



Historical Regional Network Load Cost Report, 2005 to 2009

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Market Analysis and Settlements
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Contents

- Contents 3**
- Figures..... 3**
- Tables 4**
- Section 1 Introduction 5**
 - 1.1 Regional Network Load Cost Categories 5
 - 1.2 Summary of Regional Network Load Costs, 2005 to 2009 6
 - 1.3 Reliability Regions and Local Networks 7
 - 1.4 Major Categories of Regional Network Load Cost Components..... 8
- Section 2 Infrastructure Costs 9**
 - 2.1 Infrastructure Investments, 2005 to 2009..... 10
 - 2.2 Infrastructure Costs, 2005 to 2009 11
 - 2.3 Pre-‘97 Infrastructure Costs (Rates) by Local Network, 2005 to 2009..... 12
- Section 3 Reliability Costs 12**
 - 3.1 Reliability Costs by Type, 2005 to 2009..... 13
 - 3.2 Terminated Reliability Cost Types 15
 - 3.3 Reliability Costs by Reliability Region, 2005 to 2009..... 15
 - 3.4 Voltage Support Costs, 2005 to 2009 17
 - 3.5 High-Voltage Control Costs by Reliability Region, 2008 and 2009..... 18
- Section 4 Administrative Service Costs..... 19**
- Section 5 Regional Network Load, 2005 to 2009 20**
 - 5.1 Average Regional Network Load by Year, 2005 to 2009 21
 - 5.2 Monthly Regional Network Load by Reliability Region, 2005 to 2009 22
 - 5.3 Monthly Regional Network Load by Regional Network, 2005 to 2009 22
- Section 6 Appendix 23**
 - 6.1 Description of Concepts 23
 - 6.1.1 Calculated Components..... 23**
 - 6.1.2 Allocated Components 25**
 - 6.2 Monthly Network Load Cost Report..... 27
- Document History 28**

Figures

- Figure 2-1: Infrastructure costs by component, 2005 to 2009. 11
- Figure 2-2: Pre-‘97 infrastructure costs (rates) by local network, 2005 to 2009. 12
- Figure 3-1: Average reliability costs by type, 2005 to 2009..... 14
- Figure 3-2: Average combined costs for reliability services by Reliability Region, 2005 to 2009. 16
- Figure 3-3: Reliability Agreement costs by reliability region, 2005 to 2009. 16

Figure 3-4: Southwest Connecticut Gap RFP costs, 2005 to 2009.....	17
Figure 3-5: Voltage support costs, 2005 to 2009.....	18
Figure 3-6: High-voltage control costs by reliability region, 2008 and 2009.....	19
Figure 4-1: Administrative costs by type, 2005 to 2009.....	20
Figure 5-1: Average monthly regional network load, 2005 to 2009.....	21
Figure 5-2: Monthly network load by reliability region, 2005 to 2009.....	22
Figure 5-3: Monthly network load by local network, 2005 to 2009.....	23

Tables

Table 1-1 Local Network to Reliability Region Mapping	8
Table 1-2 Major Cost Components of Regional Network Load Categories	9
Table 2-1 Pool Transmission Facilities Investments, 2005 to 2009	10
Table 2-2 Infrastructure Costs by Component, 2005 to 2009 (\$/MW-Month).....	11
Table 3-1 Average Reliability Costs by Type, 2005 to 2009 (\$/MW-Month).....	14
Table 3-2 Effective Start and End Dates for Certain Regional Network Load Cost Components	15
Table 4-1 Administrative Costs by Type, 2005 to 2009 (\$/MW-Month).....	20

Section 1

Introduction

Created in 1997, ISO New England Inc. (ISO) is the not-for-profit regional transmission organization (RTO) responsible for the day-to-day reliable operation of the electric power generation and transmission system within the New England area, oversight and administration of the region's wholesale electricity markets and regional transmission service, and management of a comprehensive regional power system planning process.

The ISO operates under the *ISO New England Transmission, Markets, and Services Tariff* (the tariff), approved by the Federal Energy Regulatory Commission (FERC).¹ The tariff contains the detailed rules governing the provision of wholesale electric energy, capacity, transmission, reliability, and ancillary and other services, including the allocation of costs and billing for these services. The larger portion of these costs, which include energy, capacity, and ancillary market charges are estimated and analyzed in \$/megawatt-hour (MWh) of electric load and reported elsewhere on the ISO Web site.²

The smaller portion of the costs of serving wholesale load in New England are those associated with the provision of *regional network service* (RNS) and other services to transmission customers that collectively provide for the use of transmission facilities, reliability, and certain administrative services. The *Open Access Transmission Tariff* (OATT) (Section II of the ISO tariff) governs the allocation of these costs, which are billed according to a transmission customer's *regional network load* (RNL). The RNL is the customer's hourly load at the time of the peak load of its local transmission network.³ The aggregate of these costs generally is referred to as "OATT costs" or "RNL costs," which are charged by \$/MW-month.

In response to requests from various New England stakeholders to increase transparency and facilitate their understanding of all the costs of serving load in New England, particularly those associated with transmission, the ISO developed this *Historical Regional Network Load Cost Report*. This report provides historical average costs (per MW-month) under the OATT for serving regional network load in the New England wholesale markets for 2005 to 2009.⁴ This report also provides the historical basis for the *Monthly Network Load Cost Report*, which provides a rolling 13-month perspective of these costs.⁵

1.1 Regional Network Load Cost Categories

These RNL costs are categorized as follows, according to provisions in the OATT:

¹ The *ISO New England Transmission, Markets, and Services Tariff* (2009), includes the *Open Access Transmission Tariff* (OATT) (Section II) and the *Self-Funding Tariff* (SFT) (Section IV). These documents are available at <http://www.iso-ne.com/regulatory/tariff/index.html> and http://www.iso-ne.com/regulatory/tariff/sect_2/index.html.

² Those costs are reported in the *Wholesale Load Cost Report*, available at http://www.iso-ne.com/markets/mkt_anlys_rpts/whlse_load/index.html.

³ The OATT provides the terms and conditions for nondiscriminatory, open-access transmission services over the New England transmission system. These provisions provide for comparable, nondiscriminatory treatment of all transmission owners (TOs), transmission providers, and transmission customers taking transmission services under the OATT. Network load is defined by the OATT as a network customer's hourly load coincident with the aggregate load of all network customers served in each local network in the hour in which the respective local network's aggregate load is at its maximum for the month (i.e., the monthly peak).

⁴ All components presented in this report and reported by the ISO are measured in \$/MW-month. To convert these to \$/kW-month, divide \$/MW-month by 1,000.

⁵ Other ISO reports summarize the operations of New England markets and the administration of the ISO tariff; see http://www.iso-ne.com/markets/mkt_anlys_rpts/index.html.

- **Infrastructure** cost category [I]—recovers the costs associated with the use of pool transmission facilities (PTFs).⁶
- **Reliability** cost category [R]—recovers the costs associated with maintaining certain power system reliability services, such as voltage control, system restoration services, and Reliability Agreements.⁷
- **Administrative** cost category [A]—recovers the costs associated with the administration of power system reliability, such as ISO dispatch and control costs, participating transmission owner (PTO) local control center (LCC) costs, and other mandated cost-recovery items.⁸

The Appendix (Section 6) describes specific components that fall within each of these cost categories.

1.2 Summary of Regional Network Load Costs, 2005 to 2009

Data from 2005 to 2009 show that RNL costs, while representing a small portion of total wholesale costs, have increased from \$3,058/MW-month in 2005 to \$5,224/MW-month in 2009. This is an increase from 6% of total wholesale costs in 2005 to 15% of total wholesale costs in 2009 and reflects a compound growth rate of 14% over the five-year period. This growth rate varied across all RNL cost categories as follows:

- **Infrastructure** costs averaged \$4,453/MW-month during 2009, reflecting a compound growth rate of 31% over the five-year period from their 2005 average of \$1,513/MW-month. In response to identified transmission system inadequacies, New England’s transmission owners have invested \$3.7 billion from 2005 to 2009 in the system, resulting in a more robust transmission system that has seen a notable increase in reliability evidenced by the marked decrease in reliability costs. The infrastructure costs for 2009 were approximately 85% of RNL costs and 8% of overall wholesale costs.

⁶ PTFs are certain transmission lines (69 kilovolts [kV] or greater), associated equipment, and facilities over which ISO New England has operational control. These facilities are owned and maintained by a group of approximately 17 participating transmission owners. PTFs do not include those lines and facilities that serve local load only or are generator leads (i.e., radial transmission from a generator bus to the nearest point on the PTF). The ISO reviews the status of transmission lines and related facilities at least once per year. A current listing of PTFs is available at http://www.iso-ne.com/trans/planning/ptf_cat/index.html. See the ISO tariff, Section II. H. II. 49 for a more detailed description of PTFs.

⁷ *Voltage control* is when reactive power is used to maintain transmission voltages for meeting the operating requirements of the New England transmission system. *System restoration* (“black-start”) services enable the ISO to designate specific generators to start without an outside electrical supply following the partial or full shutdown of the transmission system. *Reliability Agreements*, previously referred to as “Reliability-Must-Run” Agreements, were contractual arrangements established with generators deemed necessary to ensure that the units needed for reliability were available when needed to support the transmission system. These agreements, which were subject to FERC approval, provided eligible generators with monthly fixed-cost payments for maintaining the capacity that provided the reliability services. As a result of the start of the Forward Capacity Market (FCM) on June 1, 2010, Reliability Agreements have expired, and any further need to retain units in the region for reliability is addressed under FCM market rules. Refer to the ISO’s *2009 Annual Markets Report (AMR09)* for additional information on the FCM; http://www.iso-ne.com/markets/mkt_anlys_rpts/annl_mkt_rpts/index.html. Reliability costs reported here include only those reliability services whose costs are governed under the OATT.

