickly change in response to significant movements in market fundamentals. In less than five years, perceived natural gas supply shortages, high prices, and the anticipated reliance on liquefied natural gas (LNG) imports to plug the supply gap changed to anticipated abundance, low prices, and a flurry of regulatory permit applications to export LNG from the Gulf of Mexico, the Atlantic seaboard, and various terminals proposed along the Pacific coastline, including Alaska.

Figure 8 shows a comparison of historic prices at Henry Hub to the NYMEX forward curve from April 4, 2012. The forward curve represents the market's expectation of future prices at any given time.

[13] The rapid increase in NGLs in the Marcellus Shale has resulted in significant infrastructure bottlenecks as the largest demand for NGLs comes from petrochemical plants on the Gulf Coast and for use as a diluent for moving the oil sands product to refineries.

Figure 8. Henry Hub Prices, Historic and NYMEX Forward Curve



The April 4, 2012 NYMEX forward curve depicts market expectations for a rapid ascent from the present depressed price level through 2014. The forward curve shows a steady rise in commodity prices by about 5% per year, a rate significantly higher than current expected inflation rate of roughly 2%. In relation to long term forward price outlooks previously available before 2008 either through NYMEX or the U.S. Energy Information Administration, the current commodity price outlook is much lower.

There are a number of regional gas price indices that mark the value of natural gas delivered to New England. These indices are commonly used by generation companies, traders, and other market participants in submitting bids into ISO-NE's DAM and RTM. The primary gas indices of relevance for wholesale power pricing in New England include Algonquin Citygates (AGT Citygates) and Tennessee Zone 6 (TGP Z6).[14] These indices reflect positive basis relative to the cost of natural gas at the Henry Hub. The daily change in basis to New England reflects weather conditions, pipeline flow limitations, the withdrawal of natural gas from conventional storage facilities in Leidy and Ellisburg, Pennsylvania, withdrawal from the Dawn storage hub in Ontario, and LNG imports at the Distrigas import terminal in Everett, Massachusetts. During the heating season, November through March, basis can be high. During cold snaps, basis can triple

[14] Iroquois Zone 2 is also used in Connecticut, but is primarily relevant for wholesale pricing on Long Island.

or even quadruple over average monthly basis values during the heating season. These pricing dynamics are consistently captured in DAM and RTM wholesale LMPs.

Going forward, the increased market share ascribable to the growth of shale gas is likely to reduce basis in New England relative to historic norms. Unlike neighboring market areas – in particular, PJM and NYISO – the growth of shale gas production is not resulting in large new pipeline pathways into New England.[15] Therefore basis during the heating season will likely continue to capture physical deliverability constraints when the coincident requirements of the region's gas utilities and gas-fired generators are high.

While shale gas from the Marcellus and Utica Shale basins will be transported to New England via the extensive network of pipeline interconnects with gas gathering and pipelines directly connected to the shale producing basins, there are no new Federal Energy Regulatory Commission (FERC) certificated facility expansions on Tennessee, Algonquin, Iroquois, Maritimes & Northeast, and/or Portland that are designed to significantly expand pipeline infrastructure within New England's borders in 2012 through 2014. There are pipeline expansions on the drawing boards, but the typical market, regulatory, design/build cycle for new pipelines or pipeline enhancements runs several years, perhaps much longer. In contrast, both PJM and New York are presently or will soon be benefited by major new pipeline infrastructure that directly links shale gas producers with markets serving gas utilities and power generators. Several of these projects have already received FERC certificates.

In New England, Spectra Energy's Algonquin Incremental Market (AIM) Project has the potential to significantly improve regional transport capability, but the results of Spectra Energy's Open Season for AIM are not known. Whether or not there is sufficient market interest in the AIM project to support its development in the years ahead is not known at this time. Absent new and/or expanded pipeline facilities to New England, the transport basis during the critical heating season may remain high relative to other key pricing points in PJM and NYISO, and could "blow out" during brief intervals when one or more pipelines post Flow Day Alerts or Operating Flow Orders. Connecticut's EDCs and the Procurement Manager should continue to monitor the market factors affecting the development of new infrastructure in New England.

5.3 Background on New England's Power Market

5.3.1 Spot Energy Market

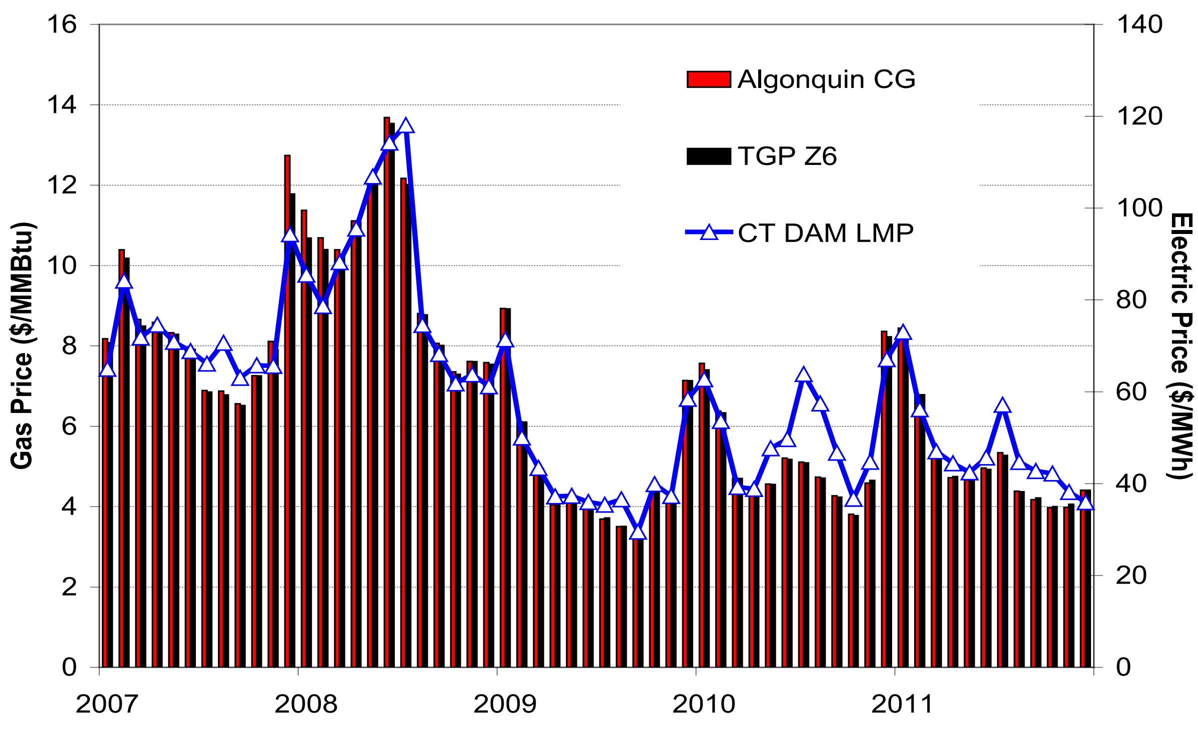
New England's generation resource mix includes natural gas fired generation resources, as well as coal, nuclear, hydro, oil, wind, and other renewable resources. Although less than one-half of the energy produced in New England is derived from natural gas,

[15] Spectra Energy's anticipated 0.8 Bcf/d new pipeline to New Jersey and Manhattan will likely sustain long term downward pressure on gas prices in New York. Downward pressure on Transco Zone 6 New York and Texas Eastern M3 pricing points will likely reduce AGT Citygates and TGP Z6 as well, except during the heating season.

wholesale energy prices are determined predominantly by the delivered cost of natural gas; generating resources burning natural gas are the marginal resource the large majority of the time and hence set the market price for energy. New England's dependence on gas-fired generation coupled with ISO-NE's FERC-approved market structure result in wholesale power prices being driven by the relevant gas index more than 70% of the hours throughout the year.[16] Figure 9 shows the average monthly day-ahead LMP for the CT Load Zone compared to the average monthly price for AGT Citygates and TGP Z6. Prices in the DAM are highly correlated with the regional gas indices in most months. DAM prices diverge from the aforementioned gas indices during extreme hot weather to account for scarcity conditions in bulk power supply and the use of peakers firing on Ultra Low Sulfur Distillate or other premium fuels. DAM prices can diverge from the gas indices during the winter when steam turbine generators using residual fuel oil are scheduled by ISO-NE and set the energy price.

Both natural gas prices at the Henry Hub and wholesale power prices in New England peaked in June 2008. Since mid-year 2008 natural gas prices and wholesale power prices in New England have generally followed a downward pricing trend, although there have been many months of significant price run-ups. Current natural gas prices are the lowest they have been since the implementation of Standard Service in January 2007.

Figure 9. Comparison of Connecticut Electric Prices to Spot Gas Prices



[16] ISO-NE 2010 Annual Markets Report, http://www.iso-ne.com/markets/mkt_anlys_rpts/annl_mkt_rpts/2010/amr10_final_060311.pdf, p. 61

Spot energy prices in the ISO-NE DAM and RTM follow typical diurnal, weekly, and seasonal patterns. Energy price volatility refers to the unpredictable departures from these regular cycles. The pricing patterns in Figure 10 show significant volatility in each of the five calendar years plotted. Energy prices in 2007 and 2008 were generally highest and most volatile. Overall price levels and volatility generally diminished between 2009 and 2011 in response to the softening of natural gas prices, as well as flattening of electric loads due to the recession and increased penetration of energy efficiency and demand response (EE/DR). In Figure 11 the LMPs are ordered by value rather than chronologically, highlighting the differences among these years.

Figure 10. Hourly LMPs in the CT Load Zone, 2007-2011

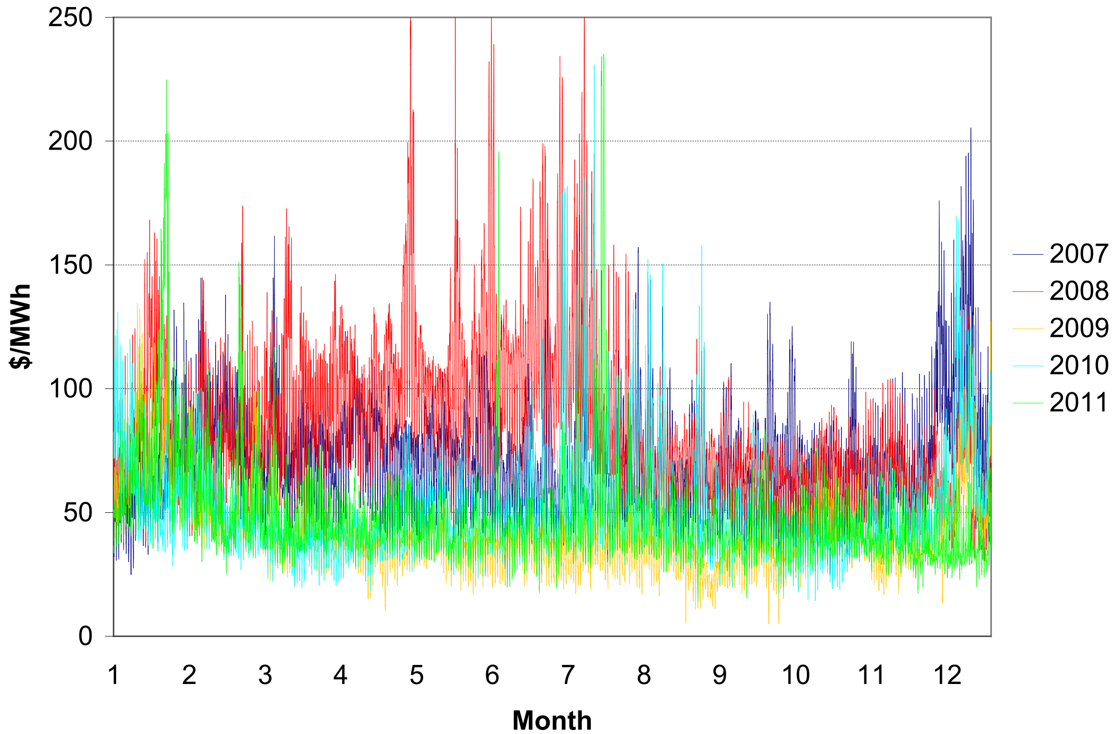
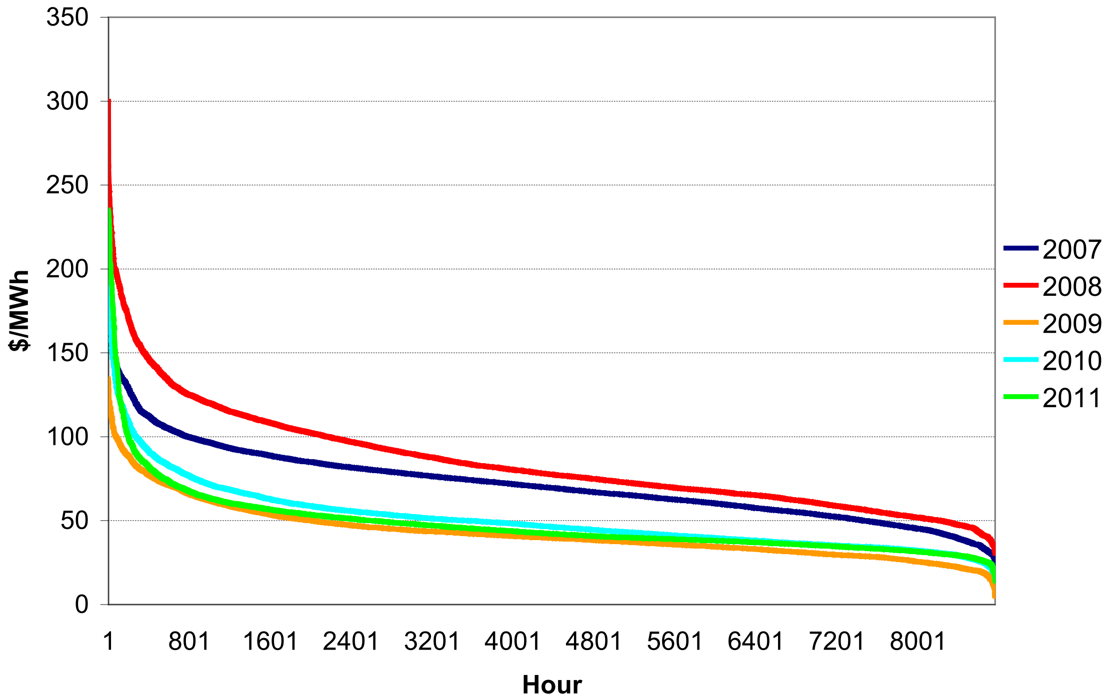


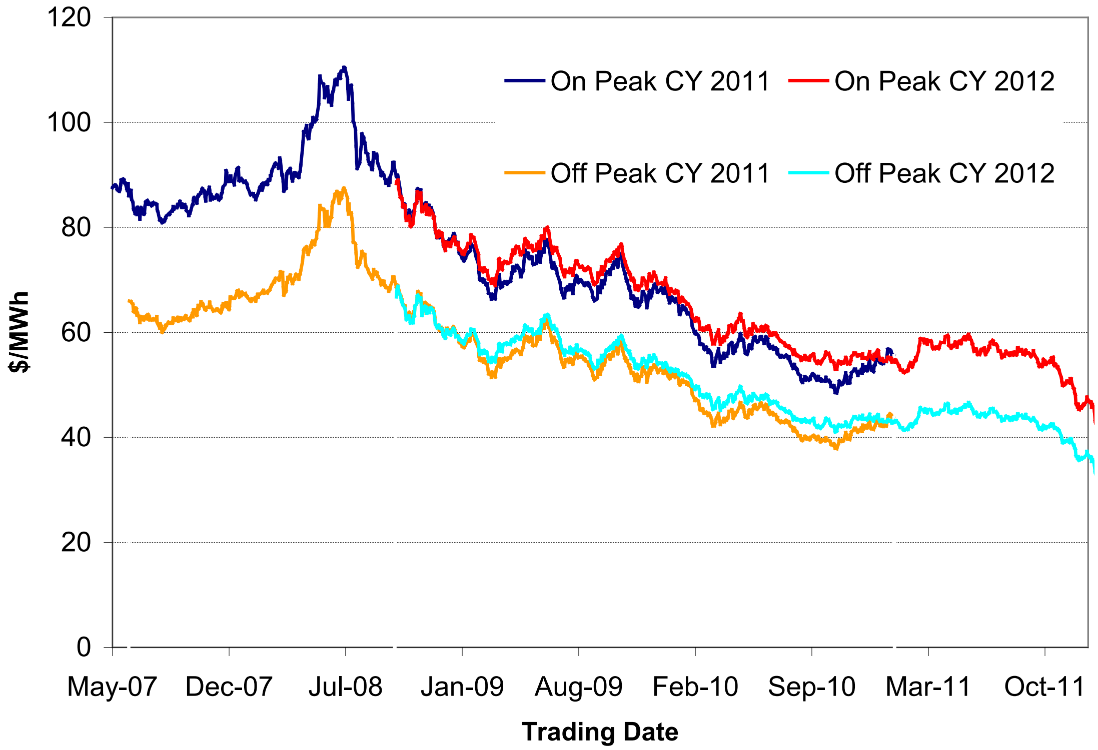
Figure 11. Price Duration Curve for CT Load Zone, 2007-2011



5.3.2 Forward Energy Contracts

As previously discussed, Standard Service has been procured as an overlapping series of forward full requirements contracts. Hence, in understanding the chronology of price changes in Standard Service, forward energy prices are more relevant than spot electricity prices. Forward power prices in New England followed a similar pattern to spot prices over this period, rising to a peak in mid-2008 while continuing to generally decline since then. Figure 12 shows on-peak and off-peak forward prices for delivery at the MassHub for CY 2011 and CY 2012 products traded on NYMEX for May 2007 through December 2011.

Figure 12. CY 2011 and CY 2012 NYMEX MassHub Forwards

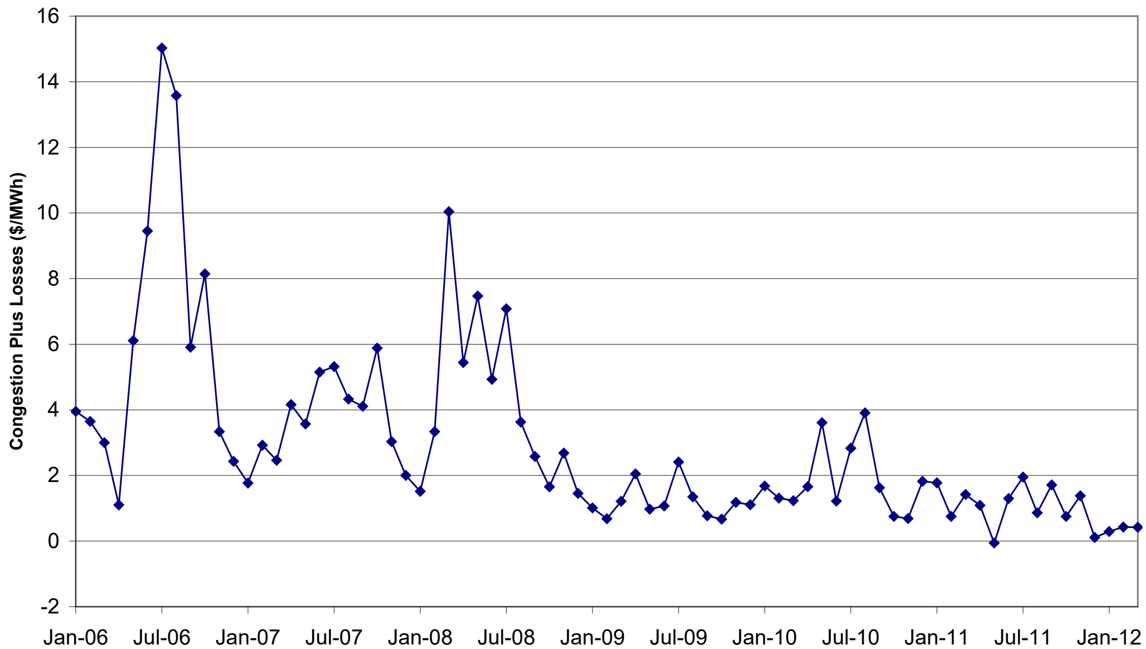


The laddered Standard Service portfolios consist of a blend of contracts procured over time. The blending of the contracts has therefore resulted in Standard Service prices that have lagged behind the decline in market forward prices since mid-2008.

5.3.3 Congestion

The price effects associated with congestion impact the absolute wholesale energy price level at the MassHub and the CT Load Zone, but also the business considerations affecting both EDCs' and suppliers' congestion management plans, *i.e.*, the relative merit of Scenario A versus Scenario B for Standard Service. As illustrated in Figure 13, prior to 2008, the LMP differential (congestion and losses) between the MassHub and the CT Load Zone had been high and volatile. Since the end of 2008, the magnitude and volatility of congestion between MassHub and the CT Load Zone has diminished in response to Connecticut's and the region's emphasis on new generation and transmission infrastructure, as well as increased DR/EE. The Middletown to Norwalk transmission project (Phase II of the Southwest Connecticut Reliability Project) was commercialized at the end of 2008. The 188 MW GenConn Devon and the 188 MW Middletown plants were commercialized in summer 2010 and summer 2011, respectively. The 620 MW Kleen combined cycle plant was commercialized in 3Q2011.

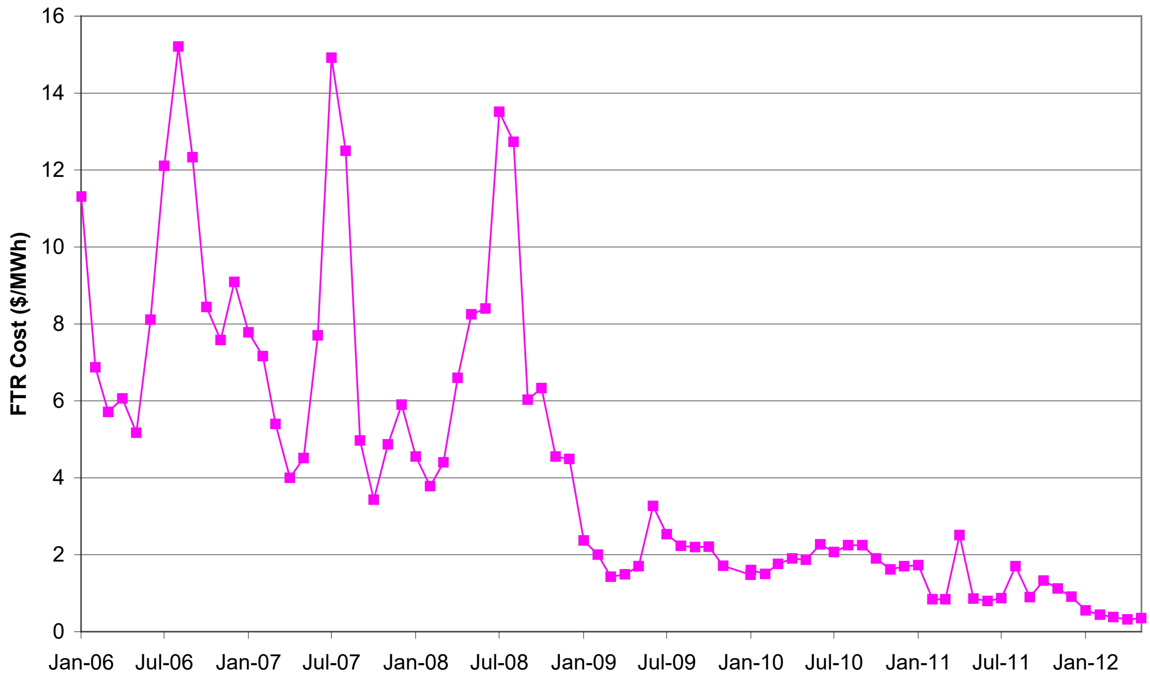
Figure 13. Average Monthly Congestion to the CT Load Zone, 2006-Present



Nonetheless, loss of a transmission line or an unscheduled outage of a major generation resource, such as Millstone 2 or 3, can cause congestion to spike. LSEs can manage a portion of their congestion risk by obtaining FTRs through annual and/or monthly auctions held by ISO-NE. An FTR is a financial instrument that entitles the holder to receive compensation for congestion costs that arise when the transmission grid is congested in the DAM, and differences in LMPs result from the dispatch of generators to relieve the congestion. Each FTR is unidirectional and is defined in megawatts from a point of receipt (where the power is injected onto the New England grid) to a point of delivery (where the power is withdrawn). For each hour when there is congestion on the system between the receipt and delivery points specified in the FTR, the holder of the FTR is awarded a share of the congestion charges collected for that hour.[17] FTRs do not represent a right for physical delivery of power. Bilateral arrangements and OTC products with a similar function as FTRs are also available to hedge congestion risk. As shown in Figure 14, like historical congestion, the magnitude and volatility of FTR clearing prices have generally diminished since the end of 2008.

[17] FTR holders can realize losses if reverse congestion occurs, *i.e.*, prices at MassHub exceed the CT Load Zone.

Figure 14. On-Peak Monthly FTR Clearing Prices, MassHub - Connecticut



5.3.4 Capacity

Since June 1, 2010, capacity prices have been set by ISO-NE through the FCM. ISO-NE projects summer peak load and the installed capacity (ICAP) needs of the power system three years in advance, and then holds an annual Forward Capacity Auction (FCA) each May to purchase capacity to satisfy the region's capacity requirements to ensure resource adequacy. Capacity prices are expressed on a dollar per kW-month basis Across New England, the total annual Capacity Load Obligation charge is the product of the region-wide capacity requirement multiplied by the capacity clearing price, times twelve. Each load asset is assessed a share of the Capacity Load Obligation charge based on a capacity requirement calculated for the load asset. A load asset's capacity requirement is based on the aggregate use of the customer load for that load asset measured during the prior calendar year's peak load hour for the ISO-NE system. During the delivery period, the LSE is assessed a daily FCM charge based on the daily "ICAP Tag" associated with the load asset. The ICAP Tag reflects the contribution of the load asset to the daily peak load for the ISO-NE system.

With the completion of the 6th FCA, forward capacity prices have been established through the end of capacity year 2015/16 (ending May 31, 2016), as shown in Table 1. Thus, over the procurement horizon for Standard Service, the capacity prices but not the quantity can be known with certainty.

Table 1. FCM Clearing Prices[18]

FCA #	Capacity Year	Clearing Price ($/kW-mo.)
1	2010/2011	4.500
2	2011/2012	3.600
3	2012/2013	2.951
4	2013/2014	2.951
5	2014/2015	3.209
6	2015/2016	3.434

In April 2012, FERC instructed ISO-NE and market participants in New England to refine the FCM, including the potential use of a sloped demand curve similar to the Base Residual Auction used in PJM, and the implementation of a Minimum Offer Price Rule to discourage the exercise of monopsony power, *i.e.*, entry of out-of-market resources. Part of the package of structural reforms to the FCM includes an extension of the existing floor price through FCA #7. Following FCA #7, removal of the FCM floor price is anticipated. Removal of the floor price coupled with the implementation of more stringent environmental regulation in New England, as discussed below, is expected to cause substantial retirements among the cohort group of old-style coal plants that lack pollution control systems, as well as residual oil-fired steam turbine generators. While the timing of these retirements is uncertain, many industry experts expect significant unit attrition to materialize prior to the end of the decade, thereby reducing the capacity overhang across the region. Increased capacity attrition effects associated with removal of the capacity floor price and environmental CapEx will likely cause capacity prices to increase significantly in order to support generation entry when new resources are needed at the end of this decade or in the beginning of the next.

5.3.5 RPS Obligation

RECs required to satisfy Connecticut's RPS can be obtained through bilateral forward contracts directly with renewable generators, OTC forwards from a broker, or through an RFP process. The LSE must procure the necessary RECs or pay the ACP, which has historically been higher than the market price for RECs. While OTC REC forwards are generally for delivery up to two years in the future, bilateral REC or green energy (energy bundled with renewable attributes) forwards may be for unit contingent or firm delivery under a long term contract.[19]

A qualified renewable generator receives market revenues from the sale of RECs, in addition to energy, capacity and potentially ancillary services. Because renewable

[18] The amount of generation and DR/EE that has cleared FCA #1-6 has exceeded the Installed Capacity Requirement (ICR) established by ISO-NE. Hence, resources that clear the FCM receive pro rated payments from ISO-NE. On a unitized basis these payments have been significantly lower than the annual clearing prices identified in Table 1.

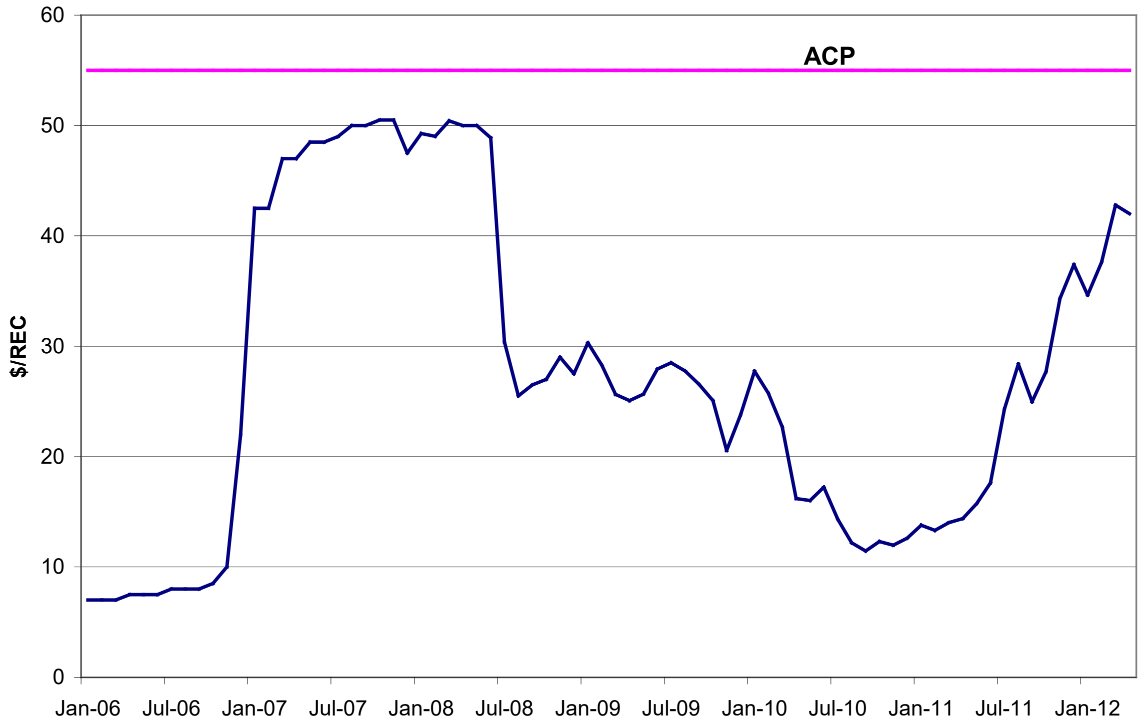
[19] Legislative initiatives have limited contract terms to 15 years.

facilities typically have higher capital costs than conventional generation, RECs represent an additional revenue stream that helps to support financing. The Class I REC requirement, as a percentage of an EDC's retail sales, increases annually until 2020, when the requirement reaches 20%. Class II and Class III RECs remain constant at 3% and 4% respectively.

Class I RECs have demonstrated a significant degree of variability over the past several years. Because Class I RECs are for the most part fungible across New England, marked price movements have occurred as a result of supply and demand fundamentals across the region, as well as regulatory changes both in Connecticut and elsewhere in New England. As illustrated in Figure 15, through most of 2006 Class I REC prices were soft reflecting a surplus of supply. At that time, qualified RECs could originate from New England, as well as from qualified projects in New York, Pennsylvania, New Jersey, Maryland, and Delaware. The enactment of PA 06-76 in June 2006 restricted geographic eligibility to just New England and adjacent control areas, which sharply limited supply and drove prices up to nearly the ACP.

Prices remained high through mid-2008, when they dropped precipitously in response to two events: (1) a PURA rule change allowing banking of RECs from one year to the next, and (2) a declaratory ruling sought from PURA to certify landfill gas injected into the interstate pipeline and delivered by displacement to a large natural gas combined cycle plant in New England. Prices generally continued to decline through 2H2010 as the REC surplus in Connecticut and elsewhere in the region was absorbed by the market. Since that time, a combination of increasing Class I REC requirements across New England, coupled with decreasing energy prices and concern that Congress will not extend the Production Tax Credit, has put upward pressure on REC prices. While Class I REC requirements will continue to grow in the region through 2020, commercialization of large off-shore wind projects, such as Cape Wind, and/or increasing energy prices, may mitigate REC prices in the future. Of course, regulatory and legislative uncertainty on the state and the federal level will remain a wildcard.

Figure 15. Connecticut Class I REC Monthly Average Prices (Current Year Vintage)



5.4 Resource Planning Considerations Affecting LMPs, Capacity Prices and Congestion Patterns in Connecticut

5.4.1 Generation and Transmission Resources

The Connecticut Integrated Resource Plan (2012 IRP) recently prepared by the Connecticut EDCs analyzed projected future electricity supply and demand, evaluated resource adequacy, and recommended policies to help make electricity cheaper, cleaner, and more reliable, while supporting in-state employment. In 2011 there were 8,150 MW of existing generating capacity resources available in the Connecticut sub-area to meet reliability requirements.[20] Based on reasonable assumptions about market conditions and the completion of transmission projects, the 2012 IRP concluded that adequate generating resources will be available in Connecticut to serve electricity loads reliably through 2022. No scenario analyzed in the 2012 IRP indicated a lack of adequate generation resources. Overall, the 2012 IRP showed that New England as a whole will not likely need new generation until 2022. However, under certain market conditions, a case can be made for new resources by 2018. These findings account for generation retirements that are likely to occur given market conditions and emerging regulations promulgated by the U.S. EPA.

[20] Source: 2012 CT IRP

Planned additions in Connecticut fall into two categories – capacity built to help satisfy RPS and capacity built for other reasons. The non-RPS additions include PSEG Power's 130 MW quick start peaker at New Haven Harbor that is scheduled to come on line on June 1, 2012. Planned additions to satisfy RPS between now and 2017 total 46 MW, including projects being developed for Project 150[21] in Connecticut. The 2012 CT IRP also assumes that 343 MW of renewables that are not yet planned will be developed.

In addition to the announced retirement of the 183 MW AES Thames plant in Connecticut, the 2012 IRP projects that additional economic retirements are likely to occur over the planning horizon. These are expected to be driven largely by weak capacity market prices and the significant capital expenditures associated with evolving environmental regulations, in particular, the Mercury and Air Toxics Standards and more stringent performance requirements for cooling water intake structures, which will affect coal and oil-fired steam units.

Because Connecticut is an import constrained sub-area, ISO-NE imposes a local sourcing requirement (LSR) in Connecticut in order to ensure that sufficient capacity is physically located within the sub-area to maintain local reliability when transmission constraints materialize.[22] In addition, ISO-NE also imposes a Locational Forward Reserve Market (LFRM) requirement on Connecticut. The LFRM requirement ensures enough quick-start capacity in Connecticut to recover from a second contingency outage occurring in Connecticut; commonly the unexpected outage of the Millstone 3 nuclear unit. The 2012 CT IRP estimates that there are adequate resources in Connecticut to meet the LSR well beyond 2022, with 600 MW of surplus in 2015/2016 and then 1,900 to 2,000 MW of surplus in 2016/2017 and beyond. The 2012 IRP also estimates that there are more than adequate resources projected to meet Connecticut's LFRM requirement through 2015, with a projected 1,501 MW available in Greater Connecticut, including 949 MW in Southwest Connecticut, well above the projected need in each area.[23]

The 2012 CT IRP summarized transmission reliability needs and ongoing studies in Connecticut, particularly in southwest and central Connecticut. In estimating resource adequacy for Connecticut the 2012 CT IRP assumed several transmission upgrades in the Connecticut sub-area designed to increase the import limit. The New England East West Solution (NEEWS) is a series of projects designed to improve system reliability and increase power flows from east to west in New England, which include thermal, voltage, and transfer import capabilities.

The Connecticut NEEWS-related upgrades include:

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[21] Project 150 (formerly Project 100) is an initiative aimed at increasing renewable energy supply in Connecticut by at least 150 MW of installed capacity.

[22] The LSR is set by the greater of the probabilistically-calculated Local Resource Adequacy (LRA), or the deterministically-calculated Transmission Security Analysis (TSA).

[23] The ISO-NE 2011 Regional System Plan indicates that through 2015 Southwest Connecticut will have no LFRM requirement, while Greater Connecticut may have a need of 400 to 1,000 MW of quick-start capacity.

- Greater Springfield Reliability Project (GSRP), which will increase Connecticut's import limit by 100 MW in 2014;

- Interstate Reliability Project, which will increase Connecticut import limit by 800 MW in 2016 and will connect the combined cycle generators at Lake Road into the Connecticut electric grid; and

- Central Connecticut Reliability Project (CCRP), which will increase Connecticut's import limit by 200 MW in 2017.

5.4.2 DR/EE Resources

The amount of DR and EE has a first order impact on capacity and energy prices administered by ISO-NE, and is therefore a relevant consideration in procurement of Standard Service. DR includes Active Demand Resources (Active DR), and Passive Demand Resources (Passive DR). Active DR is the ability to reduce participating customers' peak loads when called upon by ISO-NE if committed generating resources are insufficient to meet the peak demands.[24] Passive DR is primarily composed of EE and is designed to reduce energy demand during peak hours. Passive DR is non-dispatchable. Both Active DR and Passive DR are treated as supply resources and can participate in the FCM.[25] Connecticut has successfully expanded DR/EE through legislative initiatives and programs implemented by the EDCs. Recently, PA 11-80 has expanded Connecticut's energy conservation objectives to work toward positioning Connecticut as a leader in the nation for EE. Specifically, PA 11-80 addresses the leveraging of existing funds to provide low-cost EE financing and the utilization of savings-based and performance-contracting initiatives. Part of the implementation of PA 11-80 will involve the EDCs' continued annual submission of a Conservation and Load Management (C&LM) Plan with DEEP and PURA, in accordance with Conn. Gen. Stat. §16-245m and §16-32f. In addition to planning EE programs for a one-year budget cycle, the 2012 C&LM Plan also reports that in 2010, the EDCs delivered average EE savings of approximately 50 MW and 400 GWh per year.

5.5 Financial Indices

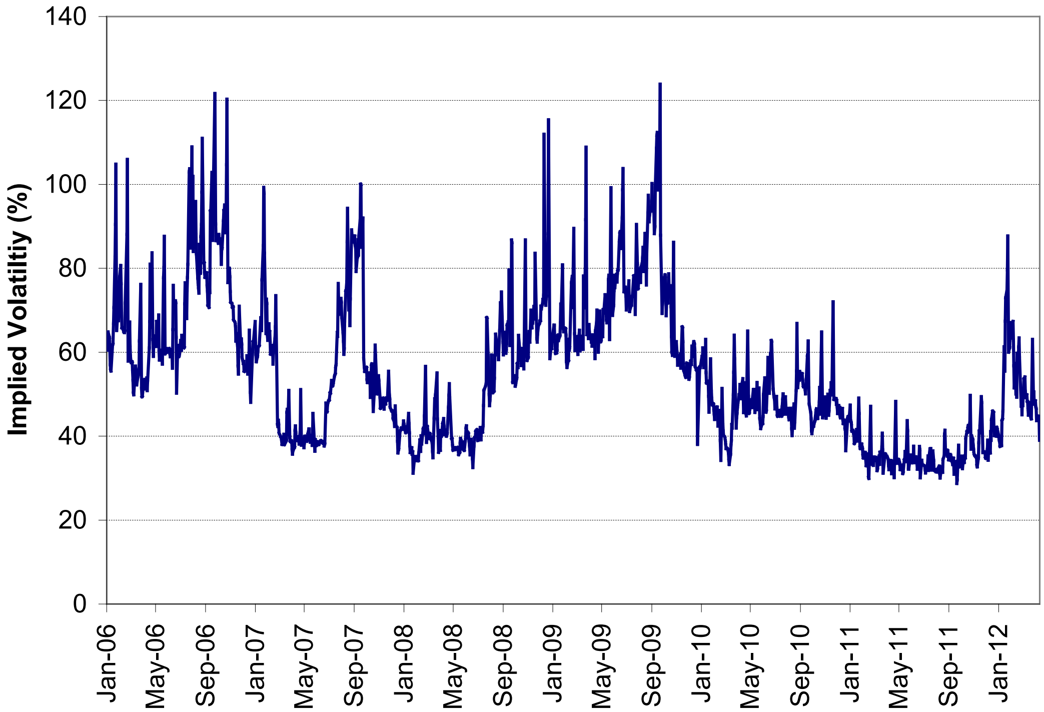
As discussed in Section 4.5, risk management is an integral component of full requirements contracts. The cost of risk management is, in part, a function of certain financial indices that reflect overall market uncertainties. Suppliers offering load-following energy services generally hedge the risks associated with uncertainties about load and price. One key measure of the market's perception of price risk is implied volatility. Implied volatility is revealed through the price of options. Since options afford holders insurance against changing prices, the protection they provide is most

[24] Active DR includes Real Time Demand Response (RTDR) and Real Time Emergency Generation (RTEG) resources.

[25] In the 2013/2014 FCM, 520 MW of Active DR and 410 MW of Passive DR cleared, and in the 2014./2015 FCM, 521 MW of Active DR and 419 MW of Passive DR cleared.

valuable when the likelihood of major price changes is highest. Conversely, the protection is worth less when the market expects smaller price movements. Implied volatility is therefore generally positively correlated with the cost of load-following risk management. Figure 16 shows the implied volatility since 2006 for options on front-month (*i.e.* settling the month after trading) Henry Hub natural gas contracts traded on NYMEX.

Figure 16. Implied Volatility on Front-Month Gas Options, 2006-present[26]

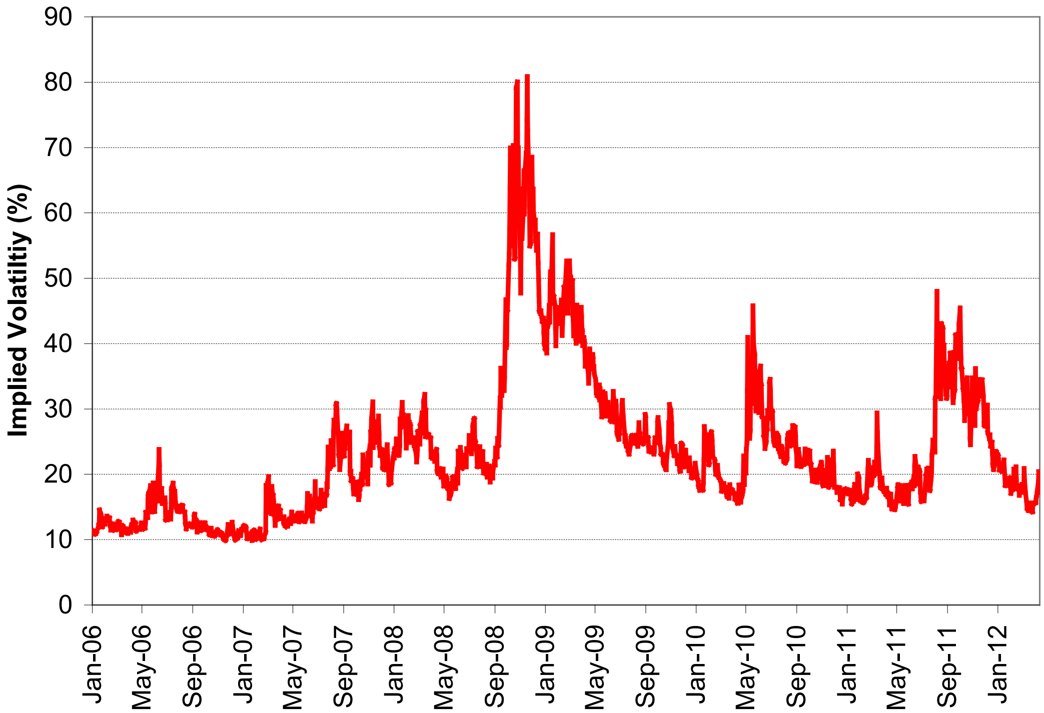


Historic implied volatility data indicate that the period following Hurricanes Katrina and Rita through the end of the 2009 was one of comparatively large uncertainty in the natural gas commodity market. The historic implied volatility data reveal that market participants expected prices to be erratic as implied volatility was high. Therefore the cost of options was commensurately high. However, from 2010 through 1Q2012, market expectations of price risk were dampened. Hence, the corresponding implied volatilities on gas options followed suit. There have been brief divergences in implied volatility, however. In early 2012, the implied volatility approached the 80% level that was characteristic of implied volatility in 2008 and 2009. This brief divergence quickly settled back in the in the 40-50% range. Given the strong statistical correlation or linkage between natural gas prices and wholesale power prices in New England, the implied volatility that applies to gas options is generally equally applicable to power options during the same period.

[26] Data were compiled by Bloomberg LP.

Global financial events have an indirect, second-order impact on the cost of credit and collateral underlying Standard Service. Like gas and power options, broader market indices likewise track the run-up and subsequent decline in volatility indices. For example, the Chicago Board Options Exchange's Volatility Index (VIX) indicates weighted-average implied volatilities for options on the S&P 500.[27] It is intended to measure the market's perception of risk for the U.S. equity market as a whole. The VIX is often referred to in financial markets as the "fear index." The VIX shown in Figure 17 indicates that overall market uncertainty was at its highest in 2009, the height of the U.S. financial crisis. Although the VIX has since receded, spikes in the VIX in both 2010 and 2011 indicated renewed concerns in financial markets as investors fretted over the potential repudiation of sovereign debt obligations in Greece, Italy, Spain and Portugal, thereby threatening the stability of the Eurozone.

Figure 17. S&P 500 Volatility Index, 2006-present



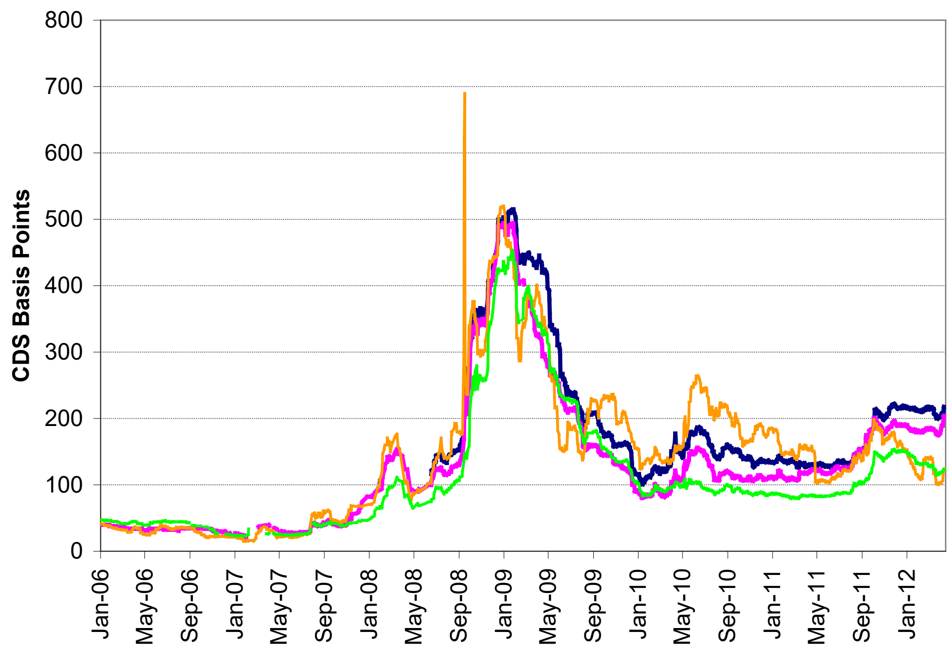
The factors that underlie the high volatility measures for natural gas and power are directly and strongly correlated. The factors that drove the VIX to high levels in the last three years are not directly and strongly correlated with commodity price volatility, however. Gas price volatility is driven by supply and demand fundamentals, including weather events and, to a much lesser extent, geopolitical events. The broader based financial sentiment captured by the VIX is more reflective of macroeconomic and geopolitical conditions. As such, energy market participants in 2009-2010 faced a highly

[27]http://www.cboe.com/DelayedQuote/DQBeta.aspx?content=http%3A%2F%2Fdelayedquotes.cboe.com%2Fnew%2Findices%2Fquote.html%3FASSET_CLASS%3DIND%26ID_NOTATION%3D8941863

negative confluence of events. Risk in the commodity markets was rising at precisely the same time that risks associated with their business operations were multiplying. The result was that the risk profile for energy firms changed dramatically and negatively during this period.

A useful measure of the total risks associated with a given firm is the cost of a Credit Default Swap (CDS) on that firm's debt. A CDS mitigates the holder's risk of a firm defaulting on its debt; were that to happen, the holder would be paid out by the CDS. A CDS is effectively insurance against a firm's default on its debt. CDS are quoted based on the number of basis points above the rate of the underlying firm's debt issuance.[28] The higher the rate, the greater the cost (and value) of the CDS, based on the market's perception of the underlying firm's riskiness. Figure 18 shows 5-year CDS rates for four prominent energy firms who have active deregulated business segments.[29,30]

Figure 18. CDS Swaps for Selected Electric Energy Companies, 2006-present[31]



Prior to 2008, the data show that the market's perception of risk was low: less than 100 basis points were required to purchase insurance against debt default. The global credit crisis induced fundamental changes in the cost of obtaining credit and collateral to

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[28] A basis point is 1/100th of a percentage point.

[29] Source: Bloomberg LP

[30] While each of the firms indicated have utility operations, they also have active unregulated marketing affiliates. In almost all cases, such transactions are supported by the parent companies.

[31] The firms represented in this figure are not necessarily firms who have been awarded Standard Service contracts. This selection is intended only to be generally reflective of firms active in the wholesale energy market.

transact energy deals. By mid-2009, the cost of purchasing insurance against debt default had risen tenfold. While the market's perception of credit defaults has since moderated in the energy sector, the cost of obtaining insurance against debt default has not returned to the pre-crisis level prior to 2008. While the cost of risk management has stabilized in 2011 and 2012 relative to the high cost and gyrations in the wake of the financial crisis, suppliers competing for Standard Service in Connecticut are expected to incur more costly financing and risk management costs in relation to pre-2008 levels.

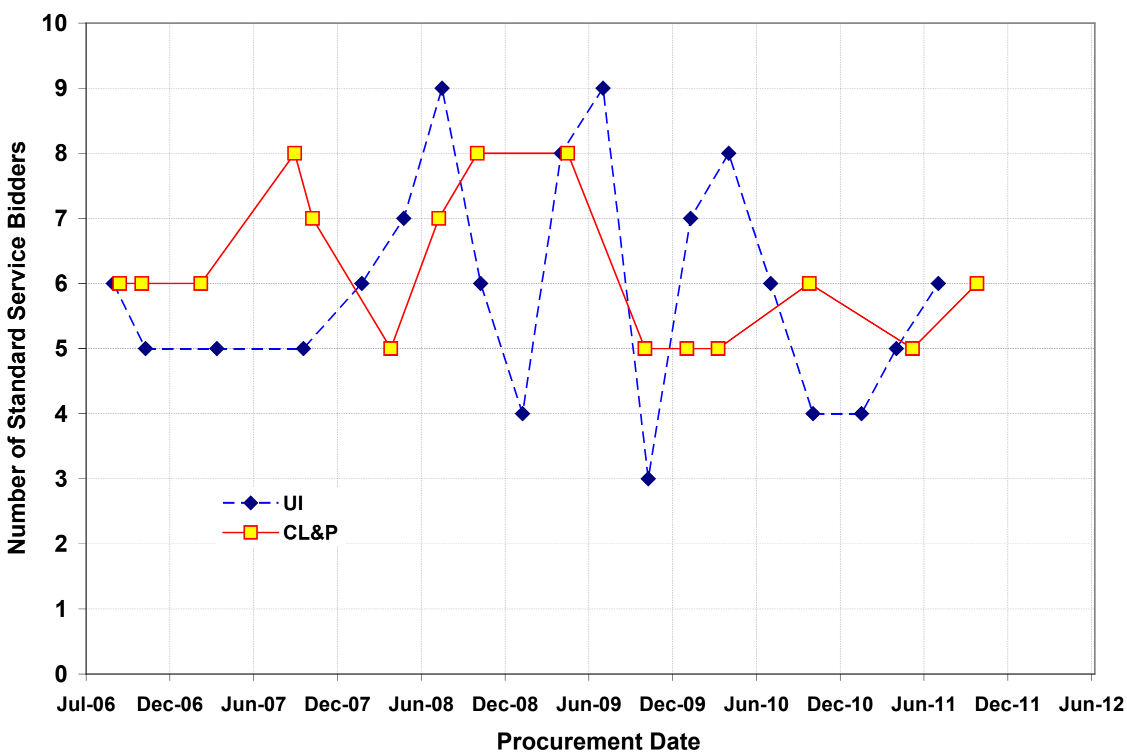
6.0 ANALYSIS OF HISTORIC BID INFORMATION

To lay the groundwork for this Power Procurement Plan, results from prior Standard Service procurement rounds have been evaluated against the backdrop of market conditions. The purpose of this historic review is to assess which aspects of the procurement design have advanced the objectives of best pricing, robust competition, and risk mitigation. All of the information presented in this section is in the public domain, consistent with PURA's Decision in Docket No. 06-01-08RE02 regarding the disclosure of auction data.

6.1 Bidder Participation Rates

The number of Standard Supply bidders participating in any single Standard Service procurement round has ranged from 3 to 9. While some bidders have participated in virtually every bid day, there have been several new participants and also bidders that have dropped out for one reason or another. Figure 19 shows the number of participants in each Standard Service round since the second half of 2006.

Figure 19. Bidder Participation in Standard Service Rounds

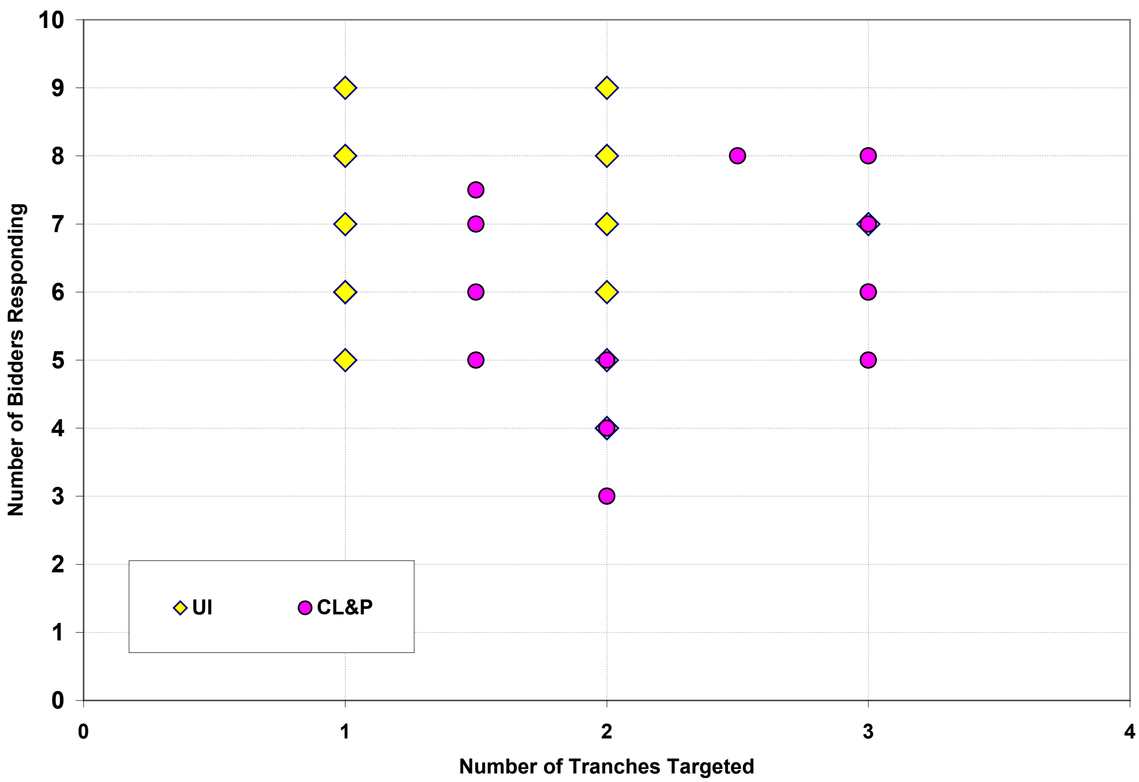


In general, there has been greater variability in the number of participants for UI's solicitations than for CL&P's. This may be insignificant or it may reflect an underlying bidder preference. In general, both UI and CL&P employ similar methods for disseminating information about bid opportunities, qualifying bidders, and scheduling bid days. Wholesale terms and conditions are also generally similar. UI's tranche size, however, is significantly smaller than CL&P's. At current migration levels, UI's peak load per 10% tranche is about 46 MW, whereas CL&P's peak load per 10% slice is about 200 MW.

6.1.1 Bidder Participation and Procurement Size

The relationship between the number of bidders offering tranches for a particular service term and several measures of the magnitude of the procurement has been reviewed. The number of responding bidders was plotted against the targeted number of tranches for the prompt year service term[32] for UI and CL&P procurements from 2008 through early 2012, as shown in Figure 20. For both UI and CL&P, the number of tranches or slices targeted for purchase was communicated to bidders, and both EDCs informed bidders that more or fewer than the target number may be purchased. There does not appear to be any significant linkage between the number of tranches targeted and the number of bidders offering tranches of the prompt year service term, and the correlation coefficients for the UI, CL&P, and combined data is insignificant.

