From: McCormack, Brian
To: cheryl.lafleur@ferc.gov
Cc: Steven.Wellner@ferc.gov; Fisher, Travis
Subject: FYI
Date: Friday, April 14, 2017 7:14:09 PM
Attachments: Signed memo from S1 to the COS.pdf

Acting Chairman LaFleur,

Good evening. I wanted to share the attached memo that Secretary Perry signed out today.

I'd like to see if you have any time on Monday to get your thoughts and discuss.

I hope you have a great weekend.

Best,

Brian

(b) (6) cell

The Secretary of Energy
Washington, DC 20585

April 14, 2017

MEMORANDUM TO THE CHIEF OF STAFF

FROM: RICK PERRY Rick Perry
SECRETARY OF ENERGY

SUBJECT: STUDY EXAMINING ELECTRICITY MARKETS AND RELIABILITY

At the most recent G7 Energy Ministerial, my colleagues discussed the need for an energy transition utilizing greater efficiency and fuel diversity. There was also notable concern about how certain policies are affecting, and potentially putting at risk, energy security and reliability. It impressed upon me that the United States should take heed of the policy choices our allies have made, and take stock of their consequences.

A reliable and resilient electric system is essential to protecting public health and fostering economic growth and job creation. The U.S. electric system is the most sophisticated and technologically advanced in the world. Consumers utilize heating, air conditioning, computers, and appliances with few disruptions. Nonetheless, there are significant changes occurring within the electric system that could profoundly affect the economy and even national security, and as such, these changes require further study and investigation.

Baseload power is necessary to a well-functioning electric grid. We are blessed as a nation to have an abundance of domestic energy resources, such as coal, natural gas, nuclear, and hydroelectric, all of which provide affordable baseload power and contribute to a stable, reliable, and resilient grid. Over the last few years, however, grid experts have expressed concerns about the erosion of critical baseload resources.

Specifically, many have questioned the manner in which baseload power is dispatched and compensated. Still others have highlighted the diminishing diversity of our nation's electric generation mix, and what that could mean for baseload power and grid resilience. This has resulted in part from regulatory burdens introduced by previous administrations that were designed to decrease coal-fired power generation. Such policies have destroyed jobs and economic growth, and they threaten to undercut the performance of the grid well into the future. Finally, analysts have thoroughly documented the market-distorting effects of federal subsidies that boost one form of energy at the expense of others. Those subsidies create acute and chronic problems for maintaining adequate baseload generation and have impacted reliable generators of all types.

Each of these and other related issues must be rigorously studied and analyzed, and the Department of Energy is uniquely qualified for the task. The results of this analysis will help the federal government formulate sound policies to protect the nation's electric grid. In establishing these policies, the Trump Administration will be guided by the principles of reliability, resiliency, affordability, and fuel assurance—principles that underpin a thriving economy.

I am directing you today to initiate a study to explore critical issues central to protecting the long-term reliability of the electric grid, using the full resources and relationships available to the Department. By Wednesday, April 19, 2017, present to me an implementation plan to complete this study 60-days from that date, that will explore the following issues:

- The evolution of wholesale electricity markets, including the extent to which federal policy interventions and the changing nature of the electricity fuel mix are challenging the original policy assumptions that shaped the creation of those markets;
- Whether wholesale energy and capacity markets are adequately compensating attributes such as on-site fuel supply and other factors that strengthen grid resilience and, if not, the extent to which this could affect grid reliability and resilience in the future; and
- The extent to which continued regulatory burdens, as well as mandates and tax and subsidy policies, are responsible for forcing the premature retirement of baseload power plants.

I have committed to the President that this report will not only analyze problems but also provide concrete policy recommendations and solutions. I also committed to the President that I will do everything within my legal authority to ensure that we provide American families and businesses an electric power system that is technologically advanced, resilient, reliable, and second to none.

From:	MinesingerK@gtlaw.com
To:	Fisher, Travis
Cc:	(b) (6)
Subject:	Checking in
Date:	Friday, April 21, 2017 1:30:25 PM
Attachments:	image001.png

Travis – I hope you are well. It's been awhile since we talked during the transition. I read an article that said you have been tasked with working on the Secretary's directive regarding baseload power. That's fantastic; it's such an important issue. Would you have a few minutes this afternoon or Monday to touch base? I can talk whenever it's convenient for you – just let me know. Thanks – Ken

Kenneth Minesinger
Co-Chair, Energy Practice Group
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From: Glazer, Craig
To: Fisher, Travis
Subject: FW: PJM Information for Your Consideration
Date: Tuesday, May 09, 2017 2:48:38 PM
Attachments: PJM RESPONSE TO DOE SECRETARY ENERGY APRIL 14 MEMORANDUM.doc (3).docx

Travis:

Here's what I sent to David Meyer in Pat Hoffman's office outlining and providing links for the specific PJM documents referenced.

I will forward a second e-mail with some data I sent along from the ISO/RTO Council on its markets analysis and information re: retirements of generation.

Many thanks.

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From: Glazer, Craig
Sent: Wednesday, May 03, 2017 4:08 PM
To: 'DAVID.MEYER@HQ.DOE.GOV'
Subject: PJM Information for Your Consideration

David:

Attached you will find a document which provides web links and reproduces key passages from 'shelf documents', (all in the public domain) which address the issues raised by the Secretary in his April 14 Memorandum.

I will be forwarding some references to relevant IRC documents under separate cover.

Let me know if you have any questions or need additional information from PJM.

Thank you.

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PJM provides the following documents and information for the Department's consideration as it prepares its Report in response to the Secretary's Memorandum of April 14, 2017.

At the outset, PJM believes clarification of terms would be helpful. The Memorandum states in part:

"Baseload power is necessary to a well-functioning electric grid."

The term "baseload power" has evolved over time. Notably, NERC's Glossary of Terms does not refer to any particular source of generation when defining "baseload."[1] Bulk electric system reliability is based on matching generation to load on a continuous basis. As a result, investment signals are as critical for ensuring the development of peaking and mid-merit units as they are for baseload.[2]

"Baseload" can generally be thought of as those units which operate the great majority of hours of the year to meet load requirements. Given the reduction in gas prices, we have seen a noticeable inversion in the types of units which clear in the market in the off-peak hours and thus fit the traditional notion of "baseload." Specifically, due to low energy prices and the overall efficiency of the units, combined cycle natural gas units are dispatched as baseload with coal units more often being cycled and thus dispatched in what has traditionally been deemed "mid-merit" units. A detailed description of this trend over time can be found in the 2016 State of the Market Report for PJM produced by the PJM Independent Market Monitor. That document can be accessed at:
http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2016/2016-som-pjm-sec3.pdf

Specifically, page 92 of that Report states:

"***Generation Fuel Mix****. In 2016, coal units provided 33.9 percent, nuclear units 34.4 percent and natural gas units 26.5 percent of total generation. Compared to 2015, generation from coal units decreased 3.3 percent, generation from natural gas units increased 18.3 percent and generation from nuclear units increased 0.2 percent."*

Marginal Resources*. In the PJM Real-Time Energy Market, in 2016, coal units were 44.9 percent of marginal resources and natural gas units were 43.8% of marginal resources. In 2015, coal units were 51.7 percent and natural gas units were 35.5 percent of the marginal resources."*

With these thoughts in mind, PJM submits the following information to assist the Department in response to the issues raised in the April 14 Memorandum.

April 14 Memorandum: Issue #1---"The evolution of wholesale electricity markets, including the extent to which federal policy interventions and the changing nature of the electricity fuel mix are challenging the original policy assumptions that shaped the creation of those markets.

In 2016, PJM undertook an extensive analysis comparing the results from moving to an organized competitive market structure as compared to those parts of the country which remained

[1] The NERC Glossary of Terms defines "baseload" as: *The minimum amount of electric power delivered or required over a given period at a constant rate."*

[2] In fact, capacity markets in the eastern RTOs are designed, among other things, to reflect the fact that a peaking unit that operates only a few hours a year may not achieve its needed revenues solely through depending on those hours when it is actually called upon to meet high load demands.

with a vertically integrated structure. The report analyzed the impacts on investment in generation as well as customer costs and thus addressed whether the 'original policy assumptions that shaped the creation of those markets' have produced the intended results.[3] That report can be accessed at:

http://www.pjm.com/~/media/library/reports-notices/special-reports/20160505-resource-investment-in-competitive-markets-paper.ashx

Relevant passages from the report's Executive Summary are highlighted as follows:

"The questions raised with regard to decisions and outcomes related to the changing nature of the supply portfolio in PJM can be summarized as:

> *Can we rely on PJM's organized wholesale electricity market to efficiently and reliably manage the entry and exit of supply resources as external forces create tremendous uncertainty and potential industry transformation?*

The goal of this paper is to answer this question….

Entry of New Resources

The markets do well in attracting new entry at an efficient cost. Competition lowers costs and excludes technologies with inappropriately high costs. Markets transparently evaluate the economics of proposed projects, and projects that are uneconomical are not built. Importantly, in the market paradigm risk is shouldered and managed by the supplier, not the customer. A financial analysis based on tools of modern portfolio theory was undertaken to try to quantify (in broad terms) the value customers receive in avoiding such risk. This analysis indicates that allowed returns on equity in regulated generation are notably higher than the models would predict given the lower risks relative to merchant investors.

Strong evidence supports the belief that markets are providing adequate returns to incent new generation investment where warranted. For the Base Residual Auctions in PJM's capacity market occurring between 2010-2015, approximately 24,000 MW of new generation were cleared and committed. Markets are driving innovation in many technologies resulting in lower capital and operating costs. That such a large volume of new investment is occurring demonstrates that investors see opportunities for sufficient returns.

Innovation

PJM markets provide an accommodating, transparent environment that allows any project or technology to demonstrate its value to the customer based on the combination of capital costs, risks and value, which collectively determine whether a project will flourish or fail fairly based on its merit. Markets do well in pricing operational attributes and innovations of new technologies – generation, storage or demand side – that provide the desired attributes more effectively and economically. Many investment risks can be efficiently managed through financing structures and through hedging tools available in PJM markets and through instruments that have evolved in the greater "ecosystem" of supporting bilateral and exchange-traded commodity markets.

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[3] In response to Issue #3, PJM provides specific statistics relevant to the impact of the renewable production tax credit on pricing in the PJM market and its consequent impact on nuclear units.

Exit of Resources

No evidence suggests the PJM markets inadequately compensate legacy units and thus are forcing a premature retirement of economically viable generators. PJM's markets are producing prices that are efficiently and reliably signaling the exit of uneconomic legacy resources and the entry of efficient, new resources. A statistical examination of retirement data in PJM compared to regulated environments refutes any assertion that PJM markets are prematurely retiring economically viable generation. When faced with similar capital investment requirements, generator retirements are roughly comparable in market and regulated environments.

In PJM, the decision to shutter a generating station, perhaps before the end of its operationally useful life or the term of its operating permit, is based on market forces – more precisely the owner's assessment of whether the market will provide revenues sufficient to meet the facility's going-forward operating costs. PJM's markets produce transparent prices that provide clear benchmarks for evaluating the continuing economic viability of generation, even for utilities and regulators in those PJM states that have retained a traditional, rate-base regime.

Markets and Public Policy

Realizing the "investment efficiency" advantages of PJM markets can require policymakers to accept tough choices and trade-offs because efficient market outcomes may inflict harm to other policy objectives. Policymakers must weigh these trade-offs but should understand that pursuing individual actions that defeat efficient market outcomes can thwart effective operation of the market. One likely result is that the market no longer can be relied upon to efficiently and effectively provide price signals to achieve efficient and reliable resource entry and exit. This paper acknowledges the widespread existence of subsidies of all sorts that influence PJM market outcomes.

PJM's mission is to provide for a reliable and efficient wholesale power supply. The markets it designs and administers to accomplish this mission do not necessarily promote and may even conflict with other valid public policy interests that state and federal lawmakers and regulators may pursue to meet environmental, social and political interests distinct from the markets' singular mission to deliver the most cost-efficient resources needed to serve customers reliably.

Although PJM markets are efficiently and reliably handling a changing resource mix resulting from forces currently affecting the industry, PJM's continuing ability to deploy market forces to handle this responsibility is threatened if actions taken by lawmakers and regulators to promote other policy interests are pursued in a way that materially distorts price outcomes in PJM's capacity and energy markets.

April 14 Memorandum ***Issue #2---"Whether wholesale energy and capacity market are adequately compensating attributes such as on-site fuel supply and other factors that strengthen grid resilience and, if not, the extent to which this could affect grid reliability and resilience in the future";***

In 2014 events which occurred during the Polar Vortex highlighted issues surrounding generator performance and the availability of on-site fuel supply. PJM recognized that its then-existing capacity market rules needed to be strengthened both to:

a. highlight through performance requirements, the need for generating units which serve as designated capacity resources to have firm fuel available in order to meet their performance requirements; and

b. ensure that there is a clear price signal valuing the attribute of on-site fuel or firm fuel availability.

PJM's proposal did not seek to manage the fuel practices of the generators but instead used both increased compensation as well as performance requirements (with penalties for non-performance) in order to incent the procurement of firm fuel supplies. Units such as nuclear and coal which, by definition, already had on-site fuel were able to receive the additional compensation under PJM's Capacity Performance construct and have that attribute recognized through the enhanced Capacity Performance product.

Links to PJM's submittal to FERC and FERC's Order re: same is listed below:

Capacity Market CP filing - http://pjm.com/media/documents/etariff/FercDockets/1368/20141212-er15-623-000.pdf

Energy Market CP Filing - http://pjm.com/media/documents/etariff/FercDockets/1369/20141212-el15-29-000.pdf

Initial Order - http://pjm.com/Media/documents/ferc/2015-orders/20150609-er15-623-000-el15-29-000-and-er15-623-001.pdf

Rehearing Order - http://pjm.com/Media/documents/ferc/orders/2016/20160510-er15-623-002-et-al.pdf

In addition, PJM prepared an analysis of the costs and benefits of its proposal. That analysis can be found at:

http://pjm.com/~/media/committees-groups/committees/elc/postings/capacity-performance-cost-benefit-analysis.ashx

PJM has seen specific physical improvements undertaken by generation owners ranging from installation or expansion of dual fuel capability to securing additional firm natural gas supplies from multiple pipeline sources.

Moreover, the Independent Market Monitor for PJM analyzes the net revenue generating units receive as compared to their avoidable costs as a measure of the overall profitability of generation units by fuel type. The net revenue calculation has oscillated over the years given its high dependency on fuel prices. The net revenue calculation for 2016 can be found at the 2016 State of the Market Report at: http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2016/2016-som-pjm-sec7.pdf

Given rising fuel prices in 2017 for both coal and natural gas, the most recent net revenue calculations broken down by fuel type will be released shortly and will be provided to the DOE as a supplement to this submittal.

April 14 Memorandum ***Issue #3---"The extent to which continued regulatory burdens, as well as mandates and tax and subsidy policies, are responsible for forcing the premature retirement of baseload power plants."***

Tax and subsidy policies have had an impact on the economics of certain types of generation. Specifically, the wind and solar production tax credits have had the most significant impact on nuclear generation. Nuclear and wind generation are competing to clear in the market during off-peak hours when wind resources are the strongest and load is reduced. In those off-peak hours, the production tax credit has created an incentive for renewable resources to bid negative prices as they must run in order to receive their payment from the federal treasury.[4] Since 2014, PJM has seen prices go negative at nuclear unit buses in approximately 2,176 hours representing 14.3% of all off-peak hours.[5]

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[4] As a result of recent federal legislation, the production tax credit has been converted into a direct payment of cash option to reflect that the market for tax credits has been reduced in recent years.

[5] The Independent Market Monitor for PJM has outlined its own views on the harmful impact of subsidies. Its analysis can be found at http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2016/2016-som-pjm-sec1.pdf

From: Glazer, Craig
To: Fisher, Travis
Subject: FW: ISO RTO Council Market Analyses
Date: Tuesday, May 09, 2017 2:50:22 PM
Attachments: IRC---2016 FERC Staff Common Metrics Report - Performance Metrics for RTOs....pdf
IRC---2015 IRC Whitepaper Resource Investment in Golden Age of Energy Finance.pdf

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And here's the second set of documents from the joint ISO/RTO Council (made up of all the North American RTOs).

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From: Glazer, Craig
Sent: Thursday, May 04, 2017 5:03 PM
To: 'DAVID.MEYER@HQ.DOE.GOV'
Subject: ISO RTO Council Market Analyses

David:

As promised, I am sending you two documents that the ISO/RTO Council produced which are in the public domain and which may be of interest to you.

The first is an independent report that the IRC commissioned analyzing the RTO markets and the requirements of investors as they consider investing in resources based on each RTOs market design. That document, which analyzes investor's priorities and views relative to each of the RTO markets is attached and also can be found at:
http://www.isorto.org/Documents/Report/201505_IRCResourceInvestmentReport.pdf

The second document is the latest RTO metrics report which we file at FERC. Pages 42-48 of that document provides information on the fuel diversity within each RTO.

I hope you will find these helpful.

Let me know if you need additional information.

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STAFF REPORT

Common Metrics Report

Docket No: AD14-15-000

Performance Metrics for Regional Transmission Organizations, Independent Systems Operators, and Individual Utilities for the 2010-2014 Reporting Period

Federal Energy Regulatory Commission • August 2016
(Revised October 2016)

2016

Common Metrics Report: Performance Metrics for Regional Transmission Organizations, Independent System Operators, and Individual Utilities for the 2010-2014 Reporting Period

Staff Report

Federal Energy Regulatory Commission

August 2016 (Revised October 2016)

This report is a product of the staff of the Federal Energy Regulatory Commission. The opinions and views expressed in this paper represent the preliminary analysis of the Commission staff. This report does not necessarily reflect the views of the Commission.

Acknowledgements

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Preface and Caveats

This report is the latest activity in an initiative originally designed to examine the performance and benefits of Regional Transmission Organizations (RTO) and Independent System Operators (ISO). The initiative arose in response to a 2008 Government Accountability Office (GAO) report recommending that the Federal Energy Regulatory Commission (FERC) do more to track the performance and benefits of RTO and ISO markets.[1] The previous report in this initiative, issued in August 2014, established a set of common performance metrics for evaluating the performance of RTOs and ISOs and individual utilities in regions outside of RTOs and ISOs (referred to hereinafter as "non-RTOs and ISOs," "non-RTO and ISO respondents," or "non RTO and ISO utilities") in areas where these entities perform identical functions. These performance metrics cover both reliability and system operations activities.

The source of data for this report is primarily information collected from RTOs and ISOs and non-RTOs and ISOs under Information Collection FERC-922, "Performance Metrics for ISOs, RTOs and Regions Outside ISOs and RTOs" (Office of Management and Budget Control No. 1902-0262). Other market-specific data were voluntarily submitted by the six Commission-jurisdictional RTOs and ISOs. Consistent with past practice in this initiative, respondents submitted information on a voluntary basis. Six RTOs and ISOs responded,[2] along with seven non-RTO and ISO utilities. Commission staff greatly appreciates the efforts of those who contributed information to this initiative.

The report contains analyses, presentations, and conclusions that, unless otherwise noted, are based on or derived from the data provided by respondents, but do not necessarily reflect the positions or conclusions of the respondents themselves. Furthermore, the opinions and views expressed in this report do not necessarily represent those of the Commission, its Chairman, or individual Commissioners, and are not binding on the Commission. Any errors are those of Commission staff.

---

[1] U.S. Gov't Accountability Off., GAO #08-987, Gov't Accountability Off. Report to the Committee on Homeland Security and Government Affairs, U.S. Senate; Electricity Restructuring: FERC Could Take Additional Steps to Analyze Regional Transmission Organizations' Benefits and Performance (2008) (2008 GAO Report).

[2] The six Commission-jurisdictional RTOs and ISOs responded. These are as follows: California Independent System Operator Corporation (CAISO); ISO New England Inc. (ISO-NE); Midcontinent Independent System Operator, Inc. (MISO); New York Independent System Operator, Inc. (NYISO); PJM Interconnection, L.L.C. (PJM); and Southwest Power Pool, Inc (SPP).

The metrics used in this report pertain to both RTOs and ISOs and non-RTOs and ISOs. However, several limitations preclude all but the most basic observations about the metrics submitted by RTOs and ISOs relative to those submitted by non-RTOs and ISOs. While the intent behind these metrics is to compare areas in which RTOs and ISOs and non-RTOs and ISOs perform identical functions, Commission staff notes that there are significant differences in the scale of operations performed by the largest RTOs and ISOs as compared to non-RTO and ISO respondents with relatively smaller service territories (e.g., PJM's footprint covers territory in 13 states and the District of Columbia,[3] whereas Arizona Public Service Company's territory covers 11 counties in Arizona).[4] These data limitations and differences must be carefully considered when comparing metrics-related information submitted by RTOs and ISOs and non-RTOs and ISOs. As such, Commission staff has largely avoided drawing these types of comparisons.

In addition, these metrics do not capture some of the potential benefits that are difficult to isolate and measure, e.g., benefits created by providing opportunities for input by a broad range of stakeholders.

[3] California Independent System Operator Corporation; ISO New England Inc.; Midcontinent Independent System Operator, Inc.; New York Independent System Operator; PJM Interconnection, L.L.C.; and Southwest Power Pool, Inc. October 30, 2015 Filing, at 279 (October 2015 RTO and ISO Metrics Report).

[4] Arizona Public Service Company November 5, 2015 Filing, at 1 (November 2015 APS Metrics Report).

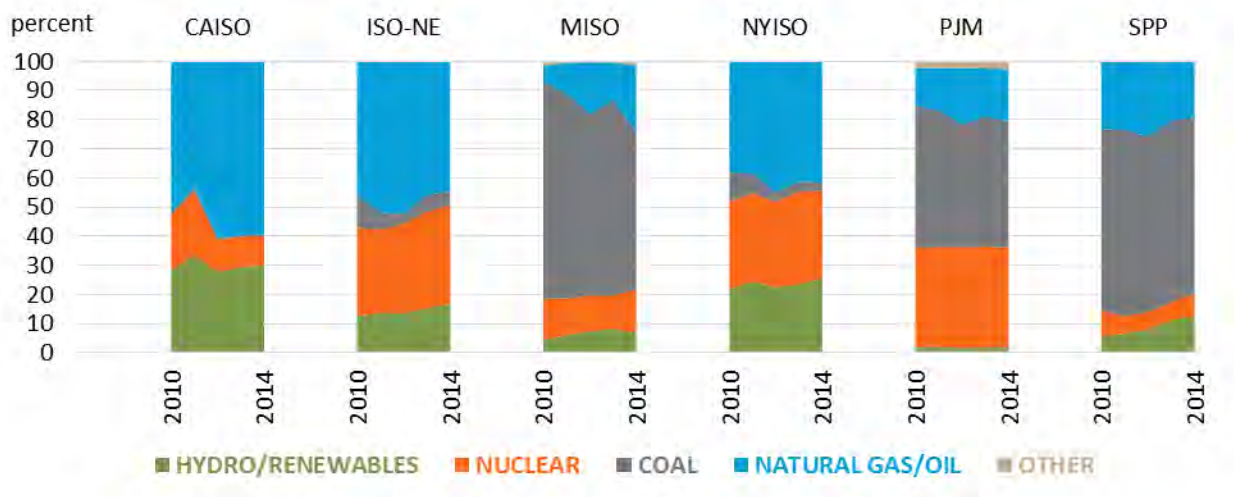
Executive Summary

This report contains a review of performance metrics for RTOs and ISOs as well as non-RTO and ISO utilities for the period from 2010-2014.

Key Insights Regarding RTOs and ISOs

RTOs and ISOs managed the dispatch of energy from a diverse set of generating fuel-types from 2010-2014. RTOs and ISOs manage the scheduling and deployment of different resource types through day-ahead and real-time energy markets, which operate as market clearing auctions that establish commitment and dispatch schedules subject to system constraints. RTOs and ISOs report managing the dispatch of energy from varying fuel sources from 2010-2014; as seen in Figure 1, most RTOs and ISOs report managing an increasing share of energy from renewable generation and fluctuations in the relative amounts of energy provided by natural gas-fired generation and coal-fired generation.

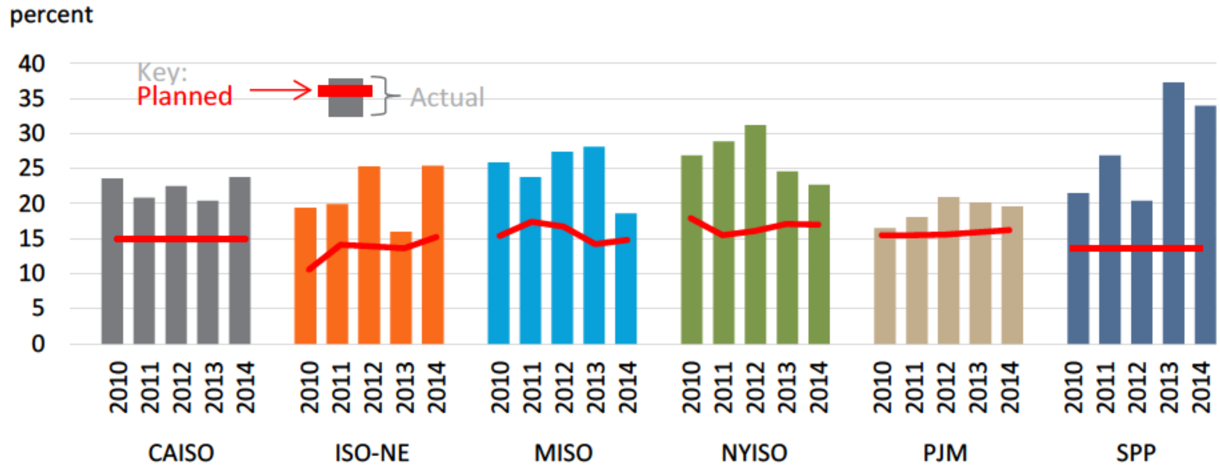
Figure 1: Share of total generation by fuel type, 2010-2014.



Source: Commission staff based on information collection FERC-922.

RTO and ISO regions maintained adequate power supplies, in accordance with planned reserve margins from 2010-2014. Planning reserves ensure that there is a low probability of loss-of-load due to inadequate supply. As shown in Figure 2, RTOs and ISOs report capacity in excess of planned reserve levels in each year from 2010-2014.

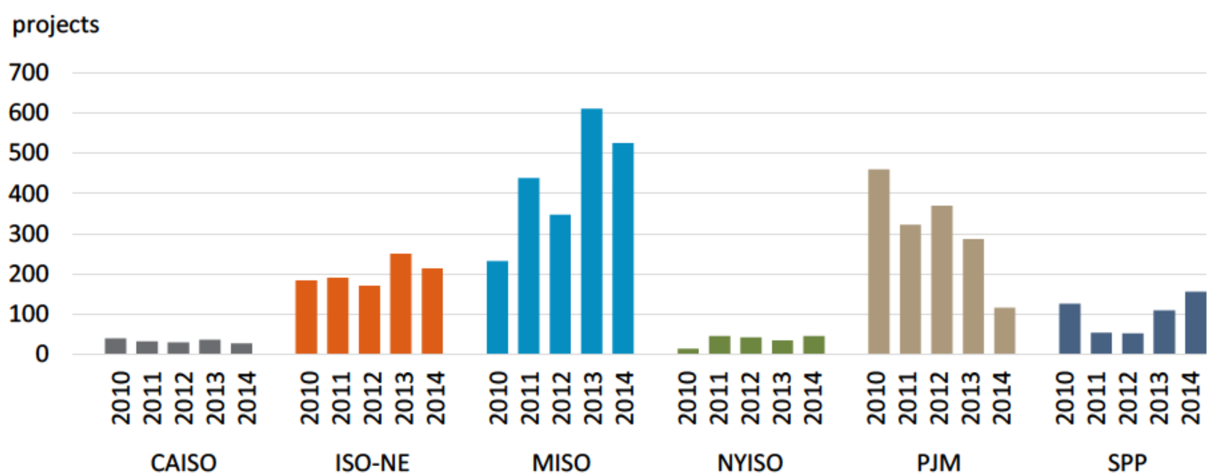
Figure 2: RTOs and ISOs planned and actual reserve margins, 2010-2014.



Source: Commission staff based on information collection FERC-922.

RTOs and ISOs report the approval of a large number of transmission projects for reliability purposes from 2010-2014. Adequate transmission is an essential element of a reliable power system. RTOs and ISOs evaluate transmission projects for reliability purposes in their planning processes. As shown in Figure 3, all RTOs and ISOs report the construction of transmission projects for reliability purposes between 2010 and 2014, helping to ensure a reliable grid.

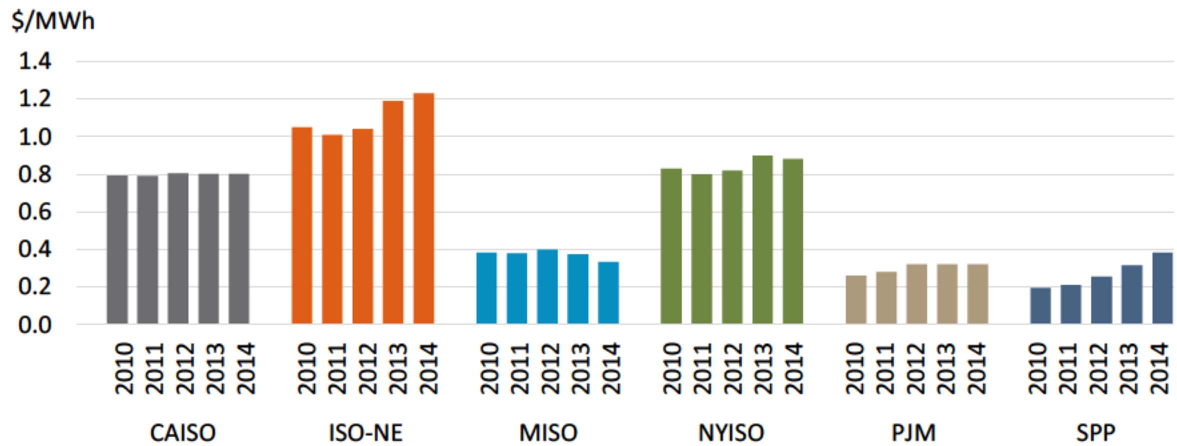
Figure 3: Number of transmission projects approved for construction for reliability purposes, 2010-2014.



Source: Commission staff based on information collection FERC-922.

Administrative costs per megawatt-hour varied across RTOs and ISOs from 2010-2014. Administrative charges (including both capital and non-capital costs) measured as per megawatt-hour of load allows for comparison across markets of different sizes. As shown in Figure 4, RTOs and ISOs report a range of administrative charges per megawatt-hour of load. In some cases, these charges were relatively flat between 2010 and 2014, while in other cases the charges increased, in nominal terms. PJM and MISO, two of the largest RTOs, report relatively low administrative charges per megawatt-hour. Administrative costs typically represent a small percentage of the total cost of wholesale power.[5]

Figure 4: Annual per-megawatt-hour administrative costs, 2010-2014.



Source: Commission staff based on 2015 RTO and ISO Metrics Report.
Note: Values are expressed in nominal dollars per megawatt-hour.

[5] *See infra* pp. 51-52.

I. Introduction and Overview

This report presents Commission staff's review of data relating to performance metrics that measure activities in which RTOs and ISOs and non-RTO and ISO utilities performed identical functions during the 2010-2014 reporting period. Additionally, the report presents Commission staff's review of certain metrics data submitted by RTOs and ISOs that are specific to RTO and ISO market and administrative functions.

During 2015, six RTOs and ISOs submitted performance metrics data in a joint report in Docket No. AD14-15-000. Additionally, seven utilities in non-RTO and ISO regions submitted performance metrics data on a voluntary basis.

Commission staff collected the 30 common metrics from RTOs and ISOs and non-RTO and ISO utilities under information collection FERC-922, "Performance Metrics for ISOs, RTOs and Regions Outside ISOs and RTOs" (OMB Control No. 1902-0262). Information Collection FERC-922 includes 30 common metrics used to measure the performance of certain reliability and system operations in areas where RTOs and ISOs and non-RTO and ISO respondents perform identical functions. The reliability performance metrics measure both day-to-day operations and long-term reliability. The system operations metrics measure certain aspects of operational efficiency. Table 13 in Appendix A lists the 30 common metrics.

Table 1 lists the entities who submitted the metrics data reflected in this report and the acronyms used to refer to these entities in the remainder of this report.

Table 1: Respondents submitting performance metrics reports for 2010-2014.

RTOs and ISOs	non-RTOs and ISOs
California Independent System Operator Corporation (CAISO)	Arizona Public Service Company (APS)
ISO New England Inc. (ISO-NE)	Duke Energy Carolinas, LLC (DEC)
Midcontinent Independent System Operator, Inc. (MISO)	Duke Energy Progress, LLC (DEP)
New York Independent System Operator, Inc. (NYISO)	Duke Energy Florida, LLC (DEF)
PJM Interconnection, L.L.C. (PJM)	Louisville Gas and Electric Company and Kentucky Utilities Corporation (LG&E/KU)
Southwest Power Pool, Inc. (SPP)	PacifiCorp (PAC) (note that some metrics are reported separately for PacifiCorp – East (PACE) and PacifiCorp – West (PACW))
	Southern Company (SOU)

This report contains the following sections:

- Background, which briefly summarizes the history of the common metrics initiative;
- Common Metrics Review, which reviews the metrics data submitted by RTOs and ISOs and non-RTO and ISO respondents;
- Other Metrics, which reviews data responsive to metrics specific to RTO and ISO markets;
- Appendix A, which contains detailed descriptions of the 30 common metrics; and
- Appendix B, which summarizes recent studies that have quantified certain RTO and ISO benefits that the metrics do not cover.

II. Background

In May 2007, Senators Joseph I. Lieberman and Susan M. Collins of the U.S. Senate Committee on Homeland Security and Governmental Affairs requested that the GAO investigate RTO and ISO costs, structure, processes, and operations.[6] In a September 2008 Report to the U.S. Senate Committee on Homeland Security and Governmental Affairs, the GAO recommended that FERC work with RTOs, ISOs, stakeholders and other interested parties to develop standardized measures to track the performance of RTO and ISO operations and markets; report on those measures; and interpret how the measures communicate evidence of RTO and ISO benefits or performance concerns.[7]

Commission staff developed the common metrics initiative in response to the 2008 GAO Report. The evolution of the initiative included Commission staff taking steps to meet five objectives. These objectives, as described in FERC's Fiscal Year 2009-2014 Strategic Plan, include: (1) developing appropriate operational and financial metrics for RTOs and ISOs; (2) exploring and developing appropriate operational and financial metrics for non-RTO and ISO utilities; (3) establishing appropriate common metrics

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[6] The Senators made this request in a May 21, 2007 letter to the GAO. The letter expressed the Senators' concern that RTOs and ISOs may not be living up to their full potential with respect to improving efficiencies and reducing costs, and that RTOs and ISOs might not have adequate incentives to minimize costs.

[7] *See* 2008 GAO Report at 56, 59-61.

between RTOs and ISOs and non RTO and ISO utilities; (4) monitoring implementation and performance; and (5) evaluating performance and seeking changes, as necessary.[8]

In April 2011, after establishing metrics for RTOs and ISOs under the first objective, the then-Chairman's Office submitted a Report to Congress summarizing RTO and ISO performance for the years 2005-2009.[9] To meet the second objective, Commission staff issued a report on performance in regions outside RTOs and ISOs in October 2012.[10] An August 2014 Commission Staff report[11] satisfied the third, fourth, and fifth objectives by establishing, implementing, and evaluating a set of common metrics. This report represents a continuation of the fifth objective.

III. Common Metrics Review

A. Reliability Metrics

1. NERC Reliability Standards Compliance

a. References to Applicable NERC Standards

This metric provides an overview of the North American Electric Reliability Corporation (NERC) standards that are applicable to each respondent. Each respondent submitted a table identifying applicable NERC functional model registrations.[12] As shown in Tables 2 and 3, there are several areas in which the respondents perform similar functions. For example, most respondents are registered balancing authorities and transmission

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[8] FERC, *The Strategic Plan: FY 2009-2014 (Revised 2013),* at 13, http://www.ferc.gov/about/strat-docs/FY-09-14-strat-plan-print.pdf.

[9] FERC, *Performance Metrics For Independent System Operators and Regional Transmission Organizations*, Docket No. AD10-5-000, at 5 (2011); *see also* FERC, *2010 ISO/RTO Performance Metrics Commission Report*, Docket No. AD10-5-000 (2010).

[10] FERC, *Performance Metrics In Regions Outside ISOs and RTOs Commission Staff Report*, Docket No. AD12-8-000 (2012).

[11] FERC, *Common Metrics Commission Staff Report*, Docket No. AD14-15-000 (2014), http://www.ferc.gov/legal/staff-reports/2014/ad14-15-performance-metrics.pdf.

[12] The timing of snapshots of each respondent's functional model registrations did not coincide, e.g., ISO-NE's submittal represents registrations as of the end of 2013; NYISO's submittal represents registrations as of the end of 2014, and APS' submittal represents registrations as of August 2015.

operators. In other areas, the RTO and ISO respondents are dissimilar from the non-RTO and ISO respondents. For instance, most of the RTOs and ISOs perform reliability coordinator functions while most of the non-RTO and ISO respondents do not.

Table 2: Selected NERC functional model registrations identified by RTO and ISO respondents.

	Balancing Authority	Interchange Authority	Planning Authority	Reliability Coordinator	Resource Planner	Transmission Operator	Transmission Planner	Transmission Service Provider
CAISO	●		●			●		●
ISO-NE	●	●	●	●	●	●	●	●
MISO	●	●	●	●	●	●		●
NYISO	●	●	●	●	●	●	●	●
PJM	●	●	●	●	●	●	●	●
SPP	●		●	●			●	●

Source: Commission staff based on information collection FERC-922.

Note: Cells marked with "●" denote that the respondent identified the functional model registration in its data submittal.

Table 3: Selected NERC functional model registrations identified by non-RTO and ISO respondents.

	Balancing Authority	Interchange Authority	Planning Authority	Reliability Coordinator	Resource Planner	Transmission Operator	Transmission Planner	Transmission Service Provider
APS	●		●		●	●	●	●
DEC	●	●	●		●	●	●	●
DEF	●	●	●		●	●	●	●
DEP	●	●	●		●	●	●	●
LG&E/KU	●	●	●		●	●	●	●
PAC	●		●		●	●	●	●
SOU	●	●	●	●	●	●	●	●

Source: Commission staff based on information collection FERC-922.

Notes: (1) Cells marked with "●" denote that the respondent identified the functional model registration in its data submittal. (2) PACE and PACW are each an individual balancing authority.

b. Violations Made Public by FERC or NERC[13]

These metrics measure the number of violations of NERC reliability standards, provide information on how these violations were reported (e.g., self-reported or reported in audits), and indicate the severity of violations, when such information is provided. These metrics also detail compliance with operating reserve standards and unserved energy (or load shedding) caused by violations.

[13] In addition to the violations data discussed in this section, certain respondents provided information regarding (1) the severity level of violations and (2) compliance with operating reserves standards. Reporting formats for the severity level of violations were not uniform, as some respondents reported that severity levels did not apply or that severity classifications changed during the reporting period. *See, e.g.*, October 2015 RTO and ISO Metrics Report at 32 (CAISO stating that "[the Western Electricity Coordinating Council] has stopped identifying severity levels of violations, and they are not included for violations identified as a result of a NERC/FERC investigation.") Additionally, all respondents who discussed operating reserve standards indicated compliance for each year in the reporting period.

i. Number of violations

The number of violations metric measures both the number of violations and how these violations were reported (e.g., self-reported or reported in audits). Mandatory reliability standards only apply based on the NERC functional model categories for which each entity is registered. As a result of the variety of categories, different reliability standards apply to different RTOs and ISOs and to different non-RTO and ISO respondents.

As shown in Figure 5,[14] PJM reports the highest total number of violations for the 2010-2014 reporting period. Most of PJM's violations were self-reported, as is generally the case across both RTO and ISO and non-RTO and ISO respondents. Because PJM is the registered Transmission Operator for the PJM region, PJM executive management has the ultimate decision-making authority to determine whether a potential violation has occurred and whether PJM must submit a self-report to NERC the relevant Regional Entity.[15]

When comparing across entities, it is important to note that it is difficult to draw conclusions based on the relative magnitude of self-reported violations. Differences in self-reported violations may or may not correspond to underlying differences in performance.

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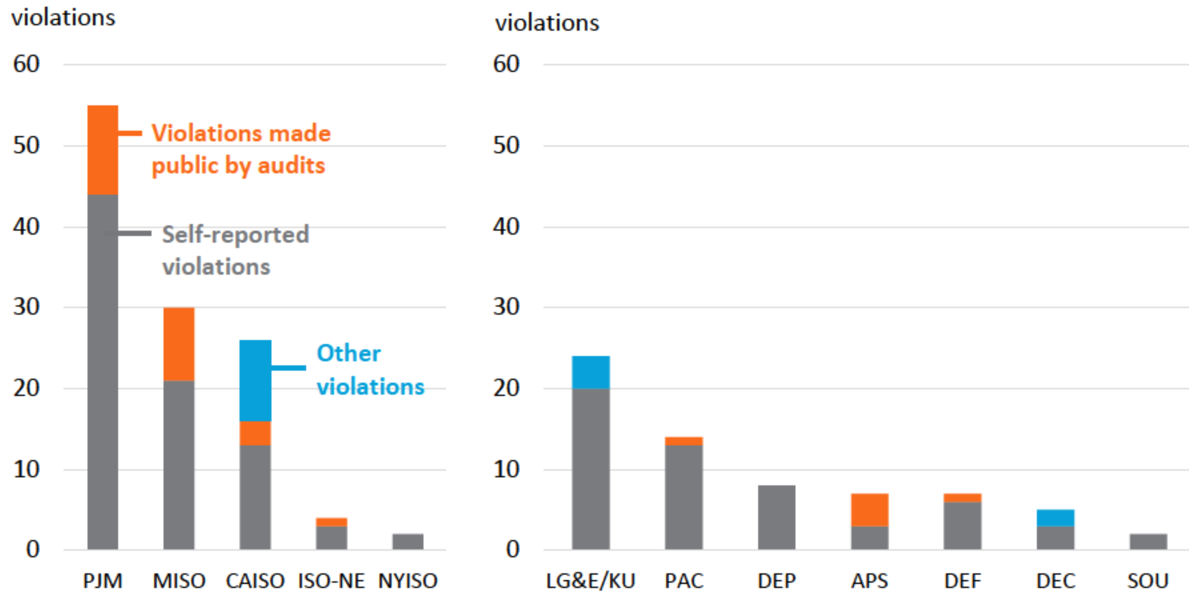
[14] Figure 5 shows total violations reported by each respondent for the 2010-2014 period. Responses are not shown by year, as the year in which a violation is made public may not correspond to the year in which a respondent self-reported a violation or was subject to an audit or spot-check.

[15] *Id.*

Figure 5: Number of violations made public by FERC/NERC as submitted by respondents, 2010-2014.



Source: Commission staff based on information collection FERC-922.
Notes: (1) "Other violations" shown in the figure reflects the difference between the reported total number of violations and the sum of (a) the reported number of self-reported violations and (b) the reported number of violations made public by audits. (2) SPP does not report any violations associated with this metric. (3) The violation totals shown for CAISO derive from values in Tables A, B, and C on pp 30-31 of the October 2015 RTO and ISO Metrics Report. (4) ISO-NE and NYISO totals reflect a supplemental response received by email on January 5, 2016.

ii. Unserved energy (load shedding) caused by violations

Among RTOs and ISOs, CAISO and PJM report instances of load shedding caused by violations during the 2010-2014 reporting period.[16] CAISO reports that in April 2010, an operator believed that load shedding was necessary to maintain an import limit; CAISO also indicates a load shedding event from September 2011, associated with the Pacific Southwest outage.[17] PJM reports that it shed a total of 154.1 MW of load on two days in 2013 in order to protect system reliability.[18] No other RTOs or ISOs report load shedding during the 2010-2014 reporting period.

[16] Additionally, CAISO discusses a load shedding event from November 2008, which is outside of the reporting period. *See* October 2015 RTO and ISO Metrics Report at 33.

[17] *Id.*

[18] *Id.* at 282.

Among non-RTO and ISO respondents, APS reports load shedding associated with the September 2011 Pacific Southwest outage.[19] No other non-RTO and ISO respondents report load shedding during the 2010-2014 reporting period.

2. Dispatch Reliability

Dispatch reliability metrics measure the performance of dispatch operations in maintaining steady-state frequency within defined limits by balancing power demand and supply in real time, as well as the availability of systems that perform real-time monitoring and security analysis functions.

a. Control Performance Standard 1 (CPS1)

CPS1 is a statistical measure of Area Control Error[20] variability. This standard measures Area Control Error in combination with the interconnection's frequency error.[21] Balancing authorities must achieve a minimum CPS1 compliance of 100 percent over a 12 month period.[22] As shown in Figure 6, each RTO and ISO respondent achieved CPS1 compliance for calendar years 2010-2014.

Among the non-RTO and ISO respondents, only LG&E/KU and PAC submitted annual CPS1 values, demonstrating compliance with CPS1 requirements for calendar years 2010-2014. APS;[23] the Duke Energy respondents (DEC, DEF, and DEP);[24] and SOU[25]

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[19] November 2015 APS Metrics Report at 6.

[20] NERC defines Area Control Error as the instantaneous difference between a balancing authority's net actual and scheduled interchange, taking account of frequency bias and meter error. *See* NERC, *Glossary of Terms Used in NERC Reliability Standards* 7 (Apr. 2016).

[21] NERC defines frequency error as the difference between actual and scheduled frequency. *See* NERC, *Glossary of Terms Used in NERC Reliability Standards* 44 (Feb. 2016), http://www.nerc.com/files/glossary_of_terms.pdf.

[22] When a balancing authority's frequency is exactly on schedule or Area Control Error is zero, CPS1 equals 200 percent. The CPS1 calculation is structured such that, if a balancing authority's Area Control Error is proportionally as "noisy" as a benchmark frequency noise, that balancing authority's CPS1 would equal 100 percent. *See* NERC, Balancing and Frequency Control 33-34 (Jan. 2011), http://www.nerc.com/docs/oc/rs/NERC%20Balancing%20and%20Frequency%20Control%20040520111.pdf.

[23] November 2015 APS Metrics Report at 6.

report compliance with CPS1 for the 2010-2014 period, although they do not report annual values.

Figure 6: CPS1, 2010-2014.

Source: Commission staff based on information collection FERC-922.
Note: PACE and PACW are separate balancing authority areas.

b. Control Performance Standard 2 (CPS2)

CPS2 is a statistical measure of Area Control Error magnitude. The intent of the standard is to limit a control area's unscheduled power flows. APS and two Duke Energy respondents (DEF and DEP) report compliance with CPS2 over the reporting period, but do not provide annual values.[26] CAISO, MISO, PJM, SOU, DEC, and PAC do not report CPS2 data, explaining that during 2010-2014 they participated in a proof-of-concept field trial that included a waiver from CPS2 requirements.[27]

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[24] Duke Energy Corporation October 27, 2015 Filing at 5 (October 2015 Duke Metrics Report).

