BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application Seeking Approval of Ohio Power Company's Proposal to Enter into an Affiliate Power Purchase Agreement for Inclusion in the Power Purchase Agreement Rider.	)	Case No. 14-1693-EL-RDR
In the Matter of the Application of Ohio Power Company for Approval of Certain Accounting Authority.	)	Case No. 14-1694-EL-AAM

**ATTACHMENTS TO
THE
DIRECT TESTIMONY OF
JOHN FINNIGAN
ON BEHALF OF
ENVIRONMENTAL DEFENSE FUND
AND OHIO ENVIRONMENTAL COUNCIL**

SUMMARY OF ATTACHMENTS:

JF-1: John Finnegan Résumé
JF-2: 2018/2019 RPM BRA Results
JF-3: 2017/2018 RPM Capacity Performance Transaction Incremental Results
JF-4: AEP financial presentation to investors
JF-5: PJM Capacity Performance Proposal

ATTACHMENT

JF-1

JOHN FINNIGAN

128 Winding Brook Lane ♦ Terrace Park, Ohio 45174 ♦ john.finnigan55@gmail.com ♦ (513)226-9558

PROFESSIONAL EXPERIENCE

Expert in litigation, energy, administrative law, government and regulatory affairs, with management experience in government affairs, and also managing in-house and outside counsel. AV Preeminent legal ability and ethical rating (highest peer review rating) by Martindale-Hubbell®.

CAREER POSITIONS

ENVIRONMENTAL DEFENSE FUND (2012-present)
LEAD ATTORNEY (2014-present)
SENIOR REGULATORY ATTORNEY (2012-2014)

- Supervise in-house and outside attorneys in EDF's Clean Energy program. Represent EDF before federal, regional and state agencies on energy-related issues focusing on energy market structure and the utility business model; smart grid deployment; renewable energy and energy efficiency.

DUKE ENERGY CORPORATION (1996-2012)
VICE PRESIDENT, GOVERNMENT & REGULATORY AFFAIRS (2008-2012)

- Managed Ohio and Kentucky government affairs department.
- Evaluated legislation in to assess impact on company; developed positions on pending legislation; built working relationships with key policymakers; developed advocacy campaigns and testimony for legislative campaigns; managed political action committee contributions and outside consultants. Highlights include representing Duke Energy on electric restructuring, smart grid, energy efficiency, solar/renewable energy and integrated resource planning legislation.
- Developed business practices and procedures to comply with regulatory requirements; monitored regulations to keep company leaders informed of business impacts; developed company positions on regulations; developed codes of conduct for Duke Energy's utility businesses; implemented tracking program to ensure compliance with regulatory requirements.
- Responsible for electricity sales for local governments' facilities and their residents.

ASSOCIATE GENERAL COUNSEL (1996-2008)

- Managed Ohio and Kentucky legal regulatory section (2006-2008).
- Led several gas and electric and gas base rate cases.
- Played key role in Ohio electric restructuring case in 2000; subsequent Ohio electric default service cases; and in obtaining Kentucky regulatory approvals for Kentucky utility to purchase power plants from Ohio affiliate company.
- Led regulatory process to implement Ohio and Kentucky gas main replacement program involving over $1 billion investment.

- Supervised litigation in Ohio and Kentucky - commercial law; wrongful death and personal injury; insurance; real property and bankruptcy matters.
- Negotiated and drafted commercial contracts, including wholesale gas and electric supply and delivery; service agreements with competitive retail suppliers; special contracts with retail customers; interconnection agreements; transfer of power plants.

PARTNER, MCCASLIN, IMBUS & MCCASLIN

- Specialized in litigation, insurance, wrongful death, contracts, civil rights law and appeals.
- Over 20 jury trials tried to completion - case citations available on request.

PROFESSOR, SALMON P. CHASE COLLEGE OF LAW
ASSOCIATE ATTORNEY, FROST & JACOBS - commercial litigation.
LAWCLERK, U.S. DISTRICT JUDGE DAVID S. PORTER

EDUCATION & CERTIFICATIONS

J.D., University of Cincinnati (Law Review)
M.B.A., Indiana University; **B.A.**, University of Cincinnati
Admitted to practice law in Ohio (#0018689) & Kentucky (#86657)
AV Preeminent legal ability and ethical rating (highest rating) by Martindale-Hubbell®

MEMBERSHIPS & COMMUNITY SERVICE EXPERIENCE

- Kentucky Chamber of Commerce Leadership Kentucky Program
- Ohio Commodores Association (statewide economic development)
- Cincinnatus Association (local civic organization)
- Director & Annual Fund Leader, Cincinnati Nature Center
- Xavier University Executive Mentoring Program
- Vice Chair and Director, Ohio Electric Utility Institute
- Director, Ohio Chamber of Commerce
- Councilman, Terrace Park Village Council

ATTACHMENT

JF-2

2018/2019 RPM Base Residual Auction Results

Executive Summary

The 2018/2019 Reliability Pricing Model (RPM) Base Residual Auction (BRA) cleared 166,836.9 MW of unforced capacity in the RTO. Accounting for load and resource commitments under the Fixed Resource Requirement (FRR) the reserve margin for the entire RTO for the 2018/2019 Delivery Year as procured in the BRA is 19.8%, or 4.1% higher than the target reserve margin of 15.7%.

The 2018/2019 RPM BRA was conducted under several new RPM design elements that were approved by FERC since last year's BRA. On June 9, 2015, in Docket No. ER15-623, FERC accepted a series of tariff reforms proposed in PJM's Capacity Performance ("CP") filing of December 12, 2014, to establish Capacity Performance Resources to ensure PJM's capacity market provides adequate incentive for resource performance. Also, on November 28, 2014, in Docket No. ER14-2940, FERC approved revisions to the Variable Resource Requirement (VRR) curve shape and Gross Cost of New Entry (CONE) values as proposed in PJM's September 25, 2014 filing. This filing was made following last year's stakeholder review of the shape of the VRR curve and key inputs to that curve, where such review is required by PJM Tariff on a specified periodic basis. The impact of Tariff revisions associated with these two filings as they relate to the setup and clearing of the 2018/2019 BRA are discussed in more detail in the "Discussion of Factors Impacting the RPM Clearing Prices" section of this report.

Under the CP provisions, for the 2018/2019 Delivery Year, PJM will procure two capacity product types through RPM auctions, Capacity Performance and Base Capacity. 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; whereas, Base Capacity Resources may not be capable of sustained, predictable operation and/or may not be expected to provide energy and reserves outside of the summer period. Base Capacity Resources include Base Capacity Demand Resources (DR), which are expected to be available only during the summer months, and Base Capacity Energy Efficiency (EE) Resources, which are expected to provide permanent continuous load reduction only during the summer months. Base Capacity Resources also include Base Capacity Generation Resources, which are expected to be available throughout the Delivery Year like all Capacity Performance Resources. But, unlike Capacity Performance Resources, Base Capacity Generation Resources will be subject to non-performance charges only when they fail to perform when needed during the summer months.

Base Capacity Resources do not provide the same level of availability as CP Resources, therefore constraints are imposed on the quantity of Base Capacity Resources that can be procured in each RPM auction. A Base Capacity DR Constraint which places a maximum limit on the total quantity of Base Capacity DR and Base Capacity EE that can be procured in the auction is established for the entire RTO and each modeled LDA. A Base Capacity Resource Constraint which places a maximum limit on the total quantity of Base Capacity DR, Base Capacity EE and Base Capacity Generation Resources that can be procured in the auction is established for the entire RTO and each modeled LDA. If these constraints are reached in the auction then these less-available resources will clear the auction at a lower clearing price then the clearing price associated with similarly located more-available resources.

2018/2019 RPM Base Residual Auction Results

2018/2019 BRA Resource Clearing Prices

Resource Clearing Prices (RCPs) for the 2018/2019 BRA are shown in the table below. The EMAAC LDA and ComEd LDA were constrained LDAs in the 2018/2019 BRA. The RCP for CP Resources located in the rest of RTO outside of these LDAs is $164.77/MW-day. The RCP for CP Resources in the EMAAC LDA is $225.42/MW-day and RCP for CP Resources in the COMED LDA is $215.00 /MW-day. For comparison purposes, the Annual RCP in the 2017/2018 BRA across the entire RTO was $120/MW-day with the exception of the PSEG LDA where the Annual RCP was $215/MW-day.

Capacity Type	2018/19 BRA Resource Clearing Prices ($/MW-day)					
	Rest of RTO	EMAAC	SWMAAC	PEPCO	COMED	PPL
Capacity Performance	$164.77	$225.42	$164.77	$164.77	$215.00	$164.77
Base Generation	$149.98	$210.63	$149.98	$149.98	$200.21	$75.00
Base DR/EE	$149.98	$210.63	$59.95	$41.09	$200.21	$75.00

The Base Capacity Resource Constraint is a binding constraint in the auction for the PPL LDA, as well as, for the overall RTO, resulting in a price decrement for Base Capacity Generation located in PPL of $89.77/MW-day relative to the RCP of CP resources located in the PPL LDA, and a price decrement of $14.79/MW-day for Base Capacity Generation located in the rest of RTO outside of the PPL LDA. Additionally, the Base Capacity DR Constraint is a binding constraint in the BGE LDA and the PEPCO LDA resulting in price decrements for Base Capacity DR and EE located in the BGE LDA and the PEPCO LDA of $90.03/MW-day and $108.89/MW-day, respectively. These price decrements for Base Capacity DR and EE are relative to the RCP of Base Capacity Generation Resource located in these LDAs

The RCP for Base Capacity Resources located in the rest of RTO outside of the EMAAC, SWMAAC and COMED LDAs is $149.98/MW-day. The RCP for Base Capacity Resources located in the EMAAC LDA is $210.63/MW-day. The RCP for Base Capacity DR & EE Resources, Base Capacity Generation Resources and CP Resources located in the SWMAAC LDA outside of the PEPCO LDA is $59.95/MW-day, $149.98/MW-day and $164.77/MW-day, respectively. The RCP for Base Capacity DR & EE Resources, Base Capacity Generation Resources and CP Resources located in the PEPCO LDA is $41.09/MW-day, $149.98/MW-day and $164.77/MW-day, respectively. The RCP for Base Capacity Resources located in the COMED LDA is $200.21/MW-day. The RCP for Base Capacity Resources and CP Resources located in the PPL LDA is $75.00/MW-day and $164.77/MW-day, respectively.

2018/2019 BRA Cleared Capacity Resources

As seen in the table below, the 2018/2019 BRA procured 2,919.3 MW of capacity from new generation and 587.8 MW from uprates to existing or planned generation. The quantity of capacity procured from external Generation Capacity Resources in the 2018/2019

2018/2019 RPM Base Residual Auction Results

BRA is 4,687.9 MW which is an increase of 162.4 MW from that procured in last year's BRA when Capacity Import Limits (CIL) were first implemented. All external generation capacity that has cleared in the 2018/19 BRA has met the requirements for the CIL exception. The total quantity of DR procured in the 2018/2019 BRA is 11,084.4 MW which is an increase of 109.6 MW from that procured in last year's BRA; and, the total quantity of EE procured in the 2018/2019 BRA is 1,246.5 MW which is a decrease of 92.4 MW from that procured in last year's BRA.

Megawatts of Unforced Capacity Procured by Type

BRA Delivery Year	New Generation	Generation Uprates	Imports	Demand Response	Energy Efficiency
2018/2019	2,919.3	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

2018/2019 RPM Base Residual Auction Results

Introduction

This document provides information for PJM stakeholders regarding the results of the 2018/2019 Reliability Pricing Model (RPM) Base Residual Auction (BRA). The 2018/2019 BRA opened on August 10, 2015, and the results were posted on August 21, 2015.

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.
- Constraints on the procurement of the more limited capacity product types are established for the RTO and each modeled LDA. The Base Capacity DR Constraint limits the quantity of Base Capacity DR and EE that can be procured in each LDA or in total across the entire RTO; and the Base Capacity Resource Constraint limits the quantity of the sum of Base Capacity DR and EE and Base Capacity Generation Resources that can be procured in each LDA or in total across the entire RTO.
- Capacity Import Limits (CILs) are established on the amount of external generation capacity that can be reliably committed to PJM. A separate CIL is established for each of five external source-zones and a single total CIL is established for the overall RTO. As described in more detail later in this report, external generation resources may seek exception to the CIL by meeting all three of the following conditions prior to the start of the auction: (1) they are committed to being pseudo-tied generation resources prior to the start of the Delivery Year; that is, they will be treated like internal generation, subject to redispatch and locational pricing; (2) they have long-term firm transmission service confirmed on the complete transmission path from such resource into PJM; and (3) they agree to be subject to the same capacity must-offer requirement as PJM's internal resources.

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 resource 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 2018/2019 BRA results and a discussion of the results in the context of the ten previous BRAs.

2018/2019 RPM Base Residual Auction Results

Summary of Results

The 2018/2019 Reliability Pricing Model (RPM) Base Residual Auction (BRA) cleared 166,836.9 MW of unforced capacity in the RTO representing a 20.2% reserve margin. The reserve margin for the entire RTO is 19.8%, or 4.1% higher than the target reserve margin of 15.7%, when the Fixed Resource Requirement (FRR) load and resources are considered.

Resource Clearing Prices (RCPs) for the 2018/2019 BRA are shown in Table 4. The RCP for CP Resources is $164.77/MW-day for CP Resources located in the rest of RTO outside of the EMAAC LDA and the ComEd LDA. The EMAAC LDA and ComEd LDA were constrained LDAs in the 2018/2019 BRA. The RCP for CP Resources in the EMAAC LDA is $225.42/MW-day and the RCP for CP Resources in the ComEd LDA is $215.00 /MW-day. For comparison purposes, the Annual RCP in the 2017/2018 BRA across the entire RTO was $120/MW-day with the exception of the PSEG LDA where the Annual RCP was $215/MW-day.

The Base Capacity Resource Constraint is a binding constraint in the auction for the PPL LDA, as well as, for the overall RTO, resulting in a price decrement (relative to the RCP of similarly located CP Resources) for Base Capacity Generation located in the PPL of $89.77/MW-day, and a price decrement for Base Capacity Generation located in the rest of RTO outside of the PPL LDA of $14.79/MW-day. Additionally, the Base Capacity DR Constraint is a binding constraint in the SWMAAC LDA and the PEPCO LDA resulting in price decrements (relative to the RCP of similarly located Base Capacity Generation Resources) for Base Capacity DR and EE located in the SWMAAC LDA and the PEPCO LDA of $90.03/MW-day and $108.89/MW-day, respectively.

The RCP for Base Capacity Resources and CP Resources located in the rest of RTO outside of the EMAAC, SWMAAC and COMED LDAs is $149.98/MW-day and $164.77/MW-day, respectively. The RCP for Base Capacity Resources and CP Resources located in the EMAAC LDA is $210.63/MW-day and $225.42/MW-day, respectively. The RCP for Base Capacity DR & EE Resources, Base Capacity Generation Resources and CP Resources located in the SWMAAC LDA outside of the PEPCO LDA is $59.95/MW-day, $149.98/MW-day and $164.77/MW-day, respectively. The RCP for Base Capacity DR & EE Resources, Base Capacity Generation Resources and CP Resources located in the PEPCO LDA is $41.09/MW-day, $149.98/MW-day and $164.77/MW-day, respectively. The RCP for Base Capacity Resources and CP Resources located in the COMED LDA is $200.21/MW-day and $215.00/MW-day, respectively. The RCP for Base Capacity Resources and CP Resources located in the PPL LDA is $75.00/MW-day and $164.77/MW-day, respectively.

The total quantity of new Generation Capacity Resources offered into the auction was 4,132.6 MW (UCAP) comprised of 3,447.4 MW of new generation units and 685.2 MW of uprates to existing generation units. The quantity of new Generation Capacity Resources cleared was 3,506.9 MW (UCAP) comprised of 2,919.3 MW (UCAP) from new generation units and 587.6 MW from uprates to existing generation units.

2018/2019 RPM Base Residual Auction Results

The quantity of capacity procured from external Generation Capacity Resources in the 2018/2019 BRA is 4,687.9 MW which is an increase of 162.4 MW from that procured in last year's BRA when Capacity Import Limits (CIL) were first implemented. All external generation capacity that has cleared in the 2018/19 BRA has met the requirements for 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. External generation resources may seek exception to the CIL by meeting three requirements prior to the start of the auction: (i) they are committed to being pseudo-tied generation resources prior to the start of the Delivery Year; that is, they will be treated like internal generation, subject to redispatch and locational pricing; (ii) they have long-term firm transmission service confirmed on the complete transmission path from such resource into PJM; and (iii) they agree to be subject to the same capacity must-offer requirement as PJM's internal resources. 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 2018/2019 BRA is 11,084 MW which is an increase of 109.6 MW from that procured in last year's BRA; and, the total quantity of EE procured in the 2018/2019 BRA is 1,246.5 MW which is a decrease of 92.4 MW from that procured in last year's BRA.

All existing generation sell offers into the 2018/2019 BRA were subject to market power mitigation through the application of the Market Structure Test (i.e., the Three-Pivotal Supplier Test). The RTO as a whole failed the Market Structure Test, resulting in mitigation of any existing generation resources. Mitigation was applied to a supplier's existing generation resources resulting in utilizing the lesser of the supplier's approved offer cap for such resource or the supplier's submitted offer price for such resource in the RPM Auction clearing.

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 or a Self-Supply 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 13,000 MW of MOPR exemption requests, making a request does not obligate a resource to offer into the BRA.

2018/2019 RPM Base Residual Auction Results

LDA	Exemption Type	Requested Quantity (ICAP MW)	Granted Quantity (ICAP MW)	Cleared Quantity (ICAP MW)
RTO*	Competitive Entry	7,177.0	7,177.0	2,311.2
RTO*	Self-Supply	0.0	0.0	0.0
MAAC	Competitive Entry	6,353.5	6,353.5	1,206.8
MAAC	Self-Supply	0.0	0.0	0.0
Total		**13,530.5**	**13,530.5**	**3,518.0**

*RTO values exclude MAAC

A further discussion of the 2018/2019 BRA results and additional information regarding the 2018/2019 RPM BRA are detailed in the body of this report. The discussion also provides a comparison of the 2018/2019 auction results to the results from the 2007/2008 through 2017/2018 RPM Auctions.

2018/2019 RPM Base Residual Auction Results

2018/2019 Base Residual Auction Results Discussion

Table 1 contains a summary of the RTO clearing prices resulting from the 2018/2019 RPM BRA in comparison to those from 2007/2008 through 2017/2018 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
Resource Clearing Price	$40.80	$111.92	$102.04	$174.29	$110.00	$16.46	$27.73	$125.99	$136.00	$59.37	$120.00	$164.77
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
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%

1) 2011/2012 BRA was conducted without 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

The 2018/2019 Reliability Pricing Model (RPM) Base Residual Auction cleared 166,836.9 MW of unforced capacity in the RTO representing a 20.2% reserve margin. The reserve margin for the entire RTO is 19.8%, or 4.1% higher than the target reserve margin of 15.7%, when the Fixed Resource Requirement (FRR) load and resources are considered. 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).

New Generation Resource Participation

The 2018/2019 Base Residual Auction results reflect a continuation of strong participation by new Generation Capacity Resources mostly in the form of new (or uprates to existing) gas-fired combustion turbine and combined cycle generation units. The total quantity of new Generation Capacity Resources offered into the auction was 4,132.6 MW (UCAP) comprised of 3,447.4 MW of new generation units and 685.2 MW of uprates to existing generation units. The quantity of new Generation Capacity Resources cleared was 3,506.9 MW (UCAP) comprised of 2,919.3 MW (UCAP) from new generation units, predominantly natural gas combined cycle and combustion turbines, and 587.6 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. 84.9% of the new generation capacity that offered into the 2018/2019BRA cleared the auction.

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	79.7	1,036.1	1,115.8	79.6	561.7	641.3
MAAC	439.9	1,054.8	1,494.7	439.6	561.7	1,001.3
Total RTO	685.2	3,447.4	4,132.6	587.6	2,954.3	3,541.9

*All MW Values are in UCAP Terms
*MAAC includes EMAAC
**RTO includes MAAC

Capacity Import Participation
The quantity of capacity imports cleared in the 2018/2019 BRA were 4,687.9 MW (UCAP) which represents an increase of 162.4 MW from the imports that cleared in the 2017/2018 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 2018/19 BRA has met the requirements for the CIL exception.

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

	External Source Zones					
	NORTH	WEST 1	WEST 2	SOUTH 1	SOUTH 2	Total
Offered MW (UCAP)	252.0	1,238.5	2,729.9	656.5	258.9	5,135.8
Cleared MW (UCAP)	252.0	1,163.2	2,359.9	656.5	256.3	4,687.9
Resource Clearing Price ($/MW-day)	$0.00	$0.00	$0.00	$0.00	$0.00	

Note: All Cleared MW quantities include resources that received CIL exception and those associated with pre-OATT grandfathered transmission; therefore, clearing at RTO clearing price

Demand Resource Participation
The total quantity of DR offered into the 2018/2019 BRA was 11,675.5 MW (UCAP), representing an increase of 3.4% over the DR that offered into the 2017/2018 BRA. Of the 11,675.5 MW of total DR that offered in this auction, 11,084.4 MW cleared. The cleared

DR is 109.6 MW more than that which cleared in the 2017/2018 BRA. Table 3A contains a comparison of the DR Offered and Cleared in 2017/2018 BRA & 2018/2019 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 1,306.1 MW of energy efficiency that offered into the 2018/2019 BRA, 1,246.5 MW of EE resources cleared in the auction.

Table 3B contains a summary of the DR and EE resources that offered and cleared by zone in the 2018/2019 BRA. Approximately 94.9% of the demand resources and 95.4% of the energy efficiency resources that were offered into the BRA cleared. The uncleared resources were offered at a price above the applicable clearing price for the LDA in which the resource was offered.

Figure 1 illustrates the demand side participation in the PJM Capacity Market from 2005/2006 Delivery Year to the 2018/2019 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 2018/2019 BRA have fallen below the levels seen in the 2014/2015 BRA.

2018/2019 RPM Base Residual Auction Results

Table 3A – Comparison of Demand Resources Offered and Cleared in 2017/18 BRA & 2018/19 BRA represented in UCAP

		Offered MW (UCAP)			Cleared MW (UCAP)		
LDA	Zone	2017/2018	2018/2019	Increase in Offered MW	2017/2018	2018/2019	Increase in Cleared MW
EMAAC	AECO	134.8	165.1	30.3	134.7	162.1	27.4
EMAAC/DPL-S	DPL	372.9	422.7	49.8	369.7	418.2	48.5
EMAAC	JCPL	169.8	206.4	36.6	159.4	200.1	40.7
EMAAC	PECO	494.1	513.0	18.9	480.0	504.5	24.5
PSEG/PS-N	PSEG	392.7	386.6	(6.1)	388.4	382.2	(6.2)
EMAAC	RECO	3.4	7.6	4.2	3.4	7.5	4.1
EMAAC Sub Total		1,567.7	1,701.4	133.7	1,535.6	1,674.6	139.0
PEPCO	PEPCO	619.8	667.1	47.3	608.4	523.1	(85.3)
BGE	BGE	803.2	813.9	10.7	791.2	660.0	(131.2)
MAAC	METED	306.6	334.9	28.3	298.9	327.4	28.5
MAAC	PENELEC	367.7	392.6	24.9	356.8	384.7	27.9
PPL	PPL	812.7	873.6	60.9	686.2	716.2	30.0
MAAC** Sub Total		4,477.7	4,783.5	305.8	4,277.1	4,286.0	8.9
RTO	AEP	1,445.5	1,441.5	(4.0)	1,426.1	1,417.6	(8.5)
RTO	APS	940.8	990.7	49.9	928.9	976.8	47.9
ATSI/ATSI-C	ATSI	1,064.4	891.9	(172.5)	1,020.2	877.0	(143.2)
COMED	COMED	1,499.6	1,901.2	401.6	1,478.1	1,876.7	398.6
RTO	DAY	211.9	234.9	23.0	209.4	231.6	22.2
RTO	DEOK	194.0	205.7	11.7	192.4	203.8	11.4
RTO	DOM	1,157.8	827.8	(330.0)	1,141.1	817.3	(323.8)
RTO	DUQ	161.9	263.0	101.1	161.4	262.3	100.9
RTO	EKPC	140.1	135.3	(4.8)	140.1	135.3	(4.8)
Grand Total		11,293.7	11,675.5	381.8	10,974.8	11,084.4	109.6

**MAAC sub-total includes all MAAC Zones

2018/2019 RPM Base Residual Auction Results

Table 3B – Comparison of Demand Resources and Energy Efficiency Resources Offered versus Cleared in the 2018/19 BRA

		Offered MW (UCAP)			Cleared MW (UCAP)		
LDA	Zone	DR	EE	Total	DR	EE	Total
EMAAC	AECO	165.1	3.0	168.1	162.1	3.0	165.1
EMAAC/DPL-S	DPL	422.7	11.3	434.0	418.2	11.0	429.2
EMAAC	JCPL	206.4	11.4	217.8	200.1	11.4	211.5
EMAAC	PECO	513.0	14.7	527.7	504.5	14.7	519.2
PSEG/PS-N	PSEG	386.6	14.5	401.1	382.2	14.1	396.3
EMAAC	RECO	7.6	0.1	7.7	7.5	0.1	7.6
EMAAC Sub Total		1,701.4	55.0	1,756.4	1,674.6	54.3	1,728.9
PEPCO	PEPCO	667.1	67.3	734.4	523.1	66.4	589.5
BGE	BGE	813.9	134.1	948.0	660.0	95.9	755.9
MAAC	METED	334.9	4.6	339.5	327.4	4.6	332.0
MAAC	PENELEC	392.6	12.4	405.0	384.7	12.4	397.1
PPL	PPL	873.6	25.0	898.6	716.2	25.0	741.2
MAAC** Sub Total		4,783.5	298.4	5,081.9	4,286.0	258.6	4,544.6
RTO	AEP	1,441.5	106.5	1,548.0	1,417.6	106.5	1,524.1
RTO	APS	990.7	10.5	1,001.2	976.8	10.5	987.3
ATSI/ATSI-C	ATSI	891.9	38.8	930.7	877.0	38.8	915.8
COMED	COMED	1,901.2	744.4	2,645.6	1,876.7	744.4	2,621.1
RTO	DAY	234.9	52.7	287.6	231.6	32.9	264.5
RTO	DEOK	205.7	18.5	224.2	203.8	18.5	222.3
RTO	DOM	827.8	12.9	840.7	817.3	12.9	830.2
RTO	DUQ	263.0	23.4	286.4	262.3	23.4	285.7
RTO	EKPC	135.3	-	135.3	135.3	-	135.3
Grand Total		11,675.5	1,306.1	12,981.6	11,084.4	1,246.5	12,330.9

