2010 ISO/RTO Metrics Report

The California Independent System Operator Corporation (California ISO), ISO New England, Inc. (ISO-NE), Midwest Independent Transmission System Operator, Inc. (Midwest ISO), New York Independent System Operator (NYISO), PJM Interconnection, L.L.C. (PJM), and Southwest Power Pool, Inc. (SPP) assisted in the preparation of this report.

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Executive Summary

The following report has been prepared by the independent system operators (ISOs) and regional transmission organizations (RTOs) that are regulated by the Federal Energy Regulatory Commission (FERC). The report provides information on various data points that are common to each of the system operators, and has been prepared at FERC's direction following the process described below.

The information included, similar to FERC Form 1 information, may be useful to the FERC, stakeholders and the public at large in compiling information and tracking certain data points that are relevant to ISO and RTO performance in the areas of reliability, wholesale electricity market performance and organizational effectiveness. That said, this report does not definitively measure ISO and RTO performance or supplant the various mechanisms already in place to measure performance. Those include FERC's triennial market-based rate analysis under Order No. 697, the respective State of the Market Reports for each ISO/RTO, FERC's State of the Market Report, or regional initiatives such as the "value proposition" and other measures developed by ISOs and RTOs.

Moreover, the information provided herein must be assessed in the proper context. For example, the report includes tables comparing forecast accuracy at each of the ISOs and RTOs. However, there are a number of factors that influence the data and could result in variations among the ISOs/RTOs, including the time of day at which the forecast is made, the region's weather variability, data points selected (i.e., hour to hour) and the geographic diversity of the control area. Where possible, and to the extent practicable, this context has been provided along with the data. Absent this context, the data tell an incomplete story.

History of the Initiative

This report originated with a review undertaken by the United States Government Accountability Office in 2008 at the request of the U.S. Senate Committee on Homeland Security and Governmental Affairs.[1] To more effectively analyze ISO/RTO benefits and performance, the Government Accountability Office recommended that the FERC work with ISOs/RTOs, stakeholders and other interested parties to standardize measures that track the performance of ISO/RTO operations and markets, and to report the performance results to Congress and the public.

Accordingly, FERC staff worked with a team composed of personnel from FERC-jurisdictional ISOs and RTOs to develop the performance metrics that form the basis for this report. As part of this process, FERC held meetings with industry stakeholders for their input and established an open comment period on the proposed metrics which will track the performance of ISO/RTO operations, markets and organizational effectiveness.

[1] *Electricity Restructuring: FERC Could Take Additional Steps to Analyze Regional Transmission Organizations' Benefits and Performance*, United States Government Accountability Office, Report to the Committee on Homeland Security and Governmental Affairs, U.S. Senate (September 22, 2008), GAO-08-987 (http://www.gao.gov/new.items/d08987.pdf).

Information Provided

Following a brief summary of the operations and geographic scope of the reporting ISOs and RTOs, this report provides information responsive to each of the FERC-proposed metrics. When applicable, the data and information are presented for the period 2005 through 2009.

These metrics were organized by the FERC, and are presented here, in the categories of reliability, markets, and organizational effectiveness. The reliability metrics provide information on compliance with and violations of national and regional reliability standards; dispatch behavior; load forecast accuracy; long-term generation and transmission planning; and planned outage coordination. Market metrics include pricing; rates for generator availability and forced outages; statistics on congestion management charges and the amount of charges hedged through congestion management markets; demand-response amounts as capacity and ancillary services; and the percentage of total electric energy provided by renewable resources. Organizational effectiveness metrics include ISO/RTO administrative charges to members compared to budgeted administrative charges and as cents per megawatt hour (¢/MWh) of load served; customer satisfaction; and the scope and results of audits of billing controls.

Each ISO/RTO provides a brief overview of their region, their data on the FERC metrics and information to the extent applicable and available, and additional information on key initiatives specific to their regional activities.

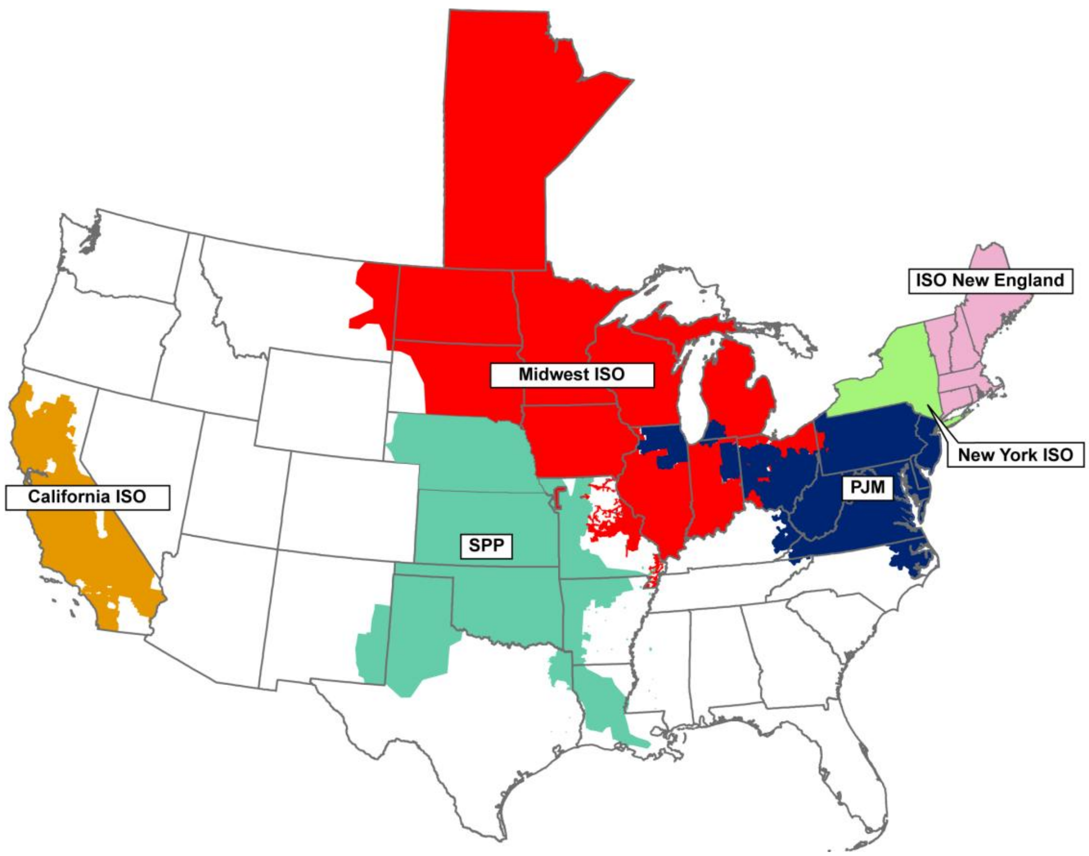
Emerging Themes

The information provided in this report reinforces the value of ISOs and RTOs. The report illustrates the transparency of ISO/RTO operations and reinforces the value of ISO/RTO operation of the grid and administration of wholesale electricity markets. Specifically, this report shows that:

- Balancing authority areas operated by ISO/RTOs function reliably;
- ISO/RTO organized markets are efficient;
- ISO/RTOs are advancing public policy energy objectives; and
- ISO/RTOs enable demand response and energy efficiency.

ISO/RTO Geography and Operations Statistics

The map and data below show to the location and breadth of operations for the ISOs/RTOs contributing to this report. These reference points will facilitate understanding some of the similarities and differences amongst the information of ISOs/RTOs in this report.



The table below summarizes the miles of transmission lines, installed generation, and population in each ISO/RTO region.

ISO/RTO	Headquarters	Installed Generation *(in megawatts)*	Miles of Transmission Lines	Population *(in millions)*
CAISO	Folsom, CA	57,124	25,526	30
ISO-NE	Holyoke, MA	33,700	8,130	14
Midwest ISO	Carmel, IN	144,132	55,090	43
NYISO	Rensselaer, NY	40,685	10,893	19
PJM	Valley Forge, PA	164,895	56,499	51
SPP	Little Rock, AR	66,175	50,575	15

Section 1 – Descriptions of Performance Metrics and Other Information

A. ISO/RTO Bulk Power System Reliability

All ISOs and RTOs are responsible for compliance with North American Electricity Council (NERC) mandatory standards and any mandatory standards for the Regional Entities (RE) that apply in the region where the ISO/RTO is located and are subsequently adopted by NERC. The mandatory reliability standards only apply to ISO/RTOs based on the NERC functional model categories for which each ISO/RTO has registered.

Therefore, different reliability standards apply to different ISOs and RTOs. For example, each region may have reliability standards that apply only within that region, given the particular infrastructure, resource mix, topographical and other differences that exist within the region. The main differences between the ISO/RTO applicable standards are the Regional Entity standards. Each region develops standards applicable for their infrastructure, environment and any other regional differences. Each ISO/RTO may also be registered for different functions, causing them to comply with different reliability standards.

Violations of such standards may be identified by an ISO/RTO and self-reported or may be identified by a NERC and/or Regional Entity audit of the ISO's/RTO's standards compliance. Such violations can then be classified as low, medium or high severity. This metric is a quantification of all NERC and RRO Reliability Standards violations that have been identified during an audit or as a result of an ISO/RTO self-report and have been published as part of that process.

Dispatch Operations

Compliance with CPS-1 and CPS-2

Each Balancing Authority (BA) is responsible for helping maintain the steady-state frequency in their interconnection within defined limits. The BAs do this by balancing power demand and supply in real-time. Under NERC standard BAL-001-0.1a – Real Power Balancing Control Performance, NERC has established standard measurements against which to monitor BA performance in meeting this responsibility. Each Balancing Authority (BA) shall achieve a minimum compliance of 100% for Control Performance Standard 1 (CPS1) (rolling annual average) and a minimum compliance of 90% for CPS2 (monthly average).

CPS-1 (Control Performance Standard 1) is a statistical measure of ACE (Area Control Error) variability. This standard measures ACE in combination with the Interconnection's frequency error. It is based on an equation derived from frequency-based statistical theory. CPS-2 (Control Performance Standard 2) is a statistical measure of ACE magnitude. The standard is designed to limit a control area's unscheduled power flows.

An alternative method of measurement is using the BAAL (Balancing Authority ACE Limit). The purpose of the BAAL standard is to maintain interconnection frequency within a predefined frequency profile under all conditions, to prevent frequency-related instability, unplanned tripping of load or generation, or uncontrolled separation or cascading outages that adversely impact the reliability of the interconnection. This standard requires the balancing authority to demonstrate real-time monitoring of ACE and interconnection frequency against associated limits and to balance its resources and demands in real-time so that its ACE does not exceed the BAALs for a time greater than 30 minutes. In addition, this standard limits the recovery period to no more than 30 minutes for a single event.

Transmission Load Relief or Unscheduled Flow Relief Events

Transmission Loading Reliefs (TLRs) are a procedure used in the Eastern Interconnection to relieve potential or actual loading on a constrained facility. In the Western Interconnection, Responsible Entities are required to take actions as requested by Qualified Transfer Path Operators that result in the specified amount of Unscheduled Flow (USF) relief events for the applicable Qualified Transfer Path. The information provided in this section illustrates the TLR level 3 events or greater and UFR activity for each ISO/RTO from 2005 through 2009.

Energy Management System Availability

The Energy Management System (EMS) at each ISO/RTO performs the real-time monitoring and security analysis functions for the entire ISO/RTO region and includes inputs from portions of adjacent control areas. . It includes a full complement of monitoring, generation control, state estimation and security analysis software. This metric measures the percentage of minutes each year that the ISO's/RTO's EMS was operationally available for use by the ISO's/RTO's dispatch operations staff.

Load Forecast Accuracy

A load forecast is an informed estimate of the future electrical demand on the ISO/RTO's system. Accurately forecasting load is critical because the forecast drives the commitment of generation and/or demand response for future periods. Inaccurate forecasting can manifest itself in either reliability problems (due to under-commitment of resources) or in additional costs (due to either over-commitment of resources or inefficient commitment of short lead-time resources).

Each of the ISOs/RTOs generates load forecasts in a number of different time periods ranging from years ahead to minutes ahead of the actual load period. This report focuses on the day-ahead load forecast for each ISO/RTO, as defined by that ISO/RTO. While there is some variation in the time of day in which each company's day-ahead load forecast is created, the use of the forecasts is similar – this is the forecast used to make day-ahead unit commitments of resources. Since SPP does not have a day-ahead market, the prior day's medium-term load forecast (MTLF) is used as the load forecast accuracy reference point.

Generally speaking, higher forecasting accuracy is good as it means that the actual load was closer to the forecast load. The ISOs/RTOs are striving to improve load forecast accuracy. Mean Absolute Percentage Error (MAPE) is commonly used in quantitative forecasting methods because it produces a measure of relative overall precision; the lower the MAPE, the more precise the forecast. However, comparisons between regions can be difficult because the load drivers vary significantly between regions. Also, results can change from one year to the next based on weather conditions and variations in patterns of customer usage across all sectors of the economy. A sampling of the regional variations includes:

- Weather Patterns – Certain regions experience more extreme weather variations (e.g., storms patterns, temperature swings). Generally, regions with more extreme weather variations would be expected to have less accuracy in their load forecasts.
- Industrial Loads – Certain regions have higher concentrations of variable industrial loads which can impact the load forecasts. Generally, regions with variable industrial loads would be expected to have less accuracy in their load forecasts.
- Geography Diversity – Broader ISO/RTO geographies can lead to netting of potential forecast inaccuracies in the ISO/RTO region for a more accurate total ISO/RTO region load forecast.

Presented in this section are load forecasting accuracy metrics and MAPE for the yearly average for all hours, the yearly average for the peak hour (the highest load hour) of each day, and the yearly average for the valley hour (the lowest load hour) of each day. In each case the metric is based on the simple average of the absolute difference between the forecasted load and the actual load divided by the forecasted load for all relevant hours.

Wind Forecasting Accuracy

This metric measures the accuracy of the wind generation forecast. The electric power industry will continue to see a significant increase in reliance on largely variable energy resources, such as wind and solar generating facilities. This transformation will impose challenges to operating the bulk power system because the magnitude and timing of variable energy resources output is significantly less predictable than conventional generation. The ability to accurately forecast variable energy resources output, therefore, becomes critical to manage uncertainty and maintain bulk power system reliability by facilitating the timely commitment and dispatch of sufficient supplemental resources. Wind forecasting is inherently less accurate than energy forecasting because the wind resource has much higher intrinsic variability than the factors which determine energy usage.

The objective of the chart in this section is to quantify the percentage accuracy of the actual wind generation availability compared with the forecasted wind generation availability as of the close of the prior day's day-ahead market.

Unscheduled Flows

Unscheduled flows are energy flows on each ISO's/RTO's transmission interface (interties), defined as the difference between net actual interchange (actual measured power flow in real time), and the net scheduled interchange (planned or pre-scheduled use of transmission). Unscheduled flow may be comprised of both inadvertent interchange and/or parallel flows.

Inadvertent interchange is relevant from an ISO/RTO perspective, not at the individual tie level. Inadvertent interchange is the difference between net actual interchange (actual power flow measured in real time), for all interties connecting the ISO/RTO with other Balancing Authority Areas within the interconnection.

Parallel flow (occasionally referred to as loop flow) is actual power flow within an interconnection that is generated within one Balancing Authority Area for delivery directly to load within a second Balancing Authority Area along a specified contract transmission path. In real time, "parallel" transmission lines through a third party Balancing

Authority Area may partially be used because of the interconnection's operating configuration, line resistance and physics. Parallel flow typically results in an un-scheduled flow of power, in on one intertie and out on another intertie through the third party Balancing Authority Area. Thus, parallel flow is a subset of unscheduled flow as it uses unscheduled transmission capacity on the respective interties.

Such unscheduled flow may or may not be detrimental from both an operations and market administration perspective depending on the direction of prevailing scheduled power flow on each intertie and the direction of the unscheduled flow. Unscheduled flow has the potential to cause path overloads if the power flow contributes to rather than counters the scheduled flow. Unscheduled flows contributing to actual power flow in excess of the system operating limit adversely impacts scheduled use of the grid, resulting in the need to curtail schedules on the specific intertie and return actual path flows within the system operating limit.

To summarize, unscheduled flow typically has two components, inadvertent energy and parallel flows. Therefore, unscheduled flow is not necessarily attributable to the ISO/RTO which has its transmission used in an unscheduled manner by others, due to system resistance, physics and operating configuration. Parallel flow manifests as unscheduled flow on a tie by tie basis, however, parallel flow "nets out" when considered from a total Balancing Authority perspective (summation of all ties), and does not contribute to inadvertent interchange. Inadvertent interchange measures a Balancing Authority's ability to properly "cover" its load in real time, by regulating with internal generation or scheduled imports and holding its planned net scheduled interchange through the operating period.

The unscheduled flow charts in this section reflect the absolute value of the total terawatt hours of unscheduled flows for each ISO/RTO and the absolute value of the total terawatt hours of unscheduled flows for each ISO/RTO as a percentage of total terawatt hours of flows. This section also includes tables reflecting the terawatt hours of unscheduled flows for the top five interfaces (or fewer if there are not at least five interfaces) for each ISO/RTO. Negative amounts represent unscheduled flows out of the ISO/RTO and positive amounts represent unscheduled flows into the ISO/RTO over the noted interface, except with respect to California ISO and ISO-NE, which have an opposite sign convention with imports being negative and exports being positive.

Transmission Outage Coordination

Centralized transmission outage coordination is an important function of ISOs/RTOs. Each ISO/RTO has procedures by which planned transmission outages should be noticed to the ISO/RTO by the transmission owner. Then, the ISO/RTO studies the planned transmission outage to determine whether such an outage request would create any reliability concerns. Even after approving a transmission outage request, an ISO/RTO can cancel a planned transmission outage if system conditions have changed such that an outage may create a reliability issue.

The four metrics in this section measure how promptly ISOs/RTOs are receiving planned transmission outage requests, how effective each ISO/RTO is at processing transmission outage requests, how often each ISO/RTO cancels previously-approved transmission outages, and the level of unplanned transmission outages in each ISO/RTO region. Each of these measures addresses transmission lines greater than or equal to 200kV.

Transmission Planning

ISO/RTO's take a long-term (generally 10 years or more) analytical approach to bulk power system planning with broad stakeholder participation to address reliability and economic benefit at intra- and inter-regional levels. By identifying system reliability and economic needs in advance, the planning process gives market participants time to propose either a market-based solution (e.g., a merchant transmission line, power plant or demand response) or regulated solution (e.g., a rate-based transmission line). Essential, large-scale transmission projects spanning the service territories of multiple transmission system owners have been completed or initiated in every ISO/RTO in the last 10 years. Supply-side resources and demand response, which are effectively integrated into the system, can sometimes assist in the resolution of transmission reliability issues, thereby potentially allowing the deferral of transmission solutions. However, creating new transmission solutions may be necessary to prevent supply-side resources or demand resources from compromising the deliverability of other existing resources.

The identified transmission planning metric provides an indication of the progress made to address reliability needs or economic opportunities early enough, to engage a broad set of stakeholders, and to successfully carry the projects to completion.

Generation Interconnection

One important role ISO/RTO's have is to facilitate unbiased and open access to all potential electric grid users. This function closely aligns with the transmission planning process, as ISO/RTO's manage the analytical and administrative processes of generation and transmission facility interconnections. This entails receiving interconnection requests, conducting impartial, diligent technical analyses of the system reliability impact, individually and collectively, of their usage and interconnection to the grid, and determining and allocating the costs of transmission upgrades to connect these facilities to the power system.

Average Generation Interconnection Request Processing Time

Generation interconnection is the process of connecting a generator to the electrical grid. When an entity is proposing to build a new generation unit or upgrade an existing unit, they apply to the ISO/RTO that manages the transmission access in that area to assess the availability of transmission capacity to export the energy from that new or upgraded generation facility. This performance metric measures the processing time for generation interconnection requests from time of access application through the study period to the delivery of final answer on the requirements for connection of the proposed units – including any proposed transmission upgrade requirements and associated costs. This metric is calculated as the simple average of the number of days between when a generation interconnection application is received and when the final application response is provided to the requestor - for all responses provided during the calendar year.

Generally speaking, a shorter average study period is preferred. However, wide variation is expected between ISOs/RTOs on this metric. There are several drivers to this variation including:

- Number of Applications – There is very wide variation in the number of generation interconnection applications in the regions. In the past few years, wind-rich regions have received large numbers of applications from wind generation developers. The number of applications has far outpaced any prior period and as a result has driven the redesign of the application and study processes in wind-rich regions.

- Complexity of Applications – Applications requesting system upgrades to support the integration of renewable resources increase the complexity of the application and thus increase the time required to complete the study. Also, some wind generator manufacturers have been reluctant to provide detailed models of their equipment, thus delaying studies and making it more difficult to complete accurate analyses.
- Tariff Requirements – There is no consistent study period requirement in the various ISO/RTO tariffs and the requirements continue to evolve to meet regional needs.

Planned and Actual Reserve Margins 2005 – 2009

Across the various ISO/RTO regions, generation planning reserve margin requirements are set by a variety of entities (e.g., the ISO/RTO, the regional reliability organization, the state utility commission) normally based on a loss of load study for the region. Once the standard is established, the generation or demand response resources required to meet that standard is either committed (by the load serving entities in the region) or acquired (via capacity auction by the ISO/RTO). This metric compares the planned reserve margin to the actual reserve margin for each region.

Generally speaking, an actual reserve margin at or slightly above the planned reserve margin is desired. An actual reserve margin less than the planned reserve margin indicates an increase in potential reliability issues during peak periods or periods of regional emergencies. Some ISOs/RTOs have implemented forward capacity markets which utilize a variable resource requirement curve to procure capacity up to three years prior to the year for which it is committed.

This section also discusses the participation of demand response resources in ISO/RTO capacity markets.

Percentage of Generation Outages Cancelled by ISO/RTO

Some ISOs/RTOs do not have the authority to approve planned generation outages, though California ISO does evaluate and approve all planned generation outages. However, each ISO/RTO may cancel a planned generation outage if the ISO/RTO assesses a reliability concern with commencing the generation outage. This measure reflects the percentage of planned generation outages reported to each ISO/RTO that were cancelled by that ISO/RTO.

Generation Reliability Must Run Contracts

Periodically, a generation owner may notify an ISO/RTO that a generating unit is going to retire or be mothballed. The ISO/RTO will complete a reliability assessment of that planned retirement or mothballing. If the results of that study indicate the ISO's/RTO's customers cannot be served reliability without that generating unit, then the ISO/RTO may place the generating unit under a reliability must run (RMR) contract until generation and/or transmission upgrades alleviate the identified reliability concern. The information under this topic reflects the number of generating units and the nameplate generating capacity of any generation units under RMR contracts.

Interconnection / Transmission Service Requests

ISOs/RTOs perform engineering studies of proposed new or upgraded generation to assess the potential transmission system upgrades required for the incremental generation capacity to interconnect reliably to the respective ISO's/RTO's transmission system. Also, ISOs/RTOs have the responsibility to review and approve or reject, based on the anticipated impact to reliability, requests for both transmission service.

The data in this section reflects the number of interconnection and transmission service requests received and completed as well as the average aging of incomplete interconnection and transmission service requests and the average time the ISO/RTO took to complete each study. This section also includes the average costs incurred by each ISO/RTO to complete each type of engineering study related to an interconnection or transmission service request.

Special Protection Schemes

The North American Electric Reliability Corporation defines a Special Protection System (SPS) as an automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation output, or system configuration to maintain system stability, acceptable voltage, or power flows. An SPS does not include (a) underfrequency or undervoltage load shedding or (b) fault conditions that must be isolated or (c) out-of-step relaying (not designed as an integral part of an SPS). A Special Protection System may also be referenced as a Remedial Action Scheme.

In comparison with planning and constructing new transmission facilities, SPSs can be placed in service relatively quickly and inexpensively to increase power transfer capability. The identified SPS metric provides an indication as the extent to which SPSs are relied upon in RTO regions, either on a permanent or interim basis until a transmission planning solution can be implemented. This metric also indicates the effectiveness of SPS operations by indicating the number of SPS activations in which the SPS operated as expected as well as number of SPS activations that were not intended.

Though SPS data has been presented for 2009 solely, there have been no material changes in the SPS levels of the ISOs/RTOs in this report during the period 2005 through 2009.

B. ISO/RTO Coordinated Wholesale Power Markets

Organized markets offer diverse power products and services, as well as an array of markets that can be used to hedge against price risks. Because average real-time energy prices correlate to short-term forward bilateral prices, ISO/RTO markets foster forward contracting that can stabilize prices. Increased and more accurate price transparency means better contract pricing.

By using advanced technologies and market-driven incentives, the commitment and dispatch of the generators within regional markets is more efficient than those absent regional markets. The centralized market commitment and dispatch allows the most cost effective unit in the region to be fully utilized before the next most cost effective unit, etc. Also the market incentives motivate generation owners to keep their plants available particularly during peak periods.

Security-constrained economic dispatch of generators performed by ISOs/RTOs also allows the transmission system to be more fully utilized and congestion to be managed on an economic basis as opposed to the strict “rights” based Transmission Loading Relief methodology. ISOs/RTOs are well-equipped to analyze and actively manage the reliability and economic considerations of congestion on the power grid and identify more efficient investment opportunities for upgrades and new facilities.

Market Competitiveness

Each ISO’s/RTO’s independent market monitor (IMM) analyzes measures of market structure, participant conduct and market performance to assess the competitiveness of the ISO’s/RTO’s markets. A subset of such measures monitored by the IMMs is included in this section of the report – price cost markup, generator net revenues, and required mitigation.

Price Cost Markup

Price cost markup percentages represent the load weighted average markup component of dispatched generation divided by the load weighted average price of dispatched generation. The markup component of price is based on a comparison between the price-based offer and the cost-based offer of each actual marginal unit on the system. Relatively low price cost markup percentages are strong evidence of competitive behavior and competitive market performance.

Generator Net Revenues

Net revenue quantifies the contribution to total fixed costs received by generators from ISO/RTO energy, capacity and ancillary service markets and from the provision of black start and reactive services. For ISOs without central capacity markets, these revenues do not include any revenues from bilateral capacity contracts. Net revenue is the amount that remains, after short run variable costs have been subtracted from gross revenue, to cover total fixed costs which include a return on investment, depreciation, taxes and fixed operation and maintenance expenses. Total fixed costs, in this sense, include all but short run variable costs.

When compared to total fixed costs, net revenue is an indicator of generation investment profitability and thus is a measure of overall market performance as well as a measure of the incentive to invest in new generation and in existing generation to serve ISO/RTO markets. Net revenue quantifies the contribution to total fixed costs received by generators from all markets in an ISO/RTO.

Although it can be expected that in the long run, in a competitive market, net revenue from all sources will cover the total fixed costs of investing in new generating resources when there is a market based need, including a competitive return on investment, actual results are expected to vary from year to year. Wholesale energy markets, like other markets, are cyclical. When the markets are long, prices will be lower and when the markets are short, prices will be higher.

As available for each ISO/RTO, the data in this section reflects the estimated generator net revenues per megawatt year for a new entrant Combustion Turbine unit fueled by gas and for a new entrant Combined Cycle plant fueled by natural gas.

Mitigation

The approach to market power mitigation in ISOs/RTOs has focused on market designs that promote competition (a structural basis for competitive outcomes) and on limiting market power mitigation to instances where the market structure is not competitive and thus where market design alone cannot mitigate market power. In ISO/RTO energy markets, this occurs generally in the case of local market power. When a transmission constraint creates the potential for local market power, the ISO/RTO applies a structural test to determine if the local market is competitive, applies a behavioral test to determine if generator offers exceed competitive levels and applies a market performance test to determine if such generator offers would affect the market price.

ISOs/RTOs have clear rules limiting the exercise of local market power. The rules provide for the capping of offers when conditions on the transmission system create a structurally noncompetitive local market (generally measured by the three pivotal supplier test), when units in that local market have made noncompetitive offers and when such offers would set the price above the competitive level in the absence of mitigation. Offer caps are set at the level of a competitive offer. Offer-capped units receive the higher of the market price or their offer cap. Thus, if broader market conditions lead to a price greater than the offer cap, the unit receives the higher market price. The rules governing the exercise of local market power recognize that units in certain areas of the system would be in a position to extract uncompetitive profits, but for these rules.

The metric in this section reflects the percentage of generator unit hours prices were capped in the respective ISO's/RTO's real-time energy market due to mitigation.

Market Pricing

Market pricing includes three separate metrics: the average annual load-weighted wholesale energy prices for each of the ISOs/RTOs, the fuel-adjusted wholesale prices and a breakdown of the components of wholesale total power costs.

The first chart in this section shows the average annual load-weighted wholesale electricity energy spot prices in ISOs/RTOs with no adjustment for fuel cost changes or for different fuel mixes in different regions. These prices frequently do not reflect the prices actually paid by utilities and other load-serving entities to purchase power, as the purchase prices may be set by longer-term contracts. The prices are the spot prices that are paid for power not covered by such contracts or supplied by the load-serving entities' own generation. Also, these prices do not reflect all costs incurred to meet electric load, as load-serving entities may need to pay additional amounts for ancillary services and capacity market charges, or may need to recover the cost of the generation they own and use to meet all or a portion of their load.

The second chart in this section shows the average annual load-weighted wholesale electricity energy spot prices, adjusted for changes in fuel costs. Fuel costs comprise the majority of the costs of providing power. These data are useful for comparing spot prices within a given RTO over time, but not for comparisons across ISOs/RTOs. Because the various ISOs/RTOs began operations at different points in time, they have different base years for the fuel adjustments, making the figures non-comparable across ISOs/RTOs. The different ISOs/RTOs also use different fuels or fuel mixes based for the fuel adjustment based on their different markets and generation mixes.

Changes in fuel-adjusted power prices within ISO/RTO areas, relative to the levels that would otherwise have prevailed, reflect a number of factors including: the cost reductions made possible through security-constrained economic dispatch, incentives for improved generator availability, investments in new more efficient generating units, changes in relative fuel prices, changes in demand levels and retirement of uneconomic facilities. Fuel adjusted price models are not complex and do not discount the impacts of fuel-price changes for normalizing costs. For instance, small changes in fuel adjusted prices from year to year may be the result of uncertainty in the methodology, rather than changes in the market fundamentals. In addition, the models and methodology used in each of the regions, while applied consistently in each region, are unique. As such, the tables included in each of the chapters are incomparable across the regions. The actions of individual market participants, acting under the decentralized incentives of wholesale market pricing, have resulted in higher power-plant availability, lower outage rates, the development of demand response programs, and new plant construction when and where needed, all of which have contributed to lower power prices.

The last chart in this section breaks down the components of the wholesale power costs relative to the various tariffs administered by each ISO/RTO. The breakdown may include the cost of energy, transmission, capacity, ancillary products and the administrative costs of the ISO/RTO, and regulatory fees depending on the regional tariff structure. Energy is typically the largest component, sometimes accounting for more than 70% of the wholesale cost.

Unconstrained Energy Portion of System Marginal Cost

The average, non-weighted, unconstrained energy portion of the system marginal cost measures the marginal energy price in dollars per megawatt hour exclusive transmission constraints and transmission losses.

Energy Market Price Convergence

Good convergence between the day-ahead and real-time prices is a sign of a well-functioning day-ahead market. Since the day-ahead market facilitates most of the energy settlements and generator commitments, good price convergence with the real-time market helps ensure efficient day-ahead commitments that reflect real-time operating needs. In general, good convergence is achieved when participants submit price-sensitive bids and offers in the day-ahead market that accurately forecast real-time conditions. The two charts below reflect the absolute value and percentage of the average annual difference between real-time energy market prices and the day-ahead energy market prices. Data on price convergence in this section does not include SPP, because SPP does not operate a day-ahead energy market.

Better convergence is indicated by a smaller dollar spread or a smaller percentage difference. Although day-ahead and real-time price differences can be large on an hourly or daily basis, it is more valuable to evaluate convergence over longer timeframes. Participants' day-ahead market bids and offers should reflect their expectations of market conditions on the following day, but a variety of factors can cause real-time prices to be significantly higher or lower than expected. While a well-performing market may not result in prices converging on a daily basis, it should lead prices to converge well on an annual basis.

Differences between ISO/RTO regions can be driven by several factors including differences in transmission congestion, market rules, virtual market participation and concentration of intermittent resources.

Congestion Management

Congestion occurs when the physical limits of a line, or inter-tie, prevent load from being served with the least cost energy. The costs associated with congestion can be hedged by load serving entities with financial rights available through an ISO/RTO. To assess the performance of an ISO/RTO with respect to the cost of congestion it is important to first quantify the total costs with respect to load served in the system and second to quantify the percentage of congestion costs that were hedged by load served in the system.

The first congestion measure is calculated as the annual congestion costs of each ISO/RTO region divided by the megawatt hours of load served in that ISO/RTO. The second measure is calculated as the percentage of congestion revenues paid divided by the actual congestion charges. While nominal congestion charges may vary from year-to-year, congestion hedging rights at ISOs/RTOs provide an opportunity for market participants to hedge their exposure to congestion charges before such congestion occurs.

Resources

Generator Availability

Competitive wholesale power markets have provided incentives for generation owners to take actions to achieve higher power plant availability and lower forced outage rates, particularly during peak demand periods. This has reduced the cost of producing electricity. The first chart in this section shows the actual average annual generator availability for each ISO/RTO calculated as one minus the Equivalent Demand Forced Outage Rate. This is a measure of generator responsiveness when the generator owner has indicated the generation should be available.

It is important to note that another advantage of ISO/RTO coordinated wholesale power markets is that more accurate data on unit deliverability and performance is required in order to participate in resource adequacy markets or constructs. This includes rigorous testing and measurement and verification requirements for units that traditionally have not provided performance data or testing results. This increased scrutiny and data accuracy, in order to ensure an “apples to apples” comparison, must be measured over time and during periods when ISO/RTO standards applied.

Demand Response Availability

A tool available to ISOs/RTOs to balance customer demand and available generation is to call upon committed Demand Response resources to reduce customer demand in times of high usage. Some ISOs/RTOs have begun to test the availability of Demand Response resources, even if those resources were not called upon by the ISO/RTO. Where data is available, the second chart in this section shows what percentage of committed Demand Response resources were either available when called upon by the ISO/RTO or were available via testing performed by the ISO/RTO.

Fuel Diversity

Fuel Diversity is the mix of fuel types installed and available (capacity) or used (generation) to produce electricity in each ISO/RTO. The breakdown among ISOs/RTOs is expected to vary widely, due to the availability of resources in the area, along with political, economic and environmental factors associated with producing electricity from various fuel types.

Renewable Resources

ISOs/RTOs accommodate and facilitate the development of renewable resources, including wind, solar, hydro, geothermal and biomass. In recent years, many states within ISO/RTO regions have established renewable portfolio standards that stimulate investment in renewable generation. Several ISOs/RTOs have experienced rapid development of intermittent renewable resources such as wind generation. Further accelerated development is expected as the state renewable requirements ramp up and may gain further momentum if proposed federal requirements are implemented. ISOs/RTOs are facilitating the integration of renewable resources through advances in system planning, system operations and market operations.

Key benefits that ISOs/RTOs provide for the integration of renewable resources, such as wind generation, are one-stop shopping for interconnection to the system, access to a spot market for energy, reliance on financial mechanisms such as financial transmission rights and day-ahead market schedules to define transmission system entitlements, and coordination of dispatch over a broad region with many dispatchable resources.

This performance metric measures the installed renewable capacity (MWs) as a percentage of total capacity (MWs) and renewable energy production (MWhs) as a percentage of total energy (MWhs). For purposes of the charts in this section, renewables are defined to include wind, wood, methane, refuse and solar.

Some jurisdictions consider hydroelectric power to be a type of renewable generation and some distinguish between small and large hydroelectric generating units. Data on total energy from hydroelectric power (including pumped storage) is included in the charts in this section.

The renewable and hydroelectric capacity data is based on either generator nameplate capacity, which is the maximum rated output of a generator under conditions designated by the manufacturer, or based on seasonal ratings as a result of capability audits by the regional ISO/RTO. Also included in this section are charts showing data on capacity from renewable and hydroelectric power resources. The capacity data is based on generator nameplate capacity, which is the maximum rated output of a generator under conditions designated by the manufacturer.

The results between ISOs/RTOs are expected to vary widely, because the growth of renewable resources in each region will be driven largely by the availability of the renewable resources in the area and the economics associated with harnessing that resource.

C. ISO/RTO Organizational Effectiveness

The members of ISOs/RTOs are looking for services to be rendered by the ISO/RTO in a cost effective manner while addressing members' needs and billing transactions accurately. The data in this section reflect those three aspects of how well each ISO/RTO is managing these objectives.

ISO/RTO Administrative Costs

Administrative costs are costs associated with carrying out the services and responsibilities to members and customers under each entity's FERC approved tariff. The ISO/RTO is entitled to recover 100% of its total expenses through this charge up to specified caps per megawatt hour (MWh) for all service under the tariffs or a dollar cap for the total revenue requirement in the case of the California ISO.

The costs are comprised of budgeted capital investment (capital charges, debt service, interest expense, depreciation expense), as applicable to each ISO/RTO's budgeting practice and operating and maintenance expenses, net of miscellaneous Income. The metrics compare annual actual costs incurred by the ISO/RTO to the approved administrative fees and budgeted costs (net revenue requirement). Generally speaking, a percentage of actual expenses to budgeted expenses as close to 100% as possible is favorable. On an annual basis a small variance from 100% means that the ISO/RTO is forecasting the financial needs of the organization and effectively managing the business to the budget. Taking a longer term view will provide a trend analysis that indicates the relative stability of the organizations' cost performance.

The first chart in this section reflects each ISO's/RTO's actual non-capital expenses as a percentage of their respective approved budgets. Specifically, the comparison below includes compensation, non-employee labor, technology expenses, etc. but excludes depreciation, interest, and debt service costs.

The second chart in this section reflects each ISO's/RTO's actual recovery of capital investment costs as a percentage of their respective approved budgets for capital investment costs. The majority of ISO/RTO capital investment relates to the hardware and software used to support ISO/RTO reliability and market administration functions.

The third chart in this section includes each ISO's/RTO's total administrative charges per megawatt hour of load served.

Customer Satisfaction

Customer satisfaction is a standard indicator of performance used in most industries, including the electric power industry and by each ISO/RTO. Customer satisfaction indicators are used by the ISOs/RTOs to better understand the customer satisfaction landscape and to develop specific actions in response to customer feedback. Although numerical customer satisfaction indicators are useful in determining general areas for possible improvements, the detailed responses provided by each ISO/RTO member afford the greatest information for developing action plans. It is this action-planning phase where the value lies in any customer satisfaction program, not simply in the numerical assessment of overall performance. This is why each ISO/RTO asks its own set of unique questions of its customers.

Billing Controls

One significant ISO/RTO function is processing and issuing timely and accurate bills to its members for transmission service, market transactions and associated fees. In order to enhance customer confidence in the ISO/RTO controls surrounding these billing processes and to assist public companies that are ISO/RTO members, each ISO/RTO in this report has committed to independent audits of their billing functions under Statement of Auditing Standard 70 (SAS 70).

There are two types of SAS 70 audits: Type 1 audits which assess the adequacy of the control design and Type 2 audits which both review the adequacy of the control design and whether the controls are being followed. The table in this section that summarizes the type of SAS 70 audit undertaken by each ISO/RTO and what type of opinion was issued by the independent auditor for each year's SAS 70 audit.

An unqualified opinion indicates that the independent auditor found the control objectives for each of the areas covered by the audit to be adequately designed and operated for the audit period. A qualified opinion means the independent auditor found the design and/or the operation of one or more of the control objectives inadequate. Specific inadequate control objective(s) are identified; the remaining control objectives covered by the audit are deemed adequate.

California Independent System Operator Corporation (California ISO)

Section 2 – California ISO Performance Metrics

The California ISO was created in September 1996 as a nonprofit public benefit corporation with the passage of California Assembly Bill 1890 that restructured the state's power market following the passage of the federal Energy Policy Act of 1992, which introduced competition into the wholesale market. It incorporated in May 1997 and in March 1998 began serving 80 percent of the state, or 30 million people, with the purpose of managing the state's transmission grid, facilitating the spot market for power and performing transmission planning functions.

The California Power Exchange operated the state's competitive wholesale power market and customer choice program until the 2000-2001 energy crisis forced it into bankruptcy in January 2001. The exchange ultimately ceased operation leaving the state without a day-ahead energy market until spring 2009 when the ISO opened a nodal market.

During and immediately after the energy crisis, the ISO began addressing underlying infrastructure challenges — specifically transmission and generation deficiencies — and started a comprehensive market redesign and technology upgrade program with FERC approval. State regulators implemented a resource adequacy obligation in 2004 that prevents under-scheduling so that utilities now must procure in advance 100 percent of their total forecast load as well as a 15 percent margin for a total of 115 percent. Developers have built more than 18,000 megawatts of mainly gas-fired generation in California since the energy crisis. About $9.5 billion in transmission expansion has been studied and approved by the ISO including the critical Path 15 link between southern and northern California. At start-up, the ISO operated a zonal market and the California Power Exchange operated a day-ahead market. However, on March 31, 2009 (for trading day April 1) the ISO launched a new market design that includes a day-ahead market, locational marginal pricing and relies on a full network model of the grid that analyzes day-ahead energy schedules and "sees" potential choke points on the grid well before they occur. The new fully integrated forward market allows the ISO to purchase the right mix of energy, standby power and transmission capacity to meet grid needs in three time frames (day ahead, hour ahead and real time). The locational marginal pricing feature of the new market shows the true cost of delivering power, including for those areas with transmission constraints, making it easier for the ISO and load serving entities to choose running the right power plant to meet local needs. And this pricing approach provides more granular information about the areas that can benefit most from new infrastructure, as well as give developers better information on which to base their economic decisions.

Under the nodal market for the nine months it operated in 2009, wholesale energy costs declined by 28 percent, and ancillary services costs dropped by 54 percent, in part because of better optimization of the system, greater market liquidity, lower demand and lower natural gas prices. The frequency and impact of bid mitigation on prices was generally low and reflected disciplined behavior by market participants, according to the ISO Department of Market Monitoring. Ancillary services costs dropped from $0.74/MWh of load in 2008 to $0.39/MWh in 2009 because the new market allowed generators for the first time to bid all their output into the energy and ancillary services markets at the same time. This increases the supply of bids, enabling the market software to find the most cost-effective way to use each unit's capacity. The new market reflected the increased activity as annual billings went from $2.4 billion in 2008 to $6.4 billion in 2009. New day-ahead market optimization created additional opportunities for buying and selling, as did the introduction of new market products.

Since the new market implementation, the California ISO has been taking strategic steps to identify where to add market functionality or refine what already exists. In 2009, the ISO delivered six market enhancements. In addition, the ISO has been focused on facilitating reliable integration of the resources necessary to meet California's renewables portfolio standard. A governor's executive order requires load-serving entities to increase their procurement portfolio to 33 percent by the year 2020. The combined impacts of these two areas touch nearly all of the core functions of the ISO, including operations, markets and infrastructure requirements. While the results of these efforts unfold over the next several years, early indications suggest the ISO is on target to lead the state and region in developing the rules and processes that aid in building clean power plants and the transmission to deliver renewable energy. To this end, the ISO has approved four major transmission projects (Tehachapi Renewable Transmission Project, Sunrise Powerlink, California segment of Devers-Palo Alto II, El Dorado-Ivanpah Substation) with a capacity of 12,300 MW that will mainly transport renewable energy.

A. California ISO Bulk Power System Reliability

The table below identifies which NERC Functional Model registrations the California ISO has submitted as effective as of the end of 2009. The Regional Reliability Organization for the ISO is the Western Electricity Coordinating Council (WECC), as noted at the end of the table with a URL to its specific reliability standards.

At this time, the WECC is the Interchange Authority and Reliability Coordinator for the Western Interconnection, while typically, the transmission owners serve as Transmission Planners and load-serving entities serve as Resource Planners. The ISO performs its Planning Authority functions in accordance with its FERC approved Order No. 890 compliant tariff. As the Planning Authority, much of the ISO's core function involves transmission expansion planning related activities, most notably producing the annual California ISO Transmission Plan.

No California ISO self-reported or audit-identified reliability standard violation was published by NERC or FERC during the 2005-2009 period covered by this report. On February 1, 2010, however, NERC published a Notice of Penalty recommending a $0 penalty with a sanction letter for an incident self-reported by the California ISO on November 30, 2007. This incident, which took place on October 2, 2007, related to possible noncompliance with IRO-STD-006-0 for a deficiency of providing off-path curtailments of 2.6 MW and 1.7 MW on a 2900 MW rated path. The recommendation was accepted by FERC without further action in a notice dated March 3, 2010.

NERC Functional Model Registration	California ISO
Balancing Authority	✓
Interchange Authority	
Planning Authority	✓
Reliability Coordinator	
Resource Planner	
Transmission Operator	✓
Transmission Planner	
Transmission Service Provider	✓

Regional Entity	WECC

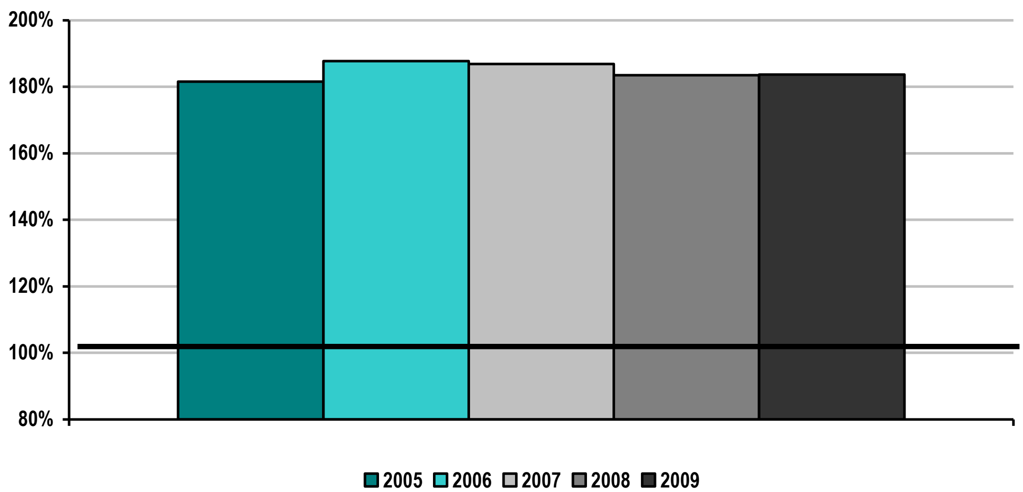
Standards that have been approved by the NERC Board of Trustees are available at:
http://www.nerc.com/page.php?cid=2|20

Additional standards approved by the WECC Board are available at:
http://www.wecc.biz/Standards/Approved%20Standards/Forms/AllItems.aspx

Dispatch Operations

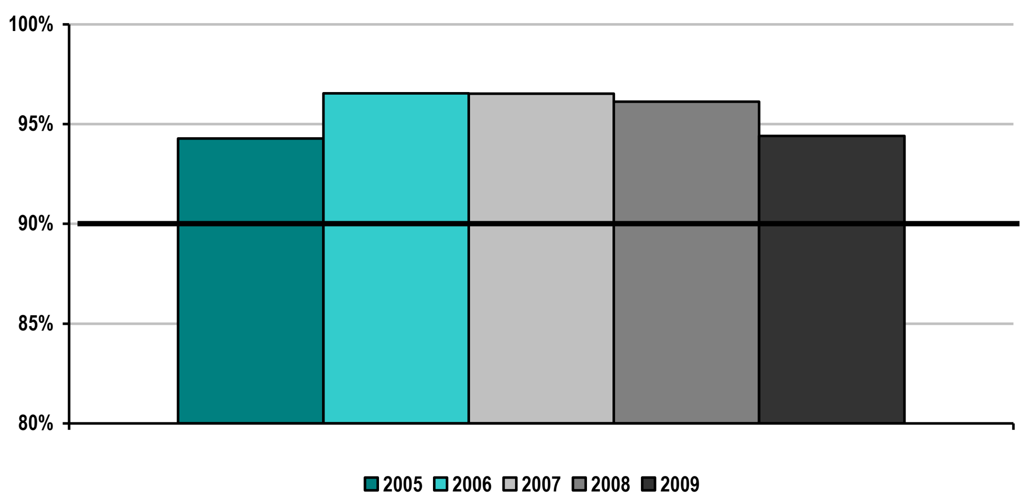
Balancing authority areas are required to maintain compliance of at least 100 percent for CPS-1 over a 12-month period. The California ISO complied with CPS-1 for each of the calendar years from 2005 through 2009, having exceeded the minimum standard by over 80% in each of the five years during this period.

California ISO CPS-1 Compliance 2005-2009



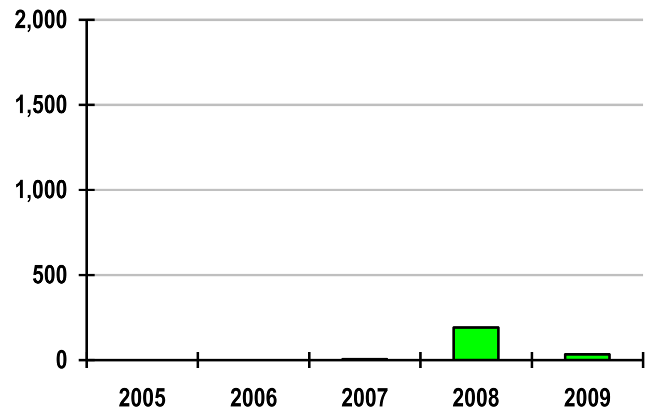
Balancing authority areas are also required to maintain compliance of at least 90% for CPS-2 during each month in a 12-month period. The California ISO complied with CPS-2 from 2005 through 2009, having exceeded the minimum standard on average by about 6%.

California ISO CPS-2 Compliance 2005-2009

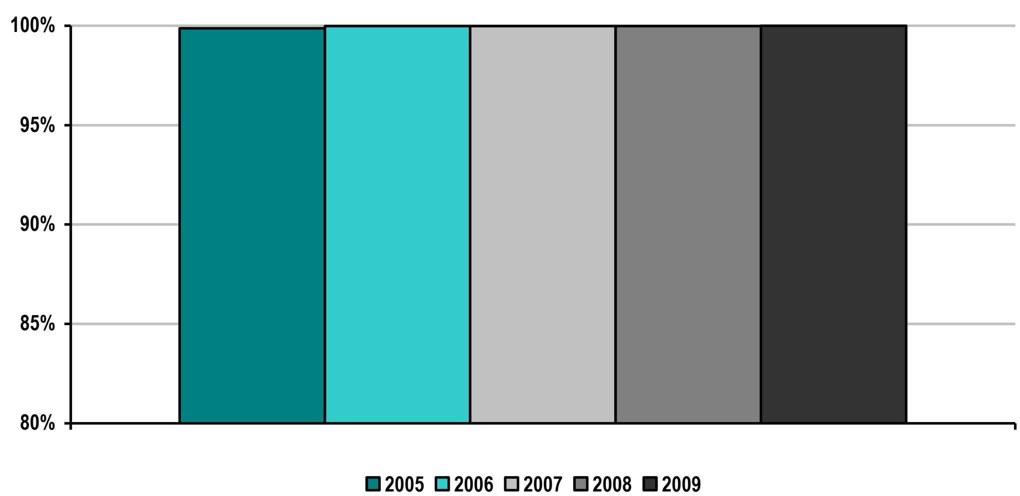


California ISO data reflects the number of unscheduled flow relief events from 2007 commencing June 18, 2007 through December 31, 2009. With respect to the ISO, 16% "no impact" events (i.e., no tag curtailment actions required), 40% involved phase shifter operation and on path tag curtailment actions only and 44% involved both on and off path tag curtailment actions. The large variability in ISO events during this period is primarily attributable to substantially different annual hydro and system conditions throughout the Western Interconnection.

California ISO Transmission Load Relief or Unscheduled Flow Relief Events 2007-2009



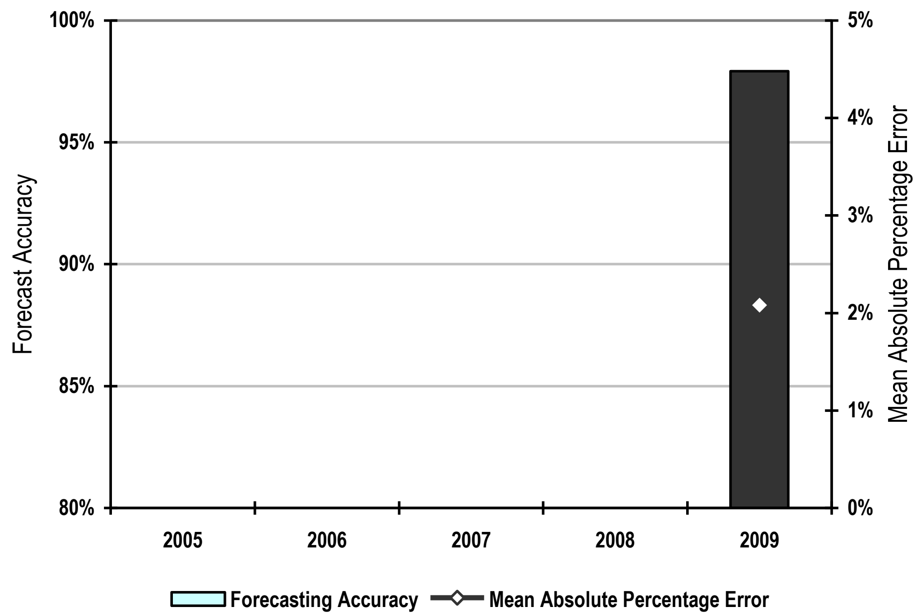
California ISO Energy Management System (EMS) Availability



Load Forecast Accuracy

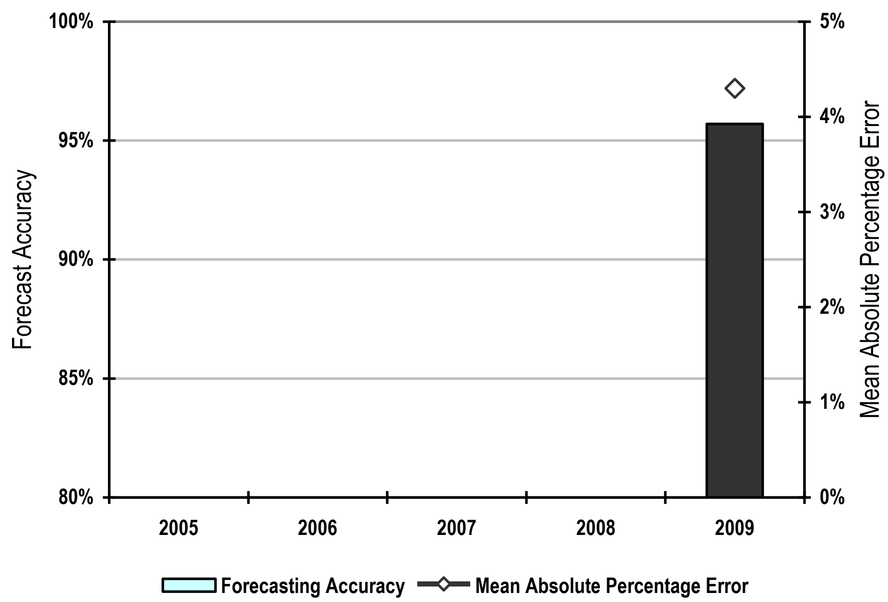
A significant portion of the load in California is centered along the coast in the areas around San Francisco, Los Angeles and San Diego. During the summer period, particularly during peaks, these regions can experience significant changes in temperature from what was predicted in the day-ahead timeframe because of the sometimes sudden and intense marine influence of the Pacific Ocean. These rapid changes are in part responsible for California ISO day-ahead peak load forecasts for the coastal areas being slightly lower than the valley load forecasts. On average the ISO day-ahead load forecast from a reference point of 9:00 a.m. is 98% accurate. Prior to the day-ahead market that started on April 1, 2009, the load forecast was not used by the ISO to make market commitments and therefore the results are not reported. Further the data structure prior to that date was different so the results are not directly comparable.

California ISO Average Load Forecasting Accuracy 2009 (1)



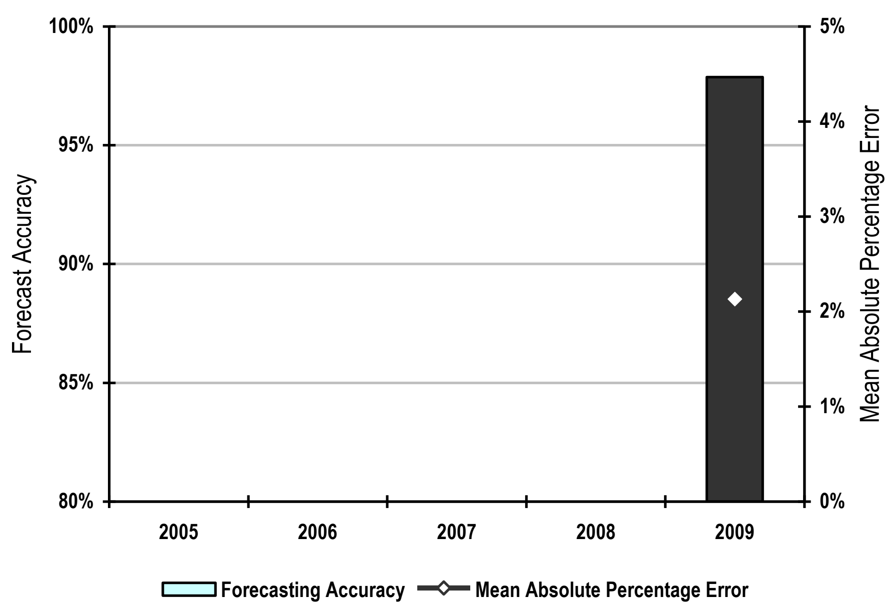
(1) California ISO data represents the period April 1, 2009 through December 31, 2009.

California ISO Peak Load Forecasting Accuracy 2009 (1)



(1) California ISO data represents the period April 1, 2009 through December 31, 2009.

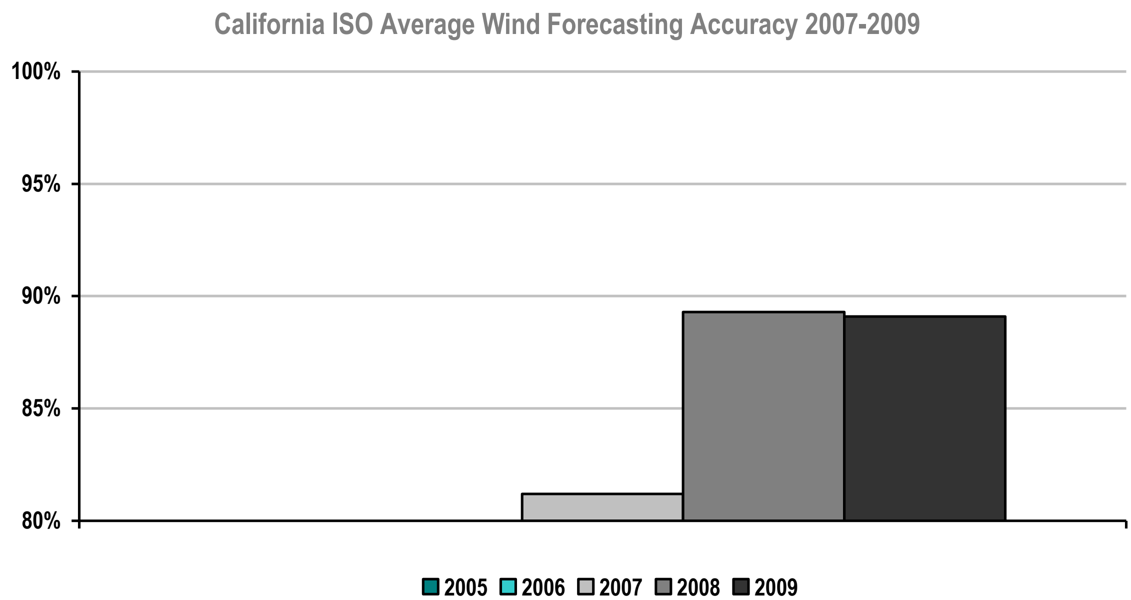
California ISO Valley Load Forecasting Accuracy 2009 (1)



(1) California ISO data represents the period April 1, 2009 through December 31, 2009.

Wind Forecasting Accuracy

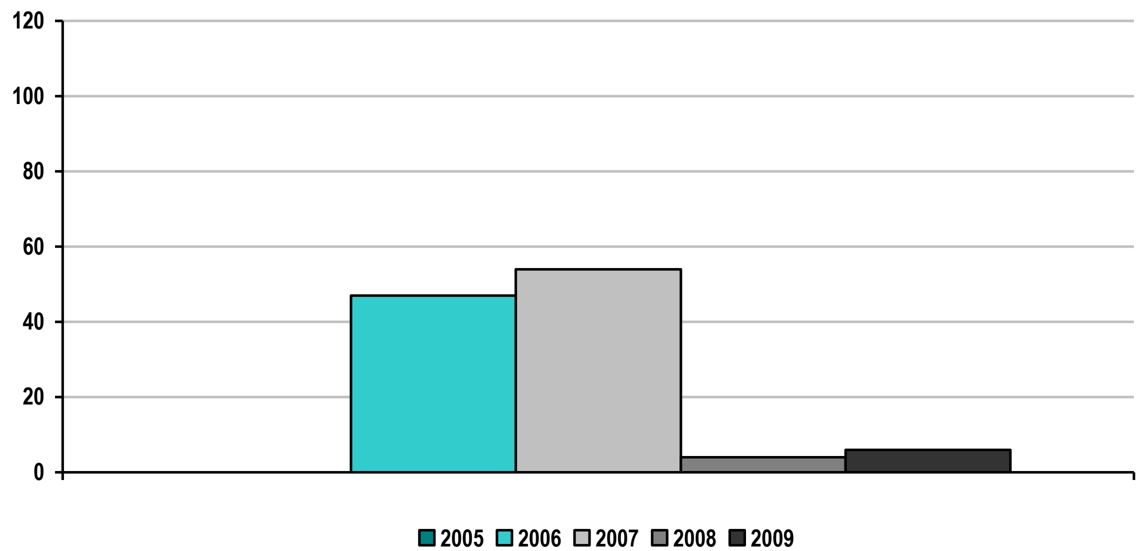
The California ISO has forecasted for wind since 2007 and improved its wind forecast accuracy to deal with the increasing penetration of wind resources to meet California's renewables portfolio standard. The data reported here uses the mean absolute error percentage, which is a method that the ISO believes softens the true error in forecasting by smoothing out the positive and negative deviation spikes that may occur during power production. The ISO is now using the root mean square error method to evaluate performance, a method it believes is superior as it does not allow for positive and negative forecast from different intervals to cancel each other out and so does not mask deviation magnitudes over a large sample.



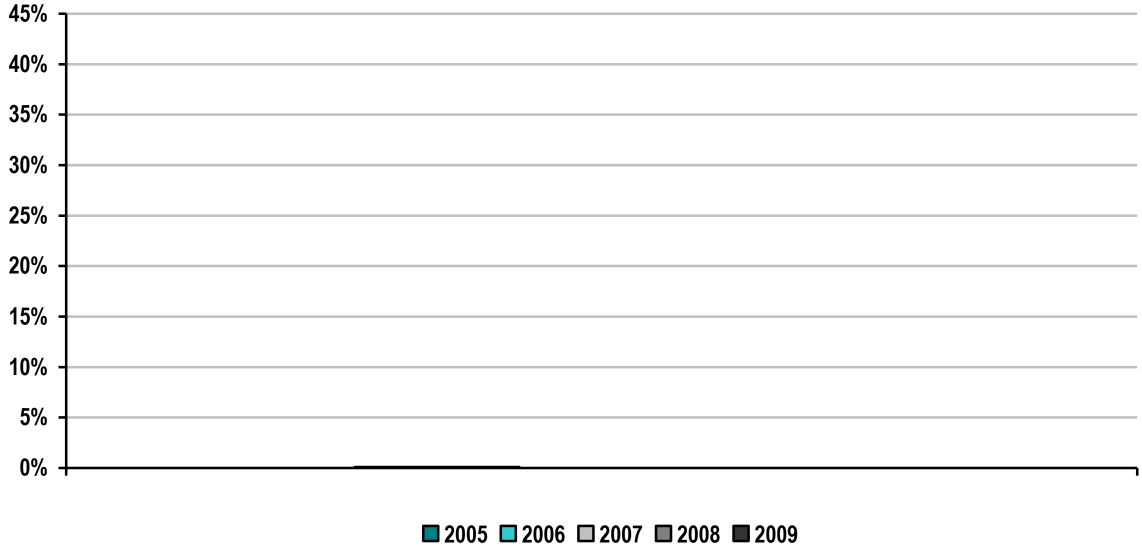
Unscheduled Flows

The Western Interconnection where the California ISO operates is a geographically large, circular 345/500 kV AC system that inherently has substantial loop flow attributable to the prevalence and reliance upon contract path historical transmission rights in 35 of its 37 balancing authority areas, as opposed to a power flow solution based dispatch methodology. The absolute value of unscheduled flow as a percentage of total flows is sufficiently insignificant such that it does not register on the second chart below.

California ISO Absolute Value of Total Unscheduled Flows 2006-2009
(terawatt hours)



California ISO Absolute Value of Unscheduled Flows
as a Percentage of Total Flows 2006-2009



The table below reflects terawatt hours of unscheduled flows for the top five California ISO interfaces. Positive amounts represent unscheduled flows out of the ISO and negative amounts represent unscheduled flows into ISO over the noted interface, which is the standard in the Western Interconnection.

California ISO Unscheduled Flows by Interface	*(terawatt hours)*				
	2005	**2006**	**2007**	**2008**	**2009**
Arizona Public Service Co.	(2)	(3)	(3)	(3)	(3)
Bonneville Power Administration	0	1	1	0	1
Los Angeles Department of Water and Power	(5)	(7)	(8)	(10)	(10)
Sacramento Municipal Utility District	0	(2)	(3)	(2)	(2)
Salt River Project	2	3	4	4	4

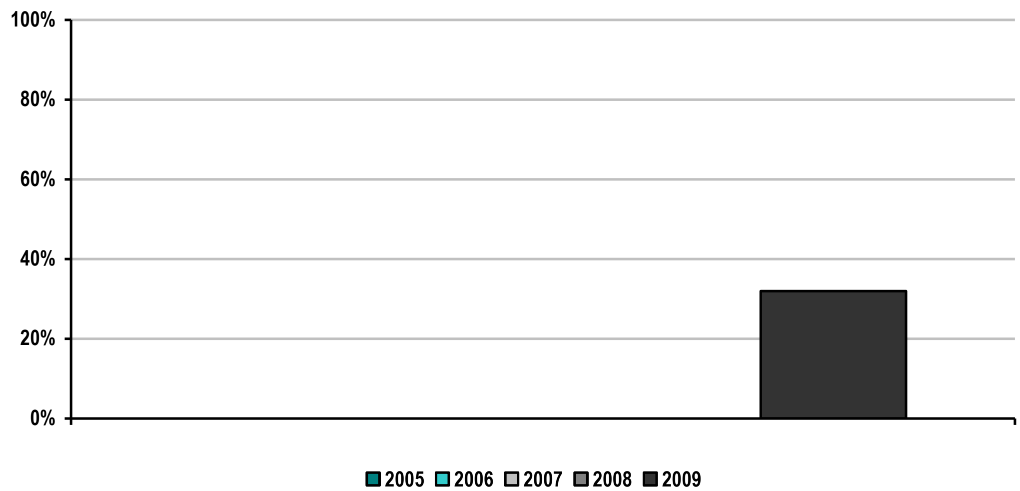
Transmission Outage Coordination

There are many variables involved in performing an outage study. Most studies can be performed in the time allowed for planned outage submission, but some outages and combinations of outages can result in more complex studies that require additional time to complete and validate. Therefore, not having 100% of the planned outages studied within established timeframes is not necessarily indicative of a failure to comply. In essence, this group of metrics looks at whether long duration outages are submitted well in advance so the California ISO may better plan for reliable and efficient operations during the outage.

ISO timeframes for approving outages changed with the introduction of the new market design in April 2009. Prior to that time, outages submitted three business days before start of outage needed to be studied one day before the start of the outage. Since that time, outages need to be studied prior to the day-ahead market. In addition, several of the metrics reference a specific voltage level for the outage that could not be systematically determined until an advanced grid topology tool was put in place concurrent with the new market. Accordingly, comparable data is not available for years 2005-2008, and only the period since April 2009 is reported here.

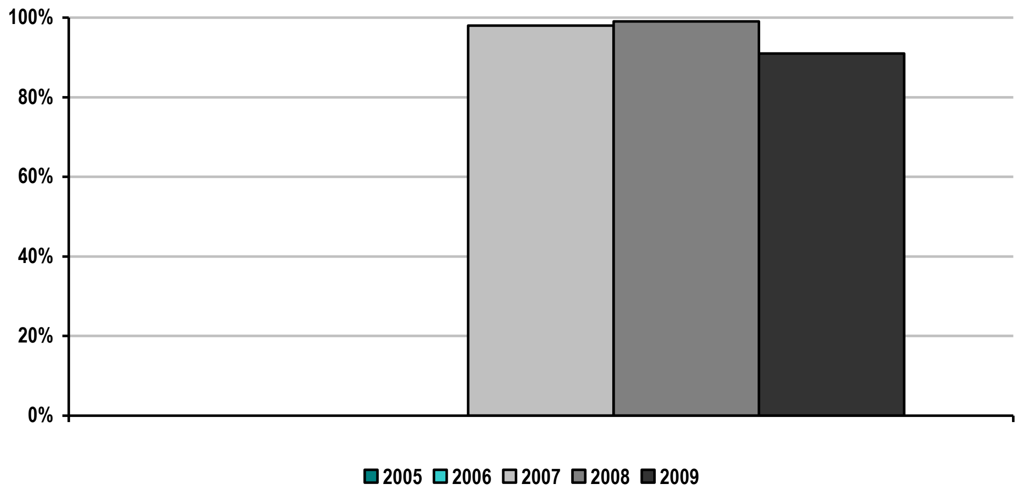
The first metric measures transmission owner performance, not ISO performance. In addition, such submissions allow time to potentially include these requirements in the transmission allocation processes as appropriate.

California ISO Percentage of > 200kV planned outages of 5 days or more that are submitted to ISO/RTO at least 1 month prior to the outage commencement date 2009



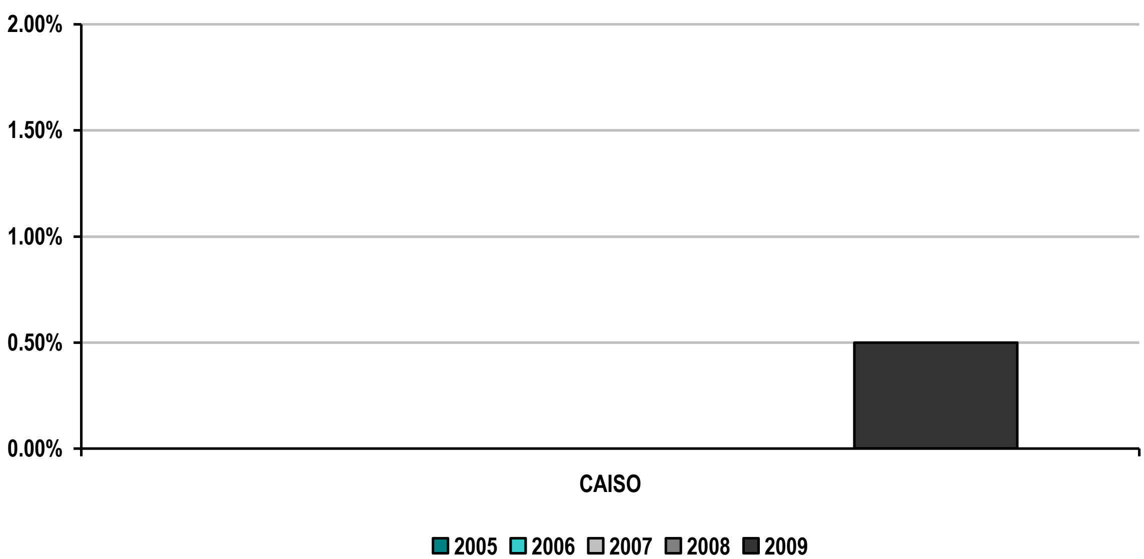
The second metric measures compliance with established timeframes; however, as discussed above, the study of a planned outage involves numerous factors and the failure to meet established timeframes in any specific instance should not be assumed to be caused by a shortcoming of the California ISO. For this metric, no voltage level is specified and the ISO was able to look back three years.

California ISO Percentage of planned outages studied in the respective ISO/RTO Tariff/Manual established timeframes 2007-2009

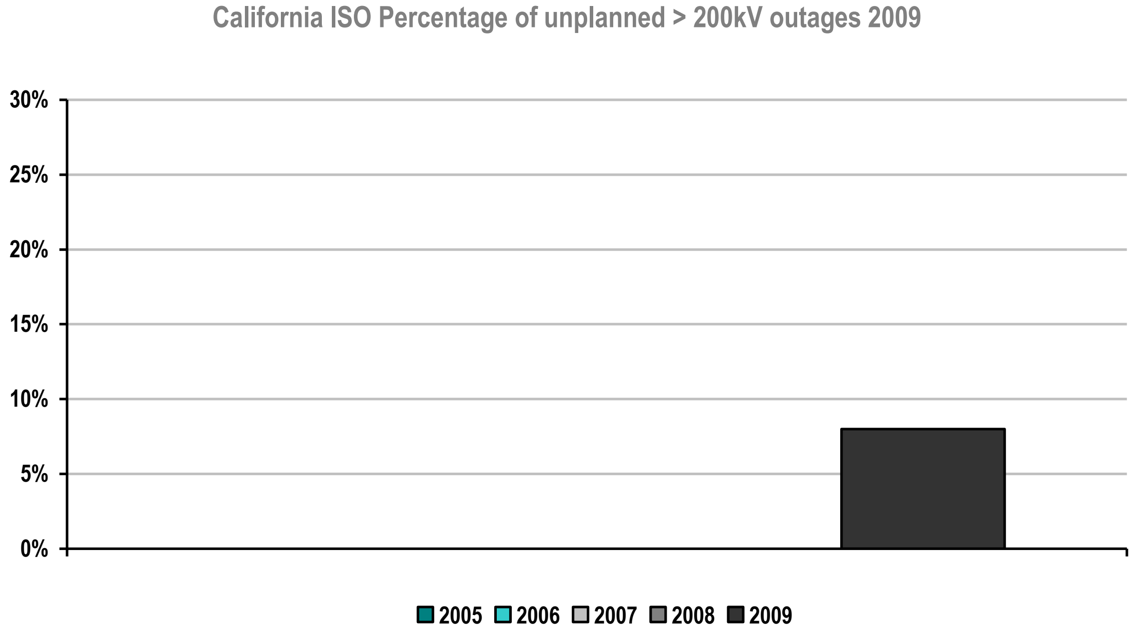


The third metric measures the frequency of cancellation of previously approved transmission outages. Such cancellations will generally occur only if there has been some system or unforeseen weather event in which an approved transmission outage would cause a reliability concern. It may also indicate whether approval of an outage was based on inaccurate or incomplete information. For example, when outages are approved in advance, a number of assumptions may be needed, which indicates the information available to fully assess the impacts of the outage is inadequate.

California ISO Percentage of > 200 kV outages cancelled by ISO/RTO after having been previously approved 2009



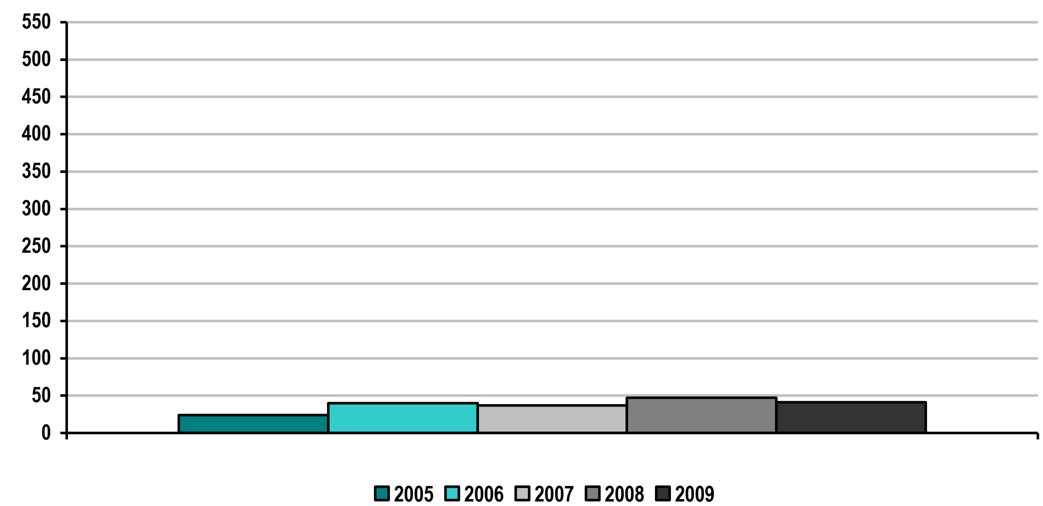
The fourth metric measures the frequency of unplanned outages. California ISO data only includes outages where start time is prior to reporting time, and therefore does not include imminent outages where reporting time is prior to start time, but still would be considered as an unplanned outage.



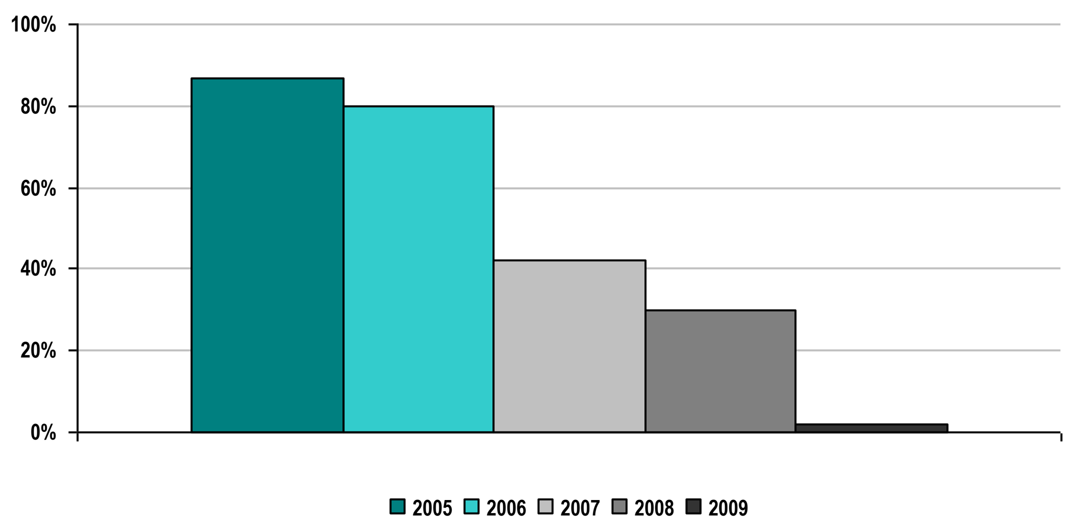
Transmission Planning

California ISO results are based on a compliant Order No. 890 process and adherence to NERC, WECC, and ISO planning standards. ISO transmission planning is an annual process that includes performing a variety of technical studies, such as short and long-term reliability assessments, economic planning assessments, and other key studies that are needed to support the markets and ensure a reliable and secure transmission infrastructure. Since implementing its Order No. 890 compliant process, the ISO has completed a reliability assessment in 2008 and a reliability and economic assessment in 2009. During 2010, the ISO developed and filed with the Commission significant reforms to modify its planning process to better address state mandated renewable integration requirements. Under these proposed reforms, which are still pending Commission approval, the ISO will continue to perform reliability and economic assessments as has been done in previous plans.

California ISO Number of Transmission Projects Approved to be Constructed for Reliability Purposes 2005-2009



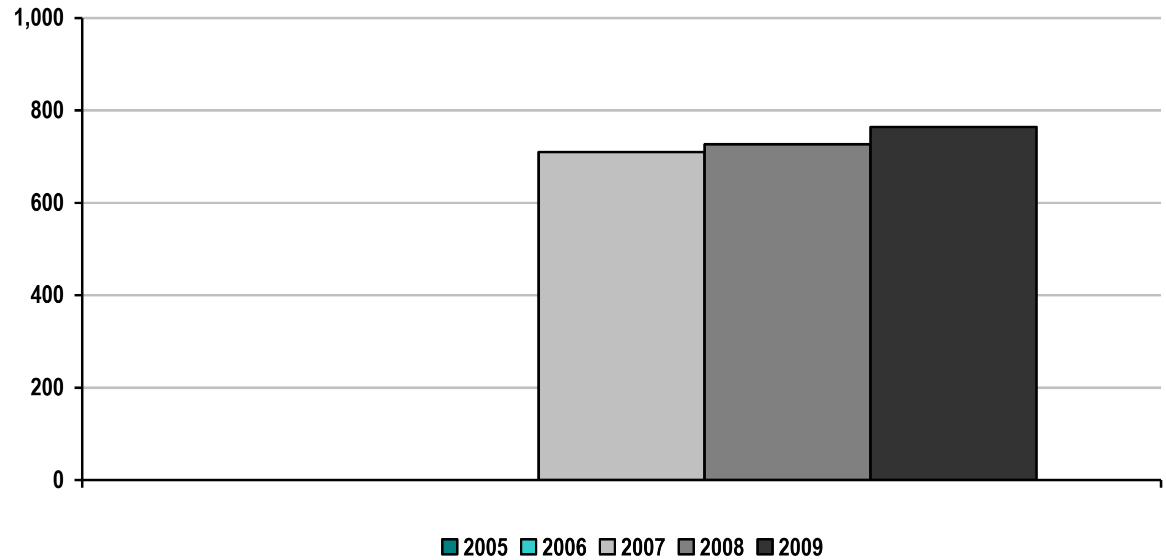
California ISO Percentage of Approved Construction Projects Completed by December 31, 2009



Generation Interconnection

In 2008, the California ISO replaced its large generation interconnection serial study process with a more efficient group study or clustering approach for interconnection requests. By using a cluster study approach, the ISO and participating transmission owners have been better able to more quickly evaluate the large volume of interconnection requests. The process includes two cluster windows each year for submitting interconnection requests and a two-phased interconnection study process. The first group to go through the process (the transition cluster) just completed the Phase II Study process, and the ISO anticipates the benefits of these and other process improvements to be reflected in 2011.

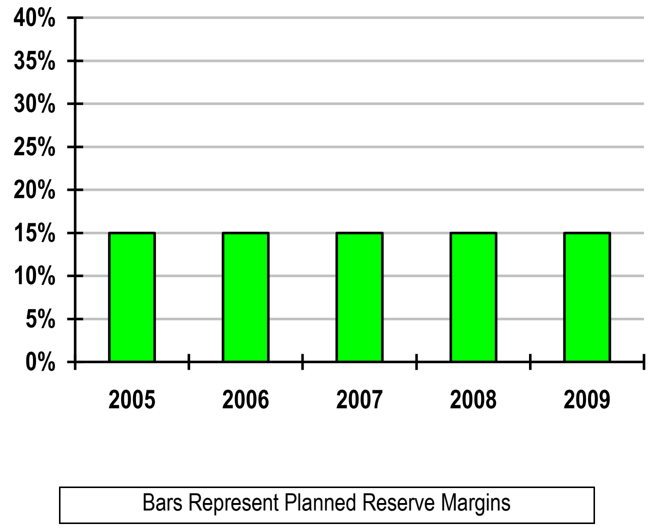
California ISO Average Generation Interconnection Request Processing Time 2007-2009



Reserve Margin

The California ISO 15% planning reserve margin is based on the California Public Utilities Commission's resource adequacy program. That requires load-serving entities to demonstrate they have acquired the capacity needed to serve the 1-in-2 forecast of retail customer load plus a 15-17% reserve margin. It also incorporates the California Public Utilities Commission approved monthly demand response amounts as capacity resources. Measuring compliance with the California Public Utilities Commission resource adequacy requirement is not an ISO function and, therefore, the ISO is not in a position to report the actual reserve percentage procured.

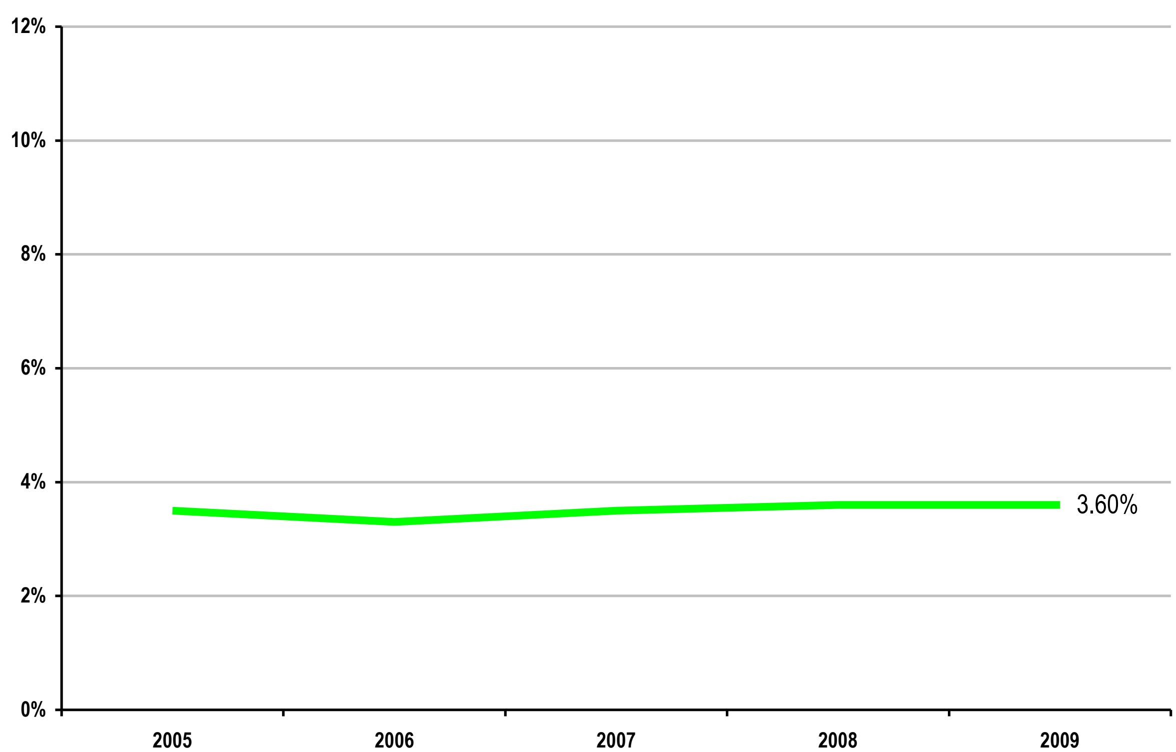
California ISO Planned Reserve Margin 2005 – 2009



Demand Response Capacity

The California ISO uses the California Public Utilities Commission methodology for determining the resources that count as demand response capacity, and the amount expected from such programs when called upon.

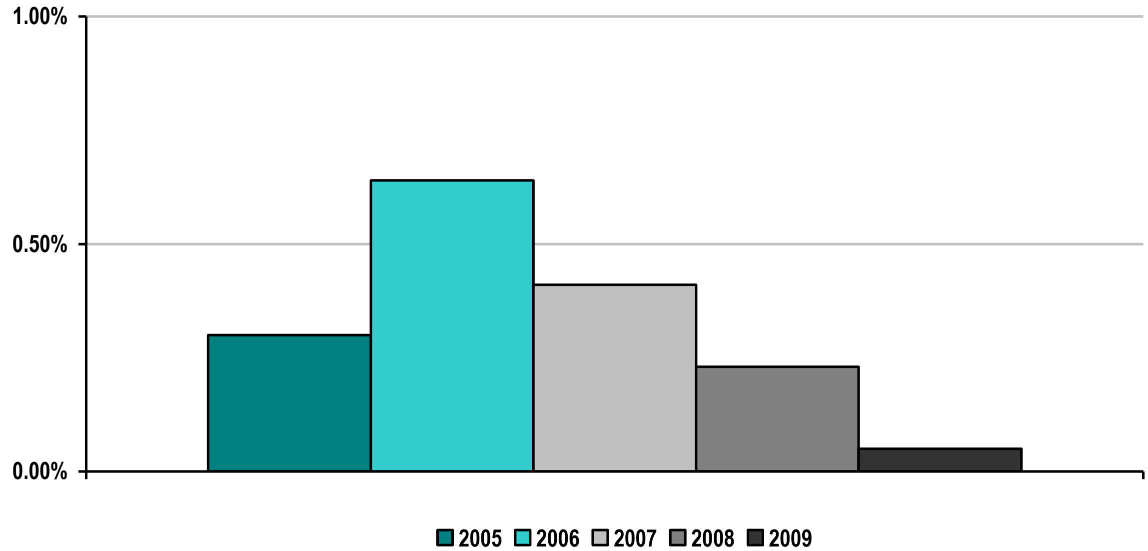
California ISO Demand Response Capacity as Percentage of Total Installed Capacity 2005-2009



Percentage of Generation Outages Cancelled by ISO/RTO

In 2009 the percentage of generation outages cancelled by the California ISO was 0.05%. There has been a downward trend over the prior four years.

Percentage of Generation Outages Cancelled by California ISO

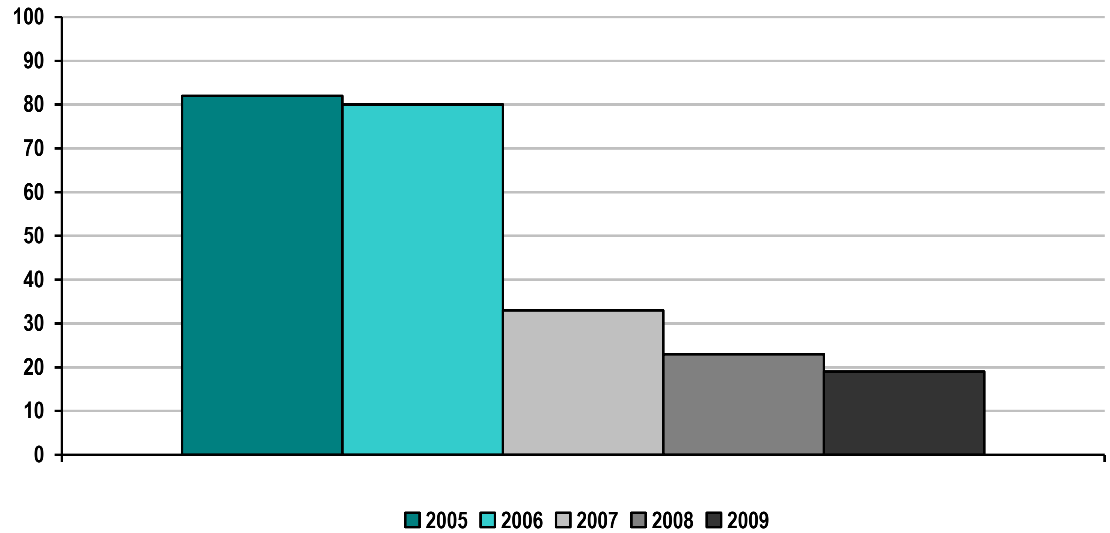


Generation Reliability Must Run Contracts

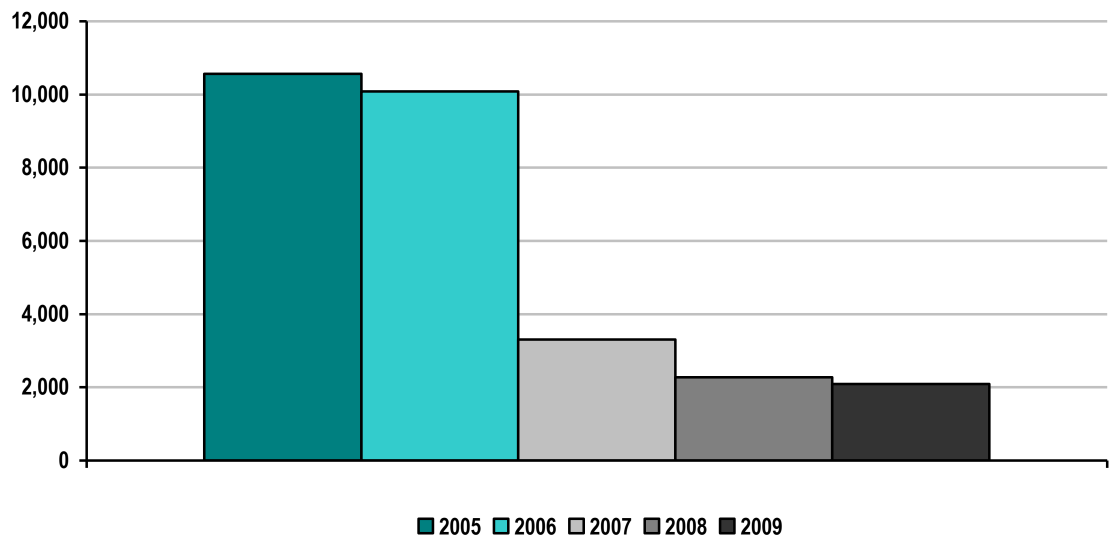
The capacity under reliability must run (RMR) contract was greatly reduced in 2007 when resource adequacy provisions established by the California Public Utilities Commission became effective and contracting under the resource adequacy program provided an alternative to RMR contracting. Capacity procured under resource adequacy now provides the California ISO with much of the local capacity needed for reliability purposes. The amount of RMR capacity continues to decline as existing RMR units are retired after being replaced with new units or electrical system improvements.

These changes have allowed the California ISO to further reduce costs by releasing a significant amount of generation under must-run contracts without undermining local reliability. In 2009, must-run costs decreased 41 percent from 2008 to $39.1 million. That is down from just over $120 million in 2007 and $254 million in 2005.

California ISO Number of Generating Units under RMR Contracts



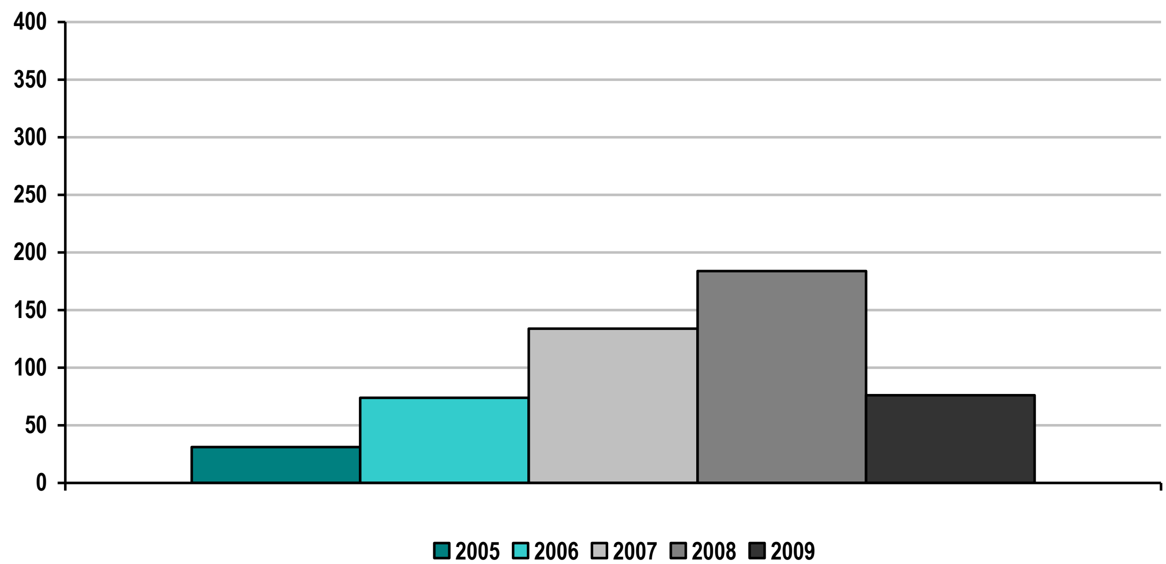
California ISO Capacity (MW) under RMR Contracts



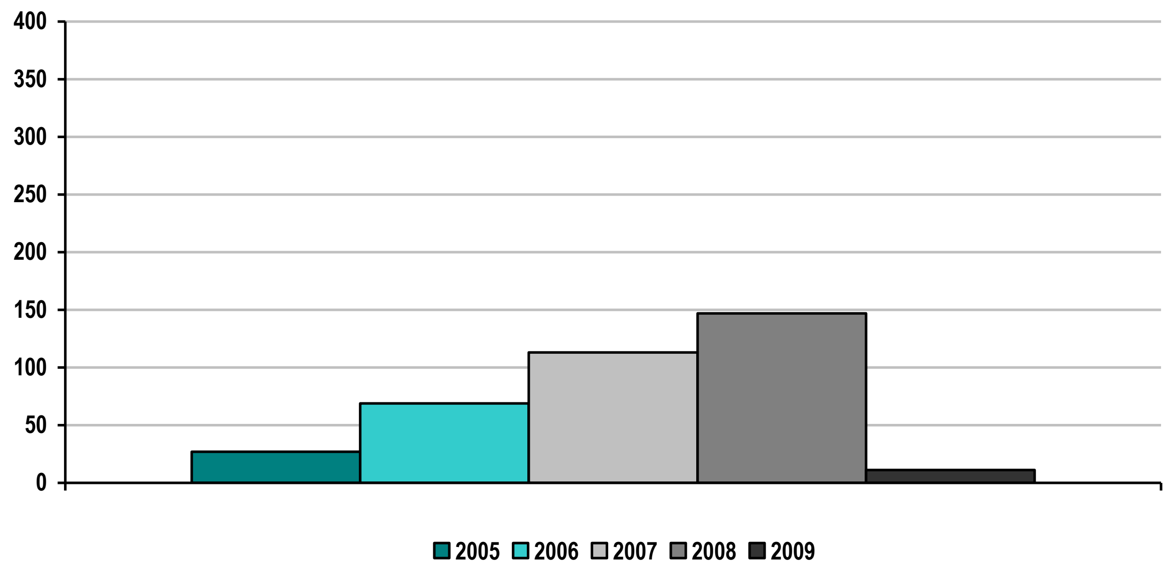
Interconnection / Transmission Service Requests

The California ISO recently completed the transition cluster process as part of a reform effort that began in 2008. The California ISO continues to improve its interconnection process and in 2011 anticipates to have meaningful comparable measures of its interconnection process improvement efforts. The following tables reflect the number of studies requested and how many were completed, as well as the average aging of studies and the time required to complete the generator interconnection process

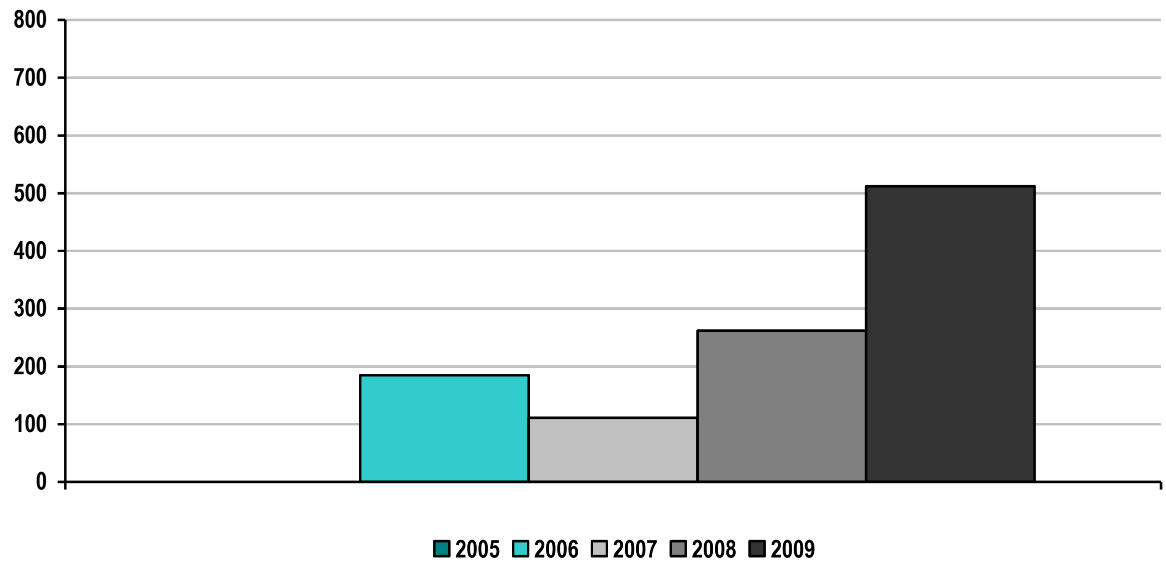
California ISO Number of Study Requests 2005-2009



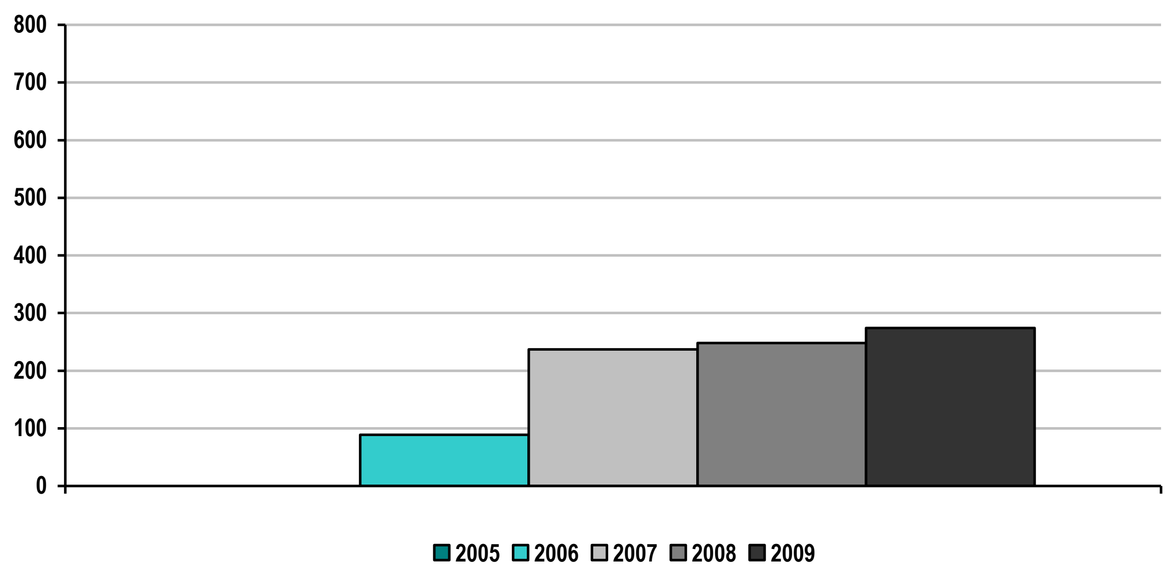
California ISO Number of Studies Completed 2005-2009



California ISO Average Aging of Incomplete Studies 2006-2009



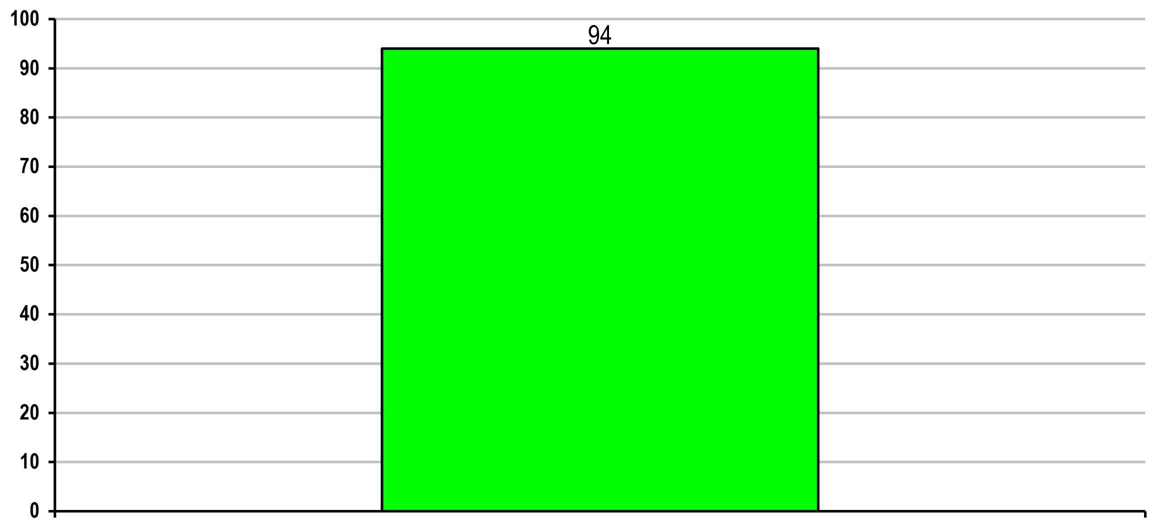
California ISO Average Time to Complete Studies 2006-2009



Special Protection Schemes

Two special protection schemes were activated intentionally and one was activated unintentionally during 2009. All three activated special protection schemes responded as designed.

California ISO Number of Special Protection Schemes 2009



B. California ISO Integrated Wholesale Power Markets

Market Competitiveness

California ISO's market design relies upon a high level of self-supply and forward-contracting by load-serving entities as a means of mitigating system-level market power. This is consistent with California Public Utilities Commission policies designed to ensure that the state's major utilities are hedged for a large portion of their energy supply needs. The potential for market power on a system level basis is addressed by an energy bid cap, which will increase in the second and third years of the new market design. During 2009, an absolute ceiling cap on overall market prices was also in effect. This market price cap is eliminated starting in April 2010.

Ownership of generation resources within most transmission constrained load pockets of the system is highly concentrated under one or two major suppliers. Therefore, the new market design includes more stringent provisions for mitigation of local market power. These local market power mitigation provisions are similar to the approach employed by PJM. Under this approach, units that must be dispatched to provide additional incremental energy to relieve transmission constraints deemed to be non-competitive may have their market bids lowered based on a default energy bid, which reflects the unit's actual marginal operating costs.

California ISO Price Cost Markup

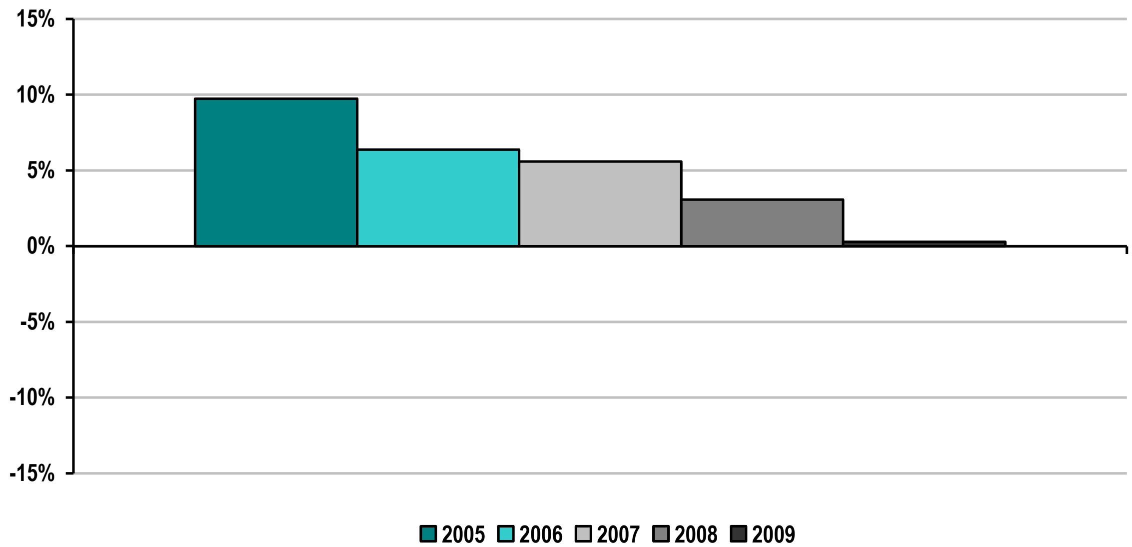
The California ISO estimates the price-cost mark-up for its wholesale market by comparing total estimated wholesale energy costs to cost that would result under competitive baseline prices. The ISO estimated these competitive baseline prices by re-simulating market outcomes after replacing market bids for gas-fired generation with bids reflective of the unit actual marginal costs.

The table below summarizes the results for the period 2005-2009. California ISO's wholesale markets have been competitive during this period with a price-cost mark-up generally ranging from 5 to 10 percent, with a clear downward trend.

The price-cost markup and other analysis indicate that prices under the new market design implemented in 2009 are extremely competitive. However, direct comparisons with the price-cost markups reported in previous years are difficult due to the different way in which price-cost markup is calculated under the new market. Specifically, since there was no formal forward energy market in previous years, market costs were estimated based on a variety of different bi-lateral price indices and cost estimates. With the new market design, these costs can be directly estimated by on prices in the ISO's day-ahead and real-time energy markets. The method used to calculate the competitive baseline price under the ISO's new market design is also modified and is based on a more detailed re-simulation of the market compared to the method used in prior years.