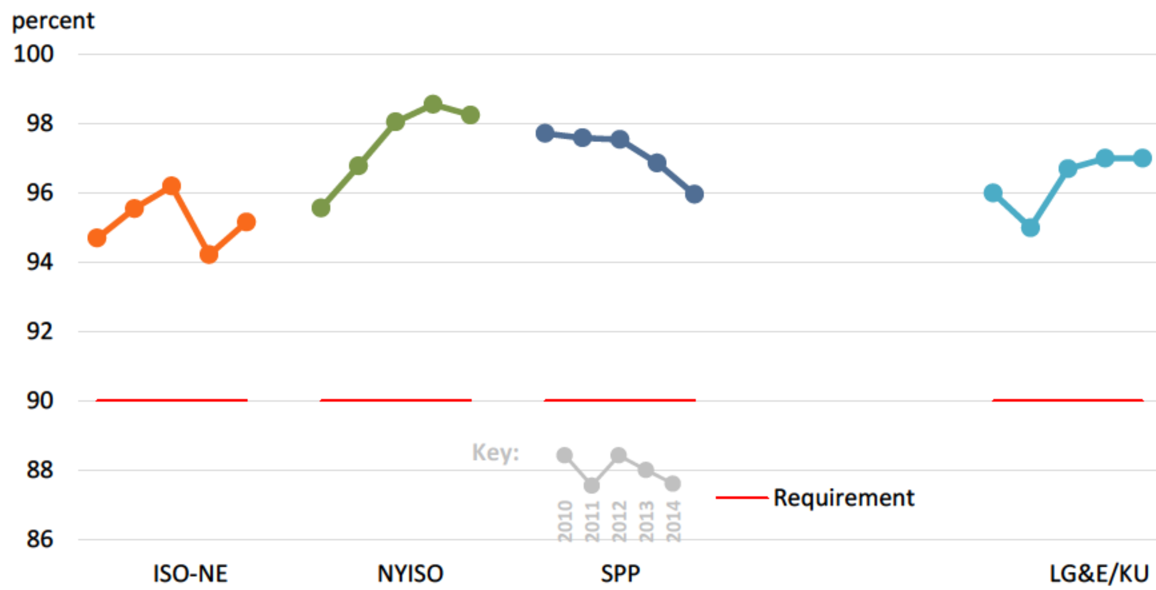
[25] Southern Company October 30, 2015 Filing at 16 (October 2015 SOU Metrics Report).

[26] *See* November 2015 APS Metrics Report at 6, October 2015 Duke Metrics Report at 5.

[27] *See* October 2015 RTO and ISO Metrics Report at 34, 159, 284; October 2015 SOU Metrics Report at 16; October 2015 Duke Metrics Report at 5; PacifiCorp February *(continued ...)*

Figure 7 displays the CPS2 metrics from ISO-NE, NYISO, SPP, and LG&E/KU.

Figure 7: CPS2, 2010-2014.



Source: Commission staff based on information collection FERC-922.

c. Energy Management System availability

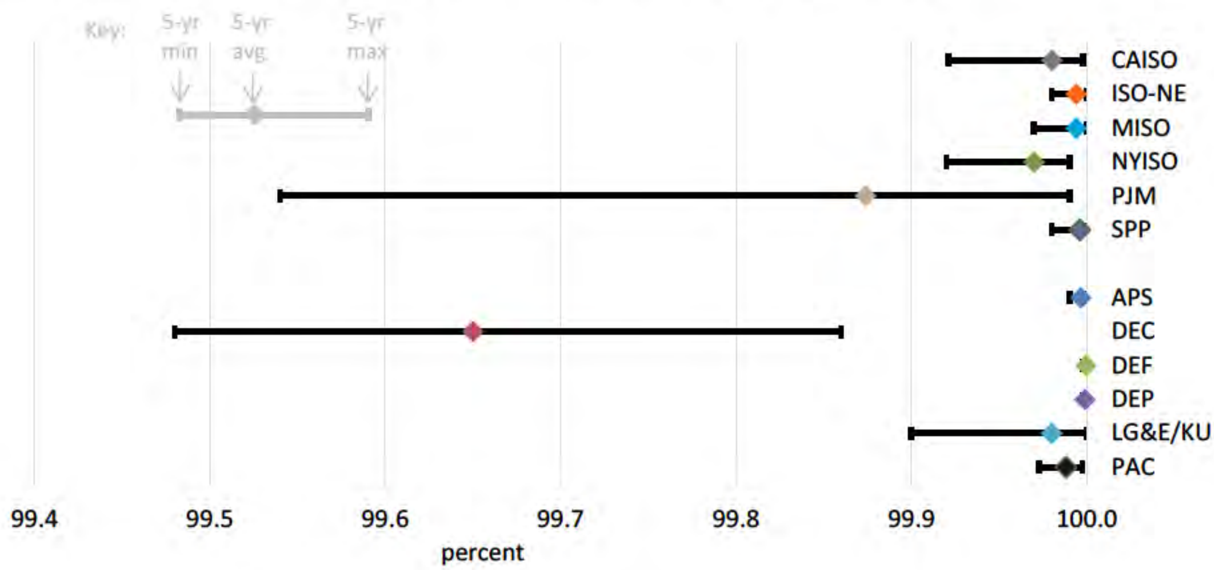
The Energy Management System availability metric measures the availability of the systems used for real-time monitoring and security analysis functions, reported as a percentage of minutes of operational availability each year. Figure 8 shows the five-year average and range of annual Energy Management System availability for respondents providing data. Lower values indicate that a respondent's Energy Management System was unavailable more often relative to those of respondents reporting higher values. Among RTOs and ISOs, only PJM reports a five-year average availability of less than 99.90 percent, with annual values ranging from 99.54 percent in 2010 to 99.99 percent in 2011 and 2013.[28] All other RTOs and ISOs report annual Energy Management System availability above 99.90 percent in every year from 2010-2014.

10, 2016 Filing at 11 (February 2016 PAC Metrics Report).

[28] PJM reports that in November 2011 it implemented a second control center with dual independent data communication links to the Energy Management Systems at each control center, and that these enhancements helped to increase availability. *See* October 2015 RTO and ISO Report at 283.

Among non-RTO/ISO respondents that report Energy Management System availability, only DEC reports a five-year average availability of less than 99.90 percent, with annual values ranging from 99.86 percent in 2012 to 99.48 percent in 2013.

Figure 8: Energy Management System availability (average and range), 2010-2014.



Source: Commission staff based on information collection FERC-922.
Notes: (1) SOU reports that it transitioned to a new Energy Management System during the 2010-2014 time period and therefore it does not provide specific annual availability values. (2) SOU reports that it had zero "Loss of [Energy Management System] capability" events pursuant to Reliability Standard EOP-004-2 during 2010-2014.[29] (3) PAC does not report this metric in percentage terms, but instead reported annual outage minutes for its Ranger EMS system,[30] and in the above chart, PAC's Energy Management System availability reflects annual outage minutes reported divided by 525,600 minutes per year.

3. Load and Wind Forecast Accuracy

The load forecast accuracy metric measures the accuracy of the day-ahead load forecast, based on the absolute percentage deviation between actual peak load and forecasted peak load.[31] As load forecasting affects resource commitment, load forecast accuracy impacts

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[29] *See* October 2015 SOU Metrics Report at 16.

[30] *See* February 2016 PAC Metrics Report at 11-12.

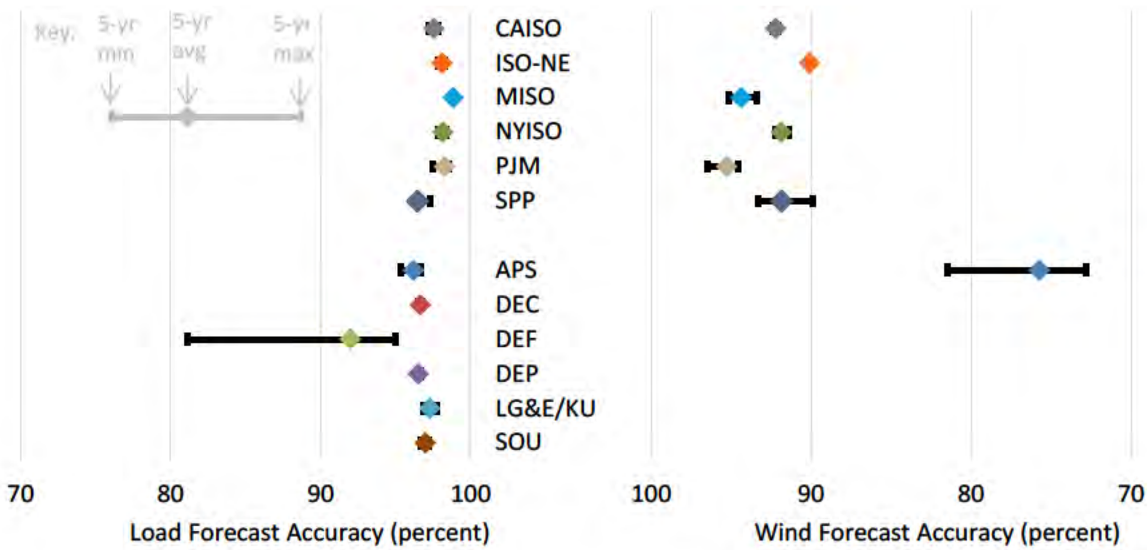
[31] RTOs and ISOs generally calculate this metric based on the mean absolute percentage error of the forecast at a reference point on the prior day. The reference point varies across RTOs and ISOs, from 5:00 a.m. on the prior day in NYISO to 3:30 p.m. on the prior day in MISO. For additional details, *see* October 2015 RTO and ISO Metrics Report at 36, 81, 161, 218, 284, 346.

the incurrence of commitment costs. The more accurate a respondent is in forecasting load, the greater the likelihood that it can commit sufficient resources in a cost-effective manner that avoids over-commitment of resources, inefficient commitment of short lead time resources, and under-utilization of available resources.

The wind forecast accuracy metric measures the percentage accuracy of actual wind availability compared to day-ahead forecasted wind availability. Accurate wind forecasting facilitates the timely commitment and dispatch of sufficient supplemental, non-wind resources.

Figure 9 summarizes the load forecast accuracy and wind forecast accuracy metrics data submitted by each respondent. The wind forecast metric is not applicable for certain utilities that do not perform wind forecasting functions because they have little to no wind generation interconnected with their systems.

Figure 9: Average and range of load forecast accuracy and wind forecast accuracy, 2010-2014.



Source: Commission staff based on information collection FERC-922.
Notes: (1) For wind forecast accuracy, ISO-NE reports values for 2014; SPP reports values for 2011-2014; and APS reports values for 2012-2014. (2) LG&E/KU report that their load forecast data are not based entirely on day-ahead information, as it contains some intra-day adjustments.[32] (3) PAC (not shown) does not report the load forecast metric as day-ahead forecasted load compared to actual load; rather, PAC reports annual load forecast values compared to actuals.[33] (4) Wind forecast error reflects mean absolute error for CAISO, ISO-NE, MISO, NYISO, and APS. SPP calculates wind forecast error based on the absolute difference between actual and forecast output divided by capacity. PJM does not explain its wind forecast error methodology in detail. PAC (not shown) reports aggregate annual forecast and actual MWh.[34]

4. Unscheduled Flows

The unscheduled flows metric measures the difference between net actual interchange (actual measured power flow in real time) and the net scheduled interchange in megawatt-hours, as reported in FERC Form No. 714, "Annual Electric Balancing Authority Area and Planning Area Report." In other words, it is a measure of what actually occurred in real time as compared to what was scheduled.[35] As such,

[32] Louisville Gas & Electric and Kentucky Utilities Corporation October 30, 2015 Filing at 5 (October 2015 LG&E/KU Metrics Report).

[33] February 2016 PAC Metrics Report at 12.

[34] *Id.* at 13.

[35] Unscheduled flows reflect the difference between scheduled flows and actual *(continued ...)*

unscheduled flows provide information relevant to operational planning that is part of a comprehensive reliability assessment for an RTO and ISO or utility.[36] When unscheduled flows exceed system operating limits, curtailments could occur, hindering efficient scheduling of the grid.

Unscheduled flows vary among the reporting entities. Table 4 reviews the unscheduled flows data submitted by each respondent. The data are not normalized across respondents and therefore do not take account of differences in the size of each system.

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flows on a particular interconnection between two balancing authorities. Unscheduled flows may also reflect the difference between scheduled and actual flows on a contract path, either between or within balancing authorities.

[36] The two components of unscheduled flows are (1) inadvertent energy, defined as the difference between actual and scheduled interchange for all interties; and (2) parallel flow (or loop flow), defined as the difference between scheduled and actual flows on a contract path. Parallel flows are a function of grid conditions and the physical characteristics of the transmission system.

Table 4: Summary of unscheduled flows in 2010 and 2014.

Respondent	2010 unscheduled flows (million megawatt-hours)	2014 unscheduled flows (million megawatt-hours)	percent change from 2010-2014
RTOs and ISOs			
CAISO	22.5	5.8	-74.1
MISO	31.0	43.0	38.7
NYISO	8.0	1.7	-78.8
PJM	29.3	28.4	-3.1
non-RTOs and ISOs			
APS	0.0	0.7	5,344.9
DEC	10.2	10.7	5.0
DEF	14.3	17.1	19.2
DEP	13.7	11.7	-15.1
LG&E/KU	0.0	0.0	-67.6
SOU	46.7	28.3	-39.3

Source: Commission staff based on information collection FERC-922.
Notes: (1) ISO-NE, SPP, and PAC do not report data for this metric.[37] (2) PAC reports total hours of transmission curtailment in WECC, along with total hours of coordinated operation of phase shifters in WECC.[38]

5. Transmission Outage Coordination

The transmission outage coordination metrics include (1) a measure of advance notice of planned outages and (2) a measure of cancellations of outages due to factors such as conflicting planned outages or forced outages that could cause reliability issues and additional congestion costs.

a. Early Notification Metric

This metric measures the percentage of planned transmission outages of five days or longer submitted at least one month in advance of the outage commencement date. The metric only applies to transmission facilities at voltages of 200 kilovolts and above. Figure 10 displays this metric for RTOs and ISOs and non-RTO and ISO respondents from 2010-2014. A higher percentage could reflect more effective outage coordination.

Among RTOs and ISOs, ISO-NE and NYISO report the highest levels of early notification, while SPP reported the lowest five-year average. In SPP, the early notification of planned outages ranged from a low of 19.3 percent in 2011 to a high of 24.9 percent in 2014. SPP reports that its tariff does not outline specific timeframes and guidelines for transmission outage coordination, but contains a general requirement that, "consistent with the SPP Membership Agreement, Transmission Owners are required

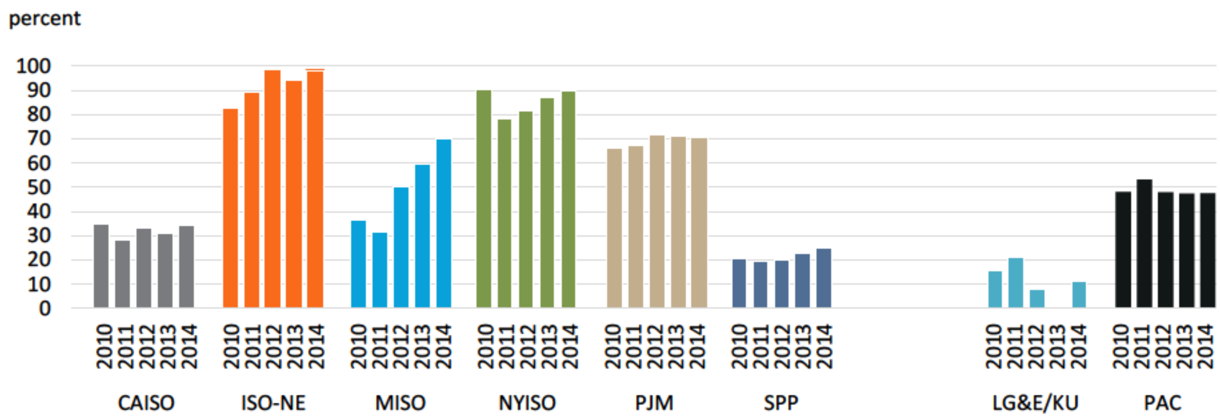
[37] October 2015 RTO and ISO Metrics Report at 85, 347; February 2016 PAC Metrics Report at 14-15.

[38] *Id.* at 14-15.

to coordinate with the Transmission Provider for all planned maintenance of Tariff Facilities."[39] By contrast, ISO-NE reports steps it has taken to improve the lead time for outage request submissions, including efforts to focus on the issue collaboratively with transmission owners and local control centers.[40]

This metric does not measure advance notification that occurs less than 30 days before an outage. For instance, in 2012, CAISO modified its tariff to require entities to submit outages seven calendar days prior to the outage;[41] however, the metric does not reflect the percentage of seven-day notifications. With regard to non-RTO and ISO respondents, LG&E/KU coordinates outage notifications with the Tennessee Valley Authority, which uses a seven-day notice requirement for planned outage requests.[42]

Figure 10: Percentage of planned transmission outages with at least one month notification, 2010-2014.



Source: Commission staff based on information collection FERC-922.
Note: APS, DEC, DEF, DEP, and SOU do not provide data for this metric. Commission staff notes that APS, DEC, DEF, DEP, and SOU report that they post planned outages on their respective Open Access Same Time Information Systems (OASIS).[43]

b. Cancelation Metric

This metric reflects cancelations of outages due to conflicting planned outages as well as

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[39] October 2015 RTO and ISO Metrics Report at 348.

[40] *Id.* at 86-87.

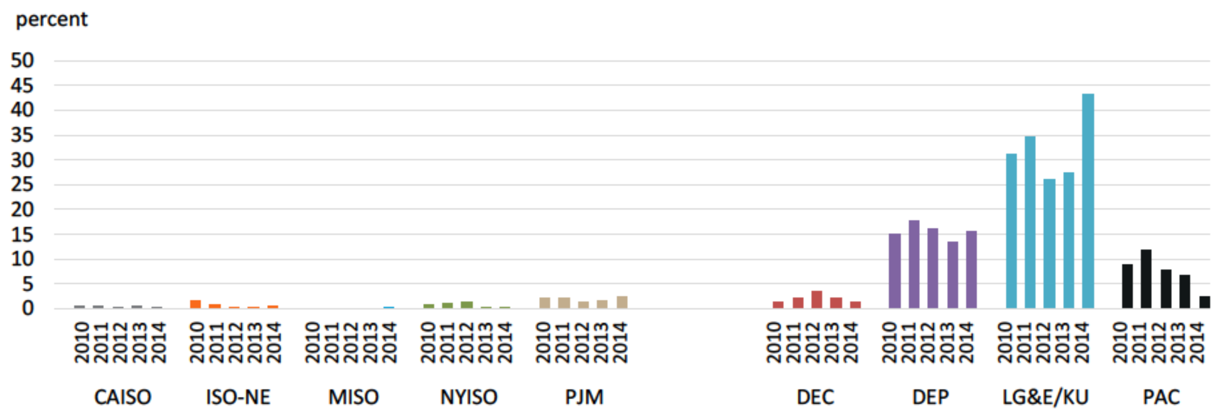
[41] *Id.* at 41.

[42] October 2015 LG&E/KU Metrics Report at 7.

[43] November 2015 APS Metrics Report at 9; October 2015 Duke Metrics Report at 13; and October 2015 SOU Metrics Report at 20.

forced outages. The metric measures the percentage of previously-approved transmission outages that are later canceled for transmission facilities with voltages of 200 kilovolts and above. Lower values represent fewer canceled outages and may indicate better outage coordination. Figure 11 shows the percentage of canceled outages from 2010-2014 for RTOs and ISOs and non-RTOs and ISOs submitting data. The RTOs and ISOs submitting data for this metric generally report significantly lower cancelation percentages than the non-RTO and ISO respondents, with the exception of DEC.

Figure 11: Average percentage of previously-approved transmission outages canceled by the transmission provider, 2010-2014.



Source: Commission staff based on information collection FERC-922.
Notes: (1) APS, DEF, and SOU did not provide data for this metric. (2) SPP (not shown) provided only two years of data. SPP's reports cancelation percentages of 0.5 percent in 2013 and 0.3 percent in 2014.

6. Long-Term Reliability Planning – Transmission

a. Transmission Projects Approved for Construction

This metric measures the number of transmission facilities approved for construction for reliability purposes. Each of the respondents has a role in approving transmission projects through their respective local and regional reliability planning processes. In reviewing this metric, it is important to consider that the size of the transmission system varies across respondents.

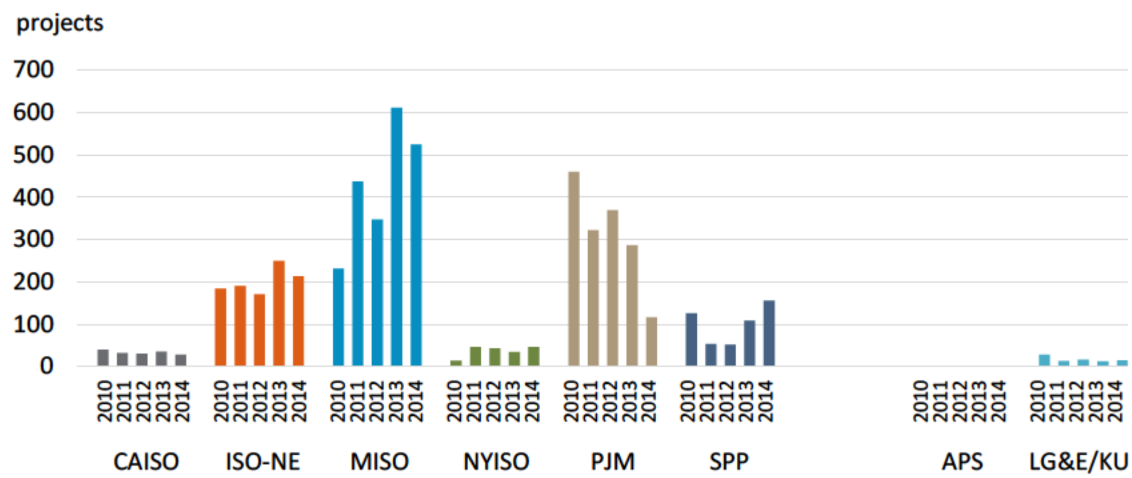
As shown in Figure 12, MISO reports more approved transmission projects than any other respondent. Over the reporting period, MISO approved 2,153 transmission projects for reliability purposes.[44] As part of the local transmission planning process, transmission owners in MISO are responsible for submitting their transmission construction plans to MISO for evaluation and possible inclusion in the MISO

[44] October 2015 RTO and ISO Metrics Report at 170.

Transmission Expansion Plan. After evaluation, projects identified as the best solution for a particular issue or opportunity are included in the report and recommended for approval by the MISO Board of Directors.[45]

Among the non-RTOs and ISOs, only APS and LG&E/KU provide data on the approval of transmission projects. LG&E/KU reports approval of 85 transmission projects from 2010-2014.[46]

Figure 12: Number of transmission projects approved for construction for reliability purposes, 2010-2014.



Source: Commission staff based on information collection FERC-922.
Notes: (1) PAC (not shown) provides data summarizing the total number of projects for all five years, but does not provide separate data describing project approvals. PAC reports projects initiated, ongoing, or completed during the 2010-2014 time frame, based on transmission reliability capital investment. PAC either initiated or completed 85 projects, 51 of which were completed during the 2010-2014 time frame.[47] (2) DEC, DEF, and DEP provide data summarizing projects completed in each year, but these non-RTO and ISO utilities do not provide separate data describing project approvals.

b. Transmission Projects Completed

This metric is a measure of transmission planning performance and represents the percentage of approved construction projects completed and on schedule.

RTOs and ISOs report the percentage of projects approved in each year that were completed by the end of the reporting period. Figure 13 shows the percent of approved projects completed for RTOs and ISOs from 2010-2014. Across RTOs and ISOs, ISO-

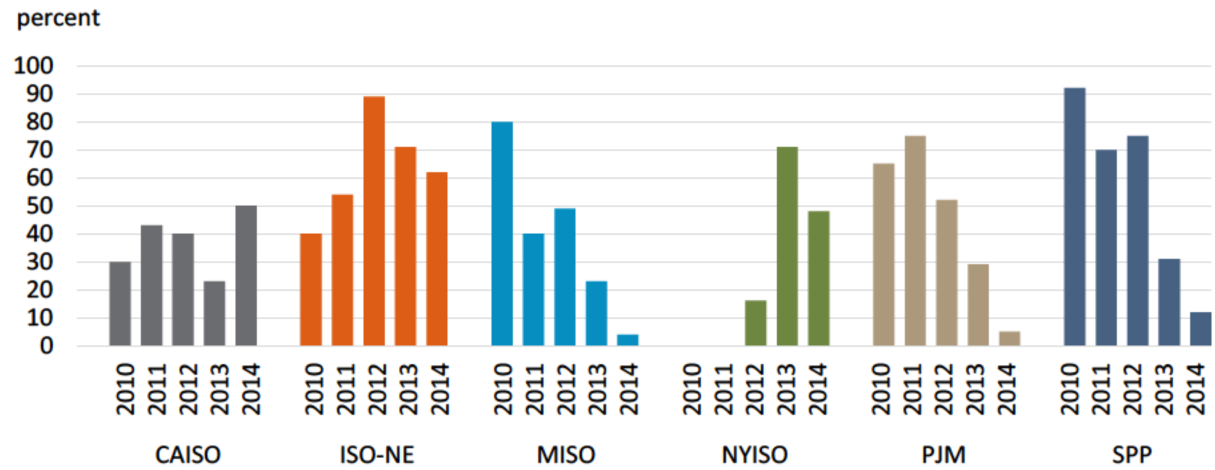
[45] *Id.* at 170.

[46] *Id.* at 8.

[47] February 2016 PAC Metrics Report at 17-18.

NE reports the highest annual average percentage of approved projects completed over this time period.

Figure 13: Percentage of approved transmission projects completed, 2010-2014.



Source: Commission staff based on information collection FERC-922.
Notes: (1) CAISO does not specify whether projects were complete before December 31, 2014. (2) CAISO reports the percentage of approved construction projects completed and projects on-schedule per the original in-service date.[48] (3) ISO-NE reports the ratio of under-construction and in-service projects to completed projects.[49] (4) MISO reports the percentage of completed reliability projects only.[50] (5) NYISO reports "N/A" for 2010 and 2011.

Non-RTO and ISO respondents report the percentage of projects that were on schedule each year. Using this measure, the Duke Energy respondents (DEC, DEF, and DEP), and SOU report 100 percent of transmission projects on schedule, as shown in Figure 14.[51] APS reports 100 percent of projects on schedule with the exception of years 2012 and 2013.[52]

[48] *Id.*

[49] *Id.* at 89-90.

[50] *Id.* at 171.

[51] October 2015 Duke Metrics Report at 14-15; and October 2015 SOU Metrics Report at 21.

[52] November 2015 APS Metrics Report at 9.

Figure 14: Percentage of transmission projects on schedule, 2010-2014.

Source: Commission staff based on information collection FERC-922.
Note: PAC (not shown) does not report a percentage, but reports 51 completed projects out of 85 initiated projects during the 2010-2014 period, and notes that one of those projects was behind schedule.[53]

7. Long-Term Reliability Planning – Resources

a. Generator Interconnection Processing Time

The time it takes to process generation interconnection requests is one measure of the effectiveness of processes in achieving timely interconnection of new resources. Each respondent interconnects generators under different operating conditions. Some entities, such as ISO-NE, report challenges in initiating and performing wind interconnection studies because of complex control interactions that increase the potential for more detailed modeling.[54]

As shown in Figure 15, among RTOs and ISOs, NYISO, MISO, and ISO-NE report the longest interconnection processing times.[55] NYISO reports that its average process time was high in 2013 for two reasons: (1) a previously-rejected project was re-studied and retained its queue position; and (2) a project presented the unique circumstance of proposing to interconnect to a 345 kilovolt tie-line between NYISO and a neighboring ISO. As a result of these projects, the necessary analysis required significant additional

[53] February 2016 PAC Metrics Report at 18.

[54] October 2015 RTO and ISO Metrics Report at 107.

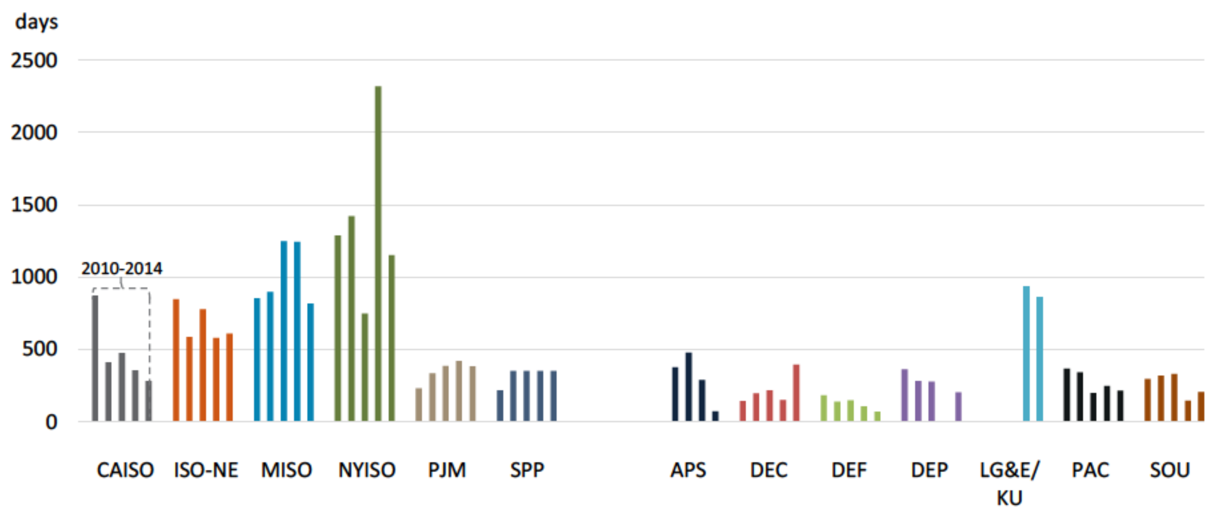
[55] *Id.* at 94-95, 174, 231.

time.[56] NYISO's average generation interconnection request processing time ranged from a low of 750 days in 2012 to a high of 2,318 days in 2013.

MISO reports that projects that completed the interconnection process prior to 2012, and then subsequently withdrew, caused several restudies that affected interconnection queue times.[57]

Among the non-RTO and ISO respondents, LG&E/KU reports the longest average generator interconnection processing time. However, LG&E/KU does not report values for 2010-2012, and their average processing time reflects a two-year average.[58] Others, such as APS, SOU, and the Duke Energy respondents (DEC, DEF, and DEP) report, on average, less than 400 days to process their respective generator interconnection requests.[59]

Figure 15: Annual average generator interconnection processing time, 2010-2014.



Source: Commission staff based on information collection FERC-922.
Note: (1) APS reports values for 2011-2014. (2) DEP reports values for 2010-2012 and 2014. (3) LG&E/KU reports values for 2013-2014.

[56] *Id.* at 231-233.

[57] *Id.* at 174.

[58] October 2015 LG&E/KU Metrics Report at 9.

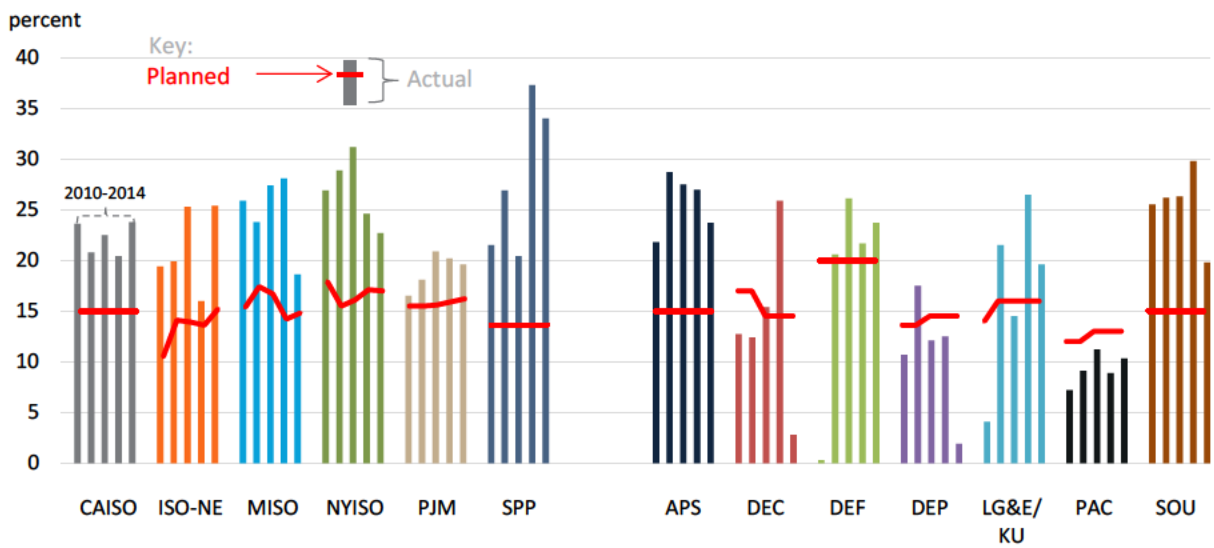
[59] October 2015 SOU Metrics Report at 24; October 2015 Duke Metrics Report at 17; November 2015 APS Metrics Report at 10.

b. Actual and Planned Reserve Margins

The comparison of the actual reserve margin to the planned reserve margin measures the extent to which generation resource planning processes are ensuring long-term resource adequacy and reliability. Actual reserve margins in excess of planned levels represent a low probability of loss-of-load due to inadequate supply.

As shown in Figure 16, RTOs and ISOs report actual reserve margins in excess of planned levels between 2010 and 2014. SPP reports the largest difference between actual and planned reserve margins from 2010-2014, with an average planned reserve margin of approximately 13 percent and an average actual reserve margin of approximately 28 percent.[60] Among non-RTO and ISO respondents, APS and SOU report actual reserve margins that were substantially higher than the planned levels. Some entities report actual reserve margins below planned levels. For example, in 2014 DEP reports that its planned reserve margin was 14.5 percent in 2014 and its actual reserve margin was 1.9 percent.[61]

Figure 16: Planned and actual reserve margins, 2010-2014.



Source: Commission staff based on information collection FERC-922.

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[60] October 2015 RTO and ISO Metrics Report at 355.

[61] *See* October 2015 Duke Metrics Report at 18. DEC, DEF, and DEP report actual reserve margin based on balancing authority reserves at the time of the actual balancing authority hourly integrated peak demand in each year. DEP reports that its peak load occurred during the winter in 2014.

8. Interconnection and Transmission Processes

a. Interconnection and Transmission Service Request Process

The number of study requests and completed studies illustrates the progress that respondents have made in completing their reliability reviews (feasibility, system impact and facility studies) of interconnection and transmission service requests in a timely and efficient manner.

With respect to the number of study requests and completed studies, PJM reports the most study requests and completions while DEP reports the fewest.[62] As shown in Table 5, MISO reports nearly four times as many studies completed as requested. MISO reports that each interconnection request may have several studies performed.[63]

Table 5: Interconnection and transmission service requests: number of study requests, number of completed studies, and ratio of completed to requested studies, 2010-2014.

Respondent	2010-2014 Total		
	Requested	Completed	Ratio
RTOs and ISOs			
CAISO	529	635	1.2
ISO-NE	174	94	0.5
MISO	354	1366	3.9
NYISO	121	123	1.0
PJM	1689	2185	1.3
SPP	289	446	1.5
RTO and ISO average	526	808	1.5
non-RTOs and ISOs			
APS	160	70	0.4
DEC	34	48	1.4
DEF	61	61	1.0
DEP	27	23	0.9
LG&E/KU	120	97	0.8
PAC	825	222	0.3

[62] *Id.* at 19-21; October 2015 RTO and ISO Metrics Report at 300-302.

[63] *Id.* at 180.

Table 5: Interconnection and transmission service requests: number of study requests, number of completed studies, and ratio of completed to requested studies, 2010-2014. (cont'd.)

Respondent	2010-2014 Total		
	Requested	Completed	Ratio
SOU	354	267	0.8
Non-RTO and ISO average	226	113	0.8

Source: Commission staff based on information collection FERC-922.
Note: The studies completed in any particular year may correspond to requests from a prior year and an interconnection request may have several studies performed; the number of completed studies can be higher than the number of requested studies.

b. Average Age of Incomplete Studies

The average age of incomplete studies metric assesses the progress that RTOs and ISOs and non-RTO and ISO utilities have made in completing their reliability reviews (feasibility, system impact and facility studies) of interconnection and transmission service requests in a timely and efficient manner.

As shown in Figure 17, relative to other RTOs and ISOs, SPP reports a consistently low average age of incomplete studies over the five-year reporting period, while MISO reports the largest decline in average age of studies between 2010 and 2014. ISO-NE reports a relatively high average age of incomplete studies from 2010-2014. ISO-NE conducts studies in the order in which projects enter the interconnection queue.[64] MISO points to its 2012 queue reform as leading to a reduction in the volume of interconnection requests in the active queue, and states that these tariff revisions and ongoing process improvements led to the downward trend in study completion time. MISO also reports that the lower average time to complete studies resulted in lower average study costs.[65]

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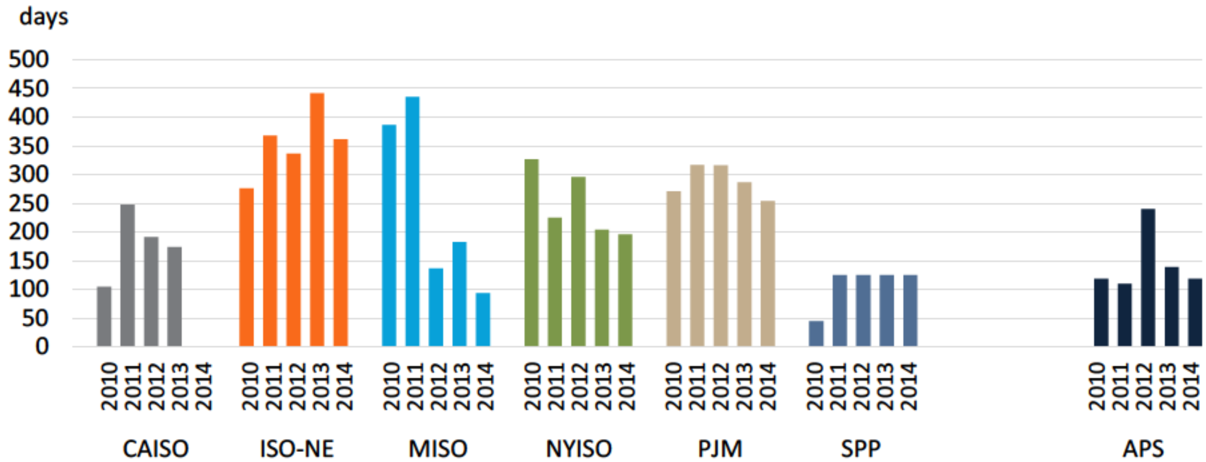
[64] October 2015 RTO and ISO Metrics Report at 104-105.

[65] *Id.* at 180.

Figure 17: Average age of incomplete studies, 2010-2014.



Source: Commission staff based on information collection FERC-922.
Notes: (1) DEC, DEF, DEP, and LG&E/KU report zero days. (2) SOU does not report annual values for 2010-2014; instead, SOU reports that as of January 1, 2015, the average age of incomplete generator interconnection studies was 48 days and the average age of incomplete transmission service studies was 28 days. (3) The CAISO value shown in the figure reflects a four-year average.

c. Average Cost of Studies

The average cost of studies metric measures the cost of completing reliability reviews (feasibility, system impact, and facility impact studies)[66] of interconnection and transmission service requests. Tables 6, 7, and 8 compare the average cost for each of these studies over the 2010-2014 period.

Among RTOs and ISOs, ISO-NE reports the highest feasibility study costs, with an average of $98,626 per study from 2010-2014.[67] In ISO-NE, some issues that affect the average feasibility study costs include the following: (1) costs incurred by the respective

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[66] As explained by PJM in its report: "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 . . . . 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." *Id.* at 301-302.

[67] *Id.* at 106.

transmission owners performing the requested and necessary studies; and (2) the fact that the interconnection feasibility study may be conducted as part of the interconnection system impact study or as a separate study.[68] Additionally, ISO-NE reports that wind interconnection studies are becoming more involved and detailed in New England, especially where the largest interest in development is occurring.[69]

Across all respondents, NYISO reports the highest facility impact study costs (approximately $319,000 per study for 2013 and 2014). NYISO reports that the higher average cost of facility impact studies in 2013 and 2014 was largely due to the unique circumstances of one proposed project to interconnect to a 345 kilovolt tie-line between NYISO and ISO-NE, resulting in complications and increased study costs.[70]

As MISO does not separate feasibility, system impact, and facility impact studies, MISO is not included in the tables below. MISO reports annual average values for total study costs from 2010-2014, with a high of $216,597 in 2011 and a low of $78,450 in 2013.[71] The details of MISO's response to this metric are accessible in Docket No. AD14-15-000.[72]

Table 6: Average annual feasibility study costs.

Respondent	2010	2011	2012	2013	2014
RTOs and ISOs					
CAISO	15,383	6,819	6,789	7,001	0
ISO-NE	94,960	88,237	98,582	148,307	63,044
NYISO	31,820	50,280	58,600	43,540	33,800
PJM	3,700	5,000	6,700	7,600	5,000
SPP	2,976	6,667	11,039	7,563	6,456
non-RTOs and ISOs					
APS	16,428	103,552	0	0	0

[68] *Id.* 105-108.

[69] *Id.* at 107.

[70] *Id.* at 239-240.

[71] *Id.* at 182.

[72] *Id.*

Table 6: Average annual feasibility study costs. (cont'd.)

Respondent	2010	2011	2012	2013	2014
DEC	5,464	2,292	8,020	3,068	
DEP					753
PAC					
SOU		17,906	14,769	10,068	12,964

Source: Commission staff based on information collection FERC-922.
Notes: (1) The values in the table are expressed in nominal dollars. (2) DEF and LG&E/KU do not submit data for this metric. (3) MISO submits average costs across all study types and does not separate feasibility study costs. (4) PAC reports only the five-year average. (5) The table reflects responses of $0 as reported.

Table 7: Average annual system impact study costs, 2010-2014.

Respondent	2010	2011	2012	2013	2014
RTOs and ISOs					
CAISO	33,199	15,516	14,992	16,268	0
ISO-NE	121,363	102,468	131,287	135,500	175,409
NYISO	43,650	53,410	66,513	45,940	118,430
PJM	10,800	7,100	13,100	16,600	11,300
SPP	15,655	20,623	18,428	25,232	20,009
non-RTOs and ISOs					
APS	37,127	27,646	152,195	384,097	411,226
DEC	27,414	109,783	25,701	62,276	5,010
DEP					297
PAC					
SOU		11,490	20,830	12,550	18,229

Source: Commission staff based on information collection FERC-922.
Notes: (1) The values in the table are expressed in nominal dollars. (2) DEF and LG&E/KU do not submit data for this metric. (3) MISO submits average costs across all study types and does not separate system impact study costs. (4) PAC reports only the five-year average. (5) The table reflects responses of $0 as reported.

Table 8: Average annual facility impact study costs, 2010-2014.

Respondent	2010	2011	2012	2013	2014
RTOs and ISOs					
CAISO	48,537	21,571	21,142	53,749	26,758
ISO-NE	131,692	0	20,404	0	18,973
NYISO		200,000	52,630	318,805	319,530
PJM	44,800	36,200	30,300	22,900	22,800
SPP	14,998	4,255	1,953	2,853	2,596
non-RTOs and ISOs					

Table 8: Average annual facility impact study costs, 2010-2014. (cont'd.)

Respondent	2010	2011	2012	2013	2014
APS	29,890	0	32,840	44,080	25,237
DEC	7,422	14,710	17,825	3,940	34,250
PAC					
SOU		37,766	15,014	6,414	12,870

Source: Commission staff based on information collection FERC-922.
Notes: (1) The values in the table are expressed in nominal dollars. (2) DEF, DEP, and LG&E/KU do not submit data for this metric. (3) MISO submits average costs across all study types and does not separate facility impact study costs. (4) PAC reports only the five-year average.

9. Special Protection Systems

This metric measures both the frequency with which the region relies on Special Protection Systems[73] and their effectiveness, as measured by successful activations and the number of unintended activations. Special Protection Systems are designed to detect abnormal or predetermined system conditions and take corrective actions, such as changing demand, generation, or system configurations in order to maintain system stability, acceptable voltage levels, or power flows.

Table 9 lists the number of Special Protection Systems reported by respondents.

[73] Other terms used to describe Special Protection Systems include Special Protection Schemes, Remedial Action Schemes, and System Integrity Protection Schemes.

Table 9: Total number of Special Protection Systems reported.

Respondent	Special Protection Systems
RTOs and ISOs	
CAISO	5
ISO-NE	27
NYISO	14
MISO	35
PJM	44
SPP	4
non-RTOs and ISOs	
APS	5
DEF	1
DEC	1
PAC	13
SOU	< 5

Source: Commission staff based on information collection FERC-922.
Notes: (1) Totals are for 2014 only. (2) DEP had no such devices. DEF had two such devices in 2010 – 2014; one of which was retired in 2011. DEC had one such device in 2010-2014. (3) SOU reports that it had less than five special protection systems as of 2014.

Respondents also provide information on Special Protection System activations. PJM reports a total of nine intentional Special Protection System activations, eight of which were on the Warren-Falconer 115 kilovolt tie line with NYISO. ISO-NE reports the successful activation of one Special Protection System in 2014, separating the Bangor Hydro and the Maritimes from the interconnected system in a controlled manner.[74] MISO and NYISO report no activations of Special Protection Systems from 2010-2014.[75] No RTOs or ISOs report unintended activations of Special Protection Systems.

B. System Operations Performance Metrics

1. Resource Availability

Resource availability is a measure of efficiency and cost management. Higher generator availability can result in the commitment of fewer higher cost peak generators (or fewer high-cost imports), thereby resulting in reduced costs.

[74] *Id.* at 108-110.

[75] *Id.* at 24, 183; October 2015 SOU Metrics Report at 26.

The intended calculation methodology for this common metric is one minus the system forced outage rate over 12 months.[76] However, respondents' submissions reveal the use of a variety of calculation methodologies, including effective forced outage rate-demand (EFORd), forced outage rate, and dividing megawatts of unavailable capacity by maximum capacity, among others. Due to concerns about the comparability of the responses received, Commission staff does not include a graphical comparison of the availability metric. Individual responses for this metric are accessible in the submittals from respondents in Docket No. AD14-15-000.

2. Fuel Diversity

a. Generating Capacity by Fuel Type

This metric measures the fuel-type mix of installed generating capacity. This metric provides insight into the different types of generating capacity installed in different regions. Generating capacity mix of certain regions reflects increasing percentages of renewable and natural gas-fired capacity and flat or declining percentages of coal-fired capacity.[77] Figure 18 illustrates the percentage capacity shares by fuel type in RTOs and ISOs and non-RTOs and ISOs, respectively. For purposes of comparison across respondents, Figure 18 aggregates hydroelectric and renewable capacity into a single category, and similarly groups natural gas and oil-fired capacity into a single category.[78] When evaluating these figures, it is important to consider that individual non-RTO and ISO respondents tend to have fewer resources in their footprints compared with the largest RTOs and ISOs.

