

ISO New England (ISO-NE)

Section 3 – ISO-NE Performance Metrics and Other Information

ISO New England is a regional transmission organization (RTO), serving Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont. ISO New England meets the electricity demands of the region's economy and people by fulfilling three primary responsibilities:









- Minute-to-minute reliable operation of New England's electric power system, providing centrally dispatched direction for the generation and flow of electricity across the region's interstate high-voltage transmission lines and thereby ensuring the constant availability of electricity for New England's residents and businesses.
- Development, oversight, and fair administration of New England's wholesale electricity marketplace, through which electric power has been bought, sold, and traded since 1999. These competitive markets provide positive economic and environmental outcomes for consumers and improve the ability of the power system to meet ever-increasing demand efficiently.
- Management of comprehensive planning processes for the electric power system and wholesale markets for addressing New England's electricity needs well into the future.

ISO New England is an independent, not-for-profit corporation. To effectively carry out its charge, the company, its board of directors and its 400+ employees have no financial interest or ties to any company doing business in the region's wholesale electricity marketplace.

The New England regional electric power system serves 14 million people living in a 68,000 square-mile area. More than 300 generating units, representing approximately 32,000 MW of total generating capacity, produce electric energy. Most of these facilities are connected through over 8,000 miles of high-voltage transmission lines. Thirteen tie lines interconnect New England with neighboring New York State and the provinces of New Brunswick and Québec, Canada. Demand resources now play a significant role in operating the New England power system. As of summer 2010, approximately 1,900 MW of demand resources, representing load reductions and behind-the-meter generators, are registered as part of ISO's Forward Capacity Market.

A. ISO New England Bulk Power System Reliability

The table below identifies which NERC Functional Model registrations ISO-NE submitted as of the end of 2009. The regional entity for ISO-NE is the Northeast Power Coordinating Council (NPCC). A link to the website for the specific NPCC reliability standards applicable to ISO-NE is included at the end of the table. For the reporting period 2007 to 2009, ISO-NE has had no violations (i.e., NERC Confirmed Violations) of national or regional reliability standards, including any operating reserve standards. ISO-NE regularly reports to stakeholders about the monthly operation of the system.

NERC Functional Model Registration	ISO-NE
Balancing Authority	
Interchange Authority	
Planning Authority	
Reliability Coordinator	
Resource Planner	
Transmission Operator	
Transmission Planner	
Transmission Service Provider	
Regional Entity	Northeast Power Coordinating Council (NPCC)

Standards that have been approved by the NERC Board of Trustees are available at <http://www.nerc.com/page.php?cid=2|20>

Additional standards approved by the NPCC Board are available at <http://www.npcc.org/regStandards/Approved.aspx>

Dispatch Operations

Compliance with Frequency Control Performance Metrics (CPS1 and CPS2)

As the registered balancing authority (BA) for New England, ISO-NE is responsible for dispatching the region's generation (i.e., supply) to meet its load (or demand) and the scheduled interchange with its neighboring BAs, which is the agreed-to level of flow over the tie lines between two regions. In real time, the area control error (ACE) determines the effectiveness of ISO-NE's dispatch, or control performance. The ACE is a measurement of the difference between the net scheduled interchange and the net actual interchange. Over generation will result in a positive ACE, and under generation will result in a negative ACE. To effectively control the ACE as close to zero as possible, ISO-NE dispatches generators selected for automatic generator control (AGC) to regulate their power output based on AGC control signals they receive from the ISO every four seconds. The regulation requirements are based on balancing the need to satisfy the Control Performance Standard (CPS) with the need to minimize regulation procurement and ultimately consumer costs.

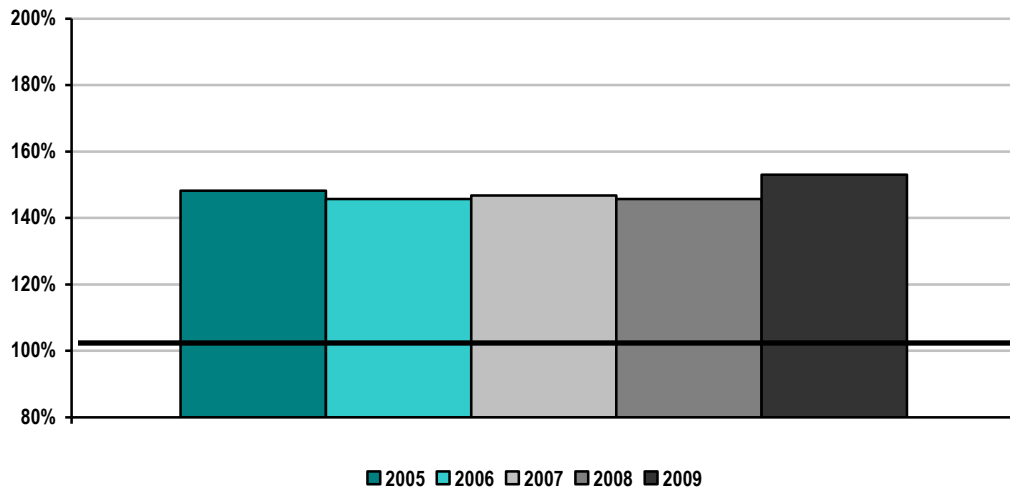
Control Performance Standard No. 1 (CPS1) and Control Performance Standard No. 2 (CPS2) are designed to maintain interconnection steady-state frequency within defined limits by balancing real power demand and supply in real time. NERC Standard BAL-001-0.1a, *Real Power Balancing Control Performance*, defines CPS1 and CPS2 as follows:

- CPS1 compliance is defined as at least 100% for a rolling annual average. ISO-NE must be 100% compliant with CPS1 throughout a 12-month period.
- CPS2 compliance is defined as greater than 90%. ISO-NE has an internal goal of managing CPS2 within a monthly average of between 92% and 97%.

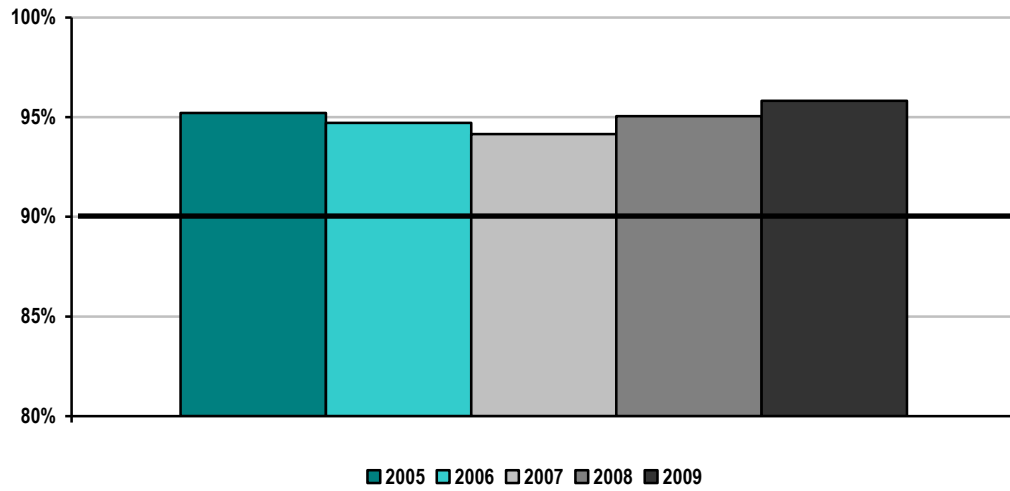
ISO-NE monitors CPS compliance every hour of every day. Further, ISO-NE reviews CPS1 and CPS2 performance on a monthly basis. In addition, ISO-NE reviews CPS compliance annually to determine whether its regulation requirements, specified as a function of month, day type, and hour, need to be adjusted or modified. Since 2005, regulation requirements have decreased as a result of more efficient and effective generation dispatch and new operational tools, such as electronic dispatch and very short-term load forecasting. The system operators have also ensured compliance with CPS2 by carefully monitoring real-time economic dispatch and those generators providing regulation service. Consequently, lower amounts of regulation are needed to provide the required regulation service and subsequently meet the CPS2 target.

ISO-NE was compliant with CPS1 and CPS2 for each of the calendar years from 2005 through 2009 as shown in the following graphs.

ISO-NE CPS1 Compliance, 2005–2009



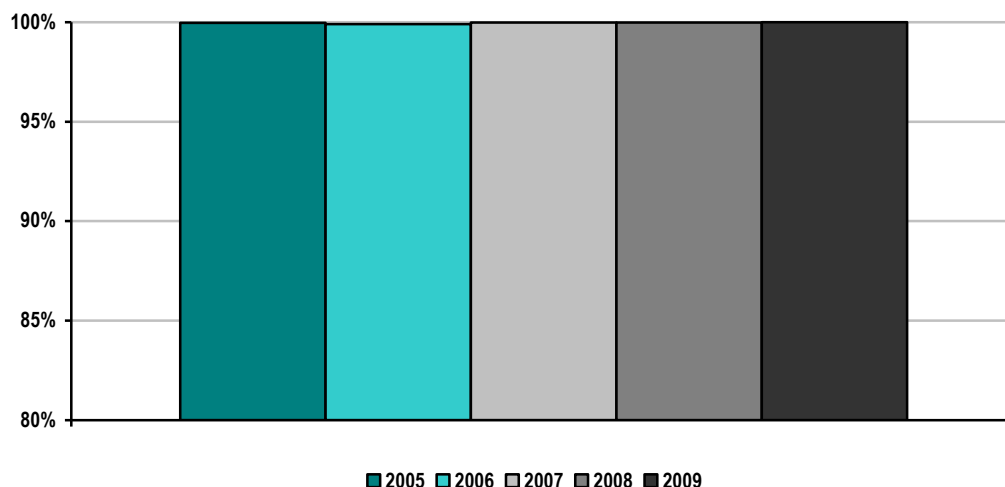
ISO-NE CPS2 Compliance, 2005–2009



ISO New England Energy Management System Availability, 2005–2009

The availability of the Energy Management System (EMS), as shown in the figure, is the key to reliable monitoring of the electric power transmission system. For the past five years, ISO New England’s EMS has been available more than 99.9% of all hours in each year.

ISO-NE Energy Management System Availability 2005–2009



Load Forecast Accuracy

The principal factor affecting load forecast error is the accuracy of the weather forecasts, with 60% of the load forecast error driven by weather forecast error. To minimize weather forecast error, ISO-NE uses three weather vendors to provide regional weather forecasts for eight New England cities. These data are used to calculate a load-weighted New England average weather forecast.

ISO-NE forecasters also use three types of short-term load forecast models to produce the day-ahead load forecast (before 10:00 a.m.), the seven-day load forecast, and an update of the current (intra-) day load forecast. One type of forecast model is an advanced neural network (ANN) model that uses weather inputs and past history to produce a short-term load forecast for the upcoming seven days. The ANN-Regular model weighs past load and weather data evenly, whereas the ANN-Fast model relies more heavily on the most recent weather data. The ANN-Fast model is particularly helpful during daylight savings time changes or seasonal holidays. Both ANN models are “retrained” annually. The second type, the MetrixND model, is solely dependent on weather inputs. The third type is the Similar Day historic model, which allows the forecaster to view a range of past “similar” days for possible use in the next-day forecast. The Similar Day model is based on predefined time and load criteria.

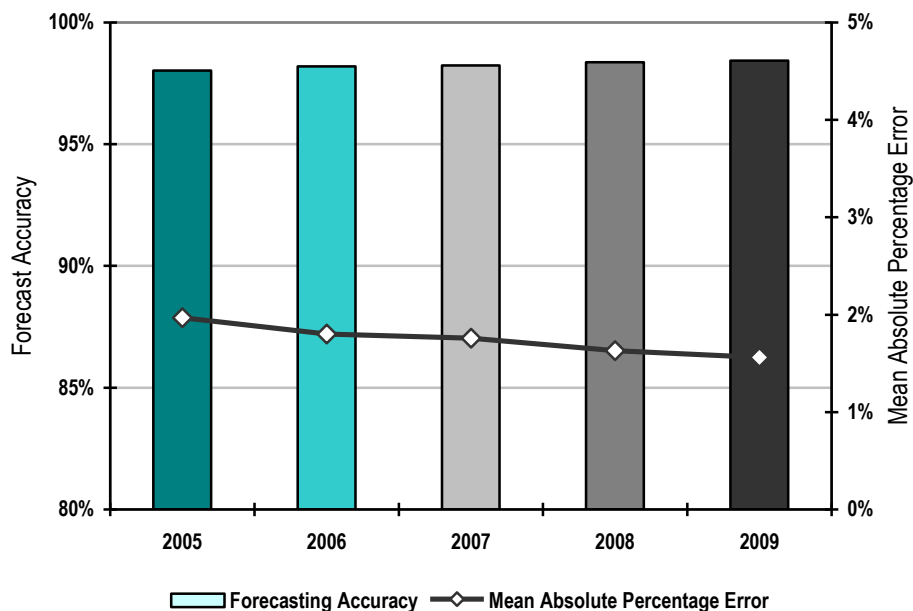
ISO-NE proactively monitors the performance of the individual load forecast models and regularly communicates with its weather vendors and the local National Weather Service office to discuss unusual weather conditions or forecasts. ISO-NE also is actively working with the University of Connecticut to develop a new type of load forecasting model that can better adapt to weather variables that contribute to load forecasting error.

ISO-NE's load forecasting accuracy is shown in the following table and figures.³

**Load Forecasting Accuracy
Reference Point**

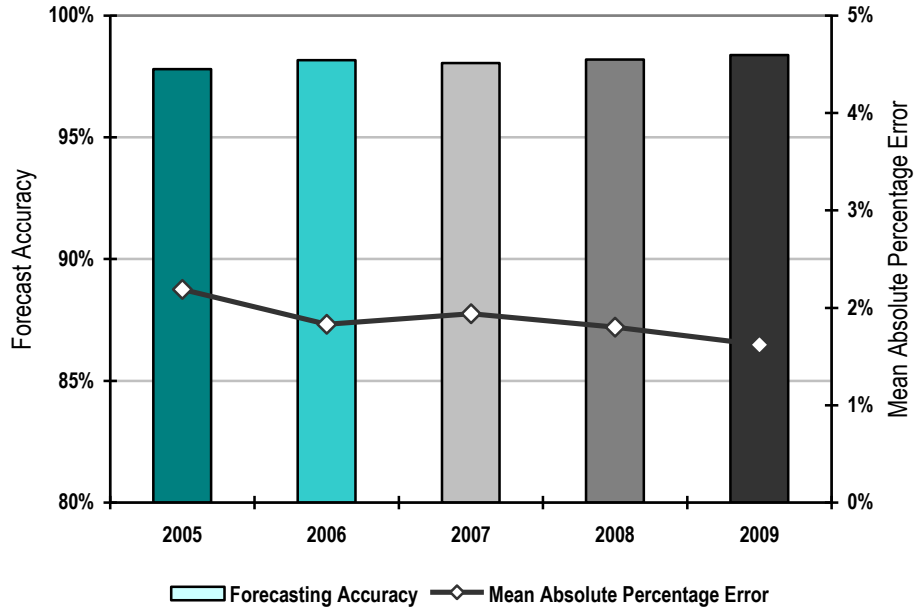
ISO-NE	10:00 a.m. prior day
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ISO-NE Average Load Forecasting Accuracy, 2005–2009

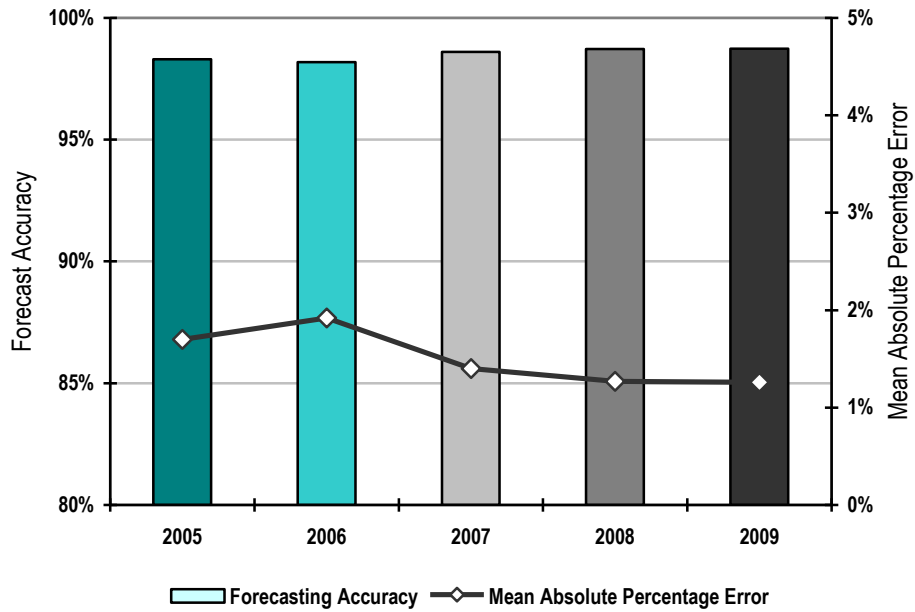


³ For ISO-NE's calculation of load forecast accuracy for 2005 to 2009, the actual loads were reconstituted for load-relief estimates resulting from the dispatch of demand response because of Emergency Operating Procedures (EOPs) invoked by ISO-NE.

ISO-NE Peak Load Forecasting Accuracy, 2005–2009



ISO-NE Valley Load Forecasting Accuracy, 2005–2009



Wind Forecasting Accuracy

Currently, ISO-NE has a minimal amount of installed wind generation capacity (approximately 175 MW). Therefore, no separate forecast for wind generation is done at the regional level.

In New England, variable energy resources (VERs) perform their own forecast of generation for each hour of the next operating day, which they submit to ISO-NE as a self-schedule (forecast) on the day preceding the operating day. While ISO-NE's current load-forecasting practice and corresponding generation requirements work well for the present-day system, it will not be viable with a large penetration of VERs into the New England transmission system. This is primarily because of the potential volume of VERs and the quantity of forecast revisions that would be required due to the nature of each VER and potentially its forecast, which may not be aligned with ISO-NE's metrics and requirements for operation of the larger system.

ISO-NE intends to transition to a state-of-the-art forecasting system, as VER penetration levels increase to a level approaching 500 to 1,000 MW of nameplate capacity. The new forecasting system will incorporate information from the New England Wind Integration Study (NEWIS) scheduled for completion in late autumn 2010.⁴

ISO-NE understands a "state-of-the-art forecasting system" to mean a generation forecasting system that, in the operational timeframe, helps to most efficiently use the energy produced by VERs and non-VERs, while also helping to ensure system reliability and market efficiency. Such a system works toward these goals by producing a forecast for expected VER generation ideally for a range of timeframes (including next hours, next day, and the following week) to allow for optimizing short-term maintenance scheduling, unit commitment, and real-time unit dispatch.

To transition from the existing forecasting method to this state-of-the-art forecasting system, the first step is to determine and describe the pertinent goals, methods, and requirements for the system. The second step is to develop, test, and implement a plan for the transition. The NEWIS technical report addresses this first step by identifying the recommended goals, methods, and requirements for a state-of-the-art wind generation forecasting system.

The second step, which will detail how ISO-NE will transition from the existing system to a state-of-the-art system, has not yet been developed because some of the recommendations depend on work that has yet to be accomplished and integrated into the findings of the NEWIS report. Although the report has focused on wind generation resources as the most significant category of VERs for the New England power grid, ISO-NE also will be examining requirements for the integration of other types of VERs. ISO-NE has yet to study generation forecasting for solar resources, but presumably VERs will depend on insulation as a "fuel" source and relevant ambient condition data for generation forecasting, including present and expected cloud cover, projected incident solar irradiance (or perhaps theoretical maximum plant output) given no cloud cover, temperature, and relative humidity. The data reporting frequency for solar resources would likely be similar to that required for wind generation resources.

⁴ NEWIS materials are available at http://www.iso-ne.com/committees/comm_wkgrps/prtcpts_comm/pac/mtrls/2010/nov162010/index.html and http://www.iso-ne.com/committees/comm_wkgrps/prtcpts_comm/pac/mtrls/2009/nov182009/newis_slides.pdf.

Finally, ISO-NE has begun discussions with New England wind stakeholders concerning data collection in real time and near real time to begin developing a wind forecast. ISO-NE expects to continue this work and have a forecast in place during calendar year 2012, which is the anticipated timeframe when the region expects to have wind resources approaching the 500 MW to 1,000 MW levels detailed above. At that time, ISO-NE would expect to participate in the metrics for wind forecasting and would provide the data in accordance with business processes envisioned by FERC.

Unscheduled Flows

Because of its geographical and electrical relationship with other systems in the Eastern Interconnection and based on the New England congestion management system specified in the ISO-NE *Open Access Transmission Tariff* (OATT) filed and approved by FERC, ISO-NE does not use the transmission-loading relief (TLR) procedures for managing congestion on the inter-balancing authority “interchange” transactions. ISO-NE is not subject to parallel flows within its footprint because of the radial interconnection with the remainder of the Eastern Interconnection. When necessary, ISO-NE-initiated curtailments are accomplished by transmission scheduling software in conjunction with security-constrained dispatch to meet all reliability requirements. These curtailments can be completed and executed in real time according to the rules specified in the ISO-NE OATT. ISO-NE does monitor and will respond to TLRs called throughout the Eastern Interconnection by other reliability entities where ISO-NE transactions may be a contributing factor.

Transmission Outage Coordination

ISO-NE coordinates transmission and generation facility outages under the authority granted in the Transmission Operating Agreements (TOAs) and market rules that define the ISO's responsibilities and obligations to operate the New England transmission system. ISO-NE also operates in accordance with all related governing documents, including FERC, regional and national reliability standards, and ISO-NE operating documents. ISO-NE's role in outage coordination is multifaceted with several aims, as follows:

- Maintain overall system reliability
- Minimize congestion and thereby reduce overall costs to New England consumers
- Provide timely and accurate information for the Financial Transmission Rights (FTR) market
- Minimize conditions that would impede the ability of generators to participate in the wholesale electricity markets
- Coordinate with neighboring reliability coordinators and balancing authorities.

ISO-NE coordinates all the transmission and generation outages with New England transmission owners (TOs), local control centers (LCCs), and New England generation owners/operators (GOs). This includes conducting reliability assessments of the transmission system and operable capacity, evaluating congestion cost impacts, and rescheduling outages when conflicts or violations could occur. In addition, ISO-NE and TO senior management meet quarterly to monitor progress made in coordinating transmission equipment outages and provide direction and feedback to operations.

