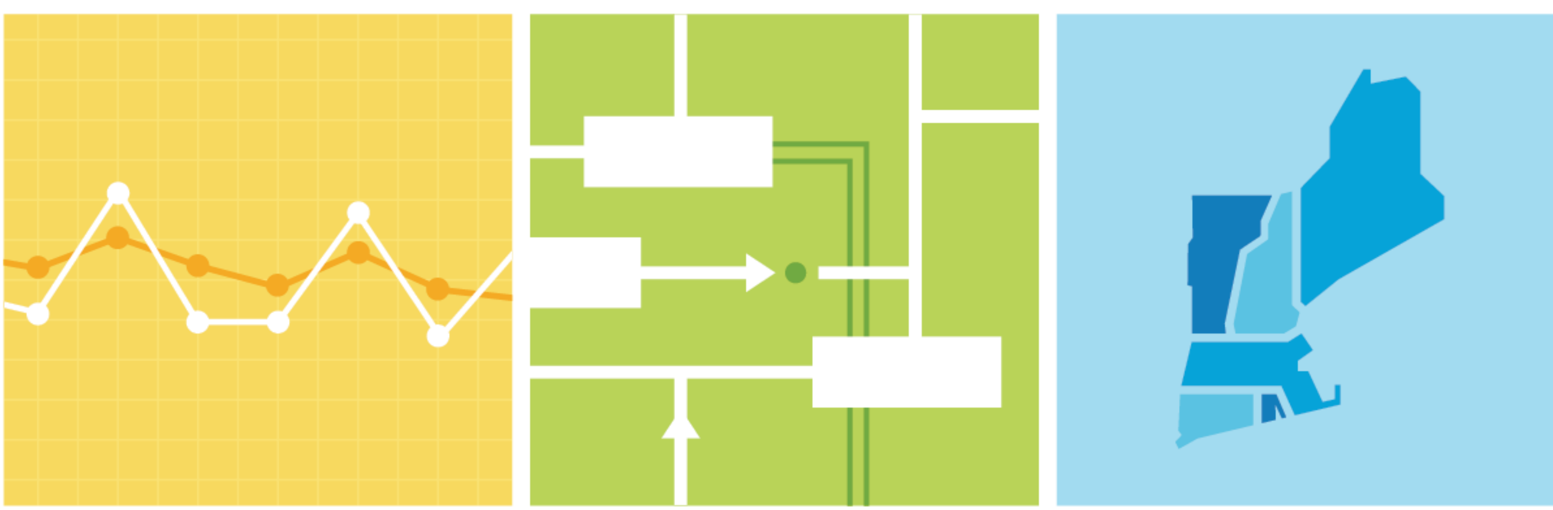
Historical Regional Network Load Cost Report, 2011–2015

JULY 14, 2016

ISO-NE PUBLIC



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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 billed by the ISO under the tariff for 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) and *Market Rule 1* (Section III of the tariff) govern 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 "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 publishes the *Historical Regional Network Load Cost Report* annually. This report provides historical average costs ($/MW-month) under the OATT to serve regional network load in the New England wholesale markets for 2011 to 2015.[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]

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[1] The *ISO New England Transmission, Markets, and Services Tariff*, includes the *Open Access Transmission Tariff* (OATT) (Section II), Market Rule 1 Standard Market Design (MR1) (Section III), and the Self-Funding Tariff (SFT) (Section IV). These documents are available at http://www.iso-ne.com/participate/rules-procedures/tariff.

[2] The ISO's *Wholesale Load Cost Report* is available at http://www.iso-ne.com/markets-operations/market-performance/load-costs.

[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 participating transmission owners (PTOs), transmission providers, and transmission customers using or providing 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 of the local network.)

[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-operations/market-performance/performance-reports.

1.1 Regional Network Load Cost Categories

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

- ***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 including resources either retained for reliability (RFR) or denied a request for a capacity supply obligation (CSO) megawatt proration in the Forward Capacity Market (FCM). (i.e., a "proration denied for reliability;" PDFR).[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, 2011 to 2015

RNL costs totaled $2.0 billion during 2015, representing 22.8% of total wholesale charges. Data from 2011 to 2015 show that RNL costs have increased from $5,767/MW-month in 2011 to $8,362/MW-month in 2015. This increase reflects a compound growth rate of 9.7% over the five-year period. Total charges to network load grew a bit more slowly (9.3% per year) over the same period. The RNL cost rate

[6] PTFs are certain transmission lines (69 kilovolts [kV] or greater) and associated equipment over which ISO New England has operational control. During 2015 these facilities were owned and operated by approximately 21 PTOs. PTFs do not include those lines and facilities that serve local load only (i.e., are local transmission or distribution facilities), are generator leads (i.e., radial transmission interconnection from a generator bus to the PTF), or are either merchant transmission facilities or other transmission facilities. The ISO and the PTOs review the status of PTF lines and associated facilities at least once per year. A current listing of PTFs is available in the PTF Catalog. 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* ("blackstart") 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. After the Forward Capacity Auction is finalized, lead participants of obligated resources can either accept by default a price proration (i.e., the full CSO with a reduced payment rate) or request an optional megawatt proration (a prorated obligation paid at the full capacity clearing price). If the ISO rejects a resource's requested megawatt proration for reliability reasons, the resource is paid a credit for the PDFR on the basis of the capacity clearing price and what the resource's payment would have been had its request not been rejected. Refer to the FCM market rules and the ISO's *2015 Annual Markets Report* (AMR15) for additional information on the FCM; http://www.iso-ne.com/static-assets/documents/2016/05/2015_imm_amr_final_5_25_2016.pdf. Reliability costs reported here include only those reliability services whose costs are allocated to RNL. A full list of reliability service billed to RNL is included later in this section.

[8] *PTOs* are companies that may be recognized as owning or supporting the PTFs in the New England Balancing Authority Area and are eligible to submit revenue requirements to recover the costs. Approximately 32 PTOs existed in 2015; of these, 23 supported a portion of the PTFs during 2015, and 21 both owned and operated PTFs. 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.

grew faster than the costs themselves as a result of a slight downward trend in network loads (down 0.4%) over the period.