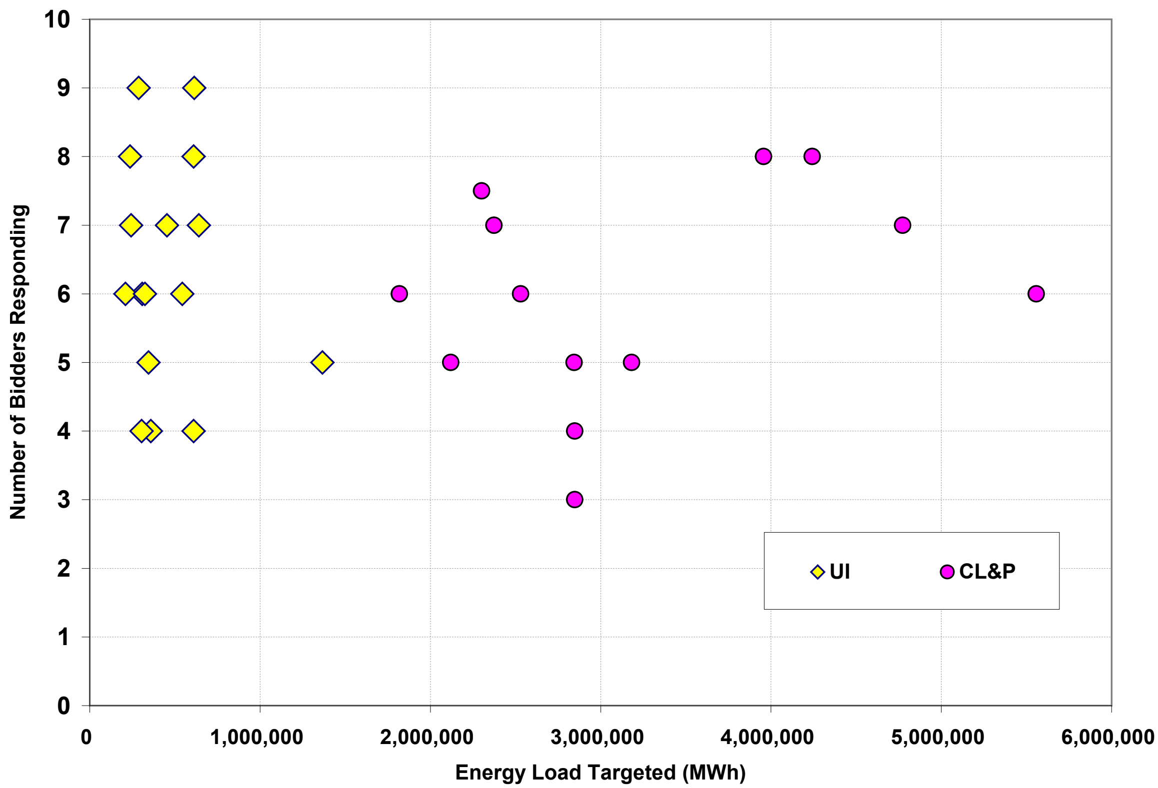
Figure 20. Number of Bidders vs. Targeted Tranches



[32] For these purposes, a prompt year service term is one that begins delivery in the calendar year immediately following the calendar year of the procurement. Where first-half and second-half delivery terms were solicited separately, only those occasions on which both halves were solicited are included. If the targeted amount or number of bidders was different for the two halves, the average number of tranches and/or bidders was used.

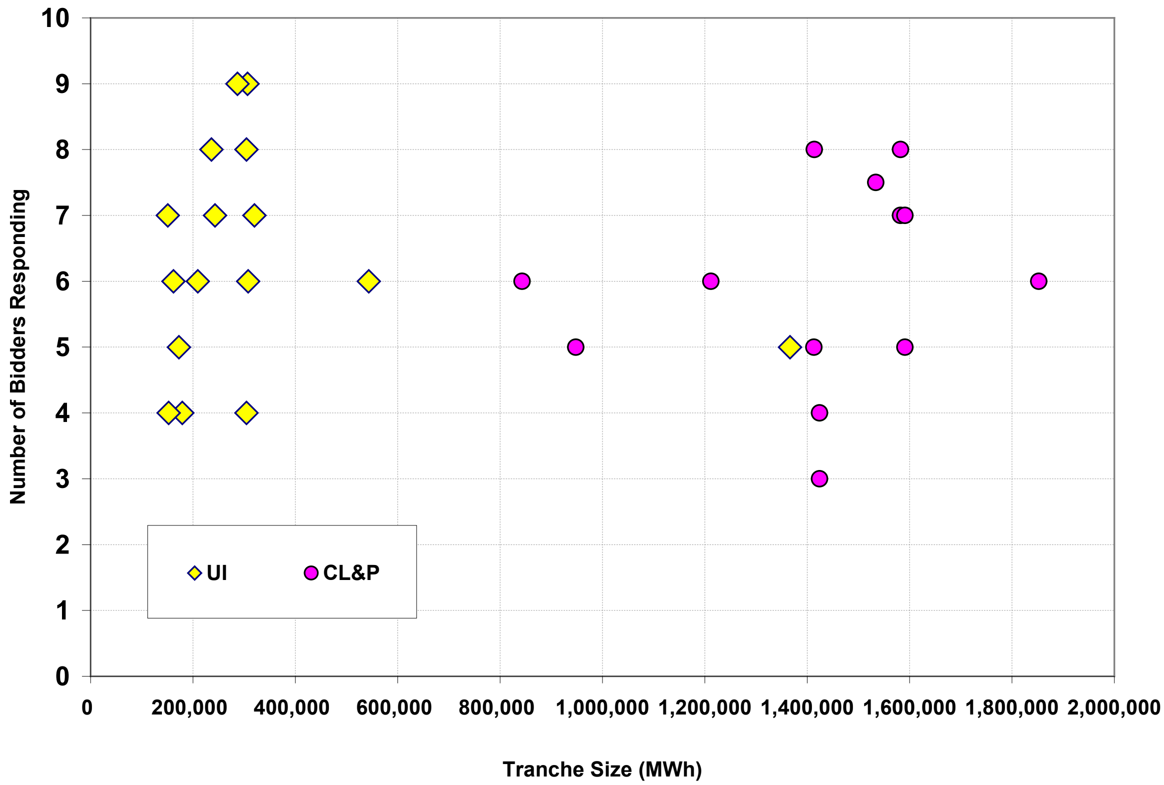
Another measure of the magnitude of a procurement is the total estimated MWh of energy represented by the targeted number of tranches. Bidder participation is plotted against the estimated target energy quantity in Figure 21. The UI data show no significant relationship, while the CL&P data imply a small (30%) positive correlation between the variables. Combining the data, the correlation for both EDCs together is insignificant.

Figure 21. Number of Bidders vs. Targeted Energy Load



A third measure is the size of the individual tranches, in terms of expected energy quantity. As shown in Figure 22, the correlation of number of bidders to this measure is small for the CL&P data at 22%. If the data point for UI at about 1.4 million MWh per tranche is excluded as an outlier, the correlation for the UI data is about 24%, still relatively insignificant. The combined data show no significant correlation.

Figure 22. Number of Bidders vs. Tranche Size



Based on the analysis of historic bid data, there does not appear to be a meaningful correlation between the bidder response rate and the tranche size or quantity of MWh. Although UI's tranche size and quantities targeted for purchase have been approximately one-fourth of CL&P's, bidder interest for UI's procurements has not correspondingly diminished. If there is a threshold below which bidder interest falls off, it appears to be below the quantities targeted by UI or CL&P in their respective Standard Service procurements. Observed round to round variability appears to be due to other factors, for example, whether there are concurrent procurements in other states.

6.1.2 Bidder Participation and Time to First Delivery

While Figure 19 does not reveal any discernible trend over time in the number of participating bidders in any round, analysis indicates that there is some increase in bidder interest for tranches or slices that will begin delivery closer to bid date. Generally, more bidders offer slices for delivery terms that will begin within 12 months than for slices sought for delivery further into the future. This trend is shown in Figure 23. In this chart, each curve represents a single CL&P bid date. The points on the curve plot the number of bidders offering Scenario A slices against the number of months from the bid date to the beginning of delivery for a service term being solicited. Most of the curves drop significantly between 9 and 18 months, showing declining interest in the longer-dated tranches. Figure 24 plots the same information for Scenario B bids and shows the same general relationship. Comparing the two charts, there is slightly more interest in

Scenario A bids inside of 18 months, while this difference is less pronounced outside of 18 months to delivery.

Figure 23. CL&P Bidder Interest and Time to Delivery (Scenario A)

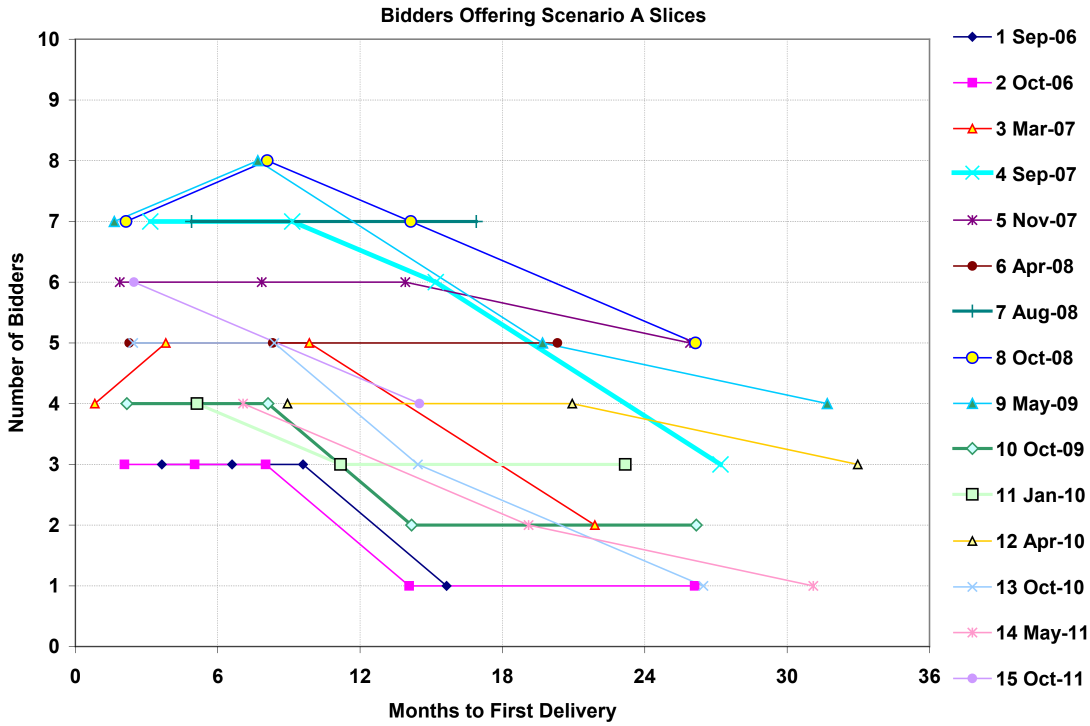
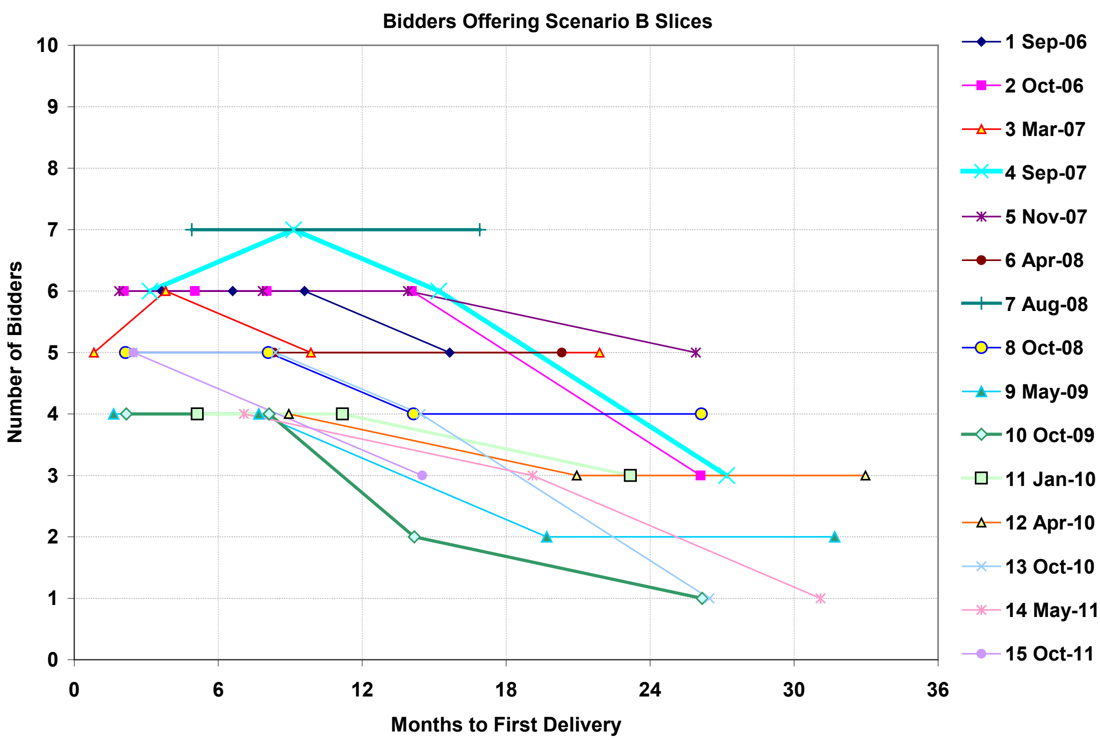


Figure 24. CL&P Bidder Interest and Time to Delivery (Scenario B)



A similar relationship between number of bidders participating and time to first delivery is shown for UI bids in Figure 25 and Figure 26. Note that UI did not solicit Scenario B bids in the first four rounds.

Figure 25. UI Bidder Interest and Time to Delivery (Scenario A)

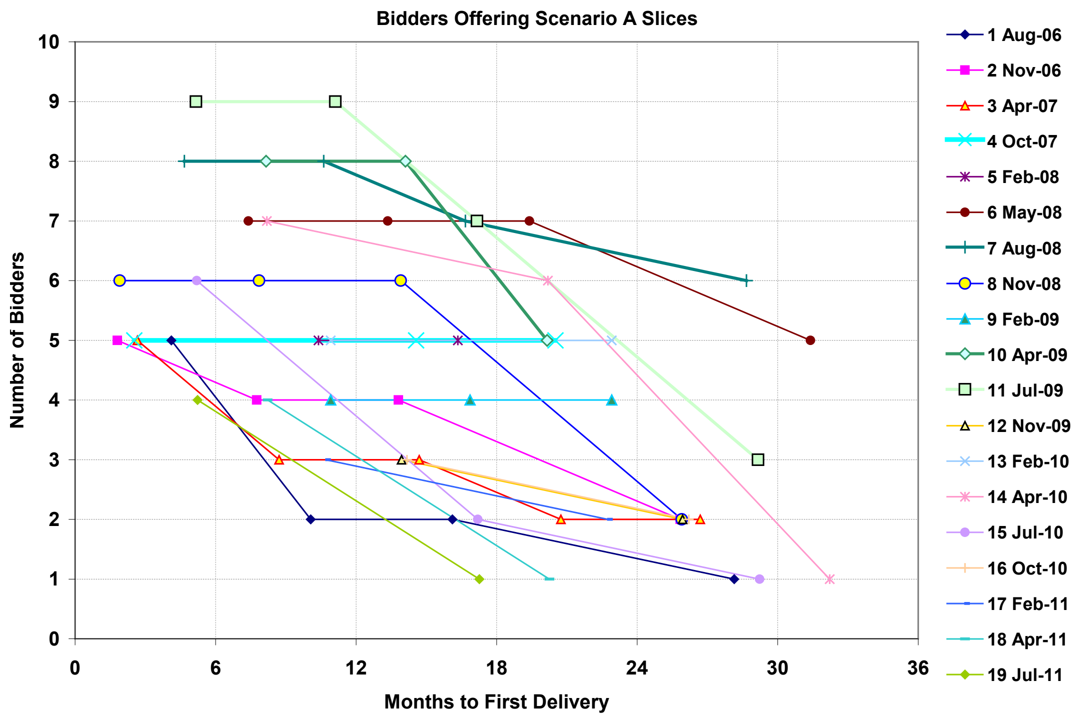
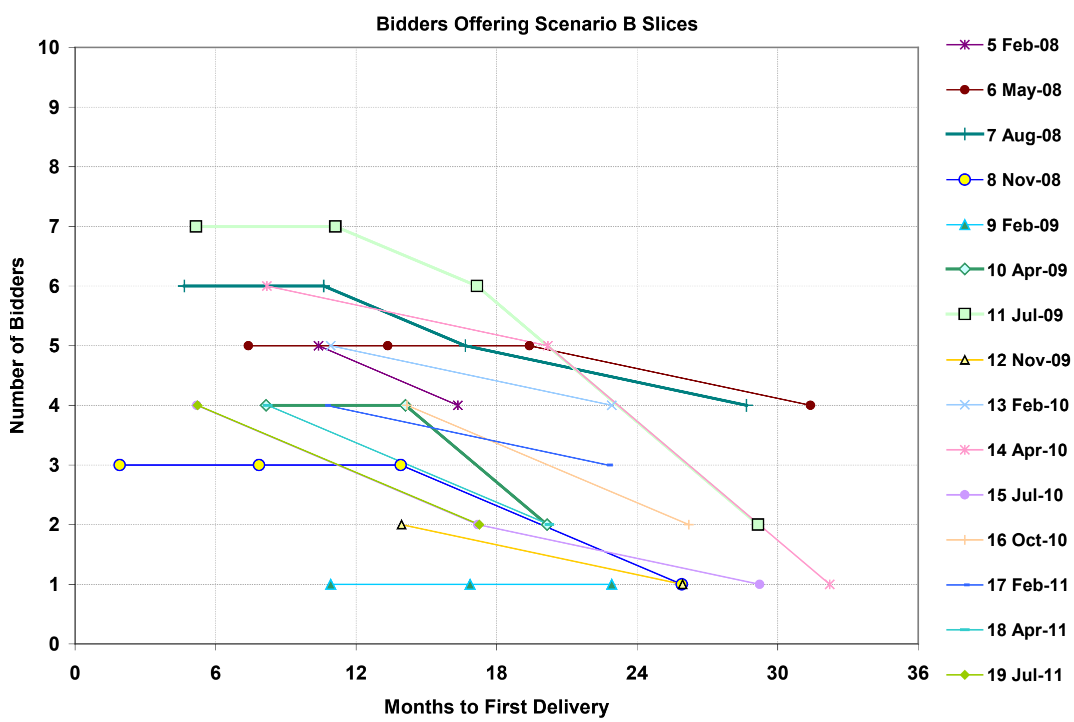


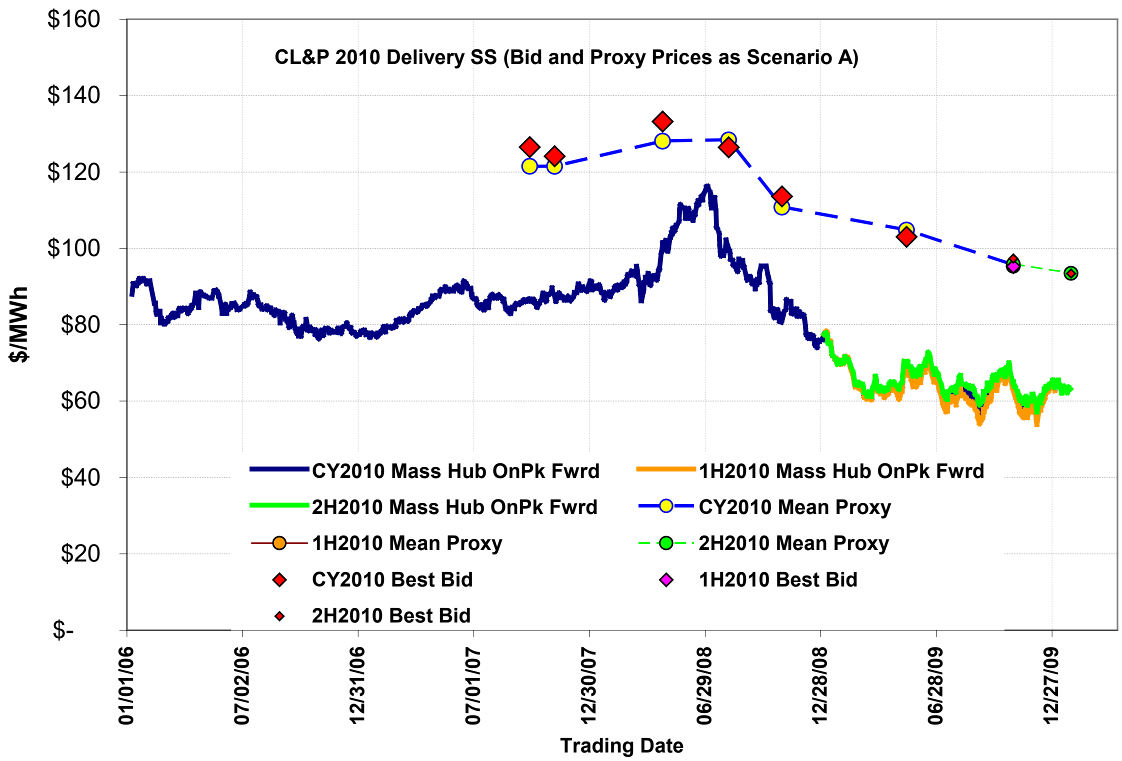
Figure 26. UI Bidder Interest and Time to Delivery (Scenario B)



6.2 Bid Pricing Relative to Market

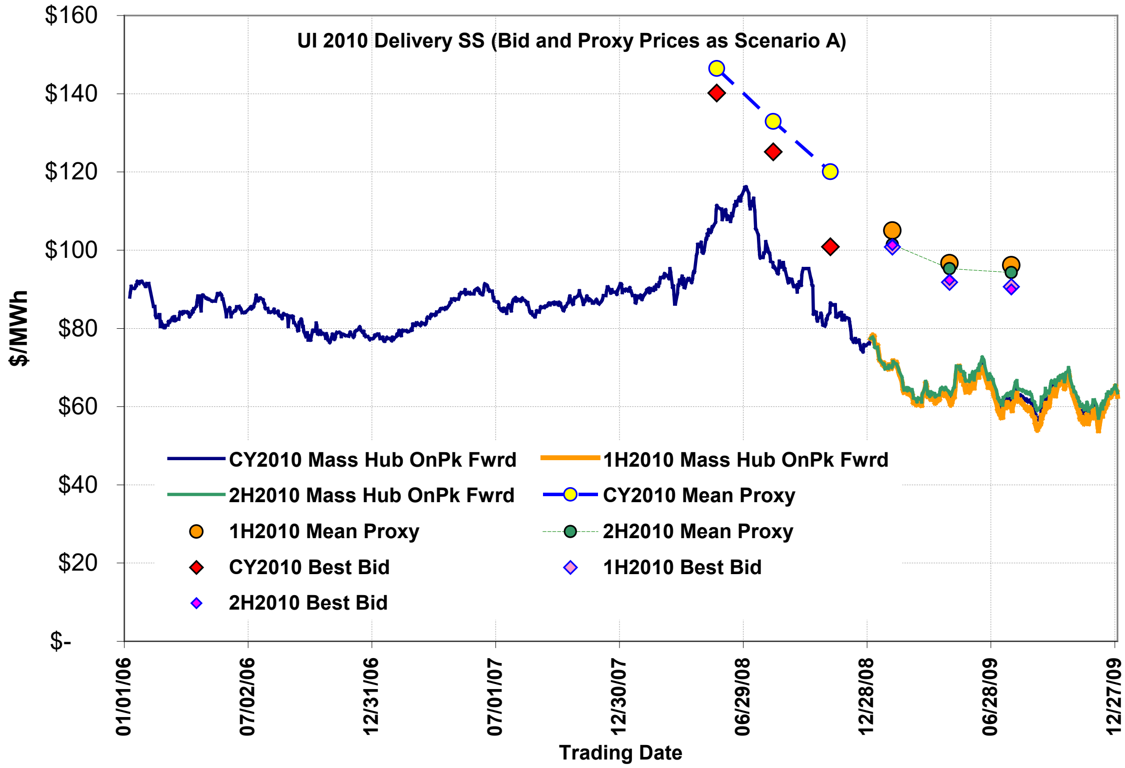
Bid prices for Standard Service have been closely correlated with the forward energy market, with adders for capacity, RPS, hedging costs, and other elements of full requirements service. Figure 27 shows forward prices, the average of proxy prices,[33] and the lowest price bids received for CL&P Standard Service supply for calendar year 2010 delivery. Figure 28 shows the same information for UI Standard Service. All proxy and bid prices are represented as Scenario A, and therefore include congestion and losses between the MassHub and the CT Load Zone. Note that the MassHub on-peak price has been used as a benchmark for the forward energy prices, but the same trends could also be shown using an around-the-clock or other representation of forward prices. Importantly, the forward price curves plotted in Figure 27 and Figure 28 are for block energy products *only.* The forward price curves do not include all of the other components required to serve load depicted in Figure 5 and are presented to illustrate the trends and market movements since 2006.

Figure 27. CY 2010 Forward, Proxy, and Bid Prices (CL&P)



[33] The proxy prices in these charts are an average of the proxy prices developed by the EDCs, the PURA consultant, and the OCC consultant. The individual proxy prices have been filed as protected information with each procurement round.

Figure 28. CY 2010 Forward, Proxy, and Bid Prices (UI)



6.3 Trends Associated with Laddering Design

The longer the period between bid day and the commencement of delivery under the full requirement bids, the greater the risk premium, and vice versa. Hence, the price differential between the MassHub on peak forward energy price on bid day and the full requirements bids generally diminishes as the bid date approaches the delivery date. This trend is shown for the CL&P auctions for various CY products in Figure 29. The dashed line is the regression line for all points shown. The regression indicates that the minimum spread is about $25/MWh, increasing to about $35/MWh over 36 months, or roughly $0.28/MWh-month. Figure 30 shows a similar analysis for calendar year products solicited by UI. This chart shows a similar Y-intercept for the regression line, but a somewhat lower slope. It should be noted that the correlation between the price differential and time to delivery is influenced by the general downward trend in forward energy prices over most of the period. As forward energy prices declined, some components of the total price remain constant (such as capacity), but others (such as hedge and collateral costs) are a function of both time and energy price.

Figure 29. Best Bid to MassHub On-Peak Forward Spread (CL&P)

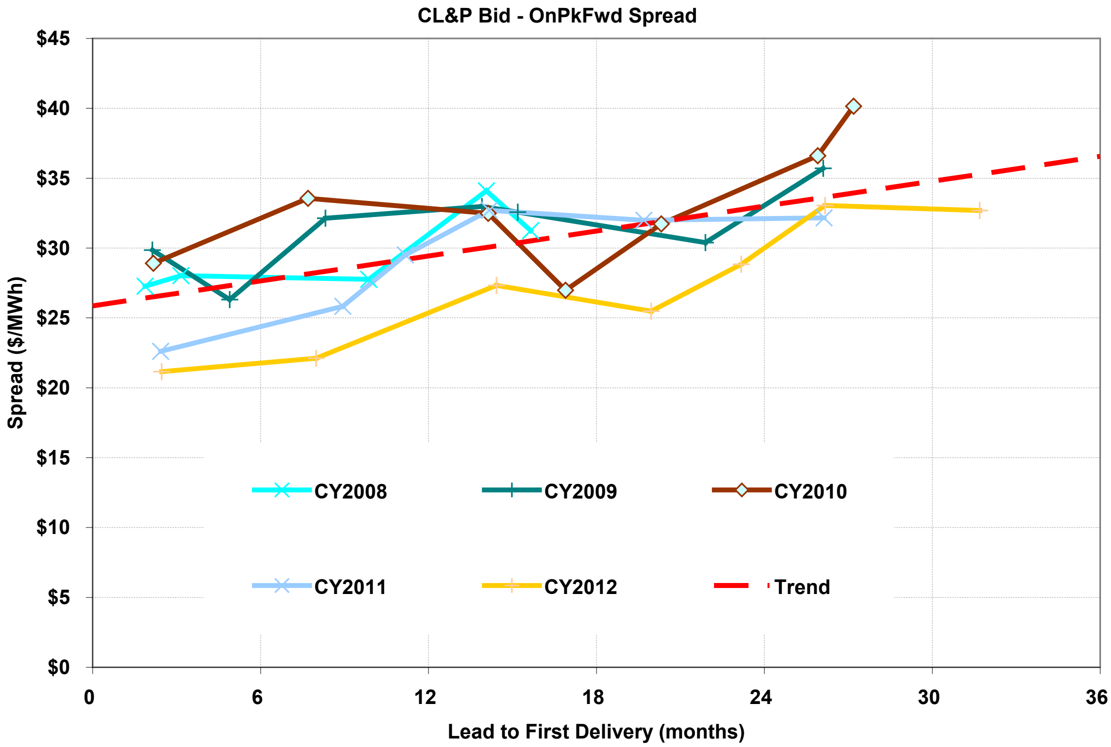
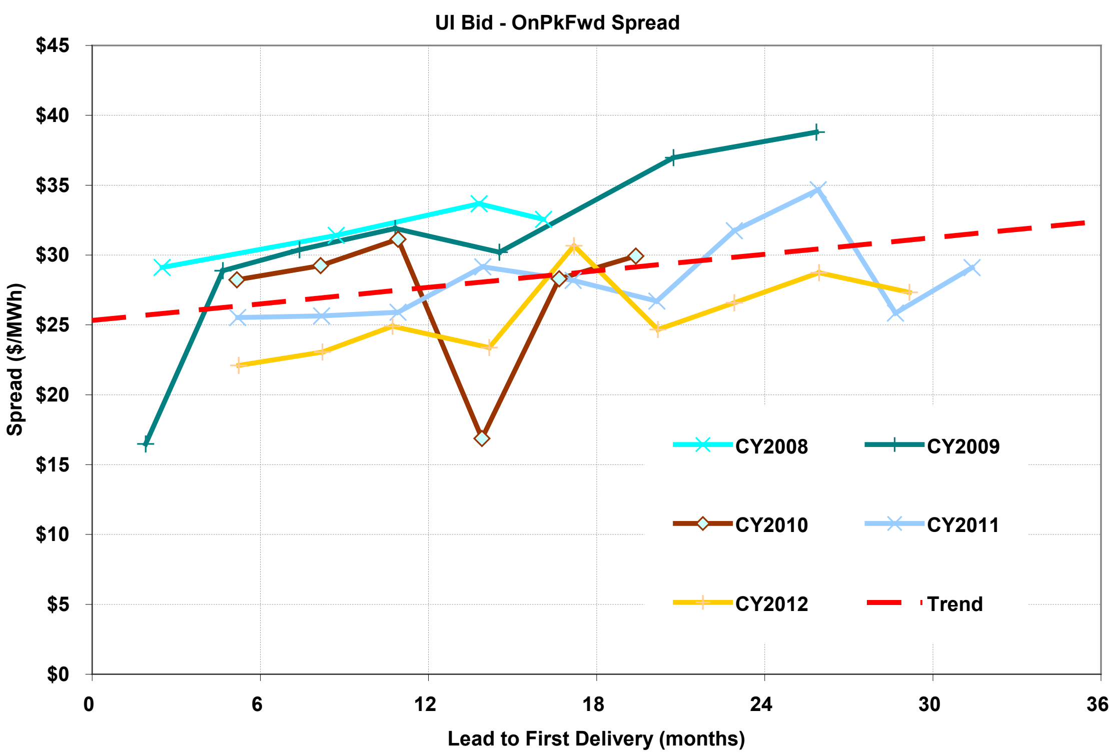


Figure 30. Best Bid to MassHub On-Peak Forward Spread (UI)



The range of the price differential for all bids received in each round is shown for the CY 2011 service term in Figure 31 for CL&P and in Figure 32 for UI. These charts also show the number of bidders offering slices or tranches for that service term. The same information is shown for CY 2012 delivery for CL&P and UI in Figure 33 and Figure 34, respectively.

Figure 31. Spread and Bidder Participation for CY 2011 (CL&P)

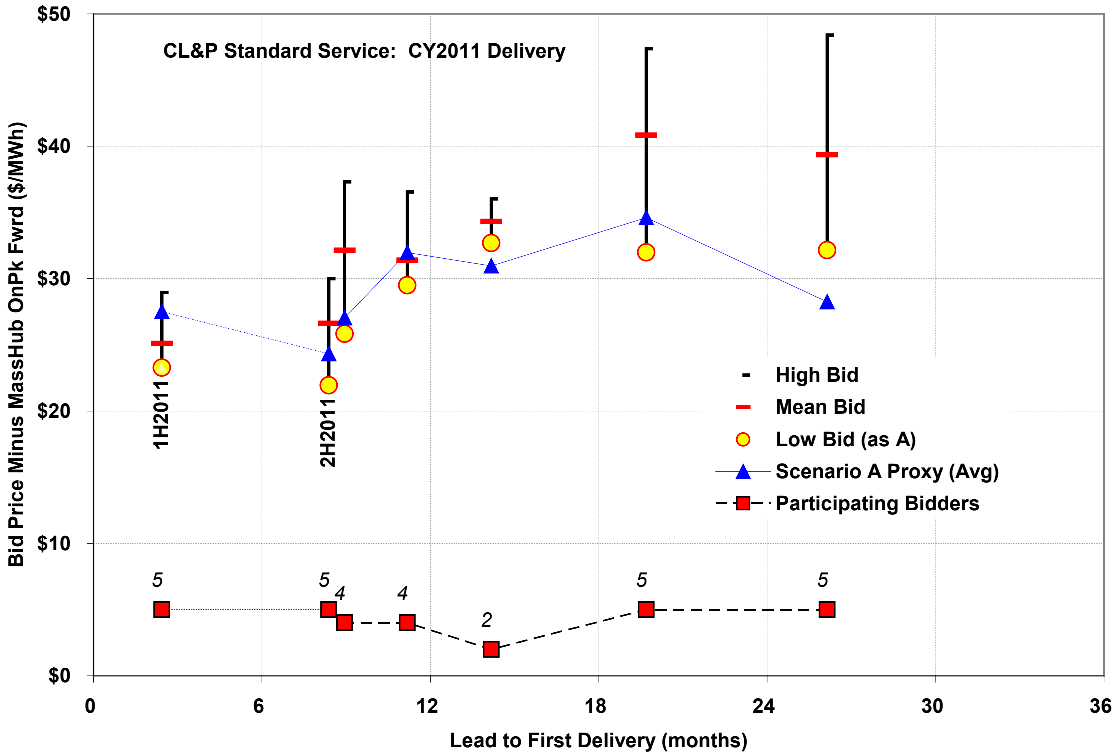


Figure 32. Spread and Bidder Participation for CY 2011 (UI)

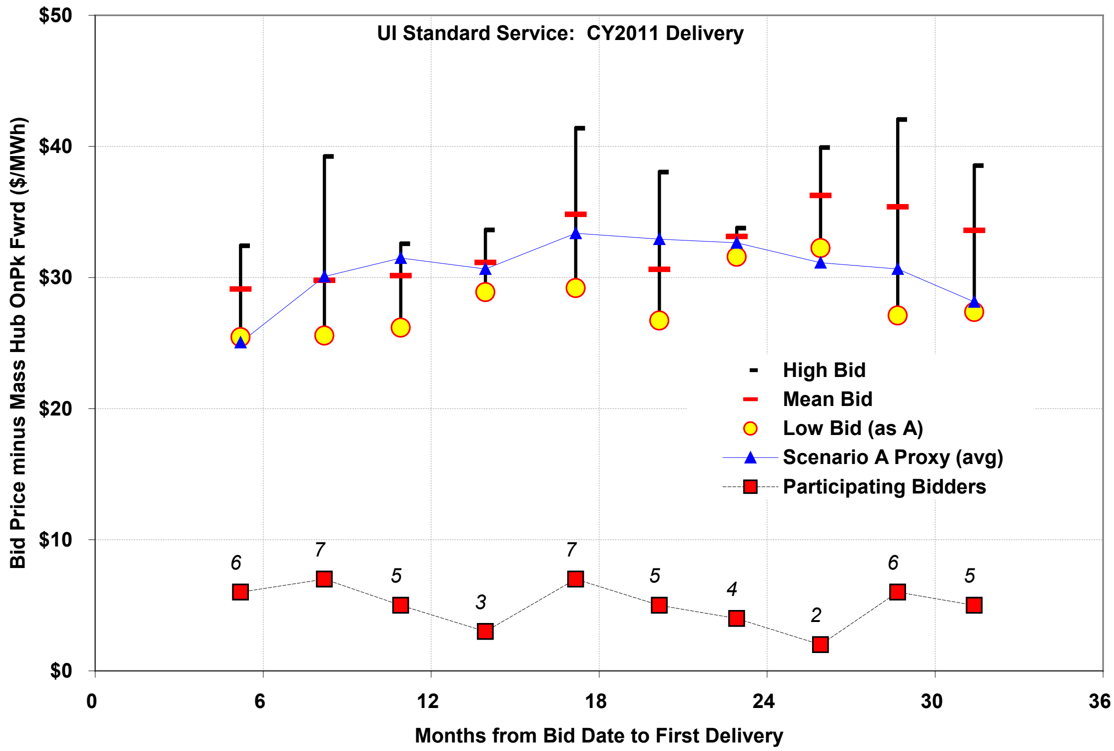


Figure 33. Spread and Bidder Participation for CY 2012 (CL&P)

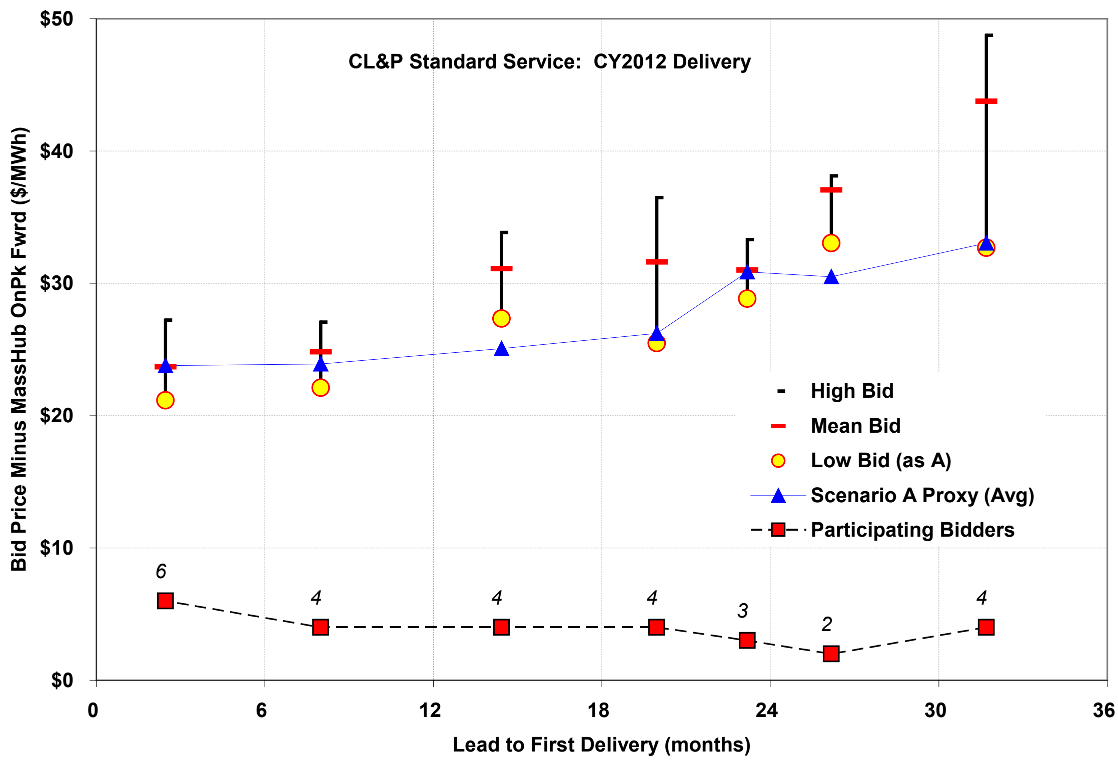
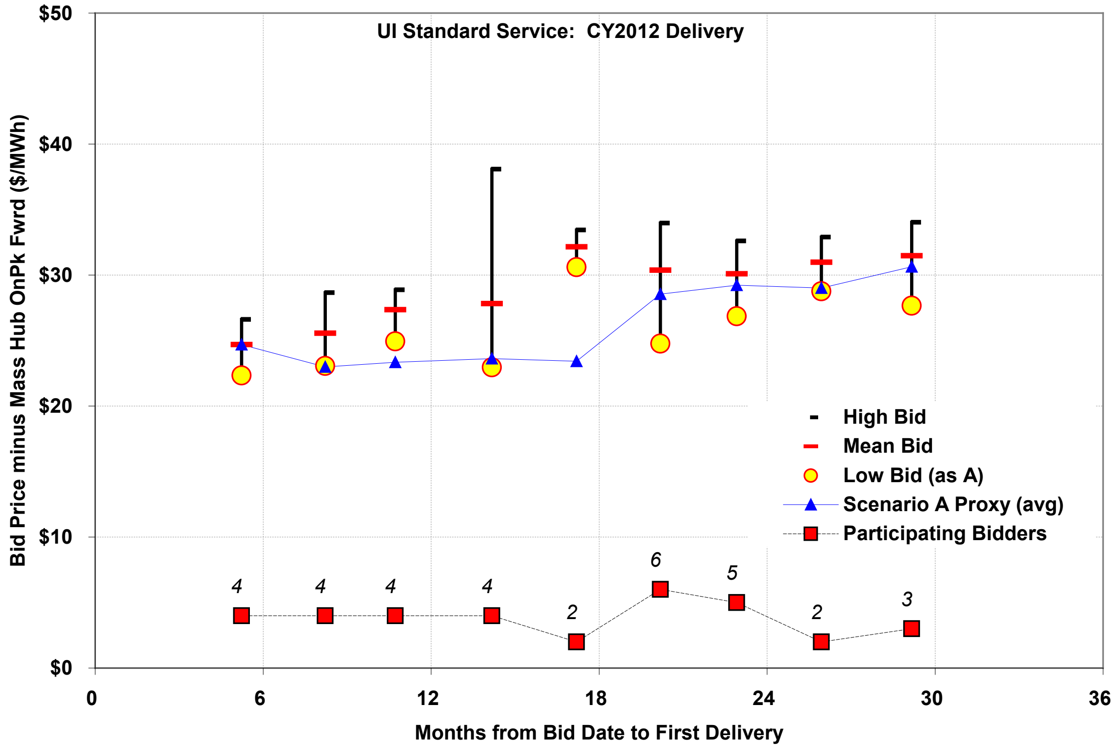


Figure 34. Spread and Bidder Participation for CY 2012 (UI)



The analysis of the historic bid and market data suggest that the differential between Standard Service bid prices and the forward energy prices for the corresponding delivery term decreases as the time between bid date and the commencement of delivery decreases. The decrease in this differential reflects a change in at least two components of the full-requirements price as the delivery date approaches: (1) the diminishing cost of collateral associated with forward energy contracts and (2) the decrease in real or implied cost of options to hedge against load uncertainty. These components can therefore be reduced by scheduling procurements closer to delivery terms.

7.0 LOAD ANALYSIS

Total electric load in an EDC's service territory represents the sum of the instantaneous use on a coincident basis of thousands of individual customers. These customers range in size from small households to large industrial facilities. While it would be impossible to predict the consumption of any single customer with precision, the patterns of consumption for some groups of similar small customers can be reasonably projected by applying statistical analysis to historical loads. This statistical analysis reflects such factors as ambient temperature, humidity, time of day, and economic activity, among other factors. Such aggregated projections and profiles are used over the short term to schedule day-ahead market purchases and, over a longer term, to estimate system-wide resource requirements through the FCM. In addressing a Power Procurement Plan for Standard Service over the next several years, it is helpful to understand Standard Service load as a subset of the total EDC load across its service territory and as a composite of four different customer classes.

Standard Service is the default service for Residential, Small C&I, Street Lighting, and those Large C&I customers falling under the threshold demand level for LRS. While a relatively small number of customers (about 2.3% of the total load) obtained their energy supply from competitive suppliers prior to the introduction of Standard Service on January 1, 2007, substantial numbers of customers in each rate class have chosen to migrate to competitive supply in the intervening years. To the extent that different classes of customers may have different incentives to migrate, the resulting Standard Service load not only diminishes in magnitude, but changes in its daily and seasonal profiles as well. This section examines the trends and risks exhibited by Connecticut Standard Service electric loads in terms of overall magnitude, composition by customer class, and choice of retail energy supplier.

7.1 Migration History

Monthly CL&P energy load, expressed as average MWh delivered per hour, is shown in Figure 35 for years 2007 through 2011. The top curve in blue shows the seasonal highs in January / February and July / August, and troughs in the transition months for all load delivered in CL&P territory, including load served by Standard Service, LRS, and competitive retail suppliers. The dashed line is a 12-month running average of those monthly loads. Over the five year period, total energy load has remained relatively stable, with a slight drop through 2009, followed by a partial recovery. Figure 36 shows a similar trend in total delivered load for UI. The general trend in total delivered load is likely attributable to the impact of the recession and the gradual penetration of EE programs implemented by the EDCs.

Figure 35. CL&P Average Delivered Energy Load

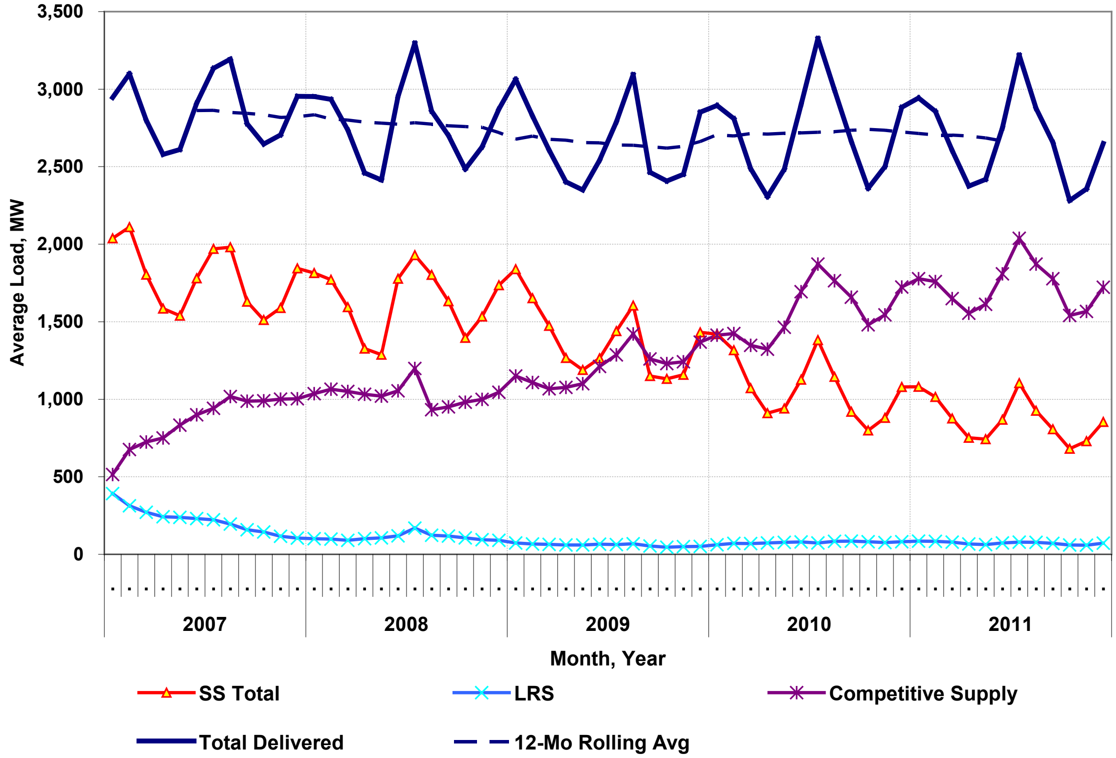
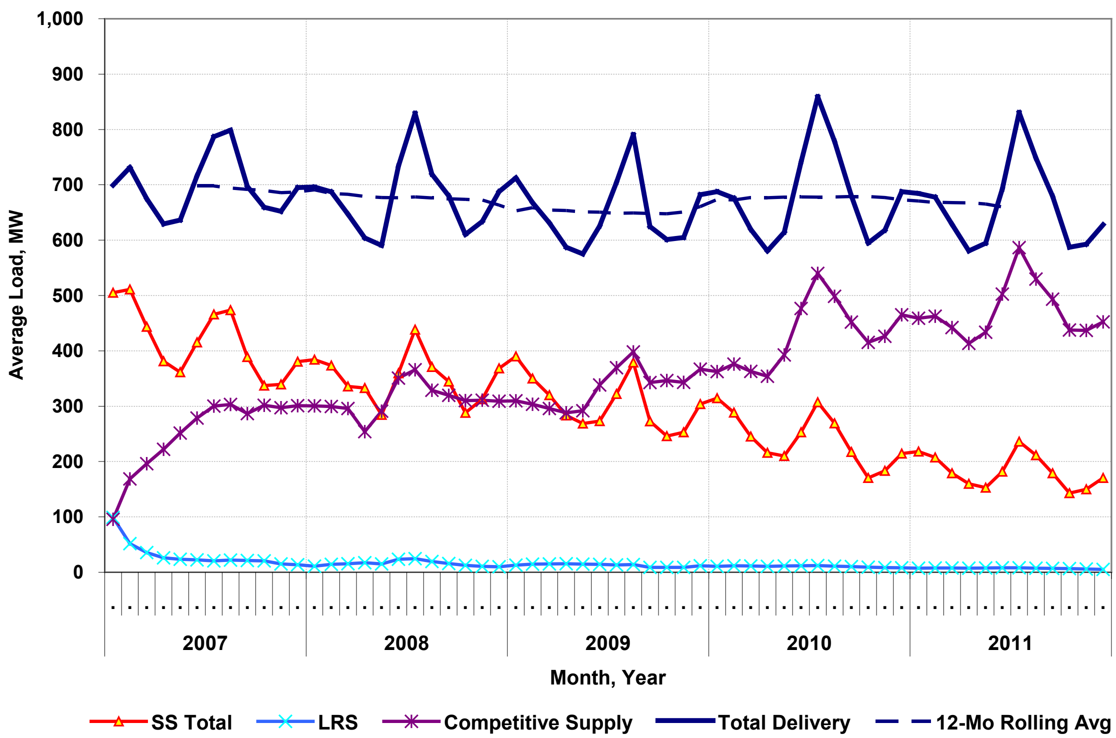


Figure 36. UI Average Delivered Energy Load



Customer migration arises from customers switching from Standard Service or LRS to a competitive retail supplier, or returning from a competitive retail supplier back to Standard Service or LRS. Until July 1, 2007, customers who left Standard Service and then returned were required to stay on Standard Service for at least six consecutive months. LRS customers were subject to a 12-month switching rule. PA 07-242 lifted all switching restrictions on Standard Service and LRS customers effective July 1, 2007.[34] Nonetheless, despite the lack of statutory restrictions, customers who select competitive supply may not be able to return to Standard Service or LRS until their retail contracts expire unless they pay the contract termination fee.

Figure 35 and Figure 36 show the monthly average energy usage (average MWh per hour) for Standard Service, LRS, and total competitive supply for CL&P and UI, respectively. Both EDCs experienced substantial migration of commercial and industrial load from LRS and Standard Service to competitive retail suppliers in the first year under the current procurement structure, which became effective on January 1, 2007. As shown in Figure 37, CL&P's share of total load declined from about 83% in January 2007 to about 66% in December 2007. UI's customer load showed a similar trend in 2007, dropping from 86% to 57% as shown in Figure 38. Most of this migration was from LRS customers and Small C&I customers on Standard Service. Figure 39 and Figure 40 show the continuation of the migration trend through 2011 for the two EDCs. Because LRS rates were set semi-annually in 2007 and quarterly starting in 2008, and Standard Service rates were set semi-annually through 2009, many Large C&I and Small C&I customers likely sought the more stable rates that could be obtained from competitive retail suppliers. In contrast, residential customers, for the most part, stayed with Standard Service during the initial years. However, beginning in 2009 residential migration has accelerated. As of December 2011, 44% of CL&P residential customers and 81% of its Standard Service eligible business customers had switched to competitive suppliers, while 52% of UI's residential customers and 78% of its Standard Service eligible business customers had done the same.