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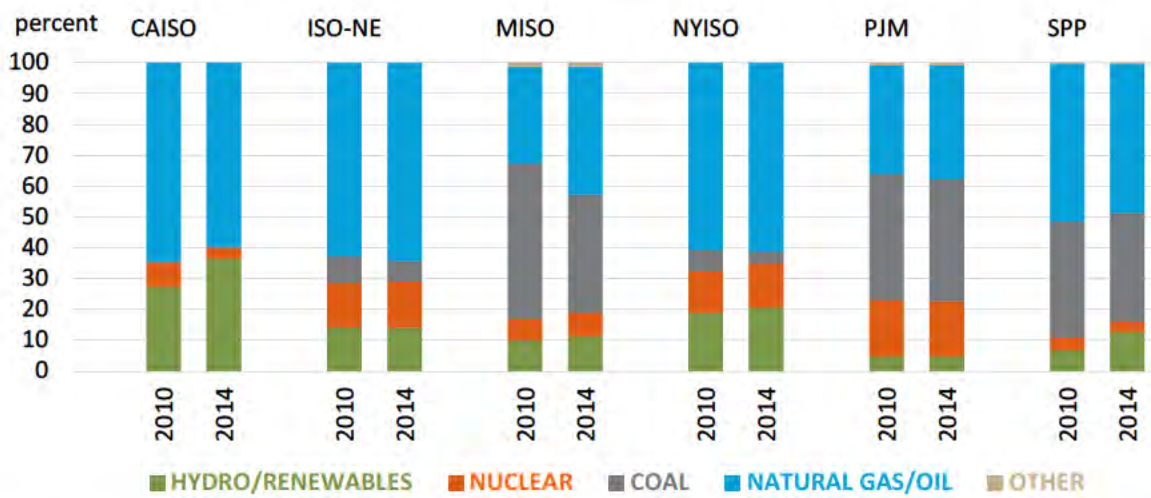
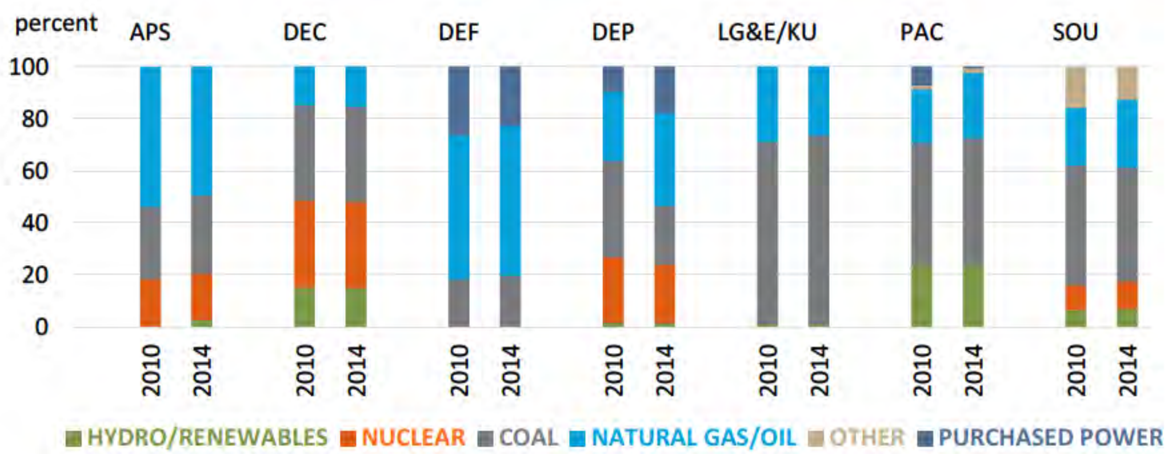
[76] *See* Comment Request, Docket No. AD14-15-000 at 17 (May 20, 2015).

[77] The specific trends differ across regions.

[78] Some respondents aggregated multiple fuel types into single categories, while others provided more disaggregated data.

Figure 18: Generating capacity mix by fuel type, 2010 and 2014.





Source: Commission staff based on information collection FERC-922.
Notes: (1) ISO-NE 2014 nuclear capacity values do not reflect the retirement of Vermont Yankee. (2) Per email correspondence on January 5, 2015, SPP revised its 2010 capacity percentage for nuclear to 3.9 percent. (3) Per email correspondence on January 11, 2016, LG&E/KU corrected its 2014 capacity percentages for coal and natural gas-fired capacity to 72.6 percent and 26.4 percent, respectively. (4) APS reports APS-owned capacity. (5) PAC includes contracted capacity. (6) DEP includes jointly-owned capacity.

i. Renewables and hydroelectric generating capacity

Among RTOs and ISOs, CAISO and NYISO report the largest shares of renewables and hydroelectric generating capacity. As of 2014, renewable and hydroelectric generators represented 36.5 percent of capacity in CAISO and 20.2 percent of capacity in NYISO. The largest relative increase occurred in SPP, where the share of renewable and hydroelectric capacity increased from 6.9 percent in 2010 to 12.6 percent in 2014.

Among non-RTO and ISO respondents, PAC reports the highest total percentage of renewable and hydroelectric generating capacity. Commission staff also notes that a number of non-RTO and ISO respondents report significant shares of capacity associated with purchased power, which could include renewables and other unidentified sources of generation. For PAC, the purchased power category represents non-renewable net purchases, but PAC's "other" category includes capacity related to certain renewable fuel types.

ii. Natural gas/oil-fired generating capacity

Among RTOs and ISOs, CAISO, ISO-NE, and SPP each report more natural gas-fired capacity than other fuel types from 2010-2014. MISO reports natural gas-fired capacity in combination with oil-fired capacity. The share of natural gas and oil-fired capacity in MISO increased significantly, from 31.3 percent in 2010 to 41.7 percent in 2014, as a number of utilities in the Gulf Coast region joined MISO in December, 2013. In the process, MISO transitioned from a majority coal-fired capacity mix in 2010 to a majority natural gas and oil-fired capacity mix in 2014. NYISO also reports that the New York Control Area has become increasingly dependent on natural gas and dual-fuel generating units,[79] although the share of natural gas and oil-fired generation increased modestly in NYISO, from 60.7 percent in 2010 to 61.2 percent in 2014.

Among non-RTO and ISO respondents, DEF reports the largest share of natural gas/oil-fired capacity during the reporting period. DEP, SOU, and PAC all report significant increases in the percentage of natural gas/oil-fired capacity.[80]

iii. Coal-fired generating capacity

PJM, MISO, and SPP report the highest shares of coal-fired generating capacity among RTOs and ISOs. Coal-fired generators accounted for the largest share of installed capacity in PJM from 2010-2014, ranging from a high of 42 percent in 2011 to a low of 39.7 percent in 2014. MISO reports that coal-fired generating capacity represented the largest share of generating capacity from 2010-2012, prior to the integration of MISO-South.

Across all RTO and ISO and non-RTO and ISO respondents, LG&E/KU report the largest share of coal-fired generating capacity (coal-fired generating capacity represented

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[79] October 2015 RTO and ISO Metrics Report at 260.

[80] For SOU and PAC, this category represents natural gas-fired generating capacity.

more than 70 percent of the total capacity mix in LG&E/KU in each year from 2010-2014).

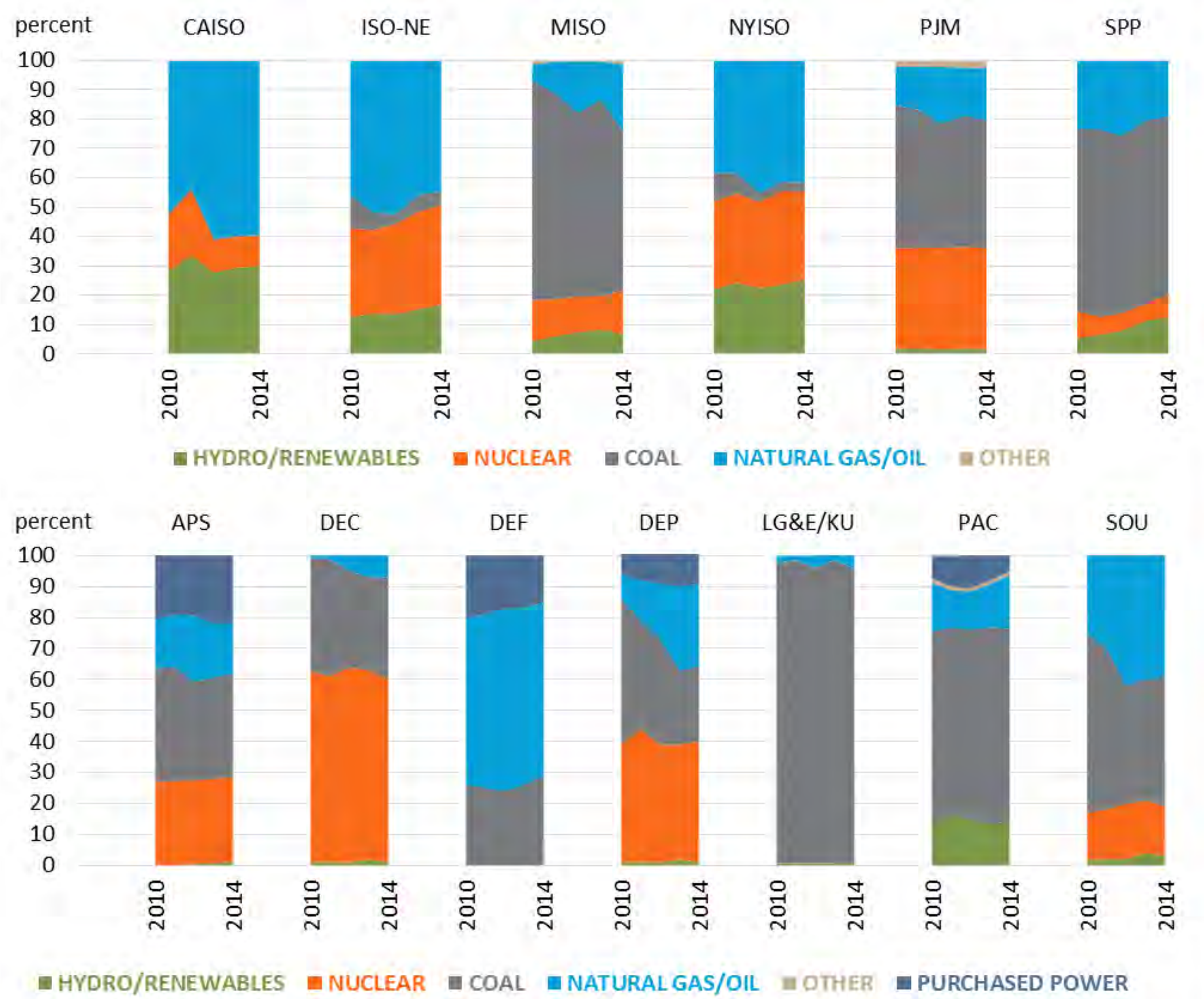
iv. Nuclear generating capacity

Across all respondents, CAISO reports the largest change in the share of nuclear generating capacity, declining from 7.8 percent in 2010 to 3.5 percent in 2014, which is attributable to the retirement of the San Onofre Nuclear Generating Station (SONGS).

b. Generation by Fuel Type

This metric measures the percentage mix of fuel types used to generate electricity (generation fuel diversity). The metric provides an indication of the level of integration of fuels with different characteristics, such as fuels with lower costs or lower environmental impacts. The mix of fuels used to generate electricity in a given time period follows from, among other factors, the types of generating capacity in service and conditions in fuel markets. Figure 19 shows the share of generation by fuel type from 2010-2014 as reported by respondents.

Figure 19: Share of total generation by fuel type .



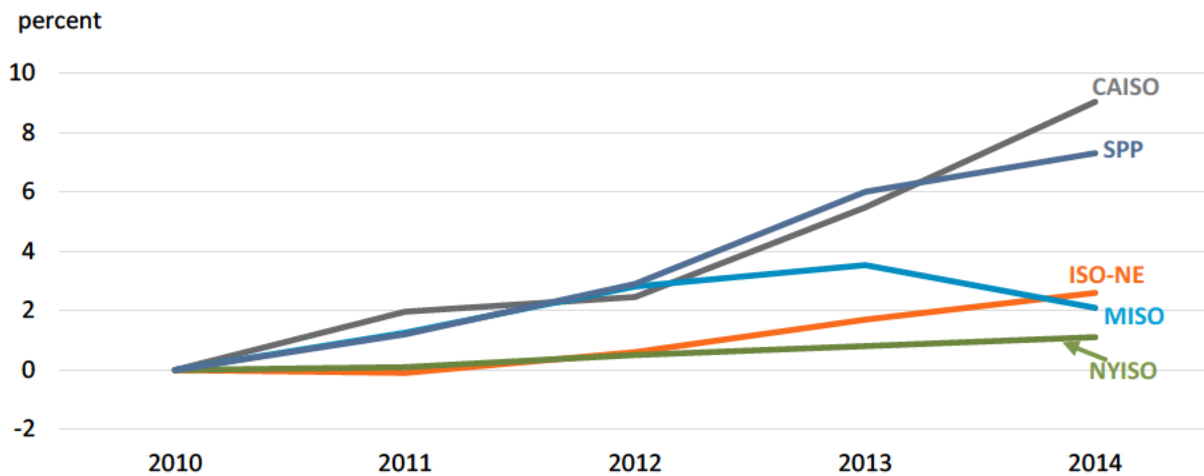
Source: Commission staff based on information collection FERC-922.
Notes: (1) SPP provided minor corrections to rounding errors in its original submittal via email correspondence on January 5, 2016. These include revising the 2014 share of natural gas-fired generation from 19.03 percent to 19.04 percent, and revising the 2010 share of hydro and renewables generation from 5.5 percent to 5.4 percent. The figure reflects the revised values. (2) Several non-RTO/ISO utilities report generation from purchased power, which may include a variety of fuel types. (3) PAC's "Other" category reflects waste heat and other sources which include biomass, biogas, geothermal, and solar.[81] PAC's "Purchased Power" category represents non-renewable net purchases.

[81] February 2016 PAC Metrics Report at 31.

i. Renewables generation

Most RTOs and ISOs generally report increases in the proportion of energy generated from renewable and hydroelectric sources between 2010 and 2014. In addition, the RTOs and ISOs separately report renewable generation as a percentage of total energy, separate from hydroelectric generation as a percentage of total energy. Figure 20 shows the increase in the share of total energy from non-hydro renewable sources relative to 2010 for five RTOs and ISOs. From 2010-2014, CAISO and SPP reported the largest gains in the share of energy provided from non-hydro renewable sources among RTOs and ISOs.

Figure 20: Gain/loss in non-hydro renewables share of total energy relative to 2010.



Source: Commission staff based on information submitted in the October 2015 RTO and ISO Metrics Report.
Note: PJM is not included in this figure. PJM reports renewables as a percentage of total energy increasing from 4.1 percent to 4.3 percent between 2010 and 2014. However, in comparing these totals to other values reported by PJM, it is not clear whether PJM included or excluded hydroelectric generation from the total.

ii. Coal, natural gas, and oil-fired generation

Among RTOs and ISOs, MISO, PJM, and SPP relied most heavily upon coal-fired generation to meet energy requirements from 2010-2014. However, in some RTOs and ISOs, the share of coal-fired generation declined as generation from natural gas-fired and renewable resources increased. PJM reports that generation produced from coal declined from 48.7 percent in 2010 to 43.5 percent in 2014.[82] In MISO, which integrated the

[82] October 2015 RTO and ISO Metrics Report at 324-325.

MISO South region in late 2013, the share of generation from coal-fired generators declined from 74.6 percent in 2010 to 54.2 percent in 2014.[83]

Trends in the total amount of generation provided by natural gas and coal-fired generation followed underlying fuel market trends. Several RTO and ISO regions report that the share of natural gas-fired generation increased between 2010 and 2012, as average natural gas prices declined, and then receded as natural gas prices increased between 2012 and 2014.

Among utilities in non-RTO and ISO regions, coal-fired generation provided nearly all the energy generated for LG&E/KU load. SOU and DEP report substantial declines in the proportion of energy produced by coal-fired generation from 2010- 2014.

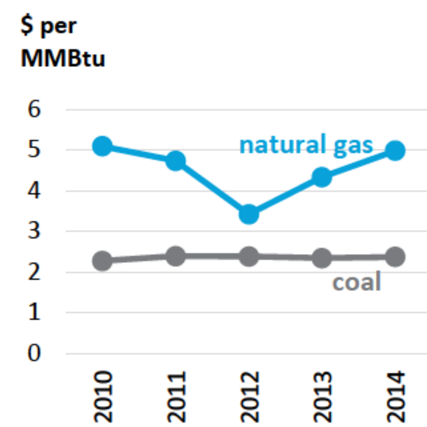
iii. Nuclear Generation

Across respondents, the most notable change in the proportion of energy provided by nuclear generation between 2010 and 2014 occurred in CAISO following the retirement of SONGS.

3. System Lambda

System lambda measures the incremental cost of energy derived from the economic dispatch function performed by a balancing authority area's control center. System lambda represents the incremental cost of energy of the marginal generating unit, assuming no system constraints, and generally tracks trends in marginal fuel costs for a given balancing authority area. The basis for the system lambda metric is information submitted in FERC Form No. 714.

Figure 21: Average cost of natural gas and coal delivered to U.S. electric power plants, 2010-2014.



Source: U.S. Energy Information Administration.
Note: Values are expressed in nominal dollars per MMBtu.

System lambda correlates with fuel prices and demand, among other factors, and reflects regional differences in the mix of generating resources. For instance, in areas where natural gas is the primary fuel used by generators on the margin, system lambda correlates with the price of natural gas. In areas with very large amounts of coal-fired generation, coal may be more likely to be the marginal fuel in a given hour. Figure 21 shows the average cost of natural gas and coal

[83] *Id.* at 203.

delivered to U.S. electric power plants from 2010-2014, expressed in nominal dollars per million British thermal units (MMBtu).[84] The average price of natural gas declined on an annual basis from 2010-2012, then increased from 2012-2014. As shown in Figure 22, the system lambda for most respondents also followed the trend of decreasing prices from 2010-2012, and increasing prices from 2012-2014. The responses from DEC and LG&E/KU do not follow this trend. As seen previously (Figure 19), the shares of natural-gas fired generation were lowest in DEC and LG&E/KU among respondents; thus, the incremental cost of energy in these regions is more likely to reflect the cost of other resource types (such as coal-fired generators).

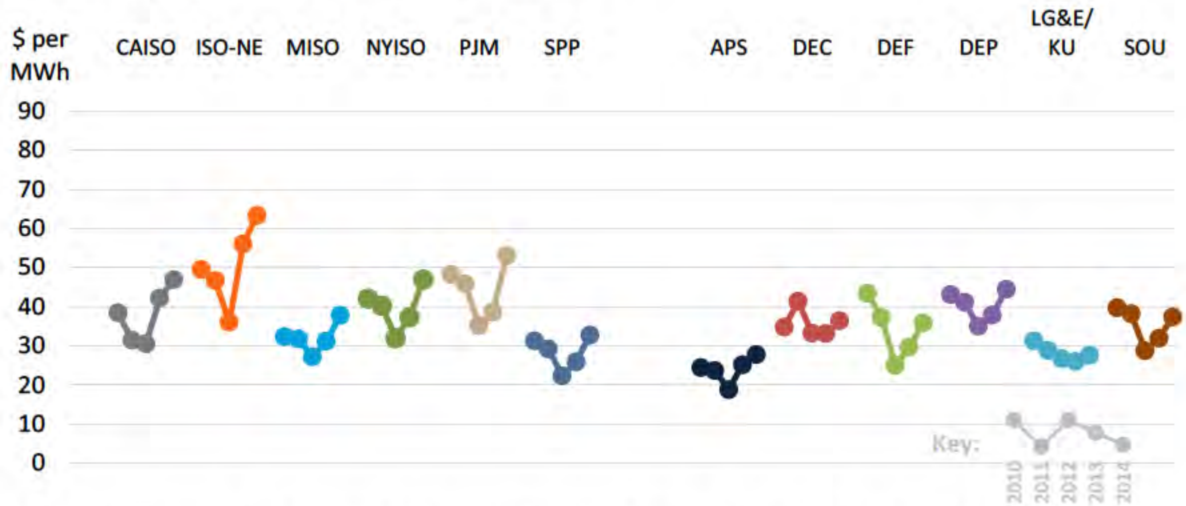
Regional variation in system lambda levels could reflect local fuel market conditions, electricity demand, and changing resource mixes, among other conditions. For example, ISO-NE reported the highest system lambda values among respondents, explaining that its system marginal cost values reflect movements in underlying fuel prices, especially during 2013 and 2014.[85] In 2013 and 2014, the northeast United States experienced extreme cold weather, operational challenges due to pipeline constraints, and fuel availability and delivery issues for both gas and oil-fired resources.[86]

[84] U.S. Energy Information Administration, *Short-Term Energy Outloo*k, (Jan. 2016) http://www.eia.gov/forecasts/steo/query/.

[85] October 2015 RTO and ISO Metrics Report at 123.

[86] *Id*. at 121-124.

Figure 22: System lambda by respondent, 2010-2014.



Source: Commission staff based on information collection FERC-922 and FERC Form No. 714.
Notes: (1) Values expressed in nominal dollars. (2) RTOs and ISOs report the marginal energy component of LMP; SOU does not provide system lambda values in this docket; values shown are based on Southern's submittals in FERC Form No. 714 (values shown for each year represent unweighted hourly averages). (3) PAC reports that it does not calculate system lambda because the PACW Balancing Authority Area carries a significant amount of hydroelectric generation on the regulating margin, and such resources do not have a fuel price component; PAC reports that the same hydroelectric resources are used as incremental regulating resources by the PACE Balancing Authority Area, through dynamic transfers.[87]

IV. Selected Other Metrics Specific to RTO and ISO Performance

A. Metrics Related to Coordinated Wholesale Power Markets

RTO and ISO respondents report a number of additional metrics that are not part of Information Collection FERC-922, because they are not common metrics that are applicable to the entire industry. For example, the RTOs and ISOs provide data that measure the performance of RTO and ISO day-ahead and real-time markets. The following sections contain an evaluation of selected RTO and ISO-specific metrics.

1. Proportionate Market Transaction Charges in 2014

RTOs and ISOs offer largely the same services. The cost of these services are charged to customers according to specified charge types. This metric should be considered in the context of differences in the scale and scope of market operations across RTOs and ISOs. The relative size of any category of cost to total cost is a function of many variables including whether there were major market design changes.

[87] February 2016 PAC Metrics Report at 30.

Table 10 summarizes the dollars billed across charge categories for RTOs and ISOs in 2014. For 2014, MISO reports billing the highest percentage of dollars for energy market transactions, at 82.7 percent.[88] Among RTOs and ISOs with capacity markets, NYISO reports the highest percentage capacity market charges relative to total dollars billed, at 30.0 percent.

It should be noted that SPP's Energy Imbalance Market was in operation through February 28, 2014, and was replaced with the Integrated Marketplace on March 1, 2014. The percentage of dollars billed in SPP reflects this transition.[89] It should also be noted that CAISO does not report the percentage of dollars billed.

Table 10: Summary of dollars billed by charge type, 2014.

RTO or ISO Category	Dollars Billed (billions)	Percentage of Total Dollars Billed
ISO-NE		
Energy Markets	9.079	72.3
Capacity	1.056	8.4
Transmission Tariff	1.819	14.5
Financial Transmission Rights Auction Revenues	0.032	0.3
Reserve Markets	0.207	1.7
Regulation Market	0.029	0.2
ISO-NE Administrative Expenses	0.171	1.3
Net Commitment-Period Compensation (NCPC)	0.167	1.3
Total	12.560	100.0
MISO		
Energy Markets	31.958	82.7
Resource Adequacy	0.145	0.4
Transmission Service	2.004	5.2
Financial Transmission Rights	4.115	10.6
Contingency Reserves	0.093	0.2
Regulation Market	0.087	0.2
Administrative Costs	0.247	0.6
Other	0.033	0.1
Total	38.680	100.0
NYISO		

[88] October 2015 RTO and ISO Metrics Report at 184.

[89] *Id.* at 360.

Table 10: Summary of dollars billed by charge type, 2014. (cont'd.)

RTO or ISO Category	Dollars Billed (billions)	Percentage of Total Dollars Billed
Energy Markets	5.023	46.7
Installed Capacity	3.222	30.0
Transmission Service	0.105	1.0
Transmission Congestion	1.198	11.1
Transmission Losses	0.478	4.4
Transmission Congestion Contracts - Billed Fiscal Year	0.391	3.6
Ancillary Services	0.171	1.6
Administrative Costs	0.161	1.5
Market-wide charges	-0.004	0.0
Other	0.004	0.0
Total	10.749	100.0
PJM		
Energy Markets	30.573	61.1
Capacity	7.735	15.5
Transmission Service	3.241	6.5
Transmission Congestion	2.572	5.1
Transmission Losses	1.677	3.4
Transmission Enhancement	0.961	1.9
Financial Transmission Rights Auction Revenues	0.960	1.9
Operating Reserves	0.918	1.8
Reactive Supply	0.280	0.6
Regulation Market	0.258	0.5
PJM Administrative Expenses	0.274	0.5
Other	0.581	1.2
Total	50.030	100.0
SPP		
Energy Imbalance Market	0.295	2.8
Integrated Marketplace	7.458	70.5
Transmission	1.506	14.2
Transmission Congestion Rights	1.165	11.0
SPP Administrative Fee	0.149	1.4
Total	10.573	100.0

Source: Commission staff based on October 2015 RTO and ISO Metrics Report.
Notes: (1) Billing amounts are expressed in nominal dollars. (2) In ISO-NE, NCPC represents make-whole payment (uplift) costs, and may relate to energy or reserves markets. (3) SPP transitioned from the Energy Imbalance Market to the Integrated Marketplace in March 2014.

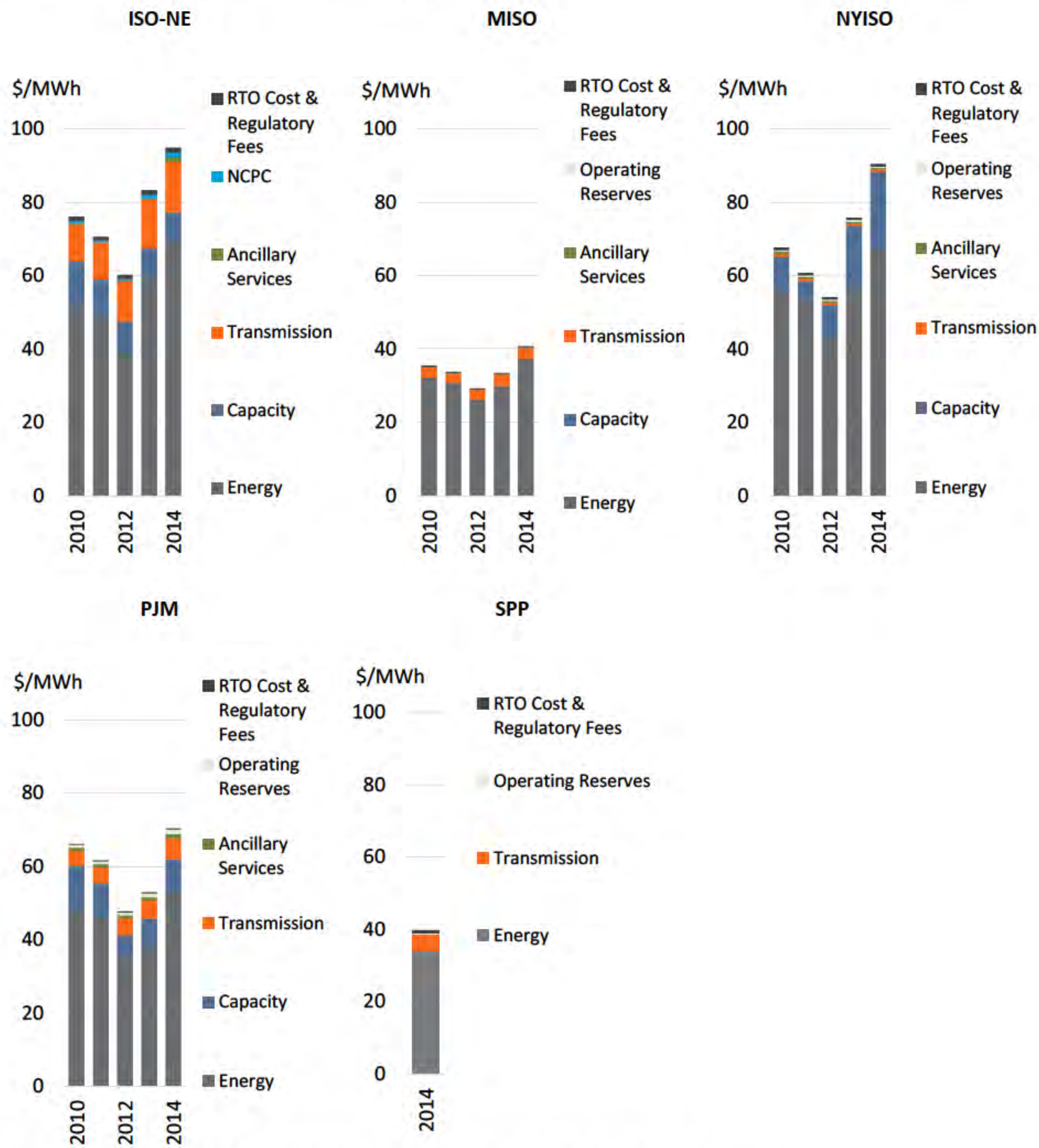
2. Wholesale Power Cost Breakdown

The wholesale power cost breakdown metric disaggregates costs paid by load, thereby providing a comprehensive assessment of all RTO and ISO market costs.[90] This metric should be considered within the context of different fuel mixes and market designs in each RTO and ISO region. As shown in Figure 23, ISO-NE and NYISO report the highest total wholesale power costs, with energy costs representing the largest component. The three eastern RTOs and ISOs (ISO-NE, NYISO, and PJM) each operate centralized capacity markets and report varying levels for the capacity-related component of wholesale power costs (with NYISO reporting the highest capacity-related costs). MISO also operates a voluntary capacity market to help ensure resource adequacy in its region. MISO reports a relatively low capacity-related component of wholesale prices as of 2014. It should be noted that SPP reports that data for this metric is only available beginning with the implementation of the Integrated Marketplace on March 1, 2014.[91]

[90] The cost breakdown includes the following cost categories: RTO or ISO costs and regulatory fees, operating reserve costs, ancillary services costs, transmission costs, capacity costs and energy costs.

[91] *Id*. at 367.

Figure 23: Wholesale power cost breakdown, 2010-2014.



Source: Commission staff based on October 2015 RTO and ISO Metrics Report.
Notes: (1) Values expressed in nominal dollars. (2) CAISO (not shown) does not report the numeric values corresponding to its wholesale power cost breakdown for 2014 and uses unique category names that are specific to CAISO. CAISO's response can be found on p. 59 of the October 2015 RTO and ISO Metrics Report.

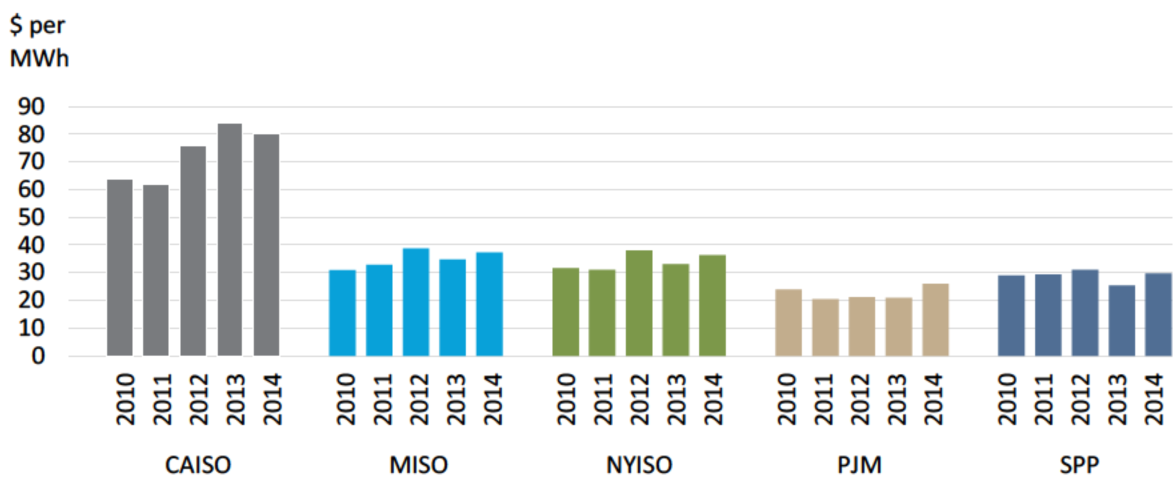
3. Fuel-Adjusted Wholesale Price

The load-weighted, fuel-adjusted locational marginal price is derived by holding fuel costs constant over a defined time period. This metric reflects the impact of load growth, new capacity, and the retirement of facilities, among other factors. As shown in Figure 24, CAISO reports the highest fuel-adjusted costs with an average of $73.20 per megawatt-hour and PJM the lowest with an average cost of $22.48 per megawatt-hour from 2010-2014.[92] PJM reports that its load-weighted fuel-adjusted wholesale spot energy prices increased 24 percent from 2013 to 2014, primarily driven by high demand and generator forced outages in PJM during periods of severe weather in 2014.[93]

Each RTO and ISO uses a different base year for its fuel adjustments. For instance, PJM uses a fuel cost reference year of 1999 because this is the first year that PJM administered both spot and day-ahead energy prices, whereas CAISO uses a base fuel cost reference year of 2008 gas prices and NYISO uses a base day for fuel-cost references year of 2000.

It should be noted that ISO-NE did not report a load-weighted, fuel adjusted locational marginal price.[94]

Figure 24: Load-weighted, fuel-adjusted locational marginal prices, 2010-2014.



Source: Commission staff based on October 2015 RTO and ISO Metrics Report.
Note: Values are expressed in nominal dollars per megawatt-hour.

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[92] *Id*. at 58 and 314.

[93] *Id*. at 314.

[94] *Id*. at 120.

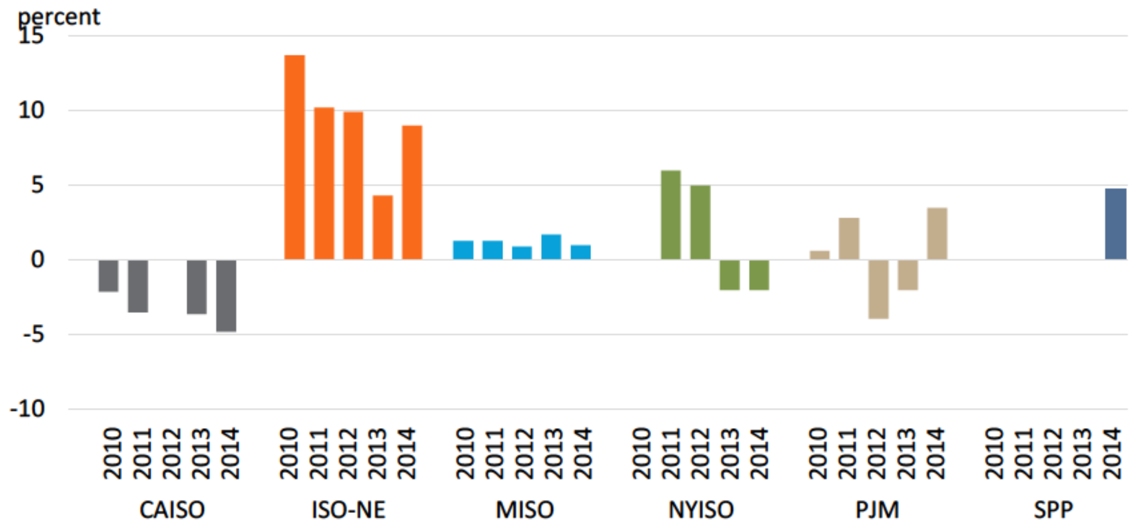
4. Price-Cost Mark-up

The price-cost mark-up metric is based on a comparison between the price-based offer and cost-based offer of marginal units.[95] Low mark-ups suggest competitive market performance. This metric reflects the percentage mark-up for each year. Figure 25 shows the price-cost markup from 2010-2014 as reported by RTOs and ISOs.

CAISO's wholesale markets had a negative price-cost mark-up in all years. In 2012, the mark-up was very close to zero percent. In 2014, the price-cost mark-up was negative 4.8 percent. CAISO states that negative mark-ups can occur because default energy bids include a 10 percent mark-up, and that many resources choose to bid below their default levels by small amounts in order to remain competitive in the market, especially as more renewable generation has come online over the past several years.

[95] *See id.* at 19 (RTOs and ISOs stating that price-cost mark-ups represent "the load weighted average markup component of dispatched generation divided by the load-weighted average price of dispatched generation.").

Figure 25: Price-cost mark-up, 2010-2014.



Source: Commission staff based on October 2015 RTO and ISO Metrics Report.
Notes: (1) CAISO compares total estimated wholesale energy costs to costs that would result under competitive baseline prices by re-simulating the market after replacing market bids for gas-fired generation with bids reflective of the unit's actual marginal costs.[96] (2) ISO-NE provides Lerner Index values as LI = (P-MC)/P, and states that beginning in 2012 it revised its methodology to calculate this index based on the day-ahead market, whereas before 2012 it was calculated based on the real-time market.[97] (3) MISO computes price-cost mark-up by comparing 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.[98] (4) NYISO's 2010 data do not appear on this figure because NYISO's Cost Price Mark-Up that year was zero percent. (5) PJM reports that the mark-up component of price is the difference between the system price, when the system price is determined by the active offers of the marginal units, whether price or cost-based, and the system price, based on the cost-based offers of those marginal units.[99] (6) SPP only reports data for 2014.

5. Percent of Unit-Hours Mitigated

This metric provides an indication of the magnitude of mitigation occurring in RTO and ISO markets, as measured by the percentage of unit hours that prices were set at the mitigated price on an annual basis. As shown in Figure 26, RTOs and ISOs report low percentages of mitigated hours from 2010-2014. Across RTOs and ISOs, CAISO reports the highest percentage of unit-hours mitigated from 2011-2014, with a downward trend

[96] *Id.* at 54.

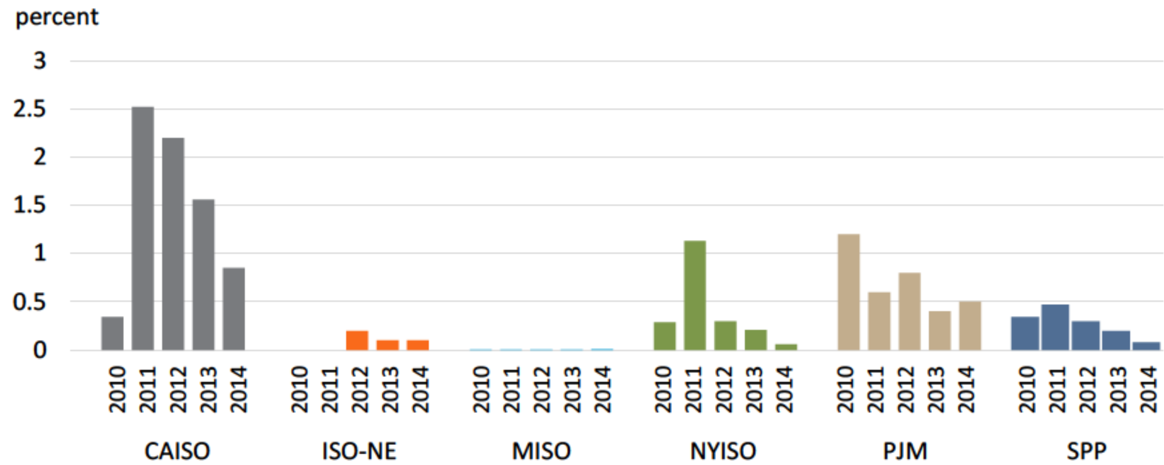
[97] *Id.* at 113-114.

[98] *Id.* at 186.

[99] *Id.* at 308.

over those four years.[100] MISO reports the lowest percentage of unit-hours mitigated among the RTOs and ISOs.

Figure 26: Percentage of unit-hours mitigated, 2010-2014.



Source: Commission staff based on October 2015 RTO and ISO Metrics Report.
Notes: (1) CAISO reports Real-Time Energy Market Percentage of Unit Hour Bids Mitigated due to Mitigation. (2) ISO-NE reports data only from April 18, 2012 onward. ISO-NE reports ISO-NE Percentage of Mitigated Hours in the Real-time Market Imposed under Market Rule 1, Appendix A, Section 5. (3) MISO reports Real-Time Energy Market Percentage of Unit Hours Offer Capped due to Mitigation. (4) NYISO reports Real-Time Energy Market Percentage of Unit Hours Offer Capped due to Mitigation. (5) PJM reports Real-Time Energy Market Percentage of Unit Hours Offer Capped due to Mitigation. (6) SPP reports Percentage of Unit Hours Offer Capped due to Mitigation.

6. Energy Market Price Convergence

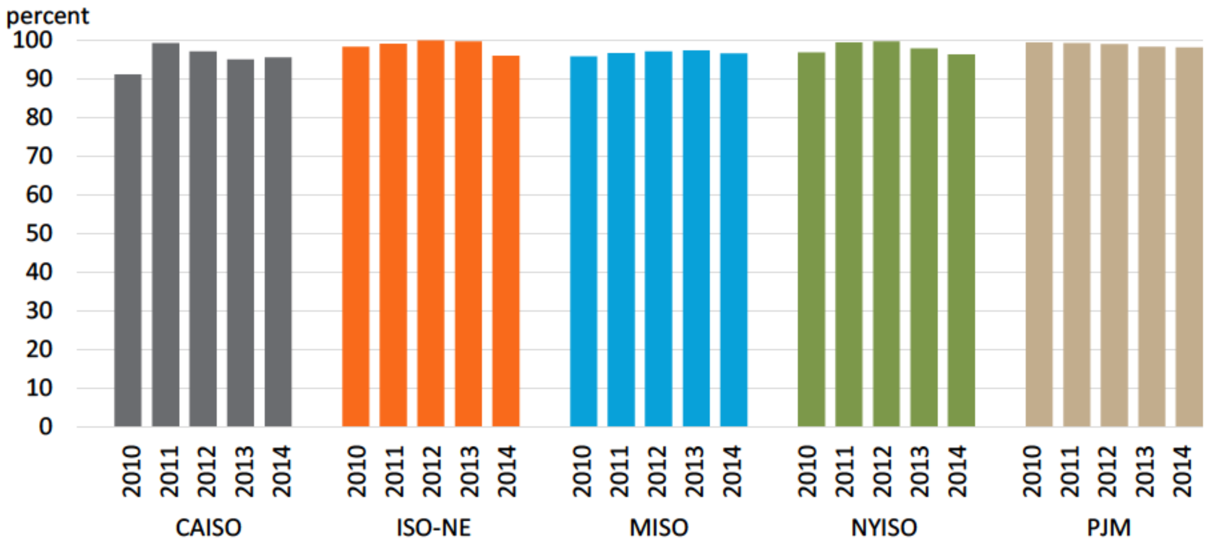
Convergence of day-ahead and real-time energy prices provides an indication of the efficiency of RTO and ISO markets. Since the majority of energy settlements and generator commitments occur in the day-ahead market, day-ahead price convergence with the real-time market ensures efficient day-ahead commitments that reflect real-time operating needs.

Figure 27 shows the trend in convergence of day-ahead and real-time energy prices over 2010–2014 for each RTO or ISO calculated as the percentage of the annual difference between real-time energy market prices and day-ahead market prices. PJM reports less than two percent divergence between day-ahead and real-time prices in each year during the reporting period. Among all RTOs and ISOs and across all years, CAISO reports the least day-ahead to real-time price convergence, at 91.2 percent in 2010. However,

[100] In 2012, CAISO adopted a new approach that uses actual market conditions to produce a more accurate assessment of transmission competitiveness. *See id.* at 57.

CAISO also reports substantially greater price convergence in each year from 2011-2014.[101]

Figure 27: Percentage day-ahead to real-time energy market price convergence, 2010–2014.



Source: Commission staff based on October 2015 RTO and ISO Metrics Report.
Notes: (1) NYISO explains that this metric is the annual index based on the deviation of the annual average load weighted Real-Time Dispatch (RTD) price from the annual average of the absolute divergence of the RTD prices from the day-ahead prices, over annual average load weighted RTD price.[102] (2) SPP only reports price convergence information for 2014 because the day-ahead market in SPP began with the implementation of the Integrated Marketplace on March 1, 2014. SPP reports 97.0 percent day-ahead to real-time price convergence for 2014.

7. New Entrant Net Revenue

Generator net revenue measures the difference between a new[103] generator's variable production costs and the energy price received. This metric can be an indicator of whether generator net revenues are sufficient to ensure new investment, if needed, and are consistent with competitive markets. This metric reflects analysis conducted by each entity's market monitor.

Table 11 illustrates the new entrant net revenues for combustion turbines. ISO-NE, MISO, and SPP had little to relatively small growth over the five-year period, while

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[101] CAISO has taken steps to improve price convergence such as improving load forecast accuracy and implementing flexible ramping constraints. *See id*. at 61.

[102] *Id*. at 254.

[103] ISO-NE reports net revenues for proxy resources, while CAISO, ISO-NE, MISO, NYISO, PJM, and SPP specify that the net revenues are for new entrants.

NYISO, which reports values for the Hudson Valley Zone, reports an increase of more than 2.5 times from 2010-2014.

Table 11: New entrant natural gas-fired combustion turbine net generation revenues.
(dollars per installed MW-year)

Respondent	2010	2011	2012	2013	2014
CAISO	53,430	44,550	49,290	31,520	28,820
ISO-NE	30,502	23,398	22,162	30,710	33,225
MISO	26,626	26,957	21,902	20,864	26,308
NYISO	25,906	12,606	35,675	88,498	92,088
PJM	32,781	36,103	23,240	19,004	51,753
SPP	26,430	10,739	3,119	2,820	31,516

Source: Commission staff based on October 2015 RTO and ISO Metrics Report.
Note: Values are expressed in nominal dollars. NYISO values reflect the Hudson Valley Zone.

Table 12 shows new entrant net revenues for combined cycle plants. Several RTOs and ISOs, including ISO-NE, MISO, and SPP report reductions in combined cycle net revenues, while CAISO, NYISO, and PJM report increases.

