Historical Regional Network Load Cost Report, 2008 to 2012

Market Analysis and Settlements

June 12, 2013

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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 New England's electric power generation and transmission system; 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 the costs of serving the region's wholesale load, which include energy, capacity, and ancillary market charges and are estimated and analyzed in $/megawatt-hour (MWh) of electric load, are reported in the ISO's *Wholesale Load Cost Report*.[2] The smaller portion of the costs, reported here, are associated with the provision of *regional network service* (RNS) and other services to transmission customers 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).[3] The RNL is the customer's hourly load at the time of the peak load of its local transmission network. The aggregate of these costs generally are referred to as "OATT costs" or "RNL costs" and are charged by $/megawatt (MW)-month.

In response to requests from 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 now publishes this annual *Historical Regional Network Load Cost Report.* This year's report provides historical average costs ($/MW-month) under the OATT for serving regional network load in the New England wholesale markets for 2008 to 2012.[4] This report also provides the historical basis for the *Monthly Regional Network Load Cost Report*, which provides rolling 13-month data for these costs.[5]

1.1 Regional Network Load Cost Categories

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

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[1] The *ISO New England Transmission, Markets, and Services Tariff* (2012), 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] The *Wholesale Load Cost Report* is available at http://www.iso-ne.com/markets/mkt_anlys_rpts/whlse_load/index.html.

[3] The OATT provides the terms and conditions for 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. The OATT defines *network load* 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 7) describes specific components that fall within each of these cost categorizes.

1.2 Summary of Regional Network Load Costs, 2008 to 2012

Data from 2008 to 2012 show that RNL costs, while representing a relatively small portion of total wholesale costs, have increased from $4,183/MW-month in 2008 to $6,452/MW-month in 2012. This increase has caused RNL costs as a relative proportion of total wholesale load-serving costs to grow from approximately 7.7% in 2008 to about 21.3% of total wholesale costs in 2012. This increase also reflects a 11.4% compound growth rate of the total charges to network load over the five-year period. This growth rate varied among the following RNL cost categories:

- ***Infrastructure*** costs averaged $5,913/MW-month during 2012, reflecting a compound growth rate of 17.1% over the five-year period from their 2008 average of $3,140/MW-month. In response to identified transmission system inadequacies, New England's transmission owners have invested $4.3 billion in the system from 2008 to 2012, resulting in a more robust transmission system and a marked decrease in reliability costs. The infrastructure costs during

[6] PTFs are certain transmission lines (69 kilovolts [kV] or greater) and associated equipment over which ISO New England has operational control. During 2007 to 2011, these facilities were owned and maintained by approximately 20 participating transmission owners (PTOs). PTFs do not include those lines and facilities that serve local load only, are generator leads (i.e., radial transmission from a generator bus to the nearest point on the PTF), or are either Merchant Transmission Facilities or Other Transmission Facilities. The ISO reviews the status of transmission lines and associated 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.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. Reliability Agreements expired at the start of the Forward Capacity Market (FCM) on June 1, 2010; any further need to retain units in the region for reliability is addressed under FCM market rules. Refer to the ISO's *2011 Annual Markets Report* (AMR11) 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 companies that own or support the PTFs in the New England Balancing Authority Area and are eligible to submit revenue requirements to recover the costs. Of the PTOs that supported a portion of the PTFs during 2008 to 2012, approximately 20 both owned and operated facilities in the local networks in 2012. Just eight PTOs currently 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 by NERC as control areas. Further information is available in the NERC glossary; http://www.nerc.com/files/Glossary_of_Terms_2012January11.pdf.

2012 were approximately 92% of total RNL costs and 19.5% of overall wholesale load-serving costs.

- ***Reliability*** costs declined over the period at a compound rate of 25.4% per year, from \$830/MW-month during 2008 to \$256/MW-month during 2012. This decline is attributable to reductions in reliability costs associated with Reliability Agreements, voltage support, and a terminated demand-response program in southwestern Connecticut.[9] Reliability Agreement costs declined from \$508/MW-month (a total of \$125 million in charges) during 2008 to zero during 2011, after the 2010 phase out of Reliability Agreements.
- ***Administrative*** costs, which grew at a 7.4% compound rate over the period, were only 4.4% of the total costs billed through the OATT and approximately 0.9% of overall wholesale load-serving costs during 2012.

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.[10] The New England Balancing Authority Area is divided into eight reliability regions that have local networks with RNS rates. In general, many 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. 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 2008 to 2012.

[9] *Demand response* is when market participants reduce their consumption of electric energy from the network in exchange for compensation based on wholesale market prices.

[10] *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." *"Through-or-out service,"* is the delivery of electricity over the PTFs through or from New England to another balancing authority area. This report removes the effect of through-or-out transactions on costs. It also 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 Networks and Transmission Owners Operating within New England's Reliability Regions

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)	NEP NSTAR[(c)]
Rhode Island (RI)	NEP
Southeastern Massachusetts (SEMA)	NEP NSTAR
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 or state jurisdiction.

(b) The NEP local network includes the National Grid USA companies 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 7) 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 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 bills.

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 Resources retained for reliability (RFR) in the Forward Capacity Market (FCM) Voltage support High-voltage control System restoration 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 (OP 4), *Action during a Capacity Deficiency*, http://www.iso-ne.com/rules_proceds/operating/isone/op4/index.html.

(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
Total RNL Costs

Total wholesale load costs include RNL costs, reported here, as well as various other wholesale load costs, including energy and capacity charges, , as discussed in Section 1. RNL costs are the smaller portion of total wholesale load costs. Table 2-1 shows RNL costs as a percentage of the cost of serving load in New England from 2008 to 2012. The primary factors affecting the costs are the decline in input fuel prices and the relative flat demand in the energy market.

Table 2-1
Total RNL Costs as a Percentage of Total Wholesale Load Costs, 2008 to 2012

Year	Total RNL Costs ($)	Wholesale Load Costs ($)	Total Wholesale Load Costs ($)	RNL % of Total
2008	1,025,538,439	12,355,901,734	13,381,440,172	7.7%
2009	1,218,514,168	6,839,986,085	8,058,500,253	15.1%
2010	1,466,433,840	8,133,722,567	9,600,156,407	15.3%
2011	1,407,148,359	7,233,272,644	8,640,421,002	16.3%
2012	1,563,140,620	5,792,577,640	7,355,718,260	21.3%

Figure 2-1 and Table 2-2 show RNL costs by major category for 2008 to 2012. Each category is analyzed separately in subsequent sections of this report.