The growth rate in RNL cost varied as follows among the RNL cost categories:

- ***Infrastructure*** costs averaged $7,851/MW-month during 2015, reflecting a compound growth rate of 10.3% over the five-year period from their 2011 average of $5,310/MW-month. The infrastructure costs during 2015 were approximately 94% of total RNL costs and 21.4% of overall wholesale load-serving costs. In response to identified transmission system needs, New England's transmission owners have invested $5.1 billion in the system from 2011 to 2015, resulting in a more robust transmission system and helping to otherwise mitigate reliability costs.
- ***Reliability*** costs increased over the period at a compound rate of 3.4% per year, from $192/MW-month during 2011 to $219/MW-month during 2015. Increased costs were attributable to a rise in costs associated with resources denied a request for a capacity supply obligation (CSO) megawatt proration in the FCM and, to a lesser degree, system restoration costs. Despite the increase, reliability costs represented only 3.4% of RNL costs and 0.6% of total wholesale costs in 2015, and remain notably lower than in past periods of study.
- ***Administrative*** costs, which grew at a 2.4% compound rate over the period, were only 3.5% of the total costs billed to RNL and approximately 0.8% of overall wholesale load-serving costs during 2015.

1.3 Reliability Regions and Local Networks

This report summarizes 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 comprised of local transmission networks ("local networks"). Table 1-1 lists these regions, the local networks, and the participating transmission owners associated with local networks during 2011 to 2015.

[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." *"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 other services provided under the OATT, including Schedule 18—*Merchant Transmission Facility (MTF) Service*, Schedule 19—*Special Constraint Resource Service,* Schedule 20—*Other Transmission Facilities (OTF) Service*, and Schedule 21—*Local Service*.

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)[b] Emera Maine Bangor Hydro Division (EM)[b] Central Maine Power (CMP) NU
New Hampshire (NH)	New England Power (NEP)[c] NU New Hampshire Transmission, LLC (NHT)[d]
Northeastern Massachusetts (NEMA)	NEP NSTAR[e]
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) Emera Maine Bangor Hydro Division was established effective January 1, 2014, resulting from a merger between BHE and Maine Public Service.

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

(d) NHT is a subsidiary of NextEra Energy Resources, LLC and is reflected under NU further in this report.

(e) The NSTAR local network was established in March 2007 to recognize the merger of Boston Edison (BE) Company, Cambridge Electric Light Company, Canal Electric Company, and Commonwealth Electric Company into the NSTAR Electric Company.

Each PTO with a local network is responsible for determining the peak RNL value on its local network in a given month and for identifying the share of peak RNL to be assigned to each of the network load assets in its local network. This report, including the Appendix, contains additional information about the local networks and 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][a]	• Resources denied for proration (PDFR) in the Forward Capacity Market • Resources retained for reliability (RFR) in the FCM • Voltage support • High-voltage control • System restoration
Administrative [A]	• PTO dispatch and control • ISO dispatch and control • New England States Committee on Electricity (NESCOE) budget[d]

(a) More information on these reliability services is available in Section 4 and Section 7 of this report.

(b) NESCOE is the FERC-approved regional-state committee for providing advisory input to the ISO regarding the development of the Regional System Plan (http://www.iso-ne.com/system-planning/system-plans-studies/rsp). 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 http://nescoe.com/.

Section 2
Total Regional Network Load Costs

Total wholesale load costs include RNL costs, reported here, as well as various other wholesale load costs, including energy, ancillary, and capacity charges, as discussed in Section 1. RNL costs are the smaller portion of total wholesale load costs billed by ISO-NE under its tariffs. Table 2-1 shows RNL costs as a percentage of the cost of serving load in New England from 2011 to 2015.[10]

Table 2-1
Total RNL Costs as a Percentage of Total Wholesale Load Costs, 2011 to 2015 ($ Billions, %)

Year	Total RNL Costs ($)	Wholesale Load Costs ($)	Total Wholesale Load Costs ($)	RNL % of Total
2011	1.40	7.23	8.63	16.2%
2012	1.51	5.79	7.31	20.7%
2013	1.86	8.72	10.58	17.6%
2014	1.86	9.84	11.70	15.9%
2015	1.99	6.76	8.75	22.8%

Between 2011 and 2015, RNL costs increased by $0.6 billion (from $1.4 billion to $2.0 billion), while wholesale load costs decreased by $0.5 billion (from $7.2 billion to $6.8 billion). This resulted in RNL costs growing as a percentage of total wholesale load costs from 16.2% in 2011 to 22.8% in 2015.

The increase in RNL costs between 2011 and 2015 were driven primarily by investments in transmission infrastructure and, to a very small extent, increased FCM PDFR costs.

The decrease in wholesale load costs between 2011 and 2015 were mostly due to lower energy market and Forward Reserve Market costs resulting from lower input fuel (natural gas) prices and lower loads in 2015 relative to 2011, although, lower capacity prices also played a role. Natural gas is the fuel that most frequently sets the price of electricity in New England. Its price has been the main driver of wholesale market costs for many years and is also responsible for the upticks in these costs during 2013 and 2014.

Figure 2-1 and Table 2-2 show RNL costs by major category for 2011 to 2015. Each RNL cost category is analyzed separately in subsequent sections of this report.

[10] ISO New England estimates the cost of serving wholesale load in the energy market for illustrative purposes via a study methodology. Please refer to the ISO's Wholesale Load Cost Reports.

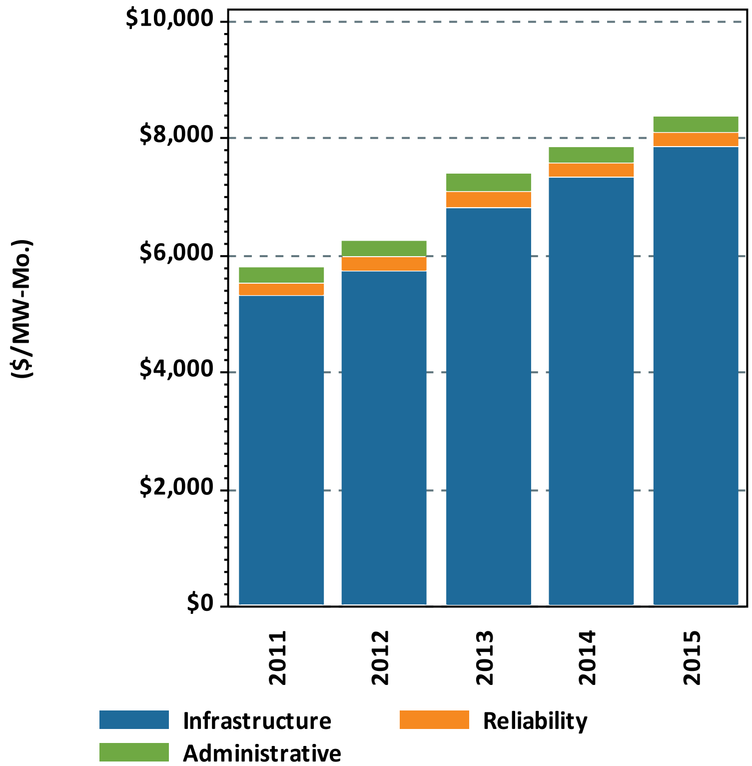

Figure 2-1: RNL costs by major category, 2011 to 2015.

