2013/2014 RPM Base Residual Auction Planning Period Parameters

Introduction

The RPM Base Residual Auction (BRA) for the 2013/2014 Delivery Year is scheduled to be conducted in May of 2010. The planning period parameters to be used as input into the 2013/2014 BRA are posted on the PJM web site at http://www.pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/2013-2014-planning-period-parameters.ashx. This document describes the 2013/2014 BRA planning period parameters and also provides a comparison of the 2013/2014 BRA planning parameters to those used in the 2012/2013 BRA.

Reserve Requirement Parameters

The Installed Reserve Margin (IRM) and Forecast Pool Requirement (FPR) represent the level of capacity reserves needed to satisfy the PJM reliability criterion of a Loss of Load Expectation (LOLE) not exceeding one occurrence in ten years. The IRM and FPR represent the same level of required reserves but are expressed in different terms of capacity value. The IRM expresses the required installed capacity reserve as a percent of the forecast peak load, whereas the FPR when multiplied by forecast peak load provides the total unforced capacity required. The FPR is equal to (1 + IRM) times (1-Pool-wide Average EFORd).

The reserve requirement parameters to be used in the 2013/2014 BRA are shown in Table 1. For comparison purposes, the values of these parameters used in the 2012/2013 BRA are also shown in Table 1.

Table 1 – Reserve Requirement Parameters for 2012/2013 and 2013/2014 BRAs

Reserve Requirement Parameters	2012/2013 BRA	2013/2014 BRA	Delta
Installed Reserve Margin (IRM)	16.20%	15.30%	-0.90%
Pool Wide 5-Year Average EFORd	6.44%	6.30%	-0.14%
Forecast Pool Requirement (FPR)	1.0872	1.0804	-0.0068

PJM RTO Region Reliability Requirement

In the RPM clearing process, the PJM RTO Reliability Requirement is used to establish the target reserve level to be procured in an RPM BRA. The PJM RTO Region Reliability Requirement, valued in terms of unforced capacity (UCAP), is the RTO Peak Load Forecast, multiplied by the FPR, less the sum of the Unforced Capacity Obligations of any Fixed Resource Requirement (FRR) Entities in the PJM Region.

The PJM RTO Region Reliability Requirement and the parameters used to derive the requirement for the 2013/2014 BRA are shown in Table 2. For comparison purposes, the values of these parameters used in the 2012/2013 BRA are also shown in Table 2. As explained below, the 2013/2014 BRA values of Table 2 will be updated after the FRR election deadline of March 3, 2010 to reflect the unforced capacity obligation of load using the FRR alternative.

Table 2 – PJM RTO Reliability Requirement for 2012/2013 and 2013/2014 BRAs

PJM RTO Reliability Requirement Parameters	2012/2013 BRA	2013/2014 BRA	Delta
Preliminary Forecast Peak Load (MW)	144,857.0	160,685.0	15,828.0
Reliability Requirement (UCAP MW)	157,488.5	173,604.1	16,115.6
Preliminary FRR Obligation (UCAP MW)	23,756.1	23,563.2	-192.9
PJM RTO Reliability Requirement (UCAP MW)	**133,732.4**	**150,040.9**	**16,308.5**

The preliminary forecast peak load for the PJM RTO for the 2013/2014 Delivery Year is 160,685 MW including a peak load contribution of 13,364 MW for the ATSI Zone and 51 MW for non-zonal network load. The ATSI zone was not included in the 2012/2013 BRA. The reliability requirement for 2013/2014 prior to adjustment for FRR obligation is the forecast peak load multiplied by the FPR or 173,604.1 MW. The FRR alternative provides an LSE with the option to submit a FRR Capacity Plan to meet a fixed capacity resource requirement and avoid direct participation in RPM; therefore, the unforced capacity obligation of FRR entities is not included in the PJM RTO Reliability Requirement used in RPM auctions. The PJM RTO Reliability Requirement for 2013/2014 is 150,040.9 MW.

Locational Deliverability Areas

The process of determining the IRM needed to meet the PJM reliability criterion assumes that internal RTO transmission is adequate and that the aggregate of all capacity resources can be delivered to the aggregate of all RTO load without transmission constraints. However, the PJM planning process divides the RTO into different sub-regions called Locational Deliverability Areas (LDAs) to recognize the reality that transmission system limitations restrict the deliverability of capacity resources into these sub-regions. In RPM, a Reliability Requirement and a Variable Resource Requirement (VRR) Curve are established for each LDA that is modeled in the BRA.