⁸ *PTOs* are participant companies that own or support the PTFs in the New England Balancing Authority Area and are eligible to submit revenue requirements to recover their costs. Of the more than 30 PTOs that supported a portion of the PTFs during 2005 to 2009, approximately 17 both owned and operated facilities in the local networks. An even smaller group of currently eight PTOs are recognized as having local network RNS rates, as discussed throughout the report. According to the North American Electric Reliability Corporation (NERC), which is the organization responsible for ensuring the reliability of the bulk power system in North America, a *balancing authority area* is a group of generation, transmission, and loads within the metered boundaries of the entity (balancing authority) that maintains the load-resource balance within the area. Balancing authority areas were formerly referred to as control areas. Further information is available in the NERC glossary; http://www.nerc.com/docs/standards/rs/Glossary_12Feb08.pdf.

- **Reliability** costs declined over the period at a compound rate of 21% per year, from \$1,393/MW-month for 2005 to \$544/MW-month for 2009. This decline is attributable to reductions in reliability costs associated with voltage control, black-start services, and, primarily, Reliability Agreements, which were responsible for over \$900 million of charges for 2005 to 2009. These reliability cost reductions, driven by the increase in infrastructure investment, were approximately 10% of RNL costs and 1.3% of overall wholesale costs in 2009.
- **Administrative** costs grew at a 10% compound rate over the period. Administrative costs were only 4% of the total costs billed through the OATT and approximately 0.5% of overall wholesale costs during 2009.

1.3 Reliability Regions and Local Networks

This report provides summaries of the RNL costs at several levels, including the balancing authority area (or pool), reliability region, and local network levels.⁹ The New England Balancing Authority Area is divided into eight reliability regions that have local networks with RNS rates. Table 1-1 lists these regions and the eight local networks and participating transmission owners operating in each one that had local RNS rates during 2005 to 2009.

⁹ *Reliability regions* are regions of the New England Balancing Authority Area that reflect the operational characteristics of the transmission system and therefore form the basis for allocating costs of certain wholesale market products and services. For example, costs for high-voltage control are allocated to RNL customers who benefit from that particular ancillary service within their specific reliability region. A *local network* is a portion of the PTF owned or operated by a PTO and serving RNL and “through or out service.” Generally speaking, several local networks serve the New England Balancing Authority Area, but only eight are identified as having a local network RNS rate. These are the local networks described in this report. Each of the PTOs with a local network RNS rate is responsible for determining the peak RNL value on its local network in a given month and also for identifying to the ISO the share of RNL to be assigned to each of the network load assets in its local network. Several of these eight local networks reside in more than one state. This report removes the effect of through-or-out transactions on costs. “*Through-or-out service*,” is the delivery of electricity over the PTFs through or from New England to another balancing authority area. This report does not provide summaries of the costs associated with the provision of Schedule 21–Local Service; Schedule 18, *Merchant Transmission Facility (MTF) Service*, or Schedule 21, *Other Transmission Facilities (OTF) Service*, under the OATT.

**Table 1-1
Local Network to Reliability Region Mapping**

Reliability Region	Local Network/Participating Transmission Owner^(a)
Connecticut (CT)	Northeast Utilities Service Company (NU) United Illuminating (UI)
Maine (ME)	Bangor Hydro Electric (BHE) Central Maine Power (CMP) NU
New Hampshire (NH)	New England Power (NEP) ^(b) NU
Northeastern Massachusetts (NEMA)	Boston Edison (BE), which merged into NSTAR ^(c) NEP
Rhode Island (RI)	NEP
Southeastern Massachusetts (SEMA)	BE, which merged into NSTAR in February 2007 Commonwealth Electric (CES), which merged into NSTAR ^(c) NEP
Vermont (VT)	Vermont Electric Power/VT Transco LLC (VELCO/VT Transco)
Western Central Massachusetts (WCMA)	Fitchburg Gas and Electric Light (FGE) NEP NU

(a) Several of the local networks reside in more than one reliability region/state jurisdiction.

(b) The NEP local network includes the National Grid USA companies that are included in the New England Balancing Authority Area.

(c) The NSTAR local network was newly established in March 2007 to recognize the merger of Boston Edison Company, Cambridge Electric Light Company, Canal Electric Company, and Commonwealth Electric Company into the NSTAR Electric Company. The BE and CES local networks were separate and distinct local networks from February 2005 through February 2007.

Each PTO with a local network RNS rate is responsible for determining the peak RNL value on its local network in a given month and for identifying the share of RNL to be assigned to each of the network load assets in its local network. The [Appendix](#) (Section 6) contains additional information about the local networks with local network RNS rates in New England.

1.4 Major Categories of Regional Network Load Cost Components

Some of the cost components reported below, such as those associated with infrastructure investments, are derived from revenue requirements approved by FERC. Others reflect an allocation of payments to RNL for the respective service rendered, as described in the OATT. Table 1-2 lists the components of each of the three major RNL cost categories. All components are described in detail in the Appendix. Not all components described are currently active in current tariff billing practices.

**Table 1-2
Major Cost Components of Regional Network Load Categories**

Category	Regional Network Load Cost Components
Infrastructure [I]	Pre-1997 transmission infrastructure costs Post-1996 transmission infrastructure costs
Reliability [R]	Reliability Agreements Voltage support High-voltage control System restoration Demand-response Winter Supplemental Program (WSP) Request for Proposals for Southwest Connecticut Emergency Capability (SWCT Gap RFP) Load-response program Demand-Response Reliability Pilot (DRRP) availability DRRP ISO Operating Procedure No. 4 (OP 4) electric energy ^(a)
Administrative [A]	PTO dispatch and control ISO dispatch and control New England States Committee on Electricity (NESCOE) budget ^(b)

(a) ISO Operating Procedure No. 4, *Action during a Capacity Deficiency (OP 4)*; http://www.iso-ne.com/rules_proceeds/operating/isone/op4/OP4_RTO_FIN.doc.

(b) NESCOE is the FERC-approved regional-state committee for providing advisory input to the ISO regarding the development of the Regional System Plan. The ISO serves as the vehicle for recovering funds from transmission customers to cover NESCOE's budgeted operating expenses. More information about NESCOE is available at www.nescoe.com.

Section 2 Infrastructure Costs

The infrastructure category of RNL costs reflects the rates charged through the tariff for the transmission owners' recovery of their infrastructure investments in the PTFs that provide regional transmission service to transmission customers. These investments serve to maintain or expand the PTFs, maintain or improve reliability, and improve the economic performance of the entire New England transmission system. Transmission rates, which are first developed by the PTOs, are currently based on PTF revenue requirements of the prior and current years, as well as the previous year's average of all monthly network load peaks for each local network (see Section 2.2).

As part of industry restructuring, and in response to FERC directives to provide a "nonpancaked," or a single transmission rate, NEPOOL undertook an 11-year transition period from 1997 to March 2008 that revised the rate structure. The result was the convergence of individual local network rates that recovered

costs associated with the PTFs (and, therefore, the overall pool transmission rate) into a single rate.¹⁰ Reflecting the transition process, the RNS rate, which is regulated by and filed with the FERC, includes the following two components:

- **Pre-1997 transmission infrastructure costs (Schedule 9 Pre-'97 RNS):**¹¹ This component is associated with PTFs and PTF upgrades placed in service or made before 1997. The pre-1997 values shown throughout the report reflect the FERC-filed rate for each local network. Pre-1997 values are also shown for each reliability region (i.e., at the pool level) for illustration purpose, as applicable. From 1997 to March 2008, each local network had a different rate.
- **Post-1996 transmission infrastructure costs (Schedule 9 Post-'96 RNS):** This component is associated with PTFs and PTF upgrades placed in service or made after 1996. The value shown in the report for each year reflects the FERC-filed rate, which has been homogenous across all local networks since 1997.

The RNS rate, which includes the pre-'97 and post-'96 components, is determined annually and effective June 1 through May 31.

The [Appendix](#) of this report provides a more detailed description of each of these components and how RNS rates are developed.

2.1 Infrastructure Investments, 2005 to 2009

Table 2-1 shows the total dollar value of PTF costs attributable to transmission upgrades made by PTOs and eligible for cost recovery for the 2005 to 2009 timeframe. The costs associated with these recent investments are evidenced by the recent growth in the post-'96 RNS rate.

**Table 2-1
Pool Transmission Facilities Investments, 2005 to 2009**

Year	PTF Investments (\$ Millions)
2005	143
2006	494
2007	328
2008	1,912
2009	799

Further details on the transmission investment projects put into service in recent years are summarized in the ISO's *2009 Regional System Plan*.¹²

¹⁰ See FERC Order 888 regarding FERC directives to provide "non-pancaked" rates; <http://www.ferc.gov/legal/maj-ord-reg/land-docs/order888.asp>

¹¹ Schedule 9 of the ISO OATT; http://www.iso-ne.com/regulatory/tariff/sect_2/oatt/index.html.