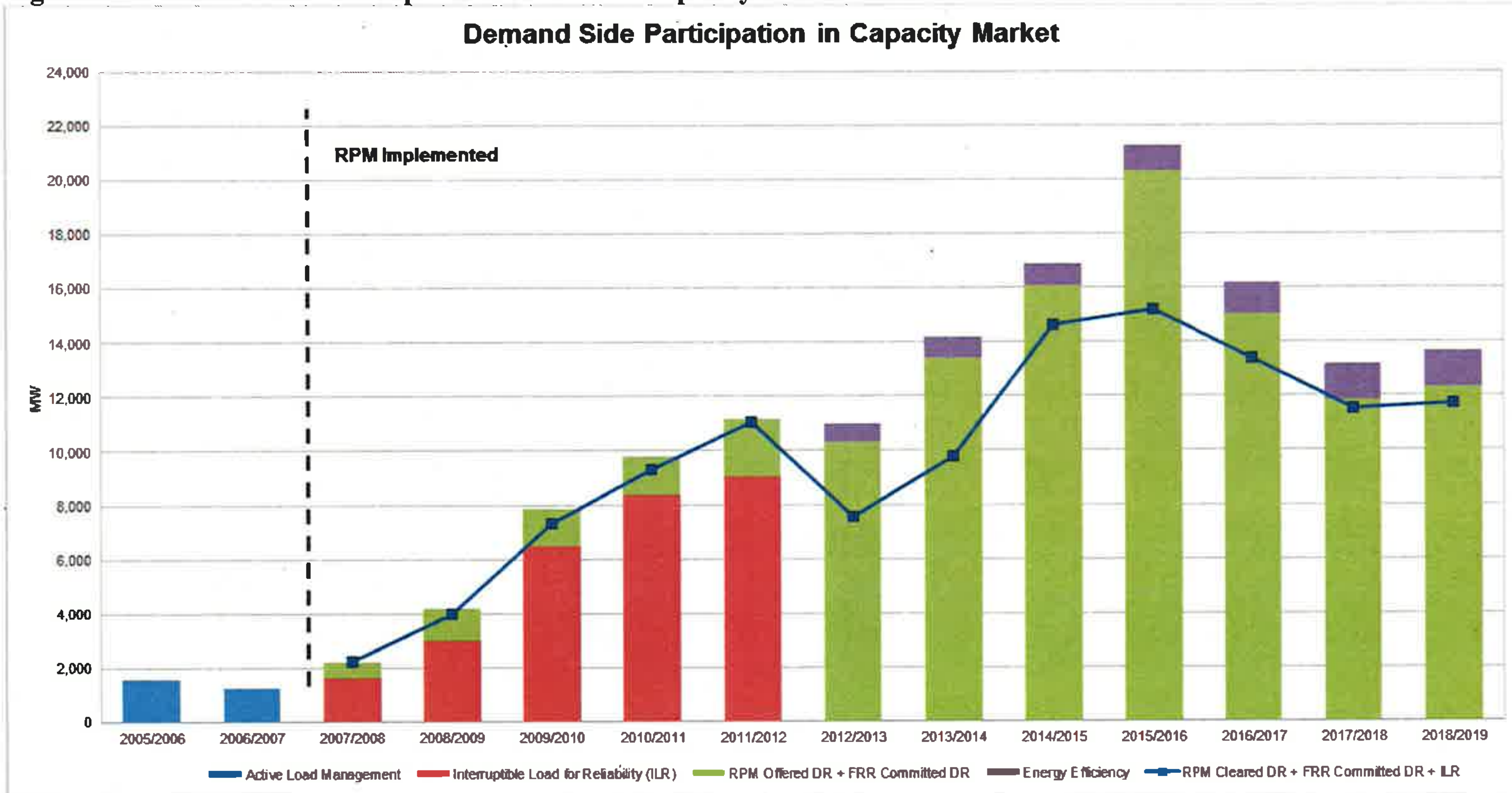
**MAAC sub-total includes all MAAC Zones

Any resource that can qualify as a CP Resource may submit separate but coupled sell offers for CP and Base Capacity product types. When sell offer segments of both capacity product types are coupled with different offer prices, the auction clearing engine will clear only one of the products at most and will clear the product that results in the lowest cost solution for the system. Any Generation Capacity Resource with a unit-specific MSOC above the CP default MSOC must submit separate but coupled sell offers for CP and Base Capacity product types. Table 3C shows a breakdown of offered and cleared capacity for each resource type grouped by coupling scenario. As shown on Table 3C, 138,228.9 MW or 89.5% of the total cleared generation capacity cleared as CP; 1,484.2 MW or 13.4% of the total cleared DR capacity cleared as CP; and, 887.3 MW or 71.2% of total cleared EE capacity cleared as CP.

Table 3C – Breakdown of Demand Resources Offered versus Cleared by Product Type in the 2018/19 BRA in UCAP

		Offered MW (UCAP)		Cleared MW (UCAP)	
Resource Type	Product Coupling Scenario	Base Product Type	Capacity Performance Product Type	Base Product Type	Capacity Performance Product Type
GEN	Capacity Performance and Base	22,255.8	22,477.7	11,194.3	9,554.7
GEN	Capacity Performance Only	-	139,204.5	-	128,674.2
GEN	Base Only	5,224.2	-	5,082.8	-
GEN Sub Total		27,480.0	161,682.2	16,277.1	138,228.9
DR	Capacity Performance and Base	4,467.5	3,528.5	3,688.8	548.2
DR	Capacity Performance Only	-	936.0	-	936.0
DR	Base Only	6,252.4	-	5,911.4	-
DR Sub Total		10,719.9	4,464.5	9,600.2	1,484.2
EE	Capacity Performance and Base	652.9	657.4	65.1	592.4
EE	Capacity Performance Only	-	314.7	-	294.9
EE	Base Only	332.7	-	294.1	-
EE Sub Total		985.6	972.1	359.2	887.3
Grand Total		39,185.5	167,118.8	26,236.5	140,600.4

Figure 1 – Demand Side Participation in the PJM Capacity Market



2018/2019 RPM Base Residual Auction Results

Renewable Resource Participation

857.2 MW of wind resources were offered into and cleared the 2018/2019 BRA as compared to 803.7 MW of wind resources that offered into and cleared the 2017/2018 BRA. The capacity factor applied to wind resources is 13%, meaning that for every 100 MW of wind energy, 13 MW are eligible to meet capacity requirements. The 857.2 MW of cleared wind capacity translates to 6,593.8 MW of wind energy nameplate capability that is expected to be available in the 2018/2019 Delivery Year.

183.7 MW of solar resources were offered into and cleared the 2018/2019 BRA as compared to 116.4 MW of solar resources that offered into and cleared the 2017/2018 BRA. The capacity factor applied to solar resources is 38%, meaning that for every 100 MW of solar energy, 38 MW are eligible to meet capacity requirements. The 183.7 MW of cleared solar capacity translates to 484.4 MW of solar energy that is expected to be available in the 2018/2019 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 Base Residual Auctions; or (3) the LDA is likely to have a locational price adder based on a PJM analysis using historic offer price levels; or (4) the LDA is EMAAC, SWMAAC, and MAAC.

As a result of the above criteria, MAAC, EMAAC, SWMAAC, PSEG, PS-NORTH, DPL-SOUTH, PEPCO, ATSI, ATSI-Cleveland, COMED, BGE and PL were modeled as LDAs in the 2018/2019 RPM Base Residual Auction. The EMAAC LDA and the ComEd LDA 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 Limited capacity product between a resource in a constrained LDA and the immediate higher level LDA. The EMAAC CETL for the 2018/2019 BRA is 940 MW lower than the 2017/2018 BRA CETL value. This reduction is primarily attributable to the addition of a significant amount of planned generation capacity in the Peach Bottom/Rock Springs area contributing to increased loading on the Rocks Spring–Keeney 500 kV line which aggravates the post-contingency voltage profile in the EMAAC area for the loss of the line. The ComEd CETL for the 2018/2019 BRA is 1,793 MW lower than the 2017/2018 BRA CETL. This reduction is primarily due to external system limitations that reduced the import capability into ComEd from outside of PJM. These external system limitations were caused by changes to the transmission system configuration anticipated for the 2018/2019 Delivery Year as well as changes to Firm transmission service reservations. The reduction in the ability to import from outside of PJM required that the imports in the CETL test for the ComEd LDA were sourced increasingly from inside PJM, resulting in the identification of transmission limitations at a lower overall transfer value.

2018/2019 RPM Base Residual Auction Results

Table 4 contains a summary of the clearing results in the LDAs from the 2018/2019 RPM Base Residual Auction.

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

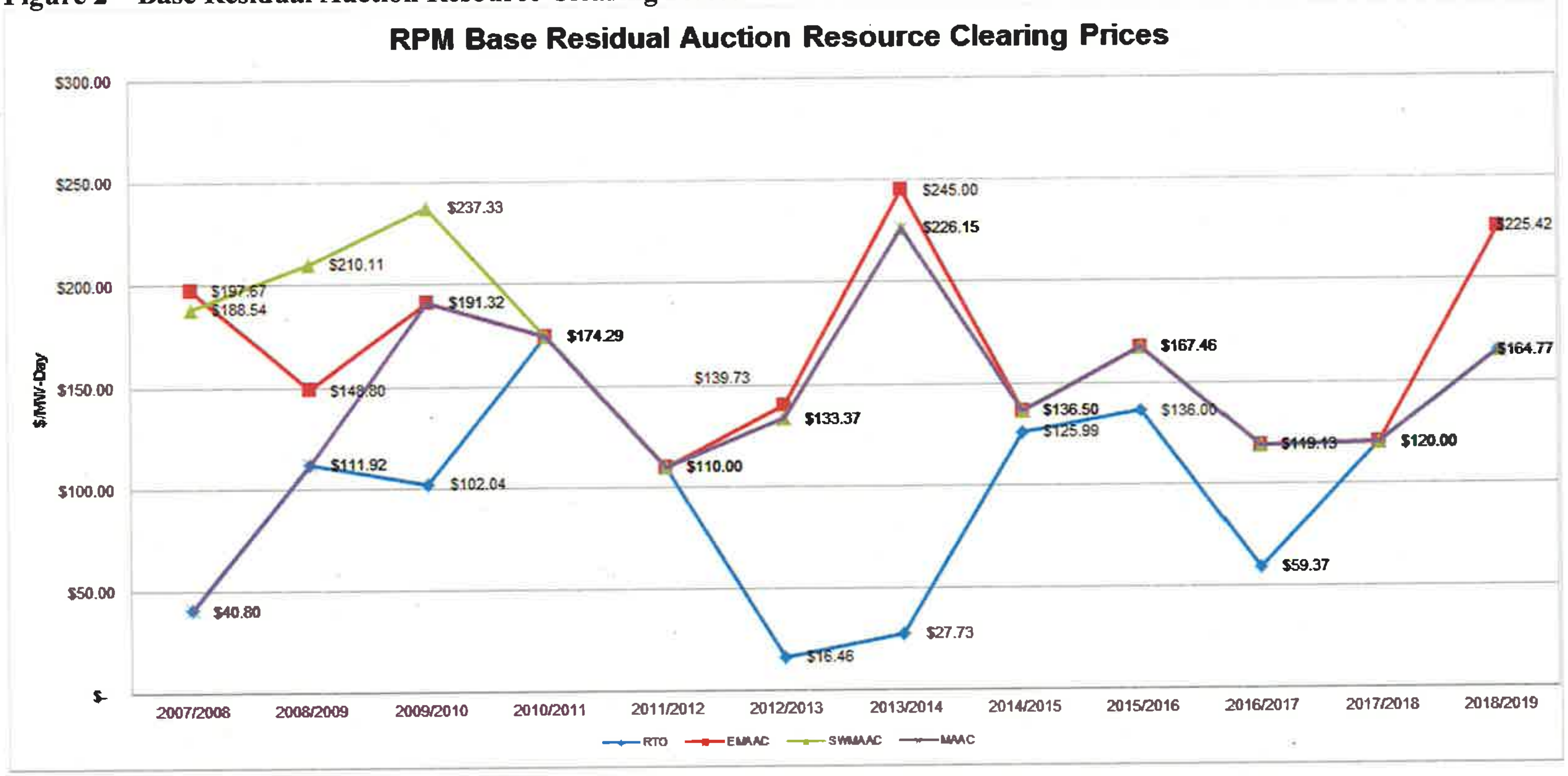
Auction Results	RTO	MAAC	SWMAAC	PEPCO	BGE	EMAAC	DPL-SOUTH	PSEG	PS-NORTH	ATSI	ATSI-CLEVELAND	PPL	COMED
Offered MW (UCAP)	179,891.2	73,545.7	12,621.2	5,991.2	4,224.9	33,840.0	1,695.9	6,939.3	3,645.3	11,085.7	2,590.4	11,157.6	26,275.6
Cleared MW (UCAP)	166,836.9	66,071.2	11,180.7	5,478.7	3,296.9	31,069.0	1,693.5	5,300.8	3,168.0	10,171.6	2,258.1	9,526.9	23,320.4
System Marginal Price	$164.77	$164.77	$164.77	$164.77	$164.77	$164.77	$164.77	$164.77	$164.77	$164.77	$164.77	$164.77	$164.77
Locational Price Adder*	-	-	-	-	-	$60.65	-	-	-	-	-	-	$50.23
Base Capacity Resource Price Decrement**	($14.79)	($14.79)	($14.79)	($14.79)	($14.79)	($14.79)	($14.79)	($14.79)	($14.79)	($14.79)	($14.79)	($89.77)	($14.79)
Base DR/EE Capacity Price Decrement	-	-	($90.03)	($108.89)	($90.03)	-	-	-	-	-	-	-	-
RCP for Base DR/EE Resources	$149.98	$149.98	$59.95	$41.09	$59.95	$210.63	$210.63	$210.63	$210.63	$149.98	$149.98	$75.00	$200.21
RCP for Base Generation Resources	$149.98	$149.98	$149.98	$149.98	$149.98	$210.63	$210.63	$210.63	$210.63	$149.98	$149.98	$75.00	$200.21
RCP for Capacity Performance Resources	$164.77	$164.77	$164.77	$164.77	$164.77	$225.42	$225.42	$225.42	$225.42	$164.77	$164.77	$164.77	$215.00

*Locational Price Adder is with respect to the immediate parent LDA

**Base Generation and Base DR/EE receive the Base Capacity Resource Price Decrement

Since the EMAAC LDA and ComEd LDA were constrained LDAs, Capacity Transfer Rights (CTRs) will be allocated to loads in these constrained LDA for the 2018/2019 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 2018/2019 Prices reflect the Annual Resource Clearing Prices.

2018/2019 RPM Base Residual Auction Results

Table 5 contains a summary of the RTO resources for each cleared BRA from 2008/2009 through the 2018/2019 Delivery Years. The summary includes all resources located in the RTO (including FRR Capacity Plans).

A total of 209,025.2 MW of installed capacity was eligible to be offered into the 2018/2019 Base Residual Auction, with 5,724.6 MW from external resources. As illustrated in Table 5, the amount of capacity exports in the 2018/2019 auction increased by 90.2 MW from that of the previous auction and FRR commitments increased by 16.9 MW from the 2017/2018 Delivery Year to 15,793 MW.

A total of 189,570.4 MW of capacity was offered into the Base Residual Auction. This is an increase of 2,096.7 MW from that which was eligible to be offered into the 2017/2018 BRA. A total of 19,454.8 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, and excess capacity owned by an FRR entity.

2018/2019 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[6]	2016/2017[5]	2017/2018	2018/2019
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
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
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
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
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
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
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
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
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
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
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
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
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

[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

2018/2019 RPM Base Residual Auction Results

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 DR Factor and Forecast Pool Requirement (FPR) for the Delivery Year.

In UCAP terms, a total of 179,891.2 MW were offered into the 2018/2019 BRA, comprised of 166,909.6 MW of generation capacity, 11,675.5 MW of capacity from DR, and 1,306.1 MW of capacity from EE resources. Of those offered, a total of 166,836.9 MW of capacity was cleared in the BRA.

Of the 166,836.9 MW of capacity that cleared in the auction, 154,506 MW were from Generation Capacity Resources, 11,084.4 MW were from DR, and 1,246.5 MW were from EE 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 2018/2019 Delivery Year.

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

	RTO*										
Auction Results (all values in UCAP**)	2008/2009	2009/2010	2010/2011	2011/2012	2012/2013	2013/2014	2014/2015	2015/2016	2016/2017	2017/2018	2018/2019
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
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
EE Offered	-	-	-	-	652.7	756.8	831.9	940.3	1,156.8	1,340.0	1,306.1
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
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
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
EE Cleared	0.0	0.0	0.0	0.0	568.9	679.4	822.1	922.5	1,117.3	1,338.9	1,246.5
Total 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
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

* 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.

Table 7 contains a summary of capacity additions and reductions from the 2007/2008 BRA to the 2018/2019 BRA. A total of 5,055.6 MW of incrementally new capacity in PJM was available for the 2018/2019 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 a reduction in the quantity of offered DR and EE to yield a net increase of 1,268.9 MW of installed capacity.

Table 7 also illustrates the total amount of resource additions and reductions over eleven Delivery Years since the implementation of the RPM construct. Over the period covering the first twelve RPM BRAs, 40.206.7 MW of new generation capacity was added which was partially offset by 33,700.3 MW of capacity de-ratings or retirements over the same period. Additionally, 11,210.6 MW of new DR and 1,205.5 MW of new EE resources were offered over the course of the twelve Delivery Years since RPM's inception. The total net increase in installed capacity in PJM over the period of the last twelve RPM auctions was 18,922.5 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	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	40,206.7
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	-33,700.3
Net Increase in Demand Resource	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	11,210.6
Net Increase in Energy Efficiency	0.0	0.0	0.0	0.0	0.0	632.3	101.1	73.1	101.3	204.8	176.4	-83.5	1,205.5
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	18,922.5

* RTO numbers include all LDAs

** Values are with 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 2018/2019 Delivery Year on an LDA basis.

Table 7A – Generation Increases and Decreases by LDA Effective 2018/2019Delivery Year

LDA Name	Increases	Decreases
EMAAC	1,172.9	(193.1)
MAAC	1,568.8	(248.8)
Total RTO	5,055.6	(3,620.8)

All Values in ICAP terms

*MAAC includes EMAAC

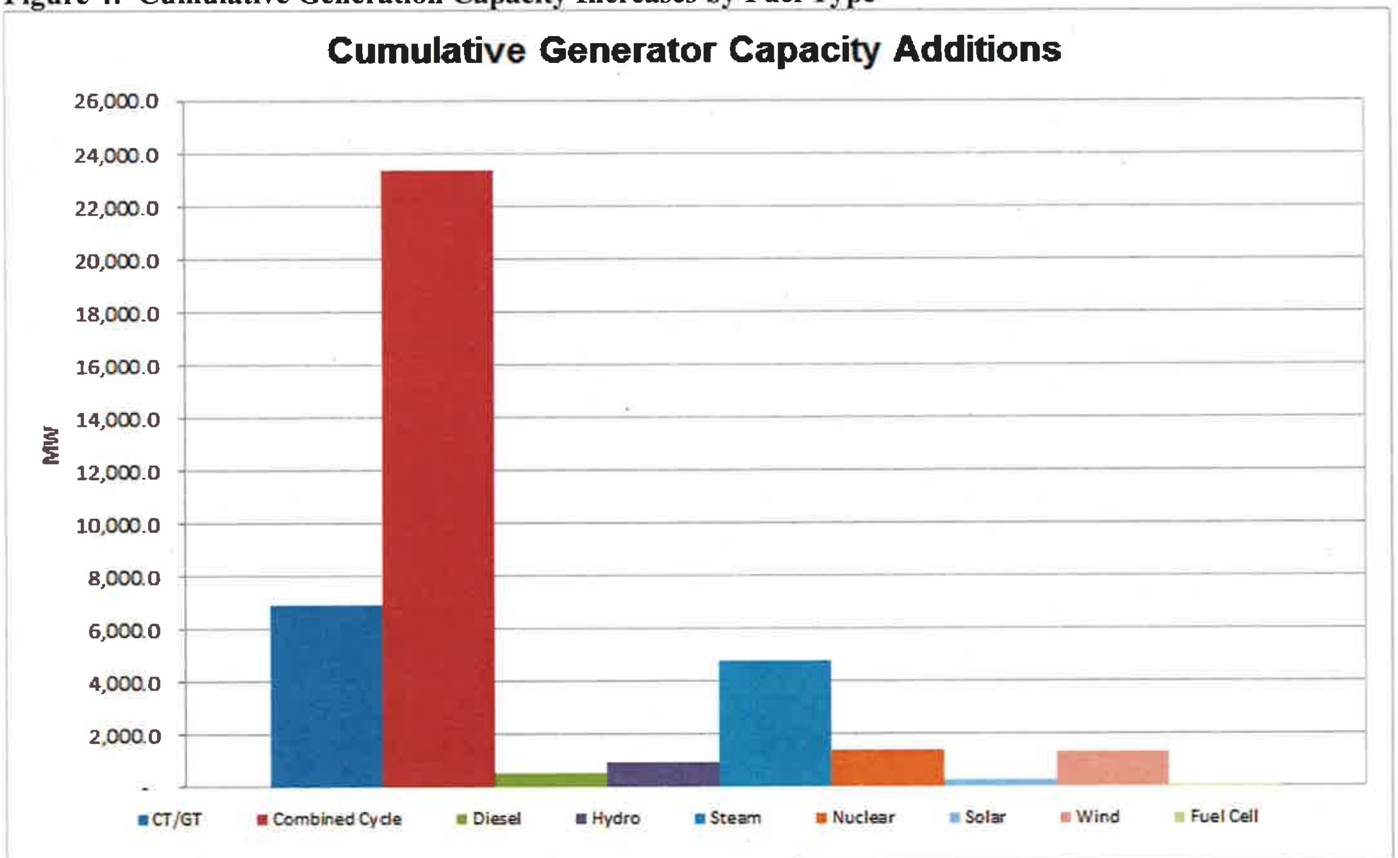
**RTO includes MAAC

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 2018/2019 BRA. The capacity offered in the 2018/2019 BRA resulted from both new generating resources and uprates to existing resources including gas, diesel, coal, wind, and nuclear resources. The largest growth remains in gas turbines and combined cycle plants.

Table 8 – Further Breakdown of Incremental Capacity Resource Additions from 2007/2008 to 2018/2019

	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
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										9.0
	2016/2017					21.0					21.0
	2017/2018					991.0					991.0
	2018/2019										-
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
	Total	6,909.7	23,368.7	493.3	877.0	4,794.5	1,402.3	205.7	1,287.5	30.0	39,377.7

Figure 4: Cumulative Generation Capacity Increases by Fuel Type



2018/2019 RPM Base Residual Auction Results

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 2018/2019 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 4,938.4 MW of cleared UCAP in the 2018/2019 BRA which equates to 7,067.5 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	2,202.7	1,085.4
Postponed or Cancelled Retirement	3,571.7	3,138.5
Reactivation	1,293.1	714.5
Total	7,067.5	4,938.4

RPM Impact to Date

As illustrated in Table 5, for the 2018/2019 auction, the capacity exports were 1,313.4 MW and the offered capacity imports were 5,724.6 MW. The difference between the capacity imports and exports results is a net capacity import of 4,711.2 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 4,711.2 MW. Therefore, RPM's impact on PJM capacity interchange is 7,027.2 MW.

The minimum net impact of the RPM implementation on the availability of Installed Capacity resources for the 2018/2019 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 2018/2019 compared to what would have happened absent this implementation is 63,441.0 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	29,464.0
Generation Upgrades (not including reactivations)	8,354.0
Generation Reactivation	1,559.7
Forward Demand and Energy Efficiency Resources	12,416.1
Cleared ICAP from Withdrawn or Cancelled Retirements	4,620.0
Net increase in Capacity Imports	7,027.2
Total Impact on Capacity Availability in 2018/2019 Delivery Year	**63,441.0**

2018/2019 RPM Base Residual Auction Results

Discussion of Factors Impacting the RPM Clearing Prices

The main factors impacting 2018/2019 RPM BRA clearing prices relative to 2017/2018 BRA clearing prices are provided below, separated out by significant changes to the market design and effects on the demand-side and supply-side of the market.

Significant Changes to RPM Design for the 2018/2019 Base Residual Auction

On June 9, 2015, in Docket No. ER15-623, FERC accepted a series of tariff reforms proposed in PJM's Capacity Performance (CP) filing of December 12, 2014, to establish Capacity Performance Resources to ensure PJM's capacity market provides adequate incentive for resource performance. 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, particularly during emergency conditions resulting in Performance Assessment Hours (PAH). Base Capacity Resources are not capable of sustained, predictable operation and/or are not expected to provide energy and reserves outside of the summer period. CP Resources are subject to a significant non-performance charge when they fail to perform under emergency conditions at any time during the Delivery Year; whereas, Base Capacity Resources are subject to a non-performance charge only when they fail to perform under emergency conditions during the summer period (at a charge rate that is lower than that for a CP Resource). The key CP filing provisions most directly related to the setup and clearing of the 2018/2019 BRA include:

- All Internal and External Generation Capacity Resources with the exception of Intermittent Resources and Capacity Storage Resources are required to offer as a CP Resource.
    - Intermittent and Capacity Storage Resource are categorically exempt from the CP must-offer requirement, but may offer all or a portion of their capability as CP. For purposes of the exemption, Intermittent Resources include wind, solar, landfill gas, run of river hydroelectric power and other renewable resources.
    - Exceptions to the CP Resource must-offer requirement are permitted if it is demonstrated that the Generation Capacity Resource is physically incapable of satisfying the requirements of a CP Resource.
- The default Market Seller Offer Cap (MSOC) for a CP Generation Capacity Resource is 85% of the Net CONE for the zone in which the resource resides. Generation Capacity Resource owners may qualify for a unit-specific MSOC above the default CP MSOC by submitting unit-specific Avoidable Cost Rate (ACR) data and information to support such offer cap.

2018/2019 RPM Base Residual Auction Results

- Any resource that can qualify as a CP Resource **may** submit separate but coupled sell offers for CP and Base Capacity product types. When sell offer segments of both capacity product types are coupled with different offer prices, the auction clearing engine will clear only one of the products at most and will clear the product that results in the lowest cost solution for the system. Any Generation Capacity Resource with a unit-specific MSOC above the CP default MSOC **must** submit separate but coupled sell offers for CP and Base Capacity product types.

- A Base Capacity DR Constraint which places a maximum limit on the total quantity of Base Capacity DR and Base Capacity EE that can be procured in the auction is established for the entire RTO and each modeled LDA. A Base Capacity Resource Constraint which places a maximum limit on the total quantity of Base Capacity DR, Base Capacity EE and Base Capacity Generation Resources that can be procured in the auction is established for the entire RTO and each modeled LDA.

- The Short-Term Resource Procurement Target of 2.5% has been eliminated; therefore, 2.5% of the target reliability requirement is no longer held back from the target procurement quantity of the BRA.

- The UCAP MW value of DR and EE is no longer discounted by the DR Factor which has historically been about 95%. Therefore the UCAP MW value is about 5% greater for each ICAP MW of DR and EE cleared in the auction.