The ISO, TOs, LCCs, and GOs have embarked on a multiyear effort to improve outage coordination within the region, which has focused on the following:

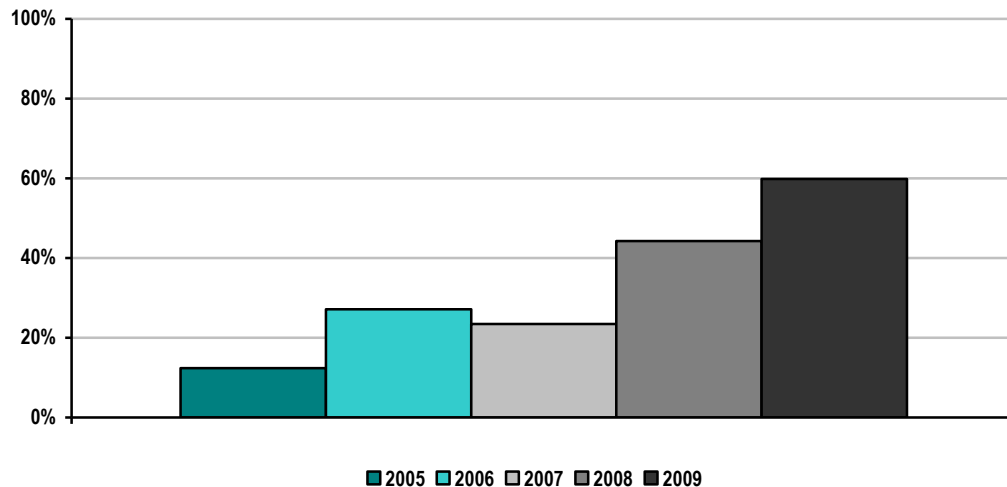
- Establishing a set of broad performance-based outage-coordination metrics to allow all parties to assess their performance regarding transmission outage coordination
- Enhancing the coordination process and procedures through cooperation by all entities (ISO-NE, TOs, LCCs, and GOs) to implement best business practices
- Implementing increased communications, both through conference calls and face to face, among TOs, LCCs, and GOs to better coordinate and facilitate outage requests
- Emphasizing outage-coordination plans during discussion at the quarterly meetings with nuclear plants
- Improving the handling of detailed outage information through the use of new web-based outage-coordination software
- Ensuring that all contributors to the outage process at all levels (project management, engineering, field, and operation personnel) are aware of the benefits of a broad coordination approach to the planning and scheduling of transmission and generator equipment outages

- Improving advanced notification to the New England stakeholders of upcoming transmission outages by way of the publicly distributed Long-Term Outage Report
- Increasing emphasis on the coordination of major transmission element (MTE) outage planning through a new metric
- Providing incentives to all parties to move toward longer lead times on outage requests (90-day minimum) through a new metric

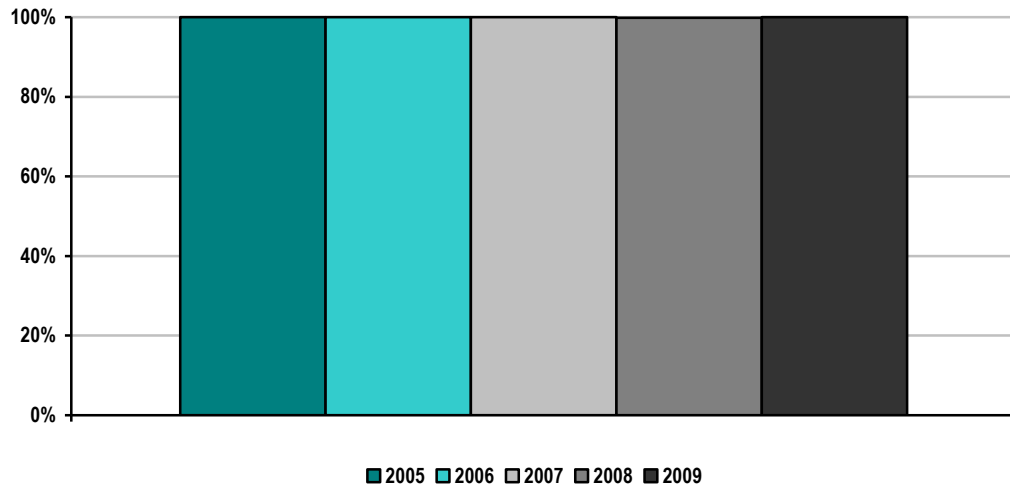
The efforts to improve outage coordination have been concurrent with a significant increase in transmission outage requests resulting from the substantial transmission build-out by the TOs. As the metrics indicate, ISO-NE, collaboratively with the TOs and LCCs, has improved the lead time of request submissions, reduced last-minute cancellations, and minimized unplanned outages while handling an outage-request volume that has increased approximately 40% over the past six years.

The following figures show ISO-NE transmission outage information for 2005 through 2009. The first figure reflects ISO-NE's percentage of >200 kV planned outages of five days or more submitted to ISO-NE at least one month before the outage-commencement date. The second shows the percentage of planned outages studied in the timeframes established in ISO-NE's tariff and manuals. The third figure shows the percentage of >200 kV outages previously approved but cancelled by ISO-NE, and the last figure shows the percentage of unplanned >200 kV outages.

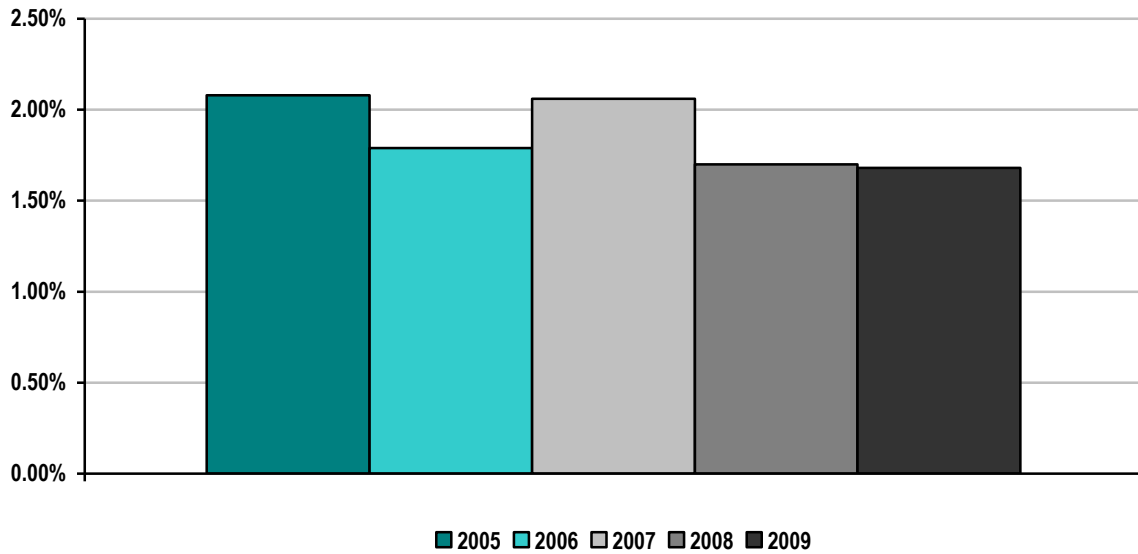
Percentage of >200 kV Planned Outages of Five Days or More Submitted to ISO-NE at Least One Month Before the Outage Commencement Date, 2005–2009



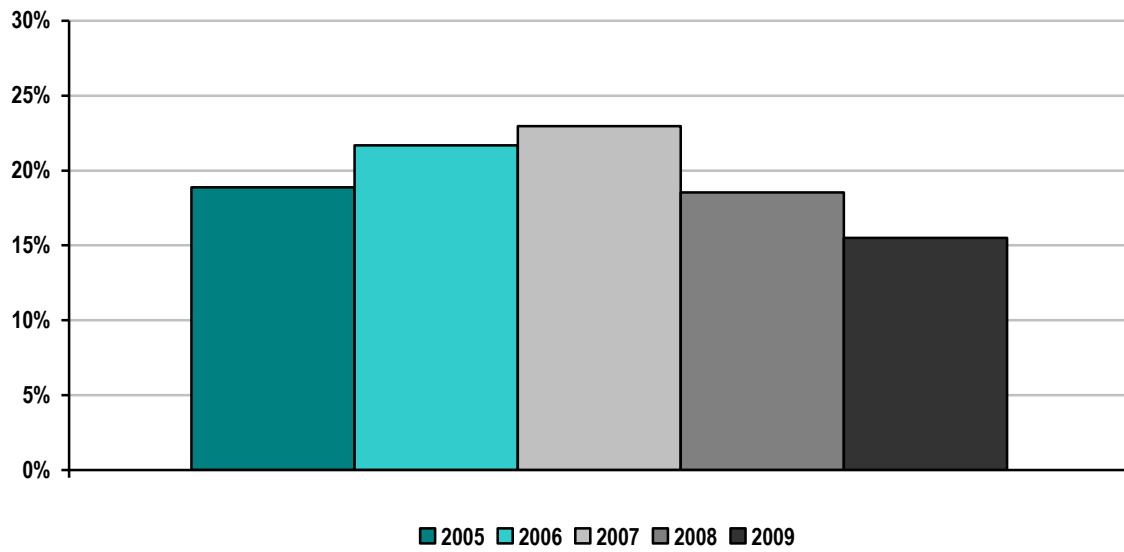
Percentage of Planned Outages Studied in ISO-NE's Tariff/Manual-Established Timeframes, 2005–2009



Percentage of >200 kV Outages Previously Approved but Cancelled by ISO-NE, 2005–2009



ISO-NE Percentage of Unplanned >200 kV Outages, 2005–2009



Transmission Planning

This ISO/RTO performance category includes several transmission planning metrics. The metric for the number of facilities approved to be constructed for reliability purposes was determined using the ISO-NE *Regional System Plan (RSP) Project List*.⁵ The *RSP Project List* is a summary of transmission projects for the region and includes information on project status and cost estimates. Some of these projects are proposed for regional reliability; others are proposed for market efficiency or are merchant transmission projects. The *RSP Project List* is compiled at least three times per year and reviewed by the Planning Advisory Committee (PAC). The projects on the list are classified, as follows, according to their progress through the study and stakeholder planning processes:

- Concept
- Proposed
- Planned
- Under construction
- In service
- Cancelled

A transmission project is considered “planned” when ISO-NE has approved it under Section I.3.9 of the ISO New England Tariff.⁶ Transmission projects with a status of “under construction” or “in service” have received approval under Section I.3.9 of the tariff.

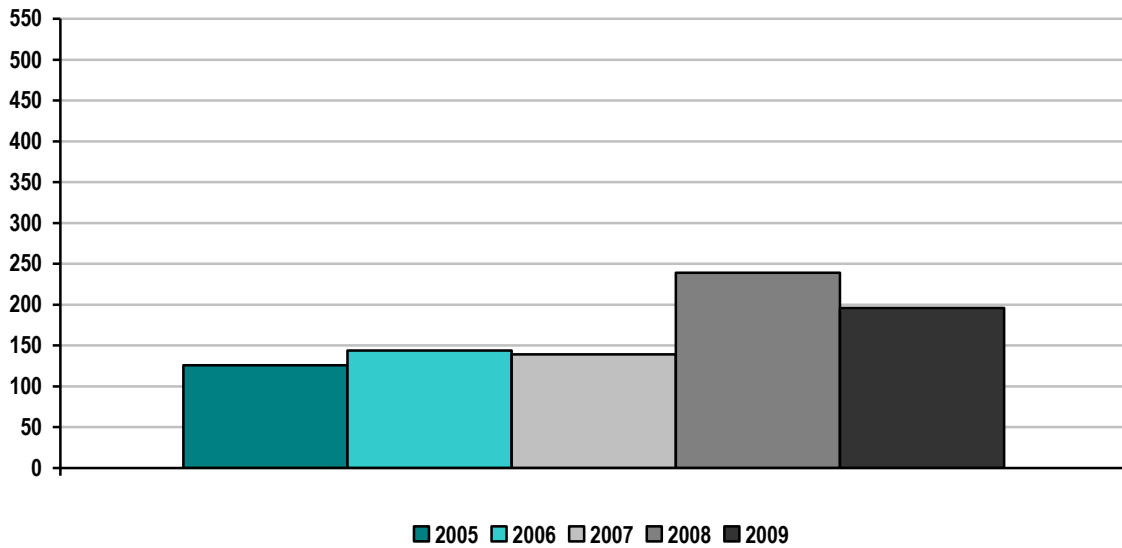
The information used for calculating the number of facilities approved in each year, as shown in the following graph, was based on the status of each project within the *RSP Project List*. In each year, transmission projects that progressed to “planned,” “under construction,” or “in service” were included, also as reflected in the following graphs.⁷ The second graph below, which depicts completed projects with ISO-NE approval, was created by comparing the number of projects that either were “under construction” or “in service” with the number of projects that were “approved.” Therefore, in the years where a significant number of new “approved” projects were added to the *RSP Project List*, the graph may show a significant decrease in the percentage of projects that were completed. In recent years, New England has placed a substantial amount of new transmission projects in service; these include new 345 kV transmission into northern Maine from New Brunswick and in southwestern Connecticut and Boston. All approved transmission projects are progressing through the implementation process and are anticipated to be constructed and placed in service unless system conditions change in a way that affects the overall need for a project. Because of new resources coming on line and changes in the demand forecast, the need for some projects in southern New England are under review.

⁵ The current *RSP Project List* is located at: http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/projects/index.html

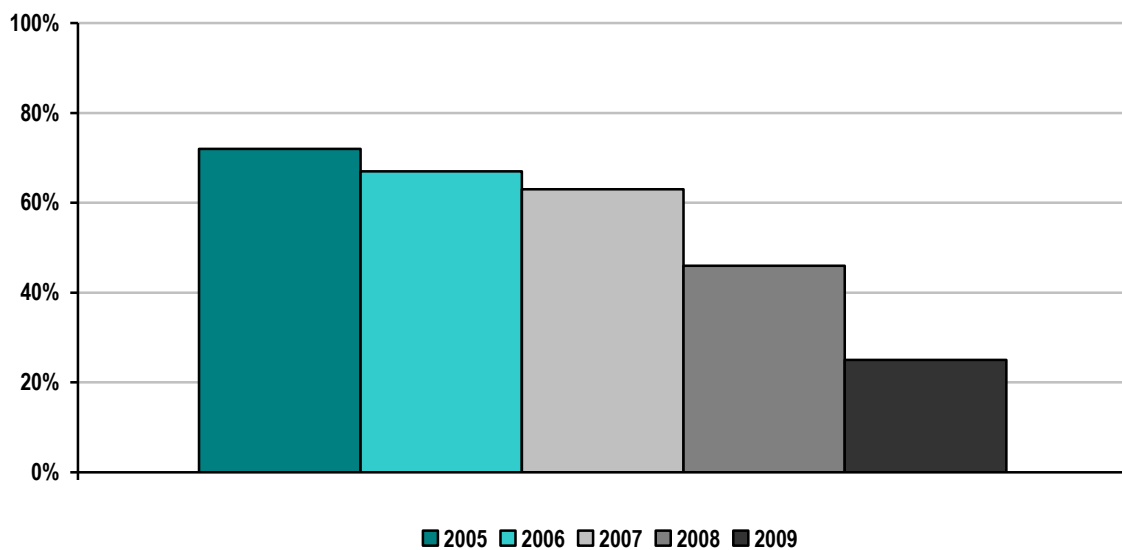
⁶ This part of the ISO tariff covers the review of participants’ proposed plans; see http://www.iso-ne.com/regulatory/tariff/sect_1/section_1.pdf

⁷ The graphs reflect many project components accounted for individually that are part of larger projects.

Number of ISO-NE Transmission Projects Approved to Be Constructed for Reliability Purposes, 2005–2009



Percentage of ISO-NE Approved Construction Projects Completed by December 31, 2009



This ISO/RTO performance metric identifies the completion of FERC Order 890 Reliability Studies. An assessment and mitigation plan update of New England’s pool transmission facilities (PTFs) has been conducted annually for 2005 through 2009. ISO-NE has demonstrated compliance with NERC and NPCC standards in each of these years.⁸

On an ongoing basis, ISO-NE, in coordination with the participating TOs and the PAC, assesses the needs (i.e., conducts “Needs Assessments”) of the adequacy of the regional transmission system (i.e., the PTFs), as a whole or in part, to maintain the reliability of these facilities while promoting the operation of an efficient wholesale electricity

⁸ The NPCC website is located at: <http://www.npcc.org>

market within New England. A Needs Assessment analyzes whether each PTF within New England's transmission system complies with the following requirements:

- Meets applicable reliability standards
- Has adequate transfer capability to support local, regional, and interregional reliability
- Supports the efficient operation of the wholesale electric markets
- Is sufficient to integrate new resources and demands on a regional basis
- Has otherwise various satisfactory aspects of performance and capability.

These Needs Assessments also identify the following:

- The location and nature of any potential problems with respect to the PTF
- Situations or scenarios that significantly affect the reliable and efficient operation of the PTF, along with any critical time constraints for addressing the needs of the PTF to develop market responses and to pursue regulated transmission solutions

In conjunction with the proponents of regulated transmission solutions and other interested or affected stakeholders, ISO-NE conducts and participates in "Solutions Studies" (i.e., mitigation plans) to develop and refine regionally cost-effective regulated transmission solutions to meet the PTF system needs identified in Needs Assessments. Each proposed transmission solution is then individually and comprehensively evaluated to ensure that it meets the established need(s) and is sufficiently robust to prevent significant adverse impacts on the reliability, stability, or operating characteristics of the existing or future power system. All studies are conducted in an organized and coordinated manner, many individual ones under the direction of ISO-NE. The aggregate result is a complete annual assessment of the New England PTFs and an update of the Regional System Plan to address various needs.

Market responses—which may include but are not limited to resources such as demand-side projects, distributed generation, and merchant transmission facilities—are reflected in Needs Assessments as long as they have an obligation through the wholesale power markets, such as the Forward Capacity Market, or have contracted with a third party, such as a state sponsored RFP. Demand response and other resources may assist in resolving reliability issues and possibly defer transmission solutions, provided they are adequately integrated into the system. For demand response to be truly effective in some locations, without compromising the ability to operate other resources or demand response in other locations, adding transmission may be needed. To date, demand response has had varying impacts on the need for continued transmission infrastructure investment in New England. Transmission projects have been reviewed as newly committed demand response has been obtained. In many cases, these resources have been insufficient in quantity or could not be implemented in locations granular enough to address a specific reliability concern. In other cases, the addition of demand response both has aided in deferring some transmission needs and has contributed to causing others.

ISO-NE has started a new initiative to begin evaluating new, innovative technologies because these technologies may be a partial or full solution for reliability issues, which could potentially defer or eliminate the need for

transmission solutions. Technologies such as flywheels, battery and thermal storage, vehicle-to-grid (V2G), and various other smart grid technologies are being evaluated for integration into the power system. New England is implementing several smart grid projects in line with the vision established in the *Energy Independence and Security Act of 2007*.⁹ In response to FERC Order 890 regarding the provision of regulation and frequency services by nongenerating resources, ISO-NE is conducting an Alternative Technology Regulation (ATR) Pilot Program.¹⁰ The goal of the ATR Pilot Program is to allow the ISO to identify alternative technologies with new and unique performance characteristics that may have been unable to participate in the Regulation Market. It also aims to allow the owners of these ATR resources to evaluate the technical and economic suitability of their technologies as market sources of regulation service.¹¹

Since 2007, ISO-NE has performed annual economic studies as part of its long-term planning process in compliance with FERC Order 890. Stakeholders are invited to submit study requests by April 1 of each year. ISO-NE then designates up to three economic studies to be performed. Study requests dealing with a specific project proposal or suggesting a specific policy position are not considered appropriate and are subsequently disregarded. All other economic study requests have been incorporated into recent study efforts, as the subject of primary investigation or as a sensitivity case to another effort, either directly or through analysis of a comparable “generic” project. The following table shows the number of economic studies requested and conducted for 2007 to 2009.

Number of Economic Studies Requested and Conducted in ISO-NE, 2007 to 2009

Year	Number of Requests Received	Number of Economic Studies	Number of Requests Addressed
2007	0	1	0
2008	11	1	9
2009	6	2	5

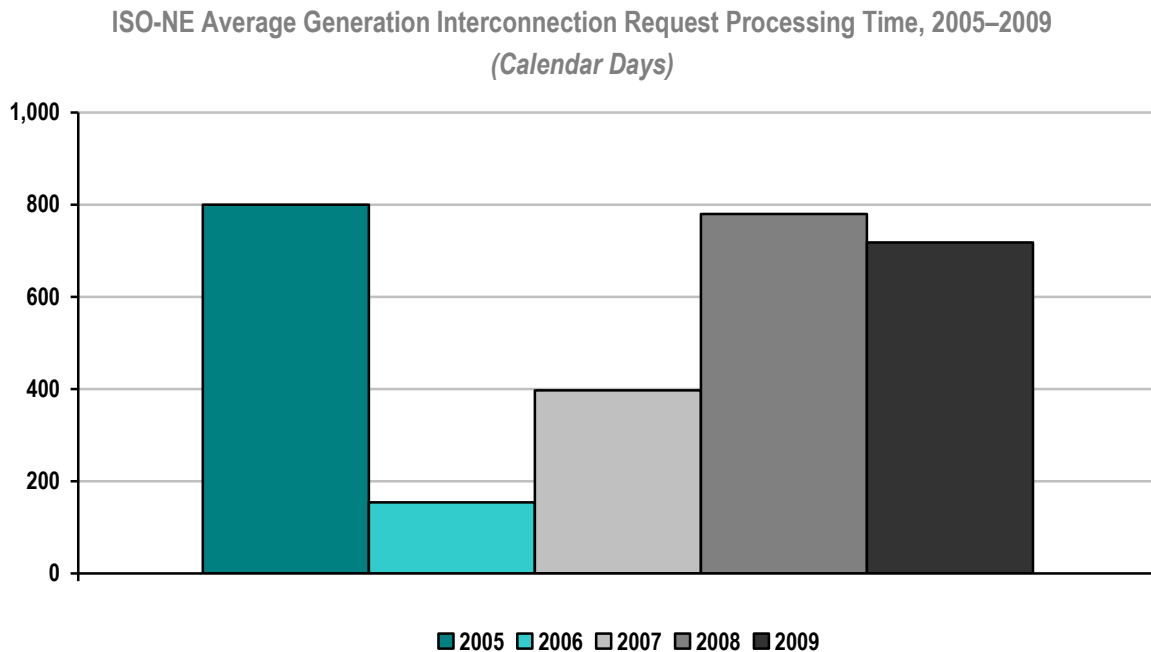
⁹ U.S. Congress, *Energy Independence and Security Act of 2007* (January 4, 2007); http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=110_cong_bills&docid=f:h6enr.txt.pdf.

¹⁰ *Preventing Undue Discrimination and Preference in Transmission Service, Final Rule*, FERC Order No. 890, Docket Nos. RM05-17-000 and RM05-25-000 (February 16, 2007); <http://www.ferc.gov/whats-new/comm-meet/2007/021507/E-1.pdf>. “Alternative Technology Regulation Pilot Program Frequently Asked Questions” web page (2009); <http://www.iso-ne.com/support/faq/atr/index.html>.

¹¹ Beacon Power has installed 2 MW of flywheels, which have provided regulation services from a location in Tyngsboro, Massachusetts. “Beacon Power Connects Second Megawatt of Regulation Service,” *Business Wire* (July 20, 2009); http://www.businesswire.com/portal/site/home/permalink/?ndmViewId=news_view&newsId=20090720005598&newsLang=en.

Generation Interconnection

The metric for the processing time for generation interconnection requests (IRs) was calculated using the date of an interconnection request as the start date. The end date was either the date an interconnection agreement (IA) was executed or the date the interconnection request was withdrawn. In each year, projects that executed an interconnection agreement or that withdrew are included in the average processing time for that year.



Processing time encompasses a number of tasks, as follows:

- Interconnection request review and validation
- Scoping meeting
- Study agreement development
- Study agreement execution by the interconnection customer
- Feasibility studies
- System impact studies
- Facilities studies
- Interconnection agreement development

The types of IRs that undergo these tasks include generation interconnection requests, elective transmission upgrade requests, and requests for transmission service that require study. The data do not include generator interconnection requests that did not fall under FERC's jurisdiction.