Table 2-2
RNL Costs by Major Category, 2011 to 2015 ($/MW-Month)

Major Category	2011	2012	2013	2014	2015
Infrastructure	5,310	5,708	6,785	7,312	7,851
Reliability	192	256	300	234	219
Administrative	265	283	318	301	291
Total RNL Costs	**5,767**	**6,247**	**7,403**	**7,846**	**8,362**

Section 3
Infrastructure Costs

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

As part of industry restructuring, and in response to FERC directives to provide a "nonpancaked," or a single transmission rate, the New England Power Pool (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 or RNS transmission rate) into a single rate. The RNS rate, which is regulated by and filed with FERC, includes the following two components:

- **Pre-1997 transmission infrastructure costs (Schedule 9 Pre-'97 RNS)**:[12] This component is associated with maintenance and upgrades of PTFs placed in service or made before 1997. The pre-1997 values shown throughout the report reflect the FERC-filed rate for each local network. Starting in March 2008, the rate has been unified across all local networks.
- **Post-1996 transmission infrastructure costs (Schedule 9 Post-'96 RNS):** This component is associated with maintenance, upgrades, and additions of PTFs 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, 2011 to 2015

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 2011 to 2015. These investment costs are reflected in the year-to-year growth observed in the post-'96 RNS rate (see Section 3.2).

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[11] NEPOOL members serve as ISO stakeholders and market participants. More information on NEPOOL participants is available at http://www.iso-ne.com/participate/governing-agreements/nepool-agreement.

See FERC Order No. 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/markets-operations/settlements/understand-bill/item-descriptions/oatt-schedule9-rns.

Table 3-1
Pool Transmission Facilities Investments, 2011 to 2015 ($ Millions)

Year	Total	Incremental Additions
2011	7,038	371
2012	8,054	1,016
2013	9,501	1,447
2014	10,413	912
2015	11,763	1,350

Details on the transmission investment projects put into service in recent years are summarized in the ISO's *2015 Regional System Plan*.[13]

3.2 Infrastructure Costs, 2011 to 2015

In their PTF 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 2011 and 2015 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 as well as prior periods.

Figure 3-1 and Table 3-2 show the average monthly infrastructure costs for both the pre-'97 and post-'96 components for 2011 to 2015. The pre-'97 cost component grew at a 5.3% average annual rate from 2011 to 2015, and the post-'96 cost component grew at a 11.6% average annual rate because of increased investments to the infrastructure, as previously discussed. This increase in costs reflects maintenance of PTFs and well as upgrades and additions to the PTFs, which include major transmission projects such as the Maine Power Reliability Program and New England East–West Solution.[14]

[13] ISO New England, *2015 Regional System Plan* (November 5, 2015); http://www.iso-ne.com/system-planning/system-plans-studies/rsp.

[14] Refer to RSP15 for information about the status of these projects; see footnote 14

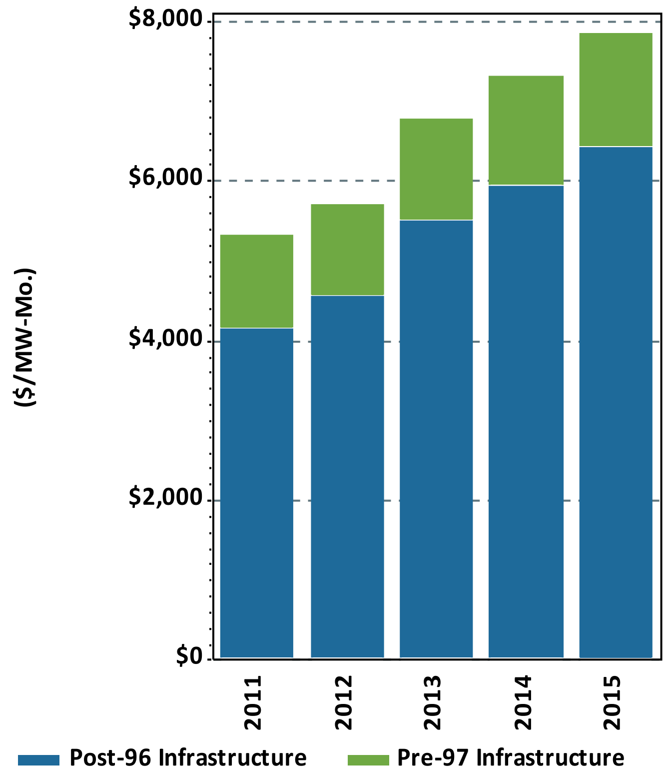

Figure 3-1: Infrastructure costs by component, 2011 to 2015.

Table 3-2
Infrastructure Costs by Component, 2011 to 2015 ($/MW-Month)

Component	2011	2012	2013	2014	2015
Pre-'97 infrastructure costs	1,166	1,150	1,300	1,378	1,431
Post-'96 infrastructure costs	4,144	4,558	5,486	5,933	6,420
Total	**5,310**	**5,708**	**6,785**	**7,312**	**7,851**

During the summer, the PTOs typically provide a multiple-year forecast of PTF additions (investments), PTO revenue requirements, and RNS rates.[15] Such forecasts are meant to be indicative, are subject to change, and are not included here.

[15] Resultant to the annual, summertime NEPOOL Transmission Committee meeting, PTOs publically post this information each year in the July to August timeframe in the 'Transmission Committee Materials' section of the Transmission Committee website; http://www.iso-ne.com/committees/comm_wkgrps/trans_comm/tariff_comm/index.html.