On November 28, 2014, in Docket No. ER14-2940, FERC approved revisions to the Variable Resource Requirement ("VRR") curve shape and Gross Cost of New Entry ("CONE") values as proposed in a PJM filing of September 25, 2014. This filing was made following last year's stakeholder review of the shape of the VRR curve and key inputs to that curve, where such review is required by PJM Tariff on a specified periodic basis. The new shape of the VRR Curve relative to the VRR curve shape used in the prior BRA for the 2017/2018 Delivery Year is best seen in Figure 2 on page 21 of PJM's September 25, 2014 filing (located at http://www.pjm.com/media/documents/etariff/FercDockets/1304/20140925-er14-2940-000.pdf). The new Gross CONE values used in the development of the VRR curve range depending on the LDA from 13% to 18.2% lower than values that would otherwise been used in the 2018/2019 BRA (see page 26 of PJM's September 25, 2014 filing).

2018/2019 RPM Base Residual Auction Results

Changes that impacted the Demand Curve:

- The target reliability requirement for the 2018/2019 BRA is 160,607.4 MW, which is 275 MW (0.2%) lower than the target reliability requirement of the 2017/2018 BRA. The target reliability requirement for the 2017/2018 BRA was 160,882 MW which was based on an actual reliability requirement of 165,007 MW minus a short-term resource procurement target quantity of 4,125 MW.

- The Net CONE applicable to the RTO VRR curve is about 15% lower than the RTO Net CONE value used in the 2017/2018 BRA. Relative to the LDA Net CONE values used in the 2017/2018 BRA, the 2018/2019 LDA Net CONE values are lower for all LDAs ranging from a 14% decrease for the MAAC LDA to a 30% decrease for the DPL-South LDA. The reduction in Net CONE values are due to the lower Gross CONE values for the 2018/2019 BRA resulting from PJM's September 25, 2014 filing as described above, as well as, higher Net E&AS Offset values relative to those used last year due to an update of the 3-year period for which the reference resource E&AS revenues were determined (the 2018/2019 values are based on LMPs from calendar years 2012 through 2014 whereas the 2017/2018 values were based on LMPs from calendar years 2011 through 2013).

- The changes to the VRR Curve shape discussed in prior section shifted the VRR Curve to the right (increasing the demand for capacity all else equal).

Changes that impacted the Supply Curve:

- With the transition to the Capacity Performance product, the implied costs of committing to be a Capacity Resource increases due to the need to make improvements in generator performance during Performance Assessment Hours. These increased costs could be related weatherization, improved maintenance, and costs for fuel assurance. This shifts the supply curve for resources up and leads to higher capacity market prices overall.

- Low natural gas and therefore energy market prices have largely led to lower net energy market revenues across the PJM system especially for coal and oil steam units as well as nuclear units which leads to higher capacity market offers from these resources.

2018/2019 RPM Base Residual Auction Results

Revision History

8/21/2015: Original version posted
8/28/2015: updated typos found in original version:

- MOPR-related data table of page 7: cleared quantities for RTO and MAAC were corrected; values were reversed in original version.
- Table 2A: Offered quantity of New Units in MAAC was corrected. Cleared quantities for New Units in EMAAC, MAAC and Total RTO were corrected.
- Titles of Table 3B and 3C changed to correctly describe data as "2018/2019" BRA

ATTACHMENT

JF-3

2017/2018 RPM Capacity Performance Transition Incremental Auction Results

Introduction

The 2017/2018 Capacity Performance Transition Incremental Auction ("CP Transition Auction") opened on September 3, 2015, and the auction results were posted on September 9, 2015. This document provides information for PJM stakeholders regarding the results of the 2017/2018 CP Transition Auction.

CP Transition Auctions for the 2016/2017 and 2017/2018 Delivery Years are part of a five-year transition to a single capacity product type beginning with the auctions for the 2020/2021 Delivery Year. Such transition over five years provides opportunity for resources to invest in, and sufficient time to build and make improvements (e.g., dual fuel, firm gas contracts, etc.) necessary to meet the operational and performance requirements expected of Capacity Performance Resources ("CP Resources").

The CP Transition Auctions seek to procure a prescribed percentage of the PJM Region's Reliability Requirement of CP Resources based upon voluntary offers from Capacity Market Sellers.[1] Resources that clear in a CP Transition Auction will convert any existing capacity commitment obtained by clearing in prior auctions for the relevant Delivery Year to CP. Capacity payments for resources that clear in a CP Transition Auction will be based on the clearing price resulting from the CP Transition Auction, and sellers that commit as CP Resources for either of these two years will be subject to the CP performance requirements and associated Non-Performance Assessment Charge.

2017/2018 CP Transition Auction Results

The target procurement quantity for the CP Transition Auction for the 2017/2018 Delivery Year was 112,194.5 MW (70% of the updated Reliability Requirement for the 2017/2018 Delivery Year). **The auction procured the entire quantity of 112,194.5 MW of CP Resources at an auction clearing price of $151.50/MW-day.** The auction clearing price cap was $210.83/MW-Day (established as 60% of the Net CONE of the PJM Region used in the 2017/2018 BRA). The auction clearing price is not permitted to exceed the auction clearing price cap. While resource sell offers into the CP Transition Auction were not subject to mitigation, any resource submitting a sell offer at a price greater than the auction clearing price cap would not clear the auction. The clearing price resulting from the auction was below the established price cap because sufficient supply of CP Resources was offered into the auction at offer prices below the cap, and is strong evidence of competitive offer behavior.

While the CP Transition Auctions are cleared as a single clearing price auction without location-specific requirements, it is important to note that the auction construct results in only conversion of existing commitments or new commitments, therefore, total commitments levels within modeled LDAs are never reduced and can only possibly increase thereby implicitly maintaining and respecting all LDA capacity import limits.

[1] The planning parameters (including the target procurement quantity and auction clearing price caps) and participation eligibility requirements for the CP Transition Auction are located at http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2016-2018-cp-transition-incremental-auctions-rules-schedule-planning-parameters.ashx.

2017/2018 RPM Capacity Performance Transition Incremental Auction Results

As can be seen from Table 1 below, the total 112,194.5 MW of CP Resources procured in the auction was comprised of the conversion of 102,177.5 MW of previously committed resources, plus 10,017.0 MW of resources that did not have a prior commitment or that cleared in a quantity greater than the previous resource commitment level.

Table 2 shows the total generation resources committed as CP via the Transition Auction. 101,259.7 MW of generation resources with prior existing RPM commitments cleared in the auction and therefore converted those commitments to CP. 9,303.1 MW of generation resources that increased their commitment level or did not have a prior RPM commitment also cleared in the auction and therefore committed as CP Resources. Table 3 further breaks down the generation resources that cleared the auction by major fuel type.

Finally, Tables 4A and 4B show the breakdown of Demand Response (DR) and Energy Efficiency (EE) resources that cleared the Transition Auction. A total of 700.0 MW of DR resources cleared in the Transition Auction, of which 245.5 MW had a prior RPM commitment and 454.5 MW did not. A total of 931.7 MW of EE resources cleared in the auction, of which 672.3 MW had a prior RPM commitment and 259.4 MW did not.

Table 1 – Offered and Cleared CP Quantities for All Resource Types

LDA	Offered Capacity (UCAP MW)	Cleared Capacity (UCAP MW)	Converted Commitment (UCAP MW)	New Commitment (UCAP MW)
RTO (minus MAAC)	87,919.6	73,726.0	66,575.9	7,150.1
MAAC	45,849.2	38,468.5	35,601.6	2,866.9
Total RTO	133,768.8	112,194.5	102,177.5	10,017.0

RTO (minus MAAC) comprised of AEP, APS, ATSI, ComEd, Dayton, DEOK, DOM, EKPC and Duquesne Zones

MAAC consists of the AECO, BGE, DPL, JCPL, Met-Ed, PECO, Penelec, PEPCO, PPL, PSEG and RECO Zones

2017/2018 RPM Capacity Performance Transition Incremental Auction Results

Table 2 – Offered and Cleared CP Quantities for Generation Resources

Zone	Offered Capacity (UCAP MW)	Cleared Capacity (UCAP MW)	Converted Commitment (UCAP MW)	New Commitment (UCAP MW)
AECO	776.3	774.9	774.9	0.0
AEP	13,787.2	10,847.0	10,725.5	121.5
APS	7,231.1	5,373.0	5,367.9	5.1
ATSI	8,737.4	7,486.1	5,150.9	2,335.2
BGE	3,167.7	2,952.5	2,436.1	516.4
COMED	21,010.9	17,477.9	13,543.3	3,934.6
DAY	3,045.9	2,366.5	2,356.0	10.5
DEOK	1,679.5	796.9	796.9	0.0
DOM	22,690.4	21,737.7	21,620.2	117.5
DPL	3,967.1	2,702.7	2,702.3	0.4
DUQ	2,306.3	2,199.7	2,170.5	29.2
EKPC	2,403.0	2,209.5	2,209.5	0.0
EXT	3,524.0	2,006.6	1,970.8	35.8
JCPL	2,746.2	1,726.3	1,131.9	594.4
METED	2,952.6	2,724.8	2,713.8	11.0
PECO	9,093.8	7,793.3	7,679.0	114.3
PENELEC	6,713.9	5,692.6	5,646.0	46.6
PEPCO	4,540.2	3,106.6	2,945.4	161.2
PPL	8,603.6	7,822.6	6,553.2	1,269.4
PSEG	2,865.6	2,765.6	2,765.6	0.0
Total RTO	131,842.7	110,562.8	101,259.7	9,303.1

2017/2018 RPM Capacity Performance Transition Incremental Auction Results

Table 3 – Offered and Cleared CP Quantities for Generation Resources by Major Fuel Types

Fuel Type	Offered Capacity (UCAP MW)	Cleared Capacity (UCAP MW)	Converted Commitment (UCAP MW)	New Commitment (UCAP MW)
Coal	43,476.9	37,455.2	33,290.2	4,165.0
Gas	48,441.7	35,298.1	34,812.9	485.2
Nuclear	30,125.0	29,969.8	25,570.4	4,399.4
Other	9,799.1	7,839.7	7,586.2	253.5
Total RTO	**131,842.7**	**110,562.8**	**101,259.7**	**9,303.1**

Table 4A – Offered and Cleared CP Quantities for DR

LDA	Offered Capacity (UCAP MW)	Cleared Capacity (UCAP MW)	Converted Commitment (UCAP MW)	New Commitment (UCAP MW)
RTO (minus MAAC)	814.0	547.1	205.7	341.4
MAAC	168.5	152.9	39.8	113.1
Total RTO	**982.5**	**700.0**	**245.5**	**454.5**

RTO (minus MAAC) comprised of AEP, APS, ATSI, ComEd, Dayton, DEOK, DOM, EKPC and Duquesne Zones

MAAC consists of the AECO, BGE, DPL, JCPL, Met-Ed, PECO, Penelec, PEPCO, PPL, PSEG and RECO Zones

Table 4B – Offered and Cleared CP Quantities for EE

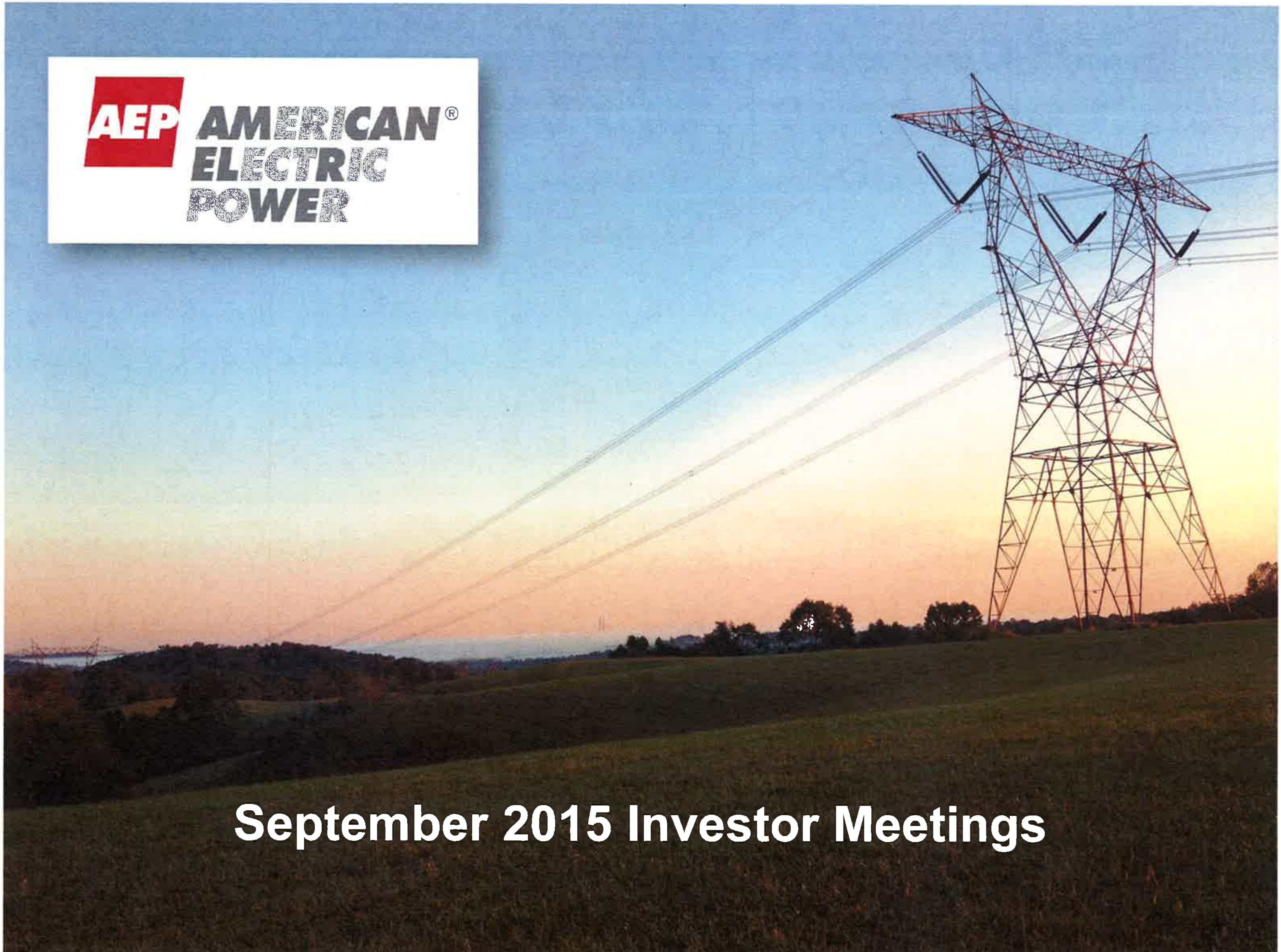
LDA	Offered Capacity (UCAP MW)	Cleared Capacity (UCAP MW)	Converted Commitment (UCAP MW)	New Commitment (UCAP MW)
RTO (minus MAAC)	689.9	678.0	458.7	219.3
MAAC	253.7	253.7	213.6	40.1
Total RTO	**943.6**	**931.7**	**672.3**	**259.4**

RTO (minus MAAC) comprised of AEP, APS, ATSI, ComEd, Dayton, DEOK, DOM, EKPC and Duquesne Zones

MAAC consists of the AECO, BGE, DPL, JCPL, Met-Ed, PECO, Penelec, PEPCO, PPL, PSEG and RECO Zones

ATTACHMENT

JF-4



September 2015 Investor Meetings

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate, growth or contraction within and changes in market demand and demographic patterns in our service territory, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load, customer growth and the impact of retail competition, weather conditions, including storms and drought conditions, and our ability to recover significant storm restoration costs, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of necessary generation capacity and the performance of our generation plants, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generation capacity and transmission lines and facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs, new legislation, litigation and government regulation, including oversight of nuclear generation, energy commodity trading and new or heightened requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of fly ash and similar combustion products that could impact the continued operation, cost recovery and/or profitability of our generation plants and related assets, evolving public perception of the risks associated with fuels used before, during and after the generation of electricity, including nuclear fuel, a reduction in the federal statutory tax rate could result in an accelerated return of deferred federal income taxes to customers, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance, resolution of litigation, our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity and other energy-related commodities, prices and demand for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing, alternative or distributed sources of generation, our ability to recover through rates or market prices any remaining unrecovered investment in generation units that may be retired before the end of their previously projected useful lives, volatility and changes in markets for capacity and electricity, coal, and other energy-related commodities, particularly changes in the price of natural gas, changes in utility regulation and the allocation of costs within regional transmission organizations, including ERCOT, PJM and SPP, the transition to market for generation in Ohio, including the implementation of ESPs, our ability to successfully and profitably manage our separate competitive generation assets, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of our debt, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans, captive insurance entity and nuclear decommissioning trust and the impact of such volatility on future funding requirements, accounting pronouncements periodically issued by accounting standard-setting bodies and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes, cyber security threats and other catastrophic events.

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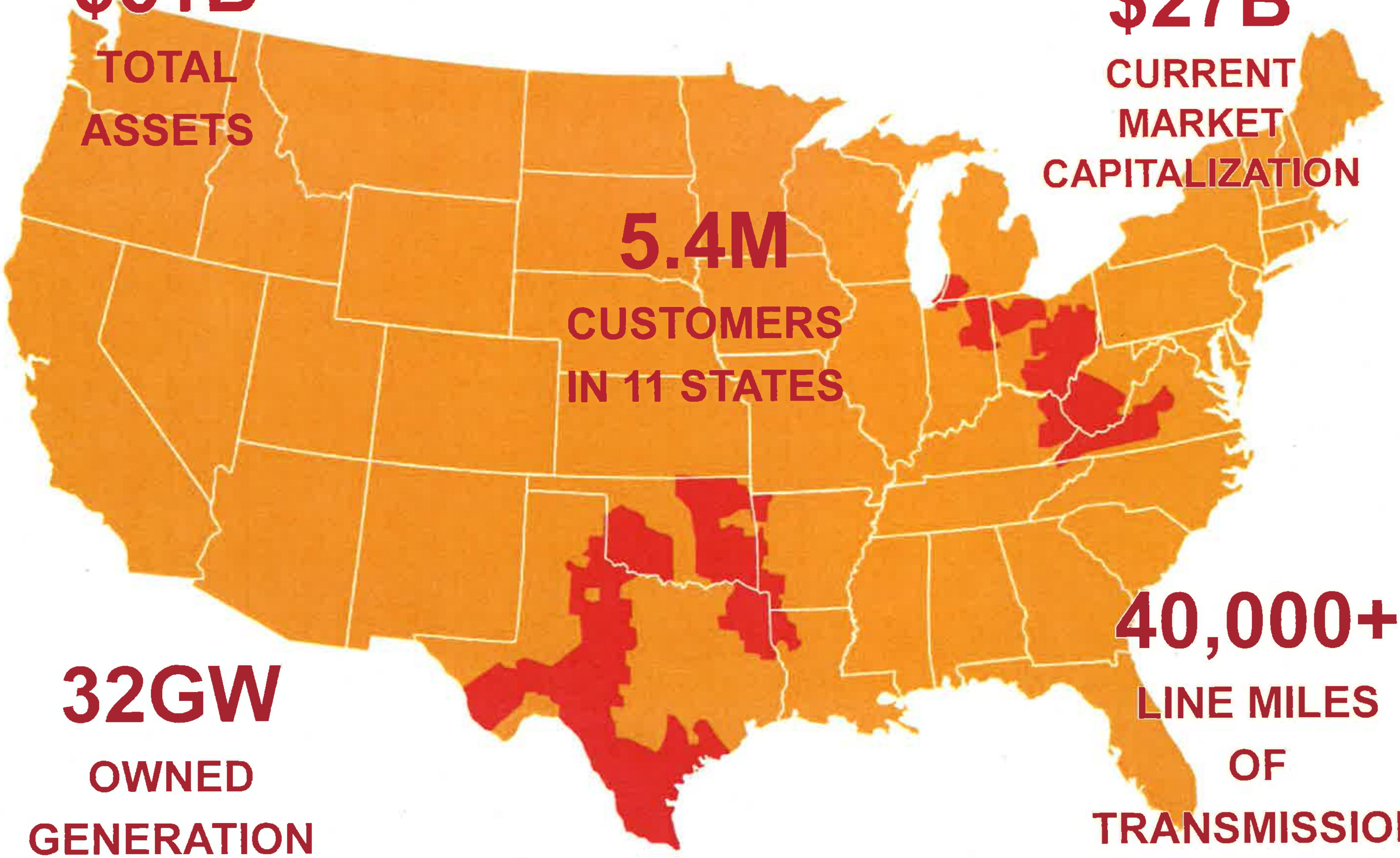
American Electric Power Company Overview

$61B TOTAL ASSETS

$27B CURRENT MARKET CAPITALIZATION

5.4M CUSTOMERS IN 11 STATES



32GW OWNED GENERATION

40,000+ LINE MILES OF TRANSMISSION

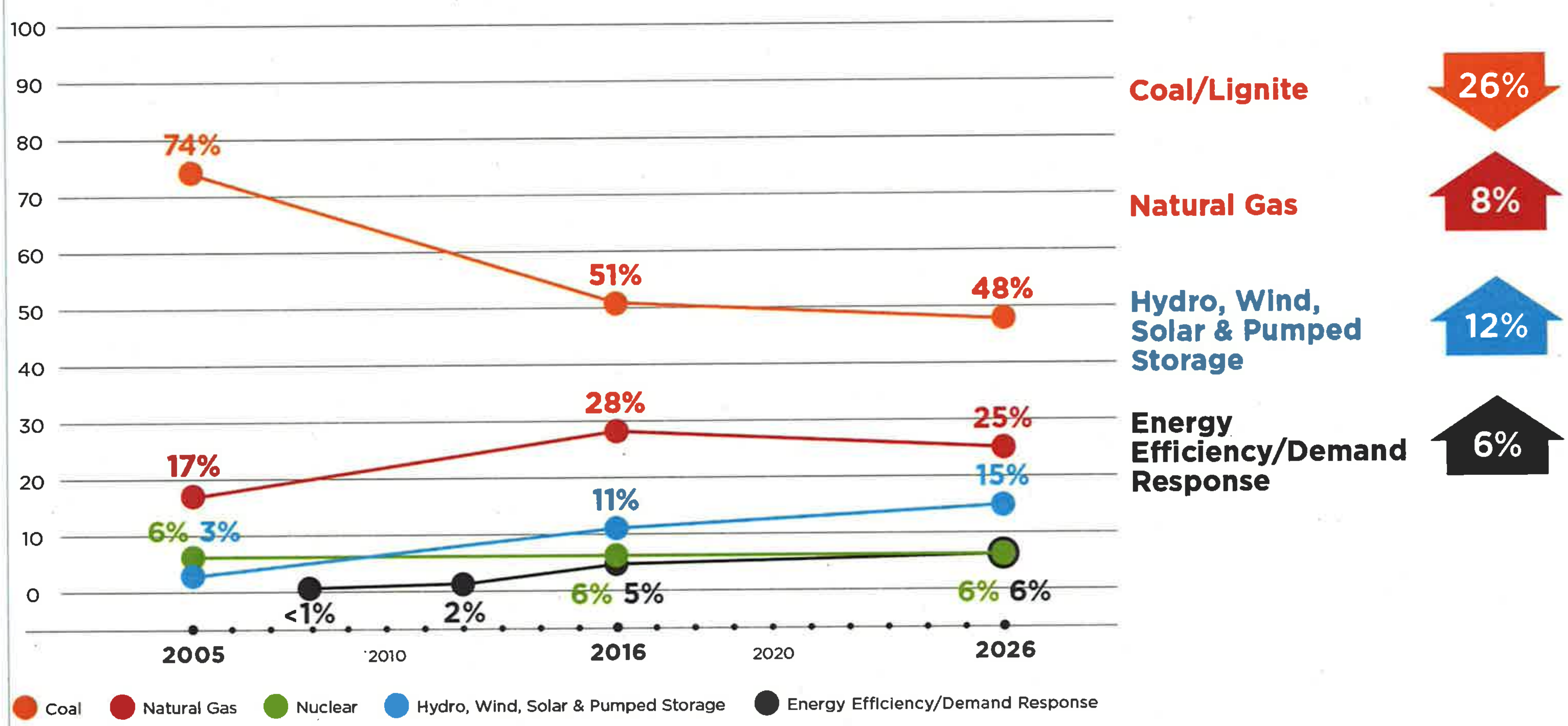
Note: Statistics as of June 30, 2015, except market capitalization which is as of August 27, 2015

AEP®

Sustainability

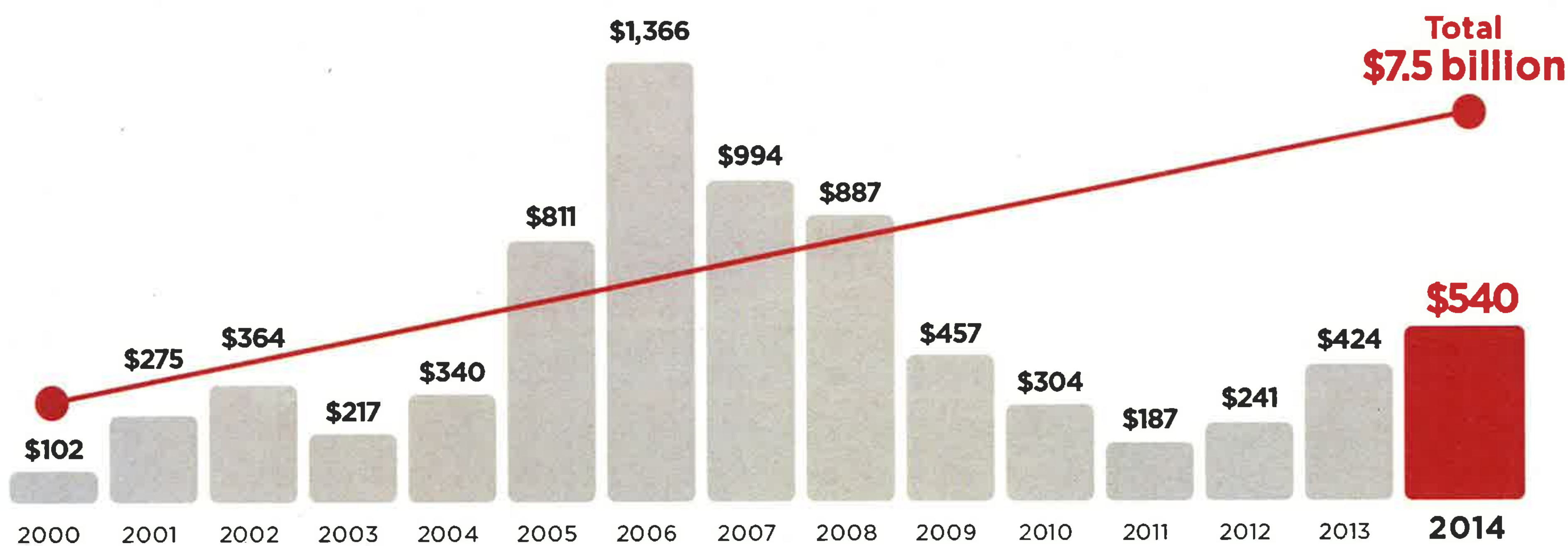
Diversifying Our Fuel Portfolio

AEP Owned Generating Capacity by Fuel (actual & projected)