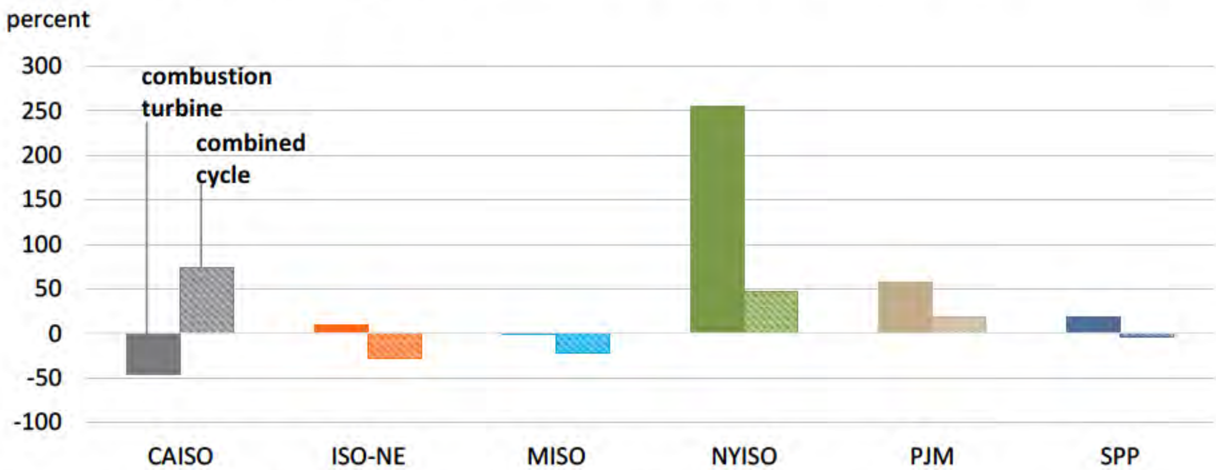
Table 12: New entrant natural gas-fired combined cycle net generation revenues, 2010-2014.
(dollars per installed MW-year)

Respondent	2010	2011	2012	2013	2014
CAISO	33,060	23,145	32,830	49,675	57,625
ISO-NE	61,246	53,026	42,458	40,146	44,380
MISO	43,899	35,561	36,847	25,627	34,714
NYISO	92,746	68,891	82,119	129,175	136,302
PJM	89,027	106,616	97,259	81,012	106,370
SPP	60,748	44,374	30,948	28,868	58,636

Source: Commission staff based on October 2015 RTO and ISO Metrics Report.
Note: Values are expressed in on nominal dollars. NYISO values reflect the Hudson Valley Zone.

Figure 28 details the percentage change in net revenues from 2010-2014 for new entrant combustion turbines and combined cycles for each region.

Figure 28: Percentage change in nominal net revenues for new entrant natural gas-fired combustion turbine and combined cycle generators, 2010-2014.



Source: Commission staff based on October 2015 RTO and ISO Metrics Report.

8. Reliability Must-Run Units

The reliability must-run (RMR) metric provides a measure of the degree to which an RTO or ISO must depend on critical facilities to maintain reliability and the flexibility of an RTO or ISO system to respond to emergencies and other contingencies. A RMR unit is typically a unit that continues to operate under a temporary contract after a planned retirement decision in order to resolve a reliability need.[104] As shown in Figure 29, CAISO and ISO-NE reported significant drops in RMR units from 2010-2014. MISO reported an increase from zero to 16 units under RMR-type arrangements.

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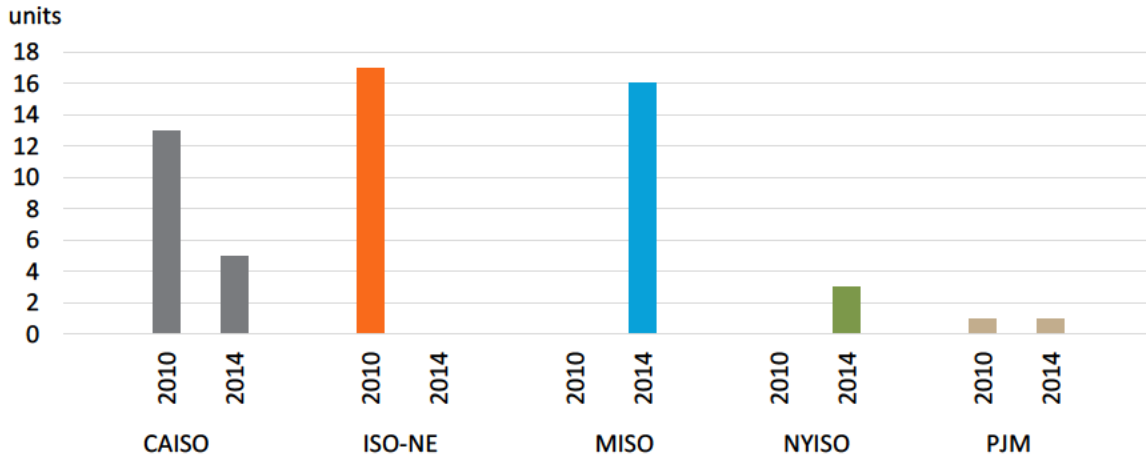
[104] RTOs and ISOs use various terms to refer to such arrangements, e.g., "System Support Resources" in MISO. For the purposes of this report, such arrangements are collectively referred to as RMR.

Figure 29: Number of units under RMR contracts, 2010 and 2014.



Source: Commission staff based on October 2015 RTO and ISO Metrics Report.
Notes: (1) NYISO reports that it did not have any RMR contracts under its tariff between 2010 and 2014; however, NYISO states that in 2013 and 2014 it had three units totaling 406 MW operating under Reliability Support Service Agreements established under state procedures. Reliability Support Service Agreements are contracts to keep resources operating while local transmission is under construction to resolve the associated reliability need.[105] (2) Beginning June 1, 2010, existing generating resources submit delist bids in ISO-NE's Forward Capacity Market indicating a price at which the resource wishes to opt out of capacity market obligations. If ISO-NE denies a delist bid for reliability reasons, the resource may be compensated at the denied delist bid price or through a cost-of-service agreement.[106] At the end of 2014, ISO-NE had zero units receiving such delist bid reliability payments.[107]

Figure 30 illustrates the change in capacity under RMR agreements or similar arrangements in RTOs and ISOs from 2010-2014. In MISO, capacity under such agreements increased from zero to 1,024 MW from 2010-2014. By contrast, CAISO[108] and ISO-NE reported sharp declines in the amount of capacity under RMR agreements or similar arrangements over the same period.

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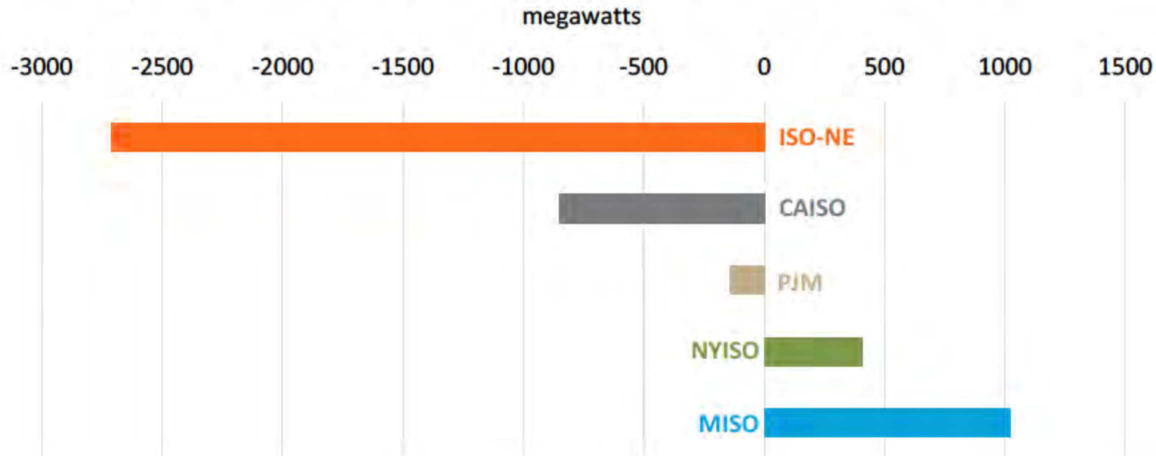
[105] *Id.* at 236.

[106] *Id.* at 101.

[107] *Id.*

[108] CAISO explains that much of the capacity needed for local reliability is provided through the capacity procured under resource adequacy. CAISO also notes that the amount of RMR capacity declines as existing RMR units retire. *See id.* at 48.

Figure 30: Change in capacity under RMR or similar agreements between 2010 and 2014.



Source: Commission staff based on October 2015 RTO and ISO Metrics Report.
Note: SPP does not report any RMR capacity between 2010 and 2014.

9. Demand Response

The demand response metrics provide an indication of the role played by demand response resources in maintaining short-term and long-term reliability in RTOs and ISOs. Demand response can lead to deferred investment in generation capacity by reducing load during peak periods.

In Order No. 745, the Commission established rules for compensating demand response in organized wholesale electricity markets,[109] which were upheld by the Supreme Court in January 2016.[110]

Figure 31 shows demand response as a percent of total installed capacity in five RTOs and ISOs from 2010-2014. Every RTO and ISO reports a decline in demand response's share of total installed capacity in 2014 relative to 2010.

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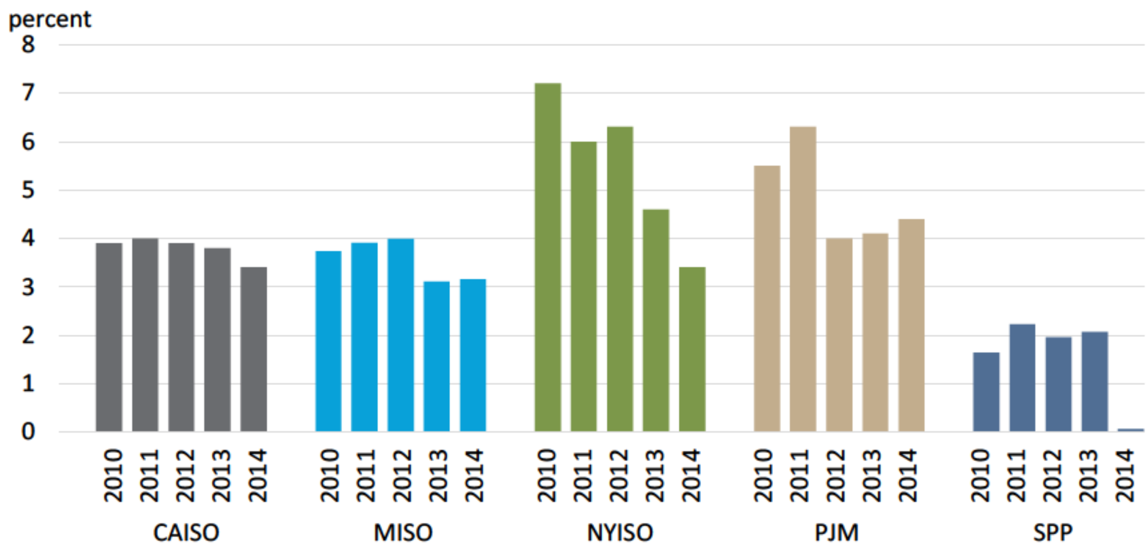
[109] *Demand Response Compensation in Organized Wholesale Energy Markets*, Order No. 745, FERC Stats. & Regs. ¶ 31,322 (2011), *order on reh'g*, Order No. 745-A, 137 FERC ¶ 61,215 (2011), *reh'g denied*, Order No. 745-B, 138 FERC ¶ 61,148 (2012), *rev'd and remanded sub nom. Elec. Power Supply Ass'n v. FERC*, 753 F.3d 216 (D.C. Cir. 2014), *rev'd and remanded*, 136 S. Ct. 760 (2016).

[110] *See FERC v. Elec. Power Supply Ass'n*, 136 S. Ct. 760, 774 (2016).

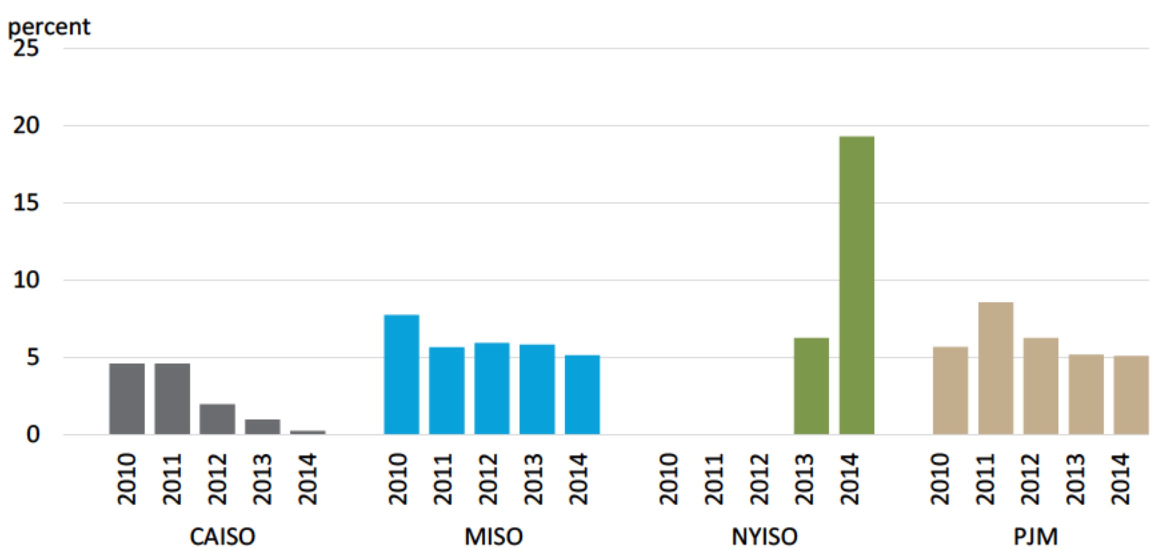
Figure 32 shows demand response as a percentage of reserves in four RTOs and ISOs from 2010-2014. During this period, CAISO reports a decrease in demand response as a percentage of reserves, while NYISO reports an increase from 2013 to 2014.

Figure 31: Demand response as a percentage of total installed capacity.



Source: Commission staff based on October 2015 RTO and ISO Metrics Report.
Note: ISO-NE does not provide data for this metric.

Figure 32: Demand response as a percentage of operating reserves, 2010-2014.



Source: Commission staff based on October 2015 RTO and ISO Metrics Report.
Notes: (1) SPP and ISO-NE do not provide data in response to this metric; (2) CAISO and PJM data indicate the shares of demand response in those CAISO and PJM's respective synchronized reserve markets.

10. Congestion Management

Congestion represents the cost to customers of paying for more expensive energy because physical transmission line limits do not allow full delivery of least-cost energy. This metric can be measured in two ways. First, annual congestion costs divided by the megawatt-hours of load served, tracks congestion cost trends relative to load growth, providing an indication of the efficiency of the overall RTO and ISO system, as well as the effectiveness of RTO and ISO efforts to manage congestion costs through transmission expansion planning and other efficiency measures. This measurement is not entirely within the control of the RTO and ISO because other factors, such as load trends, also influence this metric. Second, congestion can be expressed in terms of congestion revenues as a percent of congestion costs. In general, RTOs and ISOs use day-ahead congestion revenues to fund the financial entitlements of congestion rights holders. Figure 33 shows these metrics and provides details on RTO and ISO-specific calculation methods.

RTOs and ISOs report varying methods for calculating the percentage of congestion dollars hedged under this metric. CAISO divides the amount of net revenue the market receives by total congestion costs.[111] ISO-NE reports the extent to which day-ahead and real-time congestion revenue and negative target allocations were sufficient to fund the transmission-hedge instruments each year.[112] MISO reports the relationship between congestion revenues and congestion payments to financial transmission rights holders.[113] NYISO reports the "total annual revenue collected from the hedging contracts purchased through the Transmission Congestion Contracts auctions divided by the total annual congestion cost."[114] PJM reports that financial transmission rights revenue adequacy declined from 2010-2014 due to reasons such as increased transmission outages, flows from external RTOs onto the PJM system, market-to-market constraints, and uncontrollable circumstances, such as forced outages, voltage and thermal constraints, real-time switching, and reliability-related de-rates.[115]

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[111] October 2015 RTO and ISO Metrics Report at 63.

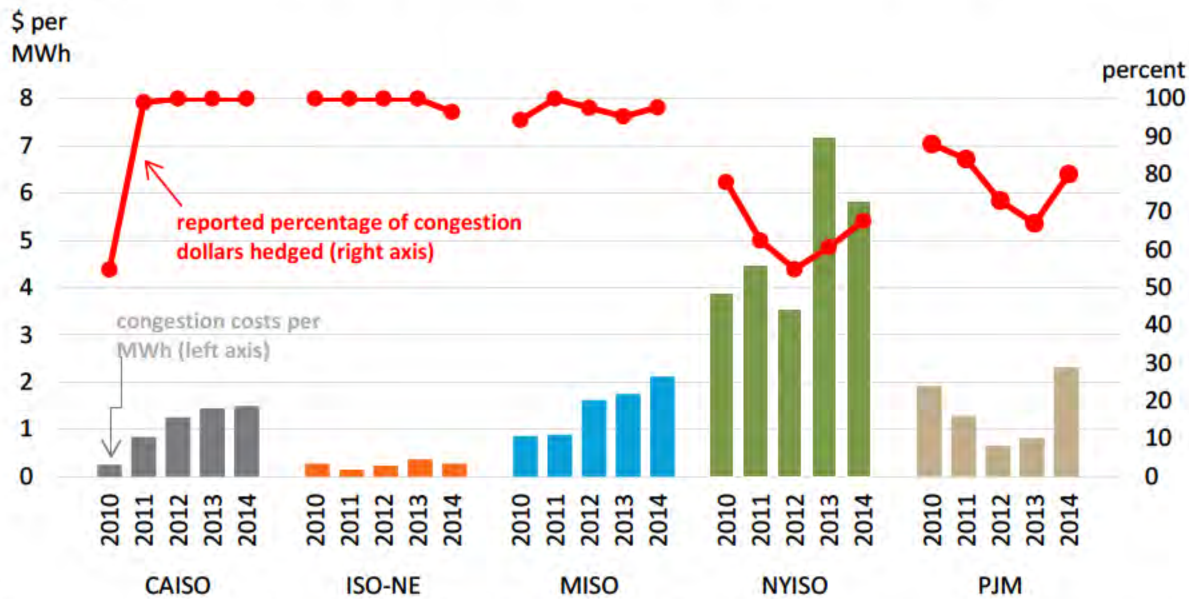
[112] *See id.* at 127-128. ISO-NE explains that negative target allocations are associated with counter-flow congestion in which a contract holder is required to contribute to the congestion revenue fund.

[113] *Id*. at 197.

[114] *Id.* at 257. NYISO also reports that there is an active market in over-the-counter contracts for differences which provide an additional hedging instrument.

[115] *Id*. at 322.

Figure 33: Annual congestion costs per megawatt-hour of load served and percentage of annual congestion costs hedged.



Source: Commission staff based on October 2015 RTO and ISO metrics report.
Notes: (1) Congestion costs are expressed in nominal dollars per MWh. (2) SPP (not shown) reports data for 2014 only. For 2014, SPP reports $2.11 of congestion costs per megawatt-hour of load served, and 85.9 percent of congestion costs hedged through congestion management markets.

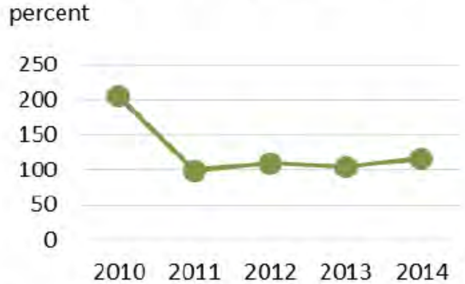
B. Metrics Related to Organizational Effectiveness

1. Administrative Costs

Administrative cost metrics measure the ability of RTOs and ISOs to manage the growth rate of administrative costs commensurate with the growth rate of system load (administrative charges per megawatt-hour of load served metric) and to keep costs within budgeted levels (actual versus budgeted administrative charges metric). The components of RTO and ISO administrative costs are capital costs – capital charges, debt service, interest expense and depreciation expense – and operating and maintenance costs net of miscellaneous income. By managing administrative costs, RTOs and ISOs can reduce customer costs.

For this metric, values below 100 percent reflect actual costs below budgeted costs.

Figure 34: NYISO capital costs as a percentage of budgeted costs, 2010-2014.

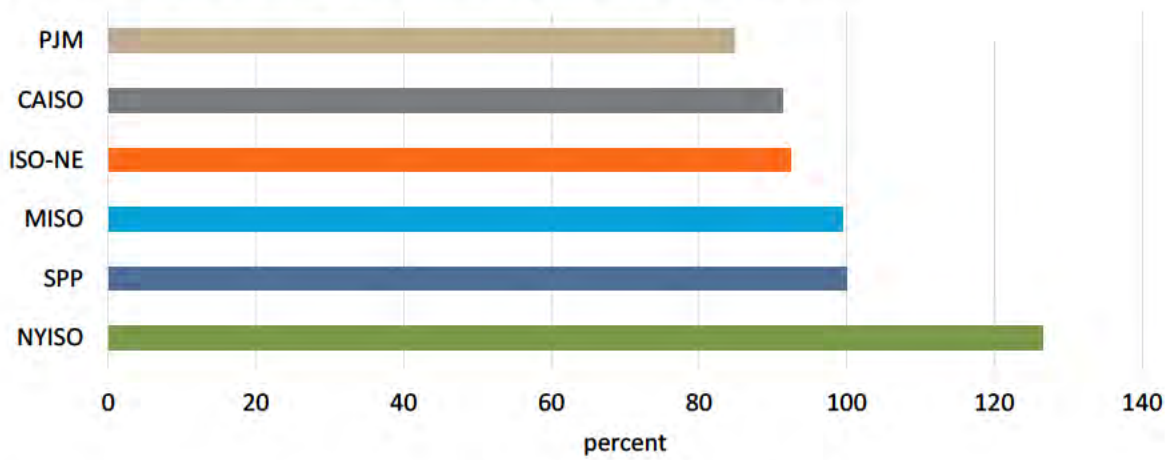


Source: Commission staff based on October 2015 RTO and ISO Metrics Report.

NYISO measured especially higher capital costs as a percentage of budgeted costs in 2010 (see Figure 34). NYISO explains that its capital recovery costs exceeded budget because anticipated long-term financing to proceed with infrastructure modifications did not receive approval during calendar year 2010. NYISO funded the cost of these capital improvements with spending under-runs on the non-capital costs portion of its annual budget recoveries. NYISO states that in a given year, it could overspend capital while underspending non-capital (or underspend capital while overspending non-capital); however, budget total spend is ultimately managed within the total overall NYISO budget.

Figure 35 shows the 2010-2014 five-year average capital costs as a percentage of budgeted costs for each RTO and ISO.

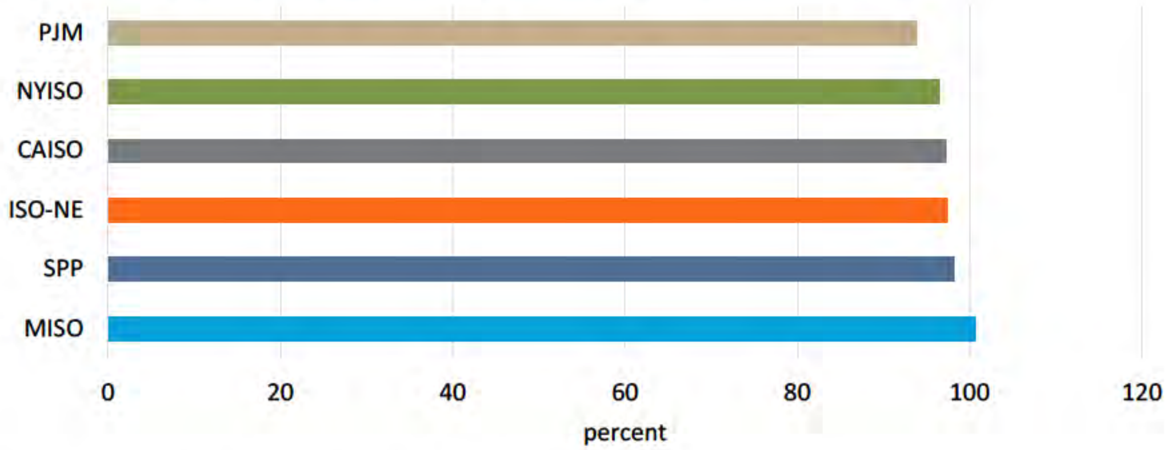
Figure 35: Five year average capital costs as a percentage of budgeted costs.



Source: Commission staff based on October 2015 RTO and ISO Metrics Report.
Notes: (1) Unweighted five-year average. (2) NYISO's 2010-2014 average reflects large capital expenditures in 2010.

The metric for noncapital (or administrative) costs, shown in Figure 36, shows each RTO's or ISO's administrative cost budget performance. The main categories of costs included in the non-capital costs metric are salaries and benefits, external professional fees, and computer services.

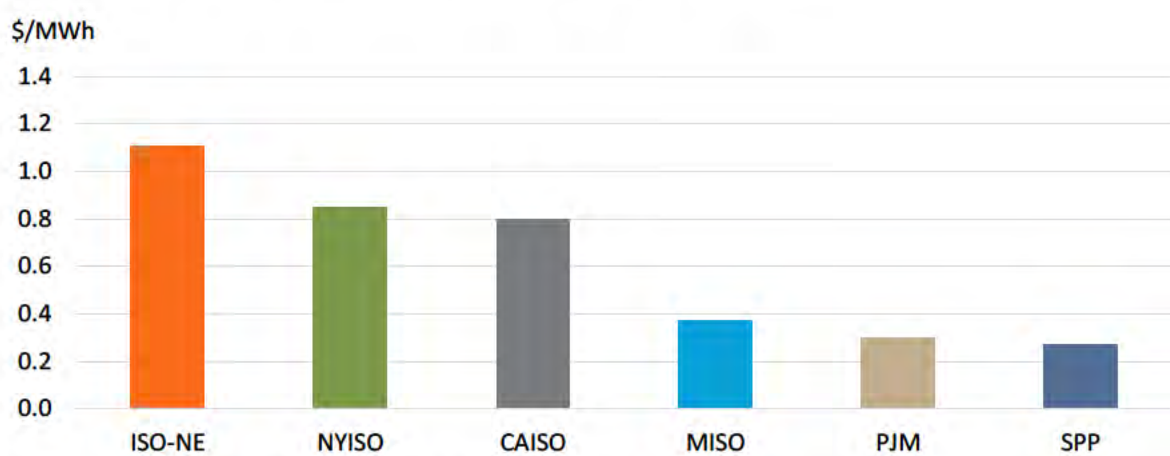
Figure 36: Non-capital costs as a percentage of budgeted costs, 2010-2014 average.



Source: Commission staff based on October 2015 RTO and ISO Metrics Report.
Note: Unweighted five-year average.

Figure 37 shows the 2010-2014 five-year average administrative cost per megawatt-hour in each RTO and ISO. Administrative costs vary widely across the RTOs and ISOs, with the five-year average administrative costs ranging from $0.27 per megawatt-hour for SPP to $1.10 per megawatt-hour for ISO-NE. While SPP has the lowest administrative costs on average over the reporting period, its annual rate of increase was the fastest rate among RTOs and ISOs (approximately 18 percent per year), and SPP reports higher per-megawatt-hour administrative costs ($0.38/MWh) than either PJM ($0.32/MWh) or MISO ($0.33/MWh) for calendar year 2014. The rate of increase seen in administrative costs in SPP may be attributable to the fact that SPP was in the process of launching its Integrated Marketplace during the reporting period.

Figure 37: Per-megawatt-hour administrative costs, 2010-2014 average.



Source: Commission staff based on 2015 RTO and ISO Metrics Report.
Notes: (1) Unweighted five-year average. (2) Average calculated using nominal dollars per megawatt-hour.

2. Billing Control Audits and Billing Accuracy

This metric indicates the accuracy and integrity of the RTO and ISO billing processes, based on audits conducted according to the Statement on Auditing Standards No. 70 (SAS 70) guidelines set by the American Institute of Certified Public Accountants. There are two types of SAS 70 audits: Type 1 audits, which assess the adequacy of the control design, and Type 2 audits, which review both the adequacy of the control design and whether the controls are being followed. An unqualified opinion indicates that the independent auditor found the control objects 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. Each RTO and ISO reports unqualified audit opinions, with the exception of MISO in 2014. MISO reports that in 2014 one control objective was deemed qualified in the area of configuring and monitoring information systems.[116]

PJM, MISO and NYISO report a billing accuracy of over 95 percent.[117] MISO reports a billing accuracy of 95.4 percent and both NYISO and PJM report a billing accuracy of 99.9 percent. It should be noted that CAISO, ISO-NE and SPP did not report on billing accuracy.[118]

3. Customer Satisfaction

The customer satisfaction metric provides an indication of the extent to which RTOs and ISOs provide value to their customers. This metric is based on independent assessments of customer satisfaction surveys undertaken by independent, third-party entities. These surveys analyze customer perspectives on a wide range of RTO and ISO activities. RTOs and ISOs achieved relatively high levels of customer satisfaction between 2010 and 2014. The average customer satisfaction rating for CAISO, ISO-NE, PJM, and SPP was 90 percent.[119] Beginning in 2011, PJM began taking customer surveys bi-annually, and CAISO did not conduct a survey in 2013.[120] ISO-NE used qualitative measures of overall performance (extremely satisfied to extremely dissatisfied) and report card data

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[116] *Id*. at 209.

[117] *Id*. at 209, 269-270 and 334.

[118] *Id*. at 72, 148 and 380.

[119] *See id*. at 72, 145-148, 333, 379.

[120] *See id.* at 72, 333.

(on a scale of zero to 100) to measure its customer satisfaction metric.[121] MISO and NYISO report average customer satisfaction ratings of 78 percent and 76 percent, respectively.[122]

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[121] *Id.* at 145-148.

[122] *See id.* at 208, 268-269, 333, 379.

Appendix A: List of Common Metrics

Table 13: Common metrics included in information collection FERC-922.

Reliability Metrics		
Metric No.	**Category**	**Description**
1	NERC Reliability Standards Compliance	References to applicable NERC standards
2		Number of violations self-reported and made public by NERC/FERC
3		Number of violations identified and made public as NERC audit findings
4		Total number of violations made public by NERC/FERC
5		Severity level of each violation made public by NERC/FERC
6		Compliance with operating reserve standards
7		Unserved energy (or load shedding) caused by violations
8	Dispatch Reliability	Balancing Authority ACE Limit (BAAL) or Control Performance Standards 1 and 2 (CPS1 and CPS2)
9		Energy Management System (EMS) Availability
10	Load Forecast Accuracy	Actual peak load as a percentage variance from forecasted peak load
11	Wind Forecast Accuracy	Actual wind availability compared to forecasted wind availability
12	Unscheduled Flows	Difference between net actual interchange and the net scheduled interchange (in megawatt-hours)
13	Transmission Outage Coordination	Percentage of planned outages (200 kilovolt and above) of at least 5 days for which the RTO and ISO or utility notified customers at least one month prior to the outage date
14		Percentage of outages (200 kilovolt and above) canceled by RTO and ISO or utility after being approved previously
15	Long-Term Reliability Planning – Transmission	Processing time for generation interconnection requests
16		Percentage of approved construction projects on schedule and completed
17		Performance of planning process related to completion of (1) reliability studies and (2) economic studies
18	Long-Term Reliability Planning – Resources	Processing time for generation interconnection requests
19		Actual reserve margins compared with planned reserve margins
20	Interconnection and Transmission Process Metrics	Number of study requests
21		Number of studies completed
22		Average age of incomplete studies
23		Average time for completed studies
24		Total cost and types of studies completed
25	Special Protection Systems	Number of special protection systems
26		Percentage of special protection systems that responded as designed when activated
27		Number of unintended activations
28	System Lambda	System Lambda (on marginal unit), based on FERC Form No. 714 information
29	Availability	(1 – system forced outage rate) as measured over 12 months
30	Fuel Diversity	Fuel diversity in terms of energy produced and installed capacity

Source: Commission staff based on May 20, 2015 Comment Request in Docket No. AD14-15-000.
Note: For purposes of this report, Commission staff considers metrics 1-27 to be reliability metrics; Commission staff considers metrics 28-30 to be system operations metrics.

Appendix B: Recent RTO and ISO Expansion Activity

Since the release of the GAO Report in 2008, SPP, CAISO, MISO and PJM have expanded their footprints. The utilities that voluntarily joined RTOs and ISOs and/or imbalance markets attribute their decision to the more efficient commitment and dispatch of generation plants and enhanced reliability, coordination, competition and economies of scale provided by RTOs and ISOs. In some cases, the expanding RTO or ISO or the joining member estimated the monetized benefits from RTO and ISO expansion (usually in the form of estimated production cost savings); the accompanying sidebar discusses notable highlights from these analyses.[123]

SPP

SPP estimates that the net Integrated Marketplace savings were $131 million in its first 12 months of performance as of the third quarter of 2015.

CAISO

A report for the fourth quarter of 2015 estimated the gross benefit of CAISO's energy imbalance market that began in November 2014 to be $45.7 million.

MISO

MISO estimates that the integration of the MISO South Region yielded net benefits between $730 and $954 million.

PJM

East Kentucky Power Cooperative estimates that its 16 member-owned cooperatives will realize $131.9 million in net benefits over its first decade of PJM membership.

In 2014, CAISO expanded the use of the imbalance energy portion of its real-time market to other balancing authority areas in the Western Interconnection.[124] Several utilities outside of RTOs and ISOs in the West are participating in CAISO's Energy Imbalance Market (EIM) to share reserves and integrate renewable resources across a larger geographic region reliably and efficiently.

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[123] *See* SPP, *Results 2014 Annual Report,*8 http://www.spp.org/documents/28682/ar-2014%2004302015.pdf; CAISO, *2015 Q4 Report: Quantifying EIM Benefits* (Feb. 2016) https://www.caiso.com/Documents/ISO_EIMBenefitsReportQ4_2015.pdf; MISO, *MISO 2014-2015 Winter Assessment Report Information Delivery and Market Analysis* 29 (May 2015), https://www.misoenergy.org/Library/Repository/Report/Seasonal%20Market%20Assessments/2015%20Winter%20Assessment%20Report.pdf; and Compete, *Public Power Utilities Flock to PJM, MISO for Benefits of Wholesale Power Market Competition* (June 2013), http://competecoalition.com/blog/tag/competitive-electricity-market.

[124] *Cal. Indep. Sys. Operator Corp.*, 149 FERC ¶ 61,058 (2014).

In 2011, American Transmission Systems, Inc. and Cleveland Public Power joined PJM;[125] in 2013, East Kentucky Power Cooperative, Inc. joined PJM.[126] In December 2013, Entergy's utility operating companies – Entergy Arkansas, Inc., Entergy Mississippi, Inc., Entergy Texas, Inc., Entergy Louisiana, LLC, Entergy Gulf States Louisiana, L.L.C., and Entergy New Orleans, Inc. – completed the integration of their transmission systems into MISO.[127] The Entergy utility operating companies, among other industry participants, comprise the MISO South Region.

On November 1, 2014, CAISO and PAC participated in the launch of the EIM.[128] In April 2015, PAC and CAISO signed a Memorandum of Understanding (MOU) to examine the potential benefits of creating a regional ISO.[129] The parties have extended the MOU to further explore costs and requirements needed to achieve the benefits of integration outlined in a study conducted by Energy Environmental Economics,[130] as well as to develop a transition agreement to outline the terms and conditions for the potential integration of PAC into a regional market.

Additionally, Puget Sound Energy and APS are scheduled to begin financially binding participation in CAISO's EIM in October 2016. NV Energy, Inc. began participating in

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[125] PJM, *PJM History,* (Feb. 2015), http://www.pjm.com/about-pjm/who-we-are/pjm-history.aspx?p=1.

[126] On May 22, 2013 in Docket Nos. ER13-1177-000, ER13-1178-000, and ER13-1179-000, the Commission accepted tariff revisions filed in connection with East Kentucky Power Cooperative, Inc.'s integration into PJM under delegated authority. *See also East Kentucky Power Cooperative, Inc*., 147 FERC ¶ 61,028 (2013) and *East Kentucky Power Cooperative, Inc*. 147 FERC ¶ 61,097 (2014).

[127] *Midwest Indep. Trans. Sys. Op., Inc.*, 139 FERC ¶ 61,056, *on reh'g*, 141 FERC ¶ 61,128 (2012).

[128] *Cal. Indep. Sys. Op. Corp.*, 147 FERC ¶ 61,231 (2014).

[129] CAISO, *News Release: Western grid integration could produce significant cost savings, environmental benefits,* (Oct. 2015), http://www.caiso.com/Documents/WesternGridIntegrationCouldProduceSignificantCostSavings-EnvironmentalBenefits.pdf.

[130] Utility Dive, *Study: Integrating PacifiCorp and CAISO grids could create up to $9.1B in savings,* (Oct. 2015), http://www.utilitydive.com/news/study-integrating-pacificorp-and-caiso-grids-could-create-up-to-91b-in-s/407203/.

CAISO's EIM on December 1, 2015.[131] Portland General Electric Company filed an agreement with FERC to participate in CAISO's EIM starting in 2017.[132] Idaho Power signed an agreement with CAISO to participate in CAISO's EIM starting in 2018.[133] As a result, CAISO's EIM will encompass seven western states – California, Oregon, Washington, Nevada, Utah, Idaho, and Wyoming.

On October 1, 2015, the Integrated System and its three primary entities became full members of SPP. The Integrated System is comprised of Western Area Power Administration-Upper Great Plains, Basin Electric Power Cooperative, and Heartland Consumers Power District.[134] This expands SPP's footprint to 14 states, adding the Dakotas and parts of Iowa, Minnesota, Montana, and Wyoming. Western Area Power Administration-Upper Great Plains is the first federal power marketing administration to join an RTO or ISO.

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[131] CAISO, *News Release*: *NV Energy enters the western Energy Imbalance Market*, (Dec. 2015), https://www.caiso.com/Documents/NVEnergyEntersTheWesternEnergyImbalanceMarket.pdf

[132] CAISO, *News Release*: *Portland General Electric formalizes agreement to join EIM*, (Nov. 2015), http://www.caiso.com/Documents/PortlandGeneralElectricFormalizesAgreementToJoinEIM.pdf, see also CAISO, Implementation Agreement Filing, Docket No. ER16-366-000.

[133] Idaho Power Company, *News Release: Company Agrees to Join Western EIM,* (Apr. 2016), https://www.idahopower.com/NewsCommunity/News/NewsReleases/showPR.cfm?prID=3796.

[134] *Southwest Power Pool, Inc*., 149 FERC ¶ 61,113 (2014) *reh'g Southwest Power Pool, Inc*., 153 FERC ¶ 61,051 (2015).

Resource Investment in the Golden Age of Energy Finance

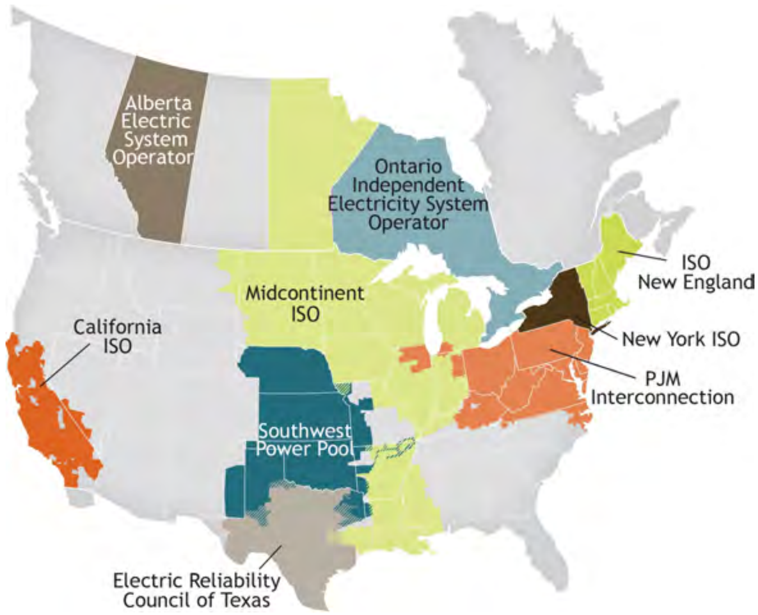
Financial Investment Drivers and Deterrents in the Competitive Electricity Markets of the US and Canada

May 2015

THE ISO/RTO COUNCIL

The ISO/RTO Council (IRC) is the umbrella group for all electricity Independent System Operators (ISOs) and Regional Transmission Operators (RTOs) in the US and Canada:

- Alberta Electricity System Operator (AESO)
- California Independent System Operator (CAISO)
- Electric Reliability Council of Texas (ERCOT)
- (Ontario) Independent Electricity System Operator (IESO)
- ISO New England (ISO-NE)
- Midcontinent Independent System Operator (MISO)
- New York Independent System Operator (NYISO)
- PJM Interconnection (PJM)
- Southwest Power Pool (SPP)



These organisations operate both the electricity transmission system and electricity spot/cash markets within their respective regions, along with a range of other markets and system-related services. Collectively their footprint spans two-thirds of electricity consumers in the US, and more than half in Canada. Through the ISO/RTO Council, its members share ideas and information, and pursue topics of common interest.

ABOUT THE AUTHORS

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Market Reform is a boutique international consultancy specializing in industries undergoing significant structural change – through competition, deregulation and the evolution of new business models and methods. Our work has a particular focus on energy, water and environmental markets.

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1 EXECUTIVE SUMMARY

Electricity markets in the US and Canada have an ongoing imperative to promote resource adequacy, and ensure there is a steady flow of resource investment within their regions. Meanwhile, these markets are also experiencing significant changes in resource mix, driven by natural gas supply, environmental policy and other factors.

The objective of the Resource Investment & Revenue Analysis Project was to better inform the members of the ISO/RTO Council regarding the factors that drive financial investment in generation and other system resource, and how these are influenced by ISO policy/market design decisions and the revenue streams flowing out of the ISO-operated markets. The study's approach was to gather this information 'from the horse's mouth'; through direct conversations with those actually responsible for making investment decisions.

The Goal of Investment

All rational investors seek an attractive risk-adjusted return on capital. This money is not 'ear-marked' for generation – that is one potential path it can take, not the destination. The goal of investment is profit. For capital to find its way into generation and other system resource, these investments must provide returns that are competitive with the many other investment opportunities competing for the same funds.

This does not mean that all investors have the same requirements or approach. One of the project's fundamental tenets is that investors are not a homogeneous group – with differing fields of interest and expertise, maturity requirements, risk appetite and return expectations. Investors can, however, be segmented into a number of investor classes, with reasonable commonality of attributes within each class. The project sought input from, and to compare and contrast the opinions of, investors spanning private equity funds, project developers, merchants/IPPs, investment funds, tax equity, underwriters/financiers, and commercial lenders.

The Current Investment Context

A number of the investors interviewed for the project believed that the US and Canada are presently experiencing "a golden age of energy finance."

The interest rate environment, coupled with a number of financial engineering innovations – such as tax equity, Yieldcos, and the expansion of the Term Loan B market – has appreciably expanded the availability of low-cost financing. This coincides with the right time in the boom/bust development cycle in many of the ISO markets.

Investment Drivers and Deterrents

The project received a wide range of direct feedback from investors on the factors that encouraged, as well as deterred, their investment in generation and other system resource, and identified a number of key themes.

The 'Fundamentals' are fundamental

First and foremost, investment is driven by the fundamentals of energy supply/demand balance. While investors have strong opinions on issues of market design, such considerations were secondary to the fundamental strictures of supply/demand balance. If demand growth is strong, they will invest even if they don't like the design, and vice versa. There was some concern, though, regarding the impact that inherently ‘lumpy’ investment can have on these fundamentals in smaller markets.

Capacity markets are loved, but feared

As a general rule, investors were strong supporters of capacity markets, for their ability to backstop energy revenues and provide greater certainty of future cashflows. There was concern, however, regarding volatility in capacity revenues in recent years, which has led to steep discounting of projected capacity revenues when assessing potential investments. Ancillary services revenues scarcely factored into investors’ considerations, with the notable exception of grid-level storage.

Renewables investment is driven by incentives

The development of renewable generation is substantially supported by incentive programs – Renewable Portfolio Standards (RPS) being most influential in the majority of markets. Tax credits are important in “lubricating the markets”, especially in financing new plant. However, as incentive programs are at risk of government intervention, the revenues derived from them tend to be discounted by investors.

Energy revenues were considered to be of lesser importance to renewables, with neither wind nor solar resource expected to be ‘investable’ without incentives for some time.

Non-renewables are principally driven by gas, if it can be delivered

Gas-fired generation has accounted for the great bulk of new investment in non-renewable resource, driven by cheap fuel supply, emissions benefits, cheaper plant and the general flexibility of gas-fired plant.

However, issues of gas deliverability are of significant concern. Pipeline capacity expansion is not keeping pace with demand growth, and gas/electric integration is inadequate. This is already an active problem in New England and is expected to become an increasing issue in other parts of the North-East and Mid-Atlantic in the next few years. These issues are leading many to question whether the gas regulatory construct needs to be re-thought, to address the changed needs of a gas system far more dynamic and interconnected than that for which the model originally evolved. Some even suggested that “perhaps there is a need for a gas ISO?”

Investors prefer open, transparent markets

Interviewees universally expressed the view that they are more comfortable investing in markets they view as open and transparent. In those markets where an incumbent can fall back upon a franchise customer base, with regulator-guaranteed returns, the playing field is perceived to be inherently uneven. By contrast, the presence of effective retail competition was seen as an important indicator of market openness.

While each investment is assessed on its own merits, investors expressed a general aversion for markets that might be subject to incumbent dominance, and attraction to markets where they view the price-setting process as transparent and free from potential manipulation or interference. The resultant ability to trade confidently was seen as contributing directly to more effective hedging, and better liquidity in both the cash and forward markets.

The desire for transparency extends to ISO operations

Concern was expressed that out-of-market actions taken by ISOs, including the dispatch of plant out of economic merit order, and the designation of resources as Reliability Must-Run

(RMR), can appear arbitrary, and if it materially impacts market results, can dull the investment climate. It was generally appreciated that there can be valid reasons for such actions, tempered by a general conviction that they are over-used, and that greater transparency surrounding the rationale for their use would aid investor confidence, and encourage better process.

Regulatory risk is unhedgeable

A repeated and serious concern raised by investors was the risk that regulators and legislators can take, and on occasion have taken, actions which interfere with the very price signals which the market relies upon to stimulate investment. These unpredictable and unhedgeable actions – which often reward the reckless and punish the prudent – can, in the longer-term, drive capital away from the market.

A lesser concern was the general level of complexity of the ISO-operated markets, and the level of ongoing ‘tweaking’ of market rules. While all those interviewed would like to see less variability in market design, this concern was greatest amongst those with a shorter-term investment horizon.

2 THE PROJECT BRIEF

2.1 Objective

ISOs/RTOs (hereafter referred to as ISOs), as the Reliability Coordinators for their respective regions, have a mandate to promote resource adequacy, and as such are strongly interested in maintaining a steady flow of resource investment within those regions. To inform their thinking – particularly in the light of significant changes in resource mix being driven by natural gas supply, technology, environmental policy and other factors – the ISOs wish to better understand:

1. the factors that are driving financial investment in prospective (and existing) generation and other system resource (e.g. demand response, storage), and;
2. how these are influenced by ISO policy/market design decisions, and the various revenue streams flowing out of the ISO-operated markets.