Several older projects, which were either capacity upgrades or equipment replacements associated with existing generators, did not result in any changes to the existing interconnection agreements. In these cases, the date of the approval of the proposed plan was used as the end of the process. Several projects withdrew after executing an interconnection agreement. In these cases, the execution of the interconnection agreement was considered to be the end of the process.

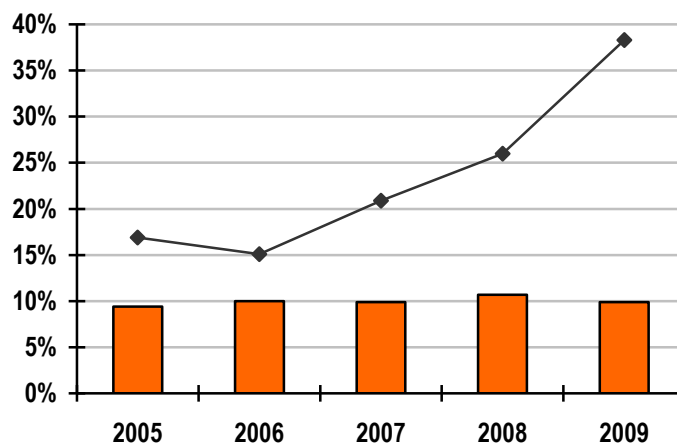
In general, a shorter processing time is preferred. The factors that contribute to the year-to-year variations in processing time include (1) the number of IRs or project withdrawals received each year, (2) the dependence of later-queued projects on earlier-queued projects, and (3) tariff requirements allowing customers to waive or combine phases of the interconnection process.

Initiating and performing meaningful wind interconnection studies continues to be challenging. Wind manufacturers have been slow to provide sufficiently accurate models to allow for the expeditious completion of studies. Complex control interactions have become a factor in wind interconnection studies and have become a risk because of the nature of electronic controls on most wind power plants and the location of many wind plants in remote, and often weak, locations on the transmission system. This has created the potential need for even more detailed modeling from the manufacturers, which further increases the study time.

Planned and Actual Reserve Margins, 2005–2009

This ISO/RTO performance metric compares ISO-NE’s actual reserve margins (ARMs) with planned reserve margins (PRMs), in megawatts. A discussion of the results and findings for New England is provided below. In the following figure, the bars represent PRMs, and line represents ARMs.

ISO-NE Planned and Actual Reserve Margins, 2005–2009



Actual Reserve Margin: The ARM is based on data published annually within ISO-NE's *Forecast Report of Capacity, Energy, Loads, and Transmission* (CELT Report).¹² Information for the ARM for a particular year and as a percentage of load is included in the CELT Report in the next year's publication.

Planned Reserve Margin: The PRM is based on the Net Installed Capacity Requirement (NICR), which ISO-NE sets annually for the region.¹³ The value for a particular year can be obtained by applying the following formula using the NICR (August value, if monthly NICR values are published) and the forecasted annual peak load published in ISO-NE's CELT Report for that year:

$$\text{PRM MW} = (\text{NICR MW}) - (\text{Forecast Annual Peak Load MW})$$

The PRM also can be expressed as a percentage of forecasted annual peak load using the following formula:

$$[(\text{PRM MW}) / (\text{forecasted annual peak load MW})] \times 100$$

The following table compares ISO-NE's ARMs and PRMs for 2005 through 2009.

ISO-NE Actual and Planned Reserve Margins, 2005–2009

Year	Reserve Margin Type	Reserve Margin (MW)	Reserve Margin (%)
2005	Actual	4,538	16.9
	Planned	2,472	9.4
2006	Actual	4,253	15.1
	Planned	2,716	10.0
2007	Actual	5,458	20.9
	Planned	2,712	9.9
2008	Actual	6,795	26.0
	Planned	2,990	10.7
2009	Actual	9,603	38.3
	Planned	2,748	9.9

The lowest ARM occurred in 2006 at 4,253 MW and 15.1%, and the highest was in 2009 at 9,603 MW and 38.3%. The lowest PRM occurred in 2005 at 2,472 MW and 9.4%, and the highest was in 2008 at 2,990 MW and 10.7%. ISO-NE believes that New England has one of the lowest installed reserve margins of all balancing authority areas and that it is reliant to a greater degree than other areas on tie-line benefits and emergency actions to meet its installed capacity requirement. The ISO currently is discussing these topics with its stakeholders. If the tie-line

¹² The CELT Report, *2010-2019 Forecast Report of Capacity, Energy, Loads, and Transmission*, is available at <http://www.iso-ne.com/trans/celt/report/index.html>.

¹³ NICR = ICR – HQICC (Hydro-Quebec Installed Capacity Credit).

benefits and emergency actions are taken into consideration, the resultant PRM will be more comparable to other balancing authority areas.

ISO-NE's Forward Capacity Market (FCM) transition period (2007–2009) encouraged the installation of capacity. Under the FCM Settlement Agreement, the amount of unforced capacity that could request inclusion was not capped, thus ISO-NE had more capacity than needed to meet its peak load and operating reserve requirements. This can be seen by the increase in the ARM from 2007 to 2009; the 2009 ARM is more than double both the 2005 and 2006 ARMs. Most of the increase during this period was the result of growth in the participation of demand-response resources and increased capacity imports in response to the FCM transition payment rate, which was in excess of prevailing rates in adjacent regions. The gap between ARMs and PRMs can be expected to increase over the next several years, as additional capacity enters the market in response to the FCM price floor which, like the FCM transition rate, is above prevailing rates in external regions. The gap is not expected to decline toward previous historical norms until the price floor is removed and as the FCM market matures over several years. As shown by the planned and actual reserves trend, the market has responded to ISO-NE's Forward Capacity Market signals, and a more than adequate amount of resources has been installed to meet the resource adequacy needs of the region.

ISO-NE's FCM began on June 1, 2010. Each annual Forward Capacity Auction (FCA) procures capacity resources to meet the region's projected resource adequacy requirement three years in the future. Additional resources or portions of resources without a capacity supply obligation (CSO) may continue to participate in the energy and reserves markets and provide additional installed capability.¹⁴ The quantity of resources procured in the FCA is derived by proposing an Installed Capacity Requirement (ICR) value.¹⁵ The ICR is a measure of the installed capacity resources projected to be necessary to (1) meet reliability standards in light of total forecast load requirements for the New England Balancing Authority Area, and (2) maintain sufficient reserve capacity to meet reliability standards. More specifically, the ICR is the quantity of resources needed to meet the reliability requirements defined for the New England Balancing Authority Area of disconnecting noninterruptible customers no more than one time every 10 years (0.1 loss-of-load expectation).

ISO-NE develops the load forecast primarily using the methodology it has used for a number of years. However, the forecast continues to reflect incremental improvements to the forecasting methodology as well as economic and demographic assumptions reviewed periodically and supported by the NEPOOL Load Forecast Committee (LFC). The methodology is updated when deemed necessary in consultation with the NEPOOL LFC.¹⁶ The peak-load forecasts of the entire New England Balancing Authority Area are a major input into the calculation of the ICR, and

¹⁴ In the ISO-NE system, a *capacity supply obligation* is a requirement for a resource to provide capacity, or a portion of capacity, to satisfy a portion of the ISO's Installed Capacity Requirement acquired through a Forward Capacity Auction, a reconfiguration auction, or a CSO bilateral contract through which a market participant may transfer all or part of its CSO to another entity.

¹⁵ The methodology for calculating the ICR is set forth in Section III.12 of *Market Rule 1*. The ICR is eventually reviewed and approved by FERC.

¹⁶ Two locations on ISO-NE's website contain more detailed information on short-run and long-run forecast methodologies; models and inputs; weather normalization; forecasts of regional, state, and subarea annual electric energy use and peak loads; high- and low-forecast bandwidths; and retail electricity prices. This information is located at: <http://www.iso-ne.com/markets/hstdata/hourly/index.html> and http://www.iso-ne.com/trans/celt/fsct_detail/index.html.

the peak-load forecasts for the individual load zones are used to develop the associated local sourcing requirements (LSRs) from import-constrained load zones and maximum capacity limits (MCLs) from export-constrained load zones.

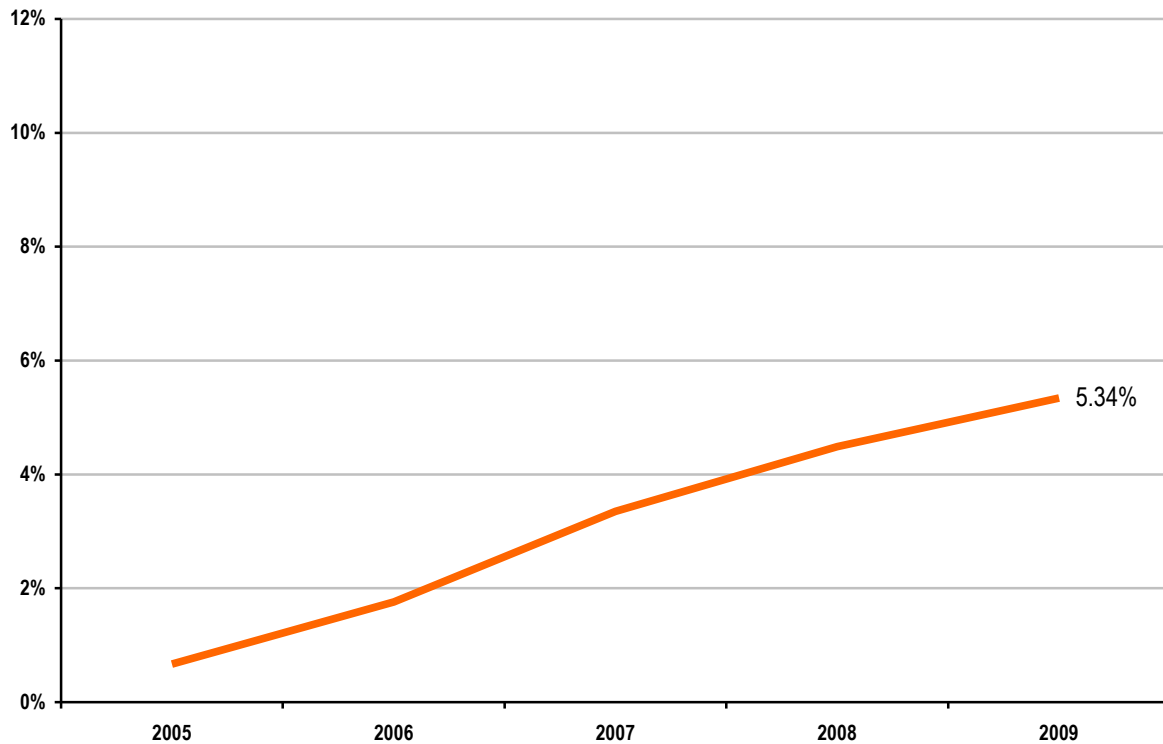
The FCM is designed to address changes in (1) the load forecast, (2) resource availability, and (3) load and capacity relief assumed obtainable by the implementation of operator actions during a capacity deficiency that occurred during the three-year period between administering the applicable FCA and the corresponding capacity commitment period (CCP). For each CCP, ISO-NE conducts three Annual Reconfiguration Auctions (ARAs) during the interim period that adjusts the amount of regional capacity procured within the FCA.

To calculate the ICR for each ARA, ISO-NE uses the most recent version of the 10-year load forecast, as published in April of each year in the most current CELT Report. By accounting for fluctuations in the load forecast, resource availability, and emergency actions for load and capacity relief from system operators, the development of the ICR for each ARA ultimately ensures that the correct amount of regional capacity is procured to ensure system reliability.¹⁷

With the implementation of the FCM, both demand-side resources and supply-side resources can provide capacity. While demand response has participated in the ISO-NE capacity markets since 1998, the number of demand resources providing capacity to the region has grown considerably. Since opening up the capacity market to demand-side resources in 2006, the region has seen the amount of demand response grow from 500 MW to more than 2,000 MW. The following graph shows the percentage of compensated capacity during summer (peak) months that was categorized as demand response.

¹⁷ Within ISO-NE's FCM, both active (demand response) and passive (energy efficiency) demand-side resources are allowed to be treated as supply-side capacity to serve regional load. Past and future nonmarket demand response and energy efficiency are not nor will be reflected within the ICR calculation. Thus, in turn, they are not nor will be reflected in the ARM or PRM.

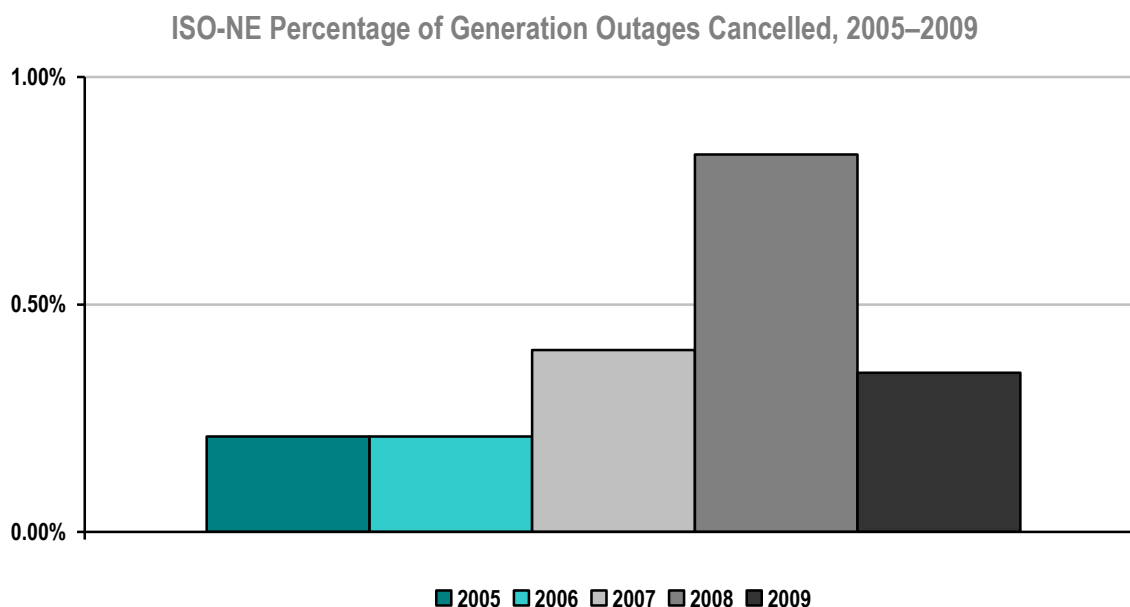
ISO-NE Demand-Response Capacity as a Percentage of Total Installed Capacity, 2005–2009



To achieve further benefits from the increase in demand resources, ISO-NE recently implemented improvements to the software and communications infrastructure used between demand resources and the ISO during real-time operations. In 2011, new dispatch rules will be in place to allow operators to call on demand resources where, when, and in the amount they are needed.

Percentage of Generation Outage Cancelled by ISO-NE

ISO-NE may cancel a planned generation outage if it assesses a potential reliability concern arising from the outage or if the amount of available capacity could be affected by the proposed outage. The following graph shows the percentage of planned generation outages ISO-NE cancelled from 2005 through 2009.



Generation Must-Run Contracts

The following table provides details about the Reliability Agreements in place with units within the New England Balancing Authority Area from 2005 through 2009. To ensure system reliability, local generation may be required to run where the system is constrained. Through its planning processes, ISO-NE develops transmission alternatives to ensure continued reliability of the power system and forecasts resource capacity requirements to meet forecast demands.

Through competition in the Forward Capacity Market and transmission system improvements, the number of generating units being compensated through Reliability Agreements has trended downward over time. All “must-run” generation contracts were terminated as of June 2010.

ISO-NE “Must-Run” Generation Contracts, 2005–2009

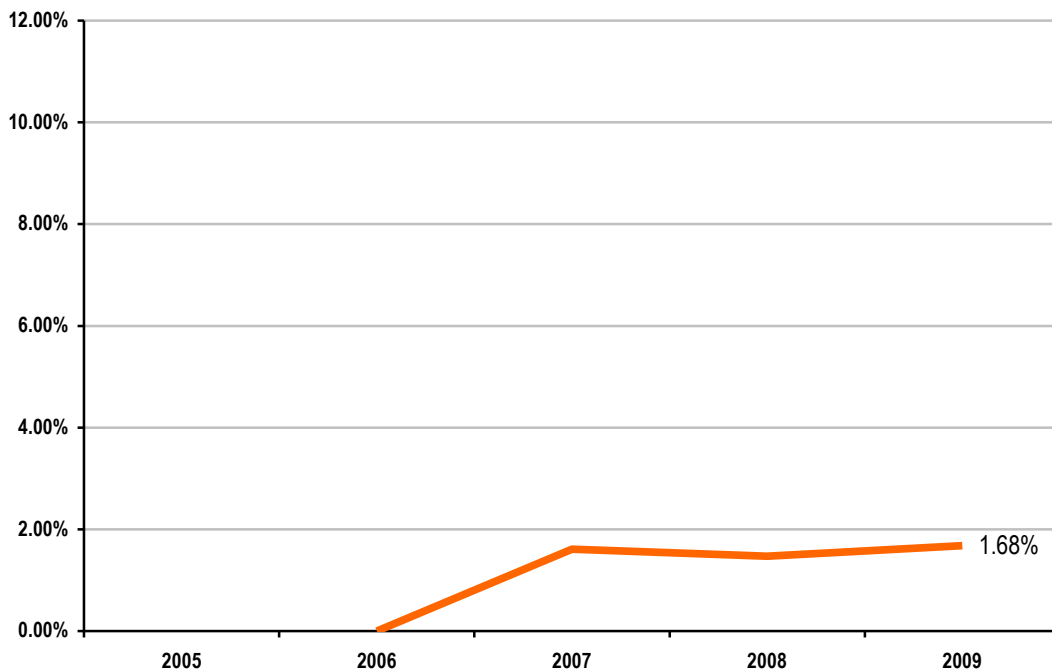
Year	Number of Units	Total MW	% of Systemwide Capacity	Total Reliability Payments
2005	14	4,719	15	\$223,706,539
2006	14	6,294	19	\$348,687,863
2007	9	3,203	10	\$140,755,214
2008	9	3,200	10	\$127,217,346
2009	8	2,711	9	\$84,925,919
			Total	\$925,292,881

In New England, a Demand-Response Reserve (DRR) Pilot Program was implemented on October 1, 2006, with the goal of determining how small demand-response resources (with a maximum load reduction of less than 5 MW) would perform under frequent dispatch conditions similar to those of generators dispatched for system contingencies. The first phase of the DRR Pilot Program commenced on October 1, 2006, and continued through September 30, 2008.

Under the DRR Pilot Program, ISO-NE separately solicited demand-response resources for each winter and summer season in the same timeframes as the Forward Reserve Market (FRM) procurement periods. A variety of small demand-response resources were selected to represent the population of resources that would likely participate in a competitive market.

The following table shows the percentage of ancillary services (defined as hourly total 30-minute reserve requirement) supplied by DRR assets:

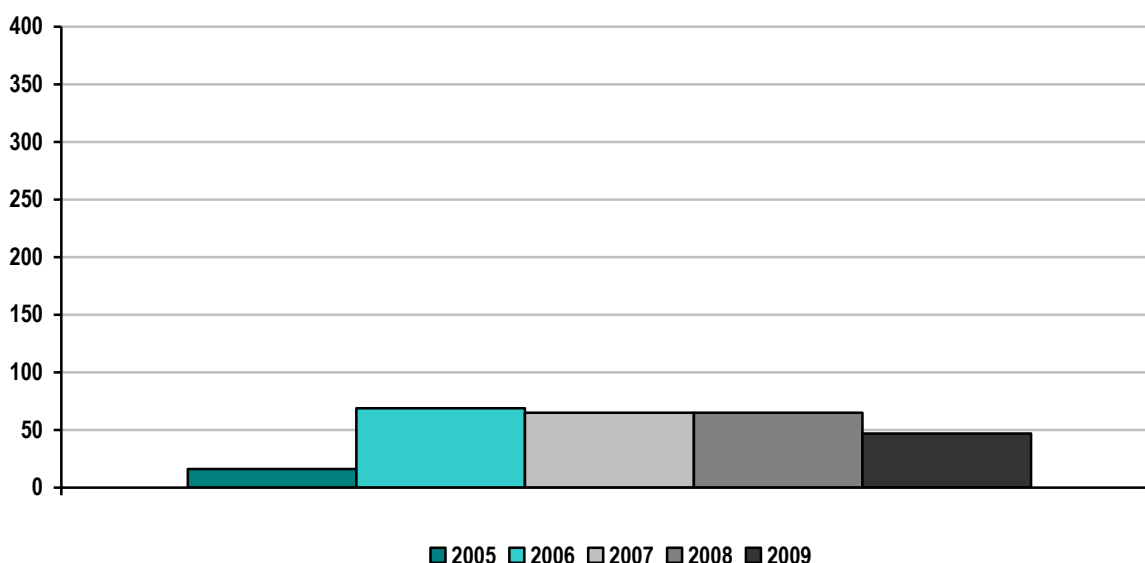
ISO-NE Demand Response as a Percentage of Synchronized Reserve Market, 2005–2009



Interconnection/Transmission Service Requests

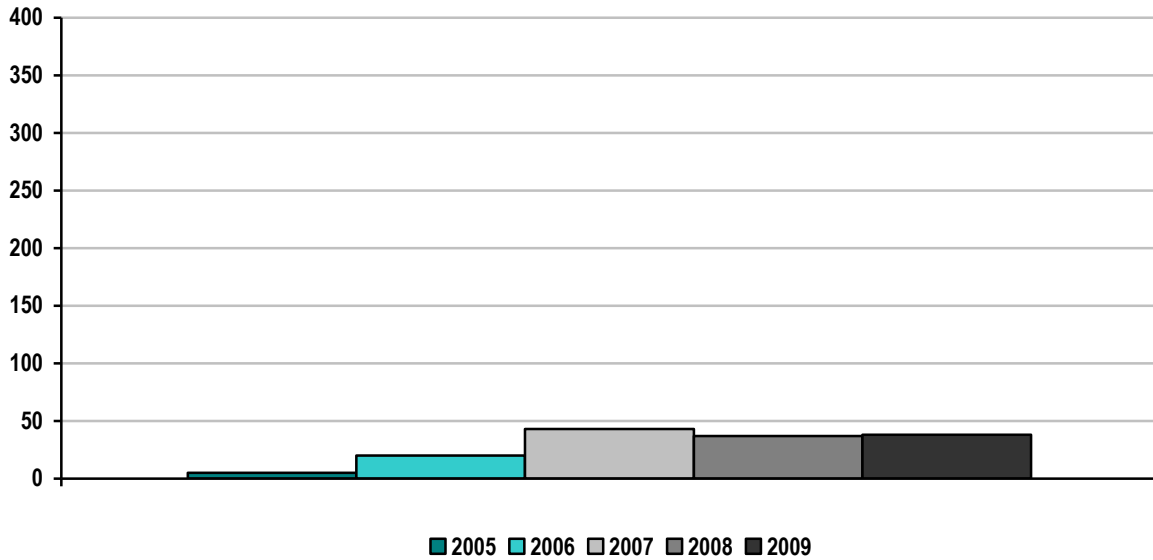
This ISO/RTO performance metric identifies the number of requests to ISO-NE for interconnection service or transmission service. The metric for the number of requests for 2005 to 2009, as shown in the following graph, was calculated by summing the number of requests ISO-NE received in a calendar year. The majority of the projects are associated with generation interconnection requests, while only a handful of projects are associated with elective transmission upgrade requests and requests for transmission service that require study. Factors affecting the number of interconnection study requests include standards resulting from FERC's Orders 2003 and 2006, the implementation of New England's Forward Capacity Market, state requests for proposals (RFPs) for generation resources, and state policies regarding treatment of renewable resources. To limit the number of interconnection requests based on speculative project proposals that caused a backlog in the interconnection queue, in 2009, FERC accepted amendments to ISO-NE's tariff, which increased the deposit structure for large generating facilities seeking interconnection. ISO-NE understands formal complaints to mean Section 206 complaints, and no entity has filed such a formal complaint against ISO-NE.