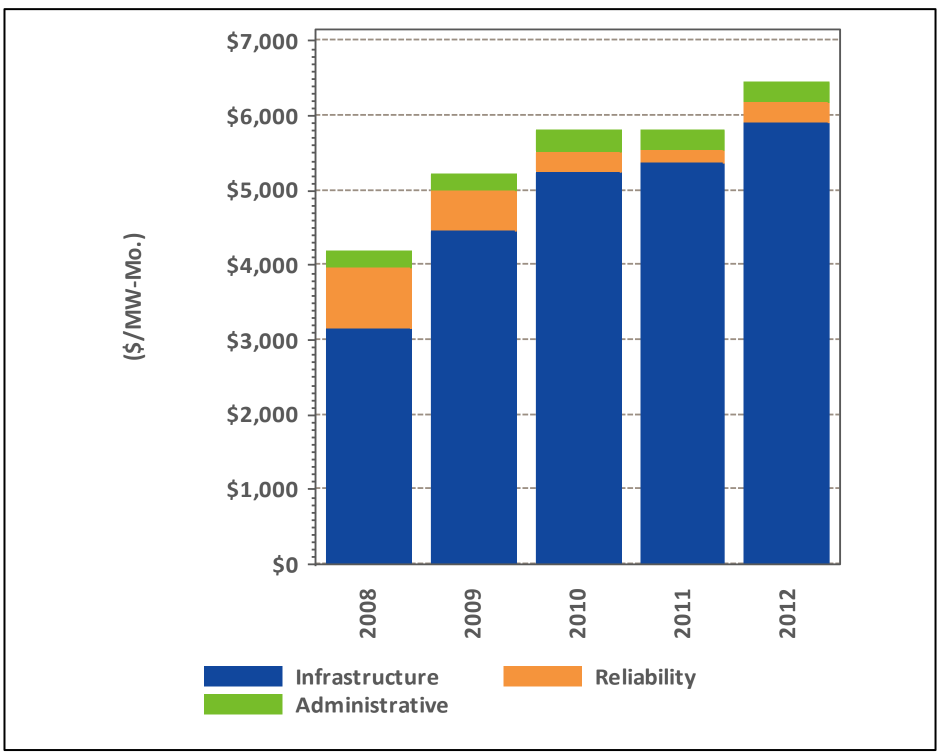

Figure 2-1: RNL costs by major category, 2008 to 2012.

Table 2-2
RNL Costs by Major Category, 2008 to 2012 ($/MW-Month)

Major Category	2008	2009	2010	2011	2012
Infrastructure	3,140	4,453	5,249	5,354	5,913
Reliability	830	544	266	192	256
Administrative	213	222	280	265	283
Total RNL Costs	4,183	5,219	5,795	5,811	6,452

Section 3
Infrastructure Costs

The infrastructure category of RNL costs reflects the rates charged through the tariff for the transmission owners' recovery of their investments in PTF infrastructure 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. The PTOs develop the transmission rates, which currently are based on the PTF revenue requirements of the prior and current years and network load levels among the various local networks (see Section 3.2).

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.[11] 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. 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)**:[12] 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 purposes, 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.

3.1 Infrastructure Investments, 2008 to 2012

Investments in the PTFs result in transmission upgrades that increase transmission reliability. Table 3-1 shows PTF investments (both total plant balance and incremental additions) made by the PTOs eligible for cost recovery under the post-96 infrastructure rate for 2008 to 2012. These investment costs are reflected in the recent growth in the post-'96 RNS rate (see Section 3.2).

[11] See FERC Order 888 regarding FERC directives to provide "nonpancaked" rates; http://www.ferc.gov/legal/maj-ord-reg/land-docs/order888.asp.

[12] Schedule 9 of the ISO OATT is available at http://www.iso-ne.com/regulatory/tariff/sect_2/oatt/index.html.

Table 3-1
Pool Transmission Facilities Investments, 2008 to 2012 ($ Millions)

Year	Total	Incremental Additions
2008	5,761	2,002
2009	6,238	477
2010	6,667	429
2011	7,038	371
2012	8,054	1,016

Details on the transmission investment projects put into service in recent years are summarized in the ISO's *2012 Regional System Plan*.[13]

3.2 Infrastructure Costs, 2008 to 2012

In their revenue requirements, the PTOs reflect both the costs associated with their PTF investments from the prior year and the forecast of costs for the current year. These PTF revenue requirements may reflect return on investment, income taxes, depreciation, tax, operation, support, and other expenses, the largest of which typically is return on investment. While the relationship between PTF investment and post-'96 RNS rates has not been directly proportional, PTF investments made between 2008 and 2012 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 3-1 and Table 3-2 show the average monthly infrastructure costs for both the pre-'97 and post-'96 components for 2008 to 2012. The pre-'97cost component grew at a 0.7% average annual rate from 2008 to 2012. In contrast, the post-'96 cost component grew at a 24.1% average annual rate because of increased investments to the infrastructure, as previously discussed. The pre-'97 cost component, which grew by an average of 4.4% per year between 2008 and 2010, declined by 5.7% in 2011, primarily due to a decrease in pre-'97 PTF revenue requirements.

[13] *2013 Regional System Plan* (October 21, 2012); http://www.iso-ne.com/trans/rsp/2012/index.html.

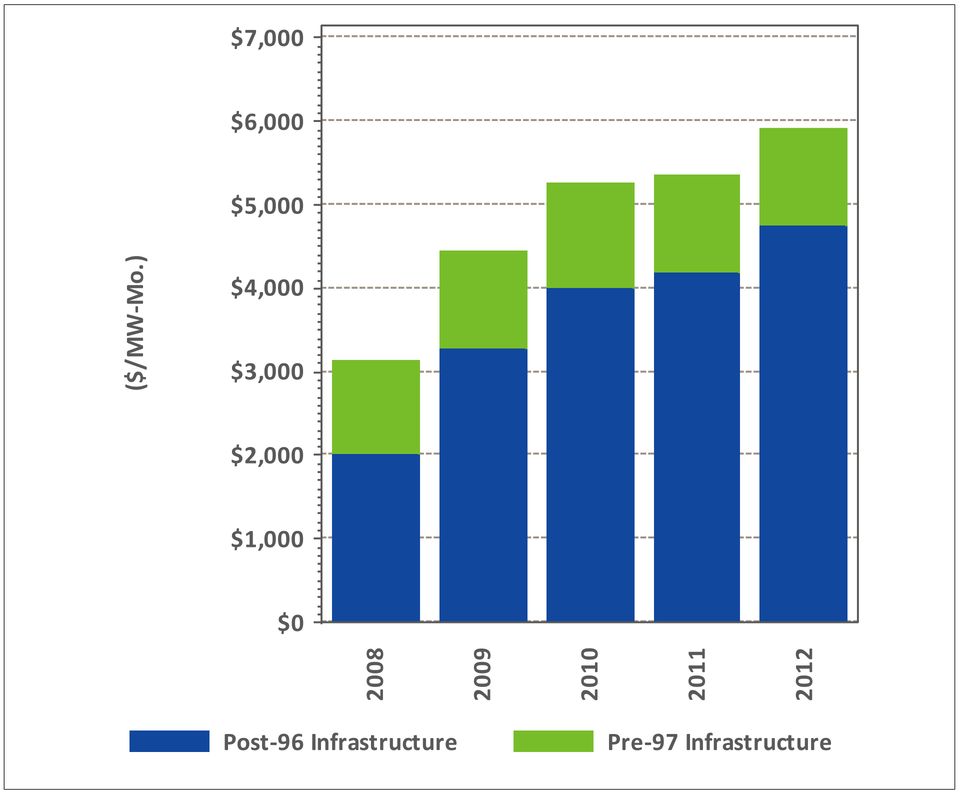

Figure 3-1: Infrastructure costs by component, 2008 to 2012.

Table 3-2
Infrastructure Costs by Component, 2008 to 2012 ($/MW-Month)

Component	2008	2009	2010	2011	2012
Pre-'97 infrastructure costs	1,140	1,188	1,241	1,171	1,172
Post-'96 infrastructure costs	2,000	3,265	4,008	4,183	4,741
Total	3,140	4,453	5,249	5,354	5,913

PTOs typically make a multiple-year forecast of PTF additions (investments), PTO revenue requirements, and RNS rates.[14] Such forecasts are meant to be indicative, are subject to change, and are not included here.

3.3 Pre-'97 Infrastructure Costs (Rates) by Local Network, 2008 to 2012

Figure 3-2 shows pre-'97 infrastructure costs (rates as filed with FERC) for each local network for 2008 to 2012. The exhibit illustrates the transition of this rate into a unified rate across all local networks

[14] PTOs publically post this information each year in the July to August timeframe in the 'Materials' section of the ISO's Transmission Committee website; http://www.iso-ne.com/committees/comm_wkgrps/trans_comm/tariff_comm/index.html.