2.2 Scope

To this end, the Markets Committee of the ISO/RTO Council engaged Market Reform to undertake the Resource Financing & Revenue Analysis Project. The study's mandate was to address these questions not from the perspective of economic theory, but by seeking the views of actual 'financial' investors in resource, through equity or debt. Investors of interest fit the following profile:

- Invests directly in resources, in part or whole, or facilitates such investment – not just an investor in securities of resource/asset owners, or of bonds issued by them.
- Directly interested in the revenue flows received by those resources.
- Active investor, involved in assessing investment value, packaging the products, directing the funds, etc. – not a passive holder.
- Investments are directly exposed to revenue risk – without the protection of a franchise customer base, or rate-of-return regulation. i.e. investment in traditional utilities was explicitly out-of-scope.

2.3 Approach

The study's declared approach was to gather its information 'from the horse's mouth'; through interviews with investor personnel integrally involved in the investment evaluation and decision-making process.

This process was guided by the following principles:

- *Grounded in practice, not theory*: The project was not approached from the perspective of economic theory, and what a theoretical 'rational investor' would do, but based its analysis on the considerations of *actual* investors, who must act with imperfect information and considering the risk of how things may evolve in the future. As such, a series of interviews with a thoughtfully selected set of actual investors was at the core of the project's activities.
- *The interviewee's opinion, not the interviewer's*: By extension, Market Reform's job was to effectively prepare for, lead and analyze these discussions, and synthesize the results – requiring the team to utilize expert judgment and challenge what they heard – but not to substitute their own opinion.

- *'Investors' are not a homogenous group*: While often discussed collectively, there is no uniform investor. Nor was it viewed as particularly useful to just take a random sample of investors. Investors were divided into a number of classes (discussed further in 3.3), with representatives of each class forming part of the interviewee set.
- *Consistent, senior interview team*: In order to ensure a consistent approach to all interviews, they were conducted by the same two principal interviewers. As the project sought access to senior investment decision makers, the interview team was commensurately senior.

The project had a target of conducting 7-8 interviews, though ended up exceeding this. In all, 21 invitations were issued, with 15 interviews conducted, 2 declines and 4 failures to respond after multiple attempts. The list of organisations interviewed is included in Appendix B. To get the most value out of the discussions, approximately two-thirds of interviews were conducted in-person, with the remainder done over the phone.

By agreement with the project's steering committee, all interviews were conducted under the Chatham House Rule, whereby an attendee is free to use any information gathered from the discussion, but is not permitted to reveal who made any comment.

3 A RESOURCE INVESTMENT PRIMER

3.1 'Financial Investors' in 'Resource'

This report is concerned with 'financial investors' in 'resource'. In its broadest sense, this is any entity that invests in system resource – generation, demand response or storage – in the form of either equity or debt.

More specifically, the project is principally interested in those investing within the footprint covered by the nine IRC members, and with exposure to the revenue streams stemming from the ISO-operated markets – as opposed to revenues assured by guaranteed regulatory recovery from a captive rate base.

3.2 What Do Investors Seek?

Ultimately, all rational investors seek an attractive risk-adjusted return-on-capital. Their precise risk tolerance, return expectations, and the trade-off between these, is unique to each organisation, and dependent upon its investment thesis and policies. For most financial investors there is no default position that they must invest in generation, or any other electric system resource, and certainly no geographic restriction on where they choose to invest. Capital is deployed where it can be utilised most effectively.

Logically, investors will always seek maximum return for minimum risk. On the other hand, in a well-functioning market there is always a competitive tension amongst and between sellers and buyers that serves to restrict investment returns – a tension well understood and respected by all those the project interviewed.

For investors, this must be balanced by the competition for funds. If an investor perceives the risk as high – whether this be due to underlying fundamentals such as falling demand, the threat of competition, or a perceived systemic bias in the market – they will seek higher returns. If this would price them out of the market, or returns are constrained by other means (e.g. regulatory controls), they will decline to participate and 'place their bets' elsewhere. If multiple participants share the same perspective, it can lead to a dearth of new investment. When driven by fundamentals this may well be a desirable outcome; in other situations, less so.

The reverse argument is also true when risk adjusted returns are considered to be attractive – if multiple investors feel the same way there can be a rush of investment. Given the 'lumpiness' of generation investment, particularly when compared against the total size of smaller markets, this can lead to a 'boom/bust' cycle.

3.3 Investor Classes

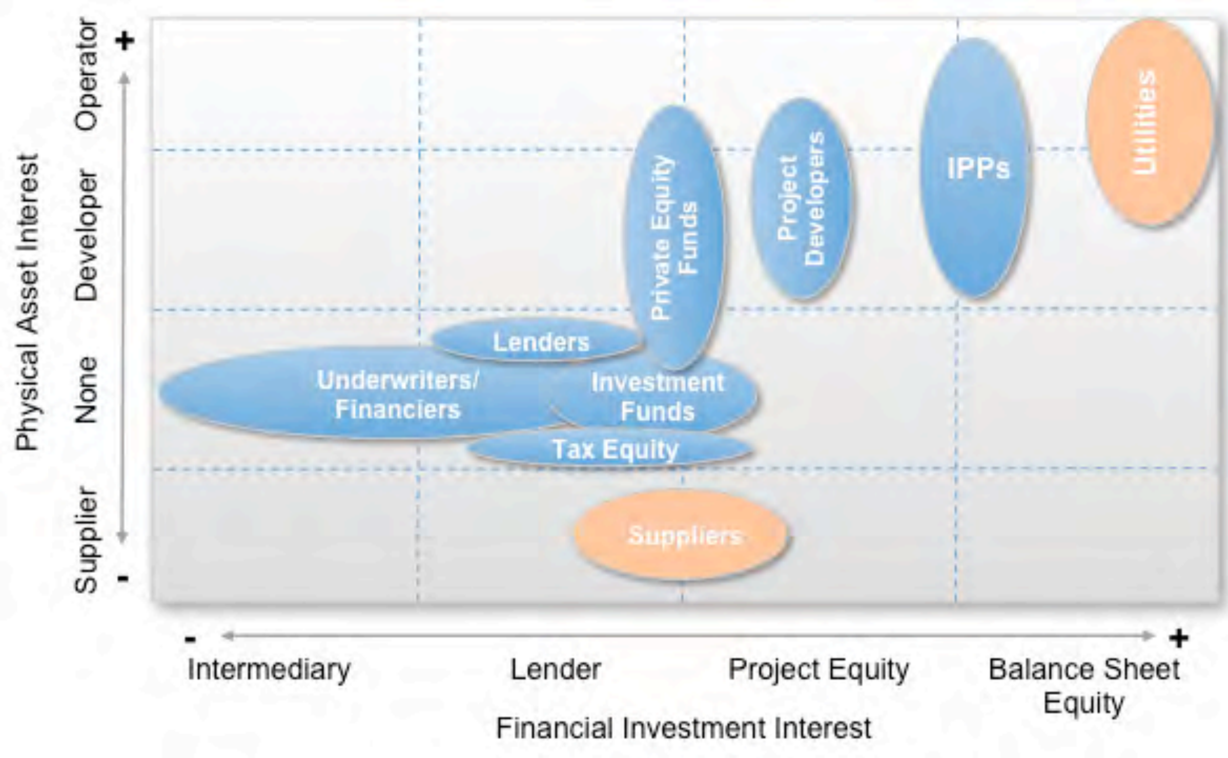
As discussed in the Approach section of this document (2.3), investors are not a homogeneous group – with differing fields of interest and expertise, maturity requirements, risk appetite and return expectations. Investors can, however, be segmented into a number of investor classes, with reasonable commonality of attributes within each class – not withstanding that some investors fall into more than one class. Key investor classes examined by the project included:

Table 1 – Investor Classes Examined

Private equity funds	Mid-stage and mature funds (early stage/venture capital tends to invest more in energy technology vs. assets). Providers of both equity and debt investment.
Project developers	Lead the development of new resources. Equity investors; projects are typically supported by equity co-investment and project-level debt. May operate the asset, or have others do this. Typically dispose of asset within 5 years of entering service.
Merchants/IPPs	Develop new resource and acquire existing resource. Projects/acquisitions typically backed by balance sheet equity and corporate debt. Typically operate the asset. Longer-term holders compared to project developers.
Investment funds	Including pension funds, mutual funds, exchange-traded funds, infrastructure funds, sovereign wealth funds. May provide equity (e.g. as a co-investor) or debt investment.
Tax equity	Corporates, banks, and insurance companies with sizable tax exposures. Only applicable to investment in renewables with tax credits. Essentially debt providers, but with an ‘equity’ element to allow transfer of tax credits (see 3.5.2).
Underwriters/ financiers	Typically investment banks. Act as intermediaries in arranging debt and/or equity financing. May also participate as lenders.
Commercial lenders	Insurance companies, commercial banks, project finance banks, mezzanine funds, bond markets. Providers of debt, often organised by underwriters. Type of debt highly dependent on project stage, and risk.

Figure 1 below provides a diagrammatic overview of the typical financial investment and physical asset interest of various investor classes in a resource. Those shown in blue are those of interest to this project.

Figure 1 – Investment Interests in Resource



3.4 Stages of Investment

New resource – or at least, project-developed resource – tends to be financed differently depending upon its stage of development, utilising higher cost funds during its riskier earlier stages, later supplanting these with less expensive longer-term funds as it moves into operation. The three typical phases are:

- *Development*: All work to identify, qualify and quantify the opportunity, determine siting and conduct interconnection studies, arrange permitting and approvals, select contractors, arrange financing, negotiate off-take agreements or other hedging, etc., through to issuance of a notice-to-proceed for construction.
- *Construction*: All construction works and commissioning of the facility, interconnection to the grid, and connection to fuel (e.g. gas pipeline), through to commencement of operations.
- *Operation*: Full operation of the resource in the electricity market

The helpful diagram in Figure 2 below – adapted from an original produced by Marathon Capital – provides an overview of the various types of debt and equity financing typically utilised in each development stage, and common providers of each type of financing.

Figure 2 – Types of Finance and Providers, by Project Lifecycle Stage[1]

Development	Construction	Operation
Debt		
Corporate Debt • Bond Markets (for IPPs)	Corporate Debt • Bond Markets (for IPPs) Bank Debt • Project Finance Banks • Commercial Banks Mezzanine Debt • Infrastructure Funds • Mezzanine Debt Funds	Corporate Debt • Bond Markets (for IPPs) Senior / Long-Term Debt • Project Finance Banks • Commercial Banks • Insurance Companies • Bond Markets
Equity		
Balance Sheet Equity • IPPs Development Equity • Private Equity • Project Developer	Construction Equity • IPPs • Private Equity • Infrastructure Funds • Equipment Providers	Tax Equity • International + Regional Banks • Insurance Companies • Corporates Project Equity • Private Equity • Investment Funds • Private Placements • Public Markets (YieldCos)

3.5 "A Golden Age of Energy Finance"

This characterisation, or similar, was used by several of the investors interviewed by the project.

The interest rate environment in the US and Canada (at the time of writing), coupled with a number of financial engineering innovations, has appreciably expanded the availability of low-cost financing. Anecdotally, debt financing deals that were being done 3-4 years ago at LIBOR plus 700-900 basis points (bps), are now being done at LIBOR plus 300-400 bps. Project debt-equity ratios have also been increasing from around 1:1, to closer to 2:1. While the variety of financing deals that can be done are limited only by the ingenuity of the financial engineers, and what a buyer and seller are willing to agree, three general trends are noteworthy:

3.5.1 Growth of 'Term Loan B'

Investors with a suitably robust balance sheet typically obtain debt financing at the corporate level, through the bond market and bank lines of credit, providing leverage across their entire asset portfolio. By contrast, project developers have historically obtained finance through the senior term loan – also known as Term Loan A – market, potentially augmented by more expensive shorter-term financing. However, Term Loan A comes with significant covenants, including the requirement that almost all off-take price exposure be hedged out 5-7 years (the holding period of the asset for many developers), and substantial amortisation (repayment of loan principal over the loan period).

The last couple of years have seen an increasing use of Term Loan B for major project debt. Term Loan B typically sits equal to Term Loan A on a security basis, but has fewer restrictive covenants – e.g. 50% vs. 100% hedging requirements – and requires nil or minimal amortisation.

[1] Adapted from the original diagram by Marathon Capital. Source: Ted Brandt, Marathon Capital, *The State of Power*

These eased restrictions imply a greater risk, and thus higher interest rates, compared to Term Loan A. However, spreads have narrowed substantially as lenders have become more comfortable with the risks associated with the use of Term Loan B for generation financing.

3.5.2 Tax Equity

'Tax equity' has become a popular method of financing renewable generation in the US. This form of finance has its origins in the various tax incentives for development of renewable generation, including:

- *Production Tax Credit (PTC)*: chiefly used by wind generation, these provide a $23/MWh credit for wind, geothermal and closed-loop biomass, and $11/MWh for other eligible technologies, generally over the first 10 years of operation. PTCs are no longer being issued for projects not already under construction.
- *Investment Tax Credit (ITC)*: chiefly used by solar, these provide a credit equal to 30% of investment value for solar, fuel cells and small wind, and 10% for geothermal, micro-turbines and combined heat and power (CHP). The solar credit reduces to 10% at the end of 2016. ITCs are realized in the year in which the project begins commercial operations, but vest linearly over a 5-year period.
- *Accelerated Depreciation*: assets can be fully depreciated within five years for most solar, geothermal and wind assets, even though their useful life may be 30+ years.

The complication is that many developers of renewable generation cannot take full advantage of these tax benefits as they are not sufficiently profitable. Tax rules do, however, allow these benefits to be assigned to other equity holders in the business. Enter tax equity.

Under a tax equity arrangement, the majority of the resource owner's tax credits are assigned to tax-equity investors. These deals are typically debt-like, paying an agreed return, and having creditor priority superior to trade creditors and regular equity, but include a call option, which allows the arrangement to be considered equity for tax purposes. Given these attributes, investors in tax equity are typically organisations with substantial available cash to invest, and sizable tax liabilities which can be offset – such as major banks, large corporates, and insurance companies.

3.5.3 YieldCos

In the current low interest rate environment, yields have been substantially reduced on traditional fixed income investments, such as treasuries and municipal bonds. As a result, there is significant investor appetite for instruments that can provide better long-term, fixed income yields.

YieldCos are a financial innovation developed to take advantage of this need. They consist of a portfolio of assets with steady revenues, backed by long-term (15-25 year) forward contracts, paying out most of their cash flow to shareholders as dividends. Due to these characteristics they are sometimes referred to as 'synthetic MLPs'. The 'sponsor' of the YieldCo – usually the original owner and ongoing operator of the YieldCo's assets – tends to maintain management control and a sizable shareholding.

Because of the requirement for steady revenues, YieldCo portfolios have tended to consist predominantly of renewable assets contracted to utilities under long-term power purchase agreements, or deregulated assets in rate-regulated regions, again under long-term utility contract.

An important part of the stated proposition for many YieldCos, and a key influencing factor in their valuation multiples, is the 'growth story' – the expectation, often explicitly promised, that they will continue to develop and/or acquire a stream of assets with attractive, steady revenues which will be 'dropped down' into the YieldCo.

There is concern, though, regarding the sustainability of this model. With the growing popularity of YieldCos and a limited supply of assets with long-term stable revenues to 'drop down', some questioned how YieldCos could keep "feeding the beast", and whether they would begin seeking out opportunities with lower quality revenues (e.g. shorter tenors), thus "debasing the currency". In the longer-term there is concern that, when interest rates come back up, YieldCos could lose their relative attractiveness to other steady yield investments, and thus some of premium valuation they presently attract.

Ultimately, the investor view of YieldCos was mixed. Some saw them as creating competition for funds, leading to an increase in the cost of capital. Others saw them as "an attractive platform", opening up opportunities for participation by investors who might not normally invest so directly in generation, and allowing asset owners to free up capital for other investments

3.6 Project Finance Example

Figure 3 below provides an overview of the various parties involved in financing a recently announced project – Panda Power's Stonewall facility in Loudon County, Virginia.[2]

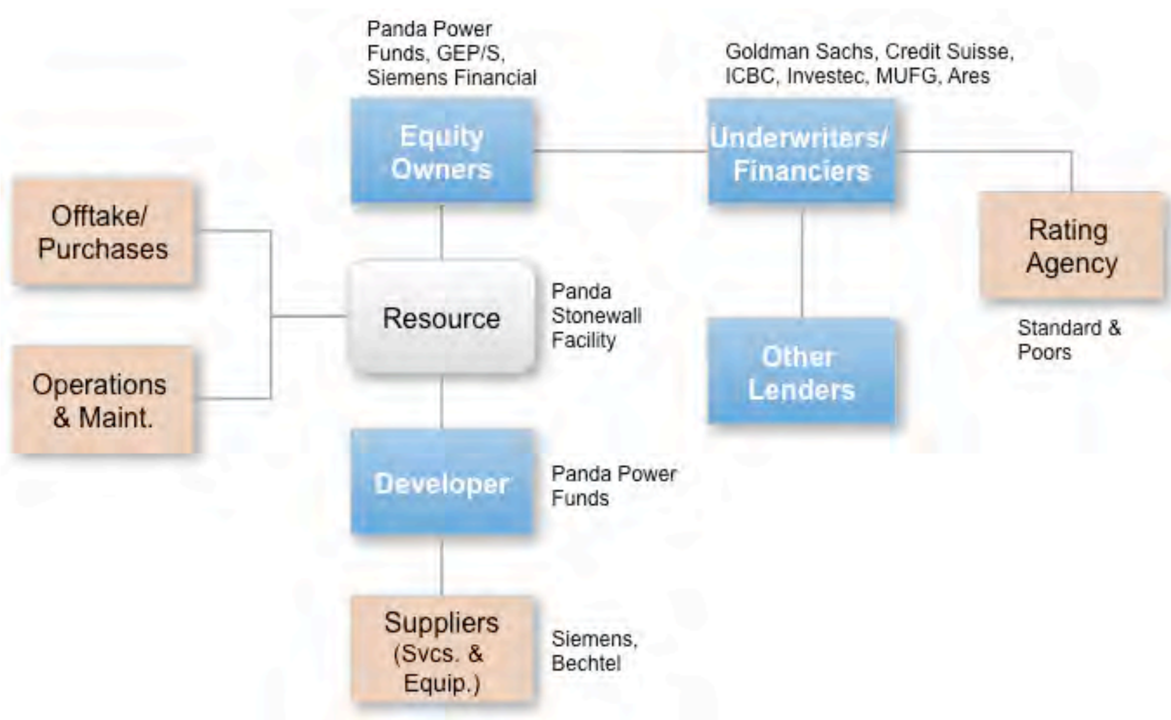


Figure 3 – Example Project Structure: Panda Stonewall

[2] Data source: Business Wire, November 17 2004, *Panda Power Funds Secures Financing for 778 MW/$571 million Virginia Power Project*. While Panda Power was interviewed for this project, all information contained in this diagram was obtained from publicly available sources.

The role of various debt and equity investors can be seen, with a few other points also worth noting:

- The definition of key equipment and construction service providers, ongoing operations and maintenance, and key off-take and fuel supply arrangements, are all essential to obtaining finance.
- The finance arm of the key equipment provider is also an equity participant in the project. Equipment provider participation in equity and/or debt has been seen in a number of recent projects.
- Participation of the rating agencies. Even though debt is not being raised from the public markets, obtaining a credit rating is generally required for Term Loan B financing also.

Figure 4 below summarises a number of the key elements which must be resolved during the development stage of a project in order to secure financing for later stages of the project lifecycle.

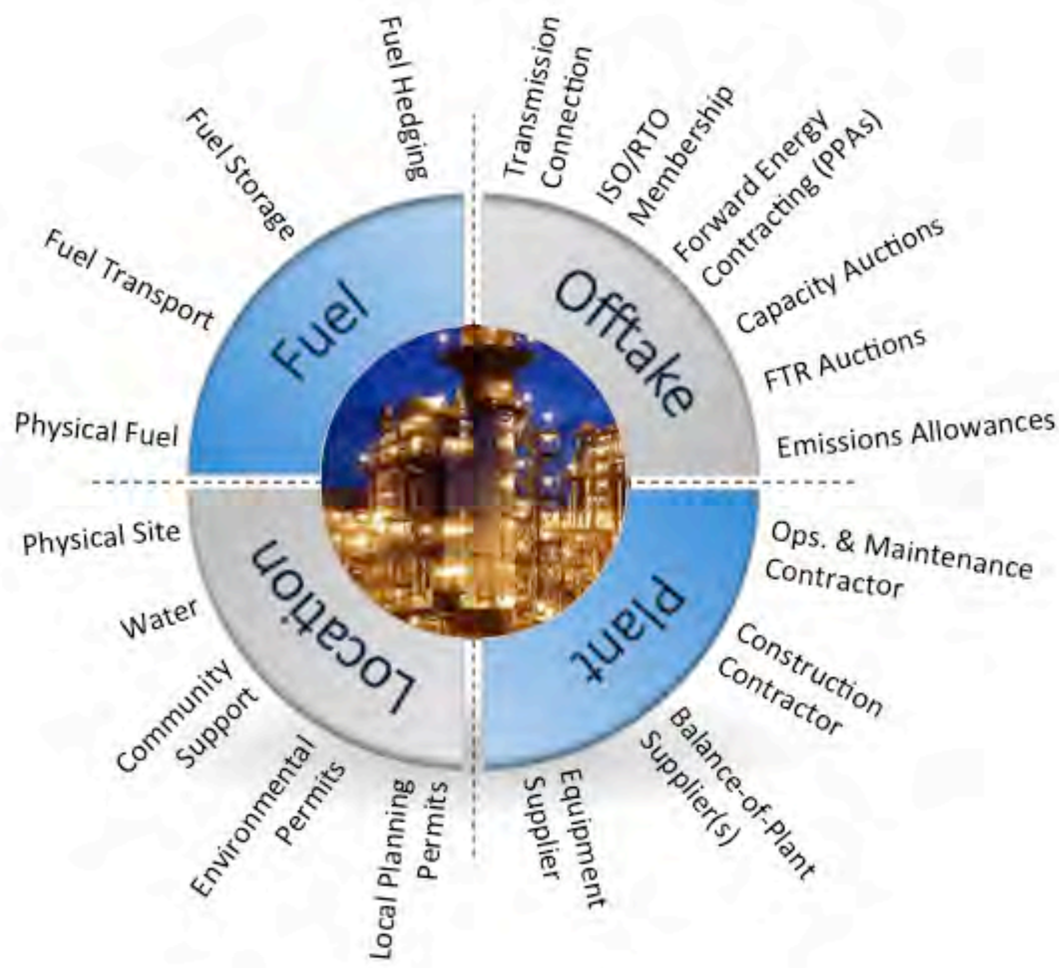


Figure 4 – Key Project Development Elements

4 INVESTMENT DRIVERS – AND DETERRENTS

The Resource Investment & Revenue Analysis Project received a wide range of direct feedback from investors on the factors that encouraged, as well as deterred, their investment in generation and other system resource. While every investor and its investment thesis is subtly different, certain influences recurred with sufficient frequency to represent key themes.

4.1 It's the Fundamentals …

4.1.1 Energy Supply and Demand

Investor:	*We are strongly in favour of capacity markets, and capacity revenues are an important contributor to our investment thesis.*
Market Reform:	*But you invest within the ERCOT region?*
Investor:	*Well, yes, they have steady demand growth.*

This paraphrased dialogue was a common one.

During the course of the interview process it became readily apparent that despite preferences for various market design features – and investors certainly had strong opinions on these – such considerations were secondary to the fundamental strictures of supply/demand balance. First and foremost, investment is being driven by energy revenues, and investors' assessments that demand will increase, or in some cases, that supply will decrease (e.g. due to plant retirements related to age, mercury emissions regulations, etc.), thus creating an opportunity for new supply to enter the market.

ERCOT was an oft-mentioned example, with a number of investors being active in the region, despite their own stated preference for markets with capacity revenues. Similarly, PJM was seen as rebounding from a demand trough, and consequently seeing strong investment. Conversely, some other regions were perceived as being in over-supply, and not seeing investment, independent of investors' perception of the market design or regulatory issues.

As a variant on this theme, several investors noted that, even if the fundamentals didn't seem to be in place for a market as a whole, they had invested where they perceived a location-specific advantage, such as siting within a constrained load pocket, or close to cheap fuel supply.

4.1.2 Relative Importance of Non-Energy Revenues

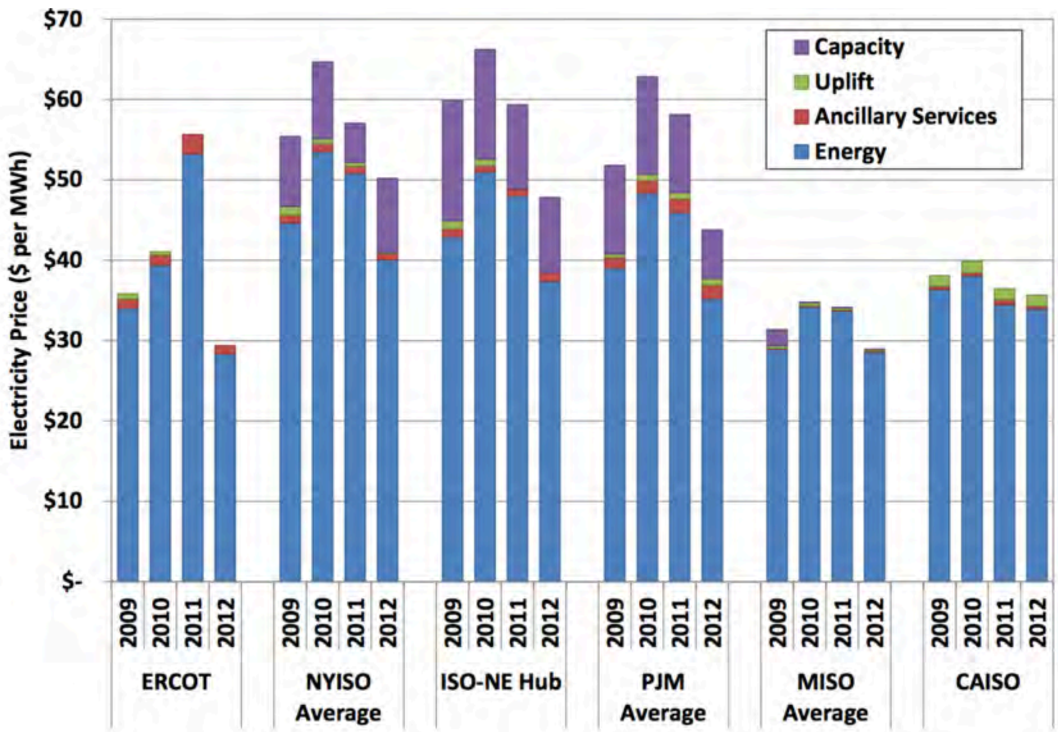
While some ISO-operated markets have a range of payment streams from which resources can derive revenues, the two principal non-energy revenue sources relate to:

- *Capacity*: Payments made to generation (and demand) resource for the capability to generate (or reduce demand) to protect the system's adequacy to serve load at times of system peak demand. This is a payment for the capability to generate, not actually doing so – which would result in an energy payment. There are a range of different treatments of capacity amongst the IRC members. ERCOT and Alberta are 'energy only' markets, with no capacity payments – the energy price alone provides the signal for new build (as is the case with every other commodity). PJM, New York and New England all have sophisticated capacity markets, albeit with different designs. Ontario, California, MISO and SPP have separate adequacy constructs or procurement mechanisms that are part-way in between, and tend to be driven by long-term contracts procured by incumbent utilities or a central authority[3].

- *Ancillary Services*: Payments for services provided to the system to maintain system security. Usually purchased by the system operator on behalf of the market as a whole, some of these services are procured via market mechanism – reserves (of various classes) and frequency regulation capability being the most common – and others via periodic contract, e.g. black-start capability, reactive power.

Figure 5 below, from the ERCOT 2012 State of the Market Report, provides an overview of the contribution of both capacity and ancillary services, in contrast with energy, to the all-in energy price across six US markets.[4] This provides a reasonable proxy for the contribution of these revenue streams to resource revenues.[5]

Figure 5 – Comparison of Price Contributors Across Markets[6]



As a general rule, investors were strong supporters of capacity markets, for their ability to backstop energy revenues and provide greater certainty of future cashflows.

However, a broad concern was expressed by some regarding volatility in capacity revenues in recent years ("no-one believes the capacity numbers are accurate").[7] Banks, in particular, indicated that this had led them to heavily discount predicted capacity revenues (e.g. by 50-

[3] In Ontario the central authority responsible for procuring such contracts is the Ontario Power Authority (OPA), which has recently been merged with the IESO.
[4] The one element of the diagram not covered above, 'uplift', refers to the costs associated with the operation of economically out-of-merit resources. This topic is discussed in further detail in 4.3.3.
[5] Note that this refers only to revenues derived from ISO-administered markets/programs. Some resources, renewables in particular, are also supported by a range of external revenue streams (discussed further in 4.2.1).
[6] Source: Potomac Economics (Independent Market Monitor for the ERCOT Wholesale Market), *ERCOT 2012 State of the Market Report*, June 2013.
[7] More specific comments on capacity market design are discussed in 5.1.

70%) in their consideration of an investment proposition. Those with a longer-term investment outlook, such as balance sheet-backed investors, indicated that they discounted projected capacity revenues less heavily, and also felt that they had a better capability to model these revenues.

Ancillary services revenues, by contrast, “don’t factor” into the investment decision-making of many investors, particularly as it relates to generation resource. A few longer-term investors indicated that they took some account of ancillary services revenues (“a distant third”), but found them to be “very volatile”, and thus discounted them heavily.

The one exception concerned investment in storage resources, where the investment thesis was substantially driven by ancillary services revenues, from frequency regulation in particular, as well as some energy ‘peak shaving’.

4.1.3 Market Scale – Size Sometimes Does Matter

Several investors expressed concern regarding the risk of investment in ‘smaller markets’, even when they generally like the market design, such as with New England and Alberta. This concern relates to the impact that large, discrete (i.e. ‘lumpy’) investments can have on supply/demand fundamentals. If multiple investors respond to price signals to invest, oversupply can result fairly quickly, depressing price and compromising the economics of the investment. While it would be possible to defer or cancel investment, this becomes more difficult and expensive the later it occurs in the development and construction process, especially if capacity commitments have been made through the capacity auction.

One obvious solution is to invest in smaller blocks, and to some extent this is what happens in these markets. However, the cost of many development activities – such as siting, permitting, arranging finance, negotiating off-take agreements, contracting fuel supply, selecting and contracting equipment suppliers, etc. – are relatively size-inelastic. Equipment and construction cost for smaller units, on a $/MW basis, also tends to be higher.

Investors appreciate that this is their risk to manage. However, when multiple opportunities are available, they will tend to spend their effort, and place their capital, where they assess it will achieve the greatest risk-adjusted returns. Thus, if other factors are equal – which of course is never precisely the case – lack of scale can have a dulling effect on investment.

4.2 A Tale of Two Resource Types

There are essentially two different theses for investment in generation resource – one for renewables, and another for non-renewable/thermal resources.

4.2.1 Renewables and Incentives

The development of renewable generation is substantially supported by incentive programs.

Table 2 – Key Renewable Incentive Programs

Incentive Program	Where
Renewable Portfolio Standards (RPS), requiring a fixed % or MW level of renewables. A Renewable Electricity Certificate (REC) is issued for each MWh of renewable energy produced.	Various states[8]

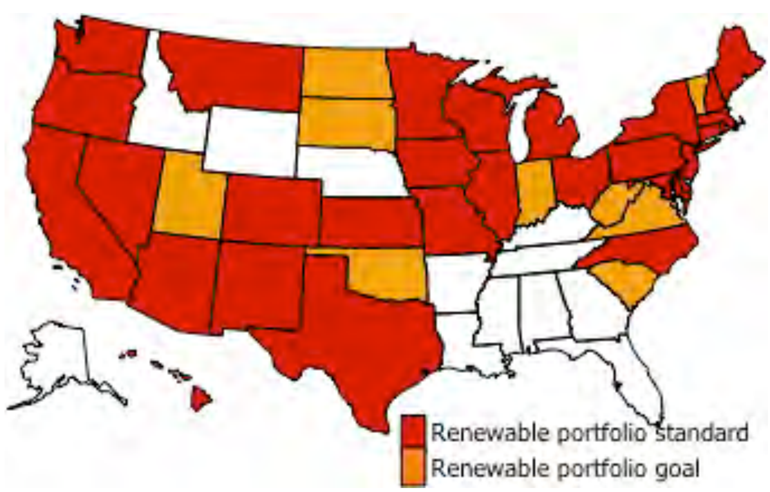
[8] While some Canadian provinces also have RPS schemes, none fall within an ISO footprint.

Incentive Program	Where
Production Tax Credit (PTC) and Investment Tax Credit (ITC) schemes.	US Federal
Feed-In Tariff (FIT)/standard offer programs: fixed payment (on a $/kWh basis) for those bringing renewable energy into the grid.	Ontario, CA, VT, ME
Tender process: to procure specified quantities of renewable plant.	Ontario
Section 1603 cash grants (in lieu of tax credits); expired for projects not in construction by Dec 31, 2011.	US Federal
Loan programs for renewables	Various states
Property tax incentives for renewables	Various state and local govt.

In the US, renewable investment is supported principally by state-based RPS schemes and federal income tax credits. There is some variation, though, regarding which has greater influence on investment decision-making.

In many regions of the US, RPS was considered more influential, serving as the key factor behind renewables being able to obtain long-term contracts. In Texas, however, installed wind generation is in excess of RPS targets – driven amongst other things by strong wind potential, and the Competitive Renewable Energy Zone (CREZ) transmission lines[9] – leading to a substantial fall in the value of RECs, and their relative importance as an investment driver.

Figure 6 – US Renewable Portfolio Standard Policies (Sep 2014)[10]



Tax credits are considered to be important in "lubricating the markets", especially in financing new plant – with tax benefits representing around 75% of the capital structure of wind deals, by one estimate. Nevertheless, as the credits aren't directly usable by most developers, tax equity was thought by many to be an inefficient way of incenting renewables development. As one

[9] The CREZ lines bring power from wind intensive regions of Texas to major load centers.
[10] Source: Database of State Incentives for Renewables & Efficiency (www.dsireusa.org)

investor commented, "we don't get into renewables as … we don't have a tax appetite." Those who do, though, "view the tax equity play as a low risk position." Tax credits were certainly seen as influencing the type of renewable investment, with many believing that investment in wind will drop off with PTC expiry, and "solar will surge" through 2016, when the ITC rate drops to 10%.

In Canada renewable incentives are province-based, with key programs including a feed-in-tariff scheme in Ontario, under which projects between 10kW and 500kW are contracted with the Ontario Power Authority at a fixed rate over a 20-year period. This program's $/kW rate for new projects has been reduced in recent years, though existing commitments continue to be met at the old rate.

In all cases, energy revenues were a lesser consideration in the investment decision, and capacity revenues did not factor into the investment thesis at all (given the intermittency of most renewables)[11]. The consensus amongst those interviewed was that solar power "is not economic on its own", and that wind power, while getting cheaper, is "still not reaching grid parity."

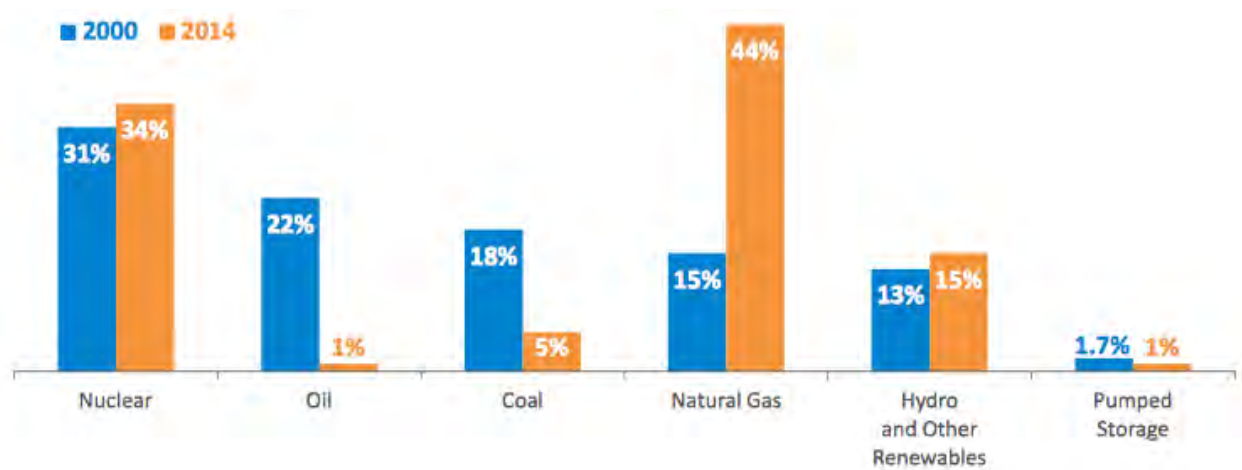
As incentive programs are at risk of government intervention, the revenues derived from them tend to be discounted by investors. Additionally, as these at-risk revenues often represent a substantial portion of the economic proposition of a project, almost all renewables investment is supported by long-term (e.g. 20-25 year) power purchase agreements (e.g. with utilities or large customers).

4.2.2 Non-Renewables – It's a Gas, Gas, Gas…

The investment thesis for thermal plant is driven principally by energy and, where applicable, capacity revenues derived from the ISO-operated markets. In recent years gas-fired generation has accounted for the great bulk of new investment in non-renewable resource (and as such, the bulk of all new resource), though there continues to be some investment in coal plant, where it is able to comply with toughening environmental standards.

Figure 7, by way of example, shows the dramatic move to gas generation in New England in the last decade or so. Recent PJM capacity auctions have also shown an uptick in gas plant, being the largest capacity contributor from the 2014/15 commitment period on.

Figure 7 – ISO New England Electric Energy Production by Fuel Type (2000 vs. 2014)[12]



[11] There was some feeling this may change if there is significant coupling of storage and solar.
[12] Source: ISO New England

Gas is perceived to have a competitive advantage for new thermal build in most regions, due to:

- The availability of cheap natural gas, due to the unlocking of substantial amounts of 'unconventional' or 'tight' gas through hydraulic fracturing and horizontal drilling.
- Reductions in cost of plant ($/MW), and increasing plant efficiency.
- Lower CO2 emissions compared to coal.

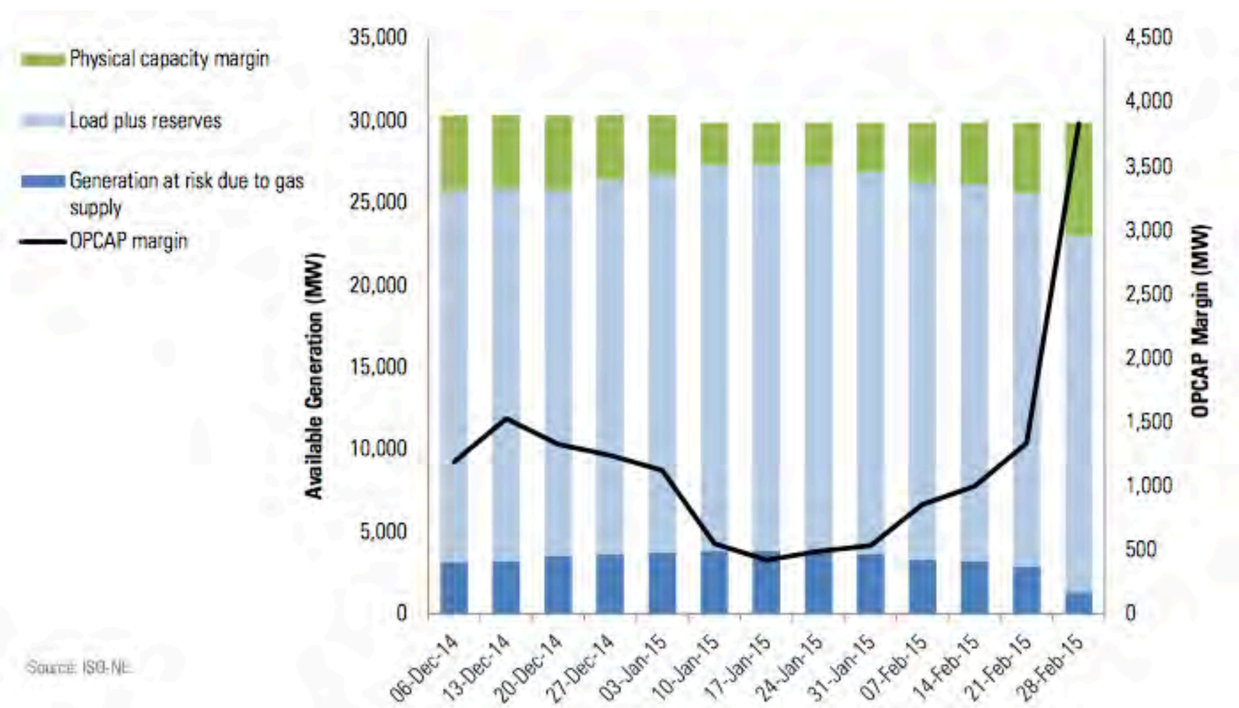
This development consists of both 'greenfield' development of new sites, as well as 'brownfield' re-powering of existing sites (generally fuel oil or coal) – which already have transmission connection, and tend to have an easier permitting process.

The gas 'play' tends to differ by region. In the North-East and Mid-Atlantic, new natural gas plants are increasingly being deployed as 'baseload' units. By contrast, in Texas, which has greater peak, flexibility and ramping requirements, new gas plants tend to be 'peaker' units.

A key threat to the continued growth of gas generation, however, is the issue of deliverability. As gas use for generation increases, constraints in the transportation of gas through the pipeline network are becoming increasingly prevalent, particularly in winter, when it coincides with peak heating demand. These problems are already manifest in New England, and New York Zones J & K – underlined by events during the 'polar vortex' during Winter 2013/14 – and are increasing in other regions. In the words of one investor: "There is not sufficient infrastructure for getting gas out of Marcellus."

This issue is highlighted by Figure 8 below, which provides an overview of ISO New England's assessment of Operating Capacity Margin for Winter 2014/15, and generation at risk due to gas supply interruption.

Figure 8 – Operating Capacity Margin Winter 2014/15[13]



[13] Source: ISO New England, as included in Morningstar Commodities Research, *Eastern US Winter Power Outlook*, 5 January 2015.

Despite what seems to be a clear need, pipeline capacity expansions to-date have mostly been 'low hanging fruit' (e.g. achieved through additional compression). While there are a number of expansion proposals, few significant additions to gas transportation infrastructure have yet been built or firmly committed to.

This has led some investors to question the current regulatory compact for natural gas in the US, where infrastructure expansion is funded by purchases of 'firm' contractual capacity (generally point-to-point or zonal), typically under long-term contract. This model was viewed as working for local gas distribution companies (LDCs), which have relatively predictable seasonal offtakes and are mostly rate-regulated, but not gas-fired generators, which have far more dynamic, market-driven consumption profiles, and may not have the forward certainty to enter into long-term (20+ year) capacity arrangements.

However, the potential of out-of-market intervention to resolve this impasse – such as the New England Governors' proposal to conduct a tender process for new gas transportation capacity, with costs to be passed on through electric tariffs[14] – has raised investor concerns regarding regulatory risk. e.g. Would such intervention disadvantage a generator who has already paid for firm capacity? Such solutions are also viewed as being 'one-off' in nature, or worse, undermining those who might invest based on price signals, and thus inviting further intervention. This raised the question: "who is looking at gas infrastructure long-term?"; with more than one investor asking, "perhaps there is a need for a gas ISO?"

Finally, even if the problem of adequate transportation infrastructure can be resolved, there remain a number of issues associated with gas/electric coordination that could impact investment thesis, spanning a range of functions and timeframes. These include:

- Planning coordination: in particular, the potential for investment in firm gas transportation ('gas by pipe') to be undercut by new electricity transmission ('gas by wire').
- Market timing: alignment of the gas day and electricity day-ahead-market timeframes – something New England and New York have addressed, but others are yet to.
- Operations coordination: coordination between pipeline and ISO operations personnel concerning outages and other operational events.

While various forums have been convened by some ISOs, and by FERC, to examine these issues, they are considered by investors to be moving too slowly. This caused the previous question to evolve to: "what about a combined gas and electricity ISO?"

4.2.3 What About Distributed Energy Resources?

None of the discussion above explicitly addresses distributed energy resources – the integrated assemblage of distributed generation, storage and demand response resources, embedded within the distribution network and behind the customer meter. Investors were well aware of developments in this area, both as an investment opportunity and as a potential disruptive technology risk to other resource investments.

The bulk of activity in distributed generation investment in the US/Canada at present is in the installation of rooftop photo-voltaic (PV) cells, at residential and commercial premises. Embedded storage is emerging as a complement to rooftop PV, providing smoothing for peaks and troughs due to solar intermittency. As with other renewable investments, however, both

[14] New England States Committee on Electricity, *Update on the New England Governors' Proposal to Invest in Strategic Infrastructure and Address Price Disparities*, Presentation to US Department of Energy Electricity Advisory Committee, 25 September 2014.

propositions are substantially supported by incentive schemes – and to a lesser extent, corporate imperatives – with neither approaching 'grid parity'.

Investors were alive to the possibility that this could change with ongoing innovation, though many felt that the "low hanging fruit" – e.g. cost reductions due to manufacturing economies-of-scale – was insufficient in itself to achieve grid parity, and more profound technological advances would be slower in coming. In the words of one: "Energy doesn't obey Moore's Law[15]." These investors were not greatly concerned about the risk to their non-renewable investments in the near-to-medium-term, but saw sizable "tail risk" to longer-term investment.

In the medium-term, investors were more concerned about the impact of rooftop PV and storage on the business proposition for distribution[16]. The reduction in distribution revenues from 'net metering' policies could lead to distribution monopolies spreading their sunk cost across fewer customers. This in turn could lead to 'bypass', further reduction of the revenue base, and yet higher charges for those remaining, ad infinitum, in a so-called "death spiral".

The final piece of the distributed energy resource puzzle is demand response. This was viewed as principally being about better control technologies, and as such, investment in this area was viewed as more of a "tech play" than one of grid resource investment – which would seem to be reflected in the evolving business models of key players in this space.

4.3 Competition, Open Access and Transparency

Interviewees universally expressed the view that they are more comfortable investing in markets they view as open and transparent – or to state the corollary, in one investor's words: "In monopolistic regions we get screwed."

4.3.1 Open Access and the Importance of Retail Competition

Investors indicated that they shied away from, or were far more circumspect, investing in regions where incumbent vertically integrated utilities are dominant, even where the region has an ISO-operated wholesale market.[17]

Much of this issue ties back to retail competition, and the perception that the 'playing field' is inherently uneven. Incumbent retail monopolies have a franchise customer base, with regulator-guaranteed returns – sometimes locking-in not just retail rates, but back-stopping individual plant investment. This insulates the incumbents, at least in part, from wholesale market outcomes and the consequences of their investment decisions – allowing them to commit to plant with lower risk, and thus cheaper funding. It also limits the size and diversity of the pool of potential purchasers in the wholesale market.