Prior to each BRA, the import capability requirement called Capacity Emergency Transfer Objective (CETO) and the import capability limit called Capacity Emergency Transfer Limit (CETL) are calculated for each potential LDA. An LDA with a CETL less than 1.15 times its CETO is modeled as an LDA in the upcoming BRA. In addition, an LDA is modeled in the upcoming BRA if the

LDA had a Locational Price Adder in any one or more of the three immediately preceding Base Residual Auctions. Per the requirements in the PJM Tariff, the MAAC, EMAAC and SWMAAC LDAs are modeled in a BRA regardless of the outcome of the CETL/CETO test or prior BRA results.

Table 3 shows the CETO and CETL values of each LDA to be modeled in the 2013/2014 BRA. For comparison purposes, the CETO and CETL values used in the 2012/2013 BRA for these same LDAs are also shown in Table 3. In addition to the MAAC, EMAAC and SWMAAC LDAs, the PS, PSNORTH and PEPCO LDAs will be modeled because their CETL to CETO ratio is less than 1.15. The PEPCO LDA has not been modeled as an LDA in any previous BRA. Although the CETL to CETO ratio for the DPLSOUTH LDA is greater than 1.15, it will be modeled as an LDA in the 2013/2014 BRA because it had a Locational Price Adder in the 2012/2013 BRA.

Table 3 – CETO and CETL Values for LDAs to be Modeled in the 2013/2014 BRA

	2012/2013 BRA			2013/2014 BRA			Delta			
							CETO		CETL	
LDA	CETO (MW)	CETL (MW)	CETL/CETO Ratio	CETO (MW)	CETL (MW)	CETL/CETO Ratio	(MW)	(%)	(MW)	(%)
MAAC	5,600	6,377	1.14	4,190	4,460	1.06	-1,410	-25.2%	-1,917	-30.1%
EMAAC	7,440	9,079	1.22	7,050	7,095	1.01	-390	-5.2%	-1,984	-21.9%
SWMAAC	5,990	7,400	1.24	5,740	6,725	1.17	-250	-4.2%	-675	-9.1%
PS	6,290	6,356	1.01	5,950	5,868	0.99	-340	-5.4%	-488	-7.7%
PSNORTH	2,720	2,755	1.01	2,620	2,570	0.98	-100	-3.7%	-185	-6.7%
DPLSOUTH	1,520	1,746	1.15	1,350	2,123	1.57	-170	-11.2%	377	21.6%
PEPCO	3,770	>4,335	>1.15	4,030	4,483	1.11	260	6.9%	--	--

Note: PEPCO CETL was not explicitly calculated for 2012/2013 upon determination that CETL/CETO ratio exceeded 115% threshold.

The CETO value for each LDA is determined using a probabilistic model of the load and capacity located within the LDA. The model recognizes, among other factors, historical load variability, load forecast error, generating unit maintenance requirements and forced outage rates of generating units. The main factors driving changes in an LDA's CETO value are changes in the peak load of the LDA, changes in the level of capacity resources (including generation, demand response and energy efficiency) located within the LDA and changes in the availability factor of capacity resources located within the LDA. The CETO of an LDA will increase for increases in LDA peak load, decreases in the level of capacity resources located within the zone and decreases in the availability factor of capacity resources located within the LDA. Conversely, the CETO of an LDA will decrease for decreases in LDA peak load, increases in the level of capacity resources located within the LDA and increases in the availability factor of capacity resources located within the LDA.

As shown in Table 3, for all LDAs except for the PEPCO LDA, 2013/2014 CETO values are lower than 2012/2013 CETO values. The decrease in LDA CETO values is primarily due to an increase in the level of DR and EE resources located in each of the LDAs. While the 2013/2014 model of the PEPCO LDA included a higher level of DR and EE resources relative to the 2012/2013 model, this effect was more than offset by an increase in the forecasted unrestricted peak load and an increase in the average EFORd of generator capacity resources located in the LDA. These factors resulted in a higher 2013/2014 CETO value for the PEPCO LDA.

The CETL of an LDA is impacted by changes in transmission system topology including the addition or removal of transmission facilities and changes in the load distribution profile within a zone or region. The CETL of an LDA may also be impacted by the addition or retirement of generation facilities.