[34] Codified in Conn. Gen. Stat. §16-244c(k)(5)

Figure 37. Migration of CL&P Energy Load in 2007

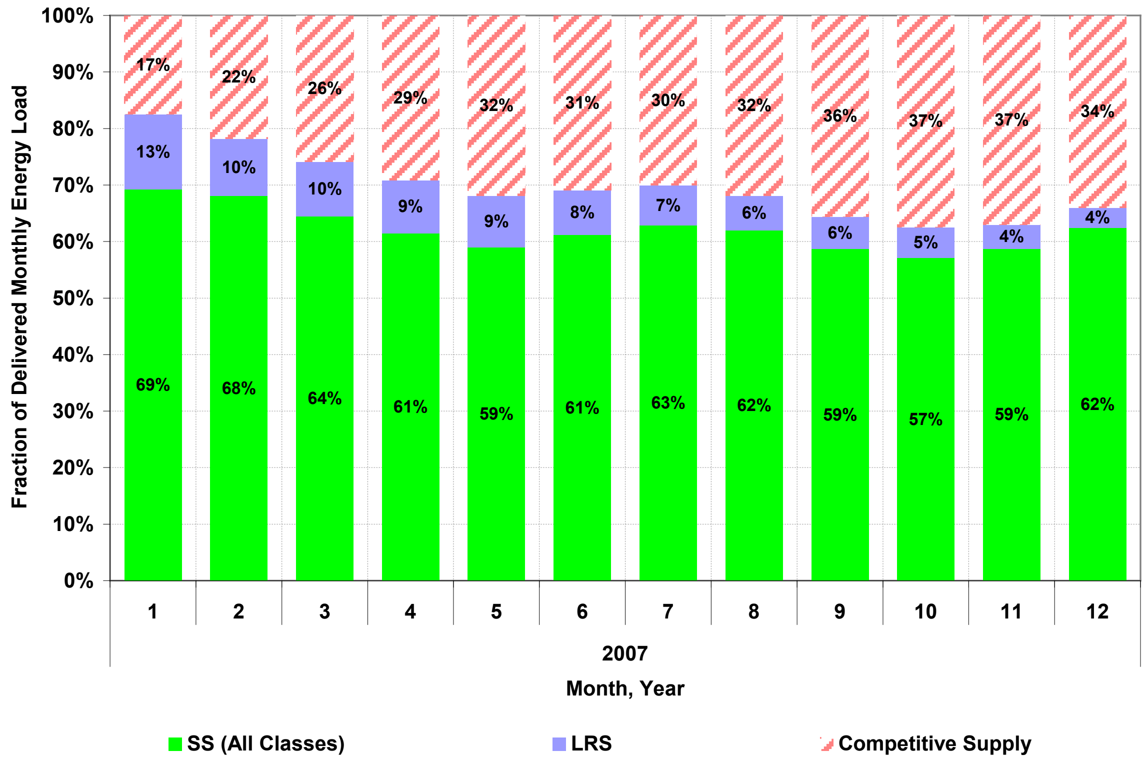


Figure 38. Migration of UI Energy Load in 2007

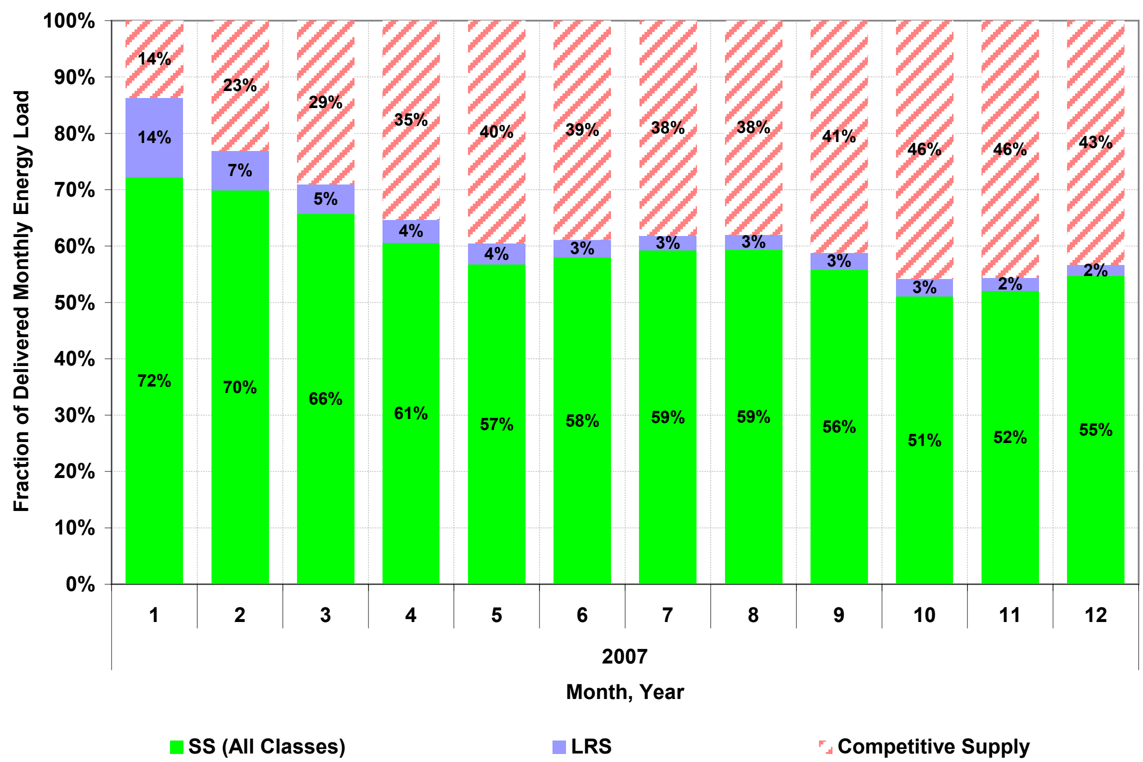


Figure 39. Migration for CL&P Energy Load (2007-2011)

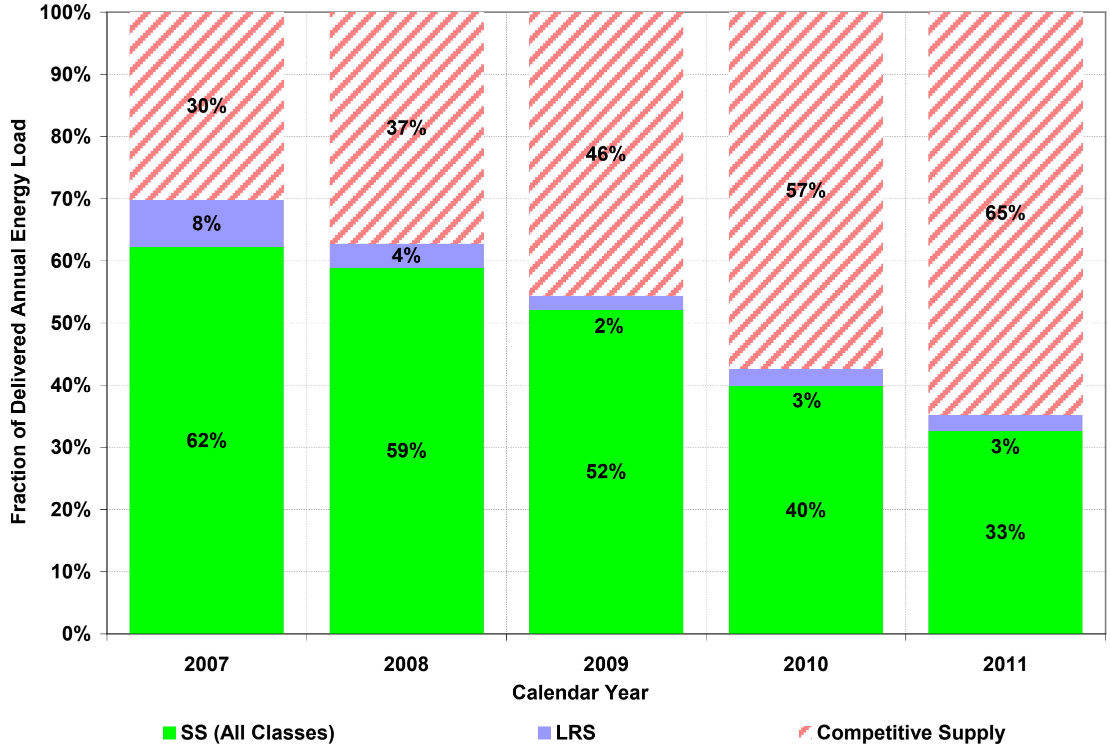
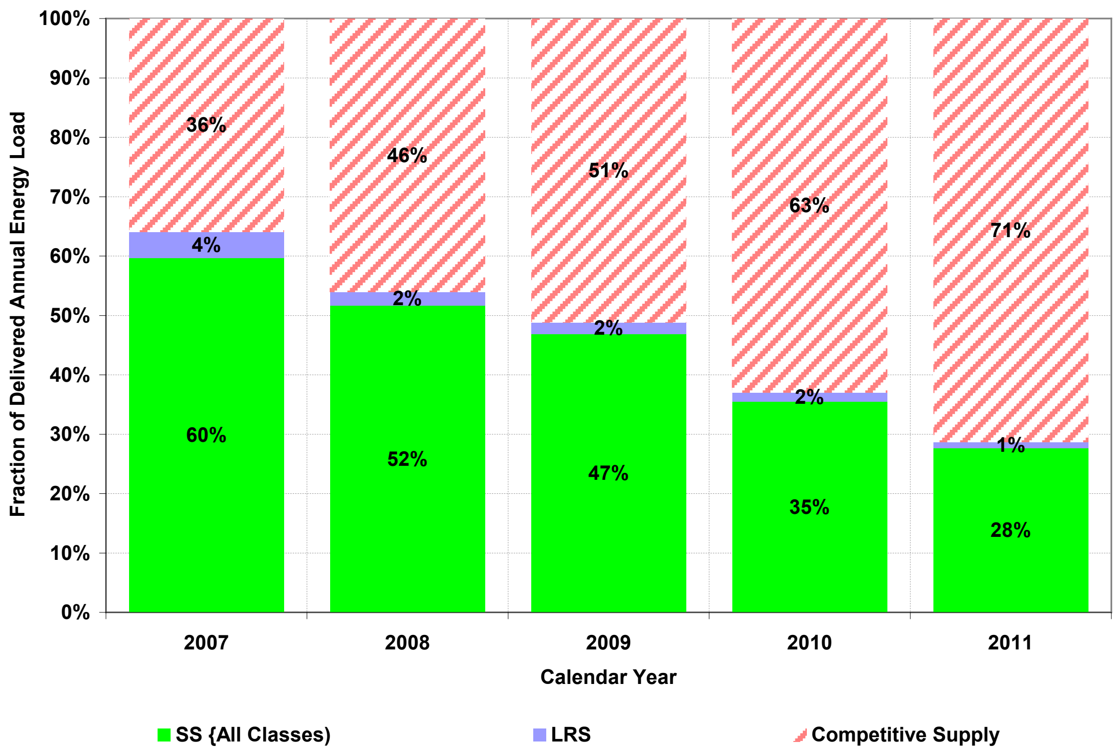


Figure 40. Migration of UI Energy Load (2007-2011)

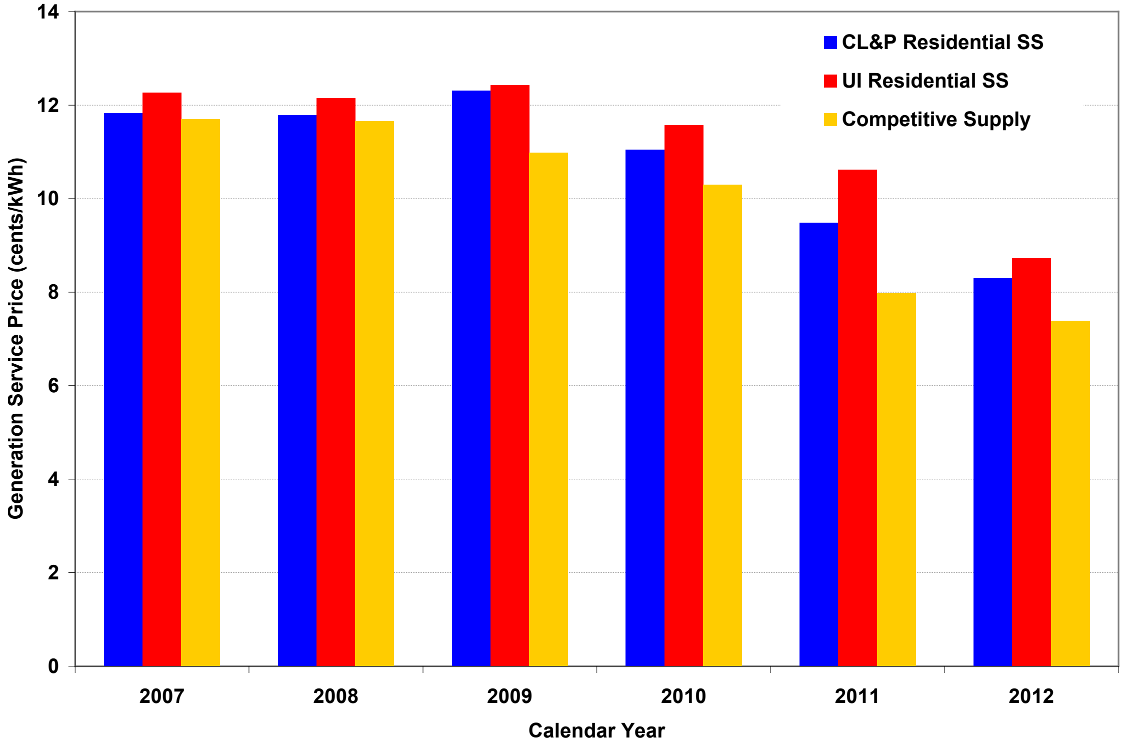


The trend in customer migration is explained largely by the difference between the Standard Service rates and the rates offered by competitive retail suppliers over time. If market conditions allow competitive retail suppliers to offer lower rates than Standard Service, or to a lesser extent, if retail suppliers offer value-added services, customers will switch from Standard Service to competitive retail supply. If, on the other hand, Standard Service rates drop below prevailing market prices, customers may return to Standard Service upon expiration of their service contract with their retail service provider.

Figure 41 shows Residential Standard Service rates for CL&P and UI, compared to the best reported competitive supply offer for a one year fixed price contract, as posted by CT Energy Info, a website developed by DEEP, the Energy Conservation Management Board and Institute for Sustainable Energy.[35] Standard Service and competitive supply prices for 2007 and 2008 are essentially identical, reflecting the facts that (1) all of the Standard Service supply contracts in these initial years were procured in a relatively short period close to the delivery periods, resulting in prices similar to competitive supply, and (2) the forward energy prices were generally rising during most of this period. Thus there appears to have been little incentive for customers to leave Standard Service. Competitive retail suppliers' prices for 2009 through 2012 were generally lower than the Standard Service prices, reflecting the facts that (1) the Standard Service supply costs were based on purchases over roughly 30 months prior to delivery, while competitive supply may have been locked in only a few months before delivery, and (2) forward energy prices have been in a general decline from mid-2008 through 1Q2012. While the general trend since 2009 has been one of increasing migration to competitive retail suppliers, consistent with the price differential, reverse migration may occur in the future if market prices begin to rise while Standard Service rates lag behind until the under-market laddered contracts roll off.

[35] www.ctenergyinfo.com

Figure 41. CL&P and UI Residential Supply Rate Comparison



7.2 Load Profiles

Serving a load asset such as Standard Service or one of its constituent rate classes from a portfolio of resources requires an understanding of the daily, weekly, and seasonal patterns exhibited by that load in the aggregate. While some large industrial customers may have relatively constant loads around-the-clock, typical business loads show substantial load shape diversity. Aggregate residential load exhibits a distinct pattern of usage, influenced by ambient temperature, day of the week, and time of day. Since total loads tend to be at their highest during daytime and early evening hours, market energy prices also tend to be highest in those hours, as more expensive resources are dispatched and set the marginal price. Individual C&I customers with predictable, stable loads that do not peak coincidentally with total system load are often the first to migrate to competitive supply, since they can negotiate prices that carry a smaller premium for high and uncertain on-peak usage. As these customers leave the EDC's default service (both Standard Service and LRS), the remaining load served by default supply becomes, on average, "peakier" and more expensive to serve. Competitive retail suppliers will generally compete for the "cream" of the load first. Therefore, *if all else were the same*, competitive retail suppliers would be able to offer lower prices than the EDCs' default service.

Based on the load data available from the EDCs, the daily load shapes or profiles for any month within the data range can be determined for total delivered load, LRS, total Standard Service, and for individual rate classes within Standard Service. Data for customers on competitive supply are available only in the aggregate, and cannot be easily broken down into the Standard Service rate classes for which the customers would be eligible.

Figure 42 and Figure 43 show the weekly profiles for CL&P for a typical winter week and summer week in 2011, respectively. Similar profiles for other months and other years for both UI and CL&P are provided in Appendix A.

Figure 42. Sample Weekly Profile for January (Hourly Load in MW)

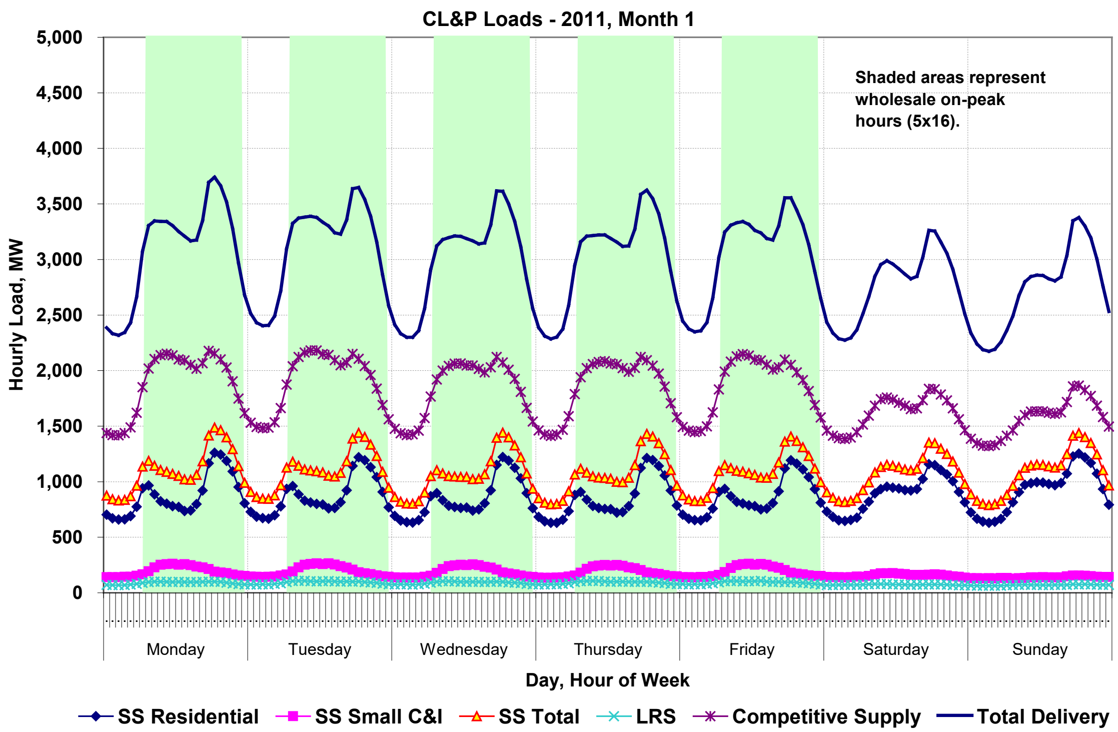
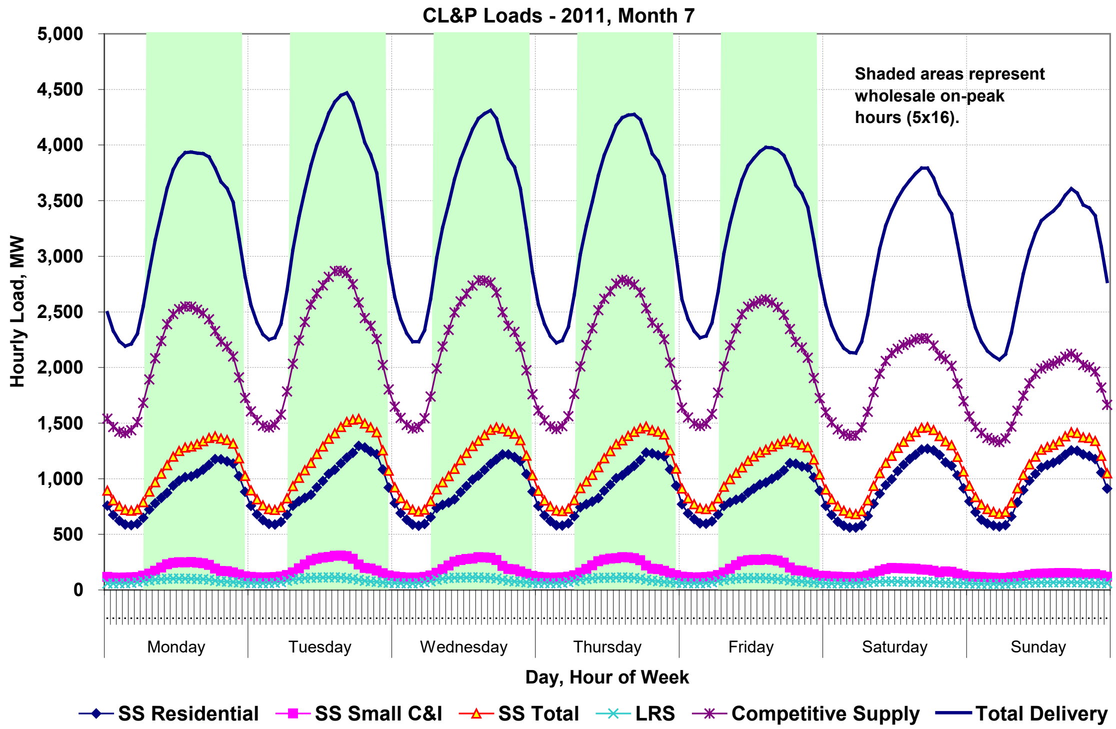


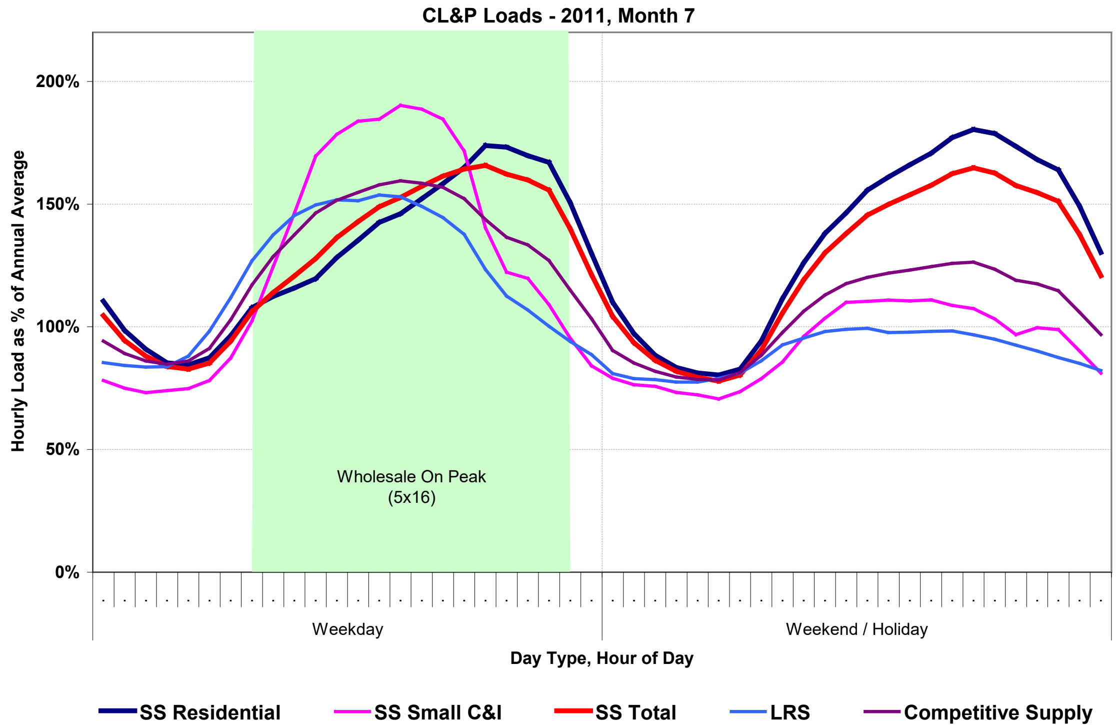
Figure 43. Sample Weekly Profile for July (Hourly Load in MW)



The profiles in Figure 42 and Figure 43 show the magnitude of the Standard Service load compared to the total delivered load on an hourly basis. The charts also allow comparison of the relative magnitudes of the Residential and Small C&I classes as components of Standard Service. The Street Lighting and Large C&I classes are too small to be represented on this chart. The weekday residential profile tends to peak in the late afternoon or evening, while the Small C&I weekday profile peaks at mid-day. As a blend of these two profiles, the Standard Service profile peaks in mid-afternoon. On weekend days, the residential profile peaks earlier than on weekdays, and the Small C&I profile is relatively flat, resulting in a Standard Service profile that looks much like the Residential profile. The aggregate profile of all competitively supplied load roughly follows the shape of the Small C&I class of Standard Service load, with a mid-day peak.

The shapes of the class profiles can be compared more easily if the loads are normalized in a way that removes the magnitude of the load from the comparison, as shown in Figure 44 for CL&P's July 2011 load. For each rate class, the average load for each hour in the month is divided by the annual average load for the rate class. To simplify the comparison, all weekdays (except for holidays) are combined in the "weekday" portion of the chart, while all weekend days and holidays are combined in the second portion of the chart. (Similar normalized profiles for other months and years for both UI and CL&P are provided in Appendix B.)

Figure 44. Normalized CL&P Profile - July

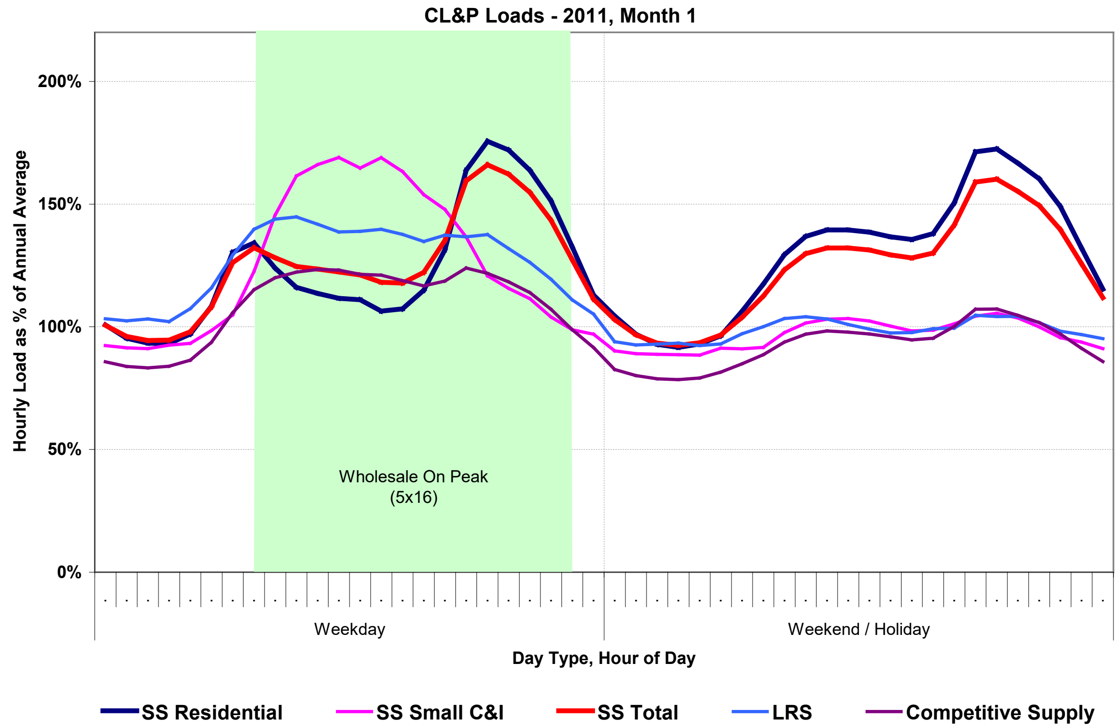


The early, more symmetric peak for Small C&I load and the late day, skewed peak for residential are clearly evident from this summer month data. The weekend/holiday loads for residential are just as high but somewhat more symmetric as those on weekdays, while the Small C&I loads are substantially lower on weekends and holidays. It is apparent that in 2011, Residential load dominates the overall Standard Service profile, while competitive supply, in the aggregate, reflects a profile more similar to that of C&I customers.

Figure 45 shows normalized profiles of the same CL&P load groupings for the month of January 2011. It should be noted that the Residential profile is fundamentally different in the winter, with bimodal peaks, a peak in the morning and a more prominent peak in early evening. The profile for the small C&I class of Standard Service is similar for both winter and summer months, with a broad mid-day weekday peak and relatively flat and low weekend/holiday load. Again, the shape of the total Standard Service load is similar to the Residential shape, since the Residential load is several times larger than the Small C&I load.

Examination of the other profiles in Appendix B indicates that the shapes of the Residential and Small C&I loads and of LRS load have not changed substantially since 2007. The shape of total Standard Service load profiles has become more similar to that of the Residential class as C&I customers have migrated to competitive supply. The competitive retail supply aggregate profile was similar to LRS in 2007, but by 2011 shows some effects of increasing residential migration to competitive retail suppliers.

Figure 45. Normalized CL&P Profile - January



Profiles for UI loads show similar effects, as can be seen in Figure 46 and Figure 47.

Figure 46. Normalized UI Profile - July

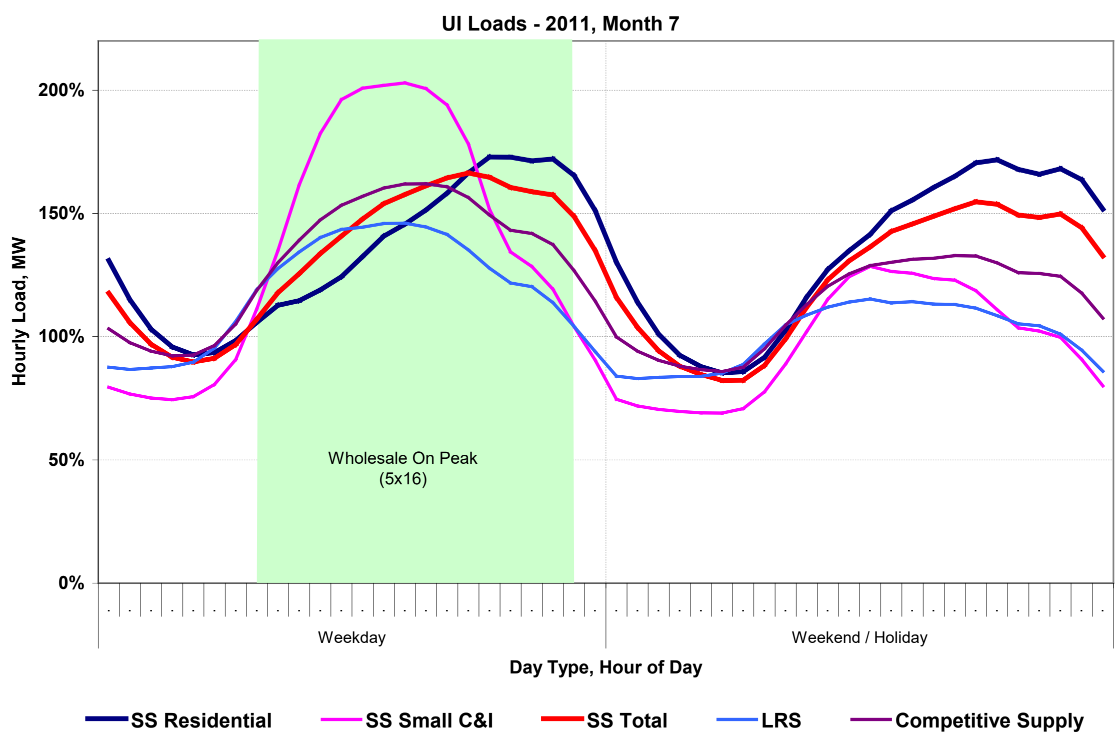
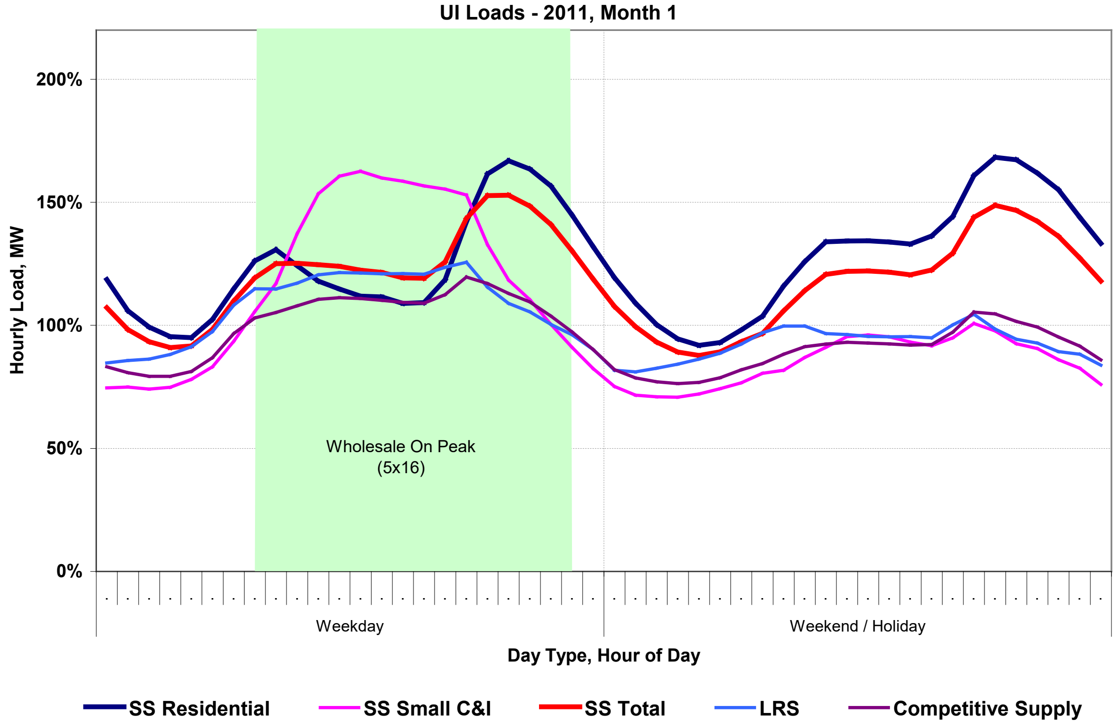


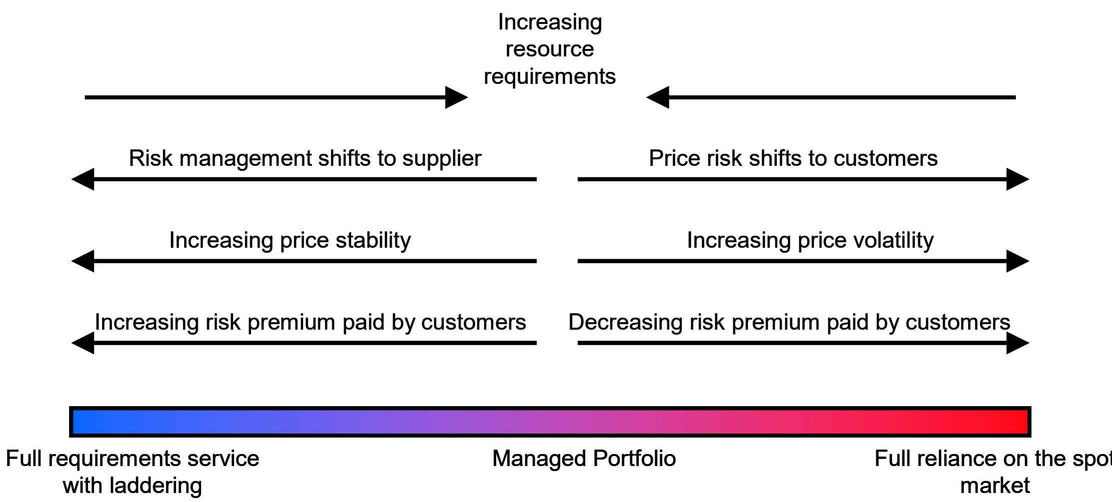
Figure 47. Normalized UI Profile - January



8.0 STANDARD SERVICE PORTFOLIO ALTERNATIVES

As discussed in Section 3.2, PA 11-80 requires that the Power Procurement Plan enable the EDCs to "manage a portfolio of contracts to reduce the average cost of standard service while maintaining standard service cost volatility within reasonable levels." Thus, the EDCs must assess and balance the inherent tradeoff between price minimization and price stability. This tradeoff may be viewed schematically as a "risk spectrum" illustrated in Figure 48.

Figure 48. Risk Spectrum

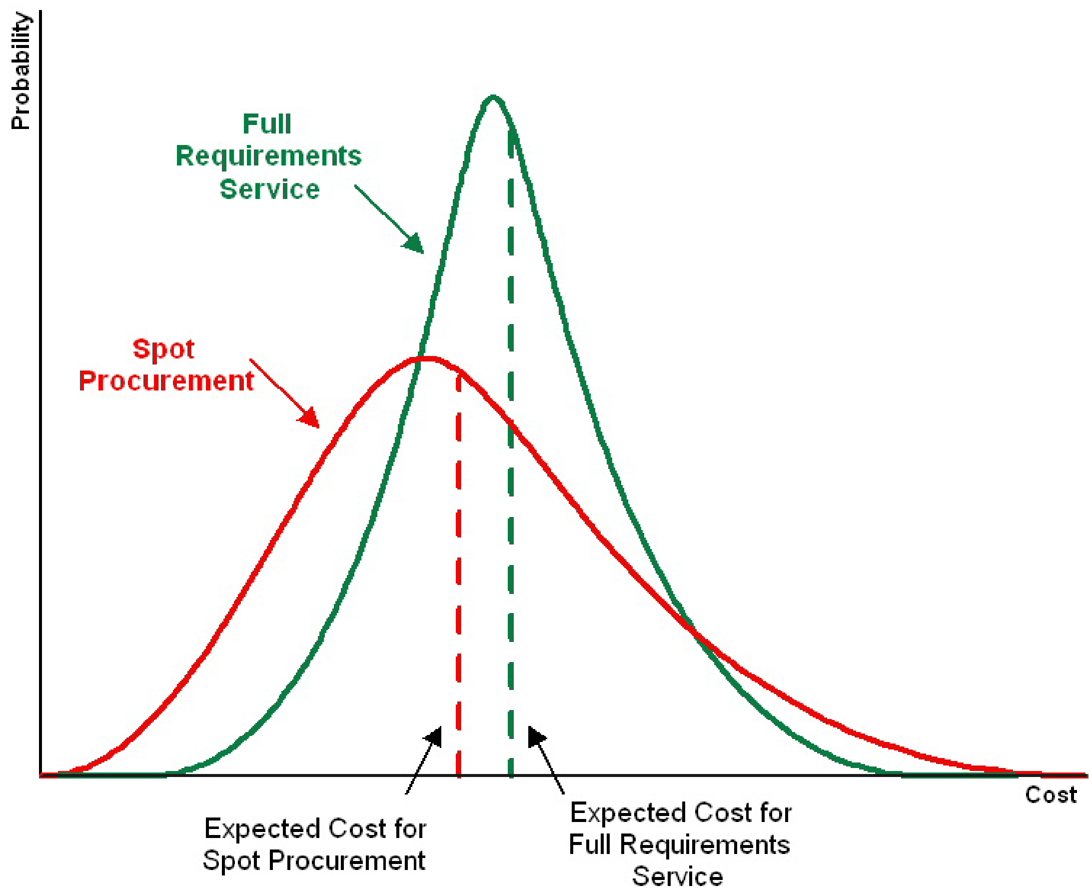


On the far left side of the spectrum is laddered full requirements service. Relying on laddered full requirements service contracts promotes retail price stability for customers but carries the largest cost premium, since market and quantity risk is transferred to the suppliers. Full requirements service represents a portfolio that is fully hedged. Under the existing Standard Service procurement for full requirements service, UI and CL&P have laid off price and quantity risk to their respective wholesale suppliers. Moreover, when the EDCs contract for full requirements service, they also transfer all responsibility for managing the load asset to the suppliers. On the far right side is full reliance on the spot energy market. Over time, relying on the spot market is most likely to result in the lowest cost to customers, but customers assume more price risk. Retail rates will necessarily be more variable in response to volatility in the wholesale market. If an EDC were to rely 100% on the spot market for energy, the EDC would retain ownership of the load asset and would simply be a price-taker through normal ISO-NE billing procedures.[36] In between these polar opposites is a broad range of structured portfolios that an EDC can utilize to serve Standard Service load. For these portfolios, the EDC would retain the load asset and would require in-house resources to manage the portfolio.

[36] One exception is RPS compliance. The EDC would need to separately procure the required RECs. In a fully passive mode, the EDC could simply pay the ACP, but this would be needlessly costly.

The contrast between full requirements service and a portfolio with full reliance on the spot market is illustrated in Figure 49. The curves represent the probability distribution of outcomes for an idealized full requirements service portfolio versus a portfolio comprised of 100% spot market purchases. By definition, hedging reshapes the composition of a portfolio to reduce the exposure to market price, quantity, and regulatory risk. Therefore, the cost of hedging necessarily adds to the expected cost of the hedged portfolio. The insurance-like additional cost to limit the magnitude of adverse customer rate outcomes becomes larger as the amount of hedge protection increases. Although the *expected* value for the spot market purchases is lower than the *expected* value for full requirements service, the distribution of outcomes for 100% reliance on the spot market is much wider, reflecting a broader range of possible outcomes for customers – both good and bad. In addition, the spot market distribution is more skewed, with greater probability of extremely large cost increases than for the hedged portfolio. Decisions regarding the terms of the hedge products, the scheduling (laddering) of procurements, and whether static or dynamic hedging is employed will affect the width and shape of the probability distribution for the hedged portfolio.

Figure 49. Illustration of Unhedged versus Hedged Portfolio Cost Distributions



In the sections which follow, the array of products which may be used to furnish Standard Service supplies and hedge uncertainty is described. Insofar as the cost of energy is by far the largest and most uncertain component of the all-in cost of Standard Service, emphasis is placed on the financial and physical products to manage the energy price risk associated with Standard Service. Procurement and management of the other electricity components – capacity, RPS requirements, ancillary services and other ISO-NE charges – are covered in Sections 4.2, 4.3, and 4.4.

8.1 Full Requirements Service

In accordance with PURA's decision in Docket 06-01-08PH01, since 2006 UI and CL&P have been procuring Standard Service supplies only as laddered, fixed price full requirements service. The EDCs have most commonly procured full requirements service in six month or one year terms.[37] Full requirements service suppliers are responsible for furnishing all of the components needed to serve the awarded load share delivered to the CT Load Zone in each hour of the contract term.[38] The load asset is transferred to the supplier, *i.e.,* the LSE. The LSE is responsible for the daily bidding and scheduling of load with ISO-NE. ISO-NE also requires the LSE to provide credit assurance to support all market transactions.

Full requirements service contracts transfer all market price and quantity risk to the supplier, which results in a risk premium embedded in the contract price. Full requirements service contracts also include the cost of energy portfolio management, credit, and administrative costs of making forward and other derivative transactions, the costs of trading with bilateral and exchange counterparties, setting aside capital or credit capacity to meet ISO-NE and/or other counterparty requirements, and the supplier's profit. As discussed in Section 6.3, the risk premium embedded in a contract price generally increases commensurate with the length of time between bid day and the commencement of delivery. Thus, the risk premium can be reduced, but not eliminated by reducing the time between bid day and the start of delivery.

Current Standard Service contracts are all based on a set of firm fixed prices per MWh of delivered energy. The contract with each supplier may specify different prices by month, customer class, and time of day, but the prices are fixed over the entire contract term, regardless of the quantities delivered. Subject to PURA approval, the EDCs set the retail rates for generation services based on the supplier's contract prices. Over or under-collection from customers is relatively small, but may occur if customer migration, unusual weather, or other reasons cause a change to the customer class load profile and level. Any resulting variance creating a surplus or a deficit would necessitate an adjustment to customer rates in a subsequent rate period.

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[37] Some contracts in 2007 were awarded as three month terms as the laddering process was initiated. Some awards have also been for two or three linked 12-month terms.

[38] Strictly speaking, the Scenario B type contracts that the EDCs execute are not entirely full requirements contracts, since the EDC is responsible for managing the LMP differential (congestion plus losses) between MassHub and the Connecticut Load Zone. For both Scenario A and B, the supplier is responsible for delivery to the Connecticut Load Zone.

Full requirements service could also be contracted as an indexed price product. In this variant of full requirements service, the supplier's contract price would be the hourly spot CT Load Zone LMP plus a fixed price adder. The supplier remains the LSE. UI solicits both fixed and indexed pricing currently for LRS. Under an indexed full requirements service transaction, the supplier's risk premium associated with managing energy price uncertainty is eliminated, but the energy market risk is transferred to the EDC and its customers. The EDCs must develop a retail rate based upon expectations of the spot market prices while that rate is in effect. During the rate period, higher or lower spot energy prices can give rise to over or under-collection from customers relative to the supplier's contract obligation. Relative to a fixed price full requirements contract, the true-up may be larger. Thus, in order to implement this variant to conventional full requirements service, there would need to be an array of regulatory and risk management provisions in order to ensure that the EDCs neither gain nor lose through over or under-collections. Importantly, under-collection during one rate period that results in a true-up in a subsequent rate period has implications not only for Standard Service customers, but potentially also for customers who take service through a competitive retail supplier. If the adjusted Standard Service price resulting from a true-up is higher than what a market price for Standard Service would be absent the adjustment, then the "bogie" for retail service providers will also be higher, putting less pressure on retail suppliers to offer more competitive rates.

Full requirements service, either fixed or indexed, is customarily solicited through an RFP process. The RFP platform allows for broad stakeholder participation, reveals the criteria for selection, and also allows for price discovery 90 days following the bid day for Standard Service. Bidders are afforded an opportunity to analyze historical load data and clarify contract terms and conditions. To promote efficiency, the governing agreement is generally negotiated and executed prior to bid day. The EDC issues the successful bidder a transaction confirmation immediately upon award, conditional upon regulatory approval. Minimizing the lag between bid submission and irrevocable contract award minimizes the risk premium that a bidder will include to cover intra-day energy market movement. For this reason, bidders are notified of award on the afternoon of bid day, and PURA issues its final decision on the contracts within about 24 hours of award.

As noted in Section 3.3.1, both EDCs' current wholesale agreements for full requirements service establish unilateral rather than reciprocal credit requirements. This is a common practice industry-wide, and to date, has not stymied robust competition in Connecticut's Standard Service procurements. Regulatory authorization for rate recovery provides adequate assurance that suppliers will be fully compensated.

The disadvantage of fixed price, full requirements service is the risk premium incorporated in the supplier's all-in price. This represents a trade-off: the advantage to customers is the price certainty over the contract term. Customers are shielded from the risk of adverse market price movements or load uncertainty. Additionally, by relying on either fixed price or indexed full requirements service contracts, the EDCs avoid serving as the LSE for the Standard Service load asset. The EDCs therefore do not need to commit the requisite credit capacity to meet ISO-NE requirements, which would become an indirect cost to customers.

8.2 Products for Self-Managed Power Supply

Should either of the EDCs self-manage a portion of Standard Service load, it would become the LSE for that portion of the load asset, thereby assuming responsibility for bidding and scheduling load, and for complying with ISO-NE credit requirements. The EDC would become responsible for designing, procuring and managing a portfolio of products to cover all of the required components of Standard Service: energy, capacity, ancillary services, RPS requirements, other ISO-NE charges, and risk management. The true-up of retail rates from one rate period to the next may be small or large, depending on the portion of load that is hedged through the portfolio of contracts. The adjustment would be smallest if the EDC relies entirely upon load-following fixed priced energy contracts, and largest if the EDC is fully exposed to ISO-NE's DAM or RTM.

The LSE responsibility creates staffing requirements, infrastructure costs, and a need to develop and implement policies and procedures for front-office, middle-office, and back-office functions. In assessing the potential benefits to customers of a self-managed Standard Service power supply, the Procurement Manager and the EDCs need to evaluate whether or not there are sufficient expected Standard Service customer benefits relative to the incremental cost to implement the LSE responsibility. The quantification of this tradeoff is explored further in Section 8.5.2.

8.2.1 Load-Following Energy

Load-following energy is a physical or financial product to hedge energy market price and quantity risks. In many respects, this product is functionally the same as the load-following energy component of full-requirements service, but with the EDC retaining the load asset and the LSE responsibility. The EDC would separately purchase capacity, ancillary services, RECs, and congestion management, if applicable. For a financial load-following energy product, the EDC bids and schedules the load with ISO-NE, but the supplier provides the EDC a fixed-for-floating hedge, settled at the designated delivery point(s). Alternatively, the product can be physically settled through ISO-NE as an Internal Bilateral Transaction (IBT). In this case, the supplier conveys through an IBT the daily energy requirement to the EDC. The advantage of an IBT is that the EDC's net energy position each day is zero, thereby avoiding the associated credit assurance required by ISO-NE. The contract term is flexible, including monthly and seasonal products. The product can be procured through an RFP process similar to that for full requirements service, and contract and credit terms would be similar. Load-following energy is a customized product that is considered an exotic product that carries a high risk premium, especially in July-August and also January-February. From the EDC and customer point of view, it would be a low risk, but high cost product, and still require the load management resources that are otherwise avoidable through conventional full requirements service.

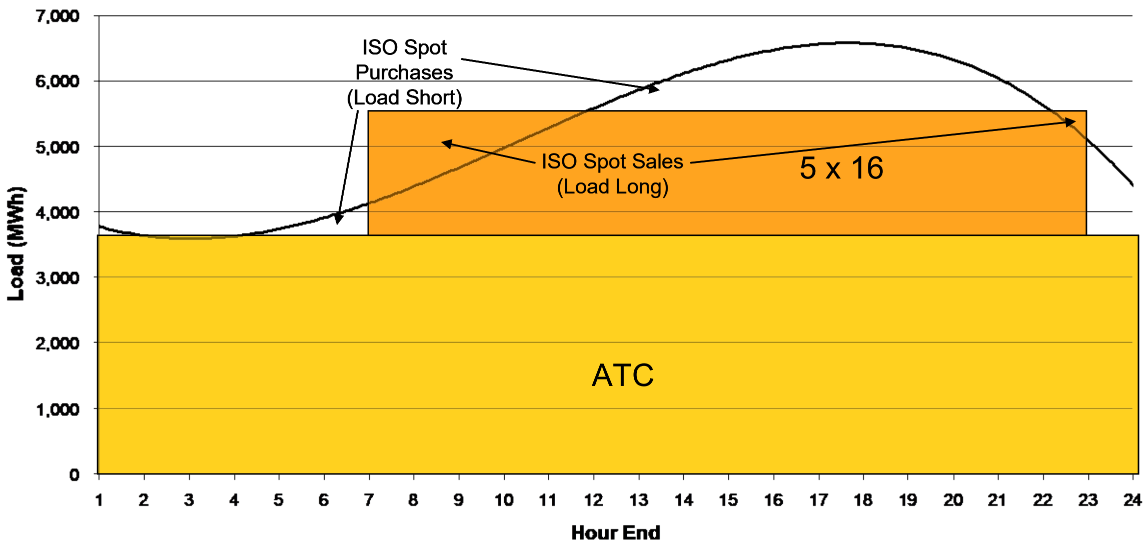
8.2.2 Block Forward Energy Products

Forward energy blocks are widely traded, liquid market products that may be settled physically or financially. This category includes standard forward energy strips, for a specified price, quantity, delivery point, and term. Standard products are around-the-clock (ATC), Peak (5x16) and Off-Peak (5x8 plus 2x24) energy blocks. Custom "super-peak" blocks could also be obtained, but at a premium relative to the more standard products. Block energy products are commonly traded in 50 MW blocks, but other lot sizes are available, both larger and smaller.[39] Forward blocks are commonly offered at a fixed ($/MWh) price for a given term. Indexed forwards are also available and are discussed below. The most commonly traded terms are CY strips and monthly strips, as well as weekly and daily products. The monthly forwards are available for the current year. Seasonal terms are generally crafted month-by-month. While brokers commonly quote prices for CY forwards out for up to four years, the forwards are liquid for about two to three years. Beyond three years bid-ask spreads widen, reflecting decreasing liquidity levels. While MassHub is the most common settlement point for standard block energy products in New England, Connecticut is also a traded but somewhat less liquid hub.

LSEs purchase a portfolio of block energy products to match diurnal and seasonal load cycles, and then balance hourly load through spot energy purchases or sales with the ISO. Other bilateral arrangements similar to the load-following energy contracts described above may also be used to balance hourly energy. As shown in Figure 50, the LSE must determine how to optimally hedge load using a combination of block purchases. In any hour or day, the cost to serve load may be in-the-money or out-of-the-money; as long as there is a "fringe" of spot purchases, the load cannot be 100% hedged. Like load-following energy, block forwards can be settled financially, or as a physical IBT transaction through ISO-NE. However, because the LSE will almost always be in a long or short position each day, the LSE can not avoid the ISO-NE credit assurance requirements.

[39] Sellers sometimes have odd lots of excess energy to sell on a forward basis, which may be offered at a discount.

Figure 50. Block Energy Balanced with Spot Energy Purchases for Weekday



Transactions for block energy forwards are commonly executed OTC with brokers over recorded phone lines, but electronic trading for standard products is also used. This product is also transacted through an exchange, such as the Intercontinental Exchange (ICE). Block forward energy transactions most commonly use standard contract forms such as the Edison Electric Institute (EEI) Master Power Purchase and Sales Agreement (MPPSA) or the International Swaps and Derivatives Association (ISDA) form with the physical power annex. Once the master contracts are in place, sellers provide verbal or electronic quotes, and buyers' verbal or electronic acceptance of an offer is binding. Electronic or faxed confirmations follow shortly thereafter. For this reason, a mechanism for real-time regulatory approval, or pre-approval, must be in place.

A variant of the forward energy strips is Unit Contingent Block Energy, which is a non-firm forward energy block from a specific generating unit. It may be transacted either as a fixed percentage of output of the unit or as a fixed MW block. Since the buyer assumes performance risk, the pricing is generally at a discount relative to a firm forward product. However, data to evaluate the risk of a given transaction may be difficult to obtain, and the buyer can be doubly disadvantaged if the designated unit contingent resource trips at the wrong time, thereby exposing the buyer to replacement energy costs in the DAM or RTM that have spiked due, in part, to that outage. Some marketers have offered "unit outage trip insurance," but non-binding prices offered for this insurance product have been costly. This product type may not offer good value and would be less likely to fit into the potential product slate to hedge price and quantity risk going forward.

8.2.3 Indexed Block Forward Energy Products

Block energy products are also available as forward contracts with pricing that is tied to NYMEX gas or other liquid indices at the time of delivery, rather than a price fixed at the time of the transaction. Thus, the risk premium incorporated in the contract price is smaller than for fixed energy blocks. For the purposes of building a portfolio to provide full requirements service, products indexed to NYMEX gas futures at the Henry Hub, AGT Citygates, TGP Zone 6, or MassHub offer limited value with respect to hedging programs that fix the future cost of gas and/or electric energy in New England. Nevertheless, indexed energy products may represent a sensible complement to a broader hedging program oriented around locking-down the delivered price of energy.

Dispatchable contracts with energy prices tied to a natural gas price index (heat rate call options) are discussed in Section 8.2.6.

8.2.4 Natural Gas Products

Futures contracts for natural gas priced at Henry Hub are available on NYMEX on a monthly basis for settlement for up to 12 years. As of May 2012, settlements are available through December 2024. The Henry Hub gas contract is the most liquid contract traded on NYMEX, particularly for delivery dates in the near future. The standard size of a NYMEX gas contract is 10,000 MMBtu.[40] In addition to Henry Hub, NYMEX also offers contracts for natural gas basis of relevance to Connecticut through its ClearPort service. Forward contracts for gas basis are for a smaller quantity, 2,500 MMBtu, and have considerably less trading volume. These contracts are offered for much shorter durations. For example, as of May 2012, the basis forward contract for Algonquin Citygates is through April 2014.[41]

NYMEX natural gas futures and basis forwards can be used to hedge a portion of Standard Service load for a longer duration than the standard energy block forwards. Given the strong correlation between natural gas costs and power prices in New England, the use of NYMEX futures can potentially achieve a good tradeoff between cost minimization and price stability. However, products oriented around delivered natural gas are an imperfect hedge, since there is a very strong correlation between delivered natural gas and wholesale electric prices in New England. As illustrated in Figure 9, occasionally there are seasonal load spikes and run-ups in energy prices when the marginal resource is not gas-fired, but rather residual fuel oil or ultra low sulfur diesel. This risk is commonly hedged through market heat rate (MHR) options.[42]

All gas contracts transacted via NYMEX enjoy the benefits of clearing on the exchange, thereby protecting traders from counterparty default. Other products that are indexed to NYMEX prices are also available from a variety of sources on an OTC basis; however, these contracts generally carry counterparty credit risk and other risks associated with transactions conducted outside an exchange that must be considered.

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[40] http://www.cmegroup.com/trading/energy/natural-gas/natural-gas_contract_specifications.html

[41] http://www.cmegroup.com/trading/energy/natural-gas/algonquin-citygates-natural-gas-basis-futures_quotes_settlements_futures.html

[42] The MHR (in units of MMBtu/MWh) is the energy price ($/MWh) for a given location divided by the indexed natural gas price ($/MMBtu).

8.2.5 Other Options and Derivatives

Aside from the array of relatively standard products described in this section, a wide variety of "exotic" or customized financial products are available. For example, the barrier option described in Section 3.3.2 was a product designed to provide a specific type of price protection. The spectrum of possibility is broad for the structuring of forwards, options, and swaps in order to achieve the desired balance between the cost and benefit of the "insurance." Because of the size and credit quality of the Connecticut EDCs, finding acceptable counterparties willing to offer customized products should not be problematic. However, the usefulness of the options and derivatives that can be customized by the EDCs with creditworthy counterparties requires rigorous assessment in the context of using such products to manage Standard Service.

8.2.6 Dispatchable Energy Products

A wide range of dispatchable energy products are available. These range from long-term contracts with specific generators to short-term call options that include indexed energy products and a specified heat rate. All such contracts involve the payment of a premium (in the form of a demand charge) for the right to call for energy delivery at a specified strike price (either fixed or as the product of a fuel price index and a contract heat rate). The option premium obligates the seller to be ready to supply energy consistent with the notification provisions set forth in the transaction agreement. In practice, most such contracts are settled financially, and the generation is dispatched in response to market price signals, rather than the buyer's specific hourly energy requirements.

Dispatchable energy contracts can provide an LSE with a hedge against high market energy prices. Intermediate or long-term generation contracts may not be in-the-money from Standard Service customers' perspective for any number of reasons, but may nevertheless provide value in capping adverse exposure during intervals when extreme weather conditions cause oil-fired and EE/DR resources to be on the margin, that is, exposure to MHR risk. Note, for example, in Figure 9, where electric prices departed from their otherwise close correlation with natural gas prices during the summers of 2007 and 2010. On the other hand, if Standard Service load continues to shrink, the demand charge associated with a dispatchable energy product will be allocated to fewer customers, thus exposing a declining customer base to increased costs.

A unit-contingent dispatchable contract carries the same risk as the unit-contingent block energy products discussed above.

Contracts for dispatchable energy are most commonly solicited through an RFP process. Due to the complexity of evaluating the net benefits of these contracts, the time between bid submission and contract award can be lengthy, sometimes many months. Regulatory review adds weeks or months to the process. For this reason, this type of product is almost always priced based on a liquid index covering the value of natural gas, *i.e.*, NYMEX gas. Proposals for intermediate terms or longer, that is, three years or more, for a fixed price invariably include a large risk premium.

In the experience of Connecticut's EDCs and in other jurisdictions, credit rating agencies typically impute debt on the EDC's balance sheet associated with intermediate or long term contracts that involve payment of a demand / capacity charge.[43] While there can be ways to reasonably minimize credit rating agency's imputation of debt, the avoidance of any debt imputation may not be realistic regardless of transaction structure. To the extent there are unfavorable accounting impacts on the EDC's credit rating resulting from intermediate or long term contracts, the EDC and their respective distribution customers will be burdened with increased direct and indirect costs. As further discussed in Section 9.4.4, these costs must be properly accounted for in an assessment of the net benefits to customers from contracts that cover dispatchable energy products.

8.3 Spot Market Purchases

An LSE has the option of relying on the DAM or RTM for all of its energy requirements for Standard Service, or for balancing energy only. If spot energy covers all of the Standard Service load, the LSE is fully exposed to spot market prices. The LSE must bid and schedule load each day with ISO-NE, but otherwise the portfolio management is inherently passive. The LSE must be a market participant and provide the ISO-NE required credit assurance covering their entire load obligation.

8.4 Contracts Resulting from Statutory Mandates

Over about the last decade, the Connecticut EDCs have entered into a number of long term contracts for capacity and other market products with generation resources located in the State. These include:

- Capacity-only contract with Kleen Energy's combined cycle plant for 620 MW
- GenConn's peakers in Middletown and Devon, totaling about 376 MW
- PSEG New Haven peaker for 120 MW
- Project 150 contracts

Other initiatives are currently underway to procure zero-emission RECs (ZRECs) and low-emission RECs (LRECs) as required by PA 11-80.

These contracts were required by State policies to promote the development of certain types of resources viewed to be needed in Connecticut (*e.g.*, baseload, peakers, renewables), and to promote economic development. All of these contracts were mandated by statute and were subject to extensive PURA proceedings. The contracts for new combined cycle or peaking generation are either financially settled as a contract for differences (CfD), or the EDCs sell all of the physical products in the market. The net

[43] Prefiled Testimony of G.J. Eckenroth and R.A. Soderman on behalf of CL&P, Docket No. 05-07-18, filed Sept. 2, 2005; Testimony by J. Judge, CFO, NSTAR in Docket No. 12-01-07, Tr. Vol. 1, pp 246-250.

costs or proceeds of these contracts are non-bypassable and are assigned to all distribution customers. With respect to the ZREC and LREC contracts, there is no liquid market since only the Connecticut EDCs have the compliance obligation. Therefore the contract costs are passed on to all distribution customers.