Where retail competition exists, the pool of retailers – and thus wholesale purchasers – is boosted by a range of new entrants, who must compete for their customers, and are thus well incented to purchase wholesale energy efficiently in order to serve them. There is no inherent bias to 'self supply', and thus equal opportunity for merchant/project and utility generation to compete. It could be argued, in fact, that without captive customers the distinction between 'merchant' and 'utility' becomes moot – perhaps one of the reasons why Alberta, which has no concept of 'incumbent', refers to itself as a 'merchant market'.

[15] Moore's Law was the observation by Gordon Moore, co-founder of Intel, that the number of transistors on an integrated circuit roughly doubled every two years.
[16] The *IEEE Power & Energy Magazine*, March/April 2015, contains a number of articles on the implications of large-scale renewable uptake for distribution systems.
[17] With the exception of renewables, where output is frequently contracted under long-term PPA (see 4.2.1).

Figure 9 below provides an overview of the status of retail competition, by state/province, mapped against the footprints of the nine ISOs/RTOs.

Figure 9 – State of Retail Competition, Mapped Against ISO/RTO Footprint[18]

4.3.2 Price Transparency, Liquidity and Hedging

Investors were similarly attracted to markets where they view the price-setting process as transparent and free from potential manipulation or interference. The resultant ability to trade confidently, and with "less event risk", was seen as contributing directly to more effective hedging, and better liquidity in both the cash and forward markets – all important investment considerations.

PJM was considered the stand-out market from a liquidity perspective – a view supported by Market Reform's own investigation of futures market data, which suggests it may now be the most liquid electricity futures market in the world, with trade multiples of over 4.7 in 2013.[19]

Concern was expressed about the depth of the forward curve across all markets, but particularly outside PJM and ERCOT. Many investors noted difficulty obtaining forward contracts beyond 6-7 years from initial development (~4-5 years from commencement of operations), with liquidity

[18] Source: ISO-RTO Council, overlaid with data on status of retail competition from: Distributed Energy Financial Group, *Annual Baseline Assessment of Choice in Canada and the United States (ABACCUS)*, January 2014.
[19] This compares with trade multiples of ~4.3 in 2013 for Nord Pool, previously the most liquid market (per Nordic Energy Regulators, *Nordic Market Report 2014*). Trade multiple = financial volume / physical volume. PJM financial volume = ~ 3000 TWh (ICE, per FERC, *2013 State of the Markets Report*) + 572 TWh (Nodal Exchange) + ~162 TWh (CME). Physical volume = ~794 TWh (*PJM 2013 Annual Report*).

very light in the back years even within that period. A number felt this had been impacted adversely by the Dodd Frank Act, and the withdrawal from electricity and gas trading of a number of sophisticated financial institutions who had previously been willing to make markets further out.

Finally, market power, and its dulling effect on the development of an effective forward market – irrespective of mitigation measures, which often serve to dilute forward market liquidity – remained a concern, and an expressed rationale for not investing in some regions.

4.3.3 Transparency of ISO Decision-Making

The transparency of ISO decisions which have an economic consequence for participants was a theme visited by several investors with an interest in plant operations.

It was generally appreciated that there can be valid reasons for resources to be dispatched out of economic merit order, and that such decisions are not made with perfect foresight. There was a broad impression, though, that in some markets this power is over-used, and more importantly, that there is a lack of transparency regarding dispatch procedures and the rationale for operator overrides of market results. In the absence of such transparency, there seems to be little impetus to reduce their frequency, or identify process improvements which might be made.

PJM's 'perfect dispatch' – a perfect hindsight look-back at unit commitment and dispatch – was viewed as a positive example in this regard. However, for those markets that currently have no review process, it was felt that even basic transparency measures, such as logging and explanation, would be valuable. In the medium-term, significant value was seen in having common transparency and information provision standards across all ISOs, and perhaps even a common platform.

The designation of resources as Reliability Must-Run (RMR) was also viewed as an overused intervention, with a price suppressing effect that is detrimental to the effective and transparent operation of the energy and ancillary services markets. As with the override of dispatch, it was felt that transparency surrounding such decisions was often lacking.

4.3.4 Transmission Connection

The ability to, and cost of, connecting to the transmission network, including any necessary network reinforcement, is a key development phase consideration in resource investment. Each ISO coordinates the transmission connection process for its respective region, with no two processes the same.

Concerns were expressed, to varying degrees, regarding the complexity, timeframe and cost of ISO transmission connection processes. ERCOT's permitting process was generally viewed as the most development-friendly, and NYISO's process, with its development queue, as providing the most useful information to potential investors. Opinions on others ranged from 'reasonable' to 'extremely difficult', with the timelines for some so slow that they were considered to function as a barrier-to-entry.

4.4 Regulatory Risk

Regulatory risk was probably the single greatest, and most consistent, concern raised by investors during this study. In this category investors tend to include not just regulatory and political action, or lack of it, but policy decisions taken by the ISO and its governance forums. These concerns took a number of forms.

4.4.1 Interference with the Functioning of the Market

There is a long history of regulatory and political interference in electricity markets in reaction to actual, or even potential, adverse events, such as short-term price spikes. Yet often times these events are the very signals which the market relies upon to stimulate investment. Interfering with them (e.g. imposing price caps, rather than relying on participants to be prudent and hedge) can entirely negate an investment thesis – not to mention rewarding the reckless and punishing the prudent. Furthermore, it is a 'binary' risk – it happens, or it doesn't – making it extremely difficult for an investor to protect (or insure) itself against.

A number of recent examples were mentioned by those interviewed. The attempt by New Jersey and Maryland to impose state-mandated power contracts – since successfully challenged by FERC – was widely regarded as government "interfering in the market for the purposes of price suppression" by "passing legislation for 3-4 lucky parties", and to have had a serious impact on the capacity markets for that year, as "reflected in the multiples." Similarly, there was general concern that the process of incenting resource investment in California "works by political fiat", and involves "picking winners", rather than establishing broad policy and letting the market function. There was a general opinion that "single-state markets are particularly prone to political interference."

One investor commented that it is focussing on achieving scale in a small number of regions, so it can better manage regulatory risk. This indicates a belief that policy issues can't be dealt with through rational argument alone, and an investor therefore must also be able to 'throw its weight around'.

4.4.2 Lack of Concerted Policy Action

Many believed that the "US has … 'shot itself in the foot' (with)… absolutely no coherent energy policy." The US is one of the few countries to have undergone significant levels of electricity market liberalisation, albeit unevenly, without comprehensive deregulation legislation. This seems to have resulted in a patchwork quilt of federal and state regulation, with the limits of FERC's authority tested from time-to-time in the courts. As noted by one investor, though, this confused policy environment can, in certain situations, "provide an opportunity for outsize returns."

4.4.3 Market Complexity and 'Tweaking'

A number of investors, particularly amongst those not actively involved in plant operations, expressed concern that the markets – probably with the exception of Alberta – "are all way too complicated", with one opining, perhaps a little tongue-in-cheek, that they are "an unholy marriage between an engineer and an economist."

This complexity is typically embodied within each market's rules. There was substantial concern regarding the impact of ongoing 'tweaking' of market rules on the predictability of revenues ("The desk view is that regulatory markets change every year").

While all those interviewed would like to see less variability in market design, there was some variation in extent. When asked to consider where they sat along the 'get it right' vs. 'keep it constant' continuum, those with a shorter-term investment interest tended to be more strongly in favour of persisting with an imperfect design that was predictable, whereas those with a longer-term investment outlook, such as balance-sheet-backed investors, were more inclined to modify the market design.

4.4.4 ISO Governance

Several investors expressed concerns about the independence of ISOs from political interference, with particular concern that some single-state/province ISOs are at risk of becoming “an extension of the Governor’s (Premier’s) office.”

The stakeholder process in some jurisdictions was seen as a handicap to investment, with many viewing it as “hostage to incumbent interests.” A number of those with a direct interest in plant operations expressed a concern that generation companies do not have “an equal voice” to load and transmission in stakeholder forums. Others were more broadly concerned with the entire stakeholder governance construct, which they viewed as “driven too much by (bloc) voting”, not “working for everybody” and “unable to produce “an apolitical market design.”

5 COMMENTS ON MARKET DESIGN CHARACTERISTICS

In additional to key themes, the interview process also captured significant investor sentiment concerning specific market design characteristics.

Some of the more consistently expressed feedback has been summarised in the discussion that follows. While none of the individual points in isolation is likely to be a substantial driver of investment, taken in totality they may be influential to an investor looking at where to 'place its bets'.

5.1 Capacity Market Design

As noted in 4.1.2, investors in general are strong supporters of capacity markets (but even bigger believers in demand growth). With respect to sentiment concerning specific capacity market design elements, there was a surprising commonality of opinion:

- There was strong support for longer commitment periods in capacity. Shorter periods were viewed more as support (albeit valued) for existing plant, rather than an encouragement to build new plant.
- There was specific support for ISO New England's capacity 'lock-in' based on the first cleared auction, though some preferred PJM's proposed construct for bidding in subsequent auctions, rather than ISO-NE's 'bid-at-zero' requirement.
- Investors were generally in favor of capacity performance incentives/penalties (as implemented at ISO-NE and proposed for PJM), despite the risk. They generally felt that good operators would be able to manage this risk, and this would provide a comparative advantage, as well as impacting relative valuation.
- There was criticism that some of the specifics of capacity performance hadn't been thought through for a wide enough range of scenarios before implementation, and were having unintended consequences (e.g. penalizing plant for events beyond its control, such as transmission outage)

Elements that received less comment, or had less agreement included:

- Some would prefer more frequent auctions (e.g. quarterly).
- A couple of investors expressed concern with the pace of recent capacity market change (e.g. at PJM). Others thought that it wasn't fast enough.

5.2 Energy Market Design

Comments regarding energy market design were somewhat more disparate, but a few themes were discernible:

- There was a general belief that the market needs more appropriate price signals during scarcity events, such as low reserve condition, not just VoLL in the event of involuntary load shedding. Consequently, there was good support for improving scarcity pricing.
- Investors believed that demand response (DR) should have a level playing field. A number believed that some previous market design constructs, until struck down by the courts, had gone too far, failing to recognize that DR is demand, not quasi-supply.
- Real concerns were expressed regarding the potential for regulatory interference in the market via bid constraints, price caps set too low, etc..

- Associated with this was a strong conviction that, where there isn't a capacity market, the energy price must be able to rise sufficiently high to incent availability, and that the remedy to the risk of price spikes is hedging, and better demand management, not price suppression.
- In markets with significant levels of intermittent generation, some believed that an ancillary services revenue stream for 'flexibility', or similar, would be "hugely valued by investors."
- Concern was expressed about the underfunding of FTRs in some markets, with the socialized shortfall representing an unhedgeable risk.

APPENDIX A – GLOSSARY OF TERMS

TERM	DEFINITION
Ancillary Services	Non-energy services required to support the reliable operation of the electricity system.
Baseload	Generation resource that tends to operate at an even level of output (often full output), irrespective of demand.
Basis Point	0.01%. Generally used with respect to interest rates.
Capacity (generation)	The amount of power (MW) a generating unit can produce.
Capacity (transmission)	The amount of power (MW) a transmission line is capable of capable of transmitting.
Capacity Factor	Measure of a generator's actual output over a period of time divided by its potential output at full capacity.
FERC	Federal Energy Regulatory Commission. Federal energy regulator for the United States.
Frequency Regulation	Ancillary service to adjust resource output in response to real-time fluctuations in demand, in order to maintain system frequency within established limits. Also known as load-following or Automated Generation Control (AGC) capability.
FTR	Financial Transmission Right. A financial right to the price differential (generally excluding consideration of losses) between two designated locations (which may be single nodes or aggregate locations). Also known as a Transmission Congestion Contract (TCC) or Congestion Revenue Right (CRR).
LIBOR	London Interbank Offered Rate. Used as the primary global benchmark for short-term interest rates.
Liquidity	The degree to which a product can be transacted in the marketplace without affecting its price. Characterised by a high level of trading activity. An indicator of market depth and transactional efficiency.
Mezzanine Debt	Secured debt finance that ranks in priority behind senior debt but ahead of trade creditors or equity. Commonly convertible into equity.
MLP	Master Limited Partnership – a limited partnership traded on a securities exchange. Allows the entity to receive the tax benefits of a limited partnership, while accessing capital in the public markets. Limited to certain types of business activity.
OTC	Over-the-counter trading. Bilateral trading between two counter-parties, facilitated by an intermediary but with all other aspects remaining between the two counter-parties.
Peaker	Generation resource that tends to operate at times of peak demand.

TERM	DEFINITION
REC	Renewable Energy Certificate. RECs are issued for each MWh of green electricity produced under an RPS scheme.
Reserves	Ancillary service. The capability to provide energy, or demand response, to replace generation lost to the system through plant outage. Most markets have various classes of reserve, generally based upon their speed of response. e.g. spinning reserve (plant already synchronised to the system) and non-spinning reserve (fast-start plant that must rapidly start-up and synchronise)
RPS	Renewable Portfolio Standard. Requirement for a percentage, or fixed amount of energy sold to end-use customers to be sourced from designated renewable sources. Often placed as an obligation on the electricity retailer.
Term Loan A	Senior term loan issued in the US market.
Term Loan B	High yield loan issued in the US market, typically of 2-7 years tenor, generally secured *pari passu* with Term Loan A.[20]
Trade Multiple	Financial trading volume / physical volume. An indicator of liquidity. Also known as trade velocity.

[20] KPMG Corporate Finance, *To Term Loan B or not to B*, KPMG 2013.

APPENDIX B – ACKNOWLEDGEMENTS

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Fiera Axium	TransAlta
Goldman Sachs	

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Project Steering Committee

AESO: Jenny Chen, Kevin Dawson

CAISO: Karl Muessen, Keith Johnson

ERCOT: John Dumas

IESO: Tom Chapman, Brian Rivard

ISO-NE: Andrew Gillespie

MISO: Jeff Bladen

NYISO: Robert Pike, Nicole Bouchez

PJM: Stan Williams (Chair), Adrien Ford

SPP: Scott Smith

Chair, IRC Markets Committee

Andy Ott (PJM, 2014)

Joe Gardner (MISO, 2015)

Project Team

Christina Stotesbury (PJM)

From: Glazer, Craig
To: Meyer, David
Cc: Fisher, Travis; Mansueti, Lawrence; Pablo, Jeanette; Horner, Nathaniel; SAM.HILE@ICF.COM
Subject: Follow Up Items from Our Meeting
Date: Monday, May 22, 2017 11:54:35 AM
Attachments: DOE---DRAFT 3 Gas and Electric Operations First Call Draft 3.docx
DOE---PJM Gas - Electric Coordination with Pipelines.ppt..pptx

David et al:

As a follow up to our meeting, I am enclosing two items that were referenced...

a. A power point detailing the efforts we undertake on a daily basis to integrate gas pipeline conditions into our operations planning as well as future efforts we have going with the natural gas industry in this regard;
b. NERC's proposed gas/electric coordination items.

Both of these are public documents. Let me know if you need any additional documents.

Also as a head's up, the results of our capacity market auction will be publicly released at COB tomorrow. I will send you our written report analyzing the results as soon as that is public.

Thank you.

CRAIG GLAZER
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Reliability Guideline

Gas and Electric Operational Coordination Considerations

Preamble

It is in the public interest for the North American Electric Reliability Corporation (NERC) to develop guidelines that are useful for maintaining or enhancing the reliability of the Bulk Electric System (BES). The Technical Committees of NERC; the Operating Committee (OC), the Planning Committee (PC) and the Critical Infrastructure Protection Committee (CIPC) per their charters are authorized by the NERC Board of Trustees (Board) to develop Reliability and Security Guidelines. Guidelines establish voluntary codes of practice for consideration and use by BES users, owners, and operators. They are developed by technical committees and include the collective experience, expertise and judgment of the industry. Reliability guidelines are not to be used to provide binding norms or create parameters by which compliance to standards is monitored or enforced. While the incorporation and use of guideline practices is strictly voluntary, the review, revision, and development of a program using these practices is highly encouraged to promote and achieve the highest levels of reliability for the BES.

Background and Purpose

Coordination of operations between the gas and electric industries has become increasingly important over the course of the last decade. The electric power sector's use of gas, specifically natural gas fired generation, has grown exponentially in many areas of North America due to increased availability, potentially more competitive costs in relation to other fuels and a move throughout the industry to lower emissions to meet environmental goals. With increased growth in usage comes greater reliance and associated risk due to the dependency that each industry now has on the other. In addition, most of the dependency risk lies within the electric industry since much of the generation capacity using natural gas as its primary fuel does not hold long term firm gas pipeline capacity/transportation rights. The operational impact of these dependencies requires gas and electric system operators to actively coordinate planning and operations. The goal of the coordination is to ensure that both the gas and electric systems remain secure and reliable during normal, abnormal and emergency conditions. This guideline attempts to provide a set of principles and strategies that may be adopted should the region in which you operate require close coordination due to increased dependency. This guideline does not apply universally and an evaluation of your areas unique needs is essential to determine which principles and strategies you apply. The guideline principles and strategies may be applied by RCs, BAs, TOPs and GOs in order to ensure reliable coordination with the gas industry. Finally, the document focuses on the areas of preparation, coordination, communication and intelligence that may be applied in order to coordinate operations and minimize risk.

Coordination

- Establish Contacts
    - An essential part of any coordination activity is the identification of the participants. For gas and electric coordination this involves identification of the natural gas pipeline, gas suppliers and LDC gas entities and operations staff within the electric footprint boundaries and in some instances beyond those boundaries. Once these contacts are established, additional coordination activities can begin. Industry trade organizations such as the American Gas Association or a regional entity such as the Northeast Gas Association (all areas in North America have regional entities that are most likely members of the American Gas Association) may be able to aid in development of operational contacts and the establishment of coordination protocols. These contacts should be developed for long and short term planning/outage coordination as well as near term and real-time operations. The contacts should include both control room operating staff contacts as well as management. Establishing and maintaining these contacts is the most important aspect of gas and electric coordination. Past lessons learned have taught the industry that the first call you make to a gas pipeline or LDC should not be during abnormal or emergent conditions.
- Communication Protocols
    - Once counterparts are identified in the gas industry, communications protocols will need to be established within the regulatory framework of both the gas and electric utility looking to coordinate and share information. The Federal Energy Regulatory Commission issued a final rule under order 787 allowing interstate natural gas pipelines and electric transmission operators to share non-public operational information to promote the reliability and integrity of their systems. Since the inception of this rule and the subsequent incorporation of those rules into the associated tariffs, followed by the appropriate confidentiality agreements, gas and electric entities have been able to freely share operational data. Some of the data that could be shared to improve operational coordination could include but is not necessarily limited to the following:
        - Providing detailed operational reports to the gas pipeline operators by specific assets, operating on specific pipelines, which specify expected fuel burn by asset, by hour over the dispatch period under review. It is important to convert dispatch plans from electric power to gas demand when conveying that information to gas system operators.
        - Combining the expected fuel to be used by asset on each pipeline in aggregate to provide an expected draw on the pipeline by generation connected to that pipeline on an hourly basis and on a gas and electric day basis.
        - Exchanging real-time operating information in both verbal and electronic forms of actual operating conditions on specific assets on specific pipelines
        - Outage planning to include sharing detailed electric and gas asset scheduling information on all time horizons and coordinating outages of those assets to ensure reliability on both

the gas and electric systems. This coordination should include if possible face to face coordination meetings.

- Sharing normal, abnormal and emergency conditions in real-time and ensuring each entity understands the implications to their respective systems. This should include proactively reaching out to the operators of stressed gas systems to discuss the impacts, adverse or otherwise, of their expected or available actions.
- The sharing of non-public operating information between the electric operating entity and Local Distribution Companies ("LDC") is not covered under FERC Order 787 and because of this, individual communication and coordination protocols should be established with each LDC within the footprint of the operating entity. Understanding the conditions under which an LDC would interrupt gas fired generation is of particular importance and incorporating this information into operational planning will assist in identification of potential at risk generation. Setting up email alerts from each LDC as to the potential declaration of interruptions is one key means of real time identification of potential loss of generation behind the LDC city gate.

- Coordinating Procurement Time Lines
  - Operating entities may want to consider changing next day operating plan scheduling practices to align more efficiently with gas day procurement cycles. The gas and electric industries operate on differing timelines for the Day Ahead planning processes and in real-time, with the electric day on a local midnight to midnight cycle. The gas industry process operates on a differing timeline with the operating day beginning at 9 a.m. Central Clock Time and uniform throughout North America. This difference in operating days can lead to inefficient scheduling of natural gas to meet the electric day demands. In many instances throughout North America, the electric industry has moved the development and publishing of unit commitments and next day operating plans in order to ensure that generation resources have the ability to procure and nominate natural gas more efficiently to better meet the scheduling timelines of the gas industry. In addition, the gas industry has adjusted some of its nomination and scheduling practices to allow for more efficient scheduling which meet the needs of the electric system. Coordinating and modifying scheduling practices to more effective time periods may allow for a higher level of pipeline utilization, but more importantly the early identification of constraints that may require starting gas generation with alternate fuels, or non-gas fired facilities for fuel diversity to meet the energy and reserve needs of the electric system.
  - Identification of Critical Gas System Components
    - It is essential that gas and electric entities are coordinated to ensure that critical natural gas pipelines, compressor stations, LNG, storage and other critical gas system components are not subject to electric utility Under Frequency and or Manual Load shedding programs.

      Electric transmission and distribution owners are capable of interrupting electrical load either automatically through under frequency load shedding relays installed in substations throughout North America or via manual load shedding ordered by RCs, BAs and or TOPs via SCADA. These manual and automatic load shedding protocols are part of every entities emergency procedures. These entities should ensure critical gas sector infrastructure is not located on electrical circuits that are subject to the load shedding described above. Electric operators should establish contact with the gas companies operating within its jurisdiction to compile a list of critical gas and other fuel facilities which are dependent upon electric service for operations. Once the list is compiled, a comprehensive review of load shedding procedures/schemas/circuits should be done to verify that critical infrastructure is not connected to or located on any of those predefined circuits. This review should be considered for evaluation at least annually.

- Operating Reserves
  - The electric industry may want to consider adjustments to operating reserve requirements to better reflect the increased reliance on natural gas for the generation fleet. For instance, if the loss of a fuel forwarding facility has the ability to result in an instantaneous or near instantaneous electric energy loss, that contingency should be reflected in the reserve procurement for the operating day. In addition some electric operators are considering the implementation of a risk based operating reserve protocol that increases and or decreases the amount of operating reserve procured based upon the risks identified to both the gas and electric system.

Preparation

- Assessments
  - Preparing the gas and electric system for coordinated operations requires up front assessments and activities to ensure that when real-time events occur, the system operators are prepared for and can effectively react. Preparation activities that may be considered include the following:
    - Developing a detailed understanding of where and how the gas infrastructure interfaces with the electric industry including:
      - Identifying each pipeline which operates within the electric footprint and mapping the associated electric resources which are dependent upon those pipelines.
      - Identifying the level and quantity of pipeline capacity service (firm or interruptible; primary/secondary) and any additional pipeline services (storage, no-notice, etc.) being utilized by each gas fired generator.
      - Developing a model of and understanding the non-electric generation load that those pipelines and LDCs serve and will protect when curtailments are needed.

  - Identifying gas single element contingencies and how those contingencies will impact the electric infrastructure. For instance, although most gas side contingencies will not impact the electric grid instantaneously, they will most likely be far more severe than electric side contingencies over time because they may impact several generation facilities. When identifying gas system contingencies, the electric entity should consider what the gas operator will do to secure its firm customers including the potential that the gas system will invoke mutual aid agreements with other interconnected pipelines which may involve curtailment of non-firm electrical generation from the non-impacted pipeline to aid the other.

- Emergency Procedure Testing and Training
  - Consider the development of testing and training activities to support extreme gas contingencies such as loss of compressor stations, pipelines, pipeline interconnections, large LNG facilities etc. that can result in multiple generator losses over time. Particular attention should be focused on any gas related contingency that may result in an instantaneous generation loss.
    - If voltage reduction capability exists within your area, practical testing and training should be considered as part of seasonal or annual work plans
    - The use of manual firm load shedding may be required for beyond criteria extreme gas and or electric contingencies. Consideration should be given to practicing the use of manual load-shedding at least seasonally if not monthly in a simulated environment. These simulations should also be used as part of annual system operator training at a minimum. The use of tabletop exercises can be a valuable training aid but wherever possible consideration should be given to using an advanced training simulator that employs the same tools the operators would use to accomplish the load shedding tasks.
- Generator Testing
  - Consideration should be given to adopting generator testing requirements for dual fuel auditing. Some items to consider when establishing a dual fuel audit program are:
    - How often should the audits be conducted and under what weather and temperature conditions,
    - Capacity reductions on alternate fuels,
    - Understanding the exact time it takes to startup, switch to alternate fuel, ramp to and operate at full capacity, ramp down and resource shut down.
    - The operating entity should consider any environmental constraints the generator under test must meet in order to swap to and operate on the alternate fuel.
- Capacity and Energy Assessments
  - Consideration should be given to the development of a forward looking capacity analysis which the electric industry is very familiar with but applying the impacts of fuel restrictions that may

occur due to pipeline constraints or other fuel delivery constraints such as LNG shipments or liquid fuel delivery considerations. In order to conduct these types of assessment the analysis needs to consider the LDC loads within the region. The weather component of the assessment should consider normal, abnormal and extreme conditions (Gas Design Day). This capacity assessment can be on several time horizons including; Real-time, Day Ahead, Month Ahead and Years into the future. These assessments should consider pipeline maintenance, construction and expansion activities as well as all electric industry considerations, including known or potential regulatory changes, that are normally analyzed.

- In addition to a capacity assessment which only represents a single point in time, consideration should be given to the development of a seasonal, annual or multiannual energy analysis that uses fuel delivery capability/limitations as a component. Such assessment can be scenario based, should simulate varied weather conditions over the course of months, seasons and or years and consider the same elements as discussed in the capacity analysis. The output of the assessment should determine whether there is the potential for unserved energy and or the ability to provide reserves over the period in question.

- Winter Readiness Training
  - Recent system events have magnified the need to ensure that seasonal awareness and readiness training is completed within the electric industry including System Operators, Generator Operators and Transmission Operators. Seasonal readiness training for winter weather could include reviews and training associated with dual fuel testing, emergency capacity and energy plans, weather forecasts over the seasonal period, fuel survey protocols and storage readiness. Other areas that require attention in winter readiness training include reviewing and setting specific operational expectations on communications protocols. Finally, any winter readiness seminars should include individual generator readiness such as ensuring adequate fuel arrangements are in place for unit availability, adequate freeze protection guidelines are in place, understanding access to primary and secondary fuels and testing to switch to alternate fuels, ensuring all environmental permitting is in place for the fuel options available to the asset, and making sure that the Balancing and Transmission Operators are kept apprised of the unit availability.

Communication

- Industry Coordination
  - In the long and short term planning horizons, regularly scheduled meetings between the gas and electric industries should be held to discuss upcoming operations including outage coordination, industry updates, project updates and exchange of contact information.
  - Operating entities should consider the development of a coordinated and annually updated set of operational and planning contact information for both the gas and electric industries. This information should include access to emergency phone numbers for management contacts as

well as all control center real-time and forecaster desks for use in normal, abnormal and emergency conditions.

- Gas and Electric emergency communication conference call capability should be considered between the industries such that operating personnel can be made available from both industries immediately, including off hours and within the confines of the individual confidentiality provisions of each entity.

- Emergency Notifications to Stakeholders
  - Operating Entities may want to consider proactive notifications to stakeholders of abnormal and or emergency conditions on gas infrastructure to ensure widespread situational awareness and obligations associated with dispatch relationships in the electric sector. An example of a notification used for generators in New England appears below:

1. Notices Indicating Abnormal and/or Emergency Conditions on the Pipeline Infrastructure Serving Generators

NOTE
Notices indicating abnormal and/or emergency conditions on the pipeline infrastructure serving a Generator in the ISO RCA/BAA could come in the form of, but **not** limited to, Operational Flow Orders, Imbalance Warnings or even a verbal notification.

A) When electronic and or verbal notices indicating abnormal and or emergency conditions on the pipeline infrastructure serving a Generator in the ISO RCA/BAA are received, the Forecaster notifies the Operations Forecast and Scheduling Supervisor (or designee)

(1) The Forecaster reviews this information and depending upon the severity of the condition may pass the publicly available information along by drafting an email and submitting it to Customer Service for dissemination to each applicable Generator Designated Entity (DE) management contact(s) and/or Lead Market Participant (MP) contact(s).

NOTE
The following guideline or one tailored to the current situation can be used as a template for drafting this notification:

"ISO-NE has received the following information via the publicly available notices published by the gas pipelines:

(Insert Notice, such as Operational Flow Order or Force Majeure, etc.)

"Because of this situation, it is critical that each applicable Generator DE or Lead MP provide ISO-NE with up to date and reliable estimates of each Generator current and future capabilities including the ability to have fuel for a Generator under their control. This includes immediately reporting any information that may prevent a Generator from operating in accordance with submitted offer data, including, but **not** limited the following:

- Planned, Maintenance and or Forced outages of the Generator facilities as soon as that information is available
- Immediate reporting of any updates to outages including overruns and or early returns to service of the Generator facilities
- Any high risk activities at a Generator location that may reduce its capability or place the capability at risk
- Any fuel reductions or outages that may limit a Generator's ability to perform in any way
- Any changes to any operating limits of a Generator which must reflect the most accurate and up to date information available
- Any changes at all in a Generator ability to follow dispatch instructions including manual response rates, ability to provide reserve, ability to provide energy, and/or ability to provide capacity
- Any changes in projected Generator self schedules

It is incumbent that each Generator DE/Lead MP provides this information, as well as all other information required under ISO rules and procedures. If you should have any questions please contact the ISO New England Control Room Forecast Desk at (413) 535-4340.

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Depending upon the level of severity and risk exposure, these written notifications may need to be followed up with direct verbal communications.

- Emergency Communication Protocols in the Public and Regulatory Community
  - Most every electric operating entity has long standing capacity and energy emergency plans in place that focus on public awareness, abnormal and emergency communications as well as appeals for conservation and load management. However, as the gas and electric industry become further dependent, considerations should be made for both industries to coordinate for extreme circumstances. Gas and electric operators in coordination with public officials may find situations where the energy of both the gas and

electric sector is required to be reduced in order to preserve the reliability of both. While these types of efforts are still in their infancy they should be explored depending upon the circumstances on your region.

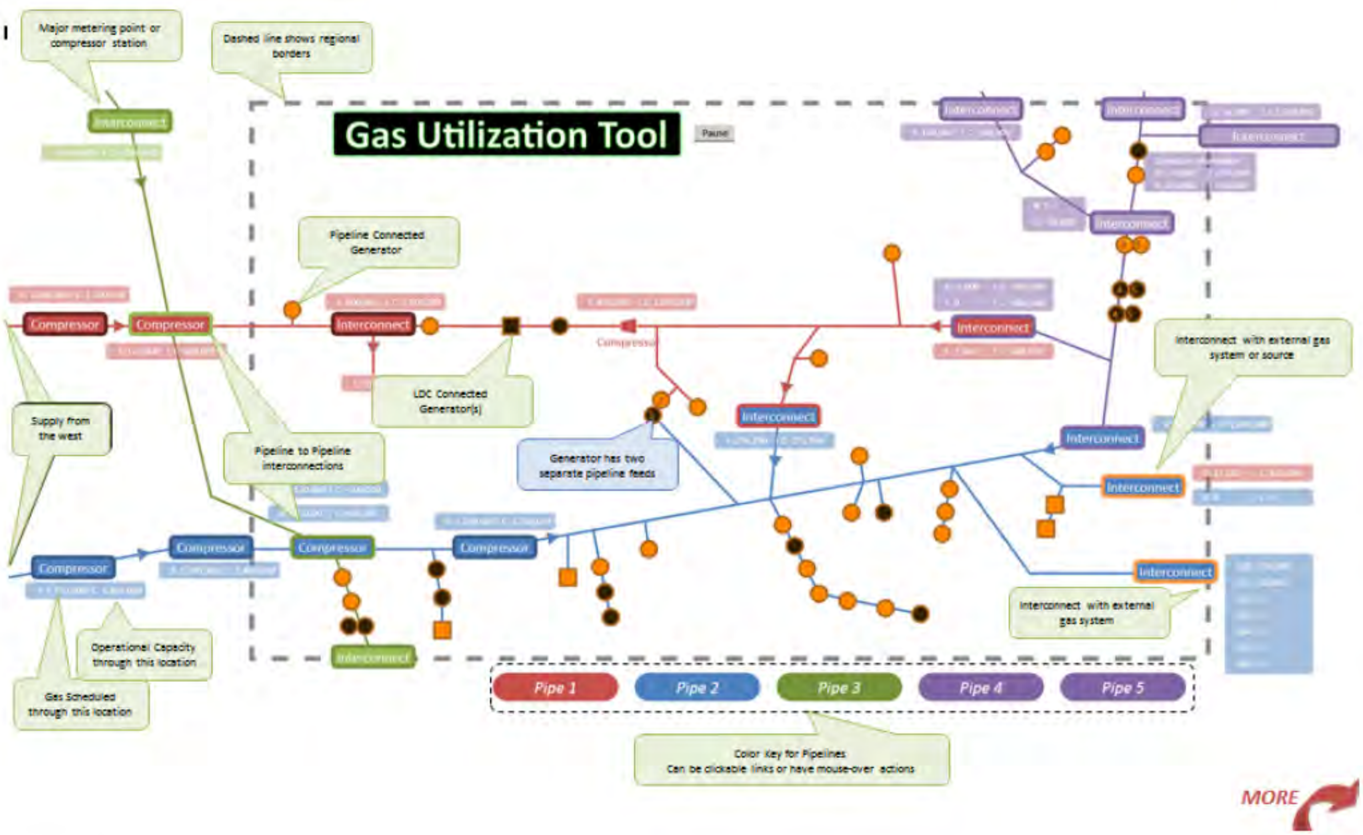
Intelligence

- Fuel Surveys and Energy Emergency Protocols
  - Energy emergency procedures and fuel surveys can be important tools in understanding the energy situation in a region. The surveys can be used to determine energy adequacy for the region's electric power needs and for the communications and associated actions in anticipation or declaration of an energy emergency. Interestingly, the fuel surveys will most likely focus on the fuel availability of other types of fuels if the gas infrastructure is the constrained resource. An example of an Energy Emergency and Fuel Survey Protocol which could be used as part of coordination efforts can be found at the following link: https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op21/op21_rto_final.pdf
- Fuel Procurement
  - Operating entities should consider evaluating determining an electric generators natural gas procurement and commitment to determine fuel security for the operating day.
    - The electric operating entity can collect publicly available pipeline bulletin board data and compare the gas procurement for individual generators against the expected electric operations of the same facility in the current or next day's operating plan. An example of this type of data collection appears below with the data helping to determine if enough fuel is available to meet an individual plant or in aggregate an entire gas fleet's expected operation for the current or future day. The report can indicate whether a fuel surplus or deficit exists by asset or for an entire pipeline. If sufficient gas has not been nominated and scheduled to the Generator meter, assessments can be done to determine the impact on system operations and the operating staff may call the generator to inquire as to whether the intention is to secure the requisite gas supply to match its expected dispatch plus operating reserve designations .

Plant	MWh Burned So Far	MWh Before Midnight	MWh After Midnight	MWh Scheduled	MWh Surplus	Gas Scheduled
1	2201	169	1932	4493	191	34600
2	777	0	663	0	(1440)	0
3	1910	0	901	2849	38	20700
4	2131	0	0	2736	605	20028
5	5903	403	0	7706	1400	53800
6	2369	0	798	3097	(70)	22500
7	1253	0	350	93	(1510)	1000
8	2402	185	1850	5129	692	45500
9	0	0	0	28	28	300
10	3	0	525	0	(528)	0
11	0	0	0	0	0	0
12	1	0	0	0	(1)	0
13	4	0	0	0	(4)	0
14	5077	389	2864	9591	1261	65621
15	3394	215	0	3347	(262)	25048
16	3554	550	6017	221	(9900)	1500
17	10639	797	4157	17418	1825	126540
18	7249	545	3892	11096	(590)	80813
19	972	45	1066	9	(2074)	100
20	0	0	0	0	0	0
21	0	0	0	0	0	0
22	6294	0	2476	1643	(7127)	17471
23	2758	0	1209	3944	(23)	30000
24	2400	250	1250	579	(3321)	5000
25	4998	0	2317	6917	(398)	52595
26	3208	250	1189	0	(4647)	0
27	2434	0	0	2747	313	23512
28	4222	0	0	5634	1412	42963
29	2121	0	0	2343	222	20000
30	0	0	0	0	0	0
31	1141	86	860	2344	257	27000
32	0	0	0	0	0	0
33	1071	0	3490	5037	476	38325

Varying configurations of generator gas supplies can quickly complicate reports. Efforts should be made prior to the development of such reporting tools to ensure that all facets of gas scheduling can be displayed. Not all scheduled gas data will be publically available, especially when dealing with LDC connected generators. Generators are often supplied by multiple pipelines simultaneously.

- Gas System Visualization
  - Several Reliability Coordinators have developed visualization tools to provide scheduling and realtime operations staff with situational awareness tools which tie the gas and electric infrastructure together at their common point of operation. What follows is an example of one such tool which has been made generic for the purposes of the illustration. The bubbles in the tool indicate the functionality which is available to the user with notes that follow.



Notes:

- The display is updated automatically or on demand. Historical data is available for 30 days in the past. Can be expanded to more days or specific days.
- Generators are clickable and additional information is provided via popup message.
- Pipeline Color Key is clickable and navigates to the specific pipeline EBB.
- All of the values are in MMBtu for the gas day. When operational capacity changes, the display automatically updates based on EBB posted capacity and schedule values.
- Schedules are for the GAS DAY, rolling over at 10:00. (e.g. Gas Day 4/15/2016 starts at 10 am on 4/15 and ends at 4/16 at 10am.)
- These are SCHEDULES and may not reflect the physical flow of gas. Schedules may not match due to differences in scheduling cycles or accounting methods used by different companies.
- Just because there's room for gas to flow at a throughput meter or cross connect, doesn't mean there's gas there to move through.
- *Delivery* is gas leaving the pipeline. *Receipt* is gas entering the pipeline.
- Schedule Badges show Delivery and Receipt where there can be bi-directional scheduling and Schedule where there is not bi-directional scheduling. Most of the schedule badges show a Capacity value as well.
  - You have to net multiple schedules to derive an estimated final schedule at a location
- Some generators have a single meter to their facility with shared ownership. Through that meter, gas can be scheduled via Pipe 4 or Pipe 5.
- Many generators have multiple connections to separate pipelines and that can be displayed as well
- Meters with zero gas scheduled have darkened icons on this display

Possibilities:

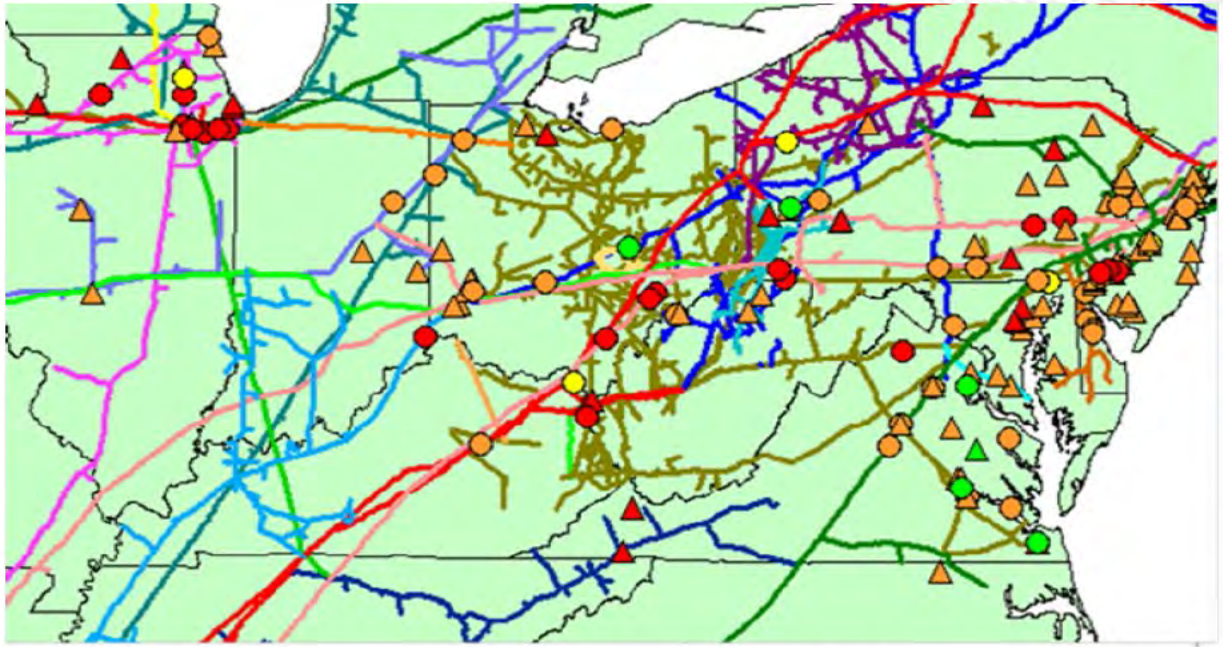
- Real-time power information for the generators as well as how much gas has been consumed and how much remains
- OFO display information based on EBB postings
- Graphical trending of any value you can select

Gas - Electric Coordination
Focus on Interstate Pipelines

May 2017

- Key Milestones
  - Established Gas Electric Coordination Team
    - November 2014
  - Signed Memorandum of Understanding with 9 key interstate pipelines to foster communication and coordination in line with FERC Order 787
    - July 2015
  - Developed analytical processes and tools to identify capacity and supply reliability risks for gas fired generation
    - 2014 through present
  - Began communication coordination with key Local Distribution Companies
    - 2014 through present

Gas - Electric Coordination Team



Algonquin
Alliance
ANR
Big Sandy
Central NY Oil & Gas
Columbia
Crossroads
Dominion Cove Point
Dominion
East Tennessee
Eastern Shore
Equitrans
Guardian
Horizon
KM Illinois
KO
Midwestern
NFG
NGPL
NGO
Northern Border
Panhandle Eastern
Rockies Express
Tennessee
Texas Eastern
Texas Gas
Transco
Vector
○ Interstate-Served Generator
△ LDC-Served Generator

	Mainline Contract	Dual-Fuel Capable
● (green)	Yes	Yes
● (yellow)	Yes	No
● (orange)	No	Yes
● (red)	No	No

- Gas Electric Coordination Team Focus
  - Real Time/Short Term
    - Run Daily Risk Assessment model to identify potential at risk generation
    - Provide risk reports to PJM dispatch for greater operational awareness
    - Conduct communications with pipelines and LDCs as needed
  - Long Term
    - Identify and develop improvements to existing processes/models to enhance and improve risk assessment and contingency analysis
    - Coordinate with pipelines and other key natural gas stakeholders to develop new pipeline services to improve gas generation reliability and flexibility.

- Winter Operational Coordination with Pipelines (November through March)
  - Weekly Operational Calls with Pipeline Gas Control
    - Review load and weather forecasts
    - Review potential capacity restrictions/areas of concern
    - Review potential system maintenance outages impacting generation
  - Daily Communication
    - Provide PJM Day Ahead award information to pipelines via secure data exchange
    - Receive nomination volumes and generator burn profiles from several pipelines
    - Notification of emergent capacity restrictions

- Summer Operational Coordination with Pipelines (April through October)
  - Monthly Operational Calls with Pipeline Gas Control
    - Review electric generator/transmission outages on the PJM side and gas pipeline maintenance activities to ensure effective planning and timing of outages
    - Review potential capacity restrictions/areas of concern as a result of summer maintenance on the pipelines (e.g. “pigging” operations)
  - Pre Winter preparedness meeting with Pipelines
  - Update database of any pipeline infrastructure and/or tariff changes impacting generation

- Key Pipeline Coordination Initiatives in the Queue
  - Drill Planning Scenario
    - Working with Argonne National Labs to assess system resilience due to both a man made and natural disaster impacting the natural gas and electric transmission systems
    - Pilot effort with an interstate pipeline to coordinate responses
  - Gas Electric Co-optimization/Contingency Analysis
    - Working with Argonne National Labs on a pilot effort to better understand the impact on gas fired generation due to varying disturbances on the gas transmission system under varied conditions
    - Pilot effort with an interstate pipeline
  - Gas Electric Web page
    - Establishing a dedicated Gas Electric landing page on PJM website for natural gas stakeholders (pipelines, LDCs, marketers) along with regulatory bodies
    - Provides a one stop shop for public data and the provision of secure data to those pipelines and LDCs that have signed Non Disclosure Agreements.

From:	Glazer, Craig
To:	Fisher, Travis; Mansueti, Lawrence; Meyer, David
Cc:	Schuhart, Denise; Horner, Nathaniel; Pablo, Jeanette; SAM.HILE@ICF.COM
Subject:	For Our Call Tomorrow:Just Released Results of PJM"s Capacity Auction
Date:	Tuesday, May 23, 2017 4:34:34 PM
Attachments:	2020-2021-base-residual-auction-report.pdf

PJM news release as well as a detailed report on the results of the capacity auction are attached. We can brief you more on this on tomorrow's call.

CRAIG GLAZER
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From: PJM News
Sent: Tuesday, May 23, 2017 4:22 PM
To: PJM News
Subject: PJM NEWS RELEASE: PJM CAPACITY AUCTION SEES STRONG RESPONSE FROM MARKET PARTICIPANTS TO STRICT PERFORMANCE STANDARDS

CONTACT: PJM News at 866-756-6397 or pjmnews@pjm.com

FOR IMMEDIATE RELEASE

**PJM CAPACITY AUCTION SEES STRONG RESPONSE FROM MARKET PARTICIPANTS
TO STRICT PERFORMANCE STANDARDS**

(Valley Forge, Pa. – May 23, 2017) – The world's largest competitive power market, PJM Interconnection, attracted a record amount of competitive resources meeting strict performance standards in its annual capacity auction. The auction procures power supply resources to meet consumers' electricity needs three years from now.

The auction produced a price of $76.53/megawatt-day for resources in most of the PJM footprint. Prices are higher in some areas due to transmission limits and retiring generators.

"The results show that PJM markets continue to achieve what they were originally intended to accomplish, ensuring reliability at the lowest reasonable cost," said Andrew L. Ott, PJM president and CEO. "Overall response to this auction, both in participation and competitive bids, reflects the market's ability to attract efficient, high performing and competitive resources that support reliability."

PJM procured 165,109 megawatts of resources for the period June 1, 2020, to May 31, 2021. The procured capacity provides a 23.3-percent reserve margin.

This is the first auction in which all resources had to meet capacity performance requirements, which were phased in. It also was the first to have participation by Price Responsive Demand resources, demand response-like resources that react to market signals.