¹² *2009 Regional System Plan* (October 15, 2009); <http://www.iso-ne.com/trans/rsp/2009/index.html>.

2.2 Infrastructure Costs, 2005 to 2009

The PTOs reflect in their revenue requirements the costs associated with their PTF investments from the prior year and, beginning in 2006, the current year reflecting forecasts. These PTF revenue requirements may reflect return on investment, income taxes, depreciation, tax, operation, support, and other expenses, the largest of which is typically return on investment. While the relationship between PTF investment and post-'96 RNS rates has not been directly proportional, PTF investments made between 2004 and 2009 have played a significant role in the size and growth of the post-'96 (and therefore overall) RNS rate over the historical period covered by this report.

Figure 2-1 and Table 2-2 show the average monthly infrastructure costs for both the pre-'97 and post-'96 components for 2005 to 2009. The pre-'97 cost component grew at a 2.25% average annual rate from 2005 to 2009. In contrast, the post-'96 cost component grew at a 66% average annual rate due to increased investments to the infrastructure as previously discussed.

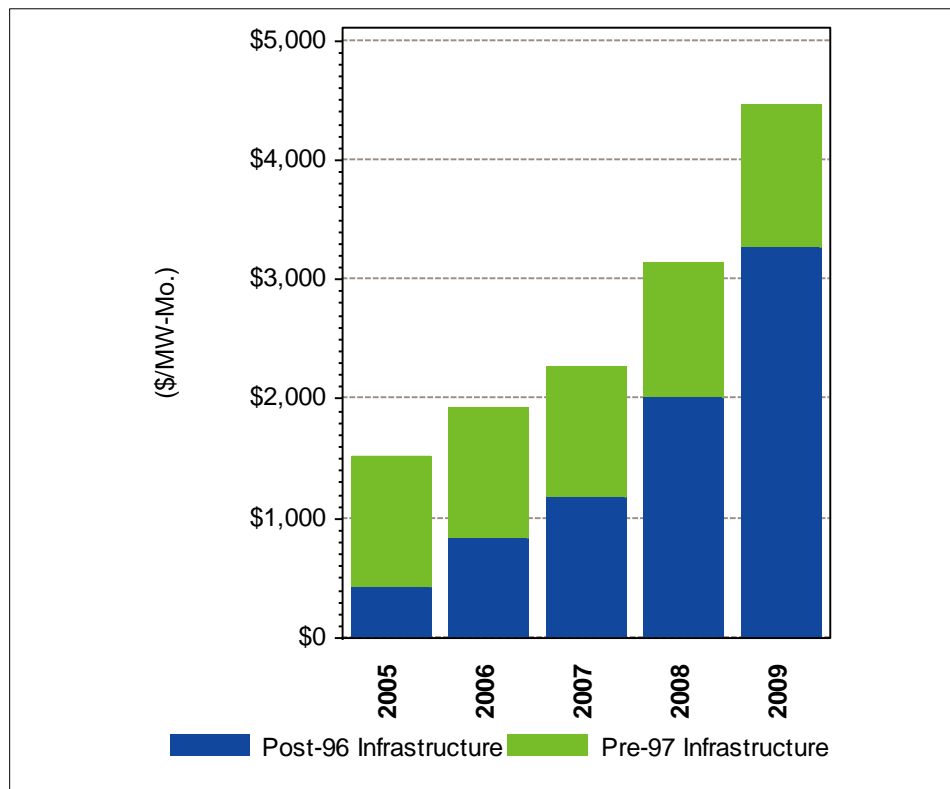


Figure 2-1: Infrastructure costs by component, 2005 to 2009.

Table 2-2
Infrastructure Costs by Component, 2005 to 2009 (\$/MW-Month)

Component	2005	2006	2007	2008	2009
Pre-'97 infrastructure costs	1,086	1,102	1,093	1,140	1,188
Post-'96 infrastructure costs	427	831	1,181	2,000	3,265
Total	1,513	1,933	2,274	3,140	4,453

PTOs typically make a multiple-year forecast of PTF additions (investments), PTO revenue requirements, and RNS rates.¹³ Such forecasts are meant to be indicative, are subject to change, and are not included here.

2.3 Pre-'97 Infrastructure Costs (Rates) by Local Network, 2005 to 2009

Figure 2-2 shows pre-'97 infrastructure costs (rates as filed with FERC) for each local network for 2005 to 2009. The exhibit illustrates (1) the transition of this rate into a unified rate across all local networks (completed in 2008), (2) the consolidation of the separate CES and BE local networks to a single NSTAR local network in 2007, and (3) the emergence of the FGE local network with an RNS rate in March 2008.¹⁴

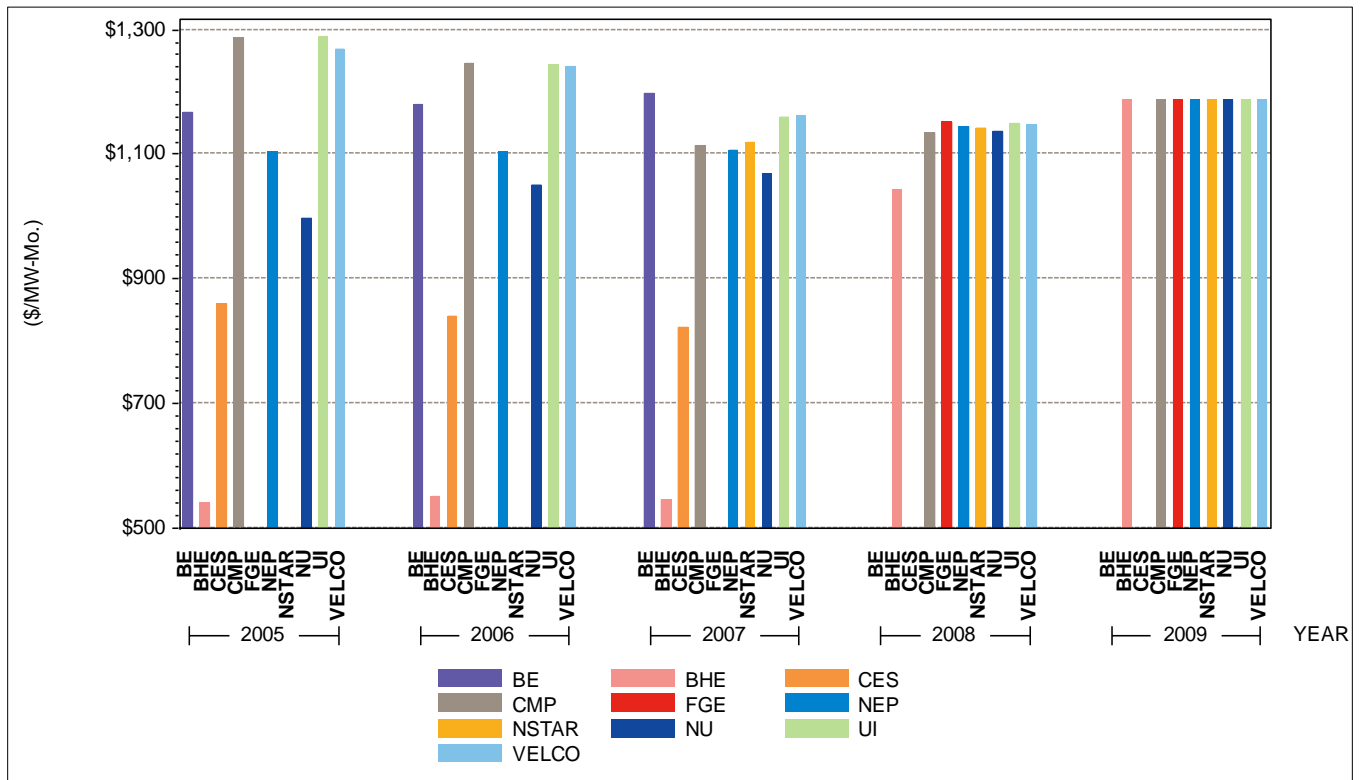


Figure 2-2: Pre-'97 infrastructure costs (rates) by local network, 2005 to 2009.

Section 3 Reliability Costs

Reliability services charged through the tariff serve to recover the costs of certain reliability programs and services administered through the OATT.¹⁵ The costs (and rates) in this category are developed by taking

¹³ PTOs publicly post this information at the ISO's Transmission Committee Web site; http://www.iso-ne.com/committees/comm_wkgrps/trans_comm/tariff_comm/index.html.

¹⁴ Prior to March 2008, FGE recovered its revenue requirements through the NEP local network RNS rate.

¹⁵ Not all reliability service costs are recovered through the OATT.

total payments for the provided service or program and dividing it by the appropriate value of RNL during the month. (Refer to Table 1-2 for the costs included in this category.)

A detailed description of each of these components is provided in the [Appendix](#) of this report.

3.1 Reliability Costs by Type, 2005 to 2009

Both Figure 3-1 and Table 3-1 show reliability costs by type from 2005 to 2009. Reductions in the costs associated with Reliability Agreements, voltage support, and demand response obtained through the SWCT Gap RFP are reflected in the notable decline in overall reliability costs. This decline is largely the result of the investment in transmission infrastructure noted in the previous section. Projects completed during the period have mitigated or eliminated the need for certain reliability programs and services.