The extremely low price-cost mark-up calculated under the new methodology and market design may also reflect increased efficiencies of this new market design, rather than increased competitiveness. On a going-forward basis, this new competitive baseline methodology will provide a more accurate tool for assessing changes in market competitiveness or efficiency over time.

California ISO Price-Cost Mark-up: 2005-2009

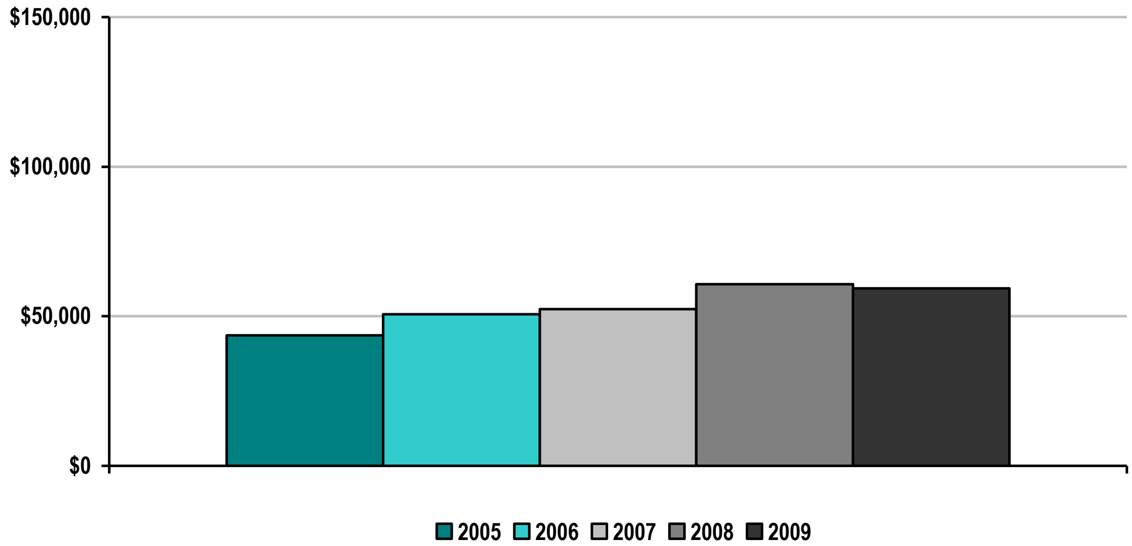


California ISO Generator Net Revenues

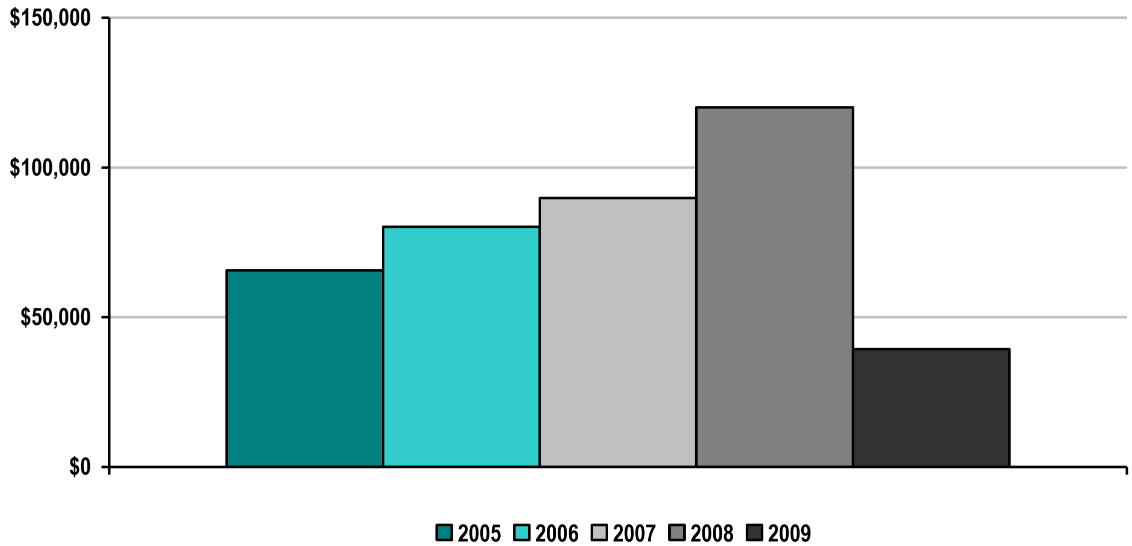
Results for a typical new combined cycle and combustion turbine unit are shown below. The significant increase in new generation costs in 2009 can be largely attributed to increases in capital and financing costs, and taxes. These cost estimates are based on surveys and third-party research reflecting a more current sampling of costs incurred by builders and investors in new generation compared than data from the California Energy Commission's (CEC) *2007 Integrated Energy Policy Report* used in this analysis in prior years.

The 2009 results for a typical new combined cycle unit show a substantial decrease in net revenues compared to 2008 net revenues. The 2009 net revenue estimates for a hypothetical combined cycle unit fall substantially below the $191/kW-yr annualized fixed cost estimated provided by the CEC. The decrease in net revenues can largely be attributed to the decrease in spot market gas market prices and the resulting decrease in electric prices. It may seem counterintuitive that lower gas prices would decrease net revenues for a new gas resource. However, since older less efficient gas units are often the marginal resources setting prices in the market, lower gas prices decrease the net revenues of new more efficient generation that are infra-marginal by a larger percentage than the decrease in spot market gas prices.

California ISO New Entrant Gas-Fired Combustion Turbine (CT) Net Generation Revenues 2005-2009
(dollars per installed megawatt year)



California ISO New Entrant Gas-Fired Combined Cycle (CC) Net Generation Revenues 2005-2009
(dollars per installed megawatt year)



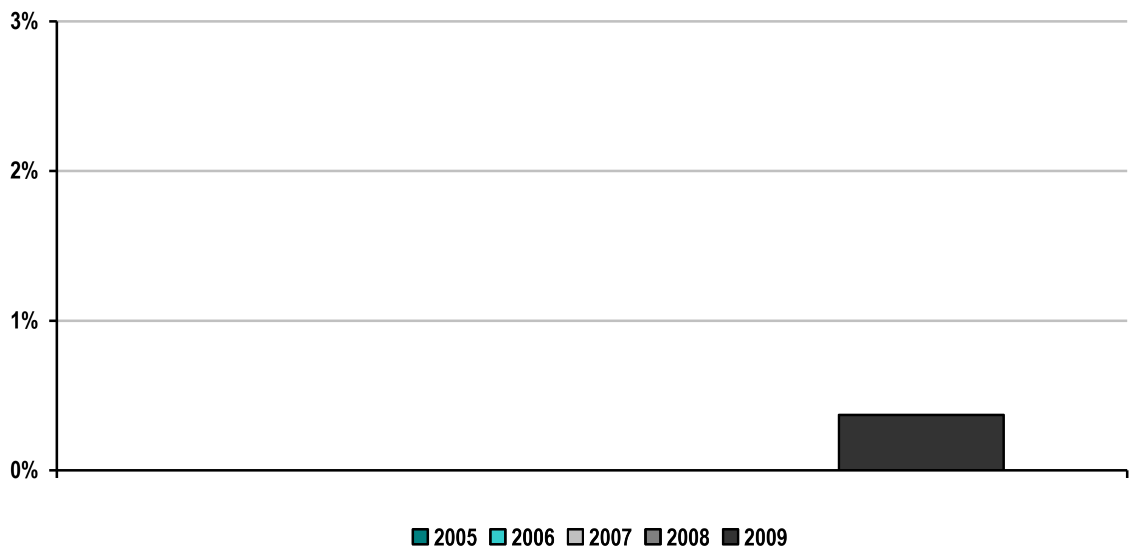
California ISO Mitigation

Mitigation of a unit's market bids is triggered only when a unit is actually required to operate or run at a higher level due to network constraints previously deemed non-competitive. If a unit is subject to bid mitigation, the unit's original market bids are compared to its default energy bid and may be adjusted downwards, if necessary, so that the unit's bid curve does not exceed its default energy bid. The unit's resulting mitigated bid curve is used in the final energy market run.

During each month in 2009, an average of only 1 to 3 units per hour were subject to mitigation in the day-ahead market. About 80 percent of units subject to mitigation actually had market bids lowered as a result of mitigation. This reflects that, in a significant portion of cases, a unit's market bid is below its default energy bid or the unit's highest priced bid clearing the competitive constraints run is higher than its default energy bid. In such cases, no modification of the unit's market bid occurs.

Only about 30 percent of units subject to mitigation may have been dispatched at a higher level in the day-ahead market as a result of bid mitigation. This reflects that the degree to which a unit's market bid curve is reduced by mitigation is often relatively small, and would not impact the level at which the unit is ultimately dispatched in the day-ahead market.

California ISO Real-Time Energy Market Percentage of Unit Hour Bids Mitigated due to Mitigation 2009(1)

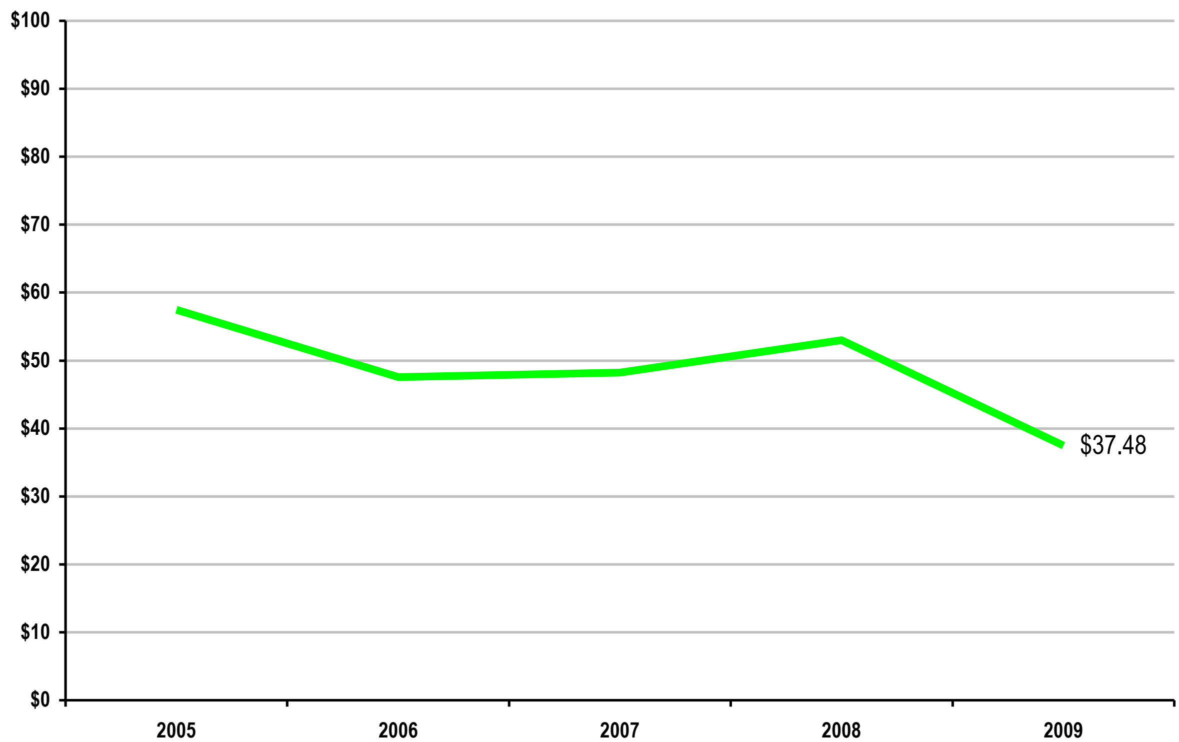


(1) California ISO data represents the period April 1, 2009 through December 31, 2009.

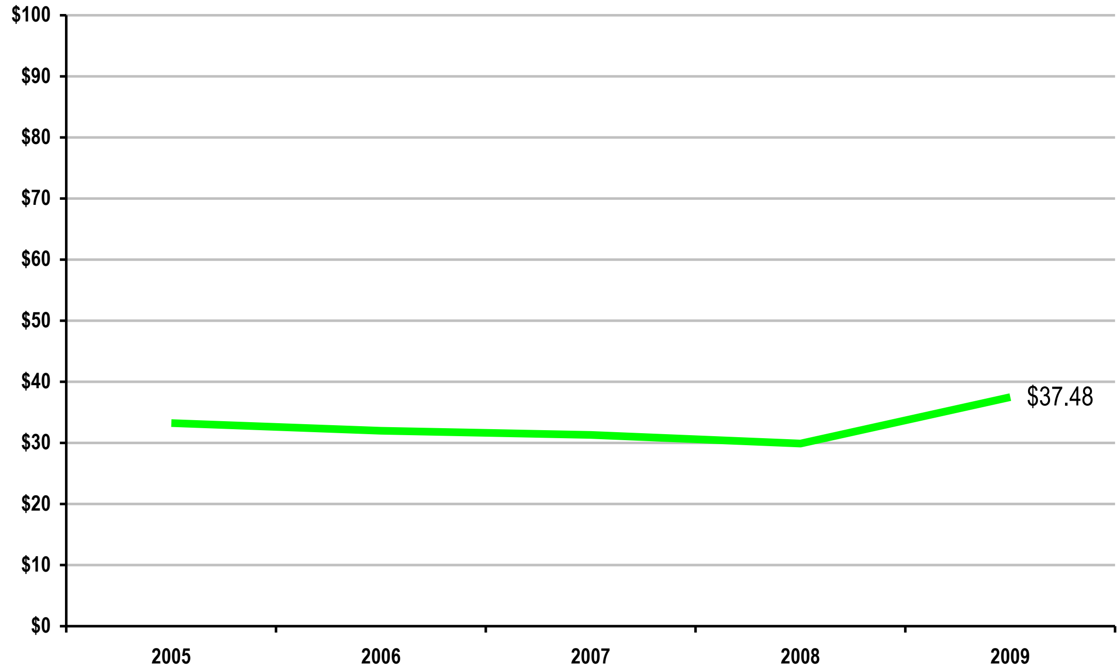
Market Pricing

The California ISO markets implemented in April 2009 introduced a new day-ahead market and redesigned real-time market. The overall performance of the new day-ahead and real-time markets were highly efficient with energy prices following patterns of well-functioning competitive markets, reflecting production costs, and trending generally with the price of natural gas, the most prevalent fuel for marginal resources on the system. The ISO includes wholesale energy pricing information for reference to prior years, understanding the market structure changed completely with the implementation of the new markets. Other metrics in this section are reported as of the start of the new market.

California ISO Average Annual Load-Weighted Wholesale Energy Prices 2005-2009
($/megawatt-hour)

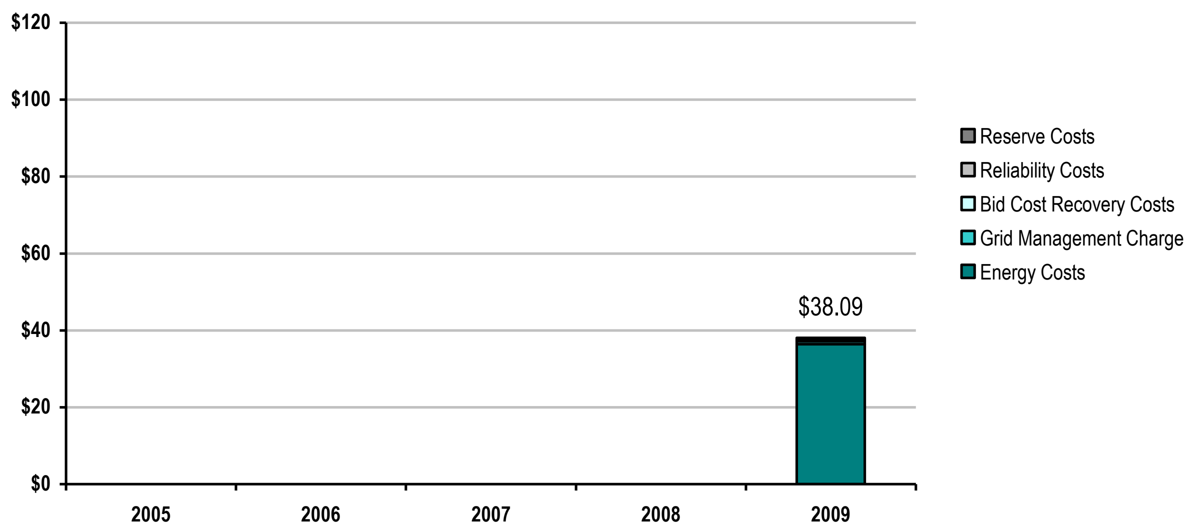


California ISO Average Annual Load-Weighted Fuel-Adjusted Wholesale Spot Energy Prices 2005-2009 (1)
($/megawatt-hour)



(1) California ISO base for fuel costs references 2009 gas prices.

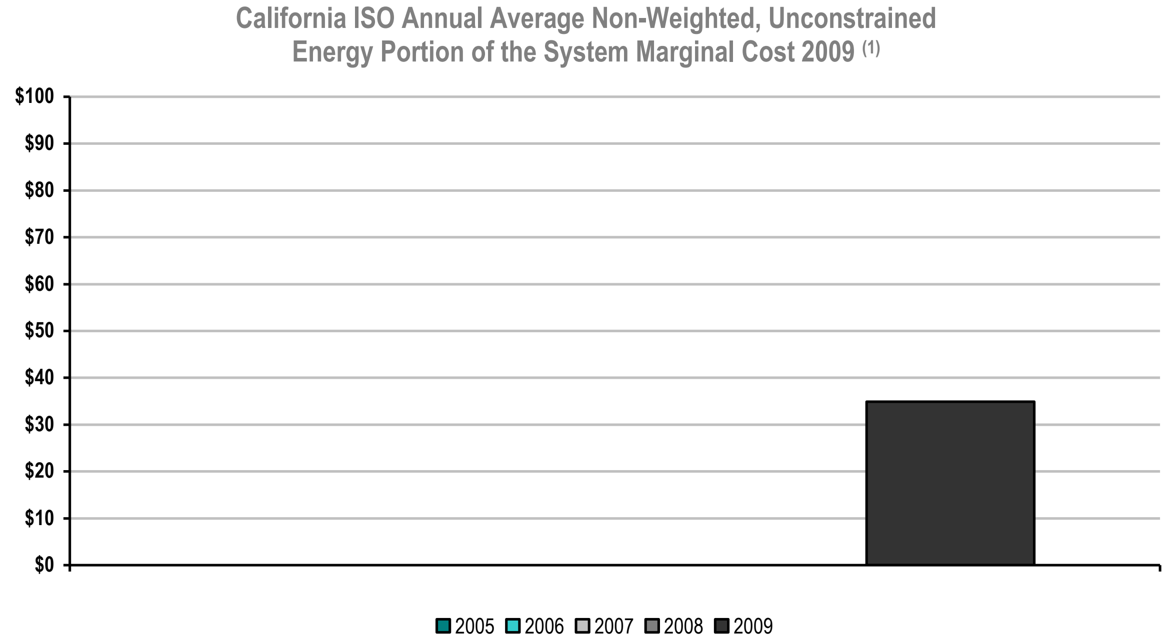
California ISO 2009 Wholesale Power Cost Breakdown (1)
($/megawatt hour)



(1) California ISO data represents the period April 1, 2009 through December 31, 2009.

Unconstrained Energy Portion of System Marginal Cost

The average, non-weighted, unconstrained energy portion of the system marginal cost measures the marginal energy price in dollars per megawatt hour exclusive of transmission constraints and transmission losses.

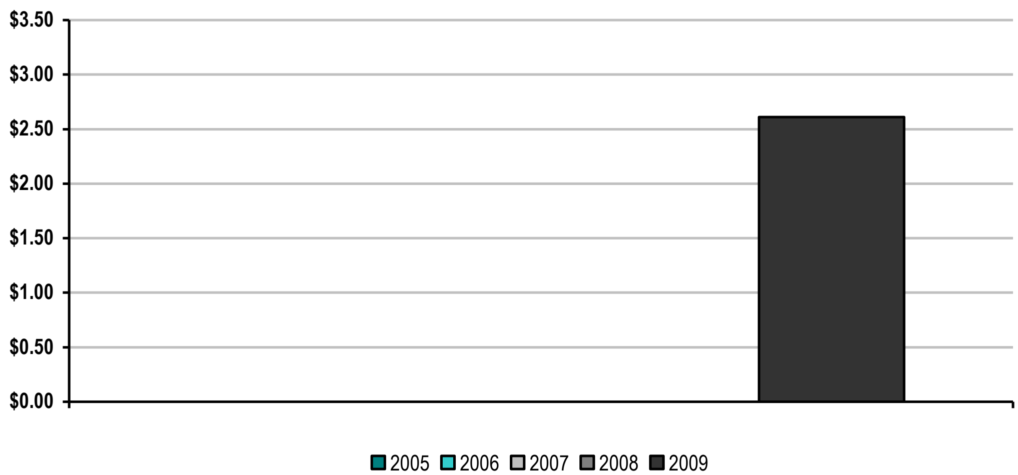


(1) California ISO data represents the period April 1, 2009 through December 31, 2009.

Energy Market Price Convergence

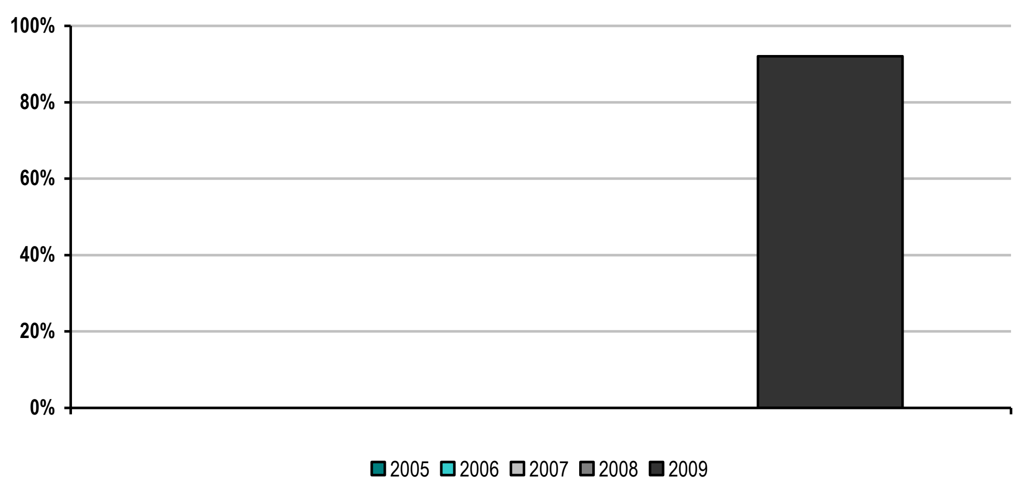
Price convergence in 2009 under the California ISO's new market exceeded 92% and subsequent periods may very well see this number rise. For example, excluding just the first month of market operations pushes the price convergence for 2009 up to 98% and excluding the first two months increases the real-time and day-ahead price convergence to 99.95%.

California ISO Day-Ahead and Real-Time Energy Market Price Convergence 2009 (1)



(1) California ISO data represents the period April 1, 2009 through December 31, 2009.

California ISO Percentage of Day-Ahead and Real-Time Energy Market Price Convergence 2009 (1)

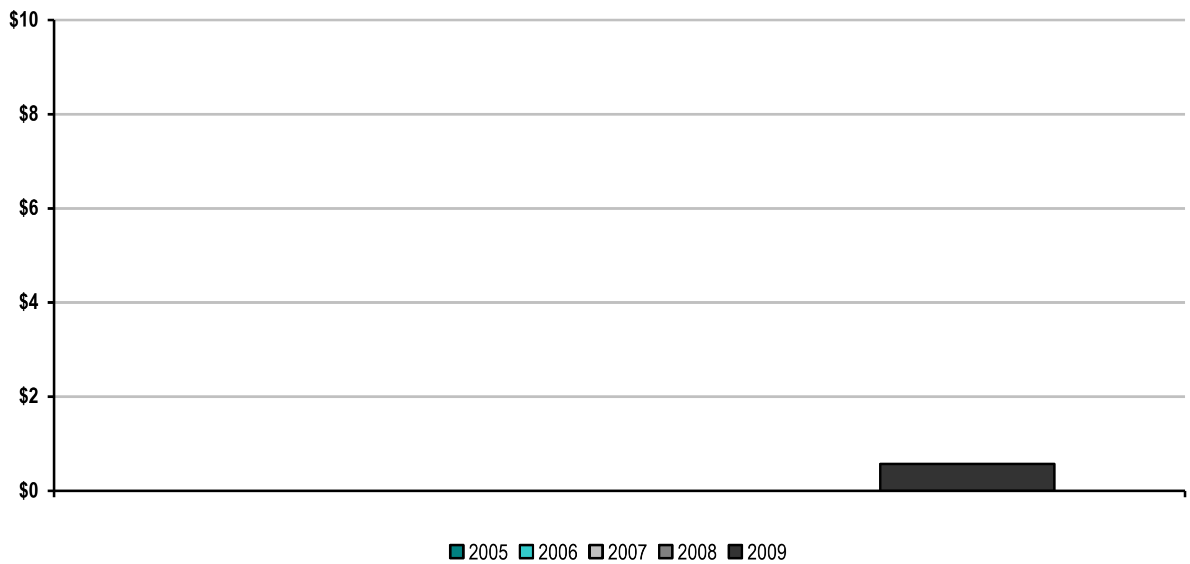


(1) California ISO data represents the period April 1, 2009 through December 31, 2009.

Congestion Management

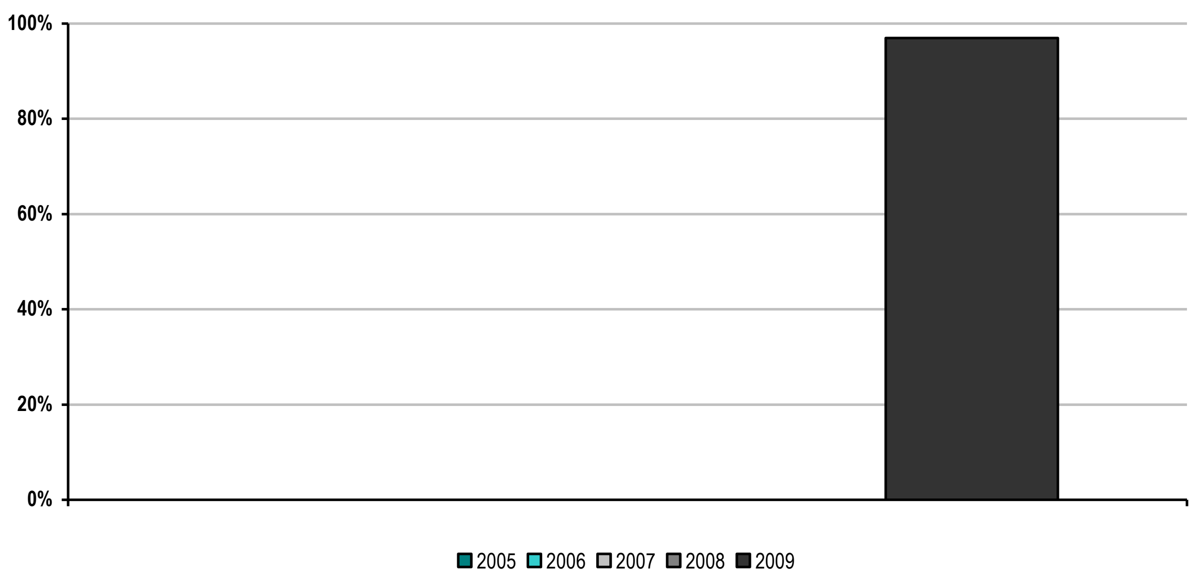
Under the new market structure, market participants can acquire congestion revenue rights through a California ISO allocation and auction process to hedge the cost of congestion on the system. The objective of the first metric is to quantify the hourly average congestion cost per megawatt of load served. The objective of the second metric is to quantify the congestion cost hedged with congestion revenue rights.

California ISO Annual Congestion Costs per Megawatt Hour of Load Served 2009 (1)



(1) California ISO data represents the period April 1, 2009 through December 31, 2009.

Percentage of Congestion Dollars Hedged Through California ISO Congestion Management Markets 2009(1)

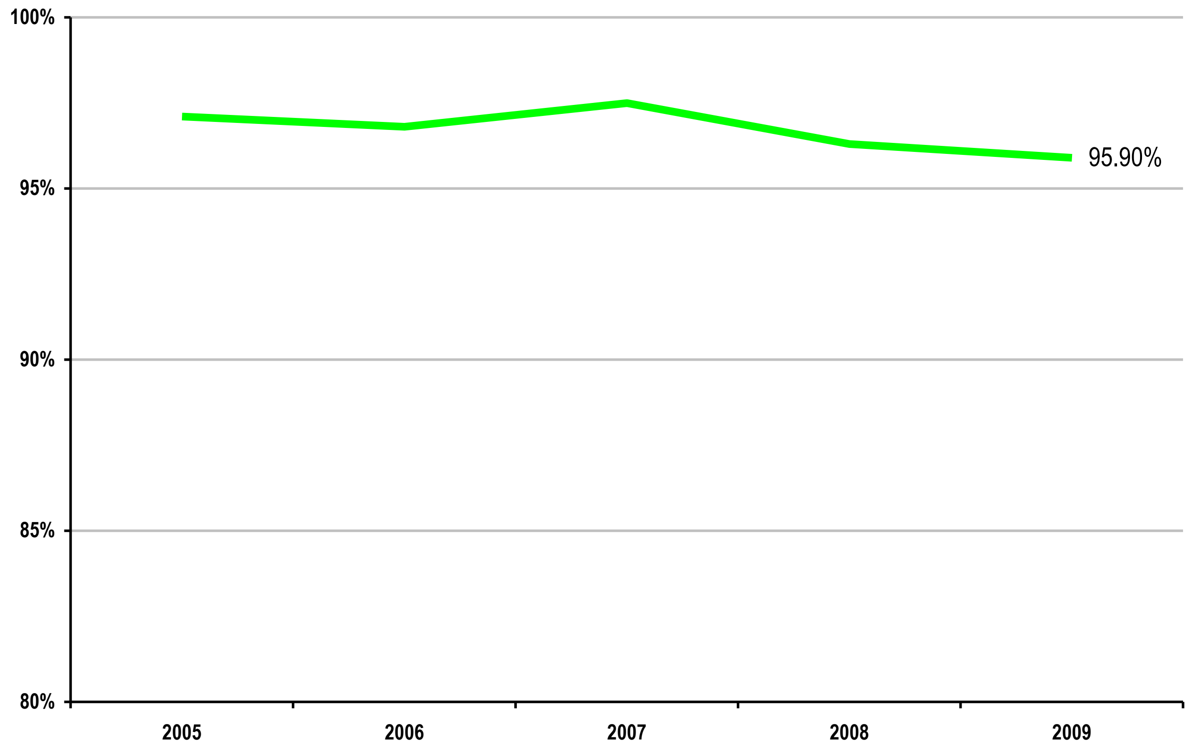


(1) California ISO data represents the period April 1, 2009 through December 31, 2009.

Generator Availability

The California ISO average annual generator availability calculation is the total generation MW unavailable due to forced outages for the year compared to the maximum generation capacity within the ISO.

California ISO Annual Generator Availability 2005 – 2009

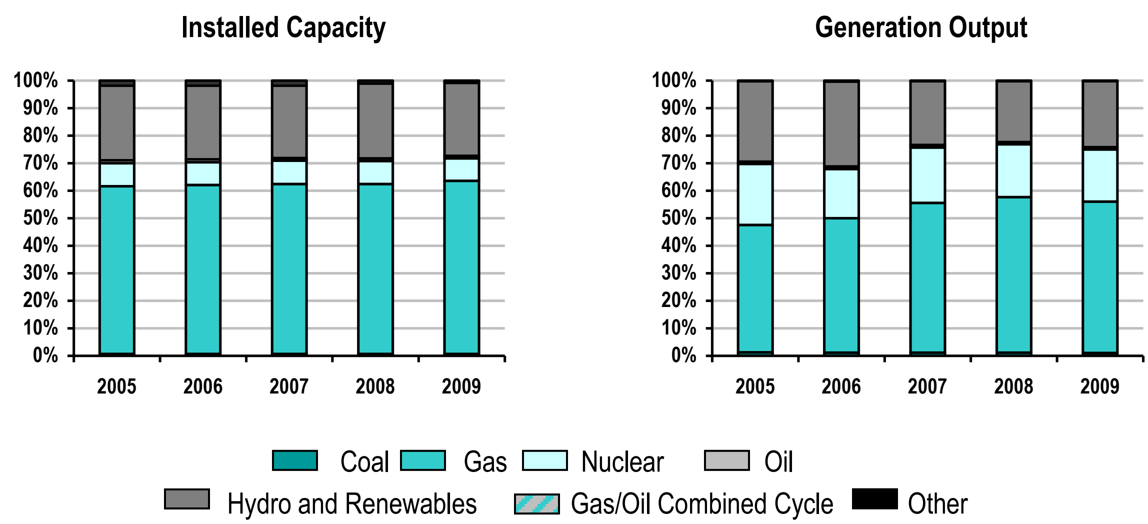


Fuel Diversity

The generation in the California ISO balancing authority area is made up of natural gas, hydro, renewables, nuclear, oil and coal. Natural gas generation, the predominant fuel source, covered 60.1% to 62.9% of the installed capacity in the ISO system from 2005 to 2009. Generation running on hydro and renewables was the second largest fuel source, 26.5% to 27.2%. Nuclear resource followed with 8.1% to 8.4%. Oil resource at 1% and other resources from 0.8% to 1.9% made up the remainder.

On the other hand, gas generation outputs varied from 46.5% to 56.5% from 2005 to 2009. Hydro and renewable outputs ranged from 22.4% to 30.8%. Nuclear generation outputs covered 17.8% to 21.8%. Coal generation outputs kept 1.1% to 1.3% and the other resources stayed 0.2% to 0.3%.

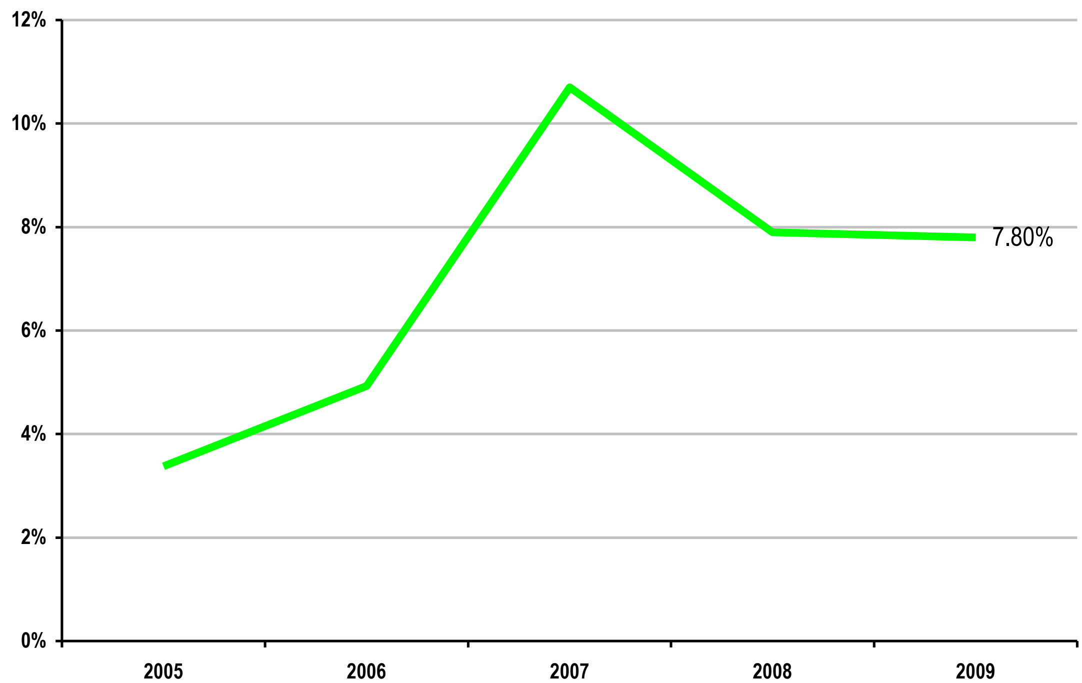
California ISO Fuel Diversity 2005-2009



Demand Response Participation in Synchronized Reserve Markets

The California ISO uses the California Public Utilities Commission methodology for determining the resources that count as demand response, and the amount expected from such programs when called upon. Demand response as a percentage of ancillary services reflects non-spinning reserve through either accepted bids or self provision. Demand response participation in other ancillary services markets is currently limited in the Western Interconnection by WECC rules, which the ISO is intends to address as part of a multi-year ancillary services redesign initiative and through its demand response initiatives such as the proxy demand resource product..

California ISO Demand Response as a Percentage of Synchronized Reserve Market 2005-2009

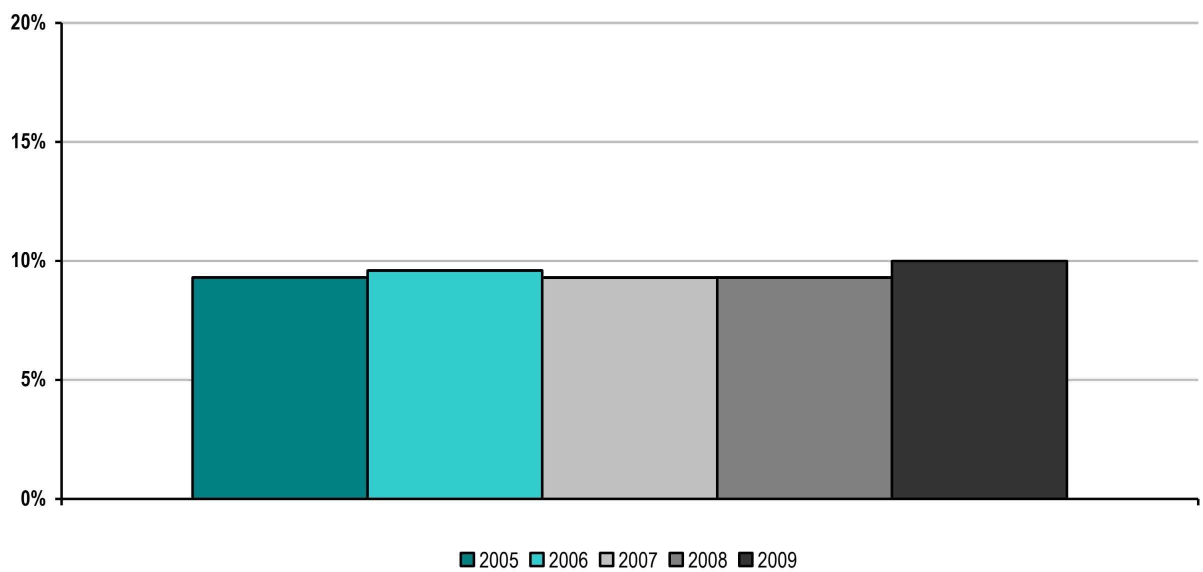


Renewable Resources

The California ISO is uses the California Public Utilities Commission methodology for determining the renewables portfolio standard (RPS)* components of renewable resources, such as wind, solar, geothermal, biomass, biogas and small hydroelectric generating units. However, the figures reported here do not include renewable resources external to the ISO balancing authority area, internal renewable resources not connected to the ISO controlled grid, or the renewable resources to which the ISO does not otherwise have telemetry even though some of these resources ultimately may count towards the renewable portfolio standard. The renewable capacities as a percentage of the total capacity in the ISO system was 11.0% to 11.7% from 2005 to 2009 while the energy ranged was 9.3% to 10.0%.

The ISO is committed to working with state policy directives to achieve 20% RPS by 2010,[2] one of the most ambitious renewable energy standards in the country. The RPS requires electric corporations to increase procurement from eligible renewable energy resources by at least 1% of their retail sales annually. It was established in 2002 under Senate Bill 1078 and accelerated in 2006 under Senate Bill 107. A gubernatorial executive order was sighed on September 15, 2009 directing the California Air Resources Board to adopt regulations increasing the RPS to 33% by 2020.

California ISO Renewable Megawatt Hours as a Percentage of Total Energy 2005-2009



**Large hydro generations are not counted in the renewables portfolio standard.*

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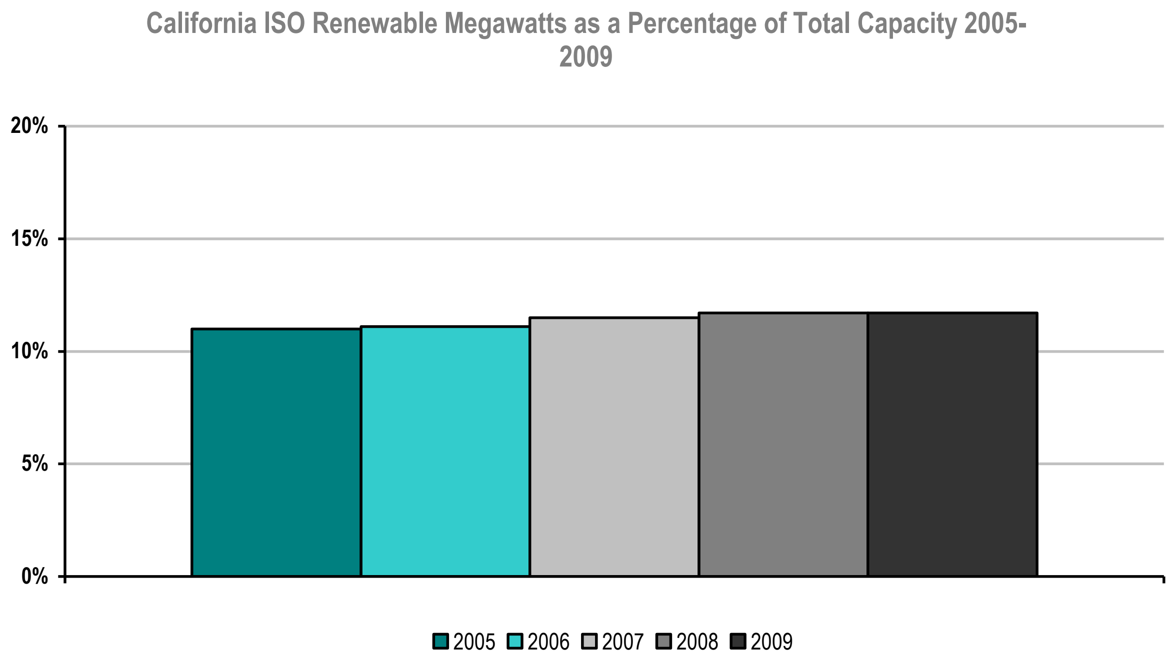
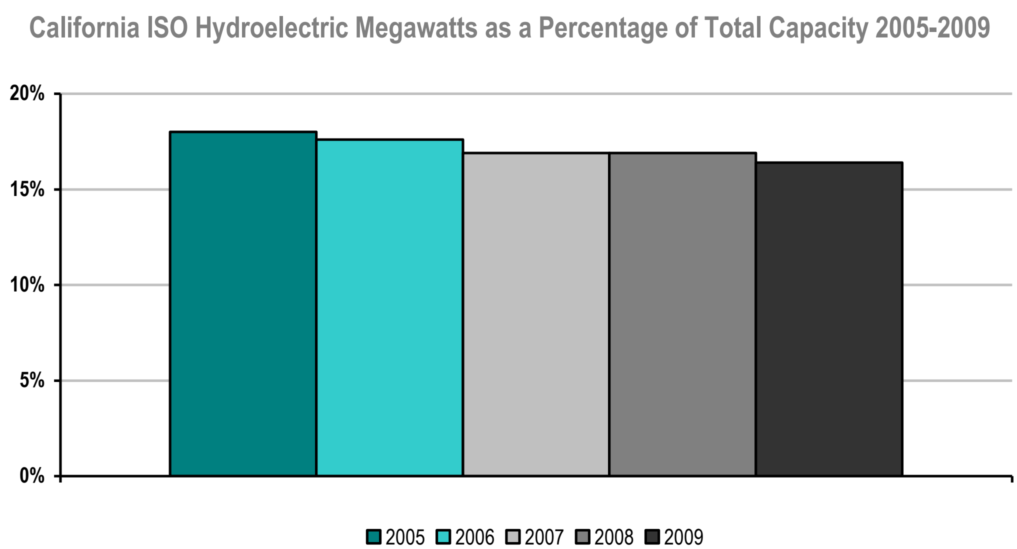
[2] In late 2009, the California Public Utilities Commission noted that the 2010 deadline would not be met and that 2013-2014 was more realistic. However, in mid-2010, based on declines in electricity consumption, rapid growth in RPS contract approvals (including short-term contracts for out-of-state wind energy), and other factors, the Commission estimated that the 20 percent target could be reached in 2011. In 2009, the California investor-owned utilities served 15.4 percent of their load with renewable energy eligible under the RPS.

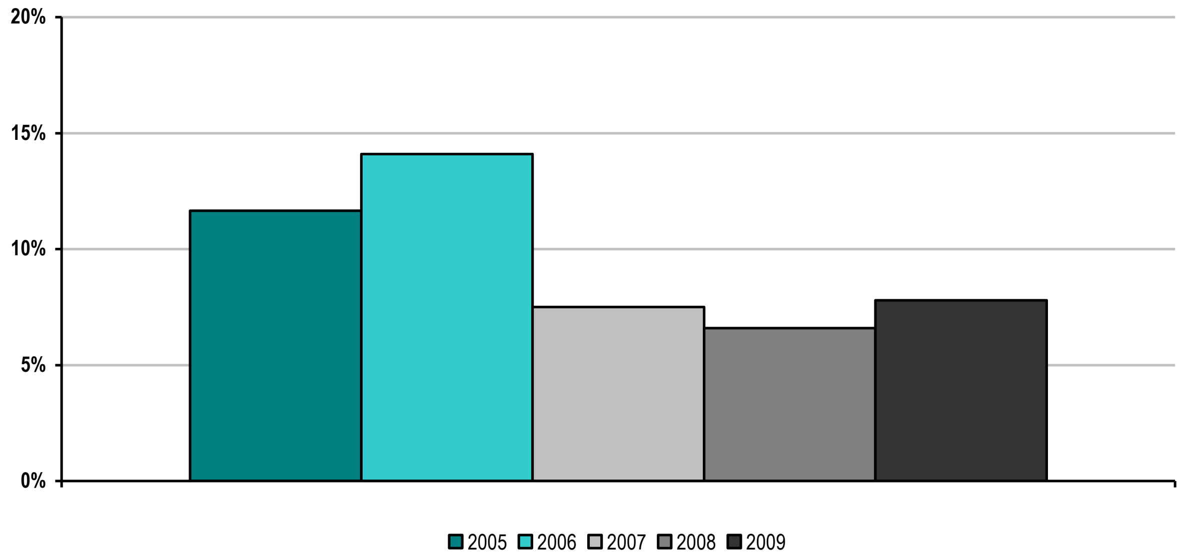
The renewable and hydroelectric capacity data on the next two charts is based on generator nameplate capacity, which is the maximum rated output of a generator under conditions designated by the manufacturer.





Data on total energy from hydroelectric power (including small resources, large resources, and pumped storage) is included in the chart below. The large hydroelectric capacities as a percentage amount of total capacity stayed 15.0% to 16.6% from 2005 to 2009 while large hydroelectric energies as a percentage amount of total energy varied from 6.6% to 14.1%.

California ISO Hydroelectric Megawatt Hours as a Percentage of Total Energy 2005-2009

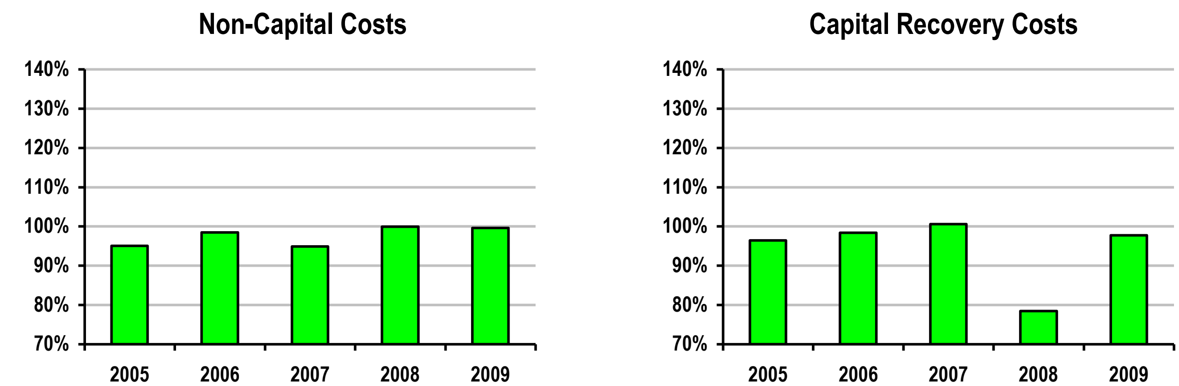


C. California ISO Organizational Effectiveness

Administrative Costs

The California ISO did not have any material variances between its approved budgets and its actual costs from 2005 through 2009. The administrative charge is made up of almost 15 separate billing components, with weather, customer activity and other factors affecting the revenue billed and collected. If collections exceed costs, it is subtracted from the next year's ISO revenue requirement. Additionally the administrative charge can be adjusted quarterly up or down to reduce or increase over collections or under collections. The administrative costs per megawatt hour of load served should be reviewed in the context of the widely varying levels of annual load served by each ISO/RTO, about 249 terawatts for the ISO.

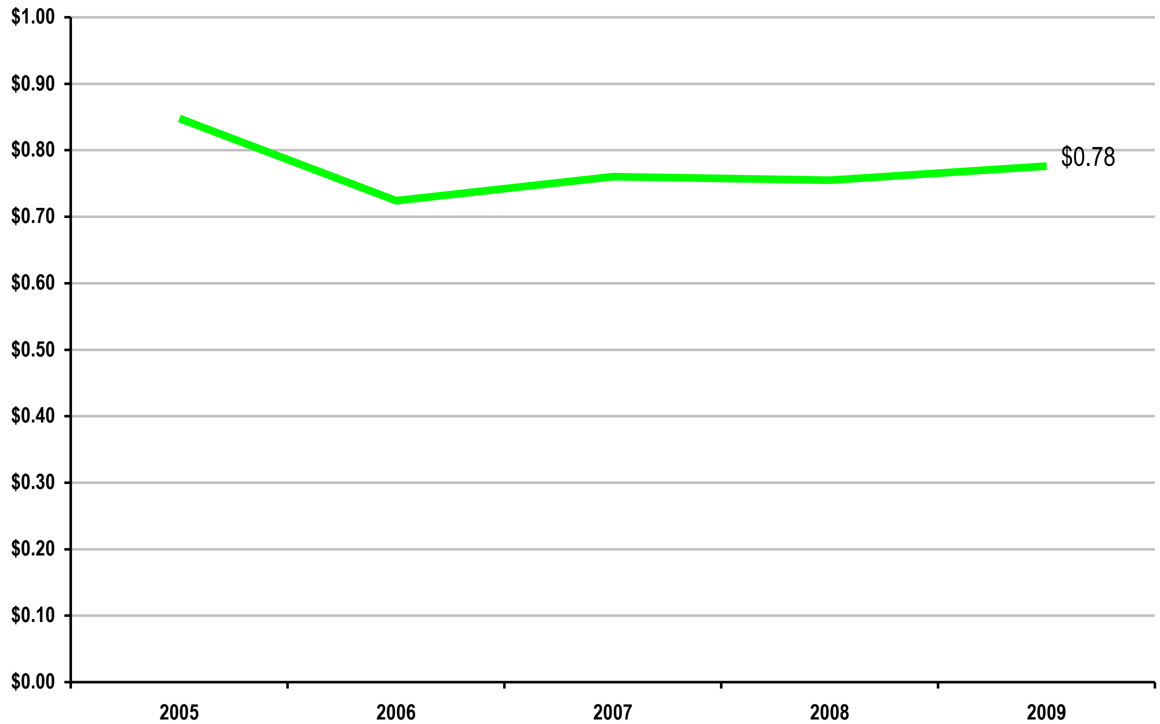
California ISO Annual Actual Costs as a Percentage of Budgeted Costs 2005-2009



Budget	$143	$129	$137	$147	$153
Budget	$62	$82	$53	$60	$199

Bars Represent % of Actual Costs to Approved Budgets; Dollar Amounts Represent Approved Budgets (in millions)

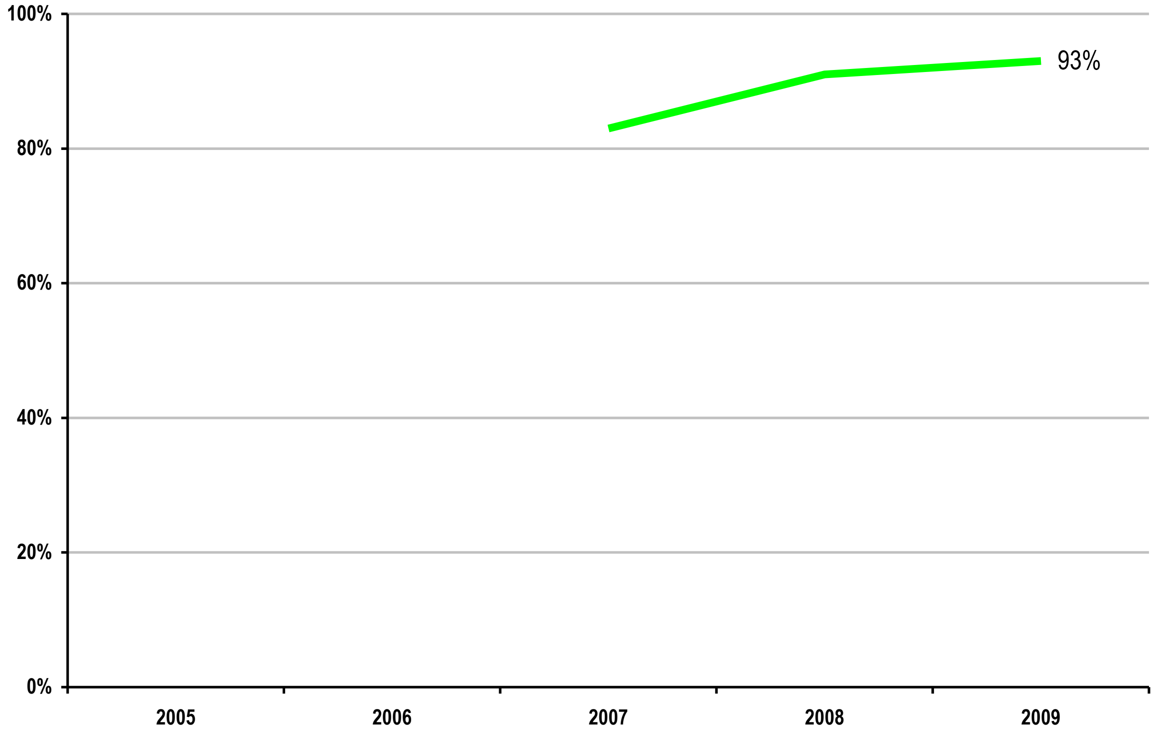
California ISO Annual Administrative Charges per Megawatt Hour of Load Served 2005-2009
($/megawatt-hour)



Customer Satisfaction

The California ISO does not use a single client satisfaction metric for developing business improvement initiatives because of the metric's limitations. Instead, the ISO uses a variety of survey instruments to test stakeholder satisfaction. Among these instruments are "transactional surveys" to gauge stakeholder satisfaction with specific projects or stakeholder processes, "corporate surveys" to annually sample senior-level stakeholders across multiple ISO business areas, and "touch point mapping exercises" in which the ISO drills deeply to better understand business interactions with its customers. Although these surveys yield no single stakeholder satisfaction score, the ISO asks two questions on overall stakeholder satisfaction within the annual executive-level corporate survey. The graphic below presents these scores for the past three years.

California ISO Percentage of Satisfied Members 2005-2009



Billing Controls

The California ISO received two unqualified opinions following implementation of its new market design in 2009. This is a testament to the completeness and accuracy of the controls operating in this complex new environment.

ISO/RTO	2005	2006	2007	2008	2009
California ISO	Qualification for Two Control Objectives in SAS 70 Type 2 Audit	Unqualified SAS 70 Type 2 Audit Opinion	Qualification for Two Control Objectives in SAS 70 Type 2 Audit	Qualification for One Control Objective in SAS 70 Type 2 Audit	Unqualified SAS 70 Type 1 and Type 2 Audit Opinions

D. California ISO Specific Initiatives

Each year the California ISO establishes, with Board approval, annual corporate goals as part of its strategic planning process. The annual goals measure short-term performance and targeted areas of focus or improvement in a given year. In parallel time, the ISO assesses long-term performance in achieving the objectives identified in the strategic plan. The following performance highlights are a collection of short and long-term performance achievements over the past five years (2005-2009) in the three areas covered by the ISO/RTO metrics in this report.

Reliability

The ISO measures reliability in terms of compliance with operations and planning standards as well as cost. In some cases, meeting the requirements is absolute while for others, some discretion exists in how to achieve a particular result. When exercising such discretion, the ISO keeps the cost impacts in mind while maintaining expected levels of reliability.

- **Renewables Planning.** The ISO has a long history of planning for renewables integration dating back to 2001 when its Participating Intermittent Resource Program was approved by the Board, and later with conditions by the FERC. The program, which responded to state rules establishing a 20 percent renewables portfolio standard, allows intermittent resources, such as wind and solar resources, to schedule energy in the ISO forward market without incurring imbalance charges when the delivered energy differs from the scheduled amount.

  In 2006, the ISO proposed, and the FERC accepted in 2007, the Location Constrained Resource Interconnection financing tool, which eases the financial burden of renewable project developers by allocating the costs to multiple generators connecting to the same facilities as they come on line.

  In 2008 and 2009, the ISO stepped up its activities by collaborating with vendors, utilities and state agencies to conduct test pilots. The ISO is participating in the Western Electricity's Coordinating Council's Western Interconnection Synchrophasor Program, which leverages a mature technology in new ways critical in managing the renewable resources, including electric vehicles charging (and storage).

  The ISO also participated in seven storage pilots in 2008-2009 that investigated several different things including how battery storage can help match renewables generation with available transmission capacity and how to best use storage for regulation, spinning reserves and frequency response.

  The Board approved the Proxy Demand Response proposal in late 2009 that set forth the conditions in which aggregators and load-serving entities could bid demand reductions into the ISO markets, and the ISO expects to follow with the reliability demand response product to integrate emergency responsive demand into ISO markets and operations.

- **Reduced Reliability Management Costs.** The ISO targeted over $1 billion of reliability management costs in 2004 and reduced this figure to $154 million in 2007. It achieved this reduction by optimizing operator commitments through targeted reliability management process changes. The ISO relied less on reliability must-run plants in recent years and especially from 2007 to 2009 with costs decreasing nearly 68 percent to $39 million.

- **Maintaining Reliability Under Extreme Operating Conditions.** The ISO developed a wildfire tracking information system that combined Google Earth, California Department of Forestry and Fire Protection real-time information, and grid topology that displays pinpoint views of threats to the grid. *POWERGRID International (*formerly *Utility Automation & Engineering T&D)* magazine awarded the warning system its 2007 Project of the Year Award.

- **Interconnection Process Improvements.** The ISO enhanced its interconnection processes that benefit the ISO and its customers in significant ways. The 2008 queue reform reduced the large number of projects requesting interconnections down to a manageable and more meaningful number. By reforming our study processes three times in three years helps ensures applicants are serious while avoiding imposition of fees that could cause otherwise promising, viable projects to fail. And by studying geographically and electrically related requests in clusters, the ISO was able to cut review time by 60 percent.

- **Generation.** More than 2,400 MW of new generation came on line in 2009 — the most since 2005. Generation additions 2006 to 2008 totaled less than 600 MW each year.

- **Transmission Planning Process Improvements.** The ISO revised planning proposals are being designed to mitigate stranded costs risks as development patterns change, making sure that the regulatory compliant process addresses reliability needs and, for the first time, state energy and environmental goals. The planning reform initiatives are successful because of the extraordinary effort our stakeholders and market participants have devoted to designing the rules. The ISO employed in 2004 the first in the nation economic methodology for evaluating the benefits of transmission called the Transmission Economic Analysis Methodology which improved the accuracy of the evaluation, and added greater predictability to the evaluations of transmission need conducted at various agencies.

- **Transmission.** If built as expected, the ISO has approved four major transmission projects, which together have a capacity of 12,300 MW, that will accommodate energy load-serving entities need to meet the state's 20 percent by 2010 renewables portfolio standard.

- **Compliance.** The ISO has strengthened its compliance efforts over the past few years despite challenging operating conditions (wildfires, loop flows from early spring melts, etc.), and implementing resource adequacy requirements. The ISO has had successful compliance audits, including in 2008, when the ISO created a new compliance department. In 2009, spot check auditors from the Western Electricity Coordinating Council found no violations, and they noted no audited entity had achieved such a feat.

Markets

In April 2009, the ISO implemented a new market, referred to in its development stage as the Market Redesign and Technology Upgrade. This effort required significant company resources and focused leadership management. To put this accomplishment in perspective the following highlights are noted:

- **Significant New Functionality.** The scope of the new market functionality was significant, including congestion revenue rights, a day-ahead market and locational marginal pricing. The new market is more transparent and granular and the pricing at its 3,000 nodes better reflects the energy's production and delivery costs.

- **Extensive Outreach and Collaboration.** The ISO conducted extensive outreach to fully support market participants as they tested their systems to ensure new market readiness. The result of this activity was increasing confidence in ISO systems and creating unprecedented collaboration that persists even now. This led the ISO to hold its inaugural Stakeholder Symposium in the fall of 2009 that drew 210 people that promoted open dialogue with members of the Board of Governors and ISO executives. The ISO also held several forums to discuss pressing issues.

- **Continued Functionality Deployment.** The ISO developed nine additional enhancements that are ready for deployment (some are pending approval). The higher priority enhancements were scarcity pricing and convergence bidding; multi-stage generator unit modeling; resource adequacy standard capacity product; and ancillary services must offer obligation. To further support our market participants as they upgrade their systems and processes to deploy new market functionalities, the ISO began holding quarterly stakeholder meetings to discuss implementation issues and schedules.

Organizational Effectiveness

Beyond cost and customer satisfaction measures, the ISO also focused on developing its people, business processes and technology capabilities. Indeed, these enabling activities are essential to meeting expectations with respect to the operations and markets metrics included in the report, all at a reasonable cost.

- **People.** The ISO developed and launched a technical training program to develop critical skills needed by operators and engineers to manage a more complex grid. It also established the President's Leadership Academy that trains participants to make better business decisions and grow their leadership skills. Human Resources implemented a comprehensive talent management strategy that reduces voluntary turnover and a global recruitment program.

- **Process.** The single biggest improvement effort in this area has focused on building a culture of customer service that included deploying an issue tracking system with performance metrics. Resolving issues now requires less than five business days on average despite having a new and complex market platform. An August 2008 comprehensive customer survey, among other things, led the ISO to develop a set of criteria to measure the timeliness of document publication and the effectiveness of those documents in informing stakeholders.

- **Technology.** The ISO continues to enhance situational awareness through development of a modernized control center in our new headquarters. It will feature a video wall pre-programmed to display critical operating information, including the status of renewable resources. In 2006, several advanced technologies were deployed in ISO control rooms to enhance grid management, including the State Estimator that allows the ISO to see beyond its footprint to better gauge system conditions.

- **Financial.** The ISO began to aggressively manage its revenue requirement in 2005 with a corporate realignment that resulted in a $27 million drop in 2006. Since that time, the ISO has been able to hold its revenue requirement to below the $197 million threshold that triggers a rate filing. In 2008, the ISO agreed with stakeholders that its payment schedule was long and exposed customers to unnecessary credit risk and implemented in 2009 its payment acceleration process. The new system reduced average cash clearing time to 17 business days from 56, and shaved settlements publication time to 7 business days from 38.

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.

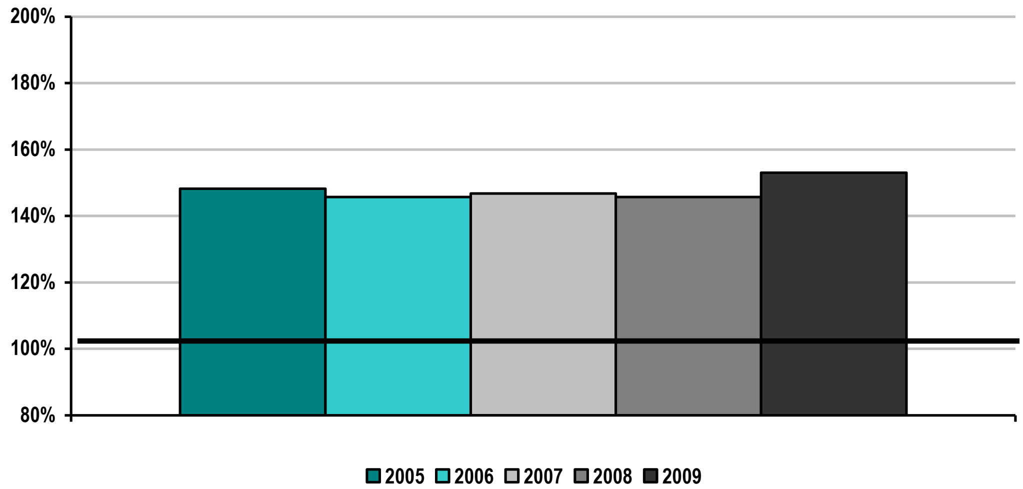
Control Performance Standard No. 1 (CPS1) and Control Performance Standard No. 2 (CPS2) are designed to maintain interconnection steady-state frequency within defined limits by balancing real power demand and supply in real time. NERC Standard BAL-001-0.1a, *Real Power Balancing Control Performance*,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

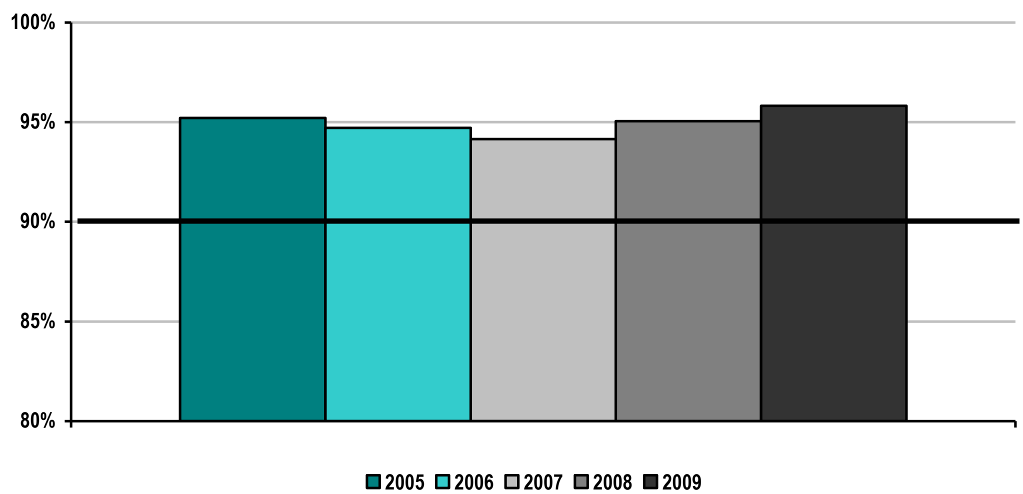
ISO-NE monitors CPS compliance every hour of every day. Further, ISO-NE reviews CPS1 and CPS2 performance on a monthly basis. In addition, ISO-NE reviews CPS compliance annually to determine whether its regulation requirements, specified as a function of month, day type, and hour, need to be adjusted 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



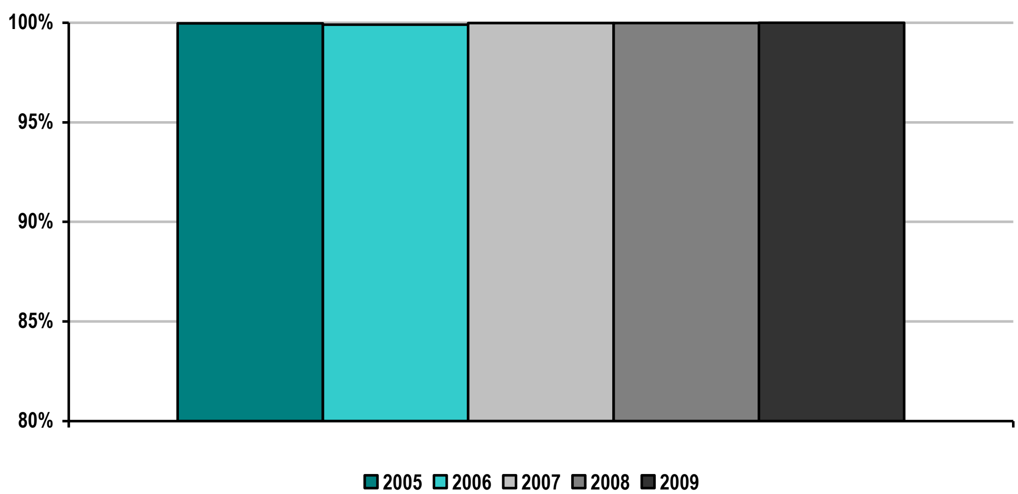
ISO-NE CPS2 Compliance, 2005–2009



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.

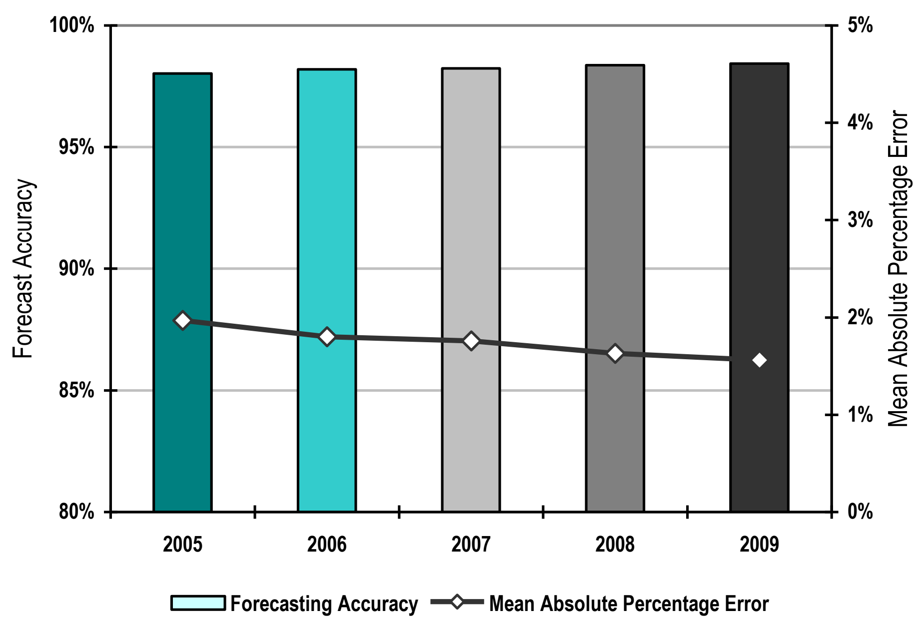
ISO-NE forecasters also use three types of short-term load forecast models to produce the day-ahead load forecast (before 10:00 a.m.), the seven-day load forecast, and an update of the current (intra-) day load forecast. One type of forecast model is an advanced neural network (ANN) model that uses weather 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]

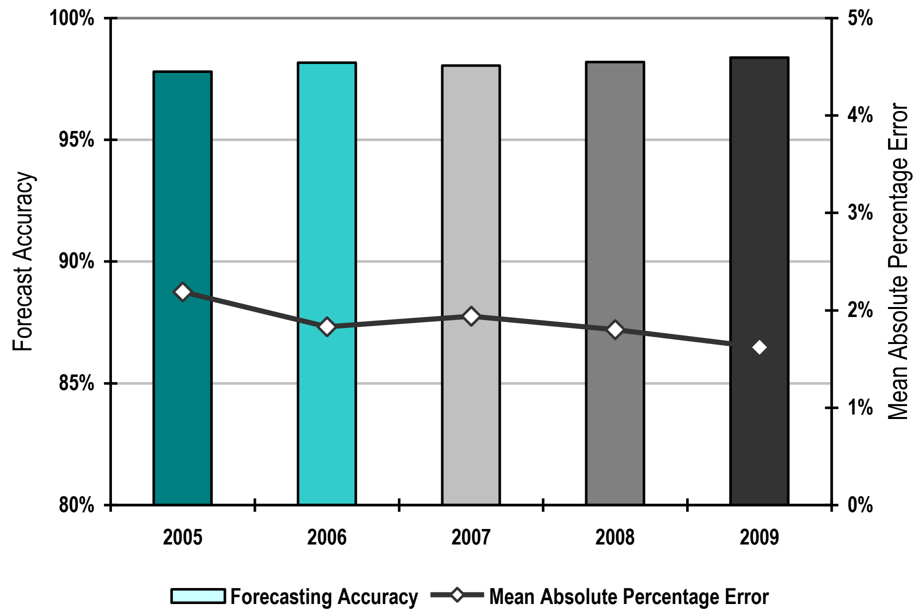
	Load Forecasting Accuracy Reference Point
ISO-NE	10:00 a.m. prior day

ISO-NE Average Load Forecasting Accuracy, 2005–2009

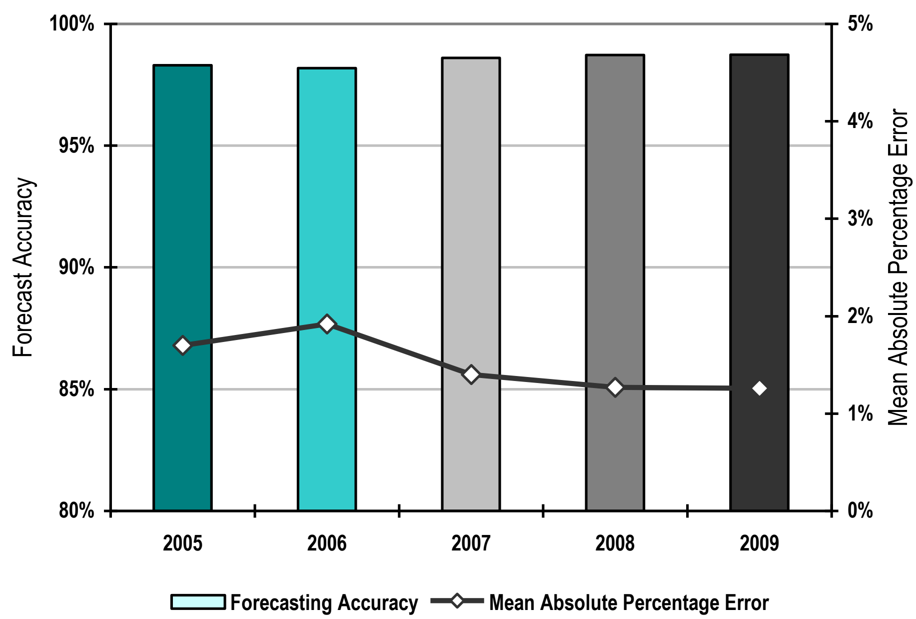


[3] For ISO-NE's calculation of load forecast accuracy for 2005 to 2009, the actual loads were reconstituted for load-relief estimates resulting from the dispatch of demand response because of Emergency Operating Procedures (EOPs) invoked by ISO-NE.

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.

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[4] 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.

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:

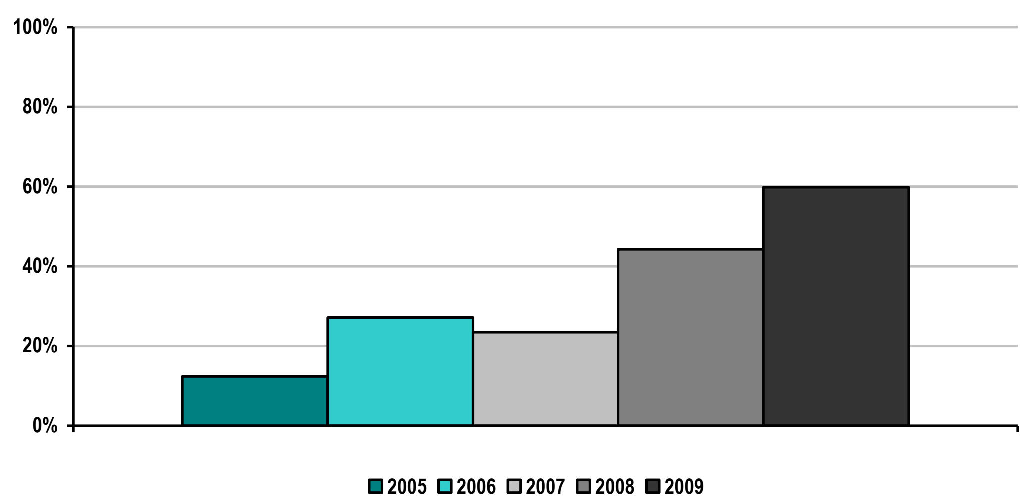
- Establishing a set of broad performance-based outage-coordination metrics to allow all parties to assess their performance regarding transmission outage coordination
- Enhancing the coordination process and procedures through cooperation by all entities (ISO-NE, TOs, LCCs, and GOs) to implement best 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

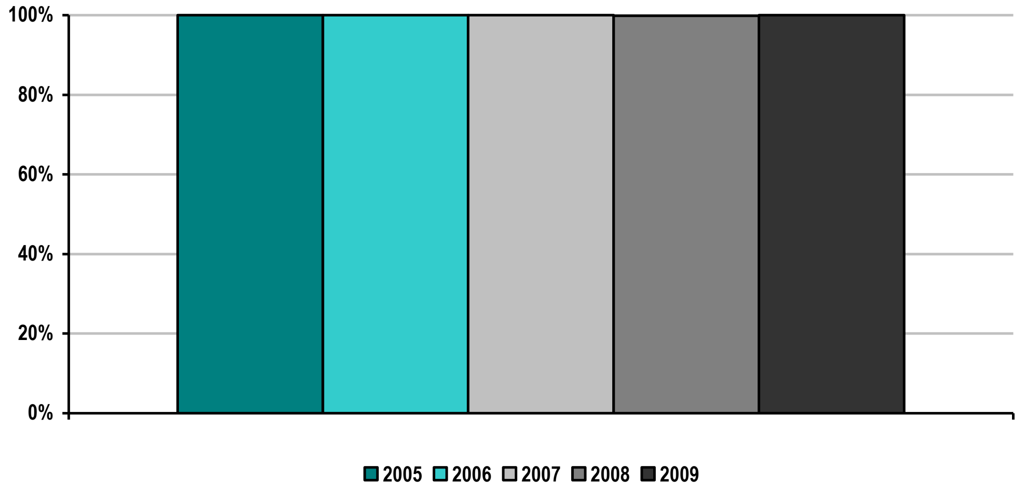
The efforts to improve outage coordination have been concurrent with a significant increase in transmission outage requests resulting from the substantial transmission build-out by the TOs. As the metrics indicate, ISO-NE, collaboratively with the TOs and LCCs, has improved the lead time of request submissions, 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.

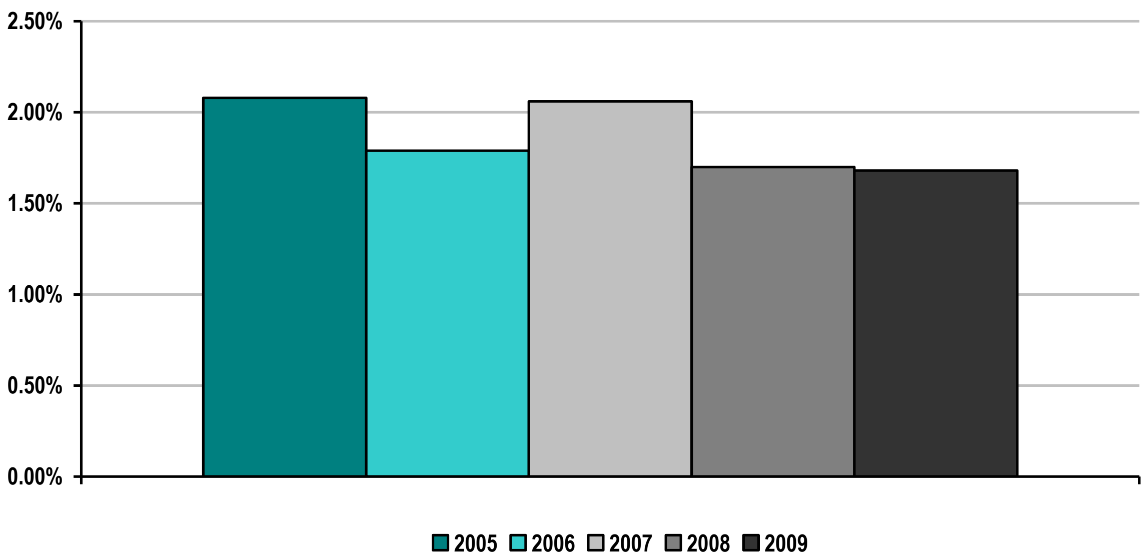
Percentage of >200 kV Planned Outages of Five Days or More Submitted to ISO-NE at Least One Month Before the Outage Commencement Date, 2005–2009



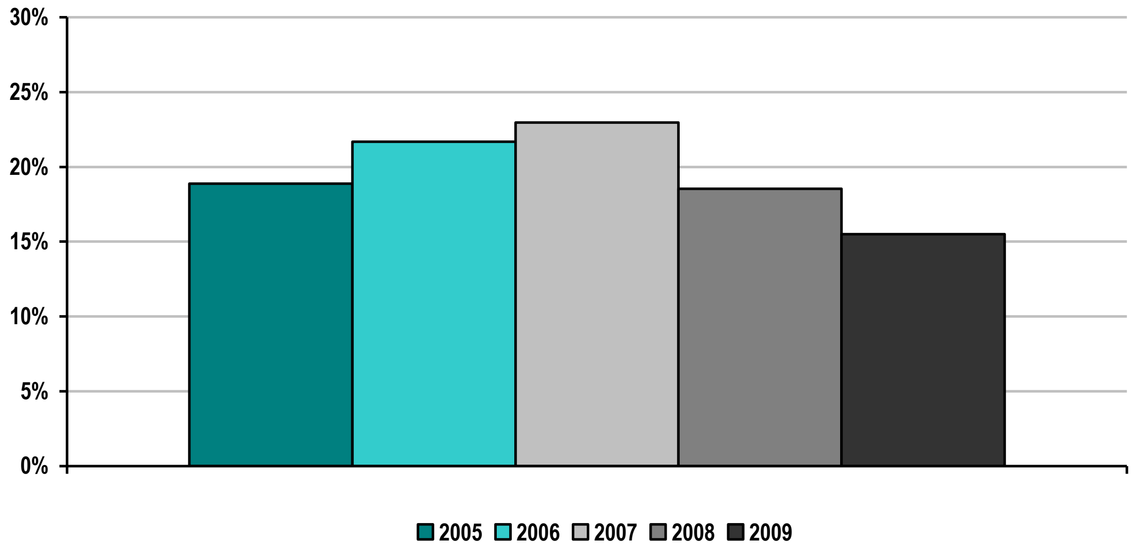
Percentage of Planned Outages Studied in ISO-NE's Tariff/Manual-Established Timeframes, 2005–2009



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.

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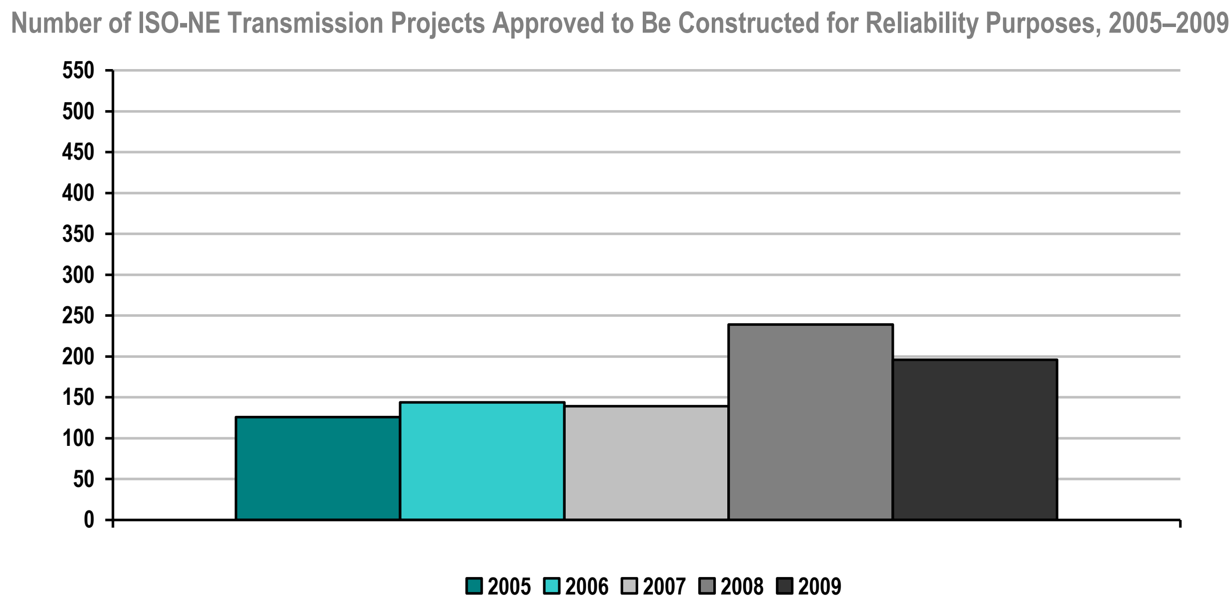
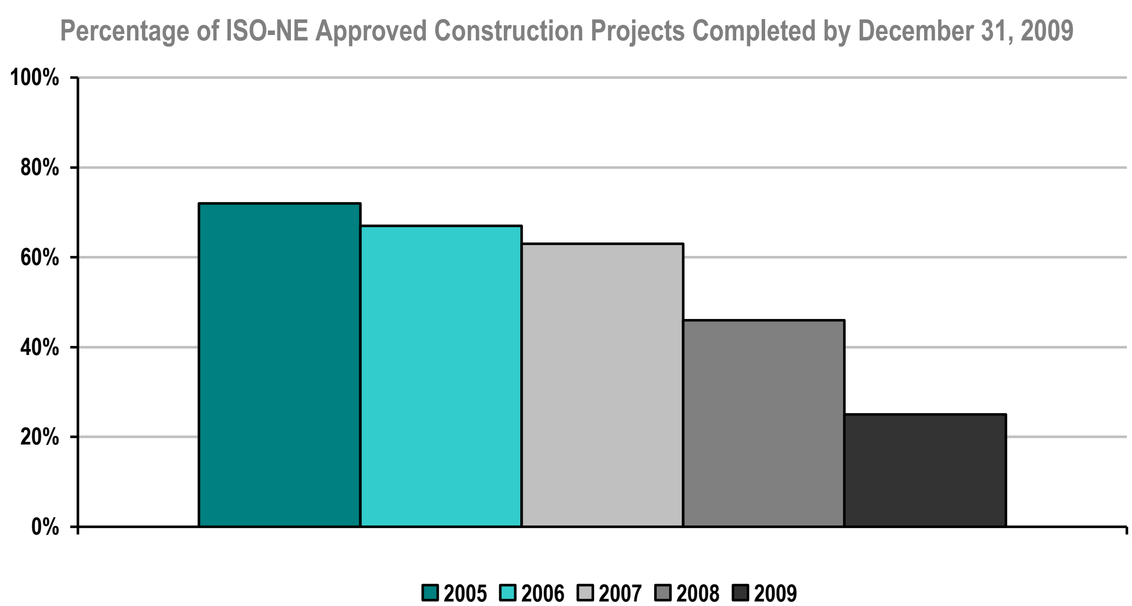
[5] The current *RSP Project List* is located at: http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/projects/index.html

[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.





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.

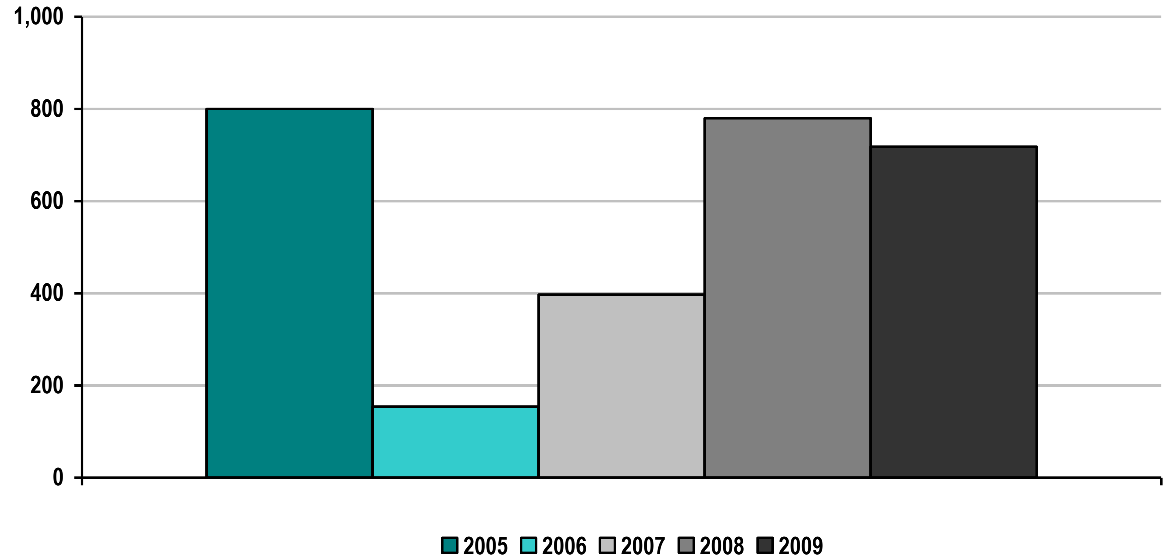
[10] *Preventing Undue Discrimination and Preference in Transmission Service, Final Rule*, FERC Order No. 890, Docket Nos. RM05-17-000 and RM05-25-000 (February 16, 2007); http://www.ferc.gov/whats-new/comm-meet/2007/021507/E-1.pdf. "Alternative Technology Regulation Pilot Program Frequently Asked Questions" 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.

ISO-NE Average Generation Interconnection Request Processing Time, 2005–2009
(Calendar Days)



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.

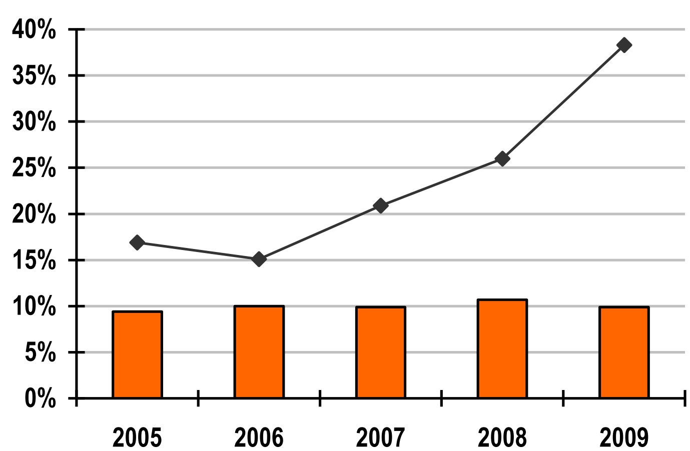
In general, a shorter processing time is preferred. The factors that contribute to the year-to-year variations in processing time include (1) the number of IRs or project withdrawals received each year, (2) the dependence of later-queued projects on earlier-queued projects, and (3) tariff requirements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

PRM MW = (NICR MW) – (Forecast Annual Peak Load MW)

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

[(PRM MW) / (forecasted annual peak load MW)] x 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 Planned	4,538 2,472	16.9 9.4
2006	Actual Planned	4,253 2,716	15.1 10.0
2007	Actual Planned	5,458 2,712	20.9 9.9
2008	Actual Planned	6,795 2,990	26.0 10.7
2009	Actual Planned	9,603 2,748	38.3 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

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[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.

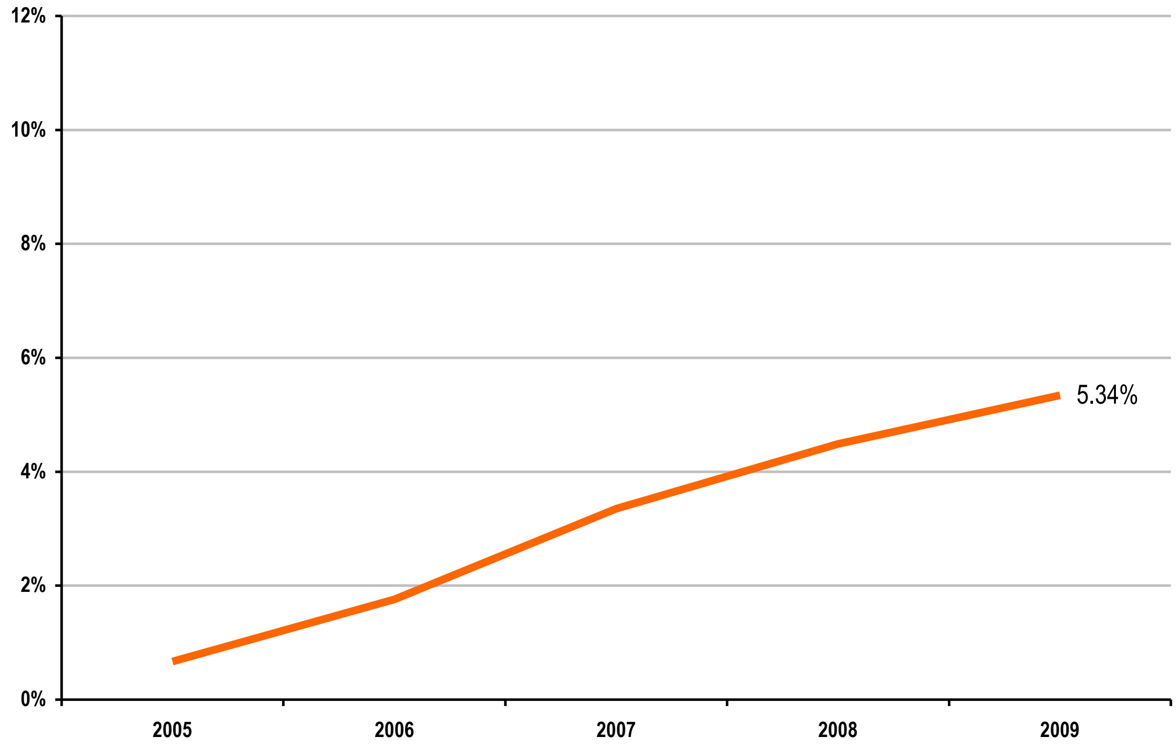
The FCM is designed to address changes in (1) the load forecast, (2) resource availability, and (3) load and capacity relief assumed obtainable by the implementation of operator actions during a capacity deficiency that occurred during the three-year period between administering the applicable FCA and 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

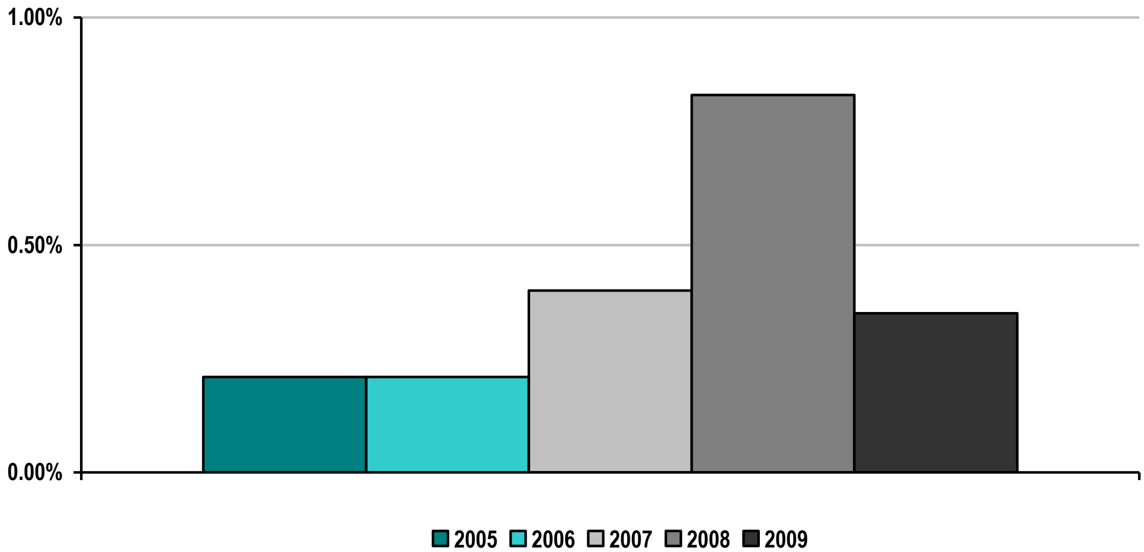


To achieve further benefits from the increase in demand resources, ISO-NE recently implemented improvements to the software and communications infrastructure used between demand resources and the ISO during real-time operations. In 2011, new dispatch rules will be in place to allow operators to call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

ISO-NE Percentage of Generation Outages Cancelled, 2005–2009



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

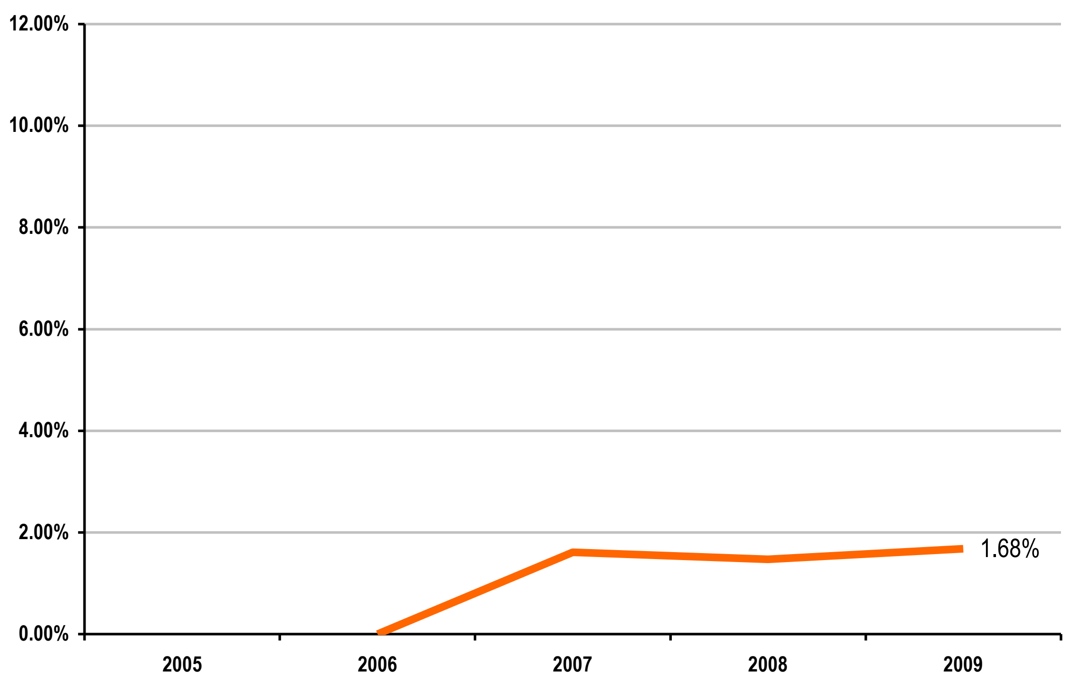
Year	Number of Units	Total MW	% of Systemwide Capacity	Total Reliability Payments
2005	14	4,719	15	$223,706,539
2006	14	6,294	19	$348,687,863
2007	9	3,203	10	$140,755,214
2008	9	3,200	10	$127,217,346
2009	8	2,711	9	$84,925,919
			Total	$925,292,881

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:

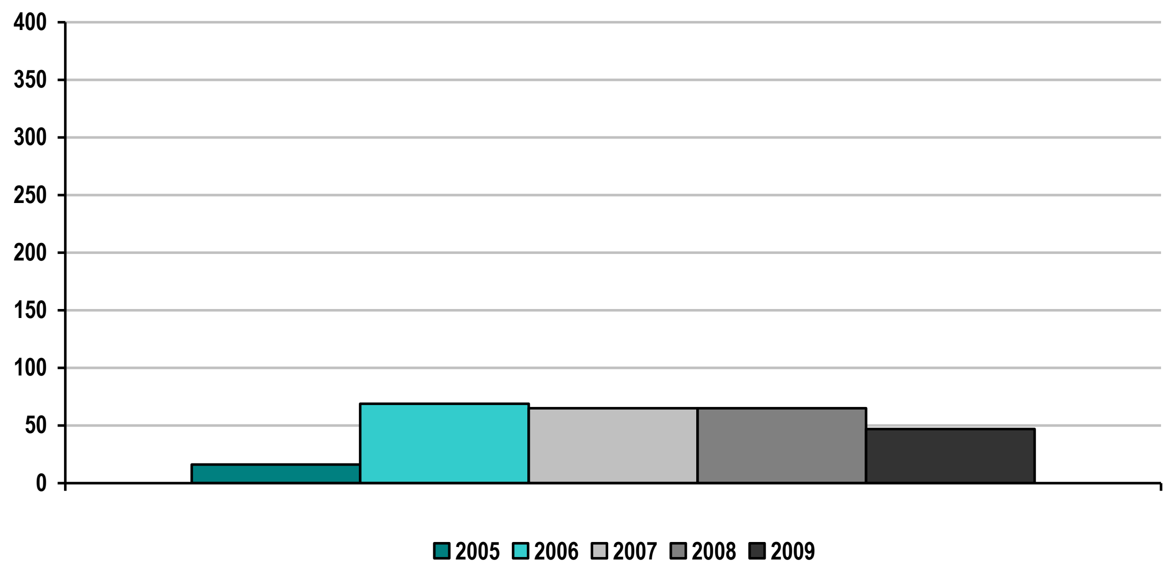
ISO-NE Demand Response as a Percentage of Synchronized Reserve Market, 2005–2009



Interconnection/Transmission Service Requests

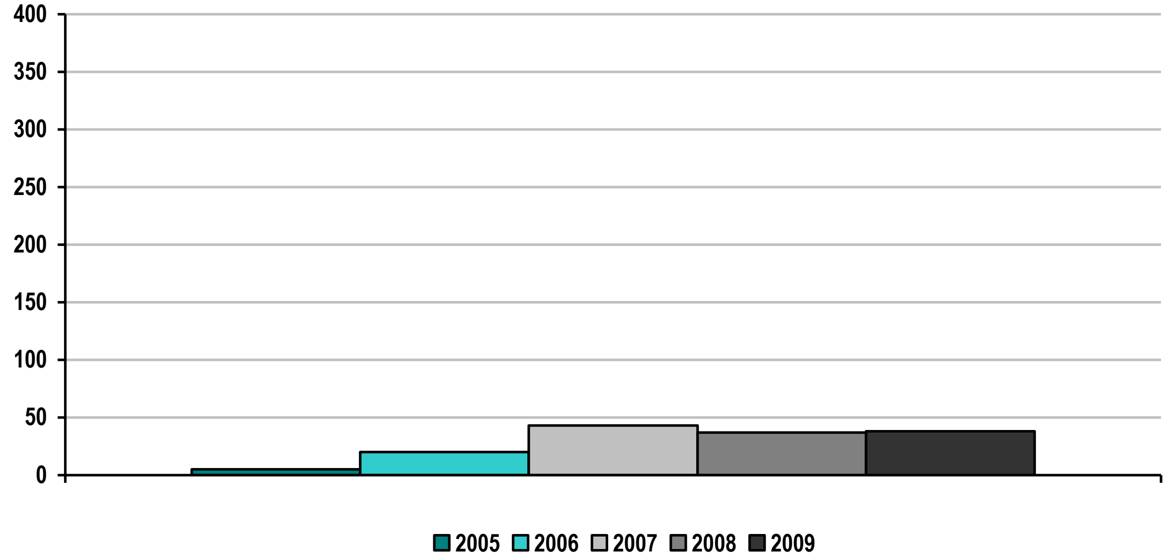
This ISO/RTO performance metric identifies the number of requests to ISO-NE for interconnection service or transmission service. The metric for the number of requests for 2005 to 2009, as shown in the following graph, was calculated by summing the number of requests ISO-NE received in a calendar year. 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



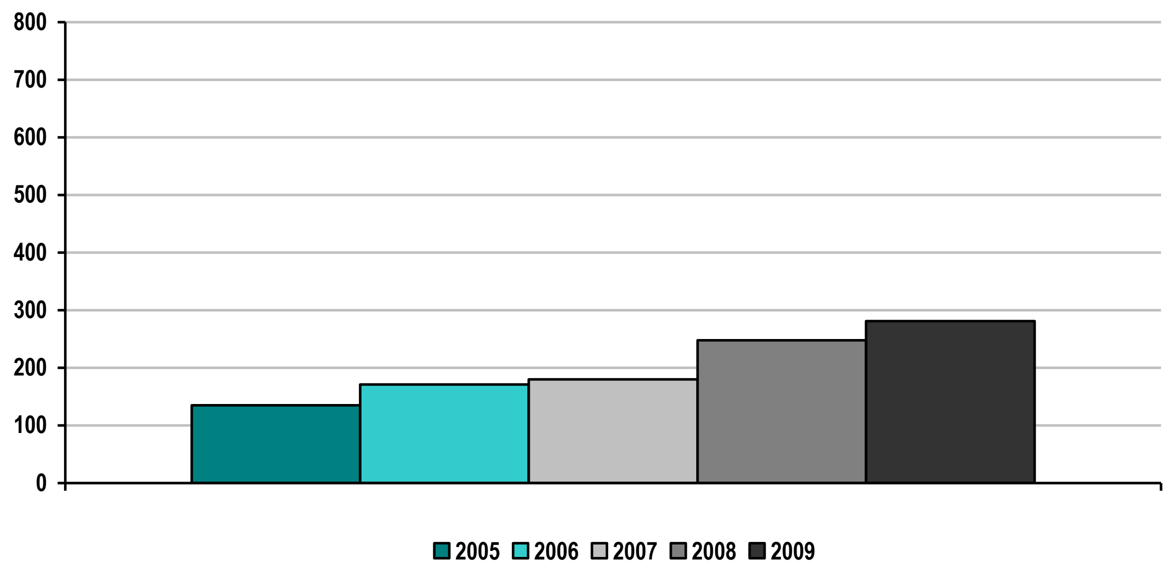
The indices in the next graph were calculated by totaling the number of studies completed in a calendar year. The studies included feasibility, system impact, and facilities studies for generation interconnection requests; elective transmission upgrade requests; and requests for transmission service 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.

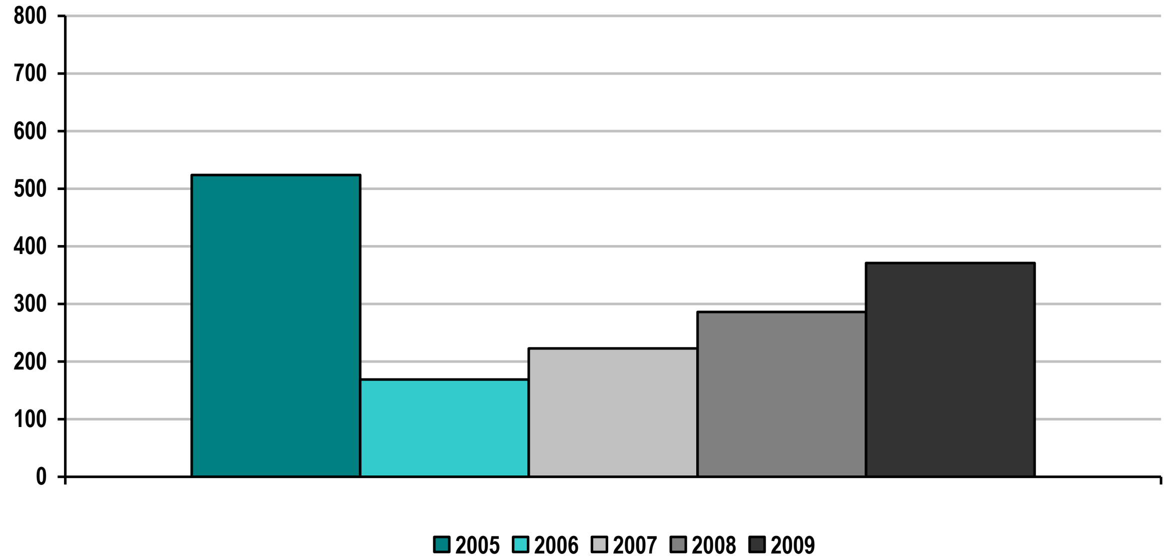
ISO-NE Average Age of Incomplete Studies, 2005–2009
(Calendar Days)



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

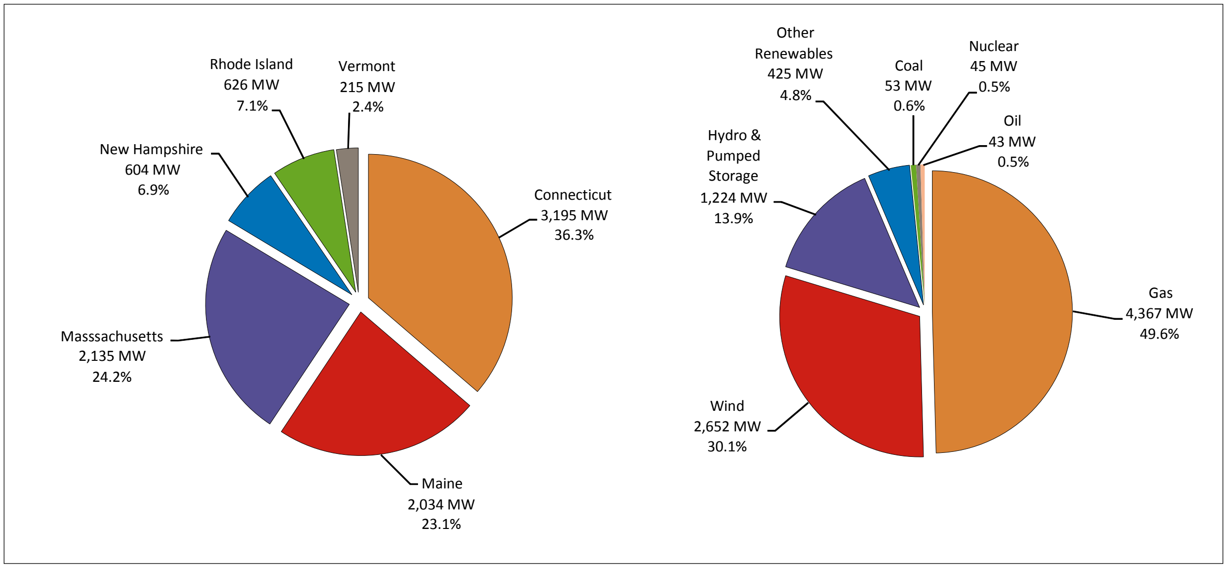
Number of Completed Facilities Studies by ISO-NE, 2005–2009

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.