PJM procures resources three years in advance to ensure adequate power supplies will be available during extreme weather or other system emergencies to meet consumers' demand for electricity. All resources must meet Capacity Performance standards, committing to perform when needed or face steep non-performance payments. To meet that requirement, generation owners, for example, ensure firm fuel supplies or make improvements to their equipment.

The auction attracted 2,350 MW of new gas-fired generation. The auction procured about 7,532 MW of demand response resources that committed to year-round availability and the higher performance requirements. There were 119 MW of solar resources and 504.3 MW of wind resources that cleared the auction. In addition, 1,710 MW of energy efficiency resources cleared.

– MORE –

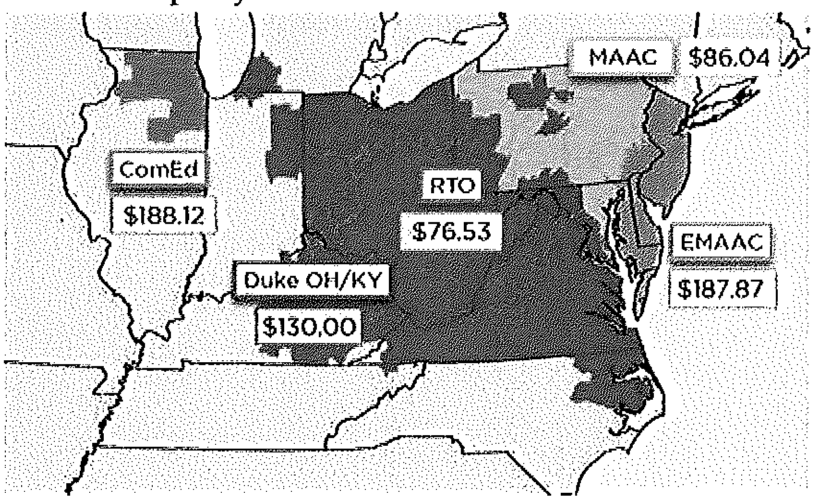
Additionally, under new rules approved by the Federal Energy Regulatory Commission in March, 398 MW of seasonal capacity (resources available in one season only) cleared in an aggregated manner to form a year-round resource. Wind generators, whose capacity is greater in the winter, combined through the auction clearing mechanism with demand response and solar resources, whose capacity is greater in the summer.

In four constrained areas, the MAAC region, Eastern MAAC, ComEd and Duke Energy (Ohio and Kentucky), capacity prices are higher than the RTO price. For MAAC, the price is $86.04 MW-day; in Eastern MAAC, the price is $187.87/MW-day; in ComEd the price is $188.12/MW-day; and in Duke Energy's Ohio and Kentucky region, the price is $130/MW-day.

(The MAAC region includes Atlantic City Electric, Baltimore Gas and Electric Company, Delmarva Power, Jersey City Power & Light, Met-Ed, PECO, Penelec, Pepco, PP&L, Public Service Electric and Gas Co., and Rockland Electric. The companies included in the subset of that region, Eastern MAAC will have a different price. Eastern MAAC consists of Public Service Electric and Gas Co., Jersey Central Power & Light, PECO, Atlantic City Electric, Delmarva Power and Rockland Electric.)

A detailed report of the results is available on pjm.com.

2020/2021 Capacity Prices



PJM Interconnection, founded in 1927, ensures the reliability of the high-voltage electric power system serving 65 million people 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. PJM coordinates and directs the operation of the region's transmission grid, which includes over 82,000 miles of transmission lines; administers a competitive wholesale electricity market; and plans regional transmission expansion improvements to maintain grid reliability and relieve congestion. PJM's regional grid and market operations produce annual savings of $2.8 billion to $3.1 billion. For the latest news about PJM, visit PJM Inside Lines at insidelines.pjm.com.

2020/2021 RPM Base Residual Auction Results

Executive Summary

The 2020/2021 Reliability Pricing Model (RPM) Base Residual Auction (BRA) cleared 165,109.2 MW of unforced capacity in the RTO representing a 23.9% reserve margin. Accounting for load and resource commitments under the Fixed Resource Requirement (FRR), the reserve margin for the entire RTO for the 2020/2021 Delivery Year as procured in the BRA is 23.3%, or 6.7% higher than the target reserve margin of 16.6%. This reserve margin was achieved at clearing prices that are between approximately 26% to 66% of Net CONE, depending upon the Locational Deliverability Area (LDA), while attracting 2,350 MW of new combined cycle gas resources.

The 2020/2021 BRA is the first where PJM has procured 100% Capacity Performance ("CP") Resources. CP Resources must be capable of sustained, predictable operation, and are expected to be available and capable of providing energy and reserves when needed throughout the entire Delivery Year. Also, the 2020/2021 BRA was conducted under the provisions of PJM's Enhanced Aggregation filing (Docket ER17-367-000 & 001) which was accepted by FERC on March 21, 2017.

2020/2021 BRA Resource Clearing Prices

Resource Clearing Prices (RCPs) for the 2020/2021 BRA are shown in Table 1 below. The RCP for CP Resources located in the rest of RTO is $76.53/MW-day. The MAAC LDA, EMAAC LDA, ComEd LDA and DEOK LDA were constrained LDAs in the 2020/2021 BRA with locational price adders of $9.51/MW-day, $101.83/MW-day, $111.59/MW-day and $53.47/MW-day, respectively, for all resources located in those LDAs. For comparison purposes, the RCP for CP Resources located in the rest of RTO and MAAC in the 2019/2020 BRA was $100.00/MW-day. For the same year, the RCP for CP Resources in the EMAAC LDA was $119.77/MW-day and the RCP for CP Resources in the COMED LDA was $202.77 /MW-day in the 2019/2020 BRA. The DEOK LDA was not modeled in the 2019/20 BRA and cleared with the rest of RTO.

	2020/2021 BRA Resource Clearing Prices ($/MW-day)				
Capacity Type	Rest of RTO	MAAC	EMAAC	COMED	DEOK
Capacity Performance	$76.53	$86.04	$187.87	$188.12	$130.00

2020/2021 RPM Base Residual Auction Results

2020/2021 BRA Cleared Capacity Resources

As seen in the table below, the 2020/2021 BRA procured 2,389.3 MW of capacity from new generation and 434.5 MW from uprates to existing or planned generation. The quantity of capacity procured from external Generation Capacity Resources in the 2020/2021 BRA is 3,997.2 MW which is an increase of 121.3 MW from that procured in last year's BRA. All external generation capacity that has cleared in the 2020/21 BRA has the requirements for the Capacity Import Limit (CIL) exception which include (1) long-term firm transmission service has been confirmed on the complete transmission path from the external resource into PJM for the relevant Delivery Year; (2) the external resource meets or will meet prior to the Delivery Year all applicable requirements to be pseudo-tied; and (3) a separate written commitment has been executed to offer all unforced capacity of the external resource into RPM Auctions under the same terms, and subject to the same conditions and exceptions, as set forth for internal generation resources by section 6.6 of Attachment DD of PJM Tariff. The total quantity of DR procured in the 2020/2021 BRA is 7,820.4 MW which is a decrease of 2,527.6 MW from that procured in last year's BRA; and, the total quantity of EE procured in the 2020/2021 BRA is 1,710.2 MW, which is an increase of 195.1 MW from that procured in last year's BRA.

Megawatts of Unforced Capacity Procured by Type from the 2014/2015 BRA to the 2020/2021 BRA

Delivery Year	New Generation	Generation Uprates	Imports	Demand Response	Energy Efficiency
2020/2021	2,389.3	434.5	3,997.2	7,820.4	1,710.2
2019/2020	5,373.6	155.6	3,875.9	10,348.0	1,515.1
2018/2019	2,954.3	587.6	4,687.9	11,084.4	1,246.5
2017/2018	5,927.4	339.9	4,525.5	10,974.8	1,338.9
2016/2017	4,281.6	1,181.3	7,482.7	12,408.1	1,117.3
2015/2016	4,898.9	447.4	3,935.3	14,832.8	922.5
2014/2015	415.5	341.1	3,016.5	14,118.4	822.1

*All MW Values are in UCAP Terms

2020/2021 RPM Base Residual Auction Results

Introduction

This document provides information for PJM stakeholders regarding the results of the 2020/2021 Reliability Pricing Model (RPM) Base Residual Auction (BRA). The 2020/2021 BRA opened on May 10, 2017, and the results were posted on May 23, 2017.

In each BRA, PJM seeks to procure a target capacity reserve level for the RTO in a least cost manner while recognizing the following reliability-based constraints on the location and type of capacity that can be committed:

- Internal PJM locational constraints are established by setting up Locational Deliverability Areas (LDAs) with each LDA having a separate target capacity reserve level and a maximum limit on the amount of capacity that it can import from resources located outside of the LDA.
- Total cleared summer-period sell offers must exactly equal total cleared winter-period sell offers across the entire RTO to ensure that seasonal CP sell offers clear to form annual CP commitments.

The auction clearing process commits capacity resources to procure a target capacity reserve level for the RTO in a least-cost manner while recognizing and enforcing these reliability-based constraints. The clearing solution may be required to commit capacity resources out-of-merit order but again in a least-cost manner to ensure that all of these constraints are respected. In those cases where one or more of the constraints results in out-of-merit commitment in the auction solution, resource clearing prices will be reflective of the price of resources selected out of merit order to meet the necessary requirements.

This document begins with a high-level summary of the BRA results followed by sections containing detailed descriptions of the 2020/2021 BRA results and a discussion of the results in the context of the ten previous BRAs.

Summary of Results

The 2020/2021 Reliability Pricing Model (RPM) Base Residual Auction (BRA) cleared 165,109.2 MW of unforced capacity in the RTO representing a 23.9% reserve margin. The reserve margin for the entire RTO is 23.3%, or 6.7% higher than the target reserve margin of 16.6%, when the Fixed Resource Requirement (FRR) load and resources are considered.

Resource Clearing Prices (RCPs) for the 2020/2021 BRA are shown in Table 1 below. The RCP for CP Resources located in the rest of RTO is $76.53/MW-day. The MAAC LDA, EMAAC LDA, ComEd LDA and DEOK LDA were constrained LDAs in the 2020/2021 BRA with locational price adders of $9.51/MW-day, $101.83/MW-day, $111.59/MW-day and $53.47/MW-day, respectively, for all resources located in those LDAs. For comparison purposes, the RCP for CP Resources located in the rest of RTO and MAAC in the 2019/2020 BRA was $100.00/MW-day. The RCP for CP Resources in the EMAAC LDA was $119.77/MW-day and the RCP for CP Resources in the COMED LDA was $202.77 /MW-day in the 2019/2020 BRA. The DEOK LDA was not modeled in the 2019/20 BRA and cleared at the RTO RCP.

The total quantity of new Generation Capacity Resources offered into the auction was 3,143.5 MW (UCAP) comprised of 2,536.6 MW (UCAP) of new generation units and 606.9 MW (UCAP) of uprates to existing generation units. The quantity of new Generation Capacity Resources cleared was 2,823.8 MW (UCAP) comprised of 2,389.3 MW (UCAP) from new generation units and 434.5 MW from uprates to existing generation units.

The quantity of capacity procured from external Generation Capacity Resources in the 2020/2021 BRA is 3,997.2 MW which is an increase of 121.3 MW from that procured in last year's BRA. All external generation capacity that has cleared in the 2020/2021 BRA has met the requirements for a CIL exception. These requirements help to ensure that external resources offering into the RPM auction have reasonable expectation of physically delivering on any RPM commitment and have high likelihood of being available for PJM when needed.

The total quantity of DR procured in the 2020/2021 BRA is 7,820.4 MW which is a decrease of 2,527.6 MW from that procured in last year's BRA; and, the total quantity of EE procured in the 2020/2021 BRA is 1,710.2 MW which is an increase of 195.1 MW from that procured in last year's BRA.

The RTO as a whole failed the Market Structure Test (i.e., the Three-Pivotal Supplier Test), resulting in the application of market power mitigation to all existing generation resources. Mitigation was applied to a supplier's existing generation resources resulting in utilizing the lesser of the supplier's approved Market Seller Offer Cap for such resource or the supplier's submitted offer price for such resource in the RPM Auction clearing.

2020/2021 RPM Base Residual Auction Results

All Generation Capacity Resources (including uprates to existing resources) of 20 MW or greater that are based on combustion turbine, combined cycle and integrated gasification combined cycle technologies that have not cleared an RPM Auction prior to February 1, 2013 are subject to the Minimum Offer Price Rule (MOPR). External Generation Capacity Resources meeting the above criteria and that have entered commercial operation on or after January 1, 2013 and that require sufficient transmission investment for delivery into PJM are also subject to MOPR. To avoid application of the MOPR, Capacity Market Sellers may request exemption through either a Competitive Entry Exemption request, Self-Supply Exemption request or a Unit-Specific Exemption request. The table below shows the requested, granted and cleared aggregate quantity (in ICAP MW) of each exemption type received and processed by PJM. While there were over 12,000 MW of MOPR exemption requests, making a request does not obligate a resource to offer into the BRA.

LDA	Exemption Type	Requested Quantity (ICAP MW)	Granted Quantity (ICAP MW)	Cleared Quantity (ICAP MW)
RTO	Competitive Entry	12,161.0	12,161.0	2,675.6
RTO	Self-Supply	0.0	0.0	0.0
RTO	Unit-Specific	0.0	0.0	0.0
Total		**12,161.0**	**12,161.0**	**2,675.6**

A further discussion of the 2020/2021 BRA results and additional information regarding the 2020/2021 RPM BRA are detailed in the body of this report. The discussion also provides a comparison of the 2020/2021 auction results to the results from the 2007/2008 through 2019/2020 RPM Auctions.

2020/2021 RPM Base Residual Auction Results

2020/2021 Base Residual Auction Results Discussion

Table 1 contains a summary of the RTO clearing prices, cleared unforced capacity, and implied cleared reserve margins resulting from the 2020/2021 RPM BRA in comparison to those from 2007/2008 through 2019/2020 RPM BRAs.

Table 1 –RPM Base Residual Auction Resource Clearing Price Results in the RTO

	RTO													
Auction Results	2007/2008	2008/2009	2009/2010	2010/2011	2011/2012[1]	2012/2013	2013/2014[2]	2014/2015[3]	2015/2016[4]	2016/2017[5]	2017/2018	2018/2019	2019/2020	2020/2021[6]
Resource Clearing Price ($/MW-day)	$40.80	$111.92	$102.04	$174 29	$110 00	$16.46	$27.73	$125 99	$136 00	$59 37	$120.00	$164.77	$100 00	$76 53
Cleared UCAP (MW)	129,409.2	129,597 6	132,231.8	132,190.4	132,221 5	136,143 5	152,743.3	149,974.7	164,561 2	169,159.7	167,003.7	166,836.9	167,305 9	165,109 2
Reserve Margin	19.1%	17.4%	17 6%	16.4%	17.9%	20.5%	19.7%	18 8%	19.3%	20.3%	19.7%	19 8%	22.4%	23.3%

1) 2011/2012 BRA w as conducted w ithout Duquesne zone load.
2) 2013/2014 BRA includes ATSI zone
3) 2014/2015 BRA includes Duke zone
4) 2015/2016 BRA includes a significant portion of AEP and DEOK zone load previously under the FRR Alternative
5) 2016/2017 BRA includes EKPC zone
6) 2020/2021 BRA Cleared UCAP (MW) includes Annual and matched Seasonal Capacity Performance sell offers

The Reserve Margin presented in Table 1 represents the percentage of installed capacity cleared in RPM and committed by FRR entities in excess of the RTO load (including load served under the Fixed Resource Requirement alternative). The 2020/2021 RPM BRA cleared 165,109.2 MW of unforced capacity in the RTO representing a 23.9% reserve margin. The reserve margin for the entire RTO is 23.3%, or 6.7% higher than the target reserve margin of 16.6%, when the Fixed Resource Requirement (FRR) load and resources are considered.

New Generation Resource Participation

The total quantity of new Generation Capacity Resources offered into the auction was 3,143.5 MW (UCAP) comprised of 2,536.6 MW of new generation units and 606.9 MW of uprates to existing generation units. The quantity of new Generation Capacity Resources cleared was 2,823.8 MW (UCAP) comprised of 2,389.3 MW (UCAP) from new generation units, predominantly natural gas combined cycle, and 434.5 MW from uprates to existing generation units.

Table 2A shows the breakdown, by major LDA, of capacity in UCAP terms of new units and uprates at existing units offered in the auction and capacity actually clearing in the auction. Ninety percent of the new generation capacity that offered into the 2020/2021BRA cleared the auction.

2020/2021 RPM Base Residual Auction Results

Table 2A – Offered and Cleared New Generation Capacity by LDA (in UCAP MW)

	Offered			Cleared ****		
LDA	Uprate	New Unit	Total	Uprate	New Unit	Total
EMAAC	199.7	42.8	**242.5**	86.1	7.9	**94.0**
MAAC **	287.8	1,042.8	**1,330.6**	174.2	1,439.0	**1,613.2**
Total RTO ***	606.9	2,536.6	**3,143.5**	434.5	2,389.3	**2,823.8**

* All MW Values are in UCAP Terms

** MAAC includes EMAAC

*** RTO includes MAAC

**** Cleared MW values may include new units that have offered in a prior BRA and not cleared

Capacity Import Participation

The quantity of capacity imports cleared in the 2020/2021 BRA were 3,997.2 MW (UCAP) which represents an increase of 121.3 MW from the imports that cleared in the 2019/2020 BRA. The majority of the imports are from resources located in regions west of the PJM RTO. All external generation capacity that has cleared in the 2020/21 BRA has met the requirements for a CIL exception.

Table 2B – Offered and Cleared Capacity Imports (in UCAP MW)

	External Source Zones					
Imports *	NORTH	WEST 1	WEST 2	SOUTH 1	SOUTH 2	Total
Offered MW (UCAP)	214.1	1,219.6	2,144.5	804.2	579.4	**4,961.8**
Cleared MW (UCAP)	214.1	1,130.1	1,327.2	746.4	579.4	**3,997.2**

* Offered and Cleared MW quantities include resources that met the requirements for a CIL Exception and those associated with pre-OATT grandfathered transmission
Attachment G of Manual 14B provides a mapping of outside Balancing Authorities to the External Source Zones.

Demand Resource Participation

The total quantity of DR offered into the 2020/2021 BRA was 9,846.7 MW (UCAP), representing a decrease of 16.7% from the DR that offered into the 2019/2020 BRA. Of the 9,846.7 MW of total DR that offered in this auction, 7,820.4 MW cleared. The cleared DR is 2,527.6 MW less than that which cleared in the 2019/2020 BRA. Of the 7,820.4 MW of DR cleared in the 2020/2021 BRA, 7,531.5 MW were cleared as the Annual Capacity Performance Product and 288.9 MW were cleared as the summer seasonal Capacity

Performance product. Table 3A contains a comparison of the DR Offered and Cleared in 2019/2020 BRA & 2020/2021 BRA represented in UCAP.

Energy Efficiency Resource Participation

An EE resource is a project that involves the installation of more efficient devices/equipment or the implementation of more efficient processes/systems exceeding then-current building codes, appliance standards, or other relevant standards at the time of installation as known at the time of commitment. The EE resource must achieve a permanent, continuous reduction in electric energy consumption (during the defined EE performance hours) that is not reflected in the peak load forecast used for the BRA for the Delivery Year for which the EE resource is proposed. The EE resource must be fully implemented at all times during the Delivery Year, without any requirement of notice, dispatch, or operator intervention. Of the 2,242.5 MW of energy efficiency that offered into the 2020/2021 BRA, 1,710.2 MW of EE resources cleared in the auction. Of the 1,710.2 MW of EE Resources cleared in the 2020/2021 BRA, 1,607.4 MW was cleared as the Annual Capacity Performance Product and 102.8 MW were cleared as the summer seasonal Capacity Performance product.

Table 3B contains a summary of the DR and EE resources that offered and cleared by zone in the 2020/2021 BRA. Approximately 79.4% of the DR and 76.3% of the EE resources that were offered into the BRA cleared.

Figure 1 illustrates the demand side participation in the PJM Capacity Market from 2005/2006 Delivery Year to the 2020/2021 Delivery Year. Demand side participation includes active load management (ALM) prior to 2007/2008 Delivery Year, Interruptible Load for Reliability (ILR) and DR offered into each BRA and nominated in FRR Plans, and EE resources starting with the 2012/2013 Delivery Year. The demand side participation in the capacity market has increased dramatically since the inception of RPM in the 2007/2008 Delivery Year through the 2015/2016 BRA, but as shown in Figure 1, total demand side participation and cleared resources for the 2020/2021 BRA have fallen below the levels seen in the 2014/2015 BRA.

2020/2021 RPM Base Residual Auction Results

Table 3A – Comparison of Demand Resources Offered and Cleared in 2019/2020 BRA & 2020/2021 BRA (in UCAP MW)

		Offered MW (UCAP)			Cleared MW (UCAP)		
LDA	Zone	2019/2020	2020/2021 *	Increase in Offered MW	2019/2020	2020/2021 *	Increase in Cleared MW
EMAAC	AECO	153.8	72.5	**(81.3)**	145.7	62.8	**(82.9)**
EMAAC/DPL-S	DPL	397.9	330.0	**(67.9)**	371.6	213.4	**(158.2)**
EMAAC	JCPL	231.2	160.1	**(71.1)**	200.8	143.9	**(56.9)**
EMAAC	PECO	565.1	408.3	**(156.8)**	527.4	363.3	**(164.1)**
PSEG/PS-N	PSEG	427.8	353.5	**(74.3)**	380.7	327.7	**(53.0)**
EMAAC	RECO	10.3	3.8	**(6.5)**	10.3	3.7	**(6.6)**
EMAAC Sub Total		**1,786.1**	**1,328.2**	**(457.9)**	**1,636.5**	**1,114.8**	**(521.7)**
PEPCO	PEPCO	570.4	346.7	**(223.7)**	483.3	211.9	**(271.4)**
BGE	BGE	729.3	430.5	**(298.8)**	256.4	246.5	**(9.9)**
MAAC	METED	379.8	294.0	**(85.8)**	321.7	241.8	**(79.9)**
MAAC	PENELEC	392.0	356.6	**(35.4)**	339.4	304.1	**(35.3)**
PPL	PPL	815.6	693.5	**(122.1)**	739.8	579.9	**(159.9)**
MAAC Sub Total**		**4,673.2**	**3,449.5**	**(1,223.7)**	**3,777.1**	**2,699.0**	**(1,078.1)**
RTO	AEP	1,603.1	1,408.5	**(194.6)**	1,416.1	1,010.5	**(405.6)**
RTO	APS	1,039.4	933.2	**(106.2)**	926.0	709.8	**(216.2)**
ATSI/ATSI-C	ATSI	978.0	815.8	**(162.2)**	897.6	688.7	**(208.9)**
COMED	COMED	1,792.0	1,794.4	**2.4**	1,757.4	1,512.9	**(244.5)**
DAY	DAY	237.6	212.4	**(25.2)**	219.8	164.6	**(55.2)**
DEOK	DEOK	248.8	200.8	**(48.0)**	236.7	152.8	**(83.9)**
RTO	DOM	816.8	700.2	**(116.6)**	729.7	585.3	**(144.4)**
RTO	DUQ	286.8	192.6	**(94.2)**	247.2	159.9	**(87.3)**
RTO	EKPC	142.3	139.3	**(3.0)**	140.4	136.9	**(3.5)**
Grand Total		**11,818.0**	**9,846.7**	**(1,971.3)**	**10,348.0**	**7,820.4**	**(2,527.6)**

* 2020/2021 MW values include both Annual and Summer-Period Capacity Performance DR

** MAAC sub-total includes all MAAC Zones

2020/2021 RPM Base Residual Auction Results

Table 3B – Comparison of Demand Resources and Energy Efficiency Resources Offered and Cleared in the 2020/2021 BRA (in UCAP MW)

		Offered MW (UCAP)			Cleared MW (UCAP)		
LDA	Zone	DR	EE	Total	DR	EE	Total
EMAAC	AECO	72.5	31.6	**104.1**	62.8	27.2	**90.0**
EMAAC/DPL-S	DPL	330.0	57.9	**387.9**	213.4	47.7	**261.1**
EMAAC	JCPL	160.1	52.5	**212.6**	143.9	47.9	**191.8**
EMAAC	PECO	408.3	82.3	**490.6**	363.3	71.4	**434.7**
PSEG/PS-N	PSEG	353.5	112.6	**466.1**	327.7	93.3	**421.0**
EMAAC	RECO	3.8	6.4	**10.2**	3.7	5.6	**9.3**
EMAAC Sub Total		**1,328.2**	**343.3**	**1,671.5**	**1,114.8**	**293.1**	**1,407.9**
PEPCO	PEPCO	346.7	99.9	**446.6**	211.9	66.8	**278.7**
BGE	BGE	430.5	156.6	**587.1**	246.5	125.1	**371.6**
MAAC	METED	294.0	33.9	**327.9**	241.8	14.9	**256.7**
MAAC	PENELEC	356.6	28.1	**384.7**	304.1	10.6	**314.7**
PPL	PPL	693.5	59.6	**753.1**	579.9	34.5	**614.4**
MAAC Sub Total**		**3,449.5**	**721.4**	**4,170.9**	**2,699.0**	**545.0**	**3,244.0**
RTO	AEP	1,408.5	168.9	**1,577.4**	1,010.5	110.2	**1,120.7**
RTO	APS	933.2	55.5	**988.7**	709.8	36.8	**746.6**
ATSI/ATSI-C	ATSI	815.8	52.7	**868.5**	688.7	33.2	**721.9**
COMED	COMED	1,794.4	808.1	**2,602.5**	1,512.9	701.9	**2,214.8**
DAY	DAY	212.4	54.3	**266.7**	164.6	33.1	**197.7**
DEOK	DEOK	200.8	67.4	**268.2**	152.8	65.8	**218.6**
RTO	DOM	700.2	274.8	**975.0**	585.3	168.9	**754.2**
RTO	DUQ	192.6	30.0	**222.6**	159.9	12.3	**172.2**
RTO	EKPC	139.3	9.4	**148.7**	136.9	3.0	**139.9**
Grand Total		**9,846.7**	**2,242.5**	**12,089.2**	**7,820.4**	**1,710.2**	**9,530.6**

* MW values include both Annual and Summer-Period Capacity Performance DR and EE

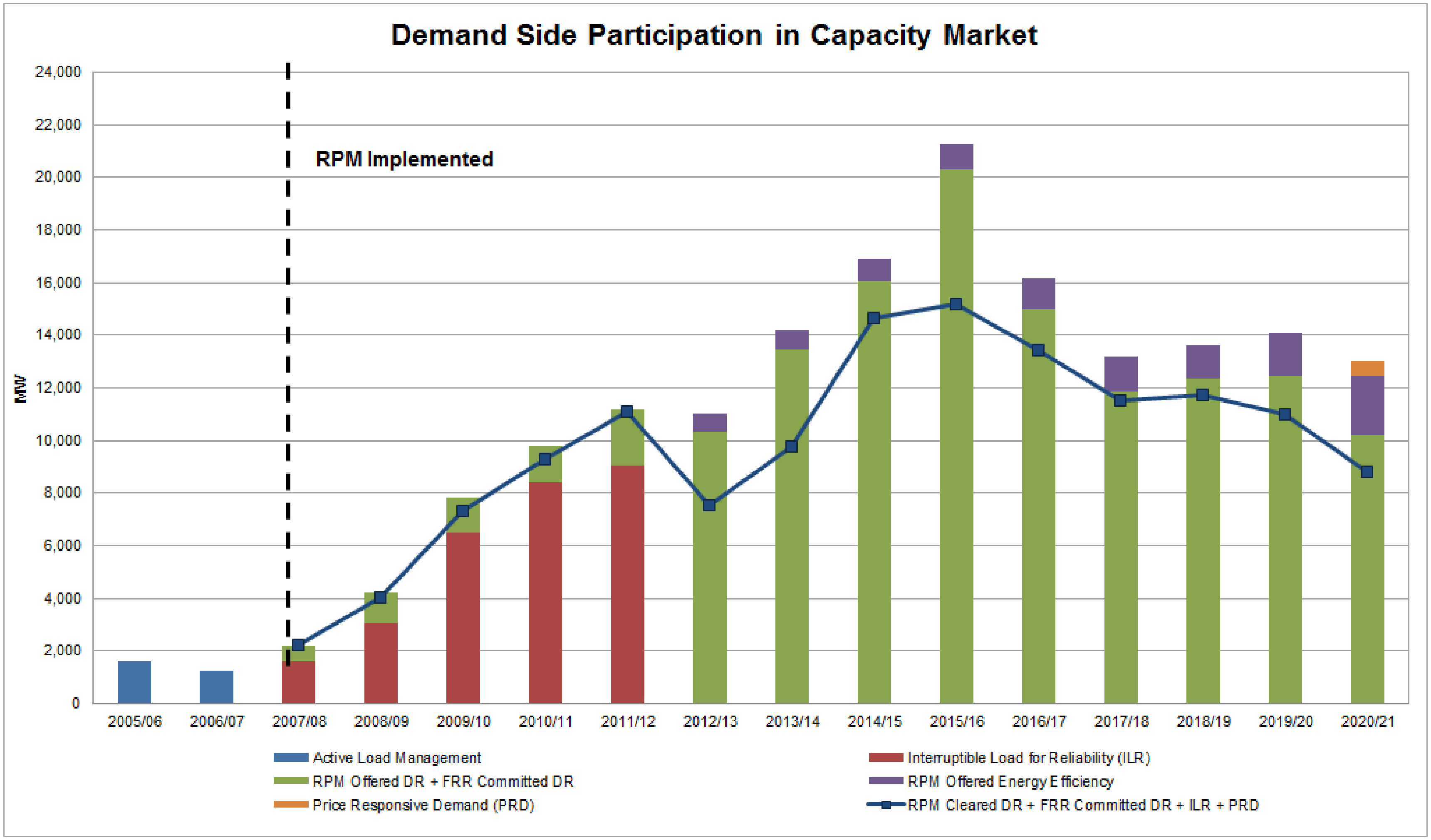
** MAAC sub-total includes all MAAC Zones

2020/2021 RPM Base Residual Auction Results

Table 3C – Breakdown of Annual and Seasonal Capacity Performance Resources by Resource Type and Season that Offered and Cleared in the 2020/2021 BRA (in UCAP MW)

	Offered MW (UCAP)			Cleared MW (UCAP)		
Resource Type	Annual	Summer	Winter	Annual	Summer	Winter
GEN	170,591.7	184.7	485.9	155,572.4	6.2	397.9
DR	8,367.2	1,479.5	-	7,531.5	288.9	-
EE	1,839.0	403.5	-	1,607.4	102.8	-
Total	**180,797.9**	**2,067.7**	**485.9**	**164,711.3**	**397.9**	**397.9**

Figure 1 – Demand Side Participation in the PJM Capacity Market



Renewable Resource Participation

887.7 MW of wind resources were offered into and cleared the 2020/2021 BRA as compared to 969 MW of wind resources that offered into and cleared the 2019/2020 BRA. Of the 887.7 MW of wind resources cleared in the 2020/2021 BRA, 504.3 MW were cleared as the Annual Capacity Performance Product and 383.4 MW were cleared as the winter seasonal Capacity Performance product. The capacity factor applied to wind resources is typically 13%, meaning that for every 100 MW of wind energy, 13 MW are eligible to meet capacity requirements. The 887.7 MW of cleared wind capacity translates to approximately 6,828.5 MW of wind energy nameplate capability that is expected to be available in the 2020/2021 Delivery Year.

125.3 MW of solar resources were offered into and cleared the 2020/2021 BRA as compared to 335 MW of solar resources that offered into and cleared the 2019/2020 BRA. Of the 125.3 MW of solar resources cleared in the 2020/2021 BRA, 119.1 MW were cleared as the Annual Capacity Performance Product and 6.2 MW were cleared as the summer seasonal Capacity Performance product. The capacity factor applied to solar resources is typically 38%, meaning that for every 100 MW of solar energy, 38 MW are eligible to meet capacity requirements. The 125.3 MW of cleared solar capacity translates to approximately 329.7 MW of nameplate solar energy capability that is expected to be available in the 2020/2021 Delivery Year.

Price Responsive Demand Participation

PRD participated for the first time in the 2020/2021 BRA. A total Nominal PRD Value of 558 MW was elected and committed in the 2020/2021 BRA. PRD is provided by a PJM Member that represents retail customers having the ability to predictably reduce consumption in response to changing wholesale prices. In the PJM Capacity Market, a PRD Provider may voluntarily make a firm commitment of the quantity of PRD that will reduce its consumption in response to real time energy price during a Delivery Year. A PRD Provider that is committing PRD in a BRA must also submit a PRD election in the eRPM system which indicates the Nominal PRD Value in MWs that the PRD Provider is willing to commit at different reservation prices ($/MW-day). The VRR curve of the RTO and each affected LDA is shifted leftward along the horizontal axis by the UCAP MW quantity of elected PRD where the leftward shift occurs only for the portion of the VRR Curve at or above the PRD Reservation price. As shown in the 2020/2021 Planning Parameters, 558 MW of PRD across the RTO has elected to participate in the 2020/2021 BRA: 330 MW in the BGE LDA, 170 MW in the PEPCO LDA, and 58 MW in the EMAAC LDA (with 23 MW located in the DPL-South LDA). The VRR Curve of the RTO and each affected LDA is shifted leftward along the horizontal axis by the UCAP MW value of these quantities at the PRD Reservation Price. Once committed in a BRA, a PRD commitment cannot be replaced; the commitment can only be satisfied through the registration of price response load in the DR Hub system prior to or during the Delivery Year.

LDA Results

An LDA was modeled in the BRA and had a separate VRR Curve if (1) the LDA has a CETO/CETL margin that is less than 115%; or (2) the LDA had a locational price adder in any of the three immediately preceding BRAs; or (3) the LDA is EMAAC, SWMAAC, and MAAC. An LDA not otherwise qualifying under the above three tests may also be modeled if PJM finds that the LDA is determined to be likely to have a Locational Price Adder based on historic offer price levels or if such LDA is required to achieve an acceptable level of reliability consistent with the Reliability Principles and Standards.

As a result of the above criteria, MAAC, EMAAC, SWMAAC, PSEG, PS-NORTH, DPL-SOUTH, PEPCO, ATSI, ATSI-Cleveland, COMED, BGE, PL, DAY and DEOK were modeled as LDAs in the 2020/2021 RPM Base Residual Auction. The MAAC, EMAAC, ComEd and DEOK LDAs were binding constraints in the auction resulting in a Locational Price Adder for these LDAs. A Locational Price Adder represents the difference in Resource Clearing Prices for the Capacity Performance product between a resource in a constrained LDA and the immediate higher level LDA. Table 4 contains a summary of the clearing results in the LDAs from the 2020/2021 RPM Base Residual Auction.

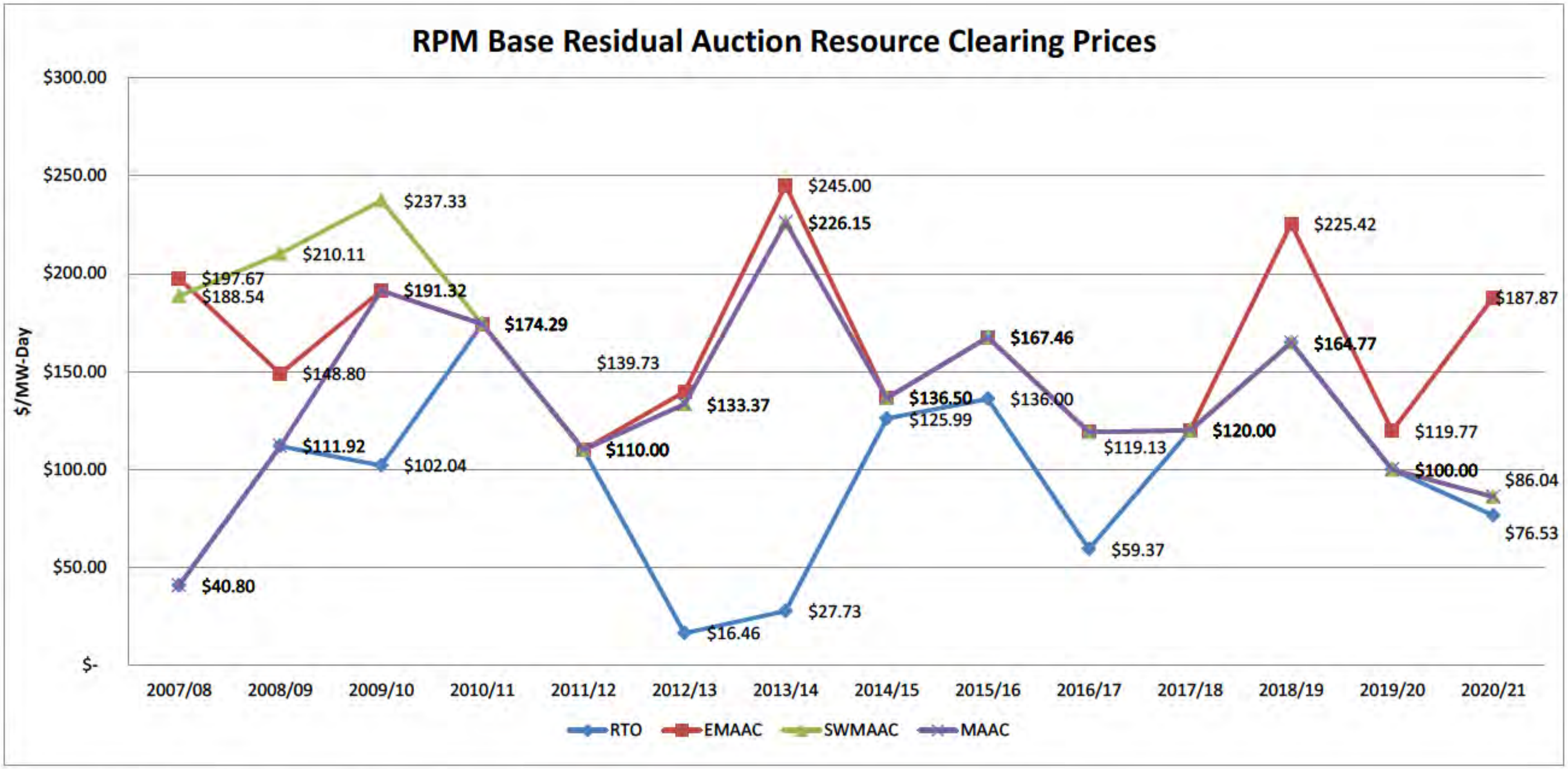
Table 4 –RPM Base Residual Auction Clearing Results in the LDAs

Auction Results	RTO	MAAC	SWMAAC	PEPCO	BGE	EMAAC	DPL-SOUTH	PSEG	PS-NORTH	ATSI	ATSI-CLEVELAND	PPL	COMED	DAY	DEOK
Offered MW (UCAP) *	183,351.5	72,972.7	12,895.4	6,941.1	3,543.3	31,045.0	1,687 9	5,699.5	3,359.1	11,705.2	2,467.4	10,929.7	27,436 8	1,669.2	3,166.7
Cleared MW (UCAP) **	165,109.2	65,817.9	10,354.4	5,918.6	2,296.9	29,608.2	1,647 2	5,097.2	2,975.4	9,925.1	1,857.9	10,345.0	23,960 3	1,527.1	2,430.3
System Marginal Price	$76.53	$76.53	$76.53	$76.53	$76.53	$76.53	$76.53	$76.53	$76.53	$76.53	$76.53	$76.53	$76.53	$76 53	$76.53
Locational Price Adder ***	-	$9.51	-	-	-	$101.83	-	-	-	-	-	-	$111.59	-	$53.47
Resource Clearing Price	$76.53	$86.04	$86.04	$86.04	$86.04	$187.87	$187.87	$187.87	$187.87	$76.53	$76.53	$86.04	$188.12	$76 53	$130.00

* Offered MW values include Annual, Summer-Period, and Winter-Period Capacity Performance sell offers
** Cleared MW values include Annual and matched Seasonal Capacity Performance sell offers w i hin the LDA
*** Locational Price Adder is w ith respect to the immediate parent LDA

Since the MAAC LDA, EMAAC LDA, ComEd LDA and DEOK LDAs were constrained LDAs, Capacity Transfer Rights (CTRs) will be allocated to loads in these constrained LDA for the 2020/2021 Delivery Year. CTRs are allocated by load ratio share to all Load Serving Entities (LSEs) in a constrained LDA that has a higher clearing price than the unconstrained region. CTRs serve as a credit back to the LSEs in the constrained LDA for use of the transmission system to import less expensive capacity into that constrained LDA and are valued at the difference in the clearing prices of the constrained and unconstrained regions.

Figure 2 – Base Residual Auction Resource Clearing Prices



* 2014/2015 through 2020/2021 Prices reflect the Annual Resource Clearing Prices.

2020/2021 RPM Base Residual Auction Results

Table 5 contains a summary of the RTO resources for each cleared BRA from 2008/2009 through the 2020/2021 Delivery Years. The summary includes all resources located in the RTO (including FRR Capacity Plans).

A total of 212,995.6 MW of installed capacity was eligible to be offered into the 2020/2021 Base Residual Auction, with 5,440.5 MW from external resources. As illustrated in Table 5, the amount of capacity exports in the 2020/2021 auction increased by 1.6 MW from that of the previous auction and FRR commitments decreased by 1,453.7 MW from the 2019/2020 Delivery Year to 13,931.6 MW.

A total of 189,917.8 MW of capacity was offered into the Base Residual Auction. This is a decrease of 4,325.2 MW from that which was offered into the 2019/2020 BRA. A total of 23,077.8 MW was eligible, but not offered due to either (1) inclusion in an FRR Capacity Plan, (2) export of the resource, or (3) having been excused from offering into the auction. Resources were excused from the must offer requirement for the following reasons: approved retirement requests not yet reflected in eRPM, resources categorically exempt from the Capacity Performance must-offer requirement, resources which received an exemption from the must-offer or Capacity Performance must-offer requirement and excess capacity owned by an FRR entity.

2020/2021 RPM Base Residual Auction Results

Table 5 –RPM Base Residual Auction Generation, Demand, and Energy Efficiency Resource Information in the RTO

	RTO[1]												
Auction Supply (all values in ICAP)	2008/2009	2009/2010	2010/2011	2011/2012[2]	2012/2013	2013/2014[3]	2014/2015[4]	2015/2016[5]	2016/2017[6]	2017/2018	2018/2019	2019/2020	2020/2021[7]
Internal PJM Capacity	166,037.9	167,026.3	168,457.3	169,241.6	179,791.2	195,633.4	199,375.5	207,559.1	208,098.0	202,477.4	203,300.6	207,579.6	207,555.1
Imports Offered	2,612.0	2,563.2	2,982.4	6,814.2	4,152.4	4,766.1	7,620.2	4,649.7	8,412.2	6,300.9	5,724.6	4,821.4	5,440.5
Total Eligible RPM Capacity	**168,649.9**	**169,589.5**	**171,439.7**	**176,055.8**	**183,943.6**	**200,399.5**	**206,995.7**	**212,208.8**	**216,510.2**	**208,778.3**	**209,025.2**	**212,401.0**	**212,995.6**
Exports / Delistings	4,205.8	2,240.9	3,378.2	3,389.2	2,783.9	2,624.5	1,230.1	1,218.8	1,218.8	1,223.2	1,313.4	1,318.2	1,319.8
FRR Commitments	24,953.5	25,316.2	26,305.7	25,921.2	26,302.1	25,793.1	33,612.7	15,997.9	15,576.6	15,776.1	15,793.0	15,385.3	13,931.6
Excused	722.0	1,121.9	1,290.7	1,580.0	1,732.2	1,825.7	3,255.2	8,712.9	8,524.0	4,305.3	2,348.4	1,454.5	7,826.4
Total Eligible RPM Capacity - Excused	**29,881.3**	**28,679.0**	**30,974.6**	**30,890.4**	**30,818.2**	**30,243.3**	**38,098.0**	**25,929.6**	**25,319.4**	**21,304.6**	**19,454.8**	**18,158.0**	**23,077.8**
Remaining Eligible RPM Capacity	**138,768.6**	**140,910.5**	**140,465.1**	**145,165.4**	**153,125.4**	**170,156.2**	**168,897.7**	**186,279.2**	**191,190.8**	**187,473.7**	**189,570.4**	**194,243.0**	**189,917.8**
Generation Offered	138,076.7	140,003.6	139,529.5	143,568.1	142,957.7	156,894.1	153,048.1	166,127.8	176,145.3	175,329.5	177,592.1	181,866.4	178,807.1
DR Offered	691.9	906.9	935.6	1,597.3	9,535.4	12,528.7	15,043.1	19,243.6	13,932.9	10,855.2	10,772.8	10,859.2	9,047.8
EE Offered	0.0	0.0	0.0	0.0	632.3	733.4	806.5	907.8	1,112.6	1,289.0	1,205.5	1,517.4	2,062.9
Total Eligible RPM Capacity Offered	**138,768.6**	**140,910.5**	**140,465.1**	**145,165.4**	**153,125.4**	**170,156.2**	**168,897.7**	**186,279.2**	**191,190.8**	**187,473.7**	**189,570.4**	**194,243.0**	**189,917.8**
Total Eligible RPM Capacity Unoffered	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**

1) RTO numbers include all LDAs.
2) All generation in the Duquesne zone is considered external to PJM for the 2011/2012 BRA.
3) 2013/2014 includes ATSI zone and generation
4) 2014/2015 includes Duke zone and generation
5) 2015/2016 includes a significant portion of AEP and DEOK zone load previously under the FRR Alternative
6) 2016/2017 includes EKPC zone
7) 2020/2021 Generation, DR, and EE Offered MW values include Annual, Summer-Period, and Winter-Period Capacity Performance sell offers

Table 6 shows the Generation, DR, and EE Resources Offered and Cleared in the RTO translated into Unforced Capacity (UCAP) MW amounts. Participants' sell offer EFORd values were used to translate the generation installed capacity values into unforced capacity (UCAP) values. DR sell offers and EE sell offers were converted into UCAP using the appropriate Forecast Pool Requirement (FPR) for the Delivery Year.

In UCAP terms, a total of 183,351.5 MW were offered into the 2020/2021 BRA, comprised of 171,262.3 MW of generation capacity, 9,846.7 MW of capacity from DR, and 2,242.5 MW of capacity from EE resources. Of those offered, a total of 165,109.2 MW of capacity was cleared in the BRA.

Of the 165,109.2 MW of capacity that cleared in the auction, a total of 155,976.5 MW cleared from Generation Capacity Resources, 7,820.4 MW cleared from DR, and 1,710.2 MW cleared from EE resources, 397.9 MW of which cleared as matched seasonal CP resources. Capacity that was offered but not cleared in the BRA Auction will be eligible to offer into the First, Second and Third Incremental Auctions for the 2020/2021 Delivery Year.