The benefits of an improved, more efficient transmission system extend beyond the reduced reliability costs reported here. Other benefits include a lowering of transmission congestion costs (reflected in wholesale market prices for electric energy), the costs of re-dispatching the system for providing reserves, and the costs paid to less economic generators that provided local-area second-contingency protection to respect system reliability requirements.¹⁶ Transmission investments should continue to play a role in mitigating these costs.

¹⁶ A *contingency* is the sudden loss of a generation or transmission resource. A *first contingency* (N-1) is when the first power element (facility) of a system is lost, which has the largest impact on system reliability. A *second contingency* (N-1-1) is the loss of the facility that would have the largest impact on the system after facility that has the largest impact is lost. See the ISO's AMR09 for further analysis of these costs over time; http://www.iso-ne.com/markets/mkt_anlys_rpts/annl_mkt_rpts/index.html.

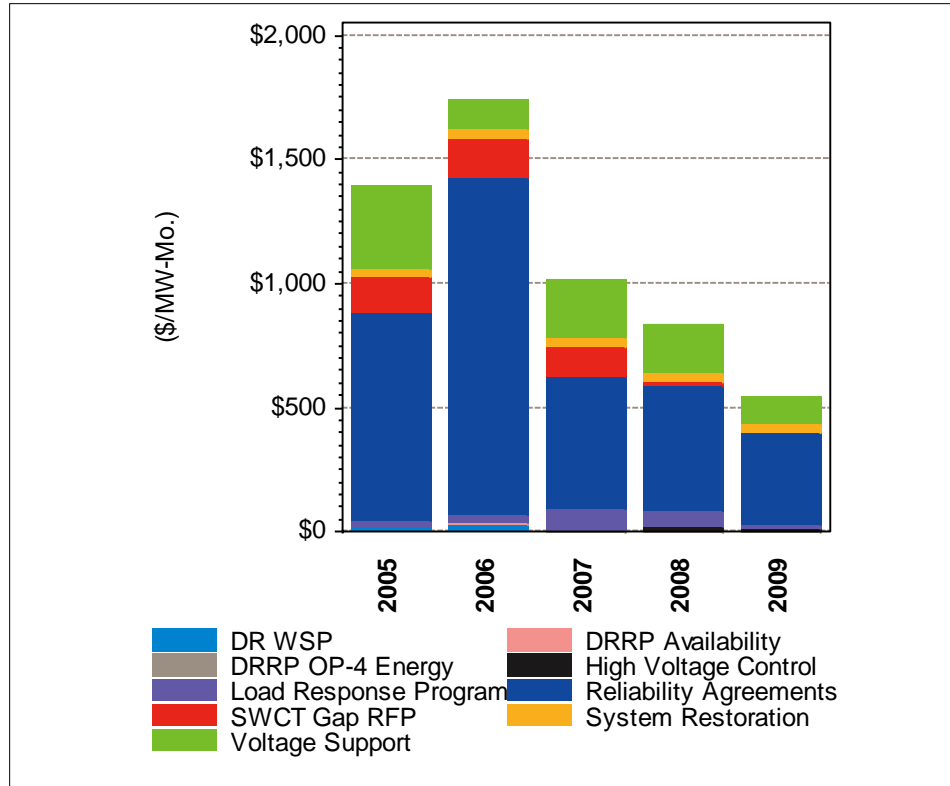


Figure 3-1: Average reliability costs by type, 2005 to 2009.

Table 3-1
Average Reliability Costs by Type, 2005 to 2009 (\$/MW-Month)

Allocated Concept	2005	2006	2007	2008	2009
SWCT Gap RFP	143.88	160.27	120.51	14.89	0.00
Demand-response WSP	14.11	30.11	0.00	0.00	0.00
DRRP availability	0.00	0.23	1.01	0.72	0.77
DRRP OP 4 energy	0.00	0.00	0.17	0.14	0.17
High-voltage control	0.00	0.00	0.00	20.24	6.05
Load-response program	26.32	30.97	84.18	55.35	21.53
Reliability Agreements	838.15	1,360.77	539.36	508.49	363.72
System restoration	32.97	36.35	40.12	41.90	44.75
Voltage support	337.35	121.07	240.03	189.44	107.27
Total	1,392.79	1,739.79	1,025.38	831.16	544.26

3.2 Terminated Reliability Cost Types

Table 3-2 shows the termination dates for certain reliability costs that are no longer in effect.

Table 3-2
Effective Start and End Dates for Certain Regional Network Load Cost Components

Cost Component Short Name	Effective Service Start Date	Effective Service End Date
Demand-response WSP	Dec 05	Apr 06
SWCT Gap RFP	Aug 06	Jun 08
Reliability Agreements^(a)	Pre-2005	Jun 10
DRRP availability	Pre-2005	Jun 10
DRRP OP 4 electric energy	Pre-2005	Jun 10

(a) Starting in June 2010, coincident with the start of the Forward Capacity Market (FCM), Reliability Agreements expired, and any further need to retain units in the balancing authority area for reliability are addressed under the market rules for FCM.

3.3 Reliability Costs by Reliability Region, 2005 to 2009

Figure 3-2 shows the aggregated reliability costs of all types by reliability region from 2005 to 2009. Declining costs in CT, NEMA, and WCMA are associated with the planned expiration schedule of Reliability Agreements and are attributable to transmission system improvements. The expirations of the demand-response supplemental RFP program and similar programs for SWCT also contributed to the cost decline in Connecticut.

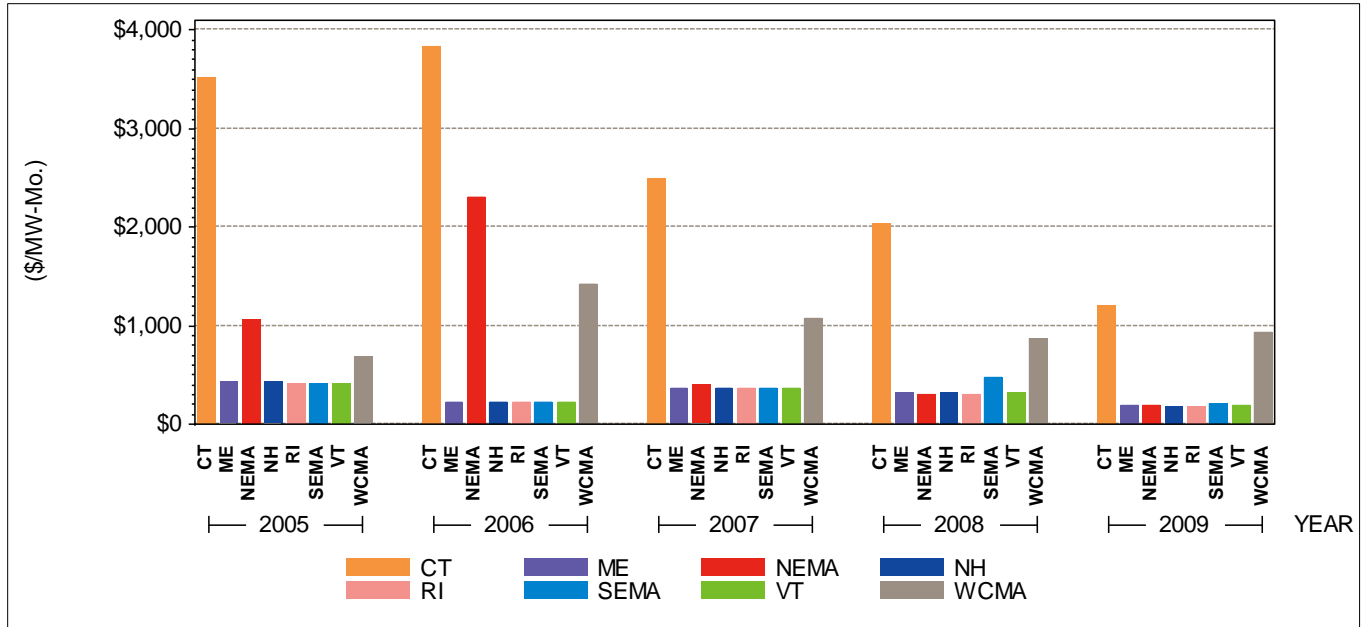


Figure 3-2: Average combined costs for reliability services by Reliability Region, 2005 to 2009.

Figure 3-3 shows Reliability Agreement costs by reliability region for 2005 to 2009. While these costs expired in June 2010, they remain subject to resettlement through the ISO’s established data reconciliation process, also known as the Data Reconciliation Process (DRP).