ISO-NE Number of Interconnection Study Requests, 2005–2009



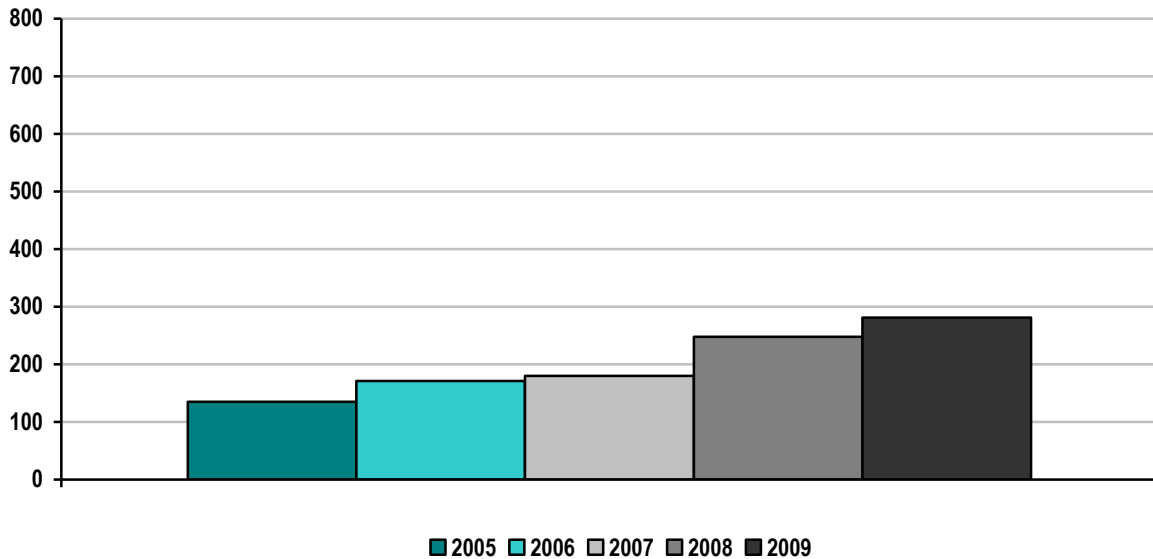
The indices in the next graph were calculated by totaling the number of studies completed in a calendar year. The studies included feasibility, system impact, and facilities studies for generation interconnection requests; elective transmission upgrade requests; and requests for transmission service that require study. These indices do not include studies for generator interconnection requests that did not fall under FERC's jurisdiction. Projects that were queued later may be electrically dependent on the results from projects that were queued earlier. This limits the number of studies that can be conducted simultaneously.

ISO-NE Number of Studies Completed, 2005–2009



The indices in the graph below were calculated by summing the age of incomplete studies as of December 31 of a calendar year. To determine the age of a study, the start date used was the date on which the study agreement was fully executed. The studies included feasibility, system impact, and facilities studies for generation interconnection requests; elective transmission upgrade requests; and requests for transmission service that require study. These indices do not include studies for generator interconnection requests that did not fall under FERC’s jurisdiction.

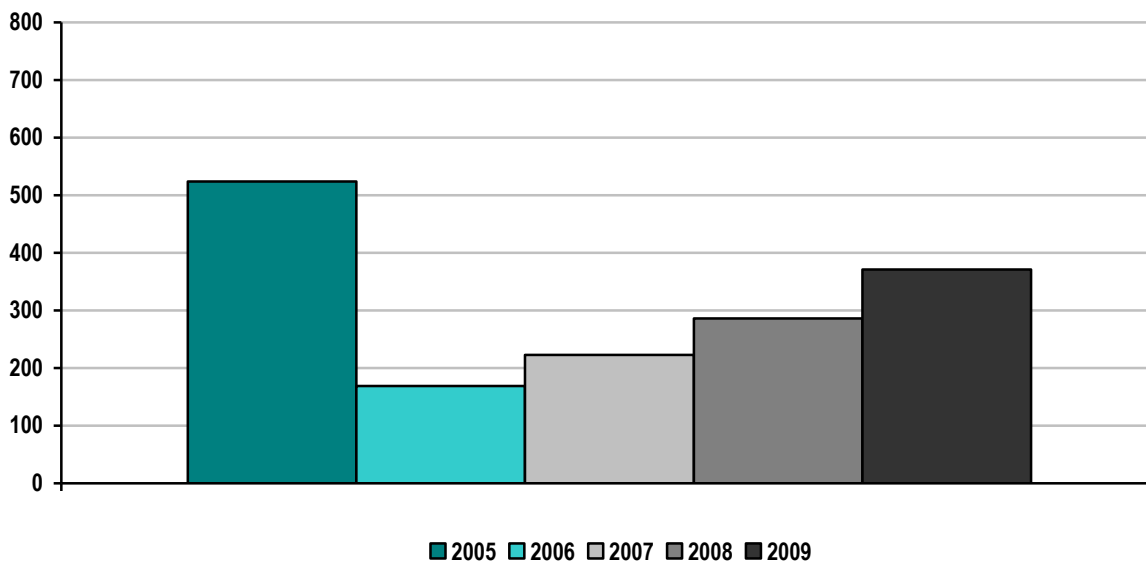
ISO-NE Average Age of Incomplete Studies, 2005–2009
(Calendar Days)



ISO-NE conducts studies in the order they enter the interconnection queue. Thus, the start of one study can be delayed if another study, with an earlier queue position, must be completed.

The indices in the next graph were calculated by summing the ages of studies completed in a calendar year. To determine the age of a study, the start date used was the date on which the study agreement was fully executed. The studies included feasibility, system impact, and facilities studies for generation interconnection requests; elective transmission upgrade requests; and requests for transmission service that require study. The indices do not include studies for generator interconnection requests that did not fall under FERC's jurisdiction.

ISO-NE Average Time to Complete Studies, 2005–2009
(Calendar Days)



Average Cost of Each Type of Study Completed

To determine the cost of a study, the annual expenses for a project were summed and counted in the year the study was completed. These expenses were then averaged for projects completed during a given year. The studies included feasibility, system impact, and facilities studies for generation interconnection requests; elective transmission upgrade requests; and requests for transmission service that require study. The indices do not include studies for generator interconnection requests that did not fall under FERC's jurisdiction.

Several issues affect the calculated indices:

- Average study costs may include costs that were incurred by the respective transmission owners performing the requested and necessary studies, which were then submitted to ISO-NE for direct billing back to the requesting customer.
- Before 2006, few feasibility studies and system impact studies were performed by transmission owners, who billed the interconnecting customers directly. The total costs of these studies are not readily available.
- The cost of developing an interconnection agreement typically is included in the cost of a system impact study, which increases the apparent cost of system impact studies.

- In several cases, a system impact study has been completed, but development of the interconnection agreement is continuing into 2010.
- Facilities studies were often performed by the transmission owner, who then billed the interconnecting customers directly. The total costs of these studies are not readily available.
- Facilities studies may be waived under ISO-NE's tariff. This accounts for the low number of facility studies.

The calculated indices are shown in the following tables.

Number of Completed Feasibility Studies by ISO-NE, 2005–2009

Year	Number of Completed Feasibility Studies	Number of Completed Feasibility Studies With Cost Data	Cost of Studies Completed in Calendar Year
2005	0	0	Not Applicable
2006	7	5	\$62,824
2007	18	17	\$66,823
2008	15	15	\$72,053
2009	16	16	\$72,095

Number of Completed System Impact Studies by ISO-NE, 2005–2009

Year	Number of Completed System Impact Studies	Number of Completed System Impact Studies With Cost Data	Cost of Studies Completed in Calendar Year
2005	5	2	\$28,285
2006	13	11	\$83,370
2007	23	22	\$85,896
2008	21	21	\$88,645
2009	20	20	\$98,926

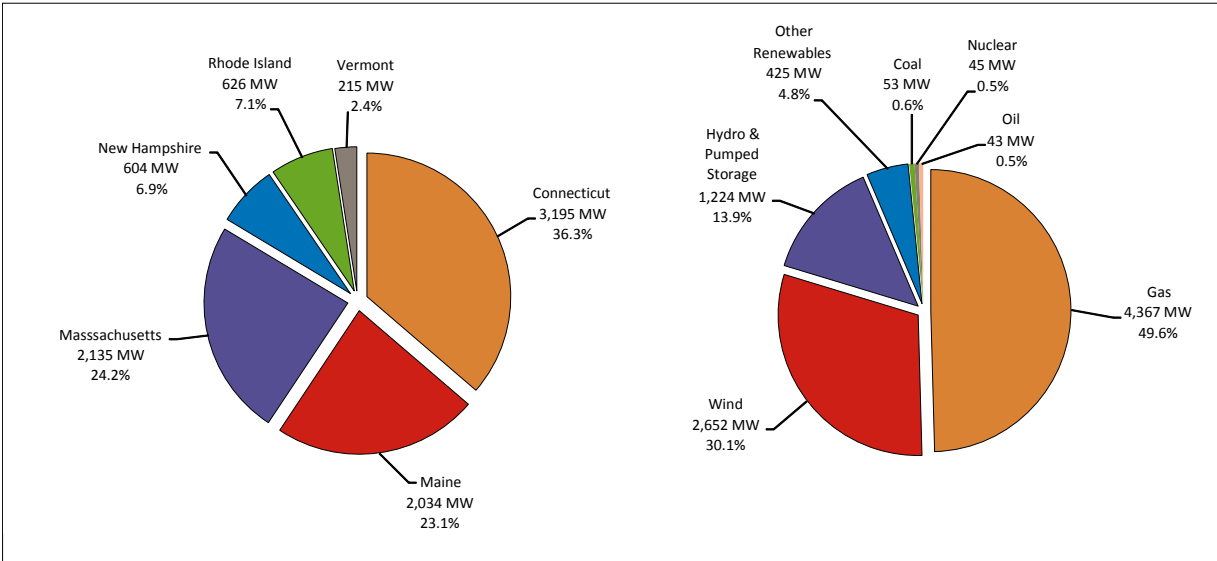
Number of Completed Facilities Studies by ISO-NE, 2005–2009

Year	Number of Completed Facilities Studies	Number of Completed Facilities Studies With Cost Data	Cost of Studies Completed in Calendar Year
2005	0	0	Not Applicable
2006	0	0	Not Applicable
2007	2	1	\$45,364
2008	1	1	\$146,685
2009	2	1	\$4,479

The following trends have been observed for the analysis periods:

- An increasing number of wind projects have been subject to Material Modification Determinations because of project proponents' changing the type of wind turbines being used in their project(s).
- Projects are trying to extend their commercial operation dates when reliability transmission upgrades in the area are delayed.
- More projects are in proximity to each other and are directly competing with other projects within the ISO-NE Interconnection Queue.
- Wind interconnection studies are becoming more involved and detailed, in part, because of the complex interactions of the electronic controls of wind generators and other equipment, especially in the weaker parts of the power system where the largest interest in development is occurring.
- Degradation in overall system performance is occurring because of the introduction of new wind resources, which do not have the robust behavior of other resources they are displacing. This further complicates interconnection studies for subsequent wind projects.
- Projects that are withdrawing from the interconnection process have generally indicated business reasons for the withdrawal, other than difficulty within the interconnection process itself.
- An increasing number of projects are being issued a "Notice of Withdrawal" because they are not meeting their obligations under ISO-NE's interconnection procedures. Most projects have been able to resolve their deficiencies.
- Most of the new generation interconnection requests being proposed are for wind or biomass projects. The following figure shows the resources in the ISO-NE Generator Interconnection Queue, by state and fuel type, as of April 1, 2010. The 84 active projects in the queue total 8,809 MW.

**Resources in the ISO-NE Generator Interconnection Queue,
by State and Fuel type, as of April 1, 2010**



Notes: The "Other Renewables" category includes wood, refuse, landfill gas (LFG), other bio gas, and fuel cells. A total of 38 MW of hydro is included in the 1,224 MW total of hydro and pumped storage. The totals for all categories reflect all queue projects that would interconnect with the system and not all projects in New England. LFG is produced by decomposition of landfill materials and is either collected, cleaned, and used for generation or it is vented or flared.

Special Protection Schemes

The New England transmission system has a number of special protection schemes (SPSs). An SPS is a protection system designed to detect abnormal system conditions and take corrective actions other than the normal isolation of faulted elements. Such actions may include changes in load, generation, or system topology to maintain system stability, acceptable voltages, or power flows. These systems are designed and maintained in accordance with the NPCC Directory 7 and ISO-NE Planning Procedure No. 5, *Special Protection Schemes Application Guidelines*.¹⁸ The NPCC identifies three types of SPSs, depending on the potential impact to the interconnected and local systems:

- NPCC Type I SPSs are associated with conditions resulting from design and operating contingencies, such that a failure or misoperation of the SPS can have a significant adverse impact on the interconnected system. This system impact is regarded as an interconnection-reliability operating limit (IROL). The corrective action taken by these SPSs, along with the actions taken by other protection systems, are intended to return power system parameters to a stable and recoverable state.
- NPCC Type II SPSs are those associated with conditions resulting from extreme contingencies, such that a failure or misoperation of the SPS can have a significant adverse impact on the interconnected system, regarded as an IROL.
- NPCC Type III SPSs are those with the potential to create local impacts only, if they fail to operate or misoperate, regarded as a system operating limit only.

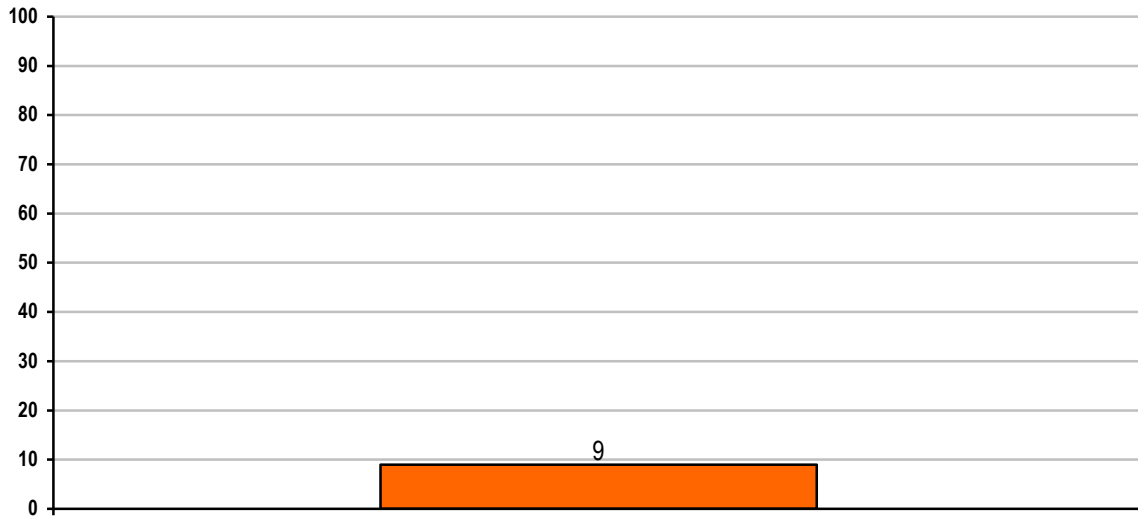
Because of the potential impacts of Type I and Type II SPSs on the interconnected system, NPCC and ISO-NE criteria require full redundancy of all components of the SPS (i.e., the SPS shall be designed with sufficient redundancy such that the SPS can perform its intended function while itself experiencing a single failure). NPCC retains the authority to provide review and concurrence on all new SPS proposals or changes to existing SPSs. There are four categories of SPS operation:

- **Normal Operation:** the SPS successfully operated as designed for the initialing system event for which it was intended to provide protection.
- **Failure to Operate:** the SPS did not operate as designed for the initialing system event for which it was intended to provide protection.
- **Unintended or Inadvertent Operation:** the SPS successfully operated for an unrelated initialing system event for which it was not intended to provide protection.
- **Misoperation:** the SPS did not successfully operate as designed (partial operation) for the initialing system event for which it was intended to provide protection.

Currently, nine Type I and no Type II SPSs are installed in New England. The following graph summarizes the number of SPSs within New England during 2009.

¹⁸ ISO Planning Procedure No. 5, *Special Protection Schemes Application Guidelines* (June 22, 2009); http://www.iso-ne.com/rules_proceeds/isone_plan/pp5_5_r3.pdf.

Number of ISO-NE Type 1 Special Protection Schemes, 2009



Type I SPSs operated 100% successfully in New England during 2009. This equates to a single successful operation of one Type I SPS as designed. The SPS tripped two key generators and two underlying 115 kV lines for loss of a critical 345 kV line. A single unintended operation of a Type I SPS took place during 2009, which tripped a generator because of an incorrect relay signal. This unintended operation did not affect system reliability.

B. ISO New England Coordinated Wholesale Power Markets

For context, the table below categorizes the \$9.3 billion dollars billed by ISO-NE in 2009 into the primary types of charges its members incurred for their market transactions.

ISO-NE Market Transaction Charges, 2009

	2009 Dollars Billed (Millions)	Percentage of 2009 Dollars Billed
Energy Markets	\$5,971.7	64.1%
Capacity	\$1,765.9	18.9%
Transmission Tariff	\$1,154.5	12.4%
Reserve Markets	\$150.5	1.6%
Operating Reserves (NCPC)	\$55.7	0.6%
FTR Auction Revenues	\$85.2	0.9%
Regulation Market	\$23.1	0.2%
ISO-NE Administrative Expenses	\$123.4	1.3%
Total	\$9,330.0	100.0%

ISO-NE focuses on the accuracy of both finalized prices and billing amounts to ensure that participants have confidence in the bill amounts included in their invoices. From 2007 through 2009, ISO-NE's posted pricing accuracy exceeded 99.4%, with 99.8% error-free hours in 2009.

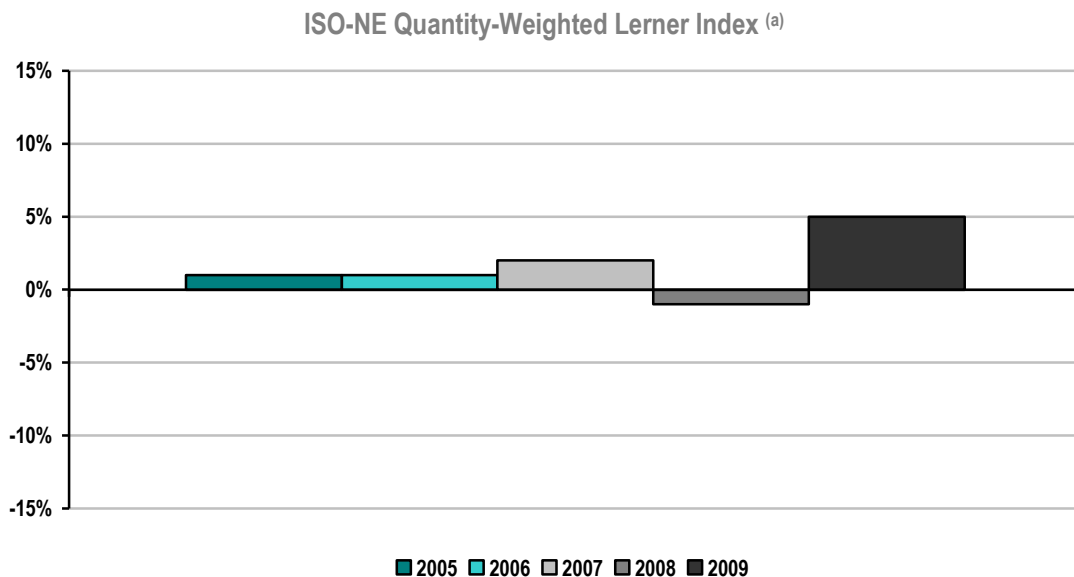
ISO-NE's billing protocols include an initial settlement and a "data reconciliation process" settlement conducted about 90 days after the initial settlement for its billable hourly and monthly market services. Beginning in October 2008, ISO-NE began deriving a metric that reflects both the number and dollar magnitude of the changes to the initial settlement. Most changes are attributable to more accurate metering information submitted by market participants.

For each of the 14 months for which data are available (October 2008 through December 2009), the dollar impact of the change in billing amounts between the initial settlement and the data reconciliation settlement as a percentage of the total market value billed averaged 0.017%, or about \$125,000 per month.

Market Competitiveness

Two types of measures can be used to assess the competitiveness of electric energy markets: structural measures of competitiveness, which analyze the concentration of generation resource ownership in the New England markets; and price-based measures, which compare wholesale market prices to the estimated cost of providing electric energy. While not included in this report, structural measures of the New England markets show that they are structurally competitive, with the Herfindahl-Hirschman Indices (HHIs) for the regionwide market well within the Department of Justice guidelines for a competitive market.

The competitive benchmark model is a price based measure of market competitiveness that produces market prices using participant offers and Internal Market Monitor (IMM) estimates of resource marginal costs. These results are used to calculate the Quantity-Weighted Lerner Index (QWLI), shown in the following table. The QWLI measures marketwide performance and is the percentage markup of market revenue over production cost. The diagnostic value of the QWLI is not its absolute value (which can be confounded by estimation error in the marginal cost calculation), but rather is observed as changes in its value through time considered together with other measures of market performance. The QWLI results, combined with a general lack of concentration and an energy market that remains tightly correlated with the regional fuel markets, support the conclusion that market prices are consistent with the price outcomes expected when resource owners offer at their short-run variable costs.¹⁹



(a) The QWLI = [(annual market cost based on market prices – annual market cost based on marginal cost estimates)/ annual market cost based on market prices].

The completion of transmission lines in Connecticut and Boston have significantly reduced congestion, thereby significantly reducing the likelihood that resources in a submarket could benefit from the exercise of market power. This risk is further mitigated by the market-power mitigation rules for constrained areas.

¹⁹ The correlation between natural gas (the dominant marginal fuel) and on-peak real-time energy prices (Hub LMPs) is approximately 0.96; the variance in natural gas prices explains about 87% of the variance in on-peak real-time Hub LMPs.