The aforementioned long-term contracts were neither designed to serve Standard Service customers nor suitable going forward to meet Standard Service requirements. With respect to the contracts formed to promote new combined cycle and peaking generation in Connecticut, the fit with Standard Service is poor. While the fixed costs borne by the EDCs under these contracts are higher than the value of the market products, in prior dockets PURA determined that the net benefits to Connecticut load offset the high fixed cost of the resources. There is no regulatory mechanism to allocate the economic benefits realized in Connecticut as a whole, and in New England at large, to Standard Service customers. Moreover, any effort to allocate the fixed and/or variable costs defined under the various CfDs to Standard Service customers would likely accelerate migration to retail service providers, thereby unfairly penalizing remaining Standard Service customers with a disproportionate cost burden. For these reasons and others, the costs borne by the EDCs resulting from prior statutory mandates should continue to be allocated to all distribution customers rather than to the subset of residential and C&I loads that rely on the EDCs for Standard Service.

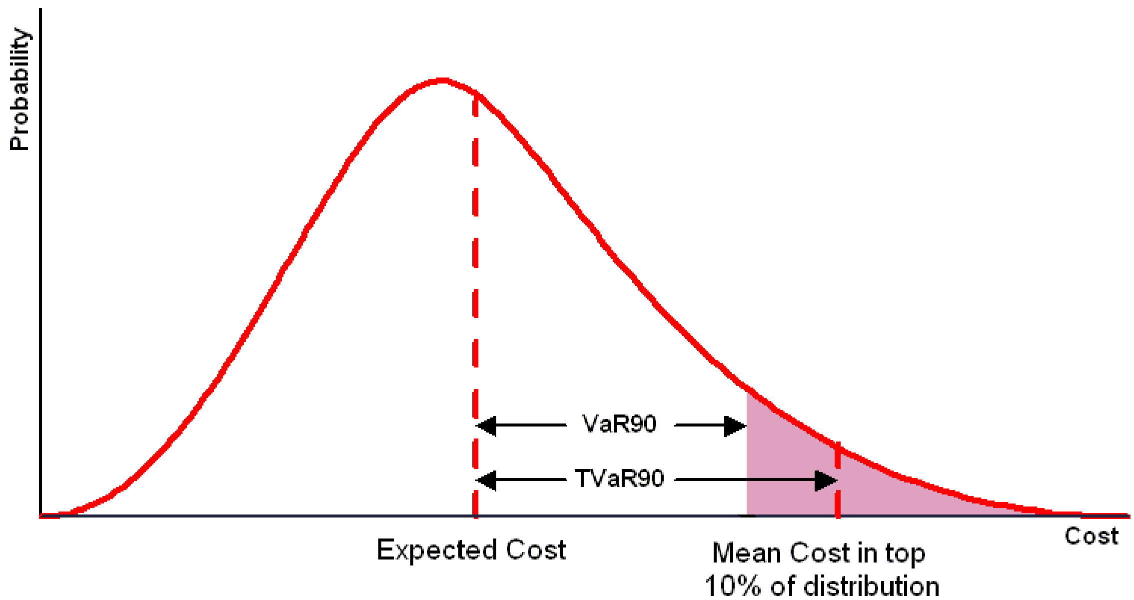
8.5 Portfolio Risk Management

8.5.1 Risk Metrics

Throughout North America, it is standard procedure for energy companies to use monthly portfolio position and risk reports for corporate risk management and procurement management purposes. For regulated LSEs, periodic position and risk reports are often provided in regulatory filings to the state regulatory commission. In Connecticut, wholesale energy companies are not regulated by PURA. However, to the extent that the Connecticut EDCs assume the LSE responsibility for a portion of its Standard Service load, there will be a need for periodic position and risk reports that inform the Procurement Manager on a regular basis of the portfolio position relative to the initial expected cost, and also the change in risk exposure attributable to the physical and financial products entered into to self-manage load. Projections of expected all-in portfolio cost relative to the expected collections from Standard Service customers over the rate period, and measures of market risk exposure may then be applied to efficiently manage the inherent tradeoff between the objectives of minimizing cost as well as the probability and magnitude of unexpected changes in cost.

Commonly applied risk measures for managing electricity supply portfolios include statistical measures of dispersion above and below the expected future cost, or downside-only (above expected cost) risk measures. Typical dispersion measures are standard deviation and coefficient of variation. The coefficient of variation is the standard deviation divided by the mean, and represents relative dispersion as a ratio. While uncertainty can result in either “good” (lower cost than expected) or “bad” (higher cost than expected) outcomes, from a customer perspective, risk is usually defined *with* *respect to adverse outcomes only*. Several specific measures of downside risk are related to the value-at-risk (VaR) measure, which is the adverse exposure of the portfolio over a certain time horizon at a specified confidence level (*e.g.*, 90%). Another way to express this is that VaR represents the maximum loss for a given probability level, relative to the expected value. The preferred metric is tail value-at-risk (TVaR), which extends to the mean value of all downside outcomes that exceed a specified confidence level (*e.g.*, the average value within the top 10% of cost outcomes). Figure 51 illustrates an idealized 90% confidence VaR and TVaR calculation.

Figure 51. Illustration of VaR and TVaR Measures



While VaR and TVaR provide information on the magnitude of "bad" outcomes, these measures relate exclusively to market uncertainties. They do not describe customers' tolerance of these uncertainties nor how customers value the tradeoff between cost minimization and rate stability, that is, how much "insurance" are customers willing to pay to ensure that Standard Service rates do not increase from one rate period to the next by more than a certain amount. Thus, it is also important to establish guidelines that define customer risk tolerance (CRT) limits and the value of risk reduction on behalf of Standard Service customers. For example, CRT may be expressed as a maximum probable (95% confidence) increase in customer rates in 12 months of one cent per kWh.[44] To assess alternative portfolios that vary in their respective risks, rules for valuing the worth of incremental risk reduction must also be developed. One quantitative rule is the Sharpe ratio, *i.e.*, the incremental cost that customers are willing to pay per unit

[44] This particular CRT limit has been ordered by the California Public Utilities Commission (CPUC). California's investor-owned utilities must explain to the CPUC how they will manage a VaR that exceeds the CRT by 25%. The CPUC is now considering changing the CRT to a relative measure expressed as a percentage change rather than a cent per kWh change.

of risk reduction. There is no bright-line set of limits and hedge effectiveness guidelines equally applicable to each EDC. Simply put, there is not a one-size fits all approach to the formulation of appropriate risk measures and associated risk management limits and guidelines. Notwithstanding the lack of a bright-line set of limits and hedge effectiveness guidelines, sound risk management policy requires that basic rules be established in advance in order to strengthen the foundation for consistent and effective monitoring of the risks to customers associated with the Standard Service supply portfolio.

8.5.2 Portfolio Optimization

Portfolio managers also typically implement an analytical system that is capable of making correct rankings or choices among alternative types of hedging programs. The ideal system would be capable of optimizing the mix of supply products. Choices include the type of products (*e.g.*, full requirements service, block energy forwards, block energy options, spot-indexed products), their respective delivery periods, and related quantities. The optimization includes customer migration impacts as well as the impact of periodic rate true-ups arising from over or under-collections.

An increasingly applied approach for managing the expected cost versus risk tradeoff is application of the "efficient frontier."[45] The efficient frontier is the best portfolio combination that achieves minimum expected costs over a set of risk levels. After the efficient frontier is calculated, managers can visually inspect its shape or quantitatively compare the incremental portfolio cost expressed in dollars per MWh for incremental risk reductions. This information is important for purposes of structuring an optimal portfolio along the risk continuum that best fits Standard Service customers' economic interests. A stylized efficient frontier graph is shown in Figure 52. The solid blue line segment of the efficient frontier curve represents the Active Portfolio Management (APM) region allowed by the risk management policy. The right-most end of the APM region may be governed by a customer risk tolerance measure. One or more alternative procurement strategies for full requirements service (differentiated by delivery terms, laddering, etc.) are available near the left-most end of the APM segment of the efficient frontier. Many less efficient procurement portfolios lie above and to the right of the efficient frontier. The efficient frontier represents the most efficient (lowest cost) portfolios available for achieving any given level of risk.

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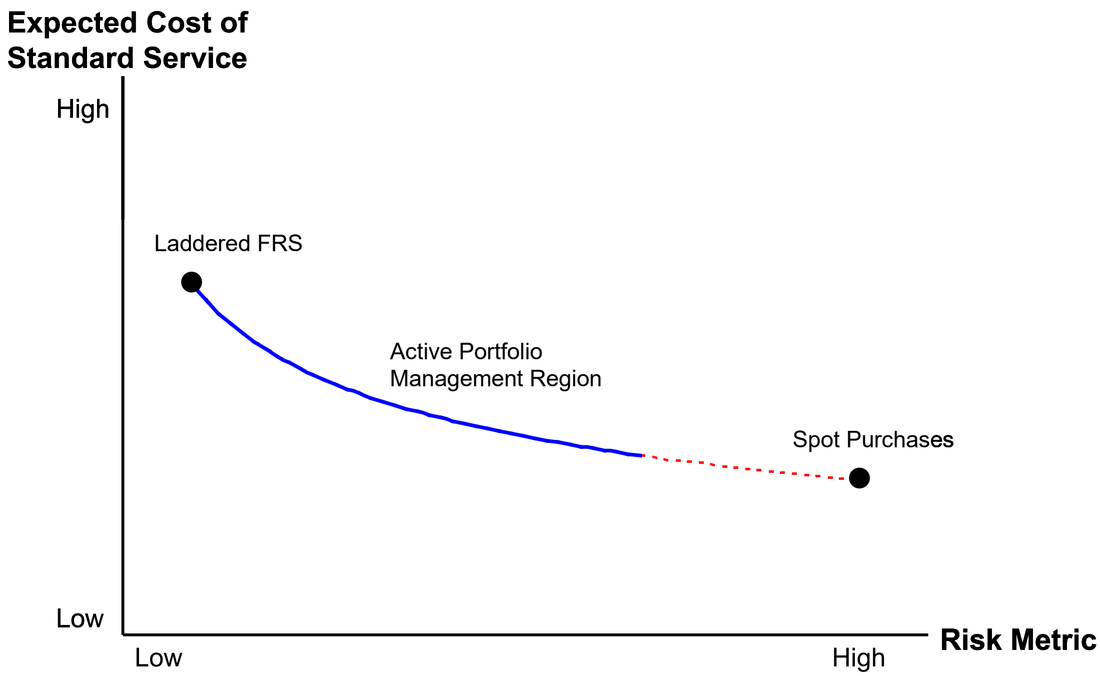
[45] The calculation is typically performed using a quantitative portfolio optimization software application.

Figure 52. Illustration of Cost versus Risk Efficient Frontier



The hedge ratio is the ratio of the quantity of a position hedged divided by the total initial (unhedged) position quantity. The hedge ratio need not involve 100% load volume cover for maximum hedge effectiveness. The optimal hedge ratio, which minimizes the variance of the uncertain value, will be less than 100% if the hedge contract's payoff is less than perfectly correlated with the underlying spot market price. One example is hedging CT Load Zone spot price with MassHub forwards. The LMPs are less than 100% correlated between the two locations, but are nevertheless extremely strongly correlated. Another example is hedging a time-varying Standard Service load profile with CT Load Zone block forward contracts. The Standard Service load and the block energy forwards are less than 100% correlated due to the different load profiles, even though each position's value is a function of the same LMPs.

A 2010 empirical study of Standard Offer Service (SOS) procurement strategies in Rhode Island by the Northbridge Group for National Grid (NGrid) used Monte Carlo simulation of energy prices, loads, and migration to evaluate alternative supply procurement strategies.[46] The three strategies examined were: (1) spot market procurement, (2) several APM programs involving laddered block energy forward (BEF) products of varying durations, and (3) full requirements service (FRS). Blends of 25% spot market

[46] The Northbridge Group, “Analysis of Standard Offer Service Approaches for Mass Market Customers," Exhibit A in National Grid's report regarding its comprehensive review of standard offer service procurement strategies, Rhode Island Public Utilities Docket 4041, January 22, 2010, provided in Docket 4149.

procurement with 75% APM or FRS products were also modeled.[47] The Northbridge study did not include uncertainty associated with unitized capacity cost ($/MWh), ancillary services costs, RPS costs, or imputed debt costs for counterparty collateral, which would reduce the simulated expected cost reduction benefit of the APM approach. Also, the Northbridge study did not model APM programs with energy options, or natural gas heat rate indexed forwards or call options. Efficient inclusion of energy options or natural gas-indexed products would tend to reduce the difference in risk distributions between the FRS and APM program cases.[48] Importantly, the Northbridge study did not include the impact of dynamic hedging, a practice that fosters more effective management of price and quantity risk resulting from extreme weather and unanticipated migration.

The Northbridge study examined a set of cases for 100% or 75% hedge ratio targets using either FRS procurement or APM procurement of energy block forward products. The cases with 75% target hedge ratio were assumed to procure the remaining volume from the spot market. Following the study, Northbridge also ran the model for a case with 90% FRS and 10% spot procurement.[49] A summary of the expected costs and downside risks for the two APM cases and three FRS cases that all apply one-year laddered products and semi-annual rate adjustments are compared in Table 2.[50] In addition to reporting expected customer cost and TVaR of customer cost, Table 2 also reports TVaR for the deferral account balance and for MtM exposure. The deferral account balance is the deficit arising from customer under-collections. The MtM exposure is important to track as it may impact the EDC's capital liquidity and collateral obligations, as discussed in Section 9.4.3.

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[47] The Northbridge study's underlying data and computer model were protected information. Hence, it is not possible to comment on the accuracy of the model and data, or whether the Northbridge study results in Rhode Island are applicable in Connecticut, particularly in light of significantly different market conditions.

[48] The reason that inclusion of energy options in a portfolio along with energy forwards is more effective in controlling risk is due to the positive correlation between energy spot market prices and load. Block forwards will result in less than full hedging when load is higher than expected, and greater than full hedging when load is lower than expected. By including call and put options with different strike prices in the portfolio in addition to forwards, a more effective and efficient hedged portfolio may be constructed. Importantly, a practical constraint associated with the use of options is the comparative lack of liquidity in the derivatives market relative to block forward products.

[49] Rhode Island Public Utilities Commission Docket 4149, Technical Session Data Request 1-2, April 14, 2010.

[50] While Northbridge used the term "average of top decile" to describe the study's downside risk measure, for consistency the risk measures are referred to here as TVaR at 90% confidence (TVaR90).

Table 2. Comparison of Expected Cost and Risk for Alternative Hedge Portfolios[51]

Hedge Product Type[52]	Target Hedge Ratio (%)	Expected Cost ($/MWh)	Expected Cost Savings for 100% Hedge (%)	Supply Cost TVaR90 (%)	Supply Cost TVaR90 ($MM)	Deferral Balance TVaR90 ($MM)	MtM Exposure TVaR90 ($MM)
BEF	100	$88.02	--	7.7	$30	$26	$37
BEF	75	$87.59	0.5%	12.4	$49	$62	$28
FRS	100	$88.94	--	3.7	$15	$0	$0
FRS	90	$88.62	0.4%	5.7	$23	$3	$0[53]
FRS	75	$88.21	0.8%	9.2	$37	$18	$0

The results of this analysis indicate that the unhedged risk increases significantly when even a relatively small share (10%) of spot energy market purchases are included in the portfolio, with little decrease in expected cost in return for customers bearing this risk. Note, for example, that as the target hedge ratio for the FRS product moves from 100% to 75%, the expected cost savings is only 0.8% while the downside risk at a 90% probability level (TVaR90) goes from 3.7% to 9.2%. Similarly, moving from the 100% BEF case to the 75% BEF case results in a much larger percentage increase in supply cost TVaR than reduction in expected supply cost.

The Northbridge study results provide useful guidance *on a preliminary basis* in evaluating options for managing Connecticut Standard Service load. Functionally, using spot energy price indexed FRS products described in Section 8.1, for a portion of Standard Service load would produce results similar to the FRS cases in Table 2. Results suggest even one or two tranches of an indexed FRS product may significantly increase customer rate volatility without materially reducing expected cost. However, it may be premature to fully discount this product without further analysis.

With respect to the BEF products, the Northbridge study only considered static portfolio management. That is, the hedges were "locked in" at the start of the delivery term and not rebalanced as warranted as spot prices diverged from expected values and/or in anticipation of extreme weather events. Thus, the Northbridge study overestimates market exposure for the static BEF portfolios relative to a dynamically hedged BEF portfolio. An argument can be made for leaving a small portion of load unhedged, in particular, for load variations during extreme weather events, both hot and cold. It would be instructive to quantify its approximate optimal hedge ratios for a BEF portfolio, perhaps on a seasonal basis. This information would be reviewed by the Procurement Manager in deciding how much load is appropriately left uncovered.

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[51] Sources: The Northbridge Group study in RI Docket 4041, January 22, 2010 National Grid filing for the 100% and 75% target hedge cases. RI Docket 4149 Technical Session Data Response 1-2 prepared by Northbridge for the 90% FRS case.

[52] All cases shown here are for one-year laddered procurement and semi-annual rate adjustments.

[53] Interpolated from the respective values for the 100% and 75% hedge target cases.

9.0 PROCUREMENT DESIGN

This section explores potential enhancements to the mechanisms by which Standard Service is procured by the EDCs. The analysis of loads and bid data presented in Section 9.3 reveals potential improvements to the laddering structure, procurement timing, and solicitation mechanisms. Lastly, this section considers credit, regulatory, and management implications ascribable to an EDC's responsibility as the LSE.

9.1 Procurement Design of Other Investor-Owned EDCs

In nearly every state where retail choice has been implemented, the investor-owned EDC remains the provider of last resort, furnishing default electric service to those customers who do not elect to shop for competitive retail supply.[54] The processes used by EDCs in other jurisdictions to procure wholesale supplies for default service customers were reviewed with an eye toward reporting key attributes in the Power Procurement Plan. The purpose of the review was to identify similarities, differences, and best practices regarding laddering design, portfolio management, bid mechanics, and credit requirements. The procurement practices reported in this section pertain to investor - owned utilities rather than municipalities or cooperatives. Unless otherwise noted, all EDC references in this section represent investor-owned utilities subject to state regulatory jurisdiction. After addressing procurement norms in various states, procurement practices among municipalities are briefly discussed.

Procurement practices in Massachusetts, Rhode Island, Maine, New Hampshire, New Jersey, Pennsylvania, Rhode Island, New York, New Jersey, Maryland, and Illinois are summarized in this section. Further details for selected EDCs are presented in Appendix C. Like Connecticut, EDCs in most states employ a separate procurement process for large C&I customers. This is analogous to LRS in Connecticut. Default electric service for these large C&I customers is usually not laddered. Rather, default service for large C&I customers is generally designed to more closely follow the wholesale market. The focus in this review is on default service comparable to Connecticut's Standard Service, *i.e.,* primarily residential and small C&I customers. Thus, procurement structures in other states covering large C&I customers are not addressed.

9.1.1 LSE Responsibility

Transfer of the load asset and LSE responsibility to the contracted suppliers is standard practice across the majority of the states and EDCs surveyed. However, there are notable examples where the EDC remains the LSE for all or a portion of its default service load, including the following:

- In New Hampshire, Public Service Company of New Hampshire (PSNH), a Northeast Utilities (NU) company, serves its default customers through a portfolio

[54] Texas is an exception. Eligible residential customers must either choose a competitive supplier or be assigned one. Munis and coops in Texas can opt out.

of self-supplied generation and market products. This is further discussed in Section 9.4.

- In Rhode Island, NGrid retains management and LSE responsibility for 10% of its residential customer load. NGrid manages this tranche through spot market purchases.

- In New York, EDCs serve as the LSE but generally do not own power plants. Certain New York EDCs, Con Edison in particular, do have legacy power purchase agreements (PPAs) with non-utility generators that cover a significant portion of their respective portfolios.[55] Other supplies are purchased on a short-term basis as needed.

- In Illinois, the EDCs are LSEs. They each conduct separate procurements for blocks of energy, bilateral capacity and RECs, and rely on spot market purchases to balance their load.

- In Pennsylvania, Duquesne and UGI remain the LSE. Duquesne contracts for all components of default supply except for Network Integrated Transmission Service (NITS), a PJM network charge. UGI purchases default supplies via fixed price energy contracts.

9.1.2 Full-Requirements Service

For the EDCs that transfer LSE responsibility to suppliers, firm, full-requirements service is the most commonly used product to serve Standard Service. However, there are variants on this structure which limit suppliers' market, regulatory, and/or quantity risks. Illustrative examples are as follows:

- In Pennsylvania, the FirstEnergy companies procure supplies that include all the components of full-requirements service except NITS. Also, 10% of the FirstEnergy companies' default service load for residential and commercial customers is indexed to market prices.

- In Maryland, suppliers' quantity risk is limited by the volumetric risk mitigation (VRM) mechanism. Suppliers bid on blocks, about 50 MW. If load differs from the block quantity by more or less than 5 MW, the supplier is kept whole for additional spot purchases or sales.

9.1.3 Long-Term Contracts

Some states, including Connecticut, New Jersey, Maryland, Illinois and California, have required EDCs to enter into long-term contracts to promote certain policy or reliability

[55] Con Edison serves gas, electric and steam customers in NYC and Westchester County. Con Edison owns power plants that produce steam and electricity.

objectives. The net benefits resulting from such contracts are typically non-bypassable. That is, any cost or credit arising from the contract is allocated to *all* distribution customers, not only default service customers.[56] Exceptions are rare. In Illinois, the two EDCs, Ameren and Commonwealth Edison, each procured long term renewable energy contracts for a portion of its RPS requirements. The energy and RECs from these contracts are assigned to their customers who do not purchase supplies from competitive retail suppliers. In Maryland, the PSC recently approved a long term CfD between the investor-owned EDCs and CPV Maryland, LLC, for 661 MW of new gas-fired combined cycle generation.[57] The Commission's Order directs the EDCs in Maryland to enter into a CfD with CPV Maryland, LLC, and to recover their costs (or return their credits) through the Standard Offer Service surcharge. Thus, the net cost or credit resulting from the CfD will be bypassable, *i.e.*, not assigned to all distribution customers.

9.1.4 RPS Compliance

In the majority of states which procure default service from wholesale suppliers, RPS compliance is bundled with full requirements service. The NGrid companies in Massachusetts, New Hampshire, and Rhode Island allow suppliers the option to submit RPS-compliant bids. The Illinois EDCs and the Unitil subsidiaries in New England contract for RECs through separate procurements. In New York, the New York State Energy Research & Development Authority (NYSERDA) is the central purchaser for all renewable energy to meet the state-wide requirements. NYSERDA's procurements are through long-term contracts.

9.1.5 Slice of System versus Customer Class

For Standard Service in Connecticut, each tranche or slice represents a slice of system. Rate classes are not disaggregated. The slice constitutes all Standard Service-eligible load in each tranche proportional to load share. Like Connecticut, Illinois is another state that uses a slice of system rather than individual rate class categories. All other EDCs reviewed contract by customer class rather than as a slice-of-system.

9.1.6 Laddering Structure

Laddering is standard practice. However, how states implement laddering in regard to contract term, timing, and structure varies significantly. Laddering terms range from 1 year to 3 years. The review of the EDCs did not indicate any that seek contracts for longer than three years. Table 3 summarizes laddering practices among the EDCs that were reviewed.

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[56] For example, last year the New Jersey Board of Public Utilities approved three standardized CfDs with 15-year terms for 1,947 MW of new combined cycle plants located in New Jersey. All distribution customers of the New Jersey EDCs share the (dis) benefits of these contracts; they are not assigned to Basic Generation Service.

[57] Public Service Commission of Maryland, Case No. 9214, Order No. 84815, April 12, 2012.

Table 3. Laddering Structures[58]

State	Laddering Structure	Note
MA	50% of Standard Offer load is purchased as 1-year service terms, every 6 months.	Residential and Commercial classes
ME	Annual procurements for 3 year contracts, each covering 33% of load	Small customers only
RI	6, 12, 18, and 24 month terms, each for 15% of load, purchased quarterly for a total of 90% of customer load	10% is spot purchases
NH	Twice per year for 1 and 2 year blocks	Unitil and Granite State Electric (NGrid)
NJ	33% for each of 3 years	
PA (FirstEnergy)	Two 24-month contracts for the same two-year delivery period, purchased separately	10% of pricing for residential and commercial customers indexed to spot market prices
PA (PECO)	1 to 2 year contracts, procured twice per year	
PA (PPL)	9 and 12 month contracts procured twice per year	
PA (DLC)	2 to 3 1-year contracts, procured in two or three solicitations for the same delivery period	
MD	2 year contracts, each for 50% of load for residential, commercial customers served by a combination of 1 and 2 year contracts	
IL	Mix of 1 to3 year contracts	Block purchases (energy only) plus some market purchases

9.1.7 Timing of Bids and Contract Approval

The timing between bid submission, bidder notification, and contract approval varies by state, as indicated in Table 4. Typically, bidders execute a master agreement in advance to expedite the transaction confirmation. Bids are generally due early on bid day so that winning bidders can be notified the same day. State regulatory approval is generally within one business week, but may be considerably less.

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[58] This table does not include large C&I customer groups similar to LRS in Connecticut

Table 4. Notification and Approval Timing

State	Winner Notification	Contract Approval
ME	Same day	Within 1 day
MA	Same day	Up to 5 business days
RI	Same day	1-2 business days
NH	Same day	Up to 11 business days
NJ	Same day	2 business days
PA	Same day	1-4 business days
MD	Same day	4 business days
IL	Same day	Up to 4 business days

9.1.8 Financial Security and Credit

About one-half of the EDCs require some type of pre-bid security to be eligible to participate in the procurement and submit binding bids. The primary purpose of such pre-bid security is to ensure that winning bidders execute contracts.

Virtually all EDCs require security to support the supplier's obligations during the term of its contract. The amount of security to be provided varies. Often it is a fixed amount per contract or tranche. In other cases it is based on the EDC's exposure to the contract, thereby changing over the contract term depending on changes in MtM value.

Suppliers are usually provided unsecured credit based on their credit ratings, supported through an unconditional corporate guarantee from the supplier or its parent; guarantees from affiliates are generally not accepted. Suppliers with investment grade ratings on senior long-term unsecured debt receive such unsecured credit; in most cases the amount of credit is also a function of the supplier's tangible net worth. In cases where the amount of credit required is greater than the amount of unsecured credit granted, suppliers may post some form of collateral. The form of collateral is generally an irrevocable LOC from an acceptable bank or other financial institution. Cash held in escrow is also acceptable security, but is seldom used. A few contracts, such as market-indexed or REC contracts with virtually no market exposure, have security requirements that are generally calculated as a percentage of the remaining contract term.

Virtually none of the wholesale supply agreements reviewed provide for bilateral credit support. Explicit authorization by the state regulatory authority of either the procurement process or the contracts themselves mitigates any risks for suppliers.

9.1.9 Auction Formats

Sealed bid auctions were the most commonly used formats. Descending clock auctions were used by some EDCs in PJM, including New Jersey, Maryland, and some in Pennsylvania.

9.2 Municipal Electric Companies

9.2.1 Connecticut Municipal Electrical Energy Cooperative (CMEEC)

CMEEC is a publicly directed joint action supply agency, is owned by various Connecticut municipal utilities and procures power on their behalf.[59] Unlike the structured procurement practices of EDCs, municipal utilities tend to serve their customers' loads through a combination of ownership (outright or shared equity interest) in generation assets and wholesale energy purchases. CMEEC owns the 85 MW Pierce peaking plant along with small diesel units. CMEEC has a small ownership share in the HQ II project.

CMEEC procures energy, capacity, and ancillary services through the ISO-NE-administered markets. Consistent with Board-approved policies, CMEEC enters into forward power purchase contracts and swaps to manage fuel price risks and reduce energy price volatility. To manage congestion risk, CMEEC obtains FTRs through the ISO-NE auctions. The Board policies permit contracts and swaps for up to five years based on a declining percentage of CMEEC member load. Most energy products are forward energy strips (7 x 24, 5 x 16, and some weekend 2 x 16 strips) that are settled against MassHub clearing price. The energy strips and swaps generally utilize ISDA master agreements with power annex that require collateral when MtM exposure exceeds the unsecured credit thresholds in the contract. CMEEC's unsecured credit is relatively high based on its Aa3 (Moody's) / A+ (Fitch) ratings, which in turn reflect the stable credit position of CMEEC's members and other favorable rating agency considerations.

CMEEC's rates for energy supply have historically been lower than UI and CL&P Standard Service and LRS rates, although the spread has narrowed with the decline in energy prices since mid-2008. There are several reasons why CMEEC's rates have historically been lower:

1. CMEEC is not subject to the state-mandated RPS. Therefore supply costs do not include the cost of RECs. Customers have the option to purchase voluntary clean energy, but this is a separate charge.

2. Migration risk is not an issue for CMEEC or its members. Customers do not have the option of retail choice. The municipals can negotiate special tariffs with some large C&I customers that simulate retail choice, but CMEEC continues to serve their load.

3. CMEEC can serve load with generation it owns.

[59] CMEEC includes Groton and Norwich, the Borough of Jewett City, and the Second (South Norwalk) and Third (East Norwalk) Taxing Districts of the City of Norwalk. CMEEC also provides the power required by the Town of Wallingford Department of Public Utilities, the Bozrah Light and Power Company, and the Mohegan Tribal Utility Authority.

In contrast to the investor-owned EDCs, CMEEC is a tax-exempt, non-profit entity. By law, Connecticut's EDCs cannot earn a profit on Standard Service, and therefore this distinction does not directly contribute to the difference in retail rates.

9.2.2 Massachusetts Municipal Wholesale Electric Company (MMWEC)

MMWEC is a non-profit, public corporation and political subdivision of Massachusetts. Like CMEEC, MMWEC serves municipal customers throughout Massachusetts. MMWEC has 20 municipal utility members. Other municipal utilities both in Massachusetts and outside the state may receive power via MMWEC. MMWEC holds equity interests in power plants in New England, as well as HQ II. MMWEC obtains power supplies for resale at cost.[60] In general, MMWEC has signed wholesale power contracts on behalf of its members for up to 5 years.[61] These contracts utilize a standard structure that includes unsecured credit thresholds and collateral requirements based on MtM exposure. One year ago, MMWEC's bonds had credit ratings of A- to A+ from S&P, A+ from Fitch, and A3 from Moody's.[62] Given the current low wholesale power prices in New England, members typically have locked in supplies for 80% to 90% of their individual requirements for two years out. A significant portion is therefore left unhedged. Members typically do not utilize FTRs or financial swaps to hedge energy costs. MMWEC is considering these options.

9.3 Full Requirements Service Refinements

9.3.1 Market Timing and Laddering

Consistent with PURA's decision in Docket No. 06-01-08PH01 and the requirements under Conn. Gen. Stat. §16-244c(c)(3), Standard Service slices or tranches are procured on multiple dates over a period extending up to 36 months prior to first delivery. The resultant portfolio of slices or tranches for a given delivery term is a blend of the forward prices prevailing over an extended period. On any given procurement date, slices or tranches might be procured for multiple future delivery terms, as shown in Figure 53, which depicts an "idealized" procurement scheme with quarterly pro-rata procurement over a 3-year period. The dates within the colored blocks represent idealized bid days. The term "laddering" arises from the pattern of procured slices at any given time, as shown in the diagram.

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[60] MMWEC owns 91% of the Stonybrook Intermediate Unit, 100% of the Stonybrook Peaking Unit, and small portions of Seabrook, Millstone #3, Wyman #4, and various wind projects.

[61] An exception is MMWEC's long-term (20 year) purchase of 12 MW from the MassPower combined cycle project that runs through 2013.

[62] The S&P ratings vary due to the underlying credit ratings of its members who participate in MMWEC's bonds in differing financial interests.

Figure 53. Idealized Laddered Portfolio

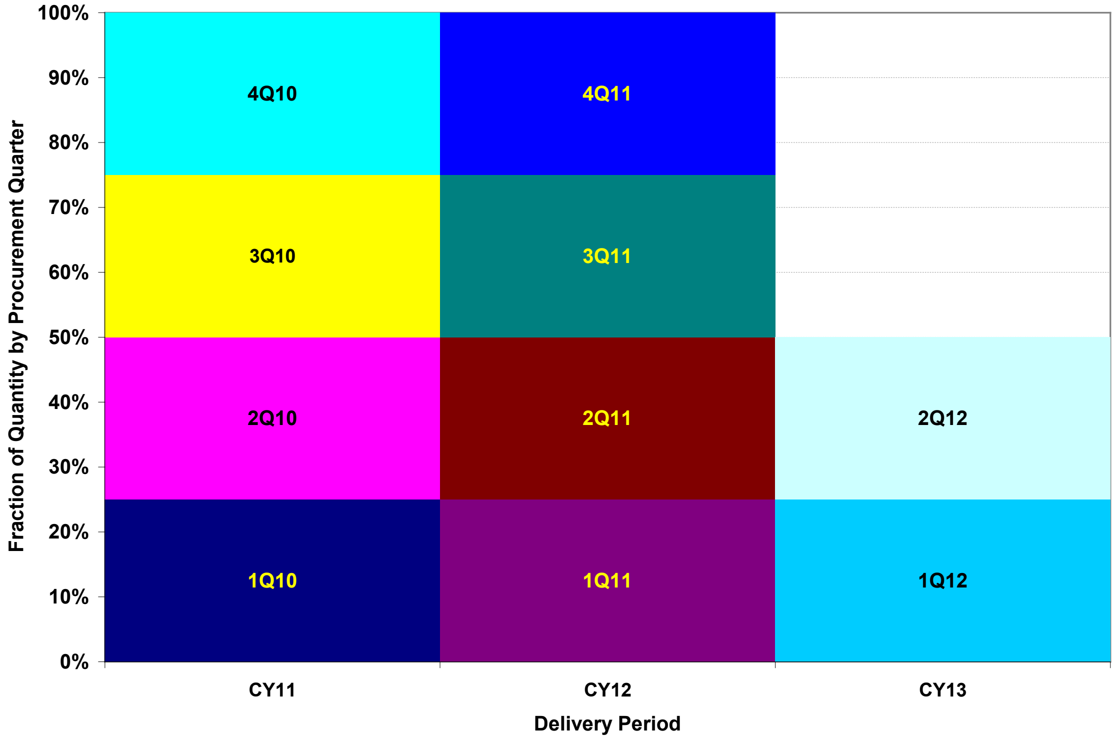
The laddering concept is intended to reduce the volatility of retail pricing by spreading the purchases over several auctions conducted at different times. The CL&P CY 2012 Standard Service portfolio includes slices procured on five different dates ranging from 3 to 27 months prior to first delivery. The UI CY 2012 portfolio includes tranches procured on seven different dates ranging from 6 to 30 months prior to first delivery. Laddering over several auction dates mitigates the effects of buying on "bad days" when forward energy prices are high relative to the days just before or just after actual bid dates. Spreading the auctions over up to 36 months has the effect of averaging the long-term changes in the forward market. Laddering mitigates severe retail rate changes from year to year, but by design, it causes the retail rate for Standard Service customers to lag behind current market conditions. As shown in Figure 12, forward prices have generally declined from July 2008 through 2011. Hence, the resultant average cost of all of the CY 2012 contracts procured by the Connecticut EDCs was higher than the cost of the last CY 2012 contracts awarded.

Whereas forward energy prices may increase or decrease from one procurement round to the next, the cost of hedging quantity uncertainty and the cost of providing collateral for forward contracts always increase with the length of time between bid day and the commencement of delivery. The average cost of full requirements service procured at intervals over 36 months, 24 months, or 18 months will generally be higher than the average cost of slices procured at intervals over 12 months, all other things being the same. This relationship was empirically derived in Section 6.3. Analysis of historic bid data suggests that the risk premium rises significantly beyond a lead time of about 18 months in advance of delivery. There is also less transparent market price information for longer-dated forwards, since monthly on-peak and off-peak products are generally only traded for the current year, after which there are only seasonal and then annual published price indications. Thus, a reasonable laddering strategy should strike a balance between minimizing the time between bid day and first delivery, while at the same time allowing for a reasonable diversification of bid dates.

Experience shows that efforts to guess the “best” day to procure full requirements service are illogical. Therefore, a best practice principle for financial risk management is to avoid trying to time the market. Scheduling purchases over multiple dates is a method for smoothing the variability of market prices, rather than attempting to time the market. However, even with a periodic laddering approach, there can be some latitude in determining how many tranches to award on each bid day. Allowing for selection of discretionary tranches, rather than adhering to a pre-determined number of tranches to be awarded, can result in opportunistic purchases of tranches that are below prevailing market prices. In this instance, a buyer is not attempting to time the market, but rather take advantage of a very aggressive bid. Under the sealed bid paradigm presently employed by the EDCs, sometimes there are bids that are substantially lower than all other bids. Alternatively, fewer than a target number of tranches can be awarded if the bidding is deemed to be non-competitive. A bright-line test oriented around the selection or rejection of discretionary tranches on an objective basis requires that the EDC develop a reasonable benchmark to gauge the competitiveness of the bids received. The reasonable benchmark is the proxy price discussed in Section 6.2, *i.e.*, the all-in price for Standard Service under workably competitive market conditions. Formulation and reliance on each EDC’s proxy price as well as that of PURA’s consultant and OCC’s consultant have been consistently employed by UI and CL&P for all Standard Service procurements to date.

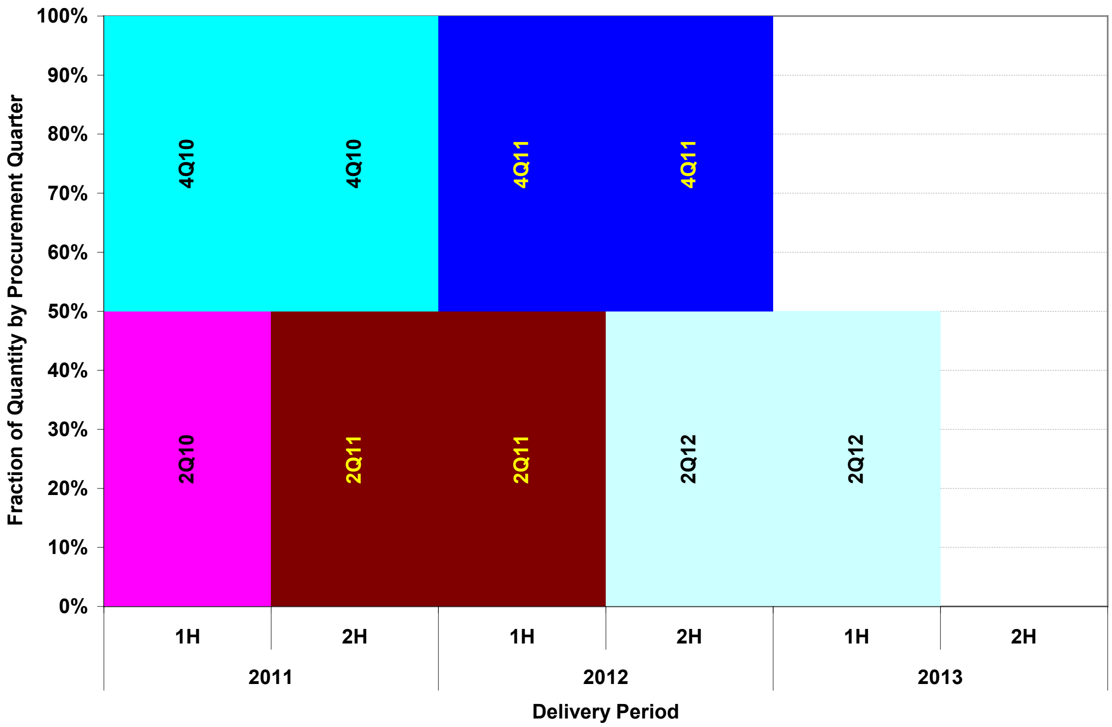
There are several approaches for diversifying procurement dates to mitigate market timing risk. These approaches also help minimize the embedded premium for longer-lead time procurements, while allowing the EDCs to retain the requisite flexibility regarding the number of awarded tranches in each procurement round. One approach would be to shorten the laddering period, and hold several procurements a year but for only the prompt delivery year. This would result in an average time from procurement to the midpoint of the delivery period of roughly 12 months, as illustrated in Figure 54. Once the annual service term is fully procured, retail rates can be published for the full year.

Figure 54. Laddered Contracts Purchased the Prior Calendar Year



Another approach would be to procure overlapping 12-month contracts at 3-, 4-, or 6-month intervals. For a 6-month schedule, the time from procurement to the midpoint of delivery would be shortened to 7.5 months, assuming a mid-November bid day for a 12-month service term beginning the following January 1, and a mid-May bid day for a 12-month service term beginning July 1. The resulting pattern of overlapping contracts is illustrated in Figure 55. As noted in Section 9.1, Massachusetts EDCs procure default service using the 6-month overlapping scheme. It should be noted that this approach would require that Standard Service retail rates be set semi-annually, rather than annually, since underlying contract prices for half of the quantity would not be known at the beginning of the calendar year. Alternatively, a full-year rate could be established using a proxy price for the open tranche, with a true-up the following year.

Figure 55. Overlapping Contracts at 6-Month Intervals



For overlapping procurements at 3-month intervals, 33% of load would be targeted for award each round, and for 4-month intervals, 25% of load would be targeted for award each round. This approach would still allow some flexibility to accept or reject discretionary tranches; however, the term quantity would obviously need to be closed out during the final procurement for the term.

Another important consideration is the total amount of load that is procured on a bid day. If the quantity is too large, the market may adversely move in response to the high demand on that day. For this reason, it is advisable to procure each EDC's Standard Service load at intervals to avoid large purchases on any single day.

9.3.2 Slice-of-System versus Customer Class

Connecticut's EDCs currently solicit full requirements service contracts for Standard Service for all customer rate classes together ("slice of system"). Rival bidders submit separate pricing for residential, small C&I, large C&I, and street lighting (as required by PURA's decision in Docket No. 06-01-08PH01), but the bids are evaluated and awarded on the basis of a weighted average price using expected loads or load weightings. The selected suppliers are compensated for actual energy loads based on the customer class, time of use, and monthly pricing.

In many other jurisdictions, however, default service is bid, evaluated, and awarded separately by customer class. WMECO, an NU company doing business in Massachusetts, procures full requirements service for the residential load segment separately from small C&I, large C&I, and Street Lighting, although WMECO may choose to bundle one or more customer classes under a single contract.

Standard Service load for both Connecticut EDCs is dominated by residential customers, with Small C&I accounting for most of the balance. Large C&I customers (not falling under LRS) and Street Lighting accounts are small fractions of the total Standard Service load, as shown in Figure 56 for CL&P and in Figure 57 for UI.

Figure 56. CL&P Standard Service Energy Load by Rate Class

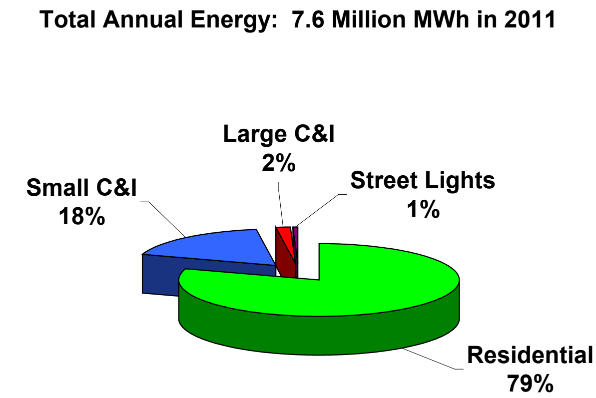
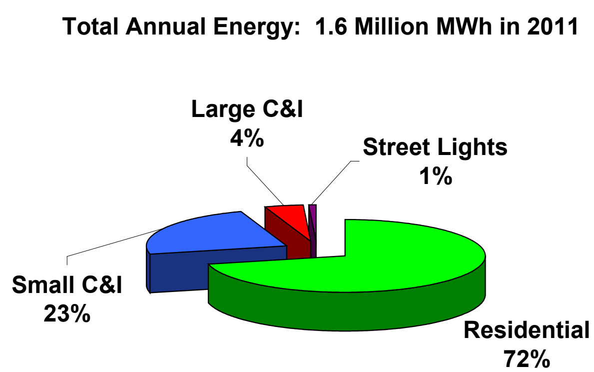


Figure 57. UI Standard Service Energy Load by Rate Class



Each customer class has different load characteristics that affect the cost of providing full requirements service. As discussed in Section 7.2, residential load has a strong summer peak, along with a bimodal peak in the winter. Since residential load represents a large number of customers, its shape tends to be stable from year to year, regardless of migration to or from competitive retail suppliers. As discussed in Section 7.1, migration of residential customers has been slower than for the C&I rate classes. Small C&I, on the other hand, is characterized by a fairly flat load during typical business hours. The migration of Small C&I customers to competitive retail suppliers has been substantial. It is likely that remaining Small C&I customers on Standard Service demonstrate the most pronounced peak profiles or, for whatever reason, are otherwise less attractive to competitive suppliers. Similarly, the Large C&I customers remaining in Standard Service are likely to be more expensive to serve than other customers in this rate class. On the other hand, Street Lighting service is generally purchased by municipalities and the load is highly predictable.

Figure 58 shows the residential load shapes for typical months based on 2011 CL&P data, while Figure 59 shows the same for UI. Both show an annual base load of about 60% of the annual average load and summer and winter peaks of about 180% of the annual average load. Weekend/holiday profiles are similar to the weekday profiles, but with greater mid-day consumption.

Figure 58. Normalized CL&P Residential Load Profiles

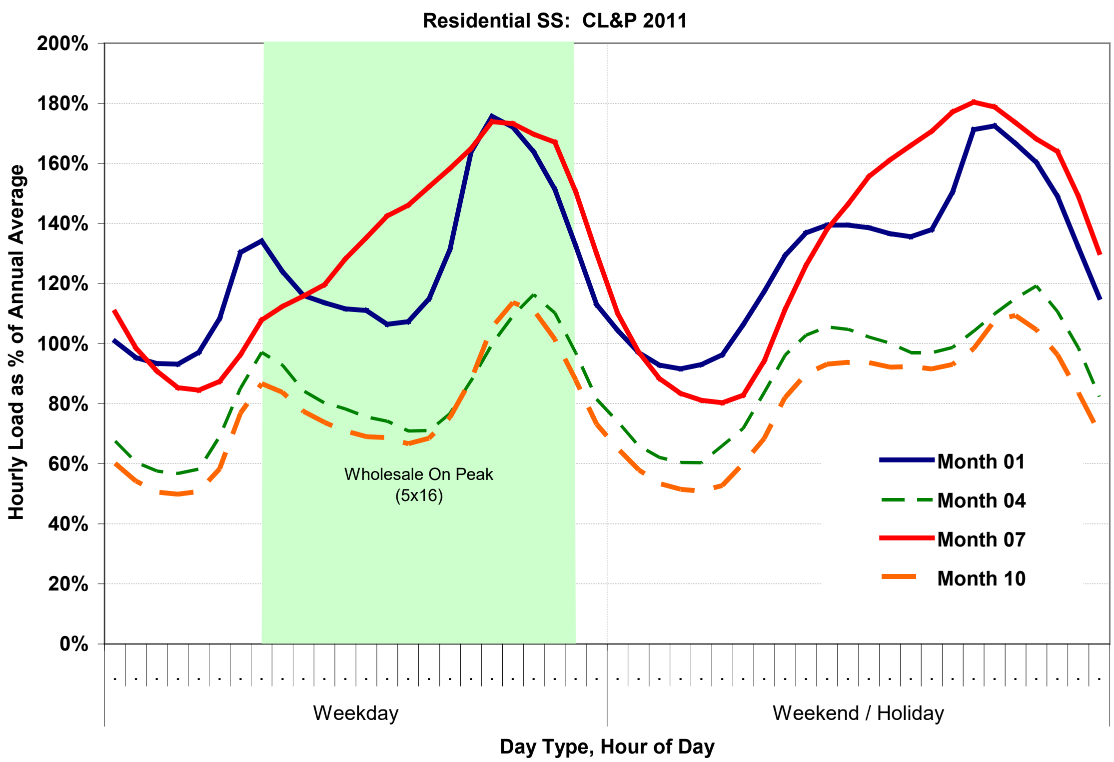
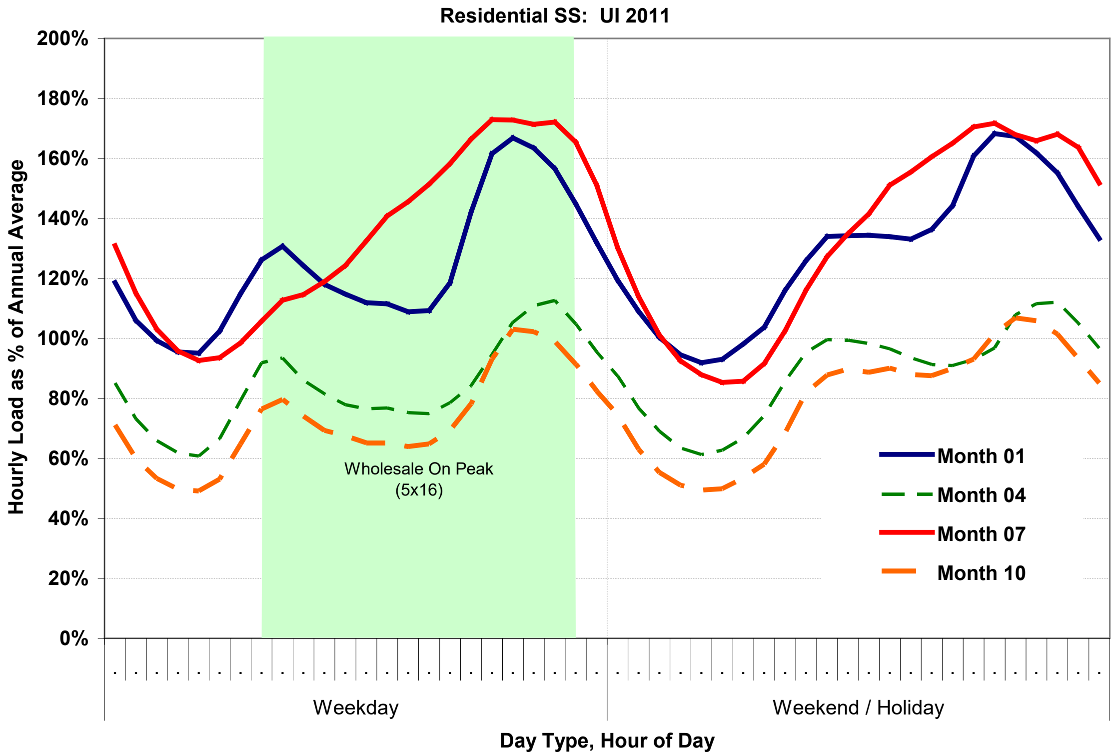


Figure 59. Normalized UI Residential Load Profiles



Small C&I profiles are shown in Figure 60 for CL&P and in Figure 61 for UI. Note that the weekday peaks occur mid-day and are generally more pronounced than the residential peaks. Weekend loads are relatively flat in all months.

Figure 60. Normalized CL&P Small C&I Load Profiles

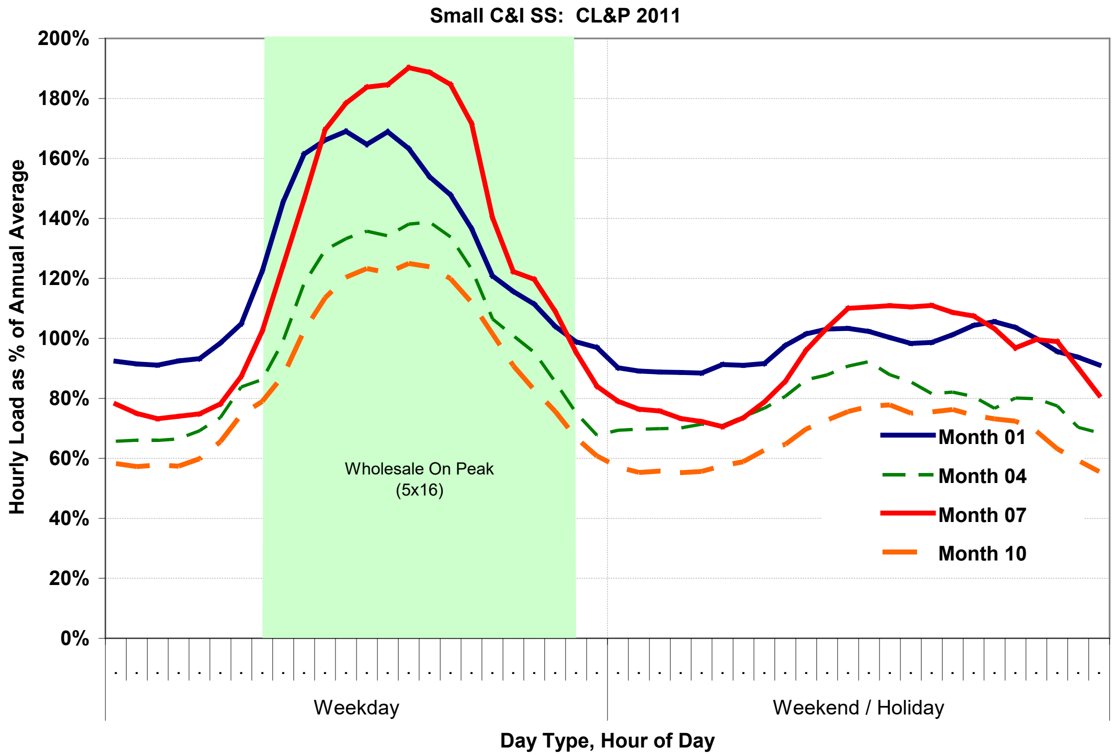
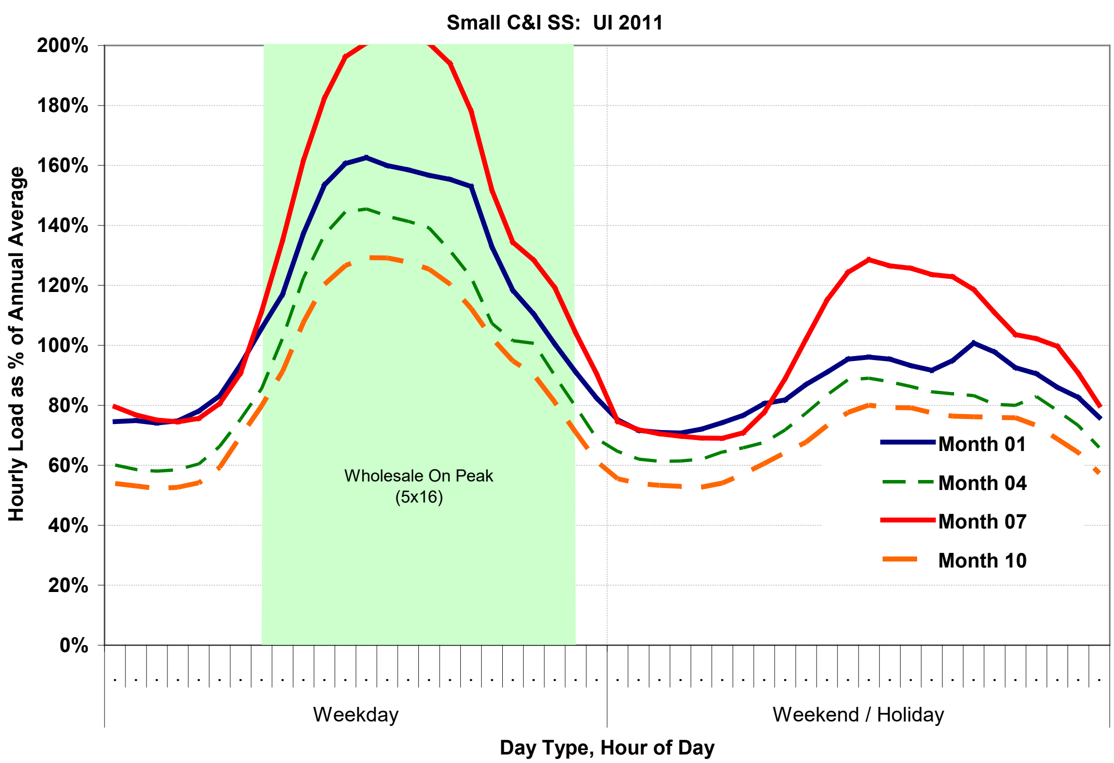


Figure 61. Normalized UI Small C&I Load Profiles



Large C&I profiles, as shown in Figure 62 and Figure 63, are generally flatter than those of Small C&I load, but they are based on a much smaller number of customers who may each have quite distinct load profiles.