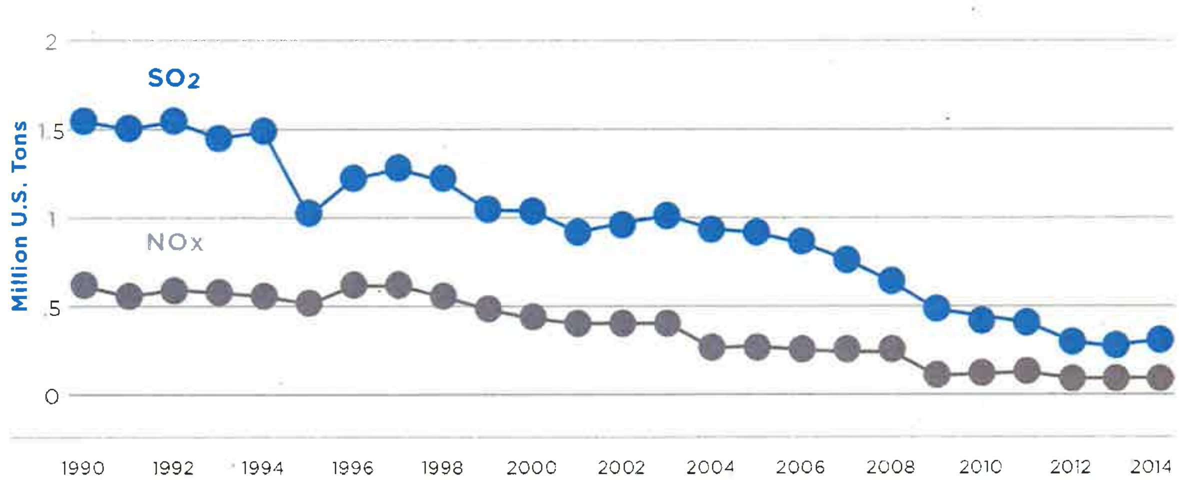
Investments Driving Emission Reductions

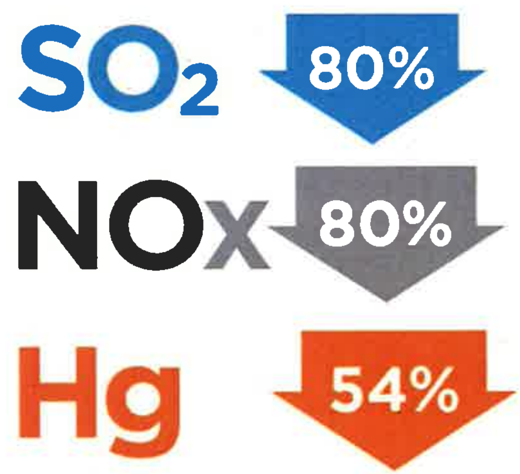
Historical Environmental Investments (in millions)



Dramatic Reductions in Emissions

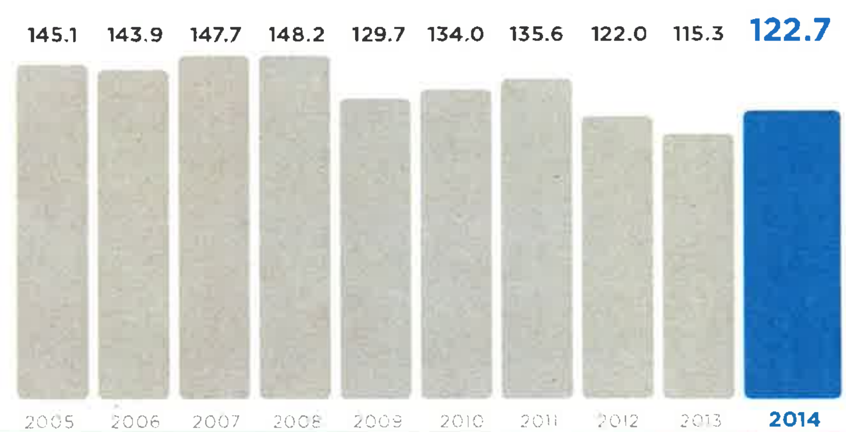
Total AEP System Emissions 1990 - 2014





Total AEP System - Annual CO_2 Emissions

(in million metric tons)



Delivering Clean Energy Resources

AEP's Renewable Portfolio (nameplate capacity)

Contributions by Regulated Operating Companies	MW
AEP Ohio	209.10
Appalachian Power	375.00
Indiana Michigan Power	465.70
Kentucky Power	58.50
Public Service Company of Oklahoma	1,137.30
Southwestern Electric Power Company	469.15
Total	**2,714.75**

Over
7,500MW
of renewable generation interconnected across the U.S. via AEP's transmission system today

FINANCIAL INFORMATION

2015-2017 Capital Spending Forecast

Capital & Equity Contributions
$ in millions, excluding AFUDC
2015: $4.6B; 2016: $3.8B
2017: $3.9B

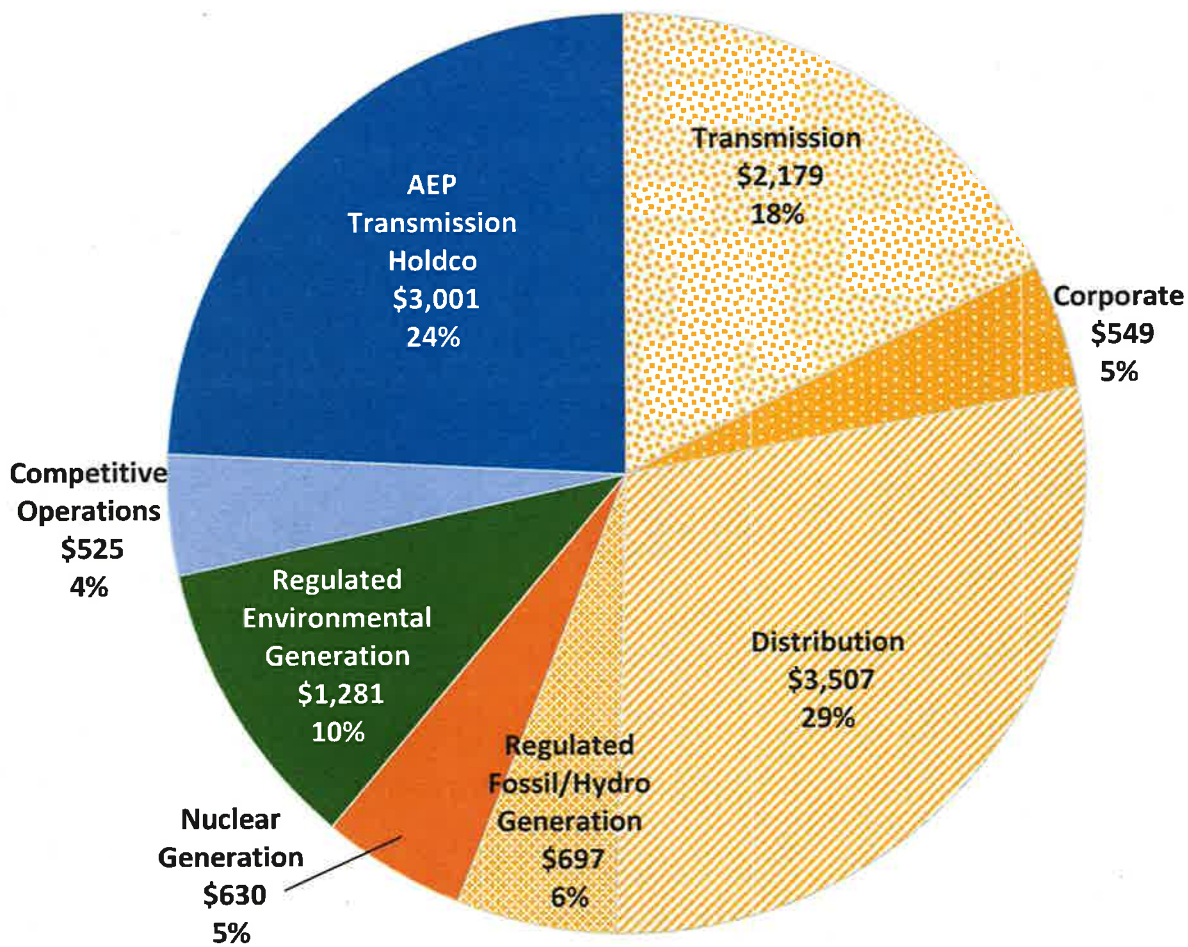
Regulated Generation Investment - $2.6B

Regulated Distribution Investment - $3.5B

Regulated Transmission Investment - $5.2B

Capital & Equity Contributions

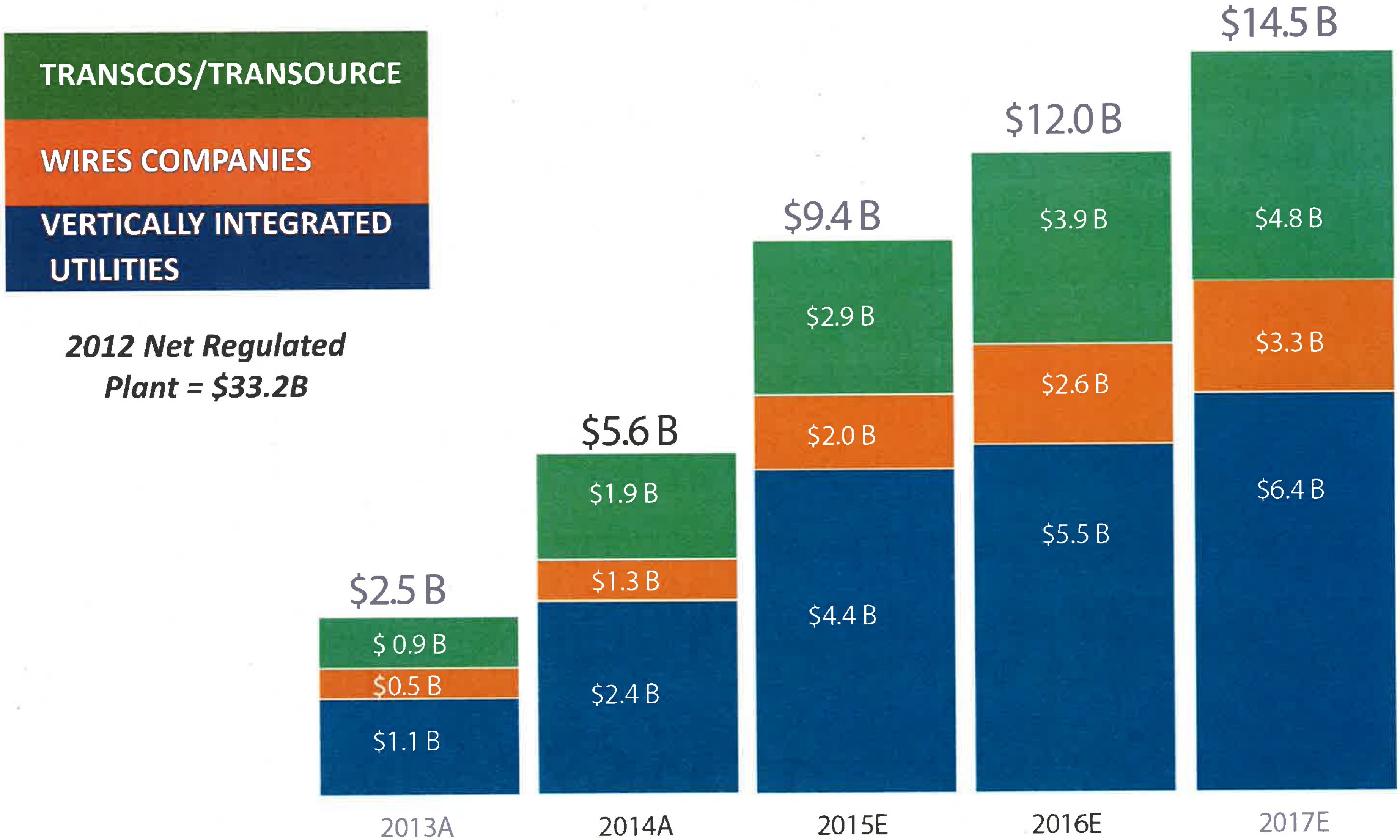
$12.3B 2015-2017, excluding AFUDC



96% of capital allocated to regulated businesses; 71% allocated to wires

Regulated Rate Base Growth

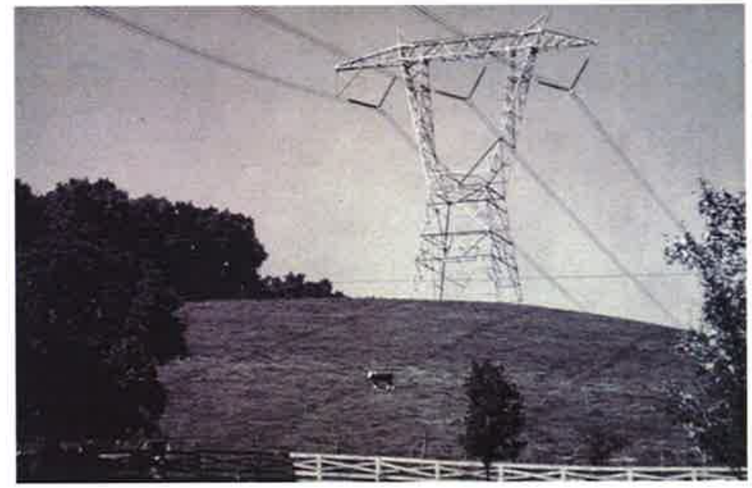
Cumulative change from 2012 base

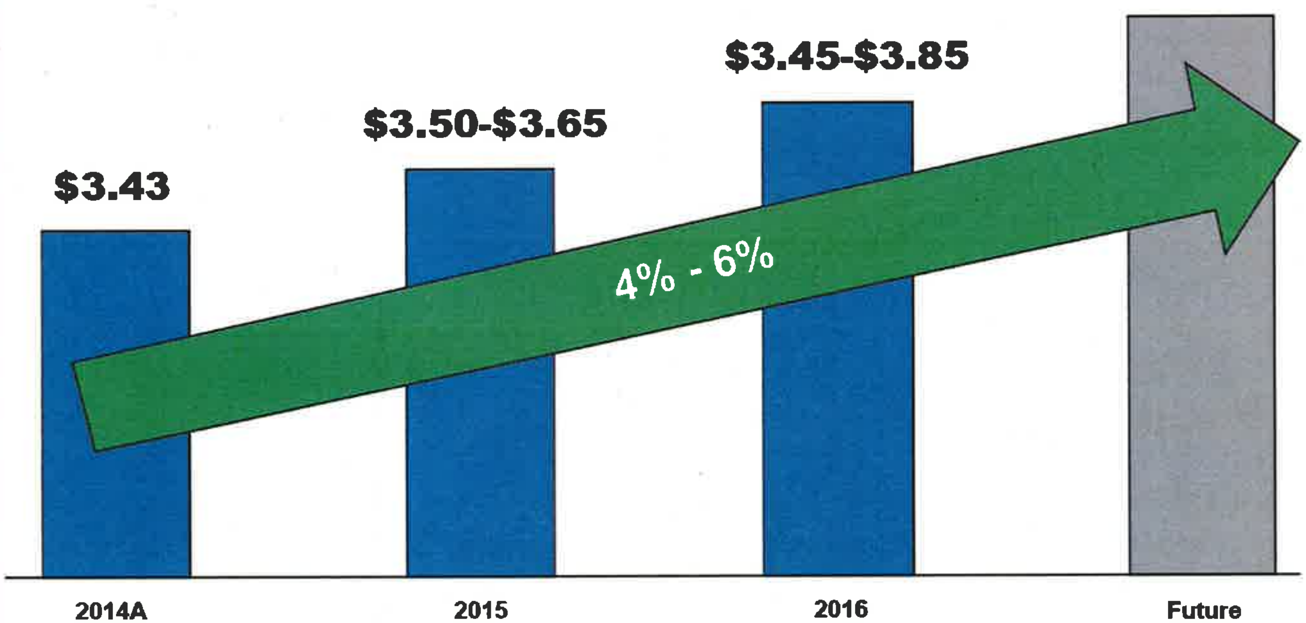


2012 Net Regulated Plant = $33.2B

7.5% CAGR in Net Regulated Plant

Forecasted 4-6% EPS Growth Rate Reaffirmed





Earnings growth achieved through capital investment and rate recovery, identified sustainable cost savings and O&M spending discipline

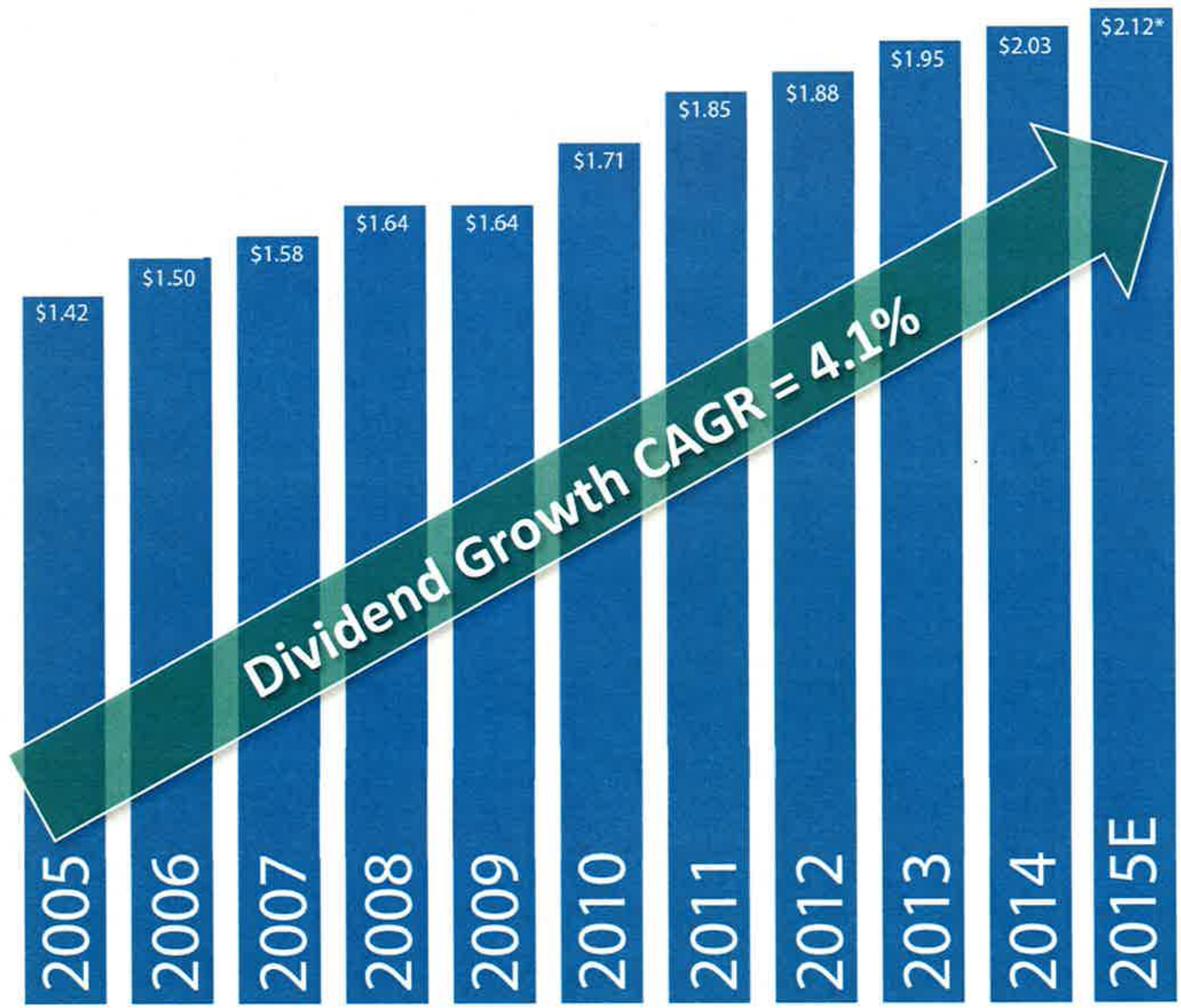
EPS Growth + Dividend Yield = 8% - 10% Annual Return Opportunity

Dividend

Targeted payout ratio of 60-70% of operating earnings

Supported by earnings from regulated operations

Declared 421 consecutive quarters



* Subject to approval by Board of Directors

AEP®

2014-2017 Financing Plan & Credit Metrics

$ in millions	2014A	2015E	2016E	2017E
Cash from Operations - Excl. Impact of Bonus Depreciation & FIT Payments	4,000	4,000	4,900	4,900
Impact of Bonus Depreciation	700	600	-	-
Federal Cash Taxes Refunded (Paid)	(100)	(400)	(800)	(800)
Cash from Securitization *	-	-	300	-
Capital & JV Equity Contributions	(4,200)	(4,400)	(3,800)	(3,900)
Other Investing Activities	(300)	(200)	(200)	(200)
Common Dividends @ $2.03/share 2014; $2.12/share - 2014 - 2017 **	(1,000)	(1,000)	(1,000)	(1,000)
Excess (Required) Capital	(900)	(1,400)	(600)	(1,000)
Financing ($ in millions)	**2014A**	**2015E**	**2016E**	**2017E**
Excess (Required) Capital	(900)	(1,400)	(600)	(1,000)
Debt Maturities (Senior Notes, PCRBs)	(1,500)	(1,700)	(1,200)	(1,800)
Securitzation Amortizations	(300)	(300)	(300)	(300)
AGR Credit Facility ***	-	500	-	-
Equity Issuances (DRP/401K)	100	100	100	100
Debt Capital Market Needs (New)	(2,600)	(2,800)	(2,000)	(3,000)
Financial Metrics	**2014A**	**2015E**	**2016E**	**2017E**
Debt to Capitalization Target	Mid 50s			
FFO/Total Debt ****	Mid -to- Upper teens			

* $300MM OH deferred fuel securitization (subject to regulatory approval)

** Assumes current quarterly dividend of $0.53 per share; dividend evaluated by board of directors each quarter; stated targeted payout ratio range is 60-70%

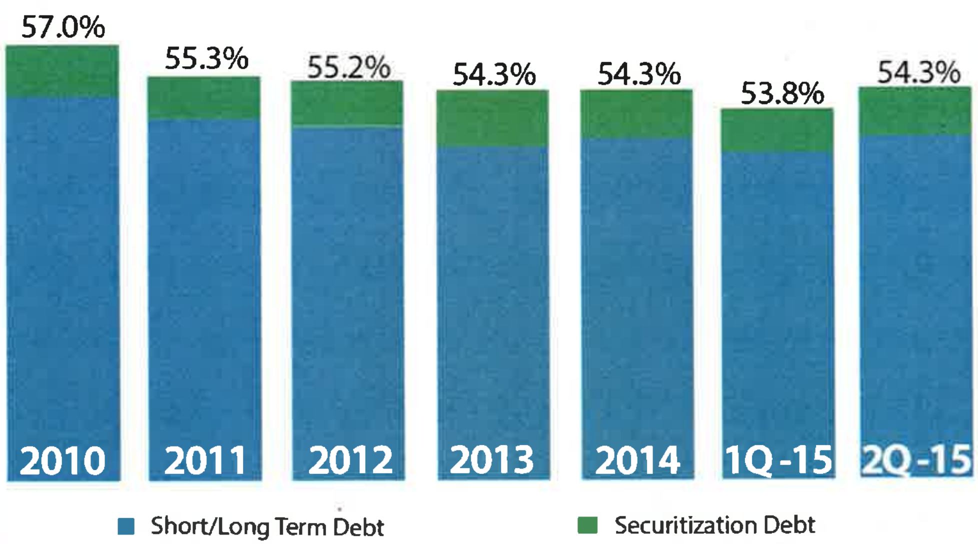
*** Interim credit facility matures May 2015, and is assumed to be refinanced for modeling purposes.