Section 4
Reliability Costs

Reliability services charged to RNL serve to recover the costs of certain reliability programs and services administered through the tariff. The costs (and rates) in this category are developed by dividing total costs 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, 2011 to 2015

Both Figure 4-1 and Table 4-1 show reliability costs by type from 2011 to 2015. These costs, which averaged approximately $240/MW-month over the five-year period, represent a 73% decrease from their average during the prior five-year period (2006 to 2010) and reflect the termination of several programs, partly as a result of transmission upgrades.

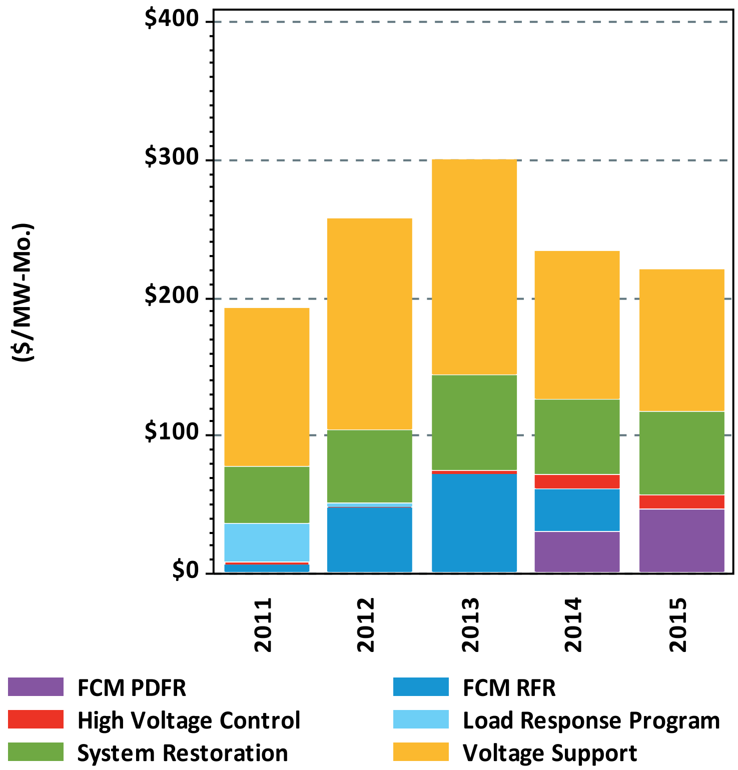

Figure 4-1: Average reliability costs by type, 2011 to 2015.

Table 4-1
Average Reliability Costs by Type, 2011 to 2015 ($/MW-Month)

Allocated Concept	2011	2012	2013	2014	2015
FCM PDFR	–	–	–	29.14	45.96
FCM RFR	5.84	46.90	73.07	30.78	0.00
High-voltage control	1.96	1.36	1.29	10.60	9.91
Load-response program	27.61	2.39	–	–	–
System restoration	41.54	52.35	69.48	55.39	60.41
Voltage support	115.03	153.25	155.83	107.85	103.02
Total	**191.98**	**256.25**	**299.68**	**233.76**	**219.31**

The increase in system restoration costs in 2013 was primarily due to a revision to the rate components in the OATT, Schedule 16—*Blackstart Service*, which became effective in January 2013. The Load-Response Program, which began in 2005, was terminated in June 2012.

Note that the benefits of an improved, more efficient transmission system (the costs of which are reflected in Section 3) extend beyond the reduced RNL reliability costs. Additional benefits could theoretically include a lowering of the following types of costs:

- 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 (LSCPR) resources to support system reliability requirements
- The costs of redispatching the system for providing local area reserves

4.2 Reliability Costs by Reliability Region, 2011 to 2015

Figure 4-2 shows the aggregated reliability costs by reliability region from 2011 to 2015. The increase in reliability charges in the NEMA reliability region during 2012 to 2014 is associated with generation either retained or denied proration for reasons of reliability in the FCM, while cost increases in Maine and NH are associated with high-voltage control service in these areas. The overall downward trend across most reliability regions after 2013 was due to a decline in voltage support costs.

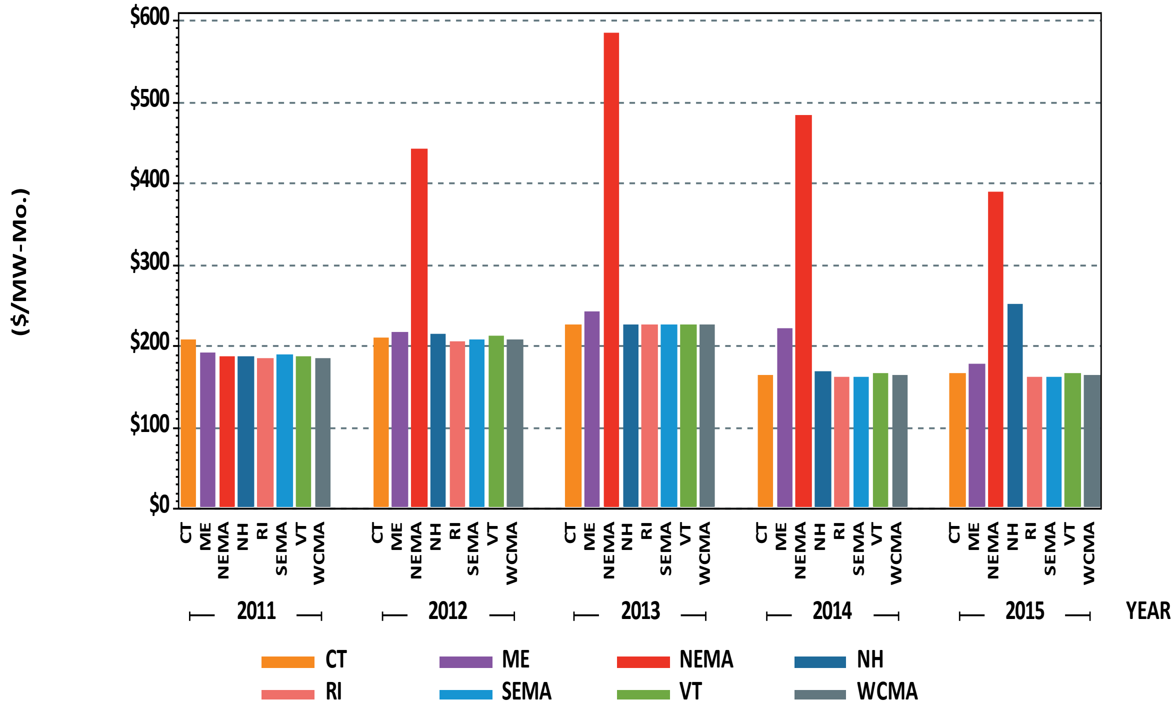

Figure 4-2: Average combined costs for reliability services by reliability region, 2011–2015.