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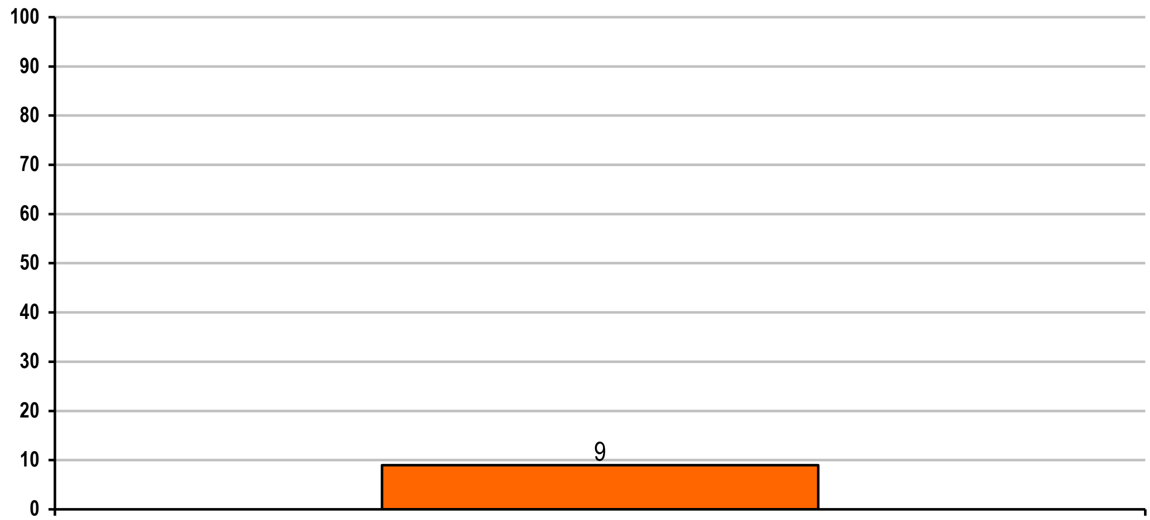
[18] ISO Planning Procedure No. 5, *Special Protection Schemes Application Guidelines* (June 22, 2009); http://www.iso-ne.com/rules_proceds/isone_plan/pp5_5_r3.pdf.

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.

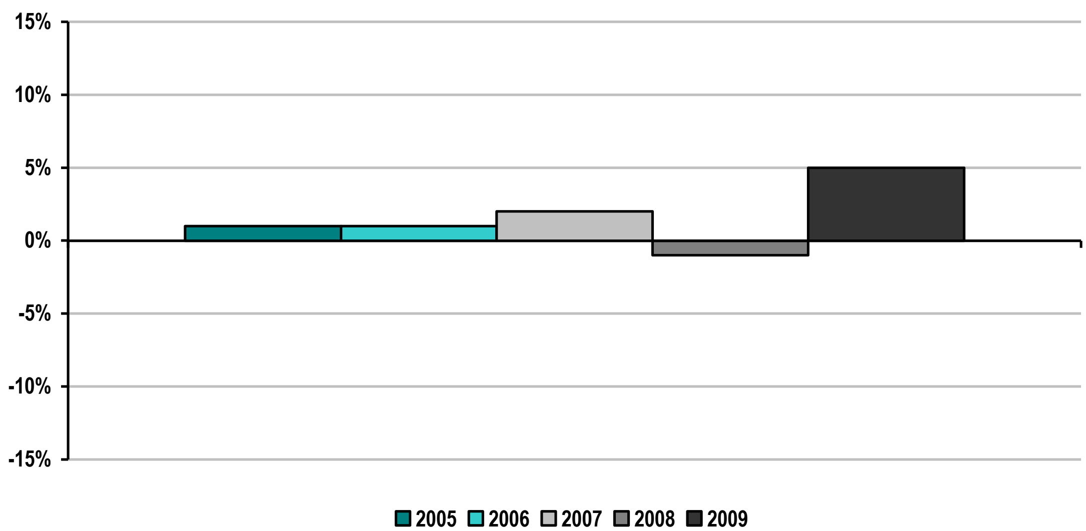
For each of the 14 months for which data are available (October 2008 through December 2009), the dollar impact of the change in billing amounts between the initial settlement and the data reconciliation settlement as a percentage of the total market value billed averaged 0.017%, or about $125,000 per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

ISO-NE Quantity-Weighted Lerner Index [(a)]



(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.

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[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.

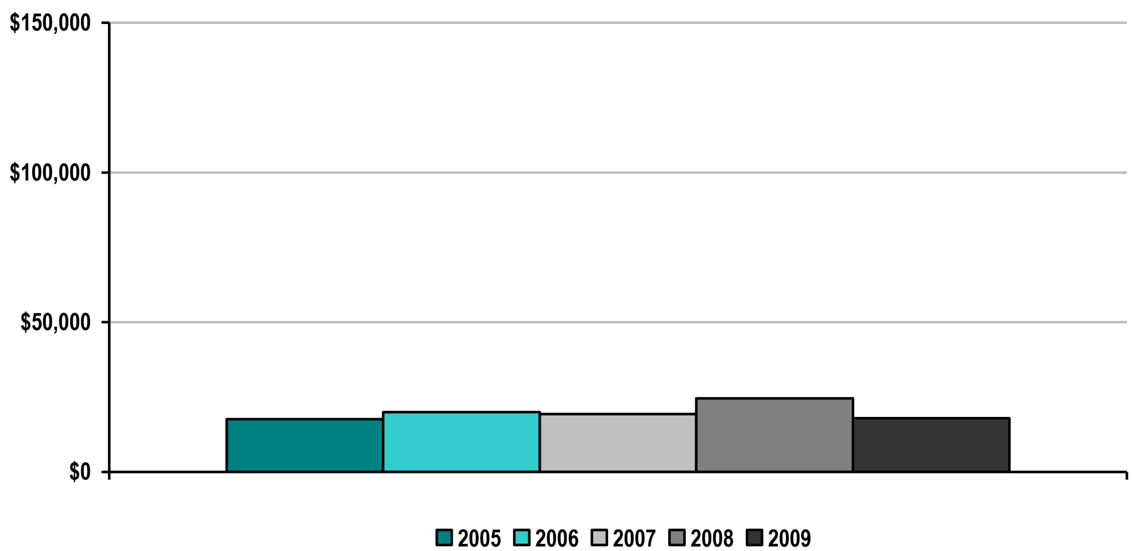
The following table presents yearly estimates of the gross margin (energy revenues minus fuel costs) earned by typical gas-fired combined-cycle (CC; also CCGT) and combustion turbine (CT) units in New England. The analysis presents the margin realized in hours when the prevailing real-time locational 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 over-estimate 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

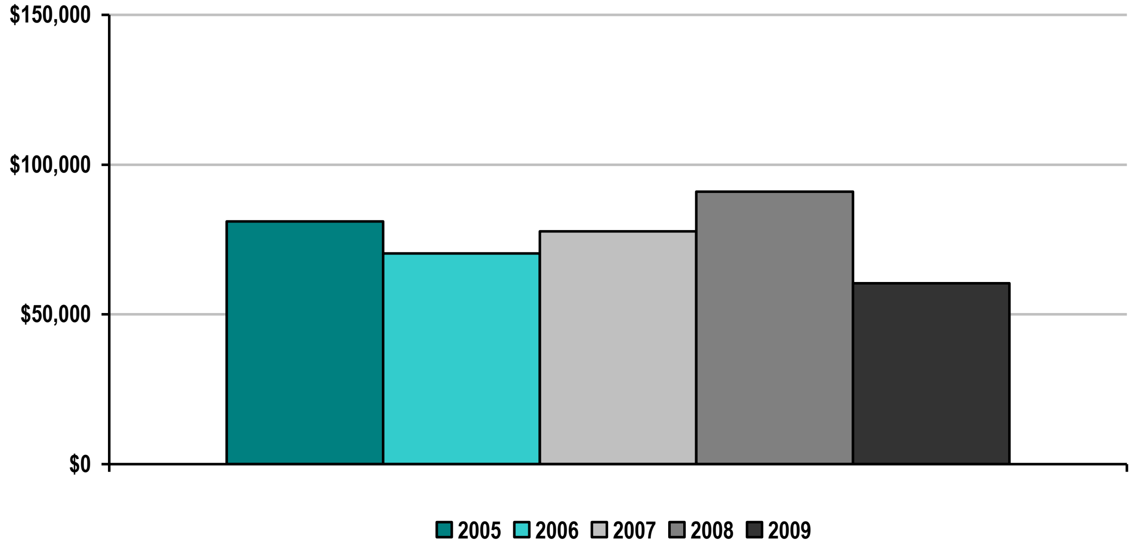
Year	Natural Gas Index ($/MMBtu[a])	Real-Time LMP ($/MWh)	Gross Margin CT ($/kW-mo)	Gross Margin CCGT ($/kW-mo)
2005	9.75	76.64	$1.47	$6.75
2006	7.40	59.68	$1.67	$5.86
2007	8.17	66.72	$1.61	$6.48
2008	10.07	80.56	$2.05	$7.58
2009	4.79	42.02	$1.50	$5.03

(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.

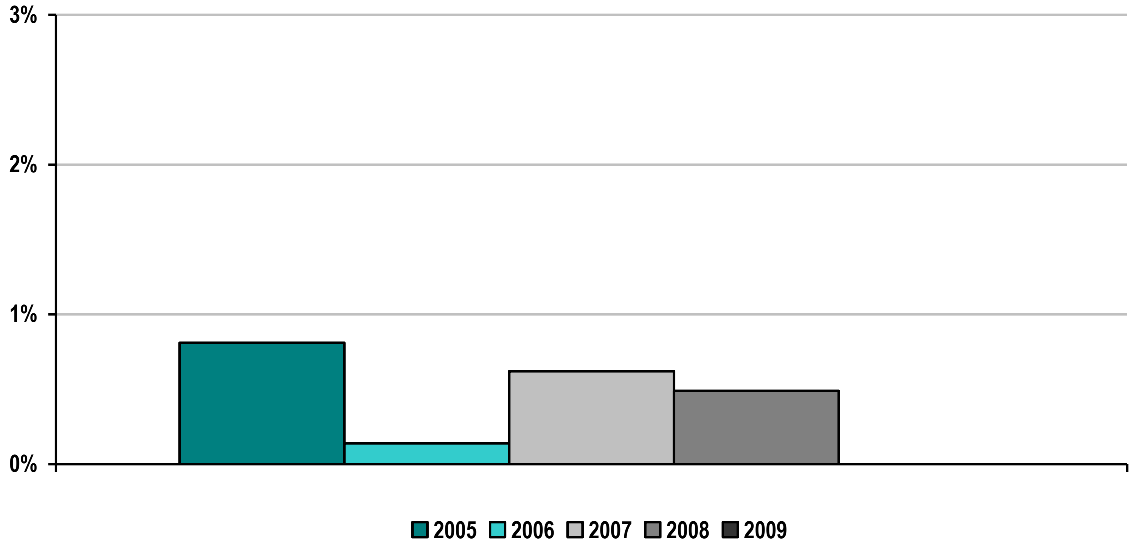
The following tables present, for each year, the number and percentage of hours that energy market mitigation in real time was imposed under the thresholds in *Market Rule 1*, Appendix A, Section 5.

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.*

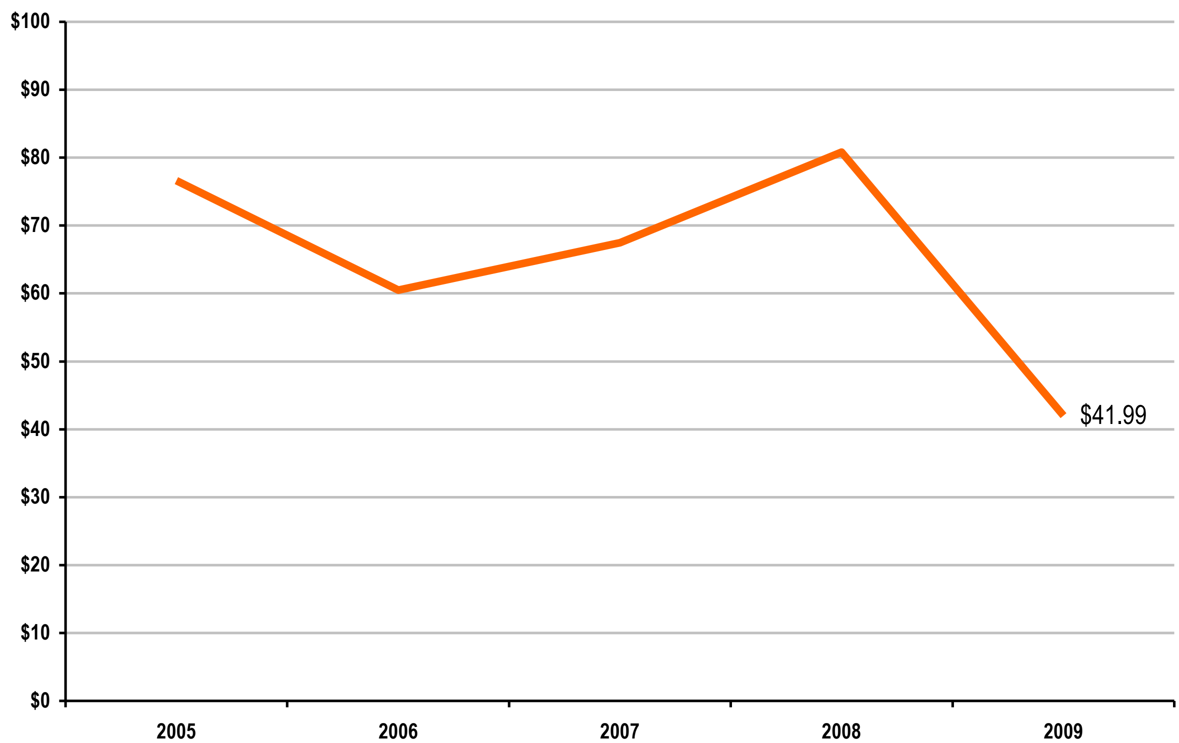
ISO-NE Real-Time Energy Market Percentage of Unit Hours Offer Capped because of Mitigation 2005–2009



Market Pricing

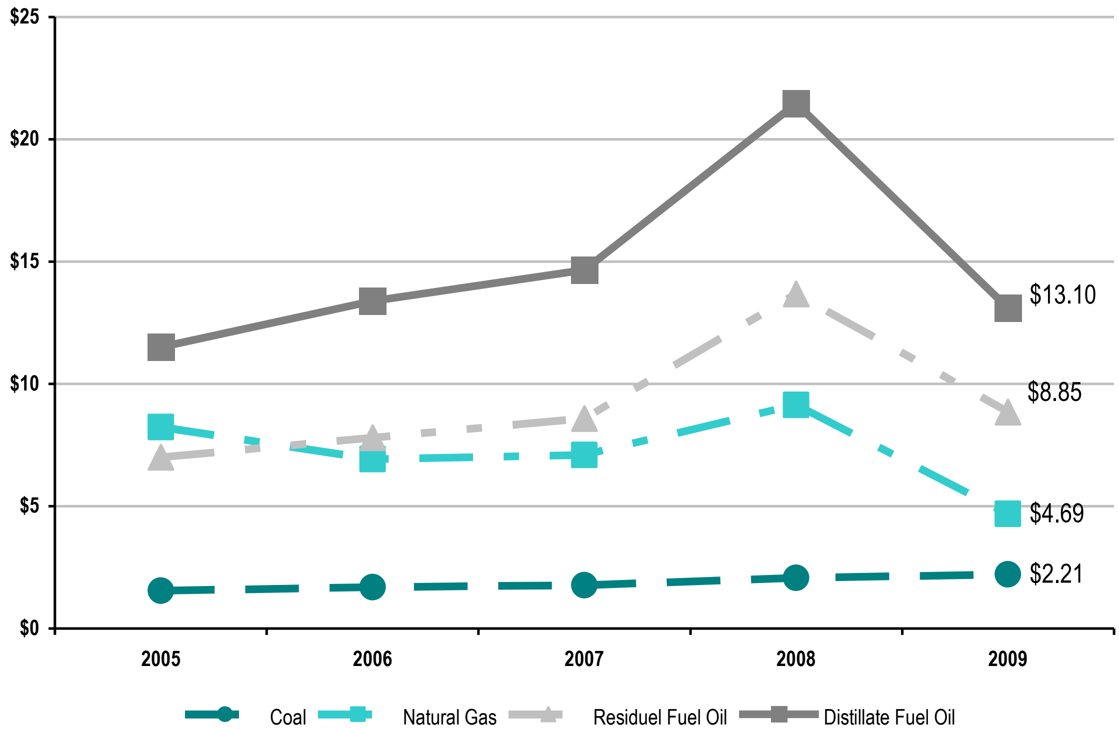
Since March 2003, the wholesale electric energy markets administered by ISO-NE have used LMPs for its transactions. These values, computed every five minutes at nearly 1,000 nodal locations, are combined using a load-weighted average to calculate zonal average LMPs for the eight load zones within the 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.

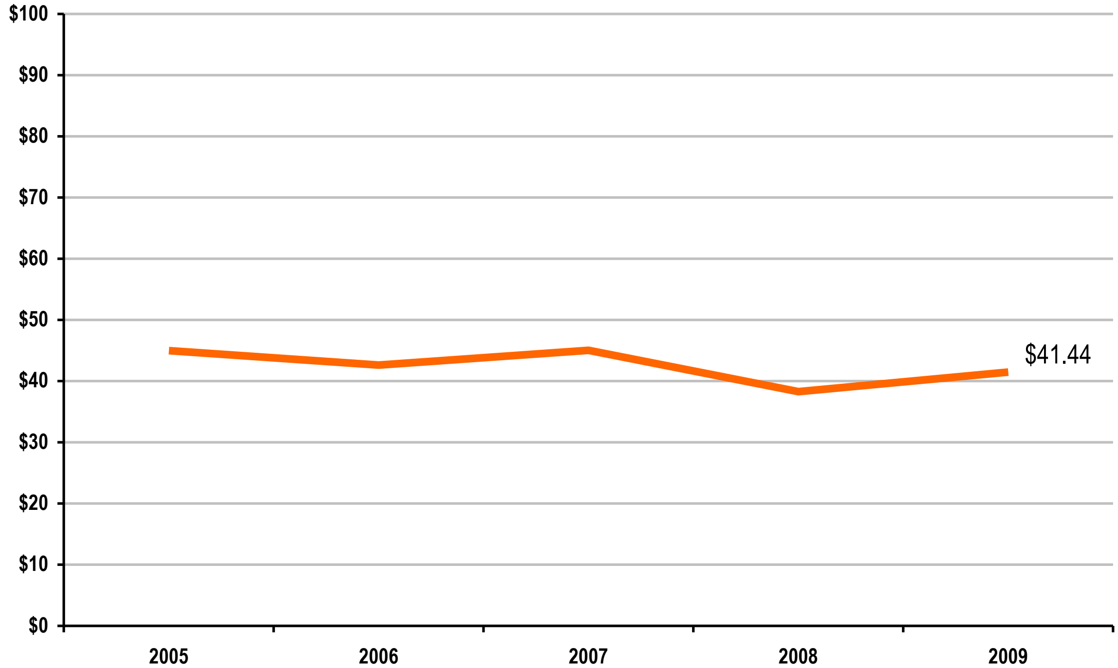
U.S. Nominal Fuel Costs, 2005–2009
($ per Million Btu)



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.

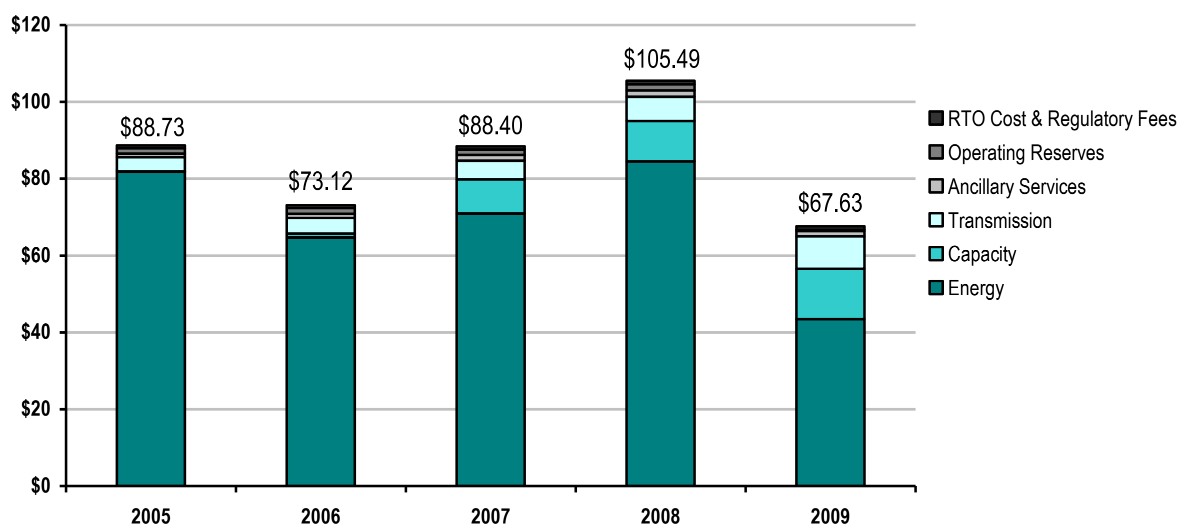
[20] *ISO New England, Inc., et al., Order on Tariff Filing*, 102 FERC ¶ 61,202 at P 19 (2003) (February 25, 2003, Order).

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.

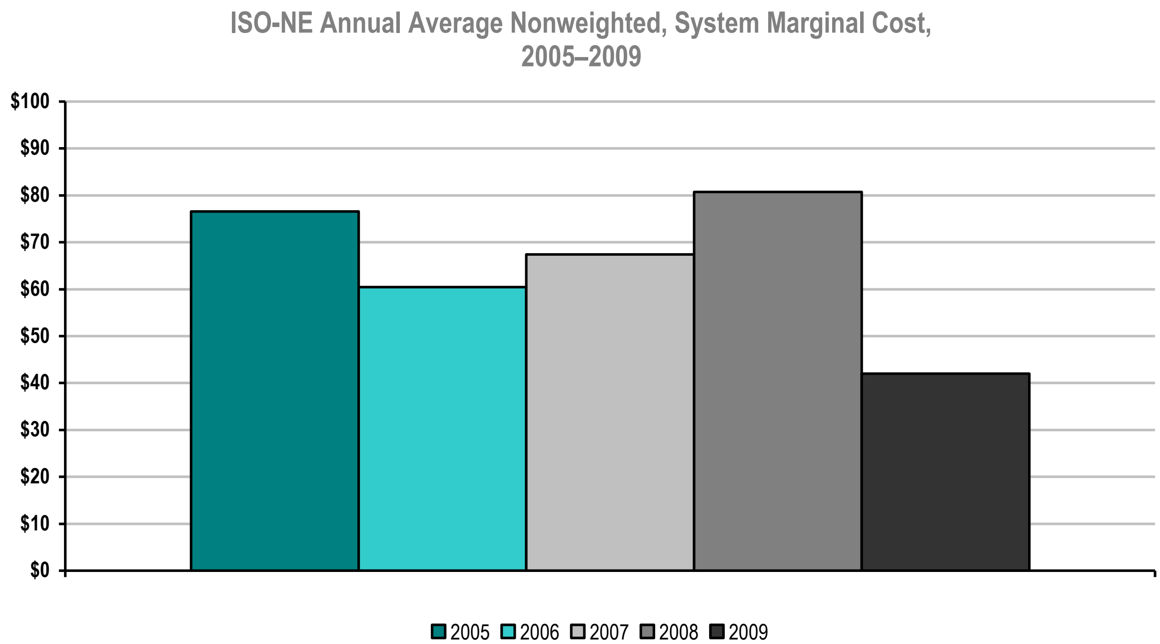
From 2005 to 2009, ISO-NE's net revenue requirements recovered through the self-funding tariff grew slightly less than 3%, from $110 million to $123.3 million. The ISO-NE net revenue requirements reflect the FERC-approved budgets adjusted for prior-year over/under collections. The increases largely reflect 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

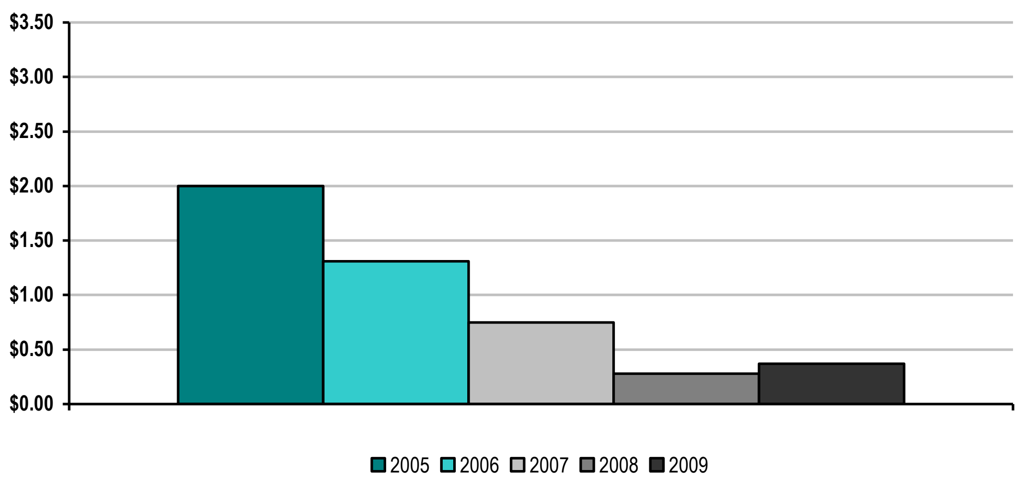
In the next graph, the hourly system price (consistent with ISO-NE's FERC Form 714 filing) for every hour in 2005 through 2009 was averaged over the entire year. Pricing in the New England wholesale markets is heavily influenced by underlying fuel prices. The values in the table reflect the movements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



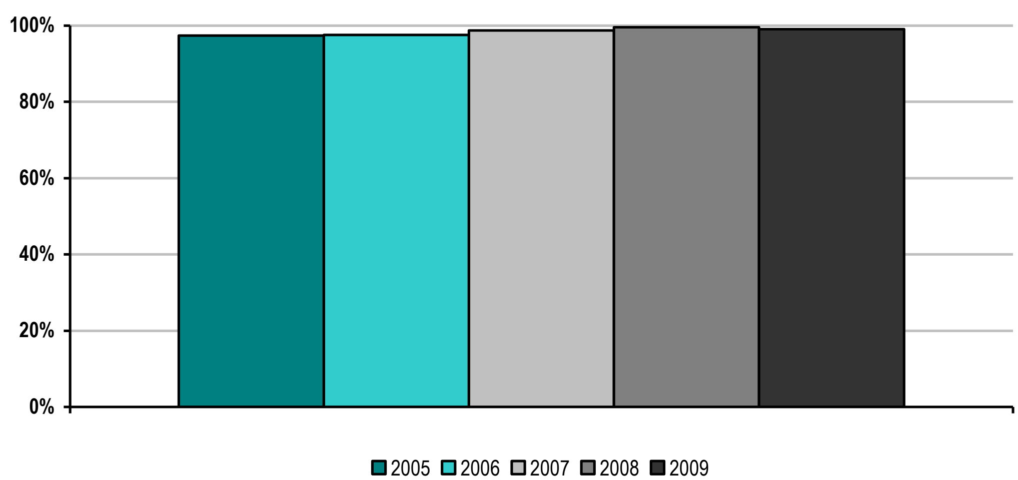
Energy Market Price Convergence

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.

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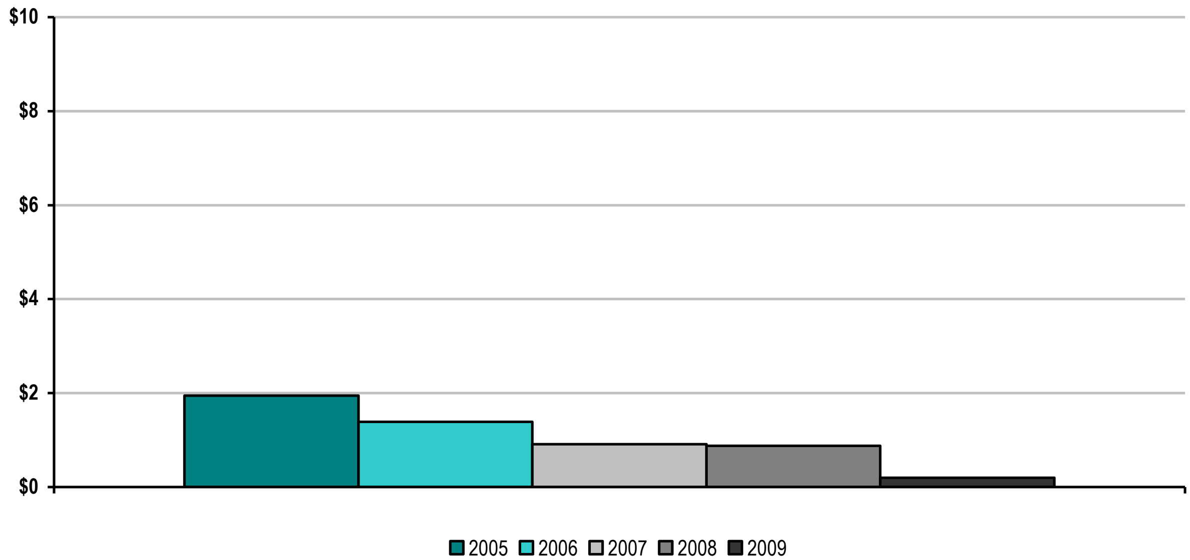
[21] See ISO-NE's RSP10, 2009 Historical Market Data: Locational Marginal Prices, Interface MW Flows (January 21, 2010); http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2010/jan212010/lmp_and_interface.pdf.

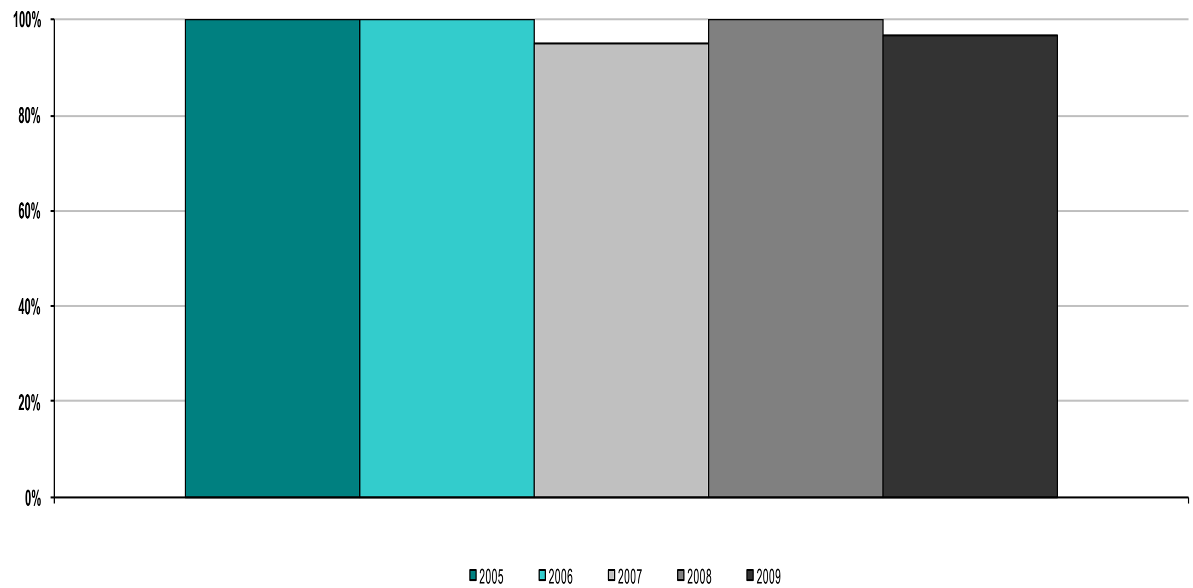
ISO-NE Annual Congestion Costs per Megawatt-Hour of Load Served, 2005–2009



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.

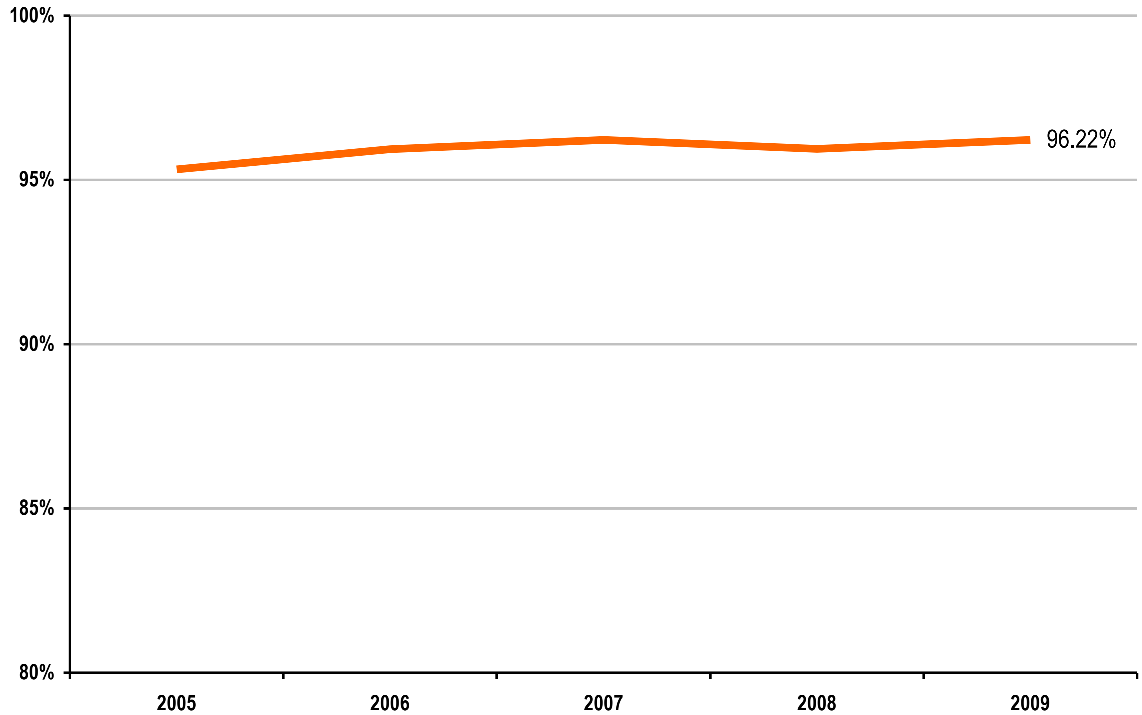
Generator Availability

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:

Generating Availability = (1 − EFORd), 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]

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[22] The most recent demand-resource availability estimates calculated by ISO-NE are available at http://www.iso-ne.com/committees/comm_wkgrps/relblty_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**

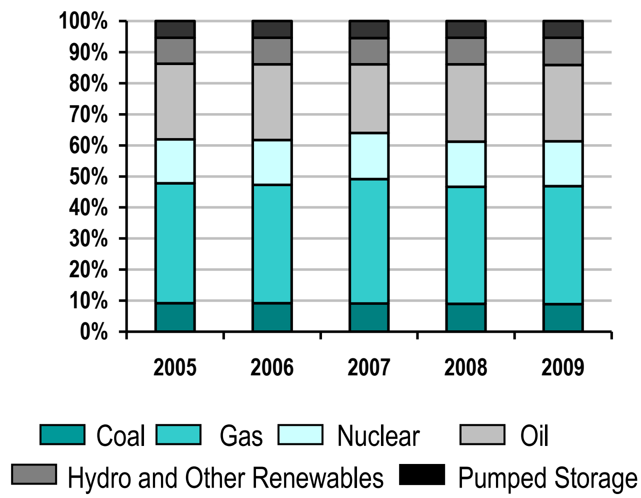
Fuel Diversity

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%)

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[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.

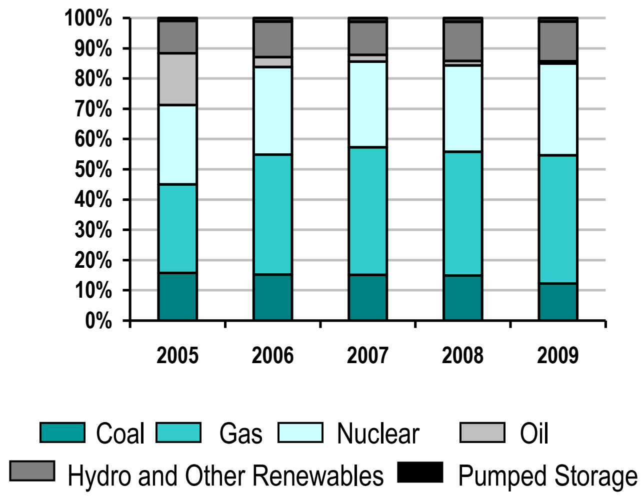
[31] The dual-fuel units in the region are reported under natural gas or oil, depending on what fuel they claim as their primary fuel type within the monthly settlement period.

[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.

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[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

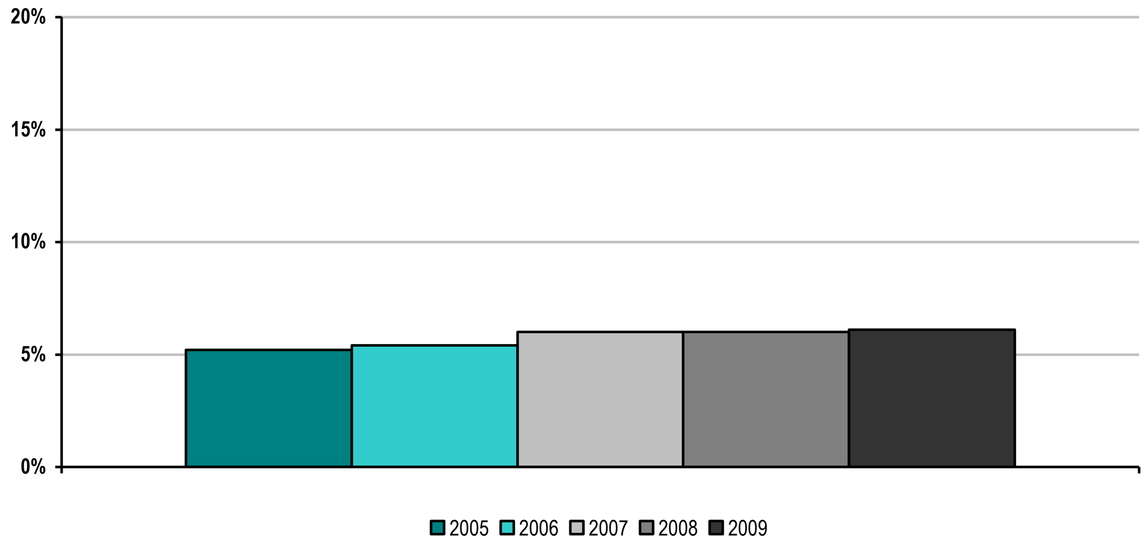
This ISO/RTO performance metric compares ISO-NE's annual amount of electric energy produced by renewable resources with the total amount of energy produced annually. To develop the information for this metric, ISO-NE compiled the historical energy production of all generating units under its dispatch 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

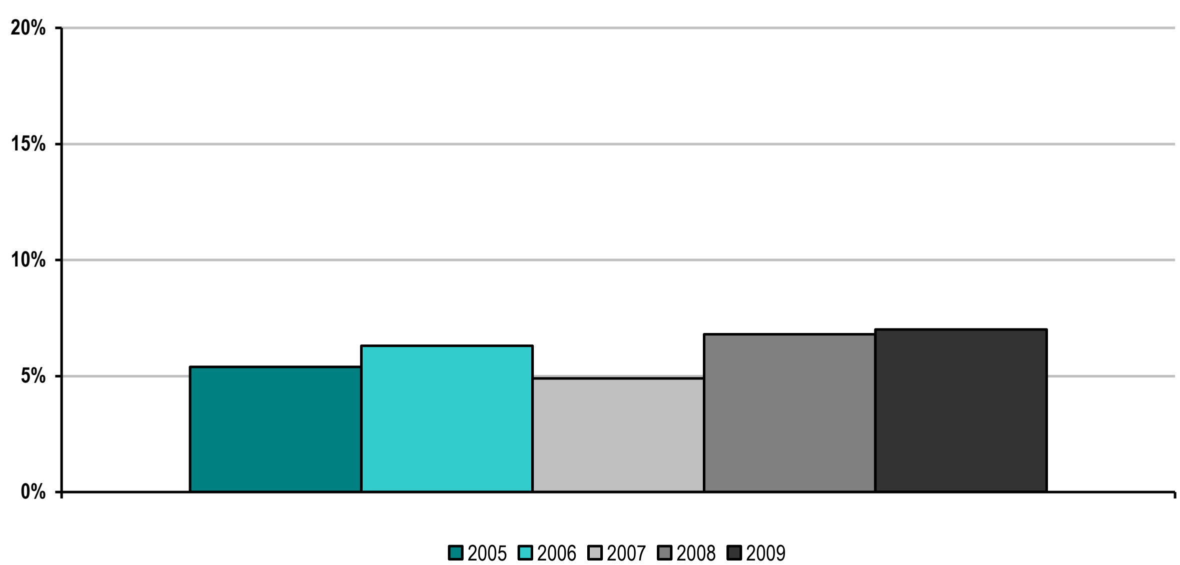
The next performance metric compares ISO-NE's annual production of hydroelectric energy with the total annual amount of energy produced. To develop the information for this metric, ISO-NE compiled the historical electric energy production of all generating units under its dispatch control for 2005 to 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.

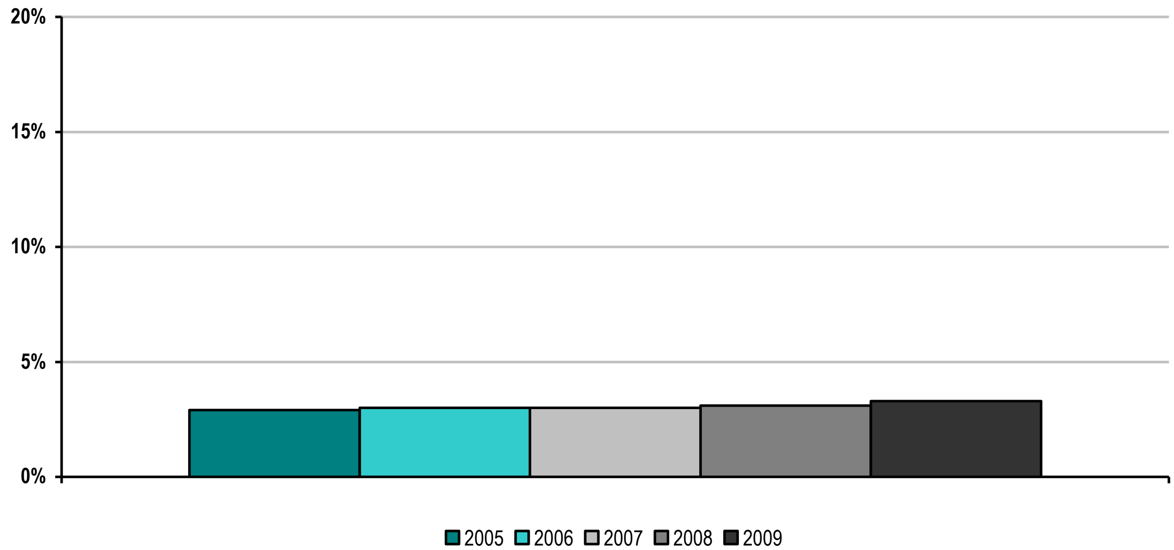
ISO-NE Capacity Provided by Renewables, 2005 to 2009

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

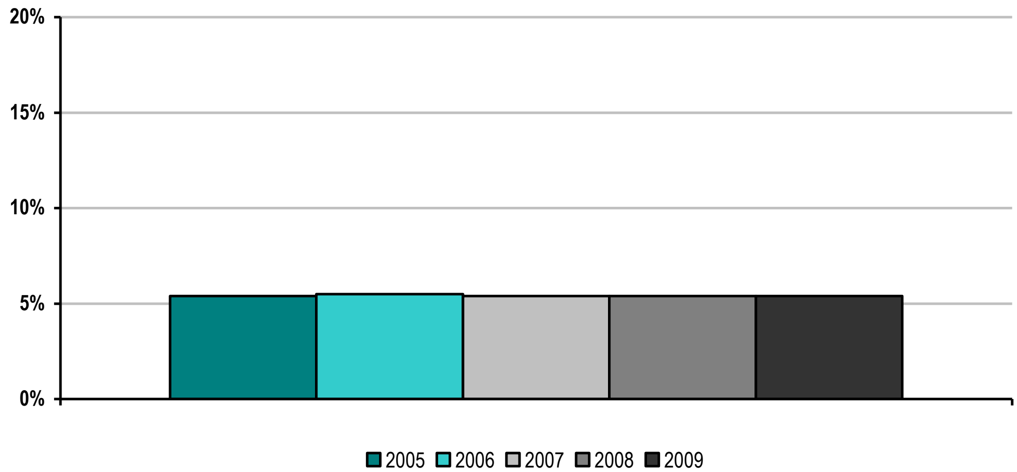
The following metric shows ISO-NE's hydroelectric summer capacity as a percentage of total summer capacity for 2005 to 2009. The following table shows all the "hydroelectric" capacity and total capacity for 2005 to 2009 and hydroelectric's percentage of total capacity for each assessment year. This information 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.

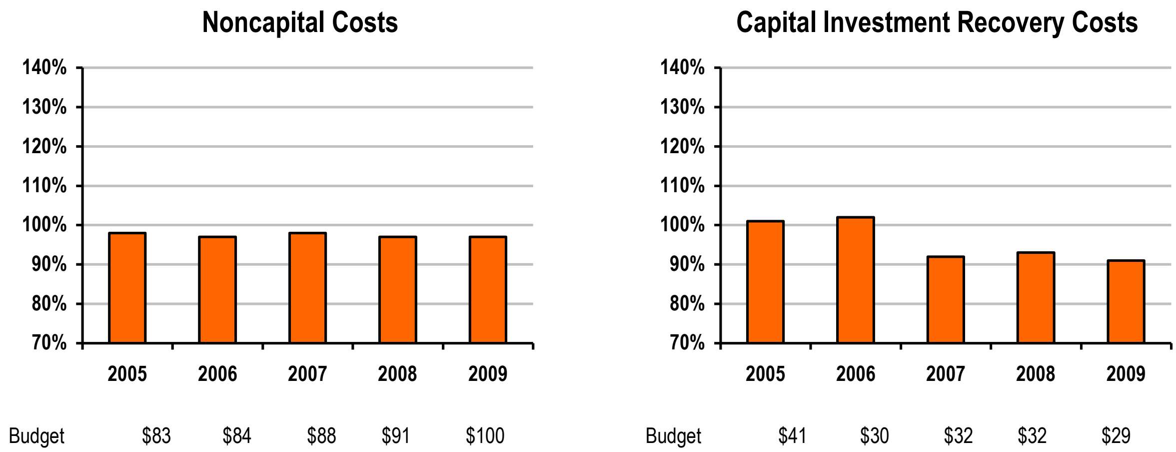
- The lowest amount of hydroelectric summer capacity occurred in 2007 at 1,648 MW, or 5.4% of the total installed summer capacity of 30,526 MW.
- As noted, five of the six New England states classify hydroelectric capacity as some form of renewable resource, mostly depending on the size of the unit and 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.

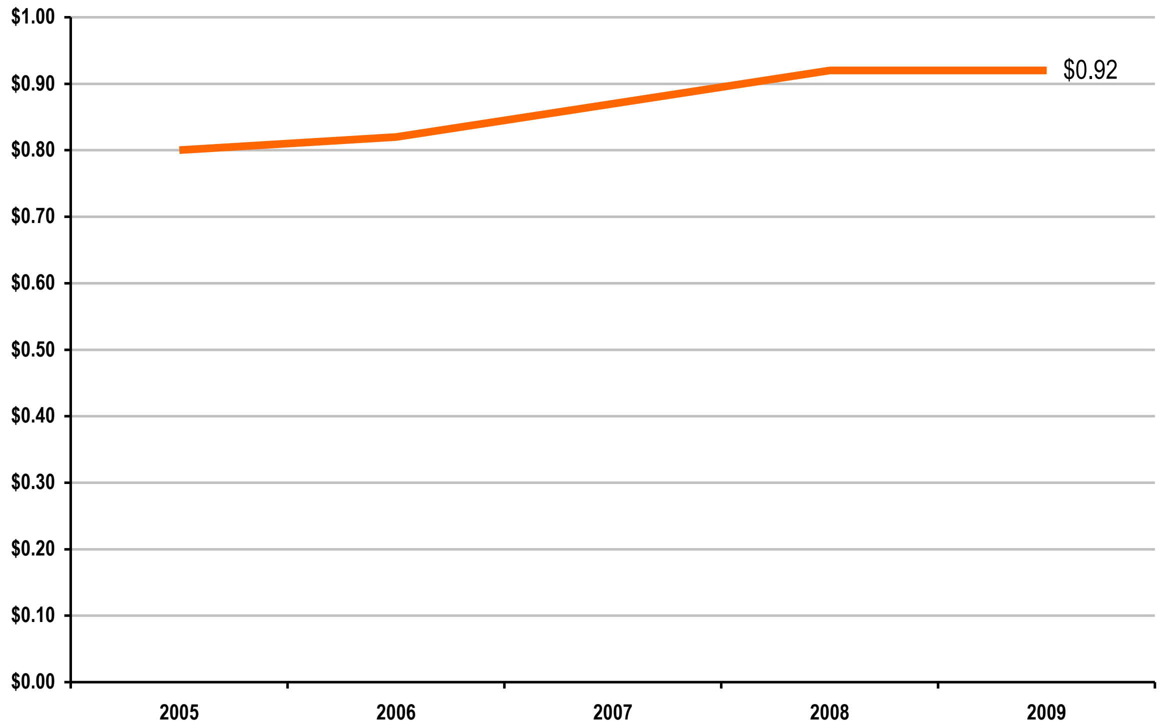
- In 2006, ISO-NE's actual expenses were 3% lower than budgeted as a result of increased interest income.
- In 2007, ISO-NE's expenses were 2% lower than budgeted as a result of a higher staffing vacancy rate and reduced communication expenses because of contract renegotiations.
- In 2008, ISO-NE's expenses 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

ISO/RTO	2009 Annual Load Served *(in TWh)*
ISO-NE	137

Customer Satisfaction

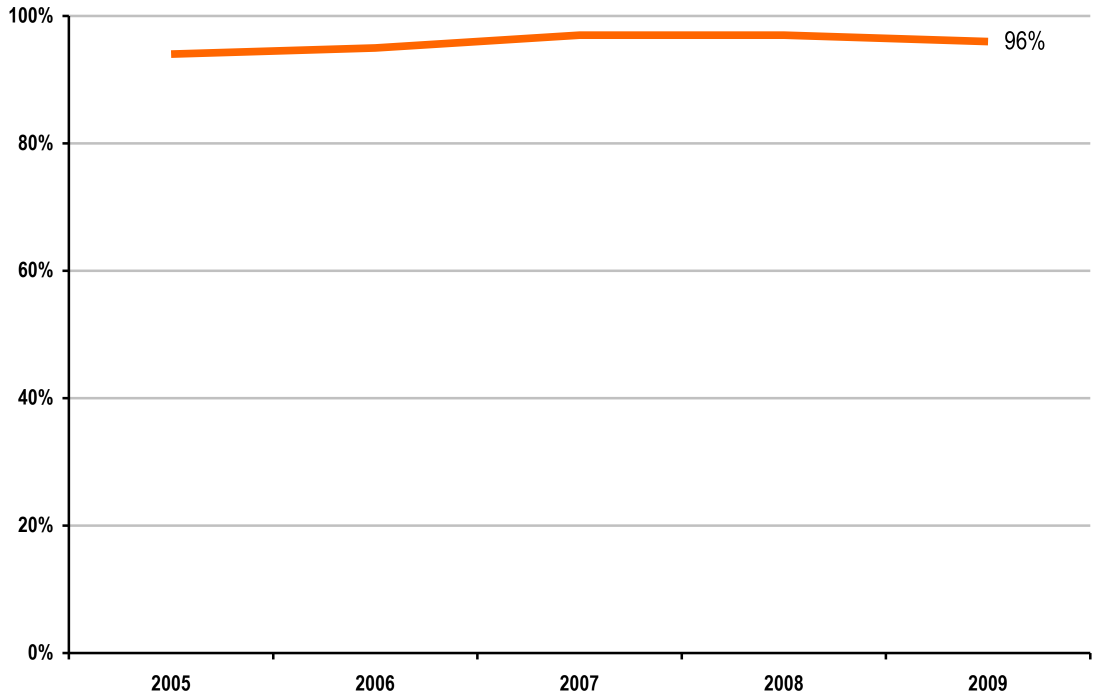
This ISO/RTO performance metric identifies customer satisfaction within the ISO-NE footprint. Since 1999, through an independent third-party administrator, ISO-NE has measured customer satisfaction with respect to its overall performance, as well as by satisfaction with its performance on service dimensions 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 competiveness 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 and12 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.

In 2009, ISO New England and regional electricity market stakeholders created the Consumer Liaison Group (CLG) to further facilitate the consideration of consumer interests in determining the needs and solutions for the region's power system and wholesale electricity markets.

Data Accuracy and Timeliness:

Pricing Accuracy: This ISO/RTO performance metric identifies ISO-NE's pricing accuracy. ISO-NE follows a rigorous process for ensuring timeliness and accuracy in its price-finalization process. Each day, the results from almost 300 five-minute cases with nearly 1,000 pricing locations in the ISO's pricing algorithm are reviewed, and corrected if necessary. Preliminary prices are posted in real time through an automated system. Prices are either confirmed or corrected for a limited and well-defined set of reasons, on average, within one business day following the operating day. ISO-NE's tariff allows up to five business days to confirm or correct prices.

The following table shows the percentage of total hours in which there were no corrections at any active nodal or zonal price location in New England.

Percentage of Total Hours that Had No Corrections at Any Active Nodal or Zonal Price Location in New England

ISO-NE	Error-Free Hours
2005	84.2%
2006	98.8%
2007	99.4%
2008	99.6%
2009	99.8%

Market Settlement Billing Accuracy: This metric includes all market products that the ISO bills (hourly and monthly markets) and assesses the percentage of inaccurate dollar billings. It also measures the accuracy of initial settlements against final settlements. Hourly markets are initially settled on a weekly basis and nonhourly markets on a monthly basis. The settlements become final after a data reconciliation period to incorporate final meter-reading values and correct any data errors within the initial settlements. The year-end metric value for the preceding 12-month period for which final settlements have been determined (2009) was 99.9875%.

Market Settlement Billing Timeliness and Frequency: ISO-NE bills its market participants on either a weekly or a monthly basis, depending on the market service. The hourly energy and ancillary services markets amounts are computed and distributed each business day, with a bill rendered weekly on Monday. The Transmission Tariff (and related services) and capacity markets are billed monthly in arrears on the first Monday following the tenth of the month. The following table presents statistics that show the time, in calendar days, between the close of the market day and the time the settlement is issued for the hourly energy markets.

Average Days to Settle the ISO-NE Hourly Energy Markets, 2005–2009

Year	Average Days to Settle Day-Ahead Energy Market	Average Days to Settle Real-Time Energy Market
2005	5.1	7.2
2006	3.6	6.3
2007	3.4	6.3
2008	2.8	4.4
2009	2.6	4.0

In January 2011, ISO-NE will move from a once-weekly bill on to a twice-weekly billing approach. This change will move funds through the ISO-NE's systems faster, at the same time reducing financial assurance obligations for market participants.

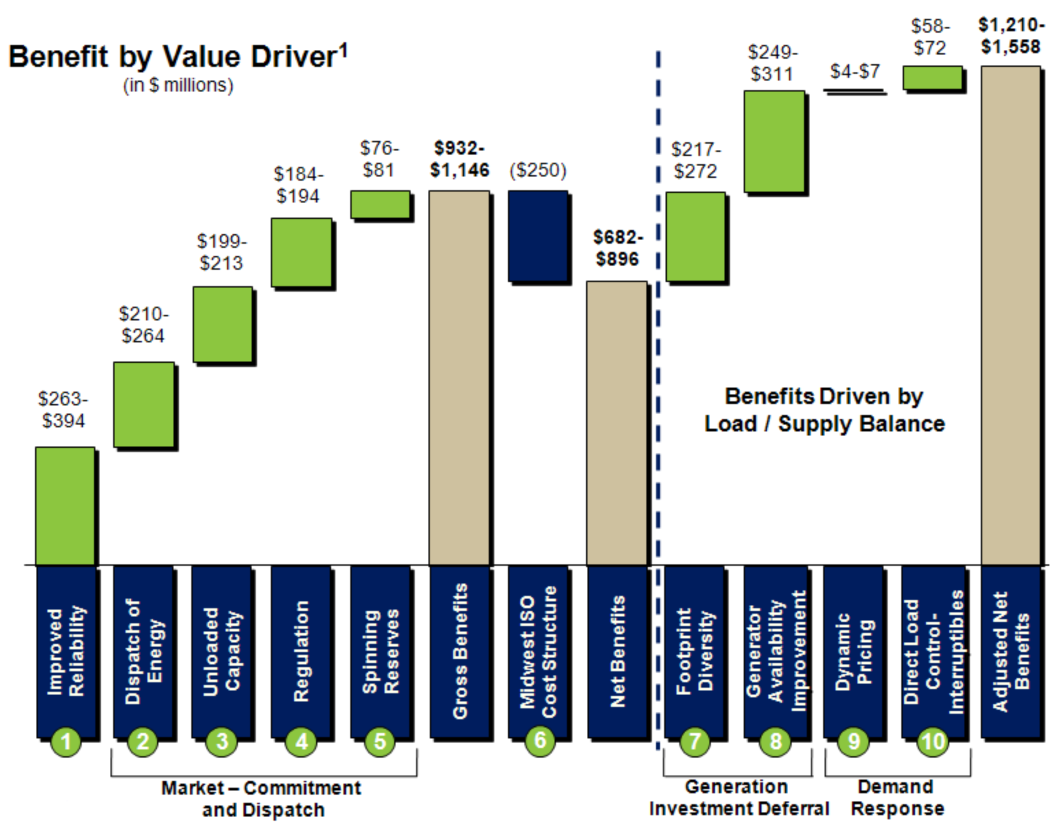
Midwest Independent Transmission System Operator (Midwest ISO)

Section 4 – Midwest ISO Performance Metrics and Other Information

On December 19, 2001, the Midwest Independent Transmission System Operator, Inc. ("Midwest ISO") became the nation's first permanent Regional Transmission Organization to be approved by the Federal Energy Regulatory Commission ("FERC"). 34 transmission owners with approximately 93,600 miles of transmission lines and generation owners with 145,570 megawatts of electrical generation are currently participating in the Midwest ISO.

On December 15, 2001, the Midwest ISO began providing reliability coordination services to the transmission-owning members of the Midwest ISO and their customers. On the same date, the Midwest ISO also began providing operations planning, generation interconnection, maintenance coordination, long-term regional planning, market monitoring, and dispute resolution services. On February 1, 2002, the Midwest ISO began providing regional transmission service under its FERC-accepted Tariff. On April 1, 2005, the Midwest ISO began operating a market-based, congestion management system which included a Day-Ahead and Real-Time energy market and a Financial Transmissions Rights market. On January 6, 2009, the Midwest ISO began operating a market for ancillary services and became a NERC-certified Balancing Authority.

The Midwest ISO Value Proposition demonstrates the quantifiable value we deliver to our region through increased efficiencies in market operations, reliability and planning. Our 2009 Value Proposition demonstrates between $700 and $900 million in annual net benefits to our region.



A. Midwest ISO Bulk Power System Reliability

As of December 31, 2009, the Midwest ISO was registered with NERC and three Regional Reliability Organizations. The table below identifies which NERC Functional Model registrations the Midwest ISO has submitted as effective as of the end of 2009. Additionally, the Regional Entities for Midwest ISO are noted at the end of the table with a link to the websites for the specific reliability standards.

Violations of these standards are subject to potential violations findings by NERC. Violations could be identified via an investigation, self-report or audit. Each of these methods has a defined process by which NERC or the RRO would go through to validate that a violation had occurred and to publically announce that violation. As of the end of 2009, NERC had made no such violation announcement with regard to any Midwest ISO operation including operating reserve standards. The Midwest ISO has not shed any load in the Midwest ISO Region due to a standards violation.

NERC Functional Model Registration	Midwest ISO
Balancing Authority	✓
Interchange Authority	✓
Planning Authority	✓
Reliability Coordinator	✓
Resource Planner	
Transmission Operator	
Transmission Planner	
Transmission Service Provider	✓

Regional Entities	Reliability*First*, MRO and SERC

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 Reliability*First* Board are available at:
http://www.rfirst.org/Standards/ApprovedStandards.aspx

Additional standards approved by the MRO Board are available at:
http://www.midwestreliability.org/STA_approved_mro_standards.html

Additional standards approved by the SERC Board are available at:
http://www.serc1.org/Application/ContentPageView.aspx?ContentId=111

Dispatch Operations

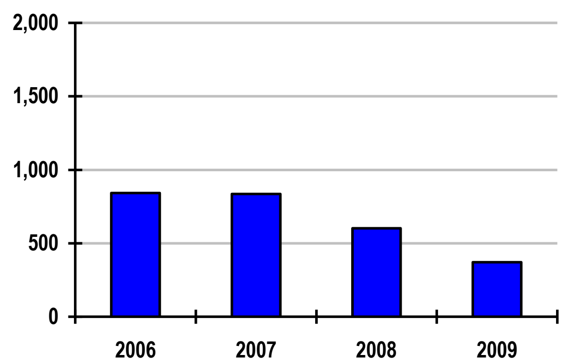
Midwest ISO CPS-1 Compliance 2009

Each Balancing Authority is responsible for complying with CPS-1 standards. The Midwest ISO became a Balancing Authority on January 6, 2009 with the start of the Ancillary Services Market. As such, Midwest ISO's compliance tracking started in 2009. Compliance with CPS-1 requires at least 100% throughout a 12-month period. At 137.8%, the Midwest ISO was in compliance with CPS-1 for 2009.

Midwest ISO CPS-2 Compliance 2009

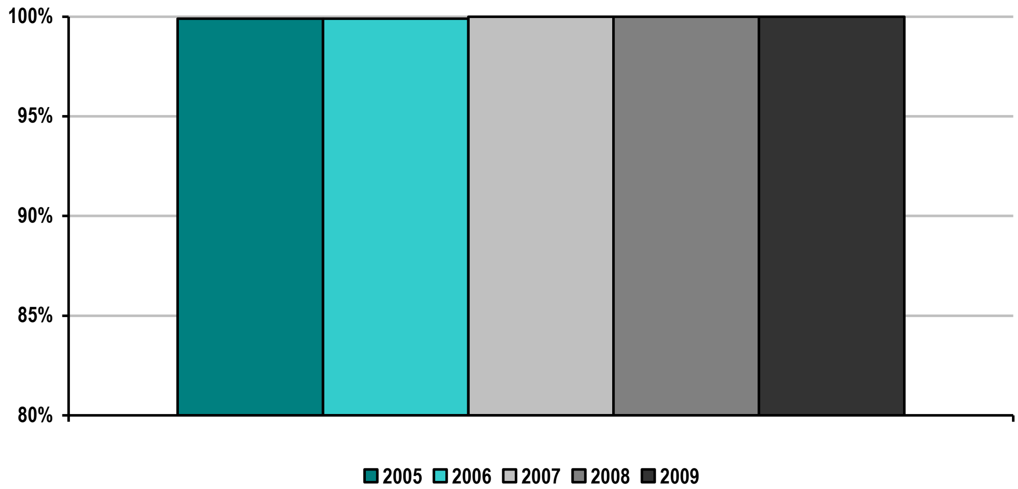
Each Balancing Authority is responsible for complying with CPS-2 standards or alternatively for complying with the Balance Authority Ace Limit (BAAL) which is currently being evaluated by NERC as a potential replacement for CPS-2. The Midwest ISO is participating in the NERC field test of the BAAL standard and hence monitors against that standard. The Midwest ISO became a Balancing Authority on January 6, 2009 with the start of the Ancillary Services Market. As such, Midwest ISO's compliance tracking started in 2009. For 2009, the Midwest ISO did not have any violations of the standard.

Midwest ISO Transmission Load Relief or Unscheduled Flow Relief Events 2005-2009



The Midwest ISO's data reflects the number of Transmission Load Relief (TLR) events. The Midwest ISO's TLR events were comprised of primarily level 3, and 4 events with level 5 events of 4%, 5%, 4% and 10% in 2006 through 2009. The reduction in TLRs for 2008 and 2009 is due to several factors including system reinforcements, lower load levels, and market operation. Primarily non-firm curtailments, the monthly average curtailments in MWh were 151,842; 87,090; 111,550; and 76,541 in 2006 through 2009. The Midwest ISO does not have readily accessible data for 2005.

Midwest ISO Energy Market System Availability 2005-2009



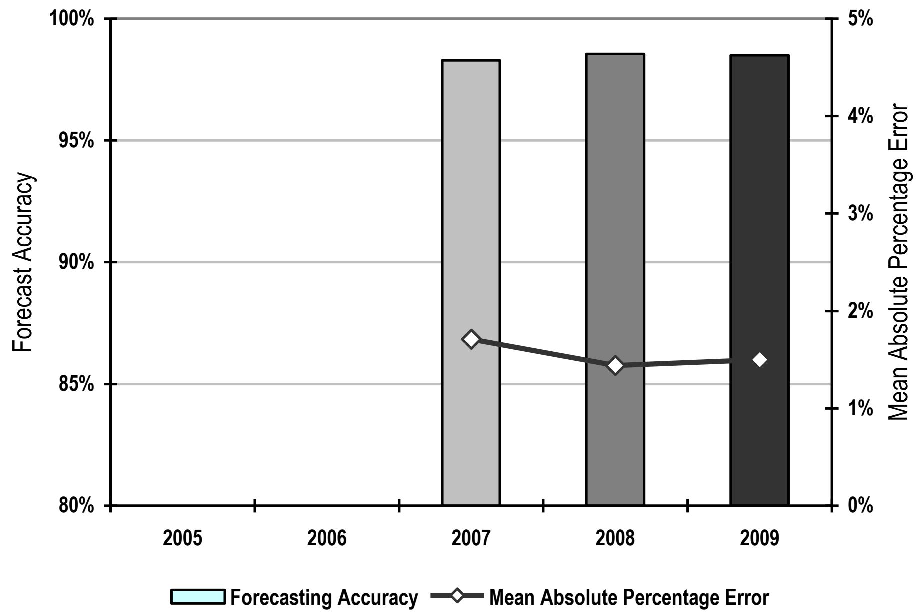
Availability of the Energy Management System (EMS) is key to reliable monitoring of the electric transmission system in the Midwest ISO Region. For the past five years, Midwest ISO's EMS has been available 99.9% or greater of all hours in each year.

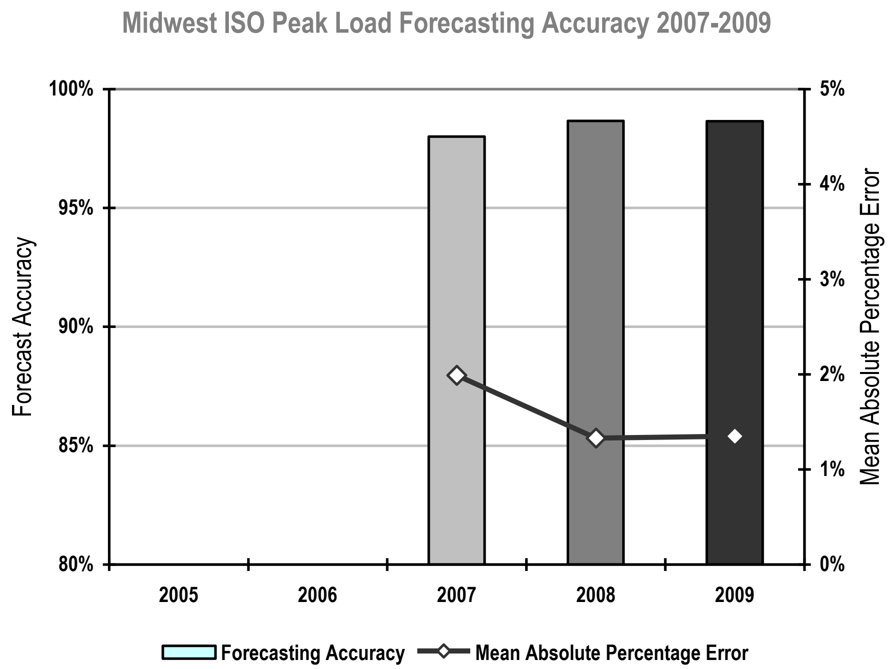
Load Forecast Accuracy

The Midwest ISO monitors load forecasting accuracy with regards to several different time reference points. The Midwest ISO's load forecasting accuracy has been relatively steady over the last 3 years. The day-ahead load forecasting accuracy reference point is 4:30 p.m. of the prior day and is the reference point for the data shown below. Load forecasting data is not available for 2005 and 2006. In the future, the Midwest ISO will retain the additional periods requested for this report.

The day-ahead load forecast does not account for the impact of interruptible load and demand response resources. Interruptible loads and DRR have an immaterial effect on the forecast considering the size of the Midwest ISO load.

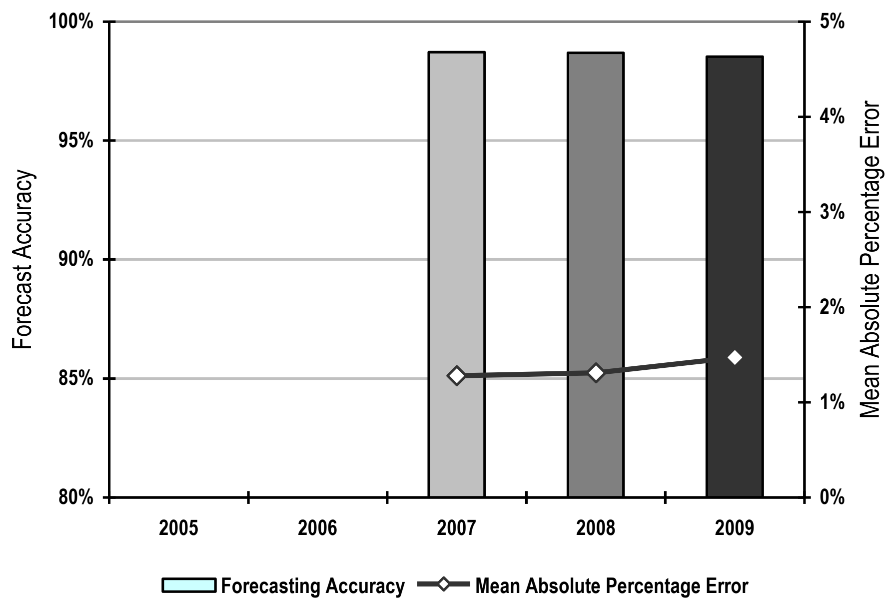
Midwest ISO Average Load Forecasting Accuracy 2007-2009





While the Midwest ISO does not procure capacity on behalf of Load Serving Entities (LSE), the peak demand forecasts created and submitted by each LSE directly determines the amount of capacity that each LSE must designate (potentially procure if short) to meet their planning resource obligations. If a LSE under forecasts its peak demand this would result in the LSE under designating (or procuring) capacity which could result in potential reliability issue. Alternatively, when an LSE over forecasts its peak demand, it will over designate (or procure) its capacity. This results in inefficient capacity procurement.

Midwest ISO Valley Load Forecasting Accuracy 2007-2009



Wind Forecasting Accuracy

The Midwest ISO's wind forecasting accuracy for 2009 was 92.83%. Wind forecasting accuracy data prior to 2009 is not available. Wind forecasting accuracy is calculated using an industry-wide methodology called Mean Absolute Error (MAE). The MAE is the average of the absolute value of the difference between forecasted and actual wind power output and is expressed as a percent of installed wind nameplate capacity. The wind forecasting accuracy is represented as one minus MAE.

The wind forecasting calculation methodology differs from the calculation methodology used for the load forecasting accuracy metric because the wind forecasting calculation methodology expresses the absolute error value as a percent of installed wind nameplate capacity whereas the load forecasting calculation methodology expresses the absolute error value as a percent of total forecasted load. The wind forecasting calculation methodology "softens" the true error in forecasting.

The Midwest ISO is continuing to explore methods for improving the accuracy of its wind forecasting, but our current accuracy appears to be consistent with the accuracy obtained in other regions throughout the world.

Unscheduled Flows

Midwest ISO 2009 Absolute Value of Total Unscheduled Flows

The Midwest ISO had an absolute value of 38 terawatt hours of unscheduled flows in 2009. This unscheduled flow occurred over 23 external interfaces. The Midwest ISO is reporting data starting on January 6, 2009 when its Ancillary Services Market started and a new scheduling system was introduced. The Midwest ISO replaced its scheduling system during that transition. While the data from that system has been retained, access to the data in this type of configuration is not readily available.

Midwest ISO 2009 Absolute Value of Unscheduled Flows as a Percentage of Total Flows

The Midwest ISO's absolute value of total hours of unscheduled flows as a percentage of total flows was 7.1% in 2009. As previously mentioned, the Midwest ISO is reporting data starting on January 6, 2009 when its Ancillary Services Market started and a new scheduling system was introduced. The Midwest ISO replaced its scheduling system during that transition. While the data from that system has been retained, access to the data in this type of configuration is not readily available.

Unscheduled flows for the top five interfaces are shown in the table below:

Midwest ISO Unscheduled Flows by Interface	**2009** *(in terawatt hours)*
PJM	(7)
Ohio Valley Electric Cooperative	(6)
Electric Energy, Inc.	5
Tennessee Valley Authority	4
Ontario Independent Electricity System Operator	3

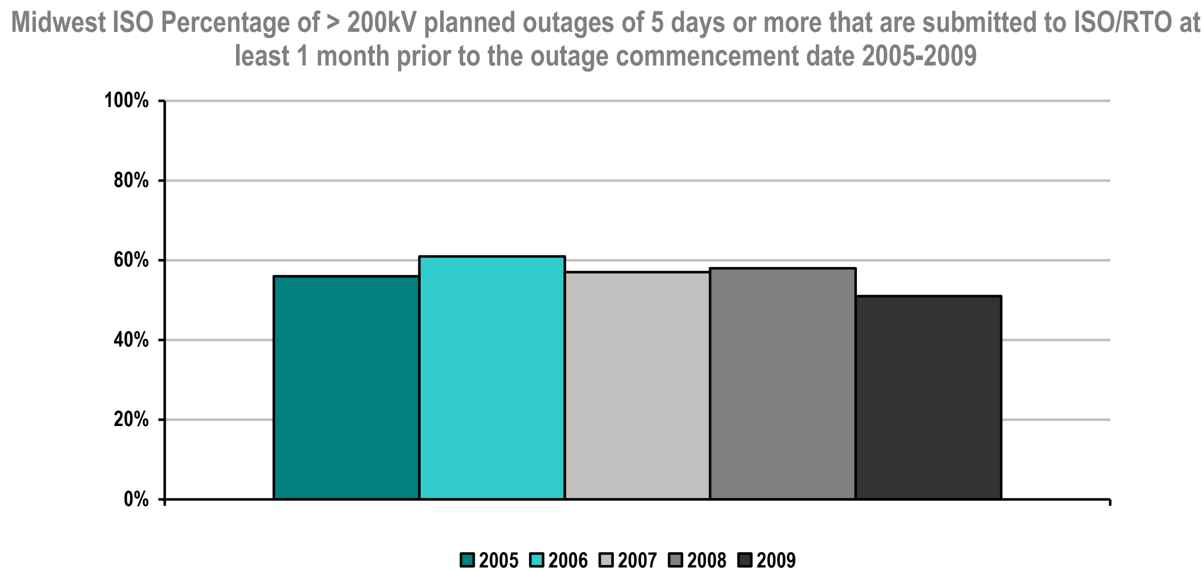
Note: A positive value denotes unscheduled flows into the ISO/RTO; a negative value denotes unscheduled flows out of the ISO/RTO.

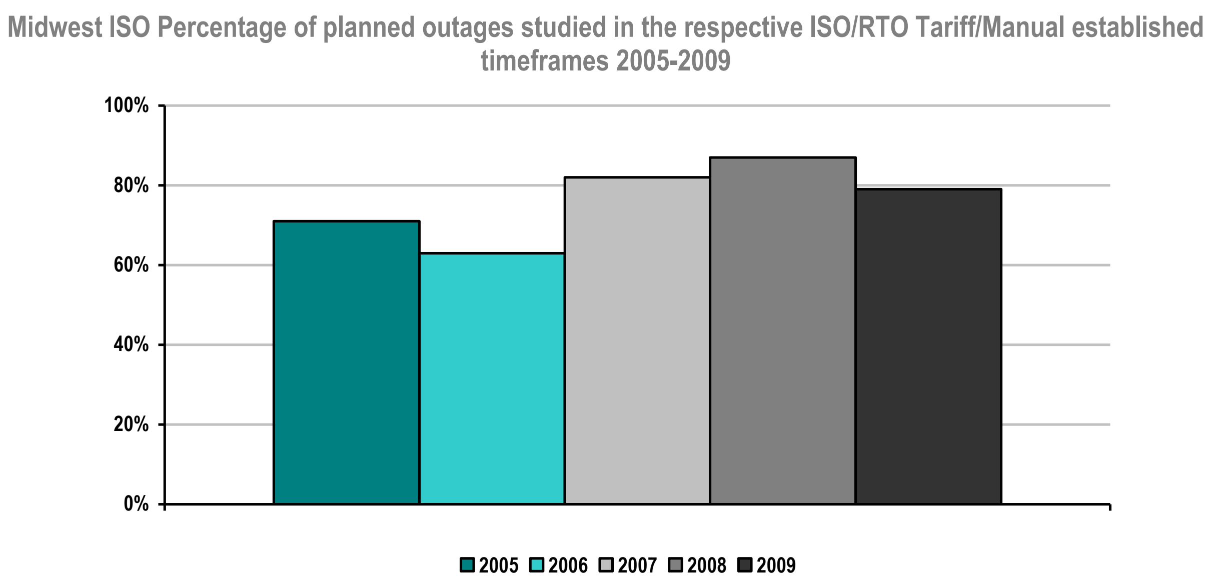
Parallel flows are a function of the interconnection's operating configuration, the resistance and physics. Another characteristic of parallel flows is that they sum to zero when all interfaces between a BA and all neighboring BAs are considered. While parallel flows from outside entities may create additional transmission system losses on a system, the real concern is the congestion the parallel flows create and the costs that are incurred when parallel flows cause facilities to exceed their limits. Parallel flows from outside entities are not limited to neighboring BAs. The Midwest ISO experiences parallel flows from other BAs that do not have an interconnection with the Midwest ISO.

The Midwest ISO has two methods to deal with congestion caused by parallel flows. The first method, the Transmission Loading Relief (TLR) approach, was developed by NERC and aims to reduce the harmful impacts of parallel flows by curtailing transactions between areas. The second method, the Congestion Management Process (CMP) approach, assigns firm flowgate rights among seams entities that are used when congestion occurs and redispatch obligations are made based on flowgate curtailment priorities. Seams agreements that contain CMPs exist between Midwest ISO, PJM, SPP, TVA, MAPP entities and Manitoba Hydro. Midwest ISO is working with IESO, NYISO and PJM to address Lake Erie loop flows through a number of initiatives including the operation of the phase angle regulators (PARs) on the MI-ONT interface.

Transmission Outage Coordination

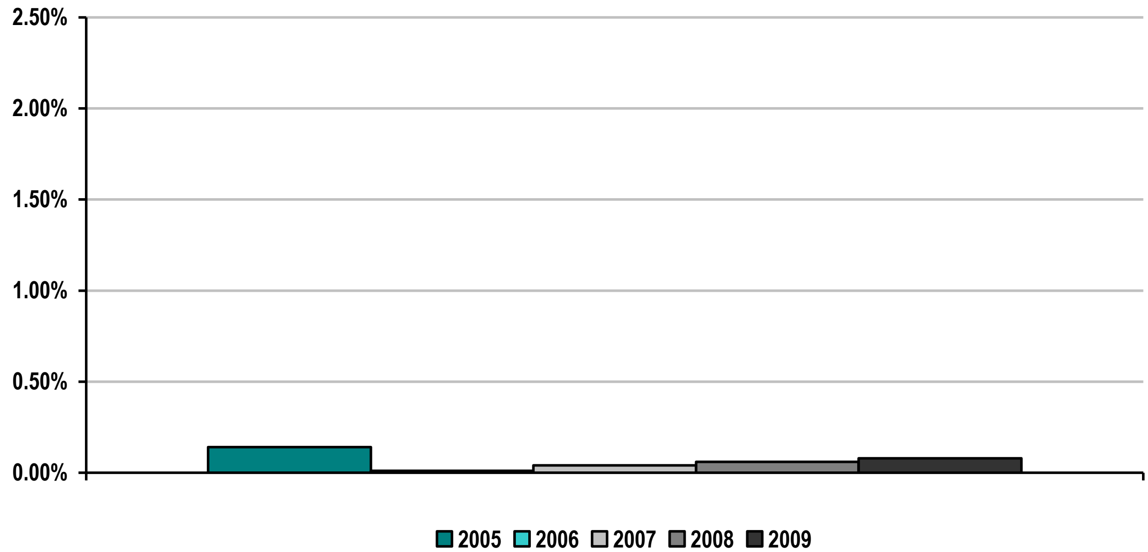
The Midwest ISO's transmission owners are required to request advance approval of transmission outages associated with scheduled maintenance. The Midwest ISO is required to study and approve or disapprove those requests within certain time periods. The following metrics reflect the performance of the parties with respect to this transmission outage coordination.





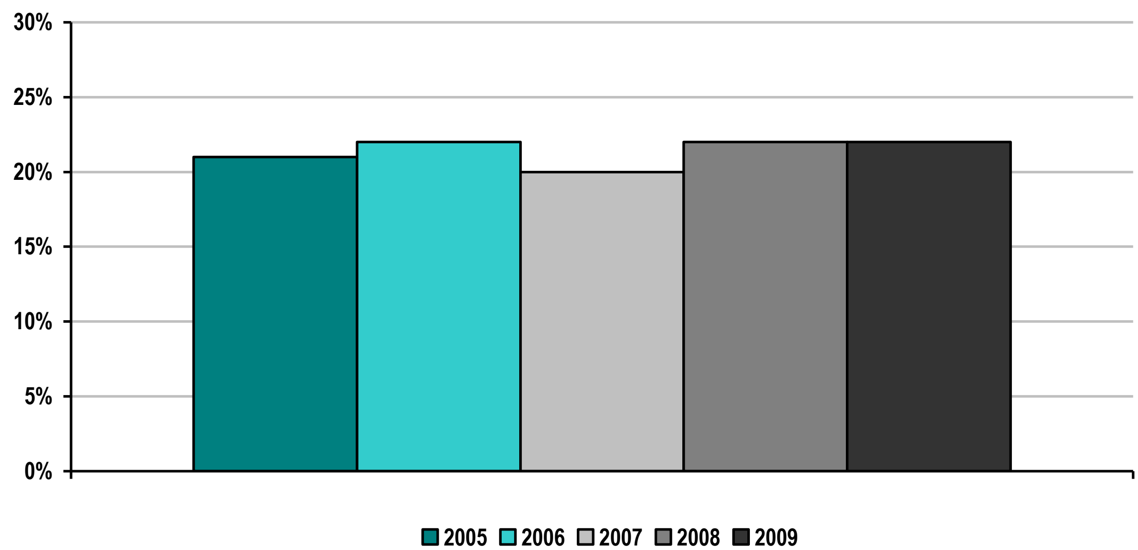
The Midwest ISO's business practices allow for exceptions (i.e. extensions) to its planned outage study timeframe in prescribed situations. However, the Midwest ISO does not track those extensions in a centralized location. Therefore, the Midwest ISO statistics shown above do not account for these prescribed extensions and represent lower than actual performance.

Midwest ISO Percentage of > 200 kV outages cancelled by ISO/RTO after having been previously approved 2005-2009



The Midwest ISO has the authority to cancel or reschedule previously-approved planned transmission outages if such outages would jeopardize system reliability conditions. However, the Midwest ISO has only needed to cancel or reschedule a very small percentage of transmission outages that it had previously approved.

Midwest ISO Percentage of unplanned > 200kV outages 2005-2009



Unplanned transmission outages may occur due to equipment malfunctions on the transmission line or an adjacent substation. They can also occur due to weather conditions that cause a transmission facility to trip out of service. Over the 2005 – 2009 time period, 20 – 22% of the outages of transmission assets in the Midwest ISO Region with 200 kV or higher voltages have been unplanned.

The impact of transmission outages on generation availability and on declared emergencies is mitigated by provisions in the Midwest ISO Tariff and Outage Operations Business Practices. All transmission and generation outage requests are submitted and reviewed/approved by the Midwest ISO prior to implementing. Generally, generation outage requests are required to be submitted prior to submission of transmission outage requests. Transmission outage requests are then analyzed and approved or rescheduled to maintain transmission system reliability and minimize impact on generation availability. Transmission outage requests are also analyzed, approved or cancelled such that the outage does not result in a declared emergency. The metric indicating percentage of outages cancelled by Midwest ISO is very low, averaging less than a tenth of a percent over the last five years, demonstrating appropriate outage coordination maintains transmission reliability and generation availability.

Transmission Planning

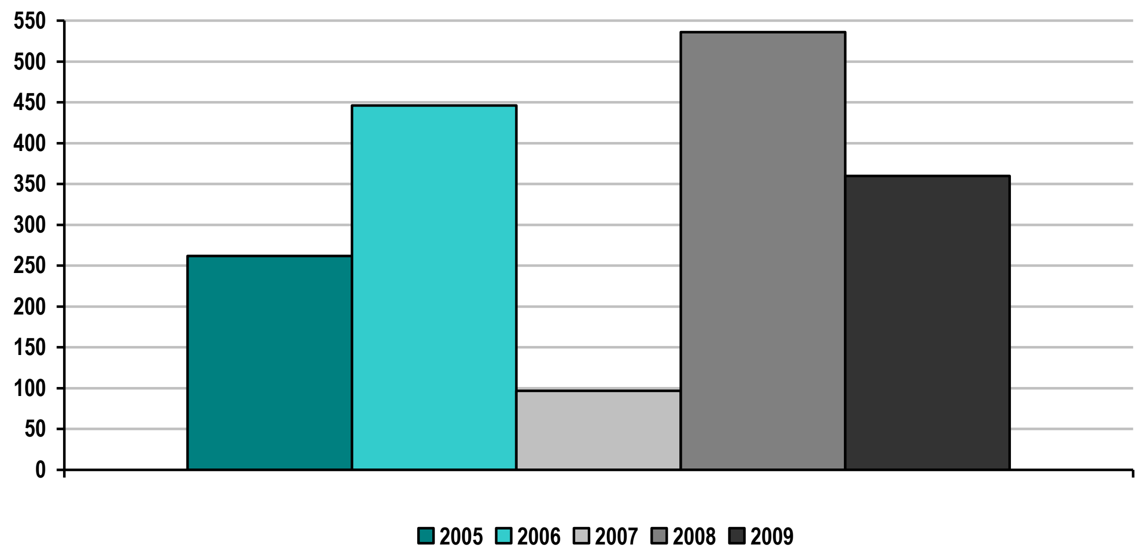
The Midwest ISO follows a top-down, bottom up planning process intended to address reliability, economic, and public policy driven transmission needs. The process focuses efforts on identifying issues and opportunities to strengthen the transmission system, developing alternatives for consideration, and evaluating those options to determine effective solutions. The goal is to identify transmission projects:

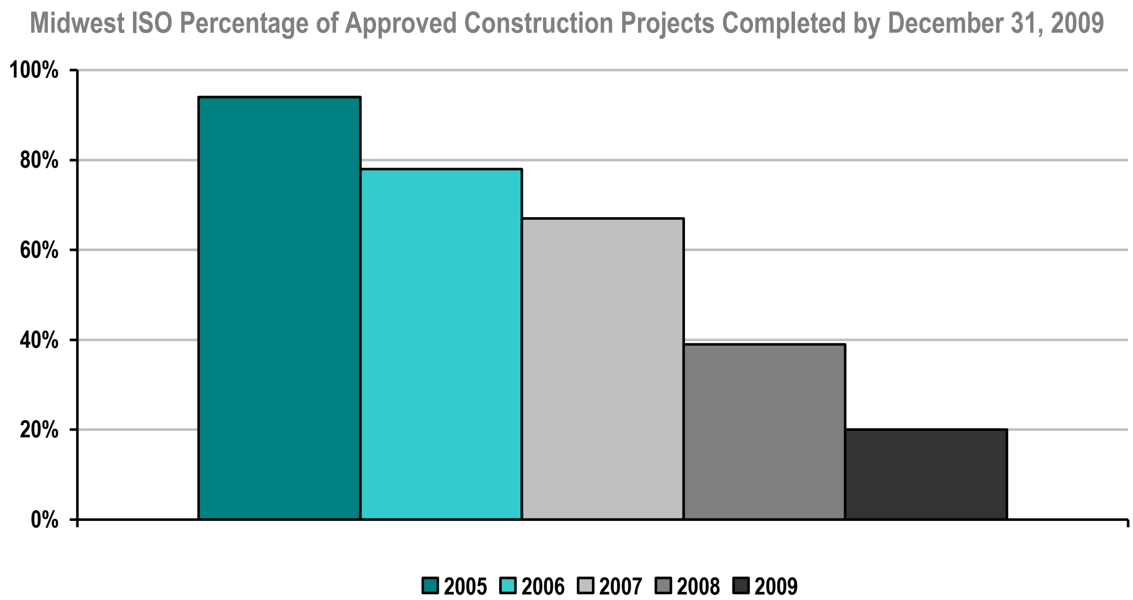
- Ensuring the reliability of the transmission system
- Providing economic benefit, such as increasing market efficiency
- Facilitating public policy objectives, such as the integration of renewable energy
- Addressing other issues or goals identified through the stakeholder process

As part of the bottom up process, Transmission Owners in the Midwest ISO are responsible for submitting their transmission construction plans to the Midwest ISO for evaluation and possible inclusion in Appendix A of the Midwest ISO Transmission Expansion Plan (MTEP). The Midwest ISO, in conjunction with its Transmission Owners and other stakeholders, also develops plans to address outstanding needs through the top-down process.

After thorough analysis, projects identified as the best solution for a particular issue or opportunity are included in Appendix A of the MTEP report and recommended for approval by the Midwest ISO Board of Directors (BOD). Once approved by the BOD, the Transmission Owner is required to make a good faith effort to complete the project. The following metrics give insight into the process and its results.

Midwest ISO Number of Transmission Projects Approved to be Constructed for Reliability Purposes 2005-2009





Projects that appear to meet a planning need but require further analysis are assigned to Appendix B until it is determined that these projects are the best alternative to identified issues. Finally, Appendix C contains projects still in the conceptual stages. Once analyzed and—if justified—projects currently in Appendices B and C move to Appendix A for approval and construction in future MTEP reports.

Value Based Planning Process

The uncertainties surrounding future policy decisions create challenges for those involved in the planning function and causes hesitancy for those with the resources to undertake transmission expansion projects. To minimize the risk in building a system under such conditions, the planning process must consider transmission projects in the context of all potential outcomes. The goal is to identify plans resulting in the least amount of future regrets in areas such as cost incurred, right of way used, and benefits achieved. This Value Based Planning Process seeks to meet this challenge through the execution of seven steps, including:

- Defining potential future energy policy outcomes
- Identifying generation capacity expansions that must occur in order to meet the objectives of each future scenario
- Modeling the potential location of generation
- Designing a conceptual transmission plan under each future
- Robustness testing to identify projects that perform well under most—if not all—future scenarios
- Testing the transmission plan against reliability criteria
- Determining cost allocation

Projects developed through this process are submitted into the MTEP Appendices for further analysis and potential Appendix A inclusion.

Demand response and energy efficiency programs and their impacts are currently reflected in the cumulative demand and energy growth rates. If a particular combination of Demand Side Management (DSM) programs is found to be economically viable, then the DSM programs will be included in the transmission planning and economic models as future generation units, and a lower demand will be reflected due to the energy efficiency programs. This in turn will have an impact on preliminary transmission portfolio design and affect—to greater or lesser degrees—the overall robust transmission overlay that will be proposed. The degree of DSM's impact on the regional plan, although dependent on many variables, may be substantially lessened if the transfer capability of the system is too low. If the transfer limits of the system are insufficient, DSM resources that may be the most economic may become trapped behind a transmission constraint.

Demand response may also be considered as a solution to an identified transmission issue. In order for demand response to be used as a solution, it must be evaluated in the Midwest ISO planning process, found to be the most effective solution, and have equivalent certainty to its alternative projects. This equivalent certainty will most likely be in the form of a legally binding contract forcing the demand response solution to be implemented, similar to the conditions required for an MTEP Appendix A transmission project.

With the addition of significant amounts of intermittent resources such as wind turbines to the transmission grid, the ability to store large amounts of energy for use during high demand times is becoming more important. Energy storage is becoming economical through the implementation of new technologies such as large-scale battery systems, flywheels, modifying the dispatch of wind generation to supply ancillary service products, and compressed air energy storage. The Midwest ISO is currently investigating the impact of energy storage on its planning models and future-based scenarios. A full-scale evaluation of energy storage is anticipated for the MTEP 11 planning cycle.

Midwest ISO Performance of Order 890 Planning Process

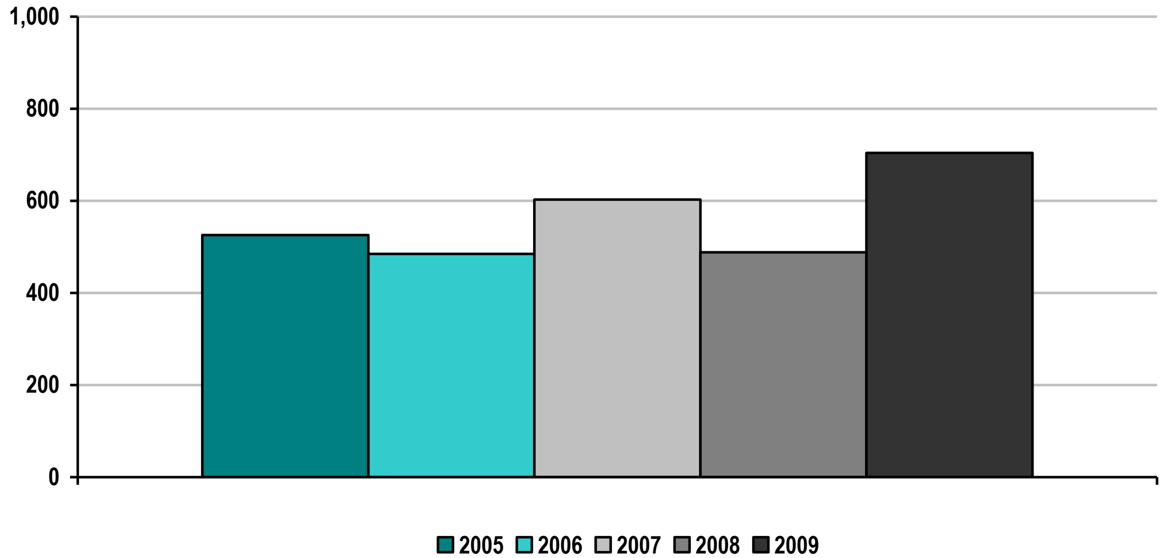
A key element of the Order 890 Planning Requirements is the involvement of transmission customers early and throughout the planning process. Subregional Planning Meetings (SPMs) are held in the West, Central and East planning regions of Midwest ISO. These SPMs provide forums for stakeholders to obtain information and to provide feedback on transmission project proposed in the current cycle.

In accordance with Order 890, Midwest ISO completed the following reliability studies in 2009: AC contingency, dynamic stability, voltage stability, load deliverability and generation deliverability. Midwest ISO also completed an economic transmission study during 2009. The results of these studies can be found on the MTEP 2009 report.

The MTEP 2009 report is available at www.midwestiso.org.

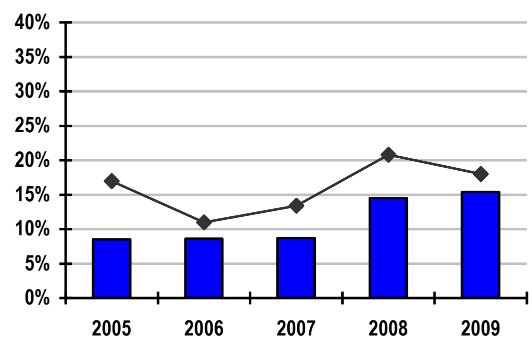
Generation Interconnection

Midwest ISO Average Generation Interconnection Request Processing Time 2005-2009
(calendar days)



In 2008, the Midwest ISO moved the focus of its process from “first in-first out” to “first ready-first served.” With that basic fundamental shift, customers now pay deposits scaled towards the size of their requests, and must show progress in non-transmission aspects of their project to proceed into later phases of the process. Within 18 months of the reform, over 230 requests received their system impact study report, compared to 40-50 per year prior to the reform.

Planned and Actual Reserve Margins 2005 – 2009

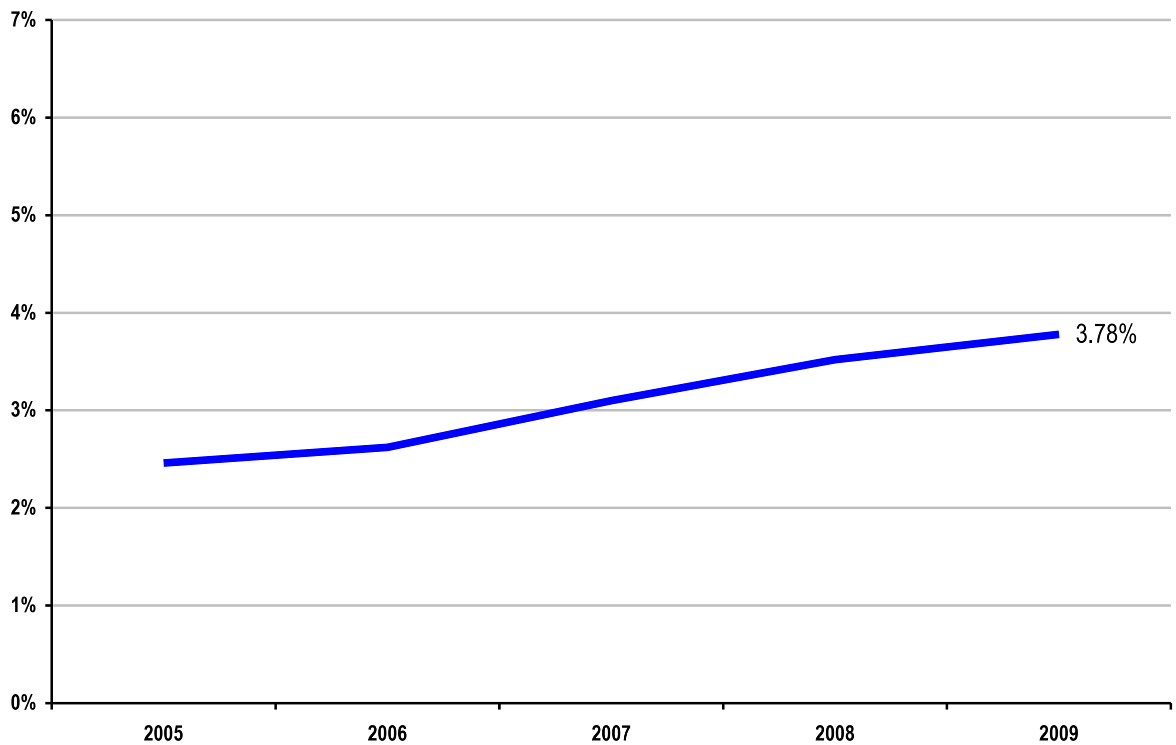


Bars Represent Planned Reserve Margins	Lines Represent Actual Resources Committed

The Midwest ISO’s resource adequacy mechanism was established in 2009. Prior to that time reserve margins were set by the Regional Reliability Organizations in the area. The Midwest ISO does not have a centrally procured capacity market. Load Serving Entities are required to designate specific capacity to meet their individual requirements. They may obtain that capacity via any of several ways including construction, bilateral contracts, existing generation, demand response, behind-the-meter generation (BTMG), or even through the Midwest ISO’s voluntary capacity auction. Demand Response and BTMG are defined as planning resources in the Midwest ISO resource adequacy mechanism and are called Load Modifying Resources (LMR). LMR are required to meet specific criteria established by the Midwest ISO's Module E in order to be registered and eligible to be used to meet LSE's capacity requirements.

Demand response resources can be used to meet the region's resource adequacy requirements. As shown in the chart below, demand response capacity as a percentage of total capacity rose from 2.5% in 2005 to 3.8% in 2009. The Midwest ISO also allows demand response resources that meet specified requirements to participate in the following markets: energy, regulation, spinning reserves and non-spinning reserves. Demand response resources are actively participating in each of these areas.

Midwest ISO Demand Response Capacity as Percentage of Total Installed Capacity 2005-2009



The Midwest ISO fosters demand response in the region through dynamic pricing and direct load control/interruptibles. As a result, generation infrastructure investment is deferred by reducing load during times of system peaks. The Midwest ISO has over 12,500 MW of total demand response capability. The deferral of generation infrastructure investment represents theoretical savings of $80 million in 2009 with the anticipation that savings will increase in future years.

Forecasted peak demands are submitted by LSE's using a 50%-50% forecast (50% probability the forecast will be over, and 50% probability the forecast will be under, the actual peak demand) using CPNode granularity and including all losses downstream from the generator bus (transmission and distribution).

LSEs must report their non-coincident peak forecasted Demand to the Midwest ISO at each CPNode for each month of the next two Planning Years and also for each summer period (May- October) and winter period (November - April) for an additional eight (8) Planning Years. The forecasts shall be based upon considerations including, but not limited to, average historical weather conditions and expected Load changes (addition or subtraction of demand). LSEs will separately register Demand Resources that qualify under Module E in order to have them subtracted from their forecasted Demand.

The Midwest ISO will calculate the Forecast LSE Requirement as the forecasted Demand for an LSE (adjusted by DR that are registered to net) for each month of the next Planning Year.

Forecasts of Demand are subject to after-the-fact assessments using standard deviation bandwidths and normalization factors provided by LSEs to identify potentially improper forecasting.

Within Module E, individual Load Serving Entities (LSEs) maintain reserves based on their monthly peak load forecasts. These peak forecasts do not sum to the system coincident peak because they are reported based solely on the entity's own peak, which could occur at a different time than the system peak. To account for this diversity within the system, a reserve margin was calculated for application to individual LSE peaks utilizing a diversity factor. This resulted in an individual LSE reserve level that is reduced from what would otherwise be a higher reserve without accounting for diversity.

The reduced reserve level delays the need for new capacity. For the most of Midwest ISO's membership, the recent economic downturn resulted in load reductions, and thus excess generation capacity to the point that under the present conditions this benefit will not rematerialize for the next few years. The Midwest ISO 2009 Value Proposition calculates a theoretical benefit of $217 to $272 assuming no excess capacity based on the cost of building new combustion turbine capacity. The benefit is the avoided annual revenue requirement of that avoided capacity.

There are numerous factors that impact the adequacy of the actual reserve margin vis-à-vis the projected reserve margin, including load forecasts and energy efficiency trends. When the Midwest ISO calculates the Planning Reserve Margin (PRM), there are a number of key factors that impact the results:

- Congestion: changes in the amount of transmission congestion on the Midwest ISO system. Congestion incorporates the notion of aggregate deliverability impact and a quantifiable MW capacity impact upon LOLE achieved.

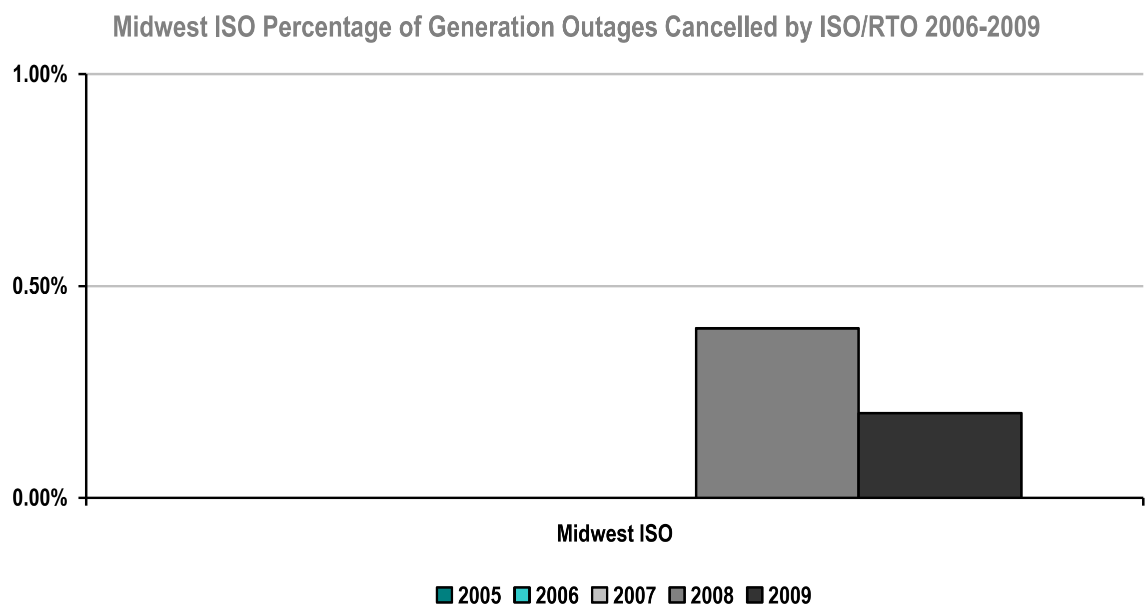
- Load Forecast Uncertainty (LFU): the Midwest ISO utilizes the summation of the NERC Variances method to calculate the load forecast uncertainty value. This method produces a sigma value. The Summation of the NERC Variances method has a solid methodology and the NERC Load Forecasting Working Group (LFWG) has consistent input from Midwest ISO membership. More forecast error is introduced for example due to the recent economic downturn.

- Forced Outage Rates: Forced outage rates are adjusted to exclude certain outage types, deemed as outside of management control, and account for the time when a unit was in demand. These adjustments to the forced outage rates yielded an Effective Forced Outage Rate Demand (EFORd) that excluded certain outages which is known as XEFORd.

- External Support: the Midwest ISO determines the level of support the external systems can provide based on historical total transmission flows and contractual flows. That applicable external support level is held to the same reliability level as the internal system.

- Membership Changes: the impact of the entrance and departure of members from the Midwest ISO market and reliability systems are factored into the PRM determination. For example, for the 2011-2012 Planning Year, the entrance of Dairyland Power Cooperative and Big Rivers Electric Cooperative and the departure of FirstEnergy resulted in changes to the PRM.

- Modeling Improvements: as the Midwest ISO compiles more accurate and comprehensive data on modeling factors such as generator performance, outages, load shapes, etc. that data improves the accuracy of the results.