**** Excludes securitization debt

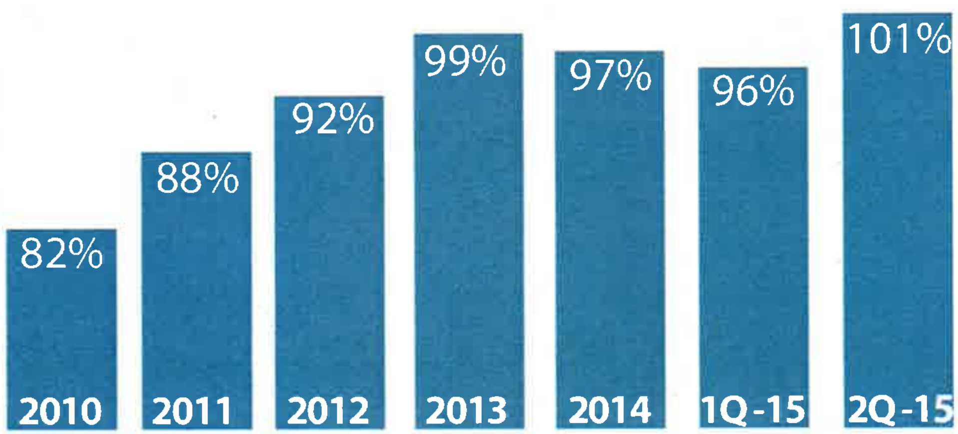
Anticipated cash flows cover planned capital investment while maintaining solid credit metrics

Capitalization & Liquidity

Total Debt / Total Capitalization



Qualified Pension Funding



Credit Statistics

	Actual	Target
FFO Interest Coverage	5.6x	>3.6x
FFO to Total Debt	21.5%	15%-20%

Note: Credit statistics represent the trailing 12 months as of 06/30/2015

Liquidity Summary

(unaudited)	6/30/2015 Actual	
($ in millions)	Amount	Maturity
Revolving Credit Facility	$1,750	Jul-18
Revolving Credit Facility	$1,750	Jun-17
Total Credit Facilities	$3,500	
Plus		
Cash & Cash Equivalents	$195	
Less		
Commercial Paper Outstanding	(397)	
Letters of Credit Issued	(61)	
Net Available Liquidity	**$3,237**	

Strong balance sheet, credit metrics, and liquidity

Current 2015 Rate Cases

Procedural Schedule

•	October 14th	Staff & Invervenor testimony due on all issues except rate design and cost of service
•	October 23th	Staff & Intervenor testimony due on rate design and cost of service
•	November 10th	Rebuttal testimony due
•	November 17th	Settlement conference
•	December 8th	Hearing commences

Oklahoma

Base rate case filed July 1, 2015

- Requested rate base of $2.1 billion
- Requested increase of $ $172M, consisting of $44M for Northeastern Unit 3 & Comanche Power Plant, $89M of traditional base rate increases, and $39M for compliance related fuel clause changes
- Requested an ROE of 10.50%
- Requested capital structure of 52% debt 48% equity

AEP Ohio Regulatory Filings

Unit/Plant	MW
Cardinal Unit 1	592 MW
Conesville	Unit 4 (CCD): 339 MW Units 5&6: 810 MW
Stuart	4 Coal Units: 600 MW
Zimmer	330 MW
OVEC Entitlement	423 MW
Total	3,094 MW

*Plants included in PPA filing:

Amended Purchase Power Agreement Filing

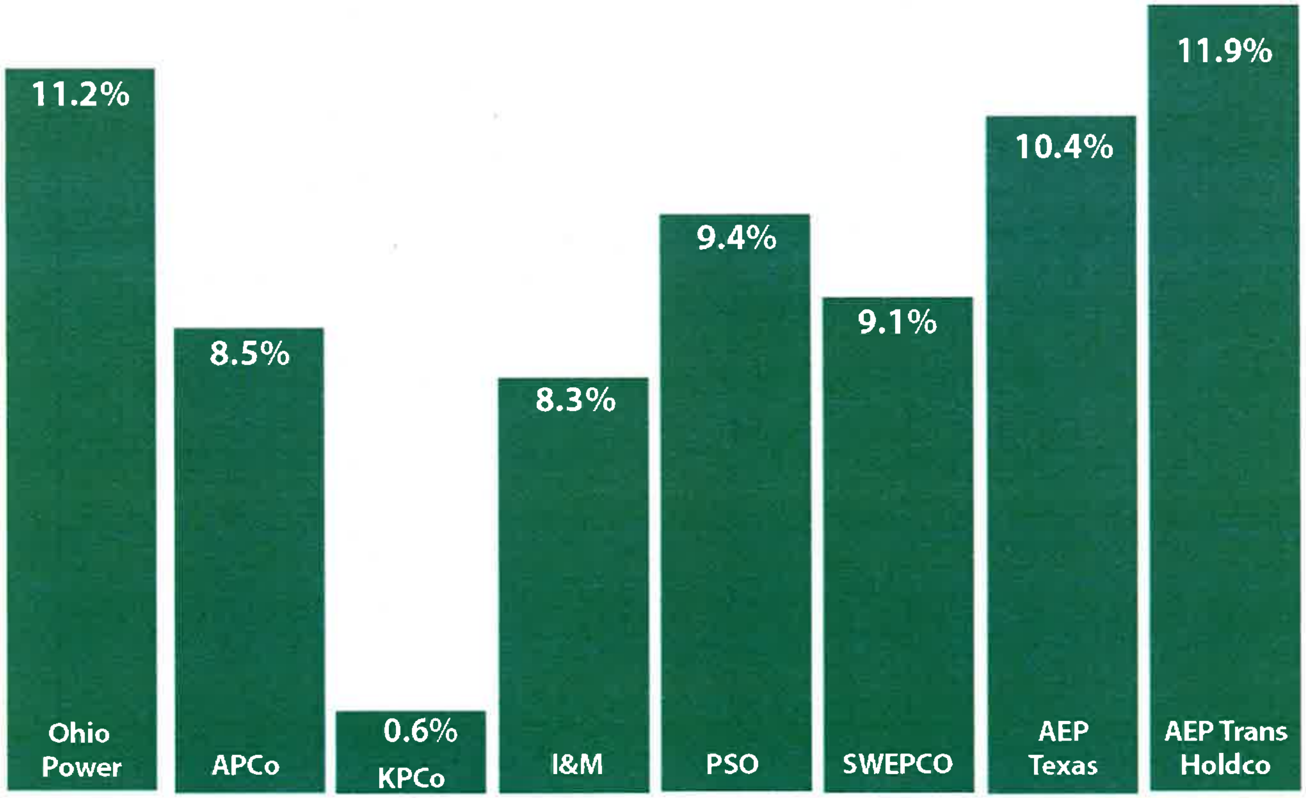
- Stabilizes retail rates in AEP Ohio's service area and protects reliability and the economy in Ohio.
- Utilize PPA recovery mechanism approved in ESP III, to include 100% of AEPGR's share of 4 plants for the remaining life of the units , along with OVEC Entitlement*.
- PPA is FERC jurisdictional, with projected initial ROE of approximately 11.2%
- Estimated rate base for AGR plants is $1.6B, with 50/50 cap structure
- Average remaining life of assets is 20 years

Procedural Schedule

- September 4th — Discovery requests to be served
- September 11th — Intervenor testimony due
- September 18th — Staff testimony due
- September 28th — Hearing commences

Regulated Returns

Twelve Months Ended 06/30/2015 Earned ROEs (Operating Earnings*)

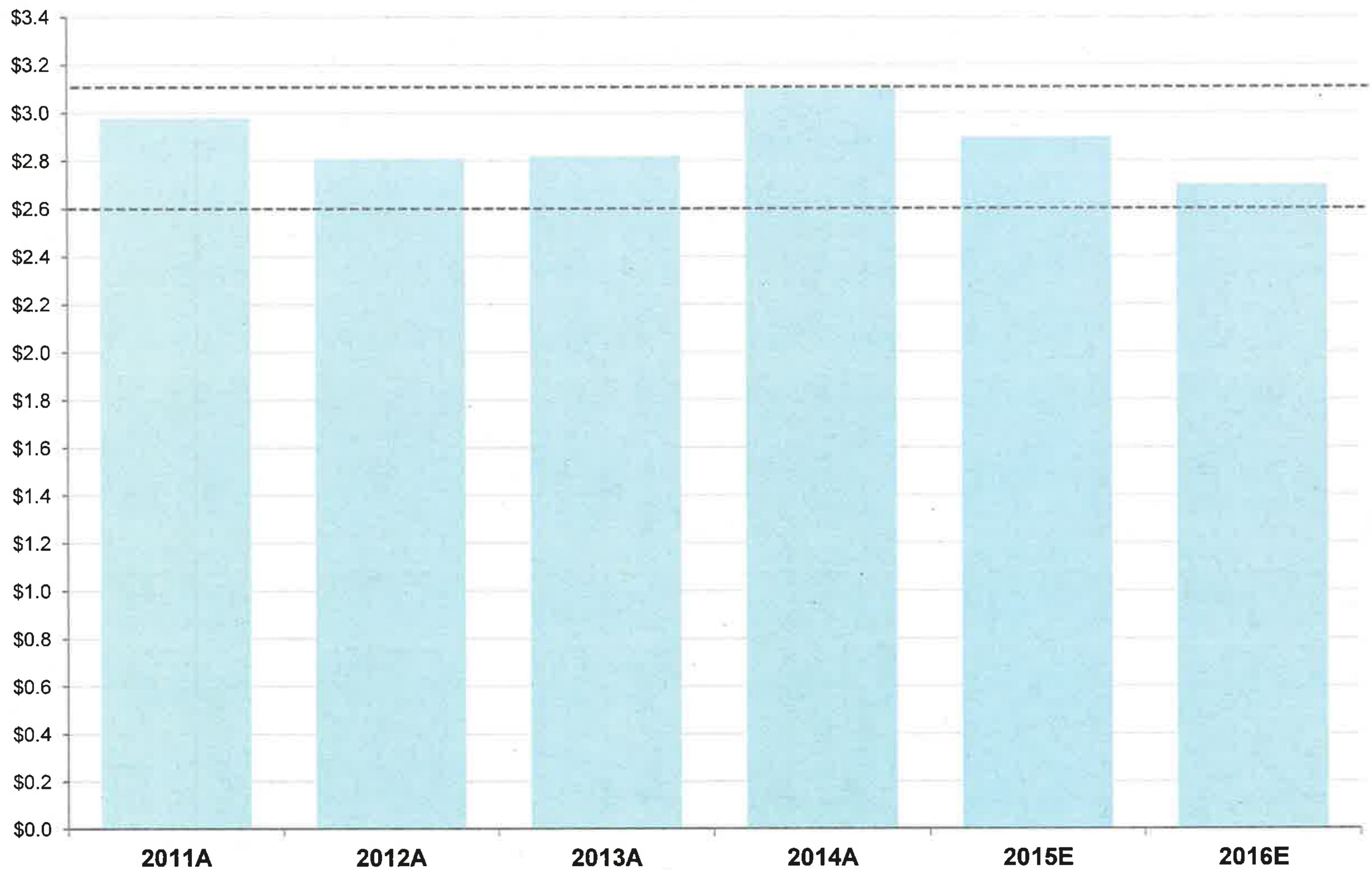


Regulated Operations ROE of 9.1%
as of June 30, 2015

** operating adjusts GAAP results by eliminating any material non operating items and is not weather normalized*

O&M Projections

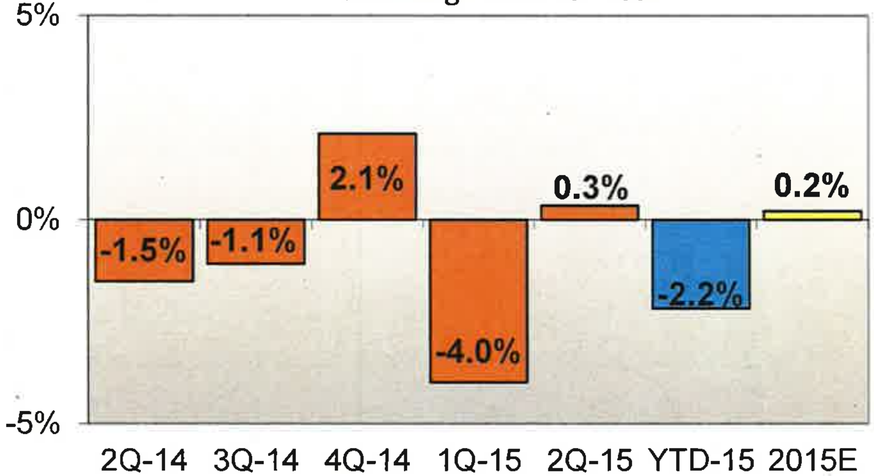
Total Annual O&M
(excluding River Operations and items recovered in riders/trackers)
$ in billions



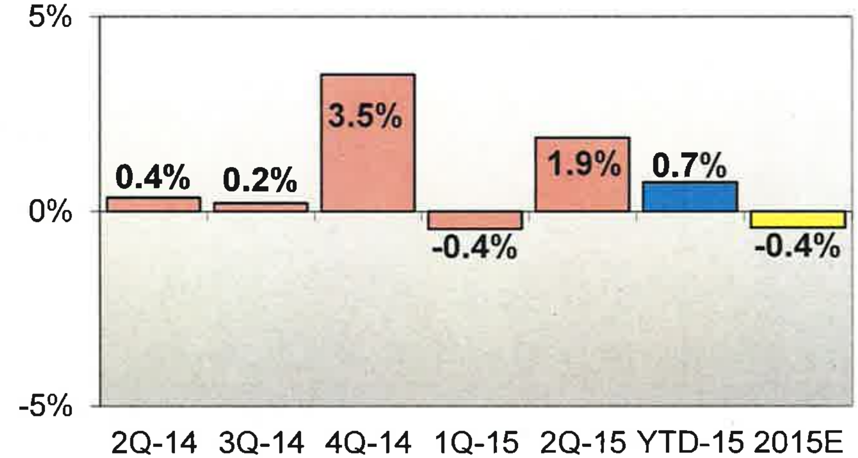
Continue O&M cost discipline through LEAN initiatives while reinvesting as needed to support our operations, customers and employees

Normalized Load Trends

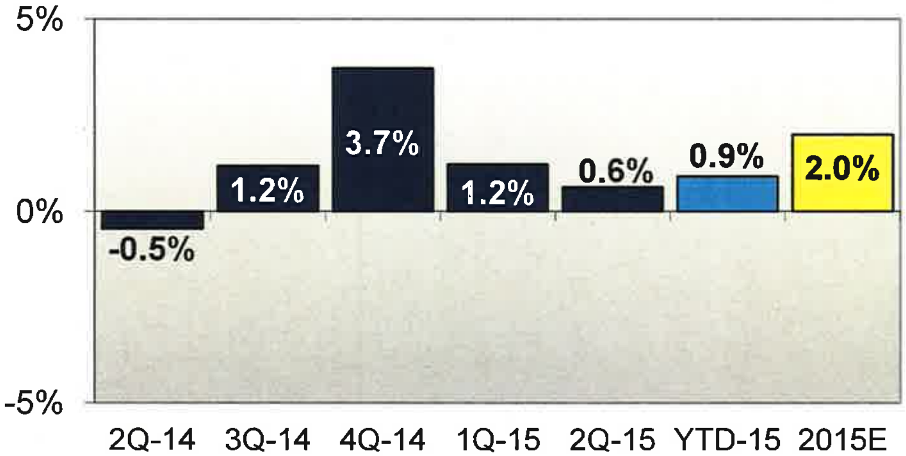
AEP Residential Normalized GWh Sales
% Change vs. Prior Year



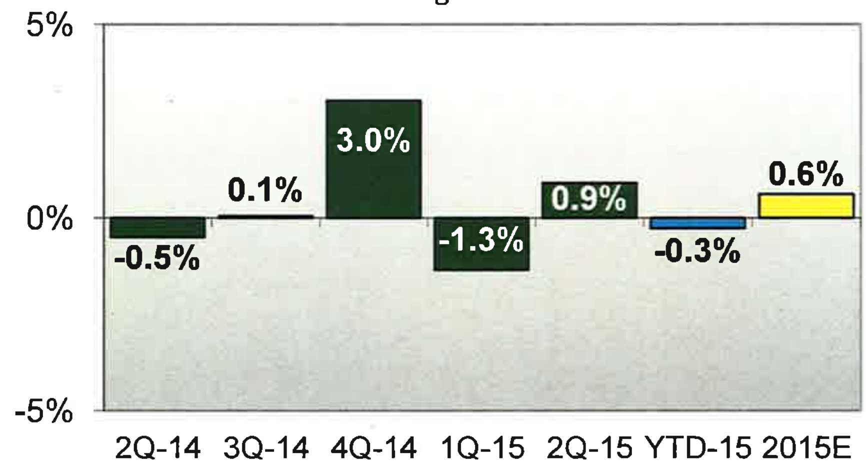
AEP Commercial Normalized GWh Sales
% Change vs. Prior Year



AEP Industrial GWh Sales
% Change vs. Prior Year



AEP Total Normalized GWh Sales
% Change vs. Prior Year

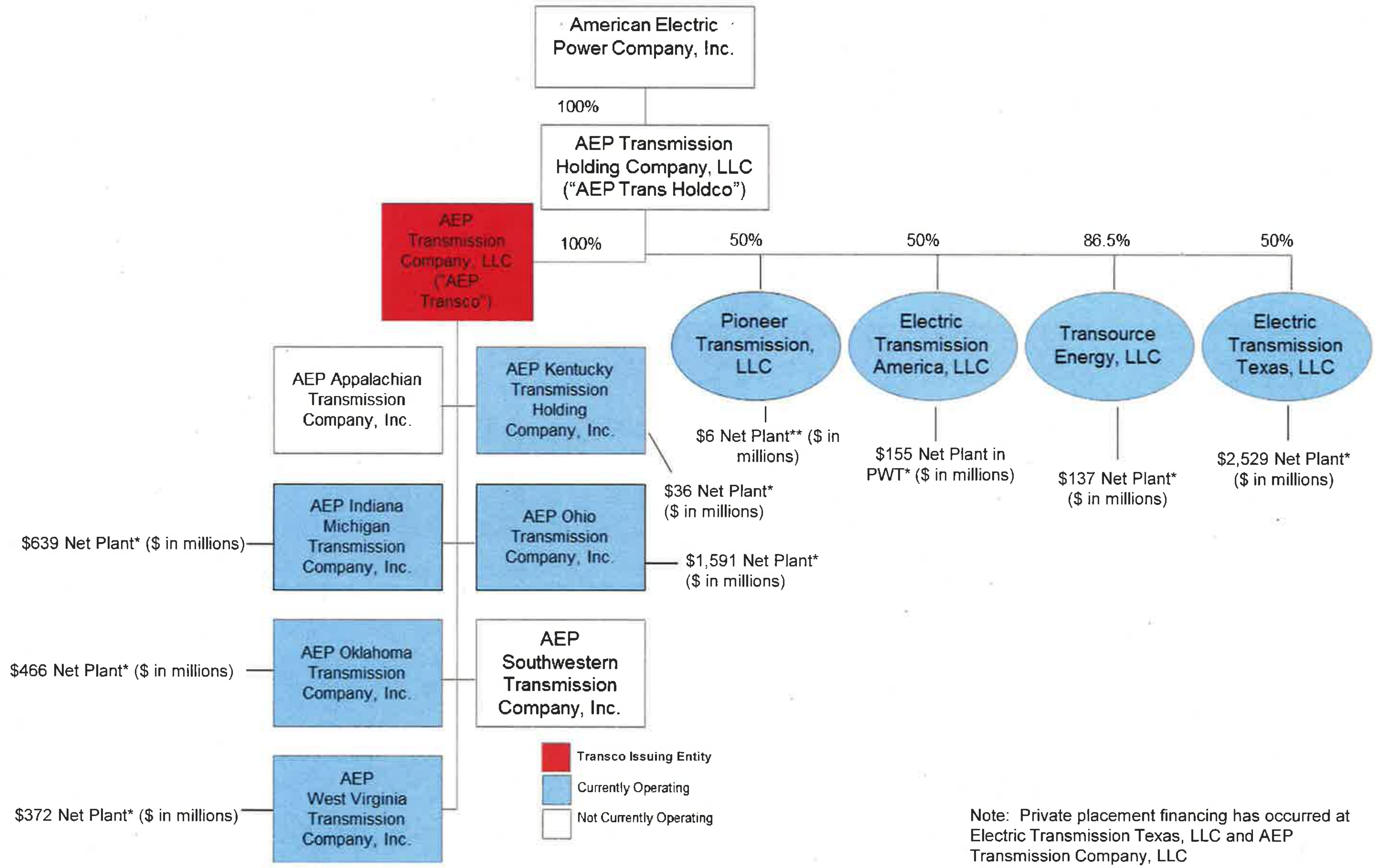


Note: Charts reflect connected load and exclude firm wholesale load & Buckeye Power backup load.

Q2-15: Positive growth in all major retail classes

TRANSMISSION GROWTH

Transmission Ownership Structure



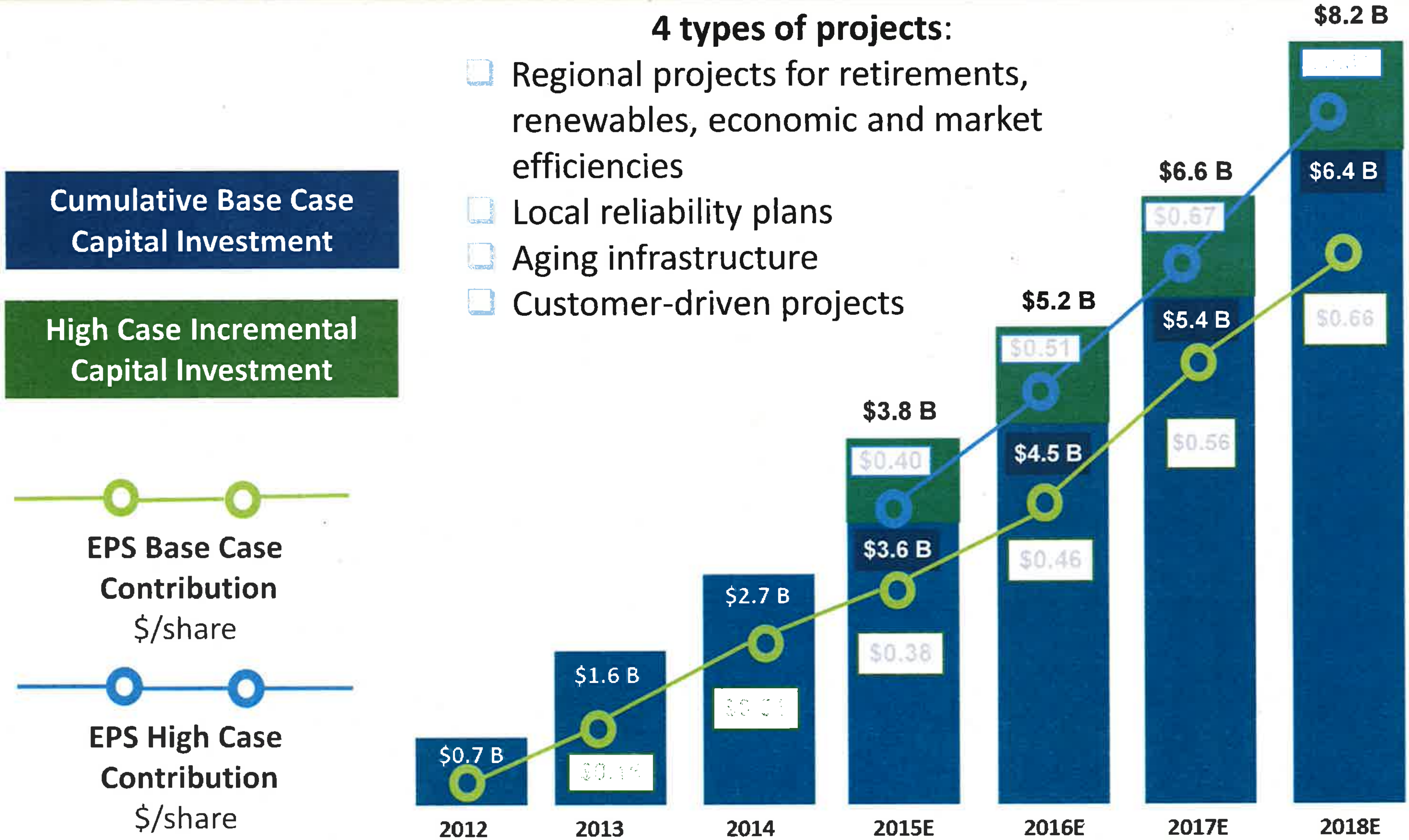
Note: Private placement financing has occurred at Electric Transmission Texas, LLC and AEP Transmission Company, LLC

* As of 6/30/2015

Transmission Holdco

4 types of projects:

- Regional projects for retirements, renewables, economic and market efficiencies
- Local reliability plans
- Aging infrastructure
- Customer-driven projects



Non-firm joint venture projects not included; high case investment is strictly related to the existing Transcos (no assumption for securing competitive opportunities); no projects included above subject to loss due to FERC Order 1000 right of first refusal

Transmission Projects/Pipeline - PJM

Aging Infrastructure

Asset Description	Transco	In-Service Date
Rebuild, replace over 500 miles of 138 kV, and below, transmission lines	MULTI	Dec-2019
Replace obsolete reactors on 8 765 kV transmission lines	MULTI	Dec-2019
Replace/upgrade key 345/138 kV transformers and increase spare complement	MULTI	Dec-2019
Replace/upgrade obsolete circuit breakers, switches and protection & control at 5 765 kV stations	MULTI	Dec-2019
Add monitoring and communications to support development of the Asset Health Center	MULTI	Dec-2019
Replace/upgrade obsolete circuit breakers, switches and protection & control at key 345 kV stations	MULTI	Dec-2019

Regional Projects

Asset Description	Transco	In-Service Date
Muskingum River - Sporn 345 kV	OH/WV	Jun-15
Kammer 345/138 kV Rebuild/Expansion	WV	Dec-15
Biers Run 345/138 kV New Station/Lines	OH	Jun-16
Baker 765/345 kV Expansion	KY	Jun-16
Sorenson 765/345 kV New Station/Lines	IN	Jun-16
Kanawha Valley Area Reinforcement Project	WV	Oct-16
Allen 345/138 kV Expansion/Lines	IN/OH	Jun-17
Wyoming 765 kV Shunt Reactors	WV	Jun-18

Local Reliability Projects

Asset Description	Transco	In-Service Date
Northern Fort Wayne 138 kV Improvements	IN	Jun-15
McClung Area Improvement Project	WV	Jun-17
Corey - Pokagon 138 kV Conversion/Rebuild	MI	Jun-17
Marietta Area 138/69 kV Upgrade (Phase 1 of 3)	OH	Jun-18
Marcellus Area Improvements	MI	Jun-18

Customer Projects

Asset Description	Transco	In-Service Date
Ball State Service Upgrades	IN	Dec-15
Shale Energy Customer Projects (Various)	OH/WV	Dec-15
West Lima Refinery	OH	Dec-15
Columbia Gas 138 kV Service	WV	Jun-16
Nottingham 138 kV New Station/Lines	OH	Jun-17

Project pipeline excludes investment related to future potential approval of VA Transco or any Order 1000 projects

Transmission Projects/Pipeline – SPP & ERCOT

Customer Projects

Asset Description	Transco/JV	In-Service Date
Grady POD/Phase 2	OK	Dec-2015
Foraker POD	OK	May-2015
Talawanda POD	OK	Jun-2016
Darlington II POD	OK	Jun-2016
Wildhorse POD	OK	Jun-2016
Prairie Chicken POD	OK	Jun-2016
Roosevelt POD	OK	Jun-2016

Local Reliability Projects

Asset Description	Transco/JV	In-Service Date
Barney Davis to Naval Base 138 kV	ETT	Dec-2015

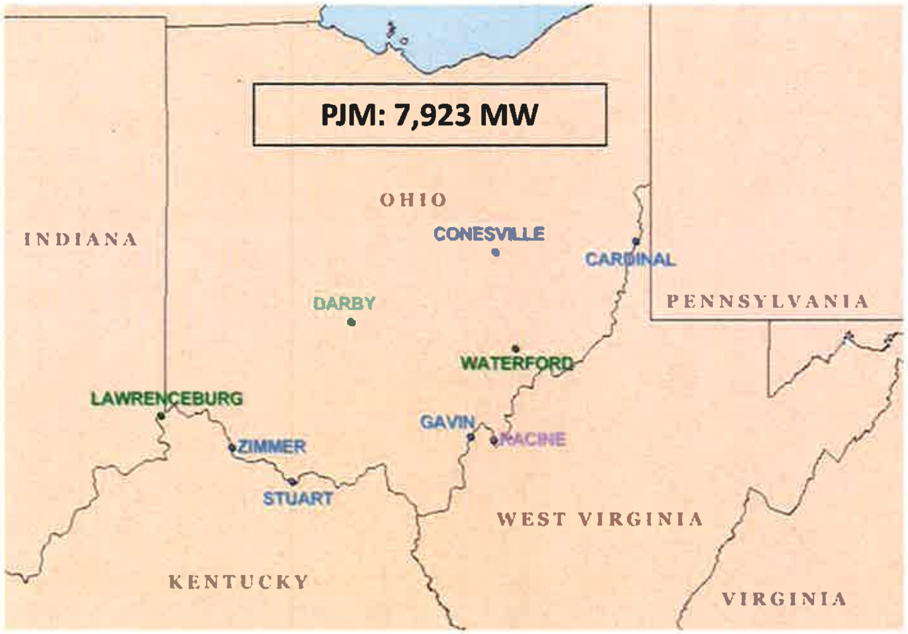
Regional Projects

Asset Description	Transco/JV	In-Service Date
Lobo to North Edinburg 345 kV	ETT	Jun-2016
North Edinburg to Loma Alta 345 kV (50%)	ETT	Jun-2016
Lobo to Molina 138 kV	ETT	May-2015
Chisholm to Gracemont 345 kV	OK	Mar-2018
Valliant to NW Texarkana 345 kV	MULTI	Jun-2015
Bluebell to Pratville 138 kV	OK	Jun-2015
Darlington to Roman Nose	OK	Jun-2016
Iatan-Nashua	Transource	2015
Sibley-Nebraska City	Transource	2017