Figure 4-3 shows FCM-related reliability charges (RFR and PDFR) over the past five years. FCM RFR charges began in 2010, coincident with the FCM. Charges in the NEMA reliability region reflect RFR charges affecting 2011-2014 and PDFR affecting 2014 and 2015.

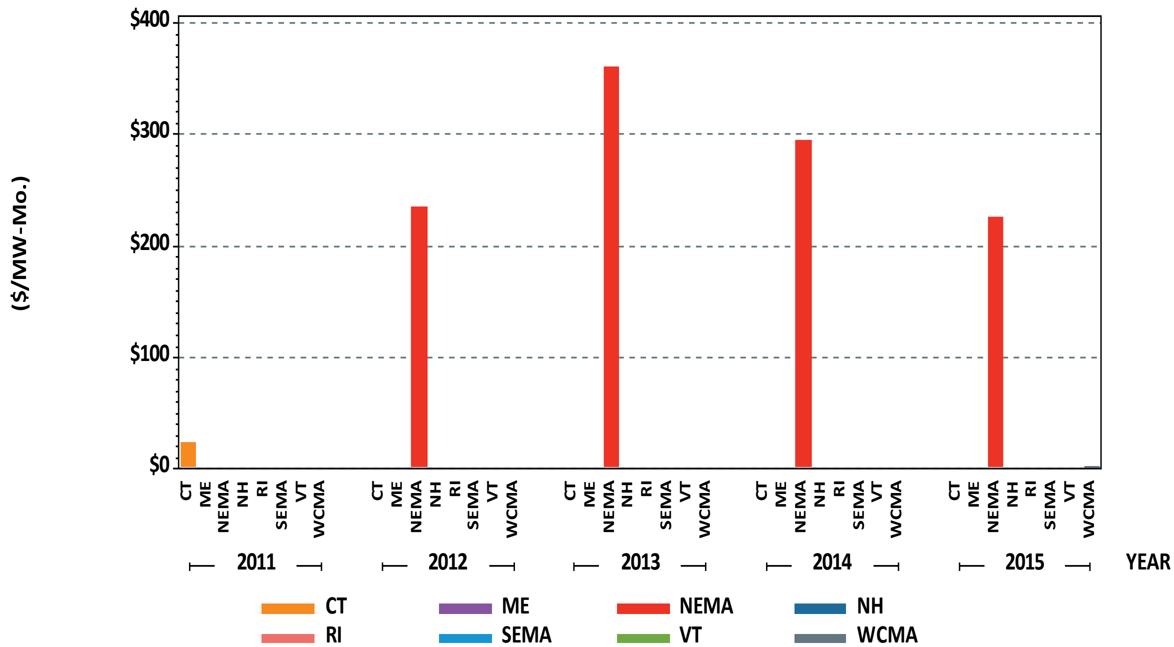

Figure 4-3: FCM reliability charges by reliability region and year, 2011–2015.

4.3 Voltage Support Costs, 2011 to 2015

Volt ampere reactive (VAR) is a measurement of reactive power used to maintain transmission system 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 in accordance with Schedule 2—*Regulation and Frequency Response Service* of the OATT.

The fixed costs and certain variable costs (excluding high-voltage control costs) for providing VAR service reflect the cost of dynamic VAR support necessary to maintain transmission voltages on the entire New England transmission system and are allocated to all RNL.

Figure 4-4 shows voltage support costs for 2011 to 2015.

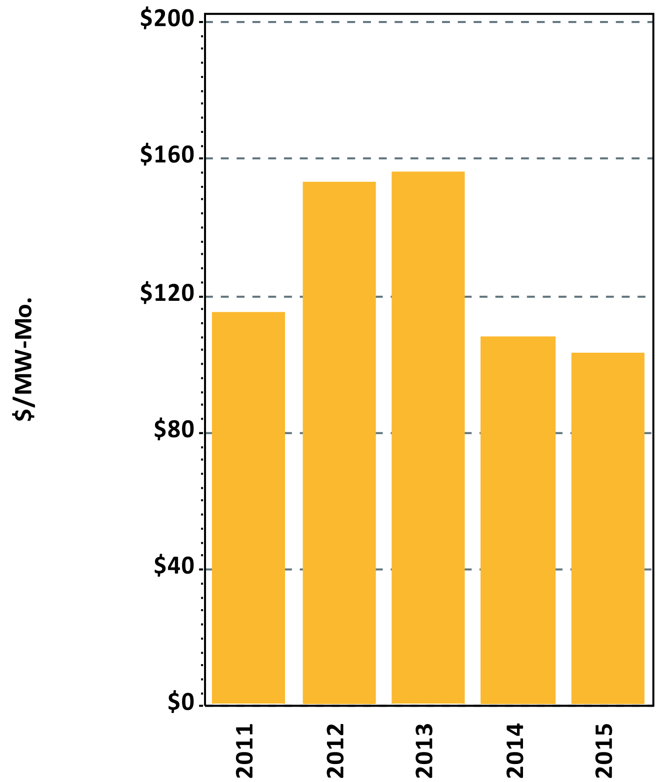

Figure 4-4: Voltage support costs, 2011-2015.

Voltage support costs have decreased somewhat steadily for the past 10 years, falling from $337MW-month in 2005 to $103/MW-month in 2015 and reflect transmission improvements made in the NEMA and Southeastern Massachusetts regions of New England. The temporary increase in these costs during 2012 and 2013 reflect an increase in variable voltage payments to out-of-merit generator commitments for voltage support, primarily in the Western Central Massachusetts region, and, to a lesser extent, in Maine.

4.4 High-Voltage Control Costs by Reliability Region, 2011 to 2015

High-voltage control costs reflect the lost opportunity costs of a VAR resource(s) committed exclusively to address high-voltage conditions within one or more reliability regions. These costs are allocated to RNL within the reliability region(s) that benefitted from the service. Figure 4-5 shows high-voltage control costs by reliability region for 2011 to 2015. The virtual disappearance of these costs in 2011 in the SEMA region, where such costs were relatively high in the past ($160/MW-month. in 2008, for example), was enabled by transmission upgrades completed there. Costs in the Maine and NEMA reliability regions increased during 2013 and 2014 as the Maine Power Reliability Project and Greater Boston Project addressed weak parts of the transmission system in these regions.