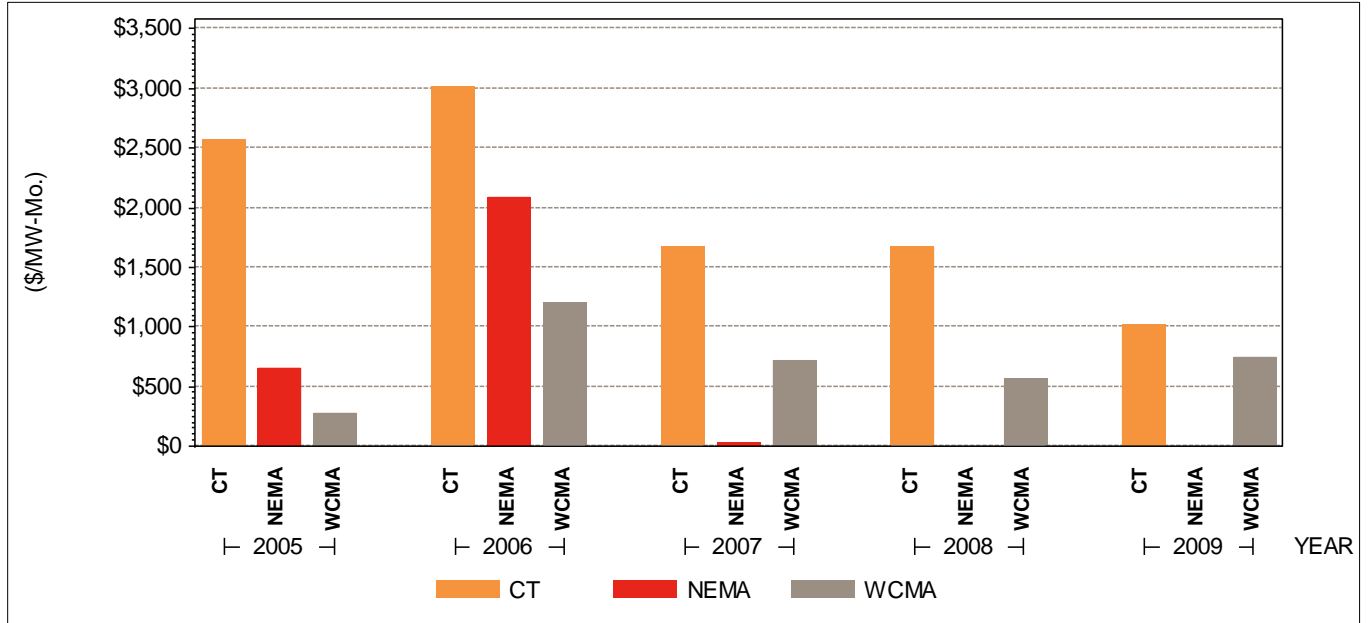


Figure 3-3: Reliability Agreement costs by reliability region, 2005 to 2009.

Figure 3-4 shows average SWCT Gap RFP costs for 2005 to 2009. These costs, which were for the benefit of and exclusive to the Connecticut Reliability Region, were terminated in 2008.

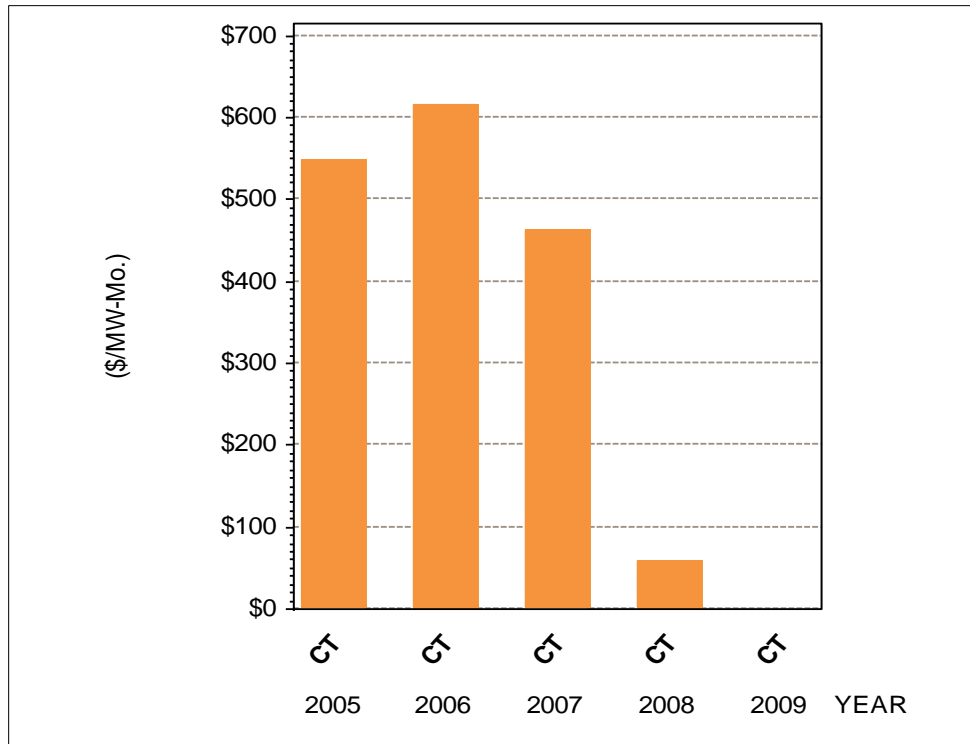


Figure 3-4: Southwest Connecticut Gap RFP costs, 2005 to 2009.

3.4 Voltage Support Costs, 2005 to 2009

Volt ampere reactive (VAR) is a measurement of reactive power used to maintain transmission voltages for meeting the operating requirements of the New England transmission system. Qualifying reactive resources that are compensated for providing VAR service may receive both fixed payments and variable payments.

Before June 2008, the cost of resources committed to providing reactive power for either system-level or regional high-voltage control were primarily allocated to systemwide RNL. Starting in July 2008, the allocation for high-voltage control shifted from systemwide RNL to RNL within the specifically affected reliability region. The allocation for voltage support costs remains at the systemwide level.

Figure 3-5 shows voltage support costs for 2005 to 2009. Transmission system improvements have helped to reduce these reliability costs over time.

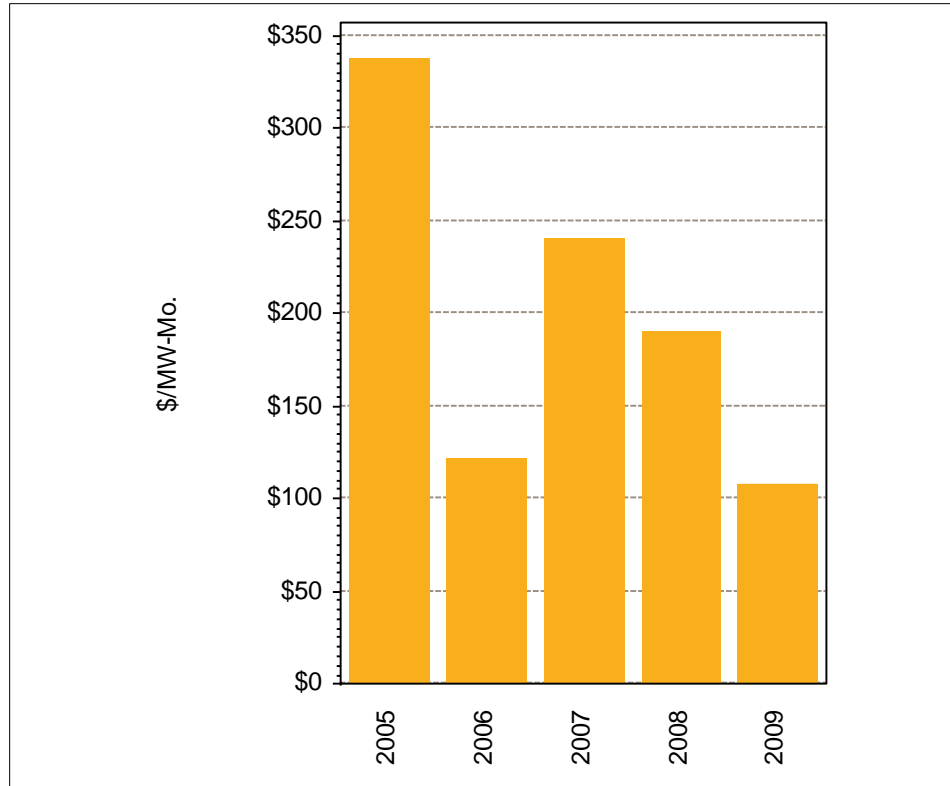


Figure 3-5: Voltage support costs, 2005 to 2009.

3.5 High-Voltage Control Costs by Reliability Region, 2008 and 2009

In 2008, the tariff was changed to allocate the costs of high-voltage control to the reliability region and not regionwide. Figure 3-6 shows high-voltage control costs by reliability region for 2008 and 2009. The bulk of these costs charged to the SEMA Reliability Region occurred during August to October 2008. These costs have declined after the addition of various transmission upgrades in the SEMA area.