(completed in 2008). Although not evident in the figure, FGE emerged in March 2008 as the newest local network having an RNS rate.[15] Slight variations in costs among the various local networks that may appear in the chart beginning in 2009 merely reflect the effect of averaging and the nonproportional change in load levels among local networks during the course of the year.

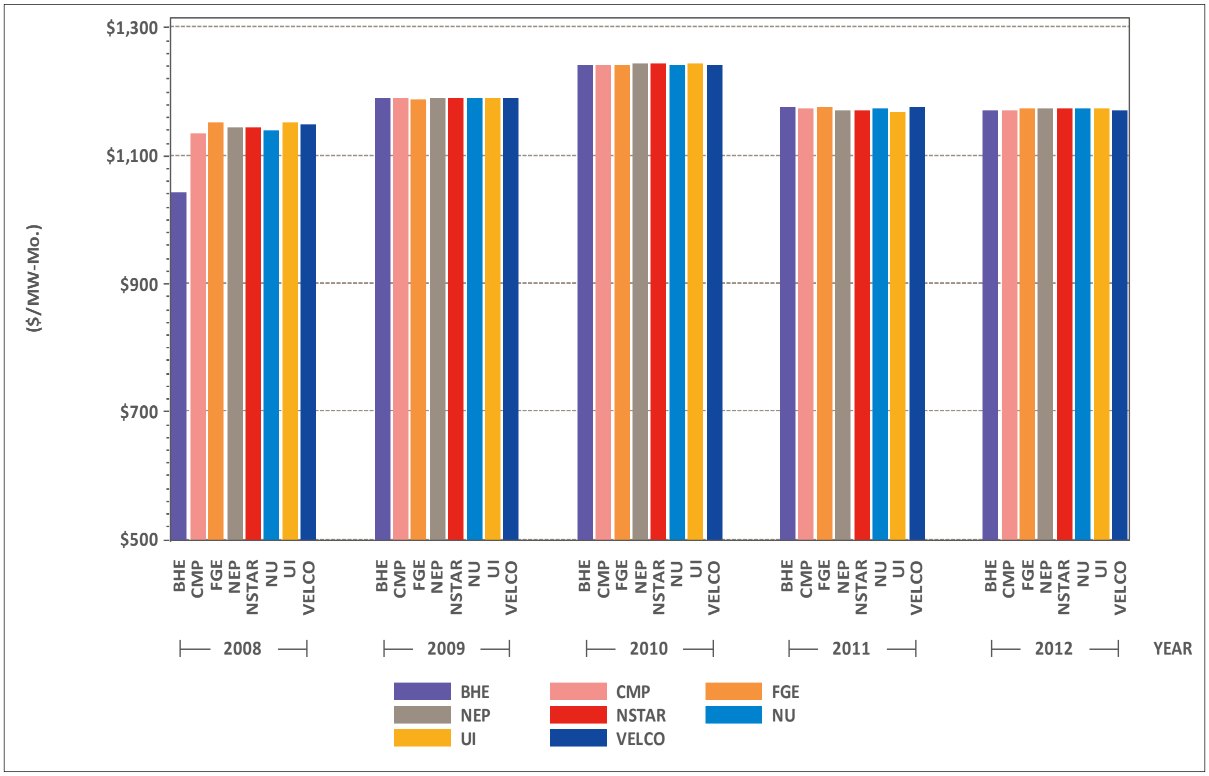

Figure 3-2: Pre-'97 infrastructure costs (rates) by local network, 2008 to 2012.

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15 Before March 2008, FGE recovered its revenue requirements through the NEP local network RNS rate.

Section 4
Reliability Costs

Reliability services charged through the tariff serve to recover the costs of certain reliability programs and services administered through the OATT.[16] The costs (and rates) in this category are developed by dividing total payments for the provided service or program 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.

4.1 Reliability Costs by Type, 2008 to 2012

Both Figure 4-1 and Table 4-1 show reliability costs by type from 2008 to 2012. The notable decline in the overall reliability costs primarily reflects reductions in costs associated with Reliability Agreements, voltage support, and demand response, largely resulting from 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.

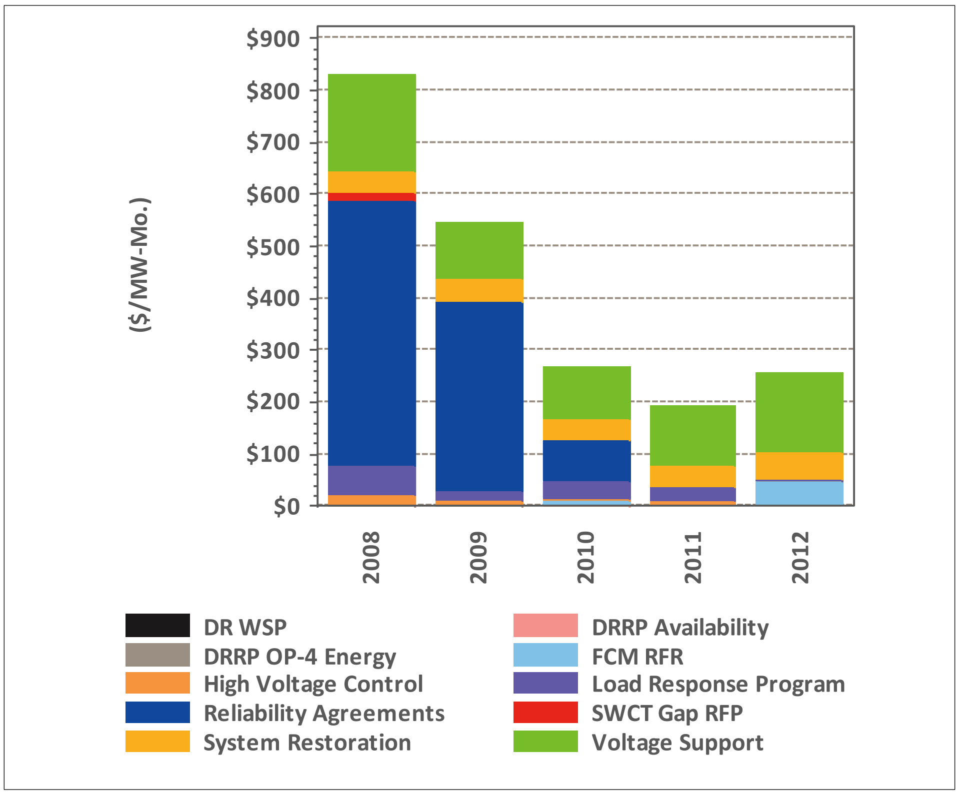

Figure 4-1: Average reliability costs by type, 2008 to 2012.

Note: "DR WSP" stands for Demand Response Winter Supplemental Program. "RFR" stands for "Retained for Reliability".

[16] Not all reliability service costs are recovered through the OATT.

Table 4-1
Average Reliability Costs by Type, 2008 to 2012 ($/MW-Month)

Allocated Concept	2008	2009	2010	2011	2012
DRRP availability	0.71	0.76	0.42	0.00	0.00
DRRP OP 4 energy	0.14	0.17	0.00	0.00	0.00
FCM RFR	0.00	0.00	7.82	5.84	46.90
High-voltage control	20.24	6.05	3.19	1.96	1.36
Load-response program	55.35	21.53	33.15	27.61	2.39
Reliability Agreements	508.49	363.72	79.86	0.00	0.00
SWCT Gap RFP	14.89	0.00	0.00	0.00	0.00
System restoration	41.90	44.75	40.92	41.54	52.35
Voltage support	187.86	107.27	100.79	115.28	153.25
Total	829.57	544.25	266.14	192.23	256.25

The benefits of an improved, more efficient transmission system extend beyond the reduced reliability costs reported here. Additional benefits theoretically could include a lowering of transmission congestion costs (reflected in wholesale market prices for electric energy); the costs paid to less economic generators that provided local-area second-contingency protection (a.k.a., LSCPR resources) to respect system reliability requirements; and potentially, the costs of redispatching the system for providing reserves.