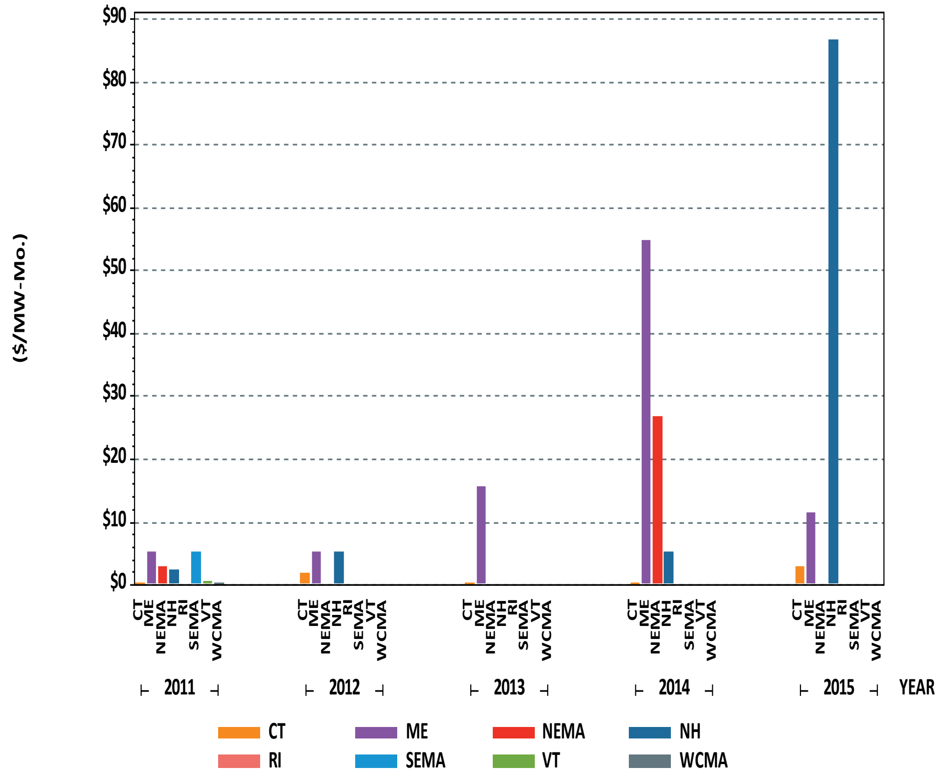

Figure 4-5: High-voltage control costs by reliability region, 2011 to 2015.

Section 5
Administrative Service Costs

Administrative service 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. The Appendix provides further background on each of these components and the calculation of their costs. Administrative service costs are allocated to all RNL.

Figure 5-1 and Table 5-1 show administrative costs by type for 2011 to 2015.

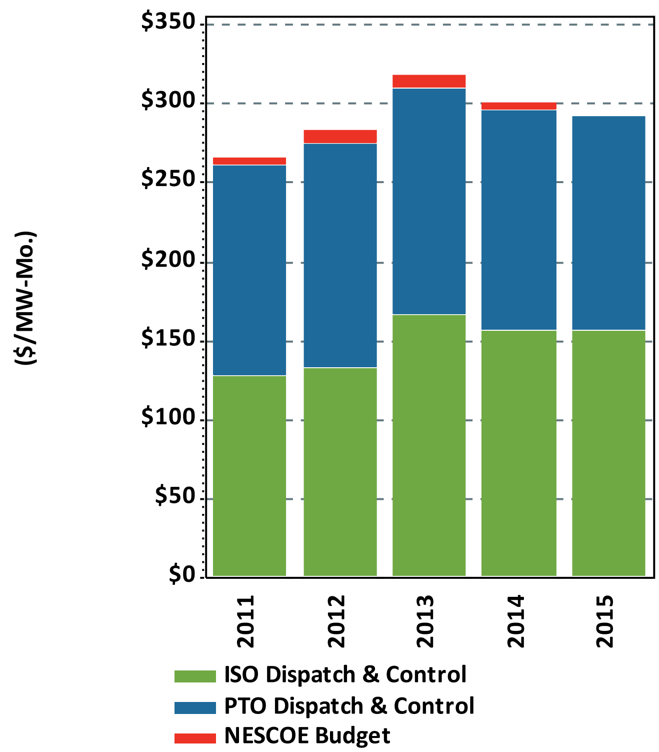

Figure 5-1: Administrative costs by type, 2011 to 2015.

Table 5-1
Administrative Costs by Type, 2011 to 2015 ($/MW-Month)

Component	2011	2012	2013	2014	2015
PTO dispatch and control	134.16	142.37	144.04	138.68	135.32
NESCOE budget	4.13	8.42	8.55	5.53	0.00
ISO dispatch and control	126.83	132.01	165.45	156.40	155.70
Total	**265.12**	**282.80**	**318.04**	**300.61**	**291.02**

The increase in ISO dispatch and control costs during 2013 compared with 2012 reflects both increased budgeted costs and a change in the year-over-year true-up. Strategic planning and other initiatives experienced increases in budgeted costs.[16] These initiatives included aligning the market design with the planning process, integrating variable resources into the marketplace, and implementing a coordinated-transaction-scheduling initiative with the New York control area. Certain accounting estimates (pension and postretirement benefit plans and lower projected vacancy) also increased. The true-up change served to increase the 2013 rate by reflecting a prior-year undercollection of funds, while the 2012 rate incorporated a prior-year overcollection that reduced the rate. A decrease in the estimated network load levels by approximately 2.9% (on average) resulted in spreading the costs over a smaller base than the prior-year's rate, also contributing to the 2013 rate increase.

The decreased 2014 ISO dispatch and control costs compared with 2013 costs primarily are due to an average 3.7% increase in network load level estimates, which lowered the 2014 rate and spread the costs over an increased base. Another contributing factor, although to a lesser extent, was a decrease in costs due to a year-over-year reallocation of work to other ISO services and lower depreciation expenses for previous years' capital projects as they became fully depreciated.