Figure 62. Normalized CL&P Large C&I Load Profiles

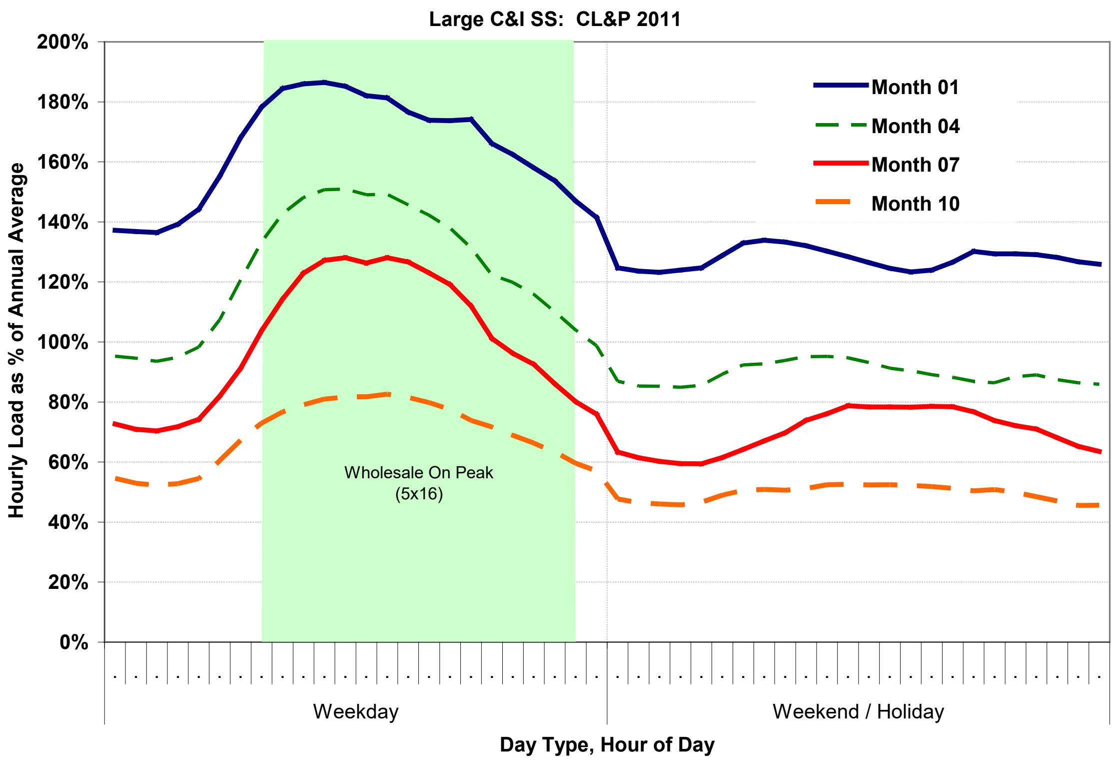
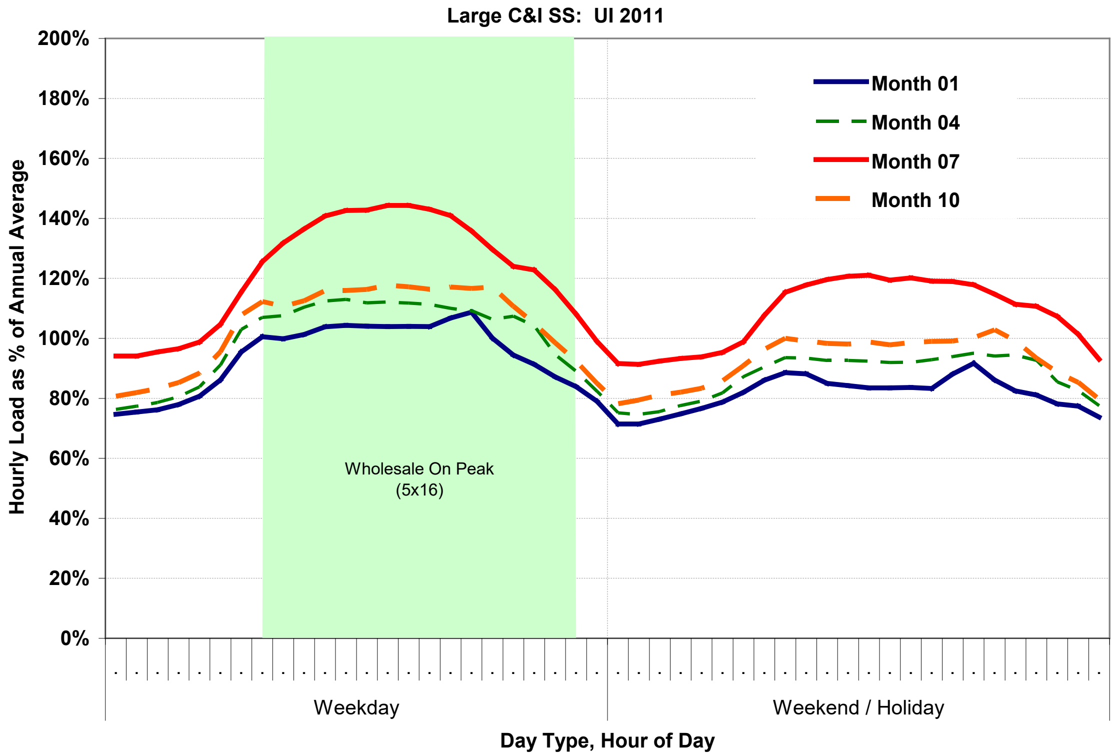


Figure 63. Normalized UI Large C&I Load Profiles



Street Lighting profiles are shown in Figure 64 and Figure 65. Note that the peaks occur in the evening, which is still within traditional peak hours.

Figure 64. Normalized CL&P Street Lighting Load Profiles

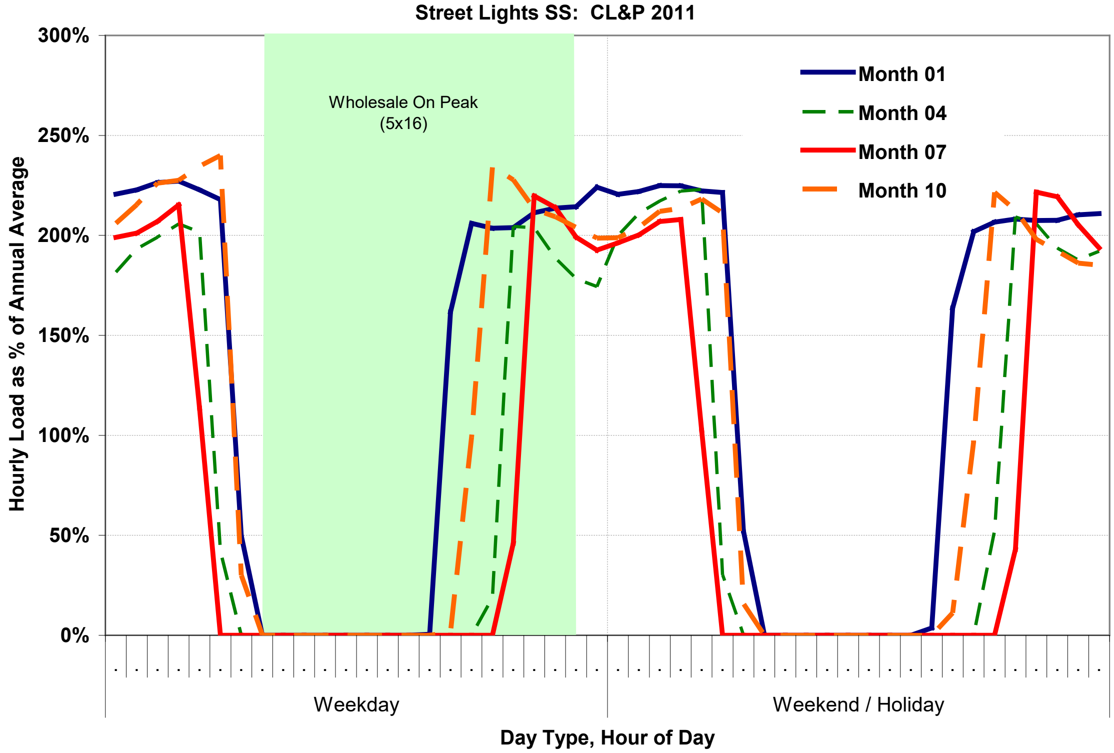
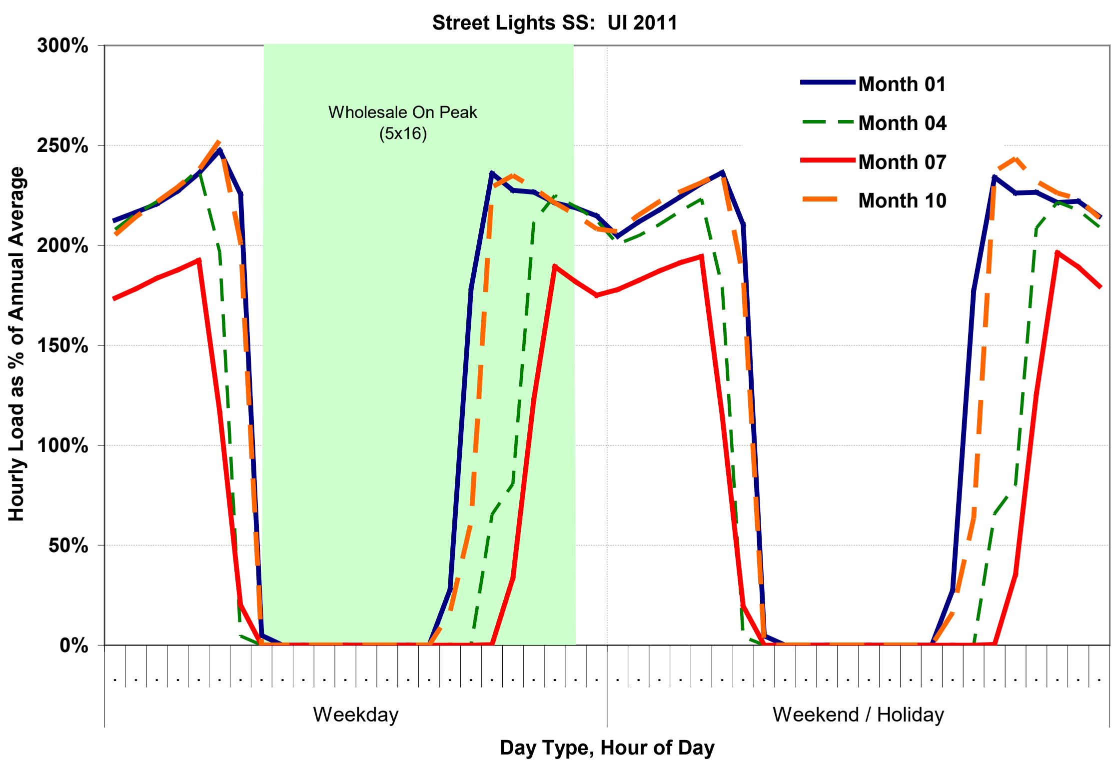


Figure 65. Normalized UI Street Lighting Load Profiles



When the EDCs procure a slice of system to serve Standard Service customers, bidders aggregate the Standard Service load. They may or may not choose to differentiate risks by rate class in their pricing models. To the extent that migration and other quantity risks may be greater for the commercial and industrial rate classes, those risks are mitigated through diversification. The aggregate cost for a slice of Standard Service *may* therefore be lower than if each class were fully priced. Hence, residential customers *may* be incurring a risk premium that would otherwise be the case if the residential rate class were separately priced. Further analysis may be required to verify the reasonableness of this assumption. Nonetheless, separating the procurement of Standard Service by rate class would allow bidders to fully price each class in accordance with the load shape and migration risk inherent to each class, thereby minimizing and possibly eliminating cross-subsidization among rate classes. One caveat is that sufficient historic load data for each individual customer class must be available. If historic data are aggregated across rate classes, bidders will add a risk premium to account for the load uncertainty.

If the EDCs procure by customer class, the slice or tranche size, as a percentage of total class load, may need to be adjusted. Tranches that are significantly smaller than a standard forward block size (about 50 MW) or for a small MWh quantity may attract less bidder interest, thus warranting the inclusion of an illiquidity premium in the pricing of each tranche. Customer classes which are comprised of only a small number of customers may also be less attractive to bidders because of the increased migration risk. For this reason, it may not be sensible to bid by customer classes, particularly for UI.

If either of the EDCs converts to bidding by customer class rather than slice of system, there will be concomitant administrative costs to effectuate the change. These costs, in conjunction with fairness and efficiency considerations, would need to be assessed against any potential economic advantages before implementing this reform.

9.3.3 Auction Type

There are two primary formats in which EDCs in other states procure full requirements electric service for their default service customers: through sealed-bid RFPs, and through simultaneous descending clock auctions. To date, the Connecticut EDCs' solicitations for Standard Service and LRS have been through sealed-bid RFPs. In this type of procurement, bidders submit their best price(s) for the tranche(s) that they wish to serve, and the successful bidders are "paid as bid." In a descending clock auction, the auction manager sets the initial price, and bidders offer the number of tranches that they are willing to serve for that price. With each "tick" of the clock, the auction manager lowers the price, and bidders may keep the number of tranches offered constant, reduce the number of tranches offered, or withdraw from the auction. As long as the total quantity offered from all bidders exceeds the requirement, the auction manager continues to lower the price with each round. The descending clock format also allows bidders to switch tranches among various terms or products if more than one term or product is being procured. When the quantity offered matches the requirement, the remaining bidders are awarded contracts. All are paid the same clearing price. There is also a hybrid type of auction where the initial rounds are conducted as a descending clock, and the final round is a sealed bid.

Auction theorists have disagreed about which format is more efficient. Proponents of descending clock auctions argue that price transparency promotes more aggressive bidding. Others assert that the opposite is true: sealed-bid auction creates uncertainty for the large suppliers regarding the bids of other participants. This dynamic induces the large or stronger suppliers into bidding more aggressively, thus moving closer to the competitive ideal.

The descending clock auction is generally more conducive to a procurement differentiated by customer class. For example, New Jersey's BGS descending clock auction treats each rate class for each EDC as a separate but related product during the auction. For a slice-of-system procurement, the auction manager would likely need to establish in advance a set of factors to relate the single auction clock price to weightings by load segment that are the basis for the contract prices (*e.g.*, by customer class, time of use, month.) If weighting factors by load segment are not differentiated, the bidders would include a risk premium that reflects the load uncertainty.

Procurements conducted by the Connecticut EDCs reveal that customers have benefited from sealed bid RFPs. *First*, on a number of occasions, low outlier bids were submitted and accepted. These bids would not have been submitted in a descending clock auction, since the clock would have stopped before the outlier price was reached. *Second*, the EDCs' Standard Service RFPs allow for considerable bid flexibility, allowing bidders to submit contingent bids for certain tranches (*e.g.*, if bid A is accepted then bid B is withdrawn) and to positively link bids for multiple delivery terms. This type of bid flexibility promotes competition and efficiency, but it would not be feasible in a descending clock format. *Third*, the RFP process permits the selection or rejection of discretionary tranches. Fewer tranches can be awarded than the target number if the bids come in over-market, and conversely more tranches can be awarded if there are more attractive, under-market bids. Consideration of discretionary tranches can not readily be accommodated during a descending clock format. *Fourth,* auction participants prepare their best offer based on their statistical models and risk management policies before the auction begins; there is no evidence that participants dynamically revise their best offer in response to the prices revealed as the clock ticks down. *Fifth*, the EDCs avoid additional costs, for example, the cost of engaging a third party to furnish the necessary software system and to conduct a simultaneous descending clock auction.

In its decision in Docket No. 06-01-08PH01, PURA considered whether the EDCs should employ a descending clock auction process to procure Standard Service and LRS. PURA concluded that there was no concrete evidence showing that a descending clock auction leads to more favorable results or lower prices.[63] PURA prohibited the EDCs from using a descending clock auction in their Standard Service and LRS procurements. Based on experience with Standard Service procurements since 2006, there appears to be no reason to revisit this decision.

[63] PURA Final Decision, Docket No. 06-01-08PH01, June 21, 2006, at p. 5.

9.3.4 Tie-Breaker Criteria

In the current sealed-bid RFP process, bidders provide individual prices by month, customer class, and for on-peak and off-peak periods. The bid sheets for both EDCs round these firm bid prices to $0.01/MWh (0.001 cent/kWh) and display them at that level. Weighted average prices are computed from the firm bid prices and used for evaluation purposes. On the bid sheets, the weighted average prices are rounded prior to evaluation: in the case of UI, they are rounded to the nearest $0.01/MWh (0.001 cent/kWh), and in the case of CL&P, they are rounded to the nearest $0.0001/MWh (0.00001 cent/kWh).

Although a rare occurrence, it is possible for rival bids to be tied. When the difference between two or more bids is miniscule, it is worthwhile to consider whether factors other than price should be applied as "tie-breakers." For example, to promote supplier diversity, there may be a preference for bidders who have no prior contract with the EDC, or who have not been awarded any other tranches in a particular service term. Alternatively, the bidder(s) with the superior credit rating may be preferred, or the bidder(s) with the better record of prior service. However, because both EDCs' wholesale power supply agreements adequately protect customers from default and performance risk, these other differentiators are not as relevant, nor as objective, as selection based purely on price. As long as the weighted price can be calculated to additional precision to the point where price differentiation is achieved, there does not appear to be any reason to introduce other non-price factors into the bid evaluation process. If, however, two or more bids are identical, then it is most appropriate to use a random method, such as a coin-flip or "short-straw," to select the winning bid(s).

9.4 LSE Considerations

The decision to assume the LSE role must take into consideration the additional costs and investments that are required to manage a portfolio of resources, which would otherwise be the responsibility of the full requirements service supplier. These include the cost of resources needed to participate in the ISO-NE markets, make forward and other derivative transactions, conduct trades with bilateral and exchange counterparties, monitor the markets, comply with expanded regulatory and reporting requirements, and commit capital for credit requirements. These obligations are described in the following sections.

Management and credit costs for an EDC to assume the LSE role may be less expensive or more expensive than those elements of cost embedded in a supplier's full requirements service price. Large generation companies or financial service firms may have economies of scale and/or scope that result in lower unit costs for these cost elements than those of an EDC. A larger trading or generation company may have lower unit costs due to its scale and greater diversity of its portfolio. If the supplier also has generation resources, it may also have a lower cost of risk due to its portfolio composition. On the other hand, the EDCs may have superior credit ratings, which would reduce the cost of providing an LOC or other credit facility.

9.4.1 Management Resources

Actively managing Standard Service load requires an LSE to have the capability and resources to forecast, bid and schedule load each day with ISO-NE, and to develop and implement hedging strategies. The LSE must have systems and infrastructure to engage in OTC trading, monitor market conditions, analyze counterparty credit exposure, comply with legal and accounting requirements, negotiate contracts with counterparties, and other administrative functions.

CL&P's affiliate, PSNH, is the LSE for its default (Energy Service) customers in New Hampshire. Consistent with prior legislative and statutory requirements in New Hampshire, PSNH did not divest its generation plants in the late 1990's and early 2000's. Unlike other NU companies, PSNH owns generating stations in New Hampshire totaling 1,150 MW. This portfolio includes Merrimack Station, Schiller Station, Newington Station, Northern Wood Power, nine hydroelectric power plants, and five combustion turbines. These resources are used in conjunction with other physical and financial options to serve PSNH's energy service customers.

PSNH actively manages its Energy Service load through a portfolio comprised of its own generation resources, spot market purchases in the DAM and RTM, and forward energy products. Resources to manage PSNH's portfolio are part of NUSCO, a centralized corporate entity that provides services to NU's operating companies: PSNH, CL&P, and WMECO. NUSCO has wholesale power transaction capabilities, treasury functions, legal staff, and risk management groups, as well as software and hardware systems to manage the PSNH portfolio and load. NUSCO has implemented procedures and controls to ensure compliance with internal risk management policies and other accounting and legal requirements, as well as a transaction reporting system with audit trail and security features to manage operational risks. There are NUSCO personnel with the primary responsibility of managing wholesale power transactions. If CL&P were to become an LSE for a portion of its Connecticut Standard Service load, there would be little incremental cost for NUSCO to also provide the LSE function for CL&P. One difference, of course, is that unlike PSNH, CL&P does not own generation resources, but CL&P's lack of generation ownership would not be expected to impair its ability to manage the portfolio of financial and physical products as an LSE.

UI has technical and management expertise to become an LSE in Connecticut. However, UI's resources are already committed on other UI business and will remain fully engaged going forward. In contrast to CL&P, UI would therefore expect to incur significant incremental direct and indirect costs to provide front, mid, and back-office operations as well as ISO-NE bidding and scheduling services. The cost of developing these management capabilities as well as potential opportunity costs during the initial LSE ramp-up period, has not been estimated. Recognition of these costs and the risks underlying UI's potential transition to an LSE may result in a cost / benefit ratio that does not warrant UI's assumption of the LSE role to serve Standard Service customers.

9.4.2 Dodd-Frank Implications

The 2010 Wall Street Reform and Consumer Protection Act, also referred to as Dodd-Frank, contains provisions in Title VII – Wall Street Transparency and Accountability that are applicable to utilities. Title VII of Dodd Frank gives the Securities and Exchange Commission (SEC) new authority over securities-based swaps, and the Commodities Futures Trading Commission (CFTC) new authority over the regulation and reporting of commodity-based swaps. Regulations promulgated under Title VII of Dodd Frank are scheduled to go into effect on July 16, 2012, or 60 days after the CFTC's publication of the definitions of "swap," "swap dealer" and "major swap participant." The CFTC definition of "swap dealer" will determine which banks, hedge funds, energy companies and other firms will be subject to new capital and collateral requirements intended to reduce risk in global swap markets. On April 19, 2012, the CFTC voted on the Final Rule, but it has not yet been published.

Based on Fact Sheets issued by the CFTC, it appears that CL&P, UI, and their subsidiaries and parent companies would fall under the *de minimus* exemption and therefore will be exempt from reporting, operational, and credit requirements otherwise applicable to a swap dealer. It is also likely, but not certain, that utilities will also remain eligible for the "end-use exemption" if they utilize swaps for the purpose of hedging a physical position. However, even if the CFTC extends the end-user exemption to utilities, the impact of Dodd-Frank is not eliminated because some of the EDCs' counterparties will not be exempt. Thus, regardless of the CFTC's determination on the EDCs' eligibility for the end-user exemption, implementation of Dodd-Frank will certainly increase the cost of doing business with counterparties that serve Standard Service, and may reduce the number of creditworthy suppliers doing business in New England.

Dodd-Frank requires that swaps be guaranteed by central clearinghouses and traded on exchanges in order to reduce risk and increase transparency. ISO-NE has taken a position that tariffed products that clear through ISOs, including IBTs, should be exempt from CFTC jurisdiction because they are adequately regulated by FERC. In particular, FERC Order 741, effective October 2011, mandates certain credit and billing practices for ISOs and RTOs to reduce customer exposure to market defaults. In light of Order 741, ISO-NE, like other RTOs, has taken the lead in creating more stringent credit and collateral requirements that generally reflect many of the guidelines and restrictions set forth in Title VII of Dodd-Frank. The CFTC has not yet made its determination on whether ISOs and RTOs will, in fact, be exempt from regulation under Dodd-Frank.

9.4.3 ISO-NE Credit and Administrative Requirements

ISO-NE manages a Financial Assurance Program (FAP) that establishes credit and security standards covering three categories of obligations: (1) Market Products (*e.g.*, DAM and RTM energy and forward capacity); (2) FTRs; and (2) transmission items associated with the Open Access Transmission Tariff (OATT). Currently, both Connecticut EDCs are subject only to the credit requirements covering FTRs, since they purchase FTRs to manage their Scenario B contracts. In the event that one or both of the

EDCs becomes an LSE and incurs other market obligations with ISO-NE, the level of credit assurance will markedly increase.

ISO-NE's credit requirements are stringent. The FAP operates on a percent threshold rate, calculated as the ratio of the total obligations to the sum of the unsecured credit (if any), posted LOCs, and collateral in BlackRock accounts (cash or other highly liquid instruments). If this ratio reaches 80%, the participant receives a warning. If the ratio reaches 90%, the participant must increase posted credit to return to beneath 90%. At 100% market activities are suspended unless cured by the beginning of the next business day. Prudent market participants monitor their exposure daily and ensure that they maintain a cushion to avoid these sanctions.

FERC Order 741 reduced the availability of unsecured credit for market participants to the lowest value of (1) $50 million per market participant or corporate family' (2) a designated percentage of tangible net worth; or (3) 20% of the Total Amounts Due and Owing, equal to the absolute value of the sum of all bills and credits to ISO-NE. FERC Order 741 also eliminated unsecured credit in the FTR markets.

Both EDCs maintain LOCs adequate for their current FTR and other market activities at ISO-NE. For illustration purposes only, CL&P estimated the impact of becoming an LSE for 10% of its Standard Service load, and purchasing spot energy, capacity, and ancillary services through ISO-NE. ISO-NE charges would include monthly capacity charges and administrative fees, and biweekly charges for spot energy purchases and ancillary services. ISO-NE would assess CL&P's market obligation as the maximum dollar value of its receivables at any time. At current market prices, and assuming a 25% credit cushion, the total credit exposure to CL&P for serving 10% of Standard Service load would be roughly $6.9 million. An LOC for this amount would cost CL&P on the order of $125,000 per year, plus administrative fees to the bank.

9.4.4 Other Credit Considerations

As long as the EDCs procure full requirements service, it is standard industry practice to not extend reciprocal credit to counterparties. The full requirements service contract is backed by the regulatory assurance of recovery from ratepayers. However, as discussed in Section 8.2.2, standard OTC products transacted under an ISDA or other standard agreement may require the EDC to provide credit support. Similarly, for purchases through an exchange such as ICE or NYMEX, credit support similar to ISO-NE's would also be required. For short-term hedges, the cost of the credit support could be estimated in a manner similar to the illustration above.

For longer term products, the obligation is based upon a counterparty's market exposure under the contract. A bilateral contract such as the EEI MPPSA gives the counterparty the right to request collateral when exposure exceeds the amount of unsecured credit that is extended. For example, if the contract becomes out-of-the-money from the buyer's perspective, the buyer can be required to post collateral equal to the difference between the contract price and the MtM value of the contract, less the amount of unsecured credit. There is no cap to the potential exposure; a severe adverse market movement can result in costly credit requirements, and the cost of providing the credit would most likely be passed on to all distribution customers.

Indirect costs associated with providing credit to support the LSE function must also be considered. Credit capacity that is earmarked to support these transactions through ISO-NE, with an exchange, or OTC can not be deployed for other business purposes. The opportunity cost associated with committing credit capacity to secure these transactions is difficult to estimate, but can not be overlooked. Additional bank fees may be incurred if there is a need to establish new credit facilities. Furthermore, as noted in Section 8.2.6, credit rating agencies generally impute debt on the EDC's balance sheet for certain types of intermediate or long-term contracts. Unfavorable accounting impacts may cause the rating agencies to downgrade the EDC's credit rating. This would result in an increased cost of debt, a cost that would indirectly be passed on to customers.

10.0 CONCLUSIONS AND RECOMMENDATIONS

10.1 Procurement Criteria

In preparing this Power Procurement Plan, the Procurement Manager, in consultation with the Working Group, developed a set of criteria intended to establish basic principles for the conduct and design of Standard Service procurements. These criteria also frame the specific recommendations for each EDC, and are the basis for the regulatory approval mechanism set forth in this Power Procurement Plan. These criteria are consistent with the directives of PA 11-80, and carry forward the applicable guidance in PURA's decision in Docket No. 06-01-08PH01.

1. The procurement process must be fair and impartial to all participants.

This overarching principle is identical to the first criterion set forth in PURA's decision in Docket 06-01-08PH01 (at p. 3). Without assurance that the procurement is conducted on a "level playing field" bidders will be unwilling to participate, and without robust competition, the best pricing can not be achieved for Standard Service customers.

2. The procurement plan for Standard Service shall require that the portfolio of Standard Service contracts be procured to produce reasonably stable rates reflecting electric wholesale market prices.

This principle is consistent with the statutory language of PA 11-80 Section 91(c)(3). The recommended procurement design and portfolios described in Section 10.2 are intended to achieve an appropriate balance between low prices and rate stability objectives.

3. The incremental costs, both direct and indirect, of implementing any changes in procurement approach must be evaluated and considered.

In developing the procurement design and portfolios recommended in Section 10.2, the Procurement Manager has considered the incremental costs arising from (1) additional staffing and infrastructure resources needed by the EDC if it serves as the LSE and self-manages a portion of the Standard Service portfolio; (2) the potential for unfavorable accounting treatment, including the imputation of debt on the balance sheets of the EDCs resulting from any changes in procurement approach; and (3) increased credit costs for an LSE to comply with ISO-NE and/or counterparty requirements, including any potential new requirements which may be imposed under Dodd-Frank implementation rules.

4. The contract approval authority, review process, and approval schedule must be appropriate for each type of transaction, giving due consideration to the type, duration, and size of the product.

The review and approval process described in Section 10.3 assumes that by approving this Power Procurement Plan, PURA delegates the requisite regulatory authority to the Procurement Manager to approve contracts between the EDCs and wholesale suppliers of products to serve Standard Service load. The Power Procurement Plan acknowledges that the approval process must accommodate the different types of transactions and products that may be utilized under the new Standard Service procurement paradigm, including products traded through an electronic exchange or OTC rather than through an RFP process.

5. **The Power Procurement Plan should allow for differences in implementation between the EDCs.**

UI and CL&P have different existing company infrastructure, staffing resources, and size of Standard Service load. While basic principles of risk management and procurement integrity apply across the board, the procurement mechanism and products sought need not be a "one size fits all" plan, but should take into account the key differences between the two companies.

6. **Affiliates of the EDCs may respond to a solicitation for bids so long as the Code of Conduct for EDCs, codified in Conn. Gen. Stat. §16-244h, is strictly observed.**

This principle echoes the criterion in the Docket 06-01-08PH01 decision (at page 3) and is consistent with Conn. Gen. Stat. §16-244c(c)(3).

7. **Any structural changes to the EDCs' Standard Service procurement strategy should be phased-in rather than initially applicable to all of Standard Service. The benefits of the change should be evaluated before broader implementation of such change is contemplated.**

Both EDCs currently have 70% of their Standard Service load for 2013 under contract. The changes to the traditional procurement process recommended in this Power Procurement Plan are limited to a portion of the remaining load. If the Procurement Manager determines that these procurement innovations benefit customers, the portion of load procured under the new process may be expanded. The Procurement Manager anticipates that quarterly updates to this plan submitted to PURA will document interim results and process improvements, including both quantitative and qualitative insights affecting the merit of expanding such procurement innovations.

10.2 Power Procurement Plan Design

10.2.1 Power Procurement Plan for UI

The Procurement Manager concludes that UI's Standard Service customers will be best served if UI continues to procure full requirements service from wholesale suppliers who serve as LSE. At this time, UI does not have available manpower resources or systems to assume the LSE responsibility without shifting personnel from other power supply-related business activities that are required by law. In light of UI's relatively small Standard Service load and manpower constraints, UI is unlikely to achieve the same economy of scale and portfolio diversity benefit that is characteristic of a competitive, creditworthy supplier. Moreover, the incremental cost for UI to add the requisite manpower resources, credit facilities, infrastructure, and risk management policies and procedures to assume the LSE responsibility for Standard Service is likely to exceed the expected benefit that may be achieved over the short run by self-managing the Standard Service portfolio. Determination of this incremental cost must account for the provision of additional credit associated with ISO-NE market participation as well as the credit that may be required in order to enter into bilateral transactions. Notwithstanding the Procurement Manager's initial determination at this juncture, UI may elect to conduct an evaluation of the direct and indirect costs to customers if UI were to assume the LSE role at a future date. If UI determines that customers will benefit from UI managing the Standard Service portfolio as the LSE, the Procurement Manager will consider at such time a proposal by UI in a future update to the Power Procurement Plan. For such a proposal, UI must present results of analysis that establish the value and robustness of the expected benefits in relation to the cost to implement the proposed portfolio.

Left unfilled for 2013 is 30% of UI's Standard Service supplies. The Procurement Manager recommends at this time that UI continue to procure full requirements Standard Service for the remainder of the 2013 service term. Thereafter, UI will continue to procure full requirements contracts for Standard Service unless directed otherwise by the Procurement Manager. While there may be some merit in designating up to two 10% tranches for an indexed full requirements product, preliminary analysis based on the Northbridge study discussed in Section 8.5.2 suggests that the avoided costs associated with an indexed full requirements product is relatively small, and the potential for a bad economic outcome for customers can be significant. Based on further analysis and consultation with UI, the Procurement Manager may or may not direct UI to solicit indexed full requirements bids in either the next procurement round or a subsequent one.

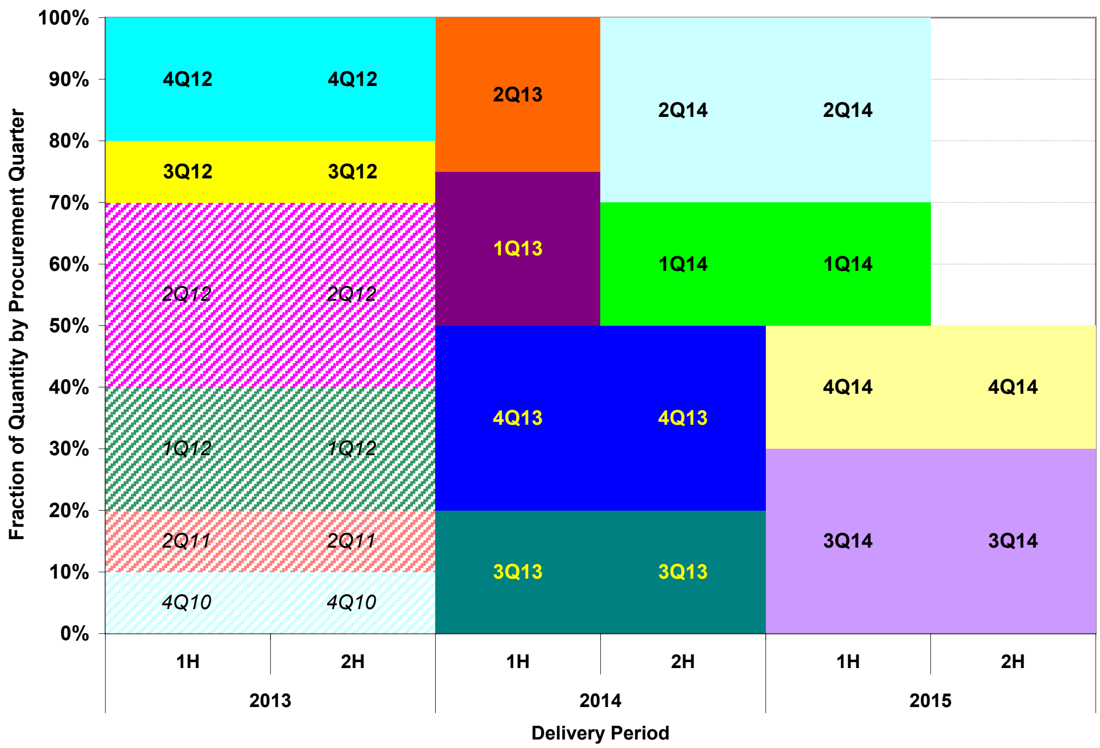
Consistent with the current procurement process and UI's existing wholesale service agreement, bidders may offer Scenario A or Scenario B bids, with delivery for all products to the CT Load Zone. Bidders will continue to offer prices for each month of the service term, on-peak and off-peak periods, and for each customer class. At the discretion of UI, UI may elect to utilize either the definition of on-peak and off-peak hours consistent with retail rates or consistent with ISO-NE definitions. All bids will be evaluated based on a load-weighted average for the service term.

The schedule of the laddering and the contract terms should be modified for 2013 and future years so that, to the extent possible, the start of delivery for any tranche does not exceed six months from bid day.[64] The intent of this schedule is to reduce the magnitude of the risk premium suppliers incorporate to compensate for various time-related risks and costs. The procurement schedule will create a portfolio of overlapping 12-month service terms, procured on four different dates. Figure 66 illustrates the procurement schedule and the resulting pattern of contracts as the transition to this procurement design is implemented. Two or three tranches, each representing 10% of UI's Standard Service load for a 12-month service term will be solicited in each quarterly procurement. Due to

[64] During the transition to the shortened-laddering schedule, the first two procurements to fill 2014 will need to be scheduled more than 6 months from the first delivery date.

the transition, it is likely that six-month service terms will be procured, a divergence from recent UI procurement procedure. To avoid procuring contracts that are too small to sustain bidder interest, the six-month term contracts may be as large as 25% of the Standard Service load. The Procurement Manager, in consultation with UI, may revise the number of tranches per service term (or the percentage of load per tranche) in the future if the total Standard Service load changes significantly due to migration or reverse migration. The procurement design allows for the selection or rejection of discretionary tranches, provided that the prompt period is fully contracted by the start of that service term.

Figure 66. UI Target Laddering Schedule



Note that at the beginning of 2014, the full calendar year will not be fully procured, and the total cost to serve load for all of 2014 will not be known with certainty. The process for developing retail rates for 2014 will be addressed by the Procurement Manager in a subsequent update to this Power Procurement Plan. PURA will continue to establish retail rates in a formal rate-setting docket.

10.2.2 Power Procurement Plan for CL&P

CL&P currently has 30% of Standard Service supplies for 2013 unfilled. The Procurement Manager recommends that CL&P continue to procure full requirements Standard Service for the remaining slices of the 2013 service term and thereafter, unless modified by a subsequent update to this Power Procurement Plan. However, CL&P has the option to propose to the Procurement Manager a plan to serve as the LSE and manage a portfolio of products for no more than 20% (two 10% slices of system) of Standard

Service load for 2013. The remaining slice(s) of 2013 will continue to be procured as full requirements service.

CL&P, through NUSCO, has the manpower resources, information technology, and the credit and risk policies and procedures necessary to bid and schedule load and participate in market transactions. Hence, CL&P may be able to demonstrate value for Standard Service customers by self-managing a portion of the portfolio to serve Standard Service customers in 2013. Working in close consultation with the Procurement Manager in 3Q2012, CL&P will formulate a reporting function and ongoing monitoring capability that is designed to track the actual performance of the portfolio relative to the expected performance of the portfolio over the service term and relative to the fixed cost of the concurrent full requirements slice(s). The Procurement Manager will rely on this reporting function and monitoring capability in order to authorize specific physical and/or financial transactions associated with self-managing the portfolio to serve Standard Service customers, as further described below. The Procurement Manager also recognizes that CL&P's willingness to assume the LSE role for a significant portion of Standard Service portfolio in 2013 is not a compulsory part of the Power Procurement Plan, but is instead a sensible complement to CL&P's existing procurement practice. While the initial limit for the self-managed portfolio is 20% of CL&P's Standard Service load for 2013, the Procurement Manager may increase or decrease this limit each year no later than October 1 for the subsequent calendar year based on the performance of the active portfolio.

For the slices of Standard Service that are not self-managed by CL&P, CL&P will solicit bids for fixed price full requirements products following the conventional process for Standard Service. Consistent with the current procurement process and the existing wholesale service agreement, bidders may offer Scenario A or Scenario B bids, with delivery of all products to the CT Load Zone. Bidders will offer prices for each month of the service term, on-peak and off-peak periods, and for each customer class. At the discretion of CL&P, CL&P may elect to utilize either the definition of on-peak and off-peak hours consistent with retail rates or consistent with ISO-NE definitions. Bids will be evaluated based on a load-weighted average for the service term. For 2013 and thereafter, CL&P will solicit bids for 10% slices of Standard Service for those slices that are contracted as full requirements service. The Procurement Manager, in consultation with CL&P, may revise the number of slices per service term in the future if the total Standard Service load changes appreciably due to migration or reverse migration, among other things.

The schedule of the laddering and the contract terms for the full requirements service slices should be modified for 2013 and future years so that, to the extent possible, the start of delivery for any slice will not exceed 6 months from bid day.[65] The intent of this schedule is to reduce the magnitude of the risk premium suppliers incorporate to

[65] During the transition to the shortened-laddering schedule, the first two procurements to fill 2014 will need to be scheduled more than 6 months from the first delivery date.

compensate for various time-related risks and costs. The term for the self-managed slices will depend on the products and terms of the products in the portfolio. The objective of the procurement schedule for the full requirements slices is to create a portfolio of overlapping 12-month service terms, procured on four different dates. Figure 67 illustrates the procurement schedule and the resulting pattern of contracts as the transition to this procurement design is effectuated, assuming that CL&P does not self-manage two slices. Figure 68 illustrates a potential procurement schedule assuming that CL&P self-manages 20% of its Standard Service load in 2013 and beyond.

For the full requirements service slices, two or three tranches, each representing 10% of CL&P's Standard Service load for a 12-month service term will be solicited in each quarterly procurement. However, due to the transition it is likely that six-month service terms must be procured for 2014. The Procurement Manager, in consultation with CL&P, may revise the number of tranches per service term (or the percentage of load per tranche) in the future if the total Standard Service load changes appreciably due to migration or reverse migration. The procurement design allows for the selection or rejection of discretionary tranches, provided that the prompt period is fully contracted by the start of that service term.

Figure 67. CL&P Target Laddering Schedule (No LSE Responsibility)

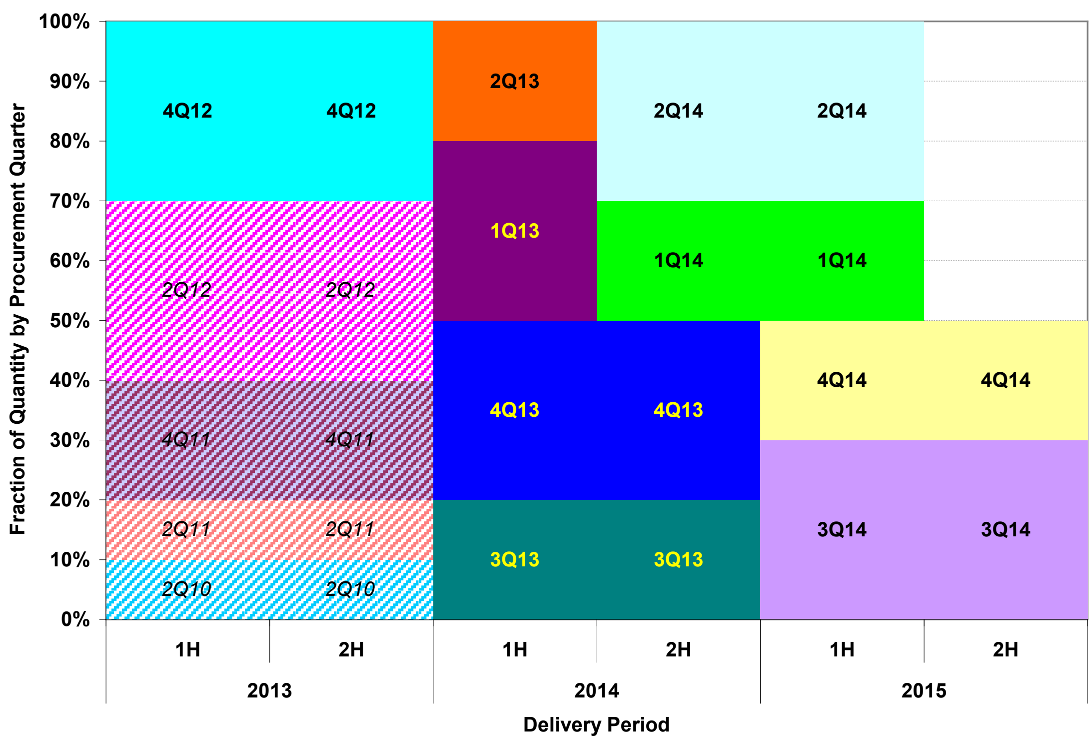
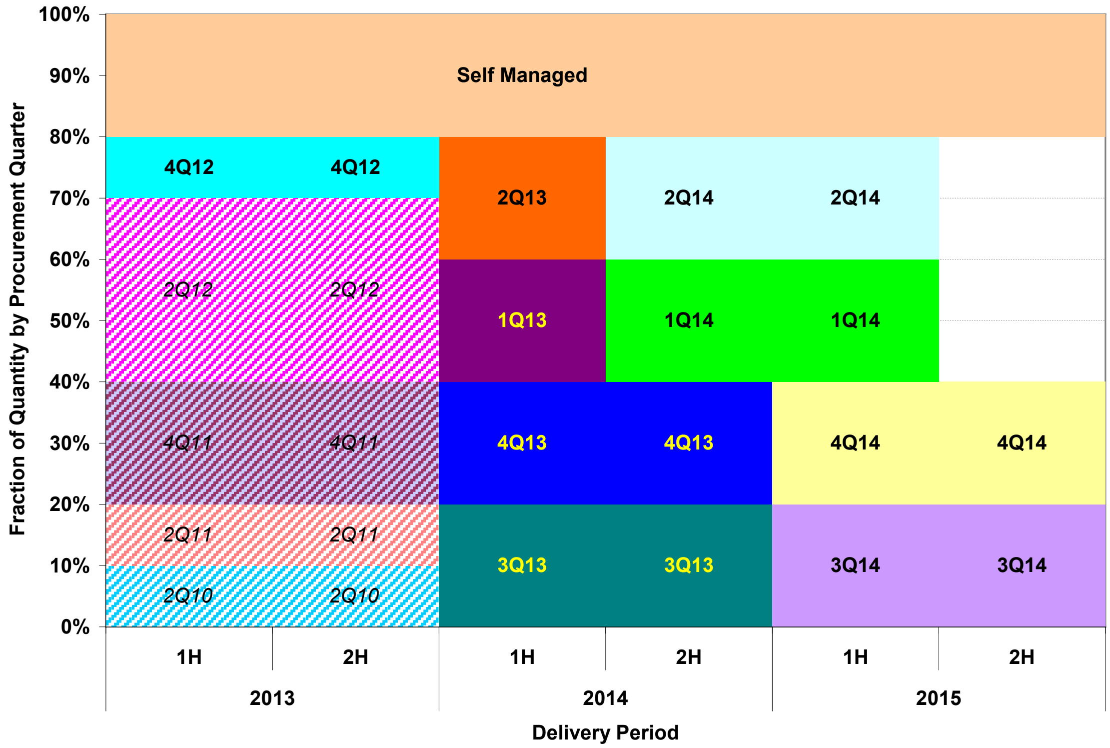


Figure 68. CL&P Target Laddering Schedule with Self-Managed Slices (LSE Responsibility)



Note that at the beginning of 2014, the full calendar year will not be fully procured, and the total cost to serve load for all of 2014 will not be known with certainty. The process for developing retail rates for 2014 will be addressed by the Procurement Manager in a subsequent update to this Power Procurement Plan. PURA will continue to approve retail rates in a formal rate-setting docket..

10.2.3 Plan and Reporting Requirements for a Self-Managed Portfolio

Prior to procuring any products for the self-managed portfolio, CL&P will submit a portfolio management plan to the Procurement Manager that identifies the enabling agreements that will be executed or are already in place (*e.g.*, ISDA), the mix and types of products to be procured, terms, and hedge ratio. The portfolio management plan will also propose guidelines for which transactions will require prior approval of the Procurement Manager, based on the term, quantity, notional value, and/or type of transaction.

The portfolio management plan will include a forecast of the Standard Service load and the cost to serve the self-managed portion of the load for 2013 based on then-current market prices ("Expected Case").[66] The portfolio management plan will also include

[66] Wherever applicable, cost will be expressed as a rate (cents per kWh) and as a total dollar value for the self-managed tranches.

forecasts of the expected cost to serve the self-managed load if energy prices and Standard Service load during seasonal peaks deviate from the expected values. Emphasis will be placed on the formulation of sensitivity cases that are higher or much higher than the expected values. These are referred to as the "High Case" and "Stress Case," respectively. The portfolio management plan will also include a forecast of the cost to serve the self-managed load if energy prices during seasonal peaks are lower than the expected value ("Low Case"). The forecasts will be provided for each month of 2013, and as annual totals. Prior to submitting the portfolio management plan, CL&P and the Procurement Manager will determine how the High Case, Stress Case and Low Case will be formulated. In lieu of these discrete cases, CL&P may elect to develop a model that illustrates the expected cost and the dispersion of outcomes around the expected cost on a probabilistic basis, similar to the methodology described in Section 8.5.1. Following approval of the portfolio management plan, and consistent with the Standard Service rate filing, CL&P will update the Expected Case and the other sensitivity cases.

CL&P will be required to submit monthly project control reports associated with CL&P's plan to self-manage up to 20% of the Standard Service load in 2013. The monthly reports will be due to the Procurement Manager at an agreed-upon date, based upon the availability of load data from ISO-NE, following the end of each month. The project control reports shall include the following elements:

- For the self-managed portion of the portfolio, a summary of the bilateral forward energy products and RECs purchased or sold by CL&P and the associated costs. This cost summary should be stated for the monthly period as well as for the year-to-date.

- The energy hedge ratio for the reporting month, and for each remaining month of 2013. The energy hedge ratio should be expressed as the net quantity of forward bilateral contracts (expressed in MWh) divided by the total Standard Service load (expressed in MWh) on an actual or expected basis, as applicable.

- Summaries for the reporting month and year to date for the self-managed tranches, including the following:

    - Forecasted (established at the time of rate-setting) and actual customer load
    - Forecasted cost (based on the rate established at the time of rate-setting and actual customer load)
    - Actual expenditures
    - A comparison of actual expenditures to the Expected Case, High Case, Stress Case, and Low Case

- An updated forecast of the self-managed load and the cost to serve the self-managed load for each remaining month of 2013

- Identification of any problem areas, risk factors, corrective actions taken, or market developments relating to CL&P's ongoing administrative efforts to self-manage up to 20% of the Standard Service portfolio.

10.3 Regulatory Review and Approval

10.3.1 Assurance of Rate Recovery

Conn. Gen. Stat. §16-244c(c)(2) provides for full recovery by the EDCs of the actual net costs of providing electric service for its Standard Service customers. The law states that PURA shall establish the Standard Service price such that: "Each electric distribution company shall recover the actual net costs of procuring and providing electric generation services pursuant to this subsection, provided such company mitigates the costs it incurs for the procurement of electric generation services for customers who are no longer receiving service pursuant to this subsection."

10.3.2 Responsibility and Authority of Procurement Manager

The Power Procurement Plan and the approval mechanism described below are predicated on the concept that the Procurement Manager has the responsibility and sole authority to approve all contracts recommended by the EDCs for Standard Service, provided such contracts and transactions are consistent with this Power Procurement Plan, once it is approved by PURA. It will be the responsibility of the Procurement Manager to ensure that all contracts and transactions approved are in full accord with this Power Procurement Plan, including any conditions that PURA may impose in its approval.

10.3.3 Approval Mechanisms

The current process for procuring full requirements service through an RFP solicitation will be modified as follows:

1. The Procurement Manager will review and approve all RFP documents, including term sheets, wholesale contracts, bid sheets, and Q&A with bidders. He will monitor all contract discussions with potential bidders.

2. In advance of bid day, the Procurement Manager will advise the EDC of any supporting information, such as a summary of prior tranches procured, rate impact, proxy prices, and other data that he will need to review the recommended bids.

3. On each bid day, the Procurement Manager and the OCC will receive copies of all bids as they are received by the EDC. The Procurement Manager, the EDC, and the OCC will each independently evaluate the bids. The Procurement Manager will not participate in deliberations by the EDC, but will monitor that the bids were submitted in accordance with the requirements of the RFP.

4. On the same day as bid day, the EDC and the OCC will each present to the Procurement Manager their respective recommendation as to the selected contracts. The EDC will also provide all other information requested by the Procurement Manager. Following discussion with the EDC and the OCC, the Procurement Manager will issue his decision on the recommended contracts, and prepare written documentation of his approval or rejection of the recommended contracts. Following the Procurement Manager's written approval of contracts, the EDC will notify the winning bidders. The Procurement Manager's written approval of contracts will constitute authorization to the EDC to execute binding agreements.

5. On the day following bid day, the Procurement Manager, the EDC's representatives, and the OCC will participate in a technical meeting before PURA to inform the PURA and to document the results of the solicitation, the executed contracts, and the reasons for the selection of these contracts.

6. All procedures regarding confidentiality of bid information established in Docket No. 06-01-08RE02 remain unchanged.

If CL&P elects to serve as the LSE for up to 20% (2 slices) of Standard Service, CL&P will submit a portfolio management plan containing the information described in Section 10.2.3 to the Procurement Manager. The portfolio management plan for 2013 must be submitted to the Procurement Manager prior to executing any transactions and at least three weeks prior to the bid day for full requirements service for the 2013 slice(s). As soon as possible after submission, the Procurement Manager will meet with CL&P to discuss the plan and its implementation. The OCC will participate in this meeting. The Procurement Manager will document his review of the portfolio management plan and any conditions for approval of the portfolio management plan. In the event that the Procurement Manager rejects the portfolio management plan, he will document the reasons and direct CL&P to procure those slices as full requirements contracts on the next bid day. If the portfolio management plan is approved, the Procurement Manager, CL&P, and the OCC will participate in a technical meeting before PURA to inform PURA of the basis for decision and to document any condition of the approval.

During the implementation of the portfolio management plan, CL&P will provide the monthly project control reports identified in Section 10.2.3. The Procurement Manager will review and approve all enabling agreements, such as ISDAs, prior to execution by CL&P. If a proposed transaction falls outside of guidelines established in the approved portfolio management plan, the transaction will require the approval of the Procurement Manager in addition to any approvals required in accordance with CL&P's internal policies and procedures. For all other transactions, such prior approval by the Procurement Manager will not be required, but the Procurement Manager shall be routinely notified by telephone or e-mail and in the monthly project control report regarding the array of physical and financial products entered into by CL&P to self-manage the portfolio.

To the extent that the portfolio management plan and the monthly project control reports contain proprietary business information, CL&P shall be entitled to submit these documents as confidential materials to the Procurement Manager and other parties who may review them.

10.3.4 Regulatory and Legislative Changes Necessitated by the Plan

This Power Procurement Plan is intended to be entirely consistent with Conn. Gen. Stat. §16-244c as amended by PA 11-80. PA 11-80 eliminated some of the previous restrictions of a Standard Service portfolio which would not have been consistent with the recommendations of this plan, such as the requirement to procure laddered contracts and the limitation to contracts for terms of not less than 6 months. Thus, approval or implementation of this Power Procurement Plan need not be conditioned on any legislative action.

This Power Procurement Plan does not address the timing for establishing retail rates for Standard Service. Conn. Gen. Stat.§16-244c(c)(2) states that PURA shall establish the Standard Service price "but not more often than every calendar quarter." Currently, retail rates for both EDCs are published annually. Although not contemplated at this time, if a future quarterly update to this Power Procurement Plan were to recommend rate-setting more frequently than quarterly, a legislative change would be required before such change could be implemented. The contracts could not be less than for 6-month terms, although contracts for shorter terms could be procured if warranted under certain conditions

PURA's 2006 decision in Docket No. 06-01-08PH01 established a number of requirements and limitations for the provision of Standard Service, as follows:

- The Standard Service portfolio was required to consist exclusively of a portfolio of laddered, full requirements service contracts
- The contract terms could not exceed 3 years
- The RFPs were required to request separate pricing for residential, small C&I, large C&I, and street lighting, along with monthly, and on-peak and off-peak pricing.

Upon approval by PURA of this Power Procurement Plan, these former provisions under Docket No. 06-01-08PH01 will be superseded by the requirements of this plan.

PURA's decision in Docket No. 06-01-08RE02 established a protocol regarding disclosure of bid data for Standard Service and LRS procurements and the processing of retail rate proposals incorporating those results.[67] This protocol shall continue to apply to

[67] PURA Docket No. 06-01-08RE02, August 20, 2008

bid data obtained by UI and CL&P through future Standard Service RFPs for full requirements service and submitted to PURA in Standard Service filings.

CL&P's portfolio management plan and the monthly project control reports submitted to the Procurement Manager are expected to contain proprietary business information. It is anticipated that PURA's decision regarding this Power Procurement Plan will address how confidential information submitted to the Procurement Manager will be protected.

PURA has in the past adopted administratively efficient processes to facilitate the timely processing of protected materials that are repetitive in nature. For example, PURA adopted an umbrella protective order for protected filings of UI because, over time, it became readily apparent that the same protected information is filed with each solicitation; while the numbers may change based on market conditions, each table in each solicitation presents the same information.[68]

PURA should explore and implement a process that appropriately balances its need to review and approve protected materials prior to approval against the need for a process that anticipates monthly submission of repetitive protected materials provided directly to the Procurement Manager. PURA may wish to hold a technical meeting after approval of the Power Procurement Plan in which it reviews a template of the monthly submission, or the initial monthly submission itself, and considers whether an umbrella protective order, or an alternative procedure, would be appropriate under the circumstances.

[68] *See*, February 9, 2011 motion of The United Illuminating Company in Docket No. 06-01-08PH02, DPUC Development and Review of Standard Service and Supplier of Last Resort Service (Motion No. 54).