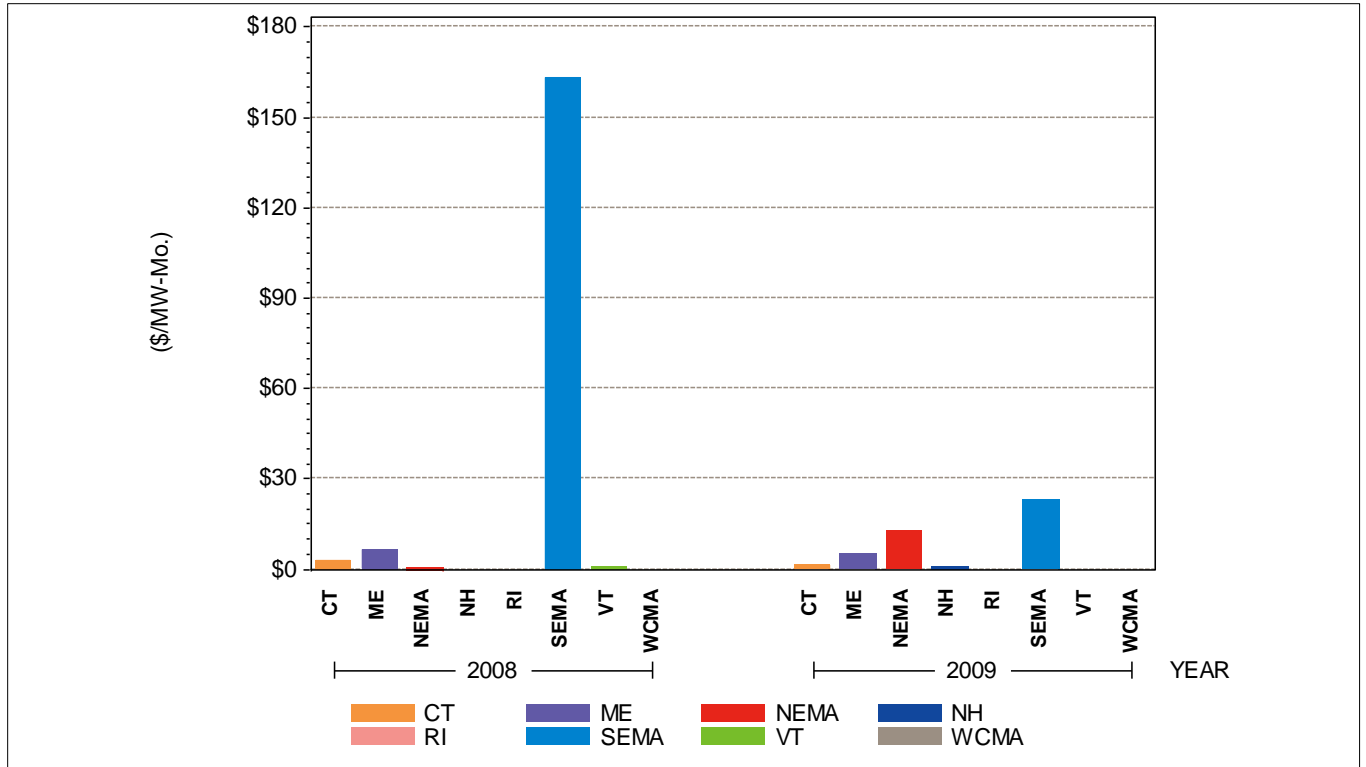


Figure 3-6: High-voltage control costs by reliability region, 2008 and 2009.

Section 4 Administrative Service Costs

Administrative cost components reflect costs incurred by the both the ISO and the PTOs for scheduling, system control, and dispatch service of the transmission system and to bill and collect for NESCOE’s operating budget. Administrative costs are based on regulated, revenue requirements of the ISO, local control centers (LCCs) (operated by PTOs), and NESCOE. ISO dispatch and control costs reflect only Schedule 1 (and not Schedules 2 and 3) of the ISO Self-Funding Tariff.¹⁷ The [Appendix](#) provides further background on each of these components and the calculation of their costs.

Figure 4-1 and Table 4-1 show administrative costs by type for 2005 to 2009.

¹⁷ ISO costs for providing scheduling, dispatch, and control service are recovered through the ISO SFT, Schedule 1, using RNL as an allocator. Other aspects of ISO cost recovery take place through ISO SFT Schedules 2 and 3, are collected in other areas of ISO operations, and not reported here because they are allocated through other (non-RNL) mechanisms. PTO dispatch and control costs stem from the OATT Schedule 1, Scheduling, Dispatch and Control Service, and are recovered through the OATT using RNL as an allocator. As the billing and collection agent for NESCOE, the ISO collects ISO Schedule 5 NESCOE payments and distributes these payments to NESCOE. Charges are based on RNL for any transmission customer that is using RNS.

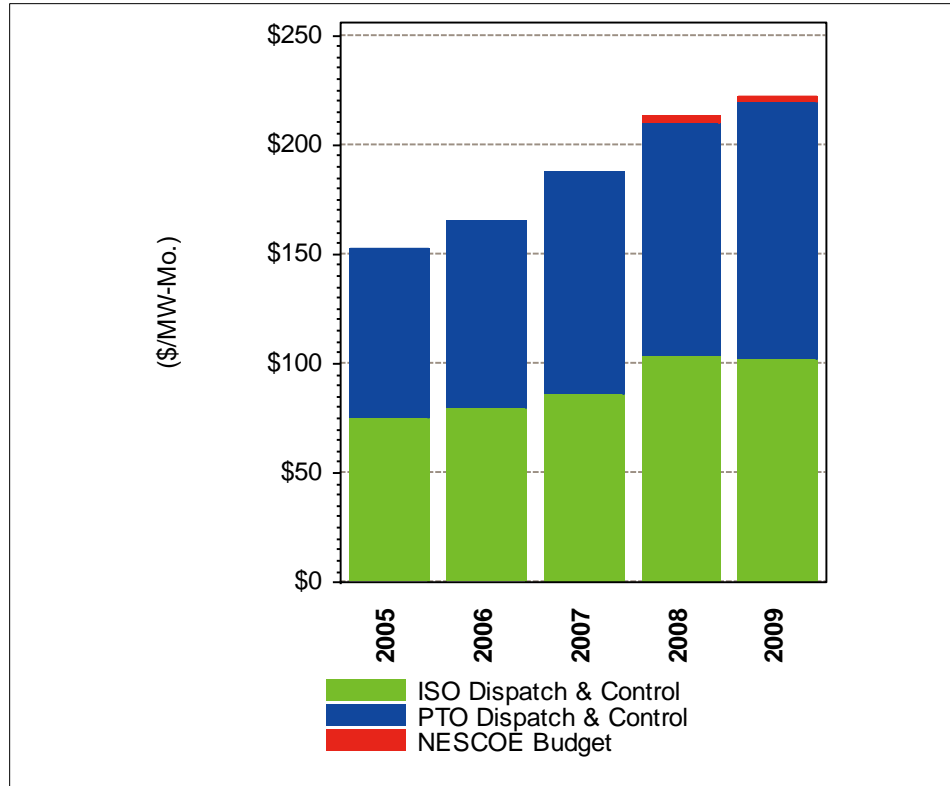


Figure 4-1: Administrative costs by type, 2005 to 2009.

Table 4-1
Administrative Costs by Type, 2005 to 2009 (\$/MW-Month).

Component	2005	2006	2007	2008	2009
PTO dispatch and control	77.61	84.87	101.75	105.44	117.08
ISO dispatch and control	74.77	79.86	85.75	103.89	101.98
NESCOE budget	0.00	0.00	0.00	3.54	2.63
Total	152.38	164.73	187.50	212.87	221.69

Section 5 Regional Network Load, 2005 to 2009

As defined in the OATT, a transmission customer's monthly RNL is based on monthly peak demand and determines the customer's use of RNS. A transmission customer's monthly RNL value (i.e., monthly network load) is the customer's hourly load at the time of the hourly peak load of the local transmission network to which the customer's load is connected.

Each PTO in New England that has a local network RNS rate calculates monthly RNL values, which it submits to the ISO. The ISO uses these values in the RNS-related settlement processes. Customers with RNL may or may not participate in the wholesale electric energy markets, depending on the way in which they do business in New England.

A *RNL customer* is a transmission customer that a PTO has identified as the billable entity for one or more of the RNL “assets” in its local network. These assets are entities modeled in the ISO’s RNS settlement process for calculating RNS settlements. They reflect one or more actual physical load facilities. The RNL cost components discussed in this report (and listed on Table 1-2) reflect the services for which these customers are charged for their assigned share of RNL. Among the eight local networks with RNS rates, approximately 80 RNL customers own approximately 130 network load assets. These assets are distinct from the assets identified in other wholesale market settlements such as for energy.

5.1 Average Regional Network Load by Year, 2005 to 2009

Figure 5-1 shows average monthly regional network load by year for the entire New England Balancing Authority Area for 2005 to 2009.

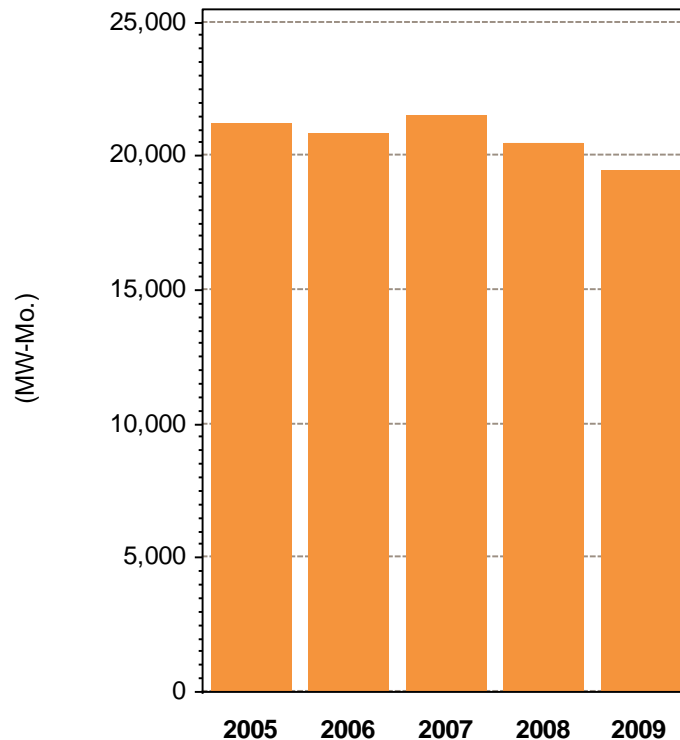


Figure 5-1: Average monthly regional network load, 2005 to 2009.