Table 6 – Generation, Demand Resources, and Energy Efficiency Resources Offered and Cleared in UCAP MW

	RTO*												
Auction Results	**2008/2009**	**2009/2010**	**2010/2011**	**2011/2012**	**2012/2013**	**2013/2014**	**2014/2015**	**2015/2016**	**2016/2017**	**2017/2018**	**2018/2019**	**2019/2020**	**2020/2021 *** **
Generation Offered	131,164.8	132,614.2	132,124.8	136,067.9	134,873.0	147,188.6	144,108.8	157,691.1	168,716.0	166,204.8	166,909.6	172,071.2	171,262.3
DR Offered	715.8	936.8	967.9	1,652.4	9,847.6	12,952.7	15,545.6	19,956.3	14,507.2	11,293.7	11,675.5	11,818.0	9,846.7
EE Offered	-	-	-	-	652.7	756.8	831.9	940.3	1,156.8	1,340.0	1,306.1	1,650.3	2,242.5
Total Offered	**131,880.6**	**133,551.0**	**133,092.7**	**137,720.3**	**145,373.3**	**160,898.1**	**160,486.3**	**178,587.7**	**184,380.0**	**178,838.5**	**179,891.2**	**185,539.5**	**183,351.5**
Generation Cleared	129,061.4	131,338.9	131,251.5	130,856.6	128,527.4	142,782.0	135,034.2	148,805.9	155,634.3	154,690.0	154,506.0	155,442.8	155,976.5
DR Cleared	536.2	892.9	939.0	1,364.9	7,047.2	9,281.9	14,118.4	14,832.8	12,408.1	10,974.8	11,084.4	10,348.0	7,820.4
EE Cleared	-	-	-	-	568.9	679.4	822.1	922.5	1,117.3	1,338.9	1,246.5	1,515.1	1,710.2
Total RTO Cleared	**129,597.6**	**132,231.8**	**132,190.5**	**132,221.5**	**136,143.5**	**152,743.3**	**149,974.7**	**164,561.2**	**169,159.7**	**167,003.7**	**166,836.9**	**167,305.9**	**165,109.2**
Uncleared	2,283.0	1,319.2	902.2	5,498.8	9,229.8	8,154.8	10,511.6	14,026.5	15,220.3	11,834.8	13,054.3	18,233.6	18,242.3

* RTO numbers include all LDAs

** UCAP calculated using sell offer EFORd for Generation Resources. DR and EE UCAP values include appropriate FPR and DR Factor.

*** 2020/2021 BRA Generation, DR, and EE offered and cleared values include Annual, Summer-Period, and Winter-Period Capacity Performan

*** 2020/2021 BRA Total RTO Cleared MW value includes Annual and matched Seasonal Capacity Performance sell offers

Table 7 contains a summary of capacity additions and reductions from the 2007/2008 BRA to the 2020/2021 BRA. A total of 4,257.5 MW of incrementally new capacity in PJM was available for the 2020/2021 BRA. This incrementally new capacity includes new Generation Capacity Resources and capacity upgrades to existing Generation Capacity Resources. The increase is offset by generation capacity deratings on existing Generation Capacity Resources and an increase in the quantity of offered DR and EE to yield a net decrease of 24.5 MW of installed capacity.

Table 7 also illustrates the total amount of resource additions and reductions over fourteen Delivery Years since the implementation of the RPM construct. Over the period covering the first fourteen RPM BRAs, 50,792.0 MW of new generation capacity was added, which was partially offset by 39,639.5 MW of capacity de-ratings or retirements over the same period. Additionally, 9,485.6 MW of new DR and 2,062.9 MW of new EE resources were offered over the course of the fourteen Delivery Years since RPM's inception. The total net increase in installed capacity in PJM over the period of the last fourteen RPM auctions was 22,701.0 MW.

Table 7 – Incremental Capacity Resource Additions and Reductions to Date

	RTO*														
Capacity Changes (in ICAP)	**2007/2008**	**2008/2009**	**2009/2010**	**2010/2011**	**2011/2012**	**2012/2013**	**2013/2014[1]**	**2014/2015[2]**	**2015/2016**	**2016/2017[3]**	**2017/2018**	**2018/2019**	**2019/2020**	**2020/2021**	**Total**
Increase in Generation Capacity	602.0	724 2	1,272.3	1,776 2	3,576.3	1,893 5	1,737.5	1,582 8	8,207.0	6,806 0	6,973 3	5,055 6	6,327 8	4,257 5	50,792.0
Decrease in Generation Capacity	-674.6	-375.4	-550.2	-301 8	-264.7	-3,253 9	-1,924.1	-1,550.1	-6,432.6	-4,992 0	-9,760.1	-3,620 8	-2,923.1	-3,016.1	-39,639.5
Net Increase in Demand Resource Capacity**	555.0	574.7	215.0	28.7	661.7	7,938.1	2,993.3	2,514.4	4,200.5	-5,310.7	-3,077.7	-82.4	86.4	-1,811.4	9,485.6
Net Increase in Energy Efficiency Capacity**	0.0	0 0	0.0	0 0	0.0	632 3	101.1	73.1	101.3	204 8	176.4	-83 5	311 9	545 5	2,062.9
Net Increase in Installed Capacity	**482.4**	**923.5**	**937.1**	**1503.1**	**3973.3**	**7,210.0**	**2,907.8**	**2,620.2**	**6,076.2**	**-3,291.9**	**-5,688.1**	**1,268.9**	**3,803.0**	**-24.5**	**22,701.0**

* RTO numbers include all LDAs

** Values are w ith respect to the quantity offered in the previous year's Base Residual Auction.

1) Does not include Existing Generation located in ATSI Zone

2) Does not include Existing Generation located in Duke Zone

3) Does not include Existing Generation located in EKPC Zone

Table 7A provides a further breakdown of the generation increases and decreases for the 2020/2021 Delivery Year on an LDA basis.

Table 7A – Generation Increases and Decreases by LDA Effective 2020/2021 Delivery Year

LDA	Increases	Decreases
EMAAC	274.9	(2,268.7)
MAAC	1,367.1	(2,368.5)
Total RTO	**4,257.5**	**(3,016.1)**

All Values in ICAP terms
*MAAC includes EMAAC
**RTO includes MAAC

Table 8 provides a breakdown of the new capacity offered into the each BRA into the categories of new resources, reactivated units, and uprates to existing capacity, and then further down into resource type. As shown in this table, there was a significant quantity of generating capacity from new resources and uprates to existing resources offered into the 2020/2021 BRA. The capacity offered in the 2020/2021 BRA resulted from both new generating resources and uprates to existing resources including gas, diesel, wind, and solar resources. The largest growth remains in combined cycle plants.

Table 8 – Further Breakdown of Incremental Capacity Resource Additions from 2007/2008 to 2020/2021

	Delivery Year	CT/GT	Combined Cycle	Diesel	Hydro	Steam	Nuclear	Solar	Wind	Fuel Cell	Total
New Capacity Units (ICAP MW)	2007/2008			18.7	0.3						19.0
	2008/2009			27.0					66.1		93.1
	2009/2010	399.5		23.8		53.0					476.3
	2010/2011	283.3	580.0	23.0					141.4		1,027.7
	2011/2012	416.4	1,135.0			704.8		1.1	75.2		2,332.5
	2012/2013	403.8		7.8		621.3			75.1		1,108.0
	2013/2014	329.0	705.0	6.0		25.0		9.5	245.7		1,320.2
	2014/2015	108.0	650.0	35.1	132.9			28.0	146.6		1,100.6
	2015/2016	1,382.5	5 914.5	19.4	148.4	45.4		13.8	104.9	30.0	7,658.9
	2016/2017	171.1	4 994.5	38.3		24.0		32.1	54.3		5,314.3
	2017/2018	131.0	5 010.0	124.8	6.0	90.0		27.0			5,388.8
	2018/2019	1,032.5	2 352.3	29.9				82.8	127.1		3,624.6
	2019/2020	167.0	6,145.0	29.9				152.3	73.0		6,567.2
	2020/2021		2,410.0	26.3	4.0			94.3	30.2		2,564.8
Capacity from Reactivated Units (ICAP MW)	2007/2008					47.0					47.0
	2008/2009					131.0					131.0
	2009/2010										-
	2010/2011	160.0		10.7							170.7
	2011/2012	80.0				101.0					181.0
	2012/2013										-
	2013/2014										-
	2014/2015			9.0							9.0
	2015/2016										-
	2016/2017					21.0					21.0
	2017/2018					991.0					991.0
	2018/2019										-
	2019/2020										-
	2020/2021										-
Uprates to Existing Capacity Resources (ICAP MW)	2007/2008	114.5		13.9	80.0	235.6	92.0				536.0
	2008/2009	108.2	34.0	18.0	105.5	196.0	38.4				500.1
	2009/2010	152.2	206.0		162.5	61.4	197.4		16.5		796.0
	2010/2011	117.3	163.0		48.0	89.2	160.3				577.8
	2011/2012	369.2	148.6	57.4		186.8	292.1		8.7		1,062.8
	2012/2013	231.2	164.3	14.2		193.0	126.0		56.8		785.5
	2013/2014	56.4	59.0	0.3		215.0	47.0		39.6		417.3
	2014/2015	104.9		0.5	41.5	138.6	107.0	7.1	73.6		473.2
	2015/2016	216.8	72.0	4.7	15.7	63.4	149.2	2.2	24.1		548.1
	2016/2017	436.6	420.0	3.3	7.4	484.3	102.6	1.7	14.8		1,470.7
	2017/2018	71.9	212.5	5.1	105.9	64.8	11.0	0.4	2.1		473.7
	2018/2019	33.4	548.0	2.4	22.9	11.9	79.3	-	14.9	-	712.8
	2019/2020	29.3	72.5	3.9	5.2	65.3			46.8	-	223.0
	2020/2021	9.3	588.8	1.2	4.6	5.7		1.0	14.7		625.3
	Total	7,115.3	32 585.0	554.6	890.8	4,865.5	1,402.3	453.3	1,452.2	30.0	49,349.0

Figure 4: Cumulative Generation Capacity Increases by Fuel Type

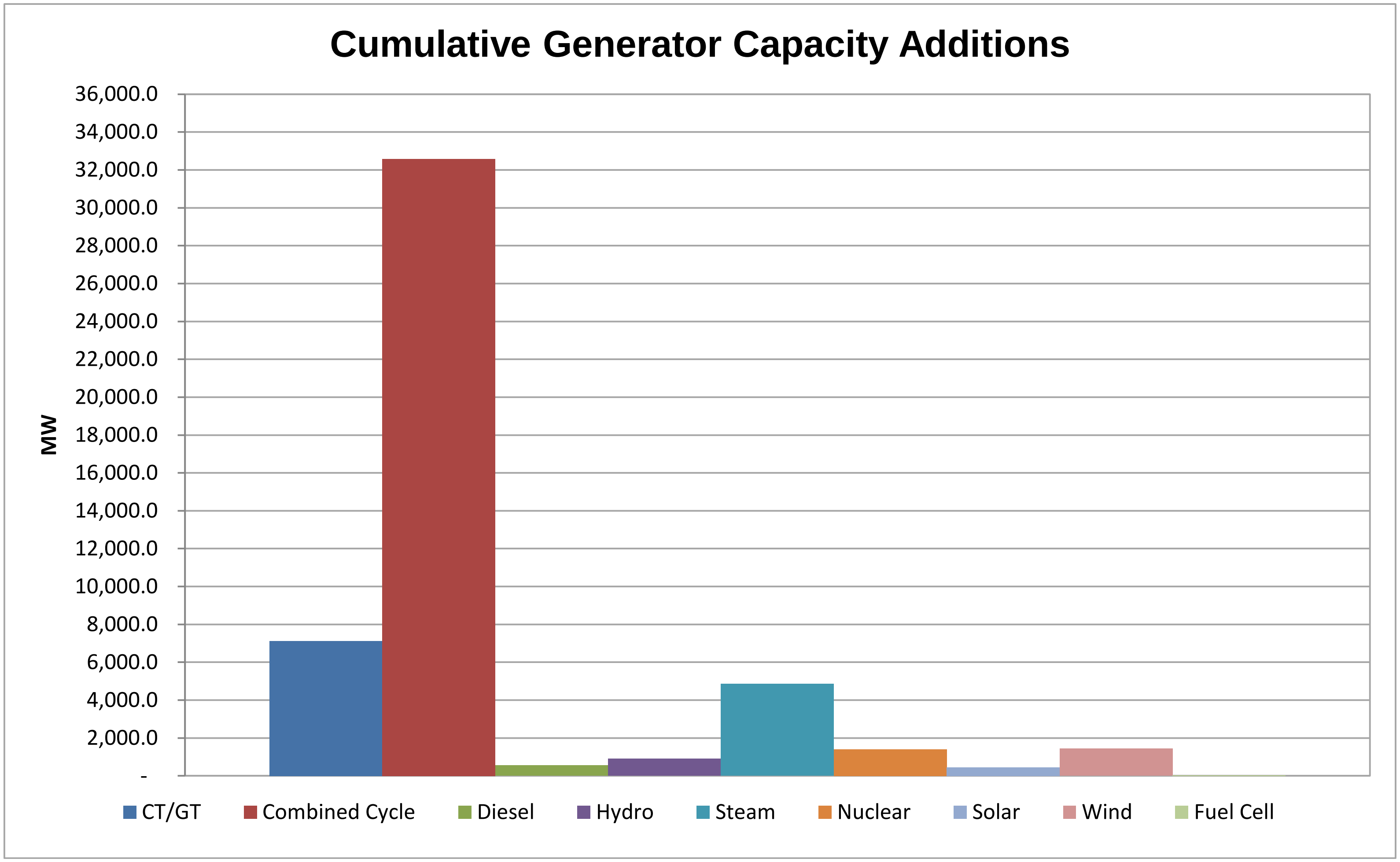


Table 9 shows the changes that have occurred regarding resource deactivation and retirement since the RPM was approved by FERC. The MW values shown in Table 9 represent the quantity of unforced capacity cleared in the 2020/2021 Base Residual Auction that came from resources that have either withdrawn their request to deactivate, postponed retirement, or been reactivated (i.e., came out of retirement or mothball state for the RPM auctions) since the inception of RPM. This total accounts for 4,369.0 MW of cleared UCAP in the 2020/2021 BRA which equates to 5,380.5 MW of ICAP Offered.

Table 9 – Changes to Generation Retirement Decisions since Commencement of RPM in 2007/2008

	RTO*	
Generation Resource Decision Changes	ICAP Offered	UCAP Cleared
Withdrawn Deactivation Requests	1,486.2	656.4
Postponed or Cancelled Retirement	3,511.2	3,057.6
Reactivation	833.1	655.0
Total	**5,830.5**	**4,369.0**

RPM Impact to Date

As illustrated in Table 5, for the 2020/2021 auction, the capacity exports were 1,319.8 MW and the offered capacity imports were 5,440.5 MW. The difference between the capacity imports and exports results is a net capacity import of 4,120.7 MW. In the planning year preceding the RPM auction implementation, 2006/2007, there was a net capacity export of 2,616.0 MW. In this auction, PJM is now a net importer of 4,120.7 MW. Therefore, RPM's impact on PJM capacity interchange is 6,736.7 MW.

The minimum net impact of the RPM implementation on the availability of Installed Capacity resources for the 2020/2021 planning year can be estimated by adding the net change in capacity imports and exports over the period, the forward demand and energy efficiency resources, the increase in Installed Capacity over the RPM implementation period from Table 8 and the net change in generation retirements from Table 9. Therefore, as illustrated in Table 10, the minimum estimated net impact of the RPM implementation on the availability of capacity in the 2020/2021 compared to what would have happened absent this implementation is 71,501.6 MW.

Table 10 shows the details on RPM's impact to date in ICAP terms.

Table 10 – RPM's Impact to Date

Change in Capacity Availability	Installed Capacity MW
New Generation	38,596.0
Generation Upgrades (not including reactivations)	9,202.3
Generation Reactivation	1,550.7
Forward Demand and Energy Efficiency Resources	11,548.5
Cleared ICAP from Withdrawn or Cancelled Retirements	3,867.4
Net increase in Capacity Imports	6,736.7
Total Impact on Capacity Availability in 2020/2021 Delivery Year	**71,501.6**

Discussion of Factors Impacting the RPM Clearing Prices

The main factors impacting 2020/2021 RPM BRA clearing prices relative to 2019/2020 BRA clearing prices are provided below, separated out by changes to the demand-side and supply-side of the market.

Changes that impacted the Demand Curve:

- The forecast peak load for the PJM RTO for the 2020/2021 Delivery Year is 153,915 MW which is 3,273 MW or about 2.1% below the forecast peak load of 157,188 MW for the 2019/2020 BRA.

- 558 MW of Price Responsive Demand has elected to participate in the 2020/2021 Base Residual Auction: 330 MW in the BGE LDA, 170 MW in the PEPCO LDA, and 58 MW in the EMAAC LDA (with 23 MW located in the DPL-South LDA).

- The reliability requirement for RPM load for the PJM RTO for the 2020/2021 Deliver Year is 2,800 MW below that of the 2019/2020 BRA due to the lower forecasted peak load and the PRD election.

Changes that impacted the Supply Curve:

- The 2020/2021 BRA is the first BRA for which PJM has procured only Capacity Performance ("CP") Resources.
    - CP capacity offered by intermittent resources is 3,400 MW lower than the total capacity offered by intermittent resources in the 2019/2020 BRA
    - CP capacity offered by DR is 2,085 MW lower than the total capacity offered by DR in the 2019/2020 BRA
    - 398 MW of seasonal capacity resources cleared in an aggregated manner to form a year-round commitment. 398 MW of summer CP resources comprised of 289 MW of summer DR, 103 MW of summer EE and 6 MW of intermittent resources cleared along with 398 MW of winter CP resources comprised mainly of winter capability from wind resources
- New generation capacity of 3,144 MW was offered into the BRA comprised of 2,537 of new generation and 607 MW of uprates.
- The RCP of constrained LDAs was also impacted by changes in CETL values. A decrease in CETL acts as a decrease in supply for an importing LDA.

From:	Glazer, Craig
To:	Fisher, Travis; Mansueti, Lawrence; Meyer, David
Cc:	Schuhart, Denise; Horner, Nathaniel; Pablo, Jeanette; SAM.HILE@ICF.COM; Keech, Adam J.
Subject:	**Additional Item for Our Call Today**
Date:	**Wednesday, May 24, 2017 10:14:21 AM**

Here's an additional public item I trust you will be interested in. Capacity clearing results by fuel type:

http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/rpm-commitment-by-fuel-type-by-dy.ashx

Will talk at 11AM today. Thank you.

Craig Glazer
PJM

From: Glazer, Craig
Sent: Tuesday, May 23, 2017 4:34 PM
To: Fisher, Travis; Mansueti, Lawrence; Meyer, David
Cc: Denise Schuhart; Nathaniel.Horner@HQ.DOE.GOV; JEANETTE.PABLO@HQ.DOE.GOV; SAM.HILE@ICF.COM
Subject: For Our Call Tomorrow:Just Released Results of PJM's Capacity Auction

PJM news release as well as a detailed report on the results of the capacity auction are attached. We can brief you more on this on tomorrow's call.

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From: PJM News
Sent: Tuesday, May 23, 2017 4:22 PM
To: PJM News
Subject: PJM NEWS RELEASE: PJM CAPACITY AUCTION SEES STRONG RESPONSE FROM MARKET PARTICIPANTS TO STRICT PERFORMANCE STANDARDS

CONTACT: PJM News at 866-756-6397 or pjmnews@pjm.com

FOR IMMEDIATE RELEASE

PJM CAPACITY AUCTION SEES STRONG RESPONSE FROM MARKET PARTICIPANTS TO STRICT PERFORMANCE STANDARDS

(Valley Forge, Pa. – May 23, 2017) – The world's largest competitive power market, PJM Interconnection, attracted a record amount of competitive resources meeting strict performance standards in its annual capacity auction. The auction procures power supply resources to meet consumers' electricity needs three years from now.

The auction produced a price of $76.53/megawatt-day for resources in most of the PJM footprint. Prices are higher in some areas due to transmission limits and retiring generators.

"The results show that PJM markets continue to achieve what they were originally intended to accomplish, ensuring reliability at the lowest reasonable cost," said Andrew L. Ott, PJM president and CEO. "Overall response to this auction, both in participation and competitive bids, reflects the market's ability to attract efficient, high performing and competitive resources that support reliability."

PJM procured 165,109 megawatts of resources for the period June 1, 2020, to May 31, 2021. The procured capacity provides a 23.3-percent reserve margin.

This is the first auction in which all resources had to meet capacity performance requirements, which were phased in. It also was the first to have participation by Price Responsive Demand resources, demand response-like resources that react to market signals.

PJM procures resources three years in advance to ensure adequate power supplies will be available during extreme weather or other system emergencies to meet consumers' demand for electricity. All resources must meet Capacity Performance standards, committing to perform when needed or face steep non-performance payments. To meet that requirement, generation owners, for example, ensure firm fuel supplies or make improvements to their equipment.

The auction attracted 2,350 MW of new gas-fired generation. The auction procured about 7,532 MW of demand response resources that committed to year-round availability and the higher performance requirements. There were 119 MW of solar resources and 504.3 MW of wind resources that cleared the auction. In addition, 1,710 MW of energy efficiency resources cleared.

– MORE –

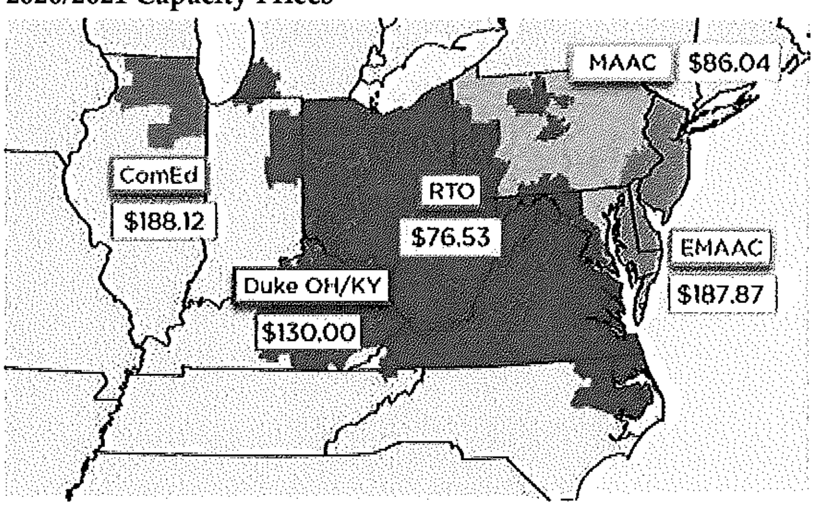
Additionally, under new rules approved by the Federal Energy Regulatory Commission in March, 398 MW of seasonal capacity (resources available in one season only) cleared in an aggregated manner to form a year-round resource. Wind generators, whose capacity is greater in the winter, combined through the auction clearing mechanism with demand response and solar resources, whose capacity is greater in the summer.

In four constrained areas, the MAAC region, Eastern MAAC, ComEd and Duke Energy (Ohio and Kentucky), capacity prices are higher than the RTO price. For MAAC, the price is $86.04 MW-day; in Eastern MAAC, the price is $187.87/MW-day; in ComEd the price is $188.12/MW-day; and in Duke Energy's Ohio and Kentucky region, the price is $130/MW-day.

(The MAAC region includes Atlantic City Electric, Baltimore Gas and Electric Company, Delmarva Power, Jersey City Power & Light, Met-Ed, PECO, Penelec, Pepco, PP&L, Public Service Electric and Gas Co., and Rockland Electric. The companies included in the subset of that region, Eastern MAAC will have a different price. Eastern MAAC consists of Public Service Electric and Gas Co., Jersey Central Power & Light, PECO, Atlantic City Electric, Delmarva Power and Rockland Electric.)

A detailed report of the results is available on pjm.com.

2020/2021 Capacity Prices



PJM Interconnection, founded in 1927, ensures the reliability of the high-voltage electric power system serving 65 million people 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. PJM coordinates and directs the operation of the region's transmission grid, which includes over 82,000 miles of transmission lines; administers a competitive wholesale electricity market; and plans regional transmission expansion improvements to maintain grid reliability and relieve congestion. PJM's regional grid and market operations produce annual savings of $2.8 billion to $3.1 billion. For the latest news about PJM, visit PJM Inside Lines at insidelines.pjm.com.

From: Yuzon, Andrea
To: Glazer, Craig; Fisher, Travis
Cc: Mansueti, Lawrence; Meyer, David; Schuhart, Denise
Subject: RE: Potential Discussion on Price Formation
Date: Friday, May 26, 2017 5:08:51 PM

Hi Craig,

Do you think we could aim for a 2:15-2:30PM meeting on Thursday, June 1st?

Thanks,
Andrea

—

Andrea Yuzon
ICF, Contractor | U.S. Department of Energy
Office of Electricity Delivery & Energy Reliability
202-586-1411 | andrea.yuzon@hq.doe.gov

From: Glazer, Craig [mailto:Craig.Glazer@pjm.com]
Sent: Thursday, May 25, 2017 11:23 AM
To: Fisher, Travis <Travis.Fisher@hq.doe.gov>; Yuzon, Andrea <Andrea.Yuzon@hq.doe.gov>
Cc: Mansueti, Lawrence <Lawrence.Mansueti@hq.doe.gov>; Meyer, David <David.Meyer@hq.doe.gov>; Schuhart, Denise <schuhart@wrightlaw.com>
Subject: Potential Discussion on Price Formation

Travis:

We had discussed a follow up phone call/meeting on price formation issues. I am writing to see if 9 to 10 or 11-1PM EDT on Wednesday May 31 would work. Let me know and I could come by. If that time does not work, then what about around 2pm On Thursday June 1 or that same time on Friday June 2.

Craig Glazer
Vice President, Federal Government Policy
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Document 9, totaling 9 pages, has been transferred to the Federal Energy Regulatory Commission (FERC) for review and direct response to the requester.

Document 10, totaling 3 pages, has been transferred to the Federal Energy Regulatory Commission (FERC) for review and direct response to the requester.

Document 11, totaling 3 pages, has been transferred to the Federal Energy Regulatory Commission (FERC) for review and direct response to the requester.

From:	Glazer, Craig
To:	Silverstein, Alison (CONTR); Fisher, Travis
Cc:	Mansueti, Lawrence; Meyer, David; Yuzon, Andrea
Subject:	RE: Resending: Materials from PJM for our Friday 9AM Call Between PJM and DOE
Date:	Thursday, June 08, 2017 10:16:40 AM

Yes. Working to get it done earlier. Got it.

Many thanks.

Craig Glazer

From: Silverstein, Alison (CONTR) [mailto:Alison.Silverstein@hq.doe.gov]
Sent: Thursday, June 08, 2017 9:52 AM
To: Glazer, Craig; Fisher, Travis
Cc: Mansueti, Lawrence; Meyer, David; Yuzon, Andrea
Subject: RE: Resending: Materials from PJM for our Friday 9AM Call Between PJM and DOE

External Email! Think before clicking links or attachments.

Craig – VERY QUICK, please, Monday latest.

Thanks – alison

From: Glazer, Craig [mailto:Craig.Glazer@pjm.com]
Sent: Thursday, June 08, 2017 5:05 AM
To: Fisher, Travis <Travis.Fisher@hq.doe.gov>
Cc: Mansueti, Lawrence <Lawrence.Mansueti@hq.doe.gov>; Meyer, David <David.Meyer@hq.doe.gov>; Silverstein, Alison (CONTR) <Alison.Silverstein@hq.doe.gov>; Yuzon, Andrea <Andrea.Yuzon@hq.doe.gov>
Subject: RE: Resending: Materials from PJM for our Friday 9AM Call Between PJM and DOE

Yes. I can certainly do that. Thanks for the time you've provided us.

Let me work to put something together. If OK, I may not have until next week but it would largely encapsulate what we discussed. But I know the need for quick action.

Craig

Craig.Glazer@PJM.COM
(b) (6)

From: Fisher, Travis [mailto:Travis.Fisher@hq.doe.gov]
Sent: Wednesday, June 07, 2017 1:31 PM

To: Glazer, Craig
Cc: Mansueti, Lawrence; Meyer, David; Silverstein, Alison (CONTR); Yuzon, Andrea
Subject: RE: Resending: Materials from PJM for our Friday 9AM Call Between PJM and DOE

External Email! Think before clicking links or attachments.

Hi Craig,

First of all, this is great material and I sincerely appreciate your time spent on the phone walking us through it. It's so good, in fact, that we are wondering how best to reflect these types of policy changes in our report (in the event we'd want to reference them).

Would it be possible for you to formalize some of this in a memo to me? We would of course check with you before using the information, but I'd like to have something we could quote or at least cite if the need arises. Let me know.

Thanks again!

Best,
Travis

From: Glazer, Craig [mailto:Craig.Glazer@pjm.com]
Sent: Friday, June 02, 2017 9:03 AM
To: Fisher, Travis <Travis.Fisher@hq.doe.gov>; Mansueti, Lawrence <Lawrence.Mansueti@hq.doe.gov>; Meyer, David <David.Meyer@hq.doe.gov>; Yuzon, Andrea <Andrea.Yuzon@hq.doe.gov>
Subject: Resending: Materials from PJM for our Friday 9AM Call Between PJM and DOE

CRAIG GLAZER
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From: Glazer, Craig
Sent: Thursday, June 01, 2017 9:06 AM

To: Yuzon, Andrea
Cc: Fisher, Travis; Mansueti, Lawrence; Meyer, David; Bresler, Frederick S. (Stu) III; Denise Schuhart
Subject: Materials from PJM for our Friday 9AM Call Between PJM and DOE

Andrea:

Thank you for arranging our call for 9AM EDT tomorrow between PJM and DOE Staff. I am attaching the following confidential preliminary draft of our thoughts on energy price formation and related resilience issues to guide our discussion tomorrow. I am taking the liberty of copying Travis et al. but undoubtedly others may need to receive this as well. As I understand that both Alison Silverstein and Alan Moser will be joining the report-drafting effort, I'd be grateful if this could be circulated to them as well.

Let me know if you have any questions or comments.

We will look to speak to DOE folks at 9AM EDT tomorrow using phone number **(b) (6)** , Code **(b) (6)**

Many thanks for your continued hospitality and assistance!

Craig Glazer
Vice President-Federal Government Policy
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Craig.Glazer@PJM.COM

From: Glazer, Craig
Sent: Thursday, June 01, 2017 6:46 AM
To: 'Yuzon, Andrea'; Schuhart, Denise
Cc: Schuhart, Denise
Subject: RE: Potential Discussion on Price Formation: Proposing Alternate Times on Thursday or Friday

Yes, the time and phone number is correct. And yes I should have some materials later today to provide to you.

Many thanks.

Craig Glazer
PJM

From: Yuzon, Andrea [mailto:Andrea.Yuzon@hq.doe.gov]
Sent: Wednesday, May 31, 2017 5:52 PM
To: Glazer, Craig; Schuhart, Denise
Cc: Schuhart, Denise
Subject: RE: Potential Discussion on Price Formation: Proposing Alternate Times on Thursday or Friday

External Email! Think before clicking links or attachments.

Craig/Denise,

I just wanted to confirm that I have this in the calendar for Friday, June 2nd from 9-10AM using the Dial-In: (b) (6) | Code: (b) (6) Please let me know

If there are any read ahead materials that you would like me to circulate prior to the meeting or reports that would be useful to have up on the monitor during the call please feel free to email them to me.

Thanks,
Andrea

—

Andrea Yuzon
ICF, Contractor | U.S. Department of Energy
Office of Electricity Delivery & Energy Reliability
202-586-1411 | andrea.yuzon@hq.doe.gov

From: Fisher, Travis
To: Glazer, Craig
Cc: Mansueti, Lawrence; Meyer, David; Silverstein, Alison (CONTR); Yuzon, Andrea
Subject: RE: PJM Memorandum re: Price Formation and Grid Resiliency Issues
Date: Friday, June 09, 2017 10:58:00 AM

Thank you so much for the quick turnaround, Craig. I sincerely appreciate your help.

From: Glazer, Craig [mailto:Craig.Glazer@pjm.com]
Sent: Friday, June 09, 2017 10:51 AM
To: Fisher, Travis <Travis.Fisher@hq.doe.gov>
Cc: Mansueti, Lawrence <Lawrence.Mansueti@hq.doe.gov>; Meyer, David <David.Meyer@hq.doe.gov>; Silverstein, Alison (CONTR) <Alison.Silverstein@hq.doe.gov>; Yuzon, Andrea <Andrea.Yuzon@hq.doe.gov>
Subject: PJM Memorandum re: Price Formation and Grid Resiliency Issues

Folks:

I am providing to you the attached Memorandum which outlines certain initiatives in the areas of energy price formation and grid resiliency on which PJM will be focusing in the next several months. However, as indicated, we believe these issues are larger in scope than any one single RTO and deserve national attention and discussion. The Memorandum outlines those issues. Also, the Memorandum notes that PJM has already placed discussion of these issues in the public domain. The Memorandum, which itself could be made public, provides links to these additional documents on our website.

Let me know if you wish to discuss.

Thank you for all of your hard work on this important report.

Craig Glazer
Vice President-Federal Government Policy
PJM Interconnection, LLC
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Craig.Glazer@PJM.COM

From: [illegible]
To: [illegible]
Subject: [illegible] Economics & philosophy
Date: [illegible] June [illegible] 2017 [illegible]

From: alison silverstein [mailto:(b) (6)]
Sent: Sunday, June 11, 2017 12:[illegible]
To: Fisher, Travis <Travis.Fisher@hq.doe.gov>; [illegible], Lawrence <Lawrence.[illegible]@hq.doe.gov>; Meyer, David <David.Meyer@hq.doe.gov>
Cc: Parks, William <William.Parks@hq.doe.gov>
Subject: Economics & philosophy

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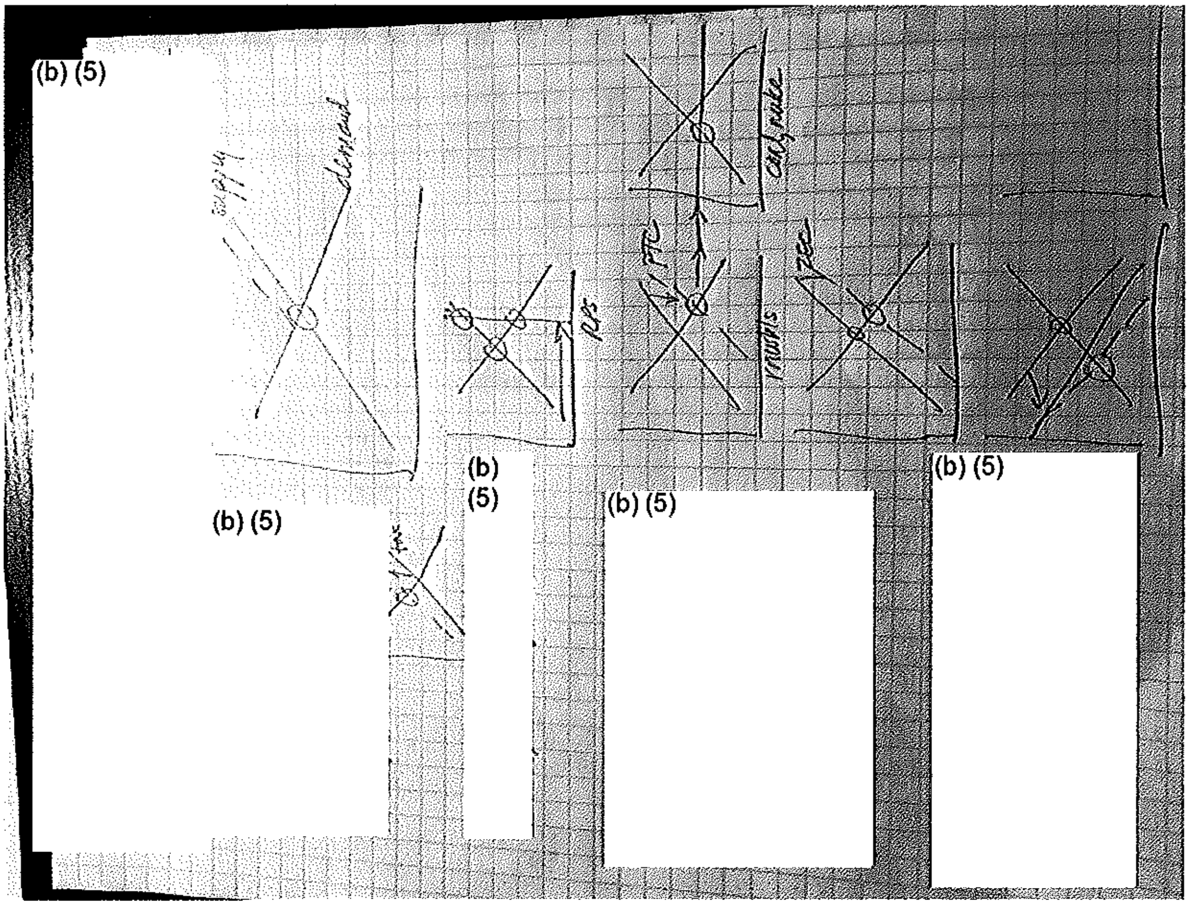
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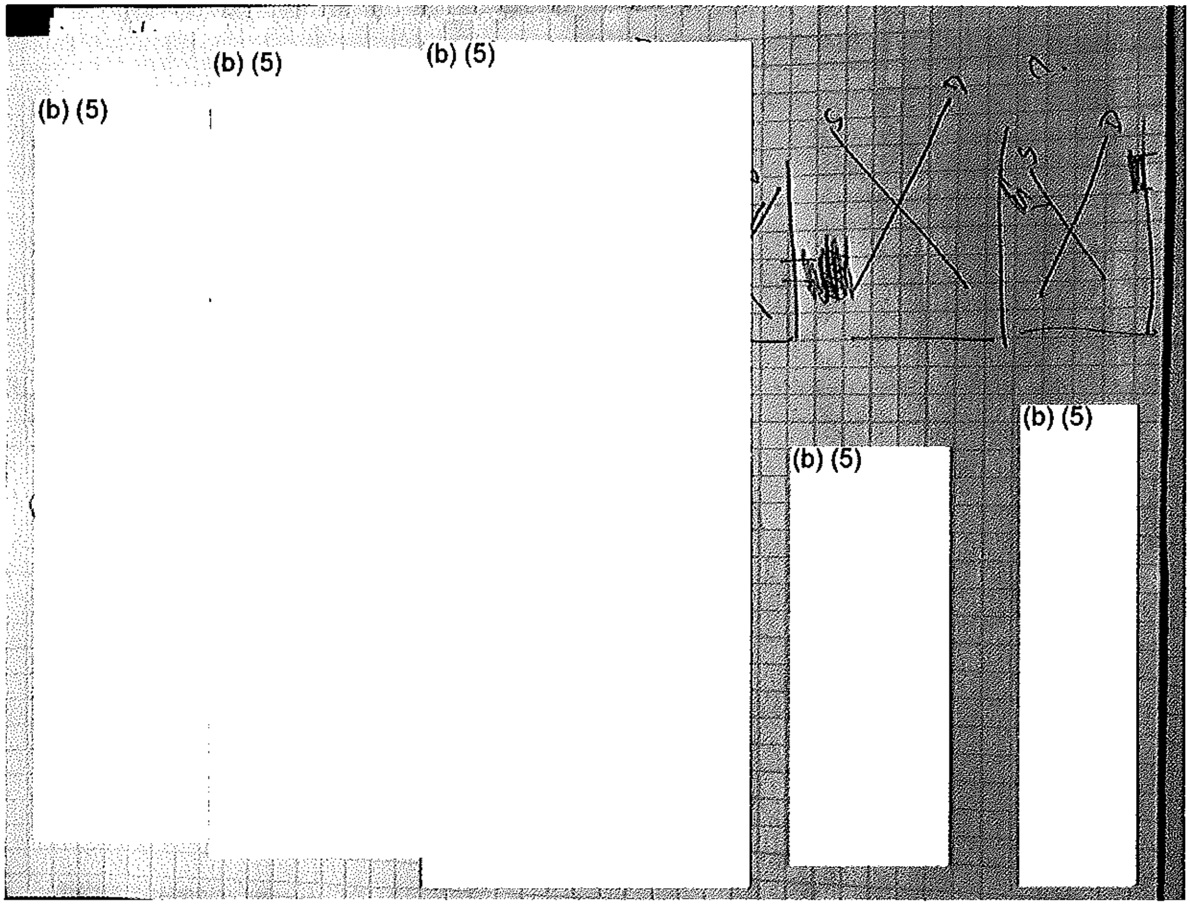
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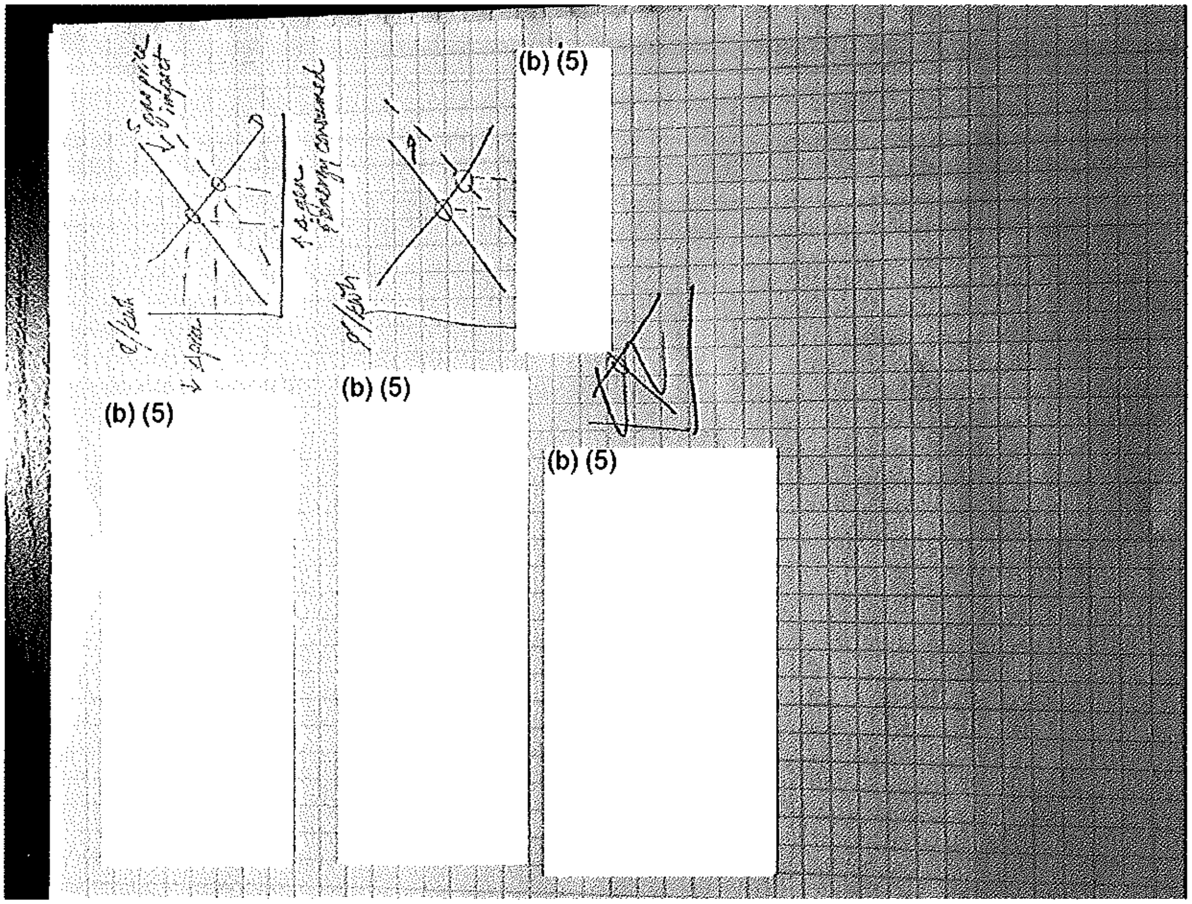

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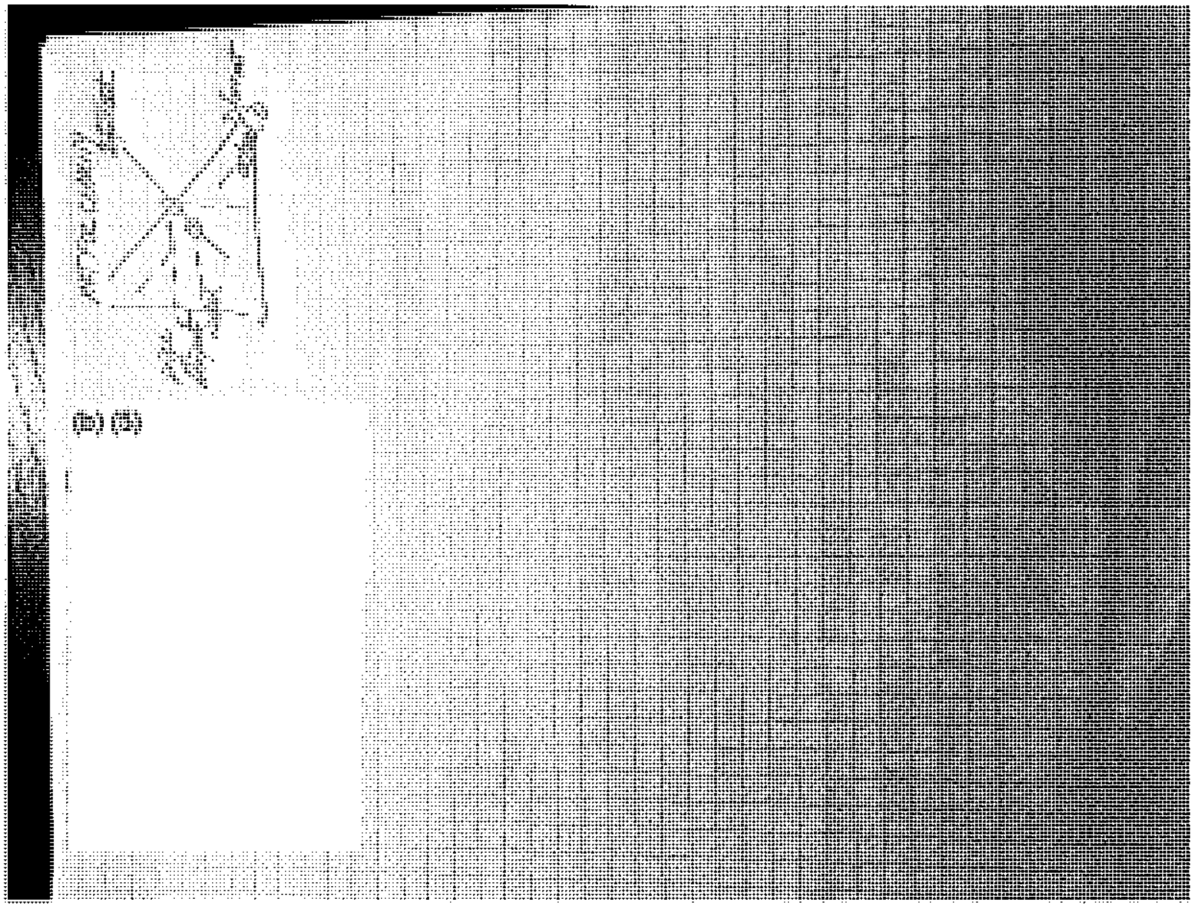

Alan Silverstein
[illegible]
(b) (6)