The decrease in CETL for the MAAC and SWMAAC LDAs is attributable to several factors. The most significant impact on the CETL for the MAAC and SWMAAC areas results from a change in the load distribution in the system model. Specifically, the 2013/2014 system model shows a significant increase in load in the northern Virginia area. The increase in load in this area results in higher loading of the Pleasant View 500/230 kV transformer which is the primary limit into the MAAC and SWMAAC LDA. A secondary and less significant factor is that the PPL portion of the Susquehanna-Roseland 500 kV project was not included in the system model for the 2013/2014 delivery year because it did not satisfy the project development milestones set forth in the tariff for inclusion. The entire Susquehanna-Roseland 500 kV project was included in the system model for the 2012/2013 Delivery Year. Another less significant factor is that Eddystone units 1 and 2 and Cromby units 1 and 2 were not included in the system model for the 2013/2014 delivery year due to their proposed May 31, 2011 deactivation.

The decrease in CETL for the EMAAC LDA is attributable primarily to the removal of the PPL portion of the Susquehanna-Roseland 500 kV project. Again, the PPL portion of the Susquehanna-Roseland 500 kV project was not included in the system model for the 2013/2014 delivery year because it did not satisfy the project development milestones set forth in the tariff for inclusion. The entire Susquehanna-Roseland 500 kV project was included in the system model for the 2012/2013 Delivery Year.

The decrease in CETL for the PS and PSNORTH LDAs is attributable primarily to the removal of the PPL portion of the Susquehanna-Roseland 500 kV project. Changes in the network configuration around the Cedar Grove area also contributed to the decrease in CETL for the PS and PSNORTH LDAs.

The increase in CETL for the DPLSOUTH LDA is attributable primarily to the conversion of the Vienna-Loretta-Piney Grove 138 kV circuit to 230 kV. A decrease in load in the Maryland Eastern Shore region also contributed to the increase in CETL for the DPLSOUTH LDA.

LDA Reliability Requirements

In RPM, a Reliability Requirement is established for each LDA modeled in the BRA. Table 6 shows the reliability requirement for each LDA modeled in the 2013/2014 BRA. For comparison purposes, the reliability requirements used in the 2012/2013 BRA for these same LDAs are also shown in Table 4. The changes in LDA reliability requirements are primarily driven by the change in LDA peak load.

Table 4 – Reliability Requirement for LDAs Modeled in 2013/2014 BRA

LDA	2012/2013 BRA (UCAP MW)	2013/2014 BRA (UCAP MW)	DELTA (UCAP MW)	DELTA (%)
MAAC	72,125	73,142	1,017	1.4%
EMAAC	40,145	40,398	253	0.6%
SWMAAC	17,220	17,899	679	3.9%
PS	13,439	13,401	-38	-0.3%
PSNORTH	6,324	6,347	23	0.4%
DPLSOUTH	3,035	2,996	-39	-1.3%
PEPCO	--	9,442	--	--

Note: PEPCO LDA was not modeled in 2012/2013 BRA therefore no reliability requirement was calculated.

Variable Resource Requirement Curve

A Variable Resource Requirement (VRR) curve is established for the RTO and for each constrained LDA modeled in the BRA. The VRR curve is a demand curve used in the clearing of the BRA that defines the price for a given level of capacity resource commitment relative to the applicable reliability requirement. The VRR curves for the PJM Region and each LDA are based on the following parameters:

- A target level of reserve
- Net Cost of New Entry (CONE)

Target Level of Reserves

The target level of reserves for the PJM RTO Region is the PJM RTO Region Reliability Requirement less the Short Term Resource Procurement Target (STRPT) where the STRPT is equal to 2.5% of the PJM RTO Region Reliability Requirement. The target level of reserves for each LDA is the LDA Reliability Requirement less the STRPT allocated to the LDA where the PJM RTO STRPT is allocated to zones based on the ratio of forecast zonal peak load to forecast PJM RTO peak load adjusted for any FRR load.