The NESCOE budget was not changed in 2015 due to over collections during the prior year.[17]

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[16] Information about the ISO's Strategic Planning Initiative is available at http://www.iso-ne.com/committees/key-projects/implemented/strategic-planning-initiative; 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/participants/budget-finance.

[17] Information about recovering NESCOE funding for 2015 can be found at http://www.iso-ne.com/static-assets/documents/2014/10/nescoe_cons._budget_er14-113-000_10-16-2014.pdf.

Section 6
Regional Network Load, 2011 to 2015

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 regional network load) is the customer's hourly load (not credited or reduced for any behind-the-meter generation) 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 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 91 RNL customers owned a combined 140 regional network load assets as of December 2015. 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, 2011 to 2015

Figure 6-1 shows average monthly regional network load by year for the entire New England Balancing Authority Area for 2011 to 2015.

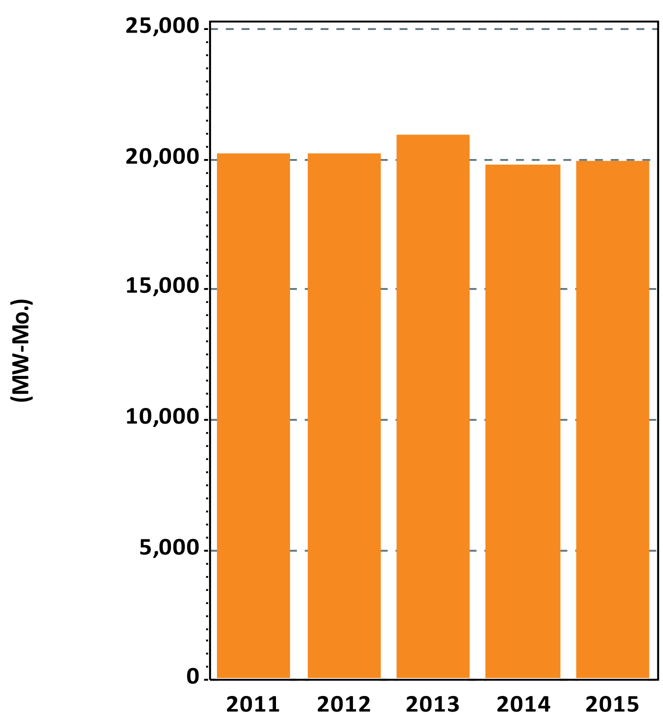

Figure 6-1: Average monthly regional network load, 2011 to 2015.

6.2 Monthly Regional Network Load by Reliability Region, 2011 to 2015

Figure 6-2 shows monthly RNL aggregated by reliability region for 2011 to 2015. 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.

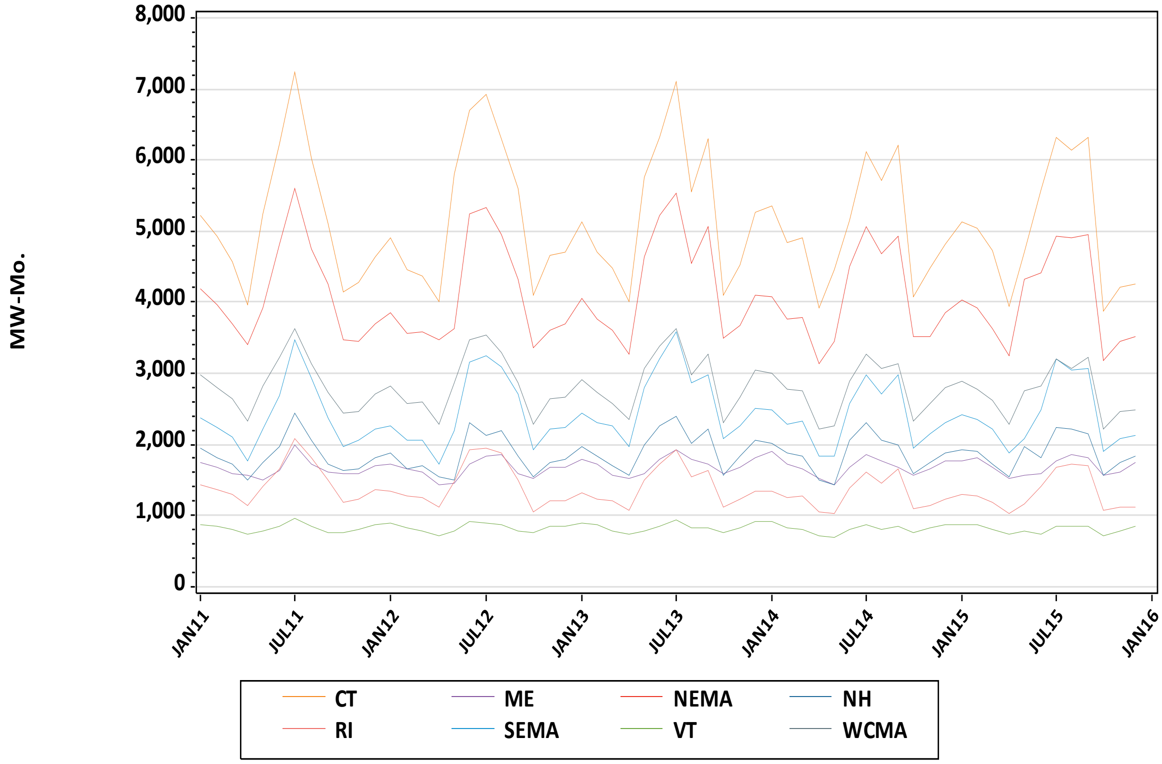

Figure 6-2: Monthly network load by reliability region, 2011 to 2015.

6.3 Monthly Regional Network Load by Regional Network, 2011 to 2015

Figure 6-3 shows monthly network load by local network, as reported by PTOs for 2011 to 2015.