The chart above includes cancelled generation outages that were denied or revoked by the Midwest ISO. The Midwest ISO does not have data available for 2005. Percentage of generation outages cancelled was 0.0% for 2006 and 2007.

Midwest ISO Generation Reliability Must Run Contracts 2005-2009

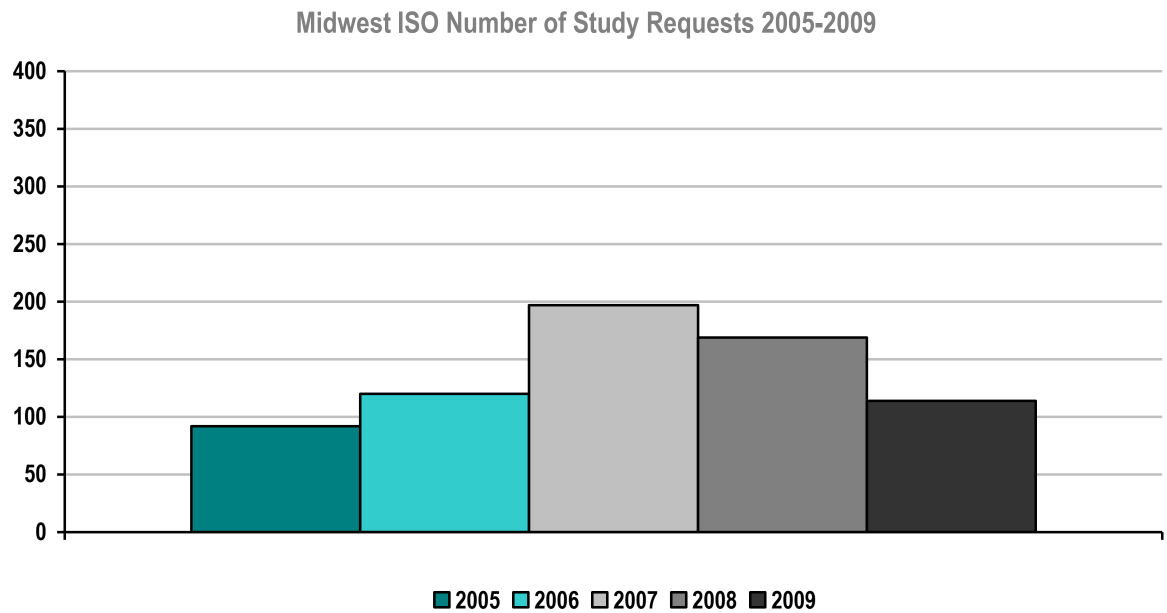
When a generating unit that wishes to retire or be mothballed is required to continue to operate for reliability purposes it is known in the Midwest ISO as a System Support Resource. The Midwest ISO had no units under these types of contracts from 2005 through 2009.

Interconnection / Transmission Service Requests

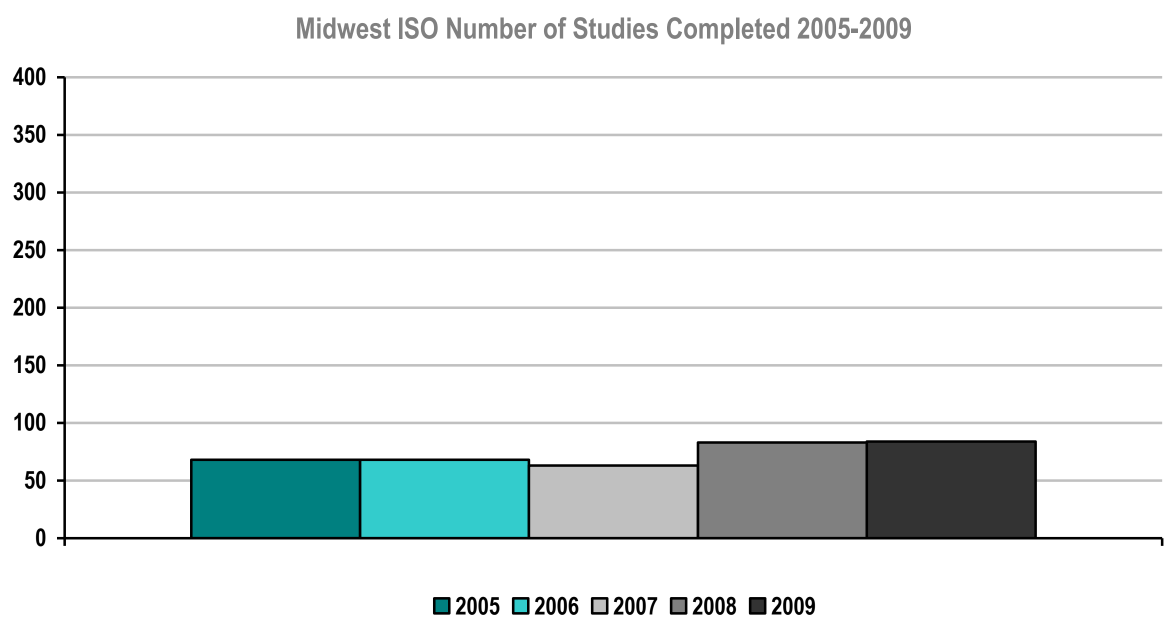
In 2008, the Midwest ISO moved the focus of its generator interconnection process from "first in-first out" to "first ready-first served." With that basic fundamental shift, customers now pay deposits scaled towards the size of their requests, and must show progress in non-transmission aspects of their project to proceed into later phases of the process. Within 18 months of the reform, over 230 requests received their system impact study report, compared to 40-50 per year prior to the reform.

Since the shift in paradigm, the Midwest ISO has seen a generally steady, if reduced, number of interconnection requests entering the queue, and the Midwest ISO has seen resistance from some customers in leaving the queue at the end of their studies. The deposit changes, in conjunction with the additional education provided to generation developers seeking to enter the process, leads to additional consideration before the submission is made, which is believed to be one driver for the reduction in study requests received. The nature of the queued requests, which are mostly wind, and the current demand for wind energy, or lack thereof, are believed to be the drivers for customers to push to stay in the queue at this point in time. Unexecuted agreements and the current formal complaint mostly center around cost allocation and related issues. Once those issues are resolved, supply/demand market forces are expected to dominate the queue debate.

Recent trends in Interconnection Requests, and Transmission Service Requests, continue to revolve around wind energy, either connecting new wind generators or moving the output of wind generators across, and sometimes out of, the Midwest ISO. Study results over the last 2-3 years have shown the need for projects such as those currently defined as "Candidate MVPs" in the Midwest ISO's continuation of the Regional Generator Outlet Study. The proposed cost allocation changes, along with the progress to-date on meeting renewable portfolio standard laws in the Midwest region, has incented a "wait and see" approach from a large number of customers in the later stages of the queue.



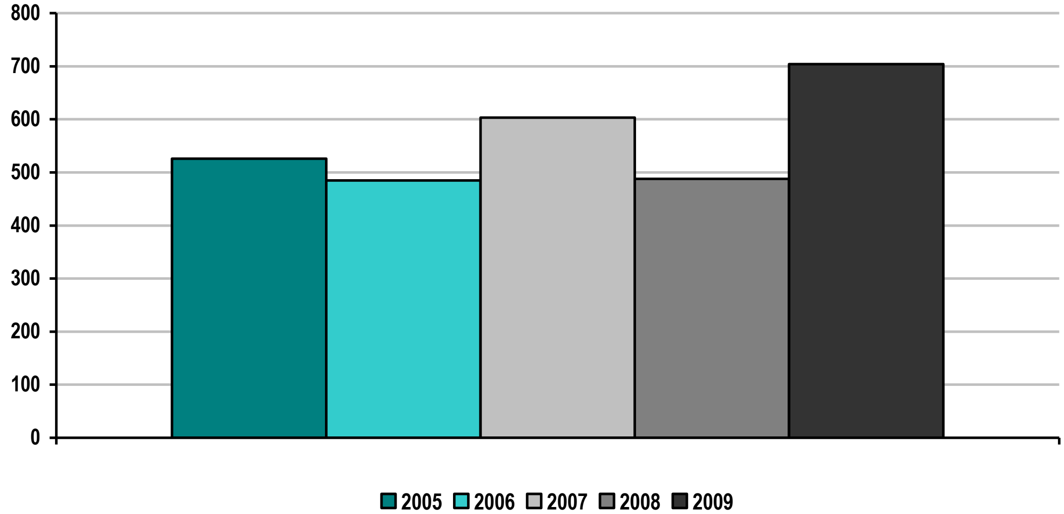
The uptick in completed studies in 2007 and 2008 reflects the process changes which allowed those requests that were able to move more quickly due to a combined project readiness and system readiness (i.e. projects in relatively unconstrained areas), to move more quickly to interconnection agreement. Although not reflected in the chart, note that requests withdraw from the queue on a regular basis for economic or other reasons. Of the 692 requests received in 2005-2009, more than a quarter have already made a decision to withdraw.



Midwest ISO Average Aging of Incomplete Studies 2009

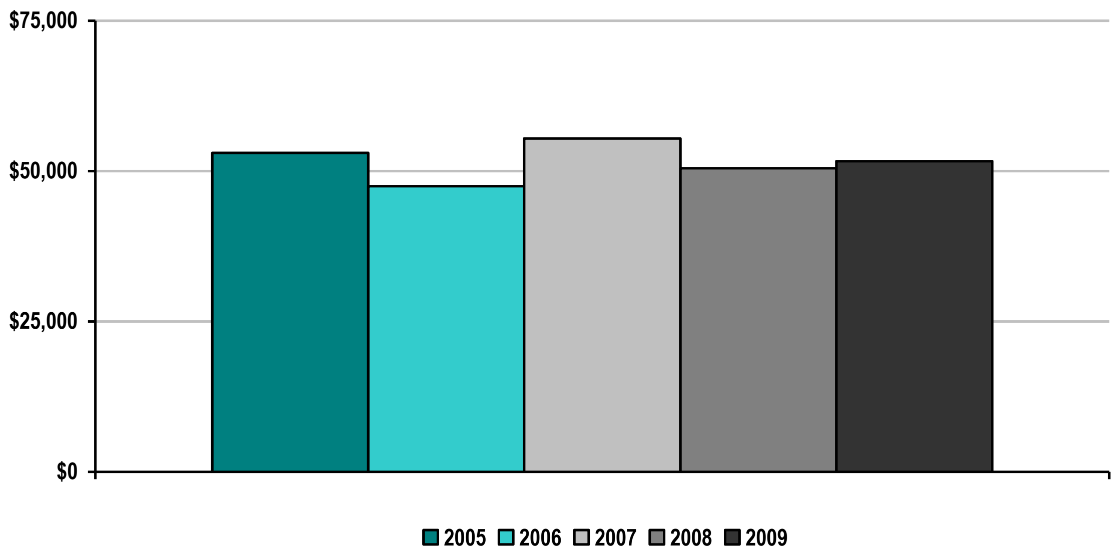
The Midwest ISO's average aging for incomplete studies for 2009 was 710 days. Average aging data prior to 2009 isn't readily available. The average aging of 710 days is reflective of the former first in-first out approach to queue processing being applied to a queue with a concentration of requests in a relatively small area. Following the queue reform, the number is staying large as those legacy projects are now facing 345kV upgrades and questions over appropriate allocation of those larger upgrades. Further complicating this issue is a restudy resulting from an unexecuted interconnection agreement in our oldest group study. The result of that study can change the baseline assumptions for the subsequent studies, and may alter those results.

Midwest ISO Average Time to Complete Studies 2005-2009
(calendar days)



Although the transmission studies for generator interconnection become increasingly more complex as more resources seek to locate in highly constrained areas, techniques such as the group study result in not only increased efficiencies identified in the transmission plans themselves, but also allow efficiencies in the project study process which keep the costs relatively steady from year to year.

Midwest ISO Average Cost of Studies Completed 2005-2009



Special Protection Schemes

Midwest ISO Number of Special Protection Schemes 2009

The Midwest ISO had 53 special protection schemes in 2009. Of the 53 SPSs, Midwest ISO's West Region had 34 SPSs, the Central Region had 6, and the East Region had 13. In 2009, there were no intentional misoperations of SPSs in the Midwest ISO. There was one unintentional misoperation of a SPS, but the SPS responded as designed.

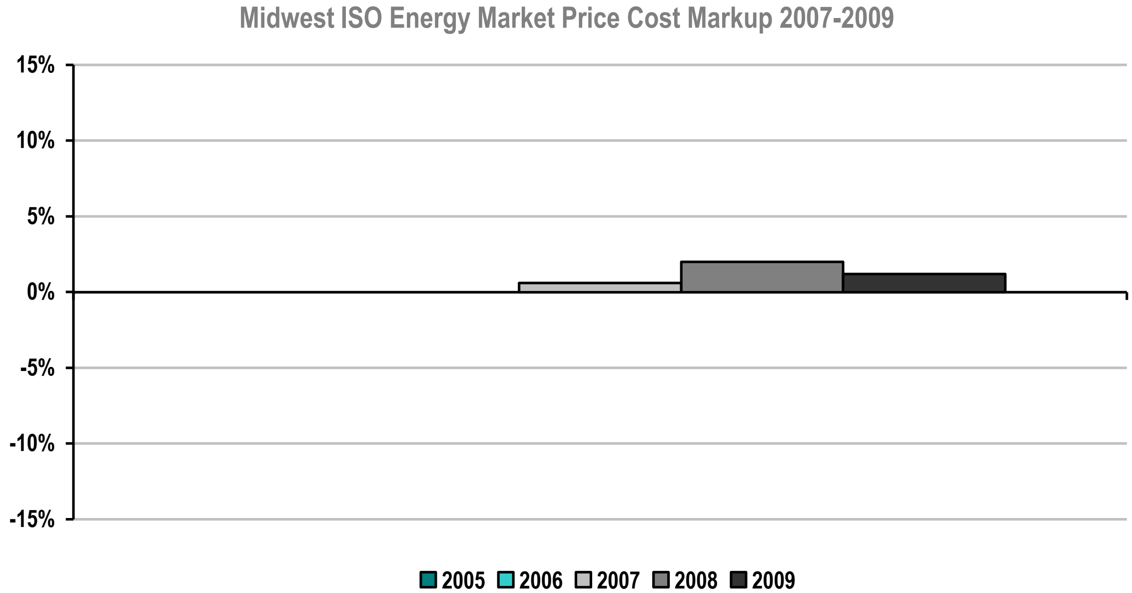
B. Midwest ISO Coordinated Wholesale Power Markets

For context, the table below represents the split of the $24.3 billion dollars billed by Midwest ISO in 2009 into the primary types of charges its members incurred for their transactions.

(dollars in millions)	**2009 Dollars Billed**	**Percentage of 2009 Dollars Billed**
Energy	$ 21,173.0	87.1%
FTR	1,396.2	5.8%
Transmission Service	1,238.1	5.1%
Administrative Costs	252.1	1.0%
Regulation Market	123.1	0.5%
Contingency Reserves	79.6	0.3%
Resource Adequacy	7.4	0.0%
Other	46.5	0.2%
Total	**$ 24,316.0**	**100.0%**

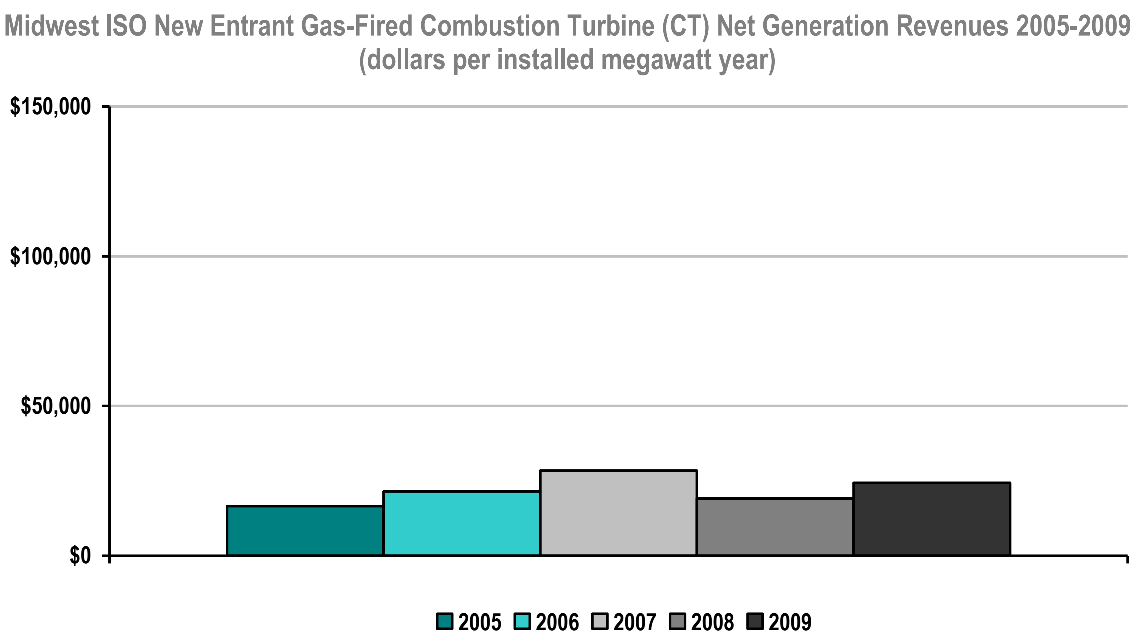
In addition, Midwest ISO's demand response as a percentage of the synchronized reserve market was 3.9% in 2009. Midwest ISO's demand response as a percentage of the regulation market was 2.7% in 2009. Midwest ISO launched its ancillary services market in January 2009. Therefore, there was no demand response participation in Midwest ISO ancillary services market prior to 2009.

Market Competitiveness

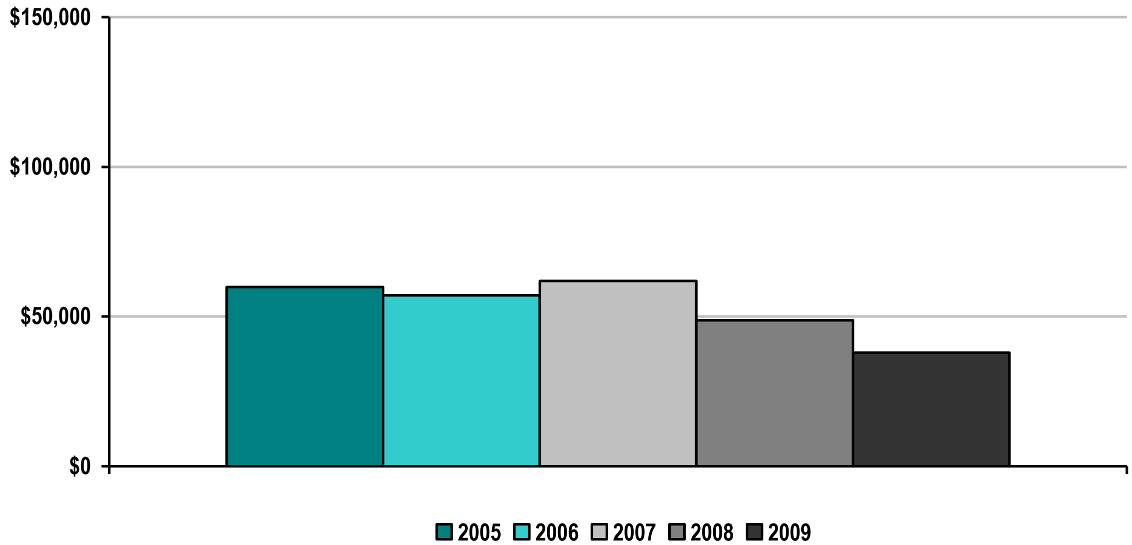


The Midwest ISO calculates price cost markup by comparing the system marginal price based on actual offers to a simulated system marginal price based on assuming suppliers had all submitted offers at their estimated marginal costs.

The overall price cost markup percentages over the past three years support the conclusion that prices in the Midwest ISO are set, on average, by marginal units operating at or close to their marginal costs. The Midwest ISO does not have data for this metric for 2005 and 2006.

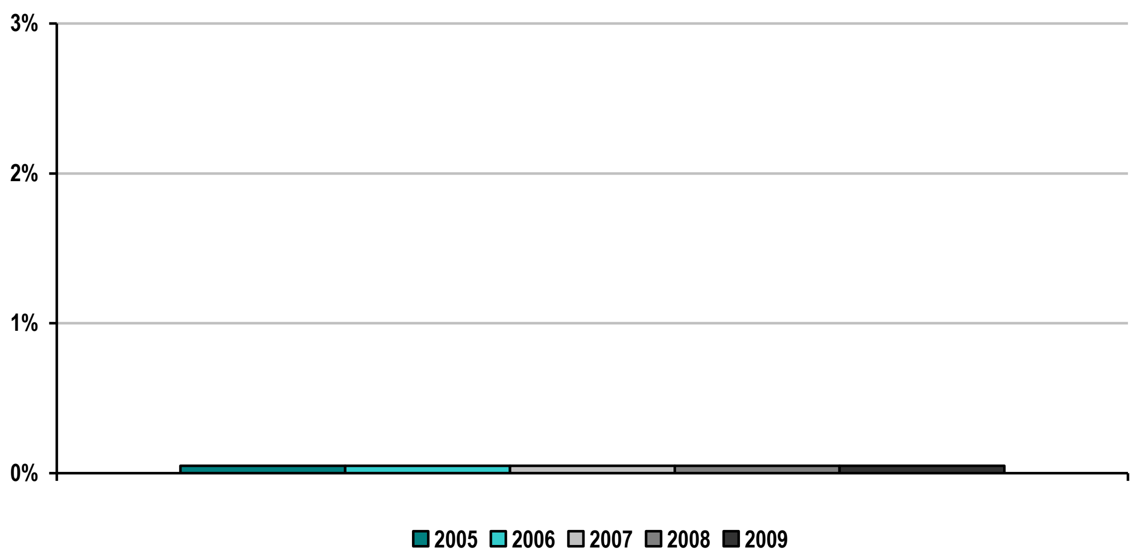


Midwest ISO New Entrant Gas-Fired Combined Cycle (CC) Net Generation Revenues 2005-2009
(dollars per installed megawatt year)



In 2009, Midwest ISO markets would not have supported investment in either gas CT or CC generation units based on their annualized costs of new investment. The Midwest ISO footprint has a sizable capacity surplus that precluded significant periods of shortage, particularly at reduced load levels.

Midwest ISO Real-Time Energy Market Percentage of Unit Hours Offer Capped due to Mitigation 2005-2009



The Midwest ISO's mitigation measures are intended to preclude abuses of locational market power while minimizing interference with the market when the market is workably competitive. The Midwest ISO only imposes mitigation measures when suppliers' conduct exceeds well-defined conduct thresholds and when the effect of that conduct on market outcomes exceeds well-defined market impact thresholds. By applying these conduct and impact tests, the mitigation measures are designed to allow prices to rise efficiently to reflect legitimate supply shortages, while effectively mitigating inflated prices associated with artificial shortages that result from physical or economic withholding in transmission-constrained areas.

In the years 2005 to 2009, total unit hours mitigated in a year ranged from 19 hours to 498 hours. Consequently, the unit hours offer capped due to mitigation is extremely small when calculated as a percentage of total unit hours.

Potomac Economics, the Midwest ISO's Independent Market Monitor, provides a competitive assessment of the Midwest ISO markets in its 2009 State of the Market Report that includes a review of potential market power indicators, an evaluation of participants' conduct, and a summary of the imposition of mitigation measures in 2009. Potomac Economics concludes:

> "Our analysis shows that market concentration measured using the Herfindahl-Hirschman Index ("HHI") is low for the overall Midwest ISO region, although it is considerably higher in the individual regions.
>
> However, a more reliable indicator of potential market power is whether a supplier is "pivotal", which occurs when its resources are necessary to satisfy load or manage a constraint. In the examination of pivotal suppliers, we focus particular attention on the two types of constrained areas that are defined for purposes of market power mitigation: Narrow Constrained Areas ("NCA") and Broad Constrained Areas ("BCA"). NCAs are chronically constrained areas –three are currently defined: one in Minnesota, one in WUMS, and one in North WUMS (a subset of WUMS) – that raise more severe potential local market power concerns (so tighter market power mitigation measures are employed), while BCAs include all other areas within the Midwest ISO that are isolated by a binding transmission constraint.
>
> Sixty-four percent of active BCA constraints had a pivotal supplier in 2009, up from 59 percent in 2008. Seventy-five percent of the active NCA constraints into WUMS have a pivotal supplier (down from 79 percent in 2009), as do 75 percent of the active NCA constraints into Minnesota (up from 69 percent). In addition, nearly 80 percent of all intervals in 2009 exhibited an active BCA constraint with at least one pivotal supplier, while 30 percent and 6.5 percent of the intervals exhibited an active NCA constraint with at least one pivotal supplier in WUMS and Minnesota, respectively. These results indicate that local market power persists with respect to both BCA and NCA constraints, and that market power mitigation measures remain critical.
>
> Although the report shows that structural market power remains a significant issue in the Midwest ISO, our analyses of participant conduct show little evidence of attempts to physically or economically withhold resources to exercise market power."

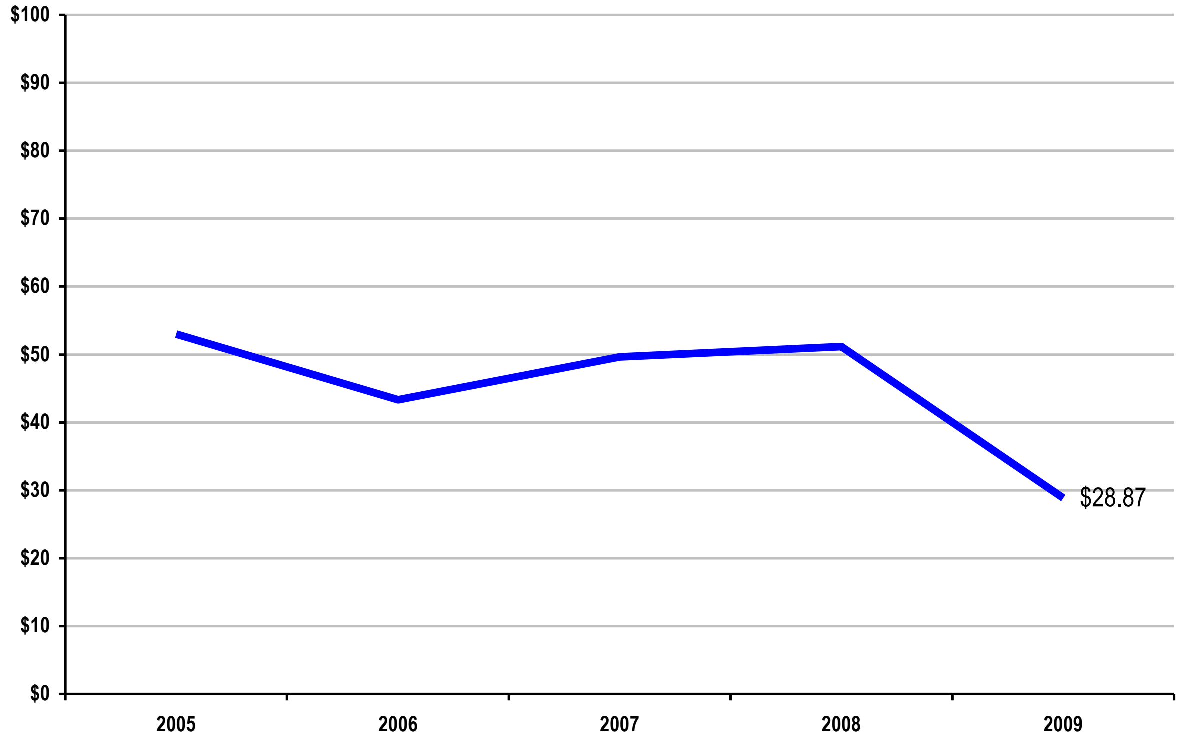
Midwest ISO's 2009 State of the Market Report also states that, "Market power mitigation in the Midwest ISO's energy market continues to occur pursuant to automated conduct and impact tests that utilize clearly specified criteria. Because conduct has generally been competitive, market power mitigation has been imposed infrequently."

With respect to price volatility, Midwest ISO's 2009 State of the Market Report states:

> "Prices in the real-time market are generally more volatile than prices in the day-ahead market. However, real-time price volatility decreased 17 percent in 2009, due in part to the introduction of ASM. ASM has resulted in improved supply flexibility that allows the real-time market to satisfy the system's demands with less price volatility. Volatility in the Midwest ISO remained substantially higher than in neighboring RTOs because the Midwest ISO runs a true five-minute real-time market that produces a new dispatch and prices every five minutes."

Market Pricing

Midwest ISO Average Annual Load-Weighted Wholesale Energy Prices 2005-2009 (1)
($/megawatt-hour)



(1) Midwest ISO 2005 data begins April 1, 2005 reflecting the start of the Midwest ISO Real-Time Energy Market

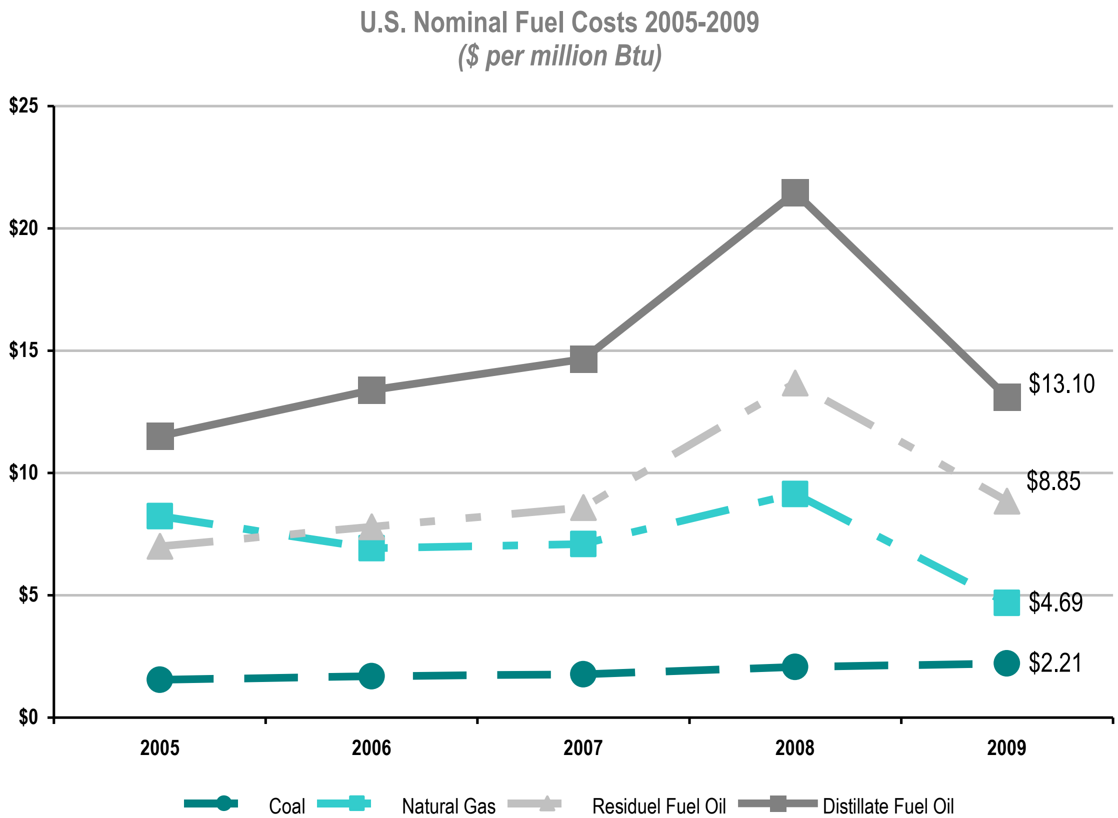
The average annual load-weighted wholesale energy prices substantially reflect the changes in fuel costs. These trends are supported by the chart below that shows the trends in the costs of key fuel sources for generation units in the U.S. electricity industry.

Peak Price Trends

Time	MISO Real-Time Load (MW)	Day-Ahead LMP ($/MWh)	Real-Time LMP ($/MWh)
8/3/2005 16:00(1)	105,525	$136.67	$129.05
7/31/2006 16:00	109,065	$222.72	$268.21
8/8/2007 15:00	103,997	$148.08	$225.64
7/29/2008 15:00	98,263	$157.92	$182.77
6/25/2009 14:00	96,334	$63.32	$46.69

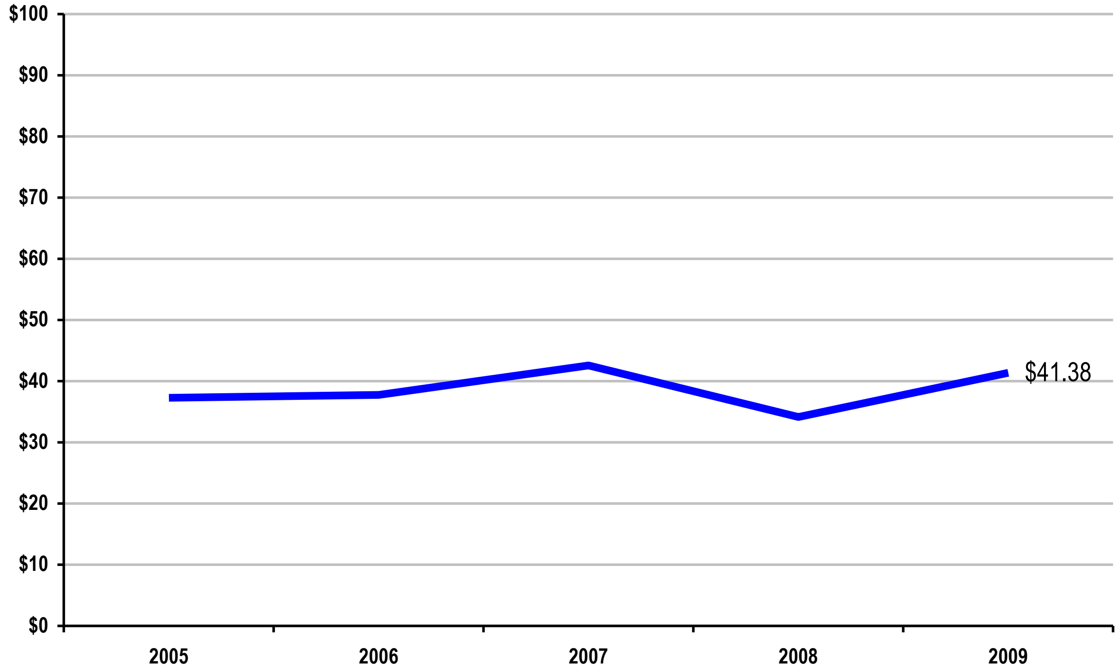
(1) Midwest ISO 2005 data begins April 1, 2005 reflecting the start of the Midwest ISO Real-Time and Day-Ahead Energy Markets

Day-ahead and real-time LMPs at the annual Midwest ISO system peak load hour show the strong correlation between the load and prices. The LMPs from 2005 to 2007 moved in the same direction as the changes in real-time load. However, in 2008 increased fuel prices across all fuel types may have caused the LMPs to be higher than 2007 albeit the peak load actually declined. The 2008 and 2009 LMPs are influenced by the broad economic slowdown and decline in weather induced electric demand due to relatively milder weather. In addition to the lower demand, in 2009 fuel prices declined causing a significant drop in LMPs compared to 2008.



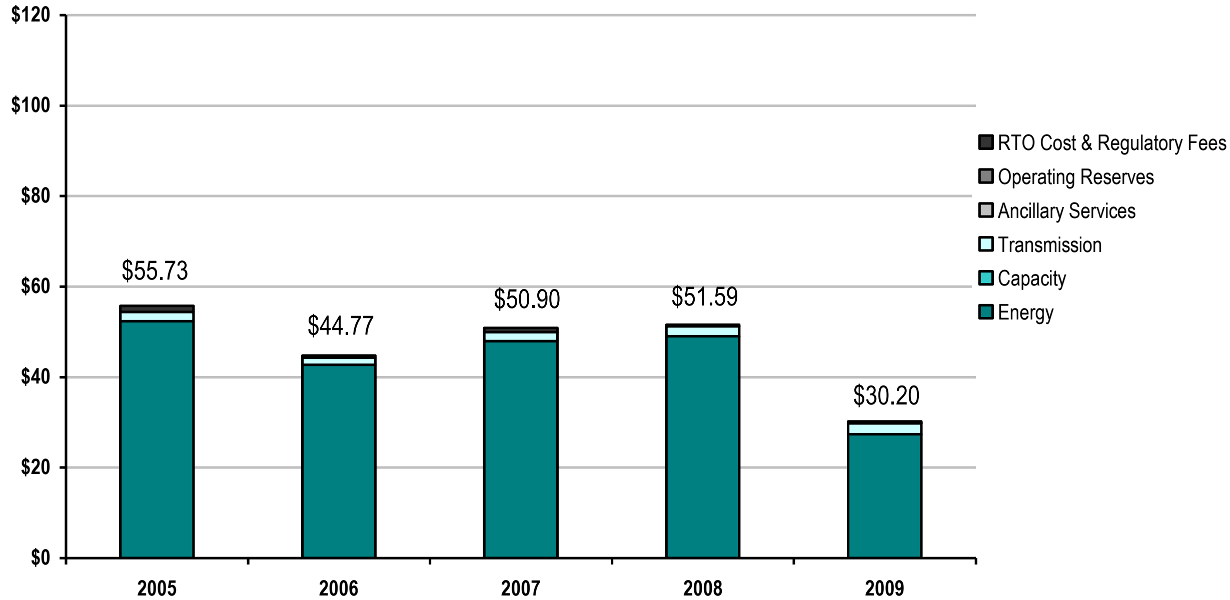
Source: U.S. Energy Information Administration, Independent Statistics and Analysis

Midwest ISO Average Annual Load-Weighted
Fuel-Adjusted Wholesale Spot Energy Prices 2005-2009 (1)(2)
($/megawatt-hour)



(1) Midwest ISO 2005 data begins April 1, 2005 reflecting the start of the Midwest ISO Real-Time Energy Market
(2) Midwest ISO's base year for fuel-cost references is 2004.

Midwest ISO Wholesale Power Cost Breakdown
($/megawatt hour)

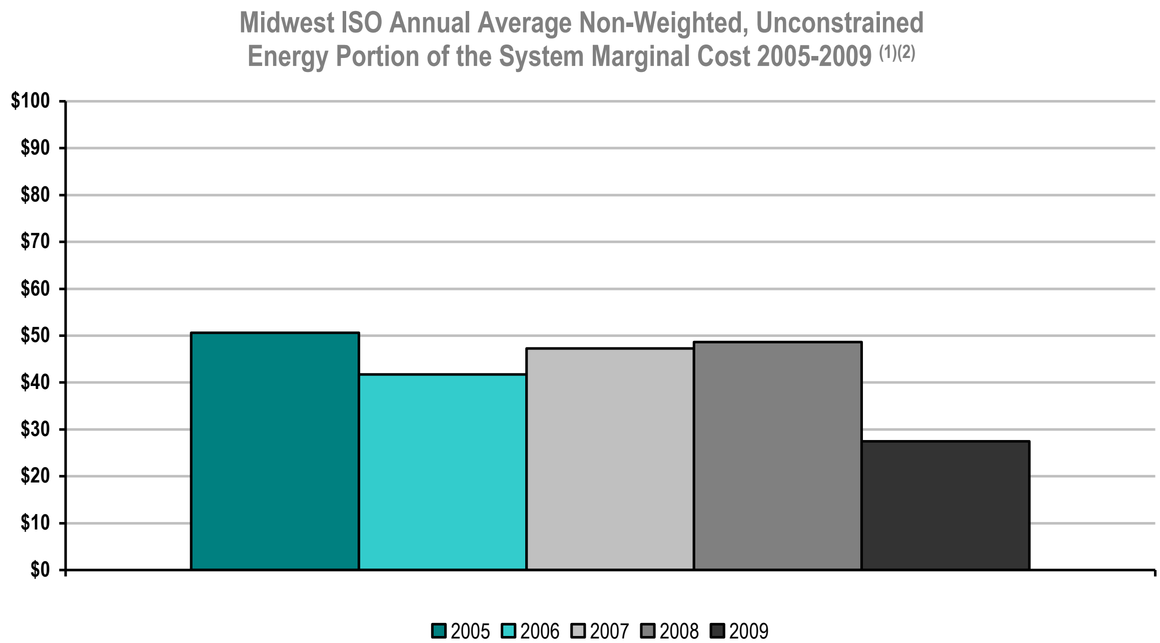


On an annual basis, energy costs have comprised 91 – 94% of Midwest ISO's total wholesale power costs for the past five years. All other components of Midwest ISO's wholesale power cost per megawatt hour account for less than 6 – 9% of the total costs per megawatt hour. In particular, the operating reserve costs (sometime referred to as uplift) vary from year to year, but represent on average less than $1.00 per megawatt hour of the total wholesale power cost in the Midwest ISO Region. In 2005 through 2009, such uplift costs represented 2.2% or less of the total wholesale power cost per megawatt hour during that five-year period.

Impacts of Demand Response on Market Prices

The Midwest ISO continues to enhance the ability of demand response to participate in its markets, including energy, ancillary services, and capacity. Efforts are ongoing to identify potential barriers and to provide solutions that encourage Market Participants to include demand response in their market portfolios. While the footprint has been long in capacity for some time, demand response has demonstrated its long-term potential during certain periods. For example, during the August 1st, 2006 event, approximately 3,000 MW's of demand response responded for ten hours. Corresponding clearing prices during this window declined by $100 - $200/MWh for participant (gross) savings of over $3,000,000. Market participants benefitted from the reduction in energy prices as well as from the reliability assistance provided to the system.

Unconstrained Energy Portion of System Marginal Cost

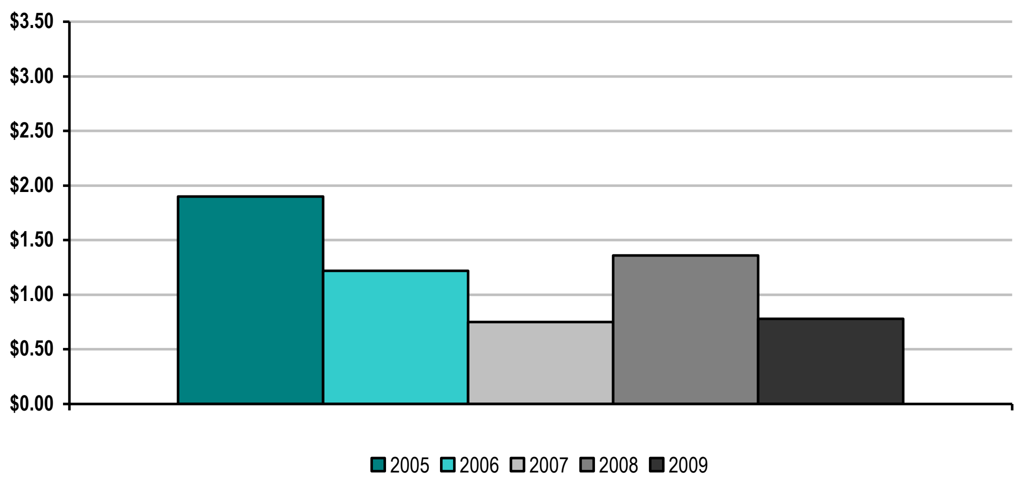


(1) Midwest ISO 2005 data begins April 1, 2005 reflecting the start of the Midwest ISO Real-Time Energy Market
(2) These values were calculated based on the annual average non-weighted Real-Time marginal energy component of LMP at the Cinergy Hub. Using the marginal energy component of LMP is consistent with how Midwest ISO publishes System Lambda in FERC Form No. 714.

Pricing in the Midwest ISO wholesale markets is heavily influenced by underlying fuel prices. The values in the table above reflect the fuel price increases experienced in 2005 and 2008 as well as the fuel price decrease in 2009.

Energy Market Price Convergence

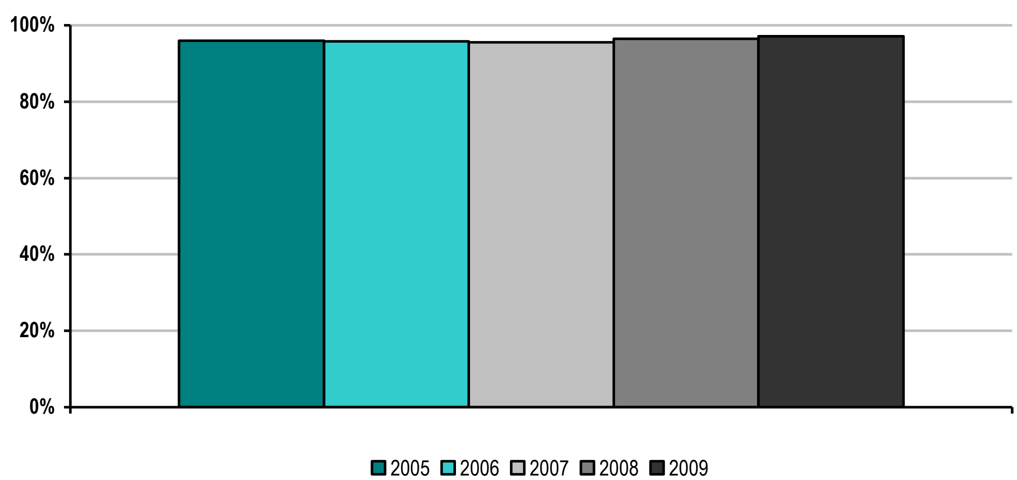
Midwest ISO Day-Ahead and Real-Time Energy Market Price Convergence 2005-2009(1)



(1) Midwest ISO 2005 data begins April 1, 2005 reflecting the start of the Midwest ISO Real-Time Energy Market

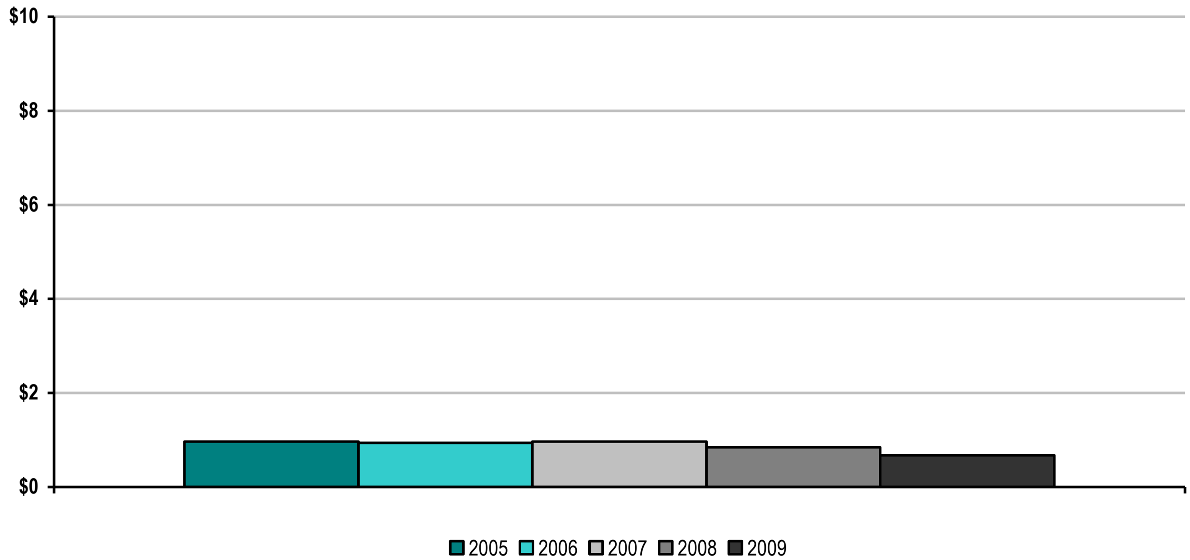
The data in the chart above reflects significant convergence between day-ahead and real-time prices since Midwest ISO's day-ahead and real-time markets started in 2005.

Midwest ISO Percentage of Day-Ahead and Real-Time Energy Market Price Convergence 2005-2009



Congestion Management

Midwest ISO Annual Congestion Costs per Megawatt Hour of Load Served 2005-2009(1)



(1) Midwest ISO 2005 data begins April 1, 2005 reflecting the start of the Midwest ISO Real-Time and Day-Ahead Energy Markets

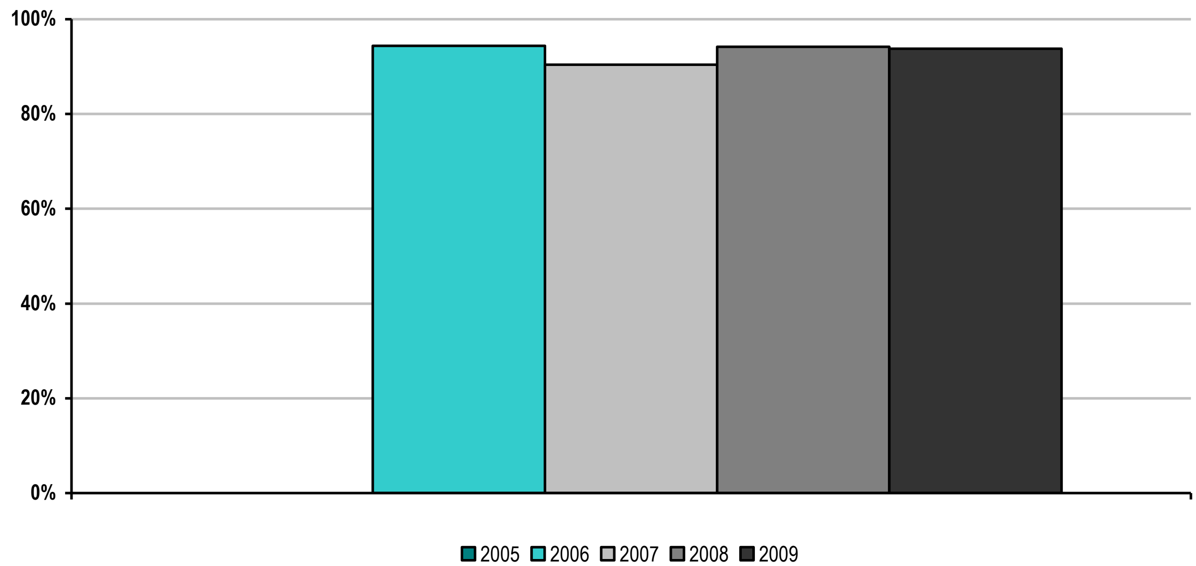
Congestion costs have been declining due to two primary factors, the addition of transmission to relieve congestion in certain key areas of the Midwest ISO footprint and a significant decrease in load within the footprint due to the economic environment. These factors have resulted in the decreased average congestion costs shown from 2007 to 2009.

In 2010, the Midwest ISO continued its evaluation of market-based congestion through analyzing the top 44 flowgates which have been congested more than 1% of the time since market launch. These flowgates were analyzed for trends and potential mitigation. It was determined that, of the top 44 congested flowgates, 34.1% had their congestion eliminated or relieved by transmission solutions proposed through the long-term, reliability based planning process. An additional 22.7% of the flowgates had their congestion alleviated or mitigated through congestion-specific targeted studies (such as the Midwest ISO Top Congested Flowgate Study or the Cross Border Congested Flowgate Study) in MTEP09 and MTEP10. The remaining 29.5% and 13.6% of these congested flowgates were coordinated and Midwest ISO flowgates, respectively, that did not have solutions identified. Continuing to address congestion is a critical component to the maintenance of a low reserve margin. For example, it is estimated by 2015 that congestion will require an incremental contribution to the reserve margin of 1.6%.

It should be stressed that not all of the proposed mitigation identified in the congestion-specific studies was implemented. A majority of the mitigation identified did not meet the cost-benefit requirements or voltage standards of the Midwest ISO or cross border cost allocation methodology. This mitigation was still eligible for construction, if a Midwest ISO stakeholder or market participant deemed it economically feasible to sponsor the mitigation.

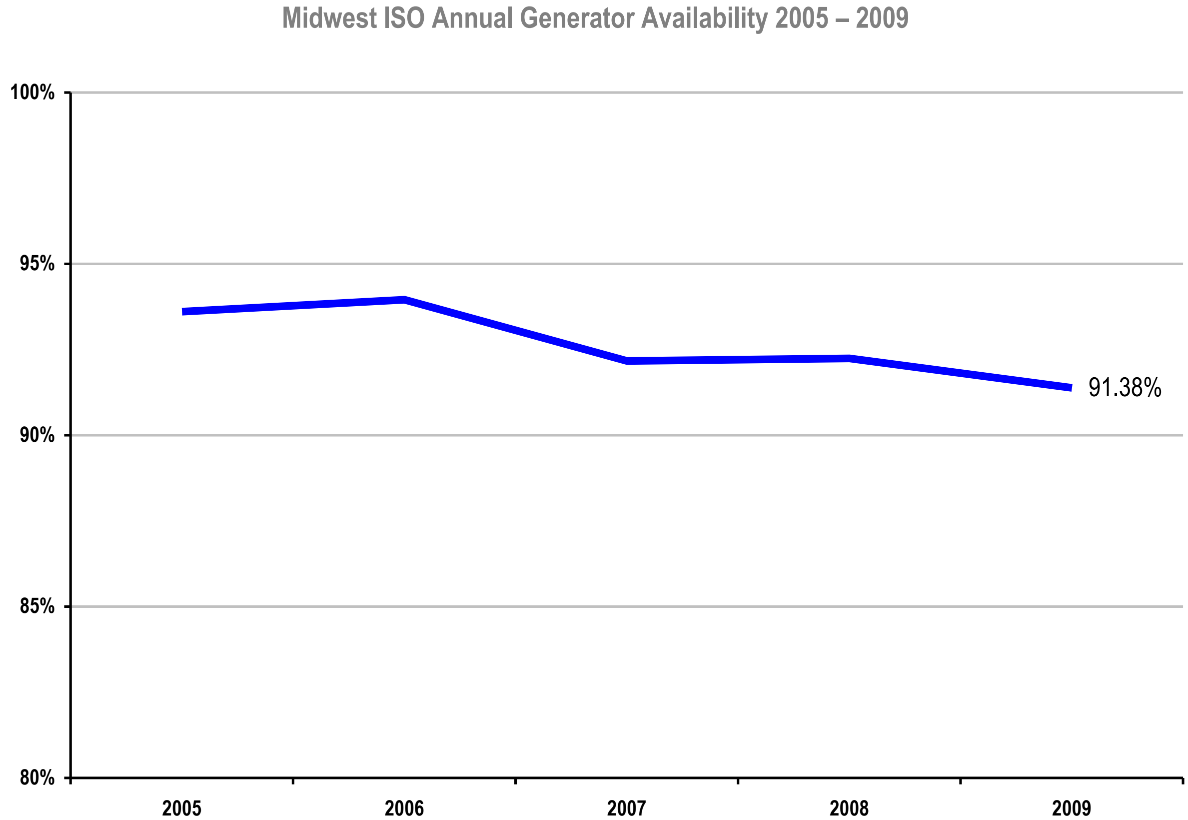
When engaging in expansion planning, careful consideration is necessary to identify transmission investments required to address chronic congestion as opposed to impulsively reacting to acute but short lived congestion. It is also important to note congestion on a particular flowgate may have only taken place part of the time in the relatively short five-year span of the market; thus, discretion should be taken before regarding historical congestion information as the sole consideration driving long-term expansion.

Midwest ISO Percentage of Congestion Dollars Hedged Through ISO/RTO Congestion Management Markets



The relationship between congestion revenues collected by the Midwest ISO and congestion payments to FTR holders is correlated with, but not equal to, congestion cost incurred by Load Serving Entities ("LSEs"). FTR value is paid to FTR holders whether or not the generator source used to serve LSE load matches an FTR source. Under least-cost regional dispatch, generation from sources other than the FTR source will be utilized when it is cost effective. As a result, FTR value may exceed congestion costs incurred for a particular FTR source and sink path. In addition, FTR holders receive revenues to offset congestion costs from sources other than FTRs. Specifically, in addition to FTR revenues realized from the Day-Ahead market, LSEs receive an allocation of FTR/ARR auction revenue. Including ARR revenues, Market Participants were funded at 96.7% in 2008 and 100.8% in 2009 after the transition from the FTR to the ARR/LTTR market mechanism.

Resources



For the Midwest ISO, the most significant driver of generation availability is the availability of actual generator performance data. In previous years leading up to the implementation of the Midwest ISO's capacity construct launched beginning June 2009, the Midwest ISO received Generator Availability Data System (GADS) data for approximately 70 % of the units operating in the Midwest ISO footprint. The balance of the units received a NERC class average. As we began replacing the class average values with actual GADS data the average Forced Outage Rates (FOR) improved in both their accuracy and capability for the Midwest ISO to calculate Unforced Capacity (UCAP) ratings used for Resource Adequacy. The Midwest ISO believes that meaningful tracking of the generator availability in the Midwest ISO begins with the June 2009-May 2010 Resource Planning Year for Resource Adequacy.

Midwest ISO's 2009 Value Proposition quantifies the benefit of improved generator availability using the Equivalent Availability Factor. The Midwest ISO's wholesale power market has resulted in power plant availability improvements of 3.1% delaying the need to construct generation infrastructure. The deferral of generation infrastructure investment represents theoretical savings of $249 to $311 million in 2009.

Out-of-merit dispatch

The frequency of out-of-merit dispatch within the Midwest ISO market is captured by transmission constraint binding hours. The Midwest ISO has seen an increase in the number of hours that constraints are bound since 2009. During 2009 there were a total of 9,745 hours of binding while through October of 2010 there have been 9,682 binding hours. A summer that included extremely hot conditions contributed significantly to the increase in binding. The tools that the Midwest ISO uses to manage constraints allow for more economical and efficient solutions that more directly impact the source of congestion. The use of a market-based Security Constrained Economic Dispatch (SCED) allows constraints to be managed in the most economical manner while allowing for maximum use of the transmission system.

Reduction of market constraints / market efficiency analysis

Midwest ISO planning looks at historical binding constraints as part of the annual Midwest transmission expansion planning (MTEP) report. For example, in the MTEP 2009 process, section 8 (market efficiency analysis) is devoted to analysis of historical congestion, a top congested flowgate study, and project-specific evaluations to mitigate top constraints. Refer to the Congestion Management section for additional details or a detailed report can be found at www.midwestiso.org.

Improving market efficiency

Through collaborative effort via the Midwest ISO stakeholder process, the Midwest ISO is always seeking ways to improve overall market efficiency. One of the recent initiatives is a new dispatchable intermittent resource that is expected to allow improved constraint control, reduced manual resource curtailments, greater market transparency, and improved price signals to intermittent resources.

Demand Response Availability

While the Midwest ISO has not experienced the need to deploy Load Modifying Resources (LMR) in an emergency (such as via Emergency Operating Procedures [EOP-002]) and thus does not have a record of LMR performance since the launch of the new Resource Adequacy construct in 2009. The Midwest ISO is currently working with stakeholders and industry organizations such as NAESB to finalize and put into practice testing, measurement and verification (M&V) standards for Demand Response. The measurement and verification procedures developed by the Midwest ISO shall take into account any applicable state regulatory, RE, or other non-jurisdictional entities requirements regarding duration, frequency and notification processes for the candidate Demand Resources.

Midwest ISO Demand Response Future Enhancements

The Midwest ISO is pursuing many improvements to evolve demand response resource participation in the region. These enhancements include:

- Extended Locational Marginal Pricing ("E-LMP") - The development of a new methodology for determining energy prices will allow, among other market benefits, demand response resources to be able to set the market price when called upon to reduce demand.

- Price Responsive Demand ("PRD") - The Midwest ISO is currently working to develop, with stakeholder participation, appropriate methods to allow for PRD in its real-time energy markets. Already able to participate in the day-ahead markets, PRD's inclusion in real-time markets could significantly impact the amount of other reserves required to reliably operate the system.

- Aggregators of Retail Customers ("ARCs") - In a filing before the FERC, the Midwest ISO has requested the ability to allow for the aggregation of demand response resources. Internal systems are already in-place for this new service, once the FERC makes its ruling.

- "Batch-load" demand response - Large-scale industrial processes are sometimes forced to interrupt their use of electricity for very brief time spans (less than 10 minutes). These industrial processes normally use large amounts of electricity and are able to reduce their use (from normal levels) for several hours at a time, but have been reluctant to register their resources because of measurement and verification ("M&V") issues related to the brief interruptions that could significantly impact the calculation of the benefit of such reduction. The Midwest ISO is currently investigating the clarification of the M&V that would enable the economically efficient incorporation of these demand response resources.

- Demand Response Availability Data System ("DADS") - The Midwest ISO is working to incorporate DADS into the formal reliability processes, similar to the way in which GADS works for generation resources.

- Demand Response / Energy Efficiency ("DR/EE") - The Midwest ISO is working to include DR/EE in the long-term planning process (MTEP). A major independent study has been conducted to project DR/EE across the Midwest ISO footprint at a detailed and local level. The inclusion of DR/EE could have significant effects upon transmission and generation requirements in long-term planning.

- Phase II NAESB Standards - The Midwest ISO is working to incorporate the developing Phase II NAESB standards for demand response M&V into its business practices.

- Load Modifying Resources ("LMR") deliverability - The deliverability of LMR may have long-term implications for reserves, as potential LMR providers weigh the benefits and restrictions of providing LMR services to the wholesale market.

- Barriers to Demand Response - The Midwest ISO continues to seek ways in which to reduce and eliminate barriers to demand response participation in all of its markets. Barriers to demand response take a variety of forms, often related to the historical precedence of generation. That is to say, current wholesale markets are based on the primacy of generation, with rules and procedures that were designed to fit generation resources. Demand resources are often required to meet requirements that, were it not for generation, would be less onerous. Examples include:

    - Definitions of contractual relationships between ARCS, LSEs, and EDCs

    - Definitions of physical/economic withholding, as it applies to ARCs

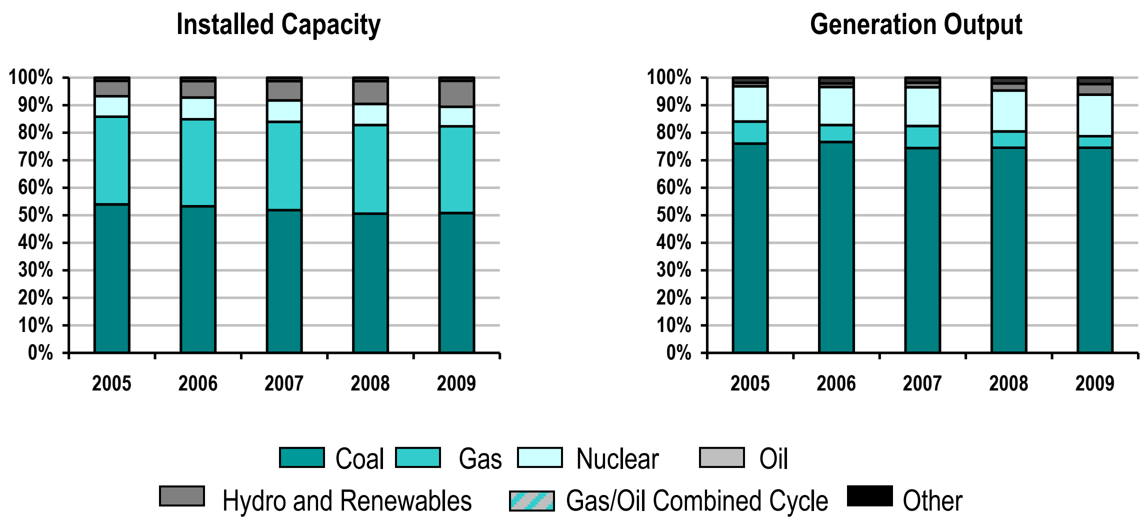
    - Metering and forecasting standards and requirements
    - Energy market issues involving DA and RT requirements for reserve offers
    - Inability of demand response resources (DRR) to control the amount of its offer in E&AS markets
    - Modeling restrictions related to generation construction schedules

- DRR Tool - The efficient use of demand response resources requires a support system that enables participants and administrators to input, track, and report on those resources. The DRR Tool, developed by the Midwest ISO specifically for demand response, provides a state-of-the-art, web-enabled system to accomplish both basic and advanced tasks including registration, double-counting avoidance, automatic reporting and alert features, and measurement and verification reports. Initially implemented this year, the DRR Tool was designed to tackle the more difficult challenges that will be faced when the FERC ultimately rules on ARCs.

- DRR Spin Services - Widespread agreement is being reached that the most efficient (and economic) use of demand response resources lies in the provision of reserve services. The Midwest ISO has consistently pursued the goal of allowing DRRs to participate in any and all markets based not on a programmatic approach – susceptible to prevailing political winds – but rather based on the physical capabilities of the resources. Market design and existing software capabilities often combine to discourage or prohibit DRRs from participation in reserve markets despite their physical ability to provide such services. The Midwest ISO was able to add spinning reserve service to those available to DRR during 2009, albeit with a 10% cap on the total MW allowed. And although that 10% value has not been binding to this point, the Midwest ISO looks forward to relaxing the cap in the near future.

Fuel Diversity

Midwest ISO Fuel Diversity 2005-2009(1)

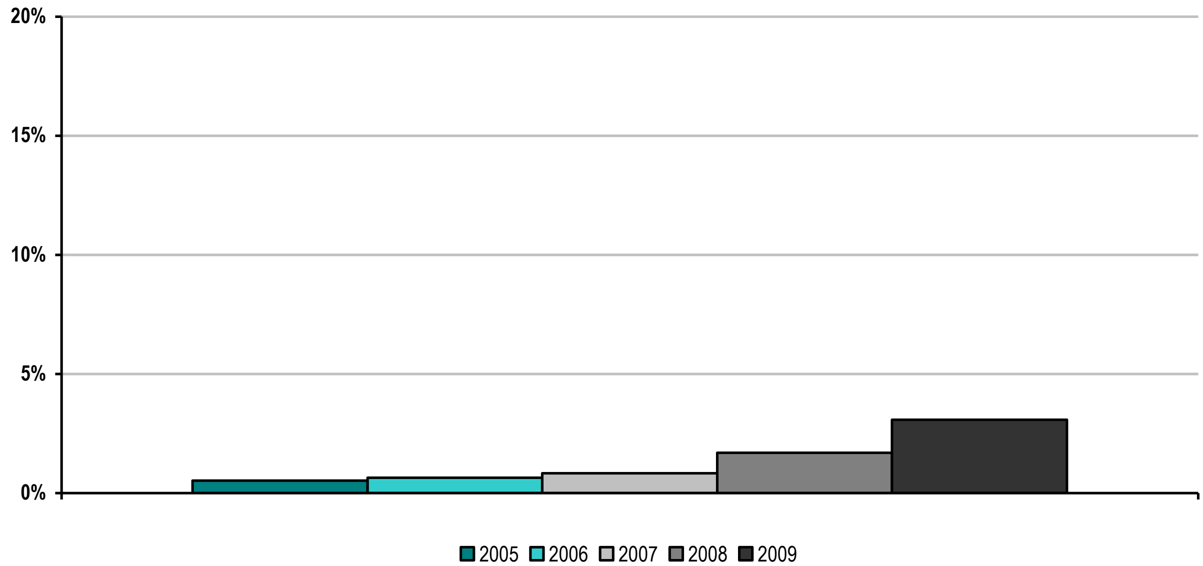


(1) "Hydro and Renewables" includes pumped storage.

In the Midwest ISO region, installed generation capacity is approximately 50% coal, 30% gas, 10% nuclear, 10% renewables. However, based on production costs in the region, security-constrained economic dispatch actually results in energy being produced approximately 75% from coal, 15% from nuclear, and 10% from other sources. Wind production is the fastest growing segment of energy production in the region growing from approximately 0.5% in 2005 to 3% in 2009.

Renewable Resources

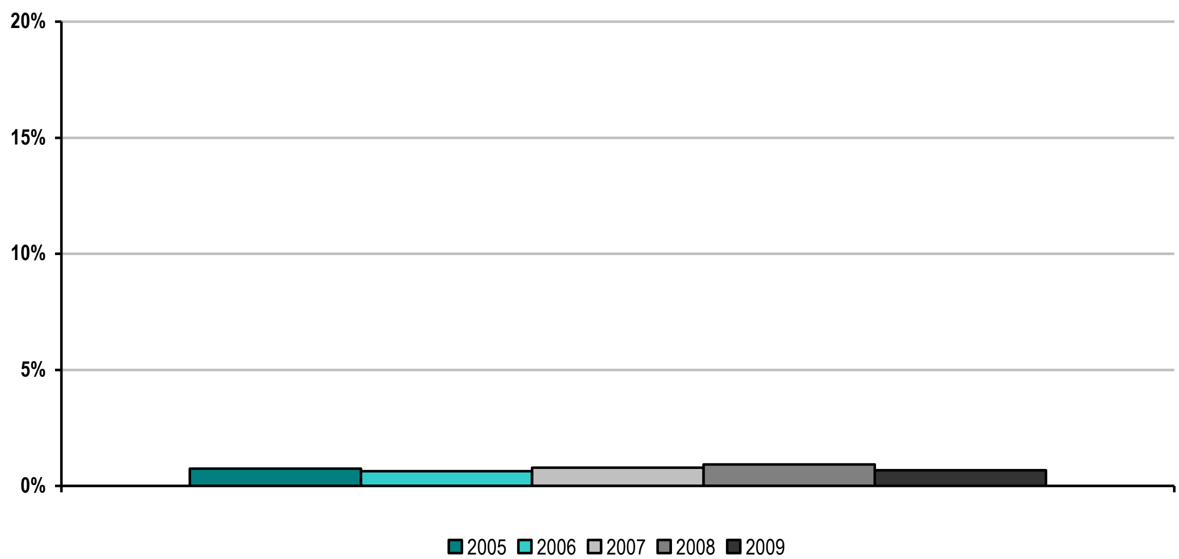
Midwest ISO Renewable Megawatt Hours as a Percentage of Total Energy 2005-2009(1)



(1) Renewables exclude hydroelectric capacity.

The Midwest ISO's renewable energy produced as a percentage of total energy rose from 0.5% in 2005 to 3.1% in 2009. In 2009, there were 1,141 curtailments of wind that were backed down due to local congestion issues. This included the curtailment of an estimated 291,674 MWh of energy and spanned over 8,005 duration hours.

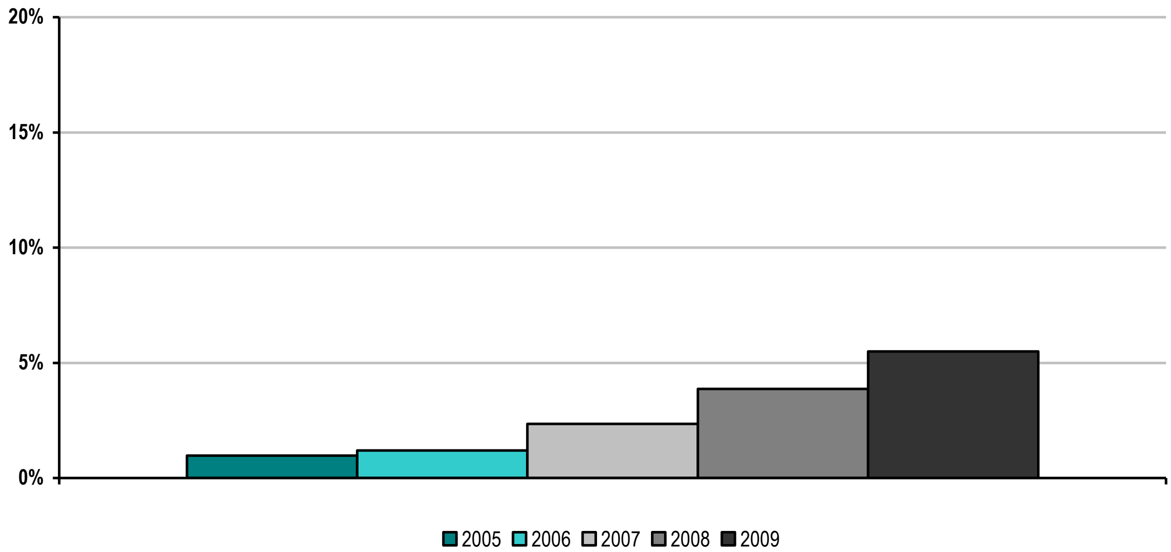
Midwest ISO Hydroelectric Megawatt Hours as a Percentage of Total Energy 2005-2009(1)



(1) Hydroelectric energy includes pumped storage.

Hydroelectric's contribution to total energy remained relatively steady at 1% from 2005 to 2009.

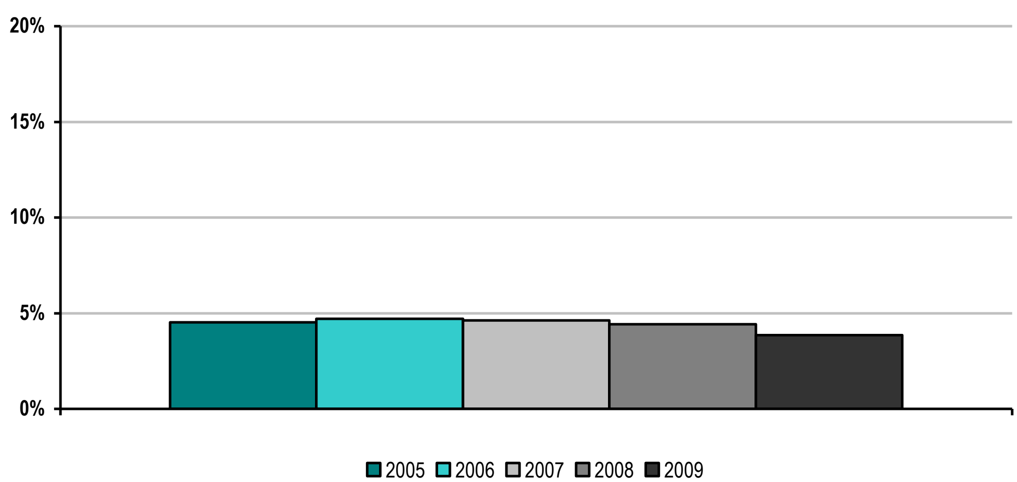
Midwest ISO Renewable Megawatts as a Percentage of Total Capacity 2005-2009[1]



(1) Renewable capacity excludes hydroelectric capacity.

The Midwest ISO's renewable energy capacity as a percentage of total capacity rose from 0.97% in 2005 to 5.50% in 2009. The average annual capacity factor of those wind units from 2005 to 2009 ranged from a low of 23.6% in 2007 to a high of 31.3% in 2009.

Midwest ISO Hydroelectric Megawatts as a Percentage of Total Capacity 2005-2009[1]

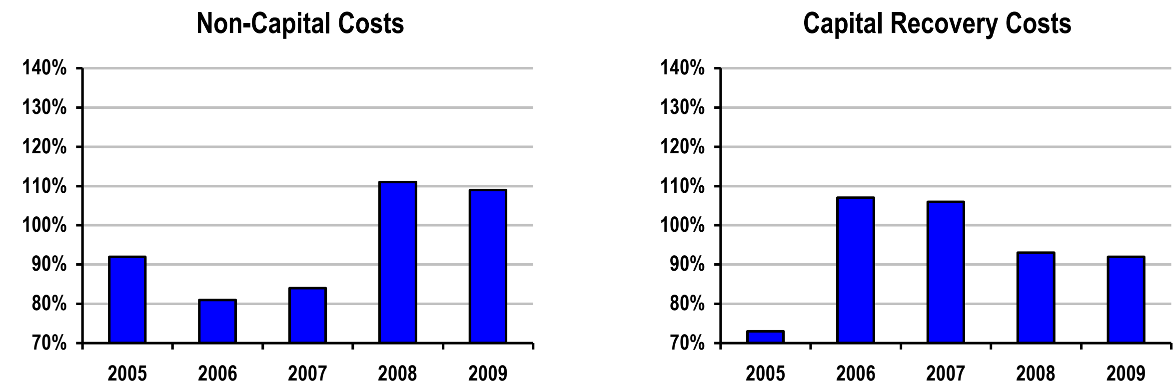


(2) Hydroelectric capacity includes pumped storage.

Hydroelectric's contribution to total capacity remained relatively steady at 4%-5% from 2005 to 2009.

C. Midwest ISO Organizational Effectiveness

Midwest ISO Annual Actual Costs as a Percentage of Budgeted Costs 2005-2009



	2005	2006	2007	2008	2009
Non-Capital Costs Budget	$153	$146	$135	$124	$153
Capital Recovery Costs Budget	$128	$104	$110	$113	$100

Bars Represent % of Actual Costs to Approved Budgets; Dollar Amounts Represent Approved Budgets (in millions)

The Midwest ISO forecasting process is designed as an integrated portion of the overall Corporate Planning Process. Operational planning and forecasting occur simultaneously and continuously in coordination with the quarterly business review process. These activities occur quarterly and look forward over the next six quarters.

The plans and forecasts are discussed during the Quarterly Business Review (QBR). The QBRs are two day senior management retreats to discuss business results and plans including planned vs. actual operating results, budget/forecast vs. actual financial performance, and their forward looking six-quarter rolling operation plan and associated forecast. The expected outcome of each QBR is a corporate plan and forecast that has been discussed and accepted by senior management. This corporate plan and forecast then guides the company forward.

Quarterly, the six-quarter rolling forecast from the QBR is presented to the Audit and Finance Committee of the Board. In establishing the budget for each calendar year, the Committee considers the last four quarters of the rolling forecast submitted to them at the August meeting as the preliminary budget for the following year. At the November meeting, the Committee will consider next calendar year's portion of the six-quarter rolling forecast as management's recommendation for budget for the following year and consider that budget for approval. The Board of Directors also reviews budget and forecast variances at each board meeting.

Stakeholder involvement is also a part of the budget and planning process. Stakeholder input is sought on the strategic plan as well as the annual budget. The Finance Subcommittee of the Advisory Committee ("FSC") reviews and provides comments to the Advisory Committee. Review of the budget with the FSC begins in August and periodic meetings are held until the FSC provides its report to the Advisory Committee and the Audit and Finance

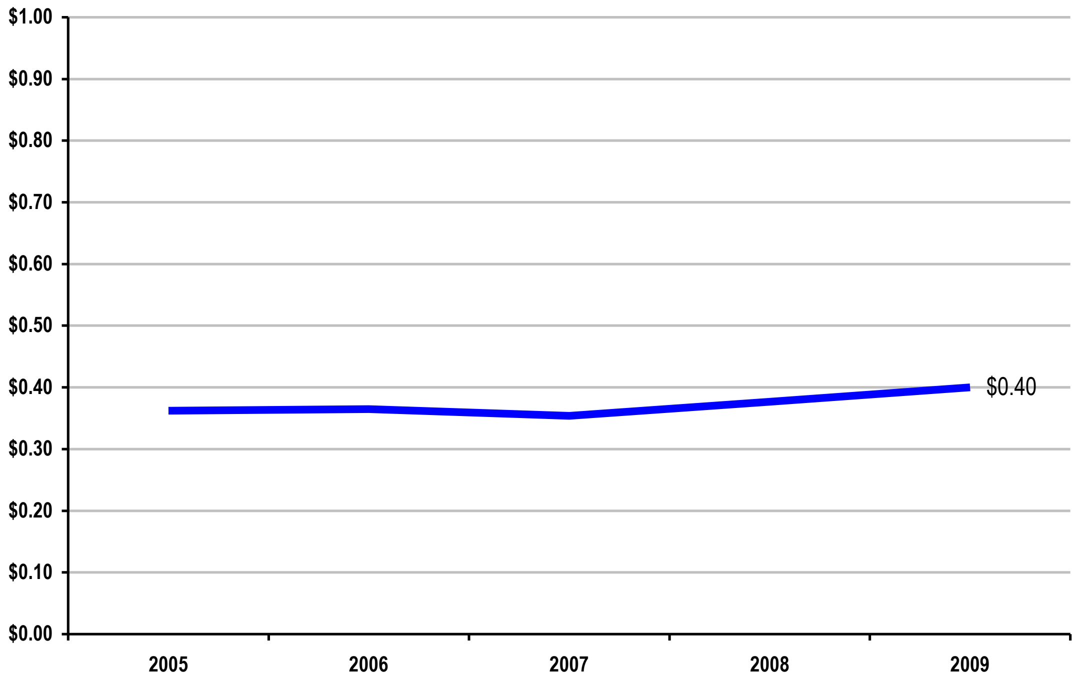
Committee of the Board of Directors. The Audit and Finance Committee of the Board of Directors reviews management's recommended budget in November and provides its feedback.

Management then submits its final recommended budget to the Audit and Finance Committee in December. After conducting a review of the proposed budget, the Audit and Finance Committee then recommends a budget to the full Board of Directors at the December Board meeting.

Base operating costs, net of miscellaneous income, for the Midwest ISO were under budget from 2005 to 2007 as a result of two primary drivers. In each year, the Midwest ISO was consistently below budget on headcount related costs (salaries and benefits) and computer maintenance driven from the start up nature of the organization. Over the same time period, the Midwest ISO was over budget on miscellaneous revenue, which is used to offset Operating Costs.

The Midwest ISO's capital investment expenses associated with financing and recovery of capital costs include interest expense, as well as depreciation and amortization expense. The under budget variance in 2005 was driven by the delay in the Energy Market start date, relative to the planned start date. The budget reflects a full year of depreciation and amortization costs, while actual expenses began on April 15th. The variances within capital investment expenses relative to budget from 2006 to 2009 are a function of interest expense. The increase in interest expense relative to budget in 2006 and 2007 is directly related to the amount of collateral held pursuant to the Credit Policy in the Tariff following the start of market operations in April 2005. The dollar volume of transactions subject to the credit policy requirements increased from approximately $100 million per year prior to energy market operations to over $40 billion per year post-market start. The increase in dollar volume settled led to an increase in cash collateral required from Transmission Customers. While the budget anticipated most of the impact of the energy market start, it did not anticipate the entire impact. The decline in interest expense, relative to budget, in 2008 and 2009 is partially related to changes in market rules that accelerated the payment of market charges as well as the significant decrease in interest earned on funds held as collateral.

Midwest ISO Annual Administrative Charges per Megawatt Hour of Load Served 2005-2009
($/megawatt-hour)

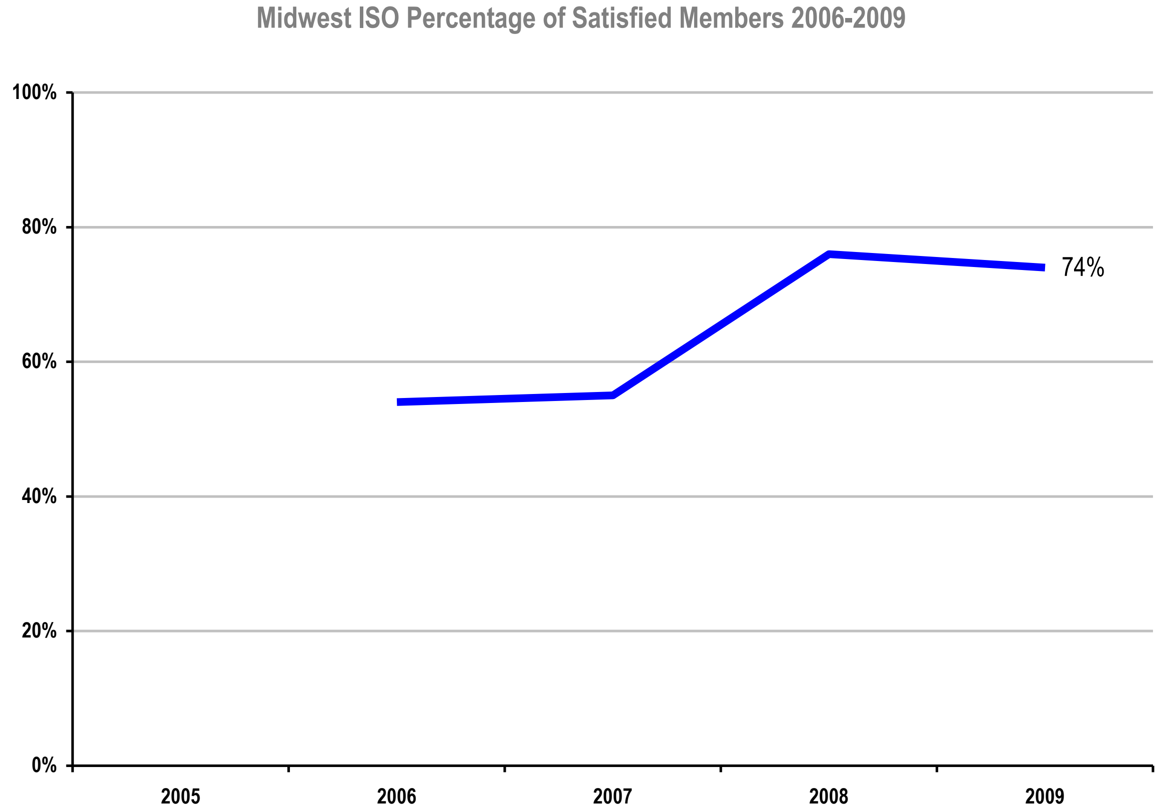


The administrative costs per MWhr of load served data in the chart above should be reviewed in the context of the widely-varying levels of annual load served by each ISO/RTO as noted in the table below.

ISO/RTO	2009 Annual Load Served *(in terawatt hours)*
Midwest ISO	513

Prospectively, the Midwest ISO forecasts its annual administration rates will approximate $0.373, $0.335 and $0.315 per MWh of load in 2011, 2012 and 2013, respectively. These administration rates reflect the ending of amortization of startup costs associated with the energy market. In addition, load reductions due to demand response have an immaterial effect on annual administration rates. The projected cost per MWh varies with the amount of load served.

Customer Satisfaction



The Midwest ISO's current survey asks 116 questions on a wide variety of subjects ranging from transmission planning to market operations to control room operations. An average score from a subset of that question set, covering key business areas, is used to determine the Midwest ISO's overall customer satisfaction rating. The metric shown above reflects a percentage of respondents' answers that rated 5 or better on a 7 point scale. The respondents to the survey include transmission owners, market participants, regulators, and other Midwest ISO stakeholders. The survey is administered by an independent firm.

The Midwest ISO utilizes the results of its Annual Customer Survey to enhance products and services, and respond to key customer themes that are identified within the survey's results.

Business area representatives have addressed our stakeholders in robust discussions surrounding Midwest ISO processes, procedures and constraints related to the Annual Survey results. Additionally, enhancements to internal practices have resulted from the feedback received via the Annual Survey mechanism.

Billing Controls

ISO/RTO	2005	2006	2007	2008	2009
Midwest ISO	Qualification for One Control Objective in SAS 70 Type 2 Audit	Unqualified SAS 70 Type 2 Audit Opinion	Qualification for One Control Objective in SAS 70 Type 2 Audit	Unqualified SAS 70 Type 2 Audit Opinion	Unqualified SAS 70 Type 2 Audit Opinion

In 2005, a single information system control objective was qualified. In 2007, two control objectives were qualified, one related to transmission settlement charges for curtailment of transactions and one related to the process for managing changes to information systems.

The Midwest ISO focuses on the accuracy of both prices posted and amounts billed to ensure members can rely on prices for transacting and have confidence in the amounts included in their Midwest ISO invoices.

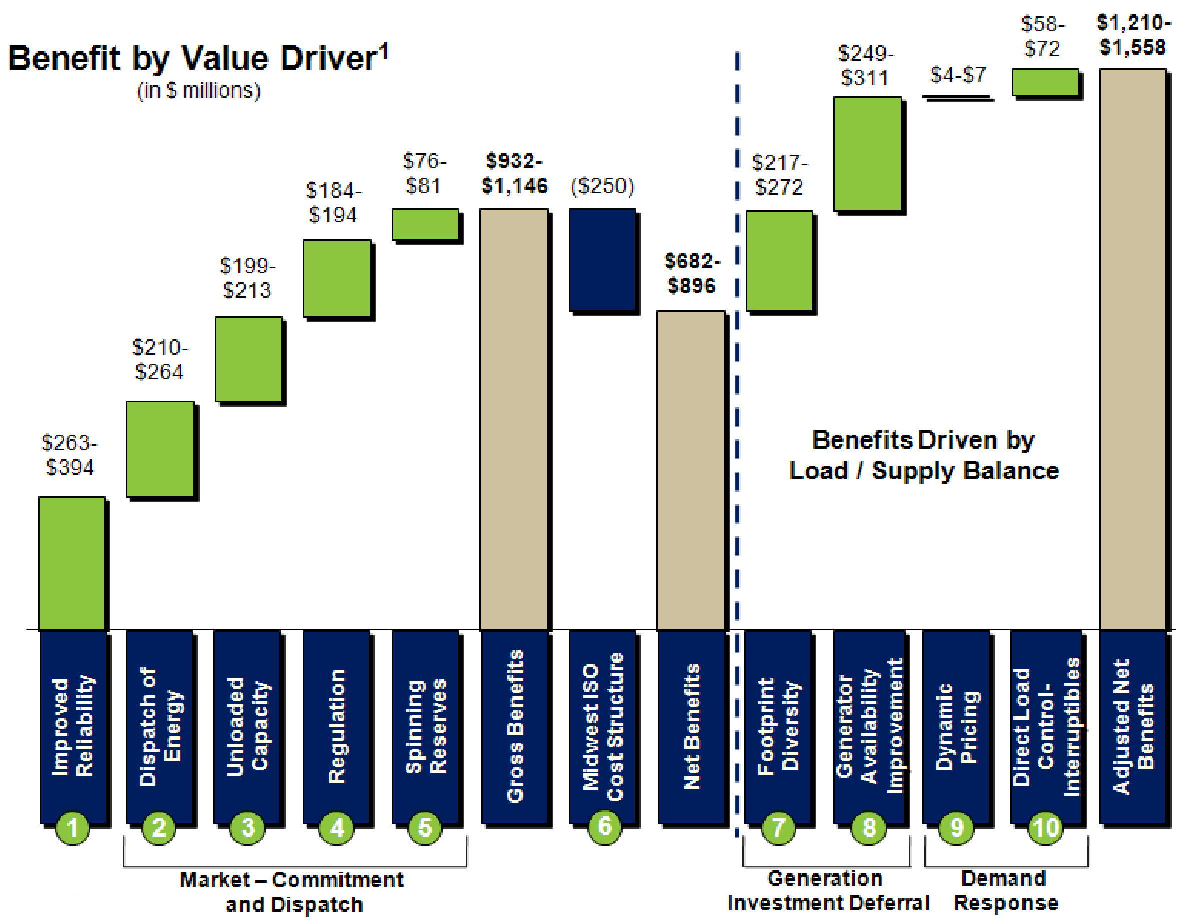
- From the start of the market on April 1, 2005 to December 31, 2009, the Midwest ISO had three Market Implementation Errors (MIE). The average dollar impact of these MIEs was $461.

- For 2009, the Midwest ISO made 16 adjustments as a result of settlement errors. The total net amount adjusted for 2009 was -$173,715.

D. Midwest ISO Specific Initiatives

As the Midwest ISO views its contributions to the region, our commitment to operational excellence is evidenced by its continued effort to develop and refine our own Value Proposition metrics. The Midwest ISO has collaborated with its stakeholders since implementing its energy market in 2005 to create and enhance this meaningful and effective set of tools to measure the value that the Midwest ISO provides. The Value Proposition metrics, which are available to the public on the Midwest ISO website, are updated regularly to provide feedback on the effectiveness of Midwest ISO operations.

The Value Proposition breaks the Midwest ISO business model into certain recognized categories of benefits to the footprint as a whole and calculates a range of dollar values for each defined category. The benefits studied are: reliability, energy dispatch, unloaded capacity, regulation, spinning reserves, diversity of resources in the footprint, generator availability, and two categories of demand response (dynamic pricing and interruptibles). After accounting for the load reductions driven by the economic downturn, our 2009 Value Proposition demonstrates between $700 and $900 million in annual net economic benefits to our region. These benefits are illustrated and described below:



Quantitative Benefits

A. Improved Reliability - $263 to $394 million in annual benefits

The Midwest ISO's broad regional view and state-of-the-art reliability tool set enables improved reliability for the region as measured by transmission system availability.

B. Dispatch of Energy - $210 to $264 million

The Midwest ISO's real-time and day-ahead energy markets use security constrained unit commitment and centralized economic dispatch to optimize the use of all resources within the region based on bids and offers by market participants.

C. Unloaded Capacity - $199 to $213 million

With the start of the Ancillary Services Market and the functional consolidation of the region's Balancing Authorities, responsibility to respond to operating issues was consolidated in the Midwest ISO eliminating the need for multiple Balancing Authorities to hold unloaded capacity.

D. Regulation - $184 to $194 million

With the start of the Midwest ISO Regulation Market, the amount of regulation required within the Midwest ISO footprint has dropped significantly. This is the outcome of the region moving to a centralized common footprint regulation target rather than a number of non-coordinated regulation targets within the footprint.

E. Spinning Reserves - $76 to $81 million

Starting with the formation of the Contingency Reserve Sharing Group and continuing with the implementation of the Spinning Reserves Market, the total spinning reserve requirement has been reduced freeing low-cost capacity to meet energy requirements.

F. Midwest ISO Cost Structure - $248 million in annual costs

Administrative costs are expected to remain relatively flat into the future.

G. Footprint Diversity - $217 to $272 million

Midwest ISO's large footprint increases the load diversity factor allowing for a decrease in regional planning reserve margins from 15.40% to 12.69%. This decrease delays the need to construct new capacity.

H. Generator Availability Improvement - $249 to $311 million

The Midwest ISO's wholesale power market has resulted in power plant availability improvements of 3.1% delaying the need to construct new capacity.

I. Dynamic Pricing - $4 to $7 million

The Midwest ISO enables dynamic pricing which provides customers with a rate signal that reflects the higher cost of providing electricity during peak times than off-peak times. Dynamic pricing allows additional generation investment deferral.

J. Direct Load Control and Interruptible Contracts - $58 to $72 million

The Midwest ISO enables direct load control and interruptible contracts which provide load serving entities the ability to curtail load. This allows the load serving entities to defer generation investment by lowering demand.

Qualitative Benefits

In addition to the quantitative benefits the Midwest ISO has demonstrated as part of its Value Proposition, there are also significant qualitative benefits that wholesale market participants derive from the existence and operation of the Midwest ISO, including:

1. Price transparency
2. Planning coordination
3. Regulatory compliance
4. Wholesale platform for integrating renewables

New York Independent System Operator (NYISO)

Section 5 – NYISO Performance Metrics and Other Information

The New York Independent System Operator ("NYISO") is a not-for-profit corporation responsible for operating the state's bulk electricity grid, administering New York's competitive wholesale electricity markets, conducting comprehensive long-term planning for the state's electric power system, and advancing the technological infrastructure of the electric system serving the Empire State.

The creation of the NYISO was authorized by the Federal Energy Regulatory Commission ("FERC") in 1998. In November 1999, New York State's competitive wholesale electricity markets were opened to utility and non-utility suppliers and consumers as the NYISO began its management of the bulk electricity grid. The formal transfer of the grid operation responsibilities from the New York Power Pool to the NYISO took place on December 1, 1999.

The NYISO monitors a network of 10,892 miles of high-voltage transmission lines and serves approximately 400 market participants. Through the end of 2009, NYISO market transactions totaled more than $75 billion.

In 2009, installed capacity in the NYISO control area totaled 38,190 megawatts (MW). The NYISO's record peak load of 33,939 MW was recorded in August 2006.

The NYISO is governed by an independent Board of Directors and a committee structure comprised of a diverse array of stakeholder representatives. The members of the NYISO's 10-member Board of Directors have backgrounds in electricity systems, finance, academia, information technology, communications, and public service. The members of the Board, as well as all employees, have no business, financial, operating, or other direct relationship to any market participant or stakeholder. NYISO stakeholder committees are comprised of representatives of market sectors that include transmission owners, generation owners, other suppliers, end-use consumers, public power, and environmental parties.

Since the inception of the NYISO, 95% of the tariff revisions filed with FERC have been developed through consensus among NYISO stakeholders about new market rules and operating procedures. The value of shared governance was noted by FERC in a January 2008 order that stated, "The Commission commends NYISO & the stakeholders for working together to resolve many issues …"

The mission of the NYISO, in collaboration with its stakeholders, is to serve the public interest by:

- *Maintaining and enhancing regional reliability;*
- *Promoting and operating a fair and competitive electric wholesale markets;*
- *Planning for the power system of the future; and*
- *Providing objective and independent technical information on energy issues.*

A. NYISO Bulk Power System Reliability

The table below identifies which NERC Functional Model registrations the NYISO has submitted as effective as of the end of 2009. In addition, the Regional Reliability Organization (RRO) for the NYISO is noted at the end of the table with a web site link to the specific reliability standards.

- The NYISO has had **no self-reported or audit-identified violations** of NERC or applicable RRO operating reserve standards.

- The NYISO has not shed any load in the New York Control Area ("NYCA") due to a standards violation.

NERC Functional Model Registration	NYISO
Balancing Authority	✓
Interchange Authority	✓
Planning Authority	✓
Reliability Coordinator	✓
Resource Planner	✓
Transmission Operator	✓
Transmission Planner	✓
Transmission Service Provider	✓
Regional Entity	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

In addition, section 215 of the Federal Power Act, as amended by the Energy Policy Act of 2005, allows the State of New York to "establish rules that result in greater reliability within the state." The NYISO is, therefore, also responsible for complying with rules established by the New York State Reliability Council, L.L.C ("NYSRC"), whose mission is to promote and preserve the reliability of electric service on the New York power system by developing, maintaining, and updating the Reliability Rules which shall be complied with by the NYISO and all entities engaging in electric transmission, ancillary services, energy and power transactions on the New York power system.

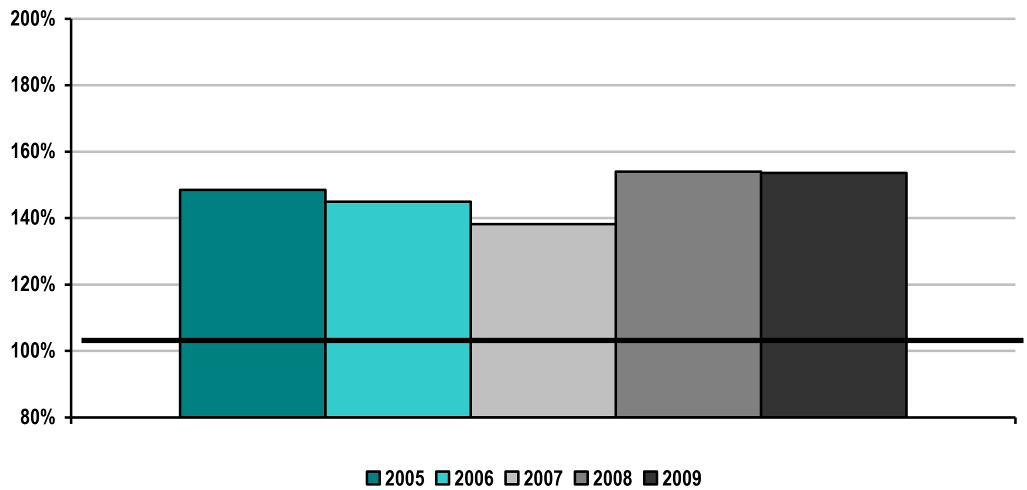
The New York State Reliability Council and the Reliability Rules they administer are available at:
http://www.nysrc.org/

Dispatch Operations

In addition to the on-going review of control performance by NYISO System Operations, a daily review of performance occurs by NYISO Operations staff each business day. The NYISO incorporates CPS compliance in its analysis and establishment of regulation requirements, which are specified by season and hour. The NYISO recently updated the regulation requirements to reflect findings of the 2010 Wind Study, which analyzed the net variability of load, and wind. Regulation is co-optimized along with energy and reserves within the NYISO's Day-Ahead and Real-Time markets, allowing the most efficient resources to provide the regulation needed to maintain Control Performance. The NYISO's current regulation requirements can be found at the following location:

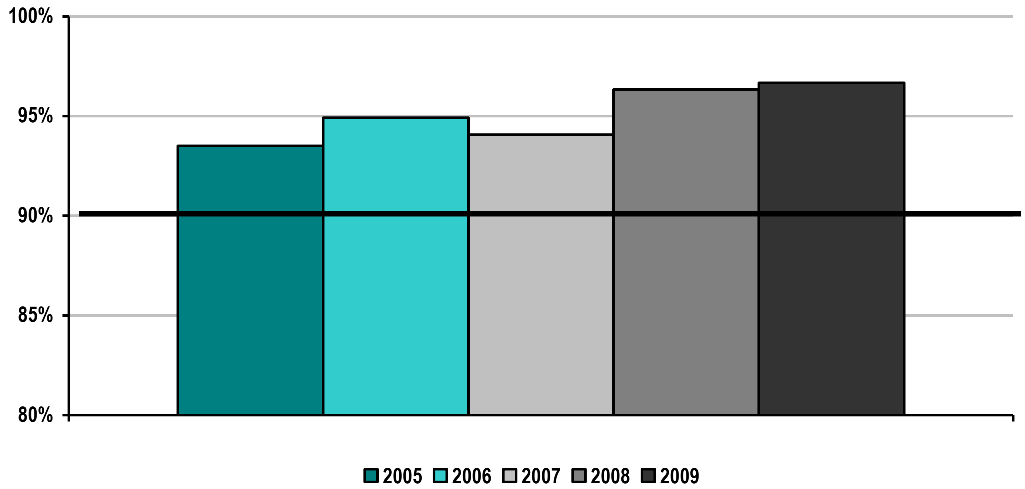
http://www.nyiso.com/public/webdocs/market_data/reports_info/nyiso_regulation_req.pdf.

NYISO CPS-1 Compliance 2005-2009



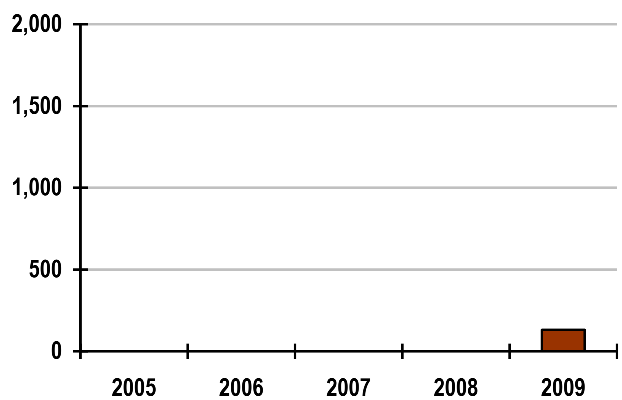
Compliance with CPS-1 requires at least 100% throughout a 12-month period. The NYISO was in compliance with CPS-1 for each of the calendar years from 2005 through 2009.

NYISO CPS-2 Compliance 2005-2009



Compliance with CPS-2 requires 90% for each month in a 12-month period. The NYISO was in compliance with CPS-2 from 2005 through 2009.

NYISO Transmission Load Relief or Unscheduled Flow Relief Events 2005-2009



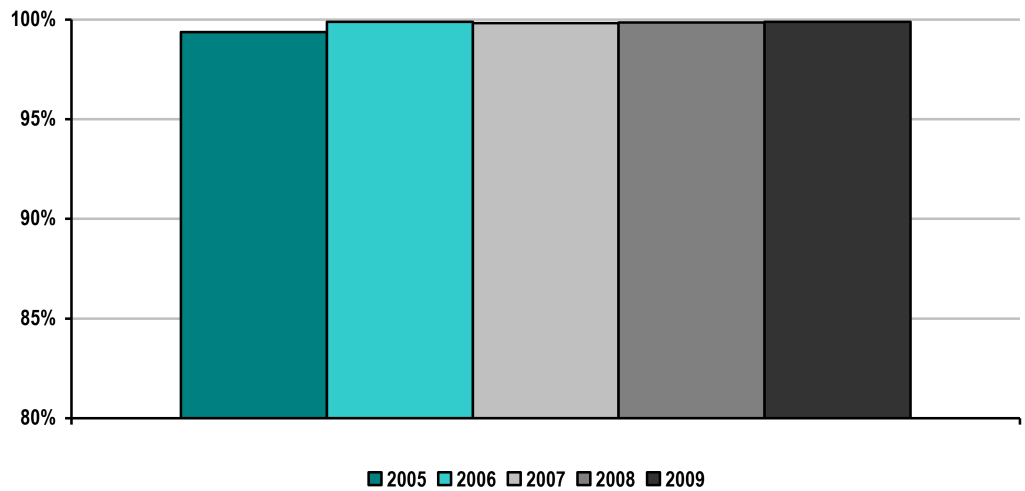
*NYISO did not initiate TLR requests prior to 2009

Prior to March 2009, NYISO did not request Transmission Load Relief (TLR) curtailments and addressed all New York transmission constraints through internal New York generation redispatch, regardless of whether the transmission constraints were aggravated by unscheduled loop flows. Since March 2009, in order to address the high levels of clockwise Lake Erie loop flows that significantly impacted New York transmission reliability constraints, the NYISO began to request TLR curtailments. All TLR curtailments requested by NYISO, as reported in the graph above, were Level 3 TLR curtailments.

Future NYISO Enhancements:

The NYISO would prefer to use market mechanisms rather than requesting TLR curtailments to address the impact of unscheduled loop flows on New York transmission constraints. In order to improve coordination of interregional power transactions, the NYISO, in conjunction with grid operators serving the Mid-Atlantic, Midwest, and New England regions of the United States and the Canadian province of Ontario, proposed a Broader Regional Markets plan, which is discussed in the "Unscheduled Flows" section of this report. In particular, the initiatives on buy-through of congestion and market-to-market coordination are aimed at reducing the need for requesting TLR curtailments.

NYISO Energy Management System Availability 2005-2009



Availability of the Energy Management System ("EMS") is an important factor that enables reliable monitoring of the electric transmission system in the NYCA. Given that a State Estimator solution is required for the EMS applications, the NYISO availability statistics are based on the number of solved State Estimator ("SE") cases as compared to the total number of SE runs. For the past five years, NYISO's EMS has shown excellent performance and has been available more than 99% of all hours in each year. Tracking of availability data in 2005 began on July 1st of that year and the data provided represents the performance from July 1st through the end of the year.

Load Forecast Accuracy

The NYISO's load forecasting model is a unified system that uses a series of equations, drivers, and historical information specific to each of the eleven LBMP zones in New York. It uses a combination of Advanced Neural Network ("ANN") and regression models to generate its forecasts. The ANN analysis takes a non-linear approach to the estimation of the model's parameters. The regression models are linear models estimated using ordinary least squares.

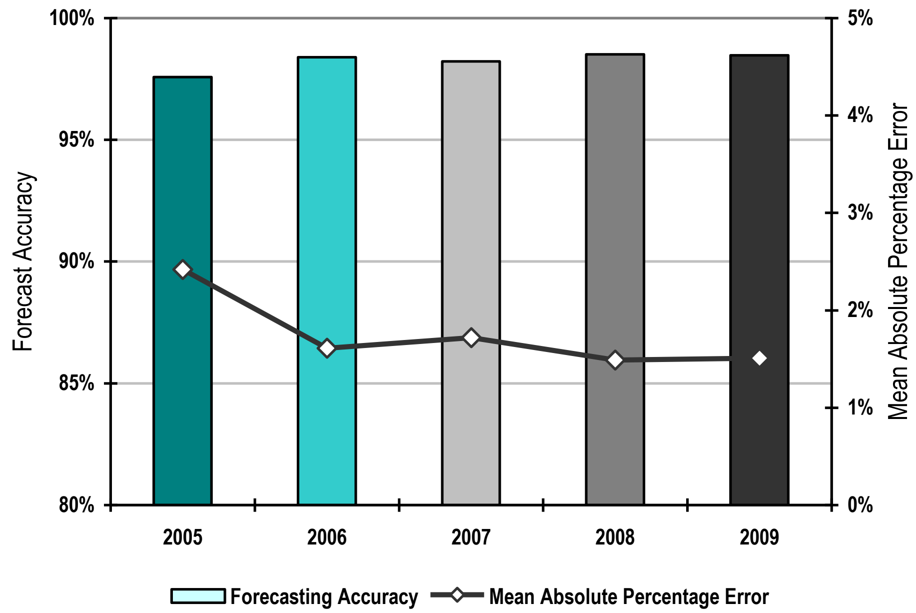
The load forecasting model uses historical load and weather data information for each of the NYISO's eleven zones to develop zonal load forecast models. These models are then used together with zonal weather forecasts to develop an independent load forecast for each zone. The zonal forecasts are summed to produce a forecast for the NYCA as a whole. The model develops the hourly load forecasts for the current day and the next six days, a total of up to 168 hours. The NYISO reviews and re-estimates its day-ahead forecasting models prior to June of each year to keep them up to date.

The load forecasting model uses proprietary weather data and forecasts from the NYISO's weather information vendor. The hourly weather data provided by the vendor include dry bulb temperature, wind speed, cloud cover, dew point, and wet bulb temperature. The data from the stations is aggregated in a manner that best represents each zone.