Net Cost of New Entry (CONE)

Table 5 shows the CONE values for the PJM RTO and each LDA to be modeled in the 2013/2014 BRA. For comparison purposes, the CONE values used in the 2012/2013 BRA are also shown in Table 5. The gross CONE for each LDA is updated each year by multiplying the values used in the previous year's BRA by the latest one-year change in the applicable Handy-Whitman Index. Using this approach, gross CONE values are 8.3% higher than the gross values used in last year's BRA. The Net CONE is determined for the RTO and for each modeled LDA by subtracting the Energy & Ancillary Services (E&AS) offset revenue from the gross CONE. The E&AS revenue offset is based on the three most recent calendar years of E&AS revenue for a reference combustion turbine. The Net CONE (in ICAP terms) is divided by (1 - Pool-wide Average EFORd) multiplied by the number of days in a year to develop the Net CONE value in $/MW-Day in UCAP terms. The Net CONE (in UCAP terms) is used in the development of the RTO VRR Curve and the VRR Curve for each modeled LDA.

Table 5 shows that Net CONE values for the 2013/2014 BRA are higher than values used in last year's BRA by 15.2% to 28.8%. This increase is due to an 8.3% increase in gross CONE values coupled with a decrease in the E&AS offset.

Table 5 – Net CONE for PJM RTO and LDAs

	2012/2013 BRA				2013/2014 BRA				DELTA	
	CONE ICAP Terms ($/MW-Year)	E&AS Offset ICAP Terms ($/MW-Year)	Net CONE ICAP Terms ($/MW-Year)	Net CONE UCAP Terms ($/MW-Day)	CONE ICAP Terms ($/MW-Year)	E&AS Offset ICAP Terms ($/MW-Year)	Net CONE ICAP Terms ($/MW-Year)	Net CONE UCAP Terms ($/MW-Day)	Net CONE UCAP Terms ($/MW-Day)	Net CONE UCAP Terms (%)
RTO	112,868	18,585	94,283	276.09	122,236	13,495	108,741	317.95	41.86	15.2%
MAAC	112,868	52,616	60,252	176.44	122,236	44,531	77,705	227.20	50.76	28.8%
EMAAC	122,040	49,474	72,566	212.50	132,169	42,885	89,284	261.06	48.56	22.9%
SWMAAC	112,868	52,616	60,252	176.44	122,236	44,531	77,705	227.20	50.76	28.8%
PS	122,040	49,474	72,566	212.50	132,169	42,885	89,284	261.06	48.56	22.9%
PS NORTH	122,040	49,474	72,566	212.50	132,169	42,885	89,284	261.06	48.56	22.9%
DPL SOUTH	122,040	49,474	72,566	212.50	132,169	42,885	89,284	261.06	48.56	22.9%
PEPCO	--	--	--	--	122,236	44,531	77,705	227.20	--	--

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Summary
The following significant changes have been observed when comparing 2013/2014 RPM BRA planning period parameters to those used in the 2012/2013 RPM BRA:

- The 2013/2014 BRA is the first BRA to include load in the ATSI Zone.

- The cost of new entry values that serve as the basis for price on the RTO and LDA demand curves increased by 15.2% (for the RTO) and by 22.9% to 28.8% (depending on LDA) over the 2012/2013 values due to an 8.3% increase in gross CONE and a decrease in E&AS revenue offsets.

- The CETL/CETO ratio for the PEPCO LDA is less than 115% therefore the PEPCO LDA will be modeled for the first time. In addition to PEPCO, the MAAC, EMAAC, SWMAAC, PS, PSNORTH and DPLSOUTH LDAs will also be modeled.

- The 2013/2014 CETL values for the MAAC and SWMAAC LDAs are lower than the 2012/2013 CETL values by 30% and 9%, respectively. The decrease in CETL for the MAAC and SWMAAC LDAs is attributable to several factors. The most significant impact on the CETL for the MAAC and SWMAAC areas results from a change in the load distribution in the system model. Specifically, the 2013/2014 system model shows a significant increase in load in the northern Virginia area. The increase in load in this area results in higher loading of the Pleasant View 500/230 kV transformer which is the primary limit into the MAAC and SWMAAC LDA.

- The 2013/2014 CETL value for the EMAAC LDA is lower than the 2012/2013 CETL value by 22%. The decrease in CETL for the EMAAC LDA is attributable primarily to the removal of the PPL portion of the Susquehanna-Roseland 500 kV project. The PPL portion of the Susquehanna-Roseland 500 kV project was not included in the system model for the 2013/2014 delivery year because it did not satisfy the project development milestones set forth in the tariff for inclusion. The entire Susquehanna-Roseland 500 kV project was included in the system model for the 2012/2013 Delivery Year.