Between 2008 and 2012, congestion costs in New England, collected through the congestion revenue component of locational marginal prices (LMPs), declined from $121 million to $30 million. Over the same period, local-area second-contingency protection costs decreased from $182 million to $18 million.

4.2 Terminated Reliability Cost Types

Table 4-2 shows the termination dates for certain reliability costs no longer in effect.

Table 4-2
Effective Start and End Dates for Certain Regional Network Load Cost Components

Cost Component Short Name	Effective Service Start Date	Effective Service End Date
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, Reliability Agreements expired, and any further need to retain units in the balancing authority area for reliability are addressed under the market rules for the FCM.

4.3 Reliability Costs by Reliability Region, 2008 to 2012

Figure 4-2 shows the aggregated reliability costs of all types by reliability region from 2008 to 2012. Declining costs in CT and WCMA are associated with the planned expiration schedule of Reliability Agreements and are attributable to transmission system improvements. The expirations of the supplemental RFP program for SWCT also contributed to the cost decline in Connecticut. The uptick in reliability charges in the NEMA reliability region in 2012 is associated with generation retained for reliability in the FCM.

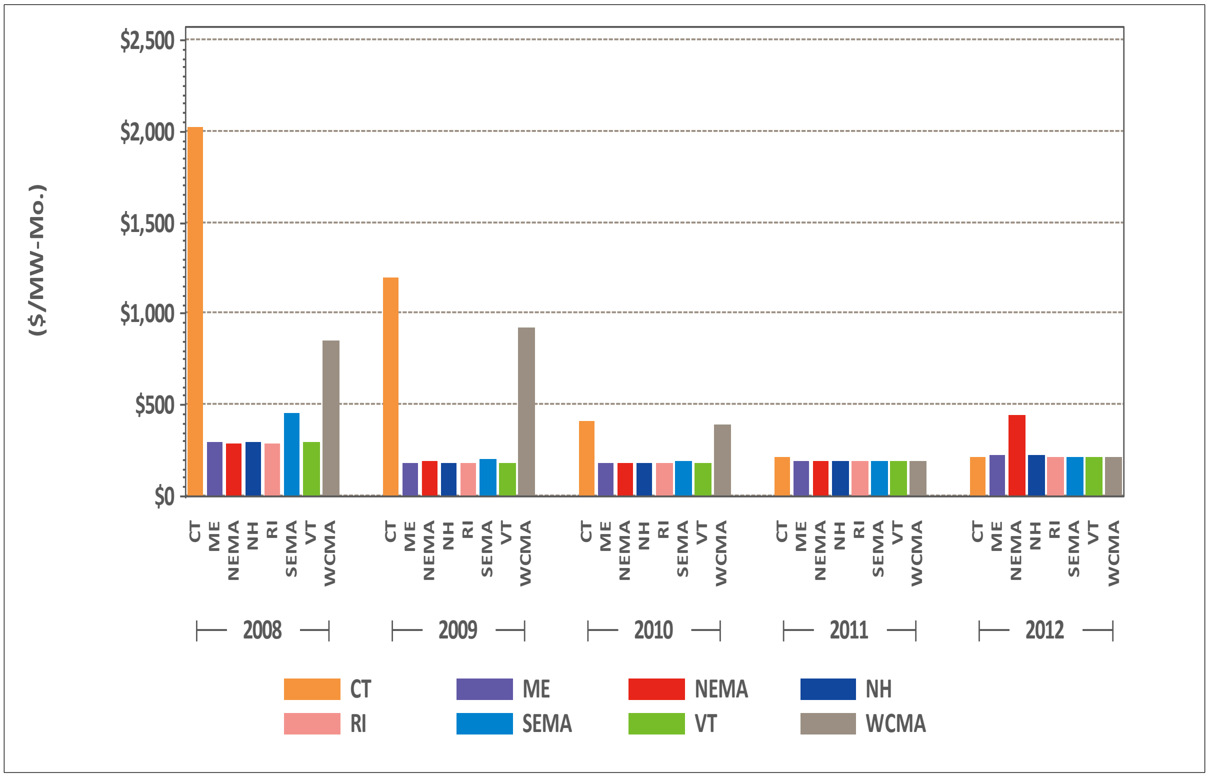

Figure 4-2: Average combined costs for reliability services by reliability region, 2008-2012.

Figure 4-3 shows Reliability Agreement costs by applicable reliability region over the past five years – these costs expired during 2010. The further need to retain units for reliability in the balancing authority area is addressed under the FCM rules.

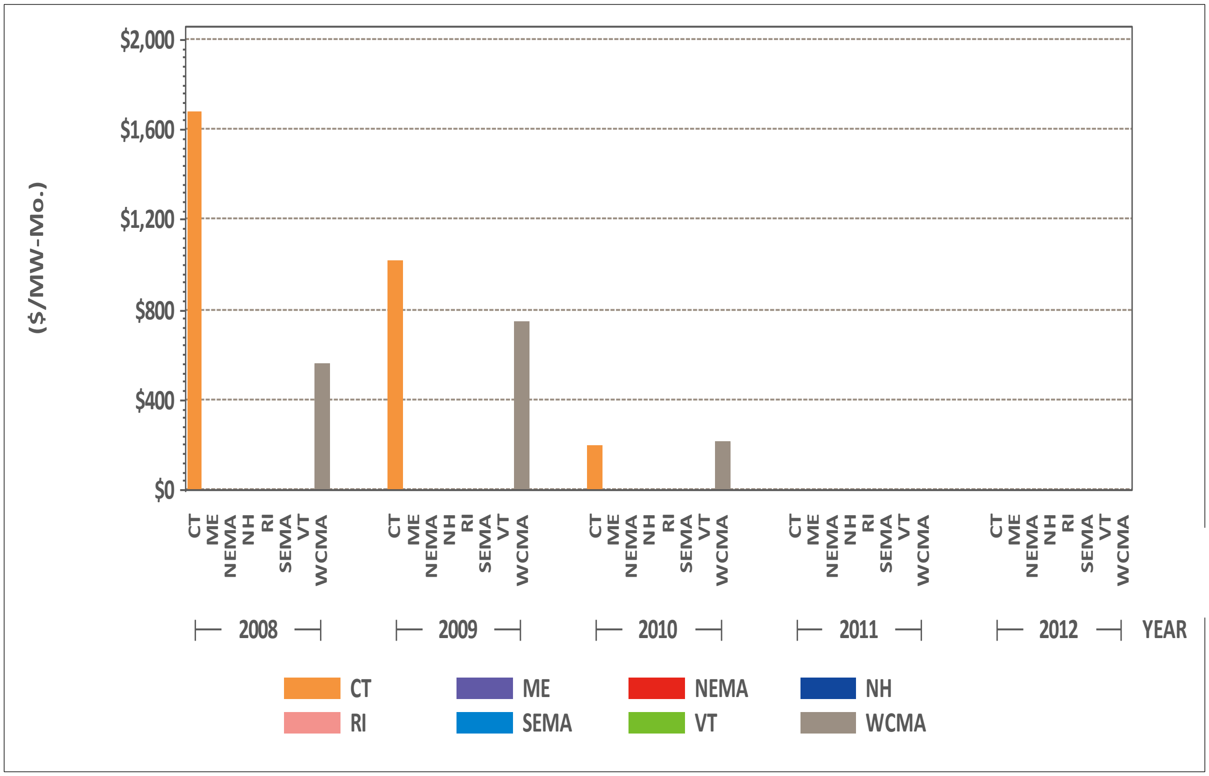

Figure 4-3: Reliability Agreement costs by reliability region and year.