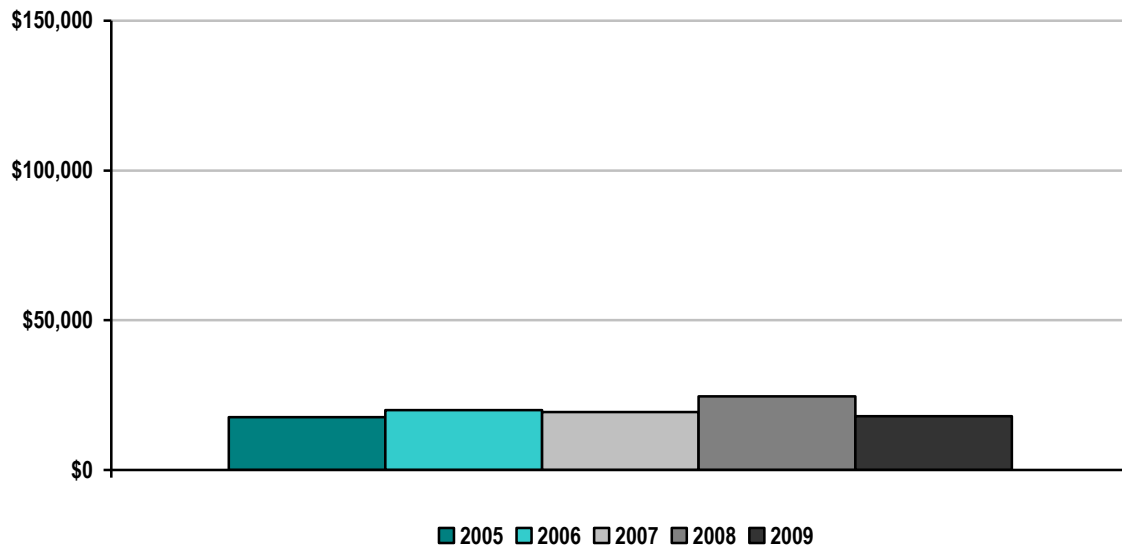
The following table presents yearly estimates of the gross margin (energy revenues minus fuel costs) earned by typical gas-fired combined-cycle (CC; also CCGT) and combustion turbine (CT) units in New England. The analysis presents the margin realized in hours when the prevailing real-time locational marginal price (LMP) at the Hub exceeded the resource's fuel cost. The analysis assumes that the resources are available in all hours, so it may overestimate the margins gained by actual units subject to outages. The analysis assumes the regional Algonquin Citygate natural gas price, a 7,800 Btu/kWh combined-cycle heat rate, and an 11,000 Btu/kWh combustion turbine heat rate.

ISO-NE Yearly Estimates of the Gross Margin Earned by Typical CT and CCGT Units in New England

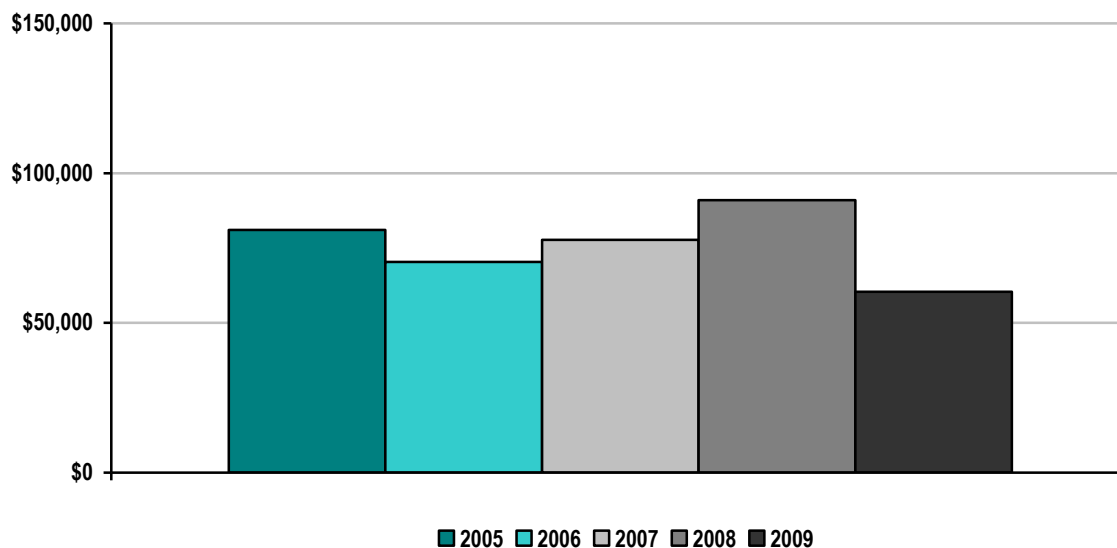
Year	Natural Gas Index (\$/MMBtu ^a)	Real-Time LMP (\$/MWh)	Gross Margin CT (\$/kW-mo)	Gross Margin CCGT (\$/kW-mo)
2005	9.75	76.64	\$1.47	\$6.75
2006	7.40	59.68	\$1.67	\$5.86
2007	8.17	66.72	\$1.61	\$6.48
2008	10.07	80.56	\$2.05	\$7.58
2009	4.79	42.02	\$1.50	\$5.03

(a) MMBtu stands for millions of British thermal units.

ISO-NE New Entrant Gas-Fired Combustion-Turbine Net Generation Revenues 2005–2009 (\$ per installed megawatt year)



ISO-NE New Entrant Gas-Fired Combined-Cycle Net Generation Revenues 2005–2009
(\$ per installed megawatt year)



In addition to energy revenues, many CC resources earn revenues for providing real-time reserve and regulation service. All resources are eligible to receive capacity revenues, and fast-start resources, such as CT units, may participate in and receive Forward Reserve Market (FRM) revenues.

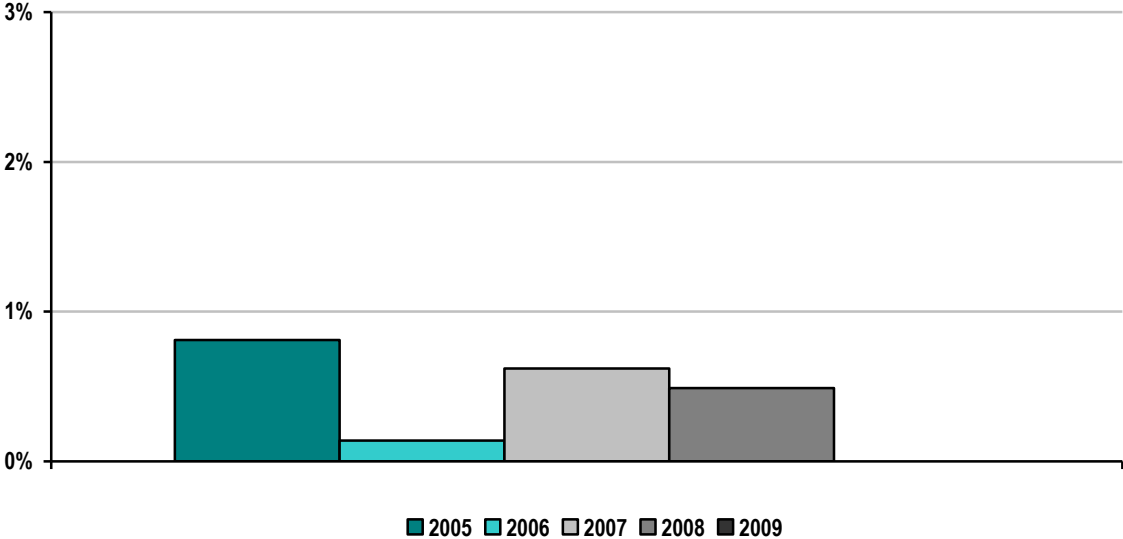
The following tables present, for each year, the number and percentage of hours that energy market mitigation in real time was imposed under the thresholds in *Market Rule 1*, Appendix A, Section 5.

ISO-NE Real-Time Energy Market Mitigation Hours Imposed under *Market Rule 1*, Appendix A, Section 5, 2005–2009

Year	Total Mitigated Hours	Total Hours Per Year	Percent Mitigated Hours
2005	71	8,760	0.81%
2006	12	8,760	0.14%
2007	54	8,760	0.62%
2008	43	8,784	0.49%
2009	0	8,760	0.00%

Note: 2008 is a leap year.

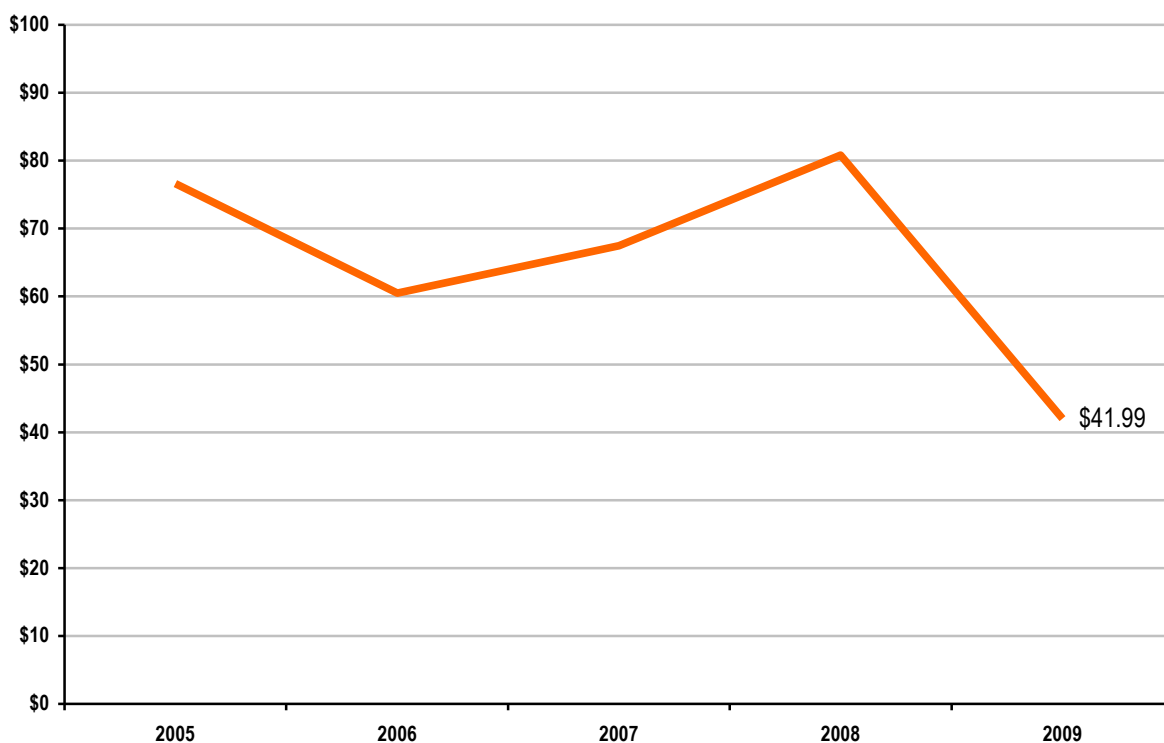
ISO-NE Real-Time Energy Market Percentage of Unit Hours Offer Capped because of Mitigation 2005–2009



Market Pricing

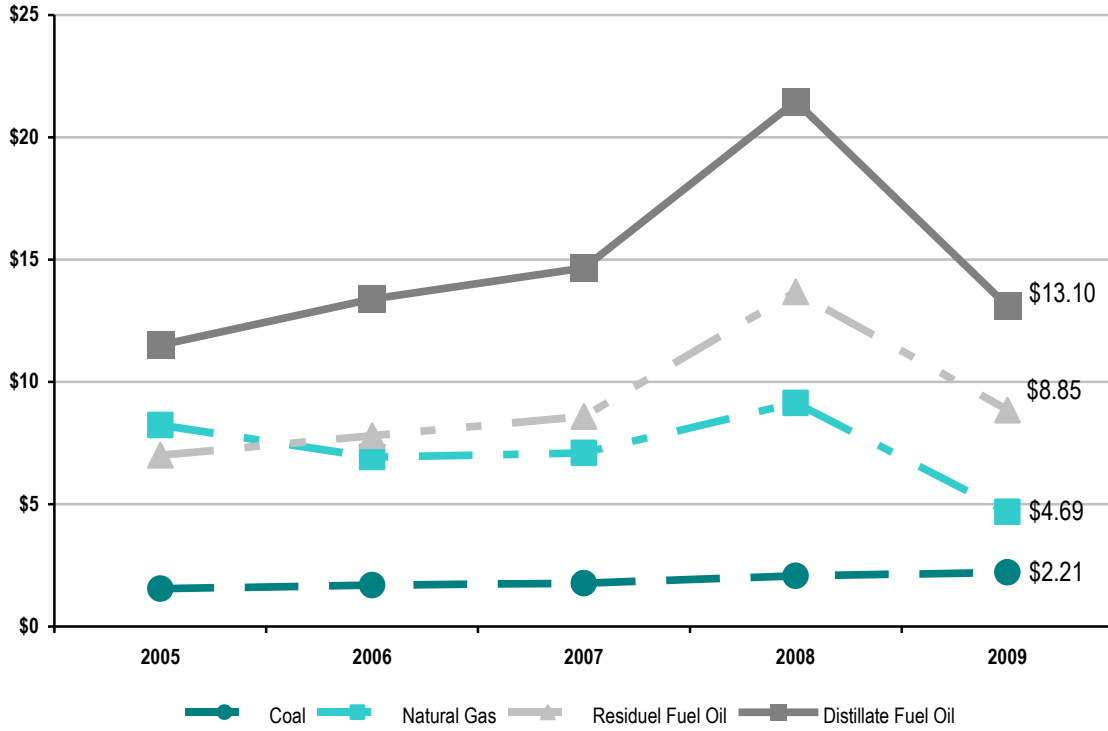
Since March 2003, the wholesale electric energy markets administered by ISO-NE have used LMPs for its transactions. These values, computed every five minutes at nearly 1,000 nodal locations, are combined using a load-weighted average to calculate zonal average LMPs for the eight load zones within the New England Balancing Authority Area. With limited exceptions, load pays the hourly zonal price at its location. For the following figure, the hourly zonal price for every hour in the year indicated was multiplied by its zonal load obligation in the real-time markets. These load-weighted average hourly prices were computed and then arithmetically averaged over the year, as shown in the figure.

ISO-NE Average Annual Load-Weighted Wholesale Energy Prices, 2005–2009
(\$/MWh)



The yearly average real-time LMP has trended downward overall in New England in the past five years. Pricing is influenced by underlying input fuel prices (natural gas), which have driven the historical price trajectory. The increase in 2008 was caused by increases in natural gas prices during that year. Peak-period (on-peak hours) pricing trends followed the same trend observed in the exhibit above, also driven primarily by fuel prices. The highest on-peak average Hub LMP was observed during 2008 at \$90.35/MWh. The 2009 on-peak average dropped by nearly half to \$46.57/MWh. The following figure shows nominal fuel costs in the United States from 2005 to 2009.

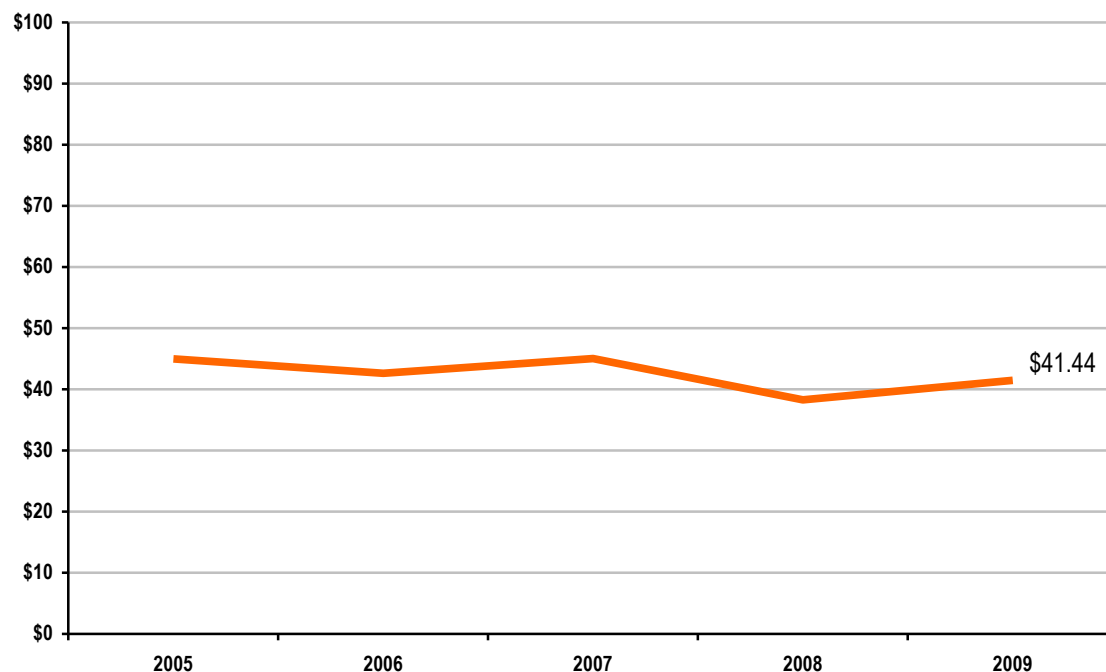
U.S. Nominal Fuel Costs, 2005–2009
(\$ per Million Btu)



Source: U.S. Energy Information Administration, Independent Statistics and Analysis

ISO-NE calculates the fuel-adjusted electricity price by adjusting the marginal LMPs by the ratio of the daily fuel prices to the average monthly fuel prices of the corresponding market intervals and marginal fuel types in the base year. ISO-NE's base year for fuel-cost references is 2000. The result of this approach illustrates the impact of fuel prices on electricity prices. The methodology used provides only a rough estimate because it does not account for the impact that changes in relative fuel prices, load growth, and resource mix since 2000 have had on system dispatch and pricing.

ISO-NE Average Annual Load-Weighted Fuel-Adjusted Wholesale Spot Energy Prices, 2005–2009
(\$/MWh)



When adjusted for fuel-price movements, the average spot energy prices in New England have declined from 2002 to 2009.

Impacts of Demand-Response Programs on Locational Marginal Prices

Every six months since February 2003, ISO-NE has filed status reports with FERC regarding participation in and impacts of demand-response programs administered by ISO-NE.²⁰ These status reports include estimates of the effects of demand-response programs on real-time LMPs. Using the information from the status reports, the following table shows the effects of ISO-NE's demand-response programs on real-time LMPs for the New England region, for January 2008 through December 2009.

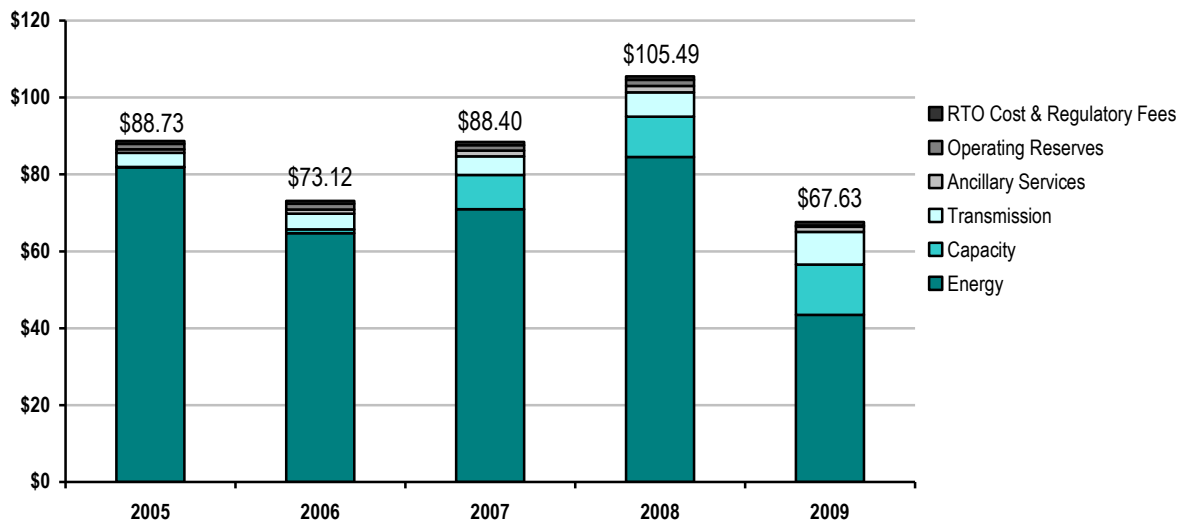
²⁰ *ISO New England, Inc., et al., Order on Tariff Filing*, 102 FERC ¶ 61,202 at P 19 (2003) (February 25, 2003, Order).

**Estimated Effects of All Demand-Response Program Interruptions
on New England's Real-Time LMPs, 2008–2009**

Reporting Period	Interrupted MWh	Observed Average Real-Time LMP (\$/MWh)	Average Real-Time LMP Decrease (\$/MWh)
Jan to Mar 2008	55,059	92.15	1.43
Apr to Jun 2008	20,773	137.43	0.31
July to Sep 2008	9,331	125.68	0.27
Oct to Dec 2008	6,023	72.38	0.26
Jan to Mar 2009	10,823	75.55	0.19
Apr to Jun 2009	5,076	43.86	0.04
Jul to Sep 2009	13,540	57.01	1.06
Oct to Dec 2009	12,435	71.85	0.13

The following graph reflects the average annual wholesale power costs for load purchasing from the New England wholesale energy markets. The costs are categorized into the major charge components ISO-NE administers, converted to \$/MWh of load served. Because of the various ways in which participants may transact business within the New England markets, not all load-serving entities are subject to all the charge categories. Of note during 2009 was the decline in energy market-related charges, which were somewhat offset by increases in capacity and transmission costs.

**ISO-NE Wholesale Power Cost Breakdown, 2005–2009
(\$/MWh)**



Over the reporting period, ISO/RTO costs and regulatory fees have remained stable, while the costs for electric energy, operating reserves, and ancillary services have declined as part of the total cost. Capacity and transmission costs have increased their percentages of the total cost over the same period.

From 2005 to 2009, ISO-NE's net revenue requirements recovered through the self-funding tariff grew slightly less than 3%, from \$110 million to \$123.3 million. The ISO-NE net revenue requirements reflect the FERC-approved budgets adjusted for prior-year over/under collections. The increases largely reflect expanded levels of service with regard to the Forward Capacity Market, demand-response integration, system planning, and increased compliance-management activities.

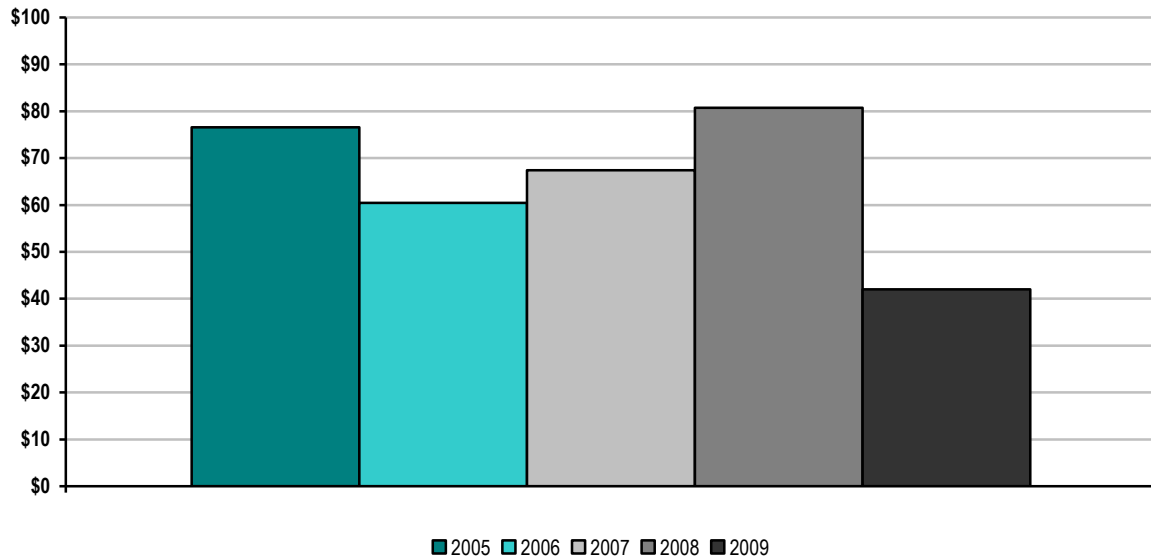
The increase in transmission costs, reflective of infrastructure additions made to the New England system over the 2005–2009 period, are responsible for the decline in operating-reserve charges. The major cause of these charges was out-of-market commitments of generators that ISO-NE made to support reliability because of inadequate transmission infrastructure in certain areas.