Appendix A

Load Profiles

Figure A1. Weekly Load Profile – January 2008 (CL&P)

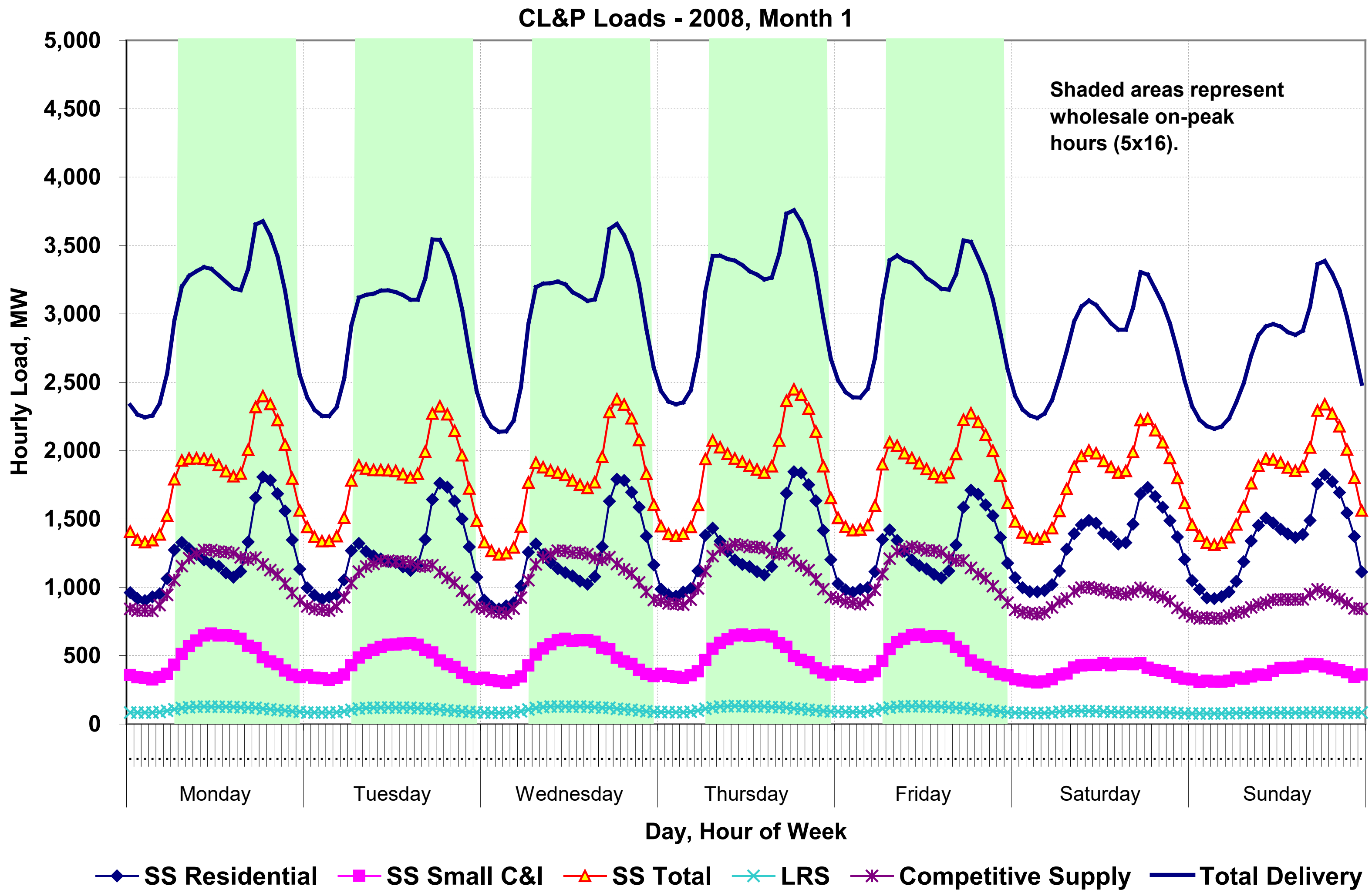


Figure A2. Weekly Load Profile – April 2008 (CL&P)

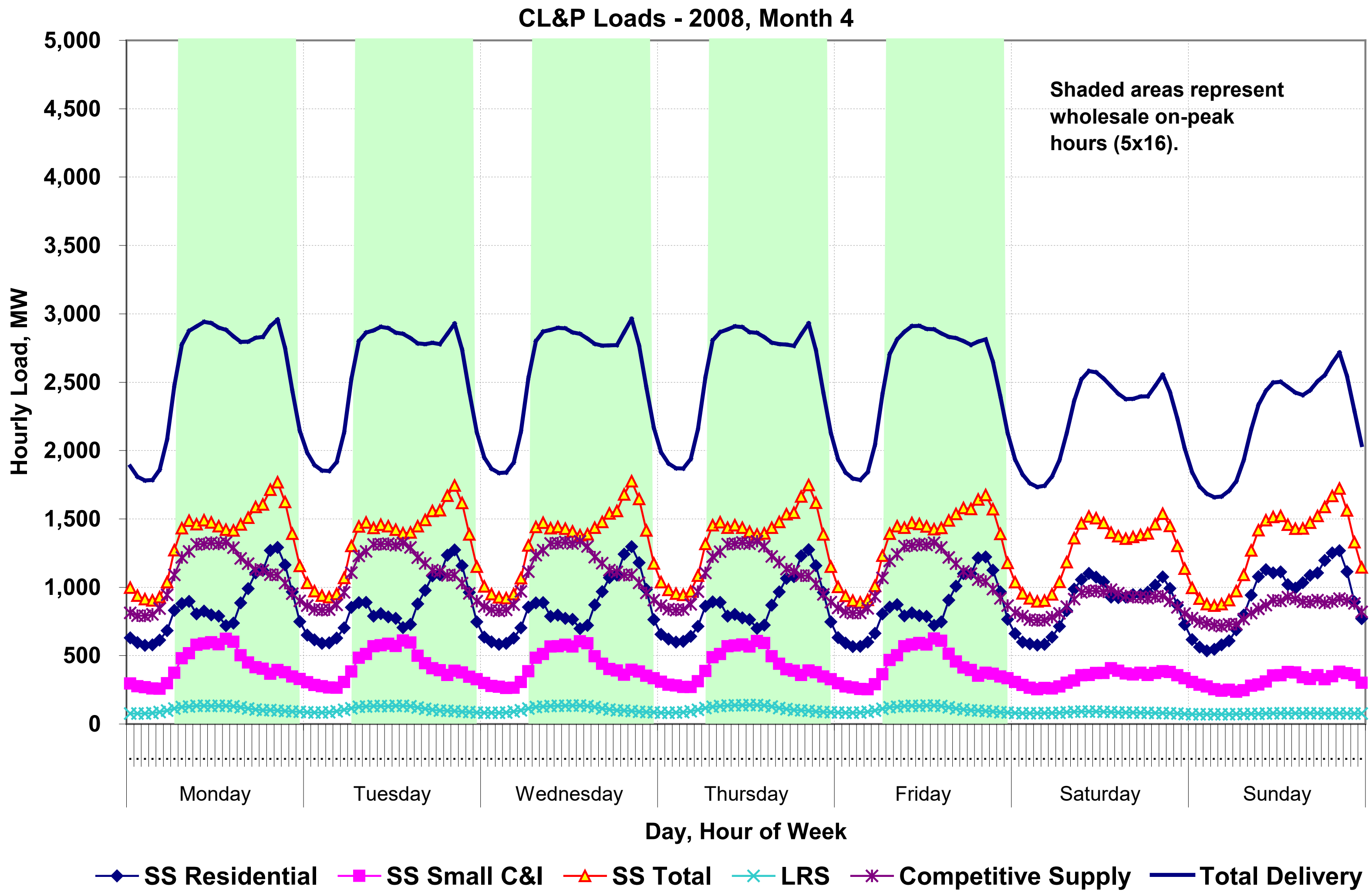


Figure A3. Weekly Load Profile – July 2008 (CL&P)

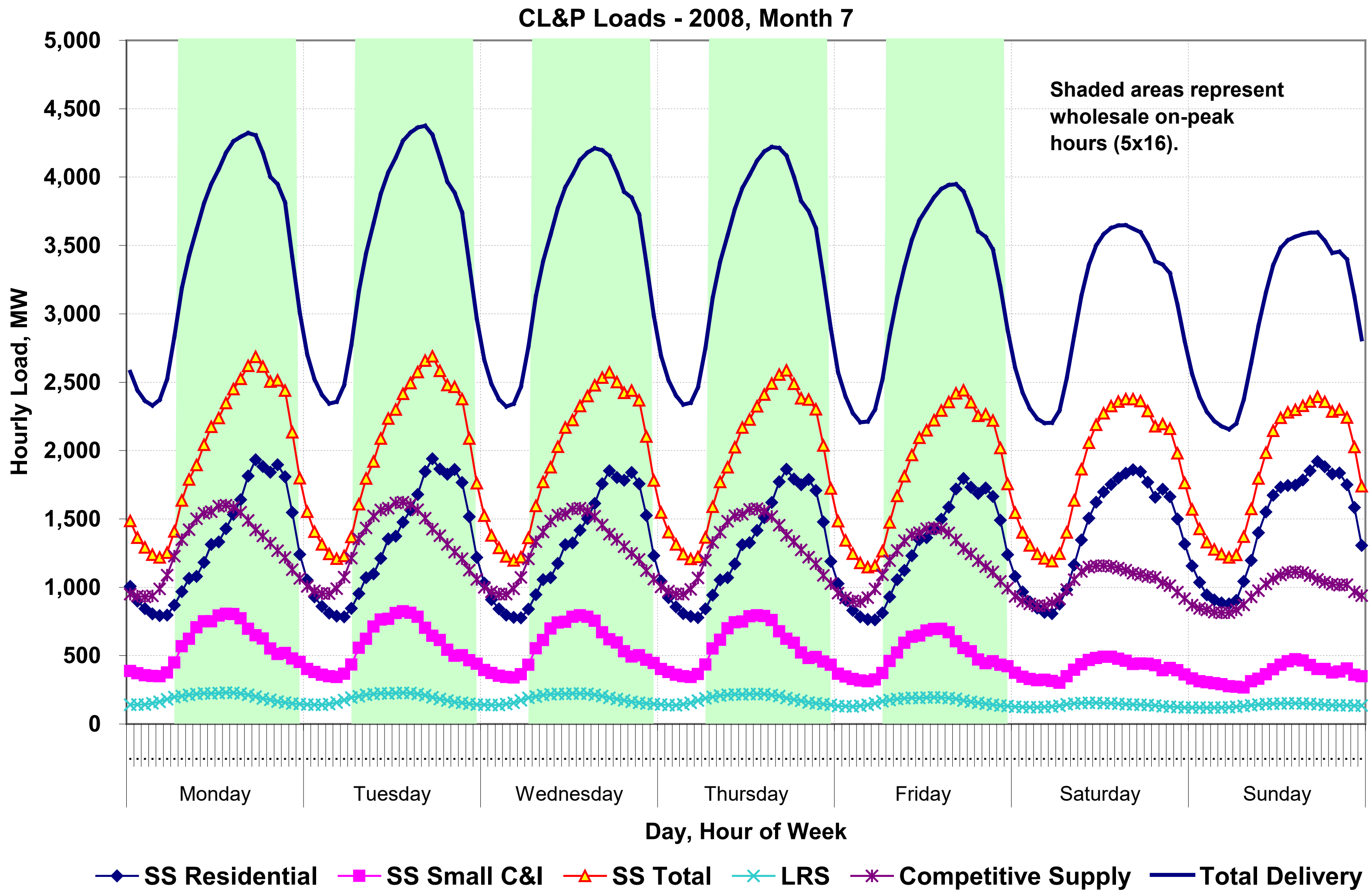


Figure A4. Weekly Load Profile – October 2008 (CL&P)

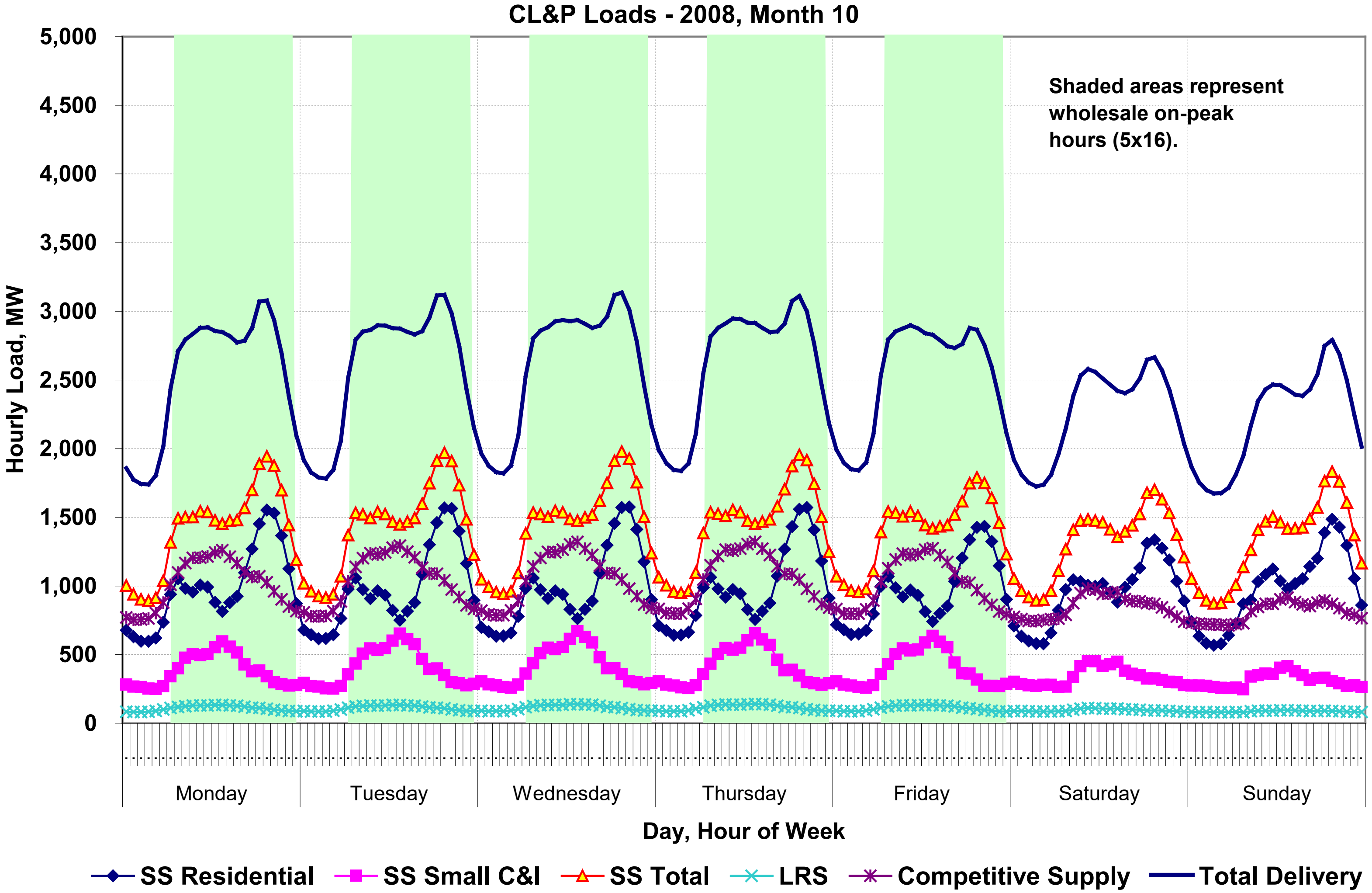
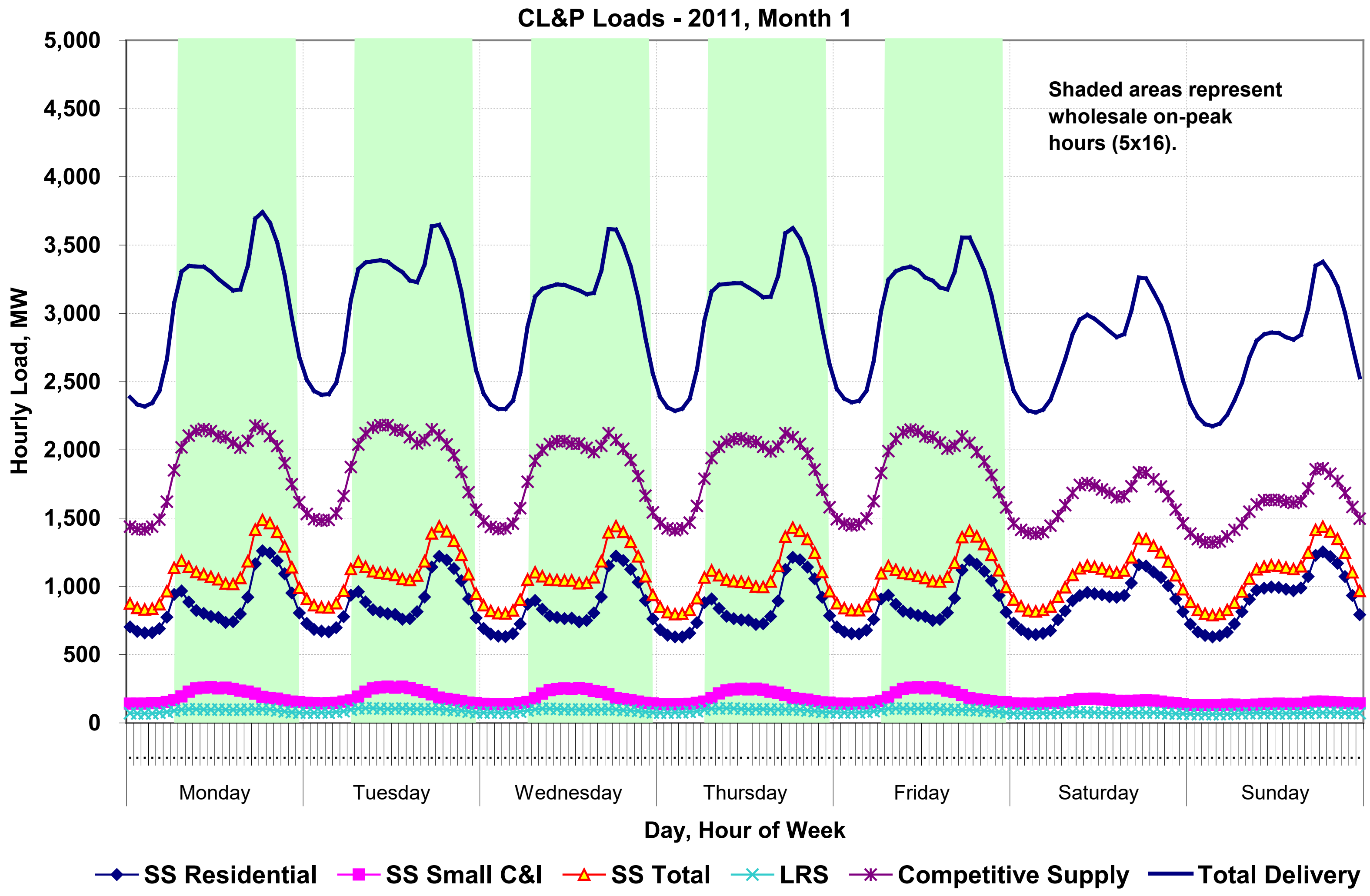


Figure A5. Weekly Load Profile – January 2011 (CL&P)



APPENDIX A

Figure A6. Weekly Load Profile – April 2011 (CL&P)

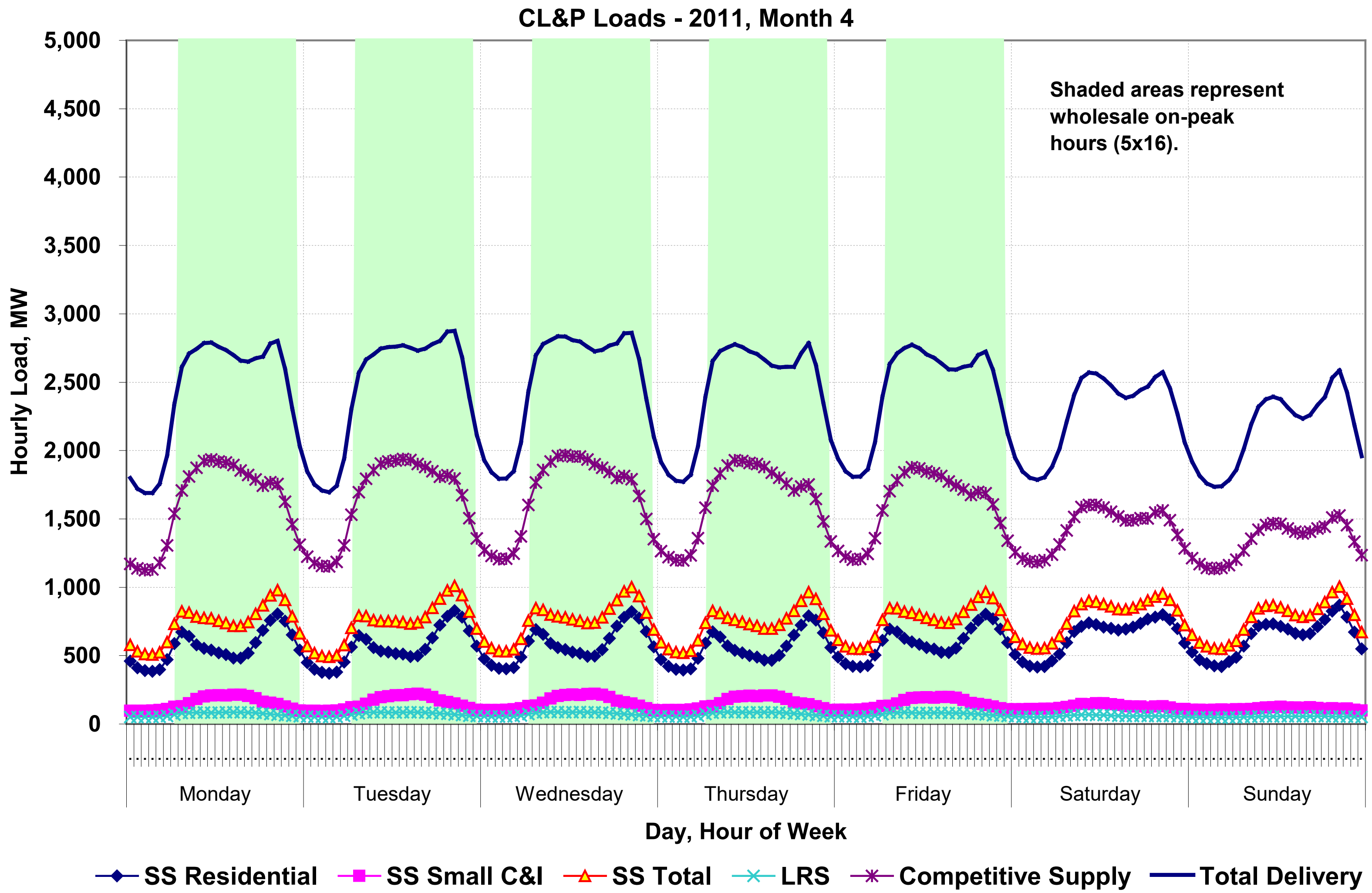


Figure A7. Weekly Load Profile – July 2011 (CL&P)

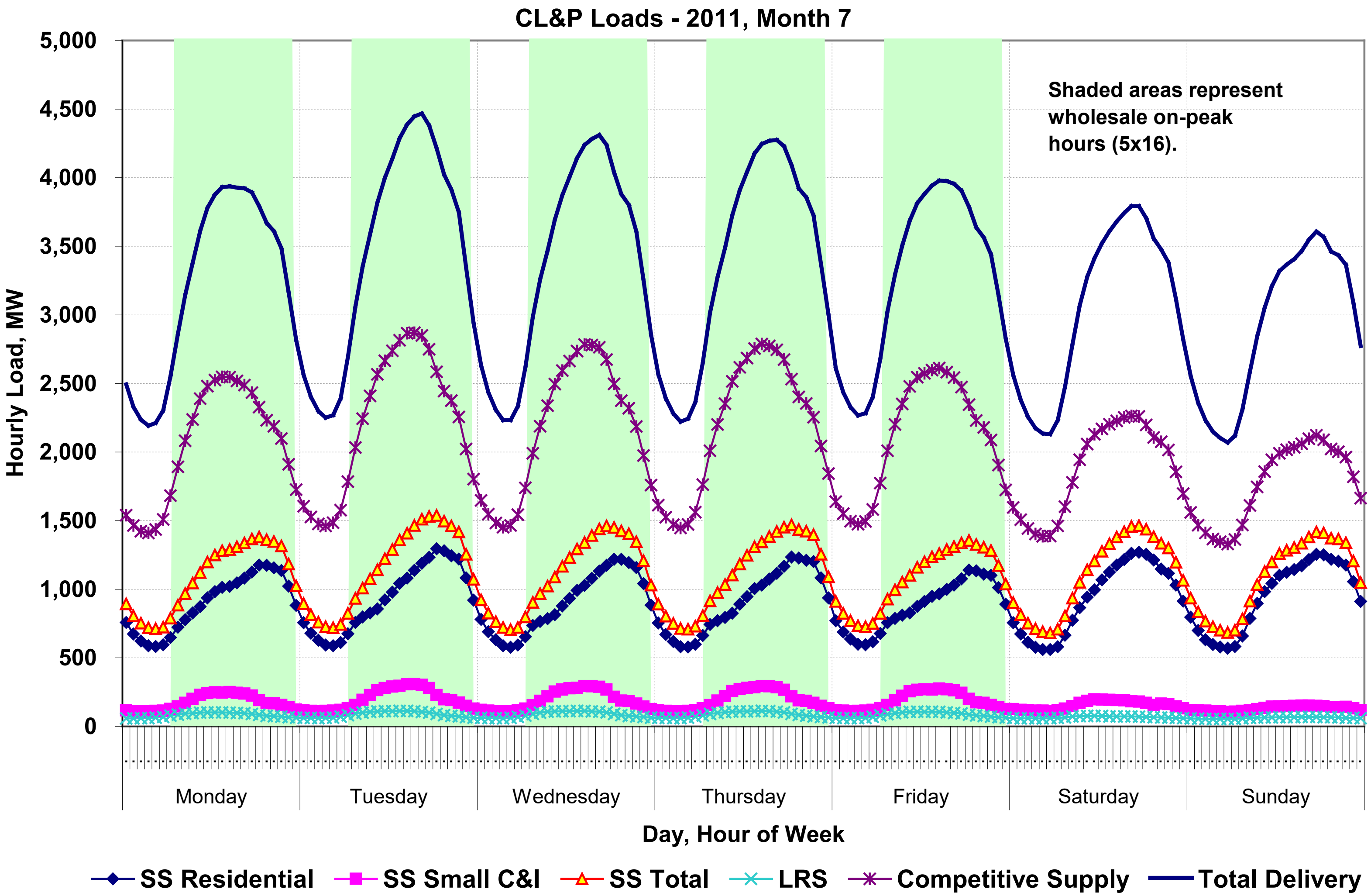


Figure A8. Weekly Load Profile – October 2011 (CL&P)

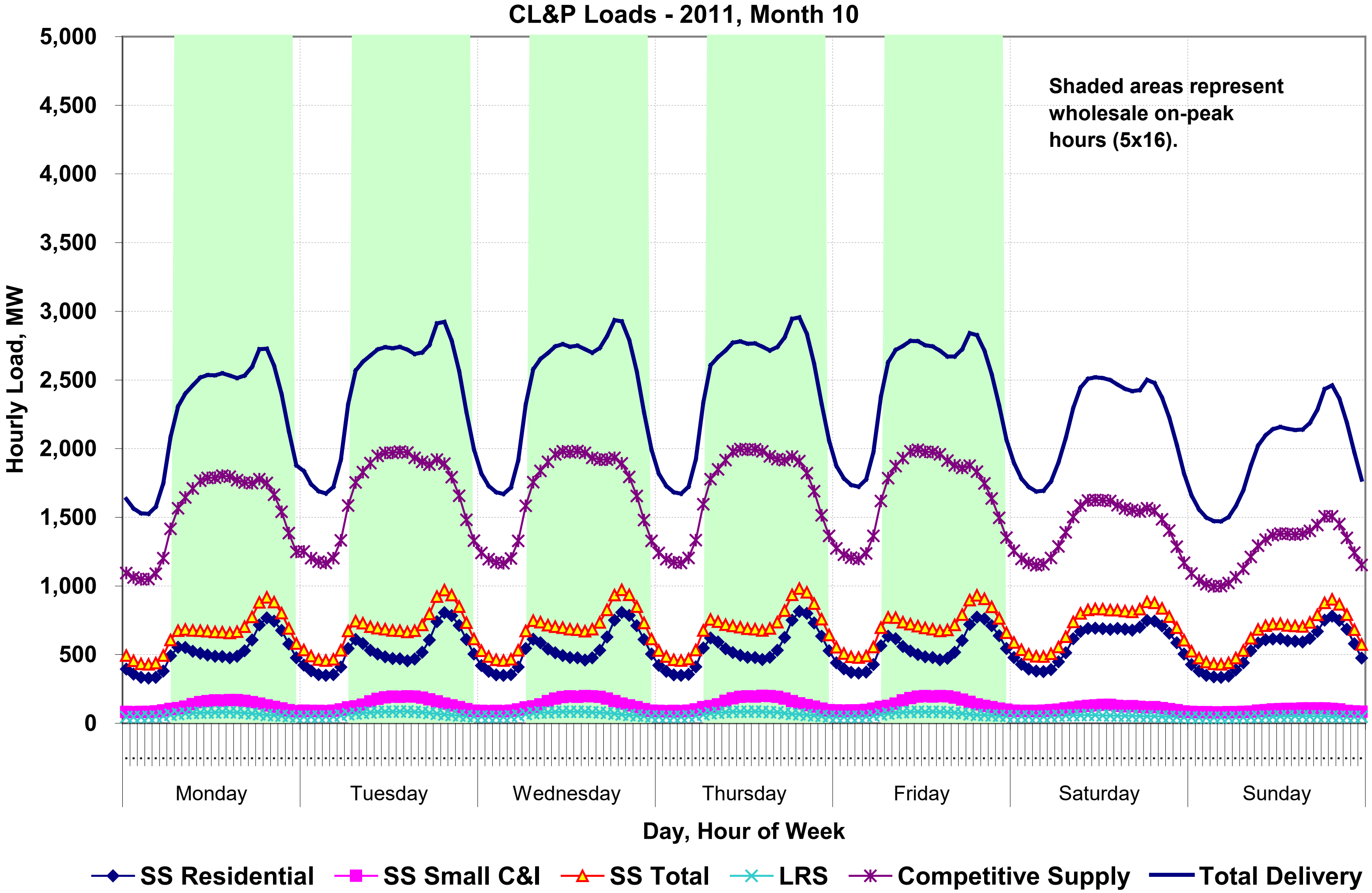


Figure A9. Weekly Load Profile – January 2008 (UI)

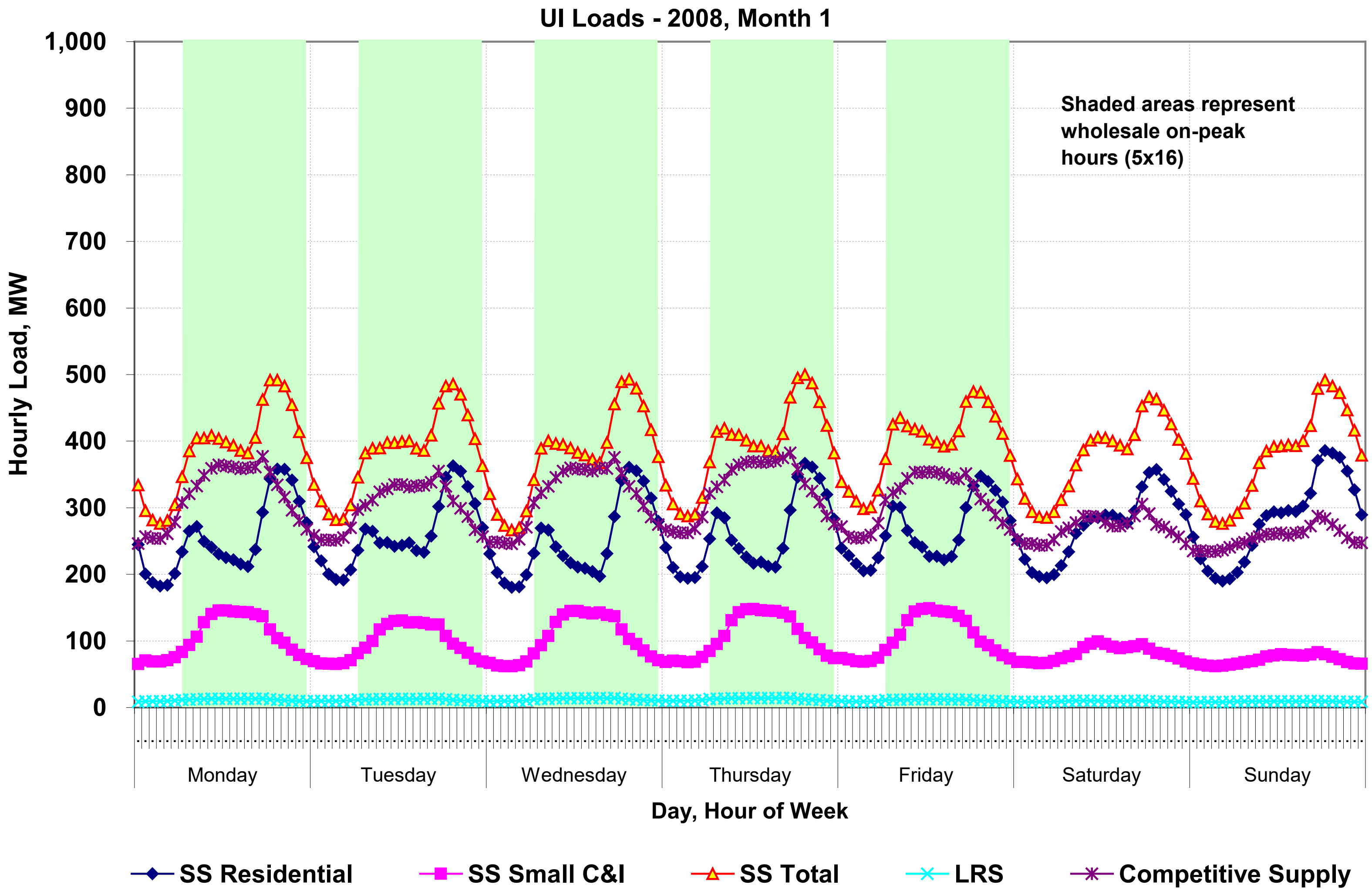


Figure A10. Weekly Load Profile – April 2008 (UI)

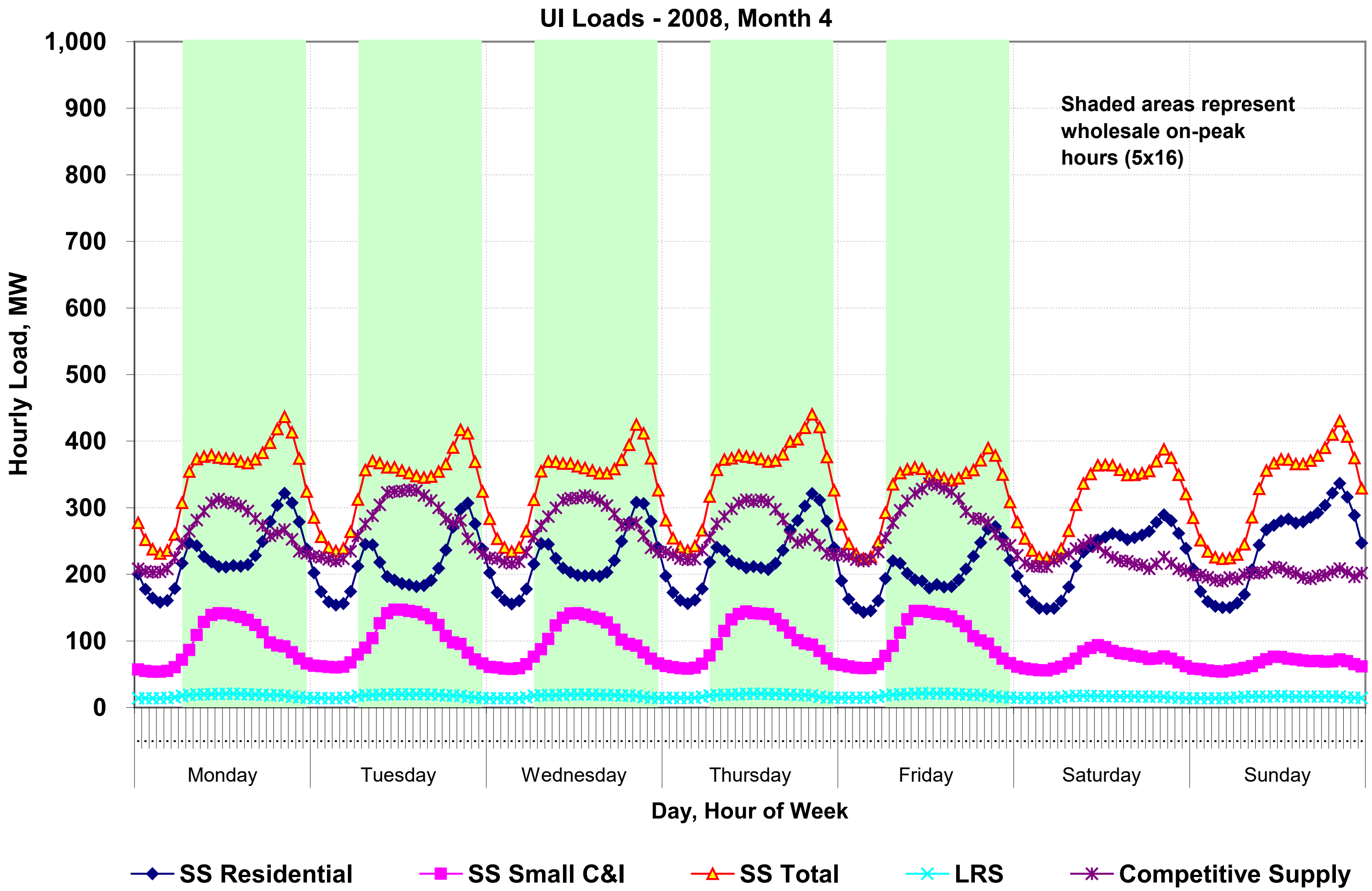


Figure A11. Weekly Load Profile – July 2008 (UI)

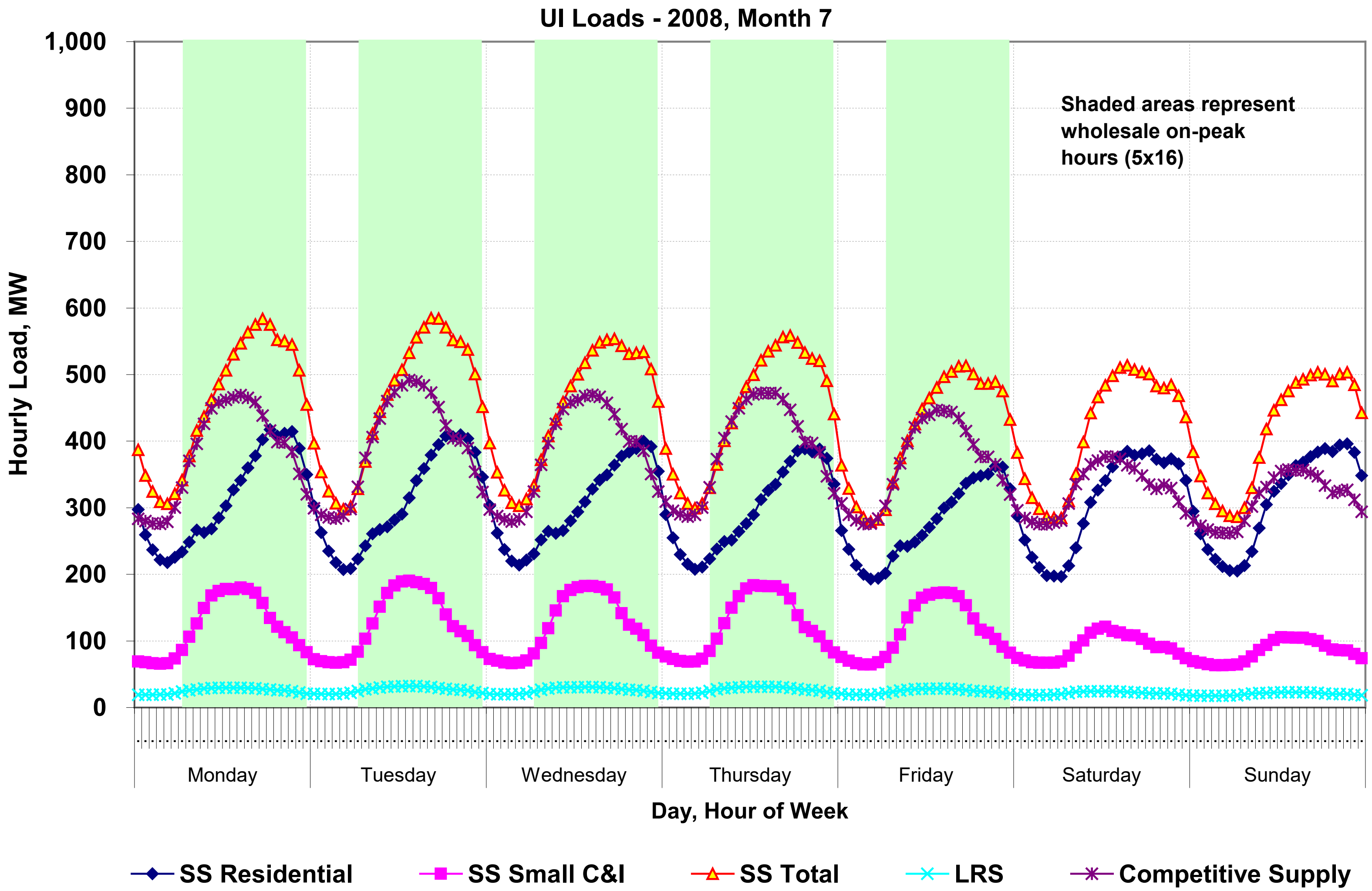


Figure A12. Weekly Load Profile – October 2008 (UI)

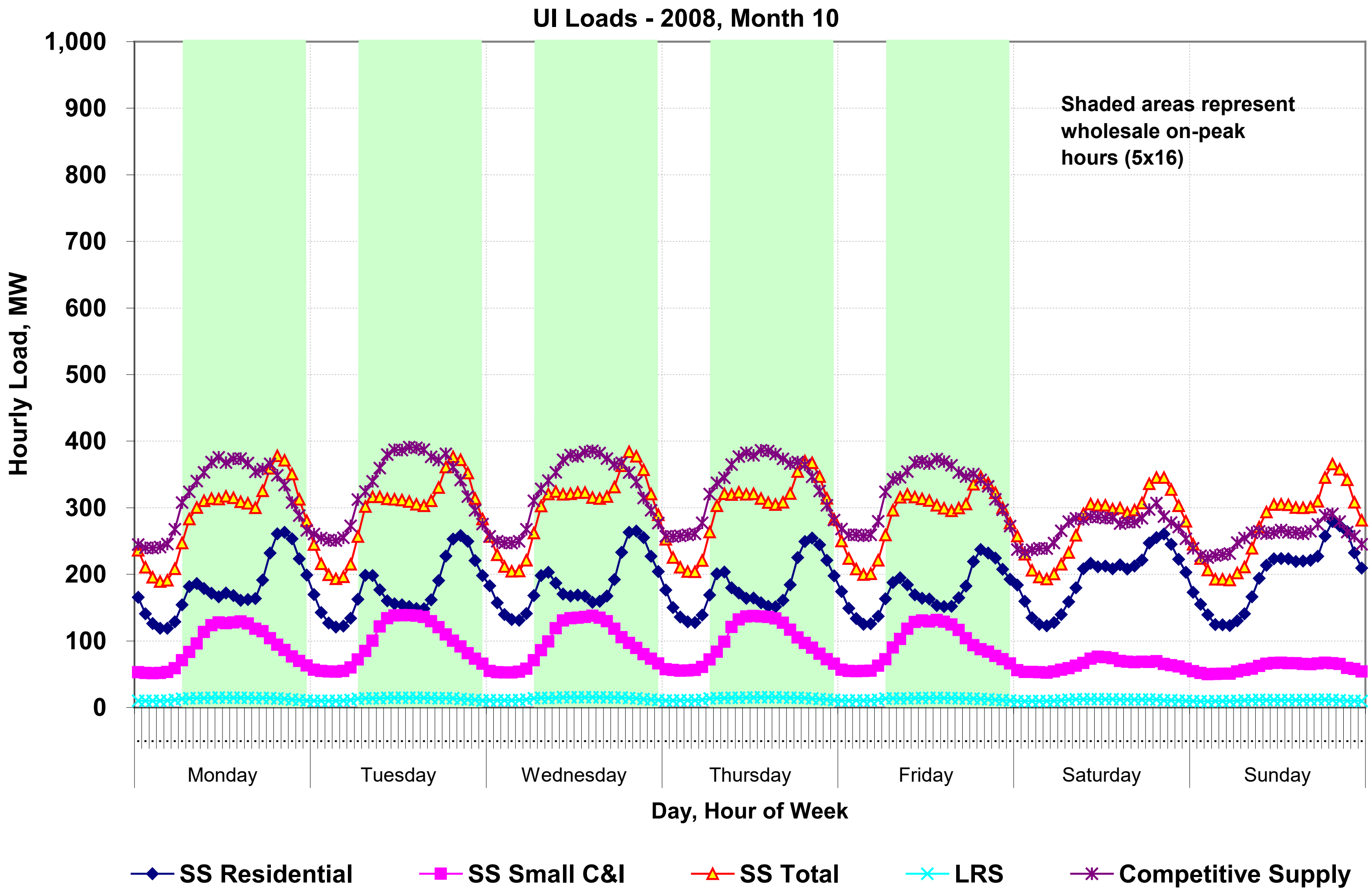


Figure A13. Weekly Load Profile – January 2011 (UI)

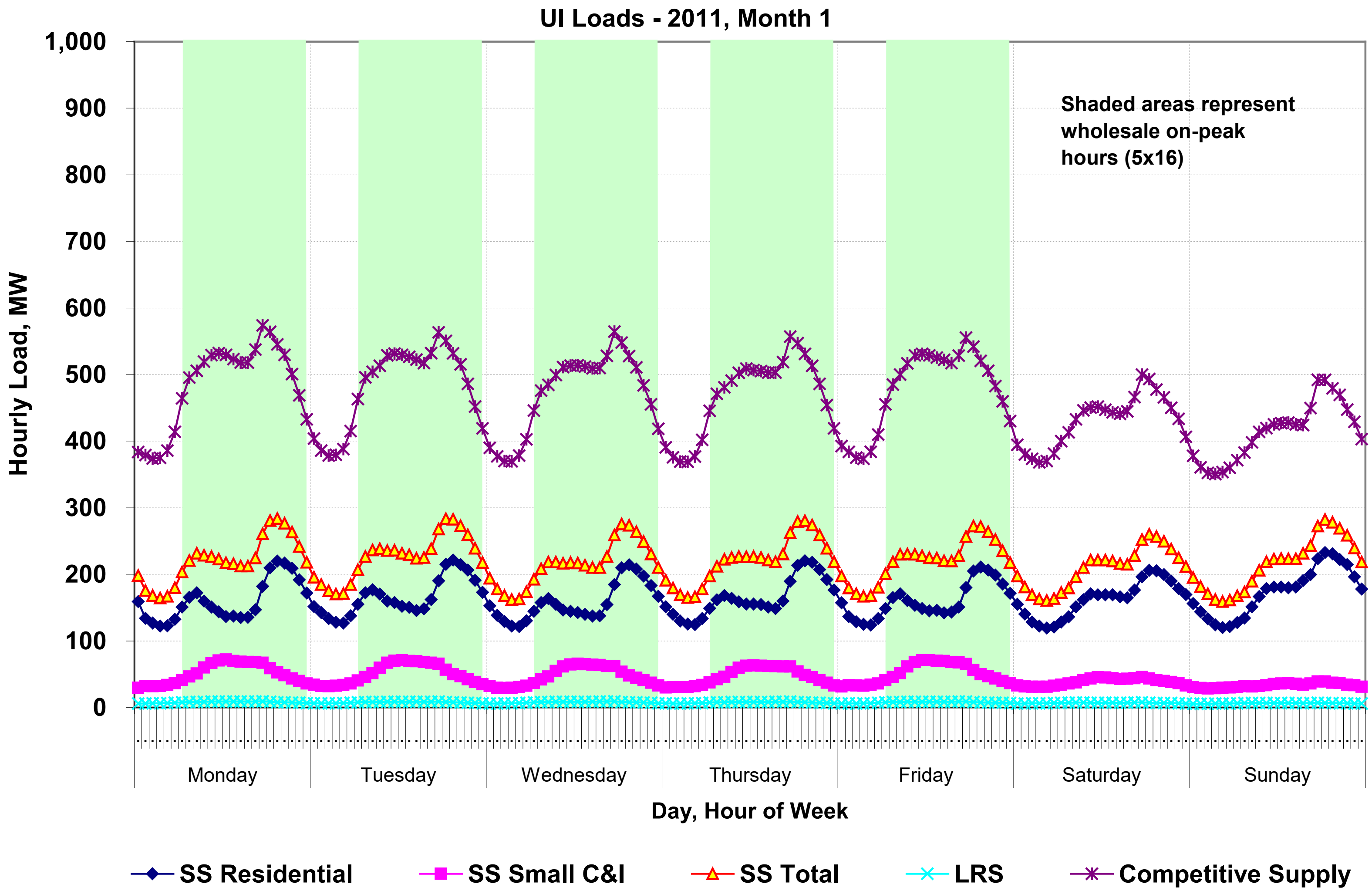
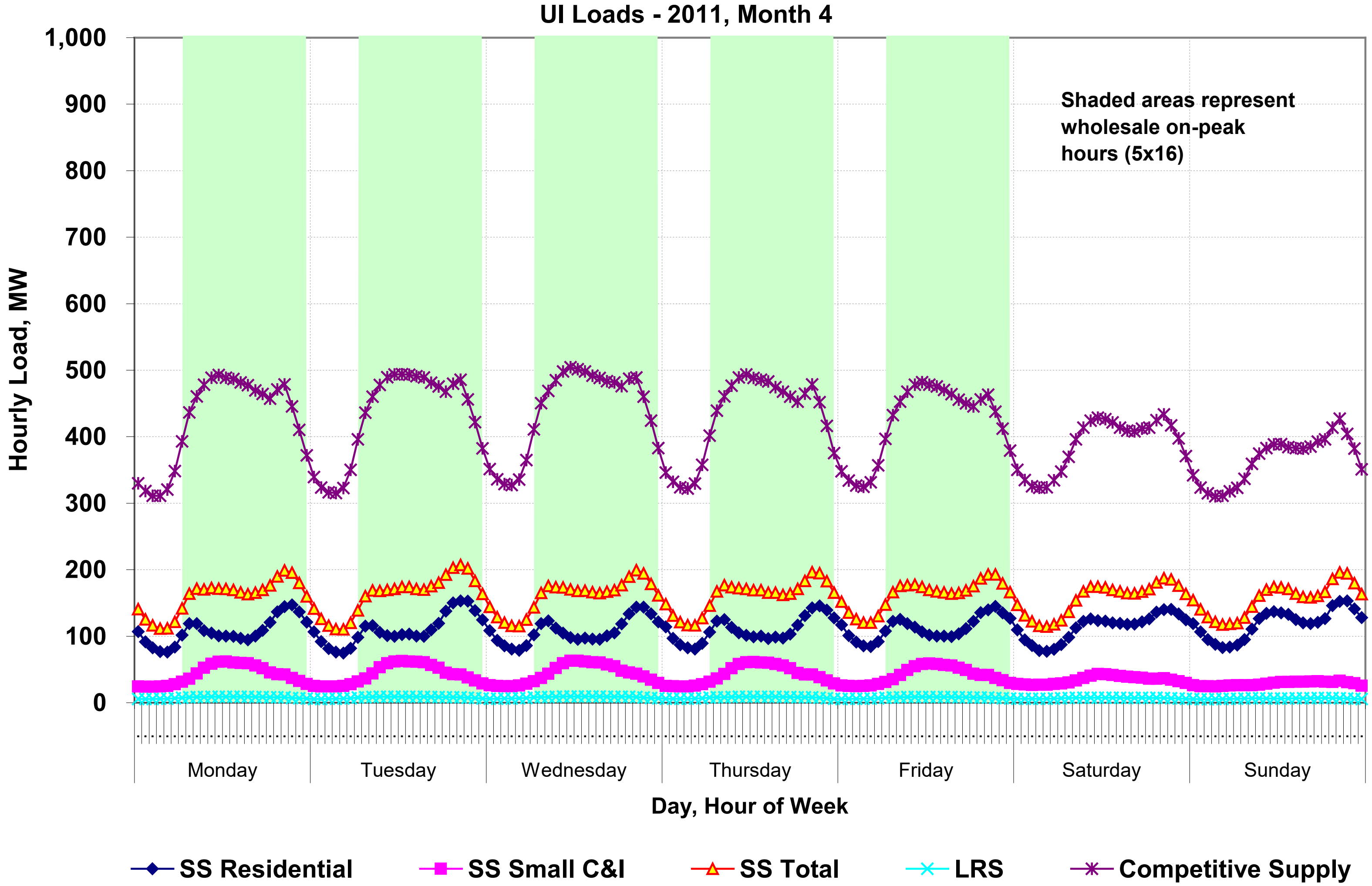


Figure A14. Weekly Load Profile – April 2011 (UI)



APPENDIX A

Figure A15. Weekly Load Profile – July 2011 (UI)

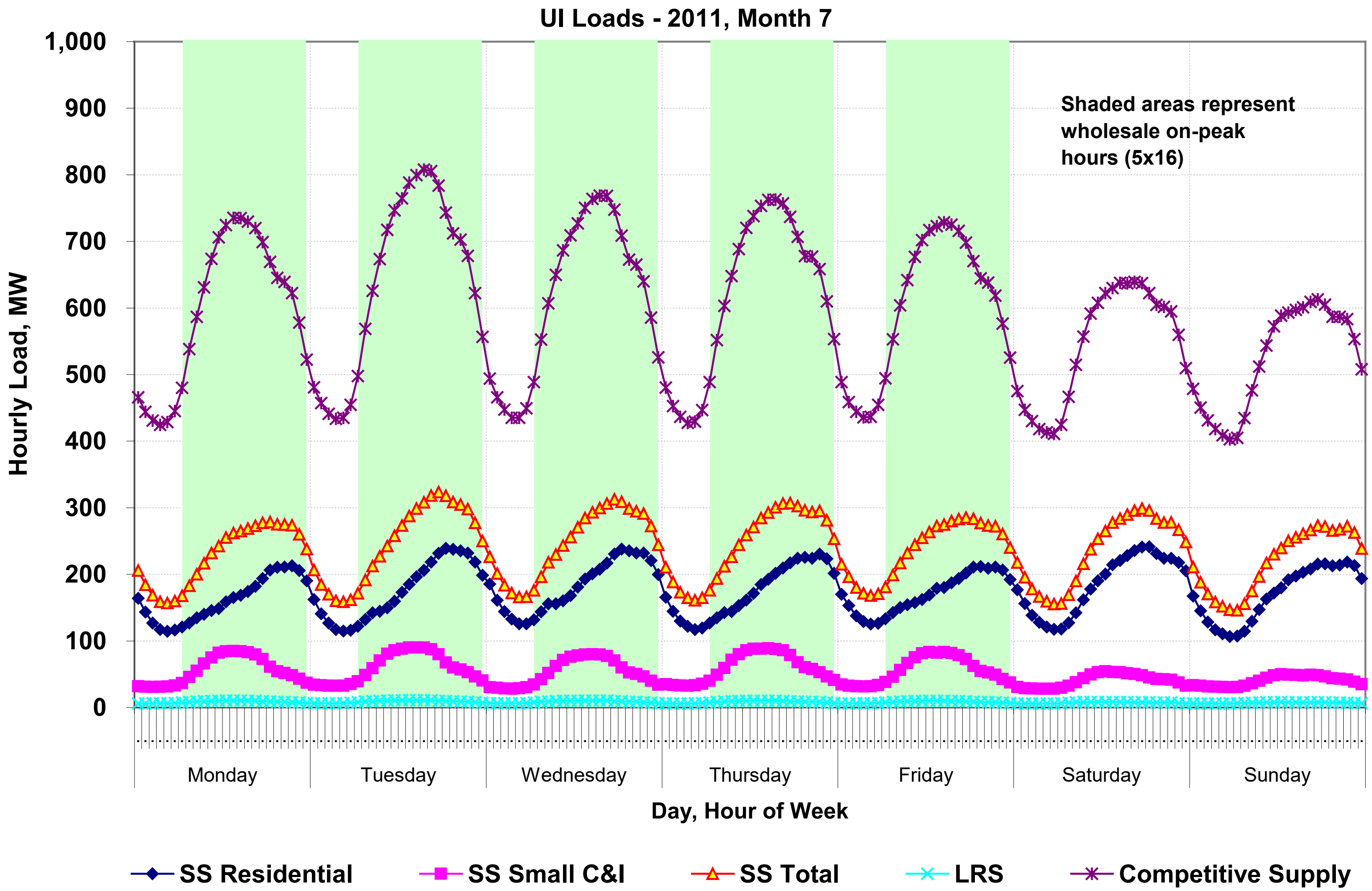
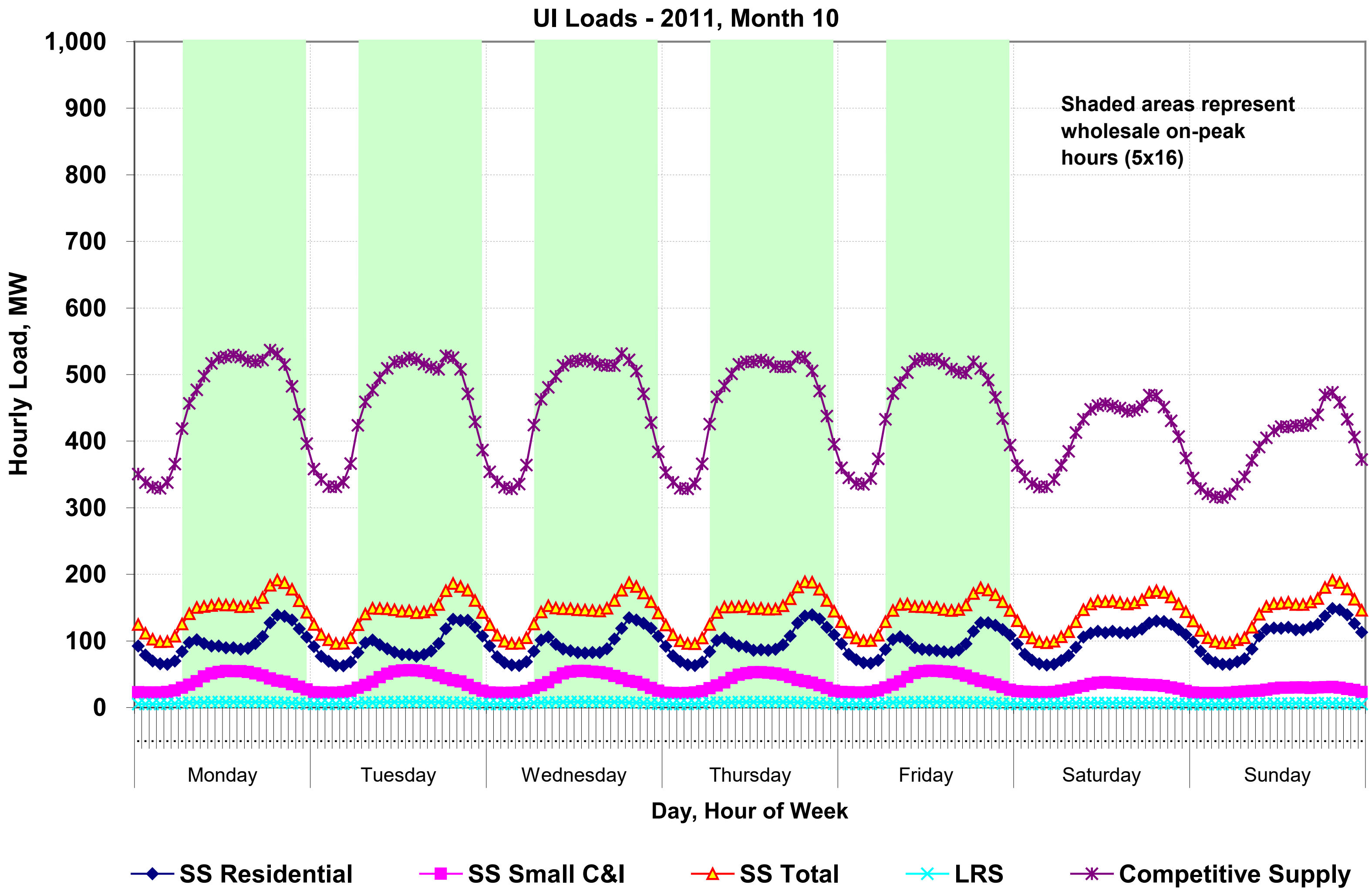