Figure 4-4 shows charges associated with generation retained for reliability in the FCM over the last five years – these costs began during 2010, coincident with the FCM.

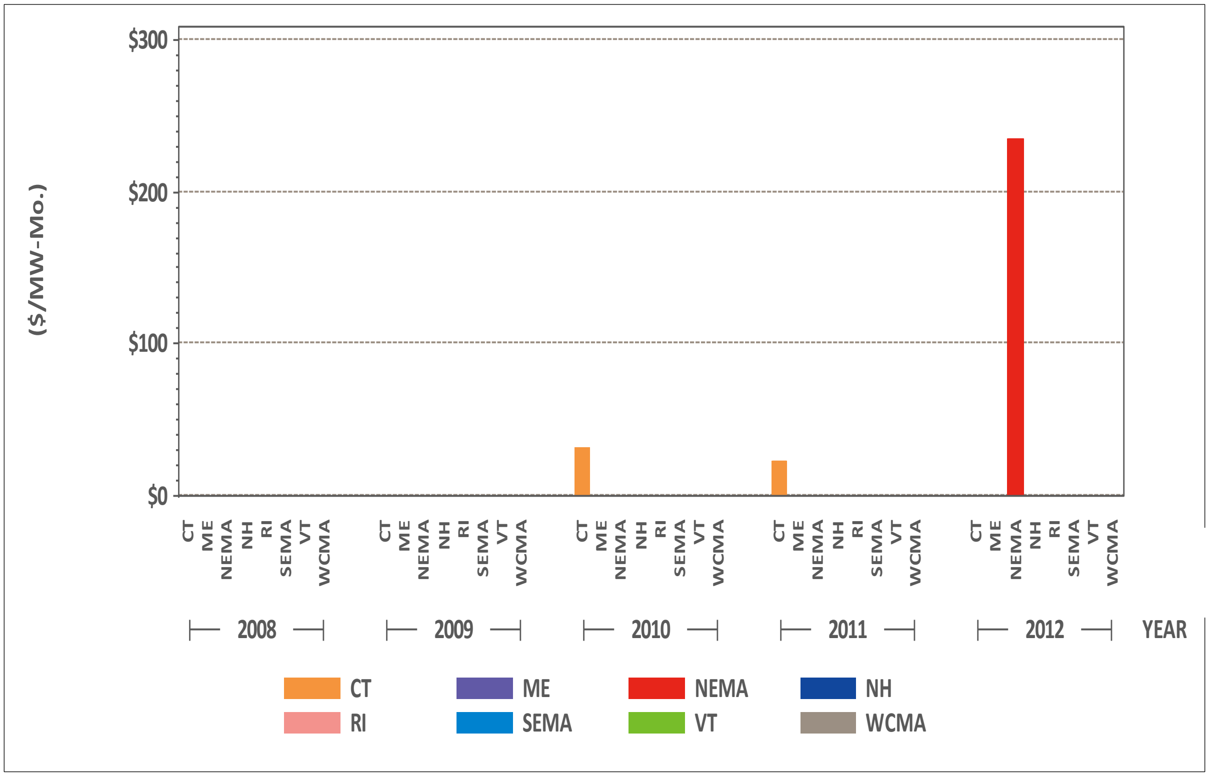

Figure 4-4: FCM reliability charges by reliability region and year.

Figure 4-5 shows average SWCT Gap RFP costs over the past five years. These costs, which were for the benefit of and were exclusive to the Connecticut Reliability Region, were terminated in 2008.

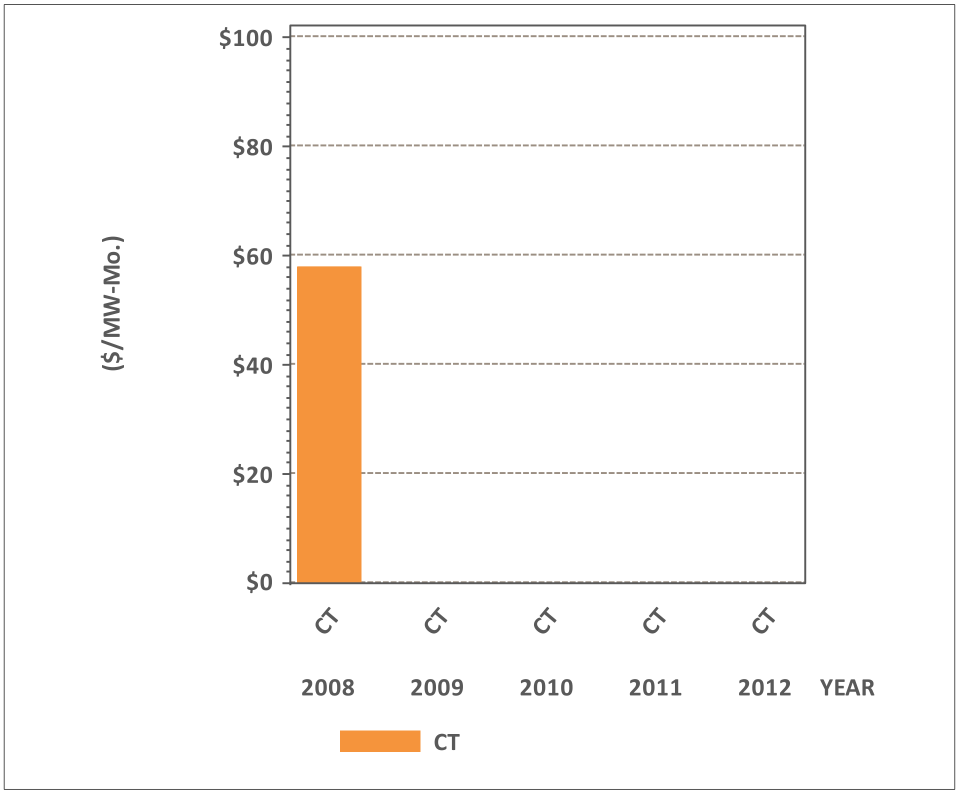

Figure 4-5: Southwest Connecticut Gap RFP costs by year.

4.4 Voltage Support Costs, 2008 to 2012

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. The reactive resources that provide VAR service can 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 was allocated primarily to systemwide RNL. The allocation for voltage support costs remains at the systemwide level. Starting in July 2008, the allocation for high-voltage control shifted from systemwide RNL to RNL within the specifically affected reliability region.

Figure 4-6 shows voltage support costs for 2008 to 2012. Transmission system improvements have helped reduce these reliability costs over the period. The uptick in these costs in 2012 is associated with voltage support needs, primarily in Western Central Massachusetts and Maine, some of which was necessitated by area transmission work.