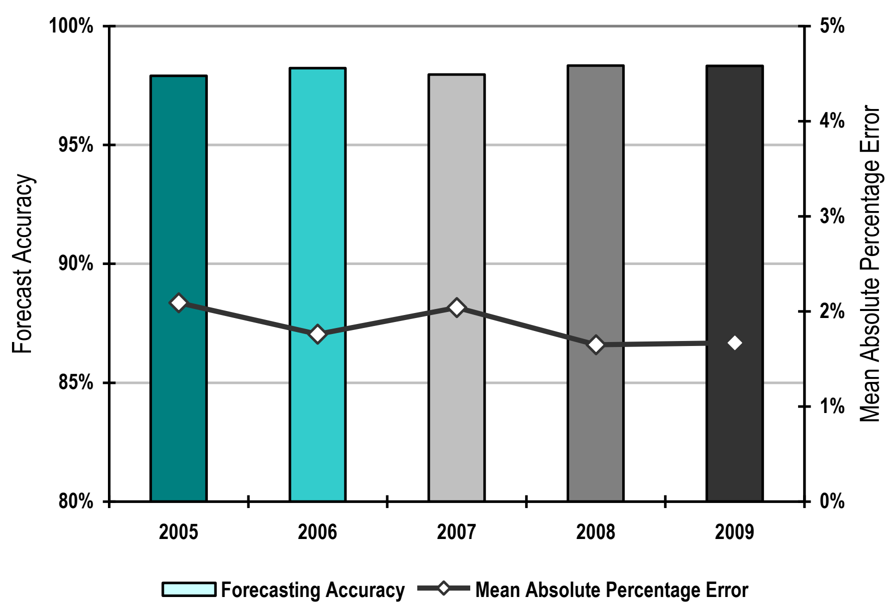
The day-ahead load-forecasting model does not currently incorporate economic assumptions or economic forecast data since these variables are virtually constant from one day to the next.

ISO/RTO	Load Forecasting Accuracy Reference Point
NYISO	5:00 a.m. prior day

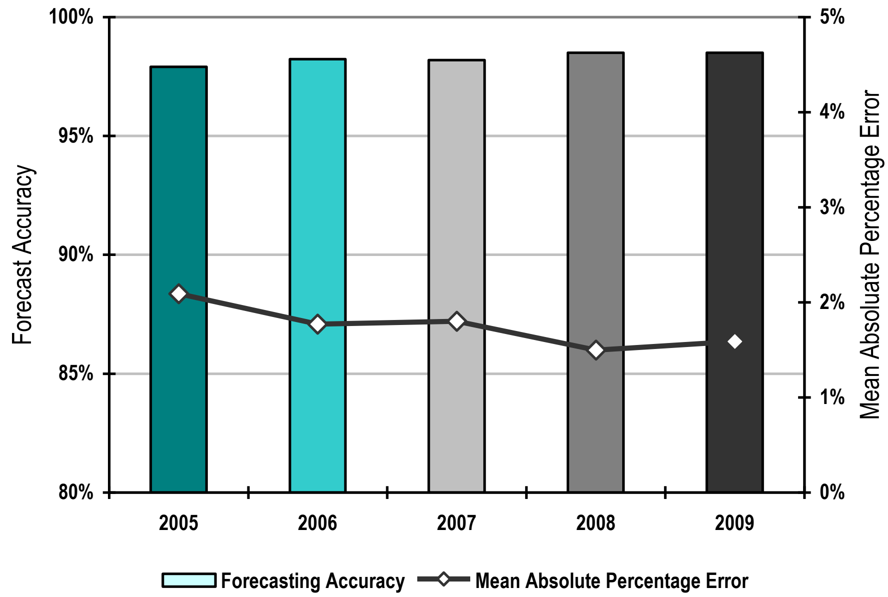
NYISO Average Load Forecasting Accuracy 2005-2009



NYISO Peak Load Forecasting Accuracy 2005-2009



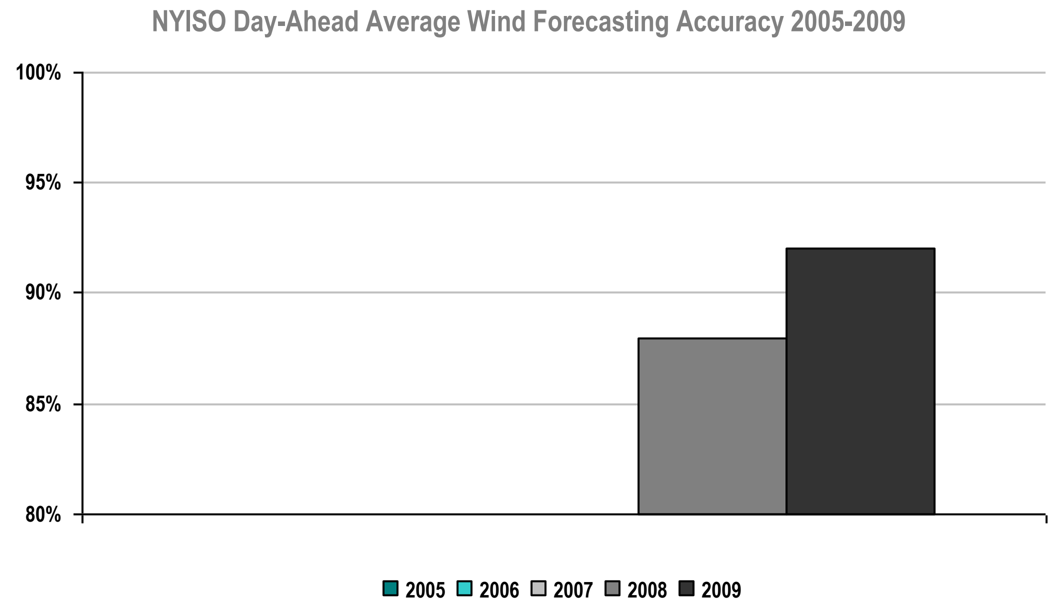
NYISO Valley Load Forecasting Accuracy 2005-2009



The three charts above show the percent accuracy and the Mean Absolute Percentage Error ("MAPE") of NYISO load forecasting for average daily load, peak load, and valley load from 2005 to 2009. The decrease in the MAPE indicates an increase in accuracy, since the error has been reduced. The NYISO's unified load forecasting approach is applied to each of the LBMP zones in the New York Control Area. Continuous forecasting system process improvements have increased forecasting accuracy and a commensurate decrease in the MAPE. The high level of accuracy contributes to efficient operation of the bulk power system and wholesale electricity markets, which provides economic benefit to consumers.

The FERC has requested that Day-Ahead forecast accuracy reflect the impact of demand response. Going forward, the NYISO can provide metrics that specifically account for such factors. During the 2005-2009 period, the NYISO activated its demand response program on only a small number of days to address peak demand. As a result, the exclusion of the impact of the programs on the metric is negligible.

Wind Forecasting Accuracy

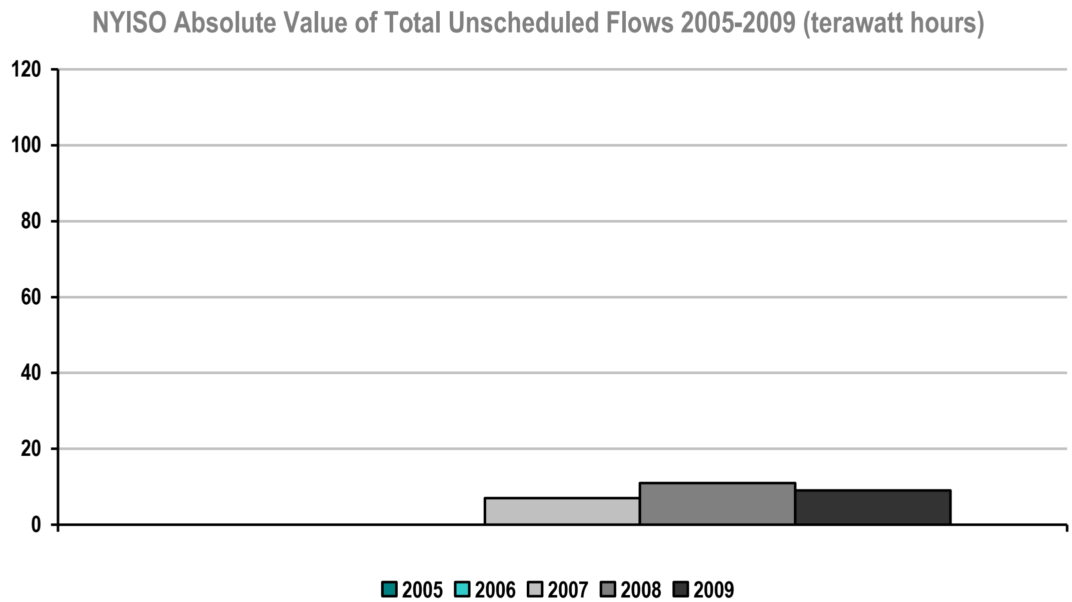


In mid-2008, the NYISO instituted one of the first state-of-the-art wind forecasting systems in the United States incorporating wind power forecasts into Day-Ahead and Real-Time Market tools to improve commitment and scheduling of resources. The centralized system enables the NYISO to better utilize and accommodate wind energy by forecasting the availability and timing of wind-powered generation. The real-time forecasts are updated every 15-minutes and integrated into the NYISO's real-time Security Constrained Dispatch. Day-Ahead forecasts are updated twice daily and are integrated into the Day-Ahead market during the reliability evaluation. In 2009, the NYISO became the first grid operator to dispatch wind power fully balancing the reliability requirements of the power system with the use of the least costly power available via an economic dispatch.

The Mean Absolute Error (MAE) on a Day-Ahead basis was approximately 12% for the second half of 2008 and improved to 8% in 2009 (the values presented in the graph above are 1-MAE, which represents the statistic in terms of accuracy rather than error). The improvement in accuracy from 2008 to 2009 is associated with having a more robust data set available to train and improve the forecast models. The Day-Ahead wind forecast statistics are based on the forecast updated at 4AM the day prior to the operating day and used in the Day-Ahead Market evaluation. The MAE in real-time on an hour-ahead basis was approximately 5% in 2008 and 4% in 2009.

The NYISO develops forecasts for variable energy resources when there is an operational need for the information. Due to the limited amount of non-wind variable energy resources, the NYISO does not currently require forecast data for these resources.

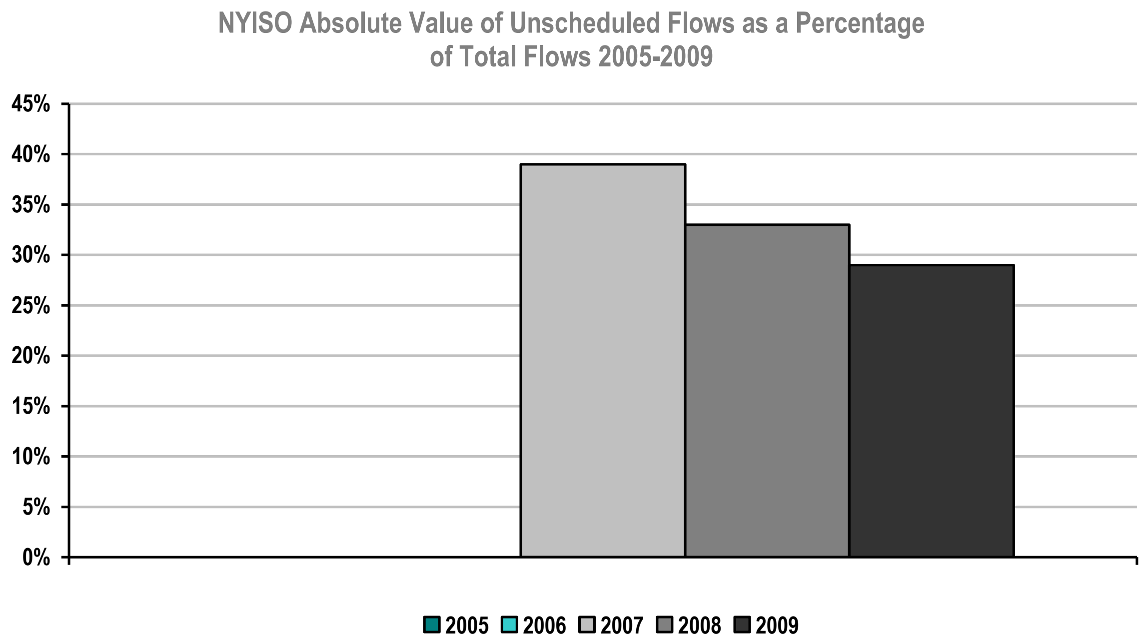
Unscheduled Flows



*Data not available prior to 2007

For context, the table below notes the number of NYISO's external interfaces. The NYISO has free flowing interfaces with PJM, Ontario, and ISO-NE and the other six interfaces are controllable line interfaces. Unscheduled flows vary in both magnitude and direction and occur primarily on the Ontario and PJM interfaces. These two interfaces reflect the same flows (the numerical conventions are such that a negative flow on the PJM interface corresponds to a positive flow on the Ontario flow).

ISO/RTO	Number of External Interfaces
NYISO	9



*Data not available prior to 2007

(in terawatt hours)

NYISO Unscheduled Flows by Interface	2005	2006	2007	2008	2009
Ontario Independent Electricity System Operator (1)	--	--	3.3	4.7	3.8
PJM (1)	--	--	3.2	4.8	3.9
ISO-NE (1)	--	--	0	0	0

(1) Data unavailable prior to 2007

The NYISO experiences a larger percentage of unscheduled flows than some of its neighboring market areas due to both the direct impact from Lake Erie loop flows, as well as the lower volume of total scheduled flows and limited number of interfaces. Lake Erie loop flow is currently an uncontrolled, unscheduled quantity that directly impacts two of the NYISO interfaces, with flows impacts observed on both the IESO and PJM interfaces. Due to the limited number of other interfaces and the smaller volume of power trading that can be managed on these interfaces, the impact from these unscheduled flows represents a significant portion of the total flows scheduled. The chart above shows that, at times, unscheduled flows account for a large proportion of flows over the collective interfaces. As discussed below, the NYISO is pursuing with all of its neighboring market areas the Broader Regional Markets initiatives, in part to address the impact produced by the Lake Erie Loop Flow unscheduled impacts and to remove barriers to more efficient interregional trading to improve the volume of trading.

Future NYISO Enhancements:

Collaborating extensively with IESO, Midwest ISO, PJM, and ISO-NE, the NYISO proposed the Broader Regional Markets plan to the FERC in January 2010. In a July 15, 2010 Order, the FERC conditionally approved the proposal, saying, "…these planned regional initiatives will be designed to reduce uplift costs and lower total system operating costs…" A preliminary analysis of the benefits of various components of the Broader Regional Markets plan conducted by Potomac Economics estimates regional annual savings of at least $368 million. The coordination of flows around Lake Erie was estimated to result in $51 million in annual savings to the region.

The Broader Regional Market proposals include both market based and physical solutions. The market solutions include:

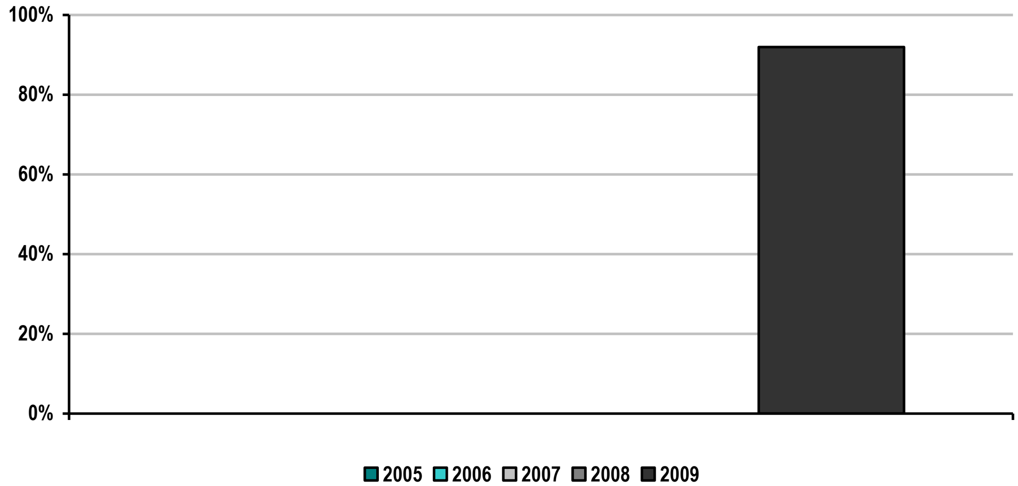
- *Buy-through of congestion, which would require that the congestion cost of a transaction be charged based on the physical flow of power, unlike the current settlement determination that is based only on the contract path.*
- *Market-to-market coordination, which would increase the level of collaboration in congestion management between system operators in the region.*
- *Interface pricing revisions, which would improve the pricing at the points at which energy moves between individual grid operators to allow for more efficient regional power transfers.*
- *Inter-regional transaction coordination, which would lower total system operating costs as transaction schedules more quickly adjust to market-to-market pricing patterns.*

In addition, the proposal includes the development of a parallel flow visualization tool designed to enhance the exchange of transmission system information and to assemble the necessary real-time data to perform the generation-to-load calculations, facilitate the calculation of impacts, and make available common and consistent information regarding the sources of power flows and their impacts to all regions. It is expected that the reactivation of a set of Phase Angle Regulators (PARs) on the Michigan-Ontario border will help to align the actual power flows around Lake Erie with the corresponding level of scheduled transactions.

Transmission Outage Coordination

The NYISO coordinates all requests for transmission outages based on their potential impact on system reliability and is not aware of any unexpected generator availability impacts or declared emergencies associated with uncoordinated transmission outages.

NYISO Percentage of > 200kV planned outages of 5 days or more that are submitted to ISO/RTO at least 1 month prior to the outage commencement date 2009



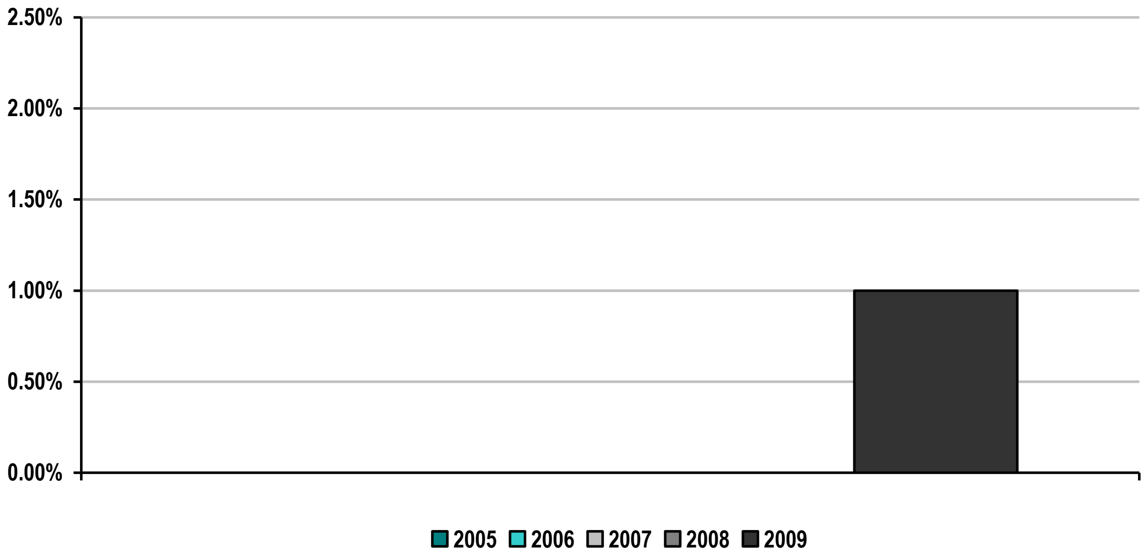
*Data unavailable prior to 2009

NYISO data for the metric, "Percentage of > 200 kV planned outages of 5 days or more that are submitted to ISO/RTO at least 1 month prior to the outage commencement date," are based on outage data that includes inter-control area tie lines and internal NYCA lines and transformers greater than 200 kV.

The NYISO requires that Transmission Owners submit outage requests for facilities expected to impact system transfer capability of the NYISO secured system "no later than 30 days prior to first of the operative TCC month," with a few exceptions allowed to address reliability needs or outages with limited impact. This requirement results in advanced notification of at least 1 month prior to outage commencement for 92% of transmission outages in 2009. Data are not available prior to 2009 due to the format of historic records. In 2009, the NYISO integrated a new outage scheduler application that will enable more efficient reporting of outage statistics on a going-forward basis.

The metric, "Percentage of planned outages studied in the respective ISO/RTO Tariff/Manual established timeframes," is not applicable to NYISO. The NYISO does not have established timeframes to study planned outages in its Services Tariff. All outages are included as part of the Day-Ahead Market evaluation for consideration prior to the operating day.

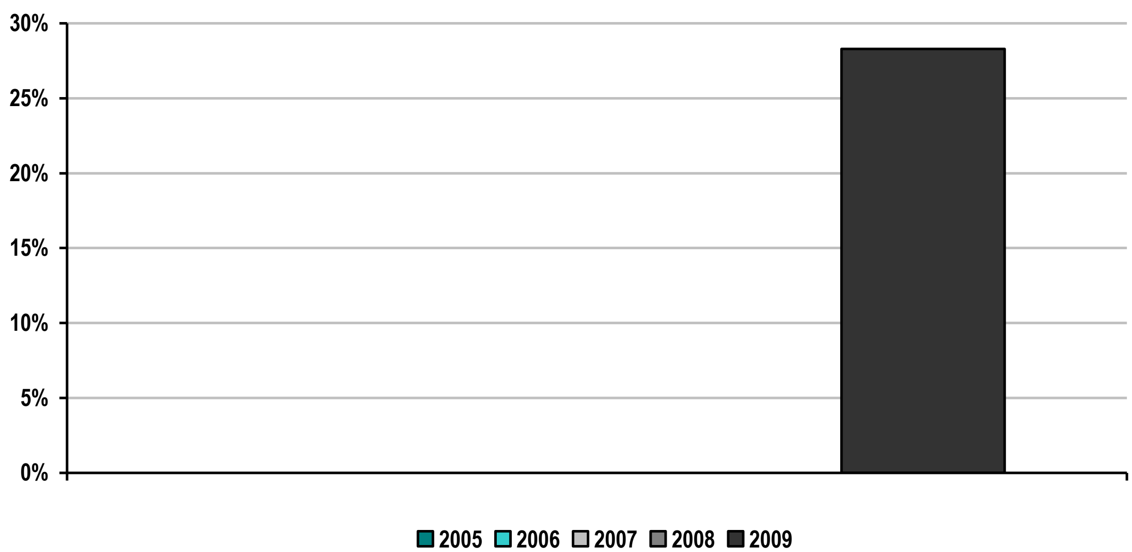
NYISO Percentage of > 200 kV outages cancelled by ISO/RTO after having been previously approved 2009



*Data unavailable prior to 2009

NYISO data for the metric, “Percentage of > 200 kV outages cancelled by ISO/RTO after having been previously approved,” demonstrates that only one percent of outages were cancelled in 2009. Data are not available prior to 2009 due to the format of historic records. In 2009, the NYISO integrated a new outage scheduler application that will enable more efficient reporting of outage statistics on a going-forward basis.

NYISO Percentage of unplanned > 200kV outages 2005-2009



*Data unavailable prior to 2009

It is necessary to have outages submitted and verified in advance of the Day-Ahead market evaluation in order to be considered planned by the NYISO. The NYISO classifies outages with less than two days notice unplanned. As a result, the NYISO statistics for "Percentage of unplanned > 200kV outages" may appear higher as compared to other areas. The NYISO data are also based on the following criteria: unplanned outages of at least 1 hour duration including inter-control area tie lines, internal New York Control Area lines, and transformers > 200kV. NYISO data for the metric, "Percentage of unplanned > 200kV outages," are not available prior to 2009. In 2009, the NYISO integrated a new outage scheduler application that will enable more efficient reporting of outage statistics on a going-forward basis

Transmission Planning

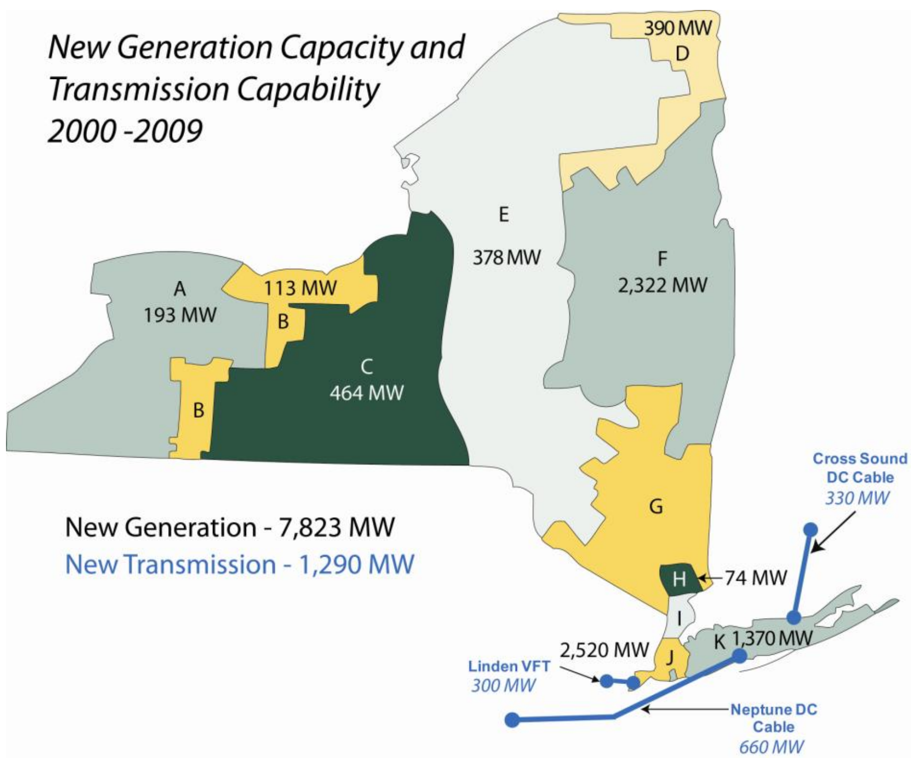
Markets and Investment Enhance Reliability

The NYISO's market-based approach to the transmission planning process is significantly different from any other regions' transmission planning processes. Consistent with the NYISO's Transmission Owner ("TO") Agreement and Open Access Transmission Tariff ("OATT"), the NYISO does not "approve" or "require" facilities to be constructed for reliability purposes. The NYISO's role is to evaluate and monitor the reliability of the system, assess reliability needs, and solicit market solutions. The market and TOs provide solutions to meet identified reliability needs, and determine which resources are financed, built, and operated.

Through this market-based approach, New York has attracted significant private and public investment in transmission and generation. This approach serves to protect consumers when investors – rather than rate-paying consumers – assume the financial risk for merchant projects.

Since 2000, over 7,800 MW of new generation has been built by public power authorities and private developers, with 80 percent of that capacity sited in the southeastern region of the state where electricity demand is greatest. This pattern of development has mitigated the need for transmission solutions to the reliability needs of the New York electric system.

Nearly 1,300 MW of new interstate transmission capability has been added to meet the needs of the metropolitan New York region. These additions are the Cross Sound Cable, an HVDC line from Long Island to Connecticut (2005), the Neptune Cable between Long Island and New Jersey (2007), and the Linden Variable Frequency Transformer project connecting PJM and New York City (2009). Several other transmission projects are in the construction phase, including a new 345-kilovolt (kV) cable from Westchester to the Manhattan. These additions have enhanced the reliability of New York's bulk power system and mitigated reliability needs.



NYISO Comprehensive System Planning Process

The NYISO's Comprehensive System Planning Process (CSPP) is an ongoing market-based process that evaluates resource adequacy and transmission system security of the state's bulk electricity grid over a 10-year period and evaluates solutions to meet reliability and congestion relief needs. The CSPP contains three major components - local transmission planning, reliability planning, and economic planning. Each two-year planning cycle begins with the local transmission plans of the New York transmission owners, followed by NYISO's Reliability Needs Assessment (RNA) and Comprehensive Reliability Plan (CRP). Finally, economic planning is conducted through the Congestion Analysis and Resource Integration Study (CARIS).

Reliability Studies

Consistent with Order 890, the NYISO's Comprehensive System Planning Process (CSPP) begins with the Transmission Owner's Local Transmission Plans (LTP). Upon review and discussion of these plans through the NYISO stakeholder process the LTP's are included in the base case of the Reliability Needs Assessment (RNA). The RNA evaluates the future reliability of the New York bulk power system through a ten-year planning horizon. In this step, the NYISO, in conjunction with Market Participants, evaluates the adequacy (Loss of Load Expectation (LOLE) and security (unanticipated loss of system elements or contingencies) throughout the entire bulk power system against mandatory national standards, regional reliability standards, and additional standards specific to New York State to identify any reliability needs, or potential reliability needs, over the planning period and issues its findings in a report that is approved by the NYISO Board of Directors.

This assessment serves many purposes, including but not limited to:

- Supporting the efficient and reliable operation of the New York bulk power system.
- Evaluating the reliability needs of the local and system-wide resource adequacy , and transmission security and transfer capability
- Identifying the location and nature of any potential factors and/or issues that could adversely impact system reliability throughout the ten year planning horizons.

The second step is the creation of the CRP that consists of proposed solutions to address the needs identified in the RNA, if any. Generation, transmission, and demand side programs are considered on a comparable basis as potential reliability solutions. A request for solutions to identified reliability needs is issued with the expectation that Market-Based Solutions will come forward to meet the identified needs. In the event that Market-Based Solutions are not sufficient, the process provides for the identification of Regulated Backstop Solutions proposed by designated transmission owners, and Alternative Regulated Solutions proposed by any market participant. The NYISO then evaluates all proposed solutions to determine whether they will meet the identified reliability needs. From this evaluation the CRP is developed, setting forth the plans and schedules that are expected to be implemented to meet the reliability needs.

The objective of this comprehensive approach is to:

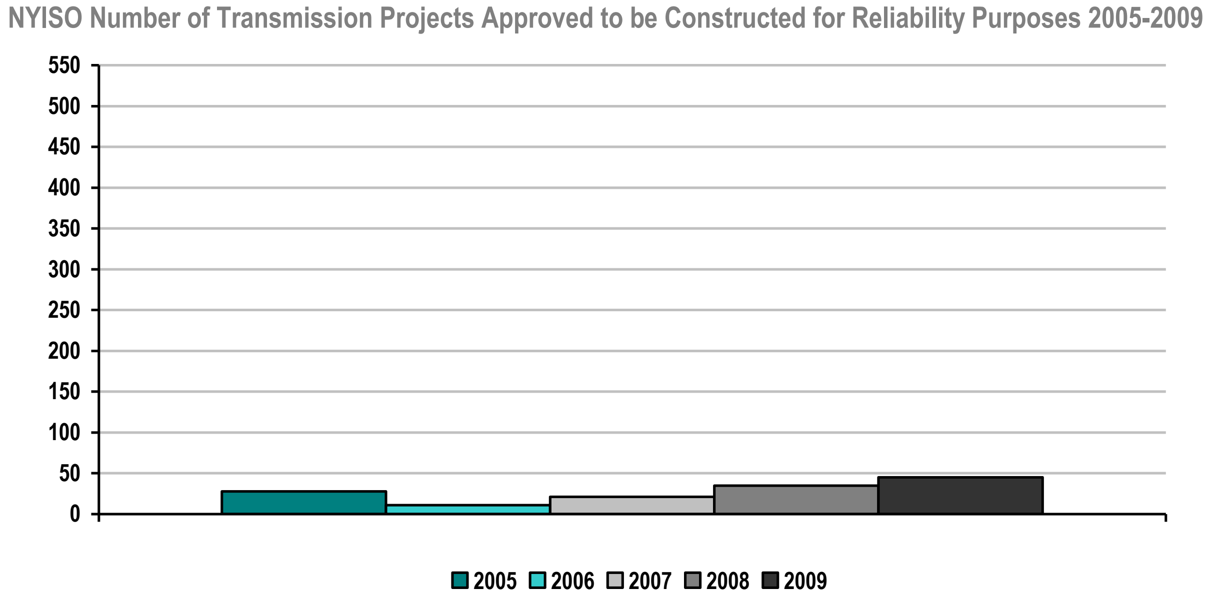
- Provide a process whereby solutions to identified needs are proposed, evaluated, and enacted in a timely manner to maintain the reliability of the system.
- Provide for the development of market-based solutions, regulated backstop solutions, and alternative regulated solutions the opportunity to respond to NYISO's reliability needs signals.
- Coordinate the NYISO's reliability assessments with neighboring ISO/RTOs.

NYISO Economic Studies

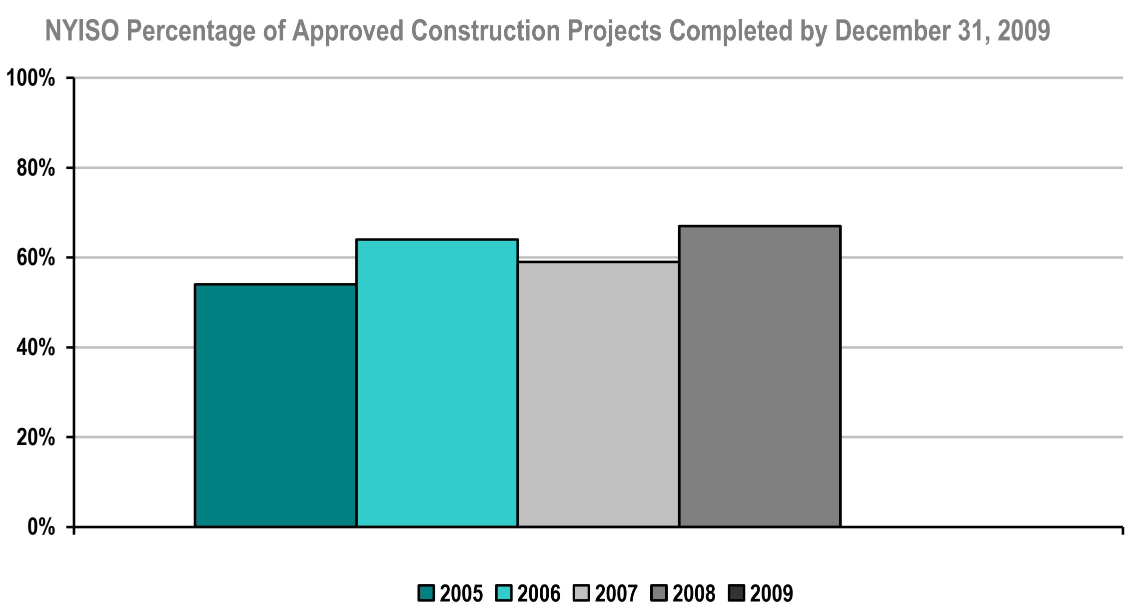
For the first time, the 2009 CRP was the starting point for the new economic planning process called the Congestion Assessment and Resource Integration Study (CARIS). The CARIS evaluates transmission constraints and potential economic solutions to the congestion identified. Generation, transmission, and demand side programs are considered on a comparable basis as potential economic solutions for alleviating the identified congestion. The CARIS is also a two-step process, (1) the study phase; and (2) the project phase. The first CARIS study phase was concluded in early 2010. Currently, one developer has responded with a request for the NYISO to evaluate its proposed congestion relief project.

NYISO Integration of Innovative Technologies

The NYISO has moved to take advantage of advanced grid-scale energy storage facilities with new market rules and associated software and control systems. In May 2009, the FERC approved tariff revisions making the NYISO the first grid operator in the nation to establish provisions for limited energy storage resources (LESRs) to provide regulation services in the NYISO market. LESRs include technologies such as flywheels and advanced battery systems that store electricity, but are limited in the amount of time they can sustain electric output. A 20 MW flywheel system is expected to become operational in 2010. Another 20 MW flywheel project is in the NYISO interconnection queue, along with three battery projects totaling 60 MW.



The transmission projects in this chart include projects developed by New York Transmission Owners through their local transmission planning processes, these projects have been included in NYISO's reliability planning base cases. The NYISO reliability planning process, discussed above, did not evaluate any transmission projects as no transmission project was submitted to meet reliability needs identified in the 2005 Reliability Needs Assessment (RNA). In 2007, 3 transmission projects were identified as viable to meet an identified reliability need, and another project was also identified in 2008. In 2009, there were no reliability needs identified due to an increase in available resources and the expansion of energy efficiency programs in the state.



**Data for completed construction projects approved in 2009 is not yet available.

For the period 2005-2009, a significant number of transmission projects that were approved have been constructed. The majority of them have been built in response to economic opportunities identified through market signals, and serve to essentially negate the need for “reliability” transmission projects. One transmission project built in 2009 had previously been identified as a viable reliability solution by the NYISO CSPP. This was the 300 MW Linden Variable Frequency Transformer project, identified in the 2007 Comprehensive Reliability Plan (CRP).

Future NYISO Enhancements:

Maintaining the integrity of New York’s high-voltage transmission network is a primary focus of efforts to sustain and enhance overall power grid reliability. New and upgraded high-voltage transmission facilities are expected to be needed to strengthen the state’s bulk power grid and facilitate the integration of more renewable resources. Future enhancements are focused on easing transmission system bottlenecks, permitting wider access to lower-cost wholesale electricity while reducing the overall cost of power.

The New York TOs have initiated a State Transmission Assessment and Reliability Study (“STARS”) project that is designed to assess the condition of the state’s electric transmission infrastructure and identify needed improvements to sustain a robust and reliable electric supply system for the future. Initial study findings are expected to be developed in 2010.

It is important to note that several previously proposed transmission projects have met with strong opposition based on environmental, health, aesthetic, and community concerns. The NYISO is actively participating in collaborative planning efforts among New York stakeholders to explore innovative solutions, such as replacing older, low capacity transmission lines with new higher capacity lines within existing rights-of-way.

Generation Interconnection

Overview

Since 2000, over 7,800 megawatts (MW) of new generation have been built by public and private suppliers, with 80 percent sited in New York City, on Long Island and in the Hudson Valley, the regions where demand is greatest. In addition, 1,290 MW of transmission capability have been added to bring power to the downstate region from out of state. These developments occured despite the expiration of New York State's power plant siting law in 2002.

The NYISO's role in the interrconnection process is that of process administrator, project and system evaluator, and arbiter to ensure that the Project Developer and Transmission Owner collaborate in good faith to keep the project moving forward in an indiscriminate manner. The process includes the identification and cost allocation of system upgrades necessary for the safe and reliable interconnection to the bulk power system. This thorough and comprehensive process includes:

- Interconnection Request submission, review, validation and approval;
- Scoping of project, including NYISO receipt of necessary technical data for each;
- Scoping of Feasibility Study(ies), including execution of study agreement and NYISO receipt of necessary technical data;
- Conduct Feasibility Study(ies) with final report meeting with Developer and TO;
- Scoping of System Reliability Impact Study(ies), including execution of study agreement and NYISO receipt of necessary technical data;
- Conduct System Reliability Impact Study(ies) with final report meeting with Developer and TO;
- Scoping of Facilities Study(ies), including execution of study agreement and NYISO receipt of necessary technical data;
- Conduct Class Year Facilities Study(ies) with system facilities upgrades and capacity deliverability cost allocation, with final report meeting with Developer and TO;
- Submission and approval of Class Year Facilities Study(ies) to NYISO Market Participant governance working groups, sub-committees and Operating Committee.
- Decisions of Project Developers to accept or not accept their Project Cost Allocatios for system upgrades
- Interconnection Agreements provided to Developer, including proof of continued site control and the achievement of development milestones, to be filed with FERC

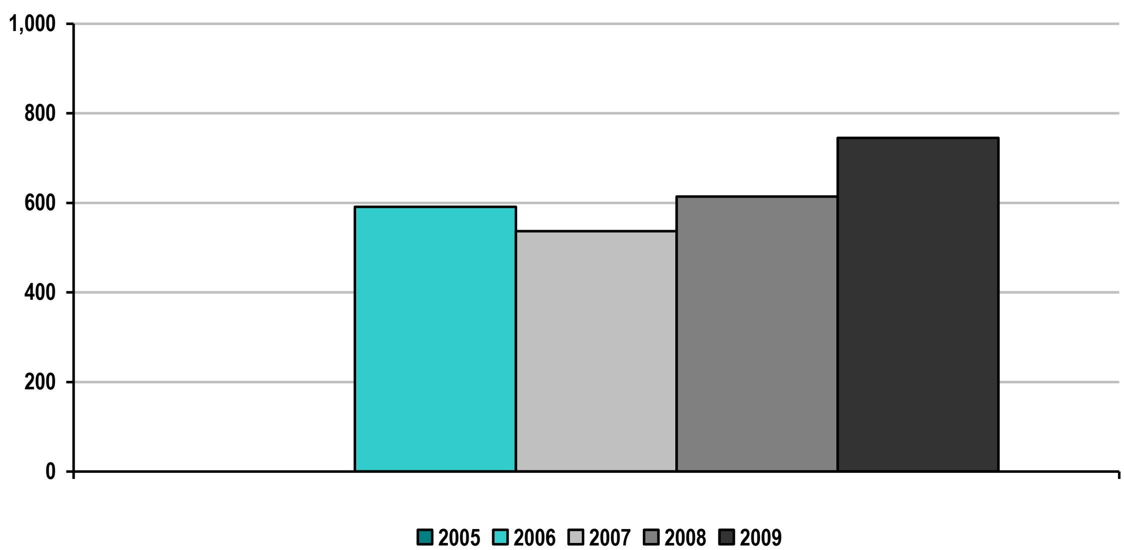
Interconnection Process Evolution and Responsiveness

The NYISO interconnection process has evolved and adapted to meet the expansion of new entrants in New York's wholesale electricity markets. The combination of open access, market opportunities, and public policy initiatives has significantly expanded the scope and array of projects submitted to the NYISO Interconnection Queue.

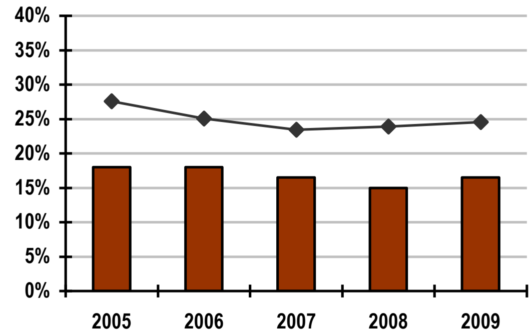
In 2004, the adoption of the “Standard Large Facility Study Procedures (“LFIP”)resulted in the initiation of many new studies, but few were completed during that year. In 2005, there was a significant influx of wind projects, creating a backlog of studies that carried over to 2006. During 2006, the NYISO implemented a number of changes in the study process to address the expanding number of projects and studies. The impact of the 2006 process changes resulted in the completion of current projects. However, hundreds of additional projects, particularly wind projects, were be submitted for study. As a result of continued enhancement of the process and the similarity of the project types (wind) completion times for studies improved. As the diversity of project types submitted in 2008 expanded, including new energy storage projects, the study times also expanded to reflect the uniqueness of each project. Also in 2008, the NYISO began implementation of the FERC required capacity deliverability studies, which significantly increased the Interconnection Request Processing Time for years 2008 and 2009 (see chart below). In late 2008 and throughout 2009, economic conditions caused developers to slow the pace of proposed projects, and several projects were withdrawn, resulting in lengthened study times. The NYISO has worked with developers desiring to keep their queue position , but moderate the pace of studies until economic conditions improve. This accommodation to developers appears to have increased interconnection study times, and slowed completion of studies in 2008 and 2009.

The integration of new technologies into the grid presents unique challenges in performing interconnection and system planning studies. In many cases, models for these new technologies submitted to the NYISO Interconnection Queue are not readily available and are under various stages of development. This means that project developers often do not have adequate and documented models from the equipment manufacturers or engineering consultants to validate the operation of the proposed equipment. In some cases, model developers claim confidentiality of their models and don't provide adequate documentation for the study analysts to verify that the models provided reasonably represent the actual characteristics of the proposed equipment. As for integrating new technologies into system planning studies, standard assumptions used to study conventional facilities do not necessarily apply. For example, energy storage and regulation facilities are not proposed for the purpose of providing peak load capacity, but rather to provide short-term power to shave peaks and fill valleys during the day.

NYISO Average Generation Interconnection Request Processing Time 2005-2009
(calendar days)



NYISO Planned and Actual Reserve Margins 2005 – 2009



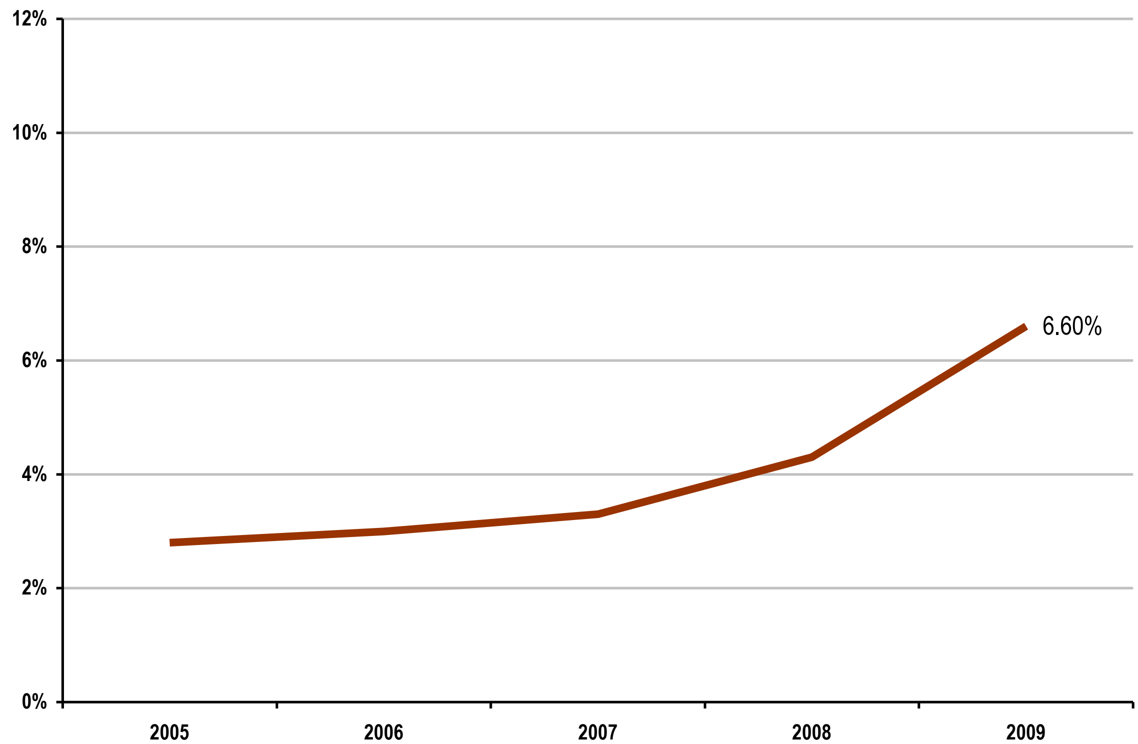
Bars Represent Planned Reserve Margins	Lines Represent Actual Reserves Procured

The Installed Reserve Margin ("IRM"), is determined annually by the New York State Reliability Council ("NYSRC"), and is subject to final regulatory approval by the Federal Energy Regulatory Commission and the New York State Public Service Commission. The statewide IRM for the 2010/2011 capability year is 18 percent. Based on the IRM, the NYISO has determined the installed capacity requirements total 38,970 MW. The total capacity available to the state is expected to be roughly 43,000 MW, which includes 37,416 MW of in-state resources, an additional 2,251MW Special Case Resources (a NYISO Demand Response program) and 2,645 MW of import capability that could be used to supply capacity from neighboring regions to New York.

Increased generator performance and improved availability of the NYCA power plants contributed to a downward trend in the reserve margin. Reserve margins are beginning to trend upwards, reflecting the ability of the markets to incent the active participation of all generation and demand-side resources. The efficient operation of the NYCA bulk electric system and wholesale electricity markets has sustained and enhanced system reliability and successfully focused resource development in regions where demand is greatest.

The NYISO's record of accuracy of load forecasting, and updating that forecast for the following summer after the current summer season, the fact that the IRM is a one-year ahead projection, which utilizes the most accurate measures of plant maintenance schedules and forced outage rates, has right-sized the IRM in such a manner that effectively addresses all reliability compliance requirements and maximizes the advantage to consumers in setting purchased capacity requirements.

NYISO Demand Response Capacity as Percentage of Total Installed Capacity 2005-2009



Regarding the metric, Demand Response Capacity as Percentage of Total Installed Capacity, the graph includes the sum of the following: ICAP Special Case Resources, Emergency Demand Response Program, and Day-Ahead Demand Response MWs. Load relief expected from demand response resources is not necessarily the sum of all the programs, due to rules that allow participation in multiple programs.

In August 2009, two of the NYISO's major demand response programs, the Emergency Demand Response Program and the ICAP Special Case Resources program, had a total of 4,067 end-use locations enrolled providing over 2,380 MW of demand response capability, a 13 percent increase over the 2008 enrollment level. The demand response resources in NYISO reliability programs represent 7.7 percent of the 2009 Summer Capability Period peak demand of 30,844 MW, an increase of 1.2 percent from 2008.

When New York experienced its record peak load in August 2006, NYISO demand response programs shaved the peak by an average of 865 MW, providing estimated **savings of $91 Million**. (The savings produced by the peak shaving can be quantified as the cost of providing a similar amount of capacity from peaking units. Assuming that the peaking unit is a nominal 195 MW Frame 7FA located in the Capital Zone, the estimate installed cost of such a facility (based upon the current S&L calculations for the demand curve reset) is $840/kW, with a combined fixed O&M plus insurance costs of 0.84%. Using annual fixed charge rate of 13% (assumed 20-yr amortization period), one unit would cost approximately $23M/year; four would be $91M/year.)

NYISO Percentage of Generation Outages Cancelled by ISO/RTO 2005-2009

The NYISO does have the authority to approve planned generation outages with approval also required from the Transmission Owners. The NYISO provides the approved generator outage schedules for the upcoming calendar year by October 1 of the prior year. Provisions allow outage scheduling on a shorter timeframe only if it is mutually acceptable to all involved parties. The NYISO rarely cancels approved planned outages. In fact, none of the planned outages were cancelled by the NYISO in 2009. NYISO data for the metric, "NYISO Percentage of Generation Outages Cancelled by the ISO/RTO," are not available prior to 2009 due to the format of historic records. In 2009, the NYISO integrated a new outage scheduler application that will enable more efficient reporting of outage statistics on a going-forward basis.

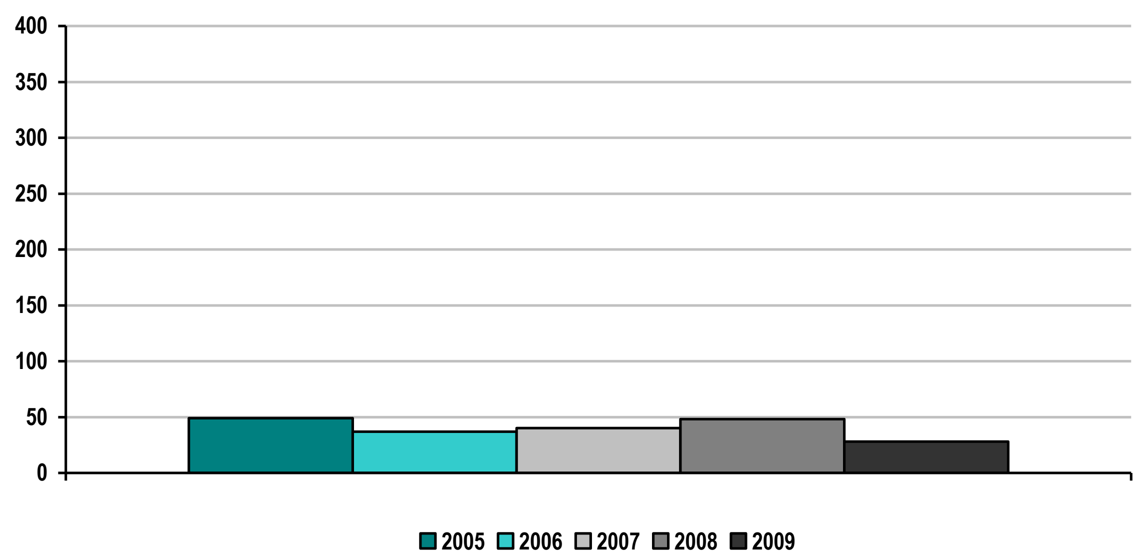
NYISO Generation Reliability Must Run Contracts 2005-2009

The NYISO did not have any generating units under Reliability Must Run ("RMR") contracts from 2005 through 2009. However, out of merit generation was dispatched in order to comply with reliability criteria.

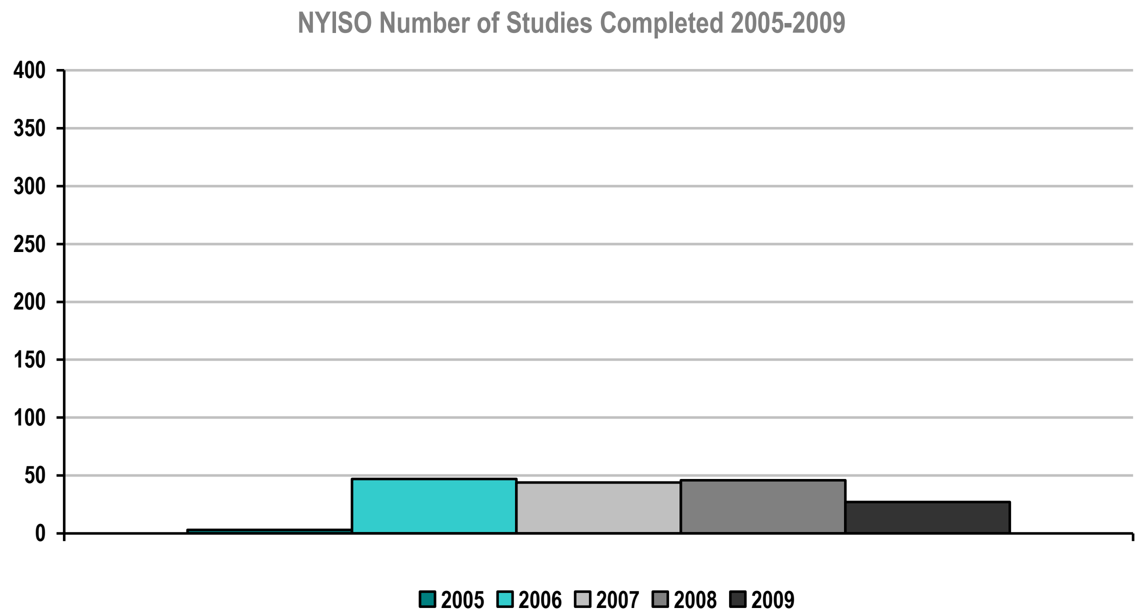
Interconnection / Transmission Service Requests

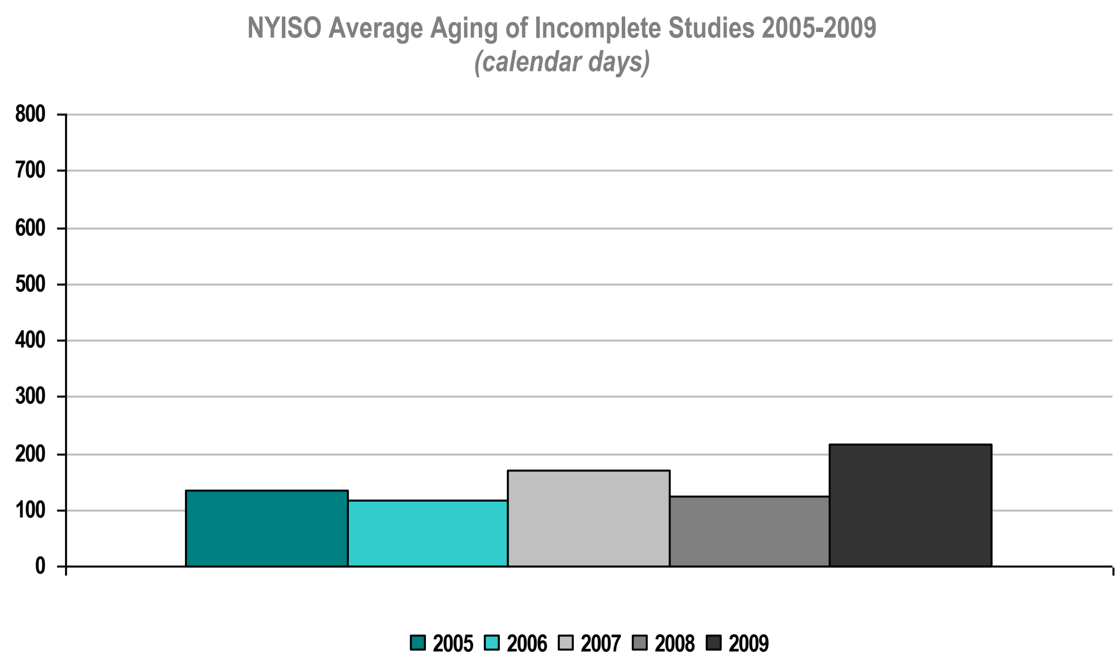
All data represented in this section include all generation, transmission, and transmission-connected load received in each designated year.

NYISO Number of Study Requests 2005-2009

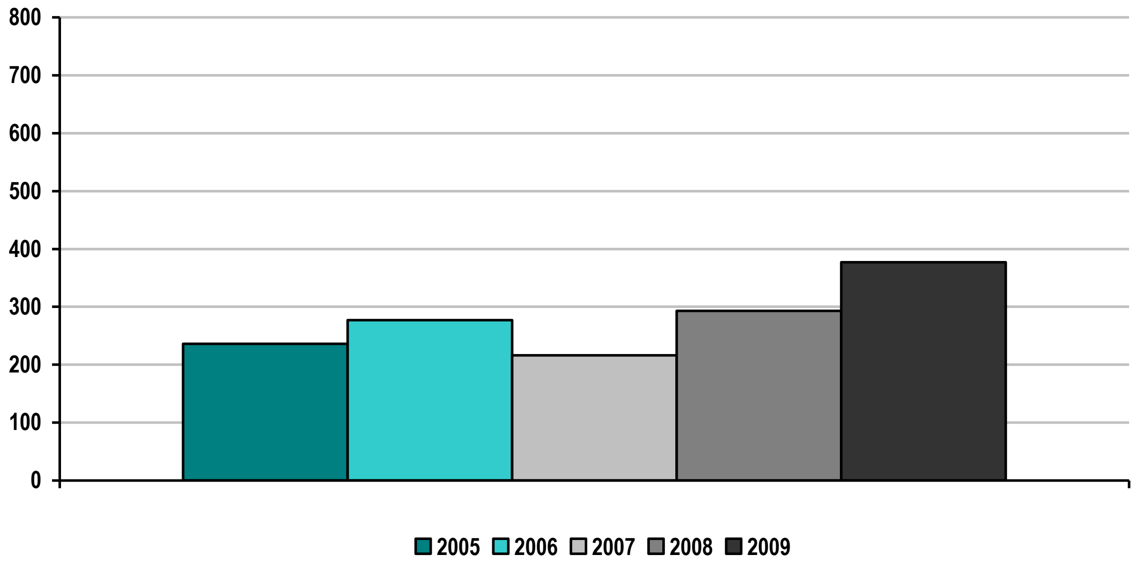


* The NYISO does not use Transmission Service Requests to determine whether or not the existing transmission system can accommodate a new project, as do most other ISO/RTO areas. As a result, a very limited number of such requests are reported in the data presented above. The NYISO Interconnection process assumes that proposed projects can be accommodated on the NYCA bulk power system. NYISO interconnection studies focus on the potential need for upgrades to allow for the safe and reliable interconnection of a proposed project and the cost allocation of any necessary facilities upgrades.


NYISO Number of Studies Completed 2005-2009
400
350
300
250
200
150
100
50
0
2005
2006
2007
2008
2009


NYISO Average Aging of Incomplete Studies 2005-2009
(calendar days)
800
700
600
500
400
300
200
100
0
2005
2006
2007
2008
2009

NYISO Average Time to Complete Studies 2005-2009
(calendar days)



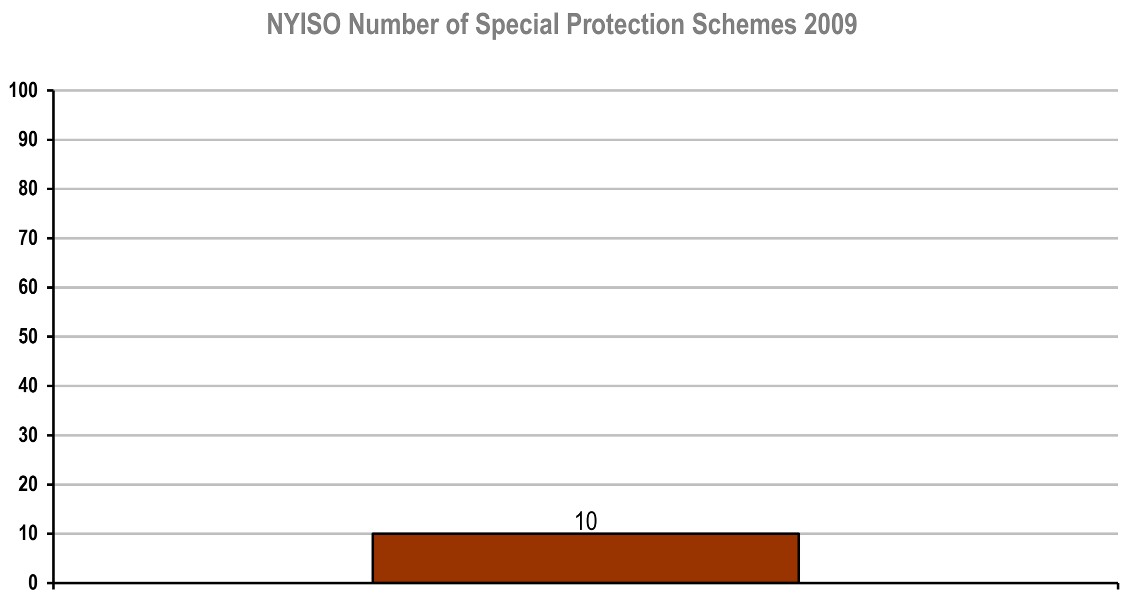
Average Cost of Each Type of Study Completed

	2005	2006	2007	2008	2009
Feasibility Study	Data Not Available	$45,805	$27,573	$24,217	$25,457
System Reliability Impact Study	Data Not Available	$54,213	$50,834	$38,990	$40,686
Facilities Study (Class Year)	Data Not Available	$113,090	$124,326	Final Data Not Yet Available	Data Not Yet Available

From 2005-2009, a total of 35 projects have gone in-service that had undergone the NYISO interconnection or transmission study process. Thirty (30) of those projects were generation projects, of which 27 were by independent generation developers, two were by a state authority (New York Power Authority), and one was by public utility (Consolidated Edison Company of NY). The other five projects were transmission projects, of which two were planned Transmission Owner projects, one involved upgrades of the Transmission Owners' systems sponsored by a generation owner, and two were merchant transmission projects developed by independent transmission developers.

During the period from 2005 through 2009, four formal complaints were filed at FERC related to the NYISO interconnection study process. No formal complaints related to the NYISO transmission study process were filed during that period. All four of the interconnection-related complaints have been resolved. One of the complaints was resolved by a FERC order directing NYISO to withdraw an Interconnection Request from its queue position. Another complaint was withdrawn by the complainant after the Commission accepted certain amendments to the NYISO's tariff that rendered the complaint moot. The other two complaints were denied by the Commission.

Special Protection Schemes



Of the ten Special Protection Schemes (SPS) in place within NYISO, there was only one SPS activation in 2009. The SPS activation response was as designed and there were no uninstructed SPS activations in the NYISO.

B. NYISO Coordinated Wholesale Power Markets

According to the *2009 State Energy Plan*, approved by the New York State Energy Planning Board and the Governor in December 2009, *"New York's competitive electricity market structure, established in 1999 and administered by the NYISO, provides an economic incentive to power plant operators to run as efficiently as possible…More efficient, i.e., lower heat rate, resources are attracted to competitive markets where they can profit by competing against less efficient producers, an incentive that does not exist in non-market regions…"*

For more information about the State Energy Plan's assessment of NYISO-administered markets, please see:

http://www.nysenergyplan.com/final/Electricity_Assessment_Resource_and_Markets.pdf

In April 2010, Potomac Economics, the NYISO's Independent Market Monitor, issued the *2009 State of the Markets Report: New York ISO*. That report concludes that the NYISO operates "a complete set of electricity markets," including:

- *Day-ahead and real-time markets jointly optimize energy, operating reserves, and regulation. These markets lead to:*
  - *Prices that reflect the value of energy at each location on the network;*
  - *The lowest cost resources being started each day to meet demand;*
  - *Delivery of the lowest cost energy to New York's consumers to the maximum extent allowed by the transmission network; and*
  - *Efficient prices when the system is in shortage.*
- *Capacity markets that ensure that the NYISO markets produce efficient long-term economic signals to govern decisions to:*
  - *Invest in new generation, transmission, and demand response; and*
  - *Maintain existing resources.*
- *The market for transmission rights allows participants to hedge the congestion costs associated with using the transmission network.*

In addition, the report says:

The performance of the New York markets is enhanced by a number of attributes that are unique to the NYISO:

- *A real-time dispatch system that is able to optimize over multiple periods (up to 1 hour), which allows the market to anticipate upcoming needs and move resources to efficiently satisfy the needs.*
- *An optimized real-time commitment system to start gas turbines and schedule external transactions economically – other RTOs rely on their operators to determine when to start gas turbines.*

- *A mechanism that allows gas turbines to set energy prices when they are economic – gas turbines frequently do not set prices in other areas because they are inflexible, which distorts prices.*
- *A mechanism that allows demand-response resources to set energy prices when they are needed – this is essential for ensuring that prices signals are efficient during shortages. DR in other RTOs has distorted real-time signals by undermining the shortage pricing.*

For more information, please see:

http://www.nyiso.com/public/webdocs/documents/market_advisor_reports/2009/2009_NYISO_SOM_Final_4-30-2010.pdf

NYISO Market Volumes Transacted in 2009

For context, the table below represents the split of the $6.17 billion billed by the NYISO in 2009 into the primary types of charges its market participants incurred for their transactions:

(dollars in millions)	2009 Dollars Billed	Percentage of 2009 Dollars Billed
Energy Markets	$ 3,056	49%
Installed Capacity	1,335	21%
Transmission Congestion	668	11%
Transmission Losses	341	6%
TCC - Billed Fiscal Year	249	4%
Market-wide charges	182	3%
Administrative Costs	134	2%
Transmission Service	102	2%
Ancillary Services	100	2%
Other *	3	0%
Total	**$ 6,170**	**100%**

* The “Other” category are contractual costs associated with operating two facilities and is based on agreements that predate the formation of the NYISO.

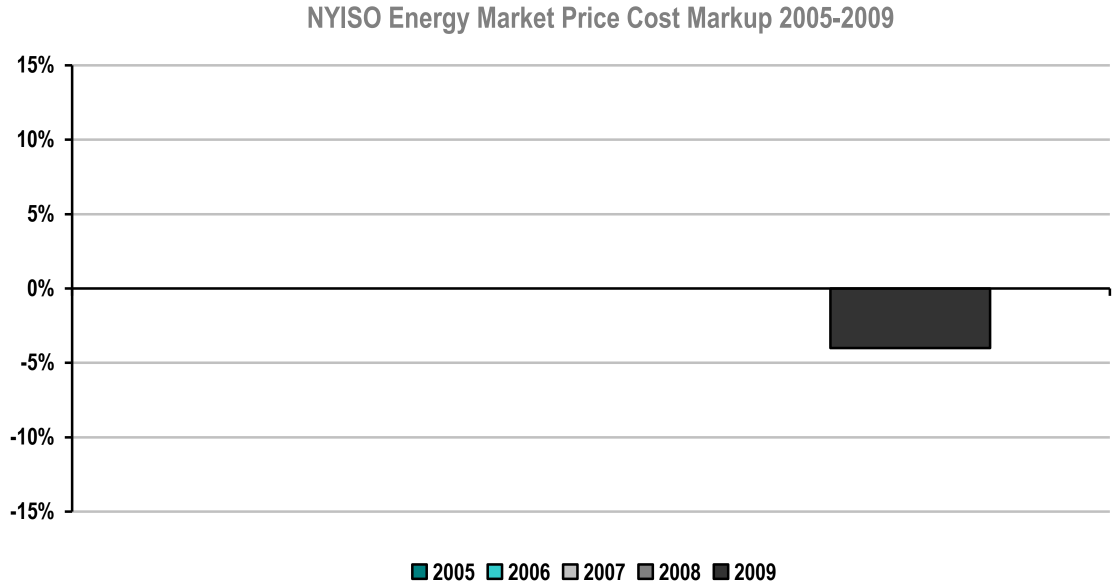
The 2009 data presented above reflect the impacts of the economic recession, which reduced electric load and decreased market volumes. In New York State, electricity usage dropped from an average load of 452 gigawatt-hours per day (GWh/day) in 2008 to 435 GWh/day in 2009. The reduced levels of power consumption, combined with sharply lower prices in natural gas, resulted in lower electricity prices. The average cost of electricity in New York was $48.63 per megawatt-hour (MWh), down nearly 50% from the 2008 average of $95.31 per MWh. It was the lowest in the NYISO's ten-year history, dropping below the $49.90 per MWh set in 2002. Reduced load and lower prices combined to produce a lower than average billing total.

Demand response programs, cultivated in the competitive market environment, have grown significantly in the New York wholesale electricity markets.

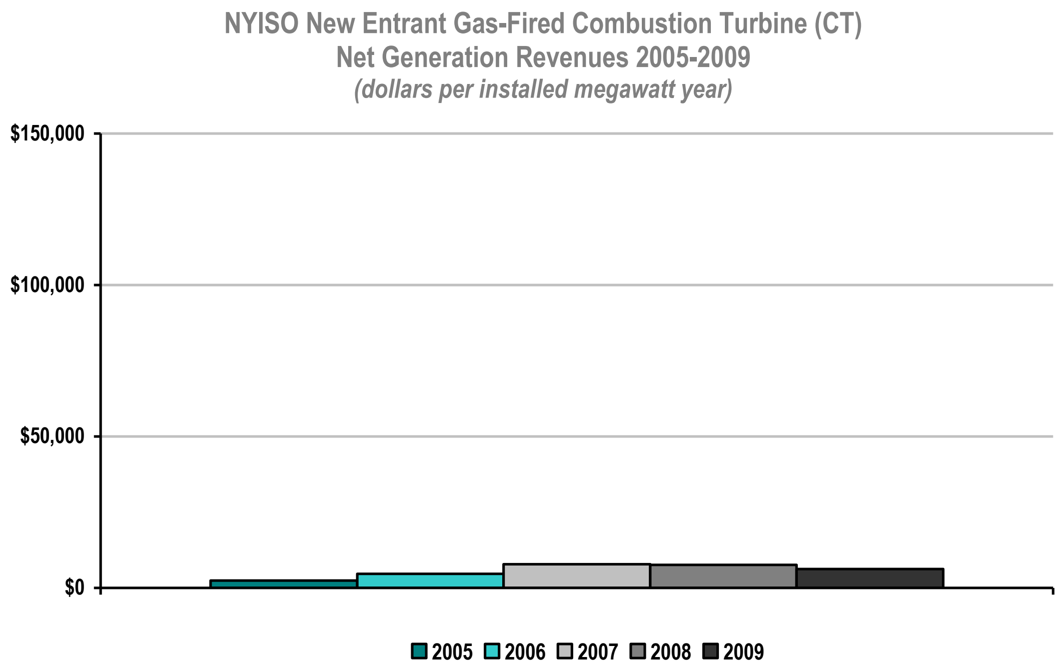
From 2005 to 2009, NYISO Day Ahead Demand Response program provided energy **savings averaging $8.9 Million** annually, for a total of **$44 Million**. (Data on the Location Based Marginal Price impact of demand response resources participating in the NYISO's Day-Ahead Demand Response Program can be found in the NYISO's annual compliance file to the FERC, Docket No. ER01-3001.)

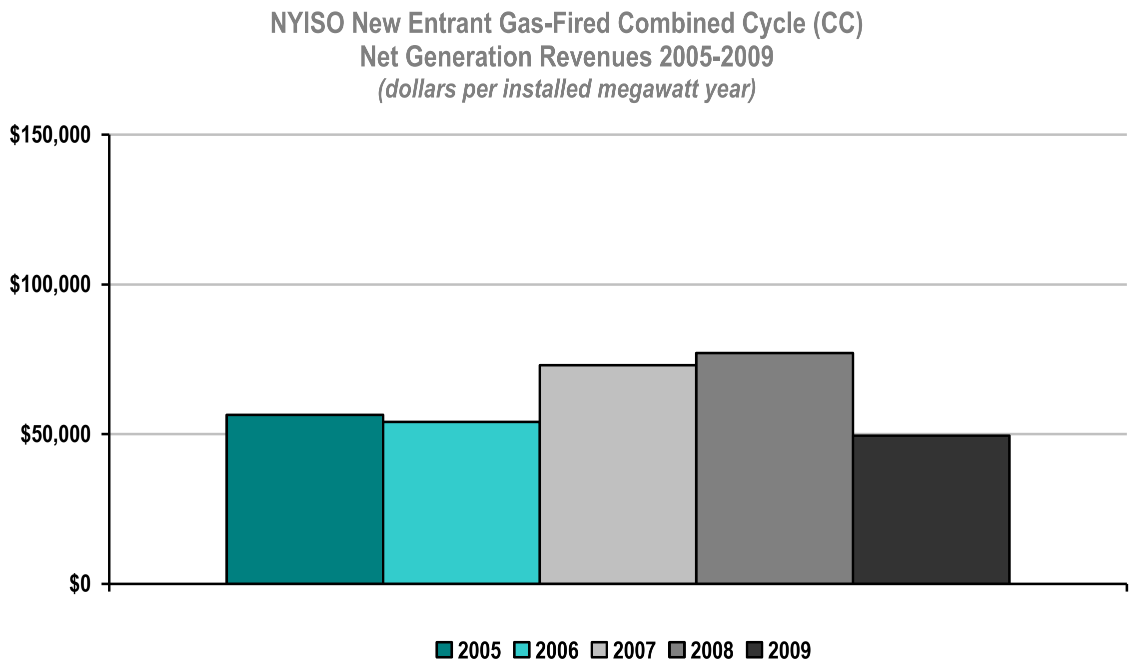
The NYISO Demand Side Ancillary Services Program (DSASP), introduced in June 2008, provides demand resources that meet telemetry and other qualification requirements an opportunity to bid their load curtailment capability into the Day-Ahead and Real-Time markets to provide Operating Reserves and Regulation Service. As of December 31, 2009, there are no resources qualified in the DSASP to include for the metric, Demand Response as a Percentage of Synchronized Reserve Market**.**

Market Competitiveness

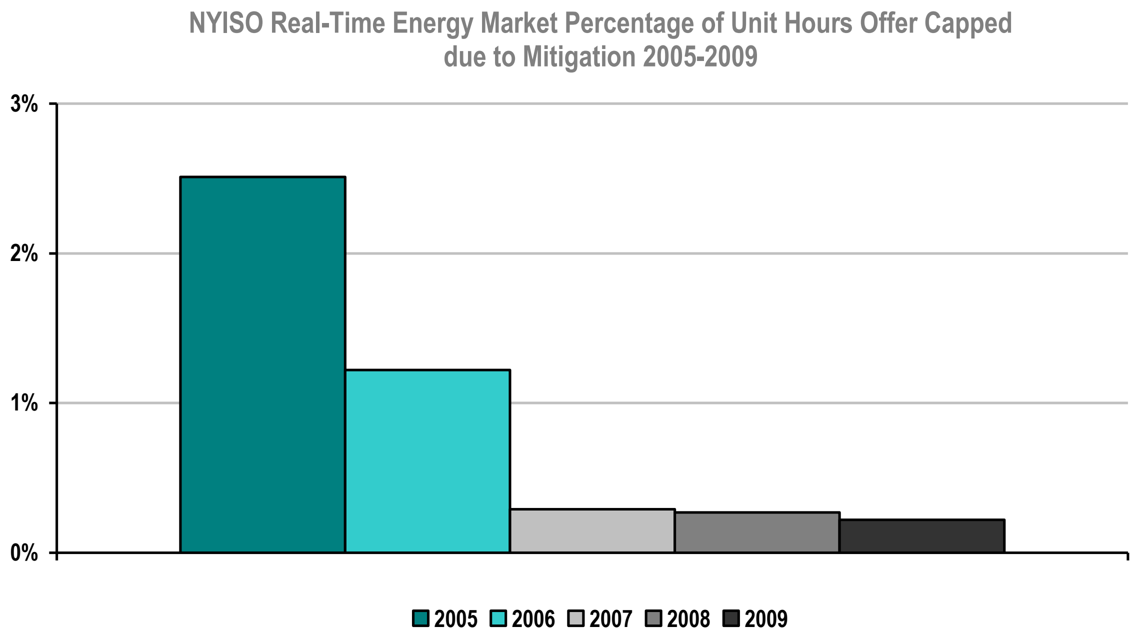


The Energy Market Price Cost Markup is useful in evaluating the competitive performance of the market. A competitive market should produce a small mark-up because suppliers should have incentives to offer at close to their marginal cost. The NYISO's Market Monitor estimates the average annual markup was -4 percent in 2009. Many factors can cause reference levels to vary slightly from suppliers' true marginal costs, so it is not expected to see a markup exactly equal to zero. Relatively low markups (-5 to 5 percent) indicate that the markets have performed competitively. The NYISO does not have data on the Price Cost Markup prior to 2009.





The above charts report the calculated net revenues for a unit located in New York's Capital Zone. However, over this time period, there is great variation throughout the state with New York City having the highest Net Generation Revenues (ranging from an average of $12,673 for a CT and $125,614 for a CC), and the West Zone having the lowest Net Generation Revenues (an average of $5,402 for a CT and $25,668 for a CC). (Note that CT revenue estimates use a 100MW unit downstate and a 165MW unit upstate). Over the 2006-2008 period, net revenue levels rose moderately in the Capital zones due to increased congestion across the Central East interface and increase in capacity prices due to increased exports to ISO-NE with the introduction of their new capacity market in 2006. In 2009, the net revenues decreased driven in part by lower loads due to the combined effects of the economic contraction and a cool summer.



The New York markets include market power mitigation measures that are intended to mitigate abuses of market power while minimizing interference with the market when the market is workably competitive. In certain constrained areas, most of which are in New York City, some suppliers have local market power because their resources are needed to manage congestion or satisfy local reliability requirements. In these cases, however, the market power mitigation measures effectively limit their ability to exercise market power or impact prices. (See the NYISO Market Monitor's *2009 State of the Market Report* for more information:
http://www.nyiso.com/public/webdocs/documents/market_advisor_reports/2009/NYISO_2009_SOM_Final.pdf)

The Automated Mitigation Program (AMP) mitigation measure applies to the Day-Ahead and Real-Time energy, startup, and minimum generation in New York City zone. The preceding chart shows the Real-Time market mitigation. In most years, there was more mitigation in the Day-Ahead market than in real time. The decline in mitigation over time reflects a decline in congestion in New York City due to system changes such as, new units in New York City, and new transmission capacity from New Jersey to Long Island due to system changes such as new units in New York City, and new transmission capacity from New Jersey to Long Island.

Market Pricing

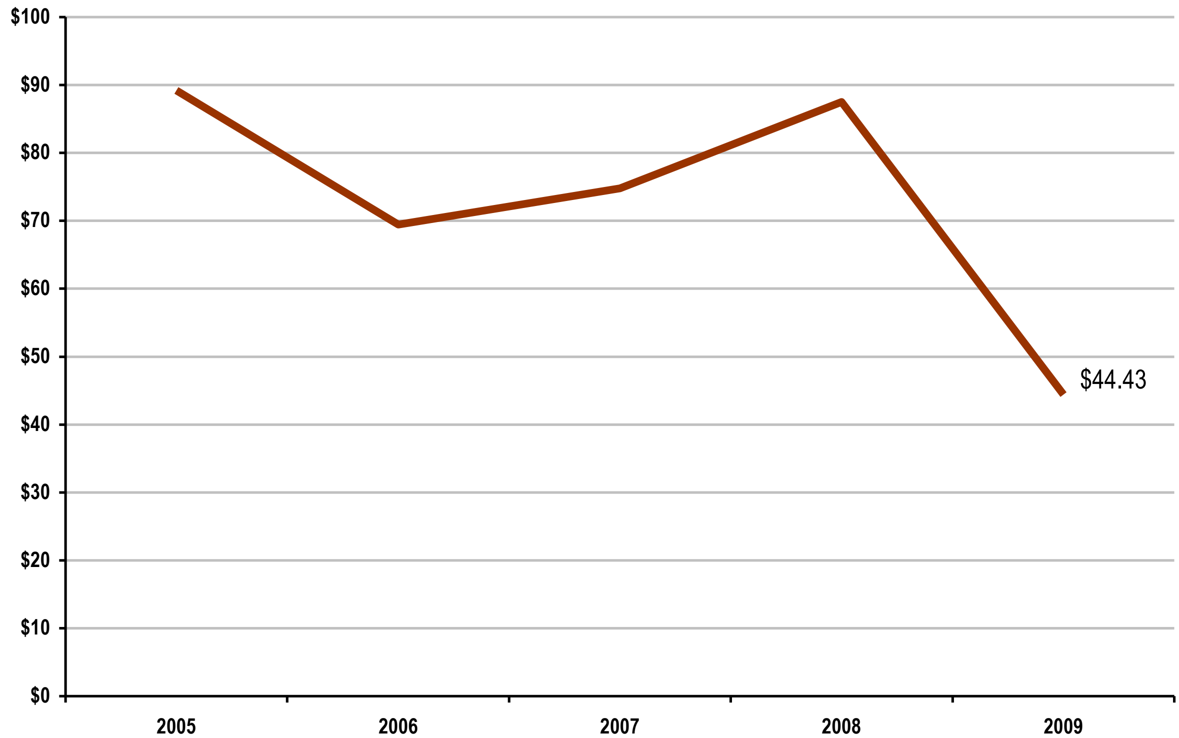
Similarly to the other ISOs/RTOs, the annual variability in the load-weighted wholesale energy prices is accounted for by the variability of natural gas and this can be seen throughout the next five charts. Adjusted for the variation in natural gas prices, the annual average real time wholesale energy prices have remained essentially flat over the past five years. This same variability can be seen in the breakdown of annual wholesale power costs. Since energy comprises the largest component of wholesale power costs, the effect of fuel variability can be seen in the wholesale cost decrease from 2008 to 2009. The final chart isolates the unconstrained energy portion of the system marginal cost also shows the same effects of fuel price volatility, unadjusted for fuel price volatility.

The New York Independent System Operator, Inc. (“NYISO”) offers two demand response programs that support reliability: the Emergency Demand Response Program (“EDRP”) and the Installed Capacity-Special Case Resource Program (“ICAP/SCR”). In addition, demand response resources may participate in the NYISO’s energy market through the Day-Ahead Demand Response Program (“DADRP”), or the Ancillary Services market through the Demand-Side Ancillary Services Program (“DSASP”).

EDRP provides demand resources with the opportunity to earn the greater of $500/MWh or the prevailing locational-based marginal price (“LBMP”) for energy consumption curtailments provided when the NYISO calls on the resource. There are no consequences for enrolled EDRP resources that fail to curtail. Resources participate in EDRP through Curtailment Service Providers (“CSPs”), which serve as the interface between the NYISO and resources.

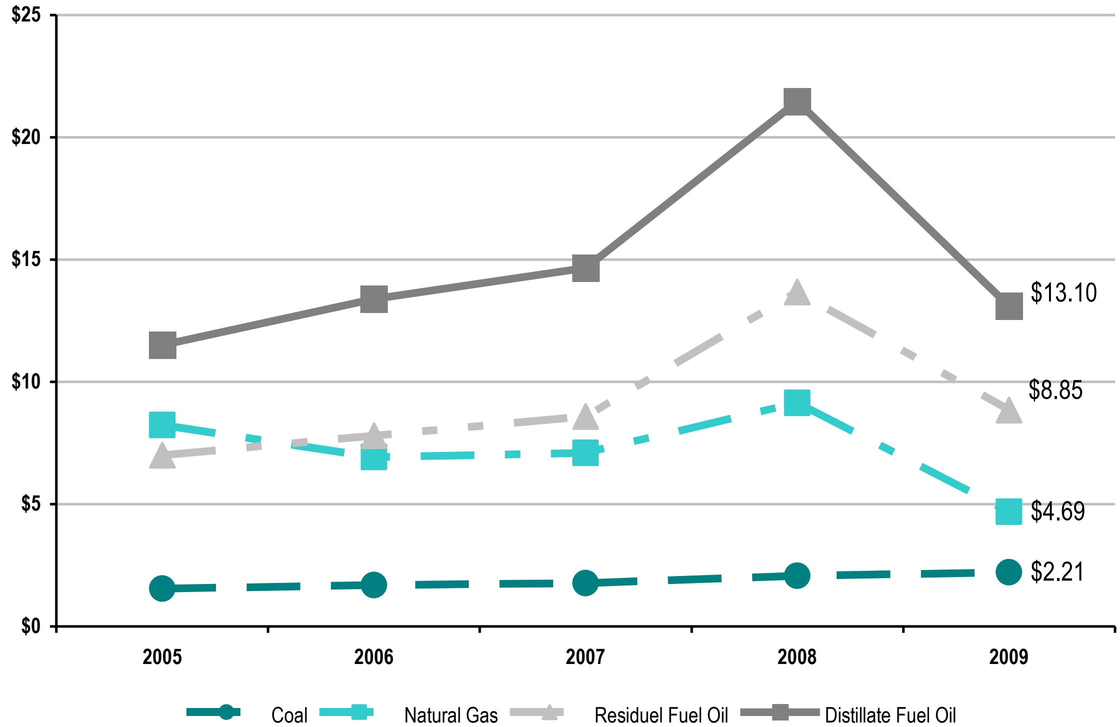
The NYISO provides an annual informational report (Docket ER01-3001 and ER03-647) about Demand Response resources. The last report found that the overall average hourly wholesale LBMP reduction from scheduled DADRP load reductions was $0.27/MWh, On a monthly basis, the average hourly price reduction was most significant in the months of January 2009 ($0.93/MWh), November 2008 ($0.70/MWh) and September 2008 ($0.64/MWh). There were no price impacts for the summer months of May through August 2009, due to minimal load reduction offers and even fewer scheduled reductions.

NYISO Average Annual Real Time Load-Weighted Wholesale Energy Prices 2005-2009
($/megawatt-hour)



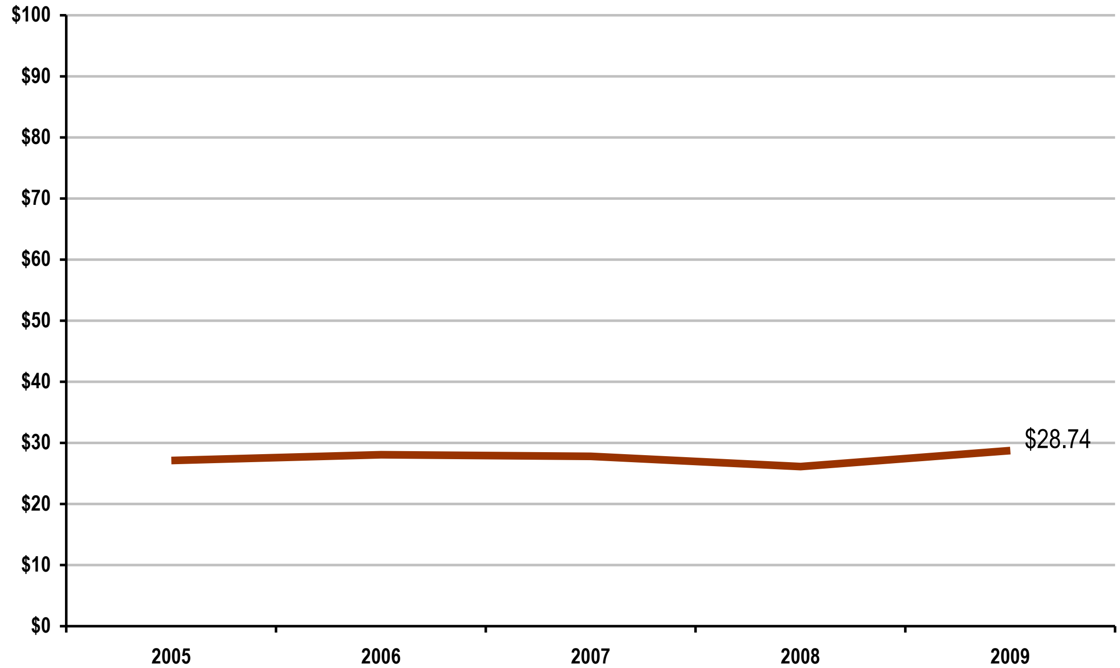
In 2009, real-time prices in 99.7% of total hours were accurately set based on the NYISO's tariffs, with price corrections required in only 27 out of 8,760 hours. NYISO's focus on price certainty has resulted in significant improvements since 2005. The primary driver for the improvements made and the high level of price accuracy achieved is due to the integration of Intelligent Source Selection ("ISS"). ISS allows for improved data integrity by identifying and removing metering errors that otherwise would have impacted the real-time markets. The percentage of hours in which there were no corrections in the real-time energy or ancillary services prices at any active nodal or zonal price location in the NYISO administered markets are as follows: 2005: 83.8%, 2006: 96.9%, 2007: 99.0%, 2008: 99.3%, and 2009: 99.7%.

U.S. Nominal Fuel Costs 2005-2009 *($ per million Btu)*

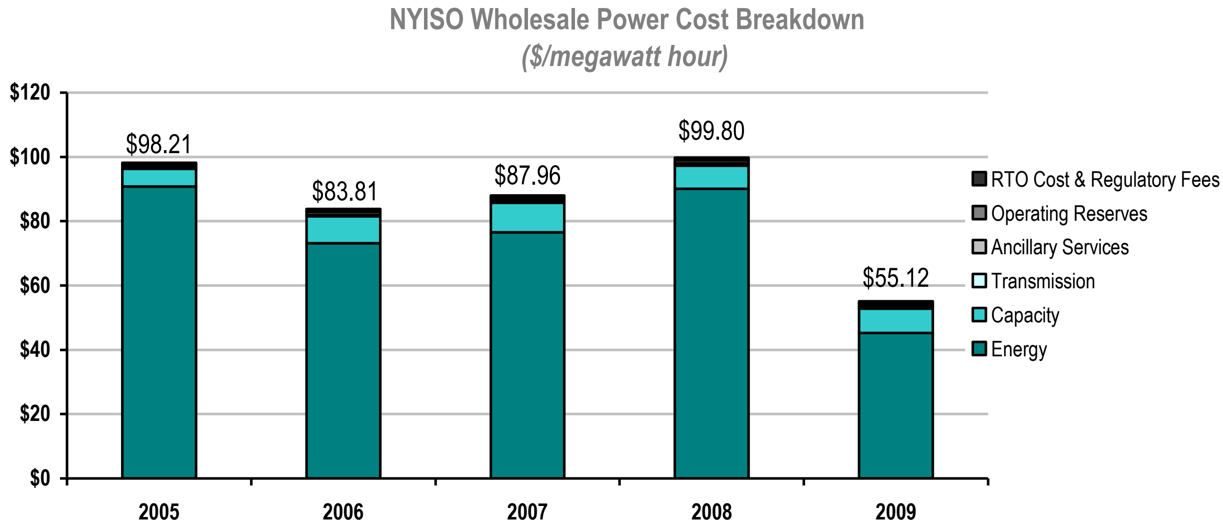


Source: U.S. Energy Information Administration, Independent Statistics and Analysis

NYISO Average Annual Load-Weighted
Fuel-Adjusted Wholesale Spot Energy Prices 2005-2009
($/megawatt-hour)

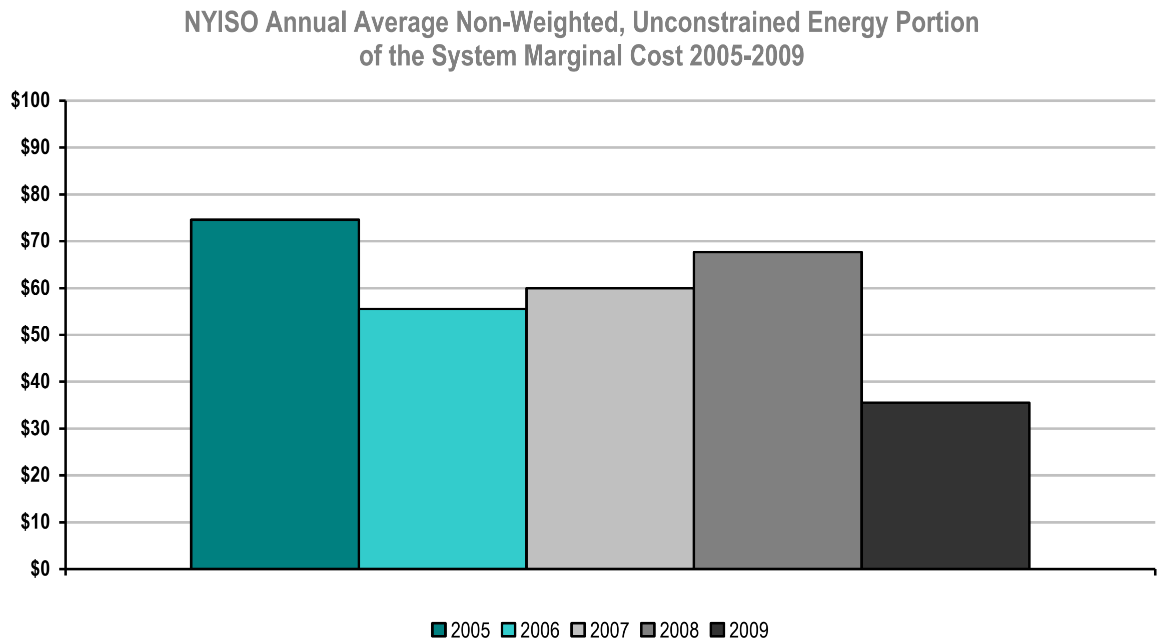


NYISO's base day for fuel-cost references is January 1, 2000.



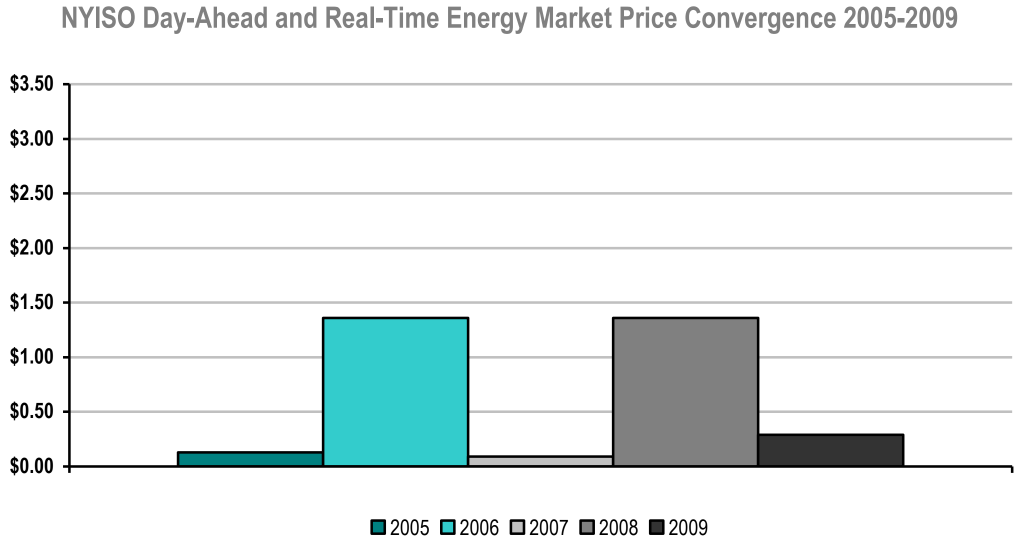
The “Transmission” charge in the above figure represents the NYPA Transmission Adjustment Charge (“NTAC”), which is a surcharge on all Energy Transactions assessed to all statewide load as well as Wheel Through and Export transactions. The NTAC recovers any residual NYPA transmission revenue requirements and is billed and collected by the NYISO. Additional transmission charges, not included in the above figure, are billed and collected by each transmission owner from both wholesale and retail customers.

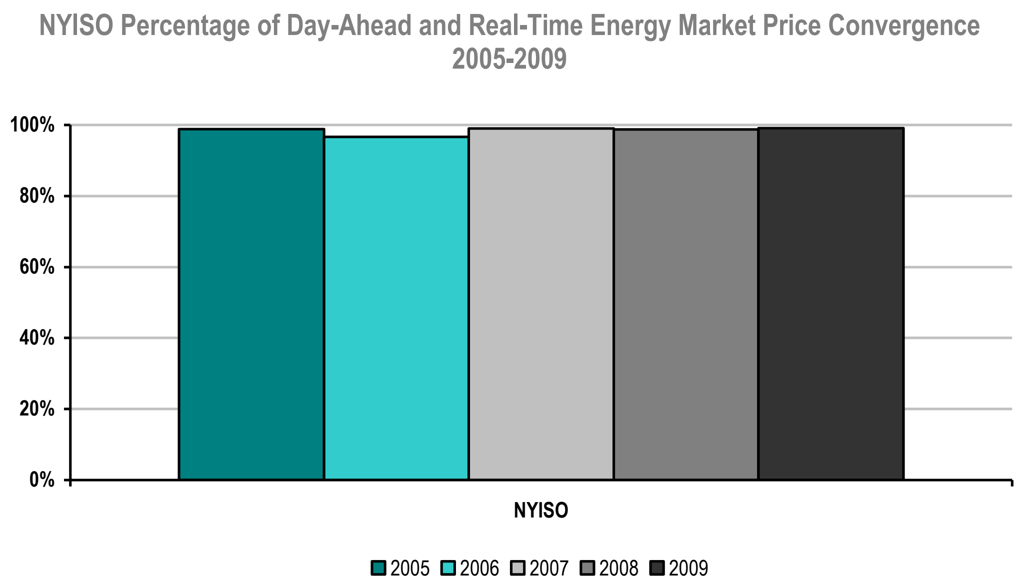
Unconstrained Energy Portion of System Marginal Cost



Similar to the other ISOs/RTOs, the annual variability in the load-weighted wholesale energy prices is accounted for by the variability of natural gas. Adjusted for the variation in natural gas prices, the annual average wholesale energy prices have remained essentially flat over the past five years. This same variability can be seen in the breakdown of annual wholesale power costs. Since energy comprises the largest component of wholesale power costs, the effect of fuel variability can be seen in the wholesale cost decrease from 2008 to 2009.

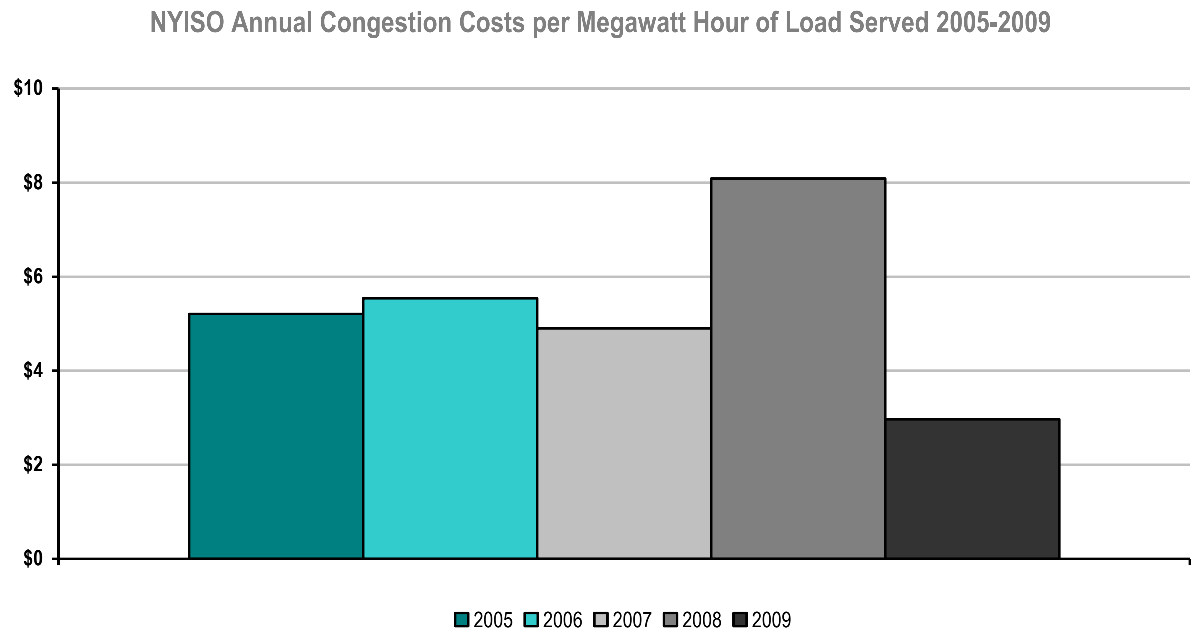
Energy Market Price Convergence

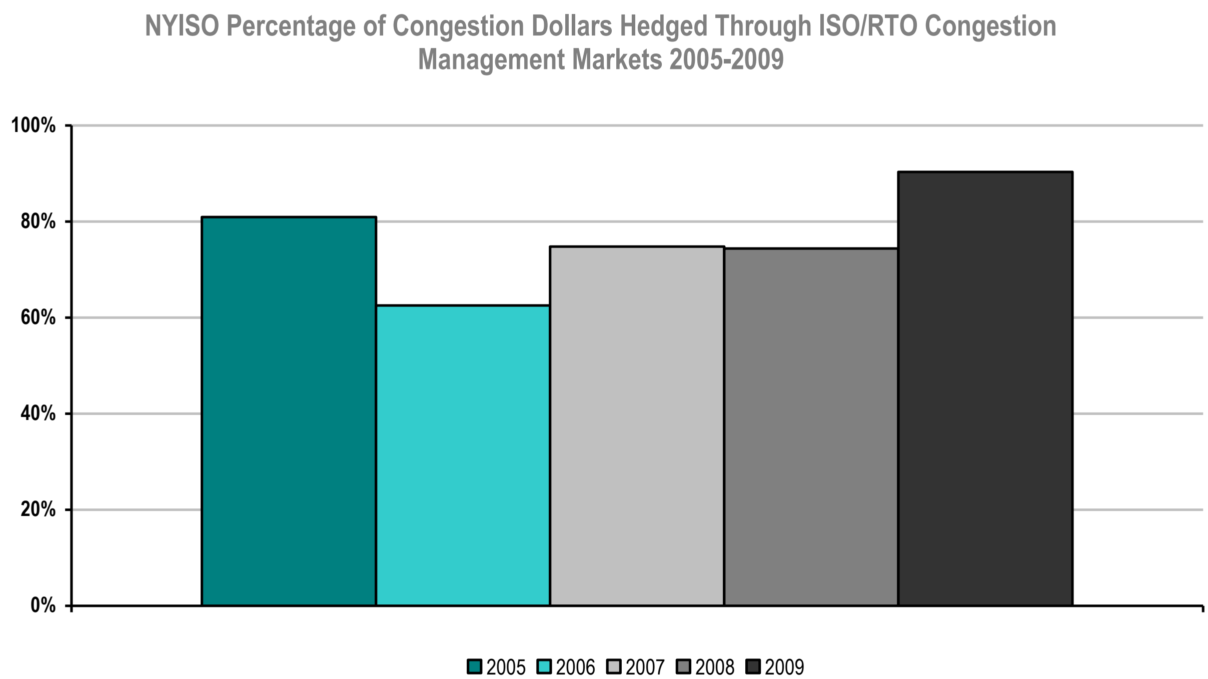




Convergence between day-ahead and real-time has varied between 96 to 99 percent while convergence measured in dollars has been more variable. This annual variation is driven by both real-time events and the cost of natural gas. The apparent discrepancy between the two charts in 2006 comes from Real Time price outliers in May/June/July 2006. The different impact on the percentage convergence of the same dollar difference in 2006 and 2008 is because 2008 natural gas prices were much greater than they were in 2006 (see the chart of "U.S. Nominal Fuel Costs 2005-2009"). The methodology used for this metric is the annual average of the hourly index where the index is load weighted RTD over load weighted DAM price. However, it was decided that the RTD price would be used as the denominator and once those values are calculated, the metric will be updated.

Congestion Management

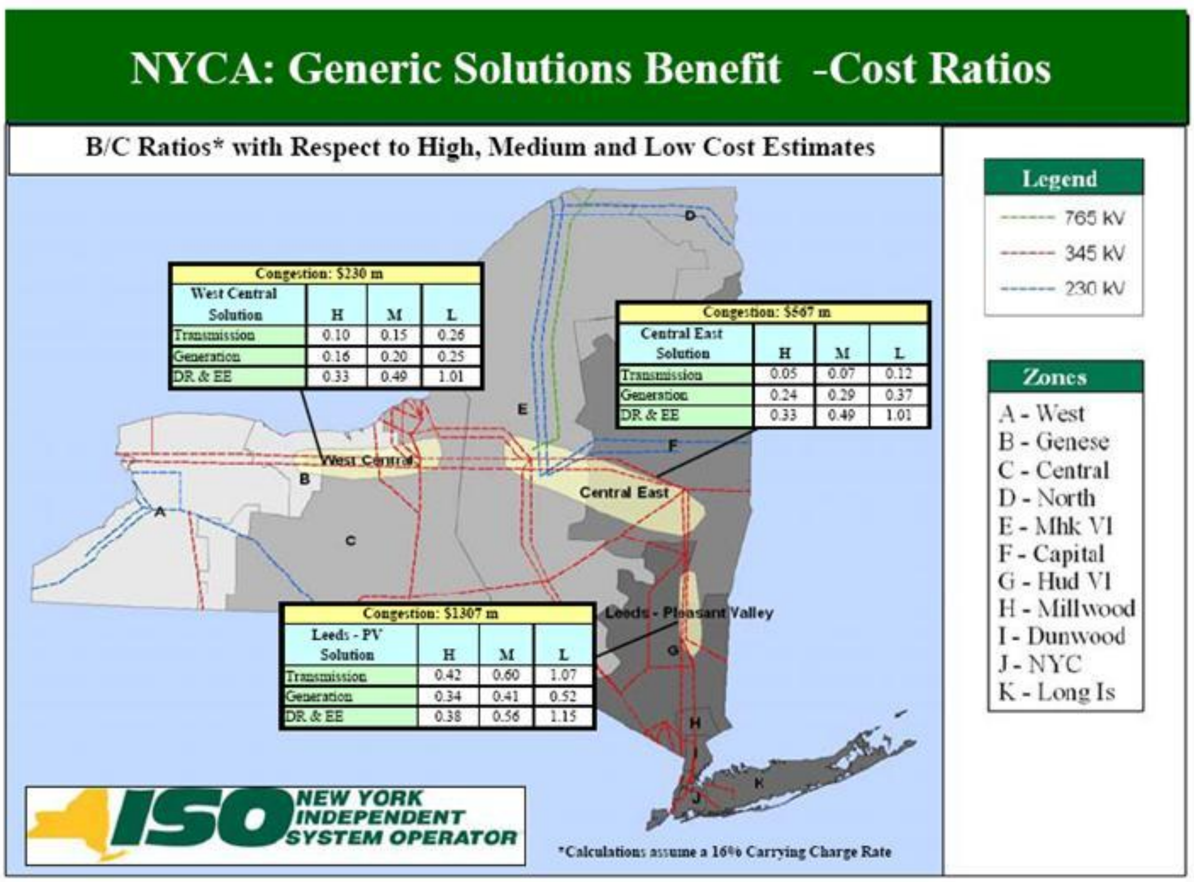




The annual congestion costs per MWh of load served vary with fuel costs. The increase in the annual congestion costs in 2008 is partially accounted for by the increase cost of fossil fuel that year. The percent of congestion dollars hedged through the NYISO markets has varied over time. Congestion hedges are generally used when loads, located in high congestion areas, are using generation located in less congested parts of the state to meet their loads. New York City and Long Island both have reliability based local generation installed capacity requirements (80% and 104.5% in New York City and Long Island respectively for the capability year starting in May 2010) and so may have less of a need for a congestion hedge. In addition, there is also an active market in over-the-counter contracts-for-differences, which provide a different instrument to hedge congestion.