Operating-reserve credits, or Net Commitment-Period Compensation (NCPC), averaged more than \$200 million per year from 2005 through 2008. This represents approximately 2.0% to 2.5% of the value of the energy market. The overall effect of transmission improvements in southwestern Connecticut and southeastern and northeastern Massachusetts (i.e., the NU loop, SEMA, and NEMA upgrades) was realized during 2009 when NCPC payments dropped to \$55 million, or less than 1% of the energy market value.

System Marginal Cost

In the next graph, the hourly system price (consistent with ISO-NE's FERC Form 714 filing) for every hour in 2005 through 2009 was averaged over the entire year. Pricing in the New England wholesale markets is heavily influenced by underlying fuel prices. The values in the table reflect the movements in the underlying increases in fuel prices experienced in 2005 and in 2008.

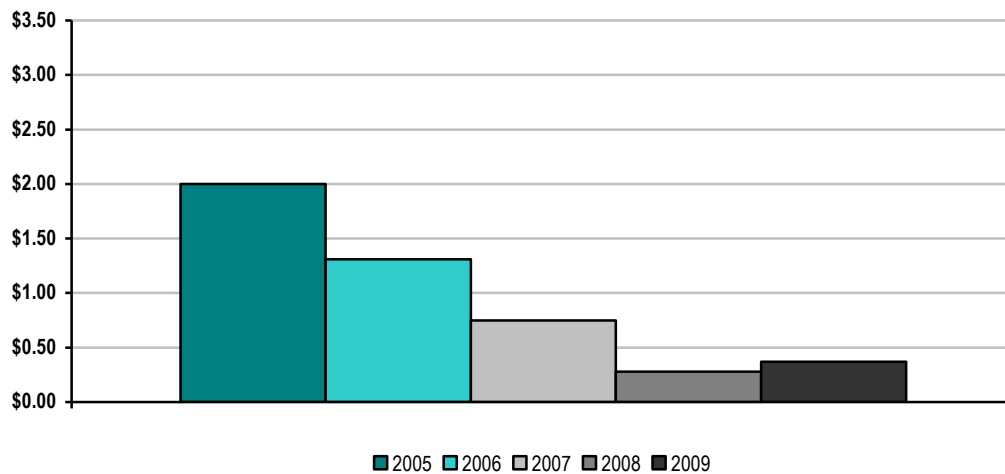
ISO-NE Annual Average Nonweighted, System Marginal Cost, 2005–2009



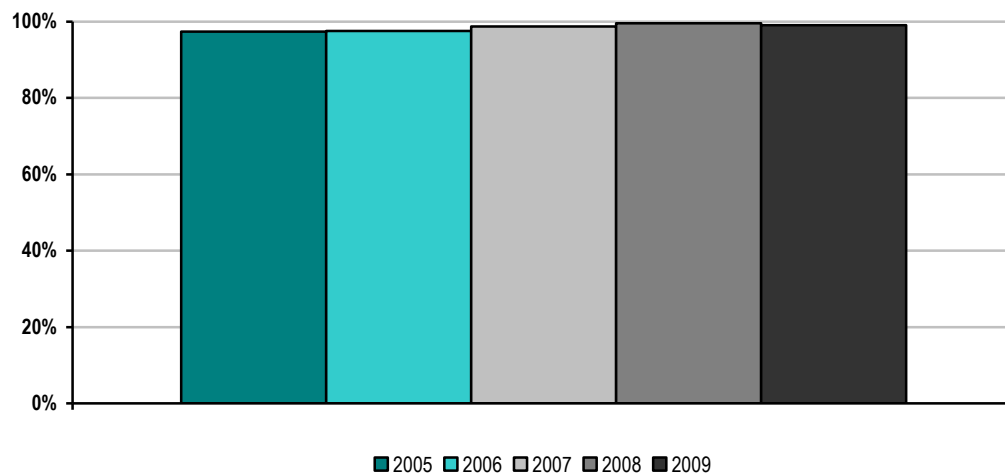
Energy Market Price Convergence

Good convergence between day-ahead and real-time prices is a sign of a well-functioning day-ahead market. Because the day-ahead market facilitates most of the energy settlements and generator commitments, in general, good convergence between day-ahead and real-time electric energy prices is achieved when participants submit price-sensitive bids and offers in the day-ahead market that accurately forecast next-day real-time conditions. Thus, good price convergence between the day-ahead and real-time markets helps ensure efficient day-ahead commitments that reflect real-time operating needs. The following two graphs reflect the absolute value and percentage of the average annual difference between Real-Time Energy Market prices and Day-Ahead Energy Market prices.

ISO-NE Day-Ahead and Real-Time Energy Market Price Convergence, 2005–2009



ISO-NE Percentage of Day-Ahead and Real-Time Energy Market Price Convergence, 2005–2009



ISO-NE's Day-Ahead Energy Market to Real-Time Energy Market average price convergence improved over the five-year period from 2005 to 2009.

Congestion Management

Transmission congestion occurs when constraints on the transmission system prevent the reliable transfer of lower-cost energy to serve an area. Quite often, these constraints occur where the transfer capability is limited for supplying an area that has a potential reliability concern. ISO-NE uses information obtained from system needs assessments developed during the planning process to help develop a variety of market signals to promote solutions to transmission congestion. These solutions can include merchant transmission or nontransmission alternatives (NTAs), such as generation, demand reduction, or other promising technologies, all of which could result in modifying or deferring a proposed regulated transmission upgrade. If the market does not respond, a regulated, robust transmission solution is developed to meet existing and future system requirements. As a result, transfer capabilities usually are increased and congestion is eliminated.

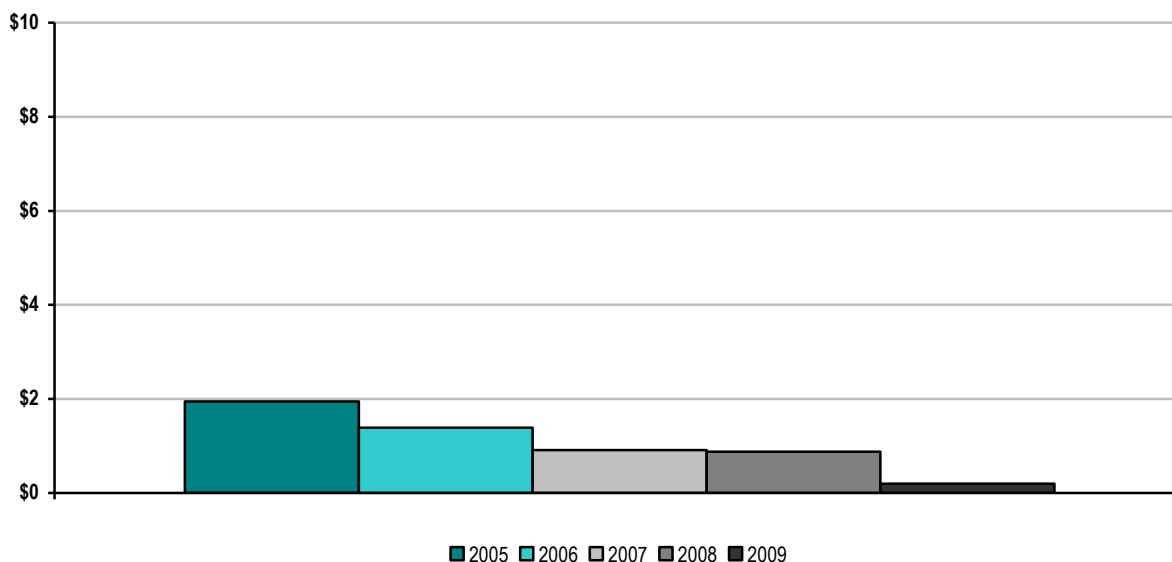
The transmission system in New England has evolved significantly over the past several years. From 2002 through 2010, more than 300 transmission projects will have been placed in service, with an additional number of projects under construction or well into the siting process. In addition to system reliability improvements, these transmission upgrades have supported marketplace efficiency by helping reduce congestion costs and other out-of-merit charges, such as second-contingency and voltage-control payments. As noted in the discussion above on market pricing, during 2009, when Net Commitment-Period Compensation dropped to \$55 million (i.e., less than 1% of the value of the energy market), the effect of the NU loop, SEMA, and NEMA transmission improvements was realized. NCPC in New England had averaged more than \$200 million per year (i.e., approximately 2.0% to 2.5% of the value of the energy market) from 2005 to 2009.

Recent experience has demonstrated that the regional transmission system in New England has little congestion. The U.S. Department of Energy (DOE) recognized the region's "multifaceted approach" to investment in new supply- and demand-side resources, as well as planning and development of extensive transmission upgrades, and it removed New England as "an area of concern" for the identification of National Interest Electric Transmission Corridors (NIETC).²¹

Transmission congestion, when it occurs, is reflected in the congestion component of the LMP. In the New England system, the overwhelming majority of the congestion that occurs is in the day-ahead market. Because virtual trading can have an impact on day-ahead load, the value of the day-ahead Congestion Revenue Fund is divided by the annual real-time load to arrive at the cost of congestion per megawatt-hour of load served.

²¹ See ISO-NE's RSP10, 2009 Historical Market Data: Locational Marginal Prices, Interface MW Flows (January 21, 2010); http://www.iso-ne.com/committees/comm_wkgrps/prtcpts_comm/pac/mtrls/2010/jan212010/lmp_and_interface.pdf.

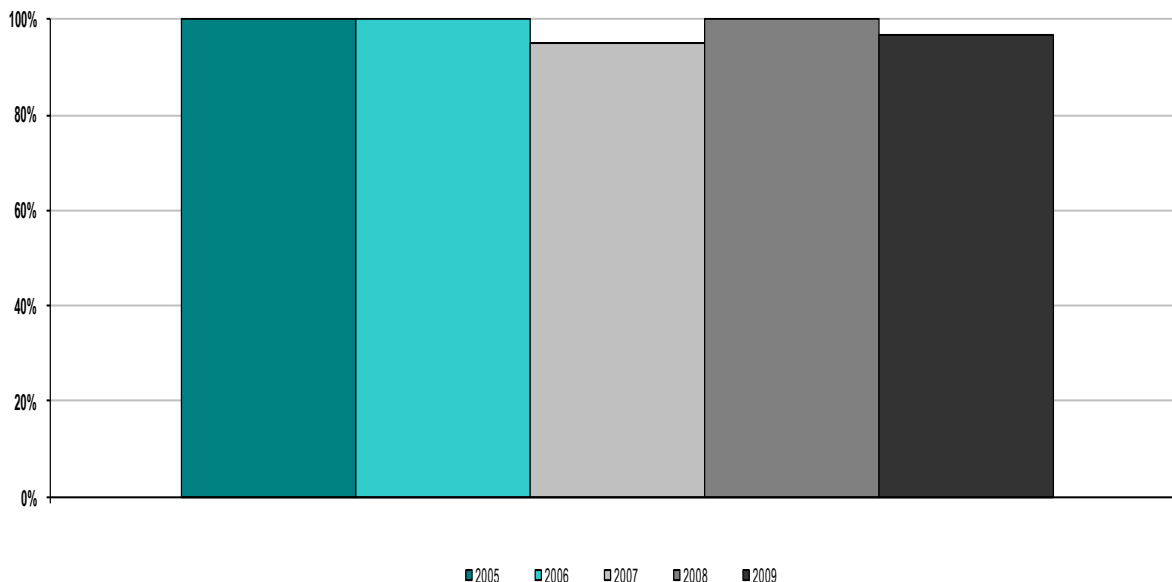
ISO-NE Annual Congestion Costs per Megawatt-Hour of Load Served, 2005–2009



Congestion revenue from the settlement of the Day-Ahead Energy Market and Real-Time Energy Market is accumulated in the Congestion Revenue Fund. Holders of congestion instruments (in New England, Financial Transmission Rights, or FTRs) can share in the refund of these collections if their FTR entitles them. These are called positive target allocations. Conversely, because New England FTRs are obligations, counter-flow congestion (which results in so-called negative target allocations) may require a contract holder to contribute to the Congestion Revenue Fund.

The following graph shows the extent to which the sum of day-ahead and real-time congestion revenue and negative target allocations were sufficient to fund the transmission-hedge instruments on a yearly basis. Over the five-year period, FTR holders in the New England markets have been able to hedge over 98% of day-ahead market congestion in each year, with FTR congestion-revenue adequacy ranging just under 95% in 2007 to 100% in 2005, 2006, and 2008. FTR market congestion-revenue adequacy reflects the relationship of actual FTR congestion revenues to the target allocations for all FTR holders in the aggregate.

ISO-NE Percentage of Congestion Dollars Hedged Through ISO/RTO Congestion Management Markets, 2005–2009



Before July 2005, excess congestion revenue was collected during the month (after FTR holders were compensated) and was carried forward for use in subsequent months, enabling payment in case of shortfalls. As of July 2005, excess congestion revenue has been collected until the end of the year and then distributed pro rata to any shortfall amounts that occurred during the year. This change ensures that all shortfalls have equal opportunity for funding regardless of the month in which the shortfall occurred.

Resources

Balancing consumer demand and available resources can be achieved by a combination of changing generation output and reducing total consumer demand. The charts and discussion below reflect ISO-NE’s history with generation and demand response resources being available when called on by ISO-NE.

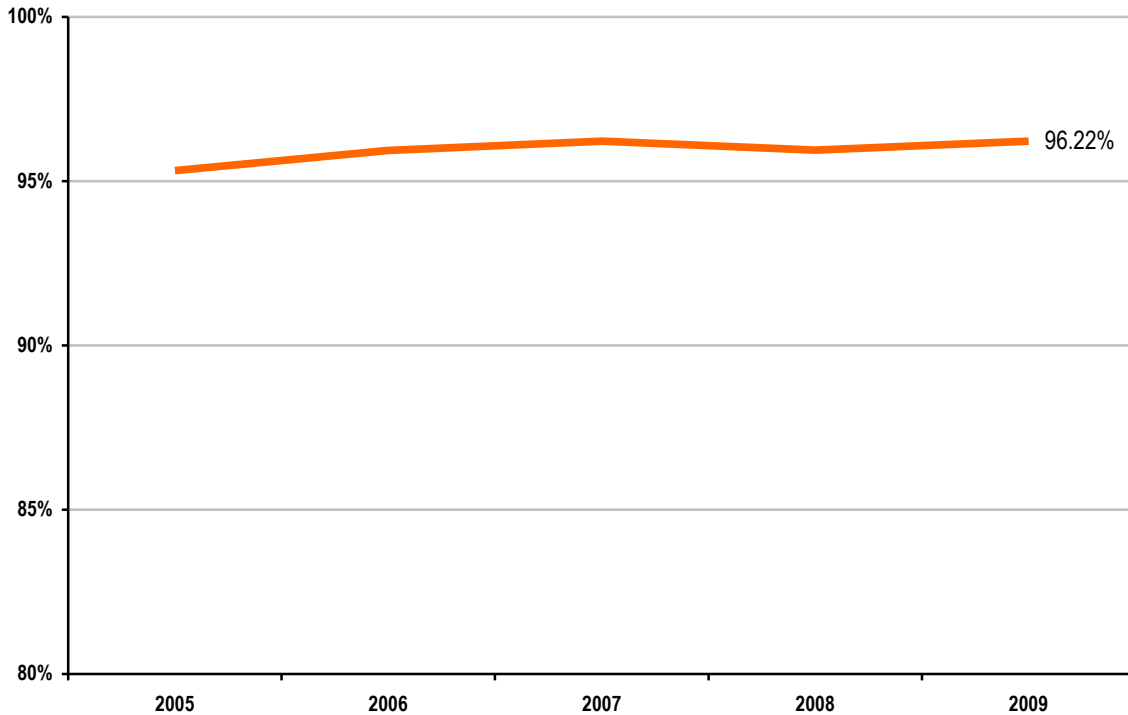
Generator Availability

This ISO/RTO performance metric identifies ISO-NE’s calendar-year generating availability as measured by the equivalent forced-outage rate demand (EFORd) calculation. Generating availability is defined as one minus EFORd, which is calculated using data on generator supply from the NERC Generating Availability Data System (GADS). The industry has used the EFORd for more than 30 years to describe the probability that a generator will not meet its demand periods for generating requirements. EFORd is shown on an annual basis:

$$\text{Generating Availability} = (1 - \text{EFORd}), \text{ where:}$$

EFORd is the equivalent forced-outage rate demand calculated for resources that submitted GADS data for the specified period, either calendar year or capability year based on NERC Appendix F – *Performance Indexes and Equations GADS Data Reporting Instruction, January 2010*.

ISO-NE Annual Generator Availability, 2005–2009



As shown in this figure, the performance of New England's generating units from 2005 through 2009 has improved. The system average generating unit EFORd has improved by approximately 0.7% during this five-year period, resulting in a decrease in the Installed Capacity Requirement (ICR) of approximately 600 MW. The ICR is the level of capacity needed to meet the reliability requirements of the New England Balancing Authority Area.

Availability by generating resource type is shown in the table below. ISO New England has not determined a specific quantitative relationship between generator availability and the wholesale cost of electricity. Trends in out-of-merit dispatch and progress made toward reducing out-of-merit dispatch and improving market efficiency are discussed above in the sections on generation must-run contracts, the ISO-NE wholesale power cost breakdown, and congestion management.

Five-Year Weighted Average Availability by Resource Category (%)^(a)

Resource Category	2005	2006	2007	2008	2009
Combined cycle	93.9	94.3	94.8	95.3	95.4
Fossil	93.2	92.8	92.4	92.3	92.8
Nuclear	98.4	98.4	98.4	98.8	98.6
Hydro (includes pumped storage)	96.6	97.7	98.4	98.5	98.1
Combustion turbine	91.5	92.3	93.4	93.3	93.3
Diesel	91.6	95.7	93.5	94.8	94.3
Miscellaneous			94.8	98.3	92.5
Total system	94.5	94.7	94.9	95.1	95.1

(a) Based on five-year average EFORd values

Demand-Response Availability

In addition to assessing expected load levels, the ISO-NE assesses expected availability of capacity resources as an input in determining the ICR. The expected availability of resources in a future capacity commitment period (e.g., June 1 to May 31 of the following year) is based on the historical performance of capacity resources in response to dispatch instructions. The expected availability of active demand resources, such as real-time demand response and real-time emergency-generation resources, is based on the historical performance of such resources during real-time demand-response event hours and real-time emergency-generation event hours, respectively.

The performance of active demand resources is assessed by dividing the measured curtailed megawatt-hours by the expected curtailed megawatt-hours. Measured curtailed megawatt-hours is equal to the difference between an active demand resource's adjusted customer baseline and its actual metered consumption during event hours. Expected curtailed megawatt-hours is equal to megawatts dispatched by ISO-NE, which would not exceed the active demand resource's enrolled megawatts or its capacity supply obligation (CSO), multiplied by the number of event hours. The resulting ratio is used to estimate the expected availability of active demand resources. A ratio of 100% means that, on average, the demand resource provided 100% of the megawatts dispatched by ISO-NE during all event hours.

Because few event hours have occurred since March 2003, when ISO-NE implemented its demand-response programs, ISO-NE, in cooperation with the New England stakeholders, has estimated active demand-resource availability for future capacity commitment periods using event statistics from August 1, 2006, through August 25, 2009. Such event statistics included active demand-resource response to both actual events and audits. Further, the only active demand resources assessed were those expected to have a CSO in the relevant capacity commitment period, given that the computed availability is used prospectively to determine the ICR in a future capacity commitment period. Passive demand resources, such as on-peak demand resources and seasonal peak demand resources (primarily non-weather-sensitive and weather-sensitive energy-efficiency resources, respectively) were assessed an availability factor of 100% when calculating the ICR.

These data show that real-time demand-response resource availability was assessed at 76%, and real-time emergency-generation resource availability was assessed at 73%. Average active demand-resource availability was 75%. As highlighted in the following table, with passive demand resources assessed at 100% availability, overall demand-resource availability was estimated to be 84%.²²

²² The most recent demand-resource availability estimates calculated by ISO-NE are available at http://www.iso-ne.com/committees/comm_wkgrps/reblty_comm/pwrsuppln_comm/mtrls/2010/feb182010/dr_performance_fca4_2_18_2010.pdf.

**Demand-Resource Availability Modeled in the 2013/2014 ICR Calculation;
Availability of Active Demand Response Based on Events from August 1, 2006 through August 25, 2009**

Load Zone	On-Peak		Seasonal Peak		Real-Time Demand Response		Real-Time Emergency Gen		Total	
	MW	Availability (%)	MW	Availability (%)	MW	Availability (%)	MW	Availability (%)	MW	Availability (%)
Maine	58.483	100	-	-	279.165	100	35.023	100	372.671	100
New Hampshire	61.842	100	-	-	45.409	74	39.135	74	146.386	85
Vermont	71.766	100	-	-	33.443	99	18.124	45	123.333	92
Connecticut	115.672	100	250.727	100	291.940	76	298.901	87	957.240	89
Rhode Island	68.612	100	1.727	100	51.417	48	93.078	17	214.834	51
Southeast Mass	112.545	100	1.727	100	153.524	56	78.961	58	346.757	71
West Central Mass	94.516	100	19.188	100	142.505	67	100.221	72	356.430	79
Northeast Mass and Boston	208.904	100	-	-	254.596	72	148.989	87	612.489	85
Total New England	792.340	100	273.369	100	1251.999	76	812.432	73	3130.140	84

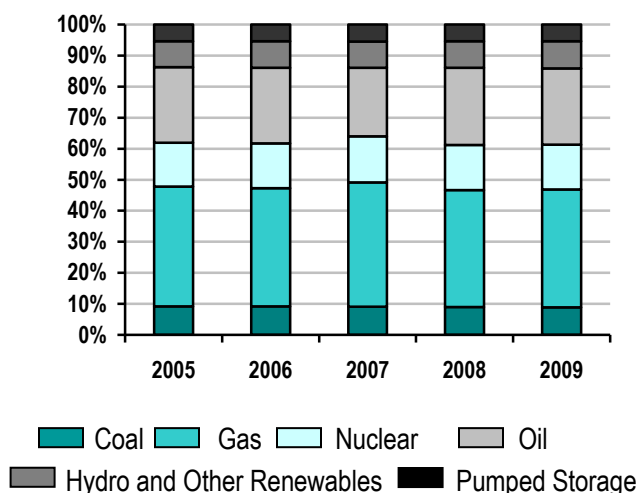
Fuel Diversity

This ISO/RTO performance metric identifies ISO-NE's fuel diversity with respect to installed capacity. To develop the information for this metric, ISO-NE compiled the installed summer capacity values for 2005 to 2009 of all generating units under ISO-NE's dispatch control and summarized their aggregate capacity (MW) by each unit's reported primary fuel type.²³ This information was then categorized into the following fuel types:²⁴

- Natural gas (11,948 MW at 38.0%)
- Nuclear (4,542 MW at 14.4%)
- Coal (2,788 MW at 8.9%)
- Oil, heavy and light (7,743 MW at 24.6%)
- Hydroelectric and other renewables (1,694 MW at 5.4% and 1,039 MW at 3.3%, respectively)²⁵
- Pumped storage (1,689 MW at 5.4%)

The fuel types themselves are self-explanatory, except for the "other renewables" category, which in New England includes capacity from landfill gas (LFG), other biomass gas, refuse (municipal solid waste), wood and wood-waste solids, wind, solar, black liquor, and tire-derived fuels.²⁶ In addition, this information does not contain, nor has it been adjusted for, historical firm imports or exports of capacity. The annual installed summer capacity values by primary fuel type are shown in the following graph.