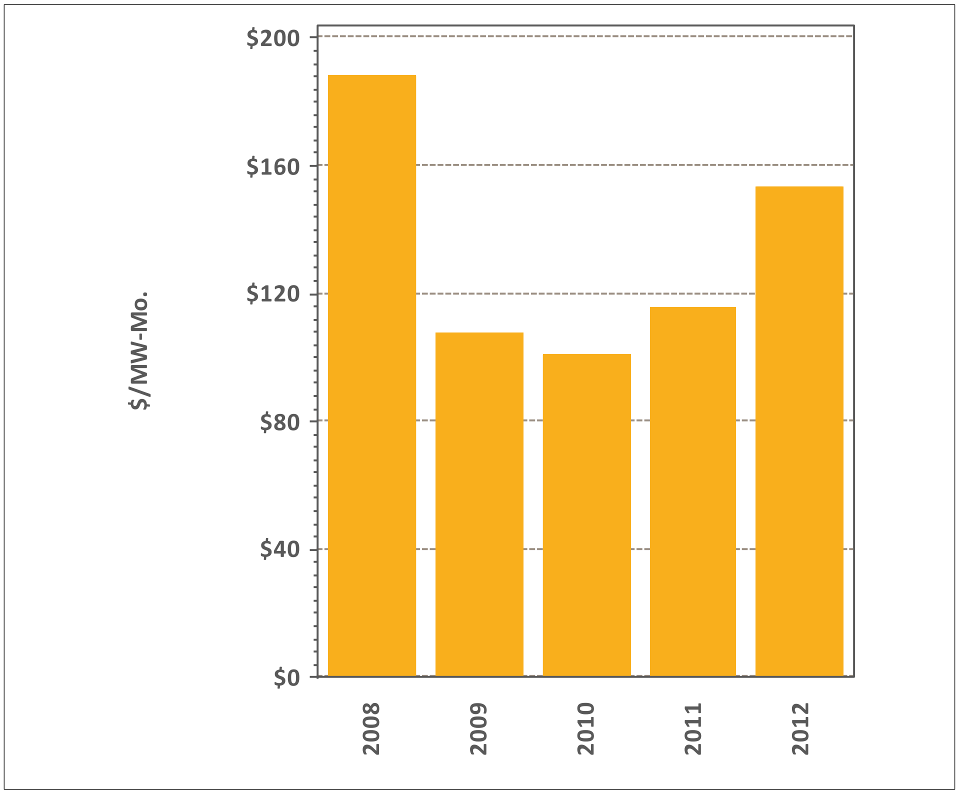

Figure 4-6: Voltage support costs, 2008 to 2012.

4.5 High-Voltage Control Costs by Reliability Region, 2008 to 2012

In 2008, the tariff was changed to allocate the costs of high-voltage control to the reliability region affected and not systemwide. Figure 4-7 shows high-voltage control costs by reliability region for 2008 to 2012. 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 reliability region.

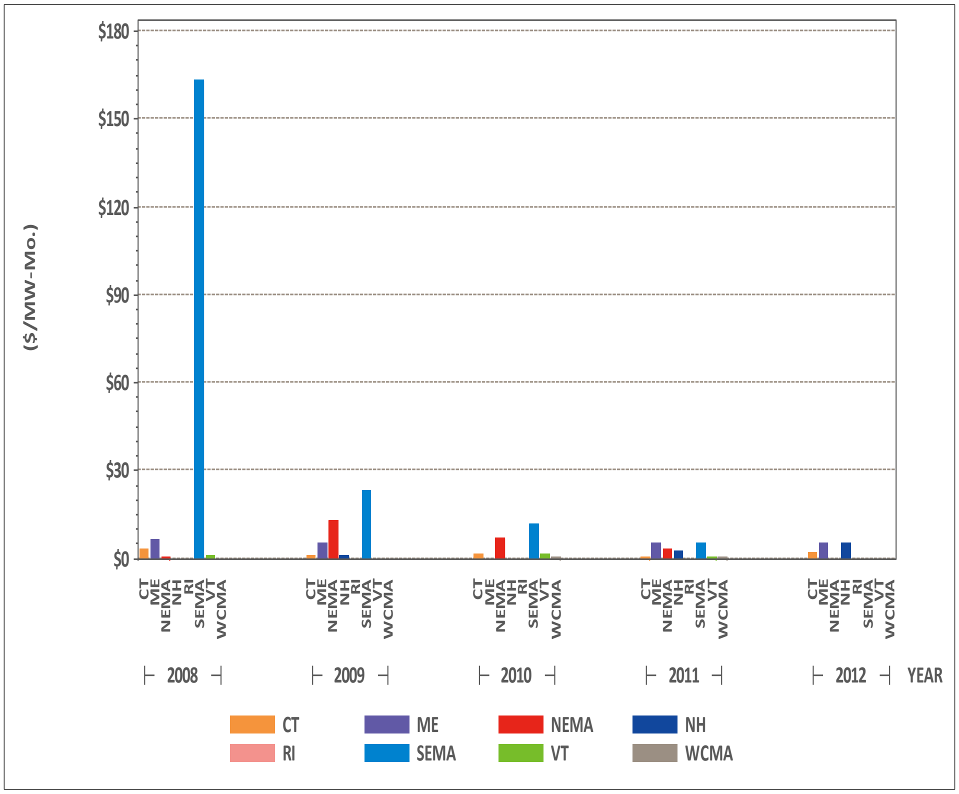

Figure 4-7: High-voltage control costs by reliability region, 2008 to 2012.

Section 5
Administrative Service Costs

Administrative cost components reflect costs incurred by both the ISO and the participating transmission owners 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's *Self-Funding Tariff* (SFT).[17] The Appendix provides further background on each of these components and the calculation of their costs.

Figure 5-1 and Table 5-1 show administrative costs by type for 2008 to 2012. The increase in 2010 ISO dispatch and control costs primarily is due to an undercollection of 2009 tariff revenues driven by less-than-forecasted energy consumption, increased allocated expenses associated with implemented capital projects, and ongoing operating costs. The decrease in 2011 dispatch and control costs was due to the year-to-year change in prior year true-up factors. While the 2010 rate included prior-year undercollections, the 2011 rate included prior-year overcollections driven by higher-than-projected energy consumption. The true-up change had a larger impact than dispatch and control costs, which included increases in 2011 over 2010 for strategic planning and measured growth initiatives, implemented capital projects, and ongoing operating costs.[18]

[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 are 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 using RNS.

[18] Information about the ISO's Strategic Planning Initiative is available at http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/index.html; Information about measured growth initiatives can be found within the ISO's annual Proposed Operating and Capital Budget presentations, typically published annually in late August and available within the Budget and Finance Committee materials at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/budgfin_comm/budgfin/mtrls/2013/index.html.