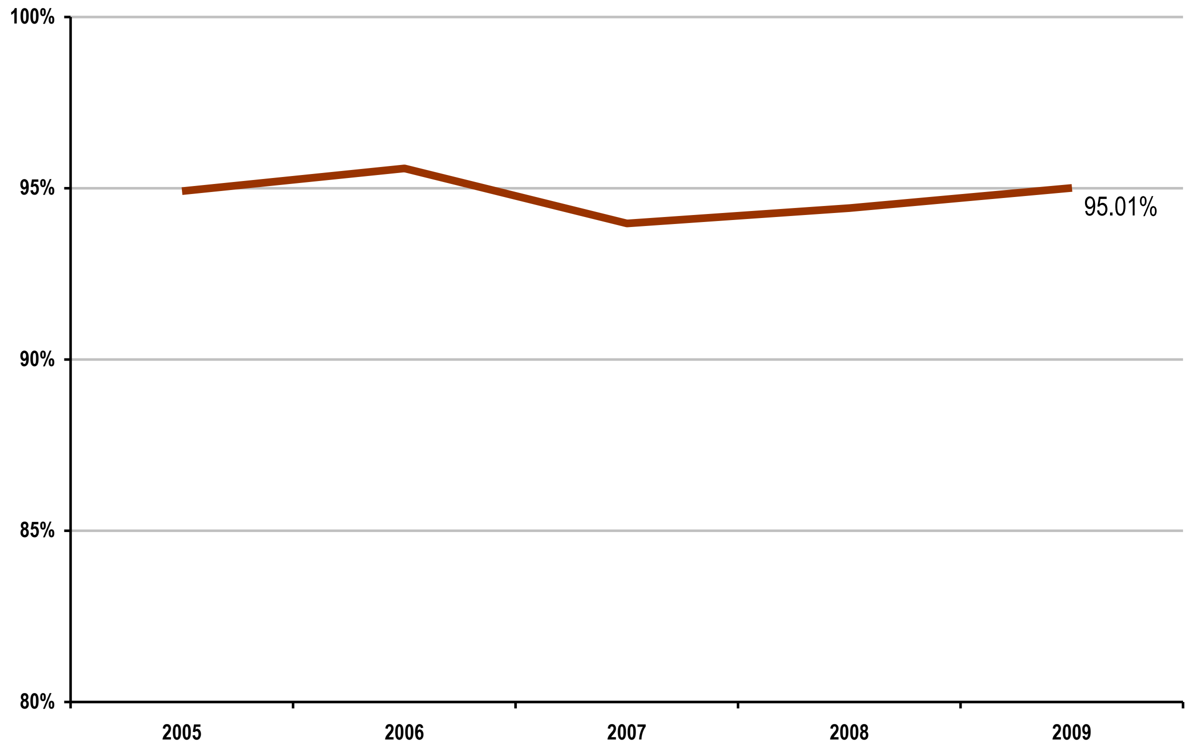
The NYISO Congestion Assessment and Resource Integration Study (CARIS) issued January 12, 2010 provided an analysis of the types of projects (e.g. transmission, generation, or demand response) and costs of relieving constraints. The full report is available at the following link:
http://www.nyiso.com/public/markets_operations/services/planning/planning_studies/index.jsp

For each of the three most congested interfaces in New York, the report showed the costs and benefits of relieving congestion using high, medium, and low cost estimates for each type of project. Based on the generic project sizes and costs, a benefit/cost ratio was calculated and reported. The graphic below presents the benefit costs ratio for the three types of solutions studied for the three most congested interfaces in New York.



Resources

NYISO Annual Generator Availability 2005 – 2009



The decline in generator availability in 2007 can be attributed to a number of factors including two large units having long outages and a number of gas turbines undergoing maintenance. In subsequent years, the addition of generation in New York City combined with lower loads led to less use of gas turbines in 2008 and 2009 improved overall generator availability.

It is noteworthy that, with the creation of the NYISO's competitive wholesale electricity markets, the availability of generating units in New York increased as power projects reduced the length of planned and unplanned outages.

Average plant availability increased from 87.5 percent (1992–1999) to 94.27 percent (2001–2007), equivalent to adding 2,400 MW of available capacity to the system. The net effect of improved unit availability provided an equivalent of 2,400 MW of capacity in New York State. The **savings from improved unit availability is estimated at $ 300 million** annually. (This estimate is based on roughly 50% of generating capacity sold in the NYISO capacity market with the remainder in bilateral markets and assumes that the 2,400 MW would have been purchased at a price set by the demand curve.)

The NYISO has taken several steps to minimize the market inefficiencies and associated costs caused by out-of-merit dispatch.

Since 2005, the Day-Ahead and Real-Time markets have jointly optimized energy, operating reserves and regulation to efficiently select the most economic resources to meet reliability needs. In real-time, the dispatch is optimized for multiple periods that span an hour, setting resource schedules to meet current and anticipated system conditions. In addition, an optimized real-time commitment starts gas turbines and allows these resources to set energy prices when they are economic, providing more accurate energy prices that minimize the need for out-of-merit actions. External transactions are also scheduled economically, allowing the real-time scheduling systems to select the most efficient set of resources to meet real-time conditions.

More recently, in order to improve the efficiency of reliability commitments and minimize uplift charges, the NYISO made two significant enhancements to the day-ahead market in February of 2009 as follows:

- Transmission owners may commit units for a reliability need prior to the economic commitment of SCUC, allowing the commitment in the day-ahead market to better reflect the anticipated real-time commitment needs.
- Local reliability rule requirements for New York City are included in the economic commitment of SCUC to minimize the need for supplemental commitments.

The independent Market Monitor for the NYISO has found that these enhancements have led to a more efficient commitment overall, resulting in less uplift charges.

Since Fall 2008, a cross-functional group at the NYISO has been reviewing market outcomes on a daily basis to identify root-cause sources of uplift and other marketplace costs. As part of the root-cause analysis, a review of the prior day's operational actions, as well as the expected intent of the market settlement rules, is considered in order to maintain or improve the efficiency of market outcomes. In addition, enhanced reporting to stakeholders of daily and monthly trends in marketplace costs was implemented.

Actual Response Levels of Committed Demand Response from 2005 – 2009

Over the past decade, a new category of power resource - demand response programs - was developed to offer an alternative to traditional generation supplies. Demand response can serve as an important resource to meet system loads during extreme summer weather conditions. It is common for New York State's summer peak demand to spike nearly 40 percent above the average level of electricity use.

New York's demand response resources have grown more than ten-fold since the programs began in the early years of New York's wholesale marketplace for electricity. Their value was most notably demonstrated when New York State experienced its all-time record peak demand of 33,939 MW on August 2, 2006 when demand response programs provided an average of 865 MW of relief per hour for the six hours in which the program was activated.

During the period of 2005 through 2009, the NYISO deployed demand response resources for one event in 2005 and five events in 2006. On July 27, 2005, the NYISO deployed demand resources for four consecutive hours. Average hourly response for the July 27, 2005 was 345 MWh per hour. In 2006, demand resources were deployed on July 18, July 19, August 1, August 2, and August 3. Average hourly response of 485 MW was achieved for nine hours on July

18 and 327 MW for seven hours on July 19. In August, average hourly response of 314 MW was achieved for five hours on August 1, 865 MW for six hours on August 2, and 398 MW for five hours on August 3.

There were no NYISO deployments of demand response in 2007, 2008, or 2009.

Details on hours and zones included in each deployment are reported in the semi-annual demand response reports submitted by NYISO.

NYISO Demand Response Future Enhancements:

The NYISO, in collaboration with its stakeholders, is continuing to evolve and enhance the administration of its demand response programs and address regulatory directives to facilitate market participation.

The Demand Response Information System (DRIS) continues to be developed by NYISO to automate program processing and enhance event performance, management, and settlement.

Telemetry requirements for the NYISO's Demand Side Ancillary Services Program (DSASP) were the subject of a May 2010 workshop on improving communications between Transmission Owners and demand response resources. The workshop's proceedings will help to guide the development of standardized processes that could help to facilitate participation by demand response resources in the NYISO's Ancillary Services markets.

As direct communication for DSASP enhances the potential for aggregations of small demand resources to participate in NYISO's ancillary services markets, changes in market rules are also among the needs to be addressed by stakeholders.

The NYISO will continue with its proposed plan of action for accommodating demand response resource participation in the real-time energy market outlined in its February 2010 FERC Compliance Filing. The NYISO expects to incorporate any decisions from the FERC regarding compensation of demand response in energy markets as it develops its preliminary market design.

At the state level, the NYISO is participating in proceeding of the New York State Public Service Commission (PSC) on advanced metering infrastructure. Detailed information is available from the NYISO filings on:

- Advanced metering (http://www.nyiso.com/public/webdocs/documents/regulatory/nypsc_filings/2009/NYISO_Comments_Staff_BC_Framework_6_15_09.pdf)
- Dynamic pricing (http://www.nyiso.com/public/webdocs/newsroom/white_papers/Dynamic_Pricing_NYISO_White_Paper_102709.pdf)
- Smart grid (http://www.nyiso.com/public/webdocs/newsroom/white_papers/Envisioning_A_Smarter_Grid_NYISO_White_Paper_091710.pdf).

Fuel Diversity

Competitive markets have resulted in a more efficient, environmentally sound bulk electric power system for New York. The NYISO's ability to optimize all system resources, the addition of cleaner, more efficient power plants, aggressive energy efficiency programs, the development of renewable energy, and improved demand-side management have combined to "green the grid."

Since 2000, power plants with generating capacity totaling 2,069 MW have retired. Of that total, 2,060 MW were powered by fossil fuels, including 987 MW of coal-fired generation. The new power plants built since the inception of electricity markets in New York run primarily on cleaner-burning natural gas, which is helping to reduce emissions that contribute to global climate change. In addition, New York has seen an increase in output from nuclear plants, which are virtually emission-free. The production of cleaner power is an important component in the state's efforts to meet newly enacted environmental standards.

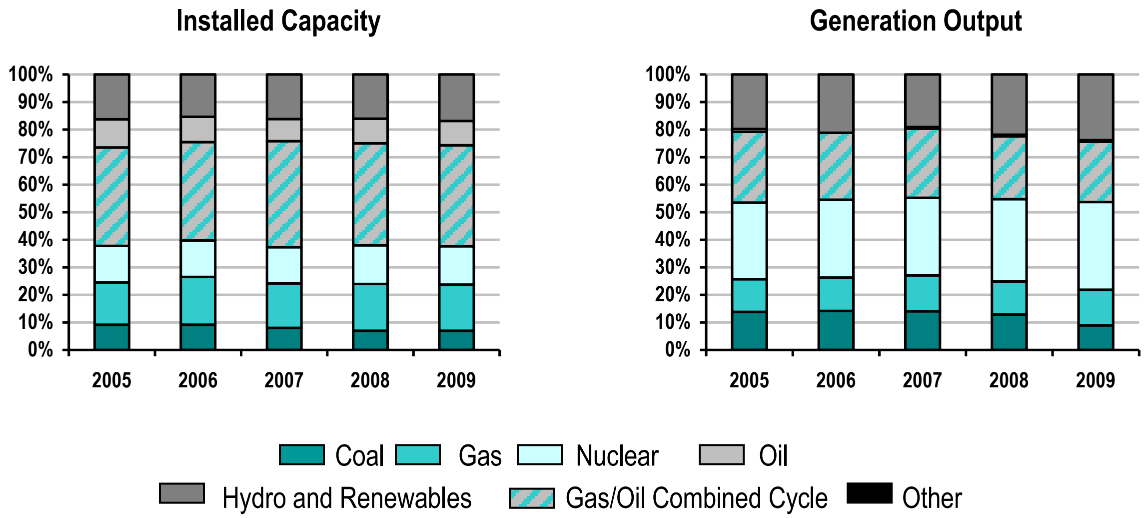
Based on data from the United States Environmental Protection Agency, the rate of power plant emissions of Sulfur Dioxide (SO2), Nitrogen Oxides (NOx), and Carbon Dioxide (CO2) sharply declined between 1999 and 2009 in New York State. The SO2 rates have seen the most dramatic decline by dropping 82% over the ten-year period, CO2 rates dropped by 31%, while NOx rates dropped by 62%. The emission rates of New York State's electricity generation rank among the lowest in the continental United States. New York's CO2 emissions rate ranks 9th, its NOx emission rate ranks 13th, and its SO2 emission rate ranks 12th lowest.

Open access to the state's electricity grid has also increased the number of existing and planned projects powered by renewable resources, which are more protective of the environment than are traditional fossil-fueled plants. Commercial power production from renewable resources, predominantly hydroelectric power projects, currently totals more than 5,600 MW of electricity. Nearly two dozen private sector energy service companies now offer customers the option to purchase green power. More than 1,200 MW of wind power has been added in recent years and over 7,000 MW of additional wind power projects are proposed for development in the state.

The NYISO has taken steps that, according to FERC, "will benefit, and encourage, wind and other intermittent generators." Those steps include a centralized wind-forecasting initiative, unique market rules for wind projects, and proposals to enhance the dispatch of wind power on New York's bulk electricity grid.

Recent New York State government policies are vigorously pursuing conservation and energy efficiency programs to control the growth in power consumption. These programs contribute to better power management, particularly during extreme weather conditions when electricity use is highest. They also help to lower consumer costs.

NYISO Fuel Diversity 2005-2009



The New York Control Area's electric generation has become increasingly dependent on natural gas and dual-fuel (seen above as "Gas/Oil Combined Cycle") generating units. High efficiency and low emissions make them especially attractive to being located in densely populated areas such as New York City and Long Island. The limited capacity of the natural gas distribution system in New York City has resulted in the adoption of a local reliability rule often requiring the use of oil as the fuel source, despite being less economic and creating higher emissions.

Renewable Resources

Open access to the grid and competitive wholesale electric markets have facilitated the increased development of renewable energy projects. New York has been a leader in the integration of renewables, pioneering key policies and programs that have encouraged a significant growth in renewable sources of energy helping to meet environmental goals, and diversifying the array of fuels used to generate electricity. In 2009, electricity produced by hydropower, wind power, and other renewable resources totaled 22 percent of New York's generation.

In 2008, the NYISO instituted one of the first state-of-the-art wind forecasting systems in the United States. The centralized system enables the NYISO to better utilize and accommodate wind energy by forecasting the availability and timing of wind-powered generation. In 2009, the NYISO became the first grid operator to dispatch wind power fully balancing the reliability requirements of the power system with the use of the least costly power available. Including wind power in the economic dispatch allows more efficient management of the resources and minimizes the duration of wind-power curtailments. More than 1,200 MW of wind power was in operation in New York State by the end of 2009, with monthly capacity factors that ranged from a low of 10.2% in June 2009 to a high of 35.7% in February 2009. Some 7,000 MW of additional wind power have been proposed for interconnection with the New York electric grid. Generating facilities using renewable resources, such as wind, tend to be sited in locations distant from population centers. As a consequence, transmission upgrades or expansion may be required to effectively supply the power demands of New York State with this renewable power. A 2004 study of wind power in New York State determined that New York could reliably manage 3,300 MW of interconnected wind generation. In the intervening years, it became apparent that more than 3,300 MW of wind might be interconnecting to New York bulk electricity system in the near future and the impacts of this increased amount of wind generation required evaluation. In order to more thoroughly assess the impacts of wind power integration, the NYISO has completed an extensive study of the impact of up to 8,000 MW of wind resource integration on system variability and operations, installed capacity requirements, transmission infrastructure, production costs, and emissions.

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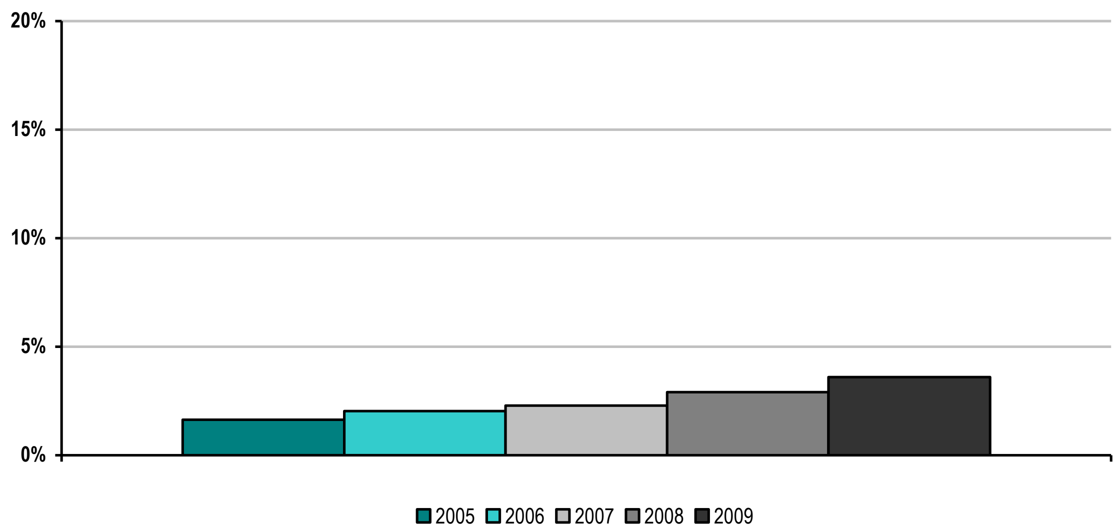
The findings of the NYISO wind study conclude that wind generation can supply clean energy at a very low cost of production. This energy can result in significant savings in overall system production costs, yield reductions in "greenhouse" gases and other emissions, as well as result in an overall reduction in wholesale electricity prices. However, wind plants as variable resources present challenges to power system operation. The wind study finds that NYISO systems and procedures (which include economic dispatch and the other operational practices available to accommodate wind resources) should allow for the integration of as much as 8,000 MW of wind generation without adverse reliability impacts.

The study determined that almost 9% of the potential upstate wind energy production would be "bottled" or not deliverable because of local transmission limitations. The study identified feasible sets of transmission facility upgrades to eliminate the transmission limitations. These upgrades were evaluated to determine how much of the wind energy that was undeliverable would be deliverable if the transmission limitations were removed. Additional alternatives were suggested and evaluated to address the significant levels of resource bottling that occurs in the Watertown vicinity. The suggested transmission upgrades and alternatives require detailed physical review and economic evaluation before a final set of recommendations can be determined. The full study is available at: http://www.nyiso.com/public/webdocs/newsroom/press_releases/2010/GROWING_WIND_-_Final_Report_of_the_NYISO_2010_Wind_Generation_Study.pdf.

New York State Renewable Portfolio Standard

The New York State Public Service Commission (PSC), in September 2004, issued its "Order Approving Renewable Portfolio Standard Policy" that calls for an increase in renewable energy used in New York State from the then current level of approximately 19 percent to 25 percent by the year 2013. In December 2009, the NYS PSC increased the RPS goal to 30 percent and extended the target date to 2015. The definition of "renewable" included existing large-scale hydropower, but limited the inclusion of hydroelectric power going forward to new run of river (non-storage) hydroelectric facilities of 30MW or less. The information presented here is consistent with New York's RPS definition.

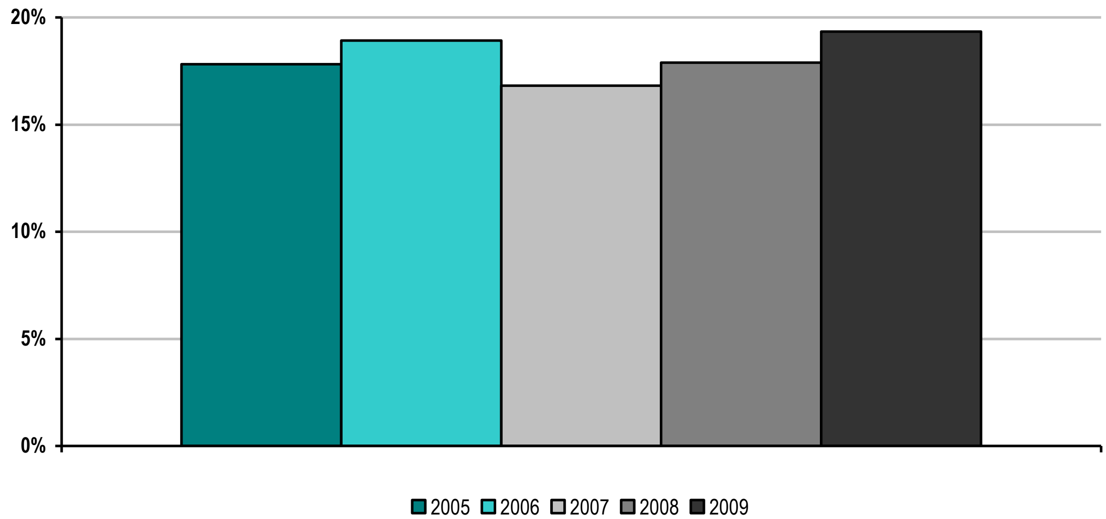
NYISO Non-Hydroelectric Renewable Megawatt Hours as a Percentage of Total Energy 2005-2009



Energy from non-hydroelectric renewables has more than doubled since 2005. This may be attributable to the combined impact of NYISO markets providing economic incentives and public policy encouraging the development of renewable generation in New York State.

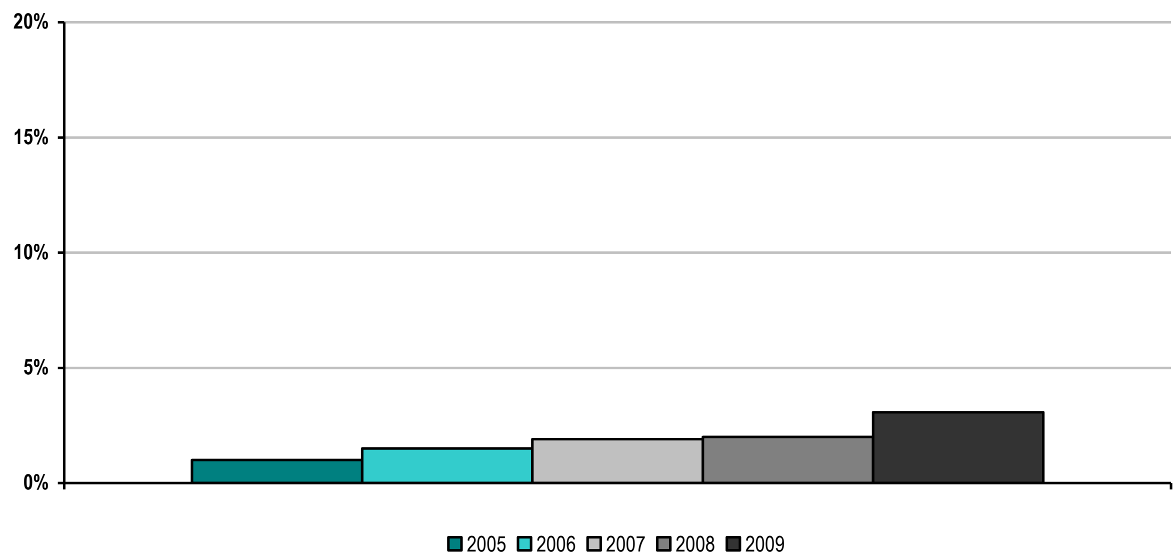
Under the definition of the NYS RPS the calculated Total Energy (all renewable resources, including qualified hydropower) for this report period is: 2005 – 19.63%; 2006 – 21.18%; 2007 – 19.27%; 2008 – 21.98%; and for 2009 – 24.13%.

NYISO Hydroelectric Renewables Megawatt Hours as a Percentage of Total Energy 2005-2009



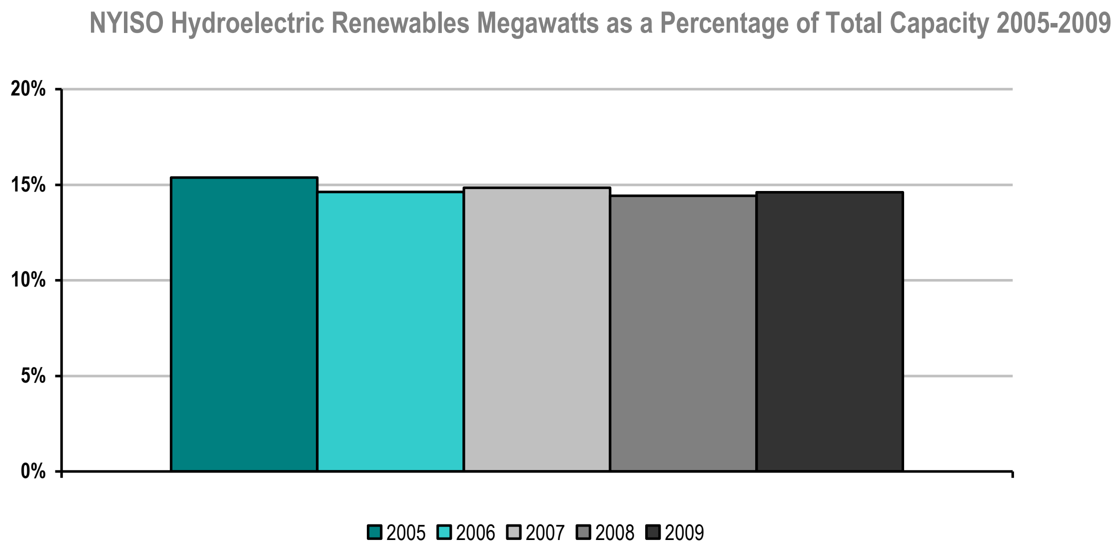
Currently, hydropower is the largest renewable resource (as defined by the NYS Renewable Portfolio Standard) in the state's energy mix.

NYISO Non-Hydroelectric Renewable Megawatts as a Percentage of Total Capacity 2005-2009



Capacity of wind resources rose from 245 MW in 2005 to 770 MW in 2009, an increase of more than 200%.

Under the definition of the NYS RPS the calculated Total Capacity (all renewable resources, including qualified hydropower) for this report period is: 2005 – 16.42%; 2006 – 16.14%; 2007 – 16.72%; 2008 – 16.41%; and for 2009 – 17.70%.



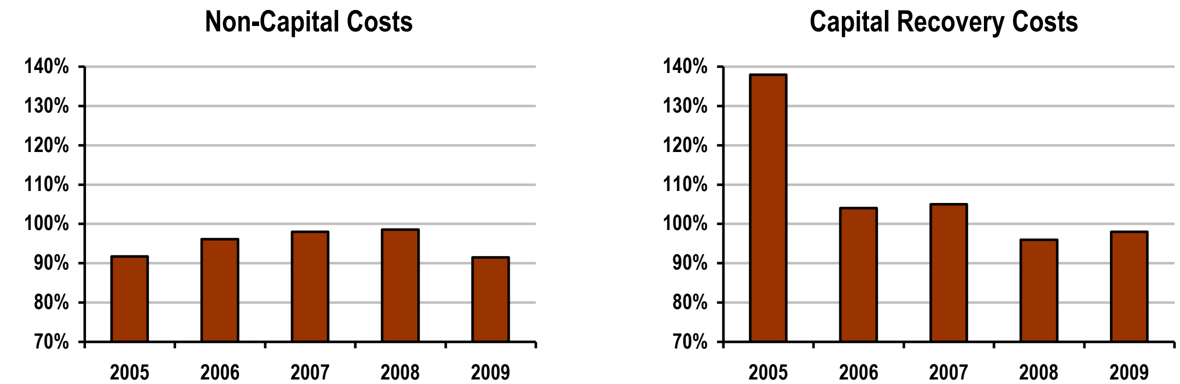
Future NYISO Enhancements:

Moving the electricity produce by wind generation to areas of high consumer demand will require substantial investment in the state's transmission infrastructure. Decisions on location and how to finance new transmission facilities will be crucial to New York State's ability to meet renewable power policy goals. The NYISO is working to support the integration of renewable resources and complementary energy storage with innovative grid operation, market design, planning initiatives and technological advances.

C. NYISO Organizational Effectiveness

Administrative Costs

NYISO Annual Actual Costs as a Percentage of Budgeted Costs 2005-2009



Budget	$110	$107	$111	$117	$129
Budget	$13	$17	$20	$11	$6

Bars Represent % of Actual Costs to Approved Budgets; Dollar Amounts Represent Approved Budgets (in millions)

*NYISO's budget includes the annual assessment of fees from the Federal Energy Regulatory Commission (FERC). In contrast, other ISOs and RTOs invoice such FERC fees within their market settlement charges and do not include FERC fees within their approved budgets. In order to ensure comparability of NYISO's budget with other ISOs and RTOs, the charts reflecting "NYISO Annual Actual Costs as a Percentage of Budgeted Costs" and "NYISO Annual Administrative Charges per Megawatt Hour of Load Served" exclude FERC Fees.

The NYISO develops its annual budget through its shared governance process in consultation with the Budget and Priorities Working Group, which is open to participation by all NYISO Market Participants. The Budget and Priorities Working Group is responsible for developing and monitoring NYISO's budgetary spending and providing guidance regarding prioritization and funding of strategic initiatives. Annually, the Budget & Priorities Working Group presents a recommended budget to the NYISO Management Committee, consisting of Market Participant membership from transmission owner, generation owner, other suppliers, end-use consumers, and public power/environmental sectors. The Management Committee votes on whether to recommend the proposed budget to the NYISO Board of Directors for approval. During the period 2005-2009, the NYISO's proposed budgets were consistently supported by the Management Committee and approved by the NYISO Board of Directors.

In addition to the review and recommendations for NYISO's annual budget, the Budget & Priorities Working Group meets approximately 10 times per year to review budget vs. actual results for all NYISO line items and to monitor progress on projects' scope, cost and schedules.

NYISO's budget consists of Capital investments, Operating Expenses (excluding depreciation expense), FERC fees, Debt Service Costs (net of current year debt proceeds), offset by miscellaneous sources of income. NYISO's budget is approved and spending is managed based on the totality of that respective year's budget. In a given year, NYISO could overspend Capital while underspending Non-Capital (or underspend Capital while overspending Non-Capital), budget total spend is ultimately managed within the total overall NYISO budget. An example of this occurred during 2005 when NYISO's Capital costs exceeded budget due to the timing of actual costs/debt service for a new facility renovation, while Non-Capital costs were significantly below budget. The noncapital costs metric identifies NYISO's administrative and operational budget performance against the planned resource allocations to meet the NYISO's objectives as discussed and vetted during the stakeholder process described above. The main categories of costs included in the noncapital costs metric include salaries & benefits, external professional fees, and computer services (hardware/software maintenance and licenses to support the NYISO operations and markets). Collectively, these largest components of the noncapital costs metric approximate over 80% of the total NYISO annual cash budget.

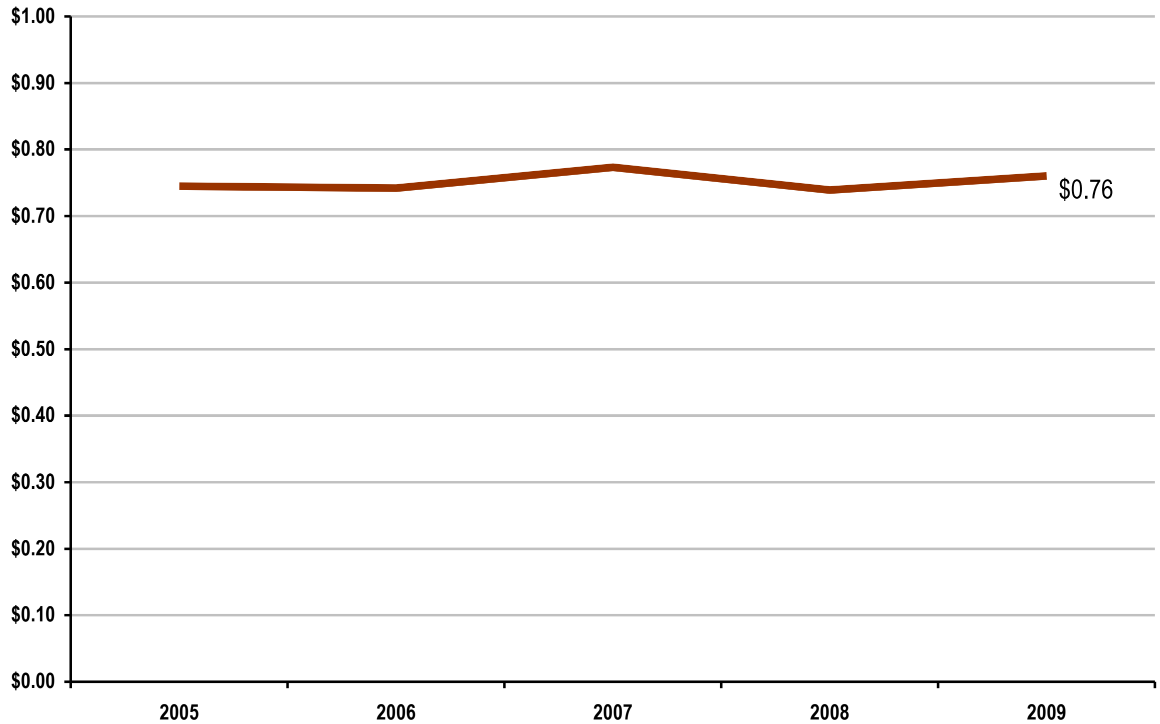
During 2005 -2009, NYISO's actual spending was less than the approved budget in each respective year with minor variances from budget generally noted (budget underruns of 4% in 2005, 3% in 2006, 1% in 2007, and 2% in 2008).

NYISO's most significant variance from budget occurred during 2009, as New York and the nation endured an historic economic downturn, the NYISO worked to achieve its essential responsibilities with efficiency and financial prudence. NYISO reduced planned spending by $12 million to account for reductions in revenues from declining power demands. NYISO cost-cutting measures included cutting Capital expenditures, renegotiating vendor contracts, and constraining compensation costs.

From 2005 to 2009, NYISO's annual administrative charges per megawatt hour increased a total of 2% over this five-year time horizon. In order to minimize rate increases to NYISO market participants and NY consumers, NYISO implemented a virtualization initiative to not only serve the evolution of grid operation and market design, but to also produce efficiencies in the operation of the NYISO. NYISO's data center "virtualization" project, which reduced the number of servers by half, realized savings of $18.7 million through the end of 2009.

NYISO Annual Administrative Charges per Megawatt Hour of Load Served 2005-2009

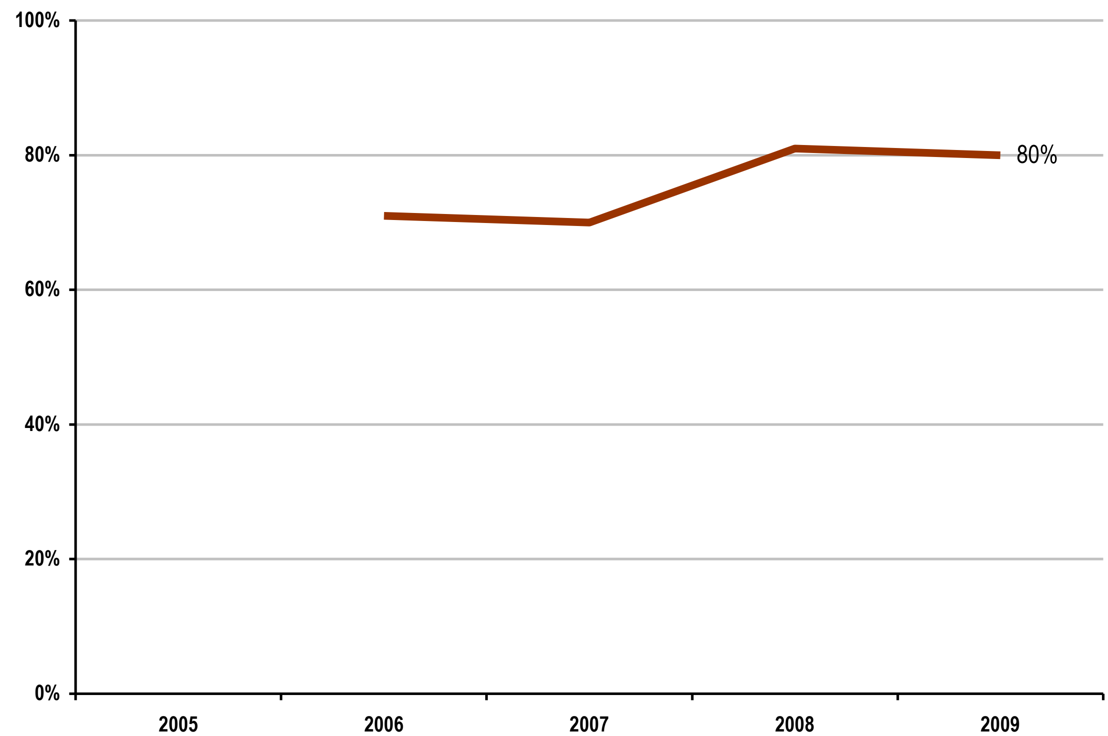
($/megawatt-hour)



ISO/RTO	2009 Annual Load Served *(in terawatt hours)*
NYISO	163

Customer Satisfaction

NYISO Percentage of Satisfied Members 2005-2009



The NYISO is committed to transparency in how it carries out its duties, in the information it provides, and in its roles as the impartial administrator of the state's wholesale electricity markets, operator of the high-voltage transmission system, and provider of comprehensive electric system planning. The NYISO actively involves stakeholders, regulators, public officials, consumer representatives, environmentalists, and energy experts who provide vital input from a variety of viewpoints. The NYISO's shared governance process actively builds consensus for changes in market rules and operating procedures. Since the inception of the NYISO, 95% of its tariff revisions have been developed through consensus among NYISO stakeholders. The value of shared governance was noted by the FERC in a January 2008 order that stated: "The Commission commends NYISO & the stakeholders for working together to resolve many issues …"

As part of these efforts, the NYISO conducts an annual survey that solicits stakeholder feedback to further enhance its shared governance process. In response to past surveys, the NYISO has implemented transparency measures including a redesign of its website for greater ease in obtaining market and operational data. Market training resources were expanded, with instructional hours doubled and web-based training options added. The NYISO restructured its Customer Relations department to better serve stakeholders and reduce the time required to resolve customer inquiries. In the first three quarters of 2010, 91% of general inquiries were resolved within 24 hours, which bettered the 89% level achieved in 2009. Overall, the average number of working days required to address all customer inquiries dropped from 5.5 days in 2009 to 3.2 days in the first three quarters of 2010.

NYISO's annual survey of stakeholders measures satisfaction using a seven-point scale. NYISO considers responses within the top three categories of this scale to be "satisfied" stakeholders. As such, stakeholders who provide a neutral response are not considered "satisfied". The data shown above under Percentage of Satisfied Members reflects only those responses in the top three categories of satisfaction. For comparative purposes, the trends of NYISO's Percentage of Satisfied Members, shown with and without incorporating "neutral" responses is as follows:

	% of Satisfied Members Including Neutral Responses (as shown above)	**% of Satisfied Members Excluding Neutral Responses**
2006	87%	71%
2007	87%	70%
2008	92%	81%
2009	91%	80%

Billing Controls

ISO/RTO	2005	2006	2007	2008	2009
NYISO	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 2009, the NYISO received an unqualified SAS (Statement on Auditing Standards) 70 Type II audit opinion for the eighth consecutive year. The SAS 70 Type II audit, conducted by an external audit firm, scrutinizes the controls related to the NYISO's processes and systems for bidding, accounting, billing, and settlements of energy, regulation, capacity, transmission, reserves, and related market transactions. The external audit firm reviews the NYISO's description of controls, and verifies that those controls are designed appropriately and operating effectively over a 12-month period. The SAS 70 report is designed for use by management of the NYISO, NYISO Market Participants, and Independent Auditors of the NYISO Market Participants.

Pricing Accuracy

The Pricing Accuracy performance metric identifies NYISO's level of real-time pricing accuracy. NYISO follows a rigorous price validation process for ensuring timeliness and accuracy in pricing outcomes. The results from 288 five-minute real-time dispatch cases with approximately 500 pricing points are posted in real-time through an automated system. Each day the prices are reviewed for accuracy and corrected, if necessary, within three calendar days as per tariff.

In 2009, real-time prices in 99.7% of total hours were accurately set based on the NYISO's tariffs, with price corrections required in only 27 out of 8,760 hours. NYISO's focus on price certainty has resulted in significant improvements since 2005. The primary driver for the improvements made and the high level of price accuracy achieved is due to the integration of Intelligent Source Selection ("ISS"). ISS allows for improved data integrity by identifying and removing metering errors that otherwise would have impacted the real-time markets. The following table shows the percentage of hours in which there were no corrections in the real-time energy or ancillary services prices at any active nodal or zonal price location in the NYISO administered markets.

NYISO	Error-Free Hours
2005	83.8%
2006	96.9%
2007	99.0%
2008	99.3%
2009	99.7%

Billing Accuracy

Market Settlement Billing Accuracy: This metric includes all settlements on NYISO Invoices from the Initial Bill through Final Bill Closeout (FBC). The values represent the percentage of the total Final Bill Settlement that was invoiced, on average, at the various invoice intervals until the requisite billing month was closed out. The primary driver of differences between the initial bill and 4 Month True-up is metering updates that occur throughout the true-up process in accordance with the NYISO tariff.

Billing Accuracy % of dollars settled during billing cycles 2005-2009			
Year	**Invoice**	**4 Month Rebill**	**True-ups & Close Out**
2005	95.33%	3.90%	0.77%
2006	95.71%	3.33%	0.96%
2007	95.57%	3.69%	0.74%
2008	95.87%	3.76%	0.36%
2009	95.62%	3.95%	0.44%
Five-Year Average	95.62%	3.73%	0.65%

NYISO Market Participants are engaged in the Billing Issues process on a regular basis through the Billing and Accounting Working Group (BAWG). The working group meetings include standing agenda items that cover highlights of the most recently issued invoices, as well as information on any open billing issue and the planned resolution strategy and timeline. In addition to this information, the Billing Issues Report includes information on upcoming code deployments, bill challenges, and pertinent FERC filings that may impact the invoice process or individual invoices in the future.

D. New York ISO Specific Initiatives

A decade ago, when the NYISO was first established, New York State faced a widening generation gap, with projections that available generation would be incapable of reliably serving increasing levels of electricity use, particularly in the downstate Metropolitan New York region. By 2009, the NYISO's assessment of the electric system's reliability needs had concluded that New York has sufficient installed generation to reliably serve load through the next ten years.

Since the inception of New York's wholesale electricity markets, new generation and interstate transmission have been built where most needed. More than 7,800 MW of new generation was built in New York, with 80% sited where demand for power is greatest (New York City, Long Island, and the Hudson Valley) and nearly 1,300 MW of transmission capability has been added to bring more power to the downstate region from out of state.

In the market environment, power producers have invested heavily in new generation and upgrades to existing facilities. Consumers have benefited through prices that are lower than they might have been otherwise. Environmental quality has been enhanced by the addition of more emission-free, renewable power resources and enhanced power plant efficiencies that have contributed to reduced emission rates.

NYISO Market Benefits – Wholesale Electricity Prices

In New York State, wholesale electricity energy prices reached historic lows in 2009 – 50 percent lower than in 2008 -- driven by lower electricity use and drops in the prices of natural gas (one of New York's primary generating fuels). Discounting fluctuations in the cost of fuel used to generate electricity, the NYISO estimates cost reductions of 10% in the energy and ancillary services markets between 2000 and 2008. Those reductions are valued at an annual savings of **$1.2 billion**. When capacity cost reductions are taken into account, overall savings are estimated at 18%, with total annual savings of **$2.2 billion**.

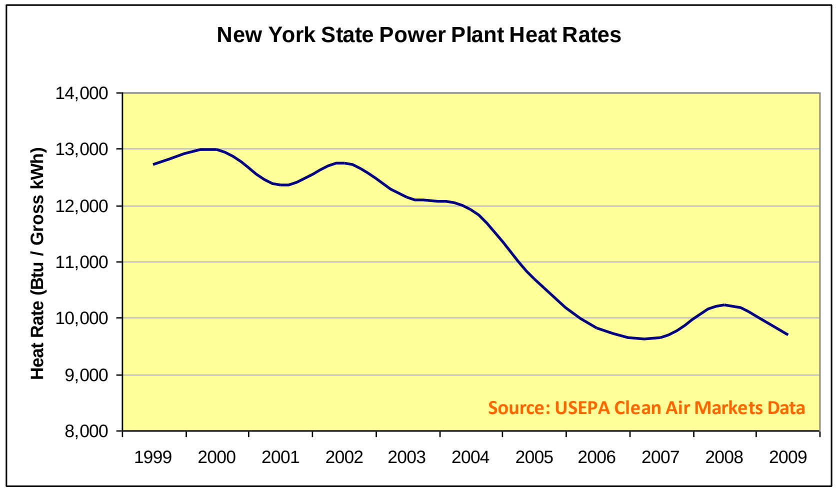
These cost reductions have developed as the system heat rate has improved and unit availability has increased (see sections below), as well as the addition of lower-cost, reduced emission generation and demand-response resources located near load centers and the expansion of renewable resources.

NYISO Market Benefits – Improved Unit Availability

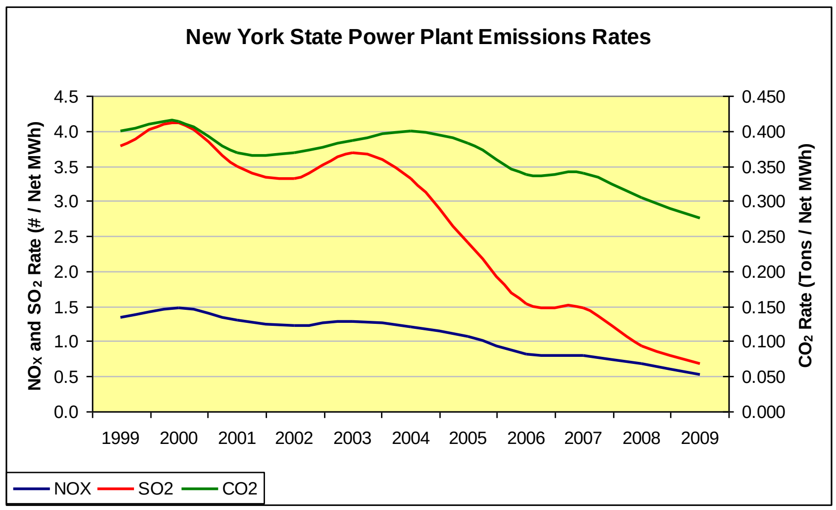
In the competitive market environment, generating units in New York improved their operations with increased availability as they reduced the length of planned and unplanned outages. Average plant availability increased from 87.5 percent (1992–1999) to 94.27 percent (20001–20097), equivalent to adding 2,400 MW of available capacity to the system. The net effect of improved unit availability provided an equivalent of 2,400 MW of capacity in New York State. The **savings from improved unit availability is estimate at $ 300 million** annually. (This estimate is based on roughly 50% of generating capacity sold in the NYISO capacity market with the remainder in bilateral markets and assumes that the 2,400 MW would have been purchased at a price set by the demand curve.)

NYISO Market Benefits - Heat Rate Improvements

In New York's competitive market environment, power plant owners have invested in generating units with better heat rates, which are able to compete and produce infra-marginal revenue. The uniform clearing price drives the selection of units with the lowest marginal cost. Units that are not selected to run do not earn energy market revenues. This dynamic has resulted in **a 25% overall improvement in heat rates** in the New York generating fleet since 2000. The heat rate improvements contribute to the bulk of the energy related savings by driving efficiency improvements in existing units and attracting new units with superior heat rates. Demand-side resources also contribute to the overall improvements in fleet heat rate as units with inferior heat rates are no longer dispatched when the load levels are curtailed through demand response programs.



Power plant emissions of carbon dioxide, as well as sulfur oxide and nitrogen oxide, declined by double-digits over the past decade as the effects of environmental regulations and air quality mandates combined with improvements in power plant efficiency resulting from improved heat rates and the addition of cleaner generation.

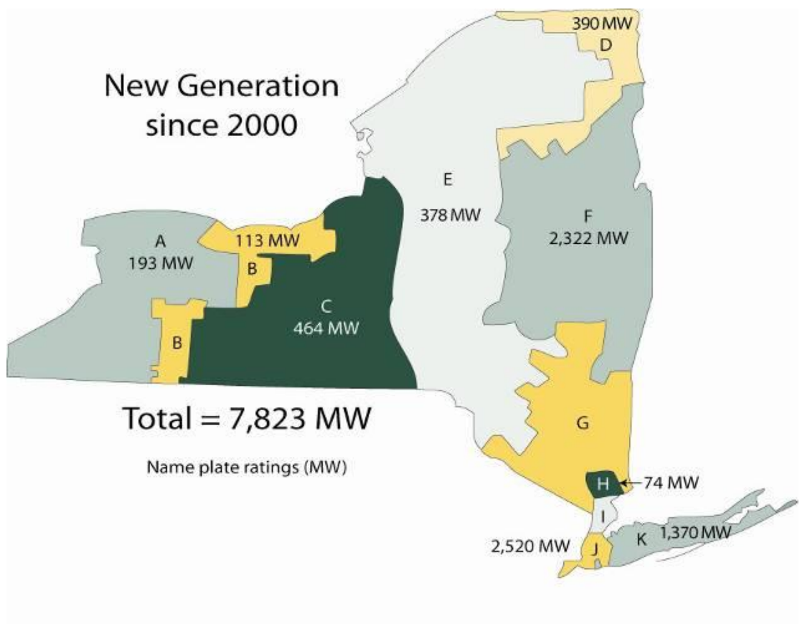


NYISO Market Benefits - Demand Response

Demand response programs, cultivated in the competitive market environment, have grown significantly in the New York wholesale electricity markets, with resources total nearly 2,400 MW in 2009. From 2005 to 2009, NYISO Day Ahead Demand Response program provided energy **savings averaging $8.9 million** annually, for a total of **$44 million**. (Data on the Location Based Marginal Price impact of demand response resources participating in the NYISO's Day-Ahead Demand Response Program can be found in the NYISO's annual compliance file to the FERC, Docket No. ER01-3001.)

When New York experienced its record peak load in August 2006, NYISO demand response programs shaved the peak by an average of 865 MW, providing estimated **savings of $91 million**. (The savings produced by the peak shaving can be quantified as the cost of providing a similar amount of capacity from peaking units. Assuming that the peaking unit is a nominal 195 MW Frame 7FA located in the Capital Zone, the estimate installed cost of such a facility (based upon the current S&L calculations for the demand curve reset) is $840/kW, with a combined fixed O&M plus insurance costs of 0.84%. Using annual fixed charge rate of 13% (assumed 20-yr amortization period), one unit would cost approximately $23M/year; four would be $91M/year.)

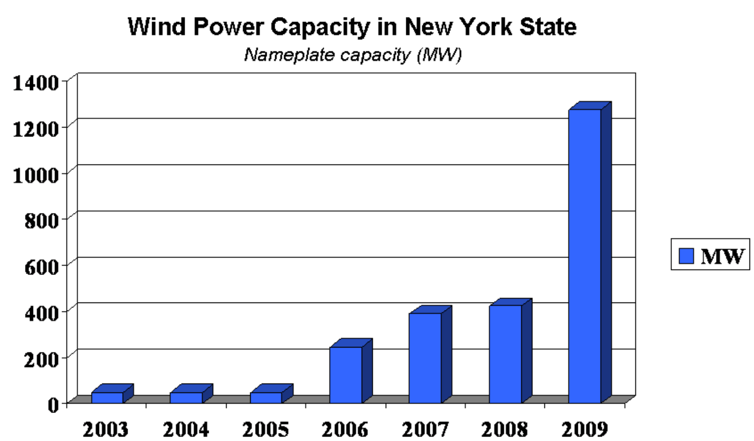
NYISO Market Benefits - Locational Price Signals



Locational price signals in the NYISO energy and capacity markets have driven investments in areas where the demand for electricity and, consequently, the prices are the highest. Investments in generation and demand side resources followed the price signals, resulting in the development of cleaner, more efficient resources in the downstate New York City area. These investments have enabled New York to reliably serve its demand within a competitive market with limited investment in transmission. The **savings associated with location of generation and demand-response resources are estimated at $500 million annually**. This estimate is based on the transmission congestion costs that would have been incurred to transport power from other regions and the costs that would have been incurred to add new transmission capacity.

NYISO Market Benefits – Renewable Resources

Open, non-discriminatory access to the grid and wholesale electricity market incentives have helped to cultivate the development of renewable sources of electricity in New York. The Empire State's first wind farm, with a generating capacity of 300 MW, went into operation during 2006. There are now over 1,200 MW of wind generation in operation with an additional 7,000 MW proposed for grid connection.



The NYISO continues to evolve its market design and grid operations, especially with regard to renewable resources. With the approval of the Federal Energy Regulatory Commission (FERC), the NYISO successfully implemented a state-of-the-art centralized wind forecasting system and became the first ISO/RTO to integrate wind into its economic dispatch system to effectively manage wind generation while maximizing transmission capability and maintaining reliability. FERC also approved another market first, authorizing the NYISO to create a pioneering regulation-only energy storage product, an innovation that will enhance system reliability and strengthen regulation market competition.

NYISO Market Benefits - Credit Management

During the period 2005-2009, the NYISO's proactive approach toward credit management prevented significant Market Participant defaults. In this time period, the NYISO allocated $0.6 million in bad debt losses to its Market Participants, 0.001% of the $46 billion total value of market transactions clearing through the NYISO markets.

The NYISO's credit management efforts include proactively removing the unsecured credit privileges of Lehman Brothers prior to that entity's bankruptcy filing, thereby **avoiding a potential bad debt loss of at least $4 million**; implementing a series of credit policy enhancements in 2008 to minimize the risk of potential socialized bad debt losses; developing an automated Credit Management System to permit flexibility to update credit requirements to match evolving market design and revising existing credit requirements for each NYISO market to more appropriately match credit requirements to market risk.

NYISO Market Benefits – Technology

The NYISO assumed control of New York's grid on the verge of the Y2K transition. Its initial investments in advanced information technology immediately advanced the technological infrastructure of grid operations and provided a foundation for sustained progress. NYISO technology continues to advance with the evolution of market design. In 2005, the NYISO performed a comprehensive system overhaul with the implementation of its Standard Market Design 2 ("SMD2"), which has served as a model for other markets. The NYISO has continued to advance its technology with deployments relating to innovative demand response programs and pioneering wind power integration.

NYISO information technology initiatives not only serve the evolution of grid operation and market design; they also produce efficiencies in the operation of the NYISO. A data center "virtualization" project partitioned hardware into virtual systems to provide a more robust, responsive, and reconfigurable system. It reduced the number of servers required, cut energy use, and reduced licensing and maintenance costs, producing a **savings of almost $20 million** over the four-year time frame of the project.

NYISO Market Benefits – Smart Grid

Consistent with its commitment to advance the technological infrastructure serving the electricity system, the NYISO worked with the owners of New York's high-voltage transmission facilities to earn **a $38 million Federal Stimulus Smart Grid Investment Grant** to install Phasor Measurement Units (PMUs) and shunt capacitors across New York State. PMUs transmit power system data 60 times each second, enabling faster responses to grid events and facilitating more effective mitigation of potential outages. Current monitoring systems sample conditions every two to six seconds. The NYISO estimates that the capacitor project will reduce line losses by 48.7 gigawatt-hours of electricity annually, with a **yearly savings of $9.7 million**.

NYISO Market Benefits – Addressing Market Issues

The transparency of the NYISO wholesale electricity markets facilitates effective monitoring and identification complex transactions. Loop flows, for example, occur in every power system due to the laws of physics that govern the actual flow of electricity. When loop flows are exacerbated by certain transactions, however, their impact becomes apparent in the marketplace. Market transparency enables grid operators to effectively identify and address such problems.

The NYISO, in addition to halting the transactions that exacerbated Lake Erie loop flow in the first part of 2008, established a monitoring and analysis group to provide enhanced daily scrutiny of the markets, developed a daily post-operations review that provides more detailed, transparent views of certain wholesale electricity costs. As a result, "uplift costs" were cut dramatically with **savings estimated at $48 million annually.**

NYISO Market Benefits – Broader Regional Markets

Pursuing market solutions to the Lake Erie loop flow issue, the NYISO coordinated the development of a "Broader Regional Markets" initiative, which proposes a comprehensive set of "Seams Reduction" projects developed with ISO-NE, PJM, IESO, HQ, and MISO. In a July 15, 2010 Order, the FERC conditionally approved the proposals, saying, "…these planned regional initiatives will be designed to reduce uplift costs and lower total system operating costs…" A preliminary analysis of the benefits of the Broader Regional Markets initiatives prepared by Potomac Economics estimates **regional annual savings of at least $368 million.**

NYISO Market Benefits – Expanded Interregional Planning

Working with the two dozen other Eastern Interconnection planning authorities, the NYISO helped to form and develop the Eastern Interconnection Planning Collaborative (EIPC). The EIPC focus is on a "bottom-up" approach to planning which starts with a roll-up of the existing grid expansion plans of electric system planning authorities such as ISOs, RTOs and utilities, in the Eastern Interconnection. Integral to the process will be the identification and analysis of a large number of resource expansion scenarios, as well as sensitivity analyses of options selected through a transparent stakeholder process that includes representatives from the entire interconnection. The results of the technical analyses will identify alternative transmission facilities that are needed to address policy scenarios such as the delivery of large new quantities of wind power and other renewable resources across the region as well as integration of enhanced demand-side strategies and programs. These studies will likely be used by federal and state regulators and other policy makers as they debate such important public policy issues. In 2009, **the U.S. Department of Energy awarded $16 million to the EIPC for the 3-year study**.

PJM Interconnection (PJM)

Section 6 – PJM Performance Metrics and Other Information

PJM Interconnection is a regional transmission organization (RTO) that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.

- Acting as a neutral, independent entity, PJM operates a competitive wholesale electricity market and manages the high-voltage electricity grid to ensure reliability for more than 51 million people.
- PJM's long-term regional planning process provides a broad, interstate perspective over a 15-year horizon that identifies the most effective and cost-efficient improvements to the grid to ensure reliability and economic benefits on a system-wide basis.
- An independent board, representing various knowledge and experience requirements, provides oversight on behalf of PJM's 600+ members. Through effective governance and a collaborative stakeholder process, PJM is guided by its vision: "To be the electric industry leader – today and tomorrow – in reliable operations, efficient wholesale markets and infrastructure planning."

Founded in 1927 as a power pool, PJM opened its first bid-based energy market on April 1, 1997. Later that year, the Federal Energy Regulatory Commission (FERC) approved PJM as an independent system operator (ISO). ISOs operate, but do not own, transmission systems in order to provide open access to the grid for non-utility users.

PJM became a regional transmission organization (RTO) in 2001, as FERC encouraged the formation of RTOs to operate the transmission system in multi-state areas as a means to advance the development of competitive wholesale power markets.

From 2002 through 2005, PJM integrated a number of utility transmission systems into its operations. They included: Allegheny Power in 2002; Commonwealth Edison, American Electric Power and Dayton Power & Light in 2004; and Duquesne Light and Dominion in 2005. These integrations expanded the number and diversity of resources available to meet consumer demand for electricity and increased the benefits of PJM's wholesale electricity market.

Currently, PJM administers a day-ahead energy market, real-time energy market, capacity market, financial transmission right congestion hedging market, day-ahead scheduling reserve market, synchronized reserve market and regulation market. PJM ensures sufficient black start service to supply electricity for system restoration in the unlikely event that the entire grid would lose power. PJM also administers demand response programs that help increase operational efficiency and improve resource diversity which in turn can reduce customer costs and reduce wholesale prices.

A. PJM Bulk Power System Reliability

The table below identifies which NERC Functional Model registrations PJM has submitted effective as of the end of 2009. Additionally, the Regional Entities for PJM are noted at the end of the table with a link to the websites for the specific reliability standards. To date, PJM has had no self-reported or audit-identified violations of NERC or applicable Regional Entities' standards, though certain potential violations are under review based on a first quarter 2010 standards audit. Also, PJM has not shed any load in the PJM region due to violating a NERC or Reliability Entity operating standard.

NERC Functional Model Registration	PJM
Balancing Authority	✓
Interchange Authority	✓
Planning Authority	✓
Reliability Coordinator	✓
Resource Planner	✓
Transmission Operator	✓
Transmission Planner	✓
Transmission Service Provider	✓

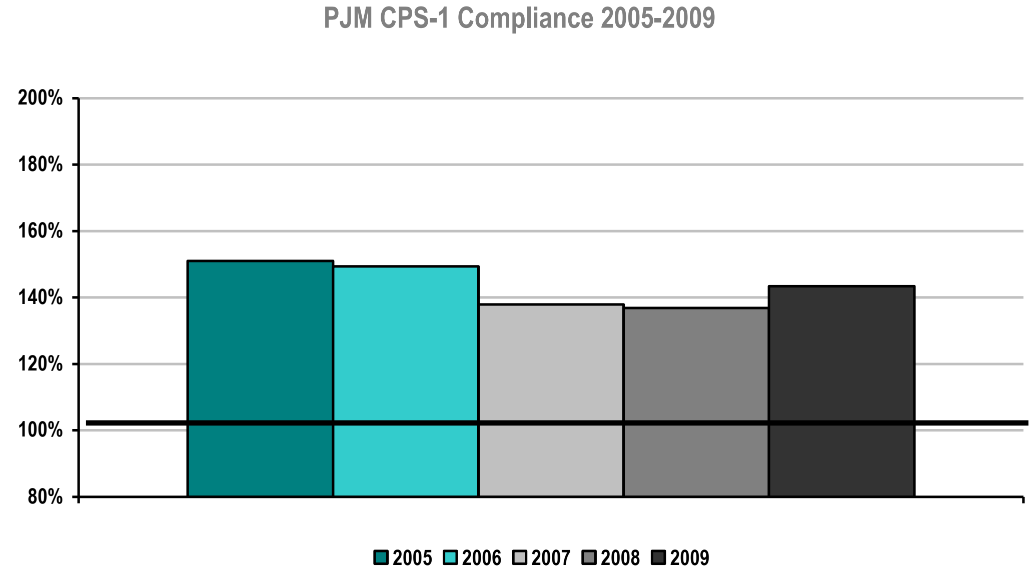
Regional Entities	Reliability*First* and SERC

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

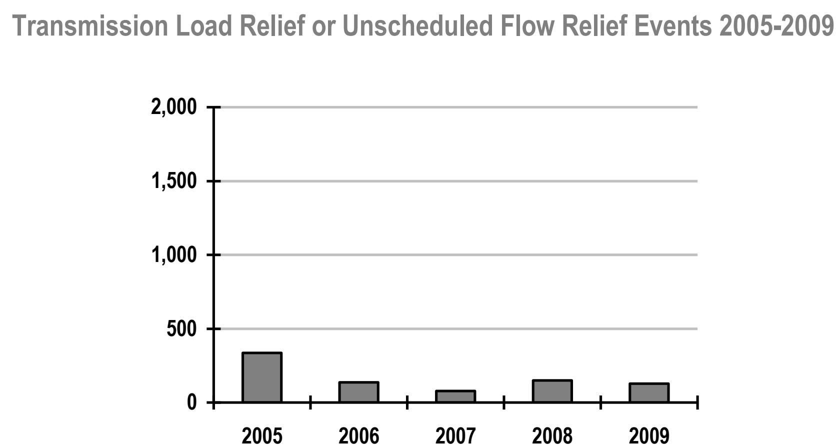
Additional standards approved by the Reliability*First* Board are available at:
http://www.rfirst.org/Standards/ApprovedStandards.aspx

Additional standards approved by the SERC Board are available at:
http://www.serc1.org/Application/ContentPageView.aspx?ContentId=111

Dispatch Operations



Compliance with CPS-1 requires a performance level of at least 100% throughout a 12-month period. PJM was in compliance with CPS-1 for each of the calendar years from 2005 through 2009. PJM began participating in a field trial to replace CPS-2 as a performance measure in August 2005 and was granted a waiver from the CPS-2 measure at that time. This new control performance measure is the Balancing Authority ACE Limit (BAAL). The BAAL performance measure combines the CPS-1 performance measure with a specific limit known as a Frequency Trigger Limit (FTL). In order to be compliant with the BAAL standard, a Balancing Authority must recover from a FTL excursion within a 30-minute period of time. PJM was in compliance with the BAAL performance standard for each calendar year from 2005 to 2009.

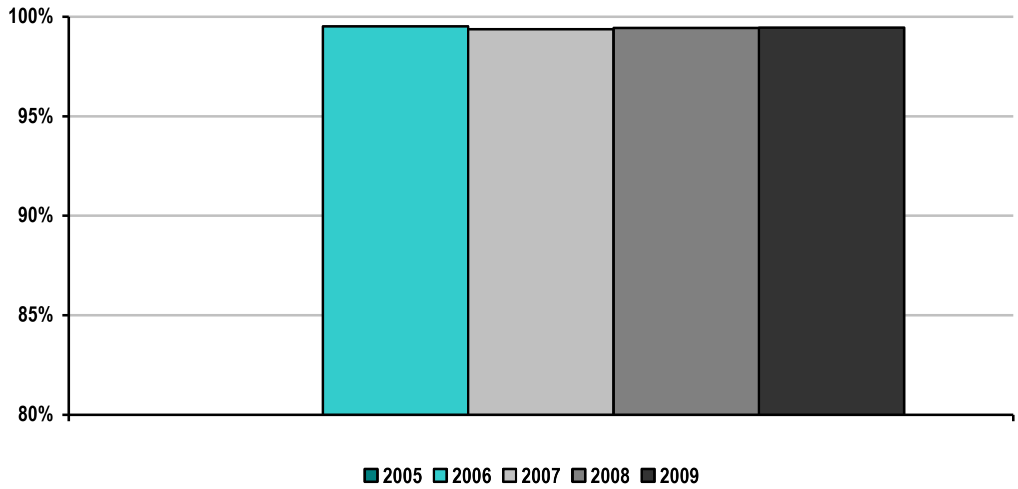


PJM data reflects the number of Transmission Load Relief (TLR) events. PJM's TLRs are almost exclusively level 3 and 4 TLRs with less than 1% of TLRs called from 2005 through 2009 being level 5. The number of TLRs in the PJM region has decreased since the integration of several transmission zones in 2003 – 2005. The levels of TLRs are also impacted by lower overall congestion levels in the past few years.

Transaction curtailments implemented under the TLR process are an extremely costly mechanism for reducing the flow on constrained transmission elements when compared to much more specifically targeted security constrained economic dispatch procedures. The TLR process relies on the administrative curtailment of wide area, control area-to-control area transactions in order to maintain flow within established ratings on transmission system elements. These transaction curtailments do not in any way reflect the economic desires of the market participants by which they are scheduled, but rather are conducted in a priority order determined by the length and firmness of the transmission service on which they are tagged. Because of the nature of this priority order, the curtailed transactions may have a five percent or smaller flow impact on the transmission constraint being controlled, and transmission system operators may therefore be required to implement thousands of MW of curtailments to achieve the necessary relief on constrained facilities. PJM, on the other hand, relies on security constrained unit commitment and economic dispatch in order to maintain transmission system reliability. This mechanism minimizes out-of-merit dispatch by economically redispatching resources that have the greatest impact on a constrained facility first, and has significantly reduced the transaction curtailments PJM has been required to implement in order to maintain transmission facilities within limits. From 2004 to 2007, PJM transaction curtailment requests were reduced in excess of 1,000,000 gigawatt hours. PJM production cost simulation results conservative estimates of the savings realized from the reduction in these inefficient transaction curtailments between $78 million and $98 million per year.

There are additional reliability benefits to the reduced reliance on the TLR procedure that are less quantifiable as a dollar value. Because TLR relies on curtailments of interchange transactions, relief from implementation of that process on a transmission facility cannot begin to be realized until at least 30 minutes after the constraint is recognized. This is because an inherent time delay exists between when a constraint is recognized, applicable transaction curtailments can be determined by the Reliability Coordinator, and those transaction curtailments can actually be implemented via the NERC electronic transaction tagging system. Additionally, because the transactions being curtailed under the TLR process are scheduled from control area to control area, it is impossible for the Reliability Coordinator to know specifically which generation resources will respond to accomplish the curtailments. The relief actually provided can therefore vary from that which was expected based on differences among unit-specific distribution factors on the constraint being controlled. Security constrained economic dispatch, on the other hand, sends electronic dispatch signals to individual generators within minutes of a constraint being identified. Within a few additional minutes, individual generators can respond to those signals and begin to provide relief on the constrained facility. While a monetary quantification is difficult, the reliability benefit of providing much more timely and targeted relief on transmission constraints is undeniable.

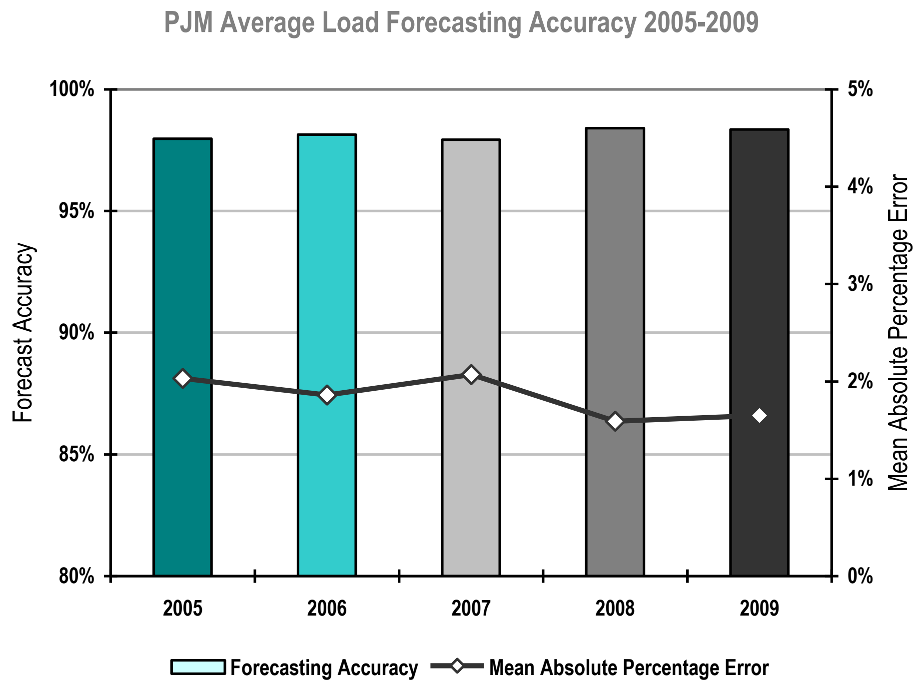
PJM Energy Market System Availability 2005-2009

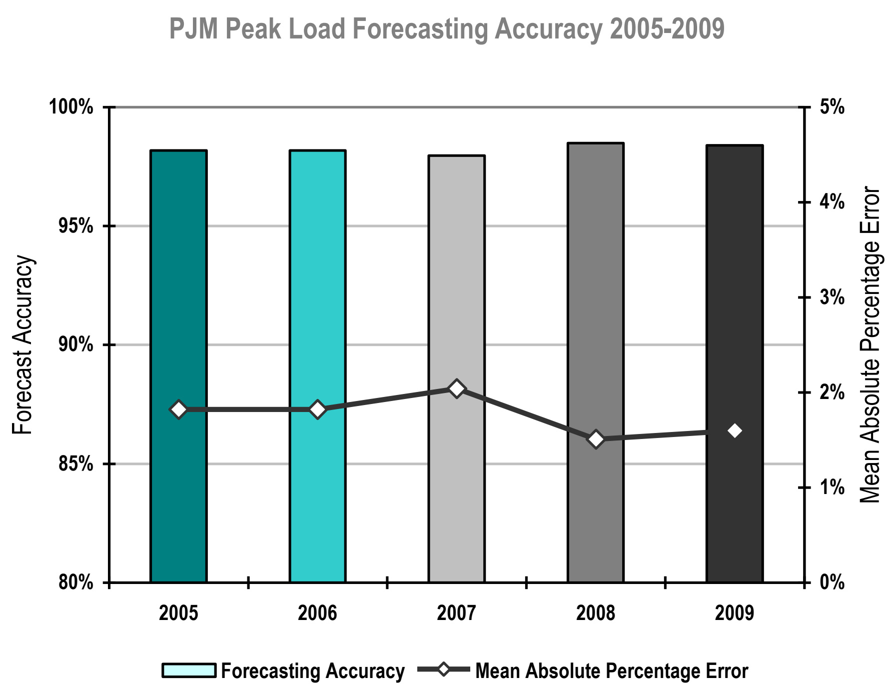


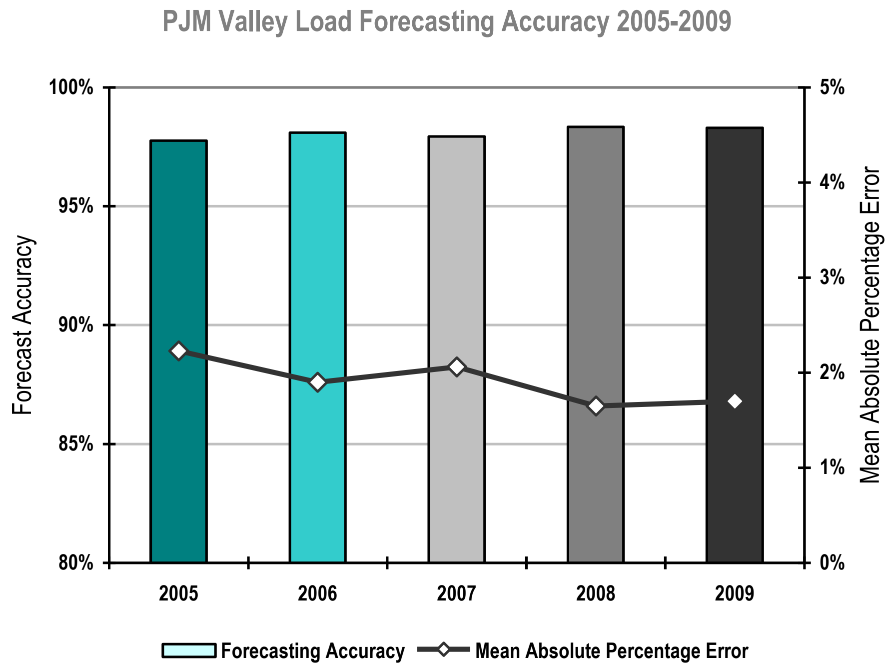
Availability of the Energy Management System (EMS) is key to reliable monitoring of the electric system in the PJM region. For the past four years, PJM's EMS has been unavailable less than 1% of all hours in each year. The majority of the time PJM's EMS system was unavailable to operators reflects challenges with data communications links, not EMS software or hardware issues. With the implementation of PJM's second control center, PJM will have dual, independent data communication links to the EMS systems at each control center to reduce the EMS availability impact of potential data communication link lapses. PJM does not have EMS availability data for 2005.

Load Forecast Accuracy

ISO/RTO	Load Forecasting Accuracy Reference Point
PJM	Noon prior day

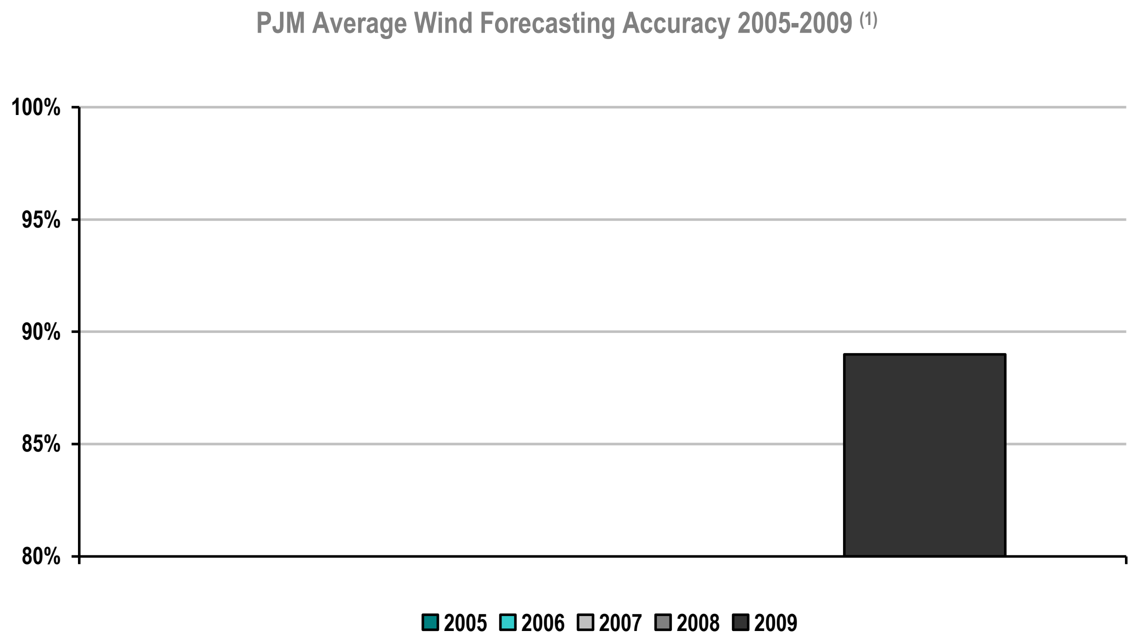






PJM has maintained its approximate 98% load forecasting accuracy for the aggregate PJM region for the years 2005 – 2009. This accuracy level is consistent for the average, peak and valley load forecasting during those years. This means that PJM is forecasting the total generation needs, as well as the daily maximum and minimum generation requirements, for the PJM region within a 2% variance to the actual needs.

Wind Forecasting Accuracy



(1) PJM data represents the month of December 31, 2009 when PJM began tracking this data.

PJM began tracking wind forecasting accuracy during December 2009. The data in this report includes the results of that single month and does not yet support any trend analysis. The potential output from a wind generation resource can be impacted by its geographic location, hub height, turbine type, turbine capacity, manufacturer's power curve, and ambient temperature operating limits.

PJM's approach to wind forecasting focuses on gathering the operating and historical data for each wind generation resource and incorporating that information in a forecast model that forecasts anticipated generation output based on predicted future operational and weather conditions. PJM's objective is to improve its wind forecasting accuracy as it gathers more historical data and experience with the current wind generators in the PJM region.

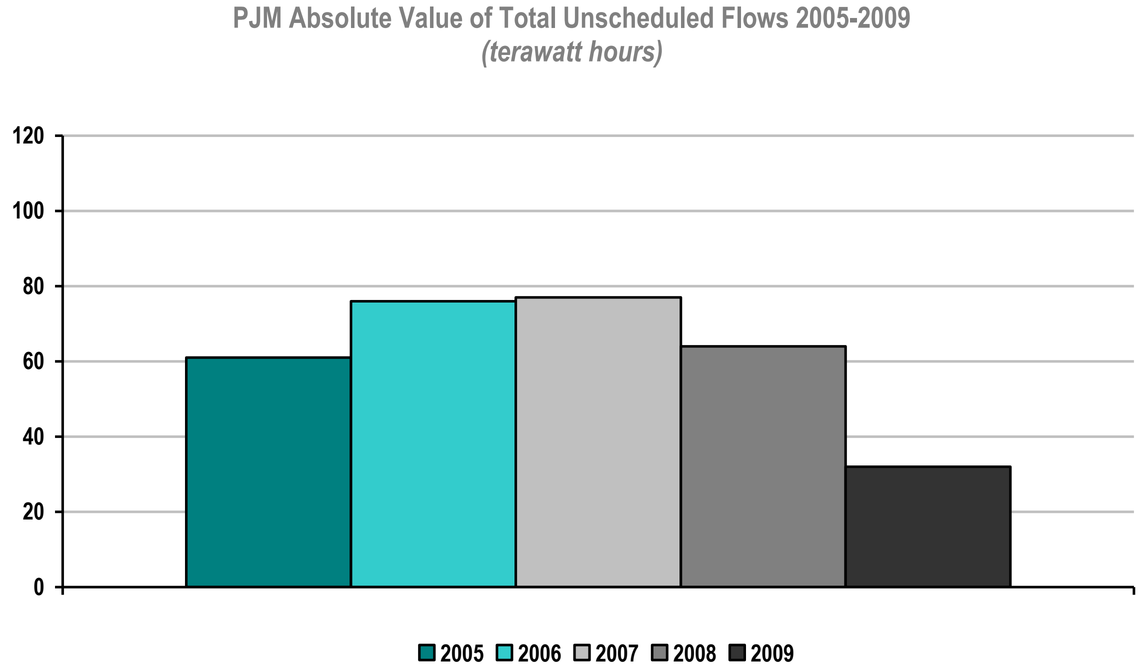
Hydroelectric and pump storage resources are scheduled in PJM's day-ahead energy market and as such do not impact forecast variability. Penetration of variable energy resources aside from wind generation are not significant enough at this time to impact the accuracy of the PJM load forecast.

PJM Wind Forecasting Future Enhancement:

During 2010 and early 2011, PJM plans to continue to focus on wind forecasting accuracy by:

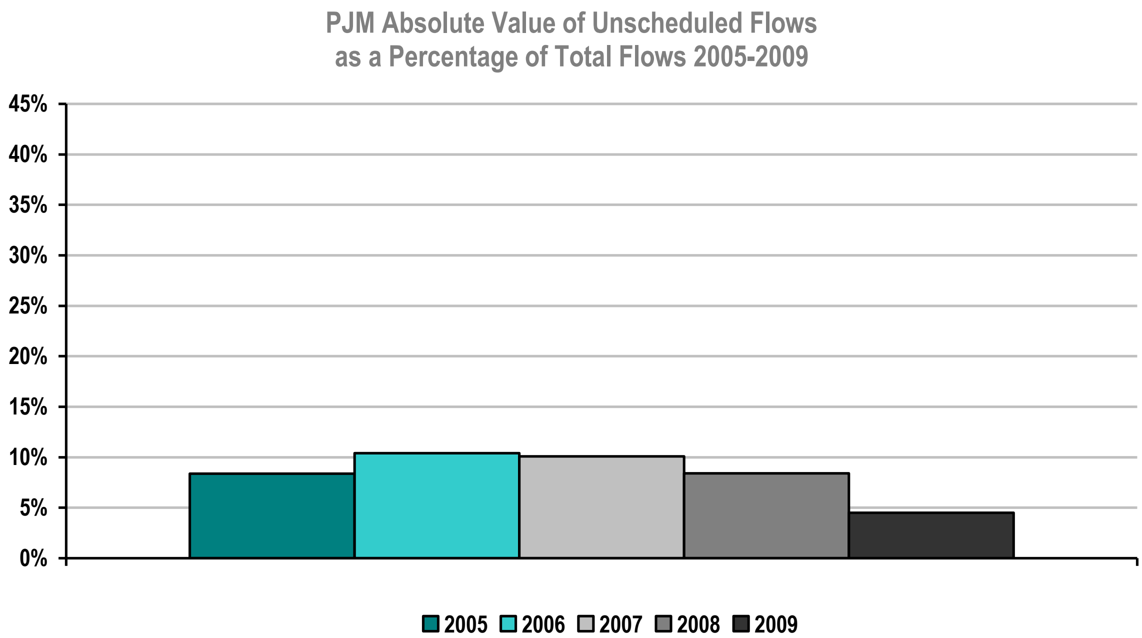
- Working with wind farms to provide more accurate turbine outage data; and
- Integrating PJM's wind power forecast application with PJM's other dispatch tools, such as security constrained economic dispatch.

Unscheduled Flows



For context, the table below notes the number of external interfaces in 2009 over which PJM may have experienced unscheduled flows.

ISO/RTO	Number of External Interfaces
PJM	19



PJM's unscheduled flows in both absolute terms and as a percentage of total flows have decreased over the past few years. This downward trend is primarily a function of a slower economy and milder weather in both 2008 and 2009 that resulted in lower transaction volumes into, out of, and through the PJM transmission system. Also, PJM has been actively engaged in the Broader Regional Markets effort with the NYISO, the Independent Electric System Operator of Ontario, and the Midwest ISO to develop effective solutions to continue to reduce unscheduled flows around Lake Erie.

(in terawatt hours)

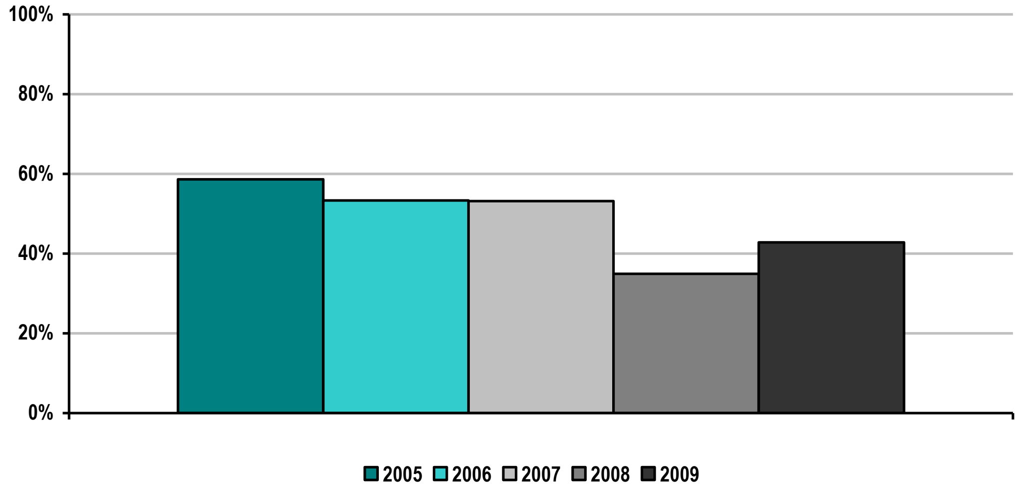
PJM Unscheduled Flows by Interface	**2005**	**2006**	**2007**	**2008**	**2009**
Progress Energy Carolinas	(4)	(3)	(5)	(6)	(7)
Midwest ISO (1)	---	(10)	(14)	(3)	7
Ohio Valley Electric Cooperative	1	(1)	(1)	2	4
Tennessee Valley Authority	(10)	(10)	(6)	(4)	(4)
Duke Energy Carolinas	3	5	6	4	3

(1) Inadvertent flows with Midwest ISO tracked commencing in 2006.

PJM's list of the highest magnitude unscheduled flows by interface demonstrates the primary unscheduled flow patterns involving the PJM region – flows from west of PJM through PJM and then out to the regions south of PJM. PJM is working on joint operating agreements with its neighboring balancing authorities to identify means to minimize such unscheduled flows. For example, PJM has been working actively with Progress Energy and Duke Energy on enhancements to the current Joint Operating Agreement to provide for enhanced congestion management between the respective organizations.

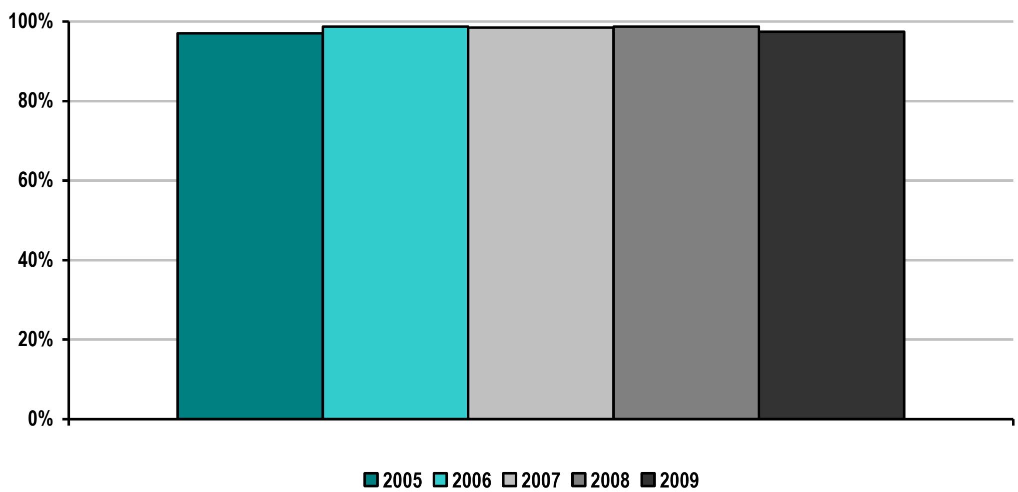
Transmission Outage Coordination

PJM Percentage of ≥ 200kV Planned Outages of 5 Days or More that are Submitted to ISO/RTO at least 1 Month Prior to the Outage Commencement Date 2005-2009



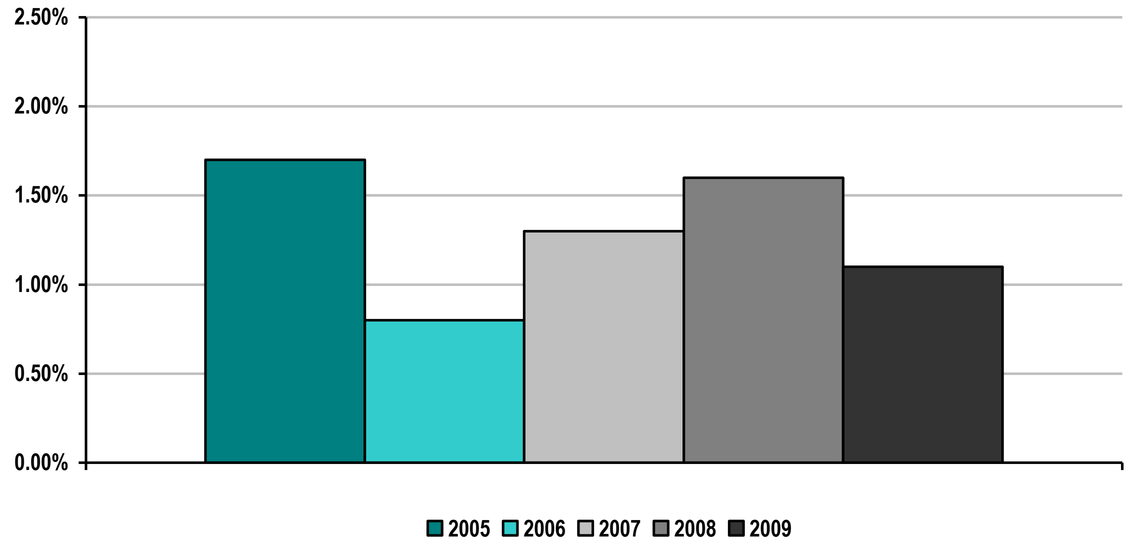
PJM's Tariff requires transmission owners to provide PJM at least five days notice of a planned transmission outage for 200 kV or higher transmission facilities. Longer term outages should be reported to PJM at least one month prior to the target outage commencement date. As noted in the preceding chart, a significant portion of the planned outages in the PJM region have been reported to PJM well before the minimum reporting requirements in the PJM Tariff.

PJM Percentage of Planned Outages Studied in the PJM Tariff/Manual established timeframes 2005-2009



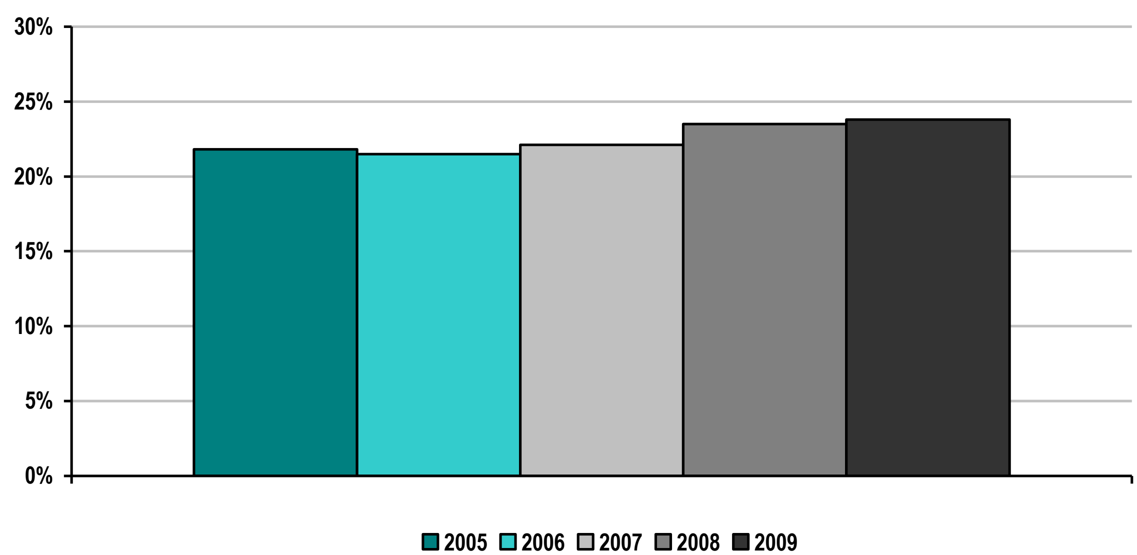
The data in the preceding chart indicates its members' substantial compliance with the PJM Tariff minimum transmission outage 5-day reporting requirement. These five days allow PJM to study the proposed transmission facility outage for potential reliability implications before the transmission outage commences. The very small percentage of outages not reported to PJM at least five days prior to the target outage commencement date will only be approved by PJM if that requested outage does not cause increased congestion or have any adverse reliability impacts.

PJM Percentage of ≥ 200 kV Outages Cancelled by PJM After Having Been Previously Approved 2005-2009



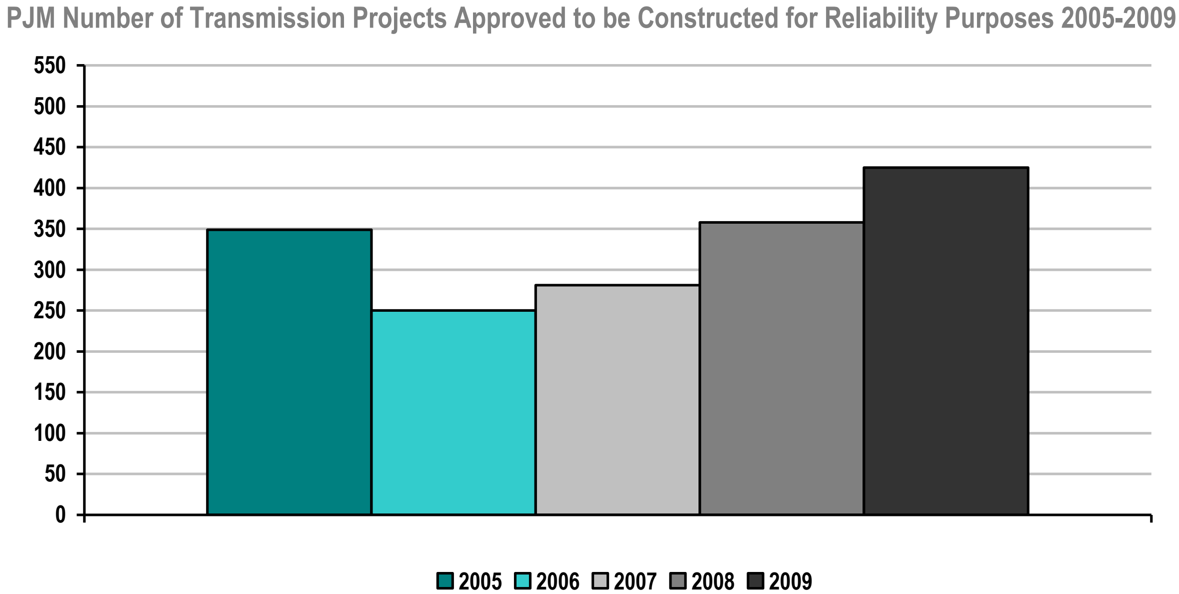
PJM has the authority to cancel or reschedule previously-approved planned transmission outages if such outages would jeopardize system reliability conditions at the time the outage is ready to commence. As such, an outage that would require an emergency procedure will be cancelled and rescheduled. When a transmission outage would impact generation availability, PJM works to schedule the transmission outage at a time where the impact is mitigated (such as when the generation would be on a maintenance outage) where possible. Historically, PJM has only needed to cancel or reschedule a very small percentage of transmission outages that it had previously approved.

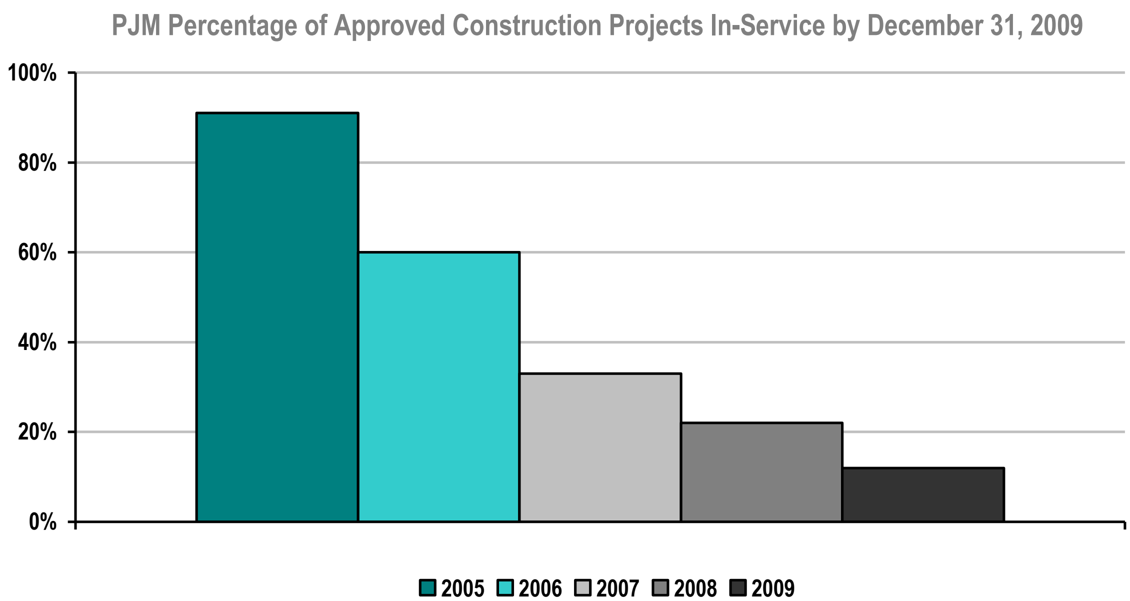
PJM Percentage of Unplanned ≥ 200kV Outages 2005-2009



Unplanned transmission outages may occur due to equipment malfunctions on the transmission line or an adjacent substation. They can also occur due to weather conditions that cause a transmission facility to trip out of service. Historically, 22 – 24% of the outages of transmission assets in the PJM region with 200 kV or higher voltages have been unplanned.

Transmission Planning





PJM's Regional Transmission Expansion Plan (RTEP) identifies transmission system additions and improvements needed to keep electricity flowing to 51 million people throughout 13 states and the District of Columbia. Studies are conducted that test the transmission system against mandatory national standards and PJM regional standards. These studies look 15 years into the future to identify transmission overloads, voltage limitations and other reliability standards violations. PJM then develops transmission plans in collaboration with the stakeholders' Transmission Expansion Advisory Committee (TEAC) which provides advice and recommendations to aid in the development of the RTEP to resolve violations that could otherwise lead to overloads and black-outs. This process culminates in one recommended plan – one RTEP – for the entire PJM region that is subsequently submitted to PJM's independent governing Board for consideration and approval.

PJM's RTEP process includes both five-year and 15-year dimensions. Five-year-out planning enables PJM to assess and recommend transmission upgrades to meet forecasted near-term load growth and to ensure the safe and reliable interconnection of new generation and merchant transmission projects seeking interconnection within PJM. PJM's 15-year planning horizon permits consideration of many long-lead-time transmission options. These options often comprise larger magnitude transmission facilities that more efficiently and globally address reliability issues. Typically, these are higher voltage upgrades that simultaneously address multiple NERC reliability criteria violations at all voltage levels. A 15-year horizon also allows PJM to consider the aggregate effects of many system trends including long-term load growth, impacts of generation deactivation, and broader generation development patterns, including renewable resources and storage technologies that may be under development across PJM.

PJM's RTEP process throughout 2009 culminated in a series of upgrades approved by the PJM Board. PJM identified and recommended these upgrades to resolve reliability criteria violations identified through 2024. Now part of PJM's RTEP, 2009 upgrade plans have been integrated with those RTEP upgrades which were approved by PJM's Board between 1999 and December 31, 2008. Consistent with findings in prior years, 2009 RTEP transmission upgrades and enhancements cover a range of power system elements: circuit breaker replacements to accommodate increased current interrupting duty cycles, new capacitors to increase reactive power support, new lines, line reconductoring, new transformers to accommodate increased power flows and other circuit reconfigurations and upgrades to accommodate power system changes.

Load growth remains a fundamental driver of transmission expansion plans. Over time, experience has demonstrated that load growth in eastern PJM load centers, if not coupled with increases in new generation and demand response, leads to increased west-to-east flows on transmission facilities in the PJM region, potentially aggravating an already heavily-loaded system. Incorporating the impacts of the economic downturn in the US since the fall of 2008 has resulted in revised dates when certain extra high-voltage (EHV) transmission lines are projected to be needed to avoid reliability standard violations.

Various state renewable portfolio standard initiatives promote demand response and energy efficiency programs. Such programs can have the effect of moderating peak demand and energy growth. PJM supports these programs and is closely monitoring developments. Currently, PJM includes demand response and energy efficiency values into its RTEP process based on the degree to which such programs clear in Reliability Pricing Model capacity auctions and are factored into reliability analyses based on the circumstances under which the programs are expected to be implemented in actual operations.

Within PJM, demand response participation may be price responsive, contractually obligated, or directly controlled. As more experience with these programs is gained, PJM will be better able to assess their impact on energy usage and peak load. PJM sensitivity studies in 2010 will attempt to provide as assessment bracketing the potential effect of states' demand response and energy efficiency programs on reliability criteria violations which drive the need for new transmission.

Through the end of 2009, the PJM RTEP process has resulted in about $15 billion of actual and planned transmission infrastructure development in the PJM footprint. In addition to their reliability benefits, the transmission upgrades planned under the PJM RTEP process have resulted in significant economic efficiencies. As of 2007, PJM incorporates economic efficiency analysis into the regional planning process in order to supplement the reliability criteria on which transmission infrastructure development decisions are based. PJM's analysis indicates that for the year 2012 alone, the transmission upgrades in the current RTEP will result in over $390 million of increased economic efficiency for the footprint. This single-year value provides a conservative estimate of the annual economic value of the PJM reliability planning process, because this value can be expected to accrue year over year into the future, and will increase with every transmission project constructed and implemented in future years as well.

The 2009 RTEP reaffirmed the need for several major transmission line projects that the PJM Board of Managers previously had authorized to address power supply problems. These transmission backbone projects are:

- Trans-Allegheny Interstate Line (TrAIL), 502 Junction to Loudon: Construction is well under way on TrAIL, and it will be in service in 2011. This 500-kV transmission line will run from near the border of Pennsylvania and West Virginia to northern Virginia. .
- Potomac-Appalachian Transmission Highline, (PATH), Amos to Kemptown: This 765-kV transmission line will extend about 300 miles from the Amos Substation in West Virginia to the Kemptown Substation in Maryland.
- Susquehanna to Roseland: This 500-kV line will run approximately 130 miles from northern Pennsylvania to northern New Jersey.
- Mid-Atlantic Power Pathway Project (MAPP): This 500-kV line will connect the Possum Point Substation in Virginia to Indian River Substation on the Delmarva Peninsula.

Market efficiency simulation results have indicated that approved RTEP upgrades will significantly reduce PJM constrained operations. These simulations project that PJM annual system congestion costs will decrease 90% (or approximately $1.7 billion) compared with the congestion costs expected absent the upgrades. The majority of the congestion cost reduction can be attributed to the addition of the new 765-kV and 500-kV RTEP backbone projects listed above.

In compliance with FERC's Order 890, PJM expanded its stakeholder process in 2008 to enhance coordinated, open and transparent planning at both the regional and local level. PJM and stakeholders already conduct a compliant planning process filed with the Commission and incorporated in Schedule 6 of the PJM Operating Agreement. Valuable stakeholder discussions culminated in the establishment of three Sub-Regional RTEP Committees – Mid-Atlantic, Western and Southern – commissioned to review proposed upgrades of more local concern. Each Sub-Regional RTEP Committee increases the opportunity for direct stakeholder participation in the planning process from initial assumption setting stages through review of the planning analyses, violations and alternative transmission expansions. The Subregional RTEP Committee provides a more local forum for gathering and considering planning issues.

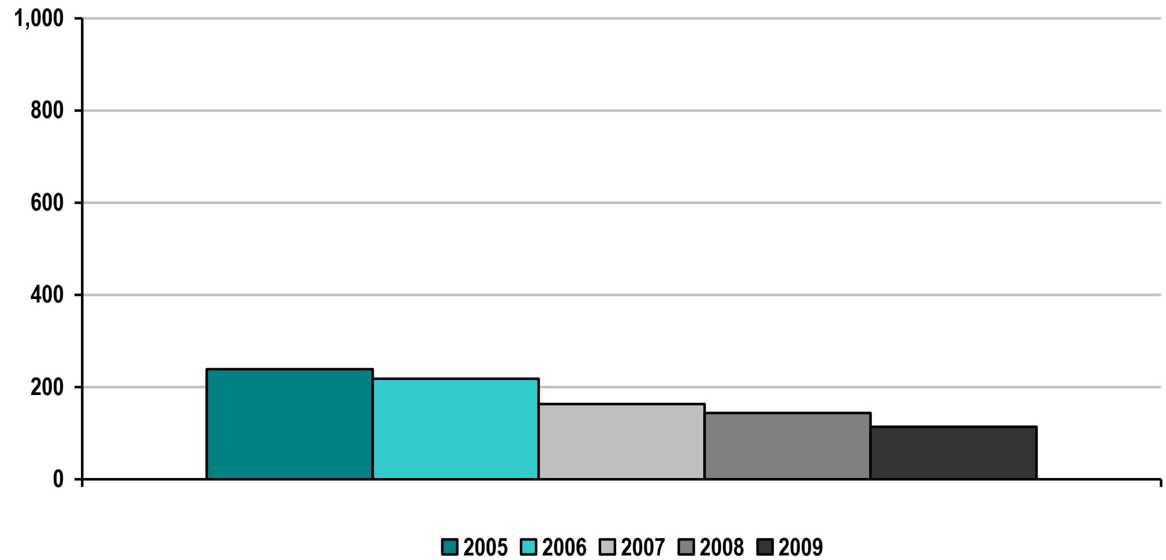
Recent developments in such areas as renewable energy resources are greatly expanding the scope of interregional planning efforts. Not least among these are the following:

- Eastern Interconnection Planning Collaborative (EIPC)
- Joint Coordinated System Planning Study (JCSP)
- Eastern Wind Integration Transmission Study (EWITS)
- PJM / MISO Joint Operating Agreement studies
- PJM / NYISO / ISO-NE Northeast Coordinated System Plan
- PJM / NYISO Focused Study
- North Carolina Planning Collaborative Coordination

In particular, the PJM-NYISO study is based on a more expansive scope than similar studies in prior years. The current study includes extensive reliability analysis of the northern New Jersey / southeast New York interface.

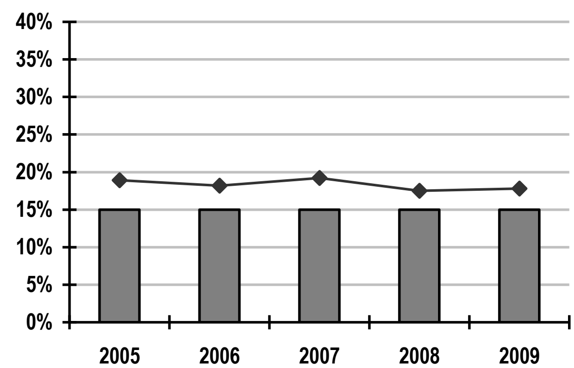
Generation Interconnection

PJM Average Generation Interconnection Request Processing Time 2005-2009
(calendar days)



PJM has made timely processing of generation interconnection study requests a high priority for the past few years with additional engineering staff and contractors engaged to complete these studies and the implementation of clustering of geographically similar studies to expedite study completion.

PJM Planned and Actual Reserve Margins 2005 – 2009



Bars Represent Planned Reserve Margins	Lines Represent Actual Reserves Procured

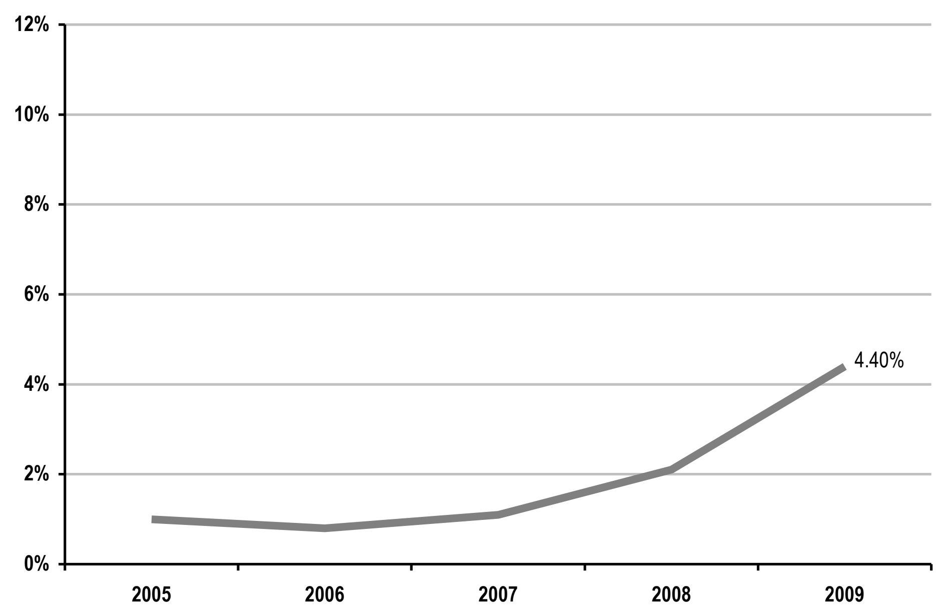
In 2007, PJM implemented a forward capacity market, the Reliability Pricing Model (RPM), which provides incentive for forward investment in generation and demand response by requiring capacity contracts to be procured three years prior to the delivery year. The RPM utilizes variable resource requirement curves to optimize the amount of installed capacity procured to minimize costs while satisfying the capacity requirements of the region. Assuming sufficient capacity resources are available, the variable resource requirement curve will allow the market to clear at quantities between the regional planned installed reserve margin (IRM) and the IRM plus five percent. Quantities above the IRM will only clear if the total procurement cost is reduced when compared to clearing at the reserve margin. Therefore, in PJM, the actual reserve margins resulting from RPM are expected to be and have been between the IRM and the IRM plus 5%.