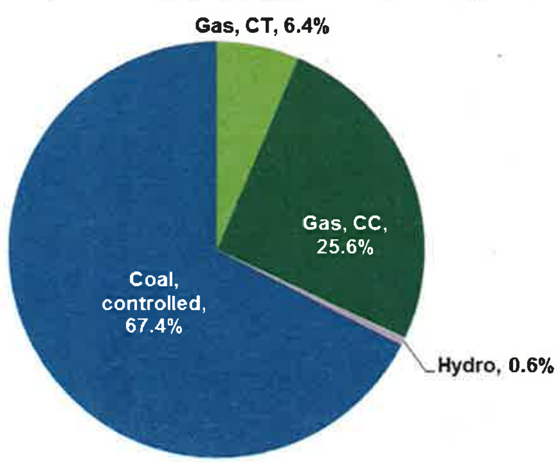
Project pipeline excludes investment related to future potential approval of SW Transco or any Order 1000 projects

COMPETITIVE OPERATIONS

AEP Generation Resources Footprint



Capacity by Fuel Type



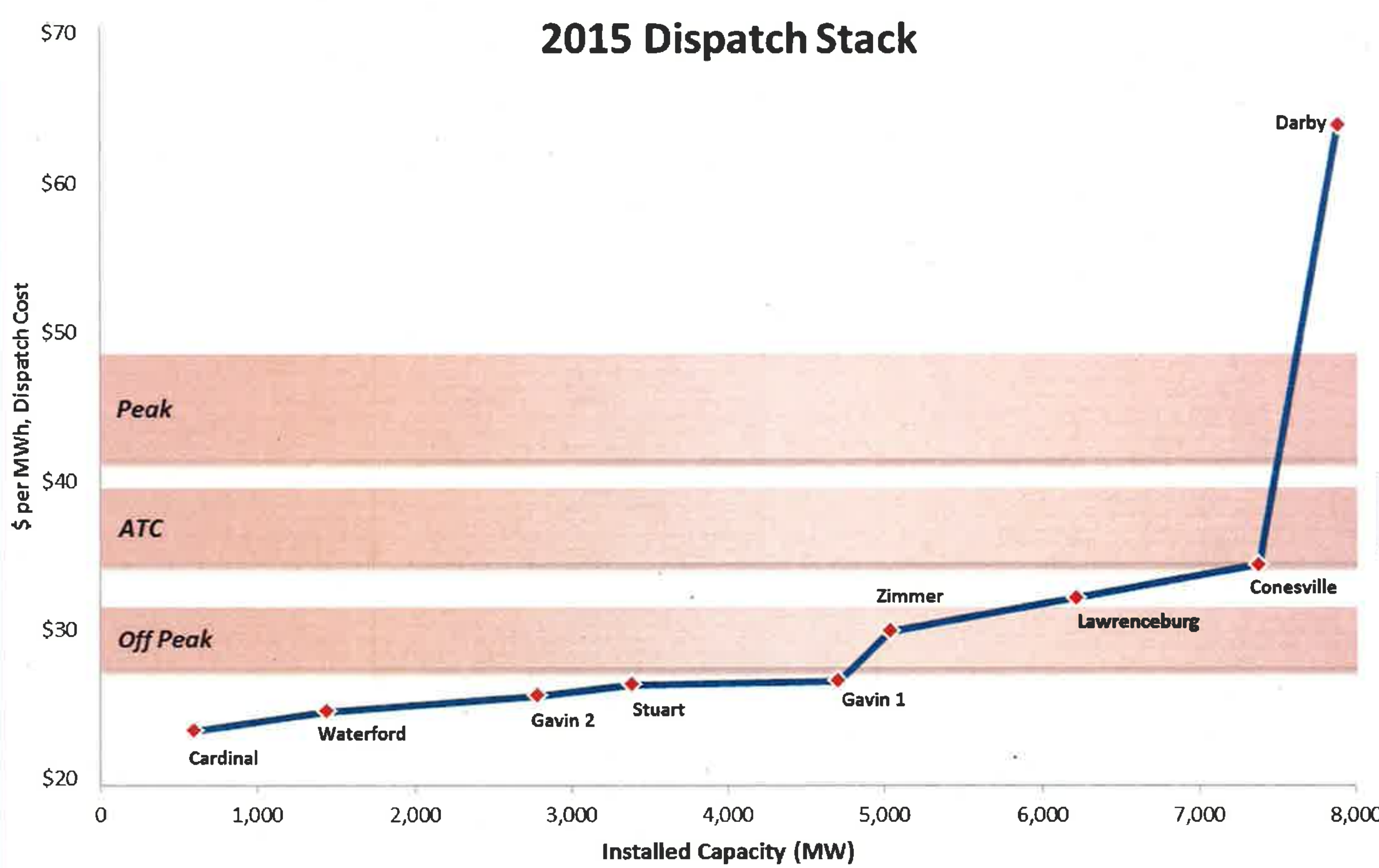
Fleet Characteristics 01/01/2015
(excludes 2,470 MW from retiring plants)

	(MW)	
Wholly-owned, AEP operated, 69% of fleet		
Gavin	2,665	Coal, controlled
Cardinal 1*	595	Coal, controlled
Conesville 5, 6*	810	Coal, FGD only
Waterford	840	Gas, CC , SCR
Darby	507	Gas, CT
Racine	48	Hydro
Joint Venture, AEP operated, 4% of fleet		
Conesville 4*	339	Coal, controlled
Joint Venture, operated by others, 12% of fleet		
Zimmer*	330	Coal, controlled
Stuart*	603	Coal, controlled
Capacity / energy entitlements, 15% of fleet		
Lawrenceburg	1,186	Gas, CC, SCR
Total	**7,923**	

* Part of the proposed PPA filed in Ohio

Note: The portfolio also includes AEP Energy Partners' assets in ERCOT consisting of the Oklaunion Coal Plant PPA (355MW), Wind Farms (311MW) and Renewable PPAs (177MW)

AEP Generation Resources: Expected Generation



Note: post-retirement view of generation stack; includes fuel, emissions and consumables costs

Generation from fleet expected to be in the range of 37-40 million MWh*

* Excludes ~2 million MWh of expected generation from retiring units

Fleet is well-positioned from a cost and operational perspective to participate in the competitive market

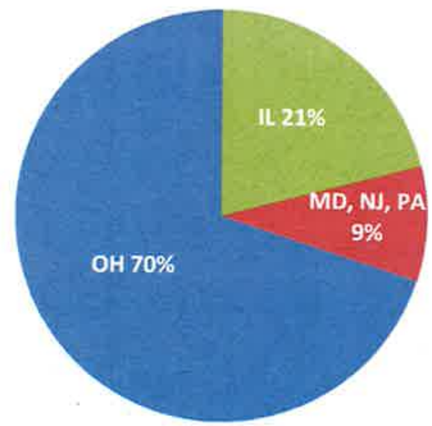
Energy Sales Opportunities

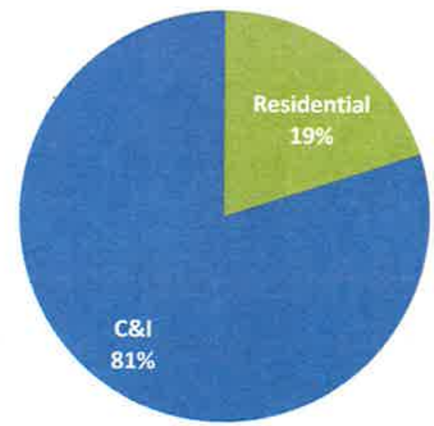
2015 Energy Sales Opportunity

Short Term	20 - 40%
Financial Instruments	20 - 40%
Wholesale Customers (Muni, Co-op, Utility Auction)	
Competitive Retail Customers	25 - 40%

AEP Energy (Retail) Profile

2014 Delivered Load





- Currently serving 260,000 customers
- Served approximately 12 TWh of load in 2014
- Provide hedging opportunities for AGR
- Customer growth in western PJM

80% of expected gross margin in 2015 is secured by energy hedges, RPM capacity, and Ohio Electric Security Plan

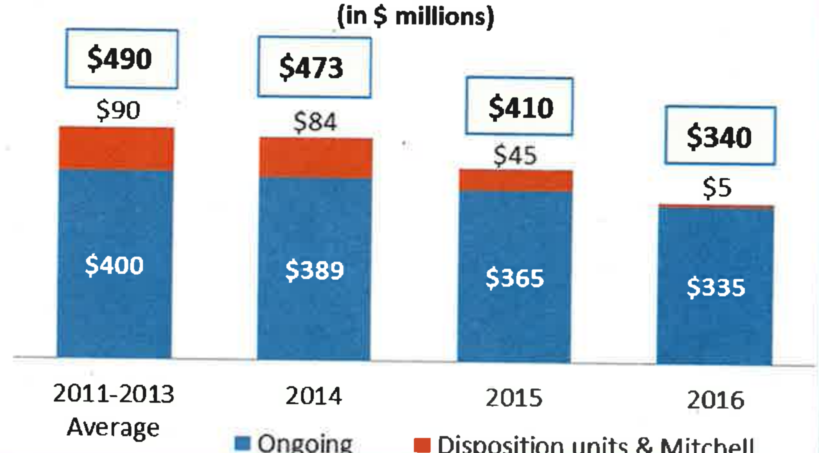
AEP Energy Supply: Earnings & Cost Management

Estimated (in $ millions)	2014A	2015 Range	2016 Range
Energy/Capacity Gross Margin	**$1,342**	**$965 - $1,035**	**$590 - $790**
Costs	473	410	340
EBITDA	**$869**	**$555 - $625**	**$250 - $450**
Capital Expenditures	150	142	146
Cash Flow*	**$719**	**$413 - $483**	**$104 - $304**

** Excludes income taxes, interest and changes in working capital*

Cost Trend

(in $ millions)



ATTACHMENT

JF-5

PJM Capacity Performance Proposal

PJM Staff Proposal

August 20, 2014

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Contents

Executive Summary - Defining Capacity Performance

Last winter's generator performance—when up to 22 percent of PJM capacity was unavailable due to cold weather-related problems—highlighted a potentially significant reliability issue. PJM's analysis shows that a comparable rate of generator outages in the winter of 2015/2016, coupled with extremely cold temperatures and expected coal retirements, would likely prevent PJM from meeting its peak load requirements.

PJM Interconnection's capacity market has been highly successful, attracting more than 35,000 megawatts of new physical generation to the system since its inception in 2007. Our capacity auctions ensure that adequate generation is committed to serve the region three years in advance of the need. The capacity market also has eased impacts from the major fuel switch that is occurring as coal generators retire and new natural gas generators replace them. However, this rapid transition is contributing to concerns about the performance of the generation fleet—particularly during extremely cold weather, like last January's.

PJM, therefore, is seeking to develop a more robust definition of Capacity Resources that provides stronger performance incentives and more operational availability and diversity during peak power system conditions. To do so, PJM is proposing to add an enhanced capacity product – Capacity Performance – to its capacity market structure and to reinforce the existing definition of the Annual Capacity product to ensure that the reliability of the grid will be maintained through the current industry fuel transition and beyond.

Capacity providers—including physical generators, demand response and energy efficiency providers—that offer and are committed to provide the Capacity Performance product will be required to meet additional eligibility qualifications and obligations designed to ensure better performance.

Under this enhanced structure, there will be four products – Capacity Performance, Annual Capacity, Extended Summer and Limited Demand Response.

Objectives

The objectives for the Capacity Performance product are to provide PJM with:

- Fuel security through a dependable fuel source
- Enhanced operational performance during peak periods
- High availability of generation resources
- Flexible unit operational parameters
- Operational diversity .

Eligibility

Under the proposal, eligible resources for Capacity Performance will be generators capable of sustained, predictable operation for 16 hours per day for three consecutive days; Annual Demand Response capable of sustained curtailment for 72 hours; and Energy Efficiency. To be eligible as a Capacity Performance resource, an officer of the generation resource's owner would have to certify that four specific requirements have been met:

- A generator must have on-site fuel (or dual-fuel backup capability) for at least 16 hours of continuous operation per day for three consecutive days at an output equal to its quantity of committed Installed Capacity.
- Generators that burn gas only must have a secured fuel supply with some combination of firm transport, firm commodity and access to storage or equivalent to provide flexible operation during peak gas-usage conditions.
- Energy efficiency plans must be determined by PJM to be complete in order to be able to offer into RPM auctions, and must demonstrate the committed level of reduction for the entirety of the Delivery Year for which they are committed.
- Annual Demand Response must be available 24 hours a day, 365 days per year, and for 72 continuous hours such that it is capable of reducing demand at least in the amount of the committed quantity for the 16 peak hours of three consecutive days.

Performance Assurance

To ensure performance, a Capacity Performance resource must deliver energy in all hours if scheduled by PJM or if self-scheduled when PJM has declared a Hot Weather or Cold Weather Alert and/or declared a Maximum Emergency Generation Alert. A resource also must offer into the Day-Ahead Market as available on a non-emergency schedule (economically for Demand Response resources). Limited exemptions would be provided only for resources not scheduled by PJM. A penalty would be applied for every hour that energy is not delivered, with a provision that failure to perform by one generator could be offset by energy produced by a non-capacity resource in the generation owner's portfolio.

High Availability and Flexibility

High availability would be defined as the capability to run for a minimum number of hours over a three consecutive day period while being offered as a non-emergency resource and with no energy limitations. Flexibility parameters would be defined for each class of resource.

Annual Capacity Product

Proposed changes to the requirements for the Annual Capacity product would eliminate many current restrictions on offers, define performance standards for peak periods and set penalties for not meeting them. They would also define rules for energy storage eligibility, and set minimum standards for environmentally limited resources.

Impact on Installed Reserve Margin

The new Capacity Performance product would not have an immediate impact on the Installed Reserve Margin calculation. This reflects the fact that the existing IRM calculations already assume higher capacity performance than is occurring, meaning that the new product should produce performance that already is factored in to the IRM calculation.

I. Introduction

The purpose of this document is to provide details regarding PJM's proposed initial solution to the issues that were described in PJM's August 1, 2014 whitepaper entitled "Problem Statement on PJM Capacity Performance Definition." PJM is proposing this initial solution to begin detailed dialogue with stakeholders on these important issues. PJM expects the solutions detailed in this paper will be adapted through the process of discussion with stakeholders.

As described in PJM's August 1 whitepaper, the issues indicate a more robust capacity product definition is required that provides enhanced performance incentives and provides more operational availability and diversity during peak conditions. Therefore, within the existing RPM structure, PJM proposes to add an enhanced product, called the Capacity Performance product, which is based on winter peak load requirements. As described below, this enhanced product includes additional eligibility requirements and obligations on resources that elect to commit in this product category. PJM also proposes enhancements and clarifications to the existing annual capacity product definition.

The overall design objectives for the Capacity Performance product are to address the concerns highlighted in the PJM whitepaper including the observed generation performance issues, winter peak operations issues and the operational characteristics of resources that are needed to ensure that system reliability will be maintained throughout the current industry transformation and beyond. The design objectives include mechanisms to incent or require the following characteristics:

- Enhanced operational performance requirement in peak periods
- Fuel security – dependable fuel source
- High availability resources
- Flexible unit operational parameters
- Operational diversity

The following sections of this document provide a detailed description of the PJM proposal. Specifically, the sections below are organized as follows:

- **Section II - Capacity Products:** The capacity products PJM proposes to be eligible to offer into Reliability Pricing Model (RPM) auctions or commit to an Fixed Resource Requirement (FRR) Capacity Plan, including a new Capacity Performance product and enhancements to the current definitions of the existing products;
- **Section III - Methodology for Establishing Maximum Product Quantities:** The analysis PJM will conduct in order to establish the required quantity of the new Capacity Performance product to be procured;
- **Section IV - Unforced Capacity (UCAP) Calculations and Installed Reserve Margin:** Description of the Unforced capacity calculation, the relationship with the new product, and the impact to the calculation of PJM's Installed Reserve Margin (IRM);

- **Section V - Capacity Performance Availability and Flexibility Requirements:** The eligibility, performance, availability and flexibility requirements for the new and existing capacity products;
- **Section VI – Changes to Base Capacity Requirements:** The changes to existing Annual Capacity requirements, which PJM proposes to rename "Base Capacity";
- **Section VII - Peak Period Performance Assurance:** The penalties PJM proposes to apply to the new and existing capacity products;
- **Section VIII - Product Offer Requirements:** The rules PJM proposes with respect to offers to provide the new Capacity Performance product in RPM auctions;
- **Section IX - Cost Allocation:** Options as to how the costs of the new Capacity Performance product could be allocated; and
- **Section X - Previously Proposed RPM Changes:** PJM's recommendations regarding the incorporation into the Capacity Performance proposal some of the other changes recently filed at FERC as part of the Replacement Capacity proposal.
- **Section XI - Transition Auction Mechanism for Delivery Years 2015/16, 2016/17, 2017/18:** Description of a transitional mechanism to address reliability requirements for Delivery Years 2015/16, 2016/17, 2017/18

II. Capacity Products

The four capacity products proposed to participate in the PJM RPM include: Capacity Performance product, Base Capacity product (which includes Annual Demand Response), Extended Summer Product, and Limited Demand Response.

Capacity Performance Product

Generation Capacity Resources, Demand Resources, and Energy Efficiency (EE) Resources may be eligible to be considered a Capacity Performance Product so long as the resource in question meets the following criteria.

1. Generation Capacity Resources are able to operate at their Capacity Performance Installed Capacity (ICAP) value for at least 16 hours per day for three consecutive days throughout the delivery year.

   In order to satisfy this criterion, it is expected that Generation Capacity Resources will have fuel on-site in the case of coal, or oil backup for gas-fired resources. In the case of gas-fired resources it is assumed appropriate transportation arrangements to ensure delivery of fuel when it is needed through any combinations of firm transportation, storage, balancing agreements, use of park and loan service, either directly or through a third party via asset management agreement. The Capacity Performance Product does not mandate how fuel availability is ensured, but rather the decisions are left up to the individual resource owner on how to best manage fuel availability risks.

Moreover, it is expected that resource owners will have made the appropriate investments in O&M and weatherization to ensure that the unit can operate as required above through extreme hot or cold weather conditions. Examples of such investments include but are not limited to ensuring stored fuel on-site does not freeze up, conveyors do not freeze, or valves and piping operate properly.

2. Generation Capacity Resources are capable of operating according the minimum flexibility requirements defined in Section V.

   Generation Capacity Resources that have long notification and start times or have inflexible operating parameters run the risk of not being available when the system needs them most and should not be eligible to be committed as the Capacity Performance product. Moreover, in order to ensure these resources are available, PJM may need to commit such inflexible resources out of economic merit order and incur operating reserve (uplift) costs to ensure the resources are available when needed. Consequently, to ensure availability at the least cost to the system, Capacity Performance resources will be required to meet minimum flexibility requirements.

3. Demand Resources (DR) that are able to achieve load reductions to their reduction ICAP value, for at least 16 hours per day for three consecutive days when called upon by PJM and must be available 24 hours per day for each day of the Delivery Year.

   Demand Resources that qualify as the Capacity Performance Product are being treated identically to Generation Capacity Resources that qualify. Effectively, DR must be capable of providing load reduction over all 16 hours of operation during any day. This requirement effectively means DR must be present summer and winter.

   The Annual DR nominated value determined using a non-summer-period Peak Load Contribution (PLC) value will not be less than that determined using a summer PLC. PJM proposes to define the non-summer-period PLC as calculated in the same manner as the current summer PLC, with the exception of utilizing the five highest coincident peak load values from the months of January and February. Alternately, Annual DR may comply as the Guaranteed Load Drop (GLD) category during the non-summer period without the requirement to reduce below the summer period PLC value.

Energy Efficiency plans that meet all current requirements in M-18, M18B, and OATT can qualify as the Capacity Performance product as long as Measurement & Verification Plan & Post-Installation Measurement & Verification Report meet an additional M&V requirement to demonstrate that the EE resource provides load reduction during winter performance hours. The demand reduction determined based on winter performance hours must be not less than the Nominated EE Value in summer EE Performance Hours. EE resources based on load reductions not realized during non-summer periods are ineligible to offer as the Capacity Performance product but will be able to clear as Extended Summer Capacity resources. Examples may include HVAC and measures that optimize building controls that impact only the summer period. Additionally, augmentation of nominated Installed Capacity (ICAP) value by use of interactive factors would not be applicable for non-summer load reductions. Interactive factors are secondary impacts of EE installations that serve to further increase the demand reduction impact of those installations during the summer months. For example, the fact that more efficient lighting that generates less heat is installed in a building may also reduce the air conditioning needs of the building and further reduce the electrical load. Such interactive factors do not apply in the winter.

4. Environmentally Limited Generation Capacity Resources and Demand Resources must be able to perform to the equivalent of at least a 10 percent capacity factor over the entire Delivery Year.

   Not all Generation Capacity Resources have unlimited run hours in a year. Many peaking units such as combustion turbines (CTs) or gas and oil steam units are subject to an air permit or regulation determined number of run hours or fuel-throughput that effectively limits operation. Historically, such limits have rarely been binding since CTs and gas and oil steam units operate at low capacity factors based on economic dispatch over the year. While such resources may be run time limited, they may otherwise be capable of meeting all the other criteria to be a Capacity Performance Product. A 10 percent capacity factor was chosen based upon the fact that historically the number of hours in a year for which Cold and Hot Weather Alerts have been called has never exceeded 876 hours.

   Demand Resources, could also face direct permit or regulatory limitations if they are based on backup generation. All DR must be capable of responding to the equivalent of at least a 10 percent capacity factor to ensure they can be available during all potential hours in which Cold and Hot Weather Alerts are in place.

5. An external Generation Capacity Resource must meet all criteria for an exemption from the Capacity Import Limits as well as the criteria that apply to Generation Capacity Resources described above to qualify as a Capacity Performance product. External Generation Capacity Resources that do not qualify for an exemption to the Capacity Import Limits may qualify as Base Capacity resources but not as Capacity Performance resources.

   The fifth criterion simply requires any resources that are physically external to the PJM footprint to effectively be electrically a part of PJM in the same way an internal resource is.

An Officer Certification will be required at the time of the Base Residual Auction or Incremental Auction for the Delivery Year in which the resource is to be committed attesting that the resource in question will satisfy the above five criteria to be a Capacity Performance product. Moreover, three months prior to the Delivery Year a second Officer Certification will be required to confirm that the committed Capacity Performance product meets the above five criteria and confirmation that all required permits allow the resource to respond to the equivalent of at least a 10 percent capacity factor over the Delivery Year.

In addition to the above Capacity Performance criteria, resources committed as the Capacity Performance Product have the following obligations:

1. Generation Capacity Performance resources must provide market-based and cost-based non-emergency energy offers into the PJM Day-Ahead Energy Market up to the committed ICAP value of the resource every day during the Delivery Year unless the resource is unavailable due to a forced or scheduled outage. Demand Response Capacity Performance resources must submit non-emergency offers into the PJM Day-Ahead Energy Market up to the committed ICAP value of the resource every day during the Delivery Year unless the resource is unavailable due to a forced or scheduled outage.

2. To the extent the resource has operational run-time limitations; it may not make itself available as emergency only but must use the Energy and Environmentally Limited Opportunity Cost to make economic offers in a way that best

allocates available run hours. Availability as emergency only will be treated for performance measurement purposes as a forced outage.

3. In the case of a Generation Capacity Performance resource, the ability to deliver energy to load on the PJM system at all times, especially during system peak and emergency conditions, as demonstrated through a generation deliverability analysis.

4. Provide energy output or load reductions to PJM if needed to maintain reliable operations during emergency conditions, which include PJM recall rights for off-system energy sales for committed resources.

5. Avoiding scheduled outages during specified peak load periods and providing outage data to PJM.

Capacity resources that satisfy the Capacity Performance product performance criteria are eligible to offer into the RPM auctions and be committed as a Capacity Performance product and receive the Capacity Performance product resource clearing price.

Base Capacity Product

Capacity resources that satisfy the current Annual resource product requirements as defined in the PJM Tariff and Manuals would generally qualify as Base Capacity with the proposed enhancements discussed below. Base Capacity products may include generation, Annual DR and EE resources.

Generation

Generation meeting the RPM eligibility requirements as defined in the PJM Tariff and Manuals but not meeting those of the Capacity Performance product above would qualify as Base Capacity.

Annual Demand Resources

Annual DR is available for an unlimited number of interruptions during the Delivery Year, and must be capable of maintaining each such interruption for at least a 10-hour duration between the hours of 10:00 a.m.to 10:00 p.m. Eastern Prevailing Time for the months of June through October and the following May, and 6:00 a.m. through 9:00 p.m. Eastern Prevailing Time for the months of November through April unless there is PJM approved maintenance outage during October through April.

PJM proposes to enhance the current definition of the Annual DR product such that the Annual DR nominated value determined using a non-summer-period PLC value (determined as described above) must not be less than that determined using a summer PLC. Alternately, Annual DR may comply as the Guaranteed Load Drop category during the non-summer period independent of the summer period PLC value.

Energy Efficiency

An EE Resource 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, and meets the requirements of Schedule 6 (section M) of the Reliability Assurance Agreement. The EE Resource must achieve a permanent, continuous reduction in electric energy consumption at the End Use Customer's retail site (during the defined EE Performance Hours[1]) that is not reflected in the peak load forecast used for the Base Residual Auction 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.

The demand reduction at winter peak load forecast must not be less than the Nominated EE Value in summer EE Performance Hours for EE to qualify as the Base Capacity product. EE for which the demand reduction in the winter is less than the Nominated EE Value in summer EE Performance Hours may qualify as Extended Summer product.

Extended Summer Product

Extended Summer DR is available for an unlimited number of interruptions during an extended summer period of June through October and the following May, and will be capable of maintaining each such interruption for at least a 10-hour duration between the hours of 10:00 a.m. to 10:00 p.m. Eastern Prevailing Time.

PJM proposes that EE resources based on load reductions not realized during non-summer periods will be treated as Extended Summer product. Examples may include HVAC and measures that optimize building controls that impact only the summer period.

Limited DR

Limited DR is available for interruption at least 10 times during the summer period of June through September in the Delivery Year, and will be capable of maintaining each such interruption for at least a 6-hour duration. At a minimum, the Limited Demand Resource shall be available for such interruptions on weekdays, other than North American Electric Reliability Corporation (NERC) holidays, from 12:00 p.m. (noon) to 8:00 p.m. Eastern Prevailing Time.

[1] The EE Performance Hours are between the hour ending 15:00 Eastern Prevailing Time (EPT) and the hour ending 18:00 EPT during all days from June 1 through August 31, inclusive, of such Delivery Year, that is not a weekend or federal holiday.