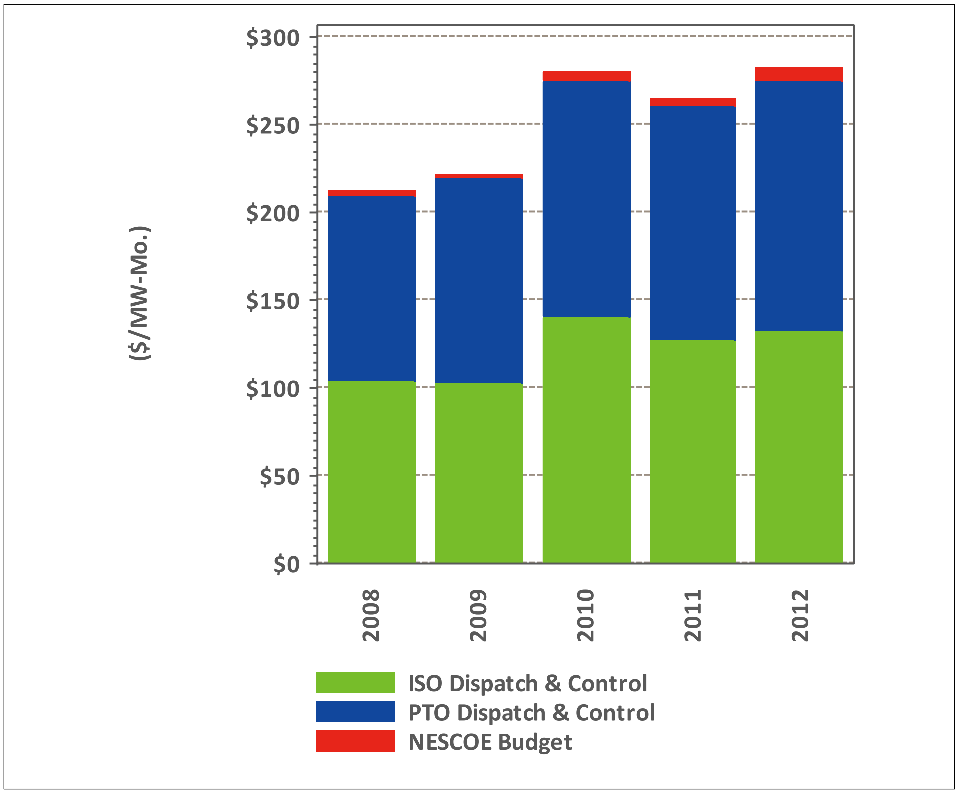

Figure 5-1: Administrative costs by type, 2008 to 2012.

Table 5-1
Administrative Costs by Type, 2008 to 2012 ($/MW-Month)

Component	2008	2009	2010	2011	2012
PTO dispatch and control	105.44	117.08	133.60	134.21	142.62
ISO dispatch and control	103.89	101.98	140.87	126.83	132.01
NESCOE budget	3.54	2.63	5.54	4.13	8.42
Total	**212.87**	**221.69**	**280.01**	**265.17**	**283.05**

Section 6
Regional Network Load, 2008 to 2012

As defined in the OATT, a transmission customer's monthly RNL is based on monthly peak demand and defines the customer's RNS usage. A transmission customer's monthly RNL value (i.e., monthly network load) is the customer's hourly load at the time of the 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 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" or physical load facilities in its local network. These assets are modeled in the ISO's RNS settlement process for calculating RNS settlements. 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 90 RNL customers own a combined 135 network load assets. These assets are distinct from the assets identified in other wholesale market settlements, such as for energy.

6.1 Average Regional Network Load by Year, 2008 to 2012

Figure 6-1 shows average monthly regional network load by year for the entire New England Balancing Authority Area for 2008 to 2012.

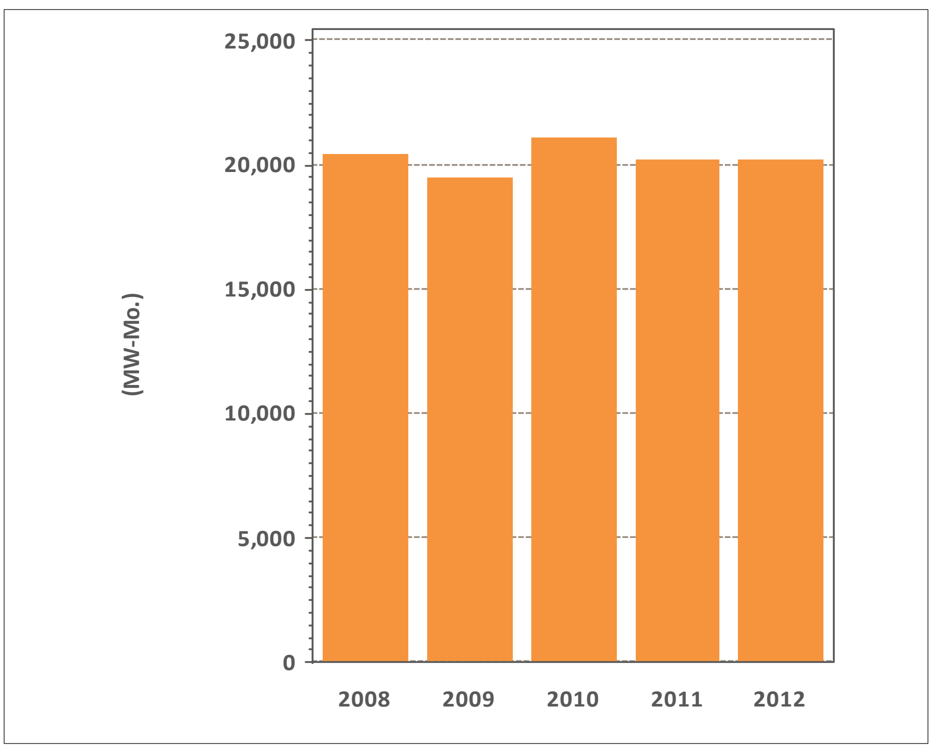

Figure 6-1: Average monthly regional network load, 2008 to 2012.

6.2 Monthly Regional Network Load by Reliability Region, 2008 to 2012

Figure **6-2** shows monthly network load aggregated by reliability region for 2008 to 2012. Since RNL reflects peak monthly demand usage, monthly aggregations of RNL appear more volatile during the highest demand months of the year, typically the summer months, and within local networks or reliability regions serving a larger customer load base.

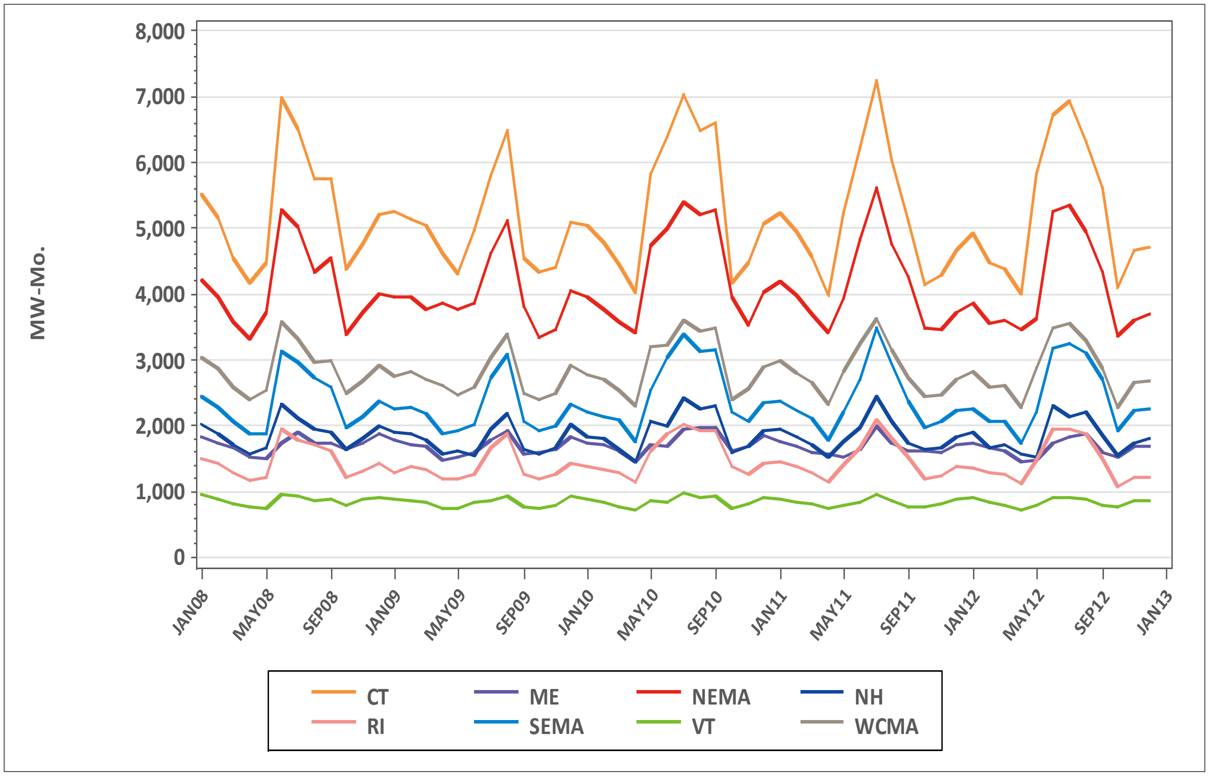

Figure 6-2: **Monthly network load by reliability region, 2008 to 2012.**

6.3 Monthly Regional Network Load by Regional Network, 2008 to 2012

Figure 6-3 shows monthly network load by local network, as reported by PTOs for 2008 to 2012.