One of the parameters of each RPM auction is the annual load forecast for the planning year for which the RPM auction is procuring capacity resources. Given RPM auctions occur three years prior to the planning year for which capacity is being procured, the planning year load forecasts will vary from the date of the initial RPM base residual auction and the actual planning year. To be able to adapt to future load fluctuations, PJM's RPM auction incorporates two features – short-term resource procurement targets and incremental auctions. In each RPM auction, the capacity that clears will reflect 2.5% less than the forecasted resource requirement to avoid over-procurement of capacity due to potential variability in the short-term resource procurement target and the uncertainty of the economic recovery. To address the risk of under-procurement, PJM also has the ability to hold incremental RPM auctions to procure additional capacity if forecasts project greater capacity needs than procured in the RPM base residual auction.

Since the implementation of the RPM auctions in 2007, approximately 11,600 MWs of incremental capacity resources have offered into PJM's RPM auctions. This incremental capacity includes 6,400 MWs of new capacity, 4,700 MWs of uprates to existing capacity resources, and 500 MWs of capacity from reactivated units.

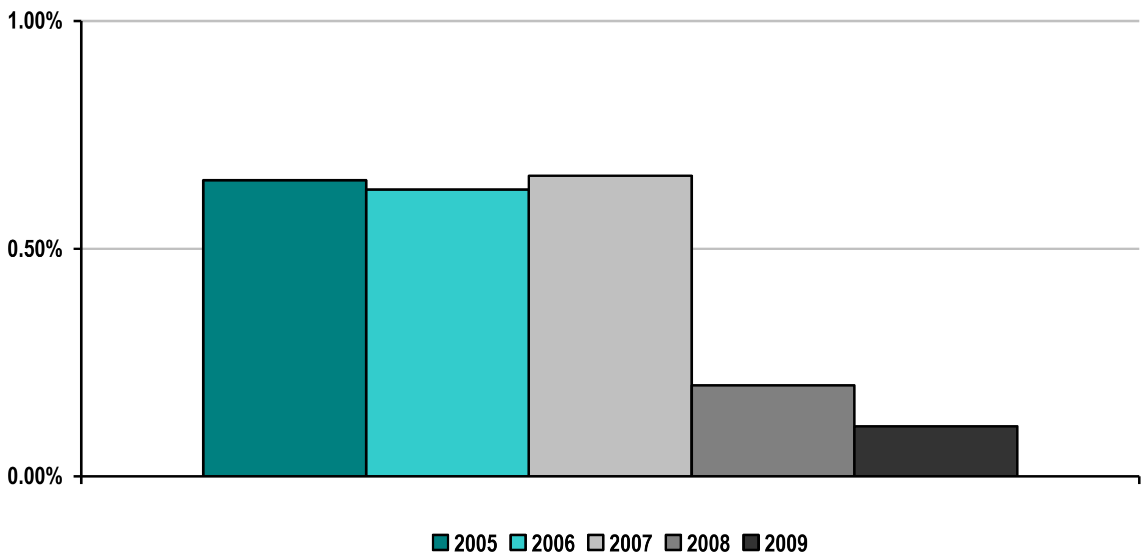
With the 2007 implementation of PJM's forward capacity market, demand resources can offer demand response as a forward capacity resource. Under this model, demand response providers can submit offers to provide a demand reduction as a capacity resource in the forward RPM auctions. If these demand response offers are cleared in the RPM auction, the demand response provider will be committed to provide the cleared demand response amount as capacity during the delivery year and will receive the capacity resource clearing price for this service.

PJM Demand Response Capacity as Percentage of Total Installed Capacity 2005-2009



Additional generation infrastructure investment savings is realized through the commitment of demand response resources to provide reliability assurance. If reliability can be maintained through the commitment of demand resources to reduce load during times of system peaks, the cost of building generation facilities to provide the additional required capacity is avoided. The PJM RPM provides a mechanism by which generation, demand response and transmission can compete on equal footing, thereby providing a transparent mechanism by which demand response can participate in the capacity market. Through this mechanism, the quantity of demand response that is providing capacity in the PJM footprint has increased by over 1,800 MW. The resulting avoidance of infrastructure development represents savings to the region of approximately $275 million per year.

Percentage of Generation Outages Cancelled by PJM 2005-2009

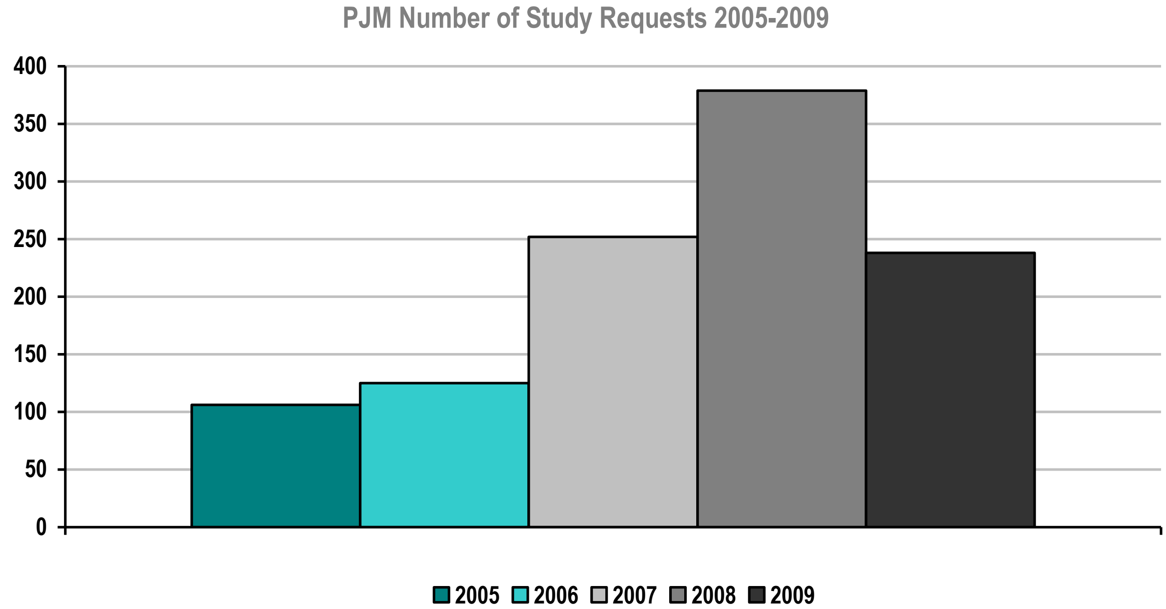


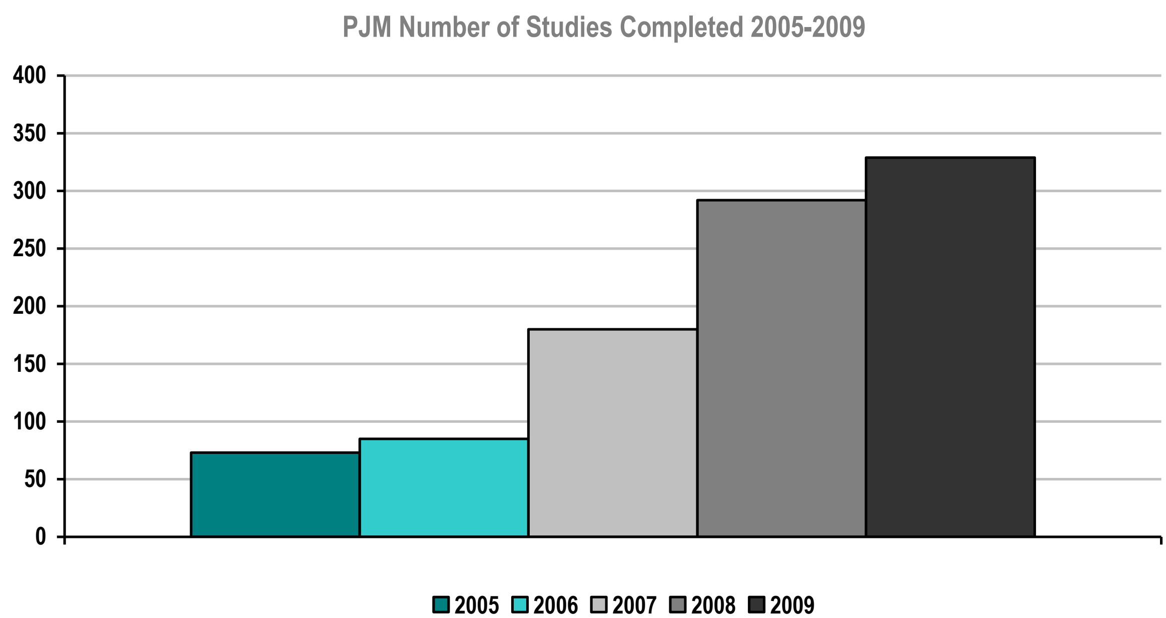
Less than 1% of planned generation outages were cancelled by PJM from 2005 through 2009. This low cancellation rate allows generation owners to complete maintenance as they have planned without incurring rescheduling costs or delays due to PJM cancellation.

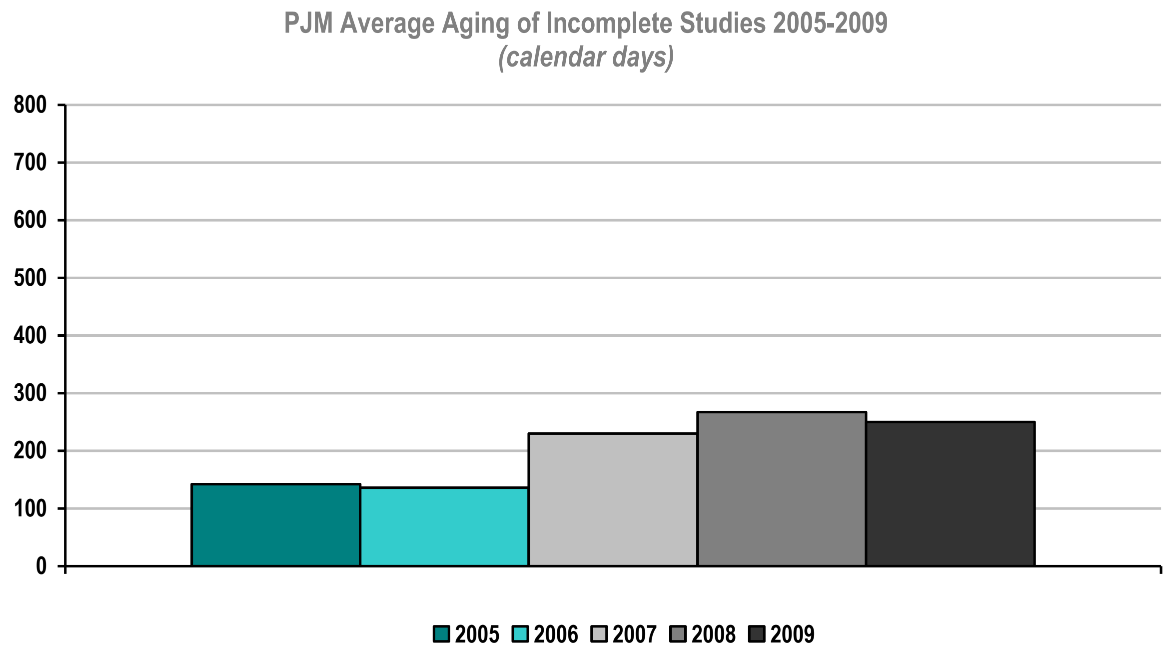
PJM Generation Reliability Must Run Contracts 2005-2009

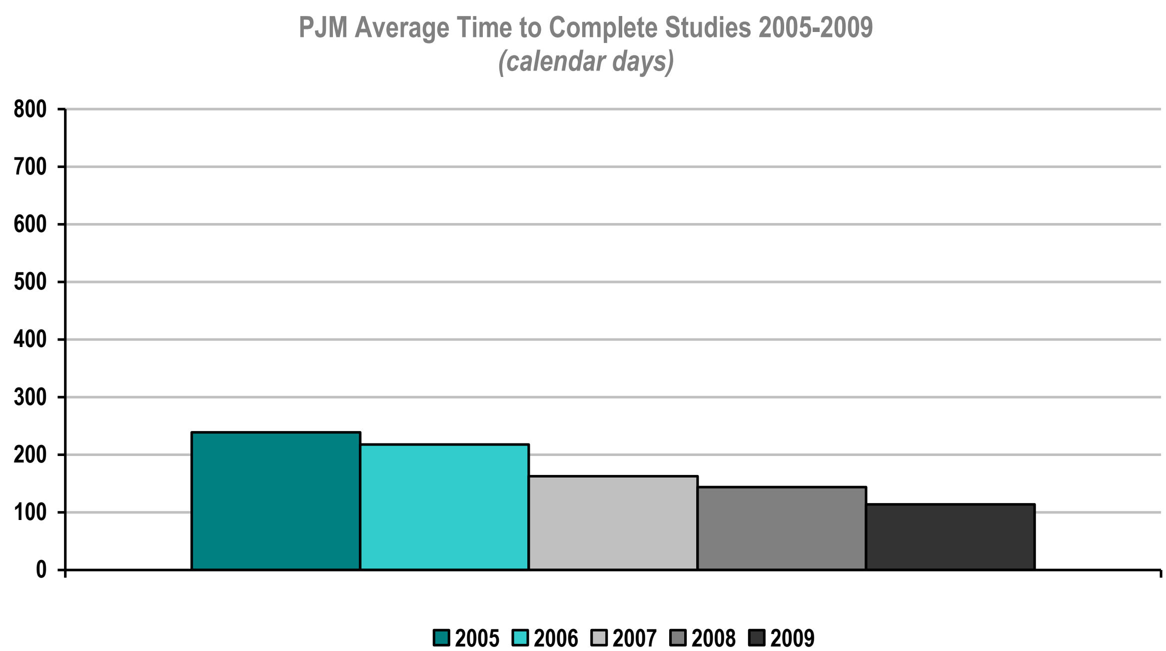
PJM did not have any generating units under Reliability Must Run (RMR) contracts from 2005 through 2008. During 2009, PJM placed one 383 MW nameplate capacity generation station under an RMR that is scheduled to expire during 2010.

Interconnection / Transmission Service Requests









From 2005 through 2009, PJM received approximately 1,100 study requests from companies interested in adding new generation or upgrading current generation output in the PJM region. On average, approximately 12% – 15% of megawatts of potential generating capacity in interconnection study requests progress to the execution of an interconnection service agreement to commence construction of the new generating capacity. So, over 80% of the studies completed by PJM relate to potential projects that withdraw from the generation interconnection queue.

A large number of those study requests were geographically concentrated in the western part of the PJM region with an increasing number of the potential developers investigating the use of storage technologies such as batteries, flywheels and compressed air, as well as wind and solar fuel sources. In terms of megawatts of potential new generating capacity, more than 50% of PJM's year-end 2009 interconnection queues relates to potential wind or solar plants. It is significant to note that the total potential new generating capacity in PJM's year-end 2009 interconnection queues represent 46% of the year-end 2009 generating capacity installed in the PJM region.

PJM completed study requests faster each year from 2005 through 2009, as represented by the more than 50% reduction in average time to complete studies during that period. At the same time, the average age of incomplete studies has actually increased. The decreasing number of incomplete studies represents older study requests that are concentrated in areas of the PJM region where transmission system complexity and study data availability have delayed completion of the feasibility portion of the study process. PJM has reduced the number of incomplete studies significantly in the past few years. For example, PJM reduced the number of open studies by more than 35% during 2009.

PJM's generation interconnection process includes three potential types of studies – feasibility studies, system impact studies and facility studies. Feasibility studies assess the practicality and cost of transmission system additions or upgrades required to accommodate the interconnection of the generating unit or increased generating capacity with the transmission system. System impact studies provide refined and comprehensive estimates of cost responsibility and construction lead times for new transmission facilities and system upgrades that would be required to allow the new or increased generating capacity to be connected to the transmission system in the PJM region. Facility studies develop the transmission facilities designs for any required transmission system additions or upgrades due to the interconnection of the generating unit or increased generating capacity. PJM has had no formal complaints regarding the interconnection processes in recent years.

The table below reflects the average costs incurred by PJM for each type of generation interconnection study. These costs are billed to and collected from the entities requesting each type of study, not from PJM's administrative costs charged to its members.

Average Cost of Each Type of Study

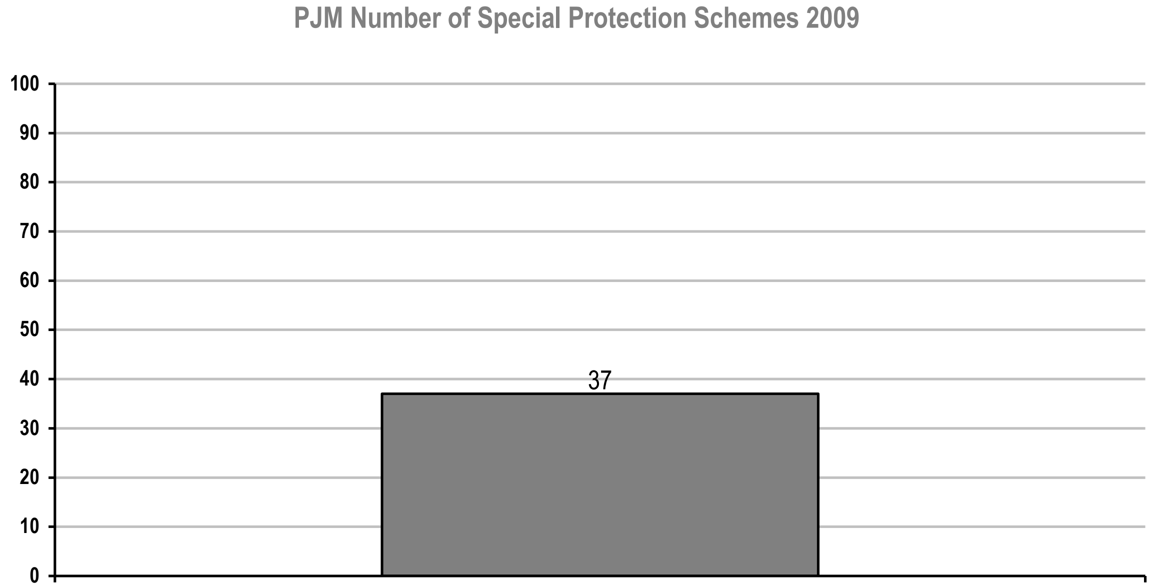
	2005	2006	2007	2008	2009
Feasibility Studies	$5,474	$4,121	$4,538	$3,514	$4,057
System Impact Studies	$12,015	$10,537	$11,224	$10,263	$14,406
Facility Studies	$30,137	$29,458	$28,635	$66,648	$54,380

PJM's average costs incurred for feasibility and system impact studies have not varied materially in the past five years. The complexity of each proposed generation project impacts primarily the costs of completing facility studies, the average cost of which has varied accordingly in the past five years.

PJM Interconnection / Transmission Service Request Future Enhancement:

- During 2010 and 2011, PJM plans to focus on process improvements to reduce both the number of incomplete generation interconnection studies and the average aging of such incomplete studies.

Special Protection Schemes



There are 37 Special Protection Schemes (SPSs) in place in the PJM region. These SPSs are automatic protection systems designed to maintain system reliability by detecting abnormal or predetermined system conditions and isolating selected equipment. All SPSs in the PJM region must be reviewed and approved by PJM to ensure they support all applicable reliability standards. Those SPSs are established throughout the PJM region as a source of automatic system protection that is in addition to the manual system adjustments available to PJM system operators.

In PJM, there were no misoperations of SPSs during 2009. There were no intended or unintended activations of SPSs during 2009.

B. PJM Coordinated Wholesale Power Markets

For context, the table below represents the split of the $26.6 billion dollars billed by PJM in 2009 into the primary types of charges its members incurred for their transactions.

(dollars in millions)	2009 Dollars Billed	Percentage of 2009 Dollars Billed
Energy Markets	$ 11,163.1	42.0%
Capacity	8,752.4	33.0%
FTR Auction Revenues	1,902.2	7.2%
Transmission Service	1,352.5	5.1%
Transmission Losses	1,267.6	4.8%
Transmission Congestion	784.6	3.0%
Operating Reserves	323.5	1.2%
Reactive Supply	239.5	0.9%
Regulation Market	228.3	0.9%
Transmission Enhancement	164.2	0.6%
PJM Administrative Expenses	155.6	0.6%
Other	217.8	0.8%
Total	**$ 26,551.3**	**100.0%**

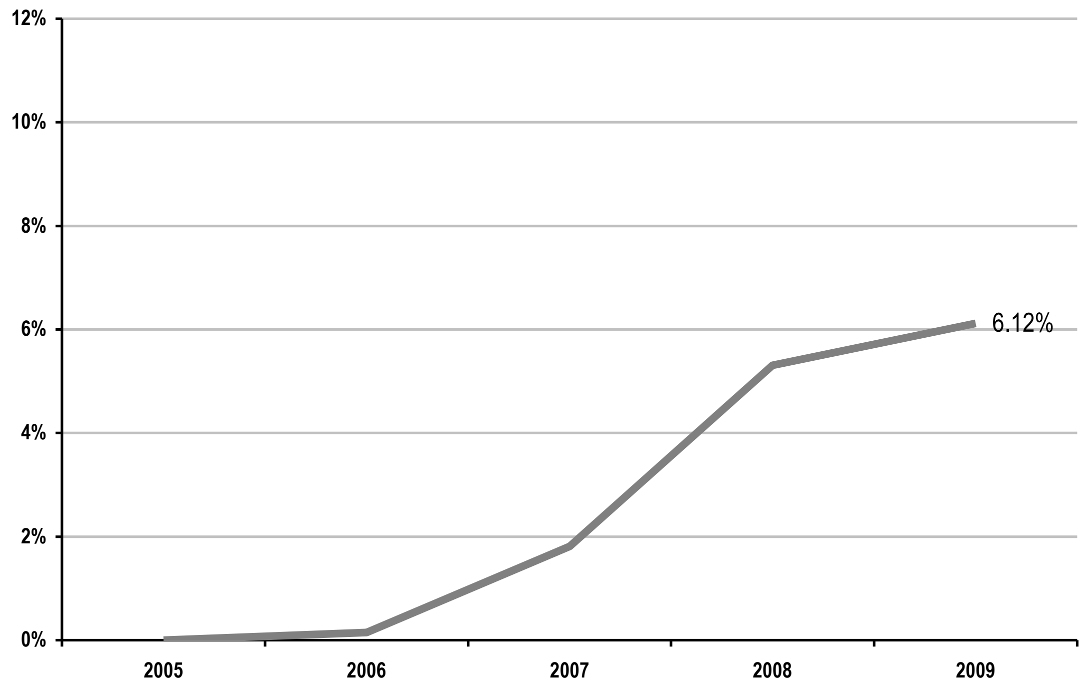
PJM has conducted an annualized, production cost analysis of the savings attributable to operating a single footprint compared to operation of the previously independently operated control areas. As is typical in such analyses, hurdle rates were utilized to simulate the ability of these independent control areas to transact with the remainder of the footprint without the benefit of a centrally operated dispatch. Based on this analysis, the energy production cost impact of the expanded PJM RTO operation is between $240 million and $345 million per year. PJM also has enhanced the efficiency of its dispatch since these integrations. The benefits of this enhanced efficiency are realized in reduced make-whole payments to generators known as Balancing Operating Reserve costs. Reduction in these costs has resulted in additional savings exceeding $100 million per year.

In addition to the production cost benefit of operating the larger footprint, the transparent price signals produced by the operation of the LMP energy market enable demand response to actively participate and compete directly with generation. Because the value of energy is made transparent in real time, demand responders that otherwise would have no incentive to reduce demand can do so in response to real time prices, thereby competing directly with generation resources. This ability, although difficult to quantify as an annual average value, has the effect of reducing the cost to all load by reducing real-time prices, most particularly during times of high system demand.

PJM maintains synchronized reserve in the amount of the largest single contingency in the entire RTO footprint and procures regulation from the most cost-efficient resources across the entire footprint. The savings attributable to the procurement of these services utilizing a market mechanism that spans the RTO footprint is between $80 million and $105 million per year.

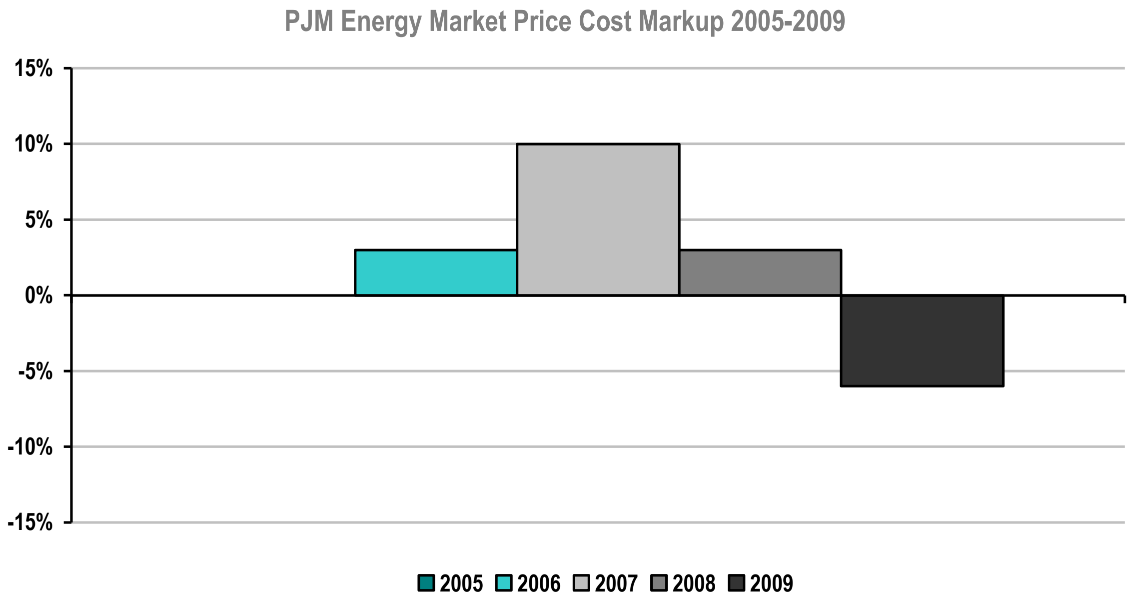
Demand response resources are eligible to participate in PJM's Regulation and Synchronized Reserve Markets. Through the end of 2009, demand response resources have not yet participated in the PJM regulation market. During 2009, demand side responders earned over $300 million through PJM energy, capacity and ancillary services markets.

PJM Demand Response as a Percentage of Synchronized Reserve Market 2005-2009



Market Competitiveness

Note: The data in this Market Competitiveness section was obtained from the 2005 – 2009 State of the Market Reports issued by PJM's independent market monitor.

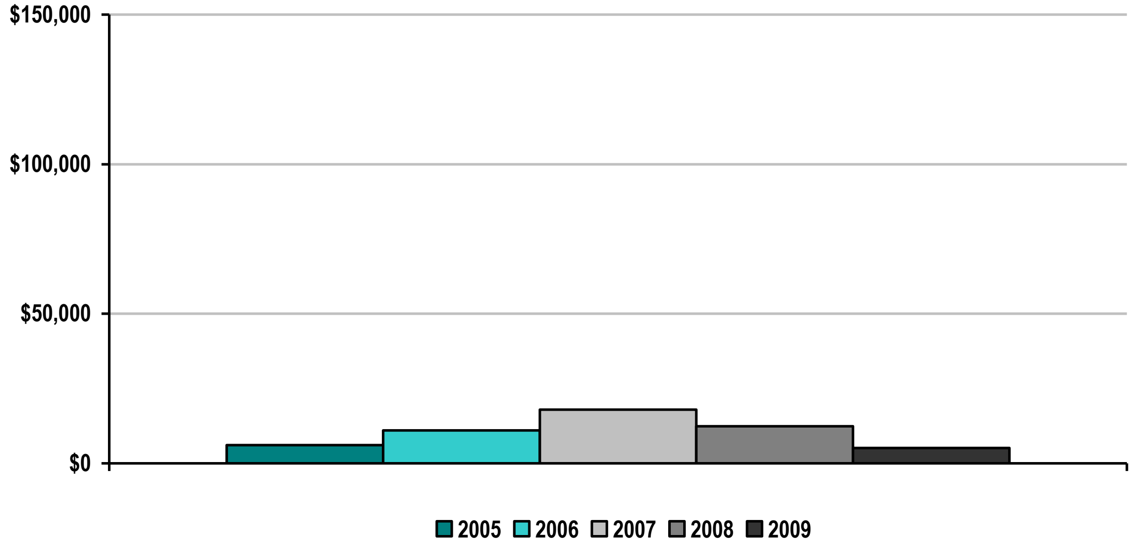


The overall price cost markup percentages for the past four years support the conclusion that prices in PJM are set, on average, by marginal units operating at or close to their marginal costs. PJM does not have data for this metric for 2005.

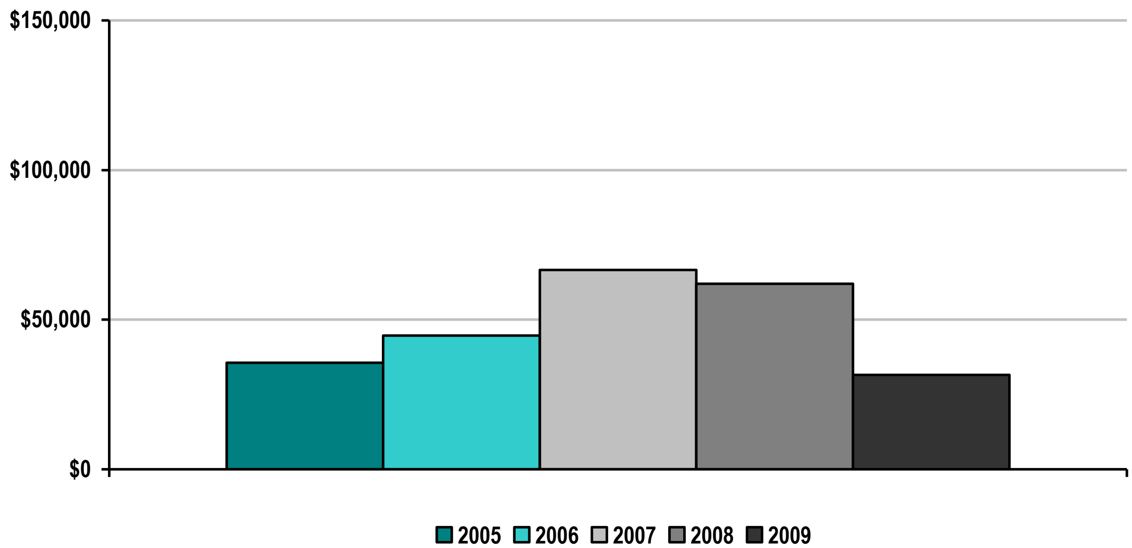
A substantial portion of the 2007 markup occurred on high-load days during the summer of 2007. Markup on high-load days is likely to be the result of appropriate scarcity pricing rather than market power. For reference, PJM's annual 2007 load was 763 terawatt hours, which is the highest annual load ever served in the PJM region. These high usage volumes drove higher locational marginal prices (LMPs) and contributed to the higher 2007 energy market price cost markup percentage.

During 2009, both coal steam units and combined cycle units that use gas as their primary fuel source had negative price cost markup percentages due to the low usage volumes that resulted in lower 2009 LMPs that were insufficient to cover those units' costs.

PJM New Entrant Gas-Fired Combustion Turbine (CT) Net Generation Revenues 2005-2009
(dollars per installed megawatt year)



PJM New Entrant Gas-Fired Combined Cycle (CC) Net Generation Revenues 2005-2009
(dollars per installed megawatt year)



For both the CT technologies and the CC technology, RPM revenue has provided an adequate supplemental revenue stream to incent continued operations in PJM for units that do not recover 100 percent of fixed costs through energy market revenue.

In 2009, total net revenues were not adequate to cover annualized total fixed costs for a new entrant CT or CC in any zone. While the results varied by zone, the net revenues for the CT and CC technologies generally covered a larger proportion of total fixed costs, reflecting their greater reliance on capacity market revenues. Energy net revenues are generally lower for each technology in most zones compared to 2008, while capacity market revenues are higher in every zone compared to 2008. For the CT and CC technologies, the increase in capacity revenue offset the reduction in energy market revenue.

There is a set of sub-critical coal units in 2008 and 2009 and a set of super-critical coal units in 2009 that did not recover avoidable costs even with capacity revenues. The total installed capacity associated with coal units that did not cover avoidable costs in 2009 was 11,250 MW. There were 122 coal units in PJM in 2009 with capacity less than or equal to 200 MW. Of those units, 35 did not cover avoidable costs and 52 were close to not covering avoidable costs.

The coal plant technologies have higher avoidable costs and are more dependent on net revenues received in the energy market. In 2009, with lower load levels and, generally, lower price levels relative to operating costs, some coal-fired units in PJM did not fully recover avoidable costs even with capacity revenues. If this result is expected to continue, the retirement of these plants would be an economically rational decision.

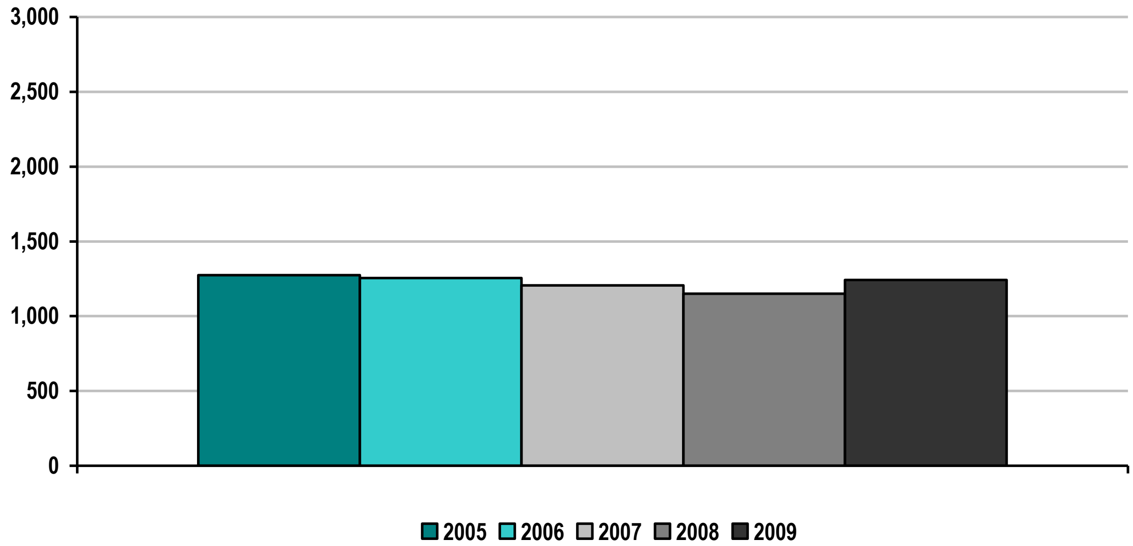
Market Concentration

Concentration ratios are a summary measure of market share, a key element of market structure. High concentration ratios indicate comparatively smaller numbers of sellers dominating a market, while low concentration ratios mean larger numbers of sellers splitting market sales more equally. High concentration ratios indicate an increased potential for participants to exercise market power, although low concentration ratios do not necessarily mean that a market is competitive or that participants cannot exercise market power. Analysis of the PJM Energy Market indicates moderate market concentration overall. Analyses of supply curve segments indicate moderate concentration in the baseload segment, but high concentration in the intermediate and peaking segments.

Despite their significant limitations, concentration ratios provide useful information on market structure. The concentration ratio used here is the Herfindahl-Hirschman Index (HHI), calculated by summing the squares of the market shares of all firms in a market. Hourly PJM Energy Market HHIs were calculated based on the real-time energy output of generators, adjusted for hourly net imports by owner.

Actual net imports and import capability were incorporated in the hourly Energy Market HHI calculations because imports are a source of competition for generation located in PJM. Energy can be imported into PJM under most conditions. The hourly HHI was calculated by combining all export and import transactions from each market participant with its generation output from each hour. A market participant’s market share increases with imports and decreases with exports. Hourly HHIs were also calculated for baseload, intermediate and peaking segments of generation supply. Hourly Energy Market HHIs by supply curve segment were calculated based on hourly Energy Market shares, unadjusted for imports.

PJM Average Hourly Energy Market HHI 2005-2009

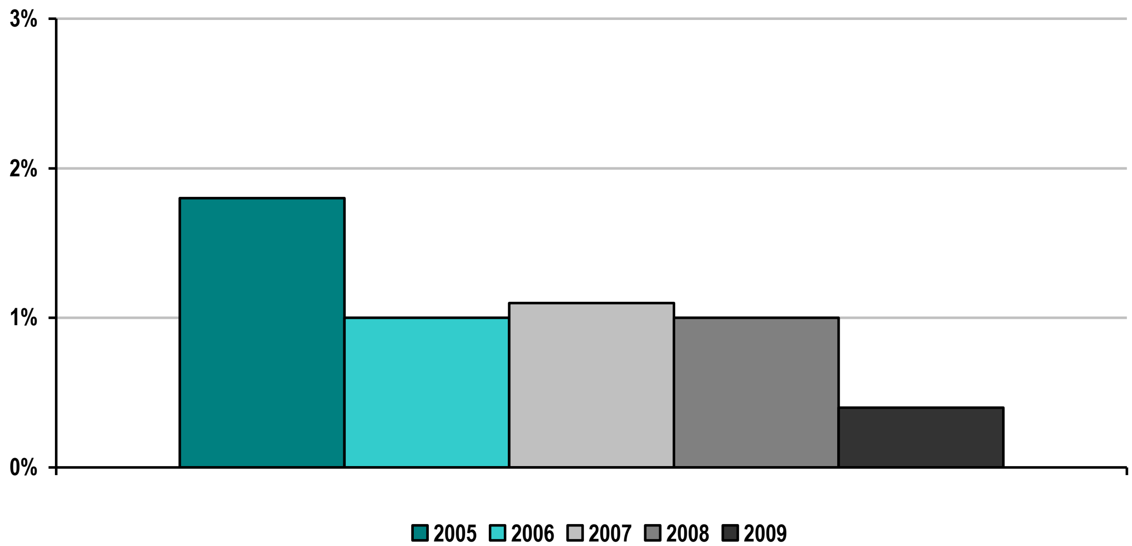


The “Merger Policy Statement” of the Federal Energy Regulatory Commission states that a market can be broadly characterized as:

- Unconcentrated. Market HHI below 1000, equivalent to 10 firms with equal market shares;
- Moderately Concentrated. Market HHI between 1000 and 1800; and
- Highly Concentrated. Market HHI greater than 1800, equivalent to between five and six firms with equal market shares.

Calculations for hourly HHI indicate that by the FERC standards, the PJM Energy Market was moderately concentrated each of the years 2005 through 2009. For the same time period, an examination of the supply curve on a segment basis, including base, intermediate and peaking plants, the hourly HHI measure indicated that, on average, intermediate and peaking segments of the supply curve are highly concentrated, while the baseload segment is moderately concentrated.

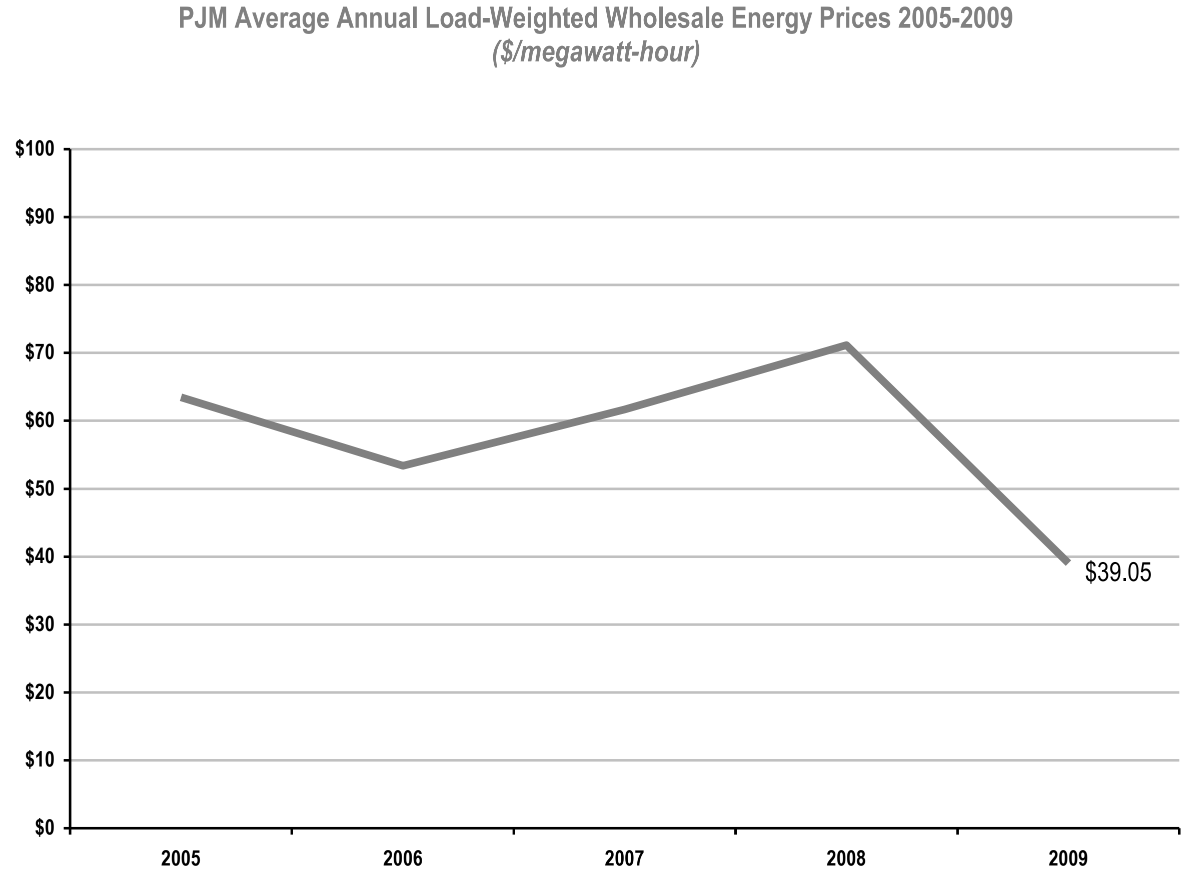
PJM Real-Time Energy Market Percentage of Unit Hours Offer Capped due to Mitigation 2005-2009



Noncompetitive local market structure is the trigger for offer capping. PJM applied a flexible, targeted, real-time approach to offer capping (the three pivotal supplier test) as the trigger for offer capping in 2009. PJM offer caps units only when the local market structure is noncompetitive. Offer capping is an effective means of addressing local market power. Offer-capping levels have historically been low in PJM. In the Real-Time Energy Market offer-capped unit hours fell from 1.0 percent in 2008 to 0.4 percent in 2009.

The analysis of the application of the three pivotal supplier test to local markets demonstrates that it is working successfully to offer cap pivotal owners when the market structure is noncompetitive and to ensure that owners are not subject to offer capping when the market structure is competitive.

Market Pricing

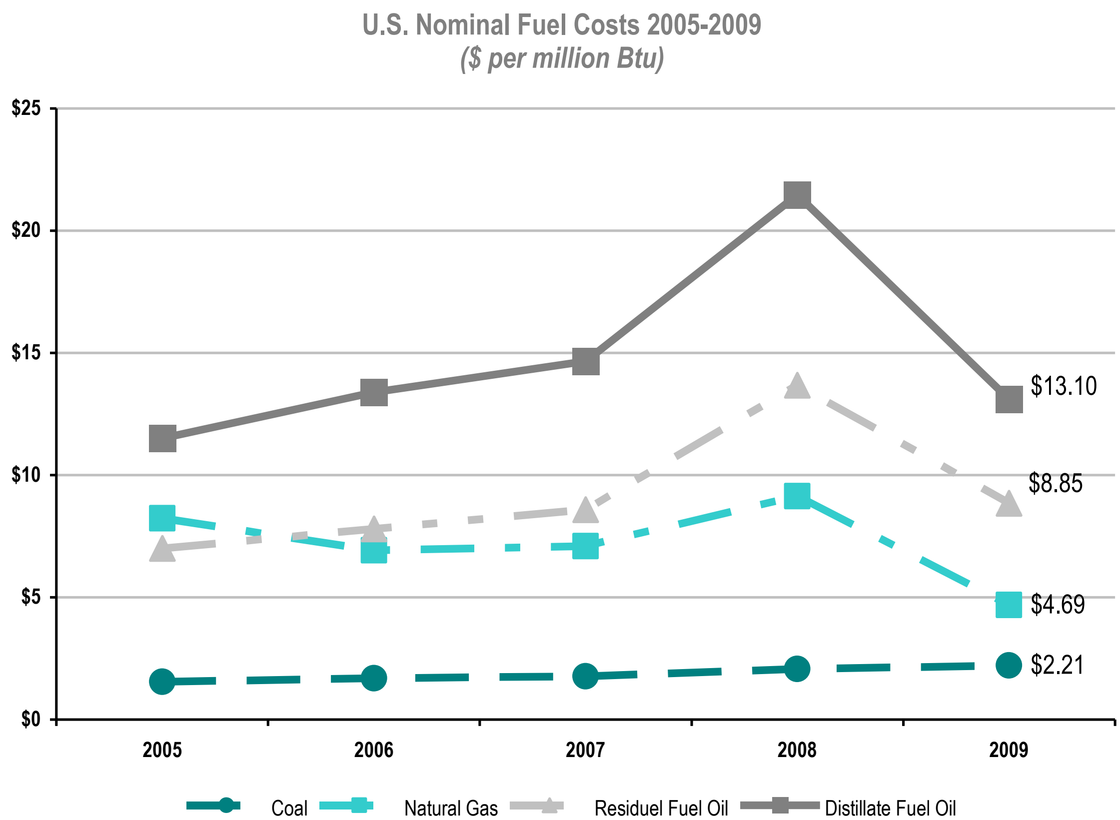


The PJM average load-weighted wholesale energy prices varied during the 2005 – 2009 period due in part to variances in underlying fuel costs and also due to 4.6% lower customer demand in 2009. For example, approximately 72% of the 2008 to 2009 reduction in wholesale electricity prices in the PJM region was due to fuel cost decreases, while the remaining 28% of the reduction was due to lower customer demand. In nominal terms, that means the fuel cost reductions from 2008 to 2009 led to a 32% decrease in wholesale electricity prices in the PJM region, while lower demand contributed an additional 13% reduction in wholesale electricity prices in the PJM region.

Conservation during heat waves not only stretches power supplies, it saves money. Reductions in electricity use during the early August 2006 heat wave produced price reductions estimated to be equivalent to more than $650 million in payments for energy for the week. Customers in the 13-state PJM region set a new record for power consumption of 144,796 megawatts on August 2, 2006. On that day alone, voluntary reductions in electricity use through demand response resulted in price reductions estimated to be equivalent to more than $230 million in payments for energy.

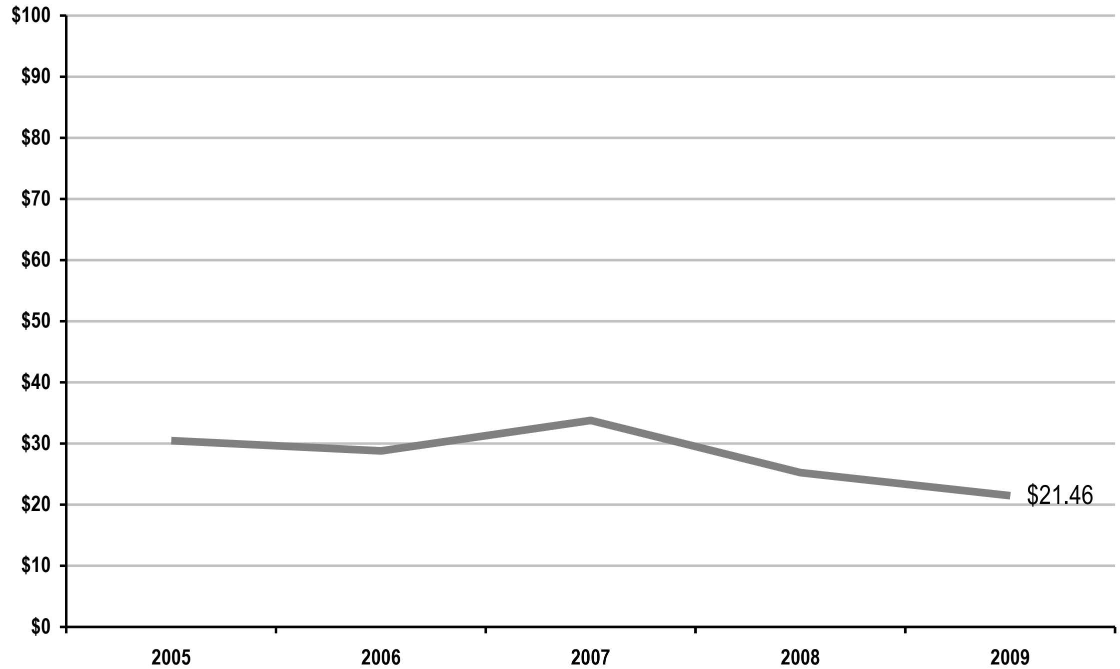
These voluntary curtailments through PJM's Demand Response program reduced wholesale energy prices by more than $300 per megawatt hour during the highest usage hours in early August 2006. While many wholesale customers, such as utilities, were hedged against high real-time spot-market prices, all customers benefit from the dramatic price reductions because future longer-term electricity sales are based on prices set in the real-time market, where prices were lower as a result of demand response.

The chart below from the U.S. Energy Information Administration is a visual representation of the fuel cost inputs from 2005 – 2009 that influenced the energy prices in the PJM region. The consistency in the trends between the preceding chart and several of the fuel cost trends on the chart on the following page are significant, because they illustrate the high correlation between wholesale energy prices and underlying fuel costs.



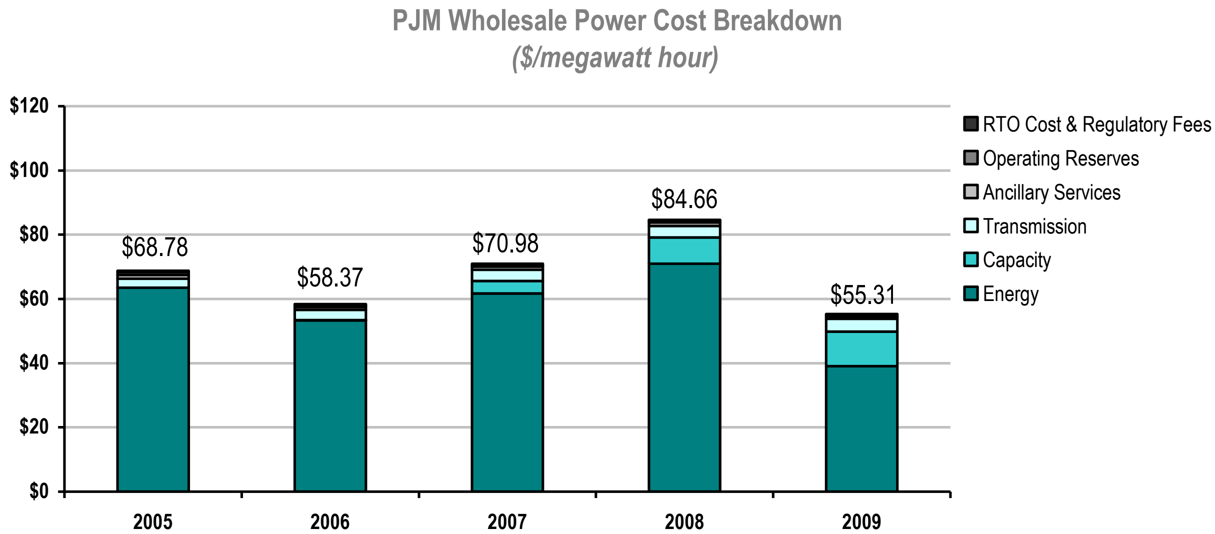
Source: U.S. Energy Information Administration, Independent Statistics and Analysis

PJM Average Annual Load-Weighted
Fuel-Adjusted Wholesale Spot Energy Prices 2005-2009
($/megawatt-hour)



For the five-year period ended December 31, 2009, the load-weighted fuel-adjusted wholesale spot energy prices in the PJM region have decreased 30% from $30.45 to $21.46. The trend in these fuel-adjusted prices reflects the lower demand particularly in 2008 and 2009 that resulted from both the economic downturn and mild weather patterns. With the lower demand, the prices of electricity decreased in the past few years in the PJM region.

PJM's base year for fuel cost references is 1999 as this is the first full year that PJM administered both spot and day-ahead energy prices.



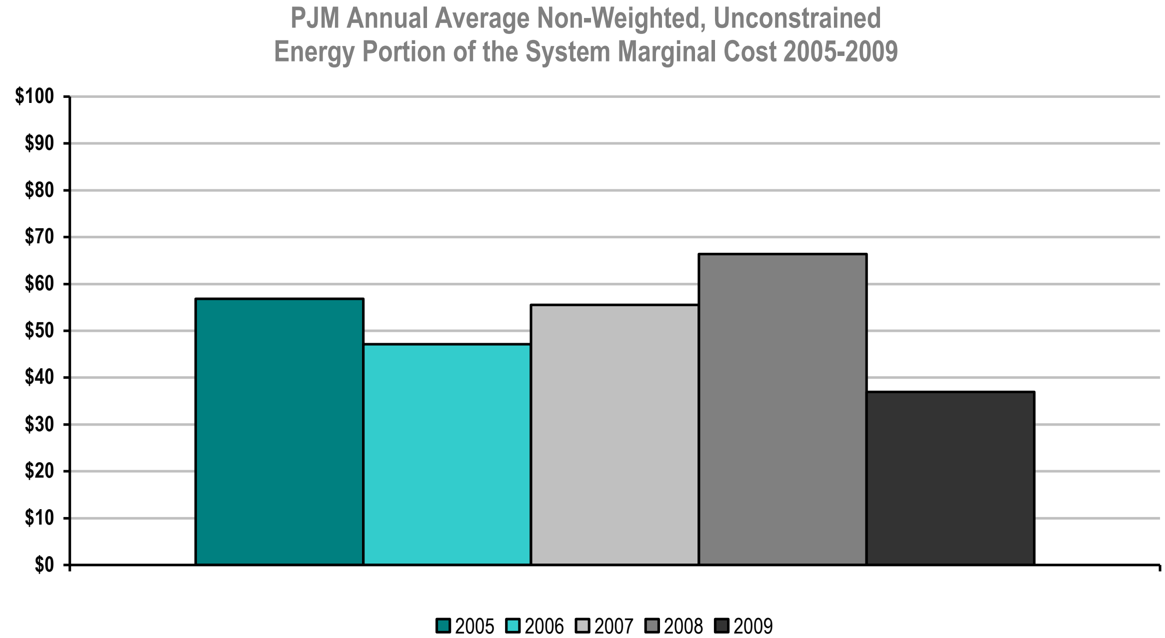
On an annual basis, energy costs have comprised 70 – 90% of PJM's total wholesale power costs for the past five years. PJM implemented its three-year forward capacity market, the Reliability Pricing Model (RPM), in 2007. Capacity revenues earned through RPM are netted against the energy cost component of total power costs per megawatt hour. If combined, the energy plus capacity components represent more than 90% of total power costs per megawatt hour for each of the five years in the period 2005 – 2009.

Recent sensitivity analyses indicate that the completion of all transmission backbone projects in PJM's Regional Transmission Expansion Plan (RTEP) would reduce total RPM capacity costs by about $3 billion (or more than 30%) annually.

And, as noted previously, fuel costs drive approximately 70% of wholesale electricity price changes in the PJM region. So, it is again logical that the trends in total wholesale power costs in the PJM region have moved consistently with fuel cost trends.

All other components of PJM's wholesale power cost per megawatt hour, exclusive energy and capacity, account for less than 10% of the total costs per megawatt hour. In particular, the operating reserve costs (sometimes referred to as uplift) have been less than $1.00 per megawatt hour of the total wholesale power cost in the PJM region. In 2005 through 2009, such uplift costs represented 1.4% or less of the total wholesale power cost per megawatt hour during that five-year period.

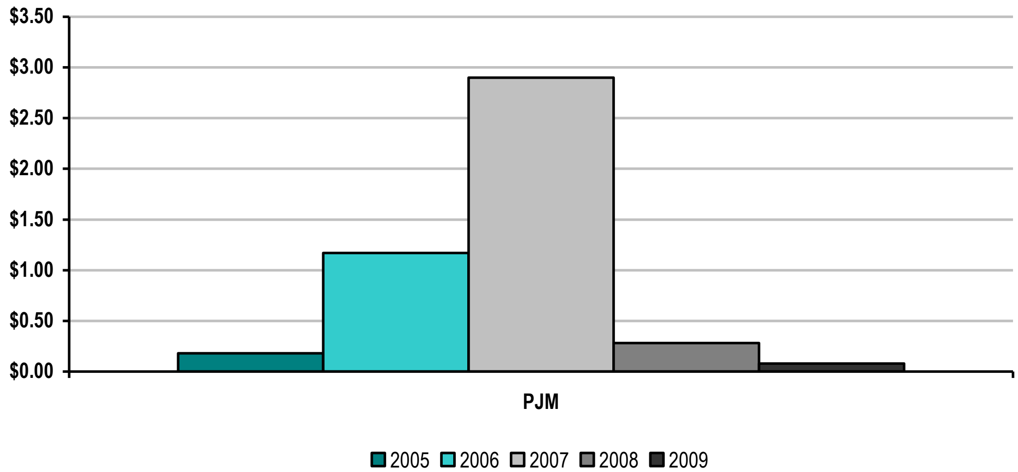
Unconstrained Energy Portion of System Marginal Cost



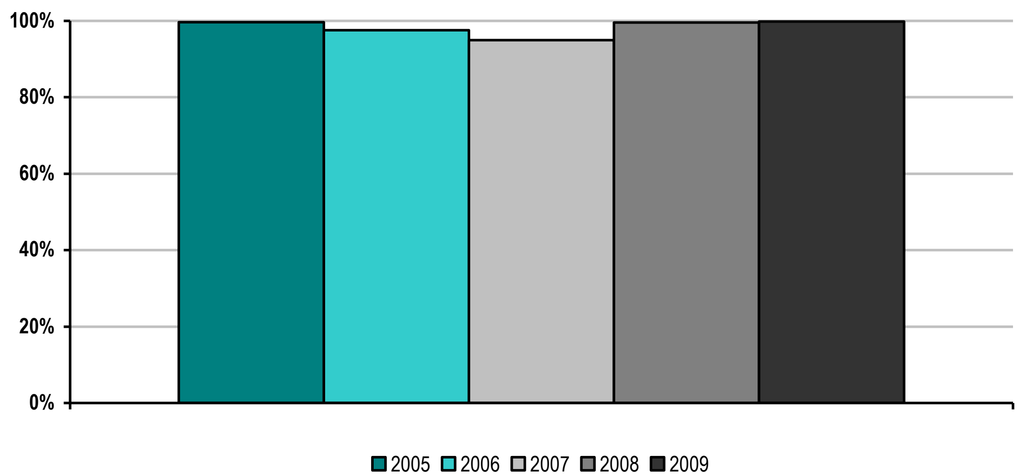
The unconstrained energy portion of system marginal cost is the marginal price of maintaining power balance in the economic dispatch in the PJM region ignoring transmission limitations. This trend chart reflects the annual average marginal price of energy across the PJM region over all hours. The trend closely follows the trend of aggregate fuel prices from 2005 through 2009, which illustrates the fact that marginal energy price fluctuations are primarily driven by fuel prices.

Energy Market Price Convergence

PJM Day-Ahead and Real-Time Energy Market Price Convergence 2005-2009



PJM Percentage of Day-Ahead and Real-Time Energy Market Price Convergence 2005-2009



PJM's nominal difference between day-ahead and real-time prices was highest in 2007 when there was greater volatility in real-time prices, reflecting high constraint levels in fall 2007 when weather remained hot in the PJM region as the fall transmission maintenance season commenced. However, the percentage of day-ahead and real-time price convergence in the PJM electricity markets averaged over 98% from 2005 through 2009.

To improve reliability and reduce potential competitive seams issues, PJM and its neighbors have developed, and continue to work on, joint operating agreements. These agreements are in various stages of development and include a reliability agreement with the NYISO and an implemented operating agreement with the Midwest ISO. One objective of such interregional coordination agreements is the harmonization of border prices. Price convergence between PJM's and bordering region's wholesale competitive market prices is one data point to assess the effectiveness of these agreements.

The 2009 real-time hourly average interface prices for PJM/Midwest ISO and Midwest ISO/PJM were $29.67 and $29.68, respectively. The simple average difference between the real-time Midwest ISO/PJM Interface price and the PJM/Midwest ISO Interface price decreased from $1.17 per megawatt hour in 2008 to $0.01 per megawatt hour in 2009. These differences represent 97.68% and 99.97% price convergence, respectively, for 2008 and 2009. This is consistent with the fact that PJM's net exports in 2009 were significantly lower than in 2008, as the price convergence in 2009 did not provide the incentives to purchase power from PJM and export to or through the Midwest ISO.

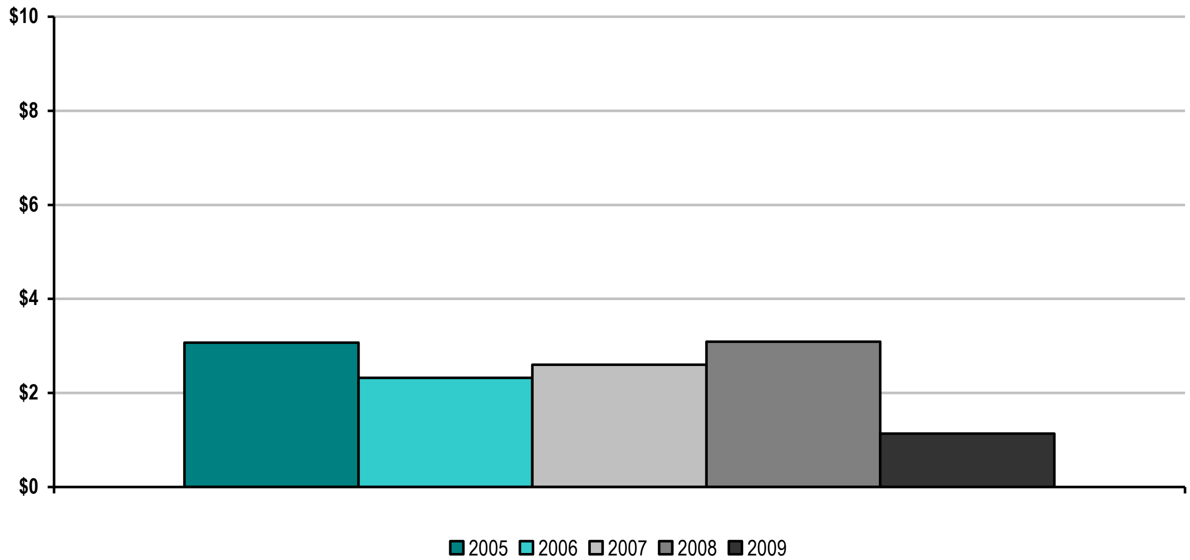
Several factors are responsible for the relationship between interface prices. The simple average interface price difference suggests that competitive forces prevent price deviations from persisting, an observation further supported by the frequency with which price differential switches between positive and negative. In addition, there is a significant correlation between the real-time monthly average hourly PJM/Midwest ISO and Midwest ISO/PJM Interface prices during the 2009 period.

PJM's price for transactions with the NYISO (excluding those transactions across the Neptune and Linden lines), termed the NYIS Interface pricing point by PJM, represents the value of power at the PJM/NYISO border, as determined by the PJM market. PJM defines its NYIS Interface pricing point using two buses. Similarly, the NYISO's price for transactions with PJM, termed the PJM proxy bus by the NYISO, represents the value of power at the NYISO/PJM border, as determined by the NYISO market. In the NYISO market, transactions are required to have a price associated with them. Import transactions are treated as generator offers at the NYISO/PJM proxy bus. Export transactions are treated as load bids. Competing bids and offers are evaluated along with the other NYISO resources and a proxy bus price is derived.

The 2009 real-time hourly average PJM/NYIS Interface price and the NYISO/PJM proxy bus price were $37.37 and $39.16. The simple average difference between the PJM/NYIS Interface price and the NYISO/PJM proxy bus price increased from $0.86 per megawatt hour in 2008 to $1.79 per megawatt hour in 2009. These differences represent 98.81% and 95.32% price convergence, respectively, for 2008 and 2009. PJM's net export volume to the NYIS Interface for 2009 was significantly higher than in 2008. This is consistent with the fact that the PJM/NYIS price was, on average, lower than the NYISO/PJM price in 2009.

Congestion Management

PJM Annual Congestion Costs per Megawatt Hour of Load Served 2005-2009

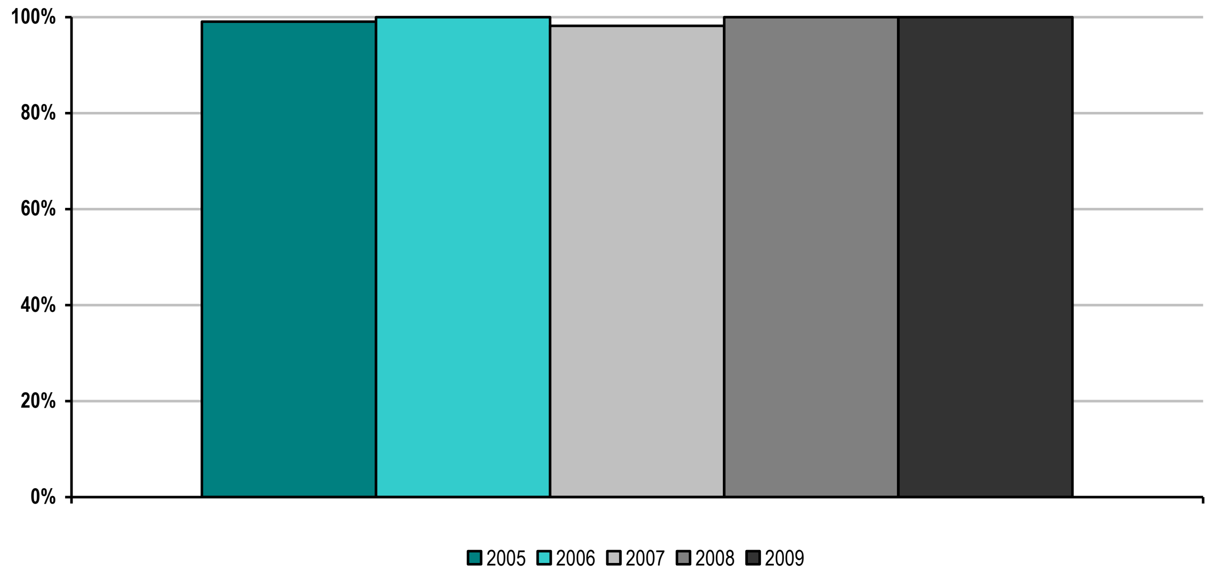


Congestion costs in the PJM region are influenced by weather, energy prices and available transmission system capacity. For example, the higher wholesale energy prices in 2008 resulted in a higher congestion cost per megawatt hour of load served that year, while lower wholesale energy prices and lower demand in 2009 caused per megawatt hour congestion to fall over 60%.

PJM's Regional Transmission Expansion Plan (RTEP) includes several extra high voltage transmission lines that will increase the available transmission system capacity in the PJM region. In the aggregate, those transmission lines are expected to alleviate 90% of the current congestion costs in the PJM region.

In order to address the need for long-term transmission rights, PJM added a stage to its FTR market. In stage 1A of the allocation process, each network service user may request auction revenue rights (ARRs) for a term covering 10 consecutive PJM planning periods. ARRs allocated in stage 1A will be modeled in a 10-year analysis in which a zonal growth rate will be applied and anticipated ARR allocation increases will be determined. If during any year of this 10-year analysis it is determined that the anticipated ARRs will not be feasible, then PJM will recommend transmission upgrades into the PJM RTEP to ensure the 10-year feasibility of stage 1A ARRs.

PJM Percentage of Congestion Dollars Hedged Through PJM's Congestion Management Markets 2005-2009



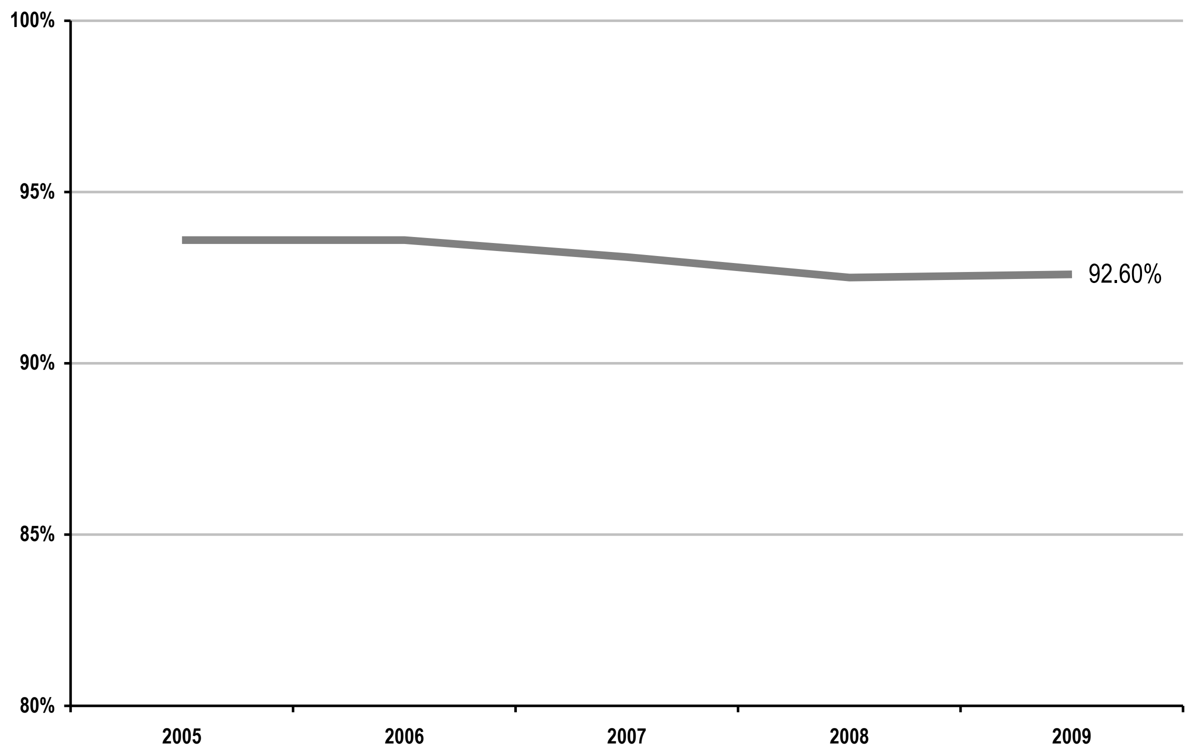
PJM's financial transmission rights (FTR) are financial instruments that entitle the holder to a stream of revenues (or charges) based on the hourly congestion price differences across a transmission path in the Day-Ahead Energy Market. FTRs provide a hedging mechanism that can be traded separately from transmission service. Market participants are able to hedge against their congestion costs by acquiring FTRs that are consistent with their energy deliveries. Participants use PJM's FTR market tool to post their FTRs for bilateral trading as well as to participate in the scheduled monthly, annual and long-term (three-year) FTR auctions.

For the past five years, PJM's FTR market has had sufficient liquidity and capacity to allow the overwhelming majority (98 – 100%) of congestion to be hedged. PJM's FTR market was 93% and 96% revenue adequate in 2005 and 2006, respectively, and 100% revenue adequate from 2007 through 2009. FTR market revenue adequacy reflects the relationship of actual FTR revenues to the target allocations for all FTR holders in the aggregate.

Resources

Balancing customer demand and available resources can be achieved by a combination of changing generation output and/or reducing the total customer demand. The charts and discussion below reflect PJM's history with generation and demand response resources being available when called upon by PJM to revise output or usage levels.

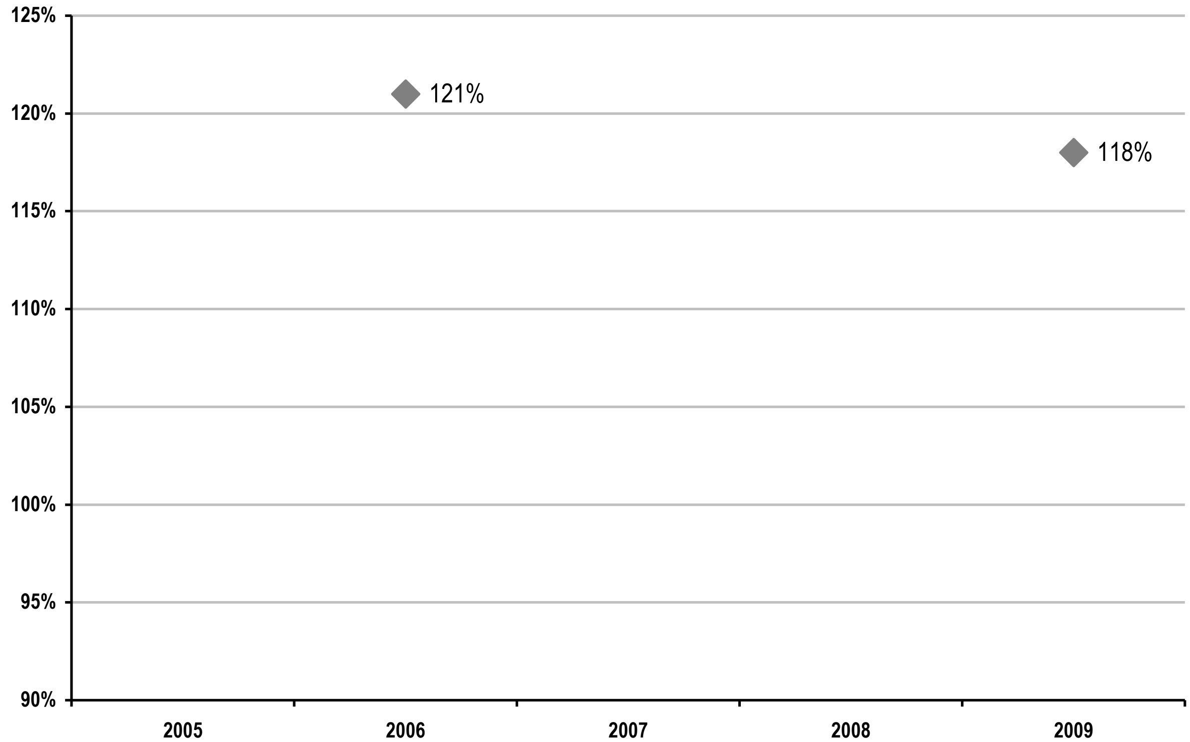
PJM Annual Generator Availability 2005 – 2009



Generator availability in the PJM region has been strong during the last five years. Older coal-fired generating units in the PJM region have had decreased availability approximately 1% in the past few years. These units have run less frequently based on their costs, and investments in upgrades to those units have become challenging financial decisions for their owners in light of the uncertainty over the impact on those units of potential future state and federal environmental legislation.

The incentives provided by PJM's transparent, single clearing price energy market have directly resulted in improved generator performance and reduced outage rates, further decreasing the required reserve margin. The PJM average forced outage rate has decreased over 2% since the initiation of the PJM locational marginal pricing (LMP) energy market in 1998. Multiplying the megawatts of reduced reserve margin times the cost of installing the additional capacity that would be required absent centralized dispatch and the improved generator availability yields a savings of between $366 million and $900 million each year.

PJM Annual Demand Response Availability 2005 – 2009



Historically, load serving entities in PJM have had the ability to meet their capacity requirements through the commitment of demand side resources. With the advent of the Reliability Pricing Model, demand side resources are able to participate in the capacity procurement process as either demand resources or interruptible load for reliability.

The 2006 Demand Response Availability represents the actual response PJM received when PJM called on demand resources in August 2006.

The 2009/2010 delivery year marks the first time PJM has required demand side resources to test their capability to deliver the reductions committed to meet capacity requirements. The test results for the 2009/2010 deliver year demonstrate that in aggregate, committed demand side resources performed at 118% of their committed capacity values.

Demand resources in 16 of the 17 transmission zones in the PJM region tested at more than 100% of their respective commitment levels. These commitments were made by 80 Curtailment Service Providers (CSPs) in 17 transmission zones with a total of 336 CSP/zone combinations.

PJM Demand Response Future Enhancements:

In 2007 and 2008, PJM worked collaboratively with its members and regulators to identify a Demand Response (DR) Roadmap of the opportunities for the evolution of DR resource participation in PJM. The DR Roadmap for the PJM region includes potential improvements in the following areas: dispatch of demand resources, data management, settlement of DR activity, DR in the planning process, and forward price signals for DR.

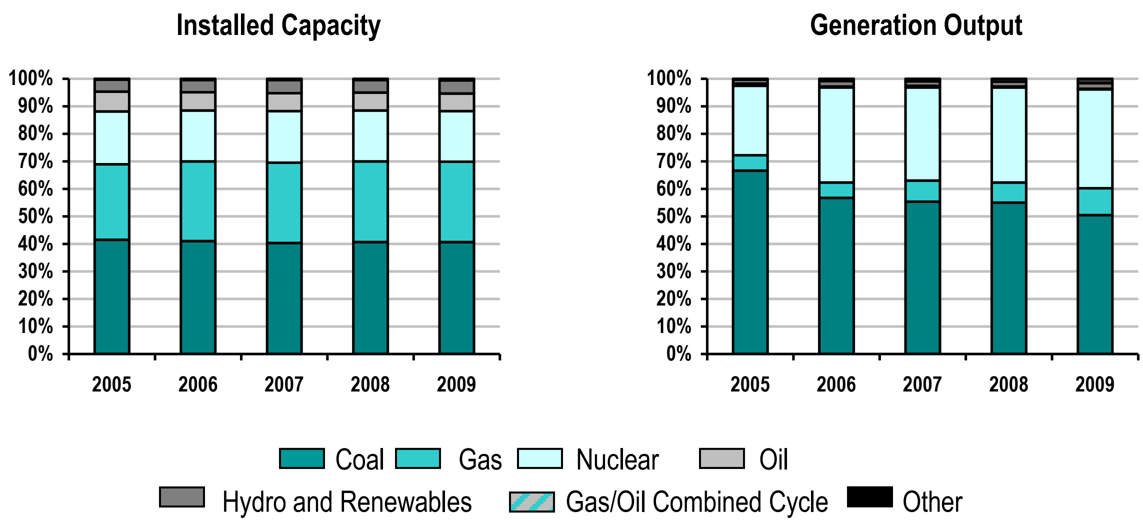
The suggestions in PJM's DR Roadmap were assembled from a variety of sources. These include Mid-Atlantic Demand Resources Initiative (MADRI) activities, recommendations from PJM Symposium on Demand Response, state commission demand response working groups, PJM's Demand Side Response Working Group, and the NARUC/FERC demand response collaborative. The next steps in PJM DR Roadmap include:

- Shortage Pricing implementation in 2011 – Shortage pricing allows for the joint optimization of energy and ancillary services in the real-time dispatch algorithm together, as well as incorporates demand curves to set energy and reserve prices during periods of operating reserve shortage. Managing ancillary service requirements simultaneously with energy in real time and calculating prices every five minutes together with locational marginal pricing (LMP) promotes more efficient commitment of resources for energy or ancillary services and clearing prices that are reflective of actual operating conditions. The joint optimization of energy and ancillary services provides benefit to the system by lowering overall production costs and the resulting five-minute pricing for reserves will enhance opportunities for innovative resources, such as storage devices, to provide ancillary services. Developing a shortage pricing mechanism will adapt market design to more readily provide shortage price signals to take advantage of innovations in demand response and smart grid technologies.

- Price Responsive Demand (PRD) implementation in 2011 – PRD is the predictable reduction in consumption in response to changing wholesale prices. In the PJM region, Smart Grid investment is under development for many market participants and this evolving Advance Metering Infrastructure will enable the enhanced measurement and control required for the implementation of PRD. As a new PJM market option, to the extent retail rates are directly linked to varying wholesale prices, PRD can enable end-use sites with load reduction capability to reduce energy bills by reducing usage during times of high wholesale prices. PRD implementation will enhance market efficiency by increasing the direct participation by demand in the wholesale market.

Fuel Diversity

PJM Fuel Diversity 2005-2009

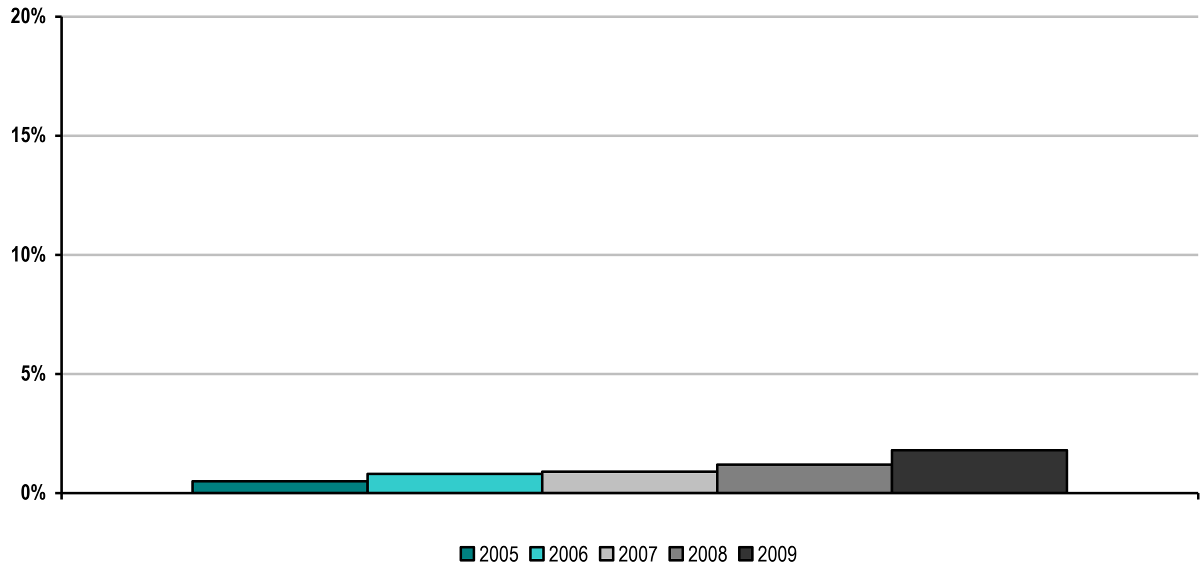


The installed generating capacity in the PJM region is roughly 40% coal, 30% gas and 20% nuclear. However, based on the costs of running the generators in the PJM region, security-constrained economic dispatch actually results in the energy for the PJM region being comprised of 55 – 65% coal, 25 – 35% nuclear and less than 10% from all other fuel sources.

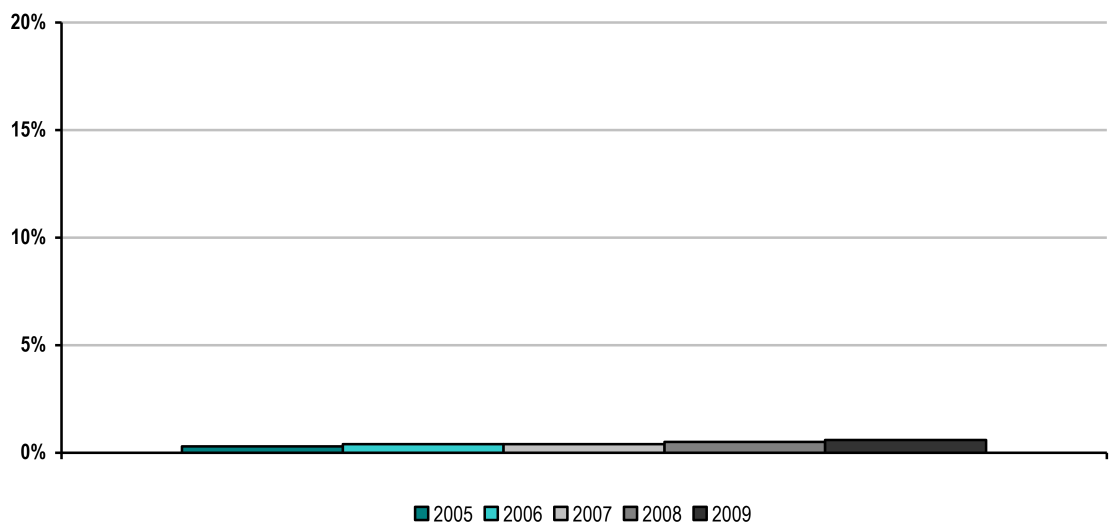
Generation in the PJM footprint does not typically encounter issues around fuel availability or deliverability. PJM has identified approximately 12,000 to 19,000 MW of coal-fired generation that may be at risk of retirement due to potential environmental policy considerations. This range of potential generation at risk represents 7 – 12% of the installed generation capacity in the PJM region. PJM is examining the issue so that reliability may continue to be maintained at the lowest possible cost.

Renewable Resources

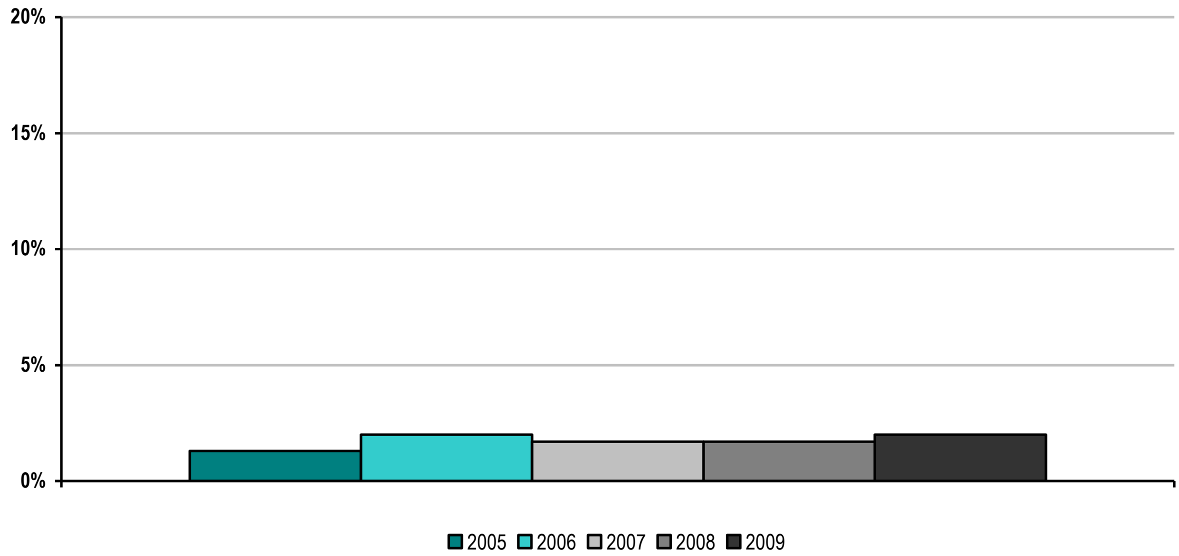
PJM Renewable Megawatt Hours as a Percentage of Total Energy 2005-2009



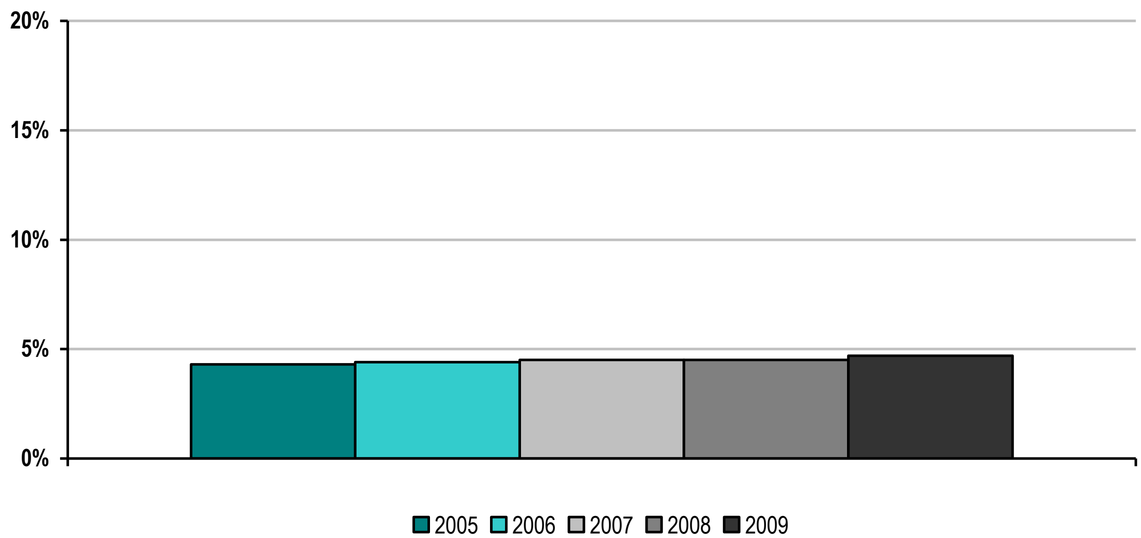
PJM Renewable Megawatts as a Percentage of Total Capacity 2005-2009



PJM Hydroelectric Megawatt Hours as a Percentage of Total Energy 2005-2009



PJM Hydroelectric Megawatts as a Percentage of Total Capacity 2005-2009



Energy and installed capacity contributions from renewable fuel has been growing in the PJM region in the past few years, with tens of thousands of megawatts of potential renewable capacity currently being studied for potential future construction. Installed hydroelectric capacity in the PJM region has not changed materially in the past few years and there are few hydroelectric plants under consideration by generation developers.

PJM's operating, planning and market rules enable the incorporation of renewable resources into the electric system in the PJM region and into the markets administered by PJM. As of March 31, 2010, PJM had over 75,000 MWs of proposed new generation under consideration in its interconnection queues, including nearly 42,000 MWs of wind generation. At the same time, there were 3,648 MWs of nameplate wind generation in operation at 46 facilities, and 2,752 MWs under construction. In addition, there are 5.5 MW of solar on line at two facilities in the PJM region.

Renewable resources offer into the PJM markets and are subject to security constrained economic dispatch, just as any other generating resource. Renewable resources like wind tend to bid in at zero cost or a negative cost, and this value is considered when economically dispatching units for reliability reasons. In the aggregate, wind resources in the PJM region have a 13% capacity factor, and solar resources in the PJM region have a 38% capacity factor.

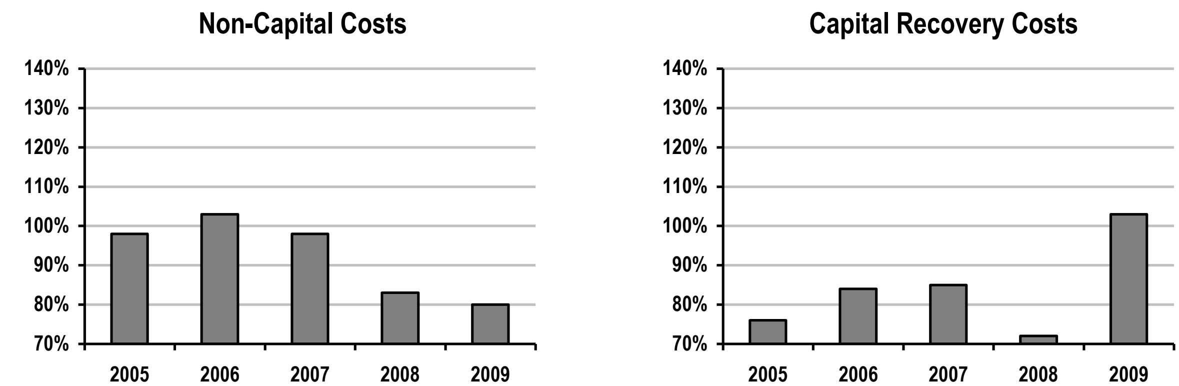
The Renewable Energy Dashboard at www.green.pjm.com illustrates a user-friendly snapshot of the amount and type of generation that currently provides power to the 51 million people in the PJM region. The dashboard also features a map indicating where proposed renewable energy projects are planned and a summary of how much electricity has been produced by renewable sources since 2005.

The amount of renewable energy proposed changes throughout the year as new projects are added and some are withdrawn from the process. The dashboard reflects PJM's on-going commitment to examine energy-related issues and provide information as it relates to the power grid and wholesale power market to help inform public policy discussions.

C. PJM Organizational Effectiveness

Administrative Costs

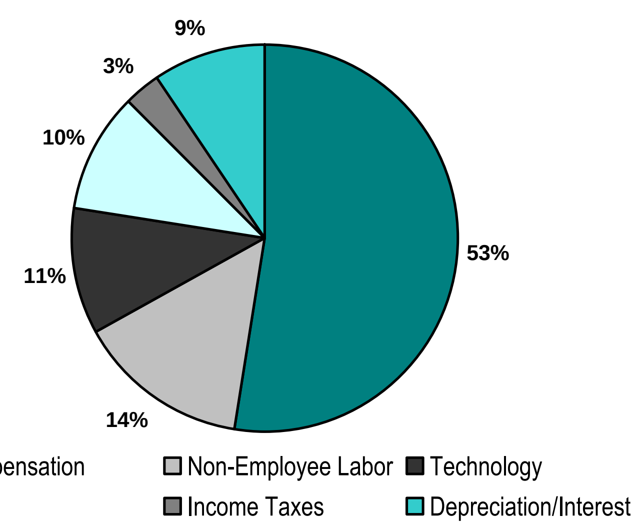
PJM Annual Actual ISO/RTO Costs as a Percentage of Budgeted Costs 2005-2009



Budget	$168	$175	$178	$177	$172	Budget	$90	$55	$34	$17	$19

Bars Represent % of Actual Costs to Approved Budgets; Dollar Amounts Represent Approved Budgets (in millions)

PJM's actual total costs for 2005 through 2009 averaged 90% of the approved budgets, without exceeding the total approved budget in any of those years. As represented in the chart below, PJM's 2005 through 2009 costs were primarily comprised of compensation, non-employee labor and technology expenses. These cost components are consistent with a service organization that utilizes significant people, hardware, software and telecommunications resources to serve its customers.



PJM develops its annual expense and capital budget in consultation with the PJM Finance Committee. The PJM Finance Committee is comprised of two member representatives elected by each of the five member voting sectors plus two members of the PJM Board of Managers. PJM's Chief Financial Officer acts as the non-voting chair of the PJM Finance Committee. PJM's Finance Committee reviews and provides feedback on PJM's preliminary expense and capital budgets during August each year. Then, after PJM management incorporates feedback, the sector-elected representatives to PJM's Finance Committee issue a written recommendation letter to the PJM Board of Managers on the subsequent year's proposed expense and capital budgets. The PJM Board of Managers includes these recommendations in their consideration of the proposed expense and capital budgets no later than October 31st of the year prior to which the proposed budgets apply.

PJM's annual expense and capital resource allocations are based on its service obligations to its members and new initiatives, regulatory directives, industry standards and market rules to be implemented. Prior to the PJM Board of Managers considering the proposed expense and capital budgets, the proposed initiatives and projects are reviewed with several stakeholder committees to ensure the alignment of priorities between the proposed budget resource allocations and the annual plans for those stakeholder committees.

In addition to the recurring review and recommendations on the annual proposed expense and capital budgets, the PJM Finance Committee meets at least quarterly to discuss actual costs compared with approved budgets and the most recent forecast of expenses and capital expenditures for the current year. The PJM Finance Committee is also consulted and asked to provide recommendations regarding (a) proposed multi-year capital projects estimated to cost $25 million or more, and (b) any potential changes to PJM's administrative cost recovery and rates in its Tariff.

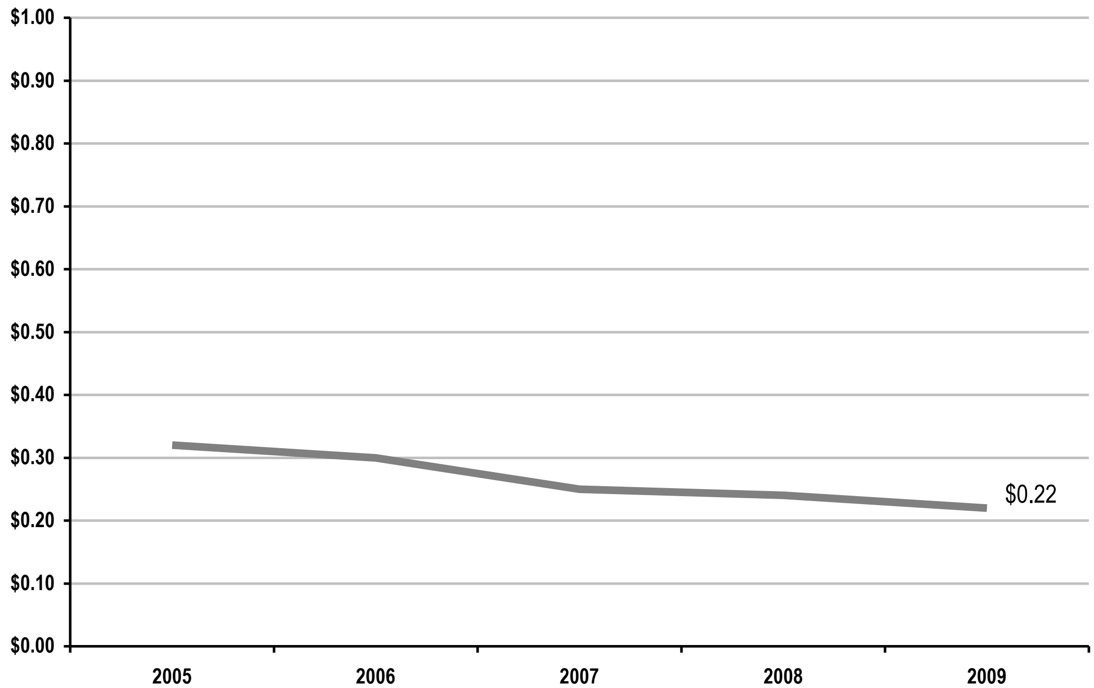
PJM recovers its administrative expenses through stated rates applicable to market participants' transaction volumes, such as megawatt hours of load served, generation sold, and FTRs held. PJM is not authorized to charge its members rates higher than these stated rates without a FERC-approved rate filing. So, the stated rates act has long-term ceilings to how much PJM can charge members for the administrative costs of their transactions. If PJM's actual costs are less than the revenues resulting from the application of the stated rates, then PJM refunds the difference to members on a quarterly basis.

PJM's 2005 through 2007 actual non-capital expenses did not vary materially from the approved non-capital budget for those years. PJM's 2008 actual non-capital expenses were 17% lower than budget primarily due to lower consulting and contracting costs required during the development of PJM's second control center and lower income tax expenses. In June 2009, PJM's Board of Managers approved revisions to PJM's postretirement medical plan resulting in a non-recurring $26 million income tax benefit which was the primary driver of the 20% variance in PJM's actual and budgeted non-capital expenses. The variances in 2008 and 2009 lowered PJM's administrative rate per MWhr of load served by about $0.04 compared with each year's forecasted rates.

PJM's capital recovery costs in the previous chart reflect depreciation and interest expense in each year, as PJM's Tariff stipulates that capital investments are recovered from PJM's members after the related assets are placed in service. PJM's 2005 actual capital recovery costs were approximately 24% lower than its approved budget primarily due to lower than budgeted technology investment related to the integration of additional transmission zones into the PJM region. PJM's 2006 actual capital recovery costs were lower than budgeted for a few reasons – the lower 2005 actual capital spending, lower interest expense on lower than budgeted borrowing levels, and the shift of a few capital projects from 2006 to 2007. PJM's 2007 actual capital recovery costs were lower than budgeted due to lower interest expense due to lower borrowings required to fund PJM's capital expenditures.

PJM's 2008 actual capital recovery costs were 28% lower than budget due to the impact on depreciation and interest expense of the revised completion dates of certain projects such as the market settlement system replacement and lower interest expense from lower borrowings than budgeted. PJM's 2009 actual capital recovery costs did not vary significantly from its budgeted capital recovery costs. With the planned completion of PJM's second control center in 2011, PJM's capital recovery costs are projected to increase from 2011 forward to reflect the depreciation and interest expenses associated with that approximate $140 million capital investment.

PJM Annual Administrative Charges per Megawatt Hour of Load Served 2005-2009
($/megawatt-hour)

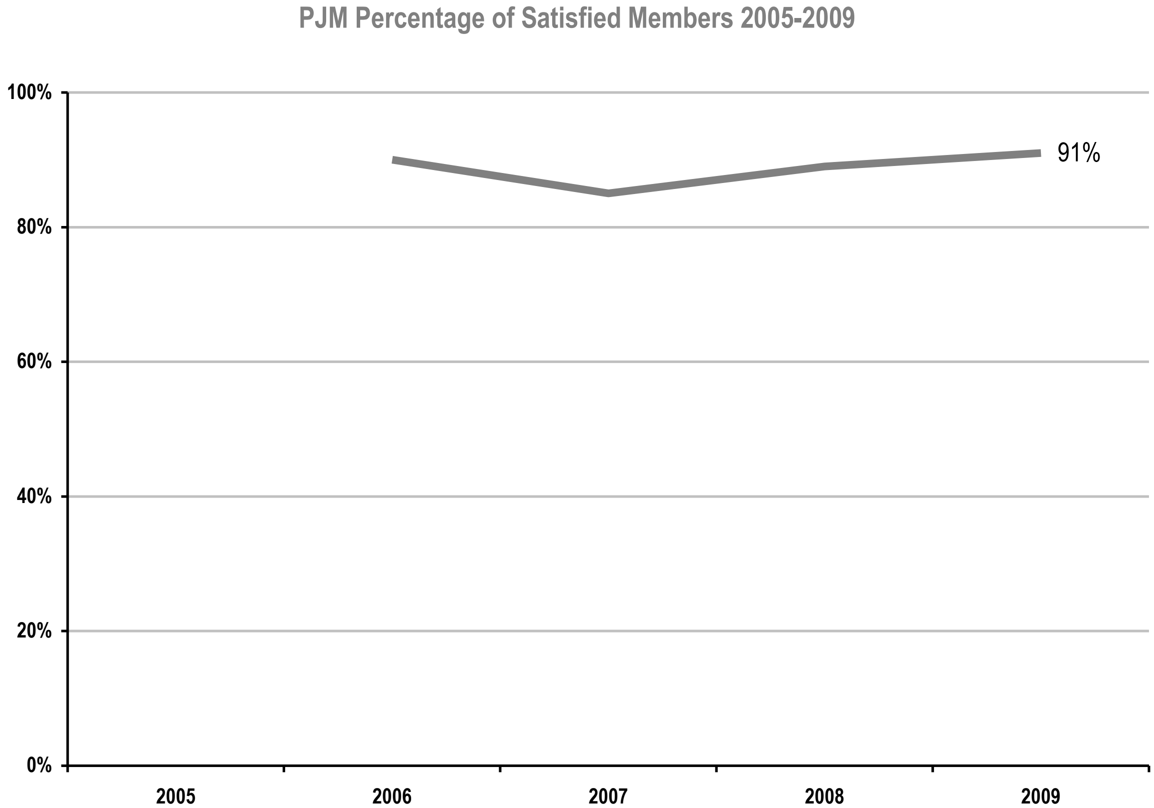


The administrative costs per MWh of load served data in the chart above should be reviewed in the context of the PJM annual load served noted in the table below.

ISO/RTO	2009 Annual Load Served *(in terawatt hours)*
PJM	710

PJM's actual to budget variances in 2008 and 2009 lowered PJM's administrative rate per MWh of load served by about $0.04 compared with each year's forecasted rates. Prospectively, PJM forecasts its annual administrative rates will be approximately $0.31 per MWh of load served as recovery of the investments in (1) a second control center and (2) new reliability and markets software and hardware commence in 2011.

Customer Satisfaction



PJM's 2005 stakeholder survey did not ask the same satisfaction questions as were asked in 2006 through 2009; hence, there is no comparable 2005 satisfaction statistic for PJM. PJM's stakeholder survey requests anonymous feedback to an independent firm on levels of satisfaction and stakeholder value derived from numerous PJM functions. Based on survey takers' self-selected description, PJM's 2006 through 2009 satisfaction percentages have not differed significantly among member sectors, e.g. electric distributors, end-use customers, generation owners, other suppliers and transmission owners. In the 2009 survey, the reliability management and training functions received the highest satisfaction ratings with the system planning and communications areas demonstrating opportunities for improvement.

PJM implements action plans to address areas for which there are opportunities for improvement. In the past few years, PJM has focused on feedback to improve stakeholder access to PJM information and stakeholder communications with the PJM Board of Managers. For example, PJM and its members established the Liaison Committee in 2007 to provide greater opportunities for direct communications between stakeholders and the PJM Board of Managers. Also, in 2008, PJM redesigned its website to facilitate stakeholder access to information on operations, markets and stakeholder committee activity. In 2009, PJM's members responded with the highest value rating in PJM's ten-year history of surveying its members.

PJM Customer Satisfaction Future Enhancements:

Based on feedback received during PJM's 2009 customer satisfaction survey, PJM will implement the following improvements during 2010:

Long-Term System Planning:

- Augment staffing levels
- Re-establish the Regional Planning Process Working Group as a member forum to address transmission planning concerns

PJM Web-site:

- Improve web-site speed
- Improve web-site, generation interconnection and planning queue searches
- Implement Issues Tracking
- Increase frequency of communications to members on web-site changes

Billing Controls

ISO/RTO	2005	2006	2007	2008	2009
PJM	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 2009, PJM's market settlement billing controls passed the stringent SAS (Statement on Auditing Standards) 70 Type 2 audit for the ninth consecutive year, even with the significant 2009 change from a monthly to a weekly billing cycle. In keeping with governance rules, such as those in the Sarbanes-Oxley Act of 2002, PJM's SAS 70 report is designed to provide an understanding of its internal controls to the auditors of the companies that use the organization's services, i.e. PJM's members. PJM's internal controls and processes related to all billing line items are included in the scope of testing completed during each twelve-month SAS 70 audit period.

PJM focuses on the accuracy of both prices posted and amounts billed to ensure members can rely on prices for transacting and have confidence in the amounts included in their PJM invoices.

- In the five years ended December 31, 2009, PJM reposted hourly energy prices once in 2006, twice in 2007 and five times in 2008. There were no energy price corrections in 2005 or 2009. The energy price corrections applied to either one pricing point or one hour's prices for each of the affected days and prices were revised from 0.06% to 6.43% for these hours. For the five-year period ended December 31, 2009, PJM achieved 99.99996% energy price posting accuracy.
- For the five-year period 2005 through 2009, PJM's billing accuracy based on dollars of billing adjustments divided by total dollars billed averaged 99.8%.

D. PJM Interconnection Specific Initiatives

Perfect Dispatch: PJM's Perfect Dispatch metric provides a measure of PJM's performance in dispatching the system in the most efficient manner possible and optimizing locational pricing as a reflection of the dispatch solution. The objective of the Perfect Dispatch measure is to compare PJM's actual dispatch solution against the ideal case if all system conditions, including actual electricity usage, had been known before the dispatch signals were sent to the generators in the PJM region. During 2009, PJM improved its generation dispatch sufficiently to reduce annual generation production costs by $122 million.

PJM Perfect Dispatch Future Enhancement:

During 2010, PJM will expand its Perfect Dispatch initiative to evaluate and optimize steam generating unit commitment actions outside of the Day-Ahead Market schedule to allow PJM to identify areas for further operational improvement in dispatch that result in dollar savings in generation production costs to members.

Credit Risk Management: PJM implemented more than a dozen improvements to its billing and credit practices during 2009 to reduce the risk of socialized default charges to its members. In particular, PJM replaced its previous monthly billing cycle with weekly billing and settlement on June 1, 2009. This change resulted in a $2.9 billion (70%) reduction in the total credit risk exposure to PJM's members. Further, PJM returned $1.0 billion of financial security to its members due to lower credit requirements under accelerated settlements.

PJM Credit Risk Management Future Enhancement:

During 2010, PJM asked its members and the Federal Energy Regulatory Commission to support revisions to PJM's Operating Agreement and Tariff to clarify PJM's legal capacity as the central counterparty for members' non-bilateral transactions billed by PJM effective January 1, 2011.

Demand Response and Energy Efficiency Capacity Market Participation: During 2009, PJM implemented capacity market rule changes that increased the opportunities for demand response and energy efficiency to participate in PJM's capacity market auction for the 2012/2013 planning year. The 5,682 megawatt increase in demand resources over the last Reliability Pricing Model auction in 2008 is enough capacity that would be equivalent to the power needs of about five million households. A total of 67% of the demand resources cleared in constrained regions, reflecting its value in helping to reduce congestion. For the first time, energy efficiency participated in the sixth RPM auction bringing 569 megawatts of new energy efficiency resources to PJM. Total revenues earned by demand response resources in 2009 from energy, capacity and ancillary service market participation exceeded $300 million, nearly a 60% increase from 2008.