ISO-NE Fuel Diversity (Summer Capacity), 2005–2009



²³ The dual-fuel units in the region are reported under natural gas or oil, depending on what fuel they claim as their primary fuel type within the monthly settlement period.

²⁴ These installed summer capacity quantities and percentages of total installed summer capacity are for 2009 only.

²⁵ The hydroelectric category reflects both daily-and weekly-cycle hydroelectric capacity that usually has storage/pondage capability and typically is dispatchable or self-scheduled. It does not include approximately 200 to 300 MW (rated monthly) of run-of-river hydroelectric capacity that typically is nondispatchable and is categorized as "settlement-only" capacity.

²⁶ LFG is produced by decomposition of landfill materials and is collected, cleaned, and used for generation or it is vented or flared. Black liquor is a by-product (alkaline spent liquor) of the paper-production process and can be used as a source of energy.

Data observations:

- Average annual summer installed capacity (MW) over the five-year period was approximately 30,988 MW.
- The lowest amount of installed summer capacity occurred in 2007 at 30,526 MW.
- The highest amount of installed summer capacity occurred in 2009 at 31,443 MW.
- The difference between the highest and lowest amounts of installed summer capacity is only 917 MW.
- As noted, the FCM transition period from 2007 to 2009 encouraged the installation of regional capacity through pre-FCM “transition” payments. The amount of “unforced” capacity that could request inclusion within this period was not capped, so in the latter years, ISO-NE had more capacity than needed to meet its summer peak load and operating reserve requirements.²⁷
- The top three installed capacity values in the region are natural gas-fired generation, oil-fired generation (burning both heavy and light end-products), and nuclear generation. Fossil-fueled generating capacity stayed relatively constant throughout the 2005–2009 timeframe, averaging approximately 23,135 MW, or approximately 75% of the entire generation fleet.
- The New England generation fleet is predominantly natural gas-fired, with the largest portion of installed summer capacity in each year ranging from a low of 11,705 MW at 37.6% in 2008 to a high of 12,205 MW at 40.0% in 2007. More than 50% of the installed capacity within the region can burn natural gas as a primary, secondary, start-up, or stabilizing fuel source.
- Regional differences play a major role in the development and sustainability of various types of electric generating capacity. Below are some issues that have and will continue to influence the regional fuel mix:
 - During the 1990s, New England’s nuclear power fleet consisted of nine stations totaling almost 7,000 MW of capacity. However, by the end of that same decade, four nuclear stations totaling approximately 2,275 MW of capacity, or approximately 33% of the fleet, retired because of economics.
 - In New England, coal-fired power is generally more expensive than in other parts of the country primarily because (1) the sources of coal are distant and (2) land-based transportations costs to the region are higher. In addition, since state and federal regulations governing air emissions and siting are stringent, the majority of coal-fired power stations (totaling 2,613 MW) in New England now take water-based deliveries of low-sulfur coal that originate from both foreign and domestic sources.
 - The annual average, regional hydroelectric capability is approximately 1,925 MW. Although a federal study in 1995 indicated that the potential exists for another 1,300 MW of hydroelectric capacity within the region, the majority of the river systems within New England have already been optimized for hydroelectric energy production.²⁸ In addition, multiple environmental considerations

²⁷ This is shown in the previous discussion of Actual Reserve Margins (ARMs) and Planned Reserve Margins (PRMs).

²⁸ In northern New England, some river systems have been optimized for the logging of wood resources for paper production in regional mills.

would reduce the likelihood that a potential hydroelectric site may be developed to its full physical potential.²⁹

- With the relatively low capital costs of building new gas-fired generation, combined with the high-efficiency conversion rates and relatively low air and water emission footprints, New England will remain heavily dependent on natural gas as a primary fuel for generating electric energy for the foreseeable future. Recent improvements to the regional and interregional natural gas infrastructure have helped expand and diversify natural gas sources to meet New England's increasing demand for natural gas to produce electric power. Also, the implementation of operating procedures and improved communications between electric power and natural gas system operators have decreased operational risks and improved the reliability and diversity of natural gas supply and transportation. These steps have mitigated most electric power system reliability concerns. Going forward, new natural-gas-fired generation will compete with renewable generation, such as wind, for future merchant development within the region.
- ISO-NE is finalizing a major study of integrating wind resources into the New England power system. The New England Wind Integration Study (NEWIS) is analyzing various planning, operating, and market aspects of wind integration; simulations that add wind resources up to 12,000 MW; and the conceptual development of a transmission system that can integrate large amounts of wind generation resources. The study, scheduled to be completed by the end of 2010, is developing models of generation output for a hypothesized fleet of wind plants suitable for ISO-NE studies.³⁰

The next ISO/RTO performance metric is fuel diversity with respect to historical energy production. To develop the information for this metric, ISO-NE compiled the 2005–2009 historical energy production of all generating units under the dispatch control of ISO-NE and summarized their annual energy output by each unit's reported primary fuel type.³¹ This information was then categorized into the following fuel types:³²

- Natural gas (50,670 GWh at 42.4%)
- Nuclear (36,231 GWh at 30.3%)
- Coal (14,558 GWh at 12.2%)
- Oil, heavy and light (895 GWh at 0.7%)

²⁹ In 1995, for the U.S. DOE, the Idaho National Engineering Laboratory assessed hydropower resources for all 50 states. The results indicated that within New England, approximately 68 projects totaling 105 MW may be available at sites with existing hydropower generation, and approximately 773 projects totaling 1,331 MW may be available at sites without existing hydropower generation or from an undeveloped site without an existing impoundment or diversion structure.

³⁰ NEWIS materials are available at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2010/nov162010/index.html and http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2009/nov182009/newis_slides.pdf.

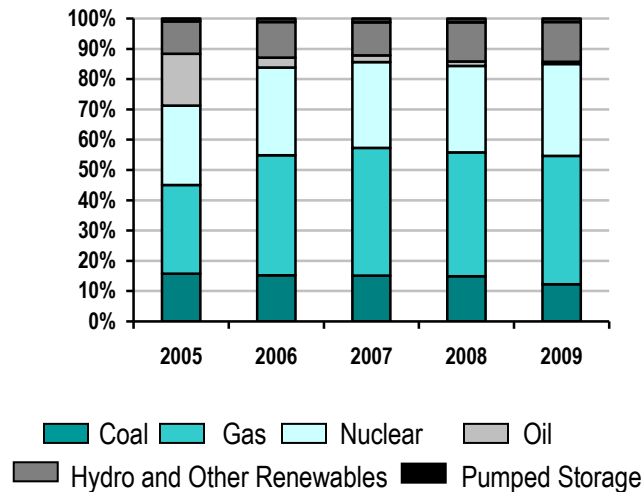
³¹ The dual-fuel units in the region are reported under natural gas or oil, depending on what fuel they claim as their primary fuel type within the monthly settlement period.

³² These overall quantities of energy (GWh) and percentages of total annual energy are for 2009 only.

- Hydroelectric and other renewables (8,353 GWh at 7.0% and 7,302 GWh at 6.1%, respectively)³³
- Pumped storage (1,419 GWh at 1.2%)

This information does not contain, nor has it been adjusted for, historical imports or exports of electric energy, although the production of energy to support exports is reflected within the annual energy production amounts. The diversity of fuels for generating electric energy in New England for 2005 to 2009 is shown in the following graph.

ISO-NE Fuel Diversity (Energy), 2005–2009



Data observations:

- Average annual electric energy production over the five-year period was approximately 126,925 GWh.
- The highest annual energy production occurred in 2005 at 131,875 GWh.
- The lowest annual energy production occurred in 2009 at 119,428 GWh.
- Annual energy production in 2009 was down considerably (about 10%) from previous years, primarily because of the economic impacts of the recession and a relatively cooler, rainy summer season.
- The top three fuels to produce electric energy within New England are natural gas, nuclear, and coal. However, no single fuel had an annual energy contribution greater than 50%.
- The New England gas-fired generation fleet had the largest portion of annual energy production in each year, ranging from a low of 29.2% in 2005 to a high of 42.4% in 2009.
- The overall production of electric energy from using both heavy and light oil products declined over the five-year period, from 17.1% (22,600 GWh) in 2005 to 0.7% (895 GWh) in 2009.

³³ The hydroelectric energy reflects the total annual amount of electric energy claimed from both daily- and weekly-cycle hydroelectric facilities that typically are dispatchable and self-scheduled along with total annual amount of energy from “settlement-only” hydroelectric facilities that typically are run-of-river and nondispatchable.

- The overall production of electric energy from coal declined over the five-year period, from 15.8% (20,789 GWh) in 2005 to 12.2% (14,558 GWh) in 2009.
- The overall production of electric energy from renewables (6.1%) and hydroelectric (7.0%) and pumped storage (1.2%) stations remained relatively constant over the five-year period, with some seasonal variation year to year.

Renewable Resources

ISO-NE Electric Energy Produced by Renewables

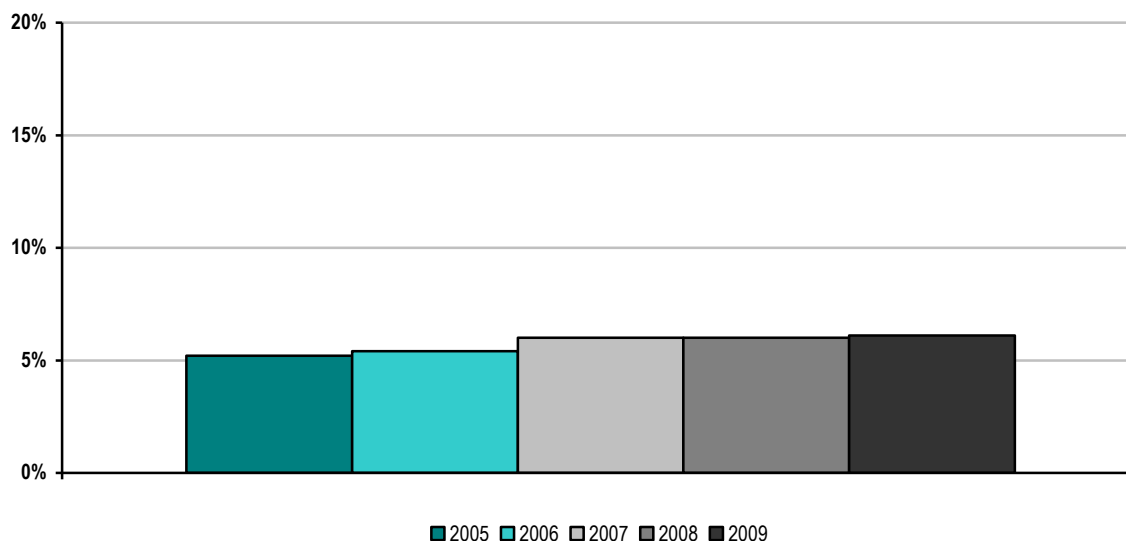
This ISO/RTO performance metric compares ISO-NE's annual amount of electric energy produced by renewable resources with the total amount of energy produced annually. To develop the information for this metric, ISO-NE compiled the historical energy production of all generating units under its dispatch control for 2005 through 2009 and summarized their annual energy output by each unit's reported primary fuel type. All the "other renewables" energy information was then categorized into the annual renewable energy category, shown in the following table, along with total annual amount of energy produced and the percentage of total energy produced by renewables for each assessment year.

ISO-NE Electric Energy Produced by Renewables, 2005 to 2009

Year	Annual Energy Produced by Renewables	Total Annual Energy Produced (GWh)	Percentage of Total Annual Energy Produced by Renewables
2005	6,832	131,875	5.2%
2006	6,888	127,851	5.4%
2007	7,810	130,721	6.0%
2008	7,542	124,750	6.0%
2009	7,302	119,428	6.1%

Although hydroelectric energy generation is shown within previous metrics, it was categorized separately and not included within the "other renewables" category, primarily because it may not be defined universally as a "renewable" resource across the country. In addition, this information does not contain, nor has it been adjusted for, historical imports or exports of renewable energy, although the production of energy to support exports is reflected within the annual energy production amounts. The following graph shows ISO-NE's annual energy produced by renewables as a percentage of total energy produced annually for 2005 through 2009, not including energy produced from hydroelectric generation.

Energy Produced by Renewables in ISO-NE as a Percentage of Total Energy Produced, 2005–2009



Data observations:

- The average annual electric energy produced by renewables over the five-year period was approximately 7,275 GWh.
- The highest amount of annual electric energy produced by renewables occurred in 2007 at 7,810 GWh, 6.0% of the total amount of energy produced, at 130,721 GWh.
- The lowest amount of annual electric energy produced by renewables occurred in 2005 at 6,832 GWh, 5.2% of the total amount of energy produced systemwide, at 131,875 GWh.
- Five of the New England states have Renewable Portfolio Standards (RPSs), and Vermont has a goal for increasing energy usage from renewable resources. These RPSs represent state policy targets to be achieved by retail competitive suppliers. The retail electricity suppliers may choose to meet some or all of their obligations using renewable resources within the ISO-NE Generator Interconnection Queue, resources from adjacent balancing authority areas, new resources in New England not yet in the queue, small “behind-the-meter” projects, and eligible renewable fuels in existing generators. Affected suppliers also can meet RPS shortfalls by paying an alternative compliance payment (ACP), which acts as an administrative cap on the cost of renewable sources of electric energy. ACP funds are used to promote the development of new renewable resources and energy efficiency in the region.

ISO-NE Hydroelectric Energy Produced

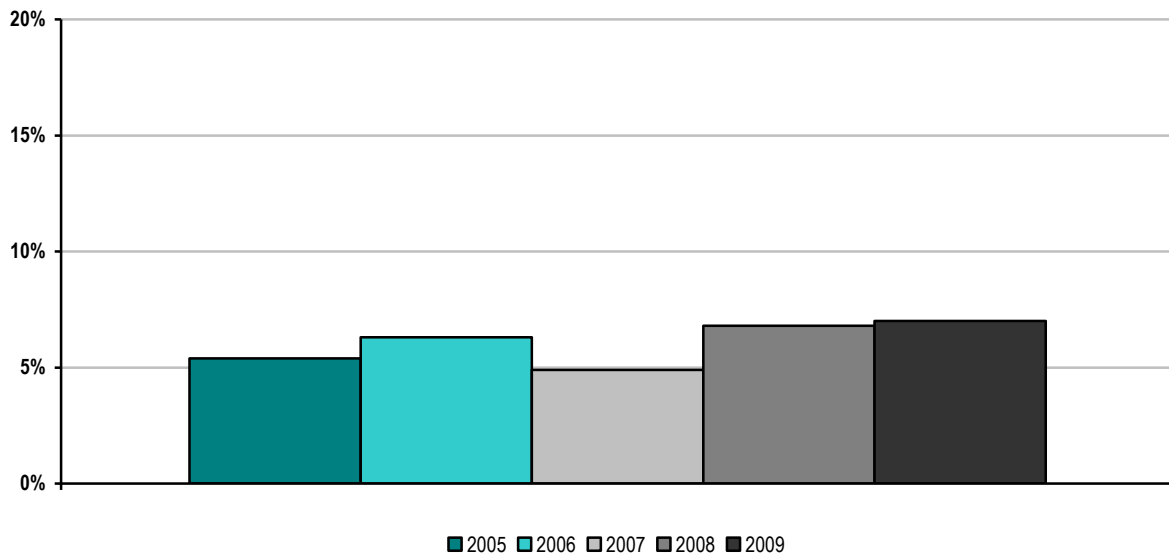
The next performance metric compares ISO-NE's annual production of hydroelectric energy with the total annual amount of energy produced. To develop the information for this metric, ISO-NE compiled the historical electric energy production of all generating units under its dispatch control for 2005 to 2009, and summarized their annual energy output by each unit's reported primary fuel type. The following table shows the total amount of "hydroelectric" energy produced in 2005 through 2009, the total amount of annual electric energy produced annually for those years, and hydroelectric's percentage of the total amount of energy produced annually for each year. This information does not contain, nor has it been adjusted for, historical imports or exports of hydroelectric energy, although the production of energy to support exports is reflected within the annual energy production amounts.

ISO-NE Hydroelectric Energy Produced, 2005 to 2009

Year	Annual Hydroelectric Energy Produced (GWh)	Total Annual Energy Produced (GWh)	Percentage of Total Annual Hydroelectric Energy Produced
2005	7,124	131,875	5.4%
2006	8,024	127,851	6.3%
2007	6,383	130,721	4.9%
2008	8,464	124,750	6.8%
2009	8,353	119,428	7.0%

The following metric shows ISO-NE's annual hydroelectric energy produced as a percentage of the total energy produced annually for 2005 through 2009.

ISO-NE Hydroelectric Energy Produced as a Percentage of Total Energy Produced, 2005–2009



Data observations:

- The average amount of hydroelectric energy produced annually over the five-year period was approximately 7,670 GWh.
- The highest amount of hydroelectric energy produced annually occurred in 2008 at 8,464 GWh, or 6.8% of the 124,750 GWh of total system energy.
- The lowest amount of hydroelectric energy produced annually occurred in 2007 at 6,383 GWh, or 4.9% of the total amount of electric energy produced systemwide, 130,721 GWh.

ISO-NE Capacity Provided by Renewables

The next performance metric compares renewable capacity with total capacity. All the “other renewables” capacity information is categorized into the “renewable” capacity category, shown in the following table, along with total capacity and the percentage of total capacity provided by renewables for each assessment year:³⁴ This information does not contain, nor has it been adjusted for, historical firm imports or exports of renewable capacity.

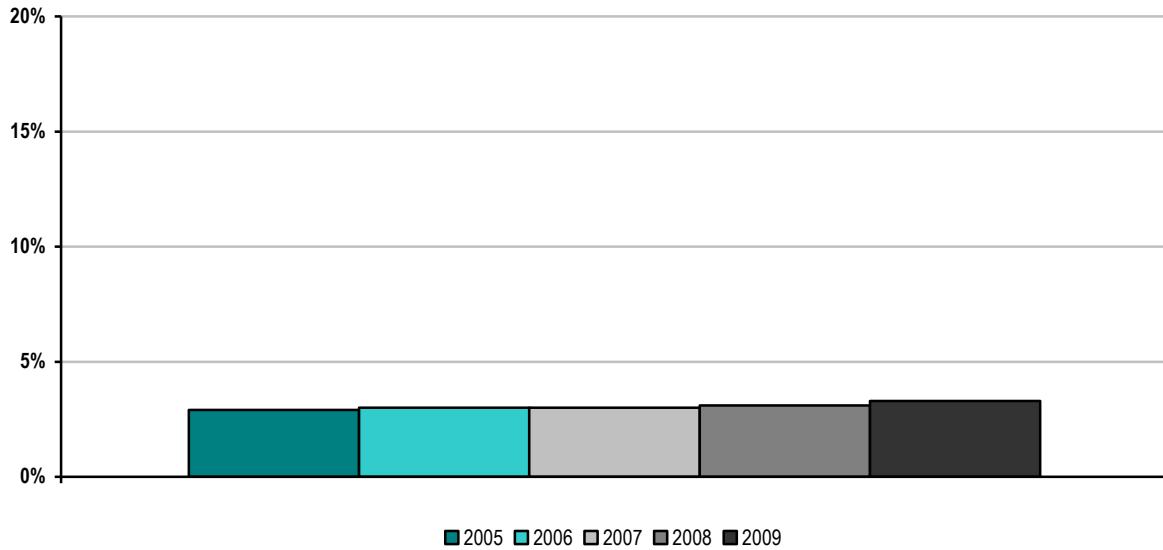
ISO-NE Capacity Provided by Renewables, 2005 to 2009

Year	Capacity Provided by Renewables (MW)	Total Capacity (MW)	Percentage of Total Capacity Provided by Renewables
2005	896	30,940	2.9%
2006	922	30,931	3.0%
2007	917	30,526	3.0%
2008	948	31,102	3.1%
2009	1,039	31,443	3.3%

The following graph compares ISO-NE’s capacity provided by renewables as a percentage of total capacity for 2005 to 2009, not including hydroelectric capacity.

³⁴ The “other renewables” category includes energy from landfill gas, other biomass gas, refuse (municipal solid waste), wood and wood-waste solids, wind, solar, black liquor, and tire-derived fuels.

ISO-NE Summer Capacity Provided by Renewables as a Percentage of Total Summer Capacity, 2005–2009



The following metric shows ISO-NE’s estimated (annual average) renewable capacity factors for 2005 to 2009. This estimated capacity factor information is representative of the “annual average” from numerous types of renewable production facilities, which include energy from landfill gas, other biomass gas, refuse (municipal solid waste), wood and wood-waste solids, wind, solar, black liquor, and tire-derived fuels, and does not represent the capacity factor of any single renewable production facility.

ISO-NE Estimated (Annual Average) Renewable Capacity Factors, 2005 to 2009

Year	Total Renewable Capacity (MW)	Total Annual Renewable Energy (GWh)	Estimated (Annual Average) Renewable Capacity Factor (%)
2005	896	6,832	87.0%
2006	922	6,888	85.3%
2007	917	7,810	97.2%
2008	948	7,542	90.8%
2009	1,039	7,302	80.2%

Data observations:

- The average summer capacity provided by renewables over the five-year period was approximately 944 MW.
- The highest amount of summer capacity provided by renewables occurred in 2009 at 1,039 MW, or 3.3% of the total installed summer capacity of 31,443 MW.

- The lowest amount of summer capacity provided by renewables occurred in 2005 at 896 MW, or 2.9% of the total installed summer capacity of 30,940 MW.
- Five of the six New England states classify hydroelectric capacity as some form of renewable resource, mostly depending on the size of the unit and its compliance with state and federal fish-passage requirements. Currently, only Maine allows pumped-storage units to be classified as a renewable resource.
- The estimated (annual average) renewable capacity factors range from a low of 80.2% in 2009 to a high of 97.2% in 2007. The high capacity factors are representative of the majority of the renewable capacity on the system, which primarily were small, thermal stations fueled by wood, biomass, or refuse, for example. These renewable power stations typically are baseload, nondispatchable units and were classified as “must-run” or self-scheduled generation.

