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.

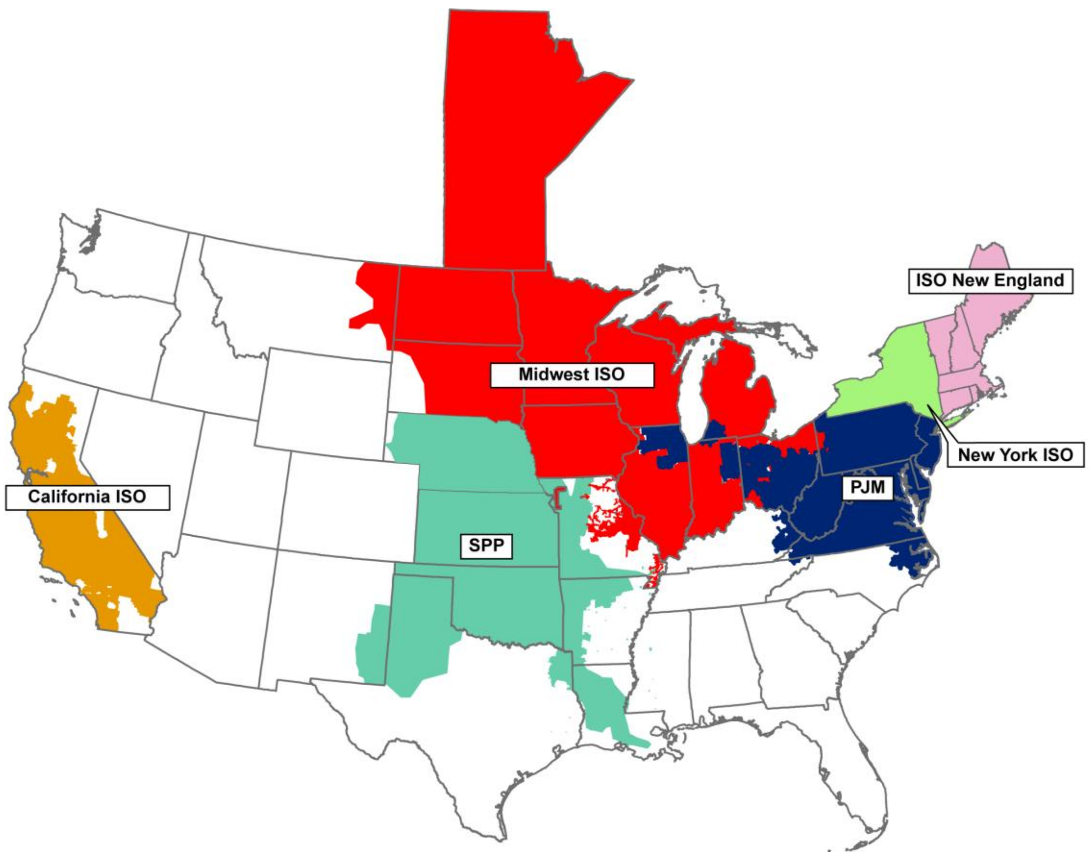
Emerging Themes

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.