Figure A16. Weekly Load Profile – October 2011 (UI)



Appendix B

Normalized Load Profiles

Figure B1. Normalized Load Profile – January 2008 (CL&P)

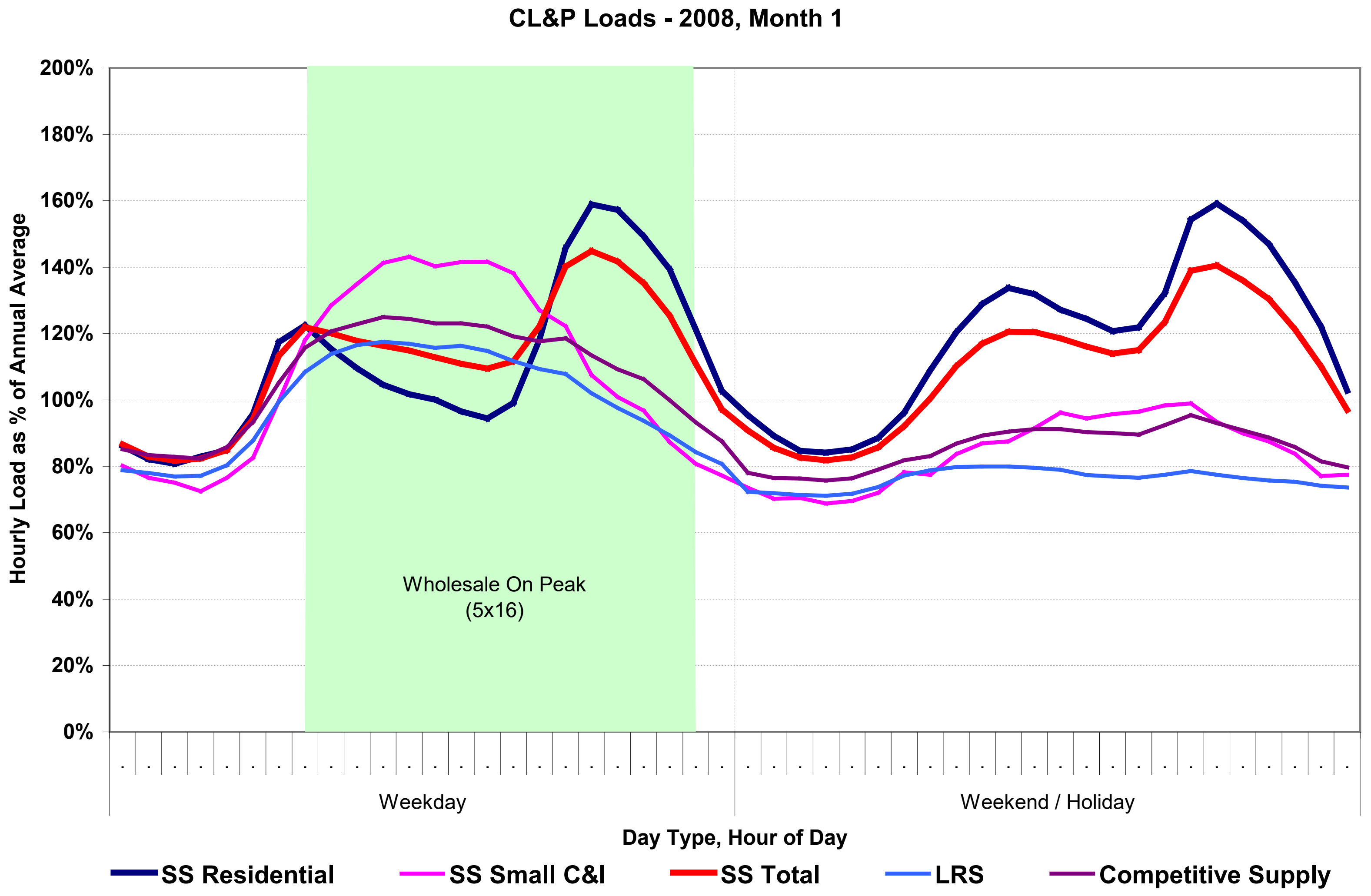


Figure B2. Normalized Load Profile – April 2008 (CL&P)

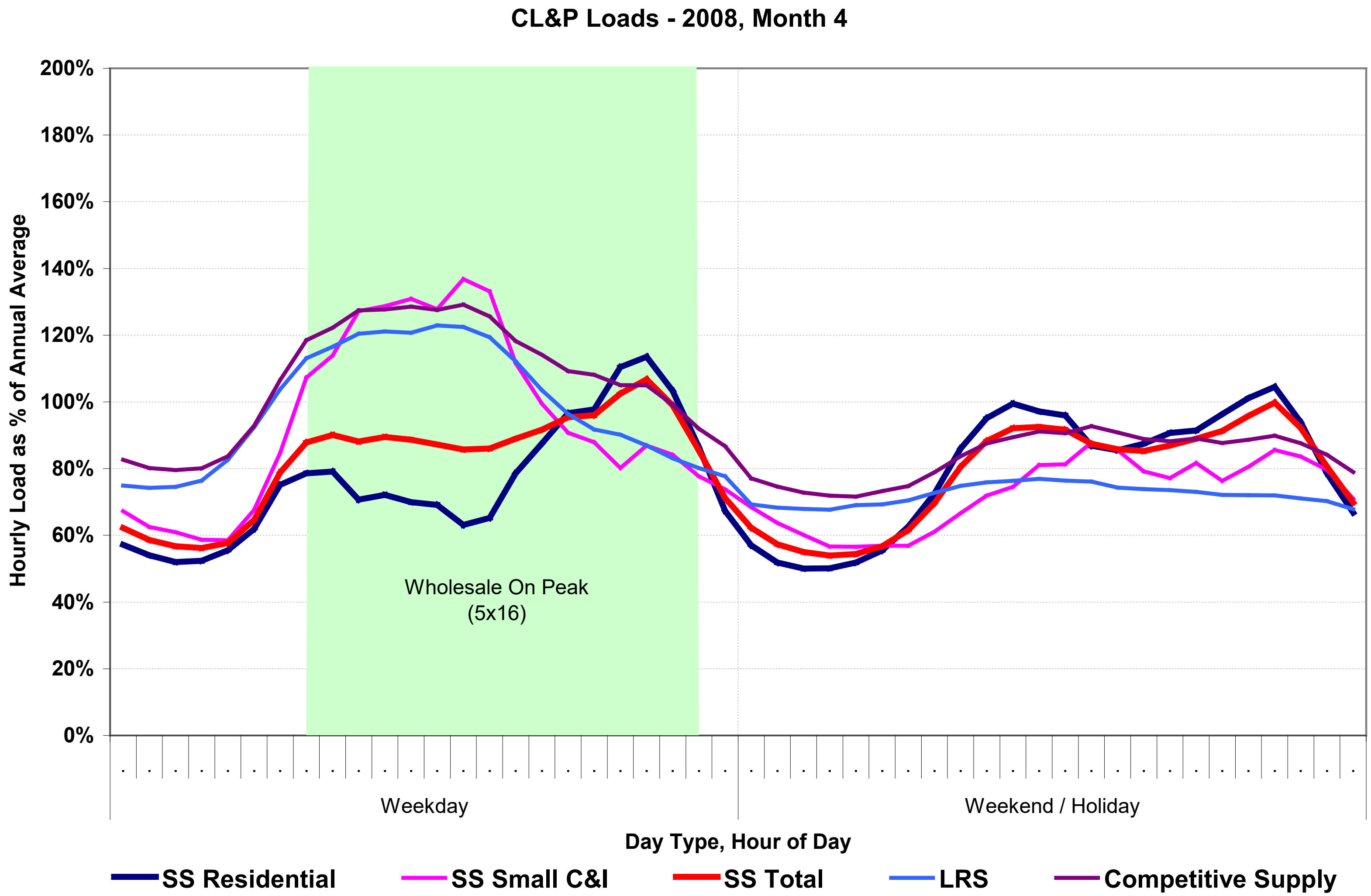
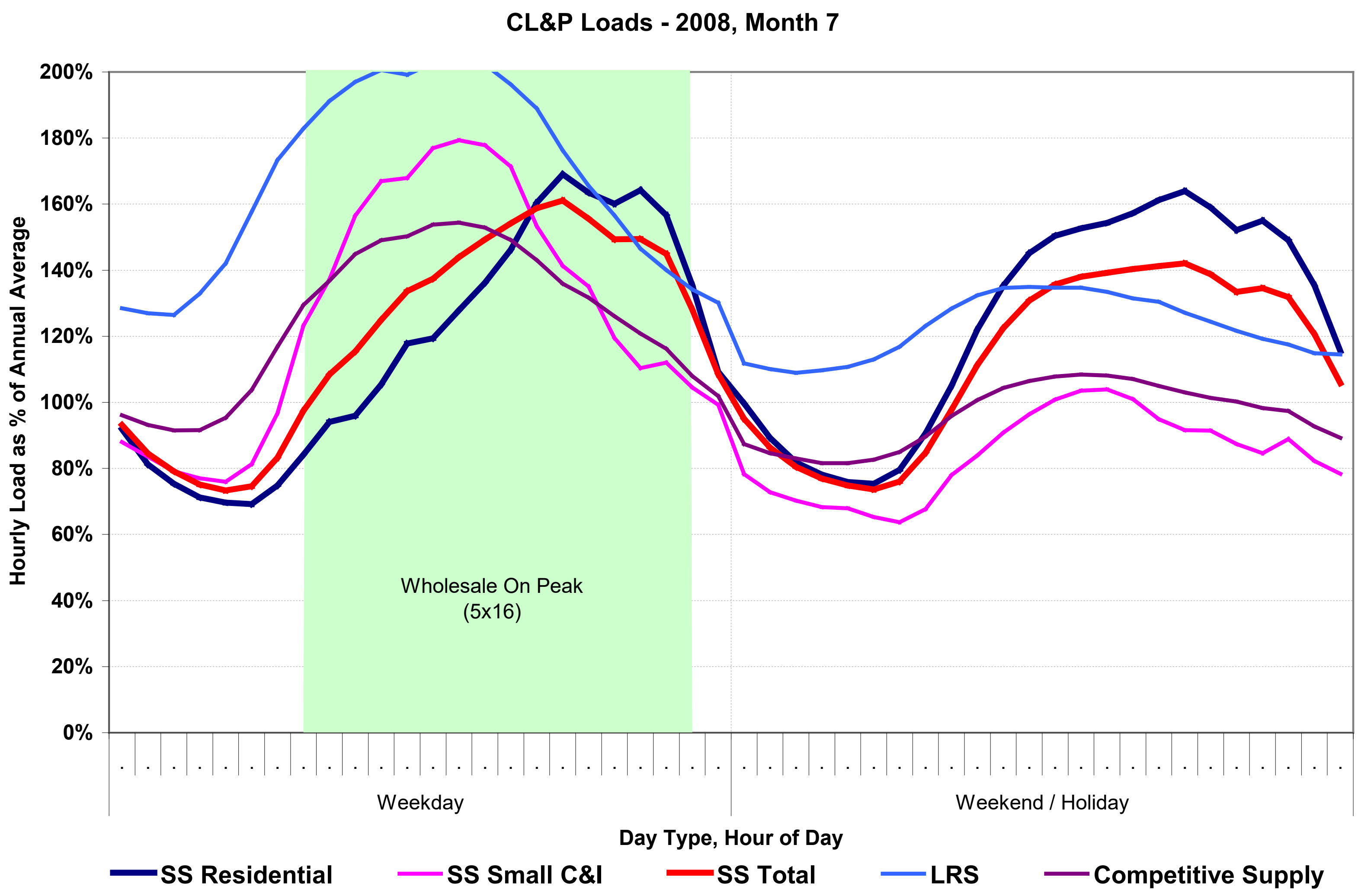


Figure B3. Normalized Load Profile – July 2008 (CL&P)



APPENDIX B

Figure B4. Normalized Load Profile – October 2008 (CL&P)

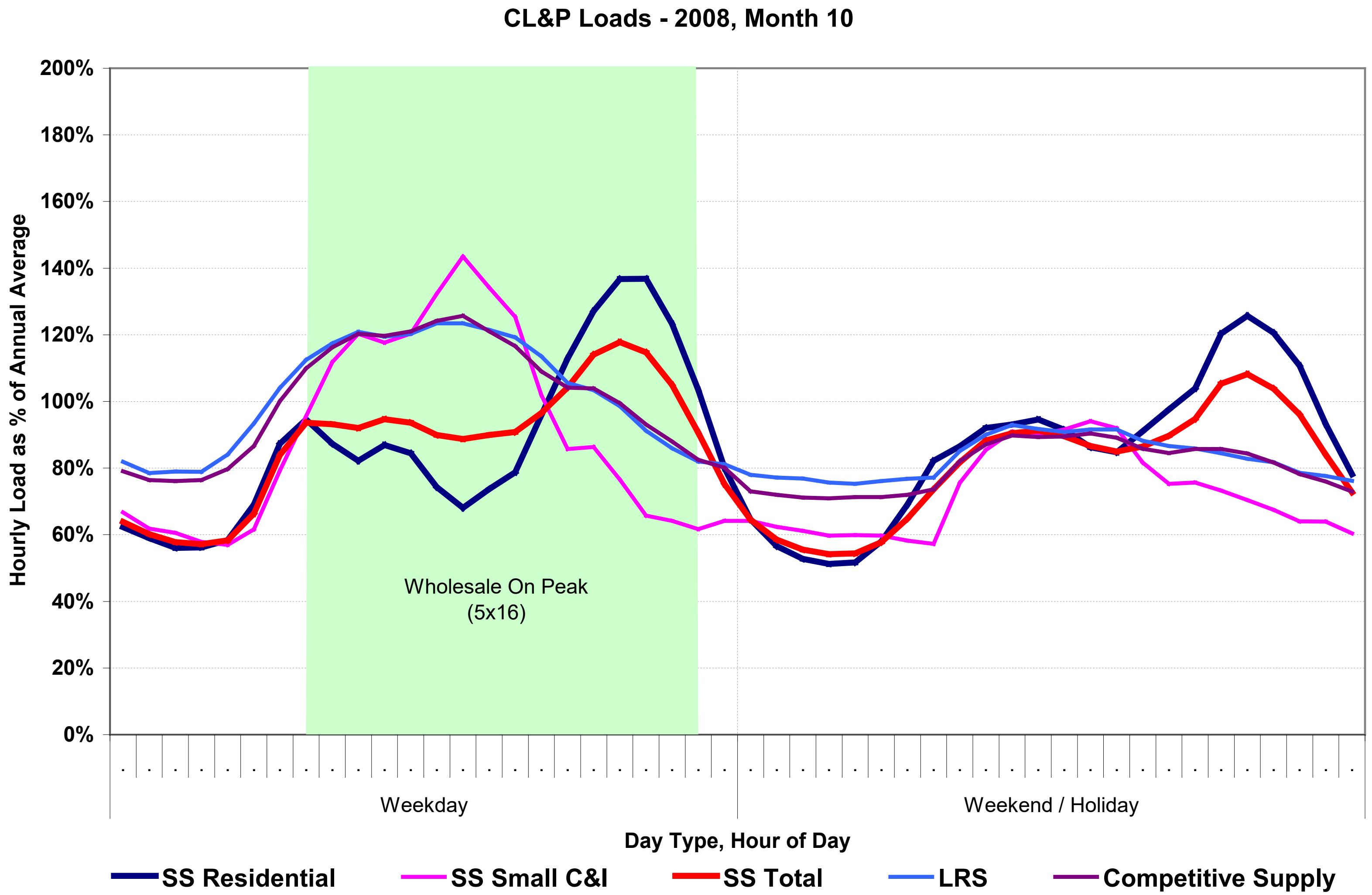


Figure B5. Normalized Load Profile – January 2011 (CL&P)

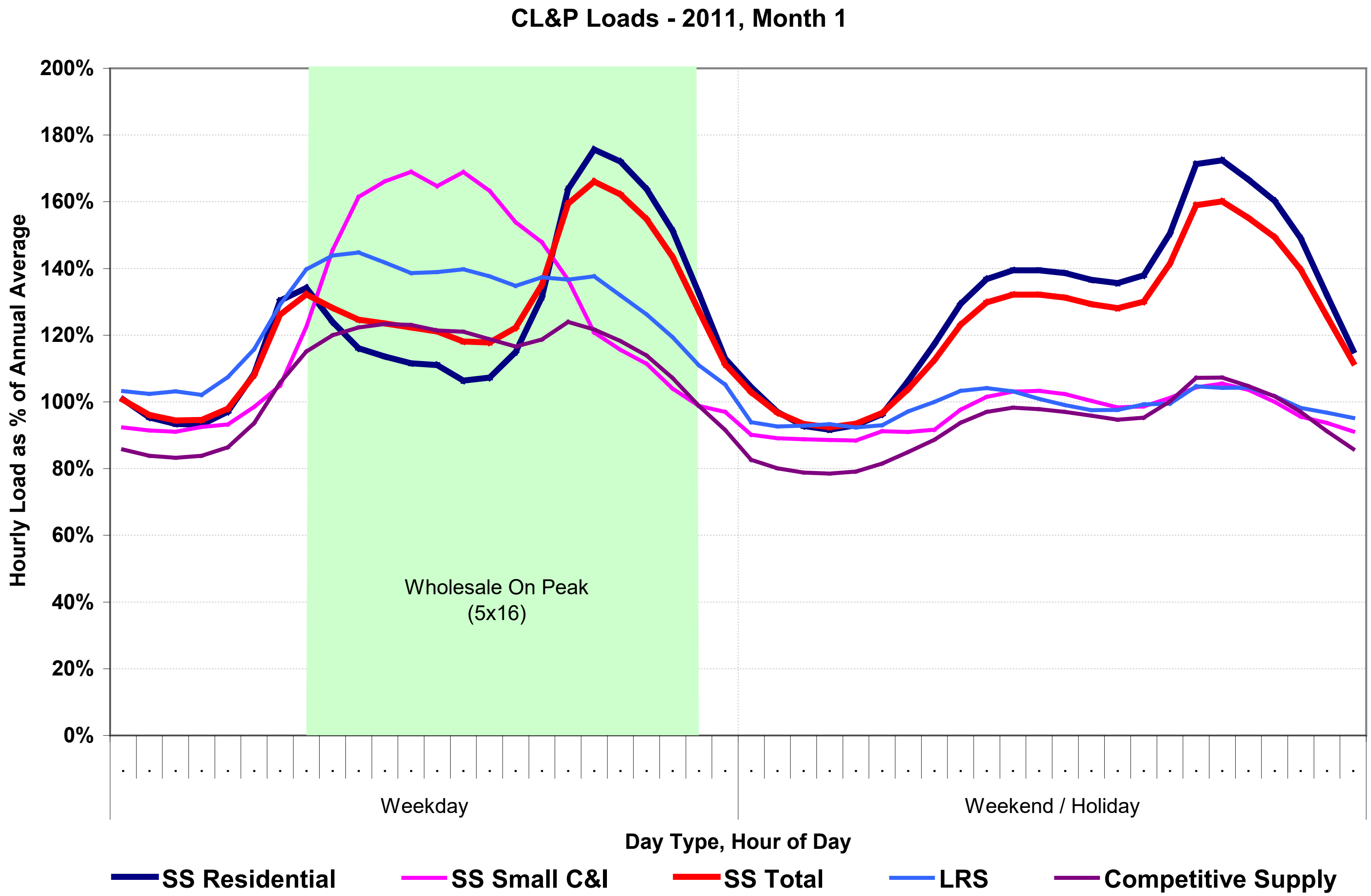


Figure B6. Normalized Load Profile – April 2011 (CL&P)

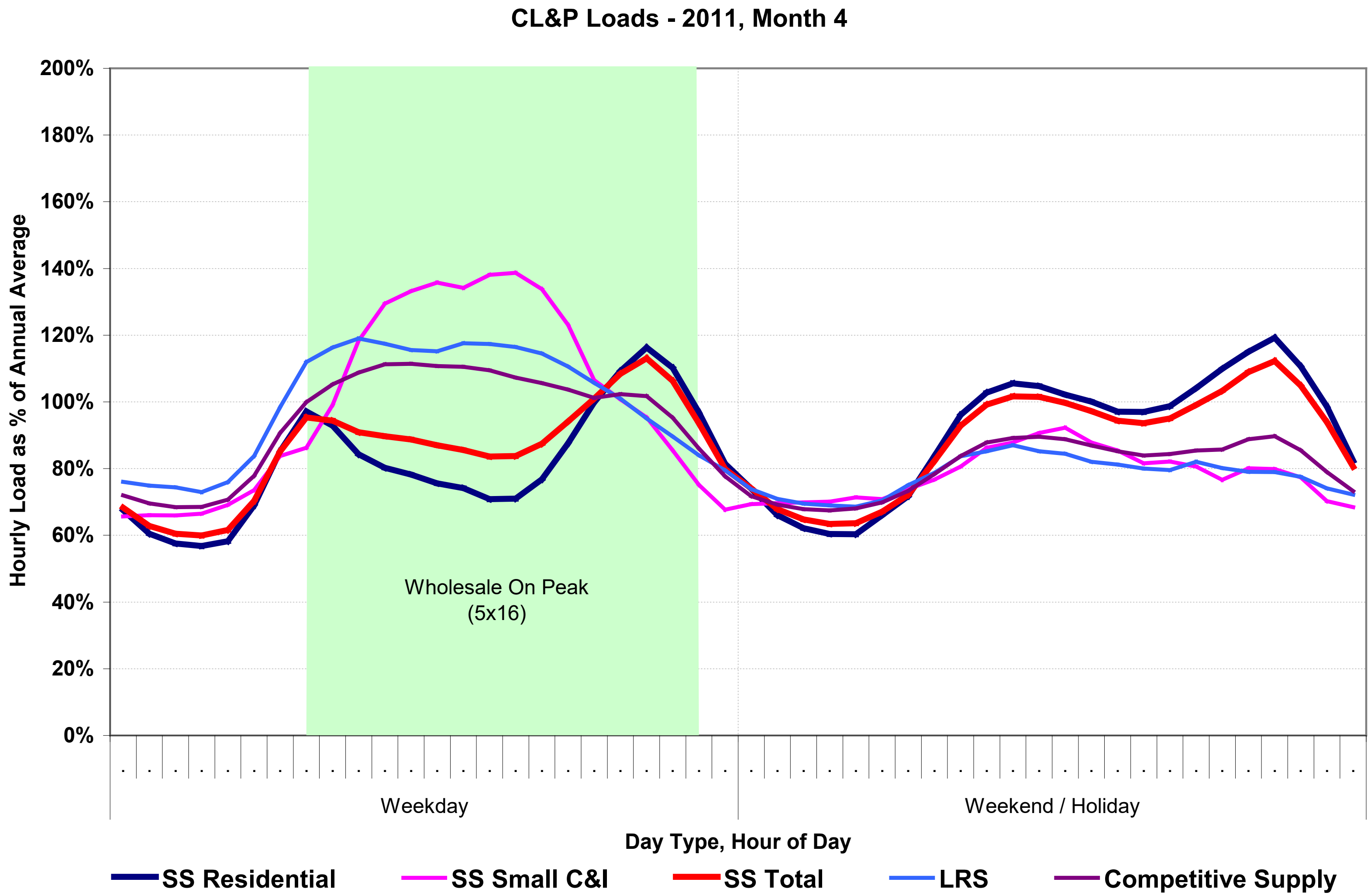


Figure B7. Normalized Load Profile – July 2011 (CL&P)

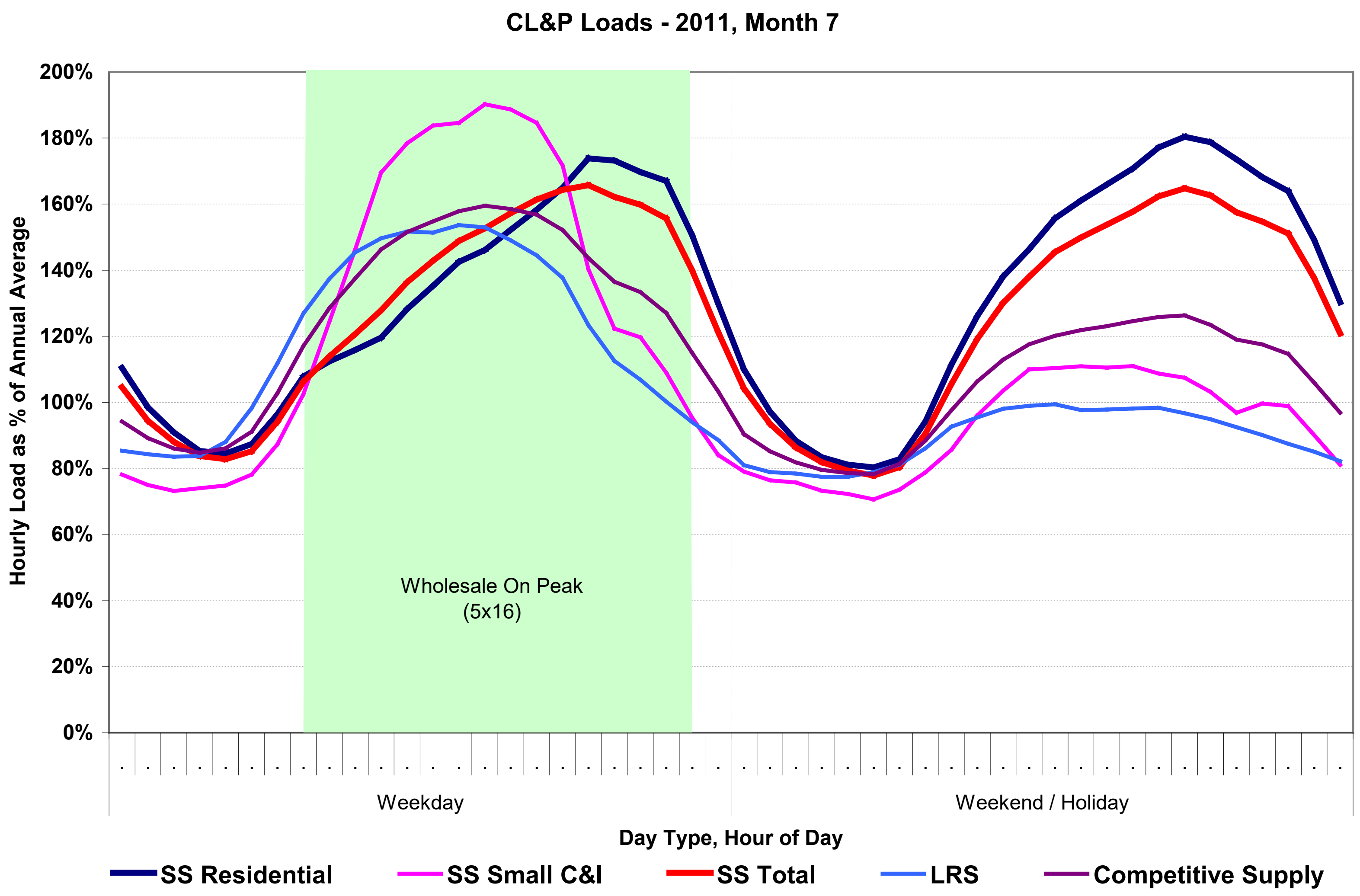


Figure B8. Normalized Load Profile – October 2011 (CL&P)

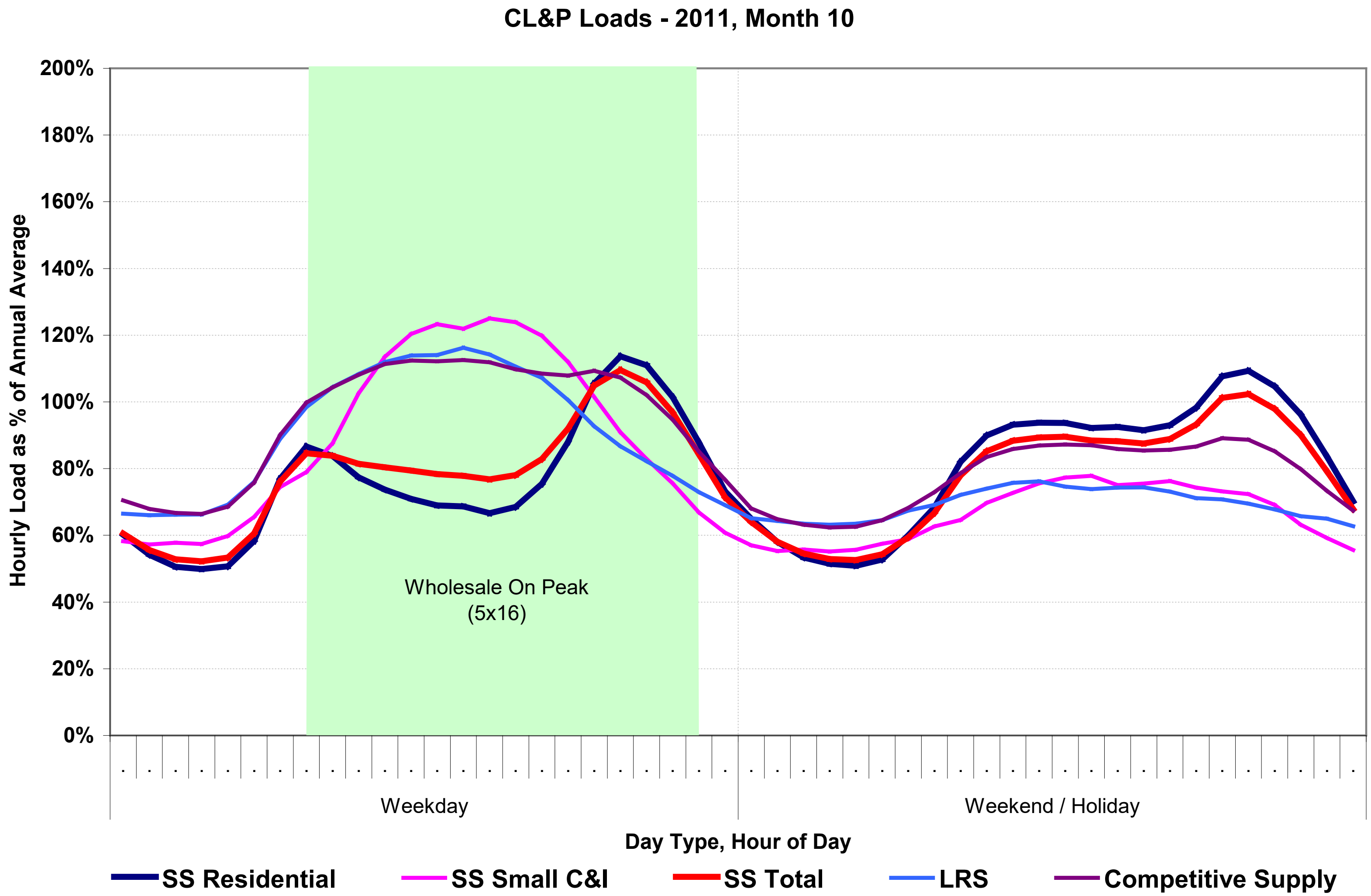


Figure B9. Normalized Load Profile – January 2008 (UI)

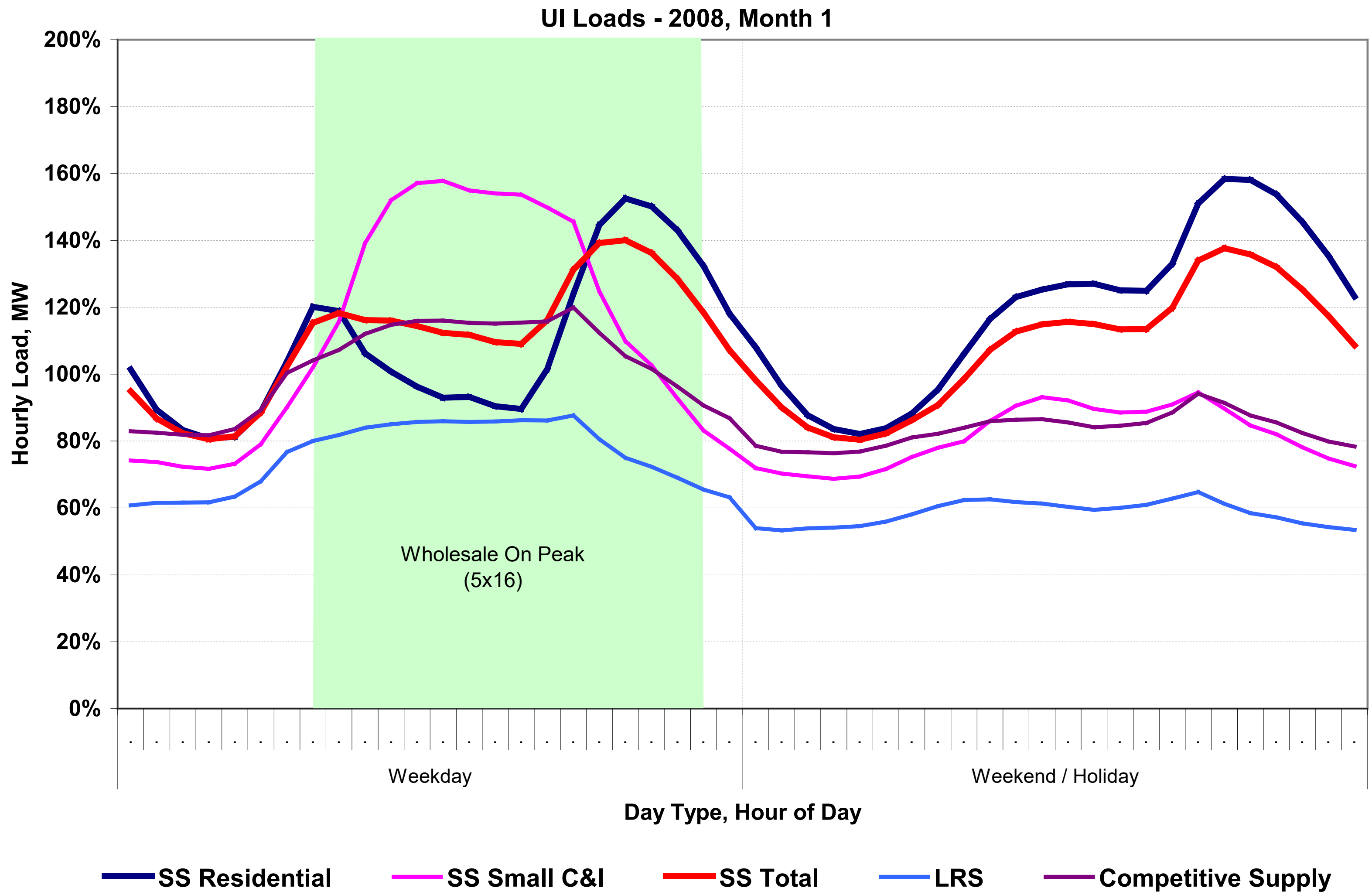


Figure B10. Normalized Load Profile – April 2008 (UI)

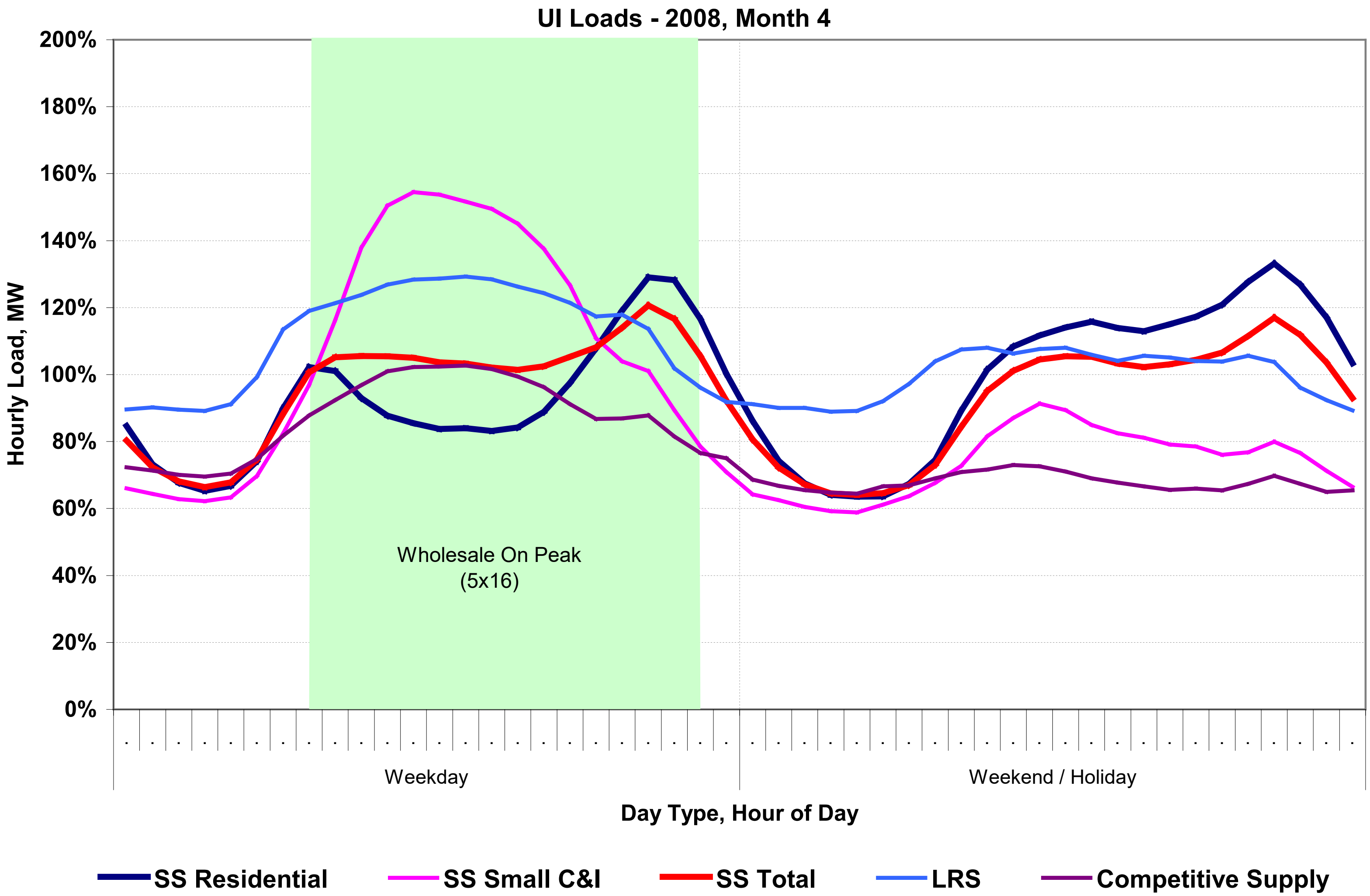


Figure B11. Normalized Load Profile – July 2008 (UI)

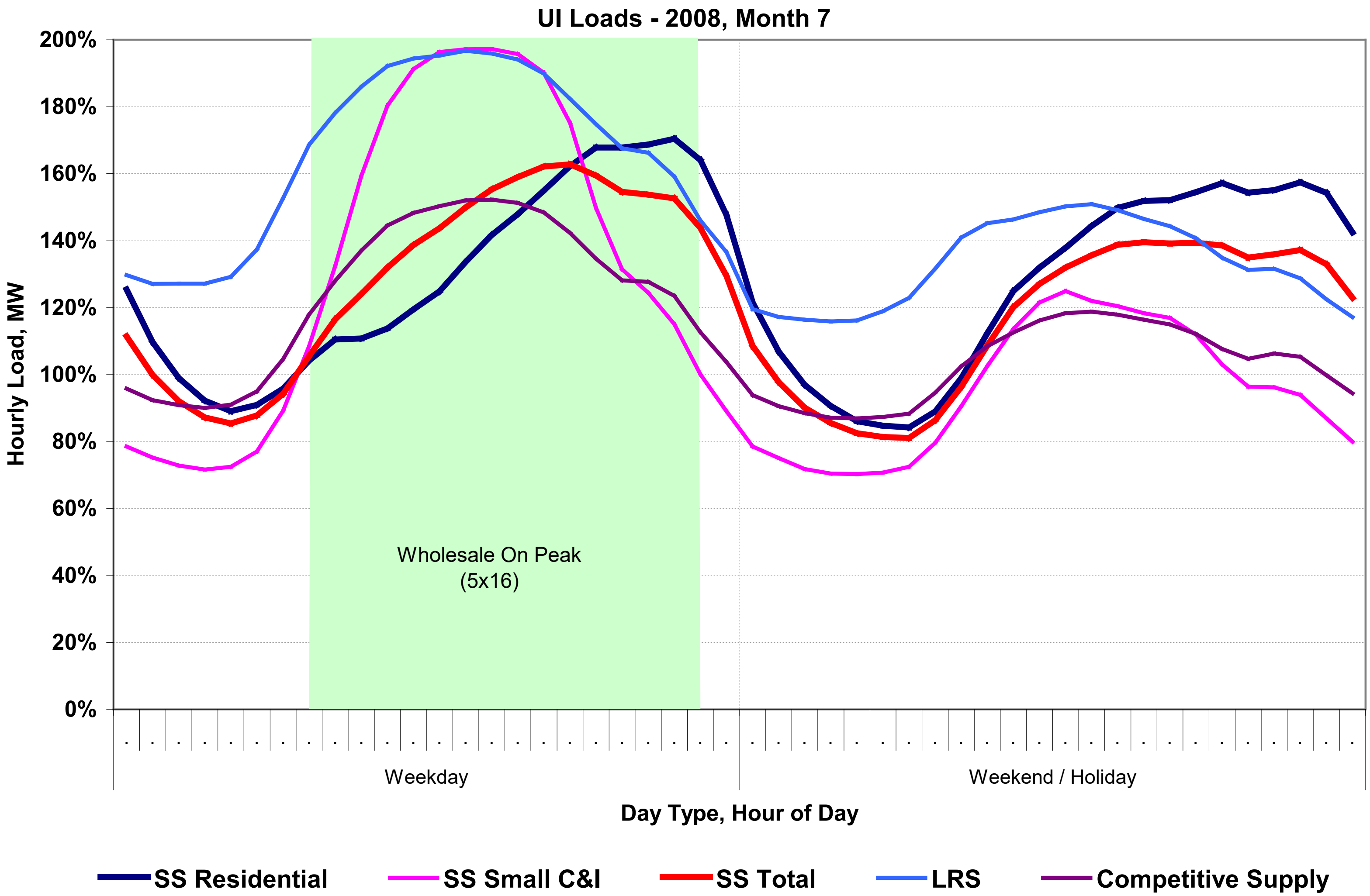


Figure B12. Normalized Load Profile – October 2008 (UI)

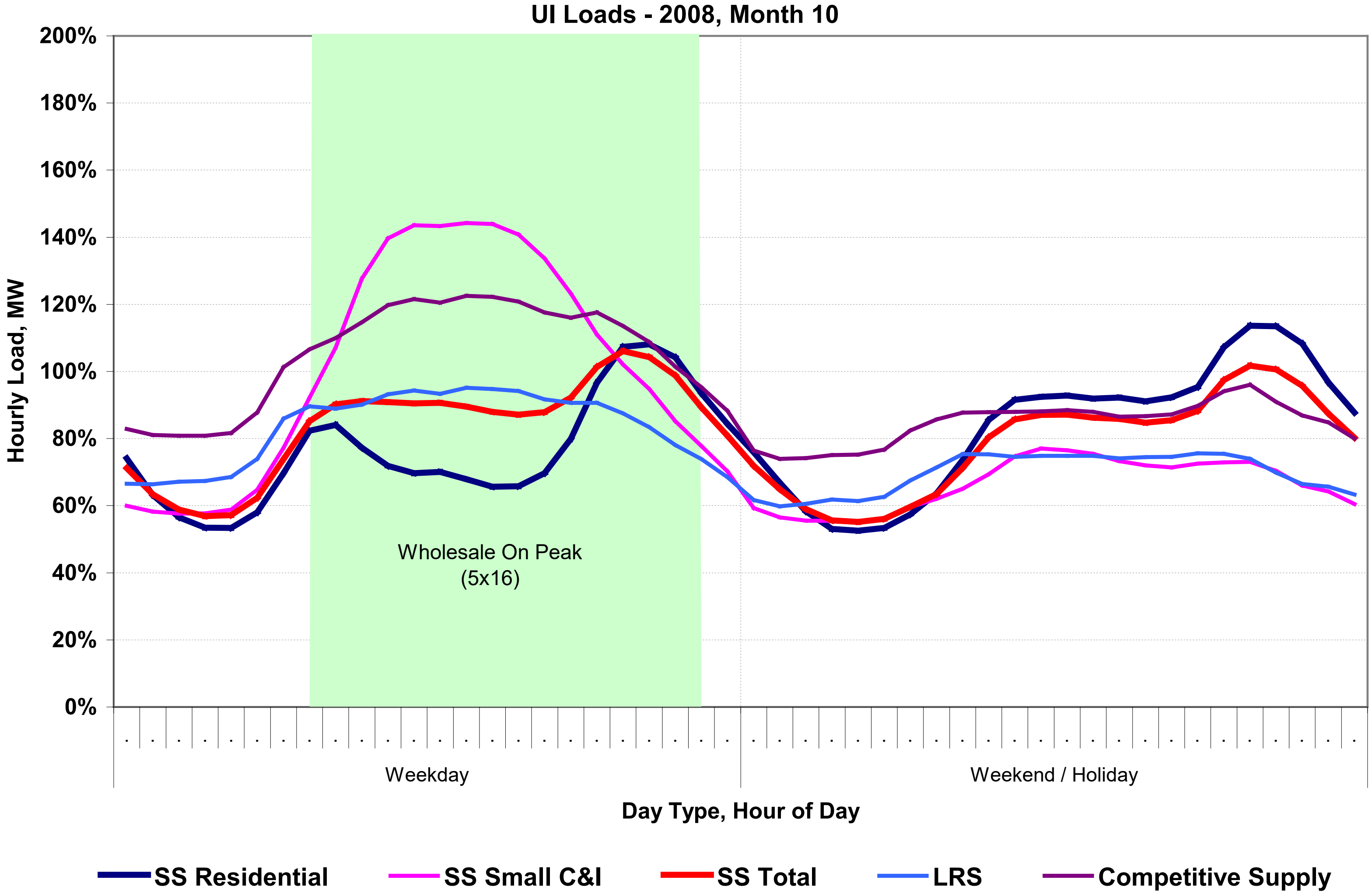


Figure B13. Normalized Load Profile – January 2011 (UI)

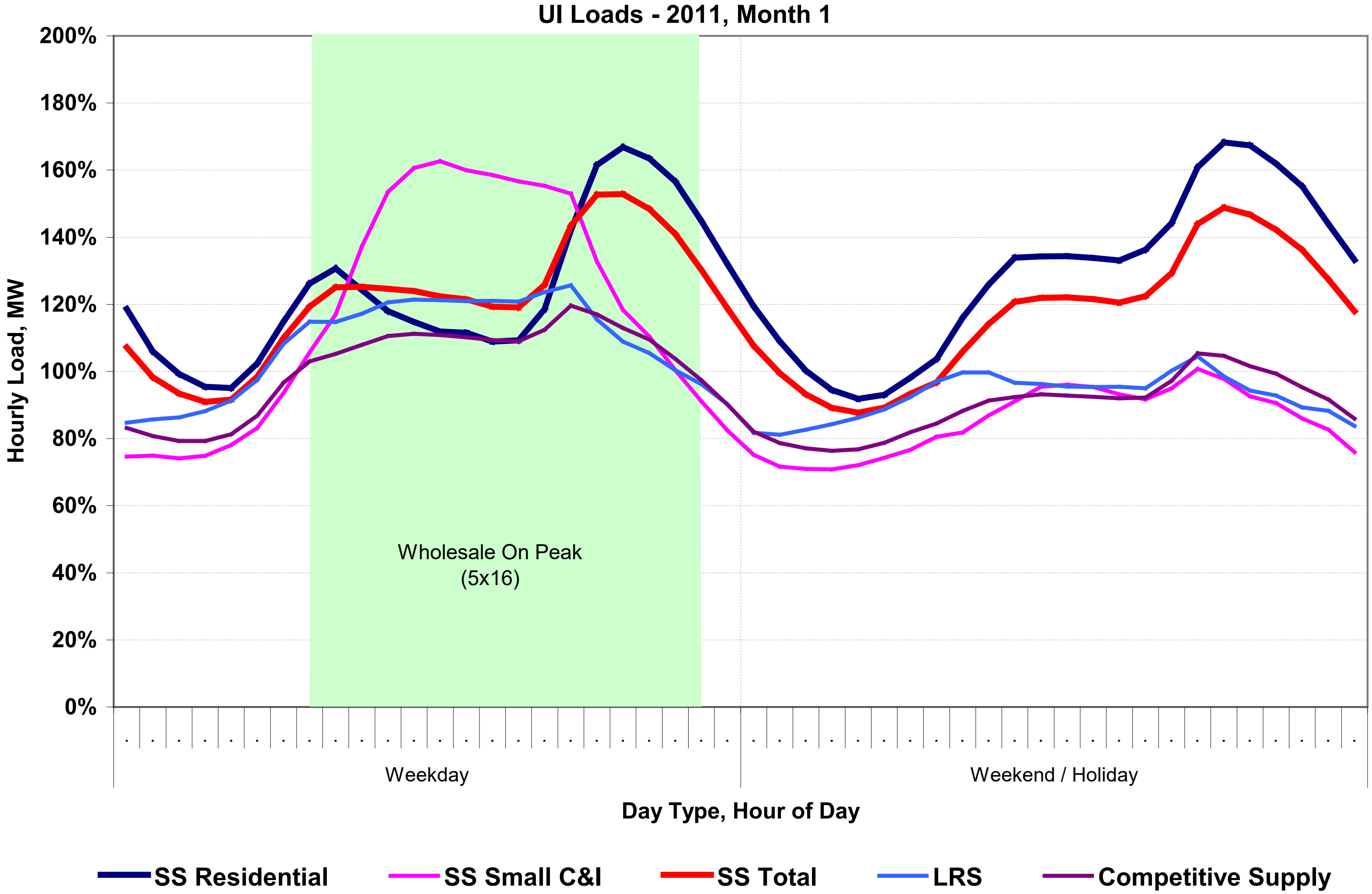


Figure B14. Normalized Load Profile – April 2011 (UI)

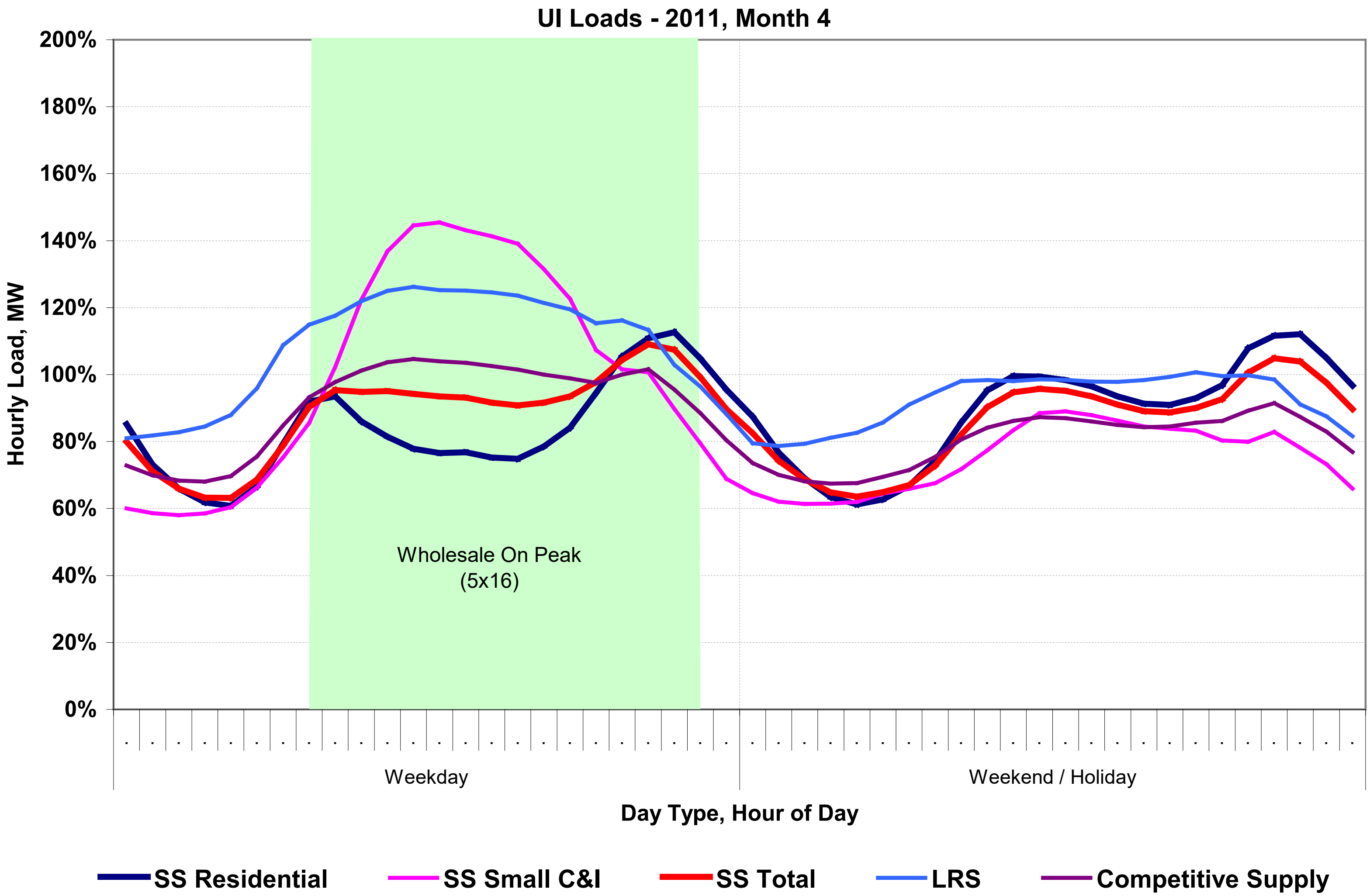


Figure B15. Normalized Load Profile – July 2011 (UI)

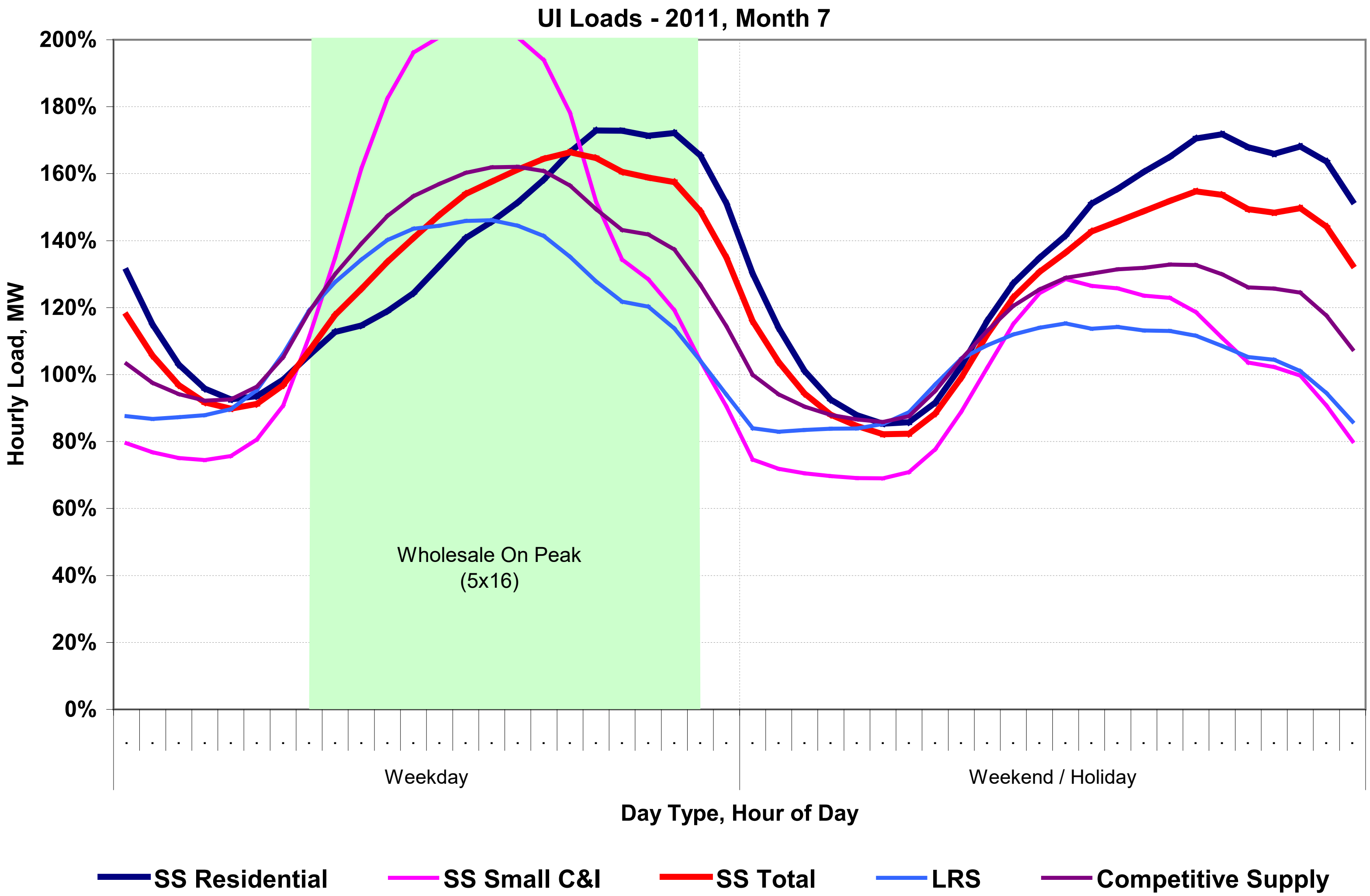
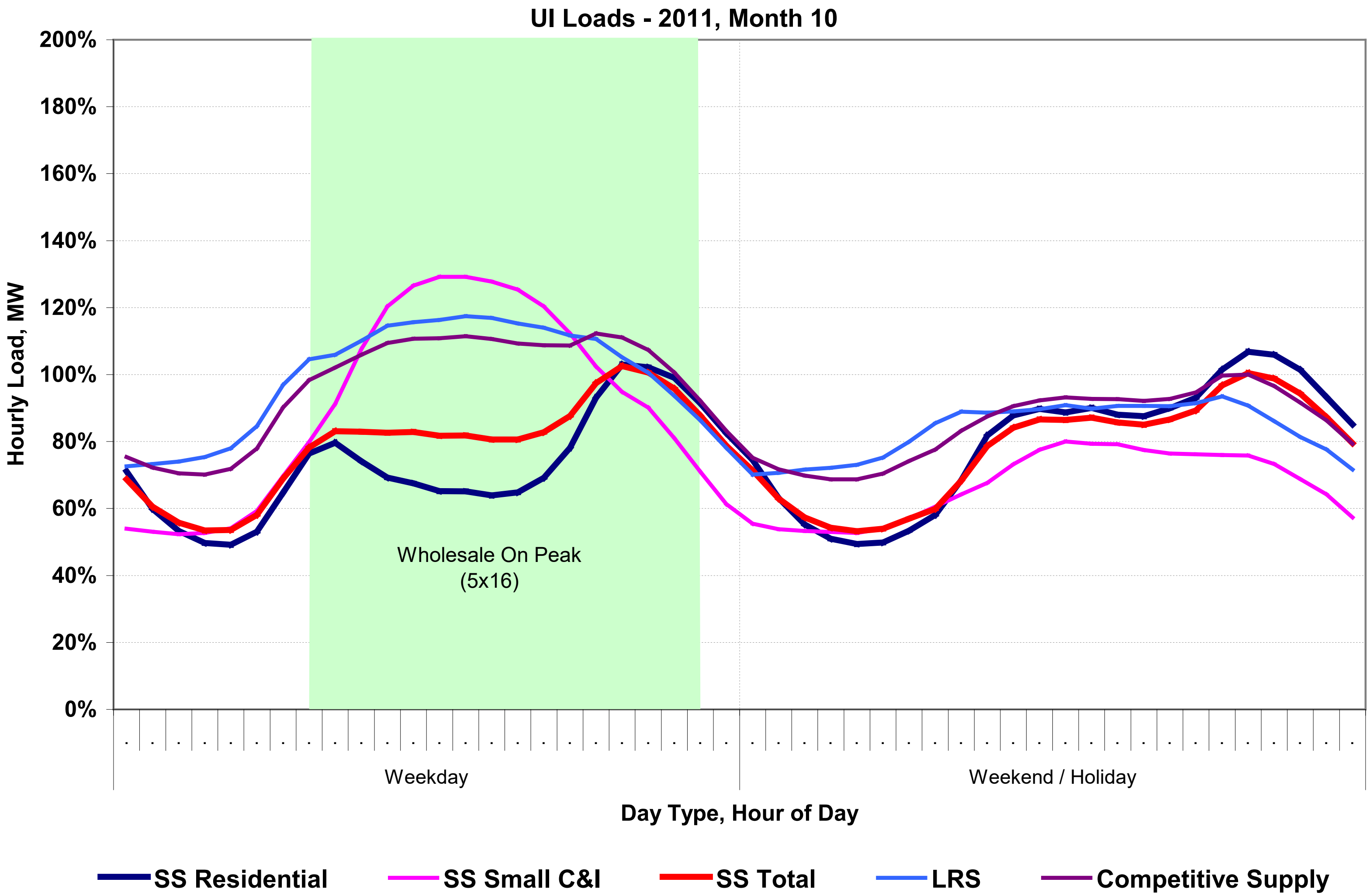


Figure B16. Normalized Load Profile – October 2011 (UI)



Appendix C

Comparison of Procurement Design in Other States

MAINE

There are three EDCs in Maine: Central Maine Power (CMP), Bangor Hydro (BHE), and Maine Public Service (MPS). Provision of Standard Offer Service (SOS) by each of the EDCs is governed by Chapter 301 of the Maine Public Utilities Commission (MPUC) rules.[69]

Customer Migration

Retail competition in Maine is active, particularly for C&I customers. As of December 2011, nearly 40% of the state's load was served by retail service providers.[70] Most Large customers contract with retail service providers, as well as about one-half of the Medium customers and 6% of Small customers.[71] Table C1 shows the percentage of load covered by retail service providers at the end of three previous calendar years for the three EDCs and also for Maine as a whole:[72]

Table C1. Percentage of Load Served by Retail Service Providers in Maine

End of Year	Small	Medium	Large	Total	Small	Medium	Large	Total
		BHE				CMP		
2011	5.7	56.1	96.3	34.7	6.7	56.1	96.7	40.4
2010	4.9	54.1	96.8	35.9	3.8	55.4	96.9	38.3
2009	2.2	50.9	96.3	33.0	2.2	52.7	95.7	35.6
		MPS				Statewide		
2011	0.3	42.1	71.9	24.3	6.2	55.6	95.6	38.9
2010	0.3	42.7	61.1	22.4	3.8	54.8	95.3	37.2
2009	0.1	39.9	57.8	21.7	2.1	51.8	94.0	34.6

Wholesale Procurement

MPUC solicits bids and selects winners on behalf of each EDC.[73] Successful bidders become the LSE for the load asset, thereby providing full requirements service for SOS, including load-following energy, losses, capacity, ancillary services, and RPS requirements. Solicitations are conducted by a sealed bid RFP.