Summary of Capacity Products

Category	Availability Expectations	Limitations	Penalties	Penalty Window
Capacity Performance	All hours of the year	none	Real-Time LMP Charge	Year Round – Hot Weather Alert / Cold Weather Alert / Max Emergency Alerts
Base Capacity	All hours of the year	none	Real-Time LMP Charge for generators / Current DR Penalties for DR	For Generators – Max Emergency Generation Loaded in summer or winter; Current rules for DR
Summer Extended DR	May through October	10 hours per day	Current DR Penalties	Summer - DR activations
Limited DR	June through September	10 x 6	Current DR Penalties	Summer - DR activations

Storage Resources

Storage resources, including pumped storage hydro plants, battery resources, flywheels, etc. can qualify as the Capacity Performance product only if they are able to deploy technology to allow them to meet the requirements for the product, i.e. must be able to produce energy at rated capacity output continuously for periods of at least 16 hours on three consecutive days. With respect to qualification as the Base Capacity product, PJM proposes that storage resources qualify to provide that amount of Installed Capacity for which they can provide energy for ten continuous hours. For example, if a given storage resource has the ability to produce a peak energy output of 10 MW; it would qualify to provide 10 MW of Base Capacity only if it had the ability to produce 100 MWh of energy without the need to recharge. If the same resource could only produce 75 MWh of energy without recharging, then the resource would be able to qualify to provide 75 MWh divided by 10 hours, or 7.5 MW of Installed Capacity.

PJM recognizes that storage resources can provide flexibility to the system. However, the purpose of RPM is to ensure that sufficient aggregate quantities of resources are available to PJM to efficiently meet the peak demand requirements of the system on a year-round basis. If storage resources could be dispatched with perfect foresight in actual operations such that they are operated in an optimal manner, then there could be a basis for qualifying storage resources to provide a greater level of capacity than for which they would otherwise qualify under the above calculation on the basis that they can follow the load shape or otherwise be dispatched for optimal benefit. However, this assumption is not realistic, nor does it necessarily reflect what occurs in actual operations. These storage resource units can be self-scheduled by the owners or may be operated under direction by PJM in a manner that does not follow the load shape if necessary due to the system conditions materializing on any given peak day.

Qualifying Transmission Upgrades (QTUs)

PJM proposes that Qualifying Transmission Upgrades (QTU) can offer into the RPM auctions only as the Capacity Performance product. The reasoning behind this proposal is that the MW quantity of capacity provided by a Qualifying Transmission Upgrade is based directly upon the increase in the Capacity Emergency Transfer Limit (CETL) into a

Locational Deliverability Area (LDA). Such a CETL increase can only be implemented such that it impacts the Capacity Performance requirement for the LDA in question but at the same time reduces the Base Capacity and more limited capacity requirements , as described in more detail below. Therefore, the only way to incorporate Qualifying Transmission Upgrades is to offer them as the Capacity Performance product.

Resource Coupling

A Demand Resource with the potential to qualify as two or more RPM product types may submit separate but coupled Sell Offers for each product type for which it qualifies at different sell offer prices and the auction clearing algorithm will select the Sell Offer that yields the least-cost solution. Separate resources will be modeled in the eRPM system for each product type. Under the current RPM rules, for coupled Demand Response Sell Offers, the offer price of the Annual Demand Resource offer must be at least $0.01/MW-day greater than the offer price of the coupled Extended Summer Resource offer, and the offer price of an Extended Summer Resource must be at least $0.01/MW-day greater than the offer price of the coupled Limited Demand Resource offer. PJM proposes to extend the concept of coupled offers to the proposed new Capacity Performance and Base Capacity products as well, such that a single resource could offer to be committed as either the Capacity Performance or Base Capacity product depending on the resulting clearing prices for each product. Under this proposal, the offer price of the Capacity Performance product resource would need to be at least $0.01/MW-day greater than the offer price of the coupled Base Capacity offer.

Limited Resource, Sub-Annual Resource and Base Capacity Resource Constraints

In the current RPM Auction clearing algorithm, the greater reliability value associated with the less limited demand resources and Annual Capacity Resources are recognized by establishing and enforcing a maximum quantity on the commitment of more limited products. The Limited Resource Constraints set the maximum level of Limited Resources to be procured in RPM Auctions for the Delivery Year. The Sub-Annual Resource Constraints set the maximum level of Limited Demand Resources and Extended Summer Resources to be procured in RPM Auctions for the Delivery Year.

PJM proposes to continue to set Limited Resource Constraints and Sub-Annual Resource Constraints for each RPM auction, and also add Base Capacity Resource Constraints for the RTO and each modeled LDA. The process by which PJM proposes to establish these maximum quantities is described in Section III of this document. The auction clearing process can select more expensive Capacity Performance products, Base Capacity Resources or Extended Summer in lieu of more limited products with lesser priced offers, if necessary, to enforce Base Capacity Resource Constraints, Sub-Annual Resource Constraints or Limited Resource Constraints. In those cases where one or more of the resource constraints bind in the auction solution, Limited Demand Resources and/or Extended Summer Resources and/or Base Capacity Resources selected will receive a decrement to the system marginal price of capacity (in addition to any locational price adder(s) received to resolve locational constraints).

For the RTO, the Limited Resource Constraint is equal to the Limited Demand Resource Reliability Target for the RTO in Unforced Capacity minus the Short-term Resource Procurement Target for the RTO. For an LDA, the Limited Resource Constraint is equal to the Limited Demand Resource Reliability Requirement for the LDA in Unforced Capacity minus the Short-term Resource Procurement Target for the LDA. The Limited Demand Resource Reliability Target for the PJM Region or an LDA is the maximum amount of Limited Demand Resources in Unforced Capacity determined by PJM to be consistent with the maintenance of reliability as more fully described in the PJM Manual for Reserve Requirements (M-20).

For the RTO, the Sub-Annual Resource Constraint is the equal to the Sub-Annual Resource Reliability Target for the RTO in unforced capacity minus the Short-term Resource Procurement Target for the RTO. For an LDA, the Sub-Annual Resource Constraint is equal to the Sub-Annual Resource Reliability Target for the LDA in unforced capacity minus the Short-term Resource Procurement Target for the LDA. The Sub-Annual Reliability Target (formerly known as the Extended Summer Reliability Target) for the PJM Region or an LDA is the maximum amount of the combination of Extended Summer Resources and Limited Demand Resources in Unforced Capacity determined by PJM to be consistent with the maintenance of reliability as more fully described in the PJM Manual for Reserve Requirements (M-20).

For the RTO, the Base Capacity Resource Constraint is the equal to the Base Capacity Resource Reliability Target for the RTO in Unforced Capacity minus the Short-term Resource Procurement Target for the RTO. For an LDA, the Base Capacity Resource Constraint is equal to the Base Capacity Resource Reliability Target for the LDA in Unforced Capacity minus the Short-term Resource Procurement Target for the LDA. The Base Capacity Reliability Target for the PJM Region or an LDA is the maximum amount of the combination of Base Capacity Resources (including Annual DR), Extended Summer Resources and Limited Demand Resources in Unforced Capacity determined by PJM to be consistent with the maintenance of reliability.

Auction Clearing Mechanism

The Auction clearing software is an optimization algorithm. This algorithm has the objective of minimizing capacity procurement costs given the supply offers, Variable Resource Requirement Curve(s), Locational Constraints, Base Capacity Resource Constraints, Sub-Annual Resource Constraints and Limited Resource Constraints.

The Base Residual Auction (BRA) resource clearing price for each LDA is determined by the optimization algorithm. As more fully described in Section III of this document, PJM proposes to enhance the methodology by which the Sub-Annual Resource Constraint is both established and incorporated into the RPM auctions. Specifically, PJM proposes to more completely recognize the interactions between the commitments of the two limited resources on the resulting Loss of Load Expectation (LOLE). As the commitment of Limited Demand Response increases, the maximum value of Extended Summer resources that maintains the same LOLE decreases. Similarly, as the commitment of Extended Summer resources increases, the maximum value of Limited resources that maintains the same LOLE decreases. In order to more completely capture this interaction, PJM proposes to fix the maximum quantity of Base Capacity resources that can be procured in RPM auctions, but allow the optimization algorithm to select the most optimal set of Limited and Extended Summer resources given the total Sub-Annual Resource Constraint, the interaction between the procured quantities, and the submitted offers.

The Resource Clearing Price within each LDA is the sum of:

- The marginal value of system capacity;
- Base Capacity Resource Price Decrement, if any;
- Sub-Annual Resource Price Decrement, if any;

- Limited Demand Response Price Decrement, if any; and
- Locational Price Adder(s), if any, relevant to such LDA.

The marginal value of system capacity is the clearing price for the Capacity Performance product resources in the unconstrained area of the PJM region.

The Resource Clearing Price within an external source zone is the sum of:

- The marginal value of system capacity; and
- Locational price decrement(s), if any, relevant to the external source zone.

A locational price decrement is applicable when a region-wide Capacity Import Limit or Capacity Import Limit for an external source zone is binding.

In the event that the Sell Offers forming the supply curve do not result in an intersection with the Variable Resource Requirement Curve, the marginal value of system capacity will be set along the Variable Resource Requirement Curve by extending the supply curve vertically from its end point until it intersects the Variable Resource Requirement Curve.

III. Methodology for Establishing Maximum Product Quantities

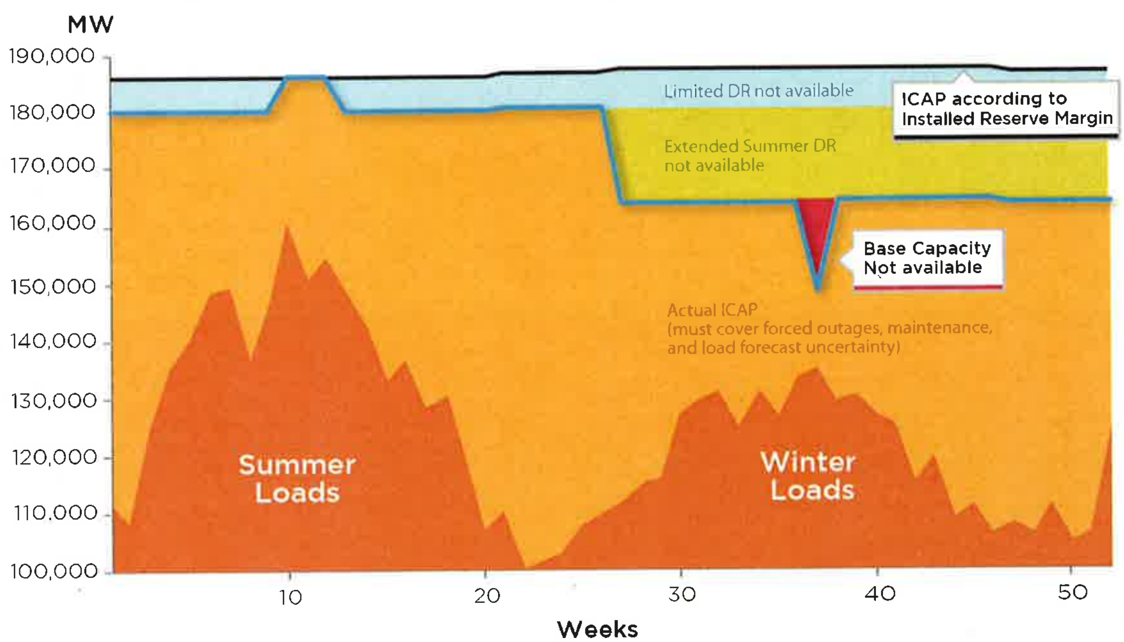
PJM proposes that all capacity products other than the Capacity Performance product be subjected to a restriction on the maximum quantity of the product that can clear in the RPM auctions. The rationale for setting this restriction is the limitation in the availability of these products in comparison with the Capacity Performance product. Since the calculation of the reliability requirement (to be procured in the RPM auctions) assumes that all resources are available on an annual basis (as is the Capacity Performance product), it is necessary to establish the maximum amount of the non-annual products that can be procured while being consistent with the reliability requirement.

In the past, PJM has set a similar maximum quantity restriction for the Extended Summer and Limited DR products. In particular, the maximum quantity allowed for the Extended Summer product has been calculated by determining the amount of annual capacity resources that can be displaced by the Extended Summer product until there is a 10 percent increase in the Loss of Load Expectation (LOLE) for the RTO (the restriction also applies to LDAs that are modeled separately in an RPM auction). This method, as it is currently applied, does not take into consideration that the Limited DR product can also displace annual resources, further increasing the LOLE risk. In other words, PJM's current procedures do not assess the combined LOLE impact of products with availability limitations[2].

[2] PJM has implemented the Extended Summer maximum quantity restriction in RPM by ensuring that the sum of Limited and Extended Summer products is less than or equal to the Extended Summer maximum quantity. However, this is not the same as assessing the combined LOLE impact of Limited and Extended Summer products when the sum of both is the Extended Summer maximum quantity (the impact is likely to be greater than a 10% increase in LOLE since the Limited product is less available than the Extended Summer product).

With the introduction of the new Base Capacity product, PJM is proposing to address this shortcoming and establish maximum product quantities for the Limited DR, Extended Summer and Base Capacity products based on their *combined* reliability impact. This method will calculate the amount of Capacity Performance resources that can be displaced by the sum of Limited DR, Extended Summer and Base Capacity products until there is a 10 percent increase in the LOLE. By applying such a method, PJM will allow resources with availability limitations to clear in RPM auctions only up to maximum quantities which do not significantly increase reliability risk.

The figure below illustrates the general approach that will be used to establish the maximum product quantities for the three limited products. The top black line represents the total ICAP procured in the RPM auction and is assumed to be equal to the IRM. (The black line is slightly higher in the non-summer periods to reflect the slightly higher unit ratings in the spring, fall and winter seasons.) The blue area represents the weeks during which Limited DR is unavailable, the green area the weeks during which Extended Summer DR is unavailable, and the red area the peak winter week during which some portion of the Base Capacity Product is unavailable. The remaining yellow area is the amount of actual ICAP reserves that are available each week of the Delivery Year. The purpose of the analysis is to determine the size of the blue, green and red areas such that the PJM system maintains an LOLE of 0.11 events/year (or a 10 percent increase in the target LOLE of 0.1 events/year).

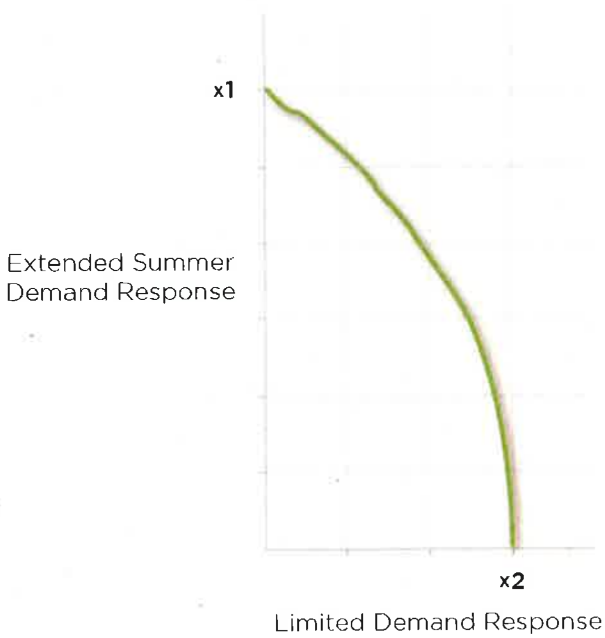


To perform the analysis, PJM will use its LOLE software, PRISM, which compares probabilistic distributions of load and available capacity on a weekly basis. The Limited DR, Extended Summer and Base Capacity products will be modeled based on their availability requirements.

Although the Limited DR product is available for interruption over the four month summer period, it is required to perform only up to ten times and for no more than six hours per interruption. Therefore, in addition to performing the above proposed methodology to compute maximum quantity restrictions, PJM will continue to compute the maximum quantity restriction for the Limited DR product based on the current 6 hour and 10 interruption performance limitation tests. The RPM auction will then use the lowest cap on the Limited DR product that is produced by the three tests. The three tests are required due to the three restrictions associated with the Limited DR product: no more than ten interruptions per year, no longer than six hours per interruption and available only from June - September.

PJM will first compute the maximum quantity restriction on the Base Capacity product and its impact on reliability as measured by a percentage increase in the PJM LOLE. The difference between a 10 percent increase in LOLE and the percentage increase in LOLE attributed to the Base Capacity product alone will be allocated to the Limited DR and Extended Summer products. PJM will then compute the allowable amount of the two DR products that can clear in the RPM auction without increasing the PJM LOLE beyond this allocated percentage. This computation will produce a graph similar to the one below:

Figure 1: Limited Demand Response and Extended Summer Product Cap



The graph shows that, if zero Limited DR clears in the auction, the cap on the Extended Summer product would be x1. If zero Extended Summer clears in the auction, the cap on the Limited product would be x2. The curve shows the various combinations of these two products that could clear in the auction while maintaining reliability at an acceptable level. Preliminary study results indicate that the RTO cap on the aggregate amount of the Base Capacity, Limited DR and Extended Summer products will be in the 10-15 percent range (expressed as a percentage of the forecasted summer 50/50 peak load). The key to this methodology is that it would ensure that the combined impact of the Base Capacity, Limited DR and Extended Summer products does not degrade the PJM LOLE by more than 10 percent.

PJM will also compute maximum product quantities for the sub-annual products for any individual LDA that is modeled separately in an RPM auction. The methodology for this computation will be similar to the methodology described above for the RTO. A base LOLE will be established for the LDA based on an LDA reserve margin equal to the sum of the LDA's internal generation and its capacity emergency import limit under peak conditions. The LDA limits on the sub-annual products will then be computed such that the LDA's LOLE does not increase by greater than 10 percent of its base LOLE. Thus a graph such as the one above indicating the allowable amounts of the Limited and Extended Summer products will be produced for each LDA modeled separately in an RPM auction. PJM will continue to compute the LDA maximum quantity restriction for the Limited product based on the current 6 hour and 10 interruption performance limitation tests. The RPM auction will then use the lowest LDA cap on the Limited product that is produced by the three tests.

IV. Unforced Capacity (UCAP) Calculations and Installed Reserve Margin

Installed Capacity vs. Unforced Capacity and Calculation of Unforced Capacity

Generating Unit

Installed Capacity (ICAP) can be thought of as the "nameplate" capability of a generating unit. ICAP represents the summer net capability of a unit, meaning the output level the unit can dependably achieve during summer conditions. Unforced Capacity (UCAP) is the ICAP value of the unit reduced by its recent actual forced outage rate (EFORd). As an equation, UCAP is calculated as:

$$\mathrm{UCAP} = \mathrm{ICAP} * (1 - \mathrm{EFORd})$$

EFORd is based on forced outage data for the October through September period that occurs immediately prior to the Delivery Year. See M-18, Section 4.2.5.

Historically, PJM has allowed generating units to remove forced outages that were defined as Outside Management Control from the forced outage rate that determined the amount of UCAP that could be sold into RPM auctions. As part of this Capacity Performance proposal, PJM proposes that exclusion of Outside Management Control outages no longer be allowed in calculations for the purposes of RPM UCAP. The performance penalties ultimately adopted as part of this proposal will apply to generation resources regardless of the reason for a forced outage, and therefore it would be inconsistent to remove Outside Management Control outages from the EFORd calculation utilized to determine UCAP capability and therefore RPM Capacity capability.

Intermittent Generation (No Change)

EFORd is not applicable to intermittent generation such as wind and solar. UCAP value is based on average of June through August peak hour output over three calendar years. See Manual 21.

Qualifying Transmission Upgrades (no change)

UCAP value is equal to the incremental import capability certified by PJM.

Demand Resources

Prior to RPM: Active Load Management (ALM, the PJM precursor to the current Demand Response products) was modeled such that the PJM Unforced Capacity Requirement was reduced by ALM (in MWs) * ALM Factor * Forecast Pool Requirement (FPR). See the calculation below:

PJM Capacity Requirement = [Unrestricted PJM Peak Load Forecast − ALM * ALM Factor] * FPR

Forecast Pool Requirement = FPR

When ALM was treated on the demand side as a reduction to the peak load forecast, ALM had an implicit capacity value of ALM * ALM Factor * FPR because the ALM quantity reduced the PJM Capacity Requirement by a value equal to ALM*ALM Factor*FPR.

Under RPM: PJM Capacity Requirement is replaced by PJM Reliability Requirement in UCAP terms. ALM is called DR and ALM Factor is called DR Factor. DR is offered as a supply resource and is not modeled to reduce PJM Reliability Requirement. See the calculation below:

PJM Reliability Requirement = Unrestricted PJM Peak Load Forecast * FPR

Under RPM, unrestricted peak load forecast is not reduced by DR and PJM Reliability Requirement is not reduced by DR (in MWs) * DR Factor * FPR. However, UCAP value of DR as a resource is still being calculated as DR MW * DR Factor * FPR.

DR Factor is determined assuming DR MW to be constant at any load level (basically assuming Guaranteed Load Drop type of DR). The fact that DR is constant even at a load higher than the load forecast results in a DR (discount) Factor of about 95 percent. The changes made in DR compliance effective 2012/2013 Delivery Year require load to be reduced to below PLC to meet the Nominated DR Value. This means demand reduction associated with Guaranteed Load Drop type DR would be higher at loads higher than the load forecast to comply with a DR event (similar to Firm Service Level type of DR). DR (discount) Factor is not justified with this compliance requirement for Guaranteed Load Drop and for Firm Service Level type DR and DR Factor should be eliminated. PJM further proposes to also change the compliance of Direct Load Control (DLC) programs to Firm Service Level type of compliance.

Also, FPR multiplier should not be applied in calculating UCAP value of DR because the PJM Reliability Requirement is not reduced by load reduction times FPR. RPM auctions are conducted to procure the Reliability Requirement based on 100 percent peak load forecast. When DR is treated as a supply side resource like generation, there is no difference between them in operations. In an emergency, effect of starting 100 MW generation and reducing 100 MW demand are the same. Implementing 100 MW DR does not produce "100 MW times FPR" amount of demand reduction.[3]

Energy Efficiency

To ensure treatment similar to DR resources, DR Factor and FPR multiplier were used to determine the UCAP value of EE when EE was defined as a product in RPM. The reasons provided above to eliminate these factors to value DR are applicable to EE also. The DR Factor and FPR multiplier used to determine the UCAP value of EE should be eliminated.

Implications of PJM Proposal on Installed Reserve Margin (IRM)

PJM anticipates that some stakeholders may question whether strengthening the performance requirements for Capacity Resources in PJM should enable PJM to reduce the Installed Reserve Margin due to the increased level of resource performance that can be assumed in the IRM calculation. However, calculation of the IRM already assumes an average forced outage rate. As recent history has shown, the actual forced outage rate of PJM Capacity Resources can be, and actually has been, much worse than the average on peak days. Therefore, because the IRM assumes a better level of performance by Capacity Resources than has actually been observed, the current IRM calculation is expected to better align with actual operating conditions during the most stressed times of the year via the PJM proposal. Improving Capacity Resource performance during the peak periods in actual operations, which is the goal of the PJM Capacity Performance proposal, will bring the actual resource performance more in line with the assumption utilized in the IRM calculation, meaning no change to the current calculation would be required.

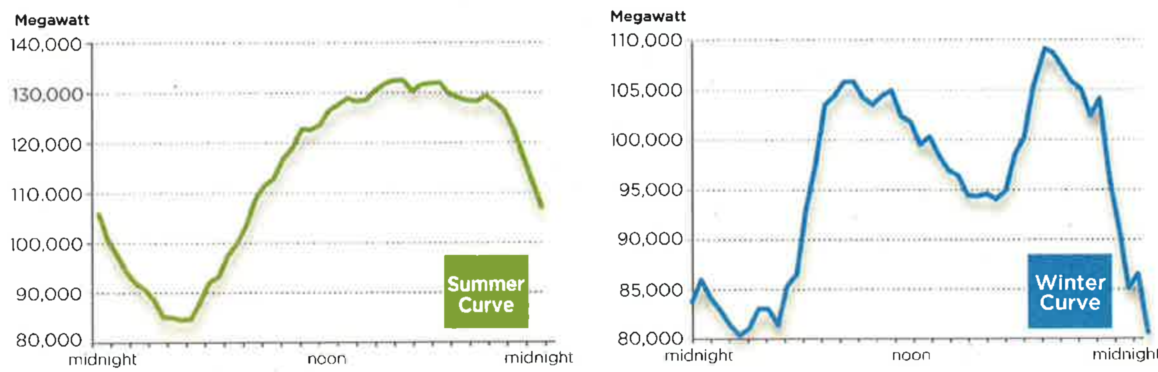
V. Capacity Performance Availability and Flexibility Requirements

General

The proposed operational requirements of committed Capacity Performance resources are described in this section. These proposed requirements are based on the operational flexibility PJM needs from supply and demand resources to most efficiently meet system needs on a peak load day. More specifically, winter peak load days pose a unique operational challenge as they have two daily peaks whereas a summer day only has one. This additional complexity is represented in the resource performance parameters and the asset classes proposed.

[3] FERC accepted a filing by ISO-NE/NEPOOL to eliminate the Reserve Margin Gross-Up for demand resources from ISO-NE market rule regarding the Forward Capacity Market (FCM) effective 2012/2013. (Order dated Dec 23, 2008; Docket No. ER09-209-000). The purpose of Reserve Margin Gross-Up has been to reflect the reserve that would not be needed if system peak load can be reduced with a perfectly available resource. Historically, vertically integrated utilities employed this approach in cost-benefit analysis of generation vs. demand–side management, but as explained above it is not applicable to RPM because DR is modeled as a supply side resource.

Figure 2: Summer vs. Winter Load Shape



Supplemental to the individual asset class requirements described in the next section, the following requirements are common to all Capacity Performance resources.

- EFORd less than 50 percent
- Must be able to operate continuously for periods of at least 16 hours on three consecutive days. This includes:
  - Generation resources with onsite fuel storage with the necessary delivery arrangements;
  - Annual DR able to fully curtail their load;
  - EE projects that achieve a consistent year-round reduction; and
  - Other resources capable of meeting the performance criteria.
- The cleared ICAP amount of the resource must be offered into the Day-Ahead Energy Market as economic excluding periods where the resource is on an outage for which a ticket was submitted and approved.
- Offer parameters submitted with a Day-Ahead Energy Market offer must be based solely on the physical limitations of the resource. This requirement applies for all schedules, regardless of whether they are price-based schedules or cost-based schedules, submitted for a given unit. PJM proposes to include in the Tariff the acceptable levels of these parameters by unit class, and also proposes to maintain the exception process such that unit operators may reflect physical conditions at individual units that may deviate from these parameters. These parameters include:
  - economic minimum
  - economic maximum
  - startup time
  - notification time
  - minimum run time
  - minimum down time
  - maximum run time

A Capacity Performance resource is expected to be staffed and ready to be operated at all times except during a planned outage. If at any point the resource's offer parameters deviate from the physical limitations of the resource it may receive a capacity penalty and will forfeit any Operating Reserves credits when operating based on non-physical parameters. (See Section VI below for additional details regarding capacity penalties.)

Flexibility Requirements

Due to the dual-peaked nature of the winter load curve, PJM values resource flexibility especially on peak winter days. The goal on a winter day is to schedule resources to meet the morning peak, either cycle them or reduce them to their minimum output during the afternoon valley, and then be able to re-start them or increase their output back up to their maximum output for the evening peak. The ability for resources to be flexible throughout an operating day is integral to efficiently dispatching the system and minimizing uplift.