ISO-NE Hydroelectric Capacity

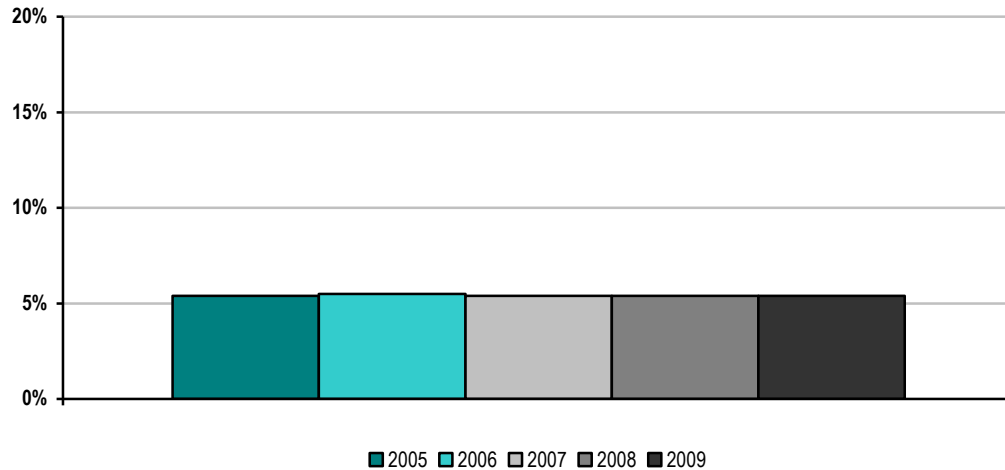
The following metric shows ISO-NE’s hydroelectric summer capacity as a percentage of total summer capacity for 2005 to 2009. The following table shows all the “hydroelectric” capacity and total capacity for 2005 to 2009 and hydroelectric’s percentage of total capacity for each assessment year. This information does not contain nor has it been adjusted for historical firm imports or exports of hydroelectric capacity.

ISO-NE Hydroelectric Capacity, 2005 to 2009

Year	Hydroelectric Capacity (MW)	Total Capacity (MW)	Percentage of Hydroelectric Capacity to Total Capacity
2005	1,663	30,940	5.4%
2006	1,691	30,931	5.5%
2007	1,648	30,526	5.4%
2008	1,679	31,102	5.4%
2009	1,694	31,443	5.4%

The next metric shows ISO-NE’s hydroelectric capacity as a percentage of total capacity for 2005 through 2009.

ISO-NE Hydroelectric Summer Capacity as a Percentage of Total Summer Capacity, 2005–2009



The following metric shows ISO-NE's estimated (annual average) hydroelectric capacity factors for 2005 to 2009. Because some small amount (200 to 300 MW, depending on monthly rating) of regional hydroelectric capacity is claimed as "settlement-only" capacity, these capacity values need to be added to the total hydroelectric capacity (MW) category to obtain a more accurate estimate of the annual average hydroelectric capacity factors. This estimated capacity factor information is representative of the "annual average" from numerous types of hydroelectric production facilities (i.e., run-of-river, daily- and weekly-cycle hydro) and does not represent the capacity factor of any single hydroelectric facility.

ISO-NE Estimated (Annual Average) Hydroelectric Capacity Factors, 2005 to 2009

Year	Total Hydroelectric Capacity (MW)	Total Settlement-Only Capacity (MW) ^(a)	Total Annual Hydroelectric Energy (GWh)	Estimated Annual Hydroelectric Capacity Factor (%)
2005	1,663	263	7,124	42.2%
2006	1,691	212	8,024	48.1%
2007	1,648	264	6,383	38.1%
2008	1,679	283	8,464	49.2%
2009	1,694	246	8,353	49.1%

(a) The majority of this "settlement-only" capacity is small, nondispatchable, run-of-river hydroelectric capacity, but it also may include small amounts of capacity fueled by distillate fuel oil, natural gas, LFG, wind, solar, wood/biomass, and refuse. These values are taken from the settlement-only section of the August version of the applicable yearly Seasonal Claimed Capability (SCC) Report and vary from a low of 212 MW in August 2006 to a high of 283 MW in August 2008.

Data observations:

- The average hydroelectric summer capacity over the five-year period was approximately 1,675 MW.
- The highest amount of hydroelectric summer capacity occurred in 2009 at 1,694 MW, or 5.4% of the total installed summer capacity of 31,443 MW.

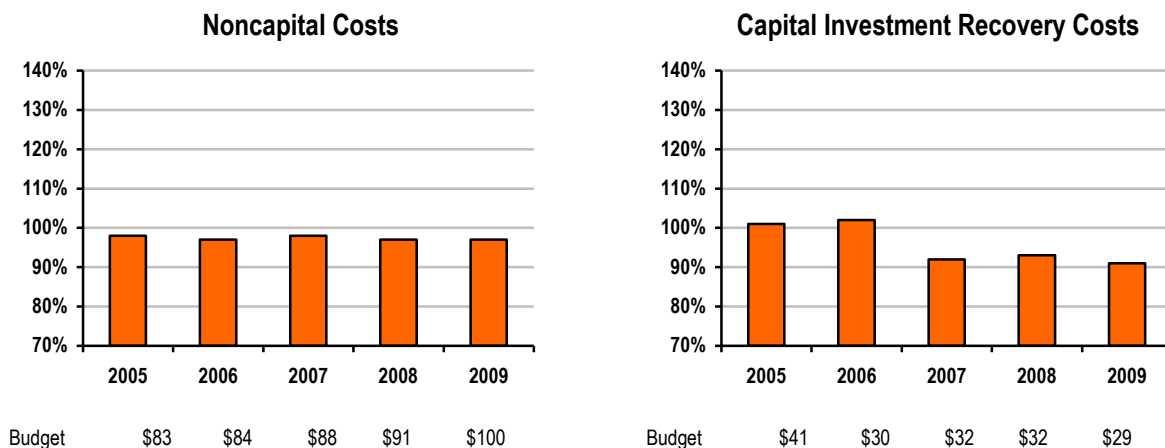
- The lowest amount of hydroelectric summer capacity occurred in 2007 at 1,648 MW, or 5.4% of the total installed summer capacity of 30,526 MW.
- As noted, five of the six New England states classify hydroelectric capacity as some form of renewable resource, mostly depending on the size of the unit and its compliance with state and federal fish-passage requirements. Only Maine allows pumped-storage units to be classified as a renewable resource.
- The estimated (annual average) hydroelectric capacity factors range from a low of 38.1% in 2007 to a high of 49.1% in 2009. These capacity factors are representative of the majority of the larger types of hydroelectric capacity on the system, which are river-based hydroelectric stations with significant pondage or storage capability. These hydroelectric power stations typically are dispatchable or can also be self-scheduled generation. Because of the prior capacity rating methodology ISO-NE used for these types of hydro facilities, the capacity values are indicative of the amount of nameplate capacity that can be provided over a short time period, usually a 2- to 4-hour demonstration window, which, combined with a large watershed behind it, is the primary reason for the relatively high capacity factors for these facilities.
- As noted earlier, the annual average, regional hydroelectric capability is approximately 1,925 MW. Although a federal study in 1995 indicated the potential for another 1,300 MW of hydroelectric capacity within the region, the majority of the river systems within New England have already been optimized for hydroelectric energy and paper production. In addition, multiple environmental considerations would reduce the likelihood that these potential hydroelectric sites would be developed to their full physical potential.

C. ISO New England Organizational Effectiveness

Administrative Costs

The following figures show ISO-NE's actual annual noncapital costs and capital investment recovery costs as a percentage of budgeted costs for 2005 to 2009.

Actual Annual ISO-NE Costs as a Percentage of Budgeted Costs, 2005–2009



Bars represent percentage of actual costs to approved budgets; dollar amounts represent approved budgets (in millions)

The metric for noncapital costs identifies ISO-NE's administrative cost budget performance. The ISO-NE budgets reflect the resource allocations based on the establishment of regional objectives through the stakeholder process. These objectives and priorities, including resource allocations, are discussed with the stakeholders throughout the budget cycle. The main categories of costs include salaries and related overhead and outside consulting support. In each year, these costs represent approximately 80% of the total budget. The next-largest categories include computer services and communication costs, which average 8% per year. Regional entity dues make up approximately 4% of the costs each year.

The primary underspend in each year is the underutilization of contingencies contained in each budget. Each of ISO-NE's annual budgets contains a board-contingency expense of \$1 million. The board contingency is in place to fund unplanned activities and their related expenses. Normally, such expenses would be funded through a company's equity or reserves. However, ISO-NE has neither. In the years reported here, and in all prior years, ISO-NE has not had to use this contingency fund. Therefore, the variance for each of the years shown also includes a savings against the board's \$1 million contingency budget.

Data on ISO-NE expenses for 2005 to 2009 are as follows:

- In 2005, ISO-NE's actual expense was approximately 2% lower than the approved budget. The variance was primarily due to staffing levels lower than budgeted, interest income higher than budgeted, and savings on insurance costs.

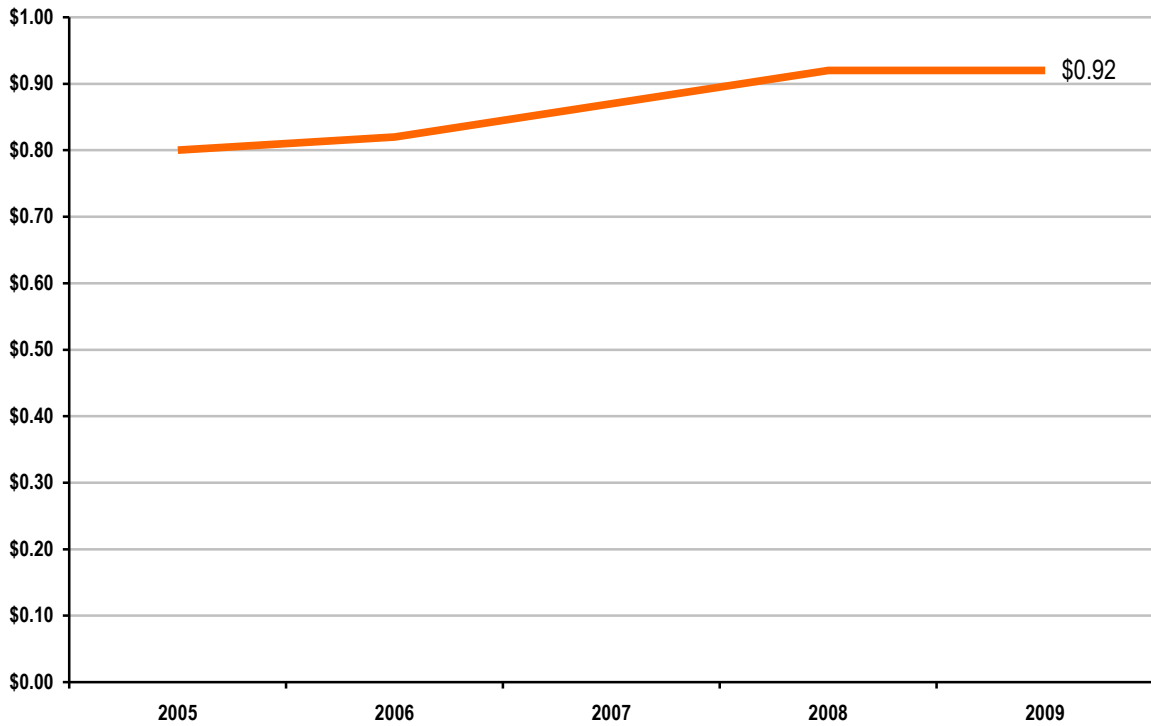
- In 2006, ISO-NE's actual expenses were 3% lower than budgeted as a result of increased interest income.
- In 2007, ISO-NE's expenses were 2% lower than budgeted as a result of a higher staffing vacancy rate and reduced communication expenses because of contract renegotiations.
- In 2008, ISO-NE's expenses were 3% lower than budgeted because of higher internal capital development, increased reimbursable transmission study cost work, and lower outside consultant costs. These reductions were partially offset by interest income lower than budgeted.
- In 2009, ISO-NE's expenses were 3% lower than budgeted, primarily due to reduced computer services resulting from the restructuring of certain licensing arrangements and less reliance on external maintenance support. In addition, certain changes in health care plans also reduced costs, partially offset by increased pension benefit costs.

ISO-NE capital investment recovery costs include depreciation, amortization, interest expense, and loss on disposal of assets. Data on ISO-NE's costs for 2005 to 2009 are as follows:

- In 2005, actual costs were 1% higher than budgeted because of slightly higher depreciation estimates.
- In 2006, actual costs were 2% higher than budgeted primarily because of the abandonment of work done on the Locational Installed Capacity project, which was replaced with a newly designed Forward Capacity Market.
- In 2007, costs were 8% below budget as a result of lower depreciation costs. The decreased depreciation expense was due to underspending for capital projects planned and changes in in-service dates for projects planned for 2007, including the Forward Capacity Market Phase I.
- In 2008 and 2009, capital investment expenses were 7% and 8% below budget, respectively. For both years, the decrease was because of lower capital project costs and changes in project in-service dates for various capital projects. In addition, a reduction in interest expense, primarily because of a drop in interest rates during both years, contributed to the variance.

The administrative costs per megawatt-hour of load served shown in the following graph should be reviewed in the context of the widely varying levels of annual load served by each ISO/RTO, with ISO-NE's data shown in the table below. Year-to-year changes in load may reflect weather patterns, demand-response penetration, and energy-efficiency gains. As such, the data are used as a reference point because many of ISO-NE's costs are fixed and load reductions may reflect regional objectives.

ISO-NE Annual Administrative Charges per Megawatt Hour of Load Served, 2005–2009
(\$/MWh)



ISO-NE Annual Load Served, 2009



Customer Satisfaction

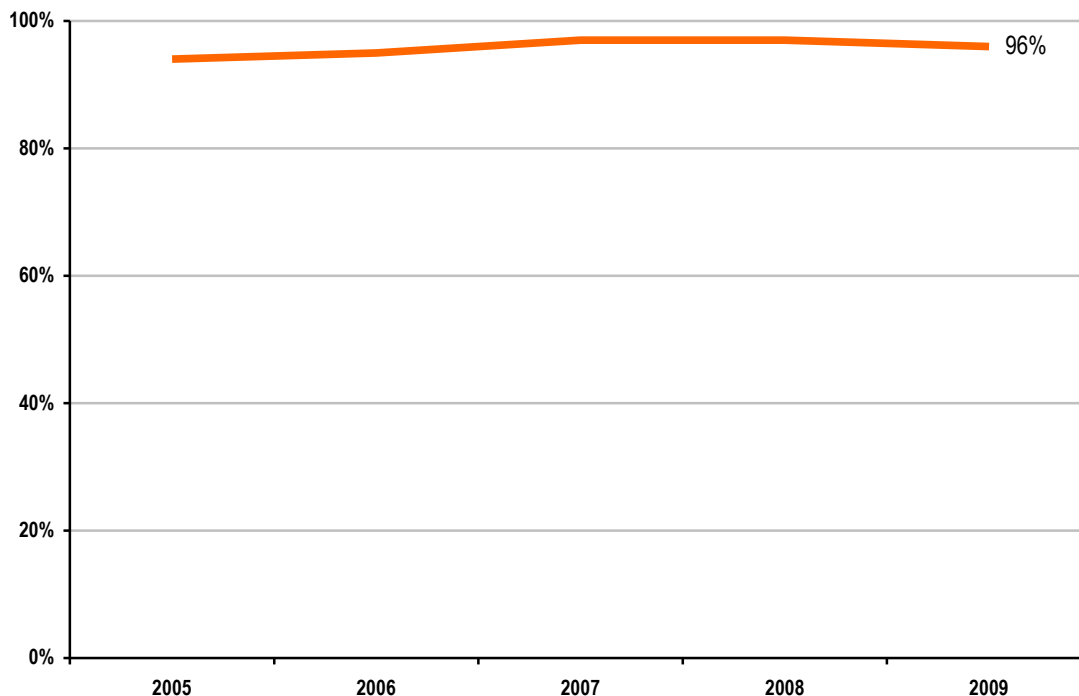
This ISO/RTO performance metric identifies customer satisfaction within the ISO-NE footprint. Since 1999, through an independent third-party administrator, ISO-NE has measured customer satisfaction with respect to its overall performance, as well as by satisfaction with its performance on service dimensions related to FERC objectives for ISOs/RTOs.

The ISO New England customer satisfaction survey measures satisfaction with specific service dimensions, such as the following:

- ISO-NE's operation of the bulk power system consistent with established FERC, NERC, and NPCC reliability requirements
- Dispatch of resources (generators, loads, and tie lines) consistent with the tariff
- Administration of the wholesale markets consistent with the tariff
- Responsiveness to customer inquiries
- Implementation of requirements as defined in the tariff
- Administration of stakeholder processes to allow for input on matters that affect the efficiency and competitiveness of the wholesale market, as well as issues that have an impact on the reliability of the bulk power system

Satisfaction with performance is measured using a six-point scale composed of "extremely satisfied," "moderately satisfied," "marginally satisfied," "marginally dissatisfied," "moderately dissatisfied," and "extremely dissatisfied." For the survey period of 2005 to 2009, for all the service dimensions except for the aforementioned administration of stakeholder processes, ISO-NE achieved net customer satisfaction results of 91% or greater from survey respondents that had an opinion. With respect to the stakeholder process, ISO-NE achieved a satisfaction rating of 85% or greater during that same five-year period. For overall performance, ISO-NE achieved a net satisfaction rating of 94% or greater for 2005 to 2009. Respondents are also asked to grade their level of satisfaction or dissatisfaction on a scale of zero to 100, with a score of 70 being passing. For 2005 to 2009, the average score from all respondents was 84% or greater. The following graph illustrates the net positive customer satisfaction with ISO-NE's overall performance for survey respondents that expressed an opinion for 2005 to 2009.

ISO-NE Percentage of Satisfied Members, 2005–2009



Billing Controls

This ISO/RTO performance metric identifies some of ISO-NE’s billing controls. Since 2004, ISO-NE has engaged an external audit firm to review the description of controls, evaluate the effectiveness of controls design, and test operating effectiveness of the controls for the ISO-NE “bid-to-bill” processes. These processes include market operations, settlements, market services, and finance processes, as well as supporting IT applications and processes. Overall performance is measured by an external auditor, whose opinion of “unqualified” (i.e., clean) or “qualified” is stated in an SAS 70 Type 2 Audit Report made available to NEPOOL participants. The results of the ISO-NE audits for 2005 to 2009 are shown in the following table.

ISO- NE SAS 70 Type 2 Audit Results, 2005–2009

ISO/RTO	2005	2006	2007	2008	2009
ISO-NE	Unqualified SAS 70 Type 2 Audit Opinion	Unqualified SAS 70 Type 2 Audit Opinion	Unqualified SAS 70 Type 2 Audit Opinion	Unqualified SAS 70 Type 2 Audit Opinion	Unqualified SAS 70 Type 2 Audit Opinion

In 2008, market participants submitted six billing disputes that resulted in billing adjustments of \$68,236. In 2009, nine billing disputes were submitted to ISO-NE that resulted in billing adjustments of \$414,302. The total value of the wholesale electricity markets administered by ISO-NE in 2008 was \$14.7 billion, and the value in 2009 was \$7.9 billion. All requests for billing adjustments (RBAs) are reported to stakeholders.

D. ISO New England Specific Initiatives

Developing Transmission Infrastructure: Transmission development has seen great progress across the region. More than 300 projects have been placed in service since 2002, a \$4 billion investment that benefits all New England consumers. An additional \$5 billion in transmission investment is planned for the next 10 years that will help the region's grid stay reliable and flexible. These reliability transmission upgrades have alleviated transmission congestion and have reduced out-of-market costs by almost 90% in 2009 because there is less of a need to operate power plants to maintain reliability in certain areas of the power grid.

New England's electricity consumers share the cost of transmission lines needed to maintain grid reliability through an established practice for cost allocation. This arrangement has provided the certainty needed for transmission owners to invest in needed power system infrastructure and has been in place since December 2003 when FERC approved this regionalized payment approach as a part of the region's transmission tariff.

The *Energy Policy Act of 2005* required the U.S. Department of Energy (DOE) to complete a transmission congestion study every three years to analyze the flow of electricity across the nation's power systems. The first study, completed in 2006, identified New England as one "area of concern" and cited significant transmission congestion in the Southwest Connecticut and Boston areas. In its subsequent study released in 2009, the DOE cited that conditions in New England have changed markedly over the past three years and removed New England as an "area of concern."

In its *2010 Regional System Plan*, ISO-NE provides additional focus and information on the ability of nontransmission alternatives to meet regional system needs.³⁵

Markets Provide Competition and Investment Certainty: In the past decade under ISO-NE administration, new electric generating capacity has increased power grid capacity by more than 30% with the addition of 10,800 MW of new generation. In addition to making electricity prices more competitive, this additional generating supply has helped to meet record-setting consumer demand and has lowered regional power plant emissions by decreasing nitrogen oxide emissions by 45% and sulfur dioxide emissions by 50%. Most of this new generating capacity uses natural gas as its fuel source. Currently, more than 30,500 MW of supply-side, generating resources are available in New England that have been procured through the Forward Capacity Market.

In less than 13 years, New England has developed a comprehensive suite of market products and services. More than 400 companies complete between \$5 and 12 billion in transactions annually to buy and sell wholesale electricity, and the region's wholesale markets and products traded in New England fall into three categories: energy, capacity, and ancillary services.

Wholesale market prices have decreased in New England for most of the past decade, including both the yearly, average locational marginal prices, as well as the fuel-adjusted prices. This trend currently reflects both lower fossil

³⁵ ISO-NE's RSP10 is available at <http://www.iso-ne.com/trans/rsp/index.html>.

fuel costs, as well as the other market and power system efficiencies, such as the reduction of transmission congestion, that have been gained through wholesale restructuring.

Investment in the Smart Grid: New England's power system continues to see improvements and innovation through smart grid initiatives, including a three year, \$18 million dollar project to upgrade measurement devices at different points across the six-state transmission system. This project will help ISO-NE system operators more accurately monitor system conditions by providing information on the system's status 30 times a second rather than the current once every four seconds. A total of \$8 million of this project is being funded through a smart grid stimulus grant from the DOE.

Providing Analysis for the Integration of Renewable Resources: In 2009, ISO-NE provided analysis to the New England states on integrating renewable and low-carbon-emitting resources into the region's energy mix. The study found that the region has significant on- and offshore wind-resource potential and the opportunity to import clean energy from hydro, wind, and potential nuclear sources in Canada.

Also, in 2009, ISO-NE launched the New England Wind Integration Study (NEWIS) to identify best practices for wind forecasting for the region through the development of technical requirements and the assessment of different wind scenario impacts. NEWIS is expected to be completed in late 2010.

Emphasis on Compliance: Compliance is an integral component of ISO-NE operations. In the area of reliability standards and operations, compliance is assessed through requirements from NERC and NPCC. ISO-NE dedicates full-time resources to ensuring the company meets existing standards and follows the development of new standards. In 2009, a NERC/NPCC audit found ISO-NE compliant with all 41 applicable reliability standards and 375 requirements and subrequirements over a two-year period, from June 2007 to April 2009. During this review, ISO-NE was one of the first organizations in the U.S. to be audited for compliance with Critical Infrastructure Protection standards.

The *Sarbanes-Oxley Act* requires the management of publicly owned companies to sign-off on their internal controls over the preparation of financial statements. Market participants rely on the ISO-NE SAS 70 Type 2 Audit to give assurance that its bid-to-bill control processes are adequate. ISO-NE's SAS 70 Type 2 Audit is performed annually and covers the controls surrounding processes and systems for bidding, accounting, billing, and settlement of energy, regulation, reserves, capacity, transmission, demand response, and tariff areas.

For the past six years, ISO-NE has received an external auditor's report with an unqualified opinion that its controls over the bid-to-bill process were suitably designed and were operating with sufficient effectiveness to achieve its control objectives.

Collaboration: In New England, a collaborative relationship exists in the electricity industry among ISO-NE, market participants (i.e., those entities involved in the wholesale electricity marketplace), state utility regulators, and other government officials. This collaboration has been the contributing factor to the success the region has seen in the past decade in developing power system infrastructure and a workably competitive suite of wholesale markets.