Market Liquidity: Another measure of the efficiency and effectiveness of wholesale power markets is the ability for financial derivative products to be developed and utilized by physical market participants to mitigate price risk, such as swap futures. The development of such products that are settled against wholesale market outcomes also signals confidence in the accuracy and relevance of the prices determined in the wholesale market. Currently, the New York Mercantile Exchange (NYMEX) trades 52 PJM-based contracts that are differentiated by location, peak or off-peak, and day-ahead or real-time markets. Open interest in day-ahead and real-time contracts traded at locations within

PJM reflects the total megawatt hours (MWhs) of energy hedged by these Swap Futures, which is 9 – 12.5% of total load in the reference PJM transmission zones. The percentage of load hedged through financial contracts is even more significant if one considers that 17% of the real-time load was served out of the real-time market, with the remainder self-supplied or served by bilateral contracts. Such statistics indicate that the combination of wholesale power markets with financial instruments facilitates less than 10% of total load served in the PJM region likely being exposed to the potential volatility of real-time prices. Further, during 2009, PJM began hosting a long-term contracting bulletin board for all the ISOs/RTOs to enable buyers and sellers interested in longer-term contracts to contact each other.

Industry Innovation / Collaboration: PJM's ability to deliver value also involves leveraging its intellectual resources and vast stores of data to assess the impact of potential public policy initiatives on the grid and markets. An example is the widely referenced study of the potential impact of climate-control legislation that PJM published early 2009. PJM also sponsored symposiums on plug-in hybrid electric vehicles and demand response and Price Responsive Demand in order to provide members and policy-makers with knowledge on the issues and how their development might affect the grid and the PJM region.

Grant Collaboration: To further broader transmission planning, the Eastern Interconnection Planning Collaborative was formed in 2009. The collaborative and the states received a total of $30 million in federal grants to address the need for wide-area planning to deal with the massive growth of wind energy and other renewable sources resulting from new energy policies in Washington. Also, the combined efforts of PJM and 12 transmission-owning members gained $14 million in matching federal stimulus funds to support a massive expansion of the number of synchrophasors throughout 91 substations in 10 states. This will vastly expand our ability to see and quickly react to abnormal conditions, thereby strengthening both the reliability and digital intelligence of the bulk electric system.

PJM Value Proposition: The following summarizes the impact of specific elements of PJM's role that produce benefits and economic value for the region it serves. **Annual savings: as much as $2.2 billion**

Reliability –
resolving constraints and economic efficiency – **from $470 million to $490 million in annual savings**

Generation investment –
decreased need for infrastructure investment – **from $640 million to $1.2 billion in annual savings**

Energy production cost –
efficiency of centralized dispatch over a large region – **from $340 million to $445 million in annual savings**

Grid services –
cost-effective procurement of synchronized reserve, regulation – **from $80 million to $105 million in annual savings**

A. Reliability Savings

PJM's ability to direct changes in the output of generating resources (redispatch) rather than curtail power-sales transactions to deal with transmission congestion enables it to deal with transmission constraints more effectively. By reducing the need for curtailments over a wide area – transmission loading relief procedures, or TLRs – PJM's narrowly targeted redispatch procedures resolve transmission constraints more quickly. This approach has significantly reduced the need for transaction curtailments to maintain transmission system reliability.

Annual savings: $78 million to $98 million

By planning for future reliability needs on a region-wide rather than a utility-by-utility or state-by-state basis, PJM's Regional Transmission Expansion Planning (RTEP) process helps focus on transmission upgrades that meet reliability criteria and increase economic efficiency.

Annual savings: $390 million

B. Generation Investment Savings

The large size of the PJM market area, combined with its diversity of demand and resources, reduces the overall level of capacity needed to ensure adequate reserves of electricity to meet peak demand or emergency situations. This capacity buffer, known as the reserve margin, would need to be higher without PJM. Consumers avoid the costs of additional generation to meet higher levels of reserves.

Annual savings: $366 million to $900 million

The commitment of demand-response resources to reduce load during system peaks also forestalls the cost of building additional generating facilities. Through the Reliability Pricing Model (RPM), demand response competes on an equal footing with generation and transmission in the capacity market. Through RPM, the quantity of demand response that is providing capacity in the PJM footprint has increased by more than 1,800 megawatts.

Annual savings: $275 million

C. Energy Production Cost Savings

PJM's centralized dispatch of the numerous resources over its expanded territory produces significant efficiencies and cost savings compared with the previous operation of independent control areas across the region. The increasing effectiveness of PJM's dispatch operations also has reduced operating reserve costs.

Annual savings: $340 million to $445 million

D. Grid Services Savings

By operating markets for grid services, also known as ancillary services, across its footprint, PJM achieves economies in providing services that are essential to the reliability of the electric system. Synchronized reserve service supplies electricity if the grid has an unexpected need for more power on short notice, while regulation helps match generation and load by correcting for short-term changes in electricity use that might affect system stability.

Annual savings: $80 million to $105 million

Southwest Power Pool (SPP)

Section 7 – SPP Performance Metrics and Other Information

Southwest Power Pool, Inc. (SPP) is a regional transmission organization (RTO) that coordinates the movement of electricity in a nine state region – Arkansas, Kansas, Louisiana, Mississippi, Missouri, Nebraska, New Mexico, Oklahoma and Texas.

Services provided by SPP include:

- **Compliance** - The SPP Regional Entity enforces compliance with federal and regional reliability standards for users, owners, and operators of the region's bulk power grid.
- **Market Operations** - In the Energy Imbalance Service (EIS) market (implemented February 1, 2007), participants buy and sell wholesale electricity in real-time. If a utility requires more energy than it scheduled, the market provides the utility another option to buy the "extra" energy at real-time prices to make up the difference and meet its demand. Participants can use the EIS market to get the least expensive available energy from other utilities. SPP's 2009 wholesale market transactions totaled $1.14 billion. SPP is currently planning for future energy markets.
- **Regional Scheduling** - SPP ensures that the amount of power sent is coordinated and matched with power received.
- **Reliability Coordination** - SPP monitors power flow throughout our footprint and coordinates regional response in emergency situations or blackouts.
- **Tariff Administration** - SPP provides "one stop shopping" for use of the region's transmission lines and independently administers an Open Access Transmission Tariff with consistent rates and terms. SPP's 2009 transmission market transactions totaled $486 million.
- **Training** - SPP offers continuing education for operations personnel at SPP and throughout the region. In 2009, the SPP training program awarded ~17,000 continuing education hours to 444 operators from 30 member organizations.
- **Transmission Expansion Planning** - SPP's planning processes seek to identify system limitations, develop transmission upgrade plans, and track project progress to ensure timely completion of system reinforcements.
- **Contract Services** - SPP provides reliability, tariff administration, and scheduling for non-members on a contract basis.

Southwest Power Pool dates to 1941, when 11 regional power companies joined to keep an Arkansas aluminum factory powered around the clock to meet critical defense needs. After the war, SPP's Executive Committee decided the organization should be retained to maintain electric reliability and coordination.

SPP incorporated as an Arkansas not-profit organization in January 1994. The Federal Energy Regulatory Commission (FERC) approved SPP as a Regional Transmission Organization in 2004 and a Regional Entity in 2007.

A. SPP Bulk Power System Reliability

As of December 31, 2009, SPP has not had any investigations or self-reports or audit findings result in violations of NERC or ERO standards that are public. However, SPP may have potential violations under review arising from circumstances prior to January 1, 2010.

The table below identifies which NERC Functional Model registrations SPP has submitted as effective as of the end of 2009. Additional the Regional Entity for SPP is noted at the end of the table with a link to the website for the specific reliability standards.

NERC Functional Model Registration	SPP
Balancing Authority	
Interchange Authority	✓
Planning Authority	✓
Reliability Coordinator	✓
Resource Planner	
Transmission Operator	
Transmission Planner	✓
Transmission Service Provider	✓

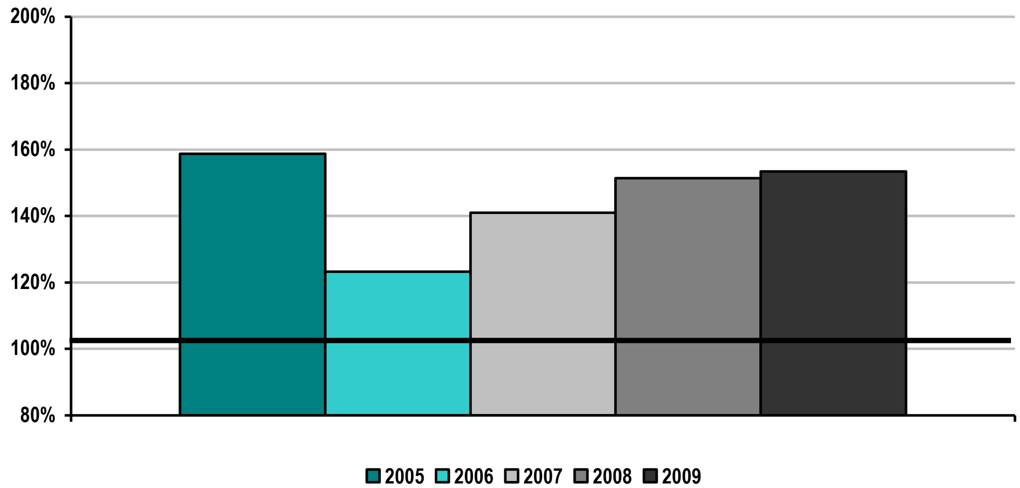
Regional Entity	SPP

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 SPP Board are available at:
http://www.spp.org/section.asp?pageID=98

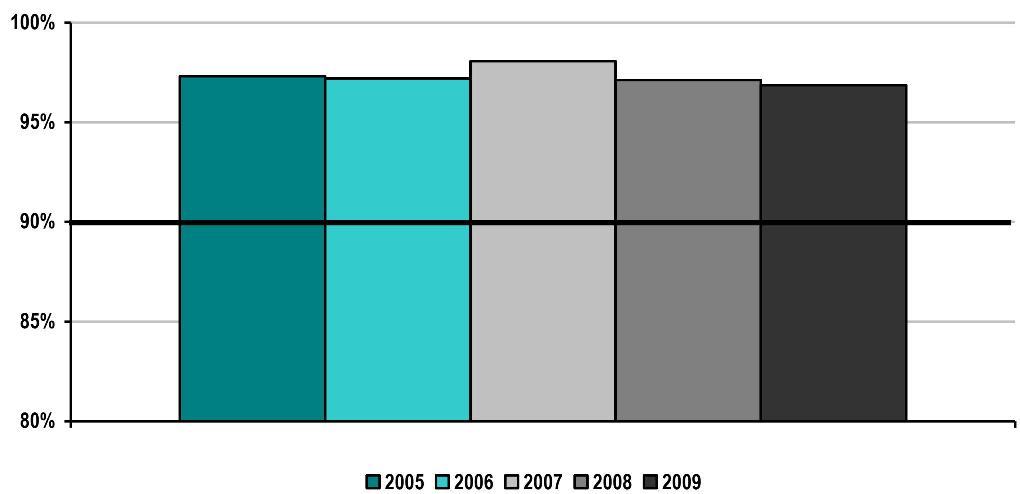
Dispatch Operations

SPP CPS-1 Compliance 2005-2009



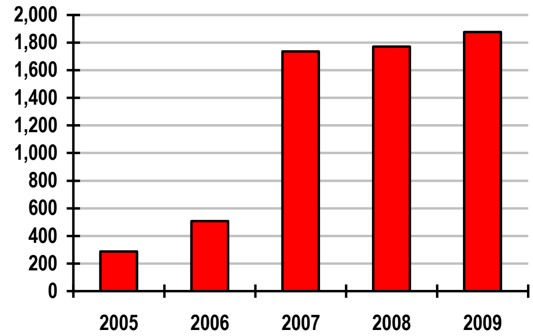
Compliance with CPS-1 requires at least 100% throughout a 12-month period. SPP was in compliance with CPS-1 for each of the calendar years from 2005 through 2009.

SPP CPS-2 Compliance 2005-2009



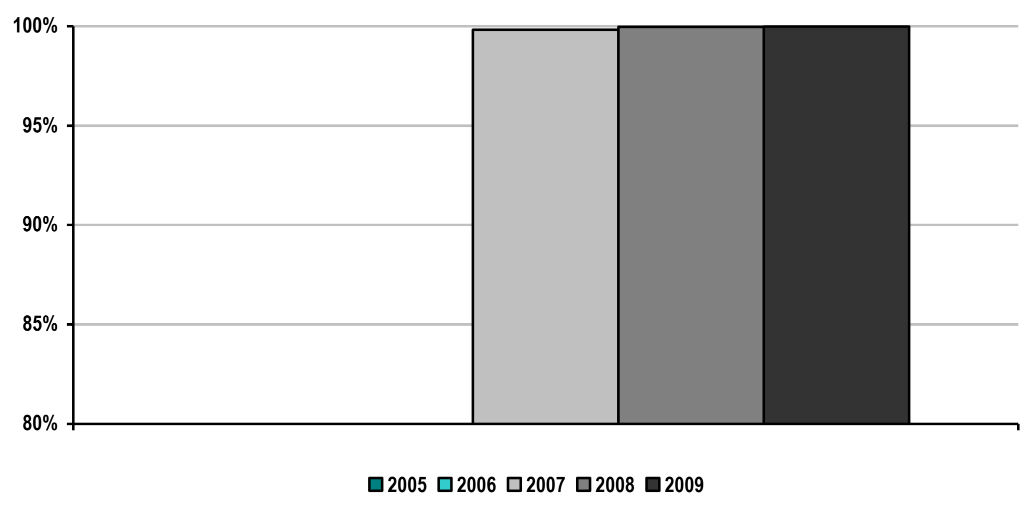
Compliance with CPS-2 requires 90% for each month in a 12 month period. SPP was in compliance with CPS-2 for each of the calendar years from 2005 to 2009.

SPP Transmission Load Relief or Unscheduled Flow Relief Events 2005-2009



SPP data reflects number of Transmission Load Relief (TLR) events. SPP's TLR events were comprised of primarily level 3 and 4 TLRs with 2%, 5%, 4%, 6% and 5% of level 5 TLRs in 2005 through 2009, respectively. The increase in SPP TLRs reflects an aspect of the Energy Imbalance Services (EIS) Market design. One of the objectives of the EIS Market is to utilize the existing transmission system by providing the most economical energy through the Tariff's Schedule 4 Energy Imbalance Service. The Market System Scheduling & Pricing Dispatch engine increases flow on flowgate interfaces by dispatching more efficient resources up and reducing others down. The SPP Tariff and Market protocols currently require SPP issue a TLR in parallel with congestion management in the Market System. Loading flowgate interfaces provides more economical energy, however when the loading approaches the constraint operating limitation, a TLR must be issued, regardless if schedules/tags/external are in IDC impact the constraint being controlled. The increase in TLRs is a direct correlation to having issued TLR in order to begin the process of having the Market System redispatch around a constraint.

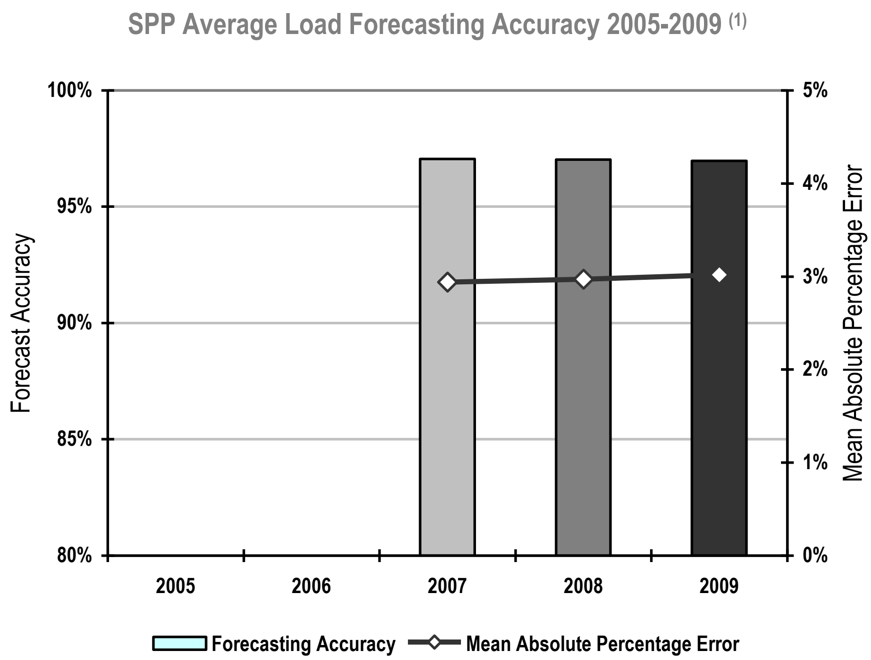
SPP Energy Market System Availability 2005-2009 (1)



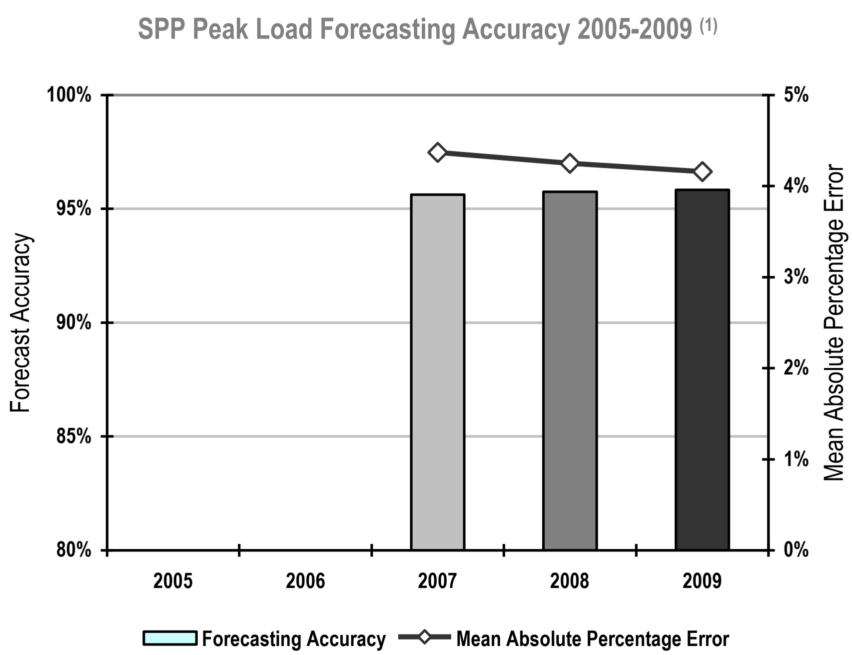
Availability of the Energy Management System (EMS) is key to reliable monitoring of the electric transmission system in SPP. Since the implementation of the Energy Imbalance Service market in February 2007, the SPP EMS has been unavailable less than 0.5% of all hours in each year.

Load Forecast Accuracy

ISO/RTO	Load Forecasting Accuracy Reference Point
SPP	6:00 a.m. prior day

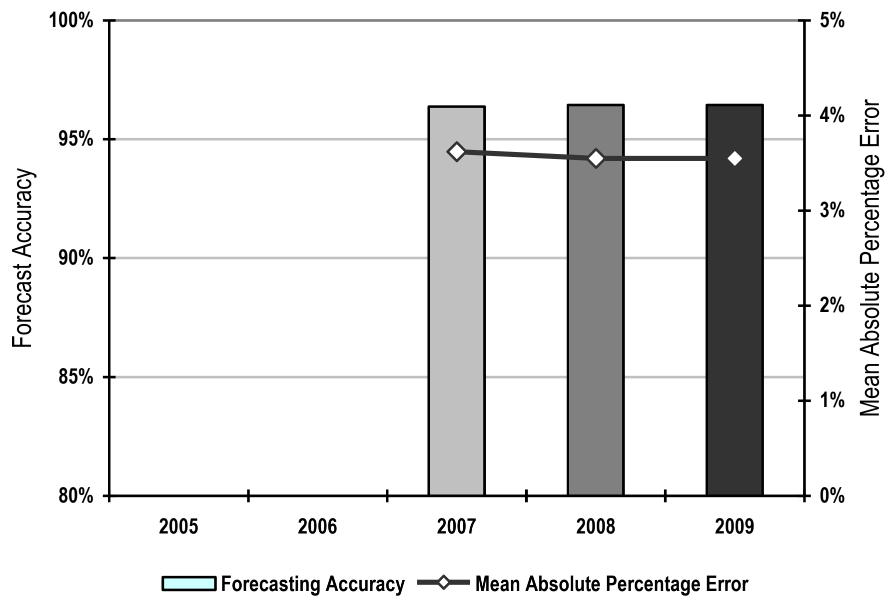


(1) *SPP began operation of an Energy Imbalance Service market on February 1, 2007.*



(1) *SPP began operation of an Energy Imbalance Service market on February 1, 2007.*

SPP Valley Load Forecasting Accuracy 2005-2009 (1)



(1) SPP began operation of an Energy Imbalance Service market on February 1, 2007.

As stated in the introduction, since SPP does not currently have a day-ahead market, the prior day's medium term load forecast (MTLF) is used as the load forecast accuracy reference point. Since SPP does not have a consolidated Balancing Authority, a forecast is calculated for each of the SPP BAs (15 at the end of 2009). Overall, the average load forecasting accuracy for SPP has been right around 97% for each of the past three years that data is available. Peak and valley forecasts see slightly higher error, which can be attributed to the number of forecasts that are required due to having multiple BAs.

Wind Forecasting Accuracy

SPP does not forecast wind. That function is completed by each Balancing Authority in the SPP Region.

During 2010 SPP is developing a system for RTO-wide wind forecasts.

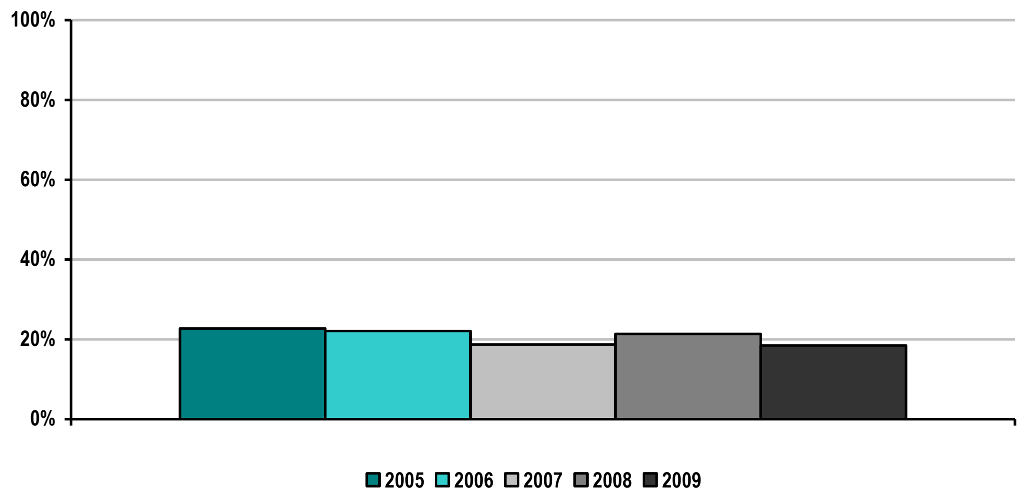
Unscheduled Flows

Since SPP does not have a consolidated Balancing Authority and is currently (end of 2009) made up of 15 distinct Balancing Authorities, volume of unscheduled flows for SPP system-wide is unavailable. For informational purposes, the number of external interfaces and the main interfaces are listed above.

Transmission Outage Coordination

The SPP OATT does not outline specific timeframes and guidelines for Transmission Outages and Coordination. The OATT states that "the Transmission Provider will provide the projected status of transmission outage schedules above 230 kV over the next twelve (12) months or more if available. This data shall be updated no less than once daily for the full posting horizon and more often as required by system conditions. The data will include current, accurate and complete transmission facility maintenance schedules, including the "outage date" and "return date" of a transmission facility from a scheduled or forced outage. If the status of a particular transmission facility operating at voltages less than 230 kV is critical to the determination of TTC and ATC/AFC of the neighboring transmission provider, the status of this facility will also be provided," and "consistent with the SPP Membership Agreement, Transmission Owners are required to coordinate with the Transmission Provider for all planned maintenance of Tariff Facilities. The Transmission Provider shall notify a Transmission Owner of the need to change previously reviewed planned maintenance outages."

SPP Percentage of > 200kV planned outages of 5 days or more that are submitted to ISO/RTO at least 1 month prior to the outage commencement date 2005-2009

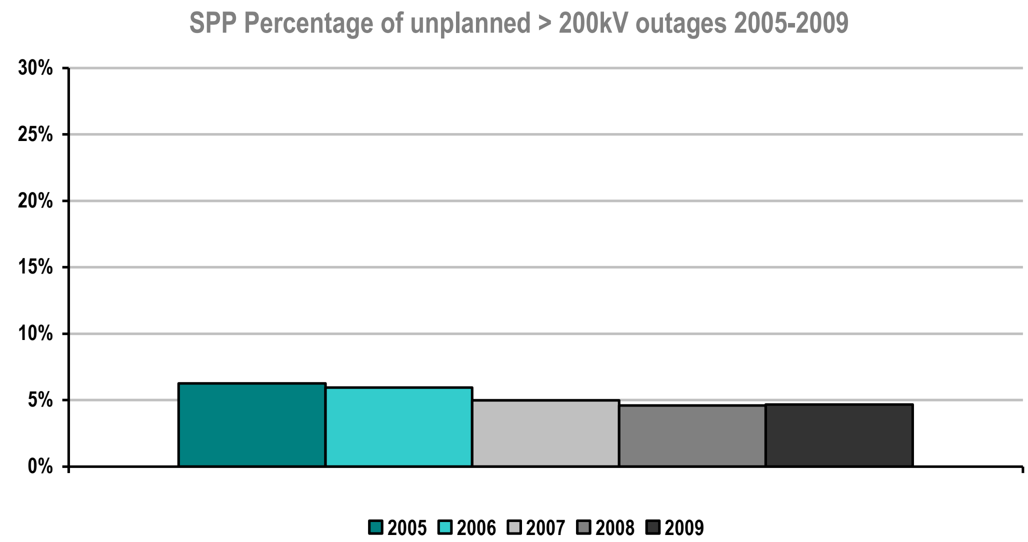


SPP Percentage of planned outages studied in the respective ISO/RTO Tariff/Manual established timeframes 2005-2009

SPP does not have established timeframes in which planned outages must be studied.

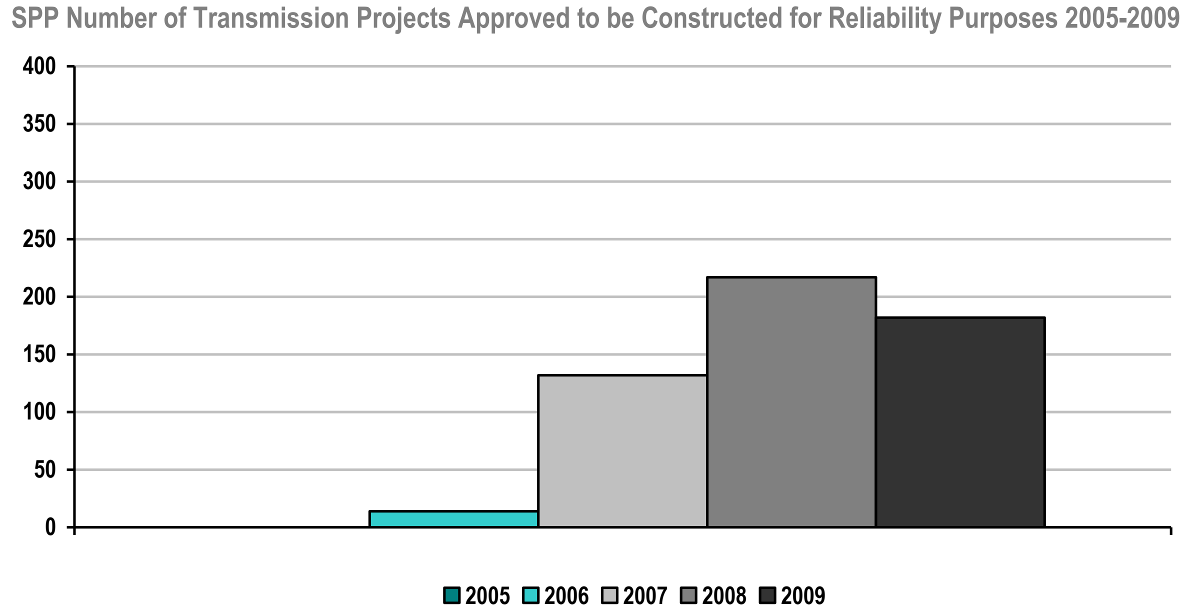
Percentage of > 200 kV outages cancelled by ISO/RTO after having been previously approved 2005-2009

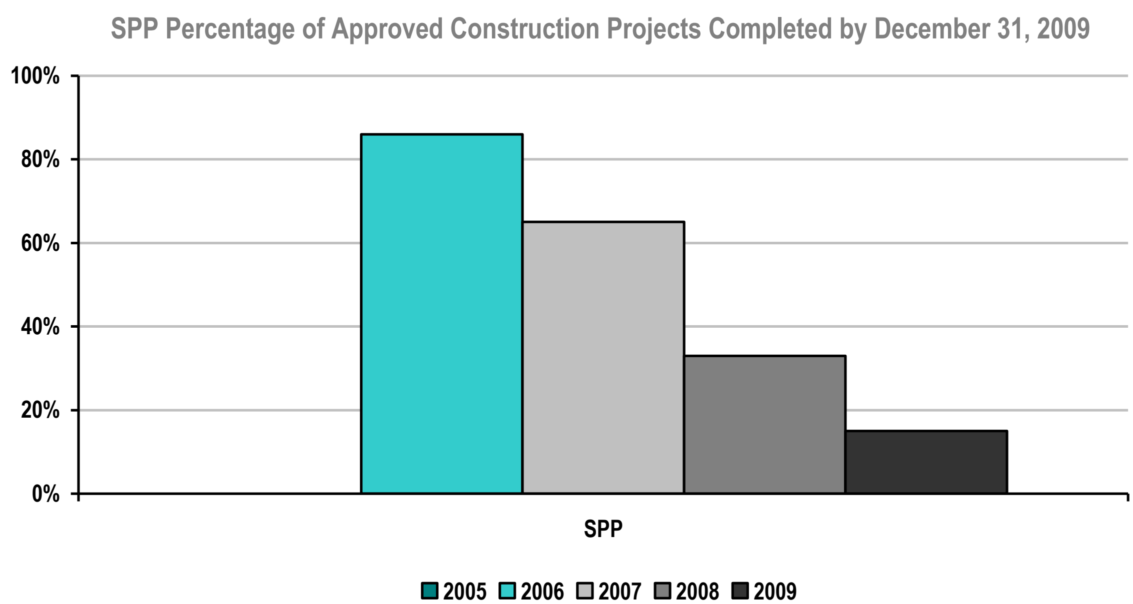
Data for this metric is not available for SPP.



In the 2009 Annual State of the Market Report, the SPP Market Monitoring Unit indicated that “SPP should move to standardize categories accounting for transmission outages which would allow for the easy reporting of extent, causes, and location of such outages. At a minimum, this type of reporting alleviates concerns of market power abuses and can enhance SPP’s transmission planning and real-time operations.” This recommendation has been adopted and its implementation is part of the 2010 Southwest Power Pool Strategic Plan, which was adopted by the SPP Board of Directors on July 27, 2010.

Transmission Planning





SPP's transmission planning process was a bottom-up, top-down approach, enabling SPP to provide efficient, reliable, and competitive generation market Transmission Services on a non-discriminatory basis. The SPP planning processes took into account its stakeholder's requirements, while coordinating with applicable federal, state and local regulatory authorities and also considering potential public policy. The SPP Transmission Expansion Plan (STEP) promotes the efficient expansion of the transmission system under SPP's control and enables competitive generation markets. The STEP identifies potential expansion projects needed to meet reliability standards and to interconnect new generation, with consideration for load growth, competitive generation market, stakeholder input, and transmission service commitments. In addition, the STEP considers plans for addressing transmission congestion and the benefits associated with development of new generation as alternatives to transmission expansion.

Reliability Planning

As part of the bottom-up approach, one component of the STEP is the reliability assessment. This process requires that Transmission Owners continue to develop expansion plans to meet the local needs of their systems and to help the RTO develop the expansion plan for reliability needs. Transmission Owners develop their system specific local plans, which SPP consolidates into the integrated STEP. At the same time, SPP assesses its system for the ability to meet applicable reliability standards. This process allows for projects with regional and inter-regional impact to be analyzed for their combined effects. It allows the exploration of modifications and alternatives to proposed plans, which may provide more cost effective solutions for regional and as well as local needs.

Economic Planning

As part of SPP's top-down approach transmission improvements are considered that provide economic benefit. One specific process is called the Balanced Portfolio. The Balanced Portfolio is one SPP strategic initiative to develop a cohesive grouping of economic upgrades that benefit the SPP region and allocates the cost of those upgrades regionally. Projects in the Balanced Portfolio include transmission upgrades of 345 kV projects that will provide customers with potential savings that exceed project costs. These economic upgrades are intended to reduce congestion on the SPP transmission system, resulting in savings in generation production costs. With a goal to identify upgrades for inclusion in a portfolio that will provide a balanced benefit to customers over a specified ten-year payback period. "Balanced" is defined by the SPP Regional Tariff, such that for each Zone, the sum of the benefits of the potential Balanced Portfolio must equal or exceed the sum of the costs. Economic upgrades may provide other benefits to the power grid; i.e. increasing reliability and lowering reserve margins, deferring reliability upgrades, and providing environmental benefits due to more efficient operation of assets and greater utilization of renewable resources.

Another example of an economic study is the Priority Projects study. This was a one-time analysis conducted in 2009 as a result of the SPP Synergistic Planning Process Team recommendations and is considered a high priority studies. Study assumptions include fuel and emissions costs, load and generation forecasts, types and locations of new generation, generation retirements, market structures, and wind profiles. Analysis also encompasses a plausible collection of assumptions for each specific model run, including varying levels of Renewable Electricity Standards, demand response, energy efficiency, fuel prices, and governmental regulations. Metrics were developed for qualifying and quantifying the projects for the studies, including Adjusted Production Cost, impact on losses, reliability and environmental impacts, capacity margins, and operating reserves.

Stakeholders

There are opportunities for stakeholder involvement throughout the SPP planning processes. All planning processes are open and transparent assessments of study assumptions, upgrade recommendations and applicable cost allocation impacts. Its implementation is only successful through the commitment of SPP members, regulators, and other stakeholders. Input from the regulators assists SPP in the development of realistic transmission expansion projects and alternatives to meet rate payer needs, as well as those of neighboring regions.

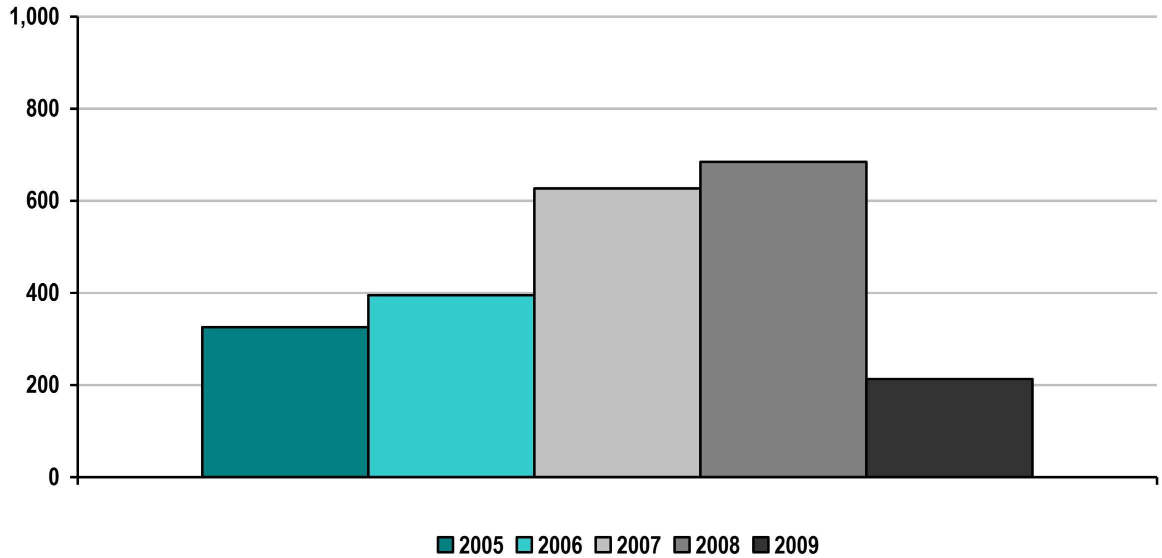
Approval

After each analysis, the SPP Board of Directors can approve proposed upgrades to begin construction. For the approved upgrades, SPP issues Notification To Construct letters to incumbent Transmission Owners notifying them to build the upgrades. SPP then tracks the progress of the upgrades through a quarterly project tracking process monitoring project schedules and costs and also tracking necessary mitigation plans if project construction schedules are unable to meet system in-service needs.

As part of the 2009 transmission planning efforts, SPP completed the following studies: reliability – AC contingency, dynamic stability, and voltage stability studies; economic – Balanced Portfolio and Priority Projects studies. The results of these studies can be found in the 2009 STEP report, available at: http://www.spp.org/publications/2009-STEP-Report.pdf.

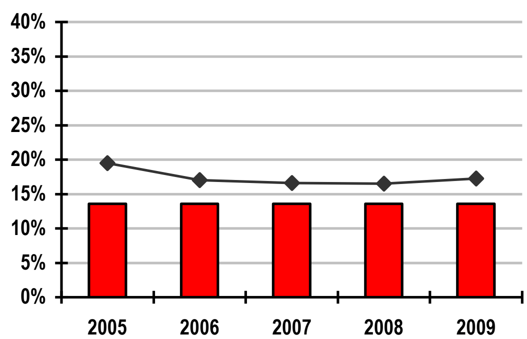
Generation Interconnection

SPP Average Generation Interconnection Request Processing Time 2005-2009
(calendar days)



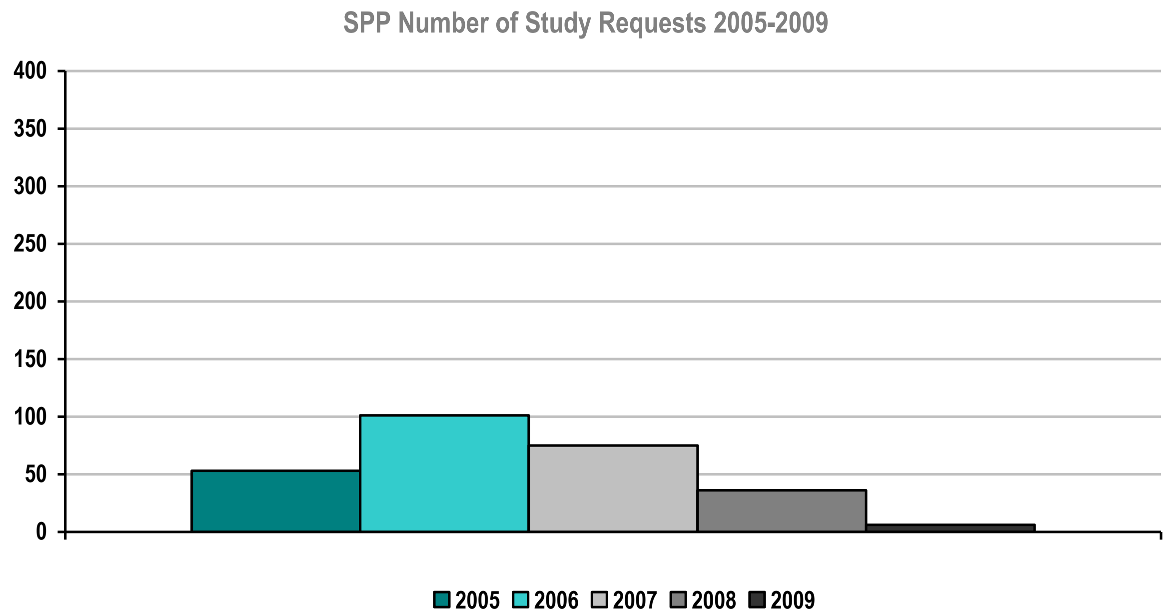
In 2009, SPP placed a higher emphasis on the timely processing of Generation Interconnection studies, as evidenced by a reduction of more than one-third the number of days required from 2008 to 2009.

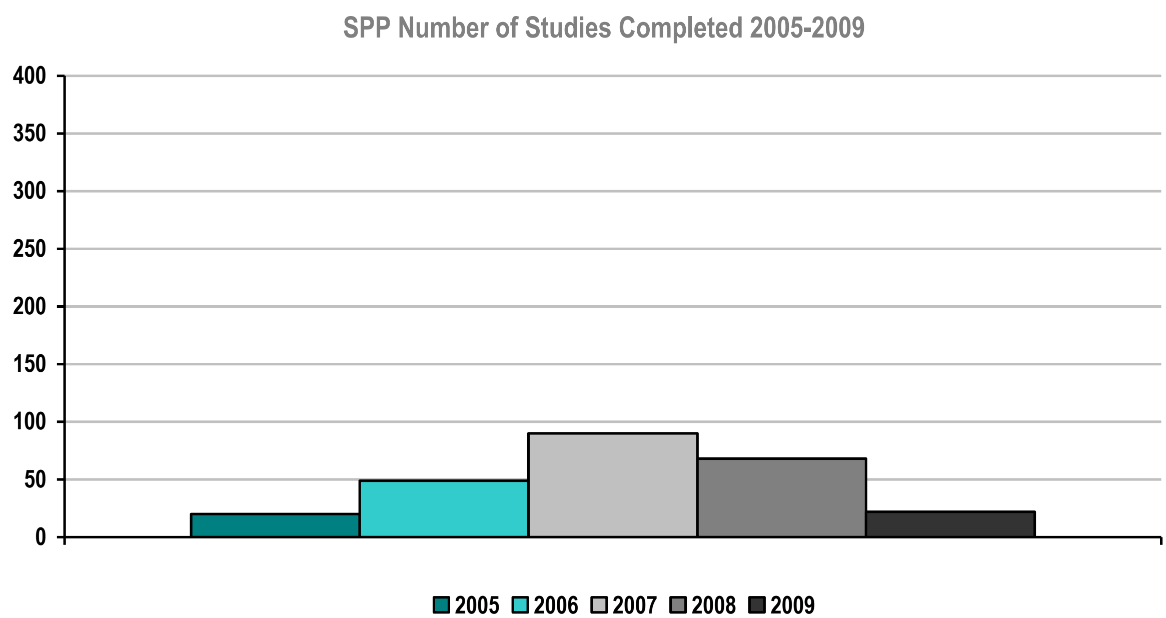
SPP Planned and Actual Reserve Margins 2005 – 2009

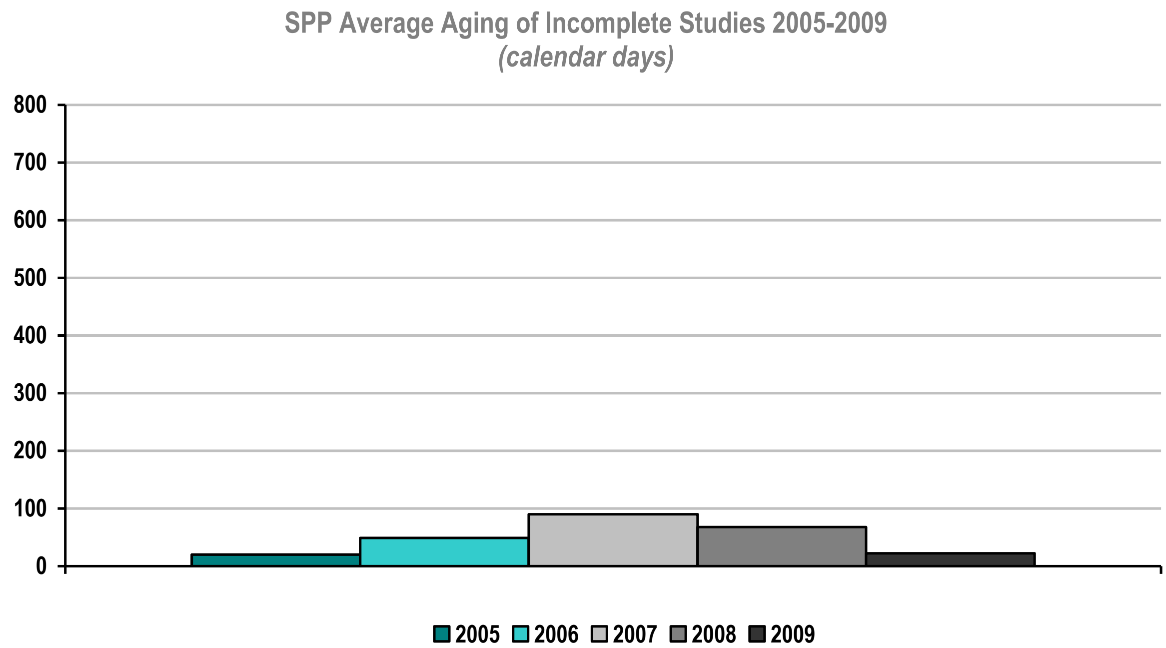


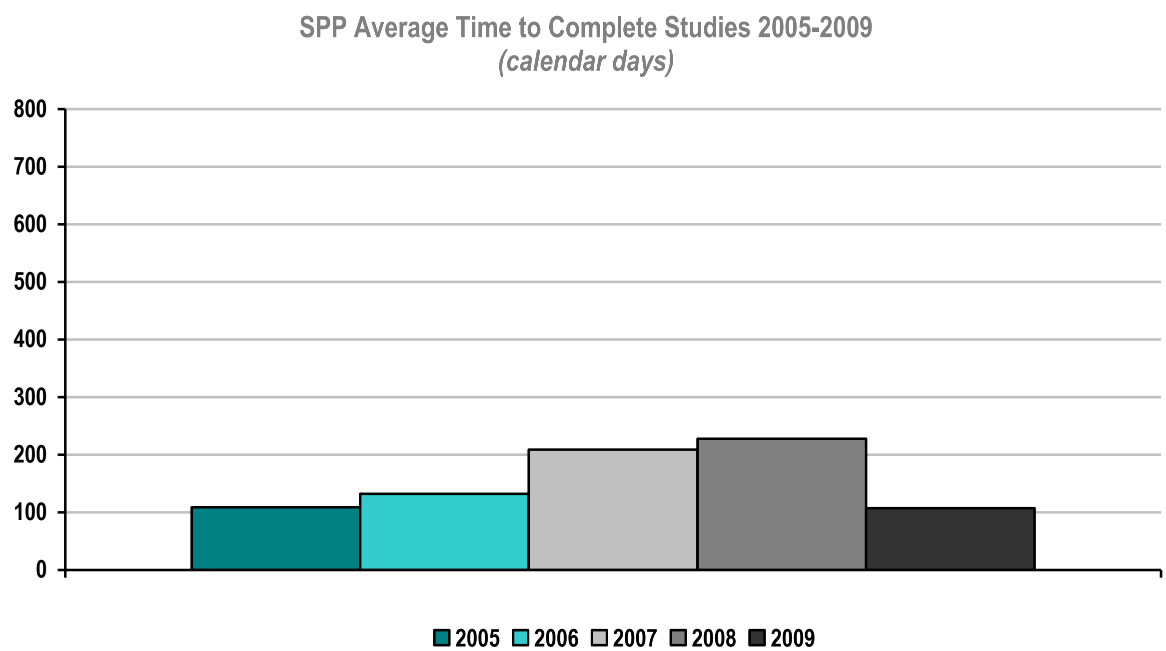
Bars Represent Planned Reserve Margins	Lines Represent Actual Reserves Procured

Interconnection / Transmission Service Requests









The generation interconnection process includes three potential types of studies – feasibility studies, system impact studies and facility studies. Feasibility studies assess the practicality and cost transmission system additions or upgrades required to accommodate the interconnection of the generating unit or increased generating capacity with the transmission system. System impact studies provide refined and comprehensive estimates of cost responsibility and construction lead times for new transmission facilities and system upgrades that would be required to allow the new or increased generating capacity to be connected to the transmission system in SPP. Facility studies develop the transmission facilities designs for any required transmission system additions or upgrades due to the interconnection of the generating unit and/or increased generating capacity.

Average Cost of Each Type of Study

	2005	2006	2007	2008	2009
Feasibility Studies	$9,264	$2,491	$6,495	$3,270	$2,888
System Impact Studies	$11,006	$16,280	$17,694	$14,942	$14,050
Facility Studies	$10,283	$7,290	$12,495	$16,960	*(Note 1)*

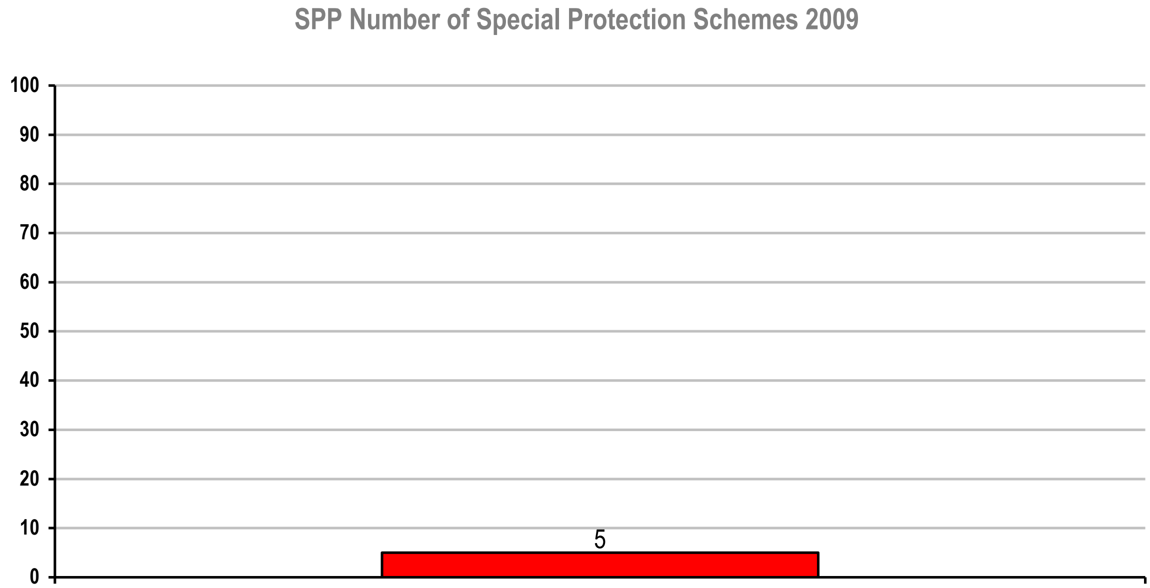
Note 1 – No facility studies were posted in 2009.

From the SPP 2009 Annual State of the Market Report:

> The high demand for generation interconnection over the past several years placed an enormous amount of stress on the generation interconnection process causing longer process times for requests and, as a result, a backlog in the queue. Other RTOs and ISOs also faced similar problems, so much so that the FERC held a technical conference on interconnection queuing practices on December 11, 2007 in response to concerns about the effectiveness of queue management. Then, following the technical conference, on March 20, 2008, the FERC issued an order directing the RTOs and ISOs to work with their stakeholders to improve their interconnection processes. SPP formed the Generation Queuing Task Force (GQTF) to help reform their process. SPP then filed its proposed reform measures, and the FERC issued an Order conditionally accepting SPP"s proposal, thus allowing them to implement the changes (effective June 2, 2009).
>
> SPP's new generation interconnection process was designed to improve processing times and give precedence to more serious projects that are further along in the development process. To attain these goals, SPP now has three interconnection queues rather than just one. That is, interconnection customers now choose to begin in one of three queues: (a) the Feasibility Study Queue, (b) the Preliminary Interconnection System Impact Study (PISIS) Queue, and (c) the Definitive Interconnection System Impact Study (DISIS) Queue. The Feasibility Queue and the PISIS Queue are not required for projects seeking interconnection in SPP. Instead, they provide an avenue for projects to acquire information that will aid them in deciding whether to move forward with their projects. These two queues require lower deposits and less strict milestones. The DISIS Queue, on the other hand, is required by SPP, and requires that the customers meet stricter milestones regarding project size, project location, project site, and in some cases, a buyer for the power that would be generated. The fact that the DISIS Queue requires strict milestones to be met discourages projects that are more speculative in nature from clogging the queue and allows those further along to have priority. Once a customer passes through the DISIS Queue, the next step is to complete a Facility Study. This study consists of SPP or the Transmission Owner specifying and estimating the cost of equipment, engineering, and construction to implement the interconnection. Upon completion of the Facility Study, an applicant may proceed to execute a Generation Interconnection Agreement.
>
> We believe the reform measures implemented by SPP are constructive because they address the recommendation from last year regarding the generation interconnection process. Specifically, in the 2008 State of the Market Report, Boston Pacific stated, "We recommend that instead of using a "first come, first served" method, SPP should allow advanced projects – projects that (a) have already secured a buyer for output or (b) have met certain milestones – to move past projects that are not as far along."25…at the end of 2009, 313 projects were currently active in the process or had executed an interconnection agreement, representing 60,768 MW of capacity. This is a significant amount of capacity. To put this number in perspective, the peak demand in SPP in 2009 was only 46,482 MW. Of all the projects in the queue, 16,744 MW of capacity have fully executed an interconnection agreement. Historically, as would be expected, not

all of the capacity that enters the interconnection process ends up being built. Going forward, we would expect that the capacity that is most likely to be withdrawn is that in the Feasibility Study Queue and the PISIS Queue as these queues are not required for interconnection and the requirements are less stringent than that of the DISIS Queue… 33,301 MW are in the Feasibility Study and PISIS Queues.

Special Protection Schemes



The SPSs in the SPP Region represent four long-term schemes and one temporary scheme. A Special Protection Systems (SPS) or Remedial Action Scheme (RAS) is designed to detect abnormal system conditions and take automatic pre-planned, coordinated, corrective action (other than the isolation of faulted elements) to provide acceptable system performance. SPS actions include among others, changes in demand (e.g., load shedding), generation, or system configuration to maintain system stability, acceptable voltages, or acceptable facility loadings. All reviews of facilities shall be for those used to monitor and control transmission facilities operated at 100kV or above.

There were no misoperations of SPSs in 2009 in SPP.

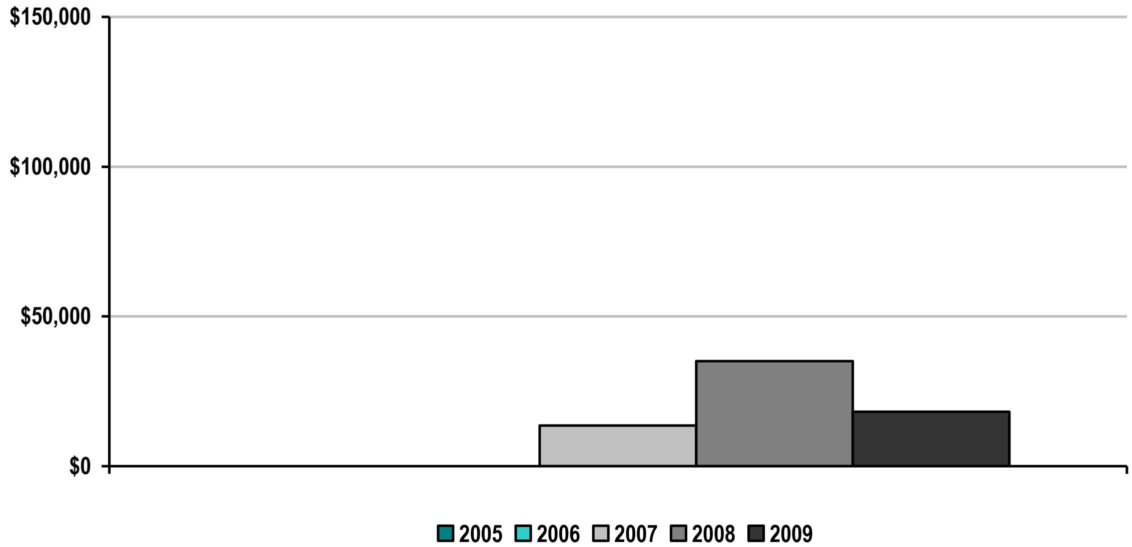
B. SPP Coordinated Wholesale Power Markets

The table below shows the split of the nearly $1.7 billion that was invoiced by SPP in 2009.

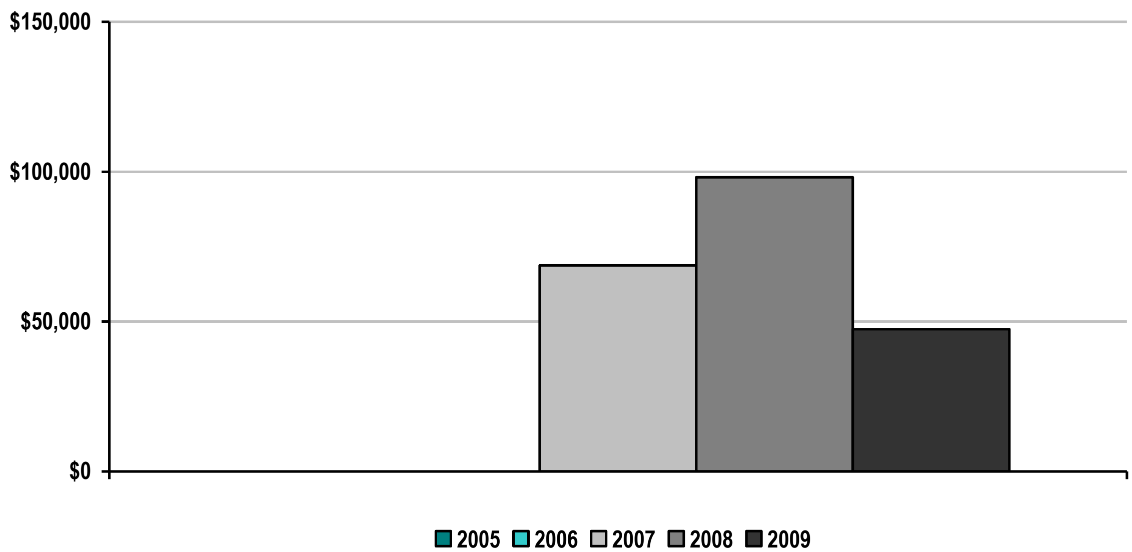
(dollars in millions)	2009 Dollars Billed	Percentage of 2009 Dollars Billed
Energy Imbalance Market	$1,144	67.5%
Transmission	$486	28.7%
SPP Admin Fee	$64	3.8%
Total	**$1,694**	**100.0%**

Market Competitiveness

SPP New Entrant Gas-Fired Combustion Turbine (CT) Net Generation Revenues 2005-2009



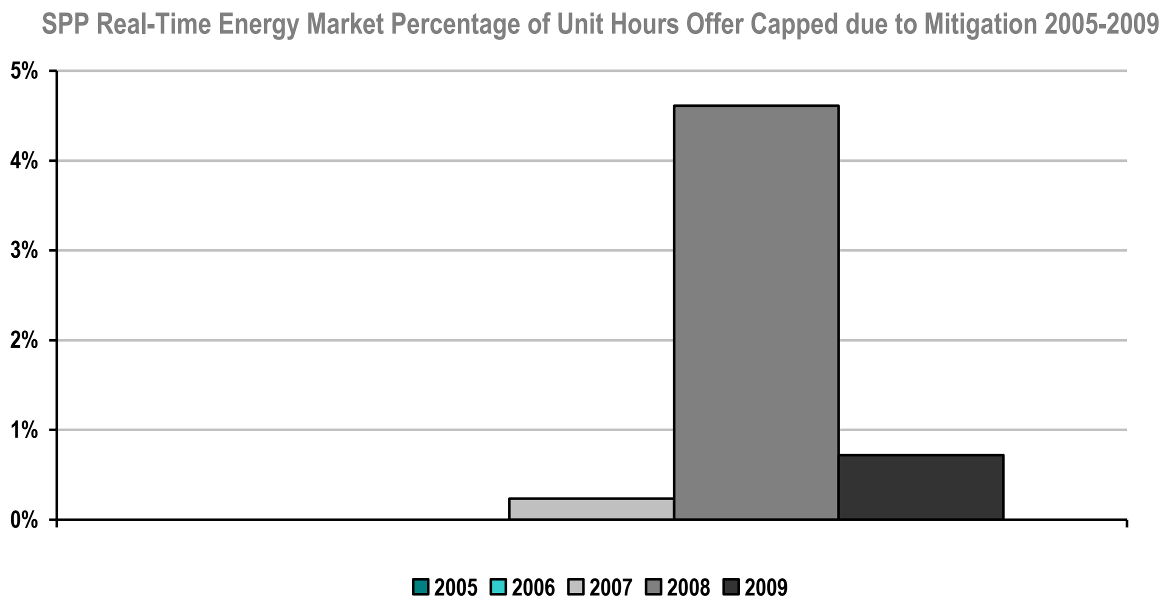
SPP New Entrant Gas-Fired Combined Cycle (CC) Net Generation Revenues 2005-2009



Net revenues in 2009 were not adequate to cover the fixed costs of either a combined cycle or a combustion turbine power plant in SPP. Net Revenue has dropped by about half from 2008 in large part because of the lower electricity prices making the margins tighter when the plants were run. So, while a combined cycle would still have run around 55% it no longer covered 60% of the fixed cost as it did in 2008, but rather less than 30%.

From the SPP 2009 State of the Market Report:

> In addition to testing revenue adequacy using SPP-wide hourly prices, we also wanted test whether prices in certain areas of SPP might be high enough to justify investment. To test this possibility, a Net Revenue calculation for two of the balancing authorities with the highest prices was calculated as those balancing authorities are most likely to show the need for new plants.
>
> … we conclude that the net revenue, even in these areas, was not adequate to cover the fixed costs of either a combined cycle or a combustion turbine power plant.



From the SPP 2009 State of the Market Report:

> Locational Imbalance Prices in SPP are calculated using, among other things, Market Participant offer curves. Because these offers are a major driver of prices, there is a potential concern with market power through submission of higher than appropriate offer prices. The FERC refers to this as Economic Withholding. To mitigate this, SPP has in place two different FERC-approved offer caps. These caps do not put a cap on prices, but rather, limit how high of an offer a Market Participant can submit.
>
> The offer cap that we term the "FERC Cap" is a hard offer cap. What we mean by this is it (a) is set at a constant level, (b) applies to all resources, and (c) applies at all times. The FERC Cap is considered to be a "safety net" against extreme cases of economic withholding. For the first three months of the EIS Market, the FERC Cap was set at $400/MWh. Since May 2007, the FERC Cap has been increased to $1,000/MWh. The cap was set at a tighter level for the first three months of market operation because of the uncertainty surrounding the start of the market.

SPP‟s other offer cap is termed the “SPP Cap.” Unlike the FERC Cap, the level of this cap (a) is resource specific and (b) varies depending upon market conditions. The SPP Cap is designed to balance mitigation and reliability; that is, it limits price spikes resulting from market power, but, at the same time, is set at a level high enough not to discourage new investment.

The following three characteristics of the SPP Cap illustrate how this is accomplished. First, the SPP Cap is levied only during times of transmission congestion, because absent congestion the SPP Market is structurally competitive. Second, it is only imposed on those resources that have the potential to wield market power; that is, it applies only to resources with a Generator to Load Distribution Factor (GLDF) of negative 5% or larger (more negative) and on other resources with negative GLDFs owned by that same company. Third, the SPP Cap is set at a level that will not discourage new investment. The SPP Cap reflects the total annual fixed and variable costs of a new peaking power plant with the fixed costs spread over the hours of congestion. Therefore, the more hours of congestion the tighter the cap becomes.

In addition, Market Competitiveness as measured by the Herfindahl-Hirschmann Index (HHI) is discussed in the 2009 Annual State of the Market Report:

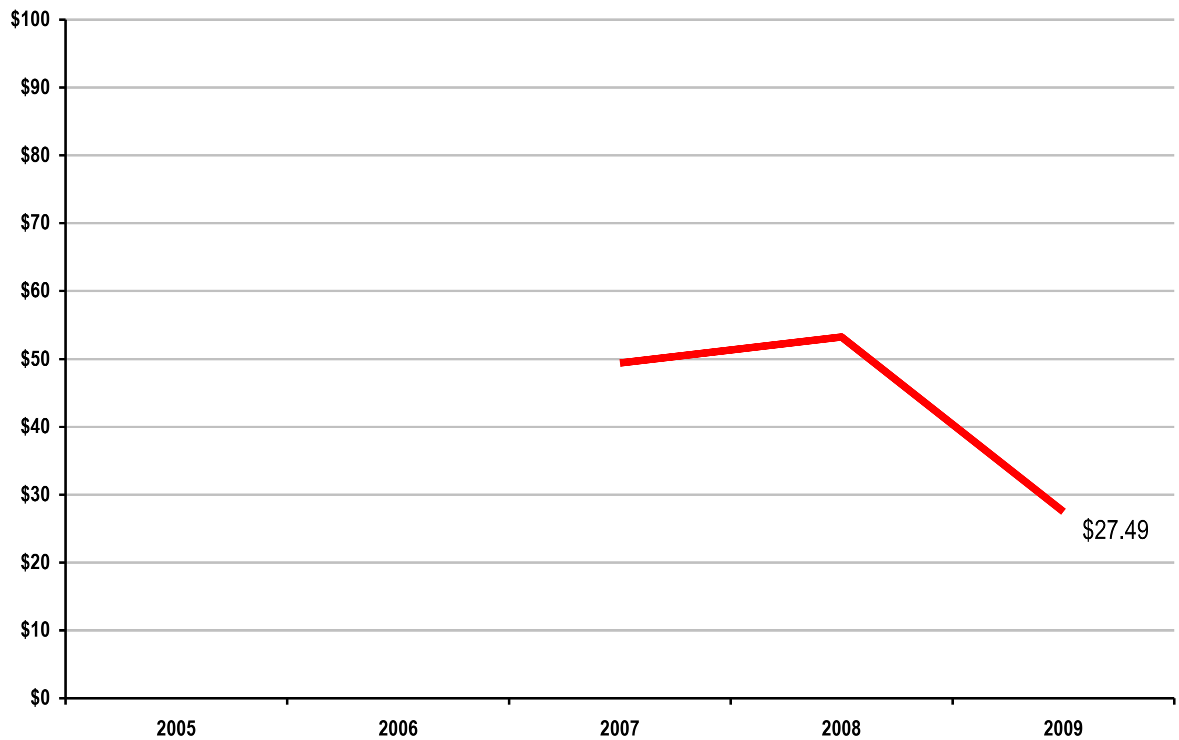
The Herfindahl-Hirschman Index (HHI) is a measure of competitiveness closely related to market shares. Some background on the HHI standard is useful. The U.S. Department of Justice has a three-part standard for HHIs when judging the competitive effect of mergers and acquisitions. An HHI at or under 1,000 is a „safe harbor‟ of sorts because the market is said to be unconcentrated. If, after a merger or acquisition, the HHI is at or below 1,000, it is generally thought that there is no competitive harm from the merger or acquisition; that is, the merger or acquisition does not make the exercise of market power more likely. An HHI between 1,000 and 1,800 is said to indicate moderate concentration. An HHI over 1,800 is said to indicate a highly concentrated market. The FERC uses these same standards when it assesses mergers and acquisitions. However, for market-based rate authority, the FERC uses a threshold of 2,500 for the HHI in one of its standards.

The HHIs… ranged from 1,106 in December to 1,604 in March. The peak capacity HHI for the year in total was 1,292, lower than that in 2008 (1,411). All of these HHI statistics fall within the moderately concentrated range, with the peak for year falling at the lower end of this range.

The SPP Annual State of Market Report can be accessed at http://www.spp.org/publications/SPP-2009-ASOM-Report.pdf

Market Pricing

SPP Average Annual Load-Weighted Wholesale Energy Prices 2005-2009 (1)
($/megawatt-hour)

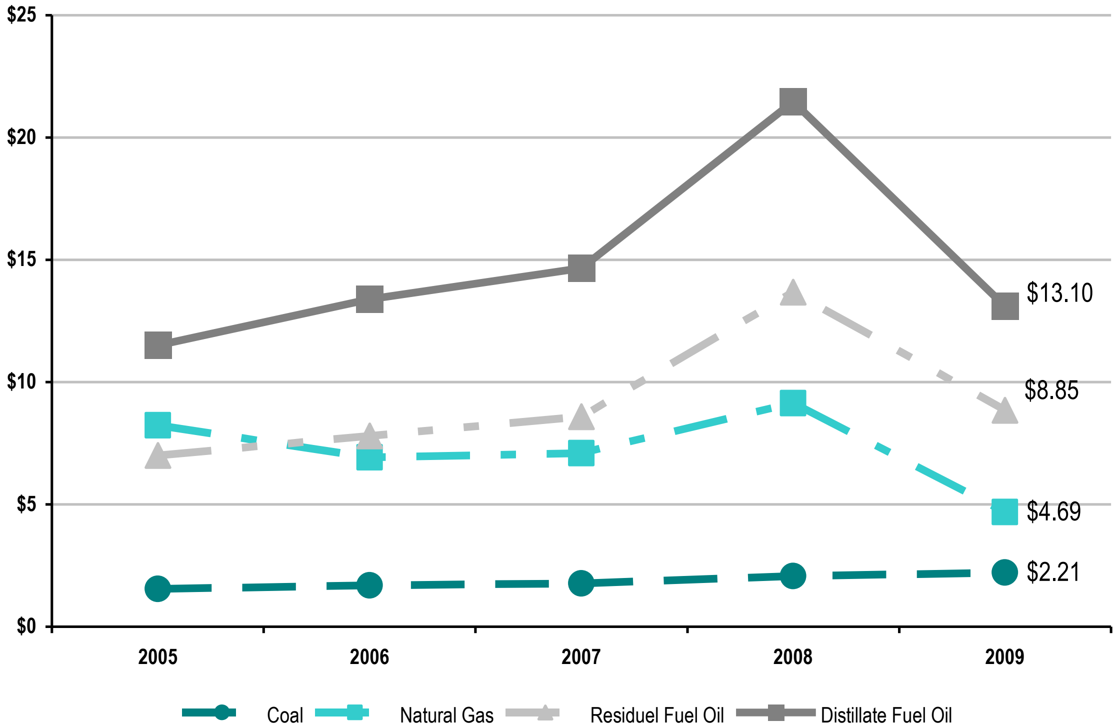


(1) SPP began operation of an Energy Imbalance Service market on February 1, 2007.

The SPP average load-weighted energy prices from 2007 – 2009 varied, due in most part to variances in fuel costs.

The chart on the following page from the U.S. Energy Information Administration is a visual representation of the fuel cost inputs from 2005 – 2009 that influenced the energy prices in SPP. The consistency in the trends between the preceding chart and several of the fuel cost trends on the chart on the following page are significant, because they illustrate the high correlation between wholesale energy prices and underlying fuel costs.

U.S. Nominal Fuel Costs 2005-2009
($ per million Btu)



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

SPP Average Annual Load-Weighted
Fuel-Adjusted Wholesale Spot Energy Prices 2005-2009
($/megawatt-hour)

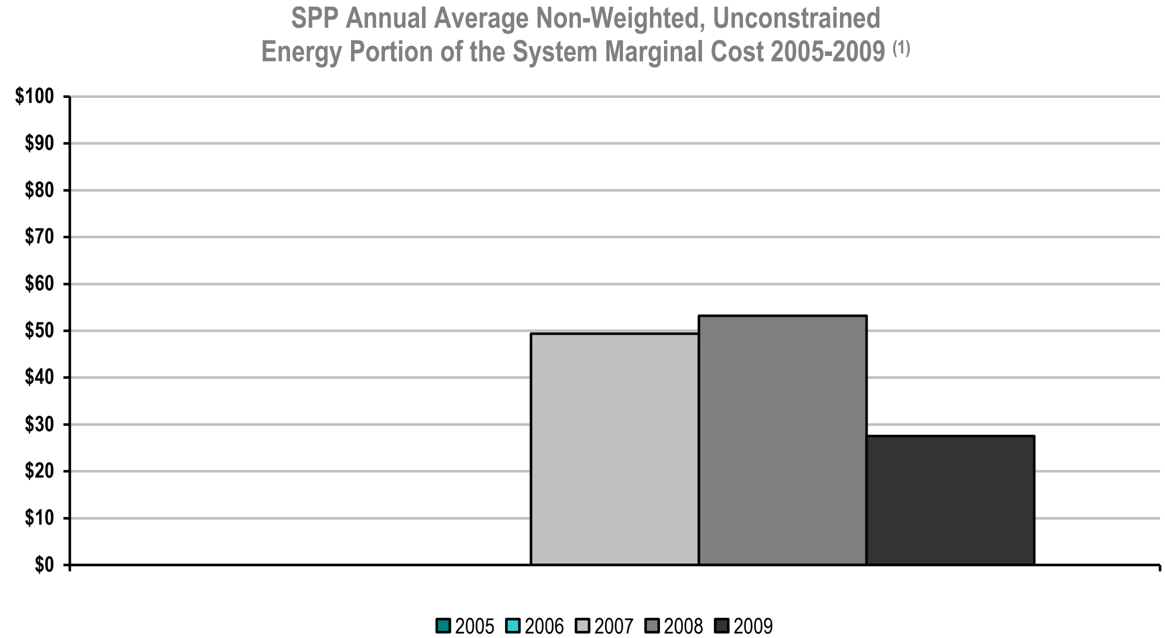
(1) SPP began operation of an Energy Imbalance Service market on February 1, 2007.

SPP's base year for fuel-cost references is 2007 as the SPP EIS Market launched on February 1, 2007.

SPP Wholesale Power Cost Breakdown
($/megawatt hour)

SPP only has a real-time energy imbalance service market.

Unconstrained Energy Portion of System Marginal Cost



(1) SPP began operation of an Energy Imbalance Service market on February 1, 2007.

The unconstrained energy portion of system marginal cost is the marginal price of maintaining balance in the economic dispatch ignoring transmission limitations. This trend chart shows the annual average marginal price of energy across SPP over all hours. The trend closely follows the trend of aggregate fuel prices from 2005 through 2009 which illustrates the fact that marginal energy price fluctuations are primarily driven by fuel prices.

Energy Market Price Convergence

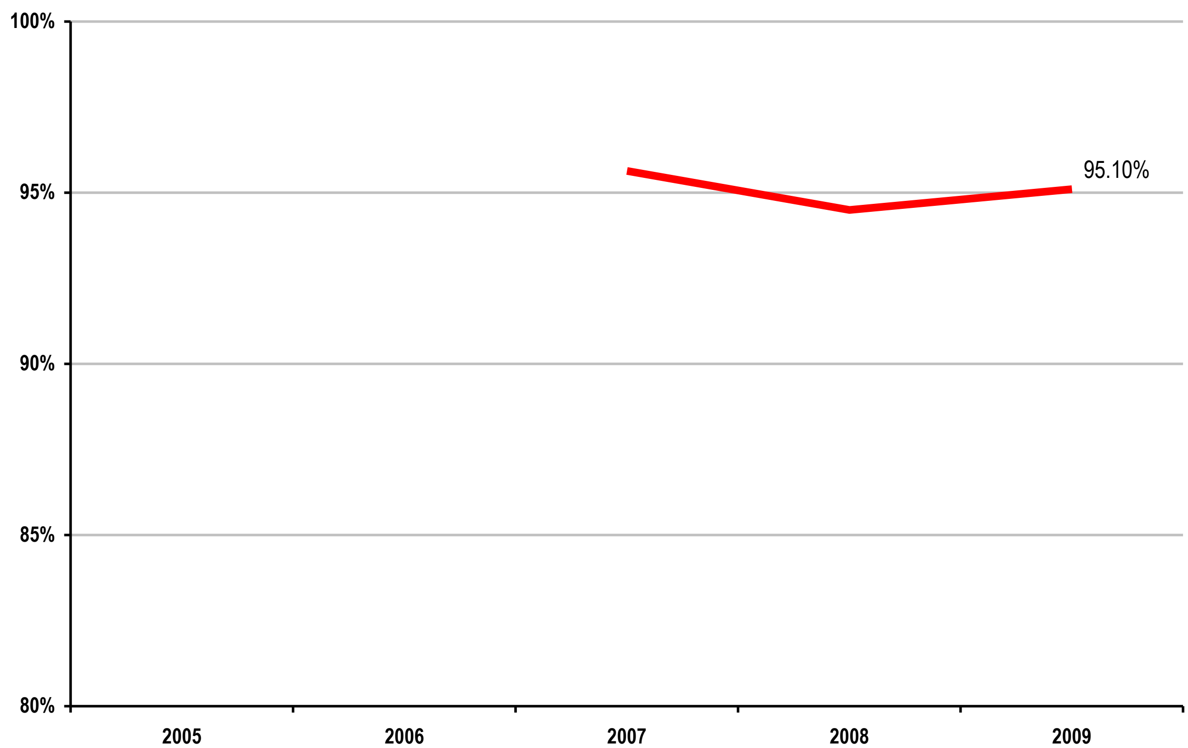
Data on price convergence in this section does not include SPP as SPP does not operate a day-ahead energy market.

Congestion Management

SPP does not operate a congestion hedging market.

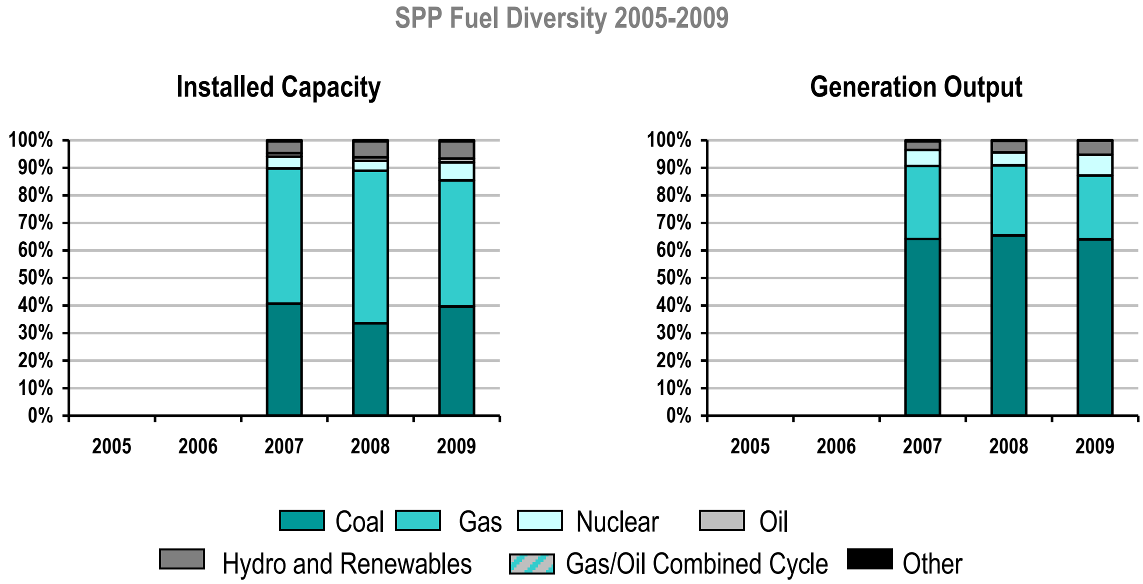
Resources

SPP Annual Generator Availability 2005 – 2009



Since the implementation of the Energy Imbalance Service market in February 2007, SPP generator availability continues to be strong. More in-depth tracking of generator availability is expected to be implemented in late 2010/early 2011 as part of the recently approved SPP Strategic Plan.

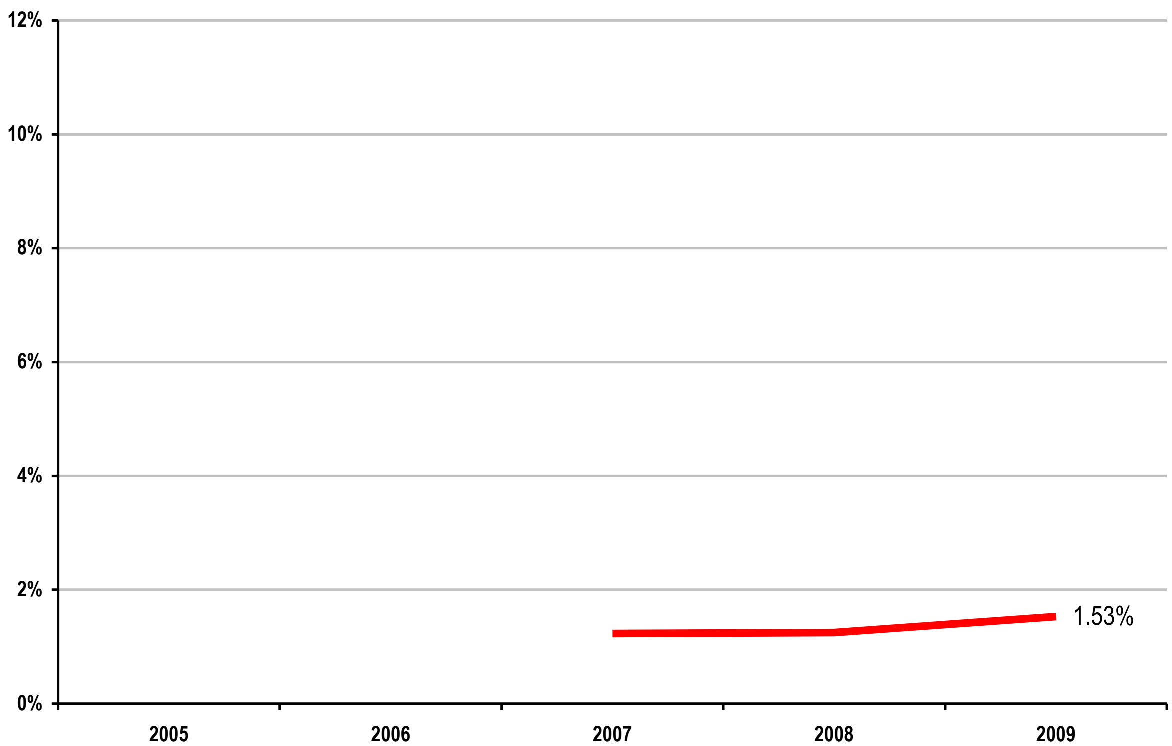
Fuel Diversity



Installed generation capacity in SPP is approximately 40% coal, 45% gas, 7% nuclear, 5% wind and less than 5% from all other fuel sources. Actual generation from baseload units (generally coal or nuclear) totals just over 72%, with gas accounting for 23%, and approximately 5% for other sources of fuel.

Demand Response

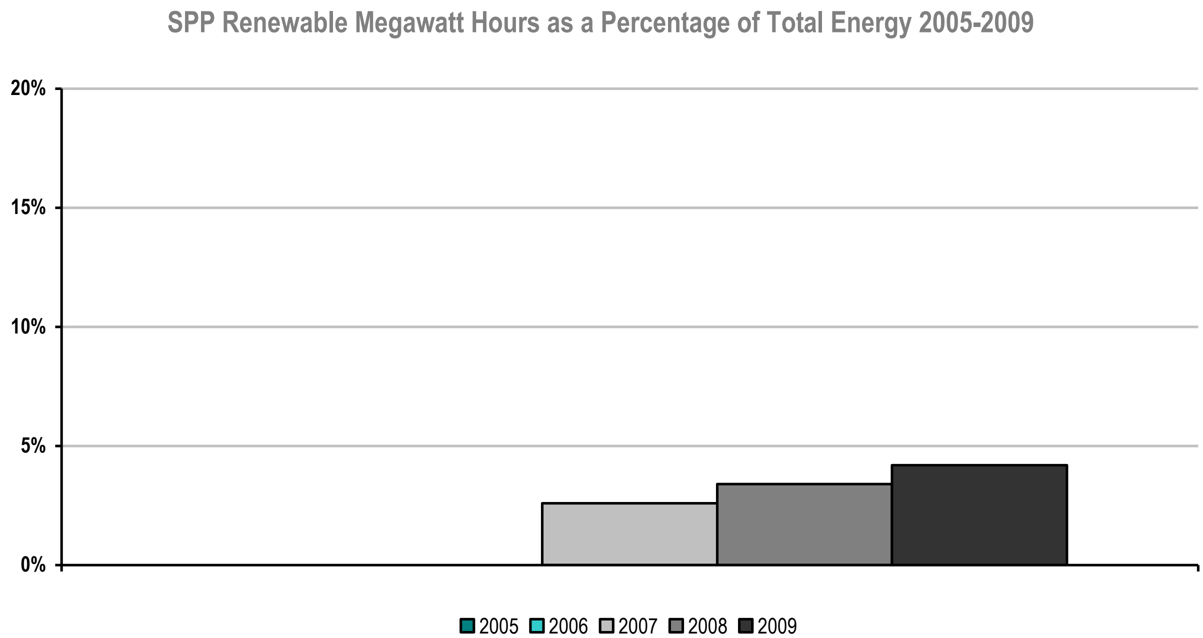
SPP Demand Response Capacity as Percentage of Total Installed Capacity 2005-2009

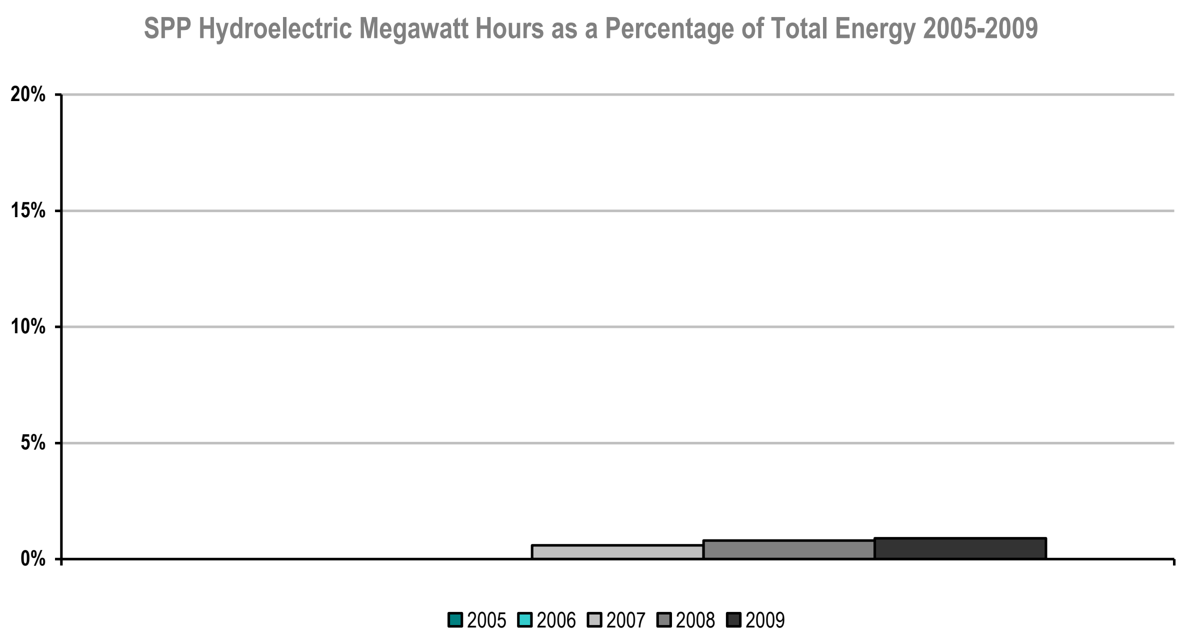


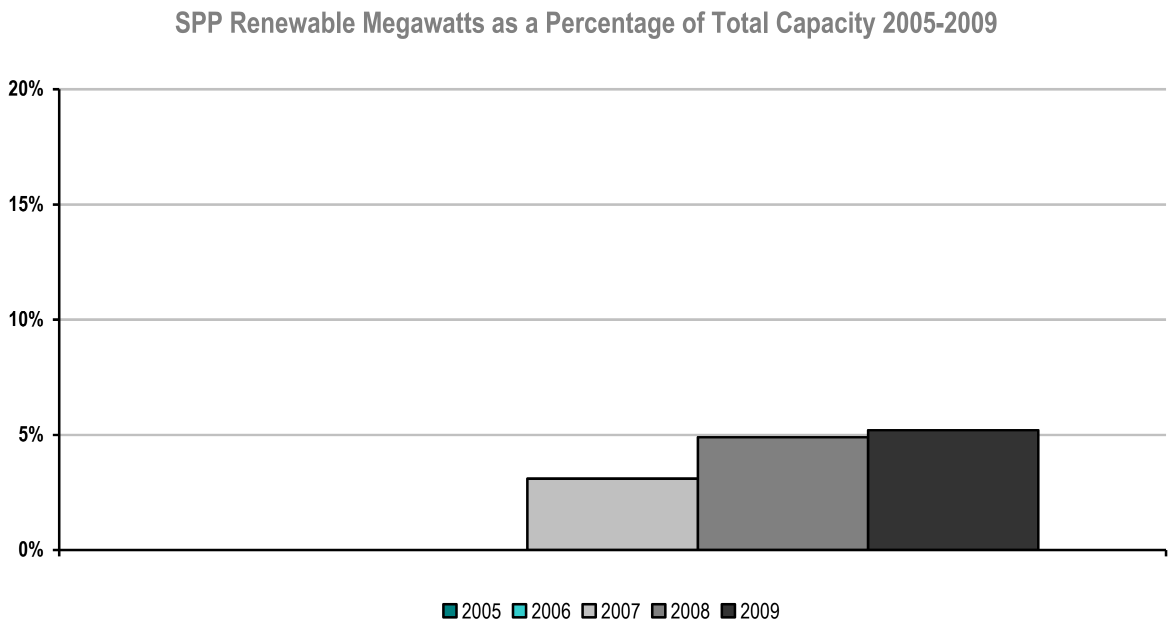
SPP Demand Response as a Percentage of Synchronized Reserve Market 2005-2009

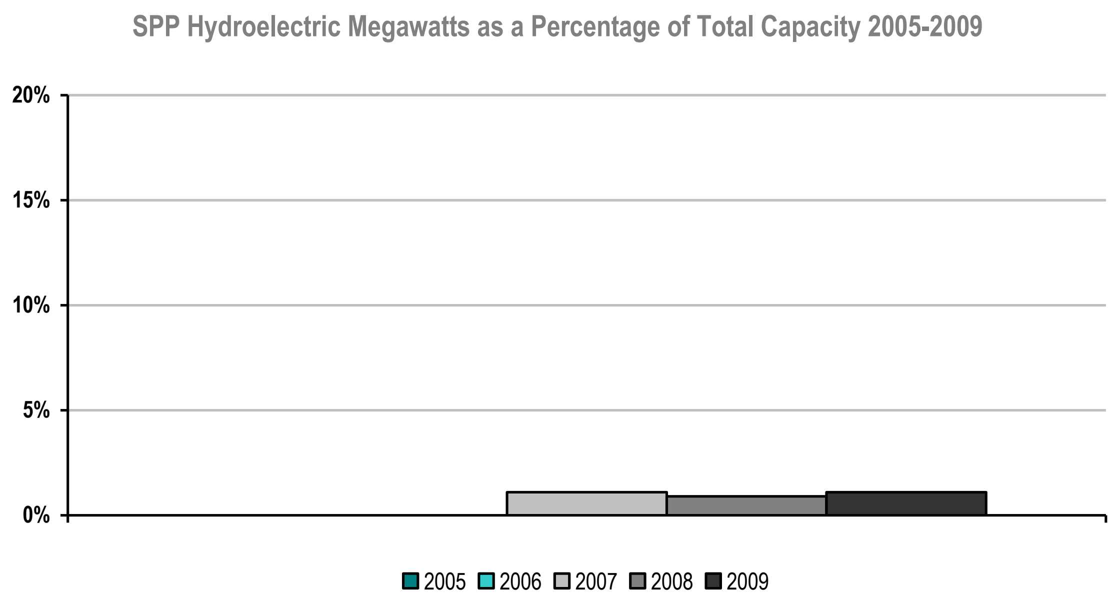
SPP does not operate a synchronized reserve market.

Renewable Resources







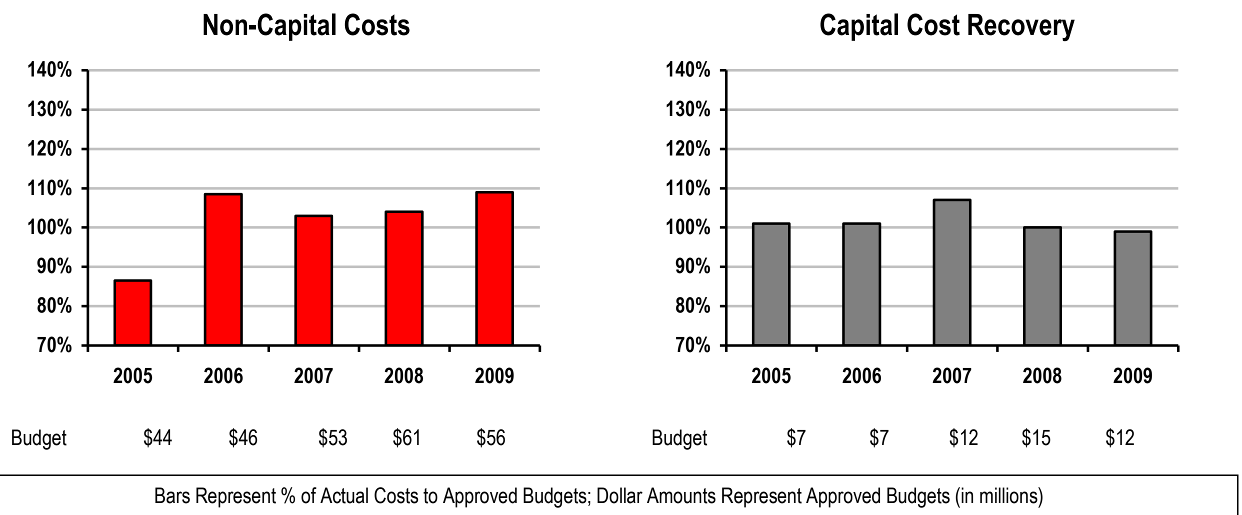


Energy capacity and production from renewable sources has been growing in SPP over the last several years, especially in wind renewables. Wind capacity has more than doubled since the implementation of the EIS market in February 2007, growing from 1,515 MW to 3,313 MW of nameplate capacity at the end of 2009.

C. SPP Organizational Effectiveness

Administrative Costs

SPP Annual Actual Costs as a Percentage of Budgeted Costs 2005-2009



SPP is a strong proponent of stakeholder involvement in the establishment and monitoring of its operating and capital budgets and the monitoring of its financial affairs. This level of involvement dates back to the start as a tight power pool and continues through today as a member-driven Regional Transmission Organization.

SPP's annual budget process culminates with the presentation of the budget to the Board of Directors. Providing some background, the SPP Board of Directors meets and acts in public, open sessions for all items except personnel issues and legal issues. Additionally, the SPP Board of Directors always meets in the presence of the Members Committee which is comprised of 15 representatives from SPP's membership. Finally, prior to all votes, the Members Committee is asked to indicate their position on each issue through a non-binding straw vote. This vote provides the Board with direct insights as to the positions of the membership on any issue.

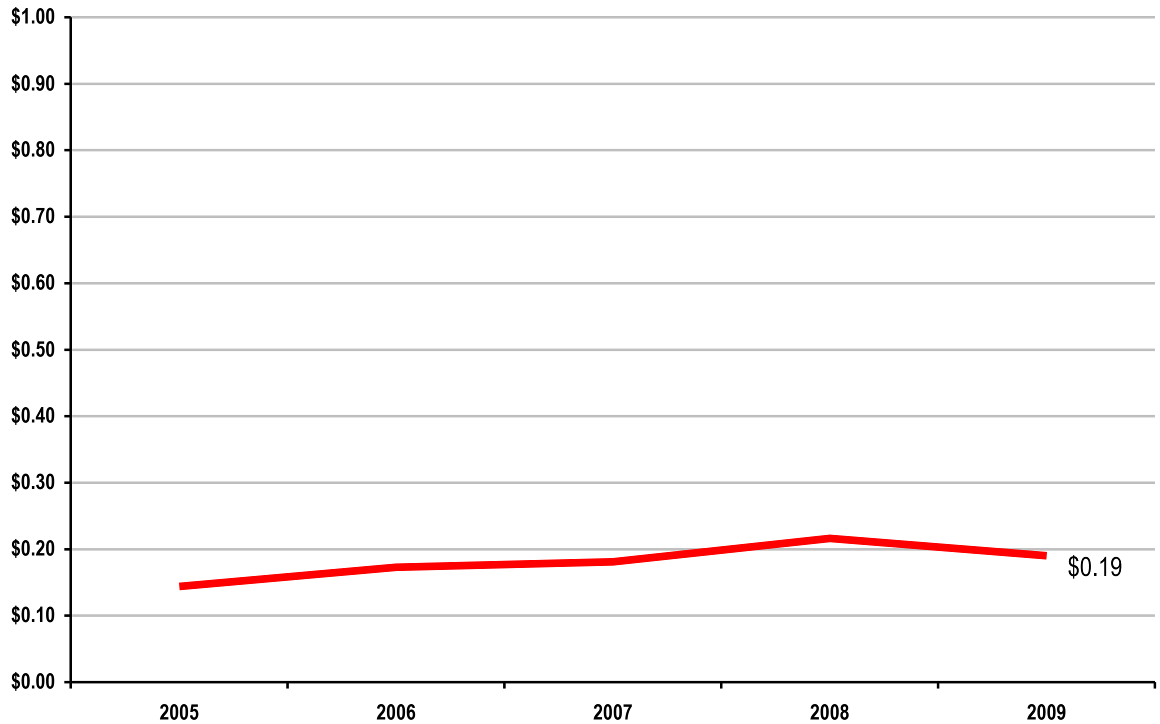
The chair of the SPP Finance Committee presents the budget to the SPP Board of Directors in open session at the Board's October meeting. Following the presentation of the budget, the Board of Directors solicits comments regarding the budget from all in attendance (even those who are not members of SPP have the ability to share their position on the budget). Following the dialogue, and assuming there is a motion to approve the budget and a second of that motion, the Board will ask the Members Committee representatives to vote through a show of hands either "yes", "no", or "abstain". Then, the Board members will enter their votes (the votes of the individual board members are via secret ballot and not shared individually).

SPP's budget has a long history prior to arriving at the SPP Board of Directors for action. The budget starts informally at the grassroots of the organization through the work of numerous stakeholder groups that define the products and services they desire SPP to perform. Major changes to SPP's products and services and business practices are approved at the Markets and Operations Policy Committee ("MOPC"). The MOPC is a full representation committee comprised of one representative from each member of SPP. The MOPC meets in open session and reports directly to the SPP Board of Directors.

Coincident with the grassroots efforts of SPP's Working Groups and MOPC, SPP's Strategic Planning Committee meets to determine the strategic direction of SPP. The Strategic Planning Committee is comprised of three members of the SPP Board of Directors and eight representatives from SPP's membership. The Strategic Planning Committee meets in open session and reports directly to the SPP Board of Directors.

SPP staff compiles the directions from the MOPC, Strategic Planning Committee, Board of Directors, and other groups to determine the direction of the company during the next fiscal year and the two years beyond. SPP staff determines the resources required to meet the goals of the organization and ultimately prepares a budget designed to meet those needs. This budget is formally presented to the SPP Finance Committee. The SPP Finance Committee is comprised of two members of the SPP Board of Directors and four representatives from the SPP membership. The Finance Committee meets in open sessions and actively seeks input from the stakeholder representatives on the Committee as well as from other interested parties. The Finance Committee diligently reviews the budget proposed by staff to ensure the resources identified are consistent with the goals and objectives of the organization and also are prudent and just. Once satisfied that the budget meets the needs of the organization the Finance Committee presents the budget to the SPP Board of Directors for approval.

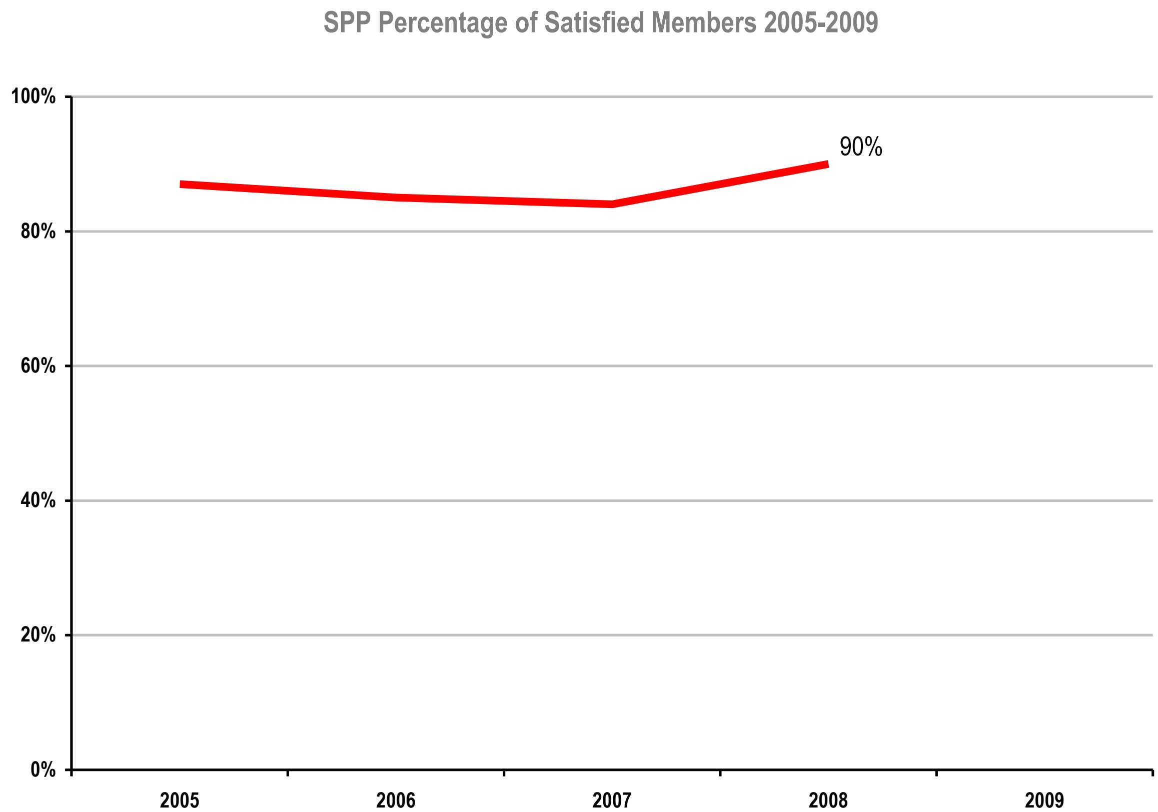
SPP Annual Administrative Charges per Megawatt Hour of Load Served 2005-2009
($/megawatt-hour)



The administrative costs per MWhr of load served data in the chart above should be reviewed in the context of the SPP annual load served as noted in the table below.

ISO/RTO	**2009 Annual Load Served** *(in terawatt hours)*
SPP	324

Customer Satisfaction



SPP's 2009 stakeholder satisfaction survey was an open-ended survey asking for comments on areas of satisfaction, dissatisfaction, and general comments. No numeric or scoring data was collected.

The percentage of satisfied members remains strong in SPP. The lowest year for member satisfaction was 2007, which was the year the Energy Imbalance Market was launched. As can be expected, with a new market coming online, there were many questions and concerns, mostly due to the unknown. Most significantly, however, the satisfaction percentage increased from 84% in 2007 to 90% in 2008 once everyone had experience in the new market.

Billing Controls

ISO/RTO	2005	2006	2007	2008	2009
SPP	Qualification for One Control Objective in SAS 70 Type 1 Audit	Qualification for Six Control Objectives in SAS 70 Type 2 Audit	Qualification for Six Control Objectives in SAS 70 Type 2 Audit	Qualification for Two Control Objectives in SAS 70 Type 2 Audit	Qualification for Two Control Objectives in SAS 70 Type 2 Audit

SPP billing controls have continued to evolve. While qualifications have continued to occur, improvement over time has been incremental and the severity of the exceptions leading to qualified opinions has decreased. Most importantly while qualifications have continued, there has been no negative settlement or financial impacts to SPP's members and customers. Corrective actions have been undertaken to produce future unqualified opinions.

D. Southwest Power Pool Specific Initiatives

Part of SPP's Value Proposition is being a relationship-based and member-driven organization. Over 500 stakeholders are involved in SPP's organizational structure of committees, working groups, and task forces. This member involvement drives SPP's decisions related to strategic vision, budget, transmission expansion, markets, and other corporate initiatives. In the last few years, SPP and its members have also worked closely with state regulators to successfully implement several innovative cost allocation initiatives. Because SPP works to gain consensus from its members and regulators, the organization has few protests on its filings. From 2006 to mid-2010, for 1154 filings there were only 74 protests and 1 hearing.

Regional State Committee Completion of Responsibilities

The SPP Regional State Committee (RSC) provides collective state regulatory agency input on matters of regional importance related to the development and operation of bulk electric transmission. The SPP RSC is comprised of retail regulatory commissioners from agencies in Arkansas, Kansas, Missouri, Nebraska, New Mexico, Oklahoma, and Texas. In 2004, the RSC adopted a transmission expansion cost allocation proposal, commonly referred to as "*Base Plan Funding"*, under which 33% of reliability upgrade costs would be allocated regionally. Following the adoption of Base Plan Funding, the RSC shifted its focus to cost allocation for economic upgrades, with a goal of promoting investment in transmission facilities that could reduce congestion and result in lower-cost wholesale electric supply to load-serving entities and ultimately end-use customers and in 2008, advanced the concept that permit one or more entities to bear a portion or all costs of building a transmission facility, called a "*Sponsored Upgrade*," in exchange for transmission credits for others' use of that facility and incrementally focusing on an approach to developing a portfolio of economic upgrades called the "*Balanced Portfolio*".

Most recently, the RSC adopted the "Highway/Byway" cost allocation methodology, a methodology which assigns costs of 300 kV+ "highway" upgrades 100% regionally. Costs of "byway" upgrades above 100 kV and below 300 kV are assigned 33% regionally and 67% zonally. "Byway" upgrades below 100 kV are allocated zonally.

With the exception of one Regional State Committee member voting "no" on the Highway/Byway cost allocation methodology, the other cost allocation proposals were approved unanimously.

Progress on Strategic Goals

SPP's Strategic Planning Committee determines the strategic direction of SPP. The Committee, comprised of three independent Board members and eight representatives from SPP's membership, meets in open session to develop strategic plans and to continually evaluate the progress of the organization in meeting those plans. Working with stakeholders and the Regional State Committee the organization has accomplished many strategic goals.

In 2005, the Board of Directors approved a strategic plan that included six primary areas of focus, including: markets development; transmission expansion; administrative processes; retention and addition of participants; enhanced regional planning; and, long-range planning. SPP has made significant progress toward these goals. The Energy Imbalance Service market was implemented in February 2007, and development is underway for the next phases of market development. In 2006, a refocus on certain areas and a desire to engage in a longer-term planning horizon yielded additional focus areas including: providing service on contract basis to increase revenue, further membership in SPP and enhance the quality of existing services, and; an effort to organize as a Regional Entity under the Electric Reliability Organization (ERO) to perform the delegated responsibilities related to the compliance, enforcement and development of mandatory reliability standards.

In 2010, the Committee established a strategic direction for SPP to position it to fulfill its mission statement over the next decade and beyond. The plan creates three foundational strategies: building a robust transmission system; developing efficient market processes; and, creating member value.

Member Involvement in Budget Approval

SPP is a strong proponent of stakeholder involvement in the establishment and monitoring of its operating and capital budgets and the monitoring of its financial affairs. The budget starts informally at the grassroots of the organization through the work of numerous stakeholder groups that define the products and services they desire SPP to perform and culminates with the presentation of the budget to the Board of Directors. Given this direction SPP staff develops the resources required to meet the goals of the organization and ultimately prepares a budget designed to meet those needs and formally presents it to the SPP Finance Committee. The SPP Finance Committee is comprised of two members of the SPP Board of Directors and four representatives from the SPP membership. The Finance Committee meets in open sessions and actively seeks input from the stakeholder representatives on the Committee as well as from other interested parties. The Finance Committee diligently reviews the budget proposed by staff to ensure the resources identified are consistent with the goals and objectives of the organization and also are prudent and just. Once satisfied that the budget meets the needs of the organization, the Finance Committee presents the budget to the SPP Board of Directors for approval.

Stakeholder Process in SPP

As noted above, because SPP works to gain consensus from its members and regulators, in the last 5 years, SPP has made over 1150 filings, of which only 74 were protested and 1 went to the hearing phase and that was a “paper” hearing.

Year	Filings by SPP	SPP Filings that were protested	SPP Filings that went to hearing
2006	167 (FERC only)	21	0
2007	176 (FERC only)	12	0
2008	258	14	0
2009	323	19	1
2010	230 (as of 7/23)	8	0