There are three general classes of resources that PJM uses to manage system needs each day. The first is a base load asset class. The base load asset class would include resource types that are typically operating any time that they are not on an outage. The base load asset class includes resources such as a nuclear generation resources that cannot be operated flexibly throughout the operating day but have a high amount of run hours over the course of the year indicating that when they are available to run they are typically operating. The second class is the interday cycling asset class which consists of resources that provide the next level of flexibility but still have some restrictive parameters. These resources are defined as those that have startup and notification times that require these resources to be committed in the Day-Ahead Energy Market in enough time to meet the winter morning peak the next day and are dispatchable throughout the operating day such that PJM can reduce or increase their output as system conditions require. This interday cycling asset class also has the capability to cycle during the overnight period between contiguous days. The third asset class is the intraday cycling asset class. This class is characterized by its ability to quickly turn on and off to meet system operational needs. These resources are required to have at least two starts per day and must be able to quickly come off and re-start.

With those concepts in mind, PJM proposes the following criteria as qualification standards for committed Capacity Performance generation capacity resources.

- Base Load Asset Class
  - Resources with more than 6,000 run hours per year
  - Startup + notification time exceeds 12 hours
  - Minimum run time exceeds 18 hours
  - Minimum down time exceeds 8 hours
- Interday Cycling Asset Class
  - Startup + notification time less than or equal to 12 hours
  - Minimum run time is less than or equal to 18 hours
  - Minimum down time is less than or equal to 8 hours
  - Economic minimum is less than or equal to 50 percent of the economic maximum

- Intraday Cycling Asset Class

  - Startup + notification time less than or equal to 1 hour
  - Two or more starts per day
  - Minimum run time is less than or equal to 5 hours
  - Minimum down time is less than or equal to 2 hours
  - Economic maximum is greater than or equal to economic minimum

Energy Efficiency, Demand Resources, Storage Technologies and External Capacity may also qualify as Capacity Performance resources. The requirements for those resources are as follows:

1. Energy Efficiency

   - Full reduction must be achieved 365 days per year.

2. Demand Response

   - Must be available to achieve full reduction 365 days per year, and able to achieve full reduction continuously for at least 16 hours per day for three consecutive days
   - Shutdown + notification time less than or equal to 1 hour
   - Minimum down time less than or equal to 1 hour

3. Storage Technologies

   - Must be available to achieve full capacity output 365 days per year, and able to achieve full output continuously for at least 16 hours per day for three consecutive days
   - Startup + notification time less than or equal to 1 hour
   - Minimum down time less than or equal to 1 hour

4. External Capacity

   - External capacity resources must meet the established requirements for an exemption to the Capacity Import Limits for RPM Auctions effective with 2017/2018 Delivery Year documented in PJM Manual 18, Section 2.3 in addition to qualifying as one of the aforementioned asset classes.

VI. Changes to Base Capacity Requirements

Changes to Current Capacity to Meet Base Capacity Requirements

Flexibility

Annual capacity resources should have a startup and notification time of less than 48 hours. Units that are unable to achieve a 48 hour notice must be made unavailable and put on forced outage until they can achieve the 48 hour startup time.

Resources that are annual resources must have operational availability of a minimum of 100 run hours per year to be considered an annual resource. This minimum is regardless of any emissions or environmental limitations.

Storage Resource Eligibility

Storage resources such as pumped storage hydro plants, batteries and flywheels must be able to run for at least 10 hours per operating day at the annual capacity output but can be split into two 5 hour blocks. In addition, the unit must have a min down time of less than 3 hours between blocks. For example, a unit can come online and run for 5 hours over the morning peak at full output and then can run for 5 hours at full output for the evening peak. However, the unit must be able to do so without the need to charge in between the run hours.

VII. Peak Period Performance Assurance

Proposed Performance Requirement

PJM proposes that all units with a Capacity Performance commitment must offer into the Day-Ahead Energy Market with at least the committed quantity of ICAP available as non-emergency. In other words, a Capacity Performance committed generating unit must offer into the PJM Day-Ahead Energy Market with an economic maximum quantity at least as great as the ICAP equivalent of the committed UCAP value. Annual DR with a Capacity Performance commitment must submit an economic Day-Ahead Energy Market and Real-Time Energy Market offer in a quantity at least as great as the committed Capacity Performance MW quantity. As detailed in other sections of this paper, for generators, the parameters associated with these offers must be at least as flexible as the physical capabilities of the unit class. The expectation for the Capacity Performance product is that it will be available to provide energy at all times that resources are needed to ensure system reliability regardless of the time of year. PJM proposes that the definition of these times be all hours of those days when either a Hot Weather Alert or Cold Weather Alert is in effect, or for which PJM declares a Maximum Emergency Generation Alert, in either the entire RTO or for the portion of the PJM Region in which the resource is located.

This performance standard would require delivery of energy during all such hours if a unit was scheduled by PJM or self-scheduled to operate. The only exception from application of the penalty would be those instances when PJM did not schedule a unit, or when the unit was on line but dispatched down by PJM. The reasons PJM would dispatch a unit down could include dispatch to provide ancillary services or to control power balance or transmission constraints. It is also possible for PJM to not schedule a resource entirely because of transmission constraint, in which case the unit would not be subject to performance penalties under this proposal.

Non-Performance Penalty Calculation

The penalty calculation PJM proposes is intended to be straightforward such that it is transparent and predictable, lending itself to ready valuation by market participants and their counterparts for the purposes of developing RPM offers and financing resource development in PJM. The calculation is also based upon the ISO-NE model which has already been accepted by the FERC.

The non-performance penalty would apply for each hour when energy is scheduled as described above, and not delivered. The hourly penalty would be calculated as follows:

Hourly Energy Penalty = MW Not Delivered * Locational Marginal Price

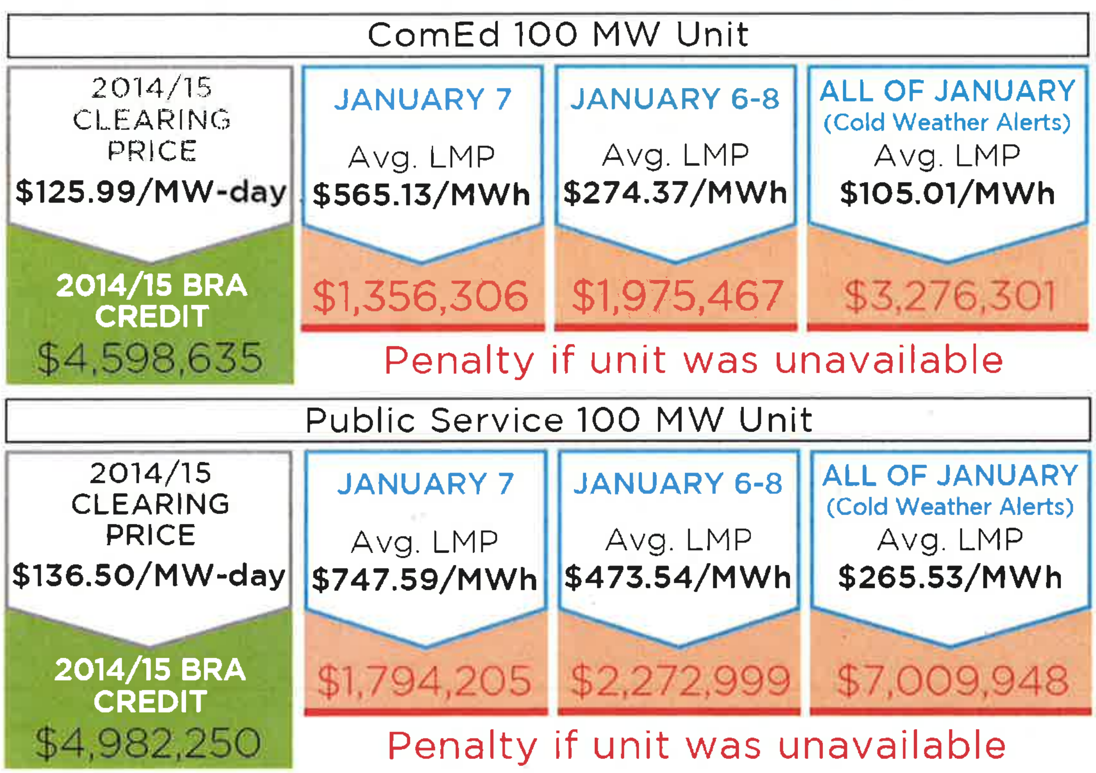
PJM proposes that the penalty apply to the lower of the quantity of MWs scheduled by PJM, or the unit's ICAP equivalent of the Capacity Performance committed UCAP value. For example, assume a unit with a 100 MW ICAP commitment is scheduled to operate by PJM and dispatched by PJM to 75 MW for a given hour. If the unit produces only 25 MW then the penalty would be the 50 MW difference between the scheduled quantity and the amount produced, times the hourly integrated LMP at the unit's bus for that hour. Assuming the same unit with the 100 MW ICAP commitment was scheduled by PJM to produce 100 MW in a given hour and the unit produced no megawatts, the penalty would be calculated as the full 100 MW Installed Capacity commitment times the hourly integrated LMP at the unit's bus for that hour.

For units that were scheduled to operate by PJM but were not on line for a particular hour and therefore did not have an economic dispatch calculated in the PJM Security Constrained Economic Dispatch (SCED) system, but were on line as scheduled by PJM for other hours of the same operating day, the scheduled quantity for any given hour will be determined by applying the hourly integrated LMP for that hour to the unit's applicable offer curve. For units that would have been scheduled to operate by PJM but were forced out for the operating day, the penalty that would apply would be for the entire 24-hour period of the day for which the Hot or Cold Weather Alert was issued. A generating unit with a Capacity Performance commitment that would have been scheduled for a given Hot or Cold Weather Alert day, and physically could have been scheduled within the timeframe necessary, but was not scheduled by PJM because its startup and notification time was longer than physically required, will incur the above performance penalty for its entire committed ICAP value for all 24 hours of the day.

PJM proposes that the penalty also apply for self-scheduled resources. For resources that are self-scheduled at a fixed output quantity, the penalty for any hour will be calculated as the committed ICAP quantity minus the unit's actual output (not less than zero MW) times the hourly integrated LMP at the unit's bus for that hour. For units that are self-scheduled at a minimum output value and then dispatchable by PJM above that value, the penalty for any given hour will be calculated the same as for units scheduled by PJM as described above.

Figure 3 below illustrates an example of how this penalty would have been calculated had it applied during January of 2014. The example supposes two 100 MW units, one in the ComEd zone in northern Illinois and one in the Public Service zone in northern New Jersey. Using the 2014/2015 RPM Base Residual Auction Resource Clearing Prices as the basis for their annual Capacity revenue, the ComEd zone unit would have received $4,598,635 in Capacity revenue for the year (the $125.99/MW-day Resource Clearing Price applicable to the ComEd zone times 100 MW times 365 days). Similarly, the Public Service zone unit would have received $4,982,250 in Capacity revenue (the $136.50/MW-day Resource Clearing Price applicable to the Public Service zone times 100 MW times 365 days). If the ComEd zone unit would have been forced out of service on the peak day, January 7, the penalty that would have applied under this proposal would have been the 24-hour average LMP of $565.13/MWh times 100 MW times 24 hours or $1,356,306. If the ComEd zone unit would have been forced out of service for the three-day period from January 6 through January 8, the penalty that would have applied under this proposal would have been the $274.37/MWh average LMP for the 72-hour period, times 100 MW times 72 hours or $1,975,467. If the ComEd zone unit would have been forced out of service for the entire month of January, the penalty that would have applied under this proposal would have been the $105.01/MWh average LMP for the days in January when Cold Weather Alerts were issued, times 100 MW times the 312 hours for the 13 days when Cold Weather Alerts were issued in the ComEd zone, or $3,276,301. In the same three sets of conditions for the 100 MW Public Service zone unit, applying the PS zone LMPs in the same manner[4], the penalties that would have been calculated under this proposal are $1,794,205, $2,272,999 and $7,009,948, respectively.

Figure 3: Example Self –Schedule Resource Penalty



[4] On January 6 and 21 the Cold Weather Alerts excluded the Mid-Atlantic region and the Dominion zone. Therefore, in the second example the Public Service zone unit's penalty was calculated based on the 48-hour period of January 7 and 8, and in the third example the 264-hour period that was the same as for the ComEd zone unit excluding January 6 and 21.

Non-Performance Penalty Offset

PJM proposes that a Capacity Market Seller may offset the penalties applied to its Capacity Resources via energy production from uncommitted units. An uncommitted unit would be defined as a unit for which all or part of the unit's capability does not have an RPM commitment for either the Capacity Performance or Base Capacity products for the Delivery Year. Energy produced by uncommitted units or portions of uncommitted units during periods when the above described penalty applies to committed units in the Generation Owner's portfolio would be used to net against those penalty amounts. The exact offset would be determined based on the product of the megawatt-hours of output from each such uncommitted unit or partially uncommitted unit and the LMP at the uncommitted unit's bus. Therefore, the penalty offset for a given Generation Owner would be the megawatt-hours of output from each unit over and above its committed Installed Capacity quantity, times the LMP at that unit's bus, summed for all such units with uncommitted megawatt. The sum of these penalty offset values would not be allowed to exceed the total penalties applied to a given Generation Owner's portfolio such that the net penalty applied cannot be less than zero.

Deficiency Penalty vs. Non-Performance Penalty

In the event that a given unit has a Capacity Performance commitment but does not achieve commercial operation by the beginning of a Delivery Year, the total penalty applied for the period until such time as commercial operation is achieved will be the greater of the Capacity Deficiency Penalty or the Non-Performance Penalty. The application of the higher of these two penalty amounts is necessary in order to ensure that resources owners do not choose to remain in a deficiency as opposed to achieving commercial operation to avoid the risk of a Non-Performance Penalty.

Capacity Performance Demand Resources and Energy Efficiency Resources

Annual DR that meets the specific qualifications, as well as EE resources that meet their specific qualifications, may offer and clear as Capacity Performance resources. Annual DR committed as Capacity Performance resources will face the same hourly energy penalty applied to Generation Capacity Performance resources. Similarly, EE resources committed as Capacity Performance resources and that either fail to achieve installation by the start of the Delivery Year or fail to achieve the required level of load reduction will be charged the hourly energy penalty applied to Capacity Performance Generation Capacity Resources for the Delivery Year.

Base Capacity Resource Penalties

PJM proposes to maintain the current penalty structure for Base Capacity Annual DR resources as well as Extended Summer and Limited DR resources. For Base Capacity generation resources, PJM proposes to apply the hourly energy penalty described above for non-delivery, but limited to those periods when PJM has loaded Maximum Generation or any more severe emergency procedure during the months of May through October. PJM proposes the elimination of the current Peak Hour Availability penalty and associated "EFORp" calculations.

Penalty Cap

PJM proposes that the total penalty applied to any individual, committed Capacity Performance resource for any Delivery Year not exceed 2.5 times the Delivery Year Resource Clearing Price credit applicable to the resource as a result of clearing in the RPM auctions applicable to that Delivery Year. Similarly, PJM proposes that the penalty applied to any individual, committed Base Capacity resource not exceed 1.5 times Resource Clearing Price credit the resource received as a result of clearing in the RPM auctions applicable to that Delivery Year. For resources acquired via bilateral transactions that did not clear in an RPM auction, the penalty caps would be based upon the RPM revenue the resource would have received had it cleared in the RPM Base Residual Auction for the applicable Delivery Year. PJM proposes these caps in order to ensure that there is some upper bound on the level of the penalty in order to allow for its valuation by prospective resources offering into RPM auctions, but maintain a maximum level of penalty that will incentivize the desired level of resource performance.

Credit Requirements

Given that PJM proposes to eliminate the current EFORp penalty and replace it with the non-performance penalties described above, PJM would propose to change the billing process by which penalties are assessed to market participants. Rather than billing penalties well after the conclusion of a Delivery Year, as is currently done given the timing of the completion of EFORp calculations, PJM would be able to begin billing penalty amounts during the Delivery Year, very shortly after non-performance actually occurred. Therefore, PJM would be able to withhold any remaining RPM revenues, and if necessary other revenues, to offset penalty charges as the Delivery Year progressed. As a result, while the potential magnitude of the penalties will increase under PJM's proposal, most significantly for Capacity Performance resources, PJM does not propose to change RPM-related credit requirements from today's levels due to the offsetting impacts of the change in the timing with which those penalties could be assessed.

VIII. Product Offer Requirements

There are three main issues with respect to offers into the capacity market: 1) The ability to reflect all costs associated with improving availability and performance during peak periods; 2) The question of must-offer requirements for the Capacity Performance product; and 3) The ability to reflect performance risk in capacity offers up to a threshold level so as to make symmetric the risk and reward for making investments to ensure performance while accounting for the fact that outages and non-performance may occur up to a certain level.

First, resource owners must be able to reflect in their capacity market offers, specifically with the Market Seller Offer Caps for Generation Capacity Resources, the costs of ensuring performance during system peaks. In general, investments and costs related to improved O&M practices are already accounted for with the Avoidable Cost Rate that goes into determining Market Seller Offer Caps under Section 6.8 of Attachment DD. Investment related to dual fuel capability and weatherization can already be accounted for within the Allowance for Project Investment Recovery, while the carrying costs associated with holding fuel inventories are accounted for in Avoidable Cost Rate. Currently the Tariff is silent on the ability to reflect the cost of firm gas pipeline transportation and other costs associated with ensuring natural gas availability and delivery which could also include storage, the cost of balancing agreements with the pipeline that allow for flexibility in takes from the pipeline, and/or park and loan services. PJM proposes to add another category into the Avoidable Cost Rate or Allowance for Project Investment Recovery to specifically account for the aforementioned pipeline services.

The ability to reflect natural gas delivery costs such as firm transportation is a necessary condition to provide the right incentives to ensure performance during system peaks. There are many different ways to secure firm delivery of gas during peaks. One is for the resource owner to directly purchase firm transportation from the pipeline. Another is to contract with a third party such as a marketer or asset manager to ensure firm commodity purchase and delivery of gas, where these costs have historically been reflected in the total gas charge on a volumetric basis. PJM is not mandating a method as to how a resource owner must ensure fuel delivery, but simply to allow these costs to be reflected in capacity market offers.

However, if a resource owner would choose to reflect the costs of firm delivery in its capacity market offer, but yet rely on a marketing or asset management agreement which states costs on a volumetric basis, those same costs should not be permitted in energy market offers as this would result in a double counting of costs. By the same token, should a resource owner choose not to reflect the costs gas delivery in the Market Seller Offer Caps and rely on volumetric recovery of costs, it would be permitted to reflect those costs in the cost-based energy market offers.

Second, there is an open question from the perspective of market power mitigation as to whether or not there should be a must offer requirement for the Capacity Performance product. If all capacity were required to satisfy the criteria for the Capacity Performance product, then the current must offer requirement would make sense. However, if there are multiple products, it is not clear how the must offer requirement should apply. At a minimum the must offer requirement to offer into the capacity market as one type of product or another should apply. But with multiple products, market incentives and competitive forces should then take over with resources offering in the product area that will result in the most surplus (clearing price minus the cost of providing the product), and assuming the design of the Capacity Performance product works as intended, there should be a sufficient incentive for most, if not all resources to offer the Capacity Performance product.

Third and finally, resource owners should have the ability to reflect performance risk, up to some threshold level, during peak periods in their offers so that there is some symmetry between risk and reward of being committed as a Capacity Performance product. To date, the Avoidable Cost Rate in Market Seller Offer Caps in the PJM capacity market includes a 10 percent adder which accounts for hard to quantify costs, which could be said to already incorporate risk along with other hard to quantify costs such as the imperfect measurement of costs in advance, or the possibility of additional costs that may be incurred from the time the capacity commitment is made to the time the capacity is delivered 3 years later.

Rather than relying entirely on the 10 percent cost adder to reflect such hard to quantify costs, resource owners should be able to reflect the risks of performance. However, in allowing such performance risk in capacity market offers, it is important to provide strong incentives for resources to make investments and incur costs to improve performance. Resource owners will only take on a commitment as a Capacity Performance product if the expected surplus from taking on that commitment (capacity price less the costs of O&M and other investments to enhance performance) is greater than the expected performance penalties to incurred if the resource does not perform at peak, where expected performance penalties are a function of the expected forced outage rate (EFORd).

So, if a resource with an EFORd of 0.25 (25 percent) were allowed to reflect the entirety of is probability of forced outage in its offer; there would be no incentive to make O&M and other investments to improve performance and reduce the EFORd because the resource would have already recovered this expected penalty from the capacity market price. If the expected penalty is completely recovered from capacity market price, the generation owner simply has an incentive to minimize costs. Consequently, performance risk should only be reflected in offers up to a target or benchmark EFORd that is assumed in the LOLE studies: the pool-wide EFORd, approximately at 0.07 (7 percent). If the pool-wide EFORd were to be used as the limit to which risk could be reflected, then resource owners in order to take on a Capacity Performance product commitment, have the incentive to incur O&M and other investments to achieve significantly better performance than PJM has historically observed during peak periods, particularly in the winter.

The proposed is a function of the pool-wide EFORd, average historic number of hours of Hot and Cold Weather Alerts, and the average Real-Time LMP the specific generation bus during those Hot and Cold Weather Alert hours:

$$\text{Risk Premium} = (\text{Pool-Wide EFORd}) * (\text{Historic Hours of Hot and Cold Weather Alerts}) * (\text{Average Real-Time LMP during Hot and Cold Weather Alerts})$$

IX. Cost Allocation

Current Methodology

Currently capacity costs are allocated to LSEs as Locational Reliability Charges. The LSE Locational Reliability Charge is calculated as the LSE Daily Unforced Capacity Obligation times the Final Zonal Capacity Price.

The LSE Daily Unforced Capacity Obligation is an allocation of the Zonal Unforced Capacity Obligation to LSEs based on the LSE Obligation Peak Loads. The Zonal Unforced Capacity Obligations are allocations of capacity procured in the RTO to zones pro rata based on zonal summer peak load forecasts. See M-18, Section 7.

The Zonal Capacity Price is calculated as the sum of (System Marginal Price + Locational Price Adder) for annual capacity, adjusted for (Limited DR and Extended Summer) product price decrements, price decrements for external capacity resources, and make-whole payments.

Cost Allocation Option 1 – Extension of Existing Method

The proposed changes to create a Capacity Performance product are primarily to assure better availability of capacity in winter. However, the concept of "critical period" penalty should assure better availability of capacity in summer also. One option to cost allocation is to use the existing method. There would not be any change in calculating the Unforced Capacity Obligations. The Zonal Capacity Price would be calculated as the sum of (System Marginal Price + Locational Price Adder) for the Capacity Performance Product, adjusted for (Limited DR, Extended Summer, and Base Capacity) product price decrements, price decrements for external capacity resources, and make-whole payments.

Cost Allocation Option 2 – Winter Peak Allocation

An alternate method would be to allocate the additional cost of the Capacity Performance product in each LDA to zones based on zonal winter peak load forecasts. A Capacity Performance product cost component would be calculated as the additional cost allocated to the zone divided by the Zonal Unforced Capacity Obligation. This Capacity Performance product cost component would be added to the Zonal Capacity Price calculated without the additional Capacity Performance product cost. The allocation of Premium Capacity cost in Option 2 can be implemented by PJM up to the zonal level.

While under this second option the additional cost of the Capacity Performance product would be allocated to zones based on the winter peak load forecast, Electric Distribution Companies (EDCs) may continue to provide PJM the current summer based Obligation Peak Loads to calculate LSE Unforced Capacity Obligations for the purpose of allocating the total zonal Locational Capacity Charges to individual LSEs. PJM would apply the Zonal Capacity Price to the LSE Unforced Capacity Obligation to determine the LSE Locational Reliability Charge based on the individual LSE PLCs as submitted by the EDCs. EDCs would have an option of modifying the Obligation Peak Load as a summation of summer peak and a fraction of winter peak. This approach would recognize the risk due to higher winter peak loads in the cost allocation.

Figure 4: Example: Assume the summer/winter risk ratio = 0.9/0.1.

Customer A — Summer PLC, 10 MW — Winter PLC, 5 MW
Effective Annual PLC
0.9*10+0.1*5 = 9.5 MW

Customer B — Summer PLC, 10 MW — Winter PLC, 10 MW
Effective Annual PLC
0.9*10+0.1*10 = 10 MW

Customer C — Summer PLC, 10 MW — Winter PLC, 15 MW
Effective Annual PLC
0.9*10+0.1*15 = 10.5 MW

X. Previously Proposed RPM Changes

In March 2014, PJM had proposed several other changes to the RPM processes, in particular related to the RPM Incremental Auctions[i]. PJM believes that enhancing the definition of the PJM Capacity product as detailed in this document will achieve the objectives of some of those previously proposed changes. PJM further believes that the remainder of those changes should be postponed until the instant proposal is implemented to evaluate its effects.

PJM had proposed to include several changes to the Incremental Auction processes considered during the Replacement Capacity stakeholder discussions. Specifically, PJM proposed to eliminate the first and second Incremental Auctions from the RPM process, to implement the Incremental Auction Settlement Adjustment, and to implement the changes to the offer price at which PJM offers excess capacity into the remaining Incremental Auction due to decreases in the load forecast.

PJM believes that given the much more explicit definition of the Capacity products provided by this proposal, as well as the more specifically delineated responsibilities of committed Capacity Resources and the more straightforward penalty structure, Capacity Market Sellers should have a much clearer picture of the capability of their resources prior to offering into the Base Residual Auction. PJM therefore suggests evaluating the remainder of the Replacement Capacity proposal items in light of the changes proposed in this document.

Other clarifications and/or revisions that PJM may need to make in order to comprehensively incorporate the new capacity product into RPM are clarifying the definition of planned versus existing resources; clean up to force majeure provisions;

Day-ahead Energy Market must offer requirement clarification regarding offering available ICAP (related to defining obligations of Capacity Resources); applicability to external resources; applicability to FRR entities; revisions to modify Qualifying Transmission Upgrades Deficiency Charge and Credit Rate; and any revisions to RPM Must Offer requirements (related to defining obligations of Capacity Resources)

XI. Transition Auction Mechanism for Delivery Years 2015/16, 2016/17, 2017/18

Based on the reliability analysis PJM has performed and reported in the Capacity Performance problem statement whitepaper posted on August 1, 2014, PJM's analysis shows that a comparable rate of generator outages in the winter of 2015/2016, coupled with extremely cold temperatures and expected coal retirements, would likely prevent PJM from meeting its peak load requirements. Therefore, PJM believes it is necessary to address fuel security, winter availability and resource performance incentives/penalties beginning in the 2015/16 Delivery Year.

In order to address the reliability shortfall caused by fuel security, winter availability limitations and performance shortfalls, PJM proposes to hold an incremental auction for the 2015/16, 2016/17 and 2017/18 Delivery Years to incrementally procure a sufficient amount of capacity that adheres to the performance standards and requirements of the Capacity Performance product described in the preceding sections of this document. The incremental auction process will establish a required amount of Capacity Performance product that must be procured and the procurement auction will provide opportunity for resources with an existing capacity commitment and resources with no capacity commitment for the applicable Delivery Year to compete to provide the required amount of Capacity Performance product for which they would receive an incremental payment.

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[i] See PJM's "Replacement Capacity" filing in docket No. ER14-1461.