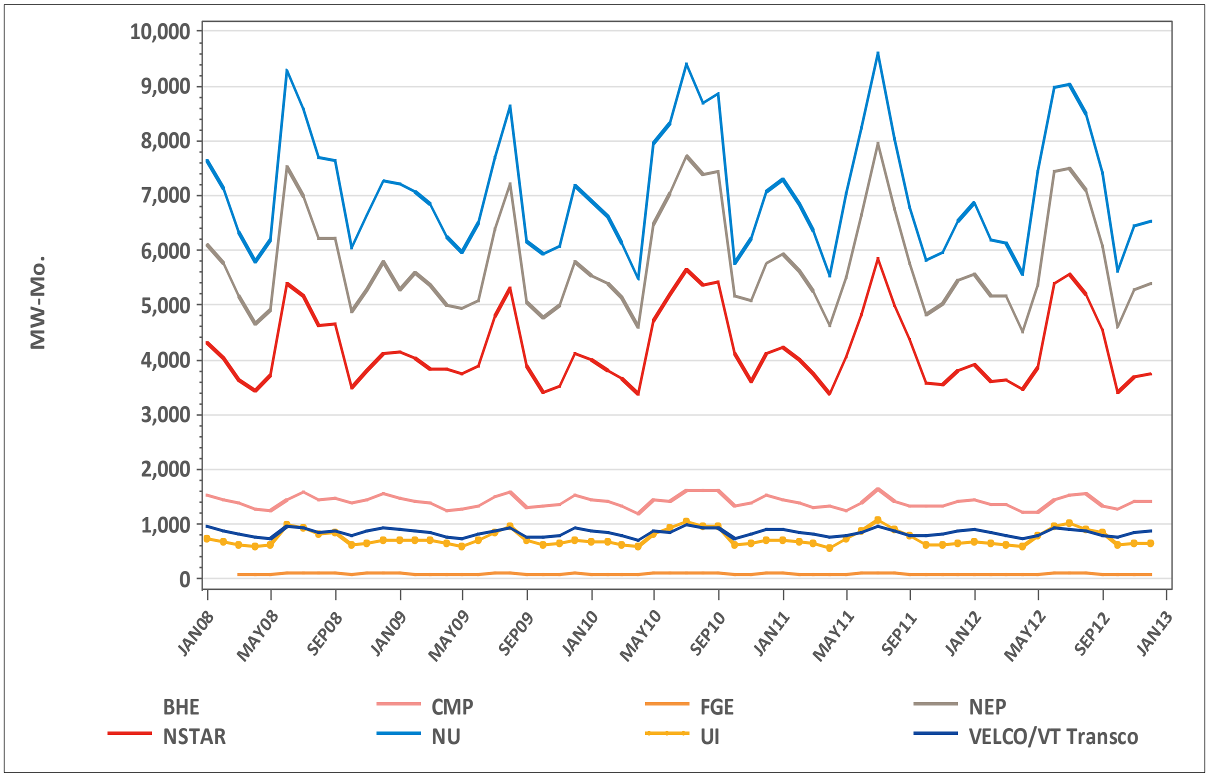

Figure 6-3: Monthly network load by local network, 2008 to 2012.

Section 7
Appendix
Description of Concepts

This section provides an overview of the concepts discussed throughout the report. Some of the concepts are *calculated* components, meaning they involve a regulated ratemaking process, while others are *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. The full definitions and processes associated with the listed terms and concepts are included in the tariff and the ISO's operating procedures.[19]

7.1 Calculated Components

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

7.1.1 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 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 website.

7.1.2 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 an RNL in the New England Balancing Authority Area. The calculation of the charges is 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.[20] 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

[19] 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_proceds/operating/index.html.

[20] 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.

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 website.

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

Schedule 1 of the SFT 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 using RNS are calculated in the same way as Schedule 1 of the OATT. The Schedule 1 rate is a FERC-approved rate ($/kW-month) determined annually by the ISO, effective January 1 through December 31, and is based on the ISO's revenue requirements, as submitted in its 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 is available 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 website.

7.1.4 NESCOE Budget (ISO SFT Schedule 5—New England States' Committee on Electricity) [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 2011 was $4.13/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 website.

7.2 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.

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

The fixed payments for VAR capacity costs (CC) are determined using 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 or absorb reactive power and relate to the phase-angle difference between voltage and current.

The variable payments include the following:

- Lost opportunity cost (LOC)—payment for generators for being dispatched down by, or at the request of, the ISO or an LCC for providing VAR service.
- Cost of energy consumed (CEC)—payment associated with hydroelectric and pumped storage generating units motoring at the request of the ISO or an 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 an 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 calculating compensation, each unit providing VAR service is determined to be providing either voltage support or high-voltage control, with the allocation of their costs 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 eliminate the effect of hourly reservations on this analysis, payments associated with reservations are removed. Remaining payments are 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 are summed for each reliability region, and each total is divided by the associated RNL to determine the appropriate $/MW-month rate for each region. A load-weighting methodology is 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 website.

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

If needed, these generators would assist the ISO in the restoration of the New England Balancing Authority Area after 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 website.

7.2.3 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:[21]

- *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.

  DRRP resources received availability payments based on pledged capability and Forward Reserve Auction prices.[22] Charges were allocated proportionately on the basis of 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 (removing the effects

[21] 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.

[22] Refer to the ISO's *Overview of New England's Wholesale Electricity Markets and Market Oversight* (May 15, 2013) for additional information on the Forward Reserves Market, http://www.iso-ne.com/markets/mktmonmit/rpts/other/index.html.

of the collection for through-and-out transactions) 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 4 of this report.

- *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 2007 to 2011 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 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 4). More information on this topic is available in Market Rule 1, Appendix E.

7.2.4 Reliability Agreements [R]

The Reliability Agreements in effect through June 2010 in New England were for full cost of service—the generator recovered its fixed costs in a monthly payment and its variable costs through electric energy market offers. Variable costs not covered by energy market revenues were compensated through daily reliability payments. All capacity market revenues and energy market revenues generators received in excess of variable costs served to reduce the monthly fixed-cost payment. Thus, the generators recovered no more than their respective fixed and variable costs.

7.2.5 FCM Retained for Reliability [R]

Under the Forward Capacity Market, which began in June 2010, an existing resource that places a bid in the auction to delist may have its delist bid rejected and be retained by the ISO for reliability reasons. In this situation, a resource would be paid according to either its auction bid price or its cost-of-service agreement. This payment is allocated to RNL residing in the supported reliability region. These charges, which also are known as FCM "Reliability Charges," are reported in $/MW-month. While these charges apply only to the specifically affected reliability region(s), they may be aggregated, divided by poolwide RNL, and reported here as a poolwide rate for illustrative purposes.

Document History

Date	Version	Description
6/12/2013	Original Posting	
6/14/2013	Rev1	Updated Table 1-1 to reflect the NSTAR regional network in the NEMA reliability region.