[69] http://www.maine.gov/sos/cec/rules/65/407/407c301.doc

[70] Retail service providers are also referred to as competitive energy providers.

[71] Customer classes are based on peak usage. For BHE, Medium customers have peak loads between 25 kW and 500 kW. Customers with smaller peak loads are designated as Small (generally residential and small commercial customers) and those with peak loads higher are Large (generally large C&I consumers). CMP's Medium customer class covers loads between 20 kW and 400 kW. MPS Medium customers covers loads between 50 kW and 500 kW.

[72] http://www.maine.gov/mpuc/electricity/choosing_supplier/migration_statistics.shtml

[73] This process is a requirement for EDCs, but optional for municipals and coops.

Solicitations for Small, Medium, and Large customers are conducted separately. Generally, solicitations to provide supplies for CMP's and BHE's Medium and Large customers have been issued concurrently. Solicitations for Small customers have been issued separately. Solicitations covering all MPS customers are generally concurrent.

Solicitations to secure supplies for Small customer classes are held annually to cover loads up to three years in advance. Each procurement seeks coverage equal to 33% of the Small load for each year. Contracts are awarded on a fixed-price basis.[74]

For Medium and Large customer classes, which include most C&I customers, supplies are procured twice a year for a six month period beginning in March and September. For the Medium class solicitations, tranches of 20% of the load are procured, and bidders must submit fixed prices per tranche. For Large customers, bids may be fixed or indexed.[75] Bidders for Large customer class solicitations must bid for the entire class load.[76]

Bid Timing and Approvals

Prior to bid day, suppliers are required to submit proposals with indicative pricing. Non-price contract terms are negotiated prior to bid day. Binding bids are submitted to the PUC on bid day. Historically, winners have been selected the same day as bid day. Agreement execution occurs within the next 24-hours.

MASSACHUSETTS

There are four EDCs in Massachusetts that are regulated by the Department of Public Utilities (DPU):[77] NGrid, NStar, and Western Massachusetts Electric Company (WMECO), and Fitchburg Gas & Electric/Unitil (FGE).[78] Provision of default service for Massachusetts ratepayers is governed by two orders issued by the DPU: DTE 02-40-B, applicable to residential and small C&I customers and DTE 02-40-B, which applies to medium and large C&I customers.[79,80]

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[74] See http://www.maine.gov/mpuc/electricity/rfps/standard_offer/sosmall0911/index.shtml for examples of recent Small customer class solicitations.

[75] Recent solicitations have called for indexing to MassHub futures traded on NYMEX.

[76] See http://www.maine.gov/mpuc/electricity/rfps/standard_offer/somedlarge0312/ for examples of recent Medium and Large customer class solicitations.

[77] Previously, the Department of Telecommunications and Energy.

[78] NGrid MA is comprised of Massachusetts Electric and Nantucket Electric, both doing business as NGrid. NStar is comprised of four gas and electric utilities that merged in 2007, Commonwealth Electric, Cambridge Electric, Boston Edison, and Commonwealth Gas Co.

[79] http://www.env.state.ma.us/dpu/docs/electric/02-40/424order.pdf

[80] http://www.env.state.ma.us/dpu/docs/electric/02-40/912final.pdf

Customer Migration

Retail choice in Massachusetts is active. A large number of retail service providers are available to consumers, particularly for C&I customers. More than 50% of the EDCs' load is served by retail service providers as of December 2011. Large customers account for the most switching; almost all large C&I customers have chosen a retail service provider, while more than half of small and medium C&I customers have done the same.[81] Table C2 shows the percentage of load covered by retail service providers at the end of the three previous calendar years.[82]

Table C2. Percentage of Load Served by Retail Service Providers in Massachusetts

End of Year	Res.[83]	Small, Med. C&I	Large C&I	Other[84]	Res.	Small, Med. C&I	Large C&I	Other
		WMECO				**FGE**		
2011	6.9	64.8	94.6	57.5	1.6	40.9	98.0	35.2
2010	7.6	60.5	95.4	60.2	2.5	40.3	97.3	36.5
2009	7.7	58.2	95.5	60.2	2.3	40.0	94.1	33.2
		NStar				**NGrid**		
2011	18.7	54.1	87.5	77.2	8.4	48.7	89.6	71.0
2010	19.0	54.8	87.9	76.7	8.3	48.6	90.0	66.6
2009	19.3	53.0	88.6	77.2	9.1	48.8	90.5	69.2

Wholesale Procurement

Basic Service is procured by each EDC as a full requirements product, including load-following energy, capacity, ancillary services, and congestion. Successful bidders become the LSE for the load asset. For some EDCs, RECs are procured with the full requirements product, for other EDCs RECs are procured through a separate solicitation.

Solicitations are conducted via sealed bid RFPs, with separate pricing offered by rate class and by ISO-NE zone. Hence, there are different rates for customers served by the EDCs who operate in multiple zones, in particular, NStar and NGrid. Bidders must submit fixed price bids. Prices can vary by month over the delivery term, but no indexing is allowed.

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[81] Small C&I customers are those that use less than 3,000 kWh/month. Medium C&I's use between 3,000-120,000/month.

[82] http://www.mass.gov/eea/grants-and-tech-assistance/guidance-technical-assistance/agencies-and-divisions/doer/electric-customer-migration-data.html

[83] Residential customers include Low Income, Residential Non-Low Income, and Residential Time of Use.

[84] Other customers include farms and streetlights.

For Residential and Commercial customers, procurements are conducted on a laddered basis. Twice yearly, the EDCs procure one year contracts to cover 50% of the expected load. Solicitations are generally conducted within a few months of the start of the delivery period. For Industrials, EDCs procure 100% of supplies quarterly, generally 2 to 3 months before the beginning of the delivery period.[85,86]

Bid Timing and Approvals

Bidders execute master agreements in advance of bid day. For each EDC, binding bids are due at 10 am. Winning bidders are notified the afternoon of the same day, and transaction confirmations (or contract addenda) are executed by close of business on the same day. Promptly thereafter, the EDC files the confirmations with the DPU. By statute, the DPU has up to five days after the filing to approve the solicitation process.

RHODE ISLAND

NGrid Rhode Island is the only EDC and serves the majority of load in Rhode Island. Rhode Island General Law 39-1-27.3 and 39-1-27.8 governs NGrid's requirement to provide Standard Offer service to customers who do not choose a retail service provider; the statutes also require NGrid to file an annual procurement plan. The 2013 procurement plan was submitted to the Rhode Island Public Utilities Commission (RIPUC) under Docket No. 4123.[87]

Customer Migration

The Rhode Island competitive market is active, particularly for C&I customers. NGrid's October 2011 quarterly report on customer migration (RIPUC Docket No. 2515) indicates that 2.5% of customers in the NGrid Rhode Island service territory have opted for retail service providers, accounting for 30.4% of load. Statistics are not reported by customer class, but the fact that less than 3% of the customers account for approximately a third of the load in the territory indicates that the largest customers are the ones doing most of the switching. Migration data for previous years are indicated in Table C3.

Table C3. Migration in NGrid Rhode Island Service Territory

Year	Total MWh	% Load	Total Customers	% of Customers
through 9/2011	211,765	30.4	12,093	2.5
2010	199,540	32.6	10,585	2.3
2009	180,552	29.1	8,227	1.7

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85 http://www.nstar.com/docs3/energy_supplier/wholesale/rfp.pdf

86 http://www.nationalgridus.com/energysupply/current/102307/NGRID-RFP-2011_11_04_NH_MA.doc

87 http://www.ripuc.org/eventsactions/docket/4315page.html

Wholesale Procurement

NGrid Rhode Island procures full-requirements products for SOS for three customer groups: Industrial, Commercial, and Residential. Winning bidders serve as the LSE and provide all the components necessary to provide SOS, including load-following energy, capacity, congestion, and ancillary services. Bidders must price RPS compliance separately.

Solicitation for SOS supplies follows different schedules for each customer class. For Industrial customers, solicitations are conducted quarterly for 100% of load, six months in advance of the first delivery date. During recent RFPs, suppliers have been required to bid on the entire industrial load as a single tranche.

For Commercial and Residential customers, solicitations are conducted on a quarterly basis. Commercial load is procured through laddered six-month and 12-month contracts are solicited, covering a total of 90% of the load. For Residential load, laddered 6-month, 12-month, 18-month, and 24-month contracts are procured. For the remaining 10% tranche of Commercial and Residential customers, NGrid retains the load asset and serves the load through spot market purchases.

Bid Timing and Approvals

Bidders execute master agreements in advance of bid day. Bidders submit indicative pricing and supporting information one week prior to bid day. Indicative bids are reviewed with the Division of Public Utilities and Carriers on the same day this information is submitted. Binding bids are due at 10 am and winning bidders are notified the same afternoon. Transaction confirmations must be executed within two business days.[88] NGrid reviews final pricing with the Division of Public Utilities and Carriers on bid day.

NEW HAMPSHIRE

There are four utilities in New Hampshire. PSNH is the largest, providing service to approximately 70% of customers. PSNH is the LSE and manages its load through a combination of its generation portfolio in New Hampshire and market purchases in order to minimize total wholesale energy costs for its customers. New Hampshire Electric Cooperative (NHEC) provides service to customers in central New Hampshire, accounting for 11% of the state's consumers. It also uses a managed portfolio approach. Granite State Electric, a subsidiary of NGrid, and Unitil Energy Systems procure default service for their customers. NGrid and Unitil serve 6% and 11 % of New Hampshire customers, respectively.

[88] http://www.nationalgridus.com/energysupply/current/20090508/NGRID-RFP-2011_10_07.doc

Customer Migration

The New Hampshire competitive market is active, particularly for C&I customers. Roughly 30% of the state's total load is served by retail service providers. Table C4 shows the percentage of load served by retail service providers for Unitil and NGrid as of the end of the three previous calendar years. Note, PSNH's customers are permitted to select retail service providers, but because PSNH remains a vertically integrated investor owned utility, it is not required to hold periodic solicitations for wholesale power to serve its distribution customers.

Table C4. Percentage of Load Served by Retail Service Providers in Unitil and NGrid Service Territories[89,90,91]

Year[92]	Domestic	Small C&I[93]	Large C&I	Outdoor Lighting	Total
Unitil					
2012	1.0	29.6	81.5	32.6	30.1
2011	0.4	27.1	83.8	30.8	29.7
2010	0.3	18.5	80.4	23.6	26.0
NGrid					
2012	0.1	23.4	71.0	53.0	33.0
2011	0.2	21.6	66.0	53.0	29.0
2010	0.1	19.6	69.0	53.0	31.0

Wholesale Procurement

Unitil's and NGrid's plans for procuring Default Service supplies are reviewed and approved by the New Hampshire Public Utilities Commission (NHPUC). The most recent NHPUC approvals were issued under Dockets DE 12-003 and DE 12-023, respectively.[94,95] Pursuant to the plans approved in both dockets, the EDCs conduct solicitations to procure full requirements service by rate class. Bidders must price RPS compliance separately.

Unitil conducts Default Service procurements separately for two groups of customers: large industrials (rate class G1) and all other customers (rate classes D, G2, and OL). Procurements for industrial consumers are undertaken on a quarterly basis to cover 100%

[89] http://www.puc.nh.gov/Regulatory/Docketbk/2011/11-028.html

[90] http://www.puc.nh.gov/Regulatory/Docketbk/2006/06-115.html

[91] Detailed migration statistics for PSNH and NHEC are unavailable.

[92] Data are as of January of each year

[93] Small C&I customers are those who have peak loads of 200kW or less. Large C&I customers are those whose peak loads are greater than 200kW.

[94] http://www.puc.nh.gov/Regulatory/Docketbk/2012/12-003.html

[95] http://www.puc.nh.gov/Regulatory/Docketbk/2012/12-023.html

of load. Procurements for non-industrial customers are undertaken on a laddered basis, whereby Unitil procures power for one-year and two-year terms, each for 25% of load.[96] Accordingly, for each delivery period, power is procured at four different times, twice as one-year terms and twice as two-year terms. Procurements are scheduled approximately two months prior to the start of the delivery period.

NGrid New Hampshire conducts Default Service procurements separately for two groups of customers: small customers, comprised of rate classes D, D-10, G-3, M, T, and V, and large customers, which fall under rate classes G-1 and G-2. Procurements for small customers take place every six months for 100% of load. Procurements for large customers take place every three months for 100% of loads. Procurements are scheduled approximately two months prior to the start of the delivery period, and are commonly scheduled to coincide with procurements for NGrid in Massachusetts.

Bid Timing

Master agreements are executed prior to bid day. Both EDCs require bids to be submitted by 10:00 am. Winning bidders are notified by 1:00 pm on the same day. Transaction confirmations must be executed within three business days. The EDCs file a summary of the procurement process along with Default Retail Service Rates within three days of receipt of executed confirmations. The NHPUC reviews and approves the Default Service Rates no later than five business days thereafter.

NEW JERSEY

Four EDCs serve New Jersey customers: Public Service Electric & Gas (PSE&G), Jersey Central Power & Light (JCPL), Atlantic City Electric Company (ACE), and Rockland Electric Company (RECO). Each EDC participates in an annual procurement of power supplies for Basic Generation Service (BGS). BGS procurements have occurred regularly since 2002.

Customer Migration

New Jersey has an active competitive market with more than 30% of the state's total load served by retail service providers. Most is comprised of C&I customers. Increasingly, residential loads have migrated to retail service providers. Table C5 shows the amount of load served by retail service providers in each New Jersey service territory.

[96] http://www.unitil.net/rfp/details.asp?id=100

Table C5. Percentage of Load Served by Retail Service Providers in New Jersey[97]

End of Year	Residential	C&I	Total	Residential	C&I	Total
		ACE			**PSEG**	
2011	14.6	69.7	37.7	11.2	60.2	39.5
2010	7.2	62.2	31.2	4.2	54.9	33.9
2009[98]	NA	NA	27.4	NA	NA	34.0
		JCPL			**RECO**	
2011	13.2	64.2	35.9	8.0	59.2	27.3
2010	7.4	65.6	34.7	2.4	42.9	19.5
2009	NA	NA	28.9	NA	NA	15.5

Wholesale Procurement

Since 2001, BGS supplies have been procured annually by the New Jersey EDCs through a descending clock auction.[99] Successful bidders are the LSEs for the tranches they are awarded. The successful bidders are responsible for RPS compliance. However, in some instances the EDC furnishes some of the required RECs.[100]

BGS for customers with peak loads of less than 750kW is procured as fixed-price, full requirements service – BGS Fixed Price (BGS-FP). This group includes nearly all the Residential and most C&I customers. BGS-FP contracts are laddered. At each auction, 33% of the load for a three year service term is procured.

BGS for customers with peak loads greater than 750kW is procured as a variable price, full requirements service – Basic Generation Service-Commercial and Industrial Energy Pricing (BGS-CIEP). BGS-CIEP is indexed to hourly energy prices and there is no laddering. Suppliers are procured annually to provide 100% of BGS-CIEP load.

Prior to the auction, BGS-FP and BGS-CIEP loads are divided into tranches based on a percentage of load for each EDC. The descending clock auction for both customer groups is concurrent but separate.[101] At the beginning of each auction round, an auction manager announces a price for each type of tranche for each EDC. Bidders announce

[97] http://www.bgs-auction.com/documents/Electric_Switching_Historical_February_2012_Update.xls

[98] Migration statistics by class are unavailable for 2009

[99] The NJBPU order approving the first BGS auction was issued December 10, 2001, see NJBPU Dockets EX01050303, EO01100654, EO01100655, EO01100656 and EO01100657.

[100] For the auction held in February 2012, suppliers were informed that PSEG, JCPL, and ACE would be providing some RECs to cover its BGS-FP loads while ACE would be providing RECs to cover its BGS-CIEP loads.

[101] Although the auctions are held "simultaneously", for the most recent auction, the BGS-CIEP clock began "ticking" one business day prior to the BGS-FP clock.

how many tranches for each EDC they would be willing to provide at that round's price. If the number of tranches being offered exceeds the number required, the auction goes onto the next round, the auction manager announces a new, lower price, and bidders once again submit offers. Bidders are told at the end of each round how many tranches above the requirement have remained in the auction to proceed to the current round. The auction closes when there is no remaining excess, at which point suppliers are all paid the current round's price to supply their tranches.[102]

Approvals

Prospective bidders must execute NJBPU-approved standard contract terms in order to qualify to participate it the BGS auction.

PENNSYLVANIA

There are eight EDCs in Pennsylvania that fall under the jurisdiction of the Pennsylvania Public Utilities Commission (PAPUC). Four of the EDCs are subsidiaries of FirstEnergy: Metropolitan Edison (MetEd), Pennsylvania Electric (Penelec), Penn Power, and West Penn Power (WP).[103] The remaining four are Duquesne Light Company (DLC), PECO Energy (PECO), Pennsylvania Power and Light (PPL), and UGI Utilities (UGI).

The provision of Default Service in Pennsylvania is governed by Pennsylvania Code Section 54, Subchapter G, which, among other things, calls for the state's EDCs to procure Default Service supplies "at market rates" subject to oversight by the PAPUC and to regularly file procurement plans.[104]

Customer Migration

The Pennsylvania competitive market is active. More than one-half of the state's total load and nearly its entire industrial load served by Retail Service Providers. Table C6 shows recent migration statistics by EDC for Residential (R), Commercial (C), and Industrial (I) rate classes as well as EDC totals.

[102] Complete auction rules are available at http://www.bgs-auction.com/bgs.auction.regproc.asp

[103] WP is formerly known as Allegheny Power

[104] http://www.pacode.com/secure/data/052/chapter54/subchapGtoc.html

Table C6. Percentage of Load Served by Retail Service Providers in Pennsylvania[105]

Year[106]	R	C	I	Total	R	C	I	Total
	DLC				**MetEd**			
2012	32.3	67.1	93.2	62.7	9.8	57.0	95.0	52.3
2011	19.8	60.1	88.5	53.5	0.2	10.2	47.8	18.5
2010	19.0	56.4	89.1	51.0	0.0	0.2	10.9	2.0
	PECO Energy				**Penelec[107]**			
2012	23.9	59.4	94.5	52.3	16.0	58.0	97.0	58.0
2011	1.2	9.5	17.5	8.9	0.2	10.2	47.8	18.5
2010	0.2	5.6	0.1	1.7	0.0	0.2	10.9	2.0
	Penn Power				**PPL**			
2012	22.0	63.0	98.0	57.0	46.3	90.4	96.6	71.5
2011	12.2	60.6	96.6	55.7	39.9	82.8	92.1	64.9
2010	11.2	60.1	84.1	39.5	17.3	36.4	64.1	37.8
	UGI				**WP**			
2012	0.0	31.0	76.7	17.8	17.4	66.8	93.9	51.2
2011	0.0	28.9	77.0	15.7	0.0	17.3	16.1	9.0
2010	0.0	5.3	16.7	3.4	0.0	1.1	0.0	1.1

Wholesale Procurement

Through May 2013, EDCs will continue to procure default service supplies under Default Service Plan I (DSP I), a series of procurement plans approved by the PAPUC from 2008-2010.[108] In Docket I-2011-2237952, PAPUC made recommendations for DSP II, covering the delivery period May 2013 through June 2015. Each EDC (with the exception of UGI) has filed a procurement plan to respond to the PAPUC's DSP II recommendations. The key difference between DSP I and DSP II is that under DSP I, the EDCs typically served a portion of their residential and commercial customer load through a portfolio of block energy forwards and spot market purchases. Under DSP II, the self-managed portion of the load will be eliminated. Instead, EDCs will procure only full requirements service contracts. Additionally, procurements have generally been simplified, with fewer contracts and less frequent solicitations. All of the Pennsylvania EDCs except for UGI have filed new procurement plans for DSP II. UGI's filing is expected in the near future.

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[105] http://www.oca.state.pa.us/Industry/Electric/elecstats/ElectricStats.htm

[106] Data are as of January of each year

[107] For 2010 and 2011, Penelec and MetEd were reported together. The same series for those years are repeated for each

[108] See dockets P-2009-2093053, P-2009-2093054, P-2010-215782, P-00072342, P-2009-2135500, P-2008-206739, P-2008-2060309, and P-2008-2063006.

FirstEnergy (MetEd, Penelec, Penn Power, West Penn)

On November 17, 2011 FirstEnergy proposed a new default service plan covering the delivery period from June 2013 to May 2015.[109] Full requirements service will be procured through a descending clock auction. Suppliers will be responsible for meeting the state's Alternative Energy Portfolio Standard (AEPS) requirements and provide Alternative Energy Credits (AECs). Pricing for residential and commercial load is based on a 90% fixed and 10% indexed to spot basis. Pricing for the industrial load is indexed to spot prices.

All contracts are for 24-month terms. Residential and commercial load will be procured in two rounds, each for 50% of the load. One procurement will cover 100% of the industrial class load.

Winning bidders are notified at the conclusion of the auction, with PAPUC approval and contract execution occurring the following day.[110]

DLC

On April 27, 2012 DLC proposed a new default service plan covering the delivery period from June 1, 2013 to May 31, 2015. Full-requirements products, including AEPS requirements, will be solicited through a sealed-bid RFP. However, winning bidders will not serve as the LSE. As stated in DLC's standard agreement, "[the supplier], for purposes of this Agreement, is not a Load Serving Entity and nothing contained herein shall be deemed to cause Seller to be a Load Serving Entity."[111]

Procurements are conducted by customer class. DLC divides its default service customers into four different classes: residential, small C&I with less than 25 kW of peak demand and lighting, medium C&I customers with peak demand between 25 kW and 300 kW, and large C&I with peak demand greater than 300 kW. Pricing for the residential, small C&I, and medium C&I classes is fixed-price. For large C&I, contracts are indexed to the PJM spot market.

For the residential class, DLC will procure full-requirements service in several different solicitations using one-year full-requirements contracts. For the 2013-2014 delivery year, DLC will run two solicitations, purchasing 50% of the load in each round. For the 2014-2015 delivery year, DLC will run three solicitations, with the initial solicitation covering 50% of the load and the two subsequent solicitations each covering 25%. DLC may also run another solicitation for the 2015-2016 year covering 25% of load. For the small C&I class, 1-year full-requirements contracts each covering 50% of load will be laddered semi-annually, following a single 6-month contract to transition to the laddering scheme.

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[109] http://www.puc.state.pa.us//pcdocs/1154243.pdf

[110] https://www.firstenergycorp.com/content/dam/customer/Customer%20Choice/Files/PA/tariffs/Miller-Testimony-12-20-11.pdf

[111] http://www.puc.state.pa.us//pcdocs/1177082.pdf

For the medium C&I class, 6-month non-overlapping full-requirements contracts will be procured following a transition period with 6-month contracts covering 50% of load to accommodate established contracts.

PECO

On January 17, 2012 PECO proposed a new default service plan covering the delivery period from June 2013 to May 2015.[112] Suppliers serve as the LSE and provide full requirements service, including, including AEPS requirements.[113] Procurements will be conducted separately for each of the four customer classes: residential, small commercials with less than 100 kW of peak demand and lighting, medium commercial customers with peak demand between 100 kW and 500 kW, and large C&I with peak demand greater than 500 kW. Service for Large C&I customers will be indexed to the PJM spot market; contracts for all other customers will be fixed price.

For the residential class, products are laddered semi-annually with a contract mix that will approach 60% 2-year full-requirements contracts and 40% 1-year full-requirements contracts after a transition period which still contains leftover block energy purchases from DSP I. Delivery periods will overlap on a semi-annual basis. For the small commercial class, 1-year full requirements contracts each covering 50% of load will be laddered semi-annually, following a single 6-month contract to transition to the laddering scheme. For the medium commercial class, 6-month non-overlapping full-requirements contracts will be procured.

PPL

On May 2, 2012, PPL proposed a new default service plan covering the delivery period from June 2013 to May 2015.[114] PPL will solicit full requirements service, including AEPS requirements, through a sealed bid RFP. The winning bidders serve as the LSE. Procurements will be conducted separately for each of the three customer classes: residential, small C&I, and large C&I classes. The large C&I class includes customers with over 300 kW of peak load. Large C&I customers will receive service that is indexed to the PJM spot market; contracts for all other customers will be fixed price.

For both the residential and small C&I classes, PPL will purchase laddered contracts with 9-month and 12-month terms to fulfill 100% of load. The last solicitations will be for 3-month and 6-month contracts to ensure that contracts terminate at the end of the planned procurement period.

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[112] http://www.puc.state.pa.us//pcdocs/1162042.pdf

[113] PECO currently holds RECs that were previously procured that will be applied to retail load in the future. Presumably, suppliers' lower costs will be reflected in lower winning bids for those tranches of load receiving an allocation of RECs.

[114] Petition for Default Service Program and Power Procurement Plan, PAPUC Docket No. P-2012-230274 http://www.puc.state.pa.us//pcdocs/1175451.pdf

Winning bidders are notified on bid day. The RFP administrator then files a report the next business day, which the PAPUC must approve by the next business day. The supplier executes the contract on the following business day, which is three days after bid day.

UGI

Unlike the other Pennsylvania EDCs, UGI has not yet filed a procurement plan for the upcoming procurement period, but is expected to follow recommendations for new procurement plans set by the PAPUC in Docket I-2011-2237952.

MARYLAND

Maryland customers are served by four EDCs: Baltimore Gas & Electric (BGE), Potomac Electric Power (Pepco), Potomac Edison (PE), and Delmarva Power & Light (DPL).[115,116] Provision of SOS in the state is governed by Order 81102, issued by the Maryland Public Service Commission (MDPSC) in November 2006.[117] Subsequent orders have refined the state's procurement guidelines; among these, Order 85163 is of particular importance.[118]

Customer Migration

The competitive market is active, particularly for C&I customers. As of December 2011, nearly one-half the state's total load and nearly all of the large customer class are served by Retail Service Providers.

Table C7. Percentage of Peak Load Served by Retail Service Providers in Maryland[119]

	End of Year	Residential	Small C&I	Mid C&I	Large C&I	Total
PE						
	2011	8.1	35.0	64.1	87.9	36.5
	2010	5.8	27.7	62.2	84.7	35.9
	2009	0.0	20.9	59.8	86.9	32.5
BGE						
	2011	24.8	35.9	71.6	96.0	49.4

[115] DPL and Pepco are each subsidiaries of Pepco Holdings, Inc. (PHI)

[116] PE changed its name from Allegheny Power in 2011.

[117]http://webapp.psc.state.md.us/Intranet/Casenum/NewIndex3_VOpenFile.cfm?ServerFilePath=C:\CaseNum\9000-9099\9064\092.pdf

[118]http://webapp.psc.state.md.us/Intranet/Casenum/NewIndex3_VOpenFile.cfm?ServerFilePath=C:\CaseNum\9100-9199\9117\001.pdf

[119]http://webapp.psc.state.md.us/Intranet/CaseNum/submit_new.cfm?DirPath=\\Coldfusion\Electric%20Choice%20Reports\&CaseN=Electric%20Choice%20Enrollment%20Monthly%20Reports

End of Year	Residential	Small C&I	Mid C&I	Large C&I	Total
2010	17.4	31.5	70.0	93.4	47.1
2009	5.3	24.3	68.2	92.1	39.3
DPL					
2011	11.8	38.5	70.7	95.6	38.0
2010	8.3	33.9	69.3	94.1	37.2
2009	2.0	28.6	67.3	96.7	33.3
Pepco					
2011	22.4	43.3	72.0	93.3	52.7
2010	15.1	33.1	71.3	95.1	49.3
2009	9.6	28.0	68.8	96.9	45.5

Wholesale Procurement

Order 81102 prescribes a detailed procurement plan to be followed by Maryland's EDCs. The goals of the procurement process are threefold: the advancement of retail competition; acquisition of energy at the best price for Maryland consumers; and the mitigation of excessive price volatility, particularly for smaller customers. Order 81102 calls for separate procurements for each of three customer types: Residential customers; Type I C&I customers with peak loads less than 25 kW; and Type II customers, with peak loads between 25kW and 600kW. The Order allows for combination of the Residential and Type I procurements for some EDCs in order to ensure that tranches put up for bid are large enough to attract bidder interest.

Since the start of retail competition in Maryland, the structure of SOS solicitations has varied, depending on the size of the SOS load for each EDC and each customer group. The most recent procurements have been conducted as follows:

- Type I – Procured as two two-year contracts, each for 50% of expected loads for PE. For BGE, DPL and Pepco, procurements are for 25% of the load as two-year contracts, laddered for delivery in June 2012 and October 2012. The remainder of the load was previously procured or will be obtained through reserve procurements.

- Type II – For all EDCs, 100% of load is covered through quarterly procurements, each issuing three contracts for an upcoming quarter. There is no laddering of Type II contracts

- Residential – For PE, a total of fifteen contracts, each for 6.7% of the total residential load, is procured, with terms of either one or two years to be laddered over several procurements with annual overlapping of delivery terms. For BGE, DPL and Pepco, procurements are held for 25% of the retail load as two-year laddered contracts. These percentages set to be roughly 50 MW blocks. Previous procurements and reserve procurements will meet load shortcomings.

The EDCs procure load-following, full requirements service including RPS requirements, except for NITS. For Residential and Type I contracts, Volumetric Risk Mitigation

(VRM) mechanism applies. Under the VRM, if load differs from the block quantity by more or less than 5 MW, the supplier is kept whole for additional spot purchases or sales.

Bid Timing and Approvals

Contracts are awarded on the same day as bids are submitted, and must be executed within the next two days. MDPSC approval is issued two business days after the contracts are executed.

ILLINOIS

Two EDCs, Commonwealth Edison Company (ComEd) and Ameren Illinois Company (AIC), serve Illinois customers. ComEd is located in PJM and AIC is located in MISO.

The Illinois Power Agency (IPA) conducts procurements on behalf of each EDC. Pursuant to IPA's most recent annual procurement plan, IPA's goals are to "'ensure adequate, reliable, affordable, efficient and environmentally sustainable' electric service at the 'total lowest cost over time,' while taking into account "any benefits of price stability.'"[120]

Customer Migration

The Illinois competitive market is active, particularly for non-residential customers. As of February 2012, nearly 60% of the state's total load and more than 80% of its non-residential load were served by Retail Service Providers.

Table C8. Percentage of Load Served by Retail Service Providers in Illinois[121]

Year[122]	Residential	Non-Residential	Total
AIC			
2012	5.73	81.31	56.68
2011	0.02	77.36	49.48
2010	0.01	73.34	46.66
ComEd			
2012	10.15	81.09	59.56
2011	0.04	76.59	51.35
2010	0.01	74.56	50.43

Wholesale Procurement

The IPA annually solicits products to serve each EDC's load. Energy is procured through a sealed bid RFP, as on-peak and off-peak forward block contracts to cover the majority of each EDCs' respective SOS-eligible loads. Block energy forward contracts

[120] http://www.icc.illinois.gov/downloads/public/edocket/302831.pdf

[121] http://www.icc.illinois.gov/electricity/switchingstatistics.aspx

[122] Data are as of February of each year

are laddered over three years as follows: 35% of load is purchased two years in advance of delivery, 35% is purchased one year in advance of delivery, and 30% is purchased for the prompt year.[123] AIC and ComEd are LSEs, and both EDCs cover their residual energy requirements through shorter-term, fixed price contracts that are transacted on an as-needed basis. Additionally, both EDCs hold risk-managed contracts that hedge price risks for customers. The IPA procures bilateral capacity for AIC through an annual RFP process.[124] ComEd procures its capacity through the PJM-administered capacity market. IPA procures RECs for each EDC through separate RFPs.

Additional solicitations have been conducted to meet specific legislative policy goals. For example, in February 2012 both utilities conducted "rate stabilization" procurements for energy and RECs that were not called for in the normal procurement schedule.[125]

Bid Timing and Approvals

Bids are due early on bid day, and winning bidders are notified on the same day. Within two business days, the Procurement Administrator and Procurement Monitor, outside consultants who oversee procurements on behalf of the IPA and the Illinois Commerce Commission (ICC), respectively, file reports with the ICC. The ICC accepts or reject bids within two business days, and the EDCs execute contracts with winning suppliers within three business days of the ICC ruling.

NEW YORK

New York customers are served by six EDCs: Central Hudson Gas & Electric (CHG&E), Consolidated Edison (ConEd), New York State Electric & Gas (NYSEG), Niagara Mohawk Power (a NGrid subsidiary), Orange and Rockland Utilities (O&R), and Rochester Gas & Electric (RG&E). Also, the New York Power Authority (NYPA) serves institutional customers in southeast New York City, in particular, in New York City. The Long Island Power Authority (LIPA) serves retail customers on Long Island. Both NYPA and LIPA are not required to solicit wholesale power to serve their respective retail customers.

The New York EDCs remain the LSE for their respective load assets. Each EDC files a procurement plan with the New York Public Service Commission (NYPSC) for review and approval.[126] NYPSC encourages spot purchases and limited futures hedging, with some older PPAs grandfathered into the plans.

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[123] Contracts generally run on a June-May basis to coincide with the PJM and MISO power years.

[124] www.levitan.com/AIURFP/Documents/2012 AIC Capacity RFP.pdf

[125] http://www.levitan.com/AIURFP/RS/index.html

[126] http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={2D1F1D71-2585-4416-8C2D-5E0EA471013F}

Customer Migration

Most of the New York competitive market is active for C&I customers, but not on Long Island where LIPA serves nearly all of its residential, commercial and industrial customers in Nassau and Suffolk Counties. As of August 2011, the most recent data available, more than half the state's total load and nearly all of the large customer loads are served by Retail Service Providers, except on Long Island:

Table C9. Percentage of Peak Load Served by Retail Service Providers in New York[127]

Year[128]	Res	Small C&I	Large C&I	Total	Res	Small C&I	Large C&I	Total
		CHG&E				**O&R**		
2011	7.6	45.9	90.2	39.5	37.7	82.3	45.6	52.6
2010	6.5	40.9	88.5	36.6	33.2	65.8	38.6	44.5
2009	5.0	35.9	87.6	37.7	31.6	56.3	36.9	40.8
		ConEd				**RGE**		
2011	21.5	59.2	91.4	49.6	32.8	75.3	81.6	63.7
2010	19.7	54.7	85.5	46.1	27.0	69.7	83.6	59.7
2009	18.7	49.0	90.5	46.5	22.8	62.5	93.6	58.8
		NGrid NY				**Statewide**		
2011	19.9	67.4	71.4	49.2	22,4	62.2	81.6	50.7
2010	17.8	64.1	67.2	46.7	19.9	57.8	77.5	47.2
2009	16.1	62.3	72.9	47.3	18.7	56.5	58.1	43.7
		NYSEG						
2011	25.8	62.5	86.8	55.0				
2010	22.2	60.1	81.5	50.5				
2009	18.7	56.5	58.1	43.7				

Wholesale Procurement

EDCs utilize a managed portfolio approach that combines spot market purchases, short-term futures hedging, and grandfathered PPAs to serve their SOS customer load. Retail rates generally vary on a monthly basis, and reflect a cost of service for the EDC, including a regulated rate of return. The EDCs are not responsible for RPS compliance. Renewable energy to meet the state's RPS goals is centrally procured by NYSERDA.

[127] http://www.dps.ny.gov/Electric-Gas_RA_Archives.html

[128] Data are as of August each year

STATE OF CONNECTICUT

POWER PROCUREMENT PLAN UPDATE FOR STANDARD SERVICE AND LAST RESORT SERVICE

Submitted to:

Public Utilities Regulatory Authority

Docket No. 12-06-02

Prepared by:

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Power Procurement Manager

In Association with:
Levitan & Associates, Inc.

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1.0 INTRODUCTION AND BACKGROUND

Pursuant to "*An Act Concerning Revisions to the Electric Restructuring Legislation*" (Public Act 03-135), Connecticut's electric distribution companies (EDCs), The United Illuminating Company (UI) and The Connecticut Light & Power Company d/b/a Eversource Energy (CL&P), were required to purchase wholesale electric generation services to furnish electric supplies for their Standard Service-eligible customers. Eligible customers were those who (A) do not arrange for or are not receiving electric generation services from a competitive retail electric supplier, and (B) do not use a demand meter or have a maximum demand of less than five hundred kilowatts. Standard Service customers are principally residential and small commercial and industrial (C&I) customers. PA 03-135 further provided that on and after January 1, 2007, the EDCs also serve Last Resort Service (LRS) customers that are not eligible to receive Standard Service and have not elected to purchase supplies from a competitive retail. LRS customers are generally large C&I customers.

Consistent with PA 03-135 and the governing Decision by the Public Utilities Regulatory Authority (PURA), the EDCs developed and implemented a procurement protocol. Deliveries to eligible Standard Service and LRS customers began on January 1, 2007. Under PA 03-135, the EDCs were obligated to procure a portfolio of wholesale electric supply contracts for Standard Service "in an overlapping pattern of fixed periods at such times and in such manner and duration as the department determines to be most likely to produce just, reasonable, and reasonably stable retail rates while reflecting the underlying wholesale market price over time." This language established the principle of "laddering" for wholesale Standard Service supply contracts in order to promote rate stability for customers. PURA's decision also mandated that the laddered contracts be for full requirements service and not exceed a term of three years.[1]

In 2011, the Connecticut Legislature passed comprehensive energy legislation, Public Act 11-80, "*An Act Concerning the Establishment of the Department of Energy and Environmental Protection and Planning for Connecticut's Energy Future*." Among other provisions, PA 11-80 created the position of Procurement Manager within PURA, responsible for overseeing Standard Service procurements by the EDCs. Under prior legislation, all Standard Service and LRS contracts were subject to PURA review and approval during a non-contested proceeding the day following each bid day. PA 11-80 granted the Procurement Manager the authority to review and approve Standard Service contracts that are recommended by the EDCs on the same day that bids are received, opened, and evaluated.

PA 11-80 also required the Procurement Manager to prepare a Power Procurement Plan, which was submitted to PURA on June 1, 2012. The Power Procurement Plan included an analysis of prior rounds of Standard Service procurements and recommended several

[1] June 21, 2006 PURA Decision in Docket No. 06-01-08PH01

significant revisions to the EDCs' Standard Service procurement structure. Importantly, the Power Procurement Plan proposed to shorten the Standard Service contract term from as much as three years to no more than one year, and also to shorten the time between execution of the contract and the start of power delivery. The procurement schedule preserved the laddering structure so that each delivery period is served by supplies contracted for on up to four different procurement dates. The Power Procurement Plan also allowed CL&P to self-manage up to 20% of its Standard Service load. PURA approved the Power Procurement Plan in a decision issued on October 12, 2012 in Docket No. 12-06-02.

PA 11-80 required the Procurement Manager to submit annual updates to the Power Procurement Plan. These updates have resulted in several modifications and refinements to the Standard Service and LRS process over the years. In the spring of 2013 the Procurement Manager sought and obtained permission from PURA Commissioners to increase CL&P's self-managed portion of Standard Service load from the 20% authorized in the Power Procurement Plan to up to 30%.

On March 11, 2014, in Docket No. 12-06-02RE01, the Procurement Manager filed an update, which included a request that PURA grant the Procurement Manager the authority to oversee and approve LRS contracts in the same manner as Standard Service. PURA approved this change to the Procurement Plan in a decision issued on August 13, 2014.

On July 31, 2015, the Procurement Manager petitioned PURA to re-open the matter as Docket No. 12-06-02RE02. PURA did not schedule any hearings for this docket.

On November 2, 2016, the Power Procurement Manager, petitioned PURA to reopen the matter as Docket No. 12-06-02RE03 for the limited purpose of amending and reviewing the Power Procurement Plan. PURA approved the requested amendments and issued its final decision on December 20, 2017. This decision allows the Technical Session to be held three days after each bid day rather than the day following each bid day, and allows the EDCs to transfer Class 1 Renewable Energy Credits (RECs) that have been procured through long term contracts or from EDC-owned generation to a Standard Service or LRS account at a transfer price approved by the Procurement Manager.

This Procurement Plan Update consolidates all the changes that have been made to the Procurement Plan and lays out the existing procurement process.

2.0 COMPONENTS OF STANDARD SERVICE AND LRS SUPPLY

Under the framework established in Docket No. 06-01-08PH01, Standard Service and LRS wholesale contracts are procured as fixed price, full requirements service. For a full requirements supply contract, the supplier is responsible for all products necessary to serve the load in each and every hour of the contract period regardless of the actual load level or spot market price. Thus, full requirements service shifts daily and hourly supply management responsibility to the wholesale supplier.

The components of full requirements service consist of:

- Load-following energy supply delivered to the CT Load Zone,
- Capacity, as required by ISO-NE rules,
- Other ISO-NE charges, including uplift and ancillary services,
- Fulfillment of Connecticut's Renewable Portfolio Standard (RPS) requirements, and
- All risk management costs, that is, hedging both price and quantity risks, as well as other financial and administrative costs incurred by the supplier.

Previously, both EDCs allowed bidders to offer Scenario A or Scenario B contracts for Standard Service. For Scenario A bids, the supplier assumed the load obligation at the CL&P metering domain in Connecticut and assumed the Locational Marginal Price (LMP) differential, *i.e.*, congestion and losses. For Scenario B bids, the supplier assumed the load obligation at the EDC's metering domain, but the EDC reimbursed the supplier for congestion and losses between the MassHub and the CT Load Zone. The volatility of congestion and losses has declined significantly since 2009. Therefore, with the approval of the Procurement Manager, the EDCs suspended solicitation of Scenario B bids in early 2016.

3.0 STANDARD SERVICE AND LRS PROCUREMENT STRUCTURE

3.1 Standard Service Bid Requirements and Schedule

Each EDC's Standard Service load is divided into ten tranches or slices, each representing 10% of the full requirements Standard Service Load for a 6-month service term, January through June, and July through December. The EDCs solicit full requirements service through sealed-bid Requests for Proposals. Bidders must offer prices for each month of the service term, on-peak and off-peak periods, and for each customer class. Bids are selected based on the load-weighted average price for each service term. At the discretion of the EDC, bidders may be allowed to submit "linked" bids. Bids may be linked across service terms (*e.g.*, first half of year linked to second half of year), or they may be linked within the same service term (*e.g.*, the EDC must accept a bid covering two tranches for 20% of the service term.) Negative contingencies are also permitted (*e.g.*, if a linked bid is selected, the independent bids for the same service terms may not be taken.)

The EDCs schedule four Standard Service procurements per year, coinciding with their respective LRS procurement dates. On each bid day, the EDCs procure contracts for up to two different service terms, commencing up to 12 months ahead, so that the aggregate price for each service term reflects an average of contracts awarded on three to four different procurement dates. The procurement schedule is intended to diversify the procurement dates, so that the composite price is an average price of multiple tranches, thereby mitigating price volatility. The relatively short 6-month contract term as well as the time between a procurement date and the start of the delivery term reduces costs to customers by reducing the migration risk, the cost of forward hedges, and various financing costs that suppliers must cover.

For each bid day, with the assistance of PURA's consultant, Levitan & Associates, Inc. (LAI), PURA prepares a proxy price for each service term, which is intended to represent a competitive bid from a creditworthy supplier. Each EDC, as well as the Office of Consumer Counsel (OCC), independently also prepare proxy prices. Proxy prices are used to gauge the competitiveness of the bids, whether bids are consistent with the wholesale market, and to determine if discretionary tranches should be selected.

Prior to each Standard Service bid day, the EDCs consult with the Procurement Manager, and then inform bidders of the target number of tranches or slices for each service term that they intend to procure. The EDCs may procure up to the intended number of contracts, but they are not obligated to enter into contracts for all of the target tranches or slices if the prices are not deemed to be competitive or consistent with wholesale market conditions, based on a comparison to the proxy prices.

The overall laddered structure assuming four procurement dates for each delivery term is represented in the figure below. The shading in the figure illustrates how discretionary tranches provide flexibility in the procurement structure. In the lower left corner, one, two, or three slices for the first half of 2017 (1H2017) delivery might be procured in the first quarter of 2016 (Q1 16) procurement event. Depending on the number of slices procured in Q1 16 and the competitiveness of bids received in the second quarter of 2016 (Q2 16) event, the cumulative purchase after that event might be from four to six slices. The cumulative purchase after the third quarter of 2016 (Q3 16) event could be from seven to nine slices. The 1H2017 service term would be completely filled by the fourth quarter of 2016 (Q4 16) event.

Standard Service Laddering Structure

Percentage of Requirement Filled	Procurement Event Quarter			
100%	Q4 16	Q2 17	Q4 17	Q2 18
90%				
80%				
70%	Q3 16	Q1 17	Q3 17	Q1 18
60%				
50%				
40%	Q2 16	Q4 16	Q2 17	Q4 17
30%				
20%				
10%	Q1 16	Q3 16	Q1 17	Q3 17
	1H2017	1H2017	1H2018	2H2018
	Delivery Term			

The EDCs, with the consent of the Procurement Manager, may add or drop procurement events if warranted, while still ensuring a diversity of procurement dates. For example, if the Procurement Manager and the EDCs reject all bids on a procurement day, an additional procurement date can be scheduled. Alternatively, if sufficient contracts at favorable prices have been awarded to complete a service term, the remaining procurements for that service term would not be needed.

In the course of a year, should the need arise for immediate modification of the Procurement Plan due to legislative, market, or other unforeseen issues, the Procurement Manager may, upon oral approval of PURA Commissioners, make such modification immediately while soliciting official review and approval of such modification in the following year's annual review.

3.2 LRS Bid Requirements and Schedule

The EDCs procure LRS services as full requirements contracts for 3-month service terms: January through March, April through June, July through September, and October through December. For each EDC, a single supplier is selected for all LRS load for each service term. The EDCs schedule quarterly LRS procurements so that they coincide with a Standard Service procurement. The EDCs and the OCC prepare proxy prices for each LRS round to determine if the bids received are competitive and consistent with the wholesale market.

3.3 Self-Management

The June 12, 2012 Procurement Plan allowed CL&P to self-manage up to 20% (two slices) of its Standard Service load, subject to approval by the Procurement Manager of a self-management plan. For self-managed tranches, the EDC is responsible for procuring all of the components required to serve load, as described in Section 2.0. Following each bid day when the Procurement Manager approves one or more tranches to be self-managed, the EDC submits a plan that details the proposed quantity and price of hedge contracts and the anticipated market purchases. The EDC is also required to submit a confidential monthly report to the Procurement Manager that tabulates the actual and forecasted load, revenues, and purchases for the current month and year-to-date.

Beginning with the service term starting January 2013, CL&P began to self-manage 20% of its Standard Service Load, increasing to 30% in second half of 2014, with the approval of the Procurement Manager. UI does not currently self-manage any portion of its Standard Service load, but may consider doing so in the future, with the approval of the Procurement Manager.

On May 26, 2017 CL&P notified PURA that effective January 1, 2018, CL&P will discontinue its self-management procurement activities authorized by the Procurement Manager in Docket No. 12-06-02. CL&P has determined that the inherent risks and exposures resulting from their voluntary self-supply activities may be too substantial for their shareholders to bear. Discussions among CL&P, OCC, and the Procurement Manager to resolve this issue are ongoing.

The Procurement Manager may direct an EDC to self-manage LRS if there is insufficient competition in a particular procurement round, or if all LRS bids are rejected as inconsistent with the wholesale market.

3.4 Approval and Documentation of Standard Service and LRS Contracts

3.4.1 Protocol for Disclosure of Procurement Results

On bid days, the Procurement Manager reviews the Standard Service and LRS bids received and the contracts recommended by the EDC. The OCC also oversees the procurement, reviews the bids, and offers its opinion regarding the recommended contracts. The Procurement Manager is authorized to approve (or reject) the recommended Standard Service and LRS contracts on the same day that the bids are received. For approved bids, the Procurement Manager is present when the EDC notifies the supplier of awards.

For each Standard Service and LRS bid day, the Procurement Manager files a public decision letter, and a confidential bid evaluation memo. The decision letter reports that the Procurement Manager participated in the EDC's procurement process, affirms that the requirements of the Procurement Plan were followed in all material respects, documents that the Procurement Manager approved one or more Standard Service and LRS contracts, requests that PURA acknowledge such approval(s), and directs the EDC to include the approved contracts in the formulation of the overall Standard Service and LRS rates. The confidential bid evaluation memo is s a protected document that furnishes details on the bids received, wholesale market conditions, contracts awarded, and the basis for selection.

PURA's August 20, 2008 decision in Docket No. 06-01-08RE02 established the procedure for EDCs' release of Standard Service and LRS bid information. Two weeks following each bid day, the EDCs publicly file: 1) the cumulative percentage of Standard Service load that has been awarded for each service term, and 2) upon award of 100% of the load for a given service term, the names of all suppliers for that service term. With respect to bid prices, the EDCs publicly file redacted bid information 90 days from the bid day.

On February 21, 2017, in Docket 12-06-02RE03, the Procurement Manager proposed a change to the technical session requirement, which was approved by PURA in its December 20, 2017 decision in this docket. In lieu of holding a Technical Meeting the day following bid day, a Technical Meeting is scheduled to take place approximately three business days after each bid day. If the Procurement Manager, PURA Commissioners and Staff concur that there is no need to hold a Technical Meeting, the meeting may be cancelled. If a Technical Meeting is warranted, the Procurement Manager, the EDCs, and a representative of the OCC will participate and review the results of the recent procurement before PURA on the scheduled day.

3.4.2 Protocol for the Disclosure of Information on Self-Managed Load

The Procurement Plan establishes the following protocol regarding disclosure of information on each tranche of self-managed load:

1. For each rate period, the EDC will publicly file the following information regarding its costs to serve the self-managed load: (1) all costs paid to ISO-NE to serve the self-managed load for the rate period, (2) all costs associated with bilateral transactions to serve the self-managed load, including costs incurred for the procurement of Renewable Energy Credits (RECs).

2. The EDC will provide this information no later than five months following the end of a rate period. For rate periods that end on June 30, the information will be provided no later than December 1, and for rate periods that end on December 31, the information will be provided no later than June 1 of the following year. This timeline accommodates ISO-NE's settlement and billing procedures. In the event that ISO-NE's settlement and billing period procedures change, the due date for the EDC to file the information regarding the self-managed load will be adjusted

accordingly by the Procurement Manager, and the revised due date will be submitted for PURA approval in the next annual Procurement Plan review.

3. If the EDC continues to procure RECs for a rate period after the due date stated in (2), the EDC will inform the Procurement Manager of such purchases. Upon completion of all REC purchases for a calendar year, the EDC will file updated information regarding REC purchases with its next regular public filing of the information under (1), above.

3.5 Transfer of Class I RECs to Load-Serving Obligation

On February 22, 2017, in Docket 12-06-02RE03, UI filed a proposed change to the Procurement Plan to allow UI to transfer Class I RECs that it produces or purchases under long-term contracts to its load-serving obligation when it self-manages Standard Service or LRS, with such transfer taking place at a transfer price that is reflective of the market price for Class I RECs at the time of the transfer, subject to approval of the Procurement Manager. PURA approved this change in its December 20, 2017 decision in this docket.

UI noted that this amendment to the Procurement Plan will benefit customers by eliminating the unnecessary sale and re-purchase of the same quantity of Class I RECs from the wholesale market, and will also alleviate the administrative burdens associated with sale and re-purchase of Class I RECs.