Since RNL reflects peak monthly demand usage, monthly aggregations of RNL appear more volatile during the highest demand months of the year, typically during the summer months, and within local networks or reliability regions serving a larger customer load base.

5.2 Monthly Regional Network Load by Reliability Region, 2005 to 2009

Figure 5-2 shows monthly network load aggregated by reliability region for 2005 to 2009.

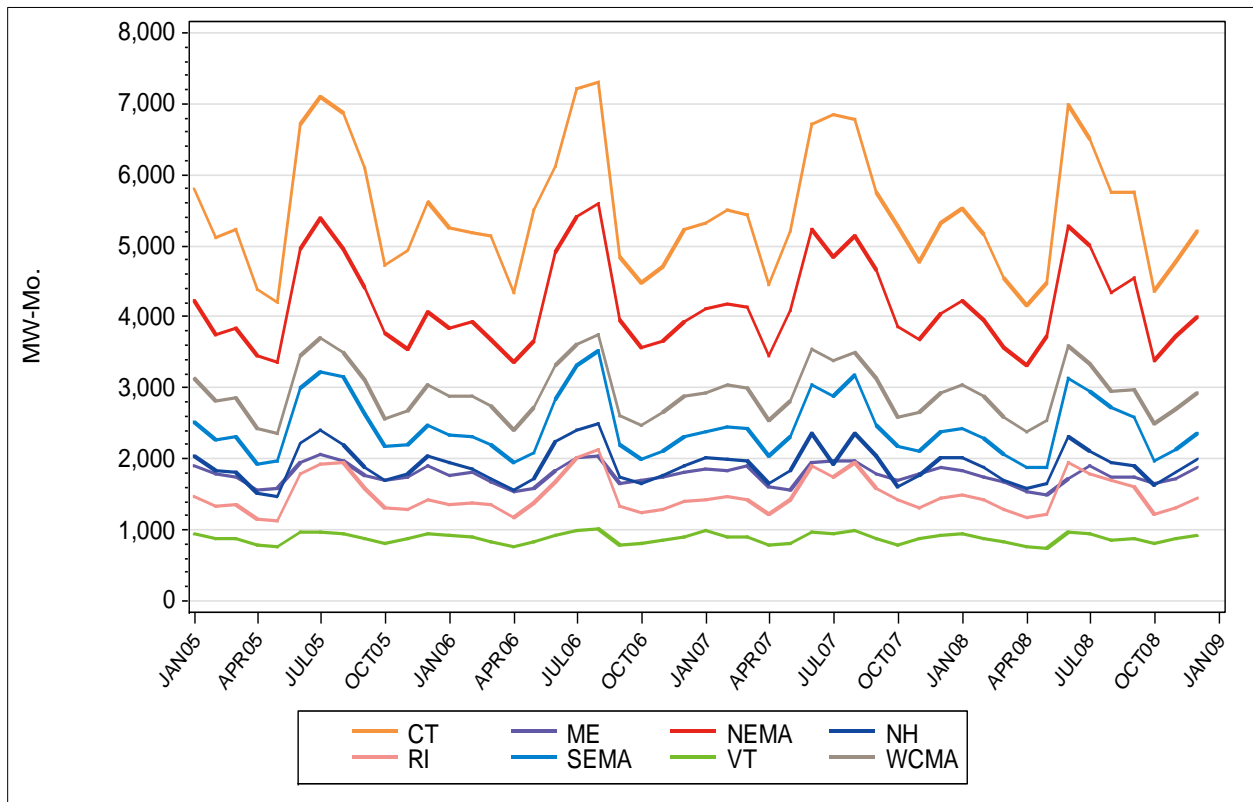


Figure 5-2: Monthly network load by reliability region, 2005 to 2009.

5.3 Monthly Regional Network Load by Regional Network, 2005 to 2009

Figure 5-3 shows monthly network load by local network, as reported by PTOs for 2005 to 2009. The February 2007 merger of the BE and CES local networks into the NSTAR local network is reflected (see Table 1-1).

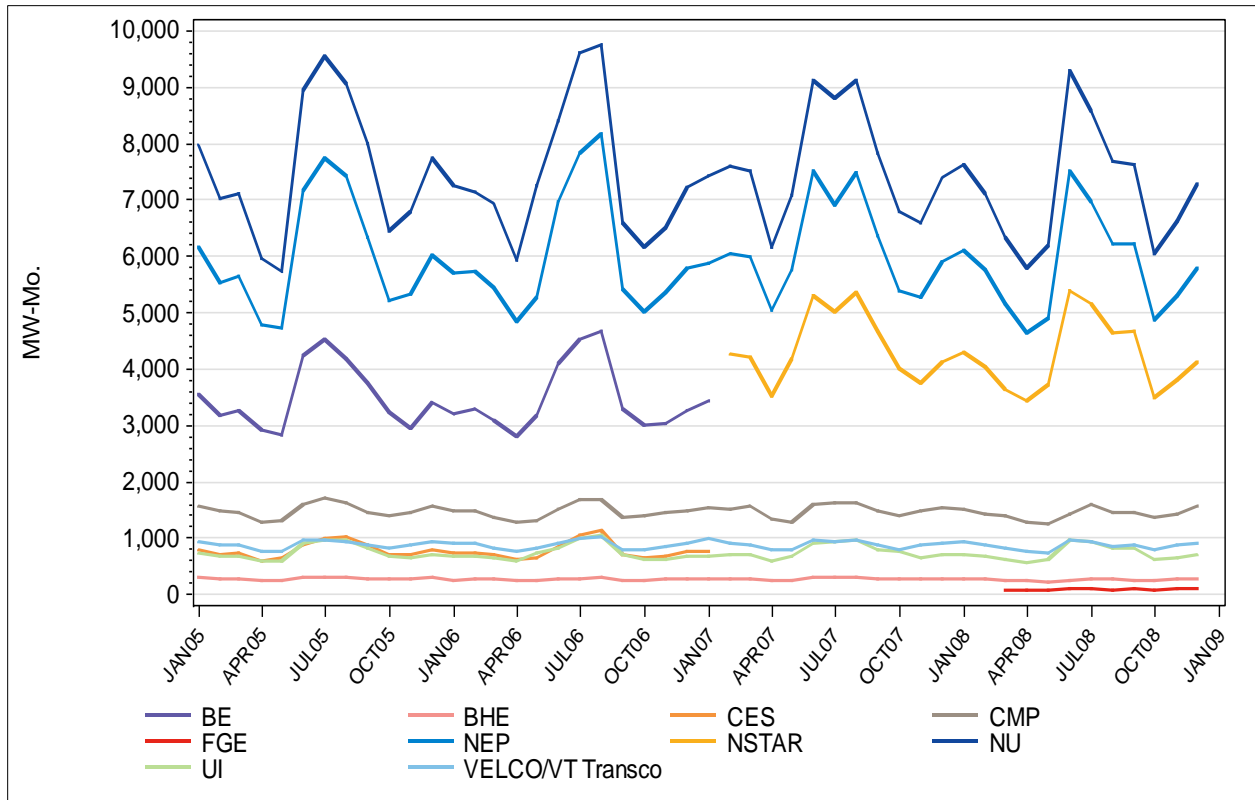


Figure 5-3: Monthly network load by local network, 2005 to 2009.

Section 6 Appendix

The descriptions included in this appendix provide an overview of the concepts contained in the report. The full definitions and processes associated with the listed terms and concepts are included in the tariff and the ISO’s operating procedures.¹⁸

6.1 Description of Concepts

This section describes the concepts discussed throughout the report. Some of the concepts are *calculated components*, meaning they involve a regulated ratemaking process, while others are deemed *allocated components*, which generally are charged proportionately using RNL as an allocator. The RNL cost categories—infrastructure costs [I], reliability costs [R], and administrative costs [A]—are provided for each component’s description.

6.1.1 Calculated Components

Calculated components involve a regulated ratemaking process and are based on revenue requirements of the individual PTOs or the ISO.

¹⁸ Definitions of terms and concepts in the tariff are available at http://www.iso-ne.com/regulatory/tariff/sect_1/index.html. ISO New England Operating Procedures (2010) are available at http://www.iso-ne.com/rules_proceeds/operating/index.html.

6.1.1.1 PTO Dispatch and Control (ISO OATT Schedule 1—Scheduling, System Control and Dispatch Service) [A]

Schedule 1 of the OATT recovers the scheduling, system control, and dispatch service costs the PTOs incur when operating LCC dispatch centers or otherwise scheduling the movement of power through, out of, within, or into the New England Balancing Authority Area. The PTOs calculate charges annually for each transmission customer that is using RNS based on RNL and the Schedule 1-approved rate (\$/kW-month), which is effective June 1 through May 31. The values shown in this report are based on a single FERC-filed formula rate.

More information on this topic is available in the [ISO New England OATT, Section II](#), Schedule 1 and Section II.B, as well as the [Understanding the Bill](#) portion of the ISO Web site.

6.1.1.2 Infrastructure Costs (ISO OATT Schedule 9—Regional Network Service) [I]

This is the major component for the recovery of costs the PTOs incur for supplying regional transmission service to those transmission customers who take RNS and serve a RNL in the New England Balancing Authority Area. Charges are calculated based on the RNL for any transmission customer and the RNS rate, which includes the pre-'97 and post-'96 components, determined annually and effective June 1 through May 31.