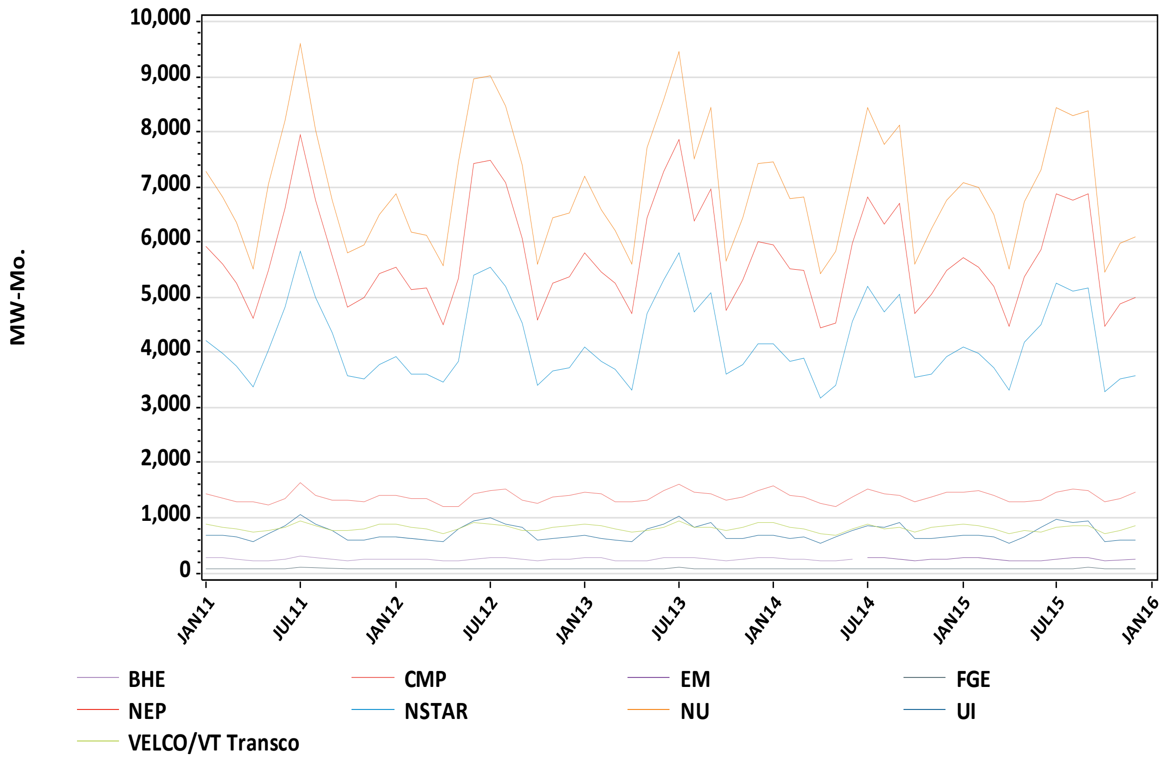

Figure 6-3: Monthly network load by local network, 2011 to 2015.

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.[18]

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 at the regional level 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 annually filing with FERC information reflecting the updated formula-based RNS rates.[19] Updated rates, typically effective as of 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

[18] Definitions of terms and concepts in the tariff are available at http://www.iso-ne.com/participate/rules-procedures/tariff. ISO New England operating procedures are available at http://www.iso-ne.com/participate/rules-procedures.

[19] A *formula rate* is a fixed method for calculating a rate based on set inputs. The charges to customers update annually; data input comes from public sources (Form 1) and the charges are recalculated pursuant to a set of protocols.

requirements (including forecasts) 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 website.

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

ISO dispatch and control costs are determined by Schedule 1 (and not Schedules 2 and 3) of the ISO's *Self-Funding Tariff* (SFT).[20] 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 accordance with Schedule 1, consistent with the calculation of charges by the PTOs under Schedule 1 of the OATT. The rate for Schedule 1 of the SFT 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 rate for Schedule 5 of the SFT 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 2013 was $8.55/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 are generally charged proportionately, using RNL as an allocator. That is, a customer's charges are determined by multiplying the total cost for the respective service by the customer's RNL and dividing by the applicable level of regional or reliability region(s) responsible for paying for the service.

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

The fixed payments for VAR capacity costs (CC) are determined using a reactive resource's qualified leading and lagging VAR capability and the applicable VAR CC rate for the capability to provide VAR service. "Leading" and "lagging" refer to the physical ability of the reactive resource to supply or absorb

[20] 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, System Control, and Dispatch Service*, and are recovered through the OATT using RNL as an allocator. As the billing and collection agent for NESCOE, the ISO collects ISO SFT Schedule 5 NESCOE payments and distributes these payments to NESCOE. Charges are based on RNL for any transmission customer using RNS.

reactive power by affecting the phase-angle difference between voltage and current, which improves the power quality on the system.

The variable payments include the following:

- Lost opportunity cost (LOC)—payment for reactive resources 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 and other reactive resources consuming energy at the request of the ISO or an LCC for providing VAR service.
- Cost of energy produced (CEP)—payment that compensates reactive resources (including hydro, pumped storage, or thermal generating units) if the ISO or an LCC brings the resource on line (and it produces real power) for providing VAR service (whether for voltage support or high-voltage control).

For calculating compensation, each reactive resource 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 through or out (TOUT) service reservations placed for external transactions through the Open-Access Same-Time Information System (OASIS). To eliminate the effect of hourly TOUT service reservations on this analysis, payments associated with such reservations are removed. Remaining payments are summed for the entire balancing authority area and divided by the pool-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 [R]

When and if needed, certain generators provide blackstart service to assist the ISO in restoring the New England Balancing Authority Area after a blackout. The $/MW-month rate of compensating resources for their ability to provide this service is derived by summing regionwide blackstart 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]

- *Load-Response Program:* Before and during the 2009 to 2010 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 the remaining two price-activated programs continued until their subsequent termination effective June 2012. [22] Each transmission customer with RNL received a proportional share of the costs of these 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 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.

7.2.5 FCM Proration Denied for Reliability [R]

This cost may result from certain FCM market operations. If the FCM auction clears at the floor price and clears more capacity supply obligation than required, the ISO will reduce (prorate downward) the market payment rate to ensure that load customers do not aggregately overpay for the capacity. Cleared resources may choose to have their supply obligation prorated downward rather than receive the lower payment rate. However, if for reliability reasons the ISO denies this option to resources in a particular capacity zone, the resources in this zone will receive an added payment equaling the difference between the auction clearing price (higher payment rate) and the prorated payment rate. This effectively creates an added cost to the marketplace resulting from a reliability constraint, and this incremental market cost is allocated to regional network load within the affected reliability region.

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[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] Effective June 2012, demand assets are paid through the Transitional Demand Response (TDR) program, the costs of which are not allocated to RNL and thus are not reflected in this report.

Document History

Date	Version	Description
7/14/2016	Original Posting	