Pursuant to FERC's regional RTO orders, the Transmission Operating Agreement, and the ISO tariff, the PTOs are responsible for making annual informational filings with FERC to reflect the updated formula-based RNS rates.¹⁹ Updated rates, typically made effective on June 1 of a given year, are based on PTOs' forecasted revenue requirements (i.e., the product of expected PTF additions and the PTOs' carrying charges reflecting an annual true-up). The annual true-up is the difference between prior year RNS revenue requirements (including forecast) and current year RNS revenue requirements reflecting actual costs. The annual true-up and interest are reflected in the RNS revenue requirements effective for the next rate year.

More information on this topic is available in the [ISO New England OATT, Section II](#), Section II.B, and Schedule 9, as well as the [Understanding the Bill](#) portion of the ISO Web site.

6.1.1.3 ISO Dispatch & Control (ISO SFT Schedule 1—Scheduling, System Control, and Dispatch Service) [A]

Schedule 1 of the *Self-Funding Tariff* is an ancillary service provided by the ISO for scheduling the movement of power through, out of, within, or into the New England Balancing Authority Area. Charges for each transmission customer that is using RNS are calculated in the same way as OATT Schedule 1. The Schedule 1 rate is a FERC-approved rate (\$/kW-month) determined annually by the ISO and effective January 1 through December 31 and based on the ISO's revenue requirements related to their FERC Form 1 filing. The value shown in the report is the FERC-filed rate and does not change by location.

More information on this topic may be found in [Section IV.A of the Self Funding Tariff](#), Schedule 1; and Section II.B, as well as the [Understanding the Bill](#) portion of the ISO Web site.

¹⁹ A *formula rate* is a fixed method for calculating a rate based on set inputs. The charges to customer update annually, data input comes from public sources (Form 1), and recalculation of the charges is done pursuant to a set of protocols.

6.1.1.4 NESCOE Budget (ISO SFT Schedule 5—New England States’ Committee on Electricity (NESCOE)) [A]

The Schedule 5 rate is a FERC-approved rate determined annually and effective January 1 through December 31. The rate shown in this report is the \$/MW-month equivalent of the FERC-filed rate. The ISO SFT Schedule 5 rate for 2009 was \$2.63/MW-month, the rate contained in this report.

More information on this topic is available in Schedule 5 NESCOE, located in [Section IV.A of the Self Funding Tariff](#), as well as the [Understanding the Bill](#) portion of the ISO Web site.

6.1.2 Allocated Components

Allocated components generally are charged proportionately, using RNL as an allocator. That is, charges are derived by dividing the total payments for the respective service by the applicable level of RNL.

6.1.2.1 VAR (ISO OATT Schedule 2—Voltage Ampere Reactive) [R]

The fixed payments for VAR capacity costs (CC) are determined based on an asset’s qualified leading and lagging VARs and the applicable VAR CC rate for the capability to provide VAR service. ‘Leading’ and ‘lagging’ refer to the physical ability of the asset to supply reactive power, and is related to the phase angle difference between voltage and current.

The variable payments include the following:

- Lost opportunity cost (LOC)—payment for generators that are dispatched down by, or at the request of, the ISO, or a LCC for providing VAR service.
- Cost of energy consumed (CEC)—payment associated with hydroelectric and pumped storage generating units that are motoring at the request of the ISO or a LCC for providing VAR service.
- Cost of energy produced (CEP)—payment that compensates a hydro, pumped storage, or thermal generating unit if the ISO or a LCC brings the unit on line (and the unit produces real power) for providing VAR service (whether for voltage support or high-voltage control).

For the purpose of compensation, each unit providing VAR service is determined to be providing either voltage support or high-voltage control, and the allocation of their costs is determined as follows:

- *Voltage support:* All VAR payments for voltage support, which does not include high-voltage control, are allocated both to systemwide RNL and to hourly reservations placed for external transactions through the Open-Access Same-Time Information System (OASIS). To remove the effect of hourly reservations on this analysis, payments associated with reservations were removed. Remaining payments were summed for the entire balancing authority area and divided by the balancing authority area-level RNL to derive the \$/MW-month rate for all periods shown.
- *High-voltage control:* VAR payments made to generators for the express purpose of providing high-voltage control are charged to the reliability region that benefited from the service. Payments were summed for each reliability region, and each total was divided by the associated RNL to determine the appropriate \$/MW-month rate for each region. A load-weighting methodology was applied to determine the New England-wide rate.

More information on this topic is available in the [ISO New England OATT](#) and Schedule 2, as well as the

[Understanding the Bill](#) portion of the ISO Web site.

6.1.2.2 System Restoration (ISO OATT Schedule 16 Black Start—System Restoration and Planning Service from Generators) [R]

These generators would assist the ISO in the restoration of the New England Balancing Authority Area after such a blackout. The \$/MW-month rate of compensating resources for providing this service is derived by summing regionwide black-start payments to generators for each month and dividing that total by the New England-level RNL.

More information is available in Schedule 16 of the [ISO New England OATT](#), as well as the [Understanding the Bill](#) portion of the ISO Web site.

6.1.2.3 Demand-Response Programs [R]

Demand-response programs compensate demand resources that reduce electricity demand during various hours of the year to provide relief from capacity constraints and promote the more economically efficient use of electrical energy.²⁰

- *Demand-Response Reserve Pilot Program availability and DRRP OP 4 Electric Energy:* The DRRP program begun in 2005 and completed in June 2010, was implemented to determine whether small generation and demand-response resources less than 5 MW could provide a functionally equivalent reserves product to traditional resources.

Availability payments were made to DRRP resources based on pledged capability and Forward Reserve Auction prices.²¹ Charges were allocated proportionately based on each customer's share of the aggregate charges under Schedules 1, 2, and 3 of the ISO *Self-Funding Tariff*, of which only Schedule 1 charges were in any way allocated to network load. To determine the portion of DRRP availability payments associated with RNL, the hourly payment rates were first summed over the relevant period and multiplied by the ratio of Schedule 1 charges (effects of collection for through and out transactions removed) to total Schedule 1, 2 and 3 charges. This amount was then divided by the RNL for the entire balancing authority to determine the \$/MW-month rate over the relevant period.

OP 4 real-time electric energy payments compensated the DRRP resources for conducting appropriate actions during the activation of ISO Operating Procedure No. 4, or during an audit of resource performance. These payments were allocated to systemwide network load. Therefore, total costs over the relevant period were divided by the RNL for the entire balancing authority to derive the \$/MW-month rate reported in Section 3 of this report.

- *Demand Response Winter Supplemental Program:* The costs of this historical program, begun in December 2005 and terminated in April 2006, were allocated to the RNL for the entire balancing authority area. The appropriate \$/MW-month value presented in this report (see Section 3) was

²⁰ A *demand resource* is a source of capacity whereby a consumer reduces the demand for electricity from the power system in response to a request from the ISO to do so for system reliability reasons or in response to a price signal. *Demand response* is when market participants reduce their consumption of electric energy from the network in exchange for compensation based on wholesale market prices. *Other demand resources* (ODRs) are demand-side resources, such as energy efficiency, load management, and distributed generation at a retail customer's site, that are outside the ISO's control but that reduce demand by at least 100 kW; participate as capacity resources in the New England Balancing Authority Area; and are subject to ISO measurement, verification, and review procedures to demonstrate their total amount of demand reduction.

²¹ Refer to AMR09 for additional information on the Forward Reserves Market.

derived by dividing total program payments by the RNL for the entire balancing authority area for the period.

- *Demand Response Supplemental Southwest Connecticut Request for Proposal:* The costs of this historical program, begun in August 2006 and terminated in June 2008, were allocated to RNL in the Connecticut Reliability Region. The appropriate \$/MW-month value presented in this report was derived by dividing total program payments by the Connecticut RNL over the relevant period. More information on this topic is available at the [RFP Webpage](#).
- *Load-Response Program:* Before and during the 2005 to 2009 period, the ISO operated three real-time, reliability-activated demand-response programs and two price-activated (voluntary) demand-response programs—one based on day-ahead locational marginal prices (LMPs) and one based on forecasted real-time LMPs. Effective June 1, 2010, the three reliability-activated programs terminated, and only the two price-activated programs continue. Each transmission customer with RNL receives a proportional share of the costs of load-response programs. These costs were divided by RNL for the entire balancing authority area to derive the \$/MW-month rate shown in this report (see Section 3). More information on this topic is available in [Market Rule 1](#), Appendix E.

6.1.2.4 Reliability Agreements [R]

The Reliability Agreements in effect through June 2010 in New England are for full cost of service—the generator recovers its fixed costs in a monthly payment and its variable costs through electric energy offers made at short-run marginal cost. Variable costs not covered by energy market revenues are compensated through daily reliability payments. All capacity market revenues and energy market revenues received in excess of variable costs serve to reduce the monthly fixed-cost payment. Thus, the generator recovers no more than its fixed and variable costs.

6.2 Monthly Network Load Cost Report

The *Monthly Network Load Cost Report* provides a 13-month perspective of RNL costs.²² That report will reflect the same categorical grouping of component reported here.

²² The *Monthly Network Load Cost Report* is available at: http://www.iso-ne.com/markets/mkt_anlys_rpts/regnl_ntwrk_cost/index.html.

Document History

Date	Version	Description
10/25/2010	Original Posting	